Renewable Energy for Industry

From green energy to green materials and fuels

Cédric Philibert

INTERNATIONAL ENERGY AGENCY

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■ Secure member countries' access to reliable and ample supplies of all forms of energy; in particular, through maintaining effective emergency response capabilities in case of oil supply disruptions.

■ Promote sustainable energy policies that spur economic growth and environmental protection in a global context – particularly in terms of reducing greenhouse-gas emissions that contribute to climate change.

■ Improve transparency of international markets through collection and analysis of energy data.

■ Support global collaboration on energy technology to secure future energy supplies and mitigate their environmental impact, including through improved energy efficiency and development and deployment of low-carbon technologies.

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Executive summary

Reducing long-term greenhouse gas (GHG) emissions of the industry sector is one of the toughest challenges of the energy transition. Combustion and process emissions from cement manufacturing, iron- and steelmaking, and chemical production are particularly problematic.

This report considers a variety of current and forthcoming options to increase the uptake of renewables as one possible way to reduce industry sector energy and process carbon dioxide (CO_2) emissions.

The main finding of this report is that the recent rapid cost reductions in solar photovoltaics (PV) and wind power may enable new options for greening the industry, either directly from electricity or through the production of hydrogen (H)-rich chemicals and fuels. Simultaneously, electrification offers new flexibility options to better integrate large shares of variable renewables into power grids.

Emergence of new options for increasing the uptake of renewables in industry

The uptake of direct renewable heat in industry is often hampered by barriers that are hard to overcome, such as long distances to high-value resources (e.g. geothermal heat); lack of nearby land space (for solar heat); high costs (of appropriate biofuels); and seasonal imbalances. However, recent solar steam developments in heavy oil fields and potential in refineries are promising.

Electrification of industrial processes, if based on renewable technologies, may offer greater potential for CO_2 emissions reductions. This would entail continued electrification of energy for motion and force, still far from being completed, and electrification of heat and steam production via a series of technologies. Some technologies, such as heat pumps and mechanical vapour recompression, are particularly effective.

Moreover, renewables-based electrolysis of water can produce hydrogen-rich chemicals such as ammonia or methanol, which can be used in various industries as precursors (e.g. for nitrogen fertilisers), process agents (e.g. for low-carbon emissions steelmaking) and fuels, as well as in other end-use sectors such as buildings and transport.

In regions where resources are especially abundant, the cost of hydro, solar and wind power can fall below USD 0.03 per kilowatt hour (/kWh) and supply an electricity load with high load factors, particularly when combined. The Horn of Africa, Australia, North Africa, northern Chile, southern Peru, Patagonia and South Africa, as well as several regions in the People Republic of China (hereafter, "China") and the Midwestern United States offer the largest and highest-quality potential.

Such low electricity prices could allow hydrogen to be produced at costs competitive with natural gas reforming, oil-cracking or coal gasification – without CO_2 emissions.

The low hanging fruit seems to be ammonia, which is used mostly to manufacture nitrogen fertilisers. When ammonia is produced from green electricity, the process requires only air and water. Global CO_2 emissions associated with manufacturing nitrogen fertilisers – an estimated 420 million tonnes of carbon dioxide per year ($MtCO_2/y$) – could therefore be eliminated by producing ammonia in areas with excellent resources and shipping it to fertiliser factories and other industries.

Under the most favourable conditions, the cost of producing green ammonia would be around USD 400 per tonne of ammonia (/tNH_3), assuming an electricity price of USD 30 per megawatt hour (/MWh) if electricity is available in large enough quantities for the load factor of the electrolysers to be at least 50%. The cost under less ideal circumstances would be USD 700/tNH_3 with electricity at USD 60/MWh and an electrolyser load factor of 30%.

In comparison, natural gas-based ammonia production ranges in cost from about USD 200/tNH_3 to USD 600/tNH_3, depending when and where it is produced. The cost in the United States is currently as low as USD 200/tNH_3 owing to abundant and inexpensive shale gas, between USD 350/tNH_3 and USD 400/tNH_3 in Europe, and higher in Asian markets. It entails CO_2 emissions of 1.7 tCO_2/tNH_3.

Ammonia could be shipped from the best resource areas at a cost of USD 40/tNH_3 to USD 60/tNH_3 depending on distance and vessel size, and would thus remain competitive with ammonia produced in areas with lower-quality resources. Moreover, ammonia-based solid fertilisers or other finished or semi-finished products such as urea could be shipped at significantly lower costs. Overall, green ammonia could be more affordable than conventionally produced ammonia in some cases, or could require a carbon price of approximately USD 25, mainly to cover transportation costs.

Figure ES-1. **Cost of ammonia at various electricity prices and electrolyser load factors**
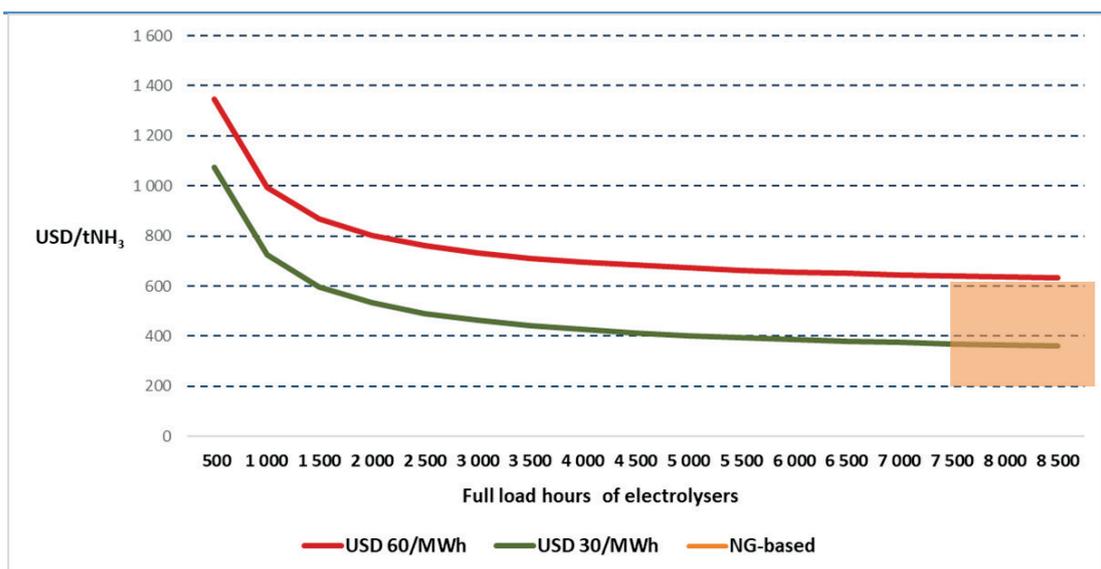
Note: Assumptions set out in Figure 12 on page 33.
Key message • **At USD 30/MWh or less, and with high capacity factors, solar and wind power in best resources areas can now run all-electric ammonia plants at competitive costs.**

Beyond current ammonia production for various industrial uses, green hydrogen could serve many other purposes to help decarbonise industry. For instance, it could serve as a precursor to manufacture methanol and other chemicals.

Green hydrogen and ammonia could also reduce CO_2 emissions associated with iron- and steelmaking: 2.3 gigatonnes of carbon dioxide per year (GtCO_2/y). Renewables-based hydrogen could be used to reduce iron ore into pig iron that would then be melted in electric arc furnaces with some scrap iron, drastically reducing CO_2 emissions in steelmaking. The Swedish steelmaking industry is currently developing this option.

Emissions associated with cement manufacturing (2.2 GtCO_2/y) could be reduced by using solar or electric heat, or by combusting hydrogen-rich synthetic fuels. The full or near-full

elimination of emissions – including process CO_2 emissions – is conceivable based on molten carbonate electrolysis of dense CO_2 fluxes, or direct electrolysis of solubilised limestone. The possible valorisation of carbon co-products such as methanol or carbon nanotubes could make emissions-free cement-making more profitable than traditional manufacturing, although these options are still only at laboratory scale.

If the new applications of solar and wind power were to be applied to current levels of production (requiring thousands of terawatt hours [TWh] of renewable electricity generation), solar and wind capacities of several terawatts would be needed. These capacities would largely be additional to those that have already been factored into the International Energy Agency's (IEA's) long-term low-carbon scenarios. Although these numbers are significant, they should not come as a surprise: energy consumption (including as feedstock) of the three subsectors (chemicals, iron and steel, and cement) exceeds 110 petajoules (PJ), equivalent to over 35 000 TWh.

Furthermore, renewables-based hydrogen and hydrogen-rich chemicals could increase the energy content of other green fuels such as biofuels, and could substitute for fossil fuels as a source of heat in various situations in industry, notably in the chemical and cement industries . Some of these hydrogen-rich chemicals would be carbon-free (e.g. ammonia), others would contain carbon but would serve as carriers and no carbon would be combusted. Still others would be drop-in fuels and their carbon burnt, but it could be of atmospheric origin.

Figure ES-2. **Concept scheme of direct and indirect electrification of industry and other end uses of renewables**
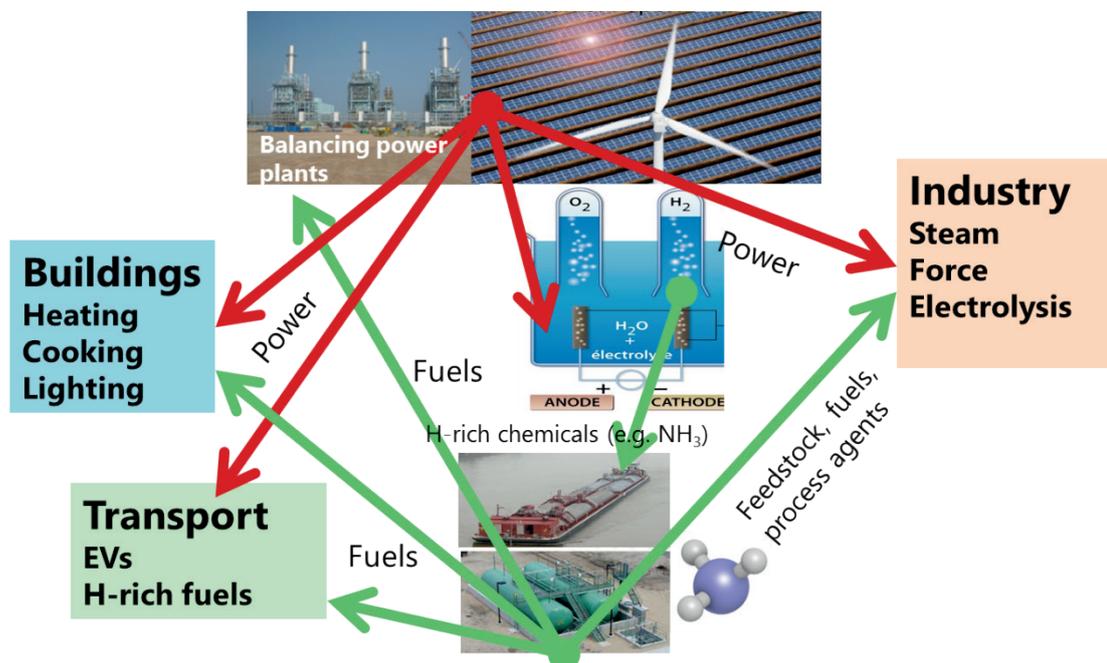
Key message • **Through electrolysis and the manufacturing of fuels, solar and wind power can overcome issues of variability, but at an efficiency cost.**

Overall, a combination of direct process electrification and use of storable hydrogen-rich chemicals and fuels manufactured from electricity may offer the greatest potential for renewables uptake by various industries. Electricity is costlier to store than heat, but is much easier to transport if connected to the grid. Hydrogen-rich chemicals are easier to store and transport than both heat and power, and this advantage may compensate for the energy lost

in successive conversions of renewable power, provided all vectors are used to their best advantage (Figure ES-2).

With current technology costs, however, using hydrogen or chemicals as fuels would entail additional costs The fact that manufacturing hydrogen from renewable electricity is becoming competitive with producing it from fossil fuels does not imply that this hydrogen can compete with fossil fuels for producing heat, power or traction – at least not yet.

While hydrogen-rich chemicals could ultimately enable nearly complete electrification of the global economy, they will likely require public support – unless carbon prices are sufficient to discourage the use of fossil fuels.

Policy and market considerations for accelerating the uptake of renewables in industry

Barriers hindering full deployment of renewables in the industry sector can be categorised as either domestic (national) or international. Concerning domestic barriers, lessons learned indicate a wide range of policy options for governments in these (and other) areas:

- energy supply regulatory regime
- access to the grid
- investment risk-reduction mechanisms
- mandates to utilities
- market and regulatory framework for valorising renewable energy and by-products
- technological warranties
- templates for simple and accurate contractual schemes for heat and power delivery
- financing of pilot projects
- financing of fundamental and applied research and development
- awareness campaigns.

However, energy-intensive industries involved in international trade may not be able to afford process modifications to reduce CO_2 emissions. A global agreement to create equality among industries (globally co-ordinated carbon pricing, for example) would in principle solve this issue, but is highly unlikely for political reasons.

Sectoral agreements may be more realistic but they come too late to encourage pioneers. These types of environmental agreements are usually negotiated to sweep laggards out of the market when emerging, greener technologies are already well established. As radically alternative production processes have not been demonstrated on a large scale, negotiations to force them through global markets would be unlikely to succeed and could even prove counterproductive.

Another option would be for governments to restrict international trading of materials based on the upstream emissions associated with them, and to introduce border tax adjustment mechanisms. There is no evidence that the World Trade Organisation (WTO) or the various rules of a large number of bilateral and multilateral trade agreements would stand in their way. Governments could agree to devise common methods for calculating how much carbon is used in making products, based on ongoing work of the International Organization for Standardization.

Jurisdictions could then decide to adopt a set of standards for the embedded carbon of the materials they use (e.g. in the context of a regional trade agreement), in line with their efforts towards achieving a zero-carbon economy.

To ensure prompt deployment of innovative clean technologies based on renewable energy in industry, public and private procurement of clean, carbon-free materials might be the most realistic short-term option. For example, the cost of CO_2 emissions-free steel would be only a small fraction of the overall cost of a clean vehicle – or wind turbine or tramway carriage. Carmakers and other manufacturers, and public and private developers of green infrastructure, may find it beneficial to bolster the green-performance image they project to their customers and the general public.

Many developers and manufacturers have done this already by procuring green power. They are now turning their attention to the "grey energy" embodied in their products and procuring preferably cleaner materials. Recently, California passed the Buy Clean California Act that targets the procurement of some steel, glass and wood types.

Public and private large-scale procurement of green goods would presumably have two results: it would protect industries compliant with tough norms and standards against unfair competition, and would provide a strong incentive for competitors to abide by the same norms and standards to get or retain access to large markets.

It is not likely that the procurement of green materials will scale up sufficiently, but it could offer a solid basis upon which to develop new processes based on widespread substitution of renewables for fossil fuels, further reducing energy- and process-related GHG emissions. This could ultimately offer new perspectives to policy makers and climate negotiators around the globe.

Introduction

This report aims to assess the potential for renewables in industry to provide energy, feedstock and processing agents in upcoming decades. It also discusses policy options that could help develop and deploy renewable energy technologies to realise this potential.

Renewables are not newcomers in industry: the situation is quite the opposite, as industry was born owing to the use of wood and charcoal for metal treatment during the Bronze and Iron ages millennia ago. It developed further with another renewable energy, hydropower, used for mechanical force. At the end of the 19th century, with combustion of coal, oil and finally natural gas producing heat, steam and electricity, the Industrial Revolution took shape and profoundly transformed our world.

Some industries have long been tied to renewable energy: hydropower, as one of the most affordable sources of electricity, encouraged industrialisation in valleys near waterfalls. As aluminium ingots were easy to transport, large aluminium smelters were often sited near important hydropower dams. Hydropower also ran hydrogen and ammonia plants in Norway, from which nitrogen fertilizers were shipped to European countries. In Brazil, iron and steelmaking industries have continuously use charcoal as source of energy and as an ore-reducing agent. The space, telecom and oil and gas industries were the first to use photovoltaic (PV) cells to deliver priceless electricity in remote places running satellites, telecom relays or cathodic protection of pipelines against corrosion. Over time, as industrial production increased and often surged in new territories, more and more fossil fuels were consumed.

After the 1973 oil shock, a movement towards reconsidering renewable sources of energy began, particularly in energy-intensive industries that had opportunities easily within reach, such as the pulp and paper industry, which manipulates large amounts of biomaterials. This movement especially gained momentum at the beginning of the twenty-first century, when onshore wind turbines became able to cost-effectively provide electricity to some industrial facilities, notably in the extractive industries unconnected or weakly connected to the power grid, or connected to grids delivering intermittent and low-quality electricity. More recently, the search for renewable energy procurement has accelerated, driven particularly by "brand" companies in the information and communications industry, as decision makers' motives broaden from techno-economic rationales to willingness to participate in global or local efforts to clean the air, conserve exhaustible resources, develop local or national resources and job opportunities, and mitigate climate change.

In the industry sector, the current pace of securing renewable energy, together with deploying other technologies or actions to reduce greenhouse gas (GHG) emissions – such as energy efficiency improvements and carbon capture and storage (CCS) – is far from being on track to achieve the United Nations Framework Convention on Climate Change (UNFCCC) Paris Agreement objectives. Global direct carbon dioxide (CO_2) emissions from the industry sector (which include energy-related emissions and CO_2 emissions from industrial processes) are projected to grow by 24% from 2014 to 2050 in the latest International Energy Agency (IEA) Reference Technology Scenario (RTS) (IEA, 2017a).[1]

Global CO_2 emissions from industry decrease in absolute terms in the 2°C Scenario (2DS) as well as in the Beyond 2°C Scenario (B2DS), but their relative share of total emissions

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[1] All numbers reported from *Energy Technology Perspectives* (*ETP*) publications refer to its definition of industry, which does not include oil and gas extraction. However, this report looks more broadly at all sorts of industrial activities.

increases, and they progressively become the primary source of CO_2 emissions. This trend would be compatible with the international community's objective to limit global climate change to manageable levels only if "negative emissions" were eventually deployed on a large scale.

The need for near-zero net emission levels

The ultimate objective of Article 2 of the UNFCCC is to "achieve stabilisation of GHG concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system." This level, which the Convention does not determine, "should be achieved within a time frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner."

Stabilisation of concentrations is generally understood to mean that the CO_2-equivalent concentration reaches a specific level and then remains at that level indefinitely until the global carbon and other cycles come into a new equilibrium. In any case, stabilisation of GHG concentrations in the atmosphere can only be achieved if gross emissions do not exceed natural removals: that is, net GHG emissions must reach zero. More specifically, the Intergovernmental Panel on Climate Change has warned, "concentrations of CO_2 in the atmosphere can only be stabilised if global (net) CO_2 emissions peak and decline toward zero in the long term" (Edenhofer et al., 2014).

Figure 1. **Indicative global energy sector CO_2 emission trajectories for different decarbonisation pathways**
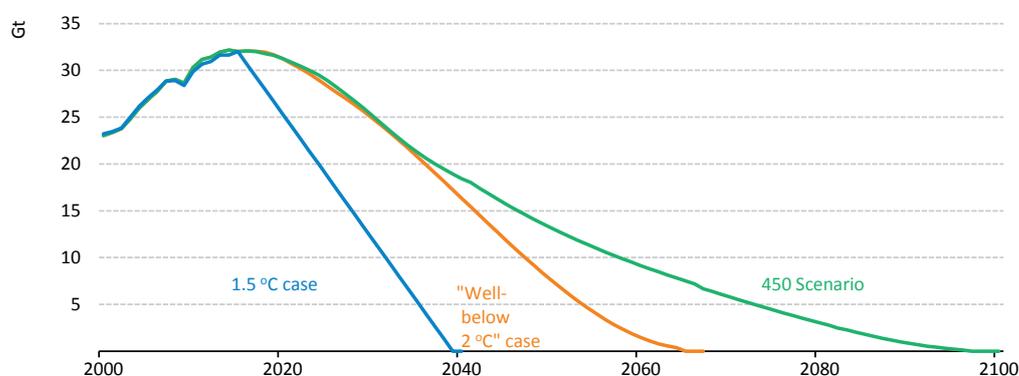
Source: IEA (2016), *World Energy Outlook 2016*.

Key message • **CO_2 emissions must reach zero net levels in any case to stabilise concentrations, but the time for achieving this is much shorter if climate change is to be limited to below 2°C.**

The objectives of the Paris Agreement, signed by over 190 countries, are to restrict the increase in average global temperature to "well below 2 degrees Celsius" above the pre-industrial level and to pursue efforts to limit it to 1.5°C. Achieving these objectives requires a rapid decline in emissions: energy sector emissions in particular need to become net-zero by around 2060 to be consistent with the "well below 2°C" objective, while reaching net-zero emissions as early as 2040 is needed to hold the increase in temperature to 1.5°C (Figure 1).

The growing role of industrial emissions

All climate-friendly scenarios – including those of the IEA – show deep GHG emissions reductions from the power sector, resulting primarily from a massive shift from fossil fuels to renewables. Direct emissions from buildings decrease thanks to better insulation, solar contributions of various types, and electrification of heat with heat pumps. The transport sector is often discussed in great detail, and the key roles of efficiency and electrification are clear, except for some important segments (long-haul freight and aviation). Still, the roles of various options remain very much under discussion among experts (e.g. Teske et al., 2017).

In the 2DS, by 2060 the power sector is already virtually decarbonised, while the industry and transport sectors become the largest source of CO_2 emissions. Over the period to 2060, the greatest cumulative emissions in the 2DS are from industry (32%), power (27%) and the transport (27%) (Figure 2).

Figure 2. Remaining CO_2 emissions in the 2DS
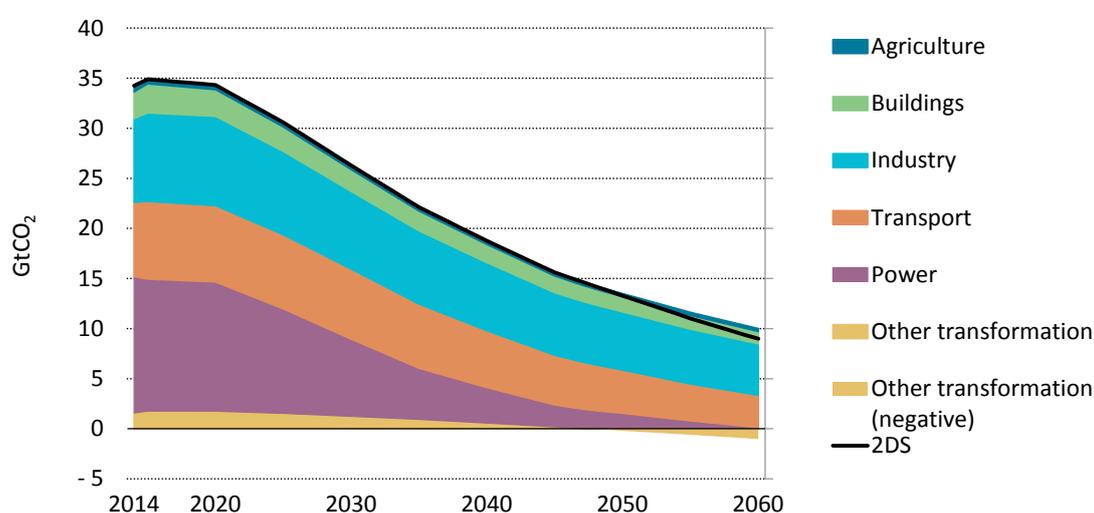
Note: Solid lines represent net energy sector CO_2 emissions for each scenario.

Source: IEA (2017a), *Energy Technology Perspectives 2017.*

Key message • **In the 2DS, the power and refining sectors should achieve zero and even negative emission levels to compensate for CO_2 emissions from industry and transport.**

Industry, however, has not yet attracted the same level of attention. While emissions would grow from about 8.5 gigatonnes of CO_2 ($GtCO_2$) per year to 10.3 $GtCO_2$ under the RTS, in 2060 they would shrink to about 5.2 $GtCO_2$ under the 2DS, and to 2.1 $GtCO_2$ under the B2DS.

However, the share of direct CO_2 emissions from industry increases considerably in the 2DS, from 24% in 2014 to 44% in 2050 Three industries delivering basic materials – cement, iron and steel, and chemicals – are responsible for 70% of all global direct industrial CO_2 emissions today (75% with the addition of the aluminium and pulp and paper industries).

These emissions result from the combustion of fossil fuels for energy purposes and from process emissions, notably from hydrogen manufacturing, limestone calcination in cement production, and iron ore reduction in steelmaking.

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Three-quarters of the energy used in industry is process heat: the rest is for mechanical work and electricity (computers, lighting, etc.). About 30% of process heat is "low-temperature" (below 150°C), 22% is "medium-temperature" (150°C-400°C) and 48% is "high temperature" (above 400°C) (Figure 3). About 10% of process heat is estimated to be electricity-based.

Figure 3. Share and breakdown of heat demand in industry
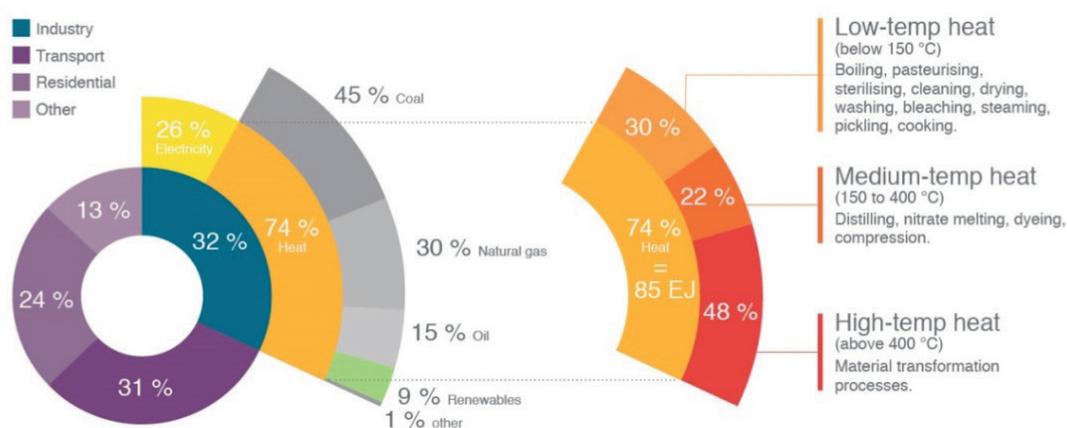
Note: EJ = exajoule.
Source: Solar Payback (2017), based on IEA statistics and calculations by IRENA.
Key message • Heat represents three-quarters of industrial energy demand worldwide, and half of it is of low to medium-high temperature.

The need for innovation

Fossil fuel use in industry and its associated CO_2 emissions can be reduced by various means, from improved energy efficiency to carbon capture and reuse or storage, as well as by novel manufacturing processes and ultimately by using different materials in industry and other end-use sectors – for example, more wood in construction. However, increased uptake of energy from renewables appears to be an ideal means to reduce fossil fuel consumption and emissions in a variety of industrial sectors of growing relevance.

Various renewable sources, such as bioenergy, solar radiation, and geothermal energy, can be used to produce heat for industrial purposes, but the availability of these resources is neither spatially nor temporally uniform. For example, in both temperate and hot but humid areas, the opportunities to cost-effectively collect solar heat at temperatures beyond ~150°C are scarce, but biomass resources can be important. Conversely, in hot and arid areas biomass resources are usually scarce, but concentrating solar power systems are able to efficiently collect the sun's energy at high temperatures.

The energy used in industry can also be sourced from renewables through electricity generation, either from dedicated facilities or from the grid, or any combination of both. For remote, off-grid industrial facilities, these sources can replace the fossil fuels used to generate power or mechanical force. Furthermore, heat can be generated from electricity using a variety of technologies.

The pillars of industrial emissions reductions in the *ETP* scenarios are energy efficiency, (especially as best available technologies [BATs] become disseminated worldwide), innovative processes and CCS. Fuel and feedstock switching, and material efficiency,

combining manufacturing material efficiency, inter-industry material synergies, decreased end-use material intensity, and post-consumer recycling, also make small contributions.

Innovative processes account for 19% of cumulative CO_2 reductions in the 2DS and 37% in the B2DS. These processes, not yet fully commercialised, include new steelmaking processes, inert anodes for aluminium smelting, oxy-fuelling kilns for clinker production in cement manufacturing, enhanced catalytic and biomass-based processes for chemical production, and integration of CCS in energy-intensive industrial processes (IEA, 2017a).

The pace of development, demonstration and deployment of innovative processes cannot be precisely known in advance, so that while some industrial sectors may achieve the required emissions reductions through process changes within the anticipated time frame, or even more rapidly, others may fail to. It is therefore important to examine alternative options, as well as options that could favour more rapid emissions reductions in the industry sector, in case reductions in other sectors (power, buildings or transport) – or relative to other GHGs – fall short of scenario projections.

Climate-friendly scenarios rely particularly on ambitious development of bioenergy resources, CCS and carbon capture and use (CCU) technologies, or on the combination of both technology families – bioenergy with carbon capture and storage (BECCS). Bioenergy is sourced from organic material that stores sunlight as chemical energy as it grows through photosynthesis, which removes CO_2 from the atmosphere; therefore, capturing and storing the CO_2 that is emitted when the bioenergy is consumed could possibly make the life-cycle emissions of BECCS negative. For this to happen, the combined amount of GHGs present in the entire supply chain (for example, from the use of fertilisers) and the GHGs that cannot be captured by CCS must total less than the amount that is captured and permanently stored.

Achieving negative emissions in some sectors (e.g. power, biofuels production and industry) could compensate for temporary "overshoots" in emissions or for lingering, particularly hard-to-suppress emissions from other sectors (e.g. transport and industry), or both.

However, CCS is proving slow and difficult to deploy, and it clearly does not reduce reliance on fossil fuels. Economic conditions for other low-carbon technologies may improve more rapidly than expected. Furthermore, BECCS is as yet an unproven technology at scale and there is a great degree of uncertainty surrounding its viability, although the uncertainties do not necessarily pertain to the CCS technology itself. Another question is what level of bioenergy resources might be sustainably available for use on a large scale by the energy sector (IEA, 2017a, 2017c, 2016), as all studies lead to the conclusion that the extensive application of BECCS needed to achieve Paris Agreement objectives would stretch the possibilities offered by bioenergy to their maximum. The supply of sustainable bioenergy will need to grow from today's 63 EJ to around 145 EJ under the 2DS and the B2DS, and even though this figure falls at the lower end of the range identified by many global estimates of available resources, mobilising this quantity sustainably will be a major challenge.

The role of renewables in the power sector, and to some extent in the buildings sector, has been investigated extensively. This is less the case for industry, for which renewables have been the topic of only a limited number of studies. To date, most energy-related innovation in the industry has been to improve energy efficiency rather than to reduce GHG emissions, as energy has always had a cost whereas emissions have not. Dennis, Colburn and Lazar (2016) coined the term "emiciency" (or "emissions efficiency"), to underline the shift in drivers from reducing energy costs to reducing polluting emissions.

Moreover, industries have considered electricity a costly source of heat, and rightly so, as electricity has been produced mostly in thermal plants from combusting fossil fuels at an

efficiency rarely exceeding 50%. Electricity could thus compete with fossil fuels only if it were running more efficient devices such as heat pumps, or if it were provided through affordable hydro generation. However, recent and rapid cost reductions in some renewable electricity-generating technologies have led to the emergence of new, affordable options that have not been considered in many studies.

Most energy models also have intrinsic limitations: for example, they do not consider the possibility of relocating activities from one country to another as international trade develops. Relocation can either be beneficial or detrimental for GHG emissions, depending on the situation. Therefore, most models may have missed potential carbon leakage; they may also miss new opportunities to find global solutions, such as relocating some industrial activities to where there are abundant renewable resources.

The first chapter of this report briefly reviews current technologies in bioenergy, solar heat and electricity from renewables. In the second chapter, emerging potential for more innovative process changes involving renewable energy are considered and discussed, focusing on extractive industries (mining and upstream oil and gas), chemicals, iron and steel, and cement. Options for producing storable and transportable carbon-neutral, renewable synthetic fuels or energy carriers for industrial use are considered more broadly in the third chapter, as well as likely implications for international commodity trading. Finally, the fourth chapter briefly discusses the policy options that could best favour a more rapid and greater uptake of renewable energy in industry.

Chapter 1. Current renewable technologies

The International Energy Agency (IEA) Renewable Energy Technology Development (RETD) Technology Collaboration Programme (TCP) recently screened over 200 renewable uptake projects realised by industries in all geographies, involving various industrial sectors and using an extensive array of renewable energy (RE) technology options. Twenty of these projects were studied in depth, and a number of useful lessons were drawn (IEA RETD TCP, 2017) from these case studies.

Different integration schemes are possible, from simple, low-investment projects to more complex, interwoven ones yielding greater GHG emissions reductions, such as:

- Green power procurement with a third-party power producer located on the industry's premises. Volkswagen's Chattanooga plant (United States) purchases green power under a 20-year power purchase agreement (PPA) from a 9.5-megawatt (MW) solar photovoltaic (PV) park adjacent to the manufacturing plant.

- Onsite installation of fully owned and operated renewable power generation assets. Vestyfen brewery replaced an oil-fired boiler by a 4-megawatt thermal (MW_{th}) wood boiler (Denmark), and Diavik Diamond Mines installed a 9.2-MW onshore wind farm at its off-grid mine (Canada).

- Onsite installation of RE production assets and process adaptation. Tenon Manufacturing (New Zealand) modified its natural gas-fuelled kilns to run on geothermal steam (27 MW_{th}).

- A paradigm shift involving renewable raw materials and energy, and valorisation of by-products. Jain Irrigation System Ltd (India) transforms by-products of the tomato transformation process into biogas in the plant, and digestate is then valorised on secondary markets as bio-compost.

Integrating renewables into industrial assets directly benefits industries, beyond the benefits they would derive from the simple purchase of renewable power. The following project drivers and motivations for industries show that they vary widely, depending on location and energy needs:

- Hedging from fuel and grid price volatility and the risk of future increases, and in some cases reduced energy costs. Codelco's dependence on expensive, road-transported fuel at its Gabriela Mistral Division mine (Chile) was a key driver of its thermal solar project (annual savings of EUR 5.3 million).

- Improved energy supply reliability. An unstable electricity supply due to its distance from the main distribution power grid drove Australian Tartaric Products (Australia) to develop a more grid-independent and stable electricity supply: a combined heat and power (CHP) plant fuelled by grape waste.

- Increased productivity. Productivity increased by 5% at a Tenon Manufacturing plant (New Zealand) after its 27-MW_{th} geothermal plant became operational, due to the wood drying more efficiently through better heat control with geothermal energy, and because all kilns could be ramped up and brought on line at the same time.

- Additional revenue opportunities through sales of excess energy to the power grid or heat networks, or to other industries. Excess power generated by the solar PV installation at Pepperidge Farm plant (United States) is sold to the grid at retail price according to the net-metering scheme in place in Connecticut.

- Greater coherence with corporate environmental and local commitments. Beyond economic profitability (annual operation expenditure [OPEX] reductions of EUR 8 million), Hima Cement Ltd's (Uganda) coffee husk project creates income-generating activities and offers a waste recovery solution to local communities. For some large "brand" companies, wanting to be seen as leaders in sustainability might in fact be their primary driver.

Despite the variety of RE applications in industry, bioenergy dominates significantly. Solar heat and electricity from renewables are the only other RE technologies offering significant potential, while others, such as geothermal heat, appear to be limited to niche markets where suitable resources are available. The following sections provide a brief overview.

A. Bioenergy

With an estimated consumption of 7.7 exajoules (EJ) in 2015, biomass is by far the largest renewable energy source in industry today. Of this consumption, 2.4 EJ were used by the pulp and paper industry, 1.2 EJ by the food and tobacco branch, 320 petajoules (PJ) by the wood and wood products industry, 200 PJ by non-metallic minerals such as the cement industry, 136 PJ by the iron and steel industry, and 113 PJ by the chemical industry (of which 40% was used for feedstock). Bioenergy consumption is most evident in industry sectors that produce biomass residues onsite suitable for fuel use. In other industries where this is not the case, bioenergy is less used because biomass fuel supply chains need to be mobilised.

Brazil, India, the United States, Association of Southeast Asian Nations (ASEAN) countries and the European Union are the largest industrial consumers of bioenergy. Shares shown in Figure 4 do not, however, include biomass used to generate electricity (total 30 132 PJ) and commercial heat (total 5 164 PJ) consumed globally by industries. Neither do they include the share of bioenergy consumed onsite to transform biomass into biofuels (IEA, 2017a).

Brazil still uses charcoal to process iron ore in Minas Gerais and East Amazonia for over one-quarter of its total iron and steelmaking, although concerns about deforestation and methane emissions have been raised (Piketty, 2011).

Figure 4. **Country/regional shares of global biomass use in industry**
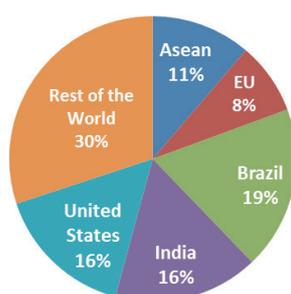
Source: IEA (2017a), *Energy Technology Perspectives 2017*.

Key message • **Brazil, India and the United States together account for half the biomass used globally in industry.**

Bioenergy fuels come in solid, liquid and gaseous forms, and can be used as – among other end uses – a source of heat, including high-temperature heat for industrial purposes, as well as a feedstock or reducing agent.

A wide range of biomass feedstocks can be used as sources of bioenergy, including wet organic wastes, residues from agriculture and forestry, crops grown for energy, including

food crops, and non-food crops such as perennial lignocellulosic plants or oil-bearing crops. Many options are available to turn these feedstocks into products that the industry sector can use. Most scenarios that include greater uptake of renewable energy in industry primarily involve a significant increase in the use of bioenergy The next steps for those companies that already hit their target of 100% renewable electricity, such as Leo and Microsoft, seem to be to extend their targets, not so much to their other (non-electric) energy needs but to the electricity consumption of their supply chains. For example, in 2015 Apple launched a 2 GW clean energy initiative in China. As a result, iPhone manufacturer Foxconn will build 400 MW of solar capacity by 2018.

B. Solar heat

Activity is accelerating with respect to solar heat for industries. While the deployment of small-scale solar water heating systems is slowing, that of large-scale solar-supported district heating systems and industrial applications is quickening (Weiss, Spörk-Dür and Mauthner, 2017). A recent study has identified over 130 companies in at least 22 countries worldwide that have realised more than 500 industrial plants with an overall combined installed collector area of 416 414 square metres (m^2) for process heat (Solrico, 2017). This represents an installed capacity of only 280 MW_{th}, likely to produce 560 gigawatt thermal (GWh_{th}) (2 PJ) of heat per year at most, assuming a relatively high capacity factor of 2 000 full load hours. The study may not cover all installations, however.

The vast majority of projects use non-concentrating technologies such as flat-plate collectors or evacuated tubes. These can be installed almost anywhere, as they use global solar irradiance, but they usually do not deliver usable heat above about 100°C. In recent years, however, new high-vacuum flat-plate collectors have been commercialised, which remain relatively efficient at temperatures up to 160°C (Horta, 2015).

Concentrating technologies, such as Scheffler dishes mostly in India (Scheffler, 2012), Fresnel collectors or parabolic troughs use direct irradiance only and are geographically limited to areas with good direct normal irradiance (DNI) – but as these linear concentrating technologies can reach or even exceed 400°C, they could be a mean of supplying medium-high temperature process heat needs. Central receiver systems or "solar towers", which can achieve higher temperatures still, have so far developed in the power sector only. A handful of medium- and large-sized solar ovens, able to respond to all temperature requirements, are used mostly for research purposes (IEA, 2011).

Another important reason for this prevalence of non-concentrating technologies rests in the relationship between solar heat cost and temperature level that makes competition with fossil fuels easier at low temperatures (Lovegrove et al., 2015) (Figure 5). The food and beverage industry, the service industry, and the textile industry, all of which mostly need low-temperature heat, are the main areas in which solar heat has been deployed.

Another example of low-temperature solar process heat is the 27.5 MW_{th} system at Codelco mining company's Gaby copper mine in northern Chile, the largest such system in service so far: it has 39 300 m^2 of flat-plate collectors and 4 000 cubic metres (m^3) of thermal energy storage, and supplies 85% of the process heat needed to refine copper. It was commissioned in 2013, in one of the world's best areas for concentrating or non-concentrating solar power or heat.

There will likely be an acceleration in deployment of solar process heat in upcoming years. In Oman, US-based start-up company Glasspoint is currently building a much larger plant than all existing ones – not only individually, but taken altogether, as it will eventually reach a

capacity of 1 GW$_{th}$ (also see the "Oil and gas extraction" section below). It will produce solar steam for Petroleum Development Oman's enhanced oil recovery operations, saving large natural gas consumption and associated carbon dioxide (CO_2) emissions. Given its sheer size, this unique innovation, based on a reinvention of parabolic trough technology, will also shift deployment of process heat technologies to solar concentrating ones.

Figure 5. Cost of solar heat in relation to temperature and size of installation
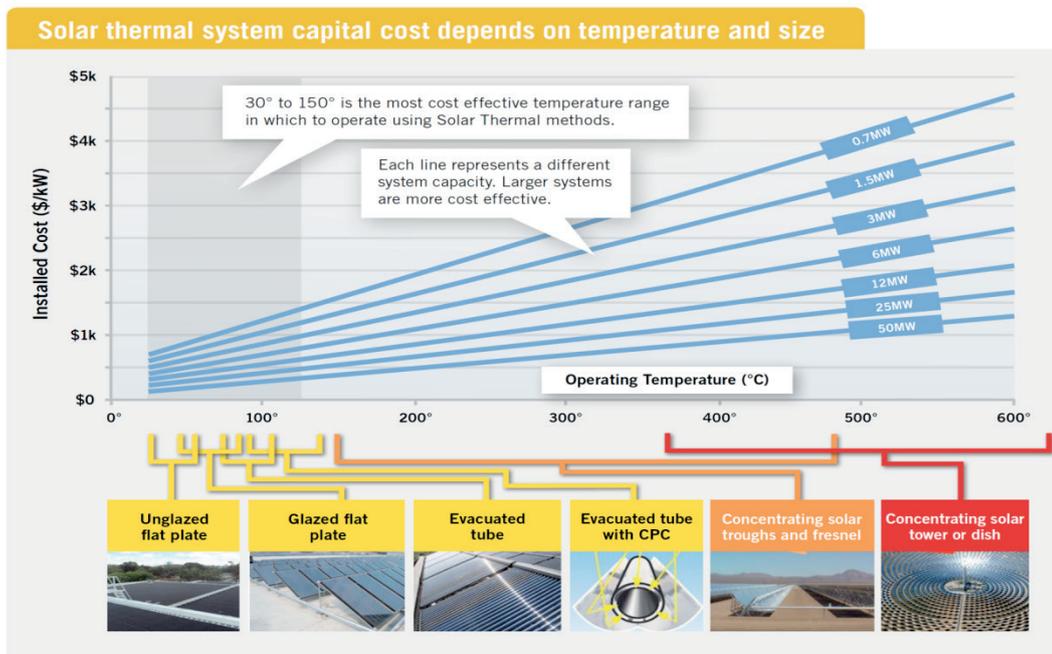
Source: Lovegrove et al. (2015), Renewable Energy Options for Australian Industrial Gas Users.
Key message • **Solar heat offers more competitive options for low-temperature heat**

Meanwhile, the solar industry is shifting attention and commercial efforts from its traditional markets – household-level space heating and water heating systems – to emerging markets such as district heating systems and industrial users, although they still represented only 3% of the global solar heat market in 2015 (Weiss, Spörk-Dür and Mauthner, 2017). District heating systems potentially have more long-term storage options and can combine a variety of resources, whereas industrial users' heat needs are more evenly distributed throughout the year than those of households, including during the months with the best resource availability. Collaborative efforts, such as those of the IEA TCP SolarPACES and TCP Solar Heat and Cooling (SHC) Task 49 "Solar Heat Integration in Industrial Processes",[2] facilitate this shift.

Various industries have teamed with academics and research centres to explore possible new uses of high-temperature solar heat, such as calcination of alumina for Alcoa (Nathan, 2016), phosphates for the Office Chérifien des Phosphates, or lime for Cemex (see Chapter 2, Section D. Cement). Various German and South African institutions and companies are also collaborating to develop a rotary solar kiln that could be used to melt and recycle aluminium. In fact, research in this field can be traced back to the 1990s regarding process emissions (Steinfeld and Thompson, 1994; Koepf et al., 2017), and much earlier for energy (IEA, 2011).

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[2] All deliverables available online at http://task49.iea-shc.org/.

C. Renewable power

The uptake of renewable power by industry can be increased in two ways, and these methods can be employed separately or combined. One method is to substitute the direct use of fossil fuels with electricity, even from the grid, assuming that most power mixes already incorporate a continuously growing fraction of renewable power. The other is to substitute electricity from the grid with renewable electricity.

Electrification

Electrification has its own independent drivers, and has always progressed more quickly than broader energy consumption. In industry, digitalisation, further automation, advanced robotics and cobotics (i.e. robots working with people) often substitute fossil fuels with electricity. Additive manufacturing (with 3-D printing), also driven by electric power, could be a source of efficiency improvements, saving materials and energy. It also allows novel geometries to be produced that would be too costly or even impossible to manufacture otherwise, which may lead to additional efficiency benefits in industry and other end-use sectors (e.g. lighter aircraft components or more efficient turbine blades; see IEA, 2017d).

Electrification has long been promoted by utilities – not necessarily contradictory to demand-side management and efficiency improvements. Decades ago, Marcel Boiteux, then President of Électricité de France, advocated for "more uses for electricity, less electricity per use." Today, utilities see in electrification not only a way to expand market shares but also an opportunity for easing grid integration of variable renewables in bringing more flexibility.

Electrification is traditionally associated with replacing steam- and gas-driven compressors, pumps and valves, of which many are still in use today (van Kranenburg et al., 2016). There are many other aspects, however, the most common of which is power to heat, as heat represents over half of the energy demand of industry.

A number of electric technologies provide heat and a substitute to fossil fuels – electric ovens, microwaves, induction, Foucault currents, heat pumps, mechanical vapour recompression (MVR), plasma torches, electron beams, radio frequencies, etc. – often with great ease of regulation, improved quality, and reductions of material wastes. Induction ovens can have many applications in mechanical construction, automobiles and aviation, and microwaves or induction can be applied to metallic components for specific effects.

Some electric technologies are particularly efficient, exhibiting apparent efficiencies greater than 100%, such as heat pumps and MVR (Box 1). Even so, the conversion ratio of heat into electricity inside thermal power plants (nuclear, fossil, bioenergy geothermal and solar thermal) that are part of the electricity mix must be taken in account to assess the true impact of electrification on the demand for primary energy.

The first effect of electrification is that in many cases it adds a constant baseload to the fluctuating electricity load of the economy, and thus reduces the "peak-valley ratio" of the power load, or the difference between peak demand and valley demand over total load. In China, for example, this ratio is expected to reduce from over 30% to about 20% as industry electrification develops (Chi, 2015). Electrification has many more benefits, however.

As the share of renewables in the power mix increases, options emerge in two broad categories. To benefit from surplus wind or solar power, which may have low or very low prices (even negative in some instances), it makes sense to immerge low-cost electric devices, such as simple resistors in boilers or tanks, providing additional flexibility to the power systems while occasionally saving fuels and associated CO_2 emissions.

If the substitution is more permanent, more efficient technologies will be considered, even if more expensive. In that case, the additional flexibility provided to power grids is less, but it subsists as load-shedding and can again be increased with heat storage.

In load-shifting and -shedding, short-duration heat storage, being much less expensive than electricity storage, can increase flexibility and allow for greater uptake of renewable power by industry, facilitating the handling of variability.

Box 1. **Heat pumps and vapour recompression**

Heat pumps deliver more energy as heat than they consume as electricity, with a seasonal performance factor (SPF) greater than 1. The IEA thus considers heat pumps as energy-efficient devices and tracks their deployment in its annual energy efficiency market reports.

However, the apparently extraordinary efficiency of heat pumps is due to the way they transfer some heat from an external, "cold" medium to another, warmer place. This medium can be the surrounding air, a body of water or the ground, and the heat is of geothermal and/or solar origin. Therefore, various other institutions consider that heat pumps deliver energy that is, for the most part, of renewable origin. The remaining part results from the final transformation of electricity-driven movements in the pump into heat, and may or may not be considered renewable, depending on the source of the electricity.

For example, the energy policy of the European Union (Directive 2009/28/EC) has defined heat pumps as one acceptable way for member countries to meet their renewable energy obligations, provided that their output significantly exceeds the primary energy needed to drive them. In practice, their SPF needs to be greater than 115% of the inverse of the ratio between total gross production of electricity and the primary energy consumption for electricity production on average in the European Union – and only the renewable portion of the heat is counted towards the obligation.

In industry, the "cold" medium from which heat pumps or MVR machines draw heat to be raised in temperature and transferred is often low-grade waste heat from various processes. An MVR machine is a particularly efficient sort of heat pump (performance coefficient of 5 to 10), as it avoids losing the latent heat of the steam in compressing the low-temperature, low-pressure steam before condensation can occur.

All-electric plants can also increase their flexibility to better support integration of variable renewables. For example, Trimet Aluminium SE, Germany's largest producer of this metal, and New Zealand's Energia Potior Ltd, have developed a process that allows adjusting the production process to fluctuating amounts of electricity. A controllable heat exchanger continuously maintains the energy balance in the furnace to mitigate the effects of these fluctuations. By the end of 2017, all 120 furnaces in an electrolysis hall of the aluminium smelter in Essen will be converted. The output can be varied in a range of plus or minus 25%, resulting in a virtual storage capacity of approximately 1 120 megawatt hours (MWh) – comparable with that of a medium-sized pumped-storage power plant.

The likely next steps in electrification would be to expand the use of electrowinning and particularly electrolysis of water and CO_2, and to considerably enhance the flexibility options for integrating variable renewables. However, increased industry electrification can also be accomplished by relocating some of the most energy-intensive industrial activities to areas with vast and affordable renewable resources; the example of aluminium illustrates both aspects. Smelters have often been located near large hydropower dams to benefit from inexpensive electricity, including plants oriented mostly towards exports, such as in Iceland; more recently, they have proven their ability to increase power grid flexibility, such as in Germany. Options for the next steps in electrification are detailed in Chapter 2.

Procurement

Procuring electricity from renewables is probably the most active area of increased renewables uptake by industries today. In many cases, procurement aims to substitute grid electricity with renewable electricity for current, usual electricity usage. In some cases, though, electricity from renewables replaces electricity generated from fossil fuels in remote industries; in a small number of instances, this electricity replaces the direct use of fossil fuels, such as for generating process heat or for motion, for example fuelling forklifts with power or hydrogen produced from dedicated solar and wind capacities (e.g. IEA RETD TCP, 2016, case 15).

Procurement can take various forms: onsite owned renewable capacities, onsite contracted renewables, renewable energy certificates and green tariffs via utilities are among the most frequent purchasing strategies – although the latter two may or may not actually drive new renewables investment as the first two do (Figure 6).

Figure 6. **Power generation capacity additions to directly serve commercial, industrial and public consumers**
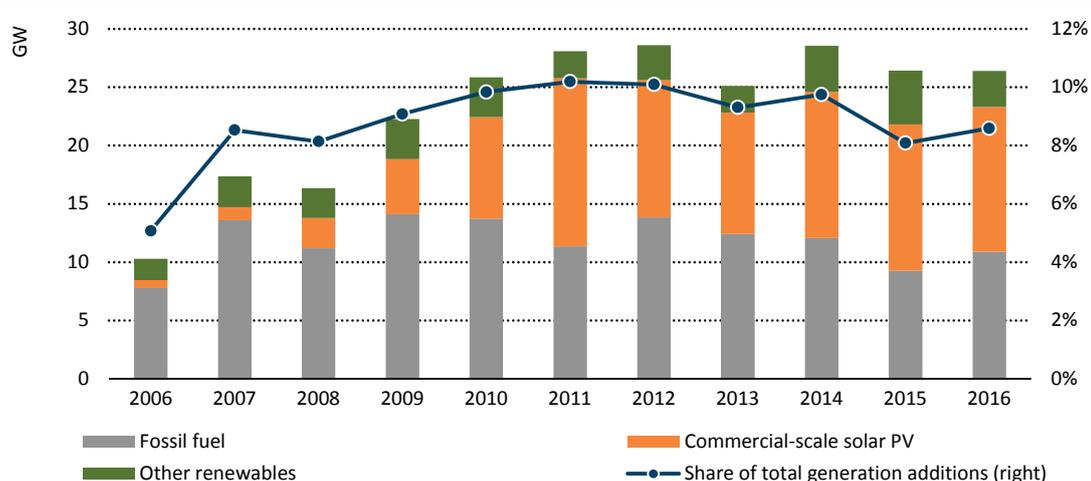
Source: IEA (2017b), *World Energy Investment 2017*, based on Platts (2017), World Electric Power Plants Database.
Key message • Generation directly serving companies and public entities, dominated by commercial-scale PV, made up 10% of all new additions in 2016.

Corporate buying of wind and solar power through bilateral energy contracts grew from below 50 MW in 2012 to over 3 gigawatts (GW) in 2015 in the United States, led by data centres. Numerous international companies of the services and industry sectors have committed to "go 100% renewable" – there were 96 at the end of June 2017, mostly international companies of US or EU origin, including Ikea, BMW Group, Coca-Cola, General Motors, H&M, Heathrow, Hewlett Packard, Lego, Microsoft, Nestlé, Nike, Philips, Telefonica, Tetra Pak, and Unilever. Companies from China (Broad Group), India (Tata Motors) and Japan (Ricoh) are also present, if in small numbers. However, in 2015 60% of the renewable power procured by RE100 companies came from the purchase of renewables certificates, and another 35% through green contracts or tariffs with utilities.

Renewables procurement has so far been a movement among large companies: of the Fortune 500 companies, only those ranked in the first 100 have a significant rate of procurement (13%); this rate falls to 1% for the following 400 companies. In May 2016, four non-governmental organisations founded the Renewable Energy Buyers Alliance (REBA), encompassing 62 companies and 95% of the renewable energy purchase agreements signed in the United States, so that the front-runners can share their expertise with companies new

to the process. Its goal is to deploy 60 GW of new corporate renewable energy capacity by 2025, raising the total amount of non-hydro renewables in the US grid by 50%.

The next steps for those companies that already hit their target of 100% renewable electricity, such as Lego and Microsoft, seem to be to extend their targets, not so much to their other (non-electric) energy needs but to the electricity consumption of their supply chains. For example, in 2015 Apple launched a 2-GW clean energy initiative in China. As a result, iPhone manufacturer Foxconn will build 400 MW of solar capacity by 2018.

Box 2. Long-term potential and scenario analyses

Existing analyses of greater industrial uptake of renewable energy rely primarily on a significant increase in the use of bioenergy. For example, Taibi, Gielen and Bazilian (2012) suggest that up to 21% of final energy demand and feedstock use in the manufacturing industry sector could be of renewable origin by 2050, a five-fold increase over current levels in absolute terms. If, in addition, half of power generation is assumed to be from renewables, the share of direct and indirect renewable energy use would rise to 31%. Bioenergy and bio-feedstocks would constitute three-quarters of direct renewables use in this sector, the remainder being evenly divided between solar heat and heat pumps. The latter could contribute almost 5 EJ per year in 2050 in low-temperature process applications. Most (43%) of this will be concentrated in the food sector, mainly in OECD countries (60%), China (16%) and the Former Soviet Union (15%).

Another insight from Taibi, Gielen and Bazilian (2012) is that development of a liquid international market for bioenergy will be fundamental to maximise exploitation of the world's biomass resources in industrial applications. They estimate that if such markets were in place by 2050, there would be enough sustainable biomass to provide more than 18 EJ of heat and almost 7 EJ of petrochemical feedstocks. In the absence of such bioenergy markets, these figures are scaled down by almost 50%, with most of the reduction occurring in OECD countries.

In the long-term scenarios of the IEA (2017a), biomass in industry would increase from almost 8 EJ in 2014 to 14 -15 EJ by 2050, with relatively little difference among the various scenarios.

The International Renewable Energy Agency (IRENA) (2015) estimates a "realisable economic potential" of 6.5 EJ to 8 EJ increase by 2030, part of an estimated "realisable technical potential" for bioenergy of 15 EJ to 24 EJ. Bioenergy is notably seen as the exclusive renewable energy option for high-temperature heat in energy-intensive sectors (up to 8 EJ), half of which would be used in the non-metallic minerals industry.

IRENA also projects 4 EJ of biomass to be used as feedstock. Biomass can be used to produce light olefins and subsequent products in several ways, including biomass gasification with subsequent methanol to olefin production, or biomass fermentation to ethanol followed by dehydration into ethylene. The energy consumption of these biomass-based processes is, however, 3.5 to 5 times greater than for fossil fuel-based ones overall, so emissions reduction benefits should be analysed carefully to take the whole cycle into account (IEA, ICCA and Dechema, 2013). More recent work focusing on EU emissions possibly suggests greater value in using biomass waste as a feedstock to replace oil-based inputs, rather than in direct energy uses. For this to materialise, however, the development of new high-performing chemical compounds that can easily be assembled from bio-based feedstock will be essential (Wyns and Axelson, 2016).

Other renewable energy sources in industry broadly accounted for 33 PJ in 2014 (IEA, 2017a). Growth from this very low base is strong, however: from 33 PJ in 2014 to 1 EJ by 2050 under the RTS, to almost 2 EJ under the 2DS and 3.6 EJ in the B2DS – thus exhibiting a much greater sensitivity to the carbon constraints of the climate mitigation scenarios, but still increasing less in absolute terms than bioenergy. IRENA (2015) estimated "realisable economic potentials" of 2.3 EJ for solar heat by 2030, and 1.1 EJ for geothermal heat, although the estimated "realisable technical potential" would be significantly higher for solar heat in industry, at 15 EJ.

Chapter 2. Emerging technologies and options

In this chapter, emerging options for further uptake of renewables are examined through end-use industrial sector energy needs, from extractive industries to the major energy-intensive industry subsectors of chemicals, iron and steel, and cement. In addition to direct solar heat, the next step of electrification – largely expanding electrowinning and electrochemical technologies – will play a central role.

A. Extractive industries

"If it's not grown, it's mined": this adage of the mining industry is a reminder of mining's fundamental role in modern life. Although the extractive industries consume only a small percentage of final energy worldwide, it provides over 80% of global primary energy. This is changing, however, as energy returns diminish in the fossil fuel industry due to growing energy requirements for extraction, transport, refining and other treatments as resources have to be tapped deeper and farther, and are tighter, heavier and sourer, while the collective preference for cleaner fuels soars.

Meanwhile, the share of fossil fuels in the global energy balance has begun to shrink. Moreover, the shift to more capital-intensive energy efficiency, renewables and enabling technologies is also a shift towards intense material utilisation: steel and concrete for wind farms, steel and glass for solar technologies, copper for grids, lithium for electric vehicles, and rare-earth elements for efficient electric motors and generators.

Oil and gas extraction

The oil and gas industry has growing energy needs, as the most accessible oil and gas fields have been exploited, and now tighter, more remote or sourer resources, or those deeper offshore, are being explored and exploited. Shale gas, tight oil, heavy oil and shale oil require significant amounts of energy to be freed from the rocks, pushed to the surface and treated or converted. Offshore and remote resources also need to be piped longer distances, at higher energy costs. Consolidating data from various professional sources, Wang, Brandt and O'Donnell (2016) estimated the upstream energy consumption of the sector at 10 exajoules (EJ) to 11 EJ in 2013.

Crude and condensate production could be fed partly on solar heat or power, in places with high solar potential. To estimate solar potential, solar resource quality is screened at the country level, based on global irradiance for photovoltaics (PV) and direct normal irradiance for heat, and countries must meet the minimums set for the approximate economic quality of a country's solar resources. Canada, the United Kingdom, Norway and the Russia Federation (hereafter, "Russia"), do not pass this test, although they together produce a large fraction of global output. Another criterion is that solar energy production needs be located onshore. According to the combination of these criteria, the share of global crude and condensate production that could be fed partly on solar heat or power would be limited to 30% to 41%.

Assuming that pumping, lifting, compression and other primary energy demands would be partly met by solar PV in oil and gas extraction, while process heat, steam generation and heated chemical separation (e.g. solvent regeneration) would be partly supplied by solar heat, Wang et al. (2016) calculated a possible PV deployment of 6 gigawatts electrical

capacity (GW_e) to 11 GW_e, and solar heat at 35 gigawatts thermal (GW_{th}) to 88 GW_{th} – a total energy contribution of up to 460 petajoules (PJ).

One spectacular illustration of this potential is the Miraah plant for enhanced oil recovery in the heavy oil fields of Oman. After a pilot plant was commissioned in 2013 to test the Glasspoint technology, Miraah was designed for a capacity of over 1 GW_{th} and construction is under way; the first steam was produced in September 2017, with the plant operating at about one-tenth of its total final capacity.

Required to adapt the usual parabolic trough technology to the exceptionally harsh conditions of Oman (wind, dust and dirt), and to the specific needs of enhanced oil recovery, the Californian start-up company Glasspoint progressively reinvented trough technology. The entire plant, covering 3 square kilometres (km^2), will be encapsulated in 36 standard greenhouses, with daily automated roof-washing. Very well-protected against winds, the parabolic mirrors are ten times lighter than those in other parabolic trough plants. Suspended from the roof, their light weight allows them to rotate around the receiver tubes, which are fixed and not further insulated. Water is turned into steam directly.

The plant is connected to the existing pipes and gas boilers. There is no other heat storage than the oily ground, but the solar input replaces 80% of the gas combustion. When fully completed by around 2020, Miraah is expected to produce 6 000 tonnes (t) of steam per day, saving 5.6 PJ of natural gas and the emission of 300 000 tonnes of carbon dioxide (tCO_2) per year.

If offshore oil and gas exploitation limits the possible role of solar energy, it offers opportunities to wind power, specifically offshore, according to TNO, a Dutch think tank (TNO, 2016). Platforms currently generate the force and electricity they need from on-board gas or diesel generators of 10 megawatt (MW) to 50 MW capacity. The ten largest platforms in Dutch waters emit one million tCO_2 annually.

Reducing these emissions to meet national emissions standards coming into force in 2019 could be achieved through expensive upgrades, while converting the platforms to renewable electricity would require a similar investment and would result in lower future emissions and costs. Operations and maintenance (O&M) expenses of electric motors are much lower than for thermal ones. The ten largest platforms would absorb up to 1.4 terawatt hours (TWh) annually, equivalent to the production of a nearby offshore 400 MW wind farm with 40% capacity factor (TNO, 2016).

While no global assessment of this potential appears to be available, wind may offer renewable electricity potential to oil and gas operations comparable with or greater than that offered by solar PV, including in the zones where the use of solar PV has been excluded: Canada, Russia, northern Europe and the northern United States – onshore and offshore.[3]

Refining

Wang, Brandt and O'Donnell (2017) also consider refineries, a sector that consumes another 12 EJ to 13 EJ. With respect to using renewable energies, refineries have an obvious advantage over oil and gas exploitation in that they are all on shore.

There are two temperature ranges in which solar heat can be used: distillation takes place at medium-high temperatures of up to 400°C, and pre-reforming usually occurs around 500°C;

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[3] Other possible synergies could be considered between the gradual decommissioning of oil and gas installations and the deployment of offshore wind such as in the North Sea (Jepma, 2017), but this is beyond the scope of this report.

these temperatures are easily reached with concentrating solar, but only where DNI is sufficient to allow for effective concentration. Thanks to the concentrating solar power industry, affordable sensible heat storage in molten salts at these medium-high temperatures is commercially available.

The significantly higher temperatures that may be needed for reforming (up to 900°C) and cracking (even higher) are also technically feasible, but more economically challenging. In both cases, a significant land area may be needed in the immediate vicinity of the refinery, which may or may not be made available.

The portion of refineries that can be partly fed from solar power or heat is estimated between 44% and 64% under the criteria of solar resource quality, i.e. global horizontal irradiance (GHI) for solar PV, and DNI for solar heat. Assuming that electricity use and hydrogen production are supplied by PV, and heat needs currently met with natural gas or steam are provided by solar thermal, Wang, Brandt and O'Donnell (2017) arrive at a possible deployment of 17 GW_e to 95 GW_e for PV, and 42 GW_{th} to 74 GW_{th} of solar heat, for a total energy contribution of up to 1.4 EJ.

Although such estimates are less than 10% of the total energy used in refining, when combined with emerging options for offshore wind, they show that upstream and downstream oil and gas activities could become significant consumers of renewables.

Another, perhaps even more important, uptake of renewables in refining could be through hydrogen. The hydrogen consumed in refineries used to be a co-product of catalytic reformation of gasoline, but the need for additional hydrogen keeps growing as standards for oil products become more stringent in most countries to preserve urban air quality, while at the same time available oil resources in some regions are becoming heavier and sourer. Hydrogen can be produced from water electrolysis run on renewables, as is examined in the subsection on hydrogen on p.28. Growing uses of biofuels such as hydrotreated vegetable oil or high essential fatty acid aviation biofuels could also lead to increased hydrogen consumption (IEA, 2017c).

Further downstream, renewables may also contribute to the transport and distribution of fuels through electricity for pumping and heat. For example, natural gas is transported in high-pressure pipes, then distributed in lower-pressure pipes – a change that requires some heat, usually obtained in combusting gas. This low-temperature heat can alternatively be provided by solar, and some stations in Germany have been equipped for this (Lauterbach, n.d.; Rezaei et al., 2011).

Minerals

The mining industry has pioneered the procurement of renewable electricity, primarily because the quality of grid electricity is not sufficient in many places, connections are too weak and often electricity has to be generated onsite with diesel generators requiring maintenance and fuels transported by road at significant costs. In northern Chile and southern Peru, 11 of 13 large solar PV facilities have been built for the needs of the local mining industry – which indeed absorbs most of the electricity.

After the Paris Agreement was signed and entered into force in record time, interest for renewables increased as the mining industry became convinced that carbon prices, one way or another, would significantly add to energy prices and risks. At a forum convened by Anglo-American in South Africa at the end of 2016, some participants expressed the view that producing energy for mines could also help serve local communities and facilitate good

relationships with them and with the authorities. Mining's social licence to operate is therefore linked with the energy challenge.

The energy consumption of mines is focused around two main areas of need, of roughly equal importance: electricity to provide force, for example for grinding, some onsite transportation (conveyors), air conditioning and ventilation, and sometimes electrowinning, depending on the nature of the material being mined and the degree of onsite preparation. The other is diesel fuel, mostly for onsite machines and transportation, notably in open pit mines where the huge haul trucks carry up to 450 t.

Heat can be a third type of energy need, but this varies more significantly with the material being mined, and heat needs can often be responded to with waste heat from other operations. There are, however, examples of uses of renewable heat in mines (IEA RETD, 2016, case 16).

Providing renewable electricity to mines from solar PV or wind (or both) is attractive, but some barriers exist. If the mine is off-grid, the economics of substituting diesel fuel are usually very favourable and existing generators can be used when needed; however, if significant excess power is generated, it cannot be exported and might be lost. Conversely, if the mine is on the grid, exporting excess power can be an option provided the utility accepts it and provides fair remuneration, which often requires the intervention of a regulator or governmental authority.

The business case for substituting grid electricity with self-generated power may prove persuasive in some countries (e.g. Australia), or less so where energy-intensive industries benefit from preferential, subsidised tariffs. In some cases, large battery storage is being added to increase self-consumption and avoid curtailment.

Another frequent difficulty when external investors are involved relates to their need for a relatively long-term power purchase agreement (PPA). Although this could also be thought of as a hedge against very volatile diesel prices for the sake of the mining industry, for most minerals the level of activity in a specific place is often uncertain 10 or 15 years in advance. Thanks to recent cost reductions, agile entrepreneurs are now offering investments in solar PV with flexible-term agreements of as little as five years, with the possibility of extension. If the contract is not renewed, the PV material is shifted to another place (Boyle, 2016).

Replacing diesel fuels is usually seen as a much more difficult challenge, which has inspired a great variety of ideas, often involving hydrogen. While hydrogen may offer a solution in some cases, electrification, particularly of haul trucks, may prove simpler and more cost-effective. Haul trucks are already "hybrids", combining an on-board diesel generator and an electric traction chain, which is more robust than a mechanical traction chain for withstanding considerable effort. Hence, electrification via overhead catenary lines is relatively straightforward and requires little additional equipment, especially on more recent models that are already equipped with flexible polyvalent power electronics.

Electric haul trucks have been at work for decades in South Africa and some neighbouring countries as a result of the oil embargo by the Organization of the Petroleum Exporting Countries (OPEC) and other oil-producing countries. The conversion is relatively easy, as these trucks stay on site and follow regular paths for several weeks, while catenaries can be extended or shifted from time to time as necessary.

The connection between mining and renewables may not stop here. Although abandoned mines are often a curse for the local community, the environment and finally the industry – except for the few that are converted into touristic attractions – old mines, especially deep ones, could be converted into pumped-storage hydropower plants, which would help

integrate variable renewables such as solar and wind. Several projects are under consideration, mainly in Germany (in coal mines) and the United States.

B. Chemicals

The chemicals and petrochemicals subsector is the largest industrial energy consumer at 28% of total global industry final energy demand, of which over half is associated with feedstocks. Ammonia, methanol and high-value chemicals account for almost three-quarters of total final energy use, including feedstocks, in the chemicals and petrochemicals subsector. This subsector is the third-largest CO_2 emitter in the industry sector, responsible for 13% of total industry direct CO_2 emissions, i.e. 3% of all CO_2 emissions (this share increases to 8% by 2050 under the 2°C Scenario [2DS]) (IEA, 2017a).

The recent Voltachem study Empowering the Chemical Industry (van Kranenburg et al., 2016) identifies two major challenges for EU chemical companies: how to strengthen their competitive position in global market, and how to become more sustainable in an economically feasible manner. As a starting point for both problems, the study investigates options for electrifying the chemical industry. It identifies power-to-heat and power-to-hydrogen as bases for various applications, as well as power-to-specialties (small volumes but high value) and power-to-commodities. It then develops the argument that:

> The most promising option for future decarbonisation of final energy and feedstock use in the chemical industry is to convert the relatively abundant potential of wind and solar energy into heat, chemicals and fuels. …Having knowledge, expertise and capital resources to convert raw materials into products and fuels, the chemical sector is well positioned in the transition to renewable electricity as an energy resource. The energy sector will benefit as well, since electrification of the chemical industry offers a source of flexibility that is needed for the energy transition. (p.9)

More recently, at the request of the European Chemical Industry Council, DECHEMA, the expert network for chemical engineering and biotechnology in Germany published a technology study called "Low carbon energy and feedstock for the European chemical industry" (Bazzanella and Ausfelder, 2017). The authors underline the following points in particular (p.7-9):

- Implementation of the technologies investigated in this study allow for a reduction of CO_2 emissions up to 210 million tonnes (Mt) annually (max) in 2050. The main share of the additional savings is enabled by chemical production of ammonia using hydrogen from low-carbon electricity and production of methanol, olefins and benzene, toluene and xylene (BTX) from hydrogen and CO_2.

- Hydrogen-based ammonia with 1.7 t and methanol with 1.5 t avoided CO_2 per tonne of product are particularly efficient in this respect.

- If the production of fuels is added to chemical production in the scenarios, the CO_2 abatement potential in 2050 increases to 117 million tonnes of carbon dioxide ($MtCO_2$) in the Intermediate and 216 $MtCO_2$ in the Ambitious scenario, corresponding to 98-180% of the chemical sector's own emissions projected in 2050.

- Reaching CO_2 emissions for the European chemical industry by 2050 in this range would entail a demand in low-carbon power that considerably exceeds the amount predicted by the IEA[4] to be available in Europe by 2050.

Hence, the production of hydrogen needs to be considered first, as a precursor of a great variety of chemical commodities – and of which its role in other industries as a processing agent or as a fuel will also be considered in the rest of this report.

Hydrogen

Currently, over 95% of hydrogen, a global production of about 60 Mt/y, is generated from fossil fuels: from natural gas through steam methane reforming (SMR), from cracking oil products in refineries, and from coal gasification, mainly in China. The remainder is produced from electrolysis, usually as a by-product of chlorine production. Most of the hydrogen goes into the manufacturing of ammonia, mostly for fertiliser production, and into refineries.

However, recent and drastic cost reductions in solar and wind power open new possibilities for competitive hydrogen production in large-scale plants. The cost of producing hydrogen through SMR ranges from USD 1 per kilogramme of hydrogen (/kgH_2) to USD 3/kgH_2 due to large disparities in the price of natural gas. Carbon capture with 90% efficiency would increase the cost of hydrogen by USD 0.67/kgH_2, a cost equivalent to USD 70/tCO_2 for stand-alone SMR plants (IEAGHG, 2017a). For ammonia and methanol plants, the cost of capture would range between USD 80 to 100 per tCO_2 (IEAGHG, 2017b). The low heating value of 1 kgH_2 is 120 megajoules (MJ), and its high heating value is 140 MJ.

Figure 7. Cost of hydrogen from electrolysis for different electricity costs and load factors
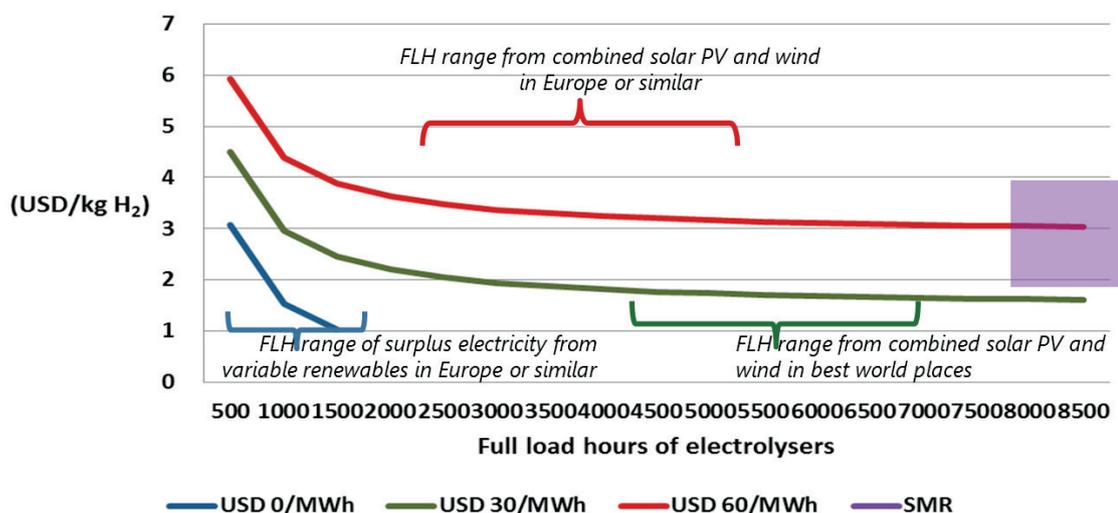
Note: Assumptions - Capex of electrolysers USD 450/kW (Simonsen, 2017), WACC 7%, lifetime 30 years, efficiency 70% (IEA, 2015b); cost of hydrogen from SMR USD 1/kgH_2 to USD 3/kgH_2 depending on natural gas prices.
Key message • For load factors above 50%, the cost of electricity becomes the dominant cost factor of the electrolysis of water.

Figure 7 shows the costs of producing hydrogen for different electricity costs and load factors, expressed in full load hours (FLH) per year, compared with SMR costs (purple

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[4] This refers to the 2DS of *ETP 2015* (IEA, 2015a), which is not a prediction but an optimisation scenario under a carbon constraint.

rectangle). Very large-scale (e.g. 400-MW) alkaline electrolysers can cost USD 450 per kilowatt (/kW) (Simonsen, 2017).

In countries with good but not excellent solar and wind resources, such as European countries, the cost of electricity would be about USD 60 per megawatt hour (/MWh), and the load factor of a combination of onshore wind power and solar PV electricity, hardly above 4 500 FLH, would bring the average cost of hydrogen from USD 3/kgH$_2$ to USD 4/kgH$_2$ (red line in Figure 7).

However, in these countries at times of excess electricity production from variable renewables, the market price of electricity would be very low, or even null or negative. Assuming an average null price, the cost of hydrogen becomes mostly dependent on the load factor of the electrolysers (blue line in Figure 7). This load factor is presumably very low, but if it can be in the range of 1 000 FLH, manufacturing of hydrogen can be competitive.

However, while at smaller scale the cost of electrolysers is significantly higher, load factor uncertainties make such an investment appear risky. Furthermore, the equipment necessary to compress, liquefy or chemically bind hydrogen for storage would also be a risky investment.

Meanwhile, a combination of low electricity costs and high load factors would allow renewables-based hydrogen generation to compete with SMR (green line in Figure 7) – except in countries with especially low natural gas costs, and provided carbon capture and storage (CCS) costs or the carbon externalities are not supported. Both renewables costs and load factors depend essentially upon the quality of the solar and wind resources.

Figure 8. Hybrid solar and wind full load hours adjusted by critical overlap in 2005
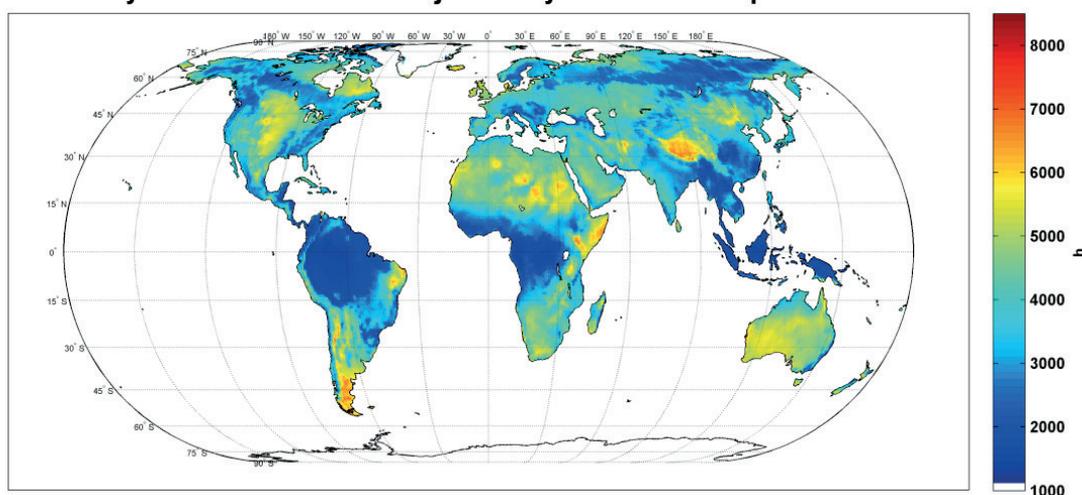
Disclaimer: The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: Adapted and based on Fasihi, Bogdanov and Breyer (2016), "Techno-Economic Assessment of Power-to-Liquids (PtL) Fuels Production and Global Trading Based on Hybrid PV-Wind Power Plants".

Key message • The combination of excellent solar and wind resources is often seen in areas remote from population and industry centres.

Based on extensive hourly wind and solar geospatial data, Figure 8 reveals vast areas (from light green to yellow and orange) where a combination of one-axis sun-tracking solar PV capacities and modern wind turbines would supply a load with load factors over 50%, and up to 6 000 FLH or more in the few red areas. This would apply, for example, to a 100 MW electrolyser supplied with 100 MW of wind and 100 MW of solar resources; the sum of the

respective capacity factors of solar and wind has been duly adjusted for overlap. Complementing this mix with some dispatchable renewable power would help considerably.

Areas with abundant hydropower (and/or geothermal resources) such as Iceland and Norway are possible choices for siting electrolysers.

Ammonia

Ammonia (NH_3) is an essential precursor of fertilisers, bringing nitrogen from the air to the soil and plants. It is also used as a refrigerant gas, in alkaline cleansers, and for manufacturing dyes, fibres, plastics, explosives, nylon and acrylics. Its production of 170 Mt/y currently absorbs half of the over 60 Mt/y of hydrogen produced. Ammonia production alone is responsible for about 420 $MtCO_2$ emissions, over 1% of global energy-related CO_2 emissions.

The cost of fuel (as fuel and feedstock) is the main cost factor in ammonia production, and most of it is spent in the generation of hydrogen. Hence, as with hydrogen, the recent and drastic cost reductions in solar and wind power open new possibilities for competitive ammonia production in large-scale plants.

Ammonia production

Since the 1920s the production of ammonia has been based on the Haber-Bosch process to synthesize nitrogen and hydrogen under pressures of 10 megapascals (MPa) to 25 MPa (100 to 250 bars) and temperatures of 400°C to 500°C over an iron catalyst. The synthesis reaction is exothermic, and no heat needs to be delivered to the synthesis loop. Most ammonia plants produce 300 000 t/y to 600 000 t/y, some up to 1 Mt/y. They are designed to be available for 330 days, or about 8 000 hours per year (Morgan, 2013).

In some plants, a fraction (up to 40%) of the CO_2 produced is captured and used in combination with ammonia to manufacture urea, a nitrogen fertiliser that can be handled safely. On average however, ammonia plants emit over 1.6 tCO_2 per tonne of NH_3 ($/tNH_3$) using natural gas, 2.5 tCO_2/tNH_3 using naphtha, 3 tCO_2/tNH_3 using heavy fuel oil, and 3.8 tCO_2/tNH_3 using coal (IFA, 2009).

Electrolysis of water is a well-known alternative to using fossil fuels to produce hydrogen – and so far, has been run mostly by hydropower. Indeed, until the 1960s, most fertilisers sold in Europe came from hydropower-based electrolysis and ammonia production at Vemork and Rjukan in Norway. Low gas prices, increased fertiliser demand and the emergence of SMR led to the closure of these plants, as carbon emissions were not considered.

Of the few all-electric ammonia plants that have remained operational until recently, the largest, in Egypt, is now being converted to natural gas reforming, mostly to free up more electricity for the growing needs of the country. However, forthcoming hydropower plants in Africa may provide large output in excess of regional needs, providing new opportunities for manufacturing ammonia and fertilisers in sub-Saharan Africa. Conversely, the prospect of running some electricity-intensive industrial processes could help very large projects, such as Grand Inga in the Democratic Republic of the Congo, find a more realistic justification than exports of electricity via hypothetical, very long-range high-voltage connections.

Despite being largely modular, electrolysers exhibit economies of scale as the compressors, gas holding tanks, transformers and balance of plant equipment are scaled up (Morgan, 2013). Capital costs for ammonia plants vary even more with scale, exerting a considerable influence on the production costs (Figure 9).

Figure 9. Costs of ammonia from SMR for various plant capacities
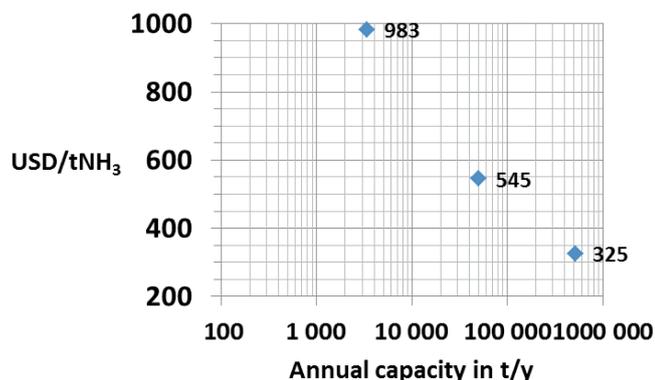
Note: Assumption - natural gas price USD 5 per million British thermal units (/MBtu).

Source: arpa-e (2017), *Renewable Energy to Fuels through Utilization of Energy-Dense Liquids (REFUEL) Program Overview*.

Key message • **Economies of scale make large ammonia plants more cost-effective than smaller ones, even in association with distributed energy resources.**

The only raw inputs for an all-electric ammonia plant, besides energy, are air and water: over 1.5 tonnes of water per tonne of ammonia (tH_2O/tNH_3). Air, made of 78% dinitrogen (N_2) is the source of nitrogen. If freshwater is not an option, plants located near seashores could use desalinated seawater. Seawater intakes and rejection of brines in the ocean are the most significant environmental issues to consider.

In ammonia plants, besides generation of hydrogen, which dominates the power demand (Figure 10), all other sub-systems are electric (Morgan, 2013) and consist of the following:

- cryogenic air separation units (ASUs) for producing nitrogen
- A centrifugal compressor running the synthesis loop (Haber-Bosch process)
- mechanical vapour compression (MVC) for desalinating seawater (if needed), the most likely large-scale option to provide sufficiently pure water to feed electrolysers.

Although not required in SMR plants, ASUs would be similar to those used in coal-based ammonia plants – a well-known technology. Electric ammonia plants would be simpler than conventional ones and avoid the need for several devices addressing natural gas impurities.

Figure 10. Indicative breakdowns of a large-scale all-electric ammonia plant's power needs
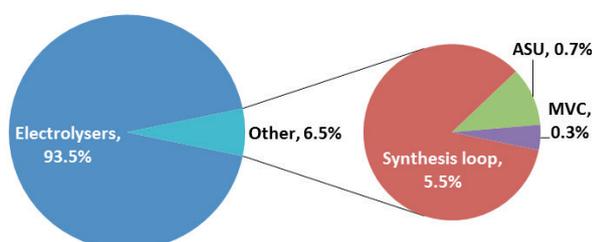
Source: Morgan (2013), Techno-Economic Feasibility Study of Ammonia Plants Powered by Offshore Wind.

Key message • **In all-electric ammonia plants, electrolysers account for over 90% of electric load.**

For very large-scale all-electric plants, alkaline electrolysers are currently the less-costly option. Electrolysers account for up to two-thirds of the total capital expenditures of an electric ammonia plant (Morgan, 2013), although recent cost evolution of alkaline

electrolysers bring this ratio closer to half. They absorb over nine-tenths of the electricity that the entire ammonia plant with all its sub-systems consumes. Figure 10 provides for indicative break-downs of power needs of a baseload electric plant of 100 000 t/y.

The ratio of electrolysers to ammonia plants should be optimised for variable electricity. If the capacity factor of solar and wind combined is expected to be 6 000 FLH, the synthesis loop, which would run continuously, would be relatively smaller.

Solid oxide electrolyser cell (SOEC) technology, working at high temperatures, offers the best prospects for and cost reductions and efficiency improvements, especially coupled with an ammonia synthesis loop (Cinti et al. 2017), but it is not yet commercially available. Proton exchange membrane (PEM) technology for electrolysers, not yet available at the required scale, would presumably offer the most flexible operations.

## *Ammonia production from variable renewables*

The best resource areas might be remote from densely populated areas and therefore be isolated from, or weakly connected to, main electric grids. Hence, large-scale all-electric ammonia plants, run primarily by dedicated newly built assets, would most likely not be connected to the country's grid, or would rely on a connection of very low capacity. Furthermore, if solar and wind capacities are an important part of the power mix in the country, the country and the ammonia plants may both experience power excesses or deficits at the same time. For both these reasons, plants cannot be designed to depend on the country's power system as a dispatchable source, or as an unlimited sink.

Variability of power creates various challenges: alkaline electrolysers can operate between 20% and 100% of their nominal load, and ASU and MVC units need small amounts of power and their outputs are storable. The synthesis loop, however, would work best with steady-state operations and requires continuous supply – but it consumes only about 5% of the total. In a recent study, Nayak-Luke et al. (2017) state that the synthesis loop can adjust to variable electric input, provided it is not discontinued, and provide insights on the economic relevance of the various cost factors.

A plant run by solar and wind with a combined load factor of 5 000 FLH to 6 000 FLH, will have 25% of its load available most of the time, and times with less than 5% capacity will be rare – a few hundred hours per year. Short-term storage of compressed hydrogen and nitrogen could be extended somewhat to ensure continuous operations of the synthesis loop, while some storage or backup would secure its electricity supply. The additional costs would be small, as the hydrogen needs to be compressed before entering the synthesis loops anyway, and only a fraction of the total power capacity would need to be made dispatchable.

Ammonia plants run on one-only variable renewable source would be somewhat more challenging – especially if run on solar only, as capacity factors are usually lower than those of wind power. Nevertheless, Siemens is running a pilot ammonia plant with a 20 MW wind farm (Wilkinson, 2017), and Yara recently announced its intent to build a pilot solar ammonia plant in the Pilbara region of Western Australia, to be in service as early as 2019 (Brown, 2017a).

A large ammonia plant designed to produce 500 000 t/y, whether for exports or local transformation into a variety of fertilisers, would consume about 4.8 TWh annually to produce over 88 000 tH$_2$ and to run all sub-systems. Assuming 5 000 FLH for combined solar and wind power capacities, the required deployment for 1 GW electrolysers could be, for example, 1.1 GW for wind turbines and several hundred MW for solar PV plants.

Figure 11. Electrolyser relative size, curtailment and load factors: The case of South Africa
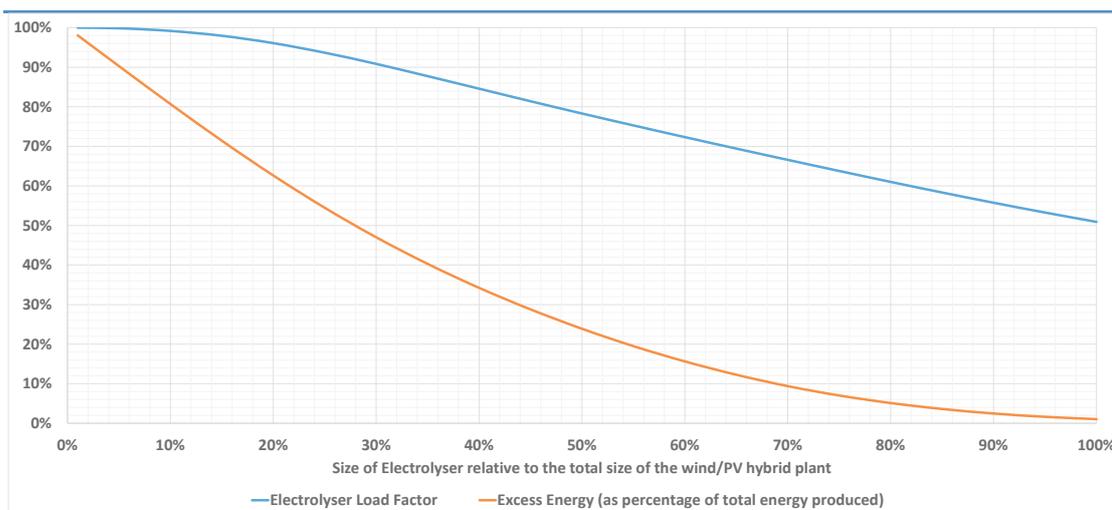
Source: Bischof-Niemz (2017), personal communication.

Key message • Proper trade-offs between high utilisation factors of electrolysers and curtailment of solar and wind power will be site-specific and require a detailed assessment of resources.

These are rough indications, however. Solar capacity may be further adjusted downward to minimise critical overlap with daytime wind power; in some places it could be only a small complement to wind power. Only detailed, specific studies with hourly outputs of solar and wind could help optimise the respective capacities of solar, wind and electrolysers.

The size of electrolysers relative to renewable capacities represents a trade-off between capacity factors and curtailment, as illustrated in Figure 11 (based on actual 2016 data of South African PV and wind farms, scaled to optimise the solar PV and wind mix). Similarly, the design of the ammonia plant and the means to ensure steady-state operation of the synthesis loop – battery, grid connection, or backup (presumably run on hydrogen or ammonia) – need to be adapted to the specific conditions of any project.

Figure 12. Cost of ammonia at various electricity prices and electrolyser load factors
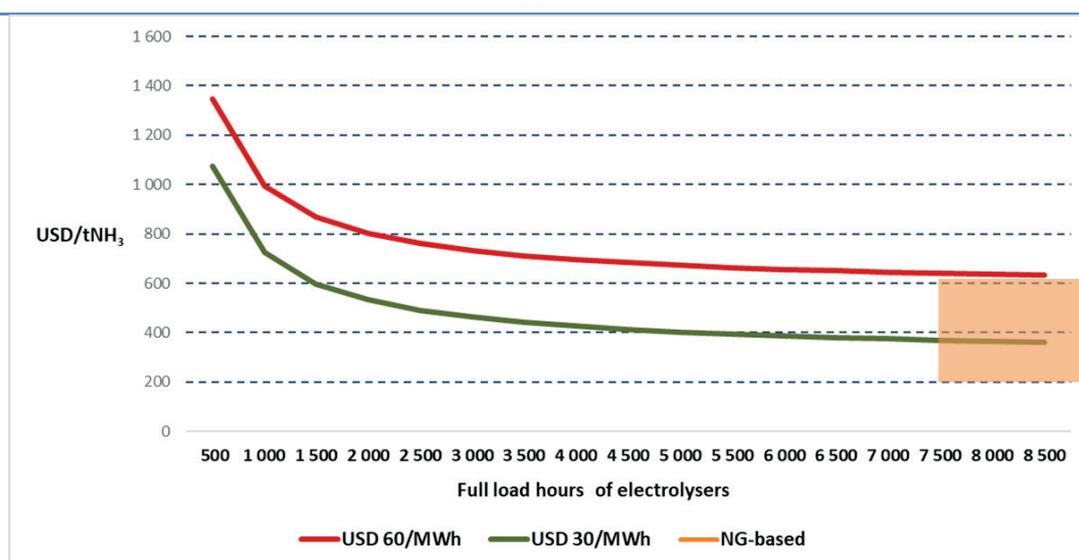
Notes: Assumptions - See Figure 7 for the hydrogen production. Additional assumptions: plant capacity 500 000 t/y, Capex USD 382 million (Haber-Bosh loop USD 250 mln, air separation unit USD 60 mln, mechanical vapour compression USD 42 mln, storage USD 30 mln) adapted from Morgan [2013], adjusted for different annual outputs); WACC 7%; lifetime 30 years; Opex USD 14/tNH$_3$ to USD 37/tNH$_3$ plus electricity.

Key message • Like hydrogen, the cost of green ammonia depends primarily on the cost of electricity as long as load factor of electrolysers exceeds 50%.

Depending on locations and fossil fuel costs, green ammonia competes with NG-based ammonia, which volatile costs range from USD 200 to 600/tNH$_3$ (Figure 9). Factoring in the cost of carbon capture of USD 80 to 100/tCO$_2$ would add USD 136 to 170/tNH$_3$ from SMR. In the case of ammonia production in areas far from consumption centres but close to port facilities, an average cost of USD 50/tNH$_3$ for large-scale, long-range shipping should be factored into the final cost (see Box 3 and Box 4). If all ammonia currently manufactured (i.e. 180 Mt/y) were produced from renewable electricity and water electrolysis, production would absorb about 1 730 TWh/y at current technology efficiencies.

As the potential of remote, high-quality solar and wind resources may vastly exceed current global electricity needs, renewable production of ammonia may serve many more purposes than its current uses in industry. As discussed in the remainder of this report, this may include various uses of ammonia or its hydrogen content as a reducing agent in steelmaking, or as a fuel for heat for stationary end-use in the industry and power sectors (Figure 13).[5]

Figure 13. **Concept scheme of renewable production of ammonia for a variety of uses**
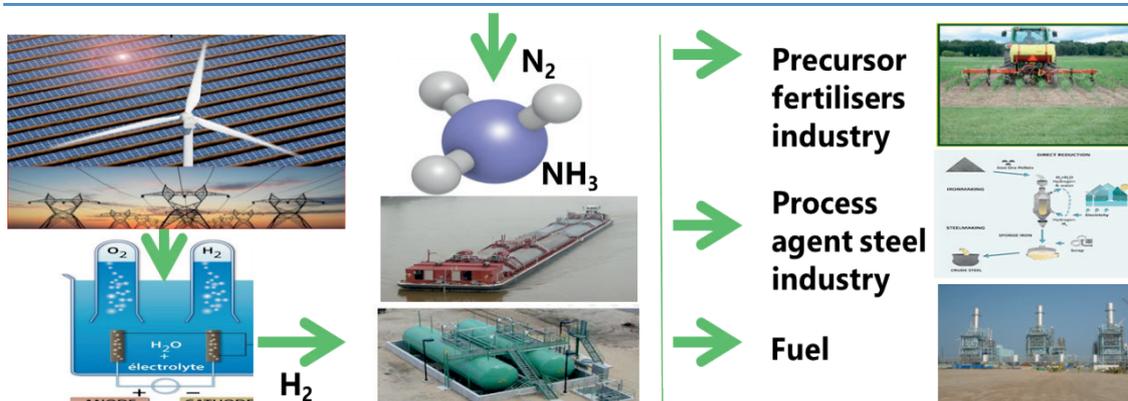
Key message • **Renewable ammonia can have multiple roles as a precursor, process agent and fuel.**

Alternative to the Haber-Bosch process, direct electrochemical ammonia synthesis in molten-salt electrolytes and on membranes are still under development. In transferring hydrogen ions from water or steam to nitrogen, they would bypass the formation of dihydrogen molecules, potentially reducing electricity consumption by up to 30%. The difficulty is precisely to avoid the formation of dihydrogen, and sufficiently selective catalysts cannot yet be identified for this. Scientists from Denmark and the United States recently demonstrated a step-wise strategy to get around this difficulty and increase the efficiency of ammonia production – but at the cost of increased electricity consumption (McEnaney et al., 2017).

Another renewables option in areas with strong sunshine and clear skies (i.e. excellent DNI) rests on concentrating solar technologies, which could directly drive water-splitting as well as air separation based on metal redox (reduction-oxidation) cycles, and research is under way at the German Aerospace Center (Reis, 2017). This technology is, however, farther from the market than electrolysis run mostly on PV and wind power. In the short term at least, the best possible contribution of concentrating solar technologies to ammonia production could be to produce high-temperature heat for SOEC technology, or make the electricity mix more dispatchable to ensure steady-state operation of synthesis loops, and perhaps smooth out variations in the electricity supplied to the electrolysers.

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[5] Possible uses of ammonia as a fuel in transport or buildings are beyond the scope of this report.

As a first step, hybrid ammonia production could make sense, especially in areas with intermittently available, inexpensive renewable power. In this context, electrolysers and natural gas reformers could co-exist, avoiding the need for an air separation unit. Reduced CO_2 formation, compared with conventional production, could be adjusted to urea manufacturing needs. (Urea, the most common fertiliser, is usually manufactured directly from NH_3 and CO_2 at ammonia plants.) Giving greater flexibility to electrolysers, Bazzanella and Ausfelder (2017) assert that hybrid ammonia production would maintain the high level of process and heat integration of today's ammonia-urea plants.

In addition to ammonia production, Anastasopoulou et al. (2016) have assessed the techno-economic feasibility of renewable power systems in Kenya and South Africa, notably associating solar and wind power to produce nitric acid, another potential precursor of nitrogen fertilisers, at small-scale plasma-assisted plants.

Methanol

Methanol (MeOH), the simplest alcohol, is a very versatile product in the chemical industry. It is used mostly as a precursor of plastics (through both propylene and formaldehyde), plywood, paints, explosives and permanent-press textiles. It is also used to form gasoline additives in some countries, enters the production of fatty acid methyl ester biodiesel, and forms the basis of dimethyl ether (DME), which is an aerosol spray propellant and a transportation diesel fuel or, in combination with liquefied petroleum gas, is used for home heating and cooking. Its global production has increased by 50% since 2009, to 72 Mt/y, and is expected to almost triple by 2050.

Two-thirds of methanol (chemical formula CH_3OH) is produced from natural gas through SMR, and one-third is produced from coal gasification, followed by catalytic reactions to combine carbon monoxide (CO) and CO_2 with H_2.

Associated CO_2 emissions are about 1 tonne of carbon dioxide per tonne of methanol ($tCO_2/tMeOH$) when produced from natural gas, and 2.4 $tCO_2/tMeOH$ to 3.5 $tCO_2/tMeOH$ when produced from coal. If methanol is used as a fuel, its combustion entails additional emissions of 1.4 $tCO_2/tMeOH$.

SMR and coal gasification are the main sources of CO_2 emissions in manufacturing methanol. These emissions can be drastically reduced or suppressed if a renewable source of hydrogen is used, such as water electrolysis operated on renewable electricity. However, the combustion of fuels manufactured from methanol, such as DME, is another source of CO_2 emissions. Manufacturing carbon-neutral fuels would therefore require that the carbon bound in methanol come from the atmosphere.

Producing methanol in a more sustainable way could be done by a variety of methods. Bio-methanol can be manufactured from wood or waste streams (IEA-ETSAP and IRENA, 2013). Methanol costs would range from USD 225/t to USD 1 300/t produced from wood, and USD 280 to USD 700/t from waste streams, compared with USD 320/t to USD 376/t from fossil fuels (as of June 2017).

An alternative method entails the production of hydrogen from electrolysis of water based on renewable electricity, followed by hydrogenation of CO_2. As discussed above, electrolysis is now close to being able to compete with SMR, especially in areas with excellent renewable resources (see Hydrogen subsection above). In Iceland, the company Carbon Recycling International currently produces 4 000 t/y of carbon-neutral methanol, based on the electrolysis of water using renewable sources of the country's power grid, and CO_2 captured from a geothermal power plant. The commercial name, Vulcanol, clearly signals the

singularity of this option that benefits from naturally concentrated CO_2 flux coming out of the earth – in this case from a geothermal plant, but it could be a volcano. In most cases, the origin of the carbon has significant implications for the climatic impact of methanol.

In what they consider "a conservative, globally applicable approach", Fasihi and Breyer (2017) model methanol production from renewable hydrogen and CO_2 captured from ambient air, as this is independent of location. They chose Climeworks technology,[6] which allows 80-90% of the required energy to be supplied by heat, which can be partially provided by the waste heat of electrolysis and synthesis units, together with heat pumps: capturing 1 tCO_2 from the air would require 1 300 kWh to 1 700 kWh of thermal energy at 100°C and 200 kWh to 250 kWh of electricity. In total, the direct air capture absorbs only 8.5% of the renewable electricity needed, the synthesis loop another 2%, and practically all the rest is required for the water electrolysis. These proportions are not fundamentally different from those observed with ammonia synthesis, despite the considerable disproportion between the atmospheric concentrations of nitrogen and CO_2.

According to Fasihi and Breyer, it will be possible in 2030 to produce the most inexpensive methanol (USD 470/t to USD 710/t) in Patagonia, the Atacama Desert, eastern Brazil, southern Africa, Somalia, the Western Sahara, Saudi Arabia and Australia, thanks to excellent renewable resources. Tibet, despite excellent solar and wind potential, is not listed due to its very long distance from consumption centres or port facilities. The modelling includes batteries to deliver baseload electricity for steady-state operation of the synthesis unit, while significant amounts of electricity are curtailed in various regions. These calculations rely on assumed future cost reductions for solar and wind power: costs at current electricity prices in most favourable places would be about 25% higher.

However, the cost of CO_2 could be reduced or suppressed if CO_2 captured from the processing of gases can be procured. The price paid could be low, null or even negative if the supply exceeds the demand and owners could avoid paying for long-term storage.

For methanol to be fully carbon-neutral when used as a fuel (its carbon oxidised and released), the CO_2 used to manufacture it should have been taken out of the air; this would be the case if the CO_2 were captured from biomass combustion. When methanol is used of durable goods, the carbon is stored in those goods. Depending on the durability of the goods, the entire cycle could even entail negative emissions (Figure 14).

If the CO_2 used to produce the methanol that is then used to manufacture durable goods were captured from the combustion of fossil fuels, there would be no emissions whatsoever – neither negative nor positive. However, even if the methanol produced from recycled CO_2 of fossil origin were combusted as a fuel, there would be a significant climate benefit. Taking into account the original CO_2 emissions avoided by using recycled CO_2 as feedstock and renewables-based electricity, as well as indirect emissions from capture and transport and small residual process emissions, Bazzanella and Ausfelder (2017) calculate that 1.53 tCO_2 would be avoided in the production of 1 t of methanol, compared with using natural gas as the feedstock and energy source. In any case, underground storage of CO_2 captured from biomass use would not be preferable if methanol were to be manufactured from fossil fuels.

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[6] On 31 May 2017, Climeworks launched its first commercial-scale direct-from-air CO_2 capture plant, which removes 900 tCO_2 per year from the air, near Zurich. Air is drawn into the plant and the CO_2 in the air is chemically bound to the filter. Once the filter is saturated with CO_2 it is heated to around 100°C. The CO_2 is then released from the filter, and collected and sold to a nearby company growing vegetables in a greenhouse. CO_2-free air is released back into the atmosphere. This continuous cycle is then ready to start again and the filter reused thousands of times.

Figure 14. Concept scheme of carbon-neutral, renewable methanol production
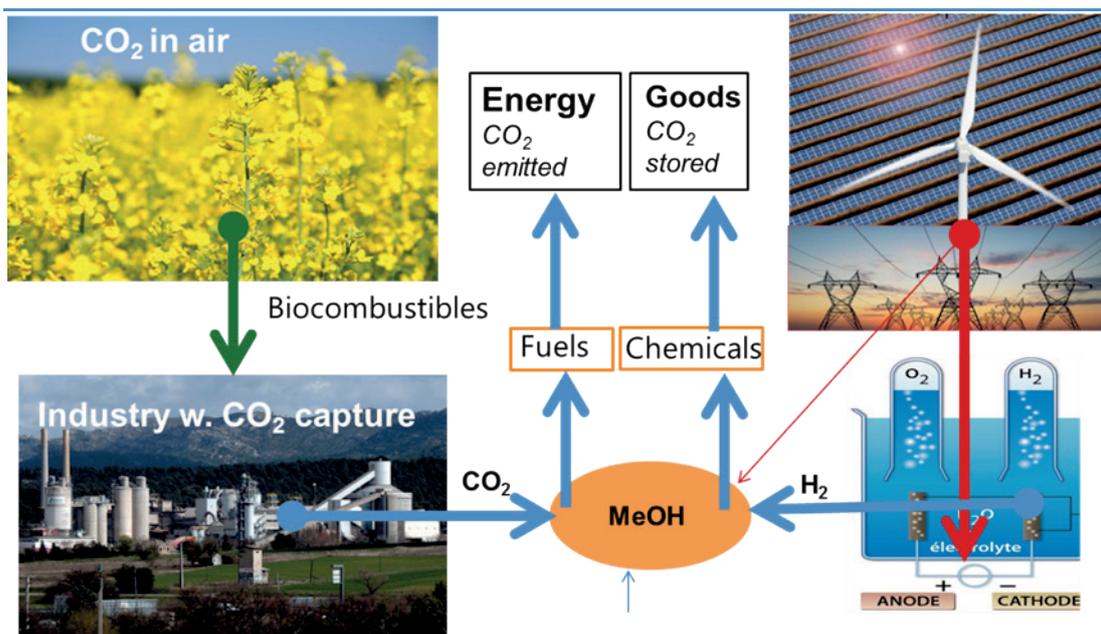
Key message • **Manufacturing methanol from renewables-based water electrolysis and recycled CO_2 would strongly reduce life-cycle CO_2 emissions and could drive negative emissions.**

Bazzanella and Ausfelder (2017) assess the cost of carbon-neutral methanol production based on renewables and recycled CO_2 in regions with the best solar and wind resources at USD 630/tMeOH – but with expensive electrolysers. With large-scale electrolysers at USD 400/kW, the cost of methanol would fall to around USD 400/tMeOH, about the same price as methanol produced from fossil fuels. In most cases, the cost of shipping recycled CO_2 to the plants, and of shipping methanol, should be added. Long-distance, large-scale shipping of CO_2 would be slightly more complex than shipping ammonia, whereas shipping methanol, at ambient temperature and atmospheric pressure, would be less complex. Retaining an average of USD 50/tMeOH for both trips amounts to a total of USD 100/t and avoidance of 1.5 tCO_2/tMeOH. The cost gap could thus be covered by a carbon price of USD 67/tCO_2.

With less favourable assumptions for electricity prices and load factors, in less-favoured regions, the cost of green methanol would be close to USD 700/t. Closing the gap with fossil fuel-based methanol would, in the least favourable case of methanol for fuel, require a carbon price of USD 200/tCO_2.

Another option is to manufacture methanol with renewable hydrogen and carbon monoxide instead of CO_2 – as with the standard process from natural gas. Carbon monoxide can be sourced from various industries and processes. While carbon monoxide from steelmaking may become scarcer if hydrogen-based direct iron reduction develops as suggested below (subsection C. Iron and steel), it could be made available in large quantities from greening cement factories (subsection D. Cement). To obtain 1 t of methanol, 875 kg of carbon monoxide and 125 kg of hydrogen are necessary; renewable hydrogen priced at USD 2/kg and carbon monoxide at about USD 50/t to USD 70/t would allow methanol to be produced at a competitive price.

High-value chemicals

Carbon is also needed for the production of materials in the petrochemicals sector, where it comprises around 75% of the total feedstock. Olefins (mainly ethylene, propylene and butadiene) are typically produced through steam-cracking various petrochemical feedstocks such as ethane, liquid petroleum gas, naphtha and gas oil. In 2014, 122 Mt of ethylene, 130 Mt of benzene, toluene and xylenes (BTX) and 86 Mt of propylene were produced globally. Naphtha is the main feedstock for producing BTX through reforming, as well as ethylene in Europe. Naphtha cracking emits 1.5 tCO_2 to 3 tCO_2 per tonne of ethylene. The main alternative feedstock is biomass, which requires significant process changes.

Organic materials such as cellulose fibres, coconut fibres, starch plastics, fibre boards and paper foams can directly substitute for petrochemical products in end-use applications. Textile materials (mainly viscose and acetate) can be produced from wood pulp and as by-products from cotton processing. Producing ethylene from bioethanol is technically relatively straightforward, and some companies are already doing it on a large scale (Taibi, Gielen and Bazilian, 2012).

The potential to use current crops (e.g. sugar beets) instead of oil as feedstock to produce ethanol and ethylene is marginal. The resources being limited, food production and biodiversity preservation would soon restrict supplies in most countries. The only large-scale conversion of ethanol to ethylene and polymers takes place in Brazil, mainly because sugar cane supplies are ample supply and the cost is relatively low.

Cellulosic ethanol conversion, based on forestry and agriculture sector residues, seems a more promising alternative as it entails much less competition for land and much lower indirect greenhouse gas (GHG) emissions. Cellulosic ethanol is currently being produced on a commercial scale in Brazil, China, India, Europe and the United States, in diverse demonstration plants that are the first of their kind. In March 2016, Avantium and BASF announced a joint venture to produce a key precursor of bio-based polyethylene furanoate (PEF). PEF has the potential to become an important product, as it can replace polyethylene terephthalate (PET). PEF has better barrier properties for gases than PET and higher mechanical strength, allowing for thinner food and beverage packaging. Furthermore, PEF can be recycled after usage.

In the European Union, the bio-based industries' public-private partnership (PPP) is the flagship chemicals innovation initiative under Horizon 2020. It consists of a total EUR 3.7 billion investment in bio-based innovation between 2014 and 2020: EUR 975 million from EU funds (Horizon 2020), and EUR 2.7 billion from private investments. The main goal of the PPP is to replace at least 30% of petroleum-based chemicals with bio-based and biodegradable alternatives by 2030. The new bio-based products will, on average, reduce CO_2 emissions by at least 50% compared with fossil fuel-based alternatives.

The deployment of biomass-based methods for producing high-value chemicals (HVC) may, however, be limited by the high cost of biomass feedstocks if biomass demand from industry, transport and power were to increase significantly in response to CO_2 emissions reductions requirements. This constraint would be partly alleviated if renewable power and hydrogen were widely used instead of biomass in these various applications.

Palm, Nilsson and Åhman (2016) figured out that both ethylene and propylene can be produced from electricity, requiring 3 tCO_2 per tonne of product, and 20 MWh/t for ethylene production and 38 MWh/t for propylene. According to Palm, Nilsson and Åhman, the process would involve recycling CO_2 with renewables-based hydrogen to provide methane (CH_4) through the Sabatier reaction. This reaction has an inefficient hydrogen use, and its CO_2

conversion rate is low, but it provides heat that could feed SOECs when commercially available, saving electricity. This would imply co-location of electrolysers and Sabatier reactors, but methane is easier to ship than hydrogen. According to Palm, Nilsson and Åhman, the production of ethylene and propylene in Europe at constant production levels would require 800 TWh per year of electricity and emit 90 $MtCO_2$, and that of all plastics 1600 TWh, with emissions of 180 $MtCO_2$.

C. Iron and steel

Iron and steel is the second-largest industry energy consumer, claiming 23% of total global industry final energy demand, but it is the largest industrial CO_2 emitter, with 28% of the sector's total direct CO_2 emissions in 2014 owing to more carbon-intensive fuel use (mostly coal) and considerable process emissions in the reduction of iron ore. This share accounts for 7% of total energy-related CO_2 emissions, and is projected to increase to 10% by 2050 under the 2DS (IEA, 2017a).

There are two main methods for making primary crude steel (CS) from iron ore. The most common uses coke made from coal to melt and reduce iron ore (mostly oxides) into pig iron in a blast furnace (BF). The hot metal is then sent into a basic oxygen furnace (BOF), where high-temperature oxygen is blown into it to reduce its carbon content (Figure 15, left) before semi-finishing steps such as casting and rolling. The other method, direct reduction (DR), reduces the iron ore in solid form with a synthetic gas made of carbon monoxide and hydrogen derived from natural gas or from coal gasification. The resulting sponge iron is then melted in an electric arc furnace (EAF) together with recycled scrap steel.

Over 90% of the direct CO_2 emissions of steel production result from these primary steelmaking methods, in which the reduction of iron ore into iron accounts for about 80% of the emissions. The specific level of CO_2 emissions depends particularly on the shares of recycled steel and of fossil fuels in the electricity mix, especially for the DR method, which emits about 1.7 tCO_2 per tonne of CS on average (IEA, 2017a).

CCS has often been proposed as a means of decarbonising the steel industry. Recycling top gases from blast furnaces with CO_2 capture has the rare benefit of reducing coal consumption by 25% (thanks to the energy content of recycled gases), while in most other applications CCS increases fossil fuel consumption. However, it only reduces overall emissions by about 60%. Reaching much higher reduction rates is possible, but several capture facilities would have to be added to steel mills at each step: at the sinter plant, the reheating furnace, the steel plant, the hot stove, the lime kiln, and the coke oven – at growing capital and operating expenses (Birat, 2011).

Al Reyadah CCS, the world's first commercial CCS project in the steel industry came on line in 2016 in the United Arab Emirates. It follows the other main steelmaking method, that of natural gas-based DR, and captures 0.8 $MtCO_2$ per year, which is used for enhanced oil recovery. This represents 11% of the country's iron and steel emissions.

HIsarna is a more innovative method that, coupled with CCS, could reduce emissions considerably. HIsarna is a smelt reduction process in which the ore is processed directly into liquid iron or hot metal. It combines a hot cyclone for ore melting and pre-reduction, and a bath smelter where the final reduction takes place. It is more energy-efficient than the BF-BOF method and operates with pure oxygen, so that off-gases have a CO_2 concentration almost high enough to be directly stored (see IEA, 2017a for more details).

Figure 15. Iron- and steelmaking methods
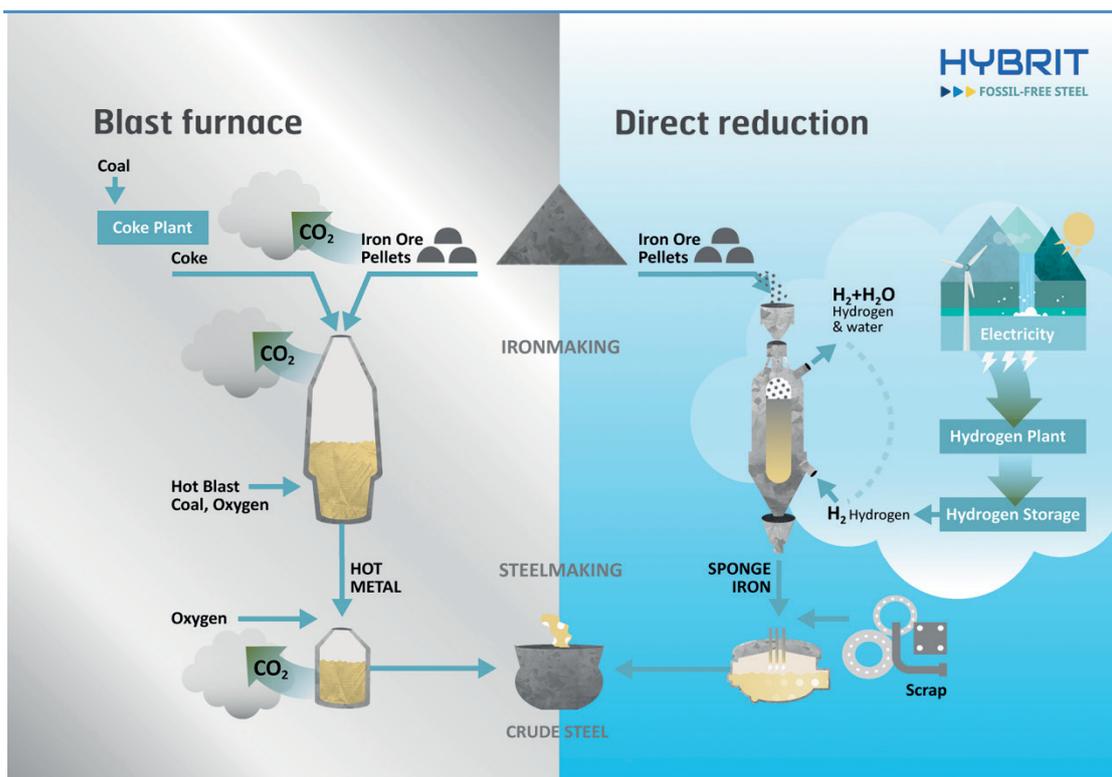
Source: Hybrit Development (2017), personal communication.

Key message • **Steelmaking with very low CO₂ emissions could be accomplished through the current DR-EAF method, using renewables-based hydrogen instead of syngas from natural gas.**

There are, however, other options that would rely on using renewables to decarbonise the steel industry. One is electrolysis of iron ore, also known as electrowinning. Two processes have been studied, together with HIsarna, as part of the European research programme Ulcos, or Ultra-Low Carbon Dioxide Steelmaking. Under Ulcowin, iron ore would be electrolysed at a "room temperature" of about 110°C. Under Ulcolysis, iron ore would be solved or suspended in an acid or alkaline solution, or melted in a saline solution for high-temperature electrolysis around 1 600°C.

Another option is to use hydrogen as the reducing agent. Based on its solid experience of using the natural gas-based DR method, the Swedish iron and steelmaking industry (LKAB and SSAB), in association with Vattenfall and with strong support from the Swedish Energy Agency, has undertaken a feasibility study for reducing iron ore with pure hydrogen, a variant that has been termed hydrogen-DR (H-DR) (Figure 15, right). The hydrogen would presumably be produced from renewable electricity – most likely a mix of hydropower and wind power – so that CO₂ emissions would be close to zero.

Weigel et al. (2016) performed a multicriteria analysis of four primary steelmaking technologies: the usual BF method, followed by BF-BOF, the same but with CCS (BF-CCS), H-DR and electrowinning.

Only the two latter options are compatible with very deep emissions reductions according to Weigel et al., as top-gas recycling associated with CCS would reduce emissions by only 60% as noted above. Electrowinning is deemed the most energy- and resource-efficient production route, with 2.6 MWh of energy required per tonne of crude steel produced versus 3.6 MWh for H-DR, 4.3 MWh for BF-CCS (mostly from fossil fuels) and 5 MWh for BF-BOF. The world average is 5.83 MWh/t (IEA, 2017c).

Weigel et al. suggest a preference for H-DR, considered significantly closer to commercialisation than electrowinning. Indeed, natural gas-based direct iron reduction is well established, and partly substituting methane with hydrogen was demonstrated by the Circored fluidised bed plant in Trinidad from 1996 to 2005, with hydrogen extracted from natural gas. A significant advantage could be the possibility to progressively enrich the hydrogen and carbon monoxide mixture from natural gas with renewables-based hydrogen in existing facilities.

A variant developed in the United States – hydrogen flash smelting – uses suspension in a flash-type furnace, in which iron ore concentrates are sprayed directly. Studies suggest energy consumption of about 38% less than in the BF-BOF method, largely the result of eliminating coke-making and the iron ore pelletizing and sintering steps, and CO_2 emissions reductions of 96% (Hasanbeigi, Arens and Price, 2014).

H-DR may also be preferred over electrowinning, as hydrogen could be produced more economically in regions with vast, excellent renewable resources and shipped into high-consuming areas, chemically bound in ammonia or other hydrogen carriers. The ability of electrowinning to absorb variable electricity supply is unknown in the iron case, as the technology is not yet fully developed. Furthermore, there might be no need to crack ammonia and use pure hydrogen to reduce iron ore. The direct use of ammonia as reducing agent is also of interest because iron ore has been shown to be a catalyst for ammonia decomposition (Hosokai et al., 2011; Yasuda et al., 2015).

Producing one tonne of crude steel by the BF-BOF method requires 0.8 t of coking coal, the price of which has recently proven very volatile – ranging from USD 80/t to over USD 200/t, with short, higher spikes. However, in a world moving towards alternative production methods, the price of coal is expected to remain closer to the low end of its range. The energy cost would therefore average out to USD 80 per tonne of steel.

With respect to H-DR, almost 1.4 t of iron ore must be reduced to produce 1 t of steel, requiring about 75 kgH_2, or 3.57 MWh of electricity. Assuming a cost of USD 30/MWh for electricity in regions with excellent resources, from which hydrogen could be shipped as ammonia, the cost of hydrogen would be about USD 2/kg. Electric arc furnaces and other devices would need another 850 kWh of power[7] to be available wherever steelmaking takes place. Assuming lower-quality renewable resources and a cost of USD 60/MWh for the electricity,[8] the energy bill would add up to USD 200 per tonne of steel.

Another possibility would be to process iron ores directly in areas with excellent renewable resources. Indeed, several of the world's largest iron ore deposits are located in southern Brazil, western China, Mauritania, northern Chile, South Africa and Western Australia, and are relatively close to areas with excellent resources. Electrowinning could be the best option to process these ores with renewables-based electricity, if the technology can be fully developed. If H-DR is the best available option, the output could be shipped as hot-briquetted iron. Processing it into steel on the spot, however, would keep it hot and thus save energy in arc furnaces and benefit from lower electricity costs.

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[7] Author's own calculation finds a total of 4.42 MWh per tonne of steel for the H-DR method, higher than Weigel et al.'s (2016) calculation based on Fischedick et al., 2014.

[8] In these regions, electrowinning with a lower electricity consumption of 2.6 MWh per tonne of steel would have a lower energy cost of USD 156 per tonne of crude steel - if enough renewable power at USD 60/MWh is available.

H-DR thus appears to be not directly competitive with BF-BOF with unmitigated CO_2 emissions. However, the additional energy cost of about USD 120 per tonne of steel represents a cost of about USD 60/tCO_2 in avoided CO_2 emissions – assuming average emissions reductions of 2 tCO_2 per tonne of steel.

For iron and steel, these economic estimates do not take into account investments in new industry capacities and infrastructure – which may or may not be different depending on the level of GHG emissions of the various technologies considered; they only represent the cost of hydrogen in comparison with other sources of hydrogen or other feedstocks and fuels. Only a full modelling exercise, beyond the scope of this report, could assess the overall cost of CO_2 emissions reductions by shifting both existing and new capacities onto new technology pathways.

In the case of steel, however, Ranzani da Costa, Wagner and Patisson (2013) have shown that, due to the more rapid reduction of iron ore with pure hydrogen than with syngas produced from natural gas, the direct reduction reactors could be significantly downsized, offering the prospect of a lower Capex for new plants.

Global crude steel production is about 1.7 gigatonnes (Gt) and growing. With a potential of 30% from scrap, 1.2 Gt of steel would come from processing 1.7 Gt of iron ore. The amount of hydrogen needed for the H-DR method would thus be 90 Mt, requiring 4 320 TWh of energy (assuming 70% electrolysis efficiency). Another 935 TWh would be needed for the rest of the process, i.e. a total of 5 255 TWh – with current technologies.

D. Cement

Cement is the third-largest energy consumer in the industry sector, accounting for 7% of total final industrial energy use, but due to important process emissions, cement has the second-largest share of CO_2 emissions from industry at 27%, i.e. 6.5% of total energy-related CO_2 emissions. This share is projected to double by 2050 under the 2DS, putting the cement subsector in first place.

More than half of the cement industry's CO_2 emissions are process emissions from the clinker production process, in which limestone ($CaCO_3$) is heated to produce lime (CaO) and thus release CO_2. However, process emissions are partially compensated for by the reverse reaction when the cement is used in construction, including in concrete, as it absorbs atmospheric CO_2 by carbonation of lime into limestone. The share of atmospheric CO_2 absorbed over (possibly very long) time by buildings has been assessed at 43% of the initial process emissions (Xi et al., 2016).

With respect to energy use, biomass and other wastes are already part of the cement manufacturing process in various factories, contributing over 5% of the cement subsector's energy consumption in 2014 (IEA, 2017a) – versus 63% from coal, 13% from electricity, 10% from oil and 9% from gas.

The SOLPART project aims to develop at pilot scale a high-temperature (950°C) solar process suitable for particle calcination in energy-intensive industries – typically cement or lime, but also phosphate ores and others.[9] Supported by the European Union and the cement (Cemex, Mexico), phosphates (Office Chérifien des phosphates, Morocco) and other industries, and

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[9] www.solpart-project.eu.

co-ordinated by the French Centre of Scientific Research using its solar oven at Odeillo in the French Pyrenees, the project is based on concentrating solar technologies.

SOLPART is expected to significantly reduce the need for combustible energy and related CO_2 emissions; however, its applicability would be limited to areas with excellent DNI. It would provide energy for the calcination of limestone but would not avoid its process emissions, and it would not reach sufficient temperature levels for clinker sintering (1 450°C).

Vattenfall, the primary Swedish state-owned energy company, is collaborating with cement producer Cementa to investigate the possibility of substituting fossil fuels with renewable electricity in cement manufacturing. Electric furnaces for temperatures up to 1 800°C (higher than needed) are commercially available, but usually not in the dimensions necessary to produce clinker (as in a rotary kiln). The research may thus initially focus on the limestone calcination phase, at 900°C. The objective of the joint pilot study "CemZero" is nevertheless to attain zero CO_2 emissions by 2030 from electrified cement production.[10] It is unclear, however, whether this goal includes process CO_2 emissions.

Another option involves molten carbonate electrolytic synthesis (for a broad review of this technology, see Chery, Lair and Cassir, 2015). It is more ambitious as it would also address the process emissions from limestone calcination. The process would generate lime using electricity, and has been demonstrated at laboratory scale. The CO_2 produced is further reduced (at high temperatures) in the electrolysis process inside the molten carbonate. Depending on the temperature, the process would produce carbon monoxide (above 800°C) or pure carbon (below 800°C), as well as oxygen (O_2).

Figure 16. **Concept scheme of low-carbon co-production of cement and carbon nanotubes**
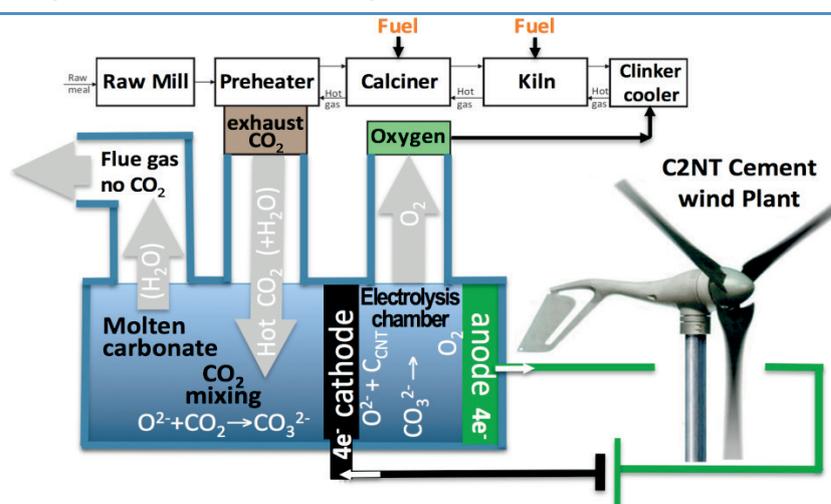
Source: Licht (2017), "Co-production of cement and carbon nanotubes with a carbon negative footprint".
Key message • Still at lab scale, molten carbonate electrolysis powered by solar and wind energy could be coupled with an oxy-fuel cement factory and produce high-value carbon nanotubes.

The process could be economically viable on a large scale through valorisation of carbon monoxide as a feedstock in chemical processes, according to Wyns and Axelson (2016). Licht (2017) suggests co-producing carbon nanotubes and cement. The exhaust from partial or full oxyfuel cement plants would be coupled to a chamber in which CO_2 in a molten carbonate electrolyte would be transformed by electrolysis into carbon nanotubes at a steel cathode,

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[10]https://corporate.vattenfall.com/press-and-media/press-releases/2017/vattenfall-and-cementa-focusing-on-zero-emissions/, accessed 28 September 2017.

and oxygen and a nickel anode (see Figure 16). Carbon nanotubes have many applications in electronics, optics and other material sciences and technologies. Their high market value could potentially make emissions-free cement manufacturing more profitable than current methods, although it would likely fall if production were to be scaled up with cement manufacturing. Emissions-free production of cement at the current global level of 4.2 Gt/y this way would require 3 600 TWh of electricity and 35 EJ of renewable heat.

Chapter 3. Renewable carbon-neutral fuels for industries

The previous sections on ammonia (page 30) and methanol (page 34) have paved the way for this broader examination of the possibility of manufacturing carbon-neutral, renewable synthetic fuels to meet the energy needs of industries. The possibility of "green" ammonia production to supply the fertiliser industry also raises the prospect of manufacturing ammonia for energy needs, particularly in the industry sector.

Economic analysis suggests that producing hydrogen from the electrolysis of water would be roughly competitive with steam methane reforming in areas where the cost of electricity would not exceed USD 30 per megawatt hour (/MWh) – a price that has been reached by various solar and wind projects in parts of the world with excellent resources. As Crolius (2017) notes, "the price of electricity is the most important driver. Doubling the price from USD 30 to USD 60 per MWh increases the cost of hydrogen by approximatively USD 1.50 per kilogramme (kg) – a major impact."

Global commodities, solar photovoltaic (PV) modules and wind turbines have relatively similar prices throughout the world. The reason for electricity cost differences is the quality of the resource, which drives the capacity factor of renewables plants. It also directs the capacity utilisation of electrolysers.

Plant capacity utilisation at rates below 50% (about 4 300 hours) is a very important cost factor accounting for multi-dollar deltas in hydrogen price per kg. At higher rates, it has a smaller impact, accounting for a cost decrease of just USD 0.50/kg as utilisation increases from 50% to 100%. Plant capital cost is also more important when capacity utilisation is low, but becomes less so when utilisation crosses the 50% point (Crolius, 2017).

Then logistical considerations come into play: the places most suited to competitive production of hydrogen are usually far from the population and industrial centres where most energy is consumed. Japan's cross-ministerial Strategic Innovation Promotion Program (SIP) "Energy Carriers" examines three different options: liquid hydrogen (H_2), ammonia (NH_3), and organic hydrides, for transporting clean energy from Australia to Japan, whether from fossil fuel with carbon capture and storage (CCS), as originally thought, or from renewable power, as appears more and more likely (Figure 17).

Organic hydrides, such as methyl-cyclohexane (MCH) from hydrogenation of toluene, could be shipped from Australia to Japan. After dehydrogenation, toluene would be returned to Australia while hydrogen would be used in Japan for energy purposes. Although toluene and MCH contain carbon atoms, these will not enter into any combustion process and thus the use of the hydrogen bound in MCH will not entail any CO_2 emissions.

This advantage is shared with ammonia, which contains no carbon atoms at all. Toluene and MCH are liquid at normal temperature and pressure, simplifying handling and shipping to the extreme, while ammonia requires some pressure or cooling and is similar to butane or propane. Even with these constraints, ammonia is considerably easier to store and ship than dihydrogen, either compressed or liquefied (Box 3 and Box 4).

Organic hydrides and ammonia present different risks for people and the environment. Ammonia is highly toxic for eyes and lungs – but its characteristic smell is detectable at very low concentrations and it is buoyant in the air. MCH is highly toxic for aquatic life, and a spill in water could have serious environmental consequences. Overall, ammonia seems more attractive, possibly due to its long record of safe industrial handling.

Figure 17. Japanese energy carrier strategies
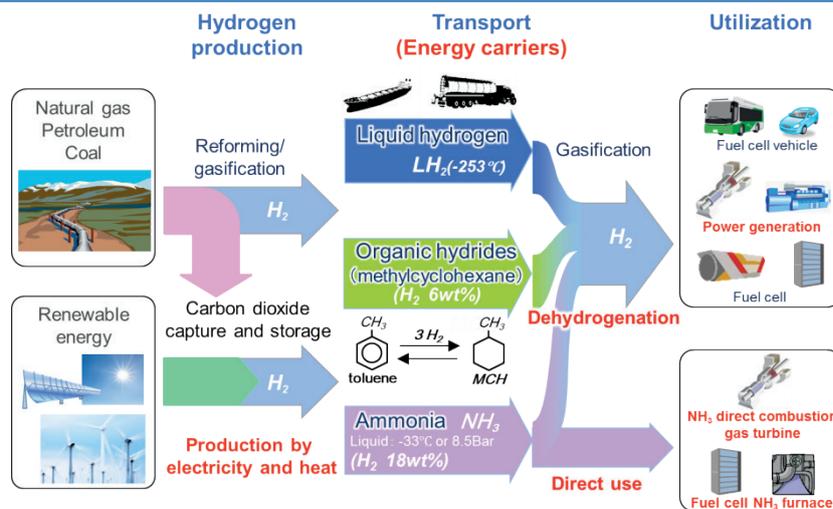
Source: Muraki, 2017, RD&D on Hydrogen and Energy Carriers in Japan.

Key message • **Liquefied hydrogen, organic hydrides and ammonia are the main options for shipping hydrogen long distances cost-effectively.**

The last question relative to ammonia relates to its final uses in industry – mostly in stationary applications. A recent publication by the Dutch Institute for Sustainable Process Technology (ISPT, 2017) sheds some light on this particular issue: it concludes that using ammonia as a fuel in a combined cycle gas turbine (CCGT) power station is best done by cracking the NH_3 into H_2 and N_2 before combustion. The time it will take for this technology to reach the market for large-scale application is estimated at five to ten years.

Under its Power to Ammonia project, the ISPT is pursuing conversion of a large natural gas power plant, Nuon's Magnum power plant in Eemshaven, to ammonia. The plant associates three CCGTs of 437 megawatts electrical (MW_e) net output each. Nuon recently associated with Statoil and Gasunie with the intention to start by combusting pure hydrogen provided from natural gas reforming (Brown, 2017b); the next step will be to begin co-firing cracked ammonia as a fuel in 2021, and the third step, full conversion to burning ammonia, would start in 2026.

One reason to crack ammonia before combustion is that direct firing, although producing the highest efficiency, would entail development of a completely new combustor requiring much time, resources and investments to achieve sufficiently low nitrogen oxide (NO_x) emissions. The combustor would also need to be larger due to the combustion properties of ammonia, and this type of development does not seem to be part of the current research and development programmes of original equipment manufacturers – but they have been developing combustors for hydrogen, targeting the integrated coal gasification combined cycle market (ISPT, 2017).

Cracking ammonia requires medium- to high-temperature heat, which could easily be derived from combustion. Effective catalysts, e.g. sodium amines, could facilitate full conversion at lower temperature levels and reduced energy losses (David, 2016).

Partially cracked ammonia, i.e. a mix of NH_3 and H_2, can also be burned in internal combustion engines and gas turbines with good efficiency and low NO_x emissions, further reducing the energy losses in cracking ammonia. Experiments at Cardiff University using a representative gas turbine combustor showed the lowest NO_x formation with a mix of $70\%_{vol}$ NH_3 and $30\%_{vol}$ H_2 (Valera-Medina, 2017). Meanwhile, Japanese researchers have also

showed that industrial furnaces can combust ammonia directly with low NO_x emissions using multi-stage and oxygen-enriched combustion (Brown, 2017c).

Box 3. Storing hydrogen as dihydrogen and ammonia

H_2 and NH_3 are both gaseous at normal temperature and pressure. For small-scale H_2 storage, a widespread option is compression in strong and heavy tanks, usually at 35 megapascals (MPa) or 70 MPa (~350 atmospheres [atm] or 700 atm), which may require up to 30% of its energy content. Embrittlement of metals by H_2 dictates specific choices of materials. Other options include metal hydrides, which store H_2 in a solid under moderate temperature and pressure that gives them a safety advantage. But they are heavy and can only store about 1.8% hydrogen by weight.

For larger storage, there are two options: compression at about 20 MPa in salt caverns, and liquefaction. H_2 liquefaction requires cooling it at - 253°C. H_2 is first compressed then cooled at -195°C with liquid nitrogen; finally, expansion to atmospheric pressure allows it to reach the liquefaction temperature. The whole process absorbs over 30% of its energy content. Salt caverns, where available, offer a more affordable and efficient option.

By contrast, ammonia is liquid at -33°C, or under a pressure of less than 1 MPa at 20°C. The industry uses 1.7 MPa to safely face temperature variations. A low-temperature NH_3 storage system can store over 40 tonnes of ammonia (tNH_3) per tonne of steel, nearly 15 times more than NH_3 pressure storage at 1.7 MPa Therefore, low-temperature storage is preferred for large-scale NH_3 storage. A two-stage refrigeration system using ammonia as the refrigerant is used to cool the ammonia to be stored upon entry to the storage facility.

Bartels and Pate (2008) assess the cost of hydrogen storage for half a year as liquid NH_3 at USD 0.54 per kilogramme of hydrogen (/kgH_2), and as liquid H_2 at USD 14.95/kgH_2, a factor of 30 with the difference due mostly to the higher capital costs of H_2 storage. The efficiency of the H_2 storage is 76.9% - i.e. the chemical energy stored is 76.9% of the chemical and electrical energies that were added to the storage. By comparison, the efficiency of the H_2 stored as part of NH_3 is 93.6%, and includes the energy required for its synthesis from H_2 and N_2, while the efficiency of NH_3 storage itself is 99%.

These cost estimates do not, however, consider salt caverns. David (2017) compares the storage of H_2 versus NH_3 in salt caverns, based on one of the world's largest salt caverns at Spindletop in Texas, which has a capacity of 7 500 tH_2 with an estimated energy content of 900 terajoules (TJ). By comparison, the same amount of energy would be stored in 100 000 cubic metres (m^3) of liquid ammonia, the volume of two large industrial NH_3 storage tanks. David concludes that "NH_3 can be more scalable and certainly more site-independent than salt mines."

Cooled NH_3 has an energy density of 15.37 megajoules per litre (MJ/l) whereas cryogenic H_2 at -253°C has an energy density of 9.98 MJ/l. As some scientists say, there is more hydrogen in ammonia than in hydrogen.

Hydrogen can also be used in a variety of fuel cell types with good efficiency to generate electricity, or electricity and heat in solid oxide full cells. Depending on their exact design and technology, fuel cells often require much greater purity of hydrogen than plain combustion, which may rule out thermal cracking of NH_3. The separation of N_2 and H_2 in that case may be conducted differently, e.g. with membrane reactors such as those commercialised by RenCat, a Danish start-up. Research is also under way to enable the durable and large-scale direct use of ammonia in fuel cells.

Although ammonia has been used as a fuel in the past to run buses or even aircrafts – the most rapid aircraft of all time was powered by ammonia – significant work remains to optimise its use in many modern combustion applications, which have been thus far

optimised for the use of fossil fuels. But no scientific or technical breakthrough seems necessary.

However, there might be cases in which carbon atoms are desired in the final product delivered to customers: drop-in hydrocarbon (HC) fuels. This is the case of methanol as a chemical commodity. As noted above, to be carbon-neutral and not only "renewable," methanol (of formula CH_3OH but often noted MeOH) should then be produced from renewable H_2 and atmospheric carbon; the same obviously applies to synthetic fuels. Atmospheric carbon could be procured either directly from the atmosphere, or indirectly via capture in the off-gases of industrial or power plants taking their energy from bioenergy.

As well as maximising the carbon capture value associated with bioenergy with carbon capture (BECC),

> …such processes could also reduce land-use requirements for energy production through reuse of the carbon components. … Another alternative is to inject hydrogen into the synthesis gas stream produced by biomass gasification. This means that a higher proportion of the carbon contained in the biomass can be converted to fuels, rather than to CO_2. This has the potential to reduce carbon losses, but also increase the efficiency with which the biomass can be used, and so contribute to reducing the biomass feedstock needed to supply the end uses. (IEA, 2017a)

According to Hannula (2016a), expanding the use of renewables-based hydrogen to process biofuels has the potential to increase its energy availability two- to three-fold, with significant implications for all end-use sectors – transport above all, but also industry (Figure 18). At electricity prices of USD 30/MWh as considered in this report, using renewable hydrogen in massive amounts would not increase the cost of biofuels. It remains to be seen, however, how logistical considerations could be addressed as biomass-rich areas do not necessarily coincide with solar- and wind-rich ones.

Figure 18. Scheme of current biofuel production and biofuel production enhanced with renewable hydrogen
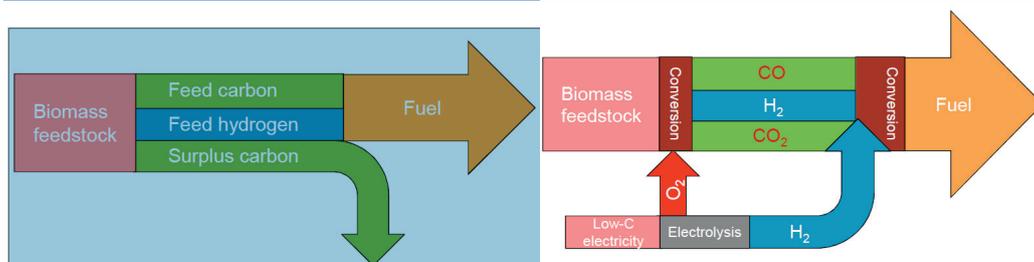
Source: Hannula (2016b), "Doubling the Output of Synthetic Biofuels".

Key message • Using hydrogen and oxygen from water electrolysis run on renewable power can augment the potential of biomass in converting CO_2 into fuel.

In any case, whether for ammonia, synthetic fuels or organic hydrides as hydrogen carriers, the overall efficiency must be carefully considered if the source of H_2 is electrolysis of water, i.e. ultimately electricity.

Grinberg Dana et al. (2016) have calculated power-to-power (PtP) efficiencies of many possible intermediate fuels: methane, methanol, dimethyl ether, NH_3, ammonium nitrate (AN) and AN-based compositions. They distinguish direct air capture from indirect (capture from fumes), assuming the greater energy expenditure of direct capture is all electric, which may not be the case.

The ISPT (2017) also assessed the PtP efficiency of using NH_3 by the type of electrolysis technology. The main consolidated results are shown in Table 1.

Table 1. **Power-to-power efficiencies of various intermediate hydrogen-rich fuels**

Fuel	PtP efficiency CO_2 from air	PtP efficiency CO_2 from fumes
CH_4	27%	31%
MeOH	27%	32%
DME	23%	28%
NH_3		35%
NH_3 PEM		29%
NH_3 SOEC		39%

Sources: Based on Grinberg Dana et al. (2016), "Nitrogen-Based Fuels: A Power-to-Fuel-to-Power Analysis" and ISPT (2017), *Power to Ammonia.*

Key message • **Synthetic hydrocarbons and ammonia have low PtP efficiencies and should only be used when electricity cannot be used directly or via more efficient storage technologies.**

The main lesson from these assessments is not the relative superiority of NH_3 over HCs, but rather the relatively low PtP efficiencies of all. It means that every time it is possible to use electricity directly, or via a more effective storage technology, such as batteries or pumped-storage hydropower, it would be preferable to do so. That is, the use of a synthetic fuel should be limited to cases in which the ease of portability or the convenience of long-term storage dominate, at least with respect to electric or mechanical force, including motion. This would also be true for low-temperature heat uses, especially at temperature levels accessible to heat pumps. In addition, at the site where the storage and conversion infrastructure is present, more efficient short-term mechanical or battery storage should first be saturated, and only when it is saturated should storage take the form of fuels. A concept that combines short- and long-term storage in one device was recently demonstrated in an integrated battery and electrolyser, the "battolyser" (Mulder et al., 2017).

Industrial uses of high-temperature heat may offer different prospects, depending on the actual availability and efficiency of electricity processes to deliver such heat or substitute it. For such applications, PtP efficiency is probably not the best criterion. This is even truer when a feedstock or a process agent is the desired product, as is the case for NH_3 in the fertiliser industry, and could be the case for H_2 in the steelmaking industry.

Furthermore, H_2 is a costly source of heat. As already mentioned, the fact that manufacturing H_2 from renewable power in the best resource areas becomes competitive with natural gas for the same purpose does not imply that this hydrogen is competitive with natural gas as a source of heat or power.

At USD 2/kgH_2, hydrogen costs USD 17.6 per million British thermal units (/MBtu), a level not seen in gas markets since mid-2012, when it concerned only liquefied natural gas (LNG) on Asian markets (IEA, 2017f). The difference with current market prices ranges from USD 7/MBtu to USD 15/MBtu, while substituting natural gas with green H_2 offsets 54.2 kilogrammes of carbon dioxide per million British thermal units ($kgCO_2$/MBtu) – hence a cost of carbon ranging from USD 129 per tonne of carbon dioxide (/tCO_2) to USD 277/tCO_2. This assessment is based on current technologies, however. Cost reductions and efficiency improvements in renewable electricity generation and H_2 and NH_3 synthesis could reduce these carbon costs in the future.

Ease of portability applies not only to the transport sector, but introduces another dimension to the analysis: the possibility of trading renewable resources globally. When a fuel can be easily transported and/or stored long-term, its production can be locally detached from its consumption for a minor transportation cost.

Box 4. **Shipping hydrogen as dihydrogen and ammonia**

As with storage, shipping hydrogen chemically bound with nitrogen in ammonia (NH_3) is easier and less expensive than shipping hydrogen as dihydrogen (H_2).

The very low (volumetric) energy density of H_2 makes its transport costly. A truck usually carries either 370 kgH_2 at 17.9 MPa, with an energy content of 48 gigajoules (GJ), or 3 900 kg of liquid H_2 with an energy content of 553 GJ. An ammonia truck would carry 2.6 tNH_3 with about the same energy content, 600 GJ, and avoid the major energy cost of liquefying H_2.

Over long distances and for larger volumes, pipelines are preferred. A 4 830-kilometre (km) pipeline network in the United States transports ammonia from port and production facilities to agricultural areas for direct use as a fertiliser (Figure 19). The United States also has 2 600 km of H_2 pipelines and Europe 1 600 km, while a dozen other countries total about 340 km.

Figure 19. **Ammonia pipelines in the United States**
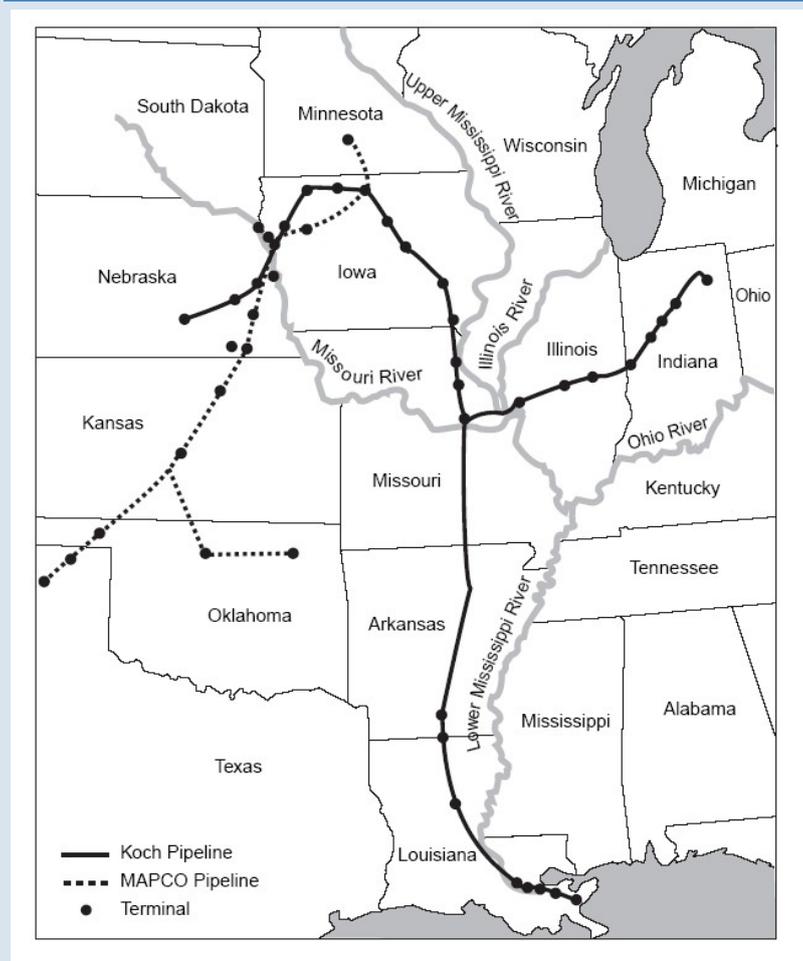
Disclaimer: The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.
Source: U.S. DOE (2006), *Potential Roles of Ammonia in a Hydrogen Economy*,
https://www.hydrogen.energy.gov/pdfs/nh3_paper.pdf.

Bartels and Pate (2008) compare piping hydrogen as H_2 and in NH_3 over a distance of 1 000 miles (1 610 km). Compression of gaseous H_2 is less efficient (86.9%) than pumping liquid NH_3 (99.2%). Including the NH_3 synthesis reduces the efficiency of piping NH_3 to 93.4%, while also including its reforming (if H_2 is the final product) further reduces it to 84.5%: the advantage of piping NH_3 increases with distance, as conversions drive larger losses. Still, the NH_3 pipeline has a hydrogen flow rate and energy carrying capacity double those of the H_2 pipeline. The cost of pipelining 1 kg of hydrogen over that distance as dihydrogen is estimated at USD 0.5 to USD 3.2, versus USD 0.2 if that same hydrogen is piped bound in ammonia.

For power generation, the efficiency detriment might thus be partially compensated for. Electricity procured from a remote place where its cost is half owing to abundant, best-quality renewable resources, the PtP efficiency of about one-third results in a cost difference of about 50% compared with the local power. Taking variable power costs to be USD 30/MWh in remote areas and USD 60/MWh in local areas (not counting possible low-cost "excess" power), the fuel cost for power from an imported storable fuel amounts to at least USD 90/MWh, compared with a fuel cost of over USD 180/MWh for power from a storable fuel of local origin.

Moreover, the renewable resources in various areas of high population density and intense energy consumption may be progressively exhausted. With the current level of deployment, the power mix in most countries is far from being dominated by renewable energy unless significant hydropower resources are available. It is unclear to what extent the deployment of renewable power – mostly solar and wind – could exceed current power consumption and support widespread electrification of the entire economy – buildings, industry, services and transport.

Consequently, the cost of renewable electricity may stop declining and instead increase in saturated areas. This long-awaited phenomenon has been so far unseen, as learning effects from technology deployment have been more rapid than the promised "saturation of good sites, when, for example, the "silent revolution" of advanced low-wind-speed turbines with higher masts and longer blades have largely broadened and expanded the mere notion of appropriate sites (Chabot, 2013).

Figure 20 illustrates this point: while Africa, Australia and South America show very large resources compared with their needs, and large countries such as China and the United States have renewable resources commensurate with their broad energy needs, Europe, Korea, Japan and other densely populated countries may in practice fall short of deploying enough capacity to harness their resources. Even if their technical potential could, in theory, cover several times their primary energy needs, it may not be realisable if only for issues relating to occupation of the land.

Figure 20. **Technical renewable energy potential in various parts of the world**
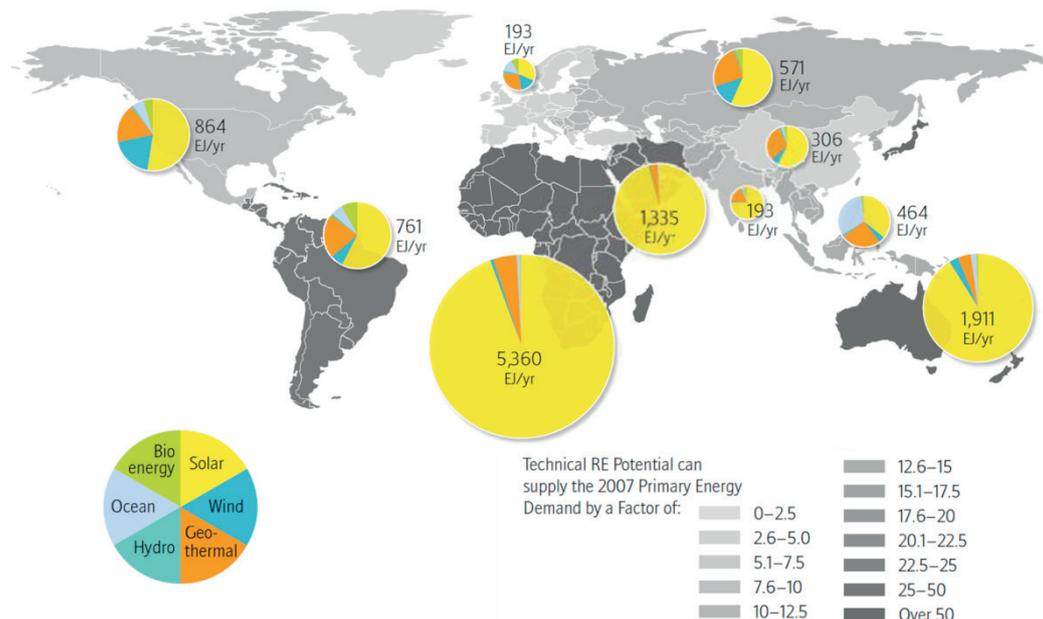
Disclaimer: The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: Teske et al. (2017), Renewables Global Futures Report based on Edenhofer et al. (2011), Special Report on Renewable Energy Sources and Climate Change Mitigation.

Key message • **The extreme abundance of solar and wind resources in some regions is likely to spur international trade in renewables-based, hydrogen-rich chemicals and fuels.**

Arguably, this map was drawn from a variety of different studies and does not enable exact comparison. But despite its shortcomings, this illustration still suggests that there could be large benefits in trading renewable fuels from regions having large excess supply to other regions – unless some unexpected technological breakthrough suddenly allows new, abundant renewable resources to be exploited in seemingly less favourable regions.[11]

This analysis was at the root of initiatives such as the Desertec Initiative or State Grid Corp of China's Global Energy Interconnection. Their current limited success does not mean the analysis was wrong, but perhaps it was too early. It also may be that connection with power lines has advantages and disadvantages: despite electricity losses, connection is more PtP-efficient for instantaneous transmission than any synthetic fuel would be. However, when the need for a storable fuel dominates, then shipping this fuel on land via pipelines and on ocean with ships proves very efficient: both concepts are complementary, not competing.

Japan's Energy Carriers SIP seems to have been inspired by similar analyses. If at its origin "clean hydrogen" was primarily considered from fossil fuels in association with CCS, over time the balance is shifting towards renewables-based water electrolysis. For transport, three main options are under consideration: cryogenic (liquefied) dihydrogen, hydrides (methylcyclohexane – toluene cycle) at atmospheric pressure, and cooled ammonia.

Nuon justifies conversion of its Magnum plant to NH_3 by noting that "additional renewable wind and solar capacity in the Netherlands is not sufficient to meet the CO_2 reduction targets. Large-scale storage and import is required to meet these targets" (ISPT, 2017).

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[11] High-altitude winds could be one such resource, if airborne wind power technologies are successfully developed.

Similarly, Jeff Connolly, CEO of Siemens Pacific, scrutinising the German market for clean energy, claims that:

> Australia has abundant potential resources in solar and wind with suitable areas multiple times the entire land mass of Germany… but how do you export renewables? It currently takes about 12 MWh of electricity to produce 1 tonne of ammonia, containing 176 kg of H_2. Cost trends are very favourable for renewable ammonia, following large declines in the cost of solar energy and emerging efficiencies in electrolysis.… The opportunities for both countries could be immense. (Connolly, 2016)

This report reveals the promises, but also the limits, of direct industrial uses of renewable heat (solar, geothermal) or biomass. Renewable electricity has much greater potential, directly or through the formation of synthetic fuels or hydrogen-carriers – hydrogen being used in industry as feedstock, process agent or energy.

The affordability of these easily transportable fuels, as well as limitations on renewable capacities in densely populated regions, will most probably give rise to a new era of international energy trade based on renewables rather than fossil fuels – an era that has already begun with international trading of wood pellets. The common-sense idea that renewables always means "local" may not survive the transition from the goal of partially responding to current electricity needs to responding to the broader energy needs of the global economy – in particular those of industry.

Chapter 4. Policy options

In this chapter, lessons learned from the recent deployment of renewables in various industrial sectors are considered first to provide useful information to industrial decision/policy makers at national and possibly sub-national levels. With respect to international trade in energy-intensive industries, such as chemicals, iron and steel, and cement, however, the main barrier for most products is likely to be competition from current greenhouse gas (GHG)-emitting technologies, as most (but not all) substitutions with renewable energy (RE) reveal a positive cost of carbon abatement. These issues are discussed in the two final sections of this chapter.

A. Lessons learned

Various barriers still hinder full RE deployment in the industry sector, but industrial decision/policy makers have a wide array of options available to overcome them. Eight issues were identified in the Renewable Energy Technology Deployment (RETD) Industry study (IEA RETD TCP, 2017) that could influence industries in deciding whether to deploy RE production assets in their facilities. Diverse policy options can be implemented to surmount these barriers, which are summarised below.

- *Energy supply regulatory regime:* In various jurisdictions, it is difficult to supply energy using independent producers and valorise energy through self-consumption and/or the right to sell excess energy produced. These are fundamental requirements for deploying renewables in industry.

  - Policy makers may ensure that these two regulatory requirements are implemented within the energy production regulatory regime. Other issues may arise from urban planning regulations, safety regulations, or normative complexity. Policy makers should verify the relevance of impeding rules.

- *Operability and integration:* Industrial installations and processes might not be adapted to integrate RE assets, especially for renewable heat, including biomass. Deep integration of renewables into processes can provide the best results, but also risks perturbing core processes. Switching from fossil fuels to renewables production can add complexity and cost.

  - Planning and anticipation are the keys to successfully conducting such changes in industry. Policy makers could create centres of excellence to promote sharing of knowledge and experience. Manufacturers of industrial process equipment should be associated, as they – and society at large – would benefit from offering new products that take renewable heat integration into account.

- *Investment:* RE projects require high upfront capital expenditures.

  - Third-party production schemes are an option for industries that lack the equity or cash needed to develop capital-intensive renewables projects. Policy makers may implement investment support mechanisms to reduce upfront costs for industrial companies.

- *Return on investment:* Renewables projects often show relatively low returns on investments; moreover, even if the profitability of assets with long technical lifespans is high, the payback time might be long compared with the company's core activities. This commonly-used criterion may dissuade industrial decision makers.

- Industries can transfer the investment to a third party, oversize the installation to sell surplus to utilities and/or other industries; enhance the value of by-products (mainly in biomass projects); and enhance heat and power synergies.

- Public authorities can direct utilities to purchase decentralised renewable electricity or heat from industrial producers under various regimes (i.e. feed-in tariffs or premiums, net-metering, etc.) and enforce a regulatory framework for valorisation of by-products.

- **Risk and insurance:** RE installations that use immature technologies or lack backup generation present a supply continuity risk, but also offer a hedge against fluctuations in market energy prices and often improve energy security. In some cases, faulty equipment can put the safety of the whole facility in jeopardy. More often, long-term continuity of the operation and solvency of the off-taker present a risk for renewable energy investments.

  - Hybridisation of existing generators can often provide affordable backup. Equipment guarantees can be negotiated with providers of mature technologies. Policy makers and regulators may guarantee access to the grid for backup power, and public authorities can also define and help deliver operational guarantees and technological warranties.

- **Contractual scheme complexity:** The complexity of contracts between industrial customers, third-party power (or heat) producers and utilities can deter investment.

  - Industries can rely on third-party producers for participation in electricity markets and contract directly with them. Specialised companies can be part of the deals, managing the complexity and aggregating demand response from various customers. Policy makers can create simple and accurate contractual schemes.

- **Technology maturity:** While solar, wind, geothermal and various biomass technologies are mature, some other options (power to gas, tri-generation) are less so and carry additional risks.

  - Participating in industry-wide research and development programmes on the integration of non-mature renewable technologies can reduce costs and risks. Governments could help finance pilot projects for non-mature technologies with significant growth potential. Policy makers should simplify the procedures and norms applicable to pilot projects within the experimental zone to limit the risks.

- **Awareness:** Industrial companies often lack awareness about technologies, possible incentives or guarantees, costs and best practices.

  - Inter-professional and sector-specific associations could share information within the industry sector as a whole. Public entities such as energy agencies can gather and compile information about existing support schemes, public research, and industry experiences. Projects benefitting from public support should be obligated to publish key elements regarding costs and benefits, and offer operational feedback.

RE portfolios and obligations to buy renewable power from independent power producers have been instrumental in ensuring rapid deployment and cost reductions in solar and wind power; similarly, obligations for shares of solar heat in domestic hot water supplies have proven effective in driving deployment of solar water heaters in a number of jurisdictions, where the obligations are now often integrated into strict building codes that either explicitly mandate the use of renewable heat or require it in practice. Such instruments should still be considered by governments and other public authorities at various levels.

B. International agreements

Energy- and GHG-intensive industries, whose products are traded internationally, may not be in a position to support additional costs for process modification to reduce carbon dioxide (CO_2) emissions. Furthermore, imposing carbon prices or directly regulating emissions potentially puts carbon-constrained industries at a competitive disadvantage relative to their unconstrained competitors. Governments thus fear that uneven carbon constraints could enhance the competitiveness of non-carbon-constrained producers.

This risk is usually characterised as "carbon leakage" (or the "pollution heaven" hypothesis), as implementing uneven GHG emissions constraints could lead to an increase in emissions outside the given country or region. This could result from short-term deterioration in competitiveness, whereby carbon-constrained industrial products lose international market shares to the benefit of unconstrained competitors. In the longer term, differences in returns on capital associated with uneven emissions mitigation actions provide incentives for firms to relocate their capital to countries with less stringent climate policies. Finally, reduced energy demand and lower prices in some countries may trigger higher energy demand and associated GHG emissions elsewhere.

Carbon leakage is formally expressed as the ratio of emissions-increase outside the country that has implemented domestic mitigation policies, over the emissions-decrease within that country (this formula can also be applied to specific sectors within the regions). This ratio could be above or below 100%: if below, it means that global GHG emissions increase if emissions in the regions benefitting from a shift in production are greater than the emissions reduction in the regions implementing a constraint of any kind. This could happen, for example, if specific GHG emissions in the regions taking mitigation action were already lower than the specific emissions in the outside regions.

Governments are usually very wary of the risk of carbon leakage, although the possible increase in global GHG emissions is only part of their concern, which also involves possible effects on economic output and employment. The risk has often prevented governments from implementing carbon pricing, either as a carbon tax or as an emissions trading scheme, or a mix of both. Alternatively, governments have implemented carbon prices with significant exemptions for the sectors most at risk, such as tax exemptions or free allocation of emission permits within emissions trading schemes.

Reinaud (2008) noted that none of the simulations focusing on sectoral leakage indicated a leakage rate near 100%: that carbon leakage would entirely cancel out an effort to reduce emissions in any industry is highly unlikely. Reinaud pointed out that the risks are restricted to a few industry sectors and subsectors, combining a high level of emissions and a high level of exposure to international competition. She also argued that ambitious climate policies imply changing the relative competitiveness of sectors and encouraging low-carbon innovation – and that possible competitiveness issues should also be weighed against a possible prime-mover advantage to companies first developing low-emitting technologies.

Since then, the global mitigation framework has evolved considerably, in a manner that should reinforce Reinaud's analysis. The Paris Agreement is significantly more encompassing than the Kyoto Protocol in including China, India and other emerging economies. However, the heterogeneity of the current national pledges may still not provide enough security for industries in the most exposed sectors.

Of the three main subsectors considered in this report, cement is less at risk, as it is traded much less than ammonia and steel. With respect to chemicals, the situation varies according

to the cost of shifting to renewables. If it is low, as for ammonia used as an industry feedstock, the risk of carbon leakage is low, while it cannot be ignored for methanol and high-value chemicals; the current shift in production and relocation of investment in this subsector towards the United States and its low-cost natural gas illustrates the cost sensitivity of this industry. Finally, international competition and trading are intense in the iron and steel subsector.

Furthermore, having renewables-based, hydrogen-rich chemicals or basic materials manufactured in areas that have excellent resources but – in some cases – relatively little local demand, may entail challenges that fall outside the conventional wisdom about environment and trade. For potential exporting countries, the challenge is to ensure that there will be a large enough market for these materials, whereas potential import countries must benefit from the differential in renewable resource quality and abundance in meeting their emissions-reduction objectives while still protecting low-carbon production, either local or imported, in relation to inexpensive, carbon-intensive imports. Renewed forms of international co-operation could presumably help meet these challenges.

A global agreement to create a state of equality with respect to GHG emissions, for example with a globally co-ordinated "single" carbon pricing system, would in principle solve this issue. While some economists consider it to be the "first-best" option, others point out that its adoption is very unlikely from a political standpoint, for it does not take inequalities in economic development into account: a single world price would be too high for some countries and too low for others. Also, the system could be economically efficient only if energy taxation were similar in all countries (Godard, 2015).

Global agreements by sector might be more realistic. Compared with countrywide, quantified targets, sector-wide approaches may (IEA, 2005):

- require lighter monitoring and enforcement
- more effectively link economic agents in these sectors and international investors
- settle part of the abatement cost uncertainty inherent to uncertain economic growth
- create emissions leakage from sectors covered to those unconstrained
- complicate international negotiations with sector-specific technicalities.

The industry sector itself implemented such agreements long ago, under the aegis of the International Aluminium Institute, the World Business Council on Sustainable Development, the International Iron and Steel Institute and others (Baron et al., 2007). However, sector-wide agreements cannot initiate the process. Substituting water electrolysis for steam methane reforming (SMR) in ammonia production, or H-DR for blast furnace-basic oxygen furnace (BF-BOF) and natural gas-based direct reduction (DR) in steelmaking – not to mention cement – will require considerable changes in these sectors. As most radically different technologies have not been demonstrated on a large scale, initiating negotiations to force them through global markets would likely not succeed and could even prove counter-productive.

Another possibility would be for governments to restrict international trade of materials based on upstream emissions, and introduce a border tax or "border carbon adjustment" (BCA) mechanisms. This seems to be compatible with the current rules of the World Trade Organisation (WTO) and the various rules of numerous bilateral and multilateral trade agreements. Specific WTO rules allow members to adopt trade-related measures for the protection of the environment. The General Agreement on Tariffs and Trade (GATT), Article XX [Article 20], recognises the need to adopt and enforce measures necessary to protect human, animal and plant life or health, and the conservation of exhaustible natural

resources. However, for a measure to fall under Article XX it must not be applied in a manner constituting a means of arbitrary or unjustifiable discrimination between countries where the same conditions prevail, or be a disguised restriction on international trade.

Contrary to a widely held belief, the WTO does not forbid discrimination among products on the basis of the processes or production methods (PPMs) used for their elaboration, provided criteria are fully consistent with domestic regulations. For example, in the "Shrimp-Turtle" dispute that opposed four Asian countries to the United States over shrimp-catching methods dangerous to turtles, the plaintiffs won because the United States had given more flexibility and assistance to some other foreign countries, while the Appellate Body of WTO's dispute-resolution mechanism confirmed that WTO members can and should adopt effective measures to protect the environment. Moreover, several countries have introduced measures, such as biofuel sustainability standards, that do distinguish products based on their PPMs.

Baron and Garrett (2017) explore in more detail how BCAs may be applied to create equality. Governments could usefully clarify this issue further with more explicit endorsement, and could elaborate common methods for calculating the amount of carbon used in product manufacturing based on the work of the International Organization for Standardization (ISO).

Another, even stronger, alternative would be for jurisdictions to adopt, in the context of a regional trade agreement or otherwise, a set of standards for the embedded carbon of heavy materials used in their economy, in line with their efforts towards becoming zero-carbon. Non-conforming products would simply be denied entry.

BCAs and standards, however, only work to avoid carbon leakage when the countries willing to protect their industry sectors implement primarily domestic measures. They would not allow initiating the process of implementing constraints based on radical, rather than incremental, process improvements or modifications.

C. Procurement

To ensure prompt deployment of innovative clean technologies based on renewables, public and private procurement of clean, carbon-free materials may be the most realistic short-term option. For example, the cost of steel represents only a small fraction of the overall cost of a vehicle. Manufacturers of brand products – carmakers in this case – may want to bolster their green performance image they project to their customers and the general public, including their own stakeholders, whether out of personal conviction or wary of possible backlash – or both. Electric cars and plug-in hybrids could lead the transition towards "green steel", and RE developers could pay attention to the life-cycle emissions of wind turbines, for example – massive steel objects implanted on the ground in an large concrete structure.

Many developers have done this already, procuring green power (see Chapter 1, section C above) and now turning their attention to the "grey energy" embodied in their products and to procuring preferably cleaner materials. For example, Walmart launched a major supply chain initiative that seeks to remove one billion tonnes of global external supply (GES) (cumulative) from its supply chain by 2030. It identified six areas in which suppliers can focus their clean-energy efforts: agriculture, waste, packaging, deforestation, and product use and design. Sustainable procurement of wood and paper-based products is not only a project of the World Resources Institute, it is also becoming a mandatory reference in industry and commerce, and for sustainable fisheries.

Public procurement may play a similar role. Public procurement accounted for 13% of the gross domestic product of Organisation for Economic Co-operation and Development (OECD) countries in 2013, and even more in some emerging and developing economies (Baron, 2016). All jurisdictions, public services and companies have buildings constructed for their own operations or for the public – schools, hospitals, social housing, etc. They procure vehicles of all sorts, railways, bridges, roads and other infrastructure, and therefore manage concrete, cement and steel in massive quantities.

The primary objective of procurement is obviously to find and buy products and services that offer good value for taxpayers' money. However, as a government-operated instrument, public procurement should also be aligned with a country's broad policy objectives, balancing these objectives with its primary purpose of finding the best value for public money.

According to Baron (2016), designing public procurement to promote low-carbon innovation can be justified on three grounds:

- Structural inefficiencies in government purchasing, e.g. focusing on upfront acquisition costs when including operating costs could lead to a more environmentally conscious choice.

- Environmental market failure, e.g. the absence of a price on CO_2 emissions due to political constraints, while an individual government may choose to include a CO_2 price to guide its own decisions.

- Insufficient support for innovation in light of positive externalities related to demonstrating and adopting new technologies, learning and network externalities.

The procurement of green materials may not grow as much as will eventually be needed. However, it could offer a foundation upon which to develop new processes based on widespread substitution of renewables for fossil fuels, further reducing energy-related GHG emissions.

Low-carbon procurement, both public and by large firms, could have domestic and international repercussions. It would create equality for domestic companies facing unfair competition from abroad, and would also provide a strong incentive to competitors to adopt new, low-emitting processes to get or keep access to important foreign markets. For example, this is the dual aim of the Buy Clean California Act signed by the Governor on 15 October 2017. This law requires the Department of General Services to establish and publish in the State Contracting Manual, a maximum acceptable global warming potential for each category of eligible materials by 1 January 2019, in accordance with requirements set out in the law. Four categories of materials are concerned: carbon steel rebar, flat glass, mineral wool board insulation, and structural steel.

The determination of some companies to develop radically new industrial behaviours and technologies to eventually gain a prime-mover advantage, combined with low-carbon procurement, could ultimately offer new perspectives to policy makers and climate change negotiators around the globe.

Acronyms and abbreviations

2DS	2°C Scenario
AN	ammonium nitrate
ASEAN	Association of Southeast Asian Nations
ASU	air separation units
B2DS	Beyond 2°C Scenario
BAT	best available technology
BCA	border carbon adjustment
BECC	bioenergy with carbon capture
BECCS	bioenergy with carbon capture and storage
BECCU	bioenergy with carbon capture and use
BF	blast furnace
BF-CCS	blast furnace – carbon capture and storage
BOF	basic oxygen furnace
BTX	benzene, toluene and xylene
°C	degree Celsius
$CaCO_3$	limestone
CaO	lime
Capex	capital expenditures
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CCU	carbon capture and use
CH_4	methane
CHP	combined heat and power
CO	carbon monoxide
CO_2	carbon dioxide
CPC	compound parabolic concentrating
CS	crude steel
DECHEMA	European Chemical Industry Council
DME	dimethyl ether
DNI	direct normal irradiance
DR	direct reduction
EAF	electric arc furnace
EDF	Électricité de France
ETP	*Energy Technology Perspectives*
ETSAP	Energy Technology Systems Analysis Programme
FLH	full load hours
GATT	General Agreement on Tariffs and Trade
GHG	greenhouse gas
GHI	global horizontal irradiance
H	hydrogen (atomic)
H_2	dihydrogen (commonly "hydrogen")
H_2O	water
HC	hydrocarbon
H-DR	hydrogen – direct reduction
HVC	high-value chemicals
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
ISO	International Organization for Standardization

ISPT	Institute for Sustainable Process Technology
LiOH	lithium hydroxide
LNG	liquefied natural gas
MCH	methyl-cyclohexane
MeOH	methanol
MVC	mechanical vapour compression
MVR	mechanical vapour recompression
N_2	dinitrogen (commonly "nitrogen")
NG	natural gas
NH_3	ammonia
N_2O	nitrous oxide
NOx	nitrogen oxides
O&M	operations and maintenance
O_2	oxygen
OECD	Organisation for Economic Co-operation and Development
OPEC	Organization of the Petroleum Exporting Countries
Opex	operational expenditures
PEF	polyethylene furanoate
PEM	proton exchange membrane
PET	polyethylene terephthalate
PPA	power purchase agreement
ppm	parts per million
PPMs	processes or production methods
PPP	public-private partnership
PtP	power-to-power
PURPA	Public Utility Regulatory Policies Act
PV	photovoltaic(s)
RE	renewable energy
REBA	Renewable Energy Buyers Alliance
RETD	renewable energy technology deployment
RTS	Reference Technology Scenario
RWGS	reverse water-gas shift
SHC	solar heating and cooling
SIP	Strategic Innovation Promotion Program
SMR	steam methane reforming
SOEC	solid oxide electrolyser cell
SPF	seasonal performance factor
TCP	Technology Collaboration Programme
UNFCCC	United Nations Framework Convention on Climate Change
WACC	weighted average capital cost
WEO	World Energy Outlook
WRI	World Resources Institute
WTO	World Trade Organisation

Units of measure

atm	atmospheres (pressure)
EJ	exajoule (1018 Joules)
GJ	gigajoule (billion Joules)
Gt	gigatonne (billion tonnes)
GW	gigawatt
GWe	gigawatt electrical capacity
GWth	gigawatt thermal
kg	kilogramme
km	kilometre
km2	square kilometre
kW	kilowatt
kWh	kilowatt hour
m2	square metre
m3	cubic metre
mln	million
MBtu	million British thermal units (1 MBtu = 1.055 GJ)
MJ	megajoule (million Joules)
MPa	megapascal (million pascals: 1 Mpa = 10 bar or 9.87 atm)
Mt	million tonnes
MW	megawatt (million Watts)
MWe	megawatt electrical
MWh	megawatt hour (thousand kWh)
MWth	megawatt thermal
PJ	petajoule (1015 joules)
t	tonne
t/y	tonnes per year
TJ	terajoule (1012 joules)
TWh	terawatt hour (billion kWh)

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