Chapter 5

Unleashing the Power of American Energy

Taking advantage of America's abundant energy resources is a key tenet of the Trump Administration's plan to increase long-term economic growth and national security. This is best achieved by recognizing how prices and technological change underpin growth in the production of renewable and nonrenewable energy sources. By promoting domestic energy production and expanding U.S. energy exports, the Administration seeks to improve the relationship the U.S. economy has historically had with global energy markets.

Since the President took office, the U.S. fossil fuels sector has set production records, led by all-time highs in both oil and natural gas. The energy content of fossil fuel production is at this apex thanks to petroleum's high energy content. The surge in petroleum production is a surprise, and is attributable to a confluence of technological improvements and relatively high prices. Natural gas production has also continued to increase, following a long-running trend. Coal production stabilized in 2017 and 2018, after a period of contraction in 2015 and 2016.

Increased production allows the United States to alter historic trade patterns by decreasing its net imports. The U.S. is now a net exporter of natural gas for the first time in 60 years, and petroleum exports are increasing at a pace such that the United States is projected to be a net exporter of energy by 2020. Reducing its net import position for energy products helps the United States by making its economy less sensitive to the price swings that have disrupted it in the past. Greater economic resilience at home is coupled with greater diplomatic influence and flexibility abroad as U.S. prominence in global energy markets grows.

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Technological and regulatory changes are forcing the U.S. energy system to further adapt. This is especially true for the electricity sector, which is adapting to the changing slate of generation assets and to economic pressures from restructured wholesale markets. Recognizing and embracing the innovations that have helped spur these changes in the U.S. energy system, and ensuring that distorting policies do not interfere, can help all Americans and people around the world—which is why the Administration is focusing on policies supporting these priorities.

Leveraging American energy abundance is a central tenet of the President's economic vision. This is best achieved by recognizing how prices and technological change underpin growth in the production of renewable and nonrenewable energy sources. In 2018, this sector of the economy yielded historic results. U.S. fossil fuels production is booming, led by all-time highs in oil and natural gas. This increase in production has helped support economic growth and allowed the United States to change historic trade patterns. Yet technological and regulatory changes are forcing the energy system to further adapt. Recognizing and embracing the innovations that have helped spur these changes in the U.S. energy system, and ensuring that distorting policies do not interfere, can help all Americans and people around the world. The Administration focuses on policies supporting these priorities.

Although proposals for a policy of energy independence have a history in the United States dating back to at least 1973, the Trump Administration's energy policy goes further by emphasizing two elements. The first is to maximize the value of U.S. production at market-determined prices. Fossil fuels, which provide 80 percent of the Nation's energy needs, loom large in this regard. Energy is useful insofar as it can ultimately provide the power, light, and work that are important economic inputs for the production of goods and services that benefit Americans. These inputs can be generated in a number of ways. For example, electricity can provide light, and electricity can be generated from a variety of sources—by burning fossil fuels like coal and natural gas, or by using renewable methods like wind and solar generation, or other means like nuclear generation.

The United States also has extensive energy resources—fossil fuel reserves; renewable resources like hydroelectric, solar, and wind; and perhaps most valuable of all, world-class engineering and research complexes that constantly innovate and improve the efficiency of both the U.S. and global energy systems. The Administration's policy of fostering maximum production embraces all these sources, with their diverse characteristics and economic applications.

The various sectors of the U.S. economy rely on different forms and sources of energy; for example, in 2017, the U.S. economy relied on petroleum for 92 percent of its transportation needs, using 72 percent of all petroleum consumed domestically. Other countries around the world satisfy their energy needs with different mixes than the United States. Because countries have different endowments of energy resources, and different energy policies, the varying demands and supplies of energy provide the opportunity for trade in power and fuels. The importance of energy trade is underscored by the prominence of a single commodity—crude oil—which in recent years has accounted for an average of over 6 percent of global trade value (United Nations 2018).

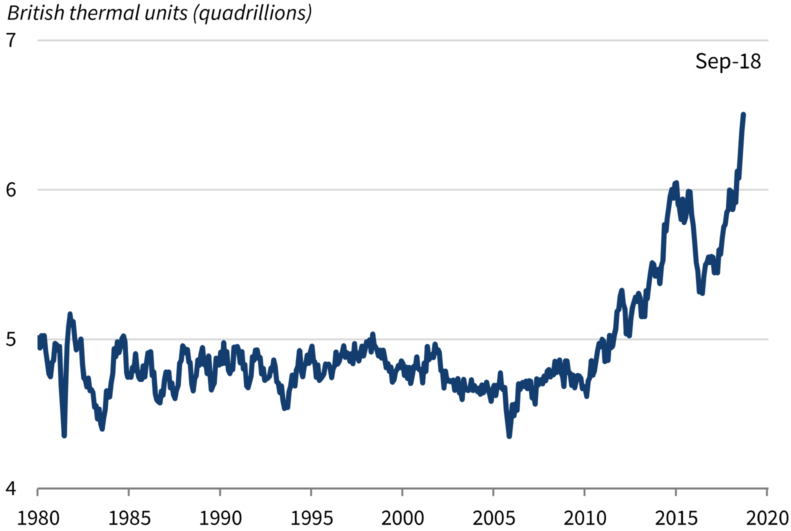
The United States can use its increased energy production to take a greater role in global energy markets, particularly those for fossil fuels. Reducing its net import position for energy products helps the United States by making its economy less sensitive to the price swings that have disrupted it in the past. Greater economic resilience at home is coupled with greater diplomatic influence and flexibility abroad as the United States' prominence in global energy markets grows. Finally, more global competition in energy supply may moderate global prices and price volatility.

This chapter outlines the key economic contours of the Trump Administration's energy agenda. The first section documents and contextualizes recent developments in U.S. fossil fuels production. The second section considers the United States' ability to engage with global energy markets through increased trade. And the third section examines specific policy issues that remain and pose challenges for the future.

U.S. Fuel Production Reached Record Levels in 2018

The United States is fortunate to have many useful energy resources—oil, natural gas, coal, solar, wind, geothermal, and more. American success in promoting fuels production is broad-based, as overall fossil fuel production has increased. In 2018, U.S. fossil fuel production set an all-time record for total energy content, as shown in figure 5-1. This record continues the recent trend—which was only interrupted by a dip in 2016, when lower prices failed to support oil and natural gas production enough to offset falling coal production. Since then, the growth in petroleum production has more than made up for lower coal production, relying on the greater energy density of crude oil to make up the difference.

Figure 5-1. Energy Content of U.S. Fossil Fuels Production, 1980–2018



Sources: Energy Information Administration; CEA calculations.
Note: Total fossil fuels defined as quadrillion Btu-equivalents of combined crude oil, natural gas, gas plant liquids, and coal production. Data represent a 3-month moving average.

U.S. Oil Production Is At an All-Time High

Reports of the demise of U.S. oil production (Bentley 2002; Hirsch, Bezdek, and Wendling 2005; EIA 2006) appear to have been premature. Thanks to a confluence of technological proficiency in available geology and world price patterns, in 2018 U.S. oil production reached an all-time high. In November 2017, U.S. oil production surpassed a monthly production record set in 1970, with oil production reaching a monthly average of 10.1 million barrels per day (MMbpd). This trend continued into 2018, as the monthly average production for the year's first three quarters was 10.7 MMbpd. Resurgent U.S. production relies on unconventional resources once deemed too diffuse and costly to exploit. However, advanced seismography, hydraulic fracturing, directional drilling, and related technologies have changed this situation by effectively lowering the cost of accessing oil and gas trapped underground. The technical innovations pioneered and perfected in the United States (Zuckerman 2014; Gold 2014) are now paying dividends in the form of increasing production. The dividends have been paid quickly, with U.S. production increasing by 6 MMbpd in eight years—the largest increase of any country in history.

Technology that was pioneered in parts of Texas and in the western States is now applied across the country, boosting production everywhere from the historically productive Permian Basin in Texas and New Mexico to new provinces like the Eagle Ford Shale in Texas and the Bakken Shale in

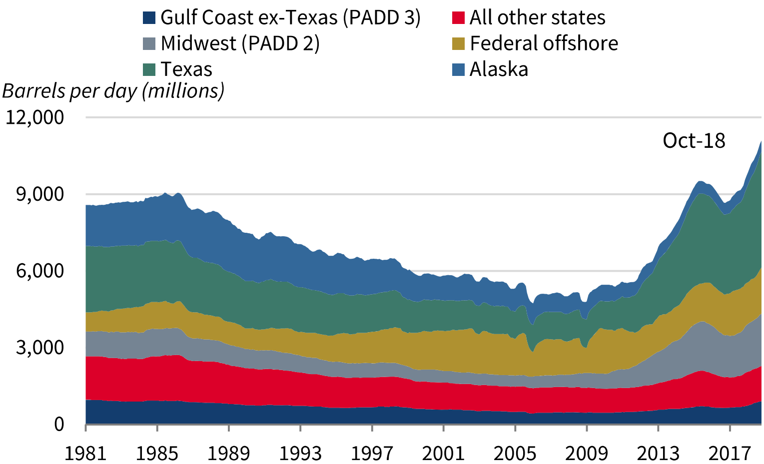
North Dakota and Montana. Production in Texas increased by 11.1 percent from December 2017 levels through the first half of 2018, while the monthly average production through October 2018 was 291 percent higher than annual production in the state 10 years ago (figure 5-2). This increase more than offsets declining production in other important regions, including Alaska and the shallow-water areas of the Gulf of Mexico.

Crude oil prices in 2018 exhibit three general characteristics. First, from the perspective of U.S. producers, price levels remained higher than the previous three years, on average. Second, price volatility was modest compared with the period 2014–16.[1] Together, these high and stable prices provided a strong incentive for producers. And third, the price discount for the main landlocked U.S. benchmark, West Texas Intermediate (WTI) crude oil—relative to the nearest waterborne benchmark, Brent crude oil—has increased to the highest level since 2013. Although both grades are priced higher due to attractive refining properties, the differential between these two close substitutes indicates that the U.S. market is separated from the global market. Many market observers take this as evidence of the existence of infrastructure constraints that require U.S. production to incur somewhat higher transportation costs that erode its value at inland pricing points. McRae (2017) documents how price basis differentials stemming from pipeline bottlenecks represent a transfer from producers to refiners and shippers, but are not transmitted to consumer prices. This is consistent with earlier work by Borenstein and Kellogg (2014), who found that the marginal barrel of gasoline is priced to Brent, leaving the consumer unaffected by a Brent–WTI basis differential.

In addition to setting a domestic production record, in 2018 the United States became the world's leading producer of crude oil after years of leading the world in combined oil and natural gas production.[2] Figure 5-3 shows the recent increase that has returned the United States to global leadership after 43 years. The production comes from a different resource base than conventional deposits in Russia and Saudi Arabia, because U.S. production, and especially production growth, rely on unconventional resources that were once considered subeconomic. However, a combination of technological innovation, market incentives, and millions of private mineral owners willing to take risks with new techniques have helped the U.S. oil and gas sector launch a new era of production. U.S. production now largely comes from geological formations like low-permeability sandstones and shales that are not developed in most other countries. An added benefit is that much of the production is

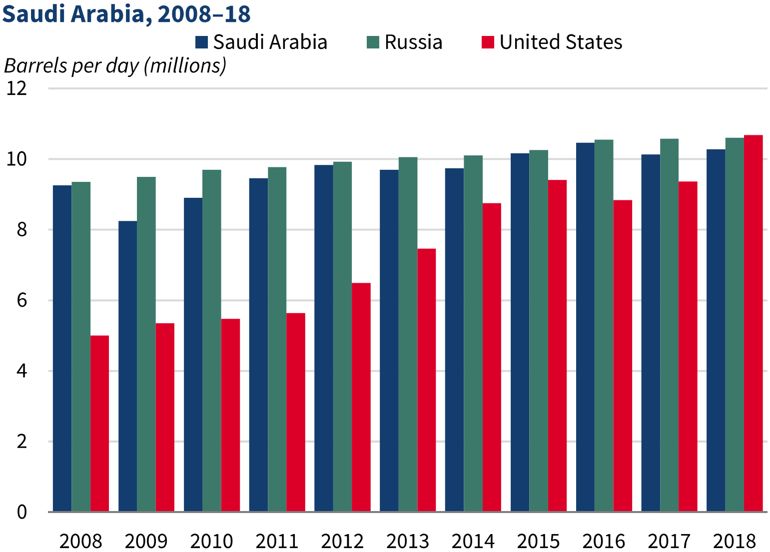
[1] Although less volatile than the preceding years, this period's volatility remains higher than that of many historical periods and may be an important concern for producers (McNally 2017).
[2] Oil and gas producers bring a cocktail of hydrocarbons to the surface, including crude oil, lease condensate, natural gas, and natural gas liquids. The exact proportions vary across different geologies. After they are brought to the surface together, the products are separated and sold through different channels for different uses.

Figure 5-2. U.S. Monthly Crude Oil Production, 1981–2018



Sources: Energy Information Administration; CEA calculations.
Note: Data represent a 5-month moving average. PADD = Petroleum Administration for Defense District. PADDs were created during World War II to help organize the allocation of petroleum fuels. PADD 2 (Midwest): Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, Oklahoma, South Dakota, Tennessee, and Wisconsin. PADD 3 (Gulf Coast): Alabama, Arkansas, Louisiana, Mississippi, and New Mexico.

Figure 5-3. Crude Oil Production in the United States, Russia, and Saudi Arabia, 2008–18



Sources: Energy Information Administration; CEA calculations.
Note: 2018 production levels are taken from EIA's 2018 *Short Term Energy Outlook* projections.

lighter and lower-sulfur grades of crude oil that command a price premium and give refiners considerable flexibility in processing because they are less costly to refine than heavier grades. The economic implications of the technological innovations that have facilitated these changes have been a long time coming (CEA 2006, 2012, 2013, 2015, 2016a, 2017). So why was 2018 the year to break production records?

In the not-too-distant past, it seemed that increased U.S. production required high prices, further reducing U.S. influence in the global marketplace. Technological innovations have increased both economically feasible and technically recoverable reserves. Innovations in directional drilling and hydraulic fracturing helped lower the breakeven costs of shale oil, while improved deepwater extraction efficiency has increased interest in offshore drilling as well. The assumption was that all these methods required fairly high breakeven prices. The threat posed by unconventional U.S. production to other global producers compelled the Organization of the Petroleum Exporting Countries (OPEC) to allow prices to fall in late 2014, in an effort to protect global market share and long-run revenues. This strategy of defending market share against new entrants is historically well-known to OPEC members, and it may or may not deliver higher revenues (Adelman 1996). Although the subsequent price drop was traumatic for U.S. producers, the ultimate result was that the marginal cost of unconventional production fell, making U.S. oil more competitive in the global marketplace (Kleinberg et al. 2016). The combination of relatively high and stable prices, accumulated cost-reducing technological improvements, and the massive endowment of unconventional resources has allowed production to expand rapidly.

Some observers have taken America's world-leading production and decreased net imports as evidence that the United States has greater influence in the global oil market, but the empirical evidence suggests more work is needed to achieve this goal.[3] The responsiveness of onshore oil production to price shocks remains limited inside the continental United States. Estimates by Newell and Prest (2017) indicate that although the response of U.S. supply to price changes is larger than before the dawn of shale oil, the U.S. remains slower to react than a traditional "swing producer" (i.e., a producer that can bring additional capacity online quickly in response to demand), such as Saudi Arabia. Newell and Prest (2017) also find that the U.S. response takes several months to come online, which is substantially less timely than the 30 to 90 days associated with typical swing production. So while the United States now enjoys more production and more responsive production than it has historically done, it has not yet reached a point that would provide it with the market power associated with being a global swing producer. The United States'

[3] During the week ending November 30, 2018, the United States had negative net imports of petroleum for the first time since at least 1973 (data from the U.S. Energy Information Administration).

lack of spare capacity implies that other countries, notably the members of OPEC, hold the key to modulating prices by being able and willing to adjust production.

As OPEC settled into a regime of production cuts that helped support prices in 2017 and 2018, geopolitical uncertainty in key oil-producing countries also boosted prices and helped bolster U.S. production (see box 5-1). Compared with the production levels of OPEC members in 2016, supply reductions in Venezuela and other countries subtracted 492,000 barrels per day on average from OPEC's production during the period between January 2017 and August 2018. Cuts by Venezuela accounted for 75.2 percent of gross output reductions by OPEC's producers between January 2017 and August 2018.

The unexpected resurgence of U.S. production over the past decade provides evidence that is hard to square with central predictions of popular models of resource scarcity. A prominent example is the "peak oil" literature, which recognizes the physical limit on the endowment of oil to predict a date of maximum extraction rate, after which production monotonically declines.[4] Growing reliance on petroleum as a fuel has been matched by episodic concerns about its continued availability. A monotonic production decline is viewed as problematic for an economy that previously had consumed increasing amounts of oil.

The paper by Hubbert (1956) was the original technical contribution to the peak oil literature, which later blossomed into a broader following (Deffeyes 2001, 2006). Hubbert's central insight was that there is a finite amount of oil to be found, and the pace of discoveries could not accelerate indefinitely, as it had for the preceding decades. Hubbert established an initial estimate for total U.S. oil reserves of 200 billion to 250 billion barrels. Conditional on U.S. oil reserves of 200 billion barrels and the historical trajectory of discoveries and extraction, Hubbert predicted peak production in 1970, with a subsequent decline. This forecast was remarkably accurate for the lower 48 States, through about 2010; production peaked in 1970, and appeared to enter a steady decline in the following years (figure 5-4). Even when considering the massive discovery in Alaska, and the effect that Alaskan oil had on aggregate U.S. production, Hubbert's simple model predicted a peak that was only off by a couple of years and seemed to encapsulate the inherent limit to oil production.

However, Hubbert's model ignored the role of prices in promoting exploration and production, and of technological innovation in expanding proven reserves. Higher prices and technological improvements allowed access to offshore and unconventional reserves, leading to an unpredicted peak increase

[4] Highlighting the economic significance of physical limits follows a long tradition dating back to at least 1798, when Thomas Malthus published "An Essay on the Principle of Population," which expressed the fear that growth in population would outpace growth in food production. As the Industrial Revolution made coal an essential economic input, William Jevons (1865) translated this same argument to a nonrenewable resource, which was the first "peak fossil fuel" argument.

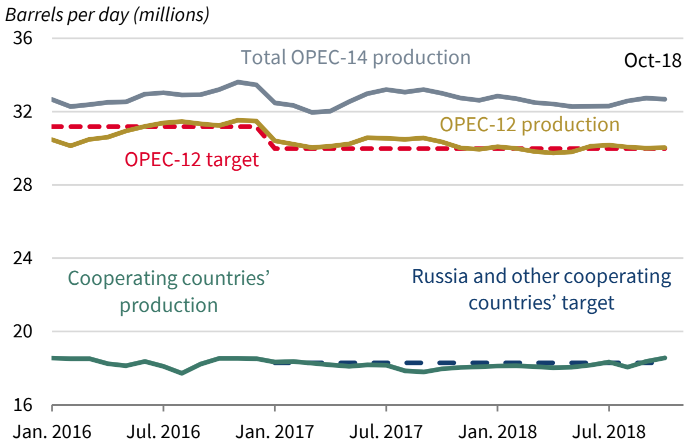
Box 5-1. OPEC's Oil Production Cuts

OPEC has 13 member states located in the Middle East, Africa, and South America. As of October 2018, OPEC producers enjoyed a 39 percent share of the global petroleum market, down from a post-2000 peak of 44 percent in September 2008 (OPEC 2018b; EIA 2018i). However, they collectively control 74 percent of world oil reserves, and most of the lowest extraction cost reserves (EIA 2018b). Since its formation in 1960, OPEC has alternated between strategies of maximizing market share and maintaining high prices. The oil price collapse in 2014 is attributed to OPEC protecting its market share at the expense of prices. Since then, OPEC has changed strategies and cut production to enjoy the resulting higher prices.

(In 2018, OPEC had 14 oil-producing members, along with the Republic of Congo. The Qatari state petroleum company announced on December 2, 2018, that it was leaving OPEC, effective January 1, 2019. Qatar is a substantial natural gas producer, but it only accounted for 1.9 percent of OPEC's oil production—less than 1 percent of global production.)

Through late 2015 and much of 2016, OPEC members discussed a targeted cut to help support prices. These discussions also expanded to include key non-OPEC producers, including Russia. The OPEC meeting on November 30, 2016, announced a target reduction of 1.2 MMbpd for the 12 cooperating members of OPEC—Libya and Nigeria are exempt—effective January 1, 2017,

Figure 5-i. OPEC Crude Oil Production versus Production Targets, 2016–18



Sources: Organization of the Petroleum Exporting Countries (OPEC); U.S. Energy Information Administration; CEA calculations.
Note: The OPEC-12 are the 14 OPEC member states, except for Libya and Nigeria, which are exempt from production cuts. The "other cooperating countries" are Russia, Mexico, and Kazakhstan, which, along with several other smaller producers, collaborate with OPEC's production schedule.

bringing its allocated production to 29.8 MMbpd and its ceiling for the OPEC-14 to 32.5 MMbpd. Subsequent OPEC meetings in May and November 2017 extended these cuts in allocations through the whole of 2018, in addition to allowing for the accession of Equatorial Guinea into OPEC with an allocation of 178,000 barrels per day (OPEC 2018a).

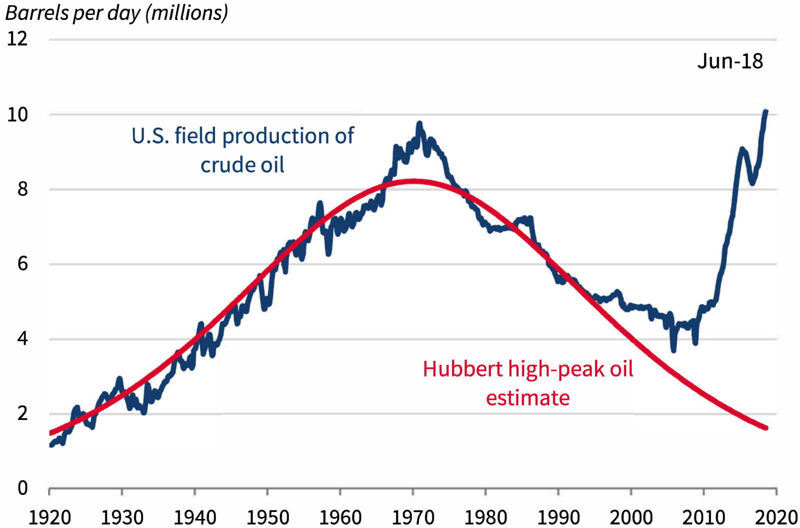
Cooperation by several other countries—notably Russia, Mexico, and Kazakhstan—has helped leverage the cuts by including more production share in the group agreeing to cuts. Adding the production of these cooperating countries to the OPEC-12, the global market share of the countries cooperating with OPEC's cuts increased to 68 percent of crude production in 2017. Compared with average production in 2016, the OPEC-12 and its collaborators have cut production by 1.33 MMbpd, or about 1.8 percent of global production.

According to data from the U.S. Energy Information Administration (EIA) on secondary reporting of OPEC's oil production, the target of 29.982 MMbpd for the OPEC-12 was met for only 1 of 12 months in 2017, with the largest monthly overage being 0.59 MMbpd (1.9 percent over target production). During the first six months of 2018, the OPEC-12 came in below the target by an average of 0.2 percent each month, or 57,000 barrels per day (EIA 2018i). See figure 5-i.

in domestic production. This experience contrasts sharply with forecasts influenced by peak oil theory, especially those that were ascendant 15 years ago, most of which expected peak oil extraction by 2010 (Laherrère 1999; Campbell 2003; Skrebowski 2004; Bakhtiari 2004). The prediction of decreasing U.S. oil production has been proved wrong by increased domestic production in 9 of the past 10 years (BP 2018), shattering Hubbert's (1956) original prediction shown in figure 5-4. Though there is a finite quantity of oil resources that can be discovered and extracted, ignoring the incentive for exploration and innovation created by high prices, and the impact that successful innovations have had on expanding the economic reserve base and reducing production costs, the physical limits do not circumscribe economic potential, as some analysts have hypothesized.

Although the physical endowment of oil is smaller than it once was, some context is useful. In 1956, as Hubbert was making his original forecast, U.S. proven reserves of crude oil were 30 billion barrels. At the end of 2017 proven reserves were 39.2 billion barrels. From 1957 to 2017, total U.S. crude oil production was 167.0 billion barrels. In addition to the 55.2 billion barrels extracted before 1957, Hubbert's estimate of the size of reserves was not unreasonable. However, what it did not anticipate was that today different kinds of resources would be considered reserves (known resources that can be profitably extracted with current technology at current prices). This

Figure 5-4. U.S. Lower-48 Production versus Hubbert's 1956 Peak Oil Prediction, 1920–2018



Sources: Energy Information Administration; Hubbert (1956); CEA calculations.
Note: Data represent a 3-month moving average. The Hubbert (1956) estimate was constructed using a stepwise logit function.

observation is not new to the economics literature (Boyce 2013), but the recent empirical record suggests that peak oil models will need to consider prices and technology to be reliable in the future. Geologists—like Hubbert—woke up every morning and looked for oil; but they expected the pace of discoveries to eventually slow down, and then production would have to decline.[5] The policy environment had no bearing; nor did prices or technology.

The point of Hubbert's paper was to emphasize the need for future energy transitions; he expected nuclear power to be more widely used. Nuclear power has its own inherent trade-offs, some of which are discussed below. Recent experience in the United States underscores the imprudence of relying upon geological forecasts alone. The incentives of prices and the role of technological innovation—which is funded by the price incentive in a market economy like the United States—are critical for understanding the production of even a nonrenewable natural resource like petroleum.

The Natural Gas Revolution Rolls On

Before technology helped U.S. oil production reach record highs, natural gas was the focus, and the "natural gas revolution" changed the national energy landscape (Deutch 2011). Hydraulic fracturing receives much of the credit. This

[5] Hubbert's earliest paper, describing single-peaked growth with a decline to zero, came in a 1934 publication for the Technocracy, a social and political movement of the 1930s that advocated replacing the price system with management by technocrats (Inman 2016).

technique was originally developed in 1948 to improve flow from oil wells, and it evolved in the 1990s toward greater volumes of water and sand injected to fracture rocks saturated with natural gas. This breakthrough depended on a fundamentally sound understanding of the relevant geophysics, the basis of which was pioneered in 1956 by none other than the same Hubbert of peak oil fame. Production of natural gas in the United States has continued to grow to record levels, reducing reliance on imports and expanding exports globally. For the 9th time in the past 11 years, in 2017 the United States withdrew a record amount of natural gas. Gross natural gas withdrawals in the United States have increased by more than 50 percent over the past 10 years, rising to 3,267 billion cubic feet (Bcf) in October 2018. This growth has relied on technological advances, including hydraulic fracturing and directional drilling, that have made the development of shale gas resources economic. The Appalachian, Permian, and Haynesville basins have led U.S. production growth.

The growth of U.S. natural gas production, led by shale and other unconventional resources, has been driven by the rise in nonassociated gas production. Nonassociated gas is produced from reservoirs where the gas is not found with substantial amounts of crude oil, whereas associated gas is jointly produced with crude oil. Nonassociated gas production in the United States grew by 29 percent between 2007 and 2017. The rise in nonassociated gas production has been centered in the Appalachian Basin, which stretches across New York, Pennsylvania, Ohio, and West Virginia to include the Marcellus and Utica shale plays, where total gas production grew from 1.3 Bcf per day (Bcfd) in January of 2007 to 31.5 Bcfd in January of 2019 (EIA 2018f). Unlike the other states, New York has effectively banned development of its shale resources (see box 5-2).

Associated gas production is rising again with shale oil production. This has created an infrastructure challenge, given that two types of infrastructure are needed—for oil and for natural gas. Oil has more transportation substitutes than natural gas, which depends on specific investments in pipeline capacity to move efficiently. In comparison, oil can move by rail or even truck where necessary, until pipeline capacity catches up with production (Covert and Kellogg 2017). As a result, the flaring of associated natural gas has increased. Firms that are unwilling to wait to extract oil have a choice between completing natural gas pipeline projects and seeking accommodation from regulators to allow more flaring. In the short run, the latter might be less expensive.

Total natural gas proven reserves (wet after lease separation) increased by over 87 percent between 2007 and 2017. In 2017, total proven natural gas (wet after lease separation) reserves stood at 464,292 Bcf, which corresponds to over 17 times the total U.S. consumption in the same year. The reserves are there; the technology is there. Two factors limit production. The first is finding uses for more gas at current prices; the second is building out infrastructure to move gas from where it is produced to where it is consumed. Continued

Box 5-2. The Important Economic Effects of State Regulation on Energy Production

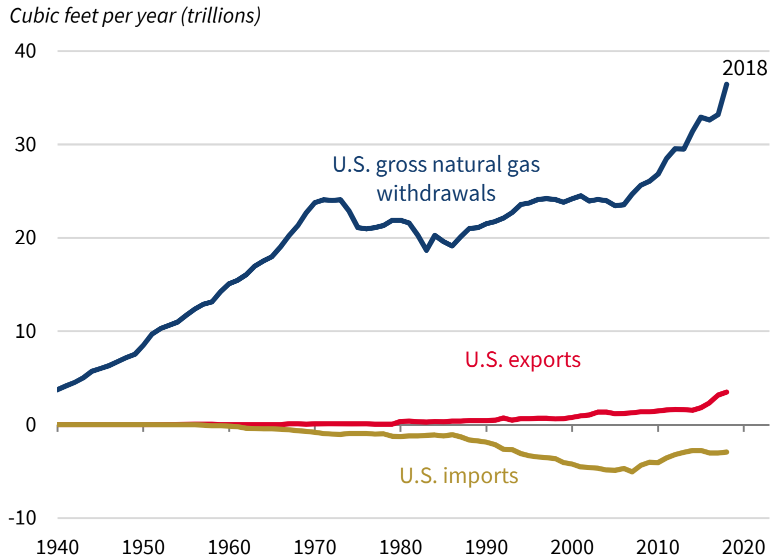
Differences in States' regulation of hydraulic fracturing ("fracking") have important economic effects. Nowhere is the contrast as stark as between Pennsylvania and New York State, which have taken divergent regulatory tacks—Pennsylvania has been accommodating and thus has seen widespread development of its underlying shale gas resources, but more restrictive New York has elected to effectively prevent development. Pennsylvania's natural gas production expanded over 30 times between 2006 and 2017, and went from making up under 1 percent to constituting 20 percent of U.S. dry gas production. In contrast, New York placed a de facto moratorium on hydraulic fracturing in 2008 that ossified into an outright ban in 2014. In light of this regulatory ban, New York received far less investment, and its natural gas production fell by 80 percent from 2006 to 2017.

Counties along the New York–Pennsylvania border that are otherwise similar provide an ideal laboratory for understanding some effects of regulation. Boslett, Guilfoos, and Lang (2015) examined the effects of the New York moratorium, and found that among those counties most likely to experience shale gas development, residential property values declined by 23.1 percent due to the shale gas moratorium. This result is also true for rural land values; Weber and Hitaj (2015) found a 44.2 percent greater appreciation in Pennsylvania's border counties relative to New York's border counties. Cosgrove and others (2015) used a differences-in-differences approach to examine the effects of increased shale gas production between 2001 and 2013, finding that after 2008 Pennsylvania counties experienced significant increases in both industry employment and wages compared with New York counties. Komarek (2016) used New York's border counties to compare with counties in the Marcellus region that were developed, and found that developed counties had a 2.8 percent increase in employment, a 6.6 percent increase in earnings, and a 3.3 percent increase in earnings per worker.

export growth is one method by which to capitalize on vast proven natural gas reserves; but as figure 5-5 shows, current exports are quite small relative to annual production. Infrastructure investments require an expectation of production and sales over a sufficiently long time horizon to amortize the fixed costs.

U.S. consumption of natural gas by consumers has increased alongside production, thanks to low and stable prices. For 7 of the last 11 years, the United States has recorded record natural gas consumption. This increase is led by electricity generation, on pace for a 10 percent increase over the previous peak in 2016. Although natural gas consumption has increased substantially for electric power consumers and natural gas vehicles, the main

Figure 5-5. U.S. Natural Gas Trade and Withdrawals, 1940–2018



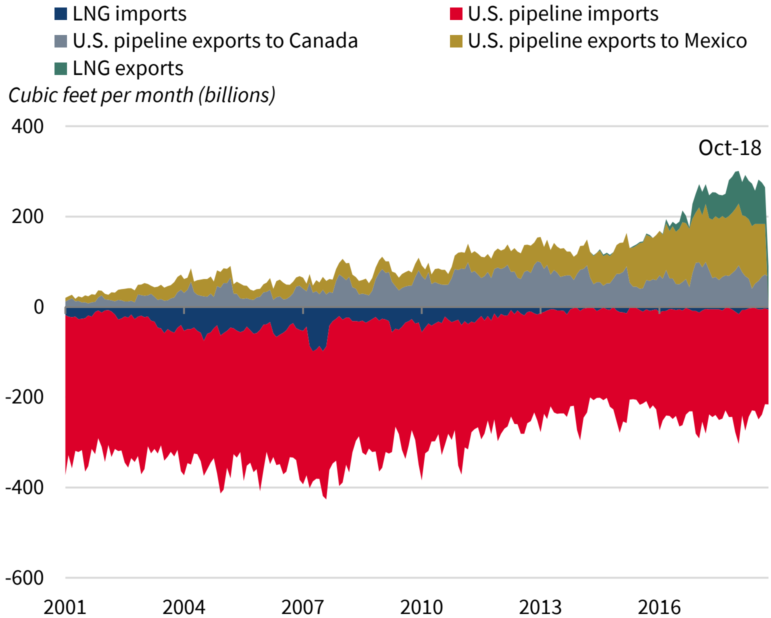
Source: Energy Information Administration.
Note: Trade data preceding 1973 are derived from EIA's tracking of international deliveries and receipts. Annual data for 2018 were reported as monthly data through October at a seasonally adjusted annual rate.

sources of natural gas demand are electric power generation, industrial uses, and residential uses. The shift toward using natural gas for electricity generation is a global trend—2016 and 2017 were the first two years on record in which natural gas–fired electricity generation made up a greater share than coal-fired generation in countries belonging to the Organization for Economic Cooperation and Development (OECD) (BP 2018). Electricity generation is an important component of creating enough demand to capitalize on American abundance and supporting production.[6]

The dramatic rise in unconventional natural gas production since 2007 has enabled the United States to become a net exporter, starting in 2017, for the first time since 1957. In total, U.S. exports of natural gas increased by 341.5 percent between January 2007 and October 2018 (figure 5-6). As a net exporter of natural gas, the United States occupies a strategic position to provide this resource, both to its Western Hemisphere neighbors and to its allies and trading partners around the world. Natural gas exports by pipeline to its neighbors make up the largest share of U.S. exports, with pipeline exports to Canada and Mexico accounting for 21.4 and 49.2 percent, respectively, of total U.S. natural

[6] An alternative interpretation is that the lower energy density of natural gas frees up other, higher-density fuels for export. Substituting an inferior product for local consumption to capture a premium in export markets is recognized in economics as the "shipping the good apples out" principle (Alchian and Allen 1964; Hummels and Skiba 2004).

Figure 5-6. U.S. Monthly Trade in Natural Gas, 2001–18



Sources: Energy Information Administration; CEA calculations.
Note: LNG = liquefied natural gas.

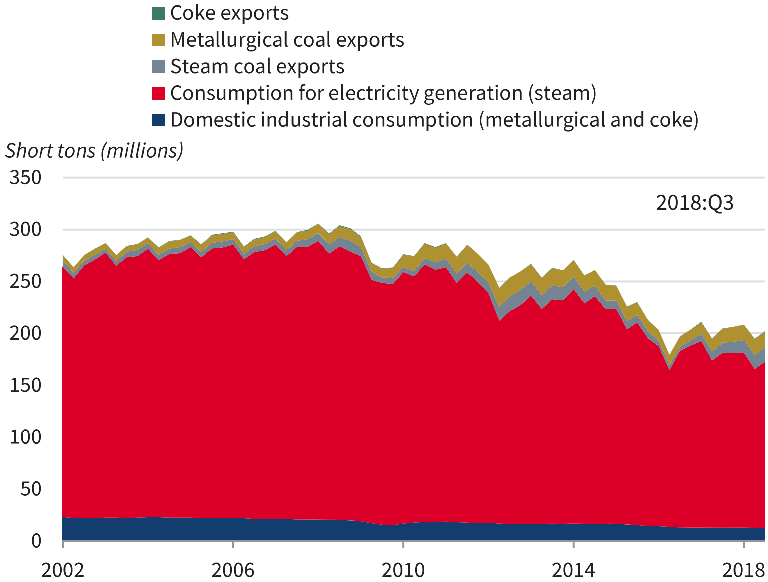
gas exports in October 2018. Total U.S. natural gas imports have fallen by 44.9 percent since January 2007; Canadian pipeline imports make up 97.2 percent of total imports.

Coal Production Is Recovering after the 2015–16 Slump

U.S. coal production has recovered after facing difficult market conditions between 2012 and 2016. After averaging roughly 1.1 billion short tons of production annually from 2000 to 2009, coal production and related employment began to slip in mid-2011. By 2016, production had dropped to 728 million short tons, 65.2 percent of the average level between 2001 and 2010 (EIA 2018c). However, production rebounded in 2017, rising 6.3 percent from the preceding year to 774 million short tons. This trend continued through the first half of 2018, as production remained 10.3 percent higher than its secular low in the first half of 2016. Increased production required a small boost in coal mining employment, which has grown by 2,900 since the President's election in 2016. This increase has been helped by the production increase in relatively labor-intensive eastern regions. Different grades and characteristics of coal make these mines competitive despite requiring much more labor per unit of output.

Higher exports are a welcome fillip to an industry that has been battered by declining demand for domestic steam coal used to fire electric generation

Figure 5-7. U.S. Quarterly Coal Disposition, 2002–18

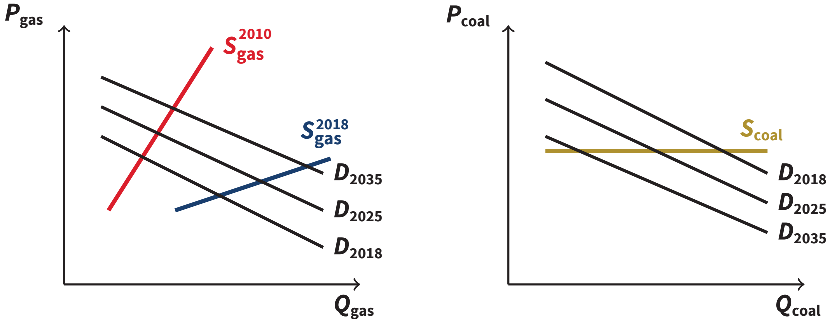


Sources: Energy Information Administration; CEA calculations.

that stems from low natural gas prices (figure 5-7). The portfolio of electric generation technologies has expanded with greater penetration of renewables like solar and wind, and inexpensive natural gas has expanded its market share at the expense of coal. Coal producers have also been affected by increased costs from new regulatory requirements; for example, coal plant retirements in 2015 and 2016 were affected by the Mercury and Air Toxics Standards (known as MATS), which made a shutdown an attractive alternative to compliance for many plants, even those receiving a one-year waiver. Although the past two years show that these trends have slowed and coal production has stabilized at a new, lower level, a reversal of the trends that return coal to the dominant position it enjoyed for decades appears improbable. The private market is showing signs of trouble as insurers and underwriters are shying away from coal projects.

The U.S. coal industry has evolved over the decades toward western and surface production. Underground and surface operations west of the Mississippi River have shifted from under 10 percent of total production 50 years ago to well over half of all production in 2018 (EIA 2012, 2018c). Western coal production has focused on steam coal. Part of the change was influenced by Federal environmental policy, which led companies to switch inputs to low-sulfur western coal rather than reducing output or changing technology (Carlson et al. 2000). This substitution was costly, however, and railroads

Figure 5-8. Changes in AEO Natural Gas Forecast, 2010 versus 2018



Sources: Energy Information Administration; CEA calculations.
Note: Shifts reflect differences in forecasts from 2010 and 2018 issues of the *Annual Energy Outlook* (EIA 2010, 2018e).

managed to capture some of the surplus (Busse and Keohane 2007; Gerking and Hamilton 2008). Productivity gains help account for the relatively modest employment gains; high levels of productivity in the West North Central Region spanning Kansas, Missouri, and North Dakota have led to moderate gains in employment over time, while the Mountain Region's nationwide eminence in productivity has allowed it to sustain employment levels roughly equal to those during the early 2000s (EIA 2018c; MSHA 2018).

The contrast between the outlook for natural gas and coal is captured in figure 5-8. The EIA's (2018b) *Annual Energy Outlook* shows a substantial revision between the 2010 and 2018 forecasts for natural gas, consistent with an anticipated shift of the supply curve out and down, implying more and cheaper natural gas. This is shown in the left panel of figure 5-8 with a shift in the supply curve from red to blue. Over time, the demand for natural gas shifts out to accommodate growth in energy demand. Hausman and Kellogg (2015) derived the welfare implications of contemporaneous supply and demand shocks. In contrast, a sector without technological change like coal does not get a supply shift, and even faces the prospect of declining demand because cheaper natural gas is an attractive substitute.

U.S. Fuels in the Global Marketplace

Trade is crucial for energy markets. Fuel commodities constituted more than a 9 percent share of global trade in 2017, on a value basis (United Nations 2018). The supply shift that the United States' oil and natural gas producers have experienced thanks to technology, along with its world-leading coal reserves, put it in an excellent position to trade energy products. The gains from trade are especially large in primary commodities like fossil fuels (Fally and Sayre 2018), for which the United States has a comparative advantage (CEA 2018).

U.S. Oil Exports Are At an Unprecedented High

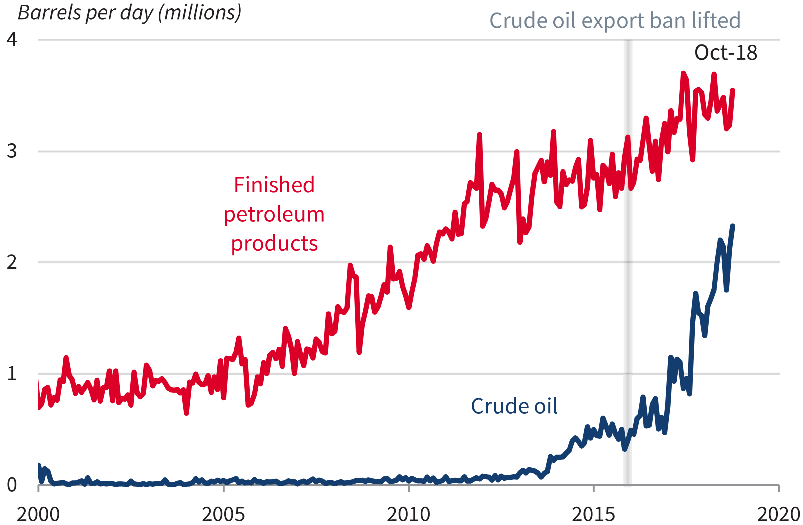
The unexpected increase in domestic oil and natural gas production has bought the United States a new degree of leeway in energy markets, especially for transportation fuels that are particularly reliant on petroleum. Domestic production offsets the demand for imported petroleum, which has contributed to rebalancing in the global market. U.S. net imports of crude oil and petroleum products averaged 2.7 MMbpd in 2018, down from the average of 12.5 MMbpd in 2005.

World production of crude oil and other petroleum liquids continued to grow through 2018 and is expected to average over 100 MMbpd (EIA 2018i). The change in the U.S. net import position for crude oil in 2018 year was about 0.74 MMbpd, equal to about half of OPEC's estimated spare production capacity in 2018 (EIA 2018i; BP 2018). This shift also significantly affects the U.S. international position in the market for crude oil and petroleum products. The U.S. petroleum trade balance was -$199 billion after seasonal adjustment in 2017, which is less than half of the –$495 billion (inflated to $2017) 10 years earlier, and is down over $300 billion from the all-time low in 2005 (U.S. Census Bureau 2018). Although the overall trade balance deteriorated over the concurrent period, increased production has undoubtedly served as a boon to the American position internationally as well as a buffer for American consumers' sensitivity to oil prices.

Petroleum exports. The United States has witnessed a renaissance in exports of crude oil since December 2015, thanks to the lifting of a 40-year ban on crude oil exports. Through September 2018, U.S. exports of crude oil were more than triple the annual levels in 2016, the first full year of exports after the lifting of the export ban. In May 2018, exports of crude topped 2.0 MMbpd for the first time in U.S. history (figure 5-9). Melek and Ojeda (2017) found that the ban was binding during the period 2013–15, but that when general equilibrium effects are taken into account, the macroeconomic effects of removal are negligible because of adjustments in the types of crude oil refined in the United States. This suggests that crude oil exports alone do not increase U.S. GDP because crude oil and refined product prices adjust.

However, in trade that does boost GDP, the United States imports a large volume of oil and capitalizes on the large and complex refining sector to produce refined products that are exported. Crude oil and refined petroleum product exports rose by 17.5 percent in the first 10 months of 2018 from the average level in 2017, driven by increased exports to Latin American nations (figure 5-10). The silver lining is the nondurable manufacturing jobs that are supported by imported oil. There is room for further gains in this direction. Despite increasing oil-refining capacity, U.S. consumption of petroleum exceeds domestic refining capacity.

Figure 5-9. U.S. Crude Oil and Finished Product Exports, 2000–2018

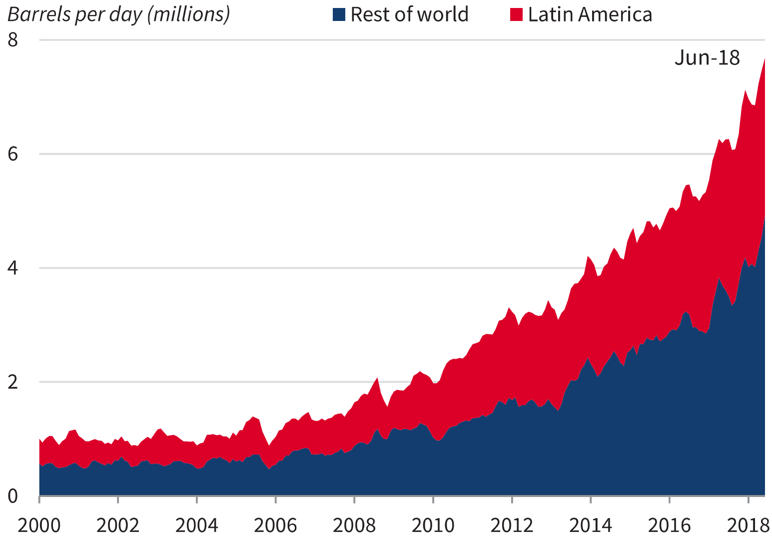


Sources: Energy Information Administration; U.S. 114th Congress.
Note: H.R. 2029 repealed Section 103 of the Energy Policy and Conservation Act (42 U.S.C 6212) on December 18, 2015, which lifted the ban on U.S. exports of crude oil starting in 1977, with certain exceptions granted by the Commerce Department.

Macroeconomic effects. Abundant crude oil has other important spillovers, notably to the macroeconomy. Trends in crude oil exports and shrinking net imports have implications for the economy's responsiveness to oil price shocks. The petroleum share of the U.S. trade balance is at historic lows; the petroleum share of the deficit was 15.8 percent in 2018, down 44.3 percentage points from secular highs of over 60 percent in 2009. The petroleum trade balance has narrowed steadily since its all-time high of $44.3 billion in November 2005 (figure 5-11). Because petroleum prices are determined in a global market and are volatile, reducing net imports of a product with inelastic demand allows domestic producers to capture windfall gains from higher prices that otherwise would be transferred to foreign producers.

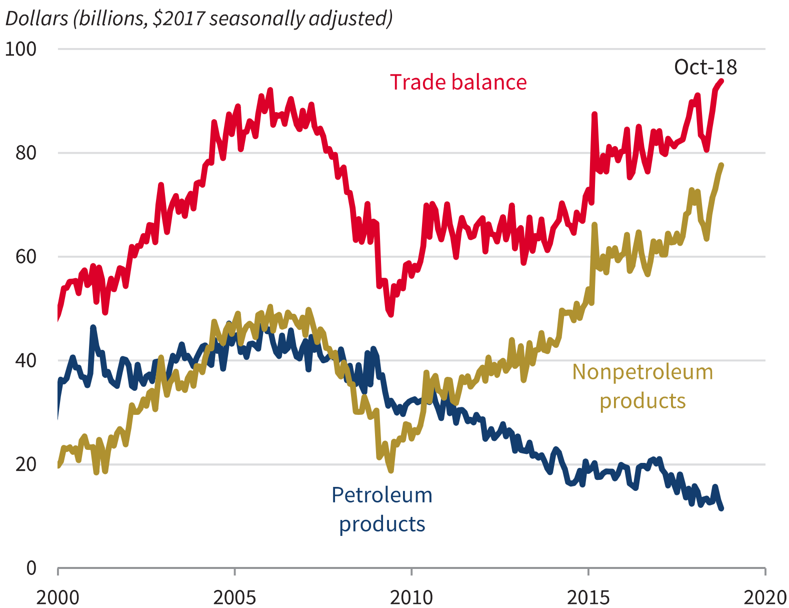
Oil price spikes have historically been correlated with negative growth effects for oil-importing economies (Hamilton 1996). Exogenous oil price shocks have significant contractionary effects on GDP growth for the United States and also for most other developed economies (Jiménez-Rodríguez and Sánchez 2004). A large body of literature finds that oil price volatility imposes substantial costs on the economy, affecting consumers directly and creating uncertainty that disrupts business investment (Jaffe and Soligo 2002; Parry and Darmstadter 2003; Kilian 2008; Baumeister and Gertsman 2013; Brown and Huntington 2015). Separating the role of oil price shocks in measuring effects on real GDP growth has traditionally been a difficult empirical task. Efforts

Figure 5-10. U.S. Crude and Petroleum Product Exports, 2000–2018



Sources: Energy Information Administration; CEA calculations.
Note: Data respresent a 3-month moving average. Latin America includes Argentina, the Bahamas, Brazil, Chile, Colombia, Costa Rica, Ecuador, El Salvador, Guatemala, Honduras, Jamaica, Mexico, Nicaragua, Paraguay, Saint Lucia, and Venezuela.

Figure 5-11. U.S. Petroleum Trade Balance, 2000–2018



Sources: Census Bureau; CEA calculations.

to tease out the effects of oil price changes are impaired by the endogenous effects of monetary tightening and other countercyclical policies aimed at correcting these trends (Hoover and Perez 1994; Barsky and Kilian 2002).

As the United States continues to expand its position as an exporter in global oil markets, it better insulates itself from the adverse welfare and GDP consequences of high oil prices and price spikes. Although the United States remains a net importer of petroleum products, its smaller net import share leaves it with less exposure to oil price shocks. For example, between 2008 and 2009 the average landed cost of imported crude oil decreased from $93.33 to $60.23 per barrel, contributing to a $136 billion lower oil import bill. Because of lower imports, a similar price difference during the first three quarters of 2018 would have only saved $72 billion. In a stunning reversal, if the United States becomes an annual net exporter, it may view supply restrictions elsewhere in the world as an opportunity rather than a threat. The speed with which this transition has taken place is unprecedented.

A second effect of the changing U.S. net petroleum position is that it may increase protection from the business cycle that is exacerbated by high oil prices. Kilian and Vigfusson (2017) observe that in the period since 1974, U.S. economic recessions have been universally preceded by increases in the price of oil. However, as the authors note, increases in real oil prices do not always predict an economic contraction in a subsequent period. One metric for defining sustained increases in the price of oil is the cumulative net oil price increase over three years (Hamilton 2003). Figure 5-12 displays the apparent correlation between persistent, upward pressure on the price of oil and recessions between 1974 and 2018.

After 60 Years, the U.S. Is Again a Net Exporter of Natural Gas

Domestic production, proven reserves, and export capacity have all increased for U.S. natural gas. The supply shock for gas has created a question of where gas should flow to balance the market. Domestic consumption has increased, led by electricity generation. Petrochemical investments are up, contributing to a strong domestic chemical manufacturing base with ethane crackers along the Gulf Coast and in Pennsylvania. That leaves two main options for outlets: domestic transportation, and foreign markets.

With greater export capacity, natural gas will play an important role as a strategic resource provided by the United States to countries around the world, in addition to the trade balance in goods. The implications of exporting U.S.-produced natural gas include higher prices in the United States and exposure to global natural gas market dynamics. Policy has the ability to affect either side of the trade-off between exports and domestic supply. The Administration has promoted increased export capacity, streamlining the process for approval of export facilities, and enabling a more active role in global natural gas markets. At this point, private final investment decisions are needed for fully permitted

Figure 5-12. Real U.S. Refiners' Acquisition Costs and Recessions, 1974–2018

Sources: Kilian and Vigfusson (2017); Energy Information Administration; Bureau of Labor Statistics; National Bureau of Economic Reserach; CEA calculations.
Note: Real oil price is defined as the monthly average refiner acquisition cost for crude oil deflated using the CPI-U. The 3-year net oil increase measure is denoted as the end of a period in which the value of the real price of oil is greater than the price in the preceding 36-month period. Shading denotes a recession.

additional export terminals. As shown below, increasing export capacity offers opportunity, but the competitive global liquefied natural gas (LNG) market must be considered before making large fixed investments.

Natural gas is less fungible than petroleum, limiting trade to transportation by pipeline, or at much higher cost by chilling until it liquefies (at –260°F), which reduces its volume by 99.8 percent and allows long-distance bulk transporting by specialized tankers. In 2017, the average price of LNG was over two times the benchmark U.S. price at Henry Hub in Louisiana. However, the costs associated with cooling for transportation, plus the costs of transportation and regasifying at the destination, in addition to covering the fixed costs of specialized liquefaction and regasification trains, accumulate and reduce the economic value of expanded LNG shipments (CEA 2006).

Domestic production of natural gas has increased almost 40 percent over the last decade, and the EIA estimates that production increased by a further 10.6 percent in 2018 (EIA 2018i). The estimated increase in production from 2017 to 2018 was the largest year-over-year growth on record. The growth of LNG exports helped the United States become a net exporter of natural gas in 2017, for the first time since 1957. The 2017 surplus was also driven by a capacity expansion of 3.1 billion Bcfd (39.9 percent) into Mexico (EIA 2018j). Pipeline exports are almost always cheaper, thanks to inherently lower transportation costs. Increasing export volumes by either transportation mode helps support higher prices for U.S. producers.

The majority of U.S. natural gas exports are by pipeline to Mexico and Canada. Delivering natural gas beyond U.S. land neighbors and U.S. domestic markets that are inaccessible by pipeline, however, requires exporting by sea after the natural gas has been liquefied. LNG has grown to be 28.6 percent of total U.S. natural gas exports by volume. The capacities for both LNG exports and pipeline exports are projected to grow over the coming two years. Currently, just three facilities in the United States have a combined capacity for LNG exports of 3.8 Bcfd. However, four additional LNG export facilities currently under construction will add 8.1 Bcfd of capacity, and a further four facilities that are approved but not yet under construction will potentially add a 6.8 Bcfd of LNG export capacity (EIA 2018h).

Although less flexible than the expansion of LNG capacity, construction of more gas pipelines into Mexico could provide additional competitively-priced avenues for increasing U.S. gas exports. Capacity for planned pipelines from the United States to Mexico is projected to grow by nearly 5.6 Bcfd from 2018 through 2020. Because the centers of Mexican demand are not located near the border, complementary infrastructure investment on the Mexican side of the border is needed. In 2018, Mexico added 2.7 Bcfd, with an additional 6.9 Bcfd under construction to move imports from south and west Texas further south to population centers (Wyeno 2018).

Liquefied natural gas. Not so long ago, the United States was considered to be a critical *import* market for LNG. Investments in domestic regasification terminals to handle these imports were seen as critical for the country's energy future. Forecasts less than 10 years old projected that the United States would run a net deficit in LNG trade through the extent of their 20-plus-year horizons. These predictions were so bleak on the export front that in the 2010 edition of the *Annual Energy Outlook* (EIA 2010), the United States was forecast to import 1.38 trillion cubic feet of liquefied natural gas in 2017 and export none. The ex post scenario instead saw the U.S. run a surplus of over 600 billion cubic feet of natural gas in 2017, with exports almost 10 times the magnitude of imports.

Liquefaction of natural gas is the most economical way to export natural gas to other markets that are inaccessible by pipeline, and thus the expansion of these LNG facilities has opened previously inaccessible foreign markets for deliveries of U.S. natural gas. LNG can be sent in bulk shipments using specialized tankers, or in smaller, containerized units. In spite of these developments, the U.S. still imports LNG, especially in the Northeast and noncontiguous states and territories, where pipeline constraints are the relevant impediment to domestic shipment. Although U.S. natural gas can be exported, it cannot currently be moved between U.S. points because there are no cabotage-certified LNG tankers. New tankers would need to be built to allow this trade; none have been built in the United States since 1980.

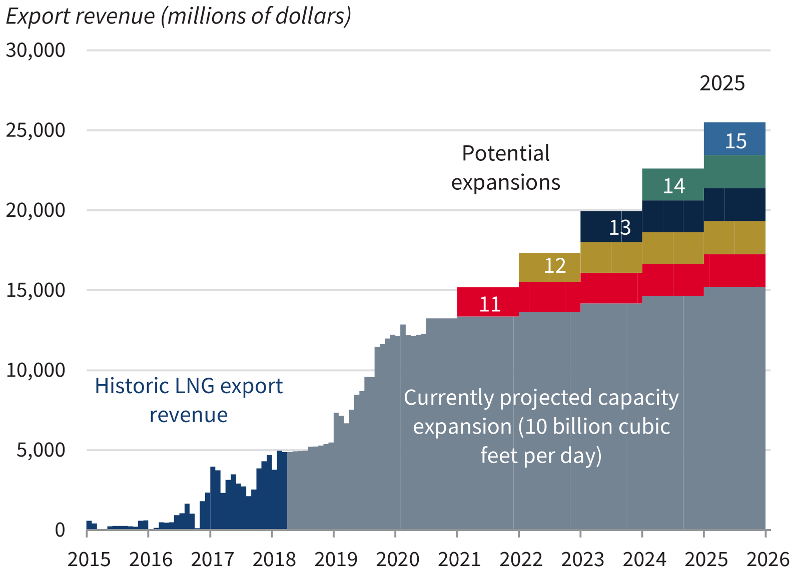
U.S. LNG export capacity is largely clustered on the Gulf Coast. Cheniere Energy opened the first export facility, and now has three liquefaction trains in operation in Sabine Pass, Louisiana. This initial investment is the first of several liquefaction trains under construction that are expected to come online in the next two years. The second U.S. LNG export terminal to open was Cove Point in Maryland, which came fully online in March 2018. Cove Point is located to take advantage of natural gas from the Appalachian Basin. After Cove Point opened, U.S. LNG export capacity at this point was 3.82 Bcfd, or about 4.8 percent of contemporary U.S. production (FERC 2018). A third export facility in Corpus Christi loaded its first precommercial cargoes in November 2018, and expects to begin commercial shipments in 2019. Three additional LNG export terminals are currently under construction: one more in Texas, one in Georgia, and one more in Louisiana. Upon completion of all three terminals, total U.S. LNG export capacity is expected to reach almost 10 Bcfd. Beyond these projects, 7.6 Bcfd in other projects are fully permitted but not under construction for lack of a final investment decision. Figure 5-13 shows how additional export capacity could increase the value of LNG exports given current price forecasts.

U.S. LNG exports can be expected to be particularly competitive in markets with high natural gas demand and a limited access to local or pipeline-sourced supply. China and Japan are the world's two largest importers of LNG, and are likely to be attractive future markets in which to increase the U.S. share of LNG deliveries. Driven by antipollution government policies, Japan and China together imported an average of 16 Bcfd in 2017, nearly four times current U.S. export capacity. Many countries can supply LNG, and China has chosen to impose tariffs on U.S. LNG imports in retaliation for U.S. tariffs on imports from China. Growth in the global LNG market overwhelms this effect, because U.S. cargoes can be delivered around the world and do not rely on particular partners.

European markets appear promising but may prove more difficult to penetrate for U.S. imports. European countries import most of their natural gas supply by pipeline from the Middle East and Russia, limiting demand for the more expensive U.S. LNG exports. Pipeline transportation remains less costly than LNG for international shipments departing from the United States (figure 5-14). LNG accounted for only 12.4 percent of European gas demand in 2017, while pipeline imports supplied 79.6 percent of Europe's consumption (BP 2018). Although the EU had 21 Bcfd of regasification capacity in 2017, LNG imports totaled only 5.6 Bcfd on average (European Commission 2018). This spare capacity provides insurance against supply interruptions from Russian gas, but the higher cost of delivered LNG makes it less attractive for long-term commercial contracts.

Additional barriers to expansion of U.S. LNG exports may stem from the industry's focus on long-term contracts, which traditionally have had destination clauses that limit the flexibility of trade to price signals. Long-term

Figure 5-13. Historic and Projected LNG Export Revenue, 2015–25



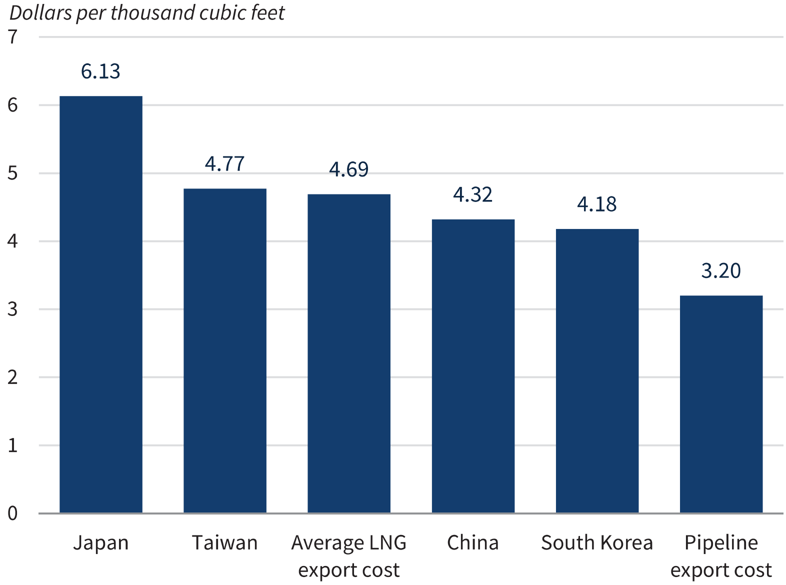
Sources: Energy Information Administration; New York Mercantile Exchange; CEA calculations.
Note: Monthly export revenue is presented at an annualized rate in nominal terms.
LNG = liquefied natural gas.

contracts reassure financiers providing capital for expensive investments in capacity. In such LNG contract structures, uncertainty over future prices and political or economic developments in the receiving country may weigh on U.S. LNG exports and investment abroad (Zhuravleva 2009). These uncertainty factors may be particularly relevant in Eastern European countries, which generally have weak and volatile economic, regulatory, and political conditions. In addition to long-term contracts, spot trading is needed for the market to recognize arbitrage gains; facilities that are locked into long-term contracts cannot capitalize on "cargoes of opportunity," such as particularly high prices in distant markets. One contractual solution to the paradox of needing both long-term and spot trades is allowing brokers to bridge the gap by paying projects for capacity and marketing LNG where it is most profitable.

Coal Exports

One reason for greater coal demand has been overseas demand; U.S. coal exports rose by 60.9 percent in 2017. This aided both the steam and metallurgical coal sectors. Exports to Europe increased by 44.5 percent, while exports to Asia increased 109.0 percent. Asian markets, especially India and South Korea, were leading purchasers of steam coal, while European countries, led by

Figure 5-14. Export Prices for U.S. LNG by Destination, 2017



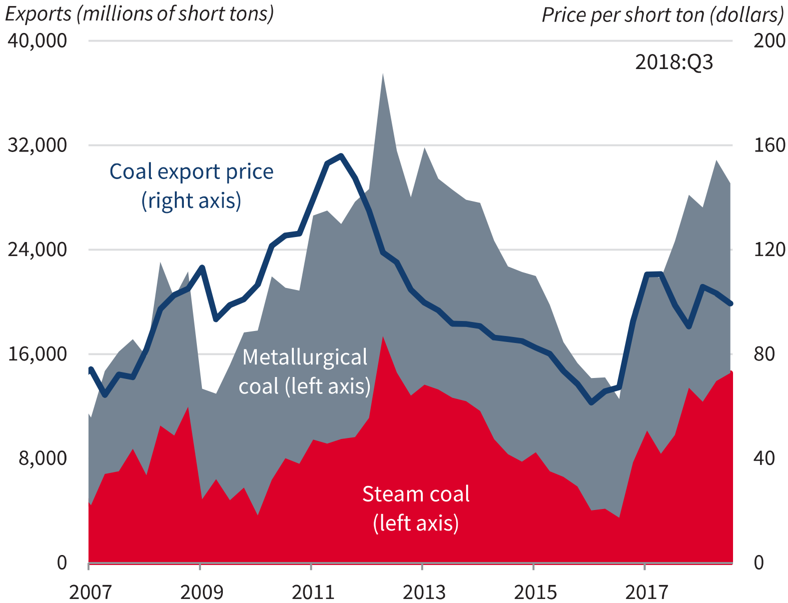
Source: Energy Information Administration.
Note: LNG = liquefied natural gas.

Ukraine and the Netherlands, purchased a plurality of U.S. metallurgical coal exports (EIA 2018c).

The coal industry has seen a minor reversal of downward trends starting in the fourth quarter of 2016. The United States exported nearly 87.2 million short tons of coal in the first three quarters of 2018, up 18.4 million short tons (27 percent) from 2017 (figure 5-15). This boom in exports was primarily driven by exports of steam coal, which grew by 44 percent in the first three quarters of 2018 over 2017 levels. U.S. coal production continued to exceed domestic consumption through 2018, allowing for renewed opportunities to further expand demand through exports; U.S. production accounted for slightly less than 10 percent of global consumption in 2017 (BP 2018).

The fuel costs of using coal to generate electricity remain among the lowest of any technology. However, thanks to the technology's higher fixed costs and inherent inflexibilities, coal-fired generation has lost market share to natural gas generation (Fell and Kaffine 2018). However, coal remains the main fuel by which many countries provide electricity to their citizens (Wolak 2017). Coal-fired generation made up 46.3 percent of electricity in non-OECD countries in 2017 and was just surpassed by natural gas in OECD countries to become the second-most-widely-used source of fuel for electric generation, after natural gas (BP 2018). The increased demand for electricity in developing regions helped bolster coal prices in 2017, leading to higher U.S. exports. Price

Figure 5-15. U.S. Quarterly Coal Exports, 2007–18



Sources: Energy Information Administration; Census Bureau.

increases were especially pronounced in Europe and Japan, where benchmark coal prices rose by 40.6 and 34.0 percent, respectively (BP 2018). Figure 5-15 documents the dynamic response of U.S. coal exports vis-à-vis export prices, and how rising prices in 2017 contributed to export growth.

Wolak (2017) examines the potential impact on the world coal market of increasing coal export capacity from the West Coast. Due to transportation cost differentials, the net effect is to increase U.S. exports to the Pacific Basin and to reduce Chinese domestic production. Increased Chinese access to cleaner-burning U.S. coal would drive up U.S. domestic coal prices and accelerate the switch to natural gas–fired generation in the United States. Projects expanding the Pacific Northwest's' export capacity have been proposed in Washington State, although local pressure over environmental concerns has slowed progress.

Energy policy has important implications for trade policy. Greater self-reliance reduces import dependence, while growing exports strengthen links to other countries. Increased leverage might seem like an unambiguous asset, but greater trade linkages also create potential vulnerabilities as trading partners recognize that U.S. interests may be sensitive to changes in trade flows.

Strategic Value

Energy trade can offer a strategic advantage to the United States. LNG exports to Europe provide an example of the strategic value of energy exports. In 2014, Lithuania received 97 percent of its natural gas from Russia. But Lithuania has begun diversifying its energy supply, building an LNG import terminal in 2014. Afterward, Russia's share dropped to 53 percent in 2017. Although the economic value of LNG exports to Lithuania is small, the strategic value of providing allies with alternative energy supplies is relatively large, if difficult to quantify. If the United States is the source of LNG shipments, this policy provides a double dividend of strategic and trade benefits.

The EU natural gas market also provides an example of the limitations of U.S. energy diplomacy. The EU has only reduced Russia's share from 31 percent of imports in 2014 to 29 percent in 2018 (through August). The United States only provided 0.2 percent of the EU's LNG imports in 2018.

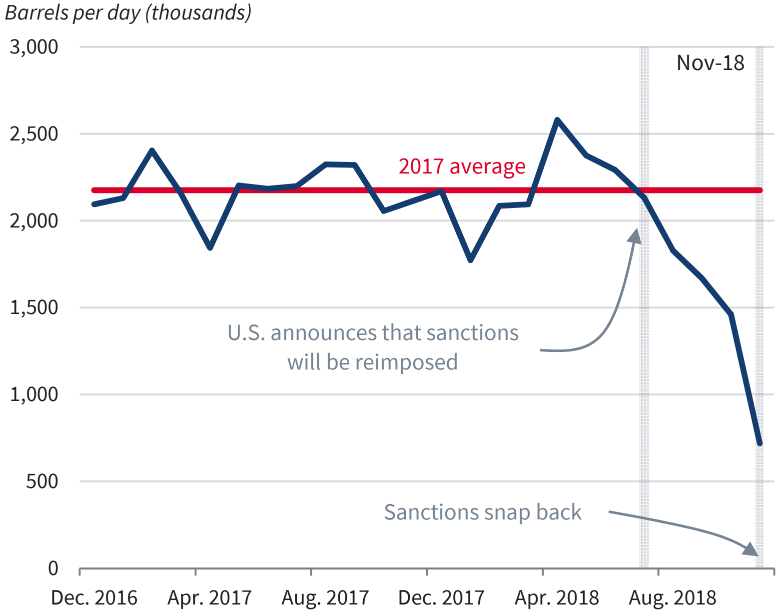
Not all fuel transactions are dominated by strategic concerns. Venezuela exported 48 percent of its crude oil to the United States in 1999, when Hugo Chávez became president; but the amount dropped to 32 percent in 2017. Oil exports represented 90 percent of Venezuela's exports in 2017, so the Venezuelan government has a strong incentive not to disrupt this trade. The U.S. refining sector has invested in processing Venezuelan crude oil that it can buy competitively on the market. Although strategic considerations alone might suggest that the United States should substitute away from Venezuelan supplies, the advantageous economics of supply mean that the oil still flows.

Because of its prominence, oil trade is a geopolitical pressure point. In 2018, the United States sanctioned oil exports from Iran, returning to a regime that was in place before the 2015 Joint Comprehensive Plan of Action. The stated goal of U.S. sanctions is to deprive the Iranian regime of oil revenue. In anticipation of implementation on November 5, 2018, global oil prices rose through October 2018. Iran exported 2.18 MMbpd in 2017. Before the November deadline, Iranian oil exports for October 2018 were already down 30 percent from their 2017 level, to 1.78 MMbpd (figure 5-16).

In an effort to minimize harm to U.S. allies importing oil from Iran, the United States granted six-month waivers exempting certain volumes from the sanctions. Eight such waivers were granted, to China, India, Japan, Turkey, Italy, Greece, Taiwan, and South Korea.

Spare production capacity, especially among OPEC members, has been vital in stabilizing global oil markets in response to unexpected shocks, due to factors ranging from natural disasters to geopolitical conflicts (Pierru, Smith, and Zamrik 2018). Spare production capacity can be brought online within 30 days and sustained for at least 90 days. Spare capacity among OPEC producers is projected by the EIA to be slightly over 1 MMbpd through 2019 (figure 5-17). Spare production capacity growth has been limited in recent years as Saudi

Figure 5-16. Iranian Crude Oil Exports, 2016–18



Sources: Thomson Reuters; CEA calculations.

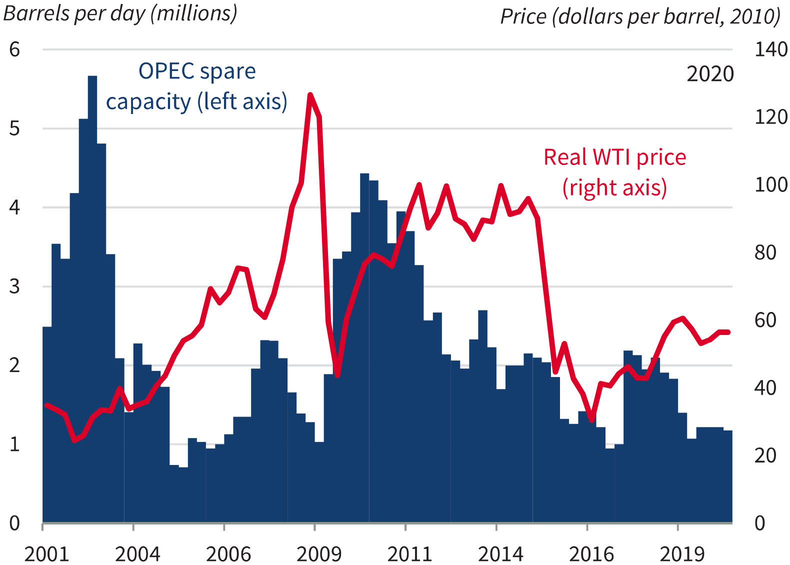
Arabia has reached capacity. Removing Iranian crude oil from the global market places additional pressure on suppliers and transfers spare capacity to Iran. Future supply interruptions may require cooperation in using spare capacity to avoid price spikes.

Energy exports also create a vulnerability as other countries recognize that they can retaliate against U.S. exports. When China wanted to retaliate against the U.S. Section 301 tariffs, it imposed tariffs on LNG. In 2018, the United States exported 103 Bcf of LNG to China, or about 15 percent of all U.S. LNG exports. Following imposition of retaliatory tariffs, U.S. LNG exports to China dropped to zero. This reflects the near-perfect substitutability of commodity products like LNG and even crude oil. U.S. exports will not be shut out of the global marketplace, but the destination could be affected by foreign trade policy, much as U.S. agriculture has been targeted in the past.

Energy Policy

Despite the promising indications from booming fossil fuel production, and the success in improving the U.S. fossil fuels trade balance, a number of energy policy issues remain salient. In a market economy like the United States, with a competitive energy sector, opportunities to increase access to production are limited, except for perhaps on Federal land and minerals. This section discusses a number of issues facing the electricity generation sector, which are

Figure 5-17. OPEC Spare Production Capacity and Crude Oil Prices, 2001–20



Sources: Energy Information Administration; Thompson Reuters.
Note: OPEC = Organization of the Petroleum Exporting Countries. WTI = West Texas Intermediate crude oil. Real WTI price is calculated using the GDP price deflator.

also important for fuels production because of the large share of fuels that are destined for electric generation units—for example, 91 percent of U.S. coal is ultimately consumed by electric power generation. The electricity sector affects many important issues, including renewable and nuclear electric generation. A third issue is the general relationship of regulation to the energy sector, which has been a particular focus of deregulatory actions. Global environmental issues are an important issue facing the United States and other countries, so the discussion concludes with an assessment of U.S. energy intensity and carbon dioxide (CO_2) emissions. International environmental policy potentially affects many linked markets, as impending maritime fuel regulations illustrate.

Increasing Access to Production

Unlike the government of any other country in the world, the U. S. Federal government directly controls only a minority of the country's produced resources, because mineral ownership is largely in private hands. Although this unusual allocation has received credit for helping spur the technological revolution in oil and gas drilling (Hefner 2014), it limits the ability of the Federal government to simply "turn up the tap" on production.

A second channel for affecting production levels is through regulation. States, not the Federal government, are the primary regulators of oil and gas extraction activity. Technological change poses a challenge for regulators (Fitzgerald 2018). Only when an interstate or Federal issue is involved does the Federal government have a role (see box 5-3). Although the Obama Administration sought a more expansive Federal regulatory role, the Trump Administration has worked to reduce unnecessary Federal regulations.

Electricity Generation

Electric power is the single largest energy sector in the United States.[7] Two major economic forces have affected the sector: changing the traditional regulatory model that provided electricity through a vertically integrated industry and moving toward a more market-based system; and technological change and its attendant price effects, which have shifted the underlying economics of alternative generation technologies.

Market design has been a central concern for electricity markets, smoothing the transition from regulated vertically integrated utilities to increasing degrees of wholesale and retail competition. Fabrizio, Rose, and Wolfram (2007) documented the efficiency gains resulting from restructured electricity markets, in which firms are exposed to more market forces rather than protected under regulation. The transition has not been seamless, as Borenstein, Bushnell, and Wolak (2002) document in the case of California. The potential for market power is one of the primary motivations for utility regulation and is a key factor that should be considered in any restructuring. Market incumbents accustomed to capturing inframarginal rents may be disrupted by restructuring, or may find new opportunities.

Regional transmission organizations and independent system operators coordinate generation and transmission to ultimately satisfy the demands of electric consumers, using a variety of more and less market-oriented structures. The Federal Energy Regulatory Commission (FERC) oversees these grid operators, and has considerable discretion in approving rate requests and operational plans. FERC could take a more interventionist role in addressing issues arising from the electricity grid; as an independent regulatory body it has substantial discretion. Although the regulatory structures are similar, the different physical characteristics of electricity as compared with natural gas help explain the slower buildout of electricity transmission infrastructure (Adamson 2018).

Because electric generation units are long-lived investments with long payback periods, disruptive changes can lead to a premature retirement of units. As a policy issue, this problems stems from concern about the resiliency of the grid to severe weather events, cyber threats, and other sources of interruption to fuel deliveries and ultimately electricity. There is some evidence that fuel supply deficiencies lead to electricity outages. In 2017, the EIA reported

[7] This includes utility-scale electric generation and combined heat and power plants.

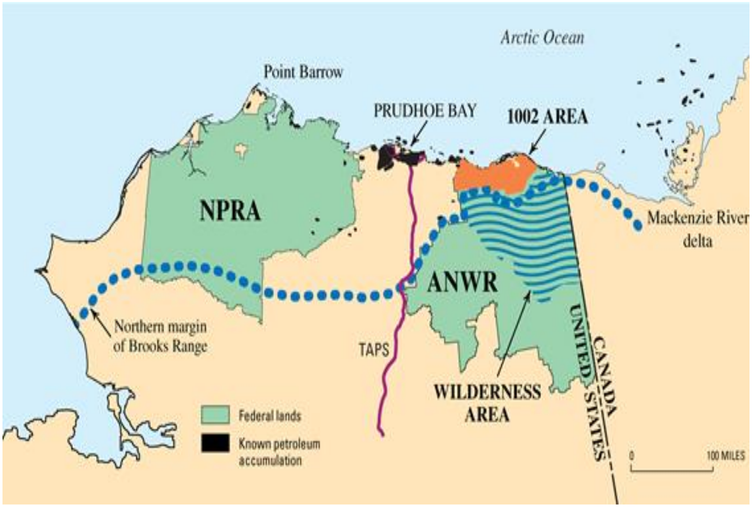
Box 5-3. The Federal Role in Promoting Domestic Fuels Production: The Case of Alaska

The 1968 discovery of the 25 billion barrel Prudhoe Bay oil field on Alaska's North Slope remains one of the largest single discoveries in U.S. history. At its 1988 production peak, Alaska was the top-producing U.S. State, with total crude oil production of 2 MMbpd, representing nearly 25 percent of U.S. production. Since 1988, Alaskan production has declined, and by 2017 it was less than a quarter of its peak production (485,000 barrels per day) and 5.3 percent of total U.S. crude oil. Two aspects of the rise and fall in Alaskan oil production relate to Federal policy. First, infrastructure is a critical element in order to realize the value of large and remote energy reserves like Prudhoe Bay, and Federal cooperation was needed. Second, in states with large shares of Federal land ownership, access to federally owned lands and minerals can play a critical role in promoting domestic production.

Prudhoe Bay, which is on the Alaskan northern plain alongside the Arctic Ocean, is the most remote and inhospitable oil and gas operating environment in the United States (figure 5-ii). It is distant from national and global consumers. Marketing the crude oil required constructing a 4-foot diameter pipeline 800 miles across the state. The construction of the Trans-Alaska Pipeline System (TAPS) required Congressional approval; legislation was signed into law in 1973 with the first crude oil flowing from Prudhoe Bay through the pipeline in 1977 (AOGHS 2018). Today, 97 percent of Alaska's total oil production comes from the North Slope region and flows through TAPS, and thence by tanker to other destinations. Normal geophysical decline on the North Slope, however, threatens the continued operation of TAPS. As throughput falls to 500,000 barrels per day—a fraction of the historic peak of 2 MMbpd—corrosion, ice formation, wax deposition, water dropout, and geotechnical concerns threaten operations. Throughput below 350,000 barrels per day is projected to severely reduce the reliability of pipeline operations (EIA 2018a; Alyeska Pipeline Service Company 2011).

Land and mineral ownership play an important role in production declines. Although 61.3 percent of Alaska's land is administered by the Federal government (Argueta, Hanson, and Vincent 2017), the Prudhoe Bay discovery occurred on land owned by the State of Alaska. As the wells in Prudhoe Bay and nearby fields have matured, exploration has stretched along the coastal plain. The State land where Prudhoe Bay is situated is bordered on either side by federally administered land. To the east is the Arctic National Wildlife Refuge (ANWR) and to the west is the National Petroleum Reserve–Alaska (NPR-A) (figure 5-ii). The NPR-A is 22.1 million acres and currently has limited exploration and production activity. A 2017 study by the U.S. Geological Survey (USGS 2017b) estimated total undiscovered technically recoverable reserves in the NPR-A to be 8.73 billion barrels of oil and 24.55 trillion cubic feet of natural gas. This was a major upward revision from the previous 2010

Figure 5-ii. Northern Alaska, the Arctic National Wildlife Refuge (ANWR), and the Coastal Plain 1002 Area

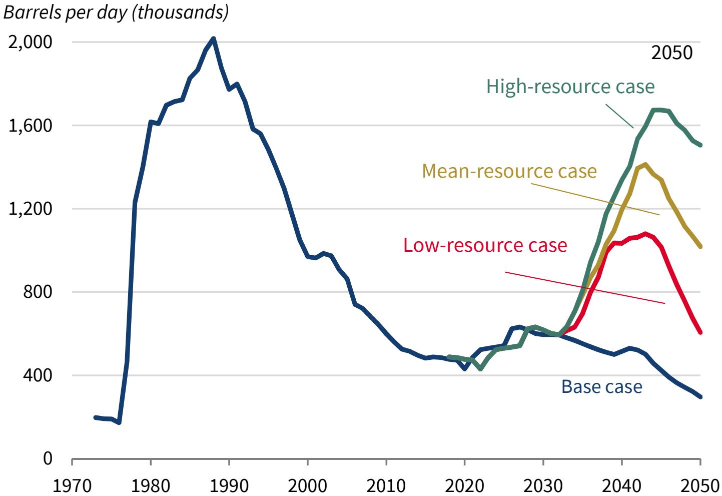


Sources: U.S. Geological Survey; Energy Information Administration.

USGS estimate of less than 1 billion barrels, and was informed in part thanks to increased exploration activity and the beginning phases of production in 2015 through 2017 (USGS 2010). The ANWR is a large tract of protected land, though only 8 percent of the refuge is of interest for oil and gas activity. This area on the coastal plain, known as the "1002 area," covers 1.5 million acres of the 19.64 million acre reserve. As a previously protected area, only one exploratory well has been drilled in the 1002 area, which was completed in 1986 (EIA 2018a). Despite a lack of exploration and its small size relative to the NPR-A, the most recent USGS assessment of the 1002 area published in 1998 estimated mean technically recoverable reserves of 7.7 billion barrels (USGS 1998).

Federal policy in 2018 prioritized expanded production on federally administered lands on Alaska's North Slope, and 2018 was a year of breakthrough success in this long-running effort (Hahn and Passell 2010). In December 2017, the Bureau of Land Management offered the largest ever lease sale in the NPR-A, with 900 tracts that cover a total of 10.3 million acres available for bid. Previously, there were 189 authorized leases covering 1.3 million acres. The President later signed a law (as part of the Tax Cuts and Jobs Act) requiring that a competitive leasing program be established for oil and gas exploration and production in the 1002 area of ANWR. The EIA has estimated that crude oil production from the 1002 area would begin in 2031, peaking in 2041 at 880,000 barrels per day, with cumulative production in the mean case at 3.4 billion barrels between 2031 and 2050. Under the EIA's ANWR high resource case, total crude oil production could greatly increase and approach the 1988 peak (figure 5-iii). Policy to expand production on other federally administered lands, including the NPR-A, could further increase production forecasts.

Figure 5-iii. Alaska Crude Oil Production and Arctic National Wildlife Refuge Production Forecasts, 1973–2050



Source: Energy Information Administration.
Note: 2018 through 2050 forecast values are taken from the EIA's 2018 *Annual Energy Outlook*.

94 major disturbances or unusual occurrences in the electricity supply system affecting a total of 17.1 gigawatts of capacity (EIA 2018e). Fuel supply deficiency accounted for 6 percent of these events and 1.2 percent of the total lost capacity (EIA 2018g). The low incidence and relatively small impact are testaments to the overall reliability of the national grid. However, more focused studies in particular regions have found evidence of substantial vulnerabilities (NEISO 2018; Balash et al. 2018; PJM Interconnection 2017).

In 2018, utility-scale electricity generation was dominated by roughly equal amounts of natural gas and coal, at about 30 percent of the total, followed by nuclear (20 percent), and renewables including hydroelectric (17 percent) (EIA 2018g). This is a substantial change in the generation mix from the preceding decade. Between 2000 and 2009, coal on average made up 49 percent of electricity generated, while natural gas made up 19 percent and all renewable energy accounted for less than 8 percent (EIA 2018g).

One challenge to the traditional system is the emergence of utility-scale renewable generation that operates at or near zero marginal cost. These sources are generally nondispatchable so that they enter the generation mix first, at zero cost. Renewable sources are intermittent, so the generation can fluctuate for uncontrollable reasons: such as variation in wind speeds for wind farms or in cloud cover for solar generation. The reliability of the grid therefore depends on the ability of other generation units to smooth out intermittency, or to "firm" the renewable generation into a reliable stream of power. Nuclear and large-scale coal generation units are not well suited to provide this firming service, which sometimes attracts a price premium. Natural gas–fired units, particularly open-cycle turbines, are particularly well suited for the task. The interaction of renewable capacity and natural gas generation that can firm renewables has been causally linked to reduction in coal-fired generation (Fell and Kaffine 2018).

Operating costs are separable into fuel costs and operations and maintenance costs that are incurred to keep a plant available. Some plants have higher costs than others; from an economic perspective, operating the lowest-cost plants provides the greatest value, all else being equal. The competitiveness of natural gas and renewable generation, especially in restructured electric markets, indicates the importance of low operating costs.

Nuclear plants have the lowest mean total operating costs for any generation technology except for hydroelectric. It is worth noting that the existing nuclear reactors have been online for decades, and the substantial fixed costs required to build units have already been amortized. The recent experience with cost overruns for new-build nuclear units underscores the importance of fixed costs to the bottom line of plant operators. The revenues required to earn an economic profit may be higher than the figures listed here due to sunk costs, though these are likely to vary on a plant (or even unit) basis.

Mean operating costs vary across types of generation units. If prices move in lockstep with the varying costs, margins remain the same. However, in part because of varying market structures and generation portfolios, regional wholesale and retail prices vary. In conjunction with cost differences, price variation leads to differences in operating margins.

Generation costs and operation and maintenance costs are not the only relevant costs. Different generation technologies create varying amounts of emissions and waste. Coal generation emits relatively more air pollutants than other fossil fuels, and creates a second by-product in the form of ash that requires special handling for disposal. In contrast, nuclear generation is emission-free, though it raises its own particular long-lived issue in the form of nuclear waste, which also requires special disposal. Natural gas falls somewhere in-between, with lesser amounts of harmful (and greenhouse) emissions than coal. A program accounting for the economic value of emissions could provide a boost to nuclear generation, depending on the value of emissions.

For example, in selected markets, nuclear units may be eligible for zero emission credits that supplement revenue from wholesale electricity sales.

Market design and efforts to dictate the dispatch order of plants must be carefully considered to avoid unintended consequences. Holding constant the stock of generation units, the likely effect of dispatching high-cost units more frequently is to reduce the cost of the marginal megawatt and reduce the market-clearing wholesale price in competitive generation markets. This means that the cost of keeping high-cost units running can be underestimated, because the gap between market-determined prices and operating costs will widen as a result of the policy. Using two-part tariffs or other mechanisms to address these concerns may provide workable solutions and regional flexibility to accommodate different grid characteristics.

The strategic need for an electricity generation reserve to promote the grid's resilience is a challenge that is analogous to many other economic problems. The entire portfolio of generation assets in the United States could be eligible to be part of a reserve, with different strategic weights placed on various types of generation—for example, nuclear or coal-fired generation might provide greater resilience benefits and therefore be preferentially selected into the reserve. Generation assets in regions of the country that are more susceptible to natural disasters or other exogenous interruptions might be more valuable to include in the reserve. Focusing the strategic needs into unit- or plant-specific weights can be accommodated in a voluntary reserve system, much like conservation programs that elicit landowner participation while minimizing public expenditures. A similar mechanism could be used to provide the strategic benefits of a generation reserve while minimizing the downstream costs to electricity consumers. In addition to minimizing the cost, such a program would retain private initiative to opt into the reserve, with the lowest qualified bids selected, rather than relying on the judgment of bureaucrats to select the most preferred units.

Renewables. Renewable generation technologies like wind and solar have marginal costs that are very close to zero. The fuel costs are zero—at least when the wind is blowing or the sun is shining. However, building windmills and solar farms requires substantial capital expenditures, and the relatively high fixed costs may not outweigh the low marginal costs that come with generation. Recognizing this difference, Federal policymakers have worked to provide incentives to increase installations of renewable generation capacity and penetration of these technologies into the generation mix. The Business Investment Tax Credit (ITC) and the Production Tax Credit (PTC) are the main Federal subsidies targeting renewable electric generation.[8]

[8] Renewables are targeted by a wide variety of State programs, including Renewable Portfolio Standards and build requirements such as those promulgated in December 2018 by the California Building Standards Commission, which will require new homes to have solar panels.

The ITC was established in 2005 and recently extended through 2022 under the 2018 Bipartisan Budget Act. The ITC provides accelerated depreciation schedules for renewable energy investments by providing an initial 30 percent depreciation rate in the year the infrastructure is installed, with the accelerated depreciation rate falling incrementally to 10 percent in the years after 2022. This effectively front-loads the depreciation of investments in renewable energy infrastructure for tax purposes and lowers the cost of capital. All else being equal, this reduces the private fixed costs of investing in renewable generation. Once renewable capacity is installed, the low marginal costs are relatively easy to cover.

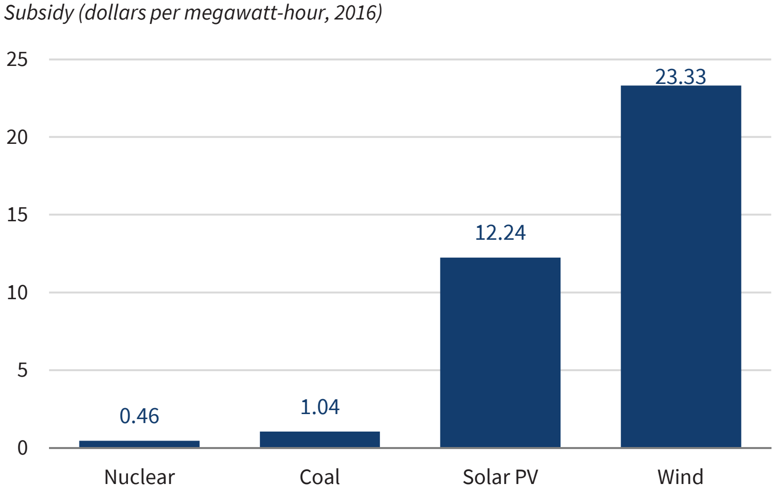
The PTC, established in 1992 and most recently renewed in 2018 (H.R. 1892, Sec. 40409), and operates a bit differently. Rather than trying to reduce the fixed costs associated with construction and installation, the PTC provides an inflation-adjusted, per-megawatt-hour (MWh) tax credit for the generation of renewable energy (wind, solar, closed biomass, and geothermal systems). For qualifying renewable generation infrastructure (facilities not claiming the ITC) constructed before 2018, the PTC provides a payment during a facility's first 10 years of service. Only new wind facilities qualify for the PTC since January 1, 2018; in 2020, the PTC is slated to be phased out entirely.

Because of the inflation adjustment, the nominal value of the PTC has grown over time. For facilities beginning construction in 2017, the PTC was $23 per MWh. Qualified wind-based generation was given a three-year phasedown period, where the generation credit is reduced by 20, 40, and finally 60 percent for facilities commencing construction in 2017, 2018, and 2019, respectively.

The EIA (2018b) presents amortized values of Federal renewable energy subsidies in its annual projections of levelized costs of electricity for new generation resources. The EIA's most recent report values the amortized tax credit for solar PV at $12.50 ($2017) per MWh for generation resources entering into service in 2022. This is smaller than the contemporary $23.33 subsidy per MWh provided by the PTC for wind facilities commencing construction before 2017, but larger than its current value of $9.48 per MWh for facilities being constructed starting in 2019 (figure 5-18).

Thanks to very low marginal costs, the increased penetration of renewable generation technologies has helped lower consumer costs at the margin (Cullen 2013; Kaffine, McBee, and Lieskovsky 2013; Novan 2015). However, the displacement of existing nonrenewable generation resources is an important policy question. Bushnell and Novan (2018) focus on western electricity markets and find that the short-term response to additional renewable generation has helped lower average prices. However, the dispatch of intermittent renewable sources creates both higher and lower prices during the day, the net effect of which is to undermine the economic viability of existing baseload generators. A redesigning and rethinking of wholesale markets may be needed to accommodate low-cost renewables without sacrificing existing capability.

Figure 5-18. CEA Estimates of Federal Electricity Generation Subsidies by Fuel Type for Fiscal Year 2016



Sources: Energy Information Administration; Internal Revenue Service; CEA calculations.
Note: PV = photovoltaic. Subsidy levels from the Investment Tax Credit for solar generation were unavailable for 2016. Estimates are from the EIA's 2018 *Annual Energy Outlook* for new generation deflated to 2016. These estimates may understate the level of subsidy in 2016 due to the falling price of solar photovoltaic technology over time.

Nuclear power. Since the days of Hubbert, nuclear power has enjoyed the status of a forward-looking technology. Today, the United States' 99 licensed light-water commercial reactors have an uncertain outlook. Of these reactors, 98 generated some electric power in the fourth quarter of 2018 (Nuclear Regulatory Commission 2018).[9] Between 2007 and 2018, 6 utility-scale nuclear power plants ceased operations. This represented a net decrease of slightly under 600 megawatts, or 0.6 percent of nuclear generation capacity. Between 2019 and 2022, 10 more nuclear generating facilities are scheduled to be shuttered, with a net loss of 9.47 gigawatts, or 9.5 percent of 2017's year-end capacity. Two new units are scheduled to come online in 2021, adding 2.2 gigawatts of new capacity. Of the 10 plants scheduled to close, 7 are permitted by the Nuclear Regulatory Commission to operate longer—an average of 14 years.

Deregulatory actions have increased efficiency and safety across a diverse mix of generation (Davis and Wolfram 2012; Hausman 2014). However, new concerns have been raised among government agencies over the resilience on the U.S. grid to disruption from natural or intentional causes. The vulnerability of nondispatchable generation, and also dispatchable generation with limited

[9] The Oyster Creek Nuclear Generation Station in Forked River, New Jersey, was shut down in September 2018, but retains an active operating license with the Nuclear Regulatory Commission.

onsite fuel storage, have been cited as potential reliability concerns for the American power system.

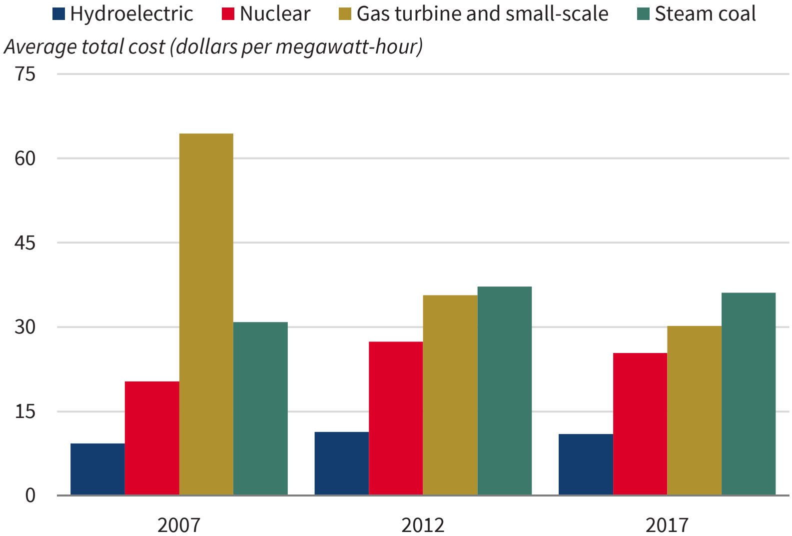
During the Trump Administration, FERC and the Northeastern independent system operators have borne increased scrutiny related to the resilience of the electricity infrastructure, including nuclear facilities. Nuclear power is a reliable source of generation, but reliability itself does not translate into resilience in the event of a disruption. Though reliability is measured by the ability to deliver the quantity and quality of power that consumers demand, resilience is the ability of the system to recover from an adverse shock like a weather event or an attack. The transmission and distribution systems of wires are one of the most vulnerable parts of the electric grid, as the experience of Puerto Rico since Hurricane Maria illustrates.

Finding the optimal balance between lowest-cost marginal generation and more resilient baseload coverage is not a novel challenge faced by governing bodies and operators in regions with restructured wholesale markets. Efforts to identify the correct levels of emergency generation, peak capacity, and excess capacity have led regulatory agencies to implement a diverse set of systems to ensure that the grid can handle seasonal or unexpected shocks to demand.

The constant baseload output associated with nuclear generation has limited its flexibility in restructured and more competitive markets. Because nuclear generators are price takers, and thus must accept the market rate for the electricity they generate rather than face the relatively large costs of a stepdown or shutdown, nuclear plants face continuing exposure to volatility in electricity prices (Davis and Hausman 2016). This situation has become especially pressing in the wake of falling natural gas prices and the implementation of more efficient combined cycle technology over time, as the availability of natural gas generation pushes down wholesale electric prices at the margin (Linn, Muehlenbachs, and Wang 2014). Jenkins (2018) tested alternative explanations for lower prices received by nuclear generators and found that cheap natural gas had the largest effect by far, though renewable penetration and stagnating electricity demand had statistically significant effects.

Lower wholesale electric costs caused by falling gas prices have undercut margins in nuclear plant revenues that may otherwise have been realized by nuclear operators over the past five years due to falling costs (figure 5-19). The Nuclear Energy Institute (NEI 2018) estimates that the real costs of nuclear generation have fallen by $7.85 per MWh (19 percent) over the past five years. Some of this reduction may be due to market forces pressuring closure of noneconomic plants; however, this decrease in real costs has outpaced the rate at which real retail electricity prices have fallen over the same period. The NEI estimates that the majority of these savings to have come from the lower costs of capital, which fell by 40.8 percent between 2012 and 2017, to $6.64 per MWh of generation.

Figure 5-19. Average Total Cost for Investor-Owned Utilities by Fuel Type, 2007–17



Source: Energy Information Administration.
Notes: Average expenses are weighted by net generation. The gas turbine and small-scale category includes gas turbine, internal combustion, photovoltaic, and wind plant generation. Hydroelectric consists of both conventional and pumped storage technologies.

The United States' nuclear reactors are aging, and construction of new ones has been very slow. Since 2000, only 1.2 gigawatts of nuclear generation capacity have been added, out of a total of 494 gigawatts of new capacity (EIA 2018d).[10] Two nuclear units are currently under construction, but the financial struggles of these plants underscore the challenges for the civil nuclear sector. In 2013, Georgia Power—a subsidiary of Southern Company—began construction of two 1.1 gigawatt Westinghouse AP1000 reactors at its Vogtle site. Funding for these new units at the Vogtle plant is backed by two unconditional loan guarantees from the U.S. Department of Energy totaling $8.3 billion. Construction of the units is behind schedule and over budget. Moreover, construction of two similar reactors at the Summer site in South Carolina was abandoned in 2017 because of escalating costs.

Construction of the new units slowed when the designer of the reactors, Westinghouse Nuclear, filed for bankruptcy in March 2017. Although some work has continued at Vogtle, the Summer project has been abandoned.[11] The cost of the units has climbed with the delays; because these are the only new

[10] This long-delayed project was initiated in 1973. The reactor was finished in 2015, and was put into service in 2016.
[11] The outlook is somewhat improved after the first AP1000 reactor went into commercial operation at the Sanmen facility in China in September 2018 (IAEA 2018), demonstrating that the new reactor design is feasible.

reactors being built in the United States, the realized costs are important for setting expectations for other licensed units that have not yet begun construction. As of November 2018, the costs of completing both new reactors at Vogtle were at least $8.0 billion, with construction to hopefully be completed by the end of 2022. Such high fixed costs render nuclear uncompetitive without additional sources of revenue. The cost overruns to date on the Summer and Vogtle plants alone add $3.97 per MWh to the levelized costs of electricity from these plants, even under lifetime dispatch factors above 80 percent. The EIA currently projects levelized costs of $92.60 per MWh, leaving little headroom for these plants between costs and wholesale prices, even without including cost overruns.

Deregulation

A priority of the Trump Administration has been to reduce unnecessary Federal regulatory burdens. Executive Order 13783 was issued to promote energy independence and economic growth by developing energy resources and reviewing agency actions and regulations (82 *FR* 16093). Since the beginning of the Administration, over 300 regulatory actions have been taken, many of them reducing regulatory burdens or exempting certain activities and affecting energy production or consumption. A total of 65 regulatory actions affecting the energy sector were completed through the end of fiscal year 2018, with projected present value savings of over $5 billion. Two examples relevant to the energy sector are the Waste Prevention rule for oil and gas production and the Stream Protection Rule, which had an outsized impact on coal operations.

In September 2018, the Bureau of Land Management (BLM) rescinded certain requirements of a 2016 rule pertaining to the waste prevention and management of oil and gas resources produced on Federal lands. The new rule reestablished long-standing requirements and eliminated duplicative requirements for oil and gas drilling and extraction operations on Federal and tribal lands. With respect to the flaring of associated natural gas from oil wells, the BLM will defer to State or tribal regulations in determining if flaring will be royalty-free. In many cases, this will mean waiving the obligation to pay Federal royalties on flared gas.

In February 2017, Congress passed and President Trump signed a resolution pursuant to the Congressional Review Act repealing the Stream Protection Rule (81 *FR* 93066–445), which had taken effect on January 19, 2017. The repeal is estimated to generate an annualized $80 million in cost savings for the surface and underground coal mining industries.

Another completed action was the 2017 repeal of the Federal coal leasing program moratorium. Because western coal resources make up 55.5 percent of national production and about 80 percent of western production is from federally owned minerals (GAO 2013; CEA 2016b), the rules for the leasing and production of these minerals can affect the amount of resource that is commercially available (EIA 2018c). Passed in January of 2016, the moratorium was drafted in tandem with the BLM's 2016 order to study how to modernize Federal coal leasing. Auctions were suspended until the analysis was completed, which was expected to be in 2019. The repeal meant that the Federal leasing program for coal reverted to the preexisting rules, although the leasing rules have undergone subsequent changes under the Trump Administration (82 *FR* 36934). This action is estimated to have made available for extraction an additional 17 billion short tons of federally owned coal reserves in the Powder River Basin alone (USGS 2017a; BLM 2017).

The Federal government also auctions leases for oil and gas development, both for onshore minerals and in offshore areas. Onshore lease sales in 2018 were another tale of booms and busts. Although a September 11, 2018, auction in Nevada garnered zero bids, one week earlier, a sale of 142 parcels in New Mexico brought in a stupendous $972 million in revenue. Bullish expectations for growth in the Permian Basin's outlook and pipeline capacity continue to drive increased interest in expanding production. Year-to-date sales in 2018 were over twice the previous record level, and nearly three times those made in 2017 (ONRR 2018).

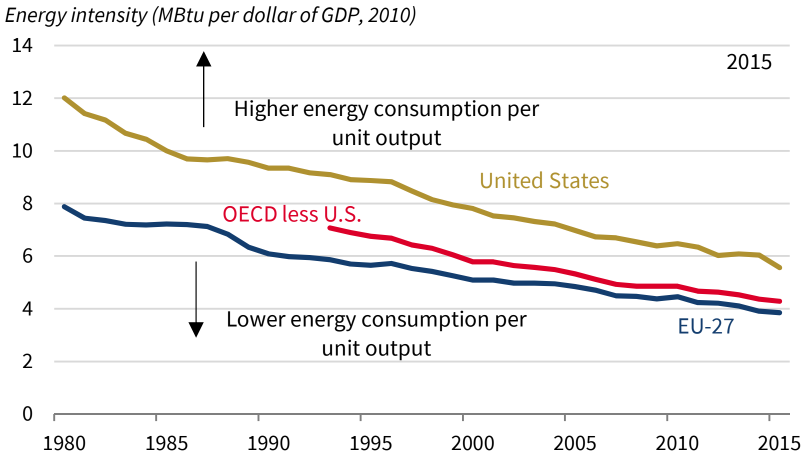
Two of the most economically significant deregulatory actions for energy have been proposed but not finalized. Repeal of the Clean Power Plan (CPP) and the Waters of the United States (WOTUS) rule are under way. Both these regulations were subject to legal challenges and stays that delayed implementation. Given the pending rulemakings, the expected level of future regulation has been dramatically reduced.

The Obama Administration passed the CPP in October 2015, with the goal of reducing CO_2 emissions from existing electric utility generating units.[12] The U.S. Environmental Protection Agency (EPA) codified final emission guidelines establishing State-specific CO_2 emission performance rates and implementation schedules for generating units. In February 2016, the CPP was enjoined by the U.S. Supreme Court at the request of West Virginia and 26 other states, which argued that the rule exceeded the EPA's authority. A repeal of the CPP was first proposed in October 2017 by the Trump Administration following pushback from State governments and industry proponents concerned about costs to consumers and outsized effects on coal-fired generation. The EPA proposed the Affordable Clean Energy rule in August 2018 as a replacement for the CPP. The final regulatory impact analysis is complete, but the rule has yet to be finalized.

The Obama Administration passed WOTUS in 2015, which expanded the interpretation of "navigable waters" under the Clean Water Act; this term was interpreted to include tributaries and bodies of water adjacent to Federal

[12] The Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Generating Units (commonly referred to as the Clean Power Plan, CPP) can be found at 40 *CFR* part 60 subpart UUUU, as promulgated October 23, 2015.

Figure 5-20. Energy Intensity of GDP, 1980–2015



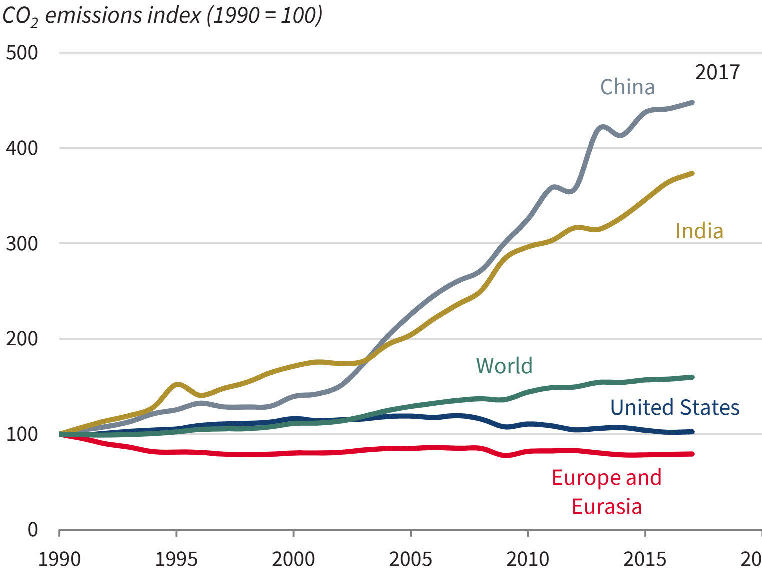
Source: Energy Information Administration; CEA calculations.
Note: Thousands of British thermal units (MBtu) per 2010 dollars of GDP at purchasing power parity of dollar-denominated expenditures. The Organization for Economic Cooperation and Development includes Australia, Austria, Belgium, Canada, Chile, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Japan, South Korea, Latvia, Lithuania, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States.

waters, including wetlands, ponds, and lakes, which critics argued was jurisdictional overreach. A proposal to formally rescind the WOTUS rule was issued in July 2017, and several public meetings on a new rule proposal took place during the fall of 2017. The executive order urges regulators to interpret "navigable waters" in a manner consistent with Supreme Court Justice Antonin Scalia's 2006 opinion in *Rapanos v. United States*; Scalia argued that "navigable waters" should only include navigable waters "in fact."

Environmental Implications

Energy inputs are essential to economic performance, but emissions are an increasing concern as the realities of climate change are confronted around the world. Compared with some others, the American economy has a relatively high energy intensity—meaning that more energy is used per $1 in output in the United States than in other countries. In 2015, U.S. energy intensity (measured as 1,000 British thermal units per $1 in output at purchasing power parity) was 5.56, less than half the same measure in 1980 (figure 5-20). However, the U.S. measure is 30 percent higher than the OECD ex-U.S. average and over 44 percent higher than the average of the 27 EU member countries (EIA 2018i). This relatively high dependence on energy for output helps explain why the United States has the largest negative growth effects associated with increasing oil

Figure 5-21. Annual World Carbon Dioxide Emissions, 1990–2017



Source: Department of Energy; Energy Information Administration; United Nations Framework Convention on Climate Change; CEA calculations.
Note: CO_2 = carbon dioxide. Emissions levels are indexed to 1990 country-level CO_2 emissions. Levels for 2015–17 are estimates from the EIA's 2018 *International Energy Outlook.*

prices in the Group of Seven (Jiménez-Rodríguez and Sánchez 2004). The continental geography of the United States may be a factor by requiring more energy in the transportation sector, which is heavily dependent on petroleum. However, over time, the energy intensity of U.S. GDP has declined as energy users have sought to be more efficient, and the decreased net petroleum import position is likely to reduce the harm from future crude oil price shocks.

A second relevant measure of energy use is the total level of emissions. The United States has remained below the average global growth rate for global CO_2 emissions since the multilateral ratification of the United Nations Framework Convention on Climate Change (UNFCCC) in 1992. Although the United States was among one of the eventual 84 signatories to the extension of the original 1992 UNFCCC, it never ratified the 1997 Kyoto Protocol, which was the first international agreement with binding emission abatement commitments. Under this agreement, the United States would have been obligated to reduce emissions of a number of greenhouse gases by 7 percent below the

1990 level, and to achieve this reduction for an average of the years 2008–12 (figure 5-21).[13]

One concern at the time was that other countries would not be bound by similar standards. U.S. gross CO_2 emissions are estimated to have grown at an average annual rate of 0.09 percent during the period between 1990 and 2017, while emissions in China and India are estimated to have grown at average rates more than 50 times as fast (5.7 and 5.0 percent a year, respectively) (EIA 2017). The European countries and Japan committed to, respectively, 8 and 6 percent emission reductions under Kyoto, but both failed to meet these goals. Emissions during the period 2008–12 eclipsed the 1990 reduction benchmarks by 11.1 percent for the EU and 8.8 percent for Japan (EIA 2018i); see box 5-4.

Although the U.S. Congress did not ratify the Kyoto Protocol, U.S. emissions markedly broke their trend after the agreement took effect in 2005. Although U.S. emissions grew by 18.8 percent between 1990 and 2004, emissions in 2016 were down 12.8 percent from 2004 levels. This inflection in U.S. emission trends was concurrent with a similar pattern in the European nations, which shrank their emissions by 16.7 percent between 2004 and 2016 after they grew by over 20 percent in the period 1990–2004.

Many factors affect emissions. Although technological change has been an important driver for the United States, other countries have adopted a policy-based approach. For example, the EU Emissions Trading System has helped participating countries reduce their CO_2 emissions by 16.7 percent starting in 2004, the year before the policy took effect, until 2016. The U.S. reduction of 12.8 percent during the same period was largely achieved without a Federal policy intervention.

Other types of emissions reveal a similar story: emissions of six air pollutants (carbon monoxide, particulate matter, sulfur dioxide, nitrous oxides, and volatile organic compounds) have all declined since 1990. Shapiro and Walker (2018) statistically decompose the declining emissions intensity of U.S. manufacturing, and find support for increasing regulatory stringency rather than compositional shifts in manufacturing (see boxes 5-4 and 5-5).

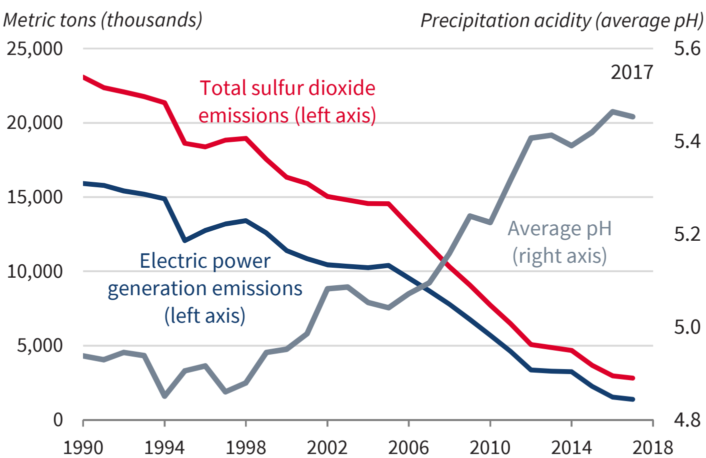
[13] Gaseous emissions into the atmosphere can cause greenhouse effects by directly absorbing radiation, or by affecting radiative forcing and cloud formation. The Intergovernmental Panel on Climate Change (IPCC) developed the Global Warming Potential (GWP) measurement to compare relative ability for anthropogenic emissions to trap heat. The GWP measures the equivalent amount of CO_2 emissions that would be required to create an equal amount of radiative forcing caused by the emission of 1 ton of a given gas over a 100-year horizon. The IPCC's accounting lists these GWPs for inventoried emissions: methane (CH_4) = 25, nitrous oxide (N_2O) = 298, hydrofluorocarbons (HFCs) = 124 to 14,800, perfluorocarbons (PFCs) = 7,390 to 12,200, sulfur hexafluoride (SF_6) = 22,800, and nitrogen trifluoride (NF_3) = 17,200.

Box 5-4. Long-Term Improvements in Environmental Quality

By many measurements, air and water quality in the United States has improved dramatically in the last 30 years and additional gains continue to be seen. Since 1990, concentrations of sulfur dioxide in the air have fallen by 88 percent, nitrogen dioxide by 56 percent, lead particulates by 80 percent, and carbon monoxide by 77 percent (EPA 2018a, 2018c). Less sulfur and nitrogen in the air has meant less acid rain and healthier lakes, while lower levels of lead and carbon monoxide protect citizens from respiratory illness (Sullivan et al. 2018). Water quality has also improved markedly in other dimensions, with streams and lakes having more dissolved oxygen and less bacteria (Keiser and Shapiro 2018).

The improvements stem from various sources, including innovations in the private sector and government policies. An illustrative example is the decline in sulfur dioxide emissions (see figure 5-iv, left axis). The most recent declines have come as abundant natural gas, made available through hydraulic fracturing and horizontal drilling, has encouraged the retirement of coal-fired electricity generation, as described in the section of the text on coal production. The electricity generation sector accounted for more than 70 percent of the total decline in sulfur dioxide emissions from 1990 to 2017 (the last year of available data), with large reductions since the mid-2000s,

Figure 5-iv. Sulfur Dioxide Emissions and Rainwater Acidity, 1990–2017



Sources: Environmental Protection Agency; National Atmospheric Deposition Program; CEA calculations.
Note: Average national rainwater pH is calculated as the precipitation-weighted negative logarithm of the concentration of hydrogen ions in rainwater accross 157 measurement sites in the United States.

when natural gas production began expanding. The more recent reductions in emissions build on early reductions that occurred following the 1990 Clean Air Act Amendments and an associated Federal cap-and-trade program implemented in 1995.

Less sulfur dioxide in the air has also improved water quality. When sulfur dioxide interacts with water and oxygen, it creates sulfuric acid and leads to acid rain, which makes streams and lakes more acidic and less hospitable to fish and other aquatic life. Data on the chemical properties of precipitation across the U.S. show that acidity has declined since 1990, with large improvements in the last decade. Data collected by the National Atmospheric Deposition Program (NADP 2018) from 157 measurement sites show that the acidity of rainwater fell by 40.3 percent from 1990 to 2017.

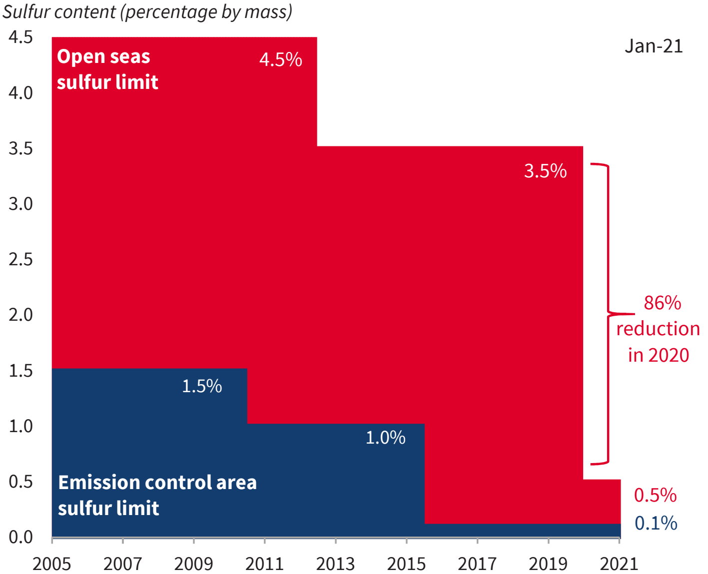
Box 5-5. International Environmental Standards and Liquid Fuels Markets: IMO 2020

Under a 2016 agreement by the International Maritime Organization (IMO), an 86 percent reduction in the sulfur content in marine bunker fuel used by 94,000 ocean-going vessels will be imposed on January 1, 2020. Sulfur emissions have been regulated in the United States, primarily in the electricity generation and transportation sectors, due to sulfur dioxide's adverse effects on public health (Burtraw and Szambelan 2009). Within 200 miles of U.S. coastlines, in waters known as Emission Control Areas (ECAs), ships must already limit the sulfur content of fuel burned to 0.1 percent (see figure 5-v). Similar ECAs exist in coastal waters off Canada and Northern Europe. Although the United States already adheres to a stricter sulfur standard, the IMO's decision to limit sulfur content in marine fuels to 0.5 percent in the open seas could have consequences for global fuel prices and shipping costs (IEA 2018).

Ships can pursue various strategies in order to comply with the new regulation, including refitting to LNG-fueled engines, the installation of scrubbers to remove sulfur from exhaust, and switching to lower-sulfur fuels. Given the high capital costs and supply constraints associated with refitting or installing scrubbers, initially, the majority of ships will likely comply by switching to a fuel compliant with the 0.5 percent sulfur limit—predominantly either distillate fuels (marine gas oil, MGO) or a lower-sulfur-content residual fuels (ultra-low or very-low-sulfur fuel oil, ULSFO and VLSFO). It is possible that some vessels will not comply initially, and the penalties are unclear at this point. The percentage of noncomplying ships will affect the amount of total high-sulfur fuel oil that will be displaced by MGO or ULSFO.

Global bunker fuel demand is estimated currently to be 4–5 MMbpd. HSFO and MGO constitute most bunker fuel demand, with HSFO consumption estimated to be roughly 3–3.25 MMbpd and MGO consumption estimated to

Figure 5-v. Global Marine Fuel Sulfur Limits, 2005–21



Source: Energy Information Administration.

be 0.8–1.25 MMbpd. LNG and LSFO (including VLSFO and ULSFO) currently constitute trivial portions of bunker fuel consumption. Though global bunker fuel represents about 5 percent of total oil demand, fuel switching by ships in 2020 may cause significant disruptions in specific product markets, with consequent price movements for all users of fuel.

Demand shifts to compliant fuels in January 2020 will be met by increasing refinery runs of MGO and ULSFO. Total desulfurization capacity by the global refining fleet is estimated to be 67 MMbpd. IMO 2020 will strain refiners because 1.5–2 MMbpd of HSFO will be displaced. As a result, the IEA (2018) estimates that existing ULSFO capacity will be able to cover only 0.6 MMbpd, or 30–40 percent, of initial HSFO displacement. Consequently, 60–70 percent of initial HSFO displacement will be filled by MGO for total bunker fuel demand to remain unchanged between 2019 and 2020, requiring greater diesel throughput by refiners. The IEA estimates that diesel capacity will increase by 1.0–1.5 MMbpd by 2020, though only 0.6–1.1 MMbpd of this additional capacity will go toward marine bunker fuel versus other diesel consumers. Under the IEA's estimates of refining capacity and supply of MGO and ULSFO, this would leave a shortfall in compliant fuel to fill HSFO displacement ranging from 0.2 MMbpd (under a high-end estimate of additional diesel and ULSFO capacity) to 0.6 MMbpd (under a low-end estimate of additional diesel and ULSFO capacity) (IEA 2018). The shortfall will likely trigger higher prices, though estimates of price shocks to fuels including diesel, gasoline, and jet fuel vary substantially.

To meet increasing MGO and ULSFO demand in the long run, refineries will need to increase their desulfurization capacity. Meeting MGO demand will require reconfiguration to optimize distillate product capacity. Meeting ULSFO demand will require upgrading to include the addition of cokers, hydrocracker, hydrotreater, and sulfur reduction units (Imsirovic and Prior 2018). Although the United States—followed by the Middle East, Russia, and China—is projected to provide most of the incremental diesel production in 2020, ULSFO production will be driven by complex refiners. A total of 8 of the 12 most complex refiners globally, as measured by the Nelson Index, are in the United States (Bahndari et al. 2018). The U.S. refining industry is well positioned to benefit from increased global demand for both MGO and ULSFO in 2020. However, U.S. fuel consumers may pay higher prices in the medium term as a result.

Conclusion

America's energy sector has bright prospects thanks to technological change and abundant resources that are already delivering record-breaking production. Improving technology has helped U.S. fossil fuel production, led by oil and natural gas, to defy projections and reach an all-time high in 2018. Investments in technology have relied on an appetite for risk-taking on the part of extraction firms and mineral owners. Successful innovation has expanded the U.S. resource base and now offers the prospect of decades of continued production. Lower expectations of the regulatory burden for extraction activities have also helped stimulate production, though the empirical magnitude of this effect has not been estimated. Domestic production will help provide energy resources to the U.S. economy that should bolster growth.

The United States' production has expanded so much that both domestic consumption and exports have increased. Natural gas consumption continues to hit all-time highs, and is increasingly penetrating electric power generation. This penetration has disrupted legacy baseload generation, including nuclear and coal. As grid operators wrestle with how to increase resilience and ensure continued reliability, the future balance between the legacy baseload and newer generators like natural gas and renewables will be struck, and this balance may differ regionally.

Expanded production also yields a dividend in America's foreign trade and its interactions with partners and allies. Growing exports of crude oil, refined petroleum products, natural gas, and coal are all evidence of greater linkages. For the first time since 1957, the United States is a net exporter of natural gas. The shrinking level of U.S. net imports of petroleum provides indirect benefits through macroeconomic channels by reducing sensitivity to oil price shocks. If the United States becomes an annual net exporter of petroleum, higher oil prices would, on average, help the U.S. economy. In this case, the net gains for producers, and to their private partners that own mineral deposits, would outweigh the higher costs for consumers. Such a change would have a number of important policy implications.

Policies focused on reducing regulatory hurdles and eliminating distorting subsidies and preferences will provide the greatest gains in cost-effectiveness and efficiency. This is especially true in electricity markets, where a dramatic increase in renewable generation capacity has threatened traditional generation assets. The restructuring of electricity markets is a deregulatory action if carried out effectively; future restructuring will need to account for renewables and to be more responsive to consumer demand, given that dynamic pricing and other strategies offer substantial efficiency gains.