Traditionally oil and natural gas have been produced from porous and permeable underground reservoirs sealed by a separate, low-permeability rock formation. These reservoirs are filled with oil and gas produced by a source rock, usually shale, located nearby. Drilling vertically into these reservoirs, companies can extract oil and gas by taking advantage of the pressure difference between the reservoir rock and the hole that has been drilled, known as a wellbore (NPC 2011). Due to the porosity of the reservoir, oil and gas naturally migrate to the wellbore and to the surface, where it can be separated and sold. Oil and natural gas exist in different ratios in different reservoirs and are often produced together.

In 1947 the petroleum industry began injecting a cocktail of water and chemicals into low-permeability reservoirs to fracture the rock and allow trapped gas to flow to the wellbore (Montgomery and Smith 2010). These “unconventional” reservoirs can be separate from the source rock (generally referred to as “tight gas”) or can be the source rock itself (as is the case with shale gas). Hydraulic fracturing can also be used to produce coal bed natural gas from coal seams (DOE 2009). In response to the energy crises of the 1970s, the federal government launched a number of programs aimed at promoting unconventional gas production. These included tax credits for gas produced from shale and other low-permeability reservoirs and research and development (R&D) focused on hydraulic fracturing (Wang and Krupnick 2013, Shellenberger et al. 2012).

It wasn’t until the late 1990s, however, that these efforts bore fruit, thanks in large part to the work of one company—Mitchell Energy. Founder George Mitchell began drilling in Texas’s Barnett Shale in 1981 and for more than a decade experimented with different fracturing techniques, many developed
with government support. In 1997, Mitchell Energy began employing “slick water fracking,” which proved more cost-effective than previous approaches. The number of new production wells drilled each year in the Barnett grew from 56 in 1996 to 518 in 2001 (Wang and Krupnick 2013). Almost all these wells were drilled vertically, but in 2002 Devon Energy acquired George Mitchell’s company and began applying another innovation in the Barnett—horizontal drilling. Lower reservoir permeability means lower concentrations of natural gas. So with unconventional gas vertical drilling requires more wells to produce the same volumes than with conventional gas. And that increases costs. Horizontal drilling, which had also been a focus of the federal government’s unconventional gas R&D programs, allows a company to access a greater amount of resource from a single well pad.

The combination of hydraulic fracturing and horizontal drilling made shale production commercially viable. All that was needed to scale it up was capital. And when gas prices began climbing at the turn of the century, capital began to flow. The number of natural gas rigs operating in the United States doubled between 2002 and 2007, driven by shale gas’s increasingly attractive economics (figure 3.1), and the average number of exploration wells drilled each month rose from 70 to 230. Natural gas production grew by 25 percent between 2007 and 2012 as newly discovered resources were developed (EIA 2013b). The Potential Gas Committee’s estimate of technically recoverable natural gas resources in the United States more than doubled in less than a decade and shale has pushed proven natural gas reserves to historically high levels (figure 3.2).¹

Natural gas prices collapsed during the financial crisis just as oil did. But because of the surge in supply, gas prices continued to decline while oil prices recovered (figure 3.3). Unlike oil, which is a globally traded commodity, natural gas trade is largely confined to North America. The United States has long imported significant quantities of natural gas from Canada and Mexico through an integrated North American pipeline network, but only minor amounts of liquefied natural gas (LNG) from the rest of the world—less than 4 percent of total supply at the peak. As a relatively isolated market, North America has what is known as gas-on-gas pricing. The price of gas is determined by North American supply and demand for gas, with a futures market based off the Henry Hub distribution center in Louisiana. In contrast, Europe, Korea, and Japan rely on foreign gas, much of it delivered as LNG, that is generally linked to the international price of crude. A 25 percent increase in US production is only a 4 percent increase in total global supply, which in an integrated market would have only a modest effect on price. But within the North American market, a 25 percent increase in US output was enough to cut natural gas prices by two-thirds.

Figure 3.1  Natural gas prices and drilling activity, 1996–2012

Source: EIA (2013b).
Figure 3.2  Proven natural gas reserves, 1950–2011

trillion cubic feet

Source: EIA (2012a).
Figure 3.3  Crude and natural gas prices, 1996–2012

Sources: EIA (2013b, 2013g); BLS (2013c).
**Broadening to Oil**

The fall in US natural gas prices has opened an unprecedented gap between the cost of oil and the cost of gas. When measured on the same basis—2012 dollars per million British thermal units—oil and gas have traditionally cost about the same (figure 3.3). This was true as recently as the end of 2008. Yet in 2012, oil cost more than six times as much as natural gas. This catalyzed the second stage of the US fossil fuel turnaround. As the relative profitability of oil production improved, that’s where the industry focused its attention.

The combination of horizontal drilling and hydraulic fracturing has come to dominate domestic exploration. In 2002 there were 50 to 100 horizontal drilling rigs operating in the United States. In 2012 there were 1,100 to 1,200. The combination of techniques can be used to produce oil as well as gas. In 2008 there were four times more rigs drilling for gas than for oil. By 2012 that ratio had switched (figure 3.4), with the Bakken Formation in North Dakota and parts of Montana and Saskatchewan accounting for much of the rise in oil-focused drilling activity. North Dakota has long been an oil-producing state, but a minor one. Between 1980 and 2000, the state produced 100,000 barrels per day (bbl/d) on average and held 150 million to 300 million barrels of proven reserves, 1 to 2 percent of the US total in both cases (EIA 2013g). The US Geological Survey (USGS) estimated there were only 151 million barrels of undiscovered but technically recoverable oil in the Bakken Formation, enough for only a few years of additional production. As companies began applying in North Dakota what they had learned from shale gas drilling, the picture changed dramatically. By 2008 proven reserves had doubled, prompting the USGS to conduct a new resource assessment. This one found 3,645 million barrels—10 percent of the US total. By 2010 proven reserves had grown to 1,814 million barrels and by the end of 2012, North Dakota was producing 770,000 barrels of oil per day. In 2013 the USGS doubled its estimates of the Bakken’s technically recoverable reserves.

Tight oil, as the new Bakken output is called, is being produced in other parts of the country as well. Production in the Eagle Ford, Spraberry, and other plays in Texas and New Mexico added roughly 1 million barrels per day to total US oil output between 2008 and 2012. Production is ramping up in Wyoming, Colorado, Oklahoma, and Kansas. Promising basins are being explored in the East, such as the Utica Shale under Ohio and Pennsylvania. There is further exploration of the massive Monterey Formation in southern California. Thanks primarily to this surge in tight oil production, US crude

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**Notes:**


Figure 3.4  Number of rigs drilling primarily for oil versus natural gas, 1999–2013

output has reversed its decades-long decline, growing by 1.5 million barrels per day between 2008 and 2012 (figure 3.5).

Shale gas production has helped increase the US oil supply in other ways as well. Along with the dry natural gas piped into homes and used to run power plants, shale, like other gas wells, produces what are called natural gas liquids (NGLs). These liquids can be used instead of naphtha, a crude oil derivative, in chemical production, and are thus classified as oil by the Energy Information Administration (EIA), International Energy Agency (IEA), and other statistical agencies. Most US petrochemical companies use NGLs instead of naphtha as their primary feedstock. Shale gas production—along with tight oil production, which also produces NGLs—has increased the country’s NGL supply by 600,000 bbl/d, bringing the growth in total US oil supply between 2008 and 2012 to 2.1 million bbl/d.

The recent reallocation of drilling rigs from shale gas to tight oil plays has not reduced US natural gas supply growth as much as one might think. Tight oil reservoirs generally contain associated natural gas as well, which is produced alongside the oil. Given the recent drop in gas prices, many gas-rich plays are no longer economic. But as associated gas is a secondary factor in the economics of tight oil plays, it keeps flowing even when gas prices are low.4

The Bakken and other tight oil plays are not the only places where US crude output is growing. Companies are employing enhanced oil recovery techniques to increase the amount of oil produced from conventional fields, including carbon dioxide (CO₂) injection, which displaces oil from a well and increases production. This carries environmental as well as energy supply benefits, as the CO₂ is sequestered rather than released into the atmosphere, thus lowering greenhouse gas concentrations. Processes such as this, which improve a reservoir’s or a well’s estimated ultimate recovery, have been instrumental in oil and gas reserve growth in the past.

The economics of deepwater drilling are also more favorable than a decade ago, thanks to technological advances as well as high oil prices. Offshore production in the Gulf of Mexico doubled between 1990 and 2009. While the Deepwater Horizon disaster and subsequent drilling moratorium dealt a blow to Gulf production, exploration work has started to recover and some large new fields have been discovered. Since sea ice levels have dropped due to climate change, the Alaskan Arctic is also being explored as a potential site of oil and gas production. Even potential oil shale plays, such as the Green River Formation in Colorado, Utah, and Wyoming, are getting a closer look.

America’s Oil and Gas Future

Whether the recent surge in US oil and gas production is the beginning of a structural expansion in US supply, as in the early 1900s, or just a momentary respite from a structural decline, as in the late 1970s and early 1980s, remains to

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4. Industry productivity has also improved, allowing companies to produce more from fewer wells.
Figure 3.5  US oil production, 1973–2012

Note: Oil includes crude oil and natural gas liquids (NGL).

Source: EIA (2013a).
be seen. The industry is still in the early stages of understanding and exploring newly discovered shale gas and tight oil resources and newly accessible fields in the Arctic and deep in the Gulf of Mexico. Much will depend on what happens to the price of oil, which depends on how producers in other parts of the world respond to the prospect of increased US supply (see chapter 4). Human capital and infrastructure constraints could limit future production potential. Policy also will play a major role in shaping future US oil and gas supply. There are active and passionate debates under way about how aggressively to develop oil and gas resources on federal lands and the best way to regulate frontier oil and gas production, whether through hydrofracking or deepwater development.

Given the uncertainty surrounding the size of the resource, the oil and gas price outlook, and the future policy environment, forecasts of future US supply growth vary widely. The EIA has significantly revised its oil and gas projections in recent years. In 2006 the EIA projected 6.4 million bbl/d of crude oil and NGL production in 2030. Its 2013 projection is 9.2 million bbl/d (figure 3.6). For natural gas, the EIA’s 2013 projection for US production in 2030 is 81.6 billion cubic feet per day (Bcfd), up from 53.2 Bcfd in the 2006 forecast (figure 3.7). In its 2013 Annual Energy Outlook report, the EIA included a side case that analyzed the effect of higher than expected unconventional oil and gas resources. In this scenario production grows to 14.6 million bbl/d and 101.1 Bcfd of oil and gas, respectively, by 2030. At the time of publication, US oil and gas production appeared to be following this trajectory.5

The IEA’s 2012 outlook projects US oil production will grow to 11.1 million bbl/d by 2020, a 35 percent upward revision from its 2011 projections and a little higher than the EIA’s 2013 reference case scenario (figures 3.8 and 3.9). In both the IEA and EIA outlooks, US oil production peaks by 2020 as the most promising tight oil plays are exhausted. As tight oil wells generally decline faster than conventional wells, US oil production falls to 9.2 million bbl/d by 2035 in both forecasts. On gas, the IEA is a little more conservative than the EIA, projecting 77.5 Bcfd of production by 2035.

A number of private sector forecasts are similar to the EIA’s 2013 reference case scenario. ExxonMobil projects that US crude oil and NGL supply will reach 9.8 million bbl/d by 2020, after which, in its outlook, the supply modestly declines (table 3.1, figure 3.8, and figure 3.9). Natural gas production peaks at 74 Bcfd in 2030, very close to the EIA estimates (ExxonMobil 2013).6 BP sees crude oil and NGL production reaching 11.5 million bbl/d and natural gas production reaching 89.4 Bcfd by 2030, a little higher than the EIA forecasts (BP 2013).


6. ExxonMobil has released a 2013 outlook with a more optimistic global production forecast but has not published US-specific production estimates.
Figure 3.6  EIA projections of US oil production, 1973–2035

EIA = Energy Information Administration; AEO = Annual Energy Outlook

Figure 3.7  EIA projections of US natural gas production, 1973–2035

EIA = Energy Information Administration; AEO = Annual Energy Outlook

Table 3.1 Comparing US supply projections

<table>
<thead>
<tr>
<th>Organization</th>
<th>Publication</th>
<th>Year</th>
<th>Scenario</th>
<th>Oil production* (million barrels per day)</th>
<th>Natural gas production (billion cubic feet per day)</th>
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<tr>
<td>Energy Information Administration (EIA)</td>
<td>Annual Energy Outlook</td>
<td>2013</td>
<td>Reference</td>
<td>10.6 9.2 9.2</td>
<td>72.9 81.6 85.9</td>
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<td></td>
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<td>53.7 53.2 n.a.</td>
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<td>72.1 75.9 77.5</td>
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<td>51.0 49.9 n.a.</td>
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<td>n.a. 53.7 n.a.</td>
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<td></td>
<td></td>
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<td>High potential</td>
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<td>n.a. 88.4 n.a.</td>
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<td>Wood Mackenzie</td>
<td>American Petroleum Institute (API) Study</td>
<td>2011</td>
<td>Current path Development policy</td>
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<td>67.3 74.5 n.a.</td>
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<td></td>
<td></td>
<td></td>
<td>Limited</td>
<td>10.7 15.4 n.a.</td>
<td>75.0 96.9 n.a.</td>
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<td>Citigroup</td>
<td>Energy 2020</td>
<td>2012</td>
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<td>14.1 n.a. n.a.</td>
<td>76.0 n.a. n.a.</td>
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<tr>
<td>IHS CERA (Cambridge Energy Research Associates)</td>
<td>America’s New Energy Future</td>
<td>2012</td>
<td>Current path</td>
<td>12.2 11.8 12.0</td>
<td>81.9 92.9 100.5</td>
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<td>ExxonMobil</td>
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<td>Limited</td>
<td>9.8 9.3 8.5</td>
<td>71.1 74.0 71.1</td>
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<td>BP</td>
<td>Energy Outlook 2030</td>
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<td>80.2 89.4 n.a.</td>
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<td>Authors’ scenarios</td>
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<td></td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td>Optimistic</td>
<td>13.0 14.5 14.1</td>
<td>82.4 94.0 97.9</td>
</tr>
</tbody>
</table>

n.a. = not available
a. Includes crude oil and natural gas liquids.

Source: Authors’ calculations.
**Figure 3.8** Government and private sector US oil production projections, 1973–2035

IEA = International Energy Agency; EIA = Energy Information Administration

Note: Includes crude oil and natural gas liquids.

*Sources:* EIA (2013e); IEA (2012a); Morse et al. (2012); ExxonMobil (2013); BP (2013); Wood Mackenzie (2011); IHS CERA (2012); National Petroleum Council (NPC 2011).
Figure 3.9  Government and private sector US natural gas production projections, 1973–2035

IEA = International Energy Agency; EIA = Energy Information Administration

Sources: EIA (2013e); IEA (2012a); Morse et al. (2012); ExxonMobil (2013); BP (2013); Wood Mackenzie (2011); IHS CERA (2012); National Petroleum Council (NPC 2011).
Other private sector estimates, however, are considerably more bullish and closer to the EIA’s high oil and gas resource side case. On the liquids side, Citigroup estimates that US crude and NGL production could reach 14.1 million bbl/d by 2020, an astounding 80 percent increase in total US output in less than a decade (Morse et al. 2012). Consultancy Wood Mackenzie (2011) sees slower growth over the next few years but believes US crude and NGL production could reach 15.4 million bbl/d by 2030. IHS Cambridge Energy Research Associates (IHS CERA 2012) expects roughly 12 million bbl/d of output between 2020 and 2035. The 2011 report of the National Petroleum Council (NPC 2011) describes a high potential scenario in which 14.6 million bbl/d of crude oil and NGL production is possible by 2035. On the natural gas side, Citigroup projects US production will increase to 81.9 Bcfd by 2020. Wood Mackenzie expects production to reach 75 Bcfd in 2020 and 97 Bcfd in 2030. IHS CERA has the most aggressive private forecast, with US production rising to 82 Bcfd in 2020 and 100.5 Bcfd by 2035.

Several caveats should be kept in mind when comparing the above forecasts. First, the IEA, EIA, ExxonMobil, BP, and IHS CERA projections are integrated supply-demand assessments, meaning they dynamically model the effect of increased energy supply on energy prices and the effect of changes in energy prices on energy demand. The NPC, Citigroup, and Wood Mackenzie assessments do not. Second, the forecasts are not all looking at the same future. The EIA projections assume no new policy beyond what was adopted at the beginning of 2013. The IEA projections assume that currently proposed policy is adopted and the ExxonMobil, BP, and IHS CERA projections incorporate policies each organization views as most likely to be adopted in the future. The Wood Mackenzie, NPC, and Citigroup estimates, on the other hand, are upper-bound projections of what is possible given the nature of the resource and the economics of production, not necessarily these organizations’ views of what is most likely to occur. Wood Mackenzie assumes that areas currently closed to development—the Eastern Gulf of Mexico, federal lands in the Rocky Mountains, offshore fields along the West and East Coasts, the Alaska National Wildlife Refuge, the Alaskan National Petroleum Reserve, the Alaskan offshore, and the portion of the Marcellus Shale in New York state—are opened and that both federal and state governments work to expedite drilling permits and make environmental regulation more industry-friendly. Wood Mackenzie then compares this future with a scenario in which no new areas are opened for exploration, Gulf of Mexico drilling permitting continues to be slow, and hypothetical federal hydrofracking regulations slow the rate of shale gas and tight oil development. The NPC (2011) describes its high-potential scenario as one of “substantial advances in technology, and regulatory burdens that are not significantly different than today” and compares that with a limited-potential scenario, described as “limited resource access, constrained technology development, as well as greater regulatory barriers.” The Citigroup report “focuses on the possible rather than providing a forecast of what’s to come” (Morse et al. 2012).
Policy explains some of the variations in recent forecasts, but differences in assumptions about the size and cost of US oil and gas resources also play a major role. IHS CERA has the most optimistic estimates for future US gas production, but does not assume any significant increase in access to federal lands relative to current levels going forward. Citigroup believes a threefold (2.5 million bbl/d) increase in Gulf of Mexico oil production is possible by 2020 in areas currently open for development, while Wood Mackenzie forecasts a 1.2 million bbl/d increase despite opening up the eastern Gulf of Mexico. IHS CERA expects deepwater production to grow by only a couple hundred thousand barrels per day between now and 2020 and then fall by roughly half between 2020 and 2035.

There is an emerging consensus that the current oil and gas boom has at least another decade to run, and with each forecast revision, the gap between projections narrows. But the magnitude of the uncertainty surrounding future US supply is still very large and must be kept in mind when assessing the boom’s economic effects. Unconventional gas development has a bit of a lead on unconventional oil, so there is more agreement on future US production. The standard deviation of the natural gas production forecasts listed in Table 3.1 is 5.4 and 11 percent of the mean for 2020 and 2030, respectively, compared with 12.3 and 20.8 percent for oil. Yet in absolute terms, the remaining uncertainty about future US gas production is still sizeable—a 23 Bcfd delta between the lower- and upper-end estimates for production in 2030. That is more than the total current natural gas consumption in China and Japan combined, and three-quarters of the size of global LNG trade today. The variation in projected oil production is even bigger. The difference between the upper-bound and lower-bound forecasts for 2030 listed in Table 3.1 is as large as total US oil production in 2008. At 15.4 million bbl/d of output, the upper-end estimate, the United States would easily surpass Saudi Arabia and Russia to become the world’s largest oil producer. And the 6 million bbl/d delta between current projections is itself larger than any oil producer in the world other than Saudi Arabia and Russia.

**US Energy Independence?**

Encouraged by the more optimistic supply forecasts discussed above, some commentators have begun to predict a development that politicians have long talked about but that the analytical community has largely dismissed: US energy independence. *Energy independence* is a loaded term, meaning different things to different people and implying potential economic and geopolitical benefits that may be elusive in practice. We start by assessing what recent supply and demand projections mean for net US energy imports, the most basic and common metric used to assess energy independence. Chapter 4 discusses what economic benefits this change in US energy trade might bring, and in what ways the United States will remain vulnerable to supply disruptions in global energy markets. Analysis of the geopolitical implications, a critical and complex question, is outside the scope of this book.
Both government and private sector forecasts expect the US energy trade deficit to fall in the years ahead, and many expect it to fall substantially. Supply affects price and price affects demand, so integrated modeling is required for a robust projection of the US energy trade balance. Taking this approach, the EIA revised its projection of US dependence on imported energy in 2030 downward from 33 percent in the 2006 outlook and to 11 percent in 2013 edition (figure 3.10). The IEA projects a 4 percent energy trade deficit that year. In BP’s outlook, US dependence on imported energy falls to 1 percent by 2030. ExxonMobil expects higher natural gas imports in the future than the EIA, IEA, or BP, so overall energy import dependency only falls to 16 percent (figure 3.11).

The Citigroup analyses focus on oil and gas supply and gasoline and diesel demand. The projections in figure 3.11 assess the effect of these estimates when combined with the EIA’s supply and demand projections for other energy sources. This is an imprecise approach, as changing oil and gas supply changes overall energy demand and supply from other energy sources, but it is a reasonable upper-bound estimate of the effect on overall energy import dependence. Using the Citigroup projections, the United States becomes a net energy exporter by 2020. Citigroup is not alone in predicting that the United States will become energy independent in roughly a decade (Verleger 2012, Adkins and Molchanov 2012). Combined with EIA demand and non-oil-and-gas-supply projections, Wood Mackenzie’s oil and gas production forecasts suggest that the United States could reduce its net energy imports to zero by 2027. Under IHS CERA’s more conservative oil production forecasts and more ambitious natural gas demand estimates, however, US net energy imports fall to about 10 percent of production but stay at roughly that level through 2035.

**Assessing America’s Oil and Gas Future**

We are loath to predict future US oil and gas supply, given how dramatically both public and private sector projections have shifted in just a couple years, and in any event are poorly suited to do so given our backgrounds and expertise. Instead, in the coming chapters we analyze the economic, environmental, and trade effects of two production scenarios that capture the range of forecasts discussed above. For this analysis, we use the National Energy Modeling System (NEMS), the model the EIA uses to produce its *Annual Energy Outlook,* which allows for an apples-to-apples comparison between our results and current EIA projections. Also, NEMS is publicly available and extensively documented, which enables others to reproduce our results. A full description of the model and the assumptions used in this analysis is available in appendix A.

As our goal is to evaluate what recent changes in US oil and gas production trends mean for economic growth, environmental quality, and international trade policy, we start by establishing a baseline against which to measure current projections—that is, what the oil and gas supply future looked like before the shale gas and tight oil boom. To do this, we reduced NEMS estimates of technically recoverable resources (TRR) to levels the EIA used for its 2008 projections. We also limited offshore drilling to areas that were open for de-
Figure 3.10  EIA projections of future US dependence on imported energy, 1973–2035

percent share of total consumption

AEO = Annual Energy Outlook; EIA = Energy Information Administration

Figure 3.11  Government and private sector projections of future US dependence on imported energy, 1973–2035

percent share of total consumption

IEA = International Energy Agency; EIA = Energy Information Administration

Sources: EIA (2013e); IEA (2012a); Morse et al. (2012); ExxonMobil (2013); BP (2013); Wood Mackenzie (2011); IHS CERA (2012); National Petroleum Council (NPC 2011).
velopment in 2008, specifically the western and central Gulf of Mexico. In this pre-shale case, US oil\(^7\) production peaks at 8.2 million bbl/d in 2020 and then declines to 6.9 million bbl/d by 2035 (table 3.1). This is a little higher than the EIA’s 2008 projections, due mostly to higher projected oil prices creating incentives for more production, even with the same resource base. Natural gas production stays roughly flat at 2011 levels throughout the projection period.

We then model two post-shale production futures. Our conservative scenario is consistent with the more restrained production forecasts above, such as the EIA’s 2013 low oil and gas resources side case, ExxonMobil’s 2012 projections, and, for natural gas, the IEA’s 2012 numbers. Under this scenario, oil production grows to 9.6 million bbl/d by 2020 and then declines modestly to 9 million bbl/d by 2035. Gas production grows to 68.6 Bcfd in 2020 and 76.5 Bcfd in 2035.

Our optimistic scenario is consistent with the more ambitious projections from Wood Mackenzie, Citigroup, IHS CERA, and the EIA’s 2013 high oil and gas resources case. In modeling this scenario, we use a number of assumptions from the EIA 2012 high TRR case—the closest EIA scenario available at the time we began our modeling—including closer spacing for tight oil and shale gas wells, a 50 percent increase in estimated ultimate recovery relative to the EIA reference case, and a more than twofold increase in estimated unproved tight oil and shale gas resources. In addition, we open all areas of the outer continental shelf (OCS) in the lower 48 states to offshore drilling, double the unproven resource estimates for these areas, and reduce drilling delays. In Alaska we triple OCS resource estimates and allow for Arctic exploration. Under these assumptions, US oil production grows to 13 million bbl/d in 2020 and plateaus at 14 million to 14.5 million bbl/d between 2030 and 2035. Natural gas production grows to 82.4 Bcfd in 2020 and 97.9 Bcfd in 2035.

By comparing our conservative and optimistic scenarios to a scenario with pre-shale policy, technology, and resource assumptions, we can evaluate the economic, environmental, and trade effects of the US oil and natural gas boom specifically, holding other variables, such as macroeconomic changes unrelated to oil and gas production, constant. The differences among the pre-shale, conservative, and optimistic scenarios reflect a combination of policy, technology, and resource factors—not the potential outcomes of any discrete decision facing policymakers today. The resource base could prove as abundant as reflected in our high scenario, but future production could fall short due to regulatory barriers to development. Likewise, production could disappoint despite policy support if more conservative estimates of resource cost and availability prove correct. Our objective here is to put the overall changes in the oil and gas supply outlook over the past four or five years in an economic context to help policymakers understand what it means for future US employment and economic output, appreciate the distributional consequences, and evaluate and manage trade and environmental policy implications.

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7. Includes crude oil and NGLs but excludes biofuels, condensates, and refinery gains.