Chapter 2
Petroleum and other liquid fuels

Overview

In the *International Energy Outlook 2016* (IEO2016) Reference case, worldwide consumption of petroleum and other liquid fuels increases from 90 million barrels per day (b/d) in 2012 to 100 million b/d in 2020 and 121 million b/d in 2040. Much of the growth in world liquid fuels consumption is projected for the emerging, non-Organization for Economic Cooperation and Development (non-OECD) economies of Asia, the Middle East, and Africa, where strong economic growth and rising populations increase the demand for those fuels. In contrast, demand for liquid fuels in the United States, OECD Europe, and other regions with well-established liquids markets grows slowly or declines from 2012 to 2040. After a long period of sustained high oil prices, conservation and efficiency improvement measures have reduced or slowed the growth of liquid fuels use among OECD consumers and, in the future, will help to temper demand growth in non-OECD countries as well.

To satisfy rising demand for liquid fuels in the IEO2016 Reference case, liquids production increases by 31 million b/d over the 2012–40 period. IEO2016 projections of future liquid fuels balances include two broad categories: crude oil and lease condensate, and other liquid fuels. Crude oil and lease condensate includes: reservoired oil (often referred to in the trade press as conventional oil), tight oil (shale oil), extra-heavy crude oil, field condensate, and bitumen (i.e., oil sands, either diluted or upgraded). Other liquid fuels refers to natural gas plant liquids (NGPL), biofuels, including biomass-to-liquids (BTL), gas-to-liquids (GTL), coal-to-liquids (CTL), kerogen (i.e., oil shale), and refinery gain.[20]

The benchmark oil price in IEO2016 is based on spot prices for North Sea Brent crude oil, which is an international standard for light sweet crude oil. The West Texas Intermediate (WTI) spot price is generally lower than the North Sea Brent price. The U.S. Energy Information Administration (EIA) expects the price spread between Brent and WTI to range between $0 per barrel ($0/b) and $10/b, and will continue to report WTI prices (a critical reference point for the value of growing production in the U.S. Midcontinent) as well as the imported refiner acquisition cost for crude oil (IRAC). The December 2015 decision by the U.S. Congress to remove restrictions on U.S. crude oil exports also has the potential to narrow the spread between the Brent price and the price of domestic production streams under certain cases involving high levels of U.S. crude oil production.[21]

Growing liquids supplies in North America—especially from the United States and Canada—brought almost 7 million b/d of additional liquid fuels to market between 2008 and 2015. That increase has been offset only partially by supply disruptions in other oil-producing regions, notably North Africa and the Middle East. Over the past two years, unplanned crude oil production outages averaged 3.2 million b/d, according to EIA estimates, and amounted to 3.4 million b/d in November 2015.[22] Organization of the Petroleum Exporting Countries (OPEC) member countries Libya, Iraq, and Iran and non-OPEC countries South Sudan and Syria have accounted for a sizeable portion of the unplanned outages. It is difficult to predict when supplies from those nations may return, given their substantial geopolitical risks, which adds considerable uncertainty to the projections.

Global liquid fuels production exceeded consumption beginning in 2014 and reached 95 million b/d in 2015. The surplus production went into storage, swelling OECD inventories to 2.7 billion barrels in November 2015. Oil markets are expected to remain oversupplied in the short term, keeping EIA's forecast for annual average prices below $50/b[23] through at least 2017.

In previous instances of oil market oversupply, OPEC members have cut production to stabilize or increase prices. However, Saudi Arabia, the only member with substantial spare capacity, is no longer willing to bear the burden of production cuts alone, and since prices began falling in mid-2014, OPEC members have not acted together to cut production. Thus, OPEC production has remained stable and even increased, as OPEC members have attempted both to maximize revenue in the near term and to preserve market share. The national economies of many OPEC members are largely dependent on oil revenues, which already have been cut by the price drop, and OPEC producers have so far been unwilling to risk further revenue losses by decreasing production.

Four main factors could provide incentives for a sustained increase in world liquids production: (1) competition among OPEC member countries for market share; (2) revenue requirements of liquids-exporting countries; (3) decreasing service costs; and (4) further technology advances that lower the cost and raise recovery rates for tight oil development.

The IEO2016 uses price paths from the *Annual Energy Outlook 2015* (AEO2015) Reference case, the AEO2015 Low Oil Price case, and the AEO2015 High Oil Price case, except for adjustments to the first few years that were incorporated to reflect the continued declines in crude oil prices that have occurred since the AEO2015 was published. Oil prices observed in 2015 and into 2016 more closely resemble prices in the AEO2015 Low Oil Price case than those in the AEO2015 Reference case. However, oil prices are expected to return to the AEO2015 Reference case path in the midterm when demand for liquid fuels returns to the growth rates projected in the IEO2016 Reference case.

[20]The terms biofuels, GTL, CTL, and kerogen are used in the text of this chapter because they are common terms; however, in the tables a more uniform nomenclature is employed: liquids from renewable sources, liquids from natural gas, liquids from coal, and liquids from kerogen, respectively.

[21]U.S. Energy Information Administration, *Effects of Removing Restrictions on U.S. Crude Oil Exports* (Washington, DC: September 2015), http://www.eia.gov/analysis/requests/crude-exports/.

[22]U.S. Energy Information Administration, *Short-Term Energy Outlook* (Washington, DC: December 2015), Figures 35 and 36, www.eia.gov/forecasts/STEO.

[23]Unless otherwise noted, all prices are reported in inflation-adjusted 2013 U.S. dollars.

In response to low oil prices, which have reduced expectations of future revenue (and thus expected profits), capital expenditures for investment in future production potential have been delayed or canceled. However, many OPEC and non-OPEC large capital investment projects scheduled to be completed over the next several years will continue as planned. However, investment is likely to continue slowing to a point at which producers (outside of tight oil plays), which provide over 90% of world crude and lease condensate supply will be unable to respond quickly to future growth in demand for liquids. As a result, prices are expected to return to the range of $80/b within the next decade. If supply growth slows as a result of underinvestment, a sustained period of higher prices may be required to induce additional capital back into the market. Even then, long project timelines will delay the reentry of some production from noncontinuous resources into the market.

World demand for liquid fuels has also been a key factor in the low world oil prices of the past few years. In non-OECD countries, strong growth of liquids demand in the early to mid-2000s has moderated substantially as economic growth in key economies, including China, India, and Brazil, has slowed. Liquids consumption among OECD countries, which reached 50 million b/d in 2005, has been trending downward generally since that time, reflecting both growing energy efficiency in the transportation sector and a lull in demand associated with slow economic growth. However, even with those trends tending to dampen demand growth, world liquid fuels consumption rises by an annual average of 1.1 million b/d in the IEO2016 Reference case.

Key influences on consumption and production are price trends and the reactions of consumers and producers to those trends, which in turn influence future prices. EIA has developed three price cases to examine a range of potential interactions of supply, demand, and prices in world liquid fuels markets: the IEO2016 Reference case and alternative Low Oil Price case and High Oil Price case (Figure 2-1 and Table 2-1). Although the three oil price cases represent a wide range of future market scenarios, they do not capture all possible outcomes, and they are not intended to represent a measure of uncertainty. Because EIA's oil price paths represent market equilibrium between supply and demand, they do not show the price volatility[24] that occurs over days, months, or years.

In the IEO2016 Reference case, world consumption of petroleum and other liquid fuels increases from 90 million b/d in 2012 to 100 million b/d in 2020 and 121 million b/d in 2040. Compared with the IEO2014, the IEO2016 incorporates a smaller increase in production from non-OPEC producers, particularly the United States, because of the effects of the drop in the oil prices that began in mid-2014. The IEO2016 Reference case assumes that OPEC countries maintain or increase their combined market share of world liquid fuels production rather than cut production. Total OPEC liquid fuels production represents between 39% and 43% of total world production throughout the projection.

In comparison with the IEO2014, production of tight oil is particularly affected by the recent drop in oil prices. Still, the largest new supplies of tight oil are projected to come from the United States—with Canada, Russia, and Argentina, among other countries, also beginning to produce tight oil in the IEO2016 Reference case. In 2040, total production of tight oil outside the United States remains below U.S. production in the IEO2016 Reference case (Figure 2-2).

Figure 2-1. North Sea Brent crude oil spot prices in three cases, 1990–2040 (2013 dollars per barrel)

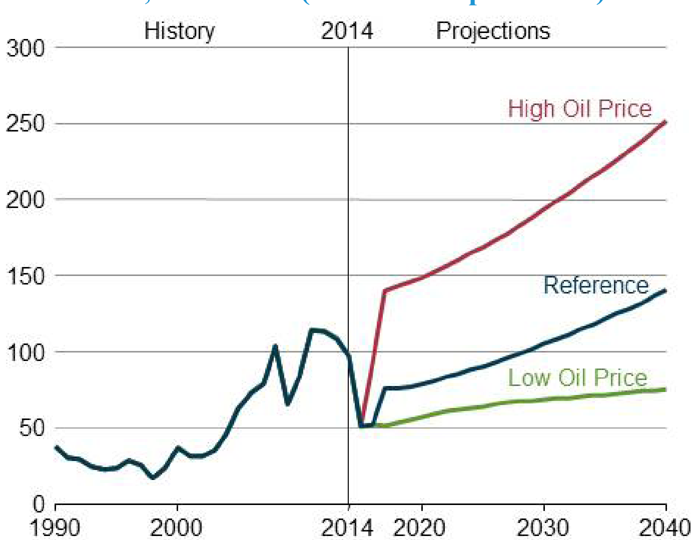
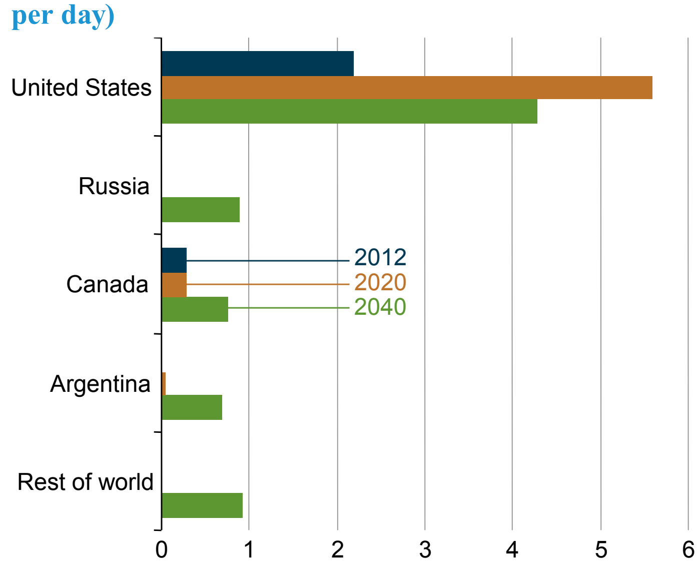


Table 2-1. North Sea Brent crude oil spot prices in three cases, 2012–40 (2013 dollars per barrel)

Year	Reference	Low Oil Price	High Oil Price
2012	113	113	113
2020	79	58	149
2025	91	64	169
2030	106	69	194
2035	122	72	221
2040	141	76	252

Figure 2-2. World tight oil production in the IEO2016 Reference case, 2012, 2020, and 2040 (million barrels per day)

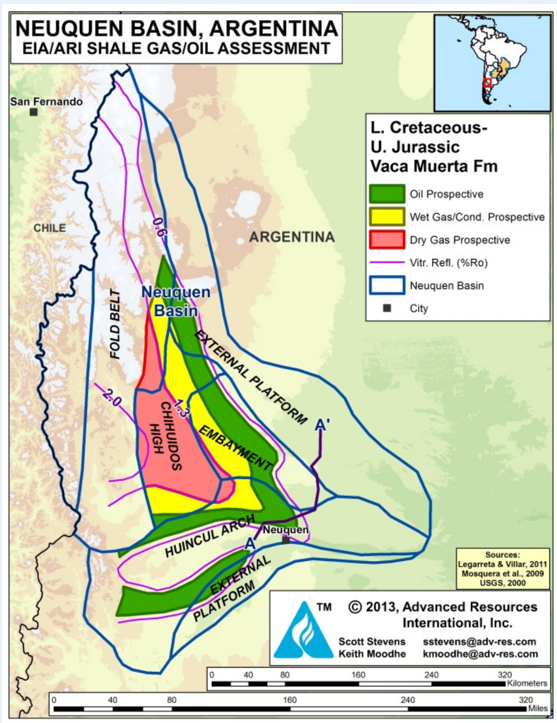


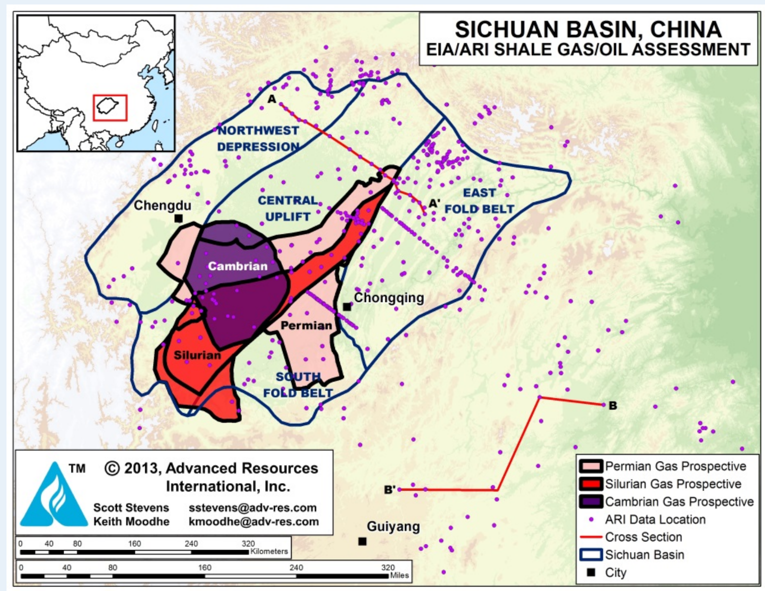
[24]Price volatility is a measure of price risk, often expressed as the degree of variation in a price series over time, as measured by the standard deviation of returns (i.e., percentage price changes). The price changes do not have to be measured on a daily basis and annualized. The price changes could be measured weekly, monthly, or even annually and then annualized.

Shale oil and tight gas: Recent developments outside North America

In 2014, only four countries—the United States, Canada, Argentina, and China—were producing commercial volumes of either natural gas from shale formations (shale gas) or crude oil from shale or other tight formations (tight oil). Since the beginning of 2014, China has drilled more than 200 shale gas and tight oil wells, and Argentina has drilled more than 275 shale gas and tight oil wells. Those two countries led shale resource development outside North America in the first half of 2015, and both have the potential to increase production significantly (Figure 2-3).[25] In addition, Algeria, Australia, Colombia, Mexico, Poland, and Russia also began exploring and producing hydrocarbons from shale and other tight resources in 2015, but they are still short of reaching commercial production.

Figure 2-3. EIA/ARI assessments of shale gas and tight oil resources in Argentina's Nequen Basin and China's Sichuan Basin





In Argentina, many international companies hold leases and have drilled wells in shale formations. Much of the initial activity has targeted shale oil and natural gas in the Neuquen Basin's Vaca Muerta Shale formation, located in west-central Argentina. National energy company Yacimientos Petroliferos Fiscales (YPF), the largest shale operator in the country, reported production in April 2015 of 22,900 b/d of oil and 67 million cubic feet per day (MMcf/d) of natural gas from three joint ventures in Vaca Muerta: one with Chevron at the Loma Campana field, a second with Dow Chemical at the El Orejano field, and a third with Petronas at La Amarga Chica field. In addition, China's national oil company Sinopec and Russia's national oil company Gazprom have recently signed a memorandum of understanding with YPF for the joint development of shale resources from the same basin.

China has identified the Longmaxi formation in the Sichuan Basin, located in south-central China, as its initial shale gas exploration and development objective. Although several international companies are active in China, much of the early effort has been led by two of China's national oil companies—Sinopec and PetroChina (owned by the China National Petroleum Corporation [CNPC]). According to China's Ministry of Land and Resources, the two companies are on schedule to reach 600 MMcf/d of shale gas production by the end of 2015. Sinopec has a commercial-scale effort underway at the Fuling Shale gas field in the Sichuan Basin, currently producing 130 MMcf/d. By the end of 2014, Sinopec had completed 75 test wells at the Fuling field, with plans to drill an additional 253 wells. CNPC has drilled 125 shale wells and brought 74 of them into production and is scheduled to produce 250 MMcf/d of shale gas by the end of 2015.

Production of other liquids increases by an average of 1.5%/year in the IEO2016 Reference case—50% faster than crude and lease condensate production. The growth in other liquid supplies is attributed in part to the coproducts of natural gas production (i.e., NGPL) and to government policies aimed at increasing the use of alternative liquid fuels in the transportation sector. Other liquids account for between 16% and 18% of total liquid supplies throughout the projection.

[25] EIA/ARI 2013 assessments noted large shale deposits in China and Argentina. See U.S. Energy Information Administration, "World Shale Resource Assessments," http://www.eia.gov/analysis/studies/worldshalegas/ (updated September 24, 2015), and *Technically Recoverable Shale Gas and Shale Oil Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States* (Washington, DC: June 13, 2013), http://www.eia.gov/analysis/studies/worldshalegas/archive/2013/pdf/fullreport_2013.pdf.

The High Oil Price case assumes faster economic growth among emerging non-OECD nations that contributes to higher world demand for petroleum and other liquid fuels. On the supply side, the High Oil Price case assumes less upstream investment by OPEC and a return to cartel-like behavior, and it assumes higher non-OPEC exploration and development costs. As a result, the average spot market price for Brent crude oil rises to $252/b in 2040, or 78% above the IEO2016 Reference case price in 2040.

The reverse is true in the Low Oil Price case. Slower economic growth leads to lower non-OECD demand for liquid fuels, while higher upstream investment and production and non-cartel behavior in OPEC, as well as lower non-OPEC exploration and development costs, contribute to increased supply from both OPEC and non-OPEC countries. As a result, the Brent spot price rises more slowly than in the IEO2016 Reference case, to $76/b in 2040, or 47% below the IEO2016 Reference case price in 2040.

The discussion presented here provides an overview of both the production and consumption of liquid fuels in the three price cases, as summarized in the notional supply and demand curves for 2040 shown in Figure 2-4. The oil price path in each of the three cases is derived from an internally consistent, illustrative scenario of supply and demand. However, other combinations of supply and/or demand could result in similar paths, and EIA does not evaluate the likelihood of either the price paths themselves or the scenarios upon which they are based. Each price case represents one of potentially many combinations of supply and demand that would result in the same price path. Because each case represents a potentially feasible equilibrium outcome, EIA does not assign probabilities to any of the oil price cases and does not consider that these three cases represent the range of all possible outcomes. The following section reviews each of the three price cases, their assumptions and indicative trends, and the potential effects of each set of factors on future liquids markets.

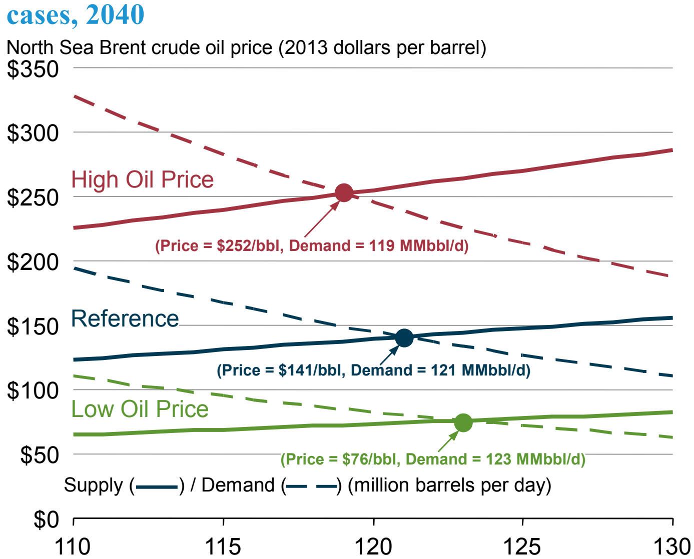
IEO2016 Reference case

The IEO2016 Reference case reflects global oil market events through the end of 2015. Over the past two years, growth in U.S. crude oil production, along with the late-2014 drop in global crude oil prices, has altered the economics of the oil market. The new market conditions are assumed to continue in the IEO2016 Reference case, with the average Brent price dropping from $113/b in 2012 to below $50/b in 2015. After 2017, growth in demand from non-OECD countries results in a return to higher world oil prices, and the Brent price rises to $141/b in 2040.

World petroleum and other liquid fuels consumption

In the IEO2016 Reference case, world liquid fuels consumption increases by about one-third (31 million b/d), from 90 million b/d in 2012 to 121 million b/d in 2040. In the medium to long term, oil prices rise as demand from the emerging, non-OECD economies continues to grow, especially in the transportation sector and also in the industrial sector. Long-term sustained increases in oil prices encourage consumers outside the transportation and industrial sectors to shift away from liquid fuels to more cost-competitive fuels wherever possible. The largest decrease in liquids consumption occurs in the electric power sector, where renewable fuels, natural gas, and nuclear power are substituted for liquids in many parts of the world.

Figure 2-4. Liquid fuels supply and demand (million barrels per day) and North Sea Brent crude oil equilibrium prices (2013 dollars per barrel) in three cases, 2040



Economic growth is among the most important factors to be considered in projecting changes in world energy consumption. In the IEO2016, assumptions about regional economic growth—measured in terms of real GDP expressed in purchasing power parity[26]—underlie the projections of regional demand for liquid fuels. World GDP increases by 3.3%/year from 2012 to 2040 in the IEO2016 Reference case, slightly lower than the average 3.5%/year increase in GDP that occurred between 1990 and 2012. Over the projection, economic growth in the non-OECD regions, averaging 4.2%/year, exceeds the OECD average of 2.0%/year.

Non-OECD regions account for essentially all the growth in liquid fuels consumption in the IEO2016 Reference case (Figure 2-7 and Table 2-2). In particular, non-OECD Asia and the Middle East account for about 75% of the world increase in liquids consumption from 2012 to 2040, with Africa and the non-OECD Americas each accounting for about 10% of the world increase (Figure 2-8). Fast-paced economic expansion among the non-OECD regions drives the increase in demand for liquid fuels, as strong growth in income per capita results in increased demand for personal and freight transportation, as well as demand for energy in the industrial sector.

[26]Purchasing power parity (PPP) compares different currencies through a market basket of goods approach. Two currencies are in PPP when a market basket of goods (taking exchange rates into account) is priced the same in both countries. See Investopedia LLC, http://www.investopedia.com/video/play/purchasing-power-parity-ppp/ (2016) and The Economist Newspaper Ltd., http://www.economist.com/content/big-mac-index.

Effects of regulation on world demand for residual fuel oil

Throughout the world, residual fuel oil (RFO) is used in many sectors, including in marine transportation, power generation, in commercial furnaces and boilers, and in various industrial processes. Also, in some areas RFO is used as a relatively low-cost fuel for space heating. RFO is one of several residuals that remain after lighter materials, including gasoline and distillate, are distilled from crude oil. RFO contains large amounts of contaminants, including sulfur, nitrogen, and heavy metals. Because of its high viscosity, RFO generally is either blended with lighter streams or heated to ensure that it can be pumped.

RFO plays an important role in the global market for liquid fuels because its price is normally below that of other liquids. However, health and environmental concerns related to the high sulfur content of RFO have led to new policies and regulations that have significantly lowered expectations for its use in the future (Figure 2-5). As demand for RFO declines, refining upgrades will be needed to convert residual material to lighter, cleaner products.

Large reductions in demand for RFO are likely to come from decreases in its use for power generation and for space heating. In the power sector, the cost of pollution controls, maintenance, and RFO heating often offset the lower cost of RFO in comparison with natural gas and other more expensive fuels. Consequently, power sector demand for RFO, especially in industrialized countries, is expected to decrease, although it may continue to serve as a transitional fuel in the power sectors of non-OECD countries that may be more sensitive to price and less sensitive to environmental and health implications. Additional significant reductions in RFO demand could come from the implementation of rules set by Annex VI of the International Maritime Organization through the International Convention of Pollution from Ships (Marpol).[27] Since 2012, Marpol regulations have required controls on emissions of sulfur and nitrogen oxides worldwide. The regulations are based on emissions associated with fuel combustion rather than on the fuels themselves. As a result, some marine transportation operators are considering the use of liquefied natural gas (LNG) as an alternative fuel for ships operating along routes where LNG is available.

Because few refineries are capable of removing sulfur from RFO, Marpol compliance is likely to be achieved by two approaches: using fuels with lower sulfur content (such as marine gasoil and intermediate fuel oil) and using scrubbers or other technologies to remove sulfur from the exhaust of combustion processes. The levels stipulated by the Marpol regulations can be met by using RFO with sulfur levels of no more than 3.5%. The rules also set more stringent requirements—consistent with RFO sulfur levels of no more than 0.1%—in designated Emissions Control Areas (ECAs), which include the North Sea, the Baltic Sea, and the coastal areas of North America and the Caribbean Sea. A 2016 study is intended to evaluate the probable availability and pricing of various compliance options for the use of RFO in non-ECA areas.[28] The study should yield a decision, no later than 2018, on when the implementation of RFO reduction standards establishing sulfur emissions levels of no more than 0.5% will go into effect—either in 2020 or in 2025 (Figure 2-6).

Figure 2-5. World consumption of residual fuel oil, 1986–2012 (million barrels per day)

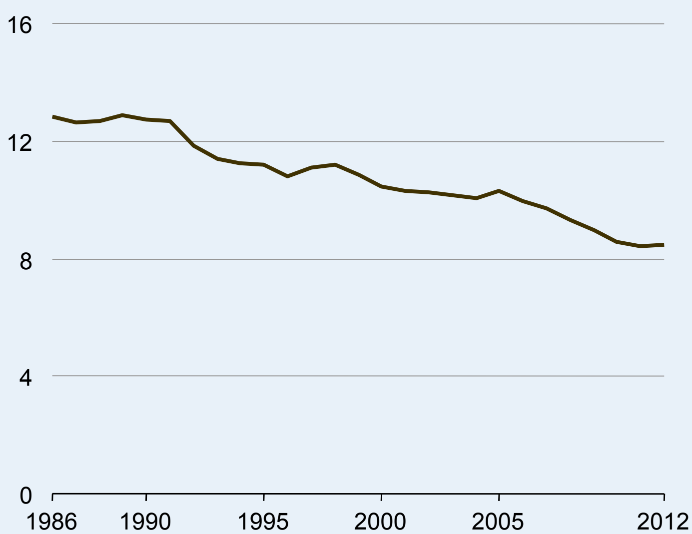
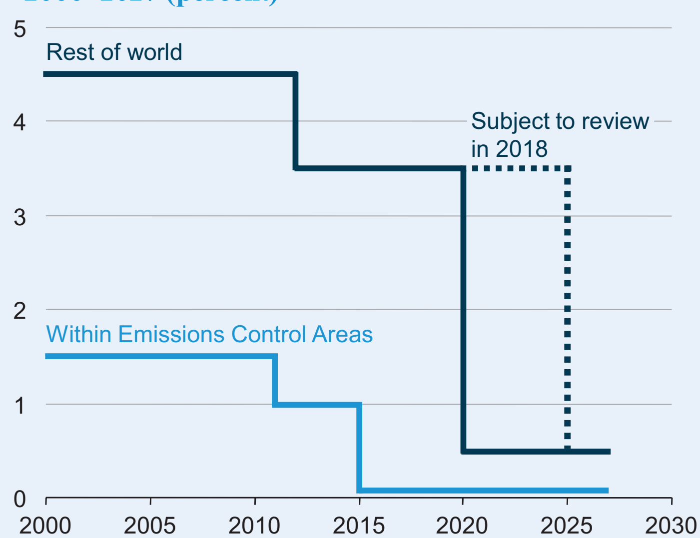


Figure 2-6. Current and proposed Marpol regulations on sulfur content of residual fuel oil, 2000–2027 (percent)



[27] International Maritime Organization, "International Convention for the Prevention of Pollution from Ships (MARPOL)" (London, UK: 2015), http://www.imo.org/en/About/Conventions/ListOfConventions/Pages/International-Convention-for-the-Prevention-of-Pollution-from-Ships-(MARPOL).aspx.

[28] When the revised Marpol Annex VI entered into force in July 2010, it included a change to the name and definition of an emission control area from SECA to ECA—an area where special mandatory measures are required to control nitrogen oxides (NOx), sulfur oxides (SOx), particulate matter (PM), or all three types of emissions from ships. See U.S. Environmental Protection Agency, "MARPOL Annex VI" (Washington, DC: September 1, 2015), https://www.epa.gov/enforcement/marpol-annex-vi.

OECD demand for liquid fuels does not grow over the projection period, as the mature economies react to sustained high fuel prices over the long term with strong efficiency gains (especially in personal transportation) and conservation. Although technology efficiency improvements and fuel-switching opportunities also are available to non-OECD consumers, the scale of growth in demand for transportation services in relatively underdeveloped transportation networks overwhelms the mitigating impact of those efficiency improvements.

OECD

For most of the OECD countries, consumption of petroleum and other liquid fuels remains flat or declines in the IEO2016 Reference case (see Figure 2-7). At 46 million b/d in 2040, total OECD liquid fuels consumption is only 0.6 million b/d higher than in 2012. In much of the OECD, slow economic growth and static or declining population levels contribute to lower levels of liquids consumption. In addition, many OECD governments have adopted policies that mandate improvements in the efficiency of motor vehicles, and consumers turn to more fuel-efficient transportation choices as high oil prices return in the long term. Efficiency gains could also lower freight-related energy demand. The U.S. Environmental Protection Agency recently proposed a significant increase in fuel economy standards for heavy trucks. Should these proposed standards be adopted as final rules, they would significantly lower projections for diesel fuel use in trucks. To the extent that these standards are implemented and affect trucks sold throughout the world, the reduction in trucking fuel use could be greatly magnified.

The United States is currently the OECD's largest consumer of liquid fuels, and it remains so through 2040. The use of liquid fuels in the U.S. transportation sector declines over the projection period as a result of significantly lower energy use by light-duty vehicles. However, the decline is moderated by increased energy use for heavy-duty vehicles, aircraft, and marine vessels. Over the course of the projection period, increases in vehicle fuel economy offset growth in transportation activity. Industrial sector demand

Figure 2-7. OECD and non-OECD petroleum and other liquid fuels consumption, IEO2016 Reference case, 1990–2040 (million barrels per day)

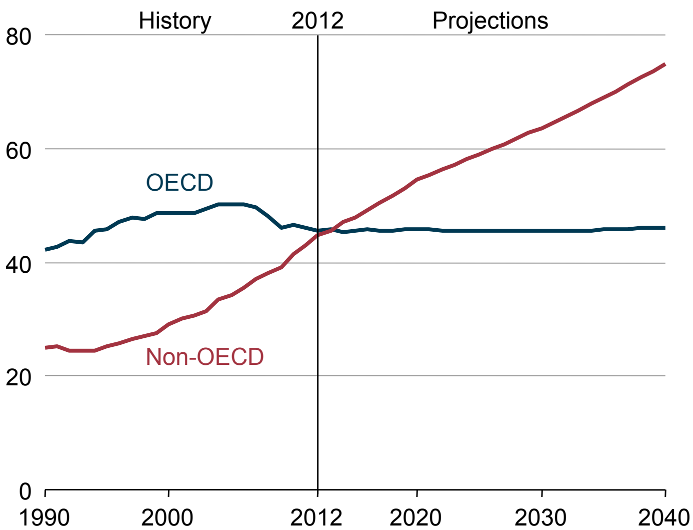


Figure 2-8. Non-OECD petroleum and other liquid fuels consumption by region, IEO2016 Reference case, 1990–2040 (million barrels per day)

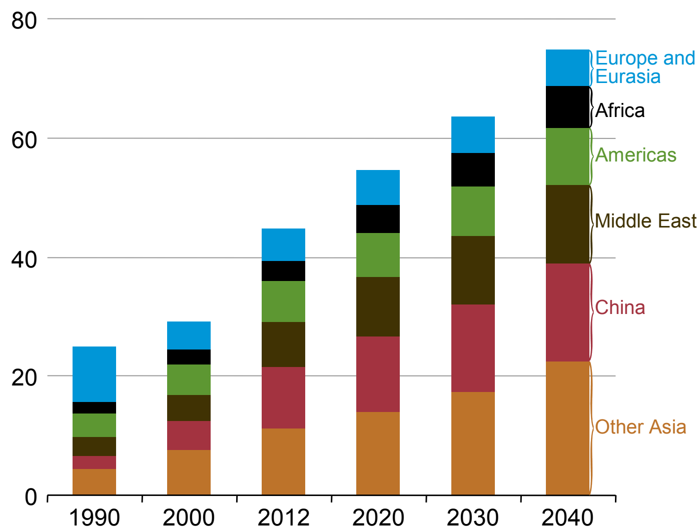


Table 2-2. World petroleum and other liquid fuels consumption by region, IEO2016 Reference case, 1990–2040 (million barrels per day)

Region	1990	2000	2012	2020	2030	2040	Average annual percent change 1990-2012	Average annual percent change 2012-2040
OECD	**42.2**	**48.7**	**45.5**	**45.8**	**45.5**	**46.1**	**0.3**	**0.0**
Americas	20.6	24.3	23.2	24.4	24.3	24.6	0.5	0.2
Europe	14.0	15.6	14.1	13.7	13.7	14.0	0.0	0.0
Asia	7.6	8.8	8.2	7.7	7.5	7.5	0.4	-0.3
Non-OECD	**25.0**	**29.0**	**44.8**	**54.5**	**63.6**	**74.8**	**2.7**	**1.9**
Europe and Eurasia	9.3	4.4	5.3	5.8	6.2	6.1	-2.5	0.5
Asia	6.6	12.5	21.5	26.7	32.2	38.9	5.5	2.1
Middle East	3.3	4.5	7.7	10.0	11.3	13.2	3.9	2.0
Africa	2.1	2.5	3.6	4.5	5.5	6.9	2.6	2.4
Americas	3.8	5.0	6.7	7.5	8.5	9.6	2.7	1.3
Total world	**67.2**	**77.7**	**90.3**	**100.3**	**109.1**	**120.9**	**1.4**	**1.0**

for liquid fuels in the United States grows over the projection period, mainly because of increased use of hydrocarbon gas liquids (HGL)—primarily ethane and propane—as feedstocks in the bulk chemicals industry. Total liquid fuels consumption in the United States rises from 18.5 million b/d in 2012 to 19.7 million b/d in the early 2020s, then declines to 19.3 million b/d in 2040.

In Canada, fuel efficiency gains result in relatively flat consumption of petroleum and other liquid fuels, between 2.4 million b/d and 2.5 million b/d throughout the projection period. In Mexico and Chile combined, liquid fuels consumption increases by 0.6%/year—the highest growth rate among the OECD regions except for Australia and New Zealand. Despite improvements in vehicle fuel efficiency, the use of liquid fuels increases in Mexico and Chile, particularly for transportation services (as the infrastructure is still relatively underdeveloped) and for industrial production as demand grows.

In OECD Europe, consumption of liquid fuels remains stable, largely as a result of improvements in energy efficiency. In addition to improvements in motor vehicle fuel efficiency, most of the nations in OECD Europe have high taxes on motor fuels, well-established public transportation systems, and declining or slowly growing populations, all of which slow the growth of transportation energy use. In 2040, liquid fuels consumption in OECD Europe totals 14.0 million b/d, or 0.1 million b/d lower than the 2012 level of 14.1 million b/d.

Petroleum and other liquid fuels consumption in OECD Asia generally declines over the long term, from 8.2 million b/d in 2012 to 7.5 million b/d in 2040. Over the past few years, the region's liquid fuels consumption rose, largely because of increased fuel use in Japan's electric power sector after the March 2011 earthquake and tsunami that severely damaged nuclear reactors at Fukushima Daiichi and subsequently led to the shutdown of all the country's nuclear power reactors by May 2012. To compensate for the loss of nuclear generation, Japan turned, in part, to oil-fired generation to meet demand for electricity in the short term. Consumption of petroleum and other liquid fuels for power generation increased by an estimated 20% from 2011 to 2012 but has fallen as some nuclear capacity has returned to operation, and as renewable generating capacity has grown. With Japan's use of liquid fuels for power generation returning to more typical levels, the country's overall trend of decreasing consumption of petroleum and other liquid fuels resumes in the medium term.

Outside of Japan, the other countries of OECD Asia—South Korea, Australia, and New Zealand—experience some growth in liquids fuels use, attributed mostly to expanding activity in the transportation and industrial sectors. In Australia and New Zealand, expected population growth rates also contribute to a rise in demand for liquid fuels. Together, the two countries are projected to account for the largest increase in demand among the OECD countries in the IEO2016 Reference case.

Non-OECD

The non-OECD share of world liquid fuels consumption grows from 50% in 2012 to 54% in 2020 and to 62% in 2040. Non-OECD Asia shows the largest growth in liquid fuels consumption worldwide in the IEO2016 Reference case, at 17.4 million b/d from 2012 to 2040, with China accounting for 6.2 million b/d of the total increase. As China's economy moves from dependence on energy-intensive industrial manufacturing to services, the transportation sector becomes the most significant source of growth in liquid fuels use. The country's liquid fuels consumption increases by 61% over the course of the projection period.

India's GDP increases by 5.5%/year from 2012 to 2040 in the IEO2016 Reference case—the highest economic growth rate among all the IEO regions. In recent years, India's government has committed to a number of economic and structural reforms that will support the strong projected growth in GDP over the medium to long term. On the other hand, the government's continued efforts to reduce subsidies on petroleum products are expected to temper demand for liquid fuels. In the IEO2016 Reference case, consumption of petroleum and other liquid fuels in India more than doubles, from 3.6 million b/d in 2012 to 8.3 million b/d in 2040, as its GDP more than quadruples over the period.

Industrial CO2 emissions and petroleum coke use in refineries

EIA has identified possible discrepancies in the international reporting of data on fuels consumed in the petroleum refining sector that may result in underestimation of energy-related emissions of greenhouse gases (GHG). Petroleum refining is one of the world's most energy-intensive industries, and as demand for petroleum products in non-OECD countries continues to grow, their refining industries are adding capacity to process more crude oil into gasoline, diesel, and other petroleum-based products. Evolving crude oil inputs, changing market demands, and increasingly stringent emissions regulations all affect the refining process. As an energy-intensive industry, petroleum refining also is a significant source of GHG emissions, and understanding and tracking the industry's fuel use is essential to understanding its contribution to global GHG emissions.

Energy consumption by refineries includes both purchased fuels and internally derived fuels drawn from the crude oil refining process itself. Petroleum coke (petcoke) is a refinery product that takes the form of a solid, carbon-rich substance resembling coal. There are two kinds of petcoke: catalyst and marketable. Most refineries worldwide produce both types of petcoke, with differences in production levels resulting from different refinery configurations and crude oil inputs. Heavier crudes typically yield higher petroleum coke production.

Catalyst petcoke, or catcoke, is a byproduct from refinery fluid catalytic cracking (FCC) units. Catcoke is burned off the catalyst matrix (generally, pellets or finer sand-sized particles) to maintain catalytic activity, providing energy for FCC processes. Catcoke

(continued on page 26)

cannot be collected and sold. Rather, it must be burned onsite as refinery fuel. Catcoke is a significant source of carbon dioxide (CO2) emissions. Marketable petcoke, on the other hand, is produced in coker units. Petcoke is collected and processed in sizable chunks by the refinery and marketed for various uses, such as fuel for cement kilns and power generators. Marketable petcoke also is widely used for nonfuel purposes, especially for conversion to carbon anodes used in aluminum production. When either type is burned, sizable amounts of CO2 are released, along with sulfur and volatile heavy metals. In some countries, including the United States, air quality regulations have made the burning of marketable petcoke prohibitively expensive. As a result, there has been an increase in U.S. exports of marketable petcoke, with more than 14% of the 2012 total delivered to China.[29]

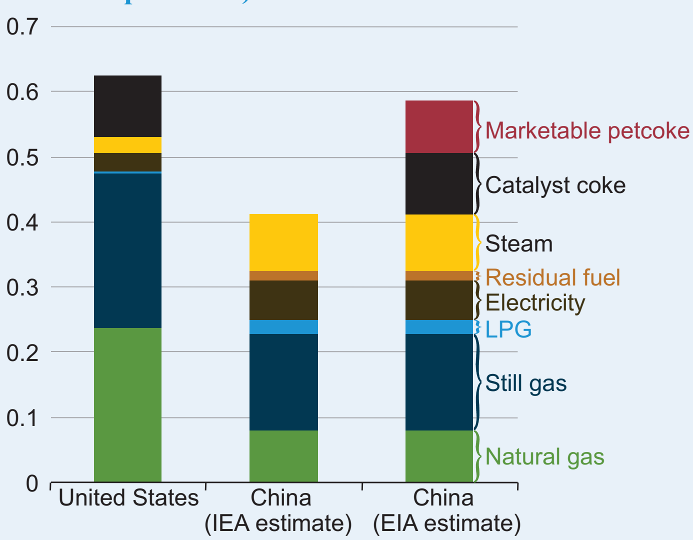
The International Energy Agency (IEA) historical database, among other compilations, provides data on the world supply of marketable petcoke, including production, trade, and consumption data for most nations. Many countries appear to omit catcoke consumption, possibly because it is not sold as a marketed fuel. For those that do report catcoke consumption, there often is no distinction between marketable petcoke and catcoke in the IEA database. However, it appears that most OECD nations (Chile, Mexico, and Poland are a few of the exceptions) provide data for consumption of both marketable and catalyst petcoke in the refining sector, the latter likely representing most petroleum coke consumption.

Other nations (including China, Russia, Brazil, and most of the other non-OECD nations) provide data for their petroleum coke supply but not for their refining sector consumption. All of these countries have some FCC units in their refineries, and it is possible that the catalyst coke portion of total petroleum coke consumption is not reported because it is burned in domestic refineries. This situation would cause CO2 emissions for some countries to be underestimated.

China is one country that does not report data on refinery consumption of petcoke. One possible way to estimate its consumption may be to assume that refining operations in the United States and China are not significantly different. If so, one would expect the American and Chinese systems to use about the same amount of energy per barrel of crude oil processed. Total U.S. production of petroleum catcoke (which is equal to refinery consumption of petcoke) is reported to be in the range of 200,000 b/d to 250,000 b/d, equivalent to about 0.1 million Btu of catcoke per barrel of crude processed in U.S. refineries. This value, multiplied by China's crude oil inputs, could provide a first-order approximation of catcoke consumption in China's refineries.

China's production and consumption of catcoke appear to be missing in official state statistics. According to IEA data, there is no reported refinery consumption of either petroleum coke type in China's refineries, which seems unlikely in view of its substantial FCC capacity. Moreover, if the missing refinery fuel is catcoke, and if the United States and China produce roughly the same amount of catcoke per barrel in their FCC units, the unreported catcoke alone is not enough to balance the production equations. Consistent with a recent report on the petcoke market in China,[30] it seems likely that some of China's refineries are using their own marketable petcoke for refinery fuel rather than selling it to outside buyers. Based on recent estimates of China's total marketable petcoke consumption (30 million metric tons in 2012) and the likely fraction of that total employed for fuel and power purposes, it is estimated that 0.08 million Btu per barrel of refinery fuel use in China is marketable petcoke (Figure 2-9).

Figure 2-9. Energy consumption in U.S. and China refineries by fuel type, 2012 (million Btu per barrel of crude oil produced)



Notes: Based on Carnegie Endowment data, EIA estimates that 90% (8.8 million metric tons) of China's fuel marketable petcoke is used as fuel in refineries, and the remaining fuel marketable petcoke (1.2 million metric tons) is used as fuel in small electric power plants. A small amount of coal was reported to have been used in U.S. refineries in 2012 and none in China's refineries.

If the consumption of catcoke and marketable petcoke is not included in the estimation of energy consumption at China's refineries, then GHG emissions from China's refining sector would be underestimated. Based on the analysis summarized here, EIA has incorporated its estimates of marketable petcoke consumed as refinery fuel in the IEO2016 baseline estimates of China's industrial sector energy consumption. Further, China may not be the only example of a country whose consumption of catcoke or petroleum coke goes unreported. Better estimates of refinery consumption of catcoke and petroleum coke fuel, not only for China but elsewhere as well, would enable construction of a more accurate baseline for world industrial sector CO2 emissions in the future.

[29] U.S. Energy Information Administration, "Petroleum & other liquids: data: exports by destination: petroleum coke" (October 30, 2015), http://www.eia.gov/dnav/pet/PET_MOVE_EXPC_A_EPPC_EEX_MBBL_A.htm.

[30] Wang Tao, "Managing China's Petcoke Problem" (Beijing, China: Carnegie-Tsinghua Center for Global Policy, May 31, 2015), http://carnegietsinghua.org/2015/06/03/managing-china-s-petcoke-problem/i9fa.

Liquid fuels demand in the Middle East grows substantially in the IEO2016 Reference case, by 5.5 million b/d from 2012 to 2040, as a result of strong population growth rates and rising incomes. In addition, liquids-intensive processes in the region's industrial sector, particularly in the chemicals industry, are an important component of its growing demand for liquid fuels. Delays in petroleum subsidy reforms in much of the region and strong growth in per capita incomes support a significant expansion of liquid fuels consumption in the region's transportation sector. Some subsidy reforms are assumed to occur in the later years of the projection, with the resulting higher prices slowing the region's growth in demand for liquid fuels.

Demand for liquid fuels in the Middle East region's electric power sector declines from 2012 to 2040 in the IEO2016 Reference case. Many of the countries in the region that produce liquid fuels increasingly turn to lower-cost natural gas and, to a lesser extent, nuclear and renewable fuels to increase the volumes of petroleum available for export and to meet demand for fuel in the transportation and industrial sectors. The timing of the Middle East shift from its reliance on liquid fuels for power generation remains uncertain, however, as the region faces delays in infrastructure improvements, and because there are limits on the supply of alternative fuels for power generation. For instance, Saudi Arabia has been unable to meet rapid growth in electricity demand with power generated from domestic natural gas and has had to import fuel oil for power generation.

As in the Middle East, growing populations and economies in African countries increase the demand for liquid fuels for both transportation and industrial uses over the IEO2016 projection. In the IEO2016 Reference case, Africa's consumption of petroleum and other liquid fuels grows by 3.3 million b/d from 2012 to 2040, as its real GDP increases by 4.7%/year from 2012 to 2040. With an expected favorable investment environment and relative political stability in the long term, growing consumer demand is projected to increase demand for consumer goods and services and to increase demand for liquid fuels, particularly for personal transportation and freight services. The transportation sector accounts for 60% of the total increase in liquid fuels use in Africa in the IEO2016 Reference case.

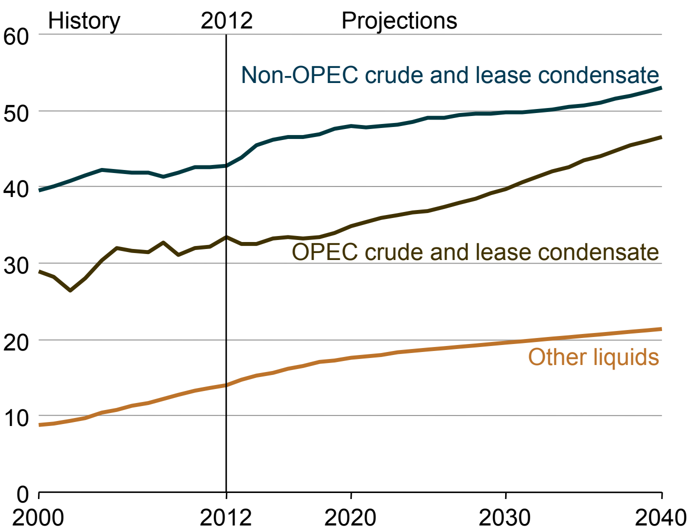
In Brazil and the other non-OECD Americas, consumption of liquid fuels increases by 2.9 million b/d, from 6.7 million b/d in 2012 to 9.6 million b/d in 2040. In some of the region's national economies—notably Brazil, Colombia, and Peru—long-term economic expansion is expected to support growing demand for liquid fuels, primarily for transportation uses but also in the industrial sector. Brazil, with the region's largest economy, accounts for about 60% of the regional growth in liquid fuels demand in the IEO2016 Reference case. Economies that are less financially secure, including Venezuela and Argentina, will have a more difficult time sustaining economic growth. Fuel subsidies in Venezuela, in particular, are costly, and it is difficult to anticipate when the Venezuelan government might be able to reduce the subsidies.

In the countries of non-OECD Europe and Eurasia, demand for liquid fuels grows moderately from 2012 to 2020 in the IEO2016 Reference case before reaching a plateau. Russia—the largest economy in the region—currently accounts for the largest share of the region's consumption of liquid fuels, but as a result of major efficiency improvements in its energy-intensive industrial sector its consumption increases more slowly than in the region's other economies. In addition, demand for liquid fuels in Russia's residential and commercial sectors is projected to slow as fuel subsidies for people living in areas with high heating requirements are reduced.

World petroleum and other liquid fuels supplies

In the IEO2016 Reference case, world petroleum and other liquid fuels supplies depend on various sources, including OPEC and non-OPEC crude oil and lease condensate supply as well as other liquids supply. Crude oil and lease condensate includes tight oil, extra-heavy oil, field condensate, and bitumen (i.e., oil sands, either diluted or upgraded); other liquids supply refers to NGPL, biofuels, CTL, GTL, kerogen, and refinery gain.

Figure 2-10. Petroleum and other liquid fuels production by region and type in the IEO2016 Reference case, 2000–2040 (million barrels per day)



OPEC crude oil and lease condensate supply

The IEO2016 Reference case assumes that OPEC maintains or increases its market share of global oil production, and that no geopolitical circumstances will cause prolonged supply shocks in the OPEC countries that could further limit production growth. Crude oil and lease condensate supplies from OPEC and non-OPEC sources increase by 23 million b/d in the IEO2016 Reference case, from 76 million b/d in 2012 to 100 million b/d in 2040. OPEC member countries account for 13 million b/d, and non-OPEC countries account for 10 million b/d of the total increase in crude oil and lease condensate production. Production of other liquid fuels increases from 14 million b/d in 2012 to 21 million b/d in 2040.

The IEO2016 Reference case assumes that OPEC producers invest in incremental production capacity, which enables them to increase crude oil and lease condensate production by 13 million b/d from 2012 to 2040 (Figure 2-10) and also enables them to account for 42% to 47% of total crude and lease condensate production worldwide over the course of the projection period. Middle East OPEC member countries, which accounted for nearly 70% of total OPEC crude and lease condensate production in 2012 (Figure 2-11), increase their crude and lease condensate production by 12 million b/d in the IEO2016 Reference case, accounting for 94% of the total growth in OPEC crude and lease condensate production from 2012 to 2040.

Non-OPEC crude and lease condensate supply

In the IEO2016 Reference case, non-OPEC production of crude oil and lease condensate increases steadily, from 43 million b/d in 2012 to 48 million b/d in 2020 and 53 million b/d in 2040. The average cost per barrel of non-OPEC oil production rises as production volumes increase, and those cost increases, along with falling investment in exploration and production, eventually slow production growth in the IEO2016 Reference case.

U.S. tight oil production, which reached 4.6 million b/d in May 2015 and is estimated to have declined to 4.3 million b/d in February 2016 has proven more resilient in the face of low prices than many market watchers initially anticipated. However, tight oil makes up only a small portion of total non-OPEC supply of crude and lease condensate, which was estimated at roughly 45 million b/d in the first quarter of 2016. Given the long investment cycle for many projects outside of shale plays, the current decline in investment can have long-term effects. Delays and cancelations of planned projects are expected to continue for the next several years, especially for projects with high development costs, such as Canadian oil sands and large offshore projects. Some existing production capacity has also begun coming offline in 2015 as well. For example, a number of fields in the North Sea have been closed earlier than originally planned. Resources with the highest operating costs and most strained financing are expected to be the first to come offline. These resources include tight oil, stripper wells, and fields that experience equipment failures—all of which require ongoing capital investments to offset declines in production from existing wells.

Other liquids supply

Other liquid fuels—including NGPL, biofuels, CTL, GTL, kerogen (oil shale), and refinery gain—currently supply a relatively small portion of total world petroleum and other liquid fuels, accounting for about 16% of the total in 2012. Other liquid fuels are projected to grow modestly in importance in the IEO2016 Reference case, as the other liquids share of the world's total liquids supply increases to 18% in 2040 (see Figure 2-10).

NGPL is the largest component of other liquids, accounting for 67% of the total in 2012 (Figure 2-12). The increase in NGPL production in IEO2016 is directly related to the increase in natural gas production, of which NGPL is often a coproduct. In contrast, increased production of other liquids (primarily biofuels, CTL, and GTL) occurs in response to high prices that support expansion of their production with available domestic resources, such as crops, coal, or gas. In the IEO2016 Reference case, sustained low oil prices in the early years of the projection make the development of the non-NGPL other liquids less economically attractive. In addition to being price-sensitive, biofuels development also relies heavily on policies or mandates to support growth.

Figure 2-11. OPEC crude and lease condensate production by region in the IEO2016 Reference case, 2012, 2020, and 2040 (million barrels per day)

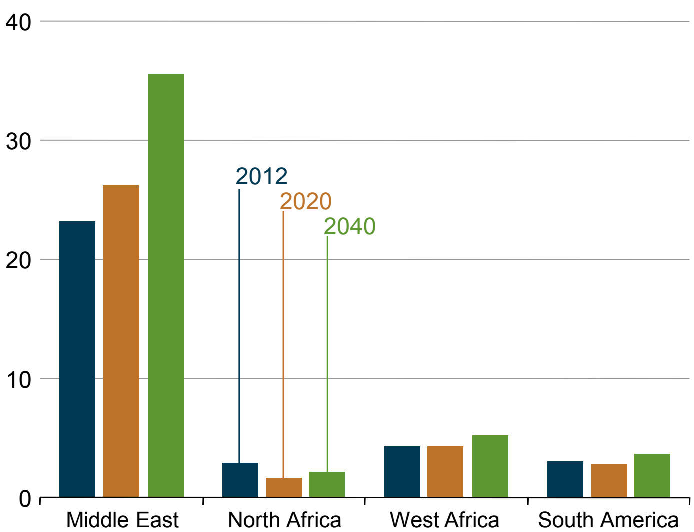
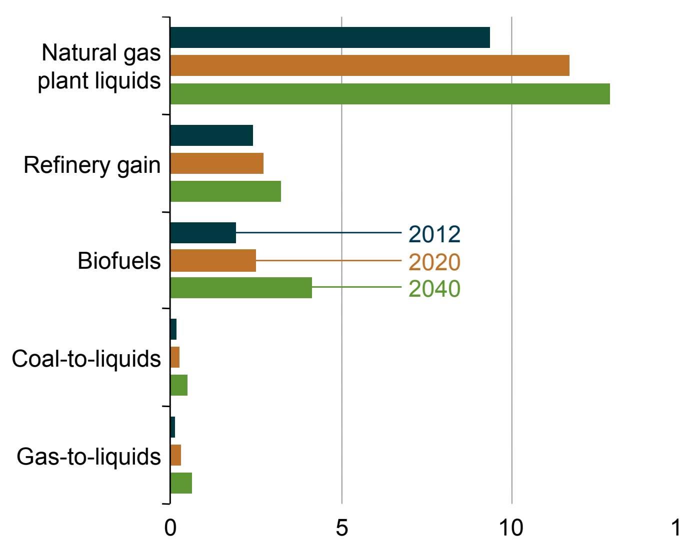


Figure 2-12. World other liquid fuels production by source, 2012, 2020, and 2040 (million barrels per day)



Iran's return to the international oil market

Implementation Day for the Joint Comprehensive Plan of Action (JCPOA) agreement among Iran, the P5+1 (the five permanent members of the United Nations Security Council and Germany), and the European Union (EU), occurred on January 16, 2016, when the International Atomic Energy Agency verified that Iran had completed the key physical steps required to trigger sanctions relief. With this milestone, the United States, the EU, and the United Nations lifted nuclear-related sanctions against Iran, which included oil-related sanctions that limited Iran's ability to sell its oil on the global market since late 2011. With nuclear-related sanctions being lifted:

- Some Iranian banks can rejoin the Society for Worldwide Interbank Financial Telecommunication (SWIFT) system to conduct financial transactions electronically on the world market.
- Iran can access its foreign cash reserves held in banks worldwide. According to the U.S. Department of Treasury, Iran's Central Bank has between $100 billion and $125 billion in foreign exchange assets globally, but its usable liquid assets are estimated at slightly more than $50 billion.
- Non-U.S. companies can invest in Iran's oil and natural gas industry, including the sale, supply, and transfer of equipment and technology.
- Countries within the EU and elsewhere can import oil, natural gas, and petrochemical products from Iran, and countries already importing from Iran can increase their purchases.
- European Protection and Indemnity (P&I) Clubs can provide insurance and reinsurance for Iranian oil tankers.

Previously imposed U.S. primary sanctions related to human rights abuses and terrorism remain in place, and some Iranian citizens and entities that were delisted under nuclear sanctions as a result of the JCPOA agreement will remain listed under these primary sanctions. In addition, the United States has imposed new sanctions on individuals and entities linked to recent ballistic missile tests by Iran.[31] As a result, non-U.S. companies may be slow to rush back into Iran until they determine how they can resume business without violating the prevailing sanctions. U.S. companies remain precluded from conducting business with Iran, with the exception of foreign subsidiaries of U.S. firms that receive case-by-case approvals from the U.S. Department of the Treasury.

Although its crude oil exports were nearly halved by sanctions between 2011 and 2014, Iran still ranks among the world's top 10 producers of oil and among the top 5 producers of natural gas. Iran's crude oil production has been relatively flat over the past three years, averaging 2.8 million barrels per day (b/d) and representing 9% of OPEC's total crude oil production.[32] Iran' s total liquids production in 2015 amounted to nearly 3.5 million b/d, and its total production of dry natural gas in 2013 was estimated at 5.7 trillion cubic feet.[33] Iran is the world's fourth-largest holder of oil reserves (nearly 158 billion barrels) and the world's second-largest holder of natural gas reserves (1.2 trillion cubic feet).[34]

The pace at which Iran will ramp up its exports now that sanctions have been lifted is uncertain. Iran has a considerable amount of oil stored offshore in tankers (between 30 million and 50 million barrels, most of which is condensate) and at onshore facilities. Initial post-sanction increases in Iran's exports are likely to come from storage, with meaningful production increases occurring after some of the storage has been cleared. Most of the production growth is expected to come from crude oil production capacity that currently is shut in, and the remainder is expected to come from newly developed fields. Iranian and Chinese companies have been developing a number of new oil fields in Iran over the past several years, which have the potential to add 100,000 b/d to 200,000 b/d of crude oil production capacity by 2017.

In addition to crude oil, Iran's current production of condensate and NGPL totals nearly 750,000 b/d, of which 75% is condensate and the remainder NGPL. Iran's noncrude liquids production has grown over the past few years, with its main buyers in Asia (mainly China) and the United Arab Emirates (UAE). Currently, there is an oversupply of condensate on the global market as a result of increased production from Australia, the United States, and the Middle East. Iran has had difficulty selling the condensate it produces both because of the oversupply and because of its high sulfur content. As a result, the condensate has been sold at a discount.[35] Iran's production of other liquids is expected to grow by 150,000 b/d by the end of 2016 and by an additional 100,000 b/d by the end of 2017, as more project phases at the South Pars natural gas field come online.

Iran has the potential to add almost 2 million b/d of crude oil, condensate, and natural gas plant liquids to the global market over the next five years. However, the global oil market already is oversupplied, and EIA projects that oil inventories will continue to

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[31] U.S. Department of the Treasury, "Treasury Sanctions Those Involved in Ballistic Missile Procurement for Iran" (January 17, 2016), https://www.treasury.gov/press-center/press-releases/Pages/jl0322.aspx.

[32] U.S. Energy Information Administration, "Iran's petroleum production seen rising as many sanctions are lifted," *This Week in Petroleum* (January 21, 2016), https://www.eia.gov/petroleum/weekly/archive/2016/160121/includes/analysis_print.cfm.

[33] U.S. Energy Information Administration, "Under sanctions, Iran's crude oil exports have nearly halved in three years," *Today in Energy* (June 24, 2015), http://www.eia.gov/todayinenergy/detail.cfm?id=21792.

[34] U.S. Energy Information Administration, "Iran," *Country Analysis Brief* (June 19, 2015), http://www.eia.gov/beta/international/analysis.cfm?iso=IRN.

[35] U.S. Energy Information Administration, "Nuclear accord creates potential for additional crude oil production from Iran," *Today in Energy* (August 13, 2015), http://www.eia.gov/todayinenergy/detail.cfm?id=22492.

build throughout 2016.[36] Consequently, Iran's ability to increase its crude oil sales may be limited by global demand and the availability of buyers.

Actual production growth after 2017 will depend on Iran's ability to attract foreign investment that will provide access to better technology, a higher level of expertise, and more financing opportunities. Iran recently modified its contract structure in hopes of increasing joint development of its oil and natural gas fields by both international and Iranian oil companies. Iran's restrictive buyback contracts will be replaced by a new Iran Petroleum Contract (IPC), which was formally introduced in Tehran, Iran, in November 2015 (although the final draft of the IPC has not been released). Notable changes include allowing foreign companies to book reserves in Iran in some cases (although they will not be permitted to own fields[37]) and increasing contract durations to as much as 25 years (which will allow IOCs to participate beyond exploration and development and into the production and secondary recovery phases). Under the IPC, fees and bonuses will be based on a project's associated risks. At the Tehran conference in November 2015, Iran unveiled a list of 53 oil and natural gas projects, along with 18 exploration blocks, which it hopes will attract at least $30 billion in foreign investment.[38]

There are notable risks associated with Iran's production outlook. The JCPOA includes a dispute resolution process and guidance for the *snap back* of sanctions if Iran strays from its commitments. As a result, there is a possibility that sanctions could be reinstated, which adds a downside risk to Iran's production outlook. In addition, the involvement of the Iranian Revolutionary Guard Corps (IRGC) in Iran's oil and natural gas industry complicates the outlook for foreign investment. The IRGC, which is subject to U.S. sanctions related to sponsorship of international terrorism, maintains ownership interests in many of Iran's service sector companies, presenting a potential problem for foreign companies that want to use Iranian contractors.

Foreign investment in Algeria's hydrocarbon development

Algeria is currently the third-largest oil producer (after Nigeria and Angola) in Africa and is also the continent's largest natural gas producer. Over the past decade, however, Algeria's production of both oil (Figure 2-13) and natural gas (Figure 2-14) has declined, leading the Algerian government to amend its law on foreign investment in hydrocarbons in an attempt to attract the investment and technology improvements needed to help stop production declines. In 2014, after the Algerian Council of Ministers gave formal approval for foreign partners to join the national oil and natural gas company, Sonatrach, in exploring and developing shale gas resources, Sonatrach offered 33 blocks in four sedimentary basins with high shale gas and oil potential to foreign bidders. Following the auction, the company signed five contracts with Repsol, Shell, Statoil, and Dragon Oil-Enel. By law, Sonatrach takes a majority share (at least 51%) of any resulting projects.

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Figure 2-13. Crude oil production in Algeria, 2005-14 (thousand barrels per day)

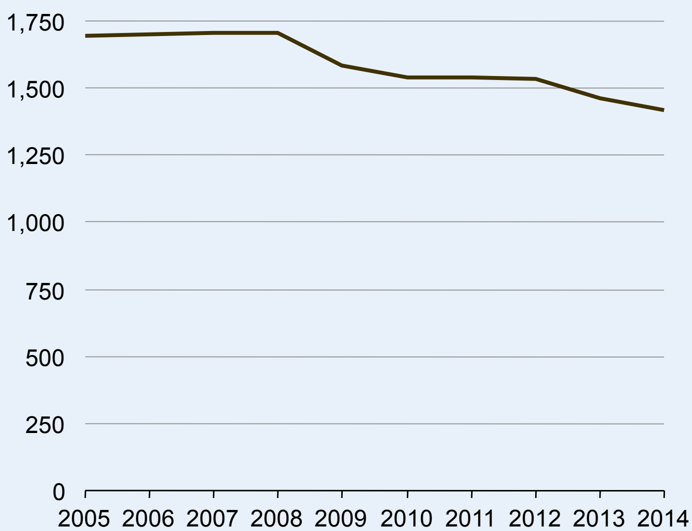
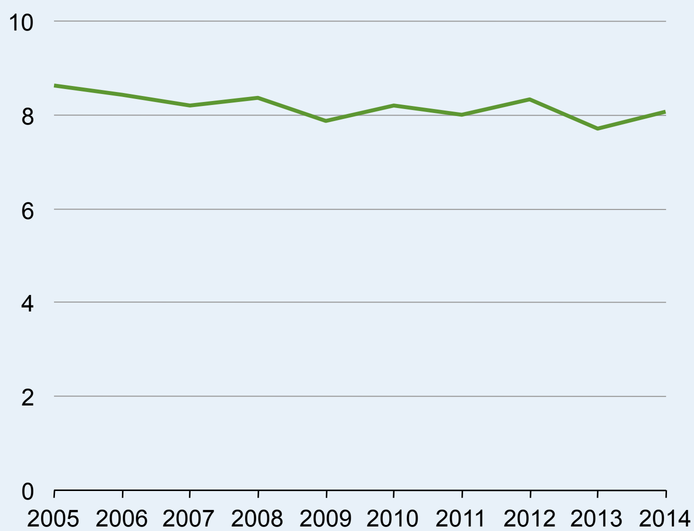


Figure 2-14. Natural gas production in Algeria, 2005-14 (billion cubic feet per day)



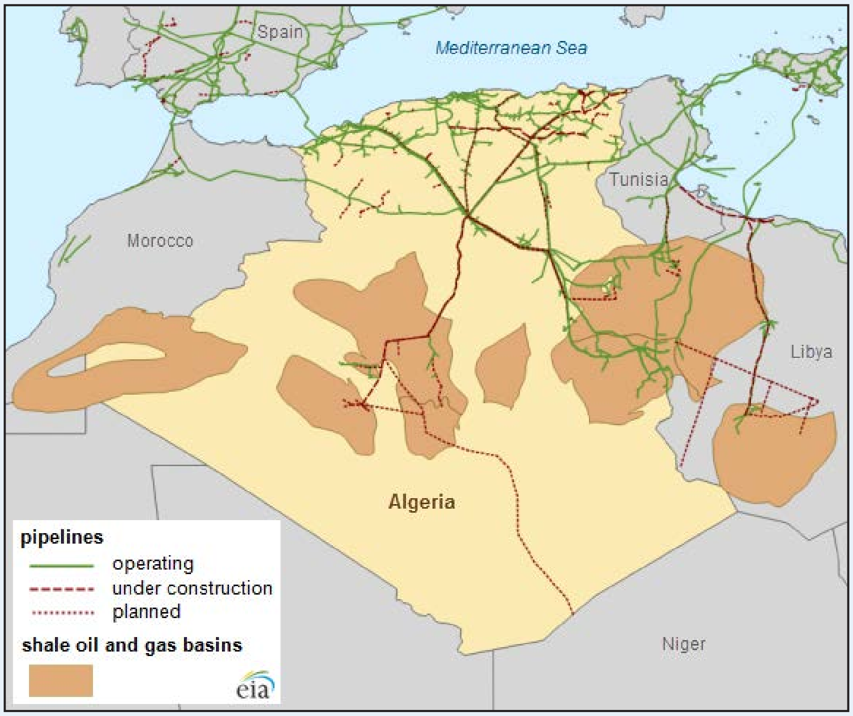
[36]U.S. Energy Information Administration, "Global Petroleum and Other Liquids," *Short-Term Energy Outlook* (January 12, 2016), https://www.eia.gov/forecasts/steo/report/global_oil.cfm.

[37]Although companies can book reserves, the National Iranian Oil Company (NIOC) retains exclusive ownership of fields.

[38]A. Lidgett, "Iran's New Oil And Gas Contract Framework Revealed," *International Business Times* (November 28, 2015), http://www.ibtimes.com/irans-new-oil-gas-contract-framework-revealed-2202878.

Algeria has large proved reserves of crude oil and natural gas, as well as resources that already are connected to world markets through an extensive natural gas pipeline network (Figure 2-15). In addition, Algeria's large shipping fleet transports liquefied natural gas (LNG) from several liquefaction plants to customers in Europe and elsewhere. Proved crude oil reserves in Algeria totaled 12.2 billion barrels in 2014. In addition, the U.S. Geological Survey (USGS) has estimated the country's undiscovered oil and NGL resources at 9.8 billion barrels, while EIA and Advanced Resources International (EIA/ARI) have estimated close to 6 billion barrels of technically recoverable shale oil resources. Proved natural gas reserves totaled 159 trillion cubic feet (Tcf) in 2014, with an additional 49 Tcf of undiscovered natural gas resources estimated by USGS and more than 700 Tcf of technically recoverable shale gas resources estimated by EIA/ARI.

Figure 2-15. Oil and natural gas basins and pipeline infrastructure in Algeria



Early this year, Sonatrach announced plans to spend $64 billion, or 70% of its total investment program from 2015 to 2018, in upstream activities to reverse the decline in crude oil and natural gas production in Algeria. Sonatrach set a target to increase gross hydrocarbon output from 1,429 million barrels of oil equivalent (MMBOE) in 2014 to 1,649 MMBOE by 2019 (from 535 MMBOE to 616 MMBOE of oil and from 894 to 1,034 MMBOE of natural gas).

Over the past three years, Sonatrach has intensified its exploration activities, drilling 275 oil and natural gas wells and seismically mapping large areas of the country with an estimated investment of $30 billion, and has conducted its own shale resource assessment and started exploration activities. The first two vertical shale exploratory wells drilled by Sonatrach in 2012 confirmed the potential for shale gas, and since 2014 Sonatrach has been engaged in a pilot project in the shale gas-rich Ahnet basin to drill, hydraulically fracture, and analyze three horizontal wells with up to 14 hydraulic fracturing stages.

While the government is seeking to reduce Algeria's dependence on oil and natural gas revenue, it has also made repeated calls for more investment in the sector. However, civil unrest and some opposition to the government's commercialization of shale resources may present obstacles to attracting foreign investment. Security is also a major concern, particularly following the attacks that took place at the Tigantourine natural gas processing plant in Illizi Province, near Algeria's eastern border with Libya, in January 2013.

Update on Mexico's petroleum sector reforms

In December 2013, Mexico took the first step toward reforming its energy sector by amending its constitution to open the sector to external investment. Since then, the Mexican parliament has passed secondary laws and instituted a regulatory framework to manage the newly restructured sector. The secondary laws passed in 2014 included the Hydrocarbons Law, which created institutional frameworks for the oil sector, along with a process for auctioning contracts; the Hydrocarbons Revenue Law, which established fiscal, legal, and regulatory regimes for the auctioned contracts; and subsidiary regulations on implementation, published in October 2014. The Comisión Nacional de Hidrocarburos (CNH, or Hydrocarbons Commission), which was established to implement the reforms, began conducting bid rounds in 2015 to auction rights for the exploration and development of Mexico's oil resources.

The petroleum sector reforms are intended to encourage foreign investment to help reverse recent declines in Mexico's oil production and to develop a healthy and diverse exploration and production (E&P) industry. The main objective of the process was to maximize hydrocarbon-related revenue to the state, rather than the number of contract blocks awarded.[39] However, the price of oil has fallen by nearly 65% since June 2014, and E&P spending has declined globally as companies seek to cover revenue shortfalls.[40] Concerns about regulatory, contract, or administrative structure on the part of companies or their investors are amplified in the present environment of low oil prices, and investment has fallen precipitously in new projects that will not result in demonstrable production for several years.

The bid round process (Table 2-3) began in August 2014 with Round Zero, in which Petróleos Mexicanos (Pemex) received the right of first refusal (before bidding was opened to other entities) on hydrocarbon resources that could be developed quickly. Pemex retained rights to explore and develop 83% of Mexico's proved and probable reserves and 21% of its prospective resources, as well as the option to migrate these entitlements to other contract structures.[41]

Table 2-3. Pemex bid Round One process and timeline as of December 2015

Process phase	Date	Activity
		Round Zero
Pemex entitlements	August 2014	• Retained projects it can develop quickly • Awarded 83% of proved and probable (2P) reserves and 21% of prospective resources
		Round One
Phase One Shallow water exploration	July 2015	• 2 of 14 blocks awarded • Production-sharing contracts (PSCs) issued, mostly for light oil resources
Phase Two Shallow water production	September 2015	• 3 of 5 blocks awarded • PSCs issued
Phase Three Onshore production	December 2015	• 25 blocks awarded, most to Mexican E&P companies • License contracts (LCs) to be issued
Phase Four Deepwater exploration and extra-heavy oil production	Third quarter 2016 (probable)	• 10 deepwater blocks in the Gulf of Mexico and 11 blocks of extra-heavy oil to be auctioned and awarded[a] • Tax and royalty regime to be used for deepwater projects
Phase Five Chicontopec Basin / tight oil	To be determined	• 61 blocks in unconventional fields, including 12 blocks in the Chicontopec field,[b] to be auctioned and awarded • May be delayed to next round

[a]IHS Energy, "Mexico: Lessons learned from early auctions drive new approaches for deepwater," *Oil and Gas Risk Service* (November 20, 2015), https://connect.ihs.com/Document/Show/gi/2852236?connectPath=Search (subscription site).
[b]C. Pascual, IHS Energy, "Mexico's energy reforms: strategic challenges ahead," *CERA Special Report* (August 2015), https://connect.ihs.com/Document/Show/gi/2823645?connectPath=Search (subscription site).

Bidding was opened to other entities in Round One, which began with an auction of shallow-water exploration blocks in July 2015 (Phase One). In response to industry feedback on the terms of the first auction, CNH made changes for the second auction in September 2015 (Phase Two, shallow-water production blocks) that resulted in considerably more industry interest. To participate in the first two phases, companies and consortia were required to meet technical and financial criteria and thresholds. (The different

(continued on page 33)

[39]"Mexico's first bid round proves a disappointment," *Petroleum Intelligence Weekly* (July 20, 2015), http://www.energyintel.com/pages/login.aspx?fid=art&DocId=893018 (subscription site).
[40]U.S. Energy Information Administration, "Sustained low oil prices could reduce exploration and production investment," *This Week in Petroleum* (September 23, 2015), http://www.eia.gov/petroleum/weekly/archive/2015/150923/includes/analysis_print.cfm.
[41]Pemex, "Newsletter No. 3: Round Zero Resolution & Round One Updates" (September 2014), http://www.ri.pemex.com/files/content/No.%203%20Round%200%20&%20Round%201.pdf.

phases of a single bid round also are referred to as tenders.) The criteria included minimum previous or current E&P experience (barrels produced, capital investments in E&P activities, and, in the case of a consortium operator, a net worth of at least $1 billion). Participating entities bid on two criteria: government share of operating profit, and incremental investment over the minimum work program commitment. The government's weighting ratio served to balance its two objectives: maximizing state revenues in the short term, and at the same time ensuring the long-term development of a healthy Mexican E&P sector.[42]

In December 2015, the third phase of Round One awarded rights to produce from onshore fields. Because it was intended to attract more participation by Mexican firms, CNH relaxed expertise criteria for companies to qualify as operators. It began allowing companies without previous E&P experience to qualify by showing evidence that members of their staff have prior experience with E&P projects.[43]

The fourth phase of Round One will include deepwater blocks in the Gulf of Mexico (GOM). With massive petroleum resources and proximity to existing infrastructure on the U.S. side of the GOM, this phase is attracting the most attention from international oil companies (IOCs). However, deepwater projects have long lead times and are technically challenging. Recognizing that the risks are more acute in a low price environment, CNH is adjusting the structure of contract terms to attract the most interest from IOCs. Contract blocks are being reshuffled and consolidated in response to complaints that offerings were too small.

The fifth phase, which may be postponed to a future bid round, will focus on the Chicontopec Basin and other tight oil resources. In a low oil price environment, however, there is less incentive to undertake new E&P ventures, especially challenging ones such as deepwater or tight oil.

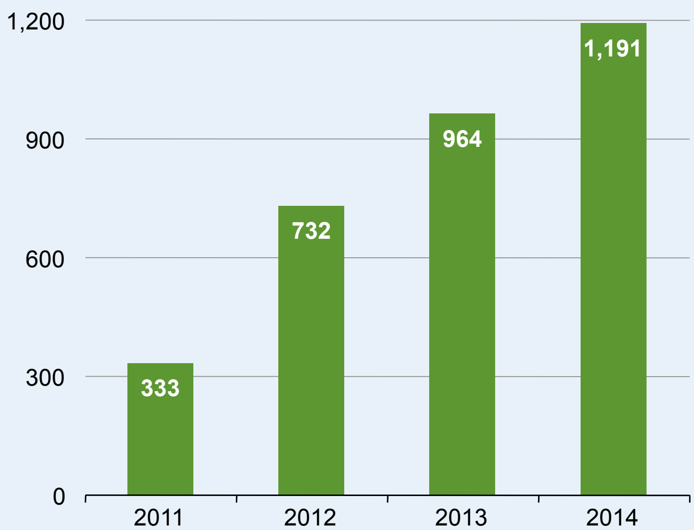
Throughout the process, Mexico's energy agencies—CNH and the energy ministry, Secretaría de Energía (SENER)—have sought input and feedback and have incorporated the feedback into the terms for subsequent phases. For example, in response to industry feedback from a relatively unsuccessful first phase, contract terms were amended to be more in line with international standards.[44]

EIA expects that CNH and the other agencies involved in the process will continue to learn from experience, adapt, and improve to garner increased interest and revenue in later phases. The process continues to be dynamic, although it is directed toward achieving Mexico's stated main objective of maximizing revenue to the state by increasing production in the next several years.

New biofuels from hydroprocessed esters and fatty acids

A new type of renewable diesel fuel is produced in response to biofuel mandates and customer demand for higher quality. Unlike other biofuels, hydroprocessed esters and fatty acids (HEFA) are nearly indistinguishable from their petroleum counterparts.[45] Worldwide, more than a billion gallons of HEFA fuels were produced in 2014 (Figure 2-16).

Figure 2-16. World production of renewable diesel fuels from hydroprocessed esters and fatty acids, 2011–14 (million gallons)



HEFA fuels are hydrocarbons rather than alcohols or esters. During the refining process, oxygen is removed from the esters and fatty acids that make up vegetable oil, leaving only hydrocarbons. Hydrocarbons from nonpetroleum sources are known as drop-in fuels, because they are nearly identical to comparable petroleum-based fuels. HEFA fuels, which are the most common drop-in biofuels, can be used in diesel engines without blending with petroleum diesel fuel. Currently, HEFA fuels are approved by ASTM International for use in jet engines, at blend rates up to 50% with petroleum jet fuel.[46]

To date, the HEFA biofuel most commonly produced has been a diesel replacement fuel that is marketed abroad as hydrotreated vegetable oil (HVO) and in the United States as renewable diesel. HEFA fuels are produced by reacting vegetable oil or animal fat with hydrogen in the presence of a catalyst. The equipment and process are very similar to the hydrotreaters used to reduce diesel sulfur levels in petroleum refineries. There are currently 10 plants worldwide that

(continued on page 34)

[42]F. Tanner et al., "Mexico: Learning from the first phase of Round 1," *Oil and Gas Risk Service* (July 30, 2015), https://www.pfcenergy.com/Members/PRM/Special-Reports-and-Quarterly-Outlooks/2015/Mexico-Learning-from-the-first-phase-of-Round-1 (subscription site).

[43]P.M. Lara, "Mexican E&P companies emerge," *Strategic Horizons* (IHS Energy: October 26, 2015), https://www.pfcenergy.com/Members/Horizons/Exploration-and-Production/2015/Mexican-EP-companies-emerge (subscription site).

[44]Energy Intelligence, "Mexico's flexibility bodes well for first bid round," *Petroleum Intelligence Weekly* (June 29, 2015), http://www.energyintel.com/pages/articlesummary/890602/mexico-s-flexibility-bodes-well-for-first-bid-round (subscription site).

[45]Note: EIA does not collect statistics on international HEFA fuels.

[46]ASTM International, "Standard Specification for Aviation Turbine Fuel Containing Synthesized Hydrocarbons," ASTM D7566-15c (West Conshohocken, PA: 2015), http://www.astm.org/Standards/D7566.htm.

produce renewable diesel, one of which is ENI's former petroleum refinery in Venice, Italy.[47] Total is planning to convert its La Mede, France, refinery to HVO production,[48] and four additional renewable diesel projects are being developed by other producers. Finnish Neste is the world's largest producer of renewable diesel. Other major producers are Italy's ENI, U.S.-based Diamond Green Diesel, and Swedish refiner Preem.

Beyond diesel, another outlet for HEFA fuels using similar technology is biojet fuel, which can be blended with petroleum jet fuel in proportions up to 50%. As with any alternative jet fuel, HEFA biojet fuel is required to meet stringent specifications to ensure its performance under a wide range of conditions. One potential consumer of HEFA bioject fuel is the U.S. Department of Defense, which intends to use biojet fuel in its JP-8 jet fuel. JP-8 is a versatile fuel used in military vehicles, stationary diesel engines, and jet aircraft.[49] This use of a common fuel simplifies logistics. There is also civilian interest in nonpetroleum jet fuel: Alaska Airlines, KLM, and United Airlines have demonstrated the use of HEFA biojet fuel on commercial flights since 2011.

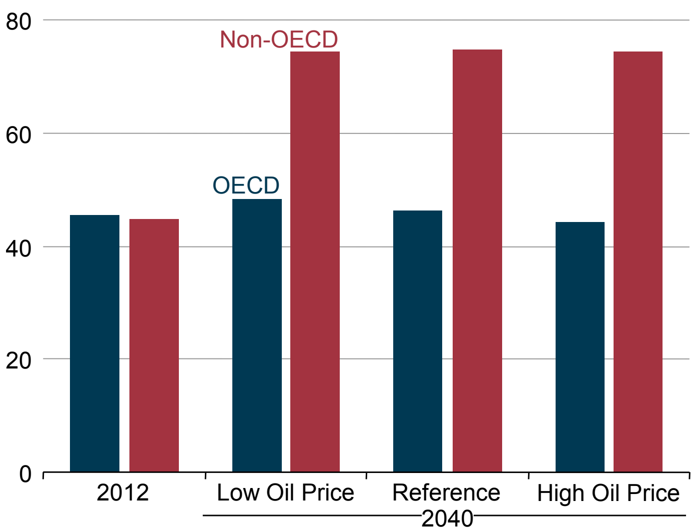
Low Oil Price case

Across the three IEO2016 price cases, OPEC's crude and lease condensate production falls as oil prices rise from the Low Oil Price case to the High Oil Price case. Alternatively, non-OPEC production of both petroleum and other liquid fuels increases as oil prices increase from the Low Oil Price case to the High Oil Price case.

In the IEO2016 Low Oil Price case, crude oil prices are $76/b in 2040. GDP growth in the non-OECD countries averages 3.9%/year from 2012 to 2040, compared with 4.2%/year in the IEO2016 Reference case. The combination of lower economic activity and lower prices results in non-OECD liquid fuel consumption in 2040 that is very close to that in the IEO2016 Reference case (Figure 2-17). Even in a scenario where low economic growth translates to lower energy demand (non-OECD energy demand in 2040 is 26 quadrillion Btu lower than in the IEO2016 Reference case), the lower prices encourage consumers to use cheap liquid fuels rather than other forms of energy. In contrast, economic growth in the OECD regions is essentially the same in the Low Oil Price case as in the IEO2016 Reference case. Total OECD energy consumption in 2040 is about the same as in the IEO2016 Reference case, but lower prices encourage consumers to use more liquid fuels compared to other energy sources. As a result, in 2040 OECD nations consume 48 million b/d of oil in the Low Oil Price case, compared with 46 million b/d in the IEO2016 Reference case.

On the supply side, OPEC's market share of world crude and lease condensate production ranges between 42% and 45% through 2020, then rises to 53% in 2040, as its production increases from 33 million b/d in 2012 to 54 million b/d in 2040, and its share of total world liquid fuels production in 2040 is 44%. In contrast, because North Sea Brent prices are lower than in the IEO2016 Reference case, non-OPEC crude and lease condensate production increases by only about 6 million b/d, to 48 million b/d in 2040, or 5 million b/d lower than in the IEO2016 Reference case. With higher average costs for resource development in the non-OPEC countries, the North Sea Brent crude oil price in the Low Oil Price case is not sufficient to make many undeveloped fields economically viable. Production of other liquid fuels, which typically are more expensive to produce, also grows more slowly than in the IEO2016 Reference case. In the Low Oil Price case, total production of other liquid fuels increases from 14 million b/d in 2012 to 20 million b/d in 2040, or 1.5 million b/d lower than in the IEO2016 Reference case (Figure 2-18).

Figure 2-17. World petroleum liquid fuels consumption in three cases, 2012 and 2040 (million barrels per day)



High Oil Price case

World oil prices in the High Oil Price reach $149/b in 2020 and $252/b in 2040, and higher assumed costs for crude and lease condensate production result in lower production than in the IEO2016 Reference case. Lower crude and lease condensate supply results in higher prices, which incentivize increased development of liquid supplies from price-sensitive emerging sources, including tight oil, bitumen, and other liquid fuels, which have higher production costs.

GDP growth in the non-OECD countries averages 4.5%/year from 2012 to 2040 in the High Oil Price case, as compared with 4.2%/year in the IEO2016 Reference case. The combination of high economic activity and high prices results in non-OECD liquids consumption that is about the same as in the IEO2016 Reference case (see Figure 2-17). Although the higher level

[47]Eni S.p.A., "Green Refinery" (October 11, 2014), http://www.eni.com/en_IT/innovation-technology/technological-focus/green-refinery/green-refinery.shtml.

[48]R. Kotrba, "A Transformative Project: Total's La Mède Conversion," *Biodiesel Magazine* (November 20, 2015), http://www.biodieselmagazine.com/articles/606885/a-transformative-project-totals-la-mede-conversion.

[49]Shell Global, "Military Jet Fuel Grades and Specifications (NATO)," http://www.shell.com/global/products-services/solutions-for-businesses/aviation/shell-aviation-fuels/fuels/types/military-jet-fuel-grades.html.

of economic activity increases non-OECD demand for total energy (total non-OECD energy consumption in 2040 is about 27 quadrillion Btu higher in the High Oil Price case than in the IEO2016 Reference case), the higher costs associated with liquid fuels encourages consumers to use other energy sources. On the other hand, the greater economic activity boosts incomes, making fuels more affordable for consumers.

OECD economic growth in the High Oil Price case is unchanged from the IEO2016 Reference case, and total energy demand is similar in the two cases. Higher oil prices in combination with the same IEO2016 Reference case economic activity mean that OECD consumers implement improved efficiency and conservation measures and switch to less expensive fuels where possible. In 2040, the OECD region as a whole consumes 44 million b/d in the High Oil Price case, or 2.0 million b/d less than in the IEO2016 Reference case.

On the supply side, liquid fuels production in the OPEC countries is lower in the High Oil Price case than in the IEO2016 Reference case, and their market share of total petroleum and other liquid fuels production declines to between 34% and 39%. Non-OPEC crude and lease condensate production increases initially in the High Oil Price case at about the same rate as in the IEO2016 Reference case. In the medium term, access to resources is lower than in the Reference case and non-OPEC production is not able to grow beyond Reference case levels, despite the higher prices. In the long term, however, high world oil prices induce more non-OPEC supply into the market. In the High Oil Price case, non-OPEC crude and lease condensate production increases to 58 million b/d in 2040, or 5 million b/d higher than in the IEO2016 Reference case (see Figure 2-18).

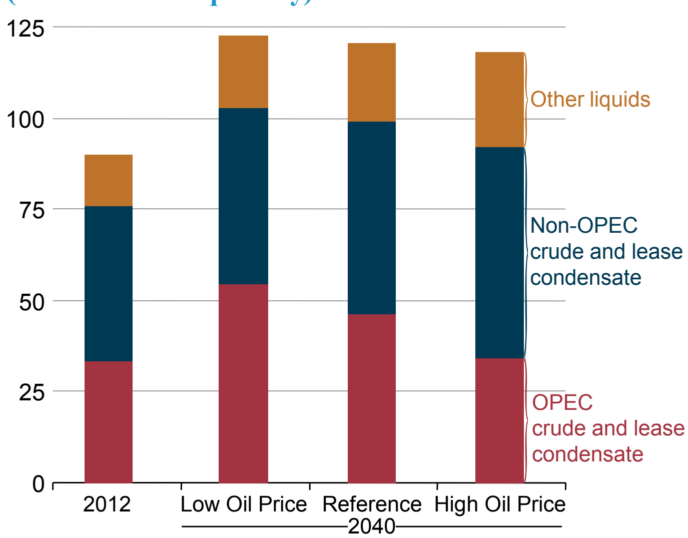
Liquid fuels production in the OPEC countries is lower in the High Oil Price case than in the IEO2016 Reference case, and their share of total petroleum and other liquid fuels production declines over the projection. As a result, the OPEC market share of world petroleum and other liquids production in the High Oil Price case never exceeds the peak of 42% that it reached in 2008 and eventually declines to 34% in 2040. OPEC petroleum and other liquids production increases by only 3 million b/d, from 37 million b/d in 2012 to 40 million b/d in 2040 (as compared with an increase of nearly 15 million b/d in the IEO2016 Reference case).

The economics of other liquid fuels also benefit from higher prices in the High Oil Price case. Non-OPEC production of other liquid fuels increases to 20 million b/d in 2040, nearly 5 million b/d higher than in the IEO2016 Reference case; and Non-OPEC production of NGPL grows to 10 million b/d in 2040, 2 million b/d higher than in the IEO2016 Reference case. Higher oil prices also lead to significant increases in non-OPEC production of biofuels, CTL, and GTL as compared with the IEO2016 Reference case. In 2040, non-OPEC other liquids supplies (excluding NGPL) are 2 million b/d higher in the High Oil Price case than in the IEO2016 Reference case.

Reserves

Proved reserves of crude oil are the estimated quantities that geological and engineering data indicate can be recovered in future years from known reservoirs, assuming existing technology and current economic and operating conditions. Most increases in proved reserves since 2000 have come from revisions to reserves in discovered fields, rather than new discoveries.[50] As of December 2015, proved world oil reserves, as reported by the *Oil & Gas Journal*, were estimated at 1,656 billion barrels—2 billion barrels higher than the estimate at the end of 2014.[51] According to the *Oil & Gas Journal*, around half of the world's proved oil reserves are located in the Middle East, and more than 80% of the world's proved reserves are concentrated in eight countries,[52] of which only Canada (with oil sands included) and Russia are not members of OPEC. In 2013, the largest increase in proved reserves by far was attributed to Venezuela, as the country now reports its Orinoco belt extra-heavy oil in its totals.[53] As a result, Venezuela's reserves alone increased by 86 billion barrels from 2012 to 2013. Russia also reported a significant gain in 2013, at 20 billion barrels. Country-level estimates of proved reserves from the *Oil & Gas Journal* are developed from data reported to the U.S. Securities and Exchange Commission (SEC), from foreign government reports, and from international geologic assessments. The estimates are not always updated annually.

Figure 2-18. World petroleum and other liquid fuels production in three cases, 2012 and 2040 (million barrels per day)



[50]International Energy Agency, *World Energy Outlook 2012* (Paris, France: November 12, 2012), http://www.worldenergyoutlook.org/weo2012/.
[51]C. Xu, T. Dunnahoe, M.T. Slocum, and L. Bell, "Reserves grow modestly as crude oil production climbs," *Oil & Gas Journal* (December 7, 2015), http://www.ogj.com/articles/print/volume-113/issue-12/special-report-worldwide-report/reserves-grow-modestly-as-crude-oil-production-climbs.html (subscription site).
[52]Canada, Iran, Iraq, Kuwait, Russia, Saudi Arabia, United Arab Emirates, and Venezuela.
[53]"Global oil production up in 2012 as reserve estimates rise again," *Oil & Gas Journal* (December 3, 2012), http://www.ogj.com (subscription site).

In some cases in the IEO2016 projections, country-level volumes for cumulative production through 2040 exceed the estimates of proved reserves. This does not imply that resources and the physical limits of production have not been considered in the development of production forecasts, or that the projections assume a rapid decline in production immediately after the end of the projection period as reserves are depleted. EIA considers resource availability in all long-term country-level projections, the aggregation of which gives the total world production projection. However, proved reserves are not an appropriate measure for judging total resource availability in the long run. For example, despite continued production, global reserves historically have not declined, because new reserves have been added through exploration, discovery, and reserve replacement.

Proved reserves are only a subset of the entire potential oil resource base. Resource base estimates include estimated quantities of both discovered and undiscovered liquids that have the potential to be classified as reserves at some time in the future. The resource base may include oil that currently is not technically recoverable but could become recoverable in the future as technologies advance. In the IEO2016 Reference case, the resource base does not pose a global constraint on oil supply.

To construct plausible projections for petroleum liquids production, underlying analysis must consider both production beyond the end of the projection period and the physical realities and limitations of production. Proved reserves cannot provide an accurate assessment of the physical limits on future production but rather are intended to provide insight as to company-level or country-level development plans in the near term. Because of the particularly rigid requirements for the classification of resources as proved reserves, even the cumulative production levels from individual development projects may exceed initial estimates of proved reserves.

EIA attempts to address the lack of applicability of proved reserves estimates to long-term production projections by developing a production methodology based on the true physical limits of production, initially-in-place volumes, and technologically limited recovery factors. 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 aboveground limitations on production as profitability and specific national regulations, among others.