Prospects for gas infrastructure

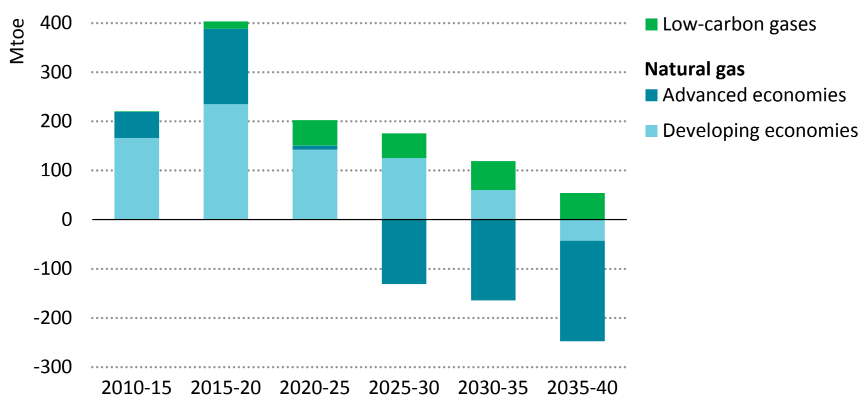
Is there a low-carbon future in the pipeline?

S U M M A R Y

- The next decade is a critical one for gas infrastructure. Short-term decisions on whether to invest in gas grids will have major long-term implications. Questions about the relative importance, and respective roles, of electricity and gas networks are central to the design of energy transitions to a low emissions future. Low-carbon electricity has huge potential to play a greater direct role in future energy systems, but there are limits to how quickly and extensively electrification can occur. Well-established gas grids can deliver twice as much energy as electricity grids today and they are a major source of flexibility. Decisions on the future of gas networks need to consider their potential to deliver different types of gas in a low emissions future, as well as their role in ensuring energy security.

- In the Sustainable Development Scenario, natural gas use grows globally to the late 2020s, to a level almost 10% higher than 2018, although advanced and developing economies follow divergent pathways. But as part of the drive for deep emissions reductions in this scenario, gas grids are gradually repurposed or retooled over time to deliver low-carbon energy. We focus here on two options: low-carbon hydrogen and biomethane.

Figure 13.1 ⊳ Change in global gas demand in the Sustainable Development Scenario, 2010-2040



Trajectories of natural gas demand diverge between advanced and developing economies. Low-carbon gases play an increasingly important role worldwide.

- Low-carbon hydrogen has seen a recent surge of interest, and could help deliver deep emissions reductions across a wide range of hard-to-abate sectors. It is currently expensive to produce: the lowest cost options are between $12-25 per million British thermal units (MBtu). Injecting low-carbon hydrogen into gas pipeline networks would not only reduce the emissions from gas consumption but also offer the possibility of scaling up hydrogen supply technologies to bring down costs through economies of scale. This would facilitate expansion of the use of hydrogen into the buildings, industry and power sectors.

- Biomethane is also attracting increased interest. We estimate that more than 730 million tonnes of oil equivalent (Mtoe) – equivalent to over 20% of annual natural gas demand globally – could be produced today in a sustainable manner. Meeting 10% of today's gas demand with biomethane would cost $10-22/MBtu. Biomethane potential is widely spread geographically though some of the lowest cost options are available in developing economies in Asia.
- In the Stated Policies Scenario, annual consumption of biomethane is just under 80 Mtoe in 2040. Most of this takes place in China and India as a result of explicit policy support, motivated in part by a push to limit growing reliance on imports. In this scenario, there is limited blending of low-carbon hydrogen into gas networks.
- There is much greater uptake of both biomethane and low-carbon hydrogen in the Sustainable Development Scenario. Biomethane use rises to over 200 Mtoe in 2040, and more than 25 Mtoe of low-carbon hydrogen is injected into gas networks. Low-carbon gases make up 7% of total gas supply globally in 2040 and they are on a steep upward trajectory at the end of the *Outlook* period. Over 15% of total gas supply in China and the European Union is low-carbon gas in 2040. Globally, low-carbon hydrogen and biomethane blended into the gas grid in the Sustainable Development Scenario avoid around 500 million tonnes (Mt) of annual CO_2 emissions that would have occurred in 2040 if natural gas had been used instead.
- Blending hydrogen into gas grids accelerates cost reductions in low-carbon hydrogen production, which encourages its wider use for other purposes. Over 80 Mtoe of low-carbon hydrogen is also used directly in end-use sectors in 2040. There is also around 150 gigawatts (GW) of combined-cycle gas turbine (CCGT) capacity equipped with carbon capture, utilisation and storage (CCUS) in 2040 in this scenario: this avoids 300 Mt of annual CO_2 emissions.
- We highlight some issues and provide suggestions for policy makers to consider in developing long-term strategies for gas infrastructure and low-carbon gases. These include: assessing carefully the levels of investment in gas infrastructure that are consistent with both energy security and environmental goals; the importance of regulation of gas networks to help maintain gas infrastructure during the transition to low and zero carbon energy; the need for low-carbon gas standards and incentives to encourage their use; how biomethane production can create jobs in rural locations; and how to manage distributional issues that may arise in energy transitions.

13.1 Introduction

The ability to deliver large quantities of energy to consumers flexibly and reliably is the foundation of energy markets today. Nearly all countries have an extensive grid for delivering electricity to consumers, but in many economies the gas grid provides a larger and more flexible energy delivery mechanism. Questions about the relative importance and the respective roles of these two networks in a low emissions future are central to the design of energy transitions.

The answers will vary from country to country, depending on the extent of existing infrastructure, resource endowments, the structure of the economy and the demand outlook. They will also depend on policy choices. At one end of the spectrum, there is the "electrify-everything" philosophy of decarbonisation, in which electricity becomes the main vector to meet final energy consumption directly. This route implies a massive expansion of low-carbon electricity generation and transmission infrastructure. The role of existing gas grids in this vision of the future is marginal; the core policy issue is how to manage their gradual decline.

However, most countries that have considered how to realise rapid and wholesale emissions reductions are looking instead at a future in which electricity and gas networks play complementary roles. Electricity consumption gains ground under this kind of approach as more end-uses are electrified, but developing or maintaining gas networks to deliver energy to power stations, factories and buildings also remains important. Maintaining gas grids could, for example, avoid additional investment in electricity networks and grid flexibility measures that would only be needed to meet short periods of high demand. Indeed, a number of recent studies have shown that co-ordinated policies across gas, electricity and heat, using different networks, can help maximise energy security and minimise the overall costs of decarbonisation (Navigant, 2019).

The Sustainable Development Scenario embodies this approach. The share of electricity in final consumption rises, but gaseous fuels[1] remain a central element of the global energy mix in this scenario, even though natural gas demand falls in many countries between 2018 and 2040.

The coming years are a particularly important period for policy makers, industry leaders and others considering the future of gas infrastructure: short-term decisions will have long-term implications. Gas infrastructure can take a long time to develop, and it has a long lifetime once constructed. Countries therefore need to consider "what comes next?" when planning for the future. On one hand, an investment decision could lock in gas use for a prolonged period and, if the gas delivered is natural gas, this could impact the achievement of long-term emissions reduction goals, even while delivering near-term gains where natural gas replaces more polluting fuels. On the other hand, opting out of gas networks

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[1] We differentiate between "natural gas", which is gas of fossil origin, and "gas" or "total gas" which includes all gaseous fuels (i.e. natural gas, biomethane, hydrogen, synthetic methane).

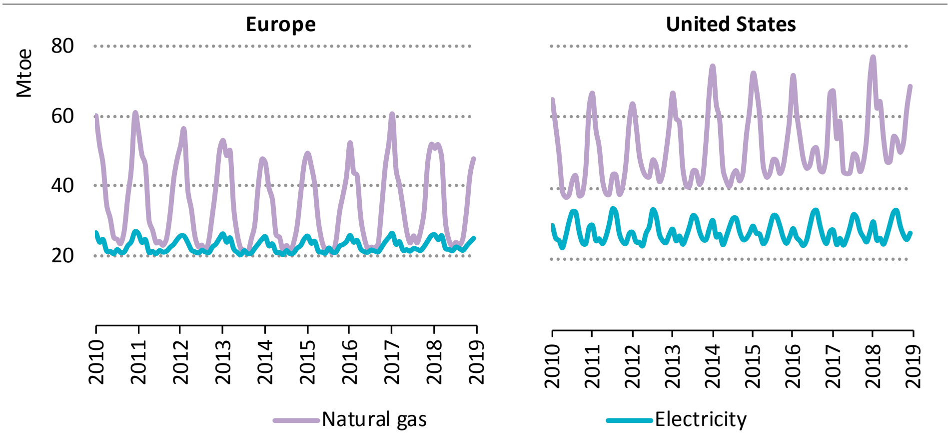
could narrow the options available to realise future emissions reductions and introduce some energy security risks if other infrastructure does not develop quickly enough to compensate.

This chapter discusses how and why it could be useful to have gas infrastructure during energy transitions and how much investment might be required. We examine the extent to which gas networks might be used to provide low-carbon energy from hydrogen, biomethane and gas with carbon capture, utilisation and storage (CCUS). Some policy considerations that help frame the role of gas grids in energy transitions are highlighted.

13.1.1 Role of gas infrastructure today

In Europe and the United States, gas infrastructure delivers between 50-100% more energy on average to end-consumers than electricity grids (Figure 13.2).[2] Gas grids also provide a major source of flexibility. In Europe, for example, gas storage capacity today is 1 000 terawatt-hours (TWh), which is more than 50 000-times current global battery storage capacity.[3] In some countries this storage helps meet peak gas demand in the winter, which can be more than twice as large as peak gas demand in the summer. Even assuming major efficiency gains from a switch from gas to electricity, replacing this level of energy delivery with electricity would be extremely challenging. Gas grids are particularly important for satisfying energy demand in buildings and industry. In advanced economies, gas provides around a third of final energy consumption in these two sectors today.

Figure 13.2 ▷ Monthly electricity and natural gas use in Europe and the United States



Existing natural gas infrastructure delivers more energy than electricity in Europe and the United States and is critical to meet seasonal demand fluctuations

[2] Infrastructure and networks are used here to refer to mid-stream assets such as LNG and transmission and distribution pipelines that transport gas from its point of production to its point of consumption.

[3] Additional storage is provided through the gas that is present within transmission and distribution pipelines.

Gas networks are also well developed in Russia, the Caspian region and parts of Latin America and the Middle East. However, gas currently plays a much smaller role in many of the developing economies in Asia that are the main sources of energy demand growth in the period to 2040. This is mainly because gas historically has not been as readily available at scale or as economically attractive as alternatives. However a number of Asian countries are actively seeking to expand their use of gas, particularly in place of coal, as a means to diversify their energy sources, reduce emissions and improve air quality. The role of gas grids in many developing economies is different from their role in advanced economies since they do not have as large a need for winter heating and so seasonal fluctuations in gas demand are far smaller (although China is one notable exception).

From a broader international perspective, transmission pipelines and liquefied natural gas (LNG) provide around 650 million tonnes of oil equivalent (Mtoe) of gas for interregional trade and are a crucial source of energy imports for a number of countries, for example those with few domestic energy resources.

13.1.2 Role of natural gas in energy transitions

Promise and limits of direct electrification

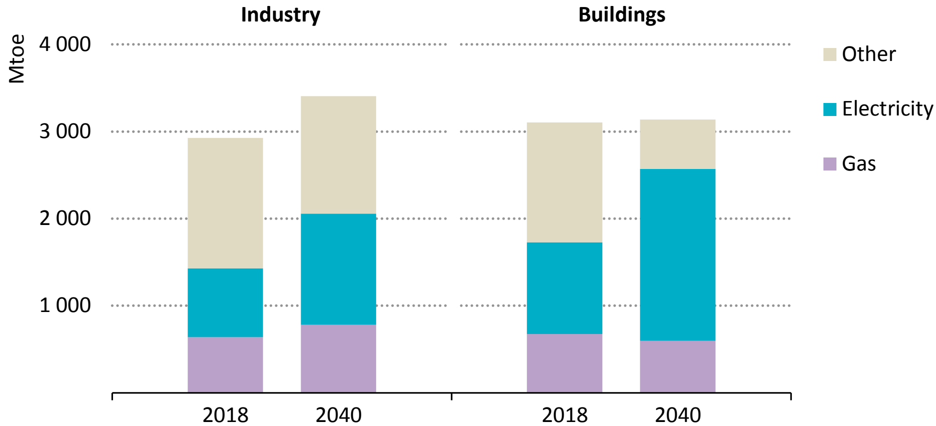
While a gas grid may play a critical role today in satisfying energy services demanded by consumers, is this role needed in the future? Global electricity demand has risen 60% faster than gas demand in final energy consumption since 2000 and the potential of electricity to provide modern energy services with no emissions at the point of use has generated interest in an "electrify-everything" approach to clean energy transitions (Jacobson et al., 2017). Indeed, it is possible to envisage a low-carbon energy system in which decarbonisation of electricity generation is accompanied by widespread electrification of industrial processes, electric heating is used rather than gas in buildings and electric transport is ubiquitous. This is already the clear direction in some Nordic countries, where electric heating is prevalent and there has been a rapid uptake of electric vehicles.

Are there limits to what can be achieved by the electrification of end-use sectors? This was one of the key questions explored in the "Future is Electric" Scenario in the *World Energy Outlook-2018* (IEA, 2018). Among other elements, this scenario assumed:

- Policies that remove non-economic barriers to the deployment of electric end-use technologies; this means that the direct use of electricity comes closer to achieving its maximum technical potential across all end-use sectors.
- More rapid adoption of connected devices leading to more electricity demand in buildings and data centres.
- Achievement of universal electricity access by 2030 and an accelerated uptake of electric appliances among households which have recently gained access.

In the Future is Electric Scenario, average electricity demand grows by around 3% per year to 2040, and electricity accounts for over 30% of final energy consumption in that year (compared with 20% today). Increased direct electricity use is largest in buildings: while today less than 15% of global space heating needs are met by electricity (whereas cooling is almost entirely electric), this grows to nearly 35% by 2040. There are also major increases in direct electricity use in industry (Figure 13.3).

Figure 13.3 ▷ Global final energy consumption in industry and buildings in the Future is Electric Scenario



Even with a major push for electrification, natural gas would still provide around 20% of final energy consumption in industry and buildings in 2040

The Future is Electric Scenario highlighted the enormous potential of electricity to play a bigger direct role in the energy system in the future. But it also suggested that there are limits to how quickly and extensively electrification can occur:

- Electricity is not well suited to deliver all types of energy services. Even if the complete technical potential for electrification were deployed, there would still be sectors requiring other energy sources (given today's technologies). For example, most of the world's shipping, aviation, heavy-freight trucks and certain industrial processes are not yet "electric-ready". While in the future these sectors could use fuels that have been generated using electricity (such as hydrogen or synthetic fuels), these liquid or gaseous fuels would need a separate delivery infrastructure.
- Making the switch to electricity raises a number of practical issues. In the industrial sector, providing large-scale high-temperature electric heat would require significant changes in their design and operation. Further, industrial facilities tend to have long lifetimes and slow turnover of capital stock, while the highly integrated nature of industrial processes means that changing one part of a given process would often require changes to other parts. In the buildings sector, installation of an electric heat pump in place of existing gas heating can mean an intrusive retrofit with a much higher upfront capital cost than replacing an inefficient boiler with an efficient one. In addition, many high-rise urban buildings are not suitable for heat pumps.

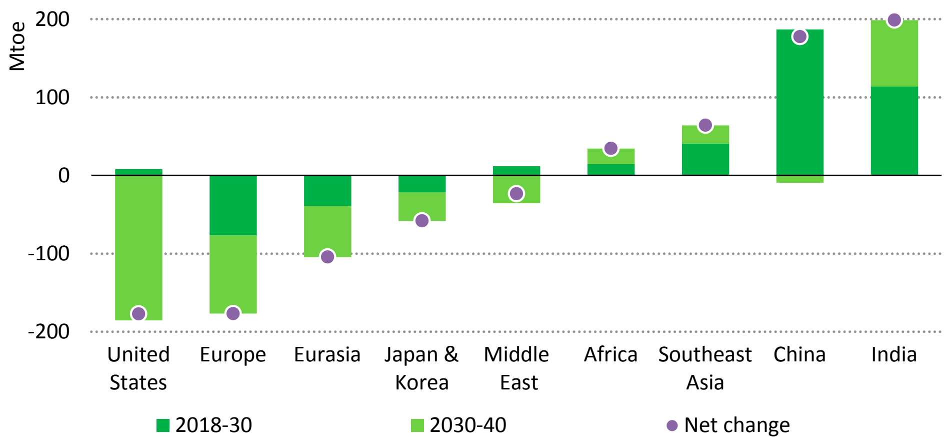
- If electrification is to lead to significant emissions reductions, it must be produced in a low-carbon way. A massive ramp up in low-carbon electricity generation would also need to be accompanied by major additions to transmission and distribution grids, which typically face hurdles related to permitting and public acceptance.
- Wind and solar photovoltaics (PV) can be complementary to some extent but there would still need to be a huge increase in hourly, daily and seasonal electricity storage. The existing peak in winter electricity demand in Europe and some parts of North America would also be heightened by heat pumps consuming more electricity in the winter. For example, if heating in all buildings in Europe was switched to electricity using heat pumps, peak winter electricity demand would increase by more than 60%. Batteries are becoming cheaper and are well suited to manage short-term variations in electricity supply and demand; however, they are unlikely to provide a cost-effective way to cope with large seasonal swings. The expansion of hydropower, which a major source of flexibility in some countries, is limited by geography.
- The value of overlapping infrastructure can be an important consideration for policy makers. Maintaining a parallel gas infrastructure system adds a layer of resilience compared with an approach that relies exclusively on electricity. It also provides a useful hedge against the risks that electrification and the development of new electricity networks do not increase at the pace needed to displace existing fuels while meeting energy service demands.
- Electrification of the entire building stock cannot happen instantaneously. Better-off consumers are likely to be the first to make the upfront investment in new electrified heating systems. Poorer consumers would continue to rely on existing infrastructure and, under existing tariff structures, would need to shoulder the cost of maintaining this infrastructure.

Natural gas in the Sustainable Development Scenario

In the Sustainable Development Scenario, electricity demand grows by nearly 2% per year and accounts for over 30% of final energy consumption in 2040. Natural gas demand grows by around 1% per year to its peak level in the late-2020s before declining slowly. The majority of natural gas demand growth in this scenario comes from countries with energy systems currently dominated by coal (Figure 13.4). Ensuring a diverse set of sources from which to import natural gas leads to investment in long-distance transmission infrastructure. LNG terminals are particularly helpful in this regard since, by its nature, LNG is more flexible than pipelines and regasification terminals require less upfront capital investment.

In the power sector, the primary way in which coal is displaced in the Sustainable Development Scenario is through increased deployment of variable renewable electricity technologies. But it takes time for the use of these technologies to ramp up; gas-fired power plants therefore have a part to play in the interim (see Chapter 4). However, this window of opportunity for natural gas is time limited and the main role of gas-fired power in the longer term is to provide flexibility, alongside hydropower, demand-side management and batteries. There is also a significant increase in natural gas consumption in the industry sector where there are limited alternative options for the generation of high-temperature heat.

Figure 13.4 ▷ Change in natural gas demand in selected regions in the Sustainable Development Scenario



There is a major divergence in the trajectory of gas demand between advanced and developing economies

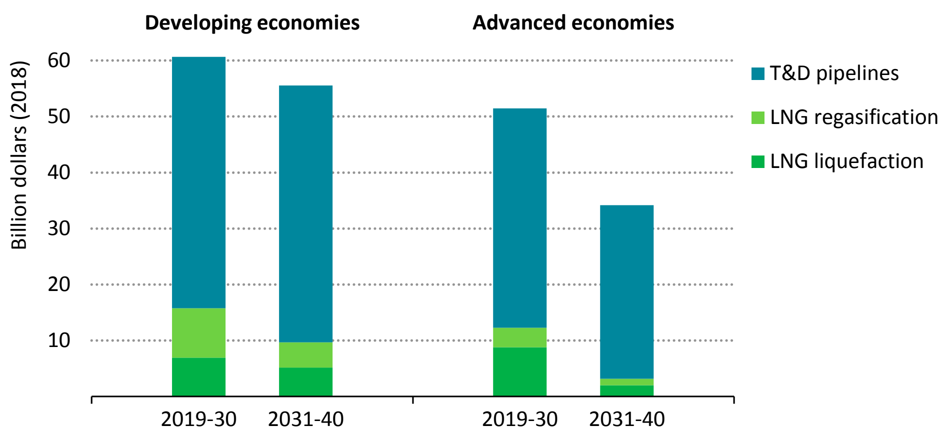
In advanced economies with existing gas grids, natural gas continues to help meet heating demand in buildings even while there is a rapid uptake in electrification. However, almost all new homes built in advanced economies in the Sustainable Development Scenario after 2030 are nearly zero-energy buildings and up to 4% of buildings are renovated each year (compared with less than 1% today). This weakens the case for purchasing new boilers or for building new gas infrastructure to deliver natural gas to buildings.

In many developing economies, the need to improve local air quality and achieve universal energy access by 2030 underpins growth in natural gas use in buildings in the Sustainable Development Scenario. The main expansion in natural gas use over the next ten years is in China, one of the few developing economies with a significant winter residential heating requirement, where it replaces coal. In general, gas pipeline expansions in developing economies are limited to urban areas. In countries that currently rely on the use of liquefied petroleum gas (LPG) in buildings, increased natural gas use in urban households means that the displaced LPG can be used in modern cookstoves in rural locations, where it can displace the traditional use of biomass. This is a major policy consideration behind the expansion of urban gas distribution networks in India.

Investment in gas infrastructure remains an important component of the energy transition envisaged in the Sustainable Development Scenario so that gas can deliver large quantities of energy and also provide a source of flexibility. Yet the trajectory of natural gas demand poses a challenge for spending levels: investment in new assets has to be sufficient to meet rising global gas demand in the near term while taking proper account of the drop in demand over the longer term.

Between 2019 and 2030, $110 billion is invested globally on average each year in LNG and pipelines in the Sustainable Development Scenario (Figure 13.5). After 2030, there is a divergence in investment trends between advanced and developing economies. In advanced economies, average annual investment drops by around 35%, with nearly all of the remaining $35 billion average annual spending used to maintain existing distribution networks. The growth in natural gas demand in some developing economies after 2030 means that investment in gas infrastructure there falls to a much smaller degree.

Figure 13.5 ▹ Average annual investment in LNG and gas pipeline infrastructure in the Sustainable Development Scenario



There is a sharp drop in investment in gas infrastructure in advanced economies after 2030

Note: T&D = transmission and distribution.

13.1.3 Need for gas supply to evolve

Even if natural gas brings benefits when replacing more polluting fuels, it is still a fossil fuel and there are clear environmental drawbacks to its use. Indeed, increased natural gas use by itself is far from sufficient to achieve the dramatic reductions in greenhouse gas (GHG) emissions and air pollutants that are needed in the Sustainable Development Scenario. The benefits of natural gas in this context depend critically on significant and rapid progress in eliminating methane emissions from the production, transmission and distribution of natural gas (IEA, 2018). In the Sustainable Development Scenario, global methane emissions from oil and gas operations in 2030 are 75% lower than today. Investing in gas infrastructure is important in this context: older gas pipelines generally are likely to have higher levels of fugitive methane emissions than newer pipelines, and failure to maintain them could undermine efforts to reduce methane emissions.

Box 13.1 ▷ What is a low-carbon gas?

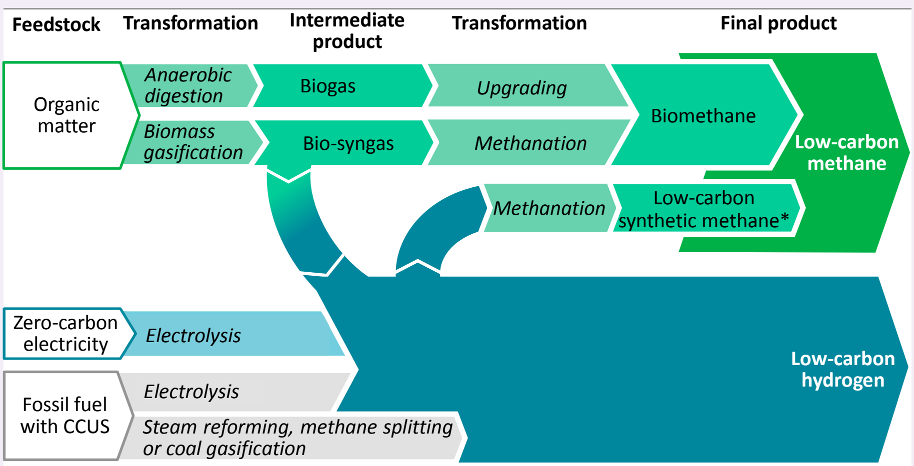
There are many ways to produce hydrogen and biomethane for use in existing gas infrastructure, with either hydrogen or methane as the delivered energy product (Figure 13.6). However, different production methods can result in very different levels of GHG emissions. The focus here is the methods that produce low-carbon gases.

Low-carbon hydrogen: Hydrogen produced by electrolysis[4] using low-carbon electricity, or from the gasification of biomass, or from fossil fuels equipped with CCUS or, potentially, through "methane splitting" (also known as methane pyrolysis).[5]

Biomethane (also called renewable natural gas): A near-pure source of methane produced either by upgrading biogas (by removing carbon dioxide [CO_2] and other impurities) or through the gasification of solid biomass or waste followed by conversion to methane (in a process called "methanation").

Low-carbon synthetic methane: Methane produced through the methanation of low-carbon hydrogen and CO_2 from a biogenic or atmospheric source.

Figure 13.6 ▷ Alternative supply routes to produce low-carbon gases



There are many pathways to produce low-carbon gases. This analysis focuses primarily on the opportunities and costs of low-carbon hydrogen and biomethane.

* Synthetic methane is only low carbon if the CO_2 originates from biogenic sources or the atmosphere.

[4] The conversion of electricity to another energy carrier is sometimes called "power-to-X". We avoid the use of this term as the "X" can refer to different products including chemicals, hydrogen, methane or heat.

[5] Colours are sometimes used to differentiate between production routes for hydrogen. "Blue" hydrogen is produced from fossil fuels equipped with CCUS, "green" hydrogen from renewable-based electricity, and "black/grey/brown" hydrogen for unabated fossil fuels. There are no established colours for hydrogen from biomass, nuclear, methane splitting or grid electricity and so the colour terminology is not used here.

To secure its role in a low emissions energy system, gas infrastructure will ultimately need to deliver truly low-carbon energy sources (Box 13.1). This chapter focusses on two main options. The first is hydrogen, including both blending of low-carbon hydrogen into existing natural gas pipelines and repurposing of gas grids to deliver high proportions of low-carbon hydrogen. Next, building on the biogas analysis in Chapter 7, we examine the potential and costs of biomethane. The outlook for hydrogen and biomethane in the Stated Policies and Sustainable Development scenarios are examined, along with the role of natural gas use with CCUS in these scenarios.

13.2 Low-carbon hydrogen

Low-carbon hydrogen could help deliver deep emissions reductions across a wide range of hard-to-abate sector. This includes: aviation, shipping, iron and steel production, chemicals manufacturing, high-temperature industrial heat, long-distance and long-haul road transport and buildings (especially in dense urban environments or off-grid).

The scope of the hydrogen discussion has expanded beyond an initial focus on road transport (IEA, 2010; IEA, 1995), and the stakeholder community has broadened to include renewable electricity suppliers, electricity and gas network operators, automakers, oil and gas companies and major engineering firms. Among governments, there is increasing attention from both energy exporting and importing countries, as well as city and regional authorities around the world.

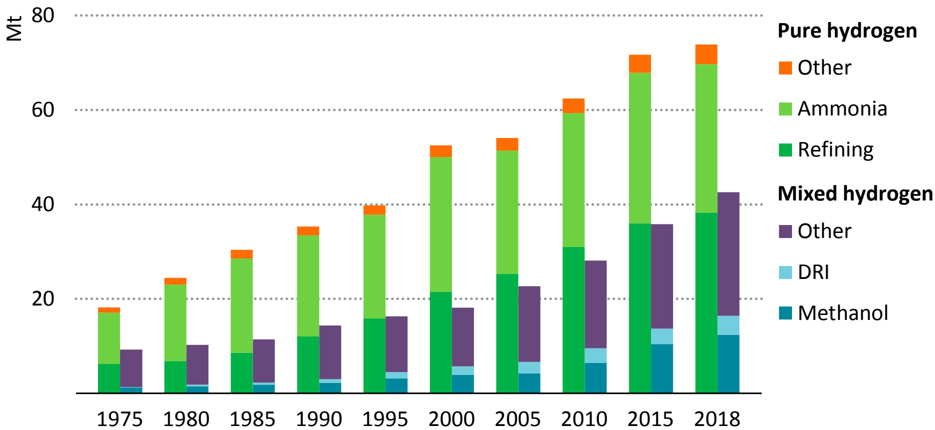
Interest in hydrogen has increased sharply in recent years, reflecting the improvement in the outlook for hydrogen as a low-carbon energy carrier, especially with the declining costs of renewable electricity. Producing low-carbon hydrogen, however, is costly at the moment and investment in hydrogen and CCUS infrastructure presents significant risks in the absence of assured supply and demand.

Injecting hydrogen into gas pipeline networks has been identified as one of four key opportunities for hydrogen over the next decade (IEA, 2019). This would not only reduce the emissions from gas consumption but also offer the possibility of scaling up hydrogen supply technologies and bringing down costs through economies of scale. This in turn could facilitate the direct use of hydrogen in the buildings, transport, industry and power sectors.

13.2.1 Hydrogen use today

Hydrogen is not new to the energy system. Supplying hydrogen to industrial users is a major business globally and there are companies with extensive experience of producing and handling hydrogen. Demand for hydrogen in its pure form is currently around 70 million tonnes (Mt) per year, equivalent to around 330 Mtoe (Figure 13.7). This hydrogen is almost entirely supplied from fossil fuels: 6% of global natural gas consumption and 2% of global coal consumption goes to hydrogen production today. Most of this is used for oil refining and chemicals production. This results in around 830 Mt CO_2 per year, a large portion of which could be avoided through the use of low-carbon hydrogen. A further 45 Mt of hydrogen is used without prior separation from other gases in the industry sector.

Figure 13.7 ▷ **Historic global annual demand for hydrogen**



Around 70 Mt of hydrogen is used today in pure form; a further 45 Mt is used in industry without prior separation from other gases

Notes: DRI = direct reduced iron steel production. Methanol, DRI and "other mixed" represent demand for applications that use hydrogen as part of a mixture of gases, such as synthesis gas, for fuel or feedstock.

Source: IEA (2019).

Hydrogen has also been used extensively in the past in gas networks. In 1950, the United Kingdom had over 1 000 facilities producing "town gas", which was a mixture of gases produced from coal or oil that had a hydrogen content of around 50% (Arapostathis et al., 2013). Over 100 000 kilometres (km) of distribution pipelines were built to transport it to end-use sectors (Dodds and McDowall, 2013). Many of these pipelines were replaced after the discovery of natural gas in the North Sea but some are still in use. Other countries, including the United States, Canada and many northern European countries such as Austria, France and Germany, also underwent government-led transitions from town gas to natural gas from the 1950s to 1970s.

The future potential of hydrogen as a low-carbon energy source results in part from its versatility. It can be used in a wide variety of applications, such as transport and heating, or converted into electricity, or transformed into hydrogen-based fuels, such as synthetic methane, ammonia or liquid fuels. It can also support the integration of high levels of renewable-based electricity by providing a long-term storage option and dispatchable low-carbon power generation. In addition it can be produced from a wide range of low-carbon energy sources, even if less than 0.7% of hydrogen production today is low-carbon. Options include production from renewables, sustainable biomass and nuclear electricity. It can also be produced from fossil fuels, if combined with CCUS and if emissions during extraction and supply are minimised.

13.2.2 Costs and potential to blend hydrogen into gas networks

Interest in blending hydrogen into natural gas grids has risen sharply in recent years leading to several major demonstration projects. There are currently 30 such projects around the world at both the transmission and distribution levels.

The case for hydrogen blending in natural gas infrastructure is primarily that a gas supply that includes low-carbon hydrogen would mean lower CO_2 emissions, and would help scale up production of hydrogen and so reduce its costs. However blending would also facilitate the transport of hydrogen from where it is produced to where it is used, as resource availability and economies of scale dictate that individual production plants are likely to serve multiple, dispersed end-users. With the exception of around 5 000 km of hydrogen pipelines in industrial clusters, there is no established infrastructure today for hydrogen transport. The existing natural gas infrastructure in many countries is extensive and could transport hydrogen at much lower unit costs than would be the case if new dedicated hydrogen pipelines had to be built.

The energy density of hydrogen is around a third of that of natural gas and a 5% hydrogen blend by volume[6] in a natural gas pipeline would reduce the energy that the pipeline transports by around 3% (Quarton and Samsatli, 2018). As a result, end-users would need to use larger gas volumes to meet a given energy need, as would any industrial sectors that rely on the carbon contained in natural gas (e.g. for treating metal). To satisfy a given energy demand, a 5% blend of low-carbon hydrogen would reduce CO_2 emissions by 2%.

In the early phase of commercial scale up of low-carbon hydrogen, the ability to use existing infrastructure will be critically important. With only modest additional investment in infrastructure or end-use equipment, existing gas grids would be able to transport the output of new hydrogen production facilities at low marginal costs, thereby reducing the overall cost of consuming low-carbon hydrogen and building consumer confidence in the viability of hydrogen as an energy carrier. The use of existing pipelines to bring hydrogen to consumers would also help avoid the need to acquire permits for new transmission and distribution pipelines, which can take years to acquire, and the need for major new construction projects.

Blending hydrogen into the gas grid would, however, raise the costs of delivered gas because low-carbon hydrogen production costs are likely to remain higher than natural gas prices. Currently, producing low-carbon hydrogen from natural gas with CCUS costs around $12-20 per million British thermal units (MBtu), while producing hydrogen from renewable-based electricity costs around $25-65/MBtu. While "surplus" renewable electricity could be obtained at very low prices in some regions, its availability today is limited. Furthermore, electrolysis is a capital-intensive process and so using only periodic surpluses of very cheap electricity would be likely to be an expensive way to produce low-carbon hydrogen. For example, if an electrolyser had access to free electricity but operated only at a load factor

[6] All blend shares in this section are given in volumetric terms.

of 10%, it would cost around $50/MBtu to produce hydrogen (IEA, 2019). Nonetheless, as variable renewable electricity accounts for an increasing share of power generation in the Sustainable Development Scenario, larger hourly disparities in wholesale power prices are likely to emerge and could improve the economics of using electrolysers at times when prices are very low.

A 5% hydrogen blend in a distribution grid for a city of 3 million people today would cost around $25-50 million each year for hydrogen supply using electrolysis, injection stations, upgrades to pipelines, compressors and metering.[7] Investment in facilities to produce the low-carbon hydrogen would represent around 80% of these costs. But early stage investments of this kind would have major longer term benefits for technology learning. If 100 projects of this size were undertaken around the world, they would stimulate an additional 1 Mt of annual low-carbon hydrogen supply and require 10 gigawatts (GW) of electrolyser capacity. This would lead to a significant scale up of manufacturing and installation capabilities, promoting efficiency improvements and capital cost reductions for electrolysers of around 20%. Supplying this level of hydrogen demand from CCUS-equipped natural gas reforming would similarly promote vital experience and cost reductions.

The largest electrolyser facilities being installed today have capacities of around 10 MW, but among the larger proposed projects for coming years are facilities of 100-250 MW in Europe and North America. These will run on wind or hydropower and inject tens of thousands of tonnes of hydrogen per year into the gas network. There also are proposed projects for blending hydrogen from natural gas with CCUS in Europe, including plans in northwest England to produce around 0.1 Mt of low-carbon hydrogen per year by 2030 for injection into the gas grid, and to convert chemical plants to low-carbon hydrogen (Cadent, 2018).

Adapting the transmission grid

High concentrations of hydrogen can corrode the steel used in transmission pipelines; the performance of the equipment connected to the pipelines, such as compressors and valves, can also be adversely affected. Existing transmission grids have usually not been designed to accommodate more than minor levels of hydrogen and so upgrades to infrastructure and equipment would be needed to accommodate meaningful blending levels. With minor modifications, however, transmission networks could probably cope with hydrogen blends of up to 15-20%, depending on the local context (NREL, 2013; NATURALHY, 2009). Moving to higher concentrations of hydrogen is possible, but would require additional modifications to pipeline integrity management systems and compression stations or the replacement of some pipework. Where natural gas transmission pipeline corridors are made up of several pipelines running in parallel, the pipelines could be adapted sequentially to minimise disruption to operations.

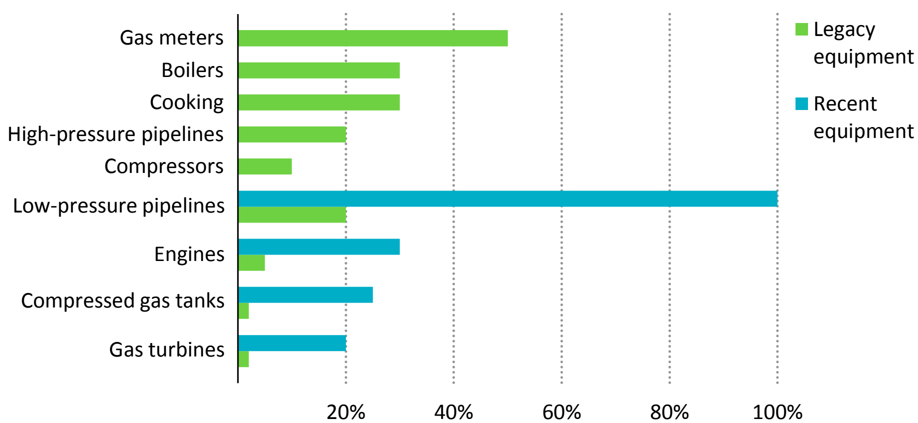
[7] Assuming a ten-year project, savings from the avoided natural gas use, and no new investments are needed to upgrade end-use equipment.

The picture is mixed in terms of underground gas storage facilities. Salt cavern storage facilities are suitable for hydrogen blends of up to 100% without the need for upgrades, but depleted oil and gas reservoirs and aquifers are more permeable to hydrogen and contain contaminants that could react with it. Recent tests have indicated that hydrogen blends might be stored effectively in depleted hydrocarbon reservoirs with hydrogen losses below 20% (Underground Sun Storage, 2017), but further research is needed to understand their performance for different blend levels and time periods.

Adapting the distribution grid

Generally, distribution pipelines are expected to have a higher tolerance for hydrogen blending than transmission pipelines. Much depends on the age of different elements of the grid. Equipment that has been added recently to distribution grids can often tolerate higher shares of hydrogen (Figure 13.8).[8] Older grids and components present a bigger problem because some elements have a relatively low tolerance to hydrogen blending and would need to be replaced or adapted to accommodate higher blending levels. As hydrogen injected into the distribution system will reach all parts of the grid that are downstream, all components must be able to tolerate it to any given level.

Figure 13.8 ▷ Estimated tolerance to hydrogen blend shares of selected elements of existing gas distribution networks



Much existing equipment would need to be adapted to tolerate meaningful levels of blending or be replaced by new equipment designed to tolerate pure streams of hydrogen

Notes: "Legacy" refers to the oldest equipment on most systems. "Recent" figures are shown where data are available.

Source: IEA analysis based on Altfeld and Pinchbeck (2013).

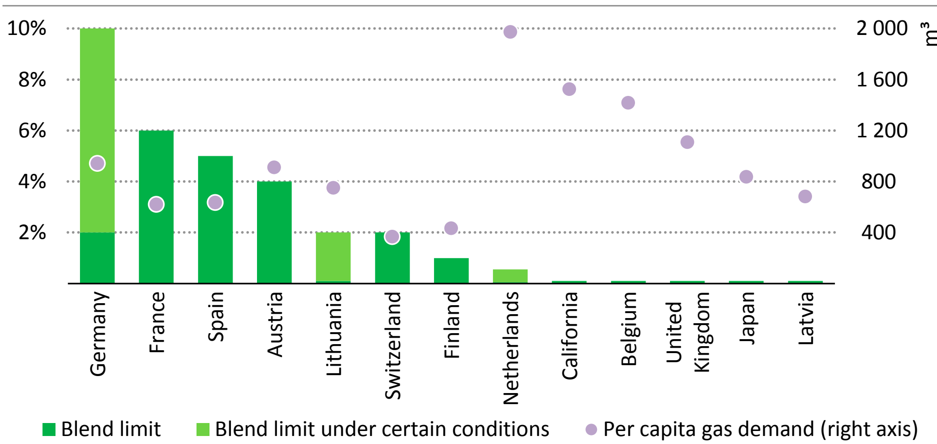
[8] In general, pipelines or equipment modified for high hydrogen blends (50% or below) can still use natural gas without added hydrogen but the combustion will not be optimised. However it is likely to be technically feasible to optimise new end-use equipment for any hydrogen blend up to 100%, as well as to produce dual-fuel appliances that can accommodate different gas supplies.

Low-pressure service pipelines that provide gas to residential buildings generally would have few problems accommodating blends of up to 20%. Indeed most service pipelines installed since the 1970s use plastic instead of steel and could accommodate a pure stream of hydrogen. Within buildings, many gas heating and cooking appliances in Europe are already certified for up to 23% hydrogen.

Other end-uses may be much more restricted. Compressed natural gas tanks, used in some vehicles, can have very low limits (although the latest "Type IV" tanks can take blends of 30%). Older natural gas engines face a similar issue and have a maximum level of blended hydrogen of 2-10%. Similarly many industrial gas users cannot accept very high blending levels: chemical producers, for example, use natural gas as a raw material and have very strict feedstock specifications. In the power sector, the control systems and seals of existing gas turbines are not designed to handle the properties of hydrogen and many are certified for less than 5% blended hydrogen. While they could accommodate higher blends if seals and safety systems were adequately adjusted, they are generally optimised for a stable gas composition rather than a blend share that varies or evolves over time.

There have been a number of successful demonstrations of hydrogen blends of up to 20% in distribution grids over the last decade. However, regulations are generally based on natural gas supply specifications or the tolerance of the most sensitive piece of equipment on the grid and in consequence only allow very low levels of blending. Currently in many countries, no more than 2% hydrogen blending is permitted (Figure 13.9).

Figure 13.9 ▷ Current limits on hydrogen blending in natural gas networks and gas demand per capita in selected locations



Today most natural gas networks have limits on allowable hydrogen concentrations; some with the strictest limits have the highest per capita natural gas demand

Note: The conditional limits shown reflect these parameters: in Germany if there are no compressed natural gas filling stations connected to the network; in Lithuania when pipeline pressure is greater than 16 bar; in the Netherlands for high-calorific gas.

Source: IEA analysis based on Dolci et al. (2019); HyLaw, (2019); Staffell et al. (2019).

Existing natural gas infrastructure, in theory, could also be used as a cost-effective means of hydrogen transportation to users who require a pure stream of hydrogen. Various options have been proposed and are at different stages of maturity:

- Separating hydrogen from a blend of natural gas prior to its use. There are a number of technologies that could potentially be used, but they are at an early stage of development and are relatively expensive.
- Transporting natural gas close to end-users and transforming it into hydrogen through methane splitting. Methane splitting converts methane into hydrogen and solid carbon (also called "carbon black"). The carbon black can be buried or used to produce rubber, tyres, printers or plastics. This process is still at a very early stage of development and a number of challenges still need to be resolved.
- Converting the gas grid to deliver a pure stream of hydrogen (Box 13.2).

Box 13.2 ▷ Using the gas grid to transport and deliver pure hydrogen

Delivering pure hydrogen to consumers would require much more change than just blending. A switch to 100% hydrogen supply for each part of the affected network would mean that new compressors and, in some cases, storage facilities would need to be available in advance. It would also require the replacement of meters, compressors and monitoring equipment, thorough inspection of older parts of a pipeline and replacement of current gas appliances. In addition, it would involve a temporary loss of access to the gas grid: during the conversion from town gas to natural gas in the 1960s and 1970s, households had their gas supplies cut for a day or two.

For consumers, it would require appliances that are ready to use 100% hydrogen. Although it would be feasible to produce such appliances, they would initially cost up to 20% more than current appliances (Frazer-Nash Consultancy, 2018). Consumers may need a lot of convincing to make such a change, especially given the likely disruption and additional costs. On the basis of stated policies, full conversion by 2030 is expected to be realised in fewer places than blending, and to be focussed on particular parts of national grids, such as town distribution networks and underused transmission pipelines.

The H21 project in the north of England is an example of a project to deliver pure hydrogen. It aims to use existing distribution pipes to deliver a pure stream of hydrogen to several urban areas from the late 2020s, while natural gas networks continue to operate in unconverted areas nearby, potentially using natural gas with blended hydrogen. The estimated costs of repurposing plastic distribution pipelines are $4 000/km (H21, 2016). While these costs have yet to be demonstrated in practice, they are at least a factor of ten lower than the cost of building new distribution pipelines. Other projects are under consideration. For example, the existing gas transmission network in the Netherlands, geared to handle its low-calorific natural gas, has pipelines that are likely already suitable for pure hydrogen transport and there are investigations underway to assess the opportunities to convert it to deliver 100% hydrogen.

13.3 Biomethane

Another alternative to pipeline natural gas is biomethane. Unlike hydrogen, biomethane, a near-pure source of methane, is largely indistinguishable from natural gas and so can be used without the need for any changes in transmission and distribution infrastructure or end-user equipment. There are two main biomethane production pathways: the first involves upgrading biogas and the second involves the gasification of biomass.

Upgrading biogas

The main production route for biogas is via anaerobic digestion of an organic feedstock (certain crops, animal manure, wastewater sludge and municipal solid waste are all suitable) (see Chapter 7). In its raw form, the resultant biogas is a mixture of methane, CO_2, hydrogen sulphide, nitrous oxides and other contaminants; the methane content varies from 45-75% according to the feedstock used. This is too low for biogas to be used as a direct replacement for natural gas or for it to be blended into existing gas networks. The biogas therefore has to be "upgraded" to remove most of the CO_2 and other contaminants, leaving a near-pure stream of methane.

Upgraded biogas accounts for around 90% of total biomethane produced worldwide today. Upgrading technologies make use of the different properties of the various gases contained within biogas to separate them, with water scrubbing and membrane separation accounting for almost 60% of biomethane production globally today (Cedigaz, 2019). The CO_2 that is separated from the methane is relatively concentrated and could be used for industrial or agricultural purposes or combined with hydrogen to yield an additional stream of methane: alternatively it could be a candidate for storage in geological formations.

Biomass gasification

An alternative method is to produce biomethane through the gasification of biomass. There are a few gasification demonstration plants currently in operation but the volumes of biomethane produced in this way are relatively small and the technology is at a lower level of technical maturity than anaerobic digestion. However there is arguably greater potential for gasification to generate economies of scale. There is also a higher level of interest from incumbent gas producers since gasification appears a better fit with their knowledge and technical expertise.

To produce biomethane through gasification, woody biomass is first broken down at high temperature (between 700-800 degrees Celsius [°C]) and high pressure in an oxygen-free environment. Under these conditions, the biomass is converted into a mixture of gases, mainly carbon monoxide, hydrogen and methane (sometimes collectively called syngas). To produce a pure stream of biomethane, the bio-syngas is cleaned to remove any acidic and corrosive components. A catalyst is then used to promote a reaction between the hydrogen and carbon monoxide or CO_2 to produce methane in a process called methanation (Box 13.3). Any remaining CO_2 or water is removed at the end of this process.

Box 13.3 ▷ Low-carbon synthetic methane

Synthetic methane is methane produced by chemically combining hydrogen with carbon monoxide or CO_2. If the synthetic methane is combusted, this CO_2 is again released to the atmosphere (unless the combustion process is equipped with CCUS). From a climate perspective, the source of CO_2 therefore is vitally important. For "low-carbon synthetic methane", low-carbon hydrogen is needed alongside a non-fossil source of CO_2.

Methanation is likely to be most cost effective when the hydrogen and carbon come from the same source (such as in biomass gasification). Another option is to use the CO_2 separated from methane during biogas upgrading or during bioethanol production. These processes result in a concentrated stream of CO_2, which can be captured and used with only moderate additional investment and energy. If there is production of hydrogen at the same site, then the two streams of methane can be combined to take advantage of the same infrastructure for onward transmission and distribution. This would also maximise the use of the carbon contained in the original biomass feedstock. In addition, CO_2 can be captured directly from the atmosphere. Cost estimates for direct air capture (DAC) are uncertain, but studies estimate that in the long-term costs for DAC may fall to a range of $100-230/tonne CO_2 (Keith et al., 2018; Fasihi et al., 2019).

Low-carbon synthetic methane production has been demonstrated at a scale of 1.4 million cubic metres per year (1.2 thousand tonnes of oil equivalent) in Germany, but costs remain high. With low-carbon hydrogen costing around $35/MBtu and CO_2 costing $30/tonne CO_2, low-carbon synthetic methane would cost around $60/MBtu. With DAC costing $200/tonne CO_2, costs would be higher still at around $85/MBtu. Cost reductions of around 50% are expected by 2040 from improvements in electrolysers, renewable electricity generation and methanation equipment. However these reductions are not sufficient for low-carbon synthetic methane to play a meaningful role before 2040 in the Sustainable Development Scenario.

13.3.1 Biomethane use today

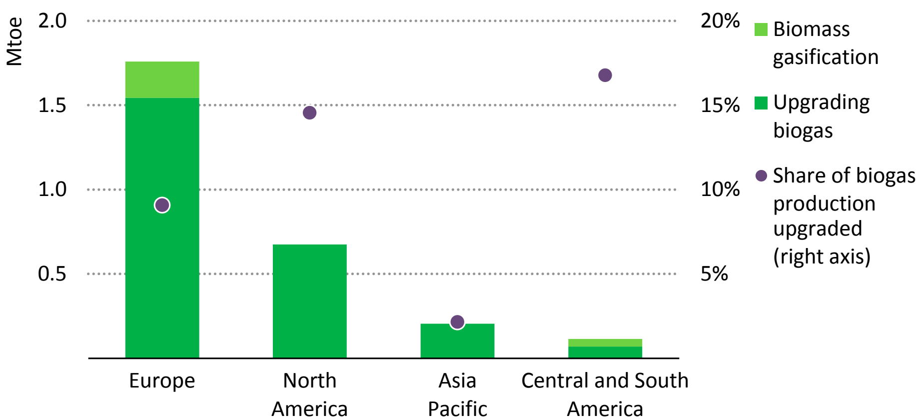
13

There are over 700 biomethane plants in operation today producing around 2.5 Mtoe of biomethane globally. Most of these plants are in Europe and North America. Three-quarters inject biomethane into existing gas networks (Cedigaz, 2019). A further 20% of plants deliver biomethane for use in road vehicles through dedicated distribution networks. The remainder is for use in buildings and industry.

Although biomethane represents less than 0.1% of natural gas demand today, its production and use are supported by an increasing number of policies, especially in the transport and electricity sectors. For example, there are biomethane production targets and ambitions in Italy, India, China and France. Biomethane is also expected to play a role in helping to achieve Brazil's 2028 target of reducing the carbon intensity of fuels in the transport sector by 10%, and in the context of low-carbon fuel standards in the US State of California and British Colombia, Canada. Biomethane production has grown by around 30% each year on average over the past decade.

Almost all plants in operation today produce biomethane by upgrading biogas. However less than 8% of biogas produced globally today is upgraded (for the other uses of biogas, see Chapter 7). This percentage varies widely between regions: in North and South America around 15% of biogas production is upgraded; in Europe, the region that produces the most biogas and biomethane, around 10% of biogas production is upgraded; in Asia, the figure is 2% (Figure 13.10).

Figure 13.10 ▷ Biomethane production and share of total biogas production that is upgraded in selected regions, 2017



Biomethane production in 2017 is mostly concentrated in Europe and North America, although these regions upgrade only a fraction of their biogas production

Note: There are negligible levels of biomethane produced in Africa, Middle East and Eurasia.

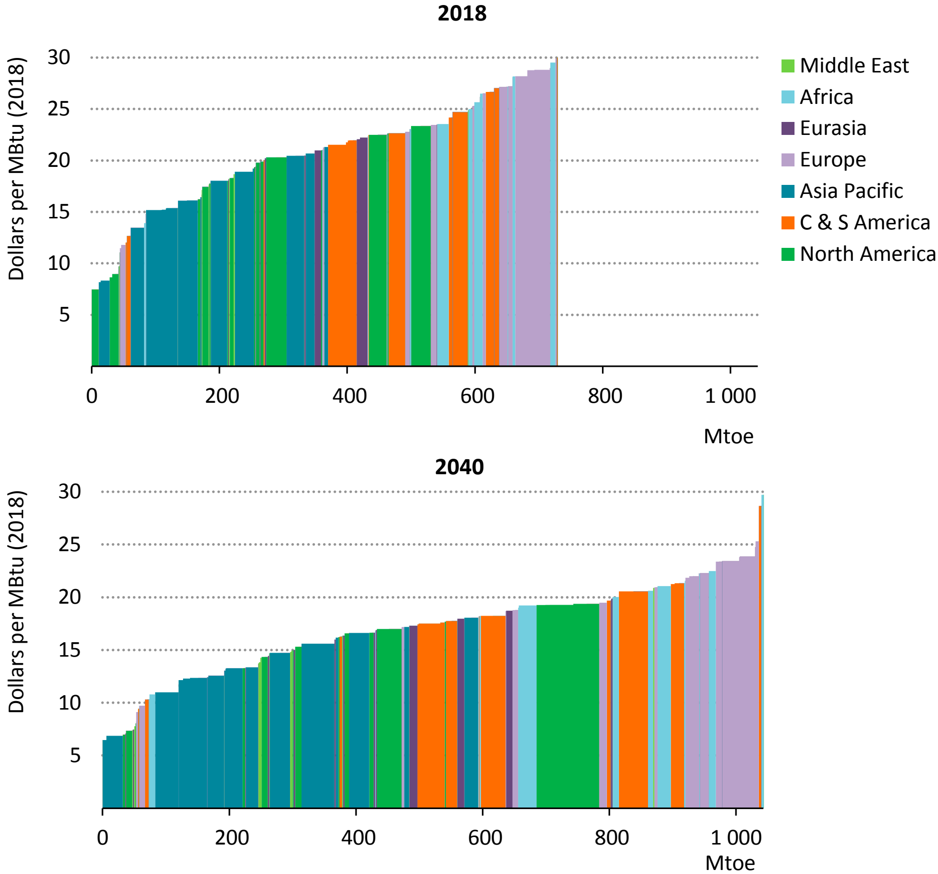
13.3.2 Blending biomethane into gas networks: costs and potential

In this *Outlook,* we provide a first-of-a-kind assessment of the sustainable technical potential[9] and costs of biomethane supply globally, and how this might evolve in the future. (This builds on the analysis for biogas described in Chapter 7.) For biogas upgrading we include the costs and availability of 17 individual biogas feedstocks grouped into four categories: crops, animal manure, municipal solid waste (MSW) and wastewater. For biomass gasification we consider two sources of solid biomass: forestry residues and wood

[9] This includes feedstocks that can be processed with existing technologies, that do not compete with food for agricultural land, and that do not have any other adverse sustainability impacts (e.g. reducing biodiversity). Feedstocks grown specifically to produce biogas, such as energy crops, are also excluded.

processing residues. Each feedstock has been assessed across the 25 regions modelled within the World Energy Model.

Figure 13.11 ▷ Global sustainable technical potential of biomethane



By 2040, over 1 000 Mtoe of biomethane could be produced globally. This potential has a wide geographic spread.

Note: C & S America = Central and South America.

We estimate that around 730 Mtoe of biomethane could be produced sustainably today, equivalent to over 20% of global natural gas demand (Figure 13.11). Biogas upgrading accounts for the vast majority of this potential: crop residues (including sequential crops)[10] provide 35%, animal manure 25%, MSW 15% and wastewater less than 5%. The remaining 20% comes from biomass gasification. This potential has a wide geographic spread: the

[10] Sequential crops are grown between two harvested crops as a soil management measure that helps to preserve the fertility of soil and avoid erosion; they do not compete with food for agricultural land.

largest share of the resource potential is in the United States and Europe (each with 16%), but there is also major potential in China and Brazil (each with 12%) and India (8%). The potential could be even larger if energy crops were included, but we exclude them from this assessment to avoid any potential competition between biomethane and food production (MTT Research, 2009). Nonetheless there still could be competing uses for some of the feedstocks: for example, forestry residues can be a sustainable source of heat, while crop residues can be used for animal feed or to produce advanced biofuels. Economic and population growth, changes in waste management and agricultural processes, and technological progress mean that this estimated global biomethane potential increases by over 40% between 2018 and 2040. Biomass gasification grows at a slower pace than biogas feedstocks and accounts for 15% of total potential in 2040.

We estimate that the global average cost of producing biomethane through biogas upgrading today is around $20/MBtu. Most of this cost is attributable to the collection and processing of the biogas feedstock, but biogas upgrading adds an additional $7-8/MBtu. Biomass gasification is currently the more expensive method of production in all regions: the average cost of producing biomethane by gasification is around $25/MBtu globally. In contrast to biogas upgrading, it is the gasification and methanation processes involved rather than the feedstock cost that make up most of the overall cost. There is a high degree of uncertainty over the cost reductions that could be achieved for both production routes, although constructing larger facilities should provide some economies of scale for both.[11] In 2040, we estimate that the average cost of biomethane globally will be around $4/MBtu lower than today.

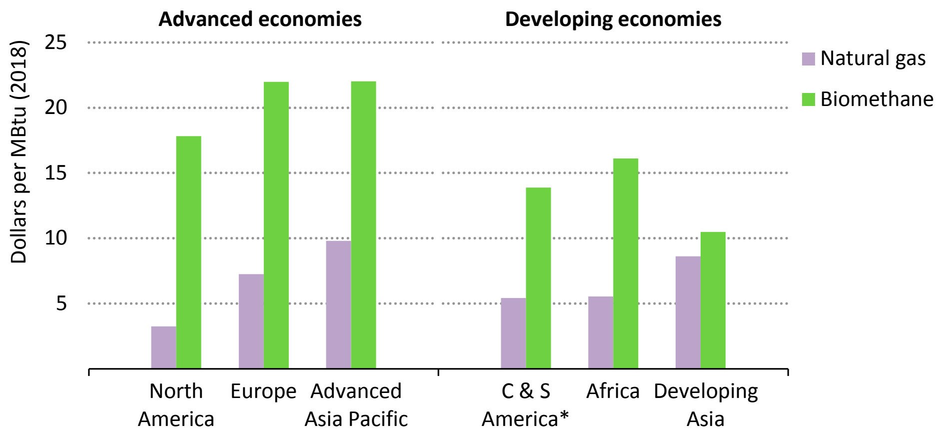
Upgrading biogas captured from landfill sites is typically the cheapest way to produce biomethane in all parts of the world. Taking into account regional biomethane costs and natural gas prices, around 12 Mtoe of biomethane could be produced today for less than the domestic price of natural gas. In the Stated Policies Scenario, biomethane costs fall while natural gas prices rise over time, and so, by 2040, nearly 75 Mtoe of biomethane is fully cost competitive with natural gas. Even so, most biomethane is much more expensive than natural gas and meeting 10% of today's natural gas demand with the cheapest biomethane options available in each region would cost $2-15/MBtu more than natural gas (Figure 13.12).

One way to reduce the cost gap would be to make use of the by-products from biomethane production. Producing biomethane through biogas upgrading leaves a residue of fluids and fibrous materials called "digestate". The handling and disposal of digestate can be costly and as a result it is often considered a waste rather than a useful by-product. However in certain locations and applications digestate could be sold as a natural fertiliser and help to reduce the overall cost of biogas production. Biogas upgrading also results in a pure stream of CO_2 that could be used by other industries. In the beverage industry, for example, CO_2 is

[11] There is slightly more scope for cost reductions with biomass gasification than upgrading biogas, and so the cost gap between the two production routes shrinks over time.

often bought for \$50-100/tonne CO_2 (Pérez-Fortes and Tzimas, 2016). The revenues that can be achieved through selling digestate or the pure CO_2 stream, however, are likely to be relatively modest and in most cases would not be sufficient to close the cost gap entirely with natural gas.

Figure 13.12 ▷ Cost of using the least expensive biomethane to meet 10% of gas demand and natural gas prices in selected regions, 2018



There is a large gap between the price of natural gas and the cost of biomethane production in nearly all regions today; policies will be critical to close this gap

* C & S America = Central and South America excluding Chile.

Note: Advanced Asia Pacific includes Australia, Japan, Korea and New Zealand.

Another way to reduce the cost gap would be to put a price on the GHG emissions from fossil fuels, including natural gas use. When biomethane replaces natural gas, its use reduces CO_2 emissions. Biomethane can also help to avoid large quantities of methane emissions that would otherwise be released directly to the atmosphere from feedstock decomposition (see section 13.5.2). With these avoided methane emissions taken into account, there are some countries – most notably China and India – where only a small GHG price would be required to close the cost gap between natural gas and biomethane. However, in advanced economies and other developing economies, a GHG price of \$50-180/tonne CO_2-equivalent would be required. While the GHG price needed to close the cost gap falls over time in both the Stated Policies and Sustainable Development scenarios, these numbers are substantially above those in most GHG pricing systems around the world today.

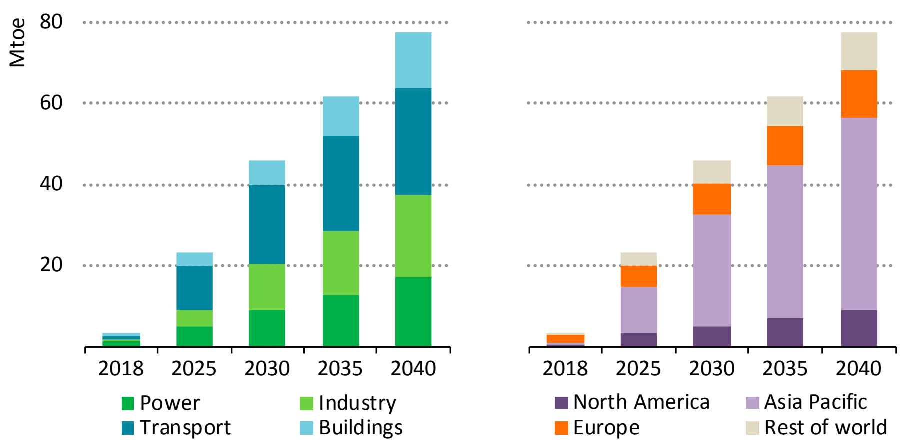
Governments could take additional policy action to place a value on the additional benefits of biomethane. For example, the benefits it brings as a domestically produced low-carbon fuel that promotes rural development and enhances waste management in ways that improve water quality.

13.4 Outlook for low-carbon hydrogen and biomethane

13.4.1 Stated Policies Scenario

In the Stated Policies Scenario, just under 80 Mtoe of biomethane is consumed in 2040. Most of this occurs as a result of explicit policy measures rather than because biomethane is cost competitive with natural gas. The majority of global consumption in 2040 is in China and India (Figure 13.13): China produces over 30 Mtoe of biomethane, which is injected into its expanding natural gas grid, while India's consumption grows to 15 Mtoe of biomethane, primarily because of its target for biomethane use in the transport sector. In both cases, support for biomethane is also motivated by a desire to limit growing reliance on imported natural gas, and thereby enhance gas security. In Europe, biomethane use reaches 12 Mtoe in 2040, accounting for 2.5% of the gas used in natural gas grids. Consumption in North America increases to just under 10 Mtoe.

Figure 13.13 ▷ Biomethane consumption by sector and region in the Stated Policies Scenario



Biomethane use grows to just under 80 Mtoe in the Stated Policies Scenario, mainly because of explicit policy support in India and China

As highlighted by the case of India, the potential use of biomethane in transport is one of the main areas of focus for policy makers today. For example, the Renewable Energy Directive in the European Union requires 3.5% of fuel demand in 2030 to be met by advanced biofuels, including biomethane, while in the United States there is support from the Renewable Fuel Standard and California's Low Carbon Fuel Standard.

Because natural gas today accounts for less than 5% of total fuel demand in transport, a key element of any biomethane transport strategy is the need to increase the number of gas vehicles on the road and to build fuelling infrastructure. These conditions are likely to be easiest to satisfy in captive fleets and road freight.[12] A significant proportion of road freight activity takes place on key transport corridors, so providing fuelling infrastructure along them would provide access to a large share of demand. In Germany, for example, 60% of all freight activity occurs on roughly 2% of the road network. Legislation to support the rollout of fuelling infrastructure compatible with biomethane is already in place in the European Union and the United States.

There are a number of reasons why policy makers are interested in biomethane to reduce oil use in transport, despite the challenges of expanding gas vehicle fleets and developing refuelling infrastructure in tandem with increasing biomethane production. First, while natural gas networks are the most cost-effective means of delivering biomethane, distribution by tanker to discrete refuelling stations is one of the lowest cost ways to bring biomethane to end-use consumers in locations where pipeline infrastructure is not available. Second, biomethane has lower CO_2 and air pollutant emissions than gasoline, diesel and many conventional liquid biofuels. Third, biomethane avoids the land-use change concerns that can arise from the use of crop-based biofuels. In addition, bioethanol and biodiesel are often subject to blend share limitations (since they are not identical to existing fuels) whereas biomethane is an identical replacement and so can fully replace natural gas. Despite these benefits, the growth of biomethane in transport in the Stated Policies Scenario is modest except in India, China, Italy and the United States.

There is also some growth in the pure use of hydrogen and hydrogen-based fuels or feedstocks such as ammonia in the Stated Policies Scenario as a result of existing policy commitments and signals, although in many cases these fuels are not produced by a low-carbon route. There is also some limited blending of low-carbon hydrogen into natural gas networks.

13.4.2 Sustainable Development Scenario

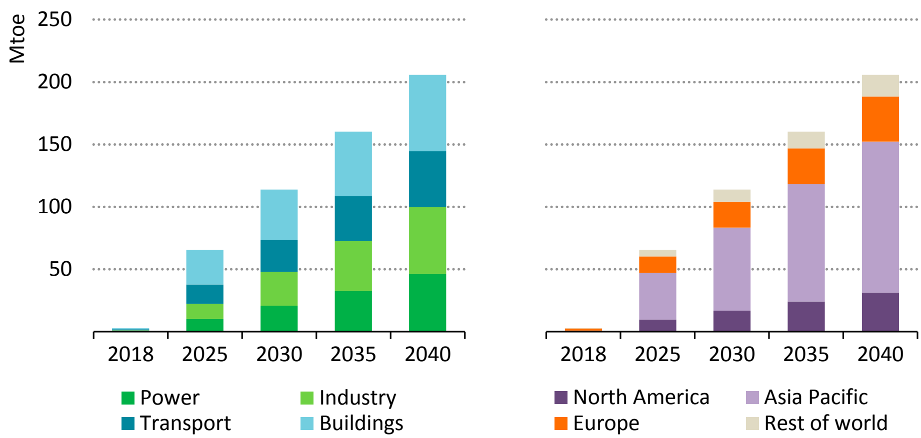
There is much more significant uptake of both biomethane and low-carbon hydrogen in the Sustainable Development Scenario. Biomethane use rises to over 200 Mtoe in 2040 (Figure 13.14). The introduction of a high GHG price across advanced economies and many developing economies is a key factor underpinning this growth. In countries with existing gas infrastructure, biomethane consumption accelerates over the course of the *Outlook* period. By 2040, there is a 10% blend of biomethane in gas grids in Europe and a 5% blend in North America. While these ratios in 2040 may not seem large, natural gas consumption has peaked and is on a downward trajectory, while biomethane consumption is rising steeply, and would continue this trend beyond 2040.

In developing economies, especially those looking to expand the use of natural gas in their energy mix, the use of biomethane provides a much greater reduction in CO_2 emissions

[12] Captive fleets are comprised of vehicles that operate on established routes and refuel at set locations or depots. Examples include municipal buses, refuse collection vehicles, and package delivery company and supermarket fleets.

than switching from coal to natural gas. Biomethane also helps to reduce air pollution, aiding the substantial improvements in air quality required in this scenario. There is a preference for the use of biomethane in the transport sector, although in many regions biomethane use is largely shaped by the existing end-uses of grid-supplied natural gas. Globally, biomethane consumption is largest in the buildings sector.

Figure 13.14 ▷ Biomethane consumption by sector and region in the Sustainable Development Scenario



There is strong uptake of biomethane in both advanced and developing economies, and production in 2040 exceeds 200 Mtoe

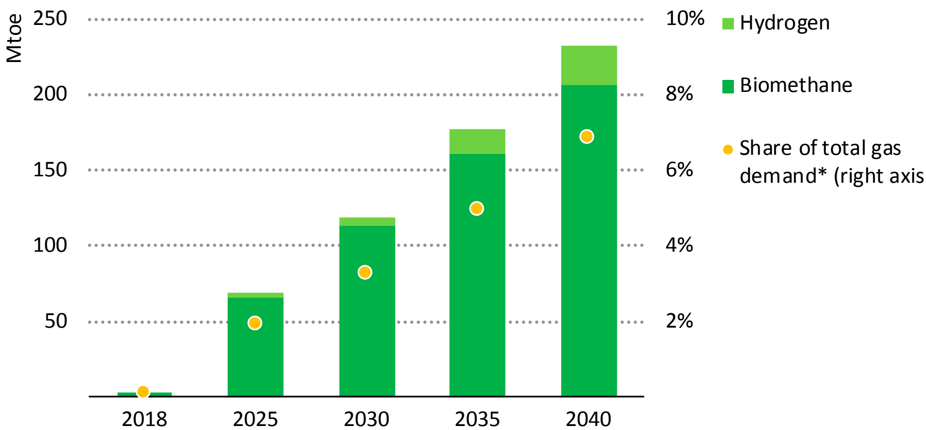
Just over 25 Mtoe of low-carbon hydrogen is blended into the gas grid in 2040 in the Sustainable Development Scenario. In energy terms, this represents a much lower level of consumption than for biomethane. However hydrogen blending is a crucial building block for the development of a global industry for low-carbon hydrogen supply and for cost reduction. The European Union leads the way initially, with a 5% blend of low-carbon hydrogen in volume terms by 2030 (1.5% in energy terms). As with biomethane, blended low-carbon hydrogen is primarily used in sectors where natural gas is consumed.

By 2030, low-carbon hydrogen supply capacity for injection into the gas grid is more than 1 000-times larger than today. This is produced both through the use of low-carbon electricity and CCUS-equipped natural gas reformers. As a result, both technologies move along the learning curve and costs fall. Coupled with explicit policies that promote the use of hydrogen in hard-to-abate sectors, this encourages the direct use of low-carbon hydrogen (i.e. without blending) and hydrogen-based fuels for other purposes.

Low-carbon hydrogen blending in the gas grid continues to grow after 2030. The European Union has nearly 10% blending by 2040 while North America and China both approach 5% hydrogen blending. As the nature of gas demand shifts, the electricity sector becomes the biggest user of blended low-carbon hydrogen.

In total, more than 230 Mtoe of blended low-carbon hydrogen and biomethane are consumed in 2040. This represents around 7% of total gas demand in the Sustainable Development Scenario in energy equivalent terms (Figure 13.15). These low-carbon gases avoid more than 500 Mt CO_2 emissions that would have occurred if natural gas had been used instead. In addition to the hydrogen injected into the gas grid, just over 80 Mtoe low-carbon hydrogen is used directly in 2040 as a fuel in end-uses.

Figure 13.15 ▷ Low-carbon hydrogen and biomethane injected into gas grids in the Sustainable Development Scenario



Over 230 Mtoe of low-carbon gases are delivered by the gas grid by 2040, accounting for around 7% of total gas demand

*Includes natural gas, biomethane and low-carbon hydrogen blended into gas networks in energy equivalent terms.

13.5 Implications for emissions and energy security

13.5.1 Reducing CO_2 emissions

Biomethane and low-carbon hydrogen can help to avoid CO_2 emissions by displacing the use of natural gas. In theory, a 10% volume blend of biomethane in a natural gas pipeline would reduce CO_2 emissions in the gas consumed by 10%. However, there are emissions from the harvesting, processing and transport of the biogas feedstock that need to be weighed against the CO_2 emissions that arise during the production, processing and transport of natural gas (GRDF, 2018; Giuntoli et al., 2015). These indirect emissions can vary considerably between sources of biomethane and natural gas and, unless minimised, they could reduce the CO_2 emissions savings from the use of biomethane.

For low-carbon hydrogen, a 10% volume blend in a natural gas pipeline would reduce CO_2 emissions by 3-4% (for a given level of energy). However the different potential energy inputs and conversion technologies to produce hydrogen mean a careful lifecycle emissions approach is needed to ensure that it is truly low-carbon (McDonagh et al., 2019). For electrolysis to produce low-carbon hydrogen, it has to use low-carbon electricity from dedicated renewable or nuclear facilities or from the grid. The latter faces challenges in part because the use of grid electricity is a relatively expensive way to produce hydrogen (IEA, 2019), but also because hydrogen produced in many countries using grid electricity would result in more emissions than hydrogen produced using natural gas without CCUS. It is not until 2035 in the Sustainable Development Scenario that the global average emissions intensity of electricity is low enough for hydrogen produced using grid electricity to result in fewer emissions than hydrogen from natural gas (the threshold is around 180 grammes of CO_2 per kilowatt-hour/kWh [g CO_2/kWh]). To produce low-carbon hydrogen using natural gas equipped with CCUS, it is critical both to minimise methane emissions that occur along the natural gas value chain and to maximise the volumes of CO_2 captured during the conversion process.

There is an additional opportunity for CO_2 emissions reductions from hydrogen and biomethane production. Biogas upgrading generates a highly concentrated by-product stream of CO_2 that could be captured for as little as $20/tonne CO_2 (Koornneef et al., 2013). As the CO_2 is of biogenic origin, storing it underground removes CO_2 from the atmosphere; the same is true for CO_2 captured from biomass gasification. However CO_2 transport and storage can be expensive and so an integrated CCUS system may only be cost effective for the largest biomethane and gasification plants or for plants that are close to CO_2 storage infrastructure. Another option would be to sell the captured CO_2 as a non-fossil source of carbon for synthetic fuels production or other forms of CO_2 utilisation (for example in the food industry). CCUS could also be applied to some large-scale end-uses of natural gas that are not replaced by low-carbon gases (Box 13.4).

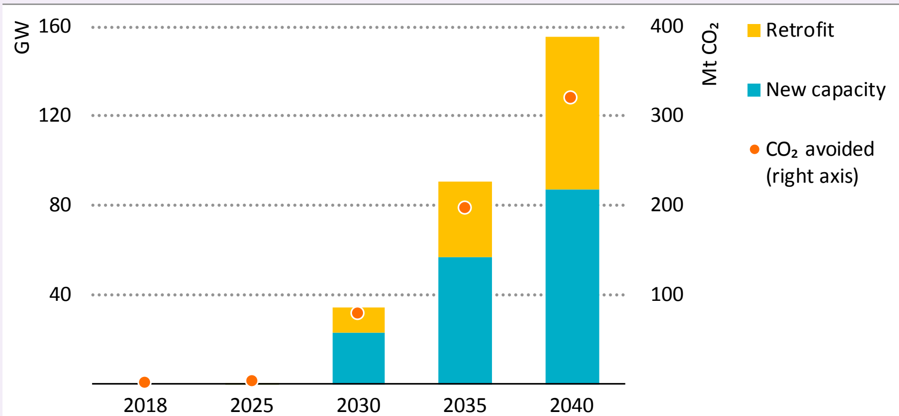
Box 13.4 ▷ Using CCUS to reduce emissions from natural gas

Today around 30 Mt of CO_2 are captured from industrial activities in large-scale CCUS facilities. Nearly two-thirds of this is captured from natural gas processing: underground deposits of natural gas can contain significant quantities of naturally occurring CO_2 that must be removed to meet technical specifications before the gas can be sold or used. This produces a highly concentrated stream of CO_2 that is relatively easy and cost-efficient to capture. Most of the captured CO_2 is used for enhanced oil recovery (IEA, 2018).

CCUS can also significantly reduce the emissions intensity of natural gas if it is applied to end-use technologies. One option is to produce electricity from combined-cycle gas turbines (CCGTs) that are equipped with CCUS. There are currently two large-scale coal-fired power plants equipped with CCUS in operation but no large-scale CCUS gas-fired plants. The application of CCUS to end-user technologies such as power plants and the use of low-carbon gases are not mutually exclusive, but care would be needed to ensure they do not detract from each other. For example, if hydrogen were to be injected into the grid, this could reduce the capture efficiency of any CCGTs equipped with CCUS.

The lack of progress with CCUS to date stems from the significant additional capital and operating costs it entails, which are currently greater than the revenue streams that can be generated from the captured CO_2 (either from making use of the CO_2 or from policies that incentivise geological CO_2 storage). In the Sustainable Development Scenario, CCUS is a critical technology to deliver the necessary emissions reductions in both the power and industry sectors and there is extensive policy support to equip new and existing gas power plants with CCUS (see Chapter 5 for a discussion of CCUS for coal use in industry and Chapter 6 for coal-fired power generation). In the power sector, there are over 150 GW of CCGTs equipped with CCUS by 2040, just under half of which are existing plants that are retrofitted (Figure 13.16). These produce around 900 TWh electricity in 2040 with an emissions intensity of less than 40 g CO_2/kWh. In total, the use of CCUS for gas power avoids over 300 Mt CO_2 that would otherwise have been emitted in 2040.

Figure 13.16 ▷ Installed CCGTs equipped with CCUS and emissions avoided in the Sustainable Development Scenario



Over 150 GW of CCGTs are equipped with CCUS by 2040, providing around 900 TWh of low-carbon electricity each year

13.5.2 Avoiding methane emissions

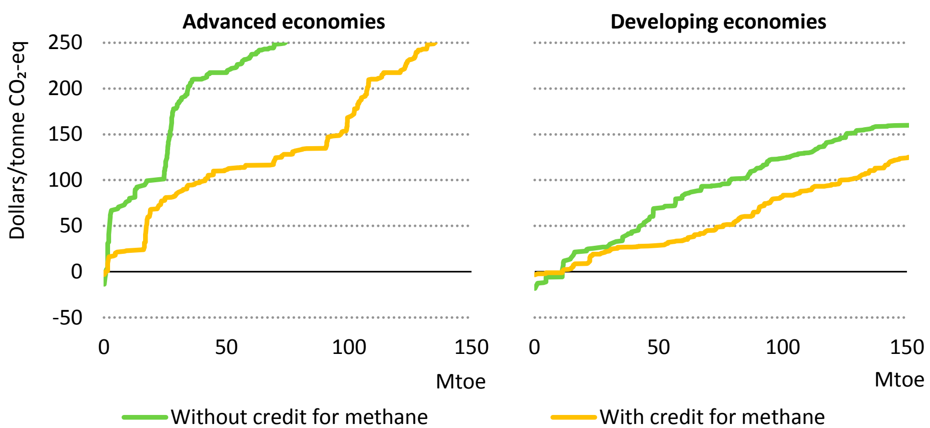
Some of the feedstocks that are used to produce biomethane would decompose and produce methane emissions if not carefully managed. Biomethane production can avoid these emissions by capturing and processing them instead. Even if these emissions occur outside the energy sector, they should be credited to biomethane.[13] This is already the case

[13] The avoided methane emissions are usually associated with the waste or agricultural sectors. Our emissions analysis generally focuses on GHG emissions from the energy sector and so any avoided methane emissions would not be shown in GHG emissions reductions between scenarios. However, avoided methane emissions are included in assessing the cost effectiveness of different GHG abatement opportunities.

within California's Low Carbon Fuel Standard. Yet estimating the size of this credit is not straightforward, as it depends on a reasonable "counterfactual" case for what level of methane emissions would have occurred if the feedstock had not been converted into biomethane, which can vary according to region, feedstock type and over time.

For example, there is wide regional variation in how methane produced within landfill sites is currently handled. In Europe, most sites have capture facilities, with the captured methane (known as "landfill gas") either flared or used for power generation. In the United States, around 55% of the methane that is generated in landfill sites across the country is captured. Around 20% of what remains breaks down before reaching the atmosphere, meaning that close to 35% of the methane generated in landfills is emitted to the atmosphere.[14] There is a lack of reliable data on landfills in most developing economies but the percentage of methane that is captured is likely to be lower than in advanced economies. Animal manure can also result in methane emissions to the atmosphere. All other potential biomethane feedstock types generally degrade aerobically (and so do not result in methane emissions).

Figure 13.17 ▷ Marginal abatement costs for global biomethane potential with and without credit for avoided methane emissions, 2018



Accounting for the avoided methane emissions through the use of biomethane would greatly boost its attractiveness

Notes: Assumed methane avoided (all percentages given as share of biomethane produced): 50% from landfills in developing economies; 35% from landfills in North America; 0% from landfills in Europe; 18% from animal manure; 0% from all other feedstocks. Excludes methane leaks that occur during biomethane production since the leakage rate for natural gas and biomethane are assumed to be similar. One tonne of methane is assumed to be equal to 30 tonnes of CO_2-eq (100-year global warming potential).

[14] Figures are based on the 2016 US Greenhouse Gas Inventory, which is the last edition to provide a clear split between methane generation and recovery from landfills (US EPA, 2016). The percentage of methane not recovered that breaks down naturally is based on US EPA (2019).

There is also a risk that biomethane production itself results in methane emissions, notably through leaks from biodigesters. There is a large degree of uncertainty surrounding the magnitude of these leaks and they are estimated to range from close to 0% up to 5% of the biomethane that is produced (Liebetrau, 2017). The latest data suggest that the average is probably around 2%. This is broadly similar to the percentage figure for vented and fugitive emissions that are estimated to occur along the natural gas value chain, which are estimated at 1.7% on average globally (IEA, 2018). Methane leaks clearly reduce some of the climate benefit of biomethane production and so should be minimised to the fullest extent possible.

There are a number of policy frameworks for how "avoided" methane emissions should be handled or credited (e.g. the Clean Development Mechanism [UNFCCC, 2018]), but there is currently no globally agreed or universally accepted framework. Different ways of handling these emissions can have a major impact on the apparent cost effectiveness of using biomethane to reduce global GHG emissions. For example, if no credit were to be awarded for avoiding methane emissions, but a credit were to be given for the CO_2 that is avoided from displacing natural gas, then less than 45 Mtoe of biomethane potential would be economic at a $50/tonne GHG price. If avoided methane emissions were to be additionally included, then more than 90 Mtoe would be economic at a $50/tonne GHG price (Figure 13.17).

13.5.3 Energy security

One of the main attractions of biomethane and low-carbon hydrogen is that they can be produced in regions that do not have extensive fossil resources, and can help to reduce the need for natural gas imports. Even as natural gas markets become increasingly liquid, competitive and resilient (see Chapter 4), this is an important consideration.

This is especially the case for countries that see significant import growth of natural gas in our scenarios. Natural gas imports in India, for example, increase from 25 Mtoe in 2018 to 180 Mtoe in 2040 in the Sustainable Development Scenario, while in China natural gas imports increase from 100 Mtoe in 2018 to 215 Mtoe in 2040. There is widespread biomethane potential in both of these countries, a significant proportion of which is available at relatively low cost. In India and China, biomethane consumption in 2040 is around 30 Mtoe and 80 Mtoe respectively in this scenario. If this energy demand had been met instead by natural gas, imports would have been around 15% higher in India and 35% in China.

13

Low-carbon hydrogen and biomethane also have the potential to help all countries meet peak periods of demand, whether for electricity or heat. Indeed, one of the factors underpinning the growth of interest in hydrogen is its ability to balance the output of high shares of variable renewable electricity generation and to provide storage, including intra-day storage.

It is also possible to envisage longer distance trade of low-carbon gases as a substitute for natural gas imports. In particular, there has been growing interest recently in the potential for importing low-carbon hydrogen, although there are a number of difficulties that would need to be resolved (Box 13.5).

Box 13.5 ▹ Long-distance trade of low-carbon gases

The low energy density of hydrogen means that long-distance transmission is complex. Compression, liquefaction or incorporation of the hydrogen into larger molecules are possible options to overcome this hurdle. If hydrogen is to be shipped overseas, it can be liquefied (by cooling to minus 253 °C, much lower than the minus 162 °C required to liquefy natural gas) or transported as ammonia or in liquid organic hydrogen carriers (LOHCs).[15] Ammonia and LOHCs are generally cheaper to ship, but the costs of hydrogen conversion and reconversion are significant. There are also safety issues arising from their use (for example ammonia and some of the LOHC carrier molecules are toxic when inhaled).

Because of the need to liquefy the hydrogen or incorporate it into other molecules, hydrogen transport is relatively energy intensive, requiring energy equivalent to 15-25% of the energy contained in the hydrogen. It is also expensive: transporting hydrogen by ship is likely to increase costs by around 50-150%, depending on the hydrogen source and transport type.

This means that, in the majority of cases, domestic production of hydrogen is likely to remain cheaper than imported hydrogen. However in places where CO_2 storage is unavailable for geological or political reasons or where there are limited natural gas or renewable resources, low-carbon hydrogen imports could become cheaper than domestic production (IEA, 2019). For example, it is estimated that producing low-carbon hydrogen in Japan in 2030 using electrolysers would cost around $55/MBtu (equivalent to $6.5 per kilogramme of hydrogen or $190 per megawatt-hour [MWh]). If a production facility were to be established in Australia that combined the use of electrolysers, solar and wind generation in a resource favourable region, production would cost just over $30/MBtu. Converting this to ammonia or an LOHC, transporting it by ship and reconverting the molecules back to hydrogen would cost around $15/MBtu.[16] Importing hydrogen therefore would be less expensive than domestic production in Japan.

This $15/MBtu transport cost means that hydrogen imports are generally only cost effective if there is a difference of $30/MWh between low-carbon electricity costs in

[15] Making an LOHC involves "loading" a "carrier" molecule with hydrogen, transporting it and then extracting pure hydrogen at its destination. The carrier molecules are not used up when hydrogen is extracted so they can be recycled.

[16] Reconversion of ammonia back to hydrogen costs around $9/MBtu. If ammonia is required at the point of end-use rather than hydrogen, then the overall cost would be lower.

the importing and exporting regions. This is a situation that is likely to be relatively rare. Nevertheless, even if importing hydrogen is not the cheapest option, some countries may wish to consider imports to increase their energy diversity and access to low-carbon energy. In addition, countries with large swings in seasonal energy needs may find it more cost effective to import hydrogen to cover winter peaks than to build local renewable power capacity and long-term storage that will only occasionally be needed.

Because it is essentially indistinguishable from natural gas, biomethane can make use of existing cross-border trade infrastructure. It therefore can be transported by long-distance gas transmission pipelines or transformed into LNG and transported overseas in a similar way to natural gas. A number of European countries have developed biomethane registries to track the injection and extraction of biomethane from natural gas networks as well as a pan-European registry that aims to facilitate international trade.

13.6 Implications for policy makers and industry

Policy makers and the gas industry face important choices on gas infrastructure. In many gas-consuming countries, the scale and flexibility of the energy that can be supplied to houses and industry through existing gas networks is unrivalled. In many developing economies, gas offers a key opportunity to reduce reliance on more polluting fuels. In both cases, investment in gas networks will be needed. Yet there is a balance to be struck between near-term gains and long-term policy objectives, and likewise a need to align expectations and timelines between policy makers and the gas industry. The fact that natural gas is a fossil fuel means it is not easy to appraise how much needs to be invested and over what period of time: investments in the near term need to be compatible with repurposing or decommissioning networks in the long term.

Debate over the future role of gas infrastructure does not lend itself to simple conclusions, even leaving aside the point that countries have different energy systems and needs. Here we outline some possible approaches for consideration by governments and other stakeholders as they weigh the complex opportunities and risks.

- **Introduce low-carbon gas standards and incentives to encourage the use of low-carbon gases.** Significant biomethane and low-carbon hydrogen blending in existing gas grids are unlikely to happen without policy support. This could take the form of specific blending targets (along with priority access for injection), support for research, development and deployment, caps on the emissions intensity of gas consumption and GHG emissions pricing schemes.
- **Assess the level of investment needed in gas infrastructure to maintain energy security while delivering environmental goals.** While the overall volumes of natural gas consumed in many regions may fall in the future, governments will want to be sure that gas is available when it is needed. In some regions, capacity markets for power

generation and demand-side response have been developed so that companies receive revenue to maintain generation capacity so that it is available when needed. Similar mechanisms may be needed to maintain gas import and transmission infrastructure.

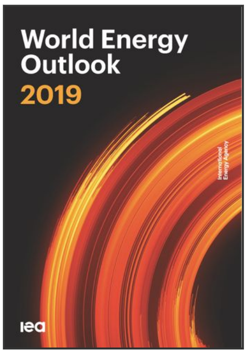
- **Broaden the regulation of gas networks to take account of the transition to low and zero carbon energy.** The regulation of gas networks today is largely focussed on competition and liberalisation. An expanded regulatory framework may be required to ensure the compatibility of gas networks with long-term decarbonisation goals. For example, where hydrogen or biomethane are injected into gas networks, robust accounting, certification and verification for the levels and types of low-carbon gas injected and subsequently used will be essential if operators are to be paid a premium for supplying low-carbon gas.[17] Incentives should include a method to credit gases that avoid GHG emissions, wherever they may have otherwise occurred.
- **Clarify and harmonise regulations in collaboration with other governments to encourage cross-border trade of low-carbon gas.** Many countries have strict limits in place on the concentrations of hydrogen that are allowed in natural gas streams which could constrain the uptake of low-carbon gases. Changes to these limits could boost the scope for using hydrogen, particularly if new limits can be harmonised across national boundaries.
- **Stimulate hydrogen blending to promote investment and cost reductions in hydrogen infrastructure.** Hydrogen blending would boost investment in hydrogen production infrastructure, helping to lower costs and support hydrogen use in other sectors as it becomes more competitive.
- **Take a long-term strategic view of goals and consider how to manage any distributional problems that may occur.** Pursuing direct electrification of heating or district heating in parallel to hydrogen and biomethane blending could reduce the number of gas grid users at the same time as increasing the cost of gas supply. This could raise the unit price of gas for remaining users. Even within countries, different strategies may be needed for distinct parts of the network rather than a single one-size-fits-all plan.
- **Improve waste management to reduce overall biomethane costs and maximise its cost-effective use.** Biomethane provides a mechanism to extract value out of waste and residues and so can promote a more "circular" approach to handling waste. Separate collection of organic waste would help reduce overall biomethane costs.
- **Encourage the creation of biomethane production jobs in rural locations near feedstocks where this would be cost effective.** Biomethane production relies upon the use of large quantities of organic feedstocks, which can be difficult or expensive to transport over long distances. Biomethane production facilities therefore are usually

[17] An example is the system in California whereby some customers can purchase certificates for biomethane blended into the grid despite the gas molecules themselves being untraceable after injection.

best located close to feedstock sources. These are often in rural areas where production facilities could provide local employment and the opportunity for local communities to participate in, and benefit from, energy transitions.

- **Minimise the risk that early investments in one low-carbon option presents new challenges for other low-carbon technologies that may be needed for longer term goals.** The production and use of hydrogen, biomethane and CCGTs equipped with CCUS can be mutually supportive, but there is also scope for them to cut across each other. For example, deploying CCGTs equipped with CCUS could help reduce the cost of CCUS more generally and lower the production cost of hydrogen. Conversely, converting end-user equipment to handle high shares of hydrogen may mean that they are not optimised for biomethane. There are no easy answers here, but a systemic approach will at least help to identify the trade-offs.
- **Establish a shared understanding about the path to minimise the risk of conflicts and misunderstandings between gas market participants with differing commercial interests.** Participants at various stages of the gas value chain can have diverse interests. While a gas producer aims to maximise sales of natural gas, a transmission operator is unlikely to be concerned about whether its revenue comes from transporting natural gas, biomethane or hydrogen, while traders tend to sell both natural gas and electricity. Differences in the commercial interests of market participants could hinder the ability of the industry to act as a whole and could lead to conflicts unless all stakeholders share common expectations about the direction of change.

Natural gas results in fewer GHG and air pollutant emissions than coal and so can help to meet the world's needs during clean energy transitions. The flexibility of gas infrastructure and its ability to deliver and store large amounts of energy mean that investment in gas infrastructure remains important in the Sustainable Development Scenario. But there is a transition to be achieved in this scenario. If it is well managed, gas infrastructure can help deliver low-carbon energy sources in the longer term and serve sectors that are difficult to decarbonise through direct electrification. Low-carbon hydrogen and biomethane have a huge amount of potential in this context. There have been previous waves of enthusiasm for low-carbon gases, but today they meet only a fraction of total energy demand. It will be different in future only if there is adequate support from both industry and policy makers.



From:
World Energy Outlook 2019

Access the complete publication at:
https://doi.org/10.1787/caf32f3b-en

Please cite this chapter as:

International Energy Agency (2019), “Prospects for gas infrastructure”, in *World Energy Outlook 2019*, OECD Publishing, Paris.

DOI: https://doi.org/10.1787/7d6c4915-en