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THE FOSSIL FUEL REVOLUTION

SHALE GAS AND TIGHT OIL

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The Fossil Fuel Revolution: Shale Gas and Tight Oil

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"To our respective parents, who never stopped supporting us even though they often wondered what we were doing."

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Introduction

It is virtually impossible to overstate the importance of the successful development of shale gas and tight oil to the energy economy of the United States. According to data tracked by the US Energy Information Agency (EIA), by 2009, shale gas had led the United States from natural gas shortages to becoming the largest producer of natural gas in the world (USEIA, 2018). Liquefied natural gas (LNG) terminals constructed on the US East Coast at the start of the 21st century for energy imports were converted less than a decade later to export LNG to Europe and elsewhere. The Marcellus Shale in the Appalachian basin is now the most productive natural gas formation in the United States (Fig. I.1).

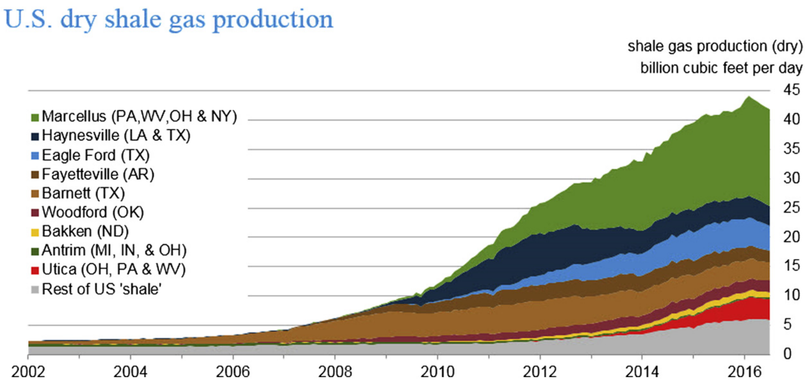

FIGURE I.1 Shale gas production trends in the United States. *U.S. Energy Information Administration reports and web pages.*

Liquid production from low-permeability shales and limestones, known as "tight oil," has experienced a similar boom. Massive oil imports from the 1970s through the first decade of the 21st century brought in more than half of the annual US oil supply from overseas. By 2013, tight oil made America the world leader in crude oil production (USEIA, 2018).

These two stunning facts have not only changed the energy picture in the United States but have disrupted the energy economy of the entire world. The business plans of many international and state-owned oil companies were dependent upon exports to the United States, one of the world's largest consumers of petroleum. Thanks to abundant tight oil production from the Bakken Shale, the second largest oil-producing state in the

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United States is presently North Dakota, exceeding other former oil giants like Alaska, Oklahoma, Louisiana, California, and Colorado. It trails only Texas, which retains first place because of equally prolific liquid hydrocarbon production from the Eagle Ford Shale and a group of tight oil formations in the Permian Basin (Fig. I.2).

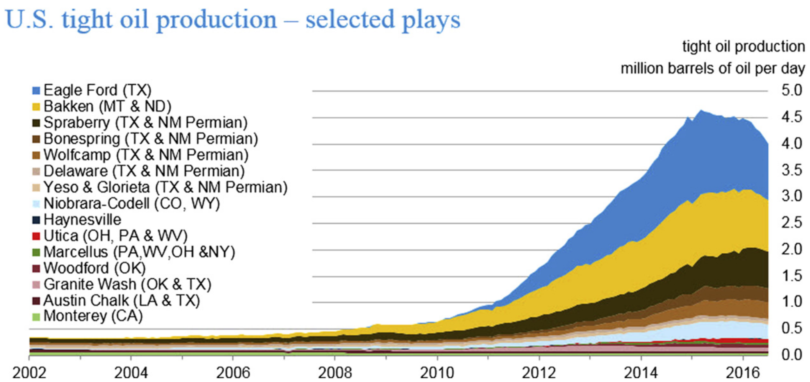

FIGURE I.2 Tight oil production trends in the United States. *EIA derived from state administrative data collected by DrillingInfo Inc. Data are through July 2016 and represent EIA's official tight oil estimates, but are not survey data. State abbreviations indicate primary state(s).*

Although the development of shale gas and tight oil created a revolution in fossil fuels, it has also sparked a revolution in the political sense of the word. Like most political revolutions, there are ardent supporters and a dedicated and vehement opposition. In the early days, the oil and gas (O&G) industry used the slang term "frack" to describe the process of hydraulic fracturing. This technology was invented in Kansas by Floyd Ferris of Stanolind Oil in 1947 to improve hydrocarbon production from low permeability or "tight" reservoirs (Montgomery and Smith, 2010). It is the primary technology applied to shales to stimulate production. Shale gas opponents adopted "fracking" as a trigger word to serve as a protest and a call to arms, and proudly self-identified themselves as "fracktivists." The fracktivists used the word to refer to the entire shale gas development process, from the arrival of the first drill rig on site to the production of "fracked gas" from a completed well.

The O&G industry, on the other hand, restricts usage of the term fracking to describe only the actual hydraulic fracturing stimulation process itself. To distinguish the original intent of the expression from the negative connotations of the term co-opted by fracktivists, industry dropped the "k" and changed the spelling to "frac." This, however, does not work very well as colloquial English, leading to spellings like "frac'ed," "fracced" or "frac'ing." Nevertheless, usage of the term "frac" versus "frack" is critical to some people, as it has become a way to quickly identify which side of the shale gas revolution someone is on.

We remind readers that this is a made-up word with no standard spelling and argue that "frack" spelled with the "k" has a great deal in common with the spellings for real, similar-sounding words like "back" or "crack." As such, we have chosen to use the spelling "frack" in this document for phonetic reasons. However, we also agree with the O&G industry that the term should be used narrowly to refer only to the hydraulic fracturing stimulation process. Describing the action of a bulldozer clearing off a well pad as "fracking" is both incorrect and absurd. Stating ominously that a pipeline will be carrying "fracked gas" makes no sense when there is no distinguishable difference between fracked gas and any other kind of gas.

Disagreements over shale development grew more intense as the massive economic promise of the resource collided head-on with fears and uncertainties about the potential environmental risks. With no actual data on environmental impacts, fracktivists could conjure up monsters under the bed of every stripe and color. Likewise with no actual data, the O&G industry tried to reassure people that they knew what they were doing, the safety of the public was paramount, and everyone should just trust them as the experts. Unfortunately, in terms of trust, sociological studies have shown that the only industry Americans consider to be less trustworthy than oil and gas is big tobacco (Theodori, 2008). Thus, when the O&G industry responded to environmental concerns raised by fracktivists with "trust us, all is well, remain calm," it was met with almost universal skepticism by the American public.

The issue soon became explosive. Disagreements between shale gas proponents and opponents at town halls and other civic meetings escalated into virulent, fierce arguments fought more intensely than anything on the worst reality TV shows. Much of this drama was dutifully recorded and disseminated by the news media, resulting in deep concerns among the general public about the supposed risks of fracking. Public relations people in the O&G industry generally handled these issues poorly, when they responded at all. Certain fracktivists were motivated to fan the flames of concern by book deals and film productions. Some politicians responded to the worried public by imposing bans on fracking in places like New Jersey and Vermont, which cost nothing because there is little or no shale gas in the geology.

New York is a state that does have shale gas resources in both the Marcellus and Utica shales, and strong disagreements over fracking. It became the epicenter for many of the most contentious debates. The state was strongly divided between those who thought fracking would be an unacceptable risk to the environment, versus those who considered shale gas development to be important for the depressed New York economy, especially upstate.

The New York State Department of Environmental Conservation carried out an exhaustive environmental impact study on the Marcellus Shale, producing a massive, 1500-page Supplemental Generic Environmental Impact Statement (SGEIS) in 2009 that was revised in 2011 in response to thousands of public comments (New York State Department of Environmental Conservation, 2011). Rigorous analyses presented in the New York SGEIS demonstrated that no significant adverse impacts to air or water resources were likely to occur from projected Marcellus Shale development. The SGEIS also provided detailed recommendations for mitigation measures that could be implemented to avoid any potential problems.

Despite the findings of his own environmental agency, the governor of New York imposed a ban on fracking shale gas wells in 2014, citing unacceptable environmental risk (Kaplan, 2014). It has been estimated that the ultimate cost of this ban to the state will be $1.4 billion in lost tax revenues and up to 90,000 direct and indirect jobs (Considine et al., 2011).

Fracking has also been banned in Maryland and in the Canadian province of Quebec, both of which have some small shale gas resources, and bans have been discussed but not implemented in Colorado and California. The New York ban taught the O&G industry that properly addressing environmental concerns up front is necessary for communities to be able to weigh the risks and benefits of granting a "social license" for the development of shale gas and other resources.

Research over the past decade has reduced the uncertainties behind many of the concerns, showing for example that hydraulic fractures do not extend upward high enough to contaminate shallow aquifers from below, and that 99.5% of shale wells are typically completed without any reportable environmental incidents (Soeder et al., 2014). The shrillness of the debate has backed off somewhat in recent years but many hard feelings still remain.

In 2010, the US Congress asked the Environmental Protection Agency (EPA) to investigate the risks that hydraulic fracturing might pose to underground sources of drinking water. The agency held a series of workshops to gather expert opinions, ran several retrospective field studies, and synthesized the results in a 1000-page final report (U.S. Environmental Protection Agency, 2015). The report concluded that while there were occasional aquifer contamination incidents from surface spills, no systemic contamination of drinking water aquifers from shale gas development or fracking had been found. Many fracktivists found these results to be disappointing and the EPA Science Advisory Board criticized the report for reaching such broad, sweeping conclusions based on minimal data. The report was revised with the conclusions toned-down somewhat, but the basic findings remain the same.

This discussion is not meant to imply that there are no environmental risks. Stray gas and surface spills of chemicals can contaminate streams and groundwater, methane leaks and particulates may pollute the air, and well pads and roads often affect both terrestrial and aquatic ecosystems (Soeder et al., 2014). More details about the potential environmental impacts of shale gas development will be explored in later chapters of this book.

So what are the origins of the shale revolution? In less than a decade, O&G production in the United States went from largely conventional onshore and offshore resources to being dominated by "unconventional" shale gas and tight oil. To some, it felt like a bolt from the blue. In reality, it took nearly 3 decades of hard work and many failures to develop and apply the proper technology to economically produce these resources (Soeder, 2018).

The first commercial American gas well was hand-dug in Fredonia, New York to a depth of about 10 m (28 ft) into the Upper Devonian Dunkirk Shale by an entrepreneur named William Hart in 1821 to supply fuel for a grist mill, a tavern, and the village street lighting (Curtis, 2002). Hart reportedly inverted his wife's washtub over the top of the open hole to create a primitive wellhead of sorts to contain the gas. Small-scale gas production from similar Devonian Shale units along the south shore of Lake Erie continued throughout the 19th and early 20th centuries, as did the limited exploration of shales elsewhere. The notion that organic-rich or "black" shales may contain natural gas has been understood historically.

The modern development of shale gas as a significant domestic energy resource can be traced to the aftermath of the so-called "energy crisis" in the United States during the 1970s. This "crisis" was actually two separate events. The first resulted from a Middle East war in October 1973 between a number of Arab countries and Israel. Because the United States was supporting Israel, oil ministers from the Organization of Petroleum Exporting Countries (OPEC) led by Libya imposed an embargo on American oil deliveries that lasted until the spring of 1974 (Yergin, 1991). At the time, significantly less than half of the oil used in the United States was imported, but the action still resulted in a four-fold increase in gasoline prices, severe shortages, consumer panic, and long lines at service stations when fuel was available. A second oil shock followed later in the decade when Iranian exports were briefly disrupted during the Islamic revolution of 1979. These energy shortages were unexpected and profoundly shocking at the time, significantly influencing the US foreign policy for decades to come (Yergin, 1991).

In 1975, soon after the OPEC embargo, the US Energy Research and Development Administration (ERDA) began a project to assess the natural gas resource potential of Devonian-age black shales in the Appalachian basin as well as similar rock units in the adjacent Michigan and Illinois basins (Soeder, 2012). ERDA was incorporated into the US Department of Energy (DOE) when it was created by the Carter Administration in 1977 and the investigation became known as the Eastern Gas Shales Project (EGSP). The project consisted of three major efforts under DOE: 1) resource characterization, 2) development of production technology, and 3) the transfer of that technology to industry (Cobb and Wilhelm, 1982). Cooperative agreements with operators were used to obtain drill cores from the Devonian Shale stratigraphic section in the Appalachian basin ranging from the Middle Devonian Marcellus Shale to the Upper Devonian Cleveland Member of the Ohio Shale. The cores were also collected from the Upper Devonian Antrim Shale in the Michigan basin and the similar-age New Albany Shale in the Illinois basin providing samples from a total of 44 wells for the project (Bolyard, 1981). The cores were characterized for lithology, frequency and orientation of natural fractures, color and other unusual features, then photographed and scanned for gamma radiation readings. Rock samples and subcores were collected for the various testing labs, government agencies, and universities that had requested them. The drill cores were eventually transferred to the state geological survey in the state where each had been obtained.

Innovative well logging techniques, directional drilling techniques, assessments of reservoir anisotropy, new hydraulic fracturing processes, and other cutting-edge technologies were tried out on gas shales during the course of the EGSP. One of the first experimental horizontal test wells in a gas shale was drilled by the EGSP in December 1986 (Duda et al., 1991). Laboratory measurements on EGSP cores found that the Marcellus Shale contained a larger component of adsorbed gas than previously thought, implying that the gas-in-place resource was more significant than the assessed values accepted at the time (Soeder, 1988). A major thrust of the field-based engineering experiments was an attempt to create a network of high-permeability flowpaths in the shale by linking together existing natural fractures using a variety of standard and novel hydraulic fracturing techniques (Horton, 1981). Many of the results were hit-or-miss, and the basic problem discovered much later was that vertical boreholes through shale simply do not come into contact with enough rock.

Transfer of these and other technologies to industry was accomplished by periodic workshops jointly sponsored by DOE and the Society of Petroleum Engineers (SPE). The EGSP research proved to be extremely valuable decades later in assisting the O&G industry with the commercial development of shale gas, and the modest DOE/SPE technology transfer workshops have since evolved into the giant, annual Unconventional Resources Technology Conference, or URTeC. The term "unconventional" is defined by DOE as a resource that requires some form of engineering treatment like fracking to be economically productive (Soeder, 2017). In contrast, "conventional" O&G resources can usually be produced directly with simple well completions.

Credit for the actual, successful application of new technology to the commercial development of shale gas goes to the late George P. Mitchell, cofounder with his brother Johnny of Texas-based Mitchell Energy (Soeder, 2017). Mitchell had been involved with shale gas since the early days of the EGSP, drilling several Appalachian basin shale wells in cooperation with DOE (Cobb and Wilhelm, 1982) and maintaining an ongoing interest in producing gas from the Barnett Shale in the Bend Arch—Fort Worth basin of Texas (Hickey and Henk, 2007). George Mitchell tried numerous experimental drilling techniques and reservoir stimulation procedures in the Barnett over a period of 18 years with many technical failures and a few technical successes that were simply not economical (Montgomery et al., 2005).

Mitchell eventually discovered that the production of economical quantities of natural gas from the Barnett Shale required the application of two key technologies: 1) long, horizontal boreholes or "laterals" that maintained kilometers of contact with the target formation and 2) the use of a "slickwater" hydraulic fracturing formulation that consisted of mostly water with a friction reducer added, very little sand for proppant, and avoided the thick gels and gums used in conventional fracking (e.g., Moritis, 2004; Mason, 2006; Pickett, 2008). Mitchell found that unlike vertical boreholes, where a single frack will propagate outward in two vertical "wings" along the direction of least principal stress, lateral boreholes could support multiple fracks performed in stages at evenly-spaced intervals. Horizontal wells also can be drilled in directions that cross multiple sets of natural fractures, which tend to be oriented vertically and are difficult to capture in a vertical borehole (Hill et al., 1993).

Thus, the two technologies that made shale gas and tight oil successful as hydrocarbon resources in the United States were directional drilling and staged slickwater hydraulic fracturing. Application of these finally allowed high-permeability flowpaths into a shale gas well to make contact with a sufficient volume of rock to produce economical amounts of gas or oil (Fig. I.3). It is important to note that neither of these technologies was actually invented by George Mitchell; his genius was in applying existing technology to the Barnett Shale and achieving success.

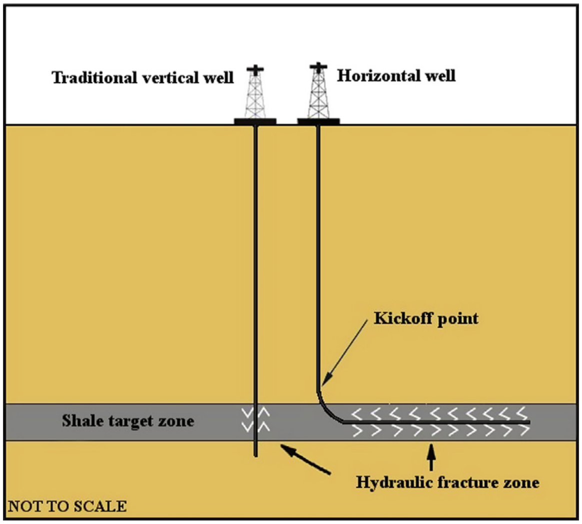

FIGURE I.3 Illustration of the combination of horizontal drilling and staged hydraulic fracturing technology used for shale gas. Not to scale. *Modified from Soeder, D.J., Kappel, W.M., 2009. Water Resources and Natural Gas Production from the Marcellus Shale, U.S. Geological Survey Fact Sheet 2009–3032, 6 p.*

Directional drilling had been invented in the 1930s with the introduction of a flexible length of drill pipe called a "whipstock" that was designed to prevent the drill string from shearing off as it went through a bend. However, turning the entire drill string from the surface and steering the bit through curves often resulted in deviated boreholes or broken drill pipe even when a whipstock was used. Downhole navigational apparatus with a compass and gyroscope was also quite primitive, commonly leaving drillers with no precise idea about where the bottom of the hole was located (Mantle, 2014).

Technological advances in directional drilling came about in the 1990s, driven by ventures into increasingly deeper water by the major oil companies involved in offshore oil production (Soeder, 2018). Semi-submersible, tension-leg drilling platforms anchored in several kilometers of water are risky, expensive, and time-consuming to move around from prospect to prospect. There was a desire to reach multiple reservoir compartments in complex structures like salt domes in extremely deep water without having to move the platform (Cromb et al., 2000). The majors put significant funding and research resources into developing advanced directional drilling technology that would allow multiple wells to be installed from a single location. Tension-leg platforms are currently able to drill dozens of wells without moving.

Directional drilling improvements included a downhole hydraulic motor and bottomhole assembly that greatly improved steering and navigation of the drill bit. Without having to turn the entire drill string from the surface, the drill pipe was much more flexible and could turn tighter corners. Some advanced bottomhole assemblies have thrust bearings that provide precise directional control. Improvements in downhole position measurement based on inertial navigation and real-time telemetry of data back to the surface now allow the use of "geosteering" to precisely place and accurately monitor the downhole location of the drill bit and the configuration of the borehole (Mantle, 2014).

George Mitchell remained convinced that the Barnett Shale had hydrocarbon potential (Kinley et al., 2008) and adapted the directional drilling and staged hydraulic fracturing technology to shale through a series of field experiments in Texas until eventually finding a combination that was effective on the Barnett at a lower cost than other approaches. An increase in gas prices in the mid-1990s improved the economics. By 1997, Mitchell Energy had perfected the slickwater frack technique in vertical Barnett wells and started trying it in horizontal wells. The company began successfully producing commercial amounts of gas from the Barnett Shale in the late-1990s, using horizontal boreholes and staged hydraulic fracturing, and started the modern shale gas revolution (Martineau, 2007).

Mitchell Energy was acquired in 2002 by Devon Energy for $3.1 billion (Sidel and Cummins, 2001). George P. Mitchell received a Lifetime Achievement Award from the Gas Technology Institute on June 16, 2010 for his persistence in developing shale gas into an economic resource. He died on July 26, 2013 at the age of 94.

Like Hollywood movie sequels, the O&G industry is well-known for copying success. Southwestern Energy noticed that the Fayetteville Shale in northern Arkansas possessed many of the characteristics of the Barnett and quietly bought up leases. By 2004, they had adapted the Mitchell techniques for Fayetteville production. Chesapeake Energy followed on the Haynesville Shale in the Arkansas—Louisiana—Texas border region. In 2006, EOG and Continental Resources had both begun using horizontal drilling and staged fracking to successfully produce tight oil from the Bakken Shale in the Williston basin in Montana and expanded it into the Parshall field of North Dakota a few years later. After struggling to adapt the Mitchell techniques to the Appalachian basin, Range Resources successfully brought their Gulla #9 horizontal Marcellus well online in 2007 at an initial production (IP) rate of 4.9 million cubic feet of gas per day (MMCFD), a so-called "barn-burner" previously unheard of in Appalachian basin shales (Soeder, 2017).

Shale gas developers became victims of their own success, with the proliferation of gas wells driving down prices. Operators began to move away from "dry gas" and focus instead on resources containing natural gas liquids (NGL) or "condensate" and oil. NGLs typically exist in a vapor phase under downhole pressures and temperatures and can be produced as a vapor with the natural gas. The compounds then condense into liquids like propane, butane, and ethane under cooler conditions and lower pressures at the surface (Soeder, 2017). NGL are significantly more valuable than dry gas and fetch a correspondingly higher price. In 2008, Petrohawk Energy began development of the liquids-rich Eagle Ford Shale in Texas, and a few years later Anadarko Petroleum and Whiting Petroleum began producing condensate from the Niobrara Formation in the Denver—Julesburg basin of Colorado. The Utica Shale, also known as the Point Pleasant Formation in Ohio, is another large, liquids-rich shale play developed by multiple operators beginning in 2011 (Hohn et al., 2015). The most significant hydrocarbon production of all is coming from a stack of six unconventional formations being developed in the Permian Basin of Texas, which are producing oil, NGL, and gas (USEIA, 2018). Cumulative production numbers in 2016 (the most recent data) published by the EIA for tight oil plays were 864 million barrels from Texas (Permian Basin and Eagle Ford), 375 million barrels from North Dakota (Bakken), and 27 million barrels from Oklahoma (Woodford).

Potential future shale development may include the Rogersville Shale deep in the Appalachian basin the Monterey Shale in multiple small basins in California, and even some of the thick, organic-rich shales filling a number of Triassic-age rift basins along the US eastern seaboard (Milici et al., 2012). Other future development may include tight limestones such as the Mississippi Lime in Oklahoma or the Tuscaloosa Trend in Mississippi and Louisiana.

This book is intended to serve as a reference and resource on shale gas and tight oil for a broad spectrum of O&G industry personnel, undergraduate and graduate students, engineers, geoscientists, and others. Unconventional oil and gas is a unique type of petroleum extraction, requiring complex engineering for successful production. It plays a singular role in both the United States and world economy. Each major shale formation is unique in terms of the technology needed to produce it and the regulatory and economic forces governing its development. We have attempted to provide explanations of the history and the physics of shale gas production, along with descriptions and definitions for each of the major shale plays. Shale gas and tight oil resources in other nations are also addressed, along with discussions about environmental concerns, economics, energy security, energy policy, and fossil fuel sustainability.

Some readers may feel we are overstating the importance of shale gas and tight oil to the energy economy of the world, and that perhaps we are not justified in calling it a fossil fuel "revolution." In response, we summarize the following information gleaned from the U.S. EIA: Shale resources began significant development in the early years of the 21st century, and unconventional hydrocarbons have increased natural gas and petroleum production in the United States by nearly 60% since 2008. The United States surpassed Russia in 2009 as the top producer of natural gas in the world and exceeded Saudi Arabia as the top oil producer in 2013 (Fig. I.4). Shale has taken the United States from a dependence on energy imports to becoming the largest fossil energy producer in the world. If a revolution is defined as a complete paradigm shift, this qualifies.

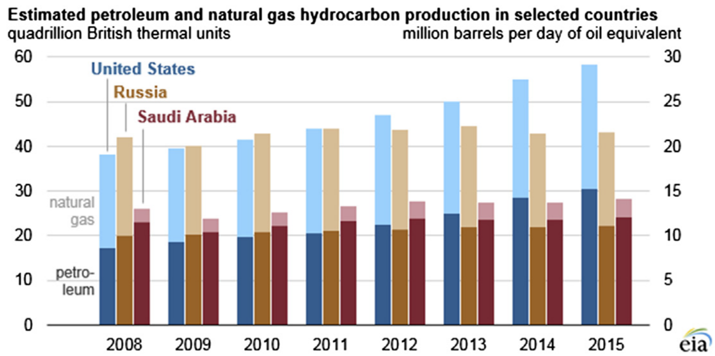

FIGURE I.4 Trends in world oil and gas production by top producers. *Reproduced from U.S. Energy Information Administration webpage (https://www.eia.gov/todayinenergy/detail.php?id=36292) dated May 21, 2018.*

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PART I

Geology of tight oil and gas shales

Shales are clastic sedimentary rocks formed from mud. They were deposited in quiet-water environments, and are typically composed of tiny flakes of clay, extremely small quartz grains, varying amounts of carbonate minerals, and often significant quantities of organic matter (Soeder, 2017). The organic carbon in shale primarily comes from decayed plant material such as algae deposited with the sediment. The plant matter can be derived from either aquatic or terrestrial sources, and each possesses a distinct geochemical character (Chen et al., 2015). Organic carbon is a favorite food source for organisms, and is frequently consumed by bacteria and animals such as worms living within the sediment. The number and types of organisms that can survive in the sediment are limited in the presence of anoxic bottom waters, and organic material tends to be preserved in these environments. Organic-rich muds are often black in color, and when lithified into a rock, become black shales.

When organic material is preserved in a rock, it can transform into petroleum, coal, or natural gas over geologic time, depending on the type of plant material preserved, and the thermal history of the rock. This is the most basic concept of petroleum geology—that fossil fuels were created primarily from ancient plant materials (not dead dinosaurs) that have been preserved and transformed into sedimentary rocks (Selley, 2014). Another important concept is that the energy of fossil fuels is derived from ancient sunlight. Photosynthesis by plants in ancient seas or on long-ago landscapes used the energy of sunlight to transform water and carbon dioxide into cellulose, lipids, carbohydrates, and other plant materials, which were then transformed to hydrocarbons possessing chemical energy.

Although the dependence of human civilization on energy from fossil fuels certainly has many environmental downsides ranging from greenhouse gas-driven anthropogenic climate change to groundwater contamination from leaking underground gasoline tanks, the high energy density of fossil fuels has allowed humanity to develop a technological civilization. Electrical power generation, transportation by road, railroad, air or sea, and massive construction projects like suspension bridges and skyscrapers would either be much slower or not possible at all without fossil energy. Chemical feedstock for everything from plastic bags to polyester clothing, lubricants, fertilizers, and many other uses are supplied by petroleum. Even if humanity switched to 100% renewable energy, or commercialized nuclear fusion, or found some other form of exotic energy, there would still be a demand for petroleum and natural gas.

Another important historical note on the early development of fossil fuels, and petroleum in particular, is that it was spurred by the desire to save the whales. Not in an environmental sense—back in 1859 when Colonel Edwin Drake drilled the first commercial oil well in

Titusville, Pennsylvania, there were not many people concerned about the environment and ecology. This was much more about money. In the era before electricity, oil lamps were widely used for lighting, and the supply of lamp oil at the time was obtained primarily from sperm whales. The species had been hunted nearly to extinction, romanticized by Herman Melville in *Moby-Dick*, and the price of whale oil skyrocketed. Colonel Drake had the intention of obtaining mineral oil in quantities sufficient to refine into kerosene, and marketing this new, much cheaper fuel as a replacement for costly whale oil. Within a few short years, kerosene dominated the lamp oil market, and whale hunting became extinct, instead of the whales.

The chapters in this first section will discuss the geology of unconventional oil and gas resources, including some general petroleum concepts, the differences between conventional and unconventional resources, and the production challenges of shale gas and tight oil. This will be followed by descriptions of the major shale hydrocarbon resources in the United States and worldwide. Other sections will address industry operations, economics, policy, and environmental issues.

1

Petroleum geology concepts

Origins of black shales

After the first commercial American gas well was hand-dug into a Devonian-age shale in 1821 in Fredonia, New York to supply village streetlighting (Curtis, 2002), the concept that organic-rich or "black" shales are a potential source of hydrocarbons was understood (Schrider and Wise, 1980). The preservation of organic carbon gives the rock its dark color, although this can vary considerably from flannel gray to the yellow-black color of ripe olives to a deep charcoal black. Attempts by the US Geological Survey (USGS) to quantify carbon content from rock color charts found that shales tend to get darker as the carbon content increases, but once the organic carbon content reaches about 4%, the shale is black and doesn't get any "blacker" with the addition of more carbon (Hosterman and Whitlow, 1980).

The mechanism for carbon preservation in shale is thought to require three important components: 1) high productivity of algae in the water is needed to produce a substantial amount of organic carbon (Wrightstone, 2011), 2) this organic material must then settle out of the water column and be deposited in a low-sediment environment, thereby preventing the "dilution" of organic carbon by large influxes of inorganic mineral sediment (Smith and Leone, 2010), and 3) anoxic bottom conditions are required to preserve the black muds by preventing benthic animals and aerobic microbes from consuming the organic material. In many cases, the transition from oxidizing to anoxic bottom conditions was abrupt, creating a sharp boundary between a "gray" shale and an overlying "black" shale (Fig. 1.1).

Anoxia can occur in deep water below a permanent pycnocline (Boyce and Carr, 2010), and also in quiet, shallow water that has little sediment influx (Schieber, 1994). There are arguments supporting both ideas, and both shallow and deepwater processes may be important for different types of black shales.

The deepwater model for anoxia is often referred to as the "Black Sea" model because it postulates a deep, restricted, foreland basin somewhat like the modern-day Black Sea (Ettensohn, 2008). One of the challenges of explaining the origins of black shales in deep water is the presence of nonblack shale units like limestones, gray shales, siltstones, and other coarser clastic rocks within the black shale sequence. In the deepwater model applied to the northern Appalachian basin, the deposition of each black shale unit was interpreted to be the result of rapid subsidence in a foreland basin, followed by infilling with shales and coarser clastics sent into the basin from the cyclic nature of mountain building during the Acadian orogeny on the eastern margin (Ettensohn, 2012).

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FIGURE 1.1 Photograph of contact between the black Cleveland Shale and the underlying gray Chagrin Shale in a drill core from Ohio. *Photo by Dan Soeder.*

The thicknesses of the clastic wedges above each black shale were measured to estimate basin depth. Order-of-magnitude water depths in the northern Appalachian basin from this approach ranged from 80 to 310 m (250—1000 ft) during deposition of the thick sequence of Middle Devonian through Early Mississippian organic-rich muds (Ettensohn, 2012). The estimates also show a general deepening of the sea bottom with time, which may have been caused by the cumulative effects of tectonic loading, along with rising Devonian sea levels. These proposed water depths are unusually deep compared to modern epeiric seas, which tend to have depths of less than 100 m. Other researchers have suggested that perhaps a different model is needed (i.e., Arthur and Sageman, 2005).

The shallow-water models were inspired by evidence of fossil skeletal material found in black shales, composed of fragments from echinoderms, bryozoans, brachiopods, and other typically benthic fauna that require oxygen to survive. The presence of these fossil fragments indicates the upper layers of sediment were not permanently anoxic, but possibly just seasonally disoxic (Smith and Leone, 2010). Another problem with a deepwater origin is that many black shale units rest on erosional unconformities at the top of their underlying limestones. The Marcellus Shale, Rhinestreet Shale, Barnett Shale, Haynesville Shale, Woodford Shale, Pierre Shale, and Bakken Shale all onlap unconformities, suggesting that many black shales were deposited during a distal basin margin transgression onto a surface that may have been eroded during a previous sea-level lowstand (Smith and Leone, 2010). Sedimentary facies of the Marcellus Shale exposed on a variety of outcrops in West Virginia indicate relatively shallow water depositional environments with intermittent anoxia, normal-marine salinity, and a fluctuating input of siliciclastic mud (Bruner et al., 2011).

The notion of shallow-water black shales aligns with a seasonal model for anoxia that postulates an early/midspring algal bloom in the water column fed by nutrients released during winter storms (Tyson and Pearson, 1991). Organic matter descended to the seafloor as a "marine snow" later in the spring. Suspended clay minerals were attracted by and surrounded the organic particles, protecting them from being consumed as the "snow" descended to the seafloor. Faster descent times in shallow water also improved the chances that the organics would reach the bottom. The water column would then stratify over the summer. As decay bacteria consumed oxygen, a redox boundary formed at the sediment-water interface, creating anoxic conditions that preserved the remaining organic matter.

In summation, the two main hypotheses for the creation of black shales are not necessarily "deep water" versus "shallow water." Arguing that it must be one or the other misses the point that individual shale formations, like most other rocks, are unique. It may in fact be a case of "deep water" for some black shales and "shallow water" for others, depending on sedimentology, depositional environment, and preservation pathways for organic material incorporated with the sediment.

Source rocks

Organic-rich sediments, like those described above, typically require a number of processes to occur in a specific order for the outcome to be economical deposits of oil and natural gas (Selley, 2014). These consist of the initial burial of the organic-rich source sediment to preserve it and lithify it into a rock. This so-called source rock must then be exposed to elevated temperatures and pressures over geologic time to convert the organic materials into O&G through a process called thermal maturation. The type of fossil fuel that results depends two factors: 1) the source of the organic matter trapped in the sediment and 2) the intensity and duration of the heating process during thermal maturation.

Kerogen types

Organic matter in source rocks commonly occurs as a substance called kerogen, defined as naturally occurring, solid organic material that cannot be extracted from rock using solvents, and yields hydrocarbons upon heating (Law, 1999). During the thermal maturation process, some kerogen converts to bitumen, which is soluble in organic solvents. Bitumen is a thick, tar-like substance that is a precursor to higher grades of petroleum.

Kerogen is formed primarily from dead plant material and comes in three main types (Soeder, 2017). Type I kerogen is derived from the most hydrogen-rich organic matter, consisting of mainly lacustrine algal deposits. It usually forms in stratified lakes, estuaries, and lagoons. The kerogen mass itself is composed primarily of a waxy maceral (the organic equivalent of a mineral) known as alginite, which is readily converted to O&G and rarely remains behind in thermally mature source rocks (Law, 1999). Type I kerogen typically makes petroleum, along with natural gas.

Type II kerogen is mixed marine and terrestrial material characterized by the relatively hydrogen-rich maceral exinite (Law, 1999). It consists of spores and pollen of land plants, leaf and stem cuticles, and marine phytoplankton that contain fatty globules known as lipids. This is an oil-prone material, which typically forms petroleum along with natural gas. When deposited with sediment, both the Type I and II kerogens create an organic-rich bottom ooze known as "sapropel," which is poor in cellulose material but rich in fatty and waxy substances and considered to be a precursor to petroleum (Soeder, 2017). Types I and II kerogens are known as "amorphous," whereas the Types III and IV discussed below are "structured" (Law, 1999).

Type III kerogen is terrestrial in origin and consists of woody or cellulose-rich organic material derived from land plants. Because it is structured, it does not form petroleum but converts to coal and natural gas during thermal maturation. Type III kerogen is not found in rocks older than the Silurian, which is the geologic time period during which the earliest known vascular or woody land plants evolved (Lang and Cookson, 1935). Coal consists of a variety of macerals classified into three major organic groups: vitrinite/huminite, liptinite/exinite, and inertinite, recognized by the morphology, texture, and gray level or reflectance of the material (Chaudhuri, 2016). One of the primary macerals making up Type III kerogen is a black, glassy material known as vitrinite that can be used to assess the thermal maturity, as discussed in the next section.

There is also a less common Type IV kerogen known as inertinite that contains no hydrogen and generates no hydrocarbons. It consists of materials like charcoal or wood ash that were deposited with the sediment. The sources of organic input to the sediment, especially in cases with mixed terrestrial and marine kerogen, can often be determined through stable isotope analysis of the associated inorganic minerals (Chen et al., 2015).

The source of kerogen is important for O&G resource development. Rocks containing predominantly Type III (woody) kerogen are not going to generate much petroleum, no matter how favorable the thermal maturation. On the other hand, both Type I and Type II kerogens will generate petroleum, although the Type II (mixed algal) is often considered more favorable.

It is important to note that all three kerogen types will generate natural gas, which can be found in coal seams, oil reservoirs, and by itself in the subsurface. Gas found with oil is known as "associated gas," whereas gas by itself is "nonassociated." Gas in coal is known as "coalbed methane" and greatly feared by underground miners because of its explosive potential. Natural gas buildup in air in a confined space like a mine will form a highly flammable mixture at concentrations between 5% and 15%.

Until about a decade ago, organic-rich shales were classified simply as "source rocks" for petroleum generation. It was assumed that oil created in the source rock would have found a path to migrate upward into a more porous and permeable reservoir rock, to be trapped by a structural fold or against a fault, and held in place by an impervious caprock. And indeed, historically, this was how all oil and gas had been produced until the shale gas and tight oil revolution. When operators learned how to produce hydrocarbons directly from the shale, the source rock became the reservoir rock. Shales are known as "continuous resources," because O&G can be produced from virtually the entire formation without the need of a trap or a seal.

Thermal maturity

As sediments are buried by younger deposits coming in on top of them, geothermal heat and overburden pressure increase with depth, driving the thermal maturity process (Law, 1999). In the absence of oxygen, and over geologic time periods, heat and pressure gradually transform sapropel into a substance called humin, and then into kerogen. With continued heating, the kerogen transforms into tar-like bitumen, and then into oil and gas.

Natural gas can be generated two ways in the subsurface. Biogenic gas is primarily pure methane given off by anaerobic microbes as a metabolic waste product from the digestion of organic matter in the sediment at low temperatures. As the rock reaches higher temperatures, thermogenic gas is created as complex hydrocarbons break down chemically into simpler methane. Thermogenic gas typically contains traces of some heavier hydrocarbons, such as ethane, butane, propane, etc., while biogenic gas does not. They can also be distinguished isotopically.

Vitrinite becomes more reflective at higher degrees of thermal maturity and the reflectance of this material can be used in a well-established, empirical correlation to determine the thermal maturity of the rock (Law, 1999). Vitrinite reflectance, expressed as %Ro is a measure of the percentage of incident light reflected from a statistically meaningful sample of vitrinite particles in a polished section of sedimentary rock. Vitrinite reflectance is ranked from 0 for immature to 2.5 for overmature. Thermal maturity is commonly expressed as a mean Ro value based on all the valid measurements in a specific sample.

The critical value for thermal maturity is the maximum temperature that had been reached during the burial process for releasing hydrocarbons from kerogen, known as Tmax. In most sedimentary rocks, this generally ranges from about 400 to 500°C (Tissot et al., 1987). Knowing the Tmax, TOC, and kerogen types in a source rock are needed to assess the petroleum-generating capacity of the formation.

An alternative method for measuring thermal maturity is known as the "Conodont Alteration Index," or CAI (Epstein et al., 1977). Conodonts are small, tooth-like fossils from a little-known, eel-like animal (Briggs et al., 1983). Their color ranges from pale yellow to black, depending on Tmax. The CAI ranks the color alteration to an index for “organic metamorphism” where higher values of Tmax drive off more hydrogen and move organic source material toward a composition of nearly pure, nonvolatile carbon (Epstein et al., 1977).

In the absence of vitrinite and conodonts, a third alternative for assessment of thermal maturity is bitumen reflectance (Ebel et al., 2015). Bitumen is not as reflective as vitrinite, and there is not a direct correlation between bitumen reflectance values and Tmax. As such, an empirical correlation has been developed to relate bitumen reflectance to vitrinite reflectance, and Tmax is then determined from the Ro values (Ebel et al., 2015). In older rocks like the Utica shale that predate the appearance of land plants, bitumen reflectance may be the only option.

Pyrolysis

The hydrocarbon generation potential of a source rock can be assessed using a controlled heating process called pyrolysis. There are two variations of this technique called “Rock-Eval” and “Source Rock Analysis” or SRA. Both operate in a similar manner, except SRA provides a TOC value along with thermal parameters. In Rock Eval, the TOC must be measured separately.

Pyrolysis works by placing pulverized and sieved samples into small crucibles, covered with a screened cap and loaded one by one into the analysis oven. The samples are heated by hydrogen combustion in a controlled manner to reach temperatures as high as 600°C. Hydrocarbons begin to volatilize out of the samples at 300°C and the vapors are carried by a helium gas stream into a flame ionization detector (FID) for analysis (Soeder et al., 2017). This technique was used traditionally to identify the kerogen type and thermal maturity of organic matter in source rocks to assess the petroleum potential of an area. Pyrolysis is increasingly being applied on shale gas formations to assess gas-in-place, resource quality, and estimated ultimate recovery of hydrocarbons in unconventional reservoirs.

The output data from SRA can be interpreted to evaluate total organic carbon content, kerogen type and quality, thermal maturity, oil versus gas potential, and organic facies. The measurements are identified as S1, S2, S3, Tmax, and TOC and indicate the following:

- S1 = the amount of free hydrocarbons (gas and oil) in the sample
- S2 = the amount of hydrocarbons generated through thermal cracking of nonvolatile organic matter (kerogen)
- S3 = the amount of CO_2 produced during pyrolysis of kerogen (oxidation)
- Tmax = the temperature at which the maximum release of hydrocarbons from cracking of kerogen occurs (top of S2 peak)
- TOC = indicator of organic richness from total organic carbon content

The data can be displayed and assessed in a number of different ways. The most common technique is to plot the hydrogen index of the sample, derived from the S2 peak divided by the TOC, against the Tmax value. Because the different kerogen types contain different amounts of hydrogen, each type plots in a different location on the graph and follows a different path to maturity as the Tmax increases (Fig. 1.2).

In the immature window, all three types of kerogen produce biogenic gas, created by microbial and organic processes. The mature window produces petroleum from Type I and Type II. The postmature window is a phase transition where the long oil molecules crack to shorter hydrocarbons like propane. Eventually, maturity reaches the "dry" gas window where virtually all the hydrocarbons have been cracked to methane, the simplest compound.

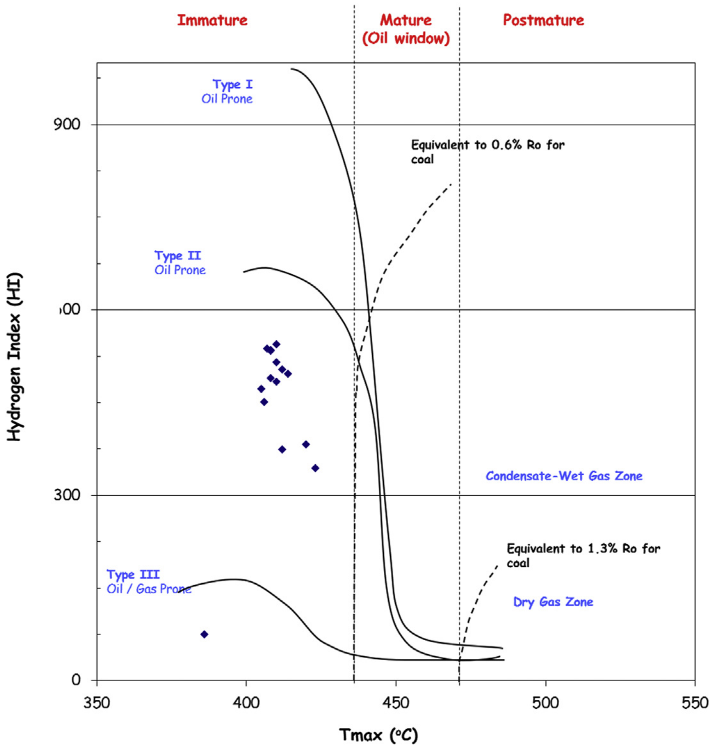

FIGURE 1.2 Rock-Eval plot of hydrogen index versus Tmax showing different areas of the graph occupied by different types of kerogen. The samples plotted are from the Niobrara Formation in South Dakota and indicate immature Type II kerogen with a bit of Type III. *Modified from Soeder, D.J., Wonnell, C.S., Cross-Najafi, I., Marzolf, K., Freye, A., Sawyer, J.F., 2017. Assessment of Gas Potential in the Niobrara Formation, Rosebud Reservation, South Dakota; NETL-TRS-1-2017; NETL Technical Report Series; U.S. Department of Energy, National Energy Technology Laboratory, Morgantown, WV, 152 p.*

Type III kerogen transitions from brown lignite coal to subbituminous and then bituminous coal through this same maturity range and produces gas. Very highest maturity coal (anthracite) is created at Tmax values well above those for petroleum. The most common "quick check" method for oil-prone versus gas-prone kerogen is known as a van Krevelen plot, or more precisely, a modified van Krevelen plot that uses Rock-Eval data (Fig. 1.3).

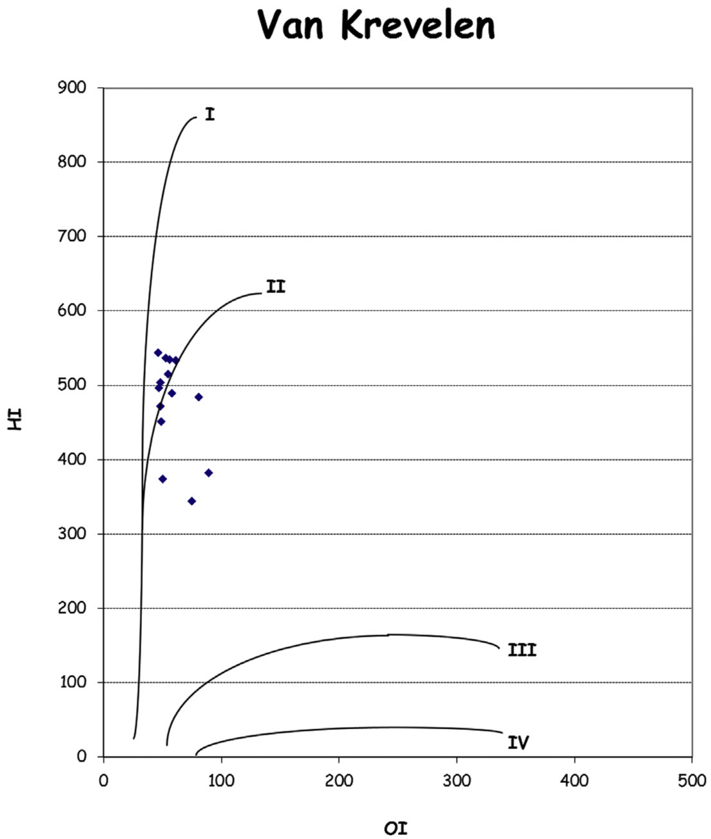

FIGURE 1.3 Van Krevelen diagram of hydrogen index (HI) versus oxygen index (OI) from Rock-Eval pyrolysis data. Type I and Type II kerogens (oil and gas prone) are readily distinguishable from Type III kerogen (coaly, gas prone) and the inert Type IV. Data from the Niobrara Formation in South Dakota. *Modified from Soeder, D.J., Wonnell, C.S., Cross-Najafi, I., Marzolf, K., Freye, A., Sawyer, J.F., 2017. Assessment of Gas Potential in the Niobrara Formation, Rosebud Reservation, South Dakota; NETL-TRS-1-2017; NETL Technical Report Series; U.S. Department of Energy, National Energy Technology Laboratory, Morgantown, WV, 152 p.*

Dirk van Krevelen (1961) was a Dutch coal scientist who assessed the thermal maturity of coal in the 1950s by plotting carbon/oxygen ratios against carbon/hydrogen ratios. He found both the hydrogen and oxygen contents associated with carbon decreased as the coal matured, leaving essentially pure carbon as the composition of the most highly mature coals. In the 1970s, Bernard Tissot modified the van Krevelen diagram to plot "oxygen index" against "hydrogen index" for petroleum source rocks. This enabled the use of the Rock-Eval data to quickly assess kerogen type and thermal maturity (Tissot and Welte, 1984).

The amount of hydrocarbons generated within black shale is related to a geological standard called the source-rock quality. This is assessed from total organic carbon, type of organic matter, and thermal maturity and rated poor, fair, good, excellent, or exceptional (Bruner and Smosna, 2011). Conditions such as burial history and thermal maturity that are favorable for the transformation of organic matter into oil or gas are called the relative oil or gas potential. A rock may have excellent source-rock quality, but if it has not been properly "cooked," it will have a low relative oil or gas potential and not be very productive. The gas content of the rock is known as gas-in-place (GIP), and petroleum is known as oil-in-place (OIP). This is calculated from the geographic extent and stratigraphic thickness of the rock unit, combined with the source-rock quality and relative hydrocarbon potential (Bruner and Smosna, 2011). Where oil has migrated out of the source rock and been trapped in conventional reservoirs, another calculation called original-oil-in-place (OOIP) attempts to add this back in to the OIP remaining in the source rock to determine total source rock potential. OIP or GIP are sufficient for unconventional production directly from the oil or gas source rock. In cases where nearly all of the OOIP has migrated out of the source rock, the shale is said to be "spent."

The amount of O&G that can be physically recovered from a subsurface reservoir is known as the estimated ultimate recovery, or EUR. This value is critically important to oil and gas operators because it determines how much revenue a well will provide during its lifetime. The EUR is also a number of high interest to potential investors.

Oil and gas are never recovered from the ground with 100% efficiency, and some is always left behind. The percentage of the GIP or OIP that can be recovered using current production technology is known as the recovery efficiency. For conventional oil and gas resources in reasonably permeable reservoirs, primary recovery efficiencies are generally around 50%. Secondary recovery methods using waterfloods or CO_2 injection will often mobilize an additional percentage of the remaining OIP. This process is known as enhanced oil recovery, or EOR. Secondary gas recovery can also be done, but requires high gas prices to be economical.

Unconventional resources tend to have significantly lower EURs than conventional O&G reservoirs, with recovery efficiencies on the order of 10% for gas shales and only about 6% for tight oil resources. Many of the current research efforts in shale gas and tight oil are focused on improving these recovery efficiencies.

There is an optimum Tmax or "peak" for petroleum generation. Typical thresholds for hydrocarbon generation events are biogenic gas generation at Tmax below 436°C and Ro $<$ 0.6; onset of petroleum generation at Tmax of 436–440°C and Ro $=$ 0.6 to 0.7; peak petroleum generation at Tmax $=$ 445–455°C and Ro $=$ 0.8 to 1.1; postpeak petroleum generation at Tmax $=$ 456–495°C and Ro $=$ 0.9 to 1.7; oil cracking/wet gas stage at Tmax $=$ 450–500°C and Ro $=$ 1.0 to 2.0; and wet gas cracking/dry gas stage at Tmax $>$500°C and Ro $>$ 1.9 (Tissot et al., 1987; Bordenave, 1993; Thul, 2012).

Thus, the thermal maturation sequence for source rocks with Type I and Type II kerogens is biogenic gas, petroleum, peak oil, oil cracking to wet gas, and wet gas cracking to dry gas. Because black shales contain hydrocarbons across the breadth of the formation, many individual shale units have different levels of thermal maturity depending on location in the basin. At the greatest burial depth in the basin center, shale might be in the dry gas stage. Toward the basin margins, shales tend to be less mature because of shallower burial depths and may contain wet gas/condensate or petroleum. These distinctions are important to producers, because petroleum is worth considerably more money than dry gas, but it can also plug pores and prevent the mobilization of lighter hydrocarbons. The components of condensate like butane, ethane, propane, pentane, etc., are valuable chemical feedstocks or specialty fuels.

In addition to determining the onset of petroleum and natural gas generation from kerogen, thermal maturity can also be used to assess the burial history of sedimentary rocks in a basin. An assessment of erosion in the Appalachian basin carried out by Rowan (2006) used thermal maturity data to conclude that 2–3 km (7000–10,000 ft) of formerly overlying sedimentary rocks have been removed from the present-day land surface. This suggests that the modern, modest ridges of the Appalachians, which rise to an average height of 3000 ft (1000 m) above sea level, were once lofty mountains with heights of 10,000 to 13,000 ft (3–4 km). These types of analyses are important because they explain why the Marcellus Shale, at a depth 5000 to 8000 ft (1.5–2 km) throughout much of the Appalachian basin, has a high thermal maturity placing it in the dry gas range. The addition of 2–3 km of now-missing rocks suggest that significant parts of the formation may have been buried as deeply as 11,000 to 18,000 ft (3.5–5.5 km), where it was exposed to elevated pressures and temperatures for millions of years (Rowan, 2006).

Because different macerals are altered by heat and pressure at different rates, thermal maturity studies also can be used to tease out details of the burial history of a rock formation. The Middle Devonian Marcellus Shale in western New York was initially buried quite rapidly beneath a thick sequence of younger Upper Devonian and Mississippian sediments deposited into the Catskill Delta, which may have been as much as 12,000 ft (4 km) thick (Milici and Swezey, 2015). The remnants of this delta now form the Catskill Mountains of New York (Schwietering, 1979). During the Pennsylvanian Period and into the Permian, the shale sequence was uplifted by the mountain building of the Allegheny orogeny and some of the delta sediments were subsequently eroded. Once the higher mountains to the east began weathering and eroding more rapidly, the shales were quickly buried again in the late Permian and Triassic periods beneath more sediment. This was followed by steady uplift and erosion to the present time (Lash, 2008).

Conventional oil and gas resources

Prior to the economic development of US shale gas and tight oil in the first decade of the 21st century, virtually all of the O&G produced in the world came from conventional reservoirs. While some may argue that methane from coal seams and gas from tight sandstones made important contributions, these were in fact relatively minor during the 20th century compared to conventional resources. It wasn't until around 2010 that hydrocarbon production from shales began to outpace conventional oil and gas wells (Fig. 1.4).

So what is a "conventional" oil and gas resource and how does it differ from an "unconventional" resource? The answer is both simple and complicated. The simple answer is that a conventional resource will produce economical amounts of O&G from a vertical well with standard completion techniques and minimal stimulation. Unconventional resources, on the other hand, require special reservoir engineering processes like horizontal drilling and hydraulic fracturing to produce economical amounts of hydrocarbons (Soeder, 2017). The more complex answer is that conventional resources are produced from high porosity, high permeability reservoir rocks where the hydrocarbons have migrated from the source rock and become trapped. An unconventional resource is produced directly from the source rock itself.

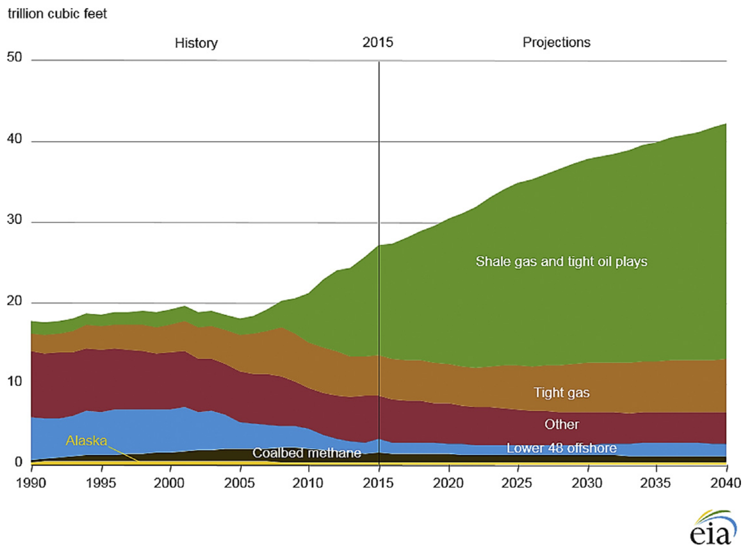

FIGURE 1.4 Production trends of conventional versus unconventional natural gas in the United States. *Modified from U.S. Energy Information Administration, August 2016. Annual Energy Outlook 2016 with Projections to 2040: Report DOE/EIA-0383, 256 p.*

Reservoir rock

Conventional reservoirs are generally composed of rocks derived from relatively coarse-grained sediment and are not the source rocks for the hydrocarbons. The larger grain sizes typically result in larger pore sizes (compare the spaces between a tub of golf balls vs. a tub of bowling balls, for example), and large pore sizes tend to be much more permeable than small pores. Conventional O&G reservoirs consist of two broad types of sedimentary rocks: sandstone or limestone (Selley, 2014). Both come in a wide variety of lithologic variations, from fine to coarse-grained, thinly laminated to massively bedded, and containing original porosity, secondary porosity, or some combination of both. What they all have in common as productive reservoirs is that they contain a sufficient degree of porosity to hold economical amounts of O&G in the pore system and they exhibit sufficient permeability for the O&G to be produced from a vertical well with standard completion techniques.

As discussed previously, source rocks generally form in quiet water, low-energy depositional environments that allow tiny clumps of organic matter to settle out of the water column along with very small sediment particles. The fine-grained sedimentary rocks that result from such deposits contain tiny pores, low permeability, and do not make very good reservoirs. Coarse-grained sediment requires fast-moving water for transport and the high energy depositional environments that favor porous and permeable reservoir rocks are not favorable for source rocks and vice versa. Thus, in conventional O&G reservoirs, the source rock and the reservoir rock are typically completely different geological formations.

Trap and seal

The porous and permeable reservoir rock requires a trap and a seal. Without these two components, any O&G that migrated into the rock from a source rock would just keep going. Traps tend to be structural or stratigraphic in nature, with many variations on details (Selley, 2014). A structural fold, dome, or the offset of stratigraphic units across a fault are common examples of structural traps. A typical stratigraphic trap might be the pinch out of a sandstone unit beneath shale. Since its origins in the early 20th century, the science of petroleum geology has expended a great deal of effort toward locating these traps.

The seal is the containment layer or “caprock” that holds the O&G in the trap. Seals are typically impermeable rock units that overlie the reservoir rock, such as shale, anhydrite/gypsum, salt deposits, etc. Maintaining the integrity of the seal is important when developing a conventional O&G reservoir, as a breach could result in unwanted hydrocarbon migration.

Migration path

Because the source rock and reservoir rock in conventional O&G resources are typically completely separate geologic formations, the final component needed for a conventional O&G reservoir is a migration pathway for the hydrocarbons to move from the source rock into the reservoir rock. These pathways often consist of permeable strata above a source rock that allow the hydrocarbons to migrate updip and fill a structural trap, as illustrated by the sandstone unit above the shale in Fig. 1.5. An updip pinch-out of a sandstone body against an overlying, impermeable shale formation could also provide a migration pathway into a trap. Less common is migration along natural fracture systems, such as faults or joints, to fill a trap.

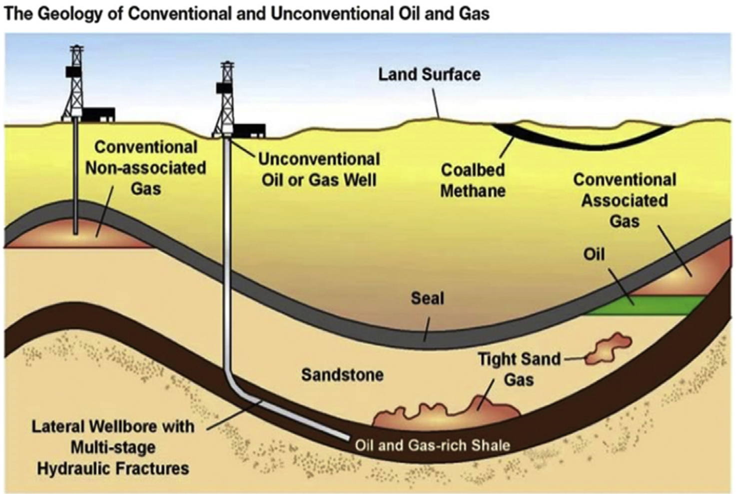

FIGURE 1.5 Illustration of unconventional hydrocarbons being produced directly from the shale source rock versus conventional oil and gas that migrated into permeable, porous rock and was trapped by structure or stratigraphy. Modified from *U.S. Energy Information Administration, August 2016. Annual Energy Outlook 2016 with Projections to 2040: Report DOE/EIA-0383, 256 p.*

Conventional O&G reservoirs require a complex series of events and processes to happen with the correct timing and in the proper order to achieve an economical accumulation of producible hydrocarbons. These are 1) organic-rich source rock, 2) proper thermal maturity, 3) reservoir rock, 4) trap and seal, and 5) migration pathway. If any of these occur in the wrong order, or with improper timing, the result will be an empty reservoir. Unconventional reservoirs, on the other hand, produce directly from the thermally mature source rock and do not require the other components (Fig. 1.5). Considering what is involved in the creation of conventional O&G reservoirs and the challenges posed by trying to locate and produce them, it is amazing to note that nearly all of the oil and gas in the world was produced from conventional resources up until the second decade of the 21st century.

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2

Unconventional tight oil and shale gas resources

The nature of continuous resource plays

Shale gas and tight oil are known as "unconventional" resources (Soeder, 2017). Unlike the complicated process described in the previous chapter for creating conventional oil and gas reservoirs, the hydrocarbons present in shales were created in-place from organic material deposited with the sediment. Thus, the black shale itself acts as both the source rock and the reservoir rock, allowing nearly the entire volume of a shale geological formation to potentially serve as an unconventional reservoir. As such, black shales are described by the US Geological Survey (USGS) as "continuous resources" because they tend to be productive from nearly everywhere without the need for traps and seals (Charpentier and Cook, 2011).

Petroleum geologists spent many decades and billions of dollars trying to locate conventional reservoir traps and seals, which was often scientifically challenging and very expensive. A great deal of advanced technology in geophysics including seismic tomography, inversion analysis, electromagnetics, and microgravity surveys were invented to find structural and stratigraphic traps. The search for conventional reservoirs also led to the development of new geologic concepts like sequence stratigraphy, sedimentary facies, geochemical prospecting, basin analysis, and others. Even with all this tech, there was never any guarantee that oil and gas would actually be found. Exploration geologists have a saying that despite all the fancy technology, you never really know what's down there until you get down there, and the only way to get down there is to drill.

The idea that shale resources might produce some level of hydrocarbons from virtually anywhere in the formation is a new concept in petroleum geology and not all petroleum geologists have adapted to it (Charpentier and Cook, 2011). Understanding that the former source rock is now the reservoir rock has been difficult for a few, and many are reluctant to give up long-cherished concepts of petroleum geology and prospecting to embrace this new paradigm. For those who have, most of the focus in petroleum geology these days is to find "sweet spots" within the shale resource plays. Varying levels of thermal maturity in these formations across a basin can result in less mature areas that produce desirable natural gas liquids and more mature areas that

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produce only dry gas. Locating the more productive sweet spots in shale hydrocarbon plays, preferably before competitors find them and lease up the area, is the newest challenge being faced by petroleum geologists.

An interesting anecdotal observation from a number of mining geologists is that the exploration for O&G resources in shale appears to be more similar to mining than to traditional petroleum geology. In mining geology, ore deposits resemble shale in that they are typically continuous resources across broad areas that vary in richness. There is usually a “core” area that would be equivalent to a shale sweet spot, with richness falling off away from the core. The boundaries of the ore body itself are defined by the concentration of the mineral and the cost of recovery, which becomes less economical at greater depths and lower concentrations. The “edge” of the recoverable ore is controlled by the price of the commodity – where the cost of the ore recovery exceeds this threshold, it won’t be mined. As commodity prices increase or decrease, the boundaries of the ore body expand or contract. This is also true to some extent for shale gas and tight oil, although other considerations like maintaining a lease or meeting a pipeline quota may influence drilling and production. Nevertheless, thinking about unconventional hydrocarbons like ore seems to make a lot of sense, especially given the economics of recovery and the volatility of oil and gas prices.

In petroleum engineering, the term “unconventional” has a slightly different meaning from the petroleum geology definition of continuous hydrocarbon resources. To an engineer, unconventional reservoirs are not capable of producing economical amounts of O&G using traditional methods of vertical well drilling and completion. Advanced engineering and enhancement with some type of reservoir stimulation technology such as hydraulic fracturing are required to recover the resource (Soeder, 2017). The commercial development of unconventional O&G required persistent trial-and-error tests of a variety of well configurations and stimulation technologies before the right combination was finally found. The history of this will be described in the next section.

The volumes of hydrocarbon resources in shale and other fine-grained rocks are huge. Bruner and Smosna (2011) collected estimates on the amount of recoverable gas in the Marcellus Shale from a number of different authors. An early estimate by Engelder and Lash (2008) asserted that the Marcellus Shale GIP exceeds 500 trillion cubic feet (TCF; one TCF equals about 28.3 billion cubic meters) over an area encompassing parts of New York, Pennsylvania, West Virginia, and Ohio. With a technically recoverable gas fraction assumed at 10% of the GIP, the Marcellus Shale alone could contain reserves of 50 TCF of producible gas. This caused quite a stir at the time, because 50 TCF of gas was more than double the annual consumption of natural gas in the United States.

Conservative assessments by the USGS concluded that about 85 TCF would be recoverable from the Marcellus Shale (Coleman et al., 2011). A longer history of production data from the Marcellus has indicated that the reserve estimates by

Engelder and Lash (2008) and the USGS are far too low. More refined calculations by Engelder (2009) based on better initial production (IP) data from newly completed Marcellus Shale gas wells caused him to revise estimates for the GIP to significantly higher values. Assuming a power-law decline rate, 80-acre well spacing, and 50-year well life, Engelder (2009) predicted a 50% probability that the Marcellus Shale will ultimately yield 489 TCF of gas. This was nearly 2 decades of consumption for the entire United States at the time of the estimate.

Even more astounding are the recent estimates done for the Utica Shale as part of a research consortium investigation of this formation. This formation has lower average organic content than the Marcellus but is about twice as deep, resulting in higher-pressure gas. The West Virginia Geologic and Economic Survey used USGS methods to determine that recoverable hydrocarbon reserves in the Utica Shale are in the range of 750–800 TCF at the 50% probability level (Hohn et al., 2015).

These estimates are built on many assumptions about the formation geology, organic content, gas generating potential, GIP, and EUR, and all have a high-level of uncertainty (Bruner and Smosna, 2011). The only truly firm conclusion that can be reached is that an improved understanding is needed of the processes that generate and store hydrocarbons in the shale. Still, it is clear from even the most conservative estimates that shale reservoirs contain significantly more oil and gas than many of the largest conventional reservoirs.

Why is this so? It has to do with the way natural resources are distributed. When resource quantity is plotted against resource quality, most natural resources are found to be distributed in what is known as a "resource triangle" (Fig. 2.1). Simply put, the highest-quality resource typically occurs in the smallest amounts, with significantly greater volumes becoming available as the quality decreases. A good example is spring water and seawater. Spring water is very high in quality but exists in limited amounts. In contrast, seawater is abundant but undrinkable. Until about 10 years ago, virtually all the petroleum and natural gas in the world was like spring water, being produced from conventional resources at the top of the triangle. The technology employed to successfully develop unconventional oil and gas was equivalent to making seawater drinkable at the cost of spring water. All of a sudden, there is a lot more water.

The ability to economically tap into lower-grade resources farther down the triangle almost always expands the resource availability. This has happened with other commodities like iron, coal, gold, and timber, to name a few. For example, before the Second World War, iron ore was primarily mined in the United States from concentrated deposits of the iron oxide hematite located along veins and fractures within the Precambrian banded iron formations (BIFs) of Michigan, Wisconsin, and Minnesota. The high volumes of steel production during the war depleted these concentrated iron ore reserves and left the economy of this region in tatters (Davis, 1964).

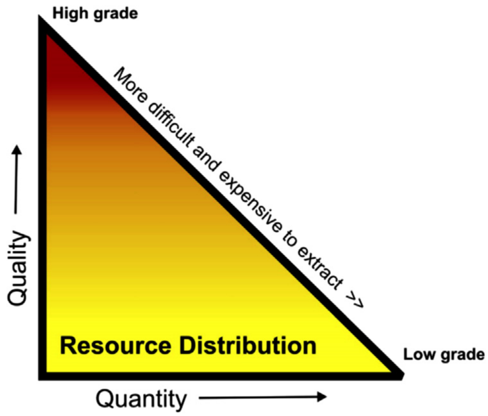

FIGURE 2.1 The resource triangle illustrating the distribution of most natural resources, including hydrocarbons, when quantity is plotted against quality. *Modified from Soeder, D.J., 2012. Shale gas development in the United States. In: Al-Megren, H.A. (Ed.), Advances in Natural Gas Technology. InTech, Rijeka, Croatia, p. 542.*

The hematite veins hosted within the BIF typically have an iron content of 50%–60%. The bulk composition of the BIF itself consists largely of silica interlaminated with another oxide of iron, magnetite (20%–30% iron content). Magnetite was not considered a good ore and the bulk of the BIF had been treated historically by the iron miners as overburden or a waste product. Nevertheless, it was still full of iron and a technology to mine the BIF directly was developed in the early 20th century at the University of Minnesota (Davis, 1964). This new process separated out the silica and concentrated the magnetite into an easy to handle, pelleted ore product called "taconite." It was thought to be too expensive by the mining industry.

With the demand for steel rising in the 1950s, as postwar consumers sought automobiles and appliances, iron ore prices also increased, making the University of Minnesota technology more economically attractive. The taconite process was implemented commercially in 1955, with the first ore production in 1956 (Davis, 1964). Railroads, lake freighters, and steel mills immediately found the uniform, round ore pellets much easier to deal with than the older, randomly sized chunks of hematite. Huge new reserves of iron ore became available and taconite is now used almost exclusively for steel production in the United States.

Unconventional O&G development has followed a similar path (Ambrose et al., 2008). Like the taconite example above, a convergence of both technology and economics was required for shale hydrocarbon resources to compete successfully with conventional O&G production. By the early years of the 21st century, natural gas distributors were facing impending supply shortages and price hikes in the United States (Soeder, 2017). Conventional gas fields in the Gulf Coast that had been producing for decades were in decline and watering out. No significant new conventional resources of natural gas had been found in North America, except for some prospects on the Mackenzie Delta in the distant Canadian Arctic. Several cryogenic terminals were constructed on the US East

Coast to import liquefied natural gas (LNG) from overseas, where one of the primary suppliers would have been Algeria. The gas shortages, both real and anticipated, had driven natural gas wellhead prices to historic highs of nearly $11 per thousand cubic feet (MCF) (1 MCF = 28.32 cubic meters). The economics had become favorable for the vast, low-grade resources of shale gas.

Some visionary thinking and new technology were still required to bring shale gas to market. Numerous trial-and-error field tests and other reservoir stimulation studies funded by the Department of Energy (DOE) on Eastern Devonian shales during the Eastern Gas Shales Project (EGSP) of the 1980s delivered inconsistent results where certain techniques worked on some wells but not on others and some didn't work at all. No one truly understood why (Horton, 1981).

It was George Mitchell of Mitchell Energy who hit upon the combination of advanced deepwater directional drilling technology and a half-century old reservoir stimulation technique known as hydraulic fracturing to develop the most effective procedure for producing substantial quantities of O&G from shale. Mitchell knew that horizontal wells in shale, called laterals, would contact a much greater volume of the formation than vertical wells. This is because black shales at best are usually less than 100 m (300 ft) thick, yet can extend hundreds of kilometers across a basin. The contact that vertical wells make with the formation is controlled by the thickness. Laterals, on the other hand, can stay within the shale for whatever length of borehole the driller is capable of drilling, making contact with an enormous volume of reservoir rock.

The current record-holder for a lateral is the Outlaw C11 H well, drilled by Eclipse Resources in the Utica Shale in Ohio (Beims, 2016). According to a June 16, 2017 company news release, this well has a lateral length of approximately 19,500 ft (5944 m) with a total borehole length from the surface to the toe of the lateral of about 27,750 ft (8458 m).

Horizontal wells have also allowed for the creation of multiple hydraulic fractures in "stages" or zones along the length of the lateral versus the single fractures typically produced in two directions from a single zone in vertical wells. Many of the EGSP stimulation failures appear in retrospect to have been caused by the failure of vertical boreholes and single stage fracks to contact enough rock to produce sufficient amounts of gas.

Although the process of shale gas development may sound simple and straightforward in this narrative, readers are reminded that it required a protracted engineering struggle over a period of nearly 18 years before George Mitchell finally found the right combination of technology for economically viable shale hydrocarbon production (Kinley et al., 2008). His persistence was what ultimately led to the shale gas revolution in the United States.

The challenges of development

The first commercial American gas well was hand-dug into a black shale in 1821 (Curtis, 2002), and there is a historical understanding that organic-rich shales often contain natural gas. Nevertheless, these resources also have been largely misunderstood for half a century. The main conventional field that has produced commercial quantities of gas from shale is the Big Sandy Field in Kentucky. This field was adopted and utilized by the DOE as the conceptual model for the design of the Eastern Gas Shales Project but we now understand that it is NOT representative of most other gas shales.

Natural gas has been produced at Big Sandy since 1921 from the "upper Devonian bituminous shale," and even in the 1950s, this production was known to be from fracture systems "provided by joints, fractures, and to a less extent, bedding planes" (Hunter and Young, 1953). The productive "bituminous" or black shale formation at Big Sandy, now identified as the Huron Member of the Ohio Shale, is draped against the Cincinnati arch, which was present as a physiographic and structural feature during the Upper Devonian period (Thomas, 1951). Geologists in the 1950s assumed that shale gas in the Big Sandy Field was produced from interbedded silts and sands deposited within the shale because the shale itself "lacked the necessary porosity and permeability" to produce gas (Thomas, 1951).

There was also a misunderstanding back then that by the time the organic-rich muds became lithified and brittle enough to fracture, the hydrocarbons would be forever locked inside the rock as kerogen and unable to migrate (Thomas, 1951). However, we now know that hydrocarbons derived from kerogen can remain mobile within a shale source rock long after the rock has been lithified. Evidence includes postlithification migration to fill a reservoir rock with a trap and seal, and direct production of hydrocarbons from lithified shales.

Thomas (1951) noted that reservoir pressures from multiple wells in the Big Sandy Field were often found to decline simultaneously, even in wells that were not being produced. Pressures also slowly rebounded when the producing wells were shut in. The current understanding of such behavior links it to highly interconnected fracture systems that rapidly transmit pressure and slowly recharge with gas from the black shale matrix. Although the matrix permeability of shale is quite low, it is not zero as postulated by Thomas (1951).

When Hunter and Young (1953) looked at production from the Big Sandy Field a few years later, they described a dual-porosity, fractured unconventional reservoir, even though those exact words were not used. Although they agreed with Thomas (1951) that most of the shale porosity was in sandy and silty zones, they also credited joints, fractures, and bedding planes as the source of commercial production.

The structure of the Cincinnati arch and the overburden that accumulated on top of the Huron Shale compacted the rock unit in a special way and created an extensive network of natural fractures at Big Sandy. These types and quantities of fractures are not common elsewhere in Appalachian basin shales or in most shale in other basins. The unique fracture system at Big Sandy allowed the shale to produce open-hole flows from vertical wells averaging about half an MCF per day after the shale zone had been shot with a gelled nitroglycerine explosive (Hunter and Young, 1953). Many of the vertical shale wells at Big Sandy were reported to have very small gas shows or no gas shows at all when being drilled, yet produced significant gas flows after stimulation with explosives (Hunter and Young, 1953).

It is important to note that even back in 1953 geologists recognized that some sort of reservoir stimulation was necessary to establish gas production out of shale, even highly fractured shale like the Huron at Big Sandy. However, stimulation with high explosives is inefficient – most of the energy from the shock wave is expended by shattering the rock close to the wellbore. Hydraulic fracturing is far more effective because it uses a slower pressure rise to create long cracks that run deep into the formation.

Reviewing these 1950s assessments from the perspective of the modern shale gas revolution, it is clear that geologists back then had correctly identified all the necessary components of a productive gas shale: organic-rich source rock, thermal maturity, and a closely spaced fracture network to collect hydrocarbons from the ultralow-permeability shale matrix and transport them to a wellbore. With a better understanding of the ways in which these various components interact, the shale gas revolution might have happened much earlier.

Under the Eastern Gas Shales Project, the DOE was so engrossed in attempting to identify the next Big Sandy Field that nearly all efforts of the program were focused on finding fractured black shales without understanding exactly what made the Big Sandy Field productive. The driving philosophy of the EGSP program was black shale + fractures = gas, but this narrow focus overlooked many of the complications that we now know exist in gas shales (Soeder, 2017).

For nearly 20 years, the EGSP searched fruitlessly for another gas field just like the Big Sandy, without realizing that in all probability, Big Sandy is one of a kind. Had it not been for economic production from conventional, vertical wells in this field, the successful technique currently in use for shale production (i.e., horizontal wells with staged hydraulic fracturing) might actually have been developed back in the 1980s. One field experiment with a horizontal well was attempted by the DOE in 1986, but the results were problematic, again because the subtleties of shale gas production were not well-understood (Duda et al., 1991). It took George Mitchell's repeated trials on the Barnett Shale in the 1990s to eventually develop the current practice.

Historical context

The historical context for the modern assessment of shale gas as a potentially significant domestic energy resource began in the wake of an oil embargo imposed on the United States in 1973 that led to the so-called "energy crisis." This embargo resulted from one of a series of Middle East wars between a number of Arab countries and Israel.

Variously identified among historians as the Yom Kippur War, the Ramadan War, the 1973 Arab–Israeli War, or the Fourth Arab–Israeli War, hostilities began on October 6, 1973 when Egyptian and Syrian armies invaded Israel (Rabinovich, 2004). Armies from Iraq and Jordan were also involved. This was followed by an Israeli counterattack. The war lasted less than 3 weeks, ending on October 25, 1973 with a United Nations-brokered ceasefire (Rabinovich, 2004).

The United States and the Soviet Union, at the height of their own Cold War tensions, had enlisted the two sides as proxies. The Soviets resupplied and supported Egypt, while the Americans airlifted material and provided intelligence to Israel. Taking sides like this led some Arab members of the Organization of Petroleum Exporting Countries, or OPEC, to question the wisdom of selling oil to the United States. Several members of OPEC, led by Libya, declared at a meeting of oil ministers in Kuwait on October 20, 1973 that they would impose a total embargo on crude oil deliveries to the United States as retribution for supporting Israel (Yergin, 1991).

The OPEC oil embargo had significant and long-lasting effects on the economy, security, and psychology of the United States. After the Second World War, many people had moved out of central cities and into suburban housing, developed in formerly rural areas. These suburbs were often located long distances from cities and were connected to them by another postwar invention, the freeway. The result was that it was virtually impossible to get around in the suburbs without an automobile. Inner city transport options like buses, streetcars, and electric rail lines were simply not available in the suburbs. Pedestrian sidewalks and bicycle paths were often nonexistent. Travel to work, shopping, church, school, and almost everywhere else required the use of a vehicle. Business establishments catering to the automobile, such as drive-in movie theaters, drive-in restaurants, drive-up bank tellers, and others became commonplace. Suburban families, especially those with driving-age children, often owned multiple vehicles.

The energy crisis challenged this suburban lifestyle. People faced the prospect of being stuck in the middle of nowhere with an empty gas tank in a useless car. In 1973, less than half of the crude oil used in the United States was imported and not all the member countries of OPEC had even joined in the embargo. Nevertheless, the reduction in imported oil supplies to America was significant enough to quadruple gasoline prices. To appreciate the shock of this, look at the current price of gasoline at the pump the next time you fill up and multiply by four.

In addition to the price hike, there were severe shortages, consumer panic, and long lines at service stations when fuel was available (Fig. 2.2). The US government even printed up small test batches of official gasoline ration coupons that were never used and are now prized collector's items. Gasoline had been rationed during the Second World War, which few people complained about because of patriotic duty, and a number of localized and brief energy shortages had occurred after the war when demand outpaced supply. However, the significant shortages experienced during the 1973—74 energy crisis created huge concerns among the public and resulted in major changes to the US domestic and foreign policy (Yergin, 1991).

FIGURE 2.2 Vehicles lined up waiting for gasoline during the 1973–74 energy crisis. *David Falconer, U.S. National Archives.*

In the rhetoric of the time, citizens demanded that something be done to prevent America from being "held hostage" to imported oil. The last Apollo moon landing had taken place in 1972, the year before the embargo, and many people expressed a belief that if the United States could land people on the moon, we certainly ought to be able to gas up our cars.

The OPEC oil embargo against the United States lasted from October 1973 until the spring of 1974, when Saudi Arabia and several non-OPEC countries like Mexico and the United Kingdom stepped up production to overcome the shortfall. The US Congress acted in 1975 to ban oil exports from the United States to retain as much domestic oil in the country as possible. This ban remained in effect for 40 years until it was lifted in 2015. A second, smaller energy crisis occurred in 1979, when Iranian oil production was disrupted for several months by the protests and disarray associated with the Islamic revolution. The 1979 crisis was less severe because the United States received only a relatively small amount of imported oil from Iran, and Saudi Arabia and other exporting nations were able to quickly make up the shortages.

The political and economic details of the 1970s energy crisis are far more complicated than any brief explanation can capture. A very long book by Daniel Yergin (1991) provides an in-depth assessment of the complex relationships between oil, money, power, and politics in the era just before the Shale Revolution and is recommended for further reading.

On August 4, 1977, the US DOE was created from a number of smaller energy agencies as a cabinet-level entity of the US government under President Jimmy Carter. James R. Schlesinger was appointed as the first Energy Secretary. Along with inherited duties like running the national labs and maintaining the nation's nuclear weapons stockpile, a primary mission of the new DOE was to find technological solutions to the energy crisis.

Alert readers may notice that the formation of DOE took place more than 3 years after the OPEC oil embargo had ended in 1974. The government tends to be far more reactive than proactive, and this is a typical response time to a crisis. Creating a new, cabinet-level agency is a politically challenging task due to turf issues with existing agencies, especially if any of those agencies have a champion in Congress. After some horse trading and painfully precise definitions of mission statements, Congress was able to roll up multiple existing agencies into the new Energy Department. The US Department of Homeland Security was created in a similar manner on November 25, 2002, more than a year after the 9/11 terrorist attacks.

The US DOE took a two-pronged approach: improving the efficiency of energy currently being used and increasing the domestic energy supply. The agency set out to identify and investigate almost every new potential source of domestic energy under the sun, including the sun itself, and funded projects on solar, wind, geothermal, ocean energy such as waves and tides, oil shales, tar sands, conversion technologies like coal gasification, coal-to-liquids, and gas-to-liquids, and new sources of natural gas. The natural gas research consisted initially of coalbed methane, tight gas sands, methane gas dissolved in deep brines under high pressures (known as geopressured aquifers), and shale gas (Schrider and Wise, 1980). The overall goal of DOE was to produce as much new, additional domestic energy as possible to offset oil imports.

Unconventional hydrocarbon resources currently include tight oil (in shales, limestones, and other low permeability rocks), tight gas sands, shale gas, oil sands and heavy oil, coalbed methane, oil shale (with solid kerogen that must be mined and refined), and methane hydrates (Nash, 2018). There has never been a doubt that the development of any of these resources would be a technical challenge. The DOE approach was very technological and engineering-oriented, with little consideration given to the economics.

In 1975, the Energy Research and Development Administration, a predecessor agency to DOE, had started the Eastern Gas Shales Project (EGSP) as an effort to assess the natural gas resource potential of a sequence of Middle to Upper Devonian black shales in the Appalachian basin, as well as similar rock units in the Michigan and Illinois basins (Soeder, 2017). Under DOE management, the project evolved into three major components: resource characterization, development of production technology, and the transfer of that technology to industry (Cobb and Wilhelm, 1982).

From 1976 to 1982, the EGSP used cooperative agreements with operators to obtain drill cores from Appalachian basin shales ranging from the Upper Devonian Cleveland Shale to the Middle Devonian Marcellus Shale (refer back to Fig. 1.1 for an example of the EGSP core). Interestingly, one of the operators engaged in the EGSP coring in the late 1970s was George Mitchell and Mitchell Energy, who eventually led the Shale Gas Revolution (Soeder, 2017). Cores were also collected from the Devonian Antrim Shale in the Michigan basin and the New Albany Shale in the Illinois basin, for a project total of 44 (Bolyard, 1981). The cores were characterized for lithology, color, orientation of natural fractures, photographed, and scanned with a scintillometer for gamma radiation readings. Rock samples were collected from the cores for the various labs, government agencies, and universities that had requested them. The cores were eventually transferred to the state geological survey in the state where each had been cut.

A series of field-based engineering experiments sought to use induced hydraulic fractures to link with existing natural fracture networks in the shale, creating high-permeability flowpaths into large volumes of rock. Many different stimulation technologies were tried, ranging from water-based fracks to more exotic attempts using cryogenic liquids or kerosene. Results were generally hit-or-miss (Horton, 1981). Transfer of these and other technologies to industry was accomplished by periodic workshops jointly sponsored by DOE and the Society of Petroleum Engineers (now the annual Unconventional Resources Technology Conference, or URTeC). The EGSP was managed by the DOE Morgantown Energy Technology Center (METC) in West Virginia, which has become a campus of the DOE National Energy Technology Laboratory (NETL).

By the time the EGSP formally ended in 1992, a number of cutting edge experiments had been done on shale. Innovative well logging techniques, directional drilling techniques, assessments of reservoir anisotropy, liquid CO_2 fracturing, and other new technologies were tried out on gas shales during the course of the program. These studies greatly assisted industry in the commercial development of shale gas decades later (Soeder, 2017).

Petrophysics

The current prolific hydrocarbon production from shale and other tight rocks often overshadows the truly difficult physics that had to be overcome to commercialize these resources. It is hard to understand just how impermeable organic-rich shale actually is unless one compares it to more conventional reservoir rocks.

Measurements of the ability for a porous rock to transmit fluid were first defined in 1856 by a hydraulic engineer named Henry Darcy, who was working on the municipal water system for Dijon, France (Freeze and Cherry, 1979). Darcy equated the flow of water through the pore system of a rock or sediment with the flow of electrons through metals, and he developed an empirical relationship for “hydraulic conductivity,” as he called it, which was similar in structure to Ohm’s Law for electrical resistance. Darcy’s Law is written as

$$Q = KA(\Delta P/\mu L)$$

where $Q =$ flow in cubic cm per second, $K =$ permeability (darcy or d), $A =$ cross-sectional area in square cm, $\Delta P =$ differential pressure in atmospheres per cm of length, $\mu =$ fluid viscosity in centipoise (cP), and $L =$ flowpath length in cm. To solve for permeability (K) it can be rewritten as

$$K = Q\mu L/A(\Delta P)$$

The basic unit of permeability is called the darcy. It is defined by a specific flow rate when all the other variables are set to fixed values. Thus, a porous medium with a permeability of one darcy will discharge fluid that has a viscosity (μ) of 1 cP (conveniently the viscosity of water at room temperature) from a cross-sectional area (A) of one square centimeter at a rate (Q) of one cubic centimeter per second under a pressure gradient (ΔP) of 1 atm per centimeter of length (L). This is illustrated graphically in Fig. 2.3. The Standard International (SI) unit for permeability is the square meter, or m^2; 1 darcy is equal to about 10^{-12} m^2.

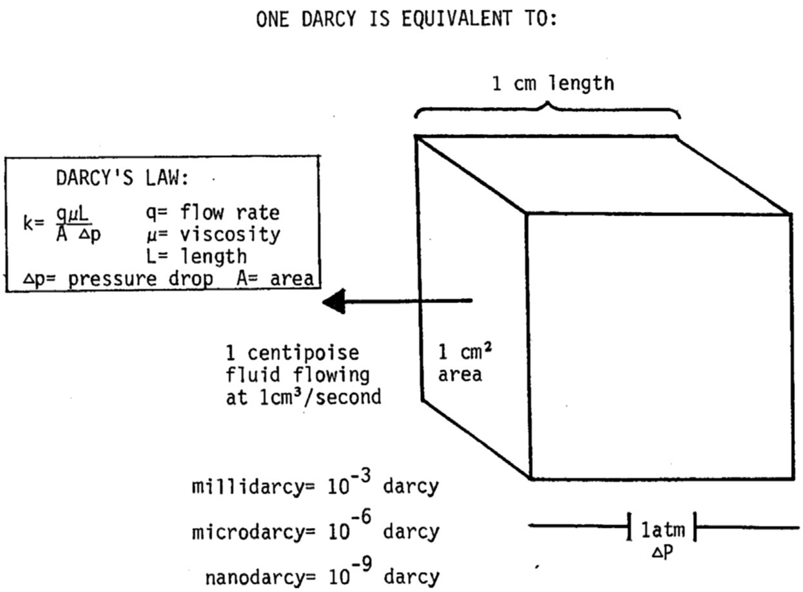

FIGURE 2.3 Visualization of the physical parameters used to define Darcy's law of permeability. *Sketch by Dan Soeder.*

To obtain rock permeability in a lab, one needs to measure the dimensions of the sample, the differential pressure across it, the fluid viscosity, and the discharge flow rate. To determine permeability to gas, A and L are known from the sample dimensions, μ is a known property of the test gas, ΔP is set for the measurement, Q is measured, and K is calculated. To determine permeability to water or another incompressible liquid, A and L are known from the sample dimensions, μ is a known property of the test liquid, Q is set for the measurement (a constant rate of liquid flow can be obtained with a syringe pump), and ΔP is measured to calculate K.

Because Henry Darcy was performing experiments with water flowing through columns of loose sand, the darcy is actually a fairly large permeability unit, and conventional oil and gas reservoir rocks typically have permeabilities a thousand times lower, in the range of 10^{-3} d, or a millidarcy (md). Tight gas sandstone permeabilities are commonly a thousand times lower still, around a microdarcy (μd) or 10^{-6} darcy (Randolph and Soeder, 1986). Shales typically have permeabilities in the nanodarcy (nd) range or 10^{-9} darcy (Civan and Devegowda, 2015). Shales this tight are currently being produced successfully for commercial amounts of O&G. The SI permeability units are generally not used on oil and gas resources because the conversion requires working with extremely small numbers: 1 md is about 10^{-15} m^2, 1 μd is about 10^{-18} m^2, and 1 nd is 10^{-21} m^2. Most researchers consider the darcy to be a more practical unit, especially when expressed as md, μd, or nd (Soeder, 2017).

The technical challenge of oil and gas production from shale can be illustrated with the one cubic centimeter sample shown in Fig. 2.3 sketch. At one darcy of permeability, it will discharge fluid at a rate of 1 cm^3/s. With all other conditions being the same, if the block is replaced with a millidarcy (md) conventional oil and gas reservoir sample, 1 cm^3 of fluid would require 1000 s, or about 17 min to discharge. Substituting a microdarcy (μd) tight gas sandstone will produce 1 cm^3 of fluid in a million seconds, equivalent to roughly 11.5 days. Finally, if we could place a nanodarcy (nd) gas shale in the block, we'd be waiting a billion seconds for 1 cm^3 of fluid, or approximately 32 years. The permeability of nanodarcy gas shale is a million times lower than that of a conventional gas reservoir rock, making the ascent of shales as the dominant source of hydrocarbon production in the United States all the more astonishing.

In the mid-1980s, core analysis measurements were being attempted on low-permeability rocks under a program funded by the DOE at the Institute of Gas Technology (IGT) in Chicago, Illinois (now known as the Gas Technology Institute, or GTI). Laboratory core-testing apparatus had been developed by IGT under a DOE program called Western Tight Gas Sands to accurately measure the porosity, permeability, capillary entry pressure, and pore volume compressibility of low-permeability sandstone samples under net pressure conditions representative of these rocks at depth (Randolph and Soeder, 1986). The core-testing device was designed to provide stable gas reference pressures upstream and downstream of samples by maintaining a closely controlled temperature. Gas was allowed to flow through a sample under steady-state, equilibrium conditions, with the outflow measured by a small differential pressure increase in the downstream line volume compared to the downstream reference pressure. The device could obtain accurate gas flow measurements as low as one standard cubic centimeter (gas at room temperature and atmospheric pressure) per million seconds (Randolph, 1983). It was modified with improved air circulation and a more leak-resistant style of tube fittings to measure shale.

Twenty-eight "zones of interest" were defined in the EGSP cores for IGT shale analysis by DOE project managers on the basis of gas production (or gas shows), correlation with gas-productive intervals in nearby wells, successful stimulation results, or indications of high organic content. These zones represented 10 different stratigraphic horizons within the Middle and Upper Devonian eastern gas shales sequence in the Appalachian basin (Soeder et al., 1986). Over two dozen samples were collected from 13 EGSP wells in Ohio, Kentucky, New York, Pennsylvania, and West Virginia, although only eight of these were actually analyzed in the IGT core-testing apparatus under the DOE project. No one fully understood how long steady-state core analysis would take on gas shale samples.

Six of the core plugs consisted of the Huron Member of the Ohio Shale from several different EGSP wells located in Ohio along the Ohio River and one near the Big Sandy field in southeastern Kentucky. The ongoing interest by DOE in historic shale gas production at Big Sandy resulted in the Huron Shale comprising the majority of samples tested by IGT. As a data check, the seventh plug was a repeat of a Huron Shale sample from one of the Ohio wells. Core number eight was a Marcellus Shale sample from the EGSP WV-6 well in Morgantown, WV (Soeder, 1988). Despite the limited number of samples, there were some interesting results.

The IGT shale core analysis found that the Huron Shale samples had no measurable gas permeability at low to moderate differential pressures. After imposing nearly 90 pounds per square inch differential (psid) pressure or 620 kiloPascals (kPa) across the cores, gas began to flow slowly through the rocks and the flow rate increased gradually for hours before eventually leveling out. This was interpreted to be a gas relative permeability curve with increasing gas flow as a liquid phase was displaced from the pore system by the high differential pressure.

The presence of a liquid in the Huron Shale was confirmed by wet zones found on the downstream ends of the core plugs after they were removed from the apparatus (Soeder, 1988). The liquid smelled of hydrocarbons and a gas chromatograph analysis of the Huron Shale core confirmed that it contained petroleum. The oil was held tightly in the tiny shale pores under very high capillary pressure, blocking gas flow. A similar analysis on the lone Marcellus Shale sample revealed that there was no oil present in this rock (Soeder, 1988). Given what is now known about liquids in shale, the discovery of oil blocking the pores of the Huron Shale is not a surprise, but it was unexpected at the time and may explain some of the EGSP well stimulation failures, which often appeared to have no rhyme or reason. Capillary blockage of shale pores with oil could have been responsible for at least some instances of ineffective stimulation.

Under a net confining pressure of 3000 psi (20,685 kPa), considered representative of initial reservoir conditions, the dry Marcellus Shale had a gas permeability of about 19.6 μd. Doubling the net confining pressure to 6000 psi (41,370 kPa) to simulate drawdown reduced the gas permeability to about 6 μd. This more than two-thirds reduction in permeability at twice the net confining pressure indicates a high sensitivity of permeability to net stress in this shale and suggests that the most important flowpaths are microfractures (Soeder, 1988). These findings went essentially unnoticed for 20 years until new developments in drilling and stimulation technology allowed shale gas production to become economical.

The engineering challenges that had to be overcome to produce shale were formidable. With the present success of shale development, some of the root causes of the DOE and EGSP failures back in the 1980s are apparent. Vertical boreholes with single fracks for shale gas production were simply not workable in most places outside the Big Sandy Field. Finding another "Big Sandy" was not in the cards because it is so rare. But perhaps an even more significant failure of the EGSP was that almost no one was thinking big enough.

Darcy's Law allows for only a limited number of adjustments to be made on the other variables to increase Q, the discharge rate of fluids. Options for increasing Q include increasing the cross-sectional surface area (A), reducing the flowpath length (L), decreasing the viscosity (μ) of the fluid, and boosting the differential pressure (ΔP). Reducing the viscosity of natural gas in shale is probably not practical, so in reality the engineers could only work with A, L, and ΔP in their attempts to develop shale gas as a commercial resource.

Shale is a dual-porosity system, with most of the pore volume located within the matrix, and less than 1% in natural fractures (Soeder, 1988). Thus, the matrix pores provide storage for hydrocarbons, while the fracture porosity provides flowpaths. The storage porosity does not flow very well, and the flowpath porosity does not have much storage. To produce economical amounts of O&G from shale, the large quantities of hydrocarbons trapped in tiny matrix pores must be recovered. The volume of free-flowing O&G in the natural fractures typically provides rapid initial production that falls off quickly. The long-term production of a shale well is defined by the movement of hydrocarbons from the matrix to the wellbore by way of the natural and induced fracture system.

Although the natural and hydraulic fractures don't contain much volume, they are critically important as flowpaths. Compared to the incredibly tight matrix, a hairline crack with an aperture of less than a micron is like an eight-lane superhighway to a gas molecule. The key to obtaining economical amounts of hydrocarbons from shale is to emplace sufficient, closely spaced, high-permeability fracture flowpaths in the rock to collect gas or oil from the low-permeability matrix pore system and get it to one of these superhighways.

So how does this work according to Darcy's law? High-permeability fracture flowpaths created at a close spacing will reduce the flowpath length (L) of the O&G movement through the matrix, which according to Darcy's law will increase Q. Fracture faces in the rock also increase the surface area (A) of the matrix in contact with high-permeability flowpaths, which again, according to the Darcy equation, will increase Q. Finally, the rapid drainage of gas, oil, and water from the high-permeability fracture system will increase the differential pressure (ΔP) between the fracture and the matrix, also increasing Q. Thus, all of these factors together enable greater amounts of hydrocarbons to flow more easily from the shale. This had been known in theory for quite some time but achieving it in practice turned out to be immensely challenging (Soeder, 2017).

Visualizing the nanometer-scale pore structures in shale has been an ongoing challenge. Many of these are far too small to see optically and require electron microscopy or similar techniques to resolve (Rodriguez et al., 2014). Methods used by materials engineering and biological science researchers for preparing and imaging soft or fragile samples were adapted for shale by Scheiber (2010) and Loucks et al. (2011).

Geological sample preparation for scanning electron microscopy (SEM) typically consists of either mechanically breaking a sample to expose a fresh surface or cutting and polishing the sample with diamond wheels to create a flat surface, like a thin section. While these methods work fine on granites and sandstones, shales are easily deformable. Mechanically breaking a shale sample "plucks" larger grains out of the fine matrix. This creates a surface of clay flakes with irregular holes that often have been interpreted as pores but are actually just former grain sites (Fig. 2.4). Cutting and polishing shale surfaces with a diamond wheel tends to smear clays and other soft structures and fills in pores with ultrafine cuttings and mud.

The current best practice for imaging shale samples uses focused ion beam (FIB) milling. This process typically employs a dual-beam instrument capable of bombarding a sample with a stream of electrons for SEM and heavier ions for FIB, usually gallium (Volkert and Minor, 2007). The focused ion beam can create images, just like an electron beam, but because the FIB is composed of more massive particles, it can also knock atoms off the surface of the sample in a process known as "sputtering." Sputtering is used to "micromachine" samples to atomic smoothness. It can bring out significantly more fine detail on shales than any other kind of sample preparation method (Fig. 2.5). Successive millings can create a series of pore structure images slicing through the sample. Individual frames are then stacked to make three-dimensional, fly-through movies.

FIGURE 2.4 Scanning electron micrograph of a freshly broken surface on Marcellus Shale perpendicular to bedding. Scale bar is 10 μm. Clay fabric and structure are clearly visible, but the "pores" are actually voids created by the removal of preexisting grains. *DOE photo.*

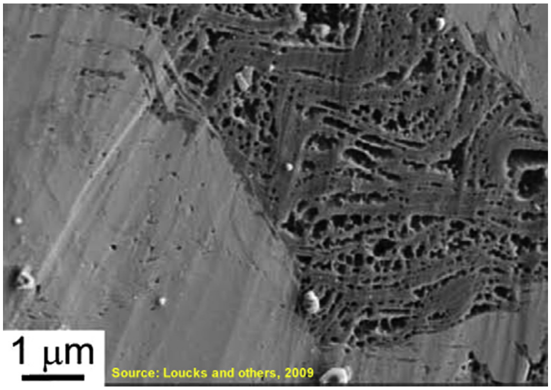

FIGURE 2.5 Scanning electron micrograph of a Barnett Shale surface milled flat using a focused ion beam (FIB). Scale bar is 1 μm. Porosity is visible within organic maceral, as are nanometer-scale pores in matrix. *Photo from Loucks, R.G., Reed, R.M., Ruppel, S.C., Hammes, H., 2012. Spectrum of pore types and networks in mudrocks and a descriptive classification for matrix-related mudrock pores. American Association of Petroleum Geologists Bulletin 96, 1071–1098, used with permission.*

A number of researchers have explored the pore structures of shale and the processes of liquid and gas movement through these rocks (i.e., Josh et al., 2012). Shale pores are generally classified as follows: 1) interparticle porosity between grains, crystals, or clay flakes, 2) intraparticle porosity within pyrite framboids, clay aggregates, dissolution pores on the rim of crystals, and moldic pores within fossils, pellets, or crystals, 3) porosity within kerogen or other organic matter (Fig. 2.5), and 4) microfracture porosity (Loucks et al., 2011).

Field operations

The potential applications of new advances in drilling and production technology to shale gas were carefully monitored throughout the last 2 decades of the 20th century by one George Phydias Mitchell, who had cofounded Mitchell Energy with his brother Johnny in the late 1940s (Soeder, 2017). George Mitchell's interest in shale gas went back at least as far as the early days of the EGSP, when Mitchell Energy had signed cooperative agreements with the DOE to drill and core a number of Appalachian basin shale wells (Cobb and Wilhelm, 1982). After the active EGSP drilling program ended in the mid-1980s, Mitchell continued to maintain an interest in producing gas from the organic-rich Barnett Shale in the Fort Worth basin of Texas (Hickey and Henk, 2007). Against the advice of his brother, partners, investors, employees, and nearly everyone else, George P. Mitchell persisted in running experiments with a variety of drilling techniques and reservoir stimulation procedures in the Barnett Shale over a period of at least 18 years. There were many technical failures and a few noneconomic technical successes (Montgomery et al., 2005). Mitchell eventually discovered that the key to producing commercial quantities of gas from the Barnett Shale was to drill horizontal boreholes and hydraulically fracture these in zones or stages (e.g., Moritis, 2004; Mason, 2006; Pickett, 2008).

A vertical well has a limited amount of contact area through the typical black shale thickness of only a few hundred feet (tens of meters). Horizontal drilling, on the other hand, creates lateral boreholes that can remain within the shale for thousands of feet (kilometers). Keeping the borehole within the target formation allows the high-permeability flowpaths of the hydraulic fractures and wellbore to contact a much larger volume of rock than is possible with a vertical hole (refer back to Fig. I-3 for a conceptual diagram).

One of the first experimental horizontal wells in gas shale was air-drilled by the DOE as an EGSP test in December 1986 (Duda et al., 1991). Although not commercially productive, the borehole demonstrated that laterals can be drilled in specific directions to intercept the dominant set of natural fractures in a formation. This turned out to be a key strategy for commercial shale gas and tight oil because the natural fractures provide already-existing high-permeability flowpaths into a target formation that can be further enhanced by hydraulic fracturing. Natural fractures in most areas are oriented vertically, and thus are difficult to intercept in a vertical borehole (Hill et al., 1993). Mitchell Energy's early Barnett Shale laterals were only a few thousand feet (1 km) long, but recent horizontal boreholes have reached lengths as great as 19,500 ft (5944 m). The depths of the shale target formations and the lengths of the laterals require exceptionally large drill rigs and related equipment (Fig. 2.6).

FIGURE 2.6 A large, "triple" hydraulic drill rig installing a lateral into the Niobrara Formation at a depth of approximately 8000 ft (2.4 km) in the Denver–Julesburg basin, eastern Colorado. Scale is indicated by the stairway and entrance door of the "dog house" office trailer attached to the side of the platform and used to operate the rig. A second rig is visible in the background at left. *Photo by Dan Soeder.*

Drill rigs come in a variety of sizes for different uses. The first major division is between "offshore" rigs and "land" rigs. So far, essentially all shale gas and tight oil development has been done on land. The smallest land rigs are mounted on trucks and can be moved about as a single unit. Larger drill rigs are modular and are transported as multiple components that are then assembled onsite. Land-based drill rigs are classified by the height of the derrick, which determines how many 30-foot (10-meter) segments of drill pipe can be recovered from a borehole with a single pull before being disconnected. Small rigs can only pull one segment of drill pipe at a time and are called "singles," and it follows that "doubles" can pull two segments and "triples" three. Most modern drill rigs are powered by electric-hydraulic systems, using a bank of generators to provide electricity for the rig's hydraulics. Manual handling and threading together segments of drill pipe using chain wrenches and other hand tools has mostly been taken over by machines. Land rigs cost about \$100,000–\$500,000 per day to operate (Soeder, 2017).

The practice of "directional" drilling, which produces the laterals, was initially invented in 1930s using a length of flexible drill pipe called a "whipstock." This allowed the drill string to be rotated from the surface and still go through downhole curves without shearing off. In those early days, steering the bit was challenging, as it would tend to wander off in random directions deep underground. Knowing the location of the bottom of the hole was equally challenging, with little more than a primitive downhole gyroscope and compass, dead reckoning, and luck (Mantle, 2014). As such, directional wells were only used in special circumstances.

Technological advances in directional drilling came about in the 1990s, driven primarily by the major oil companies involved in deepwater offshore oil production (Soeder, 2017). In order to avoid having to move the semisubmersible, tension-leg platforms required for drilling in very deep water, the majors put significant funding and research into developing advanced directional drilling technology. Moving deepwater platforms is expensive, time-consuming, and risky. Directional drilling allows operators to install multiple wells into different conventional reservoir compartments or to drill into several close targets in structures like salt domes without having to move the platform (Cromb et al., 2000).

Modern directional drilling rigs do not rotate the entire drill string from the surface to turn the cutting bit. Rather, the drill pipe remains stationary and acts as a conduit for high-pressure drilling fluid pumped downhole. The pressurized fluid enters a "bottomhole assembly" that incorporates a downhole hydraulic motor to turn the bit. With only the bit rotating, the stationary drill pipe is much more flexible and can turn tighter corners. Advanced bottomhole assemblies incorporate thrust bearings that can change the angle of the bit to provide precise directional control. Related improvements in downhole position measurement based on inertial navigation and real-time telemetry of data back to the surface now allow drill crews to perform "geosteering" to precisely place and accurately monitor the downhole location of their drill bit and the configuration of the borehole (Mantle, 2014).

Drilling efficiency in shale has been greatly improved with the introduction of the polycrystalline diamond composite (PDC) drill bit (Baker et al., 2010). These are superior to standard tricone rotary bits, which work by percussion and tend to be inefficient in soft rocks like shale. The PDC bits are designed with raised cutter teeth and have oriented jets that focus high-pressure drilling fluid onto the cutting surfaces to flush away the mud buildup that accumulates when drilling through shale (Fig. 2.7).

FIGURE 2.7 Polycrystalline diamond composite drill bit used on the Niobrara Formation in the Denver–Julesburg basin, eastern Colorado. Jets in the hub are designed to flush mud off the cutting teeth. Coin in the center for scale is 2 cm in diameter. *Photograph by Dan Soeder.*

Experienced shale drillers on the more mature plays like the Bakken in North Dakota routinely drill 2000 ft (600 m) of borehole in a day. A few laterals have even been designated as "MAD" wells for achieving mile-a-day rates.

Once the lateral is completed and casing is set, hydraulic fracturing is used to create cracks into the target formation. Hydraulic fracturing was invented in 1947 by Floyd Farris of Stanolind Oil and Gas Corporation for use in the Hugoton gas field of Kansas, with crude oil and naphtha gels as the working fluids (Montgomery and Smith, 2010). The modern water-based frack was developed by Halliburton in the early 1950s after purchasing Stanolind's patents. Fracking is a very specialized operation requiring specific equipment and expertise. Halliburton and other large oilfield service companies continue to provide the majority of hydraulic fracturing services to the oil and gas industry.

The fracking process begins by perforating a zone in the production tubing inside the lateral to create contact with the reservoir. Acid is introduced to clean out the perforations prior to the hydraulic fracturing operation. The fracking begins by mixing water, chemicals and sand in a blender, and pumping the materials downhole. Additives such as polyacrylamide are used to create a slippery fluid known as “slickwater” that reduces friction losses in long string of production tubing, where the zone being fracked may be several kilometers distant from the pump trucks. Other additives may include corrosion controls, scale inhibitors, and a biocide to control downhole microbial growth. Certain microbes can produce hydrogen sulfide (H_2S), making the gas “sour” and unsuitable for sale.

The fluid is then pressurized by large piston pumps at the surface. Once the breakdown pressure of the formation is exceeded, the rock cracks open. The initial part of the frack is called the pad and generally consists of plain water to initiate the crack. As the fracture extends into the rock, water containing suspended fine sand is introduced, with coarser sand to follow. The sand acts as a proppant to keep the fractures open after pressure is released. The first frack stage is done at the farthest end of the lateral, called the “toe” (Fig. 2.8).

FIGURE 2.8 Hydraulic fracturing operation underway on two Marcellus Shale wellheads in southwestern Pennsylvania. Pump trucks are on the right, blender and manifold in center, proppant sand in left background with two men on tank, monitoring and control trailer to left. Water supply was in a large impoundment behind photographer. *Photograph by Dan Soeder.*

During the frack job, engineers carefully monitor bottomhole pressure, pressures at the wellhead, and pressure in the annulus, along with pump rates, fluid density, and volumes of materials going downhole. Many of the fracks are computer-modeled in real time, using live data inputs. The myth that hydraulic fracturing operations are careless, reckless, or sloppy couldn’t be further from the truth. These treatments are performed by professional crews working for specialized service companies. Careless and sloppy frack jobs cost the company money through needless violations and fines, wasting of expensive materials, or by fracking into rock that is nonproductive. It is in the best interests of everyone involved for the job to go smoothly and properly and for the fractures to be placed in the target zone as precisely as possible. Given the highly competitive nature of the business, companies that don't perform efficient, on-target frack jobs don't last very long.

When the first interval of hydraulic fracturing has been completed, the pressure is released and a bridge plug is set into the production casing to close off the newly perforated and fractured zone or "stage" from the rest of the well. The hydraulic fracturing treatment is then repeated in a second stage, which is also closed off after completion with another bridge plug. The process continues until the last stage reaches the upper end of the lateral called the "heel," and begins to curve up out of the shale and into the vertical part of the well, or the "tophole." The bridge plugs are then removed and the well is produced (Soeder, 2017). Newer frack technology uses packers with a one-way check valve-type seal to close off completed fracture stages from stages in progress. When the frack operation is complete and fluids and gas begin to flow toward the surface, the check valves open and connect all the fractured zones together.

Directional drilling and hydraulic fracturing have many nuances that allow a specific set of procedures to perform well in a particular shale formation. Discovering these for the Barnett Shale took many years and someone less persistent than George Mitchell might have given up. Mitchell was ultimately successful, but the approach developed by Mitchell Energy for the Barnett will not necessarily work in other shale formations.

Range Resources struggled with this issue for almost 2 years when trying to develop the Marcellus Shale in the Appalachian basin (Soeder, 2017). Range diligently applied the drilling techniques and hydraulic fracturing formulas pioneered by Mitchell Energy a decade earlier in Texas on the Marcellus but obtained mixed results. It wasn't until Range started developing their own drilling procedures and frack fluid formulations that they finally found a combination that was effective in the Marcellus (Zagorski et al., 2012). This need for a long period of trial-and-error field tests to develop an efficient drilling and fracking approach for any new shale play requires a significant capital investment and a great deal of patience. It has been one of the issues holding back shale gas resource development in other parts of the world.

In the summer of 2004, Southwestern Energy announced that the Fayetteville Shale in Arkansas had many of the same characteristics that made the Barnett Shale gas productive, setting off a drilling boom in northern Arkansas (Bai et al., 2013). Over the next few years, similar development took place on the Haynesville Shale in the Arkansas–Louisiana–Texas border region known as the ArkLaTex (Kaiser and Yu, 2011) and the Marcellus Shale in Pennsylvania and West Virginia (Zagorski et al., 2012). Shale resources in other basins have also been explored and developed, including the Mowry and Niobrara in the Powder River basin (Anna and Cook, 2008), the Monterey Shale in California (Brown, 2012), the Woodford Shale in Oklahoma (Cardott, 2012), the Utica/Point Pleasant Formation in Ohio (Kirschbaum et al., 2012), the Montney and associated shales in British Columbia (Chalmers and Bustin, 2012), the Bakken Shale in North Dakota and Saskatchewan (Gaswirth and Marra, 2015), and many others (Fig. 2.9). Even shales on the North Slope of Alaska (Houseknecht et al., 2012) and in some of the small, Triassic rift basins on the US Eastern Seaboard (Milici et al., 2012) have been evaluated for shale gas.

FIGURE 2.9 Shale gas and tight oil plays in North America. Much of the current focus is on stacked plays in the Appalachian, Permian, and Powder River basins and on liquids-rich plays like the Eagle Ford, Bakken, and Utica. *Reproduced from U.S. Energy Information Administration reports and web pages.*

George Mitchell truly believed in the gas potential of the Barnett Shale (Kinley et al., 2008). Because of his determination, Mitchell Energy continued field experiments in Texas, eventually finding a methodology that was effective on the shale at a lower cost than other approaches. A rise in gas prices in the mid-1990s improved the economics. By 1997, Mitchell Energy had started trying the light sand frack technique in horizontal wells. The company began successfully producing commercial amounts of gas from the Barnett Shale using horizontal boreholes and staged hydraulic fracturing at the very end of the 20th century, starting the modern shale gas revolution (Martineau, 2007). In 2002, Devon Energy acquired Mitchell Energy for the tidy sum of $3.1 billion dollars, and George P. Mitchell finally retired from the oil and gas business. He received a Lifetime Achievement Award from the Gas Technology Institute on June 16, 2010 for his role in developing shale gas into an economic resource, and died on July 26, 2013 at the age of 94.

Natural fractures

Fractures or cracks are required in low-permeability rocks to produce O&G at economical rates. A fracture system provides flow channels to gather up hydrocarbons from the ultratight rock matrix for transport to a well. As mentioned previously, a typical nanodarcy gas shale is a million times less permeable than a millidarcy conventional gas reservoir. A well penetrating shale, even a horizontal well, cannot provide enough surface area in contact with the rock to produce commercial amounts of O&G. The wellbore must connect with both engineered hydraulic fractures and existing natural fractures to provide a significant number of high-permeability flowpaths into a large enough volume of rock to recover appreciable O&G.

Natural fractures come in two basic types: 1) joints, where the walls have pulled apart from each other and 2) faults, where the walls have slid past one another. Because shale is so soft, faults commonly show a grooved, polished surface known as a slickenside, making them easy to distinguish from joints (Fig. 2.10).

The orientation or direction of a fracture is called the strike and the angle it makes with respect to the horizontal is known as the dip. Joints commonly have a vertical or near vertical dip, while faults are usually angled. There are exceptions to this of course; faults can be vertical, especially if their motion is predominantly strike-slip, and horizontal joints can be found in exfoliation structures where the erosion of overburden had caused the rock to crack horizontally.

FIGURE 2.10 A slickensided fault surface cutting across a 3.5 inch (9 cm) diameter EGSP shale core. *Photo by Dan Soeder.*

Nevertheless, at the depths and overburden pressures typical of gas shales, joints are generally vertical. Many rocks contain a primary set of parallel joints and a secondary set at more or less right angles. These are known as orthogonal joints.

The flat, horizontal surface of the Marcellus Shale shown in Fig. 2.11 has a distinct set of orthogonal joints. The fractures that trend left to right across the photograph are known as J1 joints. They strike 60–75 degrees east of north, or to the east-northeast (ENE), and are the older set (Engelder and Lash, 2008). Joints strike in the direction of maximum compressive stress, and break in the direction of least compressive stress, so measuring the fracture orientation can be helpful for reconstructing the past stress and tectonic history of a basin. The J1 fractures were formed parallel to the long axis of the Appalachian basin as it subsided and filled with sediment. One hypothesis for the formation of the J1 joint set is that gas pressure generated within the shale during early burial exceeded rock strength and caused the rock to break in a process similar to hydraulic fracturing (Engelder and Lash, 2008).

FIGURE 2.11 Orthogonal joints on a flat bedding plane of the Marcellus Shale, exposed in the bed of Oatka Creek, Leroy, NY. The compass points to the north. *Photo by Dan Soeder.*

The second group of parallel joints running from lower right to upper left in Fig. 2.11 is the J2 set. These strike 315–345 degrees from north, or to the northwest (NW), and are thought to have been formed by the compression of the basin in that direction from the tectonic folding and crumpling of the crust during the Allegheny orogeny (Ryder et al., 2009). Fractures form in the direction of compression because the walls move apart at right angles from the direction of maximum force. This is essentially what happens when a rock sample is hit with a geologist's hammer. The hammer supplies downward compression on top of the rock and the sample splits into two pieces that move apart at right angles to the direction of the blow.

Marcellus Shale gas drillers generally place laterals oriented to the NW to cross and intercept as many J1 joints as possible. The J1 fractures are thought to provide better gas conduits because they are more laterally continuous than the cross-cutting J2 fractures.

Other shale plays in other basins have different stress fields and different orientations for the major and minor orthogonal joints. However, in every case, the drillers try to intercept the most prominent set of joints with their laterals.

The hydraulic fracturing process opens and extends some existing fractures and creates new fractures. There is evidence that orthogonal fractures will move slightly in a shearing motion as the frack proceeds, causing asperities on the fracture surface to be offset just enough to help prop the fractures open and reduce the amount of proppant sand needed (Bruner and Smosna, 2011). These are known as self-propping fractures and are sort of a Holy Grail to hydraulic fracturing engineers.

Because there is no extra open space underground, the new space created by the fracking must be accommodated elsewhere. The rock itself will be compressed to a degree, which changes the distribution of stress within the formation and may have effects on the nanometer-size pores in the matrix. The remainder of the new space is accommodated by closing down larger voids or other, preexisting natural fractures.

A significantly complicating factor with the physics and engineering of hydraulic fractures is how the frack process itself changes stress fields in the subsurface. As a reminder, the efficiency of a frack depends on opening flowpaths in a direction perpendicular to the axis of the lateral with the goal of having the fracture tips grow away from the wellbore at right angles and penetrate as deeply into the formation as possible. As a second reminder, the fractures grow in the direction of maximum compressive stress because the walls have to move apart in the direction of minimum compressive (or maximum tensile) stress. Recall the example of a rock being hit with a geologist's hammer. However, creating new fractures parallel to the main set of joints and increasing the apertures of existing joints imposes a compressive stress perpendicular to the strike of the main joints. Thus, the maximum principal stress direction in the shale near the lateral actually changes during the course of the hydraulic fracturing operation from perpendicular to parallel to the lateral because of the frack. The result is that the initial hydraulic fractures are oriented perpendicular to the lateral, but as the fracks extend outward, the changes imposed by them on the underground stress field causes the fracture tips to change direction and break parallel to the lateral. This is much less efficient for the effective drainage of gas from the rock, and operators try to avoid it.

One method for dealing with hydraulic fractures that have turned parallel to the lateral is to re-fracture the shale gas well after time intervals of months to years after the stresses have realigned with the regional stress gradient. Refracking can open up new flowpaths perpendicular to the wellbore and produce more gas, but the mobilization costs of bringing a crew and tons of equipment and materials back out to the well site (refer back to Fig. 2.8) can be prohibitive. As such, engineers have developed several other types of fracture treatments that can reduce or eliminate the need to refrack.

A zipper frack involves alternately fracturing matched zones in parallel laterals spaced about 300 m (1000 ft) apart in a back-and-forth pattern, stage by stage (Ghiselin, 2009). The zipper frack is designed to reduce the potential for stress fields introduced into the shale by one stage of the frack from interfering with the effectiveness of the next stage.

When properly designed and executed, this hydraulic fracturing technique can be very effective at opening up a shale gas reservoir between a pair of laterals.

Similar to the zipper frack, a simultaneous frack involves two horizontal wells that are fractured together. Instead of alternating side to side, a simultaneous frack treats the matched stages of two parallel laterals at the same time. This attempts to both minimize stress interference and prevent communication between the fracture fairways. Wells treated with this technique reportedly yield a significantly higher initial gas production than individually fractured parallel wells (Ghiselin, 2009). Other emerging technologies being investigated for stimulation of low-permeability hydrocarbon reservoirs include gas fracks, cryogenic fracks, foam fracks, and energy fracks.

Fracturing shale using pressurized gas such as carbon dioxide or nitrogen was tried experimentally during the EGSP (Horton, 1981). Gas fracturing generally provides for easier cleanup and less formation damage, although this comes at a much higher cost, reduced effectiveness at initiating the fracture, difficulty entraining and transporting proppant, and a greater difficulty in controlling the growth of the fracture. Gas fracturing is used occasionally for specific, specialized stimulations.

Cryogenic fracks use liquefied gas as a fluid to crack the rock and carry the proppant into the fractures. The gas then vaporizes, aiding in cleanup. These were also tried experimentally on the EGSP, with limited success (Horton, 1981). Liquid nitrogen, liquid carbon dioxide, and liquid methane were all tried in shale wells but introducing such intensely cold fluids into the downhole environment caused the steel well casing to contract and de-bond from the cement. Expanding ice from frozen residual pore water resulted in formation damange near the wellbore. The more modern version of this type of frack uses gases such as propane and butane that liquefy at higher, noncryogenic temperatures with better results. These gases must still be recovered at the production wellhead before the natural gas can be placed into a pipeline, but the economics are better because cryogenic handling is not needed. Still, liquid gas fracks remain more expensive than the same-sized hydraulic frack and generally used in special circumstances.

Foam fracks are another variation on a hydraulic fracturing treatment, where pressurized gas, usually nitrogen, is mixed with a liquid surfactant to create a high-pressure, foam-like material capable of cracking the rock and carrying proppant into a fracture. The foam itself is designed to break down when pressure is released, leaving behind a residual amount of material to help prop open the fracture and allowing the nitrogen to escape from the well. Although they work well on shale, foam fracks are more costly than fracking with water.

Energy fracks use chemical explosives and are the oldest type of well stimulation technology. In the old days, these were done by dropping a lit stick of dynamite downhole, or using nitroglycerine (Hunter and Young, 1953). High explosives transmit too much energy too quickly, shattering the rock in the vicinity of the wellbore, but failing to create the long, permeable flowpaths into a formation desired for stimulation. More recent research in energy fracks use a slower-release explosive such as solid rocket propellant to achieve breakdown pressures in the rock, sustain fracture growth into the formation and avoid the formation damage from high explosive shock waves. This type of energy frack is called tailored pulse loading and service companies continue to experiment with them.

Because of rock strength limits and the vertical compressive stress supplied by overburden pressure, hydraulic fracturing can only be used efficiently at depths where the stress gradient will produce vertical fractures (King, 2012). If a rock is too shallow, the low overburden pressure will result in a hydraulic fracture that breaks horizontally, or "pancakes," and does not contact a sufficient volume of shale. Overburden pressure from the weight of the rocks needed to create vertical fractures is generally considered to be sufficient at depths greater than 2500 ft or 775 m.

An alternative completion technique for formations too shallow to fracture is to drill in a branched or "pinnate" pattern of side laterals off a main lateral resembling the structure of a feather (Long and Soeder, 2011). The multiple branched laterals can have a combined length of up to 4.5 km (15,000 ft). While not as efficient as staged hydraulic fracturing for contacting large formation volumes, branched laterals can still produce significant amounts of hydrocarbons. Pinnate drilling often uses a "coiled tubing" rig, which employs a flexible hose coiled on a drum to supply drilling fluid under hydraulic pressure to a steerable bottomhole assembly (Long and Soeder, 2011). The flexible hose allows for much tighter turns than a steel drill pipe, but is more limited in depth.

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3

The revolutionary U.S. shale plays

Defining a play

The use of the word "play" to describe the production of an O&G resource may at first sound frivolous, but in oil and gas exploration, it is a legitimate term. A play is defined as a group of prospective resources with a geologically similar source, reservoir and trap, and comparable processes for hydrocarbon migration, accumulation, and storage (Patchen, 1996). In a more practical sense, a play means finding out where other people are drilling successfully for gas or oil and drilling as close to that place as possible. O&G developers are a lot like the Hollywood movie producers who find the latest formula for cinematic success, be it superheroes, space operas, historical romances, westerns, or whatever, and shamelessly copy it. Thus, a successful oil or gas well in one location often brings in many others.

Oil and gas exploration people define resources as "prospective" when they determine something might be present, "contingent" when they know it is there but the technology might not be able to produce it, and "reserves" when it is present and actually can be produced. There are many nuances, subtleties, and subcategories. These terms, known formally as the Petroleum Resources Classification System were codified in February 2000 to provide precise definitions, sharpen the distinction between the classifications, and provide consistent reporting and more uniform usage (http://www.spe.org/industry/petroleum-resources-classification-system-definitions.php). The system was developed under an agreement signed by the Society of Petroleum Engineers (SPE), the World Petroleum Council (WPC), and the American Association of Petroleum Geologists (AAPG).

Assessments of the recoverable oil and gas in a particular play are only estimates. The reported size of a resource is a reflection of the integrity, skill, and judgment of the evaluator. There are a number of different approaches that each rely on a different set of assumptions; thus, assessments are typically given as a range of probabilities. Results can be affected by the complexity of the geology, the number of existing wells, the availability of well logs, core analyses, and Rock-Eval data, and the stage of development of the play, in particular the degree of depletion and the availability of production and drawdown data. Estimates of contingent resources and reserves are the most difficult and inaccurate during the very early stages of the play and improve later on as more data become available (Coleman et al., 2011).

The amounts of hydrocarbon generated within a shale source rock are ranked by a geological standard called the source rock quality. This assessment combines data for

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TOC, kerogen type, and thermal maturity and rates it as poor, fair, good, excellent, or exceptional (Bruner and Smosna, 2011). Just having the right type and amount of organic matter doesn't necessarily make the rock a hydrocarbon resource. A rock may have excellent source rock quality, but if it has not gone through the burial history and thermal maturity to have been properly "cooked," it will not be very productive. The ability of the organic matter in a source rock to transform into hydrocarbons is an additional rating factor called the relative oil or gas potential (Bruner and Smosna, 2011).

The GIP or OIP are calculated from the geographic surface area and mean stratigraphic thickness of the rock unit, combined with a value derived from the source rock quality and relative hydrocarbon potential. Because of the assumptions built into such calculations, the numbers often vary widely. Resources assessments are typically presented as a range of low, best, and high estimates for recoverable quantities of hydrocarbons on an individual play, expressed as probabilities. As such, the low estimate is usually given a probability of 95%, best estimate has a 50% probability, and the high estimate has a probability of 5%. Although these may seem backward, there is a practical reason behind it. What this actually means is that there is a very high probability (95%) of recovering at least as much O&G as the low estimate. Recovery of additional hydrocarbons beyond that is possible, but as the amounts get higher, the probabilities drop. At the end of the scale, the probability of recovering the highest estimated amount of a resource is quite low. Most people use the 50% probability for resource estimates, although the USGS typically stays with the lower, more conservative values (Coleman et al., 2011).

Oil and gas has a lot of its own measurement and reporting vocabulary and it is important to know the terms when reviewing resource estimates or production values. Natural gas in the United States is measured in cubic feet at "standard temperature and pressure" (STP), which is room temperature (75°F or 24°C) at 1 atmosphere of pressure. It is commonly reported in volumes of a thousand cubic feet, abbreviated as MCF (1 MCF = 28.32 cubic meters). A million cubic feet is abbreviated as MMCF. The amount of energy the gas gives off when burned is termed the heating value, and it is usually expressed in British thermal units or Btu (1 Btu = 251 calories or 1054 J). Conveniently, one cubic foot of gas that meets pipeline specifications contains about 1000 Btu of energy. This makes one MCF of gas equivalent to a million Btu, or MMBtu, which is sometimes used as a unit of gas production or gas prices. The GIP in reservoir rocks and other large volumes of gas are expressed as billions of cubic feet (BCF) per square mile (1 BCF = 28.3 million cubic meters), or as trillions of cubic feet (TCF) for the entire resource (Bruner and Smosna, 2011).

Oil quantities are commonly expressed in barrels (bbl), a traditional, 19th century volumetric measurement in the Unoted States equal to 42 gallons or 159 L. Most other countries measure oil production in cubic meters (a cubic meter contains approximately 6.29 bbl), but they convert to bbl for export, because oil is priced internationally in United States dollars (USD) per barrel. Oil reserves are commonly stated in barrels of oil equivalent (BOE) to include condensate and other liquids. On a reservoir scale, reserves can be millions of BOE (MMBOE), and on a resource scale up to billions of BOE (BBOE).

The resource classification system is summarized in Table 3.1. To begin with, the definition of what exactly constitutes a "resource" is up for debate. Some explorationists consider the total estimated quantity of hydrocarbons initially in-place to be resources. Others disagree, arguing that only the recoverable portion of the hydrocarbons should constitute the actual resource. However, the recoverable portion can change, depending on price and advances in technology. The "total petroleum initially-in-place" is defined as the amount of petroleum in a known accumulation along with any petroleum already produced, plus estimated, undiscovered petroleum-initially-in-place. For natural gas, this works the same. In the order of decreasing probability of recovery potential, these resources are classified as reserves, contingent, and prospective.

Table 3.1 Petroleum resource classification system.

		Production	
Reserves			
Commercial	Proved	Proved + probable	Proved + probable + possible
Contingent			
Subcommercial	Low estimate	Best estimate	High estimate
Prospective			
Undiscovered	Low estimate	Best estimate	High estimate
Unrecoverable			
		<<<Range of uncertainty>>>	

Reserves are known resources that can be recovered economically with existing technology. These include proven reserves, which are essentially guaranteed to be recoverable, probable reserves that may be recovered with minor advancements in current technology and improved economics, and possible reserves, which may be recovered with advanced technology and significant price increases.

Contingent resources are known accumulations of O&G that are not considered to be commercially recoverable using current technology at current prices. Shale gas and tight oil were classified as contingent resources for many decades. The introduction of new technology, higher wellhead prices, more advanced resource evaluations, and improved access to markets has turned shale resources from contingent into reserves. Current contingent resources include methane hydrates in deep-sea sediments or under permafrost, and natural gas accumulations in the Mackenzie River delta in the Canadian Arctic. We know these resources exist, but they cannot be produced with current technology at current prices.

Prospective resources or "prospects" are those quantities of O&G that are estimated to be potentially recoverable from as yet undiscovered accumulations. An example of a prospect would be the potential offshore oil and gas accumulations along the continental shelf of the US East Coast. Although no one has ever found enough hydrocarbons here to write home about, all of the proper geological conditions are present for a prospective resource. A prospect may even have Rock-Eval, seismic, or core analysis evidence to suggest the presence of hydrocarbons, but this doesn't necessarily prove there is a resource. The true test comes from drilling.

The US Energy Information Administration (EIA) is the government agency largely responsible for keeping track of available energy resources and energy use. The EIA has identified approximately 22 active shale plays in the contiguous United States as of 2011 (USEIA, 2011). No new shale plays have been identified since then, but emphasis has shifted in terms of targets and production (Refer back to map, Fig. 2.9).

Companies have moved from single dry gas plays like the Haynesville and Fayetteville to liquids-rich and "stacked plays," which target multiple formations at different depths. Many shales with the proper type of organic matter and thermal maturity contain hydrocarbons in the "wet gas" window (refer back to Fig. 1.2). The term wet gas describes a mixture of methane, the simplest component of natural gas, along with more complex hydrocarbon molecules derived from the breakdown of the long-chain hydrocarbons making up petroleum. This occurs as thermal maturation goes past the oil window, but before it gets to the dry gas window. The heat and pressure cause petroleum to break down into simpler organic molecules like propane, butane, and ethane. These compounds are known as "natural gas liquids" (NGL) and typically occur in the vapor phase at downhole temperatures and pressures. When brought to the surface and cooled, they condense into liquid form, hence the common industry name of "condensate." Operators are interested in condensate because it fetches considerably more money than dry gas. Many shale formations extend across a basin where they have experienced different burial depths, and thus different levels of thermal maturation. Thermal maturity controls the location of NGLs, so for operators seeking to produce condensate, drilling a well in the correct geographic location is just as important as drilling into the correct formation.

A stacked play is when a single vertical tophole has multiple laterals branching into different formations, greatly increasing returns. Stacked plays in the Appalachian basin include the Upper Devonian Ohio Shale (primarily the Huron Member), the Middle Devonian Marcellus Shale, and the Ordovician Utica Shale. In the Permian Basin, the stacked play targets are six low-permeability, O&G-bearing units that include the Spraberry, Wolfcamp, Bone Spring, Glorieta, Yeso, and Delaware formations. Development of a Mowry–Niobrara stacked shale play in the southern part of the Powder River basin in Wyoming is also in progress, as evidenced by the 4545 drilling permits issued by the Wyoming Oil and Gas Conservation Commission in 2018 (http://wogcc.wyo.gov/).

Six tight oil and shale gas plays taken together account for nearly 90% of US domestic oil production growth and virtually all domestic natural gas production growth since 2008 (U.S. EIA, 2011). These are the Marcellus Shale, Haynesville Shale, Eagle Ford Shale, Permian Basin, Niobrara Formation, and Bakken Formation. Four additional significant contributors are the Barnett Shale, the Fayetteville Shale, the Woodford Shale, and the Utica Shale. Since January 2012, natural gas production from the Marcellus and the Utica shales alone has accounted for 91% of the increase in natural gas production from low-permeability formations in the U.S (Popova et al., 2018). The bulk of tight oil production has been from the Permian Basin, the Eagle Ford Shale, and the Bakken Formation. Table 3.2 summarizes the 10 primary shale plays developed in the United States.

Table 3.2 The 10 major U.S. shale plays.

Formation	Age	Basins and location	Primary developer	Year	Depth	Production	Core areas
Barnett Shale	Mid to Late Miss	Fort Worth, TX	Mitchell (Devon) Energy	1997	0–8k ft	Gas, NGL	Newark East Field; NW of Fort Worth
Fayetteville Shale	Late Miss	Arkoma, AR	Southwest Energy	2004	0–6k ft	Dry gas	North Central Arkansas
Haynesville Bossier	Late Jurassic	Arkla, TX–LA	Chesapeake Energy	2005	10k–13k ft	Dry gas	Lufkin, TX to Shreveport, LA
Marcellus Shale	Mid Devonian	Appalachian, WV, PA	Range Resources	2007	0–9k ft	Gas, NGL	SW PA and NW WV; NE PA
Bakken Formation	Late Devonian to Early Miss	Williston, ND, MT, Canada	EOG Resources	2006–09	4k–11k ft	Oil, gas	NW North Dakota, E. Montana, Canada
Woodford Shale	Late Devonian	Anadarko, Ardmore, OK	Newfield Exploration	2005	4k–25k ft	Bio gas, oil, NGL, dry gas	Central and southern Oklahoma
Niobrara Formation	Late Cretaceous	Denver; Powder River, CO, WY	Whiting Petroleum	2008	0–11k ft	Bio gas, NGL, dry gas	E. Colorado, E. Wyoming
Eagle Ford Shale	Late Cretaceous	Brazos, Maverick, TX	Petrohawk Energy	2008	0–20k ft	Oil, NGL, gas	Southern Texas
Spraberry, Wolfcamp, Bone Spring, Glorieta, Yeso, and Delaware formations.	Mid to Late Permian	Permian, TX	Multiple	2009	~1k–25k ft	Oil, NGL, gas	Western Texas; southeast New Mexico
Utica/Point Pleasant	Mid Ordovician	Appalachian, OH	Multiple	2011	0–15k ft	Gas, NGL	Southeast Ohio

The geology, location, characteristics, and development history of the first five of these 10 critical shale plays are discussed in detail in the sections that follow. Many of these hydrocarbon resources have been known for a long time, but the technology to extract them was lacking. Once the applications of George Mitchell's methods for lateral drilling and staged hydraulic fracturing on shale were understood by the O&G industry, operators began using them on many different formations with great success.

Barnett Shale

The Barnett Shale was the first formation where Mitchell Energy achieved the successful commercial development of shale gas in the late 1990s by using lateral boreholes and staged hydraulic fracturing. This rock unit is Middle to Late Mississippian in age (Bruner and Smosna, 2011), deposited between 347 and 323 million years ago, or Ma (Geologic age dates from Cohen et al. (2013)). The type section is at Barnett Springs in San Saba County, Texas (Plummer and Moore, 1922).

The Barnett Shale is present in the Fort Worth basin and across the adjoining Bend arch in North Central Texas, covering an area of about 28,000 square miles (72,520 sq. km). It outcrops on the Llano Uplift at the southern edge of the Fort Worth basin and dips into the deep subsurface toward the north-northeast near the Texas/Oklahoma border (Bruner and Smosna, 2011). The Barnett is relatively thick and deep in the northern part of the Fort Worth basin, which is where most of the gas development has been focused (Montgomery et al., 2005). The gas shale play covers roughly the eastern third of the geographic extent of the Barnett, surrounding the city of Fort Worth on three sides (**map,** Fig. 3.1). There are also quite a few production wells within the city itself that produced some conflicts between residents and the energy development industry (Theodori, 2008). An aircraft window seat provides views of numerous Barnett pads and wellheads on approach to Dallas-Fort Worth Airport (DFW), and many wells can be seen on the ground from the airport taxiways and ramps (Fig. 3.2).

The success of George Mitchell and Mitchell Energy at producing commercial amounts of gas from the Barnett Shale occurred in the Newark East field, which covers parts of Denton, Wise, and Tarrant counties. This is shown in Fig. 3.1 as the concentration of wells northwest of the city of Fort Worth. The Newark East field is the sweet spot of Barnett shale gas production, and the three-county area makes up the core of the play (Montgomery et al., 2005). However, the play has since expanded from the core area both northward and southward.

The Ouachita orogeny in the late Paleozoic, resulting from the collision of the ancient continents of Laurussia and Gondwana, gave the Fort Worth basin its present shape as an asymmetrical, peripheral foreland basin containing up to 12,000 ft (4.2 km) of

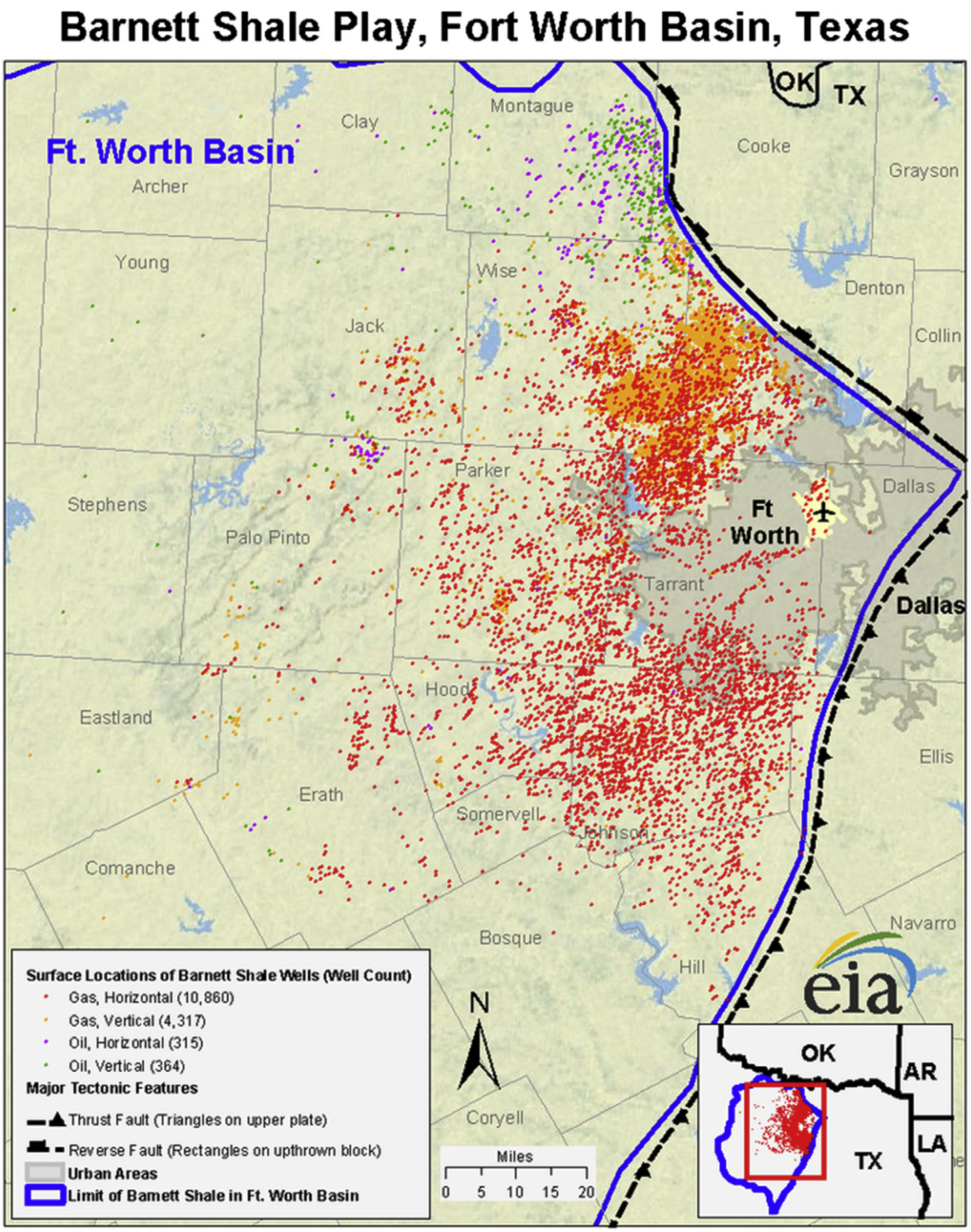

FIGURE 3.1 Map of production wells in the Barnett Shale in the Fort Worth basin of Texas. *Reproduced from U.S. Energy Information Administration reports and web pages.*

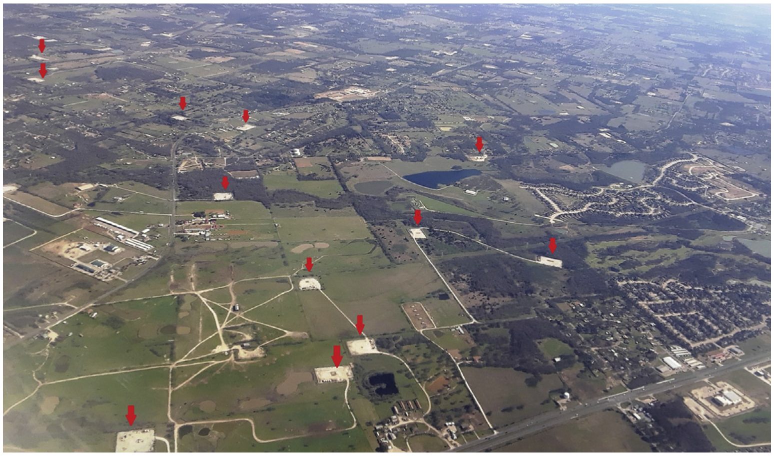

FIGURE 3.2 Numerous Barnett Shale production well pads (arrowed) interspersed among the housing developments of suburban Fort Worth, Texas, southwest of DFW Airport. *Photographed in 2019 by Dan Soeder.*

Paleozoic strata (Hill et al., 2007). As the orogenic fold belt advanced onto the margin of ancestral North America (Larussia), it caused a gradual down-warping of the preexisting carbonate platform in Middle to Late Mississippian time (Thompson, 1982). The Barnett was deposited during this initial stage of basin formation and overlain by Early to Middle Pennsylvanian rocks as the deformation continued and moved westward. The structural axis of the Fort Worth basin runs north-south, parallel to the Ouachita thrust fault (Fig. 3.3), which marks the structural boundary between the basin and the deformation belt to the east. Because the axis lies close to this thrust fault, the deepest part of the basin is located to the northeast, becoming shallower toward the west and south (Montgomery et al., 2005).

The Barnett Shale follows this pattern, thickening and deepening to the north and east (Fig. 3.3). Thermal maturity increases with a deeper burial history, so the less mature, liquids-bearing shale is present toward the west and south (Jarvie et al., 2007). The shale also thins in this direction, forcing operators into the usual O&G dilemma of selecting trade-offs between drilling depth and costs, types of recoverable hydrocarbons, and target zone thickness.

The Barnett Shale is composed primarily of a petroliferous and fossiliferous black shale, and a dark, finely crystalline, hard fossiliferous limestone (Lancaster et al., 1993). The bulk of the formation is Late Mississippian in age (Montgomery et al., 2005), and it is informally divided into upper and lower black shale members separated by the Forestburg Limestone in the deeper parts of the basin (Loucks and Ruppel, 2007). The general stratigraphy is illustrated in the north-south cross-section of the Fort Worth basin shown in Fig. 3.4.

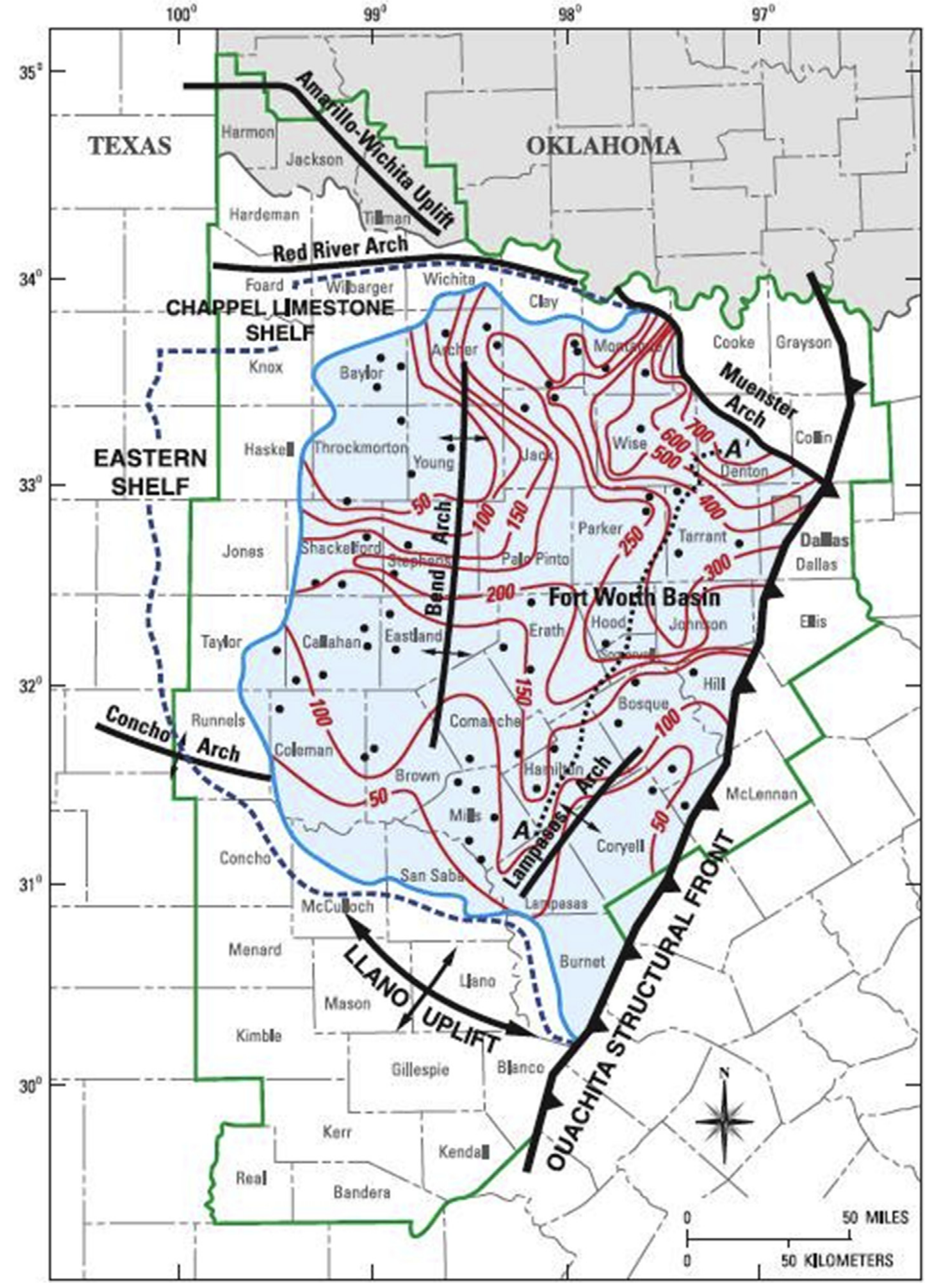

FIGURE 3.3 Map of structures in the Fort Worth basin of Texas, including isopachs of the Barnett Shale thickness in feet. The shale thickens and deepens to the north. *Modified from Bruner, K.R., Smosna, R., 2011. A Comparative Study of the Mississippian Barnett Shale, Fort Worth Basin, and Devonian Marcellus Shale, Appalachian Basin. U.S. Department of Energy Report DOE/NETL-2011/1478, 106 p.*

The Barnett may reach thicknesses as great as 800 ft (240 m) in the Fort Worth basin (Bruner and Smosna, 2011) and the Forestburg Member may be up to 300 ft (100 m) thick in the deep part of the basin. The limestone thins to a feather edge and disappears in southernmost Wise and Denton Counties (Loucks and Ruppel, 2007). The Barnett is bounded sharply on the north by the structure of the Muenster Arch and on the south by the Llano Uplift. It grades into a shallow shelf limestone to the west and is bounded on the east by the Ouachita structural front. The Barnett may in fact extend to the east beneath the Ouachita Thrust, but this is not definitive (Loucks and Ruppel, 2007). The maximum depth of the Barnett is about 8500 ft (2.6 km) near the Muenster Arch (Bruner and Smosna, 2011).

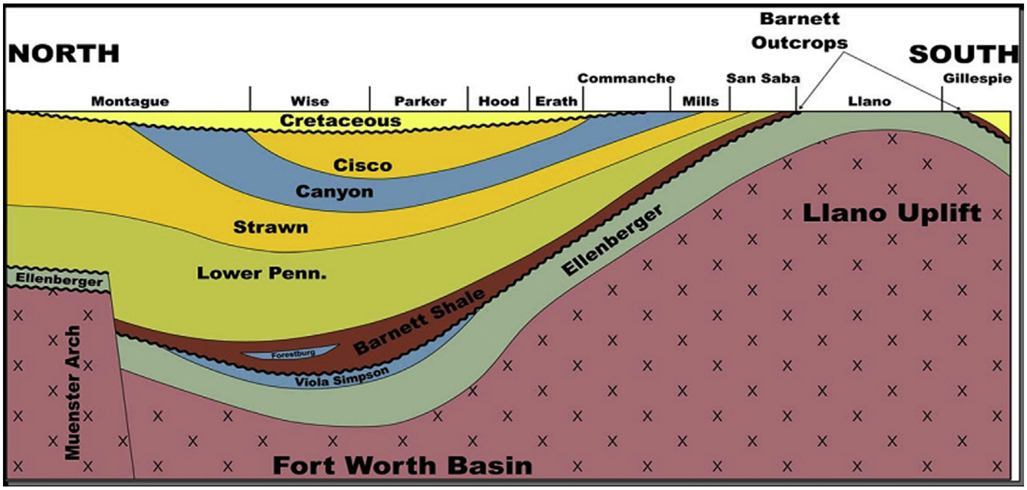

FIGURE 3.4 North to south geologic cross-section through the Fort Worth basin showing the location of the Barnett Shale above an unconformity on top of the Ellenberger limestone. The shale becomes more shallow and thins to the south, terminating in outcrops on the Llano Uplift. *Modified from Bruner, K.R., Smosna, R., 2011. A Comparative Study of the Mississippian Barnett Shale, Fort Worth Basin, and Devonian Marcellus Shale, Appalachian Basin. U.S. Department of Energy Report DOE/NETL-2011/1478, 106 p.*

The Barnett Shale rests unconformably on Ordovician-age rocks in the Fort Worth basin, including the Lower Ordovician (485–470 Ma) Ellenberger Group, composed of dolomite and limestone with abundant chert (Bruner and Smosna, 2011), and the Middle to Upper Ordovician (470–444 Ma) Viola and Simpson Formations, consisting of dense, coarsely crystalline to micritic limestone and dolomitic limestone, along with sandstone, anhydrite, and halite in the Viola (Cheney, 1929). The top of the Ordovician forms an erosional surface that exhibits karst topography, solution-collapse features, and brecciated structures. Silurian and Devonian-age rocks are absent from the Fort Worth basin. The Viola–Simpson limestones are confined to the northeastern part of the basin in the area of the Newark East field, and disappear along an erosional pinch-out that trends northwest-southeast through Wise, Tarrant, and Johnson counties (Montgomery et al., 2005). The Barnett Shale directly overlies the Ellenberger Group throughout most of the Fort Worth basin.

The Barnett Shale is overlain by the Late Mississippian to Pennsylvanian (331–323 Ma) Marble Falls Formation consisting of a lower unit called the Comyn Member composed of interbedded dark limestone and gray-black shale and an upper unit of white to gray, crystalline limestone (Montgomery et al., 2005). The shale beds in the Comyn Member are less radioactive and contain less organic matter than the underlying Barnett Shale and it is not generally considered a hydrocarbon producer. The Marble Falls thins to the east and is locally absent in places where the porous sandstone and conglomerate of the Pennsylvanian-age Bend Formation directly overlie the Barnett (Hentz et al., 2006).

In outcrop (Figs. 3.5 and 3.6), the Barnett Shale consists of black siliceous shale, limestone, and minor dolomite (Loucks and Ruppel, 2007). The bulk mineralogy is classified as 40 to 60% quartz, 40 to 60% clay minerals, and a highly variable calcite content (Jarvie et al., 2007). In the east-central part of the basin, a basal zone about 10 ft thick (2.5 m) contains abundant apatite, a phosphate mineral (Bruner and Smosna, 2011). The shale's brittleness, or propensity for fracking can be assessed from the ratio of quartz to a combination of quartz, clay, and calcite (Jarvie et al., 2007).

There is some disagreement among authors over the types and numbers of lithofacies present in the Barnett Shale. Organic-rich shale and fossiliferous shale were recognized as major depositional lithofacies (Hickey and Henk, 2007), along with four additional diagenetic lithofacies identified as rhombohedral dolomite shale, dolomitic shale, concretionary carbonate consisting of skeletal wackestone and mudstone, and phosphorite composed of phosphatic pellets, ooids, and shells. The TOC content is highest in the organic-rich shale and the phosphorite facies (Bruner and Smosna, 2011).

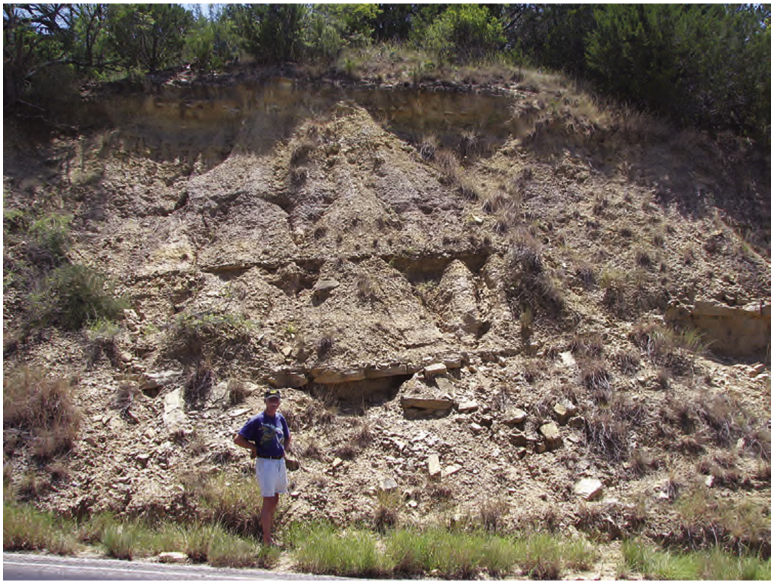

FIGURE 3.5 Outcrop of weathered Barnett Shale with ledge-forming limestone beds on the Llano Uplift near San Saba, Texas. *Photographed in 2011 by Kathy Bruner.*

FIGURE 3.6 The massively bedded Ellenberger limestone exposed at the base of an outcrop on the Llano Uplift near San Saba, Texas, overlain by about a meter of Chappel limestone beneath the weathered slopes of the basal part of the Barnett Shale. *Photographed in 2011 by Kathy Bruner.*

On the other hand, Loucks and Ruppel (2007) recognized three lithofacies based on their detailed petrologic analysis. A laminated siliceous mudstone is the predominant rock type in the lower and upper members of the Barnett Shale. A laminated, argillaceous lime mudstone is the predominant rock type of the middle Forestburg limestone member. The third, less common lithofacies is a skeletal, argillaceous lime packstone that is present in both the lower and upper shale members.

Major components of the laminated siliceous mudstone facies are silt-sized peloids and fragmented skeletal material, along with very fine grains of detrital quartz, plagioclase, and potassium feldspar. Parts of this facies are calcareous. The argillaceous lime mudstone of the middle Forestburg member consists of calcareous mud and silt, along with tiny dolomite crystals averaging 30 microns in size. Clay minerals, quartz, feldspars, and pyrite are also present, and the alternating clay-poor and clay-rich limestone layers create the laminated structure. The third skeletal lithofacies consists of beds of physically compacted mollusk and brachiopod shells and transported phosphate debris, separated by thin laminae of organic-rich mudstone (Loucks and Ruppel, 2007).

Geochemical and source rock analyses of the Barnett Shale indicate that the kerogen consists of over 90% amorphous Types I and II derived from marine algae that lived under normal ranges of marine salinity (for details on kerogen type, refer back to the "Source Rocks" section in Chapter 1). It was preserved by dysaerobic bottom conditions, along with a few percent vitrinite, exinite, and inertinite (Hill et al., 2007). The organic content of the Barnett is generally highest in the upper and lower shale members, and less so in the middle Forestburg Limestone, which averages only about 1.8% TOC (Montgomery et al., 2005). TOC values as high as 11 to 13% by weight are present in outcrop samples of the Barnett Shale on the Llano Uplift (Jarvie et al., 2001), while Barnett TOC values in the thermally mature, north-central part of the basin are lower, ranging from about 2.5 to 5.1% by weight (Montgomery et al., 2005; Jarvie et al., 2007). The lower TOC values toward the basin center are due to the conversion of trapped organic matter into O&G by the thermal maturation process, which may reduce the original TOC by as much as 50% (Jarvie et al., 2007). Nevertheless, the Barnett Shale deep in the basin is still rated as a very good to excellent source rock in terms of organic richness (Bruner and Smosna, 2011). Geochemical data suggest that the original sediment may have contained as much as 20% TOC in the southern part of the Fort Worth basin (Bowker, 2003) and 5 to 12% in the center (Montgomery et al., 2005).

Dry gas in the Barnett occurs at vitrinite reflectance values greater than Ro = 1.2 (Fig. 3.7), which follows the axis of the basin along the Ouachita front to the Muenster Arch. At lower thermal maturity, the Barnett contains "wet" gas, or NGLs, favored by many producers. NGLs increase the heating value of the gas and this can be used as a thermal maturity indicator when vitrinite-reflectance data are not available. For example, the heating value of Barnett gas in the wet gas area is reportedly greater than 1400 British thermal units (Btu) per cubic foot of gas (Bruner and Smosna, 2011). In metric units this is equivalent to 350 kilocalories per 28.3 liters. Heating values in the dry gas area range from 1050 to 1380 Btu/CF. Interstate pipelines accept gas with a nominal heating value of about 1000 Btu/CF.

The Barnett Shale has been found to contain interparticle pores approximately 3 micrometers in diameter (Bruner and Smosna, 2011). Mercury porosimetry measurements have determined that most pore throats have a radius of less than 5 nm, about 50 times the radius of a methane molecule, and some may be as small as 0.01 nm (Jarvie et al., 2007). The thermal maturation of kerogen to O&G appears to be primarily responsible for much of the matrix porosity (refer back to Fig. 2.5); calculations indicate that an original TOC of 6.41% will create a matrix porosity of 4.3% at an Ro of 1.4 (dry gas) (Jarvie et al., 2007).

The average open porosity in productive portions of the Barnett Shale ranges from 3 to 6%, whereas porosity in the nonproductive areas is as low as 1% (Bruner and Smosna, 2011). The Barnett Shale is reported to have matrix permeability to gas of 0.02–0.10 millidarcy (Jarvie et al., 2004), less than 0.01 millidarcy (Montgomery et al., 2005), 0.5–0.07 nanodarcy (Ketter et al., 2008), or in the range of microdarcies to nanodarcies (Bruner and Smosna, 2011). Matrix permeability of these tiny pores is extremely challenging to measure, some of the methods in use are questionable, and results depend on the local interplay of fractures, faults, and stress, resulting in wide-ranging values.

The organic-rich parts of the Barnett Shale contain average water saturations of 25%–43%, which increase dramatically in the calcareous parts of the formation that are organic-lean. This suggests that the process of hydrocarbon generation in the more organic-rich units has displaced water from the original sediment (Montgomery et al., 2005). The water is bound to clay minerals and/or capillary-bound in micropores and natural fractures, but there is no free water in the shale (Bruner and Smosna, 2011).

Natural gas in the Barnett Shale is stored both as free gas within pores and microfractures and also adsorbed onto solid organic matter and kerogen. This dual-storage

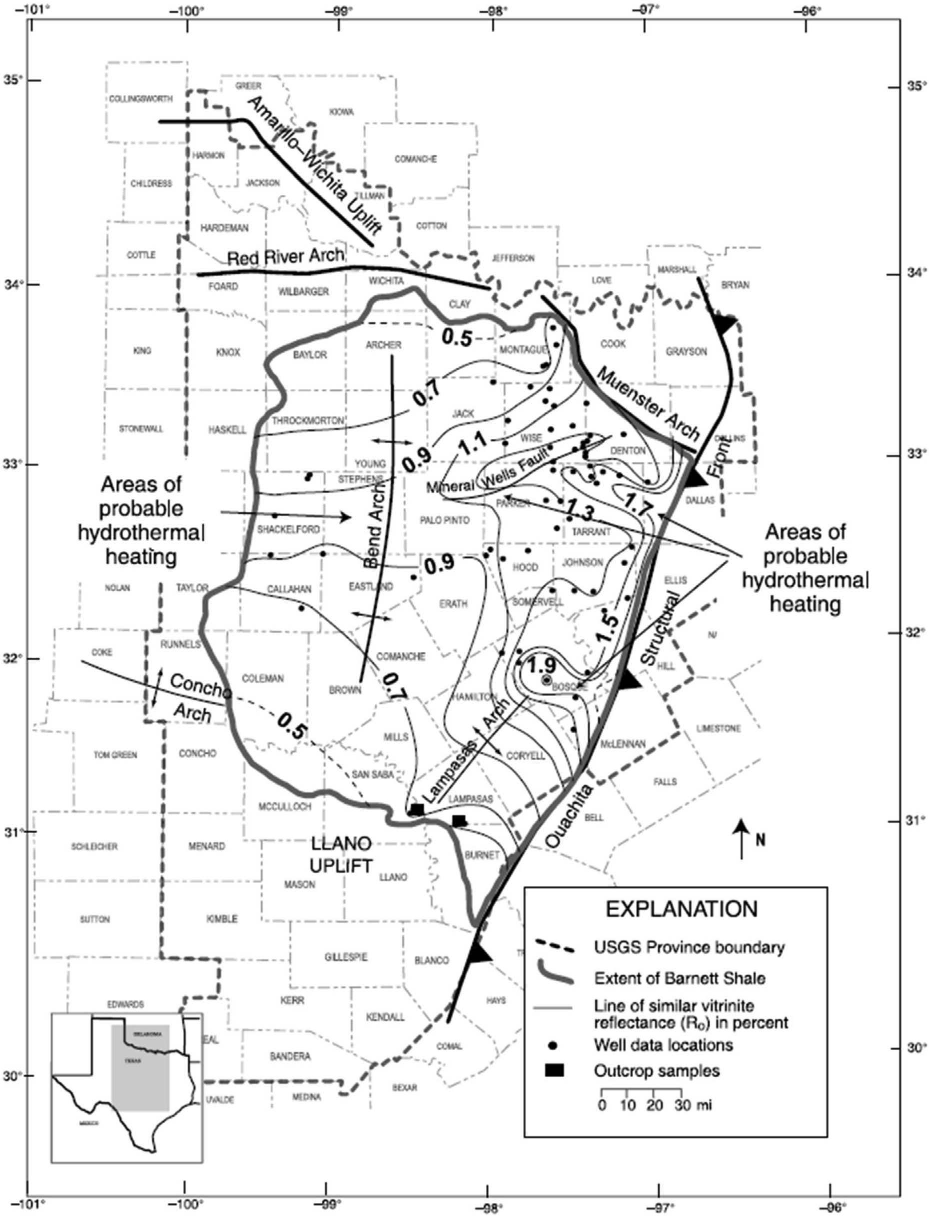

FIGURE 3.7 Thermal maturity in the Barnett shale expressed as vitrinite reflectance (Ro). *Modified from Pollastro, R.M., Jarvie, D.M., Hill, R.J., Adams, C.W., 2007, Geologic framework of the Mississippian Barnett Shale, Barnett-Paleozoic total petroleum system, Bend arch-Fort Worth Basin, Texas. American Association of Petroleum Geologists Bulletin 91, 405–436.*

mechanism is common in organic-rich shales. The adsorbed gas remains bound until reservoir pressures drop below a critical value and then contributes to production (Soeder, 2017). At a typical initial subsurface reservoir pressure of 3000–4000 psi (20.6–27.6 MPa), an estimated 80% of the Barnett Shale gas is free and stored in open pores. As pressures drop below 1000 psi (6.9 MPa), desorption of methane becomes important to gas production (Bruner and Smosna, 2011).

The conversion of kerogen to hydrocarbons is suspected to have produced microfractures within in the shale, as well as a slight overpressuring with a pore pressure gradient of about 0.52 psi/ft (11.8 kPa/m). Many of the initial microfractures have been sealed by residual oil and pyrobitumen (Bruner and Smosna, 2011). Hydrocarbon gas in the Barnett Shale is approximately 90% methane and primarily thermogenic in origin.

The Barnett Shale is a continuous gas resource that underlies thousands of square miles of Central Texas. In a classic petroleum geology sense, it can be described as a stratigraphic trap within a fault-bounded basin, occupying a structural low and straddling the basin axis. USGS estimates in 2003 were only able to obtain vertical well production data from 1981 through 2003 and did not include production data from horizontal wells. The 2003 assessment concluded that the volume of undiscovered, technically recoverable natural gas in the Barnett Shale was about 26.2 TCF (Pollastro, 2007). Operators are typically reluctant to release recent data required for accurate resource assessments, such as bottomhole pressures or decline curves, and the challenges of obtaining such data are common to all shale plays. An eventual re-evaluation of the Barnett Shale by the USGS in 2015 was able to include production data from horizontal wells, and nearly doubled the recoverable gas estimate to 52 TCF, along with 172 million bbl of recoverable petroleum, and 176 million bbl of NGL (Marra, 2018).

Fayetteville Shale

In 2004, Southwestern Energy announced that the Fayetteville Shale in Arkansas had many similarities to the Barnett Shale in terms of gas content and hydraulic fracturing ability, setting off a drilling boom in this formation. The Fayetteville had a history of modest gas flow from vertical wells, and Southwestern Energy thought that George Mitchell's techniques of lateral boreholes and staged hydraulic fracturing could greatly increase production.

The Fayetteville Shale is a fissile black shale containing thin interbeds of bluish black, lithographic limestone with septarian concretions (Huffman, 1958). It was first described by Simonds in 1888 in Washington County, Arkansas (Branner, 1891). The formation is Late Mississippian in age (331–323 Ma) and was named for outcrops along the West Fork of the White River at the town of Fayetteville in northwestern Arkansas.

The Fayetteville Shale occurs within the Arkoma basin of Arkansas and Oklahoma. This basin was formed along the Ouachita thrust front in a manner similar to the Fort

Worth basin to the south. Thus, the Fayetteville Shale is in fact quite similar in age and geologic character to the relatively nearby Barnett Shale (Shelby, 2008). A third, similar black shale, the Woodford, is present in the Anadarko basin to the west of the Fayetteville play in Oklahoma. It will be described later.

The Fayetteville consists largely of thermally mature, organic rich, fissile black shale. The upper part is composed of interbedded limestone and shale that grades upward into the overlying Pitkin Limestone (Fig. 3.8). The lower part of the Fayetteville Shale is organic rich, contains a concretion zone (Fig. 3.9), and the base rests on an erosional unconformity at the top of the underlying Hindsville Limestone (Huffman, 1958).

FIGURE 3.8 Contact between the Fayetteville Shale and the overlying Pitkin Limestone in a road cut in northwest Arkansas. Arkansas Geological Survey photo.

FIGURE 3.9 Concretion zone near the base of the Fayetteville Shale in Arkansas. Arkansas Geological Survey photo.

The Fayetteville Shale is thermally mature and primarily a dry gas play. The shale ranges in thickness from 50 to 550 ft (15–168 m) and in depth from surface outcrops to 6500 ft (1981 m). Development began in 2002 after Southwestern Energy Company had reworked and tested an older vertical well in western Arkansas and determined that commercial levels of gas within the Fayetteville could probably be extracted using the techniques that had brought Mitchell Energy success on the Barnett. The company began one of the most successful secret leasing operations in history, quietly acquiring 455,000 acres in the prime development area before even drilling the "discovery well" in Conway County. By the summer of 2004, rumors and gossip were spreading among industry people about something going on in northern Arkansas. Southwestern announced it publicly soon afterward, once all the good leases were locked down. An interesting aspect of the O&G industry is that rather than being angry with Southwestern for secretly leasing up a new shale play and cutting out the competition, the company was widely admired for their cleverness. Most of the development was in North Central Arkansas (Fig. 3.10).

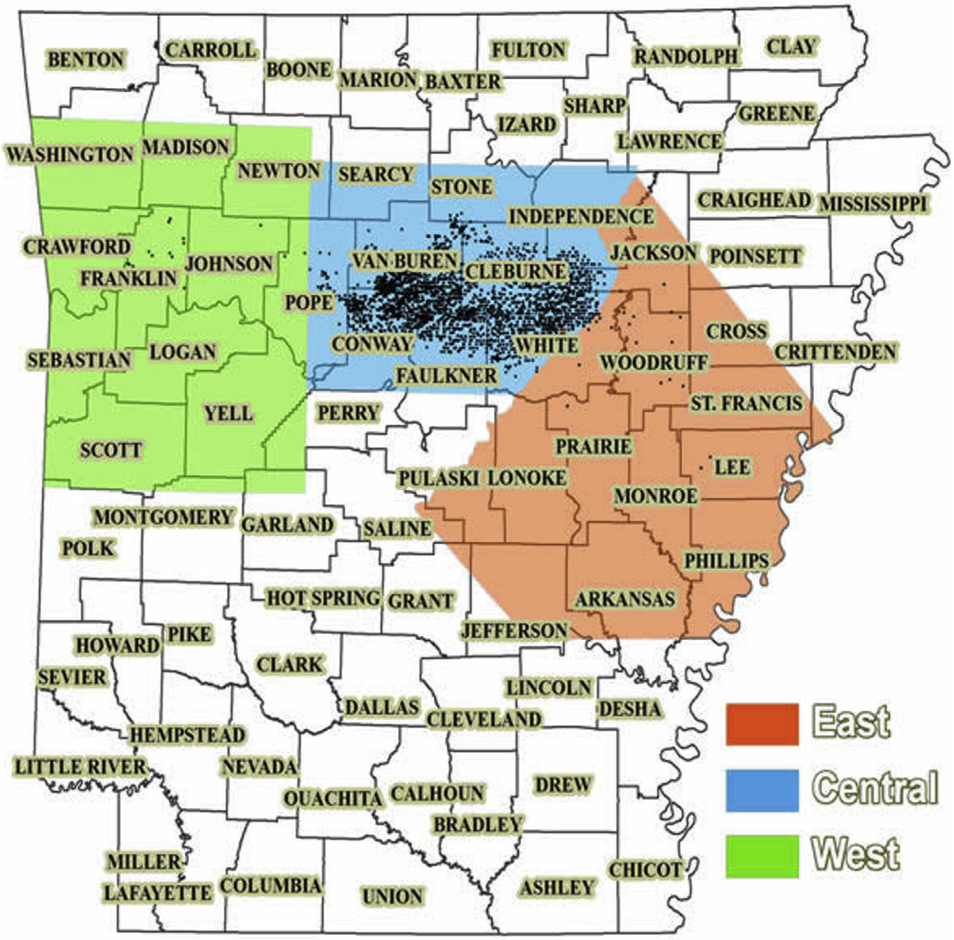

FIGURE 3.10 Fayetteville Shale development regions in Arkansas. Arkansas Geological Survey map.

Oil and gas has always been a boom and bust cycle. When shortages develop, prices go up, and everybody hurries in to drill a play. This causes production to spike, and supply outstrips demand, resulting in a price drop. So drilling ceases, people get fired, and production slackens, until shortages develop again. This cycle is well-understood in the business (e.g., a typical joke: What's the difference between an unemployed oil executive and a pigeon? The pigeon can still place a deposit on a Mercedes). However, no one was prepared for the scale of the boom in shale gas.

The Barnett boom took off relatively slowly as Mitchell Energy perfected the production techniques by trial and error and other companies gradually joined in. The Fayetteville boom went off like a rocket and essentially wrote the script for the future development of many other US shale plays. Shales are very different from conventional reservoirs, because of the "continuous" nature of the gas resource. A much greater land area is involved with many more leases, pads, and wells than in a conventional play and everything else gets scaled-up to match.

Landmen and leasing agents overran small Arkansas County courthouses searching for mineral rights and land ownership records. Local motels, restaurants, bars, gas stations, retail stores, and other businesses were overwhelmed with customers, and those who were able to cope made significant profits. As drilling commenced, understaffed small town and county law enforcement officials could not keep up with spiking crime rates, the greater frequency of disorderly conduct, squabbles, outright drunken brawls, and increased motor vehicle accidents caused by the hordes of mostly young, male, single, and well-paid outsiders invading their communities.

Similar stories have been recorded as part of the boom on most other shale plays, such as the "man camps" hastily constructed from cargo containers for housing Bakken Shale workers in North Dakota, or the concerned high school students who counted 50 huge trucks per hour hauling gravel through downtown Waynesburg, Pennsylvania to build Marcellus drill pads. During a boom, shortages become commonplace for everything from bathroom tissue to dog food. Big box retail stores didn't even bother to put items on shelves, but just brought the pallets to the front of the store and let people descend on them like a pack of wolves. Traffic jams backed up roads for hours. None of this gives the locals any warm and fuzzy feelings toward the industry crews.

The inexperienced work crews pressed into service in the early days of the boom to develop a shale play often carelessly or unknowingly inflict significant environmental damage on landscapes, streams, watersheds, and habitats while building access roads and constructing the typical five-acre shale well drill pads. A case was reported in West Virginia where a crew simply drove a bulldozer straight up the middle of a creek bed to build a road to their pad location (Soeder, 2017). Large trucks transporting gravel, water, chemicals, drill pipe, and other materials to well sites raise choking clouds of dust and leave deep ruts on rural highways. An unpaved county road used by Niobrara work crews in eastern Colorado had to be regraded on a weekly basis during periods of active drilling. Heavy equipment being moved at all hours on narrow roads may block access to homes, schools, churches, stores, and other facilities, sometimes for half a day.

This scenario has been repeated on shale play after shale play and often leaves feelings of resentment against O&G operators among many local citizens. The inexperienced work crews in the early days of the boom are pushed hard by managers to get wells in the ground as quickly as possible. In the process, they may commit numerous environmental sins that end up fueling local opposition to shale gas development that lingers for decades (Soeder, 2017).

For an idea of just how intense this boom cycle can be, consider the following: the number of lateral wells drilled annually in the Fayetteville Shale began with 54 in 2005, increasing more than tenfold in just 2 years to 574 in 2007, and increasing tenfold again to 5567 in 2014 (Seaman, 2016). That's a hundredfold increase of annual drilling activity in less than 10 years. As a result of all this overproduction, the Fayetteville Shale natural gas spot price (the current market price at which a commodity can be bought or sold for immediate delivery) fell from $13.42 per million Btu in November 2005 to $1.73 per million Btu in May 2016 (Seaman, 2016). The crash representing the bust part of the cycle was nearly as spectacular as the boom. Drilling dropped off steeply after 2015, and by 2018, there were no development rigs at all operating in the Fayetteville Shale, only workover and repair rigs.

As of December 31, 2016, Southwestern Energy, operating as SEECO, reportedly still held leases for approximately 918,535 net acres (nearly a million acres) in the Fayetteville Shale. According to Southwestern's website, shale gas wells in the Fayetteville had an average completed well cost of $2.8 million per well and an average horizontal lateral length of 5547 ft. (https://www.swn.com/operations/pages/fayettevilleshale.aspx) Whether or not this production will continue to be economic in the face of more efficient competition on other shale plays remains to be seen.

The Texas Bureau of Economic Geology (BEG) investigated the resource base of the Fayetteville Shale using methods developed for the Barnett Shale in Texas (Browning et al., 2014). Their conclusions for the Fayetteville Shale are based on data from 2011 and incorporate some necessarily broad assumptions. Recent advances in extended lateral lengths, the decline in shale well drilling costs per foot, and increases in natural gas prices all affect these findings to some degree. Nevertheless, the study has produced some interesting results. The Texas BEG assessed the resource base of the Fayetteville Shale at 80 TCF GIP. Of this, 38 TCF are said to be technically recoverable. The 3689 wells drilled through 2011 and the expected total of 10,117 wells by 2030 are estimated to have a EUR of 18.2 TCF. Because of the relatively low pore pressures in the Fayetteville due to the generally shallow depths, adsorbed gas makes significant contribution to the total. The Texas BEG study concluded that production from the Fayetteville Shale will peak at about 0.95 TCF/year, followed by slow decline (Browning et al., 2014).

The development of the Fayetteville Shale was also notable in that it sparked some of the first significant environmental studies on the potential impacts that shale gas drilling, fracking, and gas production have on water resources, air quality, habitat, and ecosystems. Although a number of similar environmental investigations have been carried out over the years, these were primarily focused on conventional O&G (i.e., Pétron et al., 2012; Pekney et al., 2014).

The first concerns about the potential impact of shale gas development on water resources were expressed by the USGS in 2009 (Soeder and Kappel, 2009), due to the large scale of the operations. Concerns were threefold: (1) potential impacts on water supplies because of the large volumes needed for fracking, (2) potential impacts to headwater streams, catchments, and small watersheds from road and pad construction, and (3) potential impacts to water quality from drilling fluids, frack chemicals, and produced water.

Arkansas researchers started looking into possible degradation of stream habitats from shale gas activities (Entrekin et al., 2015). The Fayetteville play was a good location for this, having been underway for nearly a decade. Much of the development was in rural Arkansas, where some environmental baselines had been established, and preexisting disturbance was often minimal. By comparison, untangling the environmental impacts of the Barnett Shale development from everything else that has happened in the Dallas-Fort Worth metroplex is extremely difficult. Researchers in Arkansas have concluded that Fayetteville Shale gas development will likely have substantial negative effects on forested habitats and the organisms that depend upon them (Moran et al., 2015). Aquatic organisms in streams used as water sources for Fayetteville Shale hydraulic fracturing could be stressed by high-volume, short duration water withdrawals, which often exceed median streamflow at half of all withdrawal sites in early summer, when flows are low (Entrekin et al., 2018). There are environmental issues in many shale plays, but they seem to have been defined most clearly on the Fayetteville Shale.

Haynesville Shale

A few years after the beginning of the Fayetteville Shale development boom, Chesapeake Energy of Oklahoma decided in 2006 to attempt gas production from the Haynesville Shale on the US Gulf Coast using the horizontal drilling and staged hydraulic fracturing techniques that had proven so successful on the Barnett Shale and later in the Fayetteville. The Haynesville Shale is an organic rich, calcareous mudstone that was deposited in a deep, partly anoxic basin surrounded by carbonate shelves during the Late Jurassic (164–145 Ma) (Hammes and Gale, 2014). The Haynesville spans a large area along the boundary of eastern Texas and northwestern Louisiana near the Arkansas line, in an area known locally as the ArkLaTex (Fig. 3.11).

Unlike the relatively shallow Barnett and Fayetteville shales, the Haynesville Shale lies deep under the Gulf Coast plain, at depths of 10,000 to 13,000 ft (3–4 km) in the relatively small Arkla basin (Eversull, 1984). Experience with other shales had resulted in a fairly good understanding of the economics and technology involved when the Haynesville development began, including the relationship between depth and recoverable gas. Because pore pressure increases with depth, and gas is far more compressible than oil or water, there are greater amounts of gas per unit pore volume at greater depths. However,

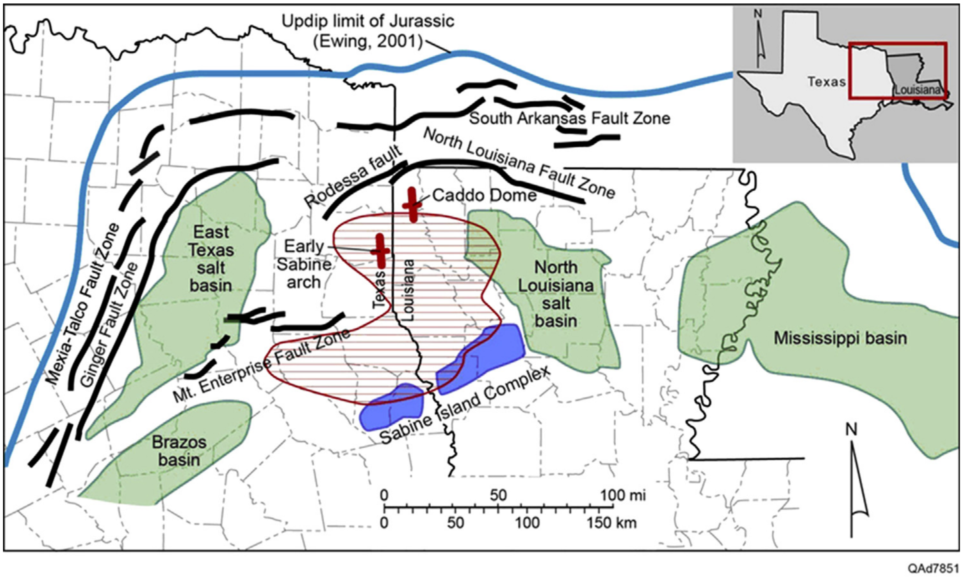

FIGURE 3.11 Red striped area showing location of Haynesville Shale development in the Arkansas, Texas, and Louisiana border region known as the ArkLaTex. Texas Bureau of Economic Geology map.

drilling costs also increase with depth. Chesapeake had to carefully consider the trade-off between the costs of installing deep wells versus the expected recovery of gas.

Upstream and midstream costs are the two major, location-specific cost variables involved with developing hydrocarbon resources anywhere in the world. Upstream cost, sometimes described more simply (if inaccurately) as "the cost of drilling," is the cost to recover the hydrocarbons from the ground. It depends on depth (deeper targets are more expensive), location, and geology. Land drilling is cheaper than deep water drilling, for example, and drilling in an "oil patch" area like west Texas where equipment and expertise are readily available is cheaper than going to someplace like southern Ohio where all of this has to be imported. Harder rocks are usually slower to drill (known as the rate of penetration or ROP) than softer rocks, and highly fractured rocks can cause a loss of circulation (LOC) incident where the drilling fluid disappears into the formation, resulting in expensive delays.

The second major set of costs are known as midstream costs and encompass the various pieces of oilfield infrastructure needed to collect and transport the hydrocarbons out of the production area to places where they can be used. Midstream costs include pipelines, compressor stations, pumping stations, gas processing plants, etc. needed to get the O&G from the production field to a refinery or distribution system. A third set of costs for downstream infrastructure like refineries, distribution systems, and the manufacture of products for sale, like gasoline or motor oil are usually not specific to the development of a particular shale play, but are shared by the industry among conventional and unconventional operators.

For natural gas, midstream pipeline infrastructure is critical for transporting it out of a production field and to consumers. Petroleum can be moved by tanker truck or railroad cars, although pipelines are safer and more efficient. But there is no choice with gas; it has to be compressed and placed in a pipeline. Many shale gas resources do not have access to existing pipelines and the gas is said to be "stranded." If the shale also contains petroleum or NGL, the gas is often burned off or "flared" so operators can recover the valuable liquids. Stranded gas without liquids is typically left in place until a pipeline is constructed nearby (Soeder, 2018).

The costs of installing this infrastructure, from the well pad to the refinery, are known as capital expense, or CAPEX. The costs of running everything, from supplies to utilities to worker salaries, are known as operating expenses, or OPEX. Companies look at both of these expense categories very carefully before deciding how, where, and when to develop a play.

Chesapeake Energy knew, of course, that the greater depth of the Haynesville would require more expensive wells. On the other hand, vast amounts of oil and gas had been produced from conventional reservoirs in this area of the Gulf Coast for decades. Thus, the amount of existing midstream infrastructure already in place was significant. If they could connect new Haynesville wells to compressors and pipelines with minimal additional CAPEX, the economics would be quite favorable. Because shale is a continuous resource, Chesapeake could place their well pads in locations that were optimal for tying into this existing infrastructure.

In the end, the economics worked out. Drilling in the Haynesville Shale ramped up between 2008 and 2011, peaking in 2011 at about 10 BCF per day (283 million cubic meters). Production then dropped as prices fell because of oversupply, eventually stabilizing at about six BCF/day (170 million cubic meters) for a number of years. It has recently climbed back into the nine BCF/day (255 million cubic meters) range as a result of stronger gas prices (Fig. 3.12). The Haynesville Shale remains a significant gas-producing formation in the United States (refer back to Figure 1 in the Introduction section).

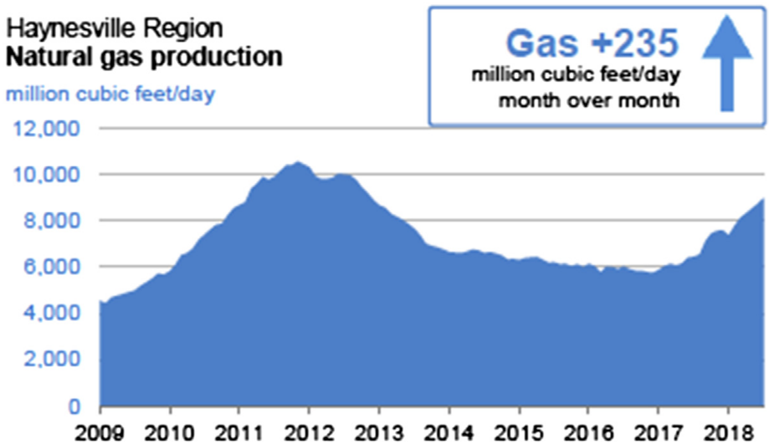

FIGURE 3.12 Natural gas production from the Haynesville Shale in millions of cubic feet per day (MMCFD) from 2009 to 2018. *Modified from US Energy Information Administration web pages.*

Because of the depth, Haynesville discovery reservoir pressures are typically about 10,000 psi (68.95 Mega Pascals or MPa), under geopressured gradients ranging from 0.7 to 0.95 psi per foot (Hammes and Gale, 2014). Gas production from the most prolific wells during their peak showed daily averages as high as 13.3 MMCFD. Drilling and completion costs reportedly ranged from $6 to $9 million per well. Hydraulic fracturing typically included 12 to 15 fracture stages per lateral using slickwater, and either ceramic or resin-coated proppant (Hammes and Gale, 2014).

Current geologic models for the Gulf of Mexico basin during Haynesville time suggest that thick evaporite units were deposited after initial rifting, followed by an influx of terrestrial siliciclastics. Highs and subbasins formed on the northern shelf, and these subbasins became the sites of major carbonate deposition interbedded with siliciclastic input from the ancestral Mississippi River and other sources (Steinhoff et al., 2011). The shelf topography controlled sedimentary facies development and depositional patterns along the northern edge of the basin and assisted with the deposition and preservation of abundant organic carbon in the Haynesville Shale (Steinhoff et al., 2011).

The name Haynesville Shale was proposed for the section of rock below a major unconformity within the Cotton Valley Formation and above the Smackover Limestone (Goebel, 1950). The Shreveport Geological Society originally suggested in 1949 that the term "Cotton Valley" be restricted to the gray sands and shales above the unconformity, and that a new formation name be introduced for the red sands, shales, and anhydrite that occur below the unconformity and above the Smackover. These rock units exist completely in the subsurface, and are known only from well logs, drill cuttings, and cores. Thus, the "type locality" for the Haynesville Shale was designated as the stratigraphic section penetrated by the Hunt Oil Company No. 1 well, located in the Haynesville oil field, Claiborne Parish, Louisiana (Goebel, 1950). The formation can vary significantly in thickness, ranging from 400 ft (122 m) in some wells to more than 2000 ft (610 m) at the type locality.

The base of the Haynesville Shale conformably overlies the Smackover Formation (Johnston et al., 2000). Note that this is quite different from the Barnett and Fayetteville shales, both of which rest on significant erosional unconformities. The partial anoxia in the basin during deposition preserved organic matter in some of the Haynesville Shale units, but other units were oxidized into "redbeds" that are found as far east as Alabama and west into Texas.

The Haynesville play is often identified as the Haynesville/Bossier play. In fact, the Railroad Commission (RRC) of Texas (the agency that issues oil and gas well permits in that state; http://www.rrc.state.tx.us/) considers the Haynesville Shale and Bossier Shale to be stratigraphic equivalents, and the names may be used interchangeably on permit applications and completion reports. The RRC position is that there are essentially two names for the same rock because of different geological naming conventions in Texas and Louisiana. That is true as far as it goes, but things are actually a bit more complicated.

The Bossier Formation of the Cotton Valley Group was named by Swain (1944) to include the marine, dark-gray to black shale, sandstone, and shoreward equivalents of these rocks beneath the Schuler Formation and above the Buckner Formation. The Buckner has since been downgraded to member status in Louisiana, and the lower member of the Haynesville Shale (known as the Buckner Anhydrite) is considered to be stratigraphically equivalent to the Buckner Formation of Arkansas (Mancini et al., 1990).

The top of the Haynesville was defined by a major unconformity within the Cotton Valley by Goebel (1950). It is not clear in the literature if this same unconformity is also used to mark the base of the Schuler Formation and subsequently the top of the Bossier. If this were the case, the Bossier would be equivalent to the upper two members of the Haynesville, described as a middle member consisting of interbedded sandstones, shales, and anhydrites, and an upper member composed of interbedded carbonate mudstones, dolomitic limestones, sandstones, shales, and anhydrites (Mancini et al., 1990).

The Bossier Shale is defined by the stratigraphy penetrated by the Phillips Petroleum Co. Kendrick No. 1 well in Bossier Parish, western Louisiana (Swain, 1944). The formation thickness reaches as much as 2000 ft in the North Lisbon field of east-central Claiborne Parish, Louisiana. Even Swain (1944), who defined it, states that the relationship to the underlying Buckner Formation is not clear, and in some areas, the Bossier rests directly on the Smackover limestone. The overlying Schuler Formation was classified by Swain (1944) as the upper formation of the Cotton Valley Group.

In another assessment 20 years after it was first defined, Mann and Thomas (1964) described the Bossier as a dark-gray to black shale and sandstone deposited in a restricted marine environment. They classified it as the basal formation in the Cotton Valley Group in Louisiana and state that it pinches out a few miles north of the Louisiana–Arkansas border. Like Swain (1944), they placed the Bossier stratigraphically under the Schuler Formation, but they also have it above the Haynesville Formation.

Dickinson (1968) described the Bossier Formation as the predominantly dark-gray, fossiliferous, calcareous marine shale of the Cotton Valley Group, and stated that it includes the stratigraphy above the Smackover Formation referred to as the Buckner by Swain (1944). So in this case, it does now appear to be equivalent to the Haynesville Shale as defined by Goebel (1950). The Texas RRC convention of using both names interchangeably to describe the Upper Jurassic gas shale above the Smackover limestone and below the Cotton Valley unconformity is geologically and stratigraphically acceptable. However, these two names for one formation did not come from different naming conventions in two different states. Rather, they came about because of the challenging and often confusing practice of performing Gulf Coast stratigraphy on rocks that can't actually be seen.

Marcellus Shale

The Fossil Fuel Revolution, which began with the efforts of the Eastern Gas Shales Project in the 1980s before achieving success in the late 1990s on the Barnett Shale in Texas, returned to the Appalachian basin with the development of the Marcellus Shale in 2006 (Soeder, 2017). Although Mitchell Energy's success on the Barnett was fairly well-known among people in the O&G industry (Montgomery et al., 2005), and there had been quite a bit of excitement a few years after that in the Fayetteville (Seaman, 2016), the Haynesville, and the Woodford shales, it took awhile for someone to realize that the venerable black shales of the Appalachian basin, which had produced natural gas in a small way since 1821 (Curtis, 2002), could also be tapped commercially using these same methods.

That "someone" was William ("Bill") Zagorski, an exploration geologist at Range Resources. Zagorski had been raised in Pittsburgh, Pennsylvania, received a degree in geology from the University of Pittsburgh, and spent 30 years in the O&G industry (Campbell, 2010). Production companies the size of Range Resources, headquartered in Fort Worth, Texas, are known in the industry as "independents," in contrast to the gigantic, multinational corporations known as the "majors." Range is considered to be a medium to large independent.

In 2005, Zagorski was in charge of drilling a well for Range Resources called Rentz#1 in the southwestern corner of Pennsylvania to test for oil and gas prospects in the Lockport Dolomite, a Silurian-age carbonate rock that occurs throughout large parts of the Appalachian basin (Soeder, 2017). The rock dolomite, named after the Italian mountains where it is common, was typically deposited originally as a calcite-rich limestone that became altered during diagenesis by the passage of magnesium-enriched fluids through the rock. The fluids caused the calcite to recrystallize into a magnesium–calcium carbonate mineral also known as dolomite (sometimes the rock is called "dolostone" to distinguish it from the mineral). The mineral dolomite often forms larger, more isolated crystals than the original calcite. This gives the altered rocks a sugary texture, which tends to create open porosity between the crystals that may contain oil and gas. At least that's the theory, anyway.

The Rentz#1 well came back with low porosity and poor gas shows from the Lockport Dolomite. Such occurrences are not all that uncommon and are part of the business of drilling for gas or oil. Still, a disappointed Bill Zagorski was left wondering what to do with this nonproductive dry hole. A few months later, he was in Houston talking with potential investors about trying to develop a shale gas prospect in Alabama using Mitchell Energy's production technology. As Zagorski tells it, "a lightbulb went on" as he recalled that there had been gas shows in the Marcellus Shale when the Rentz#1 well drilled through it on the way to the deeper Lockport Dolomite (Durham, 2010).

Reinvigorated with this new idea, Zagorski researched what was known about natural gas resources in the Marcellus Shale. One of his important sources turned out to be many of the old DOE technical papers, EGSP reports, and related literature that included information on the Marcellus. Unfortunately, these were not exactly abundant. For starters, more than a quarter century had passed since the end of drilling activity on the EGSP. The US Department of Energy had changed priorities several times in the intervening years, and many of the original reports and data files had been lost or had deteriorated.

A bigger obstacle was that most of the EGSP efforts had been focused on the Late Devonian units, in particular the Huron Member of the Ohio Shale because of the success of the Big Sandy Field (discussed earlier in Chapter 2). The Middle Devonian Marcellus Shale is at the base of the Appalachian basin Devonian shale section (Fig. 3.13), and only eight of the 34 Appalachian basin EGSP cores even included the Marcellus Shale, which in some wells was less than a meter thick (Soeder, 2017). Very few analyses had been run on the Marcellus, including just one set of porosity and permeability measurements on a single core sample (Soeder, 1988).

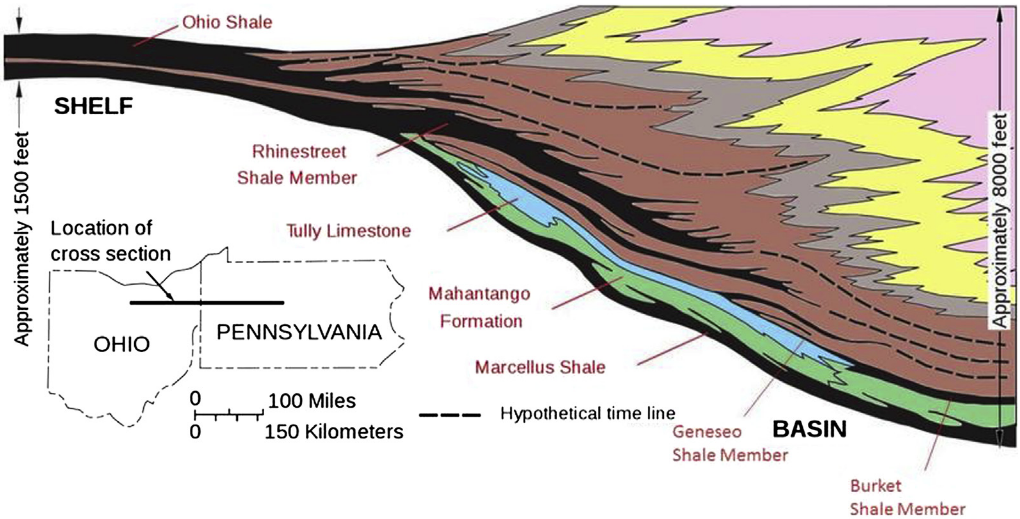

FIGURE 3.13 Schematic cross-section of the Appalachian basin, showing Middle and Upper Devonian rocks. The Marcellus Shale is at the base of a thick alternating sequence of organic rich and lean shales with a few limestones. Coarser sediments to the right are clastics from the Catskill delta. *Modified from Bruner, K.R., Smosna, R., 2011. A Comparative Study of the Mississippian Barnett Shale, Fort Worth Basin, and Devonian Marcellus Shale, Appalachian Basin. U.S. Department of Energy Report DOE/NETL-2011/1478, 106 p.*

Nevertheless, armed with whatever information he could find, and after convincing his superiors at Range Resources that the Marcellus did indeed have gas potential, Bill Zagorski returned to the Rentz#1 well to run some field tests. The well was recompleted and hydraulically fractured in the Marcellus Shale section. There was a significant return of initial gas production. Rentz#1 is a vertical well, and Zagorski began to wonder what might be recovered from the Marcellus using the Mitchell Energy technique of lateral boreholes and staged hydraulic fracturing.

In 2006, Range Resources moved a triple drill rig (refer back to Fig. 2.6) into the Appalachian basin to drill and test some horizontal wells in the Marcellus Shale on leases held by the company in southwestern Pennsylvania. Drilling rigs this large were quite rare in the Appalachian region at the time, which had typically been explored with the smaller double or even single rigs. Oilfield infrastructure that was readily available on the Gulf Coast and in Texas was also almost nonexistent in Pennsylvania. Large volumes of materials were needed for horizontal drilling, including gravel for road and pad construction, specialized drilling equipment, chemicals and additives, proppant sand, and water for fracking. Range found local sources, such as gravel quarries and municipal water suppliers, and transported in the other equipment and materials required to test lateral drilling and staged fracks on the Marcellus Shale.

The first lesson learned on a new play is that all shales are different. The Mitchell Energy frack procedure that worked so well on the Barnett was not terribly effective in the Marcellus. The lithology of these two shales differs – the Barnett is typically composed of organic rich, dense, siliceous shale and hard, petroliferous limestone that is brittle and fracks easily (Bruner and Smosna, 2011). The Marcellus, on the other hand, is composed of splintery, soft, black carbonaceous shale above a dense middle limestone and a basal, hard, siliceous shale (Bruner and Smosna, 2011). These rocks fracture in a complex manner. Along with differences in lithology, the two formations have different rock strengths, are under different stress regimes, and have different frack barrier units both upward and downward. The Marcellus typically generates longer fractures than the Barnett, but also has more of a problem with proppant embedment in the softer shale (Bruner and Smosna, 2011).

Zagorski and Range Resources found themselves experimenting with different frack fluid formulations, different proppant types, different additives, and different pressures and pumping rates. Eventually, they found a combination that was effective on the Marcellus Shale. The first successful Marcellus Shale horizontal well was Gulla#9, located in Washington County, Pennsylvania, not far from the Rentz#1 well. Gulla#9 was completed in 2007 and returned an IP of nearly five million cubic feet of gas per day (140,000 cubic meters), which is known informally as a "barn-burner" in the O&G industry. For gas shale, an IP this high was practically unheard of at the time, although some shale wells now have IPs more than 10 times greater. Zagorski has identified Gulla#9 as the "discovery" well for the Marcellus Shale, and the one that started the play (Soeder, 2017).

Bill Zagorski received the Norman H. Foster Outstanding Explorer Award and was named "explorer of the year" by the American Association of Petroleum Geologists (AAPG) at their 2013 national meeting in Pittsburgh for his discoveries in the Marcellus Shale (Brown, 2013). Even more telling about the importance of the Marcellus Shale was the fact that this 2013 meeting was the first ever held in Pittsburgh by the AAPG. In fact, it was the first annual AAPG meeting located east of the Mississippi River since 1986.

The Marcellus Shale extends across much of the Appalachian basin, covering a geographical area of some 75,000 square miles (194,250 sq. km) (Bruner and Smosna, 2011). The potentially prospective area of the Marcellus Shale may be as large as 44,000 square miles (114,000 sq. km), and estimates for the reserve potential range from 50 TCF to more than 500 TCF, making the Marcellus Shale a major, world-class hydrocarbon accumulation (Zagorski et al., 2012). The Marcellus has become the single largest gas-producing formation in the United States (refer back to Figure 1 in the Introduction section).

The Marcellus Shale outcrops along the northern rim of the Appalachian basin in New York State, and in the Valley and Ridge province along the eastern edge of the basin where it has been exposed at the surface by folding. It disappears to the west in a feather edge, and to the south it becomes part of a compressed section of Devonian shales that include the Millboro and the Chattanooga (Soeder et al., 2014). The Marcellus Shale was named by Cooper (1930) for the type section less than 1.6 km (one mile) south of the small village of Marcellus, New York. The Marcellus Shale and the Mahantango Shale above it are members of the Hamilton Group, which may or may not (depending on the author) include the Tully Limestone above the Mahantango, and a number of equivalent, minor shale formations such as the Moscow and Skaneateles (de Witt et al., 1993).

The Devonian—Mississippian sedimentary rock sequence in the Appalachian basin is fairly thick. The Marcellus Shale was deposited in an inland sea between about 393 and 383 Ma during the Middle Devonian period and represents the first significant pulse of clastic sediment into the Appalachian basin from highland areas developing to the east from the Acadian orogeny, a precursor to the later, larger Allegheny orogeny (Soeder, 2017). The Early Devonian Mandata Shale occurs beneath a thick limestone sequence underlying the Marcellus (Baez, 2004), but is considered to be a clastic influx separate from the more than 2 kilometers of sediment deposited continuously into the Appalachian basin between Middle Devonian and Middle Mississippian time (Soeder, 2017).

A significant delta complex (refer back to Fig. 3.13) fed by as many as five major river systems flowing off the Acadian mountains contributed sediment to the Appalachian basin along some 160 km (100 miles) of shoreline (Boswell and Donaldson, 1988). This delta complex was deposited primarily during the Late Devonian (383—359 Ma), and up to 12,000 vertical feet (4 km) of sediment may have accumulated above the Marcellus Shale (Milici and Swezey, 2015), exposing it to fairly high pressures and temperatures (Rowan, 2006), which cracked nearly all of the complex hydrocarbons in this rock to methane (CH_4), the simplest and most common form of natural gas. The remains of the massive, Late Devonian-age delta form the present-day Catskill Mountains in New York (Schwietering, 1979).

The lower boundary of the Marcellus Shale is sharp, resting on an erosional unconformity at the top of the Onondaga Limestone (Fig. 3.14), or on an equivalent unit to the southeast, the Needmore Shale. In contrast, the upper boundary is gradational, changing over a vertical distance of several meters into the Mahantango Shale, an organic-lean gray shale named for exposures in the valley of Mahantango Creek in Snyder County, Pennsylvania (Willard, 1935).

FIGURE 3.14 Basal contact of the Marcellus Shale above the Onondaga Limestone, Seneca Stone quarry, Seneca Falls, NY. *Photographed in 2016 by Dan Soeder.*

The Marcellus Shale is subdivided into numerous members. In the thickest part of the formation near the depocenter in northeastern Pennsylvania, there are a dozen subunits, but only three significant members extend across the bulk of the formation (Nyahay et al., 2007). The lowest of these is known as the Union Springs Member. It is generally siliceous, organic rich, pyritic, and brittle. It tends to weather into flagstones or slabs a few cm thick which break like dinner plates. Up to eight distinct beds of Tioga Ash have been identified in the upper part of the Onondaga Limestone and base of the Union Springs Member (Fig. 3.15). The Tioga Ash is a volcaniclastic deposit erupted from a

FIGURE 3.15 Tioga Ash beds in an outcrop of the Union Springs Member of the Marcellus Shale near Bedford, Pennsylvania. Rock hammer for scale is 13 inches (33 cm) in length. *Photographed in 2016 by Dan Soeder.*

long-extinct source volcano located on the piedmont in central Virginia (Dennison and Textoris, 1970).

As shown in Fig. 3.15, the head of the rock hammer is resting on a thin bed of Tioga Ash in the Union Springs Member, which has produced distinctive, orange-colored iron oxide stains on the shale beds below it. A thicker ash bed with vegetation growing in it can be seen across the middle of the photo; it too has stained the rocks below. These ash beds provide useful, “instantaneous” time-stratigraphic markers for understanding sedimentation processes during the deposition of the Marcellus Shale (Dennison and Textoris, 1970).

Above the Union Springs Member is the Cherry Valley Limestone, a relatively thin, organic rich carbonate rock that occurs in New York and northern Pennsylvania (Fig. 3.16). Another limestone known as the Pursell Member is present at approximately the same stratigraphic position within the Marcellus Shale in southern Pennsylvania and West Virginia. There is considerable debate as to whether the Pursell is a southern extension of the Cherry Valley, an equivalent but completely separate body of rock, or a totally different unit altogether (Bruner and Smosna, 2011). The consensus view at present is that these are two distinct limestone units. Neither is thick enough to serve as a frack barrier, and Marcellus fracks typically extend through the entire formation, and up into the overlying Mahantango Shale. The Tully Limestone is considered a frack barrier above the Mahantango (Bruner and Smosna, 2011).

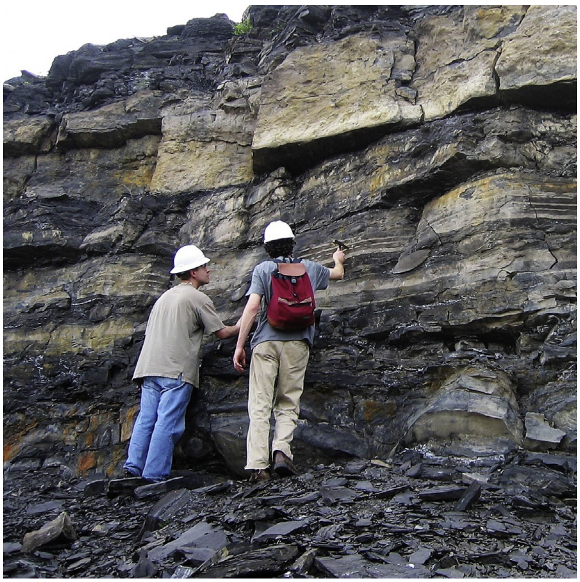

FIGURE 3.16 Cherry Valley Limestone member of the Marcellus Shale exposed in a quarry near Oriskany Falls, NY. *Photographed in 2010 by Dan Soeder.*

The upper and thickest part of the Marcellus Shale is the Oatka Creek Member, named for exposures in the bed of Oatka Creek, New York (fractures in this unit were shown back in Fig. 2.11). The Oatka Creek is less organic rich than the Union Springs, but still contains significant organic carbon (Bruner and Smosna, 2011). It is a fissile, clayey shale that typically splits into paper thin sheets on outcrops, and contains distinctive beds of bowling-ball sized carbonate concretions, commonly siderite (Fig. 3.17).

FIGURE 3.17 Oatka Creek north of Leroy, NY. The stream bed here is composed of the Oatka Creek Member of the Marcellus Shale. Ball-like objects in the stream are siderite concretions. *Photographed in 2016 by Dan Soeder.*

Production of gas from the Marcellus Shale is concentrated in two core areas in southwestern and northeastern Pennsylvania (Fig. 3.18). The discovery area includes southwestern Pennsylvania, the northern panhandle of West Virginia, and the north-central counties of West Virginia. The formation here is relatively thin (around 100 ft or 30 m) and occurs at depths of 6000–8000 ft (1.8–2.4 km). One of the attractions of this area is the significant amount of preexisting midstream natural gas pipeline infrastructure. Several major natural gas transmission lines carrying gas from the Gulf Coast to the Northeast pass through here, allowing easy access to market the gas, which is an important consideration.

The second Marcellus core area is in northeastern Pennsylvania, where the formation is thicker (up to 1000 ft, or 300 m) and shallower, at depths of 3000–4000 ft (914 m–1219 m). Wells in this area tend to be more productive than wells in the

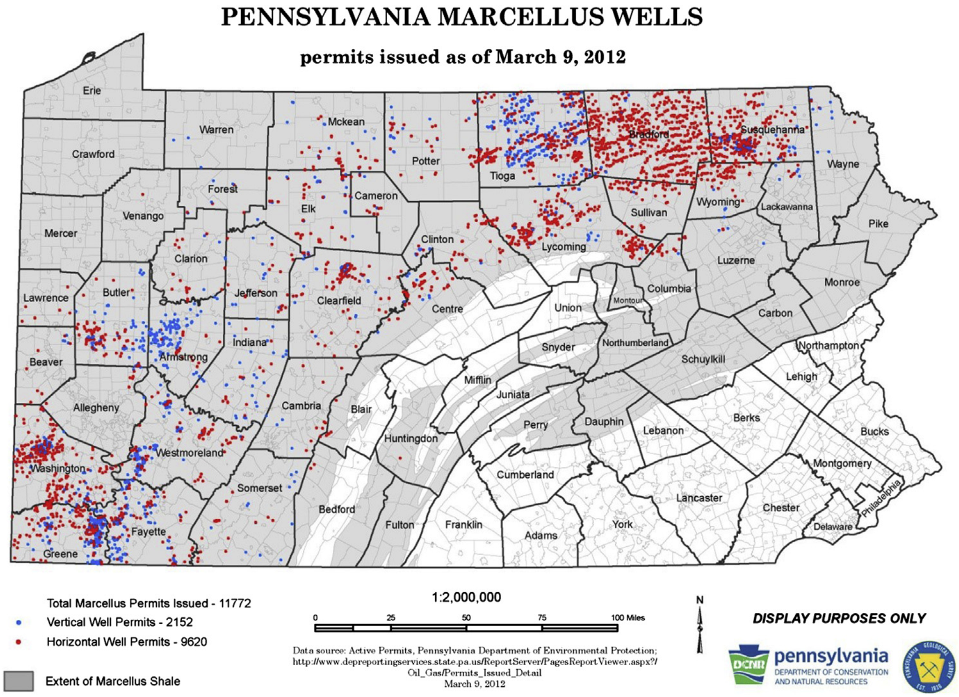

FIGURE 3.18 Permits for Marcellus Shale gas wells issued in Pennsylvania as of 2012 show core production areas in the northeastern and southwestern parts of the state. The southwestern production area extends into West Virginia. Pennsylvania Department of Conservation and Natural Resources map.

southwestern part of the state, but the natural gas transmission infrastructure is more limited. Attempts have also been made to develop the Marcellus Shale in the "central" region between the two core areas, but the low price of gas and limited midstream infrastructure have slowed the pace.

Although the Marcellus is known as an overmature shale that produces primarily dry gas, some additional hydrocarbons have been discovered along the western edge of the play near the Ohio River. Prominent among these is ethane. When placed under high temperature and pressure in combination with steam, ethane "cracks" and transforms into ethylene, a building block in the production of polyethylene (U.S. Department of Energy, 2017).

Petrochemical plants in the Appalachian basin were shut down in the 1980s, so the ethane has been shipped to Gulf Coast plants for processing into plastic and some is also being sent to Europe. This has proven to be inefficient, and Shell Chemicals began construction of a cracking plant in Monaca, PA, on the Ohio River west of Pittsburgh in 2012, which is expected to be completed by 2020 or 2021 and begin processing 90,000 bbl/day of ethane (U.S. Department of Energy, 2017). Additional ethane cracking plants have been proposed or are under development by Odebrecht/Braskem for Washington Bottom, WV on the Ohio River near Parkersburg, and PTT Global/Marubeni for Shadyside, OH, on the river south of Wheeling.

Bakken Shale

Arguably the best known "tight oil" play in the United States, the Bakken Shale in the Williston basin of northwestern North Dakota, northeastern Montana, and southern Manitoba and Saskatchewan actually has a production history extending back to 1953. That was the year Stanolind Oil and Gas drilled the first vertical production well on the Antelope anticline east of the town of Williston, ND, recovering 536 barrels of oil per day (Nordeng, 2010). Oil and gas production from the Bakken Shale in the Williston basin has been underway at various scales since then. The early production of Bakken oil from the Antelope anticline appears to be due to a well-developed natural fracture network (Murray, 1968), similar to the Huron Shale production of gas in the Big Sandy Field of Kentucky (refer back to the discussion in Chapter 2).

The Bakken Shale in the Williston basin occurs entirely in the subsurface. It was named by Nordquist (1953) for the basal Mississippian clastic zone in northern Montana, southern Saskatchewan, Manitoba, and northwestern North Dakota that occurs in cores and well logs beneath the Lodgepole Limestone. The type section for the Bakken is defined as the depth interval between 9615 and 9720 ft (2.93—2.96 km) in the H.O. Bakken No. 1 well, drilled in 1951 by Amerada Petroleum Corp in Williams Co., North Dakota. The Bakken consists of upper and lower black shale units with an unnamed middle limestone member sandwiched between the two shales. Petroleum is typically recovered from horizontal wells drilled into this middle limestone and from another limestone formation that lies directly below the Bakken called the Three Forks (LeFever et al., 2013). The Bakken Formation straddles the Late Devonian to Early Mississippian (372—347 Ma) boundary, but the upper black shale is entirely Early Mississippian (Borcovsky et al., 2017).

In the H.O. Bakken No. 1 well, the formation consists of about 105 ft (32 m) of black shale and limestone/sandstone located above the Three Forks Formation and below the Lodgepole Formation. The upper member is a slightly calcareous black shale about 20 ft (6 m) thick. The middle member consists of 60 ft (18 m) of fine-grained, calcareous sandstone interbedded with cryptocrystalline limestone. The basal member of the Bakken consists of a second, fissile black shale about 25 ft (7.6 m) thick (Nordquist, 1953). The black shales are considered excellent source rocks; the upper shale contains an average TOC of 8% in the United States and nearly 12% to the north in Canada, while the lower shale is even richer, with an average TOC of 10% in the United States and 17.5% in Canada (Borcovsky et al., 2017).

A few small exposures of the Bakken or an equivalent lithology have been recorded at the base of the Lodgepole Limestone at outcrops in Little Chief Canyon, along Lodgepole Creek, about three miles (5 km) south of the Lodgepole subagency of the Fort Belknap Indian Reservation (Knechtel et al., 1954). It was described as consisting of about 1.5 ft (45 cm) of black, conodont-bearing shale that may be equivalent to the upper black shale unit of the Bakken that occurs in the subsurface. Because of the uncertainty, Knechtel et al. (1954) decided to name this shale the Little Chief Canyon Member of the Lodgepole

Limestone and not assign it specifically to the Bakken. Fig. 3.19 shows an example of this unit from Sun Canyon, MT (courtesy of Dr. Nuri Uzunlar), along with a sample of Bakken crude oil provided courtesy of Halliburton. The Lodgepole itself was named by Collier and Cathcart (1922) for an exposure in Lodgepole Canyon, Blaine County, Montana.

Bakken petroleum is a very light crude oil, with an American Petroleum Institute (API) gravity of 44. The API gravity is the ratio of the density of a petroleum liquid relative to that of water (known as the "specific gravity" and measured at 60°F or 15.5°C). The higher the API gravity number, the lighter the oil. Heavy oils have API gravity of around 10 to 20, medium oil is around 30, and light oils are 40 and above (American Petroleum Institute, 2009). The Bakken crude (Fig. 3.19) has a consistency similar to diesel fuel or home heating oil, and is highly flammable.

Because the crude oil is so light, only a few US refineries are capable of processing it. Most of these are located on the Gulf Coast, resulting in the need to transport produced oil from the Bakken out of the northern Great Plains to the Gulf of Mexico. This has been accomplished via truck, railroad, and more recently, pipeline. All these options have been controversial. There have been some horrific highway accidents between vehicles and gigantic oil transports that have killed entire families. Oil trains have derailed and caught fire, including an incident where an unattended oil train rolled down a grade and derailed in the center of the Canadian village of Lac-Mégantic in 2013, nearly incinerating the entire town. Pipelines have been safer, but the routing for these, especially the Dakota Access Pipeline designed to transport Bakken crude out of North Dakota, have been very contentious.

FIGURE 3.19 Crude oil from the Bakken Formation floating on produced water. A hand sample of Bakken-equivalent shale from beneath the Lodgepole limestone is shown in the foreground. *Photographed in 2019 by Dan Soeder.*

Like the Marcellus Shale, the development of the Bakken required some new petroleum geology thinking to understand the resource and the production methods. As described previously, the geologist doing this thinking on the Marcellus was Bill Zagorski (2013 AAPG Explorer of the Year); the Bakken had Dick Findley (2006 AAPG Explorer of the Year) and Michael Johnson (2009 AAPG Explorer of the Year) thinking outside the box (Durham, 2009).

Dick Findley was developing the Elm Coulee Field in Montana when he discovered that the middle limestone member of the Bakken had enough porosity to accumulate oil from the overlying and underlying black shales. The Elm Coulee Field was viewed by most petroleum geologists as a traditional stratigraphic trap, with a porous limestone sandwiched in between two impervious shales (Sonnenberg, 2010).

By the late 1990s, the successful development of the Barnett Shale in Texas had made it clear that Bakken oil production could be improved significantly by applying George Mitchell's techniques of horizontal drilling and staged hydraulic fracturing (Nordeng, 2010). The first lateral at Elm Coulee was drilled with Findley's oversight by Lyco Energy, an independent based in Texas. The lateral itself returned a modest amount of oil, but Lyco discovered that after hydraulic fracturing, the returns increased significantly (Brown, 2006).

Although Mitchell Energy was busy at this time developing their shale production technology for the Barnett, very little of that information was being shared with competitors, including Lyco. Thus, like other inventions whose time has come, Lyco Energy essentially developed the horizontal drilling and staged hydraulic fracturing methodology for the Bakken independently from Mitchell. Once the success of this technique was demonstrated in 2001, other companies came in to develop the Elm Coulee play, notably Headington Energy Partners of Texas and Continental Resources of Oklahoma City. Continental also began focusing on the Nesson anticline in the center of the basin beginning in 2003, achieving success with laterals as long as 9000 ft (2.7 km).

The development of the Elm Coulee Field gave geologist Michael Johnson the idea that North Dakota's Mountrail County might be a good place to try to find another big Bakken oil field (Durham, 2009). Johnson noted some similarities in the well logs at Elm Coulee with a number of well logs from eastern Mountrail County. Additional data suggested that some of these wells had recovered free oil during drill stem testing, although not in great amounts (Durham, 2009). Johnson and his partner Henry Gordon decided that the locality near the Lear#1 Parshall well, drilled in 1981, looked especially promising. In 2006, EOG acquired the block and drilled what came to be known as the discovery well, Parshall#1-36H, a twin to the Lear#1 well. The lateral was drilled for a distance of 1200 ft (366 m) into the middle member of the Bakken and produced nearly 500 barrels of oil per day (bopd).

The boundary between thermally mature and immature Bakken Shale forms part of an unconventional stratigraphic trap for oil in the middle Bakken member in the Parshall production area (Durham, 2009). The Parshall Field is one of the most active parts of the Bakken play (Fig. 3.20). Drilling stepped out from the Parshall and Elm Coulee fields and spread across the Williston basin (map, Fig. 3.21). As techniques improved, the laterals got longer and recoveries became greater. Canadian development began to pick up in southeast Saskatchewan and southwest Manitoba after 2005 as drilling techniques developed in North Dakota were adapted for Canada (Ghaderi et al., 2017). The drop in natural gas prices in 2011 caused Bakken activity to further intensify as many production companies shifted focus to condensate and oil plays. Oil prices continued to rise, with West Texas Intermediate (WTI) peaking above $105 per barrel in late July 2014 (source: www.eia.gov/dnav/pet/hist_xls/RWTCd.xls). Bakken crude oil prices are typically indexed to WTI.

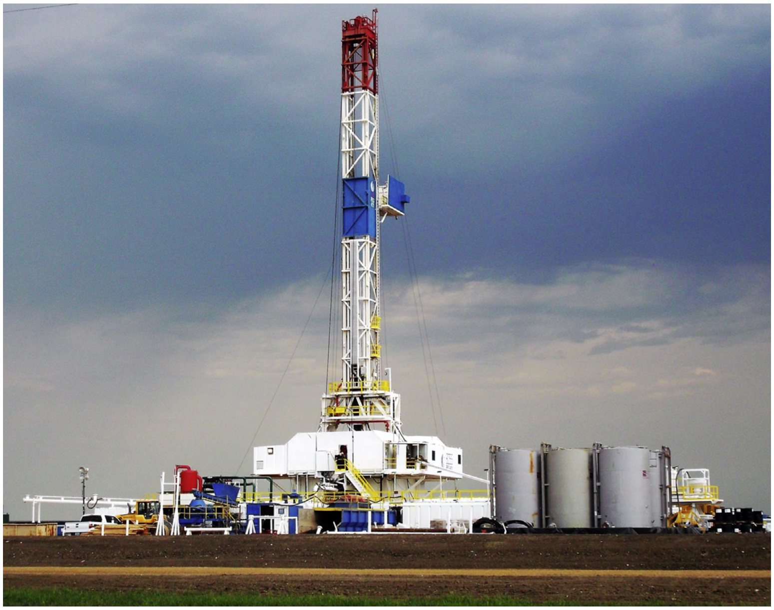

FIGURE 3.20 Triple drill rig on the Bakken play in the Parshall Field, Mountrail County, North Dakota. *Photographed in 2017 by Dan Soeder.*

Oil prices above $100/bbl caused the lightly populated northwest corner of North Dakota to become a madhouse as people flocked from all parts of the country to get in on the Bakken action. Those who experienced it tell stories of former 20-min commutes taking 2 h, no bread on store shelves, no milk, no gasoline, and few other necessities. The limited number of existing hotels in the area were completely filled, forcing workers to live in their vehicles, or in hastily assembled "man camps" with shelters constructed from shipping cargo containers and other prefabricated structures. Restaurants couldn't keep waiters, and convenience stores couldn't hold on to clerks as people left for much higher-paying jobs in the oil patch. According to the Chamber of Commerce in Watson City, a small town in the middle of the play, the local population increased from 1,500 to 15,000 in less than 5 years.

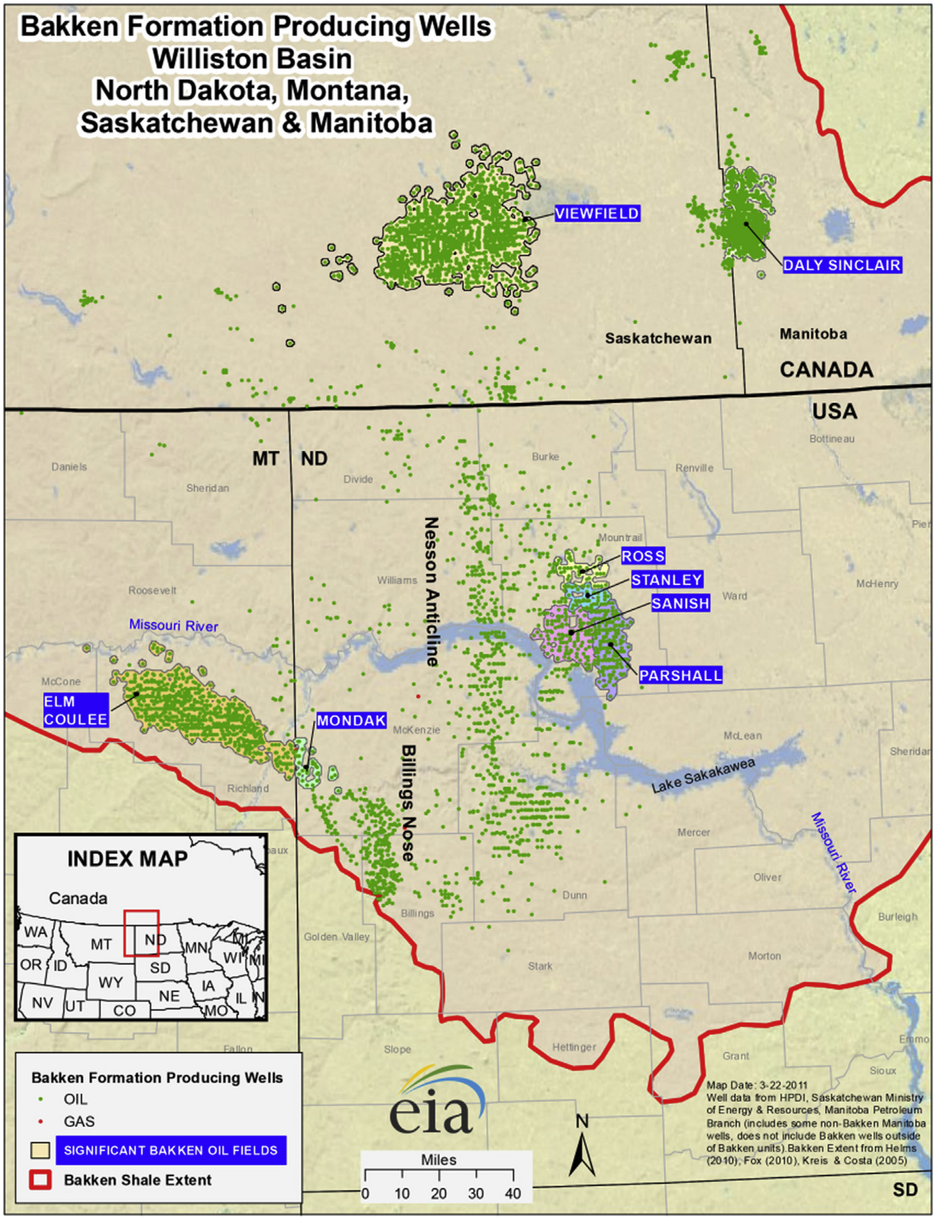

FIGURE 3.21 Location map of US and Canadian production from the Bakken Formation in the Williston basin. *Modified from US Energy Information Administration reports and web pages.*

Because oil prices were so high and natural gas so cheap, operators had little interest in the associated gas produced with the oil. The gas is dissolved in the oil at high reservoir pressures, and is separated at the surface. Gas contents in Bakken crude may be as high as one MCF per barrel of oil (Nordeng, 2010). The liquid oil is stored in stock tanks and removed by truck, but the gas has a high Btu value and requires processing before being sold to a pipeline company. This was done if a processing plant and pipeline were nearby, but if not, the gas was simply burned off, or flared. During the initial development of the Bakken, there were very few natural gas pipelines in the area, and almost no gas processing plants. Driving into the Bakken production fields at night was literally a vision from Dante's Inferno with huge, flickering flames in all directions. The addition of natural gas processing plants and pipelines in recent years has decreased flaring, and in 2012 the EPA imposed regulations on how long a well may be flared after completion. Nevertheless, even in 2017, the Bakken flares were still quite prominent on nighttime satellite images of the United States, outshining many major cities (Fig. 3.22).

FIGURE 3.22 Satellite image of the United States at night, taken in 2017. The illumination from Bakken flares is labeled. NASA image.

WTI prices fell below $45 per barrel by January 2015, rose again slightly over the summer, and then began a steady decline through fall and winter, reaching a low of $26.68 on January 20, 2016 (source: www.eia.gov/dnav/pet/hist_xls/RWTCd.xls). The effect on Bakken drilling activity was significant and abrupt. Production and service companies laid-off people by the hundreds. Those who had bought property in North Dakota were unable to sell it to anyone at any price. Many of the new hotels, restaurants, and other infrastructure constructed during the boom sat empty. A few people gamely hung on, and oil prices slowly recovered over the ensuing years. Drilling and production are now maintained at what are considered to be more sustainable levels, and the economy appears to have stabilized.

The sedimentology and sequence stratigraphy of the Bakken upper black shale unit (Fig. 3.23) have been investigated in detail (Borcovsky et al., 2017). It is a shelf-deposited mudstone that shows variation in bottom water oxygen levels, and lateral changes in the input of clay and silt.

The middle member of the Bakken (Fig. 3.24) has a maximum thickness of about 70 ft (21 m) and contains porosity ranging from 4 to 12%, with a mean around 9% (Hester and Schmoker, 1985). This is significant, because this middle member is the "reservoir" for Bakken oil production, slowly accumulating petroleum from the black shales above and below over geologic time. It is also interesting to note that temperatures in the Bakken are elevated because of the formation depth, ranging from 125 to 250°F (50–120 C) (Hester and Schmoker, 1985). In addition to being another indicator of thermal maturity, this adds to the potential for geothermal energy recovery in the Williston basin.

The Bakken has a fine-grained sandstone and coarse-grained siltstone basal unit in places that ranges in thickness from 5 to 15 ft (2–5 m). It is classified as the Pronghorn Member by the North Dakota Geological Survey (LeFever et al., 2013). Other authors (e.g., Sandberg and Hammond, 1958) have identified it as a local, informal unit of Late Devonian-age called the Sanish sand and assigned to the top of the Three Forks Formation rather than the base of the Bakken. The Three Forks Formation was named by for the section exposed at the junction of three forks of the Missouri River, near Three Forks, Montana (Peale, 1893).

FIGURE 3.23 Upper black shale member of the Bakken Formation in a core slab, showing pyrite laminae, fossil shells, and multiple fractures. Coin for scale is 2 cm in diameter. *Photo from North Dakota Geological Survey.*

Recent USGS assessments (e.g., Pollastro et al., 2008; USGS Williston Basin Province Assessment Team, 2011) suggest that the Bakken–Three Forks may have recoverable reserves of 7.5 billion barrels of oil and 6.7 TCF of natural gas (Gaswirth and Marra, 2015). The prolific Bakken–Three Forks has made North Dakota the second largest oil producing state in the nation, behind only Texas (Source: U.S. Energy Information Administration, Petroleum Supply Annual online report, https://www.eia.gov/petroleum/supply/annual/volume1/).

FIGURE 3.24 Middle limestone/sandstone member of the Bakken Formation in a core slab, showing sedimentary structures. Coin for scale is 2 cm in diameter. *Photo from North Dakota Geological Survey.*

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4

The evolutionary U.S. shale plays

Industry took lessons learned during the initial development of shale gas and tight oil in the early years of the 21st Century, and began applying this knowledge to other formations where the resource potential was perhaps a bit less obvious. These are the evolutionary shale plays and the emerging plays described in this chapter.

Woodford Shale

Horizontal drilling and significant gas production in the Woodford Shale began in 2004–05, after the nearby Fayetteville play took off. Newfield Exploration was the largest developer, along with Devon, Chesapeake, Antero, and others.

The Woodford Shale is primarily Late Devonian (383–359 Ma) in age, although the uppermost part is Early Mississippian (346 Ma), making it slightly older than the Barnett and Fayetteville shales, but similar to them in character (Cardott, 2013). It was named by Taff (1902) for the town of Woodford, Oklahoma, to describe cherty shale and a black, bituminous fissile shale that outcrop in the Ouachita and south Oklahoma folded belts and the Arbuckle Mountains. It is productive across much of Oklahoma,

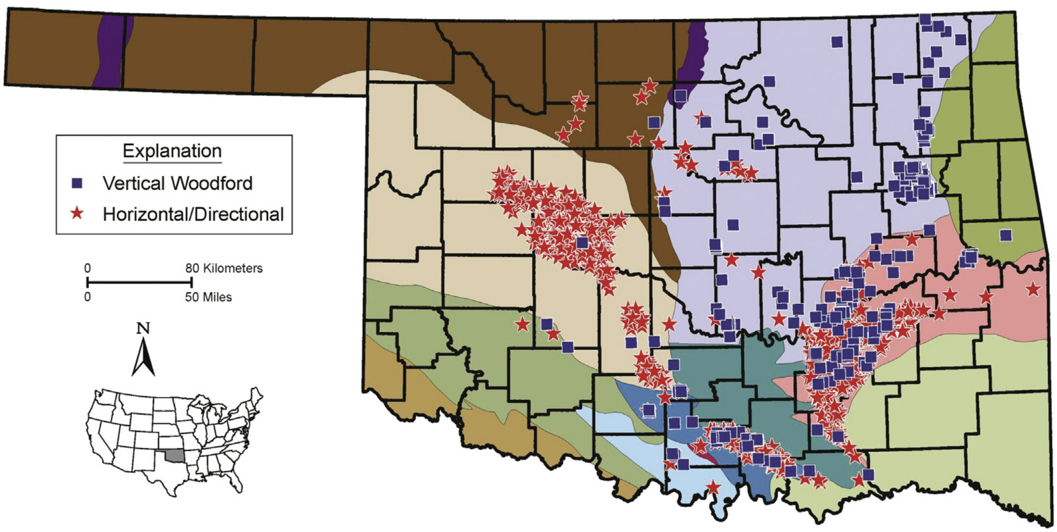

FIGURE 4.1 Wells completed in the Woodford Shale in Oklahoma between 2004 and 2012. *Blue Dark squares* are vertical wells and *stars* are horizontal. The play runs from the Arkoma basin in the east to the Ardmore basin in the south, and then northwest into the Anadarko basin. *Source: Oklahoma Geological Survey (Cardott, B.J., 2013. Woodford Shale: From Hydrocarbon Source Rock to Reservoir. AAPG Search and Discovery Article #50817).*

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where it is predominant in the Anadarko basin, and present to a lesser extent in the Arkoma and Ardmore basins (Fig. 4.1).

The Woodford occurs at depths of around 4,000 ft (1,200 m) near the Kansas–Oklahoma border and dips southward into the Anadarko basin, reaching depths of more than 25,000 ft (7,600 m). As such, like the Barnett and other shales, it contains a range of thermal maturity. In the shallow platform region to the northeast, the Woodford is generally immature to marginally mature and produces biogenic gas and some petroleum. Thermal maturity increases with depth of burial into the Anadarko basin to the southwest, passing through the peak oil and condensate windows and then into the dry gas window. Since 2009, there has been an emphasis on liquid hydrocarbon plays, but the precise boundaries of these zones are not well-defined (Cardott, 2013).

The predominant organic matter in the Woodford consists of Type II kerogen with lesser amounts of Type III. The average TOC is greater than the source rock minimum of 0.5 weight percent and reaches nearly 6% in the fissile black shale facies. Vitrinite reflectance values range from 0.56% Ro to 1.67% Ro for the petroleum and condensate areas of the play, and reach as high as 6.5% Ro (anthracite coal equivalence) in the dry gas parts of the formation (Cardott, 2013).

The Woodford Shale was deposited on a Late Devonian unconformity and is overlain by shales and limestones of Early Mississippian age. It consists of three members defined by differences in palynology, organic geochemistry, and electric log response centered on two different depocenters. The depocenter for the lower and middle members is in southwestern Oklahoma, and these thicken into the now eroded central trough of the southern Oklahoma aulacogen. The depocenter for the upper member is in the northeast part of the state, and it thickens toward the Sedgwick basin of South Central Kansas (Hester et al., 1990). The Woodford ranges in thickness from about 125 ft (40 m) in the north to as much as 900 ft (270 m) in the deeper parts of the Anadarko basin. Because of these regional depositional and thermal maturity trends, the bulk of the hydrocarbons in the Woodford Shale appear to have been generated from the lower and middle members.

The lithology of the Woodford Shale consists predominantly of a silica-rich shale that is brittle and easily fractured. The silica is mostly biogenic in origin. Solid bitumen or asphalt generated from degraded oil in the higher-thermal maturity parts of the formation often fills natural fractures (Fig. 4.2), but rather than sealing them, it creates a

FIGURE 4.2 Bitumen-filled fractures in a Woodford Shale outcrop in McAlester Cemetery Quarry, Oklahoma. Coin for scale is 17 mm in diameter. *Photo by Rick Andrews, used with permission.*

nanoporous network that is important for gas storage (refer back to the photomicrograph in Fig. 2.5).

The Woodford Shale and associated rocks in the Anadarko basin are subdivided by industry into two main production plays, the SCOOP and the STACK (Redden, 2018). SCOOP is the larger of the two and stands for South Central Oklahoma Oil Province. This is a geographic reference for the southern half of the Anadarko basin, not geological. The Woodford Shale in the SCOOP is liquids-productive in zones up to 400 ft (122 m) thick at depths of 8,000 to 16,000 ft (2.4—4.8 km). The SCOOP has been described by operators as an oil and liquids-rich province with some of the thickest, highest-quality shale reservoirs in the country (Redden, 2018). However, some companies have found the subsurface geology to be complex, and hydrocarbon recovery has been more complicated than anticipated, requiring robust oil and gas prices to make production worthwhile.

STACK is an acronym for Sooner Trend, Anadarko, Canadian, and Kingfisher. It is meant to describe a play area in the Woodford Shale and overlying Meramec Shale in the central part of the Anadarko basin located primarily in Canadian and Kingfisher counties, Oklahoma (Redden, 2018). Like SCOOP, STACK is a geographic reference for an area of gas and liquids production from shales. The Sooner Trend is a fairly significant, older conventional oil play near Enid, OK, running along the northeastern edge of the Anadarko basin and extending onto the Anadarko shelf. The STACK incorporates this trend into the shale plays.

The Early Mississippian-age rocks overlying the Woodford Shale form another tight oil and gas play in West Central Oklahoma known informally as the "Mississippi limestone" where the source rock is assumed to be the Woodford. It is generally considered to be part of the STACK play in the northern part of the Anadarko basin and extends northward along the Sooner Trend parallel to the basin axis on the Anadarko shelf. Production from the Mississippi limestone has been modeled to be within the boundary of the 99% transformation ratio of the Woodford Shale, marking the end of oil generation. Because the area is somewhat thermally mature for oil, petroleum in the Mississippi limestone play probably migrated vertically and laterally over some distance (Higley, 2013).

Niobrara Formation and Pierre Shale

The Niobrara Formation is a Late Cretaceous (100—66 Ma) chalk and calcareous shale deposited in the Western Interior Seaway (WIS) of the United States and overlain by the organic-rich Pierre Shale (the correct pronunciation, by the way, is "pier"). Both the Niobrara and Pierre reach significant depths in a number of structural basins within the WIS, where thermal maturity levels were sufficient for thermogenic hydrocarbon generation (Fig. 4.3). On the eastern platform of the WIS, the Niobrara is rather shallow (less than 3,000 ft or 1 km), and the Pierre above it is even shallower. The shallow Niobrara contains significant biogenic gas resources (Soeder et al., 2017). In the Denver, Powder River, and other deep Rocky Mountain basins, the Niobrara has been exposed to temperatures above the oil generation window, creating accumulations of natural gas and NGL that can be recovered from the fine-grained rock efficiently in vapor form. These basins are where most of the Niobrara production activity is currently taking place (Sonnenberg, 2011).

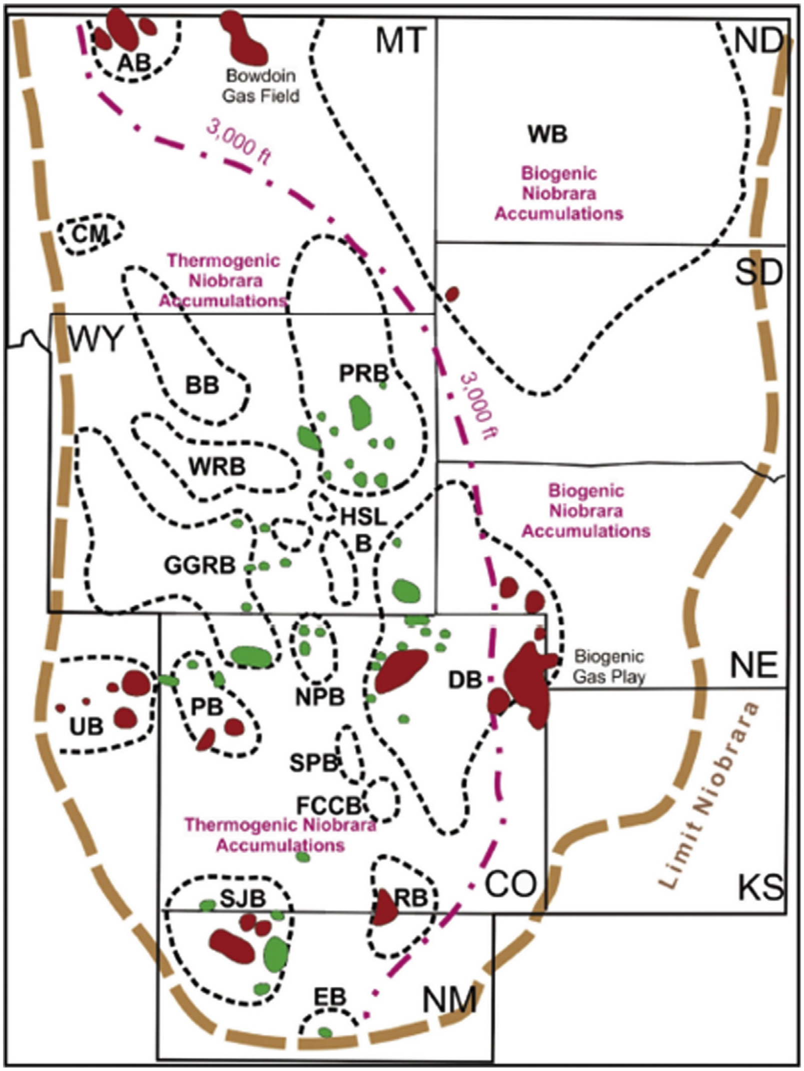

FIGURE 4.3 Niobrara Formation is distributed within the *brown dashed line* (light gray in print version). Eastern biogenic accumulations of gas and deeper, thermogenic hydrocarbons are separated by the dot-dashed red line. Oil production is shown in *green* (gray in print version) and gas in *red* (dark gray in print version). *Modified from Sonnenberg, S.A., 2011. The Niobrara Petroleum System: a new resource play in the Rocky Mountain Region. In: Estes-Jackson, J.E., Anderson, D.S. (Eds.), Revisiting and Revitalizing the Niobrara in the Central Rockies. Rocky Mountain Association of Geologists, Denver, CO, pp. 13–32; used with permission.*

The basins shown in Fig. 4.3 are identified as AB-Alberta basin, BB-Bighorn basin, CM-Crazy Mountain basin, DB-Denver basin, EB-Estancia basin, FCCB-Florence–Canon City basin, GGRB-Greater Green River basin, HSLB-Hanna–Shirley–Laramie basin, PB-Piceance basin, PRB-Powder River basin, NPB-North Park basin, RB-Raton basin, SJB-San Juan basin, SPB-South Park basin, UB-Uinta basin, WB-Williston basin, and

WRB-Wind River basin. State names are abbreviated as MT: Montana, WY: Wyoming, CO: Colorado, NM: New Mexico, KS: Kansas, NE: Nebraska, SD: South Dakota, and ND: North Dakota.

The Niobrara is generally less than 300 ft (100 m) thick across the WIS, whereas the Pierre may be as thick as 2,000 ft (600 m). Because of its chalky nature, the Niobrara tends to have better reservoir properties than the Pierre, which is a clay-rich, fissile, dense, muddy shale. Throughout much of the extent of these two formations, the Pierre Shale forms a caprock and seal on top of the Niobrara (Fig. 4.4), creating a stratigraphic trap for hydrocarbons generated and contained within the Niobrara. In this sense, the Pierre–Niobrara are both unconventional and conventional type reservoirs, trapping gas in a conventional sense, but requiring horizontal drilling and fracking to recover it.

The Niobrara Formation was named by Meek and Hayden in 1861 for bluffs along the Niobrara River in northern Nebraska (Gries and Martin, 1981). It extends from the central Rocky Mountain region into the high plains of the west-central United States. The Niobrara outcrops in a number of locations in South Dakota and Nebraska, including the flanks of the Black Hills uplift, along the Chadron arch, and in exposed bluffs near the confluence of the Missouri River and the Niobrara River (Soeder et al., 2017). The Pierre Shale was also named by Meek and Hayden in 1862 for bluffs along the Missouri River a bit farther upstream at old Fort Pierre, near the city of Pierre, the capital of South Dakota.

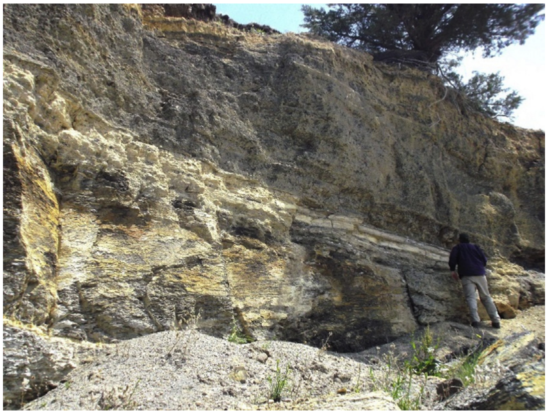

FIGURE 4.4 Dr. Foster Sawyer of SD Mines at the contact between the chalky Niobrara Formation and the overlying Pierre Shale at Elm-Creek near the Missouri River in South Dakota. *Photographed in 2016 by Dan Soeder.*

The Niobrara Formation is composed of an accumulation of marine carbonate and clastic sediments deposited as ooze on the floor of the Western Interior Seaway during the Late Cretaceous period from 89.8 to 83.6 Ma. It ranges in age from the Coniacian to the Campanian (Longman et al., 1998). The Pierre Shale consists of thick, clastic muds deposited on top of it. In the largely asymmetric structural basins of the Rocky

Mountains, the Niobrara and Pierre have been buried to depths of less than a kilometer to as deep as 11,000 ft (3.5 km), resulting in a wide range of thermal maturity levels at different locations (Nelson and Santus, 2011).

Production of gas from the Cretaceous rocks of the Denver basin (also known as the Denver-Julesburg basin or D-J) began in the early 20th century with the establishment of the Wattenberg field (Ladd, 2001), to produce an accumulation of dry gas deep in the basin center (the Denver basin is identified as DB on the map, Fig. 4.3, and the Wattenberg field is shown in the western part of the basin). Such "basin-centered gas" is common in the Rocky Mountains (Fig. 4.5), and is trapped by capillary pressure from liquids present in the rocks up-dip, such as water or hydrocarbons.

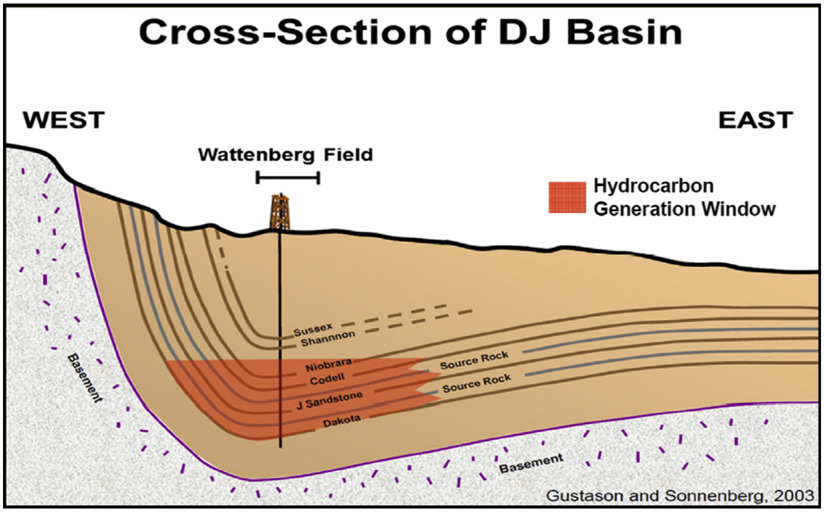

FIGURE 4.5 Geologic west-to-east cross-section of the highly asymmetric Denver-Julesburg (D-J) basin in Colorado showing basin-centered gas accumulations in deeply buried Cretaceous rocks forming the Wattenberg Gas Field. *Modified after Sonnenberg, S.A., 2011. The Niobrara Petroleum System: a new resource play in the Rocky Mountain Region. In: Estes-Jackson, J.E., Anderson, D.S. (Eds.), Revisiting and Revitalizing the Niobrara in the Central Rockies. Rocky Mountain Association of Geologists, Denver, CO, 2011. pp. 13–32; used with permission.*

Production from the Wattenberg field began to focus on some of the lower permeability units once fracking was introduced into vertical wells in the 1970s. Around 2010 or 2011, a number of established Wattenberg operators, such as Samson Oil & Gas, EOG Resources, Anadarko Petroleum, Noble Energy, Chesapeake Energy, and Whiting Petroleum began stepping out from the Wattenberg field to look at the potential for Niobrara production in other parts of the D-J basin using horizontal drilling and staged hydraulic fracturing.

Whiting, in particular, began developing an area they called the "Redtail prospect" in the more eastern part of the D-J basin in 2012. The Niobrara is a bit shallower here and less thermally mature (i.e., cross-section, Fig. 4.5), and produces a mix of natural gas and NGL. Whiting established a gas processing plant at Redtail to remove the condensate for separate sale and to reduce the Btu value of the natural gas to meet pipeline specifications.

Rock-Eval analyses of Niobrara cores revealed TOC contents as high as 6% by weight (Soeder et al., 2017), even though the formation does not appear to be especially organic-rich when viewed in outcrop (Fig. 4.6). This is presumably due to the presence of carbonate throughout the Niobrara as chalk, giving it a lighter color than expected for a fine-grained rock with an organic carbon content greater than 4% (Hosterman and Whitlow, 1980).

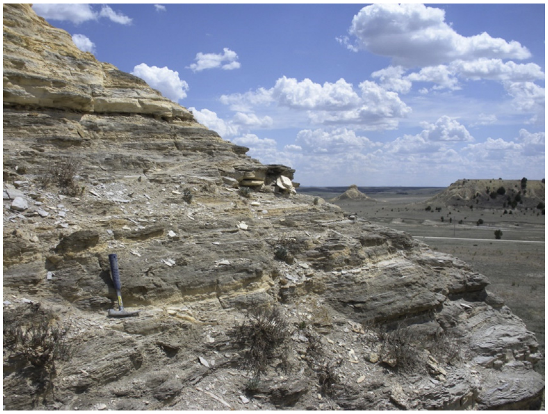

FIGURE 4.6 Niobrara formation outcrop at Slim Butte, Oglala Lakota County, South Dakota. Despite the light color, TOC content measured in the layer below the rock hammer at left was nearly 6%. *Photographed in 2013 by Dan Soeder.*

Examination of the Niobrara Formation in outcrop reveals zones of nearly pure white chalk alternating with zones of clastic, organic-rich, calcareous clay shales. Porosity in some of the pure chalk units can be quite high, approaching 50%, while porosity in the shale units is typically less than 10% (Soeder et al., 2017). As shown in thin section (Fig. 4.7) the shaly units of the Niobrara generally consist of a mixture of microfossil shells and shell fragments, clay, and organic material. The chalky units, on the other hand, often consist of nearly pure shell fragments or peloids and may contain very high amounts of secondary, solution porosity.

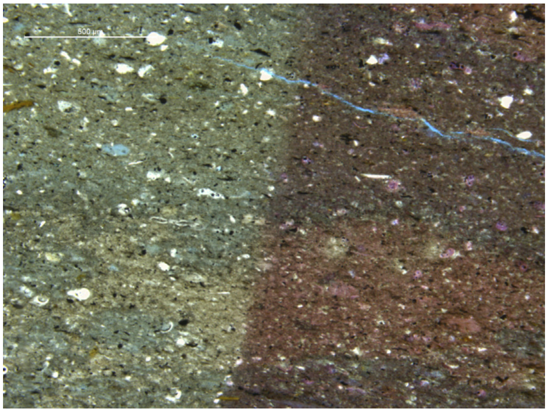

FIGURE 4.7 Thin section photomicrograph of the Niobrara Formation from Graves #31 core showing a mix of gray clay, black organic carbon, and white calcareous microfossils. Stain on the right identifies calcite; scale bar at upper left equals 0.5 mm. *DOE photograph (Soeder, D.J., Wonnell, C.S., Cross-Najafi, I., Marzolf, K., Freye, A., Sawyer, J.F., 2017. Assessment of Gas Potential in the Niobrara Formation, Rosebud Reservation, South Dakota. NETL-TRS-1-2017; NETL Technical Report Series. U.S. Department of Energy, National Energy Technology Laboratory, Morgantown, WV, 152 p.).*

Like the Niobrara, the Pierre reaches significant levels of thermal maturity in the deeper basins of the Rocky Mountains. Some of the Pierre member units contain significant TOC and Type II kerogen (Fig. 4.8), making them source rocks at the proper thermal maturity (Soeder et al., 2017). The first assessment of potential oil and gas resources in the Pierre Shale as a source rock was done by Wegemann (1911) for the Salt Creek oil field in Natrona County, Wyoming, on the western flank of Teapot Dome. Readers may be familiar with Teapot Dome as a component of the US Navy oil reserve that became the subject of a major scandal in 1921 during the administration of President Warren G. Harding.

FIGURE 4.8 Organic-rich Pierre Shale drill core from Presho, SD with an ammonite fossil on a parting surface. *Photographed in 2015 by Dan Soeder.*

The Niobrara is self-sourced for hydrocarbons (Sonnenberg, 2011). Despite the variation in lithology between different layers, most of the rock is tight and requires stimulation to produce significant amounts of oil and gas. However, the Niobrara is not unlike the Bakken, where hydrocarbons migrate from organic-rich source rocks into somewhat more permeable interbedded limestones. These mixtures of black shales and limestones have proven to be highly productive, and a fracked horizontal well in the Niobrara connecting multiple lithologies can provide significant returns.

There has not been much gas production from the Pierre Shale to date, but it is being considered as a potential component of a stacked play in the Powder River basin of Wyoming. Multiple Cretaceous-age shales in this basin, including the Mowry, Niobrara, Mancos, and Pierre are prospects for multiple completion boreholes. Leasing activity in 2018 has been significant in the southern part of the basin. Currently, most economic activity in the Pierre is centered on the extraction of bentonite from volcanic ash beds (Fig. 4.9) for use as drilling mud stabilizers for developing other shales.

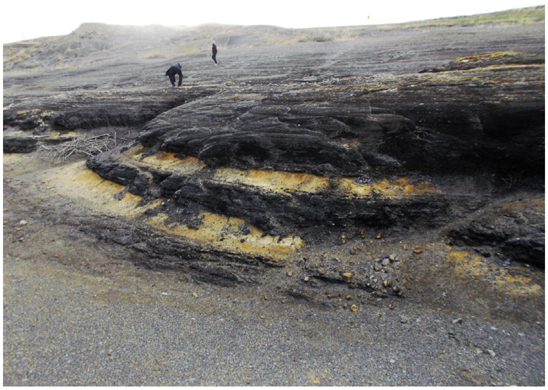

FIGURE 4.9 Prominent, yellow volcanic ash beds within the black Pierre Shale on an outcrop at Buffalo Gap, SD. People in the background provide scale. *Photographed in 2014 by Dan Soeder.*

Utica Shale

The Utica Shale is a relative latecomer to the shale gas revolution. Significant development began in southeastern Ohio in 2011–2012 as the industry recognized that this location was rich in natural gas liquids. It is difficult to know exactly which company was the first to develop the Utica Shale as a hydrocarbon prospect. Numerous operators working on the Marcellus Shale in southwestern Pennsylvania decided to try drilling dual-completion wells down into the Utica, which is considerably older than and nearly twice as deep as the Marcellus. A number of shale production companies including Antero, Chesapeake, Devon, Eclipse, Gulfport, Hess, Range, and others were engaged in developing dual Marcellus–Utica prospects. Although the Utica is leaner in TOC than the overlying Marcellus (around 2–3% vs. 6–10%), its thermal maturity and greater depth made it an attractive dry gas play. The discovery of natural gas liquids in the shallower parts of the formation in Ohio turned it into a major shale resource. Chesapeake Energy has become the biggest player by far (Patchen and Carter, 2014).

The Utica Shale was named by Ruedemann (1925) for exposures along Starch Factory Creek east of the city of Utica, Oneida County, New York. The formation is nearly 800 ft (244 m) thick at Utica, with only the upper 250 ft (76 m) exposed. It reaches considerably greater thickness along the eastern margin of the Appalachian basin, where it fills deep grabens with nearly 2,000 ft (610 m) of shale (Patchen and Carter, 2014).

The Utica Shale is Middle Ordovician in age (470–458 Ma) and overlies the Trenton Limestone throughout the Appalachian basin. The Trenton is a well-known conventional play, typically combined with limestones of the Black River Group below it (Ryder et al., 1992). The stratigraphy of these rocks is complex and challenging. Ryder in fact modified his own age assessment of the Utica Shale from Late Ordovician to Middle Ordovician based on new correlations made between Ohio and Pennsylvania.

The Ordovician stratigraphic section in the Appalachian basin consists predominantly of carbonate rocks like limestone and dolomite. The presence of organic-rich clastic sediments of the Utica Shale in the middle of all this is a bit unusual. The Ordovician rocks outcrop on the northern edge of the basin in New York along the south shore of Lake Ontario, and in the Mohawk River valley roughly as far east as Albany. There are a number of excellent exposures of the Utica Shale along the New York Thruway (Fig. 4.10) in the Mohawk valley, but visiting these sites risks citation, arrest, and a possible vehicle collision unless accompanied by New York officials like the state geologist for the field trip in the photo.

FIGURE 4.10 Viewing the contact (just above hardhat of person pointing to outcrop) between the Dolgeville and overlying Indian Castle members of the Utica Shale along the New York Thruway near Little Falls, NY. *Photographed in 2010 by Dan Soeder.*

More accessible exposures of Utica Shale in the Mohawk valley occur along Canajoharie Creek just south of the town of Canajoharie, NY and on Flat Creek, near the town of Sprakers NY. In the western part of the Appalachian basin, age-equivalent Ordovician rocks outcrop largely as fossiliferous limestones uplifted along the Cincinnati arch in southwestern Ohio, southeastern Indiana, and northern Kentucky.

The stratigraphic relationship between the Utica Shale and other Ordovician rocks in the Appalachian basin is complex. Clastic sediments that formed the Utica came off highland areas in what is now modern-day New England. The Taconic orogeny that created these mountains was a complicated event that lasted throughout the entire Ordovician Period and was caused by the closing of the ancient Iapetus Ocean. It occurred from Newfoundland to Tennessee at various stages and times (Rodgers, 1971). The orogeny was identified by a significant unconformity between the Ordovician and Silurian rocks in the Taconic Mountains of eastern New York and named after them. The suture zone of the Taconic orogeny where the converging plates joined is located in the modern Blue Ridge Mountain range that extends from Georgia to Pennsylvania (Clark, 2008). The Catoctin metabasalts that make up the core of these mountains are the metamorphosed remains of the seafloor basalts of the Iapetus Ocean.

Pulses of sediment interspersed with periods of nondeposition or erosion resulted in complex layering and facies relationships in the Utica Shale. A challenge of understanding the stratigraphy of these Ordovician rocks is that outcrops were described and named in New York, while another set of rocks the same age and in the same basin but with different lithologies were named from outcrops in eastern Indiana and northern Kentucky. One of the first missions of a Utica Shale resource assessment conducted by an Appalachian research consortium in 2013–14 (Patchen and Carter, 2014) was to assemble the stratigraphy across the basin and try to understand facies and equivalent units (Fig. 4.11).

The Utica Shale in eastern and central Ohio occurs above the Point Pleasant Formation, a less-organic but still productive unit named by Edward Orton in 1873 for exposures of limestone and shale at Point Pleasant on the Ohio River. The Point Pleasant was redefined by Wickstrom et al. (1992) to encompass the stratigraphy from the top of the Trenton Limestone to the base of the Kope Formation in the Ohio subsurface. The Kope Formation was described by Jennette and Pryor (1993) as a mixed siliciclastic–carbonate ramp consisting of calcareous and argillaceous shale interbedded with limestones and siltstones.

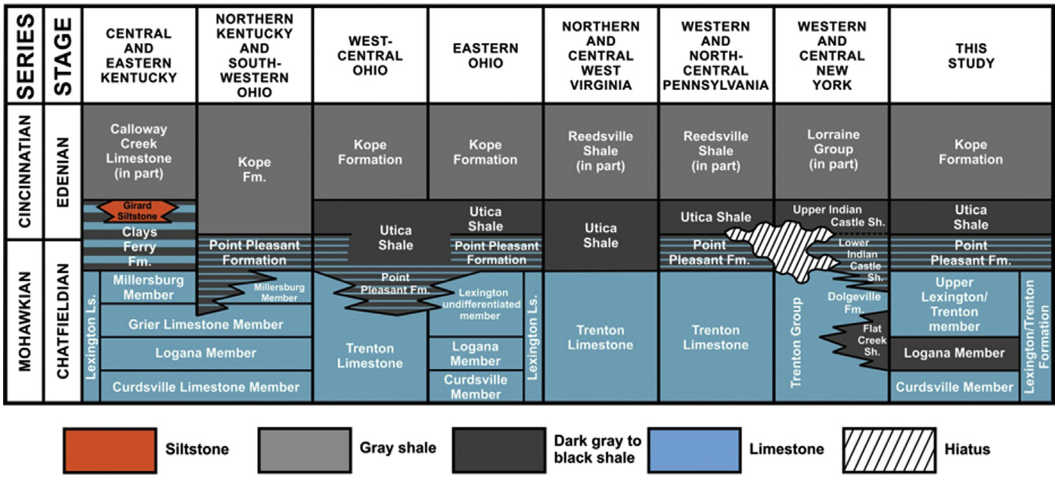

FIGURE 4.11 Utica Shale stratigraphic correlation from central Kentucky to central New York. *Source Kentucky Geological Survey from Patchen, D.G., Carter, K.M. (Eds), June 30, 2014. A Geologic Play Book for the Utica Shale Appalachian Basin Exploration; Final Report, Utica Shale Appalachian Basin Exploration Consortium. West Virginia University, Morgantown, WV, 177 p; used with permission.*

More recent assessments of Utica lithostratigraphy by researchers at the Kentucky Geological Survey as part of the Appalachian research consortium have extended the Utica Shale in the subsurface across Ohio to outcrops along the Cincinnati arch near the Ohio River (Fig. 4.12). The Utica can be found beneath the Kope Formation and above the Point Pleasant. It differs significantly in character from the Utica outcrops on the other side of the basin in New York (Patchen and Carter, 2014). The play in Ohio is now commonly referred to by both names, as the Utica–Point Pleasant.

FIGURE 4.12 Fissile and moderately organic Utica–Point Pleasant shale below the slabby, calcareous Kope Formation at a road cut in Kentucky near the Ohio River. *Photographed in 2016 by Dan Soeder.*

The thermal maturity of the Utica Shale is in the dry gas window throughout much of the Appalachian basin, but toward the west in Ohio, it falls within the NGL or condensate window. This has spurred a drilling boom from south of Akron, Ohio to Interstate 70 and from the Pennsylvania state line through the northern West Virginia panhandle and west to Zanesville, Ohio. This had traditionally been a coal-producing area with large surface mines, and the Utica development helped spur a flagging economy.

Production from the Utica—Point Pleasant has been significant in a number of ways. The longest onshore lateral recorded to date has been achieved by Eclipse Resources Corporation in the Utica Shale. The company announced in a news release on June 16, 2017 that they had successfully broken their previous lateral records of 18,544 ft (5652 m) in the Purple Hayes #1 well and 19,300 ft (6716 m) in the Great Scott 3H well with the completion of the Outlaw C11 H well, with a total borehole length from the surface of about 27,750 ft (8458 m) and a lateral length of approximately 19,500 ft (5944 m). Astonishingly, it took only 17 days from spud to reach total depth in Outlaw C11 H, meaning that the average ROP was greater than one foot per minute (13.6 in./min to be precise) (https://ir.eclipseresources.com/press-release/eclipse-resources-provides-operational-update-and-upcoming-conference-participation).

Several of the Utica—Point Pleasant wells have also had remarkable IP rates. According to the Marcellus Drilling News, July 24, 2015, an EQT horizontal well completed in the Utica was reported to have an IP of 73 MMcf/d (2 million cubic meters/day) before declining to a more sustainable flow rate of 22 MMcf/d. The previous record holder was a Utica well drilled and completed by Range Resources with an IP of 59 MMcf/d (1.7 million cubic meters/day). Recall that the IP of the Marcellus Shale discovery well, Range Resources Gulla#9, was 5 MMcf/d and that was considered impressive at the time. These "barn-burners" result from gas in the natural fracture system being produced quickly. After a few weeks, the wells typically decline to a lower, steadier flow rate as the fractures drain and are replenished more slowly by gas migrating from the matrix. Nevertheless, the volume of hydrocarbons produced from the Utica Shale is impressive.

Eagle Ford Shale

The Eagle Ford Shale is a Late Cretaceous (100—66 Ma), calcareous shale that extends along the western Gulf Coast from East Texas into Mexico (Fig. 4.13). Stratigraphically, it is located below the Austin Chalk and above the Buda Limestone and Woodbine Formation. The formation was named by Hill (1887) for exposures at the town of Eagle Ford, Texas, about 6 miles (10 km) west of Dallas, and first mapped as the Eagle Ford Shale by Miser et al. (1954).

The formation ranges in depth from surface exposures along the Balcones escarpment in San Antonio, Austin, and Dallas to depths of more than 14,000 ft (4.3 km) as it is buried beneath younger sediments southward toward the Gulf of Mexico. This variation in depth has resulted in zones of different thermal maturity, as discussed earlier for other shales like the Niobrara and the Barnett. In the Eagle Ford, there is a simple trend southward with increased depths toward the Gulf. As the depth of burial increases, the formation transitions from the oil window at a depth of about 4,000 ft (1220 m) through natural gas liquids, and eventually to dry gas at the greatest depths (map, Fig. 4.13).

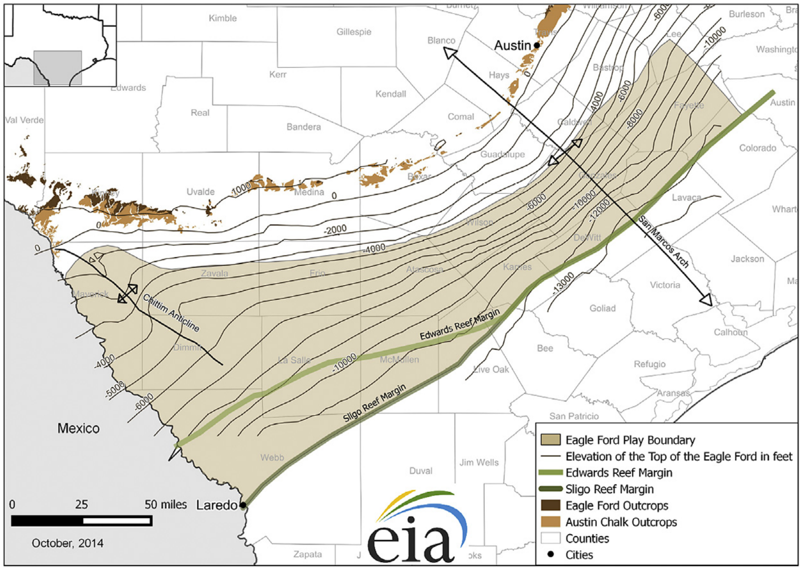

FIGURE 4.13 Map of the Eagle Ford shale play in Texas, showing zones of different hydrocarbon production as a function of thermal maturity and depth. *Source: U.S. Energy Information Administration reports and websites.*

The Eagle Ford is composed of an organic-rich, calcareous clay shale in outcrop, with carbonate content increasing to the southeast (Breyer, 2016). The high carbonate content makes the formation brittle and more amenable to hydraulic fracturing. In many outcrops, the unit consists of alternating, thin beds of argillaceous shale and limestone, with a lithostratigraphy that in many ways resembles the much older Utica Shale (Fig. 4.14; compare with Fig. 4.10).

The Eagle Ford was deposited in an inland sea bounded by the Ouachita uplift to the north, the Sabine uplift to the east, and merged with the southern end of the WIS the west. The primary basins receiving Eagle Ford deposition in Texas were the Brazos basin

FIGURE 4.14 Eagle Ford Shale in outcrop, showing the alternating slabby limestone and calcareous clay shale beds. *Source: American Association of Petroleum Geologists, used with permission.*

to the east and the Maverick basin to the south (Hentz and Ruppel, 2010). A drop in sea level in the early part of the Late Cretaceous (the Cenomanian Age, 100–94 Ma) resulted in a marine regression and the deposition of river delta sediments of the Woodbine Formation in the Houston embayment prior to Eagle Ford deposition in the eastern part of the area. Sea level began to rise again about 96 Ma, allowing for Eagle Ford deposition on top of the Woodbine deltas in the east, and directly on the Buda Limestone to the west (Breyer, 2016). This deposition occurred during what is known as the global Oceanic Anoxic Event 2 (OAE2), or Cenomanian-Turonian boundary event, a drop in ocean oxygen world-wide that resulted in mass extinctions and was possibly caused by volcanic activity (Leckie et al., 2002). The basal deposits of the Eagle Ford are limestones, known as the Six Flags and Bluebonnet members (Breyer, 2016).

According to the Texas Railroad Commission web page, the production play occurs across an area that is roughly 50 miles wide by 400 miles long (80 × 640 km), with an average thickness of 250 ft (76 m). The first horizontal Eagle Ford well was drilled in 2008 by Petrohawk Energy Corporation in LaSalle County southwest of San Antonio to produce unconventional gas. Developers quickly extended the play some 400 miles (640 km) from the Texas–Mexico border region in Webb and Maverick counties toward eastern Texas. Operators have separated themselves out by lease position into whether they are developing crude oil, natural gas liquids, or gas. Major players in the Eagle Ford include EOG Resources, Devon Energy, Chesapeake, Anadarko, Burlington Resources (ConocoPhillips), and Marathon.

In 2009, the US Energy Information Administration estimated the recoverable oil reserves in the Eagle Ford Shale at 3 billion barrels (477 billion liters), along with 21 TCF (594 billion cubic meters) of technically recoverable gas (U.S. Energy Information Administration, 2011). Eagle Ford production extends into 24 counties in Texas and has helped maintain a first place ranking for Texas as the number one oil-producing state (refer back to graph, figure I-2). However, Eagle Ford production pales in comparison to the potential from the Permian Basin.

Permian Basin

The Permian Basin is a complex structural basin located in the western part of Texas and southeastern New Mexico. It actually consists of two adjoining basins, the Delaware to the west and the Midland to the east, separated by a shallower central basin platform (Fig. 4.15). It covers an area approximately 250 miles wide and 300 miles long (400 × 483 km) and contains one of the thickest deposits of Permian-aged (299–252 Ma) rocks in the world, thus rightfully earning its name. There are also Pennsylvanian and older rocks at depth.

The other sedimentary basins described in this book are structural features, like the Cincinnati arch or Antelope anticline, are not capitalized. However, in addition to being a geologic structure, the Permian Basin is also a proper geographical location, and thus it is capitalized.

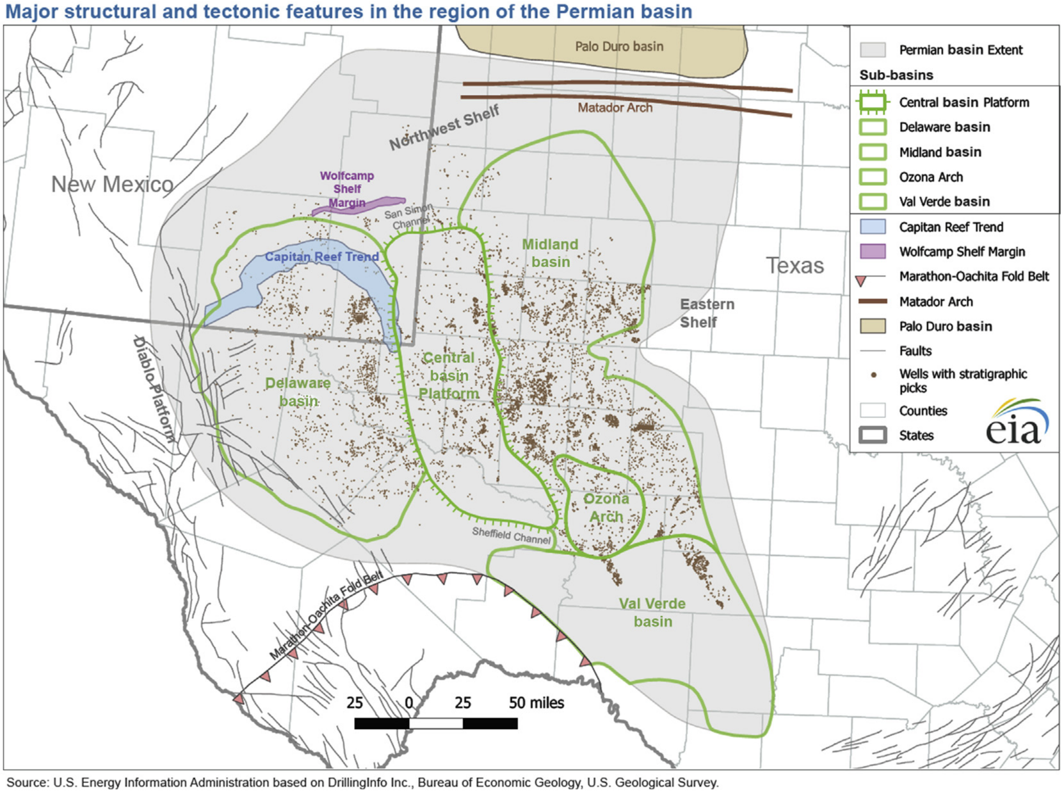

FIGURE 4.15 Map of the Permian Basin showing structural boundaries and major tight oil plays. *Source: U.S. Energy Information Administration reports and websites.*

The Permian Basin differs from the other nine unconventional plays described in this chapter in that it has a long history of substantial conventional O&G production beginning shortly after World War I. According to the Texas Railroad Commission, more than 7000 conventional oil fields in the Permian Basin had produced nearly 29 billion barrels of oil by the year 2000, resulting in a geographic designation known as the "MidContinent Oil-Producing Area," often just called the Midcontinent (Dutton et al., 2005). The towns of Midland and Odessa serve as the headquarters for oilfield activities.

Formations with formal and informal designations such as the Yates, San Andres, Clear Fork, Spraberry, Wolfcamp, Yeso, Bone Spring, Avalon, Canyon, Morrow, Devonian, and Ellenberger have all been highly productive in the Permian Basin at depths ranging from a few hundred feet (dozens of meters) to five miles (8 km) below the surface. The Delaware basin has seen significant production from the Wolfcamp and Bone Spring, which together are called the "Wolfbone." The Midland basin has undergone development in the Wolfcamp and Spraberry, together known as the "Wolfberry." It is important to understand these terms when looking at hydrocarbon resources in this basin.

The collision of the ancestral continents of Laurasia and Gondwana during the Permian created the supercontinent of Pangea, and resulting Allegheny orogeny formed the Appalachian Mountains along the Eastern Seaboard and the Ouachita Mountains in the south (Hatcher et al., 1989). These ancient mountains are now eroded down to mere nubs, but were once lofty peaks with elevations of 15,000 ft (4.5 km) or higher (Rowan, 2006). The high, steep mountain terrain shed copious amounts of sediment onto the Atlantic Coastal Plain and into the Gulf of Mexico (Clark, 2008).

The Ouachita Thrust Belt caused the crust to downwarp in west Texas and southeastern New Mexico, forming two deep subbasins in the broader Permian Basin: the Delaware and the Midland. These deep basins filled with clastic sediments eroded off the Ouachita highlands, while carbonate rocks and reefs formed on shallow shelves around the perimeter. The basins then became restricted from the sea, and thousands of feet of salt precipitated on top of the marine sediments, forming an impermeable seal.

Conventional production of O&G in the Permian Basin has been primarily from high porosity limestones, dolomites and sandstones. However, resources in the basin occur in both porous and tight rocks, so the incentive has been there to employ increasingly innovative drilling and production technologies to extract hydrocarbons over the last century.

Starting in the 1990s, operators in the Permian Basin began utilizing enhanced oil recovery (EOR) technologies to try to improve returns on various plays. Industry learned quickly that certain techniques worked better on some plays, but not others. EOR methods included waterflooding using both high and low water injection rates, carbon dioxide floods, infill drilling, horizontal CO_2 injection wells, high-pressure air injection, two-stage limited entry stimulation, and selective recompletions, among others (Dutton et al., 2005).

In 2009 or 2010 (it is difficult to know precisely), operators began applying George Mitchell's horizontal drilling and staged hydraulic fracturing techniques on six unconventional formations that together create a large, stacked play. These are the Early Permian Spraberry Sandstone, Wolfcamp Shale, Bone Spring Limestone, Glorieta Sandstone, Yeso Formation, and the overlying Middle Permian Delaware Mountain Group. The technique turned out to work quite well, especially on the Spraberry, Wolfcamp, and Bone Spring, and tight oil production from the Permian Basin took off (Fig. 4.16).

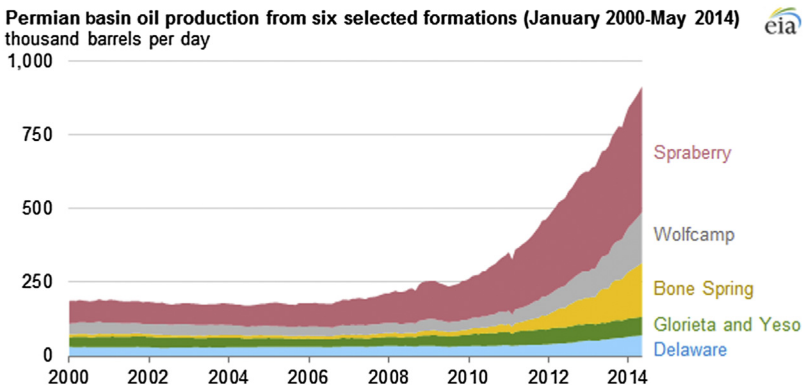

FIGURE 4.16 Oil production history in the Permian basin. *Source EIA.*

The US Geological Survey assessed technically recoverable resources in the Midland basin portion of the Permian Basin Petroleum Province and found median values of 20 billion bbl of oil and 16 TCF of gas in the Wolfcamp Shale (Gaswirth et al., 2016). The Spraberry Formation above it contains a mean estimated resource of 4.2 billion bbl of oil and 3.1 TCF of gas. At 24.2 billion bbl, the "Wolfberry" is the largest continuous oil discovery in the United States, more than three times greater than the Bakken and Three Forks in North Dakota (7.5 billion bbl of oil; 6.7 TCF of natural gas per Gaswirth and Marra, 2015). According to the Permian Basin Petroleum Association, many experts believe that 50 to 60% of the oil may be recoverable at a minimum price of about $60 to $65 per barrel.

The volume of potential hydrocarbon resources in the Permian Basin has been compared to the giant Al-Ghawar oil field in Saudi Arabia, discovered in 1948, which currently produces about 5 million bbl/day and has reserves estimated at about 70 billion bbl. The Permian Basin is currently producing about 2 million bbl of oil a day, with 80% of the reserves located at depths of less than 10,000 ft (3 km). The largest operators are Occidental, Chevron, Apache, and Pioneer Natural Resources. In an interview with Forbes Magazine, the executive chairman and CEO of Pioneer Natural Resources predicted that the Permian will eventually be bigger than Ghawar, with potential petroleum totals of more than 160 billion bbl. The main issue preventing development of the Permian Basin on a scale to rival Ghawar is the lack of pipeline capacity to transport the produced oil to Gulf Coast refineries.

Because the Permian Basin is about maxed out in terms of pipeline capacity, operators are looking elsewhere for development. The Powder River basin in eastern Wyoming is the new kid in town with a potential for stacked plays near Casper. The Wyoming O&G Commission has issued about 4000 new leases just in 2018. The main players are EOG and Chesapeake. Targets are Cretaceous formations like the Codell and Turner Members of the Carlile Shale, the Niobrara Formation, Pierre Shale, Mowry Shale, and possibly others. The Powder River is said to be a dry gas play, but there are hints at the potential for NGL and even for big oil at the right location and depth.

Emerging plays

A number of additional unconventional O&G plays are being developed as companies assess previously overlooked unconventional and tight formations and also consider ways to apply George Mitchell's production techniques on established, conventional reservoirs to recover additional oil and gas. Some of the more prominent of these emerging plays are described below.

Granite Wash: The Granite Wash play consists of Pennsylvanian-age sandstones, siltstones and shales deposited adjacent to the Wichita uplift in the Anadarko basin in northern Texas and the Oklahoma panhandle region (Koch et al., 2017). It includes at least 31 facies in seven different associations composed of stratigraphic units from the Chester Group to the Council Grove Group. The 2.5 million acre play (10,117 square km) exists completely in the subsurface, and extends across seven counties in the Anadarko basin (LoCricchio, 2012).

Clastic sediment eroded from the Wichita Mountain—Amarillo uplift was deposited in the Anadarko basin as submarine fans and turbidites, creating a massive submarine sand complex (Koch et al., 2017). There are at least 11 stacked horizons formed by overlapping sand delta lobes and submarine fans, and a minimum of 15 separate reservoirs. Hydrocarbons are present in conventional traps, and also as a basin-centered tight gas play (LoCricchio, 2012). The system is complex; overpressured in some areas and underpressured in others, and producing oil, NGL, and natural gas. Production varies laterally and vertically, and there are upper and lower play zones. NGLs are most abundant in the central part of the upper play.

The Granite Wash has become one of the most active new plays in the United States (LoCricchio, 2012). Horizontal drilling technology and the development of isolated, multistage fracture stimulation has revolutionized production. Because of the compartmented nature of the reservoirs, directional drilling has enabled operators to intersect multiple components of the play with a single well. The Granite Wash is estimated to have potentially recoverable resources of 114 billion bbl of oil, including NGL's (LoCricchio, 2012).

Austin Chalk: The Late Cretaceous (100—66 Ma) Austin Chalk was named by B.F. Shumard in 1860, but defined more specifically as the beds below the Taylor Marl and above the Eagle Ford Shale (Wilmarth, 1938). The lithology is described as chalk that averages about 85% calcium carbonate, composed primarily of micrograins of calcite and small amounts of foraminifera shells or "tests" with minor marl, interbeds and partings of calcareous clay, volcanic ash beds, and pyrite nodules. It is present along the Texas Gulf Coast in the Fort Worth syncline within the Ouachita tectonic belt province and basically traces the geographic coverage of the Eagle Ford Shale (refer back to map, Fig. 4.13), although it extends farther east into Mississippi.

Operators have been drilling the Austin Chalk since the 1930s to try to produce oil from this saturated but tight rock. The formation is estimated to contain about 4.1 billion bbl of petroleum, 18 TCF of natural gas, and 1 billion bbl of NGL that are considered technically recoverable (U.S. Energy Information Administration, 2018). The Austin Chalk was supposed to be the "next big thing" back in the 1990s as conventional drilling initially produced big gushers, but the wells rapidly declined and industry eventually wrote it off. Some operators experimented with horizontal drilling on the chalk in the early 2000s (Rao, 2012). These tests were largely unsuccessful, because the chalk is hard, brittle, fractured, and more unpredictable than shale. The economics of drilling laterals in such a rock were challenging, especially in the early days.

Operators are showing renewed interest in the Austin Chalk because horizontal drilling techniques and hydraulic fracturing have greatly improved in terms of cost, efficiency, and effectiveness thanks to the development of shale plays. Applications of these new drilling and completion technologies on the Austin Chalk have shown promise. The formation has a jumbled and fractured lithology that is more variable than shale, and operators have come to understand that the formation changes significantly over short distances, requiring a detailed knowledge of the geology. Nevertheless, the Austin Chalk overlaps the Eagle Ford Shale in much of Texas, suggesting the potential for a stacked play, and pipelines and other infrastructure put in place for the Eagle Ford would be available for Austin Chalk production as well, saving midstream costs and improving the economics.

Tuscaloosa Marine Shale: The Tuscaloosa Marine Shale (TMS), also referred to simply as the "Tuscaloosa Trend" is present along the Louisiana–Mississippi border. It has the potential to become a significant oil play, but it also has some geological challenges that have restricted development thus far. The Tuscaloosa Formation was named by Smith and Johnson (1887) for outcrops in northwestern Alabama near the city of Tuscaloosa. It was described as a Late Cretaceous, poorly sorted, kaolinitic, arkosic sand, and gravel with interbedded yellowish-orange to reddish-green mottled kaolinitic clay (Raymond et al., 1988). The Tuscaloosa overlies Washita and Fredericksburg Groups, and lies below the Eutaw Formation.

The Alabama outcrops represent the thin upper edge of a much greater sedimentary wedge that extends to the south and west in the subsurface, where it reaches thicknesses as great as 1,200 ft (366 m). The thicker parts of the Tuscaloosa are informally divided into lower, middle (marine), and upper members. The lower member is a fluvial-deltaic deposit that pinches out updip, and is not represented in the northwest Alabama outcrop facies. The middle marine shale member is the productive unit and has produced light crude oil (API gravity 38–45), and liquids-rich natural gas from depths of 10,000 to 15,000 ft (3 –4.5 km). The oil content is high, and horizontal drilling has been centered in Amite, Pike, and Wilkinson counties in Mississippi, and Avoyelles, East Feliciana, West Feliciana, St. Helena, and Tangipahoa parishes in Louisiana. From a geological standpoint, the Tuscaloosa Marine Shale has been compared to the Eagle Ford Shale in Texas. Unlike the carbonate-rich and mechanically stable Eagle Ford, however, the TMS is composed of softer clay with variable amounts of silt content that have caused borehole stability problems and poor performance with hydraulic fracturing. Some operators and investors question the ultimate commercial potential in portions of the play.

Upper Devonian: The Devonian black shales in the Appalachian basin were the primary targets of the EGSP well drilling and coring program in the 1980s that began the first serious evaluation of organic-rich shales as potential gas resources (Soeder, 2017). Although most of the recent focus in the Appalachian basin has been on the Middle Devonian Marcellus Shale and the underlying Middle Ordovician Utica Shale, much of the EGSP effort took place on the Upper or Late Devonian-age (383–359 Ma) shales in the eastern basins. This was partially because they were relatively shallow and cheaper to drill, but primarily because one of these Late Devonian units, the Huron Member of the Ohio Shale, is the productive horizon at the Big Sandy gas field in Kentucky (refer back to the discussion in Chapter 2).

Although somewhat forgotten in the frenzy to develop the Marcellus Shale, the Upper Devonian shales of the Appalachian basin are still a potential resource, and have not escaped the attention of the USGS (Enomoto et al., 2018), which has assessed the resource potential of the major Late Devonian black shale units. These include the Cleveland and Huron Members of the Ohio Shale, the Pipe Creek Shale Member of the Java Formation, the Rhinestreet Shale Member of the West Falls Formation, and

Middlesex Shale Member of the Sonyea Formation (refer back to the cross-section in Fig. 3.13). The USGS placed these various formations and members into three Assessment Units (AUs) to statistically determine the potential amounts of undiscovered natural gas and NGL resources in these shales. Their methodology indicated that the Upper Devonian shale in the three AUs has a 5% probability of containing as much as 29 TCF of natural gas, a 50% probability of containing at least 10.7 TCF, and a 95% probability of containing at least 1.5 TCF (Enomoto et al., 2018). This range of results, given in so-called "fractile values" is common for resource estimates because it also expresses the range of uncertainty. When only a single value is reported for a resource estimate, it is usually the 50% probability number.

Although the potential gas contents of the Upper Devonian shales are considerably less than what is thought to be available in the Marcellus, they remain an attractive component of a stacked play, not in the least because drillers are required to penetrate them anyway to reach the underlying Marcellus. Branching out a lateral into one of these shallower formations could add significant production to a shale gas well at a relatively small additional cost.

Rogersville Shale: Deep in the Appalachian basin lies the Middle Cambrian-age (521−497 Ma) Rogersville Shale. It was named by Keith (1896) for exposures near Rogersville, Tennessee, and described as a green argillaceous shale with occasional beds of thin red sandy shale and a bed of massive limestone. The carbonate unit was later named the Craig limestone member, and the Rogersville was included as a member of the Conasauga Group (Rodgers, 1953). The Rogersville Shale occurs in the Appalachian basin within a deep, fault bounded graben called the Rome trough, which extends from South Central Kentucky northeastward along the Ohio River and into northeastern Pennsylvania (Ryder et al., 2005). Evidence from stratigraphic and source rock studies by the Kentucky, Ohio and West Virginia Geological Surveys, and a US Geological Survey assessment of the Rome trough petroleum system (Ryder et al., 2005) using these data and additional information supplied by EQT Corporation suggests that the Rogersville could be comparable to the Marcellus and Utica in terms of resources.

It is not comparable, however, in terms of economics. The Rogersville in the Rome trough is deep. Test wells in Kentucky have gone down to nearly 16,000 ft (5 km) to reach it, with generally disappointing returns. The expense of drilling such a deep well, especially when production is expected to be relatively nonprofitable dry gas, has caused many operators to consider the Rogersville Shale an emerging play that may remain classified as "emerging" for quite some time.

Eastern Mesozoic Rift Basins: As the supercontinent of Pangea split apart during the Late Triassic (227 Ma) to create the Atlantic Ocean, numerous, small extensional basins or grabens formed along the eastern margin of North America (Fig. 4.17). The East Coast rifting ended early in the Jurassic (201−145 Ma) when regional volcanism began to intrude diabase dikes and sills into fracture systems in the crust, and the Mid-Atlantic Ridge dominated as the spreading center for the Atlantic Ocean. The eastern edge of North America was transformed into a passive continental margin, and the rift basins filled with sediments. Some sediments were organic-rich and deeply buried, becoming potential source rocks for petroleum and natural gas.

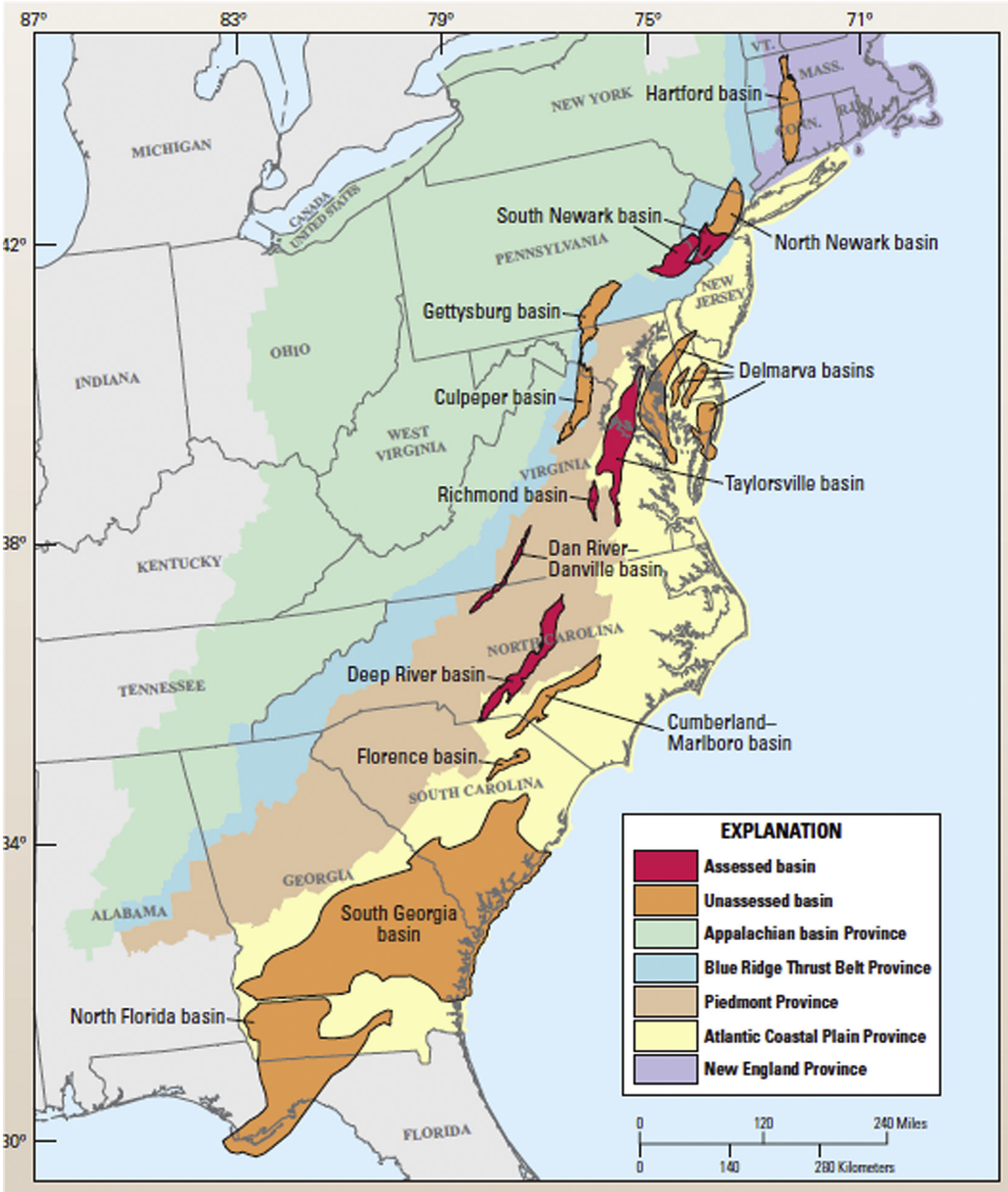

FIGURE 4.17 Map of small Mesozoic rift basins along the US Eastern Seaboard indicating those assessed for shale gas and condensate resources by the USGS. *Modified from Milici, R.C., Coleman, J.L., Jr, Rowan, E.L., Cook, T.A., Charpentier, R.R., Kirschbaum, M.A., Klett, T.R., Pollastro, R.M., Schenk, C.J., 2012. Assessment of Undiscovered Oil and Gas Resources of the East Coast Mesozoic Basins of the Piedmont, Blue Ridge Thrust Belt, Atlantic Coastal Plain, and New England Provinces, 2011. U.S. Geological Survey Fact Sheet 2012–3075, 2 p.*

Depositional environments ranged from fluvial to deltaic and lacustrine, producing boulder beds, coarse-grained sandstones, siltstones, mudstones, organic-rich black shales, and coal (Milici et al., 2012). Hydrocarbon source rocks include gray and black shales and the coals. The coal beds accumulated in marshes and swamps on the basin margins, and the shales were deposited in the deeper portions of the lakes that occupied the basins, as well as in bays and deltas closer to shore.

The USGS used a geology-based method to assess petroleum system resources within five of these Mesozoic rift basins: Deep River, Dan River—Danville, Richmond, Taylorsville, and the southern part of the Newark basin (map, Fig. 4.17). The assessments estimated that all five basins combined contain a mean undiscovered natural gas resource of 3.86 TCF and a mean undiscovered NGL resource of 135 million bbl (Milici et al., 2012). The Deep River, Taylorsville, and South Newark basins have the potential to produce the greatest amount of hydrocarbons from the five basins assessed. Levels of uncertainty are high because these basins have been drilled sparsely, if at all. Nevertheless, the Mesozoic rift basins are located close to large natural gas markets on the Eastern Seaboard and in New England, resulting in favorable economics for transport and delivery if developed. These basins may also provide modest home-grown hydrocarbon production in states like North Carolina, Virginia, and New Jersey where O&G wells are practically unheard of.

Monterey Formation: On the West Coast of the United States, the Middle to Late Miocene age (13.8—5.3 Ma) Monterey Shale is often discussed as an emerging unconventional resource and just as frequently dismissed. It was named after the town of Monterey, California, by Hanna (1928), who described it as white, organic-rich shale that is siliceous and largely composed of tests from diatoms, radiolarians, silicoflagellates, and foraminifera. It represents the youngest accumulation of pure, siliceous, organic strata in California, and is generally believed to be the source rock for most of the oil in the state. The Monterey Formation occurs in the San Joaquin basin where it reaches thicknesses of 2000 ft (600 m) or more and depths as great as 14,000 ft (4.3 km) (Tennyson et al., 2015).

The Monterey has the potential to be one of the most prolific oil-producing formations in the United States, or it could be a complete bust. Geologists are fairly certain that the Monterey Formation contains sufficient organic matter of the correct type to generate oil and that the proper thermal maturity was reached after the rock reached burial depths of about 12,000 ft (3.6 km). The USGS applied their geology-based assessment methodology to the parts of the Monterey that are thermally mature enough to generate oil and concluded that the mean hydrocarbon resource for the formation included 21 million bbl of continuous oil resources, 27 BCF of gas, and 1 million bbl of natural gas liquids (Tennyson et al., 2015).

However, more than 80 wells have penetrated the Monterey Formation to depths where it should have generated oil and none has returned more than small quantities.

The best guess among geologists and operators is that the Monterey Shale is "spent" and that oil has migrated out of the formation to fill overlying conventional structural and stratigraphic traps. Thus, there is probably relatively little recoverable oil or gas remaining in the source rock.

A confounding factor is that much of the Monterey Formation in California is tightly folded due to its proximity to an active tectonic plate boundary. This makes it difficult to drill the longer laterals that have become standard practice in shales like the Utica and the Eagle Ford to improve the economics of production. Little is known about the fracture system in the rock either, which is likely to be extensively given the presence of nearby tectonic structures. This could strongly influence whether or not any petroleum remains in the formation to be recovered.

Alaska North Slope: Given the extensive oil production in decades past from Prudhoe Bay and the North Slope in Alaska, the source rocks for this oil could potentially prove to be significant unconventional O&G resources. The USGS assessed three North Slope source rocks: (1) the Triassic (251—201 Ma) Shublik Formation, (2) the lower part of the Jurassic to Early Cretaceous (201—100.5 Ma) Kingak Shale, and (3) the Cretaceous (145—66 Ma) pebble shale unit and Hue Shale, together known as the Brookian shale (Houseknecht et al., 2012).

These formations occur at depths of less than 3,000 ft (900 m) to the north along the coast of the Arctic Ocean to depths of more than 20,000 ft (6 km) in the foothills of the Brooks Range. Like other shale source rocks discussed in this chapter, this range of burial depths has produced a range of thermal maturities in the rocks, grading from the oil window in the north through NGLs, and into the dry gas window in the south.

The lithology of the Shublik Formation consists of brittle, fractured limestone, phosphatic limestone, and chert, while the overlying Kingak Shale is an argillaceous clay shale that is soft and easily deformed. The uppermost Brookian units include fine-grained sandstone, siltstone, concretionary carbonate, and silicified tuff (Houseknecht et al., 2012).

Technically recoverable shale-oil resources in northern Alaska may be as great as two billion bbl. Oil resources are distributed approximately equally between the Shublik and Brookian formations, while the Kingak Shale has considerably less oil potential. Technically recoverable shale gas resources in northern Alaska may be as high as 80 TCF concentrated primarily in the Shublik Formation. Estimates of technically recoverable NGL range up to more than 500 million bbl. The Shublik Formation is estimated to contain most of the NGL (Houseknecht et al., 2012). Whether or not these North Slope resources will ever be developed remains to be seen. On the one hand, a significant amount of O&G infrastructure has been put into place in Alaska over past decades to produce and transport the conventional oil resources off the North Slope. On the other hand, given the availability of many other shale plays in far more forgiving environments like Oklahoma and Texas, going to the Arctic for shale gas and tight oil just doesn't seem to be an economic proposition.

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5

International shale plays

Introduction

The petroleum industry, and to a lesser extent natural gas, is a global-scale operation. Crude oil is a commodity produced, bought, sold, shipped, and utilized all over the world. Thus, it is a bit of a mystery that despite the success of tight oil plays like the Bakken, Eagle Ford, and the Permian Basin in the United States, tight oil remains a relatively minor player in other parts of the world. Many of the reasons for this are cultural, structural, and geographic in nature, and not easily overcome. World sedimentary basins containing assessed or suspected tight oil and shale gas resources are shown in Fig. 5.1.

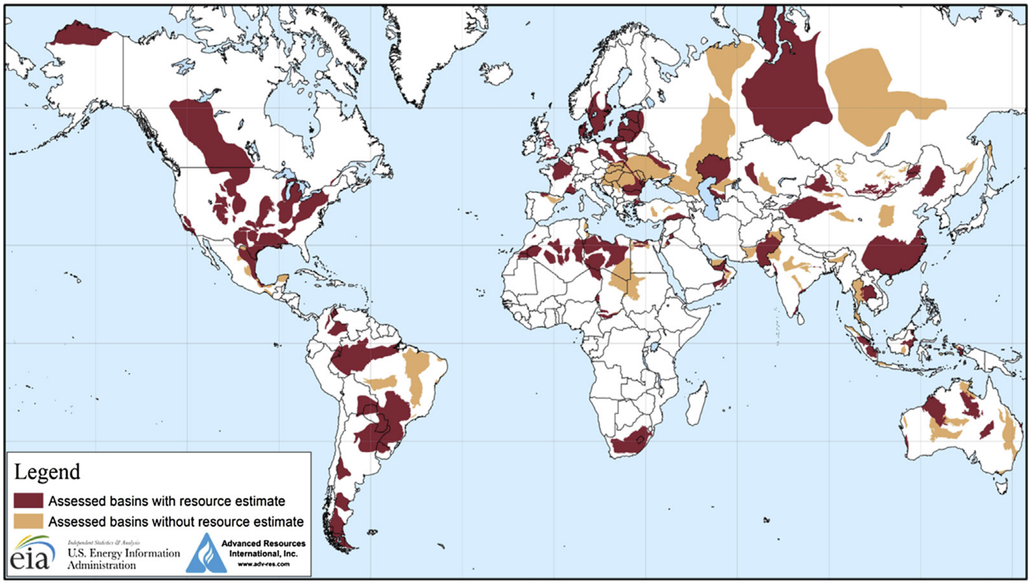

FIGURE 5.1 Worldwide sedimentary basins containing assessed or suspected tight oil and/or shale gas resources. *Source: USEIA and Advanced Resources International.*

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The major multinational oil companies, like Shell, ExxonMobil, British Petroleum, Total, ConocoPhillips and the like are truly global entities with interests and markets nearly everywhere. These are the companies one would expect to find developing shale gas and tight oil resources overseas. Indeed, many of them have gotten engaged in some international shale exploration programs in places like Poland, for example, but after low-performing or challenging wells, and in the face of difficult economics they often pull out.

Although George Mitchell's ideas about how to produce hydrocarbons directly from low permeability source rocks were certainly viewed with interest by the big oil companies, in general the majors have shown only lukewarm interest in leading the charge to develop shale gas or tight oil. Most of the US and Canadian shale development has been led by independents. By the time the majors realized that these plays could be successful and decided to get in on them, many of the sweet spots had already been leased up by midsize companies like Chesapeake, Apache, Range, and Southwestern. The majors either had to spend a lot of money to acquire good acreage, which some did by simply buying up a few of the midsize companies lock, stock, and barrel, or they were left occupying marginal leases. Still, both Shell and Chevron had fairly active operations in the dry gas part of the Marcellus Shale for a few years, but pulled back when gas prices collapsed. ConocoPhillips and ExxonMobil remain indirectly involved with shales in the Williston and Anadarko basins through wholly owned subsidiary companies.

Major oil companies tend to think large and long-term. They have made huge investments in conventional oil production infrastructure, like offshore platforms, thousand-mile long pipelines, and gigantic tanker ships. Shifting gears into what is largely a domestic resource in locations where small operators have always dominated just doesn't fit their business model. As a result, the majors have largely left development of tight oil and shale gas to the large and medium independents, and this has probably subdued some of the international aspects of the resources.

For a wide variety of reasons, many countries are interested in the potential development of their domestic shale gas and tight oil resources. Elsewhere in North America, Canada began tight oil development with the Bakken Shale in southern Manitoba and Saskatchewan and then expanded into other formations in Alberta and British Columbia. Like the United States, Canadian development has largely been spearheaded by large independents. In Mexico, the national oil company Pemex showed little interest in tight oil until Eagle Ford Shale development in neighboring Texas reached a level of intensity that was hard to ignore.

Most of the natural gas supply in Europe comes from Russia. It is both expensive and subject to the volatility of Russian politics, and many countries would like to be more energy-independent. Shale resources in Europe have been assessed in Germany (Klaver et al., 2012), the United Kingdom (Selley, 2012), Belarus and Ukraine (Sachsenhofer and Koltun, 2012), and Poland (Anthonsen et al., 2016) among other countries. The United Kingdom in particular has a special concern about the continued availability of imported natural gas supplies once the country leaves the European Union through Brexit. Poland would also like to move away from a dependence on coal and Russian gas to other energy resources, such as their own domestic gas.

In Africa and the Middle East, Saudi Arabia, several North African countries, and South Africa are interested in shale (Dittrick, 2013). In South America, Argentina has been evaluating their shale resources (Agin, 2012). Shales are also being assessed and developed in a number of Western Pacific and South Asian nations such as Australia (Wilkinson, 2010), India (Das, 2011), Indonesia and Malaysia, and China (Warren, 2012; Dong et al., 2016). In 2013, the US Energy Information Administration (EIA) and Advanced Resources International (ARI) published a thick report containing detailed assessments of 137 shale formations in 41 countries outside the United States (USEIA, 2013). These resources are summarized and explored below, but the reader is referred to the 730-page EIA—ARI report for much more detail.

Canada and Mexico

Canada: According to public information provided by Natural Resources Canada (NRCan), the principal shale gas and tight oil shale plays in the country are in British Columbia (BC) and Alberta (refer back to fig. 2.9). These two provinces dominate with production from several basins, including the Horn River, Laird, and the Cordova embayment in northern BC, and the Alberta basin, East and West Shale basin, and the Deep basin of west-central Alberta (USEIA, 2013).

Important tight gas and oil formations in BC include the Middle Triassic (247—237 Ma) Montney Shale and the overlying Doig Phosphate Shale on the western side of the Deep basin. In northern BC and the Northwest Territories, the Horn River basin and the adjacent Cordova embayment are separated by the Slave Point platform. The main shale gas formations in these two adjoining basins are the Middle Devonian (393—383 Ma) Muskwa/Otter Park Shale, and the underlying Middle Devonian Evie/Klua Shale, separated by an organically lean rock interval. A third basin, the Laird in northwestern BC contains the Middle Devonian-age, Lower Besa River Shale, equivalent to the Muskwa/Otter Park and Evie/Klua shales in the Horn River/Cordova basins. The Canol Shale is an emerging shale play located in the central Mackenzie valley in the Northwest Territories. Only a few exploratory wells have been drilled and little is known about this formation, but it could become an important future contributor to Canadian shale gas.

Like BC, Alberta contains a number of organic-rich shale formations, including the Early Mississippian (359—347 Ma) Banff and Exshaw Shale in the Alberta basin, the Late Devonian (383—359 Ma) Duvernay Shale in the East and West Shale basin, the Jurassic (201—145 Ma) Nordegg Shale in the Deep basin of west-central Alberta, the Late Devonian Muskwa Shale in northwest Alberta, and the shale gas formations of the Cretaceous (145—66 Ma) Colorado Group in southern Alberta. The Montney and Doig Phosphate plays in the Deep basin in BC extend eastward into Alberta, but in the Alberta part of the basin these are categorized primarily as tight sand and siltstone reservoirs (USEIA, 2013).

NRCan identifies the most significant tight oil resource in western Canada as the Bakken Shale in the Canadian part of the Williston basin in Saskatchewan (SK) and Manitoba. The Shaunavon Formation is also a small oil producer in SK, as is the Lower Amaranth Shale in Manitoba. Western Canada has seen shale gas and tight oil production move forward in the Deep basin and other areas of the Canadian Rockies and Great Plains where infrastructure from long-term, conventional O&G operations is already in place. Development has been slower in the more remote, wilderness regions of northern BC, the Yukon, and the Northwest Territories where there are few inhabitants, fewer roads, and very rugged terrain.

According to NRCan, gas shale formations in eastern Canada include the Kettle Point in Ontario, the Utica Shale in Quebec, the Frederick Brook in New Brunswick, and the Horton Bluff in Nova Scotia. Minor tight oil formations are the Macasty Shale in Quebec and the Green Point Formation in Newfoundland and Labrador. Eastern Canada has traditionally been less welcoming to oil and gas development than the western part of the country. Efforts were made a few years ago by Junex, a Quebec-based operator to develop the Utica Shale in the St. Lawrence valley between Quebec City and Montreal with the goal of supplying gas to those markets. However, the Province of Quebec shares a border with New York and strong resistance against fracking developed quickly. In June 2018 the government of Quebec banned shale gas development and fracking throughout the province. The restrictions also banned conventional drilling near waterways, and within a 1-km zone around the city of Montreal and other urban areas. Nevertheless, several Canadian environmental groups decried the new rules because they did not "completely shut the door on hydrocarbon development." (Canadian Broadcasting Company, June 6, 2018.)

Mexico: The oil industry in Mexico was nationalized in 1938 with the establishment of *Petróleos Mexicanos,* the government oil company more commonly known by its acronym, Pemex. As a government-owned and operated entity, the company is typically described as stodgy, conservative, rule-bound, risk-averse, and not terribly innovative. Thus, when the fossil fuel revolution hit the United States and Canada in the first decade of the 21st century, nothing similar happened in Mexico. Nearly all of the gas recovered in Mexico is "associated gas" obtained as a byproduct of conventional oil production. Steady declines in petroleum production have resulted in similar declines in natural gas. However, gas now accounts for nearly 60% of Mexican electrical power generation, and finding ways to produce more natural gas is possibly Mexico's most important energy goal. They currently import a significant amount from the United States.

The Eagle Ford Formation in Texas extends south of the border into northern Mexico's Burgos basin, where it is known as the Boquillas Formation. The Eagle Ford thermal maturity zonation as a function of burial depth continues in the Boquillas. Technically recoverable hydrocarbons in the Boquillas Formation have been assessed at 343 TCF of gas and 6.3 billion BOE for the petroleum, wet gas, and dry gas zones in the

Burgos basin (USEIA, 2013). The Sabinas basin to the west contains an additional estimated 124 TCF of shale gas resources in the Boquillas and La Casita shales, but this basin is located in a mountainous region and is structurally complex, increasing the uncertainty of technically recoverable hydrocarbon assessments. Smaller, simpler basins along the Mexican Gulf Coast southward toward Yucatan include the Tampico, Tuxpan, and Veracruz basins. These contain Cretaceous and Jurassic marine shales that are prolific source rocks for Mexico's conventional onshore and offshore fields in this area, and are estimated to contain 28 TCF of technically recoverable gas and 6.8 billion BOE (USEIA, 2013).

Unlike Texas, the Eagle Ford equivalents and other source rock shales have not been developed in Mexico, except for a few trial wells. Although Pemex is now expressing an interest in these unconventional resources after energy reforms restructured the company in 2013, they lack the expertise to deal with shale gas and tight oil reservoirs. A few US companies were invited to drill test wells after the reforms and quickly discovered the many challenges of Mexican shale gas development. These include higher costs, a smaller service industry, a confusing, often contradictory regulatory framework, a lack of pipelines and other midstream infrastructure, security problems from local narcotics trafficking, and water supply shortages. However, given the size of the resources and the need for natural gas energy in Mexico, overcoming these challenges is critical because the eventual development of Mexican shale gas resources appears to be a necessity.

The United Kingdom and Continental Europe

United Kingdom: The United Kingdom has been interested domestic shale gas resources since economically successful unconventional O&G development began in North America (Selley, 2012; Stephenson, 2015). This has become somewhat more urgent in the wake of the UK vote in June 2016 to leave the European Union known as "Brexit," because of concerns that imported energy might become more challenging for the United Kingdom to obtain as an independent, small market.

Great Britain has significant amounts of potential shale gas and tight oil resources distributed broadly in the northern, central, and southern portions of the country (Fig. 5.2). The geology of shales in the United Kingdom is more complex than that of similar rocks in North America, affecting economics, and because the industry is not fully established, drilling and completion costs for shale wells are substantially higher than in the United States and Canada.

The British Geological Survey is charged with assessing prospective shale gas and tight oil resources in the UK. Prospective resources include liquids-rich Jurassic shales in the Wessex and Weald basins in the south of England, Cambrian-age shale in Wales, and Carboniferous shales of the Midland Valley of Scotland. Perhaps the most promising gas shale in terms of hydrocarbon resources is the Carboniferous-age (359–299 Ma)

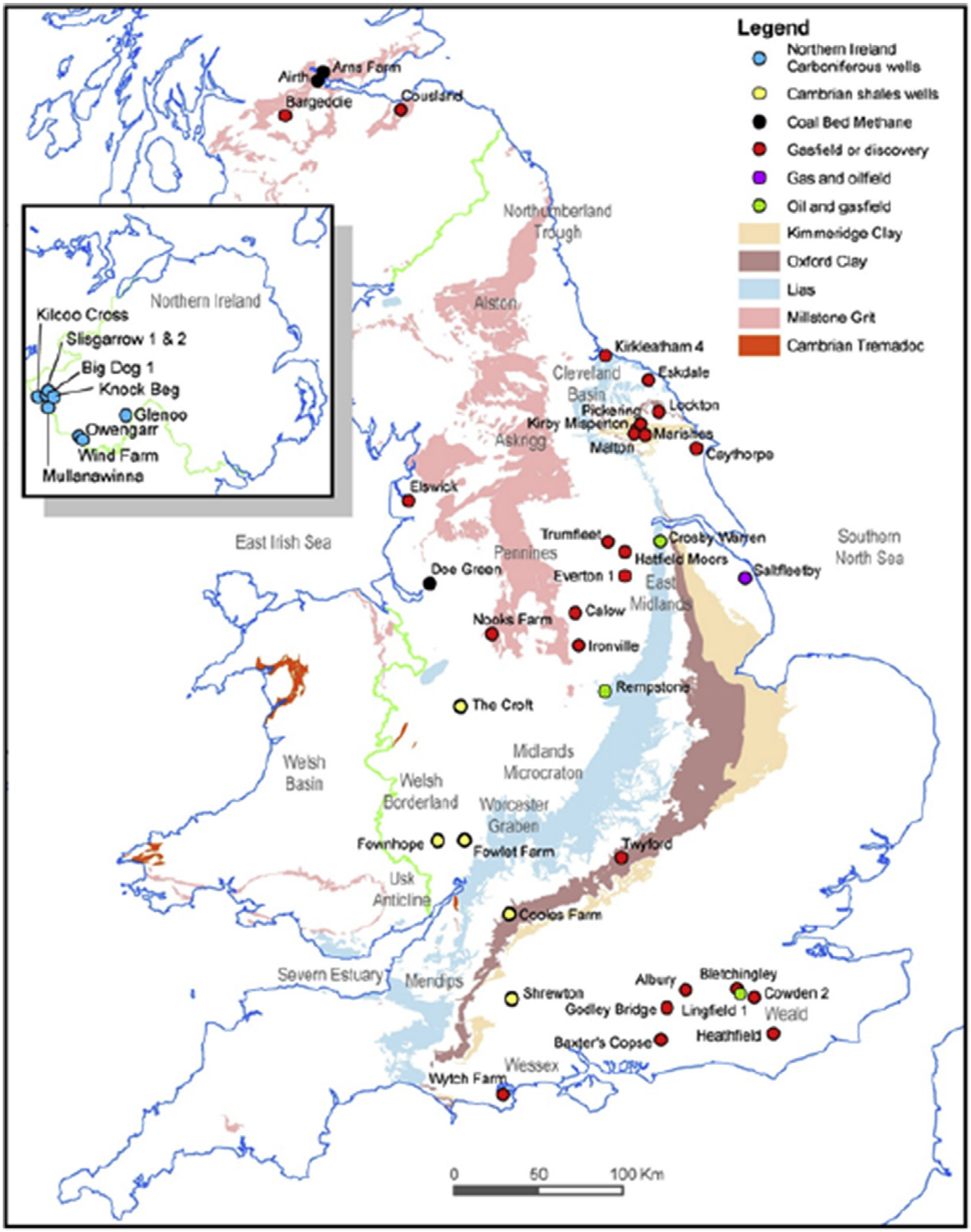

FIGURE 5.2 Potential shale gas in Great Britain. *Source: British Geological Survey websites.*

Bowland Shale located in the Bowland sub basin near Blackpool in the western portion of the Pennine basin. Exploratory drilling and coring of five vertical wells has confirmed the presence of thick, gas-bearing shales in this location. Some of the resources are quite significant; estimates by the British Geological Survey of technically recoverable shale gas in the Bowland subbasin alone range from 822 to 2281 TCF, with a median value of 1329 TCF. Other Carboniferous shales throughout the United Kingdom may be prospective as well (USEIA, 2013).

Shale testing is still at an early phase in the United Kingdom. In April and May 2011, the very first shale well to be hydraulically fractured triggered two minor earthquakes related to a nearby fault (Marshall, 2011). The UK government responded by imposing a fracking moratorium to investigate this and other potential environmental risks from shale exploration and development. Cuadrilla Resources, the operator at the Preese Hall drilling site near the town of Blackpool where the seismic events took place, immediately commissioned an investigation of the earthquakes. The study concluded that the Preese Hall earthquakes were caused by unusual circumstances, including a stressed fault in brittle rock that was permeable enough to allow large amounts of frack water to enter and lubricate it. The report indicated that such events were unlikely to be repeated. After 18 months, the government concluded that environmental risks could be managed with stricter monitoring controls and allowed shale development to resume in December 2012. However, at this writing, little shale gas has been produced in Great Britain.

Continental Europe: The country in continental Europe most interested in the potential for domestic shale gas is Poland, which is considering the development of natural gas from the Silurian (444−419 Ma) black shales that occur in a belt stretching from central Pomerania to the Lublin region (Konieczyńska et al., 2011). The Baltic basin in northern Poland and the Podlasie and Lublin basins in the east also contain Cambrian to Silurian-age marine shales with a moderate but variable organic content. The EIA/ARI assessment reduced the initial value of technically recoverable gas in these shales by 20% after obtaining more information about the relatively low TOC (USEIA, 2013). The Baltic basin is still the most favored prospective region because it has a relatively simple structural setting. Although they contain similar marine shales, the Podlasie and Lublin basins are structurally more complex with closely spaced faults that may limit horizontal drilling. A fourth prospective area, the Fore-Sudetic Monocline in southwest Poland, has Carboniferous-age, lacustrine, coaly shale with significant gas potential.

The Polish Geological Institute and the Voivodeship Inspectorate for Environmental Protection carried out environmental impact assessments in 2011 on the Lebien LE-2H shale test well, which was one of the first prospective environmental studies ever done on a shale well. (Such studies have not yet been done in the United States.) Polish scientists monitored air, water, groundwater, ecosystems, and landscape impacts prior, during and after development of the well, and concluded that when proper construction techniques were followed, environmental impacts of shale gas drilling were minimal and manageable (Konieczyńska et al., 2011).

Poland has some of Europe's most favorable infrastructure and public support for shale development. Initial exploration has confirmed that the shale resource potential is there, but also indicated that reservoir conditions are more challenging than anticipated, and that the resources are perhaps not as rich as originally thought. This appears to have slowed down investment in shale gas development in the country.

Environmental concerns have restricted or halted shale gas development in many other European countries, where Green parties possess significant political clout (Kulkarni, 2011). Hydraulic fracturing has been banned outright in France since 2011 (Lange et al., 2013). Despite possessing apparently significant shale gas resources (Klaver et al., 2012), Germany also has banned fracking of horizontal wells except for limited scientific research and restricted fracking in conventional wells. Unless the German Bundestag decides to rescind the regulations in 2021, the ban will remain in place (News Release, German Federal Government, February 13, 2017). The Netherlands followed suit, banning fracking in Holland until 2020. Fracking bans are also in place in Belgium, Bulgaria, and the Czech Republic (Osterath, 2015).

Nevertheless, other European nations continue to weigh their shale gas options. In addition to Poland, Denmark has been slowly moving forward to test and assess their shale resources. The main target is the Cambro–Ordovician (541–444 Ma) Alum Shale in the Norwegian–Danish basin (Schovsbo et al., 2014), which is prospective in several bands running northwest to southeast across the country. The geology of the Alum Shale is faulted and complex, and it may be more difficult to develop than anticipated. Several of the Silurian-age shales that are of interest in Poland may also be prospective in Denmark. In June 2014, a municipality located in the north of Denmark named Frederikshavn gave the French energy company Total permission to explore for shale gas. This was the first time a drilling license for shale gas was approved in Denmark, and it was met with angry protests from citizens.

Hungary has a number of potential shale gas and tight oil formations that could be developed (Badics and Vető, 2012). These include the Late Triassic (237–201 Ma) Kössen Marl in southwestern Hungary, which has a high organic content, good thermal maturity, and fracture barriers. It is estimated to contain up to 9 billion BOE. The Early Jurassic (201–174 Ma) Toarcian Shale in the Mecsek Mountains and under the Great Hungarian Plain is thin, but relatively rich in organic matter. It could form a potential shale gas play if it thickens locally. There is also some hydrocarbon potential in the Early Oligocene (33.9–28.1 Ma) Tard Clay in northeastern Hungary, which may contain 7 billion BOE and possibly in some Middle Miocene marine formations as well (Badics and Vetö, 2012).

Other areas in continental Europe with shale gas and tight oil potential include the Dnieper–Donets basin of the Ukraine, which contains Lower Carboniferous black shales that may hold significant gas (Schulz et al., 2011). The organic-rich sediments of Oligocene–Miocene age in the Pannonian basin of central Europe may also offer shale gas potential, as may the Late Jurassic black shales in the adjacent and structurally complex Vienna basin. Romania has made some tentative steps toward development.

European gas shale geology is complicated by interactions between the African and European plates, including the closing of the Tethys Sea, which resulted in compression and shear in the surrounding basins, faulting, folding, and the creation of the Alps and the Carpathian Mountains.

Along with environmental concerns, the issue of technology optimization for the specific shale plays also has been a significant barrier to international development. The trial-and-error type of field experimentation that appears to be required to develop an efficient drilling and fracking program on any new shale play is expensive and time-consuming. Some nations, like Denmark and the United Kingdom have begun field trials, but many countries are reluctant to commit to such an exercise.

Russia

Russia has expressed an official disdain for shale gas and tight oil over the past decade, and Russian state media have consistently bashed US shale development. As the largest exporter of conventionally produced natural gas in the world, Russia's goal is to discourage their biggest customers like France and Germany from developing their own significant domestic shale gas resources. Thus, Russian media outlets frequently run stories about how fracking sets people's kitchen faucets ablaze, contaminates drinking water, or creates earthquakes in places like Oklahoma that are otherwise seismically quiet. It is no coincidence that both France and Germany have banned hydraulic fracturing and remain dependent on Russian gas.

The irony is that the largest shale hydrocarbon resources in the world are located in Russia. International sanctions imposed after the Russian annexation of the Crimean Peninsula from Ukraine in 2014 have restricted major American oil companies such as ExxonMobil from partnering with Russian producers like Gazprom and Rosneft to develop unconventional O&G. Russia has been forced to develop shale gas and tight oil production technology without American expertise and it has been proceeding slowly. The perils of fracking reported in the Russian media are meant as a holding action until development is able to move forward.

The West Siberian basin in Russia is the largest petroleum basin in the world, roughly the size of the entire country of Ethiopia. It extends from the Ural Mountains east to the Yenisei River, and from the border with Kazakhstan northward to the Kara Sea and continues offshore to Novaya Zemlya. It contains conventional production from giant gas fields like the 350-TCF Urengoy north of the Arctic Circle and large oil fields such as Samotlor with 28 billion bbl of reserves in the central Middle Ob petroleum region. About 90% of the conventional oil and gas in the West Siberian basin was sourced from the Late Jurassic (164−145 Ma) Bazhenov Formation, a marine black shale with abundant Type II kerogen and a level of thermal maturity that gives it a high oil-generation potential (Lopatin et al., 2003). Primary oil generation and migration took place during the Tertiary.

In Late Jurassic time, a deep depression formed in the entire central part of the West Siberian basin over an area that exceeded 1 million km^2 (Ulmishek, 2003). Water depths in this depression were greater than 300 m (1000 ft) and possibly reached 700 m (2300 ft), where the organic-rich, siliceous black shales of the Bazhenov Formation accumulated under deepwater anoxic conditions. The black shale facies of the Bazhenov Formation is about 20–50 m (65–165 ft) thick, but locally absent on the crests of some of the uplifted structures within the basin, probably due to pre-Cretaceous erosion (Ulmishek, 2003). Organic-lean shales and other fine clastic sediments were deposited along the shallower margins of the basin (Fig. 5.3).

The resource potential of the Bazhenov Shale in the Western Siberian Basin can be partitioned into northern and central sections based on TOC and thermal maturity (USEIA, 2013). The north section has a lower average TOC of around 5%, but also contains a range of thermal maturity favorable for oil, wet gas or condensate, and dry gas. The central section has a higher average TOC of 10%, but is more thermally mature. Like many other shale formations, the TOC and thermal maturity of the Bazhenov varies

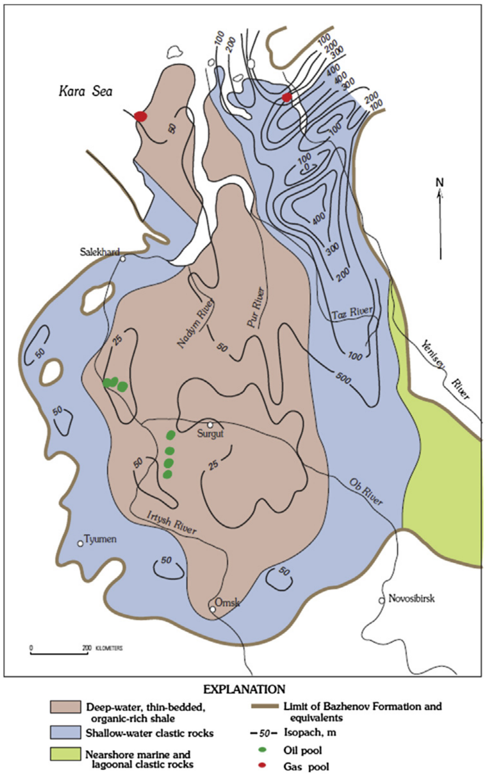

FIGURE 5.3 Lithofacies and isopach map of the Bazhenov Formation in the West Siberian Basin, Russia. Scale bar is 200 km (124 miles). *Source: Modified from Ulmishek, G.F., 2003. Petroleum Geology and Resources of the West Siberian Basin, Russia. U.S. Geological Survey Bulletin 2201-G, 49 p.*

across the basin with depositional environment and burial depth. It is exposed in surface outcrops around the edge of the basin and is as deep as 13,000 ft (4 km) in the center (Ulmishek, 2003).

The reservoir structure of the Bazhenov Formation is somewhat analogous to the Bakken Shale play of North Dakota, where a carbonate reservoir is "sandwiched" between two oil-saturated shales (refer back to the discussion in Chapter 3). Like the Bakken, the Bazhenov consists of high-TOC shale layers interbedded with carbonate/dolomite. The shales are the source of the oil, while the fractured carbonate layers provide additional reservoir capacity (USEIA, 2013).

For the vast Bazhenov Shale prospective area in the West Siberian basin, oil in place is estimated at 1.24 trillion bbl, with about 74.6 billion barrels technically recoverable (USEIA, 2013). In comparison with the estimated recoverable oil reserves of about 7.5 billion bbl in the Bakken, the Bazhenov shale oil resource may be as much as 10 times greater. GIP in the Bazhenov Shale is equally impressive, assessed at 1920 TCF, with 285 TCF considered to be technically recoverable (USEIA, 2013).

Favorable economics for development of the Bazhenov include the presence of a significant amount of existing oil field production and gas transmission infrastructure already located throughout the West Siberian basin. If and when it takes off, production could come online quickly, a fact not lost on the economic and political circles in the West. Gazprom Neft, the exploration and production subsidiary of the Russian state gas company Gazprom, is reportedly experimenting with up to 30 stages of hydraulic fracturing in laterals drilled into the Bazhenov Shale. Russia's largest oil company, Rosneft (a contraction for *Rossiyskaya neft* or "Russian oil") is also testing drilling and fracking operations in the Bazhenov. Success is only a matter of time, and expected by the 2020s.

The Late Devonian-age (383–359 Ma) Domanik Formation in the Timan–Pechora basin in northern Russia is another potential unconventional O&G resource. The Domanik consists of thin-bedded, organic-rich, siliceous shales, limestones and marls deposited in a deepwater marine setting (USEIA, 2013). TOC contents range from 1 to 15% with an average of about 5%, and include both Type I and Type II kerogens. Thermal maturity data place the Domanik Shale in the oil window. The formation is absent on the southwestern basin margin, but occurs throughout the rest of the Timan–Pechora basin. The shale is up to 300 m (1000 ft) thick, and low in clay content, so it will probably frack well, but little information is available on the net organic-rich interval, its porosity and pressure. The Domanik Formation has been correlated with the Duvernay Shale in Canada. Other potential gas shales and tight oil resources in the Timan–Pechora basin include high TOC Jurassic to Cretaceous shales, which are thermally immature, and low-TOC Silurian-Ordivician shales with higher levels of thermal maturity (USEIA, 2013).

Saudi Arabia and North Africa

The vast amounts of historical conventional oil and gas production from the Middle East and North Africa suggest that there are equally enormous source rocks present in these regions that may have untapped hydrocarbon potential. Many of these nations, including Saudi Arabia, Libya, Algeria, and others, are interested in assessing unconventional natural gas resources for domestic use. The rationale in Saudi Arabia is that unconventional gas produced for domestic electrical generation and other purposes will free-up more oil and NGL for export. In North African countries like Algeria that already export LNG, boosting supplies with shale gas could help their bottom line.

Saudi Arabia: Saudi Arabia is known for enormous conventional oil and gas fields, including Al-Ghawar, the largest conventional oil field on Earth. Ghawar had produced 55 billion bbl of oil by 2005 and is expected to produce at least that much more before depletion (Dunham, 2005). The main productive horizon is the Late Jurassic (164—145 Ma) Arab-D limestone, a very clean grainstone with greater than 30% porosity in places. The source rocks are Jurassic-age, organic-rich, calcareous mudstones deposited in intershelf basins. The structural setting at Ghawar is an anticline draped across a basement horst that has trapped vast quantities of petroleum beneath a thick anhydrite caprock (Dunham, 2005).

The presence of geologic structures favorable for traps, limestone reservoir rocks that are exceptionally porous and permeable, and a very high rate of O&G production from relatively shallow wells have caused many people to wonder why Saudi Arabia is even bothering to consider unconventional resources, especially natural gas, which is not exported (Hayton et al., 2010). However, the fact that natural gas is difficult to export is exactly why Saudi Aramco, the national oil company, is showing interest. Developing local tight gas resources for domestic use would provide cheap energy to help boost regional development within the Kingdom without cutting into petroleum reserves that are the primary export.

The Silurian-age (444—419 Ma) Qusaiba Shale is sandwiched between several thousand feet (hundreds of meters) of sandstones, comprising a lower Paleozoic siliciclastic succession in the South Ghawar and Rub'al-Khali areas (Hayton et al., 2010). This lower Paleozoic succession occurs across Saudi Arabia from outcrops to depths greater than 20,000 ft (6 km). Both the Qusaiba Shale and underlying, Late Ordovician (458—444 Ma) Sarah and Qasim sandstones contain significant gas resources in southern Saudi Arabia, with reservoirs that range from tight to conventional. Northwest Saudi Arabia is another priority area for Saudi Aramco's tight gas efforts. Conventional exploration activity in northwest Saudi Arabia is acquiring data on tight gas resources for better assessments as wells are drilled to conventional targets.

The size of the shale gas resource in Saudi Arabia is not well quantified. Former Saudi oil minister Ali Al-Naimi estimated it at about 600 TCF. Baker Hughes assessed it at 645 TCF, whereas Saudi Aramco simply classifies it as "huge." Shale resources in the Jafurah basin alone, east of the Ghawar field, could top 600 TCF and are said to rival those of the Eagle Ford in Texas. The target shales in Jafurah are the Jurassic source rocks for Ghawar. The basin is located in a major Saudi energy industry corridor between Ghawar and the Persian Gulf, and significant midstream infrastructure is already in place to transport any produced gas or liquids to markets within the Kingdom, improving the economics.

Overcoming the costs of drilling and fracking unconventional wells is a challenge for Saudi Aramco. Unlike the United States, where operators have reduced development costs through greater efficiency, experience, and advanced technology, Saudi Arabia struggles with a shortage of qualified and skilled hydraulic fracturing specialists. Obtaining sufficient water for hydraulic fracturing operations in the desert kingdom is also a formidable challenge. Individual shale gas wells in the United States range in cost from about $6 million to $8 million each, but in Saudi Arabia and many other countries, the cost can easily be double the US figure. However, if Saudi Aramco successfully develops these tight resources, the gas will replace the burning of hydrocarbon liquids for power generation and desalination, freeing up hundreds of thousands of additional barrels for export.

Persian Gulf: Conventional oil and gas production has long been an economic mainstay in the relatively small countries of the Persian Gulf. They formed a trade bloc in 1981 known as the Gulf Cooperation Council or GCC composed of the Kingdom of Bahrain, Kuwait, the Sultanate of Oman, Qatar, the United Arab Emirates, and the Kingdom of Saudi Arabia. The largest conventional gas producer in the Persian Gulf is Qatar, with recoverable reserves of about 885 TCF (USEIA, 2013), most of it offshore in the North Field. In 2006, Qatar reportedly surpassed Indonesia to become the largest exporter of LNG in the world. Abundant gas in the Persian Gulf has led to the regional development of a number of energy-intensive industries, such as petrochemicals, electrical generation, and aluminum smelting; the latter has made the GCC one of the world's largest aluminum producers. The Persian Gulf exerts a huge influence on world energy production.

The shale gas revolution in the United States was met with trepidation in the GCC. The trading bloc members were concerned about the potential loss of one of their biggest markets if the United States became energy self-sufficient from shale gas and tight oil. Like many conventional producers, they initially dismissed shale as a passing fad, but once it began to appear sustainable in North America, the GCC nations reassessed their options. Many of them began looking to the shale source rocks for their own massive, conventional O&G resources to see what might be there.

The tiny Persian Gulf island nation of Bahrain announced in April 2018 that it had found at least 80 billion barrels of shale oil in the Khaleej Al Bahrain basin, located in shallow water off the country's western coast. This discovery is larger than the US Bakken Shale in North Dakota. The kingdom's oil and gas ministry said about 14 TCF of natural gas had also been found. Little is known about how much of this oil and gas can physically be produced, let alone what the economics might be, but these types of finds are telling in that the GCC nations are not standing idly by as others develop shale resources.

The potential existence of other huge shale gas and tight oil resources in the Persian Gulf region has reopened discussions about coordination and integration of efforts for current and future discoveries. Because of the technical challenges involved in shale gas production, many of the GCC members feel that pooling their talents will prove more productive than going it alone. Qatar is presently on the outs with the GCC and is excluded from the cooperative efforts. A stated goal for the other members of the GCC is to match or exceed Qatari LNG exports if large enough quantities of shale gas become available to make the process of liquefaction economically feasible.

North Africa: For most of the Paleozoic, North Africa was a single, massive depositional basin (Peterson, 1985). Two major transgressions, first in the Silurian and again in the Late Devonian deposited significant thicknesses of organic-rich marine shales across the area (Klett, 2000). These shales identified as the Early Silurian (444–433 Ma) Tannezuft Shale and the Late Devonian (383–372 Ma) Frasnian Shale were the source rocks for up to 90% of the conventional hydrocarbons in North Africa, and are now targets for shale gas and tight oil. The Tannezuft is commonly known as the "Silurian hot shale" because of the typical strong response seen on gamma logs due to the enriched uranium content of the rock (Lüning, 2003). There are also Mesozoic marine shales that were important source rocks in various basins.

The main, organic-rich "hot shale" beds of the Tannezuft Shale in North African are present in the basal part of the sequence, deposited over a relatively short time period of 1 to 2 Ma during the earliest Silurian under conditions of exceptionally strong oxygen-deficiency in bottom waters that enhanced the preservation of organic matter (Lüning et al., 2000). This occurred during a marine transgression caused by the melting of Ordovician ice caps. The glacial landscape of northern Gondwana after the Ordovician Ice Age resulted in laterally discontinuous deposition of the Silurian hot shale, complicating resource assessments (Lüning, 2003). The shale rests on top of Late Ordovician glacial and periglacial sandstones.

Thick deposits of the Silurian hot shale occur in Algeria, Tunisia, and western Libya. It is much thinner and more discontinuous in Morocco, Mauritania, and Western Sahara and is completely absent in Egypt, which was a highland area at the time (Lüning et al., 2000). Even with this variability, the overall stratigraphy of the Silurian Tannezuft Shale is more continuous than that of the overlying Late Devonian Frasnian Shale, which has been influenced by more localized deposition.

The episodic separation and collision of Laurasia and Gondwana during the Hercynian orogeny in the Carboniferous to Permian (359–252 Ma) broke the crust of present-day North Africa into a series of small grabens separated by horsts. The graben basins contain sediments ranging in age from Cambrian though Oligocene, and are structurally complex, further complicating resource assessments (Peterson, 1985).

Libya is one of the important hydrocarbon producing countries of North Africa, with a long history of successful oil and gas exploration (Goudarzi, 1970). The three major oil and gas basins in Libya are the Ghadames in the west, the Sirte in the center, and the Murzuq in the southwest (USEIA, 2013). The basal "Silurian hot shale" within the Tannezuft Formation is the main source rock and potentially hydrocarbon-productive shale formation in the Murzuq and Ghadames basins. The Sirte basin contains two Late Cretaceous (100–66 Ma) shales: the Sirte/Rachmat and the Etel as source rocks and potential direct producers. The shales in these three basins in Libya are estimated to contain 942 TCF of GIP, with 122 TCF technically recoverable.

In addition, approximately 613 billion bbl of oil and NGL are estimated to be in place in these shales, with 26.1 billion barrels considered technically recoverable (USEIA, 2013).

Algeria has seven hydrocarbon basins that contain the Tannezuft Shale and the Frasnian Shale as source rocks and potential unconventional resources. The seven basins comprise the Ghadames and Illizi in eastern Algeria, the Timimoun, Ahnet, and Mouydir basins in central Algeria, and the Reggane and Tindouf basins in southwestern Algeria. In total, shales in these basins are estimated to contain approximately 3419 TCF of gas-in-place, with about 707 TCF considered technically recoverable. Algerian shales are also estimated to contain 121 billion bbl of oil and NGL in place, with about 5.7 billion bbl technically recoverable (USEIA, 2013).

The Ghadames basin is present not just in Libya and Algeria, but also in southern Tunisia, and the Tannezuft Shale and Frasnian Shale are source rocks and potential unconventional O&G resources in this country as well. The gas potential of the Tannezuft and Frasnian shales in the Tunisian part of the Ghadames basin is estimated at 114 TCF of GIP, with 23 TCF considered technically recoverable. In addition, the two shales are also estimated to contain 29 billion bbl of oil, with 1.5 billion bbl potentially recoverable (USEIA, 2013). Some shale gas and tight oil potential may also exist in the Pelagian basin of eastern Tunisia, which contains Jurassic–Cretaceous and Tertiary source rocks.

The Tarfaya basin in southwestern Morocco contains Late Cretaceous (100–89.8 Ma) black shales with TOC contents of up to 18%. Organic matter consists of Type 1 and Type 2 kerogens with thermal maturity levels from Rock-Eval pyrolysis indicated as being immature to early mature (Kolonic et al., 2002). It has the potential to be a significant source rock, but the low thermal maturity and high TOC suggests that hydrocarbons have not migrated out of these shales in any meaningful quantities.

Morocco and its two neighbors, Mauritania and Western Sahara, have accumulations of the Silurian hot shale and Late Devonian Frasnian Shale in the Tindouf basin, which extends into western Algeria. These two shales are also present in the smaller Tadla basin located in northeastern Morocco. Resource assessment has been challenging on these shales because the deposits are discontinuous due to deformation, erosion, and subsidence. The Tindouf and Tadla basins are estimated to contain 95 TCF of shale GIP, of which 20 TCF may be recoverable (USEIA, 2013).

Abu Gharadig, Alamein, Natrun, and Shoushan-Matruh are four Egyptian basins in the Western Desert that contain deposits of the Middle Jurassic, organic-rich Khatatba Shale, which has the potential for significant shale gas and tight oil. The Khatatba Shale in Egypt may contain 535 TCF of GIP, a resource approximately the size of the Marcellus, with 100 TCF considered to be technically recoverable. Unlike the Marcellus, the Khatatba Shale may also contain about 114 billion bbl of oil, of which 4.6 billion bbl may be technically recoverable (USEIA, 2013).

South Africa

The Karoo is a large, complex sedimentary basin in South Africa, extending across nearly two-thirds of the country. The basin is filled with Carboniferous to Early Jurassic sedimentary strata over 5 km thick, known as the Karoo Supergroup. A component of the Karoo Supergroup is the Early Permian-age Ecca Group, which consists primarily of organic-rich mudstones, siltstones, sandstones, and minor conglomerates deposited in shallow water deltas and wetlands on the northern shoreline of the Karoo Sea under warm climate conditions (Catuneanu et al., 2005). This marshy or "paludal" depositional environment produced abundant coals within the Ecca Group. These coal deposits are confined to the northern part of the basin and do not occur to the south, but the Ecca Group contains almost all of South Africa's coal resources.

The southwestern portion of Karoo Sea was very deep, with steep slopes leading up to the shoreline. This environment was favorable for underwater sediment avalanches known as turbidites to carry coarse and fine-grained material out into distant, deep water. Each turbidite layer consists of a fining-upward sequence grading from coarse sandstone at the base to siltstone and shale at the top. Organic material carried along with the turbidite remained in suspension well into the deepest part of the basin, where it settled out under anoxic bottom conditions, before being buried and eventually converted to oil and gas (Raseroka and McLachlan, 2009). The Ecca Group is quite thick in the southwestern part of the Karoo basin, approaching 1300 m (4300 ft) in some locations.

Potential hydrocarbon plays in the Karoo basin include coalbed methane, conventional natural gas, unconventional gas (associated with valuable helium at concentrations of up to 26%), tight oil, and conventional oil (Raseroka and McLachlan, 2009). The organic-rich, thermally mature black shale in the Whitehill Formation of the lower Ecca Group is persistent in composition and thickness throughout the western part of the Karoo basin and may be the best prospect for a South African gas shale (USEIA, 2013).

Tectonic and climatic shifts from the southern to the northern margins of the basin during the deposition of the Karoo Supergroup altered the lithologic character of the rocks in both space and time. Tectonic activity in the Cape Fold Belt at the southern boundary of the Karoo basin produced a series of igneous intrusions into the sedimentary sequence known as dolerite sills (Coetzee and Kisters, 2016). The most prominent and thickest sills are concentrated within the upper Ecca Group rocks, and have resulted in off-gassing, compartmentalization, and mine stability problems in the Ecca coalfields. The deeper target gas shale formations have less of these intrusive rocks, but their presence in the section complicates the assessment of shale resources, reduces the usefulness of seismic imaging, and increases the risks of shale exploration (Fig. 5.4).

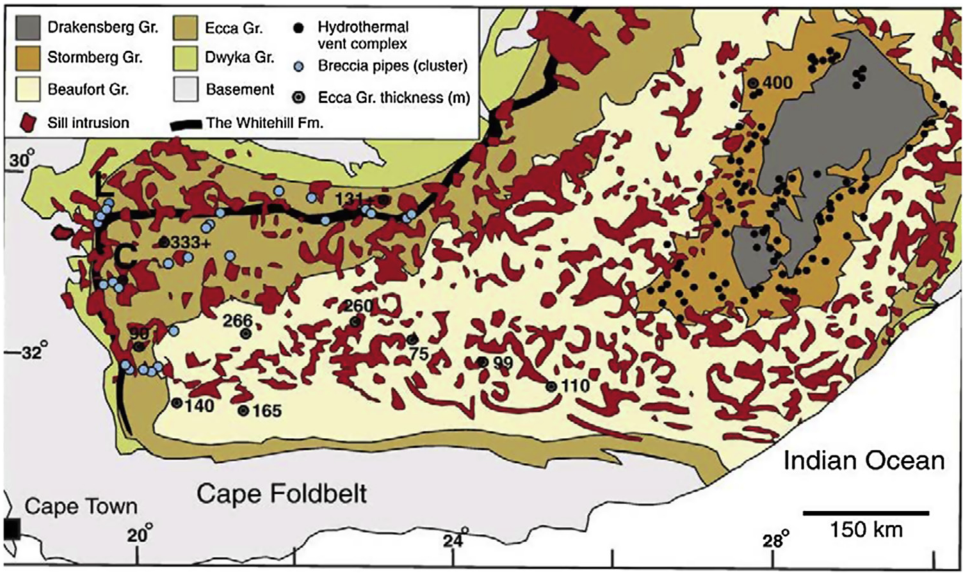

FIGURE 5.4 Map of the Karoo Basin in South Africa showing Ecca Group shales and igneous intrusions. *Source: USEIA.*

South Africa is a net importer of natural gas, primarily from nearby Mozambique and Namibia, and for energy security reasons, the country is interested in developing domestic resources of O&G, including tight oil and shale gas (Dittrick, 2013). The Early Permian Ecca Group shales in the Karoo basin are estimated to contain 1559 TCF of GIP, of which 370 TCF is expected to be technically recoverable (USEIA, 2013).

South Africa has issued a number of Technical Cooperation Permits (TCP) with major and independent companies to pursue shale gas in the Karoo Basin. These include Royal Dutch Shell, the Falcon Oil and Gas/Chevron joint venture, the Sasol/Chesapeake/Statoil joint venture, Sunset Energy Ltd. of Australia, and Anglo Coal of South Africa (USEIA, 2013). None of these have been notably successful so far.

Shell experienced problems trying to procure water supplies in a drought stricken country for fracking and considered using seawater. There was also a significant component of social resistance to the very idea of fracking. To their credit, Shell dealt with the social issues head on, implementing what they call their five operating principles for shale gas development. These include (1) safe well designs, (2) water protection including testing and reducing water use, (3) air quality improvement, (4) creating less of an impact on landscapes by reducing the "footprint" of operations, and (5) community engagement. These principles were developed for Marcellus operations in the Appalachian basin, but worked equally well in South Africa.

South America

Conventional oil and gas development in South America has long been considered to have significant potential, but much of the promise has been undermined by authoritarian or corrupt governments (Agin, 2012). There is no reason to assume that unconventional hydrocarbon production, if and when it takes off, will not suffer the same fate.

The nationalization of oil companies, including the seizure of assets from foreign investors has a long history in South America. Countries with nationalized oil companies include Argentina (YPF), Bolivia (YPFB), Brazil (Petrobras), Peru (Petroperú), and Venezuela (PDVSA), with nationalization threatened on and off in Ecuador. The Argentine oil company, YPF, began as a state-owned enterprise in 1922 and was privatized in 1993. It was partially renationalized in 2012 when President Cristina Fernández de Kirchner introduced a bill for the government of Argentina to obtain a 51% financial interest and majority control of the company. Bolivia has also alternated between privatization and nationalization, with the most recent decision to nationalize Bolivia's oil and gas sector made by President Evo Morales in 2006. Brazil created Petrobras in 1953 and has maintained it ever since as the government oil monopoly. *Petróleos del Perú S.A.* (Petroperú) was created as the Peruvian national oil company in 1969, and *Petróleos de Venezuela S.A.* (PDVSA) nationalized Venezuelan oil in 1976.

Nationalizing oil companies is not all bad. Bolivia reported oil and gas sector revenues of $31.5 billion in the public coffers in the decade after nationalization, compared with oil taxes and royalties of just $2.5 billion in the decade prior to nationalization (Agin, 2012). The problem is that nationalization tends to stifle innovation, as described earlier with Pemex ignoring the Eagle Ford Shale in Mexico. If the development of O&G in a country can continue to be successful using standard technology and methods, national oil companies may be as productive as the private sector. However, in the case of shale gas and tight oil resource development, innovation and "outside the box" thinking are almost always required for success. National oil companies are just not very good at this.

Nationalization also creates the risk that private companies will lose assets. Venezuela is a case in point. In the early 1990s, the government invited foreign companies in and incentivized investment to help accelerate development in the petroleum sector. Many of the large multinational majors responded, bringing in new technology and expertise that significantly increased production and reserves in Maracaibo and other conventional oil fields. However, things changed in 2007 when the populist government of President Hugo Chavez rallied support for national control of energy resources and mandated the transfer of international oil projects into companies where the Venezuelan state held a majority interest. Private investments came under the control of the government. The majors reacted by running for the exits with their experts and technology in tow, and Venezuelan oil production declined rapidly. This added to the intensity of the economic distress suffered a few years later when global oil prices collapsed. Companies have grown understandably cautious about making energy investments in countries when there is a risk of losing technology and other assets if a government decides to nationalize.

Although significant shale gas and tight oil resources appear to be present in source rocks in Columbia, Venezuela, Argentina, and elsewhere on the South American continent, the experts and equipment needed to economically extract hydrocarbons from these tight rocks are not on the ground in large numbers. Argentina has made the most significant efforts in South America to develop shale by bringing in consultants to help assess and produce the resources, but meaningful development elsewhere has been slow and tentative.

Columbia and Venezuela: Organic-rich, marine black shales occur in the Middle Magdalena valley and Llanos basins of Colombia, and in the larger Maracaibo basin that straddles both Columbia and Venezuela. The most important of these units is the Late Cretaceous (100–66 Ma) La Luna Shale, which is a significant source rock in the Middle Magdalena valley, Colombia's main conventional onshore production area, and a major hydrocarbon generator in the Maracaibo basin. The Capacho Formation lying immediately beneath the La Luna Shale consists of dark gray to black shales and limestones, some of which may be prospective near the top of the section. The Capacho is much thicker than the La Luna, but less organic-rich overall. A third important shale source rock that occurs in the Llanos basin is the Gacheta Formation; this is age-equivalent to the La Luna (USEIA, 2013).

The Maracaibo basin in Venezuela is one of South America's most prolific petroleum production areas. An embayment of the Maracaibo extending into Columbia is known as the Catatumbo subbasin, which is structurally more complex but contains the same Cretaceous source rocks as its larger sibling (Yurewicz et al., 1998). The La Luna Shale here is a black, laminated, calcareous mudrock similar in age and character to the Eagle Ford Shale in Texas. Organic material in the La Luna consists primarily of Type II kerogen with minor amounts of Type III. TOC values typically average around 4.5%, but may reach as high as 11.3% in some areas of the Maracaibo Basin (Blaser and White, 1984). The Maracaibo and Catatumbo basins are estimated to have 970 TCF of GIP and 297 billion bbl of OIP in the La Luna and Capacho formations. Technically recoverable shale gas and tight oil resources are estimated to be 202 TCF of gas and 14.8 billion bbl of petroleum, but no known tight oil or shale gas development is taking place in these basins (USEIA, 2013).

The Cretaceous-age Gacheta Formation in the Llanos basin of eastern Colombia contains shales that may be potential source rocks equivalent to the La Luna Shale, but TOC and thermal maturity appear to be low in much of this basin. These may improve to the west, but little is known about these rocks (USEIA, 2013).

The Putamayo basin in southern Colombia contains organic-rich Cretaceous shales in the Macarena Group, which are considered source rocks for conventional O&G production (Mora et al., 2010). Hydraulic fracturing is being used on conventional reservoirs in the Putamayo basin, although the tight oil and shale gas has not yet been developed.

Argentina has significant shale gas and tight oil potential primarily within the Neuquen basin in the west-central part of the country. There is also shale resource potential in several other sedimentary basins (Fig. 5.5), but only the Neuquen is currently being developed (USEIA, 2013). The two important source rock formations in this basin are the Jurassic-age Los Molles and Vaca Muerta marine black shales. A number of companies have been running exploration programs and testing early-stage commercial production with vertical tight oil wells in the Neuquen basin, with initial production reported to be in the 180 to 600 bbl per day range after fracture stimulation. Horizontal wells are also being tested, but technical challenges have so far prevented these from becoming spectacular successes.

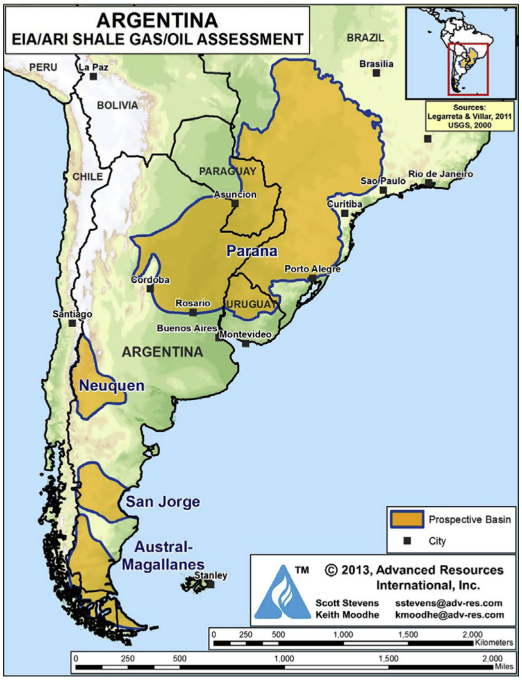

FIGURE 5.5 Sedimentary basins in Argentina containing prospective shale gas resources. *Source: USEIA.*

The Middle Jurassic (174–164 Ma) Los Molles Formation is an important source rock for conventional oil and gas deposits in the Neuquen basin. Hydrocarbon generation took place from the Late Jurassic to the Paleocene (150–50 Ma) with oil and gas migrating to reservoirs in the overlying Lajas Formation sandstones (Rodriguez et al., 2008). Evaporite deposits of the Late Jurassic Aquilco Formation act as a caprock and seal on this hydrocarbon system. Although the Los Molles Formation only contains an average TOC content of 2%, it is more than 3300 ft (675 m) thick in the basin troughs and depocenter, thinning across the Neuquen basin toward the east (Stinco, 2010). The GIP resource base of the Los Molles Formation is assessed at 982 TCF, with technically recoverable shale gas estimated to be 275.3 TCF (USEIA, 2013).

The Late Jurassic to Early Cretaceous (152–139 Ma) Vaca Muerta Formation consists of finely stratified lime-mudstone and black and dark gray marine shale containing Type II kerogen. The unit reaches thicknesses as great as 1700 ft (518 m) in the Neuquen basin (Aguirre-Urreta et al., 2008). Although thinner than the underlying Los Molles Formation, the Vaca Muerta shale is more widespread and has a higher TOC content that averages around 5%. Thermal maturity increases from east to west across the Neuquen basin from oil-prone through a wet gas window and into a dry gas zone. The GIP resource base of the Vaca Muerta Formation is assessed at 1202 TCF, with technically recoverable shale gas estimated to be 307.7 TCF (USEIA, 2013). Total shale gas resources for the Neuquen basin are assessed at 2184 TCF for GIP, with approximately 583 TCF considered technically recoverable.

The Golfo San Jorge and Austral basins in southern Argentina contain lacustrine Late Jurassic to Early Cretaceous shales with promising but untested shale gas potential. Argentina in total may have as much as 3244 TCF of shale gas-in-place, along with 480 billion bbl of tight oil. Of this, 802 TCF of shale gas is estimated to be technically recoverable, along with about 27 billion barrels of tight oil (USEIA, 2013).

Shale gas and tight oil potential in the remainder of South America primarily resides in the Paraná basin, a large structure that underlies parts of Brazil, Paraguay, and Uruguay, as well as a small area of northeastern Argentina (Fig. 5.5). It contains a section of Late Ordovician to Cretaceous sedimentary rock that totals 5 to 7 km (16,400 to 22,965 ft) in thickness. The main petroleum source rock in the Paraná basin is the Devonian (408–372 Ma) black shale of the Ponta Grossa Formation, which contains Type II kerogen. The TOC content of the Ponta Grossa Formation is as high as 4.6%, but more commonly averages a modest 1.5%–2.5%. Even with this relatively low TOC, it has produced natural gas that migrated into overlying conventional sandstone reservoirs (Vesely et al., 2007).

The Brazilian portion of the Paraná basin is partially covered by flood basalts that obscure the underlying geology and increase the cost of drilling. The basin has remained at a moderate burial depth throughout its history, and most of the stratigraphic units are thermally immature. Nevertheless, significant windows of oil-prone, wet gas-prone, and dry gas maturity occur in concentric zones around the deep, central parts of the basin (USEIA, 2013).

China and India/Pakistan

China is one of the large nations planning to move forward with shale gas development over the next 50 years. The primary fossil energy resource in China at present is coal. Along with commercial electric power generation, coal is widely employed for domestic heating and cooking, where it is commonly burned in simple stoves that have no emission controls. As a result, the air quality in major cities like Beijing is often terrible. The Chinese intend to replace coal use in many areas with natural gas (Yu, 2017). Because China possesses only modest conventional gas resources, the significant shale gas resources present in a number of basins throughout the country are being planned for development (Fig. 5.6).

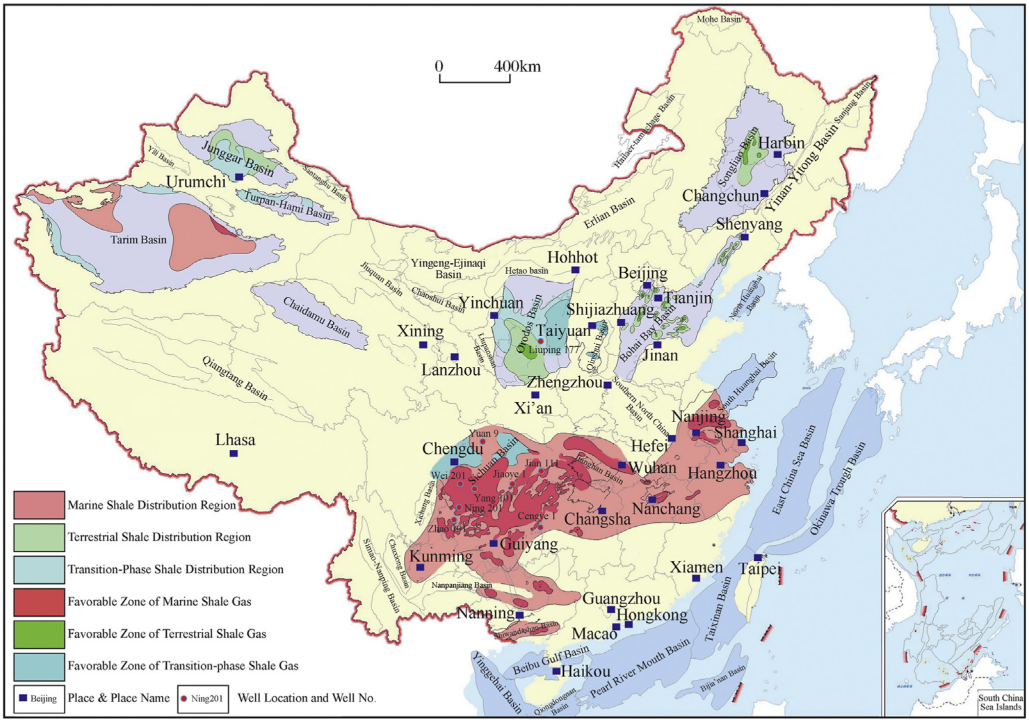

FIGURE 5.6 Locations of shale gas assessments in the People's Republic of China. *Source: Modified from Dong, D., Zou, C., Dai, J., Huang, S., Zheng, J., Gong, J., Wang, Y., Li, X., Guan, Q., Zhang, C., Huang, J., Wang, S., Liu, D., Qiu, Z., 2016. Suggestions on the development strategy of shale gas in China: Journal of Natural Gas Geoscience (Chinese Academy of Sciences) 1, 413–423, used with permission.*

Shale gas and tight oil potential in China occurs largely in seven sedimentary basins: the Sichuan, Jianghan, and the Yangtze platform in the southern part of the country, the Subei basin to the east of these, the Tarim and Junggar in the northwestern part of the country, and the Songliao in the northeast (USEIA, 2013). The complex of basins in southern China makes up the "shale corridor" (Fig. 5.6). They contain quartz-rich, Cambrian and Silurian-age, marine black shales that are roughly analogous to shales in North America (Dong et al., 2016). However, these basins are more structurally complex and faulted than most North American shale basins, adding to development challenges.

Gas produced from the shale corridor can contain significant amounts of carbon dioxide (CO_2) at concentrations of up to 18%, adding greatly to gas processing costs. Far worse is the hydrogen sulfide (H_2S) present in the Sichuan basin, which can reach concentrations as high as 50% in sour gas fields such as Puguang in the northeastern part of the basin (Li et al., 2005). Sour gas is expensive to process, but if not removed the H_2S will corrode pipelines, valves, fittings, and other critical infrastructure. It can also be deadly. In 2003, a sour gas well blew out in the Luojiazai gas field, and the H_2S killed 233 nearby villagers (USEIA, 2013). H_2S and CO_2 are less prevalent in the south, but can still be locally significant.

Nevertheless, the Sichuan basin has many things going for it. It is located close to many of China's major cities and contains existing gas infrastructure and abundant water supplies for hydraulic fracturing. The adjacent Yangtze platform and the Jianghan and Subei basins are also located close to major cities and considered to have shale gas potential, even though the geology in these areas is less favorable than the Sichuan. Given the lack of long-distance transmission pipelines in China, gas from basins located near the customer base in cities is more economical and development is more feasible. Risks in the Sichuan basin remain high because of extensive folding and faulting, and overall structural complexity (Zong et al., 2012). However, the Sichuan appears to be in position to become China's most important shale gas basin if the geologic and operational issues can be resolved.

The Sichuan basin currently produces conventional natural gas from the Triassic Xujiahe and Feixianguan formations, and limited amounts of petroleum from overlying Jurassic sandstones. Source rocks for these conventional oil and gas fields are Paleozoic marine shales including the Early Cambrian Qiongzhusi, Early Silurian Longmaxi, the Early Permian Qixia, and the Late Permian Longtan formations and their equivalents (USEIA, 2013). The two older formations are targeted as gas shales. Exploration efforts are focused on the southwestern part of the Sichuan basin, which has fewer faults and much less H_2S.

The Qiongzhusi Formation, deposited during the Cambrian on a shallow marine continental shelf is an important source rock in the Sichuan basin. The unit contains 60–300 m (200–1000 ft) of radioactive black shale, which has a TOC content of about 3% and a thermal maturity that places it in the dry gas window. The shale is fairly high in quartz and low in clay, suggesting a brittle lithology that would be favorable for fracking. The Qiongzhusi is the principal source rock for the Weiyuan gas field in the southern Sichuan basin, where PetroChina drilled the first horizontal well to test the black shale member for gas (Jinliang et al., 2012). Unfortunately, in many parts of the Sichuan basin the formation is deeper than 5 km (16,400 ft), and like the Cambrian Rogersville Shale in the Rome trough described in Chapter 4, it may be simply uneconomical to drill this deep for shale gas. The GIP resource for the Qiongzhusi Formation in the Sichuan basin was assessed at 499.6 TCF, of which 124.9 TCF is considered technically recoverable (USEIA, 2013).

The Early Silurian (443—433 Ma) Longmaxi Formation is the premier potential gas shale in southern China (Fig. 5.7). It consists of black, siliceous to cherty marine shale with a TOC content of around 4% composed mostly of Type II kerogen. Thermal maturity ranges from the dry gas window to overmature and increases with depth. The black shales of the Longmaxi Formation average 1000 ft (300 m) thick throughout the Sichuan Basin. The GIP resource for the Longmaxi Formation in the Sichuan basin has been assessed at 1146.1 TCF, of which 286.5 TCF is considered technically recoverable (USEIA, 2013).

FIGURE 5.7 Blocks of Longmaxi Shale awaiting rock properties testing at the Chinese Academy of Sciences in Wuhan, China. *Photographed in 2019 by Dan Soeder.*

The Tarim basin in the northwestern part of China has shale gas potential in black shale deposits of Cambrian and Ordovician age. This basin is remote from the cities of eastern China, and there are few existing pipelines to transport the gas to places where it is needed. Geologic structure is relatively simple, but the shales are deep. Shallower zones tend to have lower TOC and nitrogen is a contaminant in the gas. No shale gas drilling is known, even though horizontal drilling is common for much of the Tarim basin conventional oil production. Triassic lacustrine mudstone in the Tarim is shallower and may have gas potential.

The Junggar basin, northeast of the Tarim, contains Permian source rocks with an average TOC content of 4% (up to 20% maximum), an average thickness of 300 m (1000 ft), and thermal maturity ranging from oil to wet gas (USEIA, 2013). The structural geology of the basin is favorably simple. Besides the remote location, the main concern appears to be the lacustrine depositional environment of the rocks, which often results in reduced brittleness and less successful fracking compared to marine shales.

The Songliao basin, in the northeastern part of the country, is China's largest oil-producing region. Source rocks include thick, Early Cretaceous lacustrine shales in the oil to wet gas windows. Like the lacustrine source rocks in the Junggar basin, the potential abundance of clay minerals may reduce fracking effectiveness. Despite this, PetroChina considers the Songliao basin to be prospective for shales and has begun to investigate tight oil potential in shales at the giant Daqing oil field, and the gas potential of tight sandstones in the Jilin oil field (USEIA, 2013).

China does possess significant shale gas and tight oil resource potential. However, the geology is tectonically complex with numerous faults, and natural conditions are less favorable than those in North America. Geologic sweet spots on shale plays are not well-defined. Drilling is slow, and fracking is inefficient in the high-stress rocks. China's service sector is not yet capable of the large-scale directional drilling combined with massive multistage hydraulic fracturing needed to develop modern horizontal shale wells. Midstream infrastructure such as gas processing plants, long-distance pipelines, and compressor stations are also needed before the produced hydrocarbons can be delivered to consumers.

Private industry is generally cautious about shale gas development in China. Although the Chinese obviously want to move forward with it, there are still huge obstacles. For example, resource and prospect evaluations have been made impossibly difficult by the lack of access to the kinds of basic geologic, well log, and production data that are publicly available in most other countries. China considers this information to be a state secret, and tightly restricts it. As a result, significant commercial shale gas production appears to be some years in the future.

India contains several sedimentary basins with organic-rich shales, including the Cambay, Cauvery, Krishna-Godavari, and Damodar Valley. Little is known about possible source rocks or thermal maturity in other basins.

The Cambay basin is a rift basin in the western part of India to the north of Mumbai. The Late Cretaceous basalt flows of the Deccan Traps form the basement rocks here and are overlain by the Late Paleocene to Early Eocene (59.2–47.8 Ma) Cambay Shale, deposited during a marine transgression. The shale is up to 1500 ft (460 m) thick, with a TOC of about 2.5%. Thermal maturity varies with depth of burial across the basin, and ranges from the oil window through wet gas to dry gas in the deepest areas (Sharma et al., 2010). The GIP resource for the Cambay Black Shale in the Cambay basin has been assessed at 146 TCF, of which 30 TCF is considered technically recoverable, and 54 billion bbl of tight oil, of which 2.7 billion bbl may be technically recoverable (USEIA, 2013).

The Cauvery basin occurs onshore along the southeast coast of India, opposite the island of Sri Lanka. It is made up of a series of horsts and grabens, infilled with organic-rich source rocks and other sediments. The two most important source rocks are the Early Cretaceous (145–100 Ma) Andimadam Formation and Sattapadi Shale. These two units have a TOC content of about 2.5% and moderate thermal maturity in the wet gas and condensate window. Because of the horst and graben structure, the organic-rich shales are distributed into two subbasins within the Cauvery basin: the Ariyalur–Pondicherry depression in the northern part of the basin, and the Thanjavur depression at the center. The Andimadam Formation and Sattapadi Shale in the Cauvery together contain an assessed GIP of 30 TCF, of which 5 TCF is considered technically recoverable (USEIA, 2013).

The Krishna–Godavari basin is another horst and graben structure that is present along India's eastern coast to the north of the Cauvery basin. Organic-rich source rocks include the Permian-age Kommugudem Shale, a thick sequence of fluvial, deltaic, and lacustrine deposits composed of alternating units of black shale, claystone, sandstone, and coal. The Kommugudem is considered to have good gas potential, but is low in Type II kerogen needed for oil. It is overlain by the Mandapeta Formation, a thermally mature, Triassic-age marine shale identified as the source rock for conventional petroleum production from the overlying Early Cretaceous Golapalli Sandstone (Murthy et al., 2011).

The Damodar Valley basin is a narrow structure in northern India that formed as part of a rift on the Gondwana supercontinent during the Early Permian. Sediment fill was primarily fluvial and lacustrine in origin, resulting in substantial coal deposits that in fact comprise the bulk of India's coal resources. An Early Permian marine incursion deposited the Barren Measure Shale, which contains TOC values averaging 3.5% and thermal maturity in the wet gas window (Goswami, 2008). In the eastern Damodar Valley, this shale was the target of India's first shale gas exploration well (Das, 2011).

Pakistan has potentially productive shales in the southern part of the large Indus basin, which underlies a significant percentage of the nation. The Indus is divided into a number of subbasins that are bounded by the Indian Shield on the east and the Afghan mountains to the west. The lower Indus basin in the southern third of the country contains conventional oil and gas production from the Goru Formation, and the source rocks here are considered to be prospective for shale gas and tight oil (USEIA, 2013). The older and deeper source rock is the Sembar Formation, an Early Cretaceous (145–100 Ma) shale, silty shale and marl deposited in the western and northwestern parts of the basin in an open marine environment. The TOC of the Sembar Formation is approximately 2%, consisting mostly of Type II kerogen with minor amounts of Type III (Quadri and Shuaib, 1968). Thermal maturity ranges from oil to dry gas, depending on depth of burial. The productive shale interval is estimated to have a net thickness of about 250 ft (76 m) (USEIA, 2013).

A second, shallower prospective shale in the eastern part of the basin is the Paleocene-age (66–56 Ma) Ranikot Formation, where an upper carbonate unit deposited under restricted marine conditions contains dolomitic shale with bituminous material.

To the west, the Ranikot Formation undergoes a facies change to the time-equivalent Korara Shale, deposited in a deep marine environment. The Sembar and Ranikot formations extend into the central Indus basin, where the Lower Jurassic Data Shale is also being assessed for potential O&G prospects.

In the lower Indus basin, the Sembar Shale is estimated to contain 531 TCF of GIP, of which 101 TCF is considered to be technically recoverable, and 145 billion bbl of OIP, with 5.8 billion bbl assessed as technically recoverable. The Ranikot Shale contains an estimated 55 TCF of GIP and 82 billion bbl of OIP. Technically recoverable resources from the Ranikot Formation are assessed at 4 TCF of shale gas and 3.3 billion bbl of liquids (USEIA, 2013).

Australia, Indonesia, and Malaysia

Australia has the potential to develop commercial shale gas and tight oil. The country possesses geologic conditions and an industry hierarchy not unlike the United States and Canada. Small to midsize Australian independents have been instrumental in assembling geological data and drilling exploratory wells in shale, similar to the role played by independents like Mitchell Energy, Southwestern Energy, Range Resources, and Chesapeake Energy to develop shale plays in the United States. The multinational majors are now entering these plays and bringing in substantial capital investment. However, many of Australia's shale gas and tight oil resources are in remote locations with little to no existing infrastructure, and it is unlikely that development will move forward quickly.

Six sedimentary basins in Australia are considered to be the most prospective for shale gas and tight oil. These are the Cooper basin straddling the boundary between South Australia and Queensland, the small Maryborough basin north of Brisbane along the Queensland coast, the Perth and Canning basins in Western Australia, and two small basins in the Northern Territory, the Beetaloo near Darwin, and the Georgina to the north of the Amadeus basin (**map,** Fig. 5.8). Together these basins are estimated to contain a combined shale GIP resource of 2046 TCF, of which 437 TCF is considered to be technically recoverable. There is also an estimated tight oil resource of 403 billion bbl of OIP, with 17.5 billion bbl assessed as technically recoverable (USEIA, 2013).

The Cooper basin and adjoining Eromonga basin are the main onshore conventional gas production areas in Australia and contain existing gas processing facilities and transportation infrastructure. The stratigraphic section is composed of nonmarine, Paleozoic to Mesozoic rocks including Permian-age, organic-rich shales that may be prospective for gas. These are overlain by Jurassic to Tertiary deltaic deposits, which formed conventional sandstone reservoirs (Apak et al., 1997). The Permian shales accumulated in a lacustrine depositional environment, and the resulting rocks may be clay-rich and not as amenable to fracking as more brittle marine shales. The shale gas also has an elevated CO_2 content, adding to processing costs.

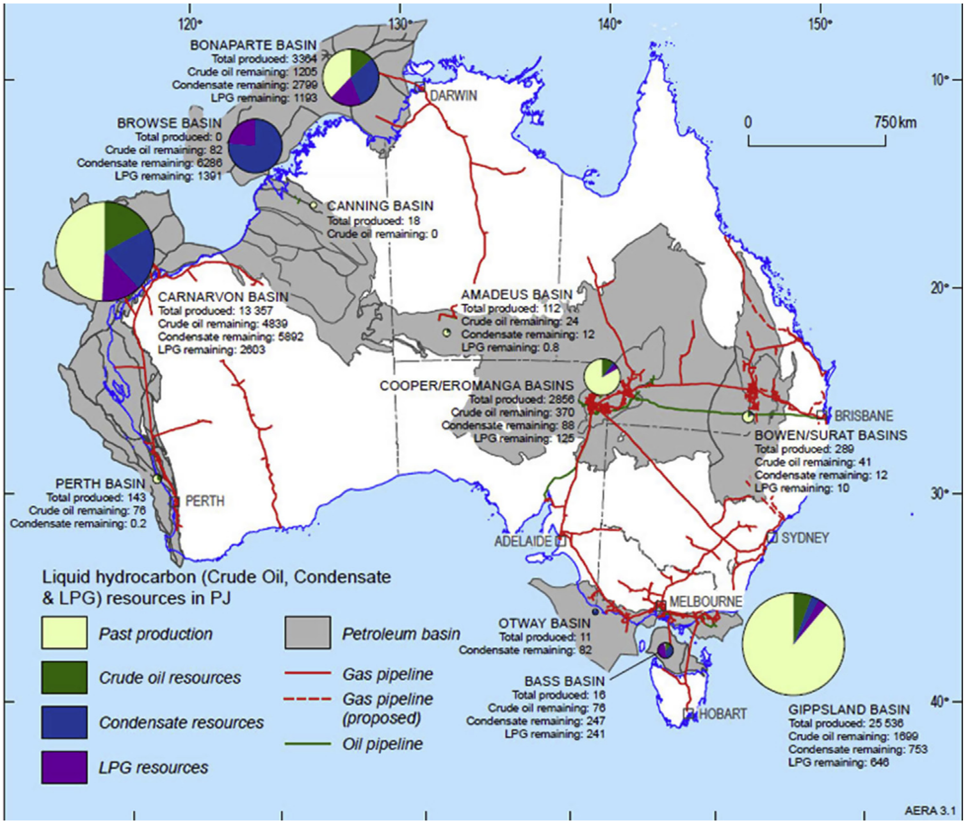

FIGURE 5.8 Australian government map of oil and gas basins and infrastructure. *Source: Geoscience Australia.*

The Maryborough basin is located on the Queensland coast just to the north of Brisbane and too small to show on Fig. 5.8 map. It is a largely unexplored half-graben. The primary shale gas unit in this basin is the Early Cretaceous (125−113 Ma) Maryborough Formation, which consists of mudstone, siltstone, and sandstone with minor conglomerate, limestone, and coal. It is the only definitely marine unit in the basin. Organic-rich members within the Maryborough Formation include the Goodwood Mudstone, the Woodgate Siltstone, and the Cherwell Mudstone. TOC in these rocks averages about 2%, and thermal maturity is in the dry gas window (USEIA, 2013).

On the other side of the country in Western Australia, the Perth basin is an active conventional O&G production area (Fig. 5.8). As such, it contains source rocks that are prospective for shale gas. The Perth basin is a relatively simple, northwest trending half-graben along the western Australia coast that is present both onshore and offshore. Two deep sedimentary subbasins occur within the onshore part of the Perth basin: the Dandaragan and Bunbury troughs. The Dandaragan trough in particular is a large syncline some 300 miles (500 km) long and up to 30 miles (50 km) wide filled with Silurian to early Cretaceous sedimentary rocks, including the deepest, thickest, and most prospective shale gas formations (Mory and Iasky, 1996).

The two primary, organic-rich shales in the Perth basin are the Permian-age Carynginia Shale and the Triassic-age Kockatea Formation. The Carynginia Shale is part of an Early Permian (298–283 Ma), largely argillaceous glaciomarine to deltaic sedimentary sequence. This is overlain by a Late Permian (259–251 Ma) sequence of nonmarine and shoreline clastics and carbonates, followed by Triassic to Lower Cretaceous (251–100 Ma) regressive, shallow marine to nonmarine clastics that include the Kockatea Shale (Mory and Iasky, 1996).

The Carynginia Shale is a shallow-water marine deposit present over much of the northern Perth basin, with a deepwater member near the base that includes shale with thin interbeds of siltstone, sandstone, and limestone. The TOC content in the Carynginia Shale averages about 4%, and the kerogen is predominantly Type III derived from land plants, making the Carynginia Shale gas-prone. Thermal maturity places it in the dry gas window over most of the Perth basin (USEIA, 2013).

The overlying Kockatea Shale is considered to be one of the primary oil source rocks in the Perth basin. It consists of dark shale, micaceous siltstone, and minor sandstone and limestone, and thickens to the south. The Hovea Member is the most organic-rich unit within the Kockatea Shale, with measured TOC values of up to 8% (Thomas, 1979). Exploratory drilling and coring of the Hovea Member has found discouragingly high clay content, suggesting that the rock will not frack very well. The Kockatea Shale is thermally mature in much of the Perth basin, but possibly oil-prone where it is shallower (USEIA, 2013).

To the northeast of the Perth basin, but still in Western Australia, the Canning basin is a large geologic feature containing up to 58,000 ft (17.7 km) of sedimentary rocks. The main prospective hydrocarbon target is the Goldwyer Formation, deposited during the Middle Ordovician (470–458 Ma) in open marine to intertidal conditions. It varies in lithology from mudstone-dominated deepwater sediments to limestone-dominated platform and terrace deposits (Haines, 2004). The shale units in the Goldwyer are considered to have excellent source rock potential, with a mean TOC of about 3%, although the upper member has TOC contents as high as 6.40% (Ghori and Haines, 2007). Rock-Eval pyrolysis indicates the Goldwyer shale is in the oil window over much of the southern Canning basin and the midbasin platform, with thermal maturity increasing to the wet gas and condensate window at intermediate depths; it is likely dry gas-prone and overmature in the deep troughs (Foster et al., 1986).

The Beetaloo is a small basin in the Northern Territory of Australia near Darwin that contains organic-rich shales within the Precambrian Roper Group. Well tests and cores have identified the Kyalla and Middle Velkerri shales as oil and gas bearing, making these two formations some of the oldest potential source rocks in the world (USEIA, 2013).

The Georgina basin is a largely unexplored structure on the Northern Territory–Queensland boundary near the Gulf of Carpentaria. The Arthur Creek Shale in this basin is a potential source rock. It consists of a Middle Cambrian (521–497 Ma) sedimentary sequence composed of dolomitic sands, silts, shales, dolomites and a basal, radioactive black "hot shale" known as the Lower Arthur Creek Shale that thickens from west to east (Bennett and Philpchuk, 2010). Drill cores analyzed by Geoscience Australia found that the TOC in the Lower Arthur Creek Shale varies from 2% to 16%, with an average of 5.5% (Tiem et al., 2011). The organic material consists of Types I and II kerogens, and thermal maturity varies with burial depth from oil-prone to dry gas-prone. The Georgina basin could have both tight oil and shale gas resources (USEIA, 2013).

Indonesia: The Energy and Mineral Resources Ministry claims that Indonesia's abundant shale gas reserves are ripe for exploitation, but the fact remains that the development of shale gas comes at a higher cost than conventional natural gas. Because shale gas resources in Indonesia are deep, and drilling technology is not as efficient as North America; cost per well in Indonesia is three to four times higher than costs in the United States or Canada. The government could have overcome this with a favorable financing scheme for the development of shale gas, but so far they have not offered any incentives. The lack of midstream infrastructure in shale gas areas is also a major obstacle to development. Nevertheless, the Energy Ministry estimates that Indonesia holds some 574 trillion cubic feet (16.3 trillion cubic meters) of shale gas potential reserves (Jakarta Globe, June 20, 2013).

Indonesia was created from the old Dutch East Indies colonies in 1945 and consists of the islands of Sumatra, Java, Celebes, the Kalimantan district of Borneo, and the western half of New Guinea, along with thousands of smaller islands. Hydrocarbon development since the 1940s has resulted in the discovery of more than 200 conventional O&G fields. Important among these is the central Sumatra basin, formed by rifting associated with subduction along the Sumatra margin that created a series of grabens filled with fluvial and deltaic sandstones, and also shallow to deepwater lacustrine shales. A significant petroleum source rock in the central Sumatra basin is the Oligocene-age (34–23 Ma), organic-rich, lacustrine Brown Shale of the Pematang Group. Different phases of compression related to subduction dynamics increased the thermal maturity of this shale, and presumably aided in oil migration to reservoir rocks. The Brown Shale source rock is thought to still contain significant amounts of tight oil reserves, but volumes were reduced by migration (Schenk et al., 2015). Organic-rich, lacustrine shales are also source rocks in the south Sumatra basin, where they reached thermal maturity for oil and gas generation beginning in the Miocene (Schenk et al., 2016).

Malaysia: Malaysia is the world's third-largest exporter of LNG and the second largest oil and natural gas producer in Southeast Asia. Six important O&G basins are present in the country, including the Malay, Penyu, Sarawak, Sabah, Sandakan, and the Tarakin (Fig. 5.9). The basins are grouped into three larger regions, including a Peninsular basin, Sarawak, and Sabah. Most of these basins are offshore from the Malaysian land mass.

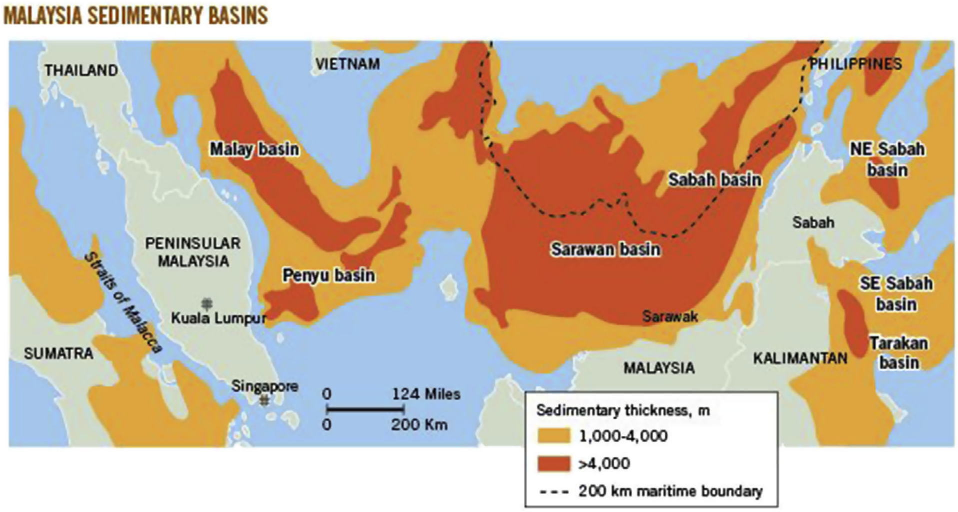

FIGURE 5.9 Basins in Malaysia with prospective shale gas and tight oil. *Modified after El-Sakka et al. (2017), used with permission.*

Malaysia is composed of a western half that consists primarily of Peninsular Malaysia and the eastern half that includes the states of Sarawak and Sabah on the northwestern side of the island of Borneo. The eastern states have been identified as a potential area for unconventional resources in Malaysia, and shale gas discoveries have been made in both the Sarawak and Sabah basins. Based on preliminary resource assessments, Malaysia may have an estimated 8.8 TCF of recoverable shale gas resources (El-Sakka et al., 2017).

Deposition of sediment in the Sarawak basin began in the Late Oligocene (28–23 Ma) along a NW–SE coastline. The structural basin was formed by NW-SE-trending right-lateral fault movement. This dextral movement was responsible for creating the present-day NE–SW coastline during the Miocene and divided the offshore Sarawak area into two subbasins (Mat-Zin and Swarbrick, 1997).

Despite the abundant petroleum in the Sarawak basin, geochemical analysis of the oil indicates that organic material in the source rocks was primarily derived from land plants. Organic carbon content falls off with distance from the coastline. The source rocks appear to consist of coastal plain and shallow marine sediments (Mat-Zin and Swarbrick, 1997). The tectonic evolution of this basin complicates any prospective shale gas or tight oil resource assessment, as well as affecting the formation of conventional structural traps.

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PART

II

The future of fossil fuels

Fossil fuels have made the development of modern civilization possible. The Industrial Revolution came about because people learned to use coal to make steam, and then figured out how to use the steam to do useful work, like running a factory or moving goods long distances by powering a railroad locomotive or a ship. Oil and gas came along later and replaced coal in areas of transportation and certain industrial processes. These fossil fuels were developed because they were a low-cost source of abundant energy.

Before fossil fuel, energy was derived from burning wood, water wheels, windmills, animal power, and human muscles. Despite the many evils that have been laid at the feet of fossil fuel, it is undeniable that coal, oil, and gas have displaced the need for animal and human muscles as a basic power source.

The shale gas and tight oil revolution contributed significantly to energy security in the United States, and as a response to the 1973–74 OPEC (Organization of Petroleum Exporting Countries) oil embargo, it was a resounding success. Marcellus Shale gas is now supplying energy to cities in the northeastern United States more securely, and with far better economics, than imported energy. East coast LNG terminals that had been constructed for imports are now being used to export gas. Electrical power generated from gas is producing cleaner air and lower carbon emissions. Natural gas liquids are being made into plastics and other products, and new plastics manufacturing capability is being built in West Virginia and Pennsylvania. The United States now both imports and exports petroleum as a global player in the world market.

Current estimates by the DOE Energy Information Administration claim that ultimate recoverable natural gas resources in the United States top 1000 trillion cubic feet (TCF). EUR numbers from the Marcellus (~490 TCF per Engelder, 2009) and the underlying Utica (~782 TCF per Hohn et al., 2015) add up to 1272 TCF of gas and gas equivalents in the Appalachian Basin alone.

However, it is not 1974 anymore, and even though OPEC is still around, they are far less of a threat. A greater concern is the long-term sustainable production and use of fossil fuels over the next century. Although there may be thousands of TCF of gas in the world, it will run out eventually, and new, more sustainable energy resources must be sought. The many other nations that desire a lifestyle similar to the United States want their fair share of access to fossil fuels.

Fossil fuels pose environmental risks to air, water, landscapes, and ecosystems from shale gas development and hydraulic fracturing. There is also a larger global concern of greenhouse gas (GHG) emissions from burning fossil fuels. The buildup of both carbon dioxide and methane in the atmosphere trap heat and contribute to global warming and climate change. These issues must be addressed if fossil fuel is to have any future at all.

Two important factors driving the future of fossil fuels are energy economics and policy. Fossil fuels presently dominate the energy landscape because they are cheaper than alternative energy like nuclear, geothermal, and renewables. However, that could change with the stroke of a pen if climate change concerns lead to a carbon tax or other penalties for using fossil fuel. Thus, both energy economics and energy policy are expected to have a strong impact on the future of fossil fuels, and these issues are explored in the last two parts of this book.

6 Environmental concerns

Numerous opinion pieces, editorials, blogs, web pages, documentaries, and countless heated verbal arguments have been devoted to the environmental risks that may or may not be associated with shale gas and tight oil development. These risks tend to be summed up by a single word: "fracking." The disagreement starts with the very use and spelling of this term.

"Frack" was originally a made-up word used by the industry as a shortcut or slang for "hydraulic fracturing." O&G operators have always used it only in reference to the actual hydraulic fracturing or stimulation process on a well. Shale gas opponents have adopted "fracking" to describe the entire process of shale gas drilling, completion, and production. In their world, the term fracking covers everything from a bulldozer clearing off a pad to the final installation of a production wellhead. The industry objects to this misuse of the term and has adopted the spelling "frac" (without the k) to distinguish themselves from shale gas opponents, many of whom proudly self-identify as "fracktivists." Depending on whether someone spells it "frack" or "frac," he or she can be instantly identified as being in one camp or the other. We find this whole thing to be silly and have chosen to use the phonetically correct spelling "frack" (similar to crack) in this book, but only in reference to the actual hydraulic fracturing process itself.

Fracktivists have spoken darkly of "fracked gas" moving through pipelines and into people's houses like some kind of evil spirit. But industry personnel know that gas is gas, whether it is recovered from a conventional well or from a hydraulically fractured shale lateral. Trying to designate shale gas as "fracked gas" is a misuse of the term, and operators have dismissed such people as those who simply do not know what they are talking about with respect to the oil and gas industry. Arguably, a more fruitful response might have been to engage the fracktivists in conversations to help them better understand the sometimes arcane workings of natural gas development. Instead, the dismissal of their concerns came across as arrogant and was interpreted by many as proof that the industry has no interest in the environment. These misunderstandings and incidents of talking past one another have grown over time, making the issue of shale gas and fracking increasingly more contentious.

The battle lines have been drawn for about a decade. Supporters of the O&G industry claim that the risks of fracking are exaggerated by the media, environmental issues are manageable, and that domestic shale resources are critical to the energy security and economic growth of the United States. Fracktivists counter that the industry is greed-

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driven and can't be trusted to be environmentally responsible and that drillers will cheerfully put the environment at risk whenever there are profits to be made. The shale gas issue also frequently gets caught up in the larger environmental debates on fossil energy use, greenhouse gas emissions, climate change, and the call for a new energy economy based on conservation and renewables. Viewpoints on both sides have some validity, but neither captures the entire truth.

The truth is in the middle, between the extremes. Yes, some environmental risks do come with shale gas and tight oil development, and there have been environmental incidents. Those who dismiss these and say the industry is perfectly safe are exaggerating. On the other hand, those who claim that every gas well is an environmental disaster are also exaggerating. The records show that the actual number of new oil and gas wells with reportable environmental violations, including fracked shale wells, is approximately 0.5% of the total, or about one out of every 200 (Kell, 2011).

Most of the reportable violations are for minor things like small spills or incorrect signage. Major incidents are rare. The most significant risk during the drilling and completion phases of a well has been identified as leaks and spills of the chemicals used for drilling and fracking that can threaten surface streams and groundwater (Brantley et al., 2014). Risk varies during different phases of the drilling, completion, and production operations (Soeder et al., 2014).

It is true that the O&G industry is often driven by the bottom line. The United States has a capitalist economy, and the CAPEX money required to drill oil wells comes from investors. Fossil energy production is a frightfully expensive operation, with each individual well costing millions to tens of millions of dollars. There is a lot of investor money on the line and not every well is a producer. Sometimes money is lost, but if company management does not make a strong effort to turn an overall profit on oil and gas production and pay dividends back to investors, it won't be very long before there are no more investors. Oil and gas companies are driven not so much by greed, but by the desire to keep the company financially solvent and in business. Most operators are responsible business people who act in a professional and honorable manner.

There are always a few bad apples in any industry, and fossil fuels are no exception. The oil and gas business is notoriously bad at self-policing, and this has allowed some of the more dubious companies to gain a stronger foothold than perhaps they should have. Oil and gas people are often reluctant to interfere with other operators, feeling that it is not their place to tell someone "how to run their business," or to "rat out" another company by reporting violations to state oil and gas or environmental agencies. There is a lot of the "golden rule" and self-preservation at play here—"I wouldn't want them to be telling me how I ought to do things," or "If I call the state environmental agency, what happens if they decide to come out here and inspect all of us?"

The success of a documentary movie like "Gasland" illustrates the depth of distrust that many Americans have with the O&G industry. This is reflected in the results of sociological studies, which report that two out of three American citizens have a negative perception and distrust of the fossil fuel industry (Theodori, 2008). The public neither knows nor cares that there is a difference between good and bad operators and readily believes that the entire O&G business is systemically bad. Good operators are resentful, and rightfully so, for being lumped in with the bad operators, but many have been slow to realize that everyone in the business often gets tarred with the same brush by a skeptical public. The whole industry is tainted by those few who are greedy and try to make a quick buck by cutting corners and taking shortcuts. If companies know of someone who is a bad operator, they will stop doing business with that company, eventually driving them out of the oil patch. However, this may take years, and a lot of damage can be done in the meantime. The industry itself needs to do a better job of getting the bad players out of the business, and if that requires a phone call to the state oil and gas commission, so be it.

When problems do occur, many companies are often reluctant to provide timely or accurate information to a worried public. The O&G industry has a strong culture of confidentiality to keep secrets about leases, costs, profits, losses, and production techniques. The reservoir pressure in a gas well is considered a company secret. Production techniques and target horizons are confidential. New prospects are top secret. Such practices allowed Southwestern Energy to lease up huge portions of the Fayetteville Shale production area without anyone else in the industry knowing about it until they began drilling (refer back to the discussion in Chapter 3). In cases like this, confidentiality can be an advantage, but the industry penchant for secrecy is hurting their credibility with the public and compromising their social license to operate.

All technologies suffer occasional failures and to expect zero accidents is an illusion. Cars crash, ships sink, airplanes fall out of the sky, oil refineries and chemical plants blow up, and trains derail and spill their loads. Drilling and hydraulic fracturing have incidents also. Instead of acknowledging an accident or incident, however, industry's instinct is to keep quiet, often out of fear of liability and lawsuits. Companies frequently require victims to sign nondisclosure agreements in return for compensation for damages, further limiting public knowledge about what happened and how. Some corporations still respond to nearly all incidents with "we're the experts—just trust us," which instantly raises the hackles of a public that has trusted industry in the past and been burned for it. Many people have concluded that the guilty party is merely stalling to cover their tracks. Concerned citizens have called company information lines with questions, only to be given a runaround and told that an expert will call them back in a day or two with answers. Those calls come rarely if ever.

On the other side of the coin, a single incident by a careless or incompetent company often blows up into a media frenzy that turns people against the entire industry. The endlessly repeating 24-hour news cycle makes a single accident involving a spill or fire seem universal. "If it could happen here, it could happen everywhere." This needlessly spreads worry and concern, when the actual risk of such an accident is extremely low.

Many of the most egregious incidents occurred in the first decade of the 21st century during the boom period of shale development when companies were in a hurry to establish leases. Inexperienced crews, short timelines, and difficulties obtaining the proper equipment contributed to problems. More recent shale gas and tight oil development with greater well spacing and far more experienced personnel have resulted in greatly reduced environmental impacts. The vast majority of people working on tight oil and shale gas these days are highly trained professionals interested in doing the job correctly and without creating an undue liability for their company from environmental or safety violations. This is not meant to serve as an excuse for the environmental damage caused during the boom periods. Indeed, a slower, more careful and measured approach should have been taken from the very beginning.

Unfortunately for the O&G industry, the public does not appear to be inclined to forgive and forget. Many people who live in former shale gas boom areas in Arkansas, Texas, West Virginia, Pennsylvania, Oklahoma, North Dakota, and elsewhere are still resentful a decade later over the damage done by the industry. Condemning an entire industry because of the actions of a few bad apples is unfair, but it happens all the time to unloved groups like government officials, Wall Street bankers, attorneys, real estate agents, used car dealers, police departments, and many other professions, including oil and gas.

Fracktivists have some of their own issues with truth in this debate. There have been many anecdotes put forth about ways in which fracking that has harmed the environment or human health. Yet, when these stories are investigated in depth, they usually turn out to be along the lines of “my brother-in-law’s cousin’s neighbor said …” with no details about what, when, where, who, or how and no real evidence of anything. Some people have exaggerated the hazards to promote movies or books. A few have even tried to get companies to pay damages for problems with water wells that existed long before the gas well was ever drilled.

Actual scientific investigations over the past few years have learned much about the true risks and environmental impacts of unconventional oil and gas development. Sadly for those who crave sensationalism, the story is rather dull. The evidence from a large number of published studies suggests that shale gas and tight oil development can indeed introduce some environmental problems in certain circumstances if not done correctly, but fears that the sky is falling are unfounded.

Most fracktivists are sincerely concerned about the potential environmental risks of shale gas and tight oil development. However, many nontechnical celebrities such as actors, musicians, movie producers, attorneys, and even some politicians have been warning the populace against the dangers of fracking.

Just as a geologist probably shouldn’t act in a movie, or a petroleum engineer represent a criminal defendant in a court of law, actors and attorneys have no business weighing in on technical issues they don’t understand. Accepting their opinions requires the belief that despite possessing advanced technical degrees and decades of experience with oil and gas, hydraulic fracturing, and environmental monitoring, the technical experts in the field have somehow failed to notice the supposedly serious environmental hazards of fracking that are being pointed out by the movie producers. Alternatively, if one believes that perhaps these technical experts are smart enough to have actually recognized the hazards, then it follows that they must be a monolithic block of anti-environmentalist, proindustry shills participating in an airtight conspiracy to allow industry to reap extravagant profits by exploiting shale resources without regard for the environment. Both assertions are absurd.

Ordinary people who don't understand how oil and gas production works, what is involved, and how it is done are being needlessly frightened by some of the more extreme pronouncements. There are significant political ramifications as well. The governor of New York banned hydraulic fracturing statewide in 2014, despite rigorous analyses by his own Department of Environmental Conservation that concluded "no significant adverse impacts to air or water resources" were likely to occur from projected Marcellus Shale wells (Kaplan, 2014). A study by the Manhattan Institute concluded that the New York ban could eventually cost the state $1.4 billion in tax revenues and up to 90,000 jobs (Considine et al., 2011).

Some fracktivists have not been above stretching the truth to support their cause. One of the most iconic pictures associated with fracking is the flaming kitchen faucet, supposedly caused by gas in the water supply well from a nearby frack. Creating a fireball in the kitchen sink by lighting a match near a faucet makes for an admittedly dramatic photograph (Fig. 6.1), and stray gas in groundwater is certainly an issue in some areas (Baldassare et al., 2014).

FIGURE 6.1 A flammable kitchen faucet caused by natural gas entering a water supply well in Pennsylvania. Some people have linked this to fracking. *Photo copyright Getty Images, used under license.*

However, at least in the case of a flaming faucet in Colorado featured in the 2010 movie "Gasland," the homeowner had reported methane in the groundwater supply long before any gas well drilling occurred in the neighborhood. The Colorado Oil and Gas Conservation Commission (http://cogcc.state.co.us/) felt compelled to place a "Gasland correction document" on their website in 2010 detailing the history of gas in this particular groundwater supply, which they ascribed to shallow coal seams penetrated by the well. Simple correlations like those in “Gasland” between natural gas drilling and flammable gas in drinking water ignore the fact that natural gas migration in shallow groundwater can have many causes that are sometimes, but not always, related to the presence of gas wells (Brantley et al., 2018).

A reliable assessment of the engineering and environmental risk of shale gas and tight oil development must be based on facts. It is important to separate incidents and accidents from any potential, systemic, deeply rooted design flaws in the underlying engineering. For example, an occasional plane crash does not mean that all of aviation is unsafe. Aircraft designs follow engineering principles developed over the past two centuries and have been tested and strengthened for more than a 100 years since the first powered flight by the Wright Brothers in 1903. Aviation accidents that do occur are likely to be related to pilot error, bad weather, mechanical failure, or some other specific problem, not to the large-scale failure of the engineering principles of flight.

Likewise, the engineering for horizontal drilling and staged hydraulic fracturing is built on similar strong principles. A great deal is already known about the envelope of risk associated with development of the tight oil and shale gas resources. The basic rotary drilling technology dates back to the 19th century, and hydraulic fracturing has been used commercially since 1949. Directional drilling and staged hydraulic fracturing are extensions of the proven technology of the earlier techniques. Operators understand how these work and the limits of the technology are well known.

Groundwater is protected behind steel casing, boreholes are steered to stay within the most productive zone, and hydraulic fracturing is carefully controlled to remain within the target formation and extend outward from the lateral rather than upward toward aquifers. Incidents with surface spills or other problems are operational issues, similar to pilot error, and can be overcome by training and experience. There is nothing in the underlying engineering principles to suggest that hydrocarbons cannot be produced safely and in an environmentally responsible manner with minimal impacts when the operations are done correctly. The actual environmental risks of shale gas and tight oil development include wellbore integrity problems that allow stray gas to migrate into aquifers, the transport of large volumes of frack chemicals and produced fluids to and from well locations, and potential impacts on small watersheds and the sensitive headwater areas of streams from the large drill pads and extensive water withdrawals needed for shale gas wells (Soeder and Kappel, 2009; Soeder et al., 2014; Soeder and Kent, 2018).

A better understanding is needed of the sources and migration routes of stray gas, the breakdown paths and rates for the natural attenuation of organic compounds used in drilling muds and hydraulic fracturing fluids, and the changes in microbial populations in the produced water as it is recycled through subsequent wells. Research needs also include quantifying air contamination issues, and investigating the potential for toxic metals, radionuclides, and organic compounds to leach from the black shale drill cuttings and other solid waste.

Environmental impacts can be short-term or long-term. Short-term impacts are related to well construction and include water withdrawals, produced water disposal, lights and noise from drilling operations, effects of water impoundments on wildlife, and air pollution. Most of these go away once the wells are constructed and the equipment moves offsite, but they can be fairly intense during the drilling process. Longer-term impacts are related to the well and drill pad occupying the landscape, and include habitat fragmentation, groundwater contamination from leaks of produced fluids or leachate from materials left on the pad, the potential introduction of invasive species, and the process of ecological succession as the open drill pad slowly fills back in with vegetation. Some of the risks, like invasive species, may not show up for some time.

Research is still needed to fill data gaps and reduce uncertainties. It is also important that risk assessments not remain static, because risk evolves over time as new practices are employed. For example, a risk analysis of Marcellus Shale drilling using a numerical model to identify pathways of water contamination concluded that disposal of produced water through municipal wastewater treatment plants would likely release substantial quantities of high TDS brine into freshwater streams (Rozell and Reaven, 2012). Regulators and industry agreed in 2011 to dispose of produced fluids by injecting the wastewater down "underground injection control" or UIC wells. The highest risk for environmental contamination identified in the 2012 study was effectively eliminated by the time the results were published. However, the use of deep well injection has resulted in a different kind of environmental risk: induced seismicity.

The environmental risks of shale gas and tight oil development can be managed and mitigated with proper knowledge of the environmental impacts, sensible and effective regulation, rigorous inspections, and strict enforcement (Soeder et al., 2014). Industries such as nuclear power plants, oil refineries, steel mills, semiconductor manufacturing plants, plastics factories, chemical plants, and pharmaceutical companies use this approach and coexist with society. The environmental risks posed by unconventional oil and gas development pale next to some of these other industries. There is no reason why the commercial production of O&G from tight rocks like shale can't be done while preserving the environment.

Risk assessment

Scientific research into fracking risks is focused on addressing the unknowns and reducing uncertainties. Current assessments rely heavily on models and empirical evidence, and the existing data strongly suggest that the environmental impacts from unconventional O&G wells are similar to the environmental impacts of conventional wells, with a few notable exceptions.

Some people have concluded that the absence of major and frequent observable impacts means that fracking causes little environmental risk. This is a fallacy, because the lack of observable impacts may in fact be nothing more than a lack of data. In both environmental and human health studies, a lack of data cannot be used to imply a lack of harm, especially when long-term issues may take decades to become apparent (Werner et al., 2015). This delay between cause and effect was one of the primary challenges linking cigarette smoking to lung cancer. It is why more data from more locations are needed for a proper risk assessment.

Causation is far more difficult to determine than correlation. For example, there might be a statistical correlation between a decrease in automobile fatalities over the past half century and a decline in the number of horse-drawn wagons in the United States. However, one would be hard-pressed to use this correlation to show that the decrease in horse-drawn wagons actually contributed to the decrease in automobile fatalities. Greater seatbelt use and safer vehicles are more probable causes. The underlying conundrum of causation is determining exactly how one thing may affect another.

A statistical analysis by Ingraffea et al. (2014) of Pennsylvania state compliance reports for 41,381 conventional and unconventional oil and gas wells concluded that shale gas wells experienced casing and cement impairment six times more frequently than conventional wells. Even though there is a statistically valid correlation between well type (conventional vs. unconventional) and the probability of cement/casing failure, the correlation does not necessarily imply causality. That requires laboratory and field experiments to determine if the more frequent failure is due to the well design, related to the installation process itself, or perhaps tied to the completion technique (Soeder, 2017). Without such a causation link, the statistics are interesting but not conclusive.

A number of US government agencies and independent researchers have investigated the risks of shale gas development and hydraulic fracturing. A special subcommittee of the Secretary of Energy Advisory Board (SEAB) developed recommendations in 2011 for industry to reduce risks, including better communication with the public and state regulators, focusing on protecting air and water, managing short-term and cumulative impacts, and promulgating best management practices.

In 2010, the United States Congress requested that the US EPA investigate possible links between hydraulic fracturing and drinking water contamination. After nearly 5 years studying contaminated sites, running numerical models, and hosting numerous technical workshops and stakeholder meetings, the agency concluded in a massive report that no evidence was found to indicate hydraulic fracturing has led to widespread, systemic impacts on drinking water resources in the United States, although specific instances were found where drinking water resources had been affected (USEPA, 2015). This somewhat imprecise conclusion has been interpreted in a number of different ways, both favorably and unfavorably, and the EPA Science Advisory Board recommended that the agency provide more quantitative analysis, clarification, and additional explanations.

In April 2012, President Obama ordered the US Department of Energy (DOE), US Department of the Interior (DOI), and the US Environmental Protection Agency (EPA) to cooperate and collaborate on studies related to the potential environmental impacts of unconventional oil and gas (UOG) development. The focus areas of the interagency UOG investigation included trends of resource development to assess potential future impacts, determining effects on both water availability and water quality, assessing air quality and lifecycle greenhouse gas emissions, establishing the mechanisms and magnitude of induced seismicity, and trying to quantify both ecosystem and human health effects. It is not known if these collaborations and investigations have continued under the Trump administration.

There are several different approaches for assessing risk. DOE used an engineering risk assessment methodology developed for the underground storage of carbon dioxide (CO_2) to assess the risks of shale gas (Soeder et al., 2014). The focus on engineering risk was to try to determine how contaminants might be released from a well site and enter the environment. The DOI and the EPA were investigating the receptors of such contaminants in aquatic and terrestrial environments and the risks posed to ecosystems and public health.

The DOE approach used an integrated assessment model, or IAM, which provides probability-based assessments of both site and system risk. The factors that contribute risk to an IAM are called features, events, and processes (FEP). The assessment investigated the features in an engineered geologic system that may have affected its behavior, along with any events or processes that may impact the risk. The performance of each of the components is determined through the use of high-fidelity mathematical models, which provide probability-based risks to health, safety, and the environment (Soeder et al., 2014).

For a system risk assessment, the individual high-fidelity models used to describe the FEP site risks are converted into reduced-order models (ROM) to simplify computation. The ROMs are then linked or integrated through the IAM to predict total system performance, system-scale interactions, and risk. The model is calibrated using field data and databases and validated by comparing against real-world performance (Soeder et al., 2014). This process is known as a site performance assessment.

A second method for assessing engineering risk is known as a "fault tree analysis." This approach addresses risk probability from both site-specific failures and cumulative, community-based failures (Rodak and Silliman, 2012). Like the IAM described above, data inputs come from smaller steps within a larger process such as hydraulic fracturing, and the unique events required for failure are assessed. The risk of an on-site spill, for example, is quantified by considering the likelihood, magnitude, and composition of the spill.

At the community level, however, the fault tree brings in additional risk considerations such as the subsurface fate and transport of the contaminants and the proximity of multiple hydraulic fracturing sites to the community groundwater supply. The fault tree adds the contribution of risk from all the well sites hydraulically connected to the groundwater source into the probability of failure calculation at the community level (Rodak and Silliman, 2012). It is also important to note that the definition of failure at the site and at the community level is different: site risk focuses on the volume of the spill and the cleanup logistics, whereas the community risk is more concerned with contaminant action levels and the cumulative health effects. The concern related to risk assessment is that regulatory agencies will continue to focus on site-specific risks that can be addressed by individual operators, when they truly need to consider the collective regional risks and the potential cumulative impact on communities (Rodak and Silliman, 2012).

Engineering risks of shale development vary during different steps of the process. Fresh groundwater can be potentially affected during drilling as the upper part of the well or "tophole" penetrates the shallow aquifers and before protective surface casing is set (Zhang and Soeder, 2015). The wellbore design, drilling process, cementing techniques used to set casing, and the method used to verify wellbore integrity are other potential engineering risks during the borehole construction phase (Dusseault et al., 2000; Kutchko et al., 2012). Risks during the hydraulic fracturing or stimulation part of the operation include surface spills and leaks from the large volumes of chemicals and additives brought on-site (Soeder et al., 2014), or unusual circumstances where the hydraulic fracture itself might go out of zone or trigger seismicity (Hammack et al., 2014; Myshakin et al., 2015). Finally, during the production phase, there is a risk that the well itself may deteriorate over time and leak gas or oil into aquifers (Dusseault and Jackson, 2014), or that toxins from muds, produced fluids, and black shale drill cuttings left behind on the surface may slowly leach into the shallow groundwater (Soeder et al., 2014).

Scientific data from a wide variety of shale gas development sites are needed to reduce the remaining uncertainties related to engineering risks of shale gas, but such data have been difficult to obtain. Operators have been reluctant to cooperate with such studies, in particular those involving groundwater (Soeder, 2015). Reasons given by industry for refusing access include concerns that environmental investigations will lead to new and expensive regulations, or that monitoring groundwater is a waste of time and money because there will be nothing to see. A number of prominent hydrologists have been calling for detailed, field-based groundwater monitoring programs near shale gas wells (Jackson et al., 2013), but with very few exceptions, operators have not allowed groundwater monitoring to be performed near drill sites (Soeder, 2015). Nevertheless, collaboration with industry is critical for scientific investigators to obtain access to a sufficient number of sites and samples for the data to be representative.

Some operators claim that their practice of collecting baseline water samples from nearby domestic supply wells prior to drilling constitutes all of the "groundwater monitoring" that is needed. Several prominent contaminant hydrologists strongly disagree, arguing that domestic wells are usually open-hole completions, which comingle water from multiple flowpaths and make it impossible to trace the source of contaminants. These scientists recommend that dedicated monitoring wells equipped with multilevel samplers be installed to obtain valid data (Cherry et al., 2015).

Access has also been refused by some landowners because of concerns that long-term groundwater monitoring studies might delay royalty payments. Others have balked at the additional site disturbance required to install monitoring wells. The owners of one site that actually contained a DOE-funded shale research well refused to allow groundwater monitoring on the property because they were already remediating existing groundwater contamination. The landowners were concerned that new monitoring wells might discover additional contaminants that would require expensive cleanup (Soeder, 2015).

While a few shale gas exploration and production companies have allowed access for a variety of sampling and monitoring tasks (i.e., Barth-Naftilan and Saiers. 2015), the number has been statistically insignificant compared to the number of wells drilled. In the few cases where industry itself has funded such studies, the results have been uniformly decried as "tainted" and invalid by fracktivists.

Oil and gas operators typically view risk from a financial standpoint rather than environmental. The disruption of field operations from a spill or other incident may have serious negative consequences for their bottom line. As such, operators often make significant investments in specialized risk management with respect to optimizing production practices to reduce the chances of incidents and downtime in the field. Although this reduction of risk is good for investors, the implementation of more careful, precise production practices is also beneficial to the environment.

Sources of risk

Risk can come from a number of sources (Soeder, 2017). The least controllable risks are natural disasters such as wind, lightning, earthquakes, floods, and similar events. A probability standard that applies to all natural disasters is that the larger ones are much less likely to occur than the smaller ones. Examples include dozens of unfelt daily earthquakes versus the rare major earthquakes that destroy cities, flooding of a low spot every rainstorm versus the once-per-century flooding of an entire neighborhood, hundreds of small meteors hitting the Earth each day versus giant asteroid impacts once every ten millennia, and so on.

Engineering a system to handle natural disasters usually has a limit that reflects the trade-off between cost and what is termed "acceptable risk." This is the cut-off point where the cost of mitigating the risk becomes more expensive than the risk itself. For example, a number of relatively cheap upgrades, such as roof tie-downs and steel shutters added to a standard house in Florida will significantly reduce the risk of damage from a low to moderate strength hurricane when compared to an unprotected house. However, a superstrong Category 5 hurricane could still flatten the house, steel shutters and all. Although the low to moderate strength storms are much more probable, a homeowner who wanted protection against even the most extreme storms could in theory build a house to achieve this. It would consist of a massive, bunker-like structure made of concrete and steel that is quite expensive. Given the low probability of a direct hit from a Cat 5 hurricane in any one place, is mitigating such a small risk worth the cost? If a homeowner decides it is not, then a Cat 5 hurricane becomes an acceptable risk.

Unconventional O&G wells and infrastructure are designed with acceptable risk limits in mind. For example, a wellhead can be protected from most incursions by a stout, chain-link fence. However, such a fence will not stop determined vandals equipped with bolt cutters, or a heavy vehicle driving onto the pad at excessive speed. Operators could spend a lot of money to install steel barricades or a concrete wall to thwart such incursions, but both vandals and high speed vehicles are rare on well pads. The fence stops most of the common threats to a wellhead, such as human teenagers or wild animals, and anything it cannot handle is an acceptable risk.

The second major source of risk is from engineering design, where a flaw in the architecture of a system introduces a risk. An example of this is the explosion of the space shuttle *Challenger* in 1986. An engineering design flaw in the O-ring seal on one of the solid rocket boosters caused a leak of hot gas that eroded the external fuel tank and led to the explosion. The leak was exacerbated by unusually cold weather the night before the launch, which caused the O-ring to lose elasticity and form a bad seal. Almost no one realized that this might be a problem until it actually became one. The only way to mitigate the risk in such a design is to reengineer the entire system. It took NASA literally years to understand exactly what had happened and to redesign the solid rocket boosters to avoid similar failures.

An engineering design flaw in shale gas wells that has since been corrected is the open-hole completion. Early wells were cased through the freshwater aquifers, but the bare rock walls were left exposed below this "surface casing" in the top-hole down to the kickoff point for the lateral. This was done primarily to save the cost of adding more casing to the well beyond the minimum required to protect groundwater. The production tubing was run down through this open hole and cemented into the lateral from the toe up to the heel. Gas in formations above the target shale was able to enter the open hole and pressurize the annular space between the production tubing and the bare rock wall. In Canada, this space is monitored, and the pressure is relieved at the surface with a device called the Bradenhead valve. US wells do not typically incorporate this design, so the gas pressure built up and eventually relieved itself by entering the shallow aquifers at the base of the surface casing. After a number of well-publicized stray gas incidents, drillers began running a string of intermediate casing, sealing off the bare rock walls behind a layer of steel and cement. Although this added some expense, compared to the multimillion dollar overall cost of a shale well, it is fairly minor. This change in design greatly reduced the number of stray gas incidents, and is now used in virtually all shale wells (Soeder, 2017).

The third major source of risk is human behavior. Accidents, mishaps, or mistakes can result from inexperience, impatience, overconfidence, poor communications, an unclear chain of command, cost-cutting, distractions, or an uncaring attitude. Most of the environmental incidents, spills, or chemical releases that have occurred on shale gas wells can be traced to a human cause (Glosser, 2013). Human-induced risk can be addressed by training, experience, and oversight. For example, airline pilots use a written checklist before a flight to ensure that they do not forget to check a critical component of the aircraft. Even if they've done preflight checks a hundred times before, the written checklist is a human risk reduction tool that supports their training and experience to make sure that every flight has gone through the full and proper inspection procedure before takeoff and is as safe as possible.

Most major disasters result from a combination of natural risks, engineering design flaws, and human error. An example is the Deepwater Horizon disaster on a drilling platform operating in 4993 feet (1522 m) of water on the Macondo prospect in the Gulf of Mexico some 40 miles (66 km) off the Louisiana coast. It suffered a blowout, fire, and major oil spill on April 20, 2010, resulting in 11 fatalities (USDOI, 2011).

The natural risks contributing to this incident were the inaccessible wellhead in extremely deep water and a high-pressure gas kick from the target formation that put immense stress on the well components. One of the engineering design flaws was a concrete plug installed to seal the well for later production that had been cured with nitrogen gas, which made the concrete too weak to withstand the pressure. Once the plug burst, natural gas traveled up the riser to the platform, igniting and setting the rig ablaze. Workers attempted to activate the blowout preventer (BOP) to kill the well, but another engineering design flaw caused the device to malfunction, damaging the remaining drill pipe. Human factors allowed the situation to build up out of control, and the response was improper and too slow once the disaster occurred. Emergency personnel were unable to put out the fire, and the platform capsized and sank two days later, shearing off the riser and releasing the drilling mud that had been holding back the oil and natural gas in the well.

Huge amounts of oil discharged into the water for months until the well was finally brought under control on September 19, 2010. The estimated five million barrels of petroleum that entered the Gulf of Mexico from this well represent the worst offshore oil spill on record. Investigations of the incident concluded that poor communications, a disjointed and conflicted management structure, and the involvement of multiple companies and contractors without clear lines of authority had made significant human error contributions to the disaster (USDOI, 2011). Such unlikely combinations of risks are often the root cause of most large-scale disasters like the Deepwater Horizon, and fortunately these are rare. Remediating any one of the risk components like the weak cement or the failed BOP would have greatly reduced the magnitude of the incident.

State environmental records show that the vast majority of shale gas and tight oil wells do not have any reportable violations (Kell, 2011; Brantley et al., 2014). Scientific data indicate that a well with the proper engineering design that has been drilled, constructed, and completed using best engineering practices will almost always produce petroleum and natural gas safely from shale formations with a minimal environmental impact. The greatest engineering risks occur during the initial drilling of the well through the shallow, drinking water aquifers before the surface casing is set (Zhang and Soeder, 2015), and then again during hydraulic fracturing operations, when large volumes of concentrated chemicals are being transported, stored, and used on the well site (Soeder, 2017).

Risks to groundwater and surface water

The consensus view among most hydrologists is that the two primary risks to groundwater from shale gas and tight oil development are stray gas in shallow aquifers and the potential for contamination from spills or leaks of the chemicals and fluids associated with these well sites (Soeder, 2018). Fracktivists have been concerned for many years that chemicals will migrate upward from a frack and contaminate shallow aquifers. This is a perceived risk, not an actual one, but the notion that chemical-laced hydraulic fracturing fluid will move upward to contaminate drinking water aquifers just seems logical to many people—after all, pressurized frac fluid is injected underground, and groundwater is underground, so there must be a high risk that the frac fluid will get into the groundwater.

In reality, “underground” is a big place, and in areas of shale gas development, geophysical data (Fig. 6.2) show that the tops of hydraulic fractures in target shales remain many kilometers below the base of drinking water aquifers (Fisher and Warpinski, 2012; Warpinski, 2013). This is supported by field studies where sensitive chemical tracers added to frack fluids have shown no indication of upward migration (Hammack et al., 2014).

Although hydraulic fracturing fluid is injected under pressure, the volumes are not large enough, and the pressure is not sustained long enough for it to reach shallow aquifers from below. This is supported by significant amounts of empirical evidence (King, 2012) and models. Each stage of a hydraulic fracturing operation uses millions of

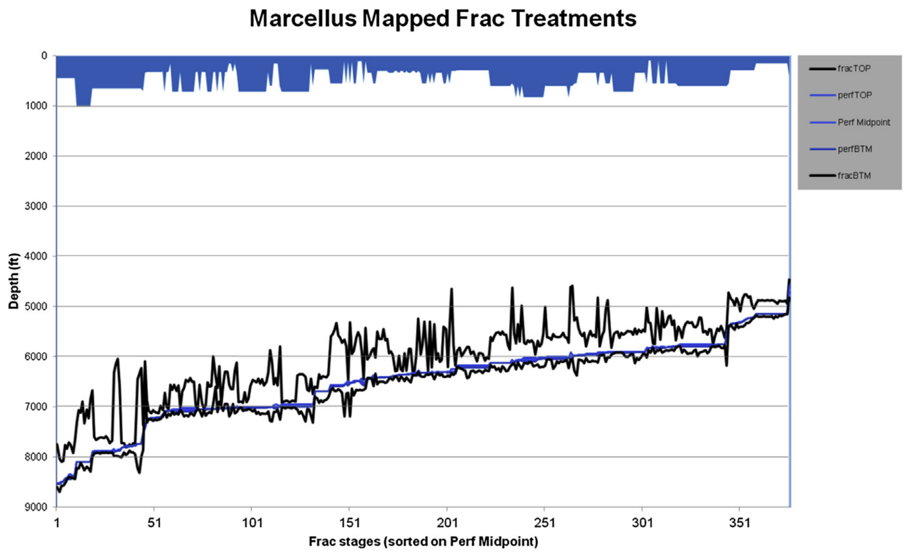

FIGURE 6.2 Heights of hydraulic fractures on the Marcellus Shale measured with microseismic data plotted against the depth of the deepest freshwater aquifer in each county (blue zones at top of graph). *Data courtesy Kevin Fisher, used with permission (Fisher and Warpinski, 2012).*

liters of fluid, but calculations and computer models agree that this is just not enough fluid volume to open up fractures to lengths that can reach shallow aquifers.

There are also physical reasons why hydraulic fractures do not reach the shallow subsurface. Fractures break vertically at depth because of the strong downward stress field imposed by kilometers of overburden. When the maximum compressive stress is downward, the maximum tensile stress or "pull-apart" direction is at right angles to that, in the horizontal plane, resulting in a vertical crack. At shallower depths, generally less than a kilometer, the vertical overburden stress becomes less than the lateral rock strength, and the rocks break horizontally along bedding planes (Hubbert and Willis, 1957). This is known in the industry as "pancaking," and is very inefficient for recovering hydrocarbons from tight rocks. Shallower targets are not hydraulically fractured, but can be produced using directional boreholes emplaced in a branched horizontal pattern called pinnate drilling (Long and Soeder, 2011).

Hydraulic fractures rarely extend beyond 300 m (1000 ft) and almost never beyond 600 m (2000 ft) from a wellbore. Drinking water aquifers are usually shallower than 100 m (300 ft). Even if pancaking was not an issue, the frack fluid would have to be pumped kilometers upward against gravity to reach a shallow, freshwater aquifer. It would literally require a deliberate decision by someone controlling the frack to attempt this.

Once the hydraulic fracture pressure is released and production starts from the well, pressure gradients in the target shale and surrounding rocks drive gas and fluids inward toward the wellbore, not upward toward the surface. Some gas may try to rise upward through buoyancy, but it is far more likely to follow the pressure drop and flow into the well. For any upward-moving gas not in the production tubing to be a threat to shallow aquifers, it would have to find an open fracture extending to the surface. The most likely place for this appears to be a microannulus created by cement failure in the tophole (Soeder and Kent, 2018). Any other route through the rock matrix or pore structure itself would take centuries. Other publications have explored these stray gas and groundwater issues in detail. The report by Hammack et al. (2014) and documents by Warpinski (2013), Soeder (2018), and Soeder and Kent (2018) cited in the references section of this chapter are suggested for additional reading.

Groundwater contamination can and does occur during hydraulic fracturing and other operations on shale gas and tight oil production sites. However, in every case documented so far, the cause has been chemical leaks or spills on the land surface. Spilled chemicals infiltrate into the ground under the force of gravity and percolate downward into the groundwater in a manner similar to nearly all other cases of groundwater pollution. Almost any kind of chemical or fluid handling operation can put groundwater at risk, including the spillage of produced water at UIC wells that may be far removed from production locations (Akob et al., 2016; Cozzarelli et al., 2017).

Stray Gas: Natural gas in groundwater is known as "stray gas." It can enter aquifers by a number of different routes, including poorly cemented or leaking gas wells, direct, natural seepage from adjacent geologic units such as organic-rich shale or coal, and it also may be generated within the aquifer itself by biological or chemical processes (Townsend-Small et al., 2016). These consist of the microbial reduction of CO_2 in the presence of hydrogen, or less commonly by acetate fermentation (Whiticar et al., 1986). Leaks of already-produced natural gas directly into the air from pipelines, compressor stations, or other midstream infrastructure are known as “fugitive emissions.” Fugitive emissions and stray gas are often used interchangeably, but the terms have distinct and separate meanings.

Methane (CH_4) is the main component of natural gas and is nontoxic, although the gas is highly flammable in air at concentrations between 5% and 15%. If it accumulates in confined spaces like basements, devastating explosions can result (Baldassare et al., 2014). Methane is also a more powerful, if shorter-lived, greenhouse gas than CO_2.

The sources and migration pathways of stray gas are challenging to determine in the subsurface. The solubility of methane in water is pressure-dependent, and it tends to move along groundwater flowpaths in response to pressure gradients. Thus, when trying to determine the stray gas content in groundwater, the methods by which the samples are collected can produce significantly different results (Molofsky et al., 2016). Various procedures being used by different researchers for sample collection, preservation and analysis have made comparisons difficult between studies, and attempts at standardization are underway.

Stray gas is common in many shallow aquifers, and defining the source requires site-specific molecular and isotopic geochemical data (Baldassare et al., 2014). Stray gas is ubiquitous in the shallow aquifers of northeastern Pennsylvania, for example, and predates the development of the Marcellus Shale, originating from microbial, thermogenic, and mixed sources (Baldassare et al., 2014). Dissolved methane is also common in the regional aquifers of the St-Edouard area of Quebec, and appears to be unrelated to gas in the underlying Utica Shale (Rivard et al., 2016). In North Dakota, methane in regional groundwater above the Bakken Shale was found to have been sourced primarily from lignite (brown coal) in the stratigraphic section (McMahon et al., 2015). The long history of oil and gas activities in California greatly complicated the effort to distinguish impacts of recent fracking on groundwater from other sources of impairment (McMahon et al., 2016). Chemical and isotopic analyses of groundwater above the Eagle Ford, Fayetteville, and Haynesville shales found that most of the methane in these aquifers was produced biogenically from CO_2 (McMahon et al., 2017).

Attempts to link the presence of stray gas with proximity to shale gas wells have produced contradictory results, starting with a study that claimed methane concentrations in groundwater increased significantly within a kilometer of producing shale gas wells in northeast Pennsylvania (Osborn et al., 2011). A second study in this same area concluded that concentrations of groundwater methane were related to topography, not proximity to gas wells (Molofsky et al., 2013). A third study using a massive regional database of domestic water well samples that included this location found that no statistically valid correlation exists between methane concentrations in groundwater and proximity to gas wells (Siegel et al., 2015).

Despite this, there is still some compelling empirical evidence suggesting that horizontal shale gas and tight oil wells may be more prone to wellbore integrity failures than vertical conventional wells. A detailed statistical analysis of 75,505 Pennsylvania state compliance reports found a six-fold increase in cement and/or casing failures in horizontal shale gas wells compared to vertical conventional wells (Ingraffea et al., 2014). Failure of well casing and/or cement has been identified as a mechanism that allows gas to migrate upward along wellbores to reach shallow groundwater (Watson and Bachu, 2009). The multiple cycles of hydraulic fracturing in shale wells (not done on conventional wells) may debond the wellbore cement from the steel casing, creating a micro-annulus that provides a flowpath for vertical gas migration (Soeder, 2017).

It is important to keep in mind that stray gas is a complex issue that rarely has easy answers (Baldassare et al., 2014). Stray gas investigations must answer two questions: what is the source, and what caused it to migrate? The use of dedicated field research sites equipped with multilevel samples as recommended by many hydrologists (i.e., Cherry et al., 2015) may help to address these questions.

Chemical Contamination: A perhaps greater risk to water resources than stray gas is the potential for the contamination of surface water bodies and groundwater aquifers from spills or leaks of chemicals (Soeder, 2018). Chemical substances present on a shale drill site typically consist of the components of drilling fluids and muds, hydraulic fracturing additives, and wastewater produced from the wells. The risks these compounds may pose to the environment are poorly understood.

Drilling mud is much more than a simple mixture of clay and water. It contains various stabilizers, lubricants, corrosion inhibitors, polymers, viscosity control agents, and other compounds, most of which are highly specialized and closely guarded trade secrets (Soeder, 2017). Mud can be water-based or oil-based, including synthetic oil. Drilling mud serves multiple functions, such as lubricating and cooling the bit, transporting the rock cuttings back up to the surface, and maintaining pressure inside the borehole to prevent fluids from entering or the walls from collapsing. When used with a downhole motor, the pressurized mud also supplies hydraulic power to turn the drill bit.

The unit density or “weight” of the drilling mud is important for controlling the stability of a wellbore, and it is monitored and adjusted carefully to achieve what is called “balanced drilling.” Mud weight is adjusted by adding minerals, typically barite, into the mud mix to increase the density, or adding water to reduce it. Mud engineers track the pore pressures in the rocks and the fracture gradient or rock strength. If the mud weight is underbalanced, or too low, oil and gas in the rocks can escape prematurely into the borehole, or the borehole walls could collapse. On the other hand, if the mud weight is too high, or overbalanced, it might exceed the hydraulic fracture gradient and crack the rock. This can allow drilling fluids to enter into the formation, called a loss of circulation (LOC). The frack gradient and pore pressure vary with location and can even vary with depth in the same hole. Mud engineering is a precise science that requires detailed planning and a thorough understanding of downhole conditions to maintain a proper borehole.

Mud is typically pumped downhole through the inside of the drill pipe. It flows out of the cutter head through special vent holes or jets (refer back to Fig. 2.7), cooling the drill bit and sweeping away the drill cuttings. The mud then returns to the surface through the annulus, the ring-like space between the outside of the drill pipe and the borehole wall, where it is captured and stored until it is recirculated. The cuttings are filtered out through a series of vibrating screens called shale shakers and are analyzed by an onsite geologist or mud-logging engineer to confirm the geology of the formation being drilled. This can be challenging because it is difficult to pinpoint the exact depth where the cuttings originated. It depends on the penetration rate of the bit and the travel time needed for the mud to return to the surface.

In the early days of shale development, the drilling mud reservoir was often just a simple pit a meter or so deep that was dug out on the pad and lined with a geotextile membrane. Water-based mud in the pit would often dry out in the sun and form a thin crust on the surface, making it appear solid. More than a few inexperienced people have tried to walk across the mud pit, thinking it was just an extraordinarily flat stretch of solid ground until they broke through the crust, usually to the great comedic enjoyment of the rig crew.

Mud pits also had a more serious problem in that the liners would frequently rip or tear, allowing the mud fluids to infiltrate into the soil (Fig. 6.3). Drillers typically didn't worry about this too much with water-based muds, because these are relatively cheap and they could afford to lose some. However, having drilling mud migrate to streams and drinking water wells alarmed environmentalists. When drilling was completed, the pits containing water-based mud were often just buried in place under a cap of soil. Mud

FIGURE 6.3 Photograph of a black substance identified as drilling mud oozing out of the ground from an eroded stream bank below a drill pad and into Indian Run in Harrison County, West Virginia, in 2010. *Photo by adjacent landowner Doug Mazer, used with permission.*

from these buried pits may seep out of hillsides sometimes years after drilling has been completed and continue to degrade the environment.

Shale drillers on some plays have switched to an oil-based mud, which they claim is more effective at lubricating the borehole and flushing cuttings off the bit. Oil-based muds are significantly more expensive than water-based muds, however, and drillers are reluctant to lose any of these fluids into the ground. As such, they have abandoned the use of mud pits and instead store the oil-based mud in steel tanks on-site. This has reduced incidents of leakage like that shown in Fig. 6.3. Because the oil-based mud is so expensive, it is retained and reused at the next well site.

Chemical additives for high-volume hydraulic fracturing are typically required in large quantities on well pads for blending during the course of the frack job. Because these chemicals are blended during the frack process itself, they are usually delivered to the site and used in concentrated form. The risk of this is offset by the fact that the chemicals are on site for only a relatively limited time period (Soeder et al., 2014). It is also important to note that there is a long history of groundwater contamination in the United States, and indeed, worldwide. Many of the chemicals present in groundwater that people like to blame on hydraulic fracturing have actually come from other sources and been there for quite some time.

Additives to a frack include acid, friction reducers, corrosion and scale inhibitors, lubricants, and biocides (Soeder, 2017). Acid cleans out the perforations and allows the frack water to more effectively enter the formation. A compound known as polyacrylamide is used to make "slickwater," an incredibly slippery substance that reduces friction losses in the sometimes very long strings of production tubing that the frack fluid must traverse to reach the formation. Corrosion and scale inhibitors prevent the production tubing from either rusting away in the harsh chemical environment, or becoming clogged with mineral precipitates. Biocides suppress the growth of sulfate-reducing bacteria downhole, which can add hydrogen sulfide (H_2S) to the gas, tuning it sour. Biocides are toxic by design and pose a significant risk to surface water and groundwater if spilled (Kahrilas et al., 2015).

Little is known about how these chemicals behave if there is a spill and they do enter the groundwater. Hydrologists have spent decades studying the natural breakdown paths and daughter products of common organic contaminants in groundwater, but not frack additives, which are primarily new and in most cases proprietary. The degradation of organic contaminants in groundwater, primarily through microbial and geochemical processes is known as "natural attenuation" or NA. It is commonly used as a contaminant cleanup strategy, because if the groundwater flow from a spill site to the accessible environment is slow enough, the chemicals will break down naturally and be rendered harmless by the time they reach the environment. When this works, it is the cheapest cleanup option for contaminated groundwater, requiring only some monitoring wells along the flowpath and periodic sampling and testing of the water. Alternatives if this so-called "monitored NA" is not viable include "enhanced NA," where the aquifer microbes are given nutrients to increase their metabolism, installation of a reactive barrier ahead of the plume to intercept it and cause a chemical reaction that will hasten the breakdown of the contaminant, or "pump and treat," where the contaminated water is actually removed from the ground and processed through a surface treatment facility. These are all considerably more expensive than monitored NA.

Contaminant hydrologists have amassed a great deal of knowledge about the breakdown paths and rates for many common organic compounds, including chlorinated solvents and petroleum-based fuels such diesel range organics (DRO), and the water soluble components of gasoline known as BTEX (benzene–toluene–ethylbenzene–xylenes). Comparatively little is known about the NA paths of organic chemicals added to frack fluid, especially the biocides (Kahrilas et al., 2015). Studies of how microbes might deal with these and other exotic compounds are being carried out at several institutions, but they are sparsely funded and are not able to keep up with the slew of new chemicals being introduced into the hydraulic fracturing field every year.

As a chemical proceeds through the NA process, some of the intermediate byproducts can be even more toxic than the original substance. For example, the friction-reducing chemical polyacrylamide used to make slickwater degrades into acrylamide, a reproductive toxin and carcinogen (Exon, 2006). It is often not until the breakdown process has completed the full path and turned the chemicals into things like salt and CO_2 that they are rendered harmless. Much more needs to be done to understand the impact of frack additives on groundwater, and chemical manufacturers should be required to complete NA studies on new organic frack additives before bringing them to market.

Produced water from completed and stimulated shale gas wells includes (1) recovered frack fluid known as "flowback" with all the additives introduced downhole, plus a few additional things possibly leached from the rock or formed by bacterial processes during the frack, (2) high TDS produced water resulting from osmotic diffusion of salts in residual shale pore water into the frack fluid that remained downhole for extended periods, and (3) potentially some high TDS formation water from more porous units above or below the shale that have been intercepted by the frack. The TDS content of the produced water can be extreme—often six to ten times saltier than seawater (Soeder, 2017). Although shales typically experience a much lower water cut than conventional reservoirs, the sheer volume of hydrocarbon production from shales over the past decade has brought large amounts of high TDS brine to the surface that required disposal.

A decade ago, oilfield brines were typically disposed of by evaporation pits, through POTWs or "publicly-owned treatment works" (the EPA term for municipal wastewater treatment plants), or simply dumped into the ocean. As disposal volumes began to increase during the shale gas revolution, ocean disposal was prohibited and POTWs proved incapable of adequately handling TDS. Many states began to informally or formally require oil and gas operators to deal with this wastewater by using expensive industrial treatment plants, or by pumping the waste down a well and into a deep, isolated disposal formation. Such disposal wells have been used for decades by the chemical industry. The US EPA is responsible for regulating these "underground injection control" or UIC wells, and several different classes of UIC wells are designated for different fluids. UIC wells for oilfield brines are designated Class II. The fluid being disposed of is classified as "residual waste," meaning it is industrial but not toxic. Excessive amounts of brine being disposed down UIC wells have led to a new problem—induced earthquakes, discussed in more detail below.

Other problems associated with wastewater disposal are vehicle accidents while transporting residual waste to UIC well sites and spills or leakage from careless handling of waste liquids during loading and unloading. The USGS has recorded an instance of inorganic compounds from a residual waste pipeline spill lingering in a North Dakota creek for 6 months after the spill occurred (Cozzarelli et al., 2017). Conventional wisdom suggested that these would have dispersed downstream in a matter of hours, but they were still detectable months later after apparently being trapped in streambed sediment. Contamination of groundwater and surface water with residual waste compounds was also noted at a UIC disposal site in West Virginia, where sloppy handling caused surface spills and leakage while trying to get the wastewater down the well (Akob et al., 2016).

On some shale plays, the produced water is recycled into the next frack. Since only a small portion of the injected frack water is recovered as flowback, this becomes a de facto disposal mechanism for a significant percentage of the residual waste by leaving it in the shale. However, recycling the frack water down multiple wells has led to the development of biocide-resistant microbes (Vikram et al., 2014). Metagenomic analysis of Marcellus Shale produced water, which may be recycled up to 15 times, was compared with Bakken Shale produced water, which is generally disposed of after a single use, and showed that microbial populations in the Marcellus samples were three to four orders of magnitude higher those observed for the Bakken samples (Lipus et al., 2017). Storing this recovered water in surface impoundments until the next frack allows the surviving, resistant microbes to biodegrade the organic frack fluid additives, some of which form toxic daughter products that may have serious impacts on human and ecological health.

Other industries use chemicals that are more toxic than any compounds on a drill site and often in even larger quantities without incident. These industries operate safely, and there is no reason to suspect that gas producers are somehow more reckless, uncaring, or less competent. Shale gas development and hydraulic fracturing ought to be carried out with the minimum impact possible to the environment. It is in the business interests of the O&G industry to practice good environmental stewardship with chemicals if they expect to have a social license to operate.

Induced Seismicity: Although not a direct risk to water resources, the earthquakes associated with shale gas and tight oil development are primarily caused by the disposal of produced wastewater and merit some discussion.

There is evidence that hydraulic fracturing can induce seismicity directly through a slow-slip process called tremor (Hammack et al., 2014), but most induced seismicity is a result of O&G wastewater disposal by means of UIC wells. The role of injected fluids in inducing seismicity was discovered after a series of earthquakes hit Denver, Colorado, in the early 1960s. The trigger mechanism was traced to the injection of liquid waste into deep disposal wells at the nearby Rocky Mountain Arsenal (Healy et al., 1968).

Disposal of O&G produced water down UIC wells has triggered numerous induced earthquakes caused by the injected fluids lubricating preexisting, stressed faults and causing them to slip. Places not historically known to be earthquake-prone, such as Oklahoma, have seen the annual frequency of seismic activity increase nearly 25 times after wastewater injection from shale development began in 2009. When the produced water from shale gas was added to the conventional O&G residual wastewater already being disposed down UIC wells, a series of earthquakes greater than magnitude 2.2 struck Arkansas and quakes above magnitude 3 hit Oklahoma (Llenos and Michael, 2013). The earthquakes eventually ended after the injection was stopped. A similar set of earthquakes in northeastern Ohio was linked to the disposal of Marcellus Shale produced water down a UIC well near Youngstown. Induced seismicity can be controlled by stopping or reducing the injection rate of wastewater and allowing the formation time to redistribute fluids and adjust stress. Practicing some restraint can go a long way toward avoiding these problems.

Air quality, greenhouse gas, and climate change

The issues of shale gas, tight oil, and air quality fall into three main categories. The first is the potential effect of the drilling, fracking, and production process itself on air emissions. The second is how the combustion of these fuels and the potential substitution of one fuel for another might impact air quality attainment in cities. The third is a general concern about the contributions of fossil fuels to greenhouse gas (GHG) emissions and climate change, what can be done about it, and how shale gas and tight oil fit into that picture.

Air emissions from production: Shale gas and tight oil development activities generate measurable emissions of various compounds in the air. These include nitrogen oxides (NO_x), volatile organic compounds (VOCs), and particulate matter (PM) from the internal combustion engines used to power generators, drill rigs, and hydraulic fracturing pumps, as well as the trucks and other vehicles employed to transport supplies to and from the drill pad locations (Pekney et al., 2018). Production of gas, NGL and oil can create methane, CO_2, and VOC emissions from venting and flaring. Methane and VOCs can also escape from produced water, and fine dust suspended in air by vehicle travel on gravel roads creates additional PM. Shale operators are interested in reducing emissions and fugitive releases of gas to avoid regulatory violations, and also to stop the loss of their product.

A number of research projects have been monitoring air at shale gas and tight oil drill sites, along with some established, conventional O&G fields in an attempt to quantify emissions and determine various options to stop leaks (Pétron et al., 2012; Soeder and Kent, 2018). Pipelines and compressor stations have also been monitored. The presence of ethane in air has been found to be a good regional indicator of the presence of O&G operations because it does not have any other atmospheric sources (Pekney et al., 2014). The isotopic signature of methane also can be used to determine if the gas has a biogenic or thermogenic origin; thermogenic gas is another indicator of O&G operations.

Human health impacts from exposure to air pollutants depend on the toxicity of the chemical and whether the exposure was acute or chronic. Information about chemicals added to hydraulic fracturing fluid is posted on the FracFocus website (http://fracfocus.org/). Although many companies offer up this information voluntarily, it is required as part of the drilling permit in some states. An examination of the FracFocus website indicates that common substances added to frack fluid include methanol, isopropanol, crystalline silica, 2-butoxyethanol, ethylene glycol, hydrotreated petroleum distillates, sodium hydroxide, hydrochloric acid, ammonium chloride, ammonium and sodium persulfate, glutaraldehyde, and polyacrylamide (Soeder et al., 2014). In order for these chemicals to have human health impacts via airborne exposure, they must be both toxic and volatile in air.

The US EPA compiled a consolidated list of over 930 chemical compounds used or found in hydraulic fracturing fluid, including 132 chemicals present in flowback and produced water. Sources included federal and state government documents and industry-provided data (USEPA, 2015). Sorting through these in terms of toxicology has been a challenge. However, the claim by some fracktivists that “hundreds” of chemicals are added to hydraulic fracturing fluid is a misunderstanding. While a great many chemicals have been tried over the history of hydraulic fracturing, no one adds hundreds or even dozens of chemicals to any individual frack. Advances in hydraulic fracturing technology have reduced the chemicals used in a single frack to around a half dozen (Soeder et al., 2014).

Sporadic well site operations like pumping a hydraulic fracture or running a generator full tilt to drill through a difficult interval create brief, high emissions (refer back to the photograph of a frack in progress in Fig. 2.8). These must be assessed against a background of many hours of low emissions when equipment is slow or idle. This variability in well site operations can result in exposures to contaminants that could be either acute or chronic, or perhaps both, depending on the circumstances. Long-term air monitoring at a Marcellus Shale research site found methane emissions to be highest during the initial production of flowback water (Pekney et al., 2018). Shale development in areas that already have marginal air quality, such as the Marcellus site mentioned above near Morgantown, WV, or the Barnett Shale in the Dallas–Fort Worth metroplex makes it difficult to separate well site emissions from freeway traffic, factories, and other industrial sources (Pekney et al., 2018). This leads into the next section, where emissions from production pale in comparison to emissions from combustion.

Air emissions from combustion: Of all the sources of fossil fuel, natural gas burns the cleanest, emitting less nitrogen dioxide, sulfur dioxide, and particulate matter (PM) per Btu than oil or coal (Pekney et al., 2018). It also does not require cracking or refining like petroleum, which can be a significant source of volatile organic compounds (VOCs) in the atmosphere. The nearly pure methane that comprises natural gas produces only CO_2 and water as combustion products. Methane itself is colorless and odorless, and methyl mercaptan must be added to natural gas as an odorant to make it detectable. Because of the high hydrogen to carbon ratio, natural gas also has the lowest CO_2 emission per Btu of energy among all of the carbon-based fossil fuels (Soeder, 2017).

Crude oil is made up of a mixture of many different hydrocarbons, and the refining process is designed to produce a variety of products from this mix. Besides making gasoline and diesel fuel, crude oil is also a critical feedstock for the petrochemical, pharmaceutical, and plastics industries. As such, it is too valuable to burn, and running our vehicles on petroleum is equivalent to cutting up furniture-quality hardwood and using it for a campfire. Petroleum combustion products include ozone, the various components of smog, and a number of carcinogens.

Despite 40 years of emissions controls and catalytic converters, the smog in US cities from gasoline-powered vehicles has not been eliminated. It is still not unusual for some cities to experience a number of days where the EPA Air Quality Index exceeds 100, which can cause problems for people with respiratory sensitivities. One of the most harmful pollutants in smog is ozone, which forms from reactions among complex gasoline combustion products like aldehydes and is driven by sunlight. The ozone molecule, composed of three oxygen atoms, can cause serious human health effects, harm birds and mammals, damage vegetation, and cause deterioration of rubber and polymer materials. Congress has debated for years about if, when, and how US air pollution regulations might consider addressing ozone.

Gasoline and diesel fuel are typically stored at service stations in large underground tanks to protect them from fire hazards. Thousands of these tanks at locations all over the country have corroded and leaked BTEX and DRO into groundwater, contaminating individual wells and in some cases entire water supply systems. Running our vehicles on something other than gasoline or diesel fuel would significantly improve air quality in cities, along with groundwater quality throughout the nation.

Alternatives to gasoline/diesel include biofuels, plug-in hybrid electric vehicles, and pure electric vehicles. Another option worth considering is natural gas–fueled vehicles, which have many advantages for rapid implementation. For starters, the type of vehicle capable of running on natural gas is already widely distributed throughout the United States. Believe it or not, a standard, gasoline-powered automobile engine will run just fine on compressed natural gas, or CNG, with a simple conversion. A DOT-approved compressed gas cylinder about the size of an SCUBA tank is installed in the trunk (or other suitable location), and a line is run from it to the engine. A few other amenities are necessary, such as a pressure gauge, regulator, and shut-off valve. The usual design leaves the vehicle's original gasoline tank in place and adds the CNG cylinder as a second fuel source. One of these "bi-fuel" vehicles typically has a range of about 160 km (100 miles) or so on the CNG fuel, and then with the flip of a switch it can go back to running on gasoline. Since most people don't drive this far in a day, the CNG tank can be refilled overnight with a home compressor, making the vehicle capable of running on natural gas nearly all the time. Converting gasoline-powered vehicles over to CNG would stop wasting valuable petroleum as fuel, expand the current stagnant market for natural gas, and bring all US cities into air quality attainment standards. The fact that this has not caught on with American automobile manufacturers, drivers, natural gas companies, and environmentalists is a mystery.

The technology is neither difficult nor new. Natural gas—fueled vehicles were first developed in Italy during the 1930s, and the bi-fuel technology became popular in western Canada in the 1980s when a glut of gas was produced from the Deep basin in Alberta. CNG vehicles also gained popularity in New Zealand around the same time. The 1980s-version had a dashboard switch to advance the spark on the distributor when running on CNG, because it didn't require a delay to vaporize in the carburetor like gasoline. On modern vehicles with computer-controlled fuel injection, especially those that can adapt automatically to various ratios of gasoline and ethanol fuel mixtures, a similar adjustment would not be necessary.

In the United States, the most common natural gas—fueled vehicles at present are transit buses. Because these are fleet vehicles, they return nightly to a central garage with CNG refueling capabilities. For CNG to gain wide use in private vehicles, refueling capabilities must be added to people's homes and at widespread service station locations. Many service stations already have natural gas supplied to the facility to heat garages or convenience stores. Adding a compressor and a pipeline out to a dispenser on the pump island is all that is needed to begin fueling vehicles with natural gas. Among other advantages to a business offering retail CNG vehicle refueling, it does not add to liabilities from a leaking underground storage tank, and there are no worries about running out of fuel to sell to customers because a tanker truck didn't arrive.

The greatest disadvantage of CNG as an automotive fuel is the volume needed to achieve a significant range. Natural gas simply does not have the energy density of gasoline, so a larger volume of fuel is needed to go the same distance. Americans typically suffer from "range anxiety," and are not happy with a vehicle unless it can potentially get them 400 or 500 miles on a single tank of fuel, even though their daily drives are often far less. A bi-fuel vehicle overcomes this worry by retaining the original gasoline tank. After your CNG cylinder runs out of fuel, you still have a full tank of gas. It is also possible to install larger or multiple CNG cylinders in vehicles to achieve longer ranges. Many vehicles have a significant amount of unused cargo area that could carry more fuel.

The carbon dioxide and nitrogen content of natural gas varies, although the energy value out of the pipeline remains relatively constant at one million Btu per MCF. While the presence of these other gases makes little difference at the burner tip of a hot water heater, they may affect the performance of an internal combustion engine. The composition of gasoline is maintained to established standards so vehicles will operate the same across the country. Standardizing natural gas composition in a similar manner would improve its viability as a transportation fuel.

In addition to cars and buses, heavy trucks such as tractor-trailer rigs or semitrucks are another potential market for natural gas fuel. Both local and long-haul trucking make up one of the largest transportation fuel use sectors in the economy. Local delivery trucks burn large amounts of fuel in stop-and-go city traffic, and long-haul trucks often run their diesel engines for days on end without ever shutting down. At least one large truck stop chain is pursuing liquefied natural gas (LNG) fueling options instead of CNG because liquid refueling is significantly faster for large trucks. Truckers operate on tight schedules with restrictions on how many hours per day they are allowed behind the wheel. Another advantage of LNG is that the act of liquefying the gas also purifies it, resulting in essentially pure methane and avoiding the uncertainties inherent in the composition of CNG.

Virtually all of the air quality problems resulting from the combustion of O&G are due to the use of gasoline as a motor fuel. Although petroleum has many other uses, natural gas is not good for much other than burning. So why not use it as a transportation fuel, especially since it burns so much cleaner than gasoline or diesel fuel? CNG and LNG fueled vehicles would provide immediate environmental benefits to the quality of air and groundwater, and greater sustainability to petroleum supplies.

Finally, there is the issue of air quality problems from coal combustion. Although it has limited use as a chemical feedstock, and for specialized processes such as providing a carbon source for steel making, the primary role of coal in the United States is making electricity. Coal is burned to heat water into steam, and the steam is used to turn a turbine blade, which then turns a generator to create electric power. Pennsylvanian-age eastern coals contain a variety of mineral and inorganic substances that tend to turn up in the combustion products. Burning coal, which is essentially nearly pure carbon, produces a lot of CO_2 along with a variety of hazardous and semihazardous gaseous, particulate, and solid materials, including sulfur dioxide, selenium, mercury, arsenic, fly ash, and bottom ash.

Sulfur dioxide (SO_2) is not a problem in itself. The trouble comes when it combines with water vapor (H_2O) and oxygen in the air and becomes H_2SO_4, better known as sulfuric acid. This "acid rain" from coal-fired power plants in the Midwest was devastating lakes, streams, and aquatic ecosystems in the eastern United States, which were unable to buffer it. Sulfur removal was mandated under the Clean Air Act, and it turned out to be fairly simple. Power plants add a small amount of limestone ($CaCO_3$) into the combustion chamber with the coal. The calcium captures the sulfur and precipitates out as $CaSO_4$, or gypsum. Some power plants actually have factories nearby that use this gypsum to make drywall. Other power plants use lignite and subbituminous coal from Wyoming, which has a lower Btu value, but is also much lower in sulfur.

The heavy and toxic metals that are left behind after the combustion of coal tend to concentrate in the ash. This ash is typically disposed of in impoundments designed to accumulate millions of tons. The ash in these impoundments is exposed to the weather and soaks up rainwater, becoming a slurry of toxic mud. One of these ash impoundments failed in Kingston, Tennessee in 2008, releasing approximately 1.1 billion US gallons (4.2 billion liters) of coal fly ash slurry that reached the Emory River and eventually the Tennessee River. Although no one was injured, it destroyed 12 homes and killed thousands of fish in the Tennessee River. Four million tons of spilled ash was collected and transported to a landfill in Alabama. The cleanup took 6 years (USEPA, 2014).

Primary energy sources are those that are used to create power, such as electricity, which can then be transmitted elsewhere to do work. Electricity can only transform the primary energy source from one form to another; it cannot make new power. Electrical generation in the United States uses a variety of primary energy sources, including coal, oil, nuclear, hydroelectric, biomass, wind, solar, geothermal, and natural gas. Known as an "all-of-the-above" energy strategy, this diversity of power sources is designed to ensure that the energy supply in the United States is not vulnerable to a single threat. Many older power plants are nearing the end of their design life and replacement plants will be locked into a particular fuel type for the next 30–50 years. Utility executives trying to decide how to power thousands of megawatts of new generating capacity fully understand that such decisions are neither simple nor easy.

Given the environmental challenges of coal, the costs to meet air emission standards, and the economics of bulk material transport to and from power plants, a different primary energy source might seem like a better option. Natural gas in fact burns much cleaner, does not produce SO_2 or toxic ash that must be removed after combustion, and can be supplied directly to the power plant right up to the burner tip via a pipeline. Natural gas power plants are also super-efficient "combined cycle" facilities that typically use a gas turbine that looks like a stationary jet engine to directly power a generator, and then capture heat from the turbine exhaust to create steam, which runs additional generators. The price is low, and the large quantities of shale gas available in the United States provide a reliable supply. This would appear to be an easy decision, but electrical utilities have a complicated history with natural gas and some residual anxiety about committing to it (Soeder, 2017).

These concerns began in 1973, when many people thought conventional natural gas production had peaked. The winters of 1977 and 1978 were unusually cold, leading to some gas supply shortages that were partly due to price controls. In reaction, Congress passed the Fuel Use Act, which prohibited the use of natural gas to generate electricity. Natural gas deregulation under the Reagan administration in the 1980s brought on a large amount of new production and a gas bubble that was supplied in part by unconventional sources like tight sands and coalbed methane. The Fuel Use act expired in 1987, and several hundred gigawatts of new natural gas generating capacity were built. After another apparent peak in conventional production in 2003/2004, gas was available, but became expensive. Much of the new gas-powered generating capacity was idled, resulting in a number of bankruptcies. Many surviving utilities swore off gas forever (Soeder, 2017).

Utility executives worry about two things when deciding on which primary fuel to use for a new power plant: reliability and price. Coal won on both counts because suppliers could easily agree to 20, 30, or even 50 year-long fixed-price contracts to supply power plants and assure the operator that delivery trains or barges would show up regularly for decades. Natural gas prices are more volatile and fluctuate with the market. Gas is currently abundant and cheap because the supply far exceeds the demand. However, should the demand increase in the future from new uses like the CNG-fueled vehicles discussed above, prices could rise quickly. A power plant designed to run on natural gas cannot easily switch to another primary fuel. This is a risk that utility executives must consider when contemplating gas-fired power plants.

The price structure of coal is also unstable, but for different reasons. Coal is cheap at the moment because of what are called "externalized costs," where most of the environmental cost for coal extraction and combustion are not included in the price of the fuel, but covered by taxpayers. These include things like watershed damage and stream restoration from mountaintop removal mining operations, repairs of structures and property from damage caused by underground mine subsidence, remediation of acid mine drainage in streams, disposal of toxic ash, the economic costs of CO_2 emissions and changing climates, and the public health costs of SO_2, mercury, arsenic, and selenium emissions that are not captured in the stack. When these costs are added in to the price of electricity, coal-fired power becomes more expensive than nuclear (Soeder, 2017).

In 2010, the EPA began tightening regulations on coal emissions from electric power plants. Congress also took up discussions of caps or limits on the amounts of CO_2 that coal plants could release into the atmosphere. Coal-fired electricity suddenly became far less economical, and after the discussion started on carbon caps, the Nuclear Regulatory Commission actually received four applications for new nuclear generating facilities for the first time in decades. Political talk about "bringing back coal" may garner votes in coal states, but it ignores growing resentment toward externalized costs and denies environmental reality. Many electric utilities are once again seriously considering natural gas, now that abundant supplies of shale gas are available. Obsolete coal power plants are being replaced with natural gas-fired electricity, with more than half of the new generating capacity in the United States gas-fired (Soeder, 2017).

Greenhouse gas and climate: The idea that humans are influencing the Earth's climate is widely accepted among nearly all scientists who have seen the evidence (National Academies of Science, 2005; National Research Council, 2011). Little knowledge beyond elementary physics is required to understand that burning fossil fuels releases CO_2 into the air that then traps heat and warms up the atmosphere. However, because some people with a stake in fossil fuels think that this may jeopardize the future of their industry, a small, vocal group of climate change "deniers" have sprung up in opposition. They attack the notion of anthropogenic climate change by exploiting small uncertainties, obfuscating the issues, misrepresenting facts, and questioning the validity of data. These are the same tactics being used by the fracktivists, although most climate deniers would bristle at the comparison. For readers who are a bit uncertain about how all this works, a review of the basic physics may be helpful.

Joseph Fourier first investigated atmospheric radiative heat transfer back in 1827 and discovered that the CO_2 molecule is transparent to short wavelengths of infrared radiation, but blocks and absorbs the longer wavelengths. The Earth receives short-wave infrared from the sun that penetrates the atmosphere and heats the surface of the planet, as anyone knows who has ever walked barefoot on the beach on a sunny day. The warm Earth then reradiates this heat back into space as longer wavelengths of infrared radiation, which is absorbed by CO_2 in the air and warms the atmosphere (Pierrehumbert, 2011). CO_2 is known as a "greenhouse" gas (GHG) because of this warming capability.

CO_2 levels in the atmosphere have been steadily increasing since continuous measurements began in 1957 (http://www.esrl.noaa.gov/gmd/ccgg/trends/) on Mauna Loa in Hawaii (Fig. 6.4). There is some debate about the source of this CO_2, but a prime suspect appears to be the combustion products of fossil fuels, which have been used in ever-increasing quantities by humans since the Industrial Revolution. Other potential

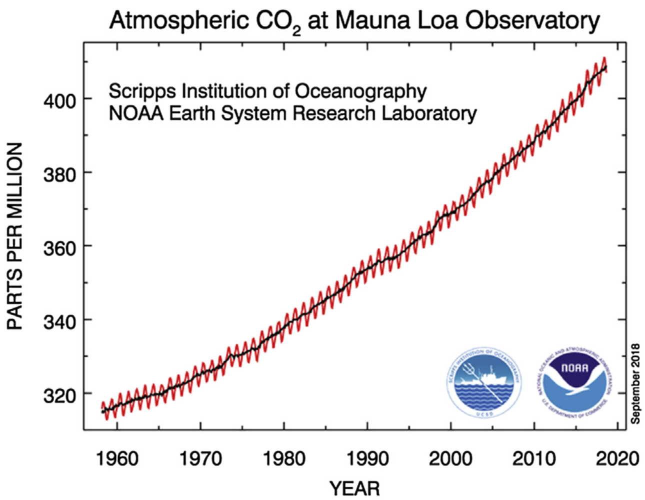

FIGURE 6.4 Carbon dioxide levels in the atmosphere measured since 1957 at Mauna Loa in Hawaii. *Source National Oceanic and Atmospheric Administration (NOAA).*

CO_2 sources such as volcanoes don't match history with the steady and increasingly steep climb in concentration of the gas. The sawtooth line in the graph is the annual seasonal flux of CO_2 as plants bloom and die in the Northern Hemisphere. The black line is the average trend, and that's the one to watch.

The details of how this increase in atmospheric CO_2 translates into potential climate change are the source of most of the uncertainty. The mean global temperature increase of 0.8°C during the last century is actually greater than expected if it was caused by anthropogenic GHG alone (Adair, 2012). This is because the Earth has been emerging from the most recent Ice Age for the past 12,000 years and climates have been undergoing a natural warming. Any human-induced warming is superimposed on this natural background signal, making the two effects difficult to separate.

A report by the IPCC or Intergovernmental Panel on Climate Change (Solomon et al., 2007) has stated that if no effective CO_2 reductions are implemented by industrial nations, concentration of the gas in the atmosphere will likely increase from 390 parts per million (ppm) in 2007 to about 1250 ppm in 2100. As of this writing it is at 410 ppm.

Climate risk assessments are probability-based. The best-case scenario is a one-in-six chance that the increase in global temperatures by the end of the 21st century will be less than 2.0°C (3.6°F), and will be lost in the natural background. However, there is also a one-in-six chance that temperature increases will exceed 5.4°C (9.7°F), leading to serious climate disruptions. Warmer air holds more moisture, so more severe droughts and larger storms could be expected. Consequences may also include the potential melting of the polar ice sheets, which could raise sea levels by up to 76 m (250 ft) and inundate significant amounts of coastal land (Poore et al., 2000).

A one-in-six probability of a bad outcome may not sound like a significant risk, but these are the same odds as Russian roulette. Risk is defined as the probability of an event times the consequences (Soeder et al., 2014). Although the probability of significant warming may not seem high, the possible consequences make it a serious risk and justify reducing anthropogenic CO_2 levels in the atmosphere. Methane is also a GHG with even more powerful effects than CO_2, although it is easily oxidized and has a much shorter lifetime in the atmosphere.

Statements that hydraulically fractured shale gas wells may leak copious amounts of methane gas into the atmosphere caused a great deal of alarm when first published (Howarth et al., 2011). If methane was indeed entering the atmosphere in large quantities from these wells, there could definitely be a problem. Several follow-on studies, including a life-cycle analysis of gas-fired electricity by Skone et al. (2011) and an assessment of the mining, transport, and combustion process of coal (Cathles et al., 2012) concluded that coal production and combustion has a much greater GHG impact than shale gas production and combustion.

The Earth has a natural carbon cycle with reservoirs of carbon in the atmosphere and the ocean, in green plants and soils, and in carbonate rocks, coal, and hydrocarbons trapped in the subsurface. The carbon cycle has been in a state of quasiequilibrium with balanced exchanges of CO_2 between the atmosphere, oceans, and land, resulting in relatively constant CO_2 levels in the atmosphere and fairly stable climates over the time scale of human civilization.

On geologic time scales, the climate has varied considerably from ice ages to warm periods due to orbital cycles of the Earth, volcanic activity, methane gas releases, or other events. One of the most extreme ancient warming events in the geological record is known as the Paleocene–Eocene Thermal Maximum (PETM) that occurred around 56 million years ago (Jardine, 2011). A rapid increase in the concentration of GHG in Earth's atmosphere caused global temperatures to rise by more than 5° C over a time period of about 6000 years, and then gradually cool over the next 150,000 to 200,000 years. The origin of the GHG responsible for this event is unclear, although it was possibly caused by volcanic eruptions that released methane from sea floor sediments where it was held in solid form as methane hydrates, a kind of ice with methane trapped in the matrix. Such evidence from the geologic past indicates that abrupt climate disruptions (6000 years is abrupt in geologic terms) can occur when a significant influx of GHG enters the atmosphere. If the CO_2 influx from fossil fuel combustion continues unabated, it too will cause climate disruptions.

What can be done about the release of GHG into the atmosphere from fossil fuels? The answer it to stop putting so much in, and to deal with what is already there. If humanity continues to use fossil fuels, and it looks like we will be doing so for at least the foreseeable future, then steps must be taken to both manage and reduce GHG input. This adds to the cost of fossil fuel, but raising fossil fuel costs will reduce use and incentivize other energy resources.

Using other sources of energy that do not add carbon to the atmosphere is the most obvious way to reduce GHG emissions. These include "renewables" like solar, wind, geothermal, and biofuels. Biofuels do not add any "net" carbon even though they give off CO_2 as a combustion product, because the source of that carbon is from material that was already part of the carbon cycle. It is the carbon being brought up from underground and entering the atmosphere from outside the cycle that is raising the CO_2 levels. Other noncarbon energy sources include nuclear power and hydropower.

So why are we not using these? Well, we are to some extent in the "all-of-the-above" energy strategy, but a lot of it comes down to the development stage of the technology and the cost. Current natural gas prices at the wellhead are around $2 to $3 per million Btu. Nothing else can provide that much energy at that price, except maybe coal. Other energy sources are more expensive, sometimes considerably more expensive. Reducing the cost of the technology and increasing the price of the product are the ways to make these competitive, as was discussed back in Chapter 2 for the economic development of shale gas. A plan for raising the cost of fossil fuel with a "carbon tax" was discussed a few years ago to help make other, noncarbon energy sources more competitive on price. Revenues from the carbon tax were to be used to manage CO_2. This almost came to pass in the US Congress in 2010, but the energy industry lobby fought it tooth and nail. The US DOE has spent billions trying to develop noncarbon energy technologies, including exotic things like nuclear fusion to make them more competitive with fossil fuel, but success has been elusive so far.

CO_2 can be removed from the atmosphere by using physical (cryogenic) or chemical (adsorption) means to capture it, and then it can be stored in deep geologic formations to "sequester" it from the air. This so-called "carbon capture and storage" or CCS technology has been a major research focus on DOE-supported coal programs over the past several decades. Coal power plants are especially amenable to the technology because they are fixed sources of CO_2 and don't move around like vehicles. The standard technology for carbon capture is called "pressure-swing adsorption" and uses organic chemical compounds called amines to adsorb the CO_2 under pressure and release it when the pressure is dropped. This can capture CO_2 in the stack gases of coal plants and transfer it into containment vessels for eventual offsite storage. Other carbon capture technologies are under development.

Research on the permanent storage of CO_2 in the geological environment is primarily investigating deep saltwater aquifers, unmineable coal seams, depleted conventional oil and gas fields, depleted gas shales, and fractured basalt formations (USDOE, 2012). The most common geological location for carbon storage at present is in depleted oil and gas fields where the CO_2 is being used to repressurize the reservoir and produce more oil in tertiary recovery operations. Some field tests have been run on deep saltwater aquifers in Illinois and other locations, and coal seams and shales have been assessed and modeled. A major challenge of geologic storage of CO_2 is to make sure that whatever is put down there stays there. CO_2 under pressures at oil reservoir depths becomes a supercritical fluid, which means more gas can be stored in less space, but it is also corrosive and a powerful solvent. There are real concerns that old oilfield infrastructure could be compromised and the CO_2 could leak back out (Watson and Bachu, 2009).

One promising storage formation is fractured basalt. Tests run in Iceland injected CO_2 into volcanic rocks, expecting the gas to react with calcium feldspars in the basalt and eventually form calcium carbonate, or the mineral calcite. The advantage of this storage technique is that the CO_2 is stored as a solid, making up part of the calcite mineral matrix. The main disadvantage seemed to be that the mineral reactions were thought to take decades if not centuries, and the carbon would have to be kept secure during those timeframes. Surprisingly, the Icelandic researchers found that substantial amounts of the CO_2 inside the basalt had transformed to calcite in just 2 years (Matter et al., 2016). There are huge basalt deposits in the world that could serve as storage for CO_2. These include the Columbia River basalts, the Deccan Traps in India, the bulk of the islands of Hawaii, Japan, and many others, and essentially the entire midocean ridge system, of which Iceland is a part, forming the longest mountain chain on the planet.

Other ideas for large-scale atmospheric CO_2 removal include fertilizing the Southern Ocean with iron, which is a critical nutrient (Gribbin, 1988). This will supposedly result in a phytoplankton bloom that removes CO_2 from the atmosphere, followed by an increase in the population of small crustaceans known as krill that feed on phytoplankton. Krill fecal pellets and manure from the whales that feed on them will descend into the ocean depths, keeping the carbon isolated from the atmosphere. Fertilizing the ocean with nitrogen instead of iron is supposedly another critical nutrient that will stimulate phytoplankton blooms. Other carbon removal schemes include the direct injection of CO_2 into deep ocean sediments, promoting the growth of large populations of marine animals called salps, which consume phytoplankton and produce large, heavy fecal pellets that quickly sink, and acidizing volcanic islands to speed up the chemical weathering processes on land to mineralize CO_2 (Nevala and Madin, 2008). Another idea suggests using captured CO_2 in concrete, where it will react with calcium oxide in the cement and cure to solid calcium carbonate. Because certain methanogenic bacteria consume CO_2 and use it to produce CH_4 or methane, suggestions have been made to set up methanogen farms and turn the CO_2 back into flammable methane gas for energy.

To some people, the whole idea of CCS seems futile, like draining the oceans with a bucket. However, any CO_2 that gets sequestered and stays sequestered is removed from the atmosphere permanently. Using a carbon tax to fund operations at CCS stations in various places throughout the world can start to slow, stop, and eventually reverse the alarming climb in atmospheric CO_2 measured since 1957. Humans put this CO_2 into the atmosphere, and we ought to be able to remove it.

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7

Energy economics

Cradle-to-grave responsibility

The notion of cradle-to-grave responsibility for an energy resource attempts to remove the economic factor of "externalized costs" (introduced for coal in Chapter 6) and level the playing field for all energy resources. In energy economics, as in most of life, there is no such thing as a free lunch.

All energy has costs, some obvious and others less so. There are capital expenses (CAPEX) associated with development, such as drilling gas and oil wells, extracting coal out of a mine, erecting wind turbines, mining and concentrating uranium ore, constructing a massive hydroelectric dam, or manufacturing and installing solar panels. There are operating expenses (OPEX) involved in producing and transporting that energy resource to where it is needed, either by ship, train, pipeline, transmission line, truck or some other means, converting, distributing, metering, and monitoring it, and cleaning up as needed. These costs are inherent in the day-to-day operations of energy companies. For example, electrical generation requires human oversight to ensure that supply and demand are in balance. Wind turbines need repairs from hailstorms or bird strikes, nuclear plants require careful, round-the-clock, expert monitoring, solar panels need cleaning, pipelines require maintenance, hydroelectric dams undergo constant inspections and repairs, coal requires material handling, and gas turbines must be started and stopped when needed. In a world where cradle-to-grave responsibility for the production and use of energy resources was accepted by all, the costs of energy supply and use would be borne solely by the customers.

Sadly, the reality is that if companies think they can get away with externalizing costs, many will try. Even wind farms have been able to externalize some of their costs by demanding tax subsidies to remain economically competitive with other forms of energy. In the case of crude oil spills, major petroleum companies have found it cheaper to pay a herd of lawyers to keep things tied up in court rather than pay the actual cleanup costs, which often end up being covered by taxpayers (Erb, 2000). Multiple legal appeals can also significantly reduce the cost liability for damages, as in the case of the Exxon Valdez oil spill in 1989, where a series of court challenges raised by company attorneys ended up reducing the punitive damages against Exxon from $4.5 billion to a bit more than $500 million (U.S. Court of Appeals, 2009).

Coal is another champion at externalized costs. Most of the land devastation, stream damage, and other environmental costs caused by surface mining the product are not paid by the coal companies or the coal users, but by taxpayers. Although coal mines are

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required to post financial assurance bonds, in most cases these have been historically insufficient to cover the costs of site restoration. The general public, including many who do not even use any energy generated from coal will eventually foot the bill to restore the land and remediate acid mine drainage in streams, along with the public health costs of mercury, arsenic, and selenium emissions. The widespread land and watershed destruction that results from the "mountaintop removal" type of surface mining used on Appalachian coal is of special concern, as is the frequent land subsidence caused by the collapse of abandoned underground mines. For example, a segment of interstate highway in southwestern Pennsylvania needed to be almost completely rebuilt due to subsidence after the coal was mined out from beneath it. The costs were paid by highway taxes, not by the coal company. (The coal company had offered to sell the coal to the state and leave it in place under the highway, but there was no mechanism for doing so.)

Many of the "cradle-to-grave" costs that tend to get passed on routinely to taxpayers are the "grave" responsibilities: waste disposal, decommissioning, dismantling, land restoration, site cleanup, and so forth. Again, these vary with the energy resource. The most formidable waste disposal problem is arguably the high-level radioactive waste from nuclear power plants. This dangerously radioactive material must be kept out of the environment for tens of thousands of years, far longer than human civilization has existed on this planet. Fortunately, the volume is relatively small. Coal combustion has created a much larger volume of toxic ash that also must be disposed of safely. Hydroelectric dams have resulted in a variety of ecological and hydrological compromises in rivers and streams. A few dams have been taken down in recent years, with many others slated for removal. These environmental remediation costs are often picked up by the general taxpayer, who may or may not have benefitted from the energy resource.

In some cases, attempts have been made to control externalized costs. The nuclear power industry, for example, had a trust fund set up by Congress in the 1950s for dealing with the large volumes of high-level radioactive waste that were anticipated from commercial nuclear power plants. Income for the fund came from a tariff paid by customers who were actually using nuclear-generated electricity. This ratepayer (vs. taxpayer) fund was used to support the characterization and design of a permanent repository for the high-level radioactive waste. Yucca Mountain in Nevada was the designated repository site (Fig. 7.1).

The current nuclear waste conundrum is probably the most serious bad example of what can result from the failure to carry out cradle-to-grave responsibility. When civilian nuclear power was first developed in the 1950s, the electric utilities were enticed into investing in this new technology by two cradle-to-grave promises from the federal government: (1) power plants would have access to an adequate supply of uranium or other fissionable materials for long-term operations (cradle) and (2) the government would assume responsibility for the final disposal of the high-level radioactive waste products, beginning in the 1980s (grave). The first part of this was carried out and nuclear power plants have always had access to the supplies of fissionable material they needed to operate.

FIGURE 7.1 The North Ramp of the Exploratory Studies Facility (ESF) tunnel under Yucca Mountain, Nevada. This U-shaped tunnel into and out of the mountain is five miles (8 km) in length and 25ft (7.6 m) in diameter. *Photographed in 1997 by Dan Soeder.*

In 1982, the Nuclear Waste Policy Act became law and established a national policy to deal with high-level nuclear waste. This law pushed back the date the US government would begin accepting high-level nuclear waste to January 31, 1998. The high-pressure water reactors common in the US typically change out a third of their fuel rods annually, creating a reactor's worth of high-level radioactive waste every 3 years. Many nuclear power plants had been designed and constructed with the original 1980s waste acceptance date in mind, and nuclear utilities were concerned about both the safety and cost of storing their waste on site for an additional decade until the government was ready to accept it.

The 1982 Nuclear Waste Policy Act made the US Department of Energy responsible for locating a suitable site and constructing a geologic repository for nuclear waste. An underground disposal option had been recommended by the National Academy of Sciences in 1957 as a means to protect the environment and public health by disposing of the waste in the deep subsurface. The idea of a "repository" was that the waste could be monitored and even retrieved if necessary. Retrieval might be required to address a problem like corrosion and leakage of a storage canister, or in case some future, unknown engineering application needed access to the large stocks of fissionable materials.

Starting in the early 1980s, DOE looked at 10 different potential sites across the country, encompassing geology that included shale, bedded salt, volcanic rocks and other lithologies. The minimum technical requirements for a repository were groundwater travel times long enough to prevent the waste from entering the accessible environment for at least 10,000 years and a site that was remote, stable, controlled by the government, and contained no existing resources of consequence that someone might try to drill or mine in the future. Site performance assessments were carried out to calculate the inherent technical risks of each location, and other factors like accessibility, land ownership, and distance from population centers were also considered. By the mid-1980s, DOE had reduced the options to three sites that would be given full-blown technical characterizations to determine their suitability for a repository. These were Deaf Smith County, southwest of Amarillo, Texas, the Hanford Site, north of Richland, Washington, and Yucca Mountain, on the western border of the Nevada Test Site (now known as the Nevada National Security Site, or NNSS).

Before these three technical characterizations could get fully underway, Congress passed an amendment to the Nuclear Waste Policy Act in 1987 that halted studies at Deaf Smith and Hanford, and specified that Yucca Mountain would be the only site fully characterized for a high-level radioactive waste repository. Based on what was known at the time, Yucca Mountain appeared to be the most favorable site. The Deaf Smith County location was not on federal land, and the repository shafts would have to penetrate the critically important Ogallala Aquifer to reach the bedded salt that would store the nuclear waste. The Hanford Site was on federal land, but consisted of thin basalt flows that could not accommodate a repository within a single unit. Designs had to include multiple basalt layers with potential groundwater flow paths along the contacts, and in many locations the fractured basalts were in direct hydraulic connection to the Columbia River.

Although the 1987 amendment to the Nuclear Waste Policy Act was intended to save time and money, it backfired. A lot of the workers who had transferred to the small town of Hereford, Texas in Deaf Smith County to start the site characterization studies ended up being stuck with houses they couldn't sell in a market where everyone was moving out. A number of scientists and engineers at the Hanford Site were laid-off or reassigned.

The greatest damage was done in the State of Nevada, however, where the 1987 amendment to the Nuclear Waste Policy Act became known locally as the "screw Nevada Bill." Opponents of nuclear power ignored the reasoning behind the decision and stoked public anger and state-wide political opposition over this "arbitrary" law that forced Nevada to become the only state in the country to host a "nuclear waste dump" at Yucca Mountain. It was also frequently pointed out that there were no operating nuclear power reactors within Nevada.

A series of legal, technical, and political challenges to Yucca Mountain that followed resulted in serious delays, as the state and local governments did everything possible to block the repository. The level of detail required for site characterization and site performance increased exponentially in response to changing requirements as Congress tried to appease Nevada politicians, who found the issue to be perfect for firing-up their base.

Every potentially negative finding at Yucca Mountain, no matter how thin, was amplified by opponents into a showstopper that would shut down the site for good. For example, the mineral deposits inside fractures along a fault adjacent to the mountain were determined to have originated from rainwater percolating downward through calcite-rich soils. One scientist disagreed, however, and interpreted these as hydrothermal minerals that had been brought up from below, which would have caused serious problems with site suitability. Literally millions of dollars were spent to investigate the origin of these fracture fillings. Stable isotope data eventually revealed that the fracture fill was a low-temperature mineral deposit much closer chemically to soil minerals than to known high-temperature hydrothermal deposits in the area.

The issue with the fracture minerals and other, similar alarms raised during the site characterization process were unable to demonstrate that Yucca Mountain had any fatal technical flaws that would preclude its suitability as a repository. Nevertheless, the constant legal and political battles slowed site assessment down to a crawl and cost significant time and money to address. The program ended up years behind schedule and way over budget.

The nuclear power industry began to protest about the excessive cost of the Yucca Mountain studies, which were being paid for by the nuclear waste fund. They were further angered when the government admitted it was unable to accept the nuclear waste in 1998, as had been promised explicitly in the Nuclear Waste Policy Act of 1982. Without an operating repository at Yucca Mountain and no other viable site even being investigated, the waste was forced to remain at nuclear power plant sites around the country in "dry cask" storage. The failure of the government to accept the waste as required by law has led to additional expenses, more legal battles, and a distrust of government by the power industry. The government paid the electric utility companies $300 to $500 million per year in compensation for retaining the waste.

Spending from the nuclear waste trust fund was halted by President Obama in 2011 when the license application submitted to the Nuclear Regulatory Commission for the Yucca Mountain Repository was withdrawn by the administration. In a judgment responding to a 2013 lawsuit filed by the Nuclear Energy Institute and the National Association of Regulatory Utility Commissioners, the US Court of Appeals has ruled that nuclear utilities may stop paying fees into the nuclear waste trust fund until either Yucca Mountain is opened as the repository designated by the Nuclear Waste Policy Act, or Congress changes the law. The fee ended on May 16, 2014.

No alternate solution has been proposed to date for dealing with the high-level radioactive waste from the 100 plus nuclear power plants currently operating in the United States and it remains at the reactor sites. A Blue Ribbon Commission appointed by the president reviewed the possible options for nuclear waste disposal after the shutdown of Yucca Mountain (Hamilton and Scowcroft, 2012). The commission recommended a multi-point strategy that included a consent-based approach to siting future nuclear waste facilities, a new organization (i.e., someone other than DOE) to implement the waste management program using the trust funds, efforts to pick up the pieces and move on with developing one or more new geologic disposal facilities and preparations for the eventual large-scale transport of high-level waste to the disposal sites (this was a weak link in the Yucca Mountain Project). The commission expressed hope that a repository would allow continued US innovation in nuclear energy technology and US leadership in international efforts to address nuclear safety, waste management, nonproliferation, and security issues.

In a world of greenhouse gases and climate change, nuclear electricity could be a significant solution to the low-carbon production of energy. However, the failure of Yucca Mountain has left the future of nuclear power very uncertain. The overall lack of a nuclear energy policy and the inability of the government to follow the nuclear waste policies that are already in place have eroded the trust of the nuclear power industry.

The investigations carried out so far at Yucca Mountain, including a five-mile long tunnel complex, numerous drill holes, aquifer tests, geologic mapping, seismic surveys, geochemical investigations, and physical studies of the response of the rock to heat and radiation have produced a huge amount of information about the performance of the site. No disqualifying technical flaws have been found. Walking away from all this and starting over someplace else for reasons that are almost exclusively political would be a huge squandering of time and fiscal resources.

The evolution of high-level radioactive waste storage from a technical issue into a legal confrontation has led to volumes of Byzantine regulations, the near-impossibility of licensing new reactors, and a lack of interest in nuclear engineering among US students. This is a political battle, and as such, it requires a political solution.

As they might say in Texas, “It’s a may-ess.”

Technology versus cost

The successful development of shale gas and tight oil came about because of the convergence of technology and cost. Both of these factors are critical for the viability of any particular form of energy. People often urge the complete adoption of renewable energy sources to combat climate change, but unless the costs are compatible with fossil fuels, the end users of the energy will refuse to pay the price. The high-level appeals that renewables will protect the oceans, stabilize the climate, preserve groundwater, and prevent even more wealth going to Big Oil tend to fall on deaf ears when these options include higher electric bills and greater cost per mile in a vehicle. Many of the renewable energy arguments are being made without discussing any of the economic considerations, which is deceitful when the bottom-line cost is of interest to consumers.

One of the economic conundrums of energy is that some parts of it are treated as a commodity, while other parts are treated as a utility. Electric power is an example of this. The resources fed into the upstream end of the system are essentially commodities, while the downstream distribution system is a regulated utility. For instance, the electric power companies are free to choose among a variety of primary power sources to generate electricity, including coal, natural gas, nuclear, hydro, wind, solar, biomass, and so on. The cost of generating electricity from these various sources can be widely different. Power companies typically use the less expensive sources for baseload, and bring the higher cost sources online to handle high demand peaks. The cost the utility company can charge a consumer per kilowatt-hour is regulated by state utility commissions. Because most electric utilities are funded by investors, power supply is a balancing act to recover enough money to pay for capital and operating costs, give investors a dividend, but avoid clashing with the utility commissions by charging above approved rates.

Utility commissions are in place because electricity, gas, water, sewer, trash pickup, and until recently cable TV and telephone services are supplied by companies with a monopoly on service in a particular area and no competition. This was done for efficiency, to avoid having multiple sets of power lines on the street or duplicate underground gas lines supplying the same customers. As monopolies, however, these companies could charge consumers almost anything they wanted, and the utility commissions are there to prevent this.

In the first decade of the 21st century, natural gas shortages were driving prices to historic highs. Typically, when this happens with an energy commodity like gas, a lot of new producers enter the field, subsequently increasing production and bringing prices down. The downside is the so-called boom and bust nature of the energy business.

The high gas prices being paid at the wellhead inspired George Mitchell to perfect the techniques of horizontal drilling and staged hydraulic fracturing on the Barnett Shale. This combination of favorable economics and new technology was absolutely required to bring shale gas online. In 2008, gas prices being paid to Barnett Shale operators were as much as $12.78 per million Btu (MMBtu), and nearly 200 drill rigs were developing the play. By April 2016, the price of gas had dropped to $2.06 per MMBtu and the Barnett rig count was at zero (Baker, 2016). Conventional wisdom among Barnett operators is that the break-even price for gas from this formation is around $6.00 per MMBtu and interest in this play is not likely to rekindle until gas gets back to that price.

This concept of a break-even price applies to all O&G operations. Bakken oil supposedly requires at least $40 per barrel to cover production costs. Increasing the supply of a commodity without increasing the demand inevitably leads to a surplus and a drop in prices. This concept is from Economics 101, but somehow the O&G industry always seems to be surprised by it.

Thus, we have seen boom and bust cycles in shale gas and tight oil that mimic those of conventional O&G production. As commodity prices go up, the cost of new technology to increase production becomes more favorable. The increased production results in falling prices, the new technology is no longer as cost-effective, and production declines. This roller coaster-like, self-correcting nature of the oil and gas business provides a none-too-gentle method for balancing supply and demand. Although it works over the long run, the cycles are hard on both companies and workers who face safety risks from an influx of inexperienced help during boom periods, and financial strains from cutbacks and layoffs during bust times.

One way to help even out the boom and bust roller coaster ride is for the industry to look at the demand side of the energy equation, not just supply. For example, the huge increase in natural gas supply that came from the shale boom could have been balanced if new uses had been found for the gas. There are only so many furnaces, stoves, and hot water heaters out there. New markets for natural gas could have offset the surplus and maintained wellhead prices at a more sustainable level. The segregation of the energy industry into upstream, midstream, and downstream sectors works against such a balance between energy supply and demand.

One new use for gas that did come about was the conversion or replacement of coal-fired electrical generation with natural gas. Many electric utility companies began adopting gas because it was less expensive to capitalize and less expensive to operate than coal (Soeder, 2017). A positive side effect was an overall decrease in carbon dioxide (CO_2) emissions by the United States over the past decade, because natural gas creates only about one third of the CO_2 per Btu compared to coal.

The large quantities of shale gas available in the United States would seem to make gas a simple choice for electrical power generation, but there is a complicated history. Electric utilities traditionally have had some anxieties about committing to natural gas because of uncertainty with supply. During the cold winters of 1977 and 1978, gas use was restricted because of supply shortages. These were due partly to price controls, but many people thought conventional natural gas production had peaked. Congress passed the Fuel Use Act to actually prohibit utilities from using natural gas to generate electricity. Gas deregulation under the Reagan administration allowed the Fuel Use Act to expire in 1987, brought a large amount of new production online, and resulted in a natural gas surplus in the 1990s (Soeder, 2017).

Several hundred gigawatts of new natural gas generating capacity were built between 1997 and 2003, only to have the price of gas climb steeply after another apparent peak in conventional production in 2003–04. Gas was available, but became expensive. Much of the new gas-powered generating capacity was idled, resulting in a number of bankruptcies.

Reliability and cost are the two things that concern power plant managers the most when determining the primary power source for new generating capacity. Coal won out over gas on both of these in the early 2000s. Coal suppliers could easily agree to multi-decade contracts to supply power plants, setting aside a prescribed tonnage of proven mine reserves. As for cost, a former DOE lab director used to point out that it cost more to have a truckload of topsoil delivered than a truckload of coal. Coal is literally cheaper than dirt. Despite these reliability and cost advantages, coal economics are at risk for having the externalized costs passed on directly to the electricity users. This nearly happened in 2010, when Congress considered imposing carbon caps on emissions and requiring power plants to implement carbon capture and storage (CCS) technology, which would have effectively doubled the cost of coal-fired electricity (Soeder, 2017).

Coal has efficiencies in baseload power plants at the multi-gigawatt scale, but once shale gas became abundant, cheap, and reliable, electric power companies began walking away from the smaller coal plants and replacing them with gas. Even if the externalized costs are ignored, coal still has handling costs not found with natural gas, including unloading barges or rail cars, transporting the fuel to the boiler, generally after some kind of processing or comminution to produce a uniform size, and then dealing with the solid combustion products such as fly ash and bottom ash, which must be trucked away for disposal. Natural gas, in comparison, can be brought right up to the burner tip by a pipeline and the combustion products are gaseous water vapor and CO_2, which do not have to be hauled away.

Natural gas power plants typically use a gas turbine that looks like a stationary jet engine to power a generator. The hot exhaust from the back end of the turbine is then captured to boil water, which powers an additional steam turbine. This so-called "combined cycle" (CC) plant is extremely efficient and cost-effective. The superior economics of CC natural gas power plants have been the main reason for the decline in coal-fired electricity and coal mine production over the past decade, not additional environmental regulations (which are actually attempts to reduce externalized costs) or any imagined "War on Coal." More details on electricity costs are discussed in the next section.

A second area of new use where natural gas could have made significant economic inroads to increase demand but so far has not is as a vehicle fuel. Calculations suggest that if three quarters of the existing fleet of gasoline-powered vehicles in the United States were to be replaced by natural gas vehicles, foreign oil imports would be completely unnecessary (Soeder, 2017). Current natural gas production would have to increase by 50 percent to meet demand, but all other petroleum products could be supplied by current levels of domestic crude oil production. The United States would not need to import a single drop. Displacing imports has been a stated policy goal of the United States since the OPEC oil embargo of 1973–74.

In addition to offsetting imported oil, a second major advantage natural gas has over gasoline is greatly improved urban air quality. Because the methane molecule is so simple, natural gas combustion products consist of CO_2 and water vapor, with perhaps some nitrous oxides if the flame is not properly oxygenated. Combustion products from the complex organic molecules that make up the bulk of gasoline react with sunlight and moisture to form brown hazes or smog. As described in the previous chapter on environmental issues, one of the most harmful pollutants in smog is ozone, created by sunlight-driven reactions in the atmosphere among gasoline combustion products like aldehydes. Ozone can cause serious human health effects, harm birds and mammals, damage vegetation, and crack rubber and polymer materials. If natural gas replaced petroleum as a vehicle fuel, air quality in current nonachievement urban areas would improve significantly.

An advantage that natural gas holds over hybrids and electric vehicles is that the type of vehicle capable of running on natural gas is widely distributed throughout the United States, and most people, in fact, already own one. A standard, gasoline-powered, internal combustion engine in an automobile will operate on compressed natural gas (CNG) with a simple conversion (Soeder, 2017). Natural gas as a transportation fuel offers a significant cost savings over the same energy equivalence of gasoline, and such a conversion should pay for itself fairly quickly. In the United States, the most common natural gas-fueled vehicles at present are transit buses, which return nightly to a central garage with CNG refueling capabilities. For this idea to expand and make a serious dent in imported oil, CNG refueling capabilities must be added to people's homes and at widespread service station locations.

Economics of different energy sources

A good way to understand the economics and efficiency of energy resources is to compare the cost of electricity generated by different methods. Electricity cannot make new power, but can only transform an energy source from one form to another. The energy sources that create power are called "primary," and electricity is the means by which the energy is then transmitted elsewhere to do work.

For example, burning coal heats up water to make steam. The steam turns a turbine, which turns a generator, which makes electricity that is then transmitted through wires to a house, where it flows through the resistance heating element of an electric stove and is converted back into heat to boil water in a kettle for tea. Although it is more efficient to just burn the coal directly under the tea kettle, the kettle would then be committed to coal. Electricity has the ability to heat the kettle with primary energy sourced from oil, nuclear, hydroelectric, biomass, wind, solar, geothermal, and natural gas, as well as coal. Forty years after the OPEC oil embargo, which clearly demonstrated the hazards of putting too many eggs in too few baskets, this primary power diversity suggests that it is still wise to pursue an "all of the above" energy strategy to ensure that not every energy resource is vulnerable to the same threats.

Electricity use fluctuates with the time of day, day of the week, and season of the year. Generating electricity is a complicated balancing act known as "dispatch," which is a dynamic process of constantly adjusting the supply to meet fluctuating demands. Electricity supply is comprised of both "baseload" and "peak load" power sources. Baseload provides a constant, relatively low-level of background power in the system to meet minimal demands. Baseload is supplied by the cheapest, steadiest power, and almost always comes from sources that are difficult to start or stop quickly, such as big coal power plants, large hydroelectric dams, and nuclear reactors. When demand for electricity increases above this baseload, such as on a hot summer day when air conditioning is widely in use, additional generating capacity is brought online to meet these peaks. Peak load electricity is more expensive to generate than baseload, but it can respond quickly to meet sudden spikes in demand. Small coal steam plants, run-of-the-river hydro plants and natural gas plants are often used as power for this so-called "peak shaving." The more expensive generating capacity is brought online only as the peak demand climbs above the available lower-cost supplies. The US power grid is now interconnected in such a way that electricity supplies can be transmitted over fairly long distances to meet peak demands.

Cost of electricity varies widely between the different primary energy sources. Two categories of cost must be considered because both drive daily decisions in the real world of electrical supply and dispatch. These are capital expenses (CAPEX), or the funding needed to construct a power plant, and operation and maintenance expenses (OPEX), the funding needed to operate the plant and generate electricity. Both of these can vary considerably among different primary energy sources and operating costs can even vary on a single source based on factors like percent capacity in use, seasonal factors, or other reasons. Cost-of-electricity data are collected by the US Energy Information Administration (EIA), which distills them down for side-by-side comparisons.

Table 7.1 summarizes the "levelized" cost of electricity (U.S. Energy Information Administration, 2018). Costs are given in 2017 dollars per megawatt-hour, but are an attempt to project the costs for power plants entering service in 2022. Costs include capital expenses, operation and maintenance (O&M) costs, and transmission costs adding up to a total Levelized Cost of Electricity (LCOE). Tax credits are then subtracted out to produce a net cost. The absolute numbers are less important than the relative comparison of cost among different primary power sources. Coal-fired electricity is listed in Table 7.1 with both 30% and 90% carbon capture and storage (CCS). It is interesting for the EIA to have assumed that this presently externalized cost will be part of the cost of electricity by 2022, and it makes coal-fired electricity one of the most expensive options on the table. The cheapest electricity is onshore wind and geothermal, both because of significant tax credits. Combined cycle (CC) natural gas electricity is so efficient that even with CCS it still ranks near the middle in cost. Solar thermal and offshore wind are very expensive despite massive tax credits. These two power sources have very high CAPEX and high OPEX. Solar thermal requires acres of precision mirrors to focus sunlight into a hot spot on a central tower. Offshore wind runs into the high construction costs typical in a marine environment. When people wonder why more renewable energy is not widely available in the United States, these costs are the reason.

Another interesting column of data in Table 7.1 is labeled "capacity factor," and given as a percentage. This defines the amount of time a power plant is online, versus being

Table 7.1 Estimated levelized cost of electricity ($/MW-h).

Plant type	Capacity factor (%)	Levelized capital cost	Levelized fixed O&M	Levelized variable O&M	Levelized transmission cost	Total system LCOE	Levelized tax credit[a]	Total LCOE including tax credit
Dispatchable technologies								
Coal with 30% CCS[b]	85	84.0	9.5	35.6	1.1	130.1	NA	130.1
Coal with 90% CCS[b]	85	68.5	11.0	38.5	1.1	119.1	NA	119.1
Conventional CC	87	12.6	1.5	34.9	1.1	50.1	NA	50.1
Advanced CC	87	14.4	1.3	32.2	1.1	49.0	NA	49.0
Advanced CC with CCS	87	26.9	4.4	42.5	1.1	74.9	NA	74.9
Conventional CT	30	37.2	6.7	51.6	3.2	98.7	NA	98.7
Advanced CT	30	23.6	2.6	55.7	3.2	85.1	NA	85.1
Advanced nuclear	90	69.4	12.9	9.3	1.0	92.6	NA	92.6
Geothermal	90	30.1	13.2	0.0	1.3	44.6	−3.0	41.6
Biomass	83	39.2	15.4	39.6	1.1	95.3	NA	95.3
Nondispatchable technologies								
Wind, onshore	41	43.1	13.4	0.0	2.5	59.1	−11.1	48.0
Wind, offshore	45	115.8	19.9	0.0	2.3	138.0	−20.8	117.1
Solar PV[c]	29	51.2	8.7	0.0	3.3	63.2	−13.3	49.9
Solar thermal	25	128.4	32.6	0.0	4.1	165.1	−38.5	126.6
Hydroelectric[d]	64	48.2	9.8	1.8	1.9	61.7	NA	61.7

CCS, carbon capture and sequestration; *CC*, combined cycle (natural gas); *CT*, combustion turbine; *PV*, photovoltaic.

[a]The tax credit component is based on targeted federal tax credits such as the PTC or ITC available for some technologies. It reflects tax credits available only for plants entering service in 2022 and the substantial phase out of both the PTC and ITC as scheduled under current law. Technologies not eligible for PTC or ITC are indicated as *NA* or not available. The results are based on a regional model, and state or local incentives are not included in LCOE calculations.

[b]Because Section 111(b) of the Clean Air Act requires conventional coal plants to be built with CCS to meet specific CO_2 emission standards, two levels of CCS removal are modeled: 30%, which meets the NSPS, and 90%, which exceeds the NSPS but may be seen as a build option in some scenarios. The coal plant with 30% CCS is assumed to incur a 3 percentage-point increase to its cost of capital to represent the risk associated with higher emissions.

[c]Costs are expressed in terms of net AC power available to the grid for the installed capacity.

[d]As modeled, hydroelectric is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

Source: Modified from U.S. Energy Information Administration, 2018. Levelized Cost and Levelized Avoided Cost of New Generation Resources. Annual Energy Outlook 2018, 20 p.

down for maintenance, refueling, or simply not operating (like solar plants at night). The capacity factor has an important impact on the cost of electricity, and it also influences the selection of a primary power source for generation. Power companies look askance at a high CAPEX primary power source like solar thermal that is online only a quarter of the time. Despite their other problems, nuclear power plants produce electricity 90% of the time, as do geothermal and natural gas CC plants. Wind and solar are notorious for having low capacity factors, and because of this, power from these sources is considered non-dispatchable.

Power storage has become a barrier to the wider implementation of wind and solar due to the intermittent nature of these sources. If power could be stored efficiently on a windy day to provide electricity on a calm day, many more wind turbines would be in use. Direct storage options include various types of batteries, which are expensive and have a limited number of recharge cycles. Some lithium ion batteries may also create enough heat to catch on fire. Indirect power storage options include compressed air energy storage (CAES), which injects pressurized air into an underground reservoir until needed to drive a generator and produce electricity. A similar option involving water is called pumped-storage and puts water into a hilltop reservoir during times of abundant electricity, where it is available to generate hydroelectric power. CAES is somewhat more compact land-wise than pumped-storage, but neither are very efficient.

Efficiency: One measure of the efficiency of a power plant to convert fuel into electricity is called the "heat rate," which is defined by the US Energy Information Administration (EIA) as the amount of energy used by a power plant to generate 1 kW-hour (kWh) of electricity. For coal, petroleum, natural gas, and nuclear prime energy sources, the heat rate is expressed as Btu per kWh generated. To determine the efficiency of electrical generation as a percentage, the Btu content of a kWh of electricity (3412 Btu) is divided by the by the heat rate. Thus, from EIA data we obtain the following conversion efficiency to electricity:

Coal: 10,043 Btu/kWh = 34%
Petroleum: 10,199 Btu/kWh = 33%
Natural Gas: 11,176 Btu/kWh conventional turbine = 30%
Natural Gas: 7649 Btu/kWh combined cycle = 45%
Nuclear: 10,459 Btu/kWh = 33%

Because power from renewable energy sources like wind and solar is produced without fuel combustion, there are no equivalent Btu conversion factors for these energy sources. The EIA has attempted to represent this several different ways for comparison with heat-sourced electricity. One method is "fossil fuel equivalence" in which the electrical output of a renewable source is back-calculated to determine the amount of fossil fuel-derived energy that would be required to produce the same electricity. This approach evolved in an era when the primary goal of US energy policy was to reduce dependence on imported petroleum and indicated the amount of fossil energy that would be displaced by a renewable energy source. Two more recent approaches used for determining the efficiency of renewables are called captured energy and incident energy equivalents.

Captured energy is the energy measured as the “output” of the device, such as electricity from a wind turbine or solar plant. The fixed factor of 3412 Btu/kWh for the electricity generated is used to measure the renewable energy required for electric generation for noncombustible renewables. The noncombustible renewable energy that is captured for economic use is counted as primary energy. The obvious fallacy of this approach is that it determines all renewable sources to be “100% efficient” because it only counts the captured energy. On the one hand, renewables like solar and wind don’t exactly “waste” energy that is not converted to electricity - it is not like there is some other market for the wind that blows around a turbine. However, the conversion process of renewable energy into electricity can be very inefficient physically and this approach does not accurately measure the physical consumption of energy used to produce electricity from these resources.

The incident energy approach uses the actual or estimated energy efficiencies of renewable technologies to determine the Btu value of the input energy used to produce the electricity. Thus, “incident energy” is defined as the gross energy that first strikes a renewable energy conversion device. For example, the efficiency of a solar photovoltaic plant is estimated empirically from the actual percentage of solar radiation striking the solar panel that is converted to electricity. For wind, this would be the energy that passes through the rotor disc, for hydroelectric, the energy contained in the water passing through the penstock, and for geothermal, the energy contained in the hot fluid at the surface of the wellbore. Few renewable energy plants actually keep track of cumulative input energy, so energy efficiencies derived from this approach remain estimates.

Conversion efficiencies of renewables published by EIA are:

Wind: 26%
Solar Thermal Power: 21%
Solar Photovoltaic: 12%
Conventional Hydroelectric: 90%
Geothermal: 16%

Descriptions of primary energy sources

The major energy sources for generating electricity shown in relation to their relative contribution to US electricity in Table 7.2.

Table 7.2 US electricity generation by source, amount, and share of total in 2017.

Energy source	Billion kWh	% Of total
Total - all sources	4034	
Fossil fuels (total)	2536	62.90%
Natural gas	1296	32.10%
Coal	1206	29.90%
Petroleum (total)	21	0.5%
Petroleum liquids	12	0.3%
Petroleum coke	9	0.2%
Other gases	12	0.3%
Nuclear	805	20.0%
Renewables (total)	687	17.0%
Hydropower	300	7.4%
Wind	254	6.3%
Biomass (total)	63	1.6%
Wood	41	1.0%
Landfill gas	12	0.3%
Municipal solid waste (biogenic)	7	0.2%
Other biomass waste	3	0.1%
Solar (total)	53	1.3%
Photovoltaic	50	1.2%
Solar thermal	3	0.1%
Geothermal	16	0.4%
Other sources	13	0.3%

Source: Modified from U.S. Energy Information Administration.

Details about each of the major energy sources are summarized below. While it is tempting to see only the best or worst aspects of each energy source, cradle-to-grave costs and efficiencies must be considered in their entirety. Each energy source in the summary below follows the same format: percentage contribution to total US electricity generation, description, energy source factors, social and environmental aspects, electricity generated by unit, generation efficiency, and capacity factor. This information was retrieved primarily from EIA webpages and reports.

Coal

Percentage of US electricity generation: 29.9%

Description

These power plants burn coal to boil water and create pressurized steam that is used to power a turbine. The turbine turns a generator, making electricity. A cooling system then condenses the steam back to water, which is returned to the boiler and reused. Coal power plants have economies of scale and many modern facilities are in the multiple-gigawatt size range. There are a number of ways to burn coal that increase efficiency. One method commonly used is called "fluidized bed" combustion, where sand-sized particles of pulverized coal are suspended in an updraft of incoming air. The particles are exposed to oxygen on all sides and their small size causes them to burn quickly and efficiently.

A small amount of limestone is often added to the combustion chamber to react with sulfur compounds and form calcium sulfate ($CaSO_4$) in the flue gas. Without the limestone, the sulfur would oxidize and vent up the stack as sulfur dioxide (SO_2), becoming H_2SO_4, or sulfuric acid once it came in contact with rainwater. Acid rain from coal power plants was devastating to lakes, streams, and many buildings in the eastern US until the simple solution of adding limestone was implemented. Some coal power plants capture the $CaSO_4$, also known as the minerals anhydrite or gypsum and sell it to nearby manufacturing facilities to make plaster or drywall. Other material trapped from the flue gases may include mercury, selenium, cadmium, and other toxic or heavy metals.

The noncombustible solid materials in the coal form ash, which can either float up the stack with the flue gases as "fly ash," or fall to the bottom of the combustion chamber as "bottom ash." Fly ash is captured by electrostatic precipitators that use a strong electrical charge to keep the ash from leaving the stack. Both fly ash and bottom ash must be removed periodically and hauled away for disposal, often to a nearby impoundment. The ash and other mineral products associated with coal are being investigated as potential sources for rare earth elements (REE), which are needed for a number of modern technologies.

Energy source factors

Coal is primarily obtained by surface mining (sometimes called "strip mining," but not by the industry) and underground mining. There are two main sources of power plant coal in the United States: (1) Pennsylvanian-age coals in eastern basins like the Appalachian, Illinois, and Black Warrior, and (2) Paleocene-age coals in western states such as Wyoming, Colorado, and Montana. The eastern coals tend to be higher in grade, ranging from bituminous to anthracite, but also tend to be higher in sulfur. Some of the eastern coal seams are considered metallurgical coals suitable for steelmaking, and can command a higher price than the run-of-the-mine coal that is used in power plants. Western coals are lower grade, ranging from lignite to subbituminous, but are also lower in sulfur. These lower-grade coals provide less Btu value per ton, so more fuel is needed per megawatt compared to eastern coals, but the reduced sulfur content also makes them economical.

Because of their increasing efficiency with larger sizes, the land footprint of a coal power plant can be quite substantial. There typically needs to be sufficient space to unload and store significant amounts of coal feedstock. Coal is often processed at the mine to create uniform-size particles ("comminution"), remove noncombustible minerals, and provide other conditioning to improve performance. Increasing numbers of power plants are using this so-called "refined coal," but if the precombustion cleaning, comminution and conditioning has to be done at the power plant site, this requires even more land. Large cooling towers might be necessary for plant operations, and sufficient land area for gathering and handling the postcombustion products is also needed. Many coal power plants are located along waterways or large rivers like the Ohio to facilitate the delivery of coal via barges or railroads. Some large surface coal mines, such as Wyodak near Gillette in eastern Wyoming have a power plant on-site to utilize the coal at the mine and sell electricity directly into the national grid.

Social and environmental aspects

Coal-fired power plants, especially the large-scale plants, are vast facilities that dominate the landscape. Their towering stacks are visible from miles away. Few people would want to live across the street from one, and they are usually relegated to industrial areas.

In addition to acid rain and heavy metals, which have been mitigated as emissions from the stacks in most plants, the most significant remaining environmental concern with coal-fired electricity is CO_2. Coal is nearly pure carbon, so when it burns, CO_2 is the primary combustion product. Natural gas produces 1/3 the CO_2 per Btu than coal and even petroleum-based fuel like heavy oil produces 2/3 the CO_2 per Btu. Carbon capture and storage (CCS) of this greenhouse gas is essential to the future of coal. Power plants are in fact considered ideal for the implementation of CCS because they are a "fixed source." Carbon capture is much more challenging on a mobile source like a car.

The surface mining of coal is incredibly destructive to landscapes and watersheds. In particular, the practice of "mountaintop removal" mining that is common in Appalachia has proven to be devastating to the environment.

Electricity generated by unit

Coal-fired power plants become more economical with size. Generation capacity of older plants is typically in the 500 MW range; newer plants often have a capacity of 1–3 GW.

Generating efficiency

Coal-fired power plants are about 34% efficient.

Capacity factor

Coal-fired power plants typically provide baseload power and are online about 85% of the time.

Natural gas

Percentage of US Electricity Generation: 32.1%

Description

Natural gas power plants generate electricity using gas turbines that look and sound a lot like a big jet aircraft engine mounted to the floor. Many of these turbines are actually manufactured by major aircraft engine brands such as Pratt and Whitney or General Electric. Like a jet engine, the gas turbines have a compressor at the front that forces air into a combustion chamber. Natural gas is injected into this chamber and burned. The hot exhaust then turns a series of turbine blades as it exits out the back of the engine.

The turbine powers the compressor in the front and also turns an electrical generator. Most natural gas generation uses an efficient and economical combined cycle system that captures the hot exhaust from the gas turbine and uses it to boil water, creating pressurized steam to turn a second turbine and another generator.

Natural gas power plants can be constructed and made operational fairly quickly. The gas turbines are essentially off-the-shelf items that can be purchased from major suppliers. The land area footprint needed for a natural gas plant is considerably smaller than that needed for a similar-size coal plant. Gas plants have no requirement for a yard to stockpile fuel, a precombustion cleaning, comminution and conditioning processes, conveyor belts to move materials, or provisions for handling volumes of ash and other combustion products. They typically consist of relatively modest industrial building, often a standard steel prefabricated construction, set on a few acres of land with power lines and a substation. The electrical generation process is contained within the building and the only emissions are water vapor and CO_2 exhaust.

Most of the natural gas combined cycle power plants in the United States are less than 10 years old. The CC system of running two generators for the price of one is very economical. Referring back to the cost of electricity comparison in Table 7.1, CC natural gas has the lowest cost of electricity per megawatt-hour for any source on the table not subsidized by tax credits. When combined with the abundance of shale gas and resulting low natural gas prices, generating electricity using CC natural gas is quite economical and has replaced coal as the primary source of electricity in the United States.

This has had several unexpected side effects, including an overall reduction in CO_2 emissions for the United States compared to a decade ago, and the shutdown of a number of coal mines with layoffs for many miners. As mentioned above, natural gas has a third of the CO_2 emissions compared to coal on a per-Btu basis. The ascendancy of CC natural gas displacing older coal fired plants has resulted in a measurable reduction of US CO_2 emissions.

The coal industry obstinately refused to acknowledge the increasing production of shale gas during the first decade of the 21st century, even though much of it was happening in the Appalachian basin where they couldn't help but notice. Many out-of-work coal miners were told that their layoffs were due to what was being called the "War on Coal," a myth promulgated by coal companies to blame mine closures on supposedly excessive environmental regulations imposed on mines and coal users by the US Environmental Protection Agency. In fact, it was cheap gas, or more precisely, cheap electricity from cheap gas that closed the mines. As of this writing, the environmental regulations have been relaxed by the Trump EPA, but the economics of coal have not improved. Only a few coal companies, such as Consol in Pittsburgh developed shale gas divisions and got in on the boom. Many others have gone bankrupt.

Energy source factors

"Nonassociated" natural gas is produced from conventional oil and gas fields where it is trapped in a reservoir above water or brine. Shale gas is also considered to be nonassociated when produced without oil. "Associated" natural gas is either trapped with or dissolved in petroleum and is produced from both conventional oil reservoirs and tight oil plays. When possible, conventional associated gas is retained in the trap at the top of an oil reservoir to provide pressure for oil production. This so-called "gas drive" pushes the oil into production wells, where it flows freely to the surface without the need of a pump. Gas dissolved in the petroleum will exsolve out at lower pressures on the surface. This was the source of much of the gas being flared from the Bakken production because pipelines were not in place to capture it. The largest quantities of US natural gas are being produced directly from shale source rocks. The single largest gas-producing formation in the United States as of this writing is the Marcellus Shale.

Social and environmental aspects

Natural gas power plants are rarely noticed by the public. Unless a former coal plant location has been retrofitted with gas turbines and remains an imposing edifice on the landscape, natural gas power plants are almost invisible. They are usually placed in a nondescript, moderate-size industrial building with relatively small exhaust stacks, and except for all the power lines in the vicinity, they blend in well with other industries. The environmental impact is low, except for CO_2 emissions, which can be solved with CCS. It is interesting to note on Table 7.1 that even when equipped with CCS, the cost of electricity from a combined cycle gas turbine power plant is still in the middle part of the price range.

Electricity generated by unit

Gas turbines can generate up to about 500 MW per unit. A combined cycle gas/steam system can generate about 50% more electricity, up to around 750 MW per unit. Most natural gas-fired power plants utilize an array of multiple turbines.

Generation efficiency

Combined cycle gas/steam generation is about 45% efficient. A conventional gas turbine without combined cycle is only about 30% efficient because a lot of the heat energy is wasted.

Capacity factor

Combined cycle gas/steam generation is baseload power that is online about 87% of the time. Conventional gas turbines without combined cycle are primarily used only for peak shaving and thus are online about 30% of the time.

Petroleum

Percentage of US Electricity Generation: Less Than 1%

Description

Electrical generation using oil-fired power plants used to be more commonplace, but after the OPEC oil embargo of 1973—74, it fell out of favor. Utility companies that employ petroleum as their primary fuel make up only about 3% of the total generating capacity in the United States and produce less than 1% of the total electricity. Oil-fired generators are either turbines or internal combustion piston engines. The turbine generators can use the oil directly like a jet engine, or the oil is burned as a heat source in a boiler to make steam that drives the turbine. Steam turbines are often capable of switching between boiler fuels and power plants that normally burn natural gas may utilize petroleum during times when natural gas may not be available. This complicates the capacity factor calculation, but in most cases for petroleum-fueled power plants, it is quite low.

Because of the high price of petroleum relative to other fuels, air pollution restrictions, and lower efficiencies of the aging, oil-fired generating technology, petroleum is typically used to supply power only for peak shaving or when very cold weather in places like New England places a high demand on the local natural gas supply. The great majority of US oil-fired generators are located in coastal states with access to marine ports. Because coal is primarily transported by rail, oil delivered by ships was more cost-competitive in the 1970s for places like Florida and Hawaii. At one time, nearly all of the electricity generated in Hawaii was from oil. However, the cost and environmental problems of petroleum-generated electricity are forcing these states to move toward other options, such as solar, wind, and geothermal. No significant, new utility-scale oil-fired generators have been commissioned since the 1990s.

Energy source factors

Oil-fired power plants burn petroleum liquids, such as distillate or residual fuel oils. The heavy residual oil left behind after gasoline, diesel and other light hydrocarbons are refined from crude oil can be used as a relatively cheap, low-grade fuel. Ocean-crossing cargo ships typically power their engines with this heavy residual fuel, which is carried in the ship’s bunkers and known as bunker oil. Bunker oil was delivered in large quantities to maritime states like Hawaii and Florida for the purpose of refueling ships and was thus made available for running generators onshore.

Oil-fired power is still in use on construction sites and in isolated areas where a compact generator is needed. Appalachian basin shale gas drillers discovered that an internal combustion diesel generator will run on a mixture of 80% natural gas and 20% diesel. For operations where natural gas is available, such as in an existing gas field, this can save considerably on fuel costs.

Social and environmental aspects

A fundamental shift in the perception of oil as a utility fuel occurred during the 1970s when world oil markets experienced sharp price increases after the OPEC oil embargo, the Iranian Revolution, and the Iran—Iraq war. Social conventions that oil should be conserved as a transportation fuel also discouraged additional petroleum-fired generating capacity in the United States. Oil-fired power plants, especially those burning heavy bunker oil, were never described as "clean." Most of the emissions were fine particulate matter (PM_{10}) instead of the toxic metals emitted by coal, but the pall of greasy black smoke across the landscape was not pleasant.

Electricity generated by unit

Oil-fired turbines are usually in the few hundred megawatt range.

Generating efficiency

Oil-fired power plants are about 33% efficient, with the steam turbines being slightly more efficient than combustion turbines or internal combustion engines.

Capacity factor

Oil-fired steam turbines are online about 10 percent of the time and approach 20% only in summer months to meet demand peaks. Oil-fired combustion turbines and internal combustion engines are online about 5% of the time and are only used for peak shaving.

Nuclear

Percentage of US Electricity Generation: 20%

Description

There are two main types of nuclear power reactors in the United States: boiling water and pressurized water. All nuclear power plant reactors use the process of nuclear fission, or the splitting of heavy atoms into lighter atoms, to create heat. The water inside a pressurized water reactor is held under pressures as high as 2000 pounds per square inch (psi). This allows the water to get very hot while remaining in a liquid state, which makes it easier to pump and circulate. The pressurized water passes through a heat exchanger where a secondary water system is used to create steam to run a turbine and generate electricity.

The boiling water reactor creates steam inside the reactor vessel itself, and this steam is used directly to run a turbine and generator. Since it employs just a single loop, the boiling water method is a simpler design, but it does allow potentially radioactive water from inside the reactor to contact the turbine blades. The pressurized water system is considered inherently safer because the radioactive water inside the reactor vessel is contained by a closed loop and nothing is released from the reactor except heat.

Overheating of the reactor core was the ultimate result of the disasters at Three Mile Island in 1979, Chernobyl in 1986, and Fukushima Daiichi in 2011. Despite these accidents, nuclear electricity is a non-GHG emitting alternative to fossil fuels and must be considered as an option in a climate-constrained world. New reactor designs use smaller cores that are much less prone to overheating and core meltdown in the event of a loss of coolant accident. The new engineering is attempting to speed up the licensing and commissioning process by using standardized architecture, remote manufacturing and assembly on location, and smaller, modular reactors that can be grouped together to provide power, and located closer to cities to reduce long-distance transmission losses. Before nuclear power can make a comeback, however, the nuclear waste problem described earlier at Yucca Mountain needs to be solved, because most utilities will be reluctant to commit to new reactors while being stuck with large quantities of high-level radioactive waste from existing reactors.

Most existing nuclear reactors in the United States are more than 40 years old. Reactor licenses are typically valid for 40 years of operation, and plants can apply for extensions of operations every 20 years. The first utility-scale nuclear power plant in the United States (and the world) was the Shippingport Atomic Power Station located on the Ohio River near Shippingport, Pennsylvania about 25 miles (40 km) west of Pittsburgh (Fig. 7.2). Construction began in September 1954 and the plant began operations in 1957. Although it produced power for 30 years, the Shippingport facility was also used for a variety of reactor experiments with different fuel mixtures and isotopes. It was decommissioned in December 1989 and replaced with the larger Beaver Valley Nuclear Generating Station on the same site.

FIGURE 7.2 The Shippingport Atomic Power Station on the Ohio River west of Pittsburgh, PA, the first commercial nuclear reactor in the United States. US Department of Energy photograph.

Social and environmental aspects

Opinions on nuclear fuel are divided. The disasters and reactor meltdowns at Three Mile Island, Chernobyl, and Fukushima Daiichi raised renewed fears among the public about the risks of the catastrophic failure of this technology. However, each of these mishaps led to the recognition of previously unknown problems and resulted in major safety improvements in nuclear facilities worldwide. Nuclear power today is considerably less risky than electricity generated from the early reactors of the 1950s and 1960s.

Nuclear electricity is climate neutral because there are no CO_2 emissions and under normal operations it contaminates neither air nor water. The solid spent fuel is the only waste product. Because the uranium fuel is mined from the ground, it is not considered a renewable energy resource. However, it is possible to remove the impurities from spent fuel by chemically processing the pellets, which reconcentrates the fissionable materials and allows the fuel to be reused. This is a much more efficient use of the mined uranium compared to the current once-through procedure. Reprocessing also has the benefit of reducing the total amount of nuclear waste that must be safely disposed of in the end.

The problem with reprocessing is that one of the byproducts in the spent fuel is plutonium, formed when uranium 238 captures a neutron to become uranium 239, which then gains an electron and transforms into plutonium 239. Because plutonium is a different element, it can be chemically separated from uranium and used to make atomic weapons. The Carter Administration banned the reprocessing of nuclear fuel in the 1970s because of nuclear proliferation fears. This issue is now mostly moot, because many of the countries the United States was the most concerned about for nonproliferation have since developed or obtained their own nuclear weapons. It is important to realize that the first atomic weapon was tested in 1945, and by today's standards, the technology is pretty simple. It should also be noted that France has been reprocessing spent reactor fuel for decades without mishaps and Japan is setting up to do the same. If nuclear power is to have a future in the United States, the reprocessing of spent fuel needs to be seriously reconsidered. Likewise, new reactor designs, including smaller-scale molten salt reactors using nuclear fuel based on thorium promise to be much safer. Thorium fuel creates a lighter isotope of uranium and does not produce the heavy "transuranic" wastes that lead to nuclear proliferation concerns.

Electricity generated by unit

Older nuclear reactors generated between 500 MW and 1 GW per power plant. Two new plants currently under construction in South Carolina and Georgia are expected to generate between 1.5 and 2 GW per plant.

Generating efficiency

Nuclear power plants are about 33% efficient at converting heat to electricity. The separate reactor/generator systems and heat exchangers contribute to losses.

Capacity factor

Nuclear plants provide baseload power and are online about 90% of the time.

Hydroelectric

Percentage of US Electricity Generation: 7.4%

Description

There are two types of hydroelectric plants. Large, baseload hydro plants use water trapped in impoundments behind dams to spin turbines and create electricity as it passes through a dam. The passageway for water through the dam is by way of large pipes called penstocks; these direct the water flow onto the turbine blades. Smaller, so-called "run-of-the-river" hydropower plants don't use a dam, but have an upstream intake and a downstream discharge and simply divert a part of the river flow through a pipe to spin a turbine, usually just for peak shaving.

The life of a hydroelectric power plant is defined by sedimentation, which will eventually negatively impact power production. Moving water carries sediment entrained by the current. Once that water slows down upon entering an impoundment behind a dam, the sediment drops out and builds up in the pool. Most dams are fifty to a hundred or more years old and sedimentation has become a problem for many. For example, the power plant at the Gavins Point dam on the Missouri River near Yankton, South Dakota has an estimated lifespan of only about 100 years. The original design for this impoundment was for 200—250 years, but the engineers underestimated the amount of sediment added to this reach of the Missouri River by the Niobrara River, a tributary that enters upstream of the dam. Larger pools can cope better with sediment and tend to have longer lifespans. Lake Oahe, the large impoundment created behind the Oahe Dam on the Missouri River above Pierre, South Dakota is estimated to have a lifetime of 1200 years for power generation. Hoover Dam on the Colorado River near Las Vegas that impounds Lake Mead is estimated to have an operational lifetime of 4000 years, approximately the age of the great pyramids in Egypt. If humanity wipes itself off the planet in future decades, Hoover Dam will continue to produce electricity for many centuries to come.

Energy source factors

The energy used to generate electricity comes from flowing river water, converting gravitational potential energy into kinetic energy. All major rivers in the United States have already been dammed and concerns about the environmental impact of dams on riverine ecosystems have put an end to large-scale hydroelectric projects. Rivers like the Missouri have dams every few hundred miles and the river itself now consist of a series of connected pools. Micro-hydros for small generation have been developed for use in streams or creeks, but the technology is not common and does not receive any tax incentives like other renewables.

Most large dams are federal projects and dam maintenance has historically been covered by congressional appropriation. As federal money has gotten tight, dam operators have learned to get better at marketing their electrical production and using these funds for ongoing maintenance and upgrades. Upgrades have increased the productivity of older dams, sometimes by as much as 50%. The dams would not have seen these upgrades were it not for the new funding stream. If the primary purpose for the dam is flood control, storing water in a reservoir for sport, irrigation, or maintaining municipal water supplies, it likely will be maintained. Many smaller dams such as mill dams or small municipal hydroelectric dams, especially in the eastern United States have been decommissioned and removed in an attempt to restore riverine ecosystems.

Social and environmental aspects

Dams and associated hydroelectric power plants have both positive and negative social and environmental impacts. Severe flooding in the 1920s and 1930s led to billions of dollars of losses in crops, homes and infrastructure, as well as many lives, convincing the government that flood control structures were needed along major rivers. The Pick and Sloan Act in Congress authorized the federal government to construct large-scale dams. During the late 1930s, dam construction reached a peak in the United States on rivers like the Tennessee, the Colorado, and the Missouri. Hydroelectric power plants were actually added to many of these dams as an afterthought, because the true concern was floods.

On the negative side, building dams meant ponding large volumes of water upstream, submerging farmland, railroads, towns, and tribal lands along the rivers. Environmental impacts include temperature changes in the water above and below power plants, a lack of sediment to replenish point bars, bottomlands and natural levees, barriers to the migration of fish and other aquatic animals, and changes in water velocity that affected fish, plant life, and wildlife.

Electricity generated by unit

Production of hydroelectricity depends on the individual dam, the amount of water impounded upstream, and the age of the generating facilities. Large dams such as Hoover produce 2 GW of electricity from the original 1930s turbines and generators in the terrazzo-floored, art deco powerhouse (worth a tour just for this). The Oahe Dam on the Missouri River in South Dakota typically produces around 100–110 MW of electric power per year.

Generating efficiency

Conventional hydroelectric power plants are about 90% efficient at converting the energy of falling water into electricity.

Capacity factor

Baseload hydroelectric power plants are online about 64% of the time. Significant amounts of downtime for maintenance are required on these systems. Run-of-the-river peak shaving plants are online 20 to 30% of the time as needed for load offset.

Geothermal

Percentage of US Electricity Generation: 0.4%

Description

Geothermal uses the subsurface heat of the Earth to boil water and turn a steam turbine and generator. Shallow, lower temperature geothermal can be used in "binary" plants to boil a volatile liquid like alcohol and drive a turbine, and "deep-direct use" geothermal utilizes heat from the Earth to keep buildings warm. The lowest temperature geothermal from just a few meters deep is used as a booster for electric heat pumps.

Current geothermal technology requires an active hydrothermal system to bring scalding hot water to the Earth's surface, as in hot springs, geysers, or fumaroles. For this reason, it makes up only a very small proportion of US electrical generation, primarily in California, but there are plans by the US Department of Energy to change this. A concept known as Enhanced Geothermal Systems or EGS is being investigated by DOE and tested at a field site in Utah. The idea is to adapt advanced drilling technology, such as that developed for shale gas production to drill deep parallel boreholes down to hot rock essentially anywhere in the Earth's crust. Such boreholes would probably have to be 6–8 km deep (20,000 to 25,000 ft) to reach rocks at the desired temperatures of 200–400°C. The wells would then be connected to each other through the hot rocks by a network of hydraulic fractures. Water (or another fluid) would be pumped down one well, flow through the fracture system picking up heat, and return to the surface via the other well. The heat would be used in a power plant to generate electricity. If this technology can be made to work in an economical manner, it has the enormous advantage of being able to be implemented almost anywhere on Earth. Hot rock is present in the subsurface everywhere if one drills deep enough. EGS may provide a practical approach to supply electricity to the nearly one billion people on Earth who do not yet have access to power.

The biggest problem with geothermal at present is its limited availability. The only nation in the world that uses significant geothermal power is Iceland, which sits atop a volcanic midocean ridge and generates a quarter of its electricity from geothermal. Overshadowing electricity, the major use of geothermal energy in Iceland, located at 65° N latitude, is deep-direct heating for 90% of all buildings, both public and private. There is enough leftover heat in the capital city of Reykjavik to warm swimming pools, spas, and even to melt ice off roads and sidewalks. The Iceland Deep Drilling Project is testing a series of boreholes that will penetrate supercritical zones at depths of 5 km (16,000 ft) to reach hydrothermal fluids at temperatures ranging from 450°C to 600°C. Fluid from reservoirs hotter than 450°C could result in a ten-fold increase in power output per geothermal well (source: Orkustofnun National Energy Authority).

New Zealand obtains about 13% of its energy from geothermal resources in the Taupo Volcanic Zone on the North Island, and Ngawha geothermal field northwest of Auckland. Several other places with active volcanoes, such as Italy, Indonesia, and the Philippines produce modest amounts of geothermal electricity. However, many places presently without electricity, such as central Africa, areas on the Indian subcontinent, and parts of South America simply don't have access to conventional geothermal resources. Being able to locate an EGS facility where power is needed is critical to the future of geothermal energy. In order to do this economically, the advanced shale drilling and fracking technology must be adapted for EGS. The reason this technology works so well in shale is because it is optimized for shale, with special drill bits, bottomhole assemblies, downhole motors, drilling mud, and operational procedures. Shale drilling did not work very well in the early days when standard oilfield tricone rotary bits were used. EGS will require similar optimization for drilling and fracking to be successful.

Energy source factors

There are two main sources for geothermal energy: active volcanic hydrothermal systems, and radiogenic heat in deep sedimentary basins. Volcanic hydrothermal systems in places like Iceland, New Zealand and California (Fig. 7.3) tend to be very hot, typically above 200 deg C, but geothermal fluids obtained from these systems are often corrosive due to high levels of dissolved hydrogen sulfide, CO_2, and other compounds.

FIGURE 7.3 The Geysers geothermal power plant in California. California State Energy Commission photograph.

Minerals tend to precipitate out of hydrothermal fluids as the temperature changes, creating additional plumbing challenges from scale build-up in the pipes. Designing heat exchangers and other infrastructure that can handle this environment often adds considerably to both commissioning time and CAPEX. At the Rotokawa Power Plant in New Zealand, the rapid build-up of mineral deposits requires that the surface plumbing be replaced on an almost annual basis. Fortunately, the scale deposits contain significant amounts of gold, which usually covers the cost of replacing the pipes.

Most geothermal power plants have five to ten production wells along with a series of injection wells to dispose of the spent water and replenish the underground reservoir. Replacement production wells are drilled every 5 years or so to maintain enough steam to support the power plant as older wells decline in pressure and temperature. The effectiveness of injection wells can also decline over time due to the build-up of silica or carbonate scale. Well life can be extended by workovers and acid treatments.

Sedimentary basins tend to have lower temperature geothermal resources in the 100–150°C range that typically consist of hot brines recovered from deep, saline aquifers. These can be used for deep-direct heating and can also generate electric power in binary systems with lower temperature working fluids (such as an alcohol vs. steam-driven turbine). Sedimentary basin heat resources are easier to characterize, prove and access, and thus easier to develop than volcanic systems. As a result, permitting sedimentary resources can be done in about 4 years, while volcanic systems may take as long as 7–10 years.

Sedimentary basin geothermal wells are nominally one to 1.5 km deep (3300–5000 ft), although a well in Saskatchewan has gone down 3 km (9840 ft). Volcanic system wells are often significantly deeper, with a well in Finland drilled to a depth of 7 km (23,000 ft). Geothermal production wells cost $5 million to $10 million per well, bringing the drilling cost for a typical eight-well pad into the vicinity of $80 million. Power plant construction includes the power plant itself, plus the steam gathering system. Once the power plant is online, facility managers focus on resource monitoring, well field maintenance, power plant maintenance, and make-up drilling. Geothermal is very CAPEX-intensive and most of the risk is front-loaded. As such, the expense of development is often funded by governments. Despite being free of carbon emissions and designed for a long lifespan, geothermal receives much less government support in the United States than wind and solar. Some risk mitigation funds and global funds structured to help finance projects are available and are typically repaid by the debt structure of the power plant. If the new EGS technology can be made successful, geothermal should become more widespread.

Geothermal projects in sedimentary basins can sometimes utilize or deepen existing, depleted oil and gas wells to save on drilling costs. Although not exactly geothermal, a DOE field experiment in the 1980s at Chocolate Bayou on the Texas Gulf Coast attempted "cogeneration" by recovering hot, geopressured brine from depths below 20,000 ft to drive a turbine and generate electricity, in tandem with a second generating unit that ran on natural gas released from the brine at the surface. The deep depths, the corrosive hot salt water, and the cost of disposing of the brine all negatively impacted the economics, but the plant began generating about 40 MW of electricity in 1985 and operated into the early 1990s. Europe, Australia, and Canada currently have ongoing sedimentary basin heat projects, and China is in the process of implementation.

A volcanic host system should last for centuries if properly conserved and sedimentary heat sources should last for many decades. Active volcanic sources replenish heat, but heat is mined from sedimentary basins and the source will eventually cool beyond usefulness. Not understanding the resource and overbuilding power plants will deplete these systems quickly. Sustainable geothermal requires a balance of resource assessment, realistic targets, and responsible production.

Social and environmental aspects

The pressurized systems and hot steam associated with geothermal power plants can pose a safety risk, along with toxic H_2S and asphyxiant CO_2 gases produced naturally with the hydrothermal waters. Seismicity can also be an issue in and around geothermal fields. Nevertheless, geothermal power is accepted by society because it is seen as a renewable and environmentally benign energy resource.

Thus, it came as a shock to many during the 2018 eruption of Kilauea in Hawaii that the Puna Geothermal Venture power plant, constructed in 1989 on the Big Island became a major environmental hazard when it was identified as being in the path of the lava flows. Production wells, some as deep as 2530 m (8300 ft) were shut in and quenched before being buried under meters of fresh lava. The organic liquid used in the binary heat exchangers was trucked off site to prevent an explosion hazard from contact with the lava. The volcanic activity resulted in the entire geothermal power plant being shut down. As of this writing, there are plans to resume operations in 2020.

Electricity generated by unit

The amount of electricity generated by geothermal projects varies widely. In California, near Santa Rosa, a system that produced 1.6 GW declined significantly and after a work over and revival now produces 600–800 MW. A typical 2.5 km-deep geothermal well (8200 ft) in Iceland yields power equivalent to approximately 5 MW. Drilling wells twice as deep to 5 km (16,500 ft) will reach a supercritical reservoir at temperatures above 450°C, and may be expected to yield 50 MW, or 10 times the power.

Generating efficiency

Geothermal plants as currently configured are not very efficient, only converting about 16% of the input energy into electricity.

Capacity factor

Geothermal power plants provide baseload electricity, remaining online about 90% of the time.

Solar

Percentage of US Electricity Generation: 1.3%

Description

Solar power has two modes of operation. The most common is solar photovoltaic (PV), which uses the now-familiar solar panels to convert sunlight directly into electricity through a process called the "photoelectric effect," first observed in 1887 by Heinrich Hertz during experiments with a spark gap generator. No one understood how it worked until Albert Einstein realized in 1905 that light was behaving as tiny particles called photons that were transferring energy to electrons when striking a substrate and this was creating an electrical potential and a current. Einstein received the Nobel Prize in physics in 1921 for his work on the photoelectric effect, and not, as many people assume, for his more famous relativity theories.

The second type of solar power is solar thermal, which uses mirrors to focus the heat of the sun to make steam and generate electricity. There are three main types of solar thermal power systems: 1) Linear concentrating systems use concave, mirrored troughs or Fresnel lenses to concentrate sunlight onto arrays of heat exchanger pipes. 2) Solar power towers employ a large group of flat, sun-tracking mirrors called heliostats to gather sunlight and reflect it onto a receiver at the top of a tower, where it can be concentrated as much as 1500 times (Fig. 7.4). Some towers will heat water directly with the concentrated sunlight to make steam; others use molten salts as a heat exchanger for better thermal energy-storage capability to allow the system to produce electricity at night or under an overcast sky. 3) Solar dish/engine systems have a large, concave dish similar to a radio telescope covered with mirrors and a thermal receiver at the focus, which transfers heat to a Stirling thermal engine that runs an electrical generator.

FIGURE 7.4 Crescent Dunes solar power tower surrounded by 10,347 heliostat mirrors in the Nevada desert near Tonopah. *Photo from DOE, National Renewable Energy Laboratory.*

Energy source factors

The energy source is sunlight, which shines every day and is free. The strength of solar energy can be affected by sun angle, length of day, and cloudiness. As such, many solar facilities are located in deserts and more equatorial climates where there are fewer clouds and less variation in the sun angle and length of day. However, solar also has been implemented successfully in more northern countries like Germany and Sweden. Solar PV panels are often placed on residential and commercial rooftops and the energy fed into the national power grid. The island-state of Hawaii, which is isolated from the rest of the US national power grid, banned rooftop PV installations for a time because the electrical system was unable to cope with all the power inputs.

Social and environmental aspects

Solar energy systems and power plants do not produce air pollution, water pollution, or greenhouse gases. However, the manufacturing process for PV cells uses materials and chemicals that can be hazardous and toxic. Some of the heat transfer fluids used in solar thermal systems, such as molten salts, are also potentially hazardous and could harm the environment if released.

As with any type of power plant, large solar facilities can affect the local environment. Clearing the land for construction may have long-term effects on habitat, especially for solar thermal plants that may require many acres for heliostats. Water is sometimes necessary for cooling turbine generators, which may be a problem for a solar installation located in a desert. Finally, the intense beam of concentrated sunlight being focused onto a solar power tower will kill any birds or insects that fly into it.

Electricity generated by unit

Most US utility-scale solar photovoltaic power plants have a generating capacity of 5 MW or less. There are two large-scale operating solar power tower projects in the United States: one near Ivanpah, CA in the Mojave Desert with 173,500 heliostats focusing sunlight onto three solar power towers that produce 392 MW of electricity. The other is Crescent Dunes Solar Energy Project in southwestern Nevada (Fig. 7.4) with 10,347 heliostats capable of producing 110 MW.

Generating efficiency

Solar thermal power plants are about 21% efficient, while solar photovoltaics are only about 12% efficient.

Capacity factor

Solar thermal power is online about 25% of the time, while solar photovoltaic is online about 29% of the time.

Wind (offshore and onshore)

Percentage of US Electricity Generation: 6.3%

Description

Although wind power has been in use for thousands of years to pump water and grind grain, the widespread use of wind turbines to generate electricity did not begin in the United States until the 1980s, when thousands of wind turbines were installed in California, largely because of state policies that encouraged the use of renewable energy sources. Wind turbines have been growing steadily in numbers since the 1990s in the United States. Europe and China have both invested heavily in wind energy and China now has the world's largest wind electricity generation capacity.

There are two basic types of wind turbines: vertical-axis and horizontal-axis. The most common design for a vertical-axis wind turbine, with blades that are attached to the top and the bottom of a vertical rotor, was patented in 1931 by French engineer Georges Darrieus. These Darrieus turbines have the advantage of being able to intercept wind from any direction, and the vertical-axis allows heavy electrical generating equipment to be mounted at ground level. However, it is difficult to adjust the vertical turbines to variable wind speeds, and they do not perform as efficiently as horizontal-axis turbines for generating electricity.

Horizontal turbines commonly have three blades like an airplane propeller mounted on a tower high above the ground. The generator is located in a nacelle at the top of the tower and the entire assembly can be rotated on the tower axis by a computer to remain facing into the wind. The angle of the blades also can be adjusted or "feathered" to maintain a nearly constant rotation rate and energy output under different wind speeds. When turned completely edge-on to the wind, the blades stop spinning altogether, which is crucial for wind turbine maintenance and repairs. Nearly all of the wind turbines currently in use in the United States are horizontal-axis turbines.

In the 1990s and 2000s, the US Federal Government established tax and investment incentives for wind power projects to encourage the use of more renewable energy resources. State governments also enacted new requirements for electricity generation from renewable sources. These policies and tax incentives resulted in a significant increase in the number of wind turbines and in the amount of electricity generated from wind energy. Less than 1% of electricity in the United States was generated from wind in 1990, but by 2017 it had increased to 6%. It is difficult to separate the economics of wind from the tax incentive, but it is safe to say that without it, wind would not be as competitive as other sources of electricity.

Energy source factors

The wind is of course available everywhere, but the locations sought for wind turbines are places that have stronger, steadier winds. Three favorite locations include mountain ridges and associated downslope valleys, treeless prairies on open high plains, and shallow water offshore from coastlines. Winds are typically stronger and steadier at higher elevations and many of the Appalachian Mountain ridges have wind turbines along the crests. California also has numerous wind turbines installed in high desert valleys and on mountain ridges. Likewise, large stretches of open prairie, such as parts of Iowa, Kansas, Oklahoma, and Texas have an abundance of wind turbines.

Offshore wind is an option in coastal areas with large cities where land is scarce. Offshore winds are typically both stronger and steadier than winds onshore, but offshore wind turbines are also costlier and more challenging to maintain in a marine environment. Placing an array of turbines 12 to 15 miles (20 to 25 km) offshore will usually put it over the horizon, but still keep it close enough to major metropolitan areas to provide electricity. As of this writing, the United States has just one operating offshore wind site, the Block Island wind farm in Rhode Island. Offshore wind generation is more common elsewhere, especially in Europe, where Denmark installed the first offshore wind farms in the 1990s. The London Array in the Thames Estuary, located 20 km (12 miles) off the Kent coast of the U.K. produces 630 MW from 175 turbines and is the second largest offshore array in the world. The largest is the Walney Wind Farm in the Irish Sea off the U.K. coast of Cumbria.

Social and environmental aspects

Although wind is an environmentally acceptable, non-GHG creating energy resource, it does still have some environmental impacts. The high towers and long blades of wind turbines are visually distracting and can be somewhat noisy. Wind turbines are subject to weather and often suffer damage from hail, ice buildup, bird strikes, and excessive heat or cold.

Horizontal wind turbines often prove fatal to both birds and bats. Even through the blades may appear from a distance to be turning slowly, the tip is actually moving at 120 mph, and in high winds up to 180 mph (190 to 290 km/h). The number of birds and bats killed annually is up for debate—estimates in the United States for onshore wind turbines range from 20,000 to nearly half a million (Sovacool, 2013). Offshore wind doesn't even have estimates, because any birds that are struck end up in the water and will either drift away or be consumed and can't be counted. Still, given the comparable environmental impacts of various energy resources, and the number of bird fatalities from other sources, wind power is relatively benign.

Electricity generated by unit

Individual wind turbines generate about 1–3 MW of power each, although the large offshore turbines on Block Island have generation capacities of 6 MW. The power of a horizontal turbine is defined by the length of the blades. The standard, onshore, horizontal-axis turbines are mounted an average of 280 ft (85 m) above the ground with blades more than 100 ft (30 m) long. Wind power is multiplied by arrays of turbines spaced across the landscape (or seascape) in wind farms. The largest onshore wind farm in the United States is the Horse Hollow Wind Energy Center in Texas, with 430 wind turbines and a combined electricity generating capacity of about 735 MW.

Generating efficiency

Wind generation turbines are about 26% efficient.

Capacity factor

Wind power is online about 45% of the time.

Biomass

Percentage of US Electricity Generation: 1.6%

Description

Biomass is the generic name for organic material from plants and animals that is used as a renewable source of energy. Biomass can be burned directly to make electricity, or converted into liquid fuels like biodiesel, or into methane gas. Sources of biomass include wood and wood processing wastes that are generally burned directly to heat buildings or generate electricity, agricultural crops and ag waste, which is usually converted into liquid biofuels, solid municipal waste burned directly to generate electricity or converted to biogas in landfills, and animal manure, converted to biogas.

Although biomass fuels burn the same as fossil fuels and give off CO_2 as a combustion product, this carbon was sourced from the atmosphere when the living material was growing. Thus, the CO_2 emissions from burning biofuels are simply returning the gas back to the atmosphere as part of the carbon cycle. People often get confused on this point, and suggest that trees "pollute the air" or that cattle flatulence is a "greenhouse gas." It is important to remember that not all carbon is equal.

The CO_2 from fossil fuel combustion is releasing carbon into the atmosphere that has been isolated underground for tens or hundreds of millions of years. This carbon is gradually adding to the total amount of CO_2 in the atmosphere (refer back to Fig. 6.4). Biomass fuel burns carbon that was already present in the atmosphere and does not increase CO_2 levels. If all fossil fuel was banned, and only biomass fuels were combusted, the levels of CO_2 in the atmosphere would remain rock-steady. However, there does not appear to be enough biomass on the entire planet to sustain the energy needs of human civilization if it was the only resource.

Energy source factors

Biomass is derived from materials that were intentionally grown to produce it, or it can be made from waste products. Trees are grown to produce wood, which can be burned for energy in various ways ranging from campfires to pellet stoves. Ethyl alcohol or ethanol can be used directly as a motor fuel or added to gasoline to reduce emissions. It is primarily distilled from corn, and a significant portion of the annual US corn crop goes into making ethanol. Some researchers are looking into the possibility of farming marine algae to produce biodiesel and other petroleum-like fuels.

Waste biomass includes municipal solid waste and manure. These can either be burned directly to make heat and electricity, or they can be fermented in an anaerobic atmosphere to create methane or biogenic natural gas. Most people would expect that biofuels from waste would be very cheap, because the feedstocks, primarily garbage and manure, are essentially free. Because significant processing is required to turn these into useful fuels, however, the costs of biofuel can be substantially greater than similar fossil fuel. A carbon tax on fossil fuels would make biofuel more economically competitive.

Social and environmental aspects

Ethanol does not contain the same energy density as gasoline and as a transportation fuel, roughly twice as much ethanol is required to go the same distance as a gasoline-powered car. Many people resent being forced to put gasoline with 10 percent ethanol into their vehicles, but because of government incentives and policies for biofuels, gasoline with ethanol is significantly cheaper than gasoline without ethanol. Biodiesel is used in trucks, but pilots have been reluctant to use bio-jet fuel in aircraft because of concerns that it will not perform as well as regular jet fuel, especially under the extreme cold temperatures encountered at high altitude. Nevertheless, some airlines worried about the reported high levels of aircraft carbon emissions have begun experimenting with "Eco-Flights" using biofueled jets to develop acceptance among both crews and customers.

Burning municipal solid waste to make electricity sounds like the environmentally correct thing to do for most people, but it is not cheap. The waste has to be sorted first, because many items in the mix, such as most plastics, cannot be burned without creating toxic vapors and compromising air quality standards. Plastics must be laboriously removed from the municipal waste stream before it can be burned. Placing the waste in a landfill and then later extracting methane requires a lot of materials handling and the installation of a system to recover the gas. Referring back to Table 7.1, the cost of electricity from biomass is surprisingly expensive, exceeding the cost of nuclear.

Electricity generated by unit

According to the EIA, 71 US power plants in 2016 generated about 14 billion kilowatt-hours of electricity from burning about 30 million tons of combustible municipal solid waste.

Generating efficiency

The conversion of biomass heat to electricity depends on the particular fuel, as some biomass stocks produce more heat than others (dense wood, for example, burns hotter than corn-derived ethanol). However, as an approximation for this estimate, the heat rate of most biofuels can be considered similar to coal and petroleum, resulting in a conversion efficiency of about 34%.

Capacity factor

Biomass-fired power plants provide both baseload and peak power and can remain online an average 83% of the time.

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PART

III

Energy policy

The security of the energy supply in the United States has been a concern of the federal government since the oil embargo by the Organization of Petroleum Exporting Countries (OPEC) in 1973—74 and additional oil shortages caused by the Iranian Revolution in 1979. As discussed back in Chapter 2, it is hard to overstate the impact this so-called "energy crisis" had on the US economy and on the daily lives of ordinary citizens.

As a quick review, the OPEC embargo resulted from the 1973 Yom Kippur War, which began on October 6, 1973, when Israel was invaded by the combined armies of Egypt, Syria, Iraq, and Jordan. The Israelis staged a successful counterattack, and the war ended on October 25, 1973, with a United Nations—brokered cease-fire (Rabinovich, 2004). At a meeting of oil ministers in Kuwait on October 20, 1973, Libya led an effort to impose a total ban on crude oil exports to the United States as retribution for the US support of Israel in the war. Although less than half of the oil used in the United States was imported, and not all the OPEC countries joined the embargo, the action still resulted in oil shortages, consumer panic, and long lines at service stations. When gasoline was available for purchase, motorists found that the prices had increased fourfold. The OPEC embargo was lifted in the spring of 1974, but a second oil shortage followed later in the decade when Iranian exports were briefly curtailed during the Islamic Revolution of 1979. Just as the Yom Kippur War profoundly affected long-term Israeli foreign policy, the resulting OPEC oil embargo against the United States has strongly influenced American foreign policy for decades (Yergin, 1991).

The oil shortages had significant and long-lasting effects on the economy, national security, and mind-set of the United States. The energy crisis exposed vulnerabilities with the suburban lifestyle that had become commonplace in the United States after the World War II. Many people felt stranded in far-flung suburban areas, stuck with an empty gas tank in a useless car. Citizens responded with anger that America was being "held hostage" to imported oil and demanded something be done. The U.S. government responded by creating the US Department of Energy (DOE) on August 4, 1977, as a cabinet-level entity under President Jimmy Carter with James R. Schlesinger as the first Energy Secretary.

A primary mission of the new Energy Department was to find technological solutions to the energy crisis. The agency attempted to improve energy efficiency along with broadening domestic energy supplies. Multiple energy sources make the nation less vulnerable to potential disruptions of a single source.

Energy security remains a concern of the United States and with many other governments around the world. Not having control of one's energy supply puts a country at risk for blackmail or domestic meddling by the nations that do control energy supplies. Human rights abuses and other odious activities by some energy-exporting countries are commonly overlooked or swept under the rug by nations who would normally make a stand on these issues but need energy. Many countries with large amounts of energy to export often exert international influence far out of proportion to what might be expected, given their populations and military strength. This section will explore some of these issues.

8

Energy security

History

A saying often attributed to the German philosopher Friedrich Hegel (1770–1831) is that the only thing we learn from history is that we learn nothing from history. This is especially true in the oil and gas world, where everyone seems to forget during boom times how the previous boom ended, and people convince themselves that the gravy train will go on forever. When it eventually runs off the rails, they are in shock and disbelief, just like they were the last time it happened. In addition to the boom and bust nature of the oil business, the development of challenging, new petroleum resources such as deepwater offshore, the Alaskan North Slope, and unconventional oil and gas typically take years to decades before showing significant results. Humans are not very good at remembering causes and effects over such long timelines, and many people today would be hard-pressed to name the underlying reasons for why the development of shale gas and tight oil was needed in the United States in the first place. The long-term effects of the fossil fuel revolution on energy security, global politics, and alternative fuels will likely keep historians busy for some time.

Although the "shale boom" peaked in 2014 after a run of about 10 years, shale gas and tight oil are still being produced in abundance, albeit less frantically, and are likely to remain important energy resources for the foreseeable future. Unconventional O&G production has made up for nearly all of the energy shortages experienced over previous decades. The decline of conventional natural gas production had become serious enough in the late 1990s for gas companies in the United States to build terminals on the East Coast to import liquefied natural gas (LNG) from North Africa. Thanks to shale gas production, the United States is completely self-sufficient in natural gas, and the import terminals are now being used to export Marcellus Shale LNG to Europe and elsewhere.

Tight oil production has also increased to the point where the United States has a minimal dependence on imports, and another 1970s-style oil embargo would hardly be noticed nowadays. The Organization of Petroleum Exporting Countries (OPEC) cartel has grown much weaker over the past four decades. Noncartel production from the North Sea, Mexico, Indonesia, and elsewhere has broken the export monopoly held by a handful of countries back in the 1970s. Other, major consumers besides the United States are also making demands on the supply, notably the growing economies of China and India. Oil is now widely traded between exporting and importing countries in an international oil economy. For example, the United States may import oil from Saudi

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Arabia, while at the same time exporting oil to China. This type of global free trade was much less common in the 1970s.

Petroleum itself has changed the course of human events many times in the past, not just in the 1970s. Throughout most of recorded history “mineral oil” had been obtained in small quantities from natural seeps for use in a variety of traditional and patent medicines. In 1859, a businessman named Edwin Drake decided to see if larger quantities of oil could be obtained by drilling a well. It was known that oil had been recovered from wells drilled in the Appalachian Basin to obtain brines for salt production, but the significance of Drake’s well is that it was the first one deliberately drilled to deliver petroleum.

The Pennsylvania Rock Oil Company had been incorporated a few years earlier to collect mineral oil from known petroleum seeps along the aptly named Oil Creek near the town of Titusville in northwestern Pennsylvania. Drake had invested his life savings in the company. The directors gave him the go-ahead to try drilling on the property, and Drake’s well reached a total depth of 69.5 ft (21.2 m) in August of 1859. Oil was present on top of the water in the borehole, and the well produced for about 2 years. Drake and his partners refined the crude oil into kerosene and sold it for oil lamps as a much cheaper alternative fuel than the increasingly rare and expensive whale oil widely in use at the time.

Other drillers began to copy and improve on Drake’s success, seeking larger and more profitable petroleum resources. The development of a new market for petroleum use in oil lamps prompted additional drilling, establishing a supply of petroleum to support business enterprises that further increased sales. By the late 1800s, significant investments were being made in oil exploration activities as the fledgling petroleum business gradually learned how to find oil. International ventures in particular required large amounts of capital that could only be invested by large corporations and national-level companies. One of the first of these international projects to achieve success was the 1908 discovery of oil in Persia (present-day Iran) by William D’Arcy, providing hints about the potentially enormous petroleum reserves in the Middle East.

Geologists typically were not employed by the early oil companies, who didn’t see them as a necessity. As a result, many wells were placed in random locations wherever drillers could get access to land. Such oil wells drilled within a play but outside of known production areas were called “wildcats,” presumably because they were out in the untamed countryside. Wildcat drillers have achieved a certain romantic fame in oilfield lore as fearless risk-takers who put everything on the line to reap great rewards, but the reality is that the return on investment in a wildcat well is usually poor. The really risky wells drilled outside of the play area are called “rank wildcats,” and investors in these are usually better off just taking their money to the casinos in Las Vegas. Even in areas within a play that had known production potential, the challenges, unknowns, and large investments in the early days of oil production typically resulted in either big wins or devastating losses (Yergin, 1991).

With the development of the internal combustion engine in the late 19th century, petroleum found another market. As gasoline and diesel powered vehicles became more numerous and more reliable, petroleum soon found its way into the machinery of war.

Just prior to the outbreak of World War I, British Lord of the Admiralty Sir Winston Churchill heeded Admiral Fisher's advice and modernized British naval ships, converting from coal to petroleum. Bunker oil was a more efficient and less labor-intensive way to power naval craft, refueling required less time and manpower, and oil gave ships a much greater range. Gasoline powered military vehicles like trucks, tanks, and aircraft also debuted in World War I.

By the time World War II rolled around, petroleum was critical to the war effort. In fact, the Japanese aggression that led to war in the Pacific was driven in large part by the need for the Empire of Japan to gain access to petroleum resources, which were not available on the volcanic islands that comprise the country. The US government rationed civilian use of gasoline for the first time ever during the war, making it clear that Americans had to do their part to ensure that war machinery had a steady supply of fuel. Unnecessary travel and other wasteful uses of energy were frowned upon as sabotaging the war effort.

An Allied strategy that developed during World War II was to deny the Nazis access to oil. Bombing raids targeted refineries, pipelines, oil trains, and distribution centers to cut off the supply of petroleum needed to power German tanks, U-boats, and aircraft. This turned out to be an effective tactic, with the outcomes of skirmishes late in the war like the Battle of the Bulge being decided in part by the availability of fuel, when many German tanks simply ran out of gas. After the war, it was clear to the United States and European allies that a secure petroleum supply was important for both for an effective military and a growing domestic economy. The notion of energy security began to develop as a concept, but only as a constituent of the greater concern, national security.

Near the end of World War II, the desperate Germans began developing chemical processes to create petroleum liquids from coal and other feedstocks. This technology was adopted by the US Department of Energy in the 1970s as a possible solution to the energy crisis by making synthetic fuels out of abundant domestic coal. Despite many different approaches and attempts, none of these "synfuels" processes could produce gasoline or other oil products at a cost that was competitive with liquid petroleum. During the war, the last thing the Nazis were worried about was the price of petrol, but it certainly mattered to American consumers.

After the discovery of Persian oil in 1908, the Middle East became a target of high interest to the petroleum industry. The Sykes—Picot agreement, signed by France and the United Kingdom and assented to by Russia in 1916 carved the Middle East into spheres of influence. The vestiges of these colonial boundaries remain in effect even today. Modern Saudi Arabia was founded in 1932, and Americans discovered commercially producible oil there in 1938.

During the 1950s, large American and European oil companies continued to explore, produce, and deliver petroleum to the global market from the giant oilfields that had been discovered in the Middle East. As countries in the region transitioned from British and French colonial protectorates into independent states, many of the new governments began to resent the vast profits being made by foreign oil companies operating on their soil while the host country received paltry royalties, which were a very small slice of the pie. In response, many of these producing nations, increasingly frustrated by their lack of direct participation in the oil business, nationalized their oil companies and banded together to create the Organization of Petroleum Exporting Countries (OPEC) in 1960.

The majors began to understand that the free ride was coming to an end. Their position was not helped by the diminished standing of the United States among Arab countries in the Middle East for supporting Israel in the 1967 Six-Day War (Merrill, 2007). By 1972, OPEC member countries were demanding that international oil company executives give them increased participation and sovereignty over their natural resources. Circumstances had changed, and the technical education of citizens in these countries allowed native populations to produce oil without the need for "help" from western oil companies. Mideast governments were also concerned that their own economies had become dependent upon exporting oil at a consistent volume and price and more control over production was deemed a necessity (Moses, 1972). The upstream end of the petroleum business essentially became nationalized in the Middle East by the early 1970s, and even companies like the Arabian–American Oil Company or ARAMCO that were supposed to be industry–government partnerships came to be dominated by the government partner. ARAMCO, now known as Saudi Aramco, is the national oil company of Saudi Arabia.

The inability to produce petroleum directly from Middle Eastern oilfields led the multinational oil companies to take on the role of importers, receiving tankers into their ports, offloading the oil into refineries, and processing it into gasoline and other useful products. As petroleum production continued to decline in older conventional oilfields, especially along the US Gulf Coast, America and other oil-consuming nations became increasingly dependent on these imports to make up the differences between what was produced domestically and what was consumed. This was the setup for the energy crisis a few years later.

Responding to America's support for Israel in the Arab–Israeli/Yom Kippur War in October 1973, OPEC used oil resources as a political weapon (Rabinovich, 2004). Led by Libya, the cartel first significantly cut back on the volume of oil shipped to the United States, and then prohibited all oil shipments (Merrill, 2007). Lifestyle changes for the average American included a doubling, then quadrupling of fuel prices when gasoline could even be found; interstate driving speeds were reduced; and keeping warm at home meant layering on a sweater, not raising the thermostat. The embargo only lasted about 6 months, but the effects have rippled down through the decades.

The oil crisis also heralded the realization that the United States consumed far more energy than it produced. At the highest government levels, policy changes came in several waves: creation of the Department of Energy in the US and the International Energy Agency at the UN, commitments with other countries for storing 90 days' worth of petroleum imports in the U.S. Strategic Petroleum Reserve, and the introduction of improvements in fuel economy and energy efficiency across several consumer sectors.

The United States did not have a comprehensive energy policy in the 1970s, and it still does not today. The petroleum industry is a private enterprise, funded by capital investment, and driven by profits. The government has little influence over the industry, even though the commodity it provides is absolutely essential to the functioning of American society. The small amount of control the government does exert, mainly on environmental issues, typically results in loud complaints from the energy companies about "burdensome regulations."

The issue of energy security is problematic. Despite the 1970s oil shocks, many in government and even more in the citizenry have essentially no understanding about what energy security actually means. History is being ignored. The most popular vehicles sold in America in the 21st century are full-size pickup trucks and behemoth sport-utility vehicles, either of which consumes more gasoline per mile than a 1968 Buick. More aircraft are in the sky than ever before, as people increasingly fly. We keep finding new ways to use electricity, and the flow of petroleum into manufactured materials like plastics and petrochemicals has increased steeply.

Another thing that has changed since the 1970s is that the United States is no longer the largest, or the most important customer for energy exporting countries. The citizens of China and India would like nothing more than to live an American lifestyle. Demand for automobiles in both countries has been rising steeply. The large Indian vehicle manufacturer, Tata, can barely keep pace. China's new middle class is seeking consumer goods, transportation, better housing, and more food, all of which require hydrocarbon resources. When the United States imposes sanctions on an energy exporting country for bad behavior, they oftentimes simply switch customers and sell their oil elsewhere. There are plenty of takers, and this is likely to increase. Energy self-sufficiency in the United States is not just a political security issue any more. In the not too distant future, we may have no choice.

Shale gas and tight oil production in the United States have made us nearly energy-independent, but for how long? Domestic petroleum and natural gas are being exported to fetch higher prices in Europe or Asia. Although the situation is complicated, and there are some benefits in terms of global energy stability, in the end the policy is greed-driven and foolish, trading away US energy security for short-term profits. These nonrenewable resources are large, but not infinite. They will not sustain unbridled use forever. This leads us to end this section with another famous saying: those who ignore history are destined to repeat it.

Defining energy security

At its simplest, energy security is reliable access to energy without threat of disruption or loss (Kalicki and Goldwyn, 2013). However, there is no consensus on a definition, and ideas about the security of a particular energy resource can change over time and often vary among different stakeholders. Nations, the military, regional or local economies, businesses, industry, and individuals all may have different perceptions of what energy security means, but the simplest definition is guaranteed access. Thus, energy security can be described as access to necessary quantities of energy at affordable prices, this energy will be impervious to disruptions, and at a national level, energy needs match strategic interests (Ebinger, 2011).

A comparison of US energy security concerns just a decade apart shows some of these changes in perception. In 2007, prior to the shale gas and tight oil boom era, the concept of US energy independence was considered unrealistic for the foreseeable future and incompatible with broader American foreign policy objectives. In fact, investment guides warned that foolish talk about energy independence could create uncertainty among international trading partners, resulting in a reluctance to invest funds in international energy development projects. This in turn would likely reduce stability in international oil markets and adversely affect everyone involved including the United States. What a difference a decade makes. By 2017, the United States had become both the world's largest producer of crude oil and the largest producer of natural gas (DOE, 2016a), moving from the impossibility of energy independence to virtual energy self-sufficiency.

Energy security for the United States has always been linked to national security. The oil embargoes of the 1970s were viewed as military attacks against the United States just as surely as the 1943 Allied bombing raid on the oil refinery complex at Ploesti, Romania, known as "Operation Tidal Wave," was an attempt to cripple the Nazi war machine (Dugan and Stewart, 1962). As such, in 2016, the USDOE presented a report to Congress on the valuation of energy security for the United States (DOE, 2016b). The report recommended an expanded role for energy security in policy decisions, and included the broader definition of energy security as formulated by the G-7 energy minsters and the European Union in 2014. The EU discussions in Brussels defined seven elements of energy security. These are summarized in Table 8.1 below and described in greater detail in the following sections.

Table 8.1 The seven elements of energy security.

1	Development of flexible, transparent, and competitive energy markets, including gas markets.
2	Diversification of energy fuels, sources and routes, and encouragement of indigenous sources of energy supply.
3	Reducing greenhouse gas (GHG) emissions, and accelerating the transition to a low carbon economy, as a key contribution to enduring energy security.
4	Enhancing energy efficiency in demand and supply, and demand response management.
5	Promoting deployment of clean and sustainable energy technologies and continued investment in research and innovation.
6	Improving energy systems resilience by promoting infrastructure modernization and supply and demand policies that help withstand systemic shocks and cyberattacks.
7	Putting in place emergency response systems, including reserves and fuel substitution for importing countries, in case of major energy disruptions.

Elements of energy security

Element 1: Development of flexible, transparent, and competitive energy markets, including gas markets

The 1920 Mineral Leasing Act authorized the US government to manage exploration and exploitation of minerals on public lands. Shortly after the OPEC oil embargo in 1973, the export of crude oil produced on public lands was banned. In 1979, Congress passed the Export Administration Act, which significantly restricted most US petroleum exports, allowing only limited amounts of gas and crude oil to be sent to Canada (Boersma and Ebinger, 2014).

Not that there was all that much to export in any case – old and tired US oilfields had been watering out for decades and were being shut in, leading to a 30-year decline in domestic oil and gas production. At the same time, American energy consumption continued to rise. The international oil markets retained a quite reasonable expectation that the United States would continue to be a net (and considerable) importer of petroleum for the foreseeable future.

This all changed abruptly with the fossil fuel revolution. The production successes on shale quickly increased American supplies of natural gas, and later oil. With static demand in the domestic energy markets, especially for natural gas, prices fell through the floor. Congress rescinded the export ban in late 2015, and upstream energy companies wasted no time getting back into global markets. The effect on natural gas can be seen clearly in Fig. 8.1.

The glut of shale gas in the US combined with flat demand caused prices to collapse from nearly $11 per million Btu to less than $2 per million Btu at the wellhead. The prices that operators were receiving for gas were often less than the cost of production. In fact, quite a few new shale wells were shut in to await price improvements and many other planned wells were simply not drilled. The newfound ability to export hydrocarbons in 2015 saved the balance sheets of many US gas producers.

Natural gas in places like Europe, supplied mostly by Russian pipelines, was selling for as high as $14 per million Btu. At these prices, shale gas could be compressed profitably into a cryogenic liquid that occupied 1/600th the volume of its gaseous state. The LNG was then placed on tankers and exported widely to South Korea, China, Japan, Mexico, Europe and the Middle East (Fig. 8.2).

The US export capacity for LNG has continued to increase. LNG import terminals constructed in the 1990s in Boston and on the Chesapeake Bay were converted for export. Since 2016, two additional LNG export facilities came online, and four more are expected by 2020, bringing US LNG export capacity to 9.6 BCF/d (EIA, 2016). Only Australia and Qatar continue to exceed the US in LNG exports. Fig. 8.3 illustrates the impact that the shale boom had on the U.S. in terms of consumption, production, imports, exports and net imports. US oil and gas exports overseas allow American participation in global markets, where the United States can serve as a stabilizing force in Asia,

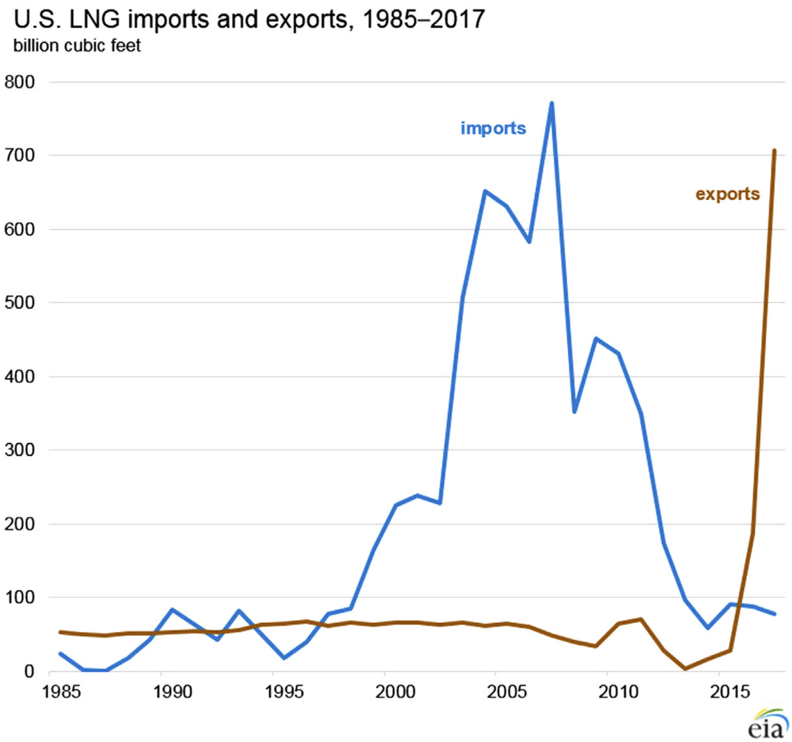

FIGURE 8.1 US liquefied natural gas (bcf) imports and exports, 1985–2017. *Source: Reproduced from US Energy Information Administration webpage.*

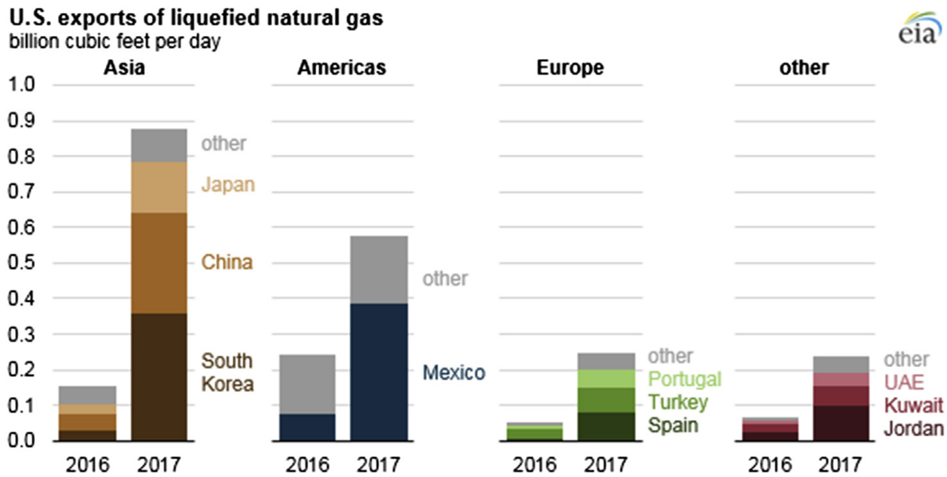

FIGURE 8.2 US exports of liquefied natural gas 2017 over 2016. *Source: Reproduced from U.S. Energy Information Administration Natural Gas Monthly.*

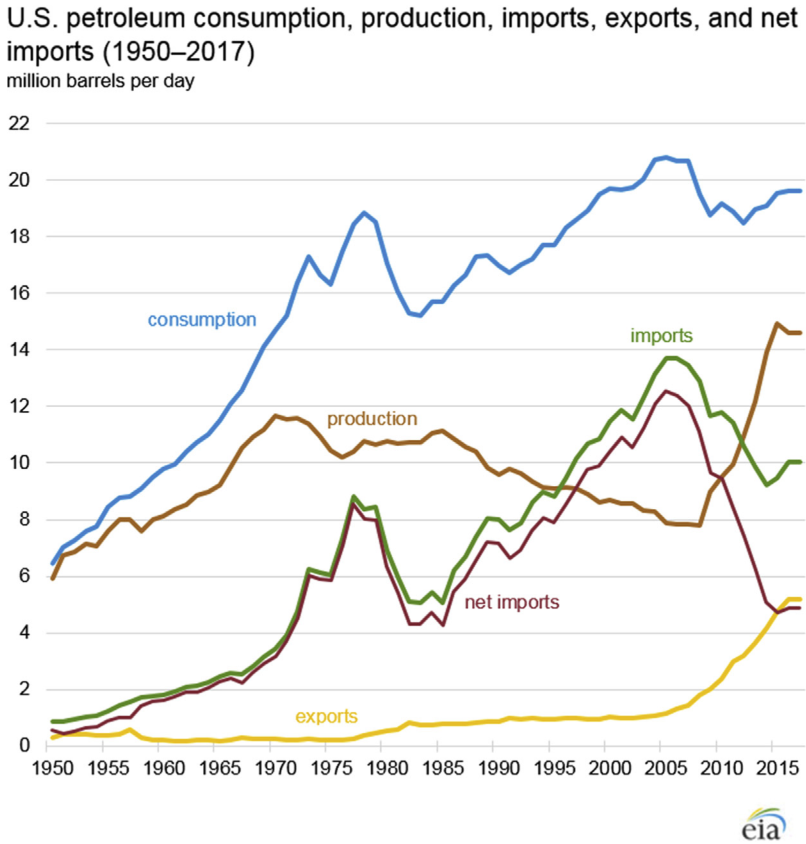

FIGURE 8.3 US petroleum consumption, production, imports, exports, and net imports. *Source: Reproduced from US Energy Information Administration webpage.*

Mexico, and Europe. However, this will be true only as long as shale gas and tight oil energy supplies remain abundant.

Element 2: Diversification of energy fuels, sources and routes, and encouragement of indigenous sources of energy supply

Fig. 8.4 illustrates the energy mix in the United States, including which sectors of the economy use different amounts of each source. On the supply or "source" side of the graph, renewables and nuclear electric power constituted 20% of the total US energy supply in 2017, natural gas made up 29%, petroleum 37%, and coal 14%. On the consumption side, electric power used 38% of the energy supply, followed by transportation at 29%, industrial uses at 22%, and finally residential and commercial at 11%. Of the two largest energy consumers, electric power used only 1% of the petroleum production and 26% of the natural gas, while transportation used 92% of the petroleum energy sources

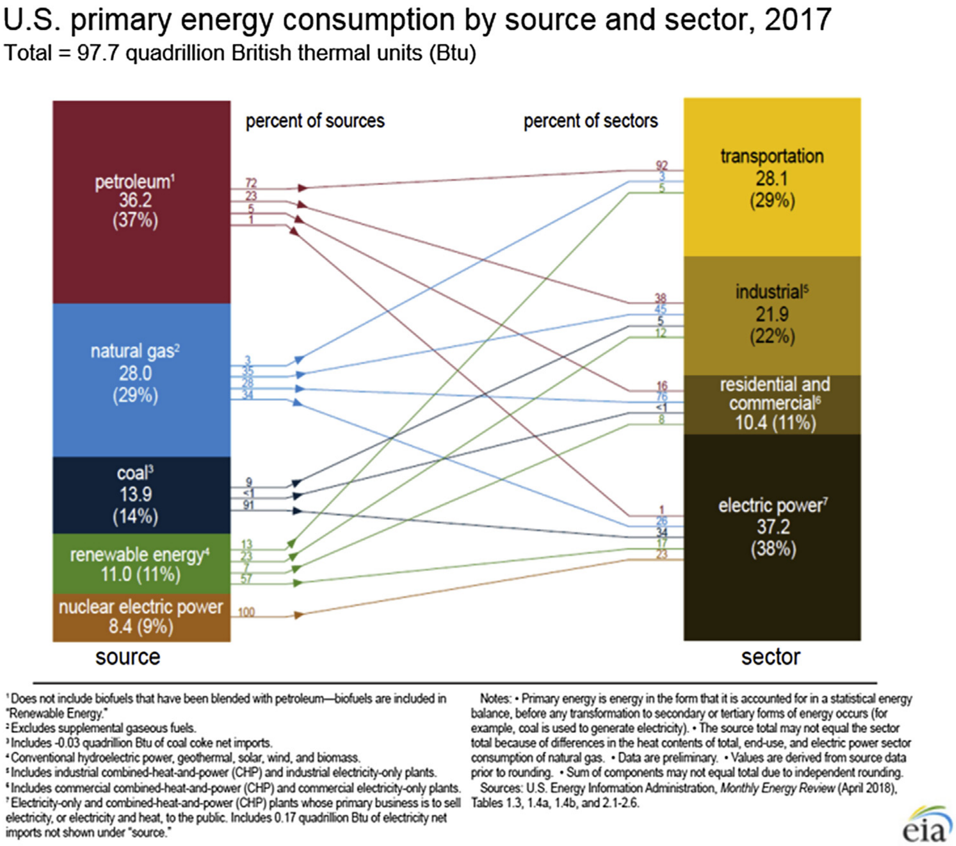

FIGURE 8.4 US primary energy consumption by source and sector, 2017. *Source: Reproduced from US Energy Information Administration webpage.*

and 3% of the natural gas. As a percentage, the largest users of natural gas were residential and commercial customers at 76%.

The EIA estimates that in 2017, almost half the crude oil produced, nearly 4.67 million barrels per day, came from US tight oil resources (Fig. 8.5) and nearly 2/3 of the natural gas (Fig. 8.6) from shale. Considering Figs. 8.4–8.6 together, US tight oil and shale gas contribute markedly to two major indigenous sources of energy.

As for the supplies of crude oil being produced in various parts of the country, Fig. 8.7 shows both the history and expected production from different segments of the continental United States. Eastern New Mexico and west Texas in the Southwest are expected to contribute the most from Permian Basin and Eagle Ford production, followed by the Dakotas and the Rocky Mountains (Bakken, Niobrara, and new development in the Powder River basin), and the Gulf Coast. The Midwest, West Coast, and East are not expected to produce much crude oil.

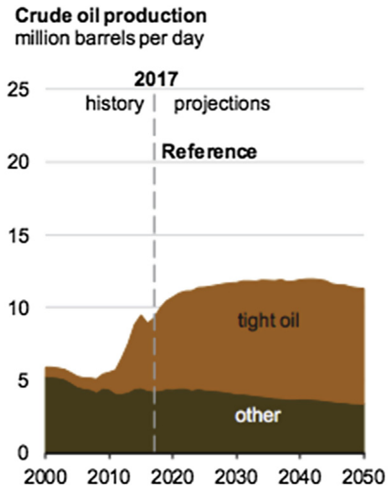

FIGURE 8.5 Crude oil production, million barrels per day, 2017. *Source: Reproduced from US Energy Information Administration 2018 Annual Energy Outlook Report with Projections to 2050, Washington, DC. https://www.eia.gov/outlooks/aeo/pdf/AEO2018.pdf.*

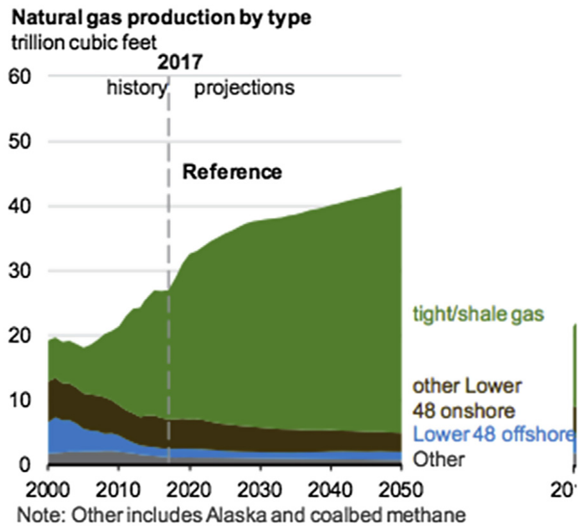

FIGURE 8.6 Natural gas production by type, trillion cubic feet. *Source: Reproduced from US Energy Information Administration 2018 Annual Energy Outlook Report with Projections to 2050, Washington, DC. https://www.eia.gov/outlooks/aeo/pdf/AEO2018.pdf.*

However, what the East lacks in crude oil, it more than makes up for in the expected production of shale gas, Fig. 8.8. Projections beyond 2017 have the East contributing an even greater share of natural gas than the rest of the United States and Gulf Coast combined.

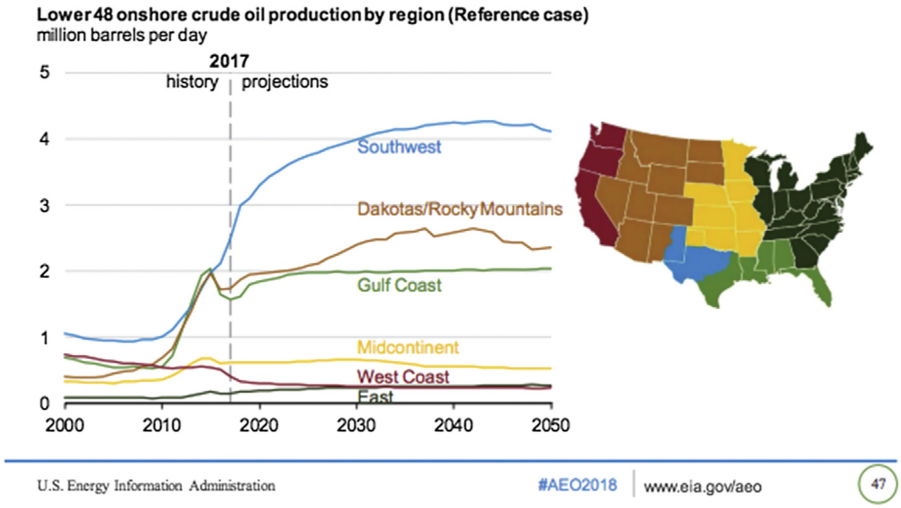

FIGURE 8.7 Lower 48 onshore crude oil production by region, reference case. *Source: Reproduced from US Energy Information Administration 2018 Annual Energy Outlook Report with Projections to 2050, Washington, DC. https://www.eia.gov/outlooks/aeo/pdf/AEO2018.pdf.*

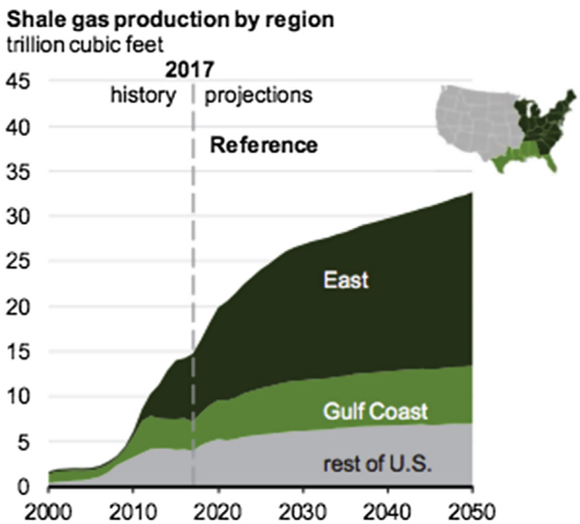

FIGURE 8.8 Shale gas production by region, trillion cubic feet. *Source: Reproduced from US Energy Information Administration 2018 Annual Energy Outlook Report with Projections to 2050, Washington, DC. https://www.eia.gov/outlooks/aeo/pdf/AEO2018.pdf.*

The final analysis for this element is a look back to 2007 at energy consumption and the projections (Fig. 8.9) compared to energy consumption and projections for 2017 (Fig. 8.10). In 2007, liquid fuels and coal were expected to rise and natural gas to level off. In 2017, petroleum and other liquids rise but not at the aggressive rate of natural gas, and coal decreases slightly before leveling off. Certainly, the shale boom continues to contribute to the production of petroleum and natural gas. US shale gas and tight oil are indigenous resources, and are projected to increase in production over the next 50 years.

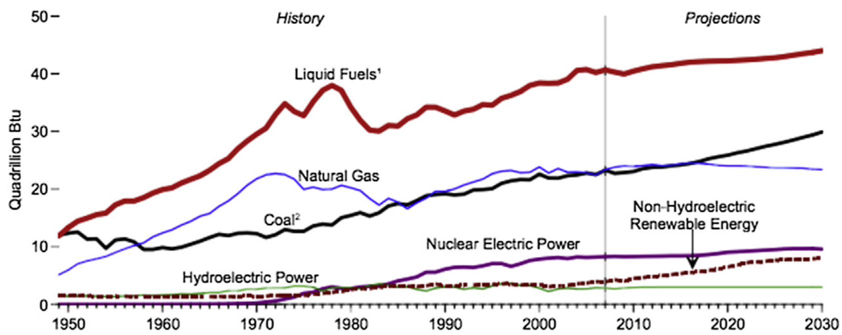

FIGURE 8.9 US energy consumption and outlook year end 2007. *Source: Reproduced from US Energy Information Administration 2007 Annual Energy Outlook Report (EIA, 2008).*

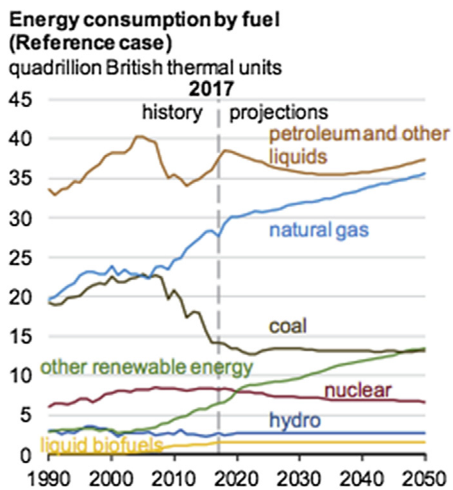

FIGURE 8.10 Energy consumption by fuel, quadrillion British thermal units. *Source: Reproduced from US Energy Information Administration 2018 Annual Energy Outlook Report with Projections to 2050, Washington, DC. https://www.eia.gov/outlooks/aeo/pdf/AEO2018.pdf.*

Element 3: Reducing greenhouse gas emissions and accelerating the transition to a low-carbon economy as a key contribution to enduring energy security

Although it may appear to be counterintuitive, massive shale gas development in the US has made significant contributions to reducing anthropogenic carbon dioxide (CO_2) emissions by displacing coal. Coal is essentially pure carbon, and it produces a great deal of carbon dioxide as a combustion product, along with sulfur dioxide, mercury, selenium, arsenic, and a variety of other environmentally damaging and toxic materials. Coal combustion also produces substantial amounts of unburned mineral matter, or ash, that must be disposed of as a bulk, toxic solid waste.

Natural gas, on the other hand, consists primarily of methane or CH_4, where four hydrogen atoms are combusted with each carbon atom. The combustion product of the hydrogen is H_2O, or water vapor. Natural gas emits about 1/3 of the carbon dioxide per-Btu of energy as coal (Soeder, 2017). It should be noted, however, that methane is a much more powerful, if less persistent greenhouse gas than carbon dioxide, and fugitive emissions entering the atmosphere from leaking natural gas transmission and distribution systems can undo much of the good of substituting gas for coal.

Over the past decade, natural gas has increasingly replaced coal as a primary energy source for generating electricity. Fig. 8.11 shows the effect of producing abundant natural gas and Fig. 8.12 shows the change in energy mix from coal to natural gas over a 35-year period.

A number of market factors affected this trend: first, the high price of natural gas in the first decade of the 21st Century made it worth the investment to develop shale gas plays. With the overwhelming success of shale, gas became both cheap and abundant, and therefore attractive to electric utilities. Utilities worry about two things in terms of the primary fuel they use to generate electricity: reliability of supply and cost. The decline of conventional gas resources in the late 20th century kept many utilities away from gas because of reliability concerns. No one wants to spend half a billion dollars building a power plant and then be unable to find fuel. The abundance of shale gas and the apparent long-term reliability of the supply have worked in its favor for power generation.

Second, policy changes toward coal greatly reduced its market desirability. Even before the US Congress started talking about carbon taxes and cap and trade back in 2010, coal plant operators were under a host of other environmental requirements to properly dispose of coal ash, remove acid rain-causing sulfur dioxide from flue gas and clean up emissions of mercury and other toxic metals. None of these issues (or costs) are associated with natural gas.

Third, although some utility companies converted existing generation capacity from coal to natural gas, many older coal plants were ending their useful lifetimes and needed to be replaced. Natural gas power plants built to operate on a combined cycle are extremely efficient and greatly lower the cost of electricity. Combined cycle systems run

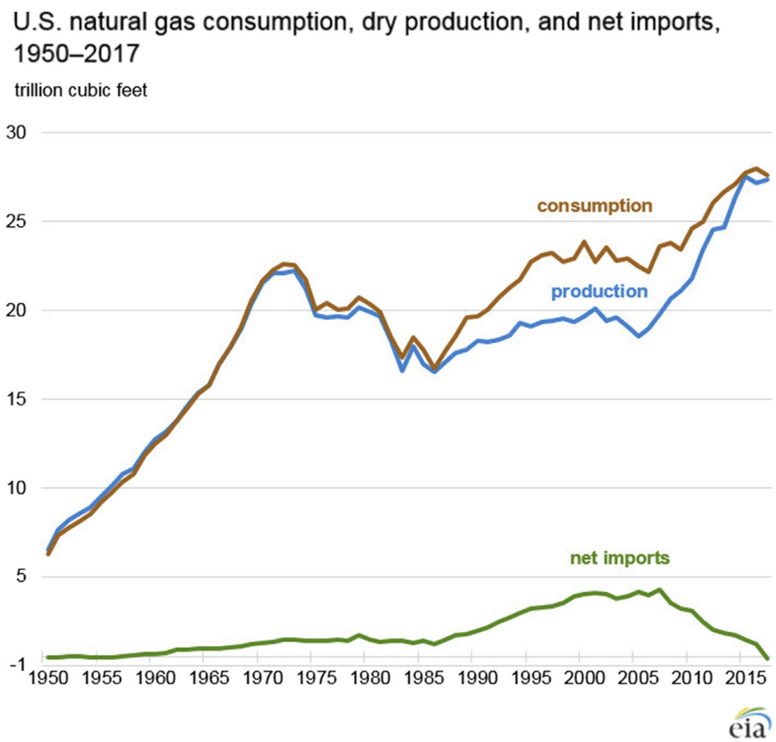

FIGURE 8.11 US natural gas consumption, dry production, and net imports, 1950–2017. *Source: Reproduced from US Energy Information Administration webpage.*

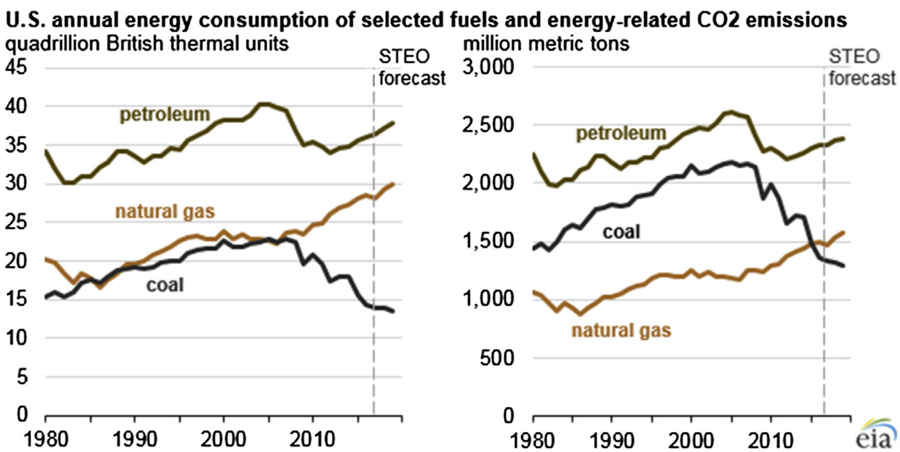

FIGURE 8.12 US annual energy consumption and energy-related CO_2 emissions. *Source: Reproduced from US Energy Information Administration webpage.*

the natural gas through a gas turbine, which turns a generator directly. The hot exhaust is then captured and used to make steam, which runs another generator. These plants are essentially 50 percent more efficient than any other fossil fuel–based generating technology. Among coal-fired power plants, only the most massive, baseload generation facilities with huge economies of scale can hope to be cost-competitive with combined cycle gas systems. This has been the real reason for the decline of coal, not any imagined "war" on it by politicians or government agencies.

Over the same decade where natural gas increasingly replaced coal as a primary energy source for generating electricity, it can be seen in Fig. 8.13 that CO_2 emissions have started a downward trend. This trend would be negated if consumption of natural gas increased substantially beyond current levels as shown in the short-term energy outlook forecast.

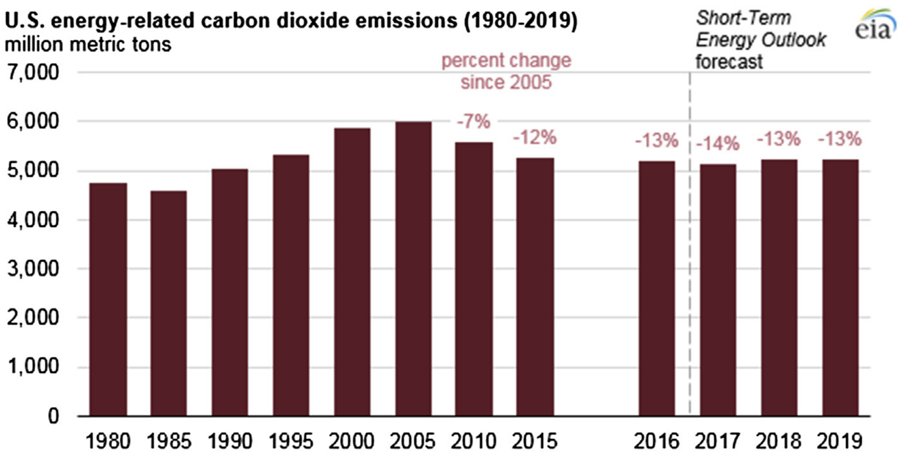

FIGURE 8.13 US energy-related carbon dioxide emissions, 1980–2019. *Source: Reproduced from US Energy Information Administration webpage.*

It appears increasing unlikely that coal will be making a comeback. Economic issues related to retrofitting electrical generators, overcoming the increased material handling and transportation limitations (rail vs. pipeline), and mitigating environmental damage suggest that the price of coal would need to be very low, and the price of natural gas very high before this had any practical favorability. If taxpayers refuse to continue to pick up the tab for the externalized costs of energy development, coal will become very expensive indeed.

In terms of decreasing the amount of CO_2 emissions for generating electricity, natural gas is at the top of the list for fossil fuels (alternative energy sources are compared in Chapter 7). It burns cleaner than coal and is less expensive than petroleum. Gas also actually burns cleaner than petroleum, which has implications for vehicle fuel and the reduction of smog in cities, but that is another discussion. For the past decade, shale gas had and continues to have a favorable impact on generating cost-effective electricity with significantly lower CO_2 emissions.

Element 4: Enhancing energy efficiency in demand and supply and demand response management

Efficiently moving fuel in and around the United States is not a new challenge. The Petroleum Administration for Defense Districts (PADDs) were created during World War II under the Petroleum Administration for War. Originally consisting of five districts[1] composed of geographic aggregations of the existing 48 states and the District of Columbia, PADDs were organized to allocate petroleum-sourced fuels for wartime gasoline rationing. Alaska and Hawaii were later added to PADD 5 after they became states. The PADDs continue to be administered by the US Department of the Interior's Oil and Gas Division (Fig. 8.14) for the purpose of collecting data to track crude oil and natural gas movement, calculate refining capability, and to assess regional petroleum product supplies.

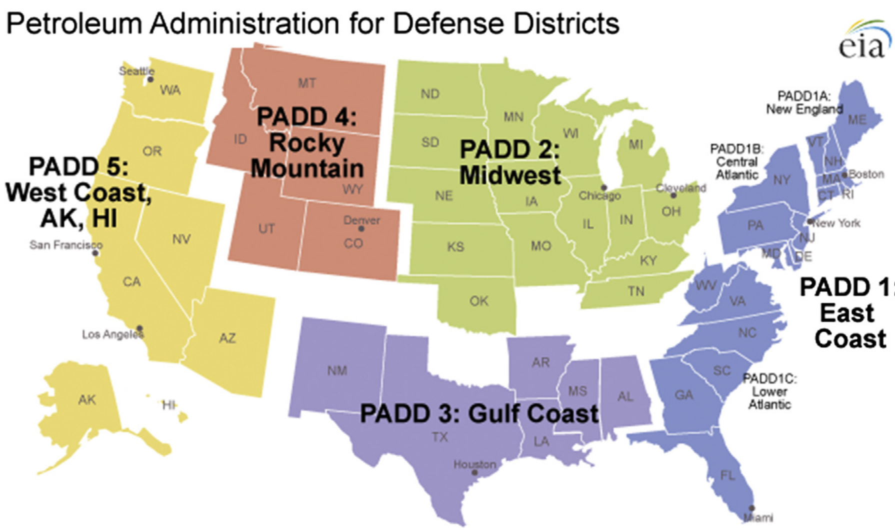

FIGURE 8.14 Petroleum Administration for Defense Districts (PADD). *Source: Reproduced from US Energy Information Administration webpage.*

In 2010, nearly three quarters of the crude oil pipeline movements were from PADD 3 to PADD 2. The volume moving by pipeline in this direction decreased consistently as

[1]There are now two additional PADDs (PADDs six and seven) which encompass U.S. Territories. PADD one is further sub-divided in to PADD 1A as New England, PADD 1B as the Central Atlantic, and PADD 1C the Lower Atlantic.

pipeline receipts of Canadian oil sands crude and Bakken crude reduced the need in PADD 2 for Gulf Coast crude. In fact, most movement has been between PADDs 2, 3, and 4 with very little into or out of 1 and 5 (Table 8.2). This shift is a function of increased tight oil availability and the decreased need for both conventionally drilled and imported crude oil.

Table 8.2 Crude oil inter-PADD pipeline movements 2010 and 2017.

PADD	From 1	From 2	From 3	From 4	From 5	Total receipts
2010						
To 1	–	2	6	0	0	**8**
To 2	0	–	440	65	0	**505**
To 3	5	50	–	2	0	**57**
To 4	0	22	0	–	0	**22**
To 5	0	0	0	12	–	**12**
Total shipments	**5**	**74**	**446**	**79**	**0**	**604**
2017						
To 1	–	2.3	1.9	0	0	**4.2**
To 2	0.7	–	368.1	227.1	0	**596.7**
To 3	0.9	493.7	–	4.1	0	**498.7**
To 4	0	84.1	0	–	0	**84.1**
To 5	0	0	0	0	–	**0**
Total shipments	**1.6**	**580.1**	**370.0**	**231.9**	**0**	**1183.7**

Source: Modified from US Energy Information Administration data.

As significant as crude oil production is for the US energy economy, unlike natural gas it cannot be used for much in its natural state, and must be refined. Tracking the refining capacity of the PADDs provides another critical data point needed for efficient demand response management. As of January 1, 2018, there were 135 operating refineries throughout the United States located in each PADD, although not surprisingly the preponderance of refining capacity is on the Gulf Coast (Fig. 8.15).

Because crude oil varies in sweetness (sulfur content) and API gravity (viscosity), not every refinery is capable of processing every crude oil (Fig. 8.16). One of the challenges for refining Light Tight Oils (LTO) like those from the Bakken, Permian Basin, and Eagle Ford plays is their propensity for being lighter and sweeter than what most US refineries are designed to process (Leffler, 2008). This was the reason for the Dakota Access Pipeline that caused so much recent concern and protest on the Standing Rock Indian Reservation in North Dakota and South Dakota. The only refineries in the nation that can handle Bakken crude oil are on the Gulf Coast, and the pipeline was envisioned as a safe and reliable method of getting it there. Although the tribal territorial and sovereignty issues are absolutely valid, these do not negate the fact that pipelines are the most

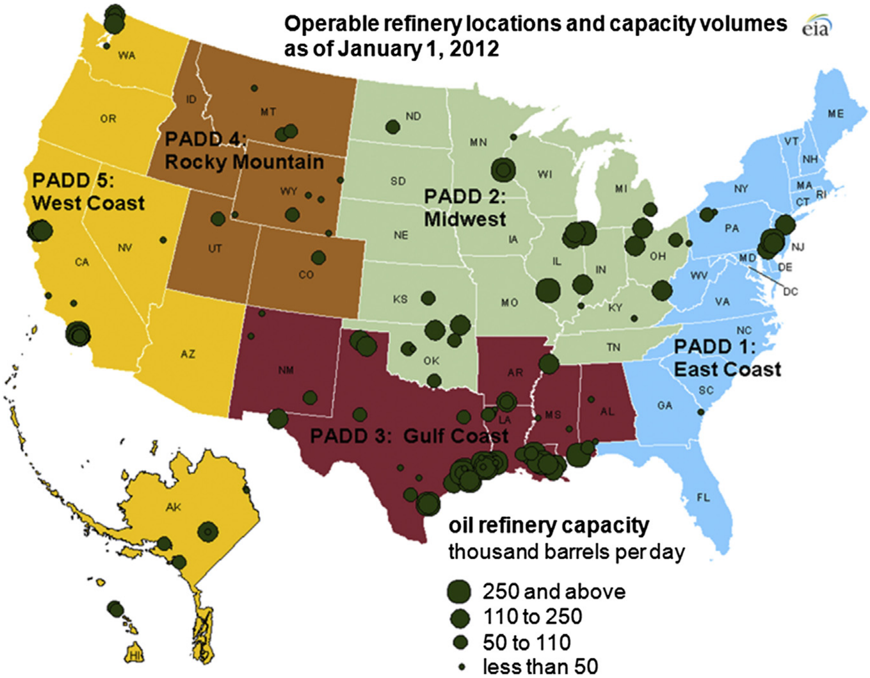

FIGURE 8.15 Locations and relative sizes of US refineries, 2012. *Source: Reproduced from US Energy Information Administration webpage.*

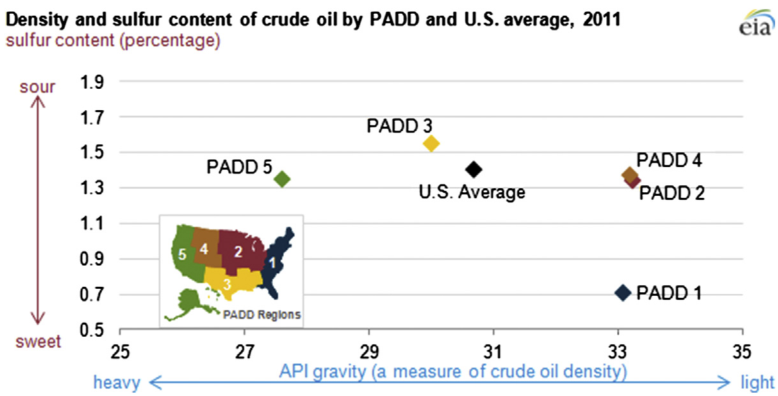

FIGURE 8.16 Density and sulfur content of crude oil by PADD and US average, 2011. *Source: Reproduced from US Energy Information Administration webpage.*

efficient method for transporting oil over long distances. The route was the problem, not the pipeline itself.

Refining capacity can be measured in two ways: barrels per calendar day (the input that can be processed in a 24-hour period including both planned and unplanned maintenance) and barrels per stream day (maximum number of input barrels that can be processed within a 24-hour period running at full capacity with no allowance for downtime). Refineries serve as the actual choke point for domestically produced and imported crude oil. No matter how much crude oil is fed into a refinery, the maximum output of products (if all goes well) will be its rating in barrels per stream day, and more likely its rating in barrels per calendar day. Figs. 8.17 and 8.18 together illustrate the operating capacity of US refineries, including the portion of processed crude oil that comes from domestic production.

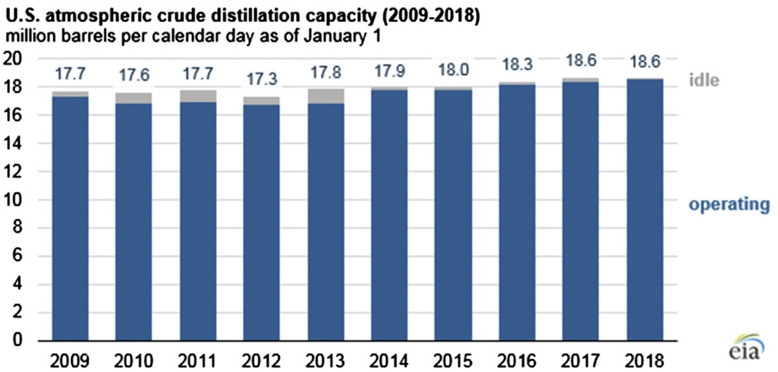

FIGURE 8.17 US atmospheric crude distillation capacity, 2009–18. *Source: Reproduced from US Energy Information Administration webpage.*

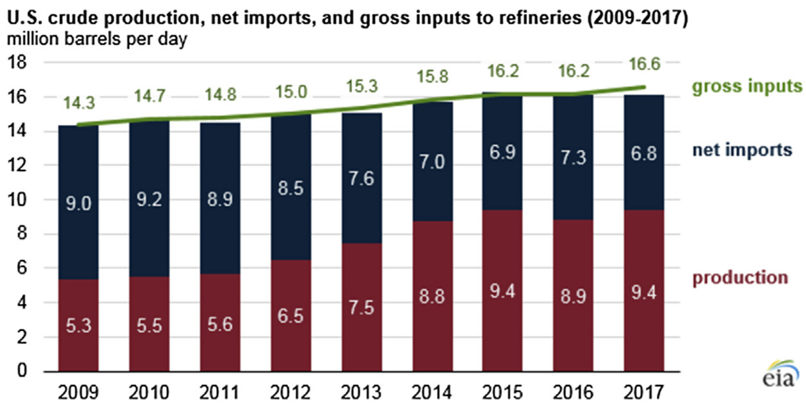

FIGURE 8.18 US crude production, net imports, and gross inputs to refineries, 2009–17. *Source: Reproduced from US Energy Information Administration webpage.*

Refinery capacity can be increased either by building new refineries or adding additional processing stacks to existing units. However, getting through the permitting process and constructing additional capacity does not happen overnight. The advent of LTOs abruptly changed the types of crude oils being processed. Because these could be handled by only a limited number of refineries, many are operating at near maximum capacity. Refinery utilization rose from 83% in 2009 to 91% in 2017. As mentioned earlier, just having crude oil available isn't enough; it must be processed into usable forms—gasoline, diesel, jet fuel, lubricants, and chemical feedstocks for consumer goods like plastic.

Element 5: Promoting deployment of clean and sustainable energy technologies and continued investment in research and innovation

Energy security requires stable and abundant indigenous resources. As discussed earlier, natural gas produces lower CO_2 emissions when used as an energy source. While other clean and sustainable energy sources exist, Element 5 should be considered in light of continued investment in research and innovation pertaining to shale gas and tight oil development. Between 1978 and 1992, the DOE invested approximately $137 million in the Eastern Gas Shales Project (Fig. 8.19). The intent of this program was to commercialize technologies, many of which contributed to the shale gas revolution and are in use today. The DOE continues to conduct R&D in reducing potential environmental impacts of shale gas development, particularly in the areas of water quality and availability, induced seismicity, methane emissions, subsurface science, footprint reduction, and transportation and storage.

The impact of R&D investment for unconventional oil and gas that led eventually to the shale revolution can be seen in Fig. 8.19 at the right side from 2005 onward. Production of natural gas increased dramatically, and as expected, after investments had been made by both the DOE and industry. As described in earlier chapters,

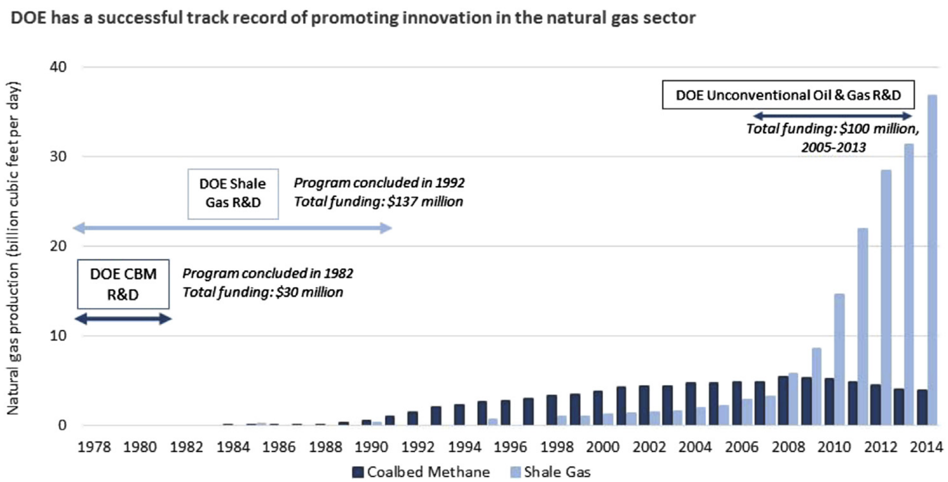

FIGURE 8.19 DOE Shale Gas R&D compared to production. *Source: Reproduced from DOE Office of Oil and Natural Gas, 2016a.*

unconventional resources were known to contain significant quantities of oil and gas but due to technical limitations could not be produced. Once the technology improved, many of these resources were produced at profitable levels, but some areas were still not economic and had low estimated ultimate recoveries. Investments in the technology by both industry and government have continued to improve the recovery of unconventional resources, including a number of plays formerly thought to be marginal.

The term estimated ultimate recovery, or EUR, is the amount of oil and gas expected to be economically recovered from a reservoir or field by the end of its producing life.[2] "Economically" recoverable is an important distinction as there are and will be plays or fields containing economically unrecoverable oil and gas. If it costs more to produce petroleum than can be made on the sale, oil companies will not produce the field. Thus, while there may be a constant amount of petroleum in the ground, the EUR will vary depending on the technology available and the price of oil or gas at the time of production.

In keeping with the national and energy security goals, increasing EURs have a direct impact. The R&D investment in unconventional oil and gas incorporated cleaner technologies in their mandates. The improvements in EURs, and concomitant decreased environmental stresses, come through either technological or operational improvements. The former, from combining horizontal drilling and hydraulic fracturing to extract petroleum or optimizing horizontal drilling techniques specific to the geology of different places, and the latter through optimizing lateral lengths, increasing frack volume and sand emplacement per foot of lateral length, and refining frack water ratios (Murali, 2018).

Element 6: Improving energy systems resilience by promoting infrastructure modernization and supply and demand policies that help withstand systemic shocks and cyberattacks

A resilient infrastructure system is essential to energy security. Transportation, storage, and distribution systems must be able to "handle a diverse and evolving mix of energy sources and products; link sources, possessors, and users across immense distances; match demands that vary on multiple time scales… and perform 24 hours a day, 365 days a year with high reliability…" (DOE, 2015). Shale gas and tight oil impacts are not seen as directly within this element as in some of the others. A couple of points are worth noting, however.

First, the expansion of pipeline capacity, both gas and crude oil, in the Rocky Mountain and northern Great Plains regions are the result of increased shale gas and tight oil production in those areas. Supply chains in those regions for petroleum products are configured in a hub and spoke system, with supply moving from in-region refining and logistical hubs outward to geographically dispersed markets (Fig. 8.20).

[2]Schlumberger Oilfield Glossary.

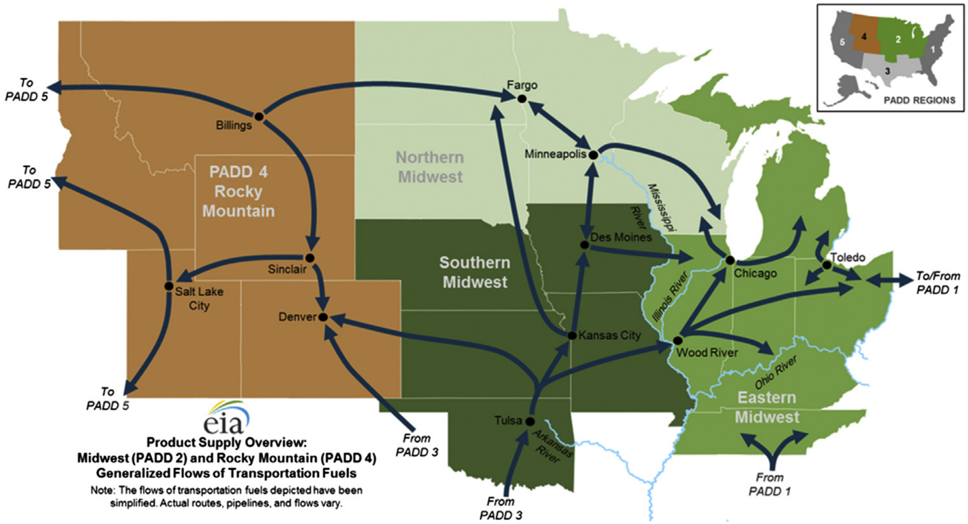

FIGURE 8.20 Product supply overview: Midwest (PADD 2) and Rocky Mountain (PADD 4) Generalized Flow of Transportation Fuels. *Source: Reproduced from US Energy Information Administration webpage.*

Bakken crude oil, a light, sweet crude, took a price hit initially simply because it could not easily or cheaply make its way out of North Dakota and Montana. With increased oil pipeline capacity, crude oil from basins in the Rocky Mountains and northern Great Plains can connect to markets and/or refineries more easily.

Second, the direction of gas movement has changed in the last decade. This is not an easy process as natural gas can be transported only via pipeline or in liquefied form. One standout example of changing gas flow direction is the south central region of the United States. Gas used to flow in this region from production wells on the Gulf Coast to large cities in the Northeast. However, the Marcellus Shale in the Appalachian basin is now the largest gas producing formation in the country. Gas flows from Pennsylvania and West Virginia into the big cities of the Northeast, but it also flows backward down the pipelines toward the Gulf Coast. Processing plants for natural gas liquids like ethane are primarily located in Texas and Louisiana. In addition, several export terminals for shipping LNG are located (or soon to be located) on the Gulf Coast, requiring additional capacity from pipeline projects. The EIA expects natural gas pipeline capacity to reach almost 19 Bcf/d as roles shift in the south central region from natural gas supply to a location of growing demand. Fig. 8.21 shows the increased contributions from other areas of the country.

Despite the consternation over Keystone XL (KXL) and Dakota Access Pipeline (DAPL), both serve vital roles in moving crude oil. The KXL moves bitumen from Canadian oil sands to storage and refineries in Cushing, Oklahoma. The DAPL moves Bakken crude oil from North Dakota to an oil tank farm in Illinois and then on to Nederland, Texas for refining.

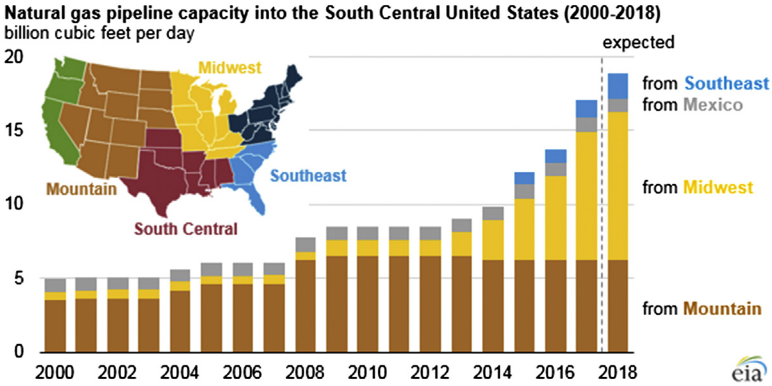

FIGURE 8.21 Natural gas pipeline capacity into the South Central United States, 2000–18. *Source: Reproduced from US Energy Information Administration webpage.*

It goes without saying that sovereignty on native lands should be respected. It is certainly possible to find alternate routes for pipelines to keep them off lands where they are not wanted. Nevertheless, it is important not to lose sight of the fact that pipelines are a safer and less environmentally disruptive method of moving crude oil around the country than tanker trucks or oil trains. Horrific accidents between cars and oil tanker trucks in North Dakota have wiped out entire families. A runaway oil train in Canada nearly incinerated the entire town of Lac-Mégantic in 2013. And for natural gas, there is simply no other way to move it.

Few alternatives to oil and refined products exist and everyone uses them, including the people who drove to Cannonball, ND to protest the DAPL. Without pipelines to provide access to newly developed oil and gas resources outside of historic petroleum producing areas, Americans would be much more reliant on imported oil and gas. Pipeline infrastructure allows access to more diverse fuel sources, which contributes to greater energy and national security.

Element 7: Putting in place emergency response systems, including reserves and fuel substitution for importing countries, in case of major energy disruptions

The Strategic Petroleum Reserve (SPR) is essentially our nation's savings account for crude oil. SPR crude oil, federally owned, is stored at four sites in underground salt caverns in Texas and Louisiana along the coastline of the Gulf of Mexico.

As a result of the 1973–74 oil embargo, President Ford initiated the SPR by signing the Energy Policy and Conservation Act (EPCA) in December 1975. With the intent of providing 90 days of supply in the event of import disruptions, the United States and its allies could protect the American economy from severe supply interruptions, while simultaneously pursuing diplomatic or military solutions to overcome the shortfall. Up to one billion barrels of petroleum could be held in reserve according to language in the EPCA legislation (DOE, 2016c).

As of August 17, 2018, the total inventory of the SPR was 660.0 million barrels, consisting of 254.6 million barrels of sweet crude and 405.5 million barrels of sour crude oil. The International Energy Agency recommends that countries have 90 days protection against import disruption available in both public and private reserves. Current reserves in the SPR are sufficient for 143 days of import disruption protection. The maximum nominal drawdown capacity of the reserve is 4.4 million barrels per day, and the time required for the oil to enter the US market is 13 days from the Presidential decision (SPR website).

The two categories of light gravity (30 degrees—40 degrees API) crude oil and sweet and sour are separately stored in the SPR. The sweet crude contains no more than 0.50 mass percent total sulfur while the sour crude can contain up to a maximum of 1.99 mass percent total sulfur. SPR storage of crude oil along the Gulf of Mexico (GOM) was done for two reasons. First, oil storage underground in leak-tight salt caverns created by solution mining on diapirs is considerably cheaper and safer than surface tanks or other structures. Secondly, the bulk of the nation's refinery capacity is located along the GOM, minimizing transport time to move crude oil from storage to refining.

How did the tight oil revolution affect the SPR? The increase in domestic petroleum production has displaced a significant volume of imported oil. Thus, the requirement for the SPR to cover a 90-day import disruption is less (Fig. 8.22). Greater domestic petroleum production means a decrease in the amount of required strategic petroleum reserves in storage.

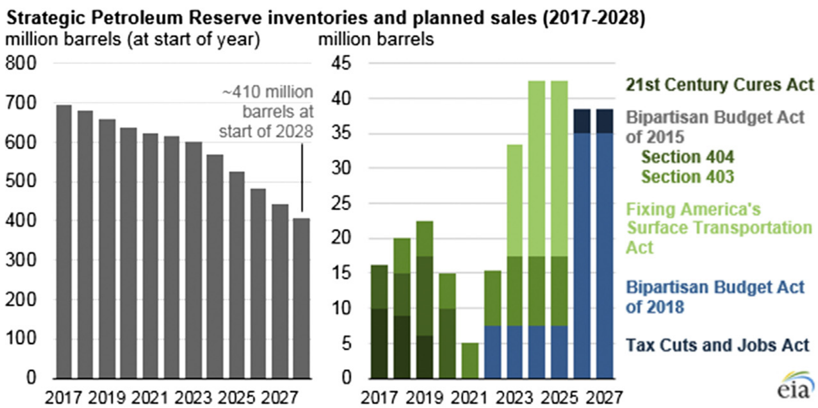

FIGURE 8.22 Strategic Reserve inventories and planned sales, 2017—28. *Source: Reproduced from US Energy Information Administration webpage.*

Limitations to withdrawing petroleum from the SPR are both physical and economic. Petroleum can only be pumped out of storage at a maximum rate of 4.4 million barrels per day because of pipeline volume restrictions and refinery capacity. Dumping large volumes of crude oil on the open market too quickly could result in extreme price drops, potentially leading to economic disruptions. The goal of the SPR is to stabilize the US economy in the event of an import disruption, not drive it off a cliff.

The fossil fuel revolution of shale gas and tight oil affected every aspect of energy security. While the definition of energy security has not changed, American perspectives and understanding of it certainly has. Thanks to shale, the United States is now an exporter of natural gas and crude oil and accessibility to fuel sources is no longer a concern of most citizens. Electricity generation has largely shifted from coal to natural gas, decreasing the rate at which CO_2 is produced. The movement of crude oil and natural gas across the country has shifted as consuming areas become producers and vice versa. The nation has more than half again as much oil in storage than is required for strategic petroleum reserves. Regardless of one's position on using fossil fuels for energy production, the fossil fuel revolution has had a remarkable and profound effect on American energy security and national security.

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9

The politics of energy

Global responsibilities

Energy is a global enterprise. Oil companies have long been international, going to all parts of the planet to obtain crude oil, refining it at many places around the world, and selling the resulting products on the global market. Despite the fact that many nations have "national" oil companies (refer back to Chapter 5), very few of these actually produce and sell oil only within their own national borders. Most behave like the other major oil companies in terms of production and sales, but just happen to be owned by their national governments instead of private investors. Many, in fact, are a combination of government and private capital, with the government retaining the majority interest in the company. Conversely, the five major investor-owned global oil companies: Chevron, ExxonMobil, Royal Dutch Shell, British Petroleum (BP), and Total have more political influence than many small countries (The Economist, 2019).

Electricity and natural gas are far less global than petroleum. This is mainly because of the different delivery systems. Crude oil is easy to transport by rail, pipeline, or ship. Loading up a behemoth tanker with Arabian Light crude oil at the Port of Jeddah on the Red Sea and shipping it to Baytown, Texas, for refining is a very small part of the cost of a gallon of the resulting gasoline.

Natural gas, on the other hand, is transported most economically through a pipeline. This limits the distance between production and utilization to within a single nation, or at best, a single continent. For gas to go overseas on a tanker ship, it needs to be converted into a cryogenic liquid—LNG, which is as cold as liquid nitrogen. The cost of such extreme compression adds considerably to the price, as does the cost of regasification on the other end. The overseas markets for LNG imports are primarily areas with limited access to gas and relatively high gas prices, primarily Japan, South Korea, and parts of western Europe.

Electricity can only be transmitted by wires, and long-distance transmission is done at very high voltages to reduce losses. Despite this, it is rare for electricity to be sent more than a few hundred miles from the generator to the user. The United States and many other countries are set up with an electrical "grid" that allows power to be shuttled from one place to another. Although it is possible with the US grid to send electricity generated at Hoover Dam to users in upstate New York, for example, the transmission losses would be unacceptable. Instead, if New York was suffering from an electricity shortage, say during a severe heat wave, power could be supplied from Pennsylvania, the resulting Pennsylvania shortage would be supplied by Illinois, Illinois by Missouri, and so on until a region with surplus power was reached.

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This complex system of power dispatching can be made even more complex by the addition of "scattered-site power," the electric industry term for rooftop solar panels, small wind generators, and other small power inputs linked into the grid. In order to handle all this, the so-called "smart grid" is being developed that uses complex computer algorithms and artificial intelligence to efficiently control the flow of power across the nation. However, because of unavoidable transmission losses over distance, electricity still needs to be generated relatively close to the point of use in most areas of the United States and the world.

The primary global impact of energy and the primary global responsibility of all governments with respect to energy policy at this writing is to address climate change. The physics of how greenhouse gas emissions from burning fossil fuels affect climate and some ideas for ways to manage them were described in Chapter 6. The consequences of climate change have become clear as glaciers melt, sea levels rise, and storms and droughts intensify. Carbon dioxide levels to date have reached 410 ppm, a 50% increase above the concentrations measured when Mauna Loa Observatory was established in 1957. One problem is that 1957 was essentially in modern times, and levels of CO_2 had already been trending steeply upward since the extensive use of fossil fuels began during the industrial revolution (Fig. 9.1). The actual increase could easily be 70% or greater above a "normal" baseline.

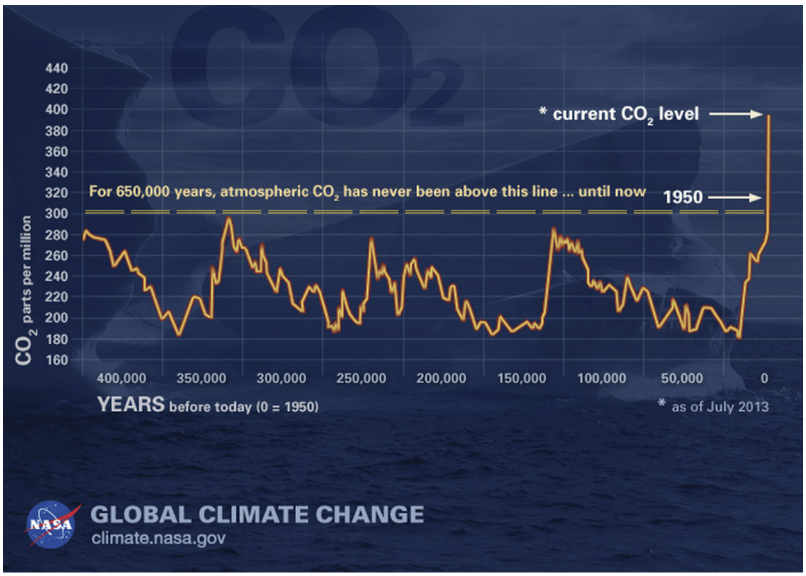

FIGURE 9.1 Carbon dioxide concentration in the atmosphere over the past 400,000 years. *Source: NASA.*

A 70% increase in CO_2 above background levels appears to have been a driving mechanism for the Paleocene–Eocene Thermal Maximum (PETM), one of the most extreme ancient warming events in the geological record that occurred around 56 million years ago (Gehler et al., 2016). The chart in Fig. 9.1 is compiled largely from glacial ice core records, where tiny samples of ancient atmosphere are preserved as bubbles in the ice. It should alarm any thinking person who views it. The 70% rise in GHG that triggered the PETM occurred over a time period of about 6000 years and was probably related to volcanic eruptions (Jardine, 2011). The rise on the NASA chart has been measured over about 60 years, a percentage rate of increase above background levels that is nearly 100 times faster than the PETM rise.

Does a high level of atmospheric GHG contribute to global warming? The geologic record from the PETM certainly suggests that it does. Geochemical studies on material from this time period indicate that approximately 2000 gigatonnes of carbon entered the atmosphere both as carbon dioxide from a series of volcanic events and as methane released from methane hydrates in sea floor sediments. Sea surface temperatures increased by about 6°C at high latitudes and 4°C at equatorial latitudes, with deepwater temperature increases of about 8°C and 6°C, respectively. Temperatures on land increased by about 5°C in the middle latitudes and by 3°C near the equator (Jardine, 2011). The PETM change in climate was not uniform; rather, the climate appears to have become more unstable, with greater ranges of rainfall and droughts, for example. The potential for more extreme events is a prediction of most climate models.

The Earth was warm enough to be free of polar ice caps throughout the Eocene. The modern Antarctic ice sheet is thought to have formed at the beginning of the Oligocene (around 34 Ma) due to global cooling from a drawdown in atmospheric CO_2 caused by increased continental weathering from the rise of the Himalaya Mountains (Zachos and Kump, 2005). If the current climb in global GHG concentrations results in a complete meltdown of existing polar ice sheets, an immense amount of water bound up in continental glaciers on land would be released into the oceans. The overall increase in sea level would be as much as 76 m (250 ft) above current levels (Poore et al., 2000).

One has only to trace the 250-ft contour line on topographic maps of coastal regions to see how destructive this would be. Almost the entire state of Florida would disappear, along with large swaths of Louisiana, the low country of North and South Carolina, the tidewater area of Virginia, all of eastern Maryland, most of Delaware, and much of New Jersey. Significant amounts of New York City would be lost as well. Fittingly perhaps, except for the northwestern corner of the District, nearly all of Washington, D.C. would be underwater, including the Capitol and the White House, and maybe that would spur the government to act on climate change. The number of people displaced and the costs would be staggering. This is not science fiction. The polar ice caps have melted in the past.

Globally, the impact is almost incalculable, affecting entire countries. Bangladesh is barely above water at current sea level and suffers greatly when storm surges come ashore from the Bay of Bengal. A 76-meter rise in the ocean surface would leave nothing dry but a small strip of land along the border with Myanmar. Some island nations like Micronesia, composed of coral atolls only a few meters above sea level, might disappear altogether. Low countries like Holland or water cities like Venice that have fought and won battles against the encroachment of the sea for centuries might find that they have finally lost the war.

There are still some climate contrarians out there who argue that climate varies naturally, and there have been significant climate excursions over geologic time. This is true, and the Earth's climate has varied across geological history from "snowball Earth" during the Neoproterozoic to "tropical Earth" in the Cretaceous. Nevertheless, this has little or nothing to do with the present situation, and it is more than a bit of a stretch to claim that the very steep climb in Fig. 9.1 leading to "current CO_2 level" is natural. Past climate changes, even the "abrupt" global warming of the PETM occurred over thousands of years, not mere decades. The amount of change and the rate of change in Fig. 9.1 are the cause for concern.

The present concentration of CO_2 in the atmosphere is unprecedented in human history and indeed in the history of the Earth since the early Cenozoic. This increase correlates perfectly in time with the human use of fossil fuels. Even if one wishes to accept this as a wildly improbable coincidence, no other sources for large amounts of CO_2 input into the atmosphere (i.e., supervolcanoes, etc.) have been identified. The carbon dioxide increase on the chart can be very much laid at the feet of two centuries of fossil fuel combustion. The amount of CO_2 emitted is actually much higher than what is shown in Fig. 9.1. The oceans have absorbed a significant amount of the gas, which forms carbonic acid when dissolved in water and has resulted in a global lowering of seawater pH. This "ocean acidification" is proving detrimental to marine life, which evolved under essentially neutral conditions. The low pH is leading to bleaching of coral reefs and affecting the ability of marine animals to form protective shells. No one knows how much more CO_2 the oceans can absorb.

For the past 10,000 years climates have been relatively stable. This stability allowed for the development of agriculture, a human lifestyle change from hunter-gatherers to farmers, the advent of permanent settlements, and the development of civilization. Increased instability is a prediction of most climate models, resulting in droughts, floods, more severe storms, and famines. These will lead to displaced populations, loss of farmland, migration of refugees, and increased tensions wherever the refugees try to resettle. We have seen this already with refugees from war zones. Given the potentially enormous populations displaced by climate change, things will be much worse. Some climate models indicate that under a "business as usual" scenario, large parts of the world will be at risk from killer heat waves by 2070, placing half a billion people in danger (Kang and Eltahir, 2018).

The single, key action that will help to counter GHG-induced climate change is an energy policy that will sequester[1] carbon from the atmosphere. Very few fossil energy companies have shown an inclination to do this voluntarily because it has no economic

[1]There has been some debate in the international climate community about the political-correctness of using the term "sequester" to describe the isolation of carbon dioxide from the atmosphere. In French culture, the word refers to being held forcefully against one's will, like a kidnapping. The US DOE has adopted the gentler term "carbon storage" to describe the process, but critics point out that the term "storage" implies retrievability, when what is really meant is "disposal." We use "sequester" here because in the United States it implies separation and isolation, which is descriptive of the process.

incentives. Thus, the control of GHG in the atmosphere must be implemented as an international policy, similar to the global ban on CFCs to protect the ozone layer. Replacing fossil fuels worldwide as much as possible with noncarbon sources of energy such as nuclear, wind, and solar will stop adding GHG. The remaining fossil fuels that continue to be used must implement technology to capture the carbon dioxide and sequester it from the atmosphere. The days of simply venting the combustion products of fossil fuels into the air must be over.

The sequestration process is known as "carbon capture and storage" or CCS under US government programs. CCS adds significantly to the cost of electricity (refer back to the discussion in Chapter 7). The US DOE has tried calling it "carbon capture, use, and storage" or CCUS to imply that there is an economic benefit to capturing the CO_2, but ironically the primary "beneficial" use for captured CO_2 is for enhanced oil recovery from conventional petroleum reservoirs, thereby adding even more fossil fuel to the energy economy.

Trying to make CCS appear to be "economical" has done little to kick-start the process. The industrial demand for carbon dioxide is relatively low and already being met. GHG is a waste product from the burning of fossil fuel and should be treated as such. It must be captured and disposed of in a safe and secure manner. This is an added cost to the production of energy, which people are going to have to be prepared to pay. It is currently externalized to all of human civilization as carbon emissions are allowed to escape scot-free from smokestacks and tailpipes into the atmosphere. Those who use fossil fuel should pay for CCS.

The cost of CCS has kept it from being voluntarily utilized by coal-fired power plants or added as a pricey accessory on gasoline-powered vehicles. It will not be implemented unless and until mandated by law. CCS generally refers only to carbon captured directly from fossil fuel combustion, but the policy should also include a related mandate to begin the removal and sequestration of the excess GHG that is already in the atmosphere. The goal of this so-called "direct air capture" (DAC) would be to reduce GHG concentrations back to the 300 ppm level where they have resided for the past 4000 centuries.

Some people have argued that banning fossil fuels or requiring universal carbon capture would incur costs that are more disruptive to world economies than climate change itself (i.e., Adair, 2012). When the actual numbers are put to this supposition, the cost of runaway climate change is much higher and far more unpredictable (The Economist, 2019). The types and amounts of energy used by a society are defined by technology, economics, and policy. Previous chapters in this book have focused on technology and economics. However, policy can also play a critical role, and address issues that cannot be solved by technology or economics.

A few suggested government policies that would address climate change, energy poverty, and energy sustainability are presented below. None of these ideas are new, but neither have any been implemented on a large scale. Time is rapidly running out to address the issues of sustainable energy before climate change crosses a threshold and cannot be turned back.

Carbon tax

The recent proposal of a "Green New Deal" in Congress is admirable, but as long as fossil fuel is the cheapest energy option available, people are not going to willingly spend more money on solar or wind power just because it is the environmentally correct thing to do. It has become apparent over the past several decades that despite the enormous amount of funding for research to improve the technology and economics of renewable energy, fossil fuels continue to remain the least expensive and highest energy density sources of power. Despite the propensity of environmentalists to blame oil companies for all the sins of fossil fuel, there wouldn't be a market if consumers were not demanding cheap energy. However, the cost advantage of fossil fuels over other energy resources is due in a large part to the zero economic consequences of GHG emissions that contribute significantly to climate change.

Any and all costs associated with climate change caused by fossil fuel GHG emissions are currently borne solely by taxpayers, and even more critically, by future taxpayers who haven't even been born yet. This is morally and ethically wrong, and our children and grandchildren are right to hold us accountable for the damage being done to the world they will inherit. Greed-driven environmental sins committed by past generations, such as clear-cutting forests, hunting whales and buffalo nearly to extinction, and turning productive prairies into dustbowls from poor farming practices can mostly be forgiven as acting out of ignorance. The GHG spike in Fig. 9.1 is clear evidence that the present generation cannot use the same excuse, and greed-driven climate change is both structural and deliberate.

If we as a society are going to continue to use fossil fuels as a component of our energy mix, and it appears that we will, then managing GHG emissions is absolutely critical to the survival of our civilization. Many of the economic advantages enjoyed by fossil fuels over noncarbon emitting energy sources can be eliminated by imposing a national carbon tax, based on the amount of CO_2 emitted per Btu of energy. This would be highest for coal, and lowest for natural gas, immediately providing a cost advantage for the cleanest fossil fuel over the dirtiest. The tax should be high enough so that the levelized cost of electricity (refer to Table 7.1) from fossil fuel—based primary energy sources is equivalent to the cost from renewables without any tax credits. (With a carbon tax, renewables will no longer need tax credits to be competitive.)

A carbon tax must be implemented by all nations, worldwide, at the same time. No country should gain an unfair cost advantage for fossil energy over others by avoiding the tax. After all, everyone on Earth is affected by the problem of climate change and everyone must be part of the solution. Nevertheless, as the greatest per capita user of fossil fuels, the United States should lead the way.

The cost of fossil fuels will increase with a carbon tax, undoubtedly resulting in much complaining. Coal and petroleum companies in particular have historically opposed the very notion of such a tax because even if they pass the cost along to consumers, the resulting higher-priced products will decrease sales and reduce profitability. The powerful energy lobby has ensured that the political desire to impose such a tax remains pitifully weak in the US Congress, even as computer models continue to predict alarming future climate scenarios that consistently underestimate the actual rates of change being observed. Congress may not find the will to deal with climate change until the tidal Potomac River is lapping against the steps of the Capitol. At that point, it will be too late.

A carbon tax will achieve three clear benefits:

1. It covers all fossil fuel carbon sources from domestic natural gas water heaters to the largest coal-fired power plants and includes GHG inputs that other taxes or tax credits might have missed. One criticism of electric vehicles, for example, is that obtaining a full battery charge using coal-fired electricity puts more GHG into the air than simply driving the same distance in a gasoline-powered car. A carbon tax will capture this. It also encourages conservation; because of the higher costs, people will drive less, eliminate unnecessary trips, turn down their thermostat, and turn off the lights. This reduces fossil fuel combustion and reduces GHG emissions. Biofuels, containing carbon derived from the atmosphere would not be subjected to the tax, making them cheaper and more desirable.
2. A carbon tax makes the cost of renewables and other non-GHG energy options more competitive with fossil fuels. It is all well and good to call for more wind and solar power, but the only way that will happen is if the cost per KWh is comparable to the cost of coal or gas-fired electricity. Technological advances have done wonders to bring solar PV and wind turbines down in cost, but they seem to have bottomed out and electric power from these sources is still more expensive than fossil energy. The answer is to raise the cost of fossil fuels with a carbon tax to bring them up to parity with renewables. The carbon tax would also counter the argument that the manufacturing process for wind turbines or solar PV panels emits more CO_2 than the turbine or PV eliminates. Any CO_2 emitted by the factory would be subject to taxation and then sequestration.
3. Finally, a carbon tax would provide a revenue stream that could be used to remove CO_2 from the atmosphere and sequester it on an industrial scale. There have been endless studies of the process, which include various methods for capturing the CO_2 and storing it underground in depleted conventional oil and gas reservoirs, unmineable coal seams, depleted gas shales, fractured basalts, and deep saline aquifers. Each option has advantages and disadvantages in terms of access, ease of injection, and retention of the gas in the subsurface (USDOE, 2012). None are perfect, but it is past time to stop studying this and use carbon tax revenues to build facilities for sequestering captured carbon dioxide on a large scale in the deep subsurface.

Almost all of the current CCS operations are set up at fixed carbon sources, like coal-fired power plants. The capture of CO_2 from the stack gases is relatively easy using a pressure-swing amine absorption technique, although other capture technologies are under development. However, carbon capture at a power plant only eliminates carbon dioxide emissions from a single source and does nothing about the high levels of GHG already present in the atmosphere. There has also been little to no effort to capture carbon dioxide from mobile sources like vehicles. This technology requires funding to develop and implement.

To address atmospheric levels of CO_2, direct air capture (DAC) is being tested on a pilot scale in both British Columbia and Switzerland (Kramer, 2018). The DAC process forces large volumes of air through devices called contractors that remove CO_2 with chemical absorbents such as hydroxides or amines. The engineering process is complicated and critics point out that the cost would be prohibitive, while the impact would be small (American Physical Society, 2011). Nevertheless, proponents claim that the technology is more efficient at atmospheric carbon dioxide removal than planting forests, and DAC operations could occupy land areas such as desert or tundra that cannot support trees. There is also a potential for a technological breakthrough that could discover a more efficient capture method and improve throughput. Current debate is centered around the cost per ton of carbon recovered and potential revenue offsets to improve the economics, such as turning the waste CO_2 into feedstock for a synthetic fuels plant. With CO_2 removal from the atmosphere being funded by a carbon tax, the economic viability of DAC would not be a concern.

The bottom line is that active measures must be taken to combat climate change. The imposition of a carbon tax on fossil fuels will eliminate an externalized cost and force industry and consumers to pay for GHG emissions. The higher cost will encourage conservation and reduced use of fossil fuels, especially coal and petroleum, the two highest emitters. The higher cost of fossil fuel also will make alternative, noncarbon energy sources and biofuels more competitive in price, and hence more attractive. Finally, a carbon tax will provide a revenue stream for implementing CCS on an industrial scale, both for fixed sources and direct air capture. We need to get on with it. The longer we wait, the harder this will be to fix.

Nuclear power

There are presently 60 commercial nuclear power plants in the United States, operating 98 reactor units. These plants generate about one fifth of the nation's electricity. Most of them were built from the 1960s to the 1980s and are nearing the end of their 40- to 60-year operating licenses. The closure of these plants could represent a major reduction in nuclear electricity production by 2050. While some people see the elimination of nuclear power as an opportunity to expand renewables, it is important to remember that renewables have some of their own issues (refer back to descriptions in Chapter 7).

Nuclear power is a carbon-free, large-scale baseload energy option that is an important domestic component of an "all of the above" energy strategy.

Nuclear power has two major problems. The first is that the two common reactor designs currently used in the United States are complex and expensive. It may require a decade or longer to commission a new reactor in the United States. The engineering performance requirements and regulatory review criteria are formidable and have caused many electric utilities to back away from nuclear power plant construction. The second problem is the nuclear waste issue, discussed in the "Cradle to Grave" section in Chapter 7. Without a viable plan for the handling and disposal of high-level radioactive waste, an electric utility would be foolish to commit to new nuclear power plants.

However, nuclear power plants are needed. The technology is mature and well-understood. New designs for small reactors that use molten salt as the heat exchanger are simpler, less expensive, and not big enough to suffer core meltdowns. Constructing multiple small reactors in parallel can provide as much electricity as a single large reactor in an array that is safer and much easier to maintain. These new designs are modular and can be manufactured to exacting specifications under controlled conditions in a factory, tested, certified, and reassembled on site. Current reactors have had essentially the entire assembly, including the core, pressure vessel, coolant pipes, heat exchangers, pumps, and controllers constructed piecemeal on site and laboriously fitted together, resulting in tedious delays to inspect and test welds and fittings, run system checks, and receive independent certifications for each system. Doing most of this at a factory will save a considerable amount of time and expense. If nuclear is to have a future, the processes for both constructing and commissioning new reactors must become simpler and more streamlined.

The nuclear waste management issue must also be resolved. Given the amount of time, money, and effort that has already been expended at the Yucca Mountain site, combined with the fact that no significant technical flaws have been found that would disqualify the site from meeting the original performance standards, this option should be revisited. Regulatory issues can be overcome if a policy mandate is put into place, the citizens of Nevada are consulted and compensated, the site is properly monitored with the ability to retrieve and repair any damaged or corroded waste canisters and the logistics of nuclear waste transport to the site are resolved. One suggestion for transport is to bring the waste in by air, which would require only the construction of a runway at the site. Flight paths could be routed away from populated areas and only flown during times of good weather. The reprocessing of nuclear fuel is also a policy issue. Worries from the 1970s about nuclear proliferation are no longer valid, largely because just about any country that wants nuclear weapons already has them, even though no one dare use them. Reprocessing nuclear fuel will significantly reduce the quantities of high-level nuclear waste that must be disposed of in a safe and permanent manner.

Nuclear-powered electricity has become a policy issue, not a technical one. Modular reactors are smaller and safer, and multiple units can be connected together in parallel to provide for large power needs. The designated US geologic repository at Yucca

Mountain has no technical problems, only political ones. US energy policy has to decide if nuclear electricity will be one of the noncarbon options to replace fossil fuels, keeping in mind that it is the only technically mature, widespread, noncarbon option that can provide gigawatts of reliable baseload electricity day and night, rain or shine.

Energy storage

Renewable energy has a major downfall: the wind does not blow all the time, nor does the sun always shine. Power dispatch for these intermittent sources of supply is challenging and complicated. Wind and solar are currently used only for peak shaving, because neither has the capacity factor (refer back to Table 7.1) to stay online consistently enough to provide steady baseload power. An efficient and effective form of energy storage is needed for these energy resources to provide electricity day and night, on windy days and calm. People who argue that a "Green New Deal" policy can replace all fossil fuels with renewable energy are ignoring some basic laws of physics unless the energy storage issue is resolved as part of it.

Some significant research is being done on physical and chemical energy storage with battery technology, new developments in fuel cells, capacitors, and mechanical means to store power. Much more needs to be done, especially in the area of efficiency. A substantial percentage of the power placed into storage devices is never recovered. In some cases like CAES or pumped-storage hydro, these losses are considered acceptable because the energy is only withdrawn during times of peak loads. However, for routine energy storage applications, far more efficient processes are needed.

Policies to address GHG and climate change with renewables must also have a strong component of support for energy storage research. Storage is the Achille's Heel of renewable energy and must be solved before the dream of 100% renewables can become reality.

Energy poverty

There are three major strategic challenges to the global energy system: (1) the risk of energy supply disruptions, (2) environmental damage to water, land, and atmosphere caused by energy development and utilization, and (3) persistent energy poverty among approximately one billion people in the world (Birol, 2007). Energy poverty is defined in a number of ways, but it essentially means little or no access to electricity or modern fuels. This includes using biomass (i.e., wood, brush, or dung) for heating and cooking, nonelectric lighting (i.e., oil lamps), draft animals or walking for transportation, and manual labor to gather fuel and obtain drinking water.

The problem of energy underdevelopment has not attracted much attention from the energy industry. The United Nations has made "affordable and clean energy" one of the goals of the Sustainable Development Program. The UN notes that between 2000 and 2016, the number of people who have access to electricity increased from 78% to 87% of the world population, while the number of people without electricity dipped to just below one billion.

One billion is still a very large number. Most of these people live in rural areas of the developing world. Another three billion people, more than 40% of the world's population, rely on polluting and unhealthy fuels such as coal stoves for cooking. A United Nations sustainable development goal (SDG7) is to ensure that everyone in the world has access to clean and efficient energy by the year 2030 (source UN websites and reports).

The UN is seeking to bring energy to all through investments in solar, wind, and geothermal power and by improving energy efficiency so less power is needed per capita. This actually makes sense, because the infrastructure for solar and wind can be fairly simple and implemented on a house by house, or village by village scale. Cheaper and more accessible solar technologies are critical for Third World countries. Solar PV cells currently in use are made from silicon, which requires a fairly sophisticated process of melting and recrystallizing to manufacture. Even though the cost of silicon PV cells has dropped significantly in the past decade, they are still priced beyond the means of many poor countries.

A new technology under development that uses materials called "perovskites" can literally be painted onto a substrate to make PV cells. Perovskite is a natural mineral composed of calcium titanate ($CaTiO_3$) and lends its name to a class of compounds that have the same type of crystal structure. Researchers at the US Department of Energy's National Renewable Energy Laboratory (NREL) have been working with a perovskite created from methylammonium iodide and lead iodide to make methylammonium lead triiodide (Source: NREL web pages).

Solar cells are designed to maximize efficiency by being tuned to a specific part of the solar spectrum. The addition of bromide or the substitution of some of the lead with tin allows the perovskite cell to reach different segments of the spectrum. Perovskite solar cells are made from a water-based slurry that can be placed onto an appropriate substrate like wet ink onto a newspaper. NREL research is focused on developing a roll-to-roll process that would allow perovskite ink to be applied to flexible glass. When perfected, the method is expected to produce PV cells much more quickly and cheaply than the silicon cells presently in use. Still, without an efficient method for energy storage, it remains technically difficult for solar power to be utilized as the only source of electricity.

Fossil energy, and certainly shale gas, can help to provide baseload electricity in areas of energy poverty. Some will say that this simply releases more fossil carbon into the atmosphere, worsening climate change. However, it is important to keep in mind that carbon emissions from the Third Word, even a fully electrified Third Word, would be miniscule in comparison to carbon emissions from the giant economies of China, the United States, and the European Union. If these three large economies fully adopt CCS and DAC to manage carbon, the planet can probably handle electricity generated from natural gas in the Third World. In addition, replacing the wood or coal fires currently used for cooking with much cleaner natural gas would provide significant positive impacts to the environment and to human health.

However, natural gas from large production fields is a challenge to bring into isolated rural areas because of the need for a pipeline. If abundant shale gas resources are developed internationally (refer back to Chapter 5), perhaps some governments with a surplus of gas might be inclined to run gas lines to remote settlements. On the other hand, a village that happens to sit directly above a shale gas resource could potentially tap it directly for a local energy supply. Because shale resources are considered to be continuous, a well drilled just about anywhere into the formation could be expected to produce something. This was investigated for the Rosebud Sioux Reservation in the United States and found to be feasible (Soeder et al., 2017).

A promising geothermal technology that might be applicable to areas of the world that are currently without electricity is Enhanced Geothermal Systems, or EGS (Feder, 2018). This was described in detail in Chapter 7, but essentially consists of a flow-through system of two deep boreholes connected by hydraulic fractures to circulate a working fluid into the deep subsurface to obtain geothermal heat. Because it taps the heat of hot rocks at depth anywhere on Earth, EGS electricity could be set up in rural towns and villages currently without electricity. If the drilling costs can be brought down to affordable and efficient levels, small EGS power plants could become significant providers of baseload electricity in areas that presently have none.

Energy sustainability

Fossil fuels have powered human civilization for more than two centuries. In the 19th century, steam from coal was used to drive factories, mills, steamships, and locomotives. The first commercial production of petroleum by Edwin Drake in 1859 at Titusville, PA, was intended to power oil lamps, replacing the increasingly expensive and rare whale oil, and essentially saved sperm whales from extinction. In the 20th century, fossil energy made possible self-powered vehicles, heavier than air flight, and electricity with all its benefits. As a technological civilization, humanity owes a huge amount of our success to fossil fuels.

However, fossil fuels are not unlimited. Even with the large quantities found or suspected in shales and other tight rocks, the supply is definitely finite. Eventually they will run out, but long before then, the atmosphere of our planet will resemble that of Venus. If all the carbon from all the fossil fuel in the world is put back into the atmosphere as carbon dioxide, the Earth will be hot, lifeless, and uninhabitable. Not only is fossil fuel production unsustainable, but fossil fuel use is not sustainable either.

So what is sustainable?

Renewables are sustainable. The sun is expected to shine on for another four billion years. The wind will continue to blow for as long as the sun heats different areas of the Earth unevenly, creating pressure gradients. Waterfalls will fall and biomass will grow. All of these resources can be tapped to provide sustainable energy that doesn't adversely affect the climate.

Two sustainable resources for baseload power are geothermal and nuclear. These are more economical at large scales than small, and can tap the heat of the Earth or the heat of radionuclides to produce steam to drive a generator. Drilling costs are the major barrier to geothermal development along with the inability to control hydraulic fracturing precisely enough at depth to ensure that injection and withdrawal wells are substantially connected through the hot, deep rock. The DOE-funded field research site in Utah known as FORGE (Frontier Observatory for Research in Geothermal Energy) is investigating both of these issues (Feder, 2018).

Nuclear power is sustainable and carbon-free as well, especially if reprocessing is used to provide essentially unlimited quantities of fuel. Other options include using a thorium-based fuel cycle, instead of uranium (IAEA, 2005). Thorium itself does not fission but is known as a "fertile" element for reactors. When exposed to neutrons, thorium undergoes a series of nuclear reactions that eventually result in its transmutation to the fissionable uranium isotope U-233. This light isotope of uranium does not produce the so-called transuranic elements like plutonium, americium, and curium that come from irradiating the heavier U-238 isotope. Transuranics are the major health concern of long-term nuclear waste. Thus, Th—U waste is less toxic on long time scales, and the absence of plutonium makes it undesirable to those looking to manufacture weapons. The sustainability of nuclear power will be defined by new reactor technology like molten salt units, new fuel cycles like Th-U, modular construction to reduce the costs and commissioning times for new reactors, and an agreed-upon policy and plan for dealing with high-level nuclear waste.

Fossil fuels have served humanity well, but their time is drawing to a close. The shale gas revolution came at a time when energy security was needed for the United States, and it has provided such security many times over. Shale gas and tight oil may yet provide similar energy security to other countries. The United Kingdom and Peoples Republic of China appear to be the two most likely candidates to develop these resources in the near future.

In the long term, however, fossil fuels are not sustainable. Changing the energy paradigm in the United States and the world will require going up against a lot of oil money and a huge amount of economic inertia. The present abundance of shale gas and tight oil should be used to help transition toward new, more sustainable energy resources. These would be simpler and more efficient nuclear power, enhanced geothermal systems that can be installed anywhere in the world, and advanced battery or other energy storage technology for intermittent power sources like solar PV and wind. There may be others out there that we don't even know about yet. The majors, large independents, national oil companies, and others need to think about transitioning to a new energy future where petroleum engineers focus on the capture and underground storage of carbon dioxide, drillers learn how to emplace geothermal wells into hot, deep rock, and geologists monitor the stability of high level nuclear waste. The only thing constant is change and those who can adapt to it will do well. Those who cannot will be left behind.

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Appendix: Glossary, acronyms, abbreviations and conversions

A Cross-sectional area term in Darcy's law.
AAPG American Association of Petroleum Geologists (professional society).
Aulacogen The failed arm of a plate tectonics triple junction rift system.
Alginite A very hydrogen-rich, oil-prone, amorphous, waxy maceral derived primarily from dead algae.
Annulus The ring-shaped space in a drilling well between the drill pipe and the borehole wall; also the space between concentric casing strings.
Anticline An upward bending structural fold in rocks; downward bending folds are called synclines.
API American Petroleum Institute.
API gravity A measure of the density and viscosity of crude oil. Higher API gravity numbers mean lighter, thinner oil.
Associated gas Natural gas recovered during petroleum production, often dissolved in the oil under pressure and released at the surface.
AU Assessment Unit; a USGS definition of part of a petroleum system used to estimate O & G resources.
Balanced drilling Act of controlling the unit weight or density of drilling mud to maintain borehole integrity and pore pressure.
Barn burner Industry slang for a new gas well that has an exceptionally high rate of initial production.
Baseload Background level of electricity in the system from large power plants to meet minimum demands (see peak shaving).
bbl Barrel of crude oil and petroleum products, equal to 42 US gallons, 35 UK (imperial) gallons, or 159 L.
BEG The Bureau of Economic Geology in Texas, a state natural resources agency.
BCF Billion cubic feet of gas—1 BCF = 28.3 million cubic meters.
BIF Banded iron formation—Precambrian sedimentary deposits of iron oxides and silica, commonly used as iron ore.
Bitumen A thick, tar-like substance derived from kerogen that is a precursor to higher grades of petroleum.
BOE Barrel of oil equivalent—used in reserves estimation to include condensate and other hydrocarbon liquids with petroleum.
BOP Blow-out preventer—hydraulic jaws and ram on the wellhead designed to close off the well in event of a blow-out.
Bottom hole assembly Downhole impeller, mud motor, cutting bit, steering, and navigational equipment used for directional drilling.
BTEX The water soluble components of gasoline—benzene, toluene, ethylbenzene, and xylenes.
Btu British thermal unit—a measure of energy equivalent to about 250 calories; a cubic foot of natural gas contains about 1000 Btu.
CAES Compressed air energy storage—a power storage method using pressurized air in underground reservoirs for electric generation.

CAI Conodont Alteration Index—that uses the color of conodont fossils to assess thermal maturity.
CAPEX Capital expenses—or construction/installation costs for infrastructure.
Casing Protective liner, usually steel pipe, installed and cemented in a well to seal off different zones; each diameter is called a "string."
CCS Carbon capture and storage—the process of removing carbon dioxide from fossil fuel combustion gases and isolating it from the atmosphere.
CCUS Carbon capture, use and storage—a DOE term for CCS that implies an economic benefit to carbon capture.
CNG Compressed natural gas—a potential vehicle fuel.
Combined cycle (CC) A highly efficient power plant that generates electricity from a natural gas turbine and uses the hot exhaust to power a second, steam turbine.
Condensate Natural gas liquids produced as vapor that condense into liquid form at the surface, i.e., propane, butane, and pentane.
DAC Direct air capture—the removal of carbon dioxide and other GHG from the atmosphere, rather than capturing it on a smoke stack.
Darcy Empirical permeability unit named after Henry Darcy; metric: 1 Darcy = 10^{-12} m^2.
deep direct-use An application of geothermal energy such as hot groundwater to directly heat buildings or other structures.
ΔP "Delta P" term for differential pressure in Darcy's law.
Depocenter The geographic location of maximum deposition of a specific geologic unit in a basin.
dip The angle of a fracture plane or other geologic structure from horizontal; a 90° dip is vertical.
Dispatch The art and science of balancing electric power generation with electric power demand.
DOE Department of Energy (US government).
DOI Department of the Interior (US government).
Drilling mud A complex fluid mix used to cool the bit, remove cuttings, maintain borehole stability, and supply hydraulic power to a downhole motor.
DRO Diesel-range organics—a class of contaminants in groundwater.
EGSP Eastern Gas Shales Project—a 1980s DOE shale gas assessment in the Appalachian, Michigan, and Illinois basins.
EIA Energy Information Agency (US government).
EOR Enhanced oil recovery.
EPA Environmental Protection Agency (US government).
ERDA Energy Research and Development Administration—precursor agency to DOE.
EUR Estimated ultimate recovery—the total amount of technically recoverable hydrocarbons from a well.
Exinite A hydrogen-rich, oil-prone maceral typically found in Type II kerogen.
Externalized costs Environmental costs of a company extracting and using an energy resource that is covered by taxpayers, such as stream restoration.
Fault A natural fracture in rock where the two sides have slid past one another.
FEP Features, events, and process—contributing factors to risk in a site performance assessment model.
FIB Focused ion beam—a method for micromilling sample surfaces to atomic smoothness and imaging them.
Flare Burning off associated stranded gas to recover easily-transported hydrocarbon liquids.
FORGE Frontier Observatory for Research in Geothermal Energy—DOE-funded field research site in Utah.
Frack Slang term for "hydraulic fracturing;" the oil & gas industry typically spells it "frac" without the k.
Fractile value Probabilities for resource estimates, usually 5%, 50%, and 95%. Lower estimates have higher probabilities; the 50% probability is typically used.

Fugitive emissions Produced-natural gas leaking into air from faulty seals or connections on surface infrastructure (see stray gas).

Gazprom The Russian state-owned natural gas production, transmission, and distribution company.

Geosteering The art and science of guiding a bottom hole assembly to drill a borehole in a precise location.

GCC Gulf Cooperation Council—Kingdom of Bahrain, Kuwait, Sultanate of Oman, Qatar, Kingdom of Saudi Arabia, and United Arab Emirates.

GHG Greenhouse gas—gases like carbon dioxide and methane that trap heat in the atmosphere.

GIP Gas in place.

Graben A downdropped block of the Earth's crust bounded by faults; see "horst."

GTI Gas Technology Institute in Chicago, formerly the Institute of Gas Technology (IGT).

GW Gigawatt—one billion watts (1000 MW) of electrical energy.

Half-graben Downdropped block of land bordered on just one side by a fault, unlike a full graben where parallel faults downdrop a block of land.

Heel The near end of the lateral where the well begins to curve upward into the top hole.

Horst A raised block of the Earth's crust bounded by faults; see "graben."

IAM Integrated assessment model (system performance assessment for risk).

IEA International Energy Agency (based in Paris, France).

IGT Institute of Gas Technology in Chicago—now known as the Gas Technology Institute (GTI).

Independent A medium sized oil and gas exploration and production company.

IP Initial production—the flow rate at which gas and liquids are produced from a well immediately after completion.

IPCC Intergovernmental Panel on Climate Change—a UN sanctioned body investigating human effects on climate.

Joint A natural fracture in rock where the two sides have moved apart, usually caused by compression.

k Permeability or hydraulic conductivity term in Darcy's law.

Kerogen Naturally occurring, solid organic matter, not soluble in organic solvents, generates hydrocarbons when heated.

kPa kilopascal—metric pressure; Imperial: 1 kPa = 0.145 psi.

kW Kilowatt—one thousand watts of electrical energy; a kilowatt-hour is a metered quantity of electricity.

L Length term in Darcy's law.

Lateral Horizontal borehole used to produce hydrocarbons from shale.

LNG Liquefied natural gas (cryogenic liquid).

LOC Loss of circulation—usually occurs when a drill bit penetrates fractured rock and loses drilling fluid down cracks.

LTO Light, tight oil—sweet, low viscosity, high API gravity oils from tight source rock formations like the Bakken and Eagle Ford shales.

Ma Mega-annum—geological abbreviation for a million years of time.

Maceral The organic equivalent of a mineral—alginite, exinite, and vitrinite are common examples.

MAD Mile-A-Day—a term for ultrafast drilling that achieves extreme rates of penetration.

Major Gigantic, multinational, oil and gas exploration, production, processing, and marketing corporations.

MCF Thousand cubic feet of gas (from the Roman numeral "M"); metric equivalent—1 MCF = 28.3 cubic meters.

Md Millidarcy—a permeability unit of one thousandth of a Darcy.

μd Microdarcy—a permeability unit of one millionth of a Darcy.

METC Morgantown Energy Technology Center—predecessor to NETL.

MMBtu Million British thermal units—1000 cubic feet of natural gas (MCF) is approximately equivalent to 1 MMBtu.

MMcf Million cubic feet of gas—1 MMcf = 28,320 cubic meters.

MMcf/d A production number of a million cubic feet of gas per day.

Mountaintop removal An extremely destructive type of Appalachian coal mining that strips overburden off seams on plateaus and dumps it into adjacent watersheds.

MPa Megapascal—metric unit of pressure equivalent to 1000 kPa (kilopascals).

μ Greek letter (Mu)—viscosity term in Darcy's law.

MW Megawatt—one million watts (1000 kW) of electrical energy.

NA Natural attenuation—the natural microbial and geochemical reactions in an aquifer that break down organic contaminants.

Nd Nanodarcy—a permeability unit of one billionth of a darcy.

NDA Nondisclosure agreement—often required by the O & G industry in return for compensation for damages.

NETL National Energy Technology Laboratory (US DOE).

NGL Natural gas liquids—heavier hydrocarbons produced as vapor that condenses to liquid at the surface; "condensate."

NOx Nitrous oxides—a combustion product of most fossil fuels.

NRCan Natural Resources Canada—the Canadian federal government resource and environmental agency.

O&G Oil and gas—refers to both the resource and the industry.

OIP Oil in place—describes current resources, not to be confused with premigration source rock "original oil in place" or OOIP.

OOIP Original oil in place—oil generated in a source rock from organic material deposited with sediment before any of it migrated to conventional reservoirs.

OPEC Organization of Petroleum Exporting Countries.

OPEX Operating expenses for supplies, salaries, utilities, etc., needed to produce energy or hydrocarbons.

Orogeny A mountain building episode caused by plate tectonic interactions or continental collisions.

Orthogonal joints A box-like set joints present in a rock at approximate right angles to one another, reflecting different episodes of stress over geologic time.

PADD Petroleum Administration Defense Districts—created during World War II to ration gasoline, now used for resource tracking.

Paludal A sedimentary term for depositional environments in marshes or wetlands, often favorable to coal.

Pancaking Oilfield slang for a hydraulic fracture turning from vertical to horizontal as it reaches shallower depths.

Paragenesis An equilibrium sequence of mineral phases.

PDC Polycrystalline diamond composite—a drill bit designed to perform in shale.

Peak shaving Electric power companies response to sudden high demands above baseload, such as air conditioning on hot days.

Pemex Acronym for *Petróleos Mexicanos*—the national oil company of Mexico.

PETM Paleocene-Eocene Thermal Maximum—a climate disruption event caused by a rapid increase in GHG some 56 Ma.

Pinnate A directional drilling pattern of feather-like branched laterals for formations that are too shallow to frack.

PM Particulate matter—often designated as PM_{25} (25 microns; dust) and PM_{10} (10 microns; smoke).

POTW Publicly-owned treatment works—The EPA term for municipal wastewater treatment plants.

Primary energy Energy sources that create power, such as coal, nuclear or natural gas, which can then be transmitted as electricity to do work.

psi; psid Pressure in pounds per square inch, psid is "differential"—Metric: 1 psi = 6.895 kPa (kPa).

Pumped storage Hydroelectric power storage when water is pumped into an elevated reservoir at low demand times and used for generation during peak loads.

PV Photo-voltaic—electricity generated directly from sunlight using solar cells; solar thermal concentrates the sun's heat.

Q Discharge or flow term in Darcy's law.

Recovery efficiency Percentage of GIP or OIP recovered.

Ro Vitrinite reflectance—used to establish degree of thermal maturity.

ROM Reduced order model—individual components of the IAM.

ROP Rate of penetration—Drilling rate.

Rosneft Russia's largest oil company, a contraction for *Rossiyskaya neft* or "Russian oil."

RRC Railroad Commission of Texas—The state agency that issues permits for oil and gas well drilling in Texas.

Sapropel Algal-derived, organic-rich bottom muds rich in fatty and waxy substances.

SEM Scanning electron microscope—uses an incident beam of electrons to image small features.

SCOOP South Central Oklahoma Oil Province—a play in the Woodford Shale and associated rocks.

Silurian hot shale Common name for the organic-rich, radioactive basal units of the Early Silurian (444-433 Ma) Tannezuft Shale in North Africa.

Slickenside A grooved and polished fault surface, common in shale, created by movement of the fault.

Slickwater Frack water treated with polyacrylamide to reduce downhole friction losses.

Sour gas Natural gas containing hydrogen sulfide (H_2S) that cannot be sold into a pipeline without cleanup.

Source rock quality The amount of hydrocarbons generated within a source rock based on TOC, kerogen type, and Ro.

SPE Society of Petroleum Engineers (professional society).

Spent shale A source rock where nearly all of the OOIP has migrated to conventional reservoirs.

Spot price Current market price at which a commodity can be bought or sold for immediate delivery.

Spud The act of beginning to drill (sometimes "spud-in"). The spud is when a drill bit starts making a hole from the surface.

Sputtering The process of micromilling samples by using an FIB to knock atoms off the surface.

STACK Sooner Trend, Anadarko, Canadian, and Kingfisher—Woodford shale play in Canadian and Kingfisher counties, OK.

Stage A segment of the lateral isolated for hydraulic fracturing treatment.

STP Standard temperature and pressure—room temperature (75 deg F or 24 deg C) at 1 atmosphere pressure.

Stranded gas A natural gas resource with no nearby midstream infrastructure to transport it to market.

Stray gas Natural gas in groundwater either generated in-situ or migrated in by a number of different pathways.

Strike The directional orientation of a fracture or other geologic structure, usually expressed as degrees from north.

Sweet crude A rating term for crude oil with low sulfur content; high sulfur crude is called sour.

TCF Trillion cubic feet of gas—1 TCF = 28.3 billion cubic meters.

TD Total depth of a well—more accurately, the total length of the borehole from the surface.

TEM Transmission electron microscope—passes a beam of electrons through samples to image tiny structures.

test Biological and paleontological term for an organism's shell or hard outer covering, from Latin "testa" for shell.

Tmax The maximum temperature a sedimentary rock was exposed to during burial over geologic time.

TOC Total organic carbon.

toe The far end of a lateral where drilling terminates and the first frack stage begins.

Top hole The vertical part of a shale gas well above the lateral.

Turbidite An underwater avalanche of sediment that flows down a steep slope, and deposits coarse material far out into a basin.

UIC Underground injection control—a disposal well regulated by the EPA. Class II wells are designated for oilfield wastes.

UOG Unconventional oil and gas—US government interagency designation for shale gas and tight oil resources.

URTeC Unconventional Resources Technology Conference—annual technical meeting.

Vitrinite A glassy, structured maceral derived from woody land plants; degree of reflectance is used to judge thermal maturity.

VOCs Volatile organic compounds that can create air pollution.

Water cut The ratio of produced water to petroleum or natural gas brought to the surface by a production well. Higher water cuts affect disposal costs.

Whipstock A length of flexible drill pipe invented in the 1930s for directional drilling.

WIS Western Interior Seaway—a large inland sea that extended from the Gulf of Mexico to the Arctic Ocean during mid-Cretaceous to early Paleocene time.

WTI West Texas Intermediate - a crude oil used as a benchmark for setting the price on oil produced in the western United States.

Additional terms and definitions can be found on the US Energy Information Administration's glossary webpage: https://www.eia.gov/tools/glossary/?id=electricity (Accessed 1 Mar 2019)

Bibliography and additional resources

Authors' note: It is impossible to include every bit of important research on a subject in a book where one of the goals is to preserve readability. In the case of shale gas and tight oil, the total amount of technical literature is massive, and growing. The supplemental bibliography provided below is an attempt to gather important publications related to shale gas development, resources, fracking, and environmental risk from a number of different sources, including lists compiled by the USEPA, the American Association of Petroleum Geologists, and the authors. Some of these references were included at the ends of various chapters, but are repeated here for completeness. This bibliography is not intended to be a comprehensive compilation of every relevant publication related to shale gas. Rather, the intent was to provide an overview and survey of the important scientific issues under investigation. — DJS and SJB.

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THE FOSSIL FUEL REVOLUTION

SHALE GAS AND TIGHT OIL

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A comprehensive reference book describing shale gas and tight oil energy resources from geologic beginnings to final usage.

The Fossil Fuel Revolution: Shale Gas and Tight Oil examines the geology and energy resources of shale gas and tight oil, exploring the ten major shale plays in the United States, plus other shales around the world. These shale resources, primarily developed over the past decade, have made the U.S. the largest natural gas and petroleum producing nation in the world, completely changing the global energy economy. This book presents shale gas and tight oil plainly and concisely, thoroughly delving into the subject matter and introducing an overarching big picture view of the shale gas and tight oil geology and production.

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