Natural Gas Series Vol. 0: **FactBook**

Introduction to Natural Gas

A.T. Kearney Energy Transition Institute
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Compiled by the A.T. Kearney Energy Transition Institute

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About "Natural Gas Series"

"Natural Gas Series" is a series of publicly available studies on natural gas conducted by the A.T. Kearney Energy Transition Institute that aim to provide a comprehensive overview of the natural gas landscape and keys to understanding its major challenges and developments through a technological prism.

About the FactBook - Introduction to natural gas

This FactBook seeks to present the rationale and challenges of the growing importance of natural gas in the global energy mix, and to capture the current status and future developments of natural gas technologies along its value chain, i.e. upstream - resources and production; midstream - processing, transport, distribution and storage; and end-uses.

About the A.T. Kearney Energy Transition Institute

The A.T. Kearney Energy Transition Institute is a nonprofit organization. It provides leading insights on global trends in energy transition, technologies, and strategic implications for private sector businesses and public sector institutions. The Institute is dedicated to combining objective technological insights with economical perspectives to define the consequences and opportunities for decision makers in a rapidly changing energy landscape. The independence of the Institute fosters unbiased primary insights and the ability to co-create new ideas with interested sponsors and relevant stakeholders.

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Having long been overlooked as an energy source, natural gas has become a crucial part of the energy mix in the past two decades

Natural gas was, for a long time, an unwanted by-product of oil production. Without economic ways of bringing it to market, gas was mostly flared or released to the atmosphere. However, in recent decades, natural gas's abundance and its low carbon content compared with other fossil fuels have considerably bolstered interest in natural gas.

Natural gas is not solely methane. It is composed of a mixture of hydrocarbon components, including methane but also ethane, propane, butane and pentane – commonly known as natural gas liquids (NGLs) – and of impurities such as carbon dioxide (CO2), hydrogen sulfide (H2S), water and nitrogen. The composition is highly variable and depends on the resource's location. In some fields, contaminants, especially those that characterize sour gas (CO2 or H2S), represent a high proportion of the natural gas mixture, making exploitation harder and more expensive. Sometimes, NGLs – hydrocarbons that are in gaseous form in the reservoir, but that become liquid under ambient conditions – account for a significant share of natural gas; a mix rich in NGLs, known as wet gas. In 2013, wet gas yields 9 million barrels of oil equivalent a day, contributing 10% to global liquid hydrocarbon supply. In all situations, natural gas must be processed to remove NGLs and contaminants.

Natural gas's main drawbacks relative to other hydrocarbon fuels are its low volumetric energy density and gaseous nature, which makes it harder to handle than solid or liquid fuels. In order to be transported, natural gas needs to be conditioned in some way – either by compression or by liquefaction. This increases shipping costs and results in limited fungibility. The global-warming potential of its main constituent, methane, presents another problem. Similar to CO2, methane is a potent greenhouse gas. However, an equivalent quantity of methane emitted into the atmosphere would entail 84 and 28 more radiative forcings than CO2 over 20- and 100-year horizons, respectively. As a consequence, methane leaks from natural gas systems, if significant and not mitigated, could negate the climate benefit of natural gas compared with other fuels.

In addition, it is essential to distinguish between energy sources, such as natural gas or wind energy, and energy carriers, such as electricity. Natural gas is an energy source that can be used as gaseous fuel, but also in non-gaseous forms – for instance, as electricity after conversion in a turbine or as a liquid after conversion in a gas-to-liquids plant. Furthermore, natural gas is not the only primary source of methane. Methane can also be produced by gasifying coal – as synthetic natural gas; from biomass and waste – as biogas; and through power-to-gas conversion, from renewables and nuclear energy. The latter two categories are seen as potential levers for reducing the carbon footprint of natural gas even further.

Natural gas systems rely on a complex, infrastructure-intensive value chain for extracting, processing, transporting and distributing energy to end-customers. The technological landscape that makes up the natural gas ecosystem is largely mature, although a few technologies are still in the "valley of death" of investment, when capital requirements and risks are difficult to overcome. At the same time, however, research, development and demonstration (R,D&D) efforts are under way with the aim of: expanding the uses of natural gas (for example, in transport); increasing the available gas resource (for example, by investigating the potential of methane hydrates and unlocking gas resources that are currently non-economic to exploit); and minimizing methane's environmental footprint (e.g. by developing carbon, capture and storage (CCS) operations, reducing methane emissions and enhancing water treatment).

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Natural gas resources are sizeable and relatively widespread thanks to the development of unconventional reservoirs

Natural gas resources are usually classified according to the properties of the reservoir in which they are trapped. Resources are referred to as conventional when accumulated in a reservoir whose permeability characteristics permit natural gas to flow readily into a wellbore; and as unconventional when buoyancy forces are insufficient and intervention is required to make the gas flow. Conventional reservoirs are broken down further into, respectively, the non-associated and associated categories, depending on whether gas is found in isolation or dissolved in oil.

There are four main types of unconventional reservoir: tight, shale, coalbed and methane hydrates. Tight and shale accumulations refer to low-permeability formations. However, unlike in tight reservoirs, gas in shale rocks has remained in the rock where it formed, making exploration and production more difficult. Coalbed methane (CBM) is generated during the formation of coal and is contained to varying degrees within all coal microstructure. The presence of this gas is well known from underground coal mining, where it presents a serious safety risk. It is called coal-seam methane in Australia, where it is an important resource. However, producing from CBM wells can be difficult because of the low permeability of most coal seams and the associated production of large volumes of water. In general, unconventional reservoirs tend to yield lower recovery rates than conventional reservoirs, and usually require more technology. Two technologies have been instrumental in exploiting unconventional resources. Hydraulic fracturing, which involves creating cracks in the rock through which the gas can flow to the wells; and horizontal drilling, which enables wells to penetrate a greater length of the reservoir than is possible with vertical wells, increasing contact with the production zone.

The fourth type, methane hydrates, is promising but still in the development phase. Otherwise known as fire ice, methane hydrates are naturally occurring crystal compounds, in which, under specific conditions of temperature and pressure, molecules of water form a solid lattice around molecules of methane. About 98% of methane hydrates resources are believed to be concentrated in marine sediment, with the remaining beneath permafrost. Four projects have achieved successful production tests – three onshore in the United States (U.S.) and Canada, and one offshore Japan. However, the industry does not expect any large-scale commercial production to happen before 2030 due to environmental and technical challenges.

Taken together, natural gas resources are abundant. Depending on data sources and the definition used for reserves, reserves amount to between 69 and 200 trillion cubic meters (tcm) and technically recoverable resources amount to up to 855 tcm. Reserves would, therefore, last between 20 and 58 years, based on a figure for gas consumption in 2013 of 3.5 tcm. Technically recoverable resources, meanwhile, would last over 200 years. While abundant, the largest conventional gas resources are concentrated in a small number of countries. In the 2000s, it was thought that Russia, Iran and Qatar owned more than 70% of known conventional gas resources. However, unconventional resources are much more widespread and recent discoveries of conventional reservoirs in East Africa or the Mediterranean Sea have opened up new gas frontiers, reducing the concentration of natural gas reserves.

According to the OPEC, natural gas production reached 3.5 tcm in 2013, led by North America, Russia, and the Middle East; of this, 83% came from conventional reservoirs. However, while conventional reservoirs continue to dominate production, output from unconventional accumulations grew 9 times faster than conventional production in 2013, reaching 0.6 tcm. Production from shale reservoirs in the U.S. has been the main driver of growth and now represents 43% of global unconventional gas production. Going forward, natural gas production is expected to continue to increase, driven by unconventional resources and new conventional resources (associated and non-associated gas). For instance, Rystad forecasts that natural gas production will reach 4.6 tcm by 2035.

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Complex infrastructure is needed to get natural gas to end-users – processing plants, transport & distribution grids, and storage units

Raw natural gas collected at the wellhead needs to be processed to meet pipeline quality standards, to ensure safe and clean operations, and to extract valuable natural gas liquids (NGLs). As of 2013, there are close to 2,000 gas-processing plants operating worldwide, with a global capacity of around 7.6 billion cubic meter (bcm) per day. More than half of capacity is located in North America, but the Middle East and Asia, where utilization rates (i.e. gas processing throughput / gas-processing capacity) are much higher than in the U.S., are expected to take over as market drivers.

The low energy density of natural gas has long been an impediment to long-distance transportation, and most natural gas is still consumed close to production centers. However, long-distance trade has increased steadily in recent decades. Along with pipelines, which have been in use since the 19th century, LNG is playing a growing role in long-distance shipping. About 21% and 10% of all produced natural gas is now traded internationally via, respectively, pipelines and LNG. As a rule of thumb, the longer the shipping distance, the more economically attractive LNG tends to become compared with pipelines. Growth in the LNG trade has been made possible by the expansion of LNG infrastructure: there are now 29 countries with import facilities and 19 with export facilities, trading 237 million tons per annum (Mtpa) of LNG. With new export and regasification facilities under construction, the expansion is expected to continue. Meanwhile, floating liquefaction and regasification concepts have garnered attention as a way of reducing development time, increasing flexibility and lowering capital costs. The first floating storage and regasification units (FSRU) have been commissioned. Four floating liquefaction (FLNG) projects have achieved a final investment decision. Nevertheless, many gas fields are too small or remote to justify pipelines or LNG investment. In order to tap these resources, known as stranded gas, two alternative technologies are being considered: compressed natural gas (CNG) and gas-to-liquids (GTL). The former is already in use onshore, but its application offshore is still at an early deployment phase. The latter is technically mature but still in its commercial infancy, with only four plants operating worldwide and subject to the development of economically viable small-scale modular systems.

Improvements in natural-gas transportation, the development of trading hubs and significant regulatory changes have combined to create a more dynamic economic environment for the natural gas business. Indexation of gas prices to the oil price is becoming less common, especially in the U.S., whose gas market is the most liquid in the world. As a result, the price spreads between three main regional blocs – North America, Europe and Asia – have widened. In order to balance seasonal demand variations and ensure supply security, natural gas can be stored, both underground and above--ground. As markets mature, storage becomes increasingly important in stabilizing prices. Underground storage vessels include depleted oil and gas fields, aquifers and salt formations; the choice depends on local geology and how the storage facility will be used. Flexibility in storage capacity has become an important parameter because of growth in the use of natural gas in power generation and because of the limited flexibility of production from unconventional gas reservoirs. As a result, salt caverns have become popular; although they are relatively expensive, their flexibility is unrivalled.

Finally, natural gas needs to be pressurized, odorized and controlled to be safely delivered to end-customers. Except for a few large customers, most end-users are supplied through low-pressure networks. Local distribution involves smaller delivery volumes than long-distance transmission, and delivery over shorter distances to many more locations. As a consequence, distribution lines make up the majority of installed pipelines. Ensuring safety is the main challenge faced by distribution-grid operators. Even if the smart gas-grid concept is less recognized than its power counterpart, natural gas grids are becoming smarter and more efficient as a result of the integration of information and communication technologies.

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Natural gas accounts for more than 20% of the global primary energy mix and its share is expected to continue to rise, albeit a slower pace than in recent years

Natural gas use has increased at an annual average rate of 2.5% since 1990 and its share of the primary energy demand mix has also risen. Going forward, growth in natural gas use is expected to continue, albeit at a slower pace than in recent years. In its reference scenario, the International Energy Agency assumes an average annual growth rate of 1.6% between now and 2035. In this scenario, natural gas demand would grow faster than demand for other fossil fuels, but slower than demand for some of low-carbon energy sources, such as wind and solar. However, this figure is global and masks regional disparities, not to mention absolute value. Natural gas use in China, for example, is expected to multiply four-fold between now and 2035. Over that period, non-OECD countries will collectively account for an estimated 82% of incremental gas demand.

Thanks to its versatility, natural gas plays a major role in all end-use sectors, except for transport. Power generation is the main driver of natural gas consumption, representing 40% of gas demand globally, up from 35% in 1990. Natural gas is now the second-most-important fuel in the power mix, after coal. However, the role of natural gas in power generation varies widely from region to region. It tends to dominate in gas-rich regions, such as Russia or the Middle East (although, in the latter, oil still accounts for a significant share of the power mix). In North America, lower gas prices resulting from the shale-gas boom have encouraged a switch from coal to gas in power generation. In Asia-Pacific, demand for natural gas in power generation has increased strongly in absolute terms, but its share of the power-generation mix has remained steady. In Europe, meanwhile, natural gas's share of the power mix has recently declined. Going forward, many experts believe it will play a vital role in facilitating the transition to a low-carbon economy by replacing coal-fired generation capacity and by compensating for shortfalls in output from intermittent renewables. Indeed, gas-generation technologies benefit from strong flexibility and efficiency performances.

For many years, the use of natural gas in commercial and residential buildings was the backbone of natural gas demand. The buildings segment still accounts for 22% of direct natural gas demand and this share is expected to remain stable in the next few decades. Thermal applications are dominant: space heating, water heating and cooking account for 54%, 22% and 11% of natural gas demand in the buildings sector, respectively. The use of natural gas in buildings varies significantly, depending on climate, urbanization patterns, or building design and insulation. In industry, natural gas is used as a heat source, but also as a chemical feedstock. Direct natural gas consumption represents around 18% of final energy consumption in industry. The chemicals and petrochemicals sectors are by far the most important consumers (accounting for 44% of total industry demand for gas). This is because natural gas is largely used as a source of heat in refineries and as feedstock for producing ammonia and methanol. Other than for chemicals, the bulk of industrial gas demand comes from small-scale industrial consumers using natural gas in small-to medium-scale boilers to generate heat. Any switch from coal to gas in the industrial sector is likely to be relatively limited and subject to the development of carbon pricing.

Finally, natural gas is garnering attention as an alternative to gasoline and diesel in the transport sector. Even if its role in transportation remains marginal globally, natural gas is already being used on a large scale in passenger vehicles in several Asian and South American countries. Natural gas's role in transport may develop further – not just in passenger vehicles, but also in heavy-duty vehicles and in rail and maritime transport. Using gas instead of oil products has economic, strategic and environmental benefits: gas is, at present cheaper than oil; it could reduce dependence on imported oil; and burning gas instead of oil could reduce local air pollution significantly. However, it is doubtful whether increasing gas use in vehicles would have a significant beneficial impact on climate change. There is also a shortage of gas infrastructure and a premium capital cost attached to gas-fuelled vehicles. In addition, natural gas's energy density is much lower than that of oil, making it a less useful fuel in transportation.

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The origins of the natural gas industry lie in the use of gas manufactured from coal

Natural gas development timeline

1785
First commercial use of manufactured gas[1] fuel for lighting.

1812
First gas company founded in London.

1885
Bunsen burner invented: ability to create a flame safe enough for cooking and heating applications

1936
First industrial gas turbine developed independently from jet engine.

1970s
First combined-cycle power plants with a power output around 200 MW.

2000s
Major development programs for compressed natural gas vehicles

1800 | 1850 | 1900 | 1950 | 2000

Manufactured Gas | **Conventional** Gas | **& Unconventional** Gas

1785 | 2014

1821
First well specifically intended to obtain natural gas drilled in Fredonia, New York.

1872
First long-distance natural gas pipeline in the U.S. completed in Pennsylvania.

1947
Hydraulic fracturing first used in U.S.

1951
First production of natural gas from coal beds.

1995
Hydraulic fracturing and horizontal drilling led to successful exploitation of shale gas in Barnett, Texas.

1915
First use of depleted reservoirs for natural gas storage.

1959
Methane Pioneer shipped the first cargo of LNG from the U.S. to the U.K.

1992
World's largest gas field, South Pars/North Field fully delineated.

1. Manufactured gas is a gas obtained by destructive distillation of coal, or by the thermal decomposition of oil, or by the reaction of steam passing through a bed of heated coal or coke.

Source: UKERC (2012), "The development of the CCGT and the 'dash for gas' in the U.K. power industry (1987-2000)"; EIA (2010), "Natural Gas Timeline"; GE (2013), "The Age of Gas & the Power of Networks"

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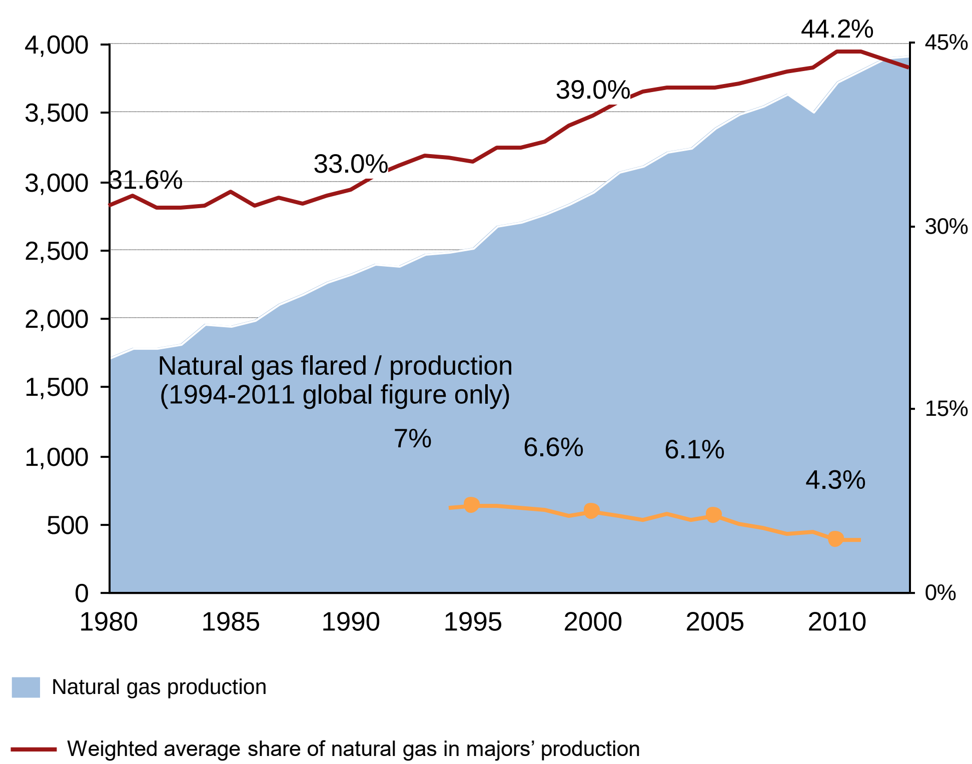
Natural gas has become a crucial part of the energy mix since the 1980s

Natural gas production, share of natural gas within majors' production portfolio and share of flared gas[1]

bcm for production, % for ratios



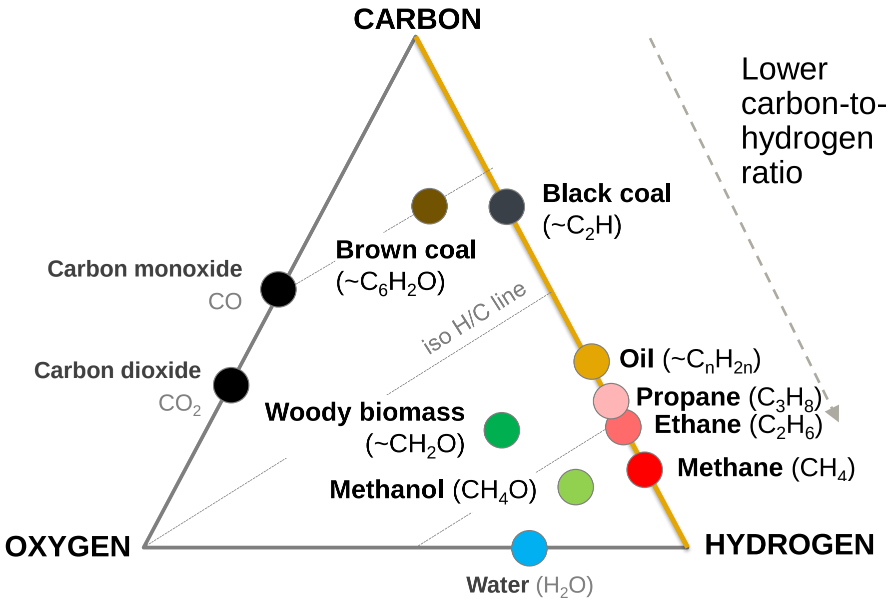
- **In the early 20th century, natural gas was essentially an unwanted by-product of oil production**. Without economic ways of storing it and bringing it to market, natural gas found dissolved in oil was largely released into the atmosphere, or flared.
- **The natural gas industry began to expand rapidly in the 1970s**, following technological breakthroughs in the transportation of gas (*e.g.* steel pipelines and liquefaction) and in end uses of gas (*e.g.* jet-engine gas-turbine technologies applied to power generation), and as a result of concerns over security of energy supply.
- **In 2013, natural gas demand reached 3.5 tcm** and accounted for 21% of primary energy supply. It continues to lag behind coal and oil as a primary energy source, but represents an increasing share of the production portfolio of the majors.
- **Going forward, growth in the natural gas industry is likely to be supported by new conventional discoveries and by the development of unconventional sources** of gas, which began in earnest in the 2000s, increasing and diversifying available gas supply.

1. Companies considered in this analysis are ExxonMobil, Chevron, BP, Shell, Total, and ConocoPhillips. The share of natural gas refers to its share of each company's energy portfolio, not its revenues.

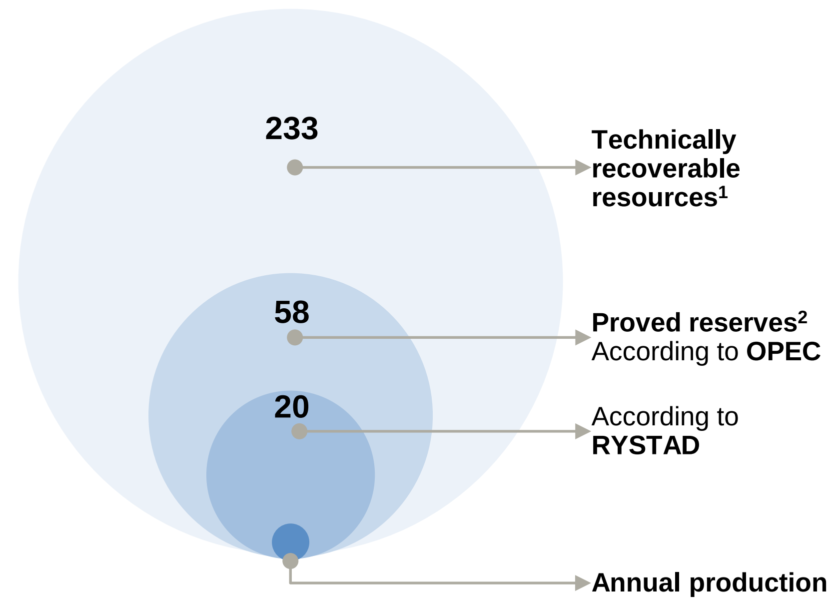
Source: A.T. Kearney Energy Transition Institute analysis, based on Rystad database for production and companies portfolio (accessed May 2014); NOAA database for flaring

The abundance of natural gas and its low carbon content relative to other fossil fuels are the main factors behind natural gas's growing popularity

Carbon-to-Hydrogen ratio
Composition of key chemical fuels



Natural gas supply
Years



- Compared to most alternative chemical fuels, the main components of natural gas (methane, ethane, propane…) have a low carbon-to-hydrogen ratio, resulting in lower greenhouse gas emissions at the point of use.

- According to current estimates and depending on data sources, proved reserves of natural gas could last between 20 and 58 years, based on 2013 production rates. Technically recoverable resources might last 233 years[1].

1. Technically recoverable resources correspond to the volume of natural gas that is recoverable using current exploration and production technology without regard to cost. It does not take into account methane hydrates; 2. Proved reserves are based on figures from the Organization of the Petroleum Exporting Countries (OPEC) and Rystad (P90 for the latter). They correspond to those quantities of natural gas which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations.

Source: IEA (2013), "World Energy Outlook 2013"; OPEC (2014), "Annual Statistical Bulletin", Rystad database (accessed July 2014)

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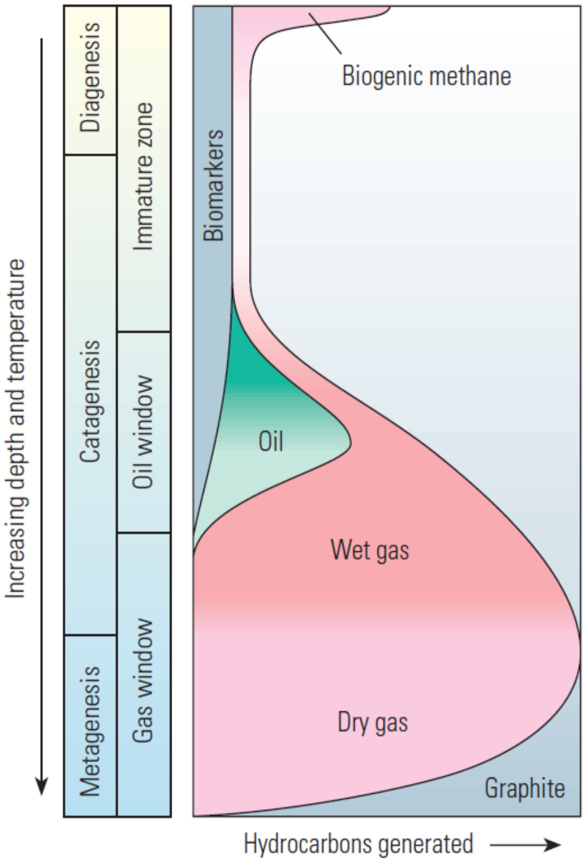
As with oil, natural gas is formed by the gradual decay of organic matter under specific geological heat and pressure conditions

Thermal transformation of kerogen



- Organic matter, such as the remains of recently living organisms (*e.g.* plants, algae, animals, plankton…), is the origin of all the hydrocarbons generated in the earth. A very small portion of this organic matter is deposited in poorly oxygenated aqueous environments (seas, deltas, lakes…), where it is protected from the action of aerobic bacteria and is mixed with sediments to form the source rock.
- Over time, the weight of gradually accumulating organic material and debris causes source rock to subside to great depths, where its organic content entrapped in a mud-like substance known as kerogen, is subject to increasing temperature and pressure.
- These conditions lead to the thermal cracking of kerogen's long molecular chains into smaller and lighter hydrocarbon molecules[1]. During the catagenis phase (50-150°C), kerogen bounds are gradually cracked into oil or into wet gas depending on the kerogen type. As temperatures rise in proportion with depth, hydrocarbon molecules become lighter as depth beneath the surface increases. During a last stage, known as metagenesis, additional heat and chemical changes eventually convert most of the remaining kerogen into methane and carbon residues.
- Hydrocarbon molecules are then expelled from the source rock during a "primary migration" phase, mainly as a consequence of high pressures. Hydrocarbons will then set off on a "secondary migration" phase, making their way upward through rocky layers. If stopped by an impermeable layer of rock, also referred to as seal, hydrocarbons may accumulate in the pores and fissures of a reservoir rock. Otherwise, they may escape from the surface or solidify into bitumen.

1. Soon after being buried, the organic matter may be converted into dry gas under the action of methanogenic bacteria, in a phase known as diagenesis (under 50°C). This dry gas usually leaks into the atmosphere.

Source: Schlumberger (2011), "Basic Petroleum Geochemistry for Source Rock Evaluation"; Tissot et al. (1974), "Influence of Nature and Diagnesis of Organic Matter in Formation of Petroleum"

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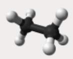
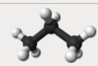
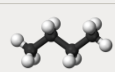
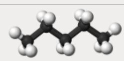
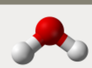
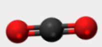
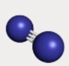
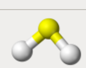
Natural gas consists mainly of methane, but also contains other hydrocarbons and impurities

Natural Gas Composition – Volume %

Natural Gas Liquids (NGLs)[1]

Hydrocarbon components			Typical	Attributes and Uses
Methane	CH_4		70% to 98%	Commercial gas for residential, industrial and power generation use
Ethane	C_2H_6		1% to 10%	Colorless, odorless, feedstock for ethylene
Propane	C_3H_8		Trace to 5%	Burns hotter than methane, common liquid fuel; Liquid Petroleum Gas (LPG)
Butane	C_4H_{10}		Trace to 2%	Safe, volatile, used in pocket lighters; LPG
Pentane	C_5H_{12}		Trace	Commonly used solvent
Non-hydrocarbon components				
Water vapor	H_2O		Inert	Occasionally used for reinjection
Carbon dioxide	CO_2		Inert	Colorless, odorless, used for reinjection
Nitrogen	N_2		Inert	Colorless, odorless, used for reinjection
Helium	He		Inert	Colorless, odorless, light gas; specialty uses
Hydrogen sulfide	H_2S		--	Poisonous, lethal, foul odor; corrosive

- **Natural gas is a naturally occurring mixture of hydrocarbon gases**[1].
- **Methane [CH_4] is the chief constituent of most natural gas, but it may also contain** lesser amounts of ethane [C_2H_6], propane [C_3H_8], butane [C_4H_{10}] and pentane [C_5H_{12}], commonly known as natural gas liquids (NGLs).
- **Impurities can also be present in large proportions**, including carbon dioxide (CO_2), helium, water, nitrogen and hydrogen sulfide (H_2S), but also mercury.
- **All of these impurities, especially CO_2 and H_2S, must be removed** from the natural gas stream before transport and commercialization. CO_2 and H_2S can corrode pipelines, are highly toxic and are significant sources of air pollution. Gases with high levels of H_2S and CO_2 are also called sour gases.

1. Some hydrocarbon components, such as natural gas liquids, can be in gaseous form in the pressure and heat conditions of the reservoir, but become liquid under ambient conditions.

Source: IEA (2013), "Resources-to-Reserves 2013"

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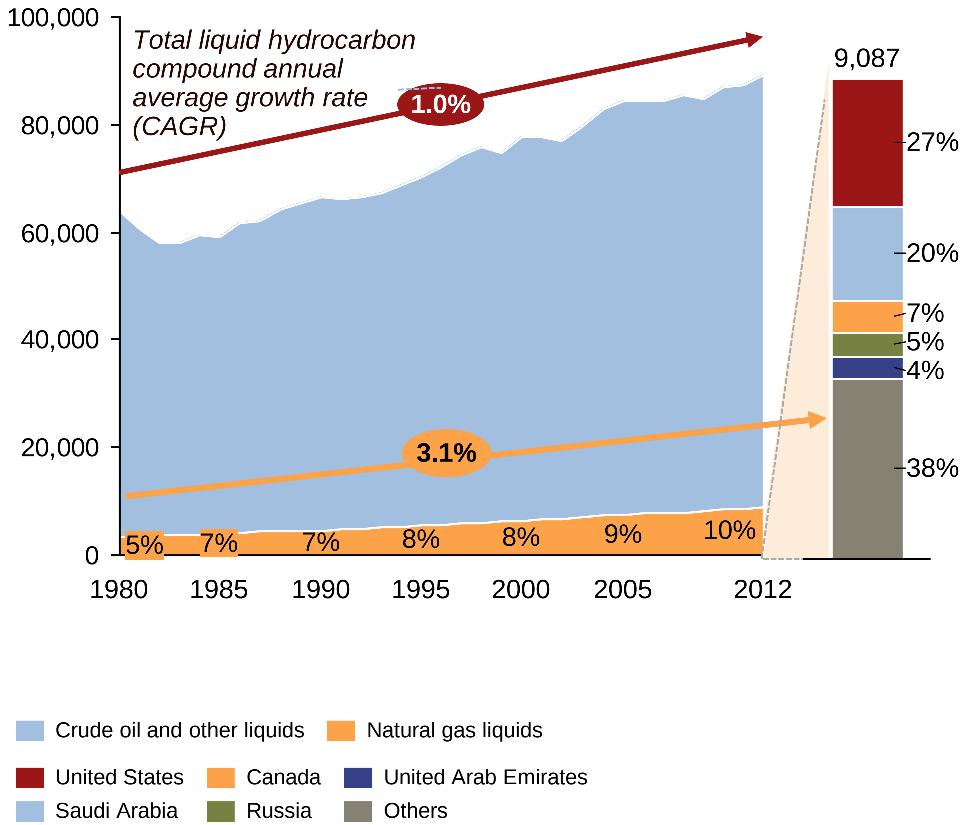
Components heavier than methane, known as natural gas liquids (NGLs), represent 10% of global liquid hydrocarbon supply

Worldwide liquid hydrocarbons production[1]

Thousand barrels per day (1,000 bbl/d)



- **Hydrocarbon components of natural gas that are heavier than methane are called natural gas liquids** (NGLs). They can be extracted in a processing plant2 and commercialized as liquid fuels.
- **Natural gas that is rich in NGLs is usually called wet gas or rich gas, as opposed to dry gas or lean gas**. Liquefied petroleum gas (LPG), to make a further distinction, is a subset of NGLs, comprising propane and butane. LPG can be liquefied through pressurization (i.e. without requiring cryogenic refrigeration), and used as a liquid fuel.
- **In 2012, supply of NGLs amounted to 9 million barrels a day, representing about 10% of world liquid hydrocarbon production**. While total liquid supply has increased at a 1% compound average annual growth rate (CAGR) since 1980, NGLs production has more than doubled with a CAGR of 3.1%.
- **NGLs all have their own prices and pricing mechanisms**. It may become commercially attractive to produce NGLs, depending on the composition of NGLs in a given natural gas stream and on average price spreads with methane. For instance, natural gasoline (the pentanes-plus fraction of NGLs) sells in the U.S. at prices that are 4 to 5 times higher than natural gas on a comparable energy basis. Conversely, ethane was in 2013 cheaper than natural gas in the U.S.

1. NGLs production in the figure above includes only natural gas plant liquids production and not lease condensate recovered at well site facilities;
2. For more information on processing (NGLs extraction and fractionation), please refer to slide 44.

Source: EIA (2013), "International Energy Statistics"; FERC (2013), "Natural Gas Market Overview: NGL Prices"

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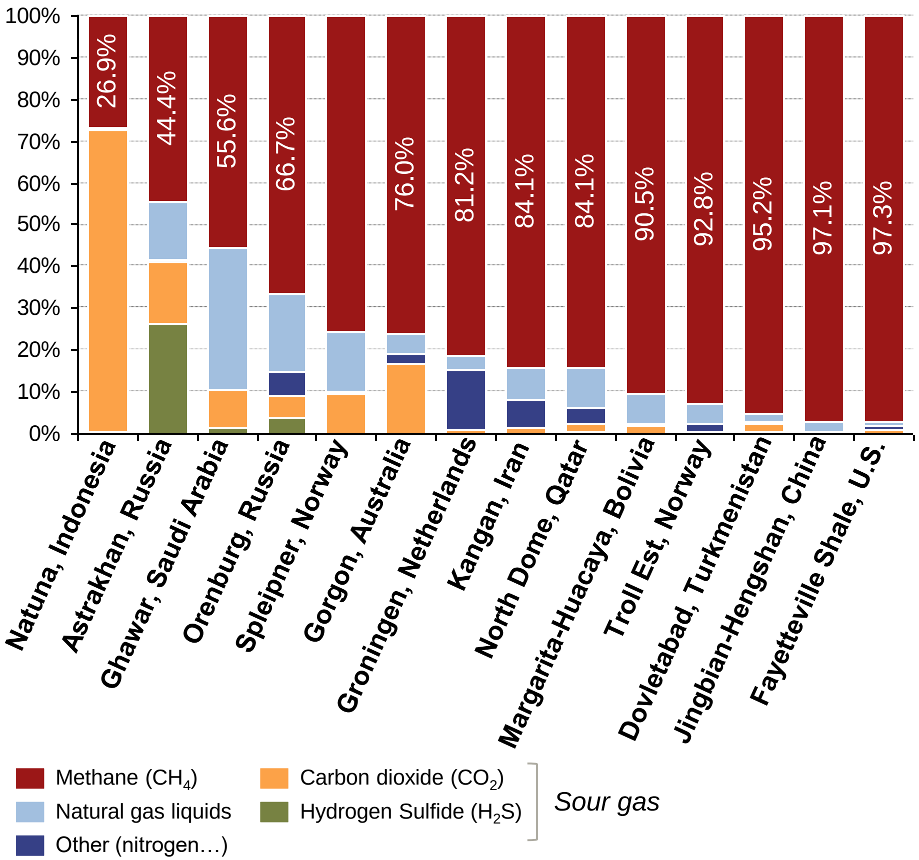
The composition of natural gas is highly variable and depends on the characteristics of each field

Composition of natural gas in major global fields – Mole (%)



- **The mix of hydrocarbon fractions and contaminants in natural gas is specific to each field[1].** In some fields, natural gas liquids (NGL) account for significant share of the natural gas mix, leading to important volumes of liquid hydrocarbons produced.
- **However, in some fields, contaminants can be found in very high concentrations.** This increases investment needs and production costs to the extent that production may even be rendered uneconomic. **Natural gas rich in hydrogen sulfide** (H_2S) **or carbon dioxide** (CO_2) **is called sour gas or acid gas[1].** CO_2 and H_2S are both extremely corrosive and H_2S is also toxic. When these gases are present, special equipment is needed (e.g. special alloys for tubing and piping) to ensure that the natural gas can be safely transported and processed, prior to being sold.
- **20-40% of global recoverable gas resources could be considered, to varying degrees, to be sour gas,** especially in the Middle East and Central Asia, but also in North America, Australia and Russia. Even if sour gas fields have a long history of successful development in several places, lowering the costs of sour-gas operation is essential if its potential is to be fully tapped. This could be through innovation in gas-separation technologies used in processing plants or more advanced deployment of capture and re-injection, including enhanced oil recovery[2].

1. The composition of natural gas varies according to the original organic matter and to the conservation conditions in the reservoir;
2. CO2, once separated, can be injected into an oil field to increase reservoir pressure. This process, known as enhanced oil recovery, mitigate the environmental impact of sour gas

Source: IHS database (accessed March 2014); Total (2007), “Sour Gas, A History of Expertise”

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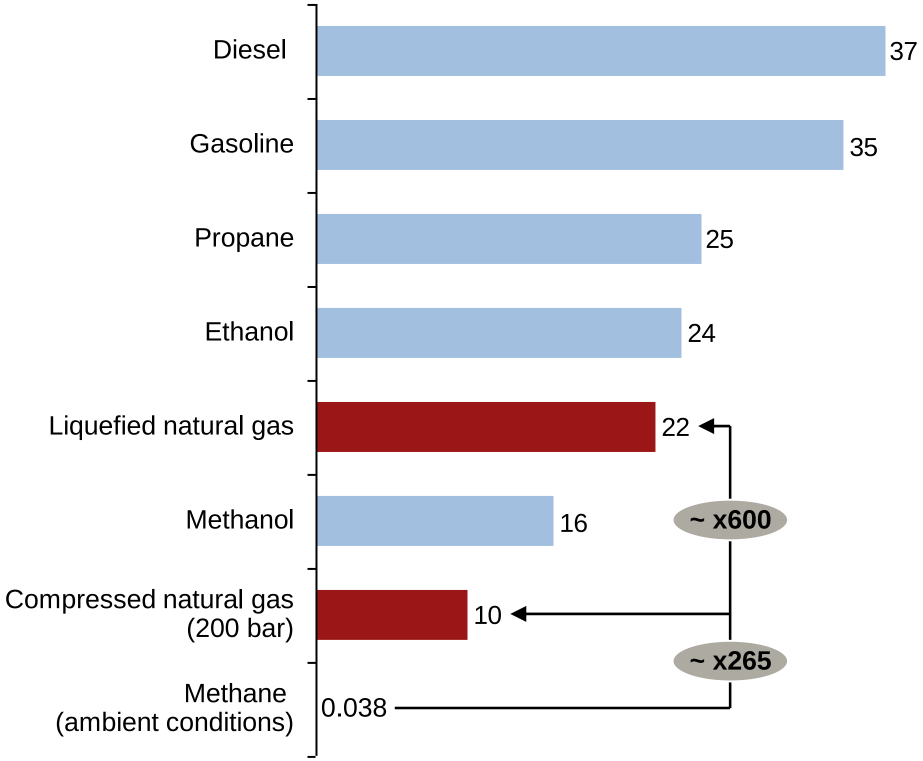
Natural gas's volatility and low energy density make handling it difficult

Volumetric Energy density of chemical fuels[1]

MJ/liter



- **Natural gas's main drawback relative to other hydrocarbon fuels is its low volumetric energy density,** i.e. energy stored per unit of volume. This becomes especially challenging when natural gas is used as a transport fuel. In addition, its gaseous nature makes it volatile and harder to handle than solid fuels like coal or liquid fuels such as crude oil.
- **As a consequence, natural gas needs to be "packaged" in some way** in order to increase its energy density and to allow for safe and economic transport and storage. **Two main conditioning technologies are used:** *1) compression, in which natural gas is pressurized, and 2) liquefaction*, in which cryogenic refrigeration turns natural gas into a liquid. Compression is by far the most common handling technology, but liquefaction, which results in greater energy density, is also a mature technology and common in long-distance transport2. Finally, natural gas can also be converted into liquid fuels in a process known as gas-to-liquids (GTL)[3].
- Whatever the technology, gas conditioning incurs high handling costs and has limited flexibility. Unlike oil, for instance, which is fungible, natural gas relies on a heavy infrastructure to reach end-customers, while being pressurized or liquefied at all times (e.g. in pipelines, storage caverns or cryogenic carrier). Without such infrastructure, natural gas would be flared or vented

1. Figures for compressed and liquefied natural gas are based on average dry-gas composition; 2. For more information, please refer to slide 46. 3. Unlike liquefaction, GTL involves changing the gas's chemical composition and does not involve cryogenic refrigeration to achieve the liquid state.

Source: A.T. Kearney Energy Transition Institute analysis, based on U.S. DoE (2012)

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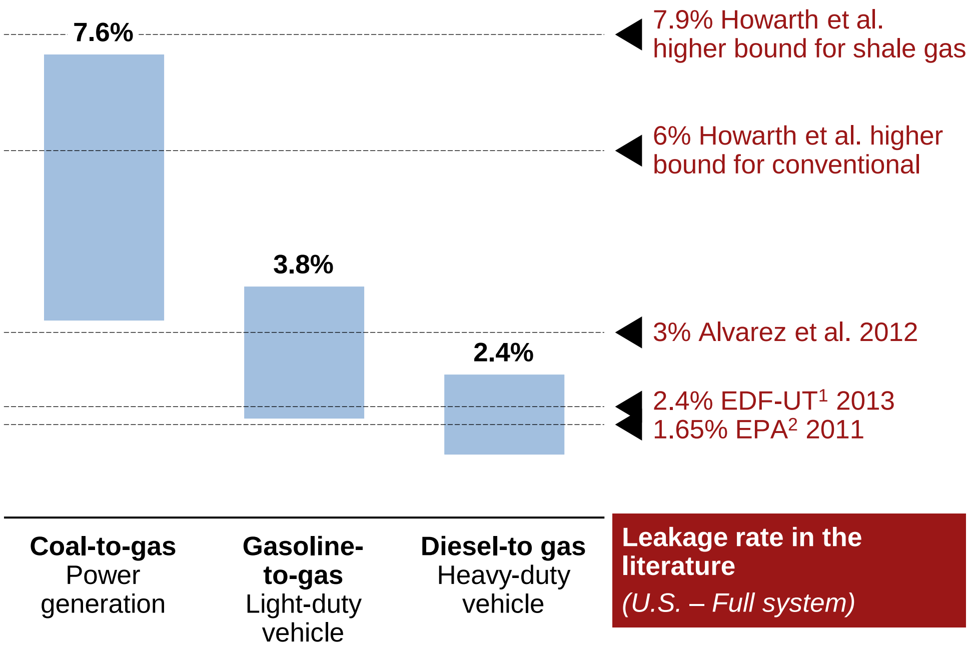
Methane emissions from natural gas systems are unlikely to negate the climate benefit of coal-to-gas switching, but may undermine the value of gas use in transport

Methane emissions Breakeven point of fuel switching

% of methane leakage, immediate/100 years



How to read this graph

For coal-to-gas generation, switching would have an immediate positive impact if the leakage rate were less than 3.2% of the gas produced. The threshold would be 7.6% on a 100-years basis.

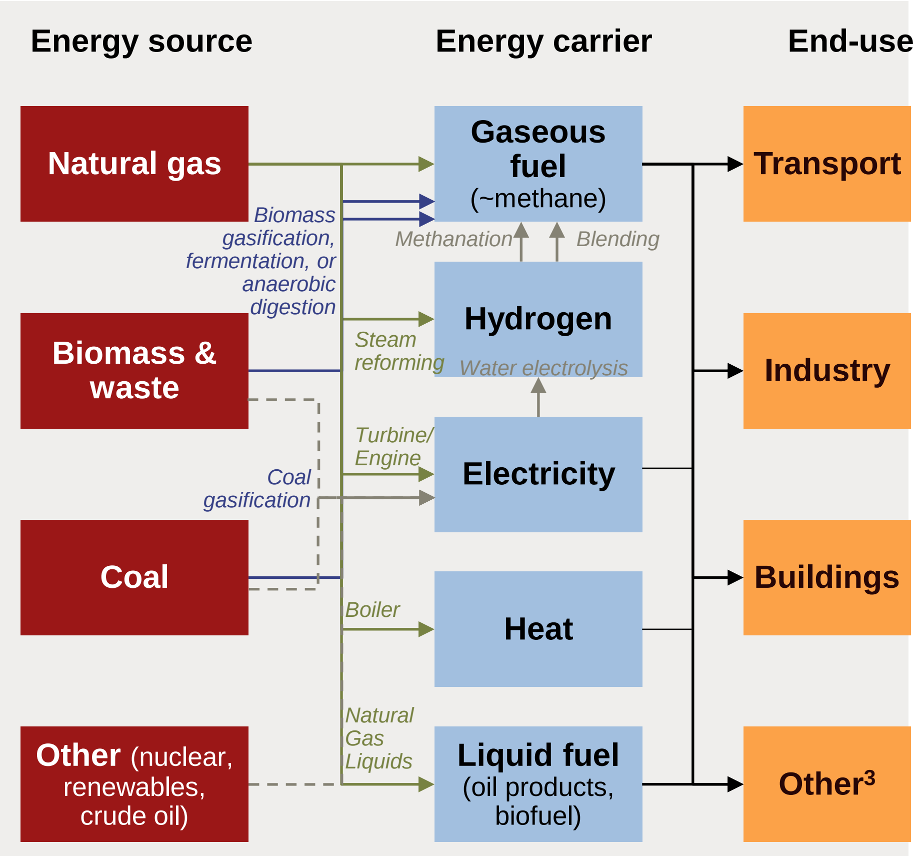
- **Natural gas industry operations entail methane emissions from venting** (intentional, for safety or economic reason), leaks in pipelines and equipment, such as valves or seals (also known as fugitive emissions), **incomplete burning** *(notably during flaring)* and **incidents** *(e.g. rupture of confining equipment).*
- **Like CO_2, methane is a potent greenhouse gas** (GHG). **However, it has a higher global warming potential** (GWP) than CO_2. According to the IPCC, methane GWP would be 28 to 84 times higher than CO_2 GWP over 100-year and 20-year horizons, respectively.
- **There is a lack of data relating to methane emissions from the natural gas system, producing conflicting results in literature on the subject.**
- Overall, **system-wide methane emissions are unlikely to negate the climate benefits of coal-to-natural gas substitution** in the long term, but may but may become more harmful when natural gas is used in transport.

1. EDF-UT for Environmental Defense Fund – University of Texas; 2. EPA for Environmental Protection Agency; This is because oil has a smaller carbon footprint than coal and because of the efficiency of gas engines. The chart assumes CNG vehicles to be 20.7% less efficient than diesel-fueled vehicles. According to current literature, the efficiency penalty ranges from 0% to 22%.

Source: Brandt et al. (2014), “Methane Leaks from North American Natural Gas Systems”; Alvarez et al. (2013), “Greater focus needed on methane leakage from natural gas infrastructure”; Howarth et al. (2011), “Methane and the greenhouse-gas footprint of natural gas from shale formations”

Natural gas is mainly used as a gaseous fuel but can also supply energy in other forms

Natural gas as energy source vs. Gaseous fuel as energy carrier: schematic of the energy system



- **In the energy system, it is essential to distinguish between energy sources**, such as natural gas or wind energy, **and energy carriers**, such as gasoline or electricity. The latter category ensures the supply of energy to end-users, either directly (e.g. wood) or indirectly, i.e. after conversion (e.g. refining, power generation).
- **Natural gas is an energy source that can be used as a gaseous fuel** (after processing), mainly as methane. However, **natural gas can also be used in non-gaseous forms**: i) electricity, after conversion in a turbine or engine, ii) heat, iii) liquid, as a result of the extraction of natural gas liquids (NGLs) or the conversion of natural gas into synthetic liquid fuels (gas-to-liquids) or hydrogen, through steam methane reforming1.
- **However, natural gas is not the only primary source of methane**. It can also be produced from i) biomass & waste (known as biogas), ii) coal, through gasification (known as synthetic natural gas), or iii) any primary sources used to generate power by virtue of power-to-gas2 processes. Biogas and low-carbon synthetic gas production, such as power-to-gas based on nuclear and renewable power generation, are seen as potential levers for further reducing natural gas's carbon footprint.

Note Legend: natural gas uses, alternative sources of gaseous fuel, power-to-gas; [1]Steam methane reforming consists of extracting hydrogen (H_2) from methane (CH_4). [2]Power-to-gas consists of converting electricity into hydrogen by water electrolysis, and hydrogen into synthetic methane by methanation, or blending with methane; [3]Other includes non-energy use (e.g. as feedstock in the chemicals industry) and agriculture needs.
Source:A.T. Kearney Energy Transition Institute analysis

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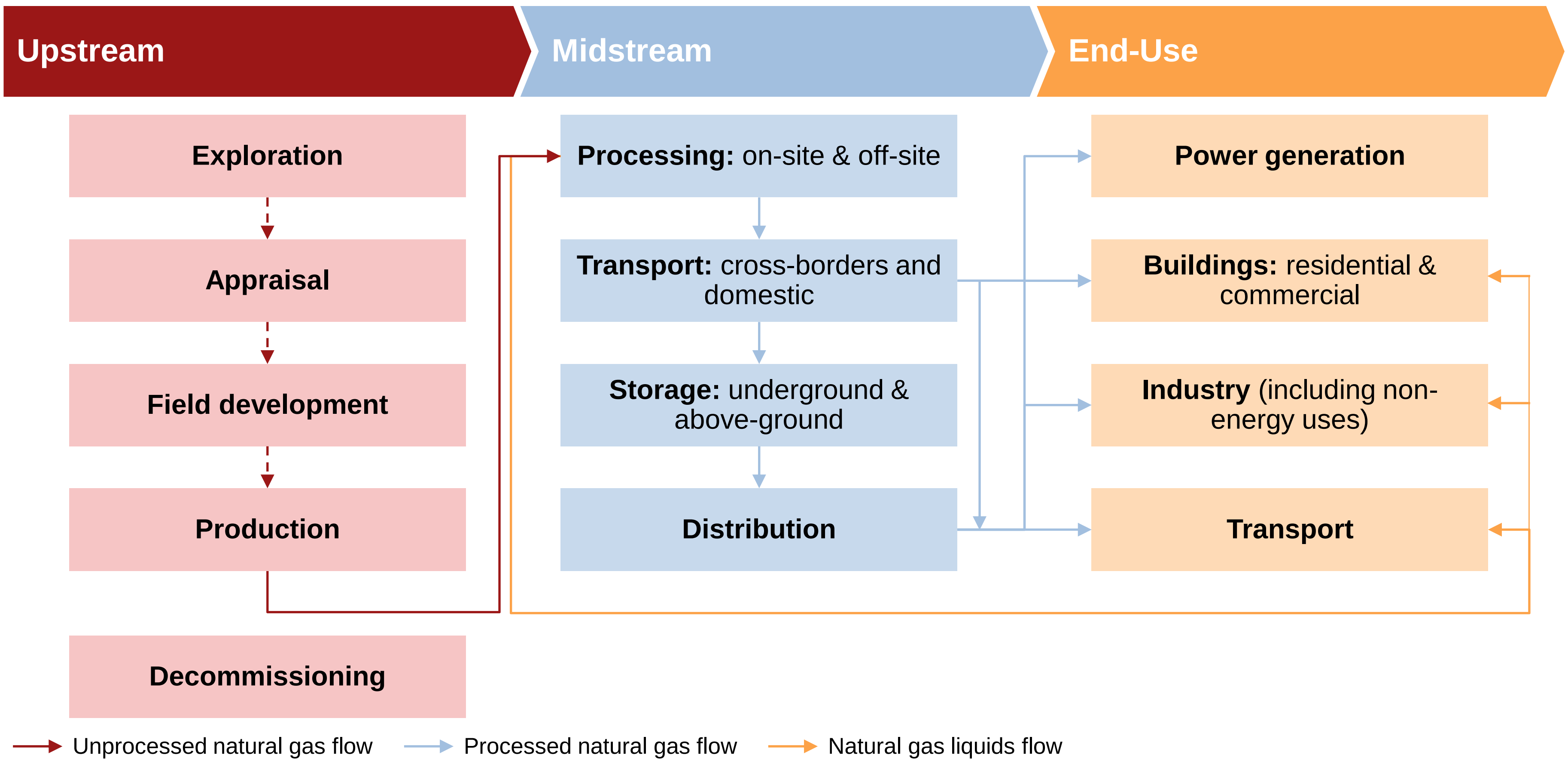
Natural gas systems rely on a complex, infrastructure-intensive value chain for extracting, processing, transporting and distributing energy to end-customers

Natural Gas Value Chain[1]



1. For the sake of clarity, natural gas losses and self-consumption, which occur throughout the value chain, are not depicted in the value chain in this slide. Moreover, natural gas can also be injected into oil reservoirs to maintain reservoir pressure and sustain production

Source: A.T. Kearney Energy Transition Institute analysis based on WRI (2012), “Defining the Shale Gas Life Cycle: A Framework for Identifying and Mitigating Environmental Impacts”

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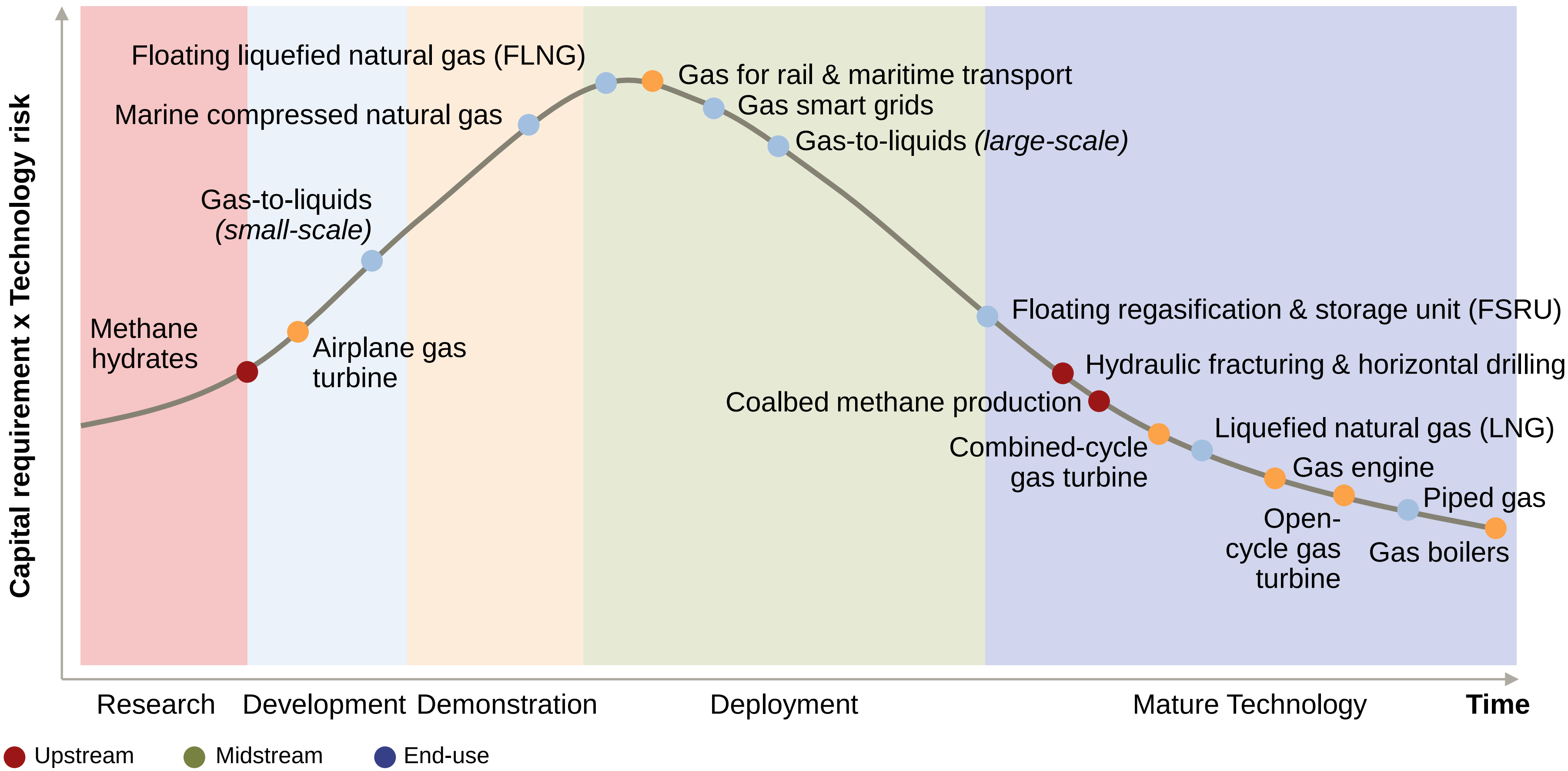
Natural gas's technological landscape is largely mature, although a few technologies are still in the investment "valley of death"

Technology maturity curve[1]



1. Investment valley of death refers to two critical stages: the early demonstration stage, in which capital required tends to outstrip the resources of a typical lab and where the high technology risk deters some private-sector investors; and the early deployment stage, in which high investment requirements and further risk taking are needed to push the project from demonstration to deployment

Source: A.T. Kearney Energy Transition Institute analysis

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Research, Development and Demonstration is under way in order to expand the use of natural gas, make more of it available and minimize its environmental footprint

Key Research, Development & Demonstration (R,D&D) axis for natural gas

Value Chain Section	Drivers	R, D&D axis
1 **Upstream** 	Investigate potential of methane hydrates	Detection of highly concentrated deposits, safe production, CO_2 injection
	Minimize environmental footprint of gas production	Detection, measurement and capture of methane emissions; water treatment, handling and re-use for unconventional gas production; alternative source of low-carbon methane such as biogas or power-to-gas; sour gas treatment (*e.g.* re-injection)
2 **Midstream** 	Unlock stranded gas sources	Small-scale gas-to-liquids concepts, floating liquefied and regasification, compressed natural gas transport, lower-cost offshore pipelines
	Improve energy efficiency of gas transport and distribution	Pipeline coating material, remote control and monitoring with smart grid concepts
3 **Downstream** 	Expand natural gas use	Use for transport (*e.g.* as bunker fuel or for rail freight) and as feedstock in the petrochemical industry (gas-to-chemical)
	Improve energy efficiency of conversion process	Novel membranes and new manufacturing processes in industry, residential gas-fired, instantaneous hot-water heaters
	Develop carbon capture and storage technologies (CCS)	Accelerate deployment of CCS both in power generation and in industry, with a focus on large-scale integrated projects and on research & development into capture processes

Source: A.T. Kearney Energy Transition Institute analysis based on MIT (2011), "The Future of Natural Gas"; IEA (2013), "Resources-to-Reserves 2013"

2. Upstream

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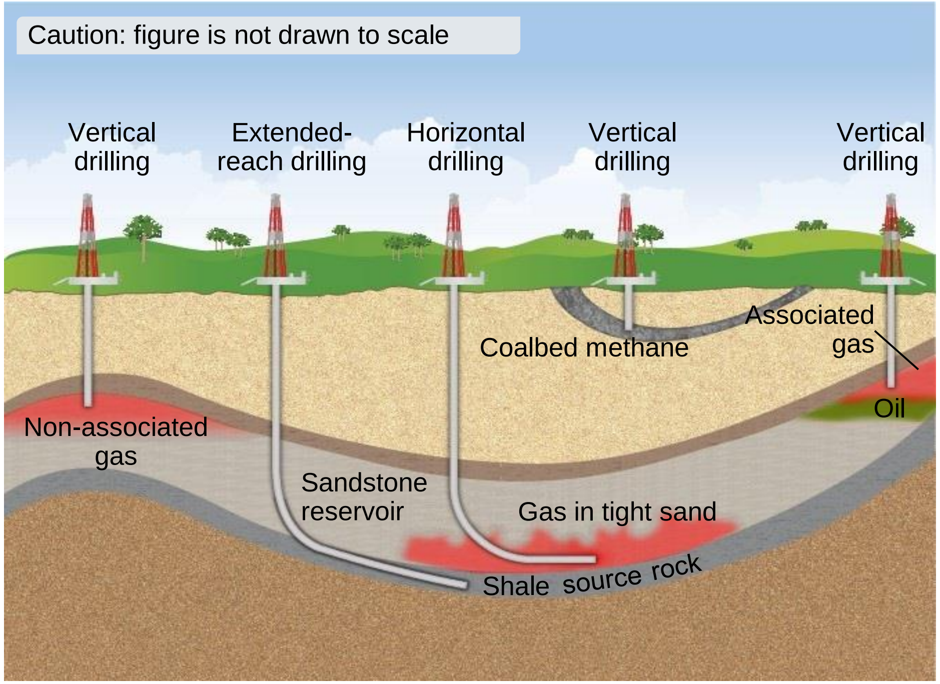
Various geological formations can trap natural gas accumulations

Schematic geology of natural gas resources[1]



See fact cards in the following slides for more information on each type of formation

- **Natural gas resources are often classified as conventional or unconventional.** These terms refer to the characteristics of the geology in which the natural gas is trapped.
- **Standard classification is as follows:**
- **Conventional reservoirs:** when resources exist in discrete, well-defined subsurface accumulations with permeability values greater than a specified lower limit:
  - Associated gas: when produced with oil
  - Non-associated gas: when isolated
- **Unconventional reservoirs:** when resources exist in accumulations where permeability is low. There are four main types of unconventional natural gas[2]:
  - Shale
  - Coalbed (or coalbed methane)
  - Tight
  - Methane hydrates[3]
- **Conventional reservoirs tend to require less technology to be developed and to yield higher recovery rates.** However, reservoirs located in deep water or Arctic environments, and those containing a high level of sour gas4 may also be very challenging to develop.

1. Picture credits Schlumberger (2011), "Basic Petroleum Geochemistry for Source Rock Evaluation"; 2. Unconventional resources also tend to be distributed over a larger area than conventional resources; 3. Methane hydrates are part of "unconventional gas". But because the exploration and production of methane hydrates is at an early stage of development phase, they will be considered separately in this FactBook; 4. Please refer to slide 15 for more details on sour gas.

Source: EIA (2010), "Schematic Geology of Natural Gas Resources"; IEA (2013), "Resources-to-Reserves 2013"

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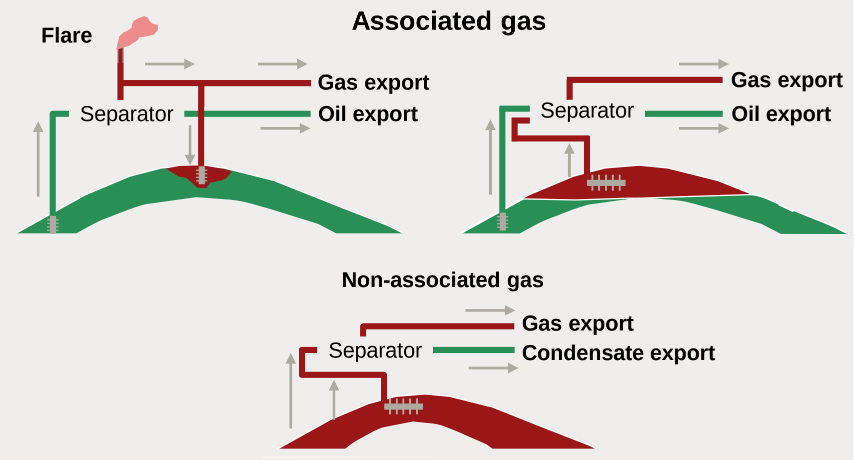
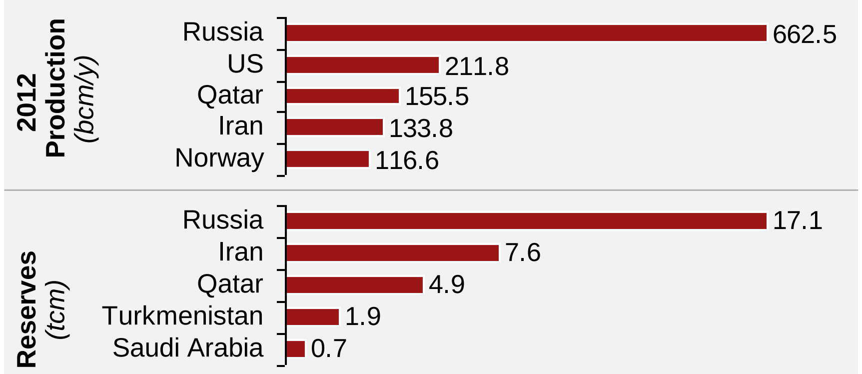
Conventional gas: fact card

Conventional gas refers to resources accumulated in a reservoir in which buoyant forces keep hydrocarbons in place below a sealing cap rock. Reservoir and fluid characteristics typically permit natural gas to flow readily into a wellbore. The term is distinct from unconventional reservoirs, in which gas might be distributed throughout a reservoir at the basin scale, and in which buoyant forces are insufficient to expel gas from the reservoir, meaning that intervention is required. Conventional gas reservoirs can either be isolated (non-associated) or associated with oil. Associated gas can be in form of a gas cap (free gas) or it can exist in solution within the oil (solution gas). Natural gas was long considered an unwanted by-product of oil and was only considered as a commercial prospect when deposits were located close to markets or gas infrastructure.



Key countries



Key data – *as of 2014*

Technically recoverable resources:	**519 tcm**
Proved reserves:	**60.4 tcm**
Current production:	**2,831 bcm/y**
First gas produced[1]:	**1821**
Cost of production per MBtu[2]:	**$0.2 – 9.0**
Recovery factor:	**60 – 80%**

1. First well specifically drilled to obtain natural gas; 2. Includes CAPEX, OPEX (production, transportation and abandonment), and taxes.
Note: Picture credits: IEA (2013), “Resources-to-Reserves 2013”
Source: IEA (2013), “World Energy Outlook 2013”; Rystad databases (accessed May 2014); BP (2013), “BP Statistical World Energy Review 2013”

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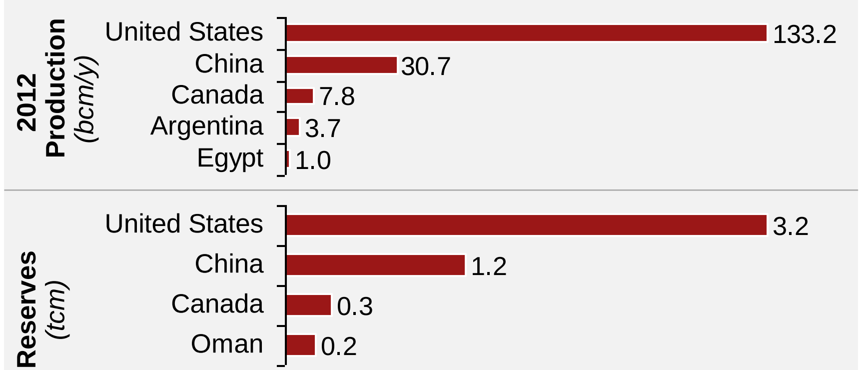
Tight gas: fact card

Tight gas is natural gas trapped in relatively impermeable reservoir rock (picture[1]), generally sandstone or limestone formations[2]. Tight-gas production can be difficult without stimulation. One of the most effective methods is hydraulic fracturing, which involves creating cracks in the rock through which the gas can flow to the wells. Horizontal drilling is also instrumental in exploiting tight gas resources since it typically penetrates a greater length of the reservoir, hence offering significant production improvements over vertical wells. Tight gas has been produced for decades, notably in the United States or in the North Sea.

Key countries



Key data – *as of 2014*

Technically recoverable resources:	**78 tcm**
Proved reserves:	**2.3 tcm**
Current production:	**215 bcm/y**
First gas produced[3]:	**1970s**
Cost of production per MBtu[4]:	**$3.0 – 9.0**
Recovery factor:	**30 – 50%**

1. Picture credits: American Association of Petroleum Geologists; 2. There is no universal definition for differentiating between conventional gas and tight gas. However, if the permeability of the reservoir rock is less than 0.1 millidarcy, the gas is often referred to as tight gas; 3. First large-scale production of tight sands was developed in the 1970s in San Juan Basin, U.S.; 4. Includes CAPEX, OPEX (production, transportation and abandonment) and taxes.

Source: Rystad databases (accessed May 2014); IEA (2013), "Resources-to-Reserves 2013"; Schlumberger (2011), "Basic Petroleum Geochemistry for Source Rock Evaluation"

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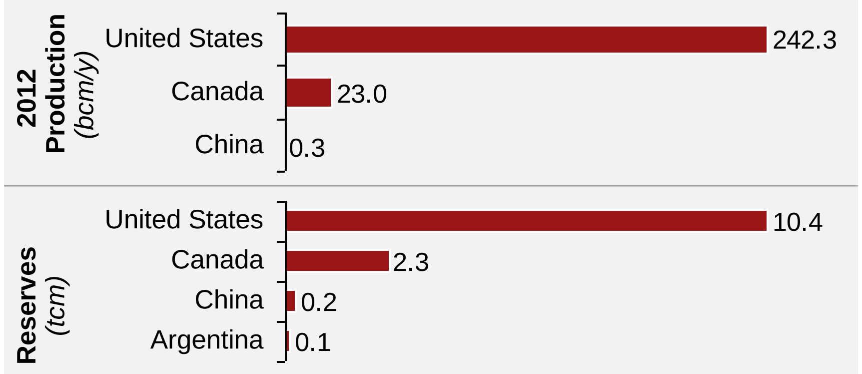
Shale gas: fact card

Shale is a fine-grained, fissile (*i.e.* easily split), sedimentary rock formed by the consolidation of clay- and silt-sized particles into thin, relatively impermeable layers (picture). It is the most abundant sedimentary rock. In gas shales, the gas is generated in place; the shale acts as both the source rock and the reservoir. This gas can be stored interstitially within the pore spaces between rock grains or fractures in the shale, or it can be adsorbed onto the surface of organic components within the shale. Until recently, producing gas trapped into shale formations was not considered profitable. However, as with tight gas1, the application of stimulation techniques and horizontal drilling have enabled the development of onshore shale gas fields during the past decade. Offshore shale development is still at an early stage of development because of the intense drilling and stimulation operations required.

Key countries



Key data – *as of 2014*

Technically recoverable resources:	**210 tcm**
Proved reserves:	**4.9 tcm**
Current production:	**266 bcm/y**
First gas produced[2]:	**1981**
Cost of production per MBtu[3]:	**$2.0 – 10.0**
Recovery factor:	**8 – 30%**

1. Picture credits: American Association of Petroleum Geologists; 2. There is no universal definition for differentiating between conventional gas and tight gas. However, if the permeability of the reservoir rock is less than 0.1 millidarcy, the gas is often referred to as tight gas; 3. First large-scale production of tight sands was developed in the 1970s in San Juan Basin, U.S.; 4. Includes CAPEX, OPEX (production, transportation and abandonment) and taxes.

Source: Rystad databases (accessed May 2014); IEA (2013), "Resources-to-Reserves 2013"; Schlumberger (2011), "Basic Petroleum Geochemistry for Source Rock Evaluation"

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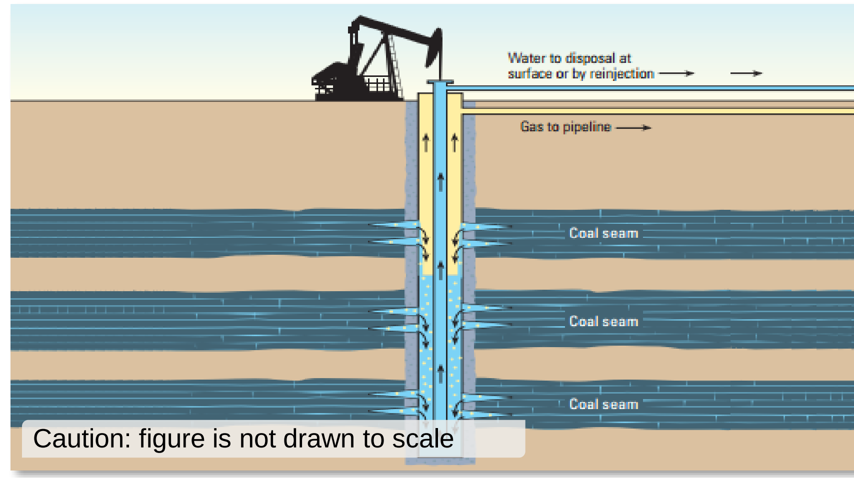
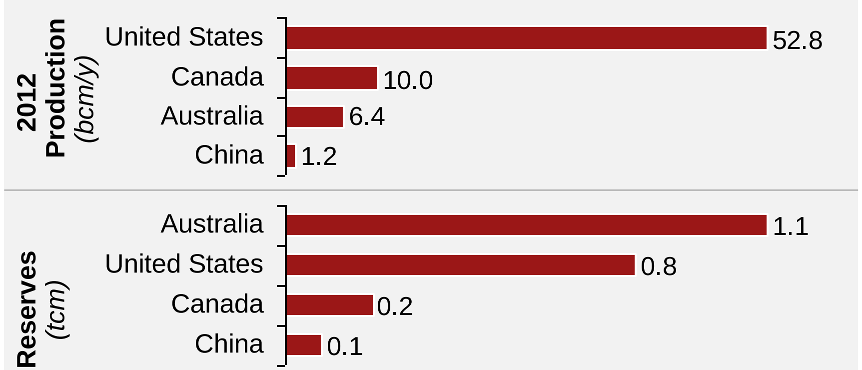
Coalbed methane (CBM): fact card

Coalbed methane[1] is generated during the formation of coal and is contained to varying degrees within all coal microstructure. Because of coal's porous nature and its many natural cracks and fissures, coal can store more gas than a conventional reservoir of similar volume. However, production from CBM wells can be difficult because of the low permeability of most coal seams. As a result, technologies such as directional drilling and hydraulic fracturing are used to open access to larger areas, enhancing well productivity. Finally, CBM production is often associated with extensive production of water[3]. Water must be removed in order to reduce pressure within the reservoir, making lifting and surface separation more complex and costly. CBM production is advanced in the U.S., Canada and Australia.



Key countries



Key data – *as of 2014*

Technically recoverable resources:	**48 tcm**
Proved reserves:	**0.98 tcm**
Current production:	**71 bcm/y**
First gas produced[3]:	**1971**
Cost of production per MBtu[4]:	**\$3.0 – 8.0**
Recovery factor:	**50 – 85%**

Note: Picture credits: Schlumberger (2009), "Coalbed Methane: Clean Energy for the World"; 1. CBM is usually composed mainly of methane and contains only a small proportion of heavy hydrocarbons and contaminants; 2. The presence of this gas is well known from its occurrence in underground coal mining, where it presents a serious safety risk; 3. Water naturally occurring and introduced during fracking operations; 4. First recorded well, drilled in West Virginia, U.S.; 4. Includes CAPEX, OPEX (production, transportation and abandonment) and taxes.
Source: Schlumberger (2009), "Coalbed Methane: Clean Energy for the World"; Rystad databases (accessed May 2014); IEA (2013), "World Energy Outlook"

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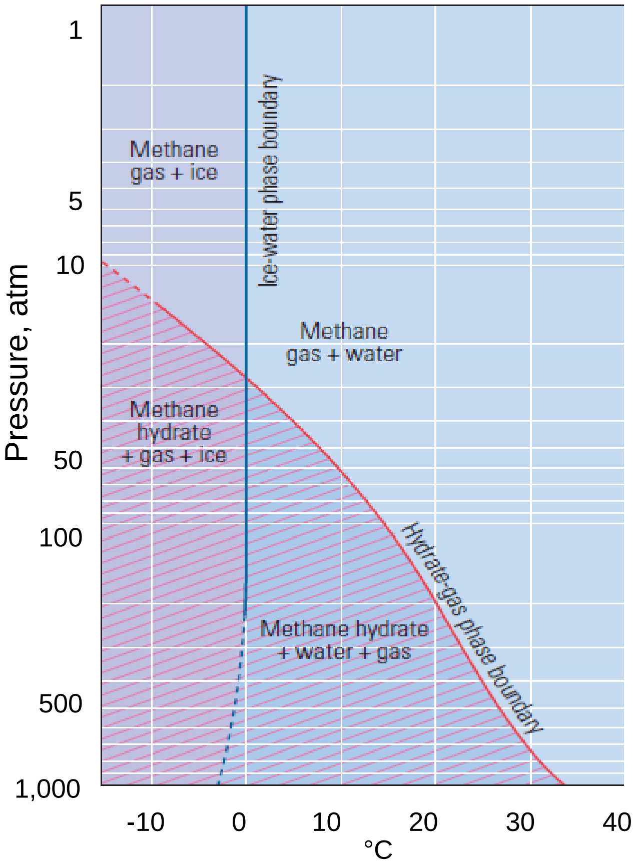
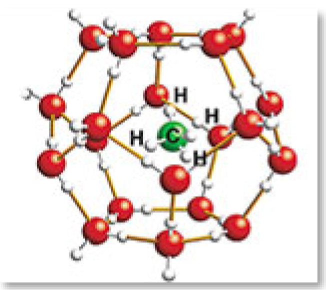
Methane hydrates could considerably increase natural gas resources but are still at a very early development phase

Phase Diagram of methane hydrate stability[1]

Pressure in atm (log scale)[2], Temperature in °C





View of a methane hydrates compound

- Methane [CH_4] (green and white) is the guest molecule in a cage formed by water [H_2O] molecules (red and white).

- **Methane hydrates are naturally occurring crystalline compounds, in which molecules of water form a solid lattice around molecules of methane.** Stable hydrates only form under specific conditions, namely low temperature, high pressure and when water and methane are present in sufficient quantities.
- **About 98% of gas-hydrate resources are concentrated in marine sediment**, with the other 2% beneath permafrost. Theoretically recoverable methane hydrates sources could exceed existing natural gas resources**.**
- **Four production methods are under investigation for methane-hydrate recovery**: 1) depressurization, which has emerged as the preferred solution, involves lowering the water level in the well; 2) thermal stimulation, which involves warming the formation; 3) chemical inhibition, which exploits the ability of certain organic or ionic compounds to destabilize gas hydrates; and 4) CO2 injection.
- **Four projects have led to successful production tests so far.** A successful recent production test offshore Japan was the first offshore, following onshore successes in the U.S. and Canada between 2002 and 2012. The industry does not expect any large-scale commercial production to happen before 2030 because of the considerable technology and environmental barriers faced. Besides, the development of methane hydrates has been affected by the shale-gas revolution. The latter has resulted in new – and less concentrated – gas resources, and in lower gas prices in most regions.

Note: Picture credits: Schlumberger (2010), “Developments in Gas Hydrates”; 1. On the diagram, the methane-water combination is solid at low temperature (hatched shading). At higher temperature and lower pressure, solid hydrate dissociates into its gas and water component; 2. 1 atm = 01325 bar.
Source: Schlumberger Oilfield Review (2010), “Developments in Gas Hydrates”; Ruppel (2011), “Methane hydrates and the future of Natural gas”

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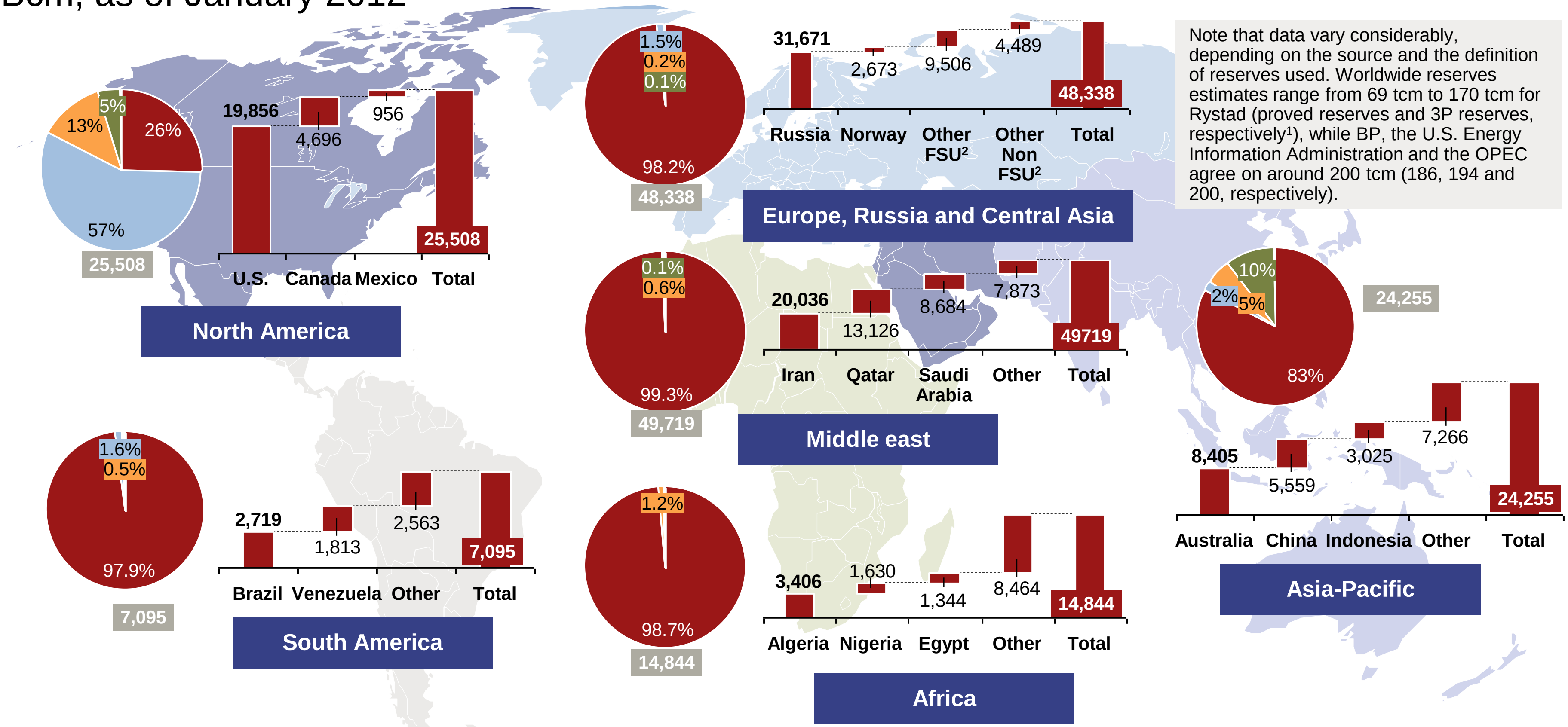
Conventional reserves in Russia and the Middle East, and unconventionals in North America make the largest contributions to natural gas reserves

Natural gas 3P reserves[1] – breakdown by type of reservoir and by region

Bcm, as of January 2012



Note that data vary considerably, depending on the source and the definition of reserves used. Worldwide reserves estimates range from 69 tcm to 170 tcm for Rystad (proved reserves and 3P reserves, respectively[1]), while BP, the U.S. Energy Information Administration and the OPEC agree on around 200 tcm (186, 194 and 200, respectively).

Legend Conventional gas · Shale gas · Tight gas · Coalbed methane

1. 3P reserves, as extracted from Rystad database (sum of P90, P50, Pmean). They correspond to the sum of proved reserves (as mentioned in slides 24 to 27), probable reserves and possible reserves, of probable reserves and possible reserves. For more information on the definition of reserves, please refer to the Society of Petroleum Engineers website; 2. FSU stands for Former Soviet Union.

Source: Rystad database Resource Based Appraisal, which includes all known resources (accessed April 2014)

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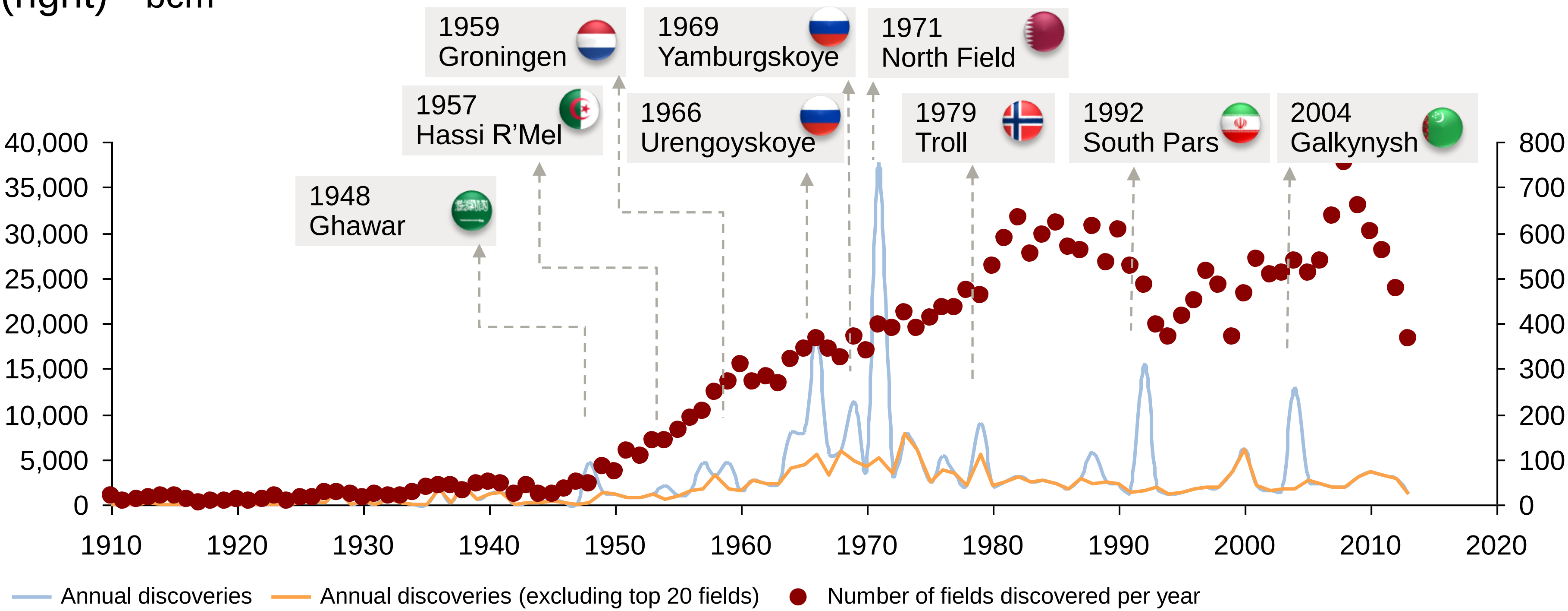
Natural gas resources are relatively concentrated geographically: 13% of discovered reservoirs account for 70% of global reserves

Volume of annual discoveries (left) **and number of discovered fields per year** (right) - bcm



- **Conventional resources of natural gas tend to be concentrated.** Giant gas fields – with recoverable totals that exceed 100 bcm – hold more than 70% of global reserves but account for just 13% of the total number of fields.

- The number of fields discovered each year increased steadily between 1950 and 1982, and has remained high ever since. But growth in the size of discoveries slowed down after 1972 as the number of giant discoveries fell.

Note: The size of discoveries is based on resources deemed recoverable in 2014, and may differ from original estimates.
Source: A.T. Kearney Energy Transition Institute analysis based on data from IHS databases (accessed April 2014)

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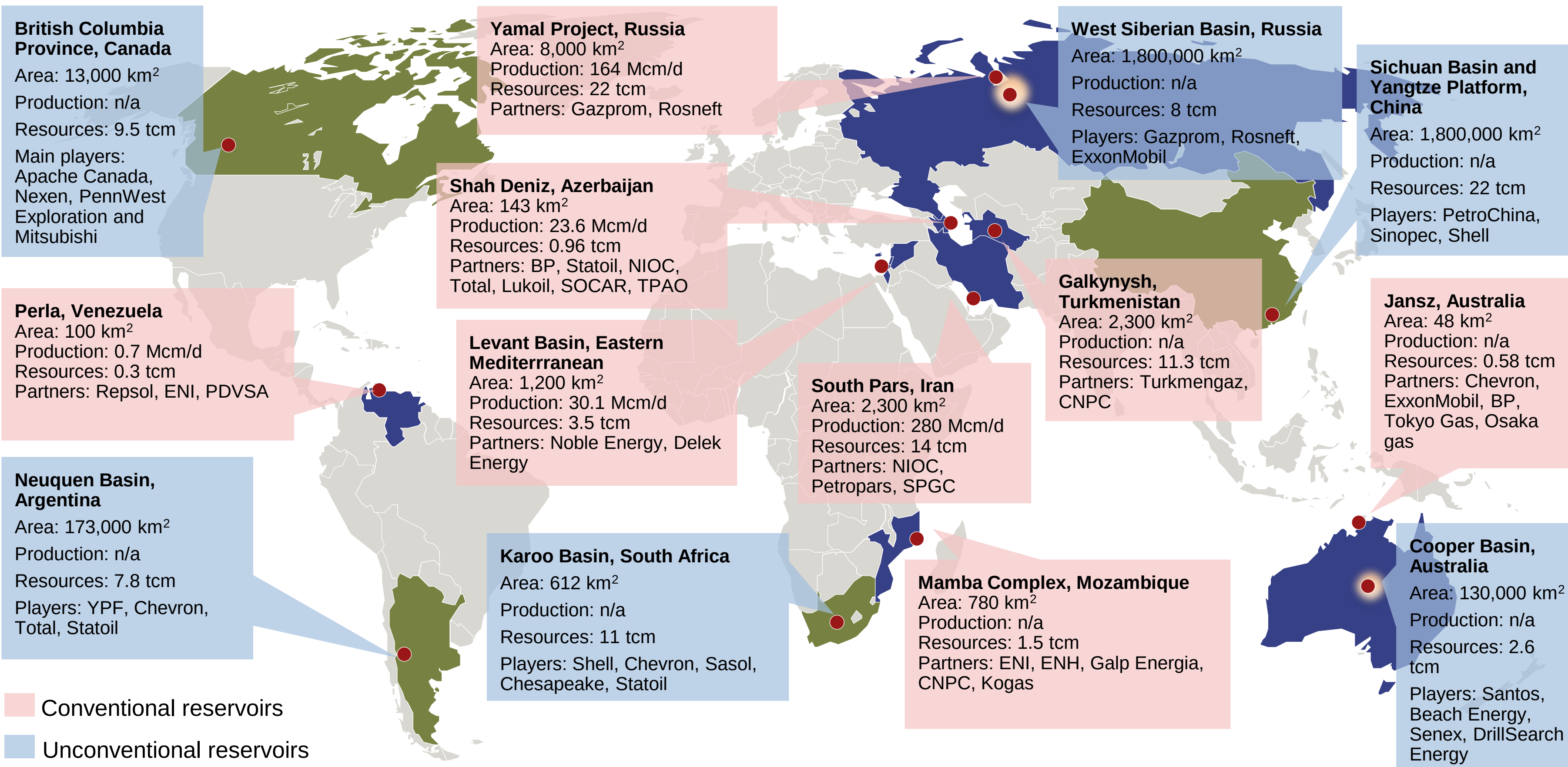
New gas frontiers, such as East Africa, the Mediterranean Sea and China, are opening up, adding to developments in incumbent producing regions

Examples of large natural gas development's projects as of April 2014[1]



1. Resources correspond to ultimately recoverable gas resources, not including condensates; Mcm/d = million cubic meters per day.

Source: Schlumberger (2013), "The Science of Shale"; IHS database (accessed April 2014); IEA (2013), "Resources-to-Reserves 2013"; EIA (2013), "Overview of oil and natural gas in the Eastern Mediterranean region"; EIA (2013), "Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States"

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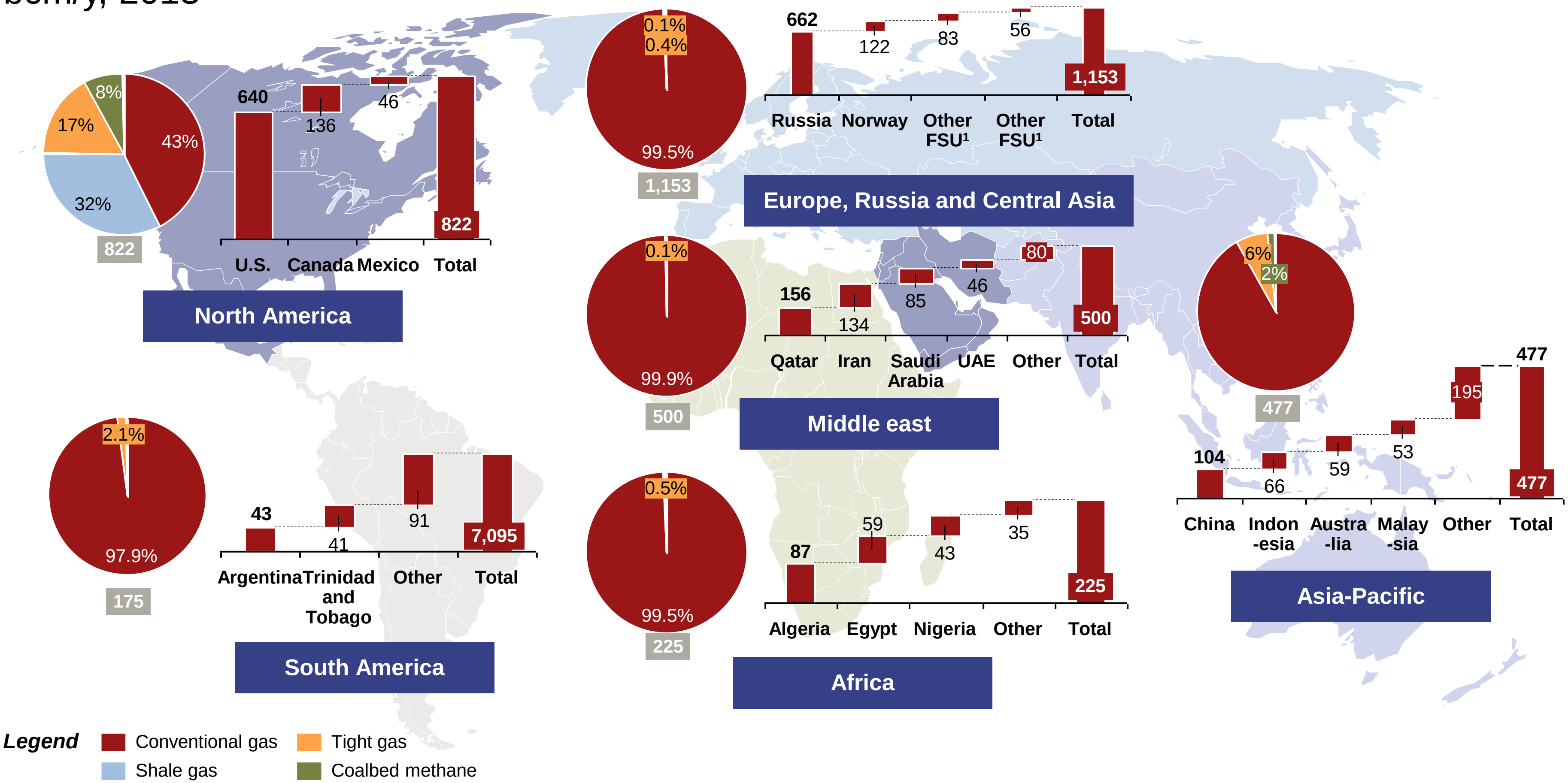
Global natural gas production reached 3.3 tcm in 2013 led by North America, Russia and the Middle-East

Natural GAS Marketed Production – Breakdown By Reservoir Type and Region

bcm/y, 2013



1. FSU stands for Former Soviet Union; 2. UAE for United Arab Emirates.
Source: Rystad database (accessed April 2014); OPEC (2014), "Annual Statistical Bulletin"

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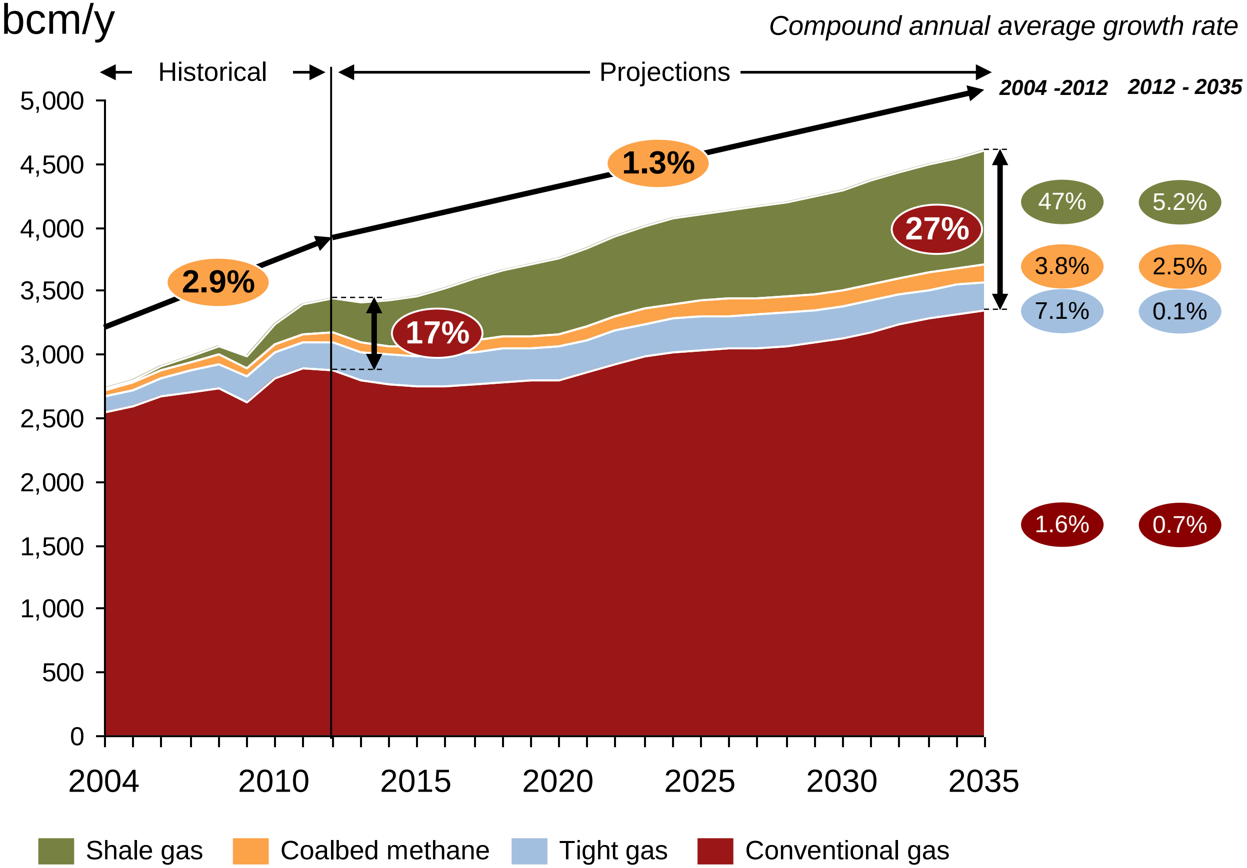
Resources in unconventional reservoirs are expected to account for an increasing share of natural gas production

Natural gas production: Historical and projections

bcm/y



- **The production of natural gas experienced strong growth from 2004 to 2012, reaching** 3.4 tcm/y. This was driven by production from unconventional reservoirs, which almost tripled over this period[1].
- **According to projections by Rystad, natural gas production is likely to continue to increase,** albeit at a slower pace, reaching 4.6 tcm/y by 2035. Shale reservoirs would make the single-largest contribution to production growth, accounting for an expected 47% of incremental natural-gas output. And, by 2035, unconventional gas production could account for 27% of the natural gas mix[2].
- **Nevertheless, forward-looking projections of this type are sensitive** to numerous parameters, such as advances in technology, global or regional economic growth, policies and incentives, and the availability of (and competitiveness of) alternative energies. For instance, one should remember that, just 10 years ago, a supply shortage was widely predicted for North America.

1. The strong growth rate in shale-gas output can be partially explained by its relatively low production base;
2. According to BP Energy Outlook, the contribution of non-shale gas discoveries to supply growth in non-OECD countries will, by 2035, rival that of shale gas.

Source: Rystad databases (accessed February 2014); IEA (2013), "World Energy Outlook 2013", BP (2014), "BP Energy Outlook 2035"

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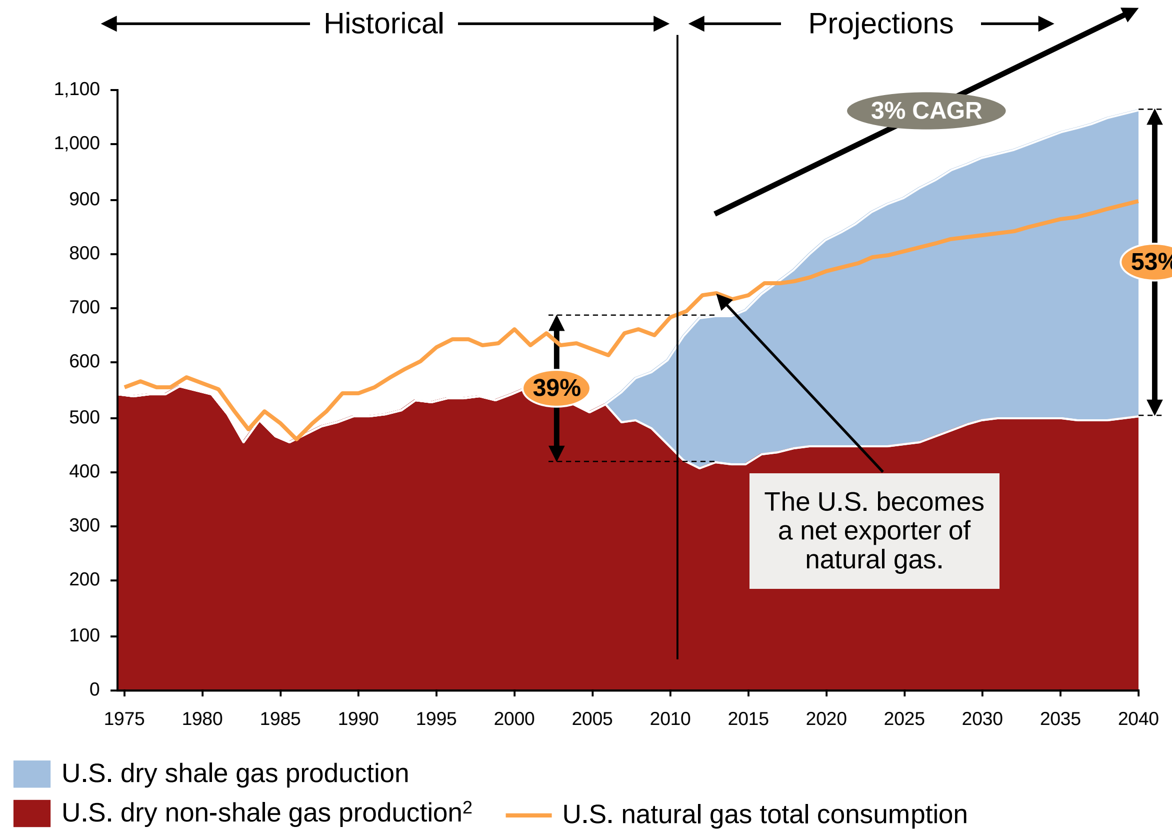
In 2013, shale gas accounted for 39% of total natural gas output in the U.S., the leading producer, with 90% of global shale-gas supply

U.S. Natural gas production and consumption (1975-2040)

bcm/year, projections by the U.S. Energy Information Agency (EIA)



- **Between 2007 and 2012, natural gas production from shale in the United States more than quadrupled[3]**. According to projections made by the EIA in 2013, shale-gas production in the U.S. could continue to increase at an average annual rate of 3% between 2012 and 2040, reaching 53% of total U.S. natural gas production in 2040. This increase would switch the U.S. from importer to net exporter of natural gas by 2017.
- **This expansion has been driven by the development of production technologies** such as hydraulic fracturing[1], **as well as by the maturing of the natural gas market, in the form of** extensive pipeline infrastructure and of a vibrant ecosystem of producers, consumers and service companies.
- **An important effect of the steep rise in U.S. production has been the fall in U.S. natural gas prices.** In July 2008, natural gas was traded on the Henry Hub at an average spot price of $12.7 /MBtu. By April 2012, it had fallen to a record low of $1.95 /MBtu in April 2012. While prices have been recovering, they were still trading at around $3.9 /MBtu in August 2014 ($4.65 /MBtu year-to-date)

1. For more information on hydraulic fracturing and drilling, refer to slide 37 & 38; 2This includes gas produced from coalbed methane, from tight gas reservoirs, and associated and non-associated conventional gas; 3As in the graph, production from tight gas reservoirs is categorized as non-shale gas production.

Source: EIA (2013), “Annual Energy Outlook 2014 Early Release”; EIA (2013), “Natural Gas Gross Withdrawals and Production”; EIA (2013), “U.S. Natural Gas Imports and Exports by State”; EIA (2013), “Natural Gas Consumption by End Use”; EIA (2013), “Natural Gas Spot and Futures Prices”

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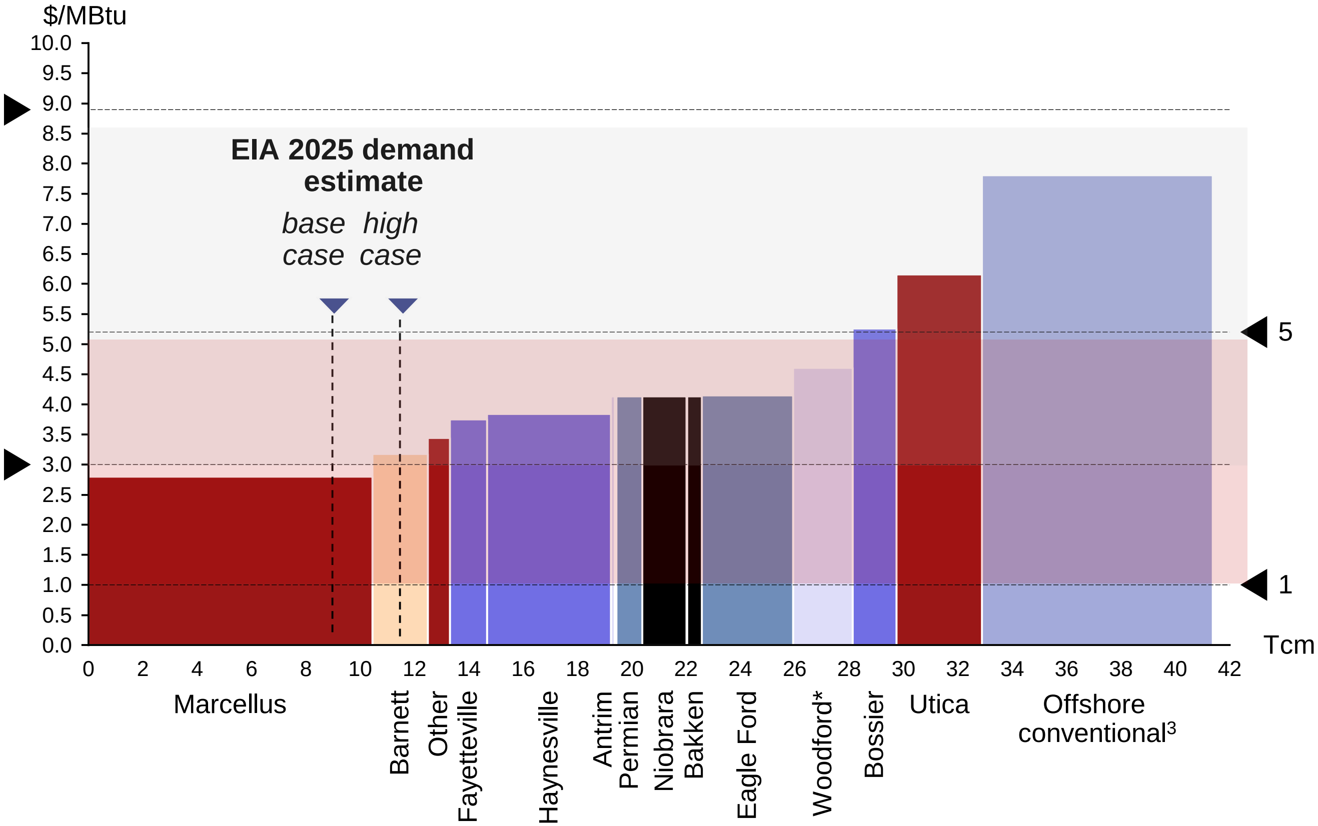
Thanks to unconventional resources, all domestic demand in the U.S. is expected to be met at low gas prices

Natural gas supply – Marginal Production cost curve *in the U.S.*

$/Mbtu



- **The natural gas production cost curves depict production costs at wellhead associated with the volume of reserves**. When compared with demand, it allows to assess the marginal cost of production of the latest cubic meter of gas needed to satisfy the demand
- **In the U.S.**, abundant unconventional resources with relatively low production costs will ensure low-cost supply, as depicted on the graph
- **On a global basis**, unconventional gas resource costs are expected to range from $3-9/MBtu. Conventional gas is expected to be, on average, cheaper to exploit ($1-5/MBtu), with the exception of complex environments, including sour gas ($3-10 /MBtu) and deep water ($5-11 /MBtu)

World range of conventional gas production costs[1] **World** range of unconventional gas production costs[2]

1. Conventional gas does not include sour gas and complex environments such as deep water, where production costs can range up to $10 /Mbtu;
2. Unconventional resources include tight, shale and coalbed reservoirs, but not methane hydrates: 3. Associated and non-associated onshore U.S. gas resources are not included in the supply curve

Source: Schlumberger Business Consulting (2013); Total (2010), “Unconventional Gas, Which Potential for Development?”.

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Upstream oil and gas consists of four major processes: exploration, field development, production and decommissioning

Upstream value chain

Rule of thumb for conventional non-associated gas reservoirs only

Phase	Description	Activities	Time	Share of costs	Oil vs. natural gas, and unconventional reservoir characteristics
Exploration	Assessment of hydrocarbon basins	Use of geophysical techniques such as seismic surveys exploratory drilling	3 to 7 years	10-15%	• There are no major differences between oil and gas in this phase. Advanced seismic technologies have played an important role in identifying unconventional reservoirs with production potential. Selective data acquisition and interpretation is essential to reduce uncertainty and identify sweet spots
Development	Engineering processes required for production	Appraisal of recoverable volume, drilling, pipe laying and well construction	2 to 5 years	40-50%	• Because complex recovery techniques are generally not required, natural gas field facilities are usually simpler than oil. However, natural gas must be piped and, unlike oil, cannot be stored in a tank at the well. Finally, unconventional production, meanwhile, requires a greater number of wells, increasing costs
Production	Operating and maintaining production facilities	Extraction, separation of the mixture of liquid hydrocarbons, gas, water, and solids	15 to 50 years	30-50%	• Unlike oil, natural gas normally flows naturally up the wellbore throughout the life of the field, allowing recovery rates of 80%. Without the need for enhanced recovery techniques, natural gas operations usually incur lower production costs. However, shale-gas fields usually experience more rapid decline rates than conventional fields and numerous wells are therefore required to maintain production
Decommis-sioning	Abandonment of the field	Sealing of wells, removing of facilities: environment returned to pre-drilling state	1 to 5 years	5-15%	• There are no significant differences between oil and gas in this phase

Source: IEA (2013), "Resources-to-Reserves 2013"

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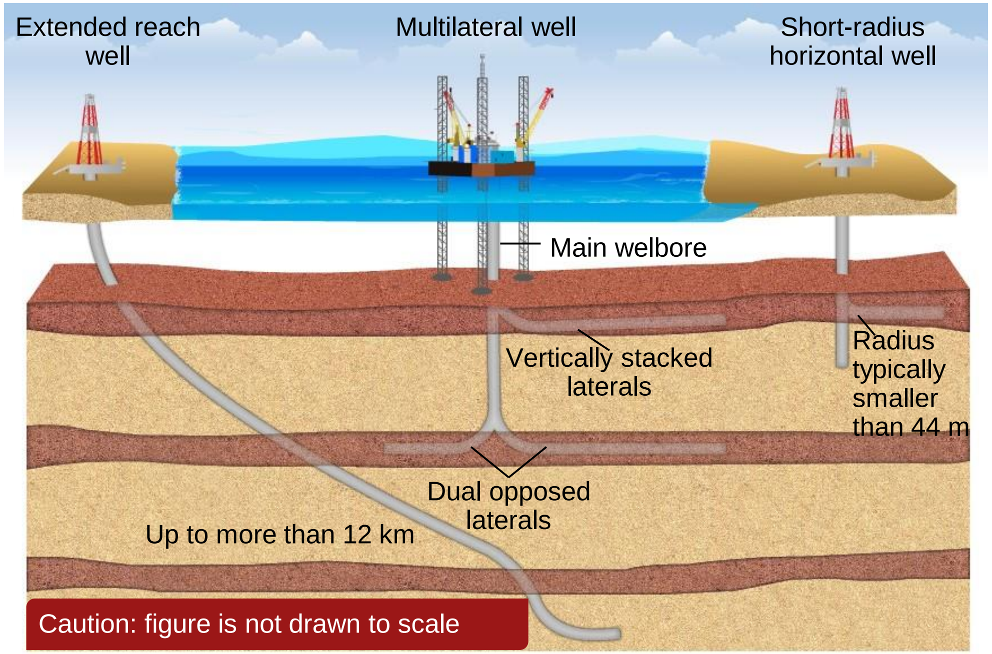
By increasing the contact area with the reservoir rock, horizontal wells are instrumental in enabling the economic exploitation of unconventional reservoirs

Schematic representation of directional drilling applications[1]



- **Due to the low permeability of unconventional reservoirs, increasing the surface area in contact with the source rock is essential.** To that end, advanced drilling technologies have been essential in unlocking resources contained in shale, tight and coalbed reservoirs
- Directional drilling involves intentionally deviating a wellbore from the path it would naturally take during the drilling process. There are three main types of directional drilling: extended-reach drilling (ERD), multilateral drilling and short-radius drilling. ERD is the term applied to a well with a horizontal length that is more than twice its vertical depth. It has been primarily developed to access offshore reservoirs from an onshore location. Multilateral drilling, in which several wells branch off from a single wellbore, significantly increases contact with the producing zone, boosting production at a limited increase in cost. Short-radius drilling produces wells with a radius of less than 44m and allows access to complex geological environments. Horizontal drilling is a subset of directional drilling and is the term used when the departure of the wellbore from the vertical exceeds 80 degrees
- In the U.S., at the end of 2012, 63% of wells drilled were classified as horizontal and another 11% were labeled directional wells. Only 26% were classified as vertical

1. Picture credits Schlumberger

Source: Schlumberger (2013), “The Science of Shale”; Schlumberger (2013), “The Art of Controlling Wellbore Trajectory”

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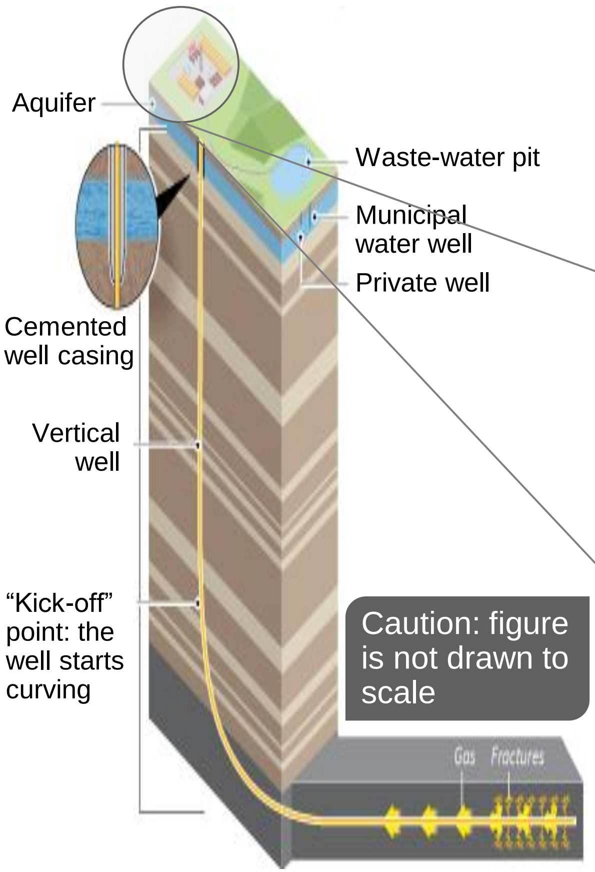
Hydraulic fracturing improves the flow of hydrocarbons by creating fractures in the formation that connect the reservoir and wellbore

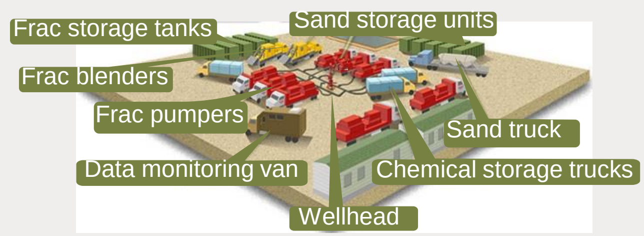
Hydraulic fracturing



Definition

- Specially engineered fluids are pumped at high pressure into the target reservoir interval, opening up vertical fractures. The wings of the fractures extend away from the horizontal wellbore in opposing directions, in accordance with the natural stresses within the formation. Proppant, such as grains of sand of a particular size, is mixed with the treatment fluid so that the fracture remains open when the flow of fluid stops. Hydraulic fracturing creates high-conductivity communication with a large area of formation and bypasses any damage that may exist in the near-wellbore area

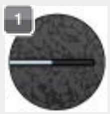
Common Fracturing equipment



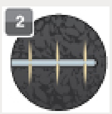
Main risks & mitigation actions

- In the absence of "green completion", which captures methane from flowback, hydraulic fracturing may entail methane venting. In addition, it is essential to carefully design and control fracture propagation to ensure that the hydraulic fracture stays within the reservoir and does not stray into adjacent formations. Also, it is crucial to direct fractures into preferred zones in order to mitigate the risk of the fragmentation of the rock causing tiny seismic emissions. Finally, careful water management is crucial in water-stressed areas to mitigate the impact of water use

Fracturing process



Production casing is inserted into a horizontal well and surrounded with cement



A perforating gun blasts holes in the casing, cement and shale

Water, sand and chemicals are pumped through the holes in the casing under high pressure, creating cracks in the rock

Natural gas is able to flow through the numerous small resulting fissures

1. Values vary according to the type of formation

Source: Kogdenko (2012), "Shale Gas: the technology behind the revolution"; IEA (2012) "Golden Rules for a Golden Age of Gas"; MIT(2011), "The Future of Natural Gas"

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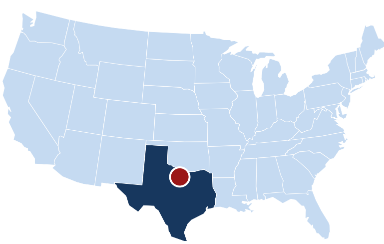
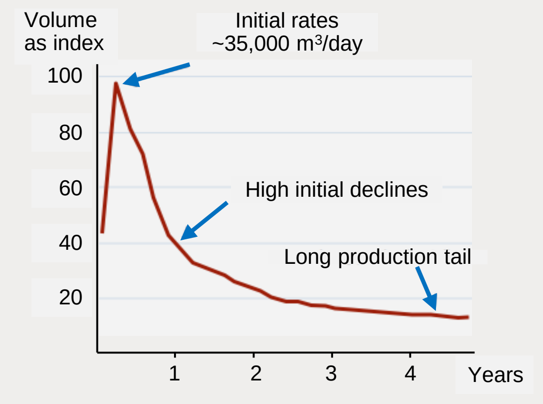
Natural gas production profiles vary significantly, according to the type of reservoir

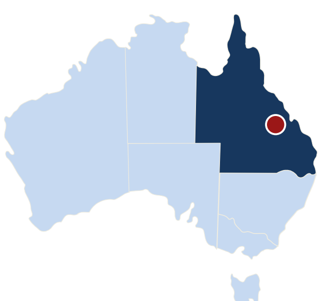
Typical production profiles of Unconvetional natural gas formations

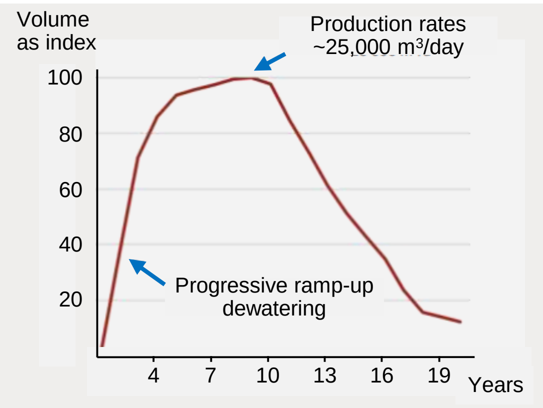
Shale gas well - Barnett, U.S.





Coalbed methane well - Bowen basin, Australia





- **Natural gas production profiles in conventional formations vary significantly, according to field size, location and management**. Larger fields are generally characterized by longer production plateaus than smaller fields. Offshore reserves are recovered more quickly than onshore ones: offshore production increases more rapidly and settles at a higher plateau. One-third of reserves are generally produced during the plateau
- **Due to the properties of the source rock, shale-gas wells usually exhibit early production peaks and then enter rapid decline** – typically 50% over 3 years. In addition, shale-gas plays generally have lower concentrations of recoverable resources – typically around 0.04-0.6 bcm/km^2, compared with an average of 2 bcm/km^2 in the case of conventional resources. Consequently, shale-gas production requires more wells
- **The ramp-up of CBM production is slower than the ramp-up of conventional and shale-gas production**. This is because of the large quantity of water, naturally occurring or introduced during fracking, that must be extracted in order to reduce pressure within the formation sufficiently to allow gas to flow to the wellbore. Natural gas production then increases as the volume of water produced decreases

Source: IEA (2009), "World Energy Outlook 2009"; IEA (2013), "Resources-to-Reserve 2013"; Total (2010), "Unconventional Gas, Which Potential for Development?"

3. Midstream

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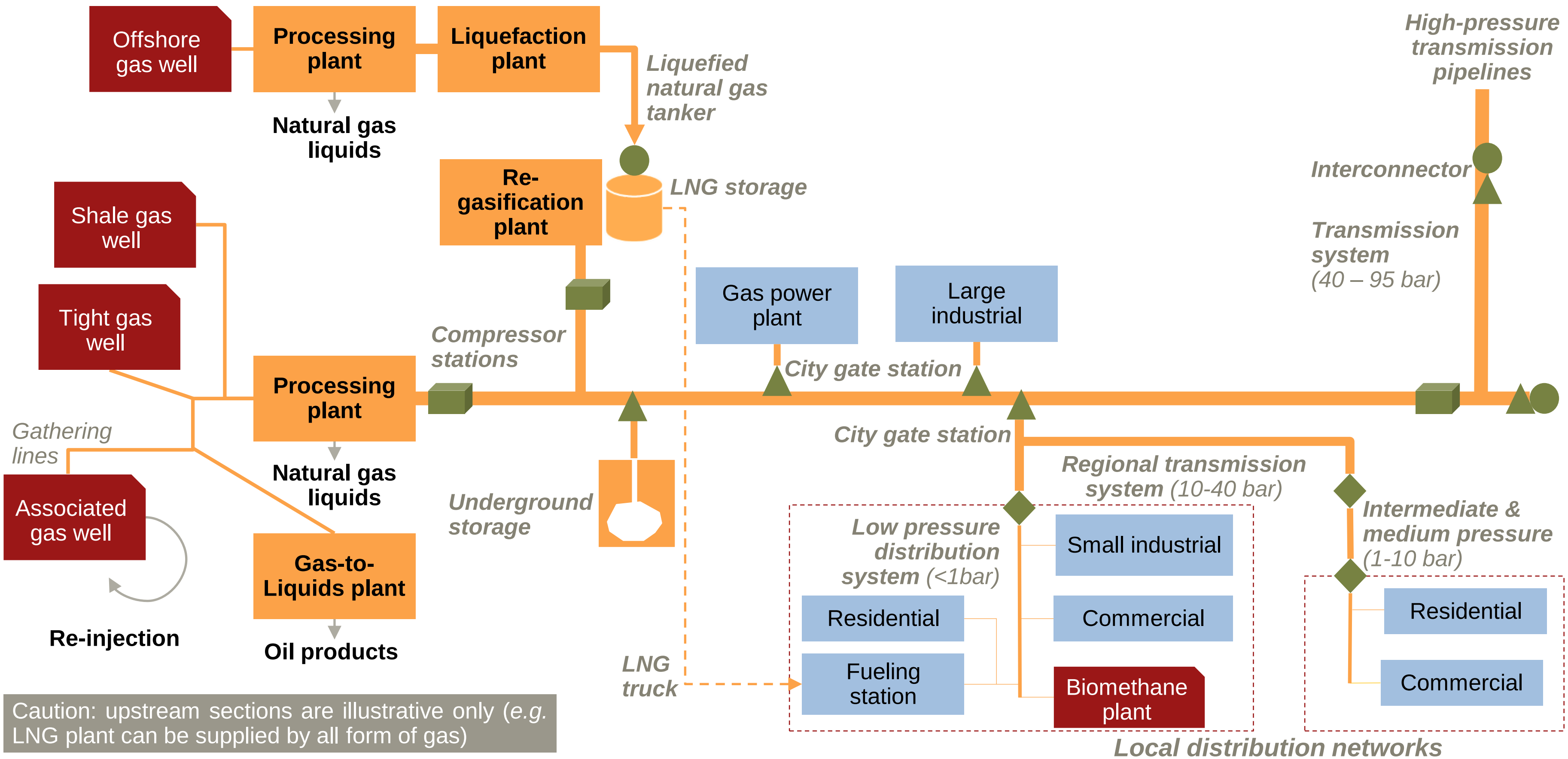
Complex infrastructure is needed to get natural gas to end-users – processing plants, transport & distribution grids, and storage units

Schematic of natural-gas infrastructure



Caution: upstream sections are illustrative only (*e.g.* LNG plant can be supplied by all form of gas)

1. LNG for Liquefied Natural Gas, NGL for Natural Gas Liquids, i.e. heavy hydrocarbon fractions.
Source: A.T. Kearney Energy Transition Institute analysis

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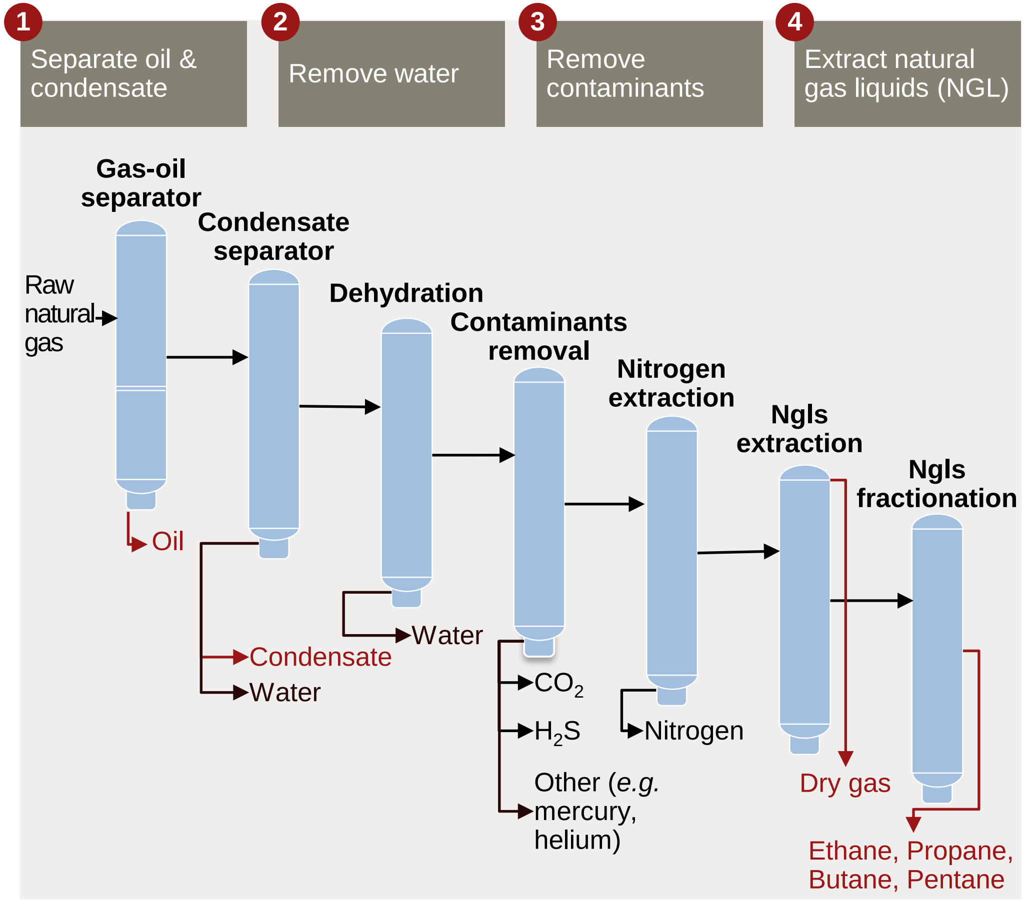
Processing is an essential step in turning raw natural gas into a commercial product and extracting natural gas liquids (NGLs)

Schematic steps for natural gas processing[1]



- **Natural gas collected at the wellhead must usually be processed to meet the pipeline-quality standards** defined by each system (energy content, water content…) and to **ensure safe and clean operation, both** of the grid and of end-appliances. The type of gas processing required depends on the composition of the raw gas and on the pipeline system's quality specifications. Although it is less complex than crude-oil refining, natural-gas processing is a crucial stage in the natural gas value chain.
- In addition to its primary purpose, cleaning, **processing also performs the vital role of extracting the heavier hydrocarbons** that raw natural gas contains, to varying degrees (these hydrocarbons are gaseous at underground pressure, but liquefy under ambient conditions into natural gas liquids2).
- **The processing layout can be configured in numerous ways.** It can be sited, entirely or partially, at the field or at a compressor station close to the producing area. Processing facilities may be split up along these locations or grouped together in a dedicated processing plant.

1. The figure depicts the main steps, but not the complexity of the engineering layout. Several steps may be optional, depending on the streams. Scrubbers and heaters may be added close to the wellhead
2. Natural gas liquids (NGL) are also known as condensates; for more information please refer to page 14.

Source: A.T. Kearney Energy Transition Institute analysis; EIA (2006), "Natural gas processing: the crucial link between natural gas production and its transportation to market"

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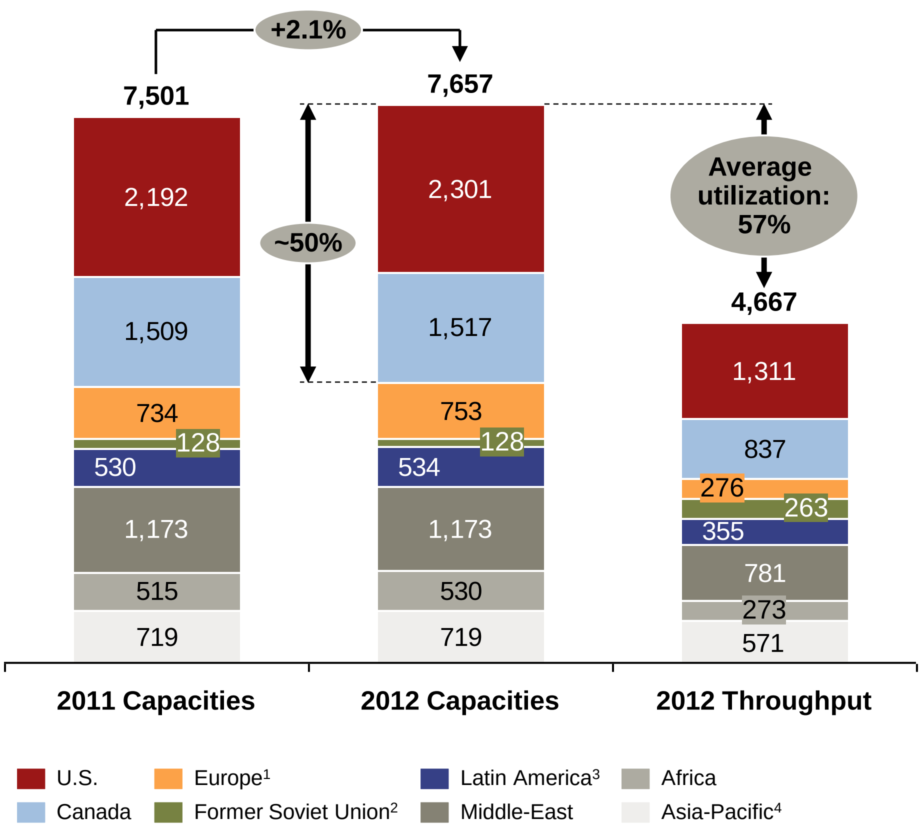
More than half of the world's natural gas-processing capacity is located in North America, but Asia and the Middle East are expected to take over as market drivers

Worldwide gas processing plants - mcm/d, capacities and gas throughput



- **As of 2013, there were 1,954 gas-processing plants operating in the world, with a global capacity of 7,657 mcm/d. In 2012**, these plants operated at an average utilization rate of 57%, processing a throughput of natural gas of 4.432 mcm/d.
- Gas-processing plants are located all over the world, since they are usually sited close to production centers. However, it is worth noting that, as of 2013, **50% of processing capacity was concentrated in North America[5],** which accounts for only 24.9% of world production. Iran, Algeria and Indonesia have processing capacities that correspond to their respective shares of production.
- **The growth of North America's shale-gas industry has been a major driver of the development of natural-gas processing capacity.** This is expected to remain an important driver of growth in processing capacity in the short term because of the prevalence of wet gas. **Going forward, the Middle East and Asia-Pacific may supersede North America as market drivers.** In those regions, utilization rates are much higher – 66.5% and 79.5% respectively – and new plants will be needed to meet expected growth in natural-gas production.

1. Include the European Union, Serbia, Montenegro and Turkey, 2. Include plants in Russia, the Ukraine, Uzbekistan and Turkmenistan, 3. Include Mexico, 4. Include all non former soviet union countries in Asia, 5. North America has a very high number of small- to mid-scale plants, whereas outside North America, most plants are large.

Source: Oil & Gas Journal (2013), "Worldwide Gas Processing Survey 2013"; Oil & Gas Journal (2013), "Rapid North American shale gas development pushes up global capacities"

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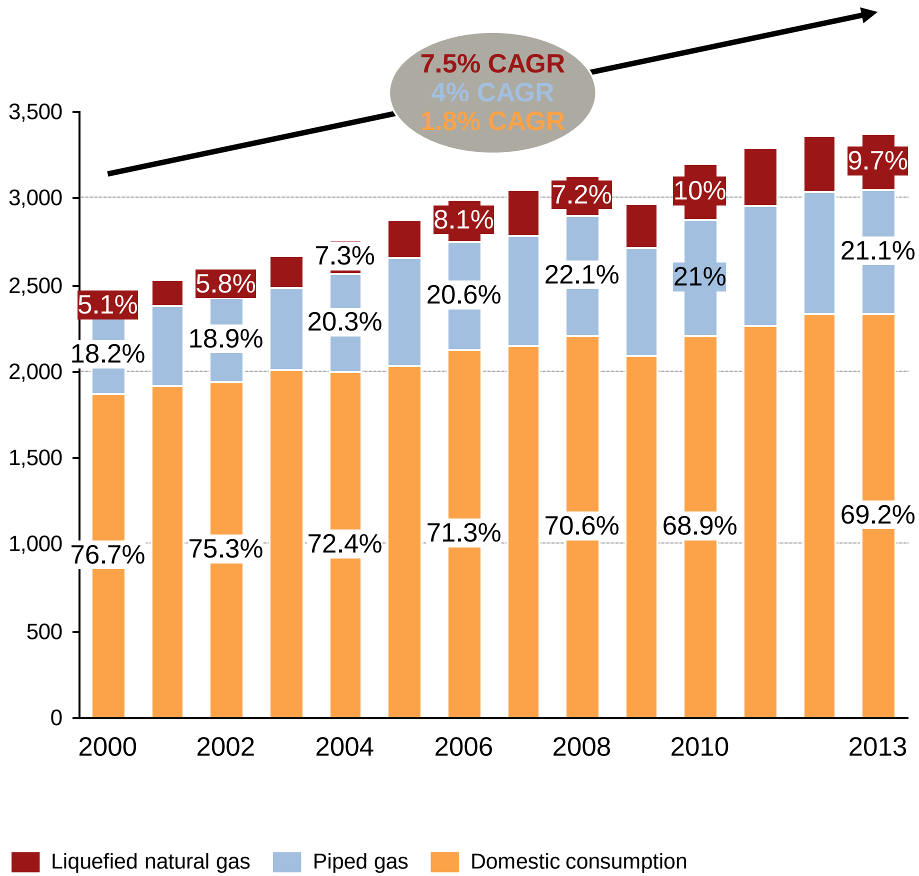
Long-distance transport technologies have played an important role in developing natural gas trade

Global gas trade volume - bcm/y



- **The low energy density of natural gas has long been an impediment to its transportation.** Without economic ways of sending it to end-consumers, natural gas produced with oil was usually flared or vented into the atmosphere.
- Technical advances, notably in pipeline materials and in super-cooling technologies used for liquefying gas, made **long-distance gas transport a possibility as early as the 1950s. The long-distance natural gas business expanded rapidly in the 1970s and 1980s.**
- **As of 2013, around 30% of natural gas was traded internationally,** mainly through pipelines (21% of all produced gas), although liquefied natural gas (LNG) is making an important and growing contribution. Trade in LNG has grown twice as fast as pipeline trade since 2000 and now represents around 10% of all gas trade.
- **Innovation continues to shape the transportation landscape.** R,D&D is focused on developing more options for transportation and on monetizing stranded natural gas resources. The main areas being researched are: floating regasification and liquefaction plants, small-scale LNG concepts, compressed natural gas (CNG), and gas-to-liquids (GTL)

1. CAGR for compound annual average growth rate

Source: BP (2013), “BP Statistical World Energy Review 2013”; IGU (2013), “World LNG Report – 2014 Edition”; GE (2013), “The Age of Gas & the Power of Networks”

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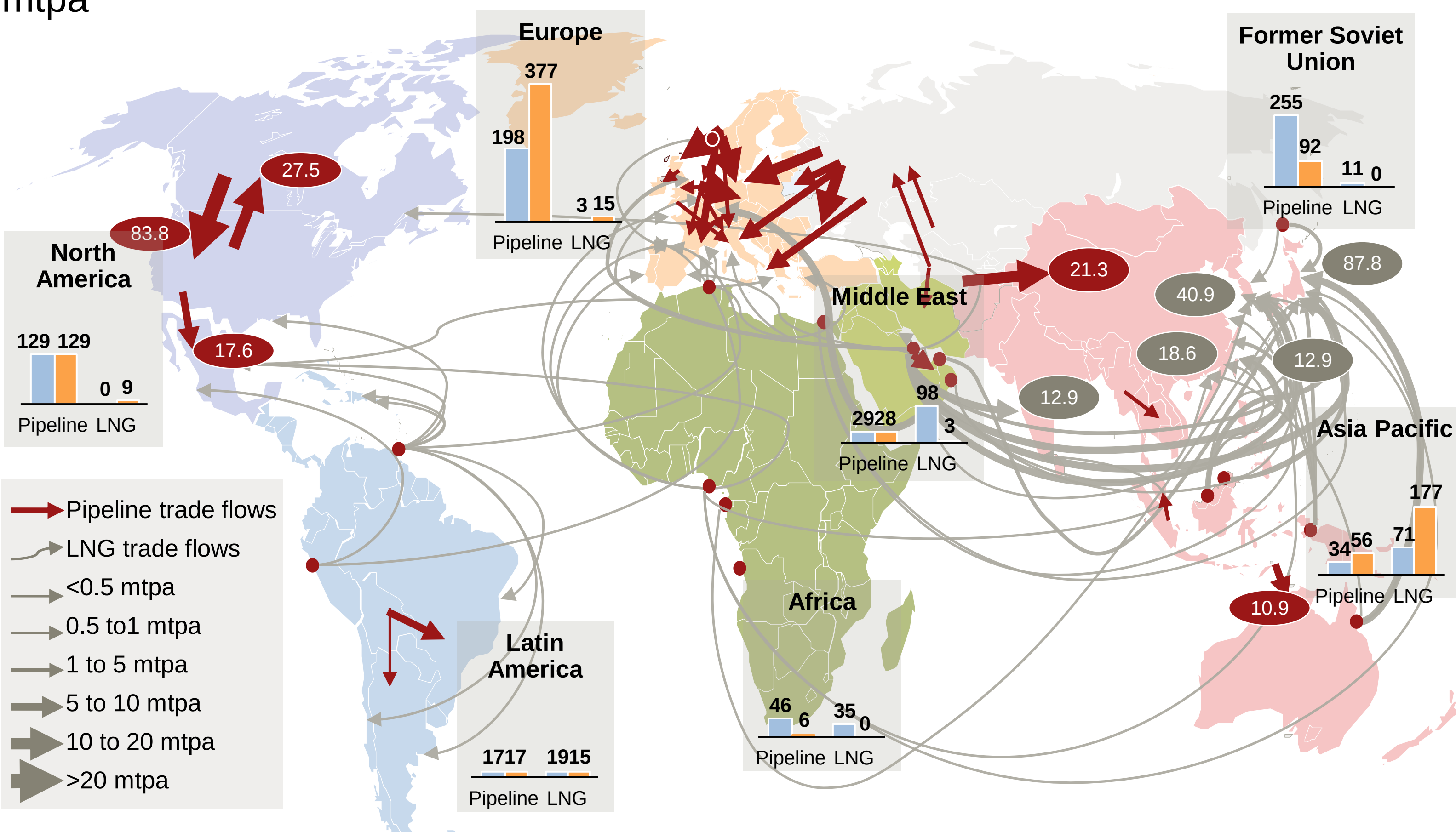
Despite the emergence of significant global LNG flows, gas trade remains dominated by regional pipeline trade

Major trade movements by pipeline (2012) and LNG (2013)

mtpa



How to read the bar charts

The bar charts depict cumulative trade movements in each region. In Africa, for instance, LNG exports in 2013 amounted to 35 mtpa and imports were zero; pipeline exports in 2012 amounted to 46 mtpa and pipeline imports 6 mtpa. The figures include intra-regional trade (e.g. 129 mtpa of piped gas were exported and imported within North America).

1. Trade movements below 0.5 mtpa for LNG and 5 mtpa for pipelines have been ignored. This explains, for instance, the absence of trade flows from Angola. The pipeline and LNG flows depicted are not accurate geographical representations of trade routes.

Source: Adjusted from IGU (2014), "World LNG Report – 2014 Edition" for LNG and BP (2013), "BP Statistical World Energy Review 2013" for pipeline

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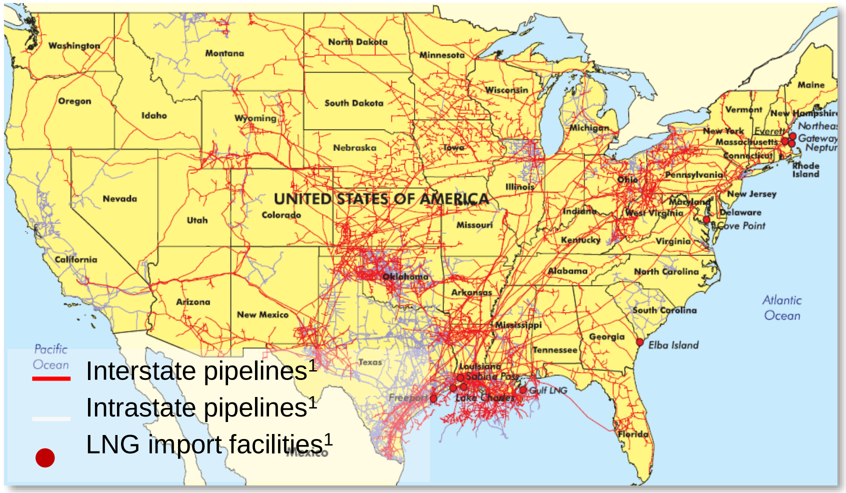
Pipelines are the backbone of gas transportation, with a global network of 1.4 million kilometers

Natural gas transport system in the U.S.



*Mallnow **compression station**[2] in Germany - an entry point for Russian gas.*

- Globally, more than 89% of natural gas is transported along a 1.4 million km pipeline grid. **One-third of this network is the transmission network,** i.e. lines transporting large volumes of gas through high-pressure, large-diameter (6''-48'') pipelines. The other two-thirds comprise thinner pipelines at production sites, called gathering lines, and the medium- and low-pressure distribution grids that supply end-customers.
- **Pressure is required to maintain the gas flow. As a result, compression stations are located every 80-160 kilometers** along the transport grid. Each station contains one or several compressor units (up to 16). These are classified by their horsepower (up to 50,000-80,000) and gas capacity (up to 90 Mcm/d)3. Compressors can use a motor (reciprocating) or a turbine (known as centrifugal)4. Gas-filtering, but also cooling and heating facilities are often included in the station to maintain gas temperature.
- **Gas transport pipelines are usually made of carbon steel and protected against corrosion** by external coating and cathodic protection systems. Most pipelines are buried, and a long period of preparation is needed prior to construction, including permitting and regulation processes.
- In addition to pipelines and compression stations, **transport grids have metering stations** to measure the gas flow, a **large number of valves** to stop the flow when needed, and **control and monitoring equipment** (e.g. smart inspection tools) to ensure safe operations and comply with stringent regulations. Partly as a result of current experiences in Europe, reverse flow is increasingly considered essential in ensuring security of supply.

1. Map from 2008; 2Picture credits: WinGas; 3Most compressor stations have horsepower below 20,000 HP and a capacity below 20,000 Mcm/d; 4Most compressors operate on natural gas. However, electricity-driven turbines are becoming more popular for environmental reasons.

Source:IEA (2013), "Natural Gas Information 2013"; INGAA (2014), "North American Midstream Infrastructure through 2035"

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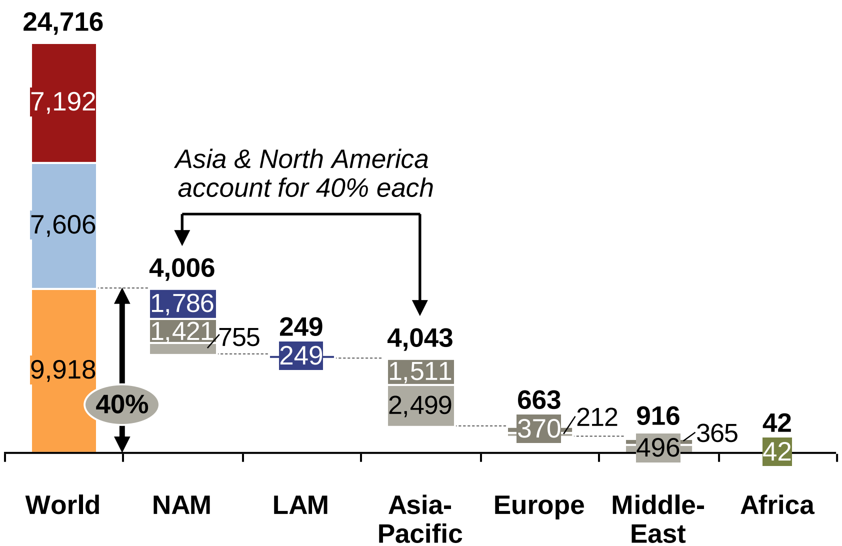
Natural gas pipelines account for the majority of pipelines planned and under construction, driven by intense activity in Asia

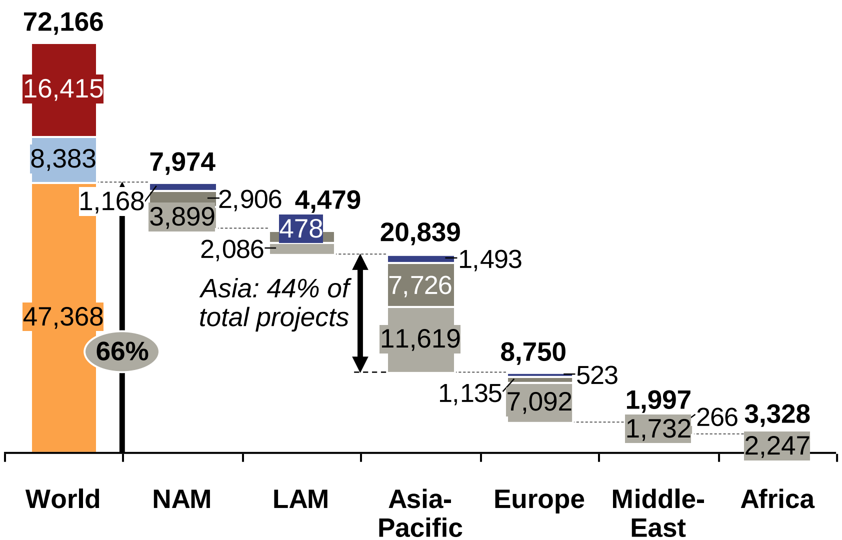
Natural gas transport system in the U.S.

Kilometers, split by diameter size in inches



Pipelines construction beyond 2013[2]

Kilometers, split by diameter size in inches



- Projects beyond 2013 include three major pipelines in **China** (Central Asia Gas Pipeline, the 7,378 km West-East Gas Pipeline, and a pipeline to Myanmar), as well as several big projects in **Europe**. These include the 900 km South Stream pipeline from Russia to Italy, under the Black Sea, and the Galsi pipeline, from Algeria to Italy. In **North America**, TransCanada Alaska will connect Alaska to Alberta and the U.S., while an 804 km pipeline is planned from Arizona to the northwest of Mexico. In **Latin America**, 1,448 km Gasoduco del Nordeste will supply Argentina from Bolivia. In **Africa**, a memorandum of agreement has been signed between Angola and Zambia for a 1,400 km pipeline. Several other major projects remain under consideration (*e.g.* the 1,850 km Iran to Pakistan pipeline or a 270 km pipeline from Iran to Iraq), but, as yet, no final investment decision has been taken.

Crude pipelines | Product[3] pipelines | Gas pipelines | 4''-10'' | 12''-20'' | 22''-30'' | >30''

1. Project planned to be completed in 2013, 2 Projects under way at the start of or set to begin in 2013 and to be completed after 2013. Includes some probable major projects whose installation will begin in 2013 or later,3 Products for refined petroleum products, such as diesel, gasoline, jet fuel…

Source: Oil & Gas Journal (2013), "Worldwide Pipeline Construction"

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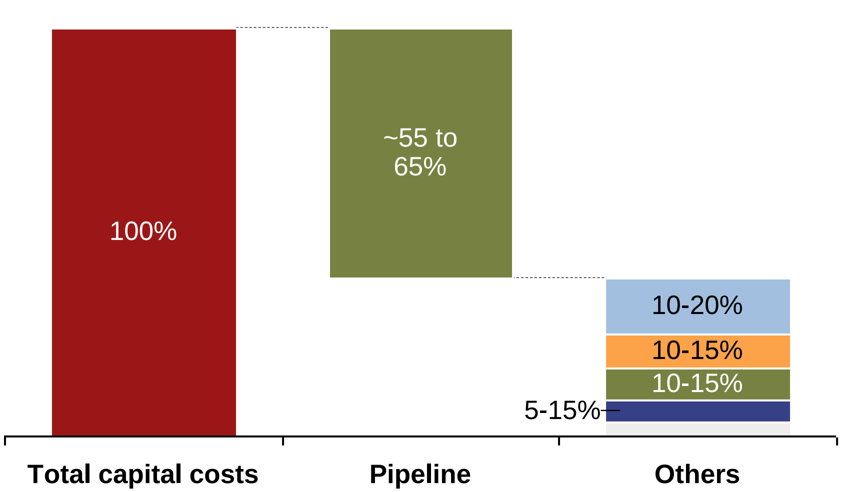
Pipeline costs vary significantly according to capacity, length and their physical environment, but are dominated by the costs of labor and materials

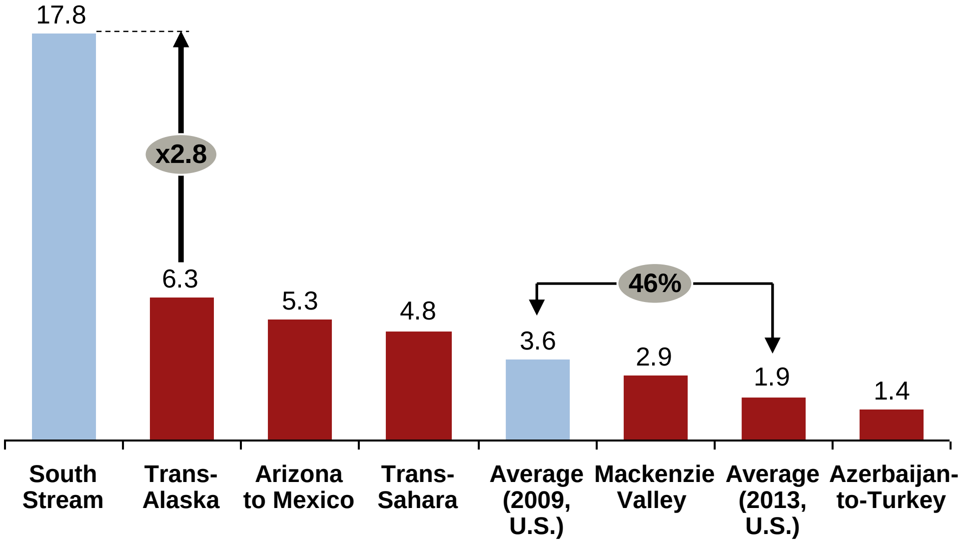
Pipeline projects: cost breakdown
%



- Although non-pipeline-related costs are important, **pipeline costs are the main drivers of pipeline project economics**. They include two main items: labor costs and materials. The latter is the most important component, and is usually higher for large-diameter and long-distance pipelines.

Construction[1] | Compression sations | Other[2] | Permits & environmental | Right of way

Gas Pipeline Projects: Estimated COST range[3]
$ million/km, 2013



- **Pipeline costs vary significantly** according to pipeline diameter, length, operating pressure and location. All things being equal and despite greater cost reductions in offshore pipelines in recent years, offshore pipelines remain more expensive than onshore pipelines.

Onshore | Offshore

1. Includes engineering and construction management, 2 Includes meter stations, valves, telecommunications, and contingency, 3 Figures are based on construction costs released by industry sources for planned projects, except the “average” for ongoing construction costs in the U.S.

Source: Oil & Gas Journal (2013), “Worldwide Pipeline Construction”; Shashi Menon (2005), “Gas Pipeline Hydraulics”

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Natural gas liquefies when it is cooled to -162°C. As a liquid, its energy density increases significantly, making it suitable for long-distance transport

The Liquefied natural gas (lng) value chain

1 Purification & liquefaction

- Before liquefaction, natural gas must be cleaned to remove contaminants, which might freeze during liquefaction or corrode pipelines. Heavier hydrocarbons are also extracted to meet gas specifications[1].
- Once purified, gas undergoes liquefaction. The main objective is to minimize the temperature difference between natural gas being cooled and the refrigerant. This is achieved thanks to multi-stage processes or refrigerant tailoring. Two main technologies can be used: mixed refrigerant, such as Air Products' C3-MR process – the most widespread option, with an 80% market share; and ConocoPhillips' pure-component cascade process[2].
- Although liquefaction is the heart of the process, compression and heat-exchanger technologies are also crucial for maximizing LNG-plant efficiency.
- Typically, LNG plants are made up of multiple processing lines, known as trains, which makes both maintenance and plant expansions easier. LNG output is stored in insulated tanks until a vessel arrives for loading.

2 Shipping

- Vessel design is dictated largely by the high energy density and extremely low temperature of LNG. LNG carriers must be double-hulled, with water ballast. On-board storage tanks require special alloys to ensure effective insulation.
- Two types of vessels dominate the market, categorized by their containment techniques: Moss-type and membrane-type. The former (picture above) uses spherical, aluminum tanks that are independent of the ship's hull. The latter uses a thin metal membrane for containment that is supported by the ship's hull. Membrane-type is now preferred (accounting for 73% of the fleet at the end of 2013). Non-conventional vessels, such as Q-Flex and Q-Max types, have the largest capacities.
- In addition to containment, vessel propulsion is one of the industry's main areas of focus, particularly the use of boil-off gas[3].

3 Storage & Regasification

- The final step in the LNG chain of activities is the import terminal, onshore or offshore, at which LNG is off-loaded from carriers and pumped into insulated storage tanks onshore. When gas is required, LNG is pumped into a vaporizer for regasification, and is then injected into the gas-transmission network.
- Storage tanks can be configured as single, double or full containment. They are extremely well insulated by carbon-steel outer shells and nickel-steel alloy inner walls. Nonetheless, boil-off always occurs. Boil-off[3] gas can either be reliquefied, or, as is usually the case, sent to the distribution gas system.

1. The processing steps described in slide 44 are therefore mostly integrated into LNG plants, 2 Note that alternative technologies are available, such as Shell's dual-mixed refrigerant process, 3 Despite the insulation, sufficient heat is conducted through the insulated tank walls to cause slight boiling of the LNG. This small amount of gas is called boil-off gas.

Source: Schlumberger (2008), "Moving Natural Gas Across Oceans"; IGU (2014), "World LNG Report – 2014 Edition"

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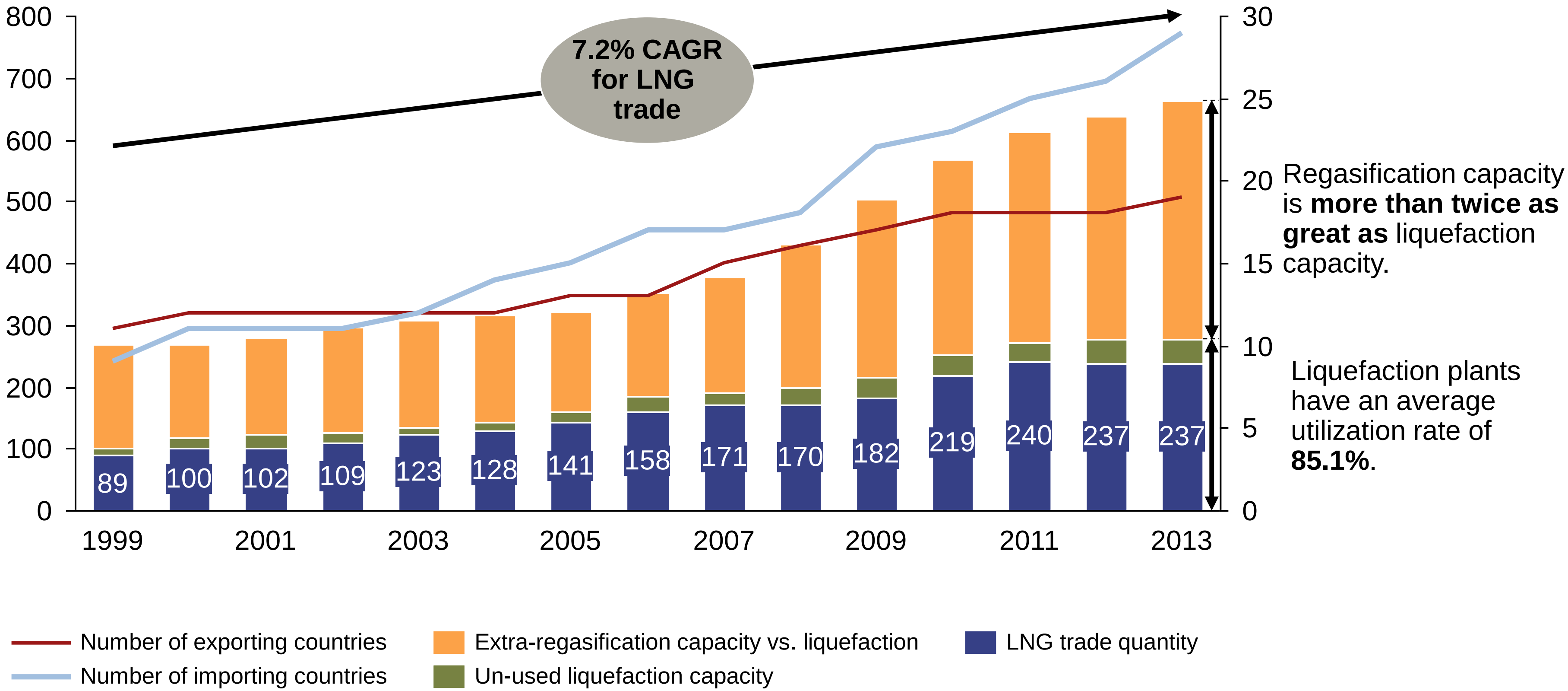
Thanks to expanding infrastructure, LNG trade has grown rapidly, despite year on year variations

LNG trade: quantity, capacity and number of countries[1]

Million tons per annum (mtpa)



1. The number of countries includes all countries with liquefaction or regasification capacity, even those with plants that have been temporarily shut down, such as the U.S. and Libya, in 2013. Data have been compiled from the IGU, GIINGL and IHS. Inconsistencies between liquefaction and regasification capacity may be apparent, depending on how shut-downs are taken into account, but discrepancies are negligible.

Source: IGU (2014), "World LNG Report" - 2010 to 2013 editions; GIINGL (2014), "The LNG Industry" – 2006 to 2013 edition; IHS database (accessed April 2014)

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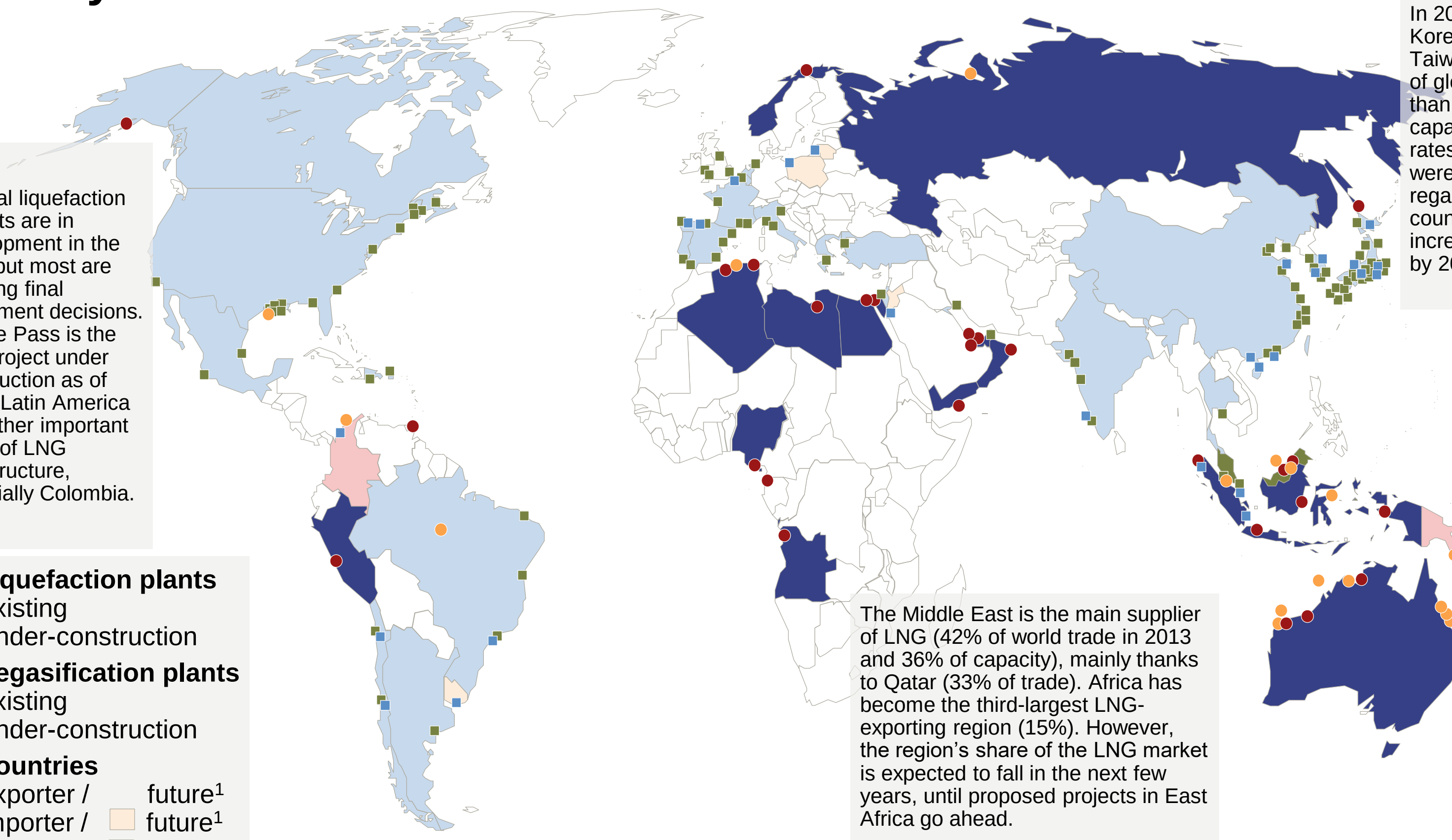
Liquefied natural gas infrastructure is now widespread internationally

Existing and under-construction liquefaction & regasification plants as of January 2014



Several liquefaction projects are in development in the U.S., but most are awaiting final investment decisions. Sabine Pass is the only project under construction as of 2014. Latin America is another important driver of LNG infrastructure, especially Colombia.

In 2013, Japan (37%), South Korea (17%), China (8%) and Taiwan (5%) accounted for 68% of global LNG imports, but less than 50% of regasification capacity. As a result, utilization rates in these four countries were very high. In addition, regasification capacity in these countries is expected to increase from 309 to 399 mtpa by 2020[2].

The Middle East is the main supplier of LNG (42% of world trade in 2013 and 36% of capacity), mainly thanks to Qatar (33% of trade). Africa has become the third-largest LNG-exporting region (15%). However, the region's share of the LNG market is expected to fall in the next few years, until proposed projects in East Africa go ahead.

Australia is the third-largest LNG exporter (22.2 mtpa, or 10% of world exports) after Qatar (77.2 mtpa) and Malaysia (24.7 mtpa) but ahead of Indonesia (17 mtpa). However, Australia, where 53% (63.8 mtpa) of the liquefaction capacity under construction worldwide is located, is expected to take over Qatar as the largest LNG exporter by 2020.

Liquefaction plants
- Existing
- Under-construction

Regasification plants
- Existing
- Under-construction

Countries
- Exporter / future[1]
- Importer / future[1]

1. Indonesia, the United Arab Emirates and Malaysia are net-exporting countries, but have import facilities. The US's Kenai liquefaction plant, in Alaska, has been temporarily shut down,
2. Based on projects under construction, announced or proposed as of Nov 2013; [2]mtpa for million tons per annum.

Source: IGU (2014), "World LNG Report – 2014 Edition"; GIINGL (2014), "The LNG Industry"

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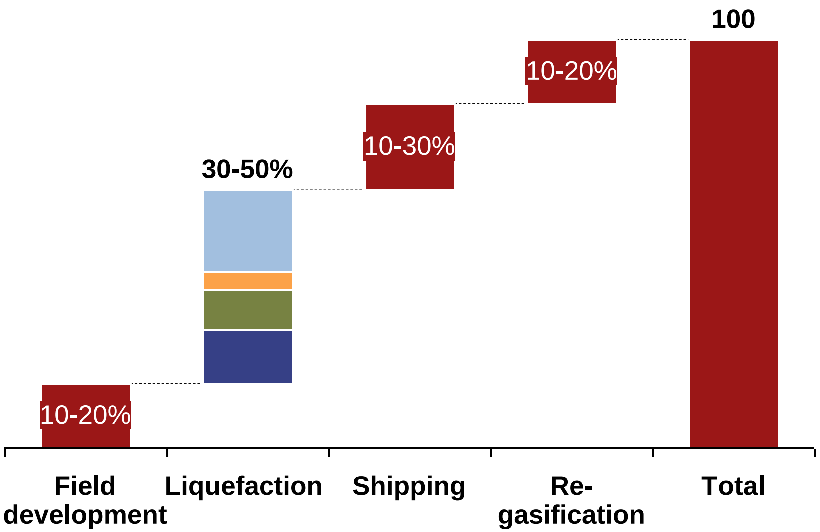
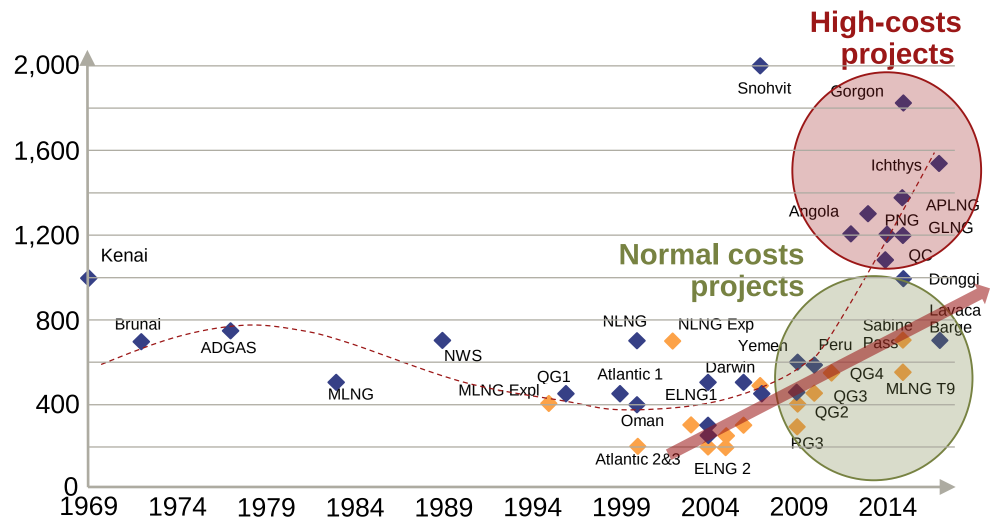
Liquefaction costs, which account for the bulk of total LNG costs, have escalated since 2004

Cost breakdown of LNG value chain
Indexed



Liquefaction plant metric costs
$/tons per annum



- Cost breakdowns are highly specific to site conditions and design practices. Liquefaction accounts for the highest portion of costs. Half of liquefaction costs, however, are not directly related to liquefaction, making a strong case for multiple train designs that can share indirect costs.
- Shipping costs vary significantly, depending on distance, ship size and year of construction. Re-gasification is usually the smallest element of overall costs.

- Spending on liquefaction plants fell from ~800$/tpa in the 1970s to $400/tpa in the early 2000s, mainly as a result of economies of scale. Since then, it has increased significantly.
- However, interpretations of this increase must distinguish between high-cost projects, mainly in Australia and Papua New Guinea, characterized by complex designs, remote locations, high local construction costs and adverse exchange-rate effects; and "normal" projects, whose cost curves follow trends similar to those experienced in other areas of the oil & gas industry.

Liquefaction[1] Gas treatment[2] Utilities Offsites[3]

◆ Complete facility ◆ Additional train ➨ Cost trend for additional train -- Cost curve CAPEX

1. Includes refrigeration (14%) and liquefaction (28%), 2 Includes fractionation (3%) and gas clean-up (7%), 3 Includes site preparation, flare, storage and jetty.
Source: Songhurst (2014), "LNG Plant Cost Escalation"; JRC (2009), "Liquefied Natural Gas for Europe – Some Import Issues for Consideration"

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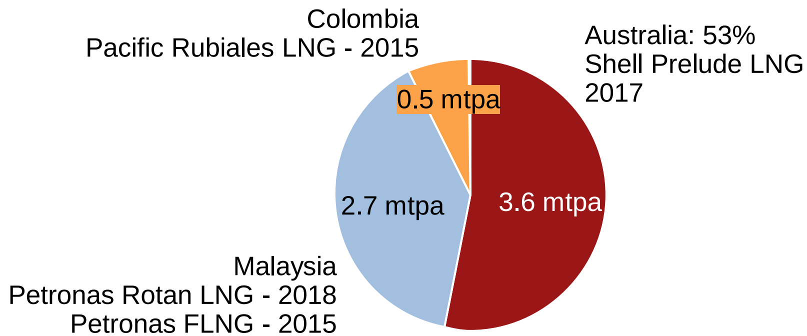
Floating liquefaction and regasification concepts can reduce development time, increase flexibility and, ultimately, lower capital costs

Floating LNG concept & projects

View of Shell Prelude LNG project[1]



- **Floating concepts were first developed for oil and gas production, but are increasingly being considered for transportation**. In the LNG value chain, they were originally deployed as import terminals, in the form of gravity-based structures (GBSs) and floating regasification & storage units (FSRUs). They are now expanding to liquefaction, in the form of floating LNG (FLNG) projects.
- **Interest in floating regasification arises from the plants' rapid development time, low capital costs and high degree of flexibility**. They play a particularly important role in extending LNG to new markets. As of 2013, there were 12 FSRU terminals and 1 GBS plant operating worldwide, accounting for 7.4% of total import capacity. However, average growth in offshore terminals has been eight times greater than growth in onshore plants over the past five years, and they account for 18% of capacity under construction.
- **FLNG is less mature and more challenging than FSRU**, but could help transform the industry. Like FSRU, FLNG provides flexibility, since: an FLNG vessel can be moved once a field is depleted; it eliminates the need for trunk lines from offshore fields to onshore plants; it makes the permitting process easier; it concentrates assembly in efficient shipyards. As a result, FLNG is expected to reduce project lead time and cap capital costs, allowing operators to access to small or remote fields that would not have been sufficient to justify a full-blown LNG project.
- **Four FLNG projects have achieved a final investment decision**. The smallest, Pacific Rubiales, is expected to start operating in Colombia in 2015. Six others are in the engineering phase, and a dozen more have been proposed. The success of the largest project (Shell's Prelude LNG) will be important in determining the future of FLNG. Several challenges need to be overcome: design and construction within a small area; ensuring safe operation in rough seas; and controlling costs, since FLNG will benefit from limited economies of scale compared with onshore plants with multiple trains.

1. Picture credits: Shell; mtpa: million tons per annum

Source: IGU (2013). "World LNG Report – 2014 Edition"; GE (2013), "The Age of Gas & the Power of Networks"

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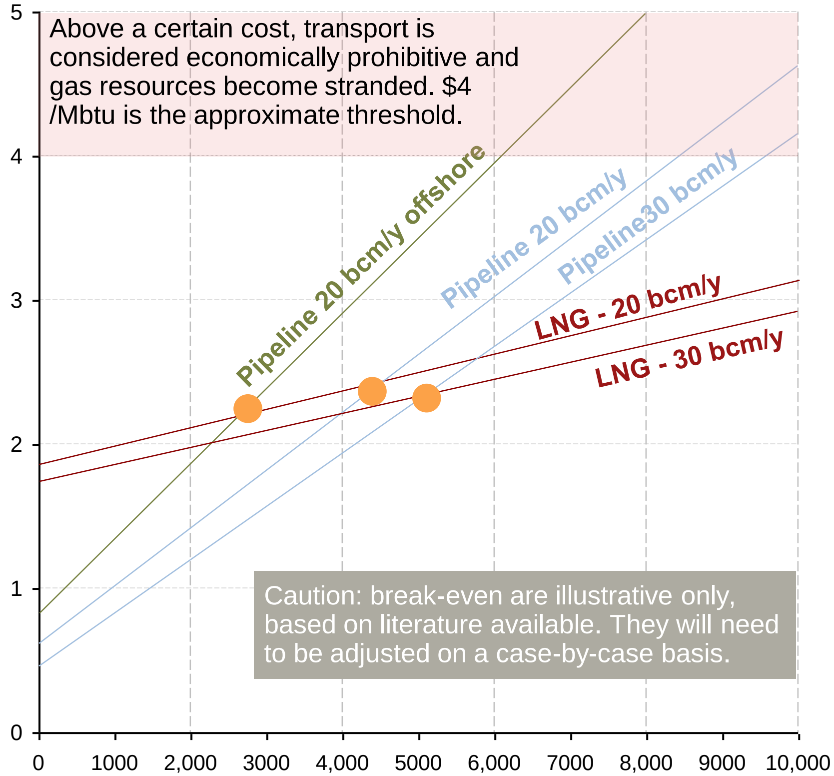
As a rule of thumb, the longer the shipping distance, the more economically attractive LNG tends to become compared with pipelines

Cost of transportation: LNG vs pipeline

$/MBtu vs. km



- **The choice between LNG and pipelines depends primarily on the distance over** which the gas will be transported **and the quantity of gas to be shipped**. For low quantities, LNG is a lower-cost option than pipelines in long-distance transportation.
- As well as local conditions (e.g. topography or regulation along the transport route, labor costs….), the point at which LNG becomes a better economic choice than pipelines is determined by several factors:
  - **Onshore/offshore**: offshore gas pipelines are more expensive, making LNG competitive over relatively short distances if the project involves offshore pipelines.
  - **Natural gas prices**: for distances up to 9,000 km, LNG tends to require more energy than pipelines, making it more exposed to price increases (i.e. the break-even point between pipeline and LNG may occur over a longer distance than when a pipelines system is used).
  - **Numbers of LNG trains**: multiple-train LNG plants benefit in general from economies of scale, making LNG competitive over shorter distances.
- When both options are **at price parity, LNG is likely to be preferred because of its flexibility**. In this picture, it should be noted that for low quantities or where very long distances are involved, neither LNG nor pipelines tend to provide economic natural-gas transportation solutions2.

1. Note that figures provide order of magnitude only,
2. This is known as ”stranded gas”. See the following slides for more information.

Source: A.T. Kearney Energy Transition Institute Analysis based on BP (2013), “BP Statistical Review of World Energy”; Ulvestad et al. (2014), “Natu”

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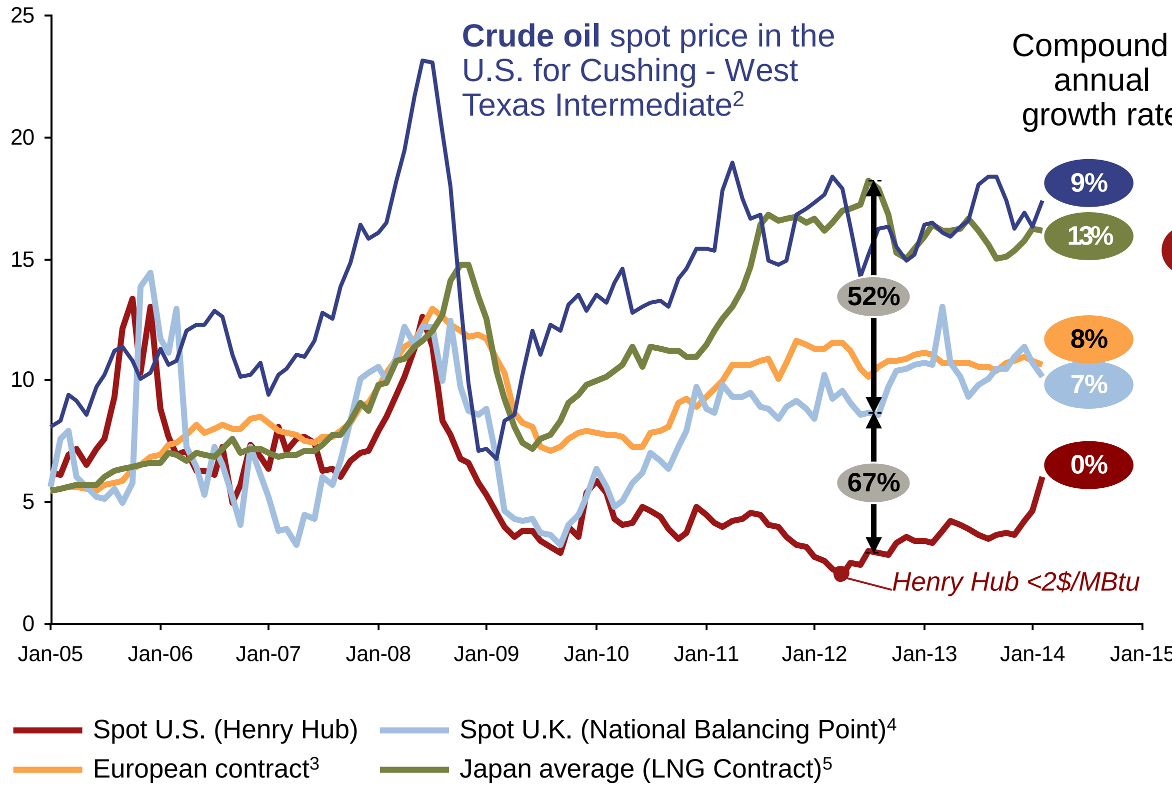
There are three regional gas markets, characterized by significant price spreads and diminishing oil-price indexation

Crude Oil and natural gas: Regional spot prices[1]

$/Mbtu, 2005-2012



1 Regional market prices

- Despite the growth of short-term LNG trade (~33% of LNG was traded on the spot market in 2013), there are three clearly defined regional markets, characterized by significant price spreads[6].

2 Delinkage with oil prices

- Natural gas prices are being indexed to oil prices less and less. This is especially the case in the U.S., which has the world's most liquid gas market. Europe is following a similar trend, thanks mainly to the emergence of new gas hubs (physical and virtual) and to contract renegotiations. However, according to the International Energy Agency, around 49% of gas sold globally in 2013 was still indexed to oil prices (although this was down from 57% in early 2010). The exception is Asia, where LNG contracts remain anchored to oil prices. In the absence of a transparent trading hub, oil-indexation is expected to remain dominant throughout the region for the foreseeable future.

1. According to the EIA, the spot price is "the price for a one-time, open-market transaction for immediate delivery of a specific quantity of product at a specific location, where the commodity is purchased on the spot at current market rates", 2. Converted from $ per barrel into $/MBtu based on an average energy content of 5.8 MBtu per barrel of West Texas Intermediate, 3. European contract represents IHS CERA's proprietary estimate of the average long-term, oil-linked gas contract price in Continental Europe, 4. NBP is a virtual hub in the National Transmission system where gas trades are deemed to occur; it is used as shorthand for U.K spot gas prices, 5. Japan average represents the average contracted price for LNG into Japan, 6. Price spreads may diminish over the long term, but will persist, according to the International Energy Agency.

Source: IEA (2014),"Energy Technology Perspectives"; EIA online data (http://www.eia.gov/dnav/ng/hist/rngwhhdA.htm)

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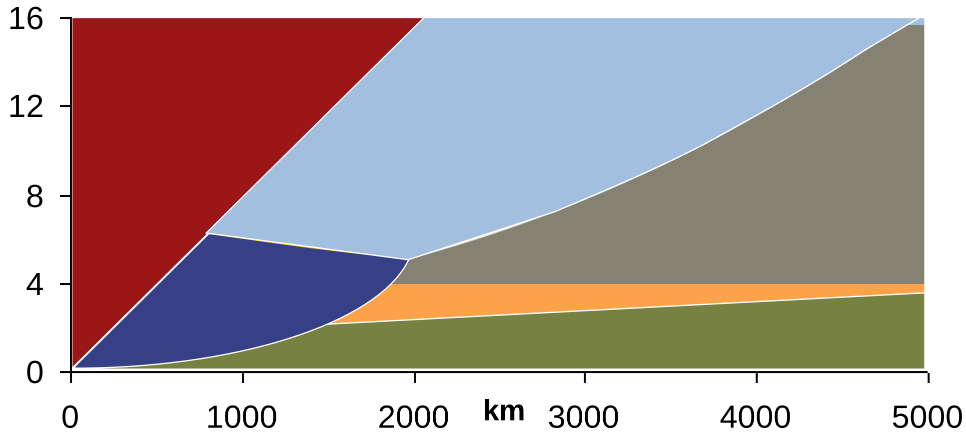
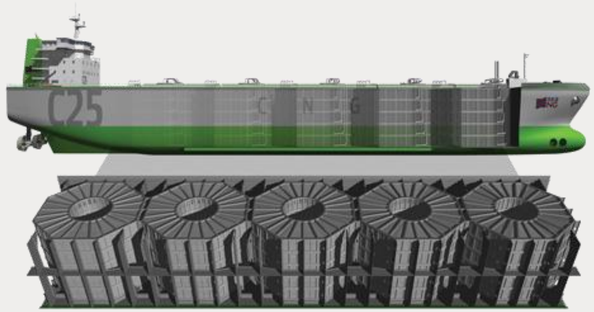
Compressed natural gas technologies (CNG) could complement pipelines and LNG to deliver natural gas from small fields to regional markets

Options to monetize natural gas[1] - Gas quantity (bcm/y) vs distance to market (km)



View of Sea NG CoselleTM CNG ship and containment



- **Many gas fields are too small or too remote to justify investment in pipelines or LNG facilities**. In some environments, the use of pipelines is simply not practical. A possible alternative is compressed natural gas, which is already being used for local gas distribution onshore, but whose application offshore, although conceptually mature, is still at an early deployment phase.
- **Marine CNG essentially acts as a "floating pipeline"**: gas is compressed at the production site (and sometimes chilled), stored in gas cylinders under high pressure (typically 200-275 bar) during transport, and delivered to end-customers.
- **CNG's main benefit is that it requires relatively little infrastructure, so capital requirements are low**: compression is a common feature of most gas-production units and less costly than liquefaction; offloading requires simple buoys. However, CNG has a lower energy density than LNG (typically around one-third, depending on the pressure). As a result, investments in CNG carriers are greater and operating costs are also higher (notably fuel costs).
- **In addition to the usual first-mover disadvantage, CNG has suffered from technical challenges** associated with containment and control/safety systems. However, R,D&D has yielded new lightweight composite systems with large-diameter pressure vessels stored vertically inside the ship, reducing costs, while improving safety and facilitating safety controls and certification. Several companies have received regulatory approval and could launch projects in the next few years (e.g. Enersea with Votrans™, Sea NG with Coselle™).

1. Note that this graph provides order of magnitude only,
2. Picture credits: Sea NG.

Source: Sea NG (2012), "Floating CNG: a simpler way to monetize offshore gas"; Economides et al. (2012), "The Optimization of Natural Gas Transportation"

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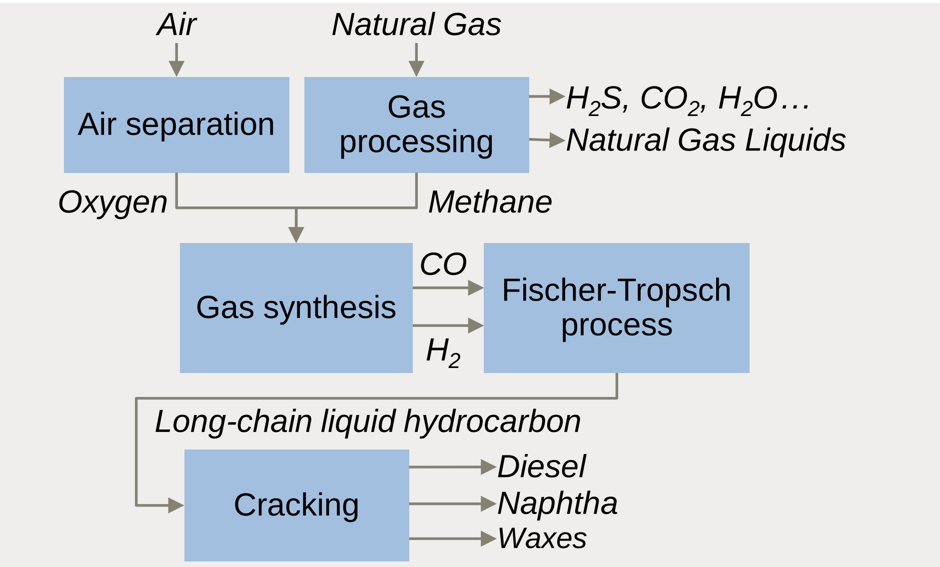
Small-scale gas-to-liquid (GTL) conversion systems may provide an alternative means of transporting and monetizing stranded gas

GTL Plants: Processed And Key Data



Country	Start date	Operator	Capacity	Investment
South Africa	1992	Sasol	45 kbbl/d	N/A
Malaysia	1993	Shell	14.7 kbbl/d	N/A
Qatar	2007	Sasol / Chevron	34 kbbl/d	$1.1 bn
Qatar	2010	Shell	140 kbbl/d	$18-19 bn
Nigeria	e2016	Sasol / Chevron	34 kbbl/d	$1.7 bn

- Despite its discovery in the early 20th Century, and past use on a relatively large scale by Germany and South Africa, the gas-to-liquids (GTL) process is still in its commercial infancy. **As of 2013, there were four commercial GTL plants operating worldwide**. The largest, Shell's Pearl GTL, started operation in 2010 in Qatar, with a capacity of 140,000 bbl/day. A fifth project is under construction in Nigeria (Sasol Escravos 34,000 bbl/d) and several others have **been proposed** (e.g. Lake Charles in the U.S.).
- **However, cost concerns have lead to project cancelations** (Shell in Louisiana and Talisman's exit from Montney in Canada). Pearl's costs were estimated to have tripled compared with its initial budget, rising to $18-19 bn. Despite a favorable price spread between oil and gas, capital costs are still too high (e.g. $80,000 per bbl/d of capacity for Pearl) and energy efficiency too low (as a rule-of-thumb, only a tenth of the energy in natural gas used in the GTL process is converted into useable products) to justify GTL on large-scale.
- **Small-scale, modular GTL systems seem to be the key to GTL becoming more widespread**. These would have the ability to monetize stranded gas and associated gas resources that are currently flared, notably those offshore. Small-scale GTL also obviates the construction of an on-site reforming unit, reducing capital costs1. As a general estimate, if 50% of the gas that is flared were to be used as GTL feedstock, it would produce around 0.7 mbbl/d of additional liquid fuels. R,D&D efforts (catalyst…) remain crucial in reducing costs and improving efficiency.

1. Reforming units account for the bulk of GTL capital costs. For large-scale projects, these must be built on site, but in small-scale projects, reforming units can be built elsewhere and shipped to the plant site.

Source: Schlumberger (2003), "Turning Natural Gas to Liquid"; EIA (2014), "GTL plants face challenges in the U.S. Market"

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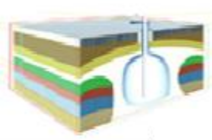
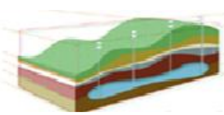
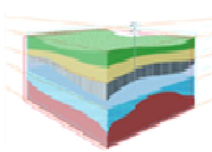
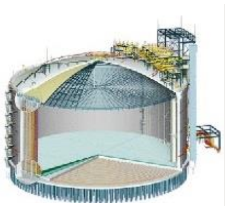
Natural gas can be stored underground or above-ground to balance the seasonal variability of demand and ensure security of supply

Natural Gas Storage Technologies

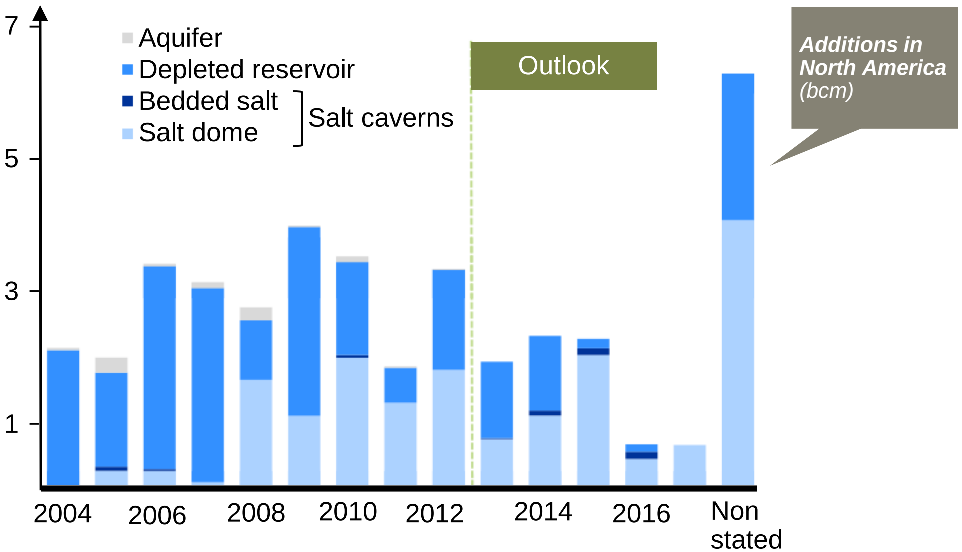
				Advantages	Disadvantages
Underground Gas Storage (UGS)	Depleted field		• Depleted reservoirs are formations that have been tapped of their recoverable oil & gas resources. The porosity and permeability of the formation determine, respectively, the amount of natural gas that can be stored and the injection/withdrawal rate. Depleted fields make use of existing gas infrastructure and provide extensive storage capacity. They make up the bulk of storage capacity in use.	+ Large capacity + Low capital costs + Low reservoir-leak risks	– Location mismatch with demand center – Cushion-gas[1] requirements – Limited flexibility
Underground Gas Storage (UGS)	Aquifer		• Aquifers are porous, permeable, underground rock formations that act as natural water reservoirs and can be used to store gas when overlaid by an impermeable cap rock. However, aquifers require more cushion gas[1] (50-80%) than depleted fields and more investment in injection infrastructure. They are usually, therefore, utilized only when there are no depleted fields nearby. They usually have high delivery rates and are used for balancing seasonal variations (summer/winter) in supply and demand.	+ Relatively low-cost + Large capacity	– High cushion-gas[1] requirements – Geological risk
Underground Gas Storage (UGS)	Salt formation		• Salt formations, whether bedded salt or salt domes, can be used to store gas due to salt's natural insulation properties. They are usually more expensive than the alternatives, since – unless abandoned mines are used – a cavern has to be created. However, they require a small proportion of cushion gas[1] (20-30%) and provide very high deliverability. As a result, they are used for daily supply-demand balancing requirements.	+ High flexibility & deliverability + Low cushion-gas[1] requirements	– High capital costs – Lower capacity – Lack of salt formations in some regions
	OTHER		• Instead of being stored underground, gas can be liquefied and stored as liquefied natural gas (LNG). LNG can deliver large amounts of energy very quickly and is therefore suitable for peak-shaving. Gas can also be stored in pipelines for short-term needs (day to day supply/demand match) by increasing the pressure (known as line packing). However, above-ground storage tanks, despite being in use for a long time, are being utilized less and less.	+ High deliverability for short-term balancing	– High capital costs – Low capacity compared with underground storage

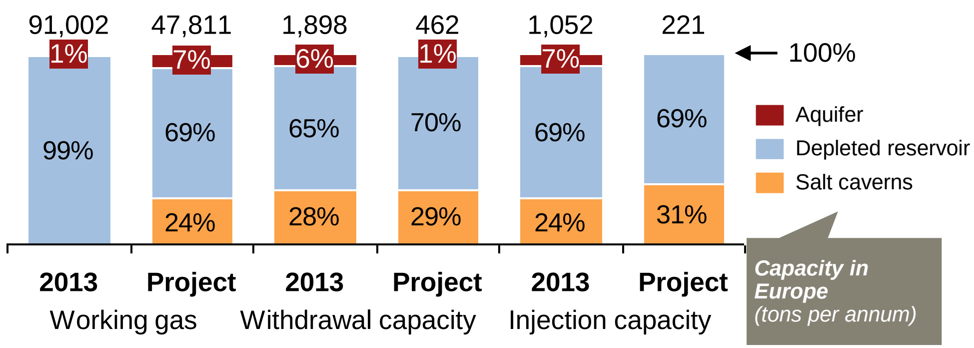
1. Cushion gas is the total volume of natural gas in a storage reservoir required to maintain a minimum rate of delivery.

Source: The Oxford Institute for Energy Studies (2013), "Gas Storage in Great Britain"; Energy Charter Secretariat (2010), "The Role of Underground Gas Storage for Security of Supply and Gas Markets"

The flexibility of storage technologies has become an important consideration because of natural gas's growing share of power generation

Working gas storage capacity by technology





- **Historically, natural gas was stored primarily to mitigate supply disruptions and to cope with seasonal variations in demand.** Because buildings' thermal needs are relatively predictable, natural gas was mostly stored in depleted oil & gas formations, which provide large-scale storage at a low cost.
- **However, recently, natural gas storage needs have radically evolved, as natural gas trade has become more liquid and as** natural gas's role in power generation has grown:
  - Storage provides a means of hedging **against natural-gas price volatility**, especially in the most liquid markets, North America and Western Europe;
  - Storage requirements are also affected by natural gas's increasing share of power generation. Indeed, many countries now use open-cycle gas turbines in peaker mode to balance supply from intermittent renewables. This transfers unpredictability and variability from the power sector into natural gas procurement.
- **In both cases, the flexibility of storage capacity has become essential**, generating new momentum behind salt caverns, which provide unrivalled flexibility, albeit at a high cost.

Source: IHS Cera Insight (2013), "Natural Gas Storage: Capacity Transparency has improved"; Gas Storage Europe Map Dataset

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Natural gas needs to be depressurized, odorized and monitored to be safely delivered to end-customers through a dense network of small pipelines

City gate gas stations[1] - Zhongshan city, China

- Except for a few customers, such as power stations or large industrial plants, which are connected directly to the high-pressure transmission system (up to 75 bar), **most end-customers are supplied by the low-pressure gas network** (up to 1 bar, and ~20 mbar at the meter)[2].
- **Unlike long-distance transportation, distribution is characterized by smaller volumes transported to many more locations, over shorter distances**. As a consequence, distribution accounts for most of the pipelines installed (e.g. in the U.K., the respective lengths of the high-, medium- and low-pressure grids are ~6,000 km, ~ 12,000 km and ~260,000 km).
- **From a technical standpoint, a typical distribution network comprises a city-gate station** (also known as an off-take point) connected to the high-pressure grid, where natural gas is monitored, filtered (e.g. for moisture content), metered and odorized. Along the way to end-customers, the natural gas flows through **depressurization** stations in order to comply with further pressure-reduction requirements.
- **Most pipelines were, historically, made with rigid steel. However, polymer is now preferred** for cost, safety and flexibility reasons, and accounts for most of the pipeline sections connected to customers' meters. Valves, together with protection devices, gas-heating facilities and flow-control regulators, complete this complex system to ensure efficient and safe operations. The grid is increasingly managed by remote control equipment.
- **Ensure safety is the main challenge distribution-grid operators face**. Grids are, therefore, equipped with leak-detection appliances and odorized to make leaks easier to detect. Measures to educate consumers about safe operation are also undertaken. In addition, considerable effort has been taken to minimize disruption from grid maintenance and pipeline installation.

1. Picture credits: Terrence Energy Ltd, 2. The quoted figures are intended to provide an order of magnitude, based on the European standard. However, they vary by system.
Source: National Grid (2013), "Appendix 4 – The Transportation System"; GrDF (2013),

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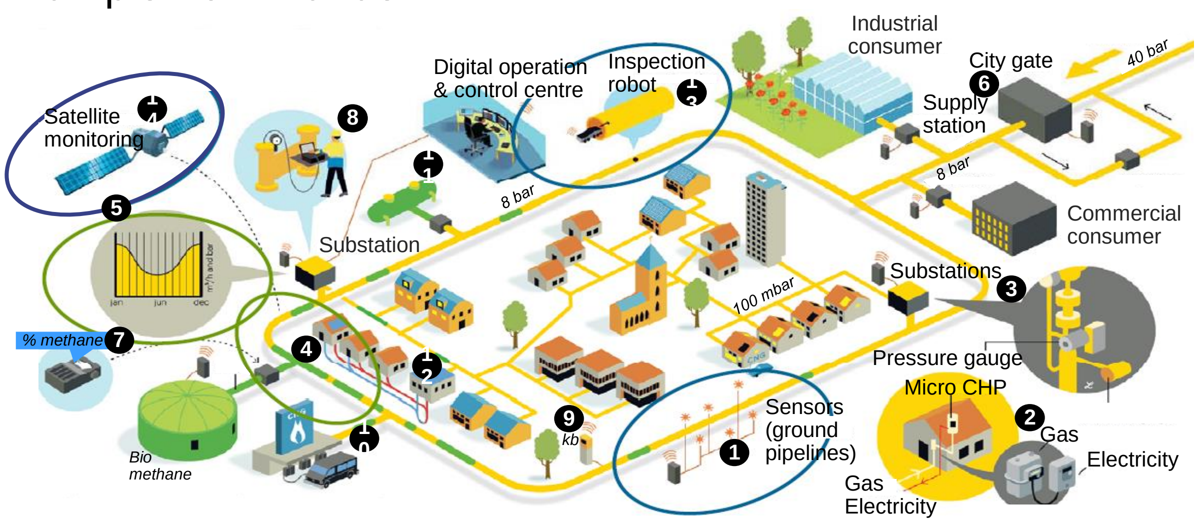
Like power networks, gas grids are becoming smarter and more efficient thanks to the integration of information & communication technologies

Schematic of a gas smart grid

Example from Liander[1]



1- Gas-grid monitoring
Sensors measure ground vibrations, traffic loads, gas leakage……

2- Smart metering
Gas meters record gas-consumption profile and make it available to consumer

3- Measurements in stations
Remote monitoring of gas pressures, volumes and temperatures

4- Gas diffusion
Sensors and computer models measure and predict gas flow diffusion and mixing

5- Dynamic pressure management
Verging the gas pressure depending on demand and supply

6- City gate
Real time data for gas pressures, volumes, temperature and quality

7- Monitoring gas quality
The quality of bio-methane added to the grid is monitored 24/7

8- Station diagnostics
Periodical diagnostics are run to ensure control systems are working properly

9- Cathodic protection
Remote diagnostics and monitoring of the polymer coating around steel pipelines

13- Residential energy hub
CHP and heat pump for district heating

14- Satellite monitoring
Monitoring ground settlement at a street and neighborhood level

- **The smart gas-grid concept is less recognized than its power counterpart.** This is mainly because gas is easier to store and transport than electricity, so supply-and-demand matching is less challenging. However, gas grids can leverage information and communication technologies to become greener, safer and more efficient.
- **Smart gas grids have four main objectives:**
  - Improve **service quality,** safety and reliability with remote control and monitoring;
  - Reduce the carbon footprint of gas by enabling increased **injection and blending of biogas and hydrogen;**
  - Help **integrate new technologies**, such as heat pumps and cooling, micro-cogeneration or fuel cells, to create smart gas utilization; and
  - Increase the **flexibility of the energy system** as a whole, converting the gas grid into storage capacity for the power grid2.
- **Several projects are under way, especially in Europe:** in France, with the deployment of smart gas meter Gaspar; and through the European Green Gas initiative of Fluxys, Gasunie, Energinet.dk, GRTgaz and Swedegas.

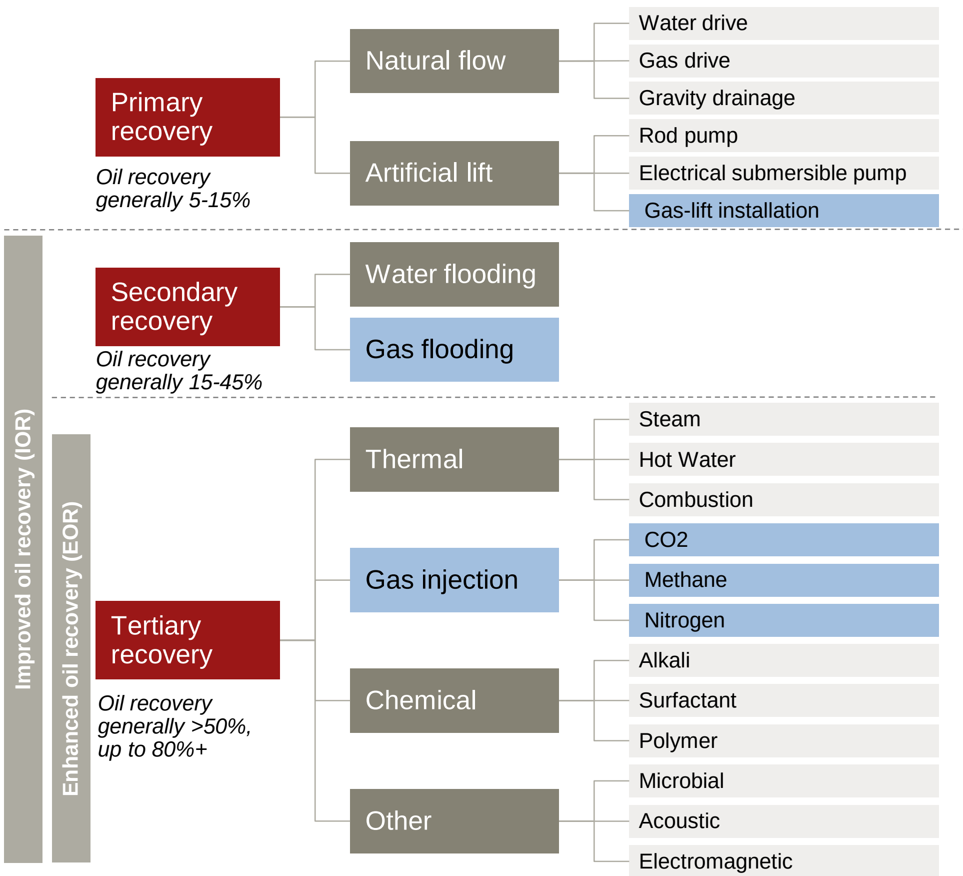
1. Picture credits: Liander (2013), "Smart Gas Grid Today", 2 For more information about the bridge between the gas and power network, including Power-to-Gas, please refer to the A.T. Kearney Energy Transition Institute Hydrogen FactBook.

Source: Lambregts (2013), "Smart Gas Grid Today" (Liander); GrDF (2013), "Smart Grids - Point de vue d'Anthony Mazzenga, Chef du pôle Stratégie"; European Commission Task Force for Smart Grids Expert Group 4 (2011), "Smart Grid

4. End-uses

Historically, natural gas has played a crucial role in increasing oil-recovery rates

Oil recovery techniques[1]



- **Oil's natural flow results in low primary recovery factors,** typically 5-15%[2]. Various techniques are therefore used to improved recovery rates. These include a number **of artificial-lift techniques**. One of the most common, especially in mature offshore wells, involves injecting natural gas through the tubing-casing annulus in a producing oil well. Injected gas creates bubbles in the produced fluid, making the liquid less dense and allowing pressure in the formation to lift the column of fluid[3]. New techniques have been developed to cope with more complex offshore environments (*e.g.* new valves or auto-gas lift to meet the safety and pressure requirements of deep-water oil fields).
- **Natural gas can also be injected to maintain sufficient pressure in reservoirs.** Also known as gas flooding, this involves "pushing" oil towards the wellbore. Natural gas injection, usually into the gas cap, is the preferred method of disposing of or storing associated gas when it has no economic value or to balance continuous supply rate with seasonal variations in demand.
- **Gas can be injected as part of enhanced recovery.** This differs from gas flooding because it changes the make-up of the reservoir. Various gases can be injected: natural gas, produced from the same or a neighboring field, exhaust gas from a nearby industrial plant/power plant, nitrogen, once separated, and carbon dioxide. The latter is the most popular and serves at the same time as a means of sequestering anthropogenic sources of a greenhouse gas.

1. The terms primary, secondary and tertiary have lost their original sense of chronological order. Tertiary recovery can be included in field development from the beginning;
2. Over the producing lifetime of an oil well, the bottom-hole pressure that sustains natural production will eventually drop sufficiently that the well ceases to flow or be profitable;
3. In most cases, gas-lift systems are based on a closed-loop system: gas is produced on an adjacent well and recovered from lifted wells.

Source: Schlumberger (2006), "The Pressure's On: Innovations in Gas Lift"; Schlumberger (2010), "Has the Time Come for EOR"

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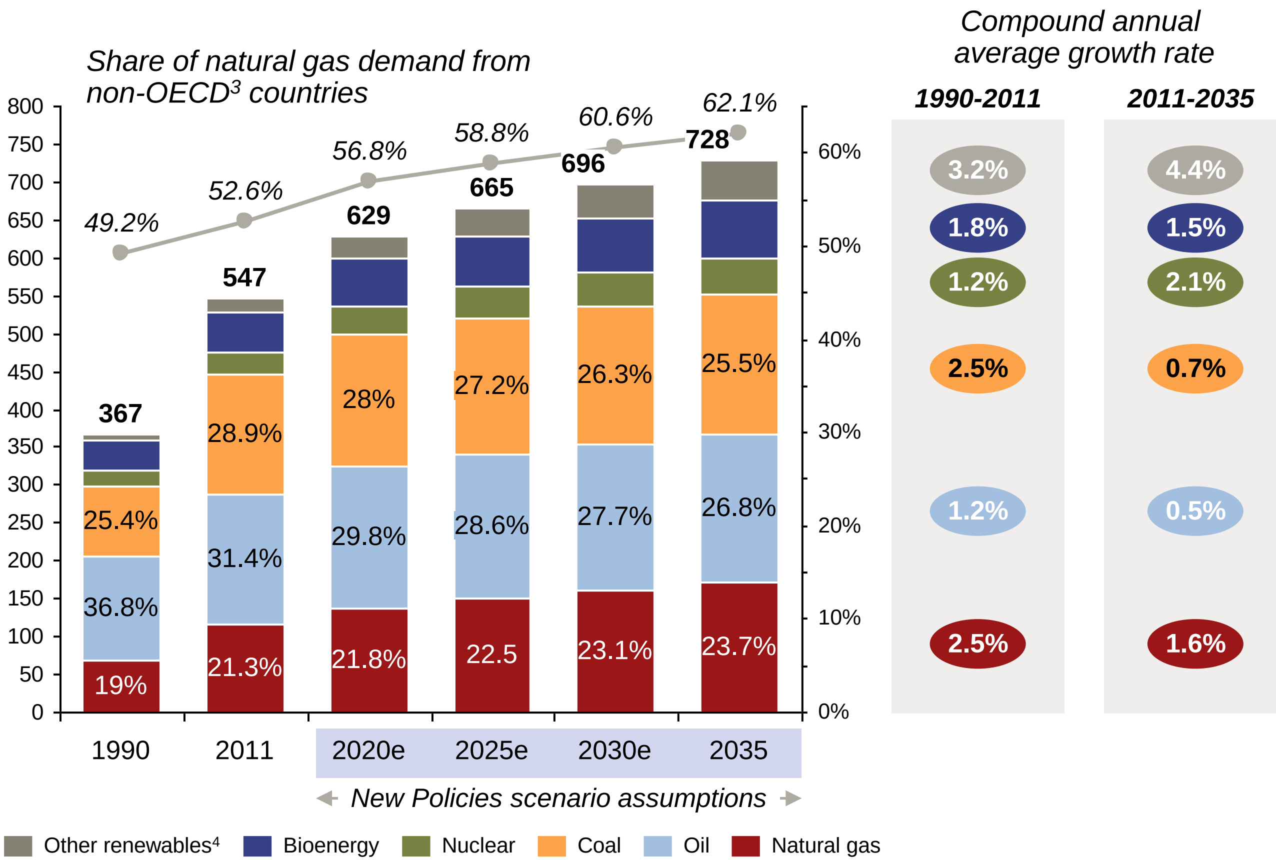
Natural gas's role in the global energy mix is growing

Total World Primary energy demand[1]

Exajoules (EJ), IEA New Policies Scenario for the forecast[2]



- **Natural gas use has increased at an average annual growth rate of 2.5% since 1990.** Its role in the energy mix has expanded at the expense of oil and nuclear power.
- **Growth in natural gas consumption is expected to continue, albeit at a slower pace.** The International Energy Agency's reference scenario[2] assumes an average annual growth rate of 1.6% between now and 2035 – with gas demand rising as high as 5 tcm. This means demand for natural gas should grow more quickly than demand for other fossil fuels, but at slower pace than demand for low-carbon energy sources.
- **Natural gas demand growth is likely to be driven by emerging economies.** Non-OECD countries[3] account for 82% of the incremental gas demand expected by the IEA and natural gas use in China is expected to multiply fourfold by 2035. The U.S. is likely to remain the largest gas-consuming country in 2035, while European demand should stabilize around 2010-levels.

1. This takes into account direct fuel demand and fuel used for power and heat generation; 2. The New Policies Scenario is the IEA's reference scenario. It assumes recent government policy commitments will be implemented even if they have not yet been ratified; 3. OECD stands for Organisation for Economic Co-operation and Development; 4. Other renewables include hydro, geothermal, solar photovoltaic, concentrating solar power, wind and marine energy.

Source: IEA (2013), "World Energy Outlook 2013"

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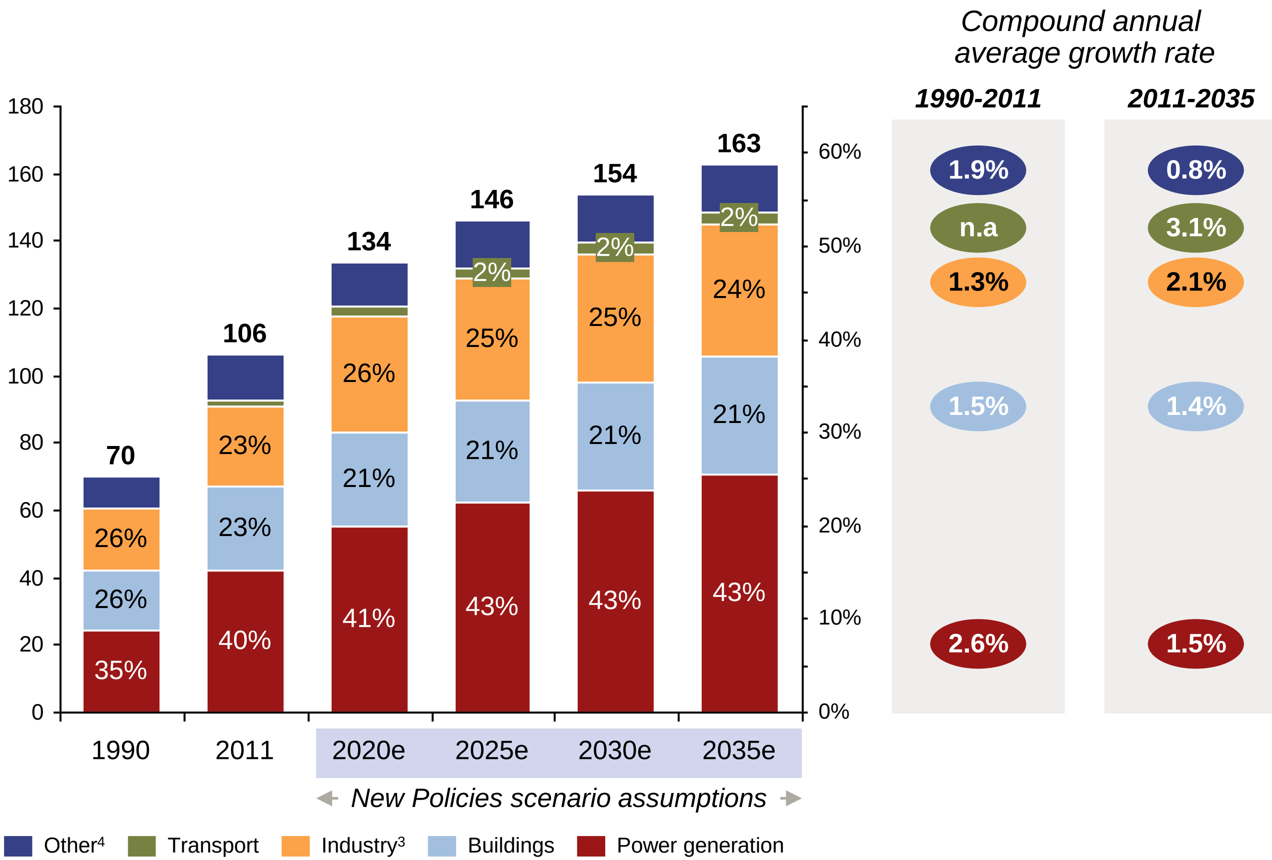
Thanks to its versatility, natural gas plays a major role in all end-uses sectors except for transport

Primary natural gas demand by sector

Exajoules (EJ), IEA New Policies Scenario for the forecast[1]



- **Natural gas demand is currently divided among three main sectors:** power generation; residential and commercial buildings; and industry.
- **The power sector is the largest and fastest-growing driver for natural gas demand (40%).** Electricity is followed by industry (23%), where natural gas can be used as fuel or as a chemical feedstock, and by demand from commercial and residential buildings (22%). Transport is the only end-use sector in which natural gas does not yet play a central role.
- **Natural gas demand is expected to grow in all sectors by 2035.** According to the IEA's reference scenario, power generation will remain the main driver of natural gas demand and will account for 51% of incremental gas use between now and 2035. Natural gas for transport is expected to be the fastest-growing end-use sector (3.1% per year). Conversely, gas demand in industry and buildings, although growing in absolute terms, will experience a diminishing role among natural gas end-uses.

1. The New Policies Scenario is the International Energy Agency's reference scenario. It assumes recent government policy commitments will be implemented, even if they have not yet been ratified; 2. Other includes the use of gas for oil & gas extraction, in liquefaction plants and for distribution; 3. Industry includes the use of natural gas as feedstock (e.g. ammonia plants).

Source: IEA (2013), "World Energy Outlook 2013"

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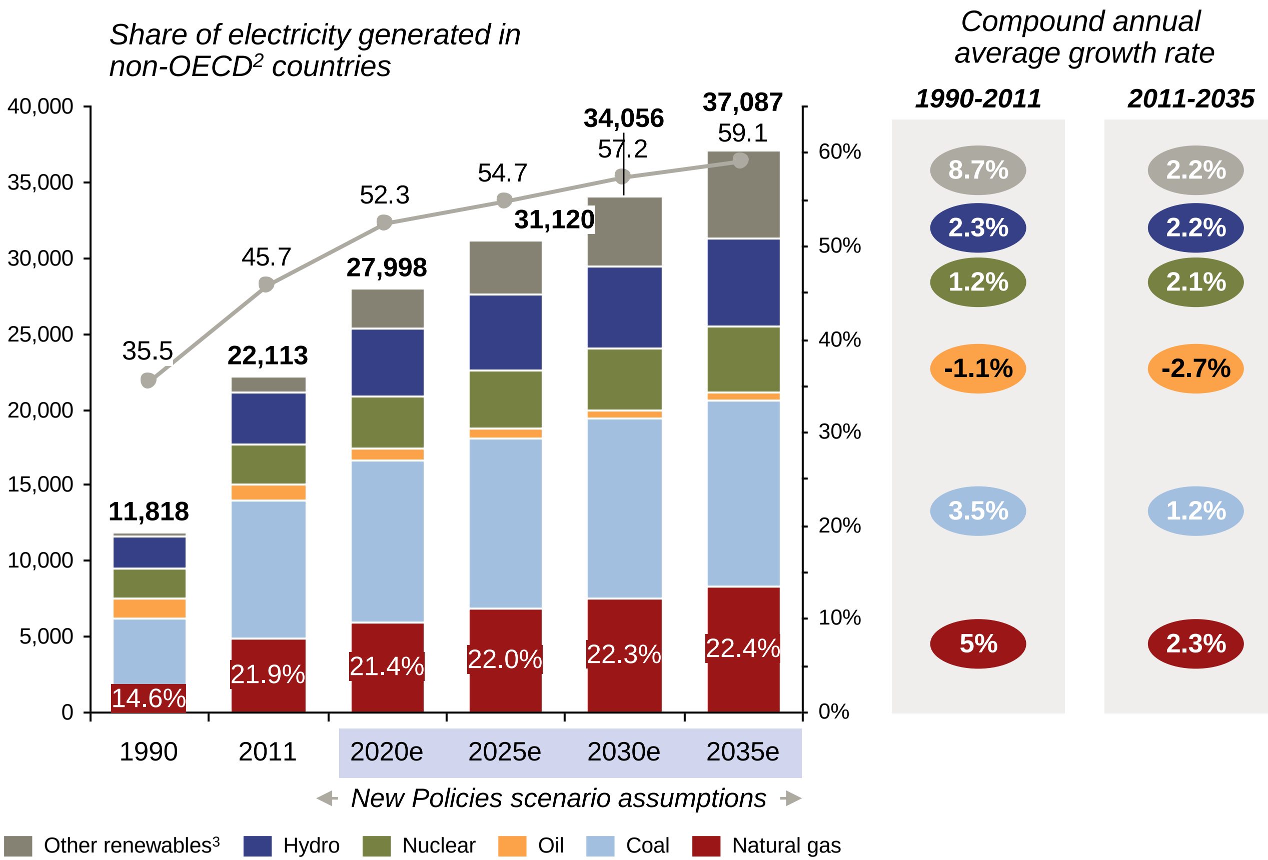
Natural gas is the second most important energy source in power generation

Electricity generation by source of energy

TWh, IEA New Policies Scenario[1]



- **Since the 1990s, natural gas has been the second-fastest-growing source of energy** used for electricity generation, **after non-hydro renewables**. It is now the world's second-most-important fuel in the power mix after coal.
- **Consumption of natural gas is expected to continue to grow, albeit at a slower pace.** In its reference scenario[1], the International Energy Agency estimates an average annual growth rate of 2.3% by 2035. In this scenario, natural gas would be the fastest-growing source of energy, ahead of renewables. By 2035, it would attain a 22.4% share of a power mix still dominated by coal.
- **Non-OECD[2] countries are the main drivers of growth in electricity demand and would account for 80% of the incremental gas demand** expected in the New Policies Scenario between 2011 and 2035.

1. The New Policies Scenario was the central scenario of IEA's World Energy Outlook 2012, and assumed that recent government policy commitments would be implemented in a cautious manner – even if they had not yet been ratified; 2. OECD stands for Organisation for Economic Co-operation and Development; 3. Include wind, bioenergy, geothermal, solar photovoltaic, concentrated solar power and marine.

Source: IEA (2013), "World Energy Outlook 2013"

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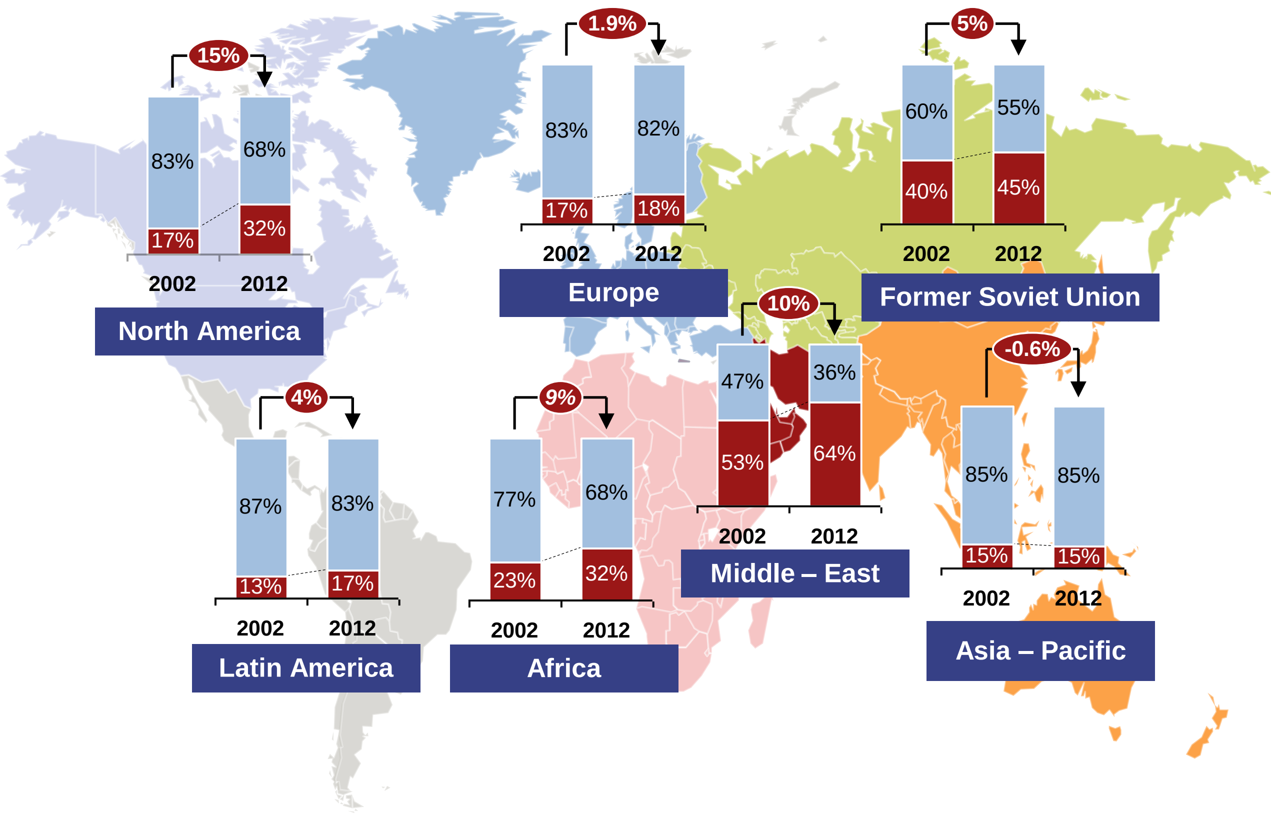
The share of natural gas in the power-generation mixes varies significantly from one region to another

Share of natural gas in regional power-generation mixes[1]



- In **North America**, lower gas prices resulting from the abundance of shale gas have encouraged a switch from coal to natural gas in power generation.
- Natural gas tends to be the main fuel used in power generation in **gas-rich regions** such as Russia and the Middle East.
- In **Asia-Pacific**, the volume of natural gas used in power generation has increased. But its share of the power mix has remained unchanged because of significant additions of coal-fired generation capacity.
- In **Europe**, the share of natural gas in power generation increased in the 2000s, but has declined significantly in the past few years, falling from 23% in 2010 to 18% in 2012. This is the result of a mix of factors, including low coal-prices, low carbon prices, and low capacity factors for gas-fired power plants due to increasing penetration of variable renewables.

Legend Share of natural gas | Share of other technologies

1. The change between 2002 and 2012 is the percentage-point difference between those two years.

Source: IEA (2013), "World Energy Outlook 2013"; IEA (2014), "Energy Technology Perspectives 2014"; IHS database (accessed, May 2014)

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Gas power-generation technologies are attractive because of their considerable flexibility and high degree of efficiency

Comparison of the main gas power

Technologies with a typical coal power plant

Type of plant	Combined-cycle gas turbine (CCGT)	Open-cycle gas turbine (OCGT)	Coal generation
Efficiency[1]	40% to 61%	30% to 40%	30% to 46%
Flexibility – Start-up time	30 to 60 minutes	<20 minutes	1 to 6 hours
Flexibility – Ramping Rate	5% to 10% per minute	20% to 30% per minute	1% to 5% per minute
Time from zero to full load	1 to 2 hours	< 1 hour	2 to 6 hours
Typical capacity	60 to 400 MW	10 to 300 MW	300 to 800 MW
Range of leverage cost of electricity[2]	$40-100 /MWh	~$100-140 /MWh	~$35-110 /MWh

- **There are two dominant gas power generation technologies:** open-cycle gas turbine (OCGT) and combined-cycle gas turbine (CCGT). Both are based on the same principle: compressed air is ignited by natural gas combustion. This spins a turbine, whose high-speed rotations drive an electric generator. However, unlike OCGT, CCGT makes use of waste heat from the gas turbine: exhaust gas is captured to boil water into steam in order to feed an additional turbine.
- **CCGT has contributed 73% of gas-turbine capacity additions since 1990.** CCGT's efficiency and relatively low capital costs – combined with its high degree of flexibility and economic competitiveness with coal, even when utilization rates are high – have strongly influenced growth in the use of natural gas in power generation. However, for peaking uses, which require a very high degree of flexibility, OCCT is still favored.
- **At a smaller scale, other technologies are available,** notably gas engines, combined heat and power (CHP) systems and fuel cells. In CHP, exhaust gas from a gas turbine is used to generate heat (or for cooling). CHP is typically small-scale (10-120 MW) and very efficient (~80% thermal efficiency). At an even smaller scale (0.1-10 MW), gas engines can also be used (*e.g*. instead of diesel generators). These usually have decent efficiency (~45%) and the ability to run on diverse quality of natural gas, including biogas or wet gas. All these technologies are still marginal, but their impact may grow.

1. Based on the lower heating value of the fuel; 2. LCOE depends on plant size, fuel costs (here, $5-12/MBtu for gas and $2-4/MBtu for coal), location (*e.g.* taxes, labor costs) and sub-technologies. It does not include carbon prices, and take into account average utilization rate (*e.g.* 10% for OCGT).

Source: IEA (2012), "Energy Technology Perspectives"; IEA (2012) Technology roadmap coal; GE (2013), "The Age of Gas & the Power of Networks"

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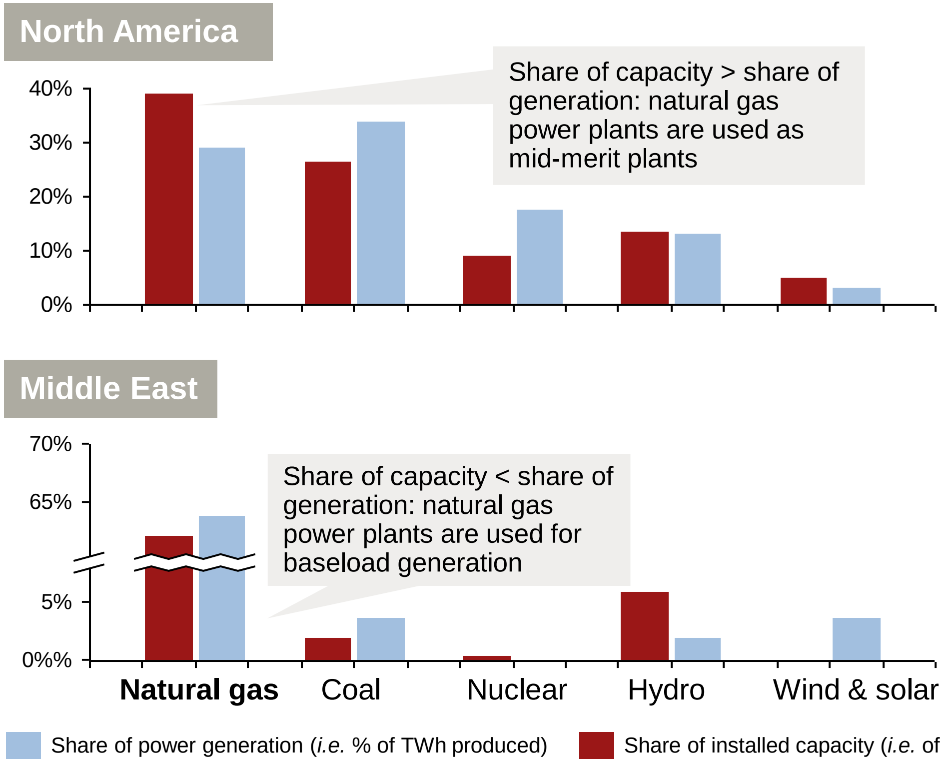
Natural gas-fired power generation could assist the energy transition by replacing coal-fired generation and by balancing intermittent power output

Share of installed capacity *vs.* Share of generation in selected power technologies



- **Natural gas power plants tend to be an important source of flexibility for power systems because of the flexibility of natural gas turbines**. System operators use gas-fired power plants to match supply and demand by adjusting their output upwards or downwards[1].
- **As a consequence, natural gas power plants are typically operated as mid-merit plants** (*i.e.* running ~50% of the time) or peaking plants (*i.e.* running less than 20% of the time), as opposed to baseload plants, such as nuclear or coal units, which are used virtually all year-long to leverage their relatively low operating costs and amortize their relatively high initial investment. However, in gas-rich regions (such as the Middle East), gas tends to be used as a baseload fuel, because of its low cost.
- **Coal-to-gas switching** is expected to be an important decarbonization lever in countries that rely on coal for power generation[2].
- **Natural gas is also expected to facilitate the integration of intermittent renewables**: gas turbines have the ability to balance the variable and imperfectly predictable output of wind and solar power. However, in the absence of appropriate rewards for flexible capacity, the increasing penetration of intermittent power raises important challenges for the profitability of gas-fired power, as Europe is experiencing since 2011[1].

1. Note that gas turbines are not the only flexibility sources (e.g. diesel generator). Besides, system operators usually call upon plants according to their marginal operating costs (known as merit order). Natural gas power plants, characterized by high marginal operating costs, are usually called upon last and, as such, set the price (being the last power plant called upon to meet a demand peak). However, wind may blow when demand is peaking, pushing gas power plants out of the market. This results in utilization rates that are too low to amortize the initial investment, forcing gas utilities in Europe to close or mothball dozens of natural gas-fired plants; 2. Note that heavy gas turbine have also proved helpful in switching from heavy-oil to natural gas.

Source: MIT (2011), "The future of Natural Gas"; IEA (2013), "Tracking Clean Energy Progress"

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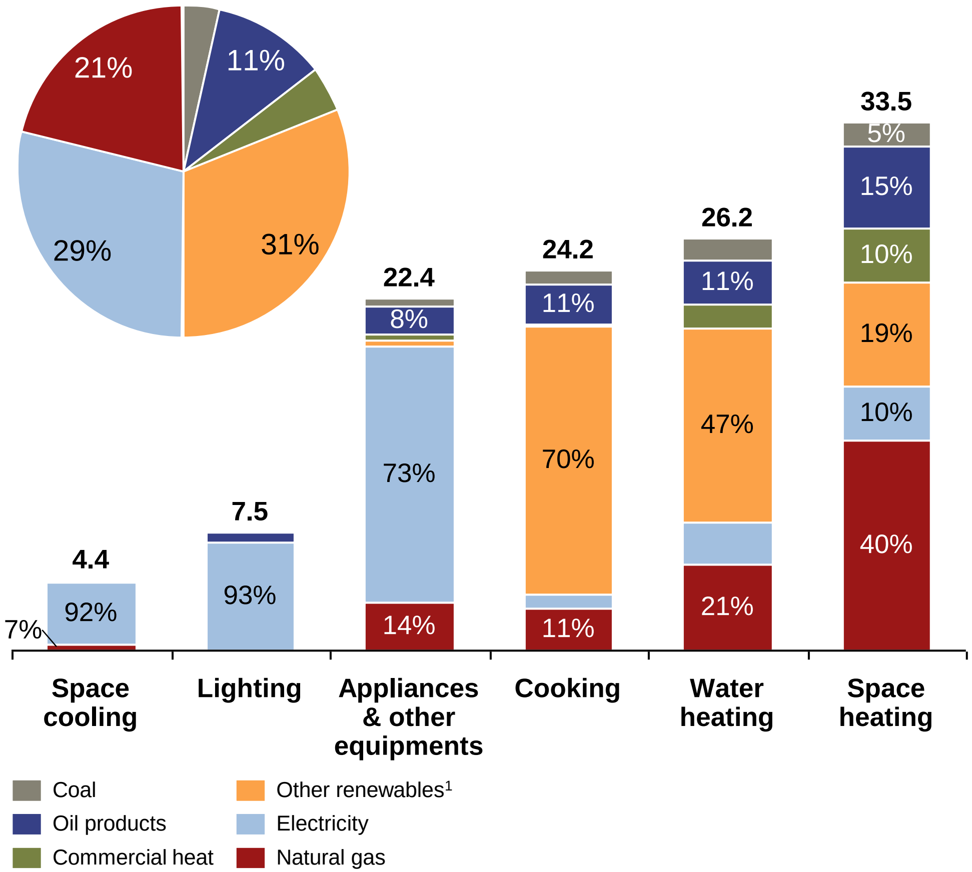
Thermal uses account for the bulk of natural gas demand in residential and commercial buildings

Energy demand in buildings by fuel

ExaJoule (EJ), 2011



- **In addition to power generation, the other major use of natural gas is in the residential and commercial sector**. In buildings, direct use of natural gas competes with other energy sources, notably bioenergy or oil. Natural gas is also used in buildings indirectly, in the form of electricity and heat, competing with coal, nuclear or hydro. Overall, buildings represent 22% of the world's direct natural gas demand. When natural gas used to generate electricity and commercial heat for buildings is added, the share rises to almost 29%.
- **The direct use of natural gas in buildings is predominantly for thermal end-uses.** Space and water heating represent 54% and 22% of natural gas use in buildings, respectively, and heat for cooking 11%. Within buildings, the commercial sector represents 30% of total gas consumption and the residential sector 70%.
- **Overall, natural gas technologies used in the buildings sector are mature and characterized by their high thermal efficiency** (*e.g.* as high as 95% for the latest gas-fired boilers). However, interest is starting to grow in the decarbonization of heating and cooling processes, a subject that was largely ignored in the past. In buildings, natural gas is used to provide low-grade heating services (average heat demand for comfort is 21°C), but could be used more efficiently in other processes because it has the ability to generate very high-temperature heat. Other technologies, such as heat pumps and combined heat and power (either distributed or large-scale with district heating), may be more suitable for space heating than natural gas boilers.

1. Include mainly biomass & waste, but also solar (e.g. solar thermal collector for water heating); 2. Most heat-pump use vapor-compression cycles driven by electric motors or gas turbines in order to move thermal energy (heat or cold) from a renewable source (ambient air, water or ground) to a specific location.

Source: IEA (2014), "Energy Technology Perspectives 2014"; IEA (2011), "Technology Roadmap Energy-efficient Buildings: Heating and Cooling Equipment"

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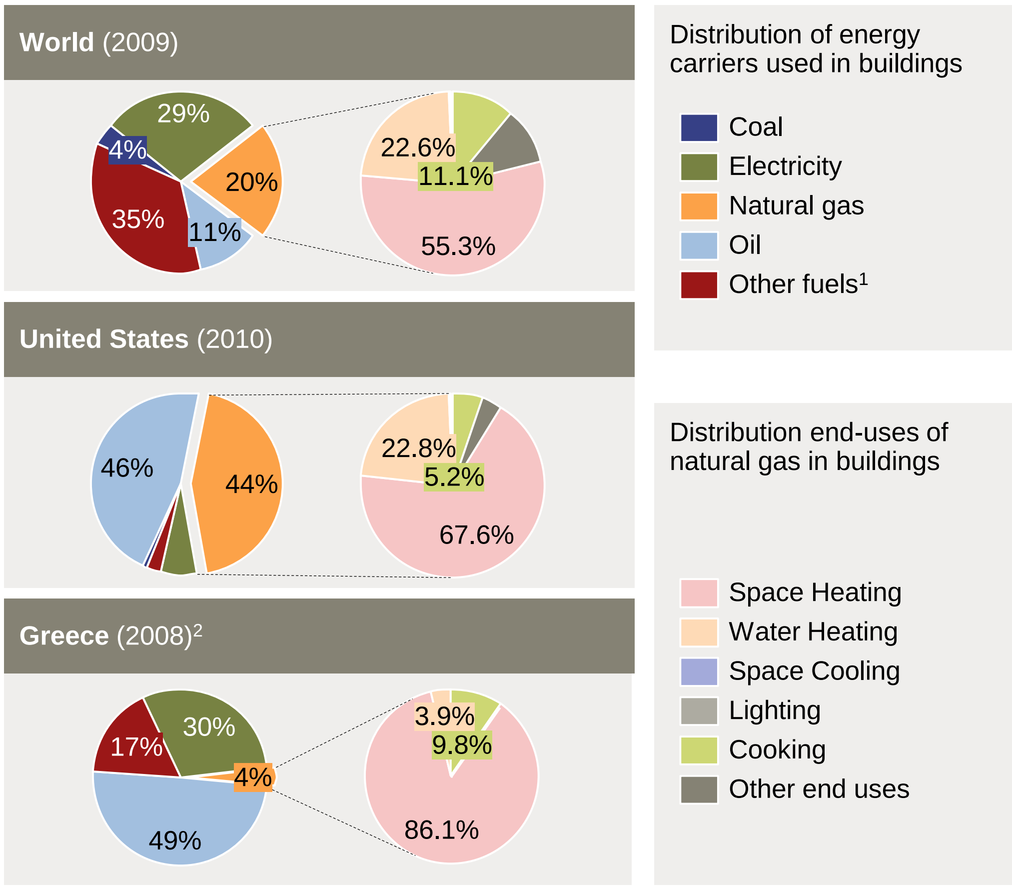
Natural gas usage in buildings varies significantly by region

Natural gas uses in buildings in selected regions[1]

Share compared with other carriers (left) and share of end-uses (right)



- **In the buildings sector, demand for energy services varies significantly from one region to another,** depending on climate, urbanization patterns, occupant behavior, and building design and insulation. These factors strongly influence the amount energy needed to meet heating and cooling comfort requirements. Demand for natural gas also varies seasonally and from year to year, depending on weather conditions.
- In Northern Europe and North America, as well as, to a lesser extent, Japan and South Korea, **the buildings sector has been the backbone of natural gas demand**. Natural gas supplies 84% of U.K. households, for example, as well as many public-sector and commercial buildings.
- **In most developing countries**, natural gas consumption is largely restricted to cities, and rural areas mostly rely on biomass. Urbanization is therefore a driver for natural gas use in buildings.

1. Other fuels include wood and biomass, solar water-heating, geothermal, and combined heat and power; 2. Data are given for the residential sector only.
Source: GEA (2012), "Toward a Sustainable Future"; IEA (2012), "Energy Technology Perspectives 2012"

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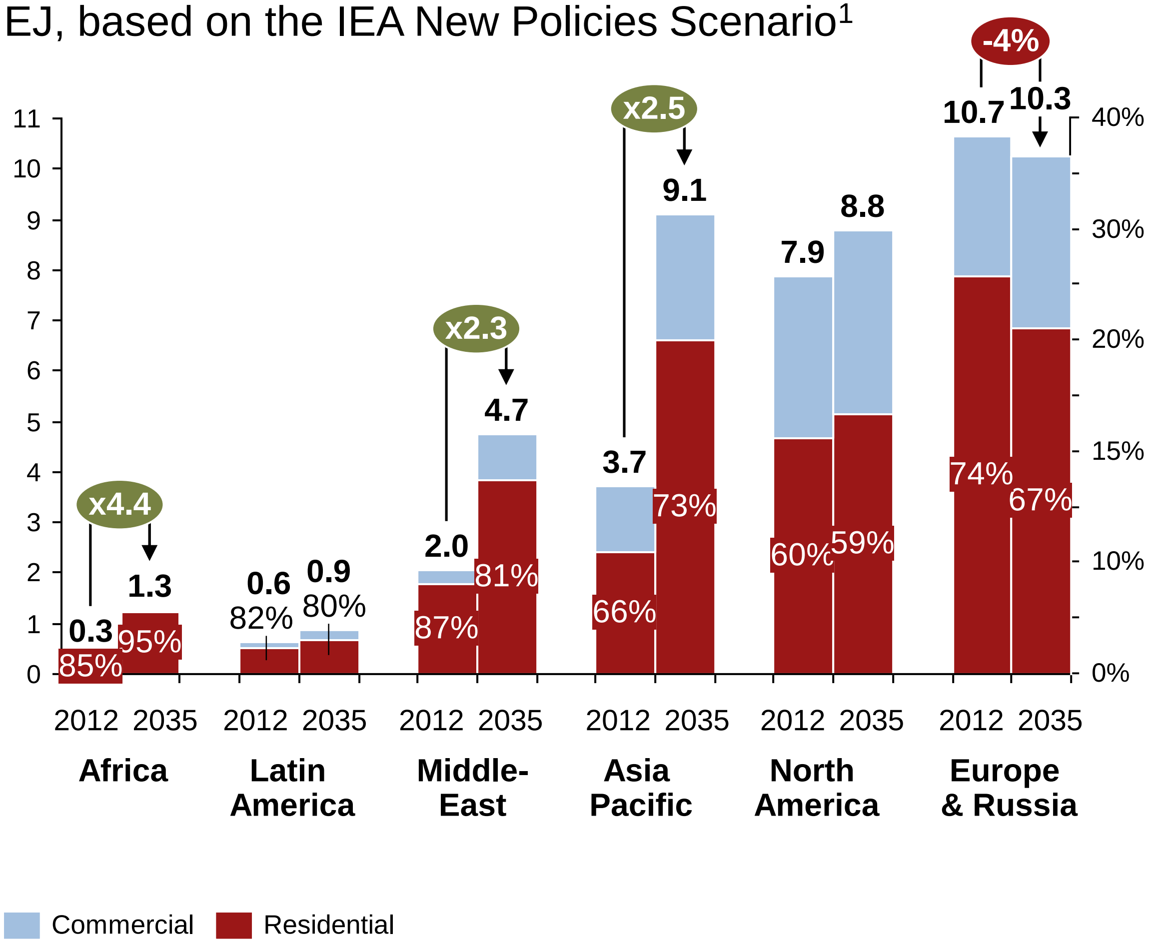
In the building sector, Asia and the Middle East are expected to be the main natural gas demand-growth drivers

Natural gas demand for buildings in 2012 and 2035

EJ, based on the IEA New Policies Scenario[1]



- **Natural gas demand for buildings is expected to increase slowly** in the next two decades, reaching 35 EJ at an average annual growth rate of around 1.5% for both the residential and commercial sectors[2].
- **This global increase conceals important regional contrasts**. **Asia-Pacific accounts for 55% of the incremental gas demand** expected by 2035 (China alone, 48%), followed by the Middle East (27%) and Africa (10%), where growth should be fastest. In these regions, the trend towards urbanization, combined with economic development, will contribute to a growing numbers of households being connected to gas-distribution networks and reduce dependence on bioenergy for heating and cooking.
- **Conversely, natural gas demand in North America should be relatively stable.** It is even expected to decrease slightly in Europe. This may be the result of the degree of economic development and of efforts to improve energy efficiency in buildings (*i.e.* providing the same energy services, with lower energy consumption) and to decarbonize heating and cooling (heat pumps, combined heat and power, solar heating and cooling...).

1. The New Policies Scenario is the International Energy Agency's reference scenario. The breakdown between commercial and residential has been derived from IHS data (Global Redesign Scenario, the closest to IEA New Policies Scenario); 2. Direct use only.

Source: IEA (2013), "Gas Medium-Term Market Report"; IHS forecasts Global redesign scenario (accessed May 2014)

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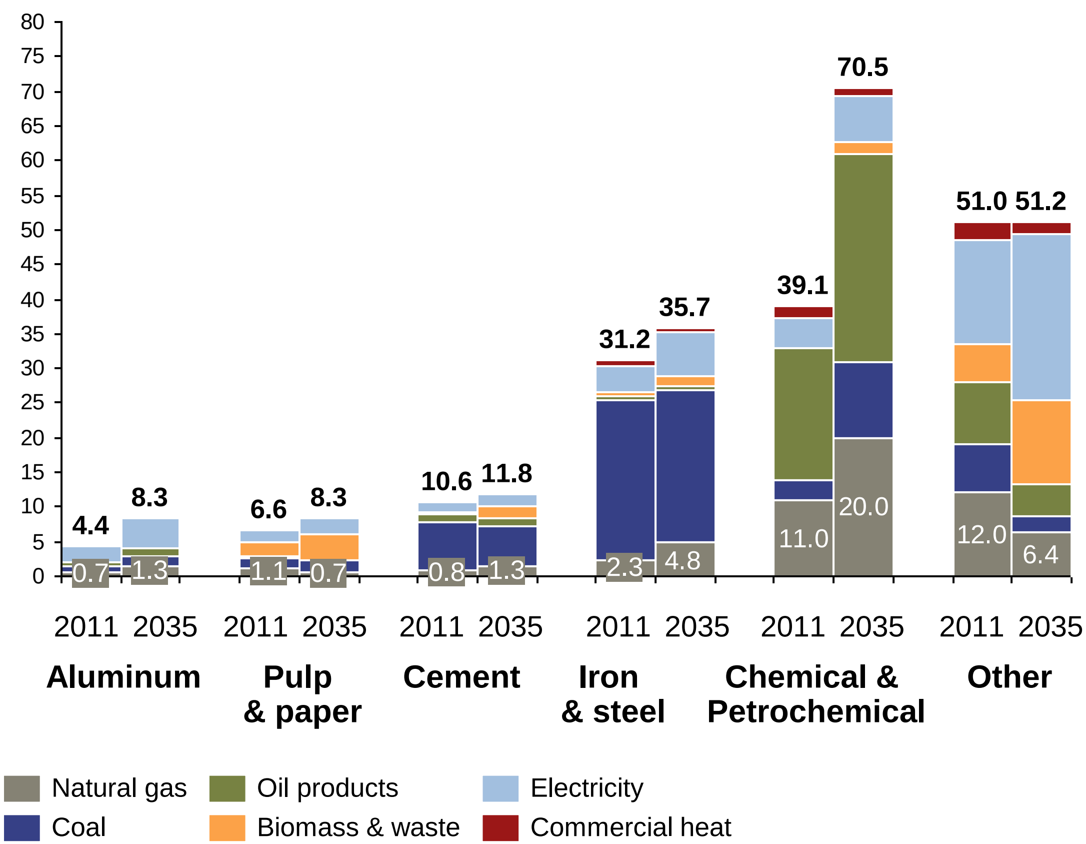
In industry, natural gas is used as a heat source and as a chemical feedstock

Energy breakdown by fuel and end-use

EJ, based on the IEA New Policies Scenario[1]



- **Direct natural gas consumption accounts for around 18% of industry's final energy consumption,** or 22% if natural gas-fired electricity is added. The industry sector is the third-largest consumer of natural gas, after power plants and buildings (23% of natural gas demand).
- **The chemicals and petrochemicals sector is by far the most important consumer** of natural gas in industry (44% of all industrial demand). In this industry, natural gas is not only used as a fuel, but also as a feedstock for producing ammonia, methanol and other chemicals. In other energy-intensive industries[2], natural gas continues to play a secondary role (*e.g.* in the iron & steel sector, coal accounts for 74% of the energy mix, compared with 7% in the case of natural gas). Therefore, with the exception of the chemicals & petrochemicals industry, the bulk of industrial gas demand comes from a wide range of industrial consumers who use natural gas in small-to-medium-scale boilers to generate heat.
- **In absolute terms, the consumption of natural gas in industry is expected to grow relatively slowly.** The IEA assumes, in its reference scenario[1], for instance, that natural gas demand in industry will grow at an annual average rate of 1.7% between 2011 and 2035, eventually reaching 39 EJ. Most incremental growth should come from sectors that are already the largest consumers of natural gas, although coal-to-gas switching in steel production could contribute 21% of expected growth.

1. The New Policies Scenario is the International Energy Agency's reference scenario; 2. Aluminum, pulp & paper, cement, iron & steel, and chemicals & petrochemicals are the main energy-intensive industries and together account for more than 50% of industrial energy demand.

Source: IEA (2014), "Energy Technology Perspectives 2014"

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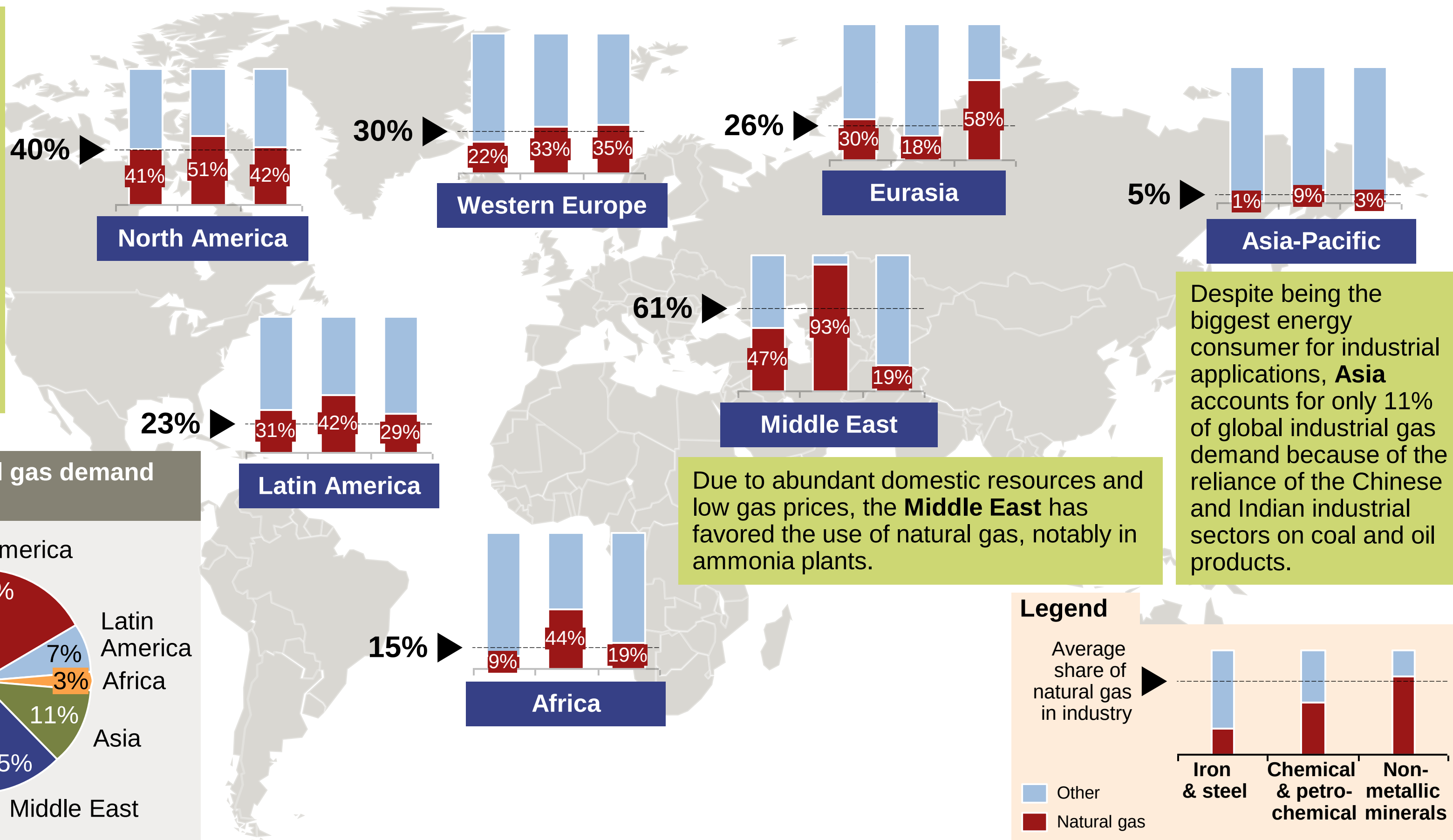
North America is leading growth in industrial natural gas demand, while Asia remains reliant on coal and petroleum products

Regional breakdown of Natural Gas Use in the industrial sector as of 2011

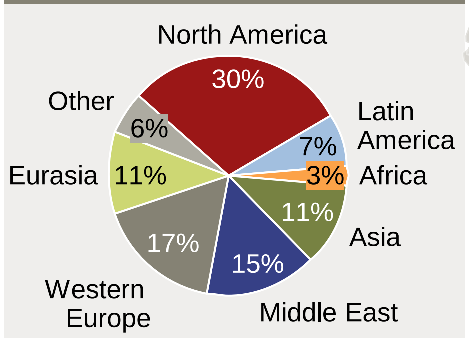
North America is the largest natural gas consumer for industrial purposes. Competitive gas prices are expected to increase natural gas consumption in industry, notably in the chemicals sector.



Due to abundant domestic resources and low gas prices, the **Middle East** has favored the use of natural gas, notably in ammonia plants.

Despite being the biggest energy consumer for industrial applications, **Asia** accounts for only 11% of global industrial gas demand because of the reliance of the Chinese and Indian industrial sectors on coal and oil products.

Share of industrial gas demand by region[1]



1. Country breakdown is based on IEA classification. Turkey is part of Western Europe, and Mexico is not included in North America.

Source: MIT (2011), “The Future of Natural Gas”; IEA (2013), “World Energy Outlook 2013”; IEA (2013), “Energy statistics of non-OECD countries”; IEA (2013), “Energy balances of OECD countries”

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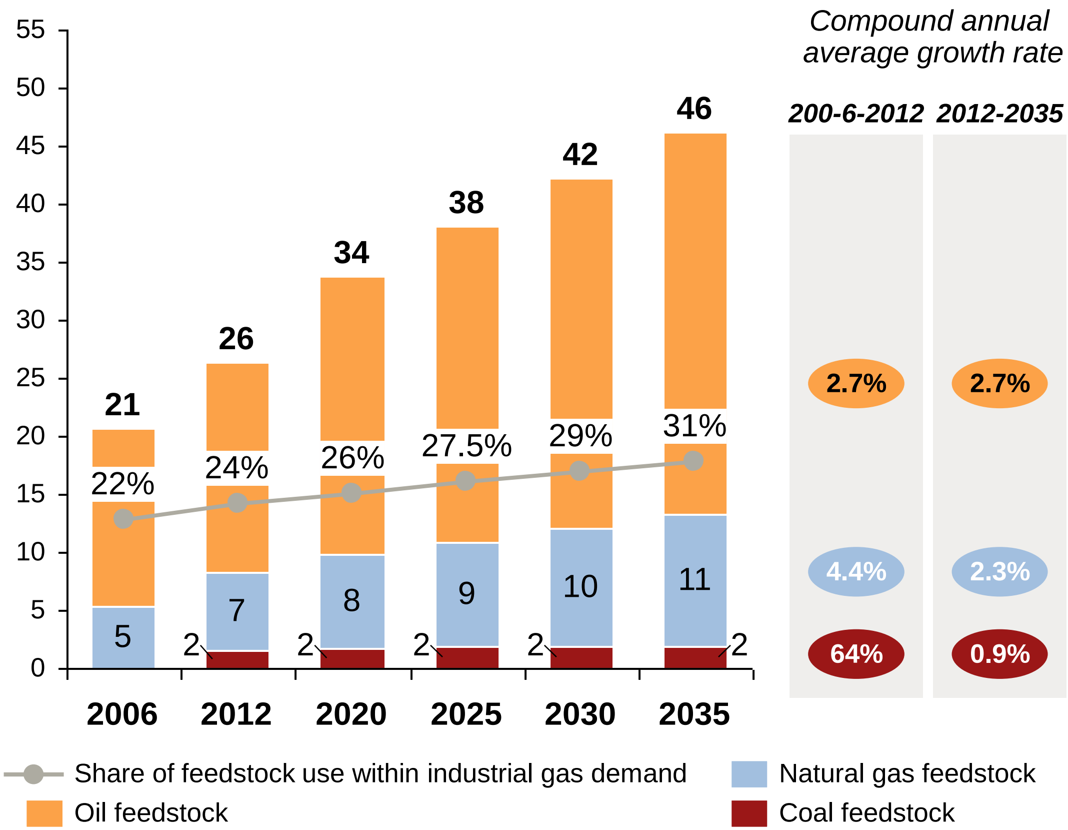
Natural gas is a crucial feedstock for the petrochemicals and fertilizer industries

Feedstock for the manufacture of chemicals

EJ, projections from IHS Global Redesign Scenario[1]



- **In addition to its use as a heat source, natural gas plays an important role as a feedstock for producing ammonia, methanol and other hydrocarbon-based products** (*e.g.* olefins, such as ethylene and propylene, using natural gas liquids[2]). Ammonia is one of the most extensively produced chemicals in the world, helping to create over 500 million tons of nitrogen fertilizer per year[3]. Similarly, methanol is a widespread chemical product, with around 100 million tons used every year as anti-freeze, solvent or fuel.
- **In recent decades, natural gas has become the primary feedstock in ammonia and methanol production**. Low natural gas prices and progress in plant design encouraged its use, leading to gains in energy efficiency. Steam methane reforming represents around 77% of hydrogen produced as a basis for ammonia; 75% of methanol production comes from natural gas. In both cases, the remainder is mainly made up of coal (especially in small-scale production in China) and of petroleum products (*e.g.* naphtha, notably in India).
- **Natural gas is likely to remain secondary in the manufacture of other hydrocarbon-based products,**. Indeed, industry expects faster demand growth for oil than gas for these purposes. Since natural gas is already largely dominant in the manufacture of ammonia and methanol, there is little growth to expect from fuel switching.

1. The Global Redesign scenario is IHS's closest equivalent to the IEA's New Policies Scenario; 2. Unlike ammonia or methanol production, olefins are most often produced by using natural gas liquids, as opposed to methane. For more information, please refer to slide 14; 3. As a compound of hydrogen and nitrogen (NH3), ammonia is a key intermediate step in the production of fertilizers such as urea, but is also used as refrigerant, cleaning agent and to neutralize flue gas.

Source: IHS database (accessed, May 2014); IEA (2009), "Technology Roadmap Energy and GHG Reductions in the chemical Industry via catalytic Processes"; IEA (2009), "Chemical and Petrochemical sector Potential of best practice technology and other measures for improving energy efficiency"

Interest in natural gas as an alternative transport fuel has been bolstered by favorable price spreads and natural gas's smaller environmental footprint than oil

Ways to use natural gas for transport

	Pros	Cons
CNG *Compressed natural gas*	• CNG refueling stations require lower investment costs than LNG refueling stations and result in lower GHG emissions (because CNG processes are less energy-intensive). It would also be easier to refit vehicles to run on CNG or as bi-fuel vehicles.	• CNG's lower energy density makes it less suitable for long-range, heavy-duty vehicles and high-mileage, light-duty vehicles. It may also be rejected by the public because of the perceived safety risk of high-pressure gas storage.
LNG *Liquefied natural gas*	• LNG benefits from a higher energy density than CNG, reducing mileage anxiety and resulting in greater autonomy. LNG is suitable for a large range of high-duty vehicles, and for marine, air and rail transport.	• LNG refueling stations incur higher capital costs than CNG-refueling stations. The liquefaction process also incurs an energy penalty and regular vehicle use is required to minimize fuel losses arising from boil-off.
Conversion to liquid fuels	• Converting natural gas into gasoline, diesel or other synthetic liquid fuels, such as methanol, can leverage infrastructure in place and allow use in existing vehicles without the need for retrofitting.	• Conversion is costly and incurs significant energy losses (especially for drop-in gasolines and diesels, which could be used without modification to the existing system).

- **Natural gas is garnering attention as an alternative to gasoline in the transport sector for three main reasons**. First, natural gas generally benefits from a **favorable price spread compared with oil** (on average, a 30-70% discount to gasoline on an energy-equivalent basis)[1]. Second, natural gas is seen as a lever for reducing **dependence on oil**, increasing security of supply in oil-importing countries and export capacity in oil-producing countries. Finally, natural gas may help **improve local air quality[2] and limit CO_2 emissions** at the point of use. Proponents of natural gas also argue that natural gas vehicles require less maintenance and are safer[3].
- Nevertheless, natural gas for transport is facing severe challenges and uncertainties. Although less severe than for battery or fuel-cell electric vehicles, the **infrastructure challenge** associated with the deployment of refueling stations needs to be overcome. The **initial cost premium of natural gas vehicles** (whether factory-produced or aftermarket-converted) over their liquid-fuel counterparts must also be addressed. In addition, at ambient conditions, natural gas's energy density is lower than that of gasoline and diesel, so natural-gas vehicles have a poorer range and their fuels require expensive conditioning. Finally, the **impact on global warming of using natural gas for powering vehicles remains uncertain and highly system-specific.** Indeed, well-to-wheel analysis depends heavily on whether or not there is methane leakage at any stage in the process (see slide 17).

1. Based on a gasoline gallon equivalent that provides the same mileage; 2. Natural gas reduces emissions of sulfur dioxides, nitrous oxides, particulates and mercury in cities, a key driver in countries such as China or India; 3. This is because natural gas burns more cleanly than gasoline, leaving fewer carbon deposits and because it is highly methane that has a narrower flammability range (5-15%).

Source: Morgan Stanley (2013) "Natural Gas as a Transportation Fuel Energy Market Wild Card"; MIT (2011) "The Future of Natural Gas"

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Light-duty road vehicles using compressed natural gas currently account for the bulk of natural gas use in transport

Natural gas applications for transport

1	**Road transport**		• Most mature market • Usually segmented into three categories of vehicles • Dedicated to gas, bi-fuel or dual
2	**Marine transport**		• Poorly developed except in the Baltic Sea and for LNG carriers • Good way of complying with pollution standards in maritime Emission Control Areas (ECA)
3	**Rail transport**		• Several projects under development in Russia, Brazil, India and North America • Strong focus on switch from diesel to LNG in freight rail • No fuel storage issues
4	**Air transport**		• Research stage • Could increase fuel efficiency • First uses focused on gas-to-liquids

- **Theoretically, natural gas can be used as a fuel for all modes of transport. However, with the exception of road transport, natural gas applications play a negligible role ,** and, in aircraft, are still at an early phase of development. Gas in road transport is also marginal.
- **Road transport vehicles are usually split into three categories**: light-duty vehicles (LDV), such as passenger cars and taxis; medium-duty such as trucks and buses. Other important criteria include mileage (low or high), refueling cycles (*e.g.* every week), and fleet membership.
- **In addition, there are three types of natural gas vehicles** (NGVs): dedicated, *i.e.* those running on natural gas only; bi-fuel, *i.e.* those with two fueling systems, allowing the use either of natural gas or gasoline; and dual-fuel, *i.e.* those that run on natural gas but that use diesel fuel for ignition assistance (limited to HDVs).
- **As of 2013, LDVs accounted for the bulk of NGVs on the road** (LDVs, MDVs and HDVs account for 93%, 4% and 2%, respectively) and CNG fuels 99% of NGVs. This may be explained by the fact that LDVs are more suited to CNG than other vehicle types, partly because they are easier and cheaper to convert.

Source: IEA (2013), “Medium-Term Gas Market Report 2013”; Macquarie (2012), “Natural gas: An economically viable alternative transportation fuel”

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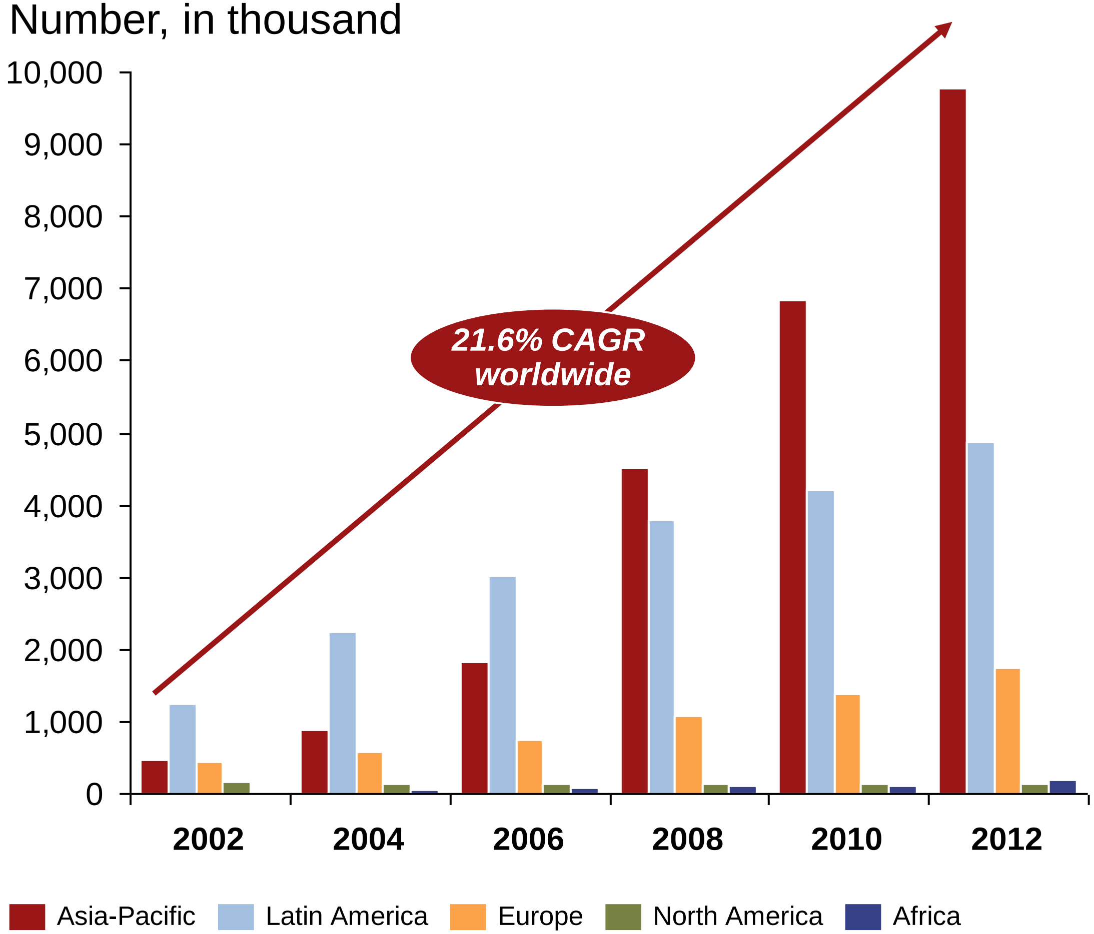
Natural gas has emerged as a credible alternative to oil since the 2000s, driven by ambitious programs in Asia and Latin America

Natural gas Vehicles deployment by region

Number, in thousand



- **The number of Natural Gas Vehicles (NGVs) has risen quickly since 2002,** at a 21.6% compound annual growth rate (CAGR) since 2002. There were 16.7 million vehicles on the road at the end of 2012. Unlike other end-use sectors, transport is almost totally dependent on liquid fuels derived from oil (96%). However, natural gas has become the third-most-important fuel for road transport, ahead of electricity and hydrogen, even though the latter two attract most of the attention.
- **This under-appreciated growth may be explained by the fact that the market is driven by Asia and Latin America, and** use of NGVs in **OECD[1] countries, with the exception of Italy, is negligible.** Asia-Pacific accounts for 58% of the NGVs on the road, led by two countries: Pakistan and Iran (which have a combined share of the world total of 69%). In Asia, NGVs market shares can be very large: up to 61% in Bangladesh, 30% in Armenia, 26% in Pakistan and 14% in Iran.
- **Historically, Latin America was at the forefront of NGV development** (in the early 2000s, it had a 53% share of the world market). Although it has been overtaken by Asia, Latin America remains a key area for natural gas use in transport. For example, NGVs account for 24% of passenger cars in Argentina. NGV development in Brazil – still in fourth place in terms of numbers of NGVs within Latin America – has been slowed down by growth in the country's biofuels industry. Colombia, Bolivia and Peru are the new market drivers.

1. OECD stands for Organisation for Economic Co-operation and Development.
Source: IEA (2013), "World Energy Outlook 2013"; NGV Global (2011), "2011 NGV Statistics"

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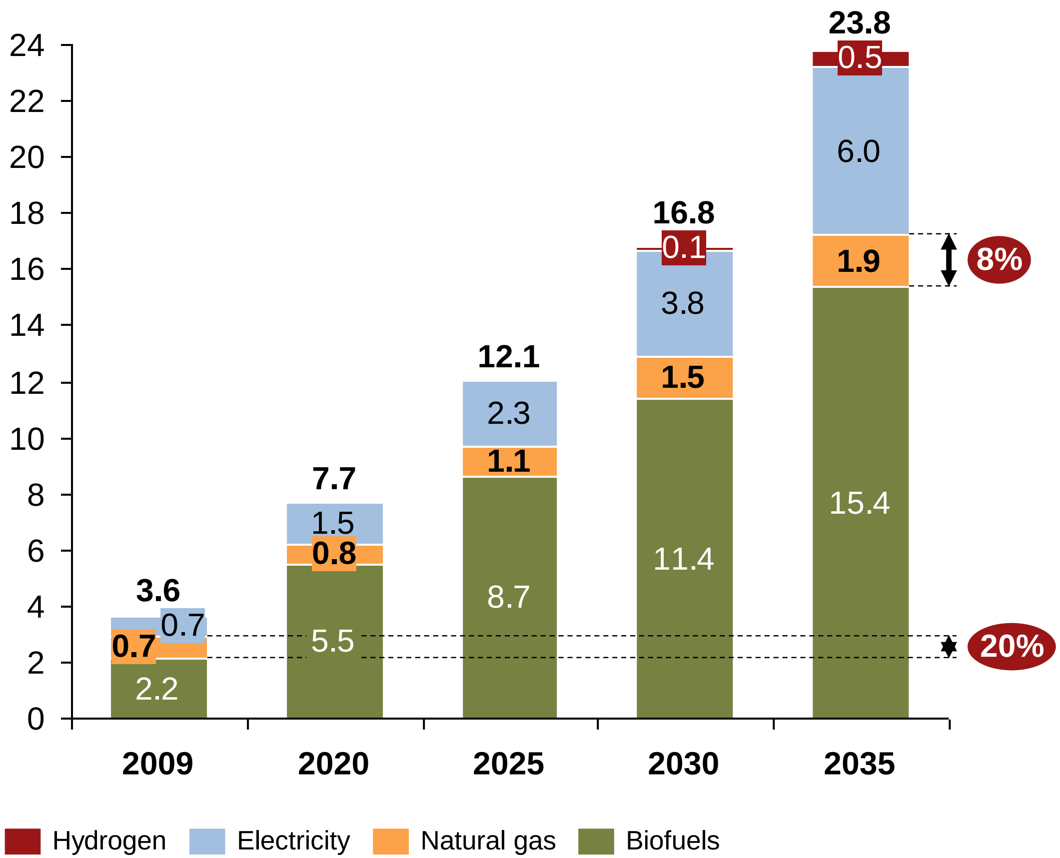
The outlook for natural gas in transport is uncertain: a tougher competition for alternative fuels could be balanced by growth prospects in China, India and the U.S.

Alternative fuels for transport

Exajoule (EJ) in the IEA 2DS scenario[1]



- **The fuel mix for transport is expected to continue to diversify** as a result of technology development and carbon constraints. Several alternatives are emerging and maturing, including a new generation of biofuels, and battery and fuel-cell electric vehicles. Therefore, **natural gas vehicles** (NGVs) **are likely to face mounting competition and their growth may slow down**.
- **China and India are expected to be the new drivers for NGVs**, overtaking Pakistan, Iran and Argentina. In China and India, NGVs may provide an efficient, low-cost way to reduce to local air pollution in the short term. In both countries, NGVs have a limited market share (1.2% and 3.5%, respectively) of rapidly expanding car markets, so the potential for growth is considerable. For instance, the IEA forecasts gas demand in China's transport sector to increase from 11 bcm/y in 2011 to 39 bcm/y in 2018.
- **Natural gas use may also rise in the U.S. transport sector.** The unconventional gas revolution, which has resulted in abundant domestic gas supply and low gas prices, has led to increased interest in NGVs.
- **Nevertheless, most energy scenarios still envisage a limited role for natural gas in transport**. For instance, if its most ambitious climate-change mitigation scenario is to be met, the IEA believes that natural gas's role as an alternative transport fuel will fall from 20% in 2009 to 8% in 2035, despite an increase in absolute consumption.

1. The 2DS Scenario corresponds to an energy system consistent with an emissions trajectory that recent climate-science research indicates would give an 80% chance of limiting the average global temperature increase to 2°C.

Source: IEA (2013), "Medium-Term Gas Market Report 2013"; Morgan Stanley (2013) "Natural Gas as a Transportation Fuel Energy Market Wild Card"

Appendix & bibliography

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Acronyms

bbl/d: billion barrels per day
bcm/d: billion cubic meters per day
bcm: billion cubic meters
boe: barrel of oil equivalent
CAGR: Compound annual (average) growth rate
CAPEX: Capital expenditures
CBM: Coalbed methane
CCGT: Combined-cycle gas turbine
CHP Combined heat & power
CNG: Compressed natural gas
CO_2: Carbon dioxide
EIA: Energy Information Administration
EOR: Enhanced oil recovery
FERC: Federal Energy Regulatory Commission
FID: Final investment decision
FNLG: Floating liquefied natural gas
FRSU: Floating regasification & storage unit
FSU: Former Soviet Union[1]
GHG: Greenhouse gas
GTL: Gas-to-liquids
GWP: Global warming potential
HDV: Heavy duty vehicle
IEA: International Energy Agency
EJ: Exajoule
kWh: kilowatt hour
LDV: Light duty vehicle
LNG: Liquefied natural gas
LPG: Liquefied petroleum gas
MDV: Medium duty vehicle
MBtu: Million British thermal units
mtpa: million tons per annum.
N/A: Not applicable
NETL: National Energy Technology Laboratory
NGL: Natural gas liquids
NGV: Natural gas vehicle
NOC: National oil company
OCGT: Open-cycle gas turbine
OECD: Organisation for Economic Co-operation and Development[2]
OIER: Oxford Institute for Energy Studies
OPEC: Organization of the Petroleum Exporting Countries
OPEX: Operational Expenditure
R,D&D: Research, development and demonstration
SNG: Synthetic natural gas
TPED: Total primary energy demand
UAE: United Arab Emirates
U.K.: United Kingdom
UKERC: United Kingdom Energy Research Centre
U.S.: United States of America

1. FSU includes Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Russia, Tajikistan, Turkmenistan, Ukraine and Uzbekistan; 2. OECD includes 21 European Union countries (all but Bulgaria, Croatia, Cyprus, Lithuania, Latvia, Romania and Malta) and Canada, Chile, Iceland, Israel, Japan, Korea, Mexico, New Zealand, Norway, Switzerland, Turkey and the U.S.

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Chemical symbols & general conversion factors

C_2H_6: Ethane

C_3H_8: Propane

C_4H_{10}: Butane

C_5H_{12}: Pentane

CH_4: Methane

H_2: Hydrogen

H_2O: Water

H_2S: Hydrogen sulfide

He: Helium

N_2: Nitrogen

General Conversion Factors for energy

1 **Gigacalorie** (Gcal) = 4.1868 x 10^{-3} **Terajoules** (TJ)

1 **Million tons of oil equivalent** (Mtoe) = 4.1868 x 104 **Terajoules** (TJ)

1 **Million british thermal units** (MBtu) = 1.0551 x 10^{-3} **Terajoules** (TJ)

1 **Gigawatt hour** (GWh) = 3.6 **Terajoules** (TJ)

1 **barrel of oil equivalent** (boe) = 6.1196 x 10^{-3} **Terajoules** (TJ)

General Conversion factors for volume

1 **U.S. gallon** (gal) = 3.7854 x 10^{-3} **cubic meters** (m^3)

1 **U.K. gallon** (gal) = 4.5461 x 10^{-3} **cubic meters** (m^3)

1 **barrel** (bbl) = 1.5899 x 10^{-1} **cubic meters** (m^3)

1 **cubic foot** (cft) = 2.8317 x 10^{-2} **cubic meters** (m^3)

1 **liter** (l) = 1.0x 10^{-3} **cubic meter** (m^3)

Other Conversion Factors

1 m^3 gas = 0.0411 **Million British thermal units** (MBtu)

1 cf gas = 0.0012 **Million British thermal units** (MBtu)

1 ton LNG = 53.38 **Million British thermal units** (MBtu)

1 m3 LNG = 24.02 **Million British thermal units** (MBtu)

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Pictures credits

Slide 1: Saipem 7000 pipe layer platform, world's second largest crane vessel built in 1986 by Fincantieri, Italy, Saipem

Slide 1: Natural gas flare on an offshore floating production storage and offloading (FPSO) unit

Slide 1: Al badar natural gas refueling station in Lahore, Pakistan

Slide 8, 1: Methane Rita Andrea 145,000 m^3 membrane-type LNG carrier built in 2006, Bermuda, GasLog LNG Service

Slide 22, 1: Offshore natural gas drilling platform

Slide 42, 1: Sabin Pass storage (~481 mmcm/d) and regasification plant (~113 mmcm/d), U.S., Cheniere Energy

Slide 47, 1: 4 million m^3/h natural gas compression station in Mallnow (3 x 26 MW compressors, operating at 100 bar max), Germany, WinGas

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Slide 60: 1.8 L powertrain Honda Civic GX natural gas light duty vehicle, American Honda Motor

Slide 60: World's first LNG-powered tugboat in Borgøy, Norway, Sanmar Shipshard

Slide 60: Russian GT1-001 gas turbine-electric locomotive powered by LNG (750 km range, with top speed of 100 km/h), Russia, Gazprom

Slide 60: Airbus A380's first GTL-powered flight from U.K. to France in partnership with Shell and Rolls-Royce, Airbus

Slide 82, 1: Gas distribution pipeline in Russia.

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