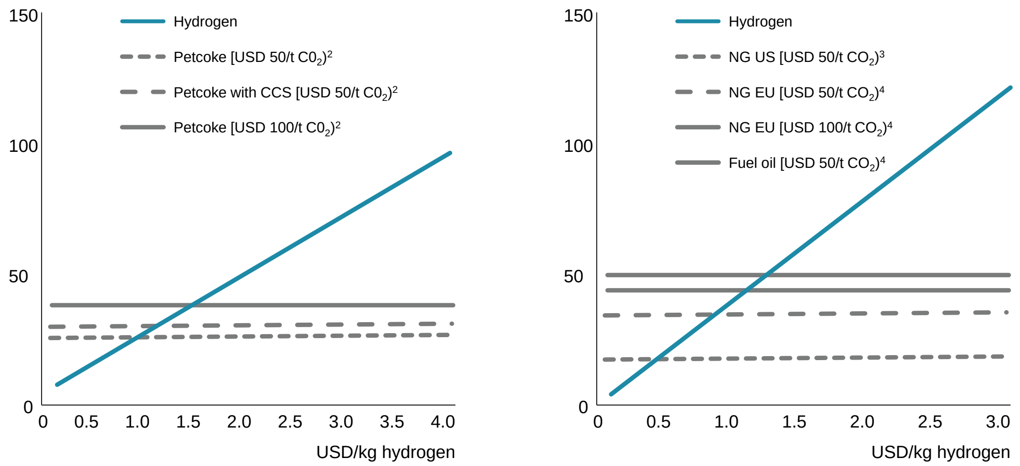
Cost development. Because the price of hydrogen will mainly determine the cost for heating, the two major drivers for cost competitiveness will be the CO_2 cost and low hydrogen production costs. Thus, to achieve long-term competitiveness and full decarbonisation, regulation needs to enforce an implicit CO_2 cost mechanism and potentially other support options. In addition, access to low-cost, low-carbon or renewable hydrogen production will be crucial for early competitiveness, while scale deployment represents a minor point for heat applications due to the limited impact of capex on the total cost.

Exhibit 32 | Competitiveness of hydrogen in example use cases in high- and medium-grade heat

High-grade heat: cement production hydrogen vs. alternatives
USD/ton cement

Medium-grade heat: PTA production hydrogen vs. alternatives
USD/ton PTA



1. Expected hydrogen cost from ATR with CCS in 2030: US USD 1.06/kg, EU/Germany USD 1.68/kg, Japan/Korea USD 1.82/kg
2. Petcoke cost of USD 0.10/kg
3. US NG cost of USD 0.12/kg
4. EU NG cost of USD 0.31/kg
5. Fuel oil cost of USD 0.39/kg

Turbines for grid power generation

Hydrogen can also fuel power generation for the grid. Power systems must fulfil two key requirements: 1) provide energy and 2) provide flexible capacity to ensure stability and resilience. Today, thermal generation via fossil fuels mainly provide energy, but the deployment of renewables is replacing thermal generation at an increasing pace – wind and solar already account for more than 50 per cent of new capacity additions.[15] With a growing share of variable renewable generation, the importance of flexible generation capacity increases. Today, flexible capacity comes mainly from fossil fuel generation and (pumped) hydro where feasible. Batteries are an option for short-term flexibility (typically 2 to 4 hours) with a high number of cycles per year (more than 300). Hydrogen turbines also offer a way to provide balance and flexibility to the grid, as stored hydrogen can be used to generate low-carbon or renewable electricity whenever the need is highest.

[15] McKinsey Global Energy Perspective, McKinsey & Company (2019).

Cost competitiveness. In tomorrow's low-carbon energy system, hydrogen-based power generation can play a role in both energy supply ('baseload') and flexible capacity. For low-carbon baseload energy supply, hydrogen is only relevant in regions constrained in renewables potential and situations where alternatives like fossil fuels with direct CCS or biomass (wood chips or biogas) are not an option. In such cases, companies could import hydrogen and use it to power hydrogen turbines.[16] For an assumed import price of USD 3 per kg of hydrogen, the cost is about USD 140 per MWh for the resulting power generation.

In contrast, hydrogen should play a major role in providing flexible capacity in a low-carbon power system both for short-term multi-hour balancing (simple cycle peak plant) and multiday or week generation via combined cycle gas turbines (CCGT) at times when renewables generation is low. In this way, hydrogen can act as a buffer and long-term storage option for the power system.

The storage of large hydrogen volumes is feasible at a low cost (cavern-based storage is expected to reach about USD 0.30 per kg of hydrogen) and in contrast to batteries, the impact of storage time on overall cost is more limited. Consequently, hydrogen should offer advantages over batteries, especially for longer storage durations of more than five hours up to days or even weeks. The main drawback of this power-to-gas-to-power route if electrolysis is used for hydrogen production is the round-trip efficiency, which is around 45 per cent.

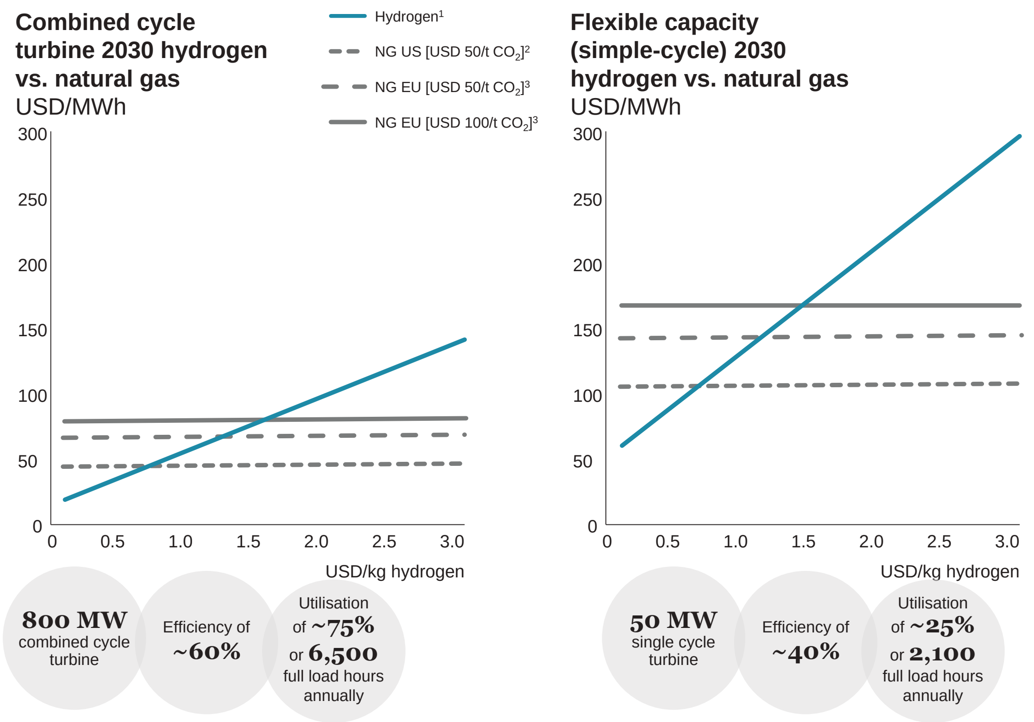
Cost development. As with industrial heat applications, hydrogen cost drives around 80 per cent of the total power generation cost, as shown in Exhibit 33. Thus, after industry proves its technical feasibility (demonstration projects for pure hydrogen are on the way in the Netherlands,[17] and the capex of hydrogen turbines should rival that of natural gas turbines by 2030), access to low-cost hydrogen will play a critical role in enabling hydrogen-based power generation. As a transition solution, blending hydrogen with natural gas in existing turbines can enable as much as a 10 per cent CO_2 reduction (for 30 per cent hydrogen volume). The fundamental economics for hydrogen break-even cost in this blended case are the same as for pure hydrogen power generation.

The economics can be illustrated through the following example. Hydrogen generation from low-cost renewables at USD 25 per MWh with a capacity factor of 50 per cent yields a cost of USD 1.70 per kg of hydrogen produced. Storing this hydrogen underground will add about another USD 0.30 per kg, thus the hydrogen costs USD 2 per kg. If this hydrogen is used to generate power, the resulting cost is USD 100 to 200 per MWh. In ideal conditions (e.g. a CCGT turbine at 60 per cent utilisation), the cost is USD 100 per MWh, while simple-cycle turbines at 25 per cent utilisation would deliver power at USD 200 per MWh. This example illustrates the cost penalty per MWh associated with the power-to-gas-to-power route.

This analysis delivers two key insights. One, companies should use hydrogen-based power for high-value flexible generation first, and two, hydrogen baseload power generation for deep decarbonisation in situations with constrained renewables potential will require strong policy support.

[16] Hydrogen-powered gas turbines is assumed in this analysis. In theory, fuel cells also allow for stationary power generation. The final choice of technology will be determined by the cost trajectory of the two alternatives.
[17] Mitsubishi Hitachi Power Systems (2018).

Exhibit 33 | Hydrogen-based power generation vs. natural gas



1. Assumed hydrogen cost from ATR with CCS in 2030 in the US at USD 1.1/kg, EU/Germany USD 1.7kg, Japan/Korea USD 1.8/kg
2. NG cost of USD 0.12/kg
3. NG cost of USD 0.31/kg

Generators

Today, generators are primarily based on diesel, emitting approximately 700 kg of CO_2 per MWh of power generated. Generators can also be based on natural gas, which emit comparatively less carbon and particles than diesel-powered ones. Biofuels, batteries with renewable electricity, and hydrogen fuel cells with low-carbon or renewable hydrogen production are all alternatives to decarbonise generators. Generators are used as backup power where it is important to secure operations under all conditions, e.g. in hospitals or data centres. They are also used for power generation in remote locations, e.g. to power telecom towers or buildings that are far from the electricity grid.

Hydrogen fuel cell generators are viable alternatives for backup power generation, e.g. in hospitals, and for power generation in remote locations where batteries and renewables are unviable due to sub-optimal conditions for renewable power generation. In areas where the conditions for renewable power generation are good, a battery for storing the energy may be the lowest-cost low-carbon alternative. Alternatively, it is possible to generate hydrogen on-site with renewables and potentially export the excess production.

Cost competitiveness. Two use cases are considered for generators: backup power and remote power generation. In the case of a 1 MW backup generator for a hospital, the fuel cell generator outcompetes battery backup storage. This is driven by much lower capital expenditure for the hydrogen system than for the battery and the low assumed utilisation of less than 2 per cent per year of such a system.

In the case of remote power generation, a telecom tower that requires a continuous power supply of 5 kW is analysed. In this use case, the cost of fuel is the most important driver due to the high utilisation, and the cost competitiveness depends greatly on location and cost of battery and renewable power. Hydrogen is best suited where the conditions for on-site renewable generation are sub-optimal. For instance, the hydrogen alternative is more than 40 per cent lower cost than a solar plant and battery in Edinburgh. When considering the case of remote power generation in southern Spain, the hydrogen fuel cell generator is about 30 per cent more expensive than the battery and solar power plant setup in 2030. A hydrogen cost of USD 6 per kg delivered to a very remote location is required to break even, which may be challenging to achieve.

For a backup generator to outcompete the diesel generator purely on cost is difficult due to the higher capital expenditure on the fuel cell and tank system and higher fuel costs. In 2030, the cost of the system is two times higher for the hydrogen compared to diesel. Given a hydrogen cost of USD 3 per kg delivered, a carbon cost of USD 200 per ton is required to make the fuel-cell-based generator competitive.

Cost development. There are two main factors influencing the cost of hydrogen generators; first, the cost of the fuel cell and tank system, and second, the cost of hydrogen production and distribution. The cost of fuel cell and tank system is of more importance for the backup generator case due to the low system utilisation. Similarly, the cost of hydrogen fuel supplied matters more for the remote generator system due to higher system utilisation provided by the steady power demand of the telecom tower.

The cost of fuel cells and hydrogen tanks are projected to decline by up to 70 per cent by 2030, driven by larger market volumes of fuel cells and tanks across several applications, such as within transportation. The fuel cell system used is similar across different applications, with some variation in the fuel cell balance of plant, which is generally less costly for larger-scale applications. The cost reduction of fuel cell and tank systems accounts for about 50 per cent of cost improvement of the backup generator and only about 10 per cent for the remote generator system.

The cost of hydrogen supplied is projected to decline by about 20 to 40 per cent, as discussed in more detail in Chapter 2. The relative cost reduction is lower for the remote power generation use case due to the long-distance distribution required, indicating that cost reductions within production are less impactful on total cost decline. For the remote generator, the hydrogen fuel cost improvement translates to about 90 per cent of total cost reduction between 2020 and 2030, underscoring the importance of fuel cost for applications with high utilisation.

Industry feedstock

Over 90 per cent[18] of the hydrogen consumed today is used as industrial feedstock, with a large majority produced from fossil fuels. Processes such as the production of ammonia and methanol as well as refining require hydrogen, thus the only way to decarbonise is to change the source of the hydrogen molecules from grey to the low-carbon and renewable routes.

For new hydrogen feedstock applications, low-carbon steel-production based on hydrogen direct reduced iron (H2-DRI) was compared with other low-carbon alternatives and the conventional steelmaking process.

Industrial feedstock users can guarantee large-scale offtake and enable scale in the hydrogen production industry. For example, an ammonia plant that produces 1 Mt of ammonia per year consumes 200 kilotons of hydrogen. To produce this hydrogen would require 1.7 GW of electrolyser capacity, assuming a 50 per cent utilisation factor. A plant of such scale would likely take up much of the short-term electrolyser manufacturing capacity and could play a key role in the needed scale-up in production. Furthermore, such projects often involve few entities in the decision-making process and do not require a system change, which can accelerate uptake compared with the distributed usage characteristics common in segments like mobility or space heating.

Across all feedstock applications, the key cost-reduction driver is the production cost of hydrogen, which was discussed earlier in Chapter 2. The cost of carbon imposed on conventional alternatives provides an additional competitiveness driver for hydrogen. Its ultimate cost will result from the location of hydrogen production and the resources available, which could involve renewables or natural gas and carbon storage resources.

In regions such as the US, the Middle East, and Southern Europe, existing low-carbon industry feedstock applications will likely break even with grey hydrogen, even with carbon costs well below USD 50 per ton. This makes industry feedstock an extremely attractive segment for low-carbon hydrogen deployment.

[18] Institute for Industrial Productivity (2019).

Existing industry feedstock applications

Ammonia production and refining

Both low-carbon hydrogen from reforming plus CCS and renewable hydrogen appear to be viable solutions for decarbonising ammonia production. About 80 per cent of the ammonia produced is used in the manufacture of fertilisers, with end products such as urea or NPK (nitrogen, phosphorous, and potassium fertiliser). Ammonia production today sources hydrogen via steam methane reforming (SMR) or coal gasification, which emits about 2.5 tons of CO_2 per ton of ammonia produced.[19]

Cost competitiveness. Producing ammonia from low-carbon or renewable hydrogen are both attractive options, and the lowest-cost alternative will depend on both the region and available resources, as discussed in Chapter 2. Green ammonia production comes at a higher initial cost, with around 70 per cent higher plant capex due to the need for an additional air separation unit for the nitrogen supply. However, this only results in an additional cost of about USD 20 per ton of ammonia produced and an increase of 7 per cent of the market price of ammonia, at USD 300 per ton. On top of this, making renewable hydrogen from electrolysis the sole source of hydrogen for an ammonia plant requires some form of storage to secure production and bridge times without production.

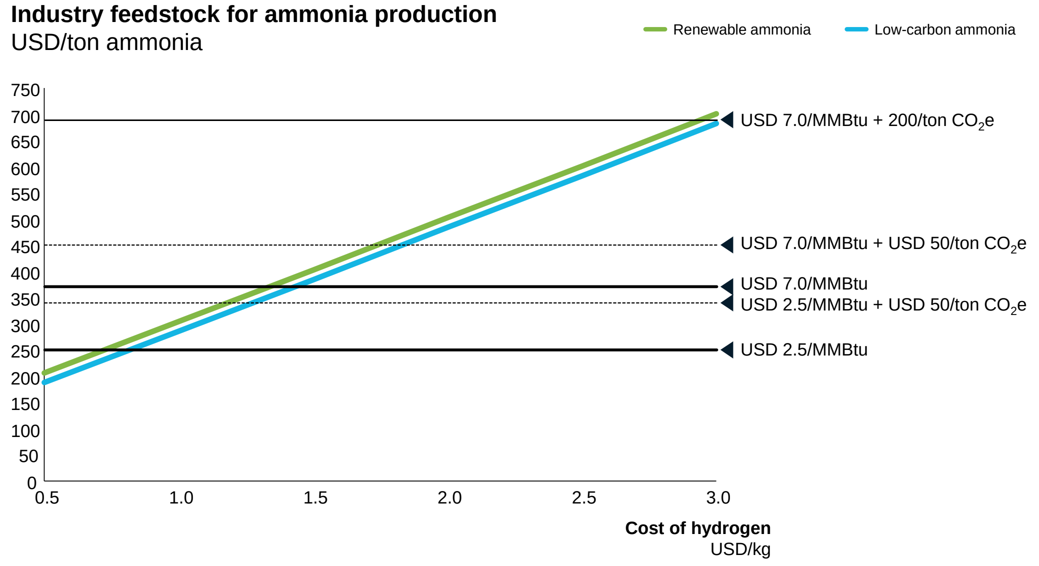
Cost development. The expected carbon cost drives the break-even point for low-carbon hydrogen using CCS, while the local price of natural gas drives the break-even point for renewable hydrogen against the usage of grey hydrogen. A natural gas cost of USD 2.50 per million British thermal units (MMBtus), such as in the US or the Middle East, yields a cost of ammonia of about USD 240 per ton. Breaking even requires a hydrogen cost of about USD 0.70 to 0.90 per kg (see Exhibit 34), which seems infeasible in the foreseeable future. However, with a cost of carbon of USD 50 per ton, the break-even point increases to USD 1.20 to 1.30 per kg for low-carbon hydrogen, achievable in regions with favourable renewables conditions or natural gas prices of about USD 3 per MMBtu.

In regions with higher natural gas prices of USD 7 per MMBtu, such as Europe, the cost of ammonia from conventional SMR is about USD 370 per ton. Breaking even with grey hydrogen requires low-carbon hydrogen costs of about USD 1.40 to 1.50 per kg, increasing to USD 1.70 to 1.80 per kg with a cost of carbon of USD 50 per ton. Increasing the cost of carbon to USD 200 per ton of CO_2e for the USD 7 per MMBtu scenario increases the cost of conventional ammonia to USD 690 per ton. In this case, low-carbon and renewable hydrogen would almost certainly be the lower-cost options across all regions, with a production cost of USD 3 per kg of low-carbon or renewable hydrogen required.

Refining is very similar to ammonia in terms of cost structure, as the two are based on SMR and hydrogen is the only effective decarbonisation option. The difference in cost lies in the additional air separation unit required for the ammonia, resulting in a slightly higher hydrogen break-even cost for ammonia (about a 5 per cent difference). Furthermore, the refinery can also use naphtha reforming to cover part of its hydrogen demand, potentially reducing the need for the storage of hydrogen that is produced from renewables.

[19] Institute for Industrial Productivity (2019), Plastics Europe (2019).

Exhibit 34 | Ammonia cost curve



Methanol production

Cost competitiveness. Methanol production from low-carbon hydrogen is competitive against grey at hydrogen costs of USD 0.80 to 1.50 per kg, depending on the region and the cost of natural gas, assuming no cost for carbon emissions. Including a hypothetical carbon price of USD 50 per ton increases the break-even cost of low-carbon hydrogen only slightly, by USD 0.10 to 0.20 per kg. These are steep targets for the production costs of low-carbon and renewable hydrogen. The cost of carbon has less influence on conventional methanol because methanol emits less CO_2 relative to natural gas feedstock, as around 70 per cent of the carbon is captured in the methanol end product.

Cost development. Methanol production requires two key input components – hydrogen and CO_2 – and is today mostly produced with hydrogen either from natural gas reforming or coal gasification. To produce methanol from renewable hydrogen from electrolysis, companies must add a source of CO_2 to the process. This CO_2 can come from a co-located industrial plant, which can supply the methanol plant instead of storing the carbon. The cost of the additional CO_2 feedstock depends on the cost of CCS and the cost of emitting the CO_2, and will vary according to local conditions and regulations. It is also possible to use carbon from biomass-based processes or base the CO_2 supply on direct air capture of carbon, which would result in truly low-carbon methanol. The latter alternative is currently costly, estimated at USD 150 per ton of CO_2.

From this perspective, methanol production from hydrogen and CO_2 qualifies as carbon capture and usage (CCU). Methanol is used in a variety of end products, ranging from formaldehyde for adhesives (about 30 per cent of the global market), to petrochemicals primarily for production of plastics (roughly a quarter of the market), and as a component in fuels (approximately 35 per cent of the market). If used as a fuel, carbon sequestration is brief, since it is released as the fuel is used. If the methanol helps to produce plastics or adhesives, carbon sequestration may be longer lasting. Consequently, many consider the latter application a 'better' end use than for fuels from a carbon emissions perspective. There are, of course, reductions in CO_2 emissions from not using conventional hydrogen production technologies due to lower process emissions, but the 70 per cent share of carbon captured in the methanol does not necessarily remain captured for long.

Low-carbon methanol production is less sensitive to carbon costs, resulting in a lower break-even point for hydrogen costs compared with ammonia. The analysis shows that a low-carbon cost of hydrogen of about USD 2 per kg supplied requires a cost of carbon of about USD 100 per ton for low-carbon methanol to break even. This suggests that ammonia or refining are initially more attractive use cases for low-carbon hydrogen feedstock. Considering a case based on direct air capture of carbon with a cost of USD 150 per ton of CO_2, the cost of methanol produced increases by about USD 200 per ton. A carbon cost of about USD 450 per ton is required to break even with grey production, given a low-carbon hydrogen cost of USD 2 per kg. Or, from a different perspective, if the cost of carbon were zero, the low-carbon hydrogen must be as low as USD 0.65 per kg.

New hydrogen applications: low-carbon steel production

Today, steel production is one of the world's largest emitters of CO_2, accounting for about 7 to 9 per cent of global CO_2 emissions from the global use of fossil fuels,[20] underscoring the importance of decarbonising this sector. The conventional alternative, a regular blast furnace, emits approximately 1.8 tons of carbon per ton of steel.[21] Hydrogen-based DRI could become competitive with both conventional blast furnaces and blast furnaces with CCS by around 2030, depending on the cost of coking coal in each region. H2-DRI was compared to a low-carbon blast furnace with 90 per cent CO_2 capture, and HISarna, a new process for producing steel from coal, also with a 90 per cent capture rate. Other hydrogen-based low-carbon alternatives are being developed, such as direct injection of hydrogen in the blast furnace, but these are not investigated here.

Cost competitiveness. The competitiveness of hydrogen-based steel production depends greatly on the cost of the hydrogen production and the cost of carbon when considering competitiveness with a conventional blast furnace.

Reaching lower costs than a blast furnace with CCS requires hydrogen costs of USD 1.80 to 2.30 per kg, with a higher break-even point in high-cost regions such as Europe or Japan. Compared with HISarna (with 90 per cent CO_2 capture), low-carbon hydrogen costs of USD 1.20 to 1.60 per kg are required to break even, with higher break-even levels in regions with more expensive coking coal.

Cost development. Competitiveness against conventional blast furnaces will largely depend on the cost of carbon. Given a cost of carbon of USD 50 per ton, H2-DRI can break even with hydrogen costs of about USD 1.60 per kg, assuming a cost of coking coal of USD 200 per ton. The implication is that even with average costs of hydrogen of about USD 2.30 per kg (achievable in several locations in 2030), H2-DRI solutions can outcompete blast furnaces with CO_2 costs of less than USD 100 per ton.

The benefit of using hydrogen from natural gas reforming plus CCS instead of coal-based production with CCS lies in that the process needs to capture less carbon, given that coal is twice as CO_2 intensive per energy unit as natural gas. If renewable hydrogen from electrolysis is used, no CO_2 capture is required at all. Using low-carbon hydrogen from reforming plus CCS yields the additional benefit of allowing decoupling of the location of the CCS and the plant itself.

[20] World Steel Association (2019a).
[21] World Steel Association (2019b).

Hydrogen industry scale-up requires **investment, policy alignment and market creation**

$70 bn

Investment required by 2030 to bridge the gap and make hydrogen competitive