

# GAS

# Medium-Term Market Report 2015



## Market Analysis and Forecasts to 2020

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International  
Energy Agency

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# GAS

# Medium-Term Market Report 2015

**Market Analysis and Forecasts to 2020**



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Energy Agency

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## FOREWORD

What a difference a year makes. Only 12 months ago prices were generally much higher and significant disparities existed across regions. The outlook for gas was generally positive, and prospects for supply and investments looked robust. That picture, however, changed abruptly during 2014, with implications for policy makers, industry, and consumers alike.

Today we see the dramatic fall in oil prices having strong spill-over effects on gas markets. In the upstream sector, oil and gas companies are responding by cutting capital expenditure programmes, refocusing on core assets, and cancelling more costly, low-return projects. Unavoidably, this will lead to slower gas production growth over time. As a result, compared to our predictions last year, the five-year production projection in the *Medium-Term Gas Market Report 2015* is reduced substantially – by 140 billion cubic metres.

How will this affect markets? It depends where you are. In some countries, slower production growth will exacerbate shortages, thus constraining demand. In others, it is genuine demand weakness today that casts doubts over the outlook for tomorrow. Gas consumption in Asia, a region regarded as a future engine of growth, proved unexpectedly soft in 2014. Liquefied natural gas (LNG) markets have quickly transitioned from extreme tightness to oversupply. Regasification infrastructure stands idle in some cases, while spot LNG prices have fallen sharply.

High LNG prices in recent years have dented the viability of gas. Consumption growth is fading amid tough competition from coal and renewables. Does this mean that we no longer see a bright future for gas? Not necessarily, but it means that we may well be at a crossroads.

Low prices should lead to a re-acceleration in gas demand in the short run, but the long-term outlook is far less clear. The ability of the industry to adjust and of policy makers to reform will largely determine the role of gas in the global energy mix. In Asia, establishing price mechanisms that reflect gas fundamentals could help increase the fuel's attractiveness as a long-term strategic option. While today's low oil prices have re-aligned oil-linked gas prices with demand and supply balances, there is no guarantee that this will remain the case. Oil prices may rise again, and both consumers and producers would benefit from taking a far-sighted approach.

In LNG markets, large quantities of flexible supplies from the United States are on the way. But from a consumer standpoint, the economic attractiveness of the Henry Hub-linked model has narrowed substantially relative to the traditional oil-based one. What the impacts will be on the next generation of LNG projects remains to be seen.

Strong environmental policies can play a role in enhancing the position of gas. In addition to offering greater flexibility and enhancing energy security, as a transitional fuel gas can provide certain environmental benefits by reducing carbon emissions and air pollution relative to other fossil fuels. However, it is the availability of ample and cheap supplies that is by far the best means of ensuring a bright future for this fuel. The industry must now prove that it can deliver production economically, at prices substantially below those that have prevailed in the recent past. Only then will the role of gas as a key part of the energy mix be assured.

Several uncertainties surround this report's outlook. Technological advances, geopolitical changes, and strategic policy shifts can all give rise to an unexpected re-shaping of gas markets. Large-scale shale gas developments in Mexico and Argentina, a rapid uptake of gas in the transportation sector, the emergence of the Islamic Republic of Iran as an LNG exporter, or further acceleration in the Russian Federation's shift to the East might all become the next black swans of gas markets. Let us not forget that only a few years ago, the United States looked destined to remain a net LNG importer for decades to come. In the next five years, the United States will become a meaningful LNG exporter. In dynamic markets such as those for gas, change is sometimes the only constant.

This publication is produced under my authority as Executive Director of the IEA.

Maria van der Hoeven  
Executive Director  
International Energy Agency

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## EXECUTIVE SUMMARY

### Global gas demand growth re-accelerates amid growing uncertainties

The *Medium-Term Gas Market Report (MTGMR)* 2015 forecasts that global gas demand will re-accelerate following a marked slowdown in both 2013 and 2014. The expectation for stronger economic growth and lower oil and gas prices provides some support for demand, even though the improvement falls short of forecasts made in earlier versions of this report. Global gas demand is projected to grow 2% on average between 2014 and 2020, slower than the 2.3% averaged over the previous ten years, with several factors weighing on the scale of the recovery.

### *In OECD countries, slower thermal generation growth dampens gas demand increases*

In OECD countries, gas demand in the power sector remains challenged by sluggish electricity growth amid continued robust deployment of renewables. The resulting compression in thermal generation growth leaves limited space for gas demand increases despite substantial shut downs in coal-fired generation capacity in both Europe and the United States. In Japan, gas demand is set to fall. The only uncertainty is how fast, due to the fact that the scale and timing of the nuclear power comeback remain unknown.

### *In non-OECD Asia, the competitiveness of gas versus other fuels remains a key demand uncertainty*

The past two years have brought a harsh reality to the eyes of the gas industry: in a world of very cheap coal and plummeting renewables costs, it was difficult for gas to compete. Gas demand growth has increased well below its ten-year average in both 2013 and 2014, and many parts of Asia have emerged as key areas of weakness. Very high import prices in 2013 and 2014 have undermined gas consumption growth, especially in the power sector. Several Asian countries took active steps to limit the share of gas usage in their power mix and have prioritised coal capacity expansions over those of gas. Other countries have run their regasification infrastructure and gas-fired power plants well below their full potential despite facing substantial power shortages in some cases.

Plunging oil and gas prices raise the question of how demand, particularly in Asia, will respond. While this report forecasts a price-driven increase in consumption, the sensitivity of Asian demand to lower prices is uncertain and has yet to be fully tested. In the short run, better affordability of gas imports is likely to result in higher consumption, particularly where this serves to reduce shortages rather than placing gas in direct competition with coal. But in the medium term, the picture becomes more complex. Trust in gas as an attractive strategic option must increase for the fuel to make sustained inroads in the energy mix of much of developing Asia. While environmental policies can play an important role in this regard, they will not do the job by themselves; thus the gas industry must prove it can deliver gas supplies at price levels substantially below those that have prevailed in the recent past.

### *China's gas demand growth slows amid major changes in its energy consumption patterns*

China's gas demand growth slowed down to single digits in 2014, a substantial slowdown from the 14% averaged during the prior five years. Considering the massive slowdown in primary energy consumption that is taking place in the country, this growth rate is still impressive. Profound changes are unfolding in China in relation to both the structure of the economy and the way energy is

deployed. However, the net effect of these transformations is less clear for gas than it is for other energy components. On the one hand, slower economic growth and the sharp slowdown in primary energy consumption growth are strong headwinds for gas. On the other hand, the ongoing intensification of China's environmental policy should be broadly beneficial for gas. In this respect, lower import prices have the potential to turn gas into an increasingly attractive option from an environment viewpoint. While the fuel remains uncompetitive when compared with coal, the price spread between the two has narrowed appreciably and has the potential to move the balance between the economic cost of using gas and its perceived environmental benefits. Overall, this outlook forecasts a moderate re-acceleration of gas consumption growth from the lows of 2014, and an average annual increase of 10% throughout the rest of the decade is projected.

### *Demand growth in Latin America, Africa, and the Middle East is constrained by supply availability*

In all these regions, production growth falls short of actual demand potential, and supply shortages remain a chronic problem, particularly where access to gas imports is limited. A combination of ill-conceived upstream policies and lower oil and gas prices weigh on production growth. In Africa, gas production is forecast to return to growth after a seven-year streak of volatile output around a declining trend. Despite the increase, the existing tension between meeting export commitments and responding to domestic demand needs is not yet resolved. As a result, the reliability of Africa's exports remains at risk, and prospects for consumption growth are capped. In Latin America, production growth will decelerate sharply relative to its recent past performance, mainly driven by countries other than Brazil and Argentina. Overall, Latin America will be forced to rely more heavily on imports to support relatively modest consumption growth.

### **Lower oil prices result in slower gas production growth over the next five years**

In June 2014, Brent prices averaged above USD 110/barrel (bbl). In January 2015, they averaged below USD 50/bbl. While prices have recovered from their lows, they remain locked in a USD 55-70 range at the time of writing. The implications of such a steep and sudden oil price resetting go far beyond the oil market itself. Gas, through its direct and indirect linkages to oil, is not immune to the tremors shaking the oil industry.

Low oil prices have clear knock-on effects on upstream investments. Oil and gas companies are responding to the new market environment by cutting capital expenditure programs. Budgets for 2015 have already shrunk, but in the absence of a meaningful price recovery, deeper cuts will follow. Companies are refocusing on core assets while putting large investments through a much tougher vetting process. Amid squeezed cash flows, more costly, low-return projects will be cancelled. As a result, growth in global gas production is set to slow.

Due to its capital-intensive nature, the liquefied natural gas (LNG) industry faces an uphill battle. Those projects currently under construction today are set to come on stream broadly as planned, as large upfront capital costs have already been incurred. Beyond that, however, new LNG plants will struggle to get off the ground. Today LNG prices simply do not cover the capital costs of new plants. Several projects have already been scrapped or postponed, and the number of casualties will rise if prices do not recover. Final investment decisions (FID) taken in the next 24 months will determine the amount of incremental LNG supplies available in the early part of the next decade. If current low prices persist, LNG markets could start to tighten up substantially by 2020.

Over the next two years at least, however, the LNG market will have to cope with a flood of new supplies. Global LNG export capacity additions throughout 2020 will amount to more than 40% of today's existing infrastructure with almost half of the incremental supply due on line in 2016 and 2017. In the short run, the responsiveness of LNG supplies to prices is low since operating costs are a fraction of the overall cost of building a plant. As long as prices are high enough to cover operating and transportation costs, LNG plants will run at full capacity as operators try to recover as much as possible of the large upfront sunk cost. In this context, excessive supplies will have to be absorbed via a price-driven response on the demand side. Asian spot LNG prices have already halved since 2014 and oil-linked contracts have also started to fall. The price responsiveness of gas demand in this new environment will be tested.

Amid falling prices and budget cuts, the US gas industry is showing an unparalleled ability to absorb shocks. US gas production increased robustly last year and has remained on an upward trend thus far in 2015. While companies' cash flows are falling, producers are responding by quickly pushing the profits' squeeze downstream. Service costs have already dropped substantially and further reductions are likely, which should attenuate the impact of low oil prices on drilling programmes. Overall, the dynamic and flexible nature of the US gas supply chain is allowing the industry to efficiently adjust to changing market conditions. Production growth in core areas of prolific shale gas formations is set to prove resilient to low oil prices. In particular, the production outlook for the Appalachian Basin remains bright, and while rig activity in the region was scaled back in early 2015, this came more in response to plummeting gas prices amid excessive supplies than as a consequence of lower oil prices.

## European gas markets face a challenging geopolitical background

The year 2014 was shaped by an escalating conflict between Russia, Europe's largest gas exporter, and Ukraine – Europe's most important transit country. This confrontation is having major repercussions on trade, financial, and energy relationships within the region. Public perception of and policy makers' confidence in gas is deteriorating while a growing sense of urgency in regard to enhancing Europe's security of supply can be detected.

The Energy Union Framework Strategy launched by the European Commission earlier this year is well attuned to these new developments. Access to sufficiently diversified gas supplies and stronger infrastructure connectivity are presented as two main pillars of Europe's future gas strategy. This report has an insight focus section analysing the progress made in strengthening European gas infrastructure in recent years and the major bottlenecks that still remain. One key conclusion is that ensuring full bi-directional flow capability on major lines that still lack it would be a low-cost option to fully leverage Europe's existing LNG, storage, and domestic production capabilities in the event of a high-scale supply emergency.

Major strategic shifts in Russia's gas export policy are occurring as well. Russia's efforts to lock in export agreements with China have intensified, reflecting Russia's strategic choice to diversify to the East. Russia recently stated that China is on track to become its largest export market, ahead of Germany and Turkey, over the medium term.

At the same time, the abrupt cancellation of South Stream and the new Turkish Stream proposal marks a major change in Gazprom's strategy towards Europe. While a desire to bypass Ukraine as a transit country remains firmly embedded in the choice to build a new route through Turkey,



Gazprom has now backtracked on its previously held position to build the required connecting lines through European territory. The proposed Turkish Stream envisions a different role for Gazprom. Russian volumes would be delivered at a newly created gas hub at the Turkish/Greek border with the responsibility of building the required missing infrastructure shifting to European buyers. The company has gone so far as to suggest that it might stop any transit gas through Ukraine by December 2019. While Gazprom's position has seemingly become more nuanced in recent months, and existing contractual obligations make any swift change in the delivery point of Russian gas unlikely, recent developments point to new challenges in the relationship between Europe and its major gas supplier.

Against this backdrop, Europe's gas import dependency will continue to increase. Lower oil prices and stricter self-imposed caps on Dutch production will result in faster domestic output declines than forecast in previous *Medium-Term Gas Market Reports*. By 2020, OECD Europe gas production is expected to stand 25% below its 2010 level. Compounding the declining trend in production is a moderate recovery in demand. Weather normalisation after a very mild 2014 plays an important part in that improvement, but higher gas usage in the power sector to compensate for the shutdown of coal-fired generation capacity is also a driver. As a result, European gas import requirements are set to increase by almost one-third between 2014 and 2020. With large quantities of cheap LNG supplies available, at least in the earlier part of the forecast period, Europe's growing import needs might well offer a welcome outlet to LNG exports struggling to find a home. This report forecasts European LNG imports to roughly double between 2014 and 2020. Even in this context, however, Russian gas is not set to be meaningfully displaced. Russian deliveries to Europe are expected to rebound following the weather-induced collapse of 2014 and then remain locked in a 150-160 bcm range for the medium term.

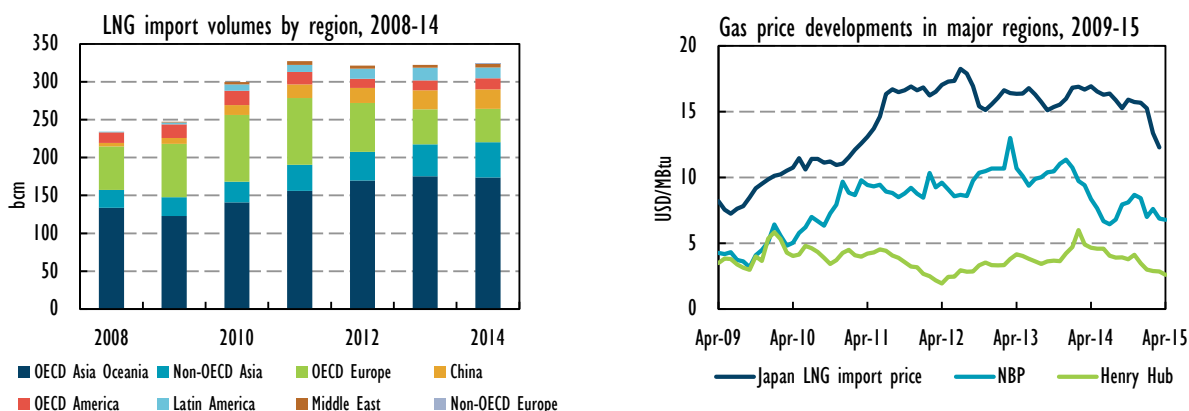
# 1. 2014 IN REVIEW: KEY MARKET DEVELOPMENTS

## Increased LNG capacity expected soon after false starts

After years of delays and large cost overruns, a huge number of Australian liquefied natural gas (LNG) projects are now crossing the finishing line. Queensland Curtis LNG, the first of seven projects due on line by 2018, began operations in December 2014. Between 2015 and 2018, 72 billion cubic metres (bcm) of new LNG export capacity will become operational in the country. With the benefit of hindsight, carrying out such a large simultaneous expansion programme seems to be questionable from a business perspective. However, for the market, the key issue is that the roll out of this long-awaited programme is finally coming to fruition. The sharp compression in spot Asian LNG prices relative to European gas prices is the reflection of a turning point in global gas market dynamics.

Regional price spreads saw dramatic fluctuations in 2014, with Asian prices falling sharply relative to European benchmarks (see Figure 1.1). In the spot market, the so-called “Asian premium” has disappeared.

**Figure 1.1** Regional price and LNG import development



Source: GIIGNL (2015), *The LNG Industry in 2014*, Paris, [www.giignl.org/publications](http://www.giignl.org/publications).

High prices and macroeconomic factors put pressure on consumption just as new liquefaction capacity was being brought on line. Capacity additions in 2014 were almost three times as large as those for the period 2011 to 2013, with three new plants beginning operations. The start-up ahead of schedule of Papua New Guinea LNG (PNG LNG) resulted in unexpected additional supplies for an industry so accustomed to operate under the assumption of delays. Asian spot prices plummeted during the fourth quarter of 2014 and the first quarter of 2015; the fundamentals were amplified by the inefficient and illiquid nature of Asian spot LNG markets. In February 2015, the spread between Asian spot LNG and National Balancing Point (NBP) prices turned negative for the first time in four years.

The paradigm of very tight global LNG markets clearing via price-driven changes in LNG trade flows has permanently shifted. LNG exports did not grow between 2011 and 2014. High import requirements from Asia, Latin America, and the Middle East were met due to large diversions of LNG flows away from Europe (see Figure 1.1). Weaker European demand and the region's ability to arbitrate between LNG and piped gas made such substantial re-adjustment possible.

Moreover, new dynamics started to emerge in 2014. The large, weather-induced drop in European demand was met almost entirely by (lower) Russian imports, which fell by 15 bcm year-on-year. LNG imports declined, but at a much slower rate than in 2012 and 2013. This was due to higher supplies and slower Asian demand growth. In OECD Asia LNG imports fell for the first time since 2009, while they remained subdued in the People's Republic of China ("China") and India. In Europe, re-exports ground to a halt in early 2015, while imports increased in the first quarter of 2015. The disappearance of west-to-east arbitrage opportunities raises questions about how LNG markets will clear in the future, with large liquefaction capacity additions looming amid a lack of a clear demand pull.

### **Expensive LNG could not compete with increasingly competitive renewables and cheap coal in 2014**

In a world of very cheap coal and plummeting costs for some renewables, it became difficult for gas to compete in the power sector. Weaker gas demand growth in many parts of Asia – in 2013/2014 – suggests that double-digit gas prices hindered gas from making inroads in Asia's energy mix. In India, gas consumption remained severely constrained by both the impact of falling domestic production and prohibitively expensive LNG imports. The country's regasification infrastructure ran well below capacity, and the utilisation of its gas-fired power fleet was just above 20% in 2014. Such low gas usage in the power sector echoes recent European experience. However, while Europe suffers from overcapacity in the power sector, India faces severe power shortages. A similar, albeit less extreme, picture can be painted for Southeast Asia.

### **China gas demand growth slows down amid large changes in the country's energy consumption patterns**

Despite economic growth above 7%, China's coal consumption fell in 2014 and growth of total primary energy demand slowed down significantly. This points to enormous changes currently unfolding, regarding the structure of the economy and the way energy is deployed. Gas stands to benefit from the ongoing intensification of China's environmental policy but also has to contend with slower growth in primary energy consumption and the rapid deployment of renewables. So, the net effect of this ongoing structural transformation in China is less clear for gas than for other energy components. In 2014, high gas import prices added to those broader trends, resulting in the slowest gas demand growth since at least 2009.

China's gas demand is estimated to have increased between 8% and 9% in 2014, a substantial decline from the 14% averaged during the previous five years. Considering the massive slowdown in primary energy consumption taking place, this growth rate still looks impressive.

High gas prices were a major strain on consumption in 2014. The average import price for LNG was USD 10.6/million British thermal units (MBtu). As recently as 2010, that price was 60% lower. Additionally, the 2013 price reform effectively resulted in higher gas prices for all sectors, except the residential, as incremental gas (defined as the volume of domestic and pipeline gas produced and imported above the 2012 level) started to be priced against oil products.

Meanwhile, existing gas prices were hiked twice since the reform was enacted. All non-residential sectors – with the exception of fertilisers – saw their city-gate price increase by 880 CNY/1 000 cubic metre between July 2013 and September 2014, which equates to roughly USD 3.4/MBtu. While gas prices increased, coal prices remained low. As a result, natural gas became more expensive in both absolute and relative terms.

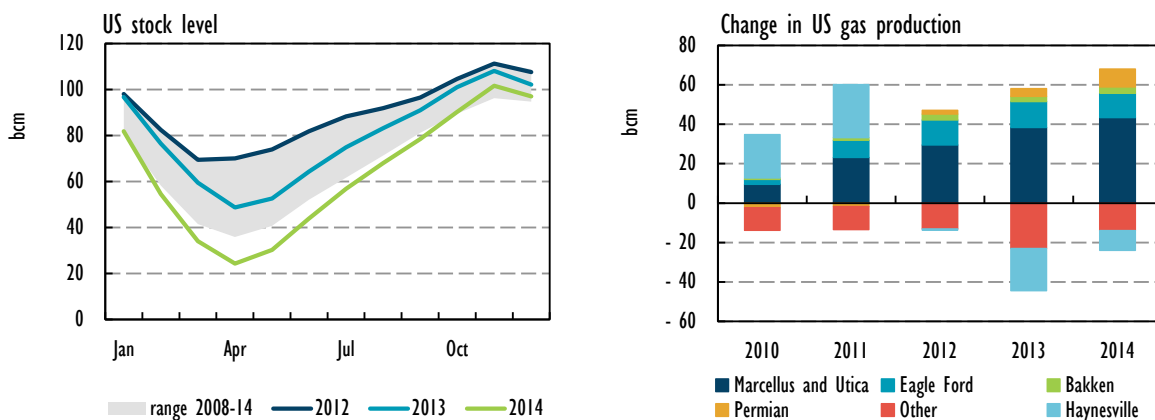
According to estimates for the price-sensitive power generation sector, gas usage increased by less than 4% in 2014, despite 10 gigawatt (GW) of new gas-fired generation capacity being added (an estimated 20% year-on-year increase). Abundant hydro availability helped to reduce the need for gas-fired generation dispatching. However, the negative economics of running gas plants slowed down demand. The residential sector bucked the broad-based slowdown, as consumption expanded robustly which was helped by unambiguous policy support and continued expansion of the pipeline distribution network.

### US gas production soars despite plunging oil prices

US gas production increased by 5.7% in 2014, the fastest growth since 2011. Additional output totalled almost 40 bcm, equal to the incremental volume of the two preceding years (2012 and 2013) combined. Production has continued on an upward trend in Q1 2015, reflecting the US oil and gas industry's unparalleled ability to absorb shocks. Producers' cash flows are falling sharply, but the impact on gas drilling programmes is softened by their ability to quickly pass the profits' squeeze downstream. Service costs have already dropped by about 15%, and further substantial reductions are likely before year end (2015).

In 2014 a disproportionate amount of the growth came from the Marcellus and Utica formations: production jumped from 140 bcm (end of 2013) to almost 180 bcm (end of 2014). Associated gas production in North Dakota and Texas also grew significantly, adding an estimated 15 bcm, more or less offsetting production declines elsewhere.

**Figure 1.2** US stock levels and change in US gas production



Source: IEA calculations based on data from the US Energy Information Administration.

Gas prices were higher in 2014. Henry Hub benchmark futures averaged USD 4.4/MBtu, the highest level since 2010. The need to stimulate a fundamental rebalancing, after an extremely cold winter, put upward pressure on prices throughout spring and summer. The scale of production response that followed was astonishing. At the end of March 2014, US gas inventories stood a massive 27 bcm below levels reached the year before. However, by the end of October, that gap had almost closed, with cumulative annual production additions totalling 25 bcm over the period. The magnitude of the supply-side response brought about by a small price increase (about USD 0.4/MBtu between April and October) is further evidence of the surprisingly high supply-side elasticity of the US gas industry.

As the steep production uptrend continued into the winter 2014/15, prices could not be maintained due to the absence of extreme weather experienced the year before. So, in Q1 2015 Henry Hub prices averaged less than USD 3/MBtu. The US gas market continues to show a tendency to tip into oversupply, with brief peaks of strength largely due to specific weather conditions.

### **Ukraine proving to be a reliable transit country while the Russian-Ukraine crisis causes deteriorating European confidence in gas**

The escalating conflict between Ukraine and the Russian Federation (“Russia”) was accompanied by a price and debt dispute which resulted in Russia cutting gas supplies to Ukraine in June 2014.

A winter package was ultimately signed in late October 2014 following several rounds of negotiations moderated by the European Commission. Under the terms of the deal, Ukraine settled USD 3.1 billion in debt payments. In exchange, Russia agreed to deliver gas without charging the export duty, following payments in advance. Ukraine could then order what was needed, without being subject to take-or-pay obligations. Outstanding issues are expected to be clarified by the Stockholm arbitration court in Q2 2016.

In the end, Ukraine did not resume imports of Russian gas until December 2014, relying instead on reverse flows, its own production and storage draws. For the full year, Russian imports averaged just 14.5 bcm compared with 28.8 bcm in 2013. Reverse flows totalled 5.1 bcm in 2014, 75% of which was imported between September and December. Reverse flows have continued at high levels in Q1 of 2015, helped by capacity expansions in the Slovak Republic to Ukraine direction. Ukraine’s storage exited the winter at below normal levels and high injections will be required through Q2 and Q3 of 2015.

In early April, the winter agreement was extended for three months. Ukraine will continue to buy gas at a USD 100/1 000 cubic metres (m<sup>3</sup>) discount relative to the price implied by the underlying long-term supply contract between Russia and Ukraine. This should de facto bring Russian gas in line with market prices at the time the deal was signed.

Despite being cut off for several months, Ukraine has fulfilled all its gas transit obligations. Moreover, the country’s leaders showed a strong commitment to deal with the difficulties in managing their own domestic energy system, while preserving transit flows. Nevertheless, with the conflict still unresolved and no outlook beyond Q2 of 2015, the supply risk to Europe remains unusually high.

The conflict between Russia, Europe’s largest gas exporter, and Ukraine, its most important gas transit country, has had major repercussions on trade, financial and energy relationships within the region. As a result, public perception of and policy makers’ confidence in gas have deteriorated while discussions over how to ensure security of supplies to Europe have intensified. In this context, the European Union launched the Energy Union Framework Strategy, which considers security of supply as a key priority.

### **Stagnating electricity consumption in OECD countries**

Electricity consumption in OECD countries was weak in 2014. Even those economies which experienced recovering economic growth tended to show soft electricity generation growth. In the United States, total generation increased by just 0.6% to stand at a level below that averaged in 2010. In Germany, power demand actually contracted. Overall, flattening electricity consumption growth in the OECD is a hindrance for gas which already suffers from continued growth in the generation of renewables.

## **Stricter environmental regulation for key energy consumers points to a policy shift away from coal and towards gas and renewables**

In the United States, regulation enacted in recent years will lead to the closing of old coal power plants. Some facilities are already shutting down, mainly due to the implementation of the Mercury and Air Toxics Standards (MATS), with an estimated 40-50 gigawatts (GW) of coal capacity to be decommissioned by 2019. The “Clean Power Plan”, set out by the Environmental Protection Agency (EPA) in June 2014, indicates a deepening commitment to tackle greenhouse gas emissions from the power sector. The plan has an emission reduction goal of 30% by 2030, relative to a 2005 baseline. The trajectory of coal capacity will be mostly affected after 2020, but, eventually, the plan will benefit gas usage in conventional power generation. In Europe, old coal-fired generation capacity will close down in coming years, due to the effect of the Large Combustion Plant Directive. In China, the government in 2014 announced strengthened national action to address air pollution and climate change: Premier Li Keqiang declared a “war on pollution”, while President Xi Jinping called for “an energy revolution” to tackle not only demand and supply bottlenecks and innovation, but also the environmental impacts of the production and consumption of energy. The government’s vision has been translated into a number of national targets, including capping China’s primary energy consumption and limiting the share of coal in the country’s energy mix. Gas is benefiting from these policies, particularly in the residential sector.

## **Reference**

GIIGNL (International Group of LNG importers) (2015), *The LNG Industry in 2014*, Paris, [www.giignl.org/publications](http://www.giignl.org/publications).



## 2. DEMAND

### Summary: Natural gas still has an uncertain position in the global energy mix

- Global gas demand is forecast to increase at an average annual rate of 2% between 2014 and 2020. This compares with an average annual increase of 2.3% over the past ten years. In absolute terms, cumulative growth stands at 431 bcm, 48% of which comes from the power sector. In relative terms, the transport sector is the fastest growing end-user segment with consumption forecast to grow by 47 bcm (5.7% CAAGR).

**Table 2.1 World gas demand by region (bcm)**

Country	2014	2016	2018	2020	CAAGR
OECD Europe	458	489	493	500	1.5%
OECD Americas	945	968	991	1 006	1.0%
OECD Asia Oceania	237	242	243	245	0.6%
Africa	123	131	139	147	3.0%
Non-OECD Asia (excl. China)	298	315	335	355	2.9%
China	178	219	270	314	10.0%
FSU/non-OECD Europe	674	668	673	679	0.1%
Latin America	168	169	177	186	1.7%
Middle East	414	435	464	493	3.0%
<b>Total</b>	<b>3 495</b>	<b>3 635</b>	<b>3 785</b>	<b>3 926</b>	<b>2.0%</b>

Notes: FSU = Former Soviet Union. 2014 figures are estimates. bcm = billion cubic metres. The compounded average aggregated growth return (CAAGR) is different for production and demand due to estimated stock changes in 2014. The world total production and demand differ due to estimated stock change and rounding.

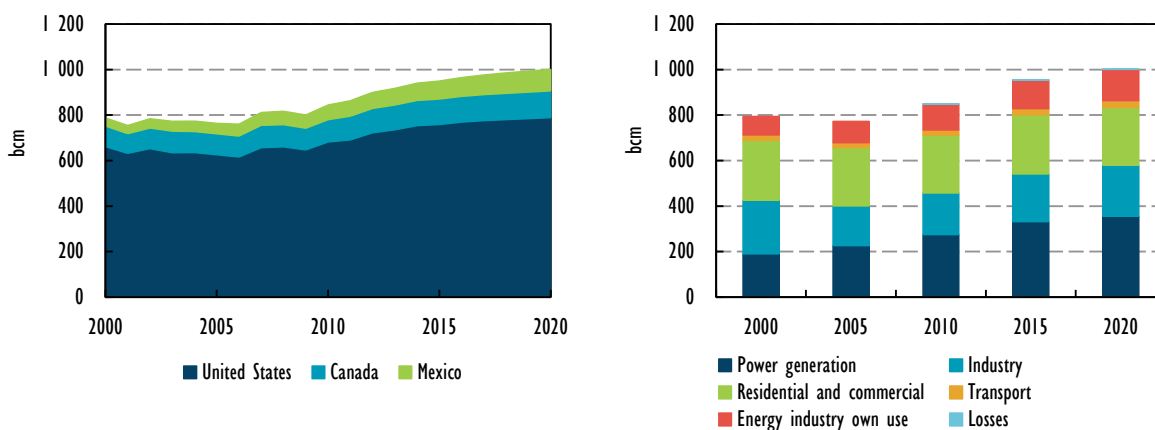
- The outlook for gas in power generation looks increasingly uncertain due to the effect of opposite forces. In many OECD countries, electricity growth is sluggish even when economic activity is expanding. The result is slower thermal generation growth while deployment of renewables continues fast. Conversely, coal-fired generation has already peaked, in both Europe and the United States and further shut downs will occur due to environmental policies, leaving some space for gas demand growth.
- In non-OECD Asia outside of the People's Republic of China ("China"), the competitiveness of gas versus other fuels remains a key demand uncertainty, especially in the power sector. Gas consumption, weaker than expected over the past two years, was undermined by very high prices. Several countries took steps to limit the share of gas usage in their power mix and have prioritised coal capacity expansions over gas. The question remains how Asian demand will respond, considering plunging oil and gas prices. This report forecasts a price-driven increase in demand, particularly in countries where higher gas demand alleviates shortages rather than entering in direct competition with coal.
- The energy transformation in China is remarkable. Primary energy consumption growth slowed down significantly in 2014, while coal demand actually fell. In this context, last year's moderate slowdown in gas consumption growth still looks impressive. Evidence of increased intensification of the country's environmental policy bodes well for gas, particularly in the residential and transportation sector. However, in power generation, gas penetration will continue relatively slowly. Competing with coal is harder than in other demand segments due to less policy support. Fast deployment of renewable generation also curbs gas demand growth in the power sector.

- FSU demand is forecast to flat line at the historically low level of 2014, with the balance of risks to the downside. Gas demand in both Ukraine and the Russian Federation (“Russia”) is negatively affected by persisting economic weakness and rising efficiency, which is also encouraged by mounting financial pressures. Rising demand in the Caspian region offsets a small projected decline from Russia.
- Demand growth in Latin America, Africa and Middle East is heavily affected by supply availability. In Latin America, production growth will decelerate sharply compared with the recent past and the region will be forced to rely more heavily on imports to support consumption growth. Expansion in the region’s import capacity coupled with ample liquefied natural gas (LNG) availability globally should allow Latin America’s demand to increase at an average annual rate of 1.7%. This report assumes some normalisation in Brazil’s hydro conditions, in spite of 2015 shaping up as a third straight year of severe drought. In Africa, gas demand is forecast to increase at an annual average of 3%, about in line with the growth recorded over the past six years. In the Middle East, demand growth will decelerate relative to the recent past, largely due to a weak outlook for Qatar.

### OECD Americas: Steady growth

OECD America’s gas demand is forecast to increase at an average annual rate of 1% between 2014 and 2020. Weather-adjusted growth should be higher at around 1.4%, due to the abnormally high winter demand in the United States (US) in early 2014. The power sector accounts for roughly 65% (40 bcm) of the overall increase, while positive contributions from the industrial sector broadly offset losses in the residential and commercial segments. From a country standpoint, the United States drives the bulk of the weather-adjusted increase in consumption, but demand additions in Mexico are also significant as the country embarks on a large expansion of its national gas network and gas-generation capacity.

**Figure 2.1** OECD Americas gas demand by country and by sector, 2000-20



### *The United States: Flatter electricity consumption growth limits the scale of gas demand additions*

US gas demand in the power sector will continue to increase over the next six years, but at a slower pace than in the recent past, with average annual growth of 1.5% expected between 2014 and 2020. Large

sources of cheap gas remain available, but flattening electricity consumption growth, amid a continued strong increase from renewable sources, squeezes the incremental need for thermal power dispatching.

Over the past six years, electricity demand has remained flat while gross domestic product (GDP) has increased by 6%. This report assumes that the recent decoupling between economic and electricity consumption growth will continue over the medium term, with total generation increasing at a modest 0.5% per year. As a result, thermal generation is set to fall slightly amid continued robust growth from renewables. All incremental gas consumption, therefore, comes from substitution away from coal.

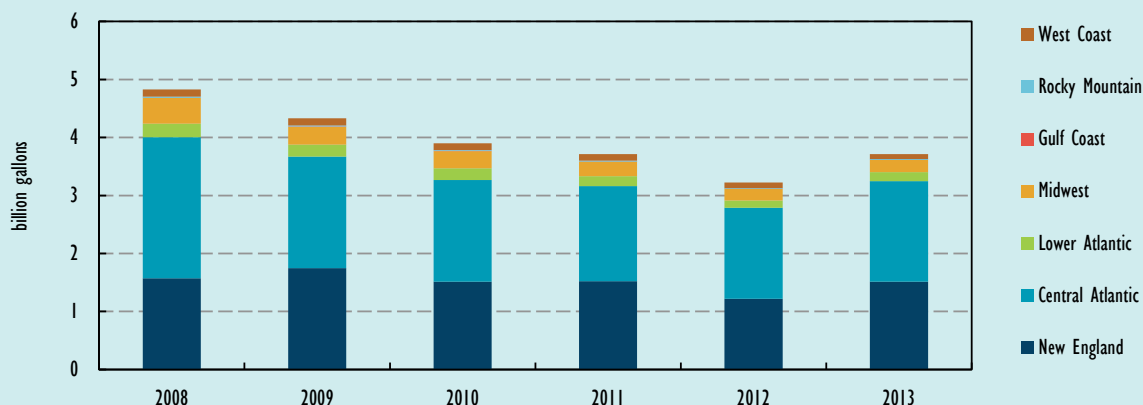
### Box 2.1 The Northeast of the United States: States in transition

#### Households

In the United States, around 6.2 million homes rely on heating oil in winter. The vast majority are located in the Northeast region of the United States, which stretches from Maryland to Maine. Deliveries take place by truck; the fuel is pumped into storage tanks, which are often in the basement of the building. Among the northeastern states, Maine is the most heavily dependent, with nearly two-thirds of homes using fuel or other “combustible liquids” in their heating systems. For the overall Northeast, about one-quarter of residential buildings is heated with heating oil.

Due to the region’s proximity to the fastest-growing producing area in the United States and recent high oil prices, a rising number of conversions from heating oil systems to systems running on gas have been taking place. Traditionally, gas prices in the Northeast tended to be well above the national average due to its distance from major producing areas and sharp weather-driven consumption swings which have often resulted in congestion of the transmission and distribution network. This clearly limited the attractiveness of switching to gas, but with massive amounts of gas now flowing from the nearby Marcellus/Utica shale plays, the economic rationale for staying with heating oil is eroding fast. Despite the sharp fall in oil prices, heating oil remains costlier than gas according to data from the largest heating company in New York, Con Edison, which offers special conversion programmes for customers.

Figure 2.2 Heating oil consumption in the United States by the residential sector



Source: IEA calculations based on data from the US Energy Information Administration.

**Box 2.1 The Northeast of the United States: States in transition (continued)*****The pipelines***

In northeastern United States, pipeline bottlenecks have led to frequent price spikes, limiting natural gas flows into the region. Following the astonishing production increase in the nearby Marcellus/Utica shale gas plays, several new projects aiming to expand New England's access to those gas resources have been launched.

The expansion of the Algonquin Gas Transmission – also known as the Algonquin Incremental market project – will boost flows to city gates in Connecticut, Rhode Island, and Massachusetts through new pipes and compressor stations. The project, which received Federal Energy Regulation Commission (FERC) approval in March 2015, is scheduled to come online at the end of 2016. In addition to expansions of existing pipes, new transmission lines will also be built.

The Constitution Pipeline, which received FERC approval at the end of 2014, will connect with the Iroquois Pipeline to serve New York as well as with the Tennessee Gas Pipeline to supply New England with Appalachian gas. The project, which has an in-service date of late 2015 through to mid-2016, will stretch for 124 miles. With a capacity of 7 bcm, it will be capable of serving approximately three million homes in northeastern United States. The pipeline is already fully contracted with long-term commitments from established natural gas producers currently operating in Pennsylvania.

The Constitution Pipeline is the first of several projects designed to bring Marcellus shale gas to northeastern markets to receive FERC approval. Among large projects still awaiting authorisation is the 100-mile PennEast Pipeline project. This line, with a planned capacity of 10 bcm, will link the Marcellus-producing region to a Transco interconnection in New Jersey.

While roughly 50 gigawatts (GW) of coal-fired generation capacity is set to retire by 2020, coal will still compete favourably compared to gas in many cases, limiting the speed of gas penetration into the country's power mix. Stable nuclear generation will also limit the potential for increases in gas demand in the power sector.

US demand in the industrial sector will remain on an upward trend through 2020, rising by 1.7% per year, supported by ample and cheap natural gas feedstock. Several new industrial projects in both the fertiliser and chemical sectors are due on stream in the near future. Four world-scale, ethane-fed steam crackers are under construction and some are at advanced planning stages. Such plants can consume up to 1 bcm per year of gas as fuel. Additionally, two large industrial facilities are due on stream in 2015, a methanol plant in Clear Lake, Texas, and a fertiliser urea plant in Wever, Iowa. While the bulk of new industrial projects are being built in the US Gulf Coast, some are planned in other natural gas/natural gas liquids rich areas, such as North Dakota.

The United States will remain an attractive place for energy-intensive industries due to the availability of ample and cheap feedstock. However, the sharp fall in oil prices is chipping away at the economic advantage of its largely gas-based petrochemical sector in relation to naphtha-based industries, more prevalent globally. Similarly, concerns over the scale of natural gas liquids (NGL) expansion as rig activity falls back sharply could lead to a slowdown of investments, resulting in a deceleration of industrial gas demand growth in the latter part of the forecast period.

In the transportation sector, gas usage for road transportation will grow over the next six years, but at a slower than before, due to the loss of economic advantage relative to gasoline and diesel powered engines. The medium and heavy-duty market segments account for the vast majority of current and incremental gas usage in the sector. In 2014, overall natural gas vehicle (NGV) sales in the United States fell by 6.5% (NGVAmerica, 2014). The poor performance was due to plunging sales of light-duty vehicles, thus reflecting the high sensitivity of the segment to oil price fluctuations.

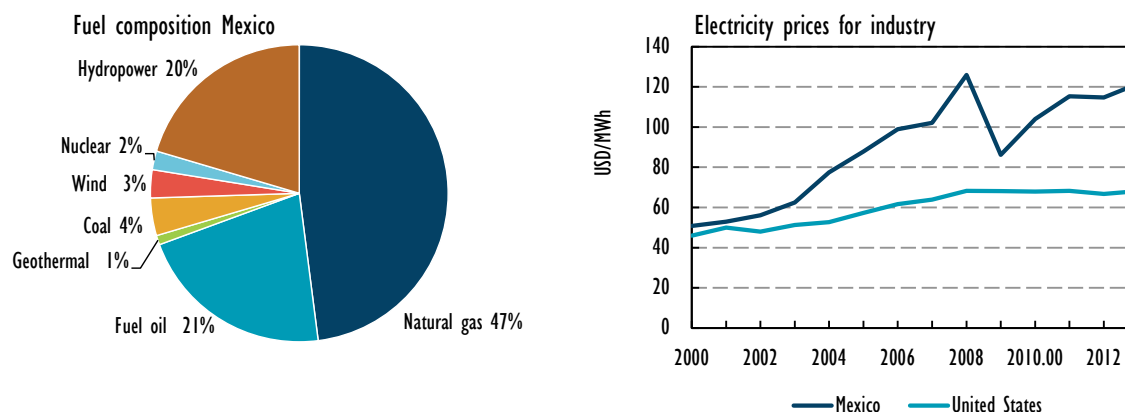
Medium and heavy-duty NGV sales held up much better, due to relatively stronger economics (higher average fuel use) and positive momentum from many fleets that had decided to transition to natural gas ahead of the oil price plunge. In the current oil price environment, conversion rates are likely to slow. While gas usage for road transport is on the rise, pipelines still dominate gas consumption in the sector. With large amounts of new midstream infrastructure set to be added to interconnect new production areas to consuming (or export) centres, gas for pipeline transport will also increase. Overall, gas demand in the transportation sector is forecast to increase by 4 bcm to reach 27.2 bcm by 2020.

The residential and commercial sector is the only end-use segment showing a flat trend, with consumption expected to fall between 2014 and 2020 almost entirely due to weather effects. Efficiency gains broadly offset population growth and substitution from heating oil, thus leaving the underlying growth trend close to zero.

### Mexico: Power-driven

Mexico's gas demand is forecast to increase robustly, growing at an annual average rate of 3.8% and reaching 95 bcm in 2020; the power sector accounts for three-quarters of the increase. Conversions of power plants from fuel oil to gas add to strong power demand growth, which thus encourages gas usage in the sector. Large investments in the transmission and distribution network to connect cheap US gas to burgeoning local demand are likely to occur until 2020.

**Figure 2.3** Fuel composition as a percentage of the total installed capacity in Mexico, 2014 and electricity prices for the industry in Mexico and United States, 2000-13



Notes: MW = megawatt; MWh = megawatts/hour.

Source: IEA (2014a), *Electricity Information 2014*, OECD/IEA, Paris, DOI: <http://dx.doi.org/10.1787/electricity-2014-en>.

Curbing rising electricity costs for industry is a top priority for the Mexican government, as the recent escalation in electricity tariffs undermines the country's industrial competitiveness. A high dependency on low-efficiency fuel-oil plants, costly subsidies for households and agricultural users, and high losses in the distribution and transmission system have resulted in high electricity charges for industry. The growing disparity with electricity prices paid in the United States is of particular concern for the government (see Figure 2.3).

To address the problem, the Mexican government is promoting the usage of natural gas in the power sector particularly through the conversion of fuel-oil plants. In 2014, the cost of generating electricity from such a unit was 2.5 times higher than that of a plant converted to burn natural gas. When comparing fuel-oil generation costs with those of a natural gas combined-cycle plant, the cost difference increases to four times (CFE, 2014).

The state-owned utility, Federal Commission of Electricity (CFE), announced in late 2014 a programme to convert seven fuel-oil power plants into natural gas units. The operation will cost USD 200 million and should be finalised in 2016. The aim of CFE is to basically abolish fuel oil use by 2017.

### Regional Insight: Historic reform of the energy sector in Mexico

In August 2014, the Mexican Congress approved secondary energy legislation that will open oil and gas markets to foreign direct investments. These laws follow the constitutional hydrocarbon reform decree of December 2013, which eliminated provisions in the Mexican Constitution banning the direct participation of foreign companies in the country's oil and gas sector.

As such, the new law ends the 76-year monopoly of state-owned company, Petroleos Mexicanos (PEMEX). It also establishes a legal framework for activities in exploration, extraction, refining, commercialisation, transportation and storage of oil and gas. Several previous governments had tried to reform the oil and gas sector, but none managed to push through structural and institutional changes as far reaching as those in the current reform.

The Hydrocarbons Law is part of a larger package of structural reforms aimed at boosting productivity and economic growth. An OECD survey estimates that these reforms could increase per capita GDP growth by as much as 1% after five years, with large front-loaded benefits coming from the energy reform package (OECD, 2015). The new laws could unlock the country's vast deepwater and shale gas resources for which Mexico needs fresh capital and advanced technology. Ultimately, whether the reform proves truly transformative will much depend on the details of its implementation. The premises are certainly good.

The reform stipulates an overhaul of the state-owned company PEMEX with the aim of transforming it into a "state-owned productive enterprise". More streamlined, more independent, and with lower fiscal obligations, PEMEX should be in a better position to face increased foreign competition. Over the past few decades, low productivity and high taxation have restricted the company's ability to invest, resulting in higher energy prices for non-subsidised consumers.

The legislation introduces three new contract models based on prevailing international standards: profit-sharing contracts, production sharing agreements, and licenses (EIA, 2014). In practice, the latter two allow foreign companies to account for their proportion of reserves, which is an attractive feature for



international oil companies (IOCs). Since 2008, the Mexican government has allowed limited participation of private companies in the oil and gas sector, and only exclusively in collaboration with PEMEX and under the restrictive terms of technical service agreements. The reform also introduces an open bidding process for awarding contracts.

To proceed with the opening of the energy sector, a “Round Zero” allocation was held in August 2014. The goal of Round Zero was to define the exploratory and production acreage that PEMEX could retain. The Secretariat of Energy awarded PEMEX 83% of the country’s proven and probable reserves and 21% of its prospective resources, less than the 31% that PEMEX had requested. The first public open bidding round – the Round One tender – was launched by the Comisión Nacional de Hidrocarburos (CNH) in December 2014.

CNH is Mexico’s upstream regulator, whose scope and power have been substantially enhanced by the reform. In Round One, the bidding process is divided in different phases: shallow water, extra-heavy oil, unconventional resources, onshore and deepwater. The bidding process for shallow water blocks is currently underway and is expected to close in July.

Alongside opening up the energy sector, the Mexican government has introduced fiscal adjustments to attract investments and stimulate oil and gas production growth. As far as natural gas is concerned, production of non-associated gas will be free of royalties when prices are below or equal to USD 5/MBtu. This measure aims to increase the attractiveness of developing Mexico’s domestic shale gas resources relative to importing gas from Texas and Arizona. For associated gas, royalty rates will increase linearly with a less favourable regime. Due to the reform, the Mexican Oil Fund for Stabilisation and Development was established. The fund is an autonomous entity with the task to manage non-tax revenues from oil and gas production.

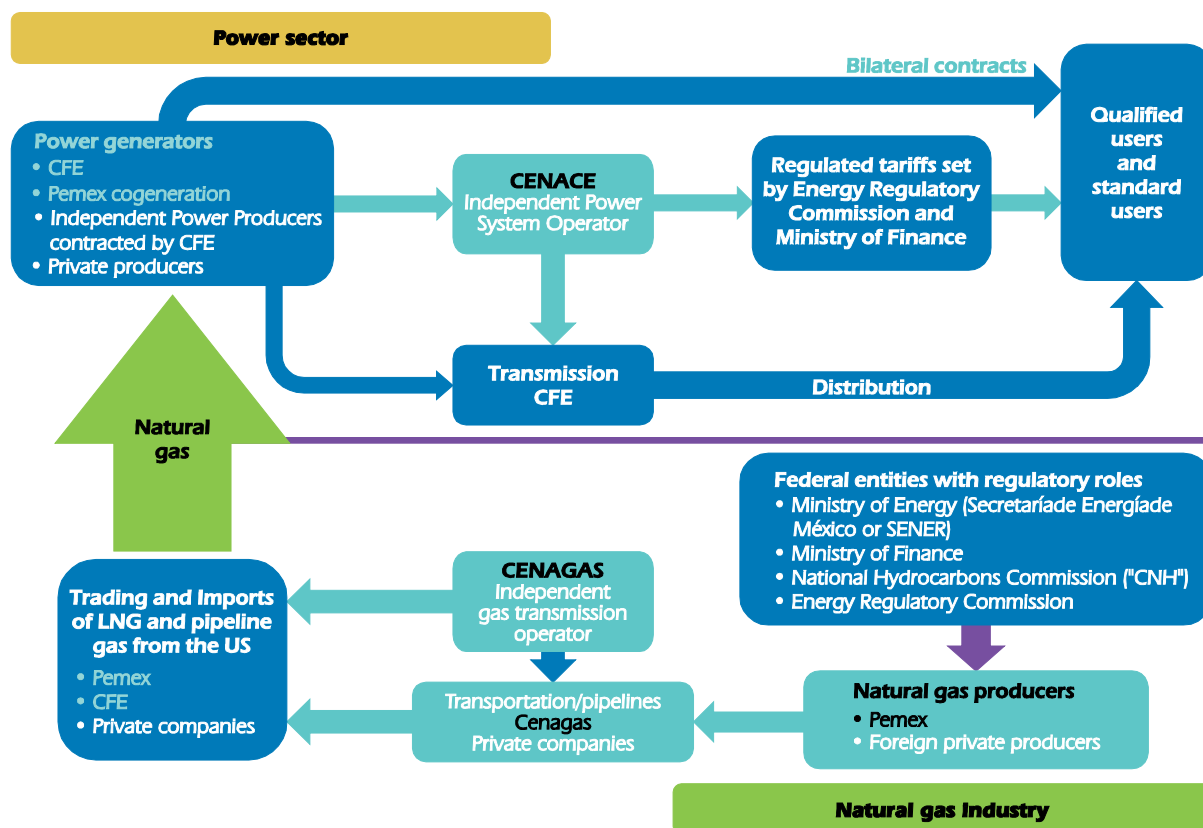
The energy legislation establishes a new legal and institutional framework for the power sector as well. The main goal of the new Electricity Law is to break the monopoly of the state-run electricity company, the CFE. Mexico had allowed private participation in the electricity sector since the 1990s and Independent Power Producers (IPPs) account for roughly one-fifth of the country’s generation. Yet, until now, CFE has been the sole authorised supplier of electricity. It has been purchasing all the electricity produced by IPPs, which had no access to the transmission or distribution system. The reform substantially alters such a framework. It introduces open access to the grid, establishes a wholesale market and creates an independent system operator.

Under an unbundled structure, the CFE retains 85% of the existing generation capacity and will continue to own the transmission and distribution network. To ensure competition, the National Center of Energy Control (CENACE), which was an integral part of CFE, now becomes an independent system operator with responsibility for the entire national grid. CENACE must ensure accessibility to the transmission network for all producers irrespective of their public or private nature. It also assumes responsibility for managing the newly created electricity wholesale market. In the new structure, regulatory and supervisory authority of the wholesale market belongs to the Ministry of Energy and the Energy Regulatory Commission.

In the spot market, electricity generation dispatches competitively, based on ascending price (bid) order. The government hopes that the introduction of a competitive spot market will lead to higher

dispatching of lower cost gas units and reduce the use of higher cost diesel and fuel-oil generation. Alongside participating in the spot market, private producers can also enter bilateral long-term contracts with large customers, in direct competition with CFE.

**Figure 2.4** Mexico's new market structure for the natural gas industry and power sector



Large end-users of electricity, mainly industrials, can choose their suppliers and the terms and conditions of power supply. CFE remains the supplier of basic services for residential customers and small and medium-sized commercial users. Certain prices, including electricity tariffs for residential customers, remain regulated and are set by the Ministry of Finance.

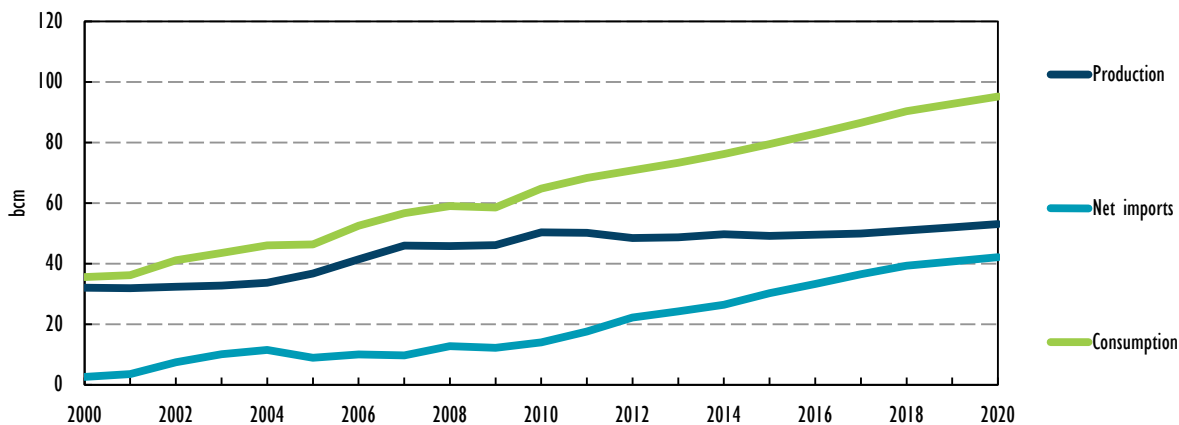
In the new market model, CFE also has the right to sell natural gas and launch tenders for the construction of new natural gas pipelines, which should challenge PEMEX's dominance in these areas. With PEMEX's monopoly position dismantled, the new legislation stipulates the establishment of a new independent operator, the National Natural Gas Control Center (CENAGAS), to manage the integrated national transportation gas system and storage. The new entity must present five-year development plans for natural gas infrastructure. As in the power sector, the reform introduces open access to the gas network and aims to establish a transparent tariffs regime.

### *Mexico: Growing pipeline imports from the United States free up LNG volumes*

Despite a large resource base, Mexico is a net gas importer and its gas trade deficit has grown in recent years (see Figure 2.5). Gas imports stood at almost 27 bcm in 2014, 8% higher than in 2013.

Two-thirds were sourced via pipelines from the United States while the rest was imported as LNG. US imports have doubled since 2010, but with better pipeline interconnectivity within Mexico, they could have grown much faster.

**Figure 2.5** Natural gas balances of Mexico, 2000-20



**Map 2.1** Mexico's natural gas pipelines and power generation plants, 2014-18



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Even in today's low oil price environment, LNG remains significantly more expensive than imported US gas. Mexico would see significant financial gains by increasing its reliance on US imports. The government is actively pursuing this approach, having embarked on a large development programme of new pipeline capacity, cross-border and within Mexico.

Central to the network expansion is the Los Ramones pipeline. The first phase started in 2014, connecting the Net Midstream pipeline in Texas with the state Nuevo Leon, located in northeastern Mexico. The full capacity of the line is 21 bcm, but utilisation will remain capped until the second phase of Los Ramones starts in mid-2016. The extension will push gas downwards reaching Guanajuato, near Mexico City. At that point, the line will allow the transport of substantial volumes of Eagle Ford gas into the growing Mexican market.

**Table 2.2 Mexico's gas strategy, natural gas pipelines and power generation plants, 2014-18**

National Gas Pipeline System based on strategic plan 2013		Length (km)	Investment (billion USD)	Online
1	Los Ramones	842	2.41	Phase 1-2: 2014-16
2	El Encimo (Chihuahua) – Topotobomgo (Sinalca)	574	1.0	2016-17
3	Sésabe - Guaymas	544	0.56	2016-17
4	Guaymas – El Oro	364	0.43	2016
5	El Oro - Mazatlán	462	0.40	2016
6	Tamazunchale	229	0.46	2014
7	Zacatecas	172	0.07	2014
8	Morelos	172	0.25	2015+
9	Mayakán	76	0.12	2014
10	Chihuahua	383	0.40	2013
International pipelines		Length (km)	Investment (billion USD)	Online
11	Agua Dulce – Frontera	200	0.83	2015
12	Tucsón – Sásabe	97	0.20	2015
Pipeline tenders to strengthen network in northwest Mexico		Length (km)	Investment (billion USD)	Online
13	Waha – San Elizario Pipeline	300	0.55	2017
14	Waha – Presidio Pipeline	230	0.40	2017
15	El Encimo – la Laguna	423	0.40	2017
16	San Isidro – Samalayuca Pipeline	23	0.055	2017
Gas power plant tenders in northwest Mexico		Capacity (megawatts)	Investment (billion USD)	Online
17	CCGT Noreste (Escobedo)	889	1.47	2017
18	CCGT Norte III	788	1.0	2017
19	CCGT Empalme	704	0.75	2017
20	CCGT Empalme II	683	0.74	2017
21	CCGT Noreste (Topolobampo II)	786	0.65	2018

Note: km = kilometre. CCGT = combined-cycle gas turbine.

Source: IEA compilation based on CFE (2014), *Key Elements of the Energy Reform and their Implications for the Gas Sector from CFE's Perspective*, CFE, Mexico.

The government aims to expand the domestic pipeline network by 75% throughout 2018. They are pursuing an integrated development plan involving the construction of new gas lines and simultaneous build-up of the power sector. In 2014, the CFE announced that it was seeking private-sector bids for five natural gas pipelines to strengthen the integration of the northern part of the country bordering the United States. The tendering process, which started at the end of 2014, includes five power plants with a capacity of almost 4 GW and planned start-up dates of 2017/18.

The new plants will be connected to new and existing pipelines, including important cross-border points to allow access to gas imports from the United States. The overall cost of the project is estimated at around USD 6.5 billion. The flipside of more pipeline interconnections and higher flows from the United States is a reduced need for LNG.

The Mexican government has announced intentions to stop importing LNG at its two largest LNG import terminals (Manzanillo and Altamira) as early as 2016 leaving only the plant in Ensenada in operation for the rest of the forecast period (SENER, 2014). While the plan looks ambitious, it underscores the country's ongoing shift towards pipeline gas. This report forecasts pipeline imports from the United States to increase by 19 bcm reaching 39 bcm in 2020. This figure could end up being even higher should all planned interconnections be put in place successfully.

### OECD Europe: In search of a bottom

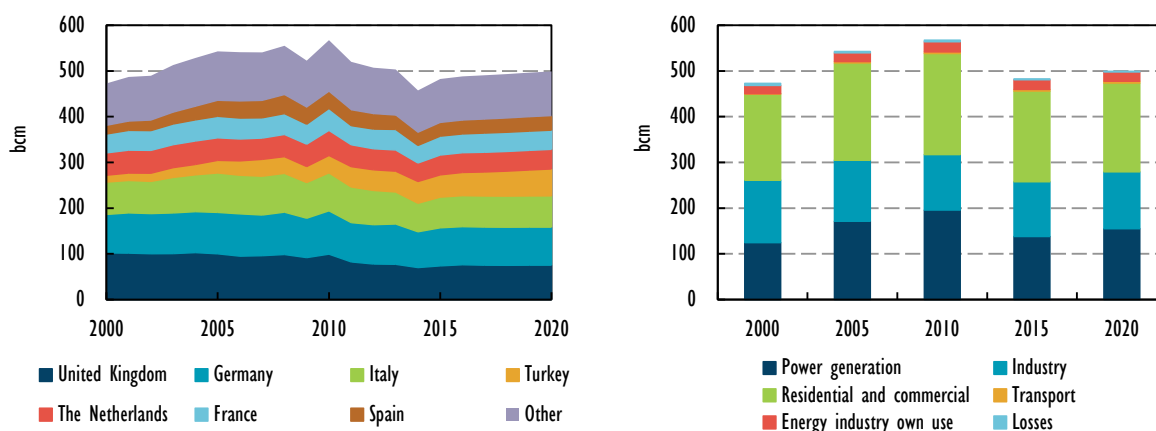
European gas demand fell sharply in 2014, driven by large weather-induced losses. Preliminary data suggest a drop of 45 bcm, 75% of which is estimated to be weather related. A mild winter in 2014, shortly after a cold one in 2013, resulted in large negative base effects. However, even when normalised for temperature variations, European gas demand fell in 2014. Evidence that the broad declining trend that has prevailed since 2009 is yet to find a turning point.

This outlook forecasts that European gas consumption will start improving in 2015 and show a mild recovery over the next five years, overwhelmingly driven by the power sector in weather-adjusted terms. Total demand, normalised for weather conditions, will increase by 18 bcm between 2014 and 2020, to reach 500 bcm by the end of the forecast period. Despite the gain, this is still 55 bcm below the level of 2008.

In the power generation sector, European gas demand will increase by 22 bcm until 2020. The main reason for the increase is because of a drop in coal-fired generation over the forecast period. Retiring nuclear capacity is an additional factor, albeit the impact is limited before 2020. A modest economic recovery provides a positive backdrop, but efficiency gains and structural changes will limit the positive pass through to electricity consumption.

This report estimates average annual electricity growth of 0.6% between 2014 and 2020. Without Turkey, that would be just 0.2%. Power generation from thermal coal and lignite plants will fall, as older coal-fired capacity is phased out amid very limited additions of new coal plants. These are concentrated in the Netherlands, Germany, and Turkey. For the Netherlands and Germany, new plants are a legacy investment dating back to decisions taken pre-2008 when the outlook for European electricity demand – and economics of coal plants – was much more positive. (see *Medium-Term Coal Market Report 2014* [IEA, 2014b]). For nuclear generation, net retirements total about 7 GW until 2020. Germany and the United Kingdom are almost entirely responsible for this decrease.

Figure 2.6 OECD Europe gas demand by country and by sector, 2000-20

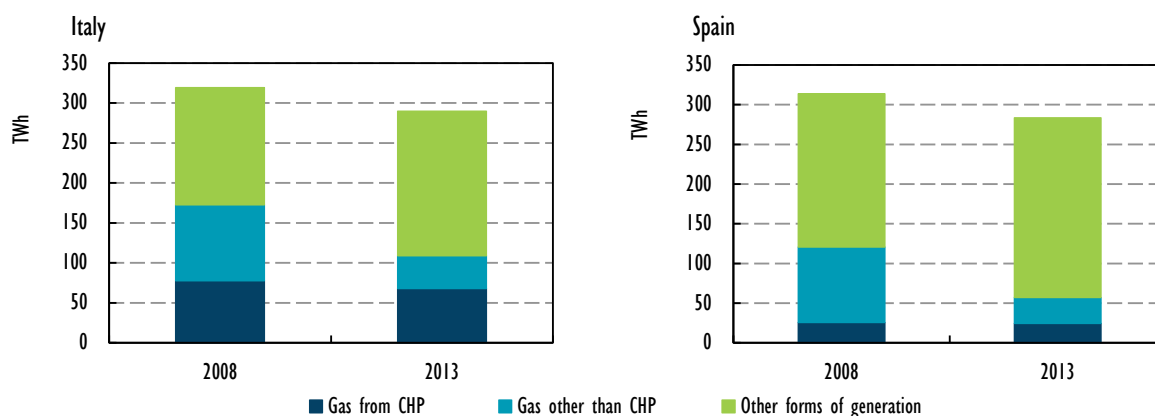


As growth from renewables generation is slowing down, there is scope for a modest recovery in European gas consumption until 2020. One-third of the projected additions come from Turkey, where power demand needs are high and growth from all forms of generation can be accommodated. The remainder of the increase is due to the room left by lower coal and nuclear generation. Despite the rise, power sector demand in 2020 will still be 20% lower than in 2008.

This outlook assumes forward price curves as input. Given relative futures prices of gas, coal and carbon, coal plants will continue to dispatch ahead of combined-cycle gas turbines (CCGT) units in the power merit order. This is reflected in this report's forecasts. However, two aspects must be kept considered.

Firstly, a large proportion of gas-generated electricity is now provided by combined heat and power (CHP) units, whose dispatching is more dictated by the heat load than by the relative price of gas and coal (see Figure 2.7). CHP plants tend to be dispatched as must-run generation.

Figure 2.7 Italy and Spain gas-fired electricity generation



Note: TWh = terawatt hour.

Secondly, while gas plants remain generally uncompetitive, they are in a better position than they used to be due to favourable fuel price movements over the past year. Should spot gas prices fall from the current USD 6.5-7/MBtu to around USD 5/MBtu, today's unused switching potential could



start to be called on. Several gas plants have been closed or mothballed, so not all the capacity that was once available would be ready to return.

In addition to what is embedded in this report's forecast, an extra 15 bcm of gas demand could be introduced into the system, if switching price levels are reached. The key conclusion is that gas demand response to price variations is becoming increasingly asymmetric. Due to the low price elasticity of remaining gas demand in the power system (mostly CHP and balancing), gas price increases would have little to no impact on consumption levels.

Conversely, the gas price level, which could trigger coal-to-gas switching, is now much closer to current prices than it used to be. Alternatively, gas demand could increase as a result of a strong reform of the EU Emission Trading System (EU ETS) trading scheme. Should carbon prices rise from the current EUR 6-7/tonne to EUR 20-25/tonne, substantial gas to coal switching could be triggered at the current gas price levels.

In the industrial sector, gas demand in OECD Europe is set to increase modestly, at an annual average rate of 0.8%. In absolute terms, half of the additions comes from Turkey. For the rest of OECD Europe, a mild economic recovery should help to lift industrial gas usage, leading to an overall increase of about 3 bcm. Plant closures during the economic crisis together with migration of energy-intensive processes will put a damper on the size of any potential demand comeback (see Box 2.2). Yet, utilisation rates are likely to increase slightly where capacity is still available. Lower oil prices and favourable exchange rate effects will also help fend off intense competition from US-based industrials.

In the residential sector, gas demand will bounce back from the extremely low levels of 2014 and is forecast to grow by 18 bcm from 2014 to 2020. The increase is due to weather effects. Temperature-adjusted, European gas consumption for space heating will decline moderately, a trend in place for some time already.

### Box 2.2 Industry-gas usage significantly underperforms compared to overall economic growth in Europe

From the early 90s until the mid-2000s, European GDP and industrial production grew at an annual average pace of 2.1% and 1.7%, respectively. Moreover, for Europe as a whole, energy-intensive sectors followed a growth path broadly in line with that of the overall industry. Both dynamics, however, have changed in recent years. Since the 2008/2009 financial crisis, the difference between the GDP growth and industrial production growth has doubled. At the same time industrial production growth has outstripped growth from the gas-intensive industry. Structural changes in the composition of economic output, the migration of energy-intensive industrial processes elsewhere, the impact of the recession and the resulting sharp fall in investments, as well as high energy prices from the mid-2000s have all helped trigger a growing disconnect between the performance of the energy-intensive industry and that of the overall economy.

Data for the 2005-12 period show that the gas-intensive industry of the five major European markets (France, Germany, Italy, Spain, and United Kingdom) contracted more sharply than their overall industrial sector. Meanwhile, over the same period, GDP growth was slightly positive.

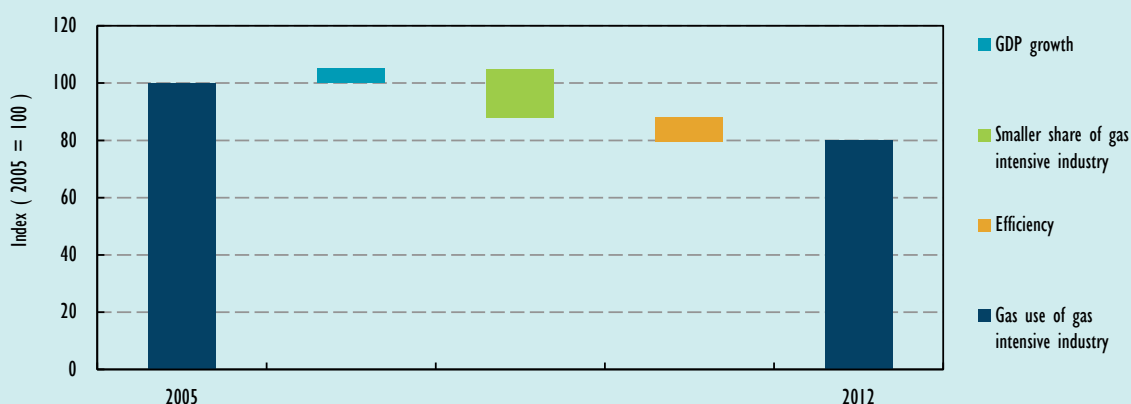
**Table 2.3** GDP, industrial production and industrial gas usage: Five major EU gas markets

2005-12	GDP	Industry	Gas-intensive industry	Gas use of gas-intensive industry
Country weighted average annual change	0.7 %	-0.6%	-1.6%	-3.0%

### Box 2.2 Industry-gas usage significantly underperforms compared to overall economic growth in Europe (continued)

A declining role of the manufacturing sector and, within it, of the energy-intensive industry, already implies lower gas demand per unit of GDP. However, even when accounting for such structural changes, the fall in industrial gas usage cannot be fully explained. For the five countries examined, gas consumption by the energy-intensive industry fell by 3% per year between 2005 and 2012, two times as fast as the sector's output. This suggests that structural changes in the economy have been accompanied by efficiency gains over the period, a result in line with the findings of the IEA *Energy Efficiency Market Report 2014* (IEA, 2014c).

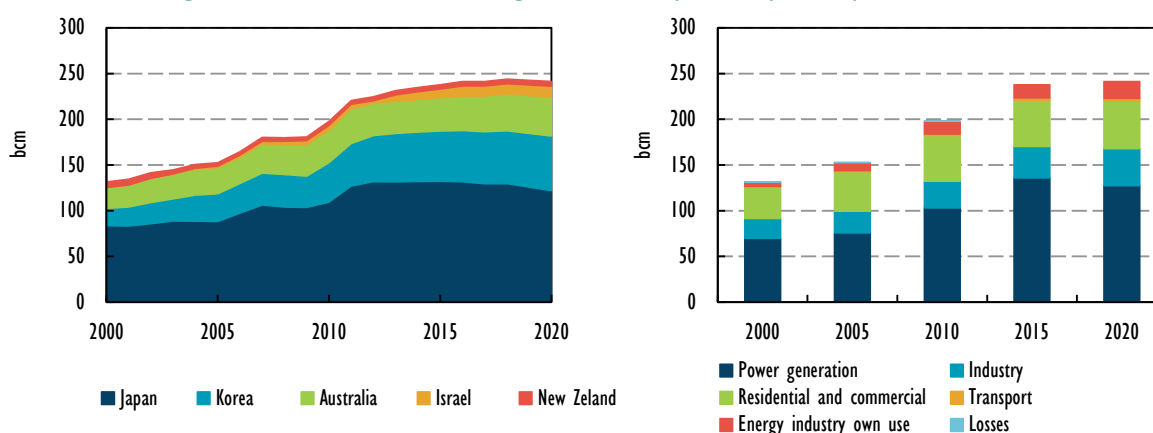
**Figure 2.8** Change in gas usage by the gas-intensive industry: Five major EU consumers



## OECD Asia Oceania: Demand peaks

Japan and Korea account for 80% of OECD Asia Oceania gas demand and their consumption patterns shape those of the entire region. They are also the two largest global LNG importers, together responsible for more than 50% of global LNG trade. Regional demand growth will slow down markedly over the time frame of this report, estimated at an average of 0.6% per year.

**Figure 2.9** OECD Asia Oceania gas demand by country and by sector, 2000-20



Note: The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

In Japan, a slow return of nuclear power combined with weak electricity demand growth results in lower gas usage. A large, coal-fired capacity expansion programme leaves little room for additional gas consumption in Korea. Israel's demand increases rapidly, but from a low base. In Australia incremental demand is tied to rising consumption from the energy industry as numerous new LNG projects become operational.

The weak demand outlook for the region stands in stark contrast with the robust performance of the recent past. Between 2010 and 2013, Japan and Korea's power sector gas consumption increased by almost 30 bcm. In both countries, the shutdown of nuclear plants – although of very different magnitudes – helped to boost gas-fired power generation, pushing gas consumption well above business-as-usual levels. Due to negligible domestic gas production and no pipeline imports, the increase in demand went hand-in-hand with an increase in LNG intakes, with significant rippling effects on LNG spot prices and trade flows.

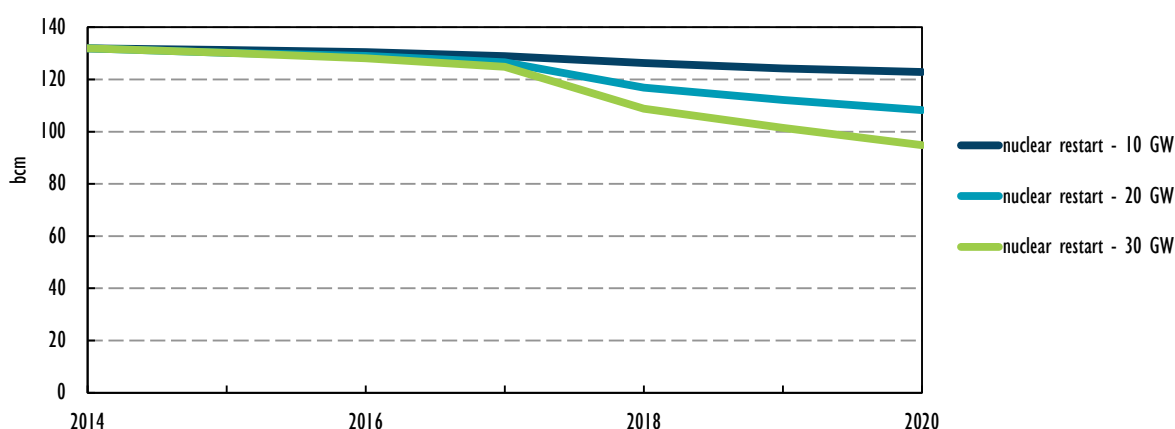
Gas demand across the two major LNG importers is estimated to have reached a cyclical peak. The major uncertainty relates to how fast demand will fall in Japan. The return of nuclear capacity will push gas out of the merit order, but as the timeline of the restart is not yet known, different trajectories for gas demand (and LNG imports) are possible. Even in the case of a slow comeback, gas consumption will suffer due to a flattening electricity demand sparked by increased efficiency after the earthquake and the fast deployment of renewables, which pushes out thermal generation from the system.

All 48 reactors in Japan were shut down in the aftermath of the Fukushima Daiichi nuclear accident, with the last going offline in September 2013. The resulting loss in nuclear generation has been mainly compensated by heavier dispatching of existing thermal units and by fast-tracking the construction of additional thermal plants. Gas-fired generation replaced roughly two-thirds of the lost nuclear output, pushing Japan's LNG imports up by about 25% between 2010 (the year before the accident) and 2014.

There is currently no confirmed plan for the return of nuclear capacity in Japan. The government is working on a regulatory approval basis, meaning that reactors can restart once they are granted safety approval status by the Nuclear Regulation Authority (NRA). Four reactors, with a total capacity of 3.5 GW, have so far been deemed safe to operate. The facilities were granted approval in 2014 and 2015, but are not yet back on line. This reflects several challenges – including strong public opposition – related to bringing back nuclear.

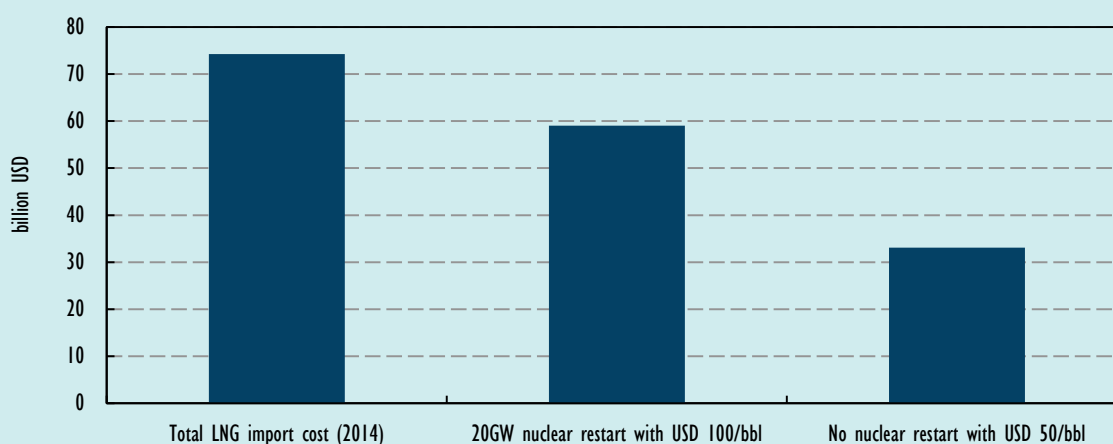
Up to four reactors could be back on line by the end of 2015, but slippages cannot be ruled out. This report assumes that only 10 GW of nuclear capacity will be back on line by 2020, resulting in a drop of gas consumption of around 10 bcm. There are upside risks to this forecast. At present, a total of 21 reactors from 14 nuclear plants have applied to the NRA for safety approval. In a more optimistic, but certainly plausible case, more than 20 GW could be operational by the end of the forecast period. The implications for Japan's gas consumption are illustrated in Figure 2.10. Other gas users will register barely any growth and, as such, Japanese gas consumption will decline by 10 bcm through 2020.

Korea's gas demand will increase at an annual average rate of 1.7% until 2020, driven by the industrial sector. Gas usage in the power sector, which accounts for about 50% of the total, is expected to stay flat. Korea is substantially expanding its coal-fired power fleet with 12.5 GW expected to be added by the end of 2017. Therefore, base-load generation will be increasingly provided by coal and nuclear, giving limited scope for gas-fired capacity to expand production.

**Figure 2.10** Japan's gas consumption under different trajectories for nuclear capacity**Box 2.3** Lower oil prices: Implications for Asian buyers

The rapid oil price decline since late 2014 will greatly benefit large Asian LNG buyers. The relief will be particularly welcomed by Japan, where high prices and surging import needs in the aftermath of the Fukushima Daiichi nuclear accident have tipped Japan's trade balance into deficit since 2011. The amount of savings Japan could generate in a low oil price environment is illustrated in Figure 2.11.

Total LNG import costs exceeded USD 70 billion in 2014. Should 20 GW of nuclear be available again, but oil prices average USD 100 per barrel, Japan's LNG import bill would drop by 20%. While significant, these savings would be less than half of those yielded by a price decline of USD 50 in the absence of any nuclear comeback, which highlights the vast financial implications of the recent price swings.

**Figure 2.11** Comparison of annual LNG import bills in Japan under different scenarios for nuclear capacity and oil prices

Note: bbl = barrel.

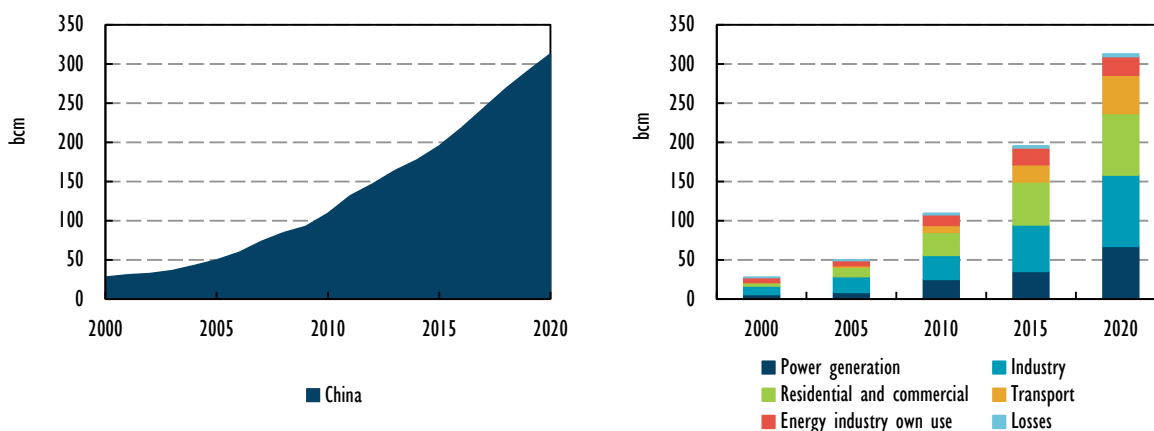
The risk that lower oil prices will result in tighter LNG markets for the next three to five years is very small, due to the low price sensitivity of short-term LNG production. However, the situation looks very different after 2020. New projects, which have yet to take final investment decision (FID) now, will be required to balance the market. From a long-term perspective, lower oil prices also pose risks for LNG consumers. Many projects currently in the planning stage have made little progress over the past year, with mounting evidence that cancellations and deferrals are to be expected in the absence of a quick recovery in prices.

## China: The outlook grows uncertain

China's gas demand growth slowed down to between 8% and 9% in 2014, a substantial deceleration from the 14% averaged during the five previous years. A sharp deceleration in primary energy consumption growth, ample hydro availability and high import prices all contributed to curtail the increase in consumption. The outlook ahead looks uncertain.

On the one hand, economic growth forecasts have been scaled back further and structural changes in the economy and the way energy is deployed appear to be occurring much faster than previously thought. On the other hand, both domestic and import prices have fallen, the latter substantially. Additionally, China continues to show a strong resolve to combat pollution, which should be broadly beneficial for gas. As a result, this outlook forecasts some re-acceleration of gas consumption growth from the lows of 2014, projecting an average annual growth of 10% throughout the rest of the decade.

**Figure 2.12 Gas demand in China, total and by sector, 2000-20**



The trend of slower economic growth continued in 2014, leading to further downgrades to the outlook. Between October 2013 and January 2015, the International Monetary Fund (IMF) cut its economic projections for China by about 0.5% for the period 2016-18. While slower economic growth impacts energy consumption, is not the main driver for gas. As gas accounts for a small share of total energy consumption, the potential for (or lack of) substitution of other fuels is a more powerful driver of gas demand trends. Looking ahead, two factors look positive for gas demand: lower import prices and the Chinese leadership resolve to address pollution (see Box 2.4).

About one-third of China's gas consumption is met by means of imports. The average LNG import price in 2014 was close to USD 11/MBtu, twice the level recorded just four years earlier. Had it not been for cheap legacy contracts with Australia, the average price would have been even higher. Some imported spot cargoes reached prices as high as USD 20/MBtu. The price of gas from Central Asia, the main source of pipeline imports, is estimated to have averaged USD 9.5/MBtu (at the Chinese border) for the full year. High imported gas prices came alongside substantial domestic price increases in all but the residential sector (see Chapter 1).

With oil prices stable and domestic coal prices low during the first three-quarters of 2014, gas became more expensive in both absolute and relative terms. The situation has been dramatically reversed over the past six months. Spot Asia LNG prices averaged USD 9/MBtu in Q1 2015, which is

around half the level of Q1 2014. Average import prices have not fallen by the same extent, largely due to the time lags embedded in the structure of long-term contracts. Given current oil prices, average gas import prices are bound to drop below USD 10/MBtu in Q2 2015 and Q3 2015.

Responding to the drop in import prices, the Chinese government cut domestic prices for all consumers outside the residential sector. In line with a previously announced government plan, the National Development Reform Commission (NDRC) merged the two tiers of its city-gate pricing system from 1 April 2015. Surprisingly, the price realignment came about via a cut to the higher tier rate (that is, volumes in excess of the 2012 consumption level) which was reduced by about USD 2/MBtu. Further downward adjustments are possible, if domestic prices are to be re-aligned with international benchmarks.

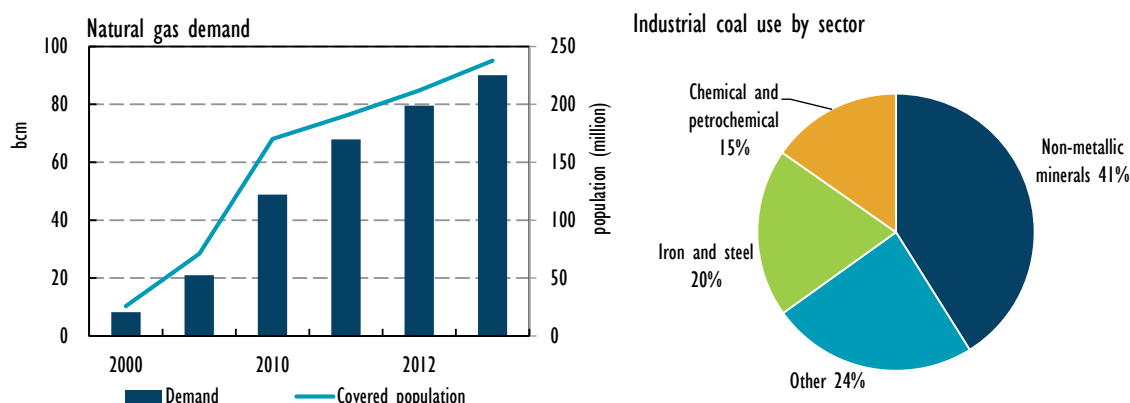
Lower gas prices, in absolute terms and relative to coal, are turning gas into an increasingly attractive option from an environmental viewpoint. Gas is still uncompetitive, but the price spread between the two fuels has narrowed significantly. The key question is whether the economic cost of using gas in China is now falling below its perceived environmental benefits.

Over the last few years, fuel switching potential has started to be exploited, but it has been focused on the residential sector and small-scale industrial applications. These sectors play a disproportionately important role in the country's pollution problems relative to their share of primary energy consumption. If supported by appropriate policies, lower gas prices could trigger higher demand for a larger portion of the industry. In 2012 China was consuming approximately 750 million tonnes (Mt) of thermal coal, across a range of manufacturing processes. Should 15% of the energy content of that coal be replaced by gas, it would yield an extra 70 bcm of consumption, equal to 40% of the country's current total gas usage.

Bucking the trend in other sectors, residential gas consumption continued to grow robustly in 2014. The medium-term outlook remains strong, driven by continued expansion in the gas distribution network and substitution away from liquefied petroleum gas and coal, amid a strong policy push. The rate of increase tails off towards the end of the decade as many coal boiler replacement projects are gradually completed and an increasing number of the urban population gets connected to the grid.

Several local governments have put subsidy schemes in place to promote the replacement of coal heating with gas. Beijing subsidises up to 50% of the project cost, with the degree of support depending on the size of the boiler. In a similar move, Hebei province plans to shut down all coal boilers with a capacity smaller than 10 steam tonnes. Meanwhile, China's urban gas pipeline network has continued to expand rapidly, increasing by 13.3% year-on-year and reaching 388 000 kilometres (km). The covered population is estimated at 240 million (CNPC ETRI, 2015).

In the power sector, gas consumption growth will re-accelerate following the subdued performance of 2014; it is set to roughly double between 2014 and 2020. Lower gas prices are helpful at the margin; running hours of existing plants will slowly increase while new capacity is also added. However, gas will not become the fuel of choice in China's power sector. In terms of capacity, gas accounts for around 4% of the total and the share of generation is even lower. The projected growth, therefore, comes from a low base (in relation to the country's electricity needs). Competing with coal is harder than in other sectors, while the degree of policy support is more moderate. Gas will have a strong role in some segments – such as co-generation for distributed systems and small-scale installations – but it is unlikely to find a widespread role as a base-load option.

**Figure 2.13** Natural gas demand and thermal coal use by sector in China

Note: Natural gas demand refers to the natural gas supplied via urban distributed natural gas pipeline network, including natural gas used by residential, public service, heating, transportation, industry, etc.

Source: CNPC ETRI, (2015) *The China & Oversea Gas And Oil Industry Report 2014*, CNPC ETRI, Beijing; IEA (2014d), *Coal Information 2014*, OECD/IEA, Paris, DOI: <http://dx.doi.org/10.1787/coal-2014-en>.

#### Box 2.4 Air pollution and climate change: New policy factors for China

In 2014 the Chinese government announced strengthened national action to address air pollution and climate change. Premier Li Keqiang declared a “war on pollution”. President Xi Jinping called for an “energy revolution” to tackle not only demand and supply bottlenecks and innovation, but also the environmental impacts of the production and consumption of energy.

China is suffering from air pollution levels far above World Health Organization safety levels, notably of particulate matter (PM) 2.5 from burning coal and from use of heavy vehicles. Chinese per capita carbon dioxide (CO<sub>2</sub>) emissions have increased over 200% since 1990 and are now nearing EU levels. In the final quarter of 2014, three new national policy plans on energy saving, energy strategy, and climate change set detailed targets for 2020. A high profile China–United States joint statement by President Xi and President Obama further committed China to peak its CO<sub>2</sub> emissions around 2030.

These developments raise new questions about Chinese environmental policy priorities, enforcement in relation to energy and the potential implication for natural gas demand, as China simultaneously leads the world in both coal production and consumption. It is also the biggest market for nuclear, wind power and solar photovoltaics.

Under the 2014-20 Plan on Upgrading and Reforming Energy Saving and Emissions Reduction in Coal-fired Electricity Generation (NDRC, 2014a), the share of coal in Chinese primary energy consumption is scheduled to fall below 62% in 2020 – from 66% in 2013. New standards are set for coal power generation fleets, so, that by 2020, 28% of coal-fired electricity generation should be CHP.

New build coal-fired power plants will no longer be approved in the major centres of population including Beijing, Tianjin, the Yangtze River Delta, and Pearl River Delta regions, unless for CHP. Beijing city has since announced that it will replace coal-fired power with natural gas plants.



### Box 2.4 Air pollution and climate change: New policy factors for China (continued)

The Energy Development Strategic Action Plan 2014-20 (The State Council of the People's Republic of China, 2014) reiterates the aim of the current 12th Five-Year Plan to cap China's primary energy consumption at 4.8 billion tonnes of standard coal equivalent per year by 2020. To achieve this, annual coal consumption will be held at 4.2 billion tonnes until 2020 (approximately 16% above 2014 levels). The use of natural gas should reach about 10% of primary energy consumption – in part by replacing coal in cooking and heavier fuels in transportation. This gas objective will be supported by increased conventional and unconventional resource exploration and a target for pipeline infrastructure to total 120 000 km by 2020. The National Energy Administration forecasts natural gas production to reach 245 bcm per year by 2020.

The 2014-20 National Plan on Climate Change (NDRC, 2014b) aims for a 40-45% cut in CO<sub>2</sub> emissions per unit of GDP by 2020, from 2005 levels. Industry will play a major role by reducing emissions by about 50% per unit of GDP and stabilising total CO<sub>2</sub> emissions from the steel and cement sectors at 2015 levels by 2020. This will be done mainly by using better quality coal and emissions filters. The share of non-fossil fuels in primary energy consumption should reach 15% by 2020. A strong focus is also placed on green buildings reaching 50% of new urban construction by 2020.

China will have to add approximately 190 TWh of renewable and nuclear power generation per year until 2020 to meet the 15% non-fossil target. A further target of 20% by 2030 was set in the joint China – United States announcement. The upcoming 13th Five-Year Plan for 2016-20 is expected to increase total hydropower capacity to around 340 GW by 2020.

The National Energy Administration also aims to double wind power from 96 GW in 2014 to 200 GW by 2020, and a fourfold increase in solar power from 26.5 GW to 100 GW. The annual solar quota for 2015 is 17.8 GW: around a fifth higher than anticipated in initial drafts. With 30 nuclear power plants currently under construction in China, a target of around 55 GW by 2020 is expected – this is a scale of mass deployment which may raise the prospect of per unit cost reductions, with global implications for the role of nuclear power.

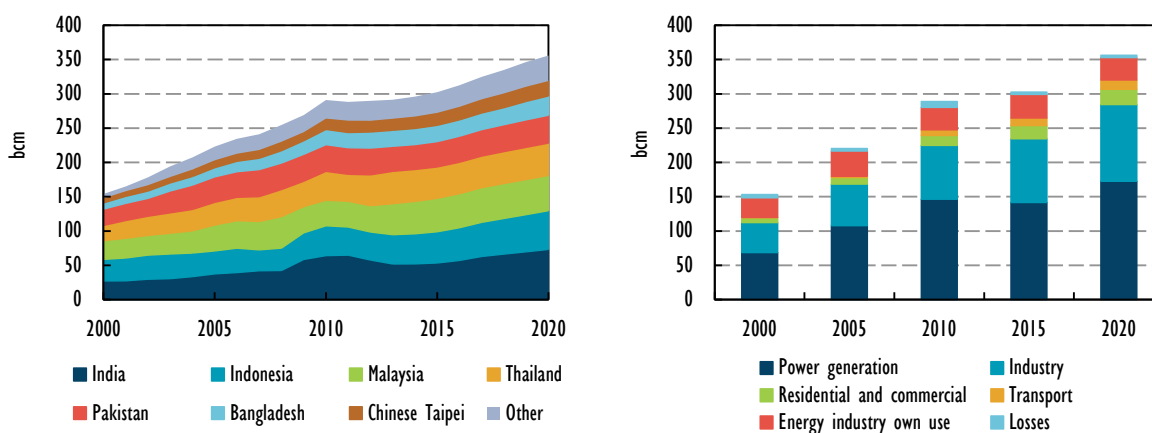
Meanwhile, the year ahead is likely to see further measures limiting emissions in the 13th Five-Year Plan, including an absolute cap on coal consumption and a nation-wide emissions trading system, based on pilot projects operating since in 2013 in seven major cities and provinces.

Large uncertainties remain about how environmental policies for energy will interact with wider China's growth trajectory. Therefore, it is difficult to forecast the direct impact on CO<sub>2</sub> emissions and the fuel mix. An important indication that enforcement will be tighter than in the past is seen in new provisions under the Environmental Protection Law that took effect on 1 January 2015. Public interest, non-profit organisations are now allowed to use the courts as interested parties to sue for environmental damages, also in cases where environmental or ecological harm has not yet occurred, but where significant risk of public harm can be shown. The first case by a non-profit organisation against an industrial polluter has already been accepted by a court in Shandong province.

## Non-OECD Asia (excluding China): Demand benefits from lower prices

Non-OECD Asia demand is forecast to increase at an average annual rate of 2.9% between 2014 and 2020, similar to the rate over the last six years. Consumption growth disappointed in 2013 and 2014, but the recent fall in prices is likely to allow some pent-up demand to re-emerge. Additionally, while gas remains uncompetitive – compared to coal – to generate power, it is now in a better position than before. When environmental considerations are part of the policy framework, gas demand is likely to benefit from the move in relative prices. From a country standpoint, India and Indonesia account for half of the projected increase in consumption.

Figure 2.14 Non-OECD Asia gas demand by country and by sector, 2000-20



### India: Price-sensitive demand to rise

Indian consumption and production dynamics will be one of the biggest uncertainties for non-OECD Asia gas balances over the next five years. This report forecasts a large upswing in demand, driven by the availability of cheap, international supplies. Incremental gas demand is projected at 17 bcm between 2014 and 2020. The growth is driven by the industrial sector. Should domestic production or imports increase faster than expected, Indian demand could grow more robustly due to a large amount of unused capacity in the power sector.

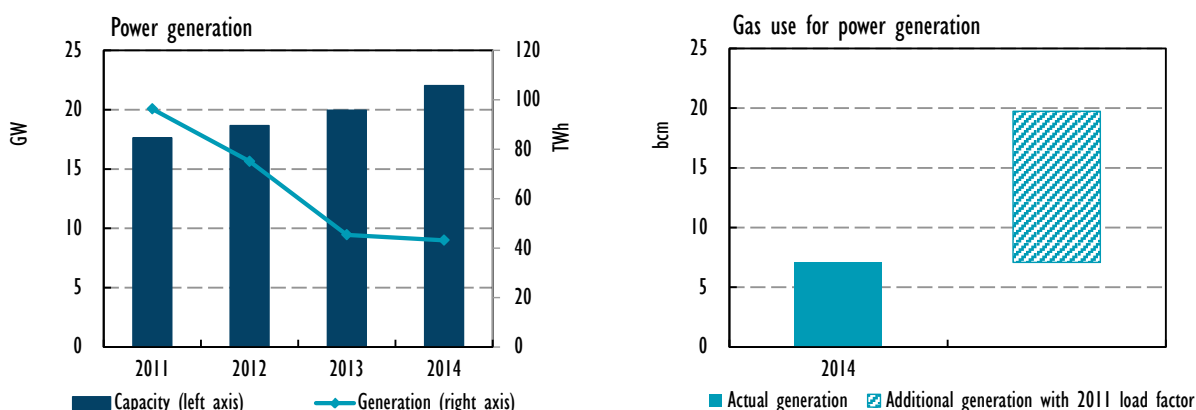
Indian gas consumption has been falling since 2010 amid declining domestic production and high international prices that have discouraged imports. Going forward, consumption should benefit from better supply availability, driven by an expected moderate recovery in production and lower international gas prices, which should make imports more affordable.

Industrial gas consumption will grow robustly, particularly in the fertiliser sector, boosted by strong economic growth and lower gas prices. Shortages of urea production, relative to domestic requirements, could be overcome more easily amid improved economics for this energy-intensive industry.

In the power sector there is significant potential for higher consumption. The country has 22 GW of installed gas generation capacity, but the utilisation rate was barely above 20% in 2014. High costs for imported LNG, which cannot be recovered by generators due to low end-user electricity prices, have resulted in units being left idle despite the country's severe power deficits. At import prices below USD 10/MBtu some pent-up demand is likely to emerge.

As an illustration, by simply increasing the utilisation rate of the existing gas fleet to 60% (the level in 2010/11), India's gas consumption could jump by as much as 15 bcm per year (see Figure 2.15). This growth could occur without any new capital investment in gas-fired capacity. Notably, gas would not gain ground against coal; rising gas-fired generation would serve to reduce power shortages rather than displace coal, which remains substantially more economical to burn than gas. The key uncertainty remains the level of supply availability, considering that the feedstock requirements of the fertiliser sector are likely to take priority.

Figure 2.15 Power generation in India



Source: IEA calculations based on data from India's Central Electricity Authority.

Import infrastructure and internal bottlenecks may emerge as constraints to the scale and speed of import growth. However, with substantial spare capacity as a starting point and growing evidence that floating storage regasification units (FSRUs) can become operational quickly once an investment decision is taken, the country's infrastructure should be able to respond to the projected increase in demand and imports. Moreover, Indian Prime Minister Modi has made a very ambitious push for domestic pipeline development.

Currently, India has about 10 bcm of spare regasification capacity with another 6 bcm scheduled to start by 2017. Although bottlenecks in the distribution network exist, lower prices can create the right incentives to get the logistics to work.

### Indonesia: Strong demand potential

Indonesia's demand growth potential is strong. Economic growth is projected at around 6% between 2015 and 2020, which should lead to robust energy consumption additions. Gas demand is expected to increase by 12 bcm, or 4.1% per year until 2020, largely driven by the industrial sector. Gas usage for power generation will increase, but at a modest rate due to strong competition from cheap domestic coal. The industrial and power sectors account for 75% of total demand. The energy industry consumes whatever is left over. The government is trying to promote gas in both the residential and transportation sector, but the impact of any acceleration in usage will remain negligible over the forecast horizon due to the very low starting point.

Supply availability is an important factor in consumption growth in Indonesia. The country is one of the region's largest gas suppliers, with exports accounting for roughly 45% of its production. Observed consumption has fallen short of potential demand in recent years, with stagnating production weighing on both LNG exports and domestic usage. While supply availability will remain an issue, new regasification infrastructure, amid lower international gas prices, will help ease constraints on demand growth.

In the power sector, coal's dominant position is unlikely to be challenged. Around 10 GW of new coal-fired capacity was recently added as part of a fast-track government expansion programme. Domestically-sourced coal continues to hold a strong competitive advantage relative to gas, even in the current lower gas price environment. Gas will still benefit from the broader supportive growth

environment and the government's ambitious plan to significantly expand the country's power generation capacity. It is also well positioned to displace expensive oil-fired power generation, which still accounts for 15% of the country's electricity mix as well as being the preferred fuel for plants located near gas-producing centres or gas import facilities.

The industrial sector shows the greatest growth potential: recent price declines could trigger the biggest demand response. In West Java, several industrial clusters have already shown willingness to pay natural gas prices of USD 6/MBtu to USD 10/MBtu, thus making current international prices look broadly affordable. With demand set to increase, further expansion of gas infrastructure will be required (both regasification terminals and pipelines) to be able to reroute domestic production and direct imports to growing demand in consuming regions. The Indonesian government's plan to create a domestic gas market and speed up infrastructure development bodes well for the future. The country has 10.9 bcm of regasification capacity, with some projects currently in the planning stage. If gas prices stay at this level, it is likely that such projects will progress quickly.

### *Malaysia: Switching to coal*

Malaysia's gas demand is expected to increase modestly, adding 4 bcm until 2020. New and planned LNG regasification facilities will greatly improve gas supply availability, allowing gas consumption to surpass its 2008 peak. A supportive economic environment and lower international prices will help boost gas usage in the industrial sector, where the bulk of incremental demand originates. However, growth potential in the power sector is limited. Breaking away from the trend of the last two decades, when gas led the fuel mix in power generation, additional capacity in the country is now dominated by coal.

After a rapid increase from 2003 to 2008, gas consumption in Malaysia started to stagnate in 2008. Demand fell sharply during the 2009 recession; the subsequent recovery was constrained by declining domestic production and lack of import infrastructure. The start-up in mid-2013 of a 5 bcm per year LNG regasification terminal in Melaka, on the west coast of peninsular Malaysia, improved gas availability and prompted a return to growth in 2014.

Gas demand in the power sector has benefitted from improved supplies following a period of acute shortages, but further increases will be limited. As new coal generation capacity ramps up, utilisation of the country's gas fleet is expected to decrease, with recent and planned domestic prices placing gas units at a disadvantage to coal. Domestic gas prices were set at about USD 5/MBtu in 2014 and will rise further as subsidies are phased out. Additional demand met by LNG imports is not entitled to subsidies, making it difficult to push incremental gas-fired generation into the merit order of the power system.

### *Other non-OECD Asia: Poor production prospects hamper consumption growth*

The rest of non-OECD Asia will add a combined 24 bcm of demand between 2014 and 2020, similar to the demand added from 2008 to 2014. Overall, the region faces poor production prospects, which makes demand additions heavily dependent on imports. Several countries are planning to build or expand regasification infrastructure, an effort facilitated by the lower price environment.

In **Thailand**, sharp declines in domestic production will constrain gas consumption growth, marking a fundamental shift from the recent past — when the bulk of additional demand was covered by higher indigenous production. Over the next six years, imports will need to increase steeply for

consumption to remain the same. Decreasing production will lead to fast erosion of the current large amount of spare capacity at the country's Map Ta Phut LNG terminal. Further import capacity – and the planned expansion of the Map Ta Phut terminal – will be required to accommodate projected demand increases. Overall consumption is set to remain flat to modestly higher through 2020. Supply risks also come in the form of reliability of imports from Myanmar. Today, Thailand imports large quantities of gas from its neighbour (around 10 bcm). As Myanmar responds to its domestic demand, meeting large export commitments to China and Thailand could become increasingly challenging.

In the **Philippines**, consumption will increase until 2020, but supply constraints will limit the speed of demand growth. The country has so far relied entirely on its own domestic production, but with the Malampaya field – the country's only gas-producing asset – facing decline, just keeping consumption flat will require the country to start importing. Some regasification projects are planned, but developers are struggling to secure off-take agreements to back their investments. The wholesale power sector – which accounts for nearly all the country's gas consumption – is deregulated and cannot easily pass fuel costs on to downstream power distributors. This makes building LNG terminals and gas-fired power plants quite challenging.

The outlook is somewhat brighter for **Viet Nam** where gas consumption will benefit from both rising domestic production and new LNG import facilities. Today, the power sector accounts for more than 90% of overall gas consumption. This will remain the case going forward. In its master plan issued in 2011 for power development, the Vietnamese government forecast gas-fired generation to increase until 2020, but at a slower pace than that of overall power generation, which is propelled by a strong reliance on coal and hydro (Government of Viet Nam, 2011).

Gas consumption is concentrated in the south of the country, where gas infrastructure exists. The region has suffered from gas and power shortages in recent years. The start-up of an LNG terminal in 2017 should allow for better supplies in the region. Overall, whether actual demand will undershoot or overshoot the target depends largely on the government's energy policy decisions. Viet Nam made important oil and gas discoveries in recent years, but bringing production on stream remains challenged by low domestic prices and an unattractive fiscal framework. Should energy policy turn more favourable towards gas, Viet Nam will have the resource base to support stronger demand expansion.

## FSU and non-OECD Europe: Consumption flat-line at low levels

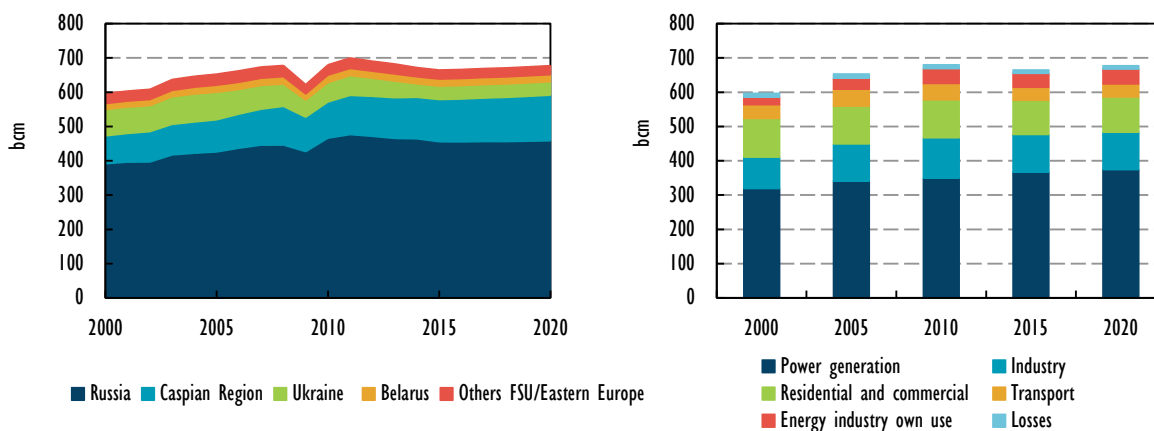
Total FSU/non-OECD Europe demand is forecast to remain broadly flat through 2020 (see Figure 2.16) and will not recover from the large fall of 2014. Consumption in Ukraine and Russia will continue to suffer from a deteriorating economic outlook and increased efficiency gains. This report forecasts Russian demand to contract at an annual rate of 0.2% between 2014 and 2020, which is offset by growing consumption in the Caspian region.

### *Ukraine: Gas demand squeezed*

Gas demand in Ukraine fell to historically low levels in 2014, dropping almost 20% year-on-year to average about 40 bcm. In comparison, Ukraine was consuming 50 bcm at the trough of the 2009 economic recession and almost 60 bcm by 2011. The scale of compression in Ukraine's gas consumption mirrors the depth of its economic recession, financial difficulties as well as gas-saving measures enacted in response to the challenging geopolitical situation. Industrial gas demand was hit the hardest,

plunging more than 20% as industrial production spiralled downwards, particularly in the Donbass region. Consumption in the residential sector also fell, mainly due to mild temperatures, lower average district heating temperatures in homes and some district heating switching to biomass.

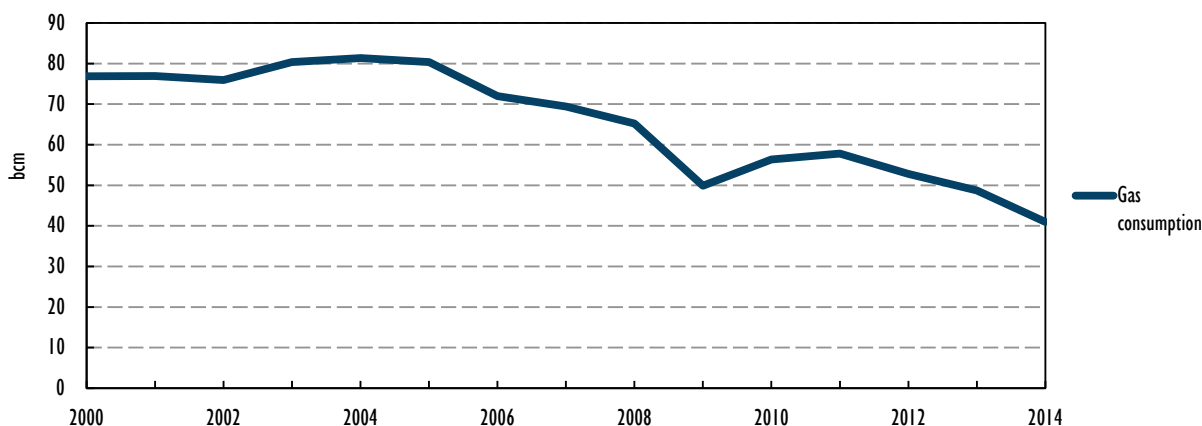
**Figure 2.16** FSU and non-OECD Europe gas demand by country and by sector, 2000-20



Looking ahead, the evolution of gas consumption in Ukraine will depend on how the economy and geopolitical landscape change. Nonetheless, even assuming a relatively constructive economic and geopolitical outlook, numerous structural factors point to flat or declining consumption patterns in the coming years. The deployment of building-level gas and heat metering stations is slow, but expected to make progress. Higher average regulated gas prices – as agreed with the IMF – will also weigh on consumption. A dampening effect on gas demand will also come from the substantial depreciation of Ukraine’s currency, the hryvnia, which raises the cost of dollar-denominated gas imports. Energy-saving efforts and energy efficiency investments are expected to occur gradually.

Higher, regulated prices will reduce opportunities for non-transparent schemes to divert cheap gas, earmarked for households, to industrial consumers who pay the market price. This should further reduce household consumption in statistics, but could lead to an increase in the share of industrial consumption.

**Figure 2.17** Evolution of Ukraine’s gas consumption, 2000-14



### Russia: A new reality

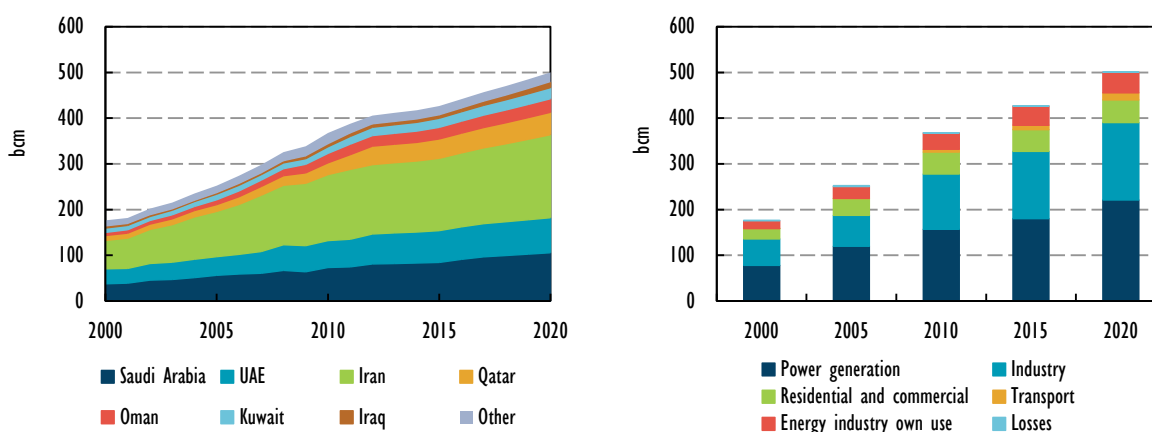
Between 2014 and 2020, Russia's gas demand is forecast to decrease at an average annual rate of 0.2%, due to a deep economic contraction in the earlier part of the forecast period. In its latest assessment, the IMF expects the Russian economy to shrink by 3% and 1% in 2015 and 2016 respectively and to recover moderately thereafter. Low oil prices are a major drag on Russia's economic performance. Other factors, including the depreciation of the rouble and high inflation – both a collateral effect of Western sanctions – also weigh on economic activity.

Gas demand is expected to stagnate in the power and district heating sector, consuming around 290 bcm annually over the period 2014-20, amid low modernisation investments and, possibly, flat power consumption growth. While there is scope for large efficiency gains in the power sector, no radical improvement is expected during the coming years. There is a strong disparity between the financial means needed to modernise the power sector, the availability of financing and the revenues that can be generated based on regulated prices. As a result, the power system is expected to continue to degrade, and overcapacity is likely. Consumption is expected to decline slightly in both the industrial and residential sectors.

### The Middle East: Steady growth

The Middle East's gas demand is forecast to increase at an average annual rate of 3% between 2014 and 2020, slower than the 4.1% recorded over the previous six years. Almost 70% of the increase comes from Saudi Arabia, Iraq and the Islamic Republic of Iran ("Iran"), where gas trade connections are non-existent or very limited and the scale of expansion in regional production continues to set consumption growth. Notwithstanding a weaker economic outlook, demand in these countries could increase more robustly than projected in this report, should the upstream sector be able to keep pace. Low domestic prices remain a major impediment to faster production growth across the region. Country-specific issues, such as the absence of necessary gas infrastructure in Iraq and lack of access to technology and capital in Iran, add to the challenge. On the demand side, the most significant change relative to the recent past is the sharp slowdown in Qatar's gas consumption growth which is affected by the absence of new LNG and gas-to-liquids (GTL) developments and a weaker outlook for the petrochemical sector.

Figure 2.18 Middle East gas demand by country and by sector, 2000-20





### *Qatar: Demand growth slows down*

Between 2008 and 2014, Qatar's gas consumption increased by almost 20 bcm, accounting for more than one-fifth of total incremental gas demand in the Middle East. The small Arab state consumes half the amount of gas that Saudi Arabia does, despite having a population 13 times smaller. Such a high level of gas usage is tied to Qatar's heavy reliance on energy-intensive industries, in particular LNG, GTLs, and petrochemicals which, taken together, account for almost 90% of Qatar's overall gas consumption.

These three sectors, which expanded rapidly over the past six years, now face a much more challenging outlook. Consequently, Qatar's gas consumption is expected to increase by an average of just 2% over the outlook of this report, compared to 12% recorded between 2008 and 2014.

After increasing by 64 bcm between 2008 and 2014, Qatar's LNG capacity is set to remain flat until 2020 due to the country's self-imposed moratorium on North Field development and LNG exports. Meanwhile, no other GTL project is set to come on line following the ramp-up at the Shell-led Pearl GTL facility. The USD 18 billion-project reached full-production capacity at the end of 2012, processing up to 16 bcm per year of gas. The plant played a key role in driving the rapid expansion of Qatar's gas demand in the recent past, but, with the facility now at full potential and no other GTL projects due on stream, the sector will not be a source of additional gas demand until 2020.

Growth in the petrochemical sector is also set to slow down as the two major petrochemical projects due on stream before the end of the decade have run into difficulties. In September 2014, Qatar Petroleum and Qatar Petrochemical Company put their USD 5.5 billion Al Sejeel Petrochemical Complex on hold which was due on stream in 2018.

While Qatar is reportedly looking into alternative downstream solutions which could yield better economics, no facility is likely to be on line by 2020. In January 2015, after the Al Sejeel's cancellation, Qatar Petroleum and Royal Dutch Shell announced they were scrapping their USD 6.5 billion al-Karaana petrochemical plant, citing high costs and the negative economic climate in the energy industry as reasons for the decision.

Lower oil prices and widespread capital expenditure cuts have also prompted IOCs to cut a number of planned petrochemical developments in Qatar, whose economic viability was already looking uncertain.

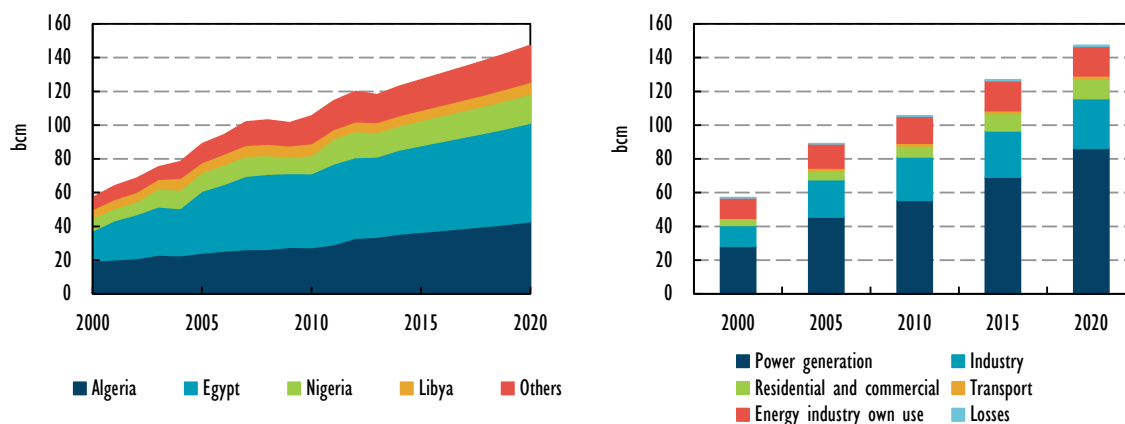
### **Africa: Powering the continent**

Africa's gas demand is expected to increase at an annual average rate of around 3% between 2014 and 2020, broadly in line with that recorded over the previous six years. The power sector is the main engine behind the increase, accounting for 85% of the additional 24 bcm of gas demand. The continent's three major producers also rank as the three major consumers. Egypt (58 bcm), Algeria (43 bcm) and Nigeria (17 bcm) represent a combined share of 80% of the 147 bcm Africa will consume by 2020. Projected consumption in this report falls short of potential demand. The underdevelopment of the power sector and limited supply availability are major obstacles to faster gas demand expansion.

Apart from the three major consumers, gas demand is set to grow robustly, but from a very low base. Most parts of Africa, especially in the sub-Saharan region, have to deal with widespread underdevelopment of the power sector and a lack of gas-fed manufacturing and petrochemical industries. The result is

little to no gas usage. Sub-Saharan Africa has the lowest electricity-access level worldwide. Cameroon, Côte d'Ivoire, Gabon, Ghana, Namibia, Senegal and South Africa are the only countries with electricity access rates exceeding 50%. The rest of the Sub-Saharan region has an average grid access rate of just 20% (IEA, 2014e).

**Figure 2.19** Africa gas demand by country and by sector, 2000-20



Energy subsidies remain an obstacle to power sector development. With electricity prices often set below recovery costs, financing power systems is challenging; thus, operational performance remains poor. Power outages are rife, impacting social life and economic activities. As a result, many companies employ expensive diesel-operated generators. Real improvement will require time, but some progress was made last year with a few countries scaling back subsidies.

In Egypt, the government launched a five-year plan to eliminate subsidies on petrol, gas and electricity. Morocco ended subsidies on gasoline and fuel oil, and significantly reduced those on diesel. Ghana and Cameroon took similar measures. Also Angola – a large oil producer – took action by raising gasoline and diesel prices by 20% at the end of 2014.

Together with cutting subsidies, a few countries are making efforts to reduce usage of expensive oil-fired generation. In 2014, Angola announced a programme to modify diesel-fired power plants to use natural gas, including the country's main power plant in Cazenga. In April 2014, the government of Kenya announced plans to build a 700 MW gas-fired power station in the coastal city of Mombasa. This is part of a national programme to expand the country's existing power capacity by adding 5 000 MW by 2017 while reducing dependency on more expensive diesel generation.

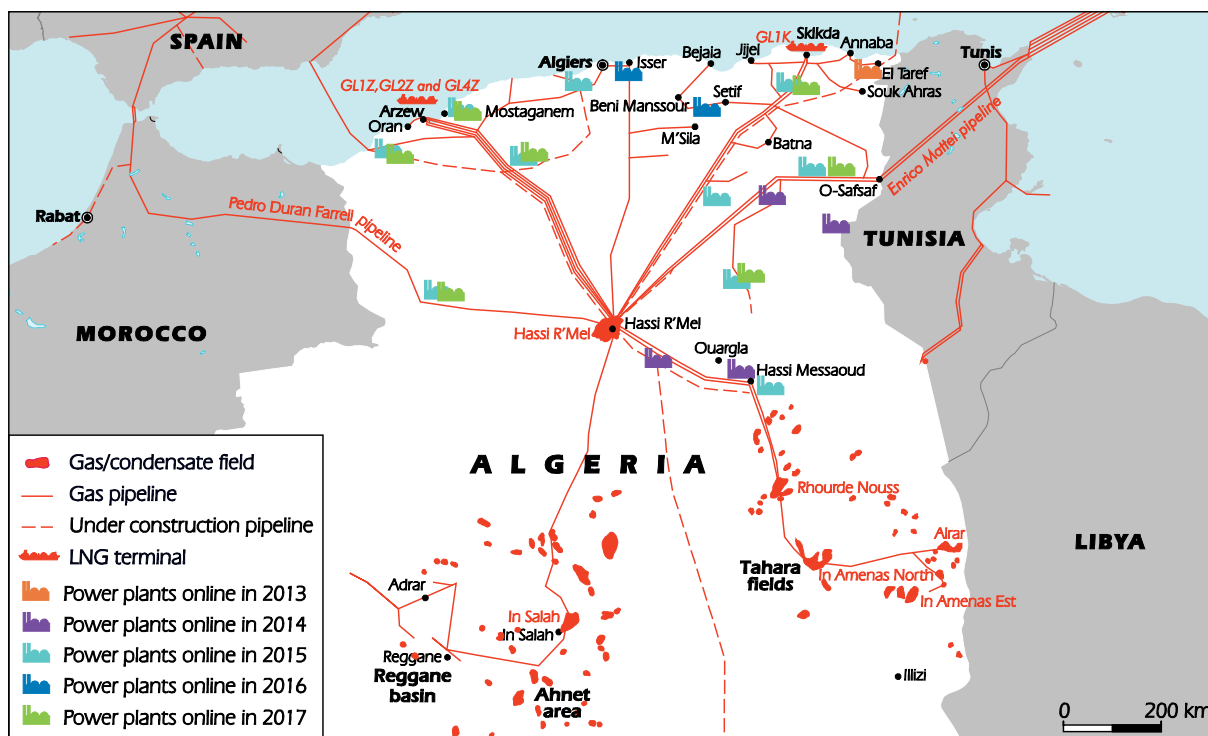
### *Algeria: Lower oil prices slow down investments in new power capacity*

Algerian gas demand is expected to reach 43 bcm by 2020, adding just over 7 bcm between 2014 and 2020. The bulk of the increase originates from the power sector where the state-owned company Sonelgaz is engaging in a large expansion programme. Due to Algeria's vast gas resources, most of its power plants run on gas. Between 2008 and 2013, public utility Sonelgaz added an estimated 7 GW of new generation capacity; gas-fired generation increased at an average annual rate of 7%. Almost all of the Algerian population has access to electricity, but despite progress made in adding capacity, power rationing has been routinely imposed, often triggering social unrest. In the summer of 2012, air-conditioning use surged on the back of extremely high temperatures causing power shortages, which, in turn, sparked riots. Widespread usage of energy subsidies is a problem as it encourages wasteful energy deployment.

Sonelgaz is trying to respond to the country's electricity needs and plans to spend USD 22 billion in generation, transmission and distribution between 2014 and 2017 (Sonelgaz, 2013). Sonelgaz awarded contracts worth USD 4 billion for the construction of six new power plants in 2014. It has also entered into joint venture agreements with major foreign players such as GE to develop an industrial complex to manufacture gas turbines, steam turbines, generators and control systems. GE will supply components to build 9 GW of additional generation capacity based on a contract worth USD 2.7 billion.

However, the development plan is unlikely to be carried out in its current form. Lower oil prices are constraining Algerian finances. The 2014 budget deficit ballooned to 18% of GDP for the first time in 15 years (IMF, 2014). In the current market environment, cutbacks on social programmes and infrastructure projects are likely. The Algerian government announced in early 2015 that funding for mega projects, such as tramways and railways, would be postponed. Should the current low oil price persist, Algeria's existing socio-economic model, whereby energy revenues go to finance social subsidies and energy infrastructure projects, will be tested.

**Map 2.2** Algeria gas network and new power plants



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

### *Egypt: Leaving the energy crisis behind?*

Egypt is Africa's largest natural gas consumer, with a share of total demand of 40%. After a period of stagnation due to political instability, economic decline and severe supply shortages, gas demand is estimated to resume an upward trend and reach 58 bcm by 2020. Improving supply availability is crucial to this outcome. With production stabilising and LNG imports secured, moderate demand growth should be achievable.

The power sector constitutes the backbone of the country's gas demand. Almost all incremental consumption until 2020 will originate from this sector. About 65% of the 30 GW existing generating capacity is gas-fired. Increased gas supply shortages due to fast declining production led to frequent blackouts in recent years. In 2014 the country faced a grave energy crisis, when extreme high summer temperatures forced the authorities to schedule rolling power cuts. The power sector has priority over available gas supplies, which forced the manufacturing industry to cut production amid gas shortages.

The gas-intensive industry has been suffering since 2007; output has been on a declining trend since, falling at an average annual rate of 3.4%. Faced with a structural gas shortage, industrial producers have been looking at coal as a possible alternative. At the end of 2014, several cement producers, which account for a large portion of the country's energy-intensive industry, started retrofitting their plants to run on imported coal.

The Egyptian government is also taking action. In July 2014, a five-year plan to eliminate subsidies on petrol, gas and electricity was launched (IMF, 2015a). Lower oil prices are creating tailwinds to this process. The government expects to spend USD 10 billion on subsidies in the fiscal year 2014/2015, 30% less than the initial budget. Lower subsidies are instrumental to reining in wasteful energy use while stimulating new oil and gas investments.

The government is also looking at diversifying its power generation capacity away from gas. In the beginning of 2015, the government announced that it would add 24.3 GW of new power capacity, 20 GW of which will be coal and the rest renewables. The government wants to reach a 2% renewable share by 2020. Egypt is also considering nuclear. During a visit by the Russian President Putin, in early 2015, the two Heads of State signed a memorandum of understanding to jointly build Egypt's first nuclear power plant.

Despite Egypt's diversification efforts, natural gas will remain the dominant fuel for electricity generation during the time horizon of this report; power sector gas demand is expected to grow at an average annual rate of 4%. In view of the supply outlook, little room is left for a recovery in industrial gas demand which is set to stabilise at best.

### *Nigeria: Lack of investment caps gas demand growth*

In relation to its resources and population, Nigeria's gas demand remains modest. Today the country consumes about 14 bcm, 45% of which goes to the power sector. The absence of an adequate and reliable power system and continued underinvestment in electricity infrastructure are the main obstacles to broader penetration of gas. This is a recurrent issue across much of Africa. This report foresees no significant change to the situation over the next five years. Nigeria's cumulative gas demand growth is set to total 3 bcm between 2014 and 2020.

Developing the country's power sector has been on the Nigerian government's agenda for years, but progress has been frustratingly slow. In 2005, Nigeria's federal government launched the Electric Power Sector Reform Act, which stipulated the unbundling and privatisation of the state-owned Power Holding Company of Nigeria (PHCN). In 2010, the government issued the "Power Sector Reform Roadmap" with the aim to increase the country's generation capacity to 40 GW by 2020. To reach this goal, the government estimated that the country will require across value-chain investments of at least USD 3.5 billion per year (Presidential Task Force on Power, 2013).

The government started the privatisation process of the highly inefficient, state-owned monopoly PHCN at the end of 2013 when it handed the company's assets over to private investors. The government hopes this will lead to growing investments and rapid improvement in power supplies. While there are early signs that newly privatised generation companies are increasing investments it might take time before new projects get off the ground.

In addition to the low level of installed capacity, low utilisation is compounding the problem. Lack of gas transportation capacity is creating bottlenecks while chronic security problems in the Niger Delta, a key producing region, hinder international companies' efforts to build the necessary infrastructure. Pipeline vandalism has emerged as another major difficulty. In spite of low hydro availability, 30% of the country's gas-fired generation remained out of service due to sabotages to pipelines in 2014.

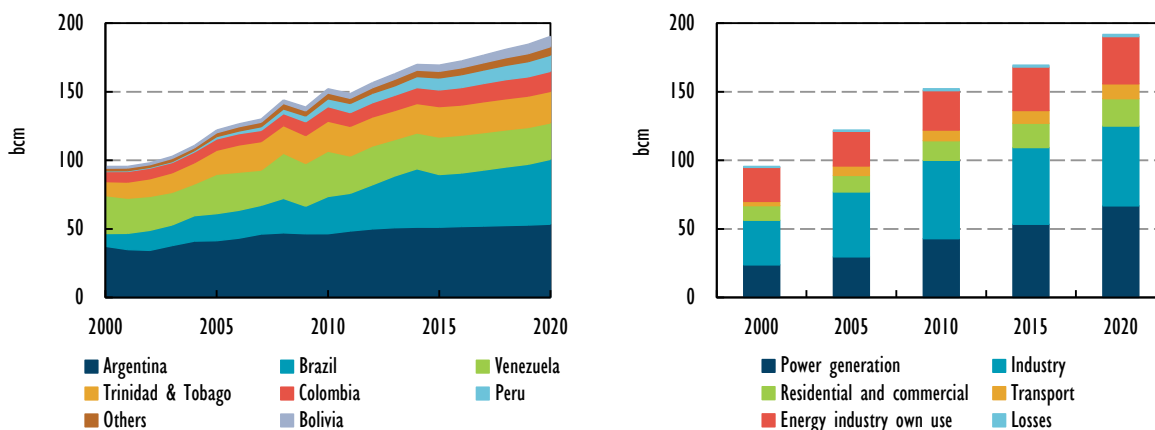
A high level of gas flaring, long distances between power stations and gas sources, and poor alignment of gas and power sector policies add to the traditional list of challenges. New on the list is the drastic fall in oil prices. Thus, with oil revenues accounting for more than 80% of the national budget, the country's finances are in ruins and foreign reserves are falling sharply. Meeting growing budgetary demands will be a daunting task. In early 2015, the finance minister announced drastic capital expenditure cuts due to low production and falling prices. Against this backdrop, progress on power and gas infrastructure investment will remain slow, putting a cap on the expansion of gas demand.

### Latin America: Lower economic growth pushing gas demand down

Latin America's gas demand growth will average 1.7% per year between 2014 and 2020. This is well below the 2.6% average annual increase recorded between 2008 and 2014. Normalisation of the hydro situation in Brazil, modest domestic production growth and weaker economic activity weigh on the demand outlook. Overall, the reduction in gas usage in the Brazilian power system is primarily responsible for the slowdown.

The economic outlook for Latin America has deteriorated over the past year. In its January 2015 update, the IMF pegs growth for the region at 1.3% and 2.3% in 2015 and 2016, respectively (IMF, 2015b), significantly below the average growth rate of the past ten years.

**Figure 2.20** Latin America gas demand by country and by sector, 2000-20



### *Argentina: Between supply shortages and an increasing energy bill*

This report projects Argentina's gas demand to increase slightly over the next five years. Supply shortages will continue to constrain demand increases with the country's gas balance witnessing only minor improvements until 2020. Since turning into a net gas importer in 2008, Argentina's net import requirements have increased by 13 bcm. By 2020, imports will stabilise, but exports will not resume.

Argentina is taking steps to stem the rise in its import dependency as growing energy bills are weighing on the country's precarious fiscal position. In an effort to stem dollar-denominated payments for gas imports, the government has started cutting expensive subsidies to residential and commercial customers, while introducing measures to reduce the attractiveness of NGVs. Argentina is one of the world's largest consumers of gas in the road transportation sector. High gasoline prices in recent years have boosted the number of car conversions from oil to natural gas. This trend was still evident in 2014.

The government has so far spared the industrial and power sectors from tough price reforms, attempting to strike a balance between tackling its fiscal problems and supporting its ailing economy. Since 2006, natural gas usage in the industrial sector has remained flat, a trend which is likely to persist, in view of the country's financial and economic challenges. The power sector, the largest gas end-user, accounts for almost 60% of total demand. Consumption in this sector will grow moderately, as faster growth is prevented by limited supplies.

### *Brazil: Thirsty for gas*

Brazil's gas consumption shot up in the past three years due to severe hydro shortages, which required switching on back-up gas-fired generation. In the power sector, gas usage has increased more than two-and-a-half times since 2011. Continued low precipitation levels earlier in the year will lead to sustained consumption in 2015 as well. Over time, the normalisation of weather should result in better hydro availability on average, although hydro generation will be more volatile than in the past. This is due to a decreasing share of hydro plants with large water reservoirs. Overall, this report forecasts Brazil's gas consumption to increase at an annual average rate of 1.1% between 2014 and 2020.

Approximately half of Brazil's gas consumption is for the power sector. With a power system heavily dependent on hydro (for about 70% of total generation) annual swings in thermal generation are common. However, the impact of the latest multi-year drought has been magnified by the structural decline in the number of hydropower plants with large water storage facilities. In the past, water stocks were an integral part of hydropower plants with firm energy of 50-60% of total existing capacity. However, due to environmental and social pressures only 10 of the 42 hydro power plants built between 2000 and 2012 were constructed with water reservoirs.

Severe droughts across the country in 2013/14 lowered water supplies to near critical levels. To address the electricity crisis, all idled thermal power plants were restarted, boosting natural gas imports and pushing electricity spot prices to record levels. The dry period has continued in Q1 2015 forcing the city of Sao Paulo to ration water.

The outlook for gas consumption in the transportation sector is uncertain. Modest growth is likely, but much will depend on gas supply availability and the degree of government support. With 1.8 million NGVs, Brazil has one of the largest natural gas vehicle fleets in the world, although its share remains limited with respect to total gas consumption and total vehicle population.

Preliminary figures suggest that gas usage in the sector declined in 2014 (Abegás, 2015). Interest from some states towards gas is decreasing. For instance, in Fortaleza the number of filling stations delivering gas has fallen to 41 from 80 a few years ago. Others states, such as Manaus, introduced measures to stimulate the use of gas in transport. Overall, much will depend on the government's policy choices and its willingness to push for continued penetration of gas. Even amid much lower international oil prices, the competitiveness of gas can be preserved, if retail gas prices continue to be set at a discount to gasoline. Gas consumption in the industrial sector has been stagnant since 2010. This situation is likely to persist in the short term due to the deep economic challenges faced by the country.

### *Bolivia: Lower oil prices threaten strong demand growth*

Natural gas demand in Bolivia has grown at an annual rate of close to 10% over the last ten years, underpinned by robust economic growth and supportive energy policies. The outlook remains positive and demand is set to reach 7.4 bcm by 2020, increasing by 80% relative to the level in 2014. However, the poor production outlook will require that exports be cut back from current levels to ensure that demand be met.

Taking advantage of ample resources, the Bolivian government has relied heavily on gas to stimulate economic growth and provide energy to citizens. Gas-fired capacity has been expanded rapidly and gas consumption in the power sector has doubled since 2004. Meanwhile, supportive policies for the petrochemical industry have led to higher gas consumption in the industrial sector, which accounts for about one-fifth of total gas usage. Residential consumption is also increasing, although from a very low base, thanks to a national campaign to increase residential coverage. Highly regulated prices and free gas installations have been used as tools in this effort. Similarly, the government is offering free conversion of oil-powered cars to gas to stimulate the uptake of NGVs.

In this context, gas consumption is likely to increase robustly, with annual growth estimated at 10% per year between 2014 and 2020. However, a protracted period of low oil prices would pose downside risks to the outlook, given the country's reliance on gas export revenues for both economic growth and the government's social agenda.

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## 3. SUPPLY

### Summary: Global production growth shifts towards OECD countries

- Global gas production is set to increase at an average annual rate of 1.9% between 2014 and 2020, a slowdown compared with the 2.4% rate of the previous ten years.
- OECD's production grows robustly, at an annual average rate of 2.2%, almost 1% stronger than that recorded over the previous ten years. Robust production additions from OECD Americas and OECD Asia Oceania more than offset continued declines in OECD Europe. In absolute terms, the United States accounts for the largest portion of the increase, but in percentage terms, Australia stages the strongest growth. Both countries will be large liquefied natural gas (LNG) exporters by the end of the forecast period.
- Non-OECD's production increases at an annual average rate of 1.7%, accounting for 57% of the global increase, compared with a share of almost 80% over the previous ten years.
- In China, the outlook for unconventional gas has weakened markedly with less optimistic prospects for both coal-to-gas projects, and shale gas developments. As conventional gas assets mature, production growth will slow down to an average rate of 5.5%, almost half the level recorded over previous ten years.
- Non-OECD Asia (excluding China) gas production will grow at an annual average rate of 1% between 2014 and 2020, with Indonesia and Malaysia accounting for 60% of the increase. The rest of the region struggles to deliver gains. The outlook for India has turned less favourable than previously forecast, as recent price reform falls short of that needed to revive the domestic upstream sector. Overall, incremental production covers less than 40% of domestic demand growth, turning the region into a net gas importer by 2020.

**Table 3.1** World gas supply by region (bcm)

Country	2014	2016	2018	2020	CAAGR
OECD Europe	254	246	238	227	-1.9%
OECD Americas	937	966	1011	1057	2.0%
OECD Asia Oceania	82	126	159	167	12.6%
Africa	203	209	216	225	1.7%
Non-OECD Asia (excl. China)	324	330	339	345	1.0%
China	124	141	156	171	5.5%
FSU/non-OECD Europe	869	874	889	930	1.1%
Latin America	178	180	183	185	0.7%
Middle East	546	566	593	621	2.2%
<b>Total</b>	<b>3 517</b>	<b>3 638</b>	<b>3 785</b>	<b>3 927</b>	<b>1.9%</b>

Notes: bcm = billion cubic metres. FSU = Former Soviet Union. 2014 figures are estimates. The compounded average annual growth rate (CAAGR) is different for production and demand due to estimated stock changes in 2014. The world total production and demand differ due to estimated stock change and rounding.

- Latin America's production growth slows down substantially, increasing by a mere 0.7% per year. The outlook for Brazil and Argentina remains positive despite a drop in the oil price and

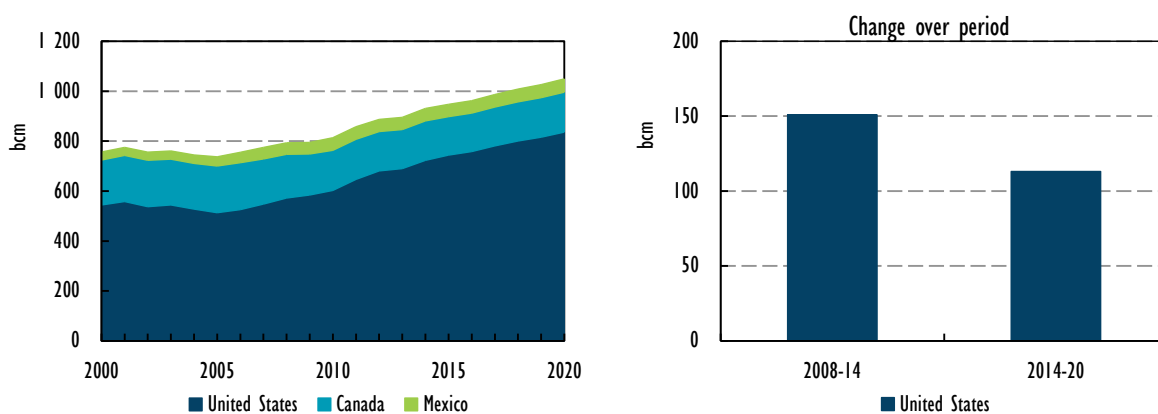
Petrobras's legal challenges. The biggest strain comes from the rest of South America. Combined production from Peru, Colombia and Bolivia – which increased by more than 20 bcm between 2008 and 2014 – is set to decline by 1 bcm in total until 2020.

- Africa's gas production will grow at an average annual rate of 1.7% between 2014 and 2020. The increase is a welcome change after seven years of volatile output showing a declining trend. Algeria, Nigeria, and Egypt will continue to account for the largest part of Africa's gas production as LNG exports from East Africa are not expected to begin within the timeframe of this report. Production additions fall short of the continent's demand needs and pose continued threats to the reliability of exports.
- The Middle East's production will grow at an average annual rate of 2.2% between 2014 and 2020, significantly less than the 7% recorded over the previous ten years. Flattening production from Qatar – where the moratorium on North Field remains in place – is the more significant contributor to the slowdown. The outlook for Iraq and Iran is challenged by a difficult geopolitical context. In Iran, improving international relationships are a necessary precondition for a substantial expansion in production. In addition, bottom-up improvements in taxation and regulation would also be required to revive the country's upstream sector, which is unlikely before 2020.
- FSU production will grow at an average annual rate of 1.1% between 2014 and 2020, with the Caspian region accounting for 85% of the increase. Russian production struggles to recover from the multi-year, low level of 2014, due to weak domestic consumption and limited export options till late in the decade. The start-up of the Power of Siberia in 2019/20 allows for a modest production recovery at the end of the forecast period.

### OECD Americas: Resourceful

OECD America's gas production will grow at an average annual rate of 2% between 2014 and 2020, adding 120 bcm over the period. The increase comes primarily from the United States, with additions from Mexico and Canada totalling just 6 bcm. Overall, the region's growth slowed down from the 2.8% recorded over the previous six years, largely due to lower oil prices.

Figure 3.1 OECD America supply by country, 2000-20

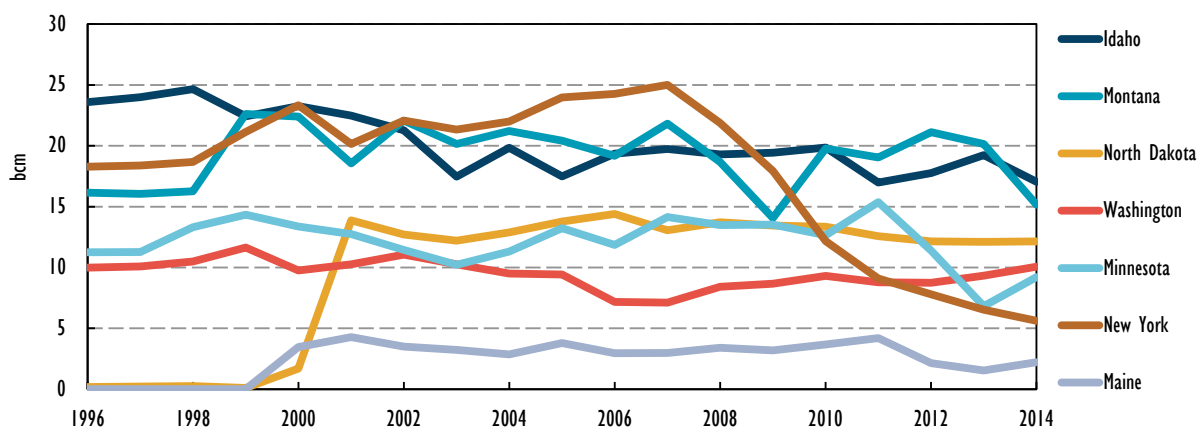


### Canada: Competition from United States clouds production outlook

Canada's upstream sector continues to be undermined by rising competition from the United States, particularly from its northeast shale formations with their impressive productivity. With limited domestic demand growth, mainly linked to oil sand developments, Canada is struggling to find marketable opportunities for its own gas. Prospects for LNG projects have deteriorated and no plant is expected to be operational over the time horizon of this report. There are several new pipeline projects for bringing gas from US Northeast into the US Midwest and Central/Eastern Canada, which could cause further volumes of Alberta's gas to be backed out from its traditional core markets.

Between 2007 and 2014, Canadian gas exports to the United States dropped by 30 bcm; 60% of that relates to exports through the New York State entry point (see Figure 3.2). The displacement reflects soaring production from the Marcellus shale and its fast penetration into the nearby markets of New England and Mid-Atlantic. So far, Alberta volumes into the Midwest have held up relatively well while those into the West Coast have nudged higher.

**Figure 3.2** Canadian gas exports to the United States by entry point, 1996-2014



Source: IEA analysis based on data from the US Energy Information Administration.

For Canadian production, the main issue is how fast and how competitively US Northeast gas can penetrate the Midwest market (which accounts for about a quarter of total US gas consumption) and possibly Central and Eastern Canada. Further displacement seems likely when judging from the pipeline of new projects. The start-up of the East–West project on the REX pipeline later in 2015 will allow for up to 12 bcm of Northeast gas to reach the Midwest market. Some projects are also looking at transporting US gas into Canada: the proposed reversal of the Iroquois pipeline that originates near Montreal and heads south into New York State is one of them.

While Canadian production will remain challenged, there are limits to the degree of displacement that can take place, particularly looking towards the end of the period. Between 2014 and 2020, the call on US gas from LNG buyers and Mexico will increase by 75 bcm. The United States' own consumption is also set to grow, increasing by about 35 bcm. If the United States can keep adding large quantities of gas at a price that remains competitive compared to Canadian volumes, then more displacement will occur. However, with export demand for US gas set to increase rapidly, Canadian production might ultimately find some room in the North American supply system to feed into a growing call from abroad.

### *United States: Production outlook resilient in the face of plummeting oil prices*

After surging in 2014, US gas production remained on a steep upward trend until early 2015 (see Chapter 1). The supply outlook remains solid, and production will increase by 114 bcm until 2020. Lower oil prices will impact growth from associated and wetter gas where economics have worsened. However, increasing activity in the Haynesville together with robust additions from the Northeast will keep production on a strong positive trend.

The dramatic drop in oil prices raises questions about the implication for the trajectory of gas output. The oil rig count has plunged – more than halving since its peak in mid-October 2014. The Eagle Ford and the Permian – the two key sources of associated gas production growth – have not escaped this trend.

US producers are cutting capital expenditures (CAPEX), which is impacting drilling activity. While service costs are falling, they have so far lagged behind the adjustment in budgets. If further cost reductions are achieved companies may revise their drilling programmes upwards later on. Deferring well completions – which account for 50% to 70% of the total cost of drilling a well – is another CAPEX deferring technique often used. This allows producers to control costs without compromising production prospects should prices rise again. A large backload of uncompleted wells means a steeper production fall on the way down, but a faster recovery on the way up.

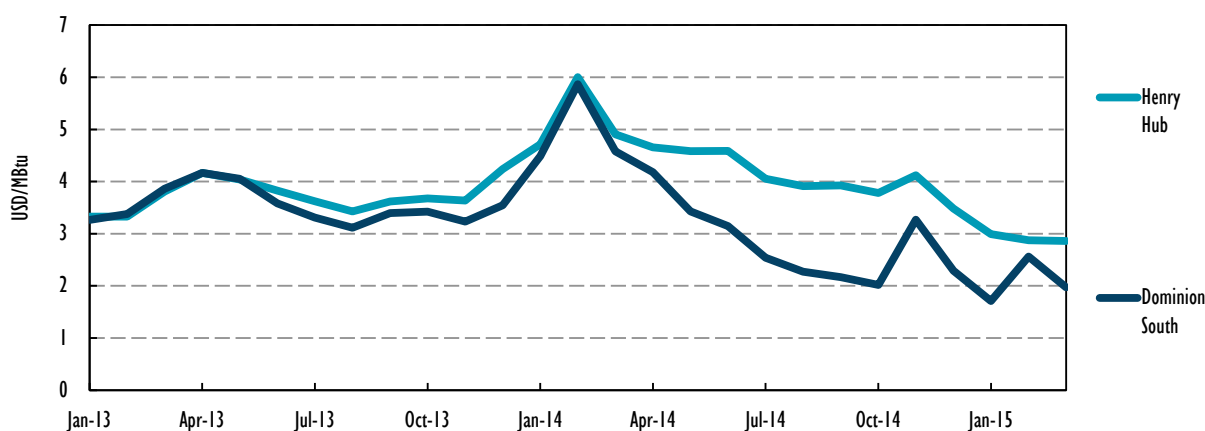
However, the rig count is just one side of the story; the other being the oil and gas volume produced by each rig. Rig productivity has continued to increase on the back of improvements in drilling efficiency and hydraulic fracturing techniques. While gains differ from play to play, the trend of rising efficiency has proved significant and sustained. Increased well productivity will partly offset the impact on production of lower drilling.

With a huge adjustment underway throughout the entire US oil supply chain, the net effect on production remains difficult to judge. On balance, the IEA expects US light tight oil production to continue to grow over the medium term albeit at a much slower pace than before (see IEA [2015]). As a result, associated gas production is also set to increase moderately throughout 2020, falling in the earlier part of the forecast period, but recovering afterwards. Texas associated gas production additions are estimated at about 13 bcm in 2014. Growth, there, might well slip into negative territory towards 2016, if oil prices do not recover.

Even in that case, total US gas production will continue to grow robustly owing to two main factors: continued strong output additions from the Marcellus/Utica shale plays and flattening decline rates in other dry gas plays, mainly the Haynesville.

Production from the Marcellus/Utica formations remains on a steep upwards trajectory. Output surged in 2014, adding an estimated 43 bcm. Growth is likely to moderate in 2015, but mainly due to transportation bottlenecks rather than lower oil prices. Take-away capacity has been scaled up in recent years and further expansions are planned. Yet, pipeline additions tend to come on line in chunks and signs of congestion in regional pipeline flows re-emerged in 2015. This has resulted in large, negative differentials between prices in the Appalachian Basin and Henry Hub in early 2015 leading a number of operators to scale back activity in the Marcellus (see Figure 3.3). Lower revenues from wetter streams have also contributed to reduce the sustainability of very low prices – at times trading below USD 1.50/ million British thermal units (MBtu). Crucially, the pull-back in the Marcellus has resulted from the need to rebalance an oversupplied gas market at this stage, rather than having been triggered by lower oil prices.

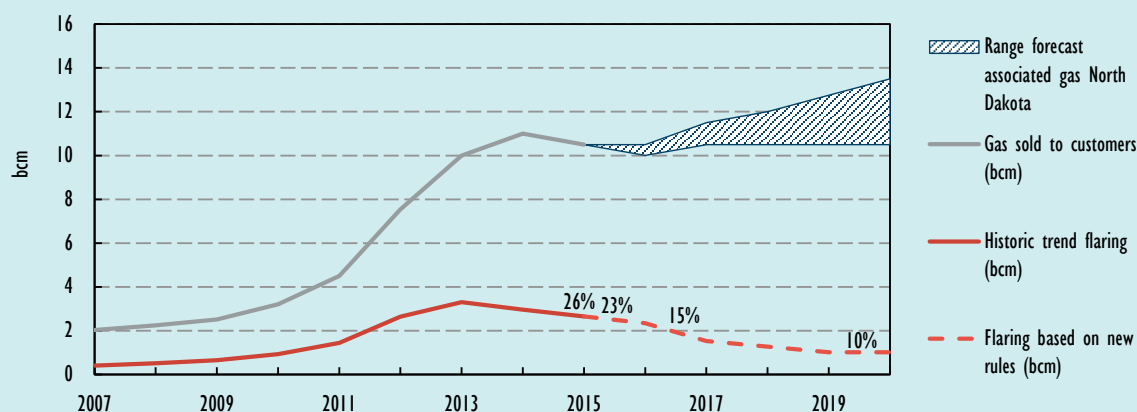
Figure 3.3 Prices Henry Hub and Dominion South



### Box 3.1 North Dakota: A step in the struggle against flaring

In July 2014, the North Dakota Industrial Commission, which regulates and promotes the state's oil industry, introduced flaring standards. The aim is to oblige drillers to capture 90% of all the gas they release by 2020, even if it means cutting back oil production. The new rules started at the end of 2014 with a first target to reduce flaring to 26% of all produced gas. Future goals are 23% by January 2015; 15% by January 2016; and 10% by October 2020 (see Figure 3.4).

Figure 3.4 Goals to reduce flaring in North Dakota



With the new regulation, the regulatory authority of North Dakota wants to bring flaring to levels more in line with producing states like Texas, which is the only state with a higher oil production than North Dakota. In Texas 0.8% of the produced gas is flared.

The high initial production in the Bakken/Three Forks was followed by rapidly declining oil and gas production. Given the environment of low natural gas prices, it was uneconomic to construct much needed large-volume gas gathering and processing capacity to reduce flaring rapidly. Despite this, in recent years, some projects have come on line slowly, thus increasing the possibilities to bring natural gas to the market and reduce flaring. Between now and 2017, several projects will come on line: a new natural gas processing plant with a processing capacity of 4 bcm and two pipelines, each with a similar capacity.



A further positive for US gas production is the improved outlook for the Haynesville. The latter stood as the largest producing shale play in the United States until 2012, when the Marcellus overtook it. At its peak in 2011, the Haynesville produced 100 bcm of gas. A shift towards liquid-rich and Northeast formations caused operators to pull back from the play, resulting in a sudden drop in production as high, initial decline rates, typical of unconventional wells, kicked in. From peak to trough, production fell by 40 bcm. However, the Haynesville is poised to make a positive contribution to overall US production in 2015. Decline rates from legacy wells have stabilised, while producers are showing renewed interest in the play, largely through re-fracking. Chesapeake is leading the pack: the company which operates more than 100 wells in the Haynesville announced it would increase capital spending in the play by almost 20% in 2015.

### *Mexico: On the right path*

Mexico's gas production has been falling in recent years; despite a better performance in 2014, it remains below its 2010 peak. Production is expected to increase gently until 2020, with the improvement skewed towards the latter part of the forecast period when new investments, helped by landmark energy reform, should start filtering through higher production. However, low oil prices may curb a much needed capital influx into the country's upstream sector.

The poor production performance of the past four years is tied to a lack of adequate investments. State-owned company PEMEX has not discovered or developed new fields at a fast enough pace to offset declines from its producing assets, with the consequence that reserves and production have fallen.

PEMEX said it invested USD 28 billion in exploration and production activities in 2014, below the level that is considered necessary to break the negative trend. High taxes and large fiscal obligations have hamstrung its ability to invest. Lower oil prices are worsening the situation, with the company announcing capital spending cuts in early 2015.

This report forecasts Mexican gas production to stabilise and trend modestly higher, but it does not foresee a turning point in the performance of its upstream sector. Production additions are mainly linked to starting up new fields from PEMEX's existing portfolio and better management of currently producing assets, partly helped by the ongoing restructuring of the company.

For a real turning point in production, larger mobilisation of capital and technology is required. Energy reform recently enacted has the potential to achieve that, but even assuming higher oil prices, large output gains would be predominately visible moving into the next decade. International oil companies are likely to seek further clarity on the regulatory framework and implementation details before committing substantial amount of capital, even if they are interested in investing.

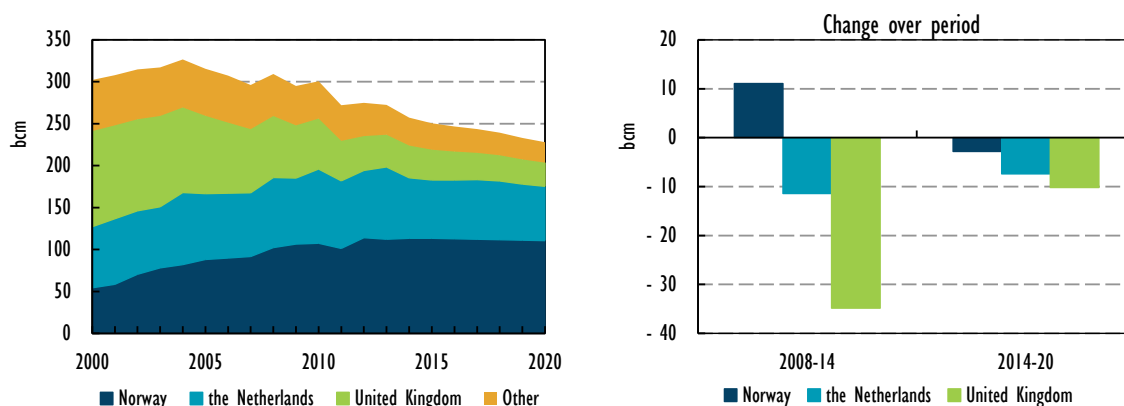
At the same time, capacity bottlenecks in rolling out the vast amount of institutional changes, that the reform prescribes, may also delay the overall investment process. Adding to this, plunging oil prices and associated CAPEX cuts will unavoidably deter large investments in upstream and inject more caution in companies' investment decisions.

### **OECD Europe: Keep on declining**

Gas production in OECD Europe will remain on a downward trend over the next five years, falling by 27 bcm between 2014 and 2020. By 2020 Europe gas production will be 25% below its 2010 level,

having dropped by 75 bcm. The United Kingdom, Norway and the Netherlands account for the bulk of the drop, but they also remain the key regional producers with growth prospects elsewhere largely unrealised over the forecast period. The forecast constitutes a downward assessment relative to last year caused by negative revisions to the investment outlook on the back of lower oil prices. More stringent assumptions on production caps in the Netherlands also weigh on Europe's production prospects.

Figure 3.5 OECD Europe supply by country, 2000-20



### Norway: Not immune to low prices

Norway's gas production will decline slightly between 2014 and 2020. This is a change compared to last year's outlook entirely driven by lower oil and gas prices. After a 2 bcm fall in 2013, Norwegian gas production was broadly flat in 2014. Before the sharp drop in prices, output was set to remain broadly unchanged in 2015/16 and then start increasing gently. Today's prices point to substantial cutbacks in investments, particularly from 2016 onwards with production struggling to stay flat until 2020 as development activity drops.

The Norwegian Petroleum Directorate forecasts oil and gas investments for production and exploration in the Norwegian shelf to fall by more than 20% between 2014 and 2017 (NPD, 2015). Major work at some large producing fields was recently completed (including at Ekofisk Sør, Eldfisk II, Troll and Åsgard) and, in the current market environment, further non-essential upgrades will be pushed back. Similarly, the development of new fields is set to be subjected to a much tougher vetting process. All this will weigh on production growth going forward, particularly moving towards the end of the forecast period.

Notwithstanding the negative setting, some new projects will still come on line in the next five years, helping offset declines elsewhere. In particular, the Gina Krog and Aasta Hansteen fields are still scheduled for start-up in 2017. The latter, with estimated recoverable resources of almost 50 bcm, is an extremely challenging project located in the Norwegian Sea, above the Arctic Circle. Far from land and infrastructure (300 kilometres [km] off the coast) in water depth of 1 300 metres, it requires the deployment of cutting edge offshore technology. The project will tie into the Polarled pipeline, a new 480 km line built to facilitate the development of discoveries in the northern portion of the Norwegian Sea.

### The Netherlands: Downward trend challenges Western European natural gas market

In January 2014, the Dutch Minister of Economic Affairs imposed a production cap on the Groningen field for 2014, 2015, and 2016 for safety reasons. The decision was taken after registering increased

earthquake activity in the province of Groningen, which hosts the country's largest-producing field. Following a number of revisions, the caps now stand at 42.5, 39.4, and 39.4 bcm, respectively, for the three years (Geq;<sup>1</sup> 35.17 megajoules per cubic metre [ $\text{MJ}/\text{m}^3$ ]).

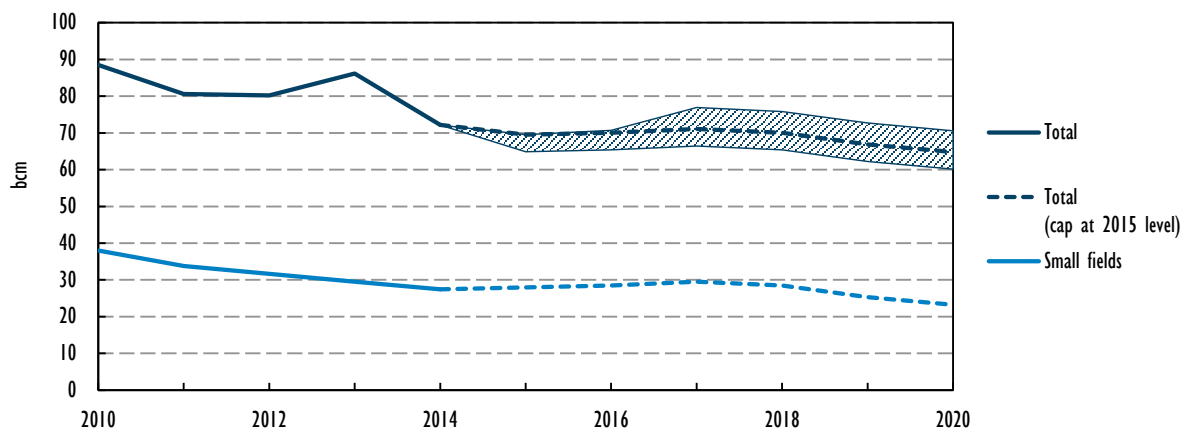
In February 2015, the Dutch government introduced an additional production limit for the first six months of 2015, setting it at 16.5 bcm (Geq). A final decision regarding Groningen's full-year production is due in July 2015. Public opinion is highly in favour of a lower cap, and Dutch politicians have often referred to a 2015 cap of 35 bcm (Geq).

Dutch gas production fell sharply in 2014, averaging 71 bcm, an 18% drop from 2013. Most of the decrease is due to the Groningen production cap, but less output from small fields also contributed to the poor performance. The underlying assumption is that the existing production cap on the Groningen field will extend to 2020 and that the declining trend of the small fields will continue during the forecast period (which now accounts for 40% of the country's gas production). As a result, Dutch gas output will fall by another 5 bcm by the end of the decade.

**Table 3.2** Groningen field production cap (Geq)

Maximum production (bcm)	2014	2015	2016	Gas year 2015 (Oct 2015-Oct 2016)
First cap (January 2014)	42.5	42.5	40	
Produced	42.4			
adjustment (December 2014)		39.4	39.4	
Latest cap (February 2015)		39.4 and 16.5 for only the first half of 2015	<i>Changed to gas year 2015 cap</i>	39.4

**Figure 3.6** Total production the Netherlands



Note: Total production scenario is based on extending the existing Groningen production cap for 2015 (41.8 bcm) up to 2020. The dashed area represents a high scenario (cap at 47 bcm) and low scenario (cap at 37 bcm) for the Groningen production. Volumes in the figure are calculated based on a conversion factor of  $33.3 \text{ MJ}/\text{m}^3$ . This differs from the Groningen gas equivalent energy content of  $35.17 \text{ MJ}/\text{m}^3$ .

<sup>1</sup> Geq = Groningen gas equivalent, i.e. gas with an energy content of  $35.17 \text{ MJ}/\text{m}^3$ .

The Dutch government has not ruled on specific annual Groningen production caps beyond 2016. Formally, the existing long-term cap of 448.5 bcm (Geq) for the period 2011-20 remains in place. For the period post-2020, the government has not introduced any short- or long-term output limit since Groningen's production is expected to start declining naturally in any case.

Besides declining Groningen production, the Netherlands has to deal with falling output from several small on- and offshore fields. Taken together, production from those fields peaked in 2000 at about 50 bcm per year (33.30 MJ/m<sup>3</sup>). Production has since declined, falling to 27 bcm in 2014. After a short-lived increase, the downward trend is set to continue through 2020 with output expected to fall by another 4 bcm. Figure 3.6 illustrates a range of possible outcomes for Dutch gas production under different Groningen production caps.

### Box 3.2 Caps on Groningen production tighten supplies to Western Europe L-gas markets

The Groningen field produces low-calorific gas (L-gas) and is the main supplier of L-gas in Northwest Europe (NWE). Total L-gas consumption in NWE is approximately 60 bcm per year under normal temperature conditions (GTS, 2013). Groningen production, together with so-called pseudo low-calorific gas\*, supplies the Dutch market (30 bcm) and a meaningful share of the Belgian (5 bcm), German (10 bcm), and northern French (5 bcm) residential sector. The rest of the European gas market uses high calorific gas (H-gas).

Low and high calorific gas are not exchangeable for use in residential or industrial gas appliances, because gas appliances are set to handle a specific calorific value range. Using gas with a different calorific value is dangerous because it either will not burn or monoxide can be released while burning.

The small gas fields in the Netherlands mainly produce H-gas. Lower Groningen L-gas production has limited substitutes and therefore has implications that go beyond the volumetric loss of an indigenous source of gas to Europe. The caps on Groningen's output increase the urgency of coping with potential supply shortages of L-gas. The issue in itself, however, is not new as Groningen's L-gas production was, in any case, expected to decline post-2020.

The Dutch government is following a twofold strategy to deal with the projected decline of L-gas availability. The first is to create (pseudo) L-gas by a quality conversion process which requires adding nitrogen to H-gas. This solution is already being used, and the Dutch TSO Gasunie Transport Services (GTS) has several nitrogen plants in operation. Due to the production caps, the need to accelerate the investment programme to increase the nitrogen capacity cannot be excluded. According to research commissioned by the Dutch government on the availability of L-gas and gas quality conversion, it is possible to supply the L-gas market with reduced Groningen gas production at a cap level of 35 bcm per year in combination with the maximum use of quality conversion capacity (GTS, 2013).

In addition to these investments, action will be taken on the demand side to transition customers from the L-gas to the H-gas market. This means switching to household appliances that can handle a high-calorific gas quality and is mainly done by introducing new norms for household equipment. The governments of the Netherlands, Belgium, France, and Germany are following a co-ordinated strategy to manage this market transition. The market uptake will go hand-in-hand with the pace of the natural decline of projected L-gas availability after 2020. Germany will start the transition this year and is also due to lower L-gas availability from its own production, whereas Belgium and France must be converted by 2024. In the Netherlands the transition must occur by 2030. This longer period will allow the Netherlands to make optimal use of the natural phase out of existing appliances (GasTerra, 2015).

\* Pseudo L-gas is created by quality conversion: blending high calorific gas (H-gas) with nitrogen to gas with a low calorific value (L-gas).

### *Shale gas in Europe: Between hope and disillusion*

Companies' interest in shale gas is evaporating fast, even in those countries where governments have proven supportive, such as Poland and Romania. Disappointing test wells, regulatory constraints, and continued public hostility have added to deteriorating economics as a result of lower oil and gas prices that have all contributed to dimming the outlook for shale gas.

Eight of the 11 international companies which had invested in Poland – including Chevron, Exxon, Talisman, Marathon, Eni and Total – halted exploration activities by the end of Q1 2015. Chevron also pulled out of shale gas projects in Ukraine, Lithuania and Romania. For Romania Chevron declared that shale gas was not competing favourably with other investments in its global portfolio.

Companies are redirecting their strategy away from assets considered riskier and less attractive. Also, CAPEX is scaled back and shale gas in Europe is falling victim to that re-orientation. In retrospect, any early enthusiasm for a shale gas boom in the region was misplaced and massive investments in the sector will not materialise in the near future. In Poland – which had been regarded as one of the most promising countries for commercial shale gas production – most of the remaining shale gas activities are now run by the state-owned company, PGNiG, and independents. While both can rely on international service companies with their strong technical capacities in the field, it might prove difficult to mobilise the necessary capital.

In the Netherlands, the government adopted a parliamentary motion at the end of 2014 that forbids shale gas extraction during the present government's term of office, which is to run until the end of 2016. Old moratoria have been reaffirmed by new governments, such as Bulgaria, while a new moratorium has been announced in Scotland. In the rest of the United Kingdom, political debate on the subject remains heated amid persisting public hostility against fracking, although the government is supportive of the technology. In Spain, exploration permits are unlikely to be granted before 2020.

Against this worsening outlook, Germany was one of the very few countries to make a step forward. The government approved a draft law for the commercial exploitation of shale gas and oil in exceptional cases before 2019 and only after successful test drilling.

### *Insight focus: Infrastructure developments Europe 2010-15*

Gas infrastructure in Europe has expanded significantly over the past five years. Regional connectivity and supply diversification will increase further, as new projects come on line. Better interconnections, also through reverse flows, are being developed within regions and from NWE to Eastern Europe and Southeast Europe (SEE)<sup>2</sup>, although some countries remain dependent on a single supply source. Eastern Europe and SEE show the greatest vulnerability in the event of a supply disruption due to limited storage and interconnections.

Underground storage and LNG regasification capacity are well developed in NWE and Southwest Europe (SWE)<sup>3</sup>, but interconnectivity bottlenecks across regions remain. This would limit full utilisation of existing infrastructure and supply flows from west-to-east in case of major supply disruptions.

<sup>2</sup> NWE: Austria, Belgium, Denmark, Germany, France, Ireland, Luxembourg, the Netherlands, United Kingdom, Switzerland.

Eastern Europe: Czech Republic, Estonia, Hungary, Lithuania, Latvia, Poland, Slovak Republic.

SEE: Albania, Bosnia-Herzegovina, Bulgaria, Croatia, FYROM, Greece, Kosovo, Montenegro, Romania, Serbia and Slovenia.

<sup>3</sup> SWE: Portugal, Spain and Italy.

Storage capacity has increased over the past five years and several new projects are planned, particularly in the United Kingdom and Italy, but in a context of low seasonal spreads, the economic viability of many of these projects is questionable. Substantial upgrades may be required in the future as storage requirements are shifting towards more flexible, fast-cycle capacity, driven by power sector demand.

### Interconnections

The level of integration and security of the European gas market has progressed since 2009, underpinned by increased connectivity within the region – mainly through reverse flows – and the establishment of new import routes.

In terms of new physical capacity, the start-up of the Nord Stream pipeline and associated downstream infrastructure such as the NEL, OPAL and Gazelle pipeline has allowed large volumes of Russian gas to reach Germany, bypassing Ukraine (see Map 3.1, arrow 1). As a result of the new route, the flows from Germany to France and from Germany to the Czech Republic have undergone a major upgrade. Nord Stream has been by far the most important addition to new, physical pipeline capacity occurring in Europe in recent years. Besides Nord Stream, the Medgaz pipeline running from Algeria to Spain has also been constructed. The pipeline, with a capacity of 8 bcm, started operating in 2011.

Besides these two additions, most of the increased interconnectivity within Europe comes from introducing reverse flows capabilities on existing lines rather than from the physical construction of new capacity. In this context, the establishment of reverse flows on the Brotherhood pipeline – the key line connecting Russia to central Europe via Ukraine – has come as a major strategic improvement for the supply security of the region. Substantial volumes can now move from Germany through the Czech Republic and Slovak Republic to Ukraine, reversing the traditional east-to-west flow (see Map 3.1, arrow 2).

Further progress in boosting west-to-east capacity relates to increased reverse flow possibilities from Germany to Austria, and from Italy to Austria, which has allowed more Austrian gas to flow to Slovak Republic (see Map 3.1, arrow 3). Crucially, however, reverse flow capabilities from Italy to Austria through the major TAG trunk line are just around 17% of the 36 bcm capacity in the original east-to-west direction.

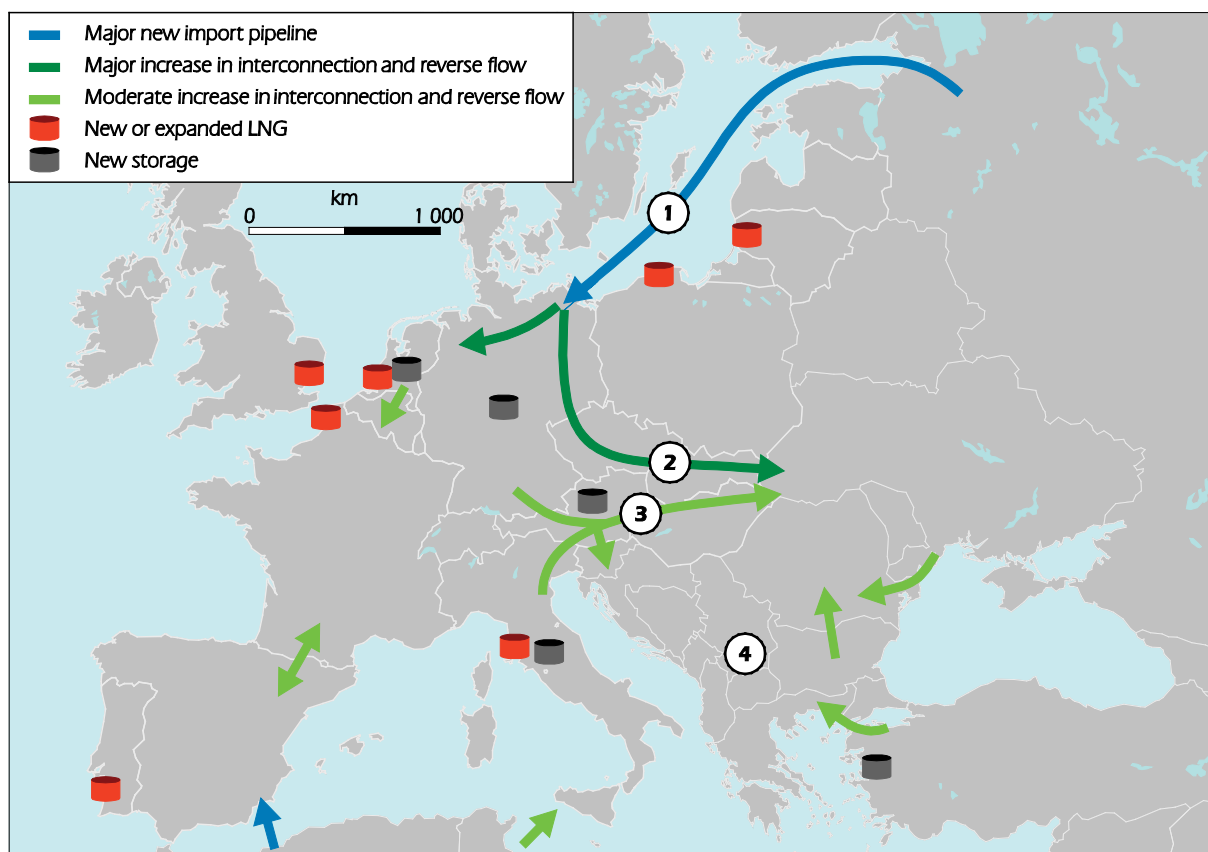
Moreover, problems with the allocation process of the Austria-Hungary portion of the line – as well as bottlenecks within Hungary – would practically limit Italy's ability to serve as a major entry point for transit gas to Eastern Europe. Partial reverse flow capacity from the Italian side has not been a major issue over the past three years because Italy has been quite short on gas. However, this could significantly change by the end of the decade when TANAP/TAP will flow increased quantities of Caspian supplies through the country.

**The United Kingdom, the Netherlands and Belgium** are well interconnected as demonstrated by the coupling of their relevant pricing benchmarks. The expansion of the Isle of Grain LNG terminal in the United Kingdom, the start-up of the Dutch LNG gate, and the upcoming opening of the Dunkirk LNG terminal in France (with a capacity of 13 bcm) has substantially enhanced the import infrastructure flexibility of NWE. The ability of Norwegian flows to arbitrage between the United Kingdom and the continent further re-inforce the flexibility of regional supply flows.

While the current infrastructure is clearly sufficient to allow a well-functioning market, it might not be enough to deal with a large-scale emergency, in an integrated market manner. More specifically, while the interconnector between the United Kingdom and Belgium allows for large bi-directional flows, the BBL pipeline offers only unidirectional capacity between the Netherlands and the United Kingdom. This may limit the ability to fully utilise the ample LNG, storage and domestic production capacity in the United Kingdom in response to Europe-wide supply emergencies. Capacity bottlenecks in a non-business-as-usual scenario also exist between France/Belgium to Germany.

In **SWE**, Spain's connection with France is limited. This could constrain the ability to fully leverage Spain's large regasification infrastructure (at about 60 bcm), should that prove necessary. Notably, however, the existing Spain to France line is already fully bi-directional; the normal flow from north to south is usually at about 5-5.5 bcm per year. In case of an emergency, back-haul swaps and full northbound flows would already free up more than 10 bcm of gas. Any further addition in transit capacity would require the construction of a new physical line which is much more costly than simply implementing reverse flows.

**Map 3.1** Interconnectivity expansion



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Note: This figure is based on a comparison of the ENTSG Transmission Capacity Map 2014 (ENTSG, 2014a), the ENTSG Transmission Capacity Map 2010 (ENTSG, 2010a), the ENTSG System Development Map 2013 (ENTSG, 2013), the ENTSG System Development Map 2010 (ENTSG, 2010b) and the GIE LNG Map (GIE, 2014b). Selected data has been adjusted by IEA. Smaller interconnectivity and reverse flow changes are not shown.



**Table 3.3** Increase in interconnection capacity (bcm per year)

Region to:	Region from:						
	SWE	NWE	Eastern Europe	SEE	Russia, Belarus, Ukraine	North Africa	LNG
<b>SWE</b>	1	4				13	7
<b>NWE</b>	12	18	5		31		18
<b>Eastern Europe</b>		41	7		4		4
<b>SEE</b>		1	3	7	6		
<b>Russia, Belarus, Ukraine</b>			7				

Note: ENTSOG = European Network of Transmission System Operators for Gas. This table is based on a comparison of the ENTSOG Transmission Capacity Map 2014 (ENTSOG, 2014a), the ENTSOG Transmission Capacity Map 2010 (ENTSOG, 2010a), the ENTSOG System Development Map 2013 (ENTSOG, 2013) and the ENTSOG System Development Map 2010 (ENTSOG, 2010b) and the GIE LNG Map (GIE, 2014b). Selected data has been adjusted by IEA.

The **SEE** region is still not well connected to the rest of Europe; thus, more investments are needed to lessen the vulnerability to Ukraine gas transit disruptions (see Map 3.1, region 4). (ENTSOG, 2013)

Most countries in the region, with a combined consumption of about 25 bcm per year, are dependent on one or two import pipelines. They have no or limited storage capacity and reverse flow on their export capacity. A few small countries consume very little gas: Albania, Bosnia-Herzegovina, Former Yugoslav Republic of Macedonia (FYROM), Kosovo and Montenegro.

Other countries consume around 2 to 4 bcm per year. Romania consumes about 12 bcm per year, 75% of which can be covered by its domestic production. Greece's LNG regasification terminal (5 bcm per year) could help provide supply diversification to the region. However, it is not possible to ship this gas to other SEE countries since there is no reverse flow capacity on the only Bulgaria-Greece interconnection. On the western side, the Austria-Slovenia capacity has increased by only 1 bcm per year.

Moreover, while Romania and Hungary are linked with an interconnector which has reverse flow capacity, very high tariffs to transit gas out of Romania currently limit its use. Infrastructure investments are needed to diversify gas supplies in the region. Subsequently, a number of projects have been proposed. Most projects are in the feasibility study phase. They are backed by projects of common interest (PCI) funding from the Connecting Europe Facility (CEF) fund, but final investment decisions are yet to be taken.

The main proposed projects are a longstanding plan for a LNG regasification terminal in Croatia; and the Ionian Adriatic Pipeline from Albania to Croatia (connecting to the TANAP-TAP southern corridor which links Europe with the Caspian region). Other projects include an extension of the interconnection between Bulgaria and Greece (currently 3.5 bcm per year) which would enable reverse flow from Greece to Bulgaria; and new pipelines: Greece to Bulgaria (5 bcm per year); Turkey to Bulgaria; and Bulgaria to Serbia (1.8 bcm per year).

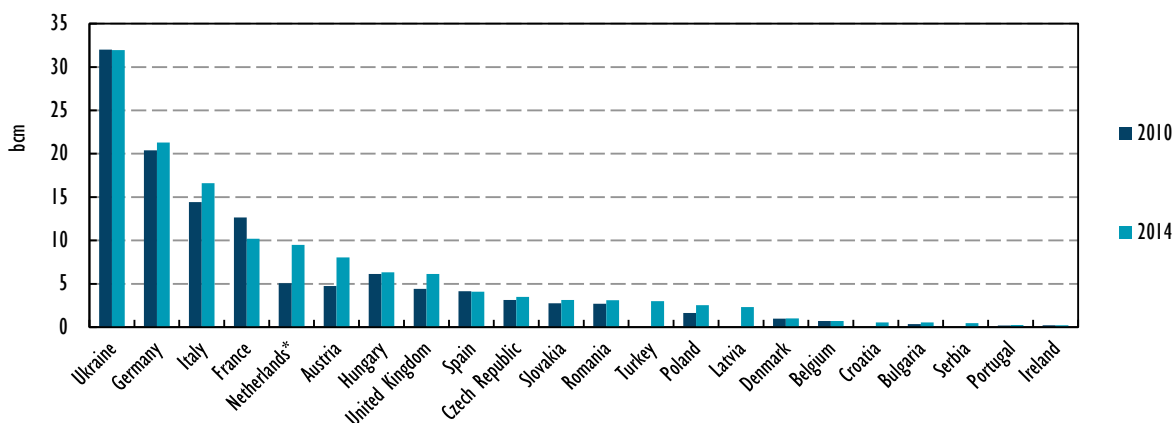
In **Eastern Europe**, progress towards increased supply diversification has been made. In 2015, Poland will start up the LNG terminal Świnoujście (5 bcm). The Independence FSRU (4 bcm) already began operations in Lithuania in late 2014. Prior to the commissioning of these two LNG terminals, Lithuania and Poland were highly dependent on Russian gas. This was caused by the fact of having a sole supplier – Belarus – and a lack of reverse flow capacity. (ENTSOG, 2013)

Over the next five years, several projects are planned for bi-directional interconnections between the Czech Republic-Poland, and the Slovak Republic-Poland, and unidirectional capacity from Poland to Lithuania. Several of these projects have been granted financial support under CEF's funding of PCIs. Furthermore, Finland and Estonia — also fully dependent on Russian gas — plan to develop interconnections with the Balticconnector pipeline together with the construction of LNG plants in both countries by 2019. There will be a full-scale plant in Finland and a small-scale plant in Estonia. However, this project is totally dependent on EU funding.

### Storage capacity

Between 2010 and April 2015, storage capacity in Europe steadily grew from 118 to 137 bcm of working gas volume (including gas storage Bergermeer in the Netherlands and 11 bcm of non-TPA in several countries<sup>4</sup>). In Germany, Italy, Austria and the United Kingdom, several projects with a phased increase of capacity were completed (GIE, 2014a). In 2015, the Bergermeer gas storage facility in the Netherlands went on line with a capacity of 4.1 bcm (included in Figure 3.7).

Figure 3.7 Storage capacity Europe 2010-14



Note: Not all data is available for Turkey, Latvia, Croatia, Serbia, and Belarus. The Netherlands started operation of gas storage Bergermeer in 2015 (included in figure).

Source: IEA analysis based on GIE (2010a), *GIE Storage Map 2010*, GIE, Brussels, [www.gie.eu/index.php/maps-data/gse-storage-map](http://www.gie.eu/index.php/maps-data/gse-storage-map); GIE (2014a), *GIE Storage Map 2014*, GIE, Brussels, [www.gie.eu/index.php/maps-data/gse-storage-map](http://www.gie.eu/index.php/maps-data/gse-storage-map).

Also, 87% of existing storage capacity comprises of depleted fields and aquifers – which are primarily used to respond to seasonal demand fluctuations – while 13% are short-cycle salt caverns.

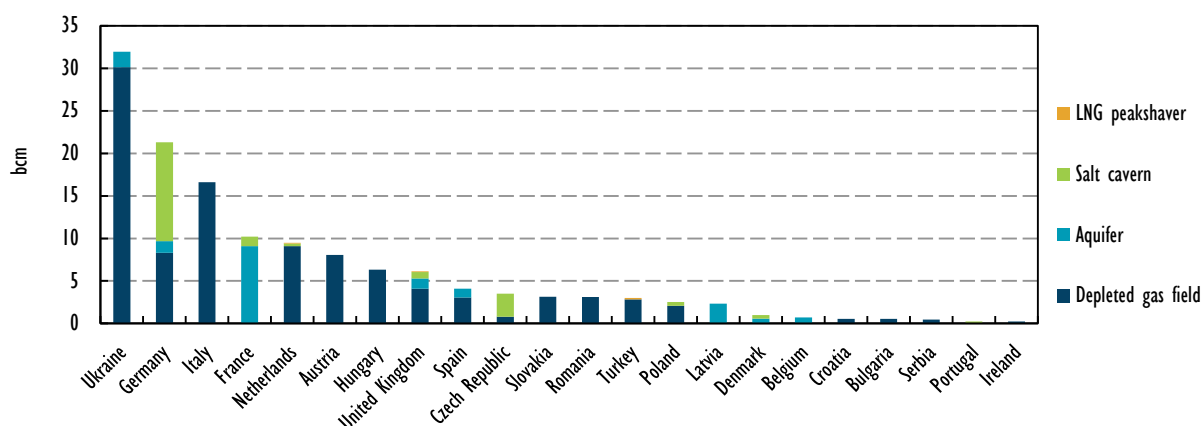
Most of the storage is located in NWE and SWE. The bulk of demand is also located in these regions, where a combination of indigenous production and large LNG import capacity tend to result in better demand coverage compared with most of Eastern Europe and SEE. Supply flexibility to Central and Eastern Europe has traditionally been provided by large storage facilities in Ukraine.

In Europe, storage plays a major role in meeting the region's large, seasonal demand variations due to its temperate climate and high degree of gas demand in the heating sector. Depleted gas fields and, in some cases aquifers, are usually the most suitable form of storage for this purpose. They tend

<sup>4</sup> Non TPA stands for Non Third Party Access: Capacities reserved for operational needs related to transmission and/or production including strategic stocks (GIE, 2014a). 5 bcm of this volume is in the Netherlands where three gas storages are considered to be part of the Groningen production system: 4.7 bcm in Italy, 0.7 bcm in the United Kingdom and 0.4 bcm in Austria (GIE, 2014a).

to have large capacity, relatively low cost, limited multi-cycle capabilities, and low injection and withdrawal rates, which make them best suited to respond to large, seasonal swings.

**Figure 3.8 Type of storages in Europe 2014**



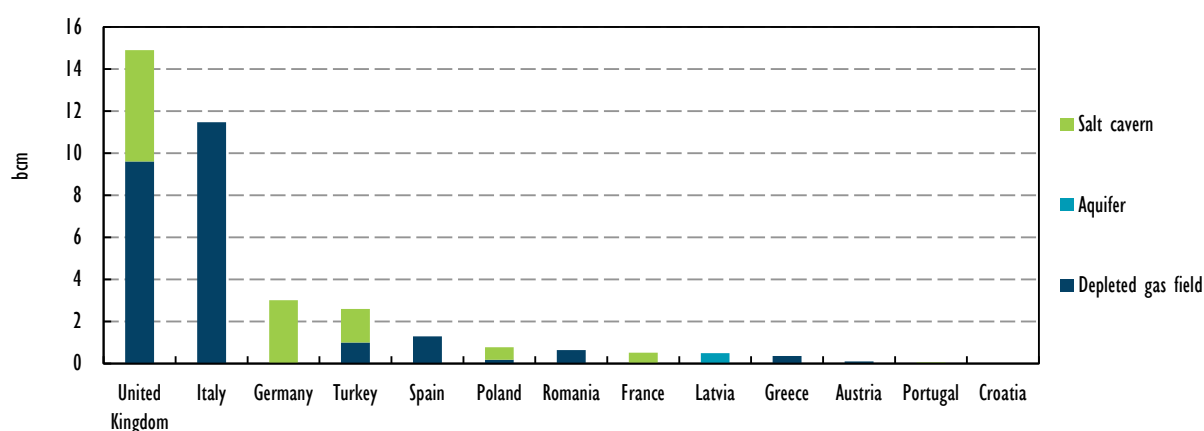
Note: Including non-TPA and the Bergermeer storage in the Netherlands.

Source: IEA analysis based on GIE (2014a), GIE Storage Map 2014, GIE, Brussels, [www.gie.eu/index.php/maps-data/gse-storage-map](http://www.gie.eu/index.php/maps-data/gse-storage-map).

The overwhelming majority of gas storage capacity in Europe has been designed for a winter-summer cycle with a rigid operation. Salt caverns, typically used to supply peak demand with a short injection/production cycle, account for a small proportion of total storage capacity.

Looking ahead, Europe's storage needs may shift increasingly towards more flexible capacity. Efficiency gains are starting to erode residential demand loads, while gas is taking up a bigger role as back-up for intermittent power generation. Raising the peak withdrawal rate compared with the mobile capacity (the gas stored annually) and enabling multi-cycles represents a very significant additional investment for a storage operator. Some countries in Eastern and SEE still require additional seasonal storage but for Europe as a whole, the trend is clearly towards increased flexibility.

**Figure 3.9 Storage capacity Europe: future planned projects 2015 onwards**



Source: GIE (2014a), GIE Storage Map 2014, GIE, Brussels, [www.gie.eu/index.php/maps-data/gse-storage-map](http://www.gie.eu/index.php/maps-data/gse-storage-map).

New proposed storage projects are mainly located in the United Kingdom, Italy and Germany. Together, these account for 29 bcm of incremental capacity, with 21 bcm in seasonal and 8 in short-cycle storages. Country-specific storage needs as well as geological/environmental constraints on what can be built differ, but the fact that roughly one-third of the proposed facilities is in salt caverns is further evidence of the growing interest towards more flexible capacity. Notably, current gas forward prices signal little economic incentives to invest in new facilities which suggest that many of the proposed projects will not move ahead.

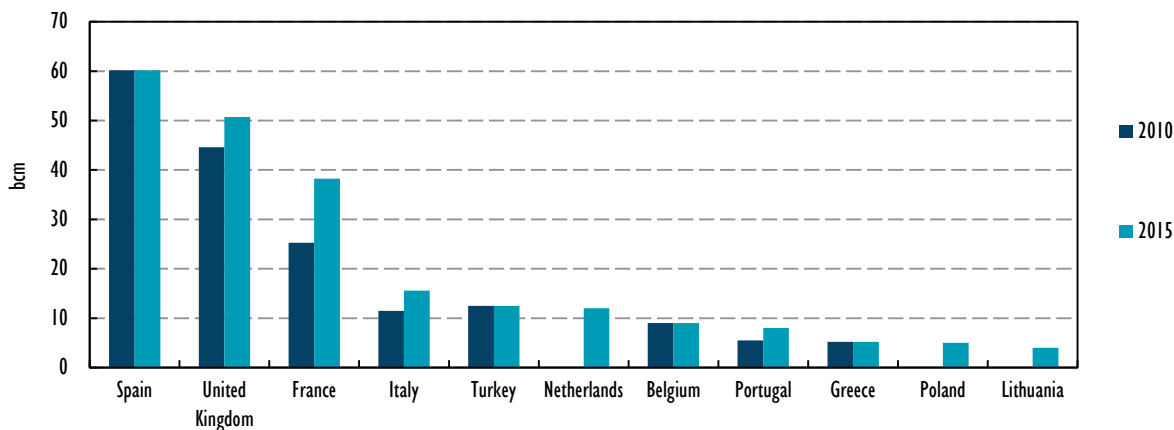
### LNG capacity

The total LNG regasification capacity in OECD Europe represents about 45% of the region's consumption. In theory, if fully utilised, this capacity could cover the entire, annual average consumption of Europe's residential and commercial sector. In 2014, NWE (the United Kingdom, France, the Netherlands and Belgium) accounted for 47% of the total capacity and Spain for another 29%. At just above 20%, average utilisation remains remarkably low mainly due to the impact of global trade flows which have pushed LNG towards the highest priced market which, until recently, was Asia. A collapse in the Asia-European price differential might result in a partial reversal of the recent trend.

LNG import capacity in OECD Europe reached 203 bcm in 2014, marking an increase of 12% since 2010. Adding to existing capacity, with what is currently under construction and due on line this year, capacity will reach 221 bcm. Recent additions came from the start-up of two terminals: the Gate terminal in the Netherlands (2011; 12 bcm) and OLT in Italy (2014; 4.1 bcm). The Sines terminal in Portugal (from 5.5 to 8.0 bcm) and the Grain terminal in the United Kingdom (from 13.4 to 19.5 bcm) were also expanded. In Norway and Sweden, smaller scale terminals came online with a total capacity of 0.8 bcm. Dunkirk LNG in France will add 13 bcm to the already existing 41 bcm in the Netherlands, Belgium and southern United Kingdom, making this region very well diversified in its supply sources.

In late 2014, Lithuania started the first LNG terminal in the Baltic Sea (Independence, 4 bcm), which will be followed by the Polish Świnoujście LNG terminal (5 bcm). Both terminals are important steps towards supply diversification in this region.

Figure 3.10 LNG regasification capacity 2010-15



Note: Including start-ups in Poland and France in 2015.

Source: GIE (2010a), *GIE Storage Map 2010*, GIE, Brussels, [www.gie.eu/index.php/maps-data/gse-storage-map](http://www.gie.eu/index.php/maps-data/gse-storage-map).

## Europe moving towards an Energy Union

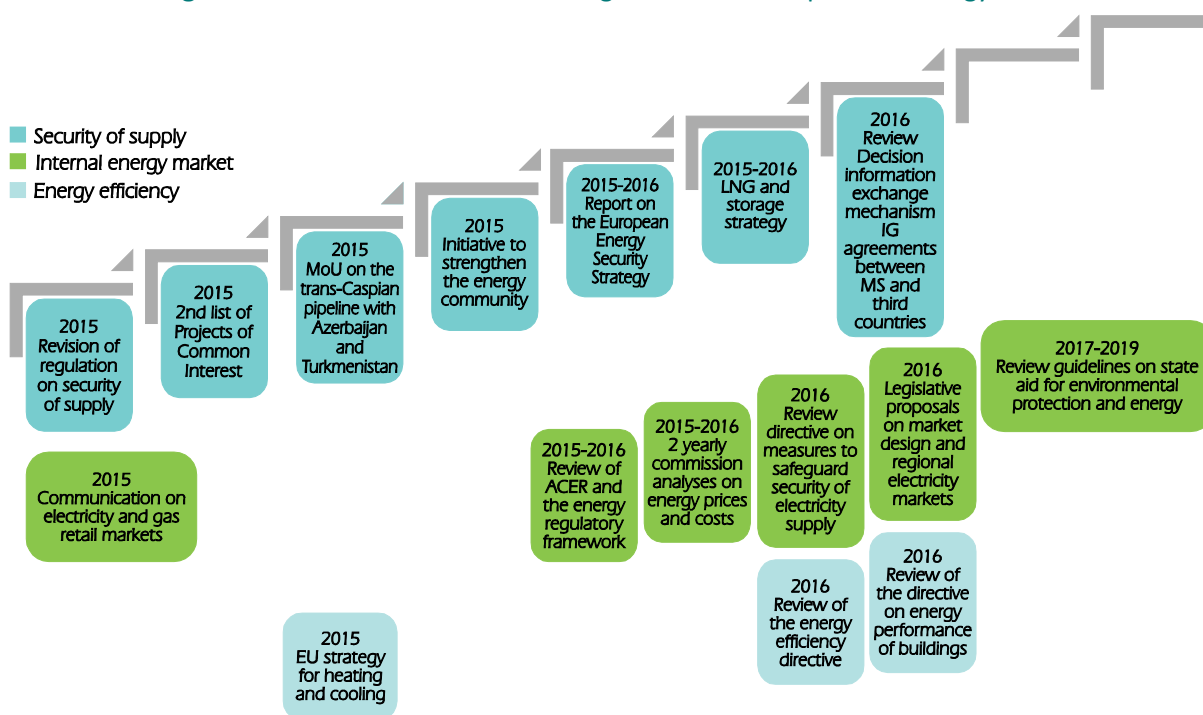
### A strategic framework

In February 2015, the European Commission (EC) presented its energy policy strategy for the next five years: “A Framework Strategy for a Resilient Energy Union” to the European Parliament, the Council, the European Economic and Social Committee, the Committee of the Regions and the European Investment Bank. With this new framework, the European Commission aims to achieve “an integrated continent-wide energy system where energy flows freely across borders, based on competition and best possible use of resources, and with effective regulation of energy markets at EU level where necessary” (EC, 2015a).

In the communication, presented by EC Vice-President for the Energy Union, Maroš Šefčovič, the Commission recognised that despite the progress achieved, the creation of an integrated, continent-wide, sustainable energy system requires further work. Europe still has 28 national regulatory frameworks, a retail market that is not functioning properly, ageing infrastructure not well adapted to integrate increasing renewables production, and poor interconnections. The current market design and national policies neither set the right incentives nor provide sufficient predictability for potential investors.

With the Energy Union Framework Strategy, the Commission has created an umbrella strategy, bringing together all the components of the energy policies of the Union. It emphasises that the strategy “has five mutually-reinforcing and closely interrelated dimensions designed to bring greater energy security, sustainability and competitiveness”. These are: (1) energy security, solidarity and trust; (2) a fully integrated European energy market; (3) energy efficiency to contribute to the moderation of demand; (4) decarbonising the economy; and (5) promoting research, innovation and competitiveness.

**Figure 3.11** Actions related to natural gas of the roadmap for the Energy Union



At the European Spring Council in March 2015, EU leaders supported the key priorities of the Energy Union, supporting EC proposals for a single market for power and gas, based on better connections between member states and more transparency in the gas market, so that suppliers cannot abuse their position to break the EU law and reduce EU energy security.

Regarding natural gas, the strategy calls for action to diversify gas supplies through a more integrated European Union, promoting LNG and new gas sources (including indigenous gas production). It also asks for action to increase the resilience of the gas sector in case of potential supply disruptions, and to boost renewable energies and energy efficiency to moderate import dependency. The details of the proposal are yet to be fully outlined.

#### **Strengthening the role of the European Union: What could this mean for gas markets?**

European gas market balances indicate an increase in import requirements until 2020. Modest demand improvements, led by the power sector, will be accompanied by substantial reductions in indigenous production from traditional producers, notably the Netherlands and the United Kingdom. Recent trends suggest fading interest in engaging in shale gas exploration in countries which have already been allowed to do so. Similarly, progress in developing new gas resources in the eastern Mediterranean has stalled. Weather-adjusted, EU import requirements are set to increase by 40 bcm between 2014 and 2020.

About 70% of the increase in net imports is due to falling indigenous production. EU gas demand will grow very modestly until 2020 and uncertainty also remains as to how fast efficiency measures would affect gas demand amid increased focus on the issue. This may pose challenges for the financial viability of private investments in gas infrastructure within the borders of the European Union. The commercial viability of import projects may prove less difficult in a context of rising import requirements.

Against this backdrop, the Commission aims to increase the European Union's role in funding gas infrastructure to deliver new gas supplies to the European Union and enhance internal gas connections, through the use of all available Community funding instruments. Funding instruments are specifically mentioned, such as the European Fund for Strategic Investments (EFSI) as well as the full involvement of European financial institutions.

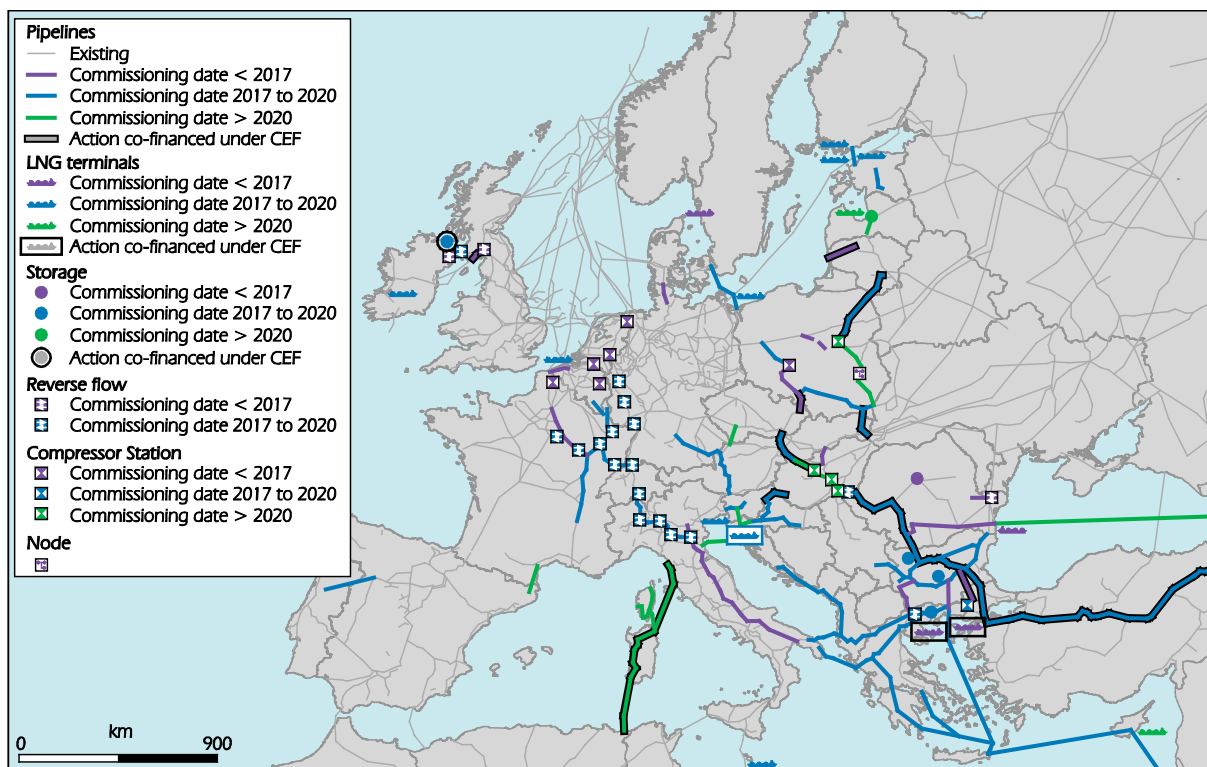
With this new step, the Commission has made it clear that it will continue to co-fund infrastructural energy projects. In October 2014, the Commission granted, in the first round of the programme, EUR 647 million for key energy infrastructure projects or PCIs (EC 2015b). EUR 392 million was allocated for gas projects and EUR 255 million for electricity proposals. The bulk of the support went to gas projects in the Baltic region and Central Eastern and South Eastern Europe.

Other institutions, such as the European Investments Bank (EIB), are also scaling up their involvement in energy projects. In June 2014, the EIB announced it would provide further assistance to the natural gas system in Greece with a EUR 40 million loan to the Hellenic National Gas System Operator (DESFA) S.A., for the extension of an LNG terminal on the island of Revithoussa, in the outer suburbs of Athens. The fact that the communication is also addressed to the EIB reflects the increasing coordination between European institutions in support of projects underpinned by security of supply considerations.

The readiness of the European Union to play a greater role in funding energy infrastructure creates new opportunities for the energy sector to enhance the reliability of the gas system. Some parts of Europe

particularly in the Baltic region, Central, Eastern and Southeastern Europe still require gas infrastructure development and stronger degree of connectivity. However, amid falling demand and several infrastructure upgrades, capacity underutilisation — particularly of LNG terminals — has been widespread. The key challenge will be to ensure appropriate mechanisms to channel investments where most needed.

Map 3.2 PCIs in Europe



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

1. Footnote by Turkey

The information in this document with reference to “Cyprus” relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Turkey recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of United Nations, Turkey shall preserve its position concerning the “Cyprus issue”.

2. Footnote by all the European Union Member States of the OECD and the European Union

The Republic of Cyprus is recognised by all members of the United Nations with the exception of Turkey. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

The Commission also announced that it would explore the use of LNG as a back-up in crisis situations when insufficient gas is flowing to Europe through the existing pipeline system. It will also look into the potential of gas storage in Europe, including the regulatory framework needed to ensure sufficient winter stockpiles. This seems to indicate increased acceptance of public policies which aim to ensure a more important role for LNG and storage capacity for security of supply reasons. The Commission will also look into the necessary transport infrastructure linking LNG access points with the internal market and how to remove obstacles to LNG imports.

The new strategy aims to strengthen the role of the European Commission during negotiations of intergovernmental agreements for gas supplies and to introduce an *ex ante* assessment of commercial supply contracts which may affect EU energy security. The Commission is already able to carry out compliance checks for intergovernmental agreements (IGAs) and related commercial agreements signed between a member state and a third country for purchasing energy.



In the communication, the Commission noticed that renegotiations of such agreements are difficult because the position of signatories has already been fixed, thus creating political pressure not to change the terms of the agreements. To avoid such situations, the Commission would be informed at an early stage of the ongoing negotiations, with the aim to carry out an *ex ante* assessment of the agreement's compatibility with internal market rules and security of supply policy. In response to concerns raised by industry, the Commission emphasised that the confidentiality of sensitive information will be safeguarded.

With the new strategy, the Commission has kept its options open despite strong opposition by some member states who are against the idea of “a single European body charged with buying gas”. The Commission will assess options for voluntary demand aggregation mechanisms for collective purchasing of gas, making explicit that eventual mechanisms could be used only during a crisis and where member states are dependent on single suppliers. Any such mechanism will have to work in full compliance with World Trade Organisation (WTO) and EU competition rules.

In the global gas market, collective purchase strategies, while unusual, are not new (IEA, 2014). In January 2013, the tripartite LNG HoA executed by Chubu Electric Power Co., Kogas and Eni was the first international joint purchase of LNG, allowing two Asian companies to re-allocate LNG among themselves. The agreement consists of 2.3 bcm of LNG per year delivered by means of about 28 shipments until 2017.

In 2014 two other alliances were made. Tokyo Gas and the South Korean state-owned company, Kogas, signed a memorandum of understanding (MOU) to further enhance co-operation in the LNG business: from optimising shipping resources and inventories to seek opportunities to jointly produce LNG and invest in upstream. In 2014, Tokyo Electric Power Co. and Chubu Electric Power Co. made a joint venture for the procurement of fossil fuel resources, primarily LNG. With the new alliance, the two Japanese utilities will be the largest private purchaser to enter the emerging global LNG market, with a projected annual demand of about 54 bcm of LNG or the equivalent of 1.22 the total imports of OECD Europe for 2014.

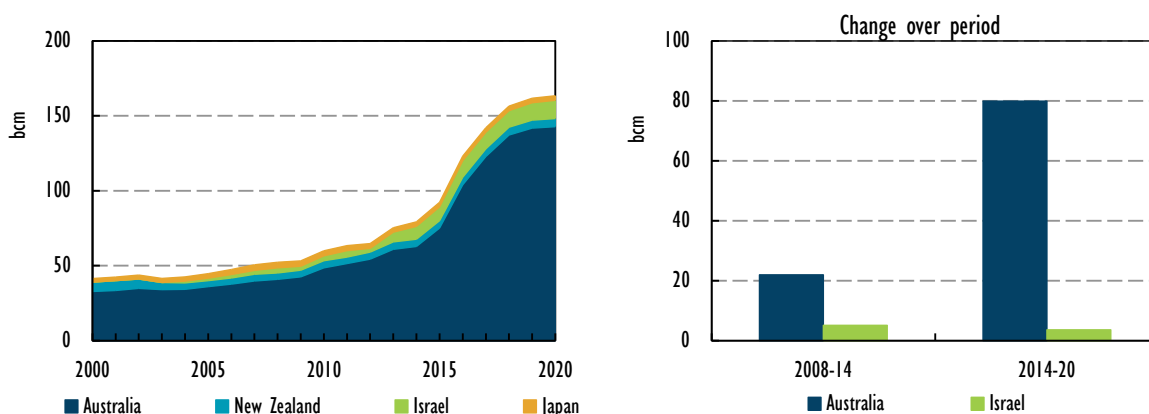
As part of the diversification strategy, the Commission aims to establish strategic energy partnerships with existing and potential EU suppliers, but with no distinction made among the various sources. However, actual gas balances suggest that the ability of existing and potential producers to reliably supply Europe differs greatly from case to case. The challenges for reliability are different in each case. For North Africa, the problem lies in fast-growing demand, partly tied to generous energy subsidies and unfavourable upstream policies which are compressing the export capability of this region. For producers with vast upswing potential in the upstream, such as Turkmenistan and Iraq and no, or limited import connection to Europe, forging a strong strategic relationship seems to be a necessary precondition for exports to emerge in the future.

The new strategy aims at strengthening EU-wide regulation. The Agency for Cooperation of Energy Regulators (ACER) still has very limited decision-making rights. They are only allowed to take decisions at the request of the national regulators or, if national regulators fail to take a decision within a certain timeframe. Therefore, the Commission advocates in the new strategy the strengthening of EU-wide regulation of the single market, through significant reinforcement of the powers and independence of ACER to carry out regulatory functions at the European level.

## OECD Asia Oceania: Riding a gas wave

OECD Asia Oceania gas production is set to surge in the coming five years, adding a total of 85 bcm. The increase is overwhelmingly driven by the start-up of new LNG projects in Australia, which after several delays and cost overruns, are finally on track to start operations. Israel's production is increasing as its large reserves are developed, but the lack of export outlets limits the size of the additions to match the needs of the domestic market.

Figure 3.12 OECD Asia Oceania supply by country, 2000-20



Note: The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

### Australia: A new natural gas giant

Australia's gas production growth will accelerate in the future, averaging almost 15% per year between 2014 and 2020 as a result of a wave of large LNG projects coming on stream. Today, about half of the country's production is exported; by 2020 that share will rise to 75%.

Australia's gas production is on track to increase by 230% by 2020. Queensland Curtis LNG, the first of seven LNG projects scheduled to start operations before 2020, began production at the very end of 2014. The other six are all at an advanced stage of construction. Once all the projects are at full capacity, Australia will outpace Qatar as the world's largest LNG exporter with a capacity of 116 bcm (see Australia section in Chapter 4). Domestic production will then surpass 140 bcm from just above 60 bcm currently.

### Israel: Not an easy task

Israel's gas production outlook has worsened due to economic and political difficulties in securing export deals and growing regulatory uncertainty. As a result, Israel is not expected to become a gas exporter before 2020, limiting the potential scale of production increases. Robust domestic consumption growth will require 4 bcm of additional production, equivalent to average annual growth of 6% between 2014 and 2020.

During 2014 Israeli's gas production has been relying almost entirely on the Tamar field as output from the older Mari-B field has fallen to less than 1 bcm per year. Tamar production started in

April 2013, reaching 5.8 bcm for the full year. Output increased further during 2014; the operator, Noble Energy, stated in Q1 2015 that production averaged 7.7 bcm per year since the field was brought on line. The field production potential is above this level. Due to limited domestic consumption growth, faster field development depends on finding export opportunities.

In 2012 Tamar operator, Noble Energy, started a pre-front-end engineering and design (FEED) for a floating LNG (FLNG) project, but little progress has been made since. The Leviathan field underpins much of Israeli gas exports potential. Located 47 km southwest of Tamar, it is the largest gas discovery in the East Mediterranean Sea, with estimate reserves more than twice those of Tamar. Leviathan is also operated by Noble Energy. Due to the size of its resources, Leviathan's development is necessarily tied to finding an appropriate export outlet. The operator is considering a FLNG option for this field as well, but progress has been slow. It is most unlikely that the facility will be on line by 2020.

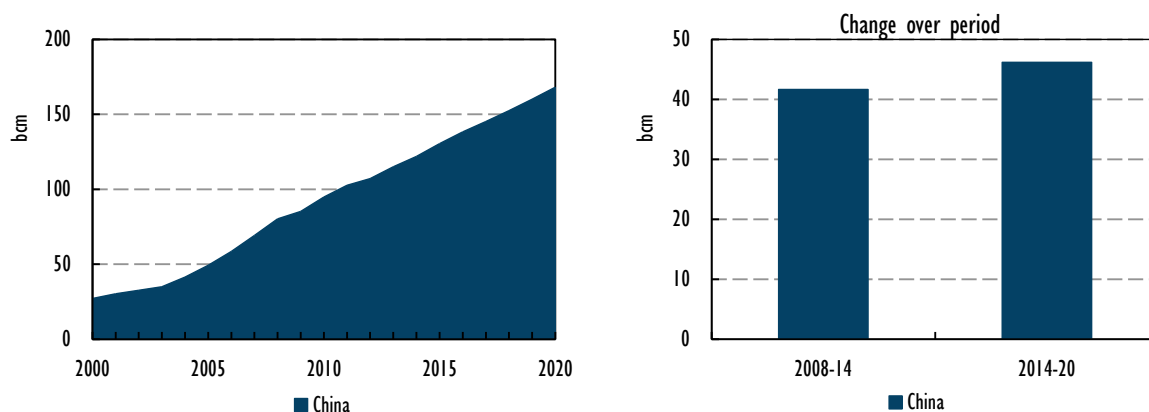
An alternative or complementary option would be to develop pipeline gas exports to regional markets. Up to today, both Tamar and Leviathan consortiums have signed gas supply agreements with companies in Egypt and Jordan on a long-term basis. Yet, the contracts are not binding. Moreover, when it comes to pipelines, the politics and fragile physical security of the region remains an obstacle to overcome.

Regulatory hurdles add to the challenge of engineering a feasible export route. In late 2014, Israel's antitrust authority issued a recommendation to break up the Leviathan consortium. This reversed an earlier decision which had ruled in favour of the current ownership structure of Leviathan. The issue centres on the possible monopolistic position of the consortium as Noble Energy and Israel's Delek Group are key stakeholders in both Tamar and Leviathan.

### China: Downscaling ambitious targets

China's gas production outlook has worsened over the past 12 months, driven by less positive prospects for unconventional gas. In August 2014, the Chinese government revised downwards its 2020 shale gas output target to 30 bcm from the previously held 60-100 bcm mapped out in 2012.

Figure 3.13 China supply, 2000-20



China's shale gas production is struggling to pick up momentum. So far, only one promising shale play has been identified: the Sinopec-operated Fuling-shale gas formation near Chongqing in the Sichuan Basin where production is expected to reach 5 bcm and 10 bcm in 2015 and 2017, respectively. The play is set to account for three-quarters of the 6.5 bcm of government shale gas output target for 2015.

All other prospects remain more or less in a testing phase. The greatest potential comes from the southern part of the Sichuan basin, where CNPC is a major player. The company is set to drill 154 wells over 2014-15 at its Changing and Weiyuan blocks for an estimated investment of USD 1.8 billion. CNPC is also developing the Fushun-Yongchuan block in partnership with Shell.

Shell has been performing extensive drilling tests, but results have so far disappointed. In September 2014, Shell's chief financial officer stated that progress in Sichuan had proved slower and more difficult than anticipated and admitted that the future development programme would probably be smaller than previously envisaged. In a similar vein, China National Offshore Oil Corporation (CNOOC) announced in early 2015 that it would wind down operations at its shale gas block in Anhui province due to disappointing results.

The experience of the past few years has made clear that shale gas development in Sichuan – where more than half of the country's estimated technically recoverable shale gas reserves are located – will prove challenging. The geology is complex and the high population density of the area and the proximity to Chongqing pose additional difficulties.

Coal gasification projects are also struggling to take off. In July 2014, Datang power – a leading coal-to-gas (CTG) developer – announced it was divesting its two CTG projects in Inner Mongolia and Liaoning provinces, probably due to technical and economic reasons. Just a month after commencing operations, production at the Keqi project in Inner Mongolia, China's first large-scale CTG development, had to be shut for three months due to corrosion of the gasifiers. Meanwhile, news from China suggests increased caution from the government regarding unbridled deployment of technology.

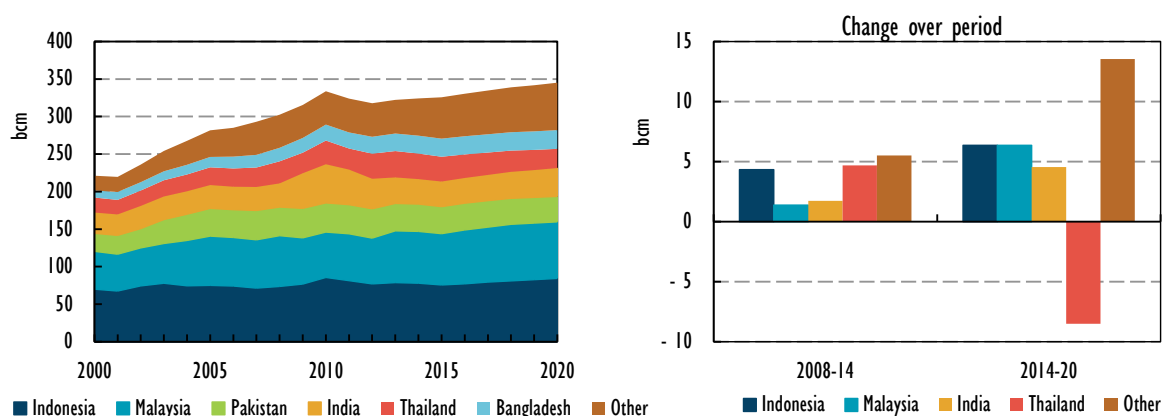
In July 2014, the China National Energy Administration (NEA) urged stricter control of CTG projects, warning against its environmental risks. Increased discussion over whether new projects should be approved is seemingly taking place.

Less growth for China's unconventional gas output will weigh on the country's overall production trajectory, which is expected to increase at an average annual rate of 5.5% between 2014 and 2020, slower than the 7.5% recorded between 2008 and 2014.

### Non-OECD Asia: The upstream sector struggles to deliver

Non-OECD Asia's (excluding China) gas production will grow by 21 bcm in net terms until 2020 with Indonesia and Malaysia accounting for more than 60% of the net increase. The rest of the region will struggle to deliver gains (Figure 3.14). In India, production is expected to stage a modest recovery because of recent price increases for domestically produced gas. However, the recent price reform falls short of previous expectations as well as of the price increase needed to trigger a more substantial revival of the domestic upstream sector. Thailand's production will decline sharply as its fields mature, while exploration is stalling due to delays in renewing existing concessions. Other countries show small variations. Overall, incremental production covers only 35% of domestic demand additions, turning the region into a net gas importer by 2020.

Figure 3.14 Non-OECD Asia supply by country, 2000-20



### Indonesia: Production growth remains below potential

Indonesian gas production has remained generally range-bound over the past 10 years. However, output has declined since 2010. This outlook forecasts a modest recovery. Indonesia is the third largest gas resource holder in the Asia Oceania region, behind China and Australia. Yet, discoveries have been few in recent years and progress on major upstream developments remains slow. Chevron's Indonesia Deepwater development (IDD), INPEX's Abadi FLNG, and BP's Tangguh expansion have all stalled.

Indonesia's resource potential is yet to be fully unlocked. The new Indonesian government has taken encouraging steps such as lowering taxes on oil and gas exploration, streamlining administrative processes and ceasing fuel subsidies. More is needed to maintain and attract new investments, particularly as oil and gas companies slash CAPEX.

Chevron's multi-billion, deepwater development (IDD) is encountering delays. The project is the largest upstream development underway in Indonesia. It consists of five fields over four blocks governed by four separate production sharing contracts (PSCs). At full capacity, the project would yield 13 bcm per year with most of the gas expected to feed the Bontang's LNG plant (25% is reserved for the domestic market).

The first phase of the project consists of developing the Bangka field. This was sanctioned in early 2014 and a substantial subsea engineering, procurement and construction contracts (EPC) contract was awarded to Technip in October 2014. The field will be developed as a subsea tie-back to an existing Floating production Unit (FPU) already operated by Chevron. However, Chevron has postponed developing the Gendalo-Gehem fields, reportedly by as much as two years. The infrastructure investment needed to bring these fields on line is substantially larger than for the Bangka field, requiring the construction of two, new floating and production units. Delays in going forward with this project could exacerbate the supply-feed challenges that the country's LNG industry is already facing.

After prolonged uncertainty, the Indonesian government has decided not to extend Total's production sharing contract for the offshore Mahakam gas field, with the existing agreement due to expire in 2017. From 1 January 2018, control will pass to state-owned Pertamina. Mahakam is the country's most important gas-producing asset and the major supplier to the Bontang LNG terminal. Production from the field is estimated at 17 bcm per year in 2014. Total is now understood to be in discussion with Pertamina on a possible asset swap in return for a continuing participating interest in the Mahakam block.

No progress has been made in developing the East Natuna gas field over the past year. The field, located in the Natuna basin within the South China Sea, is estimated to hold recoverable gas reserves of 1.6 tcm, almost half of the country's total. While the project has been in planning for decades, positive momentum was seemingly building last year with the government considering incentives, such as a longer PSC period, tax breaks and an improved production sharing split to the producer. Yet, in April 2015, still no PSC had been granted. Considering the project's technical challenges – linked to the carbon dioxide-rich nature of its gas – and the unfavourable price environment, real progress is not foreseen over the timeframe of this outlook.

### *Malaysia: Good policy, more production*

Following sharp declines in 2009-10, Malaysia's gas production has stabilised over the past few years. Production is expected to increase moderately, adding 6 bcm until 2020, as few projects reach the production stage.

Recent government efforts to support upstream investments in deepwater and stranded fields, where a larger portion of resources are now located, have been yielding positive results. As associated gas production offshore peninsular Malaysia mature and decline, investments and incremental output are increasingly concentrating on the offshore Sarawak and Sabah states. Domestic price hikes and better fiscal terms have encouraged new exploration, brought about new discoveries and pushed investments in areas previously considered uneconomic.

In particular, Malaysia is pioneering the monetisation of stranded gas by means of floating LNG. Petronas's first facility is scheduled for completion in late 2015. The vessel with a capacity of 1.9 bcm will be moored in Malaysia's Kanowit gas field, 180 km offshore Sarawak. A second floating LNG project is under construction offshore Sabah, expected to be on line in 2018. Adding a ninth train to the Petronas-Bintulu LNG facility will also contribute to increased output over the outlook horizon of this report.

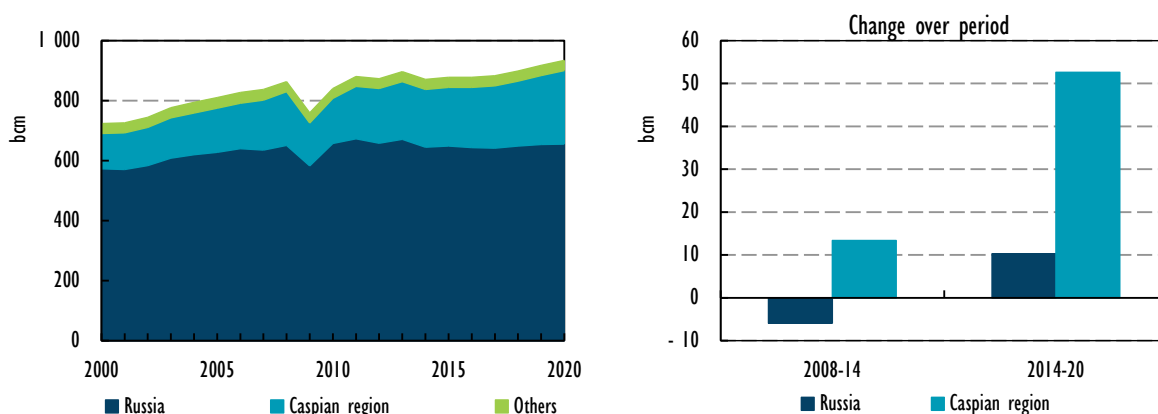
### **FSU: Caspian region drives production higher**

Former Soviet Union (FSU) production will grow at an average annual rate of 1.1% between 2014 and 2020, with the Caspian region accounting for almost 85% of the increase. Russian production struggles to recover from the multi-year, low level of 2014, due to weak domestic consumption and limited export options until late in the decade. The start-up of the Power of Siberia in 2019/20 allows for a modest production recovery at the end of the forecast period.

### *Russia: Production growth is constrained by lack of demand*

Russia's gas production will bounce off the bottom reached in 2014 but with projected average annual growth of just 0.2% until 2020, it will remain below the average level of 2010-14. Output dropped by 4.2% in 2014, hitting a multi-year low of 645 bcm. The dismal performance was due to a combination of three factors: lower demand in Europe; lower demand in Ukraine; and flat to falling demand in Russia. The last two trends are set to continue, until 2020, but in Europe consumption should rebound from the weather-induced drop in 2014. Together with the normalisation of the weather, modest growth in the power sector will push European gas consumption higher. Russian production will benefit from this increase.

Figure 3.15 FSU supply by country, 2000-20



Gazprom's position remains challenged by continued production growth from independent producers. Gazprom continues to act as a swing producer in a market where domestic demand has flatlined and then the call for export dropped. Its gas production reached the lowest level in the company's history last year (the company was created in 1993), contracting by a massive 44 bcm. Its share of total production fell to 68% from 73% in 2013.

This trend will continue, albeit at a slower pace, as exports to Europe are set to recover from the weather-induced collapse in 2014 and Gazprom is expected to cut back on imports from Central Asia by about 10 bcm per year. Novatek and Rosneft will further increase production, driven by the development of new gas deposits and associated gas rather than from asset takeovers as in recent years. Gazprom's share in production will then stabilise by the end of the forecast period as exports to China begin.

The opening up of an export route to China will help to drive Russian production higher in 2019-20. This report assumes that the construction of the Power of Siberia will proceed on time because of its strategic importance for Russia and China. However, Russia and Gazprom's worsening financial situation increase the risk of delays. Should the connection between eastern Russia and northern China not be operational by 2020, the projected Russian gas production growth will not materialise. The proposed Altai pipeline, connecting Western Siberia to West China, is not foreseen to be on stream by 2020.

With the exception of the Eastern gas programme which is heavily investment driven, it will be the demand for Russian gas that determines the country's gas production profile over the next five years. Production capacity substantially exceeds output levels, reportedly by more than 100 bcm. This means that should the need for Russian gas arise (domestically or externally), production can ramp up accordingly.

A large portion of swing capacity is concentrated in the Yamal peninsula, in the Bovanenkovo field, where development has been at the core of Gazprom's investment strategy in recent years. Little demand for Russian gas since 2008-9 has resulted in slower than anticipated output growth at Bovanenkovo and underutilisation of the existing production infrastructure. The commissioning of a new gas facility (GP-1) in 2014 pushed Bovanenkovo's capacity up by another 30 bcm to a total of 90 bcm per year, while output from the field for 2014 is estimated at 40 bcm. Clearly, large production flexibility now exists which could be called upon, if needed.



Russian companies are suddenly facing a much tougher financing environment as USD-denominated revenues are falling. Those companies whose CAPEX is denominated in roubles are coping better with the situation as the rouble's sharp depreciation provides a buffer. By contrast, those companies which require foreign technologies, especially when subject to US and/or EU sanctions, have revenues in roubles and short-term repayments in dollars are hit the most.

In this context, even when not directly targeted by sanctions, Russian companies are subject to higher costs and more difficult access to domestic and foreign credit. The Russian state also faces increasing demands for financial support which it will ultimately need to prioritise. Against this backdrop, Gazprom will probably be forced to make strategic choices and delay, reconfigure or cancel some of its major investment projects currently planned. These include: Power of Siberia upstream and transportation system, the Turkish Stream, the Altai pipeline, Sakhalin II expansion, Vladivostok LNG, and Baltic LNG.

Two major uncertainties are 1) whether Yamal LNG will be delayed over financing problems; and 2) whether none, part, or all of Turkish Stream will be built according to Gazprom's plan and timeline. This report takes a cautious view of both developments, in that the start-up of Yamal LNG is assumed beyond 2020, and only one or possibly two legs of Turkish Stream are assumed to be implemented over the next five years. We recognise, however, that the outlook for both projects remains highly uncertain at the time of writing.

### *The Caspian region: Supplies to China going strongly*

#### **Turkmenistan**

Increased exports to China are Turkmenistan's main gas production growth driver until 2020. The construction of line C of the Central Asia-China Gas pipeline started in September 2012. The line – which has a design capacity of 25 bcm – became operational in May 2014 and is scheduled to reach full capacity by the end of 2015 after all necessary supporting facilities are brought on line. In addition to the 30 bcm provided by line A and B, the overall system should thus be able to transit 55 bcm from 2016. The overall Central Asian-China pipeline system will expand further until 2020.

Once a fourth line is added, the total export capacity will reach 85 bcm. A number of intergovernmental agreements were signed between China, Uzbekistan, Tajikistan and Kyrgyzstan – the designated transit countries for line D – in the latter part of 2013. These were followed in 2014 by a number of commercial arrangements between CNPC and the relevant Central Asian national oil companies (NOCs) to establish partnerships/joint ventures to construct and operate sections of the planned trunk line.

CNPC reported that construction of the Tajikistan section of line D started in September 2014. The vast majority of the gas transiting through the system will originate from Turkmenistan. China and Turkmenistan have now contractual agreements in place for 65 bcm of gas.

The development of the Galkynysh field, where production started in 2013, will underpin most Turkmen export commitments until 2020. Once the first phase of development is completed by 2018, the field will produce about 30 bcm of gas. Output will rise to 60 bcm upon completion of a second phase, early in the next decade. China's involvement in the development of the Galkynysh field, both on the technical/operational and the financing side, underlines a solid strategic partnership that bodes well for future Turkmenistan production growth.

Map 3.3 Central Asia regional pipeline system



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

What could potentially derail the otherwise bright outlook for Turkmen gas production growth are pricing tensions, in a global gas market that is tipping towards oversupply and where the number of supply sources available to China is rising. Turkmen gas currently lands in the eastern coast of China at a price above that of most (although not all) LNG. Figures mentioned for the Russian-China deal, via the Eastern route, suggest Turkmen gas would lose out to Russian gas too. Whether the relatively uncompetitive position of Turkmen gas becomes an issue depends on the degree of over (or under) supply of the Chinese gas market over the next few years. Our balances indicate a Chinese market better supplied than in the recent past, which suggests that the risk of price tensions may be rising.

In early 2015 Gazprom announced it will reduce its gas imports from Central Asia. As a result, Turkmenistan is set to become increasingly dependent on China as the outlet for its gas. Against this backdrop, Turkmenistan is pursuing diversification export policies. The country remains actively involved in the development of the Turkmenistan-Afghanistan-Pakistan-India (TAPI) pipeline. The project, with a total length of 1 735 km, would have the capacity to ship 33 bcm of gas and would supply markets in Pakistan and India, with potential deliveries also to Afghanistan. In a step forward, the TAPI pipeline company was incorporated in November 2014. The official start of construction is expected this year. Delays are likely, however, due to major geopolitical and security challenges, particularly in connection with the Afghan sector of the line.

### Uzbekistan

Production has shown signs of stabilisation in the past two years, flattening out just above 60 bcm after the sharp decline of 2009/10. Output should gradually recover until 2020, mainly as Lukoil – the

largest foreign investor in the country's upstream sector – proceeds with the development of its Kandym-Khauzak-Shady-Kungrad PSA project.

The first stage of the development, the Khauzak-Shady area, was commissioned in November 2007. Production from the field is now at target level, yielding 3.7 bcm of gas. The second stage of development, focusing on the Kandym group of fields, is currently under way. In February 2015, the company signed a contract for the procurement and construction of a gas treatment facility with a projected annual capacity of 8 bcm. Additionally, the company operates the South Gissar project which is scheduled to enter full-scale operation in 2017 (about 1 bcm of gas was already produced by 2013). Lukoil should then be able to add an extra 10 bcm to its existing production levels over the next three to four years, thus helping reverse the recent stagnation in the country's gas output.

Lukoil's production is mainly targeted at the Chinese market. According to CNPC, 10 bcm of Uzbek gas should feed into line C of the Central Asia gas pipeline system over the next couple of years. The target looks challenging in view of growing domestic demand. However, Russia's decision to cut back on Central Asian imports may help. Since Russia pays high prices for Central Asian gas and its own domestic market is oversupplied, the choice seems economically rational. In early 2015, Gazprom announced it would import 10 bcm less of Central Asian gas this year. Today, the vast majority of Uzbekistan's exports are directed to/through Russia. With flows in that direction falling, there should be scope for ramping up deliveries to China.

### Kazakhstan

Vastly differing from other Central Asian countries, Kazakhstan's gas production comes almost entirely in association with oil; moreover half of the volume of gas extracted is then re-injected. Today roughly 70% of the country's marketable gas production flows from Tengiz and Karachaganak. The third phase of the Karachaganak project should be in operation by the end of the decade. FEED is set to start this year; EPCs are planned to be awarded in 2016. Gas output will increase, but it remains unclear how much will be available for commercial use, after re-injections.

The start-up of the giant Kashagan field continues to be pushed back and is now scheduled by the end of 2017. According to the operating consortium, the entire 96 km long oil and gas pipelines, which connect the field with the Bolashak onshore oil and gas treatment unit, must be replaced at an estimated cost of USD 3 billion. During the first phase of development, about 50% of the gas produced in Kashagan will be re-injected, while the remainder will predominantly serve as fuel for production plants.

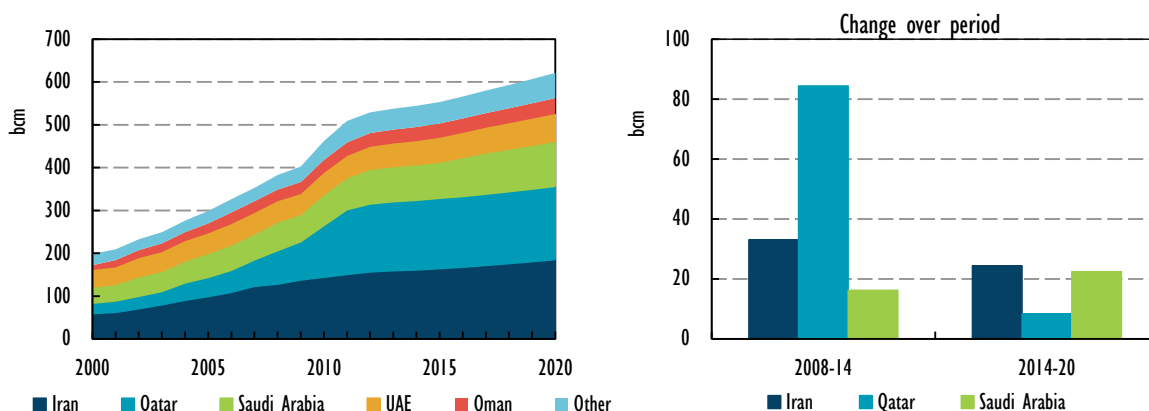
### Azerbaijan

Production should grow modestly this year as some de-bottlenecking work at Shah Deniz is completed. After that, production will stay broadly flat until the end of the forecast period when the second phase of the field becomes operational. According to the field operator BP, the first gas supplies to Georgia and Turkey (around 6 bcm) are targeted for late 2018, while gas deliveries to Europe (around 10 bcm) should start flowing in late 2019/early 2020.

### Middle East: Saudi Arabia and Iran drive production growth

Production in the Middle East will grow by 75 bcm between 2014 and 2020 or 2.2%, a notable slowdown from 6.1% between 2008 and 2014. Qatar is overwhelmingly responsible for the slowdown. The Gulf state will add 8 bcm of gas over the forecast period, only one-tenth of that added between 2008 and 2013. The moratorium on North Field development caps LNG expansion. A much slower investment outlook for the petrochemical sector also contributes to diminishing production growth. Saudi Arabia and Iran account for more than 60% of incremental output. However, with the two countries having none (Saudi Arabia) or very limited (Iran) gas trade connections, the effect of their output performance is felt only within the borders of their own markets.

Figure 3.16 Middle East supply by country, 2000-20



#### Saudi Arabia: Turning to non-associated gas

Saudi Arabia gas production will grow robustly in this outlook, adding 25 bcm by 2020. The Wasit gas programme accounts for the bulk of the additional output. Debottlenecking of existing facilities and smaller projects, such as Midyan and Fadhili, will also contribute to the increase.

Saudi Arabia gas production was nearly all in association with oil until 2012. As the Kingdom is not planning further additions to its oil production capacity after rolling out a large expansion programme over the past decade, there is now increased pressure to develop non-associated gas resources. Until 2020, output additions will mainly originate from offshore fields in the Persian Gulf.

The large Wasit gas programme is next in line after the Karan gas field was brought into operation in 2012. The project had an initial start-up date of late 2014, but has reportedly been pushed back to late 2015/16. Wasit's integrated facilities will be able to process 26 bcm per year of non-associated gas from the offshore Arabiyah and Hasban fields, thus providing 17 bcm of additional sales gas. Such volume equates to 20% of the Kingdom's current consumption, boosting gas availability to the power and industrial sector.

The Fadhili gas-processing plant should also start operations during the time horizon of this report. The project will process non-associated gas from the onshore Khursaniyah field and offshore Hasbah field and provide 5.5 bcm marketable gas per year.

Saudi Aramco is directing efforts towards new frontier areas. It has intensified exploration activity in the northwest of the country, including the Red Sea, and initiated a shale gas development programme. In 2013 Saudi Aramco started constructing a 1 GW gas-fired power plant in the northern region fed with shale gas. Scaling up shale gas activities will be challenging, not least due to water constraints.

Progress over the next five years is set to be limited, particularly considering the large conventional deposits that remain untapped. Gaining experience with the technology may be a reason why the Kingdom is involved in shale gas. The service-intensive nature of shale gas operations and its associated employment opportunities could be another reason, in a country where youth unemployment is regarded as a critical national challenge. Saudi Aramco estimates that 10 000 jobs could be created for any 10-20 bcm of shale gas production, with up to four times as many indirect jobs (Saudi Aramco, 2014).

### *Iraq: Slow progress amid increased security threats*

Iraq's gas production will continue to be subjected to security, financial and political challenges over the next five years. As a result, this report forecasts moderate growth of 6 bcm until 2020. The outcome remains highly sensitive to above-ground developments.

There are two main potential growth areas over the forecast horizon. The first is in the semi-autonomous Kurdistan region in northern Iraq where Genel Energy plans to develop the Miran and Bina Bawi fields, estimated to contain 240 bcm of gas. The company expects to make a final investment decision (FID) on the two blocks in the first half of 2015. Progress has varied over the past 18 months.

On the positive side, Turkey and the Kurdistan Regional Government (KRG) signed a deal in late 2013 to export 4 bcm gas in 2017 increasing to 10 bcm by 2020. As consumption and revenue opportunities in the domestic market are limited, it is crucial to open up an export outlet for domestic resource development. Conversely, a subsequent agreement between Genel and the KRG puts the financial burden on KRG to build the required gas-processing facilities and negotiate off-take agreements. This seems a major obstacle considering KRG's lack of resources, illustrated by its failure to meet payments to oil companies operating in the region. The precarious security situation in northern Iraq adds to the negative picture and risks of major delays are high.

A second potential area of gas output growth is in the South, near Basrah, the country's main oil production and export hub. A large quantity of associated gas continues to be flared there in the absence of essential processing facilities, gathering systems and distribution pipelines.

In May 2013, the Basrah gas company, a joint venture between Royal Dutch Shell, Mitsubishi and Iraq's South Gas Company, started operations with the aim to capture associated gas from three, large oil fields for use in the domestic market. The potential is huge, but progress has been slow, with many challenges standing in their way, ranging from limited economic incentives to a lack of connecting infrastructure.

### *Iran: Behind schedule*

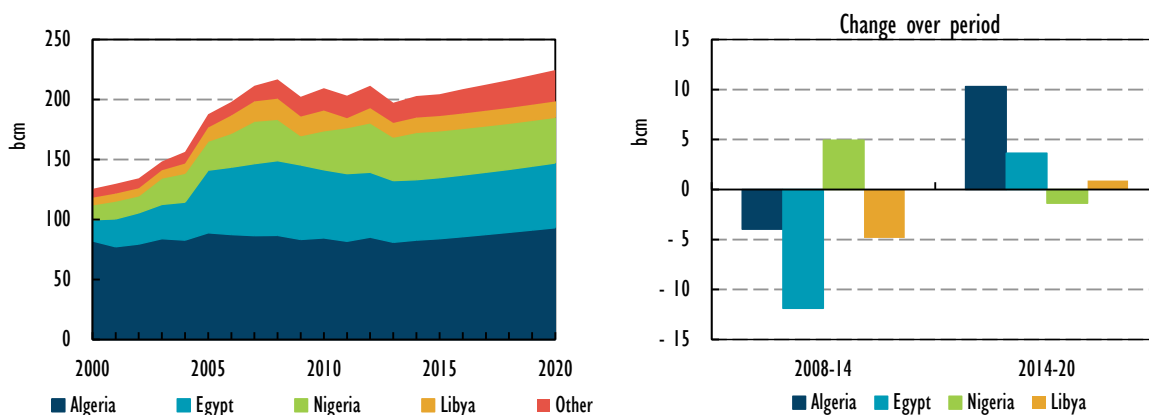
Iran's gas production growth until 2020 hinges on the continued development of its massive South Pars field. Progress has been made though at a much slower pace than initially envisaged. Production is expected to increase by 25 bcm by 2020.

After years of delays and budget overruns, Phase 12 of the huge gas project finally started operating in March 2015. Once at capacity, it will yield 30 bcm of gas. Iran's struggle to bring Phase 12 on stream clearly illustrates the challenge of operating under sanctions, where access to technology and capital is much more difficult. Subsequent stages of South Pars' development — notably Phase 15-16 and 17-18, which together will account for an extra 40 bcm — are set to encounter delays from their official start-up schedule of late 2015/16.

### Africa: Hungry for investments

Africa's gas production will grow at an average annual rate of 1.7% between 2014 and 2020, reaching 225 bcm by the end of the forecast horizon. The increase is a welcome change after a seven-year run of volatile output around a declining trend. Production was higher in 2014, but still 8 bcm below the level reached in 2007. Algeria, Nigeria and Egypt will continue to account for the largest share of the continent's gas production, with a combined share of 82% in 2020. LNG exports from East Africa are not expected to begin within the timeframe of this report. Production additions fall short of the continent's demand needs, however, posing continued threats to the reliability of exports.

Figure 3.17 Africa supply by country, 2000-20



### Algeria: Production growth capped by an unattractive investment environment

Production is set to increase by 10 bcm until 2020, but there are downside risks. Encouragingly, gas production recorded a gain of 2% in 2014, halting the declining trend of the prior five years. In September 2014, Sonatrach announced its plans to invest large sums — estimated at USD 90 billion — in the oil and gas sector from 2015 to 2019. About a quarter would be for gas development. The plan includes starting production at six fields with a total capacity of 27 bcm per year over the next three years.

Several challenges persist. Last year's exploration bidding round was very disappointing. Of the 31 fields on offer, only four blocks were awarded. This signals that there is little appetite for investing in Algeria's upstream sector, despite improved fiscal terms following amendments to the country's hydrocarbon law in 2013. As foreign capital remains on the side lines, Algeria itself will have less financial room for manoeuvre, squeezed between low oil prices and high levels of social spending. Overall, chances are that investments in oil and gas will fall well short of initial planned levels.

Meanwhile, Algerian shale gas resources are set to remain underground until 2020. Sonatrach is carrying out a pilot drilling programme in southwestern Algeria's Ahnet Basin (in the Salah province),

scheduled for completion in the second half of 2015. Despite initial encouraging results, the Algerian government stated earlier in the year that it will abandon plans for shale gas drilling. The backtracking comes in response to continuing public demonstrations in the region, where Sonatrach has drilling operations. Campaigners are concerned about the environmental impact of hydraulic fracturing, potential ground water contamination and aquifers' depletion. Protests have remained localised and the government may decide to resume drilling, if public opposition subsides, but the medium-term outlook for the country's shale gas industry looks quite grim.

### *Egypt: Slow progress but moving forward*

Production remains mired in difficulties, now standing 20% below its 2008 peak. However, early signs of stabilisation have emerged as the government is taking steps to revive investors' confidence in the country's upstream sector. Production is expected to increase moderately until 2020 at an average annual rate of 1.2% due to a projected, gradual improvement of the country's investment climate.

Egypt has made progress in repaying outstanding debt to IOCs, with an estimated USD 5 billion repaid during 2014. Clearing debts is critical to rebuild confidence with potential investors. Moreover, price reforms have also moved forward as subsidies on oil products have been cut and higher gas prices agreed for certain projects. Low, regulated domestic prices are a major obstacle to develop untapped gas finds in the Mediterranean and Nile Delta Basin.

The government's willingness to enter price negotiations for a few projects suggests some form of compromise. A relatively successful oil and gas exploration bidding round in late 2013 and numerous new exploration deals sealed with Western companies in 2014 suggest that investors' confidence is slowly recovering.

A major deal signed with BP in March 2015 is the most positive sign to date as the company has committed to invest about USD 12 billion to develop large quantities of offshore gas, equivalent to about a quarter of Egypt's current production. BP hopes to start output from the project, called West Line Delta, by 2017. The project also marks a clear change of strategy from the past, when IOCs' large-scale investments in gas extraction were earmarked for export. With this project, the company aims to deliver gas to the domestic market, responding to Egypt's growing energy needs.

### *Nigeria: Energy sector still waiting for reforms*

Nigerian gas production will decrease at an average annual rate of 0.6% until 2020, falling to 38 bcm by the end of the decade. The IEA's poor outlook for Nigerian oil supply (IEA, 2015) affects growth in associated gas, which accounts for a large part of the country's total.

Nigeria is the world's ninth largest gas reserve holder, and the largest in Africa, ahead of Algeria (second) and Egypt (third). Despite a generous resource endowment, gas production has disappointed in recent years, fluctuating around a flat line since 2011. Several above-ground challenges are discouraging investments and preventing growth. Poor governance and corruption are endemic problems while sabotage to energy infrastructure is routinely disrupting oil and gas output, particularly in the Niger Delta region. Both the economy and the oil and gas sector are in dire need of reforms, which have so far failed to materialise. The long-awaited and controversial Petroleum Industry Bill (PIB),



reform legislation seen as crucial to revive investors' confidence in the country's oil and gas industry, continues to be pushed back.

Moreover, adding to the country's specific challenges, the shifting focus of IOCs to new gas opportunities in the eastern part of Africa will make it increasingly difficult to attract more investments, thus suggesting continued challenges to sustain gas production levels.

### Angola

With limited domestic consumption, the country's production profile is a function of its LNG exports. Angola's LNG facility in Soyo had been plagued by technical problems since it started operations in 2013; it has been shut since mid-2014. The terminal operator indicated that production may resume by the end of 2015. This report forecasts that Angola will re-enter the LNG market next year and gradually ramp up production to the plant's full operating capacity of 7 bcm by 2020.

### Libya

Gas production and exports managed to recover in 2014, but remain 30% below the level of 2008-10. This report forecasts a small output increase until 2020, but it recognises that production could move either way, depending on the evolution of the country's political and security situation. In the short term, production is likely to be volatile as fields are periodically shut and restarted amid the ebb and flow of the violence.

The bulk of gas production now originates from the western part of the country from onshore facilities at Wafa, much of which feeds into the Green-stream pipeline to Italy. In February 2015, the Wafa field was reportedly shut and several foreign staff evacuated in response to a terrorist assault, which is likely to have cut supplies available for exports.

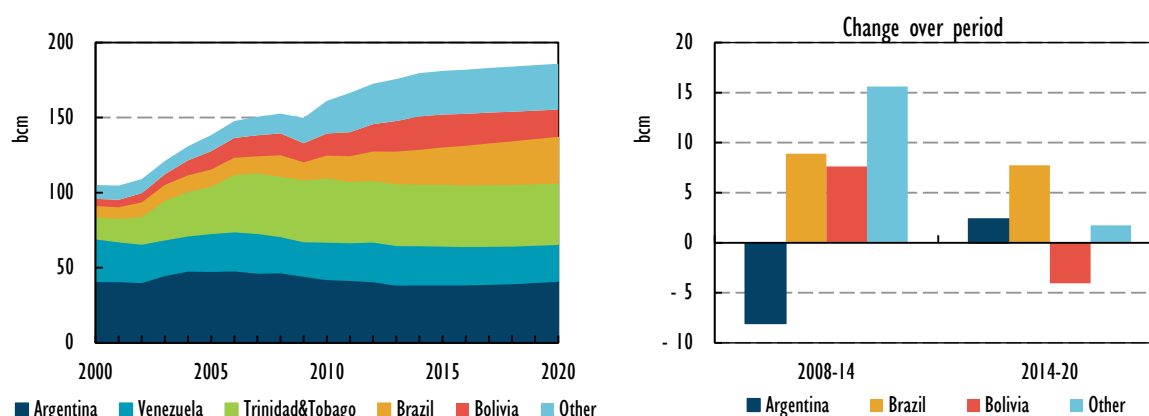
### Others

Limited production additions will occur in countries other than those described over the forecast horizon of this report. Positive developments can be highlighted in Ghana where the Italy-based Eni, the trading company Vitol and the Ghana National Petroleum Company signed an agreement in early 2015 to proceed with the Offshore Cape Three Point (OCTP) integrated oil and gas project. The first oil is expected in 2017, and the first gas in 2018. The project aims to unlock 42.2 bcm of gas-in-place, enough to fuel Ghana's thermal power stations for the next 15 years. It is expected to result in more than 700 MW of new power generation capacity coming on line by 2017.

## Latin America: Slowing growth

Latin America's production will increase until 2020, but at a much slower pace than during the previous five years, adding 8 bcm (see Figure 3.18). The outlook for Brazil remains positive despite ongoing challenges for Petrobras, while Argentina will manage to reverse the declining production trend. The biggest change comes from the rest of the continent. Combined production from Peru, Colombia and Bolivia — which increased by more than 20 bcm between 2008 and 2014 — is set to decline by 1 bcm over the next six years, as numerous large fields start to decline. Production falls in Bolivia pose risks to regional supply security, with Brazil and Argentina both dependent on pipeline flows from their neighbour.

Figure 3.18 Latin America supply by country, 2000-20



### Brazil: Compounding problems

Brazil's natural gas production reached a new record in 2014, increasing by more than 9% year-on-year. Production will continue to rise robustly in the earlier part of the forecast period, on the back of investments already made or fully committed. Low oil prices and Petrobras's legal challenges — in the aftermath of a large corruption scandal — will weigh on investments and cause delays to the start-up of new fields as the end of the decade draws closer.

Natural gas production recorded a robust increase in 2014, underpinned by growing output from the Mexilhão, Uruguá-Tambaú, Sapinhoá and Lula fields, better interconnections between wells and platforms, and higher operational efficiency. The share of associated gas from pre-salt resources remains small, but continues to increase: it now represents 14% of total gas production, up from 0.5% in 2008.

Despite the strong performance, the production outlook has worsened, as Petrobras struggles with the challenge of low oil prices and the fallout of a massive corruption scandal. The huge investment programme of recent years has generated persisting negative, free cash flows and a large accumulation of debt, which currently stands at more than five times the company's EBITDA ("earnings before interest, taxes, depreciation, and amortisation") level.

Allegations of a large kickback scheme involving former Petrobras executives, construction companies and politicians are adding to the difficulty of an already stretched balance-sheet. In April 2015, the company finally presented its annual audited results, after a long delay due to the auditors' initial refusal to sign off the statement. The results showed a write-off of USD 16.8 billion, including USD 2.5 billion directly related to the corruption's probe. Despite Petrobras' efforts to restore investors' confidence, the company's ability to borrow will suffer, not least because of its large debt levels.

Amid the uncertainty, the credit rating of Petrobras has come under pressure, with cuts applied by all three major agencies. Payments to several engineering firms involved in the corruption scandal have been frozen, which is set to result in delays of services and equipment delivery. In late January 2015, Petrobras slashed its planned capital expenditure for the year. While the cuts are so far slated towards refining, marketing and exploration, which should limit the near-term impact on gas production, they are testament to the company's challenging situation. If their financial difficulties persist, the company's large development programme of its pre-salt reserves could encounter delays.

On the positive side, recent oil and gas offshore discoveries in the Sergipe-Alagoas basin could open a new producing frontier in the next decade. Compared with the pre-salt fields, resources in the Sergipe-Alagoas are shallower and closer to shore which should make their exploitation easier. Petrobras announced plans to install a single production platform capable of producing 100 000 barrels per day (mb/d) in 2018, followed by a second one of the same size in 2020. Petrobras expects the new fields to also contain large quantities of natural gas, although it has not yet given any estimate for the volumes in place, stating that further appraisal is required. The new discoveries are the result of an intensive drilling program that started in 2008.

### *Argentina: Warming up to foreign investors*

Argentina's production downtrend halted in 2014 after five straight years of annual declines, in large part thanks to higher wellhead prices. A warmer attitude towards foreign investors, following YPF's nationalisation in 2012, can also be detected. However, companies are likely to be wary of committing substantial capital and will wait for further guarantees to back up the government's long-term commitment towards investment-friendly policies. This report forecasts that Argentina's gas production will increase modestly, adding 2.4 bcm between 2014 and 2020.

In an attempt to address Argentina's growing gas deficit, the government issued measures to increase the profitability of exploring and producing in the country. In 2013, wellhead prices for new developments were increased to USD 7.5/MBtu, three times the prevailing average in the Neuquén basin in southern Argentina, the country's main producing zone. With a large exploration and production programme to finance, higher prices are a lifeline for the state-owned company, YPF. Foreign investors are also warming to the idea of investing in the country, attracted by Argentina's vast shale oil and gas reserve base.

Last year, the state-owned company YPF signed new contracts with foreign partners for developing shale oil and gas assets from the Vaca Muerta formation located in the Neuquén province. In December 2014, YPF signed a USD 550 million deal with Malaysian Petronas whereby the latter will provide the bulk of the financing for a three-year pilot project. If drilling is successful, a much larger investment could follow.

The provincial energy company, Gas y Petróleo del Neuquén S.A., owned by the Argentine province of Neuquén, has also announced smaller deals with Royal Dutch Shell and Total, worth USD 250 million and USD 300 million, respectively, to explore and develop acreage in the Vaca Muerta. Such agreements came about after large investment commitments were made by Chevron over the past two years, worth in excess of USD 2 billion. Adding to the improving situation, the United States and Argentinean governments have agreed to deepen co-operation in various energy-related areas, including non-conventional oil and natural gas resources.

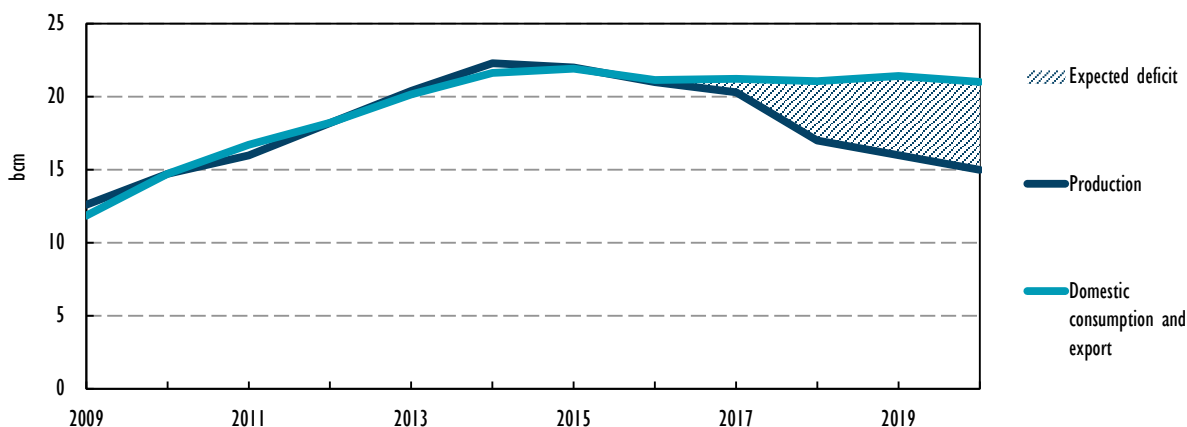
These steps are positive, but Argentina will have to show further sustained efforts towards improving its investment climate to attract the capital needed for large-scale shale developments. The government's history of heavy-handed intervention and its precarious financial situation — the country is still dealing with the fallout of last's year default — remain a concern for many potential investors. Before the end of the decade, shale gas will make a minimal contribution to Argentina's overall gas production; this is well illustrated by Chevron's output target of just 1 bcm by 2017 from its assets in the Vaca Muerta.

### Bolivia: Growing challenges

Bolivia's natural gas production reached a new record in 2014, adding to the strong growth of the previous five years. Looking ahead, production growth is set to slow down and then to start falling as some of the largest fields move into their natural decline phase. Such changes in output trends may adversely affect the supply security of the region, as Bolivia is an important gas supplier to both Brazil and Argentina.

Production from existing fields such as San Alberto, Sabalo and Margarita which account for more than 70% of total exports to Brazil and Argentina, is maturing and recent discoveries are not sufficient to sustain the production uptrend. The Bolivian government had plans to intensify exploration activity, but the sharp fall in oil and gas prices has already forced state-owned company YPFB (Yacimientos Petrolíferos Fiscales Bolivianos) to make downward revisions to its capital expenditure programme. This outlook forecasts production to decline moderately until 2020, which raises questions about the sustainability of current export levels to Brazil and Argentina in view of continued strong demand increases. Difficulties to meet both domestic demand and long-term export commitments could start to surface by 2017 (see Figure 3.19).

**Figure 3.19** Balance of demand and domestic production Bolivia, 2000-20



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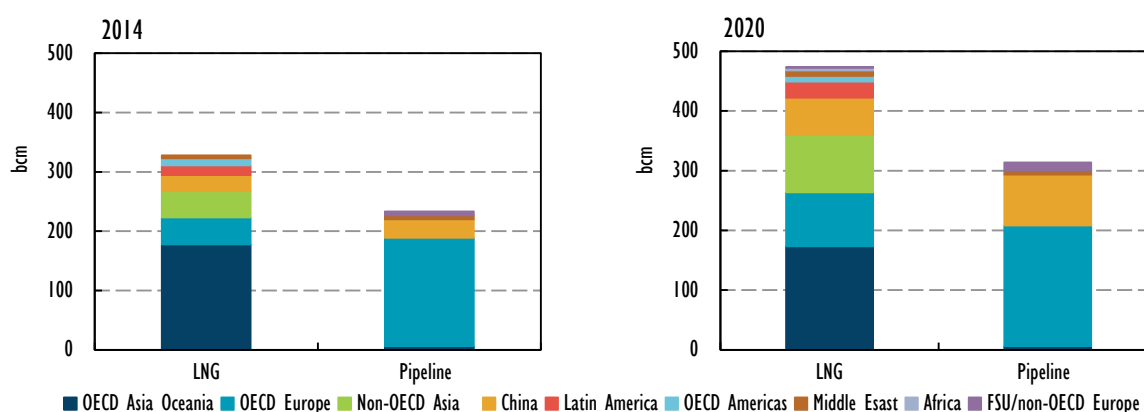
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## 4. TRADE

### Summary: Global gas trade expands rapidly driven by LNG

- Inter-regional gas trade will expand by 40% between 2014 and 2020, surpassing 780 billion cubic metres (bcm) by 2020. Liquefied natural gas (LNG) will account for 65% of the increase.
- Today, OECD Asia represents more than half of total LNG imports; Europe accounts for 80% of inter-regional pipeline imports. By 2020 trade patterns will become more diversified.
- People's Republic of China ("China") will emerge as an increasingly important pipeline importer, accounting for more than 25% of inter-regional pipeline trade by 2020. With increased import flexibility and arbitrage capacity between pipeline imports and LNG, China might become a stabilising factor for regional market balances.
- On the LNG side, OECD Europe, China and non-OECD Asia will all expand their share of global LNG imports substantially. By contrast, OECD Asia will see its previously dominant share of global LNG imports dropping by more than 15% between 2014 and 2020.
- Some regions will experience pronounced changes in their net trade position, reflecting new demand and supply dynamics. OECD America will turn into a net gas exporter and non-OECD Asia into a net gas importer. At the same time, OECD Asia Oceania imports will halve as intra-regional trade grow quickly. China's imports will rise by more than 2.5 times.
- Global LNG capacity additions will amount to an impressive 164 bcm between 2014 and 2020, 90% of which will originate from the United States and Australia. The bulk of new LNG supplies will hit the market in 2016 and 2017. Annual additions are estimated to peak at 45 bcm in 2016, with that volume equalling 86% of the cumulative increase of 2011-14. By 2020 incremental annual LNG capacity will have already fallen to half that level.

**Figure 4.1** Breakdown of imports by region, 2014 and 2020

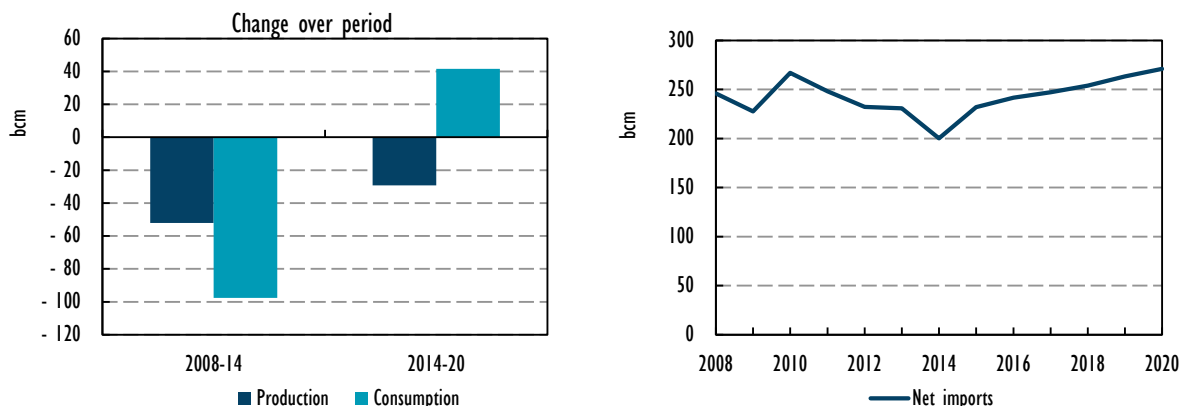


- Surging LNG supplies come up against weak demand over the past two years. The result is an oversupplied outlook for LNG markets, until 2017, at least. In the short term, the price sensitivity of LNG production is low and excess supplies will have to be absorbed via a price-driven response on the demand side. Spot LNG prices have already halved since early 2014 and oil-linked contracts have also started to fall, in line with the general three- to six-month lag in the pricing mechanism. The responsiveness of Asian demand in this new price environment will be tested. This outlook forecasts non-OECD Asia (including China) to absorb 60% of incremental LNG supplies over the forecast period.
- Europe is set to take 30% of incremental LNG supplies, with its imports doubling between 2014 and 2020. Due to falling production and modestly rising demand, such a large increase can be accommodated against broadly stable Russian flows.

### OECD Europe: LNG imports will double

European gas import requirements will grow by 70 bcm until 2020, or by about a third relative to their level in 2014. Falling domestic production explains more than 40% of the change in the region's trade position. The remainder is more or less equally accounted for by a rebound in residential consumption, due to weather normalisation, and by underlying, improved consumption.

Figure 4.2 OECD Europe gas trade balance, 2008-20



Europe has two main options in order to meet its increased import needs: getting more Russian gas or turning to LNG, as the potential for additional volumes from North Africa and the Caspian is limited until 2020. North Africa's pipeline exports to southern Europe have dropped by 14 bcm since 2010 and there is no sign of a recovery. A combination of poor investment incentives, robust demand increases and security issues severely limit the potential for a sustained production upswing in the region and its ability to boost supplies to Europe.

Caspian gas will start to flow to Turkey and then Southeast Europe by 2019/20, displacing some Russian volumes (the main supplier to the region). Initial quantities are estimated at about 10 bcm by 2020. This will not be sufficient to alter the overall picture, in which Russian gas and LNG will make up the bulk of additional imports.



This report forecasts Europe's LNG intake to roughly double between 2014 and 2020, surpassing 90 bcm and covering 65% of the region's incremental import requirements. Russian deliveries are set to rebound following the weather-induced collapse of 2014. However, after that, they will remain locked in a 150-160 bcm range, with LNG covering the majority of the growing regional imbalance.

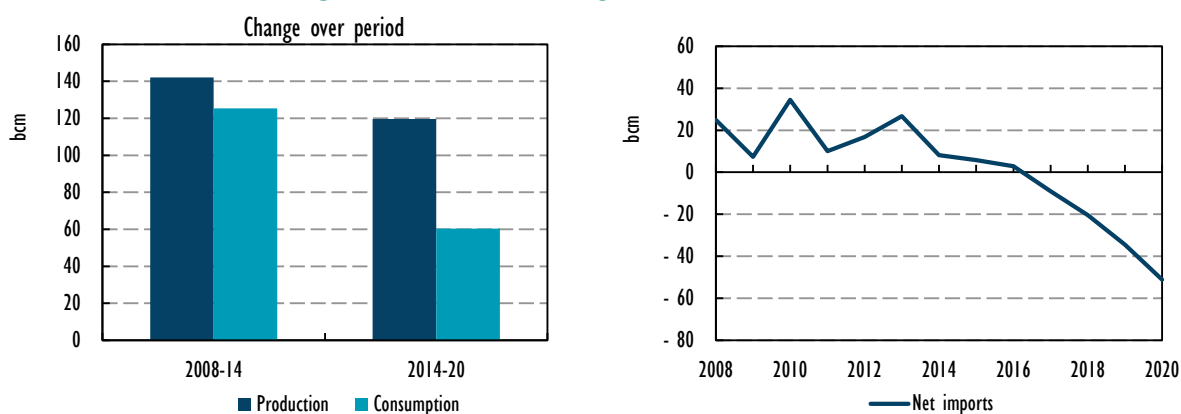
There are risks to this outlook. The first is the scale of Asian demand's response in a world of abundant and cheap LNG. Due to Europe's ability to arbitrage between pipeline gas and LNG, the region is set to continue playing the role of residual market, absorbing whatever Asia does not take. Ample LNG supplies mean that even with a robust, price-driven demand response in Asia, substantial quantities of LNG must flow to Europe for global gas markets to clear.

Should Asia take less LNG than what is assumed in this report, Europe will need to make up for the difference. This could lead to two possible outcomes: either more Russian volumes are displaced or gas prices will have to drop to a level low enough to stimulate additional consumption in the European power sector. Both scenarios look conceivable, the actual turn out would be dependent on Gazprom's pricing strategy, if faced with such developments.

### OECD Americas: Turning into a net exporter

The gas trade balance of the OECD Americas will change from a small deficit to surplus during the forecast horizon of this report. Production is projected to grow almost twice as fast as domestic consumption due to strong export growth. As a result, the turnaround in the regional gas trade position will occur swiftly (see Figure 4.3).

**Figure 4.3** OECD America gas trade balance, 2008-20



The region's trade path is overwhelmingly defined by the continued strong growth in US shale gas production. In the United States, incremental demand is expected to account for just about a third of incremental production, which results in large quantities of gas available for exports to both intra-regional and inter-regional buyers.

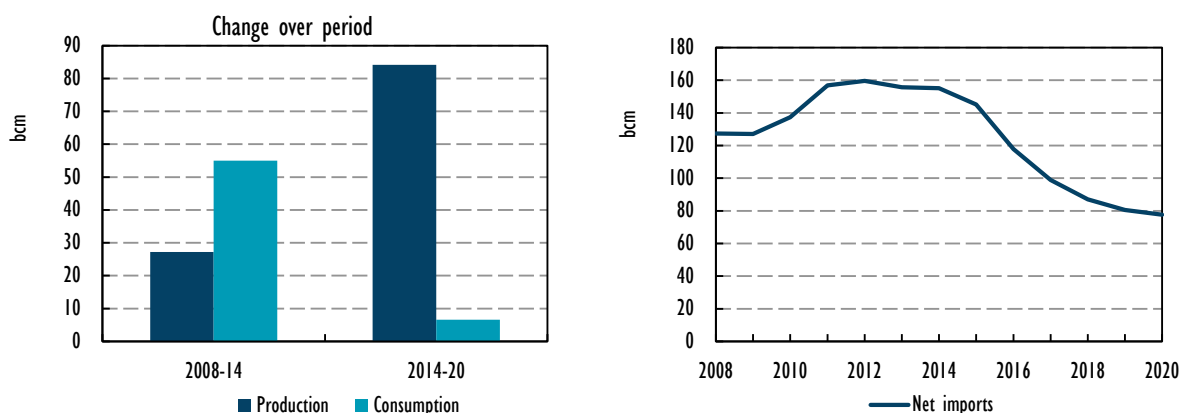
Within the region, Mexico becomes a primary destination for US gas. US gas flows to Mexico are forecast to rise by almost 20 bcm between 2014 and 2020, which backs out Mexico's LNG imports. The process of LNG displacement due to rising US shale gas production will spread from the United States, where imports have now dropped to hit operational limits, to Mexico where there is the potential to replace the more expensive LNG volumes.

Canada will struggle to find an outlet for its own gas, outcompeted in its traditional core markets by the United States. Production will remain broadly flat until 2020, with Alberta's volumes challenged by the increased penetration of gas from the Marcellus/Utica plays into the US Midwest and Central/Eastern Canada. The availability of upswing potential in Canada leaves North America well positioned to respond to possible disappointments in US gas production over the medium term.

### The Asia Pacific region: Softer balances

The **OECD Asia Oceania** trade balance will undergo massive changes over the next five years. As Australian LNG plants are brought into operation, the import deficit of the region will be cut in half. Slower demand growth, as Japanese consumption falls back, also helps loosen the regional gas balance (see Figure 4.4).

**Figure 4.4** OECD Asia Oceania net gas imports halve throughout 2020



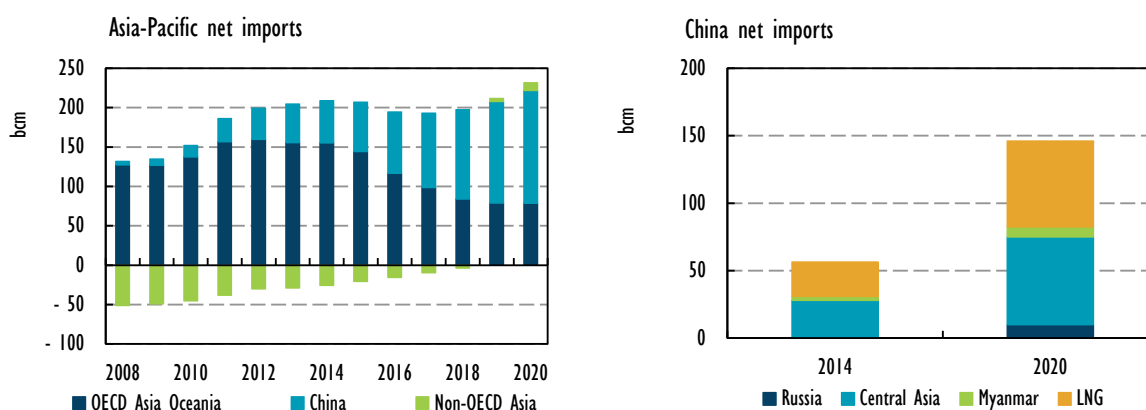
Countries in the OECD Asia Oceania category cannot be seen in isolation from the rest of Asia, as the effects of the upcoming surge in Australian LNG projects will reverberate across the region. Asia, as a whole, will experience a rare drop in the need for long-haul LNG over the next two years (see Figure 4.5), when the majority of new Australian projects come to market. Asian gas balances will then start tightening again as 2020 approaches, but overall the need to pull LNG away from other regions is drastically reduced. Asia Pacific's<sup>1</sup> net imports will increase by 50 bcm between 2014 and 2020, half the increase recorded over the previous six years.

Along with a slower increase in import needs, the Asia Pacific region will also have better access to pipeline gas than before. Until 2020, pipeline trade will remain exclusively limited to Former Soviet Union (FSU) exports to China. However, as China builds capacity to arbitrage between piped gas and LNG, the country is set to increase its role as a stabilising factor for regional gas balances.

**China's** gas imports are set to increase by just over 90 bcm, between 2014 and 2020, with 60% of the increase coming from higher pipeline flows from Russia, Central Asia and Myanmar. Physical pipeline import capacity is estimated to reach 110 bcm by then, which leaves some scope for ramping up deliveries, if market conditions change sufficiently.

<sup>1</sup> Asia Pacific = China + OECD Asia Oceania + non-OECD Asia.

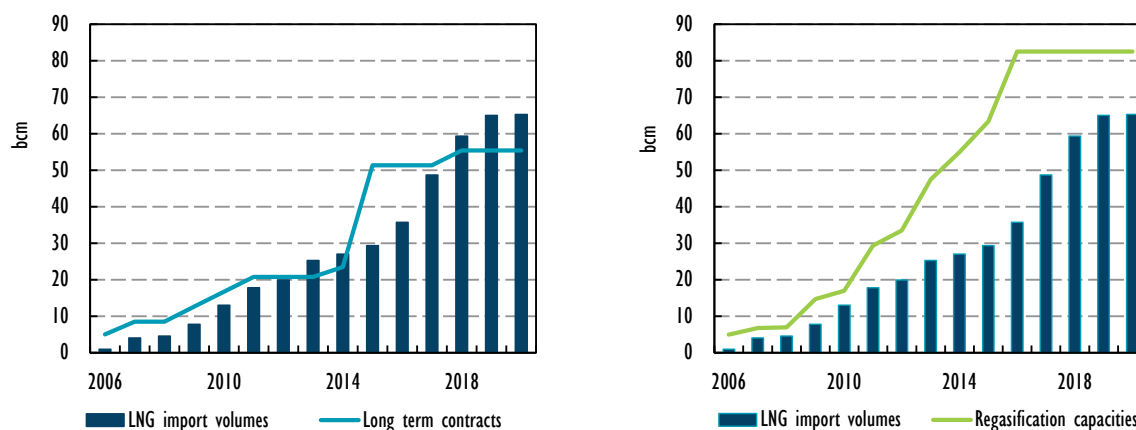
Figure 4.5 Growth in Asia Oceania net import needs slowing down



China's import need remains one of the major uncertainties for global gas balances. Disappointing demand figures, amid an unexpectedly sharp slowdown in primary energy consumption, have resulted in downgrades to future consumption prospects. At the same time, the outlook for the supply side has also worsened as developing shale gas is proving more challenging than anticipated. Also, government's support towards coal gasification is waning. As a result, China's import needs remain broadly in line with last year's forecast despite demand and supply revisions in the region of 10%.

This report expects China to absorb a significant chunk of incremental LNG supplies, taking just above a quarter of new supplies entering the market between 2014 and 2020. Judging from both regasification capacity additions and contractual obligations, the country could take significantly higher volumes during the 2015/17 period (see Figure 4.6). The question is really whether demand will be there, particularly as line C of the Central Asia pipeline system will become fully operational by the end of 2015, adding an extra 25 bcm of import capacity.

Figure 4.6 China is over-contracted for 2015/17 relative to its LNG import needs



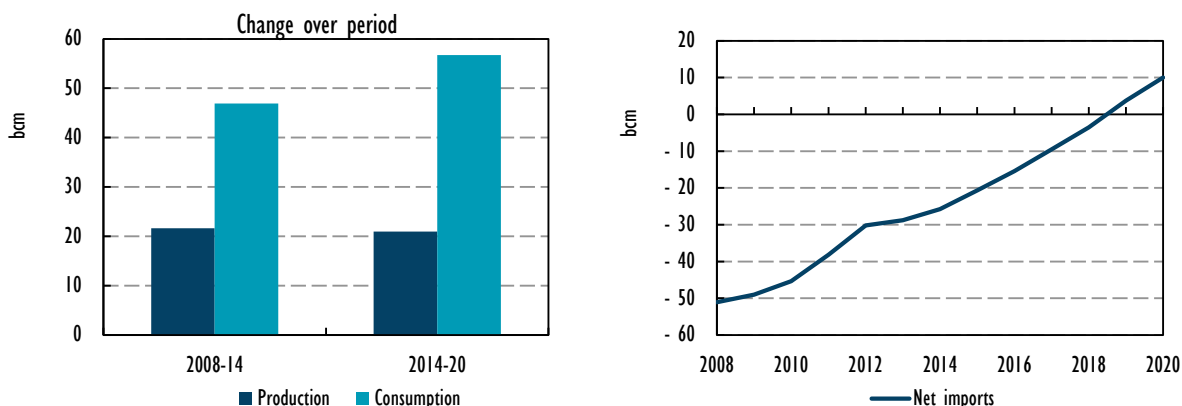
While China plays an important role in absorbing new LNG volumes, **non-OECD Asia (excluding China)** is emerging as the major outlet for incremental supplies until 2020, with regional LNG intakes more than doubling from the level in 2014 to reach 96 bcm.

Non-OECD Asia's upstream performance remains generally below potential, hindered by low domestic prices and unfavourable investment policies. The result is a fast drop in the region's ability to cover its incremental demand with domestic production (see Figure 4.7). This does not mark a new trend, as the region's net exports have roughly halved over the past ten years, but it represents a substantial acceleration of that process, particularly on the back of a three-year period of flattening net exports.

The sensitivity of gas consumption and gas imports to prices is an important factor behind the softer demand over the past two years, a period when LNG prices averaged above USD 15/MBtu. At such price levels, the attractiveness of gas is significantly reduced and so is the fuel's ability to make inroads in the region's energy mix. In countries with available import capacity, such as India, utilisation rates have dropped sharply, a reflection of the challenges in passing the cost through to final customers. In others, high prices are turning policy makers away from gas with many countries setting plans to limit its share in their energy mix.

This outlook assumes that demand will now display a parallel degree of sensitivity to the recent downward price move, resulting in a pick-up in regional LNG imports. The resetting in the gas price level of the past 18 months could meaningfully alter the way gas is deployed in the region. In the short run, better affordability will boost imports, particularly when lower prices go to reduce shortages rather than placing gas in direct competition with coal. In the medium term, gas penetration might accelerate, if confidence about the sustainability of the recent price drop grows.

**Figure 4.7** Non-OECD Asia's import dependency is on the rise

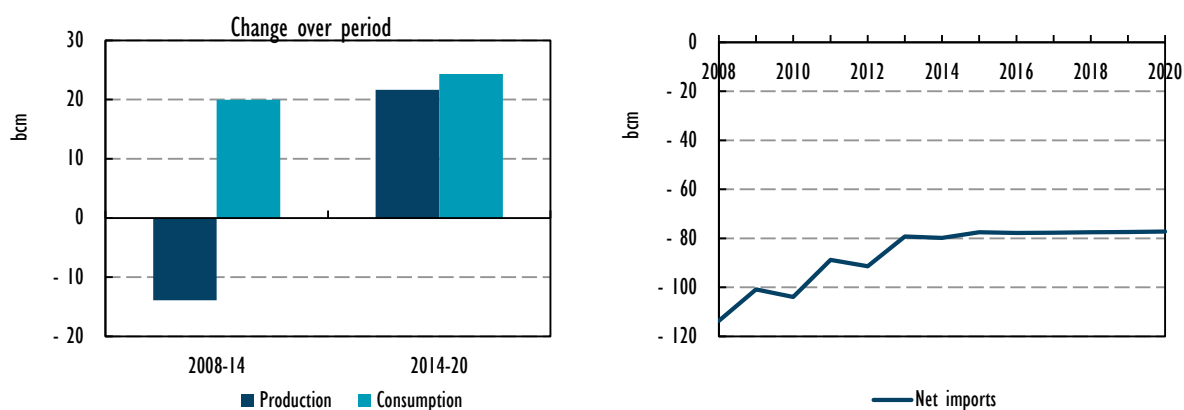


### Africa: Exports stabilise

Exports from the region have fallen sharply over the past six years, dropping by almost 30%. Three of the four major exporters have experienced outright output declines and a fall-back in exports. Security issues, heavily subsidised prices and poor upstream policies have taken a heavy toll on Africa's upstream performance and its reliability as a supplier.

This outlook forecasts net exports to stabilise around recent low levels as the expected recovery in output barely meets additional consumption requirements (see Figure 4.8). Across the region, potential demand exceeds actual usage, but a combination of poor supply availability, low affordability, and lack of infrastructure hinder faster expansion. While the continent remains a large net exporter, it will start importing gas over the forecast period, driven by Egypt's remarkable transition from exporter to importer (see Box 4.1).

Figure 4.8 Africa gas trade balance stabilises



#### Box 4.1 Egypt turns into an LNG importer

In 2014, Egypt's LNG exports ground to a halt. Due to increasing domestic demand, amid a poor upstream performance, the Egyptian government continued to divert gas resources away from exports and towards the domestic market. Egypt has two LNG facilities with combined capacity of about 17 bcm. The Diametta plant, a joint venture between Gas Natural, Eni and EGAS, was idled in 2012. ELNG, the country's second plant, is located in Idku, near Alexandria. It has two trains and nameplate capacity of about 10 bcm. Utilisation rates fell to less than 50% in 2013; the facility shipped only five cargoes in 2014.

Against this backdrop, Egypt is tapping into the LNG market as an importer, choosing to do so via a floating storage and regasification unit (FSRU). Currently, 18 such units exist globally and a few more are planned or under construction. Egypt leased the ship from Norwegian company, Hoegh LNG.

The contract, signed in November 2015, has a five-year duration, starting in Q2 2015. The ship is located in the Red Sea port of Ain Sukhna, at the southern entrance of the Suez Canal. The country's first cargo arrived from Qatar on 1 April 2015. Egypt has also signed a number of contracts with international companies, such as Noble Energy, Gazprom, Trafigura, Vitol and Shell for the delivery of LNG over the next few years. It also signed an agreement with the Algerian state-owned company, Sonatrach, for six LNG shipments.

Egypt is also considering importing gas from Israel. Negotiations, particularly regarding possible deliveries from the giant Leviathan field, have been ongoing. However, progress remains slow amid difficult political negotiations. This report forecasts Egypt to gradually increase its imports to reach close to 5 bcm per year by 2020. Lower global prices and ample LNG supplies should facilitate this transition.

### Latin America and the Middle East: Small changes tilted towards higher imports

Latin America is a small net gas exporter today, mainly thanks to LNG exports from Trinidad and Tobago. Although gas imports tend to fluctuate, at times significantly, depending on regional hydro availability, these imports are on an upward trend overall. A weak supply outlook means that import requirements will rise further. Over the outlook period, Colombia and Uruguay will become LNG importers while both Argentina and Brazil will see their LNG intakes increasing further, partly on the back of falling exports from Bolivia. The region's trade position is set to be broadly in balance by 2020.

The Middle East, a large net gas exporter, is set to remain so over the forecast period. Net imports will nudge higher, but changes to the regional gas trade balance are relatively small as the two largest regional consumers, Saudi Arabia and Iran, have almost no external gas trade connections. The world's largest LNG exporter, Qatar, plans to keep its exports at current levels for the foreseeable future. Smaller players in the region will see their net exports decreasing.

Overall, both Kuwait and the United Arab Emirates will see imports increasing, as domestic production growth continues to lag behind the resource potential of these countries. Oman may face challenges in maintaining LNG exports at current levels as the end of the decade draws closer due to rising domestic consumption. Yemen is a possible wildcard. The security situation in the country has deteriorated sharply and its 9 bcm per year LNG plant is currently offline. This report assumes that LNG exports from Yemen will resume at full capacity relatively quickly. Therefore, the risk of a prolonged disruption is not factored in the baseline forecast of this report.

### **FSU: Exports shift to the East**

The FSU is currently the largest exporting region and will remain so until 2020, with net exports set to increase by 55 bcm relative to 2014. With the exception of a weather-related recovery in Russian exports to Europe, and about 10 bcm of incremental exports from Azerbaijan to Turkey and South East Europe, the increase reflects growing pipeline trade with China. By 2020, the Central Asia–China pipeline system should be able to handle 85 bcm per year of gas, the majority of which will be sourced from Turkmenistan. At the same time, Russia's efforts to lock in export agreements with China have intensified over the past year-and-a-half, reflecting Russia's strategic choice to diversify to the East. This report forecasts the Power of Siberia to start operating by 2019/20 with limited volumes.

### *Russia pushes ahead with diversification strategy to the East*

After decades-long negotiation, pipeline export projects to China intensified gear last year. In May 2014, Gazprom and CNPC signed a 30-year agreement for 38 bcm of gas supplies via the Power of Siberia pipeline project (the Eastern route). They followed in November with a framework agreement for 30 bcm of gas over 30 years through the proposed Altai pipeline (the Western route) (see Map 4.1).

Meanwhile, the two sides are also reportedly considering possible transportation via the Sakhalin-Khabarovsk-Vladivostok (SKV) pipeline route. Russia stated that China is on track to become its largest gas export market, ahead of Germany and Turkey, over the medium term. While Gazprom's projections look optimistic, they are also a clear indication of the company's strategic push to quickly open up an export outlet to China.

This report assumes that the Power of Siberia project will proceed. However, sanctions, challenges to project management – given the many elements of the system that need to be developed and synchronised such as upstream production, gas-processing plant, pipeline sections in Russia and China – and failure to lock in a USD 25 billion Chinese prepayment, pose risks of delays. The Western route and gas from Sakhalin have very little chance to be operational by 2020 due to Gazprom's financial limitations combined with China's lack of urgency to procure the gas.

Map 4.1 Three possible routes to China



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

### Eastern route

In May 2014, during President Putin's visit to Shanghai, Gazprom and CNPC sealed a USD 400 billion Purchase and Sale Agreement for Russian gas supplies, totalling 38 bcm per year over 30 years, via the Power of Siberia gas pipeline. The two parties did not disclose the pricing formula but did, at that time, disclose that it was a contract with an oil-basket price link.

A simple calculation would point to an average price of about USD 350/thousand cubic metres (kcm) (USD 9.2/million British thermal units (MBtu)<sup>2</sup> based on an oil price presumably around USD 100/bbl, which was prevalent at the time. This is more or less in line with experts' consensus view that the price could range between USD 350 and 390/kcm (USD 9.2-10.3/MBtu) at the Russia/China border with an oil price of USD 100/bbl. Such a price level is in line with that of Central Asian gas to the Central Asia/China border. Crucially, transportation costs within China are twice as expensive for the latter, implying that Russian gas in Shanghai/Beijing might enjoy a price advantage over Central Asian gas.

Construction work for the Power of Siberia pipeline began in 2014; the first laying of pipelines is expected by the end of 2015. Gazprom must start deliveries between 2018 and 2020; the exact start-up date depends on whether the infrastructure is ready and China's gas demand needs. The very end of the decade seems more likely given the huge challenge to build such a long pipeline (at least 2 170 kilometres (km) between Chayanda and Blagoveshchensk on the Russia–China border) in such a short period. Developing the complex Chayanda field on time will also add to the challenge.

<sup>2</sup> The applied conversion is 37.9 MBtu = 1 000 cm.



Gazprom has earmarked the Chayanda and Kovykta gas fields as sources for this route. Chayanda pre-development has already started with exploration wells drilled. The transmission line for transporting its gas is under construction, which makes the field the key gas source to start feeding the Power of Siberia. However, Chayanda has expected annual production of 25 bcm at a maximum, and so additional resources must be developed to meet the 38 bcm contractual obligation.

While Kovykta was initially indicated by Gazprom as feed gas for the Power of Siberia, it is unclear if and when the field will be developed. High project costs (Kovykta is located 800 km further away) make other options more attractive. Instead of Kovykta, Sakhalin gas field (Sakhalin 3) or non-Gazprom's associated gas in East Siberia (Rosneft's) could be chosen.

**Table 4.1** Three routes to China

	<b>a) Eastern route</b>	<b>b) Western route</b>	<b>c) Sakhalin route</b>
Agreement	Purchase and Sale contract in May 2014	Framework agreement in Nov. 2014	Reportedly under consideration
Volume	38 bcm for 30 years	30 bcm for 30 years	<10 bcm (depends on domestic consumption and LNG projects)
Planned launch	2019-20	Not earlier than 2020	Not earlier than 2020
Gas source	East Siberia - Chayanda field (25 bcm/yr) - Kovykta field (35 bcm/yr)	West Siberia	Sakhalin 3 - Kirinskoye (5.5 bcm/yr) - South Kirinskoye (16 bcm/yr)
Pipeline	Power of Siberia	Altai pipeline	SKV pipeline
Length (in Russia)	4 000 km	2 600 km	1 800 km
Designed capacity	60 bcm	30 bcm	30 bcm

### Western route

In November 2014, at Russia's initiative, Gazprom and CNPC signed a framework agreement which entails Gazprom's commitment to supply 30 bcm/yr of gas from West Siberia to northwest China through the proposed Altai pipeline for 30 years.

Development costs for the western route would be substantially lower than for the Eastern one, as there is no need to develop new gas sources. As noted earlier, Gazprom's gas production assets are estimated to be capable of producing more than 100 bcm above current production levels. Most of the company's excess capacity is located in West Siberia: 30 bcm could easily be secured at a relatively low cost. Additionally, about 80% of the new pipeline would be laid along an existing one. Consequently, the pipeline route, that would need to be newly developed, will be short. Yet, it would cross very challenging mountainous terrain, thus resulting in very high construction costs for that section. The Altai route is clearly a very attractive option for Gazprom. It could be for CNPC too, provided that the gas price offered at the border reflects the need to transport the gas 4 000 km within China to consumption centres in the East.

Russia and China could sign the contract in 2015, but the project is unlikely to be launched before the end of the forecast period. The biggest obstacle might prove China's unwillingness to lock itself into another big purchasing commitment from Russia at a time of softer domestic demand and ample LNG availability.

Transportation bottlenecks from the Chinese side would also need to be addressed, due to a lack of capacity of its domestic West-East gas pipeline. The existing capacity of this latter pipeline is 77 bcm and is set to be filled with gas from domestic fields and supplies from Central Asia. Some gas may be absorbed by the chemical industry in the Xinjiang region (northwest of China, beginning of domestic pipeline to be connected to Altai pipeline), but would require a clear, competitive advantage to Central Asian gas and would in any case be of limited scale.

### Sakhalin route

The option to send gas from Sakhalin to China is reportedly under consideration. Gazprom had originally envisaged transporting Gazprom's Sakhalin 3 gas to a planned Vladivostok LNG plant. However, as the latter is losing momentum (see LNG section in this chapter), the company is exploring the possibility of sending additional volumes of gas to China via the SKV pipeline. This option could be attractive to China due to the short distance to its largest consumption centre. The volume that can reach China is however much smaller than that which would be carried through the Eastern/Western routes.

Sakhalin 3 is expected to produce around 22 bcm, but roughly a third of that gas should feed the third train of the Sakhalin 2<sup>3</sup> LNG project. Several bcm would be needed to meet local demand. Less than 10 bcm would be available to be shipped to China. In addition, the launch of Sakhalin 3 South Kirinskoye field is not planned in the near future. Sakhalin could provide more gas through Sakhalin 4 and further projects, but the development of those fields has just begun and remains a decade from commercial production.

### *Gazprom rethinks its position in Europe*

#### Rising competition amid oversupplied LNG market

Gazprom's exports to Europe stood at 147 bcm in 2014, down 10% year-on-year, for an average price of USD 341/kcm versus USD 385/kcm in 2013. The revenue impact of lower oil prices and possibly lower exports volumes, including to Ukraine, is likely to be in the range of USD 20-25 billion in 2015, compared to 2013.

While European sales are likely to recover from the weather-induced loss of 2014, this is not the case for the Former Soviet Union market. Weak consumption in Ukraine will continue for some time to come, while the start-up of an LNG terminal in Lithuania and Poland will back out some small Russian gas volumes from eastern Europe.

Turkey remains by far the most optimistic export outlet for Gazprom in Europe. Turkey's gas consumption increased by 7% in 2014. The call for Russian gas remains on a steady upward trend, especially as Gazprom can provide crucial supply flexibility in winter. Not surprisingly, the country is moving to the top of Gazprom's priority list.

European gas market balances suggest that Russia's gas exports are likely to range from 145-165 bcm per year for the next five years under a business-as-usual scenario, in other words, barring abrupt policy shifts from either Russia or Europe. A modest improvement in demand amid steady domestic production losses will increase OECD Europe's import needs by more than 60 bcm between 2014 and 2020.

<sup>3</sup> Sakhalin 2 gas sourcing for first and second trains, but it is not enough to feed a third train.

Beyond the recovery from the weather-driven demand loss in 2014 (which accounted for a large 15 bcm), the assumption is that the bulk of the region's incremental import needs will be met via LNG. Gazprom will face strong competition from large quantities of LNG in need of a buyer in an increasingly well-supplied LNG market. The arrival of Shah Deniz 2 gas in Turkey and southeastern European markets, by the end of the decade, will put further pressure on Gazprom.

How Gazprom will respond to the competition is a key determining factor of how European gas markets will ultimately balance. With a pragmatic pricing strategy, the company has the ability to preserve and even increase its market share due to its low-cost production base.

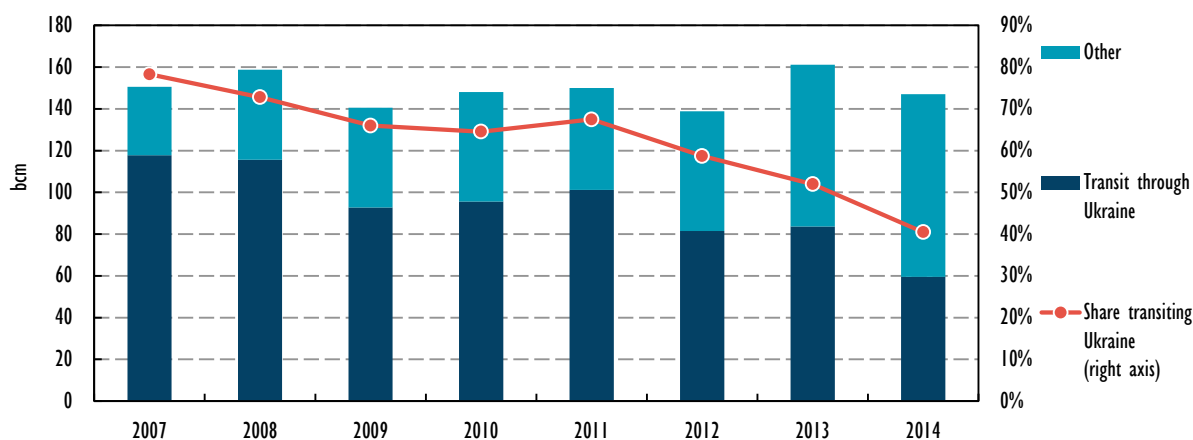
### Ukraine's transit importance is decreasing

Ukraine's role in transiting Russian gas decreased substantially in 2014. At 62 bcm, it represented 40% of total Russian gas supplied to Europe (versus 51% in 2013 and 65% in 2007) and over 50% of Russian gas supplied to the European Union. This marks an unprecedented low level (see Figure 4.9).

While Russia's willingness to divert as much gas as possible away from Ukraine is not poised to change, a number of temporary factors – mainly low overall export volumes due to mild weather – has compressed deliveries through Ukraine to levels which might not be sustainable. As other export routes are more or less fully utilised – unless restrictions on the OPAL line are lifted – increased Russian exports to Europe will necessarily be accompanied by higher transit volumes through Ukraine over the next two years at least.

Stabilisation of transit flows through Ukraine will be put to the test again, if and when the Gazprom sponsored Turkish Stream project is brought on line. Every additional string of the project (there are four planned) will result in a drop of about 13 bcm in Ukraine's transit volumes.

**Figure 4.9** Evolution of Ukraine's role for the transit of Russian gas, 2007-14



### Turkish Stream project

In December 2014, on a visit to Ankara, President Putin surprised the gas industry, including managers from Gazprom, by announcing that South Stream was cancelled and that it would be replaced with a new project running through Turkey. The difference is that the pipeline would not land in Bulgaria, but in Turkey instead.

Moreover, Gazprom will not be building any pipelines running through EU territory as it had planned, but instead it would rather consider only co-investing in some infrastructure developed by TSOs. At the time of the cancellation of South Stream, two out of its four sections were then ready to be laid, with pipe orders made, partial deliveries obtained, and laying ships already waiting in the Black Sea.

Moscow related the cancellation to obstacles created by DG Energy and Bulgaria on the construction of the pipeline. It is likely that Gazprom had started to feel increasingly frustrated by the challenge to reconcile its expectation of the project with EU legislation, and wary of ending up building an expensive equivalent of the Nabucco pipeline, which other suppliers could also use in future. However, increased costs due to financial sanctions surely played a role in the abrupt change of strategy.

Despite the low gas price environment, Gazprom has since been quick to announce a new route for Turkish Stream (660 km offshore along the previous route, 250 km offshore along a new route, and about 180 km inland Turkey through the Thrace region). The company stated that the pipeline will have the same capacity as South Stream and deliveries will start by the end of 2016. It also announced that it was busy negotiating gas price reductions with Turkish Botas.

Map 4.2 Turkish Stream



Gazprom also stated that it would stop any Russian gas transit through Ukraine from 31 December 2019. It would also create a new gas hub at the Turkish/Greek border where the re-routed gas volumes need to be taken, initially inviting European companies to build the missing infrastructure should they want to take Russian gas. That position was then slightly nuanced when Gazprom announced in April 2015 that it would be willing to consider participating in an infrastructure project aimed at bringing Turkish Stream gas from the Turkish/Greek border to Baumgarten.

As the project stands now, Gazprom will face higher costs from the offshore section as foreign partners have not re-engaged in the new project. This comes at a time of lower USD-denominated revenues, given much lower sale prices in Europe, and high CAPEX commitment to develop the Power of Siberia system for gas supplies to China. Gazprom has ways to free up resources should cash flow be insufficient. It could reduce dividend payments or delay other projects, such as Vladivostok LNG, Baltic LNG 5 million tonnes per annum (Mtpa) capacity now planned at Ust-Luga) and Kovytko development. The company could also secure funding from the Russian government.

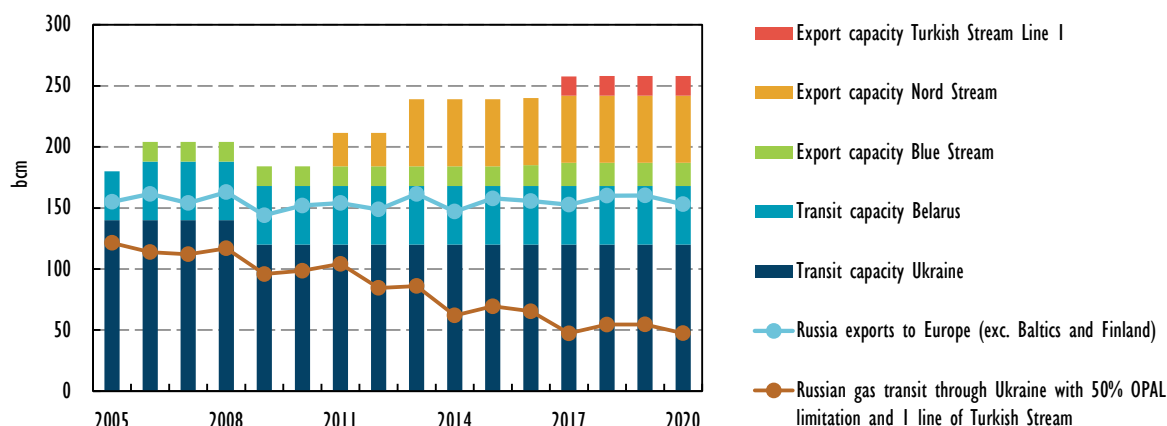
Prior to this agreement, Gazprom and Botas had also agreed to increase the capacity of Blue Stream by 3 bcm per year to 19 bcm. Once the first line of the Turkish Stream is online, Russia will be able to fully supply Turkey through the Black Sea, bypassing Ukraine. The second line could be used to supply Southeast Europe and Greece, using existing infrastructure via reverse flows, such as on the Trans Balkan line.

As far as these two lines are concerned, costs for Gazprom – additional to the sunk cost already made for South Stream – would not be prohibitive and additional import infrastructure requirements for the European side would be relatively small. Overall, such a portion of the Turkish project looks feasible if Gazprom wants to proceed with it.

From a financial and contractual point of view, it will be much more challenging to continue with lines 3 and 4. These two lines with combined capacity of around 30 bcm are supposed to reach the Greek border under a take-it-or-leave-it assumption. There are several ideas floating such as building a pipeline to reach the Slovak Republic via Bulgaria and Romania from the Greek/Turkish border (East Ring).

Another option is to ship Turkish Stream gas via a new pipeline that would cross Greece, FYROM, Serbia, Hungary and end in Baumgarten, or increase capacity of the TAP pipeline to accommodate Russian gas. It is clear that developing such a massive infrastructure in the European Union would require Gazprom's current gas off-takers, which get gas through Ukraine, to receive pricing terms attractive enough to get them to agree switching their delivery point. This would also require an overhaul of existing contract terms, many of which extend well beyond 2019.

**Figure 4.10** Current and future Russian gas export volumes to Europe and transit flows through Ukraine



Note: 50% OPAL limitation assumed.

In any case, it is difficult to see how European buyers will agree to changes regarding their gas selling-point: from an established location to a new one, where the connecting infrastructure is lacking. They are likely to request massive price reductions or simply refuse. Against this background, gas transit through Ukraine could drop by an additional 13 bcm to 27 bcm, compared to that experienced in 2014, depending on whether one or two Turkish Stream lines get built (see Figure 4.10).

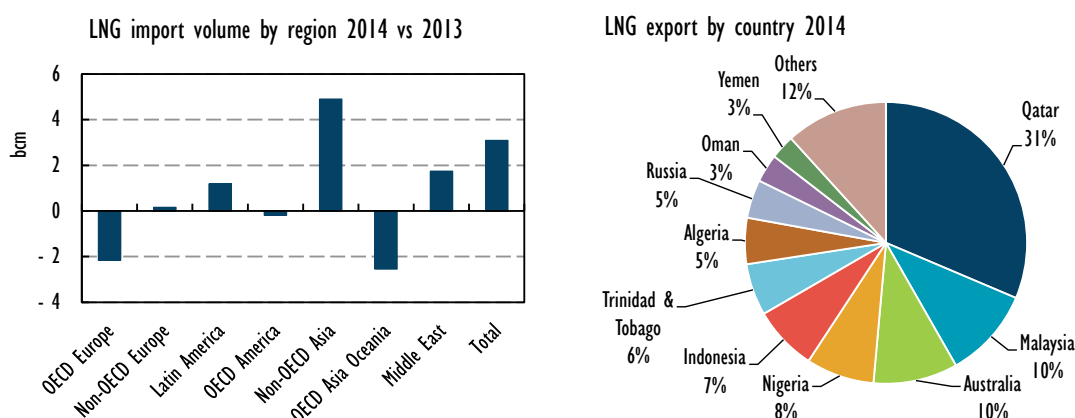
Under the assumption that only one line of the Turkish Stream is built, Ukraine will still transit significant quantities of Russian gas, yet less than the historically low levels of 2014. If further lines are built then transit volumes through Ukraine would fall more sharply. In this scenario, Ukraine would need to reconfigure its gas transmission system and carefully consider planned modernisation investments. Gas transit revenues would decrease sharply.

## LNG markets: Looser balances

### *LNG markets: 2014 was a watershed year*

Global LNG trade increased 3 bcm or 1% in 2014, reaching 325 bcm (Figure 4.11). It was the first annual increase since 2011. All regions, with the exception of OECD America, OECD Europe and OECD Asia Oceania, recorded gains. OECD Europe saw the fourth, annual, consecutive decline in LNG imports, with all countries, except Turkey and the United Kingdom, shedding volumes. OECD Asia Oceania also witnessed lower LNG intakes, driven by falling Korean imports. The latter dropped by 4 bcm, marking the largest annual decline for the country since LNG imports started in 1986. In Japan intakes were stable at around 120 bcm for a third straight year, around 20% higher than pre-Fukushima levels.

**Figure 4.11** Comparison of LNG import volumes by regions, 2014 vs 2013



Source: IEA analysis based on GIIGNL (2015), *The LNG Industry in 2014*, GIIGNL, Paris, [www.giignl.org/sites/default/files/PUBLIC\\_AREA/Publications/giignl\\_2015\\_annual\\_report.pdf](http://www.giignl.org/sites/default/files/PUBLIC_AREA/Publications/giignl_2015_annual_report.pdf).

Non-OECD Asia, including China, recorded the largest increase among importing regions, pegged at 5.6 bcm. China and India together accounted for 47% of that, a modest figure, considering the size of their regasification capacity and recent import patterns. South East Asia further cemented its position as a fast-growing LNG importer, with Indonesia, Malaysia and Singapore, all displaying higher import volumes.

Driven by surging Brazilian requirements, Latin America's LNG imports increased by 1.2 bcm with the country facing the worst drought in history. As a result, Brazil overtook Argentina as the largest LNG importer in the region.

In 2014 non-OECD Europe entered the club of LNG importers as Lithuania started up Klaipeda FSRU. It received its first commercial cargo from Norway in December under a five-year contract between Lithuania's Litgas and Norway's Statoil.

In 2014 additional LNG capacity was twice as much as during the previous three years, with three new LNG projects coming on line. Capacity additions were partly offset by continued poor performance at some of the existing plants. Three new LNG projects came on line last year.

In May 2014, the ExxonMobil-operated PNG LNG began ramping up production at its 9.6 bcm, two-trains facility. Unusually, for an industry often plagued by severe delays, the project came on line ahead of schedule. This was despite the complexity of the project linked to the challenging location of the gas fields in the highlands of Papua New Guinea.

In August 2014, Algeria's Gassi Touil LNG started operations at its 6.4 bcm per year facility. This was followed by the start-up of Australia's Queensland Curtis LNG (QCLNG) in December. The project started loading LNG from its liquefaction facility late in the year, while the first cargo left Australia for Singapore in early January 2015. Production from QCLNG will expand further as 2015 progresses, with a second train due on line in Q3 2015. Plateau production of 11.6 bcm per year is expected to be reached in 2016.

About 40% of total LNG produced in 2014 was sourced from the Middle East with Qatar remaining the world's largest LNG exporter, accounting for 31% of global LNG trade. Production from the new projects was partly offset by poor performance elsewhere, predominantly Egypt, where volumes virtually ground to a halt.

### *LNG markets: Looser balance in 2016 and 2017*

This report forecasts LNG trade to increase by 45% and reach 473 bcm per year in 2020. The increase in imports will be led by three regions: China, Non-OECD Asia and Europe, which together account for more than 90% of incremental additions (Figure 4.12). OECD Asia and North America will see their imports decline, driven by lower intakes from Japan and Mexico. Africa will turn to LNG imports for the first time in history with Egypt taking in about 4 bcm of gas by 2020. Latin America and the Middle East will see their imports increase by a combined 11 bcm as both regions struggle to meet incremental demand.

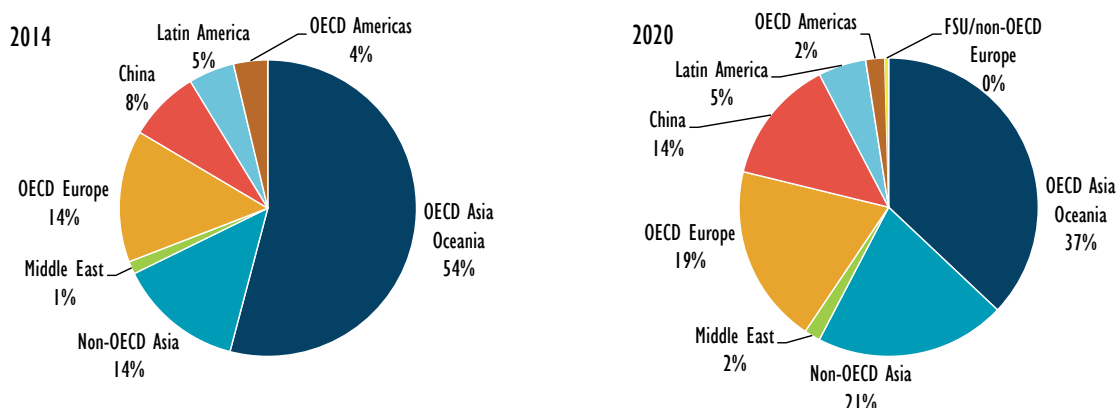
In non-OECD Asia, imports will become increasingly widespread across countries. Pakistan, Bangladesh, Philippines and Viet Nam will all join the club of LNG importers by 2020. Malaysia and Indonesia will start to use new import terminals, although often by rerouting their own domestic LNG production. India will take almost 12 bcm of additional gas compared with current levels.

China LNG imports are forecast to increase by 38 bcm, with the bulk of the additions occurring in the 2016-18 period, when incremental LNG supplies are also set to peak. Growing pipeline import capacity from Central Asia and Russia will result in slower LNG import growth in 2019/20.



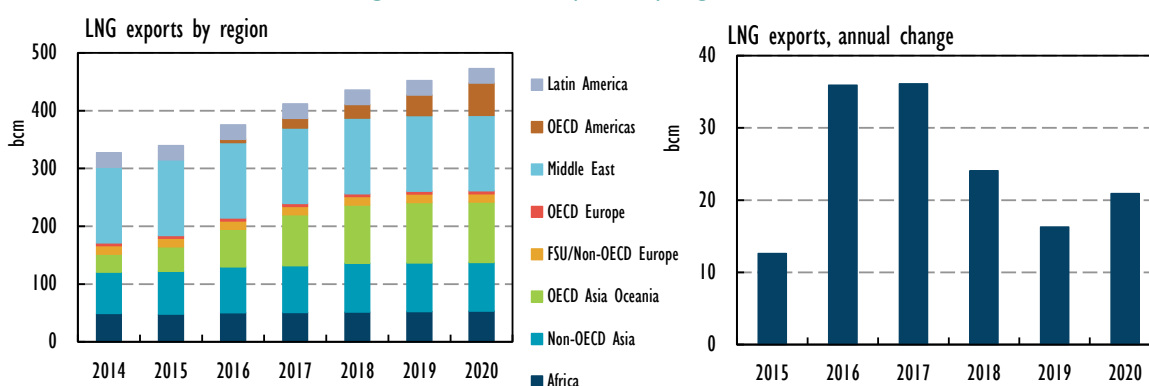
Europe will once again emerge as a residual market, importing what other regions do not take, due to its capability to arbitrage between pipeline and LNG flows. The region's imports will double approximately, reaching 91 bcm by 2020. As for China, incremental intakes in 2016/17 look particularly large, mirroring the surge in LNG supplies over those two years (Figure 4.13).

Figure 4.12 LNG imports by region, 2014-20



New LNG supplies will come primarily from OECD Asia Oceania and North America, on the back of surging volumes from Australia and then the United States. Together the two regions account for 90% of additional LNG exports between 2014 and 2020. The bulk of new supplies is set to come on the market in 2016/17, when more than 70 bcm are brought on line (see Figure 4.13).

Figure 4.13 LNG exports by region, 2014-20

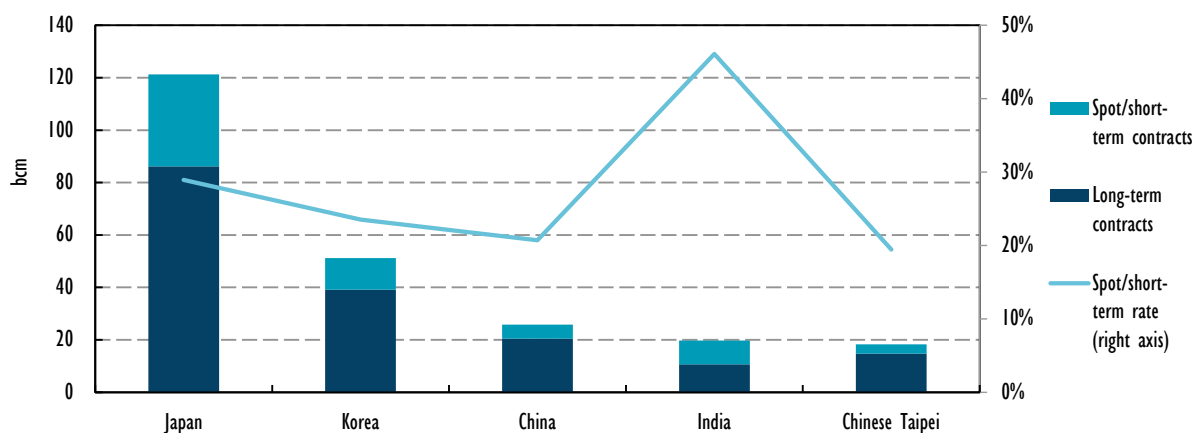


### Asian buyers look well supplied under long-term contracts

While spot purchases are growing, long-term contracts remain the backbone of the contract structure of LNG transactions. Asian countries, such as Japan, Korea and Chinese Taipei, are fundamentally short gas and consistent LNG buyers, procuring the bulk of their volumes under long-term contracts.

On average, major Asian LNG importers procured about 72% of their volumes through long-term contracts in 2014 (Figure 4.14). However, there are clearly differences across countries. India purchased just 54% of its LNG from Qatar, under the only long-term contract that it has in place, highlighting a higher than average reliance on spot purchases. In China and Chinese Taipei, the share of spot buying was around 20%, thus showing a decrease from the previous year and soft gas demand in both countries.

Figure 4.14 Contracted LNG volumes vs import volumes in 2014

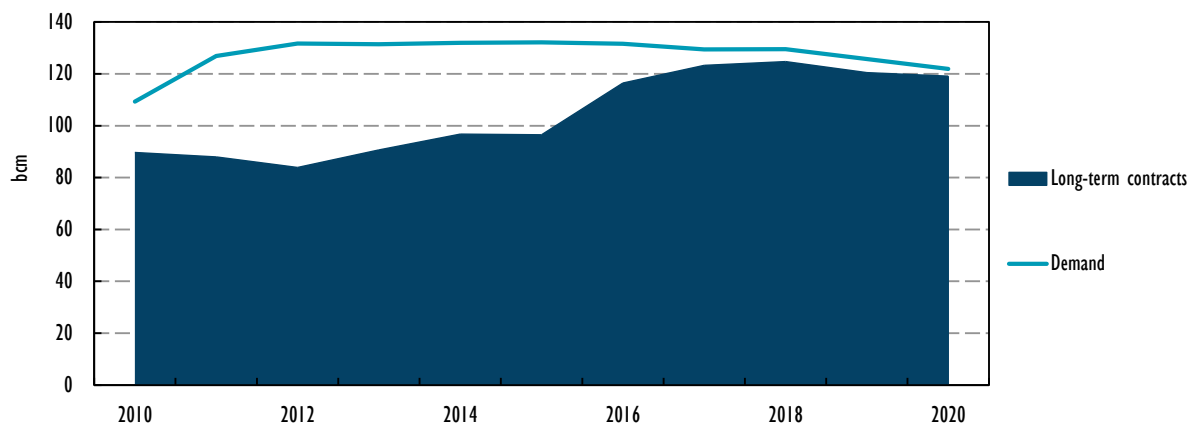


Source: IEA analysis based on GIIGNL (2015), *The LNG Industry in 2014*, GIIGNL, Paris, [www.giignl.org/sites/default/files/PUBLIC\\_AREA/Publications/giignl\\_2015\\_annual\\_report.pdf](http://www.giignl.org/sites/default/files/PUBLIC_AREA/Publications/giignl_2015_annual_report.pdf).

The relatively high share of spot transactions in Japan is a consequence of the country's gas demand upswing in the aftermath of Fukushima. Japan's long-term contracts in relation to its gas demand can be compared (Figure 4.15). Gas consumption increased rapidly after the 2011 nuclear accident, but this increase was met by spot transactions and short-term deals.

This situation will quickly change as purchased volumes under long-term contracts start growing rapidly from 2016 onwards, on the back of supplies secured from Australia and the United States. Even assuming a limited return of nuclear capacity, which underpins Japan's gas demand forecasts in this report, the country will barely need to tap into the spot market. Should nuclear capacity return faster than assumed, Japan looks significantly over-contracted for 2020, making the country likely to enter the spot market on the selling side. Either way, it is clear that the major role Japan played in the tightening of the spot market since 2011 is now in the process of unwinding.

Figure 4.15 Contracted LNG volumes vs gas demand in Japan, 2010-20



From the producer's side, most new projects under development are underpinned by long-term contracts. The six, new Australian LNG projects under construction have secured about 90% of their capacity under short- and long-term deals, of which 41% is contracted by Japanese companies, 22%

by Chinese, and the remainder by firms from Korea, Chinese Taipei and India. In the United States, 80% of the capacity of the four LNG projects under construction is underpinned by long-term off-take agreements. Asian buyers have subscribed large quantities, but European companies will also lift significant volumes, roughly equal to 30% of the capacity. This trend could indicate that US projects are attractive to European buyers, reflecting the proximity to European markets.

### Investment in LNG export infrastructure

Global LNG balances are easing fast. Throughout 2014, markets' concerns have shifted from how demand can be met to how supply can be absorbed. This topic will shape LNG markets over the next few years, with export capacity set to increase by more than 40%, or 164 bcm, between 2014 and 2020. Almost half of the additions will come on to the market in 2016 and 2017. A price-induced demand response will need to be triggered for such large incremental supplies to be absorbed.

Not only will new LNG liquefaction capacity increase, but average utilisation will also rise. Projects plagued by poor operational performance today will continue to struggle in the future. However, 90% of the new capacity will be located in the United States and Australia, which are expected to enjoy higher load factors than the current global average.

Lower oil prices pose little risk to the timing of projects already under construction. The Australian projects are at an advanced stage of development, while project sponsors in the United States have limited price exposure once off-take agreements have been signed. However, low oil prices will affect LNG projects which have not yet been sanctioned; companies have already pushed back final investment decision (FID) in a few cases.

Several large projects – mainly in Canada and East Africa – are due to go to FID in 2015 and 2016. If oil and gas prices do not recover, deferrals are likely. Meanwhile, the outlook for Russian LNG has deteriorated sharply due to Western sanctions and associated mounting financing difficulties. Yamal LNG is the only project with a real chance of being operational within the forecast horizon, but, with financing yet to be secured, this report conservatively assumes that it will be postponed until after 2020. No projects from Russia, Canada or East Africa are expected to be on line by 2020. The result is a more balanced market by 2019/20.

### *Second wave of LNG export capacity to hit the market over next two years*

Global LNG export capacity has almost doubled over the past 10 years, growing from 223 bcm in 2004 to 425 bcm in 2014. Of those additional 200 bcm, almost half came on line in 2009/10, largely on the back of Qatari additions (Figure 4.16).

Seven new countries started exporting LNG in the past 10 years, a significant increase from the preceding three decades where the number of LNG exporters was stable at 12. While Southeast Asia, Oceania, the Middle East and Africa were already dominant exporting regions, the start-up of liquefaction facilities in Russia, Norway and Peru has broadened the geographical scope of LNG trade.

After a massive capacity increase in 2009 and 2010, few additions followed between 2011 and 2013, when the average annual capacity increase was less than 10 bcm, with just one or two projects added each year. These low volumes would have gradually helped rebalance the LNG market following the

supply glut of 2009/10, but the unexpected surge in Japan's LNG demand in the aftermath of the Fukushima Daiichi nuclear accident vastly accelerated that process, tilting the market from balance to tightness. In 2014, three new projects started up with a total capacity of 27 bcm. This was almost three times the average addition of the previous three years.

Figure 4.16 Additional LNG export capacity by year, 2005-20

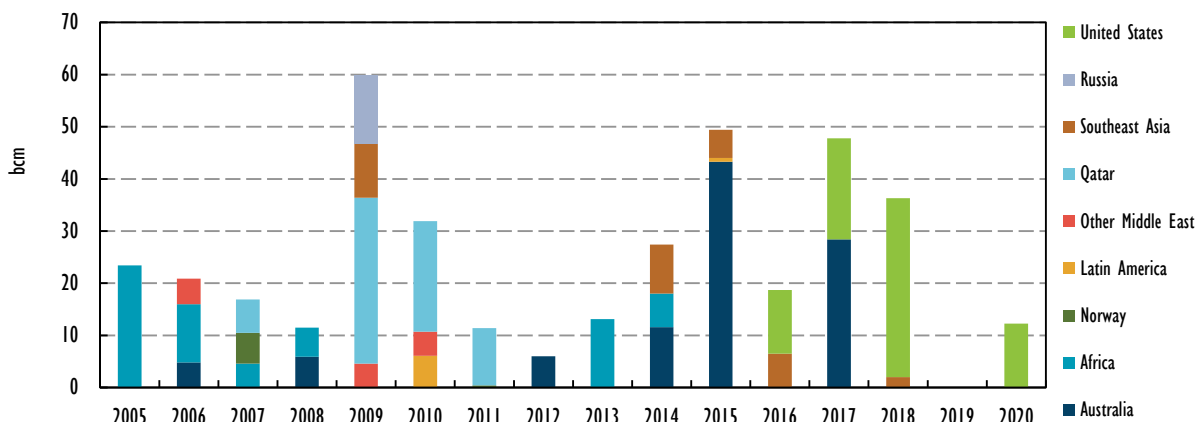


Table 4.2 LNG projects under construction (as of May 2015)

Country	Project	Capacity (bcm/yr)	Major stakeholders	Target online
Indonesia	Donggi Senoro LNG	2.7	Mitsubishi, Pertamina, Kogas, Medco	2015
Indonesia	Sengkang	2.7	Energy World Corporation	2015
Colombia	Caribbean FLNG	0.7	Pacific Rubiales, Exmar	2015
Malaysia	MLNG Train 9	4.9	Petronas	2015
Australia	Gorgon LNG	20.4	Chevron, Shell, Exxon Mobil	2015
Australia	Gladstone LNG	10.6	Santos, Petronas, Total, Kogas	2015
Australia	Australia Pacific LNG (APLNG)	12.2	ConocoPhillips, Origin, Sinopec	2015
Malaysia	PFLNG 1	1.6	Petronas, MISC	2016
United States	Sabine Pass LNG	24.5	Cheniere Energy	2016
Australia	Wheatstone	12.1	Chevron, Apache, KUFPEC	2016-17
Australia	Prelude FLNG	4.9	Shell, Inpex, Kogas	2017-17
Australia	Ichthys	11.4	Inpex, Total	2017-18
Russia	Yamal LNG*	22.4	Novatek, Total	2018+
Malaysia	PFLNG 2	2.1	Petronas, Murphy Oil Corporation	2018
United States	Cove Point LNG	7.1	Dominion	2018
United States	Cameron LNG	16.3	Sempra Energy	2018-19
United States	Freeport LNG	18.0	Freeport, Macquarie	2018-19
<b>Total</b>		<b>174.6</b>		

Note: FLNG = floating LNG. Although Yamal LNG is under construction, it is not assumed to be online by 2020.

Source: IEA compilation based on information from companies' website.

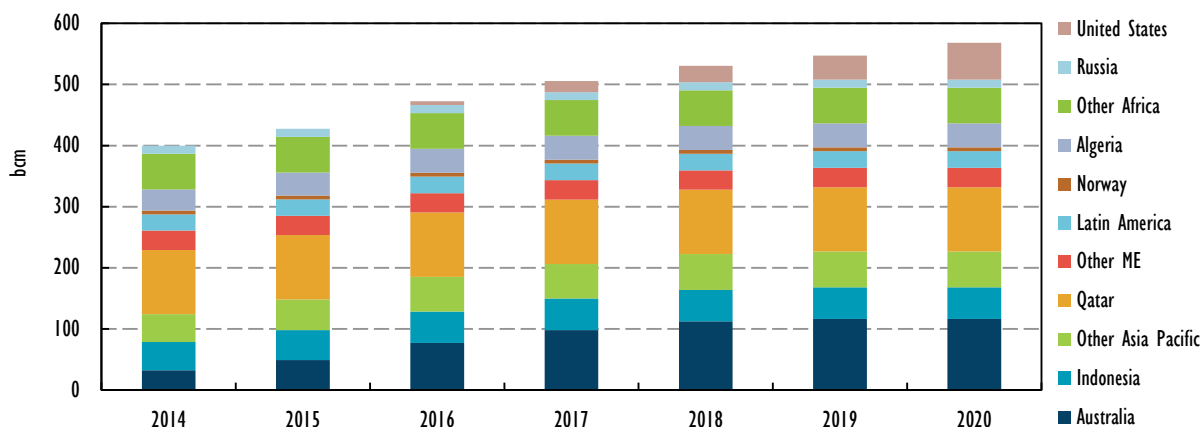
As of today, there are 17 new LNG projects under construction in the world with a total capacity of about 175 bcm per year (Table 4.2). Australia ranks as the major contributor to the additional volumes. Following the start-up of QCLNG in 2014, Gorgon LNG, Gladstone LNG and APLNG are

scheduled to start production this year. These three projects will add 43 bcm of LNG export capacity. Another 28.4 bcm will be operational in Australia by 2020, which will propel the country to the position of the world's largest LNG exporter.

The United States is the second largest contributor to additional LNG export capacity until 2020. There are currently four LNG projects under construction in the United States with a total capacity of 66 bcm per year, 87% of which will be on line by 2020. In addition, in May 2015, Cheniere took FID on two of its three trains Corpus Christi project. Construction work should start shortly and production is expected to begin before the end of the decade. The initial two trains have planned capacity of 12.3 bcm.

Four of the 17 projects under construction are FLNG units. Shell's Prelude FLNG in Australia was the first such project in the world to take FID in May 2011. Since then, FLNG has emerged as an attractive option mostly for developing small-scale plants. As well as Prelude, three other FLNG projects are under construction: one offshore Colombia and two offshore Malaysia, with export capacity ranging between 0.7 and 2.1 bcm per year, significantly smaller than conventional large-scale LNG plants.

Figure 4.17 LNG export capacity, 2014-20



Note: Ramp-up periods for new capacity are included.

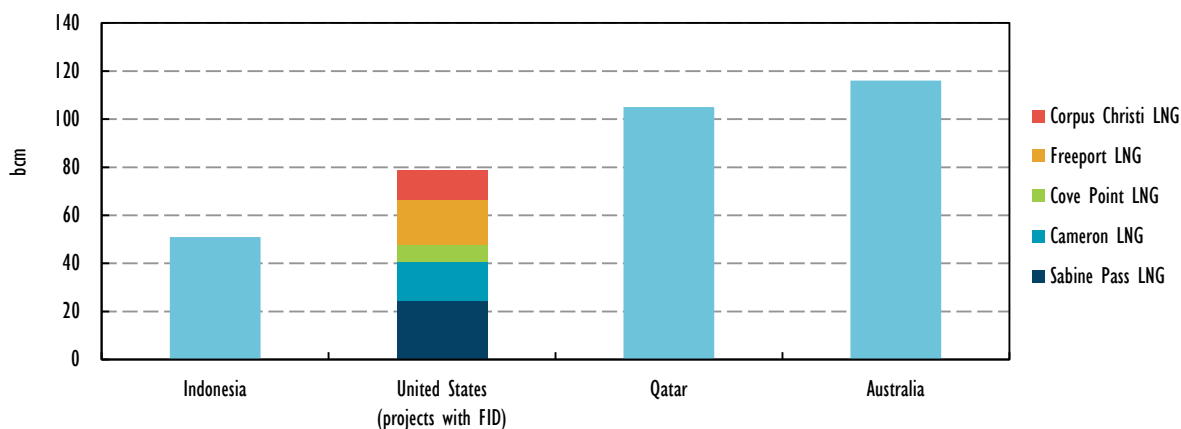
Considering ramp-up times, 164 bcm of additional LNG export capacity will be operational by 2020, thus taking the global total to 561 bcm. Of this, all, except the Corpus Christi project in the United States, is today under construction (Figure 4.17).

### *United States: On track to become the World's third largest exporter by 2020*

Up to May 2015, the US Department of Energy (US DOE) had received 54 LNG export applications totalling close to 480 bcm of LNG export capacity (Office of Fossil Energy, 2015). Of these, ten projects equal to 130 bcm have received authorisation to export to non-FTA countries. Four of them are under construction and on track for a pre-2020 start-up. A fifth project, Corpus Christi is also assumed to begin operations by the end of the decade. The United States is thus on track to become the world's third largest LNG exporter by 2020 (see Figure 4.18).

Despite the high number of pending applications, this report expects slow progress on projects that have not yet received FID.

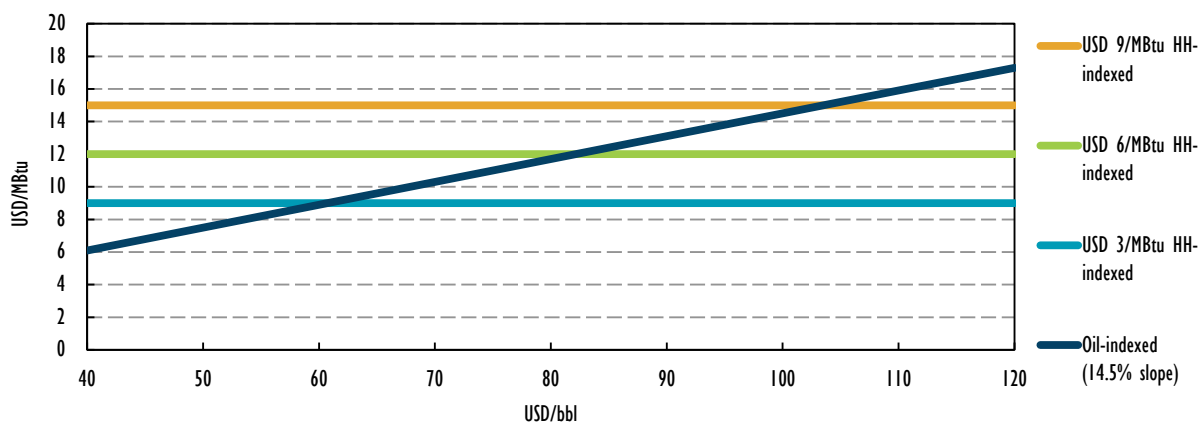
Figure 4.18 Top LNG export countries by 2020



Note: The ramp-up period of new capacity is not accounted for.

Lake Charles LNG and Jordan Cove LNG are not expected to be on line by 2020. While both projects have made some progress, it does not seem enough to shield them against the negative impact of low oil prices. Both projects have already obtained DOE approval, but they still lack FERC's authorisation. Jordan Cove LNG would be the first greenfield project on the West Coast of the United States and, as such, would not benefit from the existing large-scale infrastructure already developed in the Gulf Coast. It would also require the construction of a 368 km long pipeline to bring feed gas to the plant, which could face local environmental opposition. Conversely, Lake Charles had trouble with the financing, leading the owner, Energy Transfer Partners, to push back FID to 2016.

Figure 4.19 Comparison of oil-indexed and HH-indexed LNG price delivered to Asia



Projects in the United States will struggle to receive FID in today's low oil price environment. As greenfield liquefaction facilities require about four years from FID to start-up, there is a limited time window for new projects to be sanctioned so that they can begin operations before 2020. The key challenge is deteriorating interest on the buyers' side. US LNG projects with Henry Hub (HH) indexed pricing attracted many Asian customers between 2012 and mid-2014 when the average differential between a traditional oil-linked LNG contract and a US HH-linked one was about USD 6/ MBtu on a delivered basis to Asia. With the steep fall in oil prices, that price gap has evaporated. One can compare the economics of the two contract models for an Asian buyer (see Figure 4.19). The analysis

assumes a 14.5% slope for the oil-indexed price on a “delivered ex ship” (DES) basis. For the HH-indexed price, both the liquefaction fee and transportation cost are assumed equal to USD 3/MBtu. At current gas and oil prices, the economic advantage of US LNG disappears.

In addition to their reduced economic attractiveness, US LNG projects suffer from weaker than expected Asian demand. While not a US-specific disadvantage, lower consumption further reduces the chance of off-take agreements being signed.

### Canada: A darkened outlook

No Canadian LNG project will start production over the forecast horizon of this report. As of May 2015, 12 LNG projects have received approval by the National Energy Board (NEB), including US-based projects Jordan Cove and Oregon LNG. A further 15 applications are under review. All ten approved Canadian projects are located on the west coast, in the province of British Columbia (Table 4.3) (NEB, 2015). Spanish firm Repsol is planning to build an export terminal on the East coast of Canada, but has not yet received EB approval. The project would make use of Canada's sole existing LNG import facility. Before construction can start, all projects still require approval from the federal government and other provincial authorities as well as First Nations.

**Table 4.3** Canadian LNG projects with NEB approval as of May 2015

Project	Capacity (bcm/yr)	Major stakeholders	(Expected) FID	NEB's approval	Targeted online date
Kitimat LNG	13.6	Chevron, Apache	2014+	Oct 2011	2018+
LNG Canada	32.6	Shell, PetroChina, Kogas, Mitsubishi	2014+	Feb 2013	2019+
Pacific Northwest LNG	16.3+	Petronas, Japex, Petroleum Brunei, IOCL, Sinopec	2014	Dec 2013	2018+
Prince Rupert LNG	28.6	BG	2015	Dec 2013	2021+
WCC LNG	40.8	Imperial Oil, ExxonMobil	n/a	Dec 2013	2021+
Woodfibre LNG	2.9	Woodfibre	2015+	Dec 2013	2017+
Triton LNG (FLNG)	3.1	AltaGas, Idemitsu	2014+	Apr 2014	2017+
Aurora LNG	16.3+	CNOOC, INPEX, JGC	2015+	May 2014	2021+
Grassy Point LNG	27.2	Woodside Energy	2017	Jan 2015	2021+
WesPac LNG	4.1	WesPac Midstream	n/a	May 2015	2016+
<b>Total</b>	<b>185.5+</b>				

Note: CNOOC = China National Offshore Oil Corporation.

Source: IEA compilation based on information from companies' websites and NEB (2015), *LNG Export Licence Applications*, Government of Canada, Calgary, [www.neb-one.gc.ca/pplctnflng/mirpp/lnxprtlncc/index-eng.html](http://www.neb-one.gc.ca/pplctnflng/mirpp/lnxprtlncc/index-eng.html).

Despite their proximity to Asian markets, Canada's LNG projects are at a disadvantage to United States projects. US projects under construction today are all brown-field facilities, resulting in much lower capital costs per unit of capacity, as operators can leverage existing regasification infrastructure. By contrast, all but one of the proposed Canadian plants are greenfield units. Additionally, they also follow the traditional integrated upstream model whereby the LNG plant and the connected upstream asset are developed in an integrated fashion. This adds to the project's upfront costs and, for Canada, specifically dedicated pipelines must be built to connect LNG plants on the coast with inland gas fields in remote areas.



Procuring the required skilled labour is more difficult and costlier in this environment. Proceeding with such large cost items is challenging under any market condition, but the plunge in oil prices will certainly make companies think twice before pushing ahead. As a result, deferrals are likely. Not surprisingly, in late 2014, Pacific Northwest LNG, which was understood to be close to taking FID, announced it would postpone making a final decision on the project.

Lack of progress amid deteriorating market conditions has prompted the Canadian government to make concessions on the taxation front. In February 2014, the government of British Columbia proposed provincial LNG taxation which was heavily criticised for placing too much of a burden on the industry and thus undermining the competitiveness of West Coast projects. Fiscal terms were ultimately sweetened in the final version of the proposal unveiled in October 2014. Amid falling oil prices, the Canadian Federal government pushed through further investment-friendly policies in February 2015, agreeing to grant tax breaks to British Columbia projects and thus allowing LNG investors to recover capital costs more quickly.

### *East Africa: Not without challenges*

East Africa's proposed LNG projects are not expected to be on stream by 2020. In Mozambique, there are two large gas developments currently being targeted, one led by US-based Anadarko in Area 1 and the other by Italy-based Eni in Area 4. Both companies have appraised large gas deposits in their respective blocks, with total estimated recoverable resources of almost 5 trillion cubic metres (tcm).

The two companies have agreed to centralise their onshore LNG export projects in the peninsula area of Afungi, at the request of the Mozambique's government, feeding them with gas from both Area 1 and Area 4. Four trains are planned initially for the onshore LNG site with a total capacity of 27.2 bcm per year, which could then be expanded up to 68 bcm per year. Positively for the progress of the project, Anadarko has signed heads of agreement (HOA) with Asian customers for sales covering more than two-thirds of the capacity of its two trains. In May 2015, the company also selected the contractor for the initial phase of development.

Main point to watch for is whether the project is sanctioned over the next 12 months as this would leave the minimum time required for a 2020 start-up. The abundance of the region's resources and its proximity to some Asian markets are key competitive advantages of Mozambique's projects. However, these projects must cope with the remoteness of the location, and lack of basic infrastructure, making them high-risk projects. A regulatory framework, still in its infancy, comes as an additional challenge. Besides this onshore LNG project, Eni plans to build two FLNG projects in Area 4. The company has already awarded contracts for front-end engineering design (FEED) for the two FLNG facilities and is trying to complete the process and select the bidders during 2015 (IEA, 2014).

The United Republic of Tanzania lags behind Mozambique in terms of upstream and LNG developments. Statoil and BG Group, the two major companies involved in the country, plan to jointly develop an LNG export project, but details of the development plan are still lacking, although the Tanzanian government seems in favour of building an LNG-onshore facility. Meanwhile, the development of a proper legislative framework is also an issue. Long-awaited reform legislation has been postponed and with parliamentary and presidential elections due in October, decision-making might prove slow until political uncertainty clears.

### *Australia: Finally crossing the finishing line*

Australia is set to overtake Qatar as the world's largest LNG exporter over the forecast horizon of this report. There are currently 72 bcm of capacity under construction, on top of the 11.6 bcm which is ramping up at Queensland Curtis LNG (QCLNG). The scale of upcoming additions is impressive, considering that just one LNG project, North West Shelf LNG, was operating in the country until 2006. Large gas resources, mostly in Western Australia, led to an investment boom in the late 2000s.

After Gorgon LNG took FID in 2009, six other LNG projects were approved within 13 months. The massive construction activity that followed has been the root cause of the large cost overruns that have plagued the Australian LNG industry since. After a very painful journey, the end is finally in sight. All projects are now at an advanced stage of construction and on track to start up according to their revised timelines.

QCLNG came on stream at the end of 2014, and three other projects are due on line in 2015: Gorgon LNG, Gladstone LNG and APLNG. Once at full output, these four projects will lift Australia's total LNG export capacity by 55 bcm. After Wheatstone LNG, Prelude FLNG and Ichthys LNG are also brought on line and reach plateau, Australia's LNG export capacity will grow by another 28 bcm to reach 116 bcm per year. The country will then be the world's largest LNG exporter.

Projects that are currently not under construction continue to struggle with many delays and cancellations announced in the past 12 months. Browse FLNG driven by Australia-based Woodside Energy, illustrates well the difficulty to push new projects through. The proposed facility would exploit large gas reserves from three major fields. The original plan was to build an onshore terminal with four trains and capacity of 16 bcm per year with the potential for expansion to 34 bcm. The project was placed on hold in 2013 as it was deemed uneconomic due to rising labour costs and a strong Australian dollar. Woodside Energy then modified the design, scaled back the size, introduced a FLNG concept, and reduced capacity to 4.9 bcm per year. The project was targeting FEED in mid-2014 and to take FID in late 2015, but the timeline has slipped and FEED is now expected with at least a one-year delay.

Arrow LNG was formally shelved in January 2015. The project, a 50/50 joint venture between Shell and Petro-China envisioned construction of two trains with a capacity of 10.8 bcm in its first phase. A second phase would then have doubled capacity with the addition of two further trains. The project, based on development of coalbed methane resources (CBM), had been on the table for a long time. It was already in its planning stage when the other three Australian CBM-fed LNG projects at Gladstone in Queensland, which are today on or close to on stream, had yet to take FID.

The two project sponsors had initially planned to also be the off-takers of the total capacity of the facility. However, even after receiving state government approval in 2013, they did not move on with FID due to poor economics. Shell finally announced during the presentation of its Q4 results that it would not go ahead with the LNG plant and focus instead on the upstream portion of the project. Similarly, Bonaparte FLNG, driven by GDF Suez and Australia-based Santos, was finally scrapped in January 2015. The project sponsors have announced they will review alternative development options, including feeding gas resources via pipeline to the existing Darwin LNG project for backfill.

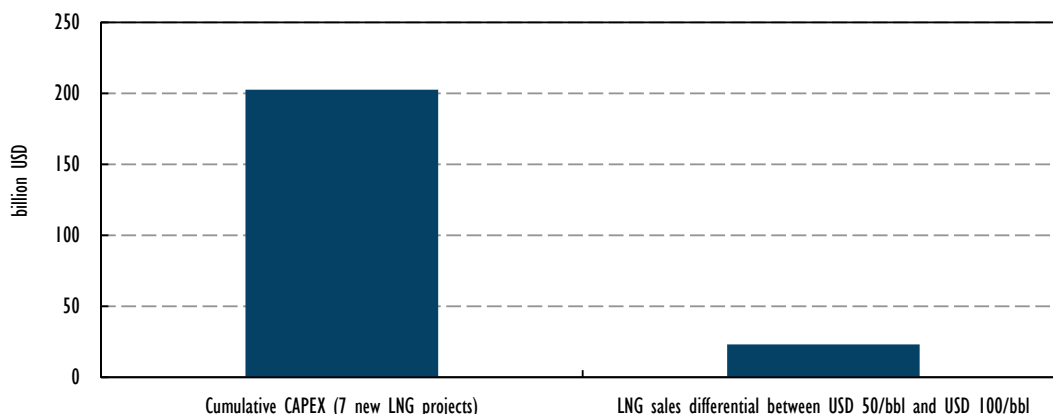
Expanding, existing LNG facilities will also prove difficult under current market conditions and persistent high labour costs in Australia; Gorgon LNG Train 4, Pluto LNG Train 2 and Darwin LNG Train 2 are unlikely

to be sanctioned quickly. Companies operating these projects have all announced capital expenditure cuts this year amid an ongoing, widespread cost reduction effort by the oil and gas industry.

On average, IOCs have announced CAPEX reductions in excess of 10% in 2015 while signalling further cuts, if prices remain low. Australia will deliver on the projects under construction, but after that, further expansion is set to stall. Not a single project has reached FID since 2012, and no real candidate for a go ahead can be singled out. Moreover, low oil prices will sharply lower the return on capital of projects soon to be on line whose volumes are sold on an oil price linked basis. This might discourage further investments. After years of large capital outflows and cost overruns, new projects may place output onto a market where prices are low and revenues are likely to come in well below target. The impact that low oil prices would have on projects' revenues can be put in perspective (Figure 4.20).

Assuming an average oil-index pricing formula with a 14.5% slope, an oil price drop of USD 50, from USD 100 to USD 50, would reduce projects' revenues by a USD 20 billion per year, or almost 10% of the cumulative capital expenditure of the new seven Australian projects.

**Figure 4.20** Revenue sensitivity to oil price changes for new Australian LNG projects



### *Russia: LNG strategy hit by economic and market realities*

The outlook for Russian LNG projects has deteriorated sharply as falling oil prices and financial sanctions are restricting project sponsors' ability to raise capital amid reduced cash flows. Weaker than expected Asian demand together with growing competition from other LNG producers add to the negative picture, calling into question the feasibility of the proposed plants.

Yamal LNG is the only project with a real chance to be developed by the 2020 forecast horizon of this report. The project's operator Novatek expects to produce 7.5 bcm by late 2017 or early 2018 when the first of three trains is due to become operational. All construction works are reportedly on schedule and 96% of the volumes have been sold. Yamal LNG is also not affected by technological sanctions.

All this is positive, but the key hurdle for the project is financing. The consortium has managed to secure funding for 2015, largely thanks to government's support arranged via funds from the National Wealth Fund, worth RUB 150 billion (about USD 2.5 billion). However, the problem is that, in the absence of extra cash flow commitments from the project stakeholders (Total, Novatek and CNPC), additional funds need to be raised. If no new shareholder enters the project, Chinese banks are likely to have to play the key role.

Reportedly, CNPC is seeking more favourable terms for its contracted LNG volume of 4 bcm in exchange for financing a higher share of the project. Overall, the consortium is understood to have committed funding worth about a third of the total estimated cost of USD 27 billion. If financing can be secured over the summer or by the end of the year at the latest, as the project's sponsors are hoping, Yamal LNG could well be on line before the end of the decade.

The Vladivostok LNG project seems slated for indefinite postponement in spite of Gazprom's plan to still launch it by 2018. The company has so far failed to secure commitments from buyers and support from foreign partners, both preconditions for the project to move on. Complicating the situation further, Gazprom faces a severe lack of funding. Gazprombank, which is due to finance the entire project, is on the US and EU sanction list and as such will struggle to raise finance at a reasonable cost.

To make headway in the LNG space, Gazprom's most competitive option would be to add a third train to its existing Sakhalin 2 facility. This would allow optimising existing infrastructure and lower costs substantially, compared with what would be the case with other proposed greenfield facilities. The FEED for the project is currently being drawn up and a final investment decision is due by the end of 2015 or in 2016. Gazprom has recently postponed the timeline of the project by two years, with the facility now expected on stream in 2021. Such a move suggests that the company might be rethinking its export strategy. Recent pipeline export deals and delays in progressing with LNG projects could indicate a shift away from a comprehensive export strategy to Asia towards one that clearly prioritises pipeline gas.

Rosneft's Far East LNG is also not expected to be on line by 2020. The main difficulty stems from the lack of access to the Sakhalin 2 pipeline, which Rosneft would need to ship gas from its Sakhalin-1 gas resources in the north to its LNG plant in the South. The capacity of Sakhalin 2 pipeline is reportedly about 18 bcm per year of which 16 bcm is needed to feed the Gazprom-led Sakhalin 2 LNG plant. Rosneft filed a suit against Sakhalin Energy to obtain access to the pipeline and is also looking for clarifications on the conditions for its expansion. The pipeline is not part of the state unified gas system, while the Sakhalin 2 project is covered by a production sharing agreement which exempts it from many aspects of the Russian legislation. Rosneft's request was recently rejected by a Russian court, but the company has signalled that it will appeal against the decision.

### *Other regions: Mini-scale LNG on the rise*

Outside the regions described in detail above, there is a cumulative 13 bcm of new LNG capacity expected to be built within the forecast horizon of this report, almost all located in Indonesia and Malaysia. Beyond what is currently under construction, South East Asia will face difficulties to expand its export capacity further as incremental production falls short of demand growth. Besides MLNG Train 9 in Malaysia, other projects are designed as mini-scale LNG facilities with capacity between 1.6 bcm to 2.7 bcm per year, highlighting a new tendency towards smaller, modular LNG facilities. Colombia is also planning to add a new, small LNG export unit with capacity of just 0.7 bcm per year, although the start-up of the project has been pushed back due to poor economics. The project, which is designed as FLNG, would have a capacity of less than 15% that of Shell's Prelude FLNG in Australia.

## Investment in LNG import infrastructure

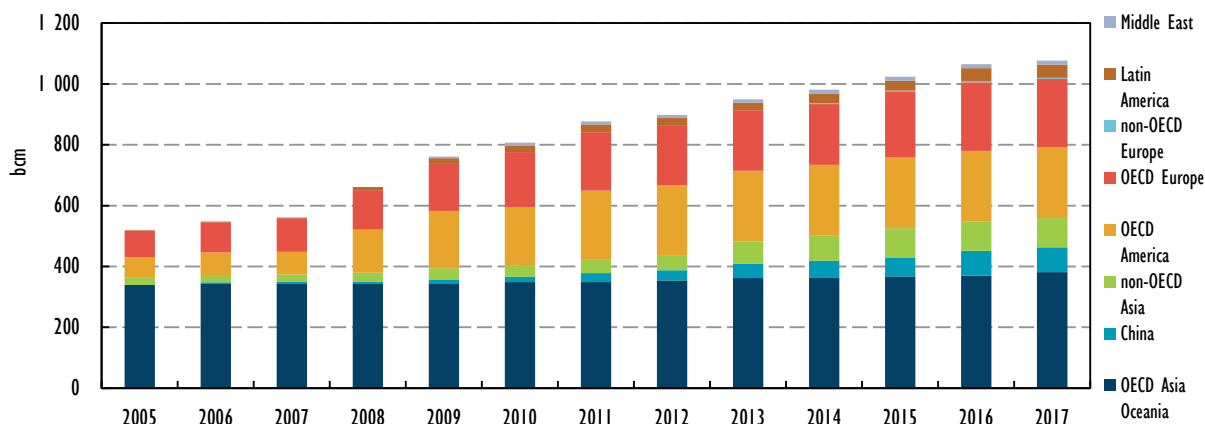
Global regasification capacity stood at 981 bcm in 2014, having nearly doubled over the past decade. With a global share of 37%, OECD Asia Oceania is the largest capacity holder among the regions. Its dominance has decreased notably since 2005, however, when it accounted for a much larger 65% of global regasification infrastructure. Such a decrease highlights the steady emergence of new LNG consumers. (Figure 4.21).

China's relevance as an LNG buyer has grown fast. The country has built 13 regasification terminals with a total capacity of 54 bcm in the space of a decade. Rapid expansion will continue. Seven new regasification terminals are currently under construction, all scheduled to be on line by 2017, when China's total LNG regasification capacity will exceed 80 bcm.

OECD America and OECD Europe hold sizeable LNG regasification capacity, but utilisation levels have plunged in both regions, due to unexpected positive changes in production (shale gas in the United States) and unexpected negative changes in demand (economic weakness and fast deployment of renewable energy). Looking ahead, OECD Americas, led by the United States, will make a radical shift from importer to exporter, with mirroring trends occurring in its underlying LNG infrastructure. By contrast, Europe's LNG import capacity will increase further, but mainly due to security of supply considerations or legacy investments. Additions in the region are skewed towards the early portion of the forecast period with the large Dunkirk terminal in France and the Swinoujscie plant in Poland due on line this year.

Non-OECD Asia and Latin America were important, but smaller contributors to global regasification capacity additions between 2005 and 2014, but their importance is set to grow. Non-OECD Asia LNG import capacity stood at 84 bcm in 2014, up 60 bcm since 2005, while Latin America's LNG import infrastructure increased to 33 bcm from 2 bcm in 2005. Both regions have shown a tendency to opt for FSRUs technology, due to shorter construction times, lower capital intensity and suitability to the geographical characteristics of several consuming countries in the region.

Figure 4.21 Global regasification capacity, 2005-17



## OECD regions

OECD regasification infrastructure has increased by a modest 10% over the past five years, pushing close to 800 bcm in 2014. Increases were similar in Europe and the Americas, with each region bringing 45 bcm of new regasification capacity on line. Since 2008, in Europe new terminals were

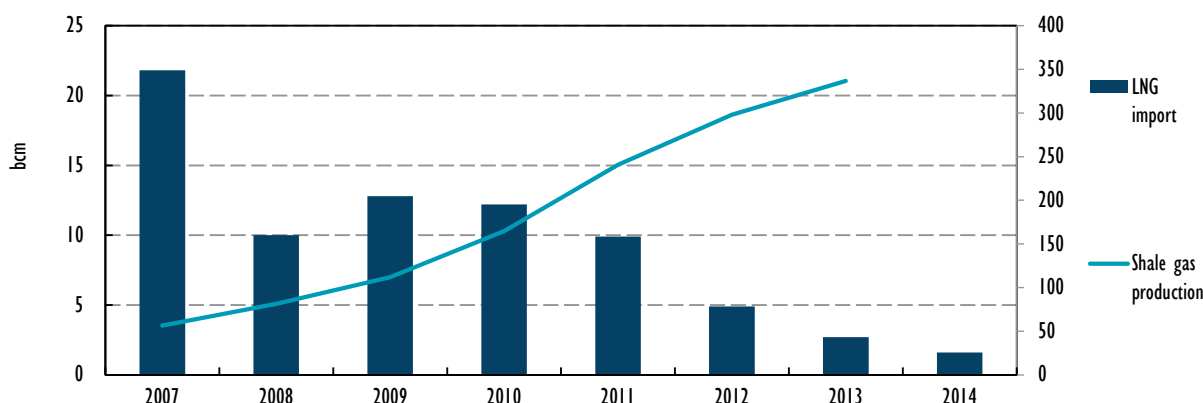
built in France, Italy, Netherlands, Norway, Portugal, Spain, Sweden and the United Kingdom. In OECD Americas, four new regasification terminals started up; however, for three (located in the United States), utilisation has dropped to a minimum as import needs have plunged. OECD Asia Oceania added 22 bcm of regasification capacity over the same period, recording the lowest rate of increase among the OECD regions, reflecting the already high import capacity, notably in Japan.

With the United States turning into an exporter and ample spare capacity available in Europe, OECD regasification infrastructure will grow very modestly until 2020. In North America, United States LNG imports fell by 20 bcm between 2007 and 2014 to virtually nil. (Figure 4.22). The overall drop in North American imports has been somewhat smaller due to sustained LNG intakes from Mexico and Chile, but it is clear that the US shale boom has made much of the region's import infrastructure redundant.

This regional trend will remain in place as growing US production is increasingly pushing south, thus helping displace Mexico's LNG imports. Bucking this trend, Chile's LNG imports are set to rise until 2020. As a consequence, the country is expanding capacity at one of its two existing import facilities, where works are scheduled to be completed in 2015. Capacity at the Quintero LNG terminal in central Chile will increase from the current 3.4 bcm per year to 5.1 bcm per year. Plans for further expansion to 6.8 bcm per year are under consideration. Several other projects are currently at the planning stage; all of them consider adopting a FSRU model.

In Europe, LNG import requirements will grow substantially until 2020, but they can be largely accommodated via greater use of existing facilities. Projects started during 2014/15 and the majority of those under active consideration aim to address country-specific security of supply risks rather than responding to broader market pressure.

**Figure 4.22** LNG import volumes vs shale gas production in the United States, 2007-14



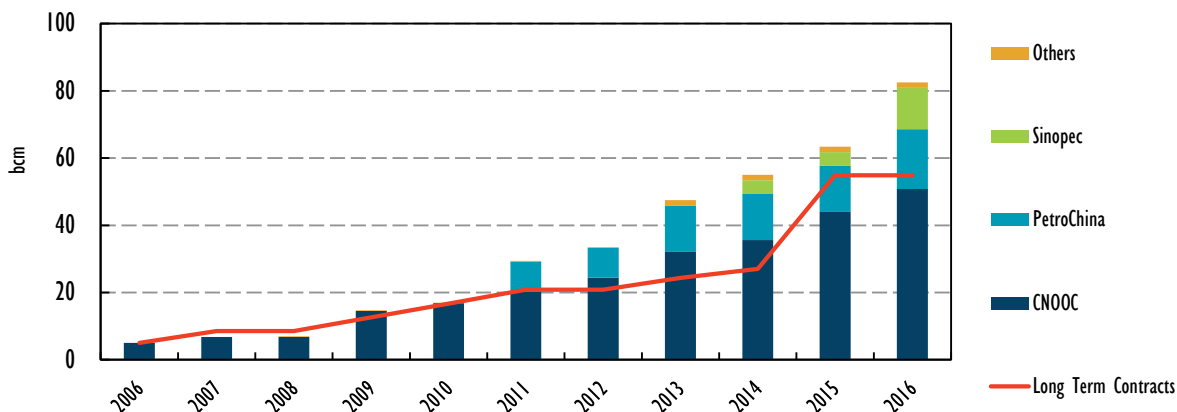
Source: IEA analysis based on EIA (2015), Natural Gas Gross Withdrawals and Production, EIA, Washington, D.C., [www.eia.gov/dnav/ng/ng\\_prod\\_sum\\_dc\\_u\\_nus\\_m.htm](http://www.eia.gov/dnav/ng/ng_prod_sum_dc_u_nus_m.htm).

### *China: Large capacity additions on the way*

In 2014, 30 bcm of new LNG regasification capacity came on line globally, 80% located in Asia. China added two receiving terminals, one in Shandong province, in the north, and one in Hainan province, in the far south, with a total capacity of 6.8 bcm per year. The start-up of the Qingdao LNG in Shandong marks Sinopec's entrance to the LNG import business, an activity so far dominated by China National Offshore Oil Corporation (CNOOC) and PetroChina.

The newly commissioned facility received its first cargo in December 2014 from the ExxonMobil-led PNG project. Exxon and Sinopec have a long-term contract in place for 2.7 bcm per year of LNG. There are currently seven regasification projects under construction in China. Two of these, with combined capacity of 8.5 bcm per year, are due on line this year in southern China. Once all the new projects start up, the total regasification capacity will exceed 80 bcm per year (Figure 4.23).

**Figure 4.23** LNG regasification capacity vs import volumes in China, 2006-16



### Non-OECD Asia: New importers enter the scene

#### India

India has four regasification terminals operating today, with a total capacity of 32 bcm per year. All the terminals are located on the country's west coast, where the pipeline network is developed and major demand centres are located. India started importing LNG in 2004 when state-owned Petronet brought the Dahej regasification terminal on line, in Gujarat, with an initial capacity of 6.8 bcm per year. A 25-year contract between Petronet and Rasgas has underpinned much of the imports into the terminal since. The facility was expanded to 13.6 bcm per year in 2009. Construction to add a second LNG jetty and accommodate larger vessels up to Q-Max size was concluded in 2014.

India's second LNG terminal, Hazira, came on line in 2005, with initial capacity of 3.4 bcm per year that was then expanded to 4.9bcm per year in 2008. The terminal located near Dahej is a joint venture between Shell (75%) and Total (25%). The terminal's imports are mainly sourced from Shell's global equity LNG portfolio via spot transactions (primarily from NWS in Australia and Oman). Shell is considering expanding the terminal capacity to 13.6 bcm per year, and a final investment decision is expected in 2015.

In 2013, two additional regasification terminals came on stream, Dabhol LNG and Kochi LNG. The former, with a capacity of 6.8 bcm per year, is operated by RGPPL, a joint venture between GAIL and NTPC, India's largest power company. The terminal serves as an entry point for gas into the western and southern parts of the country. The simultaneous commissioning of the Dhabol-Bangalore pipeline has allowed bringing gas from the terminal to Bangalore, India's a third most populous city located in southern India.



The Kochi LNG terminal in Kerala, operated by Petronet with a capacity of 3.4 bcm per year, came on line in mid-2013. The terminal is the southernmost of the country's four LNG facilities. However, its ability to supply the regional market is severely limited by a lack of pipeline connectivity. Construction of a 1 000 km pipeline linking the terminal to southern industrial hubs such as Bangalore and Mangalore is facing delays, which has resulted in underutilisation of the plant. Once the pipeline is operating, import volumes into Kochi should grow.

There are no new projects under construction as of today although several new facilities have been proposed and a few have reached a more advanced planning stage. In the current low price environment where the affordability of imported gas will improve, new LNG regasification facilities are likely to be sanctioned and be on line before 2020.

### Indonesia

Indonesia will have 15 bcm of operating regasification capacity from mid-2015. Lampung LNG, the country's second regasification terminal, was brought into operation in 2014. The facility is a FSRU chartered by Indonesia's state gas distributor Perusahaan Gas Negara (PGN) and anchored 6 km offshore Lampung in South Sumatra. It received its first cargo from the Tangguh project in July 2014. The facility is expected to feed the gas-hungry industrial sector in West Java through the South Sumatra West Java pipeline which is already in place.

The country's regasification capacity is set to grow further. Conversion of the Arun LNG liquefaction terminal in North Sumatra into a regasification unit has been completed and the plant received its first cargo from BP's Tangguh in February 2015. Import capacity of Arun is 4.1 bcm per year. Pertamina's agreement to buy 2 bcm of gas from Cheniere Energy's planned Corpus Christi LNG project with start-up in 2018/19 underscores the country's growing difficulty to meet demand increases with domestic production.

In the medium term, Indonesia's demand growth is projected to outstrip production growth by a substantial margin, resulting in the need for additional regasification capacity, particularly around West Java. Whether Indonesia will simply reroute more of its domestic production towards local consumption or tap into the global LNG markets is an open question. Either way, Indonesia's trade position will worsen with net exports expected to decline by 6 bcm between 2014 and 2020.

### Singapore

Singapore's Jurong LNG terminal became operational in March 2013, with initial capacity of 4.8 bcm per year. In January 2014, the terminal's capacity was expanded to 8.2 bcm per year. There are plans to bring the terminal's capacity to 15 bcm per year by 2018. Singapore also plans to build a second regasification facility in the near future, proof of its ambition to turn into an Asian LNG trading hub. The Jurong plant is Asia's first open-access terminal. Singapore is also looking into providing LNG bunkering services, building on its established position as a major bunkering port.

As of today, all the capacity at the terminal is managed by BG Group as sole aggregator. The Energy Market Authority (EMA) of Singapore is currently planning to secure up to two new LNG importers for the country's next allocation of LNG. In June 2014 it launched a request for approval (RFP) for the appointment of new importers. The process is ongoing and a final decision should be reached by the end of 2015.

## Malaysia

Malaysia turned into an LNG importer in April 2013. The LNG regasification terminal, located 3 kilometres offshore Melaka, is designed as an FSRU with capacity of 5.2 bcm per year. The terminal was built to cope with growing gas supply shortages and ensure security of supply to peninsular Malaysia (the main consuming region) as surrounding indigenous gas production is declining.

Petronas plans to build a second regasification terminal in Southern Johor with capacity of 4.8 bcm per year, aiming for completion in 2018. The procurement and construction contract (EPC) for the project was awarded at the end of 2014. In contrast to Indonesia, most of Malaysia's domestic demand is expected to be met by means of indigenous production. In particular, the start-up of the 4.9 bcm per year MLNG Train 9 liquefaction project in 2016 should allow full utilisation of the regasification and storage capacity at the Melaka terminal using the rerouting of Malaysia's own production.

## The Philippines

The Philippines are set to become an LNG importer this year. The Hong Kong based Energy World Corporation (EWC) is currently building the Pagbilao LNG terminal in the south of Luzon Island, with capacity of 4.1 bcm per year. The import project is tied to the construction of a 650 MW CCGT power plant adjacent to the regasification terminal. It seems, however, that only 200 MW will be ready in 2015 which may limit the amount of LNG intakes. EWC plans to initially supply the Pagbilao facility from its own Sengkang LNG liquefaction terminal in Indonesia, which is also expected to come on line this year. Further supplies will need to be secured as Sengkang has capacity of just 0.7 bcm per year.

Power generation accounts for nearly all of the Philippines' gas consumption. Thus, LNG imports are critically tied to the speed of increase in power demand. The country's total power capacity stands at just 16 GW, one of the lowest per capita rates in the region. The sole gas field in the country, located in Malampaya and operated by Shell, has been feeding power plants in the Luzon's Island for years. Yet, the field has now reached a plateau and production will decline in coming years. In the absence of new discoveries, the country's gas consumption will become reliant on LNG imports. Few LNG projects have been proposed, but lack of affordability of imported gas has proved a difficult obstacle to their development. The recent drop in gas prices could help some of them to move on.

## Thailand

Thailand is planning to expand its Map Ta Phut LNG receiving terminal, the second largest terminal in Southeast Asia which started operation in 2011. State-owned PTT is yet to take final investment decisions for the project, but it already awarded engineering, procurement and construction (EPC) contracts at the end of 2014. To meet the target start-up date of 2017 construction should start soon.

After the expansion, capacity of the terminal will double, reaching 13.6 bcm per year. Despite current low utilisation levels, Thailand's import needs are set to increase quickly as indigenous production will drop substantially over the next five years. Adding to the tightening domestic gas balance, LNG imports may also increase, if Thailand chooses to lower its high dependency on Myanmar gas. Starting this year, the Map Ta Phut terminal will receive 2.7 bcm per year of Qatari LNG, based on a 20-year, long-term contract between Qatargas and PTT. The latter also intends to source 2 bcm per year of LNG from Mozambique, once the project starts operating.

## Viet Nam

Viet Nam is also expected to become an LNG importer over the next five years. State-owned Petro Viet Nam is currently developing two regasification terminals: Thi Vai LNG with a capacity of 1.4 bcm per year, and Son My LNG with a capacity of 4.9 bcm per year. Both terminals will be located in southern Viet Nam. Thi Vai LNG is scheduled to come on line in 2017; and Son My LNG is expected to follow in 2020. The two projects will help provide flexible supplies to cope with swings in hydro generation which dominates the country's power generation mix. In Jun 2014, Petro Viet Nam and Shell signed a framework agreement for the supply of LNG to the Thi Vai terminal. They also signed a memorandum of understanding (MOU) to jointly develop the Son My LNG project.

## Pakistan

Pakistan had plans to import LNG as far back as 2005, but for many years no real progress was made. Things have finally started moving in earnest over the past 18 months. Elengy Terminal Pakistan Limited, a wholly owned subsidiary of Pakistan's largest conglomerate Engro Corporation, built the country's first regasification terminal at Port Qasim in Karachi.

Construction of the FSRU facility took less than 10 months, and the terminal took its first cargo in early 2015. Capacity currently stands at 2 bcm per year, but there are already plans to expand it to 5 bcm. The same company has now issued a tender for construction of a second FSRU unit.

Meanwhile, in October 2014, the Pakistan government announced it would build a regasification terminal at Port Gwadar, 100 km off the Iranian border, with a capacity of 7.1 bcm per year as well as a 700 km long pipeline between the terminal and Nawabshah city, near Karachi. Execution of the Gwadar-Nawabshah pipeline project would also open the possibility to transport gas from Iran in the future by extending the pipeline an additional 100 km to the Iranian border.

Natural gas plays a major role in Pakistan, accounting for approximately 50% of the country's total primary energy. Stagnating production and lack of import infrastructure are causing severe shortages, estimated at 20 bcm per year. Should the above-mentioned projects proceed, Pakistan may have as much as 15 bcm of LNG import capacity by 2020. With international gas prices now at levels competitive with Pakistan's domestic prices, the country might emerge as an important LNG importer.

## Bangladesh

Bangladesh is considering investing in LNG regasification capacity as a way to address worsening gas supply shortages. Gas plays a key role in the country's energy mix but robust consumption growth against stagnant production has caused shortages, often forcing rolling blackouts. In early 2014, the newly elected government decided to fast track construction of the country's first regasification terminal in an effort to address the worsening energy crisis and spur economic growth.

The project would be a FSRU with capacity of 6.8 bcm per year located in the Bay of Bengal. The plan is for imports to start in 2017 allowing gas to reach the Chittagong region, in southeastern Bangladesh. In mid-2014, Excelerate Energy was awarded a contract to design and build the unit. On top of this project, Bangladesh plans to build a second terminal, this time onshore, in Moheshkhali Island in the Bay of Bengal. The project is designed with capacity of 4.8 bcm per year. Currently Japan's Mitsui, India's Petronet and Shell have been shortlisted as potential contractors to build the plant.

## Chinese Taipei

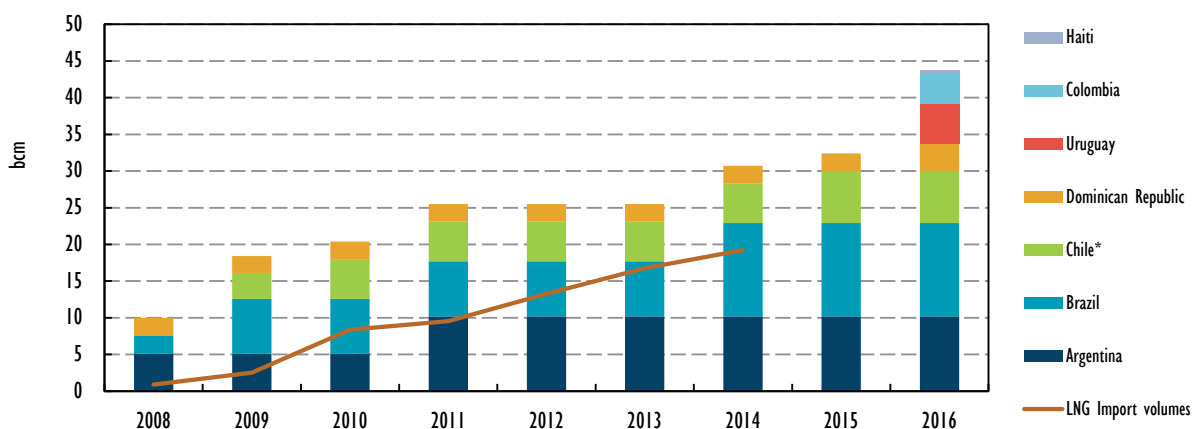
Chinese Taipei has two operating regasification facilities with a total capacity of 18.4 bcm per year. State-owned Chinese Petroleum Corporation (CPC) is the sole importer of LNG in Chinese Taipei, controlling all natural gas supply to the country. CPC is currently planning to build a third terminal at Datan in the northern part of the country to meet growing demand in the region.

## Latin America: FSRU technology dominates

### Argentina

Argentina currently has two regasification terminals totalling 10.2 bcm per year of capacity. The first facility was commissioned in 2008 and is located in Bahia Blanca, 640 km south of Buenos Aires. It is an LNG Regasification Vessel (LNGRV) chartered from Excelerate Energy with peak capacity of 5.1 bcm per year. It is basically a ship that can function as a traditional LNG carrier with a regasification facility attached.

Figure 4.24 LNG regasification capacity vs import volumes in Latin America, 2008-16



\* Chile is included in the gas balances of OECD Americas.

Due to continued gas shortages, the country commissioned a second LNGRV from Excelerate Energy, which started operations in 2011 (see Latin America section in Chapter 3). This facility, named Escobar LNG, with its annual peak capacity of 5.1 bcm per year is located 64 km outside Buenos Aires city. Since Argentina has currently no new terminal under construction or realistic plans to build one, higher utilisation rates of existing units by 2020 seem likely. This report forecasts a modest recovery in Argentina's gas production by the end of the decade. Should that not materialise, the country might well need to fast track the construction of a new terminal.

### Brazil

Brazil has three LNG receiving terminals with a total capacity of 12.7 bcm. All are FSRUs. The latest terminal, located in Bahia State in northeastern Brazil, came on line in 2014 and has a capacity of 5 bcm per year. There are several other LNG projects in the planning stage, the majority targeting additions in northeastern Brazil where supply shortages are increasing due to demand growth and lack of pipeline connection.

Brazil sources the majority of its imports via pipeline from Bolivia. LNG intakes have so far been used to balance out large demand swings tied to fluctuations in hydro availability which is Brazil's primary source of electricity generation. Pipeline connectivity will remain an issue in some states. LNG might increasingly meet base-load requirements there. Additionally, the sustainability of pipeline flows from Bolivia is called into question over the forecast horizon of this report (see Latin America section in Chapter 3). As a result, Brazilian LNG imports are set to increase through 2020 and additional import capacity will be required to fulfil those needs.

### Uruguay

Uruguay has no operating LNG regasification capacity currently, but the country's first terminal is under construction. Due to frequent supply disruptions caused by cutbacks in import flows from Argentina, Uruguay took the decision to build an LNG regasification terminal at Montevideo Bay in 2013. GDF Suez was selected to build and operate the terminal, which is scheduled to be on line in 2016. The facility will be an FSRU with capacity of 5.5 bcm per year, making it the world's largest FSRU upon commissioning. Capacity at the terminal will exceed Uruguay's projected demand. As a result, Uruguay's state-owned company Ancap has signed a MOU with Argentina's YPF for gas supplies equal to the amount of spare capacity at the terminal.

### Colombia

Colombia's first regasification terminal is under construction. It will be a FSRU with a capacity of 4.1 bcm per year located near the northern city of Cartagena on the Caribbean Sea. The facility is due to start operating in mid-2016. Colombia's gas production is plateauing and poised for a gentle decline over the forecast period which will increase import needs. The facility is set to play an important role as a source of gas for back-up power generation as the country's electricity system is heavily dependent on hydropower. Quite unusually, Colombia is simultaneously working on an LNG export project. The Caribbean FLNG project with capacity of 0.7 bcm per year is currently under construction in a dockyard in China. The plant was originally expected to start up in 2015, but commissioning has been postponed due to the recent fall in oil prices.

**Table 4.4** LNG regasification terminals came online in 2014

Country	Project	Capacity (bcm/y)	Major stakeholders
Brazil	Bahia LNG (FSRU)	5.2	Petrobras
China	Hainan LNG	2.7	CNOOC, Hainan Development Holdings
China	Qingdao LNG	4.1	Sinopec, Huaneng Group
Indonesia	Lampung LNG (FSRU)	3.8	Perusahaan Gas Negara (PGN)
Japan	Hibiki LNG	1.4	Saibu Gas, Kyushu Electric
Korea	Samcheok LNG	9.2	Kogas
Lithuania	Klaipeda LNG (FSRU)	3.0	Klaipėdos Nafta
Singapore	Jurong Island	3.4	Energy Market Authority
Sweden	Lysekil LNG	0.3	Skangass
<b>Total</b>		<b>33.1</b>	

Source: IEA compilation based on information from companies' websites.

**Table 4.5** LNG regasification terminals expected to come online in 2015

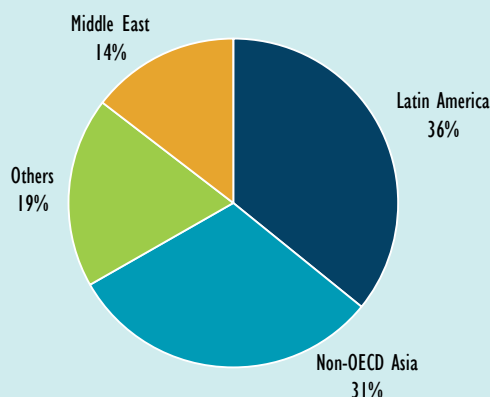
Country	Project	Capacity (bcm/yr)	Major stakeholders
Chile	Quintero expansion	1.7	GNL Quintero
China	Guangdong expansion phase3	3.1	CNOOC, BP
China	Shenzhen LNG	5.4	CNOOC, Shenzhen Energy
France	Dunkirk LNG	13.0	EDF, Fluxys, Total
Indonesia	Arun LNG conversion (FSRU)	4.1	Pertamina, ExxonMobil, JILCO
Japan	Hitachi LNG	1.4	Tokyo Gas
Jordan	Aqaba LNG (FSRU)	4.8	Hashemite Kingdom of Jordan
Pakistan	Mashal LNG (FSRU)	2.0	Sui Southern Gas Company
Philippines	Pagbilao LNG	4.1	Energy World Corporation (EWC)
Poland	Polskie LNG	4.9	PGNiG
<b>Total</b>		<b>44.5</b>	

Source: IEA compilation based on information from companies' websites.

#### Box 4.2 FSRU: Increasingly fashionable trend

Offshore floating technology is not new to the petroleum industry. Floating production, storage and offloading (FPSO) vessels have been in operations for oil developments since the 1970s, proving instrumental in developing fields far offshore and in deep seas. As the LNG industry started to grow and demand mushroomed in new regions, floating technology began receiving attention.

Gulf Gateway, the world's first FSRU import terminal, commenced operations off the coast of Louisiana in the Gulf of Mexico in March 2005. From 2008, use of the technology really started to take off. There are currently 17 FSRU in operation globally and at least two under construction. Floating regasification capacity is 74 bcm per year, accounting for about 7% of the world's total. With many FSRU projects under consideration globally, both the volume and share of FSRU capacity are likely to increase further.

**Figure 4.25** Share of Operating FSRU by region

FSRU are particularly popular in Latin America, the Middle East and non-OECD Asia (Figure 4.25). These regions account for the bulk of additional LNG imports and show a clear preference for FSRU technology. In Latin America, countries with multiple terminals and substantial regasification capacity, like Brazil and Argentina, exclusively employ FSRU technology.

### Box 4.2 FSRU: Increasingly fashionable trend (continued)

The employment of FSRU technology brings a number of specific advantages. First and foremost, it has lower upfront capital costs relative to a traditional on-land terminal. While the size of the capacity is clearly a key factor, capital costs for an onshore facility are in the range of USD 1 billion. By contrast, FSRU costs are substantially lower ranging between less than USD 100 million to USD 300-400 million. Costs are lower when conversion of an existing LNG carrier is used and when no additional marine and onshore infrastructure is needed.

A second important advantage is the shorter construction time. For an existing vessel moored at a suitable site, it can take less than a year. For a new FSRU, it can require up to three years, which is however substantially less than the three to five years typical of a traditional on-land facility.

A third, important advantage is the flexibility embedded in the technology. Should a country that opted for an FSRU no longer require the capacity, the unit can be removed without the need of large-scale works and be shipped elsewhere, if still in good condition. Diverting the FSRU to different sites can also be done on a temporary basis, usually to address upswings in consumption during the peak demand season.

FSRU technology also comes with disadvantages. It has limited capacity for regasification and storage compared with onshore terminals and, if capacity needs expanding, another FSRU has to be added. Weather and marine conditions can also affect the operation of an FSRU and under adverse weather, such as typhoons or heavy storms, the FSRUs may need to be evacuated (JOGMEC, 2013).

While the history of FSRU technology only spans ten years, recent trends show a clear increase in its deployment, particularly in regions where most of the additional import demand will be generated.

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# THE ESSENTIALS

**Table 5.1** World gas demand by region and key country (bcm)

Country	2000	2010	2014*	2016	2018	2020
OECD Europe	473	567	458	489	493	500
<i>G4</i>	298	325	249	269	268	269
<i>Western Europe</i>	399	462	353	378	378	379
<i>Central and Southeast Europe</i>	60	88	93	98	103	108
OECD Americas	794	850	945	968	991	1006
<i>United States</i>	661	682	751	767	780	788
OECD Asia Oceania	132	198	237	242	243	245
<i>Japan</i>	84	109	132	130	126	123
Africa	57	106	123	131	139	147
<i>Algeria</i>	20	27	35	38	40	43
<i>Egypt</i>	18	44	50	53	55	58
Non-OECD Asia (excl. China)	153	289	298	315	335	355
<i>India</i>	27	64	52	57	63	69
<i>ASEAN</i>	87	150	168	176	186	195
China	28	110	178	219	270	314
FSU/non-OECD Europe	597	680	674	668	673	679
<i>Russia</i>	391	466	464	455	456	458
<i>Caspian Region</i>	81	106	122	127	130	134
<i>Non-OECD Europe</i>	30	31	28	27	27	27
Latin America	96	152	168	169	177	186
<i>Brazil</i>	9	27	42	37	41	45
Middle East	176	368	414	435	464	493
<i>Iran</i>	62	144	155	162	171	182
<i>Qatar</i>	11	26	41	40	43	46
<i>Saudi Arabia</i>	38	73	83	91	100	106
<b>Total</b>	<b>2 505</b>	<b>3 320</b>	<b>3 495</b>	<b>3 635</b>	<b>3 785</b>	<b>3 926</b>

Notes : G4: France, Germany, Italy and the United Kingdom.

Western Europe: Austria, Belgium, France, Germany, Ireland, Italy, Luxembourg, the Netherlands, Portugal, Spain, United Kingdom, Switzerland.

Central and Southeast Europe: Czech Republic, Estonia, Greece, Hungary, Poland, Slovak Republic, Slovenia and Turkey.

ASEAN: Brunei Darussalam, Cambodia, Indonesia, Laos, Malaysia, Myanmar, Philippines, Singapore, Thailand and Viet Nam.

China includes Hong Kong.

Caspian region: Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyz Republic, Tajikistan, Turkmenistan, Uzbekistan.

Non-OECD Europe: Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Gibraltar, Latvia, Lithuania, Former Yugoslav Republic of Macedonia, Malta, Montenegro, Romania, Serbia.

\* 2014 figures are estimates. Figures can be different compared to previous reports due to statistical differences, rounding and stock changes.

Table 5.2 World sectoral gas demand by region (bcm)

Country	2000	2010	2014	2016	2018	2020
OECD Europe	473	567	458	489	493	500
<i>Residential-commercial</i>	188	221	180	197	196	194
<i>Industry</i>	137	121	118	121	123	125
<i>Power generation</i>	124	196	132	143	148	155
OECD Americas	794	850	945	968	991	1006
<i>Residential-commercial</i>	263	255	274	254	254	254
<i>Industry</i>	236	182	203	216	222	226
<i>Power generation</i>	190	275	316	341	352	356
OECD Asia Oceania	132	198	237	242	243	245
<i>Residential-commercial</i>	35	50	51	51	52	52
<i>Industry</i>	22	29	35	37	39	42
<i>Power generation</i>	70	103	135	135	131	128
Africa	57	106	123	131	139	147
<i>Residential-commercial</i>	4	6	10	11	11	12
<i>Industry</i>	12	26	27	28	29	29
<i>Power generation</i>	28	55	66	73	79	86
Non-OECD Asia (excl. China)	153	289	298	315	335	355
<i>Residential-commercial</i>	7	15	19	20	21	22
<i>Industry</i>	44	79	90	97	105	113
<i>Power generation</i>	68	146	140	150	161	171
China	28	110	178	219	270	314
<i>Residential-commercial</i>	5	30	49	60	70	79
<i>Industry</i>	11	31	55	66	80	92
<i>Power generation</i>	6	25	32	42	56	67
FSU/non-OECD Europe	597	680	674	668	673	679
<i>Residential-commercial</i>	113	111	102	102	103	104
<i>Industry</i>	91	118	114	110	109	110
<i>Power generation</i>	319	349	368	367	370	374
Latin America	96	152	168	169	177	186
<i>Residential-commercial</i>	11	14	17	18	19	20
<i>Industry</i>	33	57	53	53	54	55
<i>Power generation</i>	24	43	58	57	63	69
Middle East	176	368	414	435	464	493
<i>Residential-commercial</i>	23	48	48	48	49	50
<i>Industry</i>	58	121	138	142	150	158
<i>Power generation</i>	78	157	178	191	208	225
<b>Total</b>	<b>2 505</b>	<b>3 320</b>	<b>3 495</b>	<b>3 635</b>	<b>3 785</b>	<b>3 926</b>

Note: 2014 figures are estimates. Figures can be different compared to previous reports due to statistical differences, rounding and stock changes. This table does not show other sectors such as energy industry own use, transport and losses. The industry sector includes gas use by fertiliser producers.

**Table 5.3** World gas production by region and key country (bcm)

Country	2000	2010	2014	2016	2018	2020
OECD Europe	302	301	254	246	238	227
<i>Norway</i>	54	107	113	113	112	111
OECD Americas	758	815	937	966	1011	1057
<i>United States</i>	544	603	723	755	797	837
OECD Asia Oceania	42	61	82	126	159	167
<i>Australia</i>	33	49	65	106	140	145
Africa	126	209	203	209	216	225
<i>Algeria</i>	82	85	83	86	89	93
<i>Egypt</i>	18	57	50	51	52	54
Non-OECD Asia (excl. China)	223	334	324	330	339	345
<i>India</i>	28	51	33	34	35	38
<i>ASEAN</i>	159	216	220	222	229	233
China	27	95	124	141	156	171
FSU/non-OECD Europe	724	840	869	874	889	930
<i>Russia</i>	573	657	645	646	644	654
<i>Caspian Region</i>	118	150	191	194	211	242
<i>Non-OECD Europe</i>	14	13	13	13	13	12
Latin America	105	161	178	180	183	185
<i>Argentina</i>	41	42	39	39	40	41
<i>Brazil</i>	7	15	23	26	29	31
Middle East	198	462	546	566	593	621
<i>Iran</i>	59	144	161	167	176	185
<i>Qatar</i>	24	121	163	165	168	171
<i>Saudi Arabia</i>	38	73	83	91	100	106
<b>Total</b>	<b>2 505</b>	<b>3 279</b>	<b>3 517</b>	<b>3 638</b>	<b>3 785</b>	<b>3 927</b>

Notes: 2014 figures are estimates. Figures can be different compared to previous reports due to statistical differences, rounding and stock changes.  
G4: France, Germany, Italy and the United Kingdom.

Western Europe: Austria, Belgium, France, Germany, Ireland, Italy, Luxembourg, the Netherlands, Portugal, Spain, United Kingdom, Switzerland.

Central and Southeast Europe: Czech Republic, Estonia, Greece, Hungary, Poland, Slovak Republic, Slovenia and Turkey.

ASEAN: Brunei Darussalam, Cambodia, Indonesia, Laos, Malaysia, Myanmar, Philippines, Singapore, Thailand and Viet Nam.

China includes Hong Kong.

Caspian region: Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyz Republic, Tajikistan, Turkmenistan, Uzbekistan.

Non-OECD Europe: Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Gibraltar, Latvia, Lithuania, Former Yugoslav Republic of Macedonia, Malta, Montenegro, Romania, Serbia.

**Table 5.4** Fuel prices (USD/MBtu)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
<b>Natural gas</b>										
Henry Hub	8.84	6.75	6.98	8.86	3.95	4.39	4.00	2.75	3.73	4.39
NBP	7.34	7.64	6.03	10.74	4.77	6.56	9.02	9.48	10.64	8.25
German border price	5.83	7.88	8.00	11.61	8.53	8.03	10.62	11.09	10.73	9.11
Japan LNG	6.02	7.12	7.74	12.66	9.04	10.90	14.78	16.70	16.05	16.25
<b>Oil</b>										
WTI	9.73	11.38	12.46	17.18	10.63	13.69	16.36	16.23	16.88	16.01
Brent	9.38	11.23	12.50	16.72	10.60	13.70	19.18	19.25	18.73	17.07
JCC	8.79	11.05	11.90	17.65	10.45	13.65	18.81	19.79	19.03	18.14
<b>Coal</b>										
US Appalachian	2.38	2.09	1.81	4.27	2.07	2.67	3.07	2.43	2.46	2.42
NW European steamcoal	2.55	2.69	3.72	6.18	2.96	3.82	5.10	3.89	3.43	3.16
Asian coal marker	2.60	2.37	3.55	6.22	3.31	4.43	5.28	4.43	3.82	3.27

**Table 5.5** Relative fuel prices (HH 2004/WTI 2004/US APP 2004 = 1)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
<b>Natural gas</b>										
Henry Hub	1.50	1.14	1.18	1.50	0.67	0.74	0.68	0.47	0.63	0.74
NBP	1.24	1.30	1.02	1.82	0.81	1.11	1.53	1.61	1.80	1.40
German border price	0.99	1.33	1.36	1.97	1.45	1.36	1.78	1.85	1.82	1.54
Japan LNG	1.02	1.21	1.31	2.15	1.53	1.85	2.50	2.83	2.72	2.75
<b>Oil</b>										
WTI	1.36	1.59	1.74	2.40	1.49	1.92	2.29	2.27	2.36	2.24
Brent	1.31	1.57	1.75	2.34	1.48	1.92	2.69	2.70	2.62	2.39
JCC	1.23	1.55	1.67	2.47	1.46	1.91	2.63	2.77	2.66	2.54
<b>Coal</b>										
US Appalachian	1.00	0.88	0.76	1.80	0.87	1.12	1.29	1.05	1.03	1.02
NW European steam coal	1.07	1.13	1.57	2.60	1.24	1.63	2.15	1.63	1.44	1.33
Asian Coal marker	1.09	1.00	1.49	2.62	1.39	1.86	2.22	1.86	1.61	1.38

Notes: All prices are yearly averages of their respective average monthly prices. To convert oil prices in USD/bbl, the prices in USD/MBtu have to be multiplied by 5.8. To convert coal prices in USD/tonne (6 000 kcal), the prices in USD/MBtu have to be multiplied by 23.8.

Sources: IEA, ICE, German Customs, Japanese Customs, EIA, Bloomberg, McCloskey, Federal Reserve and European Central Bank.

**Table 5.6** LNG liquefaction (bcm per year, existing, under construction)

Region	Operation	Construction
<b>Asia</b>	<b>136</b>	<b>87</b>
<i>Australia</i>	44	73
<i>Brunei</i>	10	-
<i>Indonesia</i>	40	5
<i>Malaysia</i>	33	9
<i>Papua New Guinea</i>	9	-
<b>Middle East</b>	<b>137</b>	<b>-</b>
<i>Abu Dhabi</i>	8	-
<i>Oman</i>	15	-
<i>Qatar</i>	105	-
<i>Yemen</i>	9	-
<b>Europe</b>	<b>6</b>	<b>-</b>
<i>Norway</i>	6	-
<b>FSU/non-OECD Europe</b>	<b>13</b>	<b>22</b>
<i>Russia</i>	13	22
<b>Africa</b>	<b>97</b>	<b>-</b>
<i>Algeria</i>	39	-
<i>Angola</i>	7	-
<i>Egypt</i>	16	-
<i>Equatorial Guinea</i>	5	-
<i>Nigeria</i>	30	-
<b>OECD Americas</b>	<b>-</b>	<b>66</b>
<i>United States</i>	-	66
<b>Latin America</b>	<b>26</b>	<b>1</b>
<i>Colombia</i>	-	1
<i>Peru</i>	6	-
<i>Trinidad and Tobago</i>	20	-
<b>Total</b>	<b>415</b>	<b>176</b>

**Table 5.7** LNG regasification (bcm per year, existing, under construction)

Region	Operation	Construction
<b>OECD Asia Oceania</b>	<b>366</b>	<b>18</b>
<i>Israel</i>	2	-
<i>Japan</i>	263	7
<i>Korea</i>	101	12
<b>Non-OECD Asia (excl. China)</b>	<b>82</b>	<b>4</b>
<i>Chinese Taipei</i>	14	-
<i>India</i>	32	-
<i>Indonesia</i>	11	-
<i>Malaysia</i>	5	-
<i>Pakistan</i>	5	-
<i>Philippines</i>	-	4
<i>Singapore</i>	8	-
<i>Thailand</i>	7	-
<b>China</b>	<b>54</b>	<b>28</b>
<b>OECD Europe</b>	<b>200</b>	<b>18</b>
<i>Belgium</i>	9	-
<i>France</i>	25	13
<i>Finland</i>	-	0.3
<i>Greece</i>	5	-
<i>Italy</i>	16	-
<i>Netherlands</i>	12	-
<i>Poland</i>	-	5
<i>Portugal</i>	8	-
<i>Spain</i>	60	-
<i>Sweden</i>	0.6	-
<i>Turkey</i>	13	-
<i>United Kingdom</i>	51	-
<b>FSU/non-OECD Europe</b>	<b>3</b>	<b>-</b>
<i>Lithuania</i>	3	-
<b>Middle East &amp; Africa</b>	<b>18</b>	<b>8</b>
<i>Jordan</i>	-	8
<i>Kuwait</i>	8	-
<i>United Arab Emirates</i>	4	-
<i>Egypt</i>	6	-
<b>OECD Americas</b>	<b>232</b>	<b>-</b>
<i>Canada</i>	10	-
<i>Chile</i>	5	2
<i>Mexico</i>	23	-
<i>Puerto Rico</i>	4	-
<i>United States</i>	195	-
<b>Latin America</b>	<b>30</b>	<b>13</b>
<i>Argentina</i>	10	-
<i>Brazil</i>	13	-
<i>Colombia</i>	-	4
<i>Dominican Republic</i>	2	1
<i>Haiti</i>	0	0.4
<i>Uruguay</i>	-	6
<b>Total</b>	<b>984</b>	<b>89</b>

Note: The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

# GLOSSARY

## Regional and country groupings

### *Africa*

Algeria, Angola, Benin, Botswana, Cameroon, Congo, Democratic Republic of Congo, Côte d'Ivoire, Egypt, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Libya, Morocco, Mozambique, Namibia, Nigeria, Senegal, South Africa, Sudan, United Republic of Tanzania, Togo, Tunisia, Zambia, Zimbabwe and other African countries (Burkina Faso, Burundi, Cape Verde, Central African Republic, Chad, Comoros, Djibouti, Equatorial Guinea, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Mauritius, Niger, Reunion, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Swaziland and Uganda).

### *China*

Refers to the People's Republic of China, including Hong Kong.

### *Europe and Mediterranean*

Includes non-OECD Europe/Eurasia, OECD Europe and North Africa regional groupings.

### *Latin America*

Argentina, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, the Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Trinidad and Tobago, Uruguay, Venezuela and other Latin American countries (Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermudas, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands (Malvinas), French Guyana, Grenada, Guadeloupe, Guyana, Martinique, Montserrat, St. Kitts and Nevis, Saint Lucia, Saint Pierre et Miquelon, St. Vincent and the Grenadines, Suriname and Turks and Caicos Islands).

### *Non-OECD Europe/Eurasia*

Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Georgia, Kazakhstan, Kyrgyz Republic, Latvia, Lithuania, the Former Yugoslav Republic of Macedonia, Moldova, Romania, Russian Federation, Serbia, Tajikistan, Turkmenistan, Ukraine and Uzbekistan.

### *North Africa*

Algeria, Egypt, Libya, Morocco and Tunisia.

### *OECD*

Includes OECD Europe, OECD Americas and OECD Asia Oceania regional groupings.

### *OECD Americas*

Canada, Chile, Mexico and United States.

### *OECD Asia Oceania*

Australia, Japan, Korea and New Zealand. For statistical reasons, this region also includes Israel.<sup>8</sup>

<sup>8</sup> The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

## OECD Europe

Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, Netherlands, Norway, Poland, Portugal, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey and United Kingdom.

## Other developing Asia

Non-OECD Asia regional grouping excluding China and India.

## List of acronyms, abbreviations and units of measure

### Acronyms and abbreviations

ACER	Agency for Cooperation of Energy Regulators
CAAGR	compounded average annual growth rate
CAPEX	capital expenditure
CBM	coalbed methane
CCGT	combined-cycle gas turbines
CEF	Connecting Europe Facility
CENACE	National Center of Energy Control (Mexico)
CENAGAS	National Natural Gas Control Center (Mexico)
CFE	Federal Commission of Electricity (Mexico)
CHP	combined heat and power
CNH	Comisión Nacional de Hidrocarburos
CNOOC	China National Offshore Oil Corporation
CO <sub>2</sub>	carbon dioxide
CPC	Chinese Petroleum Corporation
CTG	coal-to-gas
DOE	Department of Energy
EBITDA	earnings before interest, taxes, depreciation, and amortisation
EC	European Commission
EFSI	European Fund for Strategic Investments
EIA	Energy Information Administration
EIB	European Investments Bank
EMA	Energy Market Authority
ENTSOG	European network of transmission system operators for gas
EPA	Environmental Protection Agency
EPC	Engineering, procurement and construction
EU ETS	European Union Emission Trading System
EWC	Energy World Corporation
FEED	front-end engineering and design
FERC	Federal Energy Regulation Commission
FID	final investment decision
FLNG	floating LNG
FPSO	floating production, storage and offloading
FPU	floating production unit
FSRU	floating storage regasification unit
FSU	Former Soviet Union



GDP	gross domestic product
Geq	Groningen gas equivalent
GTL	gas-to-liquids
GTS	Gasunie Transport Services
HH	Henry Hub
H-gas	high calorific gas
HOA	heads of agreement
IDD	Indonesia deepwater development
IGA	intergovernmental agreements
IMF	International Monetary Fund
IOC	international oil companies
IPP	independent power producer
KRG	Kurdistan Regional Government
L-gas	low-calorific gas
LNG	liquefied natural gas
LNGRV	LNG regasification vessel
MATS	mercury and air toxics standards
MOU	memorandum of understanding
NDRC	National Development Reform Commission
NEA	National Energy Administration
NEB	National Energy Board
NGL	natural gas liquids
NGV	natural gas vehicle
NOC	national oil company
NRA	Nuclear Regulation Authority
NWE	Northwest Europe
OCTP	offshore cape three point
OECD	Organisation for Economic Co-operation and Development
PCI	projects of common interest
PEFC	Programme for the Endorsement of Forest Certification
PGN	Perusahaan Gas Negara
PHCN	Power Holding Company of Nigeria
PIB	petroleum industry bill
PM	particulate matter
PNG LNG	Papua New Guinea
PSC	production sharing contracts
SEE	Southeast Europe
SFM	sustainable forest management
SKV	Sakhalin-Khabarovsk-Vladivostok pipeline
SWE	Southwest Europe
TPA	third-party access
WHO	World Health Organization
WTO	World Trade Organization
YPFB	Yacimientos Petrolíferos Fiscales Bolivianos

*Units of measure*

bbl	barrel
bcm	billion cubic metre
bcm/yr	billion cubic metres per year
Bt	billion tonnes
GW	gigawatt
kcal	kilocalories
kcm	thousand cubic metres
km	kilometre
m <sup>3</sup>	cubic metre
MBtu	million British thermal units
MJ	megajoule
Mt	million tonnes
Mtpa	million tonnes per annum
MW	megawatt
MWh	megawatt/hour
tcm	trillion cubic metres
TWh	terawatt hour

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# GAS

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Global natural gas demand remained weak in 2014, falling well below its ten-year average. High prices for gas in the past two years undermined its competitiveness, bringing to light a harsh reality: in a world of cheap coal and falling costs for renewables, gas has laboured to compete. Although Asia has been regarded as an engine of future gas demand growth, the fuel has struggled to expand its share of the market in many parts of the region. This has raised questions over the viability of gas as an attractive strategic option across Asia.

The context for gas markets is changing rapidly, however. Falling oil prices have resulted in much lower gas prices in many parts of the world. As a result, gas demand is enjoying the tailwind of substantial price drops while the upstream sector is suffering amid large capital expenditure cuts. The interaction of these opposing effects on gas markets is examined in the IEA *Medium-Term Gas Market Report 2015*, which provides a detailed analysis of global demand, supply and trade developments through 2020. The impact on global gas markets of Russia's strategic shift in its gas export policy and the rising tide of liquefied natural gas supplies are given careful consideration. Two special insights also feature in this report. The first analyses the progress Europe has made in strengthening its gas infrastructure since 2010 and the major bottlenecks that still remain in enhancing the security of supply in the region. The second takes a close look at reforms to the gas and electricity sector in Mexico, investigating their impacts on North American gas markets.

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