

Overview

Consumption of natural gas worldwide is projected to increase from 120 trillion cubic feet (Tcf) in 2012 to 203 Tcf in 2040 in the *International Energy Outlook 2016* (IEO2016) Reference case. By energy source, natural gas accounts for the largest increase in world primary energy consumption. Abundant natural gas resources and robust production contribute to the strong competitive position of natural gas among other resources. Natural gas remains a key fuel in the electric power sector and in the industrial sector. In the power sector, natural gas is an attractive choice for new generating plants because of its fuel efficiency. Natural gas also burns cleaner than coal or petroleum products, and as more governments begin implementing national or regional plans to reduce carbon dioxide (CO<sub>2</sub>) emissions, they may encourage the use of natural gas to displace more carbon-intensive coal and liquid fuels.

World consumption of natural gas for industrial uses increases by an average of 1.7%/year, and natural gas consumption in the electric power sector increases by 2.2%/year, from 2012 to 2040 in the IEO2016 Reference case. The industrial and electric power sectors together account for 73% of the total increase in world natural gas consumption, and they account for about 74% of total natural gas consumption through 2040.

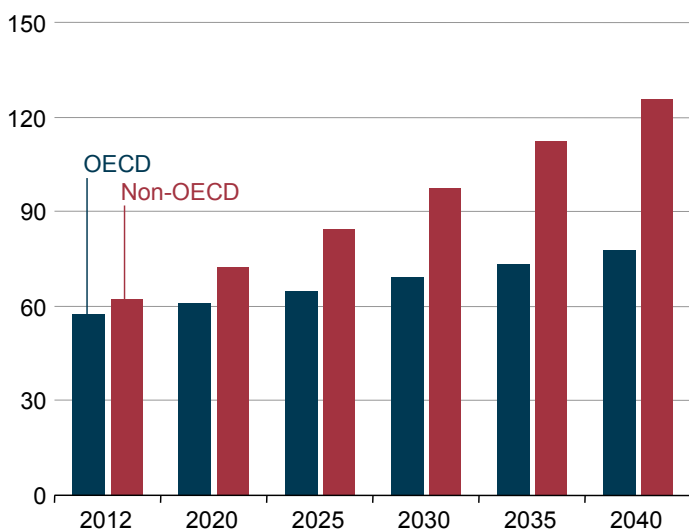
Consumption of natural gas increases in every IEO region, with demand in nations outside the Organization for Economic Cooperation and Development (non-OECD) increasing more than twice as fast as in the OECD (Figure 3-1). The strongest growth in natural gas consumption is projected for the countries of non-OECD Asia, where economic growth leads to increased demand. Natural gas consumption in the non-OECD region grows by an average of 2.5%/year from 2012 to 2040, compared with 1.1%/year in the OECD countries. As a result, non-OECD countries account for 76% of the total world increment in natural gas consumption, and their share of world natural gas use grows from 52% in 2012 to 62% in 2040.

To meet the rising natural gas demand projected in the IEO2016 Reference case, the world’s natural gas producers increase supplies by nearly 69% from 2012 to 2040. The largest increases in natural gas production from 2012 to 2040 occur in non-OECD Asia (18.7 Tcf), the Middle East (16.6 Tcf), and the OECD Americas (15.5 Tcf) (Figure 3-2). In China alone, production increases by 15.0 Tcf as the country expands development of its shale resources. The United States and Russia increase natural gas production by 11.3 Tcf and by 10.0 Tcf, respectively. In Russia, production growth is supported primarily by increasing development of resources in the country’s Arctic and eastern regions. U.S. production growth comes mainly from shale resources. Total natural gas production in China, the United States, and Russia accounts for nearly 44% of the overall increase in world natural gas production.

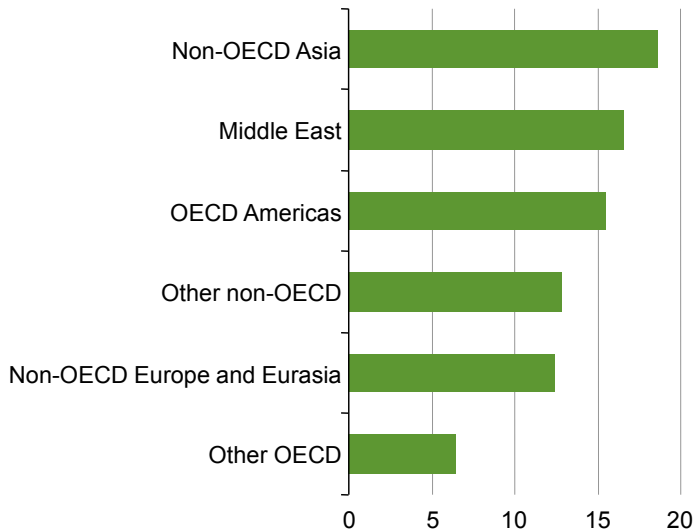
Although there is more to learn about the extent of the world’s tight gas, shale gas, and coalbed methane resource base, the IEO2016 Reference case projects a substantial increase in those supplies—especially in China, the United States, and Canada (Figure 3-3). The application of horizontal drilling and hydraulic fracturing technologies has made it possible to develop the U.S. shale gas resource, contributing to a near doubling of estimates for total U.S. technically recoverable natural gas resources over the past decade. Shale gas accounts for more than half of U.S. natural gas production in the IEO2016 Reference case, and tight gas, shale gas, and coalbed methane resources in Canada and China account for about 80% of total production in 2040 in those countries.

Liquefied natural gas (LNG) accounts for a growing share of world natural gas trade in the Reference case. World LNG trade more than doubles, from about 12 Tcf in 2012 to 29 Tcf in 2040. Most of the increase in liquefaction capacity occurs in Australia and North America, where a multitude of new liquefaction projects are planned or under construction, many of which will become

**Figure 3-1. World natural gas consumption, 2012–40 (trillion cubic feet)**



**Figure 3-2. World increase in natural gas production by country grouping, 2012–40 (trillion cubic feet)**



operational within the next decade. At the same time, existing facilities in North Africa and Southeast Asia have been underutilized or are shutting down because of production declines at many of the older fields associated with the liquefaction facilities, and because domestic natural gas consumption is more highly valued than exports.

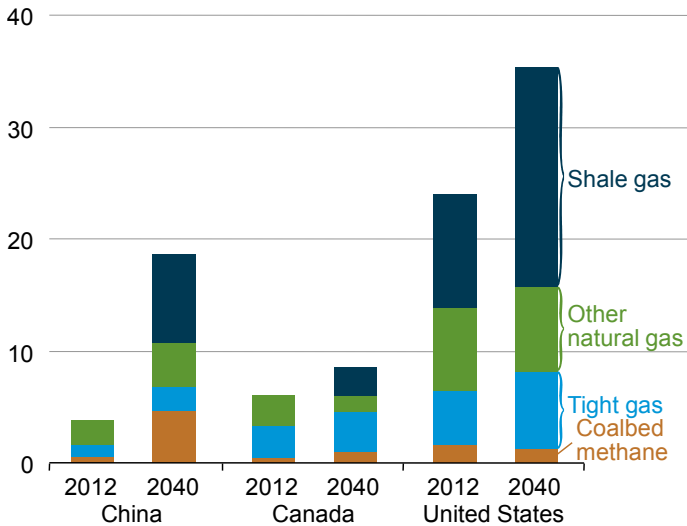
## OECD natural gas consumption

### OECD Americas

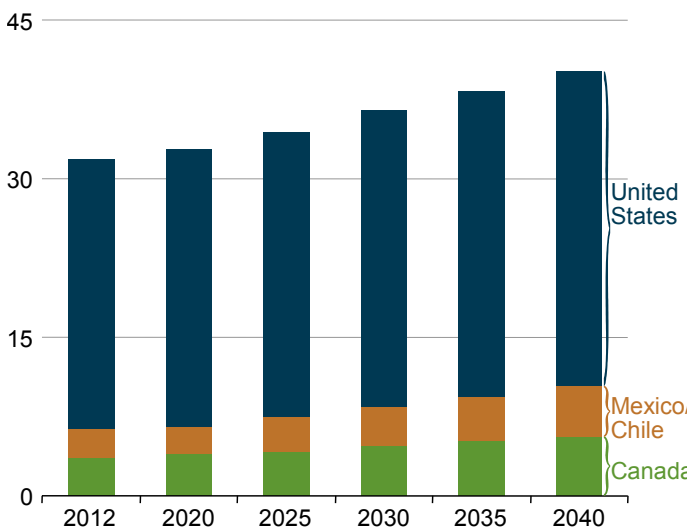
Annual natural gas consumption in the OECD Americas region rises steadily to 40.1 Tcf in 2040 (Figure 3-4), including increases of 1.0 Tcf from 2012 to 2020 (0.4%/year) and 7.3 Tcf from 2020 to 2040 (1.0%/year). The OECD Americas region accounts for 41% of the total increase in natural gas use by OECD countries and 13% of the increase in total world natural gas consumption over the projection period.

The United States—the world’s largest consumer of natural gas—leads the OECD Americas region in annual natural gas consumption growth with an increase of 4.2 Tcf from 2012 to 2040, or 51% of the region’s total increase (Figure 3-5). While the recently finalized Clean Power Plan (CPP) regulations in the United States are not included in the IEO2016 Reference case, its effects are considered in discussions, tables, and figures throughout the report, based on prior U.S. Energy Information Administration (EIA) analysis of the proposed rule that has similar elements. With implementation of the proposed CPP, U.S. natural gas consumption would be 1.7 Tcf higher in 2020 compared to the IEO2016 Reference case. Most of the increase in natural gas consumption would occur in the electric power sector as a substitute for coal-fired generation. After 2020, the effect of the CPP on natural gas use in the power sector decreases as generation from renewable energy increases. In 2040, projected U.S. natural gas consumption is 1.0 Tcf lower with the CPP than in the IEO2016 Reference case. Effects of the final CPP on natural-gas-fired generation will depend on natural gas prices, renewable technology costs, and state-level implementation decisions. An increase in natural gas use through 2040 is certainly possible in scenarios with low gas prices and implementation strategies that favor gas.

**Figure 3-3. Natural gas production by type in China, Canada, and the United States, 2012 and 2040 (trillion cubic feet)**



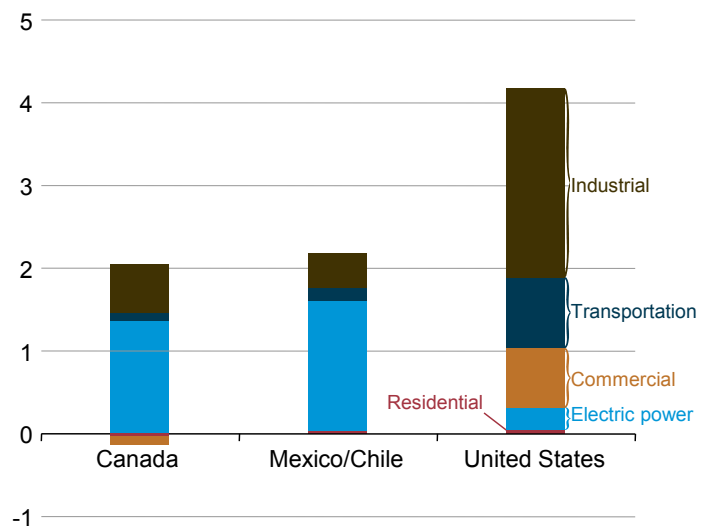
**Figure 3-4. OECD Americas natural gas consumption by country, 2012–40 (trillion cubic feet)**



Projections for combined annual natural gas consumption in Mexico and Chile include absolute growth in the two countries of 2.2 Tcf (26% of the OECD Americas total increase), followed by Canada with 1.9 Tcf (23% of the OECD Americas total increase). Increasingly, Mexico has met its growing demand for electricity with generation from natural gas-fired units, using natural gas imported by pipeline from the United States, particularly since 2011 as the growth of Mexico’s overall natural gas consumption has outstripped its domestic production growth. In the IEO2016 Reference case, the electric power sector accounts for 39% (3.2 Tcf) of the growth in natural gas consumption from 2012 to 2040 in the OECD Americas region, with 1.6 Tcf of the increase occurring in Mexico and Chile and 1.3 Tcf in Canada.

Effects of the final CPP on natural-gas-fired generation will depend on natural gas prices, renewable technology costs, and state-level implementation decisions. An increase in natural gas use through 2040 is certainly possible in scenarios with low gas prices and implementation strategies that favor gas.

**Figure 3-5. OECD Americas change in natural gas consumption by country and end-use sector, 2012–40 (trillion cubic feet)**



Natural gas use in the OECD Americas industrial sector grows by 1.4 Tcf from 2012 to 2020, with 1.3 Tcf (97%) added in the United States, where industrial consumption increases by an average of 1.8%/year. The growth of natural gas use in the U.S. industrial sector slows somewhat from 2020 to 2040 averaging 0.5%/year and increasing by a total of 1.0 Tcf over that period. In Canada, natural gas consumption in the industrial sector grows by an average of 0.2%/year from 2012 to 2020 and by 1.1%/year from 2020 to 2040. In the Mexico/Chile region, industrial sector natural gas use grows by averages of 0.1%/year from 2010 to 2020 and 1.2%/year from 2020 to 2040.

### OECD Europe

Natural gas consumption in the OECD Europe region grows by 1.3%/year on average, from 17.8 Tcf in 2012 to 25.3 Tcf in 2040 in the Reference case (Figure 3-6), with the electric power sector accounting for more than one-half (4.6 Tcf) of the total increase. The average increase of 3.6%/year in natural gas consumption for power generation from 2020 to 2040 is higher than for any other energy source used in the sector. The share of natural gas in the power generation mix is projected to grow, as older nuclear and coal-fired units will be gradually decommissioned and replaced primarily by new natural gas-fired and renewable capacity.

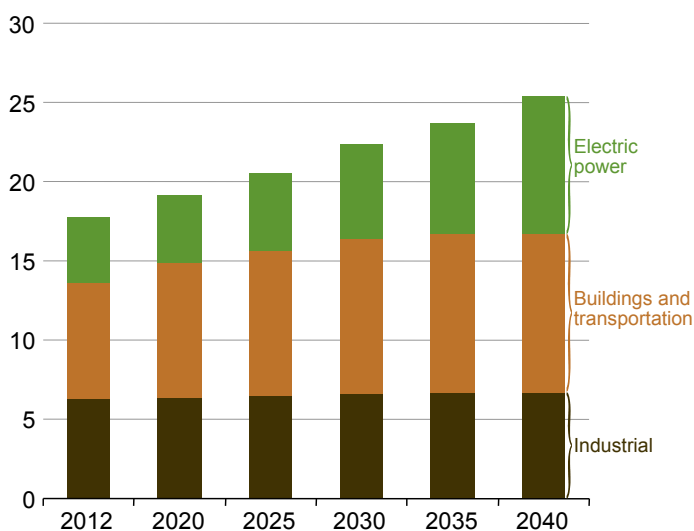
### OECD Asia

Natural gas consumption in OECD Asia grows by an average of 1.6%/year in the IEO2016 Reference case, from 7.9 Tcf in 2012 to 12.2 Tcf in 2040, with Japan's consumption increasing by an average of 0.9%/year. Japan has relied primarily on short-term and spot cargo shipments of LNG to offset the loss of nuclear generating capacity when a large part of its nuclear generation capacity was shut down after the Fukushima Daiichi power reactors were severely damaged by the March 2011 earthquake and tsunami. All but 2 of the country's 50 reactors remained offline as of January 2016,<sup>54</sup> and environmental concerns have led the government to encourage natural gas consumption, making LNG a fuel of choice for power generation to substitute for the lost nuclear generation. According to the International Gas Union, Japan operated 23 major LNG import terminals in 2014, including expansions and satellite terminals, with the total gas send-out capacity of 9 Tcf/year being well in excess of demand.<sup>55</sup> From 2020 to 2040, Japan's real GDP increases by an average of 0.5%/year, by far the lowest in the region, as a result of its declining population and aging work force. Although Japan's natural gas consumption does not slow between 2020 and 2040, its consumption of energy from liquids and coal does decline. As a result, the natural gas share of Japan's total energy consumption rises from 25% in 2020 to nearly 30% in 2040.

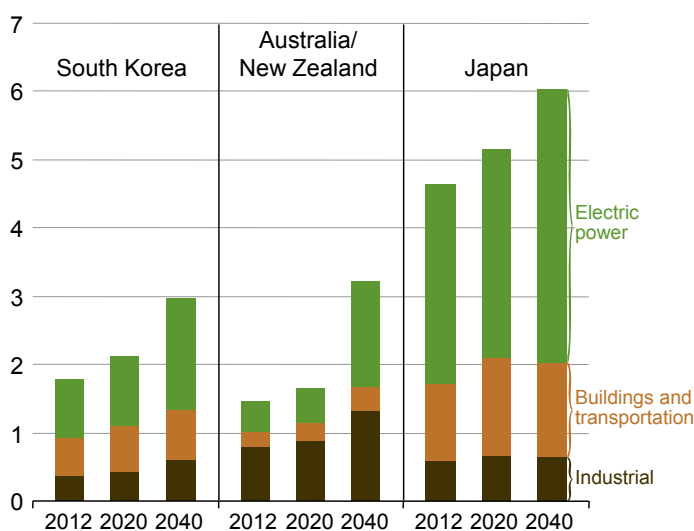
South Korea's natural gas consumption grows at average rates of 2.3%/year from 2012 to 2020 and 1.7%/year from 2020 to 2040 in the IEO2016 Reference case. Growth in demand for natural gas in the South Korea's industrial, residential, and commercial sectors slows, while in the electric power sector it remains above 2%/year throughout the 2012-40 period.

Australia and New Zealand have OECD Asia's strongest average annual growth in electricity sector natural gas consumption from 2012 to 2040 in the IEO2016 Reference case, averaging 4.6%/year and more than tripling, from 0.4 Tcf in 2012 to 1.5 Tcf in 2040 (Figure 3-7). Australia increases the share of natural gas in its power generation mix to reduce its more carbon-intensive coal-fired generation. The two countries' combined share of OECD Asia's total natural gas use for electricity generation grows from 10% in 2012 to 21% in 2040 in the IEO2016 Reference case.

**Figure 3-6. OECD Europe natural gas consumption by end-use sector, 2012–40 (trillion cubic feet)**



**Figure 3-7. OECD Asia natural gas consumption by country and end-use sector, 2012–40 (trillion cubic feet)**



<sup>54</sup>Nuclear Energy Institute, "Japan Nuclear Update" (Washington, DC: January 26, 2016), <http://www.nei.org/News-Media/News/Japan-Nuclear-Update>.

<sup>55</sup>International Gas Union, World LNG Report - 2015 Edition (Forenbu, Norway: 2015), pp. 79-81, [http://www.igu.org/sites/default/files/node-page-field\\_file/IGU-World%20LNG%20Report-2015%20Edition.pdf](http://www.igu.org/sites/default/files/node-page-field_file/IGU-World%20LNG%20Report-2015%20Edition.pdf).

## Natural gas prices in Asia

In Asian markets, unlike those in the United States, natural gas prices typically reflect contracts that are indexed to prices for crude oil or petroleum products. The declines in crude oil prices between August 2014 and January 2015 and low oil prices since then (Figure 3-8) had a significant effect on Asian natural gas prices and markets. However, Asian countries are developing regional trading hubs to set natural gas prices that better reflect natural gas market dynamics. In 2014, almost 30% of global trade in LNG occurred on a short-term<sup>56</sup> or spot basis. Asian countries accounted for three-quarters of that total and one-third of the global natural gas trade.<sup>57</sup> From 2011 to 2014, high crude oil prices resulted in higher prices for LNG imports. In Asia, most natural gas is imported as LNG, with LNG prices traditionally indexed to crude oil on a long-term, contractual basis.

Currently there is no globally integrated market for natural gas, and pricing mechanisms vary by regional market. In most cases, internationally traded natural gas is indexed to crude oil prices, such as North Sea Brent or Japan customs-cleared crude (JCC), because of the liquidity and transparency of crude oil prices and the substitutability of natural gas and petroleum products in some markets. For example, some Asian countries have the option to burn either natural gas or petroleum for electricity generation.

Although long-term contracts indexed to crude oil prices remain Asia's predominant pricing mechanism, natural gas is beginning to be traded in one-time transactions on the spot market, or under short-term contracts that more closely reflect international natural gas supply and demand balances. Short-term and spot LNG trade in the Asia Pacific market almost tripled from 2010 to 2014 (Figure 3-9), when it represented 21% of global LNG trade and 7% of natural gas trade.

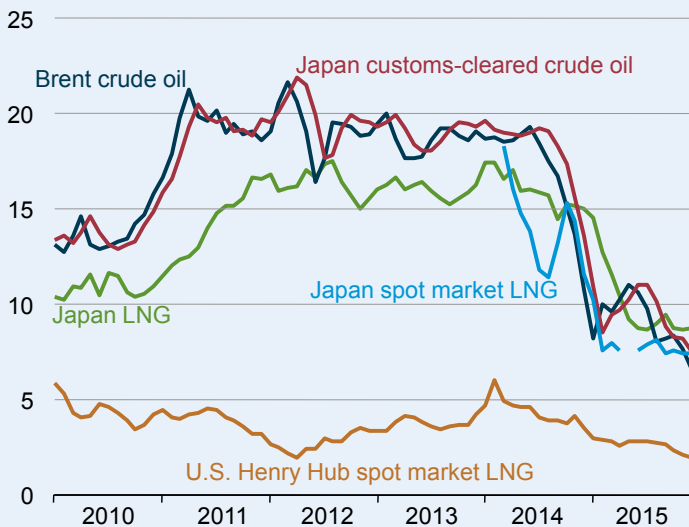
Several Asian countries—including Japan, China, and Singapore—are developing regional trading hubs with the goal of increasing price formation transparency:

- In September 2014, Japan launched an LNG futures contract on the Japan over-the-counter exchange (JOE), settled against the Rim Intelligence Co. Daily Pricing Index. However, only one trade has been made on the JOE since its inception. The country's lack of pipeline connectivity with other markets, low volumes of flexible LNG, and lack of LNG price transparency and liquidity have limited spot LNG trading activity on the JOE.
- In June 2015, Singapore's Stock Exchange launched the Singapore SGX LNG Index Group (SLInG). The index will provide free-on-board prices (excluding shipping costs) for LNG cargos from Singapore to different destinations reflecting regional spot prices. As of June 2015, 13 market players had signed up to participate in the index, and 10 more were expected to join; however, trading volumes to date have been moderate.
- On July 1, 2015, China launched the Shanghai Oil and Gas Exchange, which will trade both pipeline gas and LNG. China's diversified natural gas market, with expanding pipeline infrastructure and gas-on-gas competition, may offer a more liquid Asian natural gas price index, but high levels of government regulation make it less attractive as a regional benchmark.

In Europe, where natural gas is imported both by pipeline and as LNG, natural gas prices are either indexed to crude oil prices or based on the spot market. Although most of trade in Europe is based on long-term contracts, hub-based spot trading has increased

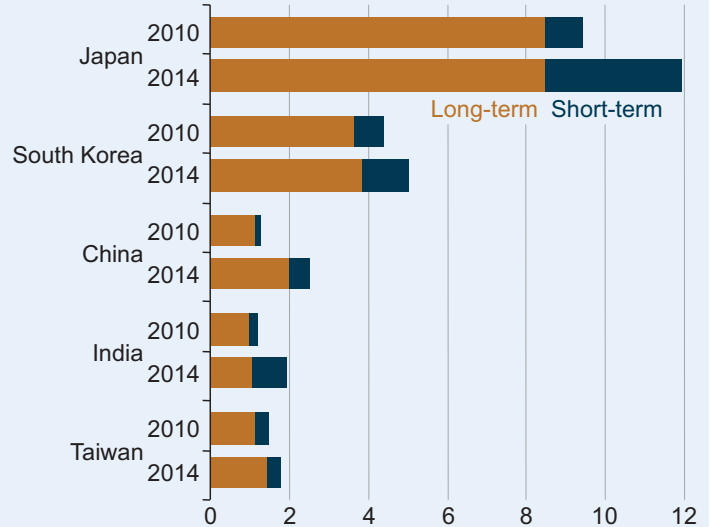
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**Figure 3-8. World crude oil, natural gas, and liquefied natural gas prices, 2010–15 (nominal dollars per million Btu)**



Note: Japan spot market LNG price for May 2015 was not reported.

**Figure 3-9. Asia Pacific natural gas trade by country and contract type, 2010 and 2014 (billion cubic feet per day)**



<sup>56</sup>Defined here as trade volumes delivered under contracts with duration of 4 years or less.

<sup>57</sup>Includes natural gas trade by pipeline and LNG.

significantly over the past decade. The primary benchmark prices for spot trading are the National Balancing Point (NBP) in the United Kingdom and the Title Transfer Facility (TTF) in the Netherlands. The NBP and TTF prices have a strong influence on hub prices in other European markets because of their liquidity and interconnectivity with continental Europe. Other trading hubs in continental Europe are growing in terms of traded volumes and the numbers of hubs and participants. With the increasing volumes and liquidity in the European hubs, hub pricing is beginning to play a larger role. Some recent pipeline contracts in continental Europe now include a hub-based price, rather than a traditional linkage to a basket of crude oil products.

Prices at Henry Hub, the U.S. natural gas benchmark, can also affect global pricing through LNG trade. By 2020, when all current U.S. liquefaction projects are expected to be completed, the United States will account for almost one-fifth of global liquefaction capacity and will have the third-largest LNG export capacity in the world (after Qatar and Australia).

Almost 80% of U.S. LNG export volumes for projects currently under construction have been contracted on pricing terms directly linked to the Henry Hub price, or under a hybrid pricing mechanism with links to Henry Hub. The flexibility of destination clauses in U.S. LNG export contracts and the introduction of hub indexes are expected to promote greater liquidity in global LNG trading, shift pricing away from oil-based indexes, and contribute to the development of Asian regional trading hubs and pricing indexes.

## Non-OECD natural gas consumption

### *Non-OECD Europe and Eurasia*

The countries of non-OECD Europe and Eurasia relied on natural gas for 47% of their primary energy needs in 2012—the second highest of any country grouping in IEO2016, after the Middle East. Non-OECD Europe and Eurasia consumed a total of 23.0 Tcf of natural gas in 2012, the most outside the OECD and more than any other region in the world except the OECD Americas. Russia's 15.7 Tcf of natural gas consumption in 2012 accounted for 68% of the Non-OECD Europe and Eurasia region's total (Figure 3-10).

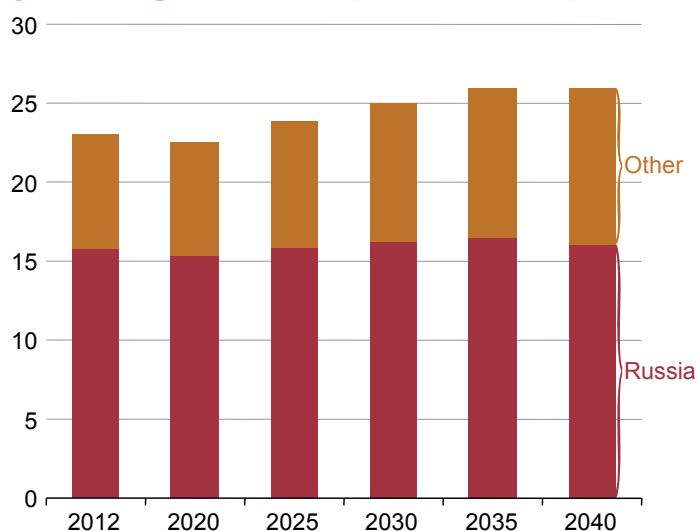
In the IEO2016 Reference case, overall natural gas consumption in non-OECD Europe and Eurasia grows by an average of 0.4%/year from 2012 to 2040, including a decline of 0.3%/year from 2012 to 2020 and an increase of 0.7%/year from 2020 to 2040, for a total increase of 2.9 Tcf over the 2012–40 period. With Russia accounting for only about 10% of the region's total increase, the average increase for the rest of the non-OECD Europe and Eurasia region is 1.1%/year, compared with Russia's average of 0.1%/year. In the electric power sector, natural gas consumption falls by an average of 0.1%/year from 2012 to 2040 in Russia as growth in its overall energy use slows but grows by an average of 1.4%/year in the region's other countries.

### *Non-OECD Asia*

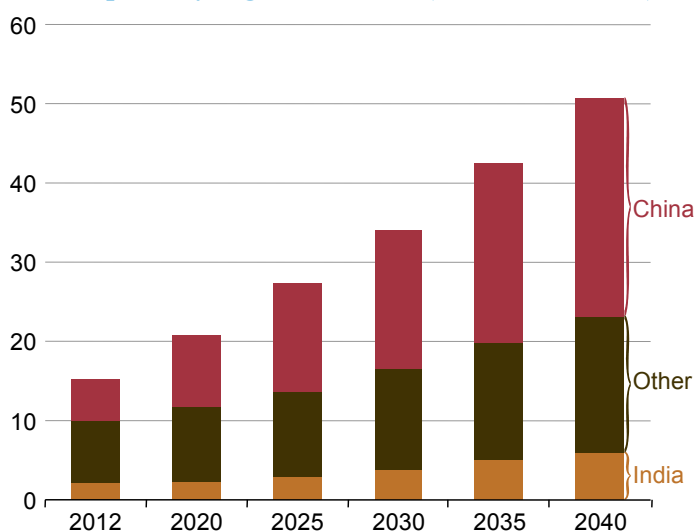
Among all regions of the world, the fastest growth in natural gas consumption in the IEO2016 Reference case occurs in non-OECD Asia. Natural gas use in non-OECD Asia increases by an average of 4.4%/year, from 15.1 Tcf in 2012 to 50.8 Tcf in 2040 (Figure 3-11). Over the period, non-OECD Asia accounts for more than 40% of the total incremental growth in world natural gas use, moving from its current position as the world's fourth-largest natural gas consuming region to the second-largest natural gas consuming region in 2030 and the largest consumer in 2040. OECD Asia's total natural gas consumption increases from less than half that of the OECD Americas region in 2012 to more than 25% above the OECD Americas total in 2040, and its share of total world natural gas consumption increases from 13% in 2012 to 25% in 2040.

China accounts for almost two-thirds (63%) of the growth in non-OECD Asia's natural gas consumption from 2012 to 2040. Total consumption of natural gas in China increases by an average of 6.2%/year in the IEO2016 Reference case, from 5.1 Tcf in 2012 to

**Figure 3-10. Non-OECD Europe and Eurasia natural gas consumption, 2012–40 (trillion cubic feet)**



**Figure 3-11. Non-OECD Asia natural gas consumption by region, 2012–40 (trillion cubic feet)**



27.5 Tcf in 2040. China’s central government is promoting natural gas as a preferred energy source and has set an ambitious target of increasing the share of natural gas in its overall energy mix to 10% (or approximately 8.8 Tcf) by 2020 to alleviate pollution from its heavy coal use.<sup>58</sup> In the IEO2016 Reference case, natural gas consumption in China totals 9.1 Tcf in 2020, or about 6% of the country’s total energy consumption. In 2040, the natural gas share of China’s energy consumption is 15%—still less than coal’s 44% share. However, the 6.2% average annual growth rate for natural gas consumption from 2012 to 2040 is far below the 9.7% average growth rate for nuclear energy.

In India, natural gas accounted for about 8% of total energy consumption in 2012, almost double the share in China’s energy mix. In other countries of non-OECD Asia, natural gas use accounts for 23% of overall energy consumption in 2012, and its share rises to 25% in 2040 in the IEO2016 Reference case, as natural gas consumption increases by an average of 2.8%/year, from 7.9 Tcf in 2012 to 17.2 Tcf in 2040. Although natural gas remains the second-largest source of energy consumption after liquids, its annual growth rate is less than the rates for renewables (3.4%) and nuclear energy (2.9%).

### Middle East

In the Middle East region, natural gas accounted for almost half of total energy consumption in 2012, more than in any other region. In the IEO2016 Reference case, Middle East natural gas consumption increases by an average of 2.5%/year from 2012 to 2040, and the industrial sector accounts for the largest share of the region’s total natural gas consumption (Figure 3-12). Natural gas use in the industrial sector grows by 7.7 Tcf from 2012 to 2040, accounting for more than half of the 14.2 Tcf total increase in natural gas consumption. In the electric power sector, natural gas use grows by 5.2 Tcf from 2012 to 2040, when it totals 9.8 Tcf. Natural gas-fired generation gains a portion of the market as the use of crude oil for electricity generation declines.

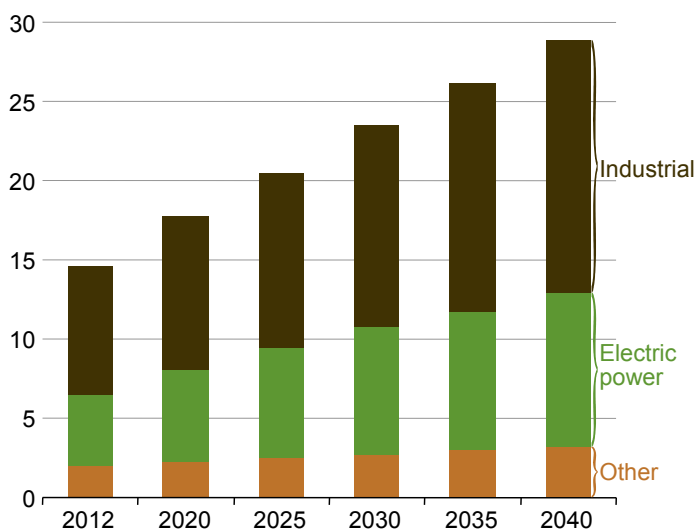
### Africa

Africa’s natural gas consumption totals 11.1 Tcf in 2040 in the IEO2016 Reference case, or 2.5 times the 2012 total (Figure 3-13). The region’s natural gas use increases by an average of 3.3%/year from 2012 to 2040, a rate that is second only to the 4.4%/year average increase for nuclear energy over the same period. Africa’s electric power and industrial sectors account for 79% of the increase in the region’s demand for natural gas from 2012 to 2040 and for 84% of its total natural gas demand in 2040. Natural gas consumption in the electric power sector grows from 2.2 Tcf in 2012 to 5.5 Tcf in 2040, accounting for 49% of the total increase in Africa’s natural gas use over the period. More than 85% of the increase in natural gas use for electricity generation in Africa occurs from 2020 to 2040, when it averages 3.6%/year, as compared with an average of less than 2.5%/year from 2012 to 2020.

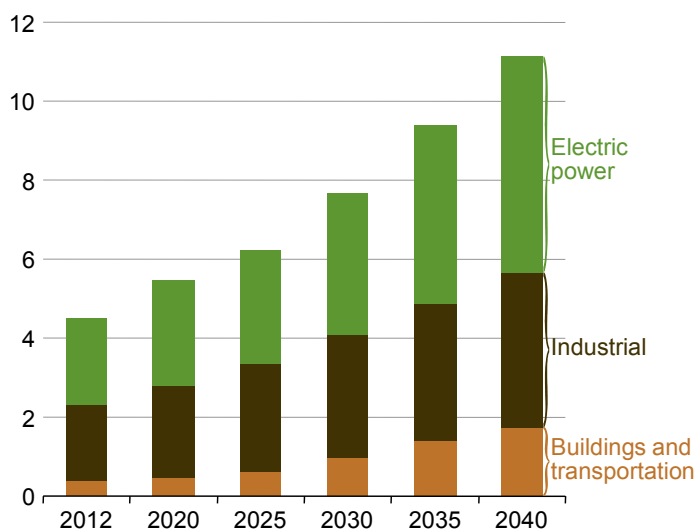
### Non-OECD Americas

Natural gas consumption in the non-OECD Americas region increases by an average of 2.0%/year in the IEO2016 Reference case, from 5.1 Tcf in 2012 to 8.9 Tcf in 2040 (Figure 3-14). The industrial sector accounts for more than one-third of the consumption growth from 2012 to 2040, followed by the electric power sector at approximately one-quarter. Brazil’s natural gas consumption grows by an average of 2.6%/year from 2012 to 2040, or by a total of 1.1 Tcf—more than 25% of the overall increase of 3.9 Tcf for the non-OECD Americas region. The increase from 0.7 Tcf in 2012 to 1.4 Tcf in 2040 in Brazil’s industrial sector natural gas consumption accounts for more than 60% of the country’s total increase in natural gas use from 2012 to 2040. Consumption of

**Figure 3-12. Middle East natural gas consumption by end-use sector, 2012–40 (trillion cubic feet)**



**Figure 3-13. Africa natural gas consumption by end-use sector, 2012–40 (trillion cubic feet)**



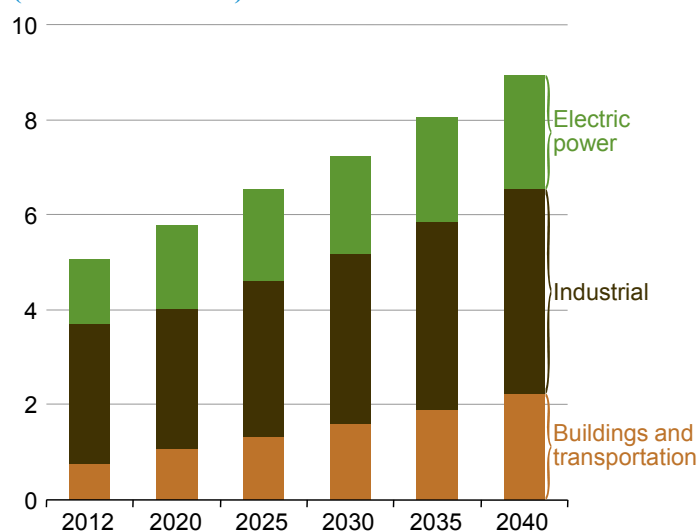
<sup>58</sup>E. Ng, “High prices threaten Beijing’s target of natural gas accounting for 10pc of energy use,” *South China Morning News: China Business* (June 21, 2015), <http://www.scmp.com/business/china-business/article/1824591/high-prices-threaten-beijings-target-natural-gas-accounting>.

natural gas in both the industrial and electric power sectors grows by approximately 2.3%/year from 2012 to 2040, when the industrial sector accounts for 64% and the electric power sector accounts for 22% of Brazil's total natural gas consumption.

## World natural gas production

To meet projected growth in natural gas use in the IEO2016 Reference case, the world's natural gas supplies increase by nearly 83 Tcf (69%) from 2012 to 2040. Much of the increase in supply is projected to come from non-OECD countries, which in the Reference case account for 73% of the total increase in world natural gas production from 2012 to 2040. Non-OECD natural gas production grows by an average of 2.1%/year, from 75 Tcf in 2012 to 136 Tcf in 2040 (Table 3-1), while OECD production grows by 1.4%/year, from 44 Tcf to 66 Tcf.

**Figure 3-14. Non-OECD Americas natural gas consumption by end-use sector, 2012–40 (trillion cubic feet)**



Production from continuous resources grows rapidly in the projection, with OECD tight gas, shale gas, and coalbed methane production averaging 3.0%/year, from 20 trillion cubic in 2012 to 47 Tcf in 2040. Over the same period, non-OECD production of tight gas, shale gas, and coalbed methane grows from nearly 2 Tcf to 34 Tcf. However, numerous uncertainties could affect future production of those resources. There is still considerable variation among estimates of recoverable shale gas resources in the United States and Canada, and estimates of recoverable tight gas, shale gas, and coalbed methane for the rest of the world are more uncertain, given the sparse data currently available. Moreover, the hydraulic fracturing process used to produce shale gas resources often requires significant amounts of water, and available water supplies are limited in many of the

**Table 3-1. World natural gas production by region and country in the Reference case, 2012–40 (trillion cubic feet)**

Region/Country	2012	2020	2025	2030	2035	2040	Average annual percent change 2012-40
<b>OECD</b>							
United States <sup>a</sup>	24.0	28.7	30.4	32.9	34.0	35.3	1.4
Canada	6.1	5.8	6.6	7.2	7.9	8.6	1.2
Europe	10.3	8.7	9.1	10.1	11.1	11.9	0.5
Australia/New Zealand	2.1	3.3	4.2	5.0	5.9	7.0	4.4
Other OECD	1.9	1.4	1.7	2.2	2.8	3.6	2.3
<b>Total OECD</b>	<b>44.4</b>	<b>47.9</b>	<b>52.0</b>	<b>57.4</b>	<b>61.9</b>	<b>66.4</b>	<b>1.4</b>
<b>Non-OECD</b>							
Russia	21.8	21.9	23.4	25.9	29.3	31.8	1.4
Europe and Central Asia	6.7	7.0	7.0	7.3	8.1	9.1	1.1
Iran	5.6	7.4	8.7	10.1	11.4	12.4	2.9
Qatar	5.5	5.8	7.0	7.6	8.0	8.4	1.5
Other Middle East	8.1	9.8	10.6	12.1	13.5	15.1	2.2
North Africa	5.6	7.1	7.1	7.1	7.3	7.7	1.1
Other Africa	2.0	2.7	4.1	6.1	7.6	8.8	5.5
China	3.7	7.2	11.1	14.2	16.7	18.7	6.0
Other Asia	10.9	11.1	11.4	12.2	13.4	14.6	1.0
Americas	5.5	6.1	7.0	7.6	8.4	9.4	2.0
<b>Total Non-OECD</b>	<b>75.3</b>	<b>86.1</b>	<b>97.4</b>	<b>110.1</b>	<b>123.5</b>	<b>136.0</b>	<b>2.1</b>
<b>Total World</b>	<b>119.7</b>	<b>134.0</b>	<b>149.4</b>	<b>167.5</b>	<b>185.4</b>	<b>202.4</b>	<b>1.9</b>
Discrepancy <sup>b</sup>	-0.1	0.8	0.4	0.9	0.1	-0.9	

<sup>a</sup>Includes supplemental production minus any projection discrepancy.

<sup>b</sup>Balancing item. Differences between global production and consumption totals result from independent rounding and differences in conversion factors derived from heat content of natural gas that is produced and consumed regionally.

world regions that have been identified as possessing shale gas resources. Further environmental concerns can also add to the uncertainty surrounding access to shale gas resources.

**OECD production**

**OECD Americas**

Natural gas production in the OECD Americas grows by 49% from 2012 to 2040. The United States, which is the largest producer in the OECD Americas and in the OECD as a whole, accounts for more than two-thirds of the region’s total production growth from 24 Tcf in 2012 to 35 Tcf in 2040 (Figure 3-15). U.S. shale gas production grows from 10 Tcf in 2012 to 20 Tcf in 2040, more than offsetting declines in production of natural gas from other sources. In 2040, shale gas accounts for 55% of total U.S. natural gas production in the IEO2016 Reference case, tight gas accounts for 20%, and offshore production from the Lower 48 states accounts for 8%. The remaining 17% comes from coalbed methane, Alaska, and other associated and nonassociated onshore resources in the Lower 48 states.

Natural gas production in Canada grows by 1.2%/year on average over the projection period, from 6.1 Tcf in 2012 to 8.6 Tcf in 2040. In Canada, like in the United States, much of the production growth comes from growing volumes of tight gas and shale gas production.

Mexico’s natural gas production is relatively flat in the midterm, but it more than doubles in the later years of the projection, as production from shale gas resources grows, supported by the country’s recent energy reforms. Total natural gas production in Mexico increases from 1.7 Tcf in 2012 to 3.3 Tcf in 2040. Like Canada and the United States, Mexico is thought to have substantial shale gas resources, the most prospective of which are extensions of the successful Eagle Ford Shale in the United States. However, because the shale resources in Mexico have not been explored as fully as those in the rest of North America, there is more uncertainty surrounding estimates of their size and potential for production.

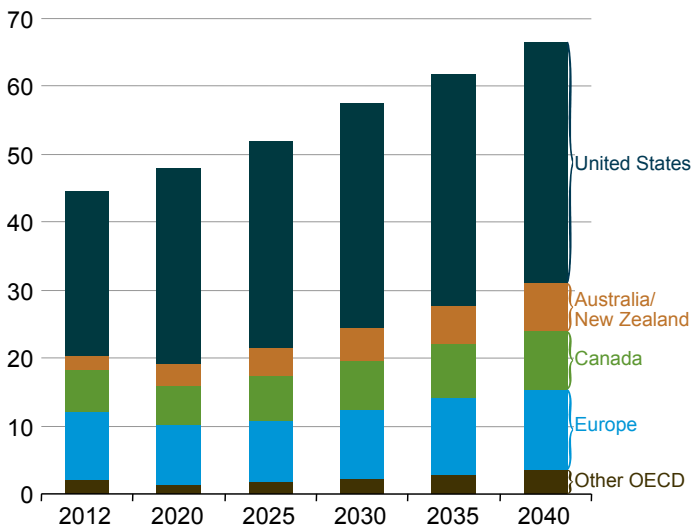
**OECD Europe**

Norway, the Netherlands, and the United Kingdom are the three largest producers of natural gas in OECD Europe, accounting for more than 80% of the region’s total natural gas production in 2012. In the IEO2016 Reference case, OECD Europe’s natural gas production declines in the mid-term and then begins to grow again in the later part of the projection, as production from tight gas, shale gas, and coalbed methane resources becomes more significant (Figure 3-16). Overall, natural gas production in OECD Europe in 2040 is 1.6 Tcf higher than in 2012. Contributing to OECD Europe’s total production is the growth in natural gas production from Israel, which became an OECD member country in September 2010 and is included in OECD Europe for statistical reporting purposes.

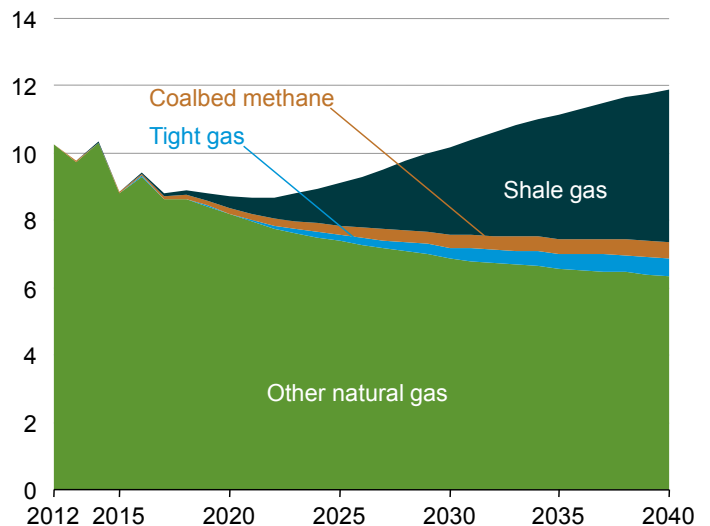
**OECD Asia**

Natural gas production in the Australia/New Zealand region increases from 2.1 Tcf in 2012 to 7.0 Tcf in 2040 in the IEO2016 Reference case, at an average rate of 4.4%/year. In 2012, more than 90% of production in the Australia/New Zealand region came from Australia, with production in Western Australia (including the Northwest Shelf area of Australia’s Carnarvon Basin) accounting for approximately 58% of the country’s total production.<sup>59</sup> Much of Australia’s production is used as feedstock at the

**Figure 3-15. OECD natural gas production by country and region, 2012–40 (trillion cubic feet)**



**Figure 3-16. OECD Europe natural gas production, 2012–40 (trillion cubic feet)**



Note: Other gas includes gas produced from structural and stratigraphic traps (e.g., reservoirs), historically called conventional.

<sup>59</sup>U.S. Energy Information Administration, “Australia: International Energy Data and Analysis” (Washington, DC: August 28, 2014), <https://www.eia.gov/beta/international/analysis.cfm?iso=AUS>.



Northwest Shelf LNG liquefaction facility. Similarly, many of Australia's new natural gas field developments are tied to liquefaction projects that have several export contracts in place.

Both Japan and South Korea have limited natural gas resources. Consequently, they have limited current production and limited prospects for future production. Both countries receive most of their natural gas supplies in the form of imported LNG. In 2012, natural gas production in Japan accounted for only 3% of the country's natural gas consumption, and in South Korea domestic natural gas production accounted for less than 1% of natural gas consumption. Although substantial deposits of methane hydrates in both Japan and South Korea have been confirmed, both countries are investigating how those resources could be safely and economically developed. The IEO2016 Reference case does not include methane hydrate resources in its estimates of natural gas resources, and widespread development of hydrates on a commercial scale is not anticipated during the projection period.

### Non-OECD production

#### Middle East

The three largest natural gas producers in the Middle East—Iran, Qatar, and Saudi Arabia—together accounted for 76% of the natural gas produced in the Middle East in 2012. With more than 40% of the world's proved natural gas reserves, the Middle East accounts for 20% of the total increase in world natural gas production in the IEO2016 Reference case, from 19.2 Tcf in 2012 to 35.8 Tcf in 2040 (Figure 3-17).

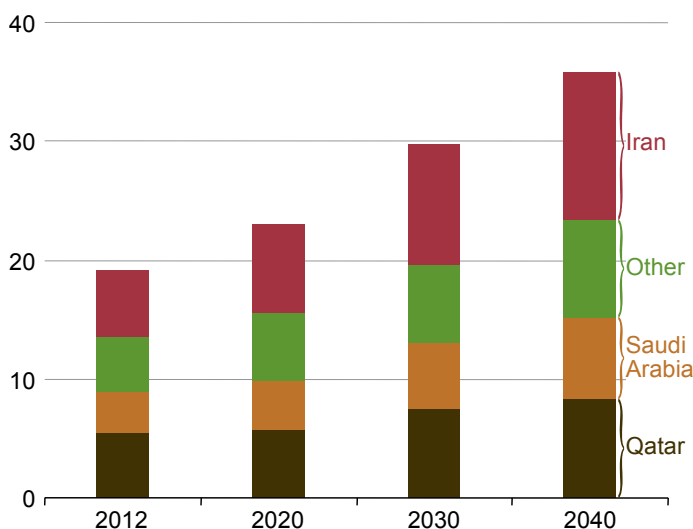
The strongest growth among Middle East producers from 2012 to 2040 in the IEO2016 Reference case comes from Iran, where natural gas production increases by 6.8 Tcf, followed by Saudi Arabia (3.4 Tcf of new production) and Qatar (2.9 Tcf). Although Iraq is the region's fastest-growing supplier of natural gas, with average increases of 15%/year over the projection period, it remains a relatively minor contributor to regional natural gas supplies. In 2040, Iraq's natural gas production totals 1.0 Tcf, or about 3% of the Middle East total.

#### Non-OECD Europe and Eurasia

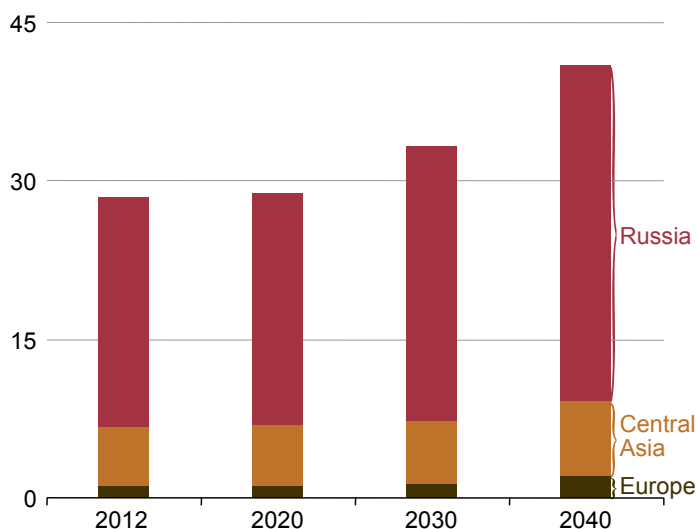
In the IEO2016 Reference case, 15% of the global increase in natural gas production comes from non-OECD Europe and Eurasia, which includes Russia, Central Asia, and non-OECD Europe. In the region as a whole, natural gas production increases from 28.5 Tcf in 2012 to 40.9 Tcf in 2040 (Figure 3-18). Russia remains the largest natural gas producer, accounting for more than 75% of the region's total production over the projection period. In the IEO2016 Reference case, Russia's natural gas production grows on average by 1.4%/year from 2012 to 2040, supported primarily by growth in exports to both Europe and Asia.

Natural gas production in Central Asia, which includes the former Soviet Republics, grows by 0.9%/year on average, from 5.5 Tcf in 2012 to 7.1 Tcf in 2040. Much of the projected growth is in Turkmenistan, which already is a major natural gas producer, accounting for 44% of the region's total production in 2012. Also contributing to Central Asia's production growth is Azerbaijan. Almost all of Azerbaijan's natural gas is produced in two offshore fields—the Azeri-Chirag-Deepwater Gunashli (ACG) complex and Shah Deniz. The second phase of Shah Deniz development is expected to start producing in 2018, with a peak capacity of 565 Bcf per year (in addition to the 315 Bcf in Phase I), according to BP, the development operator.<sup>60</sup> When it is completed, Shah Deniz will be one of the largest natural gas development projects in the world.

**Figure 3-17. Middle East natural gas production by country, 2012–40 (trillion cubic feet)**



**Figure 3-18. Non-OECD Europe and Eurasia natural gas production, 2012–40 (trillion cubic feet)**



<sup>60</sup>BP, "BP Azerbaijan: Operations and Projects: Shah Deniz Stage 2," BP Azerbaijan (undated), [http://www.bp.com/en\\_az/caspian/operationsprojects/Shahdeniz/SDstage2.html](http://www.bp.com/en_az/caspian/operationsprojects/Shahdeniz/SDstage2.html).

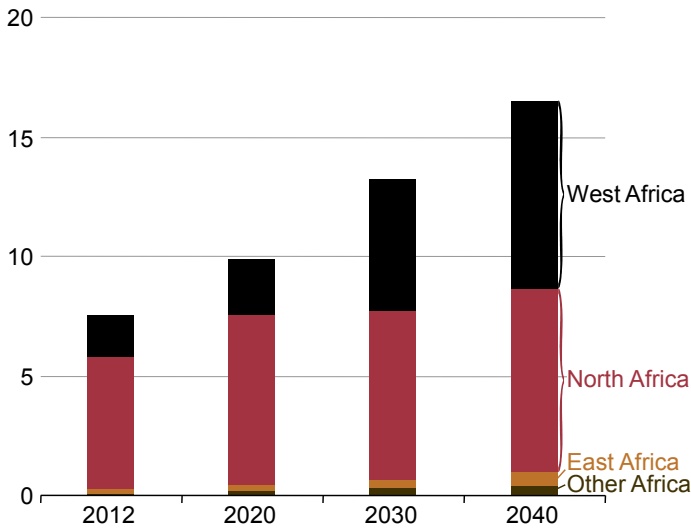
**Africa**

Natural gas production in Africa grows in the IEO2016 Reference case from 7.6 Tcf in 2012 to 9.8 Tcf in 2020 and 16.5 Tcf in 2040 (Figure 3-19). In 2012, about three-quarters of Africa's natural gas was produced in North Africa, mainly in Algeria, Egypt, and Libya. West Africa (with Nigeria and Equatorial Guinea providing virtually all of West Africa's production) accounted for another 23% of the 2012 total, and the rest of Africa accounted for 3%. Remaining resources in West Africa are more promising than those in North Africa, which has been producing large volumes of natural gas over a much longer period. Accordingly, in the IEO2016 Reference case, production growth in West Africa is higher than in North Africa, with annual increases over the projection period averaging 5.6%/year and 1.1%/year, respectively.

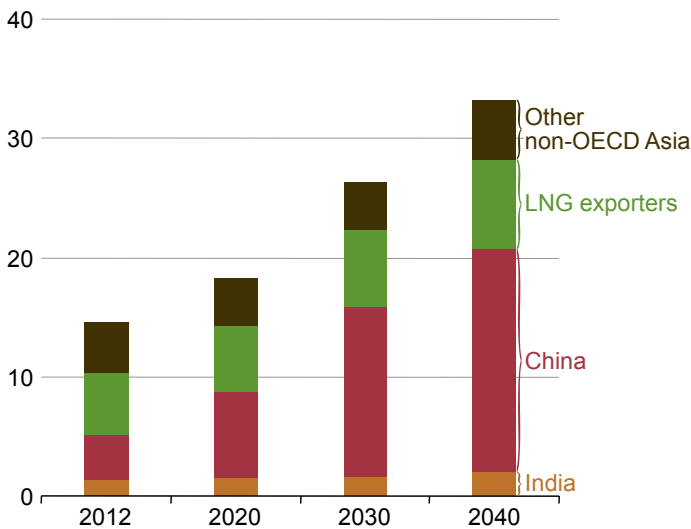
Nigeria is the largest natural gas producer in West Africa, although there also have been recent production increases in Equatorial Guinea, which brought an LNG liquefaction facility online in 2007. Angola was expected to add to West Africa's production in the near term with the startup of its first LNG liquefaction facility in 2013. However, in April 2014, Angola LNG temporarily shut down the plant because of ongoing technical issues, which led to infrequent exports while it was open. Technical issues at the plant included electrical fires, pipeline leaks and ruptures, and a collapsed drilling rig. Recommissioning of the Angola LNG plant began in January 2016 and operator Chevron expects the first LNG shipment to occur in the second quarter of 2016.<sup>61</sup>

In Nigeria, security concerns and uncertainty over terms of access have delayed proposed export projects and limited mid-term production growth. In the IEO2016 Reference case, export projects in Nigeria regain their former momentum later in the projection period, raising production for the West Africa region from 1.7 Tcf in 2012 to 7.9 Tcf in 2040. West Africa's share of the continent's total natural gas production more than doubles in the IEO2016 Reference case, from 23% in 2012 to 48% in 2040.

**Figure 3-19. Africa natural gas production by region, 2012–40 (trillion cubic feet)**



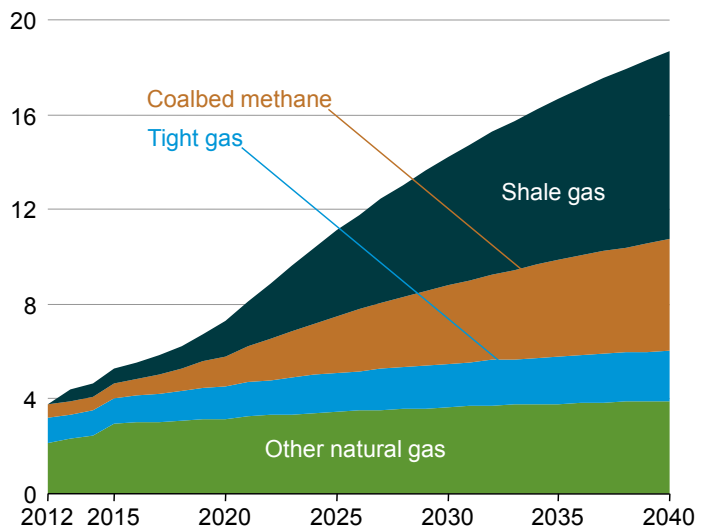
**Figure 3-20. Non-OECD Asia natural gas production by source, 2012–40 (trillion cubic feet)**



**Non-OECD Asia**

In the IEO2016 Reference case, natural gas production in non-OECD Asia more than doubles from 2012 to 2040, increasing by 18.7 Tcf (Figure 3-20). Growth from production in China accounts for 80% of this increase. From 2012 to 2040, China has the largest increase in natural gas production in non-OECD Asia, from 3.7 Tcf in 2012 to 18.7 Tcf in 2040, growing at an annual average rate of 6.0%. Much of the increase in the latter years comes from tight gas, shale gas, and coalbed methane reservoirs. China already is producing small volumes of coalbed methane and significant volumes of tight gas (Figure 3-21) (see below, "Shale gas development in China: Government investment and decreasing well costs").

**Figure 3-21. China natural gas production by type, 2012–40 (trillion cubic feet)**



Other gas includes gas produced from structural and stratigraphic traps (e.g., reservoirs), historically called conventional.

<sup>61</sup>Chevron CEO: Angola LNG to ship in 2nd quarter," LNG World News (February 1, 2016), <http://www.lngworldnews.com/chevron-ceo-angola-lng-to-ship-lng-cargo-in-2nd-quarter/>.

## Shale gas development in China: Government investment and decreasing well costs

As China continues to invest in domestic oil and gas production, and as the cost of drilling shale gas wells has fallen (Figures 3-22 and 3-23), China's development of shale gas has increased. Although the Chinese energy market has increasingly relied on imported natural gas, future shale gas production could help to meet natural gas demand even as the country faces difficulties in developing other natural gas resources, including coalbed methane (CBM).

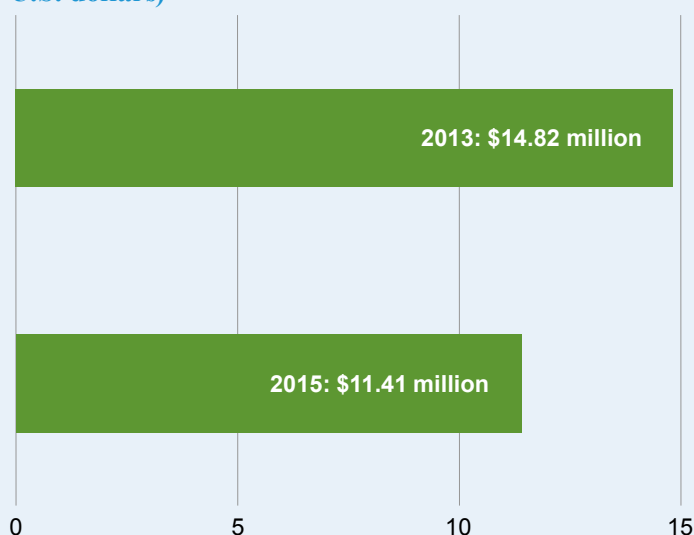
Over the past 25 years, China has worked to develop its substantial CBM resources, estimated by China's Ministry of Land and Resources (MLR) at more than 1,000 Tcf.<sup>62</sup> Commercialization began slowly in the 1990s, with CBM exploration programs operated by foreign companies, including BP, Chevron, and ConocoPhillips. However, the initial wells had low production rates, and by 2000 exploration activity had slowed. Although well performance has not improved much since 2000, the development of CBM supported by government loans and subsidies has accelerated. PetroChina, China United Coalbed Methane Corporation, Jincheng Coal Group, and other Chinese companies have reduced well costs and have benefited from higher natural gas prices. Currently, there are more than 20,000 CBM wells in China, producing a total of 0.36 Bcf/d. However, CBM well productivity in China is significantly lower than in some other countries, including Australia and the United States. CBM development in China has focused on the Ordos and Qinshui basins in Shanxi Province, which are considered to have the country's best geologic conditions, but significant geologic challenges—including low permeability and undersaturation—have constrained well productivity.

The difficulty of increasing CBM output has led China to increase its efforts to develop shale gas resources, taking an approach similar to that used for CBM development. China's technically recoverable shale gas resources are estimated at 1,115 Tcf.<sup>63</sup> The amount that becomes economically recoverable will depend on the market price of natural gas from foreign sources, including both pipeline gas and liquefied natural gas, as well as the capital and operating costs and productivity of shale gas production in China. More than 700 shale gas wells have been drilled in China over the past 4 years, and production has reached 0.38 Bcf/d.

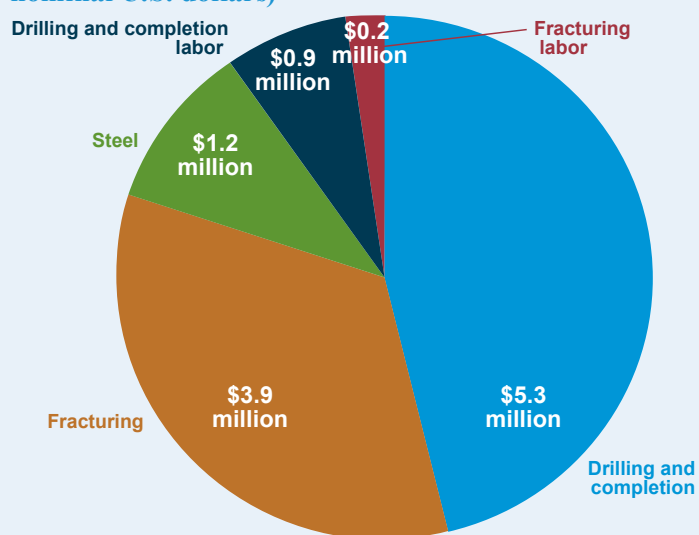
As Chinese companies have gained experience in shale gas production, their drilling costs have declined. According to China National Petroleum Corporation's Economics and Technology Research Institute, the cost of drilling in shale formations in the

(continued on page 48)

**Figure 3-22. Cost of drilling a shale gas well in the Sichuan Basin, 2013 and 2015 (million nominal U.S. dollars)**



**Figure 3-23. Cost components of shale gas well development in the Sichuan Basin, 2015 (million nominal U.S. dollars)**



Note: Component costs are based on the EIA/ARI component-based cost model, which assumes average well depth of 11,500 feet with 4,000 feet of horizontal drilling. Cost data for 2013 are based on reports from Platts October 2013 reporting statements by Ma Yongshen, Sinopec chief geologist. Cost data for 2015 are based on statements from China National Petroleum Corporation's Economics and Technology Research Institute at the Third IEA Unconventional Gas Forum in Chengdu, China, in April 2015.

<sup>62</sup>Liu Chenglin, Che Changbo, Fan Mingzhu, Zhu Jie, and Yang Hulin, "China CBM Geology and Resources Evaluation," *China Coalbed Methane* (2009), <http://www.nios.com.cn/common/files/File/2009.03-English.pdf>.

<sup>63</sup>U.S. Energy Information Administration, "World Shale Resource Assessments" (Washington, DC: September 24, 2015), <http://www.eia.gov/analysis/studies/worldshalegas/>.

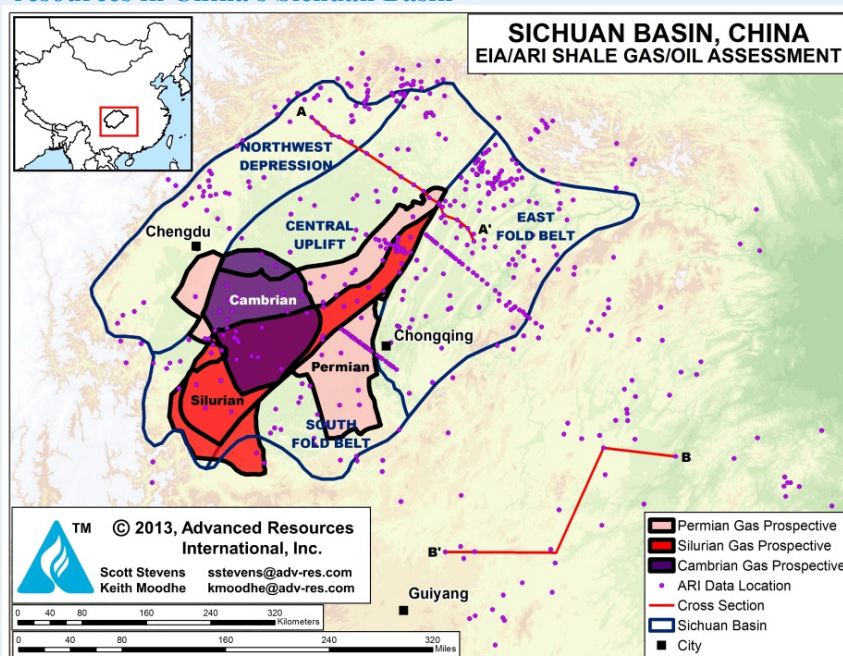
Sichuan Basin was between \$11.3 million and \$12.9 million per well in mid-2015<sup>64</sup>—23% lower than the cost cited in 2013 reports from Sinopec, another Chinese national oil company.<sup>65</sup>

China has also invested heavily in joint ventures in U.S. shale plays, with its financial involvement representing 20% of total foreign investment in U.S. shale plays.<sup>66</sup> This investment likely has provided China with valuable expertise that can be applied to its own domestic production, helping to lower well development costs.

Decreasing well costs and increasing experience in developing shale gas have been supplemented by continued government investment in the development of shale gas. In 2012, to encourage shale gas exploration, China's government established a four-year subsidy program for any Chinese company achieving commercial production of shale gas, with subsidies of \$1.80 per million British thermal units. The subsidies were extended in mid-2015, at a lower rate, through 2020.<sup>67</sup> Initially, shale gas development has been focused on the Longmaxi formation in the Sichuan Basin (Figure 3-24), which is estimated to hold 287 Tcf of technically recoverable volumes.<sup>68</sup>

According to MLR, Sinopec and PetroChina are on schedule to reach 0.6 Bcf/d of shale gas production by the end of 2015. Although it is still a small fraction of China's overall production, which was estimated at 13.0 Bcf/d in 2014,<sup>69</sup> shale gas eventually could help to meet growing demand for natural gas in China and limit growth in the country's natural gas imports.

**Figure 3-24. EIA/ARI assessment of shale gas and tight oil resources in China's Sichuan Basin**



Natural gas production in India grows by an average of 1.3%/year in the IEO2016 Reference case, from 1.4 Tcf in 2012 to 2.1 Tcf in 2040. India faces several production challenges. For example, a large portion of its current production comes from aging western offshore fields, and production volume from the Krishna Godavari Basin—located off India's eastern coast—has failed to meet earlier expectations. India has several basins that are prospective for shale gas. India's oil ministry has announced that the government will unveil a shale gas and oil policy in the near future and begin selling shale gas development blocks, although no

<sup>64</sup>International Energy Agency, "3rd IEA Unconventional Gas Forum" (Chengdu, China: April 10, 2015), <https://www.iea.org/workshops/3rd-iea-unconventional-gas-forum.html>.

<sup>65</sup>Reported by Platts (quoting Mr. Ma Yongsheng, Sinopec's Chief Geologist in China) in October 2013, for a horizontal well at Fuling field in the Sichuan Basin.

<sup>66</sup>U.S. Energy Information Administration, "Foreign investors play large role in U.S. shale industry" (Washington, DC: April 8, 2013), <http://www.eia.gov/todayinenergy/detail.cfm?id=10711>.

<sup>67</sup>IHS Energy, "Market Briefing, China Oil and Gas Service, China Upstream Market Briefing Second Quarter 2015" (July 2015), <https://www.ih.com/products/cera-china-energy-research.html> (subscription site).

<sup>68</sup>U.S. Energy Information Administration and Advanced Resources International, Inc., *World Shale Gas and Shale Oil Resource Assessment* (June 26, 2015), <http://www.eia.gov/todayinenergy/detail.cfm?id=21832>; and U.S. Energy Information Administration/Advanced Resources International, Inc., *EIA/ARI World Shale Gas and Shale Oil Resource Assessment: Technically Recoverable Shale Gas and Shale Oil Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States* (Fairfax, VA: June 2013), [http://www.adv-res.com/pdf/A\\_EIA\\_ARI\\_2013%20World%20Shale%20Gas%20and%20Shale%20Oil%20Resource%20Assessment.Pdf](http://www.adv-res.com/pdf/A_EIA_ARI_2013%20World%20Shale%20Gas%20and%20Shale%20Oil%20Resource%20Assessment.Pdf).

<sup>69</sup>BP, *BP Statistical Review of World Energy June 2015* (London, UK: June 2015), <http://www.bp.com/content/dam/bp/pdf/energy-economics/statistical-review-2015/bp-statistical-review-of-world-energy-2015-full-report.pdf>.

awards have been made to date. In the later years of the IEO2016 Reference case, shale resources provide nearly one-quarter of India's total natural gas production.

### Non-OECD Americas

Natural gas production in the non-OECD Americas region nearly doubles in the IEO2016 Reference case, from 5.5 Tcf in 2012 to 9.4 Tcf in 2040 (Figure 3-25). Brazil's natural production grows by an average of 4.0%/year and triples from 0.6 Tcf in 2012 to 1.8 Tcf in 2040. As a result, Brazil's share of regional production increases from 11% in 2012 to nearly 19% in 2040. More than one-third of Brazil's natural gas production growth from 2012 to 2040 comes from tight gas, shale gas, or coalbed methane production. Recent discoveries of oil and natural gas in the presalt Santos Basin are expected to increase the country's natural gas production, particularly in the Tupi field, which could contain between 5 Tcf and 7 Tcf of recoverable natural gas.<sup>70</sup>

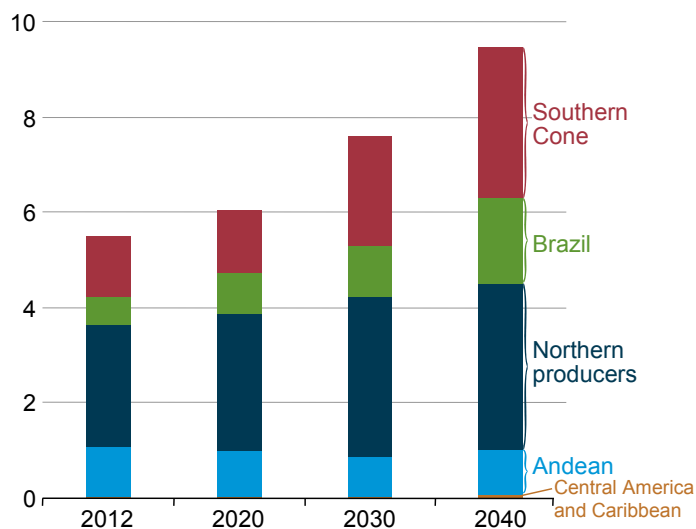
Despite recent declines in natural gas production, countries in the Southern Cone (mainly, Argentina) become the region's leading natural gas producers by 2040 in the IEO2016 Reference case, with annual production in the Southern Cone growing by nearly 150%, from 1.3 Tcf in 2012 to 3.1 Tcf in 2040. All of the production increase in the Southern Cone comes from tight gas, shale gas, or coalbed methane gas fields, as production from other resources<sup>71</sup> declines over the projection period. Currently, Argentina leads the non-OECD Americas region in its pursuit of tight gas and shale gas development.

While the growth of natural gas production in Brazil and in the Southern Cone increases natural gas production in the non-OECD Americas region overall, production from the Northern Producers (primarily, Colombia, Venezuela, and Trinidad and Tobago) grows by an average of 1.1%/year, which is the region's second-lowest rate of production increase, after the Andean producers (Bolivia, Ecuador, and Peru). Venezuela's 198 Tcf of proved natural gas reserves are the Western Hemisphere's second-largest reserves, after the United States. An estimated 90% of Venezuela's natural gas reserves are associated, meaning that they are co-located with oil reserves. Although Venezuela has plans to increase its production of nonassociated gas, largely through the development of its offshore reserves, those plans have been delayed by a lack of capital and foreign investment.

## World natural gas trade

International trade in natural gas is undergoing rapid transformation. From 2000 to 2012, global LNG trade more than doubled, from less than 5 Tcf/year to more than 12 Tcf/year, and its growth continues in the IEO2016 Reference case through 2020 as

**Figure 3-25. Non-OECD Americas natural gas production, 2012–40 (trillion cubic feet)**



new liquefaction capacity comes online. World LNG flows adjusted quickly in 2011 and 2012, to accommodate a surge in Japan's demand for LNG in the wake of the Fukushima disaster and to account for the underutilization of LNG liquefaction capacity in North Africa and Southeast Asia. As nuclear capacity in Japan is restored, world LNG markets are expected to loosen in the near term because of growing supply and weakening demand.

Although LNG trade has grown considerably in recent years, flows of natural gas by pipeline still account for most of the global natural gas trade in the IEO2016 Reference case, which includes several new long-distance pipelines and expansions of existing infrastructure through 2040. The largest volumes of natural gas traded internationally by pipeline currently are in North America (between Canada and the United States) and in Europe (among many OECD and non-OECD countries). By the end of the projection period, the IEO2016 Reference case includes large volumes of pipeline flows into China from both Russia and Central Asia (see "Global LNG trade and supply," below).

## Global LNG trade and supply

In 2014, natural gas accounted for 25% of the energy used worldwide, with LNG accounting for 10% of global natural gas consumption and 31% of global natural gas trade. From 2005 to 2014, LNG trade increased by an average of 6%/year, nearly twice the growth rate (3.3%/year) of pipeline natural gas trade.<sup>72</sup> In 2015, LNG trade continued to expand, by about 3%, with new liquefaction capacity additions in Australia and Indonesia.<sup>73</sup> In the IEO2016 Reference case, world LNG trade expands by

(continued on page 50)

<sup>70</sup>G. Duffy, "'Huge' gas field found off Brazil," BBC News (Sao Paulo, Brazil: January 22, 2008), <http://news.bbc.co.uk/2/hi/americas/7201744.stm>.

<sup>71</sup>Other includes gas produced from structural and stratigraphic traps (e.g., reservoirs), historically called conventional.

<sup>72</sup>BP Statistical Review of World Energy, 64th edition (June 2015), <https://www.bp.com/content/dam/bp/pdf/energy-economics/statistical-review-2015/bp-statistical-review-of-world-energy-2015-full-report.pdf>.

<sup>73</sup>Based on preliminary estimates from IHS Strategic Report, "Global Gas in 2016, The tipping of the scales" (February 2016), [www.ihs.com](http://www.ihs.com) (subscription site).

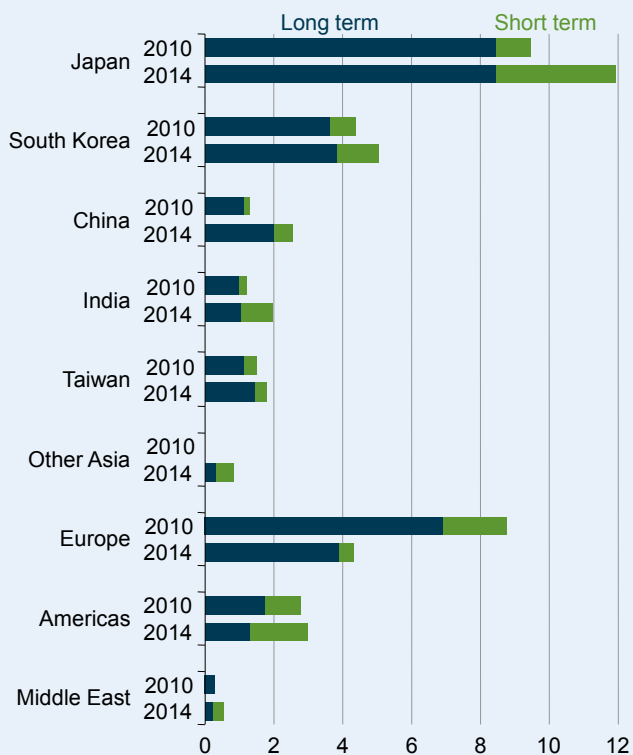
nearly one-third from 2012 to 2020, as large volumes of new liquefaction capacity come online and as more countries opt for LNG as a flexible source of support for their energy systems, particularly where access to natural gas by pipeline may be limited by geographic or economic conditions.

Strong growth in overall global LNG trade over the past 10 years has been accompanied by even stronger growth in LNG trade on spot<sup>74</sup> and short-term<sup>75</sup> markets. Short-term and spot trade in LNG, which in 2000 accounted for less than 5% of the natural gas traded worldwide, grew from 2.5 billion cubic feet per day (Bcf/d) in 2005 to 9.3 Bcf/d in 2014, and its share of total LNG trade increased from 13% to 29%. The growth of short-term and spot LNG trade was aided by a number of developments, including LNG contracts with destination flexibility, decisions by importing countries to procure LNG without long-term contracts, large pricing differentials between the Atlantic and Pacific basins (which supports interbasin arbitrage), a proliferation of LNG marketers with flexible supply portfolios, and an increase in LNG carriers available for spot and short-term charter. The number of countries entering LNG trade has also increased considerably, contributing to the development of more flexible trading patterns between exporters and importers.

The Asia Pacific region,<sup>76</sup> which accounted for almost one-third of world natural gas trade and three-fourths of LNG trade in 2014,<sup>77</sup> led the world growth in LNG demand over the past decade. From 2010 to 2014, as Japan, South Korea, China, and India experienced strong growth in demand for LNG, they sought to supplement contracted volumes with short-term and spot purchases. In addition, delays in the commissioning of new supply projects also contributed to the market tightness. Combined demand for short-term LNG from the four countries nearly tripled, from 2.1 Bcf/d in 2010 to 6.1 Bcf/d in 2014. In Japan alone, short-term market demand increased by 2.5 Bcf/d, while demand for long-term contracts increased by only 1.2 Bcf/d (Figure 3-26).

While demand for LNG in the Asia Pacific region has grown over the past 5 years, demand in Europe has declined. European nations imported a total of 8.7 Bcf/d of LNG in 2010, with short-term demand accounting for 21% of the total; in 2014, their imports totaled 4.3 Bcf/d. European LNG trade was characterized by strong growth in re-exports, primarily to Asia. Of the total volume of short-term LNG purchases imported to Europe in 2014 (1.2 Bcf/d), three-quarters was re-exported to countries in Asia, the Middle East, and South America.

**Figure 3-26. Global LNG trade by contract type, 2010 and 2014 (billion cubic feet per day)**



Note: LNG imports to Europe are shown as net of re-exports.

From 2008 to 2014, 12 countries became LNG importers: 4 in Asia (Thailand, Singapore, Malaysia, and Indonesia), 3 in South America (Argentina, Brazil, and Chile), 3 in the Middle East (Dubai, Kuwait, and Israel), and 2 in Europe (the Netherlands and Lithuania). Together they accounted for 9% (3 Bcf/d) of the world's total LNG imports in 2014. Most of those 12 countries are relatively small markets that opted for floating regasification units (FSRU) as a fast and cost-effective way to meet growing demand for natural gas. Most of the 12 countries have flexible seasonal demand and procure LNG primarily in the spot market. In 2014, spot and short-term imports accounted for three-quarters of their combined total LNG imports. In 2015, four additional countries became LNG importers,<sup>78</sup> and three of them—Egypt, Pakistan, and Jordan—opted for floating regasification. In 2016, Colombia and Uruguay are expected to begin LNG imports using FSRU as receiving terminals.

Qatar maintained its position as the world's leading supplier of both spot and long-term LNG volumes in 2015, and it is expected to hold that spot until the end of the decade, when both the United States and Australia are expected to close the gap. However, although Qatar holds abundant reserves of natural gas, its government has chosen to continue a self-imposed moratorium on development of its North Field and construction of new LNG export facilities. No new projects are expected in Qatar until 2020 or later.

(continued on page 51)

<sup>74</sup>Generally, spot trade implies a single transaction between a buyer and a seller.

<sup>75</sup>Short-term contracts have a duration of 4 years or less.

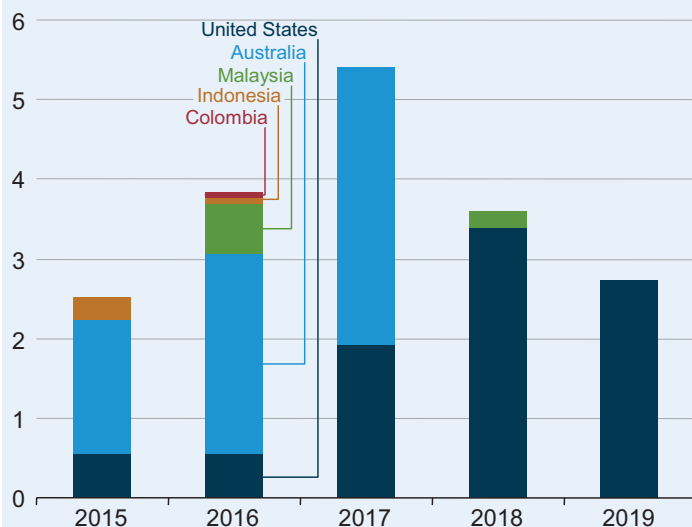
<sup>76</sup>The Asia Pacific region includes Australia, China, India, Japan, Malaysia, Singapore, South Korea, Taiwan, and Thailand.

<sup>77</sup>BP Statistical Review of World Energy, 64th edition (June 2015), <https://www.bp.com/content/dam/bp/pdf/energy-economics/statistical-review-2015/bp-statistical-review-of-world-energy-2015-full-report.pdf>.

<sup>78</sup>U.S. Energy Information Administration, "Floating LNG regasification is used to meet rising natural gas demand in smaller markets" (Washington, DC: April 27, 2015), <http://www.eia.gov/todayinenergy/detail.cfm?id=20972>.

Although Malaysia was the world's second-largest exporter of LNG in 2014, both Australia and the United States are on track to surpass Malaysia in the near future, with liquefaction projects already under construction and expected to enter service by 2020. In the IEO2016 Reference case, global liquefaction capacity in 2019 reaches 57 Bcf/d, a 32% increase from 2015, led by capacity additions in Australia and the United States that together account for 93% of the new liquefaction capacity coming online over the 2015–19 period (Figure 3-27).

**Figure 3-27. Global LNG capacity additions by country, 2015–19 (billion cubic feet per day)**



Note: Nameplate capacity is shown, not adjusted for ramp-up.

Australia, already a significant player in the LNG industry, exported 3.2 Bcf/d of LNG in 2014 and brought the first of its seven new projects—Queensland Curtis LNG Train 1<sup>79</sup>—online in late 2014 and Train 2 in mid-2015. Six additional projects are under construction and are scheduled to come online by 2018. With this growth, Australia is expected to overtake Qatar as the world's leading LNG exporter with 11.5 Bcf/d of liquefaction capacity by 2019. In the United States, five liquefaction facilities are currently under construction, and the first export cargo from the Lower 48 states was shipped in February 2016. Several additional projects in the United States are well into the planning and application process.

The short-term outlook for LNG trade points to a potential oversupply, as it will take some time for the market to absorb the large volumes of new LNG supply coming online. In the midterm, new liquefaction projects on the east coast of Africa (Mozambique, Tanzania) and in western Canada, and offshore floating liquefaction projects in Malaysia and Australia will be considered as the LNG market moves beyond its traditional supply sources. In the long term, the number of LNG exporters and importers is expected to continue growing as projects move to more remote areas.

### OECD natural gas trade

In 2012, 23% of the natural gas demand in OECD nations was met by net imports from non-OECD countries. That share falls to 16% in 2040 in the IEO2016 Reference case, with both imports and exports from different OECD regions shifting substantially over the projection period. As exports of LNG from the United States and Australia increase in the first decade of the projection period, total net imports to the OECD—predominantly to Europe, Japan, and South Korea—begin to decline after 2016. Over the entire period from 2012 to 2040, net imports of LNG to the OECD fall in the IEO2016 Reference case by 0.4%/year, and net imports in 2040 are 13% lower than they were in 2012.

### Liquefied natural gas: Growing use of floating storage and regasification units

Floating regasification is a flexible, cost-effective way for smaller markets to receive and process LNG shipments. Several countries have turned to floating regasification as a short-term solution to meet growing demand for natural gas. Three of the four countries that began importing LNG in 2015—Pakistan, Jordan, and Egypt—are using floating regasification rather than building full-scale onshore regasification facilities. In addition, the technology is being used in other countries as a temporary solution while onshore facilities are being built.

Floating regasification involves the use of a specialized vessel—a floating storage and regasification unit (FSRU), which is capable of transporting, storing, and regasifying LNG onboard—and either an offshore terminal, which typically includes a buoy and connecting undersea pipelines to transport regasified LNG to shore, or an onshore dockside receiving terminal. An FSRU can be either purpose-built or converted from a conventional LNG vessel. The technology can be developed in less time than an onshore facility of comparable size. As of 2015, 18 FSRUs were functioning as both transportation and regasification vessels, and 5 permanently moored regasification units had been converted from conventional LNG vessels to FSRUs.

The use of floating regasification has grown rapidly in recent years (Figures 3-28 and 3-29), particularly in emerging markets facing short-term supply shortages. The technology was first deployed in the U.S. Gulf of Mexico in 2005. Floating regasification capacity totaled 7.8 billion cubic feet per day (Bcf/d) at the end of 2014, representing 8% of global installed regasification capacity, according to data from the International Gas Union.

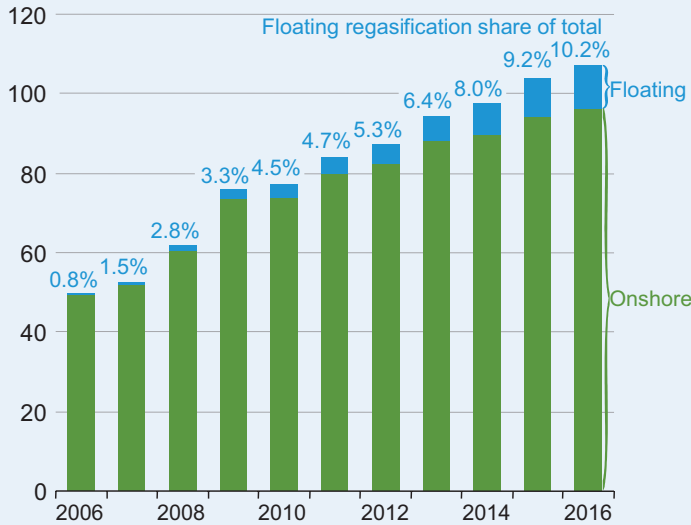
(continued on page 52)

<sup>79</sup>Australian Petroleum Production & Exploration Association, "Australian LNG projects" (not dated), <http://www.appea.com.au/oil-gas-explained/operation/australian-lng-projects/>.

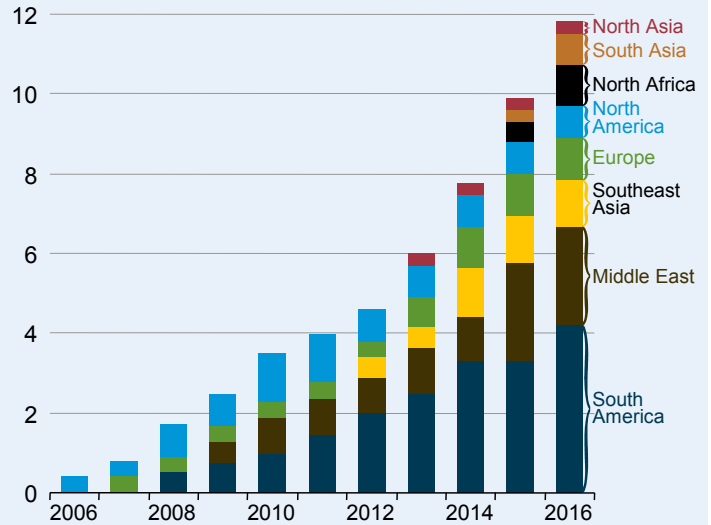
In the spring and fall of 2015, four more floating terminals came online—one each in Pakistan and Jordan and two in Egypt—adding 1.9 Bcf/d of new capacity.<sup>80</sup> Seven more floating regasification terminals, totaling 3.1 Bcf/d capacity, are being developed in Uruguay, Chile, Ghana, India, the Dominican Republic, Puerto Rico, and Colombia, with expected online dates in 2016–17. When those terminals are completed, global regasification capacity will total 12.7 Bcf/d.

Floating regasification is likely to remain a preferred technology option for emerging markets because of its flexible deployment capabilities, smaller capacities, quick startup, and relatively low costs as compared with the costs of onshore terminals.

**Figure 3-28. Floating LNG regasification share of total world regasification capacity, 2006–16 (billion cubic feet per day)**



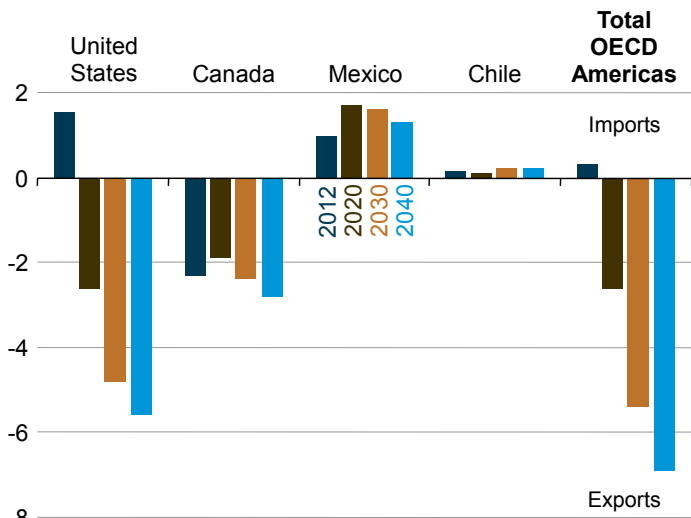
**Figure 3-29. Floating LNG regasification capacity by region, 2006–16 (billion cubic feet per day)**



**OECD Americas**

With the exception of Mexico, regional net imports among the nations of the OECD Americas trend downward through 2040 in the IEO2016 Reference case (Figure 3-30). In the United States, rising domestic production reduces the need for imports, primarily as a result of robust growth in regional production of shale gas. The United States becomes a net exporter of natural gas in 2017, with net exports growing to 5.6 Tcf in 2040. Most of the growth in U.S. net exports can be attributed to exports of LNG globally, although U.S. pipeline exports to Mexico also grow steadily as increasing volumes of natural gas for Mexico imported from the United States fill the growing gap between production and consumption in Mexico. In 2012, U.S. exports to Mexico totaled 620 billion cubic feet. In the IEO2016 Reference case, Mexico’s net natural gas imports more than double, to 1.3 Tcf in 2040, after reaching their highest level in the mid-2020s. Beyond 2025, increases in Mexico’s natural gas production slow the country’s demand for imports (see “U.S. natural gas exports to Mexico,” below). U.S. domestically sourced exports of LNG (excluding exports from the existing Kenai facility in Alaska) begin in 2016 and grow to 3.4 Tcf in 2030, with more than three-quarters originating in the Lower 48 states and the remainder in Alaska.

**Figure 3-30. OECD Americas net natural gas trade, 2012–40 (trillion cubic feet)**



U.S. domestically sourced exports of LNG (excluding exports from the existing Kenai facility in Alaska) begin in 2016 and grow to 3.4 Tcf in 2030, with more than three-quarters originating in the Lower 48 states and the remainder in Alaska.

In the IEO2016 Reference case, pipeline exports of natural gas from Canada to the United States continue declining as U.S. shale gas production grows. However, Canada remains a net exporter of natural gas, with LNG export volumes replacing some of the lost pipeline export volumes. Canada’s net exports of natural gas in 2040 in the IEO2016 Reference case are 22% higher than they were in 2012.

<sup>80</sup>International Gas Union, *2016 World LNG Report* (Fornebu, Norway: 2016), p. 5, <http://www.igu.org/publications/2016-world-lng-report>.



## U.S. natural gas exports to Mexico

With new U.S. pipeline export capacity being brought online, and connecting pipelines in Mexico ramping up to full capacity, exports of natural gas by pipeline from the United States are beginning to gradually displace Mexico's imports of LNG. According to EIA data, U.S. pipeline exports to Mexico set a monthly record high average of 3.3 billion cubic feet per day (Bcf/d) in July 2015, and over the first seven months of 2015 they averaged 2.7 Bcf/d—35% higher than the total for the first seven months of 2014. Mexico's LNG imports declined in the first seven months of 2015, according to data from the Secretaría de Economía. Before the boom in U.S. shale gas production, Mexico had expected only limited growth in pipeline imports from the United States. However, with the rise of U.S. shale production and the decline in natural gas prices, Mexico's need for LNG imports has fallen, and its LNG regasification terminals have been operating below capacity.

Currently, Mexico has three regasification terminals: Altamira, on the east coast, commissioned in 2006, with 0.7 Bcf/d capacity; Ensenada (also called Energia Costa Azul) on the west coast in operation since 2008 with 1.0 Bcf/d capacity; and Manzanillo on the west coast commissioned in 2012 with 0.5 Bcf/d capacity. While use at the Manzanillo terminal has been relatively high, averaging 85% in 2013–14, utilization at the Altamira terminal averaged around 50%, and the Costa Azul terminal in the Baja Peninsula was virtually unused.

LNG imports at the Manzanillo terminal provide natural gas for the gas-fired power plants in Mexico's Central West region. The location of the Manzanillo terminal provides a unique point of entry and serves to relieve pipeline bottlenecks in the region. As a result, LNG imports to the terminal are expected to remain high over the next few years, until additional pipeline capacity is developed to provide alternative sources.

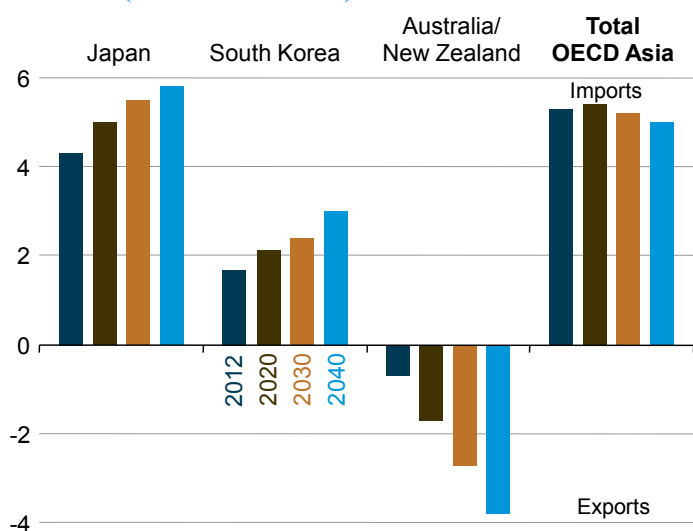
Imports at the Energia Costa Azul terminal, on the other hand, have averaged only 4% of the terminal's nameplate capacity since 2011, despite a long-term contract with the Tangguh liquefaction project in Indonesia. Originally, the terminal was constructed to supply the Southern California market and new power plants in Mexico's state of Baja California. However, those plants also could be supplied via U.S. pipelines, and the terminal depended mostly on natural gas demand in California, which was limited by the availability of less costly U.S. supplies. Because the Costa Azul contract allowed for diversion of supply volumes to other markets, most of contracted supply from Indonesia has gone instead to higher priced Asian markets over the past several years. Semptra Energy, the terminal's operator, is considering a conversion of the terminal to a liquefaction facility.

At the Altamira terminal, LNG imports in 2008–15 have consistently averaged about 50% of the terminal's capacity. Terminal operators Shell and Total have a supply contract with Mexico's Comisión Federal de Electricidad (CFE), which allows them to supply CFE with either pipeline natural gas or LNG. However, the contract stipulates that at least 50% of the supply must be LNG. In the first six months of 2015, imports to the Altamira terminal declined by 14% from the same period a year earlier, as increasing availability of pipeline gas from the United States at lower prices displaced some of the LNG imports. In September 2015, CFE canceled a tender for several spot cargos into Altamira between September and December, noting the increased availability of less-expensive pipeline natural gas from the United States. The Manzanillo terminal may follow suit in the coming years as additional pipeline infrastructure becomes available in the region to alleviate the existing bottlenecks.

### OECD Europe

In OECD Europe, total natural gas imports continue to grow by an average of 2.1%/year from 2012 to 2040 as local production sources decline, especially in the United Kingdom. The pipeline share of OECD Europe's natural gas imports grows in the IEO2016 Reference case to between 40% and 50% of the region's total natural gas supply, and its LNG imports grow to about 20% of the region's total natural gas supply in 2040.

**Figure 3-31. OECD Asia net natural gas trade, 2012–40 (trillion cubic feet)**



### OECD Asia

The world's two largest importers of LNG are Japan and South Korea in the OECD Asia region. The Australia/New Zealand country grouping, also in OECD Asia, is becoming the world's second-largest exporter of LNG (after Qatar). Supported by a fivefold increase in Australia's exports from 2012 to 2040, OECD Asia's net demand for imports falls from 5.3 Tcf in 2012 to 5.0 Tcf in 2040 (Figure 3-31).

Japan and South Korea continue to be major players in world LNG trade, even though their total consumption of natural gas is relatively small on a global scale. Although their combined natural gas consumption represented slightly more than 5% of world consumption in 2012, it represented almost 50% of world LNG imports. Because the two countries are almost entirely dependent on LNG imports for natural gas supplies, their overall consumption patterns translate directly to import

requirements. South Korea’s imports grow moderately in the IEO2016 Reference case, in line with the country’s growth in natural gas demand.

Japan has experienced dramatic growth in LNG imports since the Fukushima nuclear disaster in early 2011, with total LNG imports in 2012 approximately 25% higher than in 2010. Beginning in 2015, there has been a gradual restart of Japan’s nuclear capacity, and in the IEO2016 Reference case, those gradual restarts are assumed to continue and to lessen the country’s need for LNG imports. When nuclear power generators are able to provide about 15% of Japan’s total generation, the country’s natural gas import demand is expected to return to the slow growth trend anticipated before the Fukushima event, based on relatively slow economic growth and declining population.

**Non-OECD natural gas trade**

Net exports of natural gas from non-OECD countries decline by less than 1.0%/year on average in the IEO2016 Reference case. As with the OECD countries, the relatively small decline for the region in aggregate obscures changes in the trading patterns of the separate non-OECD regions and countries.

**Non-OECD Europe and Eurasia**

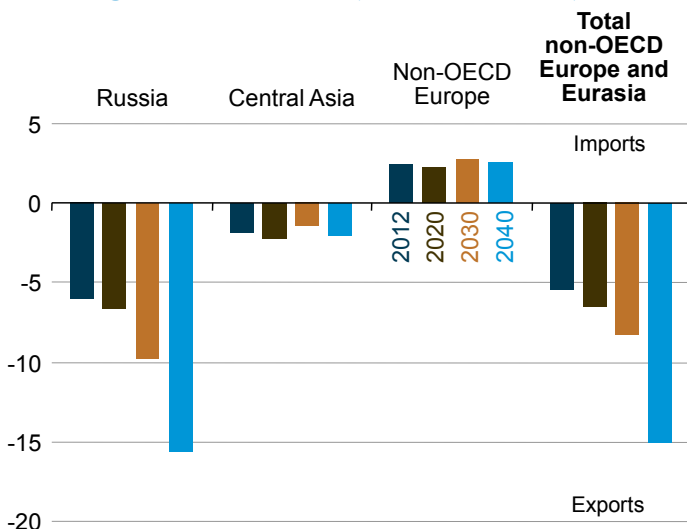
Net exports of natural gas from Russia, the largest exporter in the world, represent the most significant factor in exports from non-OECD Europe and Eurasia, which grow in the IEO2016 Reference case by an average of 3.7%/year, from 5.4 Tcf in 2012 to 6.5 Tcf in 2020 and 15.0 Tcf in 2040 (Figure 3-32). With Russia providing the largest incremental volume of exports to meet the increase in demand for supplies from non-OECD Europe and Eurasia, its net exports grow by an average of 3.4%/year, from 6.1 Tcf in 2012 to 15.6 Tcf in 2040. LNG and pipeline exports from Russia to customers in both Europe and Asia increase throughout the projection, while exports from Central Asia increase by an average of 0.3%/year.

**Middle East**

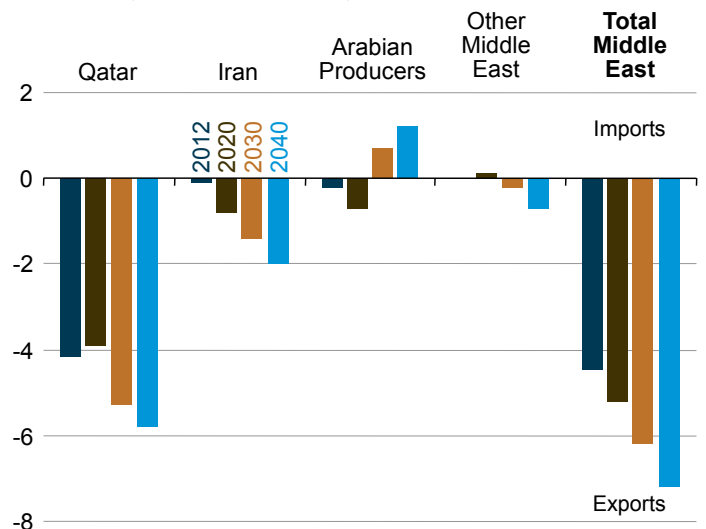
Net exports of natural gas from the Middle East grow by an average of 1.7%/year, as flows from the region increase from 4.4 Tcf in 2012 to 7.2 Tcf in 2040 (Figure 3-33). An important factor in the increase is the growth of LNG supplies from Qatar after 2025. Qatar’s natural gas exports grow by an average of 1.2%/year from 2010 to 2040 in the IEO2016 Reference case. With the current moratorium on further development of Qatar’s North Field, no new LNG projects are being initiated. Qatar enacted the moratorium in 2005 to assess the effect of ongoing increases in production on the North Field before committing to further increases.

Iran is another Middle Eastern country that is expected to increase its natural gas exports over the projection period. Net natural gas exports from Iran grow from 0.1 Tcf in 2012 to 2.0 Tcf in 2040 according to the IEO2016 Reference case. International sanctions against Iran’s oil and natural gas sectors have been eased as a result of the Joint Comprehensive Plan of Action (JCPOA) agreement reached between Iran, the P5+1 (the five permanent members of the United Nations Security Council and Germany), and the European Union (EU). The JCPOA agreement has the potential to increase Iran’s natural gas exports (both by pipeline and, in the longer term, LNG) beyond the amount projected in the IEO2016 Reference case (see also “Potential for increased natural gas exports from Iran following the end of international sanctions,” below).

**Figure 3-32. Non-OECD Europe and Eurasia net natural gas trade, 2012–40 (trillion cubic feet)**



**Figure 3-33. Middle East net natural gas trade, 2012–40 (trillion cubic feet)**



## Potential for increased natural gas exports from Iran following the end of international sanctions

After Russia, Iran has the second-largest proved reserves of natural gas in the world,<sup>81</sup> and it has a strong potential to develop those resources at a faster pace after the recent lifting of nuclear-related sanctions. Iran is targeting a substantial increase in natural gas production in the coming years, not only to meet rapidly growing domestic demand, but also to boost its export capacity, primarily by pipeline. In the longer term, Iran plans to build LNG export facilities for global shipments of natural gas.

Additional production of natural gas for export markets will compete with Iran's domestic demand for natural gas, which is used both for reinjection in the production of oil and as a feedstock in the country's rapidly growing domestic petrochemical industry. According to estimates by the National Iranian Gas Company (NIGC), more than \$100 billion in investment capital will be needed to rebuild Iran's natural gas industry.

Iran is currently the fourth-largest natural gas consumer in the world after the United States, Russia, and China, with total consumption of 15.4 Bcf/d in 2014<sup>82</sup> and 16.6 Bcf/d in the first 6 months of 2015. From 2005 to 2014, Iran's domestic consumption of natural gas grew by 66%, second only to the rate of increase in China.<sup>83</sup> In 2014, Iran's natural gas production and consumption were closely matched, with net exports of 0.1 Bcf/d. In 2014, the residential, commercial, and public sectors and small industries accounted for 55% (8.4 Bcf/d) of Iran's total natural gas consumption. Power plants and large industries accounted for 45% (7.0 Bcf/d) of Iran's total natural gas consumption in 2014. According to NIGC's Strategic Objectives document, Iran plans to increase the natural gas share of its domestic energy mix and more than double its natural gas processing capacity, from approximately 20 Bcf/d in 2014 to 42 Bcf/d by 2025,<sup>84</sup> while reducing its consumption of fuel oil in power generation and replacing its aging oil-fired plants with new natural gas-fired plants.

NIGC estimates that to meet the rapidly growing domestic demand for natural gas, Iran will need more than \$20 billion in investment to upgrade and expand its domestic pipeline infrastructure. Iran plans to expand the domestic pipeline network to more than 35 Bcf/d by 2017, adding 1,709 miles (2,750 km) of new pipelines at a cost of \$6.3 billion and investing more than \$15 billion in expansion and upgrades of the existing domestic pipeline network. Those expansions are likely to require foreign capital, and to attract foreign investors Iran has proposed various investment schemes, including *build-operate-own-transfer*. Some foreign investors may be reluctant to proceed at this point because of concerns about corruption, red tape, and state influence over the economy. Consequently, it may take some time for the expansion plans to materialize.

Iran has increased its domestic natural gas production fivefold over the past 20 years. Most of its natural gas production comes from the South Pars field, the largest natural gas field in the world, which Iran shares with Qatar. On Qatar's side, the field is called the *North Field*. Iran is developing 28 phases in South Pars, 10 of which are operational.<sup>85</sup> Phase 12 began production in early 2015 (3 Bcf/d of natural gas and 120,000 b/d of condensate). Production from phases 15 and 16 began at the end of 2015.<sup>86</sup> Between 2015 and 2020, Iran has the potential to add between 8 Bcf/d and 9 Bcf/d of new natural gas production, primarily from South Pars. The Kish field, the largest nonshared natural gas field in the country, is being developed. Kish has a production target of 0.9 Bcf/d of natural gas and 4 million barrels of gas condensate<sup>87</sup> per year, and \$1.4 billion has been allocated for its development. In addition, after 2020, Iran plans to develop its North Pars, Golshan, and Ferdowsi natural gas fields.

In 2014, 93% of Iran's pipeline exports (0.9 Bcf/d) went to Turkey, and 0.03 Bcf/d went to Armenia and Azerbaijan (net of imports from Azerbaijan). Iran imported 0.7 Bcf/d from Turkmenistan in 2014, or half of its contractual volumes, as Iran's growing production allowed it to become more self-sufficient in delivering natural gas to its major consumption centers in the northern part of the country. The price of Iran's natural gas exports to Turkey is one of the highest in the region, and it has been used as a benchmark for Iran's other proposed pipeline export projects. However, the reluctance of Persian Gulf countries to sign contracts at those prices has been the main obstacle to Iran's development of new pipeline export projects. Future contracts for exports to Gulf countries are likely to require some reduction in the prices of Iranian natural gas exports.

Iran's Sixth Development Plan, which outlines its economic development goals for the next five years, sets a target to increase natural gas exports to more than 6 Bcf/d by March 2021. The target is based on expanding production primarily from the South Pars field, which can be exported by pipeline to Iran's neighboring countries. In the plan, Iran has prioritized pipeline exports over LNG exports, with a potential total of 3 Bcf/d to 4 Bcf/d in the next several years coming from projects that are close to completion.

(continued on page 56)

<sup>81</sup>C. Xu and L. Bell, "Global reserves, oil production show increases for 2014," *Oil & Gas Journal* (December 1, 2014).

<sup>82</sup>FACTS Global Energy, "Iran Oil & Gas Monthly Report" (Datafile) (London, UK: August 2015), <https://www.fgenergy.com/> (subscription site).

<sup>83</sup>Reuters, "Fitch: Major Iranian Gas Exports Will Take at Least Five Years" (July 10, 2015), <http://www.reuters.com/article/2015/07/10/idUSFit92836320150710#xjyCPxxARoAqX4sD.97>.

<sup>84</sup>Domestic upgrades key to Iran exports," *World Gas Intelligence* (August 12, 2015), [http://www.energyintel.com/pages/about\\_wgi.aspx](http://www.energyintel.com/pages/about_wgi.aspx) (subscription site).

<sup>85</sup>Phase 11 of South Pars development was initially allocated to the Pars LNG project, with a production target of 1.9 Bcf/d of gas and 80,000 b/d of condensate; however, because of sanctions, the project failed to progress.

<sup>86</sup>R. Yeganehshakib, "Will South Pars help bring Iran's economy back to life?" *Almonitor* (December 30, 2015), <http://www.al-monitor.com/pulse/originals/2015/12/iran-south-pars-phases-15-16-inauguration-impact.html#>.

<sup>87</sup>"Iran allocates \$1.4 B to develop Kish gas field," *Natural Gas Europe: Greater Caspian Region Weekly Overview* (July 12, 2015), <http://www.naturalgaseurope.com/greater-caspian-region-weekly-overview-july-12th-24609>.

The focus of Iran’s export pipelines is on neighboring Persian Gulf countries, Pakistan, potentially India, and in the longer term, exports to European countries via Turkey.

Exports of natural gas from Iran to the Persian Gulf countries—particularly, Iraq, Oman, Kuwait, and the United Arab Emirates (UAE)—are likely to begin by 2017-18.<sup>88</sup> There also are plans for Iran to increase exports to Iraq by 0.9 Bcf/d, to a total of 1.6 Bcf/d, but the duration of that export contract is expected to be short, because Iraq’s domestic production increases in the mid-2020s. Iran is also planning pipeline exports to Oman (0.7 Bcf/d to 1.0 Bcf/d via a proposed 109-mile subsea pipeline); to Kuwait (0.3 Bcf/d to 0.5 Bcf/d); and to the UAE (0.6 Bcf/d to 1.5 Bcf/d). The existing pipeline network connecting Iran’s Salman field to the Sharjah Emirate of the UAE can deliver 0.6 Bcf/d, but a dispute over the contract price has delayed gas shipments and is currently in international arbitration. If the pricing issue is resolved between parties, Iran can start exports to the UAE quickly.

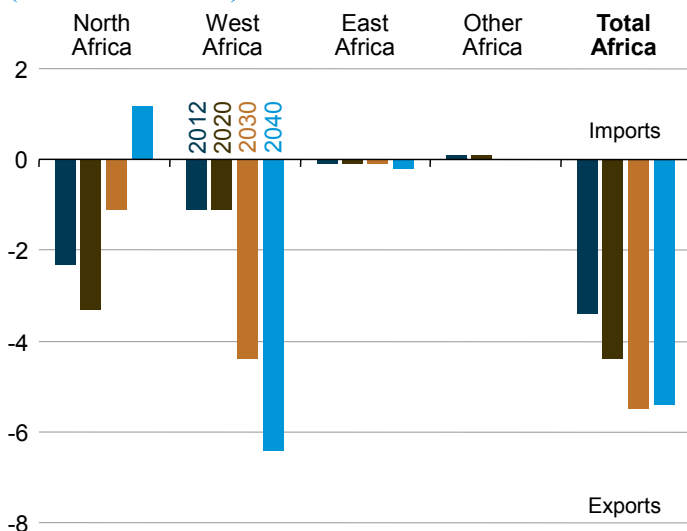
Proposed projects to export natural gas by pipeline from Iran to countries outside the Persian Gulf involve considerable risk for a variety of reasons. The proposed projects include:

- Pakistan plans to link the Iranian pipeline with a proposed \$45 billion China-Pakistan Economic Corridor. Iran has built all but the final 155 miles on its side, and China is building a 435-mile stretch inside Pakistan that would move natural gas from Gwadar port in the West to Nawabshah in the South. The project requires building a short 50-mile leg to Gwadar from the border with Iran, which is likely to be financed by China. Risks include terrorist threats in Pakistan’s Balochistan province, an enclave of Pakistani insurgents, and contract pricing that has not been finalized.
- Iran is in discussions to revive the Iran-Pakistan-India Peace Pipeline project, which may be a longer-term development. India has proposed to develop Iran’s 12.8 Tcf Farzad-B natural gas field and is considering construction of subsea pipeline to link Iran directly with India. However, at an estimated cost of about \$5 billion, the project is both expensive and technologically challenging.
- Iran also is considering exports to Europe via Turkey. An estimated \$5.1 billion investment would be required to expand a 1,120-mile, 56-inch-diameter pipeline that would connect Assaluyeh with Bazargan near the Turkish border.

LNG exports from Iran may be a longer-term development. Iran will face strong competition, and its projects may not be economically viable in the current environment of low oil prices. Among the projects that have been proposed, the Iran LNG project (capacity 1.4 Bcf/d) may be the most likely to materialize after 2020. Iran has already spent \$2.5 billion to build LNG port facilities, tank storage, and other infrastructure for the project and can now gain access to liquefaction technology not available when sanctions were in place. NIGC’s announced target of increasing its natural gas liquefaction capacity to 10% of the world total by 2025 is not likely to be met.<sup>89</sup> However, some smaller projects—including delivering natural gas via pipeline to Oman to use spare capacity in the Qalhat LNG liquefaction project, and use of Das Island liquefaction facility in Abu Dhabi—are more likely to be developed in the next few years.

Elsewhere in the Middle East, Yemen, Oman, and Abu Dhabi of the United Arab Emirates (UAE) also are current exporters of LNG. However, the potential for growth in their exports and exports from other countries in the Middle East appears to be limited by their need to meet increases in their own domestic demand. The IEO2016 Reference case shows a similar trend for smaller producers in the Arabian Peninsula as a whole, including Kuwait, Oman, the UAE, and Yemen. As a group, they exported about 0.2 Tcf of natural gas on a net basis in 2012, and the volume of their net imports rises to a total of 1.2 Tcf in 2040.

**Figure 3-34. Africa net natural gas trade, 2012–40 (trillion cubic feet)**



*Africa*

Net exports of natural gas from Africa increase in the IEO2016 Reference case by an average of 1.7%/year (Figure 3-34). In 2012, the region’s net exports totaled about 3.4 Tcf, with 2.3 Tcf coming from North Africa. Net exports from West Africa grow at a robust average annual rate of 6.5% from 2012 to 2040, with much of the growth coming in the later part of the projection. Security concerns and uncertainty over terms of access in Nigeria have significantly delayed any progress on currently proposed LNG export projects.

Persistent, significant above-ground challenges in East Africa hamper export growth in that region. This is primarily owing to production and export proposals representing a large change in scale of operations for the oil and natural gas industries in Mozambique and Tanzania, where physical and regulatory infrastructures are not yet in place to support large-scale production and export of natural gas (see “Potential for

<sup>88</sup>“Iran’s Gas Exports Outlook Post-Sanctions,” *FACTS Global Energy*, Issue 238, published July 22, 2015 (subscription site), <http://www.fgenergy.com>.

<sup>89</sup>D.R. Jalilvand, *Iran’s gas exports: can past failure become future success?* (Oxford, UK: June 2013), <http://www.oxfordenergy.org/wpcms/wp-content/uploads/2013/06/NG-78.pdf>.

increased natural gas exports from Iran following the end of international sanctions," and "Liquefied natural gas: Growing use of floating storage and regasification units," above).

### Non-OECD Asia

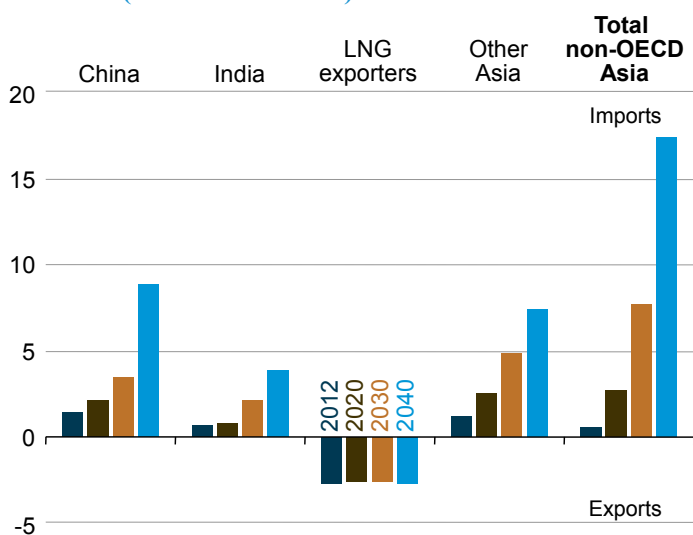
Non-OECD Asia has the highest regional growth rate in net imports of natural gas in the IEO2016 Reference case. With net imports of 17.5 Tcf in 2040, non-OECD Asia becomes the world's largest importing region, surpassing OECD Europe by 2040. China has the largest increase in import demand, to 8.9 Tcf/year in 2040, when nearly one-third of its annual natural gas consumption is supplied by imports (Figure 3-35).

To meet future demand, China is actively pursuing multiple potential sources for natural gas imports. Chinese companies have signed long-term agreements to deliver at least 6.6 Bcf/d through 2030.<sup>90</sup> Most of those contracts are with Asian firms sourcing LNG from Australia, Indonesia, Malaysia, Qatar, and Papua New Guinea. Moreover, there are additional contracts tied to new liquefaction projects located in Australia, Russia, and the United States that are scheduled to come online by 2020.

China is also pursuing multiple sources for pipeline natural gas imports, which have increased as production from Central Asia and Myanmar has grown and the non-OECD region's natural gas infrastructure has improved. China's total pipeline imports of natural gas exceeded its LNG imports in 2012, and in 2014 its LNG imports totaled 1.1 Tcf, up by 20% from 2013 LNG imports.<sup>91</sup> China's first natural gas import pipeline, which was completed in late 2009, now transports supplies from Turkmenistan and Uzbekistan. Another pipeline from Myanmar was completed in 2013, with the capacity to carry 0.4 Tcf/year of natural gas from Myanmar's offshore fields in the Bay of Bengal to Kunming in China's Yunnan province.<sup>92</sup> China also began importing natural gas from Kazakhstan in July 2013, but the quantities have been very small, constituting about 1% of the total pipeline imports into China in 2015.

In addition, Russia and China signed a significant natural gas agreement in May 2014. The deal was signed after a decade of negotiations over the import price and the supply route,<sup>93</sup> with China agreeing to purchase 1.3 Tcf of natural gas per year from Gazprom's East Siberian fields at a total cost of \$400 billion over a 30-year period. The proposed Power of Siberia pipeline will connect Russia's eastern Siberian natural gas fields and Sakhalin Island to northeastern China. China's National Development and Reform Commission, which approved construction of the pipeline on the Chinese side in late 2014, anticipates that it will come online in 2018. In November 2014, Gazprom and the China National Petroleum Commission also signed a memorandum of understanding for China to import 1.1 Tcf/year from Russia's western Siberian natural gas fields, although many key details, including pricing details and required infrastructure expansion plans, have not yet been addressed.<sup>94</sup>

**Figure 3-35. Non-OECD Asia net natural gas trade, 2012–40 (trillion cubic feet)**



India has also increased its natural gas imports. Since 2013, unexpected production declines in India's Krishna Godavari basin have meant that the country must rely more heavily on LNG imports. As a result, Indian companies have invested in increasing the country's LNG regasification capacity in recent years to meet rising demand. In early 2013, GAIL (India's largest state-owned natural gas processing and distribution company), NTPC (India's largest power utility), and several other smaller players restarted the Dabhol project (originally proposed by the now-defunct Enron Corporation), which includes a regasification terminal to fuel three natural gas-fired power stations.<sup>95</sup> Dabhol LNG also ships natural gas to southern India through the new pipeline to Bengaluru. GAIL is installing a breakwater facility to double Dabhol's capacity by 2017. Petronet's LNG terminal at Kochi, commissioned in late 2013, is experiencing low utilization as a result of delays in the approval and construction of a proposed pipeline to Mangalore and other parts of southern India, according to IHS. India's natural gas imports grow in the IEO2016 Reference case by an average of 6.7%/year, to a total of 3.9 Tcf in 2040.

<sup>90</sup>Estimate derived from IHS Energy, "Liquefaction Sales Contract Database" (March 24, 2015), [www.ihs.com](http://www.ihs.com) (subscription site).

<sup>91</sup>U.S. Energy Information Administration, "China: International Energy Data and Analysis" (Washington, DC: May 14, 2015), <https://www.eia.gov/beta/international/analysis.cfm?iso=CHN>.

<sup>92</sup>Du Juan, "Myanmar-China gas pipeline opens," China Daily USA (July 30, 2013), [http://usa.chinadaily.com.cn/epaper/2013-07/30/content\\_16851851.htm](http://usa.chinadaily.com.cn/epaper/2013-07/30/content_16851851.htm).

<sup>93</sup>E. Mazneva and S. Kravchenko, "Russia, China Sign \$400B Gas Deal After Decade of Talks" *Bloomberg Business News* (May 21, 2014), <http://www.bloomberg.com/news/articles/2014-05-21/russia-signs-china-gas-deal-after-decade-of-talks>.

<sup>94</sup>J. Paton and A. Guo, "Russia, China Add to \$400 Billion Gas Deal With Accord," *Bloomberg Business News* (November 9, 2014), <http://www.bloomberg.com/news/articles/2014-11-10/russia-china-add-to-400-billion-gas-deal-with-accord>.

<sup>95</sup>U.S. Energy Information Administration, "India: International Energy Data and Analysis" (Washington, DC: June 26, 2014), <https://www.eia.gov/beta/international/analysis.cfm?iso=IND>.

**Non-OECD Americas**

Natural gas trade in the non-OECD Americas region has become increasingly globalized as several countries have become involved in the LNG trade. In the IEO2016 Reference case, new LNG regasification capacity facilitates growth in the region's gross imports of natural gas through 2040, but the discovery of large new natural gas reserves throughout the region increases its gross exports by a larger amount. As a result, the region's overall trade balance remains relatively flat, with net exports increasing from 0.6 Tcf in 2012 to 0.7 Tcf in 2040 (Figure 3-36), after declining in the middle years of the projection.

Although LNG regasification facilities in Brazil and in the Southern Cone (excluding Chile, an OECD member state since 2010) have received LNG supplies fairly consistently over the past three years, the Southern Cone becomes a net exporter of natural gas by 2030 in the IEO2016 Reference case, largely as a result of the discovery of substantial shale gas reserves in Argentina's northwestern Neuquén province.<sup>96</sup> Net imports to Brazil remain essentially flat from 2012 through 2040. Overall net exports from the Andean region end in 2030 and net exports from the Northern Producers increase by an average of 0.5%/year from 2012 to 2040.

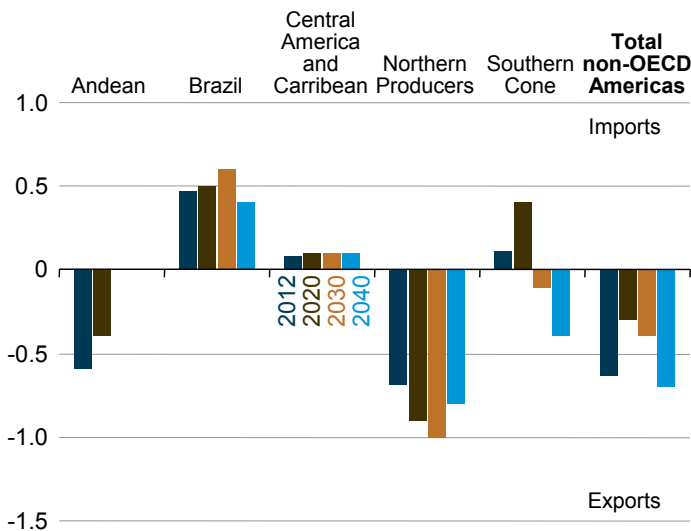
**World natural gas reserves**

As reported by *Oil & Gas Journal*,<sup>97</sup> the world's proved natural gas reserves have grown by about 40% over the past 20 years, to a total of 6,950 Tcf as of January 1, 2016 (Figure 3-37). Estimated proved reserves in the non-OECD region as a whole have grown by 43% (1,912 Tcf) since 1996, while proved reserves in the OECD region have grown by 21% (104 Tcf) since 1996. As a result, the share of world proved natural gas reserves located in OECD countries has declined from 10% in 1996 to 9% in 2016.

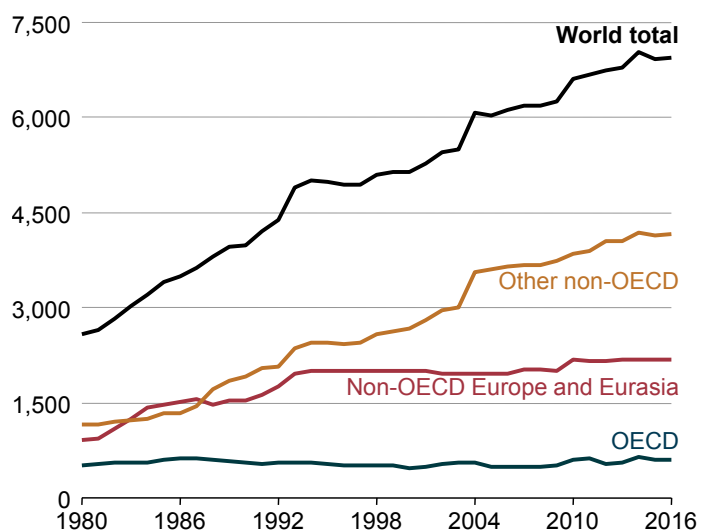
The annual rate of growth in world proved natural gas reserves from 1980 to 1995 was notably higher than it has been in more recent years. Since 1995, the annual growth rate, while variable, has slowed to a reasonably steady rate of about 1.6%/year. Over the past 10 years, estimates of proved world natural gas reserves rose by 838 Tcf, or an average of 1.3%/year, as compared with 1,179 Tcf, or 2.2%/year on average over the previous 10 years (from 1996 to 2006). Estimated proved reserves in the non-OECD countries rose by 723 Tcf, or an average of 1.2% annually, over the past 10 years, compared with 2.4% annually from 1996 to 2006. The most rapid annual increase in non-OECD proved reserves in this period, at 12%/year, occurred from 2003 to 2004, supported by an increase in Qatar from 509 Tcf to 910 Tcf. In comparison, proved reserves in the OECD countries declined by 0.2%/year from 1996 to 2006 and increased by 115 Tcf, or an average of 2.1%/year, over the past 10 years.

World proved natural gas reserves generally have grown in each year since 1980, but declines have been reported for four years (1995, 1996, 2005, and 2015). Although world reserves increased by a modest 0.4% from 2015 to 2016, that increase follows a decrease of 1.5% (105 Tcf) from 2014 to 2015, and the estimate for 2016 still is lower than the 2014 level. Estimates of proved reserves in both the OECD and non-OECD regions show a similar trajectory; however, the absolute decrease in 2015 and the increase in 2016 were greater in the OECD countries, even though their reserve levels are less than one-tenth the levels in the non-OECD countries. Accordingly, the percentage decrease from 2014 to 2015 was 9.0% for the OECD countries, compared to 0.7% for the non-OECD countries, and the increase from 2015 to 2016 was 2.9% for the OECD countries, compared to 0.2% for the non-OECD countries.

**Figure 3-36. Non-OECD Americas net natural gas trade, 2012–40 (trillion cubic feet)**



**Figure 3-37. World proved natural gas reserves by region, 1980–2016 (trillion cubic feet)**



<sup>96</sup>U.S. Energy Information Administration, "Argentina: International Energy Data and Analysis" (Washington, DC: April 2014), <http://www.eia.gov/beta/international/analysis.cfm?iso=ARG>.

<sup>97</sup>"Worldwide Look at Reserves and Production," *Oil & Gas Journal*, Vol. 113, No. 12 (December 7, 2015), pp. 22-23, <http://www.ogi.com/articles/print/volume-113/issue-12.html> (subscription site).

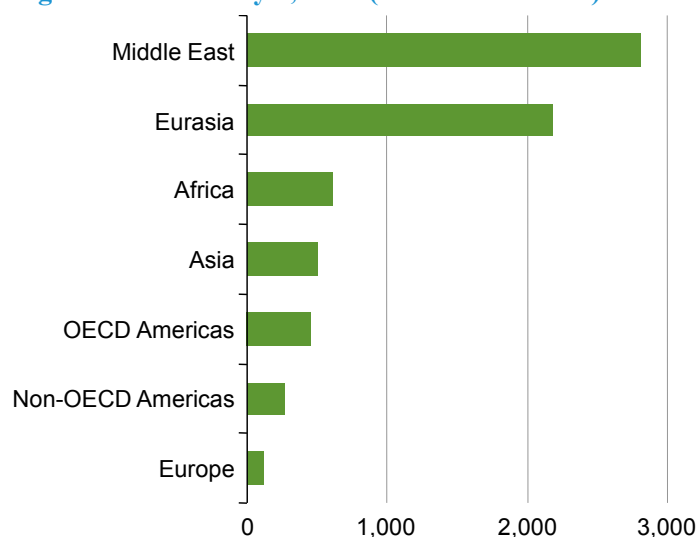
Estimates of world proved reserves increased by 31 Tcf from 2015 to 2016, with more than one-half of the increase (17 Tcf) coming from OECD countries. From 2015 to 2016, proved reserves in the OECD Americas rose by 29 Tcf, proved reserves in OECD Europe fell by 11 Tcf, and proved reserves in the countries of OECD Asia were nearly flat. Estimated proved reserves in the non-OECD countries increased by 13 Tcf from 2015 to 2016, with a combined 17 Tcf of additional proved reserves in China, Malaysia, India, and Angola partially offset by a decrease of 2 Tcf in Indonesia's proved reserves.

The largest change in proved natural gas reserve estimates was for the United States, where estimated proved natural gas reserves increased by 30 Tcf (9%), from 338 Tcf in 2015 to 369 Tcf in 2016. The second-largest change was for China, where estimated proved reserves increased by 11 Tcf (7%), from 164 Tcf in 2015 to 175 Tcf in 2016. As a result, China's estimated proved reserves are now the world's 10th largest, up from the 11th largest in 2015. The third-largest change in estimated proved reserves was for Saudi Arabia, with estimated reserve additions of 6 Tcf (2%), from 294 Tcf in 2015 to 300 Tcf in 2016. Although there were no changes in proved reserves for Russia and Iran, their proved reserves are ranked first and second in the world at 1,688 Tcf and 1,201 Tcf, respectively. Qatar and the United States are ranked third and fourth, at 866 Tcf (down 1%) and 369 Tcf (up 9%), respectively.

Current estimates of proved natural gas reserves worldwide indicate a large resource base to support growth in markets through 2040 and beyond. Like reserves for other fossil fuels, natural gas reserves are spread unevenly around the world. Natural gas proved reserves are concentrated in Eurasia and in the Middle East, where ratios of proved reserves to production suggest decades of resource availability. However, in the OECD countries, including many in which there are relatively high levels of consumption, current ratios of proved reserves to production are significantly lower. The impact of that disparity is reflected in the IEO2016 projections of increased international trade in natural gas.

Almost three-quarters of the world's proved natural gas reserves are located in the Middle East and Eurasia (Figure 3-38), with Russia, Iran, and Qatar together accounting for about 54% of world proved natural gas reserves as of January 1, 2016 (Table 3-2). Proved reserves in the rest of the world's regions are distributed fairly evenly. Despite high rates of increase in natural gas consumption, particularly over the past decade, most regional reserves-to-production ratios have remained high. Worldwide, the reserves-to-production ratio is estimated at 54 years. Central and South America has a reserves-to-production ratio of 44 years, Russia 56 years, and Africa 70 years. In contrast, the Middle East's reserves-to-production ratio exceeds 100 years.<sup>98</sup> The United States has a reserves-to-production (R/P) ratio of 13 years.<sup>99</sup>

**Figure 3-38. World proved natural gas reserves by region as of January 1, 2016 (trillion cubic feet)**



**Table 3-2. World natural gas reserves by country as of January 1, 2016**

Country	Reserves (trillion cubic feet)	Percent of world total
<b>World</b>	<b>6,950</b>	<b>100.0</b>
<b>Top 20 countries</b>	<b>6,359</b>	<b>91.5</b>
Russia	1,688	24.3
Iran	1,201	17.3
Qatar	866	12.5
United States	369	5.3
Saudi Arabia	300	4.3
Turkmenistan	265	3.8
United Arab Emirates	215	3.1
Venezuela	198	2.9
Nigeria	180	2.6
China	175	2.5
Algeria	159	2.3
Iraq	112	1.6
Indonesia	102	1.5
Mozambique	100	1.4
Kazakhstan	85	1.2
Egypt	77	1.1
Canada	70	1.0
Norway	68	1.0
Uzbekistan	65	0.9
Kuwait	63	0.9
<b>Rest of world</b>	<b>591</b>	<b>8.5</b>

<sup>98</sup>BP, "Natural gas: Total proved reserves," *BP Statistical Review of World Energy June 2015* (London, United Kingdom: June 2015), <http://www.bp.com/content/dam/bp/pdf/energy-economics/statistical-review-2015/bp-statistical-review-of-world-energy-2015-full-report.pdf>.

<sup>99</sup>A 13-year R/P ratio does not imply that the United States will run out of gas in 13 years. The U.S. gas resource base is sufficiently large to allow for continuing expansion of both reserves and production (under most economic, technical, and environmental scenarios). It would not be unusual, for example, for an R/P ratio to remain constant or grow over time, despite production growth. Under R/P, the United States has had 10 years or so of natural gas remaining for the past 100 years. Clearly, the R/P ratio can be a misleading statistic.

Proved reserves include only estimated quantities of natural gas that can be produced economically from known reservoirs, and therefore they are only a subset of the entire potential natural gas resource base. Resource base estimates include estimated quantities of both discovered and undiscovered natural gas that have the potential to be classified as reserves at some time in the future. In the IEO2016 Reference case, the resource base does not pose a constraint on global natural gas supply. By basing long-term production assessments on resources rather than reserves, EIA is able to present projections that are physically achievable and can be supported beyond the 2040 projection horizon. The realization of such production levels depends on future growth in world demand, taking into consideration such above-ground limitations on production as profitability and specific national regulations, among others.