

How Natural Gas can Support the Uptake of Renewable Energy



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How natural gas can support the uptake of renewable energy

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Executive Summary

Gas will play a major role in addressing climate change. In the UNECE region, by far the most important contribution that gas can make will be in the form of ‘green’ or ‘blue’ gas that has been largely or totally decarbonised, rather than as natural gas used for power generation or as feedstock for petrochemical products. Such development requires significant advances in the technologies and costs of carbon capture and storage (CCS) as well as the development or adaptation of infrastructure to cope with new fuels, notably hydrogen.

The most immediate issue for natural gas remains its relationship with renewable energy. This is the theme of this paper, the first in a series. A second paper addresses the ability of natural gas to replace other fossil fuels and a third the prospect for new markets and opportunities for natural gas.¹ The reduced cost of renewables and increased demand for flexibility in electricity distribution systems mean that in much of the UNECE region, the absolute requirement for any significant increase in gas will be limited. Gas producers might seek to increase their market share in the UNECE region by lowering the price for exports or subsidising domestic sales.

The climate emergency has prompted a focus on several key issues: these include the need to decarbonise energy production and consumption as swiftly as possible; the need to develop sustainable energy systems; and the need to tackle air pollution. Efforts to address any one of these three issues will probably help the others as well, but it should not be taken for granted that the goals are identical and the priority given by UNECE member States to each of these goals may well vary, as may the priorities of national governments and major cities.

There is a need to strike a balance between the imperatives of rapid decarbonisation and the provision of sustainable energy on the one hand and the need for the gas industry to secure commercial returns on its investments at a time of rapid energy transition. These two issues were long thought to be complementary, holding out the prospect of a major role for gas in the energy transition for at least a decade and perhaps for much longer. But, as the cost of renewables falls dramatically and as perceptions of the climate emergency intensify, such assumptions are increasingly questioned. The third issue raises the question of what will be the impact on both decarbonisation and sustainable energy development if the gas industry does not make the necessary investments to promote a broader range of gas utilisation.

These papers have a specific focus concerning the role that gas can play in tackling the climate emergency. They do not address the overarching issue of whether the UNECE region, let alone the world as a whole, will actually engage sufficiently with the climate emergency in order to create even a chance for the increase in average global temperature to be limited to 1.5 or even 2.0 degrees centigrade, rather than the 3.0 to 6.0 degrees

¹ The second paper is entitled: *How Natural Gas Can Displace Competing Fuels*.

The third paper is entitled: *The Potential for Natural Gas to Penetrate New Markets*.

An additional note concerning the question of gas and emissions, and the development of decarbonised gases, will also be part of this series. UNECE is, in addition, working on developing a programme to address specifically the prospects for developing hydrogen. This paper, *How Natural Gas Can Support the Uptake of Renewable Energy*, will be published both in print and electronically. The remaining elements of this series will be published only electronically.

centigrade increase for which the world is currently headed. They also do not address the question as to whether governments, corporations, producers and consumers will change their policies and their habits in order to attain the Paris Agreement and to ensure the development of sustainable energy systems within a specific timeframe.

The gas industry naturally thinks that it can contribute significantly both to sustainable energy and decarbonisation. But while the industry stresses that natural gas emits less carbon than coal or oil, and would thus seem to constitute a logical alternative to coal in power generation, it has to confront two harsh realities. The first is that in the most industrialised parts of the UNECE region, it faces increasingly strong commercial competition from renewables. The second reality is that it too faces increasingly strong social opposition on the grounds that it is a carbon-emitting fossil fuel.

A combination of these factors contributes to the attitude of some governments who are prepared to offer subsidies for various renewables' technologies that reduce or eliminate the advantages that gas might otherwise have. Nor is there necessarily the consistency that might be obtained were governments to levy taxes on energy suppliers that specifically related to the amount of carbon emitted.

Perhaps the biggest problem faced by the natural gas industry is simply that there is very little appetite amongst politicians to address the practical aspects of tackling the climate emergency, decarbonisation, sustainable energy provision and air quality. Likewise, there is an increasing need to educate the public about these issues. At present, it looks as if the overall pace of such changes, despite the inducement of low-cost renewables, still means that too little will be done to address decarbonisation, energy sustainability and air pollution until an accumulation of climate-related disasters induces a widespread sense of panic about the climate emergency.

The three papers are intended to be considered collectively. They constitute an attempt to assess the various roles that natural gas might play in both the development of sustainable energy policies and in the reduction of CO₂ emissions. Overall, how big role gas can play – or, indeed, whether there is a long-term role for gas at all – will depend on the policies adopted by governments and the way in which markets will operate both the UNECE region as a whole and, equally importantly, in its sub-regions.

The social, political and economic challenges posed by the climate emergency, and by aspirations to promote both energy sustainability and decarbonisation, will inevitably lead to different approaches in different UNECE regions. In particular, the way energy markets develop and, above all, the way that energy markets are designed, will play a significant role in determining the contribution that gas can play in tackling decarbonisation and addressing energy sustainability.

The UNECE's Pathways to Sustainable Energy project, to which these papers are a contribution, embraces climate objectives, but its main focus is to contribute to the energy dimensions of the UN's 2030 Agenda for Sustainable Development, as set out in 2015 when the entire UN membership unanimously adopted 17 Sustainable Development Goals for implementation by 2030. This means that while these papers seek to address the various roles that gas may play in energy development both in the context of sustainable energy development and decarbonisation, they should be assessed in a broader social, environmental and economic context.

1. Introduction

There is a strong medium-to-long-term future for natural gas so long as the gas industry wholeheartedly embraces the energy transition and partners with renewables to produce carbon-free products, notably hydrogen, whilst embracing carbon capture, use and storage (CCUS).

Natural gas has several key advantages. It is highly flexible and can be used for heating, cooling, cooking, waste disposal and transportation as well as feedstock for chemicals, fertilisers and pharmaceutical products. Moreover, throughout most of the UNECE area there are already extensive distribution networks that enable gas to be transferred both across borders and within member States. These networks can be adapted to carry hydrogen either mixed in with natural gas or as self-contained systems; they can be used to distribute CO₂; and they can be used both for seasonal storage of renewable gas and, as power-to-gas systems are developed, as short-term storage for excess electricity produced from renewables. The inherent flexibility of interconnected gaslines means that, in effect, a largely existing gas distribution network across much of the UNECE region may avert the need to build new electricity grids.

Natural gas is also a potential complement to renewable energy in that it can provide cover for the intermittency of power generated by renewables – in other words when the wind isn't blowing or the sun isn't shining. Indeed, the ability of natural gas to provide a relatively low carbon backup at peak energy usage times rather than play a traditional role of round-the-clock baseload may prove to be its greatest contribution to the energy transition.

This has profound implications in terms of future investment in natural gas, since it implies a focus on better use of existing natural gas plant and infrastructure, rather than the creation of new plant and infrastructure. It also means that consideration of the way in which natural gas can support the development of renewable energy needs to be matched by consideration of the way in which natural gas is simply complementary to renewable energy.

Moreover, the view that one of the main strengths of natural gas is its ability to serve as a baseload supplier not only has the potential to put it in competition with renewable energy but, in various parts of the UNECE, this may be a role that is required for only a limited time and is epitomised in the concept of the merit order. Since renewable energy has near to zero marginal costs, it ranks first in the merit order and, when available, will always become the *de facto* baseload. As the availability of renewable power grows, so does its share of the market, with higher fuel costs pushing conventional generation out of the market. This is especially challenging for coal and nuclear, which possess limited ability to adjust quickly to changing conditions or power requirements, but it also implies that power generation from natural gas will eventually be limited to covering the intermittency in power production from renewables, rather than providing the baseload.

2. The Immediate Future for Gas from Now to 2030

The immediate future for gas, as noted in the first paper in this series, *Gas Displacing Competing Fuels*, is promising in view of the phasing out of coal in various regions of the UNECE and in some cases the phasing out of nuclear power as well. Beyond 2030 or thereabouts, the future is less clear. As the costs of renewable energy, notably solar- and wind-power, fall dramatically, the role of gas as a principal fuel for power generation will come under increasing pressure in many parts of the UNECE region. There will prospectively be less requirement for natural gas while the increasing role of low-emission or renewable energy will also put pressure on the gas industry to further decarbonise the gas sector. The question for the gas industry is whether new forms of ‘green’ gas, derived from biomethane, or gas required for hydrogen production, can ensure there is little or no reduction in overall gas use.

Such a transition will not be easy, not least because of fragmentation of the gas industry. Discussion of gas-related issues increasingly focusses on the gas value chain, a phrase that tacitly acknowledges that in much of the UNECE region there is no longer a monolithic gas industry. The gas value chain, from producer to consumer, is fragmented, which makes decarbonisation on an industry-wide basis far more complex to achieve, since it cannot be centrally imposed; producers, networks and consumers will all have different attitudes towards the necessity of decarbonisation and different ideas and options for achieving such a goal. For the next 10 years or so, the gas industry will need to find ways to provide affordable and efficient solutions for low-carbon energy mixes whilst simultaneously seeking to further reduce its carbon footprint. In terms of the relationship of gas to renewables, a key issue in much of the UNECE region will be the provision of cover for the intermittency of power generation from renewable energy.

This is an increasingly open question. While there is a persistent need to ensure that traditional fuels – essentially fossil fuels but also nuclear and hydro – are available to provide backup for renewable energy input into major electricity networks, it is far from clear for how long this situation will persist. Data compiled for the UNECE by IIASA, the Vienna-based International Institute for Applied Systems Analysis, anticipates a broad complementarity between gas and renewables in the next decade. IIASA’s Reference scenario anticipates that gas will account for 40% of electricity generation by 2030, while renewables will account for 26%. Under IIASA’s P2C scenario, which seeks to assess prospects if policies are pursued in line with the Paris Agreement to limit the increase in global temperature to two degrees centigrade, the share of both fuels increases, with natural gas rising marginally to take 41% of the market and renewables climbing significantly to 36%.

At some stage in the next few years the adoption of new technologies will require mechanisms to distinguish between natural gas and gas that has been effectively decarbonised through CCUS or via production processes that yield negative emissions through involvement of waste or manure. As and when decarbonised gas and post-combustion CCUS becomes more widely available, gas should then play a major role alongside renewables in energy provision in the UNECE region. The various prospects for the role of natural gas in terms of the context of the continuously evolving energy transition are specifically addressed in the UNECE Pathways to Sustainable Energy project, for which extensive modelling has been carried out by IIASA.

Such a mechanism will need to be recognised across the UNECE gas network. Any decarbonisation of gas should be verifiable to the market participants. There will have to be many discussions on standard approaches. For example, if a gas well is to be used for CCUS when exhausted, the decarbonisation may occur after the gas is used and there will be a ratio of carbon stored during CCUS to carbon emitted through the use of the gas. This may be more or less than one. Obviously, such standards may well impact on the relative economic viability of gas fields by favouring the ones that are capable of storing more carbon dioxide. There must also be trust that the exhausted field will be used for CCUS at the end of its life.

Examples such as the one above illustrate the importance of discussing a longer-term relationship between natural gas and renewable energy, which will depend very largely on the introduction of effective and sustained government policies regarding carbon taxation and emission standards. A time of swift energy transition paradoxically requires an injection of stability in order to avert economic and social upheavals.

Current assessments indicate that for at least the next decade, and possibly for some years after that, there will need to be substantial back up for intermittent renewables to ensure provision of electricity all year and round the clock, particularly for times when supply from intermittent sources may not be available.

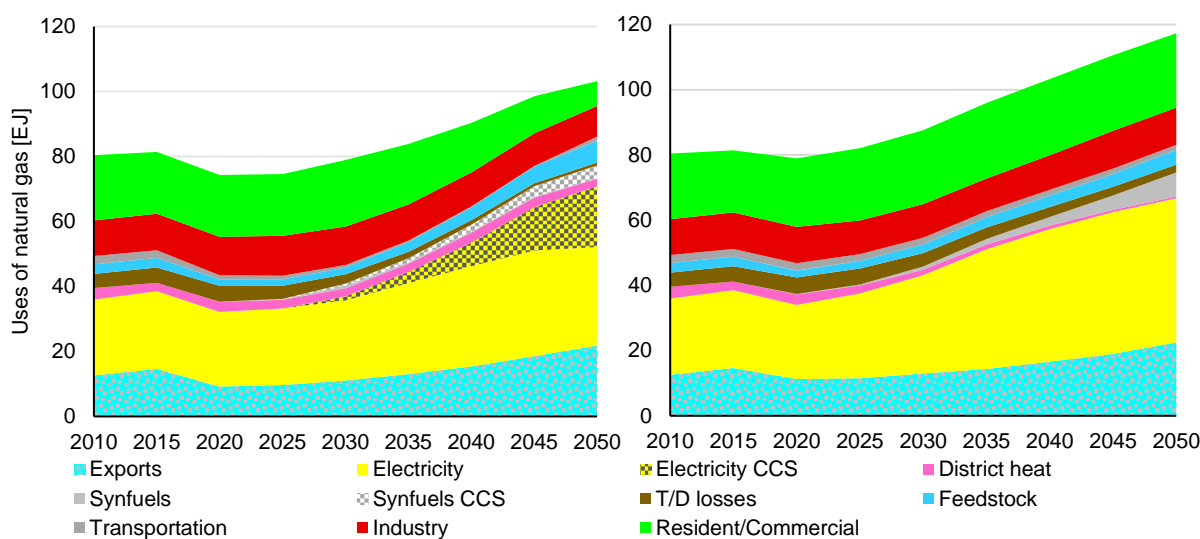
Gas is well placed to serve such a role for a wide variety of uses until such time as new forms of energy storage can be developed to enable consumers to rely on wind and solar and other renewables for 24-hour supply, 365 days a year. But much depends on whether the requirement is for peak-load and balancing – for example, as in the UK and perhaps in Germany – or for baseload, as in Russia.

3. The Longer-Term Future for Gas – Beyond 2030

Forecasting for how long natural gas will be needed for balancing and meeting peak load is uncertain. In theory, the biggest contribution gas can make would be to hold steady for the next decade and then simply step out of the way and let renewables (including decarbonised gases) to take over. In the IIASA P2C scenario, natural gas usage in the UNECE region peaks in or around 2035 and declines sharply in the 2040s. However, if gas with CCS is included, then overall gas usage in electricity generation continues to rise to an annual plateau of around 6,300 TWh between 2045 and 2050.

Overall, the biggest difference between IIASA's P2C and reference scenarios is that gas use in the UNECE region under the P2C scenario gas would total 81,586 exajoules (EJ), equivalent to roughly 2,160 bcm. This would be some 18.2% below the reference total of 99,689 EJ (equivalent to around 2,640 bcm), largely due to a sharp decline in residential and commercial use. However, gas still looks set to remain an important fuel in electricity generation in both scenarios, although slightly diminished in the P2C scenario, while its role in exports remain the same in both scenarios. In the P2C scenario, gas plays a very significant role in the creation of synthetic fuels (see Figure 1).

Figure 1
Gas Use in the UNECE Region under the P2C and Reference Scenarios, 2010 – 2050
P2C Scenario **Reference Scenario**



Companies also have to run scenarios to chart a potential route to achieving the Paris Two Degree target. In its “Sky Scenario” of 2018, Shell envisages natural gas accounting for 36% of primary energy use in 2030, the same level it attained in 2015, but then falling dramatically to just 15% in 2050. What takes its place is, essentially, electricity derived from renewables, together with some biomass.

In this context, all scenarios seem to show that the need for effective complementarity between gas and power networks and distribution systems, along with the requisite infrastructure planning required for sector coupling, will become increasingly important over the next 10 to 15 years to enable gas to cover for power – and vice versa. They also show the importance of gas across sub-regions of the UNECE. In particular, smart grids and distributed energy systems, which already improve the efficiency of both electricity distribution and use in some of the more populous areas of the UNECE, should prove particularly helpful in serving UNECE subregions that include vast areas with relatively low population density, such as Russia and Central Asia.

What the IIASA P2C model shows is that there has to be a major transformation of the gas sector if it is to compensate for the decline in the use of natural gas anticipated in both the IIASA P2C and Shell Sky scenarios. However, such a transformation requires the various elements of the gas industry to develop a coherent strategy against a background of great uncertainty.

3.1. The Prospect of Hydrogen

There are considerable prospects for gas, notably in hydrogen. In May 2019, the European Commission issued a statement that “hydrogen is one of the most popular forms of energy storage and its capacity to store large quantities of renewable energy sources over long periods of time demonstrates its significance in the clean energy transition.”¹ But while there is certainly considerable potential - indeed, hydrogen advocates would argue there is genuinely very great potential - for hydrogen to become a major resource both as fuel and

for energy storage, at present it is one of the most popular *approaches* for prospective energy storage rather than for actual current energy storage. At present, the development of hydrogen as a commercial business is still very much in its infancy, with the focus still on trial projects. Nor is there any common standard concerning the carriage of hydrogen, which can be carried using existing natural gas pipelines. For instance, while the Netherlands allows a natural gas pipeline to carry up to 12% as hydrogen and Germany allows up to 10%, Belgium only allows up to 0.1%. Advocates of Hydrogen consider it is safe for natural gas pipelines to carry as much as 18-20% in the form of hydrogen. It should be noted that UNECE is working on developing a separate assessment of the prospective role of hydrogen in the energy transition.

3.2. The Prospect of CCUS

Carbon capture, use and storage offers a real prospect for natural gas to work with renewable energy sources on decarbonisation. In particular, it helps to address the problem of how to cope with hard-to-abate emissions from heavy industry, notably steel, cement and petrochemicals.

CCUS generally takes two forms: CCS (carbon capture and storage), which captures CO₂ and then stores it in the ground, and CCU (carbon capture and use), which enables the sequestered carbon to be used in products or industrial processes. Gas stands to play a significant role in CCS development since depleted gas fields constitute logical potential CO₂ storage sites, notably offshore fields in Norwegian and Dutch waters. CCU, as the International Association of Oil and Gas Producers (IOGP) stated in a May 2019 report, can offer electricity storage options and thus “assist sector coupling, by enabling the integration of renewable energy into the gas grid.” This can be done either through processing CO₂ with renewable hydrogen or by using electricity derived from renewables to co-process water and CO₂. The IOGP report adds: “When renewable hydrogen is reacted with CO₂ to produce synthetic methane, this allows additional options for supply of renewable gas into the network with minimal infrastructure upgrades.”

Fossil fuel energy companies, such as Exxon Mobil and Equinor, are involved in developing CCS projects to find ways of preventing their oil and gas investments from becoming stranded assets in a decarbonising world. Although development remains limited, with just 21 CCS projects in operation or under development around the world in 2018, some of them have been operational for decades. Norway’s Equinor has been using the offshore Sleipner field, which it describes as the world’s longest ongoing project on CO₂ storage in the world, to store about one million tonnes CO₂ from natural gas produced in its vast operations in the North Sea and the Norwegian Sea. In the US, CCS is used to enhance oil recovery.

But while Norway’s extensive gas development has made it possible to secure general public acceptance of offshore CCS, introducing CCS or CCU in many others parts of the UNECE will not be easy, since a number of European countries have placed either outright bans on their development or have imposed limits on how long the CO₂ can be stored, where it can be stored, or when they will allow such storage to be developed.

This means that cross-border transport and storage systems will be required if CCS and CCU are to play a significant role in the overall decarbonisation of the UNECE region.

3.3. The Existential Threat

At present, it is difficult, if not impossible, to make a business case for projects involving gas decarbonisation while the deployment of CCUS is uncertain. Yet, for gas network operators in richer areas of Europe, failure to develop a decarbonised business model constitutes an existential threat. They face a prospect of gas use declining in the 2030s as renewables and distributed energy systems reduce the need for gas to serve as a balancing factor. The networks therefore require some other reason to keep on carrying gas in their existing infrastructure.

Put bluntly, the future of gas in much of Europe post-2030 is set to decline unless methane can be decarbonised. But this requires corporate investment in decarbonisation projects at a time when there is little or no commercial incentive for companies to do much more than attempt to test various technologies and run a few pilot projects to check these technologies actually work.

In sum, the decarbonisation of gas requires the redesigning of energy markets so that they favour carbon-free or decarbonised fuels. Future elements would almost certainly have to include a radical rethink of regulatory requirements and the introduction (or, in some markets, expansion) of carbon pricing and carbon taxing systems. Moreover, given the fragmented state of the gas sector and the need for governments to play a major role in tax and regulatory issues, in effect this means some kind of social contract between regulators and corporate bodies has to be forged.

Moreover, for the gas industry as a whole – including private and public producers, investors, distributors, regulators and consumers – there is the question of the reputation of gas. At a time when fossil fuels are coming increasingly under fire for their massive contribution to carbon emissions and climate change, the industry needs to be seen to be promoting decarbonisation through its own investments in CCUS as well as in promoting its role as a complementary source to renewables and as a replacement for more polluting fossil fuels.

This will not be easy; but a regulatory revolution is essential if the fledgling hydrogen and carbon capture industries are to succeed, and thus set gas on a firm pathway towards long-term cooperation with renewables. Current cooperation between such bodies as Gas Infrastructure Europe (GIE), the European Network of Transmission System Operators for Gas (ENTSOG) and transmission and distribution system operators (TSOs and DSOs) will have to be intensified and amplified by carbon pricing and taxing mechanisms.

4. The Baseload Issue and the Role of Natural Gas in Compensating for the Intermittency of Renewable Energy

Natural gas is currently one of the main fuels for large-scale round-the-clock power production, the others being coal, nuclear, hydro and fuel oil. If the goal is reduction of the carbon footprint of energy production in the shortest possible time, while at the same time ensuring 24/7 supply, then natural gas is an obvious option. That is because it produces less carbon than either coal or fuel oil and requires much less upfront investment and much less time to develop than a new nuclear power plant, while – for at least in much

of the UNECE region – the ability to develop new large-scale hydro facilities is limited by ecological and political considerations.

There is already some tension between the goals of decarbonisation and the provision of round-the-clock energy, notably electricity, on a sustainable basis. Historically, electricity networks were based on the concept of baseload and this remains one of the prime justifications for utilisation of natural gas in the near- to medium-term. However, it is starting to become outmoded in some UNECE subregions. Baseload is commonly associated with combined cycle gas turbine power plants which considerably improved the economics of gas power stations by comparison with previous simple cycle gas turbine plants. This, and the arrival of competitive markets, promoted the development of gas, but only to a limited extent. It also depended on whether the country increasing its reliance on gas, such as the UK, was also a gas producer or whether, as in the case of France, it was essentially a gas importer. As a consequence, gas pricing mechanisms were or were not aligned with the imperatives of a competitive power market. Thus, while the UK's first combined cycle gas turbine (CCGT) plant came on line in 1991, France's first one only became operational in 2009. Although Germany's first CCGT plants preceded those of France, they were less commonly seen as baseload providers in view of the country's continued reliance – until comparatively recently – on nuclear, coal and lignite. Germany has demonstrated that in such an environment even the most efficient CCGT plants risk losing their commercial viability if they are essentially required to simply serve as backup to cover the intermittency of renewables rather than as baseload providers in their own right (*see below, The case of Irsching 4 & 5*).

Gas does possess some very important advantages in terms of supplying the power market. Firstly, it has the ability to provide flexibility, since output can be increased or decreased according to hourly, daily or seasonal demand. Secondly, it can be stored, in tanks, in underground caverns, and in pipelines. The former, so-called city-gate storage, enables it to provide immediate supply for power stations in specific locations, notably cities – and helps reduce transmission losses; the latter, called line pack, enables it to shift gas flexibly around the distribution network, whether on a regional, national or even international basis. Underground gas storage typically is for longer-term, seasonal storage.

However, in time, the issue of intermittency should be expected to dissipate as the energy system in the UNECE region evolves, with power networks embracing larger areas. It should also be noted that in some UNECE member States the complementary nature of different forms of renewable energy should serve to reduce intermittency. In Spain, most of the wind power is generated in winter or at night, when solar production is slow or negligible.

However, the most significant impact on the requirement for gas to play a major role in tackling intermittency may well come from development of large-scale battery storage. The International Energy Agency (IEA) anticipates that if battery costs are reduced over the next two decades by 70%, then by 2040 battery storage will be the biggest single factor in handling fluctuating electricity demand. In this context, it should be noted that batteries are more likely to find their niche in addressing diurnal rather than seasonal demand variations. But while there is sufficient knowledge of large-scale battery storage technology to make it perfectly reasonable to assume that it will be in widespread use in 2040, just when it will become commercially available on a wide scale remains uncertain.

Broader networks that span national boundaries should, in time, ensure an improvement in demand-side management and improve the situation with regard to loss of load probability (LOLP) throughout the system. Such developments are likely to weaken the requirement for gas to serve as a balancing fuel.

Moreover, the flexibility of gas is under increasing challenge from the development of flexible, decentralised energy provision. In the UNECE region, much of the relationship between natural gas and renewable energy will be determined by whether energy provision in member States and subregions develops along largely centralised or decentralised lines.

Three contrasting examples can be given. In the UK, the development of an increasingly flexible national grid means that market expectations for natural gas are that its prime role for the next decade will be as a back-up provider to renewable energy for peak-period generation and that it will be totally off the system at some point in the 2030s. In Germany, the government has to date used coal, rather than gas, as a backup for renewables but with coal-fired power generation due to be phased out by 2038, and possibly much earlier, there is at least a limited window for gas to increase its share of the overall energy market. In Russia, on the contrary, the situation is likely to prove different with its reliance on fossil fuels – possibly with gas replacing coal – likely to last into the 2040s. This reflects such key factors as the relative lack of commercialisation of renewables in much of the country, particularly given expectations that domestic prices for natural gas will remain heavily subsidised and the centralised nature of much of Russia’s energy economy. This contrasting picture is examined below.

4.1. The United Kingdom

The United Kingdom, the country in which coal fueled the industrial revolution, ran its power system without any use of coal whatsoever for two weeks from 17 to 31 May 2019. This was made possible by generation from renewables. Nor was this an isolated instance; it is expected to become the new normal, on the grounds that, as Emma Pinchbeck of Renewables UK has said, “the market expects gas just to be providing back up generation at peak – and then totally off the system in the early 2030s.”²

Yet until very recently there had been a widespread assumption that it would be natural gas, rather than renewables, that would provide the fuel for electricity generation as coal came offline. Several factors challenge this assumption. On the supply side, record-breaking cost reductions have radically improved the economics of renewables. For example, the UK’s September 2019 offshore wind auction resulted in prices for electricity delivery as low as £39.65 (\$50.05) per megawatt-hour, whereas the lowest price in the previous auction in September 2017 was £57.50 (then worth \$75.75). Even in the US, where gas prices are much lower than in the UK or continental Europe, the Rocky Mountain Institute has concluded the US is already at the point where renewables and storage are less expensive than new gas-fuelled generation.

On the demand side, the push for more flexible, smart and electric technology further eased the way. The result was that renewables’ capacity grew faster than expected while the share of gas has shrunk and, in particular, new gas plants have struggled to get built. In 2018, natural gas was still the principal fuel for UK electricity generation, accounting for 131.5 TWh out of a total consumption of 333.9 TWh. But this was down on the 2017 total of 136.8 TWh out of 338.6 TWh. As for renewables, they rose from 93.4 TWh in

2017 to 105.6 TWh in 2018, so that they now account for almost one-third of all the UK's electricity generation.³ It is quite reasonable to suppose that within two or three years renewables will overtake gas as the UK's principal source for generation and that in four or five years renewables may well account for half of all UK generation.

Renewables – offshore wind, onshore wind, solar and some biomass – are now a mainstream source of energy in the UK. Their advance was not wholly driven by market forces. Political actions in the 1980s, when the then Conservative Government began a long move out of coal in the wake of a major confrontation with the principal miners' union, coupled with the availability of resources in the North Sea, prompted a major shift to gas. A highly beneficial, but wholly unintended consequence, was a steady decline in carbon emissions. Gas, in turn, provided cover for the intermittency of solar and wind power as renewables started to make inroads into the power market in the wake of the Renewables Obligation introduced by the UK Government in April 2002. This generally required electricity suppliers to ensure that a proportion of their electricity was derived from eligible renewables sources. The proportion was set at 3% for the financial year 2002-2003 and was due to reach 15.4% in 2015-2016. In practice, renewables advanced much faster, supplying no less than 33.3% of UK electricity in 2018. This advance was aided by several other non-market factors, including both subsidies and an element of carbon pricing.

The decline of coal and the rise of renewables has had a striking impact on UK greenhouse gas emissions. These totalled 449 million tonnes (mt) in 2018, of which 364 mt was CO₂, constituting a 44% decline in all greenhouse gas emissions since 1990 and a 39% fall in CO₂ emissions since 1990. At the same time, the massive shrinking of the UK coal industry also drew attention to a subject that is likely to become ever more prominent as measures to tackle climate change are proposed or introduced: the social acceptability of the direct costs of the energy transition to consumers.

Between 1997 and 2005, the British government paid out some £2.3 billion in respect of claims made for miners suffering from chronic obstructive pulmonary disease (COPD) and mineworkers suffering from white finger vibration (WFV). Overall, the then Labour Government, which had made the implementation of a long-delayed but legally enforceable compensation package for miners one of its first commitments on taking office in 1997, anticipated that when the payments for ill health, vibration impact and other industrial compensation injuries were taken into account the bill would rise to around £7.5 billion. That was then the equivalent of around £400 (then worth \$720) for every family in Britain. But these were indirect costs to consumers, paid for out of general taxation, and prompted no criticism.

By and large, there has been little public outcry concerning the costs associated with the expansion of renewables in the power market. However, transport and heating, the sectors that most need to be addressed if the UK is to achieve carbon neutrality by 2050, pose a very different kind of problem since the costs of switching to renewables are far more directly borne by the consumer. Both entail considerably greater capital outlays: in transport, because the cost of buying an electric or hybrid vehicle remains well above that of a traditional petrol or diesel engine vehicle; in heating, because the replacement of coal- and gas-fired central heating systems and the need to radically improve home insulation will require considerable expenditures by homeowners and landlords. A ban on the use of gas in central heating for new homes is due to come into effect in 2025.

The transport sector provides an example of government reluctance to impose direct costs on consumers. The British government is quite prepared to pursue an indirect approach that ensures citizens pay steadily increasing fares for public transportation, since the actual increases are the responsibility of the private companies who generally manage the UK's transportation systems. However, for the last nine years it has declined to enact an increase in fuel duty, even though a mechanism for supposedly automatic annual inflation-linked increases is officially part of the UK policy to combat climate change. In 2013, the government introduced a carbon floor price – in effect, a carbon tax – which currently stands at £18 (\$22.85) per ton of carbon dioxide emitted in electricity production. In 2018, the government also drew up plans for Carbon Emissions Tax, but this would only be introduced if the UK should wind up leaving the European Union without a formal separation agreement. In practice, if this tax is implemented, it would effectively replace the UK's participation in the EU's Emission Trading System.

The government's carbon floor price has so far been relatively uncontroversial. But it is worth noting that widespread protests in September 2000 prompted the then Labour Government to scrap what was supposed to be an inflation-linked automatic increase in the fuel duty on gasoline and diesel motor fuel when it presented its annual budget two months later. This tax, introduced in 1993 by a Conservative Government to combat air pollution, has been frozen since 2011 at 57.95 UK pence per litre (\$2.78 per US gallon) by successive governments, despite severe financial restraints stemming from the 2009 financial crisis.

4.1.1. The Baseload Issue in the United Kingdom

The advance of renewable energy in the UK energy system also poses a key question for gas: under these circumstances, what constitutes baseload?

Conventional energy market design postulates an integrated national or regional power system with large-scale thermal plant that generates baseload to serve a largely centralised distribution system. The players engaged in such markets – whether public or private sector providers – have sometimes found it extraordinarily hard to envisage a different system. So, the emergence of a flexible, decentralised system, with renewables-based power as the incumbent/market setter, was not really anticipated by the market, although it had been advocated by some academics and groups seeking to find ways of helping the UK to meet its decarbonisation targets.

Now it looks increasingly as if real value from natural gas in the UK market will not come from the provision of baseload, but from its antithesis, the ability to provide rapid, flexible power supply at short notice, and integrate with other renewable and electric technologies in the system, such as electric vehicles. This implies that the prime focus for investment will be not only systems to produce renewable energy but related elements such as batteries, smart technologies and companies that can utilise smart grids to aggregate and sell power in clever new business models.

In the UK, at least, this is the result of a market operating within a regulatory framework that already includes an element of carbon pricing. It has not come about because of any inherent opposition to gas, reflecting the position of those who argue that gas remains a fossil fuel and is therefore undesirable from an ecological viewpoint. Just as market

conditions have seen a combination of cheap gas and renewables cause US coal consumption to fall by more than 40% from 2008 to 2018, from 535.9 MTOE to 317.0 MTOE, while overall primary energy consumption grew marginally from 2,258.6 MTOE to 2,300.6 MTOE, so have market conditions in the UK prompted a decline in gas consumption from 84.1 MTOE to 67.8 MTOE over the same period.

The changing dynamic is openly acknowledged by National Grid ESO, which manages Britain's electricity distribution system. In a recent presentation, Julian Leslie, head of National Control at National Grid, argued that while the UK currently still needs gas in the grid to provide security, by 2025, the system would be sufficiently flexible that, if necessary, "markets could deliver a zero carbon solution listed in gigawatts."⁴ Since 2010, he argued, National Grid had been working to build a system that could cope with renewables. However, he acknowledged, "What works for the energy sector may not work for industry."⁵

Whether a similar pattern will happen as Germany, Czechia, Italy, the Netherlands and Spain phase out coal is not quite so clear, since much depends on government policy. But the Carbon Tracker data (see Paper One: *How Natural Gas Can Displace Competing Fuels*) would appear to indicate that market forces – specifically low production costs – will play a significant role in promoting renewables rather than natural gas for new power generation. As with the UK, this reduces the requirement for gas to serve as a baseload provider, although it would still be required in a balancing function. In this context, the argument that gas should serve as a baseload power provider because it is a less polluting fuel loses much of its force. The trend in the UK – and probably in Germany, Czechia, Italy, the Netherlands and Spain as well – would seem to indicate that within the next few years' renewables will take the lead, with natural gas playing the role of a complementary generation fuel.

This has profound implications for the natural gas industry. If gas is not primarily required for baseload provision but for balancing, then the need to build major new gas-fired power stations is either limited or non-existent. That makes it difficult to secure financing, particularly at a time when it looks increasingly as if new gas-fired plant will have to pay back a high proportion of its capital expenditure in its first five years of operation. In the UK, at present, construction work is under way on the 840MW Kirby 2 combined cycle gas turbine (CCGT) power plant, in Lincolnshire which is due to open in 2022. But efforts to develop other CCGT projects are faltering, not least because of two of the main defining characteristics of Keadby 2. The first is that although Keadby 2 should be the UK's most efficient CCGT plant, with a headline efficiency of 57%, remains a financially a risky project. Financial analysts note that Keadby 2, being developed by SSE (formerly Scottish & Southern Energy) and Siemens, is being built without a "clear wholesale/capacity market price signal to support new CCGT economics" and without the support of a 15-year capacity agreement.⁶ The second is that it does look to have secured a first mover advantage, since another CCGT project which had been expected to make faster progress than Keadby 2, the Drax Group's 1.8 GW Damhead 2 project in Kent, now appears to be stalled.

It also is worth noting that Drax itself epitomises the role of renewable energy in changing UK power generation. The original 3.9 GW plant, opened at Drax in North Yorkshire in 1973 as part of a state-owned enterprise, was fired by coal. Since 2012 it has been converting much of the plant to wood pellets, which by 2017 accounted for 70% of the

station's output – and around 20% of the UK's renewable power. Since then, two further coal units have been taken offline, with one being converted to run on biomass. In May 2019, the Drax Group announced its intention to develop Europe's first bioenergy carbon capture storage (BECCS) facility. If successful, it was said, the project "could make the renewable electricity produced at its North Yorkshire power station carbon negative."⁷ However, just as much focus will likely be placed on whether the group can deliver on its 2017 plan for two more coal units to be replaced with CCGT units, together with up to 200MW of battery storage. As UK analyst Timera has noted: "Time will tell if SSE (& Siemens) get paid for the risk they are taking in developing Keadby 2. But pulling the trigger first makes it even more difficult for other new CCGT projects to follow." Drax itself implicitly acknowledged this when it bought Scottish Power's production assets, which included two run-of-the-river hydro schemes and one of the UK's four pumped storage plants, a diversification that enables it to offer much greater flexibility and increased decarbonisation.

If the outlook for CCGTs looks limited, the outlook for offshore wind, Britain's boom sector, looks much brighter. So far, some £20 bn (\$24.5 bn) has already been invested in UK offshore wind and a further £46 bn (\$56.5bn) is anticipated over the next ten years. What's more, the country's wind projects no longer require subsidies. On 20 September 2019, the government awarded contracts for six new offshore wind and four new remote island onshore wind plants at guaranteed prices that are already below current wholesale prices and expected to be well under the anticipated electricity price when the plants come on stream in 2023-25. Again, this serves to support the argument that, in the UK at least, the role of gas over the next decade or so will increasingly be to help balance electricity output, rather than to provide baseload.

4.1.2. The United Kingdom and Net Zero Emissions by 2050

It should be noted, however, that the UK still has a long way to go if it is to achieve its coal of effective decarbonisation by 2050. In August 2019, the UK Parliament's Science and Technology Committee summarised the current position as follows: "Since 2000, the UK has achieved greater decarbonisation than any other country in the G20. It has outperformed its first (2008–2012) and second (2013–2017) carbon budgets by around 1% and 14%, respectively, and is on track to outperform its third carbon budget (2018–2022). However, the Committee on Climate Change has warned that the UK is not on track to meet its fourth (2023–2027) and fifth (2028–2032) carbon budgets."⁸

The report lists 10 recommendations to get the UK ready for net zero by 2050. Significantly (and discounting references to greenhouse gas), these contain only one brief reference to gas per se: "The Government must urgently develop a clearer strategy for decarbonising heat. This will require large-scale trials of different heating technologies, such as heat pumps and hydrogen gas heating, operating in homes and cities to build the evidence base required for long-term decisions."⁹

The Committee's chairman, Norman Lamb, declared: "Throughout our inquiry, it was worrying to hear that although the Government may be ambitious when it comes to reducing carbon emissions, it is not putting the policies in place which are needed to achieve those targets. We need to see the Government put its words into actions. The Government's own projections suggest that the UK is not currently on track to meet its current emission targets, let alone net zero by 2050."¹⁰

4.2. Germany

Germany is in a somewhat paradoxical position. It has a radical energy transition programme, the *Energiewende*, that includes ending reliance on both coal and nuclear – and yet it is far from clear that the country will manage to meet the Paris target for decarbonisation. It is spending extensively on renewables but continued reliance on coal to cover intermittency has led to its carbon emissions remaining stubbornly high. Indeed, not only have emissions actually increased in some years, but as one senior German energy official has said, “the sad truth” is that “we are actually having to buy emission certificates from other countries when it would be much better investing in Germany.”¹¹

The situation is changing. Climate change is an increasingly important political issue and on 20 September 2019 the government unveiled a package of measures intended to ensure an integrated approach to both energy transition and decarbonisation.

4.2.1. Germany’s Climate Package

The Climate Action Package includes such measures as:

- The introduction in 2021 of a phased-in CO₂ price for transport and buildings. This will start at €10 per tonne, rising to €20 in 2022, to €25 in 2023, to €30 in 2024 and to €35 in 2025. After that the government will set a cap on emissions, to be lowered every year.
- A commitment to spend more than €54 bn (around \$59 bn) by 2023 on reducing greenhouse gas emissions, not least through additional spending on public transport, tax breaks to improve energy efficiency in existing buildings, and financial incentives for use of electric vehicles.
- A ban on oil-fired heating systems from 2026.
- A commitment to expand offshore wind power and to ease the planning process of onshore wind power.
- An end to the current cap on installation of new rooftop solar PV.
- The introduction of a Climate Action Law with legally binding targets – although the details of the new law have yet to be agreed by Germany’s coalition government.

Perhaps the most important element may be the introduction of a mechanism to ensure both an annual reassessment of the country’s progress in meeting its targets and the necessary adjustments stemming from these reassessments. At present, Germany is not on target to meet its 2030 targets and the new carbon tax, while constituting a breakthrough in view of considerable opposition to such a move, has been criticised for being too low, and with too small a rate of increase, to ensure it has a significant impact. As the package was unveiled, Finance Minister Olaf Scholz said that Germany would also push for the whole of the European Union to establish an emissions trading system covering all sectors. Although there has been some discussion concerning the possibility that the phasing out of coal, promised for 2038, might be accelerated, the package contained no mention of this. The government’s phase out of nuclear power is expected to continue on schedule, with the last seven operational reactors closing by the end of 2022.

However, one particularly striking element of the paper is that it completely fails to discuss whether there is a role for natural gas in the *Energiewende*. The word ‘gas’ is mentioned, but in the context of hybrid heaters. And while the government does pledge to promote biogas, synthetic gas and “climate neutral gases” – albeit without specifying what kind of support would be available – there is no mention of natural gas.¹²

Yet natural gas will, in fact, almost certainly have a significant role to play. A few days after the plan was published, when the author asked a government minister as to what would be the main replacement for the loss of nuclear and coal powered generation, the minister replied simply: “It will be gas.”

This is certainly logical. Officially, the goal is to increase the delivery of renewables from 225.7 TWh in 2018 to 421 TWh in 2030, to account for 65% of the country’s power generation by 2030. But there is no indication that Germany will reach or even come near, this target since current plans for renewable energy development are primarily focussed on development of some 20 GW of wind energy capacity, while the total capacity increase required to meet the 2030 target is around 104 GW. Moreover, by the time the last coal plant closes in 2038 (or earlier), Germany will need an extra 143 TWh in replacement generation, for which a further 75GW of capacity would be required. And all these figures simply assume that demand remains stable at current levels, whereas it remains quite reasonable to suppose that although energy efficiency programmes are in place, actual demand for electricity in Germany will increase between now and 2038.

In addition, such a hefty reliance on renewables raises the balancing issue. What form of energy would serve to maintain power generation when there was too little wind or sunshine?

The failure to address the question of what kind of role gas might play in Germany’s energy balance over the next 20 years or so – or even whether there is a role for gas – may simply be a consequence of past practices. Germany is Europe’s biggest single gas importer, with imports totalling 100.8 bcm in 2018. Yet the use of natural gas to cover intermittency in the power market has for long been limited. The rigidity of the domestic gas market, not least as a result of excessive gas price indexation to oil, has restricted the ability of natural gas to compete with cheap coal imports, notably from the US, in providing flexibility to cover the intermittency of renewables.

4.2.2. The Case of Irsching

Indeed, between 2015 and 2018 the owners and operators of two of Germany’s most efficient CCGT power plants, the Irsching 4 & 5 units near Ingolstadt in Bavaria, applied three times to the German federal authorities for the units to be postponed on the grounds that they could find no way to ensure their commercial viability. One account of the 2018 request said the owners considered the units were well suited to accommodating fluctuations in electricity generated by renewables. However, it then cited the owners as saying: “This backup function is not being adequately compensated” and that instead, “the legal environment forces owners to provide this service at prices that do not cover costs”, which “makes it untenable for the owners and, in their view, unconstitutional.”¹³

Yet there are signs of change. By the start of 2023, Germany's first two LNG import terminals are expected to be operational. This should constitute sufficient competition to ensure that the price of pipeline gas, which comes mainly from Russia, reflects prices at European gas hubs rather than oil-indexed prices. This, in turn, should increase the ability of gas to provide the flexibility necessary to cover for the intermittency of renewables, and will almost certainly encourage the development of further LNG import terminals.

Whether this also implies that natural gas will actually increase its share of the German energy market will depend largely on the response of the two main pipeline suppliers, Russia and Norway, to the competition engendered by the prospect of German LNG imports. At present, planning for Germany's first land-based regasification plant, at Brunsbuettel at the mouth of the River Elbe, is at an advanced stage, with tenders for EPC work for an initial 5 bcm/y capacity project expected by the end of 2019. At Jade Bay, near Wilhelmshaven, the necessary planning permits for Floating Regasification and Storage Unit (FRSU) of up to 10 bcm/y capacity have been secured, and its developers say that the project should be operational by the second half of 2022.

In February 2019, German Economy Minister Peter Altmaier named Brunsbuettel and Wilhelmshaven as two of the three sites for LNG import projects, the third being an FRSU project at Stade. "All three projects are carefully considered and examined," he told a meeting of German and US energy officials and industry lobbyists on 12 February.¹⁴ "I am quite optimistic that at least two of the terminals will be realised within a very foreseeable period of time," he added.¹⁵ Altmaier also said that that Germany was weighing up the extent of state subsidies and regulations before private investors build the new LNG terminals.

Germany needs to diversify its gas supplies because it produces very little itself whilst having to cope with the collapse of the Netherlands' giant Groningen gas field. Groningen traditionally fuelled around one quarter of all German gas, but in 2018 the Netherlands supplied just 15.8 bcm of total German imports, with Russia providing 55.3 bcm and Norway 24.7 bcm. Turning to LNG reduces German dependence on pipeline gas, notably from Russia.

As well as being Europe's biggest gas importer, Germany is also Europe's biggest investor in renewable energy. An assessment by Germany's Climate Policy Initiative in 2016 put the size of total investments between 2005 and 2015 at no less than €150 billion. In 2018, renewables accounted for 37.8% of German electricity production. As noted in the Climate Action Plan, by 2030 they are planned to provide 65% and by 2050 at least 80%.

The Climate Policy Initiative report said: "Energy companies and utilities, households, farmers, energy co-operatives, municipalities, banks, and institutional investors all provided capital to renewable energy projects, relying upon policy that provided reliable revenues, attractive returns and certainty. Since the cost of renewable energy was often higher than energy from more conventional energy sources, policy was needed to plug the gap between renewable energy costs and the prevailing market price for electricity."¹⁶

In phrasing that is even more relevant in 2019 than when it was written three years earlier, the report added: “Today, the cost of many forms of renewable energy has fallen to the point where the cost gap has virtually disappeared. Yet policy is still needed, not so much because there is a cost gap, but because the financial, operating and ownership characteristics of most renewable energy investments are different from historical, conventional electricity investments, and these different characteristics need to be integrated with the existing industry and market structures.”

In other words, Germany needs to get the design of its energy market right if it is to take full advantage of renewables – and the same, of course, applies to its utilisation of natural gas. There is some official acknowledgment that government may need to play a more direct role. Michaela Spaeth, the German Foreign Office’s Energy & Climate Ambassador, commenting in June 2019 on plans for two LNG projects – she did not identify which – said the government would provide support if there was interest from private companies. She then added: “If not, we will build them.”¹⁷ However, for the gas industry, the main question may not be the ability to maintain current consumption levels by diversifying the sources of imports but whether the market proves favourable for the construction of new simple cycle gas power plants to serve as replacements for coal and nuclear, as well as balancers to cover the intermittency of renewables.

Then there is the question of whether the provision of natural gas to the German market will be improved by uncertainties concerning the end date for coal. Officially this is set for 2038 but it may well be earlier. In Moscow, Ms Spaeth declared: “We will try to be out of the coal industry in 2038. As a person, not a diplomat, I hope it would be earlier. We need to get out of carbon industry as soon as possible.”¹⁸ Indeed, Ms Spaeth added that “we hope to leapfrog fossil technology” and that she anticipated “only an interim period where gas is going to play a major role as baseload.”¹⁹ This could come early as 2030, Ms Spaeth speculated, since “we expect demand for natural gas to diminish” and “by then we expect to have storage solution and that renewables will dominate the entire energy mix. But this requires some incentives to put forward the storage systems we need.”

Her comments may not represent current policy, but they may well reflect a more general set of attitudes among German policy makers, not least because of concerns that while the world is currently on a trajectory to see global temperatures rise by three degrees, rather than the 1.5 or 2 degree Paris targets, even a renewables-friendly society as Germany is not meeting its own *Energiewende* targets.

4.3. Russia

Russia is in a peculiar position that reflects the complexity of the role of energy in a country that extends from the Arctic to the temperate climes of the Black Sea. In one city alone, Chita, the temperature can range from minus 49.6 centigrade in winter to 43.2 degrees centigrade in summer. The complexity of tackling climate issues in a country with so many different climatic zones may help to explain why it was not until 23 September 2019 that Russia effectively ratified the Paris Agreement with a spokesman for President Vladimir Putin telling the UN Climate Action Summit in New York that “the Russian Federation has accepted the Paris Agreement and is becoming a full-fledged participant of this international instrument.”²⁰

The importance of this move as a sign of Russia’s official commitment to addressing climate change can scarcely be overstated. But there are still contradictory influences in play. An increase in average temperatures would improve the climate for human habitation in some Arctic and sub-Arctic regions, while reduced levels of Arctic ice benefit Russian maritime transport via the Northeast Passage and, as such, Russian policymakers believe this will help reduce carbon emissions.

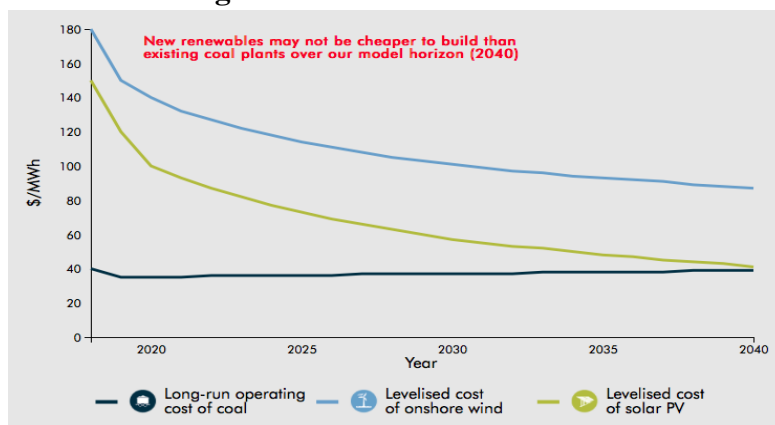
Whether such gains are sufficient to offset the losses, such as permafrost thawing, flooding and wildfires – let alone damage caused in the rest of the world – lies outwith the scope of this paper. But it does mean that approaches to decarbonisation in Russia will be very different to discussions in many other areas of the UNECE.

The key factors are economic. Russia relies extensively on its oil and gas exports to fund its development. According to the Russian RBC news website, “Russia’s Natural Resources and Environment Ministry estimates that the combined worth of the country’s oil, gas and other resources amounts to 60% of its gross domestic product.”²¹ Russia, therefore, has little incentive to reduce production levels, although the Government may see some scope for promoting increased use of renewable energy domestically in order to free up fossil fuel output for sale abroad. Indeed, this would be a natural progression from the current policy, which aims to promote energy efficiency at home, both to ensure a more reliable domestic market and to free up resources, notably of natural gas, for export.

4.3.1. Coal’s Enduring Power

For coal, renewables are starting to pose a challenge, but one analytical assessment suggests it will take more than 20 years for renewables to prompt the closure of existing coal-fired plants. The assessment comes from the UK’s Carbon Tracker, which in a 2018 report noted that while new renewables should be cheaper to develop than new coal in 2020, it would take until 2040 for it to be cheaper for Russia to rely on new solar photovoltaic supplies than on existing coal-fired power plants, while installing onshore wind power is likely to still prove considerably more expensive in 2040 than relying on existing coal plant (see Figure 2.)

Figure 2.
Coal’s Advantage in Russia



Source: Carbon Tracker²²

This medium-term commercial viability of coal does at least mean that it should be easier for Russia – not least in terms of the social consequences – to plan for the longer-term phase out of coal should it, too, come to the conclusion that this was necessary on environmental grounds.

In the meantime, however, Russia's focus on gas exports means that there is not much of a prospect for gas replacing coal in Russia's current power generation mix. Whether this proves true will depend very much on the outcome of the complex development of Russian gas resources for markets in the Asian-Pacific region, notably China. It is possible that Russia may find itself in a position where it has the ability to produce more gas from new fields in Siberia than is required to meet export commitments in these markets, opening opportunities for some fuel switching at home.

Yet there is a need for decarbonisation, as President Putin's Special Representative on Energy, Ruslan Edelgeriyev, has acknowledged. He also noted that "it's a global challenge to the Russian economy, it means major structural changes for the Russian economy."²³ Russia, said Edelgeriyev, is gearing up to address the issue. A draft law on state regulation on the emissions of greenhouse gases is in the works. "It's not going to be a carbon tax, but we will have market mechanisms and project mechanisms," he said then added: "Fiscal measures will have to be there so people understand it's a serious matter."²⁴ Russia, said Edelgeriyev, has good programmes on both climate and energy savings with both aluminium giant Rusal and Gazprom already engaged in major efforts to reduce their carbon footprint. "I believe we in the Russian Federation are not as good as Europe, but we are quite serious about matters of climate change. We have good (approaches) but there is room for improvements and a big window for opportunities. And we should look into this window for the future."²⁵

The idea that Russia has opportunities is vital. Russia, and, indeed, other energy producing countries in the UNECE region, have to look at the renewables market in an economic context. They have to consider the possibility that government revenues might be hit by the need to reduce fossil fuel prices to compete with renewables in export markets. They also need to assess whether they risk budgetary problems by subsidising fossil fuel for domestic consumption beyond the point at which renewable energy become commercially competitive.

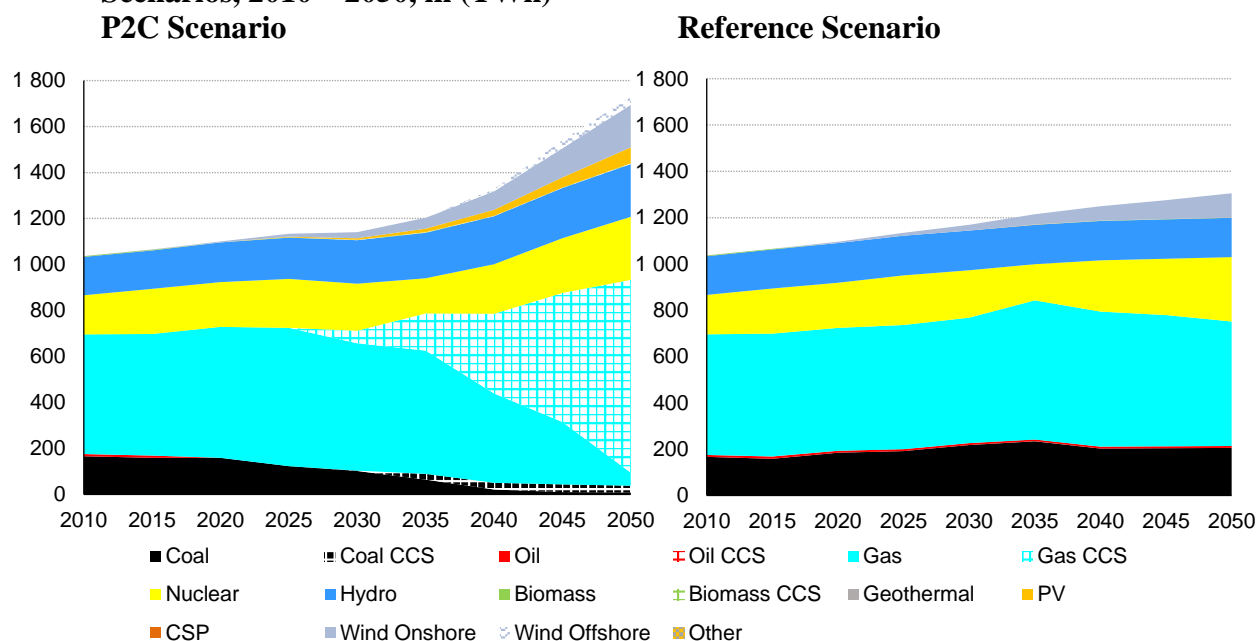
Inasmuch as the Russian authorities do look to the potential for diversification from traditional fossil fuels, it is to nuclear that they generally cast their eyes. This is not surprising given Russia's long-standing interest in developing not only large-scale nuclear power plants but also small-scale reactors to serve isolated communities and a variety of nuclear engines. The state nuclear giant, Rosatom, and other Russian proponents of nuclear power, also see a long-term future in nuclear fusion.

4.3.2. Gazprom Looks to Hydrogen

There is at least one notable exception to this, Gazprom itself. Russia's gas giant naturally wants to assess the prospects for its basic commodity, and it has already started to look at hydrogen. Gazprom is working both to produce less polluting fuels and on ways of decarbonising gas in order to achieve the Paris climate target. In particular, it is focussing on hydrogen, both by adding hydrogen to gas pumping units in order to reduce emissions and by providing hydrogen as a fuel into industries that

are hard to decarbonise and that could benefit from provision of alternative carbon-free fuel. Gazprom is focussing on production of hydrogen through methane pyrolysis, which requires heating gas to high temperatures to generate the hydrogen, and which then leaves a residue of solid carbon, that can then be used in a variety of ways, notably to make steel or batteries. In a brief commentary on the Special Envoy’s address, Tatiana Mitrova, the director of the energy centre at Skolkovo, said: “In our research, the climate agenda and carbon payments would give an impulse to the economy of Russia.” IIASA’s modelling (see Figure 3) provides an indication of how implementation of the Paris targets might impact Russian gas usage in power generation. On the same occasion, Sergey Esyakov, First Deputy Chairman on the Energy Committee of Russia’s State Duma (parliament), noted “we still have a potential to develop renewables.”²⁶ However, Esyakov added, what could help a Russian energy transition was an improvement in energy saving and energy efficiency.

Figure 3
Electricity Generation Mix in Russian Federation under the P2C and Reference Scenarios, 2010 – 2050, in (TWh)



At present, Russia is still in the early stages of securing energy efficiency. In April 2013, Russia’s State Programme for Energy Efficiency and Energy Sector Development, 2013-2020 set a target of achieving a 13.5% reduction in the energy intensity of Russian GDP by 2020, compared to the level in 2007. However, an academic study in 2018, citing the *Global Energy Statistical Yearbook, 2017*, noted that, as of 2016, “the energy intensity of the Russian economy declined from 0.337 thousand TOE/thousand USD in 2005 prices to 0.326 thousand TOE/thousand USD (2005), i.e. by 3.3% from 2007 to 2016.”²⁷ The study added: “The level of energy intensity of Russia’s GDP remains one of the highest in the world and outruns the indicators of developed countries 1.7–4.4 times.”²⁸ In the longer-term, Esyakov asserted that Russia was targeting a 40% saving from energy efficiency, but had so far only achieved 13%.

4.3.3. A Call for Incentives

As for the relationship of gas and renewable energy, Esyakov made the crucial point that the price of gas needed to be taken into consideration, and that “we need more incentives and motivation for renewables.” In effect, the Energy Commission Deputy Chairman was noting that in Russia natural gas costs for consumers remain well below the production costs of most renewables.

The time it took for Russia to ratify the Paris Agreement is an indication that efforts to tackle the climate emergency are only just getting under way in that subregion of the UNECE. But there are few incentives to encourage wholesale development and application of renewables, or, indeed, to generate the kind of energy market in which one could see whether gas and renewable energy might either compete or complement each other. For example, although Russian electricity pricing has been modestly reformed in recent years to reduce subsidisation, with prices rising a little faster than inflation over the decade from 2008 to 2018, there appears to be no sign of any real drive to ensure that tariffs to final consumers actually reflect the costs involved in developing and delivering electricity supplies, let alone the introduction of any kind of tariff system that would favour renewable energy or discourage reliance on fossil fuels, notably natural gas.

The fact that large areas of Russia – albeit, often with sparse populations – are off-grid should promote the idea that a combination of renewable energy and local smart grids will actually help Russia spread the benefits of improved energy provision throughout the country. In this context, the provision of power to cities and urbanised regions by means of the existing centralised grid and the development of decentralised energy systems should actually complement each other. Moreover, new smart grids would increase the opportunities for some of Russia’s stranded gas assets, as well as wind, solar and biomass, to contribute to domestic energy provision.

Going forward, both the extent and the speed of such a transition, as Russian energy expert Alexey Khokhlov, has noted, will very much depend on how quickly new forms of energy storage can be developed and commercialised in order to complement the introduction of renewable energy. Russia is indeed already “trying to create a closed loop system to the east of the Urals,” Esyakov said in an apparent reference to a renewables heating initiative to serve less populated areas.²⁹ There may also be some increased scope for fuel switching as a result of the Russian government’s decision in August 2019 to permit Gazprom, the state gas giant, to increase the amount it can sell on the domestic market at unregulated prices from 17.5 to 25 bcm a year, although much of this may simply compensate for reduced availability from other Russian gas producers.

The biggest block to the development of renewable energy is still the fact that domestic gas prices remain well below export price levels and, despite Gazprom’s increased ability to supply the domestic market, there is still only a limited prospect that this gap will diminish in the near future.

Nonetheless, there is at least one possibility that Russian thinking might yet change. In June 2019, Ms. Spaeth, the German Foreign Office’s Energy & Climate Ambassador, noted: “Our cooperation with Russia is going forward,” citing one particular example,

an agreement concluded with the Russian government for a joint project to develop a masterplan “on what it means to decarbonise the Russian economy.”³⁰ Ms Spaeth said this project had started on 1 March 2019 and that the goal was the development of a climate strategy “and how it would impact on the Russian economy so that the carbon intensity of the Russian industry could be minimised.”³¹

In a further intervention, Ms Spaeth argued that there would also be a role for Russia in supplying renewables-based energy to Eastern Europe, which would not be able to satisfy growing power demand from domestic renewables. She continued: “We are already confronting space limitation when it comes to onshore wind. We are already looking for partners and we see a potential partnership with Russia, which has a huge potential in wind.”³² The fact that Germany remains Russia’s biggest single gas export market and that Russia is Germany’s biggest supplier makes will likely ensure at least a continuation of large scale gas trade between the two countries for the the next two decades or so – although Ms Spaeth’s comment concerning her hope that Germany will leap frog fossil fuel technology should also be borne in mind.

Overall, while Russia’s 23 September 2019 announcement to the United Nations signals the country’s intent to pursue energy development that is in line with the Paris Agreement, Russian authorities have yet to chart a clear path to decarbonisation that covers such issues as the relationship of gas to renewables in detail, with the notable exception of its determination to promote hydrogen production by means of methane pyrolysis.

4.4. Central Asia

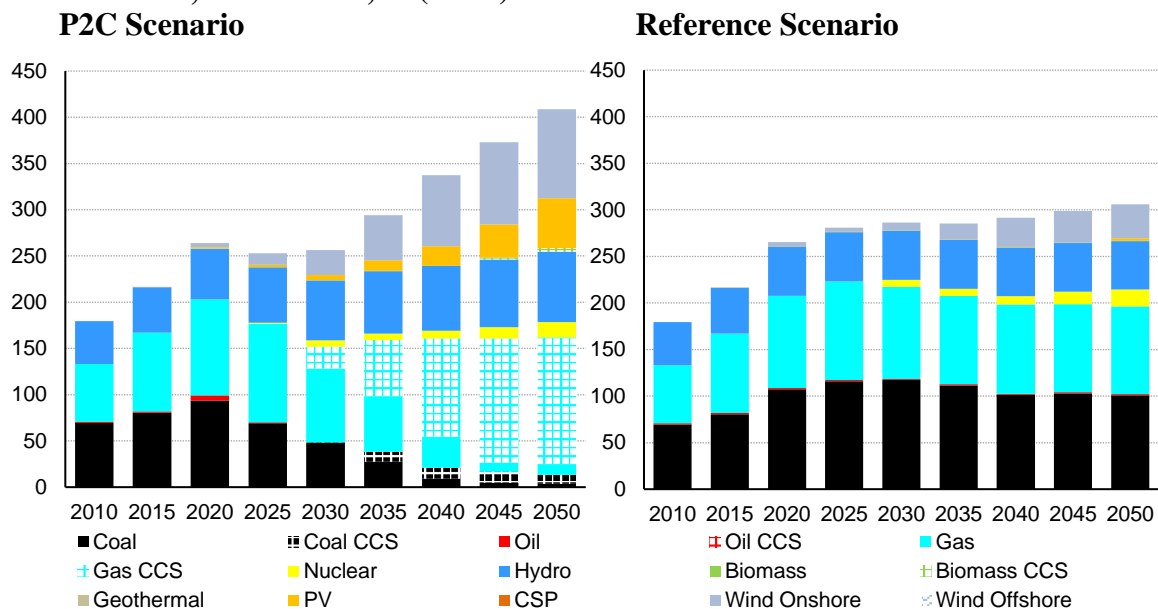
The way in which gas and renewables serve to support each other as part of a concerted effort to achieve the Paris climate limitation targets is strikingly exemplified in Central Asia. Although the five countries in the region – Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan and Uzbekistan – have very different energy economies, what is clear is that the region as a whole stands to benefit significantly in terms of both sustainable energy development and decarbonisation should these countries succeed in implementing the Paris agenda. So while IIASA’s reference scenario postulates that natural gas will account for 31% of electricity production in 2050 – or 96 TWh out of a total 306 TWh – its P2C scenario anticipates that natural gas accompanied by gas carbon capture and storage will account for 36% of a much larger electricity supply, namely for 148 TWh out of a total of 409 TWh.

But while gas actually gains ground, in both relative and absolute terms, the gain for renewables is even greater. Thus while onshore wind is expected to contribute 36 TWh to 2050 electricity production in the reference scenario, this soars to 96 TWh under the P2C scenario. As for solar photovoltaic, it soars from a mere 3 TWh in the reference scenario to 56 TWh in the P2C scenario (*see Figure 4*).

Moreover, all five countries look set to benefit. The three gas major producers – Kazakhstan, Turkmenistan and Uzbekistan – obviously gain from increased demand for gas. The growth of renewables is not just confined to wind and solar (which can be developed in all five countries), but also embraces hydropower, which is the backbone of both domestic power supplies and energy export potential for Kyrgyzstan and Tajikistan. The IIASA scenarios indicate that while there might be some very modest

growth from 53 TWh in 2015 to 56 TWh in 2050 under its Reference scenario, the P2C scenario anticipates hydropower accounting for 76 TWh in 2050.

Figure 4
Electricity Generation Mix in Central Asia under the P2C and Reference Scenarios, 2010 – 2050, in (TWh)



As for the environment, in the early 2040s the P2C scenario anticipates the almost complete elimination of coal, an issue particularly pertinent to Kazakhstan, and which would contribute significantly to emission reduction.

4.5. Different Regions, Different Trajectories

While there are similarities between UK and German developments, and some extremely important cooperation between Germany and Russia, the trajectory of the energy transition in each of the three countries still looks to be very different. Moreover, while it can be argued that the transition in much of Northern and Western Europe may well bear considerable resemblance to that of the UK, and that the transition in Central Asia and perhaps the Belarus, Ukraine and Moldova subregion may more closely resemble that of Russia, the experience of Germany demonstrates there are also bound to be considerable differences that reflect both the policies and circumstances of individual UNECE member States.

5. Conclusion

In June 2019, Laszlo Varro, chief economist at the International Energy Agency, said that “improved energy efficiency and accelerated renewable deployment are the most important steps in the transition.” He then added a third factor: the need to reform fossil fuel subsidies.

All three factors will impact on the relationship between natural gas and renewable energy - *energy efficiency* has the potential to reduce the absolute amount of energy that is produced and consumed; *accelerated deployment of renewables* would cut into the share of the energy market currently held by all fossil fuels, including gas; and *reform of fossil fuel subsidies* would almost certainly serve to boost the market share of renewables over gas, although, if introduced in a measured and predictable manner, it might also inject a sufficient degree of stability to help gas navigate a pathway to a decarbonised future.

But in considering how best to ensure that the energy transition proceeds smoothly, a further factor needs to be considered: the social acceptability of the price to be paid for measures required to tackle climate change. Social attitudes are particularly likely to be shaped by costs. Carbon pricing, whether in the form of direct taxation or not, will almost certainly add to consumer costs in the short term, and perhaps in the medium term as well. So will removal of subsidies for existing fossil fuels.

It is the direct costs that are the problem. Consumers may well pay little attention to such indirect costs of energy activity as the treatment required for coal miners suffering from bronchitis or emphysema, and injured through persistent handling of vibration machines, since these are commonly borne by the state and the impact on ordinary consumers is hidden in the morass of general taxation, even when they are considerable. So while renewables may help to bring direct energy costs down for consumers – whilst putting pressure on gas and other fossil fuels – the question of social acceptability means that governments may prove reluctant to introduce measures that increase other energy-related costs to consumers. In November 2018, the *Gilets Jaunes* in France put to government plans to hike fuel duty to combat pollution and global warming, just as the September 2000 protests prompted the UK to cancel its supposedly inflation-linked automatic increase. In Germany, a June 2019 analysis of the *Energiewende* stated that unions in Germany support the process and recognised that decarbonisation was creating jobs. However, the report’s authors also concluded that while the people of Germany generally supported the *Energiewende’s* main goals, popular support for actual implementation was unlikely. “The decreasing approval of many energy transition projects is clearly making it more difficult, for example, to expand renewable electricity supply and thus achieve the targets for the period up to 2030 and 2050,” they wrote.³³

Moreover, for all the UK’s success in commercialising renewable-powered electricity, the relevant committee of the British parliament has still concluded that the UK is not on track to achieve its goal of net zero emissions by 2050.

Somewhat ironically, in those parts of the UNECE region where countries are members of the OECD, by and large the best prospect for natural gas may well lie in governmental reluctance to implement the policies that would actually be required to

meet the Paris Agreement targets. This is because of the inherent advantages of natural gas in a business-as-usual environment, since it is an established fuel source with a wide variety of uses and, in much of the UNECE area, is already served by extensive distribution infrastructure.

This constitutes a potentially likely short-term future. But in the longer term, beyond 2030 or thereabouts, the question is how the gas sector can ensure its future in a world in which the commercial costs of renewables and battery storage fall so low that they threaten even the role of gas as a cover for intermittency. For gas to secure such a future, the gas industry will have to work proactively with governments to ensure the existence of predictable regulatory and taxation structures, notably concerning carbon pricing, so that the industry can accurately assess the kind of market within which it is expected to secure demand. This is almost certainly necessary for development of cost-effective solutions on both the renewables and decarbonised gas fronts. But it still looks as if such proactive cooperation may be some years away in much of the richer nations of the UNECE region.

Countries outside the OECD are likely to pursue two very different courses, though both would benefit natural gas. The gas producers, Azerbaijan, Kazakhstan, Russia, Turkmenistan and Uzbekistan, will naturally favour gas in order to harness both its availability and cost effectiveness in terms of energy provision for their domestic markets as well as for export customers. The issue of combatting climate change is likely to prove secondary to the familiar provision of a proven source of affordable energy and export income. The approach taken by the second group, a cluster of countries in Southeastern Europe and the Caucasus, is likely to opt to rely on gas because of close commercial relations with Russia.

Throughout the UNECE region, the gas industry, governments and societies will have to work out how to cope with an energy transition that is likely to be characterised by such unpredictable factors as the pace of technological innovation and affordability, drives for energy efficiency, and the social acceptability of programmes to tackle climate change.

In technology, much will depend on the speed with which new technologies become affordable, either in straight commercial terms or as a result of government subsidies or regulation. In energy efficiency, which has done so much to eliminate any increase in demand in Northern and Western European markets, a key question is whether it will continue to play this role over the next decade or two, and the extent to which it will also limit energy demand elsewhere in the UNECE region.

But perhaps the biggest issue is the social acceptability of the kind of transition required to promote renewables – and whether this might provide the circumstances in which gas can seek to secure a major role in consumer markets for the next 20 years or so.

How governments that are officially committed to combatting climate change and effecting decarbonisation will actually tackle these issues remains unclear, particularly at a time when both Germany and the UK, two countries that might be considered market leaders in terms of their efforts to combat climate change, look likely to miss their own decarbonisation targets, while Russia's decarbonisation efforts are just beginning.

Yet, of all the countries in the UNECE region (with the possible exception of the United States), Russia is the country that potentially stands to gain most from striking a balance between natural gas and renewables, to ensure a smooth energy transition.

But developments in the UK and Germany also indicate that there are significant problems in richer, more industrial UNECE areas. In sum, both the UK and Germany face major challenges if they are actually going to implement their aspirations for carbon neutrality by 2050.

All this places gas in a very delicate position indeed. It is not possible to envisage replacement of natural gas in the immediate future, but whether the role of natural gas should be enhanced through further investment looks likely to depend very much on which part of the UNECE is under discussion.

Both state producers in Russia and other UNECE subregions in the Caucasus and Central Asia, and major private sector companies in Europe and North America, have already invested vast sums in developing major gasfields, and in the infrastructure to carry their output to market, that there simply is no possibility that they will move swiftly to replace gas with renewables or even to reduce the volumes of gas produced and exported. The expenses incurred so far can be regarded as sunk costs. So long as actual production and transportation costs remain low, they will continue to supply UNECE markets with gas. But they will be under increasing pressure when it comes to investing in further expansion. Total costs will have to come in at levels that can compete with renewable energy.

If the immediate priority for governments is decarbonisation, it is possible that a combination of carbon pricing and regulation might prompt a fresh round of investment in gas-fired generation in Northern and Western Europe but, right now, that does not look likely. (The question of whether natural gas can tap other geographical markets, or find new outlets outside the traditional power sector, is addressed in Paper 3: *The Potential for Natural Gas to Penetrate New Markets.*)

Over the next ten years or so, natural gas looks likely to play a complementary role to renewables, rather than a strictly supportive role. Thereafter, however, the potential to develop hydrogen and CCUS offers real opportunities for interplay with renewables.

This means that at present the principal requirement for both a fragmented gas industry and for governments in much of the UNECE region is to focus on better use of existing natural gas facilities and networks, rather than the creation of new plant and infrastructure, and to reinforce existing research and efforts to develop hydrogen production and CCUS that would enable gas to play a significant role in long-term energy provision.

Abbreviations

Bcm	billion cubic meters
CCGT	Combined cycle power plant
CCUS	Carbon capture, use and storage
DSO	Distribution system operator
EJ	Exajoules
ENTSOG	European Network of Transmission System Operators for Gas
EPC	Engineering, procurement, and construction
FSRU	Floating Storage Regasification Unit
GIE	Gas Infrastructure Europe
IEA	International Energy Agency
IIASA	International Institute for Applied Systems Analysis
IOGP	International Association of Oil & Gas Producers
LOLP	Loss of load probability
Mt	million tonnes
MTOE	Million Tonnes of Oil Equivalent
OECD	Organisation for Economic Co-operation and Development
TSO	Transmission system operator
TWh	Terawatt per hour
UNECE	United Nations Economic Commission for Europe

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How Natural Gas can Support the Uptake of Renewable Energy

There is a strong medium-to-long-term future for gas so long as it wholeheartedly embraces the energy transition and partners with renewables to produce carbon-free products, notably hydrogen, whilst embracing carbon capture, use and storage (CCUS).

Gas has several key advantages. It is highly flexible and can be used for heating, cooling, cooking, waste disposal and transportation as well as feedstock for chemicals, fertilisers and pharmaceutical products. Moreover, throughout most of the UNECE area there are already extensive distribution networks that enable gas to be transferred both across borders and within member states. These networks can be adapted to carry hydrogen, either mixed in with natural gas or as self-contained systems.

But the crucial element remains the ability and willingness of a fragmented gas industry to promote decarbonisation of the gas sector in order to tackle the global climate emergency.

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