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COAL

Coal suffers from an incredibly bad image. It has few advocates other than the hundreds of thousands whose livelihoods depend on mining and burning coal by the trainload for generating electricity. No one strikes it rich in coal; that metaphor is reserved for oil. For some, coal brings back an image of coal miners who go in hock to buy a set of tools when they are young and quit decades later with black lung, still in hock to the company store. That might be one of the better images. Another would be the mangled bodies of miners caught in mine mishaps or those trapped by cave-ins awaiting their fate in pitch blackness. Still another would be youngsters harnessed to sleds dragging coal up narrow underground passageways on their hands and knees like pack animals or straddling precariously above fast-moving conveyor belts of coal, picking out the rocks. For still others the image of coal is as a pollutant of the first order that has to be eliminated under any or all circumstances. Nothing short of unconditional surrender can appease these environmental militants.

Yet, at the same time, this biomass fuel from ages past is irreplaceable and absolutely essential to ensure that the lights go on when we flick the switch. World coal consumption, essentially stagnant during the 1990s, surged by 47 percent between 2000 and 2008. Not only is the world consuming more coal, but its share of the energy pie increased from 23.4 percent in 2000 to 29.2 percent in 2008. Coal is becoming more important as a primary source of energy, not less as many people desire. Wishful thinking will not make coal go away, but there are ways to alleviate the worst of its adverse environmental consequences. This chapter reviews the history of coal, its importance in today's economy, and what is being done to overcome its principal drawbacks.

THE FIRST ENERGY CRISIS

The first energy crisis was associated with living biomass (wood). It was an on-and-off-again crisis that extended over centuries. One of several reasons why the natural growth of forests could not keep up with the axe was glassmaking. Glassmaking has a long history, going back to about 3000–3500 BCE, as a glaze on ceramic objects and nontransparent glass beads. The first true glass vases were made about 1500 BCE in Egypt and Mesopotamia, where the art flourished and spread along the eastern Mediterranean. Glassmaking was a slow, costly process and glass objects were considered as valuable as jewels; Manhattan Island was purchased from the Indians for $24 worth of glass beads, and Cortez was able to exchange glass trinkets for gold!

The blowpipe was invented in Syria around 30 BCE. Using a long thin metal tube to blow hollow glass shapes within a mold greatly increased the variety of glass items and considerably lowered their cost. This technique, still in practice today, spread throughout the Roman Empire and made glass available to the common people. Transparent glass was first made around 100 CE in Alexandria, which became a center of glassmaking expertise, along with the German Rhineland city of Köln (Cologne). During the first golden age of glass, glassmaking became quite sophisticated. For example, glassmakers learned to layer transparent glass of different colors and then cut designs in high relief. All these achievements in glassmaking were lost in the 400s with the fall of the Western Roman Empire.

The so-called Dark Ages take on new meaning with the disappearance of glassmaking, but vestiges of glassmaking remained in Germany, where craftsmen invented the technique for making glass panes around 1000 CE. These were pieced together and joined by lead strips to create transparent or stained glass windows for palaces and churches. The second golden age of glass started in the 1200s when the Crusaders reimported glassmaking technology from the eastern Mediterranean. Centered in the Venetian island of Murano, glassblowers created Cristallo glass, which was nearly colorless, transparent, and blown to extreme thinness in nearly any shape. In the 1400s and 1500s, glassmaking spread to Germany and Bohemia (Czech Republic) and then to England, with each country producing variations in type and design of glass objects. The ubiquitous glass mirror was invented comparatively late, in 1688 in France.[1]

Glass is made from melting a mixture of mostly sand (silicon dioxide) plus limestone (calcium carbonate) and soda ash (sodium carbonate) in a furnace, along with glass waste, at a temperature of around 2,600–2,900°F. Considering what has to be heated to such high temperatures, clearly glassmaking was an energy-intensive process that consumed a lot of wood. As forests were cleared, glassmaking furnaces were moved to keep close to the source of energy rather than moving the source of energy to the furnaces. The first energy crisis began when English manors for the rich and famous were built with wide expanses of glass panes that opened up their interiors to sunlight. Not only did this put a strain on wood resources for making the glass, but also on heating since interior heat passes more easily through a glass pane than a stone wall covered by a heavy wool tapestry.

The growing popularity of glass was not the only villain responsible for deforestation. Part of the blame lies with the increased demand for charcoal used in smelting iron, lead, tin, and copper. Consumption of these metals increased from a growing population, greater economic activity, and an improving standard of living as humanity emerged from the deep sleep of the Dark Ages. Deforestation started around London in 1200 and spread throughout the kingdom. By the 1500s metal ores had to be shipped to Ireland, Scotland, and Wales for smelting, deforesting these regions in turn. One of the economic drivers for the founding of the Jamestown colony in Virginia in 1607 was to take advantage of the New World's ready supply of trees to make glass for export to England. The rapidly escalating price of firewood, the economic consequence of deforestation, provided the necessary incentive to search for an alternative source of energy. The final answer to the energy crisis was not deforesting the living biomass of the New World, but burning the long-dead biomass of the Old World.

THE ORIGIN AND HISTORY OF COAL

Switching from wood to coal had an environmental consequence. Living plants absorb carbon dioxide from the air, which is released when they decay. For sustainable biomass energy, carbon dioxide is simply recycled between living and dead plant matter and its content in the atmosphere remains unchanged. One way to decrease the amount of carbon dioxide in the atmosphere is to increase the biomass, such as planting trees on treeless land (afforestation), but this is neutralized when living and dead plant matter are once again in balance. The other way is to interrupt the decay process. And this is what happened eons ago when huge quantities of dead plants were quickly submerged in oxygen-starved waters. This delayed onslaught of decay interrupted the natural carbon dioxide cycle.

The partially decayed plants submerged in swamps first became peat. Peat has a high moisture content that is squeezed out if buried by silt of sand, clay, and other minerals from flowing water. Continued burying, either by the land submerging or the ocean rising, added sufficient weight to transform the original deposits of sand and clay to sedimentary rocks and peat to coal. Three to seven feet of compacted plant matter is required to form one foot of coal. Some coal veins are 100 feet thick, which gives one pause to consider how much plant life is incorporated in coal. Most coal was formed 300–400 million years ago during the Devonian and Carboniferous geologic epochs when swamps covered much of the earth and plant life thrived in a higher atmospheric concentration of carbon dioxide. The interruption of plant decay by the formation of massive peat bogs removed huge amounts of carbon dioxide from the atmosphere, clearing the way for a more hospitable environment for animal life. However, some coal is of more recent vintage, laid down 15–100 million years ago, and the newest coal has an estimated age of only 1 million years. When coal is burned we are completing a recycling process interrupted eons ago, or much more recently for those who believe that coal stems from Noah's Flood.

Peat bogs are found in Ireland, England, the Netherlands, Germany, Sweden, Finland, Poland, Russia, Indonesia, and in the United States (the Great Dismal Swamp in North Carolina and Virginia, the Okefenokee Swamp in Georgia, and the Florida Everglades). The high water content has to be removed before peat can be burned as a biomass fuel whose heat content is much lower than coal. Peat is burned in Ireland for heating homes and in Finland for heating homes and generating electricity as a substitute, along with wood waste, for imported fossil fuels. Peat is also mixed with soil to improve its water-holding properties and is a filter material for sewage plants. Once removed, fish can be raised in the resulting pond or, if the peat bog is drained, agricultural crops can be grown, or the peat bog can simply remain fallow. There is always the possibility that these peat bogs may one day become coal beds if buried by hundreds of feet of silt and water.

As in many other areas, the Chinese beat out the Europeans in burning coal. Coal from the Fu-shun mine in northeastern China was consumed for smelting copper and casting coins around 1000 BCE. In 300 BCE the Greek philosopher Theophrastus described how blacksmiths burned a black substance that was quite different from charcoal. From evidence in the form of coal cinders found in archaeological excavations, it is known that Roman forces in England burned coal as a fuel before 400 CE. Although the Romans did not record burning coal, they did record a "pitch-black mineral" that could be carved into trinkets for adorning the human body. That pitch-black mineral was an especially dense type of coal. Like glassmaking, burning coal for heat and blacksmithing and offerings to the gods, plus carving into trinkets for the fashionable of Rome, disappeared along with the Roman Empire. We presume that ever-expanding human knowledge being passed on to following generations has always been ongoing, is ongoing, and will always be ongoing. This, as history clearly shows, is an unwarranted presumption.

The English rediscovered coal in the 1200s during an early episode of deforestation around London, about the same time that the Hopi and Pueblo Indians began burning coal to glaze their ceramic ware in what is now the U.S. Southwest. After the coal gatherers picked up the coal lying on the ground on the banks of the River Tyne near Newcastle, they began chipping away at the exposed seams of coal in the nearby hillsides. Coal mining started when holes became tunnels that bored deep into the thick underground seams of coal. A new profession and a new class of people emerged, ostracized by the rest of society by their origin (displaced peasants) and the widely perceived degrading nature of their work. Coal miners as individuals were at the mercy of the mine owners until they learned to band together for their mutual benefit and protection, giving birth to the modern labor movement.

And there was plenty of incentive for miners to band together as the coal miners bored deeper into the earth. Mining is a very dangerous occupation. Cave-ins can trap the miners. If not immediately snuffed out by the falling rock, they remain trapped, awaiting rescue or dying from asphyxiation or starvation. To combat the peril of cave-ins, miners bonded with huge rats that lived in coal mines by sharing their meals with them. Miners remained alert to the comings and goings of the rats on the theory that rats could sense a cave-in before it occurred, not unlike rats deserting a sinking ship. Perhaps miners' casualty lists best document the perspicacity of rats to sense impending disaster.

In addition to cave-ins, coal miners had to contend with poisonous gases. Mining could release pockets of carbon dioxide or carbon monoxide, odorless and colorless gases of plant decay trapped within the coal seam that quickly killed their victims by asphyxiation. Canaries were the best defense since their chirping meant that they were alive. When they stopped chirping, they were already dead, a dubious warning system at best. A third colorless and odorless gas was methane, also released by mining operations when they exposed pockets of natural gas embedded in the coal seam. Unlike carbon dioxide and monoxide, methane is lighter than air and combustible. As methane accumulates along the ceiling of a mine, it eventually comes in contact with a lighted candle where it either burns or sets off a horrific explosion, depending on its concentration. A new professional, called, euphemistically, a fireman, would wrap his wretched body with wet rags and crawl along the bottom of the mine holding up a stick with a candle at the end, hoping he would discover methane before it was sufficiently concentrated to set off an explosion. Now all he had to do was hug the mine floor while the methane blazed above him.

Coal found in the hills around the River Tyne was moved down to the river and loaded on vessels for shipment to other parts of coastline England, notably London. Access to water provided cheap transportation on ships whereas the overland movement of coal on packhorses was prohibitively expensive. Roads hardly existed and, where they did, deep ruts made them impassable for heavily laden horse-drawn wagons. By 1325, coal became the first internationally traded energy commodity when exported from Newcastle to France and then elsewhere in northern Europe. Thus, coal saved not only the English but also the European forests from devastation. The saying "carrying coals *to* Newcastle" originally referred to something only a simpleton would do since Newcastle was the world's first and largest and most famous coal-exporting port. Six and a half centuries later, coal was carried to Newcastle when Britain began importing coal.

Burning coal made an immediate impression on the people. In 1306, the nobles of England left their country estates to travel to London to serve in Parliament, as was their custom. This time there was something new in the air besides the stench of animal dung, raw sewage, and rotting garbage. The nobles did not like the new pungent aroma spiced with brimstone (sulfur) and succeeded in inducing King Edward I to issue a ban on burning coal. It is one thing for a king to issue a ban, and quite another to enforce it, the classic limit of power faced by parents of teenagers. Regardless of the king's edict, the merchant class of newly emerging metallurgical enterprises had to burn coal because wood was not available in sufficient quantities around London, and what was available was too expensive. Simple economics overruled the king's ban. The fouling of the air of London and other English cities remained for centuries to come. It is hard to imagine that the charming English countryside we know, speckled with quaint towns, cottages, and farms was once, like the eastern United States, nearly one continuous forest.

From the beginning, coal was a matter of dispute between the church, which happened to own the land where the coal was found, the crown, which coveted this natural resource, and the merchant class that transformed coal into a considerable amount of personal wealth. As church, crown, and capital struggled over who would reap the financial benefits, merchant vessels were built to ship coal on the high seas. This, in turn, necessitated building naval vessels to protect the merchant fleet from marauders and pirates. The English also imposed a tax on non-English vessels carrying coal exports, which greatly favored the building and manning of English ships. In this way, coal contributed to making England a sea power and is, therefore, partly responsible for the emergence of England as the world's greatest colonial power. Growth of sea power put more pressure on forests for lumber to build ships and, in particular, trees fit for masts, which eventually would be harvested in English colonies in the New World.

The Black Death did not enhance coal's reputation as its victims turned black while smelling brimstone in the air from burning coal, widely interpreted as to where they might be heading. The Black Death wiped out about one-third of Europeans. The depopulation of London meant less coal had to be burned, improving the quality of its air, and forests regained a toehold in the countryside. The reign of Elizabeth I was marked by increases in population and economic recovery after the Black Death, spurring demand for firewood. She greatly expanded the English Navy to defend the kingdom against the Spanish Armada, increasing the demand for lumber and masts to build warships and charcoal for smelting iron for ship armament. This again put pressure on the kingdom's forests, resulting in widespread deforestation throughout England and another steep rise in the price of firewood.

The adoption of the chimney in London homes in the 1500s allowed for the conversion from wood to coal for heating in the early 1600s, a conversion already completed by industry. While the ability of chimneys to keep the heat inside and channel smoke outside was an advantage for those who dwelt inside, the same could not be said for those who ventured outside. Appalling amounts of acrid smoke eroded and blackened stone in statues and buildings, stunted plant life, affected the health of the population, and made black and dark brown the colors of choice for furnishings and fashion.

London was not the only city that suffered from severe air pollution. During the rapid advance of the Industrial Revolution in the nineteenth century, Manchester became the center of British textile manufacturing and Pittsburgh the center of American steelmaking. The former suffered mightily from coal burned in steam engines to run the textile machines and the latter from coal consumed in making steel. Not all cities suffered equally. Philadelphia and New York were spared at first because of rich anthracite coalfields in eastern Pennsylvania. Anthracite, a hard coal of nearly pure carbon, burns with little smoke. Unfortunately, anthracite reserves were in short supply when coal-burning electricity-generating plants were built at the end of the nineteenth and early twentieth centuries. These plants burned cheaper and more available bituminous coal. New Yorkers staged an early environmental protest against the fouled air that the utility managers could not ignore, so they switched to anthracite coal to appease people while they were awake, but switched back to bituminous while they slept.

We tend to think of air pollution caused by burning coal as a nineteenth-century phenomenon affecting London, Manchester, and Pittsburgh. Yet, only a little over a half-century ago, for four days in early December 1952, a temperature inversion settled over London, trapping a natural white fog so dense that traffic slowed to a crawl and the opera had to be cancelled when the performers could no longer see the conductor. Then coal smoke, also trapped in the temperature inversion, mixed with the fog to produce an unnatural black fog that hugged the ground and cut visibility to less than a foot. Perhaps unbelievably from our vantage point, 4,000 Londoners died from traffic accidents and inhaling sulfur dioxide fumes. Parliament subsequently banned the burning of soft coal in central London, bringing to an end a quaint 700-year-long tradition. In the twenty-first century, Beijing, Shanghai, and other cities in Asia have picked up where London left off. While the results of living in a cloud of polluted air are not as calamitous as in London, nevertheless dwellers in Asian cities suffer from various health impairments.[2]

Coal and the Industrial Revolution

Coal played an important role in England's emergence as the world's greatest seafaring nation and, subsequently, as the world's leading trading nation and colonial power. It also played an important, if not a pivotal, role in bringing about the Industrial Revolution and England's subsequent emergence as the world's greatest industrial power.

At first coal mines were above the River Tyne and narrow downward shafts dug from the mines to the outside world took care of removing water seepage from rain. As the coal seams bent downward, it was only a matter of time before mining took place under the River Tyne and the North Sea. This opened up a whole new peril for the miners: death by drowning. Even if mining did not breach the river or the sea, water was continually seeping in through the ground, threatening to flood the mines, though not necessarily the miners. For many years the chief way to prevent flooding was to have men haul up buckets of water to the mine surface. As mines went deeper into the earth, a vertical shaft was dug where a continuous chain loop with attached buckets brought water from the bottom of the mine to the surface. Water wheels and windmills powered a few of these continuous chain operations, but most were powered by horses. The capital cost in chain loops, along with their attached buckets and the operating cost of feeding and tending to the horses, encouraged the development of bigger mines employing larger numbers of miners in order to produce the greater quantities of coal needed to cover the higher capital and operating costs. Concentrating coal mining in a smaller number of larger operations meant even deeper mines, perversely exacerbating the problem of water removal.

By the 1690s, Britain's principal industry of providing 80 percent of the world's coal was threatened with a watery extinction. The nation's intellectual resources were focused on solving what seemed to be an overwhelming challenge: how to prevent water from flooding the ever-deeper mines. Denis Papin proposed the idea of having a piston inside a cylinder where water at the bottom of the cylinder would be heated to generate steam under the piston that would drive the piston up. Then the heat would be removed, creating a pressure differential between the top and bottom of the piston as the steam condensed to form a vacuum. Atmospheric pressure on top of the piston would drive the piston down and then the water in the bottom of the cylinder would be reheated to generate steam to drive the piston back up. The up-and-down motion of the piston could power a water pump. Thomas Newcomen, who may or may not have heard of Papin's idea, worked ten years to develop a working engine that did just that.

The Newcomen engine was a piston within a cylinder. Steam from burning coal was fed into the cylinder space below the piston, forcing it up. Then a cold-water spray entered the cylinder space and condensed the steam to create a vacuum and a pressure differential between the top and the bottom of the cylinder. Atmospheric pressure on top of the piston would drive the piston down. Simultaneously, an exhaust gate would open, allowing the water from the spray and condensed steam to drain from the cylinder space. Then the exhaust gate would close and steam would reenter the cylinder space. This continual cycle of feeding steam followed by a spray of water into the bottom of the cylinder kept the piston moving up and down. A crossbeam connected the moving piston to a water pump. Mines could now be emptied of water without horses and chain loops with attached buckets, which by this time had reached their limits of effectiveness. By 1725 Newcomen engines were everywhere and had grown to prodigious size, but the alternate heating and cooling of the lower cylinder walls during each cycle of the piston movement made them extremely energy-inefficient. With coal cheap and plentiful, the Newcomen engine had no technological rival for sixty years. As energy-inefficient as Newcomen engines were, they nevertheless saved the English coal-mining industry from a watery grave and enabled England to maintain its pre-eminence in coal mining for another century.

Thus, coal or, to be more exact, the threat of coal mines filling with water, brought into existence the first industrial fossil-fueled machine that delivered much more power with far greater dependability than wind or water. The fickleness of the wind makes wind power vulnerable and water power is constrained by the capacity of a water wheel to translate falling or moving water into useful power and by the occurrence of droughts. The Newcomen engine had no such limitations.

The building of Newcomen engines required iron and smelting iron consumed charcoal, another contributor to the deforestation of England. The pressure on forests was lifted in 1709 when Abraham Darby, who also advanced the technology of casting pistons and cylinders for Newcomen engines, discovered that coke from coal could substitute for charcoal from wood in smelting iron. It is a bit ironic that coke itself had been discovered some sixty years earlier, in 1642, for brewing beer. London brewers needed a great deal of wood to dry malt. As wood supplies dwindled, they first experimented with coal, but quickly found out that sulfur in coal tainted the malt and, thus, the flavor of the beer. The brewers discovered coke by copying the process of making charcoal from wood, which is essentially baking coal in the absence of oxygen to drive out volatile elements and impurities. Coke is harder than coal, almost pure carbon, and burns at a high temperature without smoke. Malt dried with coke produced a pure, sweet beer.

In 1757 James Watt, an instrument maker for the University of Glasgow, was given an assignment to repair the University's model of the Newcomen engine, which spurred his lifelong interest in steam engines. Watt soon realized that the shortcoming of the Newcomen engine was the energy consumed in reheating the cylinder wall after each injection of cold-water spray. His idea was not to cool the steam in the hot cylinder, but to redirect the steam to another cylinder, or condenser, surrounded by water, where the steam could be condensed without cooling the cylinder wall. Rather than a valve opening to allow a cold spray to condense the steam, a valve opened to allow the expended steam to escape from the cylinder to the condenser. The condensed steam created a vacuum in the bottom of the cylinder, which allowed atmospheric pressure on top of the cylinder to push the piston down. In this way the power cylinder wall would remain hot throughout the operation of the engine, improving its thermal efficiency.

James Watt was assisted by the moral and financial support of Matthew Boulton, a well-known Birmingham manufacturer. After obtaining a patent, the first two steam engines were built in 1776. One pumped water from a coal mine and the other drove air bellows at an iron foundry. The foundry owner, John Wilkenson, invented a new type of lathe to bore cylinders with greater precision, a device that would prove useful for manufacturing steam engines. The final version of the Watt engine came in 1782, when Watt developed the double-acting engine where steam powered the piston in both directions. Steam entering one end of the cylinder drove the piston in one direction, while a valve opening on the other end of the cylinder allowed the spent steam from the previous stroke to exhaust into a condenser. This operation was reversed to drive the piston in the opposite direction. Valves for allowing live steam to enter the cylinder space or spent steam to enter the condenser were opened and shut by the movement of the piston. To further enhance energy efficiency, steam was admitted inside the cylinder only during the first part of the piston stroke, allowing the expansion of the steam to complete the stroke. To further cut heat losses a warm steam jacket surrounded the cylinder and a governor controlled the engine speed. With these enhancements, the Watt steam engine could operate with one-quarter to one-third the energy necessary to operate an equivalent Newcomen engine. Both the Newcomen and Watt engines spurred technological advances in metallurgy to improve metal performance and in manufacturing technology to make cylinders and pistons, lessons not lost on the military for building bigger and better cannons.

Watt's intention was to improve the energy efficiency of the Newcomen engine for pumping water out of mines. Boulton saw Watt's invention as something greater than a more efficient Newcomen engine or a more reliable means of powering his factories than water wheels. Boulton was a visionary who saw the steam engine as a means to harness power for the good of humanity. In Boulton's vision, steam engines would not only drain mines of water but power factories that could be built at any location where coal was nearby. Goods made by machines powered by steam engines would free humans from the curse of drudgery and poverty that had plagued them throughout history.

The world's first industrialized urban center was Manchester, England. The city became the textile center of the world, processing cotton from slave plantations in the United States. Coal was consumed in making iron that went into constructing factory buildings, steam engines, and textile-making machines. Coal also fueled the steam engines that powered the machines and gas given off by heating coal was piped into the factory buildings and burned in lamps to allow round-the-clock operations. All this coal burning smothered Manchester in a thick black blanket of smoke that rivaled pollution in London and, later, Pittsburgh.

The demand for coal from mines near Manchester was so great that narrow shaft seams, which only children could fit into, were brought into use. They had to crawl on their feet and hands dragging heavy sleds of coal behind them like pack animals. Many of these children lived like animals in abandoned portions of mine shafts, separated from their families and daylight. For workers in the Manchester factories, the long hours, the harsh working conditions, the poor pay, the putrid stench of the atmosphere, their appallingly poor health and high death rates, and the breakdown of the family had to be an Orwellian nightmare at its worst, not Boulton's vision at its best. What Freidrich Engels saw in Manchester was recorded in his work *The Condition of the Working Class in England* (1844), which in turn helped Karl Marx shape *The Communist Manifesto* (1848).

Coal and Railroads

The amount of coal a horse can carry on its back is limited, but its carrying capacity can be improved by having it pull a wagon. The dirt roads of the day, with their deep muddy ruts, were impassable for horses hauling heavy wagonloads of coal. A horse's capacity to move cargo jumps by several orders of magnitude when, instead, it pulls a barge on still water. Canals, not roads, could move large volumes of coal to inland destinations. One of the first canals in Britain moved coal to Manchester from nearby coalfields where horses pulled barges from towpaths alongside the canal. This began the canal-building boom in England where, by the early 1800s, canals were used not only to move coal, but all sorts of raw materials and finished goods to and from cities. Since the nature of the terrain and the availability of water restricted canal construction, wagon ways, where horses were harnessed to cargo-laden carriages riding on wooden rails, complemented canals. Rails made horses more effective in moving coal than pulling loaded wagons on muddy, rutted, dirt roads.

Rails also improved coal-mine productivity. It turned out that getting coal out of the mine was as labor-intensive as mining coal. Often human pack animals were responsible for hauling coal on its journey to the mine surface. One human pack animal would pick up a small wagonload from another human pack animal, tow it a bit, and pass it on to still another human pack animal, then walk back to get the next. Lifetimes were spent hauling coal out of mines and, sometimes, living in mines. Mine operators did what they could to make hauling coal easier, but not strictly for altruistic reasons. Installing rails reduced operating costs by having the same work done by fewer human pack animals, thus improving productivity and, incidentally, profitability. Most rails were made of wood, but a few were made of iron.

Because the use of rails had solved the problem of how to move heavy loads, the concept of the railroad was in place when George Stephenson, the father of railways, put together the elements of iron track with a high-pressure Watt's steam engine on a locomotive platform with flanged iron wheels that pulled flanged iron wheeled carriages. Fittingly, the world's first railroad connected a coal town with a river port twenty-six miles away. The Age of the Railroad began in earnest a few years later, in 1830, when a train on its inaugural run between Liverpool and Manchester hit a top speed of an unbelievable thirty-five miles per hour. By 1845 Britain had 2,200 miles of track, a figure that tripled over the next seven years. While the building of railroads meant relatively cheap and fast transportation between any two points in England, the iron for the rails was not cheap.

Coal and Steel

The Iron Age began sometime around 2000 BCE, perhaps in the Caucasus region, where iron first replaced bronze. Iron is harder, more durable, and holds a sharper edge longer than bronze. Iron is also the fourth most abundant element, making up 5 percent of the earth's crust. Iron ore is made up of iron oxides plus varying amounts of silicon, sulfur, manganese, and phosphorus. From its start, smelting iron consisted of heating iron ore mixed with charcoal until the iron oxides began reacting with the carbon in the charcoal to release its oxygen content as carbon monoxide or dioxide. Adding crushed seashells or limestone, called flux, removed impurities in the form of slag, which was separated from the heavier molten iron. This left relatively pure iron, intermixed with bits of charcoal and slag that could then be hammered on an anvil by a blacksmith to remove the remaining cinders, slag, and other impurities. The result of the hammering produced wrought (or "worked") iron with a carbon content between 0.02–0.08 percent. This small amount of carbon, absorbed from the charcoal, made the metal both tough and malleable. Wrought iron was the most commonly produced metal throughout the Iron Age.

By the late Middle Ages, European iron makers had developed the blast furnace, a tall chimney-like structure in which combustion was intensified by a blast of air pumped through alternating layers of charcoal, flux, and iron ore. The medieval ironworkers harnessed water wheels to power bellows to force air through the blast furnaces. Centuries later, this would be one of the first tasks for James Watt's steam engines, in addition to pumping water out of coal mines. The blast of air increased the temperature, which allowed the iron to begin absorbing carbon, thereby lowering its melting point. The product of this high-temperature process was cast iron, with between 3–4.5 percent carbon. Cast iron is hard and brittle, liable to shatter under a heavy blow, and cannot be forged (that is, heated and shaped by hammer blows). The molten cast iron was fed through a system of sand troughs, formed into ingots, which reminded people of a sow suckling a litter of piglets, and became known as pig iron. Pig iron was either cast immediately or allowed to cool and shipped to a foundry as ingots, where it was remelted and poured directly into molds to cast stoves, pots, pans, cannons, cannonballs, and church bells.

These early blast furnaces produced cast iron with great efficiency and less cost than wrought iron. However, the process of transforming cast iron to more useful wrought iron by oxidizing excess carbon out of the pig iron was inefficient and costly. More importantly, what was desired was not wrought iron from cast iron, but steel. Steel is iron with carbon content between 0.2–1.5 percent, higher than wrought iron but lower than cast iron. Crucible steel, named after its manufacturing process, was not only very expensive, but the extent of the oxidation of carbon, and therefore the carbon content, could not be controlled. Regardless of its cost, steel was preferred over wrought iron because it was harder and kept a sharp edge longer (the best swords were made of steel) and was preferred over cast iron because it was more malleable and resistant to shock.

Early rails made from wrought iron were soft and had to be replaced every six to eight weeks along busy stretches of track. Steel, in contrast, is perfect for rails because it is harder than wrought iron and more malleable than cast iron. Steel rails, however, were prohibitively expensive. The man of the hour was Henry Bessemer, who was not responding to the needs of the railroad industry, but the military. Bessemer had invented a new artillery shell that had been used in the Crimean War (1853–1856). The army generals complained that the cast iron cannons of the day could not handle Bessemer's more powerful artillery shell. In response Bessemer developed an improved iron-smelting process that involved blasting compressed air through molten pig iron to allow the oxygen in the air to unite with the excess carbon and form carbon dioxide. Ironically, Bessemer's invention, patented in 1855, was similar to the method of refining steel used by the Chinese in the second century BCE.

In 1856 the first Bessemer converter, large and pear-shaped with holes at the bottom for injecting compressed air, was completed. Other individuals contributed to improving the Bessemer converter by adding manganese to get rid of excess oxygen left in the metal by the compressed air and limestone to get rid of any phosphorus in the iron ore, which made steel excessively brittle. Limestone becomes slag after absorbing phosphorus and other impurities and floats at the top of the converter where it is skimmed off before the steel is poured out. Bessemer converters were batch operations to which iron ore, coke, and limestone were added; within a short period of time, molten steel was on the bottom and slag was floating on the top. After removing the slag, the converter was then emptied of its molten steel and then reloaded to make another batch.

The economies of large-scale production utilizing the Bessemer converter transformed undesired wrought-iron rail at $83 per ton in 1867 to desired steel rail at $32 per ton by 1884. It was not long before the Bessemer process had a technological rival: the open-hearth furnace. The open-hearth furnace, while it took longer, could make larger quantities of steel because raw materials were continuously added and slag and steel continually removed. Moreover, steel could be made with more precise technical specifications and scrap steel could be consumed as feedstock along with iron ore, coal, and limestone. Improvements in the chemical composition of steel had increased the life of steel rails and their weight-carrying capacity several fold by 1900, when the open-hearth furnace had largely replaced the Bessemer converter. Another man of the hour, Andrew Carnegie, organizationally shaped the steel industry and, in so doing, reduced the price of steel rail to $14 per ton by the end on the nineteenth century. Carnegie also introduced the I-shaped steel girder for building skyscrapers, a major addition to steel demand once the Otis elevator was perfected.

By 1960, the basic oxygen furnace had, in its turn, replaced the open-hearth furnace. The basic oxygen furnace is essentially a modification of the original Bessemer converter. The first step is feeding iron ore, coke, and limestone into a furnace with air blasted through the mixture to produce molten iron, which is periodically tapped from the bottom of the furnace while the molten slag is periodically removed from the top. The molten iron then goes into the basic oxygen furnace where steel scrap and more limestone are added, along with a blast of oxygen to produce almost pure liquid steel.

In making steel, coking coal supplies carbon to remove the oxygen in the iron ore and heat to melt the iron. Coking, or metallurgical coal, must support the weight of the heavy contents in a furnace yet be sufficiently permeable for gases to rise to the top and molten steel to sink to the bottom of the furnace. Thus, coals are divided into two types: thermal coal fit only for burning and coking coal fit for steelmaking. The liquid and gaseous byproducts in producing coke from metallurgical or coking coal find their way into a host of products such as synthetic rubber, ink, perfume, food and wood preservatives, plastics, varnish, stains, paints, and tars.[3]

The world's largest steel producers are China (501 million tons, over triple its 2001 production, Japan (119 million tons), the United States (91 million tons), Russia (69 million tons), India (55 million tons), South Korea (54 million tons), Germany (46 million tons), Ukraine (37million tons), Brazil (34 million tons), and Italy (31 million tons). The basic oxygen furnace produces 66 percent of the world's crude steel production—about 1,327 million tons in 2008—incidentally consuming 600 million tons of coal. Most of the remaining steel production is made from a more recent innovation, the electric arc furnace.[4] The raw material for electric arc furnaces is scrap. Incidentally, steel is the most recycled commodity on Earth: fourteen million cars in the United States alone are recycled annually. Whereas 1 ton of steel made from raw materials requires, in round terms, 2 tons of iron ore, 1 ton of coal, and a half ton of limestone; 1 ton of recycled steel needs a bit more than 1 ton of scrap. While coal is absent as a raw material in making steel with the electric arc furnace, an electric arc furnace uses a lot of electricity, as one can imagine, which is mainly generated by burning coal augmented by capturing the waste heat of steelmaking. Thus, coal is consumed directly in making steel with the basic oxygen furnace and indirectly in making steel with the electric arc furnace.

Coal played a vital role in shaping the world as we know it today. Coal was needed as a substitute for wood for producing glass and smelting metals after the forests were cut down. Coal became a major export item for England, spurring the development of the English navy. The challenge posed by flooding coal mines frantically called for a solution—the Newcomen engine—the first industrial power-generating machine not dependent on wind or water. The Newcomen engine spurred further advances in metal and toolmaking and led directly to Watt's steam engine. Watt's steam engine powered the Industrial Revolution with coal, steel, and railroads. Coal, then, is at least partly responsible for England becoming a world sea power, a colonial power, and, after the birth of the Industrial Revolution, the world's first and mightiest industrial power. This lasted for over half a century before being challenged by the emergence of rival centers of industrial power in the United States, Germany, and Japan.

Rise and Fall of King Coal

Though early steam locomotives were fueled by wood, it was not long before they switched to coal. One reason was deforestation; the other was the availability of coal as the most commonly carried commodity. Coal became the sole source of energy for fueling locomotives, which for decades before the automobile age was the sole source of transportation on land other than horses. Robert Fulton invented the first steam-driven riverboat, the *Clermont,* which propelled itself from New York to Albany in 1807. While wood could be burned on riverboats, ocean-going vessels burned coal, a more concentrated form of energy that took up a lot less volume. The famed clipper ships of the waning decades of the nineteenth century marked the final transition from a source of power that was undependable, renewable, and pollution- and cost-free to one that was dependable, nonrenewable, polluting, and not cost-free. Now coal had it all on land and sea. Thomas Edison's first electricity-generating plants were fueled by coal, although hydropower was soon harnessed at Niagara Falls. Coal and hydropower were the principal sources of energy for generating electricity during the first half of the twentieth century.

Coal's share of the energy pie peaked at 60 percent in 1910. Oil, natural gas, and hydropower contributed another 10 percent, and biomass 30 percent. After 1910, things began to change for King Coal. Coal maintained its pre-eminence in passenger transportation until Henry Ford put America, and the world, on gasoline-driven wheels. In 1912, the *Titanic* had 162 coal-fired furnaces fed continuously by 160 stokers working shifts 24/7 shoveling as much as 600 tons of coal per day. This might work well for passenger vessels, but coal-burning warships were constrained in fulfilling their primary mission by the large portion of the crew dedicated to shoveling coal, rather than manning guns, and the amount of space dedicated to holding coal rather than carrying ammunition. Moreover, warships with a heavy cargo of coal moved slowly and their pillars of smoke signaled the enemy as to their whereabouts. Admiral Sir John Fisher, head of the British Navy, spearheaded the transformation from marine boilers powered by coal to oil in the years prior to the First World War. Naysayers scoffed at the idea, but as soon as the obvious advantages of oil over coal were demonstrated in higher speed, greater firepower, and less emissions to betray a vessel's presence, it became a race to dump coal in favor of oil. As ships made the transition from coal to oil, the worldwide network of coal-bunkering stations supplied by coal colliers was converted in tandem to handle oil supplied by tankers (ship's fuel is still referred to as bunkers).

Coal and wood remained the chief sources of energy for cooking until the advent of the electric stove in the 1920s, along with stoves that burned natural gas and liquid propane. About this time, homes began a slow conversion from coal to heating oil and natural gas. Automobiles were taking passengers away from electric trolleys, whose electricity was generated from coal, for inner-city transportation. Intercity railroad passenger train traffic, powered by coal-fueled locomotives, declined as a network of roads sprang into existence. When the fall of King Coal from pre-eminence sped up during and after the Second World War, one individual stood out: John L. Lewis, a former coal miner and president of the United Mine Workers. A contentious personality who had the audacity to defy President Franklin Delano Roosevelt by leading a coal miners' strike during the war, Lewis was instrumental in raising the pay and improving the health and retirement benefits and working conditions for coal miners. As laudable as these well-deserved benefits were, they also increased the price of coal and, in so doing, hastened its demise. Perhaps no better proof of this was Perez Alfonso, a Venezuelan oil minister, who wanted to erect a statue to honor Lewis for boosting the market for Venezuelan oil exports.

The rise in the price of coal from John L. Lewis's success was an added inducement for homeowners to switch from coal, which had to be shoveled into a furnace (from which ashes had to be removed and disposed of) to the much greater convenience of heating oil, propane, and natural gas, which did not require the effort associated with coal. In cooking, the switch was already far advanced from coal to electricity and natural gas and propane.[5] While oil-driven automobiles, buses, and airplanes were diverting people from coal-burning passenger trains, and trucks had taken over local distribution of freight, railroad freight trains still carried the bulk of the nation's intercity freight. Trucks were unable to cut deeply into intercity freight traffic because the road network was relatively undeveloped and better fit for automobiles than trucks. All this changed with the launching of the interstate highway system by President Dwight D. Eisenhower.

A large steam locomotive pulling a loaded freight train burned 1 ton of coal per mile, which required a fulltime fireman to continually shovel coal. Railroads were enormous consumers of coal and railroad executives displayed equally enormous reluctance to abandon steam locomotives when the diesel engine first appeared in the late 1930s. Steam locomotives had become an intimate part of railroading folklore. Distinct in design and operating nuances, they had to be maintained by a dedicated crew that became inseparable from the locomotive, which required a lot of downtime for maintenance and repair.

Railroaders were unwilling to switch from steam to diesel, even though diesel locomotives had inherent advantages. Diesel engines were fuel-efficient because they burned gallons of diesel fuel per mile, not a ton of coal per mile. The diesel engine avoided the inherent energy inefficiency of a steam engine from which the latent heat of vaporization was passed to the atmosphere. In a diesel engine, fuel sprayed into the cylinder space above a piston is ignited by heated compressed air. The expansion of the gases of combustion powers the first downward stroke. After the power stroke, the piston is forced up to expel the exhaust gases, then down to draw in fresh air, then up to compress the air. The heated compressed air ignites another spray of fuel whose expanding gases of combustion powers another downward stroke. Thus, every other downward stroke is a power stroke that, through a crankshaft connected to the other pistons, drives an electricity generator that powers electric motors attached to the engine wheels.

Diesel engines have other advantages as well. They are more reliable because they require less maintenance and repair, both in downtime and cost; less manpower, because no coal has to be shoveled; and less frequent refueling. Steam locomotives of various horsepower have to be built to handle freight trains of different sizes, whereas a number of standard-sized diesel engines can be hooked together to obtain the requisite horsepower. In short, the only reason to keep steam locomotives once diesel engines made their appearance was management's reluctance to change.

The advantages of the diesel engine could no longer be ignored when John L. Lewis's success in improving the lot of coal miners increased the price of coal. The first diesel engines were restricted to moving freight cars around freight yards and were excluded from long intercity runs, the exclusive domain of the steam locomotive. Steam locomotives could persevere as long as all railroad managers agreed to use steam locomotives on intercity freight trains, ensuring equal inefficiency in operations for all. But this holding action could not ignore the competitive threat of a growing volume of trucks gaining access to intercity traffic made possible by the interstate highway system. If any railroad bolted to diesel for hauling intercity freight, then the inherent efficiencies and advantages of diesel locomotion would give that railroad a competitive edge over the others. And that is what happened: one railroad bolted. As soon as one made the switch to diesel for intercity freight trains, it was a race to convert locomotives from coal to oil similar to the race to convert ships from coal to oil. Despite efforts by steam locomotive aficionados and railroad executives to hold the fort, the steam whistle and the chugging locomotive spewing steam, smoke, and at times blazing ashes disappeared within a decade.

Adding to King Coal's woes, electricity-generating plants built after the Second World War were designed to run on oil, natural gas, and nuclear power in addition to coal and hydro. King Coal was no longer king in transportation, electricity generation, heating houses and commercial buildings, and home cooking. By 1965, its share of the energy pie was down to a still respectable 39 percent and declined to 30 percent in 1970 and remained around 25–29 percent until recent years when its share expanded to 30 percent.

TYPES OF COAL

Aside from peat, a precursor to coal, there are four types of coal. The lowest quality of coal and the largest portion of the world's coal reserves is lignite, a geologically young, soft, brownish-black coal, some of which retains the texture of the original wood. Of all coals, it has the lowest carbon content, 25–35 percent, and the lowest heat content, 4,000–8,300 British thermal units (Btus) per pound. The next step up is sub-bituminous coal, a dull black coal with a carbon content of 35–45 percent and heat content 8,300–13,000 Btus per pound. Both lignite and sub-bituminous coals, known as soft coals, are primarily thermal coals for generating electricity. Some sub-bituminous coals have lower sulfur content than bituminous coal, an environmental advantage.

Next are the hard coals, bituminous and anthracite. Bituminous is superior to soft coal in terms of carbon content, 45–86 percent, and energy content, 10,500–15,500 Btus per pound. Bituminous coal is the most plentiful form of coal in the United States and is used both to generate electricity (thermal coal) and, if it has the right properties, as coking or metallurgical coke for steel production. Anthracite coal has the highest carbon content, 86–98 percent, and a heat content of nearly 15,000 Btus per pound. Anthracite coal was closely associated with home heating because it burned nearly smokeless. As desirable as anthracite is, it is also scarce. In the United States, anthracite is found in only eleven counties in northeastern Pennsylvania and is a largely exhausted resource.

COAL MINING

Coal mines have historically been subterranean regions where accidents and black lung have taken their toll. Mining coal in the twenty-first century is an activity carried out differently than it was in the past. In developed nations, no gangs of men swing pickaxes to remove the over- and underburden of rock to gain access to the coal, then again to chip out the coal. No gangs of men shovel the rock or coal into small wagons or carts for the trip to the surface. Now the most popular way of removing coal is continuous mining machines with large, rotating, drum-shaped cutting heads studded with carbide-tipped teeth that rip into a seam of coal. Large gathering arms scoop the coal directly into a built-in conveyor for loading into shuttle cars or a conveyor for the trip to the surface. Continuous cutters ripping and grinding their way through coal seams can do in minutes what gangs of miners with pickaxes and shovels took days to accomplish.

The next most popular method for removing is a machine resembling an oversized chain saw that cuts out a section of coal in preparation for blasting to allow for expansion. Holes are then drilled for explosives that blast large chunks of coal loose from the seam. Loaders scoop up the coal into conveyors that fill shuttle cars to haul the coal out through the shaft. For both methods of mining, long rods or roof bolts are driven into the roof of the mine to bind layers of weak strata into a single layer strong enough to support its own weight. If necessary, braces are used for additional support. Wood is favored because it makes a sharp cracking sound if the roof begins to weaken.

An increasingly popular and efficient means of mining introduced into the United States from Europe in the 1950s is longwall mining where a rotating shear moves back and forth in a continuous, smooth motion for several hundred feet across the face or wall of a block of coal. The cut coal drops into a conveyor and is removed from the mine. Some of the rock on top of the coal also collapses, which is then removed to the surface or piled in areas where the coal has been removed. The main supports for the rooms created by longwall mining are pillars of solid coal, which are the last to be mined before a mine is abandoned.

Regardless of the type of mining technology employed, mine shafts for transporting miners and coal either slope down to coal beds that are not too deeply located in the earth or are vertical to reach beds of coal more than 2,000 feet beneath the surface. Huge ventilation fans on the surface pump air through the mineshafts to reduce the amount of coal dust in the air, prevent the accumulation of dangerous gases, and ensure a supply of fresh air for the miners.

In recent decades, surface mining has gained prominence over subterranean mining. In the western part of the United States, 75 percent of the coal produced is obtained from surface mines with coal deposits up to 100 hundred feet thick. Surface mining also occurs in Appalachia. Surface mines produce 60 percent of the coal mined in the United States, while the remaining 40 percent comes from underground coal mines located primarily in Appalachia. Although there are large open-pit mines in other parts of the world, such as Australia and Indonesia, globally speaking about two-thirds of coal comes from underground mines.

A few utility plants are located at the mouths of mines, but most coal is loaded on barges and railroad cars for transport to electricity-generating plants or export ports. In the United States, about 60 percent of the coal mined is moved by railroad to the consumer, often in unit trains of a hundred automatically unloading coal cars, each holding 100 tons of coal, or 10,000 tons of coal in a single trainload. Coal is unloaded by hoppers in the bottom of coal cars that open to drop the coal onto a conveyor belt located below the rails or by a rotating mechanism that empties 100 tons of coal by turning the coal cars upside down as though they were toys. Coal is still a major revenue generator for railroads around the world. Coal in the United States not moved by rail is primarily moved by barge on 25,000 miles of inland waterways. One unconventional way to move coal is to pipeline pulverized coal mixed with water from a coal mine to a power station, where the water is decanted and the pulverized coal is fed directly into a boiler.

After mining, coal is processed to ensure a uniform size and washed to reduce its ash and sulfur content. Washing consists of floating the coal across a tank of water containing magnetite for the correct specific gravity. Heavier rock and other impurities sink to the bottom and are removed as waste. Washing reduces the ash and pyretic sulfur-iron compounds clinging to the surface of the coal, but not the sulfur chemically bonded within the coal. Washing can also reduce carbon dioxide emissions by 5 percent. Magnetite clinging to the coal after washing is separated with a spray of water and recycled. Coal is then shipped by rail or barge to power plants. Some power plants run off a single source of coal while others buy various grades of coal that are mixed together before burning in order to obtain optimal results in heat generation, pollution emissions, and cost control.

Coal-mining operations are highly regulated in the developed world. In the United States, a company must comply with hundreds of laws and thousands of regulations, many of which have to do with the safety and health of the miners and the impact of coal mining on the environment. Legal hurdles may require ten years before a new mine can be developed. A mining company must provide detailed information about how the coal will be mined, the precautions taken to protect the health and safety of the miners, and the mine's impact on the environment. For surface mining, the existing condition of the land must be carefully documented to make sure that reclamation requirements have been successfully fulfilled. Other legal requirements cover archaeological and historical preservation, protection and conservation of endangered species, special provisions to protect fish and wildlife, forest and rangeland, wild and scenic river views, water purity, and noise abatement.

In surface or strip mining, specially designed draglines, wheel excavators, and large shovels strip the overburden to expose the coal seam, which can cover the entire top of an Appalachian mountain. Coal is loaded into huge specially designed trucks by large mechanical shovels for shipment to a coal-burning utility or to awaiting railroad cars or barges. Surface mining has lower operating and capital costs and provides a safer and healthier environment for the workers than underground mining. After the coal is removed, the overburden is replaced and replanted with plant life to restore the land as closely as possible to its original state. Reclaimed land can also be transformed into farmland, recreational areas, or residential or commercial development, as permitted by the regulators.

Critics of surface mining point out the damage done to the landscape when the overburden removed from the top of a mountain or hill is dumped into nearby valleys, called "valley fill." In addition to the destruction of the landscape and vegetation, valley fills become dams creating contaminated ponds of acid runoff from sulfur-bearing rocks and heavy metals such as copper,

Table 4.1

Employment, Productivity, and Safety

	Employment (2000)	Miners per Million Tons Output	Deaths	Deaths per Million Tons Output
Australia	18	76	4	0.02
United States	77	96	38	0.05
United Kingdom	8	241	4	0.05
South Africa	54	298	30	0.17
Poland	158	1,561	28	0.28
India	456	2,171	100	0.48
Russia	197	1,195	137	0.83
China	5,000	5,501	5,786	6.36

lead, mercury, and arsenic exposed by coal mining. They also object to the dust and noise of strip-mining operations and "fly-rocks" raining down on those unfortunately residing nearby. The scars of surface mining are clear from the air. Residents in West Virginia are split between those who support the economic benefits of surface coal mining and those who want to transform West Virginia into a recreational destination for tourists.[6] Another problem is abandoned underground mines, which eventually fill with water. The water can range from being nearly fit for drinking to containing dangerously high concentrations of acids and metallic compounds that may end up contaminating ground and drinking water.

Of course, the record also shows that there are large established companies mindful of their legal obligations to restore the landscape and protect the environment. There are instances of reclamation carried out so effectively that, with the passage of time, there is no apparent evidence that strip-mining had ever taken place. Aside from corporate ethics, there are sound business reasons for being a responsible corporate citizen such as the desire to remain in business for decades to come. For these companies, the extra costs in protecting the health and safety of the miners and safeguarding the environment generate huge payoffs by allowing them to remain in business over the long haul. Private ownership is a right granted by governments on the basis that the conduct of business is better handled by businesspeople than government bureaucrats. If in reality, or if in the perception of the electorate, the supposed benefits of private ownership are not being achieved, then private ownership itself is threatened.

There has been environmental degradation, but much of this lies with fly-by-night companies that fold without meeting their light-of-day responsibilities. While critics of coal extraction in developed nations abound, the developing nations, most notably China and India, seem to exist on another planet. Coal mining, particularly in the tens of thousands of small mines, violates elemental concerns over health and safety of the workers and the environment. No one in those countries seems to care about spontaneous combustion of coal-mining residues that burn on forever or drinking water and agricultural lands permanently contaminated with poisonous metal compounds.

Employment of coal miners has changed drastically in recent decades as machines have replaced labor. Although there are 7 million coal miners in the world, 5 million are in China and another half million are in India, where the use of picks and shovels is the dominant coal-mining technique. Table 4.1 shows employment, productivity, and safety in terms of the number of miners per million tons of output, the number of miners' deaths, and deaths in terms of a million tons of output for 2000.[7] The table shows the enormous disparity in worker productivity and mortality rates between the developed and developing worlds. More recent data suggest that official coal mining deaths in China may be closer to 4,000, but there is also an element of underreporting from remote areas that suggest that the death rate may be higher than what the statistics show. Note that coal mining in the United Kingdom, where it all began, is now a faint vestige of its former vigor.

Needless to say, the lowest fatality rates occur in nations where there is the strongest commitment to health and safety standards for miners and for workers in general. China has the most abysmal safety record, and that may be a gross understatement. Most casualties are associated with small mines employing women and children, not the large state-owned mines. Methane explosions from lack of proper ventilation and gas monitoring are responsible for half of the deaths. These figures reflect mine mishaps, not deaths from health impairment from mining. A nonfatal occupational risk for miners and for many other industrial workers is loss of hearing. For coal miners, loss of hearing, caused by explosives used to dislodge coal and machinery noise in close quarters, occurs slowly and often without the miner's awareness. With regard to fatal occupational risks, the most common disease is pneumoconiosis, commonly known as black lung disease. Black lung disease has dropped precipitously for mines with ample ventilation to reduce coal dust, but still remains a problem in China and India and other nations where relatively little is invested in protecting the workers' health. China's terrible record in protecting miners extends to the end users. Drying chilies with coal contaminated with arsenic was responsible for thousands of cases of arsenic poisoning. Drying corn with coal contaminated with fluorine caused millions to suffer from dental and skeletal fluorosis.

COAL IN THE TWENTY-FIRST CENTURY

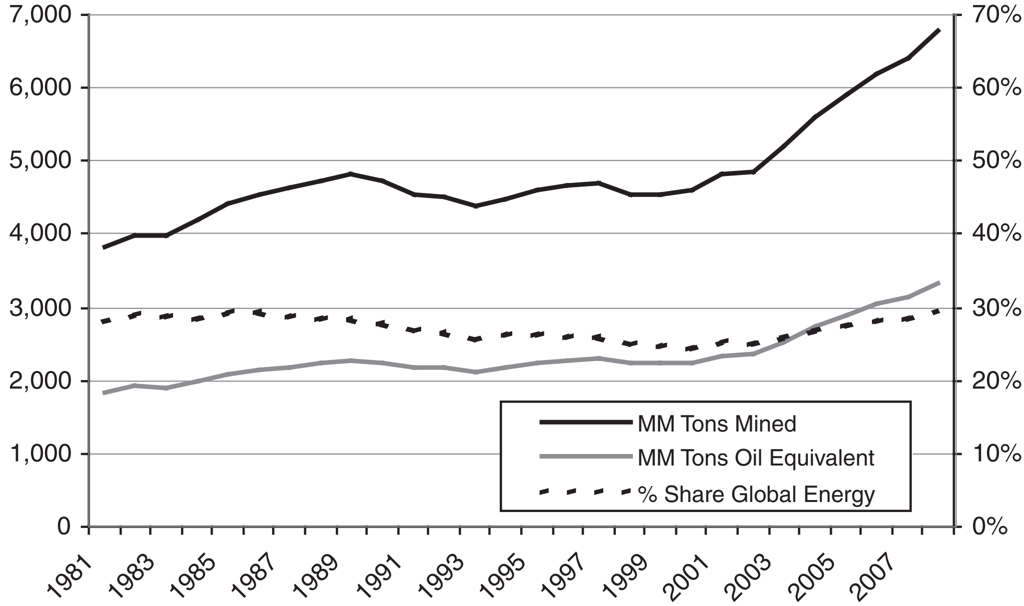
Coal's retreat in relative standing among other energy sources ended in 2000. Coal is here to stay and is gaining ground in absolute and relative terms. Despite criticisms leveled against coal, it does have virtues that cannot be ignored such as being:

- abundant, frequently reserves are measured in hundreds of years;
- secure, in that coal is available in sufficient quantities without the need for large-scale imports for most coal-consuming nations;
- safe (does not explode like natural gas, but of course mine safety is an issue);
- nonpolluting of water resources as oil spills are (although there are other adverse environmental consequences of mining and burning coal);
- cost-effective, by far the cheapest source of energy.

As seen in Figure 4.1, the volume of coal production leveled out in the 1990s but is heading upward again. The top line is coal mined in physical tons and the bottom line is coal production expressed in terms of the equivalent amount of oil that would have to be burned to match the energy released by burning coal. As the figure shows, close to 2 short tons of coal have to be burned to obtain the same energy release as burning 1 metric ton of oil.[8]

Figure 4.1 also shows the relative contribution that coal makes in satisfying world energy demand for commercial sources, excluding biomass. Since 1981, the percentage of coal's share in satisfying energy needs had been slowly eroding until 2001 when there was a resurgence in coal consumption and in its share of the energy pie. This trend is expected to continue from coal-fired electricity generation capacity being added all over the world but particularly in the United States,

Figure 4.1 **Global Coal Production and Percent Contribution to Global Energy**

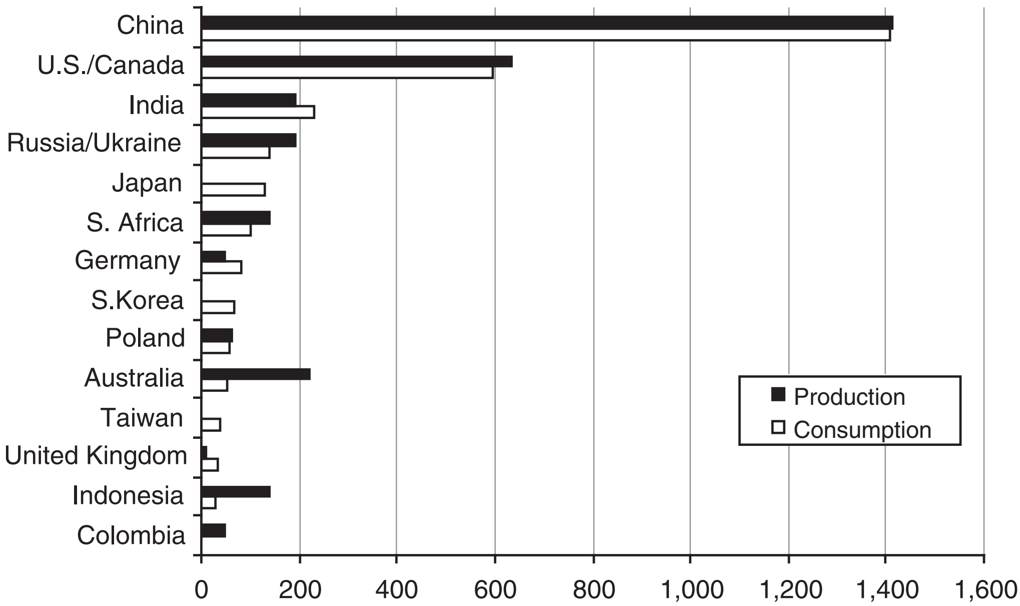


China, and India. However, there has been a sharp decline in ordering new coal-fired electricity-generating capacity in the United States because of the risk of a cap and trade program being imposed by the Obama administration. The global economic recession starting in 2008 also affects utility plans to add capacity. Regardless of the situation in the United States, China and India will remain principal drivers of the world coal business.

Figure 4.2 shows the world's largest consumers and producers of coal in 2008 in terms of millions of tons oil equivalent. China is the world's largest consumer and producer of coal and both exports and imports coal. China suffers from a poorly developed internal logistics system. Movement from inland distributions to coastline population centers relies heavily on China's river systems. Movement of goods and commodities along China's long coastline, where a number of its principal population centers are located, is by water rather than by land. As a substitute for moving commodities along its coastline, China selectively exports and imports. China imports thermal coal to utilities located on its coast from Australia and Indonesia and exports thermal coal to neighboring countries such as North and South Korea and Japan. By becoming a major world steel producer, China has become a major importer of metallurgical or coking coal. The steam locomotive has not entirely gone the way of dinosaurs. China, India, and South Africa still rely on steam locomotives to move coal.

The relative importance of the United States, along with Canada and China, as consumers and producers of coal can be seen by the huge step down to the third largest consumer and producer, India. Thermal and metallurgical or coking coal are two distinct markets. It is possible for a large bulk carrier to move thermal coal from Australia to Europe and return with a cargo of metallurgical coal from the United States or South Africa to Japan. The largest steam and coking coal exporters in 2008 were Australia (252 million tons), Indonesia (203 million tons), Russia (101 million

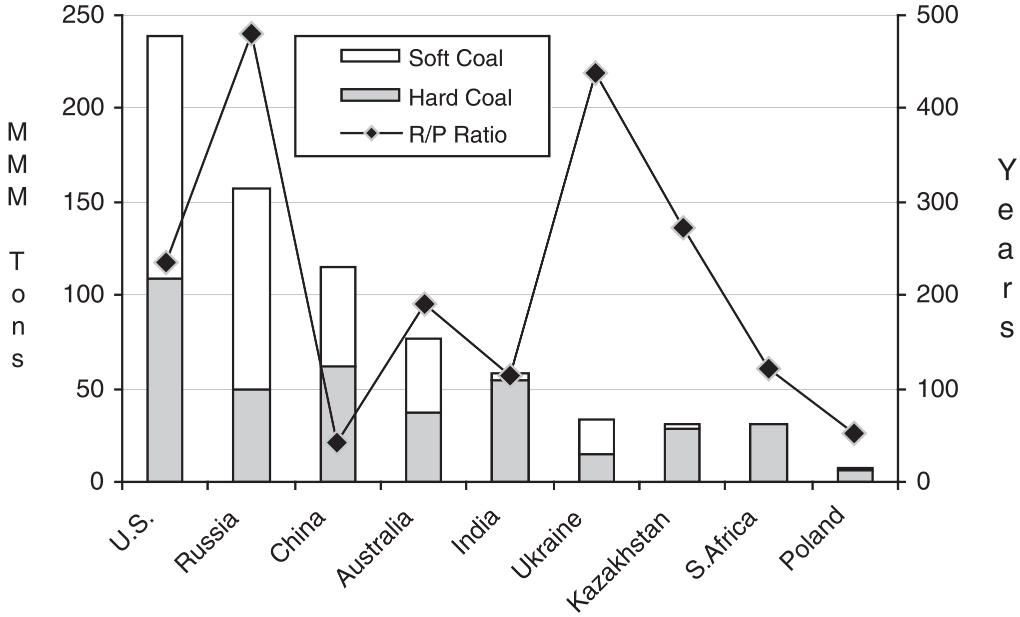
Figure 4.2 **World's Leading Producers and Consumers of Coal** (MM Tons Oil Equivalent) **in 2008**



tons), Colombia (74 million tons), United States (74 million tons), South Africa (62 million tons), and China (47 million tons). The largest importers were Japan (186 million tons), South Korea (100 million tons), Taiwan (66 million tons), India (60 million tons), Germany (46 million tons), China (46 million tons), and United Kingdom (44 million tons). Japan, South Korea, and Taiwan view coal as a means of reducing their reliance on Middle East oil. The United Kingdom, once the world's largest exporter of coal, now imports a large share of its coal needs. Both the United Kingdom and Germany have been phasing out the large subsidies paid to keep its domestic coal-producing industry alive in favor of far cheaper imports.

South Africa has abundant coal resources and limited oil resources, and oil-exporting nations were reluctant to trade because of its past apartheid policies. As a consequence, South Africa became a world leader in producing petroleum products (synthetic fuels) and chemicals from coal. The Fischer-Tropsch process, dating back to the 1920s, transforms low-quality coal to high-grade petroleum fuels plus other products.[8] The Germans relied on this technology to make gasoline from its plenteous supplies of coal during the Second World War to compensate for not having indigenous oil resources to run its war machine. These plants were the highest priority targets during Allied bombing of Nazi Germany. The South African plants have been producing 130,000 barrels per day of a mix of 20–30 percent naphtha and 70–80 percent diesel, kerosene, and fuel oil since 1955. About 0.4 tons of coal are consumed for every barrel of oil produced with an overall energy efficiency of 40 percent (60 percent of the energy content of the coal is consumed in transforming coal to liquids). Coal is first gasified to yield a mixture of hydrogen and carbon monoxide, which, after passing through iron or cobalt catalysts, is transformed into methane, synthetic gasoline or diesel fuel, waxes, and alcohols, with water and carbon dioxide as byproducts. Synthetic fuels from coal are higher in quality than those made from oil. For instance, diesel fuel made by the Fischer-Tropsch process has reduced

Figure 4.3 **Known Coal Reserves (Billion Tons) and R/P Ratio** (Years)



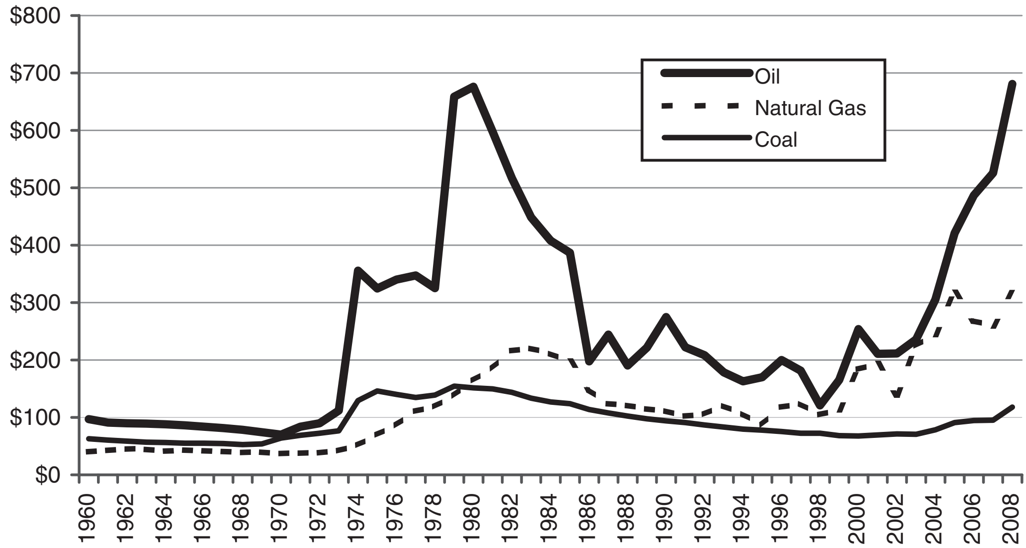
nitrous oxides, hydrocarbons, and carbon monoxide emissions with little or no particulate emissions compared to oil-based diesel fuels.[9]

China is building a coal-to-liquids plant in Inner Mongolia that will produce 20,000 barrels per day of motor vehicle fuel plus other oil products with a planned expansion to 100,000 bpd. The process is a direct liquefaction process transforming coal to a solvent at a high temperature and pressure and then followed by a more complex chemistry to produce 20–30 percent naphtha and 70–80 percent diesel fuel and liquefied petroleum gas. The process is more efficient and uses 0.3–0.4 tons of coal per barrel of oil produced. If successful, other coal-to-liquid plants will be built. One adverse environmental aspect of coal-to-liquid technology is a large emission of carbon dioxide during the production process amounting to about 0.6 tons of carbon dioxide for every barrel of oil.[10]

Unlike oil, where the world's total proven reserves divided by current consumption equal only forty years, over a century (120 years) would be required for current consumption to eat away at proven coal reserves. The reserve to production (R/P) ratio has to be handled gingerly as we have a knack for discovering new reserves. (Theodore Roosevelt estimated that oil reserves would be exhausted in twenty years, given consumption and known reserves in the 1910s.) Moreover, reserves are made up of known reserves plus estimates of probable reserves, and as such are subject to error. Some criticize R/P ratios because they are based on current, not future, consumption and to that extent overestimate the life of existing reserves. On the other hand, they do not take into account future discoveries and so underestimate the life of existing reserves. Unlike oil, there is no active ongoing search for new coal reserves, which means that coal reserves could be substantially upgraded. Figure 4.3 shows the world's largest known coal reserves in terms of size, ranked by how long they will last at the present rate of consumption.

The United States has the world's largest reserves of coal of 238 billion tons with a R/P ratio of 234 years, whereas Russia has 157 billion tons with a R/P of 481 years. The world's largest

Figure 4.4 **U.S. $/Ton Oil, Natural Gas, and Coal Prices** (Constant 2008 $)



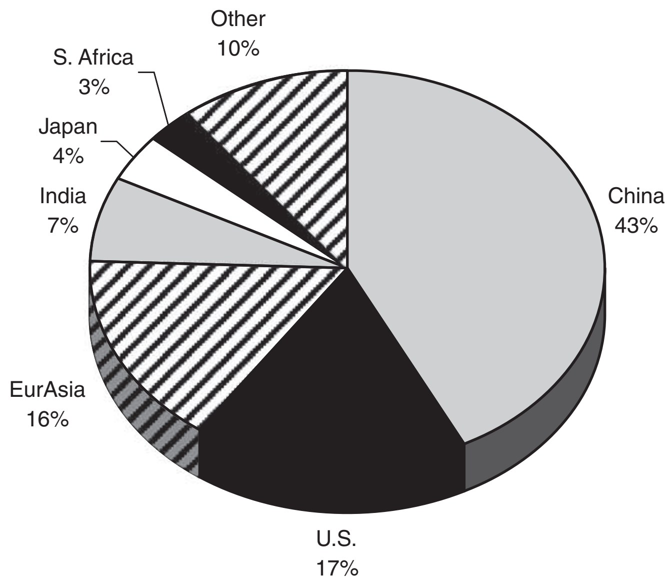
consumer of coal, China, has reserves of 115 billion tons with a R/P of only 41 years. Of course, the nature of the reserves does not reflect the type of coal actually being mined. As previously mentioned, soft coals are lignite and sub-bituminous and hard coals are bituminous and anthracite. Premium bituminous coal for making coking coal for steel production is found in Australia, the United States, Canada, and South Africa. Significant portions of reserves in Russia, Ukraine, and China are soft coals, generally perceived to be greater pollutants than hard coals. But there are exceptions. India has only hard coal, but of poor quality in terms of heat, ash, and sulfur content. Both China and India burn coal with virtually no environmental safeguards. Ash, the residue of burning, is released to the atmosphere in the form of airborne particulates (soot) and sulfur is released as sulfur dioxide gas.

The United States's enormous reserves of coal enhance the nation's energy self-sufficiency. Its reserves can last nearly 250 years at the present rate of production. The coal situation in the United States is quite unlike oil where two-thirds is imported, and the R/P ratio on domestic oil is only twelve years. Some of the imported oil is from volatile and unstable and, at times, distinctly unfriendly nations. Coal does not demand an enormous overseas military presence to ensure security of supply. Moreover, coal has other virtues: it is cheap and its price is much more stable compared to oil and natural gas as shown in Figure 4.4.[11]

A picture is worth a thousand words. Since the oil crisis of 1973, coal prices have been much lower than oil and natural gas (for the most part) and much more stable. But a picture does not include everything. What cannot be seen is that coal is a reliable domestic source of energy not subject to the whims of oil potentates.

The picture for Europe would reflect higher mining costs for coal than in the United States. The picture for Japan would reflect higher shipping costs since all coal must be imported. The picture for China and India would reflect lower mining costs in terms of lack of investment in

Figure 4.5 **Percent Share World Coal Consumption by Nation in 2008**



mechanization, near-slave wages for miners, with little spent for personal safeguards for their health and safety and for environmental safeguards to protect the population from pollution. This heavy reliance on low-cost coal affects the competitive position of China and India in world trade since the cost of energy is an element in the price of exported goods.

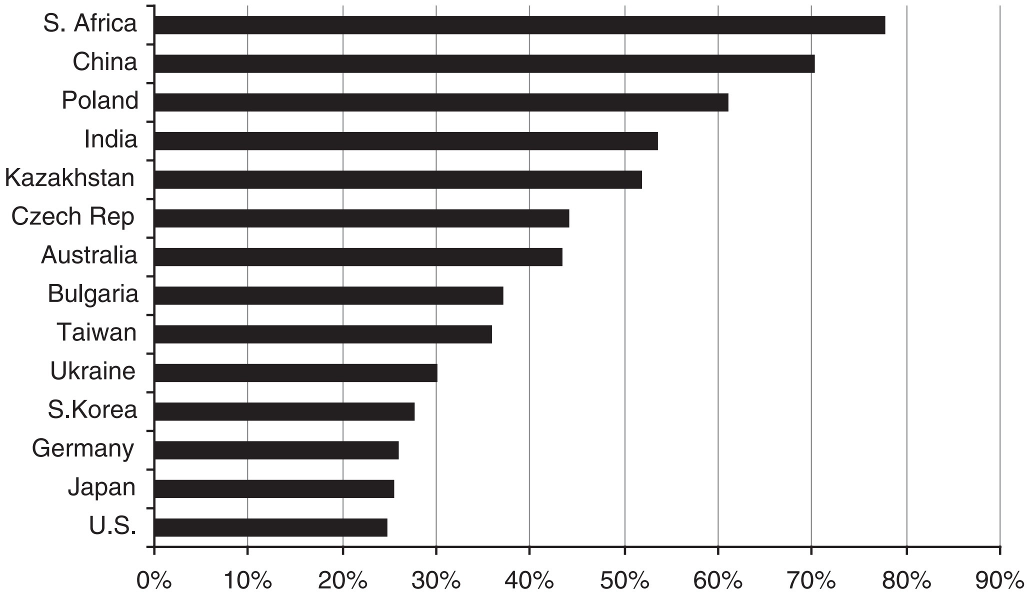
ROLE OF COAL AMONG THE MAJOR CONSUMERS

The primary use of coal is in electricity generation followed by steel production. Electricity and cleaner-burning heating oil and natural gas heat homes and cook food in developed nations, but coal (and biomass) are still burned for heating homes and cooking food in China and India. The six leading consumers of coal in 2008 were China, the United States, Europe, Russia and Central Asia (EurAsia), India, Japan, and South Africa as shown in Figure 4.5.

As seen in Figure 4.6, the nations with the greatest dependence on coal (over 50 percent) as an energy source are South Africa, China, Poland, India, and Kazakhstan. In 2000, China's coal consumption temporarily dipped as a result of an order from Beijing to close 50,000 small and inefficient mines for safety and economic reasons. The official data released by China on coal consumption presumed that these mines were closed and no longer producing coal. However, just as King Edward I's ban on burning coal in London was not heeded on the streets of London, it turned out that orders emanating from Beijing were not carried out in the provinces. China, without much in reserves of oil and natural gas, depends on coal as an industrial and residential fuel. Without replacement energy, thousands of small inefficient mines could not be closed, although the official statistics presumed that they were.

The failure of thousands of mines to close when ordered to do so also underscores a critical problem in China; its relentless pursuit of economic development is driving energy consumption through the roof. As much as China desires to diversify its energy sources to reduce the nation's

Figure 4.6 **Percent Dependence of Various Nations on Coal**



reliance on coal, it cannot cut coal consumption without suffering severe economic dislocation. As long as China's economic locomotive speeds faster and faster, coal will play an increasingly important role. China's building of hydropower dams and nuclear power plants will cut into coal consumption, but it will be years before their construction is completed.

On the surface, India is in a better position than China because it is less dependent on coal, although its dependence has been slowly climbing from its low point in 1999. From another perspective, India is in a worse position than China. China has an enormous trade surplus that is supporting the development of alternative sources of energy to coal (natural gas, hydro and nuclear power). India suffers from a negative trade balance and is less able to finance development of alternative energy sources or the import of energy such as natural gas. Thus, greater coal consumption, and possibly greater biomass consumption, may be the primary solution to India's growing energy needs rather than importing clean energy such as natural gas—unless energy providers are willing to accept rupees rather than dollars (one liquefied natural gas import scheme calls for rupee payments). Until there is a slowing of their economic locomotives, coal consumption in India and China will continue to expand both in volume and relative share of the energy pie.

King Coal was being unceremoniously dumped in the United States until the oil crisis in 1973 when coal's share of the energy pie fell to a low point of 18 percent. Even so, coal consumption in absolute terms was still rising slowly. Consumption accelerated after the oil crisis as coal found a ready market to replace oil as a fuel for electricity generation, rising to 24 percent of the energy pie in 1985. A slowing in the growth of electricity consumption and the collapse in oil prices in 1985 removed the financial incentive for building large coal plants. For environmental and economic reasons, there was a major shift in favor of building lower capital cost and smaller natural gas-burning electricity-generating plants, which better fit growth patterns.

Since 1985 coal's share of the energy pie has been relatively constant, yet coal consumption continued to increase in line with total energy consumption. This is quite remarkable considering that nearly all new electricity-generating plants in the United States in the 1990s and early 2000s were fueled by natural gas. With virtually no coal-burning plants built during these years, the only conclusion one can reach in examining the upward trend in consumption is that existing coal plants were operating at higher average utilization rates. This near-total reliance on natural gas during the almost twenty-year natural gas "bubble" of low natural gas prices burst in 2003 when demand finally outstripped supply. As natural gas prices rose to record levels, utilities took a second look at the idea of constructing coal-fired plants, and began ordering a number of new plants. With the building of these plants, coal's share of the energy pie slowly began to increase. Despite the bad publicity coal receives in the United States, it is still viewed as a national asset, plentiful, cheap, and secure, providing half the nation's electricity. Existing coal-fired electricity-generation plants and new ones being built will keep the coal industry a viable business and ensure the employment of tens of thousands of coal miners for a long time to come even in the face of a costly carbon cap and trade program. It will take decades to replace coal-fired plants with clean-burning alternatives and at a great cost. All that a cap and trade program will do is reduce the future number of coal-fired plants with the consumer bearing a higher cost of electricity.

Europe is one place in the world where coal is in retreat, both in relative and absolute terms. Coal consumption was slowly declining and its share of the energy pie was dropping fast until the oil crisis in 1973. Then coal's share leveled off as coal consumption increased to displace oil in electricity generation. Since 1985, it has been downhill for coal being replaced by nuclear power and natural gas. Nuclear power has been aggressively pursued in Europe, particularly in France. A natural gas pipeline grid has been built connecting the gas fields of Russia, the Netherlands, North Sea, Algeria, and Libya, with customers throughout Europe. Nuclear power and natural gas have largely displaced coal and oil for electricity generation and as an industrial fuel. Moreover, the Europeans are intent on ensuring that the role for coal is not resurrected by relying on wind and natural gas to meet incremental electricity needs. The interruptions of Russian gas supplies in 2006 and 2008/09 as a result of a pricing dispute with the Ukraine have tempered the willingness of Europeans to rely on Russian natural gas and they have inaugurated a program to diversify natural gas supplies.

Coal mining is a heavily subsidized industry in parts of Europe. Given an average import price of $40 per ton range, the average subsidy per ton of coal produced in Germany is estimated to be $144 per ton and $75 in Spain. France has an even higher subsidy rate, but its coal production is small. Subsidizing industry has been losing its allure for the last few decades. The United Kingdom has done away with coal subsidies by closing its most inefficient and heavily subsidized mines and significantly increasing the productivity of those remaining. Moreover, UK coal must compete with other forms of energy after the UK privatized its electricity-generating industry, including imported coal. UK coal production is a shadow of its former self, and German coal production is in a long-term decline. Both nations import a large portion of their coal needs. While European coal production is in a long-term slow decline, it supports steelmaking and still-existent coal-burning electricity-generation plants.

Before the fall of communism in 1989, coal consumption in Russia was fairly steady, although nuclear power and natural gas were eroding coal's share of the energy pie. After 1989, the reduction in coal consumption was primarily caused by the fall in electricity demand that accompanied the collapse of the Russian economy. During the 1990s, oil consumption for electricity generation was sharply curtailed to make room for exports, slowing the decline in the role of coal. Looking into the future, the primary beneficiary for satisfying incremental demand for electricity will be natural gas. The organizational and financial restructuring of coal mines in Russia, the Ukraine, Kazakhstan, and Poland have resulted in the closing of the most inefficient and heavily subsidized mines and enhanced productivity of those remaining. The restructuring has basically stabilized aggregate coal production for these nations.

Japan does not look at coal as a pollutant as much as a means to diversify energy sources to reduce its reliance on oil, most of which comes from the Middle East. Consumption of coal is increasing in recent years as a result of building more coal-fired electricity-generating plants. In addition to thermal coal for generating electricity, Japan, as a major world steel producer, also imports coking or metallurgical coal. As in North America and Europe, coal is burned in an environmentally sound manner in Japan. The role of coal in Japan was stable at around a 17–18 percent share of the energy pie but has recently increased to 25 percent. Coal is having a bit of a revival in Asia, besides China, India, and Japan, as a means of energy diversification. South Korea, Thailand, Malaysia, and the Philippines have built coal-fired electricity-generating plants.

CASE AGAINST COAL

The case against coal can be put simply, in one word—pollution. Pollution from lower-grade coals, whether soft or hard, is greater than higher-grade coals in terms of the quantities of ash and nitrous and sulfur oxides released during combustion. Also, a greater quantity of lower-grade coals has to be burned for the same release of energy. Airborne, nitrous oxides contribute to smog and sulfur oxide droplets collect on the upper surfaces of clouds, enhancing their reflectivity. This reduces the amount of sunshine reaching the earth and, paradoxically, is a counter-pollution measure to carbon dioxide that reduces the amount of heat that can escape from the atmosphere. Eventually, sulfur and nitrous oxides return to Earth in the form of acid rain, which harms plant and marine life and erodes stone buildings and statues. Mercury, arsenic, selenium, and other heavy metals are also released when coal is burned. Surface mining destroys the landscape and, along with residues from underground mining, affects water supplies.

Abandoned coal mines can catch fire and burn underground. Once on fire, there is little that can be done to stop coal-mine fires other than entering the mine with earth-moving equipment and taking away the source of the fire: the remaining coal in the mine. In 1962, burning trash near the mouth of a mine near Centralia, Pennsylvania, started an underground inferno that has been spreading ever since despite several attempts to extinguish it. The fire is burning at a depth of 300 feet beneath the surface and giving off enough heat to bake the surface, threatening to cremate bodies buried in the local cemetery. There is also venting of poisonous gases and opening up of holes large enough to swallow automobiles. It is thought that the fire will continue for another 250 years in an eight-mile area encompassing 3,700 acres before the fire runs out of fuel. Centralia has been largely abandoned except for a few diehards.[12]

Coal fires are not all the fault of men. Lightning igniting brush fires can cause spontaneous combustion of coal exposed to the atmosphere. Burning Mountain in Australia has been burning for an estimated 6,000 years. Most of the thousands of coal mine fires that threaten towns and roads, poison the air and soil, and worsen global warming are, however, inadvertently started by man. The estimate of the amount of coal burned each year in mine fires in China varies between 20 and 200 million tons per year; the high-end estimate is an appreciable fraction of China's total coal consumption. As bad as China is, India is even worse. Rising surface temperatures and toxic byproducts in the groundwater and soil have turned formerly populated areas into uninhabitable wastelands.

CLEAN-COAL TECHNOLOGIES

Coal is indispensable in the generation of electricity. A great deal of corporate- and government-sponsored research is dedicated to producing a clean coal, termed an oxymoron by critics. Modern coal-burning utility plants remove 99 percent of the ash produced as residue falling to the bottom of the combustion chamber and by electrostatic precipitators that remove ash from the flue gas. A flue gas desulfurization unit sprays a mixture of limestone and water into flue gas to reduce sulfur oxide emissions by 90–97 percent. Sulfur oxides chemically combine with the limestone to form calcium sulfate, or gypsum.[13] Sulfur emissions have fallen 2–3 percent per year in the United States, despite rising coal consumption, through greater use of scrubbers to remove sulfur and greater reliance on low-sulfur coal.

After mining and washing, coal is transported by train, barge, or truck and piled outside the electricity-generating plant until needed. A conveyor then moves the coal into the plant where it is first crushed and pulverized into a fine powder before being blown by powerful fans into the combustion chamber of a boiler in a conventional plant to be burned at 1,300°C–1,400°C, which transforms water in tubes lining the boiler to high-pressure steam that is fed to a turbine.

In addition to a conventional boiler, a fluidized bed combustion chamber can burn pulverized coal of any quality including coal with a high ash and sulfur content. The pulverized coal is burned suspended in a gas flow with heated particles of limestone at half the temperature (1,500°F) of a conventional coal-fired boiler. At this lower temperature, about 90 percent of the sulfur dioxide can be removed by the limestone absorbing the sulfur dioxide to form calcium sulfate or gypsum without the use of an expensive scrubber. In a conventional plant, water tubes in the combustion chamber generate steam to drive a steam turbine. In a fluidized bed combustion plant, both steam and hot combustion gases drive two types of turbines. Steam from the boiler tubes is fed into a conventional steam turbine. Hot combustion gas, after ash and gypsum have been removed, is fed into a gas turbine. Both the steam and gas turbines power electricity generators. The spent combustion gases from the gas turbine pass through a heat exchanger to further warm condensed water from the steam condenser returning to the combustion chamber. The two advantages to a fluidized bed combustion plant are an enhanced energy efficiency of 45 percent and a reduction of about 40–75 percent in nitrous oxide emissions from the lower temperature of combustion. Fluidized bed combustion chambers normally operate at atmospheric pressure, but one currently being developed would operate at a considerably higher pressure.

The first thermal plants built around 1900 were only 5 percent energy-efficient. The current rate of U.S. efficiency averages around 35 percent, with new plants achieving up to 45 percent, depending on the type of design. The average OECD efficiency is 38 percent, but efficiency in China is only 28 percent. Increasing energy efficiency is a major action item for reducing carbon dioxide emissions because the greater the efficiency, the less coal that has to be burned to generate the same amount of electricity.

Coal gasification is a thermochemical reaction of coal, steam, and oxygen to produce a fuel gas largely made up of carbon monoxide and hydrogen. The integrated coal gasification combined cycle (IGCC) is more complicated than fluidized bed combustion, and in some ways is a step back into history. Manufactured gas, the predecessor of natural gas, was the reduction of coal to a mixture of hydrogen, carbon dioxide, carbon monoxide, and methane that was distributed by pipeline to consumers. Similarly, coal is not burned in coal gasification, but processed to produce combustible products.

The process begins with an air-separation plant that separates oxygen from nitrogen. Coal is milled and dried in preparation for being mixed with oxygen and hot water for gasification. Synthetic gases (syngas), mainly carbon monoxide and hydrogen, are then treated to remove solids (ash) and sulfur. Some of the nitrogen separated out by the air-separation plant is added to the clean syngas prior to burning to control nitrous oxide generation. The syngas is then burned in a combustion chamber to drive a gas turbine and, in turn, an electricity generator. In addition to burning syngas to drive a gas turbine, a steam turbine also runs off steam produced in the gasifier and in cooling the synthetic gas from the gasifier. The spent steam is partly reheated by the exhaust from the gas turbine and fed back into the steam turbine and partly condensed to water to feed the gasifier (the combined cycle part of the IGCC).

The byproducts of an IGCC plant can be hydrogen for the hydrogen economy or a range of motor vehicle fuels. The advantages of IGCC are increased energy efficiency of above 50 percent, less generation of solid waste, lower emissions of sulfur, nitrous oxides, and carbon dioxide, and recovery of chemically pure sulfur. In a conventional coal plant, carbon dioxide emissions are mixed with the intake air, which is 80 percent nitrogen. Carbon dioxide emissions from an IGCC plant are pure carbon dioxide that can be sold or captured. The government-subsidized Wabash River coal gasification plant, in operation since 1971, removes 97 percent of the sulfur, 82 percent of the nitrous oxides, and 50 percent of the mercury from plant emissions. The higher thermal efficiency of an IGCC plant reduces carbon dioxide emissions for the same amount of power output produced by conventional coal-fired plants that operate at a lesser degree of thermal efficiency. These plants cost considerably more than conventional plants and represent a higher level of technological sophistication, along with a greater technical challenge in operation.

Advanced hybrid systems that combine the best of both gasification and combustion technologies are under development. Here the coal is not fully gasified, but partially gasified to run a gas turbine with the residue of gasification also burned to run a steam turbine. Again, higher energy efficiencies with even lower emissions are possible. Ultra-low emissions technology is being funded by the ten-year, $1 billion FuturGen project to build the world's first integrated sequestration and hydrogen-production research power plant. FuturGen employs coal gasification technology integrated with combined cycle electricity generation. FuturGen will be the world's first zero-emissions fossil fuel plant capable of transforming coal to electricity, hydrogen, and carbon dioxide. Hydrogen can fuel pollution-free vehicles using low-cost and abundant coal as the raw material. Electricity can be sold as well as the carbon dioxide byproduct. FuturGen was killed by the Bush Administration in 2007 because of cost overruns, but it was reinstated in 2009 by the Obama Administration.[14]

As with everything else that has to do with this planet, nothing is constant. The concentration of carbon dioxide cycles over the ages peaked at 280 parts per million (ppm). Unfortunately, the start of the Industrial Revolution coincided with a cyclical peak. Since then humanity has added over 100 ppm from burning fossil fuels. The current carbon dioxide concentration of 385 ppm has never occurred before in the known climatic record of the world, which goes back about 400,000 years; thus, there is no precedent for judging its impact.

No practical way exists to capture the 3 tons of carbon dioxide emitted by driving a thirty-mile-per-gallon automobile 10,000 miles.[15] However, a stationary coal-fired power plant does lend itself to capturing and storing its carbon dioxide emissions. A typical large coal-burning power plant of 1,000 megawatts produces about 6 million tons per year of carbon dioxide, equivalent to the emissions of 2 million automobiles. There are about 1,000 of these plants in the world. Flue gas is roughly 15 percent carbon dioxide and the remainder mainly nitrogen and water vapor. Rather than passing the carbon dioxide through a smokestack for disposal in the atmosphere, flue gas passes through an absorption tower containing amines that absorb the carbon dioxide. An associated stripper tower heats the amines, releasing the carbon dioxide and regenerating the amines for another cycle through the absorption tower. The question is on what to do with the carbon dioxide from the stripper tower.

If the power plant sits on top of impermeable caprock below which is a horizontal porous sand formation filled with brine, carbon dioxide can be pumped down a vertical pipeline that reaches the porous formation and is then dispersed via horizontal pipelines running through the formation. The brine formation should be more than 800 meters beneath the surface, where the pressure is sufficient for the injected carbon dioxide to enter into a "super-critical" phase where its density is near that of the brine that it displaces. In addition to the carbon dioxide displacing brine, brine also absorbs some of the carbon dioxide. When carbon dioxide saturates an area of the formation, more horizontal pipelines are necessary to open up new areas. Huge volumes of carbon dioxide can be safely stored in this manner, but the geologic formation has to be about six times larger than a giant oil field to contain the sixty-year lifetime plant output of about 100,000 barrels per day of carbon dioxide condensed to a super-critical phase.

Carbon sequestering means that more coal has to be burned for a given level of power generation to dispose of the carbon dioxide, but it may be possible to also get rid of sulfur dioxide along with the carbon dioxide as a side benefit. The cost of carbon dioxide sequestering is equivalent to a $60 per ton surcharge on coal. This will work its way through the rate structure to the electricity consumer in the form of a rate hike of about two cents per kilowatt hour, or a 20 percent surcharge for consumers paying ten cents per kilowatt hour and more for those paying less. A problem with sequestering carbon dioxide is the relatively low percentage (15 percent) of carbon dioxide in flue gas. Presumably this would have to be separated, which is a very costly process. One idea being explored is burning coal with pure oxygen and then recycling the flue gas back through the combustion chamber to significantly raise the concentration of carbon dioxide in the flue gases for potential separation.

Carbon sequestration is not without its risks. Lake Nyos in Cameroon sits in a volcanic crater where carbon dioxide seeps into the bottom of the lake where it is held in place by the weight of the overlying water. One night in 1986, the lake overturned and released between 100,000 and 300,000 tons of carbon dioxide. Carbon dioxide, heavier than air, poured down two valleys, asphyxiating 1,700 individuals and thousands of livestock. Any geologic formation holding carbon dioxide must act as an effective lock against escape. Carbon dioxide can also be pumped into depleted oil and natural gas fields. Carbon dioxide associated with natural gas production in certain fields in the North Sea and Algeria is separated and sequestered in nearby porous geological formations.

A payback can be generated if carbon dioxide sequestering increases fossil fuel production. Carbon dioxide pumped into methane-rich fractured coal beds displaces the methane, which can then be gathered and sold. Carbon dioxide can also be pumped into older oil reservoirs, where its interaction with residual crude oil eases its migration through the porous reservoir rock to the production wells. One coal-burning plant pipelines its flue gas emissions over 200 miles for tertiary oil recovery.

Not all research is space age. One project is exploring the possibility of adding 10 percent biomass to existing coal-burning plants, which may reduce greenhouse-gas emissions by up to 10 percent. One Japanese utility adds 1 percent biomass in the form of solid municipal sludge to its coal intake, which has improved the performance of the utility.

There are two types of ash: fly ash removed by electrostatic or mechanical precipitation of dust-like particles in the flue gas and ash from the bottom of the combustion chamber. Ash represents a disposal problem; most ends up in landfills. Alternatively, ash from burning coal, gypsum from flue gas desulfurization units, and boiler slag can be made into "cinder" construction blocks, which consume less energy and release less pollution than cement construction blocks. Fly ash added to concrete makes it stronger, more durable, less permeable, and more resistant to chemical attack. Gypsum can be used as a low-grade fertilizer. These waste products can also be used as aggregate or binder in road construction. The Japan Fly Ash Association is dedicated to improving the quality of coal ash, establishing a reliable supply, conducting research for recycling coal ash as an environmental benefit. Research is also being conducted on methods to reduce metals emissions, particularly mercury.

ELIMINATING COAL NOT SO EASY

Carbon dioxide is the result of a chemical reaction that occurs during combustion. Switching from coal to oil or natural gas only reduces, not eliminates, carbon dioxide emissions. For the United States, further reliance on natural gas would be very costly if demand starts to exceed supply. Switching from coal to oil increases oil imports and U.S. dependence on Middle East oil exporters. Switching to nuclear and hydropower and renewables (wind, solar), and the hydrogen fuel economy would eliminate carbon dioxide emissions entirely, but major impediments have to be overcome. Switching from coal to nuclear power cannot occur unless public opposition to nuclear power is somehow lessened. Switching from coal to hydro is hampered by a lack of suitable sites for damming. Switching from coal to wind and solar, while possible as incremental sources of power, cannot replace coal because generation is dependent on the wind blowing and the sun shining. Switching from coal to hydrogen, while environmentally the best choice—along with solar and wind—is stymied by a less than fully developed and commercially feasible technology.

Much can be done to reduce coal-burning emissions without resorting to clean-coal technologies. Physical washing removes sulfur-iron compounds (pyretic sulfur) on the surface of raw coal, but not sulfur embedded in coal's molecular structure. While coal washing is prevalent in the United States, Europe, Japan, and other developed nations, it is not in China and India, whose high ash and sulfur content coal would benefit most from washing. Although China and India are making headway in washing coal, there are capital constraints in establishing washing facilities, and possibly a shortage of available water in certain areas. A shortage of capital might apply for India, but China, with a large balance-of-payment surplus, does not lack capital. In the past, China lacked the national will to deal with pollution because capital invested in pollution controls could not be dedicated to its economic development. Having said that, China is becoming more concerned over the environmental consequences of its economic policies and is starting to take remedial steps.

Closing small and inefficient mines can improve the environment. Fewer and larger mines ease inspection efforts by government authorities and larger coal volumes more easily justify investments to protect the health and safety of workers and minimize harm to the environment. Using coal and biomass in home cooking and heating is a major source of uncontrolled pollution in Asia. On the surface, greater amounts of coal would have to be burned to switch home cooking from coal to electricity, but burning coal in a few locations provides the means of monitoring and controlling pollution emissions.

The future of coal is certain: It already plays too significant a role in generating electricity to be dismissed out of hand. What is uncertain is what is going to be done to reduce its adverse environmental impact. Two projects may point the way in which the industry may evolve. The Prairie State Energy Campus (PSEC) is a $4 billion joint venture comprising eight public electric utilities and Peabody Coal, the world's largest coal company.[16] The venture is unique in that the participants own both the electricity-generating plant and the coal reserves set aside to service the plant. Coal will be from a mine located adjacent to the plant that will supply 6.4 million tons per year on a continuous basis using the room and pillar technique. The plant is the largest of its kind at 1,600 megawatts compared to the more typical large-sized plants of 1,000–1,200 megawatts and will be capable of serving around 2 million households when completed in 2012. The plant will burn pulverized coal ground to the consistency of talcum powder, which in conjunction with the supercritical steam generating technology, will have an efficiency advantage that will cut the carbon footprint by 15 percent compared to existing plant technology. The plant will be among the cleanest coal-fueled plants in the nation. Coal will be burned at a lower temperature to reduce nitrous oxide emissions, which are further reduced by a selective catalyst-reduction unit that converts a portion of the nitrous oxide emissions to nitrogen and water. Dry and wet electrostatic precipitators will remove 99.9 percent of the particulates in the emissions, and an advanced sulfur dioxide scrubber using limestone and water will remove 98 percent of the sulfur. Mercury will be significantly reduced by the collective action of the selective catalyst reduction unit and the dry and wet electrostatic precipitators. Total emissions are expected to be cut in half compared to existing plants.

The other project is two proposed 629 megawatt IGCC plants to be built by American Electric Power, a major coal-burning utility. In a typical coal-burning utility plant, carbon dioxide is 15 percent of the flue gas whereas in an IGCC plant, the carbon dioxide is a separate gas stream, which allows carbon sequestration to avoid adding carbon dioxide to the atmosphere. American Electric Power is also involved with the technological development of using chilled ammonia that would isolate carbon dioxide from flue gas for sequestration in deep saline aquifers or for tertiary oil recovery. The company is also looking into the use of oxy-coal combustion (burning coal in pure oxygen) as a means of isolating a pure stream of carbon dioxide for sequestration or tertiary oil recovery.[17]

This is one side of the ledger. On the other side, hundreds of coal-burning utility plants are being built in China and India without regard for pollution control. These plants will add particulates and sulfur dioxide to the atmosphere that affect the health of those who breathe the fumes in addition to contributing to acid rain. China and India are trying to adopt clean technologies for generating electricity such as hydro and wind, but the magnitude of their growing demand for electricity is such that they are forced to rely heavily on coal. The problem is that this reliance on coal is on the basis of minimum concern over the environmental impact despite public announcements to the contrary.

To appreciate the magnitude of the problem, North America burns 18.4 percent of the world's coal with essentially no growth rate between 2000 and 2008. Europe including Russia burns 15.8 percent of the world's coal also with no net growth between 2000 and 2008. China alone burns 42.6 percent of the world's coal, greater than North American and Europe including Russia combined, and had a growth rate of 7.9 percent between 2006 and 2007. Adding in India, both nations burned 49.6 percent of the world's coal with growth of 9.2 percent between 2000 and 2008. These two nations represent half of the world's current consumption and are expected to maintain their robust growth rates. China alone is now the world's largest contributor to carbon dioxide emissions. Clearly, leaving these nations out of the successor instrument to the Kyoto Protocol is a major flaw.

NOTES

1. GlassOnLine Web site from www.glassonline.com/infoserv/history.html.
2. Barbara Freese, *Coal A Human History* (Cambridge, MA: Perseus Publishing, 2003).
3. Joseph S. Spoerl, "A Brief History of Iron and Steel Production," available from author at Saint Anselm College, Manchester, NH.
4. These statistics, as well as statistics on imports and exports and the role of coal in electricity generation, are available from the World Coal Institute at www.worldcoal.org/resources/coal-statistics/coal-steel-statistics/index.php.
5. I remember my father shoveling coal and having to remove and dispose of ashes from a coal furnace before converting to a heating oil furnace in a residential home on Long Island. I also remember my mother cooking on a combination wood- and coal-burning stove before switching to a propane-fueled stove in an upstate farmhouse. And I'm not that old!

6. John McQuaid, "Mining the Mountains," *Smithsonian Magazine* (January 2009), pp. 74–85.

7. The statistics in Table 4.1 are from *Sustainable Entrepreneurship* (December 2001), prepared by the World Coal Institute for the UN Environment Program; the figures are mostly for 2000, but a few are for 1999.

8. Volume data for all figures from *BP Energy Statistics* (London: British Petroleum, 2009). Sasol Corporation Web site www.sasol.com.

9. Clean Alternative Fuels: Fischer-Tropsch Fact Sheet published by the U.S. Environmental Protection Agency.

10. *World Energy Outlook* (Paris: International Energy Agency, 2008).

11. Sources in Figure 4.4 for the price of coal at FOB (free on board, used to specify that product is delivered and placed on board a carrier at a specified point free of charge at the mine mouth) is the U.S. Department of Energy www.eia.doe.gov/emeu/aer/coal.html, for bituminous coal in short tons. Source for the price of oil is *BP Energy Statistics* for $/bbl (dollar cost per barrel) FOB West Texas Intermediate; $/bbl price was multiplied by 7 in order to obtain $/metric ton (cost in dollars per metric ton). Natural gas prices in $/1000 cf were obtained from tonto.eia.doe.gov/dnav/ng/hist/n9190us3a.htm and translated to bbls at 5,610 cf/bbl. The price of coal was multiplied by 1.1 to convert from short tons to metric tons and then by 2 to convert physical tons to tons of oil equivalent to approximate the relationship between oil and coal in terms of equivalent energy released; these figures do not include shipping costs. Adjustments were made to price all three energy sources in 2008 dollars.

12. Kevin Krajick, "Fire in the Hole," *Smithsonian Magazine* (May 2005), p. 54ff.

13. World Coal Institute, London, Web site www.worldcoal.org for clean coal technology.

14. FuturGen is described in the U.S. Department of Fossil Energy Web site www.fe.doe.gov.

15. Robert H. Socolow, "Can We Bury Global Warming?" *Scientific American* (July 2005), p. 33ff.

16. Praire State Energy Campus Web site http://www.prairiestateenergycampus.com/.

17. American Electric Power Web site www.aep.com/citizenship/crreport/energy/generation.aspx.

5

THE STORY OF BIG OIL

When we think of oil, we think of gasoline and diesel fuel for motor vehicles, but the beginning of the oil industry was kerosene for illumination. Kerosene was the foundation of the Rockefeller fortune and marked the birth of Big Oil. Oil provided an alternative fuel for lighting; if oil ran out, it would be back to whale oil, tallow, and vegetable oils. Oil was not indispensable or vital to the running of the economy; now, no oil, no economy. The transition from a preferred fuel for lighting to something without which modern society cannot survive started with Henry Ford putting America on wheels in the early 1900s. The transition was complete by the First World War when military vehicles, tanks, and fighter aircraft fueled by oil played a pivotal role in securing victory for the Allies. Oil had become as important as armaments and ammunition in the conduct of war. During the Second World War, one of the principal targets of the Allies' bombing was the coal plants that produced gasoline to fuel the Wehrmacht. As a depleting resource, oil has moved beyond supporting war efforts to being a cause of war. This chapter looks at the historical development of two of the world's largest oil companies and the role that Big Oil may play in supplying the world with energy products as we proceed "Beyond Petroleum."

HISTORY OF LIGHTING

Prior to 1800, only torches, lamps, and candles lit the darkness of night. Torches were oil-, pitch-, or resin-impregnated sticks. Lamps—shallow rocks, seashells, or man-made pottery containing a natural fiber wick that burned grease or oil, animal fat, or rendered fat, called tallow—first appeared during the Stone Age. Candles go back to 3000 BCE and were made of tallow until paraffin wax, in use today, made its debut in the nineteenth century. To varying degrees, these modes of illumination produced more smoke than light.

In the early 1800s, the best lamp fuel was whale oil, which became increasingly expensive with the decimation of the whale population. There were plenty of alternatives to whale oil such as vegetable oils (castor, rapeseed, peanut), tallow, turpentine (from pine trees), and a variety of wood and grain alcohols. The most popular lamp fuel was a blend of alcohol and turpentine called camphene. Alcohol was obtained by distillation where vapors from a heated fermented mix of grain, vegetables, or fruits were separated, cooled, and condensed into a liquid. The distilling process for making alcohol for lamp fuel or whiskey was adopted in its entirety by the early oil refiners to separate the constituent parts of crude oil.

Another source of lighting in the 1700s and 1800s was coal gas. Gas emissions (hydrogen, carbon monoxide, carbon dioxide, and methane) produced by baking coal in a closed environment with insufficient air to support combustion were piped to street lamps in cities in Europe and America. Lamplighters lit the street lamps in the evening and extinguished them in the morning.

Coal gas was also piped into factories, buildings, and residences for illumination, but the benefits of coal gas were restricted to urban centers. This experience in piping coal gas to streetlights and buildings would be put to good use when natural gas was discovered in association with oil during the latter part of the 1800s. Nevertheless, despite these advances in lighting, most human activities stopped at sunset.

HISTORY OF OIL

Asphalt, or tar, was found on the surface in the Caspian Sea, the Middle East, Indonesia, Burma, California (the La Brea tar pit in Los Angeles is a tourist attraction), western Pennsylvania, and elsewhere. Oil was a medicine for various ailments for much of human history. Tar or pitch was mixed with clay as masonry cement in ancient Babylonia, still visible today. The Egyptians used tar as an adhesive in mummification. Romans burned oil as a fumigant to get rid of caterpillar infestations. Cracks between a sailing vessel's wooden planks were sealed with tar to prevent water from seeping through and sinking the vessel. Tar caulked Noah's ark and the bulrush cradle bearing Moses. Oil-soaked soil was burned as a fuel in the tenth century in the Baku region around the Caspian Sea, where Marco Polo also recorded oil seeping from the ground in the fourteenth century. Travelers in Baku in the seventeenth century recorded holes dug into the ground where oil was collected and then transported in wineskins on camels.[1]

Incendiary weapons made of naphtha also have a long history that goes back to the fourth century BCE. Of these the most famous was Greek Fire, which was mechanically projected from flamethrowers installed in the prows of Byzantine ships. Greek Fire was instrumental in turning back two invading fleets against Constantinople in 678 and 718 CE. Similar to modern napalm, it adhered to whatever it struck and could not be extinguished with water. The secret of Greek Fire, thought to be a mixture of naphtha, resins, and sulfur, was passed down from one eastern Roman emperor to the next until it was lost in only about a half century of time, perhaps as a consequence of a less than orderly transfer of power. The Arabs developed a form of Greek Fire to fight Crusader ships and the Chinese developed a similar weapon in the tenth century that was ignited with gunpowder.

In more recent times, Seneca Indians collected oil that seeped from the earth in western Pennsylvania for war paint and caulking canoes. Some of this natural seepage found its way into Oil Creek, giving it an oily sheen long before the discovery of oil. Immigrant settlers in the area dug holes that slowly filled with oil. These small quantities of seep oil, also called rock oil or its Latinized version, petroleum, were sold as medicinal cures for just about everything, first as Seneca Oil, which, when properly pronounced with the accent on the second syllable, became Snake Oil.

As in all human activities, not one, but many individuals made contributions whose aggregate impact was to launch a major industry. In the 1840s, Abraham Gesner, a medical doctor turned geologist, obtained a distilled liquid from coal that he named kerosene from the Greek words for wax and oil. In 1850, he formed the Kerosene Gaslight Company to light houses and streets in Halifax, Nova Scotia. Gesner was convinced that kerosene would one day overtake whale oil if it could be cheaply made.[2] James Young, a Scotsman, patented a process in 1850 for distilling paraffin wax and oil from oil shale and bituminous coal. Paraffin wax was made into candles for the first time and paraffin oil was burned for lighting and heating. By 1862 production of paraffin wax and oil consumed about 3 million tons of oil shale and bituminous coal annually and continued for over half a century before being replaced by distilling crude oil. Distilling oil from oil shale was revived in the United Kingdom during the Second World War to produce petroleum products. It may resume again if crude prices are driven to a point that can economically justify processing vast deposits of oil shale found in parts of the world.

Western Pennsylvania and the Baku region were not the only areas where seep oil was "mined." During the 1850s seep oil from holes dug in the ground in Galicia and Romania was refined for its kerosene content to light lamps. Refining in the United States was more influenced by the activities of Samuel Kier, a whiskey distiller in Pittsburgh, than by Young or Gesner or the refining activities in Europe. In the 1850s Samuel Kier modified a one-barrel still for distilling seep oil in Pittsburgh, Pennsylvania. He later built a five-barrel distilling unit and bought seep oil by the gallon. The experience gained in developing these first tiny commercial refineries was crucial in the development of the American oil-refining industry.

About this time a group of promoters, headed by George Bissell, in search of something to promote, commissioned Benjamin Silliman, a chemistry professor at Yale College, to examine the commercial potential of oil. Silliman's report noted the superior properties of distilled oil to burn brighter and cleaner compared to other illuminating fuels. Bissell also had the intuitive insight to come up with the idea to drill rather than dig for oil. As with so much else, the Chinese had beaten the West by 2,500 years when they succeeded in drilling for oil using a drill bit attached to bamboo poles.[3] Bissell did not know about drilling for oil in China, nor did he know that a well was drilled, not dug, in 1846 in Baku, thirteen years earlier, nor about an oil well drilled in Canada about the time when he thought of the idea. Reinventing the wheel, so common in the past, is less likely in today's world of global communication and information systems. Based on Silliman's report and his insight to drill rather than dig, Bissell put together a group of investors who bought newly minted shares in the Pennsylvania Rock Oil Company.

The oil industry did not spring from nothing—it was an event waiting to happen. It was an accepted fact of the time that anyone who discovered an abundant and cheap source of oil would "strike it rich." In 1859, the event happened, but not before the Pennsylvania Rock Oil investors backing "Colonel" Edwin Drake, a retired railroad conductor (and never a colonel), had given up hope, one by one, on Bissell's idea to drill for oil. The last remaining investor sent a letter notifying Drake that no further funds were forthcoming and to cease operations.

Drake put Bissell's insight into action and modified a derrick device that drilled either for freshwater or for brine for salt manufacture to drill for oil. Drake was first to place a pipe within the drill hole to prevent the ground from closing in and plugging the hole, the forerunner of casing a well, still in practice today. He rigged up a hand-operated water pump to extract oil from the casing within the well if any should appear. As strange as this may sound, his entire approach was ridiculed as Drake's Folly. Anybody with half a brain knew that the only true and tried way of obtaining oil was by digging a hole and extracting the tiny quantities that seeped into the bottom. It seems so strange from our perspective that people who dug for or, in essence, mined liquid oil and drilled for water and salt brine could not make the mental leap to drill for oil.

Besides these technological innovations, Colonel Drake made three strategically important decisions. First, Drake employed William A. Smith (Uncle Billy), who rigged up Drake's contraption so that it would actually work; second, Drake chose to drill in soil saturated with oil; and third, Drake ignored the letter from the last financial backer to cease and desist. He borrowed money to keep the operation going. Despite the fact that he was at the point of financial exhaustion, he doggedly stuck to his guns, a story that would be repeated many times in the development of the oil industry, creating fortunes for some and financial ruin for others. For Drake, it would be a bittersweet combination of both when the "crazy Yankee struck oil." Everyone agrees that the well was sixty-nine feet deep, but there is disagreement on the output of the well, ranging from ten to twenty-five barrels per day and on the price fetched in the market, ranging from \$20 to \$40 per barrel. Regardless of the actual flow rate and market price, overnight a new industry was born—Drake's claim to fame. For this singular achievement, Drake was to die a pauper, the first of a small, select group of individuals who would not profit from their renowned success.

Immediately, the area around Titusville became a gold rush town typical of the Wild West. A dollar invested in a producing well could yield thousands of dollars in profits. The most despicable and disreputable jostled with the honest and upright to build oil derricks almost on top of each other. The winner of this bonanza would be the individual who had the most wells pumping oil as fast and as furiously as possible. Revenue is price multiplied by volume. Since there is nothing one can do about price, the secret of producing untold wealth was to maximize production before the price fell or the oil field went dry.

Pandemonium reigned. The landscape was disfigured with fallen trees and uprooted vegetation, littered with derricks drilling for or pumping oil, construction gear and equipment tossed hither and yon, with trees, plants, soil, derricks, equipment, and drillers covered in oil. Oil was first stored in pits dug into the ground, soon replaced by wooden, and later, by metal tanks. Barrels originally intended for storing and transporting whiskey were expropriated to get the oil from the pits or tanks to a refinery. The early whiskey turned oil barrels ranged in capacity between thirty and fifty gallons and were standardized at forty-two gallons in the early 1870s. As one might expect, there were insufficient numbers of barrels to carry the oil to market. A barrel boom ensued as cooperage firms employing joiners tried to keep up with the demand. Teamsters moved the barrels of oil on horse-drawn wagons from the oil fields around Titusville to the Allegheny River for loading onto barges that were floated downstream to Pittsburgh, the world's first refining center, thanks to Samuel Kier.[4]

While joiners and teamsters prospered, drillers either made their fortunes or went broke trying. Wells drilled with wild abandon pumping full out soon flooded the market with unwanted oil. Maximizing revenue by maximizing volume works well when supply is less than demand. It is a different story when supply exceeds demand. Oil prices plunged from ten dollars to ten cents per barrel in less than a year, making a barrel more valuable than the oil within. Pumping oil continued unabatedly as prices spiraled downward because individual drillers could still maximize revenue by maximizing production as long as the price of crude oil exceeded the cost of extraction. One driller showing restraint and slowing his rate of production only meant lower revenue for him as others pumped with all their might. Drillers collectively seemed unable to sense the repercussions of what maximizing production today would do to price tomorrow; if they did, there was nothing they could do about it. The oil industry would have to wait for Rockefeller to teach the valuable lesson that practicing restraint today could maximize profits tomorrow.

As boom went bust, overnight fortunes evaporated into a spate of bankruptcies since money was entirely reinvested in drilling rigs, which lost all their value. Collapsing oil prices were not all that brought on the bad times; too many wells operating full out were sucking oil fields dry in no time. Consider the town with the quaint name of Pit Hole, about fifteen miles away from Drake's well in western Pennsylvania. Oil was discovered in what was a sleepy farming "community" of two buildings in January 1865. By September, nine months later, the population had exploded to 12,000–16,000, with a host of hotels and boarding houses to provide shelter and food for one flood tide of those looking for honest work along with another of rank speculators, unscrupulous stock-jobbers, reckless adventurers, and dishonest tricksters.[5] Near-valueless land a few months earlier was selling for over $1 million and interests in producing wells for hundreds of thousands of dollars. Considering the value of a dollar in 1865, these were considerable sums. The post office in Pit Hole became the third busiest in the state after Philadelphia and Pittsburgh. With so many oil wells built with such wild abandon pumping with all their might, the oil field soon went dry. Some oil drillers were bankrupt before their equipment arrived. Aided by two major fires, the city was mostly abandoned in a little over a year. Lumber from the remaining buildings was scavenged for construction elsewhere. Today Pit Hole is a ghost town without buildings.

Gesner was proven right. While oil is now generally under attack by environmentalists, it was oil or, more exactly, kerosene that saved the whales from extinction. In 1846 the whaling fleet numbered 735 vessels and was making a healthy rate of return, especially when the price for whale oil peaked in 1856 at $1.77 per gallon. By 1865 plentiful supplies of kerosene selling for fifty-nine cents a gallon sharply undercut the price of whale oil. The whaling fleet shrunk to thirty-nine vessels by 1876. The price of kerosene kept declining to a little over seven cents per gallon by 1895, when whale oil was selling for forty cents per gallon. With this price differential, there was no incentive to buy whale oil. Kerosene wiped out the whaling industry.[6]

Enter John D. Rockefeller

Building railroads made a major change in the Oil Regions, which started in Pennsylvania and later spread to Ohio, West Virginia, and Indiana. Oil could now be more cheaply transported to Cleveland by loading barrels on railcars, and later pumping oil into railroad tank cars, than loading barrels onto barges bound for Pittsburgh. The railroads made Cleveland the new world refining center, where John D. Rockefeller, a bookkeeper, happened to reside.

Rockefeller shaped the oil industry more than anybody else. As with many movers and shakers, he started life a nobody. His father, William “Big Bill” Rockefeller, was an itinerant trader taking advantage of price disparities that arose in a world of stationary buyers and sellers who did not know the price of goods over the next hill. Big Bill was a conniver and would play deaf and dumb if it suited his purpose. Considering his business practices, which were at times questionable, and his general behavior toward women, it is strange that he hated tobacco and liquor. It is stranger yet that he ended up marrying a strict Baptist, Eliza Davison, who shared his disdain for liquor but not tobacco (she smoked a corncob pipe). John Davison Rockefeller, their first child, born in 1839, would pick up their mutual aversion to liquor.

The newly wedded couple moved into Bill’s cottage where his long-term housekeeper Nancy Brown also lived. Both women gave birth to their first babies about the same time. The Davison family eventually prevailed on Big Bill to send Nancy away. As an itinerant trader, Big Bill was away from home for months at a time. His trading activities had to be fairly successful because he could support one family with his Rockefeller name at one end of his travels and another family under a pseudonym at the other, which he managed to keep secret for many years. He could also finance John D. Rockefeller’s first commercial ventures. Big Bill also taught John D. valuable lessons in business such as picking him up as a toddler and then dropping him to the floor with the stern admonition never to trust anyone, not even one’s own father![7]

From his earliest days, buying and selling flowed through John D.’s veins. After Big Bill moved his family to Cleveland, Rockefeller enrolled in a commercial school without completing high school. Like his mother, Rockefeller was a strict Baptist and, as a fifteen-year-old, taught Bible class and sang in the choir. He would be an active churchgoer for the rest of his life. At sixteen, Rockefeller was beating the pavement looking for his first job. He eventually found one at a wholesale firm dealing in everything from grain to marble. He was a meticulous bookkeeper and a persistent collector of unpaid invoices. After three months of working from six in the morning to ten at night, the firm thought well enough of Rockefeller to put him on salary.

Even at what was low pay for what he did, Rockefeller showed two seemingly contradictory character traits that would be with him throughout his life: frugality and philanthropy. He was frugal with what he spent on himself and he was frugal in the conduct of business; absolutely nothing went to waste. Yet he was generous with those in need. Rockefeller believed that his ability to make money was a gift from God that was not to be neglected without suffering God's damnation. He must have emblazoned in his mind the parable of the talents where God severely punished the one who did not put his talent to use. Rockefeller also believed that money received was a gift from God and would eventually have to be given back to Him.

Rockefeller seemingly never had an inner personal conflict between being a model family man at all times and a model churchgoer on Sundays, including teaching Sunday School and singing in the choir, with his role as an utterly ruthless businessman for the rest of the week. His approach to business was to unmercifully crush his competition, bringing unChristian-like suffering, misery, and distress to many. In his mind, he viewed his business practices as ultimately beneficial to humanity by bringing order out of disorder and eliminating the waste inherent in untrammeled competition.

Rockefeller carried out his pledge to God that money made as a gift of God would have to be returned. By the time of his death, he had given away much of what he had earned except for a not-so-small kitty to provide for his old age. Of course, much of what remained when he died was given to his only son, John D., Jr., but major beneficiaries were the first college for African-American women, Spelman College in Atlanta, Georgia (which says a lot about the man), the Rockefeller Foundation, Rockefeller University, the founding of the University of Chicago, and the building of Rockefeller Center in New York City during the Great Depression. John D., Jr., would continue returning his father's gift to God by funding the restoration of Versailles and the Rheims Cathedral, creating the Acadia and Grand Teton National Parks, donating land for the construction of the United Nations headquarters in New York, and restoring Colonial Williamsburg.[8]

After Rockefeller served his apprenticeship in a trading firm, he formed the firm Clark and Rockefeller with his friend Maurice Clark with a loan from his father. The firm successfully traded in grain and other commodities. In the early 1860s, with Cleveland hosting twenty refineries, oil began to draw Rockefeller's attention and he visited the Oil Regions. There is a photograph of the early movers and shakers of the oil industry. They stand in a group. Off to the side, distinctly separate from the others, stands a solitary figure in the middle of an empty field. It is not known whether this is Rockefeller, but it is thought that it was Rockefeller because Rockefeller stood alone in creating the oil industry.

Rockefeller was first to recognize the four principal facets of the oil business. One was production, the world of speculative drillers who, collectively, were unable to exercise self-control—a world of boom and bust, depending how supply and demand lined up. The second part of the oil industry was transportation, moving crude from the oil fields to refineries and oil products from the refineries to market. While oil transport first depended on canals and rivers, railroads had taken over much of the transport business by the time Rockefeller arrived on the scene, and railroads did not interest Rockefeller. The third part of the business was oil refining and the fourth, marketing. Refineries were relatively few compared to the number of drillers, and combining refineries under one corporate umbrella was possible, whereas combining drillers under one corporate umbrella was not. By creating a horizontal monopoly, a monopoly that controlled only refining, Rockefeller realized that he could control the entire oil industry. As the sole refiner, he would become the sole buyer of the nation's supply of crude oil and the sole seller to satisfy the nation's thirst for kerosene and lubricating oils.

With financial assistance from Big Bill, Rockefeller formed the firm Andrews, Clark, and Company in 1863 for an investment of $8,000 to get into the refining business. In 1864 he married Laura Spelman, a woman as strong in character and as firm in her religious beliefs as his mother. In 1865, he bought out Clark by carrying out what Clark thought was a bluff and renamed the firm Rockefeller and Andrews. Exercising his God-given penchant for making money, Rockefeller bought and sold oil and the profits rolled in. He brought his brother Will into the firm and opened up the firm's second refinery, the Standard Works. The word *standard* was purposely selected to evoke in the minds of customers the image of a steady and reliable source of oil products made to a consistent standard.

The refineries of the day produced only three products: lubes, or lubricating oils, for machinery; kerosene for lighting; and naphtha. Naphtha is lighter and more volatile than kerosene and could not be used in kerosene lamps without the risk of an explosion. While most refiners dumped naphtha into the nearest stream and burned the heavy end of the barrel for fuel, Rockefeller developed products for the heavy end of the barrel and burned naphtha to fuel his refineries, a sign of his frugality and aversion to waste. It is ironic that what is now considered the most valuable part of a barrel of crude oil, gasoline, which is primarily naphtha, was for four decades a waste product of the refining process. Naphtha would have its day with the coming of the automobile.

People were awed by Rockefeller's rapid ascent to business prominence. His overwhelming impression was one of power. His blank eyes revealed nothing, yet his eyes seemed to penetrate and read the minds of others. He knew everything going on in the oil business as if God had given him special powers to see "around the corner." Seeing around the corner was a special knack that Rockefeller had for posting paid observers who reported to him all that was happening in the oil patch. Rockefeller was secretive in nature and devised a code for internal communications within Standard Oil. His contracts contained secrecy clauses that voided the contracts if their contents were revealed. With or without God's help, Rockefeller knew everything happening around him and those around him knew nothing about what Rockefeller was doing and, more importantly, what he was up to.

Other than providing his family with the accoutrements of success, and giving to charities and to deserving individuals in need, Rockefeller plowed every penny the company earned back into oil. He believed and practiced frugality to an extreme. He knew that a penny saved a million times over was a lot of money that could also be plowed back into the firm. In addition to generating cash, he also knew how to tap bankers' money and borrowed heavily to finance the expansion of his business. In 1867 Rockefeller and Andrews became Rockefeller, Andrews, and Flagler, and by 1869 the three partners employed 900 workers producing 1,500 barrels per day of oil products. With 10 percent of the global refining capacity, they were the world's largest refinery operators. This implies a total global refinery capacity of 15,000 barrels per day, which is about one-tenth to one-twentieth the capacity of a typical modern refinery.

Rockefeller was a trust maker compared to Theodore Roosevelt, a trust buster. In Rockefeller's mind, a trust had real benefits. It deals directly with the one principal fault of the free market, a lack of stability marked by boom and bust. When supply is short of demand, prices shoot up, bringing on a boom, encouraging overenthusiasm for increasing productive capacity. This lasts until there is an excess of productive capacity, which transforms a shortage into a glut, causing prices to collapse. The ensuing bust lasts until demand catches up with supply, fueling the next boom.

A trust brings stability to an industry in chaos. A trust would never overindulge in building excess productive capacity to bring on a bust because the decision to expand productive capacity is in the hands of a single individual, or a small group of individuals acting as a cartel. A trust, as the sole buyer, would be able to purchase supplies and raw materials at the lowest cost, which means lower prices for consumers. Focusing on oil, a trust would have large-capacity refineries whose inherent economies of scale would further lower costs, which could never be achieved with many independent producers, each operating a small refinery. An oil trust would set prices for its products at levels that ensured the industry's profitability. Steady profits would be able to pay for an adequate supply of oil at a fair price, which, in turn, would provide job security for workers, ensure sound bank loans and a flow of dividends for shareholders. In essence, Rockefeller wanted to set up a system that outlawed the business cycle along with its layoffs, bankruptcies, stock-market plunges, and banking crises.

After taking over a market by wiping out the competition, Rockefeller did not take advantage of being the sole supplier and set an exorbitant price, as one might expect. Rather, he set a price where he could make a profit, but not a profit high enough to tempt new entrants into building a refinery. Rockefeller could maintain a monopoly by not being too greedy. Too high a price would only invite a new competitor to build a refinery, which Rockefeller would then have to crush by lowering prices below the competitor's costs, forcing the sale of the refinery to Rockefeller. Even so, some individuals were not above building a refinery just to force Rockefeller to buy it.

In 1870 the company was renamed the Standard Oil Company, with Rockefeller, now thirty-one years old, having the largest share (29 percent) of the company's stock. By 1879, in less than a decade, the Standard Oil Company owned 90 percent of the nation's refining capacity, having removed most, though not all, of its 250 original competitors by one of the following methods:

- Rockefeller's God-given talent for making money when others failed.
- Rockefeller's penchant for secrecy, preventing others from knowing what he was up to, but through "his men" knowing everything going on in the industry. For instance, railroads had to tell Rockefeller the details of shipments by his competitors including the volume, destination, and shipping rate. Corporate intelligence was a major weapon in Rockefeller's business arsenal for vanquishing his foes.
- Rockefeller's realization of the inherent economies of scale of large refineries before anyone else. Rockefeller had the best-operated, most efficient, and the largest refineries, making him the low-cost producer. He concentrated his refining at three plants, which at one time represented 75 percent of global refinery capacity. His refining costs were half those of his competitors. Being the low-cost producer was a major card to hold in the corporate game of King of the Hill since Rockefeller could lower his price to a point where his competitors were losing their shirts while he was not. Rockefeller was not above buying a refinery from an independent and closing it, then adding capacity to one of his refineries to replace the scrapped capacity, benefiting from further gains in economies of scale.
- Rockefeller, as the largest refinery operator, was able, through the efforts of Henry Flagler, to get the railroads to offer a secret rebate for Rockefeller's business.[9] Railroads, as common carriers, were at least morally, though not legally, bound to charge the same rates for everyone. With the cost of shipping crude oil about the same as its value, shipping was an important component in determining profitability. As the industry's largest shipper and also the owner of a fleet of railroad tank cars, Rockefeller took advantage of the intense competition among three railroads to negotiate a secret rebate. This rebate cut Rockefeller's shipping cost by nearly half. Then, on top of this, he negotiated a drawback, a kickback, of the shipping rates charged to his competitors. Rockefeller's competitors had to pay not only twice the shipping rate he did, but, to add insult to injury, part of what they paid to the railroads also flowed to Rockefeller through the innocuous-sounding South Improvement Company.
- Rockefeller was the first to sell his products in Europe and Asia. From the beginning, a large portion of U.S. kerosene production was exported and Rockefeller made Standard Oil the first multinational oil company and the United States the world's largest oil exporter. With widely dispersed markets throughout the United States and the world, Standard Oil was the only company so positioned that profits in one area subsidized losses in another. This was a

great advantage for Rockefeller when it came time to give a competitor a "good sweating." Rockefeller could bring any competitor to heel, domestically or internationally, through discriminatory price-cutting without suffering an overall loss.

- Rockefeller was not above sabotaging a competitor's refinery if that was necessary to bring the competitor under his control. He practiced corporate espionage by paying employees of competitors to spy for him. He was also a master at corporate deceit. One time, Rockefeller purchased a refinery on the condition that the seller would not reveal the purchase. The ex-owner continued to operate the refinery as an "independent" and combined with other independent refinery operators in order to better combat Rockefeller's ruthless takeover of the refining business. The sellers learned too late that they were now within the firm grip of Rockefeller's octopus.
- Rockefeller knew how to handle bankers and was always able to cajole, when he could not convince, bankers to finance his acquisitions. The bankers were willing lenders because Rockefeller never defaulted on one penny of his borrowings, a valuable piece of business advice from his father.

Rockefeller achieved his high-water mark of over 90 percent control of the refining industry in the late 1870s. The lines on his face began to reveal the never-ending stress of working strenuously by day and worrying mightily by night. Even though Rockefeller seemingly held all the cards, it was not a simple matter for him to achieve his objective of total control over the refining industry. The American independents were just as determined to escape from Rockefeller's grasp, survive, and come back to fight again as Rockefeller was to subdue them. The American independents were absolutely determined and dedicated to not ending up as Rockefeller's property just as, a few years later, the Russian independents would be equally determined and dedicated to not ending up as Nobel and Rothschild property.

To combat Rockefeller's control over the railroads and his favorable shipping rates, the independents started building a pipeline to connect the Oil Regions with the east coast market. Rockefeller put every legal impediment in their way that his lawyers could devise. He bought land through which the pipeline would pass with the intent to deny permission for its construction. The independents, utterly determined to defeat Rockefeller, would change the pipeline path around Rockefeller's land. Then Rockefeller convinced the railroads not to sell the right-of-way for the pipeline to cross their tracks. Unable to cross a railroad track, the pipeline ended on one side of the track and started on the other side. Oil from the pipeline had to be loaded on wagons to cross the railroad tracks and then be put back into the pipeline. When this failed to stop the flow of oil, Rockefeller had the railroads park a train across track crossings to disrupt transfer operations.

Despite this towering wall of opposition, the independents managed to complete the pipeline. Pumping oil through a pipeline is far cheaper than shipping by railroad. For one thing, railroad tank cars had to be taken back empty for another shipment—an expense not relevant to a pipeline. Another voided cost of a pipeline was the cost of moving a locomotive and tank cars along with the oil. Moreover the capital cost of a pipeline is less than a railroad. The completion of the pipeline meant that Rockefeller had not only lost his strategic advantage over the independents, but that he now suffered from a strategic disadvantage. Once the independents could reach the east coast market cheaper than Rockefeller, Rockefeller did an about-face and became a pipeline builder. He eventually built 13,000 miles of pipelines connecting the Oil Regions with the east coast markets and took over nearly 90 percent of pipeline traffic, amply demonstrating what it was like to cross his path.

Rockefeller also manufactured kerosene lamps and sold them at cost to induce people to switch to kerosene. He pioneered in making lamps and stoves safer to lower the death rate of several thousand per year from kerosene fires and explosions. The hazardous nature of kerosene increased when unscrupulous refiners spiked their kerosene with more volatile naphtha rather than throw it away. Consumers could count on Rockefeller's "standard" kerosene product to be free of such dangerous adulteration. To expand his market beyond kerosene, Rockefeller spearheaded the development of other oil products including asphalt for road construction, special lubricants for railroad locomotives, and ingredients for paint, paint remover, and chewing gum. By creating products for the lower end of the barrel, he could burn the upper end, naphtha, as fuel to run his refineries while his competitors burned the lower end for fuel and were forced to dispose of the naphtha as waste. He made sure that Standard Oil stayed with the business it knew best: oil. Having established a horizontal monopoly in refining that stabilized the price of oil, he then strove for a vertical monopoly by acquiring oil-producing properties. By 1879, Standard Oil's oil fields from Pennsylvania to Indiana pumped one-third of the nation's oil. This was also the year that Thomas Edison invented the electric light bulb, the start of a slow death for the kerosene lamp.

When Rockefeller got into oil production, he discovered that natural gas associated with oil production was flared or vented to the atmosphere. Because of his aversion to waste, Rockefeller started plowing his oil profits into developing a natural gas industry. Natural gas could supply streetlights, buildings, and factories as a substitute for coal gas if there were a means to get natural gas from the oil wells to towns and cities already served with coal-gas pipelines. Standard Oil was active in building natural gas pipelines and obtaining municipal franchises to supply communities with natural gas, which was cleaner burning, cheaper, and had a higher heat content than coal gas. Sometimes he had to pay a bribe to get a municipal franchise, and sometimes he resorted to corporate trickery. One municipality decided to split a franchise between two independent firms so that consumers could benefit from competition. Although the two companies that won the split franchise seemed to be rivals, in reality both were subsidiaries of Standard Oil.

Is there anything that can be said in favor of the way Rockefeller conducted business? Actually there was one—when a competitor was crushed and had no choice but to sell to Standard Oil, Rockefeller would offer either cash or shares in Standard Oil, recommending the latter. Frequently sellers, after being beaten by Rockefeller into abject submission, took the cash just to avoid further entanglement with him. This was indeed unfortunate because the value of the stock would, in time, vastly exceed the value of cash.

Ida Tarbell, a journalist-author of a series of magazine articles starting in 1902 in *McClure's Magazine* entitled "The History of the Standard Oil Company," exposed the company's nefarious business practices. These articles turned public opinion against Rockefeller and fueled Theodore Roosevelt's aversion to monopolies. Ida was a perfect person to write such a series of articles. Her father was a joiner, or barrelmaker, who profited in the early days of oil by being the first to make wooden tanks for storing oil, rather than pits dug in the ground. He built a house for his family by scavenging lumber from an abandoned hotel in Pit Hole. His days of prosperity ended abruptly with the advent of metal tanks. Throughout his life, he was a strong advocate of American independents. He was allied with one that was eventually crushed by Standard Oil, a fate shared by Rockefeller's brother Frank.

By 1882 Standard Oil, a conglomerate of subsidiaries created by Rockefeller's numerous acquisitions, was becoming difficult to control. Rockefeller reorganized the company as the Standard Oil Trust, whereby control of forty-one companies was vested in nine trustees including Rockefeller, who operated out of Standard Oil's New York City office at 26 Broadway. As the years went by, Rockefeller controlled less of the company's operations and spent more time grooming his successors plus time in court fending off victims seeking restitution and at hearings fending off government inquiries into his business practices. Rockefeller was moving into the public spotlight, and the public did not like what they saw. Rockefeller's business practices did not fit the picture of America as a land of opportunity for pioneers and family owned businesses. Forcing competitors to sell against their wishes, even if the price were fair, was not considered a fair business practice.

Rockefeller's business practices, while not technically illegal at the time, inspired legislation that made them illegal. The Interstate Commerce Act of 1887 required railroads, as common carriers, to charge the same rates for all customers and outlawed secret rebates and kickbacks and established the first federal regulatory watchdog agency, the Interstate Commerce Commission. In 1890 Congress passed the Sherman Antitrust Act, which banned trusts and combinations that restrained trade and sought to control pricing through conspiratorial means. In 1892 the Ohio Supreme Court ordered the local Standard Oil company to leave the Standard Oil Trust, but Rockefeller instead dissolved the Trust and set up a new corporate holding company, Standard Oil of New Jersey (New Jersey was selected for its lax corporate laws). Standard Oil Trust as a legal entity lasted only ten years, but its name would last forever. Independently of Standard Oil, Rockefeller also got involved in investments in mining iron and copper ores and banking, which, in the Rockefeller tradition, all made money. The banking investment turned out to be a predecessor bank to Chase Manhattan, which was eventually run by his grandson, David Rockefeller.

With all these successful achievements in business, Rockefeller had one more favor from God awaiting him: Theodore Roosevelt. Rockefeller the trust maker fought Roosevelt the trust buster for years before Roosevelt won in 1911 with the Supreme Court decision that forced Standard Oil to dissolve itself into thirty-four separate and distinct companies. Rockefeller, rather than holding shares in Standard Oil, now held the equivalent number of shares in thirty-four companies including what would become Exxon (Standard Oil of New Jersey), Mobil (Standard Oil of New York), Amoco (Standard Oil of Indiana), Sohio (Standard Oil of Ohio), Chevron (Standard Oil of California), ARCO (Atlantic Refining), Conoco (Continental Oil), Marathon (Ohio Oil), Pennzoil (South Penn Oil), and twenty-five others.

Before the divestiture, and with Rockefeller exerting less control, Standard Oil was becoming bureaucratic and lethargic, the twin banes of large successful organizations. After the breakup and an initial period of cooperation among the sister companies, each went their separate ways, opening up and exploiting new markets that Rockefeller had not envisioned. The net impact of splitting up Standard Oil was to invigorate the company with a host of new managements and multiply the stock value of Rockefeller's original holdings in Standard Oil many times over. Rockefeller, fully retired after the Standard Oil breakup, became far wealthier than when he was actively engaged in business. Rockefeller died in 1937 at age ninety-eight, two years shy of his goal and, by all accounts, well-pleased with the course of his life. He had given away all but $26 million of his money, although a nice chunk of change was in his son's hands. Whether God was actually pleased with him is unknown.

Enter Marcus Samuel

The story of the transition of a small trading house in seashells to a major oil company known as Shell Oil serves as a counterpoint to the story of Standard Oil. It has more twists and turns and impinges more on the affairs of other oil companies, which, one day, would become part of Big Oil. The story begins with Marcus Samuel, the father of two sons, who would found Shell. The elder Marcus, a British Jew, purchased seashells and other objects from sailors who frequented the London waterfront. The shells were cleaned, polished, and, attached to boxes, sold in seaside towns and curio shops. By the 1860s, the elder Marcus began to branch out into general merchandise purchased as it landed on the dockside in London. Marcus saw the end of an era of shipping when a vessel left London with goods without any clear idea of what the goods would be sold for until the vessel arrived in Asia, where the proceeds would purchase Asian goods whose value was unknown until the vessel docked in London. Trading was a real gamble in terms of commercial risk: buying goods with no idea of what they would fetch if they survived the hazards of being carried aboard a vessel at sea. The opening of the Suez Canal, which shortened the voyage time between London and Asia, and the start of a regular mail service, which allowed buyers and sellers to communicate with each other, reduced the extent of operating in the dark although traders still had to contend with price changes during the weeks or months between buying and selling goods.

The elder Marcus's volume of business began to blossom as the British Empire expanded, first into India and then to British enclaves in Singapore, Hong Kong, Shanghai, and other Asian ports such as Bangkok, and finally the opening up of trade with Japan. Rather than buy and resell goods as they arrived in London, Marcus started working through agents in Bangkok, Singapore, and elsewhere to secure imports paid for by exports of British manufactured goods. The elder Marcus set up a trading house and conducted business through letters that took weeks to exchange, never visiting his agents. The agents learned to trust Marcus because he kept his word even if market conditions changed. This was a bit unusual in a world where reneging on deals was fairly common, particularly during times of financial distress when banks closed and trading houses collapsed. In 1870 the elder Marcus died, and the eldest son Joseph took charge of the family business, while the two younger sons, Marcus and Samuel, inherited only their father's reputation for sticking by his word.[10]

After spending some time at the family business, the younger Marcus—at twenty years of age—set out on his first voyage to Asia in 1873. Marcus discovered a famine while visiting his father's agent in India and surplus rice while visiting his father's agent in Bangkok. Marcus put together his first international deal with rice merchants and ship owners to relieve the famine in India, a deal both humanitarian and profitable. He returned home in 1874, shortly before his mother's death and, on his second voyage in 1877, made the acquaintance of the great trading families in Asia. At that time trade was either between Asia and Europe via the newly opened Suez Canal or within the borders of a nation. Marcus sold goods he acquired—not in England, as was expected—but to other Asian nations, "at the least possible distance." Strange as this must sound from a modern perspective, Marcus is credited with the start of intraregional trade among Asian nations as opposed to trade being confined within a nation's borders or with England.

Marcus reached Japan just as it was opening its borders to trade and established an office to import English textile machines in exchange for Japanese wares such as rare seashells, china, and silk. As the years progressed, the two brothers, operating from their office in London, built up a substantial trading house working through trusted employees and third-party agents in Asia. By the 1880s they owned the largest foreign concern in Japan and were involved with all types of cargo including Japanese coal exports for fueling steamships and kerosene imports in tin containers, called case-oil, from the Black Sea port of Batum.

At that time Standard Oil was a leading force in the case-oil market, but it was not alone. The Russian czar permitted the development of Caucasus oil in 1873 by awarding a concession to the Nobel brothers, Robert and Ludwig; a third brother, Alfred, was the inventor of dynamite and originator of the Nobel Prizes. The two Nobel brothers developed the oil resources of the landlocked Caspian Sea, located in the Baku region of modern Azerbaijan. As in Titusville, oil seeped to the surface and was "mined" for centuries before the two Nobel brothers began drilling for it. Although we tend to think of the oil industry as strictly American, the Nobel brothers made several important contributions to drilling and refining oil and in shipping oil by pipeline and tanker. The Nobels led the effort to make Baku a major world supplier with Caspian oil, which at the beginning of the twentieth century accounted for over half of the world's supply of oil (11.5 million tons versus U.S. production of 9.1 million tons).

To get kerosene to Europe, the case-oil was shipped in barges from a Caspian Sea refinery through the Volga River and canal system, then transferred to the Russian railroad for transport to a Baltic Sea port, and then by water to Europe. The Nobels had high shipping costs and, once their case-oil arrived in Europe they faced Standard Oil. Rockefeller moved into Europe early on, first moving kerosene in barrels to Europe on general cargo vessels and later in bulk on the world's first tankers. These early tankers proved to be dangerous. Fires and explosions often cut their lives short, a weak point that Marcus would eventually exploit.

The Nobels had learned a valuable lesson from Rockefeller's successful control of the railroads, which assured him a monopoly over American oil. The Nobels' version was to gain virtual control over water transportation up the Volga River. To beat this monopoly, the independent Russian producers started to build a railroad from Baku to Batum, on the Black Sea. If completed, Caucasus oil would be shipped by rail from Baku to Batum and then by tanker through the Black and Mediterranean seas to Europe. The oil would arrive in Europe cheaper than the Nobels transporting it to Europe via the Volga River and the Russian railway system to a Baltic port. This would place the Russian independents at a competitive advantage with the Nobel brothers in Europe. The Nobels, just as ruthless as Rockefeller, lowered the price of Russian oil and starved the Russian independents of the funds necessary to complete the railroad. Confident that they had crushed the Russian independents, the Nobels had inadvertently opened up the opportunity for the Paris Rothschilds to enter the oil game by financing the completion of the railroad. The Rothschilds extracted an exclusive purchasing arrangement from the Russian independents as a price for financing the railroad. With a secure source of oil, the Rothschilds built a refinery at Batum and began to market kerosene in Europe in competition with the Nobels and Rockefeller.

The Nobels were in deep trouble because transporting oil by canal and railroad to the Baltic via the Volga River was more expensive than by rail to the Black Sea and then by tanker to Europe. Like Rockefeller, the Nobels were not easily beaten. They built a pipeline from the Caspian Sea to the Black Sea, using their brother's dynamite to clear the way. Now it was the Rothschilds' and the Russian independents' turn to "sweat" as it was cheaper to pipeline oil to the Black Sea than to transport by railroad. Having lost their strategic advantage, the Rothschilds were in a weak bargaining position, locked in third place after Standard Oil and the Nobels in the race to supply kerosene to Europe.

In 1885 a London ship broker, Fred Lane, "Shady" Lane to his critics, was the London representative of the Paris Rothschilds. Lane approached Marcus with the idea of selling Rothschilds' kerosene in Asia. The Rothschilds were eager to diversify their market to counter their competitive disadvantage in Europe. But no matter where the Rothschilds attempted to sell kerosene in Europe, Standard Oil would step in, lower the price, and chase them away. Another approach was needed and that was to establish the Rothschilds in Asia, and over the following years Lane and Marcus hatched a strategy to do just that.

First, the relatively expensive transportation of case-oil, including the cost of tin containers, would be replaced by bulk transport in newly built tankers from Batum to Asia via the Suez Canal. Storage depots would be built in the principal ports in Asia to receive bulk oil shipments. The storage depots, where possible, would be connected to railroads or roads for bulk transport in railroad tank cars or horse-drawn wagons to inland destinations. To assure the success of the venture, the Rothschilds entered into a low-priced long-term supply contract for kerosene. As attractive as this sounded, it had one serious drawback. Bulk shipments of kerosene in tankers were not allowed to transit the Suez Canal because of their poor safety record. If Marcus could build tankers to a higher standard of safety and receive permission to transit the Suez Canal, then the Rothschilds would have a strategic advantage over Standard Oil.

The project faced enormous obstacles. The first obstacle was financing the tankers. Marcus became an alderman of the city of London, which, in addition to his being a successful businessman, would aid in garnering the necessary financing for the tankers, whose ultimate use was to be kept a secret from those providing the financing. The Rothschilds could not put up the financing as that would compromise the secrecy of the project. The second obstacle was that the Rothschilds had a hidden agenda—they intended to use the contract with Marcus as a means for putting together a more attractive deal to amalgamate their interests with Standard Oil. This made the Rothschilds an unreliable partner, although Marcus did not know it. The third obstacle was the Suez Canal Authority, who had no idea what tanker standards should be imposed to permit safe transits. Marcus was building tankers whose standards might or might not satisfy the Suez Canal Authority. The fourth obstacle was building storage terminals in Asia, for which Marcus had no experience, just as he had no experience with building tankers. The fifth obstacle was that Marcus, while a successful trader, had no background either in oil or in leading such a Herculean business enterprise, although he must have had the Rothschilds' confidence that he could successfully take on Standard Oil. The sixth obstacle was keeping Standard Oil from learning the entirety of the plan, in which case the project would face its full fury. The seventh obstacle was the two brothers themselves who continually bickered with one another because they had different personalities, different approaches to business, and, most importantly, different perceptions of risk. The eighth obstacle was that the financial stake was of such a magnitude that, if it failed, Marcus would be disgraced. The ninth obstacle was that Marcus preferred to act through inexperienced blood relatives, two nephews in particular, rather than through those with experience, although operating through his nephews might have been necessary in Marcus's mind to preserve secrecy.

The tankers under construction for Marcus incorporated the lessons learned from fires and explosions on existing tankers. Kerosene would not be carried in the bow section of the ship, which would protect the cargo in case of a collision. Tanks were added to contain the thermal expansion of the cargo when the vessels passed through warm tropical waters. The individual cargo tanks were of limited capacity and airtight to enhance safety and would be thoroughly cleaned after discharging their cargo to prevent evaporating residues from forming an explosive gas mixture. The tankers would be registered with Lloyds Register's highest classification rating.

Two young nephews of the Samuel brothers were put in charge of building storage facilities in Asia, but they had no experience in acquiring property rights and building storage tanks. Port authorities opposed bulk storage facilities for oil products because they were considered potentially unsafe. Local business interests were against constructing storage tanks since change of a nature they did not understand could best be addressed by resisting it. The nephews were bombarded with micromanagement cables from their uncles that ran from close scrutiny of their expense accounts to attending to other aspects of the firm's trading activities. Their uncles' advice on building storage facilities was anything but helpful.

Owners of existing tankers who had been denied permission to pass through the Suez Canal were not keen to see a new class of tankers built that could. This would make their vessels obsolete, at least from the point of view of trading between Europe and Asia. Members of the Russian imperial family, who were large shareholders of a Black Sea fleet of tankers, were in a position to have the Russian government petition the Suez Canal Authority to deny permission to Marcus's new tankers. Other petitioners included tanker owners and tin-plate manufacturers of cases for holding oil, whose business would be threatened by bulk shipments of kerosene, plus a host of companies, many of which were not engaged in the case-oil trade or shipping. Standard Oil's name did not appear among those opposing Marcus's application. It would have been utterly out of character for Standard Oil to be absent from such proceedings, but for whatever reason Standard Oil preferred to pull the legal strings through other parties and remain hidden behind lawyer-client privilege.

In the end, the Suez Canal Authority concluded that tanker transits would add to canal revenue and accepted Lloyd's highest classification rating as adequate criteria for safe passage. Despite all odds, including near-continuous interference from their uncles, the two young nephews succeeded in having storage tanks built in Bangkok and Singapore and were making progress in building tanks in Hong Kong and Kobe when, in 1892, the first tanker, the *Murex,* named after a seashell, passed through the Suez Canal with a cargo of Rothschild kerosene. The vessel unloaded its 4,000 tons of cargo at Bangkok and Singapore (actually at Freshwater Island, outside the jurisdiction of the Singapore port authority, which had denied permission to build an oil storage facility within Singapore). Ten more vessels were launched in 1893, creating a fleet of eleven vessels, all named after seashells as a tribute to the elder Marcus. By the end of 1895, sixty-nine Suez Canal tanker transits were made, of which all but four were tankers either owned or chartered by the Samuels. In 1906, Marcus shipped 90 percent of the 2 million tons of oil that passed through the Suez Canal. Marcus and the Rothschilds had beaten Standard Oil at its own game, a singular achievement, which by any measure must rank as a commercial miracle.

In 1892, after being told by a doctor that he was dying from cancer, Marcus organized the Tank Syndicate to carry on the tanker business after his death. The Tank Syndicate included family and friends such as merchants responsible for local distribution and individuals who had supplied storage tank facilities. The syndicate members were also responsible for garnering return cargoes for the tankers, which the Samuels sold in Europe. Trading transactions were done on the basis of a joint account for the syndicate members, all of whom became quite rich. When the doctor was proven wrong, the Tank Syndicate was reorganized as The Shell Transport and Trading Company in 1897.

All this was built on a house of cards. The Rothschilds were negotiating with Standard Oil and the Nobel brothers to form a world cartel, thus ending the intermittent price wars between the oligarchs. Standard Oil, sensing the importance of Marcus to the Rothschilds, opened negotiations to make Marcus part of Standard Oil. Marcus turned down a generous offer because he did not want to see a British firm become American or lose the Shell trademark and his identity as a businessman. In the game of King of the Hill, only one is left standing at the top, the primary reason why proposals for amalgamation among the Oil Kings failed. With the failure to come to terms with Standard Oil, Marcus was back skating on thin ice without a truly secure source of oil.

As fortune would have it, a company by the name of Royal Dutch in the Dutch East Indies produced oil, but was unable to transport and market its production. Royal Dutch was none of the things its name might imply. Its chief claim to fame was being the first oil company on record that relied on a government (the Dutch authorities in Dutch East Indies) to protect its oil holdings from insurgents. Royal Dutch had borrowed money to finance kerosene held in storage just as the price of kerosene crashed from Marcus's bulk-oil shipments and Standard Oil's campaign to chase American independents out of the Asian market. Royal Dutch approached Marcus about buying its Sumatra refinery output, but Marcus proved to be a tough negotiator, perhaps too tough. A subsequent rise in oil prices saved Royal Dutch and Marcus lost his first opportunity to obtain a secure source of oil and take over a company that perfectly complemented his own. In the end, Royal Dutch would take over Shell on its terms.

In 1895, the cards turned on Marcus. Standard Oil, the Rothschilds, the Nobels, and the Russian independent producers reached a price agreement. The oligarchs controlled the entire world supply of oil except for that of the American independents. As oil prices stiffened, Marcus had to cut the shipping rate on his fleet to stay in business, although selling return cargoes of general merchandise carried on Shell tankers made up for the losses in shipping oil. As things were becoming more difficult for Marcus, fortune smiled and the Shell fleet profited from the Sino-Japanese war because different elements within Shell supplied both China and Japan. Shell would come out a winner no matter who won. Marcus represented that portion of Shell allied with Japan. Marcus was able to take commercial advantage of Japan's winning the war by becoming a merchant banker and floating the first Japanese sterling loan in London in 1896. Now a merchant banker, Marcus's star continued to ascend with his election as sheriff of London, which placed him in the direct line of succession to the highest civic office in Britain, lord mayor of London. With his newfound wealth, Marcus purchased a 500-acre estate bordering on the parsonage of Bearsted, marking the high point of his career when he was only forty-three years old.

The contract with the Rothschilds was half over and an alternative source of oil would have to be arranged if the contract were not renewed. As luck would have it, a Dutch East Indies mining engineer with an oil concession in Borneo showed up at Marcus's door in 1896. By this time Mark, the younger of the two nephews, was carrying quite a load. He was responsible for building tank storage facilities and inland distribution points, identifying new agents to handle distribution, ensuring proper discharge and cargo handling of the Shell tankers, and tending to a myriad of instructions from London on the firm's trading business plus continuing to explain every item on his personal expense account. He also covered his uncles' mistakes, such as how to get the kerosene from the company's tanks to users. Users could not accept bulk shipments; they bought kerosene in a tin. The uncles had not taken this last crucial step in the supply chain into consideration, thinking that the buyers would supply their own tins; they did not. The only tins were the blue Standard Oil tins, which had other uses that did not include buying Shell kerosene.

This, too, became Mark's responsibility. He was building storage facilities with no previous experience; now, with no previous experience, he had to build a factory for making Shell red tins that competed with the Standard Oil blue tins. Once the factory was set up, Mark was selected to do something else for which he had no experience: operate an oil field in Borneo. His preparation was a crash course consisting of a three-week visit to Baku, cut short to two weeks to hasten his return to Singapore. Mark's training proved inadequate for drilling for oil in the fever-ridden, rain-drenched, mosquito-infested, inaccessible jungle in Borneo at the Black Spot, a place where the soil was saturated with oil. Mark faced severe challenges in acquiring and getting the necessary equipment and workers to the site. Once on site, the equipment would break down and parts were difficult to obtain while tropical diseases decimated the workforce.

In retrospect, it would have been better for Marcus to make a deal with Royal Dutch, when it was having financial difficulties, to transport and market their refined oil rather than develop an oil field and build a refinery. Royal Dutch, with its headquarters in The Hague, Netherlands, had a successful oil concession in the Dutch East Indies and was knowledgeable about exploration, production, and refining. Royal Dutch was a perfect complement to Marcus: one company rich in exploration, production, and refining and poor in distribution and marketing, the other rich in distribution and marketing and poor in exploration, production, and refining. Marcus was betting on Borneo crude taking the place of Royal Dutch, but Borneo crude was not fit for making kerosene. It was more useful as a fuel oil substitute for coal to power factories and ships.

In 1898, Standard Oil decided to get control over oil production in the Dutch East Indies. To do so, Standard Oil let out a false rumor that its intent in taking control over Dutch oil producers was to stop production and replace Dutch oil with Standard Oil's American oil. The next step would be to get rid of the Russian oil coming in on Shell tankers and have the Asian market for itself. The rumor worked as shares in Dutch East Indies oil companies plummeted, and Royal Dutch and Shell were again talking to one another. Since the original talks, Royal Dutch had not been sitting idle, depending on Shell for marketing and distribution. Henri Deterding, a bookkeeper who by now was a rising star in Royal Dutch, strongly advocated Royal Dutch having its own marketing department, if only to be able to play a tougher hand in the cat-and-mouse negotiations with Marcus. A cooperative arrangement between the two companies, signed in 1898, while flawed because agents of both companies continued to compete against one another, did prevent Standard Oil from carrying out its plans to bring the entire Asian market into its embracing tentacles.

That same year Marcus scored a publicity coup. The British warship *Victorious* went aground in the Suez Canal, much to the embarrassment of the British Navy. All attempts to free the vessel failed until Marcus showed up with the Shell-owned *Pectan,* the most powerful tug in the world. The tug freed the *Victorious* and Marcus deliberately did not submit a salvage claim, which he was entitled to, and in return received a knighthood from Queen Victoria. Not one to let a knighthood stand in the way of a commercial deal, and with Borneo oil being too heavy to make kerosene but perfectly fit for burning as ships' fuel instead of coal, Marcus used the *Victorious* incident to establish a relationship with the British Navy. This was the opening shot of what would become nearly a fifteen-year campaign to induce the British Navy to shift from burning coal to oil, something that Marcus had already done with his tankers.

Marcus found strong support in a young naval officer who would one day be Lord Fisher, head of the British Navy. Coal smoke revealed the presence of a warship and oil burned with relatively little smoke. With higher energy content, oil consumption would be less than coal, allowing warships to travel further without refueling. Refueling time would be considerably shortened since coal was carried on board in bags, whereas oil could be much more rapidly pumped aboard a vessel. Oil removed the necessity for stokers to shovel coal into the ship's boilers, reducing crew size. Converting space for holding coal to carrying ammunition increased the ship's battle endurance. However, to Fisher, the most important advantage of oil over coal was the greater speed that the British Navy had to have in order to stand up against the emerging German navy.

Marcus and Fisher, however, could not overcome the principal argument against converting to oil—coal was a domestic fuel whereas oil had to be imported from foreign sources. Thus, oil was less reliable and less secure than coal, a critical matter for warships. Although Shell had refueling stations for oil in the Pacific, they had none in the Atlantic. The lack of sufficient coverage to supply fuel oil was an obstacle to convincing ship owners and admirals to switch from coal to oil. Until this chicken-and-egg conundrum was resolved, the British Navy and ship owners who traded worldwide could not convert to oil. Nevertheless, ship owners trading within a region adequately covered by fuel oil bunkering stations could switch from coal to oil.

The fortunes of Shell and Royal Dutch oscillated like a pendulum on an overwound clock. In 1897, troubles hit Royal Dutch when its wells went dry. Royal Dutch then purchased Russian oil for sale through its marketing outlets in direct competition with Shell. A price war with Shell would have ended with the demise of Royal Dutch, but Marcus chose not to do so because he felt that the Asian market would grow to accommodate both companies. This was quite unusual thinking at a time when oil magnates did not hesitate to crush one another at the first opportunity. Unusual or not, this marked Marcus's second failure to acquire Royal Dutch.

In 1898, it was Shell's turn to face a sharp decline in its Borneo production. Shell's people in Borneo tried to keep the matter a secret from its competitors, but an agent in Singapore got wind of it and kept Standard Oil better informed of the situation than was Shell's London office.

Declining production was just one of the worries on Marcus's shoulders. In addition to running a major oil company he was trading goods that still included seashells, operating a merchant banking house for floating Japanese bonds in England, and participating in an active civic and social life. Marcus had little time to spend on the upcoming renewal of the Rothschild contract. He had to demonstrate that Shell, through its producing properties in Borneo, could live without the Rothschilds' contract in order to be able to renew the contract on favorable terms. Borneo crude would generate significant savings in shipping costs for Shell, but, perversely, would leave Shell tankers bereft of cargoes.

Marcus had to carry out this critical renegotiation in a business environment of continually shifting alliances among Standard Oil, the Rothschilds, the Nobels, and the Russian and American independents. One grouping of these companies would gang up against the others in one part of the world and another group would do the same somewhere else. Alliances came and went like liaisons in a brothel. How quickly the alliances could shift was clear when, in late 1899, Standard Oil broke its agreement with the Nobels and started a price war in Europe to get rid (again) of the American independents. The Nobels, caught by surprise and with a large inventory of high-priced kerosene, decided to join forces with the Rothschilds and the Russian independents to push Standard Oil out of Europe. Then, Standard Oil decided to join the very group set up to ostracize it to exert a more formidable force against the American independents in Europe. The American independents could not compete against an alliance of Standard Oil, the Nobels, the Rothschilds, and the Russian independents. Shell was now in danger if this alliance were expanded to include Asia.

In response to this threat, Marcus started discussions with Dutch East Indies producing companies to secure an alternative source of oil, excluding Royal Dutch, which was still selling Russian oil in Asia in direct competition with Shell. In the midst of the Boer War, which strained relations between England and Holland, Marcus was able to strengthen his position with the Dutch independents in the East Indies, who found getting in bed with a British firm infinitely more tolerable than getting in bed with Standard Oil. Unfortunately, Marcus let an opportunity to fix long-term contracts with the Dutch independents, who resented Royal Dutch selling Russian oil in Asia in competition with their own, slip through his fingers.

Meanwhile, Royal Dutch had obtained a new concession and was among the first to hire geologists to assist in identifying sites for exploratory drilling. The world was rapidly running out of sites where the surface soil was saturated with seep oil. Marcus was against hiring geologists because he thought that they were better able to tell where oil could not be found rather than where it could be found. He failed to realize that negative information, if true, is valued intelligence. Despite his failed attempts to secure a long-term supply of oil, he was still making money, particularly when ship rates rose to replenish the British army during the Boer War. With shipping rates and oil prices escalating, Marcus, against his brother's objections, took long positions in kerosene to cover the period until Borneo would be producing kerosene in sufficient quantities to meet Shell's needs. Marcus had placed two bets: one on kerosene prices continuing to rise and another on Borneo producing kerosene in sufficient quantities to take the place of the Rothschild kerosene. He built more tankers (two, each at 9,000 tons, were the world's largest tankers at that time), expanded his storage facilities, and filled them with high-priced kerosene. He would lose both bets.

The year 1900 started well for Marcus. He reported record profits to his shareholders and called for a stock split to permit more shareholders to buy shares. He renewed his contract with the Rothschilds but without the exclusive right to sell Rothschild oil in Asia. Marcus was not worried because the Rothschilds, without tankers, would not be able to sell their oil in Asia, an impediment that they would eventually find their way around. Only a few months later, Marcus's world began to collapse. It started with falling coal prices, which diminished the market for fuel oil as oil-fired ships reverted to coal. Then freight rates collapsed. Then the Russian economy slumped, further reducing demand for fuel oil. With less demand for fuel oil to run Russian factories, the Russian independents began producing more kerosene, creating a glut at Batum. As kerosene prices fell at Batum, Standard Oil dropped its prices, and the rest of the world followed suit. This left Marcus with a huge inventory of high-priced kerosene plus a slew of term contracts to continue buying kerosene at even higher prices. To make matters worse, the Boxer Rebellion broke out in China in 1900, and Shell's property was looted including 60,000 tons of kerosene along with the steel in the storage tanks. Troubles next spread to India, where Shell had more storage than all its competitors combined, also filled to the brim with high-priced kerosene. Shell competed against cheap kerosene from the Russian independents, the Nobels, Royal Dutch, and a new competitor, Burmah Oil.

Burma was the last place where oil was discovered by drilling into oil-saturated soil. Since Burma and India were British colonies, Burma could export oil to India without paying the import fees associated with oil from foreign sources such as the Dutch East Indies and Russia. The situation in China and India left Marcus's newly expanded fleet without cargoes at a time of low freight rates. To top this off, the Borneo oil field was producing a fraction of what was expected and the refinery built to process Borneo crude suffered severe operating problems.

Motorcars were just beginning to appear in England. With only a few thousand registrations, Marcus saw automobiles as another business opportunity, as did other oil magnates. Up to this time, naphtha produced from refineries was either burned or in some way discarded. Automobiles would be an ideal market for selling a waste product. Gasoline in England was already being sold in blue Standard Oil tins when Marcus began dreaming of bright red Shell tins. He had made the opening moves to sell gasoline in London by leasing storage space, overlooking the fact that gasoline was not a permitted cargo for transiting the Suez Canal in bulk tankers. Not yet having obtained permission from the Suez Canal Authority to use the canal, Marcus shipped a cargo of gasoline from his Borneo refinery around the Cape of Good Hope, a dangerous undertaking. Standard Oil was fully prepared for the arrival of Shell's first shipment of gasoline to England. It had forced every agent and distributor in Britain to enter into a contract not to sell any brand but Standard Oil. This knocked Shell out of the gasoline market in England. Then the carnivorous Standard Oil purchased a U.S. west coast fuel oil producer for the sole purpose of exporting fuel oil to Asia and put the final squeeze on Marcus. Caught in the Standard Oil juggernaut in England and Asia, "discussions" began between the two firms.

Meanwhile, Royal Dutch, which at times bordered on bankruptcy, aided by advice from geologists was now on the comeback trail with discoveries of new oil fields in the Dutch East Indies. Deterding, now president of Royal Dutch, had done all that he could in the past to prevent an amalgamation between Royal Dutch and Shell. Marcus had lost his strongest supporter at Royal Dutch with the death of Deterding's predecessor and now faced an individual who relished taking full advantage of Royal Dutch's ascendancy over an ailing Shell. Whereas in the past Marcus was absolutely determined that Shell would not play second fiddle to Royal Dutch, now the tables had turned and Deterding was just as adamant that Royal Dutch would not play second fiddle to Shell. To add insult to injury, Royal Dutch geologists discovered oil in the same location in Borneo where Shell, without geologists (at Marcus's insistence), had failed. Just as prospects for Marcus were almost pitch-black, a new twist entered his life.

Spindletop

Patillo Higgens left his hometown of Beaumont as a one-armed young man who could fight better than most Texans with two. He returned in the middle 1880s as a Baptist churchgoer and Sunday school instructor and made a living in real estate and timberland. He took his class to picnic on a large mound that rose fifteen feet above the flat prairie and covered thousands of acres. He punched a cane into the ground and lit the escaping gas to amuse the children. Higgens was intrigued by the sour smell, the square boxes that held blue, green, and yellow waters for bathing or drinking or passing livestock through to rid them of the mange, and St. Elmo's lights that hovered over the mound at night. These were signs of something, but it was not until he paid a visit to the Oil Regions in Pennsylvania and elsewhere (trying to figure out how to get into the brick-making business) that he figured out the source of these mysterious signs.[11]

Without funds, he convinced others to purchase land on what would eventually be called Spindletop after a nearby town, and tried to keep himself in the picture. In 1892, Higgens formed a company called Gladys City to corral investors in what he saw as a future oil company (the stock certificates featured the portrait of a local young girl named Gladys, along with imaginary oil wells, tanks, and refineries). Higgens was convinced that oil would be discovered if a well were drilled to 1,000 feet, but time was against him. He had purchased options on some land parcels and was having difficulty raising the necessary funds.

Spindletop made life tough for drillers with its quicksand, gas pockets, and loose conglomerate. The first hole was drilled to a little over 400 feet before being abandoned by the driller. Higgens persisted. A second driller made it to 350 feet before Spindletop put a stop to his attempts to uncover its secrets. To beef up support for drilling a third well, Higgens got a Texas state geologist's opinion about Spindletop. He did opine: petroleum means rock oil and with no rocks in Spindletop, no oil. This is what Higgens did not want to hear. The geologist, utterly convinced of his findings, sent a letter to the local newspaper to warn the good people of Beaumont not to waste their money looking for oil. This letter convinced the local townspeople of what they already suspected: Higgens was losing his mind from sniffing the sour gas fumes coming from Spindletop. As a last act of desperation, Higgens advertised for investors. He received only one response from a Captain Lucas.

Lucas was looking for sulfur, not oil, and had a theory about finding sulfur in salt domes. After listening to Higgens, it was an easy leap of faith to think that oil might also be found in salt domes. Higgens, short on cash, arranged for Lucas to obtain a lease on all of his Gladys City landholdings, for which Higgins ended up with a 10 percent share. Higgens was reduced to acting as an agent on commission for the company he had founded. Lucas brought in a rotary rig, not the traditional cable-tool rig used by the previous two drillers. Spindletop proved to be too much for Lucas's rig. Lucas ran out of money after drilling two dry holes. Now with four dry holes, and unable to raise funds locally, Lucas sought help from Standard Oil. After examining the property, Standard Oil's expert geologist opined that no one would ever find oil at Spindletop, as did another geologist employed by the federal government.

Lucas then made contact with a team—Galey, a driller, and Guffey, a promoter—with close ties with the Mellons. Guffey demanded that Lucas get rights to all the land on Spindletop before doing any drilling and that Higgens be kept in the dark to keep their involvement a secret. With Mellon money backing Guffey, Lucas was able to get leases on 15,000 acres, except for what would turn out to be a critical omission, the many small tracts that ran across the top of Spindletop, which included the thirty-three-acre lot owned by Lucas. The new partnership left Lucas with a relatively small share, greatly diminishing Higgens's 10 percent residual interest as well.

Galey visited the property and drove a stake into the ground. Had he driven the stake fifty feet away, the well would have missed its target. Galey arranged for the Hamill brothers, who had their own rotary rig, to drill the well. When the Hamills hit the same quicksand that had stopped the other drillers, they found that using drilling fluid spiked with mud, obtained by driving a herd of cattle around a slush pit, would seal the sidewalls and keep the quicksand from filling up the well bore. This was the first use of drilling mud, now universally used in drilling. When they reached a point where the mud would not seal up the sidewalls, the Hamills devised a means of inserting a pipe casing that supported the walls of the well, allowing drilling to proceed. At about 650 feet, the Hamills ran into gas pockets that made the circulating mud boil and flow up rather than down the drill pipe. The Hamills overcame this problem, along with others, when the drill struck the salt dome caprock at 880 feet.

The night of January 9, 1901, turned out to be the last great show of St. Elmo's fire, ghostly blue flames usually associated with an electrical discharge, ever seen on Spindletop. The next morning, while the Hamills were lowering drill pipe into the now 1,200-foot-deep drill hole, mud suddenly started to spurt high above the derrick. The crew ran for their lives as six tons of drill pipe blasted from the hole destroying the derrick. This was followed shortly thereafter by a cannon shot of gas followed by a one hundred-foot-high, 100,000-barrels-per-day geyser of oil, clearly visible from Beaumont and everywhere else within a twelve-mile radius, accompanied by a stupendous roar. Higgins found out about the oil geyser that afternoon when he rode into town. A few days later the Hamills would be the first to devise a way to cap an oil gusher, the local pronunciation of *geyser.*

Pandemonium reigned in Beaumont as in Pit Hole. In the months that followed, Beaumont grew from 9,000 to 50,000 inhabitants with six special trains running between Beaumont and Houston daily. Those who did not go back to Houston could share the same hotel room with twenty other people. The bars and brothels never closed. Stock manipulators and scoundrels sold leases that either did not exist or turned out to be far from Spindletop, even far into the Gulf of Mexico. Stocks in companies without clear title to the land or without a promise to do anything were traded daily in an improvised stock exchange. It did not matter if the title to the land or a lease was bogus or compromised if it could be sold at a higher price. Fortunes were made on dubious securities and leases. Eventually lawyers would make even more money settling litigation over whom, exactly, possessed title to producing wells. Higgens was lost in all the pandemonium surrounding Spindletop. Like Drake, he would die without fame or fortune, but at least not quite a pauper.

After the discovery of Spindletop, Guffey lined up financial support from the Mellons. The Mellons, while primarily bankers, had previous experience in the oil patch. In 1889, the Mellons owned an oil field in Pennsylvania and had decided to fight rather than become Standard Oil property. In 1892, they succeeded in getting a contract with a French company to refine their oil. Immediately the Pennsylvania Railroad hiked its shipping rates to prohibitive levels, and the Reading Railroad refused to carry Mellon oil. When the Mellons attempted to build a pipeline to the east coast, hired thugs of the Pennsylvania Railroad fought the pipe layers by day and ripped up laid pipe by night. The Mellons were forced to sell out to Standard Oil, but they did make a handsome \$2.5 million for their troubles. (It was not Rockefeller's price that people objected to necessarily but his forcing the sale against the sellers' wishes.)

There was one thing Texans, and the Texas legislature, was bent on doing: keeping Standard Oil out of Texas. They succeeded by passing antitrust legislation that made it virtually impossible for Standard Oil to establish a toehold in Texas. Spindletop gave birth to Gulf Oil, the successor company to Guffey Petroleum Company and Texaco, the successor to the Texas Fuel Oil Company. Moreover, the spate of oil exploration in the rest of Texas set off by Spindletop would create Sun Oil and Humble Oil, named after a town. Humble Oil would eventually become Standard Oil's entry into Texas oil fields when it acquired a half interest in the firm in 1917. Eventually, Humble Oil, the most misnamed company imaginable, would be absorbed into Exxon. Oil flowing from Spindletop, which would account for half the nation's production, broke the Standard Oil monopoly in America. Spindletop oil, heavy and better fit for burning as a fuel than for making kerosene, was immediately recognized as a replacement for coal.

Spindletop and Shell

The Mellons, back in the oil business by financially backing Guffey, wanted the oil sold to anyone but Standard Oil. Marcus realized that Spindletop crude was unfit for kerosene production, but was an ideal fuel oil. With Spindletop crude, Marcus could fulfill Fisher's dream of fuel oil being available in both hemispheres to supply the British Navy. In June of 1901, Marcus agreed to buy half of Guffey's production for twenty-one years at about twenty-five cents per barrel, plus a 50 percent share of the profit in the net sales of the oil with a minimum takeoff of 100,000 tons per year. This was the second major transaction for Marcus in 1901; the first was the sale of the company's seashell business to a relative.

In the game of oil, the positions of the chairs had again shifted. Standard Oil now saw Shell not as a competitor about to be crushed, but as a means of getting its hands on Spindletop oil. Rather than wiping out Shell, the objective now was to make Shell part of the Standard Oil family. Deterding knew that any alliance between Standard Oil and Shell would spell trouble for Royal Dutch, so Deterding entered the unholy alliance and the three companies divided the non-Russian world oil market among themselves. They actually reached an agreement on divvying up the world market by oil products, of which there were then five: kerosene, the mainstay of the business, lubricating oils, the emerging markets in gasoline, fuel oil, and what was called solar oil, a substitute for coal for manufactured gas to light municipal street lamps and buildings. There was also agreement on which geographic areas each firm would operate.

In the midst of these critical discussions in late 1901, Marcus took time out for the pomp and ceremony of becoming lord mayor of London. While Marcus was being showered with honors, the Rothschilds were attempting to unite themselves with the Nobels and the Russian independents into a single marketing entity to counter any Standard Oil-Shell-Royal Dutch combine. In early 1902, talks between Standard Oil, Shell, and Royal Dutch collapsed, despite their marked progress in carving up the world market. The cause of the failure was the same for the failure of every proposed amalgamation: the name of the game is King of the Hill, not Kings of the Hill. No one could agree on which oil company would head the combine other than their own.

The pleasantries exchanged during negotiations between Standard Oil, Shell, and Royal Dutch gave way to open commercial warfare. This rekindled negotiations between Deterding and Marcus, which led to the signing of the British-Dutch Agreement in mid-1902. After the signing, the Rothschilds wanted to join the two, which Marcus opposed and Deterding supported. In the end, Deterding won and the British-Dutch Agreement was amended to become the Asiatic Agreement, marking the birth of the Asiatic Petroleum Company. Because the agreement called for all three companies to participate in a joint venture for refining and marketing oil products in Asia, the Rothschilds had finally found a way around Marcus to market oil in Asia. The Rothschilds, as in the past, saw the agreement as a means to improve their negotiating strength with Standard Oil. Marcus saw the Asiatic Agreement as something temporary to keep Standard Oil at bay. Deterding saw the agreement as something permanent, leading to the final ascendancy of Royal Dutch over Shell. This was virtually assured when Marcus allowed Deterding to be in charge of Asiatic Petroleum's operations.

The gods turned against Marcus. The *Hannibal,* a British warship put on trials to test out Marcus's idea of burning oil, was enveloped in black smoke when the fuel was shifted from coal to oil. The experiment was a total failure because the wrong atomizers had been installed. This would delay the conversion of the British Navy from coal to oil for another ten years, much to the chagrin of Marcus and Fisher. The Port Arthur refinery built to process Spindletop oil was having serious operating problems, but this was nothing compared to the news that the production of the hodgepodge of oil wells at Spindletop, one nearly on top of the other, had gone into a sudden decline, particularly those owned by Guffey. A young nephew of the Mellons surveyed the scene and concluded that the refinery was unworkable, the oil was gone, and their investment was wasted. The only way to recoup the Mellon investment in Spindletop was to create a totally new integrated oil company with a massive capital infusion. Rockefeller came out of partial retirement to tell the Mellons personally, with some degree of relish, that there was no way Standard Oil would assist them.

Colonel Guffey was set aside and new management installed to allow the Mellons to reorganize Guffey Petroleum into what would become Gulf Oil. Honoring the Shell contract was impossible, not because oil production at Spindletop had essentially ceased, but that the price of oil was above twenty-five cents per barrel. The Mellons could not buy oil on the open market to honor the contract without taking an enormous financial loss. Unwilling to absorb such losses, the Shell contract was unilaterally canceled and Andrew Mellon inveigled Marcus to substitute a much less onerous contract, which in the end was also not honored. Shell's tankers, built to carry Spindletop oil, were converted to cattle carriers.

Some think that Marcus should have sued the Mellons and saved Shell through litigation. This would not have been as easy as one might expect because the terms in the contract left something to be desired if exposed to the scrutiny of a court of law. Others thought that Marcus might have been thinking of the long-term implications of not suing the Mellons, perhaps hoping for a potentially profitable collaboration between Gulf and Shell in the future. The implication of future collaboration might have been a keen insight on the part of Marcus, but the short-term effect was disastrous.

If this was not bad enough, Marcus received word that Deterding was unhappy with the Asiatic Agreement and that adjustments would have to be made to the agreement, adjustments of a type that would not benefit Marcus. Although his investiture as lord mayor of London, with its pomp and ceremonies, was a great honor for Marcus,[12] the time consumed prevented his meeting with the representatives of the Rothschilds and the Nobels to deal with yet another problem in Germany where Shell was facing the full fury of Standard Oil. This placing of civic responsibilities ahead of business was to cost Marcus dearly.

In early 1903, Lane submitted a letter of resignation stating that he was unable to continue as a director of a company as poorly managed as Shell. He complained of Marcus's attention being diverted from the oil business to trading merchandise, running a merchant bank, participating in civic activities, placing inexperienced nephews in charge of major projects, and relying on a brother's opinion rather than a more formal approach to planning before making critical business decisions. Indeed, the head count in Shell's London office, the heart and soul of a major world oil enterprise, was just under fifty including clerks, typists, bookkeepers, and messengers.

Things were going from bad to worse with Deterding running Asiatic Petroleum. Deterding limited Shell's profits to freight paid for its tankers and rentals on its storage facilities. Money made in marketing and distributing kerosene in Asia ended up in the Royal Dutch accounts. By the sleight of hand of a very experienced and adept bookkeeper, Shell suffered declining profits while those of Royal Dutch rose. Moreover, Asiatic Petroleum was extremely late in issuing its financial reports, without which Shell could not issue its final financial statements. This proved to be something else that depressed the value of Shell shares. Deterding had placed Marcus in a desperate strait, having wrecked Shell's profits and the value of its shares. Exhausted from his year as lord mayor of London and disillusioned with those about him, Marcus was at the point of giving up, something Deterding had been striving for since taking charge of Asiatic Petroleum.

Before Shell fell under Royal Dutch rule, Marcus was given a last-minute reprieve in the form of a financial shot in the arm from the profits made by the Shell fleet's support of Japan in the 1904 Russo-Japanese War. This proved to be the incendiary that ignited the 1905 Russian Revolution when revolting oil workers set fire to the Baku oil installations, a dress rehearsal for 1917 and a training ground for Stalin. The pathetically slow progress of the coal-fueled Russian fleet as it sailed from the Baltic to its destruction off Japan provided impetus for the British Navy to switch to oil. When the British Navy did switch, Shell was no longer an independent company.

The emergence of the automobile age in the United States made gasoline a mainstay for Standard Oil and kerosene a byproduct. Standard Oil dumped its excess American kerosene in Europe and formed a joint marketing effort with the Rothschilds (Shell's partner in Asiatic Petroleum), and the Nobels to keep kerosene prices low. Shell, whose mainstay was still kerosene, had to face this combine alone. Everyone was losing money by selling kerosene in Europe, but Shell did not have the financial wherewithal to outlast the others. Like wolves gathering for the final kill, Shell was forced to sell six of its best tankers at a tremendous loss to recoup its investment in Germany. By 1906, beaten in Europe by Standard Oil and beaten in Asia by Deterding, Marcus had no choice but to appeal to Deterding for an amalgamation of the two companies.

Marcus went to Deterding's office. Deterding gave Marcus his first and final offer. If Marcus left without accepting the offer on the spot, the offer was dead and so was Shell. The offer was the formation of a holding company called Royal Dutch-Shell Group, of which Royal Dutch would own 60 percent and Shell 40 percent. Although Marcus was nominally in control of the holding company, the King of the Hill was definitely Deterding. To further ensure Royal Dutch dominance, Deterding had Royal Dutch buy 25 percent of Shell's shares at thirty shillings per share when the price of the stock three years' previous had been three pounds. Deterding considered this a very generous offer under the circumstances, which it may have been. Maybe it was Deterding's way of thanking Marcus for passing up several opportunities to take over Royal Dutch and become King of the Hill himself.

Two new operating companies were formed, one British and one Dutch. The British company controlled transportation and storage, and the Dutch company production and refining. Royal Dutch and Shell were then emptied of all assets and became holding companies in which each party held a 60–40 percent share in the two operating companies. Asiatic Petroleum continued to market products in Asia with two-thirds shareholding of this company reallocated 60 percent to Royal Dutch and 40 percent to Shell; the remaining third stayed in the hands of the Rothschilds. In 1907, when the Group was formally established, Marcus, though personally rich, considered himself an abject failure.

As with so much of his life, there was a new twist. Deterding, contrary to all the rules of the game, did not leave Marcus out in the cold. Deterding decided to operate out of Shell's London office and not out of Royal Dutch's Hague office. With Marcus sitting in the same office, Deterding found that he could be more effective if he kept Marcus informed of the latest developments and conferred with Marcus before making any major policy decisions. This consultative arrangement between Deterding and Marcus worked to their mutual advantage, and this unique method of managing a large firm survived the two individuals. After Deterding retired from Shell, all major decisions had to receive a favorable ruling from two committees—one representing Royal Dutch and the other Shell. The committees were made up of personnel with long-standing records of achievement who, rather than retire to a golf course in Scotland, met on a regular basis to confer on important matters and make recommendations based on their extensive experience. This consultative and collegial method of decision making, unique in the corporate world, has been adopted by the principal operating companies within the Royal Dutch-Shell Group.

Deterding, though a Dutchman, saw a greater commercial advantage if the newly formed Group was associated more closely with Britain than Holland to take advantage of operating within the British Empire. In 1910 the British Navy finally switched to fuel oil, which was a great boon to the Shell Group. However the Group was considered non-British because its sources of oil did not lie within the British Empire, and a Dutch company owned 60 percent. Shell still benefited by selling fuel oil obtained from foreign sources to qualified British companies, which, in turn, supplied the British Navy. Even though Deterding was "on top," Marcus was not idle. He turned his attention to Egypt, and, following up on rumors, insisted that the Group explore for oil because if found (and it was found) the Shell Group would have a source of oil on British colonial soil. This would permit the Shell Group to sell fuel oil directly to the British Navy. Deterding was no slacker either. He acquired oil properties in California that were later expanded to Oklahoma, allowing the Shell Group to confront Standard Oil on its home turf, plus getting involved with oil fields in Mexico and Venezuela. In 1912, with Lane in the middle, the Rothschilds exchanged their Russian holdings for stock in Royal Dutch-Shell, thereby becoming one of its largest shareholders. In light of what was to occur only a few years later, this exchange of oil properties in Russia for shareholding interests in Royal Dutch-Shell proved to be a most astute move because diversification mitigated the financial risk of having all one's eggs in a single basket.

Winston Churchill, as first lord of the admiralty, agreed with Fisher on converting warships from coal to oil, with one major reservation. Churchill believed that the British Navy should not rely exclusively on contracts from suppliers, but that the government should have its own oil fields to guarantee a supply of fuel for the navy. Marcus attempted to convince Churchill that the Shell Group, along with Standard Oil, could supply the British Navy in any location throughout the world. Marcus argued that the navy would be better served building storage facilities, not buying oil fields. Despite Marcus's pleas, the British government went ahead with Churchill's plan and purchased a 51 percent interest in Anglo-Persian Oil Company, an offshoot of Burmah Oil, in 1914, weeks before the start of the First World War.[13]

Anglo-Persian Company was originally formed in 1908 when another oil explorer with the drive of Colonel Drake, ignoring a letter to cease looking for oil, found oil. A 130-mile pipeline, the first in the Middle East, was laid between the oil field and a refinery built in Abadan. Having only one outlet to the marketplace, through the Shell Group, Anglo-Persian Oil was in a weak bargaining position and vulnerable to a Shell Group takeover. Moreover, it was in a weak financial condition. The company wanted an investment by the British government to gain a major new client, the British Navy, and planned to expand its refinery with the proceeds to become the largest in the world, diversify its markets, and serve those markets with its own tanker fleet. By owning an oil field, Churchill felt that he would not be at the mercy of oil companies with regard to price and supply. The British government did not interfere with the running of Anglo-Persian Oil, and its members on the board of directors made sure that the company's operations did not conflict with the government's strategic objectives.

At the start of the war, the Shell Group chartered its entire fleet of over seventy tankers to the British Admiralty at prewar rates as a show of support for Britain. As a consequence, the company had to charter in other tankers at up to four times these rates to meet its needs. The Dutch side of the company transferred as much of their operations to London as possible. Marcus converted his mansion into a military hospital, and his two sons and two sons-in-law served in the military. Only one survived.

The Shell Group became the sole supplier of aviation fuel and the principal source of motor vehicle fuel to the British Expeditionary Force. The toluene in the explosive TNT (trinitrotoluene) came from processing coal. Though crude oil normally contains only trace amounts of toluene, Shell's Borneo crude was unusually rich in toluene (10 percent). To process Borneo crude for its toluene content, the Shell Group's refinery in Rotterdam was dismantled and "smuggled" to England. In addition to having the Shell Group invest in National War Loans, Marcus spearheaded the conversion of general cargo vessels into tankers and had others fitted with double bottoms for supplying fuel to the expeditionary forces in Europe. He was also active in introducing diesel propulsion to replace oil-fueled steam propulsion plants. In 1916, when it was clear that Romania would fall to German forces, Marcus and Deterding authorized company personnel to destroy the Shell Group's Romanian oil assets without any promise of restitution by the British government. Ironically, Shell Group gasoline was distributed in Britain before the war under a contract with British Petroleum, at that time a German-owned marketing company. British Petroleum shares were seized by the British government and turned over to the Anglo-Persian Oil Company, marking the official birth of BP.

The British government was the first government to have majority ownership of an oil company but chose not to run it. The first government that actually ran an oil company was the Soviet Union after it expropriated the oil-producing properties of the Nobels, the Shell Group, and the Russian independents after the Russian civil war. But the Nobels did not leave empty-handed because Exxon bought their oil rights in Russia in 1920, on the remote chance that the Whites would win the Russian civil war. Although the Nobels received money for their oil properties, they were out of the oil business. The Rothschilds' loss could have been disastrous, aside from their one-third ownership of Asiatic Petroleum, had they not exchanged their Russian oil-producing properties for shares in Royal Dutch-Shell. The Russian independents were lucky to escape with their lives. Now the Soviet Union was in the oil business and depended on oil exports to build communism, in much the same way that Russian oil rebuilt the Russian economy after the fall of communism in 1991.

In 1920, despite all that Marcus had done in support of the British war effort during the First World War, the public rose against him and accused him of greed in the face of rising petrol prices. Only a decade earlier the darling of London society, Marcus was now a pariah, accused of siphoning money out of everyone's pocket. It was his turn to endure the vituperation heaped on Rockefeller. Marcus's appeal to the harsh law of supply and demand for establishing the price for oil to clear the market did not endear him with the public. This display of public ill will might have played a role in his retiring as chairman and board member. In 1925 he became Lord Bearsted (Deterding was knighted in 1921 in recognition of his war services), and two years later both Marcus and his wife died within twenty-four hours of one another.

Emergence of Oil as a Strategically Vital Commodity

Winston Churchill was the first government official to sense the strategic importance of oil. Oil had its beginnings in lighting, but kerosene lamps were giving way to electric light bulbs. Automobiles were toys for the rich at the beginning of the twentieth century, but when Henry Ford began to mass-produce Model Ts, the era of the horse and wagon ended. During the years prior to the First World War, oil was becoming an integral part of national economies without anyone taking notice, but during the war, when success in combat depended on a steady and reliable flow of oil to fuel military vehicles, tanks, and fighter planes, it was noticed. National survival placed a whole new emphasis on the importance of oil. Oil was no longer a consumer item but a means to ensure military success; a commodity of national security importance.

The Second World War only reinforced the lessons learned in the First. Oil followed only armaments and ammunition in importance for winning a war. Hitler, cognizant of Germany's lack of raw materials and energy, except for coal, built facilities in Germany that made gasoline from coal. Gasoline fueled the aircraft and tanks essential for the success of the blitzkrieg: a rapid deployment of armies to envelop an enemy before resistance could be organized. The Nazi army quickly invaded Romania to seize its oil fields. Hitler's thrust into the Soviet Union and Rommel's invasion of North Africa were to meet at the Baku oil fields, placing Middle East and Soviet oil under Axis control. Fortunately for the Allies, both suffered from severed supply lines. Hitler's army's replenishment lifeline was cut at Stalingrad as was Rommel's gasoline lifeline to North Africa. Likewise, in the Battle of the Atlantic, Hitler tried to cut the British lifeline of troops, armaments, ammunition, and oil flowing from the United States with submarine U-boats. Germany's capacity to wage modern warfare ended when the Allies finally won air supremacy and bombed Hitler's coal-to-gasoline production plants.

The war in the Pacific was likewise heavily influenced by oil and by attempts to interrupt its flow. In the months prior to Pearl Harbor, the United States imposed an embargo of scrap steel and oil to Japan as a sign of its disapproval of Japan's invasion of China. With the United States supplying 80 percent of Japanese oil, the embargo forced Japan to set its sights on the Dutch East Indies oil fields. The Japanese knew that the supply line of oil from the Dutch East Indies to Japan was long and vulnerable to naval interruption. Only one navy was powerful enough to interrupt Japan's oil lifeline; the oil embargo made Pearl Harbor inevitable. Severing the lifeline of raw materials and oil to Japan from its conquered territories in Southeast Asia was a major goal of the war in the Pacific.

Era of the Seven Sisters

For over a half-century, between the First World War and the oil crisis of 1973, the world oil business was conducted largely through the seven sisters: Exxon, Shell, British Petroleum (BP), Gulf, Texaco, Mobil, and Chevron, each ranking among the world's largest companies. Exxon, Mobil, and Chevron were the leftovers of the Standard Oil Trust breakup. Gulf and Texaco were the products of keeping Standard Oil out of Texas (Exxon eventually became a major player in Texas through its subsidiary, Humble Oil). BP, Churchill's brainchild, branched out far from its original purpose. Since the 1973 oil crisis, the seven sisters have been reduced to four: Exxon and Mobil have recombined, Chevron purchased Gulf Oil and combined with Texaco, and BP, while it did not combine with any of the other seven sisters, absorbed three leftovers of the Standard Oil breakup, Sohio, Amoco, and Arco. Apparently, the earlier conflicts that had plagued attempts to amalgamate had been overcome. As the decades passed, top executives with no links to the founders or their immediate successors, stepped aside to let others head the amalgamations, their hurt feelings assuaged by generous bonuses and retirement packages.

The seven sisters were fully integrated multinational companies that controlled every facet of the oil business. Upstream activities included exploring and developing oil fields. Downstream activities included refining crude oil and distributing refined products by pipelines, tankers, and tank trucks to gas stations and industrial, commercial, and residential end users. The oil companies felt that they owned an oil field, even if it were located in a foreign nation under a concession agreement. Every aspect of the oil business from exploring, drilling, production, refining, distribution, and marketing was not only controlled but the assets in oil fields, pipelines, tankers, refineries, storage facilities, tank trucks, and filling stations were owned by the oil companies. Price and production volumes were set with the oil companies sitting on one side of the table and oil producers on the other, with a generally one-way dialog between the two. This world collapsed in 1973, a pivotal year in the oil industry.[14]

The seven sisters both competed and cooperated. They competed with one another over market share and cooperated with one another in exploring and developing oil-producing properties. Oil industry leaders had to learn to deal with this dichotomy, but in a way they were groomed to both cooperate and compete from the beginning. An individual I know was starting to climb the corporate ladder as drilling manager in an isolated part of South America. Over the hill was another individual in charge of drilling for a competing oil company. When a drill bit broke in the middle of nowhere, the individual could order a replacement from the home office but it would have taken weeks to receive it, which would have caused him to miss the scheduled completion date. Alternatively, he could walk over the hill and borrow one from his competitor. The competitor's drilling manager was more than willing to cooperate because he knew that he now also had a ready source of replacement parts across the hill that would allow him to complete his drilling program on time. Because the performance of both men would be judged in terms of the time and cost required to complete their respective drilling programs, both advanced their careers by walking over the hill when they needed spare parts.

Costly and risky oil exploration and development programs are often carried out by a syndicate of oil companies. The potentially enormous losses associated with exploration and oil-field development can be spread over the participating companies in a syndicate without having a single oil company bear the entire risk of loss. The risk of loss has not been reduced, but the extent of loss a single company must bear is limited to its share of the syndicate. But to some degree, the risk of loss is reduced since cooperation allows oil companies to share particular skill sets and technological expertise with others. Thus, not every company has to be an expert in every facet of exploration and development. In a well-structured syndicate, companies assume responsibility for specific functions they are particularly adept at fulfilling. Nevertheless, each participant keeps a wary eye on the others to ensure that no one takes advantage of a situation as Deterding did with Marcus.

Opening Up the Middle East

The opening up of the Middle East is synonymous with the rise of Calouste Gulbenkian. His father and uncle were petty merchants who rose to the position of being responsible for collecting revenues for the Sultan's privy purse in Mesopotamia. This gave them the opportunity to found a merchant bank to finance transactions between Constantinople and Baghdad.[15] As a reward for Gulbenkian's father's service to the Sublime Porte, he was given the governorship of Trebizond, where he became involved with kerosene imports from Baku on behalf of the Turkish government. Through contacts developed with the Baku oil exporters as a representative of the Turkish Crown, he enriched himself greatly as a private merchant handling kerosene imports into the Ottoman Empire.

His son Calouste was educated in Britain. As a young man in the 1890s, Gulbenkian was sent to the Caucasus to learn about oil, which began his lifelong interest in oil. He wrote a book about his experiences, including an assessment of the Baku oil industry, which attracted the attention of the Turkish Crown. Gulbenkian was commissioned to do a report on oil prospects in Mesopotamia (now Iraq). The book was a compilation of existing sources plus observations from railroad engineers who had been in Mesopotamia, a place Gulbenkian was never to visit. The book whetted the Sultan's appetite and induced him to transfer enormous land holdings from the government to the Crown for his personal aggrandisement should oil be discovered.

Fleeing Turkey with his family during the Armenian massacres of 1896, Gulbenkian appeared on the world stage of oil as the London representative of Mantachoff, a leading Armenian Russian oil magnate. Gulbenkian worked with Frederick Lane, who he considered the father of the British oil industry, to bring Russian oil interests into the Royal Dutch-Shell Group. Gulbenkian's experience led him to believe in the importance of pooling oil resources, production, and marketing to achieve price stability, an idea shared by others responsible for creating the oil industry. Unlike his father, Gulbenkian had no interest in the business aspects of oil. He saw himself as a creative architect of oil business arrangements. His failure to seize upon an early opportunity to get involved with an oil concession in Persia, which became the basis for the Anglo-Persian Oil Company, led him to adopt his lifelong business obsession—never give up an oil concession!

In 1908, an oil strike in Persia whetted Gulbenkian's interest in Mesopotamia. Gulbenkian convinced Deterding to open a Constantinople office with Gulbenkian in charge, although he also continued to be a financial advisor to the Turkish embassies in Paris and London and to the Turkish government. However, others shared Gulbenkian's intuitive insight. The Germans were eager to build a railroad to Baghdad that would give them oil rights for about thirteen miles on both sides of the track. The Anglo-Persian Oil Company saw Mesopotamia as an area with great oil potential. The Ottoman-American Development Corporation also had its eye on Mesopotamia. The British government, alarmed over growing German influence in Turkey, needed someone known to European oil interests who spoke the language, had the contacts and knowledge of the oil industry, plus possessed the business acumen, skills, and foresight to represent their interests in the Near East. Gulbenkian possessed all these traits and was in the right place at the right time; if he had not existed, the British government would have had to invent him.

In 1910, in addition to his other activities with Shell and the Turkish government, Gulbenkian became an adviser to British financial interests when they formed the National Bank of Turkey in order to make loans within the Ottoman Empire. Working under the auspices of the National Bank of Turkey, Gulbenkian formed the Turkish Petroleum Company in 1912; Deutsche Bank held 25 percent of the stock, Gulbenkian 40 percent, and the National Bank of Turkey 35 percent. To entice Shell into the deal, Gulbenkian gave Shell a 25 percent interest, reducing his to 15 percent. Neither the National Bank of Turkey nor the Turkish Petroleum Company had any Turkish investors.

When Anglo-Persian Oil pursued an oil concession in Mesopotamia, Gulbenkian rearranged the shareholding in the Turkish Petroleum Company to include Anglo-Persian Oil. (Gulbenkian believed that it is better to embrace rather than fight a potential competitor.) The ownership of the Turkish Petroleum Company was now split: Anglo-Persian Oil had a 47.5 percent share, Deutsche Bank a 25 percent share, Shell 22.5 percent, and Gulbenkian 5 percent, with the Turkish National Bank no longer sitting at the shareholders' table. In 1914, just before the outbreak of the First World War, the Ottoman government wrote a letter to the British and German ambassadors in Constantinople acknowledging that the Turkish Petroleum Company had an oil concession in the provinces around Baghdad and Basra.

After the War, Britain and France proceeded to carve up the Middle East as spoils of war, excluding the United States because it had not officially declared war on Turkey. The British government agreed with Gulbenkian's assertion that the concession granted to the Turkish Petroleum Company by the Ottoman government was still valid, even though the Ottoman Empire no longer existed. The British government wanted to turn Deutsche Bank's quarter share over to Anglo-Persian Oil. To avoid giving too much power to Anglo-Persian Oil, Gulbenkian inveigled the French government to take over the German quarter share interest in the Turkish Petroleum Company as a war prize. In 1922 the U.S. government, concerned over a possible shortage of crude oil, negotiated an interest in the Turkish Petroleum Company in the name of the Near East Development Corporation (again with Gulbenkian's support, based on his practice of embracing potential rivals rather than fighting them). The corporation did not specifically name any U.S. oil companies, but was eventually represented by six; these were reduced to two, Exxon and Mobil. After deliberations with Gulbenkian's involvement, the Turkish Petroleum Company was evenly split among the Near East Development Corporation, the French government, Shell, and Anglo-Persian, which accepted a halving of its share for a 10 percent overriding royalty. The new reorganization still contained Gulbenkian's 5 percent share. This would become a bone of contention from this point forward between Mr. Five Per Cent and his partners, even though there was not a single drop of known oil reserves. Without any activity in oil production and marketing, the oilmen, working out of luxury hotel suites, saw no value in Gulbenkian's creative architectural corporate designs. Gulbenkian noted this lack of gratitude by remarking that "oil friends are slippery"!

In 1925, the new nation of Iraq signed an agreement with the Turkish Petroleum Company, to be renamed the Iraq Petroleum Company, whereby the government of Iraq would receive a royalty on any oil produced, if any were discovered, until 2000. At some point in the discussions, the government of Iraq was promised 20 percent participation, but the participation was excluded from the final agreement. This would be a bitter source of contention between the Iraq Petroleum Company, owned by the oil companies, and the host government of Iraq for nearly half a century.

All this maneuvering was merely an academic exercise because the Iraq Petroleum Company was a scrap of paper until the 1927 discovery of one of the world's largest oil fields. Gulbenkian now insisted that the concession granted by the Ottoman Empire was not restricted to Iraq, but included all the lands under the former empire. Gulbenkian took a map and drew a red line over what he thought was the former Ottoman Empire, which included all of the Middle East (Turkey, Jordan, Syria, Iraq, and Saudi Arabia) except Kuwait and Iran. Although the Ottoman Empire did control the religious centers along the Red Sea (what was to become Saudi Arabia), its control over the vast emptiness of deserts inhabited by nomads was nominal, to say the least. No one, including Gulbenkian, foresaw the implications of having what was to become Saudi Arabia within the Red Line Agreement. Signed in 1928, the Red Line Agreement stipulated that no oil field within the red line could be developed unless there was equal participation by the companies owning the Iraq Petroleum Company, which, of course, included Gulbenkian's 5 percent share.

As the only oil company with operating experience in producing Middle East oil, BP initially handled Iraqi oil production. Exxon and Mobil soon became more actively involved as did Compagnie Francaise de Petroles (CFP), a national oil company organized by the French government in 1924, modeled after BP, to handle its share of the Iraq Petroleum Company. The world of oil now had three governments involved with oil: the British government's half interest in an independently run BP with a concession in Iran and Iraq, the French government's wholly owned interest in an independently run CFP, with a concession in Iraq, and the Soviet Union, which exercised absolute control over its oil resources.

In addition to opening up the Middle East and playing second fiddle to Frederick Lane in bringing in Russian oil interests to the newly formed Shell Group, Gulbenkian brought Shell into the Turkish Petroleum Company and helped raise money for Shell as an intermediary with New York investment bankers. He also arranged contracts for Shell to supply the French and Italian governments with petroleum products during the war. In 1918 he orchestrated the Shell takeover of Mexican Eagle Oil Company, the start of Shell's activities in Mexico. To further cement his relationship with Shell, Gulbenkian arranged for his son, Nubar, to become the personal assistant to Deterding. It was rumored at the time that Nubar might be in line to succeed Deterding, but his son's career with Shell ended abruptly some years later when Gulbenkian yanked him away to become his personal assistant.

Gulbenkian was asked to act on behalf of British investors with an oil concession in Venezuela called, appropriately, Venezuela Oil Concessions (VOC). Gulbenkian brought this investment opportunity to Deterding's attention, which ended up with Shell owning two-thirds of VOC and Gulbenkian and other shareholders, including Venezuelans, with the remaining third. Deterding believed that any investment made by Shell was to be controlled and run in the best interests of Shell. Deterding practiced what he preached. As majority and controlling owner, Shell was in a position to determine the price of oil exported from Venezuela. It was in Shell's financial interests to set a low price for the exported oil, but not in the financial interests of the minority VOC shareholders. Gulbenkian's failure to reach an agreement with Deterding on his behalf and the behalf of other minority shareholders eventually led to a breach between the two.

After the Second World War, Exxon and Mobil, the two remaining U.S. shareholders in the Iraq Petroleum Company, took on the decades-old task of squeezing out Gulbenkian's 5 percent share. During these discussions, Walter C. Teagle (Exxon's president) referred to Gulbenkian as an oil merchant, to which Gulbenkian angrily responded that he was a business architect, not an oil merchant, a perfect description of his role in oil. Gulbenkian once pointed to a strange-looking ship in a harbor and asked what it was and had to be told that the ship was a tanker that might be carrying his oil! While oilmen had a jaundiced view of Gulbenkian, Gulbenkian's view of oilmen as cats in the night—"by their sound no one can tell if they're fighting or making love!"—was equally negative.

Finally Gulbenkian was informed that the 1928 Red Line Agreement was void because it violated American antitrust legislation, an interesting tactic on the part of oil companies, which were occasionally threatened by Congress for violating the same legislation. For Gulbenkian's alleged violation, Exxon and Mobil stated that they were no longer bound by the 1928 Agreement. The revised 1948 Agreement left Exxon and Mobil free to develop Saudi Arabian oil reserves on their own. Between 1948 and 1954, Gulbenkian negotiated a replacement for the Red Line Agreement from his various hotel suites. The 1954 agreement not only reaffirmed his 5 percent interest in the Iraq Petroleum Company, but he was also reimbursed for previous unpaid receivables.

Gulbenkian's annual succession of seventeen- and eighteen-year-old mistresses ended with his death in 1955 at the age of eighty-six. After his death, he bequeathed the bulk of his wealth and future revenue to a foundation based in Lisbon. In the end, the oilmen won. Gulbenkian's 5 percent share was wiped out with the nationalization of the Iraq Oil Company in the 1970s; but so too were theirs. Nevertheless, the Gulbenkian Foundation has continued to prosper, with income from his shareholdings in a Middle East oil company and other investments.

Early Attempts at Oil Price Controls

Rockefeller, of course, was the first to attempt to control prices, and he pretty much succeeded when he achieved 90 percent control over the U.S. refinery industry. His idea of an acceptable price for kerosene was the price that would not encourage outsiders to build refineries. Too high a price would only create more problems for Rockefeller by providing an incentive for others to get into the refining business. This idea is still alive. OPEC realizes that an oil price that is too high financially underwrites the development of high-cost non-OPEC oil fields that will eventually erode OPEC's market share.

The first to attempt to bring order to the oil industry on a global scale was the oil power brokers of the day, Teagle, of Exxon (a distant relative of Maurice Clark, Rockefeller's first partner) and Deterding, of Shell. In 1922 they stood together, along with others, to present a united front in dealing with oil sales by the Soviet Union, which they viewed as buying back stolen property.

While the two power brokers were shaking hands and expressing mutual dismay over Soviet duplicity in expropriating oil properties without compensation, Deterding secretly purchased a large quantity of Soviet oil at less than the agreed price with Exxon, which he promptly dumped in the Far East. Subsequent attempts by Teagle and Deterding to restore some semblance of order sometimes worked and sometimes did not, but in 1927 Deterding abandoned any further pretext of cooperating with Exxon over the matter of Soviet oil. This time the reason was not related to oil, but to his second marriage to a White Russian. Cross-accusations between Teagle and Deterding eventually induced Deterding to start what turned out to be a disastrous price war. The Soviets thought that they had succeeded in creating chaos in the world oil patch by successfully playing one oil company off another, perhaps bringing back memories of the Nobels and the Rothschilds. Soviet satisfaction over spreading confusion in the capitalistic world of oil stemmed not so much from their conspiratorial plans, or Deterding's ill-fated venture into a price war, but from a world flooded with crude from the Soviet Union, Mexico, and Venezuela.

The 1920s started with a feeling that oil would be in short supply, so the U.S. government forced Exxon and Mobil to get involved with Middle East oil through its interest in the Turkish Petroleum Company. By the late 1920s, and continuing on through the global depression of the 1930s, the world was awash in oil. Something had to be done. Oil companies had made massive investments on the basis of a certain projected price of crude oil; as crude prices sank, so did the return on these investments. In 1928, in a Scottish castle, Deterding held a social affair that happened to include Teagle from Exxon and Mellon from Gulf Oil and other oil magnates, including the head of BP. This social affair led to a pooling arrangement to control price through cooperation in production and in sharing incremental demand among the cartel of supposedly competing oil companies. The reference price would be American oil in the U.S. Gulf, with adjustments to take into account freight from the U.S. Gulf.

Once this system was set up, other oil companies joined. If a participating oil company purchased oil in the Middle East and sold it in France, the selling price would not be the FOB price in the Middle East plus freight from the Middle East to France, but the price of oil in the U.S. Gulf plus freight from the U.S. Gulf to France. This system stabilized the price at a healthy level for the oil companies as long as others joined, which they did. With a mechanism in place for allocating incremental production to meet growing demand among the participating oil companies, the global oil business, with the exception of Soviet oil, was under the control of a cartel of oil companies. Of course, for those U.S. oil companies involved in this arrangement to fix pricing and production was in direct violation of the Sherman Antitrust Act. The Rockefeller dream of world control over oil, for the most part, had finally come true, but not with domination vested in the hands of an individual, but a small group of executives who, in the aggregate, controlled most of the world oil. The success of this agreement hinged on all the individuals continuing to cooperate, something rarely seen in the world of oil.

In 1930, only two years after the system was set up, price stability was threatened by yet another mammoth oil discovery. Like Drake and Higgens, an old wildcatter, Dad Joiner, persisted where others had given up. Joiner did not drill on land that had promising geologic characteristics but on land owned by promising widows who might invest in Joiner's ventures. Joiner must have had a way with the widows for they were all financially disappointed with Joiner's ventures; except for one, on whose east Texas farm in Kilgore Joiner brought in a gusher. Joiner had proved the oil geologists wrong and Kilgore became another Pit Hole and Spindletop all rolled into one, with oil derricks almost on top of one another pumping with all their might. This strike would lead to the discovery of other oil fields in east Texas much larger than anyone imagined. Unfortunately, Joiner was in financial straits from his past ventures with widows and could not hold onto his holdings.

Forced to sell out to H.L. Hunt, who made billions on Joiner's and other east Texas properties, Joiner was to die as poor as Drake and Higgens.

The east Texas oil boom, coming at the time of the Great Depression, created a glut and oil prices collapsed locally to ten cents a barrel. Teagle and Deterding were powerless because they did not control the east Texas oil fields. The Texas "independents" demanded federal and state intervention. The state governments of Texas and Oklahoma obliged and declared martial law on the basis that the independents were squandering a valuable natural resource, particularly at ten cents a barrel. Using conservation to justify the states' actions, and the local militia to enforce their will, oil production was stopped. Then the Texas Railroad Commission was authorized to set up a rationing system to control production. Although individual producers cheated whenever they could, the Texas Railroad Commission eventually got the upper hand over the producers and was able to ration production of individual wells and prices rose. This government action to protect and conserve a natural resource, which today would be viewed as environmentally desirable, served the interests of the global oil cartel as well. Thus, capitalism and conservation joined hands with a common objective, but different goals. Deterding's pooling arrangement and the Texas Railroad Commission's rationing of production stabilized the world price of oil and both were valuable lessons for OPEC when it gained control over oil prices and production in the 1970s.

Enter Saudi Arabia and Kuwait

With the price of oil reestablished by controlling east Texas production, the last thing the oil companies wanted was another east Texas discovery. Another oil rogue, New Zealander Frank Holmes, believed that oil was waiting to be discovered in Arabia. Gulbenkian's Red Line Agreement prohibited exploration in Arabia without the joint cooperation of the signatories. Socal, the name of Chevron at that time, was not a signatory of the Red Line Agreement, and for $50,000 bought Holmes's concession in Bahrain, an island nation off of Saudi Arabia, and in 1931 struck oil. While Bahrain would never become a major oil producer, it indicated that Holmes might be right about Arabia.

In 1927, the desert king Ibn Saud subdued his rivals along the Red Sea coastline and named his new kingdom after his clan. In 1930, desperate for money, King Saud inveigled Socal to buy a concession in Saudi Arabia. The major oil companies, bound by the Red Line Agreement and in no mood to discover more oil, passed up the opportunity to make a deal with King Saud. Socal did some exploration, which turned out to be promising; but short on capital in the event that oil were discovered, the company teamed up with Texaco, another nonsignatory to the Red Line Agreement. Texaco bought a half share of Socal's interests in Bahrain and Saudi Arabia. Eventually oil was discovered in Saudi Arabia, and in 1939 King Saud opened up a valve and oil began to flow into an awaiting tanker. The king was so pleased that he increased Socal's and Texaco's concession to an area as large as Texas, Louisiana, Oklahoma, and New Mexico combined.

Frank Holmes was also involved with opening up Kuwait, which was also outside of the Red Line Agreement. Eventually BP and Gulf set up a joint venture after a fair degree of behind-the-scenes maneuvering by the British and U.S. governments. In 1938 oil was discovered. Although Frank Holmes was instrumental in opening up oil exploration in Bahrain, Saudi Arabia, and Kuwait, all successful finds, he made no fortune from the enormous wealth that he was instrumental in creating for the oil companies and producers. Originating and transforming a good idea to reality does not necessarily translate into personal wealth. This is the lesson of Drake, Higgens, Joiner, and Holmes; something else was needed.

Exit the Key Players

Hitler inadvertently took down three leading oil company executives. The first to fall was Deterding, who was showing signs of mental imbalance (megalomania) as his management style became increasingly dictatorial. In his memoirs, composed in 1934 in the midst of the Great Depression, when tens of millions of idle workers were desperately seeking work, he wrote that all idlers should be shot on sight. Upset over the loss of Shell properties in Russia after the revolution, Deterding's position against communism hardened with his second marriage to a White Russian and his third to a German. Deterding became a Nazi sympathizer because of their determination to rip communism out root and branch. Deterding would not be the only industrialist, statesman, monarchist, or church leader to support the Nazis for this reason. The board of directors removed Deterding from his position in 1936 by forcing him to retire, and he died six months before the war started. Shell's penchant for collegiality and corroboration in the decision-making process might be partly in reaction to Deterding's last years of rule.

The second to fall was Rieber, the head of Texaco. In 1937 Rieber diverted Texaco tankers taking oil to Belgium to support Franco in Spain, and in 1940 he got around a British oil embargo against Germany by shipping oil to Germany from neutral ports. Unable to take money out of Germany, Rieber worked out a barter agreement whereby he accepted German-built tankers in exchange for oil. Rieber was forced to resign in 1940 in the wake of a British intelligence revelation that a Texaco employee was sending information to Germany about American war preparations.

The third to fall was Teagle, who had entered into an agreement before the rise of Hitler with I.G. Farben, a German chemical company. Farben was to research and develop synthetic rubber for Exxon in exchange for Exxon's patents for tetraethyl lead, a vital ingredient in aviation fuel. Teagle was unable to see the military implications of this arrangement even after Hitler's rise to power and after the Japanese had overrun the rubber plantations in Southeast Asia. Teagle refused to break what he considered first and foremost a business deal, which remained in force until revelations by the U.S. Justice Department led to his resignation in 1942.

All three were counterpoints to Marcus Samuel, who put civic duties and patriotism above business. Deterding, Teagle, and Rieber put business above all else. Buy for a little less here, sell for a little more there, was their key to success. Business plans were to fit the immutable laws of supply and demand. The name of the game is making money. Politicians come and go and have little use other than passing laws and establishing regulations that protect business interests or guarantee their success. Governments rise and fall, but business remains forever; it is the great constant.

Shareholders and Stakeholders

The modern corporation is based on the premise that its mission is maximizing shareholder wealth. One way to do this is to spawn new products and expand market reach to millions of individuals as Rockefeller did. Another way to maximize shareholder wealth is to widen the spread between the price received for a product and its cost of production, also a Rockefeller practice. While maximizing wealth for a corporation's shareholders is what the game is all about, there are other constituencies, or stakeholders, affected by the operation of a private corporation. For instance, an oil company has some degree of latitude concerning where profits are assigned. Profits can be shifted between upstream activities (crude oil production) or downstream activities (refining and marketing) through internal transfer prices. If an oil company has its oil fields, refineries, distribution system, and market within the borders of a single nation, such as the United States, it does not matter how profit is assigned internally when a company consolidates its financial statements and tax returns. The federal government collects the same in income taxes regardless of how internal transfer prices are set, although internal transfer prices can affect state income taxes. When an oil company is buying crude oil from one nation, processing it in a second, and selling in a third, the internal assignment of profits through transfer pricing can heavily influence taxes and royalties paid by oil companies to host governments. This in turn affects the well-being of the people of oil-exporting nations, who are, in every sense of the word, stakeholders in a company that is exploiting their nation's natural resources.

Deterding noted the importance of the triangle linking the mutual interests of an oil company with the people and with the host government in which all three should benefit from developing a nation's oil resources.[16] Although Shell operated in Mexico, the government and the people felt they were getting a raw deal from the oil companies and, in 1938, nationalized the industry. The oil companies struck back by refusing to buy Mexican oil until they received restitution, which Pemex, the newly formed national oil company of Mexico, was forced to pay in order to gain access to foreign markets. Now two nations directly controlled their oil resources: the Soviet Union and Mexico. Yet the oil companies did not learn the essential lesson of Mexico—a one-sided relationship in which an oil company exploited the oil resources of a nation with limited benefit to the people or the government was not in the best long-term interests of the oil company. No one viewed Mexico as a harbinger of more to come when new oil discoveries in Venezuela diverted oil company attention from Mexico.

Development of Saudi Arabia's Oil Fields

Saudi Arabia was the answer to Washington's worry, one that had first bothered Theodore Roosevelt and would come back now and then to haunt government energy policymakers: The world was going to run out of oil. Socal and Texaco operated in Saudi Arabia under the corporate umbrella of Aramco, the Arabian-American Oil Company. Socal and Texaco advanced the idea during the early years of the Second World War of the U.S. government setting up a Petroleum Reserve Corporation to buy a controlling interest in Aramco and constructing a refinery in the Persian Gulf. The idea was well received by Franklin D. Roosevelt, who, like Churchill, was attracted by the idea of government ownership of a foreign oil field. However, the oil companies abruptly broke off negotiations in 1943. Only in hindsight can one see the timing between the success of Rommel in North Africa and the proposal for the Petroleum Reserve Corporation and Rommel's defeat in 1943 with the proposal's demise. Obviously, oil company investments in the Middle East would be in danger if Rommel succeeded in his master plan to link his army in North Africa with Hitler's in Baku. Oil companies generally oppose government intervention in their operations unless, of course, such intervention promotes their agenda.

The U.S. government then proposed constructing a thousand-mile pipeline to carry Saudi crude to the Mediterranean and the oil companies would guarantee a 20 percent interest in the oil fields as a naval reserve. The Trans-Arabian Pipeline (Tapline) pipeline was completed, without U.S. government involvement, in 1950 when Saudi crude was loaded on a tanker in Sidon, Lebanon. The pipeline, passing through Saudi Arabia, Syria, and Lebanon, was shut down in 1975 during a time of turmoil in Lebanon. However, the pipeline's capability of carrying oil cheaply to Europe when in operation meant a great deal to Socal and Texaco.

Having achieved such success in Saudi Arabia, Socal and Texaco passed up an opportunity to become dominant players in the oil business by not wanting to challenge the other major oil companies. They felt that involvement of the other major oil companies was necessary for access to oil markets, capital to develop Saudi oil resources, and garnering diplomatic support if there were an unfriendly successor to King Saud. Admitting Exxon and Mobil and excluding the other signatory oil companies violated the Red Line Agreement. Using American antitrust legislation as a lame excuse, Exxon and Mobil walked away from the Red Line Agreement and joined Aramco, thereby locking BP, Shell, and CFP out of Saudi Arabia.

Aramco proved to be a model for a company operating in a host nation. Its employees had their own town and concentrated on the business of finding, developing, and operating the oil fields and building and running refineries, pipelines, and terminals. By any measure, Aramco was considered a "good corporate citizen." Aramco permitted the United States to have two allies diametrically opposed to one another. The state department dealt directly with Israel and, when necessary, used Aramco as a go-between in its dealings with Saudi Arabia. In the twenty-first century the company is known as Saudi Aramco, with 54,000 employees of whom 86 percent are Saudis. The company prides itself on its ability to manage Saudi energy resources and contribute to the nation's development.

Shoes Begin to Fall

It is one matter when foreign producers supply 10 percent of the world's oil, which can easily be replaced by other sources. This keeps the producers in a weak bargaining position as they learned in Mexico. It is another matter when their share grows to 30–40 percent, which no longer can be replaced; then their bargaining position is not quite so weak. The oil companies failed to realize the growing bargaining strength of the oil producers that accompanied the growing world dependence on foreign oil. The next shoe to fall after the Mexican nationalization of its oil industry came in 1948, when Venezuela passed a law for a 50:50 sharing of profits, an idea of Juan Pablo Perez Alfonso, the Venezuelan oil minister and chief architect of OPEC. The idea was not total anathema to the oil companies if sharing profits meant forestalling nationalization as had occurred in Mexico (better to have half than none). Moreover, the oil companies had the power to define profitability by how they allocated profits through internal transfer pricing.

King Saud, whose huge family's lifestyle had become incredibly expensive, joined the fray and demanded a share of the profits. Aramco turned to the U.S. government for support, and the government, fearing a communist takeover in the Middle East, agreed to have the Aramco partners treat the additional payments to Saudi Arabia as a foreign income tax. This was a great boon to the Aramco partners because this meant, under rules on double taxation, that taxes paid to the U.S. government would decrease one dollar for every extra dollar in taxes paid to Saudi Arabia. In other words, the U.S. government, hence U.S. taxpayers, was subsidizing the extra cost of oil. Such a ruling could not be restricted to some oil companies, equal treatment demanded that this apply for all. The upshot of this ruling was that it became more profitable for oil companies to develop oil properties overseas than domestically. The oil companies could shift a part of what they were paying foreign suppliers in the form of taxes to reduce their U.S. taxes, something that would not apply to a U.S. source of supply. Another tax bonanza for the oil companies was applying the oil depletion allowance to foreign as well as domestic sources of oil. These two tax rulings placed oil companies in a quasi tax-free environment at that time, which is not true today.

Next Shoe to Fall

BP, still half-owned by the British government, had expanded into activities far beyond those envisioned by Churchill. While its principal source of oil was still Iran, BP had a major position in Iraq and Kuwait and had developed a worldwide marketing network served by its fleet of tankers. In 1951, a new Iranian leader appeared on the scene, Mohammad Mossadegh, who called for nationalization of Iranian oil fields after BP's refusal to adopt a deal similar to that between Aramco and Saudi Arabia. The Iranian prime minister, who opposed Mossadegh, stated that he would not allow Iran to repudiate its concession with BP. That remark caused his assassination, opening the way for Mossadegh to become prime minister and nationalize BP's oil fields. The Labor Party, then in power in Britain, was hardly in a position to enforce this legacy of colonialism. With no help from the British government, BP took legal action, not in Iran, but in every nation where a cargo of Iranian oil landed. This lasted two years. By then the civil unrest that resulted from the loss of revenue led to a coup, encouraged by the CIA, which reinstated the son of a previous shah. In 1954 an agreement was hammered out whereby the National Iranian Oil Company, formed by Mossadegh, would remain owner of the oil fields along with the Abadan refinery. However, the oil would be sold through a consortium in which BP had a 40 percent share, Shell 14 percent, with the rest divided among CFP and the five remaining American sisters. In other words, the seven sisters, eight counting CFP, had total market control over Iranian oil production. The agreement taught the oil companies their first lesson—ownership of an oil field is not nearly as critical as access to its oil.

Later on, five smaller U.S. oil companies inveigled a 5 percent share. Among these were Getty Oil and Tidewater, both owned by Jean Paul Getty. Getty was the son of a lawyer who struck it rich in oil in Oklahoma. The son was just as talented, if not more, as his father. Getty became a billionaire, partly as a result of his flying with an oil geologist over the Neutral Zone between Saudi Arabia and Kuwait. The Kuwait side of the Neutral Zone was already producing oil. The geologist noted from the air that a certain sector of the Neutral Zone in Saudi Arabia had geologic features similar to that of the oil-producing sector in Kuwait. Getty immediately started negotiating with Ibn Saud for a concession. Drilling revealed a huge oil field, big enough to make Getty a billionaire and for the geologist to be reimbursed for his travel expenses.

Besides Getty there was Hunt, another billionaire not given to sharing with those responsible for his wealth (Dad Joiner comes to mind), and Armand Hammer. Hammer had received a medical degree but did not practice medicine, as his father had, who had befriended Lenin. Hammer took advantage of his father's relationship with Lenin to make commercial deals in the Soviet Union, including setting up a pencil factory and purchasing Russian art treasures for pennies on the dollar. Hammer, at an age when many contemplate retiring, got interested in oil and eventually took over a small oil company called Occidental Petroleum. By dint of his determination and driving force, Hammer transformed Occidental Petroleum into an international oil company with the discovery of three major oil fields in Libya. Hammer would play a pivotal role in the oil crisis of 1973.

Another thorn in the side of the seven sisters was Enrico Mattei, head of the Italian State Oil Company, who was able to prick the seven sisters by negotiating an independent concession with the Iranian National Oil Company (NIOC) in 1957 and making a private deal with Khrushchev for cheap Soviet oil, much as Deterding before him had done. The seven sisters then had to contend with CFP's discovery of oil in Algeria. New discoveries of supply remained ahead of rapidly growing demand. Despite the best efforts of the seven sisters to keep production matched with demand to sustain prices, there was a glut of oil on the market and oil prices remained cheap. Unbeknownst to the Iranian government, the oil companies in the consortium that purchased the output of the NIOC made a secret side-agreement to reduce Iranian sales in order to avoid a global glut of oil. Neither the shah nor the NIOC knew about this agreement, which effectively made Iran a swing producer to maintain world oil prices.

This perhaps marked the zenith of oil company power. The oil companies had reinstated their position

Table 5.1

Shareholders' Ownership Percentage

	Iran Consortium	Iraq IPC	Saudi Arabia Aramco	Kuwait KOC	Abu Dhabi Petroleum
BP	40	23.750	—	50	23.750
Shell	14	23.750	—	—	23.750
Exxon	7	11.875	30	—	11.875
Mobil	7	11.875	10	—	11.875
Gulf	7	—	—	50	—
Texaco	7	—	30	—	—
Socal	7	—	30	—	—
CFP	6	23.750	—	—	23.750
Others	5	—	—	—	—

in Iran even though their properties had been nationalized by preventing access to the world market, the same stratagem used in Mexico. Mossadegh's political demise served as a warning to other interlopers. Notwithstanding the success of Hunt, Getty, Hammer, and Mattei, there were limited opportunities for third parties to reach the market unless they went through one or more of the seven sisters. The seven sisters exerted the power of Rockefeller's horizontal monopoly on a global scale. Table 5.1 lists the shareholders of the various Middle East oil concessions in play up to the eve of the 1973 oil crisis.

Nasser's 1956 takeover of the Suez Canal did not affect the oil companies as much as it created fortunes for tanker owners. Because it took longer to get the oil around South Africa, Humble Oil, the Texas subsidiary of Exxon, took advantage of the temporary shortage of oil in Europe and raised crude prices by thirty-five cents per barrel. This incurred the wrath of Congress, which from a contemporary perspective appears ludicrous when price changes of thirty-five cents per barrel are hardly noticed. Of course, thirty-five cents per barrel of oil when it cost around $2 per barrel was a large percentage change. What this showed was a major consuming government's keen interest in keeping a lid on oil prices; in fact, one might conclude that consuming governments depended on oil companies to keep a lid on oil prices. Keeping communists out of the oil-producing nations and keeping oil prices low for consumers were the reasons why the U.S. government never seriously pursued antitrust actions against the American oil majors, which clearly violated the Sherman Antitrust Act when they cooperated with competitors to fix prices and limit production. The British government took a far more pragmatic view of the situation and did not share the U.S. government's vexation when oil companies attempted to stabilize something as critical to the world economy as oil.

Birth of OPEC

By the late 1950s cheap Soviet crude was cutting into the seven sisters' markets in Italy, India, and Japan. The seven sisters had to lower their prices in these nations to maintain their market presence, which, of course, meant lower profit margins. In 1959, Exxon resolved that it must cut posted prices to oil producers to preserve its profit margin. When the other oil companies followed suit, the Arab oil producers organized the first meeting of the Arab Petroleum Congress, the fruit of private talks between the oil ministers of Venezuela and Saudi Arabia. A second round of Exxon-inspired cuts provoked a stronger surge of unity among the oil producers. Another meeting in 1960 of the oil ministers of Saudi Arabia, Iran, Iraq, Kuwait, and Venezuela gave birth to the Organization of Petroleum Exporting Countries (OPEC). The purpose of OPEC was not to raise oil prices but to prevent further reductions in posted prices. The original unity of purpose was gone by the second OPEC meeting in 1961, when a rough and tumble battle broke out among OPEC members as each sought to garner a larger export volume at the expense of others. OPEC was behaving no differently than the earliest oil drillers in Pit Hole; it was every man for himself.

By no measure could OPEC be considered a success during the 1960s. There was little coordination among the members and politics kept getting in the way of negotiations. Meanwhile, new sources were coming onstream, such as Nigeria, putting more pressure on OPEC's approach to maximizing revenue by maximizing production, another reminder of Pit Hole. In 1965, OPEC failed at an attempt to gain control over future increases in production just as it failed to gain control over current production. The seven sisters meanwhile were trying to restrain production to prevent further declines in oil prices. The irony is that in only ten years, OPEC would take over the oil companies' role of restraining production to control prices. The role reversal would not be complete as the OPEC idea of price in the 1970s would be radically different than that of the oil companies in the 1960s.

The 1967 Six-Day War between Israel and Egypt sparked the first Arab boycott. The war was over before the boycott had any effect, which was doomed anyway when Venezuela and Iran refused to join. The formation of the Organization of Arab Petroleum Exporting Countries (OAPEC) within OPEC in 1970 did not succeed in strengthening the resolve of OPEC to bring order to the oil market. Order, of course, meant maximizing the respective production volume of each member to maximize revenue. Oil company attempts to rein in production to maintain prices, which varied for each member of OPEC, irritated the oil producers who now had to contend with new oil production from Qatar, Dubai, Oman, and Abu Dhabi.

In 1970, the Alyeska Pipeline Company was formed to handle the 1968 oil discovery by Arco (then Atlantic Richfield) in Prudhoe Bay on the north slope of Alaska. Compared to the Middle East exporters, this is expensive oil. Arco, short on crude, viewed the development of the North Slope field as vital to its survival. Two other major participants were Exxon and BP, the latter having acquired Sohio to gain greater access to the U.S. market. These two companies, with more cheap Middle East oil than they wanted, did not need expensive North Slope oil. At first the environmentalists were successful in blocking the building of an 800-mile pipeline to Valdez. Congress set an interesting precedent by overriding environmental concerns in the wake of the 1973 oil crisis and authorized the construction of the pipeline. Alaskan oil began flowing in 1977.

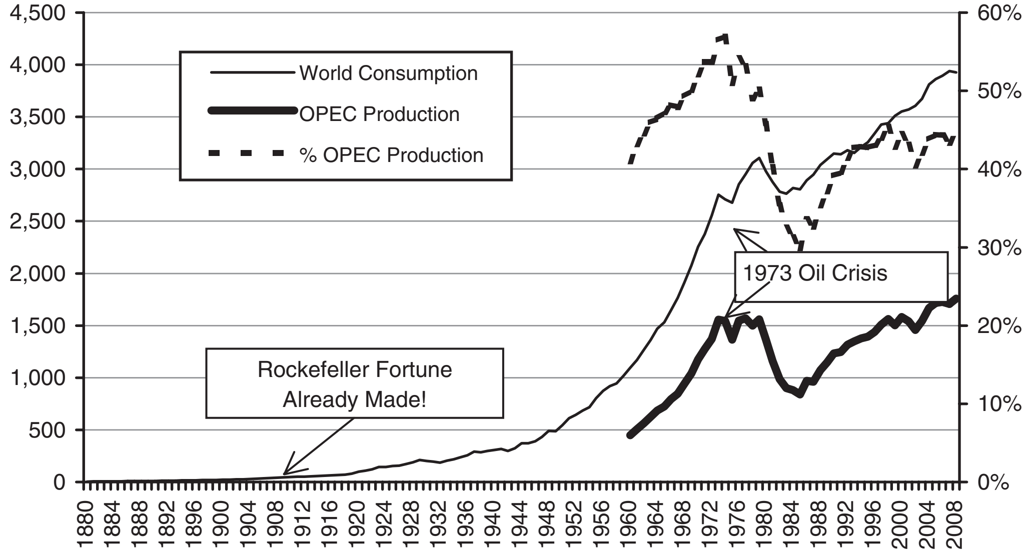
Another source of high-cost oil was the 1969 discovery of the Ekofisk oil field in the Norwegian sector of the North Sea by Phillips Petroleum. This was followed a year later by the BP discovery of the Forties field north of Aberdeen and the following year by the Shell and Exxon discoveries of the Brent field off the Shetland Islands. The involvement of Exxon, BP, and Shell in oil fields far more costly to develop than buying Middle East crude, intentionally or unintentionally, could be interpreted as manifesting their concern over the rising dependence on Middle East oil.

The 1973 oil crisis was not caused by a shortage of oil. Indeed, the greatest worry right up to the eve of the crisis was how to keep new production from flooding the market and further weakening oil prices. The producers were worried about anything that would shrink their export volumes. The shah of Iran wanted to increase export volumes in order to expand Iran's military power and develop its economy, and saw his role as a guarantor of stability of the Middle East, for which he had received President Richard Nixon's blessing.

1973 Oil Crisis

Figure 5.1 shows the growth of world oil consumption from the beginning of the oil age and OPEC production since 1960.[17]

Figure 5.1 **Growth in World Oil Consumption and OPEC Production** (MM Tpy)

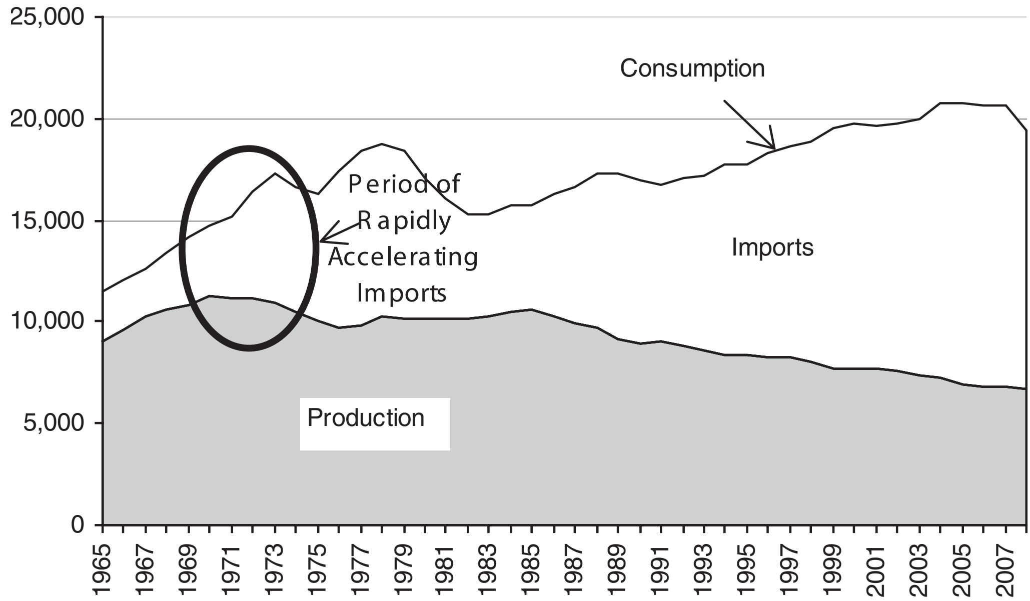


From the birth of the automobile age around 1900, oil consumption began to double about every decade. Even the Great Depression did not dampen growth in oil consumption, but the age of oil did not begin in earnest until after the Second World War, when successive doublings really started to kick in (one penny doubled is two pennies, two pennies doubled is four, doubled again eight, doubled again sixteen, doubled again thirty-two). The slopes of the curves for both world oil consumption and OPEC production appear about the same from 1960 to 1973, which implies that nearly all incremental oil demand was coming from the OPEC nations. A closer examination reveals that in 1960 OPEC was supplying 38 percent of world oil consumption, 47 percent in 1965, and 56 percent in 1973, meaning that OPEC exports were growing faster than world oil demand. Much of this rapid growth in consumption was in Europe and Japan, both recovering from the War. While oil consumption growth in the United States was more subdued, nevertheless the U.S. was heavily responsible for growth in OPEC demand as it made the transition from being the world's largest oil exporter to the world's largest oil importer, as shown in Figure 5.2.

The early 1970s was a period of rapidly rising U.S. oil imports, of which a greater portion was coming from the Middle East. The oil crisis halted growth in U.S. consumption, and twenty years were to pass before U.S. consumption would surpass its 1978 peak. Middle East exports around 2000 were just about back to where they were in the late 1970s. Though the United States is criticized as the energy hog of the world, its share of the oil pie has been much worse in the past. The U.S. portion of world oil consumption was 42 percent in 1960, which declined to 23 percent by 2008. Obviously, incremental growth in oil consumption has been concentrated elsewhere.

The high point of oil company ascendancy over national powers was the BP-inspired embargo against Mossadegh that led to his fall from power in 1953 and brought Iran to heel. Between then and the 1973 oil crisis, there was a shift from a buyers' to a sellers' market that occurred without public fanfare. The question raised by Figure 5.2 is—why did it take so long? Another way of putting it, from the consumers' perspective, would be that the oil companies should be congratulated because they had kept oil prices low for as long as they did. Yet, there had to be an

Figure 5.2 **U.S. Oil Consumption, Production, and Imports** (000 Bpd)



underlying unease with respect to the state of the oil market. Why else would major oil companies start searching for oil in such high-cost areas as the North Slope and the North Sea?

The underlying shift from a buyers' to a sellers' market needed a precipitating event to make it manifest. Actually, it was a series of events that started with Colonel Gadhafi's successful military coup in Libya in 1969. At this time, Libya was supplying about one-quarter of Europe's needs with high-quality and low-sulfur crude. Moreover, Libya is located on the right side of the Suez Canal from the point of view of European oil buyers. The Canal was closed in 1956, then reopened in 1957 when Nasser nationalized it, then closed again in 1967 during the Israeli-Arab War and not reopened until 1975. Libya received no premium for its oil, considering its quality and nearness to market. Gadhafi was not to be cowed by the major oil companies' resistance to any price change. In 1970, Gadhafi struck at the weakest link in the supply chain: the independents, particularly those dependent on Libyan crude. Of these, the most dependent was Occidental Petroleum. Gadhafi chose his target wisely.

Hammer pleaded with the majors to sell him replacement oil at the same price he was paying for Libyan oil. In their shortsightedness, they offered Hammer higher-priced oil. Facing a disastrous interruption to supply, Occidental gave in to Gadhafi's new price and tax demands, which were relatively modest from today's perspective. Flushed with victory, Gadhafi went after the majors. To everyone's surprise, the majors did not embargo Libyan crude and replace it from other sources as they had with Mexico and Iran. Instead, they capitulated to Gadhafi's demands, a stiff price to pay for not coming to Hammer's aid. The producers now sensed that a fundamental change had taken place in the market. The world was shifting from a buyers' to a sellers' market.

As a consequence of Gadhafi's success, a hastily convened OPEC meeting in Caracas in late 1970 agreed to higher minimum taxes and higher posted prices that, when announced, only made Gadhafi leapfrog with even greater demands, followed by Venezuela. This infuriated the shah because this challenged his leadership. To shore up the resistance of the independents to further

OPEC demands, the majors agreed that appropriately priced replacement oil would be provided to the independents to prevent them from caving in to producer demands. It was too late.

With U.S. government support, the oil companies attempted to get the oil producers to agree to common terms and to moderate their demands, that is, to get control over Gadhafi. A meeting was held in Tehran in 1971 attended by delegates from the oil-producing nations, the oil companies, and the U.S. State Department. The shah insisted that Libya and Venezuela not attend. The majors hoped that the presence of the State Department would aid in their negotiations, but it proved to be a weak straw. The State Department wanted to avoid a confrontation between the oil companies and producers because it depended on Iran and Saudi Arabia to act as regional police to suppress communist-inspired radicals. The State Department and the oil majors were not on the same page. Similarly, government representatives of several European nations and Japan proved equally inept at influencing the outcome. Without strong government backing, and considering the importance of OPEC oil in the general scheme of things, the oil companies made no new demands and shifted their approach from confrontation to a call for moderation. It was now a matter of damage control.

The capitulation of the oil companies to the oil producers was the final piece of evidence that convinced the oil producers that the market had shifted in their favor. One top oil executive publicly quipped that the buyers' market was over. The agreed price increase in February of 1971 was an extra thirty cents per barrel on top of the posted price, escalating to fifty cents per barrel in 1975. This price adjustment held for the Gulf producers; now a meeting was necessary with Libya. A separate Tripoli agreement, signed six weeks after the Tehran agreement, called for a higher price without Libya providing a similar guarantee on future prices. The shah was infuriated by Gadhafi's leapfrogging over what he had agreed to.

Whereas the 1960s were years of worry over looming oil gluts, the early 1970s were years of a growing concern over a potential shortage, a reversal of the change in perception that occurred between the early and late 1920s. This change in sentiment spurred the oil producers to increase their demands for part ownership of their natural resources in the two-year hiatus between the Tehran agreement and the oil crisis of 1973. The oil producers felt that the original concessions granted to oil companies belonged to a bygone age of colonialism and imperialism. They wanted to move into the modern era and control their national resources through joint ownership rather than merely collecting taxes on their exports. The producers favored joint ownership with the oil companies over nationalization because nationalization removed the oil companies' incentive for making money in the upstream, or production, side of the business. By limiting their profits to the downstream side of refining and marketing, oil companies would only be interested in buying crude at the cheapest price and the producers would be back to undercutting one another as the only way to attract an oil company's attention.

Joint ownership turned out to be an idle thought. The British withdrawal of their military presence from the Middle East in 1971 created a power vacuum that allowed Iran to seize some small islands near the Strait of Hormuz. Gadhafi used Iranian aggression as an excuse to nationalize all of BP's holdings in Libya, along with Bunker Hunt's concession, and then 51 percent of the remaining concessions, including Hammer's. Algeria and Iraq joined in the frenzy of nationalizing oil assets. In early 1973 the shah announced his intention not to have the NIOC renew its operating agreement with the oil companies when it expired in 1979, and to transform NIOC from a domestic oil producer into a major global oil company.

By making separate deals with oil companies, the oil producers were fast learning how to play one of the seven sisters off another just as effectively as the seven sisters used to play one producer off another. The oil companies were beside themselves as their oil fields and physical assets were transferred from their books unto the books of the oil producers. They were at loggerheads over a common approach that would minimize their loss of power and enable them to obtain restitution. Their appeals to the U.S. government for help were interpreted as a sign of weakness. Then the independent oil companies broke ranks with the seven sisters and began a bidding war to assure their oil supplies, another sign of weakness. The imposing facade of oil company power was exposed for what it was: an imposing facade.

With governments standing helplessly aside, the oil companies prepared to meet with the OPEC producers in Vienna in October 1973. The meeting took place just as Syria and Egypt invaded Israel, hardly an auspicious omen. The meeting broke down when the oil producers demanded a price hike to $5 per barrel. The oil companies played a weak hand and tried to refer the matter to their respective governments before making a formal reply. Oil companies had never appealed to their governments for permission before, so why now unless they were in desperate straits? Shortly after, in mid-October, King Faisal delivered an ultimatum to Nixon: immediate cessation of U.S. military aid to Israel or face an embargo. The ultimatum arrived just as the U.S. Senate had overwhelmingly voted to send reinforcements to Israel.

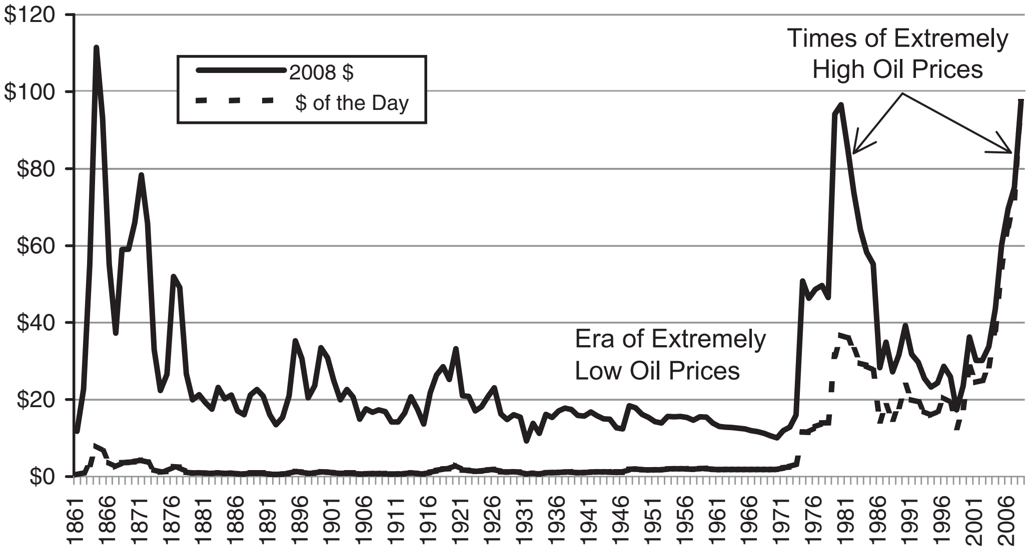
Events were now entirely out of the hands of the oil companies and consuming nations. In quick response to continued U.S. military support of Israel, the members of OPEC meeting in Kuwait unilaterally raised the price of a barrel of oil from $3 to $5, accompanied by a 5 percent cutback in production. The oil weapon, mentioned in the past, was now taken out of its sheath for the first time. The production cut was intended to sway the United States not to continue supporting Israel. Then, three days later Saudi Arabia announced a 10 percent cutback in production plus an embargo of oil to the United States and the Netherlands. This embargo had to be carried out by the oil companies themselves, even though a majority of them were U.S. companies. Of course, Saudi Arabia could not stop the oil companies from supplying oil to the Netherlands and the United States from other sources. Nevertheless, the embargo created a hiatus in oil moving into the United States, resulting in long lines at gasoline stations in November only a month later. The irony was that on October 21, when the embargo went into effect, Israel agreed to a ceasefire. But the Humpty Dumpy of the old world could not be put back together again. The oil companies made fruitless attempts to regain control over market prices. The first oil shock reached its apogee in December, when independents panicked over oil supplies and Iran conducted an auction with the highest bid coming in at $17 per barrel.

One argument advanced for raising oil prices by the oil producers was the fact that European governments collected more in taxes on a barrel of crude than what they received for selling a finite and depleting resource (this relationship still holds). Another was that when oil displaced coal, it proved that oil was underpriced with respect to coal. Hence, it was in the long-term interests of energy consumers to reinstate coal as a source of energy, which could be accomplished, according to the shah, if crude were priced at $11.65 per barrel, the price necessary to make oil products from coal and shale oil at that time. The benefit to consumers was that a higher price of oil would cut oil consumption and postpone the time when the world would run out of oil.

The shah was absolutely right. If the oil crisis had not happened, there presumably would have been three more doublings between 1973 and 2003. World oil consumption was 2,750 million tons in 1973; three doublings is a projected consumption of 11,000 million tons compared to the 3,682 million tons consumed in 2003. An oil crisis was inevitable at some point because there was no way for production in 2003 to triple to accommodate a continued doubling of consumption every decade.

As the shah was justifying why oil prices had to be increased, an oil auction held in Nigeria fetched a whopping $23 per barrel, although the winner did not show up to take delivery. At the

Figure 5.3 **History of Crude Oil Prices** ($/Bbl)



end of 1973, with an OPEC meeting to determine the appropriate price for a barrel of oil, the shah of Iran unilaterally announced a price of $11.65 per barrel, much to the chagrin of the other producers.[18] Even though the shah would be accused of moderation in a sea of immoderation, his price still represented a doubling of the then-posted price and a quadrupling of the posted price only a few months earlier. He accompanied his announcement of the new price with the warning that Western living styles would have to change and everyone would have to learn to work harder. The world no longer had to face a cartel of oil companies but a cartel of oil-producing states. The greatest transfer of wealth in history was about to occur.

First Time of High Oil Prices

Figure 5.3 shows the history of oil prices in constant dollars and dollars of the day. Dollars of the day are actual prices of oil paid at points in time. Constant dollars reflect the purchasing power of 2008 dollars. Crude prices expressed in constant 2008 dollars are higher than in current dollars, reflecting the loss of purchasing power from inflation (in 1980/81, crude prices were about $36 per barrel in dollars of the day whereas in constant 2008 dollars, prices are nearly $100 per barrel).[19]

Although the peak price in 2008 was $147 per barrel, the average annual price shown in Figure 5.3 was $97 per barrel. In terms of constant 2008 dollars, the highest annual average price occurred in 1864, when prices expressed in constant 2008 dollars averaged $110 per barrel. This explains a lot about Pit Hole. With Rockefeller in control by 1880, oil prices in terms of 2008 dollars averaged $21 per barrel, and varied between $13–$35 per barrel until 1910. From 1910–1930 the average was $19 per barrel with about the same range. Thus, oil prices were fairly stable for a half century. The Great Depression of the 1930s saw average prices decline to $15 per barrel, ranging between $9–$18 per barrel, again in 2008 dollars. The 1940s and 1950s were a continuation of depression prices, averaging $15 per barrel with a narrow range between $12–$18 per barrel. This is another thirty years of essentially constant prices that were close to those of the Depression. The 1960s up to 1972 was the absolutely worst period for oil producers, with an average price of $13 per barrel, ranging between $10–$14 per barrel. It is ironic that the oil producers were facing the lowest prices in the history of oil while export volumes were virtually exploding. As long as exploding export volumes stayed ahead of exploding import volumes, the oil companies could maintain the upper hand. As soon as exploding import volumes got ahead of exploding export volumes, which happened when Saudi Arabia imposed its embargo, all hell broke loose.

After the 1973 price hikes, the shah now had the means to make Iran the military powerhouse of the Middle East, transform its economy to that of a modern state and make NIOC a global oil powerhouse. Rather than giving him the means to pursue his grandiose dreams, all he got for his financial bonanza was exile (he went on a vacation from which he never returned in early 1979). The Iranian Revolution, which broke out in 1978 as national strikes, ended in 1979 with the ascendancy of Khomeini, a cleric with a decidedly anti-Western bent. The Iranian Revolution marked the second oil shock when the cessation of Iranian crude exports of over 5 million barrels per day (bpd) caused oil prices to climb precipitously to $37 per barrel on an average annual basis, prices that would not be seen again until 2004, in terms of dollars of the day but not until 2008 in constant dollars.

The cessation of Iranian production and the accompanying panic buying and hoarding brought about a reoccurrence of long lines of automobiles at gasoline filling stations. As Khomeini was finding his way around Tehran, Saddam Hussein staged a coup and made himself dictator of Iraq. Two years later, in 1981, Saddam cast his eye on Khomeini's army, whose weapons were no longer being supplied by the United States, and whose officers, commissioned by the shah, had been purged and replaced by loyal, but untrained, revolutionaries. Saddam decided that Khomeini's army, unlike the shah's, was no match for Iraq's army, newly equipped by the Soviet Union, and he invaded Iraq.[20]

While the Iranians and Iraqis were waging war and Saudi Arabians were having problems digesting their newfound wealth, changes in the world of energy were at work that would come back to haunt the oil producers. Among these was a worldwide economic decline that reduced overall energy demand. High oil prices instigated a desperate search for alternative sources to oil, leading to a resurgence of coal, an accelerated pace in building nuclear power plants, a greater reliance on natural gas and anything else not called oil, including wood-burning electricity-generating plants. There were great gains in energy efficiency where cooling a refrigerator, heating a home, running an automobile, truck, locomotive, marine, or jet engine could be achieved with significantly less energy. Conservation of energy took the form of keeping indoor temperatures higher in summer and lower in winter, driving the family car fewer miles, and recycling energy-intensive products such as glass, aluminum, and paper. Companies set up energy managers to scrutinize every aspect of energy use in order to identify ways to reduce consumption.

In addition to slashing demand, high-priced oil caused an explosion in non-OPEC crude supplies, best exemplified in the North Slope of Alaska and in the North Sea. The North Slope of Alaska is an inhospitable place to develop and operate an oil field and necessitated the construction of an 800-mile-long pipeline to the port of Valdez over mountain ranges and tundra. North Slope production peaked at 2 million bpd a few years after the pipeline started operating in 1977. The North Sea was an even greater challenge with its hundred-knot gales and hundred-foot seas. Floating oil-drilling platforms explored for oil in waters a thousand feet deep. "Oceanscrapers," structures higher than the Empire State Building, were built on land, floated out to sea, and flooded (carefully) to come to rest on the bottom as production platforms. North Sea oil started with 45,000 bpd of output in 1974 and grew to over 500,000 bpd in 1975, to 1 million bpd in 1977, to 2 million bpd in 1979, to 3 million bpd in 1983, eventually peaking at 6 million bpd in the mid-1990s. Every barrel from the North Slope and North Sea was one barrel less from the Middle East.

Oil exporters dictated prices after the 1973 oil crisis, but continually changing prices implied that OPEC could not control the price as well as the oil companies had. When oil prices fluctuate widely, no one knows, including the oil producers, what will be tomorrow's price. This provides speculative opportunities for traders who try to outwit or outguess oil producers. All they needed was a place where they could place their bets. Once the traders started placing bets, buyers and sellers of oil had an opportunity to hedge their investments against adverse price changes.

Future and forward contracts of commodities with wide price swings were already traded, providing buyers with a means to hedge against the risk of a rising price and sellers a means to hedge against the risk of a falling price. The first futures were traded in grain in the nineteenth century. Grain growers could then short the futures market and lock in their revenue whereas bakers could buy futures and lock in their costs. Futures then spread to other agricultural products and industrial metals to stabilize prices, provide a means of hedging against price swings, and function as chips in a gambling casino for speculators whose buying and selling add depth to the market. There was no reason to have a futures contract in gold, interest, and currency exchange rates when these were essentially fixed by government fiat. As governments lost control over gold prices, interest and currency exchange rates during the 1970s, future contracts were developed to help buyers and sellers deal with the risk of price and rate volatility.

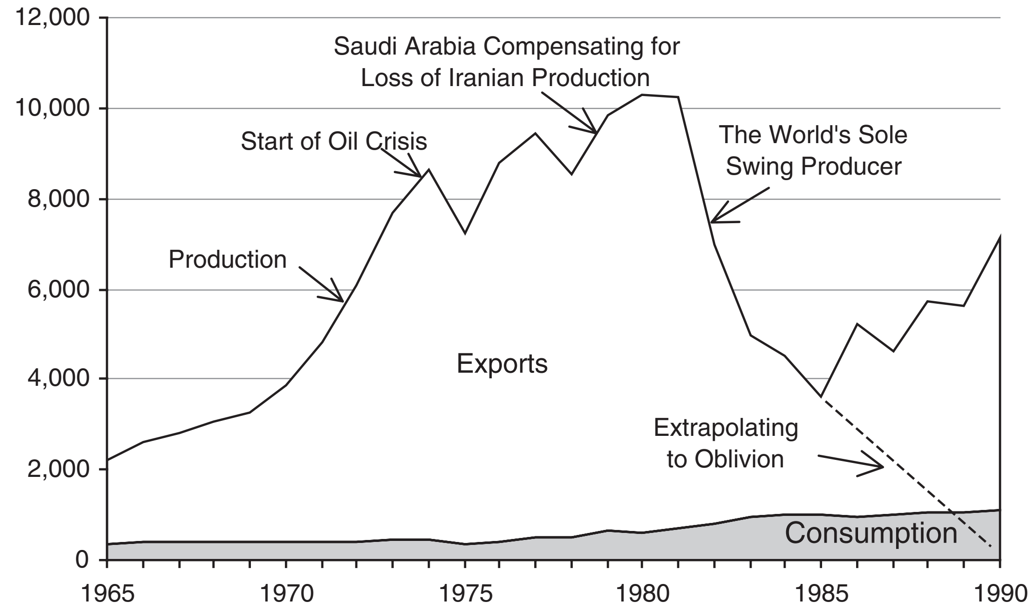
When oil companies controlled oil prices within a narrow range, there was no point in having futures. When they lost control over pricing, and with oil prices gyrating widely from a combination of oil producer greed, political instability, and Middle East conflicts, it was only a matter of time before someone would create a futures contract in oil. The New York Mercantile Exchange (NYMEX), with a long history in butter, cheese, and eggs, and later potatoes, needed a new trading commodity to keep its doors open. In the early 1980s, NYMEX started trading futures in heating oil, then gasoline, and finally crude oil. First attracting primarily speculators, soon oil companies as buyers and oil producers as sellers started trading. The development of a cash and futures market, with contracts that could be settled in monetary or physical terms and with market crudes expanding from West Texas Intermediate to a variety of specific crudes in the Middle East, West Africa, and the North Sea eventually eroded the oil producers' control over price. Since the early-1980s, the primary determinant of oil prices has been the relationship between supply and demand. The oil producers (OPEC) attempt to influence price by cutting back or expanding production, and in this indirect way affect the price of oil. But they no longer dictate price as they had in the years immediately following the 1973 oil crisis.

End of High Oil Prices

With consumers doing everything they could to reduce oil consumption, and with every OPEC and non-OPEC producer operating full out, taking advantage of the price bonanza to maximize revenue, it was becoming increasingly difficult to maintain price. There had to be a swing producer to maintain a balance between supply and demand to keep prices high and, as Figure 5.4 clearly shows, the swing producer was Saudi Arabia.

Saudi Arabia's production was initially boosted as replacement crude during the Iranian Revolution in 1978 and 1979 and during the early years of the Iran-Iraq war. After production in Iran and Iraq was restored, Saudi Arabia had to cut back sharply to maintain price. Those holding huge inventories in anticipation of further price increases had a change of heart when some semblance of order was restored and prices began to decline. Liquidating excess inventories caused OPEC

Figure 5.4 **Saudi Arabia Oil Production, Exports, and Consumption** (000 Bpd) **1965–1990**



oil demand to slump just as panic buying and hoarding caused it to jump. With OPEC members producing full out, Saudi Arabia had to cut production again to keep prices from eroding further. Saudi Arabia was now playing the same historical role played by the United States when the Texas Railroad Commission had the authority to control oil production to maintain oil prices. The United States ceased being a swing producer in 1971 when the Commission authorized 100 percent production for all wells under its jurisdiction.

From the perspective of 1985, with cessation of exports just over the horizon, Saudi Arabia was at the end of the line of playing the role of swing producer. Something had to be done. In 1985 Saudi Arabia unsheathed the oil weapon, not against the consuming nations but against its fellow OPEC members. Saudi Arabia opened the oil spigot and flooded the market with oil, causing oil prices to collapse below $10 per barrel threatening to financially wipe out OPEC. Saudi Arabia then forced its fellow producers to sit around a table and come to an agreement on production quotas and a mechanism for sharing production cutbacks whereby Saudi Arabia would cease to be the sole swing producer. The cartel would now act as a cartel.

Era of Moderate Oil Prices

Thus began the era of moderate oil prices, shown in Figure 5.3. Immediately world and U.S. consumption began to increase (see Figures 5.1 and 5.2) along with OPEC (Figure 5.1) and Saudi Arabia (Figure 5.4) production. What happened to energy conservation and efficiency? By the mid-1980s, most of the mechanisms to achieve energy conservation and efficiency were already in place. Energy conservation and efficiency are noble undertakings; wasting a nonreplenishable resource cannot be justified. But the dark side of energy conservation is that it only works when prices are high. If energy conservation and efficiency succeed in decreasing demand to the point where prices fall, then it becomes a different ball game. Suppose an individual buys a fuel-efficient car when the price of gasoline is high. The individual is using less gasoline. If repeated over millions of individuals, reduced consumption may be sufficient for the price of gasoline to fall. Once gasoline is cheaper, there is a temptation to take an additional vacation trip, perhaps as a reward for having a fuel-efficient automobile, which increases gasoline consumption.

A house has been insulated, and the temperature is lowered to use less heating oil in winter to cut heating oil consumption. If repeated in millions of homes, the cut in consumption may be sufficient to cause the price of heating oil to decline. When this occurs, the temptation is to increase the indoor temperature for greater comfort, causing heating oil consumption to rise. Fuel-efficient jet engines cut jet fuel consumption. If the airline industry converts to fuel-efficient jet aircraft, reduced consumption eventually cuts the price of jet fuel. Suppose that fuel-efficient jet aircraft are underemployed from a lack of passenger traffic. As jet fuel prices fall, the temptation is to use the savings in jet fuel to underwrite a cut in the price of passenger tickets to attract more business. Cheaper tickets encourage more flights, increasing jet fuel consumption. Fresh fruits can be flown to Europe and the United States from New Zealand and Chile as jet fuel prices decline, which causes jet fuel demand to climb. Thus, if conservation and efficiency succeed in cutting demand to the point where energy prices decline, then cheaper energy will restore consumption, closing the gap between current usage and what energy consumption was before conservation and efficiency measures were put into effect. This phenomenon is clearly seen in Figures 5.1, 5.2, and 5.4. Ultimately, conservation and efficiency are self-defeating, which does not mean that energy conservation and efficiency should be discarded. It has to be recognized that high prices have to be sustained in order to maintain the benefits of conservation and efficiency.[21]

Second Time for High Oil Prices

The second time for high oil prices was from 2007 to late 2008 with the all-time record price of $147 per barrel set in 2008. The pseudo-economic growth fueled by enormous debt acquisition by U.S. consumers resulted in higher crude oil growth rates in both the United States and Asia, particularly China as Manufacturer of the World. Spare capacity for the OPEC producers fell to about 1–2 million barrels per day, a far cry from the late 1970s/early 1980s when Saudi Arabia could make up for the cessation of exports from Iran of nearly 6 million barrels per day and still have capacity to spare. A low level of spare capacity is just another way of saying that demand is getting too close to supply, which can cause huge jumps in price as described in Chapter 2 with regard to electricity rates in California. Another contributing factor was the enormous investing of hedge funds in commodities, particularly oil. It was felt, though not proven, that their enthusiastic if not blind buying of near-term futures affected the cash price of a range of commodities of which oil was but one. Some commentators felt that the subsequent collapse of oil prices to $32 per barrel in late December 2008 was aided and abetted by hedge funds liquidating their positions. But this is a difficult point to prove as the sharp retreat of world economies dampened oil demand, which of itself would cause prices to fall. Speculators do not control the direction of the market, at least not for long. Oil prices were going up because demand was getting too close to supply. Oil prices were going down because demand was weakening as economies slumped. The net impact of the speculators may have been to exaggerate price change movements whether up or down by acquiring or liquidating massive positions in futures. Some maintain that buying and selling in the futures market do not affect cash prices. However, there is a physical connection between cash prices and futures if the two trade with a difference sufficient for a person or company to purchase oil, place it in storage for future delivery, and sell the oil when the futures contract matures. When the difference in the cash and futures price pays for the interest of borrowing money to buy the oil and for the storage costs and yields a profit when the position is unwound or liquidated, then the supply of oil is reduced by the amount of oil tied up in these transactions. A reduction in supply affects cash prices. If acquiring or liquidating huge volumes of short-term derivatives affect cash prices, then financial derivatives whose purpose is to hedge price risk may of themselves, through the actions of speculators, add to price volatility, and in this sense contribute to the very risk they are supposed to mitigate.

It's Not Oil Prices Anymore, It's Oil Security

The British pulled out of the Middle East in 1971, leaving a power vacuum that contributed to the unfolding of events that led to the 1973 oil crisis. Before the 1973 oil crisis, U.S. military presence was limited to providing military weapons and advice to Saudi Arabia and Iran either for cash or as part of a military aid package. After the oil crisis, the U.S. military presence and involvement ballooned. It started under President Carter in 1979 when forces loyal to Khomeini held U.S. embassy personnel hostage for 444 days, a situation worsened by a failed rescue mission. The U.S. Navy was charged with keeping the Arabian Gulf sea lanes open during the long Iran-Iraq War from 1981–1989. Failing to vanquish Iran, and desperate for money to repay loans for military equipment, mainly from the Soviet Union, Saddam cast his eye south to another neighboring state, Kuwait. Furious that Kuwait had refused to cancel Iraq's debts as he had requested and short on funds, the temptation to take over Kuwait's enormous oil fields proved more than he could resist.

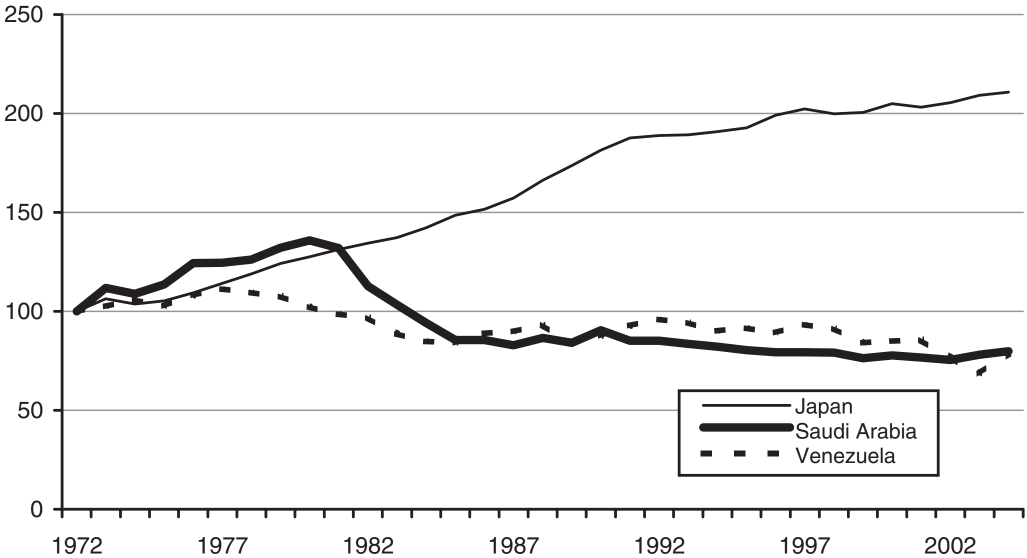
The United States led the coalition forces in the first Gulf war of 1990–1991. The retreating Iraqi forces set fire to Kuwait's oil fields, creating an environmental disaster in their wake. U.S. military presence in the Middle East remained strong between the first and second Gulf wars. In 2003, it was Iraq's turn to be devastated. Now, with occupying troops in Iraq, the United States is a de facto OPEC member. President George Bush's policy of transforming Iraq to an island of democracy in a sea of autocracy, led by a stable government capable of keeping the terrorist elements at bay, now has to succeed under President Obama. There is no alternative. If this policy fails and terrorists seize control of Iraq, there will be no oil security anywhere in the Middle East.

When examining the current situation in the Middle East, one should consider the lasting benefits of the oil producers finally receiving just compensation for their oil exports. Although living standards have increased in Kuwait and the smaller Gulf producers, can the same be said of Iraq, Iran, Nigeria, and Venezuela? Wars and corruption have taken their toll. Figure 5.5 is the per capita gross domestic product (GDP) of Saudi Arabia and Venezuela, the founding nations of OPEC, and Japan, a leading oil importer, indexed at 100 in 1972. Admittedly, this may not be the best way to determine whether the population has benefited from higher oil prices, but it is at least an indication of the pace of internal development of a nation's capacity to produce goods and services.[22]

The chart shows that per capita GDP contracted in Japan immediately following the price hikes in 1973, then resumed its upward course despite the high price of oil. Ironically, the Japanese benefited from the oil crisis even though they import all their energy needs. In the early 1970s the Japanese were producing higher-quality, more fuel-efficient automobiles than the mediocre gas guzzlers being sold at that time in the United States. In the wake of the oil crisis, the Japanese succeeded in capturing a significant share of the U.S. automobile market, which they managed to keep after Detroit began producing higher-quality automobiles with better gas mileage. Per capita GDP for other nations in Asia, particularly the Industrial Tigers, which include South Korea, Taiwan, Singapore, and Hong Kong, would show an even more dramatic rise.

For the oil exporters, Saudi Arabia and Venezuela, per capita GDP expanded in the years immedi-

Figure 5.5 **Per Capita GDP in Japan, Saudi Arabia, and Venezuela Since the 1973 Oil Crisis**



ately following the 1973 oil crisis, particularly for the former. However, these gains began to evaporate during the era of high oil prices and continued to erode during the era of moderate oil prices. What is surprising is that the decline in per capita GDP has fallen below 100. This implies that these nations are producing fewer goods and services now on a per capita basis than they were before the oil crisis. However, this does not necessarily mean a lower standard of living because per capita GDP may not entirely reflect the portion of petroleum revenue that is distributed to the people in the form of social, educational, and medical services. The falling per capita GDP does imply an increasing dependence on oil revenue to sustain living standards. This can be blamed on an understandable, though not a constructive, attitude that people in oil-exporting nations should not have to work. Perhaps the oil producers should heed the shah's advice that Westerners should learn to work harder.

Another contributing factor for the declining per capita GDP in Venezuela and Saudi Arabia is their booming populations. The population of Venezuela has more than doubled, from 11 million in 1972 to 26 million in 2008, while the population of Saudi Arabia has more than tripled, from 6.6 million in 1972 to nearly 28 million in 2008. GDP would have to double for Venezuela or triple for Saudi Arabia simply to keep per capita GDP constant. Part of Venezuela's decline in per capita GDP in the early 2000s was a consequence of civil unrest. Perez Alfonso, principal architect of OPEC and Venezuelan oil minister in the 1970s, wrote that oil was the "devil's excrement" and would eventually ruin Venezuela. Maybe he will be proven right. Venezuela, Iran, Nigeria, Mexico, Russia, and perhaps other oil exporters need high-priced per barrel oil to fulfil the social promises that they've made to their people. Political instability in these nations may occur if there were a prolonged period of low oil prices.

OIL AND DIPLOMACY

Oilmen, most of whom have engineering backgrounds, often end up playing a diplomatic role to protect their investments in foreign nations. An excellent example before the 1973 oil crisis occurred when Great Britain imposed a trade embargo against the then-existing nation of Rhodesia (now Zimbabwe). South Africa deemed such an embargo illegal for the oil companies operating in South Africa. No matter what BP and Shell did, as British companies operating in South Africa, they were breaking someone's law. If they continued to trade with Rhodesia, they violated British law. If they stopped trading, they violated South African law. During this period of apartheid, Shell was despised by the general public for dealing with South Africa and, perversely, reprimanded by the South African government for its practice of hiring, training, and giving blacks positions of responsibility and authority in violation of apartheid. As a result, Shell found itself breaking the law in both Britain or South Africa and, simultaneously, being criticized by outsiders for having investments in South Africa, and by insiders (the South African government) for not upholding the spirit of apartheid.[23]

Another time when oil companies found themselves on the proverbial horns of a political dilemma was during the Yom Kippur War in 1973, when U.S. oil companies had to enforce an embargo of Saudi crude to America. The challenges of oil companies operating in foreign nations remain no less daunting. Helping Russia to reopen its oil resources has put oil companies at loggerheads with the government over its practice of unilaterally changing tax laws and terms of contractual agreements, with no means of judicial appeal, and restrictions on the rights of minority shareholders in Russian corporations. Oil company executives and Russian government officials have had to work together to come to some sort of compromise that affects Russian laws on taxation, the nature of contracts, and judicial appeal, and the rights of minority shareholders before major investments could be made. The laying of pipelines in the Caspian Sea region brings oil companies in contact with governments hostile to one another through which the pipelines must pass. Tariff structures, security measures, and ways for resolving disputes have to be just as carefully planned as selecting the pipeline route and engineering its construction. Resolving the conflicting interests of different peoples and governments to determine a fair share of the benefits of oil exports for the people and their governments, along with the participating oil companies, still poses enormous challenges.

OIL AND ENVIRONMENTALISTS

In more recent times, oil executives have had to learn to deal with environmental groups that have learned ways to pursue their agendas other than public communication media and demonstrations. Shell's plans to dispose of an abandoned North Sea oil platform were changed by environmental groups lobbying for a government ruling that resulted in a different and far more costly means of disposal. In addition to being active in sponsoring environmental laws, environmental groups have learned to gain their objectives through loan covenants, conditions that have to be satisfied before funds can be advanced. In response to environmental group lobbying, the World Bank imposed environmental conditions as loan covenants that affected the construction of two pipeline projects; one for moving oil from an oil field in Chad to a port in Cameroon and the other for moving oil in Ecuador from an oil field in the Amazon over the Andes to an exporting port. These loan covenants ensured that a portion of the oil revenues would be paid directly to indigenous peoples, along with changes in pipeline routing to deal with environmental concerns. Both the government oil companies and those building and operating the pipelines had to agree to comply with these loan covenants to obtain World Bank financing.

The environmentalists point to oil as being primarily responsible for pollution, along with coal. Pollution-emission regulations, a concept that no one can really oppose, can pose significant operational challenges for the oil companies. Yet these seemingly insurmountable barriers to their continued existence are surmountable. The oil companies have learned to cope, if not thrive, in this changing business environment. The "Beyond Petroleum" of BP, which must sound sacrilegious to the ears of oilmen of yore, is recognition that oil companies must operate in an environmentally friendly way and consider issues beyond their focus on oil.

Of course, this world of environmental concern exists mostly in North America, Europe, Japan, Australia, and New Zealand. The rest of the world is more interested in making economic progress without any overdue sensitivity over adverse environmental consequences, as epitomized by the nonreaction of most Asian nations to a brown cloud of pollution that hangs above a large portion of the continent. Nevertheless, oil companies must respond to environmental challenges in the quality of their product and in the nature of their operations or face a daunting public relations challenge.

ROLE OF OIL COMPANIES AFTER THE OIL CRISIS

Although the oil companies were literally thrown out of producing nations after the oil crisis, there has been a return to the situation that existed prior to the oil crisis. Oil companies are, to widely varying degrees, involved with oil production with nearly all the producers that had previously nationalized their oil fields and facilities. The major difference is that the accounting entries for oil reserves in OPEC nations have been obliterated from oil companies' books. These were always fictional because the oil fields were located outside the nations of domicile of the oil companies. The oil companies never had any legal recourse to protect their property rights against actions taken by host governments. This makes ownership a spurious claim, to say the least.

National oil companies operate under encumbrances that Big Oil does not have. National oil companies are limited in their activities to exploiting a nation's wealth of oil and natural gas and, by government fiat, do not and cannot look outside the box. Most national companies are not run as government bodies even though they are wholly owned by their respective governments. Normally, they operate as quasi-independent oil companies. While some have managed their nations' energy resources and infrastructures quite well, others have a less than sterling record. Some oil-exporting nations are looking at privatization, at least in part, as an alternative to a nationalized oil company or to introduce a taste of competition to reinvigorate a moribund organization. Lest we forget, *privatization* would not be a word had it not been for the failure of government-owned companies to deliver goods and services that they were set up to provide.

While national oil companies do not worry about making a profit or surviving in an extremely competitive world, their financial life is not one of idle comfort. National oil companies are the chief revenue generators for many oil-producing nations and they have to fight over every dollar with their exclusive shareholders, their national governments. National oil companies sometimes come up short in the struggle over whether a dollar of revenue should be spent supporting a social program, funding a government expenditure, or being plowed back into the oil infrastructure. Some national oil companies are short on funds needed to maintain oil productivity, others lack technical expertise to expand their oil infrastructure or have limited access to markets. Having chased the oil companies out with a broom, oil companies are back under a variety of contractual arrangements to assist national oil companies with capital infusions, technical expertise, and market access. Since these are the same functions oil companies provided before their oil reserves and properties were nationalized, the circle has been closed.

Oil companies have learned that what counts is not who owns the oil fields but who has access to the oil. Access is provided under a variety of joint venture and production-sharing agreements with the producers. These agreements would not be necessary if the national oil companies could fully replicate the oil companies' contributions in capital, technology, and market access. Having said that, some oil producers have been successful in becoming more integrated by acquiring refineries and service stations in consuming nations and tankers to ship their oil. Kuwait purchased Gulf Oil's refinery and distribution system in northern Europe. Venezuela purchased refineries offshore and in the United States and owns a chain of gas stations in the United States. Both nations have tanker fleets to transport a portion of their oil exports. These investments assure Kuwait and Venezuela of outlets for their oil exports and secure transportation. These moves by producing nations to become integrated oil companies have not diminished the role for the major oil companies and hundreds of independents in the global oil business. Just as Marcus Samuel remarked, there is room for both Shell and Royal Dutch to succeed in an expanding Asian oil market (although he may have lived to regret that remark), so too is there room for government and privately owned oil companies to succeed in an expanding world oil market.

A Changing World

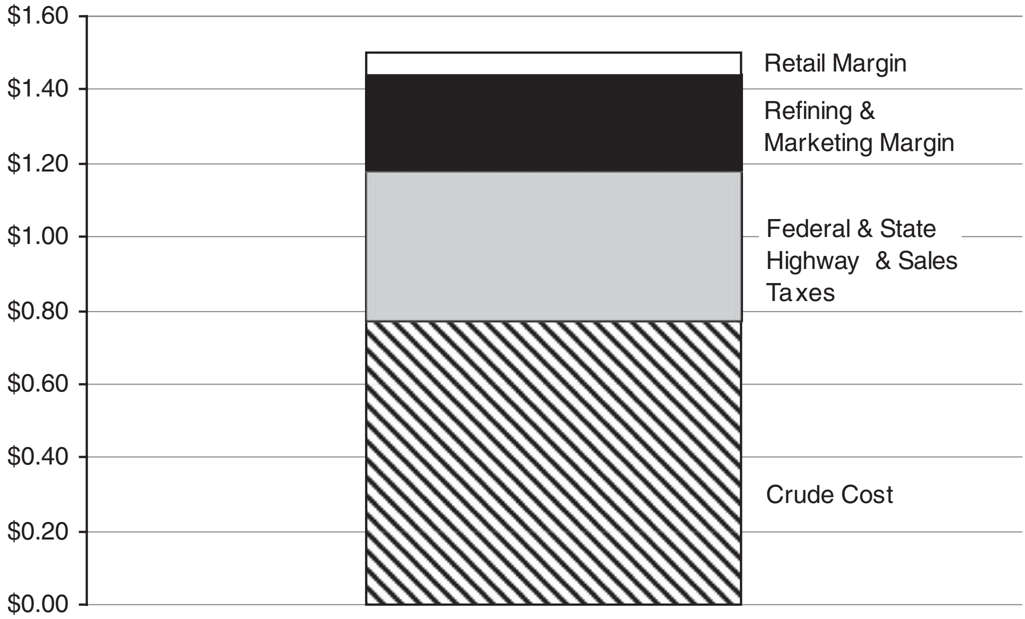
The world of the twenty-first century is different for the oil companies, but in one respect it is easier: they need not worry about pricing. That is no longer in their hands, or not nearly as much in the hands of the oil producers as they would like; that role has been taken over by the immutable laws of supply and demand. Moreover, they are no longer concerned about ownership of oil in foreign lands as long as they have access to that oil. Before the oil crisis, the goal of the oil companies was to reduce costs, that being the price of crude oil. The irony is that profits are not based on costs but on the spread between the price of oil products and the cost of crude oil. It does not matter what the cost of oil is as long as the margin can be maintained. In addition, an oil company can enter into a variety of contracts and financial derivatives such as swaps, futures, and forwards to hedge against the risk of an adverse change in oil prices.

One can expand this concept to the environmental cost of doing business. It does not matter what incremental costs are placed on an oil company's operations to safeguard the environment as long as every oil company is bearing the same cost. Then it becomes just another cost of doing business, such as the cost of crude oil or the obligation to pay taxes, all of which are simply passed on to consumers in the form of higher prices. Ultimately, it is the consumer who pays for higher-priced crude, increased environmental costs, and additional tax burdens. As long as these are approximately equally borne by all oil companies and can be passed on to consumers, why should the oil companies care? All they have to focus on is maintaining their margins, which in the last analysis means covering their costs. Furthermore, they really do not have to be overly concerned about security of supply. Before the 1973 oil crisis, it was not a significant concern and, since the crisis, the responsibility has been assumed by the taxpayers who foot the bill for an American and Allied military presence in the Middle East.

Are Oil Companies' Margins All That Great?

Some politicians accuse oil companies of making unconscionable profits. Oil companies do make a lot of money in the tens of billions of dollars. In Figure 5.6, the retail margin of six cents per gallon is mainly for gas station operators, which are normally not owned by the oil company. The profit has to be embedded in the 26 cents per gallon for refining and marketing.[24] For oil-producing companies, excluding refiners, profits are also made for producing crude. The normally accepted estimate for after tax profits is ten cents per gallon or less.[25] The other interesting fact is that oil companies are major contributors to federal and state tax receipts as shown in the

Figure 5.6 **Cost Factors of a U.S. Gallon of Regular Gasoline in 2008**



highway and sales taxes paid on every gallon of gasoline, taxes on profits, and payments to the government for oil leases. Governments make far more in revenue on a gallon of gasoline than do oil companies.

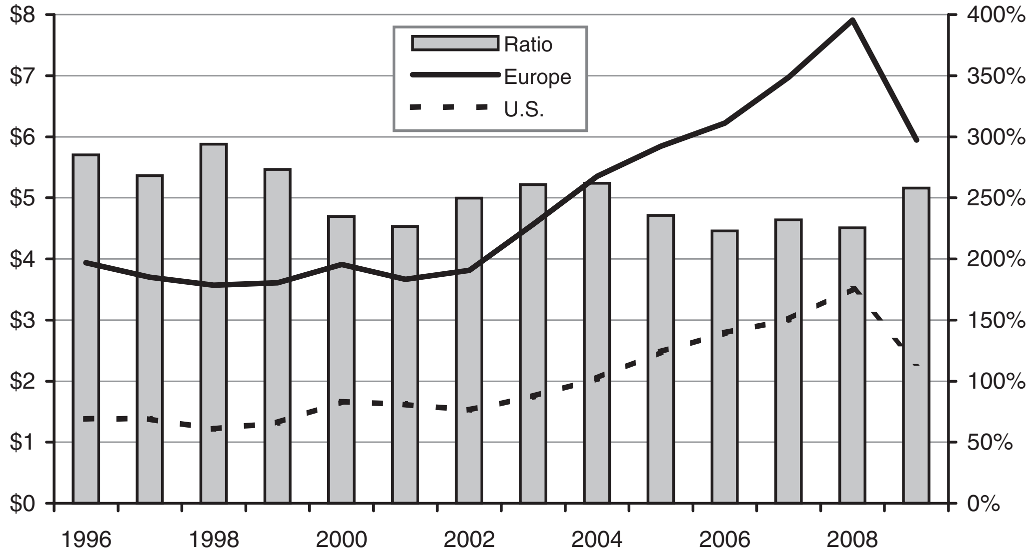
Figure 5.7 shows the comparison between European and American prices. Europeans pay between 2–3 times what Americans pay for gasoline, and motor vehicle fuel taxes are an important source of revenue for European governments.[26] This is the primary reason why Europeans prefer fuel-efficient, smaller-sized automobiles and are more sensitive about their driving habits. European oil consumption in 2008 was about the same as in the early 1990s.

European governments still make far more in tax revenue from selling a gallon of gasoline or diesel fuel than the oil producers get for selling a gallon of a depleting natural resource; one of the justifications of the price hikes in 1973. As a point of comparison, mineral waters sell at a substantial premium to gasoline. When one compares the effort to explore, develop, refine, distribute, and market one gallon of gasoline with the cost of bottling one gallon of mineral water plus taking into consideration the amount paid to governments in the form of sales and highway taxes and paid to the producing nations for the crude, the oil industry has got to be one of the most efficiently run operations on Earth. We get far more on the ten cents per gallon we pay the oil companies than the dollar or more we pay the oil producers.

Future Role of Oil Companies

Most oil companies specialize in some facet of the oil business. They have neither the capital nor the technical expertise nor the desire to explore energy alternatives outside the oil box. Big Oil is a relatively small group of publicly traded corporations that play a paramount role in finding and

Figure 5.7 **Average Annual Price of Gasoline Europe vs. U.S. ($/Gallon)**



developing large oil fields and in refining and marketing oil. Unlike smaller oil companies, they have an eye on the future of energy with or without oil. Big Oil is aware that the energy business goes beyond getting crude out of the ground and gasoline into a tank. They realize that the era of oil may draw to a close much as the era of biomass in the nineteenth century and the era of coal in the twentieth. This is not to say that oil will disappear any more than biomass and coal have disappeared. The major oil companies are investing in the development of alternative fuels. If not enthusiastic endorsers of developing alternative energy technologies, they are certainly cognizant of their own well-being. Oil is but one facet of the energy industry, and if the role of oil changes Big Oil wants to be part of that change. This is the only way they can ensure their survival as major players in the energy game.

Big Oil's ability to adjust to a changing business environment has been amply demonstrated. They have survived the greatest assault imaginable on their privileged position by losing control over vast oil resources once considered their own. They have also lost the ability to determine the price of oil. Such losses could have led to their demise, yet they are prospering more now than ever before. Once unceremoniously thrown out of oil-producing nations, they have since been invited back by the national oil companies that had taken over their oil fields and distribution and refining assets.

There are some who say that oil is too important to be left in the hands of businesspeople bent on making a buck. Oil should be in the hands of a benign government body that knows best how to serve the wide interests of the people rather than the narrow interests of the shareholders. As alluring as this sounds, the privatization of the ex-Soviet oil industry revealed the outmoded technology, managerial ineptness, and the disregard for the environment of a government-owned and -operated oil company.

Unfortunately, profit has a bad name. For many, all profit means is the right of unscrupulous individuals or companies to gouge the public when the opportunity arises, as was exercised by certain energy traders and merchants who supplied electricity to California during the 2000 energy crisis. Allegations have been made of certain supplying companies holding back on generating electricity to create an artificial shortage that hiked electricity rates. In fairness, the California state regulatory body that established a flawed energy policy and provided poor oversight must bear some of the blame. Nevertheless, this crisis—along with the exposure of executive compensation for certain companies of hundreds of millions at the expense of corporate liquidity and stakeholder value—reinforced the public's generally negative image of corporate executives as profit-gouging, irresponsible, selfish, self-serving gluttons. These accusations arose again in 2008/09 when executives of top financial houses paid themselves aggregate bonuses of billions of dollars for creating what turned out to be pseudo-profits,

Profit means that revenue covers costs. No one can seriously argue against the concept of a public or private undertaking covering its costs; that is, having enough money in the bank to pay its bills. The only objection that can be raised against profits is the degree of coverage. As has been shown, profits made by oil companies expressed in cents per gallon are quite modest in comparison to what consuming governments receive in the form of taxes and what producing governments receive in the form of revenue. The key question is whether we are getting value for what the oil companies charge for their services. By focusing on making money, oil companies have been able to bridge the gap between consumers and suppliers, acting as a neutral third party serving the widely divergent interests of both.

The oil companies' possession of engineering technology, capital resources, and market access cannot be duplicated. If we interpret profits as some excess over costs, which by any measure cannot be considered excessive, then the oil companies should continue to play their historical role of a neutral buffer between consumers and suppliers. If we believe what they report in their annual reports, major oil companies view themselves as energy companies with a particular focus on oil, with that focus subject to change as conditions warrant. If tar deposits in Canada and Venezuela and oil shale deposits around the world become technologically and economically feasible, the oil companies will be there. If another fuel replaces gasoline as the fuel of choice, the oil companies will be part of the transition. Their survival as major global companies hinges on their ability to adapt to changing times. As this chapter readily shows, they have proven their adaptability in the past, and there is every reason to expect that they will do so in the future.

NOTES

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6. James S. Robbins, "How Capitalism Saved the Whales," Web site www.alts.net/ns1625/gesner.html.
7. Unless otherwise noted, the primary source for the life of John D. Rockefeller is Grant Segall's, *John D. Rockefeller: Anointed with Oil* (New York: Oxford University Press, 2001).
8. John D. Rockefeller, Jr.'s philanthropic works are described in the June 2004 issue of the *Smithsonian Magazine,* Dorie McCullough Lawson, "Who Wants to Be a Billionaire?"

9. Rockefeller considered Flagler the brains behind Standard Oil. After 1885, and while still a director of Standard Oil, Flagler became a prominent Florida developer in St. Augustine, Palm Beach, and Miami. He also organized the Florida East Coast Railroad, which ran the length of the state from Jacksonville to Miami. He extended the railroad to Key West, which was considered an engineering feat of the day (see www.flagler.org).

10. Unless otherwise noted, the primary source for the life of Marcus Samuel is Robert D.Q. Henriques' *Bearsted: A Biography of Marcus Samuel, First Viscount Bearsted and Founder of "Shell" Transport and Trading Co.* (New York: Viking Press, 1960).

11. James A. Clark and Michel T. Halbouty, *Spindletop* (Houston, TX: Gulf Publishing, 2004). First published in 1952 by Random House.

12. As Lord Mayor, Marcus did what he could to counter pogroms in Romania and Russia, warning the Russian ambassador that continued violence against the Jews would lead to the undoing of the czar.

13. As mentioned previously in the text, Burmah Oil had the unique status of being, in the eyes of the government, the only true British oil company. This mantle was taken over by BP when it became involved with North Sea oil. Burmah Oil would eventually be without oil-producing properties when the Burmese oil fields were exhausted. As a result of speculative investments, Burmah Oil went bankrupt in 1974 and its 20 percent holding in BP was taken over by the Bank of England.

14. Unless otherwise noted, the primary source on the oil business up to the 1973 oil crisis is Anthony Sampson, *The Seven Sisters: The Great Oil Companies and the World They Made* (New York: Viking Press, 1975).

15. Ralph Hewins, *Mr. Five Percent: The Story of Calouste Gulbenkian* (New York: Rinehart & Co., 1958); Nubar Gulbenkian, *Portrait in Oil: An Autobiography of Nubar Gulbenkian* (New York: Simon and Schuster, 1965).

16. Stephen Howarth, *A Century in Oil: The "Shell" Transport and Trading Company, 1897–1997* (London: Weidenfeld & Nicolson, 1997).

17. The statistics reported in Figure 5.1 can be found in *BP Energy Statistics* (London: British Petroleum, 2009).

18. A detailed chronology of events prepared by National Public Radio (NPR), "Gas & Oil Prices: A Chronology," is available at www.npr.org/news/specials/oil/gasprices.chronology.html.

19. *BP Energy Statistics* (London: British Petroleum, 2009).

20. The primary source for the post-1975 history is Daniel Yergin's, *The Prize: The Epic Quest for Oil, Money, and Power* (New York: Simon & Schuster, 1991).

21. Herbert Inhaber, *Why Energy Conservation Fails* (Westport, CT: Quorum Books, 2002).

22. International Monetary Fund, *International Financial Statistics Yearbook* (Washington, DC, 2008); International Monetary Fund, *World Economic Outlook, A Survey by the Staff of the International Monetary Fund* (Washington, DC, 2008).

23. Stephen Howarth, *A Century in Oil: The "Shell" Transport and Trading Company, 1897–1997* (London: Weidenfeld & Nicolson, 1997).

24. California Energy Commission at Web site www.energy.ca.gov.

25. The average oil profit per gallon for 2007 was reported as 10 cents per gallon by the Oxford Club Investment, Web site www.investmentu.com/IUEL/2007/20070323.html, and the Associated Business Press quoted the first quarter of 2008 Exxon's earnings being described as four cents per gallon of gasoline and diesel, down from eight cents per gallon from the previous year's first quarter as listed on Web site www.wmi.org/bassfish/bassboard/other_topics/ message.html?message_id=298879. In the first edition of this book, I estimated that the Shell Group made 8.5 cents per gallon and Amerada Hess made 6.6 cents per gallon on its oil sales in 2003. Ten cents per gallon is a fair estimate in good years for the oil companies, while 5–10 cents per gallon is a fair estimate of overall profitability for more typical years.

26. U.S. Energy Information Agency, Web site www.eia.doe.gov/emeu/international/gas1.html.

6

OIL

This chapter describes the journey oil takes from deep in the earth until it reaches consumers in a wide range of products from plastics to motor vehicle fuels to fertilizers and pesticides. The sojourn starts with exploration and the development of oil wells onshore and offshore, the refining and transportation of oil products, and the use of enhanced recovery methods to get the most out of oil fields. The adequacy of oil reserves to continue to fuel our economy, the potential of nonconventional oil sources, and alternative motor vehicle fuel substitutes are covered. The chapter ends with a discussion of the geopolitical aspects of oil with a call to internalize an externality called oil security.

THE EARTH AS AN OIL MANUFACTURER

Terra firma it is not; the daily chronicle of earthquakes and volcanoes attests otherwise. The earth, with a radius of less than 4,000 miles, has a core with a radius of about 2,000 miles made up mostly of an alloy of nickel and iron. The center of the core is solid with a liquid outer portion. Enormous currents of electricity flow around the core generating the earth's magnetic field, which protects the earth from harmful radiation from the sun and from space. If stripped of the mantle and crust, the core would shine as brightly as the sun, heated by the weight of the overburden and radioactive decay. Between the core and the outer crust is a nearly 2,000-mile-thick mantle of semiliquid rock and metals called magma. Magma is less dense than the core of pure metal, but denser than the crust, which is made largely of rock. Magma is a viscous fluid with upward convection flows of hotter magma from near the core balanced by downward flows of cooler magma from near the crust. There may be an internal structure to magma consisting of gigantic plumes hundreds of miles high. The upper 50- to 150-mile portion of the mantle is called the asthenosphere, which has a chemical composition closer to that of the crust than the underlying magma.

Literally floating on top of the asthenosphere is a relatively thin, brittle crust made up of mainly less dense stone mixed with metals called the lithosphere. The lithosphere is only between four to seven miles deep beneath the oceans and up to sixty miles deep beneath mountain ranges. Its average depth of nearly twenty miles is only 0.5 percent of the earth's radius. Oceanic crust is mostly relatively heavy basalt while the continental crust is mostly relatively light granite. The crust is broken into major segments called tectonic plates including the Eurasian, North and South American, African, Pacific, Antarctic, Australian, Arabian, and Indian plates. There are also smaller plates such as the Philippine plate, the Juan de Fuca plate (off west coast Canada and United States), the Caribbean plate, the Cocos plate (west of Central America), the Nazca plate (west of South America), and the Scotia plate (between the Antarctic and South American plates). These plates separate, collide, or slip by one another in response to underlying flows of magma in the asthenosphere.

We recognize the continents and oceans as major geological features, but so too is the mid-ocean ridge, largely unseen except where it protrudes above the ocean in Iceland and the Azores. Made of two mountain chains separated by a rift valley, the mid-ocean ridge can be up to two miles in height above the ocean floor and as much as 1,000 miles wide. The ridge is 35,000 miles in length and encircles the world like the stitching on a baseball. Tectonic plates along the mid-ocean ridge are separating about as fast as a fingernail grows with new crust formed by upwelling magma from volcanoes and fumaroles. The East African rift marks a plate separation that may one day be a new body of water like the Red Sea; other rifts include Lake Baikal, Rio Grande, and Rhine Graben.

Subduction occurs when two plates collide and one overrides the other, forcing the lower plate back into the mantle to become new magma. Subduction zones are located at ocean trenches such as the Chilean trench and the Marianas trench in Indonesia and are marked by volcanoes. If two tectonic plates collide, but neither is massive enough to cause the other to submerge, a mountain chain may emerge (e.g., the Caucasus and Himalayas). The collision between two plates in the Middle East was not sufficient to create a mountain range or a subduction zone, but folds in the rock capable of trapping the earth's greatest concentration of oil and natural gas. A fault is created when plates slip by one another laterally such as the San Andreas fault in California. Faults and folded rock are critical in the formation of oil reservoirs.[1]

The original theory of the origin of oil in the Western world was that it came from dead animal matter, but a cemetery, where bodies decay and turn to dust, is not a future oil field. For the earth to manufacture a fossil fuel, the decaying process must be interrupted either by dead plant and animal matter falling into oxygen-starved waters or rapid burial. It was once thought that oil came from dinosaurs, the symbol of Sinclair Oil. This theory has been discredited because the earth could not possibly have sustained a population of dinosaurs, even over millions of years, large enough to create so much oil even if one ignores the special circumstances that must accompany death for dinosaurs to become a fossil fuel. In the twenty-first century the accepted theory postulates that ocean plankton, algae, and other forms of simple marine life die and sink into oxygen-starved waters that prevent further decay. Sediments from rivers mix with the partially decayed matter to form an organically rich concoction. Continued burying by more layers of sediment squeezes out the water, and when buried by a mile or more of new sediment over millions of years, the original sediment is transformed to sedimentary rock and the organic matter to oil.

Based on this hypothesis, a favorite place to explore for oil is near river mouths such as the Mississippi and Niger rivers, where shifting deltas and rising and falling sea levels over millions of years have created widespread oil and gas deposits at various ocean depths. Geologists look for what appear to be buried river mouths in sedimentary rock for likely places to drill. A location where oil and natural gas may be in the making is the Bosporus, where Mediterranean water enters the Black Sea. Dead and dying marine organisms sink to the bottom and mix with the sediments in oxygen-starved waters. If buried by a mile or more of overburden during the next many millions of years (a scenario that requires the Black Sea to drop by more than a mile or the land around the Black Sea to rise by more than a mile, or some combination of the two), then the sediment will be transformed to rock and the entrapped organic matter to oil. Then a new budding oil field can await discovery by a petroleum geologist yet to be born eons from now.

The crust has three general types of rocks. Upwelling magma, when cooled, becomes igneous (fire-formed) rock such as granite and basalt. Deeply buried igneous or sedimentary rocks, subject to enormous heat and pressure, can be transformed into metamorphic rocks such as marble and slate. From a Western petroleum geologist's point of view, the presence of igneous and metamorphic basement rock underlying sedimentary rock is good reason to stop drilling because oil and gas are found only in sedimentary rocks.

Two of the three types of sedimentary rocks are created by erosion, which would level the earth were it not for emergence of new mountain chains from colliding tectonic plates (the Himalayas are still rising as the Indian plate continues to plow into the Eurasian plate). Wind, rain, and flowing water are the principal agents of erosion. When water seeps into cracks and crevices of rock and freezes, it expands, fracturing the rock and making it more vulnerable to erosion. The debris of erosion suspended in flowing water is another powerful force of erosion that can cut deep gorges into solid rock. When carbon dioxide in the atmosphere mixes with water, it forms dilute carbonic acid that eats away at limestone and forms underground caverns. Finally, the debris of erosion, as gravel, sand, and clay, is deposited in river deltas. Other sources of sediment are shells of dying plankton deposited on the ocean floor and the precipitation of dissolved calcium carbonate from evaporating seawater in shallow lagoons. Under sufficient pressure from overburden, and with calcium carbonate and silica acting as cementing agents, gravel is transformed into a conglomerate, sand to sandstone, clay to shale, lime mud to a gray to black limestone, and microscopic seashells to white limestone called chalk, such as the White Cliffs of Dover. The most common form of sedimentary rock is shale and the most common form of petroleum reservoir rock is sandstone.

The compressive force of plate movements near subduction zones creates folds in hot, plastic sedimentary rocks. An upward fold is called a syncline and a downward fold is called an anticline. Anticlines are shaped like an upside down or inverted bowl and faults (breaks in sedimentary rock layers caused by tectonic plate slippage) of nonpermeable rock (or caprock) form traps to prevent oil and gas from completing their migratory journey to the earth's surface. If they are not trapped, natural gas and the lighter components in oil evaporate as they migrate toward the earth's surface, finally emerging as a viscous crude or thick tar called seep oil.

Different types of sedimentary rock layered one on top of the other are on display at the Grand Canyon, each with a unique geological origin. A typical cross-section of the earth contains a mile of sedimentary rock with about 100 layers of various types of sedimentary rocks underlain by a basement of igneous or metamorphic rock. Sedimentary rock layers on the ocean floor are only about one-half mile thick on average, with the thinnest at the mid-ocean ridge, becoming thicker as the ocean floor approaches the continental shelf. The thickest sediments (about ten miles in depth) are located on continental shelves, but can also be found inland. Colorado is one such place where sedimentary rocks were formed when that area of the world was covered by a shallow sea. Glaciers can strip basement rock of their sedimentary rock cover as occurred in eastern Canada and New York's Central Park. Drilling for oil in Central Park would be useless: no sedimentary rock, no oil. Even with the earth covered by a mile of sedimentary rock, the presence of sedimentary rock does not mean the presence of oil. The secret to success in oil drilling is identifying traps overlain with nonpermeable caprock and underlain by sedimentary rock whose pores, or spaces between the grains, are saturated with oil and natural gas.

Sedimentary rocks buried deep in the earth were originally made from debris from eroding mountains or the deposition of shells from marine life. These rocks may one day be uplifted by colliding tectonic plates and again become mountains vulnerable to erosion. The rough jagged peaks of the Alps, Rockies, Andes, and Himalayas are geologically new compared to the far older rounded Urals and Appalachians. As new and old mountains erode, their sediments are deposited in river deltas, which if buried by a mile of overburden, become new sedimentary rock, which over time may be thrust up again as a recycled mountain range. The Himalayas are such a range where, three to five miles above sea level, marine fossils can be found in sedimentary rock.

FORMATION OF OIL

Dead organic matter must lie in either stagnant, oxygen-free waters at the bottom of the sea until buried or be buried quickly after death and achieve a concentration of 1–3 percent by weight to become a future oil reservoir, although this concentration can be as high as 10 percent. The next step is burying the organically rich sediment deep enough to generate the temperature and pressure necessary to transform organic matter to oil. With 7,000 feet of overburden, the pressure is sufficient to raise the sediment's temperature to 150°F, the minimum to produce a heavy and generally undesirable grade of crude oil. Preferred light crudes are produced as one approaches 18,000 feet and 300°F. Beyond 18,000 feet, the temperature and pressure are sufficient to transform oil to graphite (carbon) and natural gas. The oil window is 7,000–18,000 feet below the surface of the earth, meaning that sediments at river mouths must be buried between 1.5–3.5 miles of debris to produce oil by either the ocean bottom sinking or the surrounding land mass rising or a combination of both. The properties of the oil depend on the type of organism, its concentration, depth of burial, and the nature of the surrounding sediment. Oil properties vary from one field to another and no two oil fields have exactly the same properties. Commercial grades of crude are really a mix of oil from different oil fields in the same region that have similar properties. A few are from different oil fields with dissimilar properties such as Urals, a specified mix of light sweet crude from western Siberia and heavy sour crude from the Ural region of Russia.

Once formed in source rock, oil and natural gas, being lighter than water, begin to migrate laterally and vertically through migratory rock. Oil and gas pass through the pore space within the sedimentary rock structure and through fractures in rock layers. This migration may extend as far as 200 miles from source rock. The rate of migration depends on the porosity and permeability of the migratory rock. Porosity is a measure of the spaces (pores) within the rock that can be filled with fluids (oil, gas, and water), and permeability is a measure of the ease with which a fluid can pass from one pore to the next. Both are critical in determining the flow of hydrocarbons (and water) into a well; generally speaking, the greater the porosity, the greater the permeability. Oil and gas migration continues until interrupted by an intervening rock formation shaped like an inverted bowl or a fault made of a well-cemented rock with no spaces between the grains. Once migrating oil and gas are trapped in reservoir rock, natural gas, the lightest, rises to the top of the reservoir and forms a gas cap; saltwater, the heaviest, sinks to the bottom, leaving oil in the middle. In some reservoirs, a small concentration of natural gas may remain mixed with crude oil without forming a gas cap; in still others, there is no associated natural gas. The subsurface water that makes up the water table is fresh, produced by rain percolating through the soil; but the water beneath the water table is more or less as saline as ocean water.

Contrary to a popular conception that originated with the dawn of the oil age, an oil reservoir does not consist of a void space filled with a pool of oil; rather, it is migratory rock turned reservoir rock, saturated with oil and gas that is prevented from continuing its journey to the earth's surface. The geometry of a trap is one determinant of the size of an oil field; the larger the dome or fault of caprock and the greater the distance from the top of the trap to the spill point (where oil and gas can flow around the caprock and continue migrating to the surface), the larger the size of the potential oil field. Other determinants are porosity, which determines the quantity of oil and gas contained in the reservoir rock, its permeability, which determines the flow of the oil and gas to a well and its potential recoverability, and, of course, the concentration of oil and natural gas in the reservoir rock. Sandstone has the largest pores for the greatest porosity and permeability, followed by limestone, and then shale, which have the smallest pores. Most reservoir rocks are sandstone and limestone, but even here tight sands and dense limestone have low degrees of porosity and permeability.

Salt domes are another mechanism that can trap oil. Salt can be deposited hundreds or thousands of feet deep when ocean water in shallow lagoons, which were periodically connected and disconnected from the ocean, evaporates to form salt pans. These accumulations of salt pans, which can reach depths of thousands of feet, are then buried by a mile or more of overburden. The less dense salt does not begin to flow through the overburden until the overburden has reached a depth where the lighter density salt can exert sufficient thrust to begin flowing through weak spots in what has now become a mile or more of rock. The plug of salt works its way toward the surface, fracturing rock layers along the way and forming potential traps for oil. The top layer of the salt plug becomes a dome of nonpermeable gypsum, limestone, dolomite, or other rock residue left after salt has been leeched out by subsurface waters. Salt dome caprock can be 100–1,000 feet thick and a salt plug can be from one-half to six miles across and extend as much as four miles below the surface. There are hundreds of salt domes in the Gulf of Mexico and the coastal plains of Texas, Louisiana, and Mississippi; most do not trap oil. Spindletop, an exception—with oil trapped below its salt dome of dolomite—was drained after only one year of unrestrained production. It became a new site for oil production when, twenty years later, oil was found trapped in fractured rock along its flanks.

The amount of partially decayed organic or biotic matter that would have to be contained in ocean sediment to create all the known reserves of oil and natural gas might strain one's imagination. In the 1950s Russian petroleum geologists proposed an alternative theory for the origin of oil, but it was and generally still is discredited by Western geologists. The theory was revived in the 1990s when an oil well named Eugene Island 330 suddenly began producing more oil. The well had originally begun production in 1972, and peaked at 15,000 barrels per day. By 1989, production had declined to 4,000 barrels per day. Then, suddenly, production rose to 13,000 barrels per day and estimates of its reserves were revised upward from 60 to 400 million barrels. The well was located near a huge towerlike structure with deep fissures and fractures and the new oil was from an earlier geological age. Seismic evidence seemed to suggest that the new oil was flowing up from one of the deep fissures.

The inorganic or abiotic origin of oil theorizes that there are vast deposits of natural gas in the earth's mantle. Natural gas penetrates the crust and is transformed into crude oil as it rises toward the surface with its properties determined by surrounding rock. As it ascends to the surface, the oil picks up organic matter in the sedimentary rock, which, according to those who support the abiotic theory of oil's origin, explains the presence of organic matter in oil. If natural gas rises close to a volcano, it is transformed into carbon dioxide and steam, gases commonly emitted by volcanoes. The presence of helium in oil and gas, but not in sedimentary rock or organic matter, is put forth as further evidence of an inorganic origin from within the earth's mantle. The most compelling argument against the abiotic origin made by Western petroleum geologists is that they have successfully discovered oil and natural gas on the basis of a biotic or organic origin. Coincidentally, this is the same argument advanced by Russian petroleum geologists who have discovered oil in the base rock beneath sedimentary rock on the assumption that oil has an abiotic origin.

If the abiotic explanation is true, as some earth scientists maintain, then oil and gas may become sustainable forms of energy if the earth produces oil and gas as fast as we consume them. This would have an enormous impact on energy policy if oil and gas were being replenished by the earth or if oil and gas reserves are underestimated by a factor of 100 as suggested by some advocates of an abiotic origin.[2] However, even if the abiotic origin of oil is true, we can still run out of oil in a relatively short time if the rate of production significantly lags the rate of consumption.

OIL EXPLORATION AND PRODUCTION

In the early years of oil, drillers imagined that they were drilling for a pool or an underground river of oil using oil seeps as a guide for where to drill. Such exploration was successful if the surface oil came from an oil reservoir directly beneath the seep. Many seeps offered little reward to the driller as they merely marked the spot where the migratory rock breeched the earth's surface. Drilling straight down missed oil embedded in a layer of migratory rock slanted at an angle to the surface. Since the first oil was found near a creek, early oil drillers followed creek beds, thinking that oil flowed beneath running water. Once oil was discovered, production wells were placed as close as possible to one another to ensure commercial success. Spacing wells more widely apart increased the chance of drilling a dry hole beyond the perimeter of an oil reservoir. This practice—having the greatest possible concentration of wells furiously pumping oil—rapidly exhausted an oil reservoir and another search for seep oil began. Once sites marked by seep oil were exhausted, and the creek theory debunked, oil drillers turned to geologists for advice on prospective sites. Geologists examined the land for hints of the presence of three necessary conditions for oil: (1) source rock to generate petroleum, (2) migratory rock through which petroleum moves toward the earth's surface, and (3) reservoir rock where there is an impediment preventing further migration. Whether sedimentary rock is source, migratory, or reservoir rock is a matter of circumstance.

Early geologists became geophysicists when they started using gravity meters and magnetometers to search for oil. A gravity meter is sensitive to the density of rocks below the surface. A mile of sedimentary rocks on top of basement rock is dense compared to a salt dome or a layer of porous reef or lighter rocks, which are detectable as anomalies or variations in gravity. Gravity meters were particularly useful in discovering salt domes in Louisiana and Texas during the early 1900s and in the 1948 discovery of Ghawar, the world's largest oil field, in Saudi Arabia. Magnetometers, because they are sensitive to anomalies or variations in the earth's magnetic field generated by magnetite in basement rock, are useful for estimating the thickness of overlying sedimentary rock. Both gravity and magnetic anomalies may indicate an anticline or fault that holds an oil reservoir.

Seismic analysis measures the time interval between creating a sound burst and the return of its echo from a subsurface geological structure embedded within sedimentary rock capable of reflecting sound. Seismic analysis is very useful in identifying potential traps. Dynamite was first exploded in shot holes dug through the surface soil to solid rock. The shot holes were laid out in geometric patterns to get a better idea of the subsurface structures. Later, explosive cord was used in a trench about one foot deep or suspended in air. Nowadays, seismic work on land may utilize a specially-rigged truck that lowers a pad to sustain most of its weight. Hydraulic motors in the truck vibrate the ground, creating sound waves whose echoes can be analyzed for subsurface structures.

Seismic surveys on land are often conducted in difficult, inaccessible, inhospitable, and often unhealthy terrain such as jungles, deserts, mountains, or tundra. Seismic surveys are easier to conduct at sea. An array of pressurized air guns towed by a seismic boat is fired and the returning echoes are recorded by hydrophones, also under tow. The geometry of the array of air guns, their size, and sequence of firing are arranged to obtain a high signal-to-noise ratio of any returning echoes to more easily identify subsurface structures. Though the first successful use of a seismic survey occurred in 1928 when an oil field in Oklahoma was discovered, seismic analysis did not reach its full potential until after the Second World War with the advent of computers capable of processing the enormous volume of data contained on a digital magnetic tape.

The first seismic pictures were two-dimensional (2-D) vertical views of what was beneath the ground. While this was valuable information in itself, a better picture of the size of a potential oil field would emerge if its horizontal dimensions were known. This could be obtained by taking a series of 2-D seismics; but by the 1980s, computer-processing speed, data storage capacity, and software programs had advanced to the point of being able to digest and analyze the mountain of seismic data necessary to obtain a three-dimensional (3-D) view of a subsurface structure. A 3-D seismic on land involves parallel receiver cables with shot points laid out perpendicular to the receiver cables. At sea a vessel, or several vessels sailing in parallel formation, towing several lines of air guns and hydrophone receivers collects the requisite data. Once processed, an underwater subsurface structure can be rotated on a computer screen in order to assess its shape in terms of length, width, and depth from any angle. Though 3-D seismics are costly, they are also cost-effective because they lower the probability of drilling unsuccessful exploratory oil wells, reduce the need for development wells to determine the size of an oil field, and make it possible to plan the placement of production wells to effectively drain a reservoir. Three-D seismics can identify natural gas reservoirs by the unique sound reflections of natural gas in rock. Four-D seismics are a series of 3-D seismics taken over time to assess the remaining reserves of a producing field.

Drilling Rights

The United States and Canada are unique in permitting individuals and companies to own both the surface and the subsurface rights of land. All other nations consider subsurface minerals the property of the state regardless of who owns the surface land. In the United States and Canada, surface rights to build a house or farm the land can be separated from the subsurface rights to explore and develop mineral finds. If separated, a lease agreement has to be reached between the owners of the surface and subsurface rights with regard to access to the land, the conditions for exploration and the development of any discovered minerals, including oil and gas. Lease agreements usually contain a bonus payment on signing and a royalty payment to be paid to the owner of the surface rights if minerals, including oil and gas, are found and stipulate a time limit for the start of exploration. If exploration has not started by the time established in the lease, the lease becomes null and void and the subsurface mineral rights revert to the owner of the surface rights. Leases can also be farmed out to third parties who conduct exploration, and working interests can be sold to third parties to raise funds to develop an oil or mineral find.

Large portions of the United States and Canada are not owned by individuals, but by the federal governments. In the United States, the federal government holds auctions for mineral rights on its land holdings and offshore waters. Rights to drill on blocks on the continental shelf, whose depth is within the capability of offshore drilling rigs, are offered periodically in a closed-bid auction. The highest bidder has a five- or ten-year period, depending on the depth of the water, to begin exploration or the mineral rights revert back to the federal government. The U.S. government receives a one-sixth royalty if oil is found. Canada has different rules that vary among the provinces. In addition, if oil is discovered on land, there are government regulations on the spacing of production wells to avoid overproduction, the fruit of the bitter lessons learned from the early exhaustion of oil fields in western Pennsylvania, Spindletop, and elsewhere. Of course, providing a long-term optimal return on a costly investment is also a strong guiding force for oil field managers in determining the spacing between producing wells.

For the rest of the world, governments own the mineral rights regardless of who owns the surface land. Oil companies normally enter into individual or collective contracts with governments or their national oil companies for the three phases of oil and gas operations: exploration, development, and production. The type of contract most commonly used before the oil crisis in 1973 was an exclusive concession granted to an oil company for a defined geographic area. The oil company bore all risks and costs and the host government received some combination of bonuses, taxes, and royalties if oil and natural gas were discovered. Since the oil crisis, the most common form of contract has been the production-sharing contract that was first written in Indonesia in

1966. Again, the oil company bears all risks and costs. The oil company explores for oil, and, if it is successful, develops the oil field for production. A large share of the initial oil and gas revenue is dedicated to the recovery of exploration and development costs. After these costs, with a stated rate of return, have been recouped, the oil company and the host government, usually through its national oil company, share the remaining revenue. Some contracts have the host government's national oil company bear a portion of the costs and risks of exploration and the responsibilities of development. Service contracts are payments to oil companies for services rendered in exploration, development, or production, with the profits of production residing solely with the host government. However, a host government may provide incentives to the oil company for meeting certain goals, and, from this perspective, the oil company shares in the profits. Of course, some national oil companies prefer to go it alone without assistance from Western oil companies.

Drilling Equipment

There are three types of wells: exploratory or wildcat wells, appraisal or development wells, and production wells. Wildcat wells are drilled a significant distance from known oil fields in search of new oil. This is the pure gambling aspect of oil. Less risky exploratory wells are drilled near existing oil fields to see if they extend in one direction or another. If oil is discovered, then the development phase of an oil field begins with the drilling of appraisal, or step-out, wells to measure the extent of an oil field and determine the number and placement of production wells. Appraisal wells are normally abandoned after an oil field has been evaluated. Drilling onshore or offshore is similar, with the major difference being the nature of the drilling rig and in having from several hundred feet to two miles of drill pipe between the rig and the well bore.

Cable-tool rigs have a long history for drilling for freshwater or brine, which was evaporated for its salt content. By the time of "Colonel" Drake, the founding father of the oil industry, a cable-tool rig was a four-legged wooden tower, called a derrick, between seventy-two and eighty-seven feet high. A steam engine drove a wooden walking beam mounted on a Samson post that created an up-and-down motion. A chisel-pointed steel cylinder, or bit, about four feet in length, attached by a cable or rope to the walking beam, pulverized the rock at the bottom of the well. Every three to eight feet, the bit was raised and a bailer lowered into the well to remove the rock chips. Drake was the first to use a cable-tool rig to drill, not for freshwater or brine, but for oil. He was also the first to install a casing of large diameter pipe in the well to keep water from filling the well and to prevent the sides of the well from caving in, a practice still in use today.

The advantage of the cable-tool rig was its simplicity of design and operation, requiring only two or three men (a driller, a tool dresser, and maybe a helper). The disadvantage was that it was slow, averaging about twenty-five feet per day depending on the type of rock. While rotary drilling bits had been used to drill for water as far back as the early 1820s, the cable-tool rig was exclusively used to drill for oil after Drake's discovery. Captain Lucas, developer of Spindletop, is credited with the first use of a rotary rig for oil exploration, where cable-tool rigs could not drill to the desired depth in the soft, sandy soil. The Hamill brothers, employed by Lucas, were major innovators in rotary rig operations. The rig employed at Spindletop, while primitive by contemporary standards, possessed the essential elements of a modern rotary rig. Early rotaries required five or more people to operate and were much more efficient in drilling a hole than a cable-tool rig.

The modern tricone rotary drilling bit, exclusively in use today, is capable of drilling hundreds or a few thousand feet per day depending on the type of rig and the nature of the rock. A rotary drilling bit is a fixed attachment at the end of a drill string, rotated by rotating the entire drill string. The invention of the tricone rotary drilling bit in 1908 by Howard Hughes, Sr., founder of

Hughes Tool Company, with its greater productivity should have spelled the instant death of the cable-tool rig, but it did not. Drilling with a rotary drilling bit requires more costly equipment and a larger and more knowledgeable crew, making it more expensive and complex to operate. Despite its higher productivity, as late as 1950, half of the drilling rigs in the United States were still cable-tool rigs. Desperately in need of replacement after being idle during the Great Depression of the 1930s, and worn out by operating without spare parts during the Second World War, cable-tool rigs quickly passed from the scene by a massive conversion to rotaries. This greatly benefited Hughes Tool and the son of its founder, Howard Hughes, Jr., the infamous billionaire Hollywood movie producer, aircraft designer, mining mogul, casino owner, front for a government secret mission to raise a sunken Soviet submarine, tax evader, and ladies' man, who died a bitter and mentally disturbed recluse in 1976. The lesson with Hughes is that one does not have to discover oil to become an oil billionaire. Maybe there is another lesson. . . .

When drilling on land, the ground is first prepared to support a rig and a cellar is dug into the ground in preparation for the conductor casing. For shallow wells of up to 3,000 feet, the rig can be mounted on the back of a truck. For deeper wells, the rig is broken down into segments, transported by truck, and reassembled at the site. The deeper the well, the stronger the rig has to be to support and pull out the drill string. Drilling a well starts with drilling, called spudding, a hole twenty to one hundred feet deep to cement in a conductor casing of up to twenty inches in diameter. The conductor casing stabilizes the top of the well and provides an anchorage for the blowout preventer, which, as the name suggests, is a sure-fire way to seal a well against a blowout of natural gas and oil.

A cable passing through the topmost crown block of a rig is connected to a kelly (a very strong four- or six-sided molybdenum steel pipe forty or fifty-four feet in length) by a swivel. The sides of the kelly are gripped by a rotary table turned by electric motors powered by diesel engines of 1,000–3,000 horsepower. Attached to the kelly is drill pipe in lengths from eighteen to forty-five feet, but most commonly thirty feet. Every thirty feet, drilling is stopped to add another length of drill pipe below the kelly. The outer diameter of drill pipe varies between three and six inches. Drill pipe nearest the bit is heaviest in gauge to provide additional weight to control drilling and prevent the drill string from kinking and breaking.

The tricone drill bit is a solid fixed cone at the bottom of the drill pipe with three counter-rotating sets of teeth of steel, or high-grade tungsten carbide steel, or industrial diamonds, depending on the type of rock and the speed of drilling. The well bore is larger in diameter than the drill pipe to allow the drill pipe to rotate and slide up and down in the well. The drill string, driven by the kelly, rotates fifty to one hundred turns per minute, enabling the teeth of the drill bit to pulverize the underlying rock. The teeth on the drill bit wear out after 40–60 hours of use on average, but can last as long as 200 hours, depending on the type of rock and the type of teeth. The success of the tricone drill bit was that it lasted much longer than previous bits, sharply reducing the number of trips that had to be taken to replace the drill bit. The increased drilling productivity allowed Hughes to charge a premium price for his bits and, thereby, amass a large fortune.

Tripping out refers to the process of pulling the drill string and unscrewing each length of pipe for stacking in the derrick. For an offshore drilling rig that is floating on mile-deep water and drilling a well two miles into the earth's crust, tripping out requires pulling up and disconnecting three miles of drill pipe. For deeper waters and wells of greater depth, this may mean up to eight miles of pipe, a length at the current limits of drilling technology. After a new bit is attached, the reverse process of *tripping in,* or connecting from three to eight miles of pipe, is performed, so that during an entire trip six to sixteen miles of pipe must be handled. Taking a trip is dirty, tough, and dangerous work; no wonder the workers are called roughnecks. Drilling is a twenty-four-hour, seven-day (24–7) operation requiring three shifts of workers working eight-hour shifts, or two shifts of workers working twelve-hour shifts plus spare shifts to give the workers time off.

Drilling mud, which carries away the debris of pulverized rock from the bottom of the well, is forced down the center of the drill pipe and passes through the middle of the tricone bit. The mixture of mud and pulverized rock is forced to flow up the annulus, the space between the drill pipe and the walls of the drill hole or well bore. Separators on the surface remove rock chips so that the mud can be recycled. Drilling mud, first introduced by the Hamill brothers when they drove cows through a mud pit at Spindletop, is now a science. Mud consists of a mixture of clay, weighting material, and chemicals mixed with water or diesel oil. Bentonite clay remains suspended in water for a long time after agitation and adding barite or galena controls drilling mud's viscosity and weight. Viscosity affects how fast the mud can pass through the tricone bit and the weight of the mud, along with the weight of the drill pipe, must exceed the pressure of oil, gas, or water in the well to prevent a blowout. Depending on the circumstances, it may be necessary to add bactericides, defoamers, emulsifiers, flocculants, filtrate reducers, foaming agents, or a compound to control alkalinity. When drilling through soft or porous rock, rising mud can penetrate the surrounding rock to strengthen the sides of the well and form a seal, preventing subsurface fluids from flowing into the well.

Nothing about drilling is easy. One of the many challenges facing a driller is the possibility that the drill string might bend and bind itself to the well wall or break as a result of metal embrittlement, which occurs when hydrogen sulfide enters a well. Nothing is more risky. Safe operations to reduce the risk of an accident are of paramount importance. An unexpected release of high-pressure gas into the well, whose expansion in the mud lowers its density, may lead to a blowout. A blowout can shoot drill pipe out of a well like cannon shot, wrecking a rig and killing or maiming the drillers. If a blowout is about to occur, pipe rams and other means within the blowout preventer seal the well. Drillers are sensitive to the dangers that threaten drilling by relying both on instrument readings and sight, sound, and smell for warnings of potential trouble.

In the case of the United States, only 22 percent of exploratory wells were successful in 1973, but this increased to 71 percent in 2008, primarily as the result of improvements in computer software, processing speeds, and storage capacity for 3-D seismic analysis.[3] However, these exploratory wells were not true wildcat wells in that most of them were drilled in the vicinity of known fields. True wildcat wells, drilled far from any known source of oil, have much lower success ratios.

Seventy-eight percent of development wells were successfully completed in 1973, and this improved to 92 percent in 2008. Failure in drilling production wells can be caused by the well hole missing the oil reservoir (3-D seismic pictures can reduce the chances of this happening) or by twisting, binding, or breaking of the drill string, shattering of the drilling bit, or the damage incurred when a tool is dropped down the well. When the drill string or drilling bit breaks, various methods of fishing out the broken pipe or bit have been devised, including the use of powerful magnets and explosives. If these fail, the well may have to be abandoned. In 1973, the average rig drilled wells whose total depth amounted to 22 miles each year. If the average depth per well is two miles, then this is equivalent to drilling eleven wells a year. In 2008, the total average depth per rig was 35 miles, and on the basis of two miles per well, 17.5 wells a year, a 60 percent increase in productivity. Land rig activity has remained flat in the United States as oil exploration moves into more promising areas overseas and into offshore waters.

Directional Drilling

One would think that a drill string made up of thirty-foot lengths of steel pipe would be rigid, but this is not at all true when the drill string is measured in miles. It is rather flexible, sometimes described as being similar to spaghetti, and, like a rubber band, actually twists several times when being rotated before the bit begins to turn. Drilling a vertical hole requires constant attention. The bit, turning clockwise, tends to introduce a clockwise corkscrew pattern to what one would suppose would be a straight hole. Moreover, nonhorizontal layers of hard rock can cause a deviation or drift from the vertical. Drift measurements are necessary every several hundred feet of drilling, or when a bit is being changed, to verify the vertical direction of a well hole.

Wells on land are drilled vertically, and a producing oil field is served by many individual wells. Historically, the only slanted wells were those that tapped a neighbor's oil field! The idea of horizontal drilling was patented in 1891, but for drilling teeth, not oil. The first true horizontal well was drilled in 1939. In the 1970s, control over direction was still poor but markedly improved in the 1980s by the development of the steerable downhole motor. It was not until the 1990s that horizontal drilling came into its own when the decade started with 1,000 horizontal wells and ended with twenty times as many. To a casual observer drill pipe is rigid, but it can actually flex when strung together for thousands of feet. In contemplating horizontal wells, it should be kept in mind that the drill pipe does not rotate; it is mud forced to flow through the drill pipe that actually powers the drilling. Normally the mud motor that drives the drill bit is fixed vertically so that the well is drilled straight down, but it can be bent via a joint that can cause the drill pipe to depart from the vertical. The drill pipe can be curved until it becomes horizontal. A Measure While Drilling (MWD) device equipped with an accelerometer and magnetometer placed just above the mud motor lets the driller know the direction and angle of inclination and its precise location in relation to 3-D seismic imaging of potential oil or gas bearing geological structures. The MWD can also be equipped with Logging While Drilling devices such as gamma ray detectors and instruments to measure resistivity and conductivity and other variables. These technological advances allow the driller to stay within oil or gas-bearing zones in real time without having to pull out the drill pipe and run a wireline-based logging tool down the hole to evaluate the well's progress.

Horizontal drilling can be used to enhance recovery after production from a vertical well is nearing exhaustion. Reentry is made in the vertical well to attach a whipstock at a preset depth. A special bit at the end of the drill pipe is deflected by the whipstock to cut a hole through the metal casing and out the side of the well. From this window, a MWD mud motor passes through the original drill pipe and starts drilling a curved path that eventually becomes horizontal.

Horizontal drilling is necessary from offshore platforms where multiple platforms with vertical wells would be prohibitively expensive. Thus, a single platform with vertical wells that turn horizontal can cover a much wider area that vertical wells alone. Horizontal wells are employed in low-porosity rock formations such as dense shale or limestone to extract the low volume of gas, which cannot be commercially tapped by vertical wells. Once the horizontal well is drilled, "fracks" (fissures caused by fracturing the rock with high pressure water) allow gas to escape into the wellbore. This technique is also being used to extract coal bed methane from coal seams too deep to mine. Despite being more costly to drill, horizontal wells take advantage of oil and gas fields being wider than they are thick. A horizontal well can drain a much larger area of an oil or gas formation and be cost effective by reducing the total number of wells that have to be drilled to tap an oil or gas field. Horizontal wells are two to three times more costly to drill, but they can be up to twenty times more productive in extracting oil or gas than vertical wells. The longest reach of a horizontal well is 35,000 feet (6.6 miles) from an onshore production rig in the United Kingdom tapping the offshore Wytch Farm oil field.

Historically, one horizontal well was drilled from a single vertical well with the vertical wells being quite close to one another on a small plot of land or from an offshore production platform. It is now possible to have multiple horizontal wells branching from a single vertical well with other branches emanating from these branches called multilateral branching. Multilateral branching allows for more effective drainage of pockets of gas or oil reservoirs, and may one day cover an area tens of miles from a single production platform in several or all directions. Horizontal wells are better for environmentally sensitive areas, such as northern Alaska, since they can tap a wider area with fewer staging pads and roads whose simpler infrastructure would reduce the risk of environmental damage.

Recently developed techniques include a rotary steerable drill string that rotates for faster well completion than a mud motor. Another technique is a highly specialized type of mud motor with kick pads that orient the drill bit to the right angle rather than relying on a bent mud motor. Another innovation is substituting flexible coiled tubing that can be continuously unreeled from a giant spool up to 4,000 feet in length for a rigid drill string. The tubing is made of special alloys to allow it to be reeled on a giant spool like electrical cable, yet be strong enough to maintain its shape within an oil well. Coiled tubing allows for uninterrupted drilling, reduces the equipment footprint at the drill site, and lets the production well wander, or snake, horizontally from one gas or oil formation to another.

Taking the lead from oil companies, horizontal drilling is now being used to lay underground water and gas pipelines and communication cables without opening a trench. Horizontal drilling is being used to remediate land under airport runways and industrial plants to clean up spilled jet fuel and chemicals without disturbing the operations of the runway or the industrial enterprise and to introduce microbes for bioremediation of toxic soil. Horizontal drilling can be used to place leak-detection censors or install gas- or liquid-collection systems beneath solid or hazardous waste landfills, dewater hillsides to prevent mudslides from endangering housing developments or stabilize mine waste dumps, and convey fluids between vertical wells and treatment facilities.[4]

Offshore Drilling Rigs

Seventy percent of the earth's surface is covered by water, a tempting prospect for oilmen when the promise of discovering large onshore oil fields dimmed. In the 1890s a slanted well was drilled onshore to tap an offshore oil deposit, and oil rigs were built on wharves extending out to waters thirty feet deep in the Santa Barbara channel. In 1910, a gas well was completed one mile from shore in Lake Erie. In 1937 a grounded barge in shallow waters off Louisiana was the first submersible drilling rig, which does not mean that operations were conducted underwater. The submerged barge formed a barrier to keep the water out and exposed the bottom for drilling as though it were on land.

The birth of the modern offshore drilling industry occurred after the Second World War. The Depression of the 1930s dampened demand for developing new oil fields and the War dedicated the nation's resources to the production of ammunition and armaments, making it necessary for onshore oil fields to be worked with old equipment. Steel was not available for building rigs, for manufacturing spare parts, or for producing consumer goods and automobiles. The end of the war also marked the end of postponing the good life. Americans proceeded to build homes, manufacture consumer goods to fill the homes, and build roads and manufacture automobiles to fill the roads. The postwar demand for oil exploded, but the chance of discovering major or giant new fields onshore was not overly bright because much of the land surface had already been explored. The gently sloping Gulf of Mexico and its relatively shallow waters, bordered by onshore oil fields, provided a promising new area for exploration.

In very shallow waters, submersible drilling barges were sunk to rest on the bottom and keep water away from the well for drilling to proceed as though it were on dry land, a practice still in use. Floating drilling barges were and still are used in waters up to about twenty feet in depth. The drilling platform is mounted in the center of the barge and the drill pipe runs through a moon pool, a hole in the bottom of the barge surrounded by a cylinder that keeps water from flooding the barge. Kerr-McGee was among the first companies to convert excess barges and landing craft built during the Second World War to floating offshore rigs and was a technological innovator in developing a new industry. In 1947, the first offshore production rig was built on steel pilings driven into the sea floor by a pile-driver that repeatedly drops a heavy weight on a piling. The rig was in waters eighteen feet deep, twelve miles off the coast of Louisiana.

Legislation was passed in 1953 that granted state control over mineral rights in coastal waters and past that point to the federal government. Sales of leases are an important source of revenue for states that permit offshore drilling (Louisiana and Texas) and the federal government. Most states have banned offshore drilling in their coastal waters or new exploratory activity if offshore operations already exist (California). States have also succeeded in prohibiting exploration in offshore waters outside their jurisdiction such as the Hudson River canyon, where some believe an oil field may exist. In 1998 President Clinton signed an executive order extending a moratorium on leasing oil-drilling sites on the outer continental shelf until 2012. This moratorium includes nearly all the coastlines of California, Washington, Oregon, the Aleutian Islands, New England, the north and mid-Atlantic, and the eastern Gulf of Mexico, which includes an extensive area off the coast of southwest Florida. The Middle East is not the only place where oil companies face geopolitical risk.

In 1954, a submersible called "Mr. Charlie" was built. It consisted of a lower barge with a moon pool on which cylindrical columns were built to support a drilling platform. The barge was sunk in waters up to forty feet deep by flooding the lower barge, leaving the drilling platform above the water surface. When the well was completed, water was pumped out to refloat the barge for towing to a new location. "Mr. Charlie" drilled hundreds of wells before retiring in 1986 and was a springboard in the development of offshore drilling technology. For deeper waters, jack-up rigs were developed. These consisted of three legs and an upper and lower hollow hull. In transit, the lower and upper hulls are together with the legs sticking up in the air. At the drill site, the lower hull is flooded and the legs are jacked down until the lower hull is firmly on the ocean floor. For hard ocean bottoms, cylinders built on the legs, rather than a lower hull, support the rig. With the lower hull or cylinders firmly on the bottom, the jack-up rig continues to jack down the legs, raising the upper hull with the drilling platform off the surface of the water until it is 100 feet above the ocean surface. The drilling platform must be high enough above the water surface to prevent waves from striking and possibly capsizing the rig. The first jack-ups were used in waters up to 80 feet deep and are now capable of operating in waters up to 400 feet deep. In order for the drilling platform to be 100 feet above the water surface, the legs have to be 500 feet long. When being towed to a new site, the jacked-up legs stick up 500 feet into the air (equivalent to a thirty-story building), presenting a rather ungainly sight with transits limited to fair weather.

Drilling in deeper waters required another major step in technological development, which began with the government-sponsored Project Mohole (1958–1966), which envisioned drilling a well 25,000 feet deep in 15,000 feet of water. The purpose of the project was not to advance offshore drilling, but to enhance the understanding of the earth's geology by drilling through the crust in a place where it was thin enough to obtain a sample of the earth's mantle. While the project itself was never completed, it helped advance the technology of deep-water drilling. Five holes, one 600 feet deep, were drilled in 11,700 feet of water through a moon pool in the bottom of the drilling vessel. A system of swivel-mounted propellers was invented that imitated the method lobstermen use to keep their boats on station while retrieving lobster pots. The system was a precursor of computer-controlled dynamic positioning.[5]

Drill ships and semisubmersibles are employed for deep-water drilling. A semisubmersible is a floating drilling platform mounted on top of a set of columns connected to large pontoons. The pontoons are empty when in transit, then flooded when on-station to lower the rig to a semisubmerged state with the pontoons thirty to fifty feet below the ocean surface. When in a semisubmerged condition with the drilling platform above the surface, the rig is quite stable even in stormy seas such as in the North Sea, where waves may strike the drilling platform. An anchor system was sufficient to keep the first generation of semisubmersibles on-station for drilling in water up to 2,000 feet deep. Modern ultra-deep fifth-generation semisubmersibles drill in waters up to 10,000 feet deep, and are kept on-station by a dynamic positioning system. Either sound impulses from transmitters located on the ocean floor or global positioning navigational satellites keep track of the rig's position and computer-controlled thruster engines maintain the rig on-station.

Drill ships have a drilling rig mounted at the center of the ship where the drill pipe passes through a moon pool. Depending on the depth of water, a drill ship remains on-station utilizing either an anchoring system or dynamic positioning. While top-of-the-line drill ships can also drill in waters 10,000 feet deep, drill ships lack the inherent stability of semisubmersibles. The vertical motion of a drill ship from wave motion would place an enormous strain on the drill string. A motion-compensated crown block keeps the drill string steady even though the ship is not. The *Discoverer Enterprise,* built by Transocean, can drill in water up to 10,000 feet deep, with well depths (combined horizontal and vertical length) of 35,000 feet, a figure not that far from the overall goal of the Mohole Project. At its extreme limits of operational capability, the drilling rig is rotating over eight miles of drill pipe. To reduce the number of connections that have to be made when making a sixteen-mile trip, this drill ship uses 135-foot pipe lengths rather than the more conventional 90-foot lengths usually used for offshore drilling.[6]

Similar to drilling on land, offshore drilling starts with a 100- to 250-foot, 30-inch diameter conductor pipe to which the blowout preventer is bolted. Remotely operated vehicles (ROVs) do the necessary work at the bottom of the ocean with lighting systems, television cameras, and remotely operated "arms" and "wrists" doing work at pressures that would crush a human body. A flexible, metal hollow tube called the marine riser connects the drilling rig with the borehole. Transponders and underwater television identify the location of the borehole and a jet-assist device at the bottom of the marine riser lets the driller guide the riser into the borehole. The drill string passes through the marine riser forming a closed system for circulating drilling mud. Once set up, drilling progresses much as it does on land, except for longer drill pipes and the additional risks of drilling at sea. Crew safety takes on a greater sense of urgency because the crew on an offshore drilling rig has limited means of escape if the rig catches fire, explodes, or capsizes during a storm. An additional risk is drilling into a large pocket of natural gas, which, if released in massive quantities, surrounds the rig and causes a loss of buoyancy that may result in its capsizing or sinking.

Drilling offshore wells requires a crew that varies with the size of the operation, but basically consists of a driller, who oversees operations, plus an assortment of derrickmen, motormen, diesel-engine operators, pump operators, mud men, and crane operators, plus roughnecks and roustabouts. Roughnecks handle connecting and disconnecting drill pipe and roustabouts handle supplies, including bringing drill pipe onboard the rig. Others are employed in maintenance and repair of machinery and equipment, keeping the rig on-station, and maintaining a livable environment. Schedules vary, but basically there are four crews, two aboard the rig working twelve-hour shifts and two on shore waiting their turn. The length of their stays onboard the rig depends on the rig's location: the more remote the location, the longer the stay. Crew transfers can be accomplished either by fast boats for rigs relatively close to shore, or by helicopters.

The growing number of offshore-drilling rigs capable of drilling in ever deeper waters is an indication of the growing challenge of finding new oil fields; an indication that we may be running out of places to look for oil. The world fleet of offshore rigs totaled 586 in mid-2000s, of which 383 were jack-up rigs, 160 were semisubmersibles, 36 were drill ships, and 7 were submersibles. Of the 383 jack-up rigs, 174 are capable of drilling in waters over 300 feet in depth. The 160 semisubmersibles have gone through five generations of technological advancement; none of the first generation rigs remain. Eighty-four of the second generation, thirty-six of the third, twenty-eight of the fourth, and twelve of the fifth-generation rigs are still in operation. High-end semisubmersibles and drill ships, used for drilling exploration and development wells, can cost up to $350 million each. Depending on the operational capacity of the rigs and the state of the market, the rate to employ a semisubmersible or drill ship can range from $30,000 to over $200,000 per day. Although a rule of thumb is that each million-dollar increment in construction cost increases the daily rate for employment by $1,000 per day, wildly fluctuating rates are not so much in tune with what it costs to build a rig as much as in fluctuations in the underlying demand with respect to supply. Net demand for jack-up and semisubmersible rigs in mid-2000s, in terms of numbers, was about the same as in 1990. But newer rigs have greater operational capabilities and higher productivity than older rigs, thus masking rising demand. Generally speaking, jack-ups are employed in the more shallow waters of the Gulf of Mexico, South America, and the Middle East. Semisubmersibles are employed in the North Sea, and along with drill ships, in deeper waters of the Gulf of Mexico and offshore Brazil.

Of these areas, the North Sea is by far the most challenging, where drilling proceeds 24–7 in freezing weather with frequent, strong, and long-lasting storms. These rigs have to be capable of operating in hundred-knot winds and hundred-foot waves. However, rigs operating in the relatively calm waters of the Gulf of Mexico must be able to withstand hurricane force winds and waves. Petrobras, the state oil company of Brazil, has introduced many technological developments and was the first company to successfully drill in water more than 8,000 feet deep. This record was broken in 2003 when a Transocean drill ship operated at a record depth of 10,000 feet in the Gulf of Mexico. Transocean, the world's largest offshore drilling rig company, also held the record for the deepest subsea completion in waters of nearly 7,600 feet. The company's most recent delivery is an ultradeep semisubmersible ultimately capable of drilling in 10,000 feet of water with a drilling depth of 30,000 feet, a total of 7.6 miles of drill pipe. Petrobras and Transocean frequently swap new world offshore drilling records. New and exploitable oil fields have been discovered offshore Nigeria, Angola, Brazil, and in the Gulf of Mexico, dwarfing onshore exploratory efforts.

Once an oil field has been discovered and appraised, a permanent offshore production platform is installed. In shallower waters, a production platform is built on steel piles. For deeper water (hundreds of feet), a bottom-supported steel structure with hollow chambers to hold water is constructed on its side on land. Upon completion, the structure is placed on a barge and towed to the site. The barge is then partially flooded to launch the structure, which initially floats horizontally on the surface. By flooding designated chambers, the structure is slowly brought to an upright position; further flooding sets the structure on the sea bottom. Steel piles that pass through the structure's jacket are driven into the sea bottom. Once the structure is fixed to the sea bottom, equipment modules are loaded and assembled on the production platform.

Pile drivers cannot operate in the thousand-foot ocean depths of the North Sea. The first production platforms were gravity-based platforms built on land with massive steel and concrete bottoms with steel and concrete legs connected to a platform that extended above the ocean surface. The structures, ranking among the tallest on Earth, were built on their side, maneuvered onboard a barge, and towed to deep water. Near the site, the barge was partially flooded to offload the platform, which was then partially flooded to an upright position. After being towed to its final site, other hollow chambers in the base were flooded to allow the platform to sink vertically until its massive base penetrated deep into the ocean bottom. The remaining hollow cylinders connecting the base with the platform could be used for more seawater ballast, for storage of the diesel fuel needed for its operation or crude oil. Gravity-based platforms were extremely expensive and are no longer built.

Nowadays, the tension-leg buoyant platform is used for producing oil and natural gas in deep waters. The platform floats above an offshore field; hollow steel tubes called tendons connect the floating production platform with heavy weights on the sea floor. These tendons are under tension and pull the platform down into the water to prevent it from rising and falling with waves and tides. Tension production platforms are very stable and have been successfully employed in the Gulf of Mexico and elsewhere in waters thousands of feet deep. Although tension production platforms are built to survive extreme weather, in 2005 Hurricane Katrina proved too much for one of them and turned it upside down. Like offshore exploratory rigs, production rigs operate 24–7.

Deep-sea production platforms are usually connected to a shoreside terminal by underwater pipelines, except in isolated regions of the North Sea, the offshore waters of Canada (Hibernia), West Africa, and Brazil, where shuttle tankers move oil from storage tanks within the production platform to a terminal. Besides isolation, another reason for not pipelining oil to a shore location is security of supply in locations where terminal operations are threatened by civil disturbances. When an oil field is exhausted, a production platform becomes obsolete and has to be removed and disposed of at considerable cost. In 1995, the environmental group Greenpeace aroused sufficient public opposition to Shell Oil's plan to move an obsolete production platform to deep water for sinking that Shell had to opt for the far more expensive method of towing the platform to a shoreside facility for dismantling.

A Floating Production, Storage, and Offshore Loading vessel (FPSO), often a conversion of an older but still seaworthy large crude carrier, has a production platform incorporated on the vessel's hull above an installed moon pool. The vessel provides storage for the oil and has an offloading arm for pumping crude from its tanks to shuttle tankers for transport to shoreside terminals. The advantage of a FPSO over a fixed production platform is that it is far less costly to build and install and its storage capacity eliminates the need for an underwater pipeline. The FPSO, because it relies on an anchoring system to remain on station, cannot serve deep oil fields that require dynamic positioning. FPSOs can, however, exploit offshore oil fields that are too small to economically justify building a fixed production platform and laying a pipeline to shore. Once an oil field is exhausted, a FPSO sails to another oil field, avoiding the cost of dismantling a fixed platform and building a new one.

Evaluating a Well

Completing a production well, whether on- or offshore, is more costly than drilling an exploration or appraisal well. A careful evaluation of various logs obtained during the course of drilling an exploratory or appraisal well has to be completed prior to making a decision on whether to drill a production well. The lithographic, or sample, log records the nature of the coarser samples of rock chips separated from the drilling mud as to the type of rock, texture, grain size, porosity, microfossil content, and oil stains. Oil stains are examined in ultraviolet light to assess their nature and quality. The drilling-time log records the rate of penetration through subsurface rocks; a change in the rate of penetration indicates a change in the type of rock. The mud log records the chemical analysis of drilling mud for traces of subsurface gas and oil at various depths. The wireline well log, first introduced by Conrad Schlumberger in France during the 1920s, was, as with Hughes Tool, the basis for another oil fortune not directly related to owning oil-producing properties. The wireline well log was obtained by removing the drill string and inserting a sonde, a torpedo-shaped device laden with instruments. The first instrument was an electrical log to measure the resistance of the rocks to electricity. Changes in resistance indicate the degree of saturation of water, oil, and gas. Later additions included a natural gamma ray log to read the background radioactivity of rocks in the well. Since shale is the only sedimentary rock that emits radiation from radioactive potassium, the gamma ray log identifies the presence of shale rock or the degree of shale in mixed rock. A gamma-emitting radioactive source in the sonde creates a density or gamma-gamma log from returning gamma rays to measure porosity. The neutron porosity log records the results of bombarding rock adjacent to the well bore with neutrons. The intensity of returning neutrons from collisions indicates the presence of hydrogen, which is found in oil, gas, and water. The comparative results of the neutron porosity and gamma-gamma density logs identify the presence of natural gas. The caliper log measures the diameter of the well bore, which can widen when soft rocks slough off from the upward flow of mud in the annulus. This information is needed to calculate the amount of cement needed to case the well. The acoustic velocity, or sonic, log measures the speed of sound through a rock layer, which, for a known type of rock, indicates its porosity and the presence of fractures. The dip log measures the orientation of rock layers, or slant, from the horizontal.

Originally the sonde, with its various sensors, required pulling the drill string and removing the drill bit; since 1980, it is located just above the drill bit to provide real-time log analysis. Results of these logs are interpreted at each increment of depth by experts as to the likely productivity of the well; a key factor in deciding whether to complete a production well. If the experts decide to abandon a well, its conductor casing is pulled for salvage and the well is cemented at appropriate levels to prevent saltwater and oil seepage from rising and polluting surface waters.

Completing a Well

After the decision has been made to complete a well, the process starts with preparing a well for casing. Casing stabilizes a well, preventing the sides from caving in and protecting freshwater aquifers near the surface that might be polluted with oil, gas, and saltwater. If the casing is to be installed in a single operation after the well is completed, drill pipe is lowered with a used bit to circulate mud and remove any remaining cuttings from the bottom of the well. Wall scratchers remove mud from the sides of the well. Casing is thin-walled steel pipe, usually in thirty-foot lengths sized to fit inside the well bore. After the well is prepared for casing, casing pipe is screwed together and lowered into the well. A guide shoe guides the casing down the well and centralizers position the casing string in the center of the well. A float collar near the bottom of the casing string acts as a check valve to prevent mud in the well from flowing up the casing pipe. After the casing is in place, Portland cement is mixed with additives to control its density and the timing required for the cement to set. Cement is pumped down the center of the casing through the float collar, forcing its way through the bottom plug out of the casing pipe and up the annulus between the outer casing wall and the well bore. Then a top plug is added and mud is pumped down the casing, which forces the remaining cement in the casing into the annulus. The driller has to ensure that an adequate amount of cement is injected into the annulus to complete the cementing of the casing string. When the top plug meets the bottom plug cementing is complete and the wiper plugs, guide shoe, and cement at the bottom of the well are drilled out and the mud is removed from the casing pipe.

A variation of this method is to case a well in segments. After the well is drilled, the lowest section of the casing is cemented first, then a plug is installed at the top of the casing. More casing is added with holes drilled in the coupling with the installed casing to force cement out of the bottom to fill the annulus. The plug is removed and the process is repeated until the entire casing is installed. Some wells have three or four concentric casing strings installed in segments as the well is being drilled, with the largest diameter casing installed at the top of the well. After the casing is installed, the well is drilled deeper and another, narrower casing is added. This process continues until the narrowest casing string is added at the bottom of the well.

If the well ends in a producing zone, the bottom of the well is opened and filled with gravel. Smaller diameter liner pipe is run down the casing to the bottom of the well. Then the casing pipe is perforated, and fractures are created in the rock and in any impregnated mud to ease the flow of oil and gas to the perforated casing wall and then into the liner pipe. Perforation was first accomplished in 1932 using a bullet gun, a device lowered to the bottom of the well that fires bullets similar to ball bearings in all directions. The bullet gun is still in use and has been successfully employed in horizontal wells. Bullets are reduced to fine particles after firing. Shaped charges are also used, along with hydraulic injection of large volumes of diesel oil, nitrogen foam, water, or water with acid under high pressure for limestone reservoirs (the acid contains an inhibitor to prevent corrosion of the steel casing and tubing). Working over a well, which must be done several times over its lifetime, includes not only fixing mechanical problems and cleaning out the bottom of the well, but also taking measures to enhance the permeability of the surrounding rock.

The annulus between the liner pipe and the inner casing wall is sealed to prevent oil and gas from coming in contact with the casing pipe, which would corrode and weaken the casing. If the well passes through several producing zones, each has its own tubing and packing to ensure that the output of each zone is segregated in order to identify the output of each zone. Normally, a well will not have more than three producing zones. Shaped charges, or firing bullets, perforate the casing and fracture the surrounding rock at each producing zone. Seals are installed to ensure that oil and gas enter the liner pipe, not the casing pipe.

A "Christmas tree," normally made from a single block of metal, is mounted on top of the casing with a master valve that can shut off a well under emergency conditions. Other valves control the pressure and flow from each producing liner pipe or tubing string within the well with associated gauges that measure the tubing pressure. A new well usually has sufficient reservoir pressure to cause the oil to flow naturally from the top of the liner pipe or tubing string. If the reservoir pressure declines to a point at which oil no longer flows from the well, the most common form of lifting device is the sucker rod pump. A motor powered by electricity or natural gas from the well drives a walking beam mounted on a Samson post to obtain a vertical up-and-down motion to drive a pump. On the downward stroke, a ball unseats from a seal, letting oil flow into the pump. On the upward stroke, the ball seats and forces the oil up while the space below the pump fills up with more oil. The pumping rate has to be less than the fill rate for the pump to operate properly. A gas lock can form in the pump if natural gas is present. A sucker rod pump may have to be used in natural gas fields that release a lot of water. A gas lift system, which injects some of the natural gas produced by the well into the annulus between the tubing and the casing, can be installed for wells producing a mixture of saltwater, oil, and gas. Gas lift valves installed along the tubing string allow the gas to enter the tubing. The expanding bubbles in the liquid force the mixture of water, oil, and natural gas up the tubing. Gas lift systems are simple and inexpensive to operate, but are only effective for relatively shallow wells. Alternatively, an electrically or hydraulically driven submersible pump can be installed at the bottom of a well.

Moving the Oil to the Well

The primary force that causes oil and gas to flow through pores in the reservoir rock toward the bottom of the well is the pressure differential between the oil and gas within the reservoir rock and the pressure at the bottom of a well. The driving force in the reservoir can be provided by dissolved natural gas in the oil or by a natural gas cap on top of the oil that expands as oil is removed from a reservoir. Natural gas cannot maintain the same initial reservoir pressure as it expands, which causes oil production to decline with time. Subsurface water entering an oil reservoir from its bottom or sides as a primary driving force can maintain nearly constant reservoir pressure and oil production. An oil well goes "dry" when natural gas or water reaches the bottom of the well. Gravity can also be an effective drive mechanism for wells drilled into the bottom of steeply inclined reservoirs. Most oil reservoirs have more than one of these four primary driving forces.

Natural gas reservoirs are either driven by expanding gas or by water. Natural gas wells do not go dry in the sense that oil does, but their pressure may decline to somewhere between 700–1,000 psi, the lowest pressure acceptable for a gas pipeline. A compressor can extend the life of a gas well. If production from an oil well falls below 10 barrels per day, it is known as a stripper well. Stripper wells number about half a million in the United States, with many producing as little as 2 or 3 barrels per day. They are kept in production or reactivated if shut-in as long as revenue exceeds the costs of operation and reactivation.

Maintaining Reservoir Pressure

The recovery factor—the portion of the oil and gas removed from a reservoir—depends on the driving force. The recovery factor is lowest for oil reservoirs driven by natural gas in solution with the oil or by gravity, higher if driven by a natural gas cap, and higher yet if driven by water. The overall average recovery factor for oil fields is only about one-third (natural gas fields have higher recovery factors). Thus, when a well that relies on the natural drive of the reservoir goes "dry," about two-thirds of the oil is still in the ground.

Secondary methods to maintain reservoir pressure and promote oil recovery normally involve injecting water or natural gas. Injection wells, either specifically drilled or converted from abandoned producing wells, are placed to enhance the flow of oil in the direction of the producing wells. Water injection is the most common method for maintaining the pressure of an oil reservoir and is an environmentally acceptable way of getting rid of any brine produced by the well to avoid contaminating the freshwater table. If brine cannot be pumped into subsurface rock below the freshwater table, it must be disposed of in an acceptable manner. Brine may be placed in open tanks to let evaporation get rid of most of the water before disposal.

Depending on the type of reservoir rock, an alkaline chemical such as sodium hydroxide is mixed with the injected water to enhance recovery. Injected water must be compatible with the type of reservoir rock to ensure that a potential chemical reaction does not decrease its permeability. Pores in the reservoir rock can be plugged by injecting suspended solids in the water or by slimes feeding on injected bacteria and organic matter. Natural gas from an oil well, called associated natural gas, is normally sold, but for isolated wells far from natural gas pipelines, it is often reinjected into the oil field to maintain reservoir pressure. However, natural gas is not as effective as water in enhancing oil recovery.

Secondary methods can raise recovery to 40 percent on average from the one-third average recovery of primary methods. To reach 50 percent, tertiary or enhanced recovery methods must be employed. The price of oil plays a critical role in determining whether more costly tertiary recovery methods should be employed. Thermal recovery is utilized when the remaining oil is heavy and viscous. “Huff and puff” burns crude oil at the surface of the well to produce steam that is injected down a well. The well is shut in to allow steam to heat up the surrounding crude to reduce its viscosity, enhancing its flow through the rock. Then the well is put back into operation to extract the heated crude. Steam flooding is a continuous process in which injected steam maintains pressure on previously injected condensed steam to drive heated crude toward the producing wells. Placement of the steam injection wells is critical to ensure that the oil flows in the right direction. Thermal recovery is effective as long as crude production exceeds the amount burned to produce steam.

A fireflood is setting subsurface oil on fire and keeping it burning by forcing large quantities of air down an injection well, with or without water to create steam. The heat reduces the viscosity of the crude while increasing the pressure within the reservoir rock to enhance the flow of oil toward the producing wells. The amount of air has to be limited to avoid burning all the oil in the reservoir. Firefloods cannot be used if there is any appreciable sulfur in the oil because of the formation of sulfuric acid that eats away the liner pipe. Though simple in concept, firefloods are difficult in practice.

A chemical flood involves inserting detergent into injected water to form tiny droplets of oil to aid in their migration to a producing well. As long as water is not present, miscible floods of natural gas liquids such as butane and propane act as solvents and wash the oil out of the reservoir rock. This is one of the most effective tertiary methods of oil recovery, but it is very expensive unless the butane and propane can be recovered for recycling. Carbon dioxide floods involve either carbon dioxide as a gas or dissolved in water. Soluble in oil, carbon dioxide promotes migration to the producing wells by increasing the volume of oil and reducing its viscosity. Injected carbon dioxide can be separated from the oil at the surface of the producing well for recycling. This is not sequestration of carbon dioxide as it returns to the surface dissolved in the oil. Carbon dioxide is brought to the well in a liquefied state in tanks or is piped in from wells that produce large amounts of carbon dioxide or as a waste byproduct from nearby power, chemical, and fertilizer plants.

Tertiary recovery methods do not always succeed and require high-priced crude oil to justify their cost, but they do reduce the need to find new oil fields. With tertiary recovery, about half of the oil can be removed from an oil reservoir on average, although, as with any average, there are higher and lower recovery factors. Nevertheless, tertiary recovery methods still leave about half of the oil entrapped within the pores of reservoir rock after an oil field has gone “dry.”

GETTING THE OIL TO A REFINERY

Most wells produce a mixture of oil and saltwater with or without associated natural gas. The output from a well enters a gas oil cylinder-shaped separator where natural gas, if present, rises to the top and water sinks to the bottom, leaving oil in between the two. A heater or demulsifier may be necessary to break down an emulsion of oil and water. A certain retention time is necessary to allow the two to separate. Natural gas, if present, is diverted to a natural gas pipeline gathering system. Once separated from water, oil is pumped to a staging area that serves a number of wells and then through collecting pipelines to larger capacity pipelines that eventually connect to refineries or oil export terminals.

Pipelines provide the lowest cost means of moving crude oil and oil products on land. Crude oil pipelines are not built unless there are sufficient reserves to guarantee pipeline throughput and provide an adequate financial return. Technological advances made in building the “Big Inch,” a twenty-four-inch pipeline, and the “Little Inch,” a twenty-inch pipeline from the U.S. Gulf region to the northeast during the Second World War set off an explosion in pipeline construction. Modern trunk lines are up to forty-eight inches in diameter and have a throughput capacity of 1–2 million barrels per day, depending on pumping capacity. Additives to make oil more "slippery" by reducing the friction or turbulence at the boundary layer between the oil and steel pipe can improve pipeline throughput capacity. The speed of oil in a pipeline is not very impressive, about that of a fast walk, but over twenty-four hours a pipeline with a diameter of four feet can move a lot of oil. The pipeline industry in the United States and Canada is regulated as a common carrier. Tariffs are set to limit earnings on investment with assurances that all shippers have equal access and pay the same base rate.

Oil pipelines are like blood vessels in a living being, with the United States having hundreds of thousands of miles of gathering and collecting pipelines connecting countless producing wells to refineries. Most offshore oil fields such as those in the Gulf of Mexico and the North Sea are connected to land by underwater pipelines, although more remote fields use shuttle tankers. The Louisiana Offshore Oil Port (LOOP), located about twenty miles off the Mississippi River mouth in deep water, is a system of three single buoy moorings that serves large crude carriers carrying oil from the world's exporting oil nations. A discharging crude carrier pumps cargo from its tanks through a hose to the floating buoy. The floating buoy is connected via an underwater pipeline to an offshore marine pumping station. The pumping station moves the crude to onshore salt caverns for storage and connection to other crude oil pipeline systems that serve two-thirds of U.S. refinery capacity from the Gulf Coast to as far north as Chicago and as far east as the Middle Atlantic states. Russia also has an extensive crude oil pipeline system to handle domestic distribution and exports to Europe. Crude oil pipelines have been built to ship landlocked Caspian crude to Black Sea ports, and a major pipeline has been built to ship Caspian crude to a Mediterranean port in Turkey. Major projects under consideration involve pipelining Siberian oil to China and Japan and Russian oil to Murmansk, a year-round ice-free Arctic port, for export to Europe and the United States.

In addition to crude oil pipelines, product pipelines take the output from refineries to oil distribution terminals near population centers. Large product pipelines move refined products from the U.S. Gulf Coast refineries to the Atlantic and northeast markets and from Russian refineries to markets in Europe. Tank trucks complete the movement from storage tanks at pipeline distribution terminals to wholesalers and retailers. In a few nations, railroads still move crude and oil products where the volume is insufficient to justify building a pipeline.

Tankers and Barges

Water transport is an even lower-cost alternative than pipelines because the "highway" is free, although investments have to be made in ports, terminals, and ships. Tankers and barges move about half of the oil produced either as crude from exporting terminals to refineries or as refined oil products from refineries to distribution terminals and customers. All the OPEC producers export oil by tanker, although pipelines can shorten the tanker voyage. The first Middle East export pipelines, now inoperative, carried Saudi crude to ports in Lebanon and Syria, eliminating the tanker movement from the Arabian Gulf to the Mediterranean via the Suez Canal. A portion of Iraqi crude is pipelined to a Mediterranean port in Turkey and some Saudi crude is pipelined to a Red Sea port for transfer to tankers for transit to the southern terminal of the Sumed pipeline that parallels the Suez Canal. Oil is shipped in tankers from the northern terminal of the Sumed pipeline in the Mediterranean to ports in southern and northern Europe. The Sumed pipeline allows the use of very large tankers that cannot transit the Suez Canal fully loaded to move Middle East crude to Europe. However, in about ten years' time, the Suez Canal will be widened and deepened enough to accommodate most of the world's largest tankers fully loaded.

Refineries on or near the coastline distribute oil products locally by small tankers and barges. Barges distribute the output of Rotterdam refineries up the Rhine River into central Europe and along the northern European seaboard and from refineries in the U.S. Gulf up the Mississippi River and along the Atlantic seaboard. Product carriers move cargoes from export-refining centers in the Caribbean, Mediterranean (southern Italy), Middle East, Singapore, India, and Korea to nearby and far-off markets. Price differentials arise between regions when production and distribution do not exactly match demand. Traders take advantage of price differentials once they exceed shipping costs to arrange a shipment from a low-priced to a high-priced market. Arbitrage trading completes the balancing of global refinery supply with global consumer demand.

Standard Oil was the first company to export oil. The initial shipments of kerosene from the United States to Europe were carried in barrels on general cargo sailing vessels, some of which were lost at sea when leaking fumes came in contact with an open flame in the ship's galley. The first tanker, the *Gluckauf,* built in Germany in 1886, was compartmentalized into several cargo tanks whose outer tank surface was the hull itself, now called a single-hull tanker. The vessel's deadweight ton (dwt) capacity was 3,000 tons. As a rough rule, the cargo capacity of a tanker is about 95 percent of its deadweight. Shell Trading was a major impetus in building larger and safer tankers in the early part of the twentieth century to ship Black Sea kerosene to Asia through the Suez Canal. By the end of the Second World War, the standard tanker, which had been built in large numbers for the war effort, was 16,000 dwt. As world oil movements increased in volume in the postwar era, tankers grew in carrying capacity to take advantage of their inherent economies of scale. The same size crew is required regardless of the size of the ship and the cost of building a vessel does not rise proportionately with its carrying capacity. Thus, the larger the tanker, the less its operating and capital costs in terms of cents per ton-mile of transported cargo. Though there was talk of mammoth tankers of 750,000 and 1 million dwt in the early 1970s, the 1973 oil crisis cut short the development of these behemoths. Indeed, the fall in oil exports after the 1973 crisis brought on the most devastating and long-lasting tanker depression in history.

Very few tankers over 500,000 dwt were built (the largest are just over 550,000 dwt) as they proved to be too unwieldy to serve most of the world's terminals and ended their days as storage vessels. Water depth in ports, channels and alongside terminals, terminal storage capacity, cargo availability, and the annual throughput volume determine the optimally sized tanker for each trade. The largest tankers, called Very Large Crude Carriers (Vlccs), range between 200,000–350,000 dwt. Tankers above 350,000 are known as Ultra Large Crude Carriers (Ulccs). These vessels, which number a little over 500, dominate Middle East exports. Seventy percent of Middle East cargoes are destined for Asia, 30 percent are headed around South Africa primarily to North America, and the rest to northern Europe. This is the opposite of the split in cargo destinations in the early 1970s, when these tankers made their debut, and reflects the growing importance of Asia for Middle East exports. While these vessels were originally built to serve Middle East crude exports exclusively, nowadays Middle East exports provide about 70 percent of Vlcc employment. The remaining 30 percent hauls primarily West African crude to the United States and Europe and as backhaul cargoes to Asia. Other backhaul cargoes to Asia are North Sea crude, fuel oil from Europe and the U.S. Gulf, and orimulsion (a mixture of 70 percent bitumen and 30 percent water, which is burned as a substitute for coal) from Venezuela. A few Vlccs move Saudi crude from the Red Sea pipeline terminal to the southern Sumed pipeline terminal and from the northern Sumed terminal to northern Europe.

The next size category, Suezmax tankers between 120,000–200,000 dwt, number about 300 vessels, and are primarily employed handling crude exports from West and North Africa and the North and Black Seas. Tankers smaller than Suezmaxes have more diverse trading patterns. Yet, despite there being about 4,500 tankers above 20,000 dwt, the 500 Vlccs, which represent a bit over 10 percent of the world fleet in number, make up over 40 percent in carrying capacity. Clean or refined oil products are usually transported in carriers of less than 50,000 dwt, although naphtha shipments between the Middle East and Japan are carried in product carriers as large as 100,000 dwt. Clean products tankers are smaller than crude carriers, reflecting terminal capacity and water-depth restrictions and lower throughput volume of clean products versus crude oil trades. They are also more sophisticated than crude carriers, with coated tanks and segregated cargo-handling systems to ensure cargo integrity. There are thousands of tankers and barges below 20,000 dwt, but these vessels are normally involved with intraregional distribution of oil products, not interregional trading.

Oil Spills

Although larger-sized tankers reduce the number of tankers needed to transport oil, and, hence, the number of collisions, the environmental consequences of large tankers breaking up in open or offshore waters is worsened considerably by the greater quantity of oil that can be spilled. Tankers sinking far out at sea barely get mentioned in the press, but an oil spill that reaches land is another matter. Two of the first large oil spills were the *Torrey Canyon* in the English Channel in 1967 and the grounding of the *Amoco Cadiz* on the French coast in 1978. This sharpened environmental opposition to tankers, which came to a head in the 1989 *Exxon Valdez* spill in Alaska. Although only 15 percent of the vessel's cargo entered the environment (the rest was safely offloaded on barges), it was enough to foul nearly a thousand miles of pristine coastline. The uproar over this spill was responsible for the passage of the U.S. Oil Pollution Act of 1990, which greatly increased the limits of liability associated with oil spills and required a gradual phase-in of double-hull tankers calling on U.S. ports. This was followed by amendments to an international convention that required double-hull construction for all tankers delivered after July 1996, along with a mandatory phaseout schedule of single-hull tankers based on age.

Double-hull tankers have a space between two hulls, where the inner hull is the exterior surface of the cargo tanks. Thus a grounding, or a collision, must be of sufficient force to pierce both hulls before oil can be spilled into the environment. The space between the outer and inner hulls holds ballast water to maintain a tanker's stability when it is empty and returning to a load port, and is empty when the tanker is carrying a cargo. In single-hull tankers, ballast water had to be carried in the cargo tanks. Although these tanks were cleaned prior to taking on ballast water, there was still some contamination of ballast water from oily residues. Ballast water in double hull tankers is free of oil pollution. However, this does not prevent the migration of sea life from one part of the world to another when ballast water is pumped overboard at the load port.

The sinking of the *Erika* in 1999 polluted the French shoreline and the sinking of the *Prestige* in 2002 polluted the Spanish and Portuguese shorelines with fuel oil. The lighter ends of crude oil tend to evaporate when released, somewhat reducing environmental damage. Fuel oil is the residue of the refining process after the lighter end products have been removed. This makes fuel oil a worse pollutant than crude oil. The environmental damage wrought by these two spills reinforced public determination for "oil-spill-proof" tankers. Like the unilateral action taken by the United States after the *Exxon Valdez* incident, the European Union unilaterally shortened the phase-in of double-hull standards in European waters without bothering to obtain international approval or cooperation.

No one makes money in an oil spill other than those involved in cleanup operations and in handling lawsuits stemming from real or perceived damage. Certainly tanker owners and oil companies do not profit from an oil spill. The 1989 *Exxon Valdez* spill has cost Exxon $2.1 billion in clean-up costs, $0.3 billion in compensation payments, $0.9 billion in fines and a potential for another $2.5 billion in punitive damages under appeal, which was ultimately reduced to $0.5 billion plus twenty years of legal fees.[7]

Tanker owners and oil companies have taken positive and costly steps to ensure the safe delivery of cargo. The record for tanker spills has improved markedly since the 1970s, with less crude spilled in absolute (total tons) and in relative terms (percentage of oil carried). But this record of achievement, never accepted in the public's mind as a manifestation of good intentions, evaporated as soon as the first drop of fuel oil from the *Erika* and the *Prestige* reached the shoreline.

Most people take great solace in the double hull being the magic cure for tanker spills. Actually, spills are the result of human error, the root cause of collisions whether they be groundings, floundering on reefs, shoals, and rocks, poor tanker vessel design, shoddiness of construction, lack of thoroughness in tanker inspections, and in not maintaining a vessel fit for service at sea. It is true that double-hull construction prevents oil spills from low-energy collisions or groundings where only the outer hull is breeched. This is not true for high-energy collisions or groundings where both hulls are breeched. The *Exxon Valdez,* a single-hull tanker, floundered on an underwater rock that breached its single hull. The crude cargo, being less dense than water, kept the vessel afloat, permitting barges to come alongside and remove 85 percent of the cargo. Had the vessel been double hulled, the floundering would most probably have breeched both hulls. Water entering the space between the two hulls could have sunk the vessel, making it much more difficult to offload the cargo, and perhaps resulting in greater oil spillage. Try selling that concept to members of Congress reacting to public outrage!

Refining

There are approximately 40,000 oil fields in the world, which means there are 40,000 grades of crude oil because no two crude oils from different oil fields are exactly the same. However, oil from different oil fields in the same geographic region, with more or less common characteristics, share the same gathering and collecting systems that blend the slight differences into a common commercial oil such as West Texas Intermediate, Brent Blend, and so forth. Each commercial grade of crude oil has unique properties that determine its value with respect to others.

American Petroleum Institute (API) degree ratings measure the density of crude oil. Light crudes have a lower density than heavy crudes. Condensates, extra-light forms of crude oil found in natural gas fields, have API ratings as high as 65 degrees. Medium crudes are 22–30 degrees and heavy viscous crudes vary between 7–22 degrees. Sweet crudes are under 0.5 percent sulfur and sour crudes are over 1 percent sulfur, with intermediate crudes between the two.[8] Crude oils are also classed as naphthenic or paraffinic. Naphthenic crudes are more highly valued because they produce more naphtha, the principal ingredient in gasoline and the principal driver of the entire oil industry. Paraffinic crudes are waxy, an undesirable trait. Some extra-heavy waxy crudes are unfit for refining and are burned directly as fuel. Waxy crudes require heating coils in the cargo tanks to keep the oil warm enough to be pumped in cold weather. There have been a few instances of heating coils failing during cold weather transits, resulting in the cargo congealing into one enormous ship-shaped candle.

The most highly valued crudes are naphthenic, light, sweet crude such as West Texas Intermediate. The output product slate of a refinery using light sweet crude is skewed to gasoline and other valuable light-end products. Arab Light is a paraffinic light sour crude oil, less desirable and less light than West Texas Intermediate. Heavy crude has an output product slate skewed to gasoil and fuel oil such as Duri, an Indonesian heavy sweet crude and Bachaquero 17, a Venezuelan heavy sour crude. The output product slate of a particular crude oil depends on the design of the refinery and its mode of operation. Some refineries are rather simple in design and restricted to light sweet crudes. Others are designed to run on a single type of crude oil with little ability to vary the output. If the output is too great for one product and not enough of another, the refinery operator may export one and import the other to balance supply and demand rather than change the refinery product slate. Often the residues of simpler refineries, called straight run, are sold to more sophisticated refineries capable of cracking straight run into more valuable clean products. More sophisticated refineries, so-called merchant refineries, can take a variety of crudes and process them with different modes of operation for different product slates. A mathematical modeling technique called linear programming selects the type of crude based on delivered cost, the output slate based on product prices, and the refinery mode of operation that maximizes profitability.

There is no such thing as a generic or plain vanilla oil product. Each oil product has several grades, each with a specific slate of characteristics or requirements to meet the demands of different markets. Motor gasoline has different specifications or limitations on octane rating, vapor pressure, sulfur, lead, phosphorus, gum, and corrosive impurities in addition to volatility standards (the degree of evaporation at specified temperatures). Specifications of gasoline sold in Europe are different than those in the United States. The U.S. gasoline market is fragmented, where California, for instance, has different specifications for gasoline than other states.

Jet fuels have specifications on acidity, aromatics, olefins, sulfur and mercaptans (a malodorous form of organic sulfur), flash point, gravity, vapor pressure, freezing point, viscosity, combustion and corrosion properties, and thermal stability. Although the same as jet fuel, kerosene for lighting and heating has, as one might expect, fewer and less demanding specifications. Gasoil for home heating and diesel fuel have standards that vary in terms of flash, pour, and cloud points, carbon, ash, viscosity, specific gravity, cetane (analogous to octane) rating, sulfur, and corrosive impurities. Diesel fuels have another set of specifications, depending on the type of diesel engine. Even heavy fuel oil, the bottom of the barrel, the residue of the refining process, has various specifications with regard to flash and pour points, water, sediment, sulfur, ash content, and viscosity, depending on its end use, that is, whether it is to be burned in industrial plants or as bunkers for marine engines.

Refining is a bit of a misnomer since refining suggests purification. Refining is not so much purifying crude oil, but transforming it into different products by separating, altering, and blending various hydrocarbon molecules. The refinery process starts with preheating crude oil and adding chemicals and water. The mixture sits in a desalting unit where gravity separates the oil and water, washing out inorganic salts and trace metals that can corrode refining equipment and poison catalysts. Atmospheric distillation first heats crude oil above 720°F, and the resulting vapors enter a distillation column or fractionating tower stacked with perforated trays. Hydrocarbon vapors rise and condense to a liquid on the trays and are transformed back into a vapor by heat exchange with other upwelling hot vapors. The vaporized hydrocarbons rise to a higher tray, condense, and are turned back to a vapor and rise again. Eventually a particular hydrocarbon vapor reaches a tray where it condenses to a liquid, but cannot collect enough energy from passing hydrocarbons to change back to a vapor. This continuous exchange of heat between liquid and vapor allows hydrocarbon molecules of a similar nature to collect on the same tray. The sorted liquid hydrocarbons are drawn off through outlets placed at different heights on the distillation column. The lightest hydrocarbons with the lowest boiling points or temperatures of condensation are drawn off at the top of the fractionating tower and the heaviest hydrocarbons with the highest boiling points or temperatures of condensation at the bottom.

Starting at the top of the fractionating tower, methane in the oil escapes without condensing and is collected and used in the refining process. Flaring of unwanted gases, while common in the past, now means a loss of revenue. The lightest hydrocarbons of butane, propane, and ethane condense below 90°F. A refinery does not just produce simple butane and propane, but also more complex forms such as butylene and propylene. To provide a brief taste of the complexity of the refining process, an alkylation unit with either a sulfuric or hydrofluoric acid catalyst (a catalyst promotes a chemical reaction without being part of it) can transform butylene to alkylate, a high-octane ingredient for motor gasoline or aviation fuel, plus other light end byproducts, butane and isobutane.

Light end products of the refining process can become part of the gasoline pool or end up as petrochemical feedstock to create the wonderful world of plastics. Walk around a house and look at all the objects made from plastic. One would be surprised at the extent of plastic in automobiles or the use of plastic in medical facilities (tubing and plastic bags for intravenous feeding and a host of other uses, blood sample vials, gowns for patients and medical personnel, bedding, gloves, and even body parts). This amazing world of plastics comes from the light ends of the distillation process that are feedstock for steam crackers that produce ethylene plus a whole array of other petrochemicals such as propylene, butadiene, butylene, benzene, toluene, xylene, and raffinate. Ethylene can be changed into other petrochemicals such as polyethylene, ethylene oxide, dichloride, and others to become plastic packaging, trash bags, plastic containers, antifreeze, flooring, paints, adhesives, polyester for textiles, and upholstery for furniture. Propylene goes through its intermediary transformations to end up as polyurethane foams, polyester resins, protective coatings, film, and adhesive for plywood. Butadiene ends up in tires, rubber goods, nylon, and high-impact plastic products. Benzene becomes polystyrene, which is found in insulation and disposable dinnerware, while other forms of benzene become detergents, fiberglass, herbicides, and pesticides. Toluene and xylene can end up in the motor gasoline pool or in paints, coatings, and in polyurethane and polyester products, depending on their respective value in the gasoline pool or as paints and plastics.

The next level down in a fractionating tower produces light naphthas that condense between 90°F–175°F and become part of the gasoline pool. Heavy naphthas condense between 175°F–350°F and are fed into a catalytic reformer to produce a mix of reformate for high-octane gasoline and BTX (benzene, toluene, xylene). The mix of reformate and BTX from a catalytic reformer can be varied according to their respective prices in the gasoline pool or as petrochemicals. The butane and isobutene byproducts of naphtha reforming are sold or used elsewhere in the refining process and the hydrogen byproduct is consumed in a refinery's hydrotreating and hydrocracking units.

Kerosene condenses between 350°F–450°F and can be sold as kerosene or jet fuel with or without a run through a hydrotreater. A hydrotreater uses hydrogen from the naphtha reformer and a catalyst to purify kerosene and gasoil to improve combustion performance and remove sulfur. Sulfur comes out as hydrogen sulfide and is then reduced to pure sulfur for sale to industrial users and fertilizer manufacturers. Light gasoil condenses between 450°F–650°F and is sold as heating oil and diesel fuel. Heavy gasoil condenses between 650°F–720°F. Catalytic cracking splits the long hydrocarbon chains of heavy gasoil into shorter chains by breaking carbon-carbon bonds with a special silicon dust catalyst. The resulting free carbon sticks to the silicon dust, which inhibits its effectiveness until it is burned away in a regenerator. The output of the cat cracker is primarily naphtha and gasoil; the mix is adjustable to make more gasoline during the summer or more heating oil during the winter. Heavy cycle oil produced by the cat cracker is either recycled or becomes part of the residual fuel pool.

In addition to catalytic cracking, hydrocracking is another method used to break long hydrocar-

Table 6.1

Historical Development of Refining Processes

	Process	Purpose	By-Product
1862	Atmospheric distillation	Produce kerosene	Naphtha, tar
1870	Vacuum distillation	Lubricants	Asphalt, resids
1913	Thermal cracking	Gasoline	Resids
1916	Sweetening	Reduce sulfur	Sulfur
1930	Thermal reforming	Improve octane	Resids
1932	Hydrogenation	Remove sulfur	Sulfur
1932	Coking	Gasoline base stocks	Coke
1933	Solvent extraction	Improve lubes	Aromatics
1935	Solvent dewaxing	Improve pour point	Waxes
1935	Catalytic polymerization	Improve gasoline yield and octane	Petrochemical feedstocks
1937	Catalytic cracking	Improve gasoline octane	Petrochemical feedstocks
1939	Visbreaking	Reduce viscosity	Distillates, tar
1940	Isomerization	Alkylate feedstock	Naphtha
1942	Fluid catalytic cracking	Improve gasoline yield and octane	Petrochemical feedstocks
1950	Deasphalting	Increase cracking feedstock	Asphalt
1952	Catalytic reforming	Upgrade low-quality naphtha	Aromatics
1954	Hydrodesulfurization	Remove sulfur	Sulfur
1956	Inhibitor sweetening	Remove mercaptans	Disulfides
1957	Catalytic isomerization	Convert to high octane molecules	Alkylation feedstocks
1960	Hydrocracking	Improve quality and reduce sulfur	Alkylation feedstocks
1974	Catalytic dewaxing	Improve pour point	Waxes
1975	Residual hydrocracking	Increase gasoline yield from resids	Heavy resids

bon chains into shorter chains of more valuable naphtha, jet fuel, and light gasoil. Hydrocracking employs high temperatures (650°F–800°F) and hydrogen from the naphtha reformer under high pressure (1,500–4,000 psi) in the presence of a catalyst to split hydrocarbon chains. Refiners prefer to consume hydrogen byproduct from naphtha reformers rather than purchase it or strip it from methane. Refinery operators have a long history of the safe production and distribution of hydrogen within a refinery, which may come in handy someday if society begins the slow shift to a hydrogen economy.

What is left at the bottom of the distillation column is called atmospheric (or atmos) or straight run resid. Simpler designed refineries that cannot further process straight run resid normally sell it to more sophisticated refineries that can. Vacuum distillation heats straight run to nearly 1,100°F, then injects a blast of steam in a vacuum to create light and heavy vacuum gasoil. The heavy vacuum gasoil can be fed to a cat cracker to further break down the hydrocarbon chains into lighter end products. What is left is called flasher bottoms, a heavy fuel oil burned as an industrial and utility fuel, as bunkers for marine engines, or made into lubricating oils. Viscosity breakers, or visbreakers, also break up long molecular chains of hydrocarbons to recover more gasoline and gasoil from resids. Cokers crack heavy refinery streams into light products, leaving nearly solid carbon, called petroleum coke, which looks like charcoal briquettes and is burned like coal. Petroleum coke and asphalt are the very bottom of the bottom of the barrel. Considering the nature of asphalt and petroleum coke, one can conclude that refinery operators have learned to squeeze the last light hydrocarbon molecule out of crude oil. All this did not happen overnight. Table 6.1 shows the historical development of refinery processes (note how many are associated with increasing gasoline yield).[9]

OIL RESERVES

Oil resources are the totality of oil in the ground. Half of this is irretrievable, even with the most costly recovery methods. Oil that is retrievable is called reserves. Reserves of an oil and gas field are not known with certainty until the last well is dry. Reserves are an estimate of the amount of oil and gas that can be removed from a reservoir under current oil prices employing current extraction technology, not the amount of oil resources actually in the ground. Thus, an improvement in the price of oil that can support more costly recovery methods, or an advance in oil-extraction technology, can change the amount of proven reserves. Oil resources are fixed by what is in the ground whereas reserves are a variable dependent on oil prices and extraction technologies. Proven oil reserves can be considered working inventory but not an inventory that appears on the balance sheets of oil companies. Proven oil reserves are reported as a footnote in an annual report. The reported book value of a share of oil company stock based on its balance sheet does not include the value of the company's proven reserves. Proven reserves are, however, acceptable as collateral for bank loans.

Proven reserves are reserves that can be calculated with reasonable accuracy based on field production and the results of appraisal or development wells that measure the potential size of an oil field. The calculation of proven reserves is based on the volume of the pay zone, the porosity and permeability of the reservoir, the degree of oil saturation, and the recovery factor. Porosity is obtained from well logs or cores and oil saturation from a resistivity well log. The recovery factor is estimated by the reservoir drive, nature of the oil, and permeability of the reservoir rock. Another method of estimating proven reserves is based on the decline curve, the falloff in production over time. The materials balance method is another mathematical approach that correlates the volume of oil, water, and gas produced with the change in reservoir pressure.

Proven reserves are either developed (within reach of existing wells) or undeveloped (new wells would have to be drilled to access the oil). Probable and possible reserves are calculated in a fashion similar to proven reserves, but their lower classification reflects the greater degree of uncertainty associated with the underlying data. Rule 4.10(a) of Regulation S-X under the U.S. Securities Act of 1933 was promulgated to protect investors from being fleeced by unscrupulous speculators selling east Texas oil properties. The required methodology for calculating proven reserves is based on actual production. In 2004 the U.S. Securities and Exchange Commission (SEC) ordered Shell Oil to remove over 4 billion barrels of oil, equivalent to 20 percent of its reserves, from proven reserves because Shell had not followed the prescribed methodology. Shell had categorized certain deep-water reserves as proven based on the results of exploratory wells and 3-D seismic analysis of their reservoir structures. Shell retorted that the SEC was using a dated methodology applicable to onshore reservoirs, not deep-water offshore reservoirs. The SEC response was that its rules are clear—an assessment of proven reserves must be based on actual production from existing wells using an analytical approach that can substantiate at least a 90 percent chance of recoverability. Without following the SEC script for determining reserves, this portion of Shell's reserves could not be considered proven, but could be considered probable if a 50 percent chance of recoverability could be demonstrated or, lacking that, the reserves could be considered possible. Thus, while Shell's total proven, probable, and possible reserves remained unchanged, the portion considered proven took a significant hit.

More ominous was the *Petroleum Intelligence Weekly* (*PIW*) report in January 2006 that Kuwait's assessment of proven reserves of 99 billion barrels, representing 10 percent of known world reserves, might be overstated by as much as four times. If true, then Kuwait's proven reserves are only 25 billion barrels. *PIW* estimated that proven and unproven reserves may total 48 billion

Table 6.2

Write-up of OPEC Reserves

Nation	Year	Write-up of Reserves Billion Barrels
Kuwait	1983	25.7
Venezuela	1985	26.5
Iran	1986	33.9
Iraq	1986–87	35.0
United Arab Emirates	1986	64.2
Saudi Arabia	1988	85.4

barrels, about half the official estimate. If true, writing off 5–7.5 percent of the world's known petroleum reserves in one blow cannot be lightly dismissed.

Are We on a Slippery Slope?

Indonesia, the United Kingdom, and the United States have three things in common—they were once exporters, their production has already peaked (down 3.2 million bpd [barrels per day] from their aggregate production of 12.5 million bpd in 1997), and are now oil importers. Nations whose oil production is less in 2008 than in 2000 include Argentina, Australia, Brunei, Colombia, Denmark, Egypt, Indonesia, Mexico, Nigeria, Norway, Oman, Romania, Syria, the United Kingdom, the United States, Venezuela, Vietnam, and Yemen. In some cases, the fault is not finding sufficient replacement oil and in others mismanagement of oil resources. Indonesia is the first OPEC nation to become a net oil importer and is no longer a member. However, Indonesia is still a net energy exporter as it continues to exploit its vast natural gas and coal resources.

The United States, once the world's largest oil exporter, is now the world's largest oil importer. Despite discoveries of oil in the North Slope of Alaska and in the Gulf of Mexico, oil production in the United States has been in a slow decline from exhaustion of Lower 48 oil fields and the decades-long prohibition of exploration in the Arctic National Wildlife Reserve and in offshore waters other than Louisiana and Texas. The prohibition of oil drilling in offshore Florida waters was strongly supported by yacht owners who did not want their ocean vistas ruined by the drilling rigs that provide oil for their fuel-guzzling yachts—an obvious disconnect between desire and reality. Those who own gas-guzzling SUVs for their daily trips to the shopping mall, yet oppose anything the oil industry proposes, are guilty of the same disconnect.

World oil reserves are 1,258 billion barrels (1.258 trillion barrels), a figure that includes 270.5 billion barrels of OPEC write-ups, shown in Table 6.2.[10] These write-ups are held in suspicion as they were not accompanied by new discoveries. While it is true that existing reserves could have been recalculated to the higher totals, it is also true that during this time, OPEC was setting production quotas based on proven reserves. A warranted or unwarranted write-up of proven reserves would have resulted in a higher oil production quota and higher revenue.

Table 6.3 lists the world's largest oil fields. The cumulative percentage is based on the adjusted proven reserves of a little over 900 billion barrels, net of the write-ups in Table 6.2. The Ghawar field represents 7 percent of the world's proven resources. The total of the Ghawar and the Greater Burgan fields represent 10 percent of the world's proven reserves, and so forth.[11]

These eighteen supergiant fields account for one-third of the world's known proven reserves in

Table 6.3

World's Largest Oil Fields

Ultimate Recovery Oil Millions Bbls	Country	Field Name	Discovery Year	Cumulative Percentage
66,058	Saudi Arabia	Ghawar	1948	7
31,795	Kuwait	Greater Burgan	1938	10
22,000	Iraq	Rumaila North & South	1953	13
21,145	Saudi Arabia	Safaniya	1951	15
17,223	Abu Dhabi	Zakum	1964	17
17,000	Iraq	Kirkuk	1927	19
16,820	Saudi Arabia	Manifa	1957	20
13,390	Venezuela	Tia Juana	1928	22
13,350	Iran	Ahwaz	1958	23
13,010	USA-Alaska	Prudhoe Bay	1967	25
13,000	Kazakhstan	Kashagan	2000	26
12,631	Iran	Marun	1964	27
12,237	Saudi Arabia	Zuluf	1965	29
12,000	Iraq	Majnoon	1977	30
11,800	Iran	Gachsaran	1928	31
10,276	Abu Dhabi	Murban Bab	1954	32
10,265	Saudi Arabia	Abqaiq	1940	33
10,000	Iran	Fereidoon	1960	34

40,000 oil fields. Two-thirds of these were discovered in and prior to 1960, nearly half a century ago. All but three are in the Middle East. OPEC, which is made up of Middle East nations plus Algeria, Libya, Angola, Nigeria, Ecuador, and Venezuela, possesses 76 percent of the world's oil reserves and produces nearly 45 percent of the world's oil. Asia consumes 30 percent of world oil production, North America 27 percent, and EurAsia (Europe plus Former Soviet Union) 24 percent. Asia, North America and Europe are dependent on imports, but Asia is far more dependent on Middle East imports than North America or Europe. The location of major world oil reserves and major oil consumers illustrates with great clarity the geopolitics of oil—the world is utterly incapable of extricating itself from reliance on OPEC oil. But the United States could become independent of Middle East (not OPEC) oil if it had the will to do so.

In 1956 M. King Hubbert, a geophysicist with a background in exploration for Shell Oil, postulated that U.S. oil production would peak in the early 1970s based on an assessment of discoverable oil (known oil reserves plus that yet-to-be discovered). Scorned by his contemporaries, he turned out to be basically right. Hubbert was off a bit on the actual timing of the peak in production because, since he made his original prediction, more oil was discovered in Alaska and in the Gulf of Mexico than he anticipated. But he was not off by much.

Modern-day followers of Hubbert assess the quantity of ultimately discoverable oil and compare that to cumulative production on a global scale. Oil production peaks when cumulative production has consumed half of the ultimately discoverable reserves. Ultimately discoverable reserves consist of known reserves, including enhanced production from played-out fields through secondary and tertiary recovery methods, and an assessment of what has not yet been discovered. When on the downhill slope of a bell-shaped curve, exploration and extraction become more expensive as fewer and smaller oil fields are discovered in more remote areas and more costly methods have to be employed to maintain production in aging oil fields. Furthermore, oil becomes more viscous as a field ages, a fact that increases refining costs.

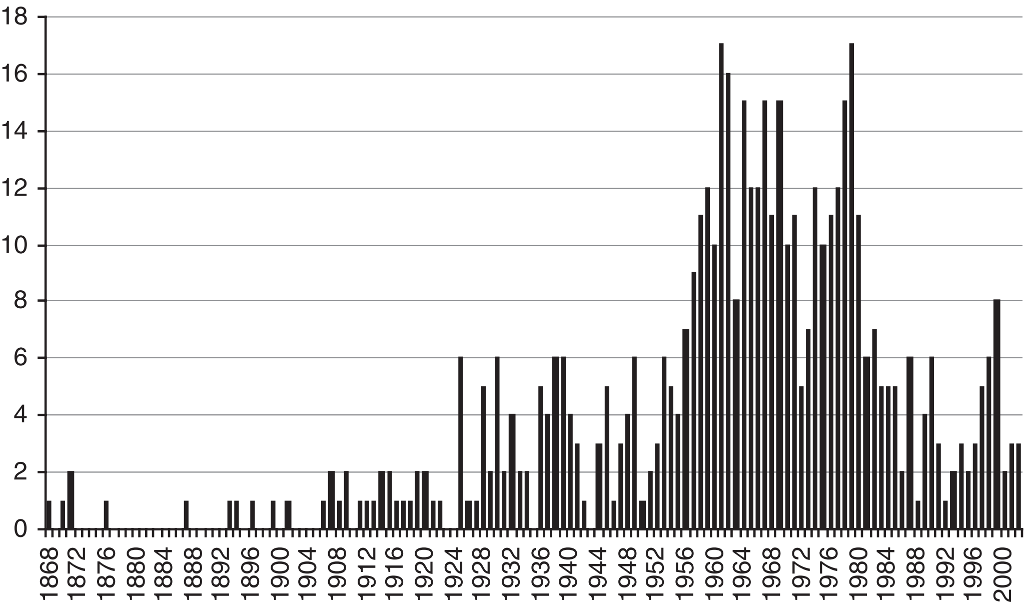
When applying Hubbert's thinking on a global scale, one still has to deal with the challenge of assessing ultimately discoverable oil. As with discoveries in Alaska and the Gulf of Mexico, any discovery that increases the assessment on ultimately discoverable oil postpones the peaking of production. Right now the favorite assessment for ultimately discoverable oil is between 2–3 trillion barrels. The lower estimate comes from followers of Hubbert,[12] while the higher estimate is from the U.S. Geological Survey.[13]

If we take the lower estimate of ultimately discoverable and recoverable oil of 2 trillion barrels and assume that 1 trillion barrels have already been consumed, we are either peaking now or shortly will be. If the higher estimate of 3 trillion barrels is valid, then we have some breathing room. The higher estimate places us 0.5 trillion barrels away from peaking if we have already consumed 1 trillion barrels. At consumption levels of 80 million barrels per day, we will consume the 0.5 trillion barrels separating us from peak production in seventeen-and-one-half years. If consumption grows by 1 million barrels per day, which is less than historical growth, peaking occurs in sixteen years. At an annual growth of 1.5 percent per year, peaking occurs in fifteen years. Whether peaking occurs at fifteen or twenty years is not critical; what is critical is that, even if peaking occurs in twenty years, we will end this century with no oil. Many of us will be dead by then, but what of our progeny?

The times of trouble do not begin when the oil is gone, but after production has peaked. This is not a prescription for cheap oil, but expensive oil. Oil-extraction costs are already rising as we explore in more inhospitable and remote locations for oil. The historical survey of water-depth capacity and level of sophistication of offshore-drilling rigs attests vividly to the increasing challenge of finding new oil fields. Higher-priced oil slows or depresses economic activity in industrialized nations and sends developing nations with little indigenous supplies of oil and a perennial negative trade balance into an economic tailspin. Every unsuccessful exploratory well decreases the overall chance of finding another supergiant oil field. Huge finds are necessary to increase reserves in a world of rising consumption. Decreasing oil reserves after peak production will create greater stress among nations in an ever more evanescent search for security of supply. We may be at the beginning of the times of trouble with our military involvement in the Middle East, which started in the 1980s during the Iran-Iraq War to keep the sea lanes open, then escalated sharply in 1990 with protecting Kuwait and escalated sharply again with the invasion of Iraq in 2003. Figure 6.1 shows the historical record for discovering giant oil fields of greater than 500 million barrels. Clearly the peak of discovery has passed. Prior to 1968, the problem faced by oil executives was how to control production to maintain price in the face of mounting discoveries. Since 1968, with the exception of two or three years, discoveries have not kept up with consumption by a significant margin. Current estimates are that discoveries compensate for only one third of consumption; a sure-fire prescription for running out of oil.

In 1980, remaining proven oil reserves were about 670 billion barrels, compared to the current estimate of 1.2 trillion barrels. One may wonder how reserves can be getting larger if the rate of discovery of new fields lags behind consumption. Part of the answer is that Figure 6.1 only measures large finds of over 500 million barrels; smaller fields are not being counted. Part of the answer also lies in the fact that proven reserves of a new field, once established, may not always be written down as it is being depleted. Proven reserves of major OPEC exporting nations with no discoveries of note remain the same year after year despite significant production. This cannot be, but any write-down would reduce their production quotas. Reserves should take into consideration both new discoveries and the depletion of existing reserves and write-ups of existing reserves. The U.S. Geological Survey evaluated the growth of petroleum reserves between 1996 and 2003.[14] During this eight-year period (including 2003), oil reserves increased 240 billion barrels of which

Figure 6.1 **Number of Giant Oil Field Discoveries**



69 billion barrels were new discoveries and 171 billion barrels were write-ups of existing oil reserves. Sub-Saharan Africa was the largest source of new discoveries (20 billion barrels) followed by the Middle East and North Africa (14 billion barrels). In terms of write-ups of existing reserves, nearly half (83 billion barrels) occurred in the Middle East and North Africa. During these eight years, total consumption was 197 billion barrels, less than the additions to reserves. Indeed, the ratio of proven reserves to annual production has been in a slight uptrend since 1980 of 40 years, or 30 years if the write-ups in Table 6.2 are removed. Taking the figures at their face value, additions to reserves mainly in the form of increases to existing reserves are keeping slightly ahead of consumption. This would suggest that we are not yet at peak oil. The problem is that reserves of older fields not being adjusted to reflect production result in an overstatement of reserves.

Since the beginning of the oil age, predictions of the world running out of oil have been made, and all have been proven wrong. In 1879, the U.S. Geological Survey was formed in response to a fear of an oil shortage. In 1882 the Institute of Mining Engineers estimated that there were 95 million barrels left, an amount that would be exhausted in four years at the then-present consumption rate of 25 million barrels per year. In the early 1900s, Theodore Roosevelt opined that there were about twenty years of reserves left and hearings were held in Washington on the adequacy of supply. In 1919, the *Scientific American* warned that there were only twenty years of oil left in the ground and made a plea for automobile engines to be designed for greater energy efficiency (déjà vu?). In 1920, the U.S. Geological Survey estimated that U.S. reserves were only 6.7 billion barrels, including what was known and remaining to be discovered (current U.S. reserves are 30 billion barrels after eighty-odd years of production).[15] In the 1920s, the U.S. government, worried over the adequacy of oil supplies, secured an interest in the Turkish Petroleum Company and had to almost coerce reluctant U.S. oil companies to get involved with Middle East oil.

All these forecasts have been proven wrong, but that does not mean that the current spate of dire forecasts is necessarily wrong. The big difference between past and present forecasts is a lack of large oil discoveries. A forty-year hiatus in discovering supergiant fields should not be ignored. If oil cannot be replenished as fast as it is being consumed, then it is a wasting asset. It is not a question of whether, but when, we run out of oil. Yet, all this hand-wringing is based on proven reserves. There is something unsettling about considering only proven reserves, which is a variable based on current oil prices and current extraction technology. Increase price or improve extraction technology, and proven reserves will increase from the reclassification of probable reserves to proven and, perhaps, possible reserves upgraded to probable. Oil reserve statistics are also subject to manipulation for political or commercial reasons. Perhaps some OPEC nations exaggerated their reserves to get a higher production quota. Perhaps others do not want the world to know the true amount of their reserves in order to sustain oil prices. A particular geographic area may be a very strong candidate for harboring enormous oil reserves, but exploration might be postponed on the theory that what may be in the ground will be worth more if discovered tomorrow than if discovered today.

Probable and possible reserves and unconventional sources of oil could make a difference. As things stand, unless the world experiences the thrill of a discovery of supergiant fields with some degree of regularity, it is clear that the frequency of discovering major oil finds is dropping, the size of newly discovered oil fields is falling, the cost of extraction is increasing, the overall quality of oil from aging fields is dropping—all signs that oil is peaking. Having said that, top oil company executives maintain that there is plenty of oil to be discovered beneath the ground, but the problem is above the ground. Above-ground challenges include not being able to negotiate a reasonable deal with national oil companies, not being permitted to drill as in offshore waters of the continental United States or Alaska, and reneging of contracts and unilateral changes in contractual arrangements as in Venezuela and Russia.

Was 2004 a Watershed Year?

Two prominent government projections published in 2004 indicated that a doubling to a near tripling of Middle East oil exports by 2025 and 2030 would be necessary to keep up with world growth in demand.[16] A review of the Middle East oil producers rapidly leads to the conclusion that Saudi Arabia is the mainstay of incremental exports. The presumption that Saudi Arabia has the spare capacity to export whatever is required is now being questioned. The reservoir pressure in Ghawar, the world's largest oil field and responsible for 60 percent of Saudi output, is maintained by pumping in seawater. Over time seawater mixes with crude oil, with an increasing concentration of seawater in oil coming from producing wells. The end of Ghawar will be marked when mostly saltwater comes out of its oil wells.[17] While Saudi Arabia vociferously denies the rumor that Ghawar is showing signs of aging by an increasing presence of seawater, other supergiant oil fields in Russia, Mexico, Venezuela, the United States, and Indonesia are showing indisputable signs of aging.

While once Saudi Arabia was capable of ramping up its production when another OPEC member such as Nigeria and Venezuela stopped exporting oil, this is no longer possible other than for short disruptions. Events in 2004 indicated that Saudi Arabia was not capable of pumping sufficient quantities of light to medium sweet grades of crude to satisfy demand by the world's refinery operators. Although Saudi Arabia was able to pump heavy sour grades in large quantities, there was insuffiient capacity of the world's refineries to refine this crude, causing a record price spread between these two grades plus a sharp rise in sweet crude prices.

The world was up against two constraints in 2004: the capacity of the oil producers to meet demand for light sweet crude and the capacity of the oil refiners to process heavy sour crude.

The decline in OPEC's theoretical maximum production capacity from 39 million bpd in 1979 to 32 million bpd in 2004 has to be treated as another warning that the Middle East cannot be considered an infinite source of oil.[18] The matter is worse when viewed in terms of spare capacity. In both 1979 and 2004, OPEC production was 31 million bpd. This implies a spare capacity of 8 million bpd in 1979 and only 1 million bpd in 2004. There is little margin for OPEC as a group to satisfy world demand if a single major OPEC nation ceases to export for other than a short period of time. The runup in prices in 2008 demonstrated just how narrow the gap between supply and demand had become.

Some people look to Russia as a potential safety valve for augmenting global spare capacity. Russia has large oil and natural gas reserves but has proven to be a difficult place to invest. Russia has made life difficult for both domestic and foreign oil companies by unilaterally redefining tax liabilities and changing contractual obligations. Changing the rules of the game does not make Russia a safe place to invest. Nor is Russia a dependable exporter. In 2006 and again in 2009, Russia interrupted natural gas shipments to the Ukraine over a price dispute that also interrupted natural gas flows to Europe in the midst of the winter heating season. Having Russia fill the shoes of the Middle East, even if physically possible, would not be an effective way to deal with geopolitical risk.

The United States was once the world's swing producer when oil production was controlled by the Texas Railroad Commission. The Texas Railroad Commission curtailed production to maintain price in order not to waste a natural resource. Of course, maintaining price was also in the interests of Big Oil, but not necessarily for conservation purposes. In 1971, the Texas Railroad Commission authorized 100 percent production for all wells under its jurisdiction, thus ending the days of the United States being a swing producer. Since the oil crisis of 1973, the mantle of swing producer has been worn by Saudi Arabia. Saudi Arabia, by all accounts, has been a fairly responsible swing producer, seeking a price that was not too low to support its social programs in medical care, housing, and education for its rapidly growing population as well as providing funds to build a value-added infrastructure of refineries and petrochemical plants. Saudi Arabia also realizes that too high a price dampens world economic activity, subsidizes the development of high-cost oil fields elsewhere, and promotes alternative sources of energy. This is the lesson Saudi Arabia learned to its disadvantage during the late 1970s and early 1980s.

OPEC maintains what it deems an acceptable range of oil prices by raising production quotas when oil prices are too high and lowering them when prices are too low. Since most oil producers within OPEC operate at or near their maximum sustainable rates, the nation with the greatest capacity to increase production and the strongest will to reduce production is Saudi Arabia. In 2004, Saudi Arabia made several announcements of its intention to increase production to dampen oil prices. Increased Saudi production did not cool oil prices as expected. Contrary to the naysayers who maintained that Saudi Arabia was bluffing, tanker rates soared, proof of higher Saudi export volumes. However, prices did not react as much as Saudi Arabia desired. What this showed was the lack of sufficient spare capacity in Saudi Arabia to keep oil prices from getting out of control. Proof positive that there was no longer sufficient spare capacity in the world to control prices occurred in 2008 when prices soared to $147 per barrel.

The primary source for incremental oil demand that taxes OPEC's capacity to produce oil from 2004 to 2008 was China, which rose in rank to become the world's first or second largest consumer of a number of commodities such as copper, tin, zinc, platinum, steel and iron ore, aluminum, lead, nickel, driving up prices for all these commodities to record levels. Capital goods exports from Europe and Japan for machinery and electricity-generating equipment surged in response to China's rapid industrialization. All this collapsed in 2008 in the wake of a series of bursting bubbles beginning with the U.S. housing market. Thus the $147 per barrel price in oil lost nearly

80 percent of its value in six months time not from an economic retreat caused by high energy prices as in the late 1970s and early 1980s, but from a global bursting of a series of financial bubbles that sent the world economies into a tailspin.

Even with moderate oil prices in 2009, oil remains in a very precarious state. This can be seen in the Baku-Tbilisi-Ceyhan (BTC) Oil Pipeline, built by British Petroleum, which came onstream in 2005. Its fully rated capacity of 1 million bpd of Caspian crude will be exported from the Turkish port of Ceyhan. This may seem like a lot of oil by any measure, but is it? This crude is needed as replacement of declining North Sea oil production, which in 2008 was down 2 million bpd since 2000. Thus, this new source of crude does nothing but half fill the gap of declining North Sea oil and in no way contributes to satisfying incremental growth in global oil consumption.

China is well aware of its inability to expand its domestic oil production in significant volumes, yet it is unwilling to reduce its growth in oil demand by sacrificing economic development. This leaves the nation vulnerable because it relies on the Middle East as a major and growing source of oil. In order to reduce its reliance on Middle East oil, China has been actively pursuing diversification of oil supplies by encouraging Russia to build an oil pipeline to ship Siberian oil to China, by investing or buying oil properties in Indonesia, Europe, and Canada, and by taking an active role in the development of oil projects in other nations such as a major oil export project in Sudan. With China shopping for oil in the Atlantic basin, it is sure to come in conflict with the United States over an increasingly scarce and vital commodity.

Events in 2004 raised the question of whether refinery capacity in the United States was adequate. The well-publicized fact that no grassroots refinery has been built in the United States since 1976 ignores that there was excess U.S. refinery capacity between the mid-1970s and mid-1990s, which provided little in the way of an economic incentive to build new refineries. However, there was an ongoing program of upgrading and debottlenecking existing facilities that increased refinery throughput capacity, called refinery creep. Luckily for the United States, its refiners invested in facilities to handle heavy grades of crude oils that remained in plentiful supply during times of limited spare-producing capacity. Moreover, the switch by Europeans from gasoline- to diesel-driven automobiles freed up gasoline refining capacity to help meet growing U.S. gasoline import needs. Once this spare capacity is consumed, presumably more refineries will have to be built; if not in the United States then somewhere in the Atlantic basin, and if not there, then in the Middle East, which will only increase our reliance on Middle East oil.

One might think that high oil prices would be a strong incentive for building refinery capacity, but that is not how the system works. It is the spread between the price of oil products and the cost of crude oil that determines refinery profitability. A high price of crude oil does not automatically translate to high refinery profits unless the spread widens. Even a widening price spread between crude and refined oil products may not be sufficient to induce refinery construction. A refinery operator who is making a great deal of money on a refinery with a cost base of $200 million may not have the financial wherewithal to construct an equivalent-sized refinery that would cost $2 billion unless the spread widens further.

Of course, none of this need happen. This logjam of constraints has been broken by a severe economic contraction caused by a global financial meltdown. When a global economic recovery takes place, these constraints will reappear. The current economic malaise has given the world a reprieve in time to perhaps discovering a supergiant oil field or two. One potential area is the South China Sea, where territorial claims by six littoral nations have inhibited exploration. Another potential area for discovery of a supergiant oil field is, surprisingly, Iraq, which is largely unexplored. In late 2009, Iraq signed a deal with oil companies that will greatly increase its crude oil production. Another potential area of discovery is offshore Cuba, which may contain a 10 billion barrel oil field, an unproven estimate until wells are drilled to confirm its existence. Russia, Vietnam, and China have made deals with Cuba to explore not far from offshore U.S. waters, but they appear reluctant to begin operations. Perhaps it's related to Cuba not paying foreign operators for existing Cuban production and then buying out their ownership interests for a small fraction of what was owed to them. It would be ironic that the masters of expropriation are wary of having their investments expropriated! Another unexplored potentially large oil field resides within the United States in the Bakken formation in western North and South Dakota, eastern Montana, and Canada. The U.S. Geological Survey estimates that a potential oil field of 3–4.3 billion barrels may exist in this formation, a 25-fold increase from its earlier 1995 estimate. The step-up in an unproven estimate is based on new geological models designed to evaluate the potential of the Bakken formation, advances in drilling and production techniques that make extraction of oil from this formation possible, and the results of early drilling activity.[19] As with Cuba, these estimates are not included in proven reserves until "proven."

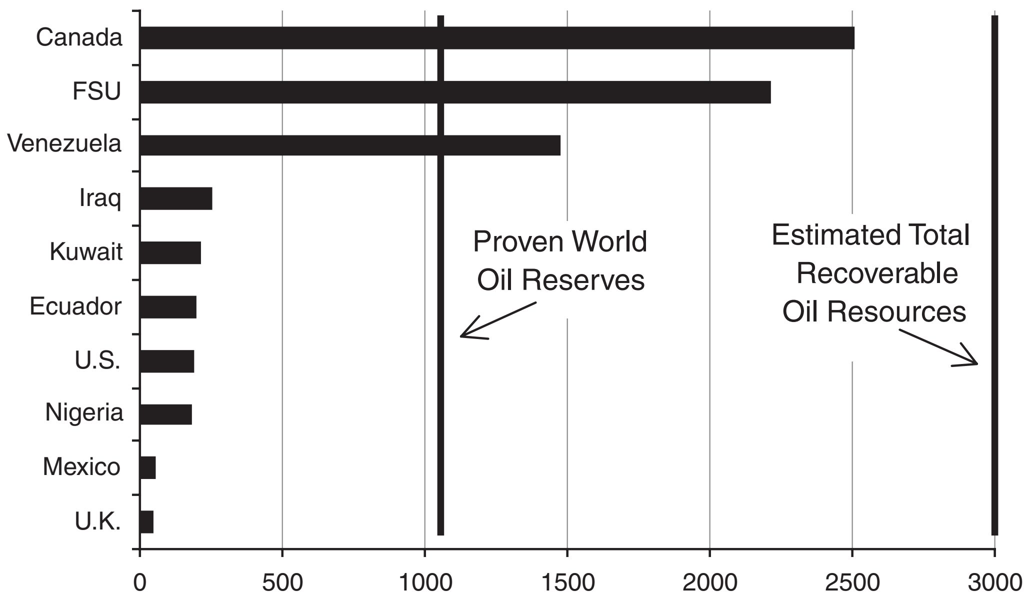
SYNTHETIC CRUDE

Synthetic crude, or syncrude, is a nonconventional source of oil that must be processed to produce an acceptable grade of crude oil before it can be fed into conventional refineries. Major nonconventional sources of synthetic crude are bitumen deposits in Canada, Venezuela, and Russia, plus oil shale found in various parts of the world. Bitumen is a thick, sticky form of crude oil, sometimes called extra-heavy oil, with the consistency of molasses; too viscous to flow in a pipeline unless mixed with light petroleum liquid. Bitumen also has high sulfur and metals content that complicates upgrading to a syncrude fit for a conventional refinery. These undesirable traits are offset by huge deposits of bitumen, as shown in Figure 6.2. With the exception of a small portion of heavy crude in Venezuela's proven oil reserves, these deposits are not included in official oil reserve figures.

In Canada, huge volumes of oil migrated horizontally and vertically through more than seventy miles of rock without entrapment by anticlines or faults. As the seep oil emerged on the surface, it mixed with sand and some clay and became a feast for microorganisms that transformed the oil into bitumen. It is estimated that the bacteria consumed between two and three times the present volume of bitumen, an incredible amount of oil when one considers that Canadian tar sands (now called oil sands) hold about 2.5 trillion barrels of bitumen. This implies that the original source rock generated 5 to 7.5 trillion barrels, compared to 2 or 3 trillion barrels of ultimately discoverable global oil reserves, including all that has been consumed since Drake first discovered oil in 1859. That is a whole lot of ocean plankton, algae, and other forms of simple marine life to die and settle in oxygen-starved sediment in a single province of Canada.

As a recoverable resource using present technology, Canadian oil sand is equivalent to 175 billion barrels of crude oil, somewhat less than the 264 billion barrels of proven oil reserves in Saudi Arabia. This estimate is based on a price of crude oil high enough to financially justify the necessary capital investment. In 2009, older syncrude plants required about $30 per barrel to sustain their operation, newer and more costly plants $60 per barrel, and even more costly grassroot investments $80–$90 per barrel. Technological advances could considerably raise the estimated amount of proven oil reserves since the estimate of 175 billion barrels of recoverable oil is based on surface mining. The Athabasca deposit in Alberta is the world's largest oil sand deposit, containing about two-thirds of Canadian bitumen resources. Oil sand with about 12 percent bitumen by weight is mined similar to the way coal is surface-mined. The overburden is removed and stockpiled for reclamation after strip-mining operations cease. However during mining operations, the land surface is scarred as in strip-mining coal. Giant

Figure 6.2 **World Heavy Oil and Bitumen Resources** (Billion Bls)



mining shovels working 24–7 fill huge trucks with 360–380 tons of oil sand for transport to an upgrading plant.[20]

The first step is an extraction plant where the oil sand is crushed and mixed with hot water. It is then sent to a large separation vessel where sand falls to the bottom and bitumen, trapped in tiny air bubbles, rises to the top of the water as froth. The froth is skimmed off, mixed with a solvent, and spun in a centrifuge to remove the remaining water and sand. Water and sand residue, called tailings, are placed in a settling pond where any remaining bitumen is skimmed off the surface. Sand is mixed with water and returned to the mine site by pipeline to fill in mined-out areas, and the water is separated and pumped to a settling pond for recycling. This method minimizes undesirable environmental consequences and recovers over 90 percent of the bitumen in the sand. For deeper deposits of oil sands, wells are drilled and high-pressure steam is injected into the well to soften up the surrounding bitumen. Bitumen flows into the well and is then pumped to the surface. When production slows, a cycle of "huff and puff" softens up another batch of bitumen. This method recovers a relatively small portion of the bitumen and also releases a poisonous gas, hydrogen sulphide, which requires environmental safeguards to prevent its escape to the atmosphere.

After the bitumen is extracted, it is ready for upgrading, which converts it into synthetic, or processed, crude with a density and viscosity similar to conventional crude oils. Upgrading involves removing carbon and sulfur and adding hydrogen. Coking removes carbon atoms from the large, carbon-rich hydrocarbon chains, breaking them up into shorter chains. Hydrotreating removes sulfur, which is sold to fertilizer manufacturers. Hydrocracking adds hydrogen to hydrocarbon chains to increase the yield of light-end products when the syncrude is refined in a conventional refinery. The processed syncrude is mixed with condensate, a very light oil associated with natural gas production, for pipelining to a refinery.

The process for making syncrude requires a lot of natural gas as a source of hydrogen for hydrocracking and hydrotreating and to heat water for extracting the bitumen from the sand. A great deal of water is used for separating the bitumen from the sand and in pumping the spent sand back to the mine site. While water can be recycled up to seventeen times, the residue is a black foul liquid collected in tailing ponds. Care has to be exercised that this liquid does not escape to the environment. Thus, the enormous reserves of bitumen are ultimately dependent on the availability of water, a naturally replenishable resource up to a point, and natural gas, a wasting resource. Without a pipeline to ship local supplies of natural gas to market, syncrude production creates value for stranded gas. With a pipeline that can ship natural gas to markets in Canada and the United States, the issue then becomes whether to consume natural gas locally for syncrude production, where its value is determined by the price of crude oil, or to sell it as commercial pipeline natural gas to the Lower 48. In terms of the environment, natural gas consumed in producing syncrude and treating the oil sand, plus the energy consumed in mining and transporting bitumen to the syncrude plant, multiply carbon emissions of gasoline made from syncrude over crude oil by three times. The Obama administration is not a proponent of gasoline from syncrude because of this marked increase in its carbon footprint. Syncrude production in Canada was 800,000 bpd in 2003, increased to 1,200,000 bpd in 2008, and is expected to reach 3,300,000 bpd in 2020 taking into consideration reduction in expansion plans from low crude oil prices in early 2009.

Alberta's 175 billion of proven reserves are surface oil sands that can be stripped-mined. But five times that amount lies out of reach of strip mining, about equal to the entire oil reserves of the Middle East. Little of this resource is being tapped by the "huff and puff" method of forcing down steam which loosens up the bitumen allowing it to be pumped to the surface via wells. To improve the efficacy of recovery of deep oil sands deposits, various proposals have been made such as drilling a hole and igniting the oil sands to heat up its surroundings allowing the heated crude to flow to the surface via wells. Another idea is pumping down a solvent that absorbs the crude in the oil sands. The mixture of solvent and crude is separated at the surface for recycling of the solvent. Still another idea is to force hot high pressure air into the oil sands that heats the crude so that it can flow to the surface. It is possible that this method may partially refine the crude by the time it emerges at the surface, avoiding or reducing the need for synthetic crude treatment. While not proven solutions, a technology will have to be developed to tap below-surface deposits of oil sands if they are to play a significant role in satisfying North American oil needs.

Bitumen deposits in Venezuela are located in the Orinoco region and lie on the surface. Unlike Canada, the bitumen is not intermingled with the soil. Bitumen mixed with 30 percent water and other chemicals is sold as a coal substitute called Orimulsion. Bitumen for syncrude manufacture is mixed with naphtha to reduce its viscosity for pipelining to a syncrude plant. There the naphtha is recovered and pipelined back to the bitumen deposit for recycling. The costs of getting bitumen to a syncrude plant and preparing it for processing are far less in Venezuela than in Canada.

Venezuela entered into four grassroots joint ventures with foreign oil companies. But these plants were taken over by Venezuela without due compensation to the investors. Having scared off further foreign investment by oil companies, Venezuela began courting China and Iran as potential investors in new syncrude production facilities, but neither nation seems anxious to consummate a deal.

Syncrude may not be a significant substitute for conventional crude oil, considering its capital and natural gas requirements, but it could be effective in reducing U.S. reliance on Middle East crude oil imports. Middle East oil exports to North America have been relatively flat at 2.4 million bpd (some Middle East crude is exported to east coast Canadian refineries whose output is both consumed domestically and exported to the United States). A tripling of current Canadian syncrude production of 1.2 million bpd would make the United States essentially independent of Mideast crude. It is possible that syncrude plants could be built in Venezuela, although one may argue over the geopolitical risk associated with substituting syncrude from Venezuela for crude from the Middle East. Venezuela's attitude toward the United States could change if Venezuela viewed a large step-up in syncrude production as a means of creating and sustaining a "Greater Venezuela." Whether President Obama can improve U.S. relations with Venezuela remains to be seen, but Venezuela, hurt by falling revenues in early 2009 and apparently unable to entice China or Iran to invest, has put out feelers for oil companies to enter into joint ventures to build syncrude plants. But this would first require resolution of problems associated with Venezuela's past treatment of oil company investments.

Syncrude can also be made from oil shale. Like so many things, "oil shale" is a misnomer. The oil in the rock is not oil, but an organic material called kerogen that has not been heated to the requisite temperature to become oil. Hence, the process of making oil from oil shale involves the application of heat to complete the process. Nor is it necessary for the rock to be shale, it can be any kind of rock that contains kerogen, although normally it is a relatively hard rock called *mari.* About 72 percent of the world's oil shale resources are in the United States. Most of this lies in a 16,000-square-mile area, mostly in Colorado, with extensions into eastern Utah and southern Wyoming, called the Green River formation. The Green River formation is estimated to have as much as 2 trillion equivalent barrels of oil. Other nations with oil shale resources are China, Brazil, and Morocco, each with 5 percent of world reserves, Jordan, with 4 percent, and the remaining 9 percent in Australia, Thailand, Israel, Ukraine, and Estonia. Estonia burns oil shale for power generation.[21]

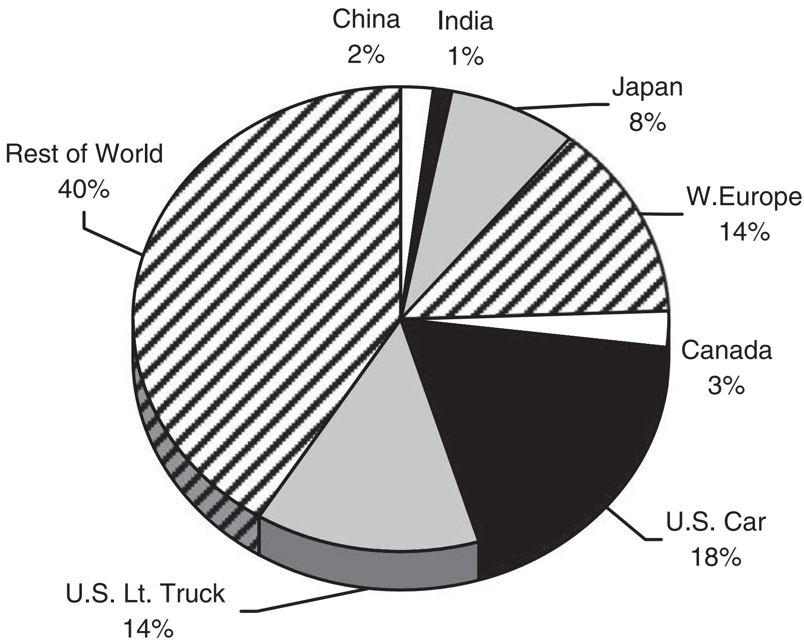
Oil shale has to be mined, transported, crushed, and heated to a high temperature (450°C) in the presence of hydrogen to produce a low-quality crude oil. The process requires a great deal of water, a commodity in short supply in the western United States, plus natural gas as a source of energy to heat the oil shale and as a source for hydrogen. The crushed rock residue takes up more volume than the original rock, presenting a significant disposal problem in the scenic Rockies. The United States invested a great deal of money during the oil crisis in the 1970s to commercially develop oil shale, but to no avail. As promising as oil shale may appear, in a practical sense, mining of shale does not offer a viable solution to a shortfall in conventional oil production.

This negative outlook may change. Shell Oil's Mahogany Project in northwest Colorado took a different approach to oil shale. Rather than mining the oil shale and then extracting the oil, electric heating elements were embedded between 1,000 and 2,000 feet below the surface to heat the shale rock *in situ* to 650 to 750° F. Over time, this produces a hydrocarbon mix of about one-third natural gas and two-thirds light high-grade oil, which can be retrieved by traditional drilling methods. The high-grade oil can easily be refined to gasoline, jet fuel, and diesel oil. The process is energy-efficient; that is, the energy derived from the projects exceeds the energy consumed in heating the shale, but, of course, is not as energy-efficient as simply drilling for oil. Denser oil shale formations may be capable of producing up to a billion barrels of oil per square mile. If these estimates of oil shale resources are accurate, and if this method proves to be commercially feasible, the Green River Formation will have 2–4 percent more oil reserves than Saudi Arabia.

CHALLENGE OF OIL: THE AUTOMOBILE

Oil is the fuel of choice for automobiles, trucks, buses, railroad locomotives, aircraft, and ships. Ship's bunkers are the waste or residue of the refining process. Trucks, buses, and railroads consume diesel fuel and airlines jet fuel. For the most part, automobiles run on gasoline, although Europe has succeeded in inducing a switch from gasoline- to diesel-fueled automobiles through tax incentives. Figure 6.3 shows the percentage distribution of the world population of automobiles (SUVs, vans, and pickups included only for the United States as light trucks).[22]

Figure 6.3 **Percentage Distribution of 747 MM Automobiles** (2007)



Henry Ford pioneered the motor vehicle industry in the United States in the early 1900s. Even as late as 1950, 76 percent of the world's motor vehicles of 53 million were registered in the United States. In 2007, the U.S. population of motor vehicles consisted of 135 million automobiles plus another 101 million minivans, vans, pickup trucks, and SUVs designated as light trucks, a large portion of which are used for personal travel. The initial rapid growth in the population of motor vehicles after the Second World War was concentrated first in Europe (1960–1985), then Japan (1970–1985), afterward in the emerging economies of the Industrial Tigers (Korea, Taiwan, Singapore, and Hong Kong), from there to South America and eastern Europe, and now India and China.

Table 6.4 shows the number of automobiles owned per 1,000 people. The U.S. automobile figures includes SUVs, pickups, and vans, which exaggerates the number of automobiles per thousand people in the sense that pickups and vans are also used for commercial purposes.

The greatest potential growth in automobile ownership is in China and India. If the number of automobiles in India and China were to increase to 100 per thousand people, the population of automobiles for a combined human population of 2.5 billion in 2009 would be 250 million automobiles less the current population of about 20 million, for a jump of 230 million automobiles, or 30 percent on top of a present population of 747 million. Light distillates consumption is 26.4 million barrels per day. Suppose that 80 percent of this is gasoline for motor vehicles or 21.1 million bpd. An increase of 30 percent in automobiles would increase global gasoline consumption

Table 6.4

Automobiles per One Thousand Population (2007)

United States	785
Canada	583
U.K.	514
Germany	500
France	474
Japan	452
China	10
India	8

to 27.5 million bpd; 6.4 million bpd in incremental gasoline demand would require incremental refinery consumption to handle 21 million bpd of crude assuming 30 percent of refinery output is gasoline. (Thirty percent is the global refinery conversion rate of gasoline from crude oil.) This is equivalent to adding two Saudi Arabias. Even if this were physically possible, there would be huge oil price increases reflecting supply shortages and much wider refinery margins to justify building enormous additions to refinery capacity. Clearly the progress of China, and to a lesser extent India, into the automobile age will place China and the United States at loggerheads over a vital commodity; another reason to exit the Middle East.

Vehicles That Use Alternative Fuels

One way to attack oil demand for motor vehicles is to find an alternative to gasoline. The U.S. Department of Energy defines alternative fuels as substantially nonpetroleum methods that enhance energy security and the environment. The list includes methanol and ethanol fuels of at least 70 percent alcohol, compressed or liquefied natural gas, liquefied petroleum gas (LPG), hydrogen, coal-derived liquid fuels, biofuels, and electricity, including solar power. All are currently more costly than gasoline and diesel oil and, more importantly, lack an infrastructure for serving customers. As Table 6.5 shows, the energy content of alternative fuels is lower than gasoline and diesel oil, which means that motor vehicles that use alternative fuels will get lower mileage (miles per gallon) than those running on gasoline and diesel fuel.[23]

The antigasoline public sentiment is “fueled” by the desire to improve air quality and the concern over oil security. California suffers from the worst polluted air in the nation, and the state energy authorities are acutely aware of declining California and Alaska oil production and its impact on oil security. The state leads the nation in initiating legislation to promote the demise of the conventional gasoline engine. Many states look to California as a model for motor vehicle pollution legislation.

Ethanol and biodiesel, both biomass fuels, were discussed in Chapter 3. Gasohol (E10) is now fairly available in the United States and is no longer limited to the Midwest corn-growing region. There are 1,413 refueling sites offering E85 principally located in Minnesota, Illinois, Indiana, Iowa, and Missouri. There are 651 biodiesel sites, but not all these sell B100; B20 is a more commonly available. Leading states are North and South Carolina, Tennessee, and Texas.

Methanol is an alcohol fuel made from natural gas, but it can also be produced from coal and biomass. The primary methanol fuel is M85 (85 percent methanol and 15 percent unleaded gasoline). In order to use methanol as a fuel, engine parts made of magnesium, copper, lead, zinc, and aluminum must be replaced to prevent corrosion. Methanol cannot be handled in the same

Table 6.5

Energy Content of Motor Vehicle Fuels

Fuel	Btu/Gallon
Diesel	129,000
Gasoline	111,400
E85(3)	105,545
Propane	84,000
Ethanol (E100)	75,000
Methanol (M100)	65,350
Liquid hydrogen	34,000
CNG at 3,000psi	29,000
Hydrogen at 3,000psi	9,667

distribution system as petroleum products, and the necessity of building a new distribution system limits methanol's potential use as an automobile fuel. There are no commercial outlets in the United States selling methanol, and there is little point to change to methanol from an environmental point of view because emissions from M85 are not significantly lower than those from gasoline.

Interest in natural gas (mostly methane) as an alternative fuel stems from its clean-burning qualities and its availability through a well-developed pipeline distribution system. But engines must be modified in order to accommodate natural gas, which is stored in tanks either as compressed (CNG) or liquefied (LNG) natural gas. CNG-fueled vehicles require compression stations either at distribution centers or homes served by natural gas. Natural gas distribution companies commonly use CNG-fueled vehicles. Major American car manufacturers have models that run on CNG exclusively or are bifueled to run on either CNG or gasoline. Most CNG-fueled vehicles are restricted to fleet buyers such as natural gas producers or distributors who have ready access to the fuel. LNG-fueled vehicles must have some way of keeping natural gas in a liquefied state unless their tanks can withstand the pressure created when the liquid gasifies. There are thirty-five sites where LNG can be purchased, of which twenty-nine are in California. CNG is sold at 790 sites, of which 189 are in California followed by 89 in New York and 60 in Utah. The run-up in natural gas prices and the growing need to import natural gas are inhibiting factors for a significant conversion of automobiles from gasoline to natural gas.

LPG is propane or butane alone or as a mix. LPG is a byproduct of natural gas processing and petroleum refining. As a vehicle fuel in the United States, LPG is mainly propane and has been in use for over sixty years. Propane is gaseous at normal temperatures and must be pressurized to remain in a liquid state. Emissions from the combustion of propane, however, are significantly lower than those produced by gasoline and diesel fuel, making propane the fuel of choice for forklift trucks and other vehicles that must operate in closed spaces such as warehouses and terminals. There are a few fleets of municipal taxis, school buses, and police cars of propane-fueled vehicles, with 2,200 refueling sites nationwide, of which 525 are in Texas and 206 in California. However, large-scale switching from gasoline to LPG is not possible because the quantity of LPG is fixed by refinery operations and domestic production of natural gas.

Electricity can run a vehicle via a battery or a fuel cell. Batteries store electricity, while a fuel cell generates electricity. The cost and weight of batteries have discouraged their use in the past, but progress has been made for battery-powered vehicles to become technologically and economically feasible. Nissan produces two automobiles that run on electricity for sale in California. GM is planning to offer an electric car around 2012. Some electricity-generating companies are thinking about refueling electric automobiles overnight in garages without running special cables to a house. However, it would be advisable to have time-sensitive meters that charge lower rates during times of least demand such as overnight and on weekends. There are 435 commercial electricity "refueling" sites in the United States with 370 in California. A large number of battery-powered vehicles would have significant repercussions on electricity generation, transmission, and distribution capacity and on the economics of running an electric utility.

The assertion that electric vehicles are pollution-free is true only if viewed in isolation. Electricity stored in motor vehicle batteries is not pollution-free if it is generated from burning fossil fuels. Nor is the electric vehicle energy-efficient when the inefficiencies of electricity generation and transmission are taken into account. From this viewpoint, electric vehicles are neither pollution-free nor energy-efficient. However, if the electricity to power an electric vehicle comes from wind or solar energy (including solar-powered cars) or from hydro or nuclear, then the argument that electric vehicles are pollution-free is valid.

Vehicles fueled by hydrogen are another possibility. Its chief advantage is that the only combustion emission is water; it is the preferred fuel for a fuel cell for the same reason. Hydrogen-fueled vehicles and fuel cells are discussed under Hydrogen Economy in Chapter 10; but for now the prognosis for large numbers of automobiles fueled by hydrogen, either for direct combustion in a conventional engine or feedstock for a fuel cell, is quite dim.

Despite intense government and private efforts to support the technological development of vehicles run by alternative fuels, including the development of fuel cells, over the past thirty-five years (all of this started in the aftermath of the 1973 oil crisis), most of the world's fleet of automobiles and trucks is still powered by gasoline and diesel fuel. In the United States, the total population of automobiles, vans, pickups, SUVs is 236 million. Vehicles fueled by LPG (including forklifts) number 174,000; CNG-fueled vehicles nearly 118,000; LNG-fueled vehicles 2,700; E85 fueled vehicles 246,000; electric vehicles 51,000; and 119 hydrogen-fueled vehicles. Counting forklifts as motor vehicles and assuming E85 fueled vehicles never run on gasoline, both unwarranted assumptions, the total population of alternative-fueled vehicles is only 0.25 percent of the entire motor vehicle population. Or put another way, 99.75 percent of the motor vehicle population runs on oil.

It is possible that long-term oil consumption could be affected by technological breakthroughs that bring the cost of alternative fuels closer to that of gasoline and diesel fuel. The other way is for the price of gasoline to rise to a level that can support alternative fuels, which occurred in 2008 when gasoline approached $4 per gallon. But this didn't last long. Although not a challenge to crude oil yet, the conversion of natural gas to motor vehicle fuels (discussed in Chapter 7), could eventually have some impact on crude oil demand as a motor vehicle fuel, but not in the near future.

One thing is certain; the lack of significant progress for motor vehicles fueled by alternative means is not being hampered by the automobile industry. Automobile manufacturers share the general public sentiment that the conventional gasoline engine is becoming archaic and needs to be replaced. Carmakers are not wedded to the oil industry, but they are wedded to a technology that works and a fuel that is readily available. Until there is an alternative fuel that works and is readily available, oil will remain the preferred fuel. There will be no easy divorce from oil.

Enhancing Engine Efficiency

There has been substantial private and governmental support to enhance engine efficiency. Increased efficiency has two benefits: better mileage with less pollution. Doubling mileage cuts both fuel consumption and pollution emissions in half.

The U.S. Department of Energy, through the National Renewable Energy Laboratory, has funded development costs for hybrid electric vehicles (HEVs) with high fuel economy and low emissions. GM and Ford have begun to offer hybrid vehicles, although Honda and Toyota have had models available for a number of years (another testament to the decline of American leadership in technology).

An HEV obtains higher mileage by converting the energy lost during deceleration to electrical energy that can be stored in a battery. HEVs can be designed in a series or parallel configuration. In a series configuration, the primary engine drives a generator that powers electric motors to drive the vehicle and charge the battery. The vehicle is driven solely by the electric motors. HEVs now on the market have a parallel configuration in which the car is driven directly by a gasoline-fueled engine augmented by electric motors. The electric motors are run by electricity stored in a battery that supplements the power from the gasoline engine, and cut in when the car needs extra power. The nickel metal hydride or possibly the lithium-ion battery is recharged during deceleration, when regenerative braking captures the energy normally passed to the environment as waste heat, and also during normal motor operation if a charge is necessary. The electric hybrid can also be charged by plugging into a conventional electricity outlet. This is the forerunner to an all-electric car.

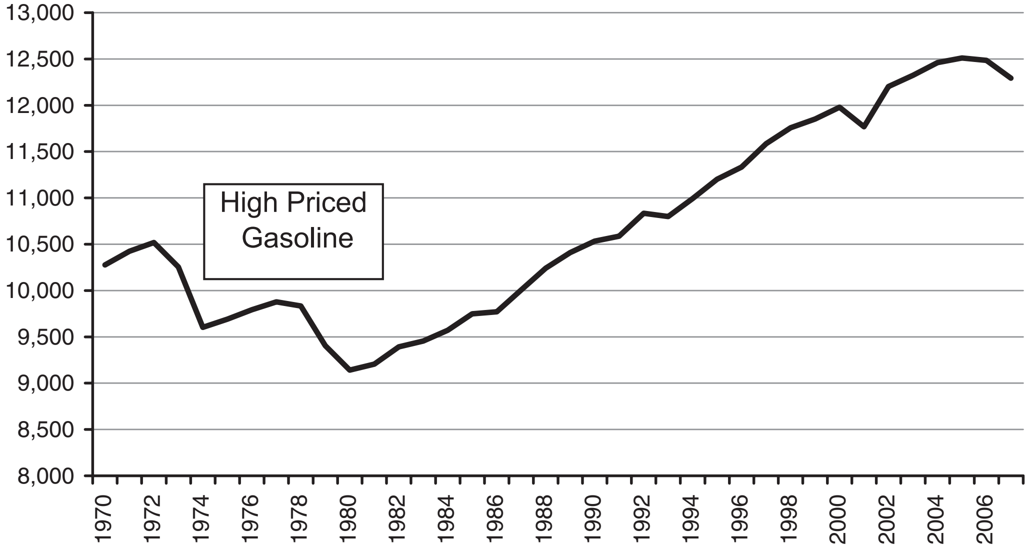
Supplemental acceleration using electric motors means that automobiles can be built with gasoline or diesel engines of lower horsepower, which consume less fuel. Fuel efficiency is further enhanced by "cutting out" the firing of a cylinder at cruising speed when on level ground. In addition, an HEV has less weight because its engine components are made from lighter-weight aluminum, magnesium, and plastic. The vehicle's body, also made of lightweight aluminum, is aerodynamically designed to reduce wind resistance. Depending on the style of HEV, mileage can range from thirty to more than sixty miles per gallon. An HEV's mileage performance, compared to that of a conventional automobile, is more impressive in stop-and-go traffic than in steady highway driving. HEVs' engine emissions meet California's stringent ultra-low vehicle emission standards. The most striking aspect of HEVs is that their sales jumped when gasoline prices spiked during the summer of 2004 and again in 2008, sending SUV sales into a slump. Moreover, HEV sales slump and SUV sales jump when oil prices are low. This lesson is vital in coming to terms with the future when oil becomes a more scarce and expensive resource.

INTERNALIZING AN EXTERNALITY

The government supports the oil industry by ensuring security of supply. This is not a subsidy to the oil companies because oil companies are not in the business of military interventions. Government participation in the civilian economy is common. The automobile industry would have been truncated (to say the least) if town, county, state, and federal governments did not build roads. It would be just as unfair for automobile companies to be responsible for building roads as it would be for oil companies to ensure oil security. The big difference is in the method of payment. The cost of building and maintaining roads falls on the user in the form of a highway tax, whereas the cost of oil security falls on the taxpayer as a government expenditure. It is high time that those who benefit from oil bear the full cost of oil through an oil security tax.

The United States consumes 7 million bpd of gasoil as both heating oil and diesel fuel for equipment, machinery, motor vehicles (mostly trucks), and locomotives. The advantage of trucks over railroads is their flexibility—they can go anywhere there is a road. The advantage of railroads is their inherent efficiency—a train crew of only three members can haul several hundred containers or truck trailers on flatbed railcars, a number that would require an equal number of truck drivers. Aside from this labor savings, railroads with steel wheels on steel tracks are far more energy-efficient than trucks with rubber wheels on concrete or asphalt roads. An optimal blend of both modes of transport is intermodal transport (piggyback) of combining trucks for

Figure 6.4 **Average Miles Driven per Year for Passenger Cars**



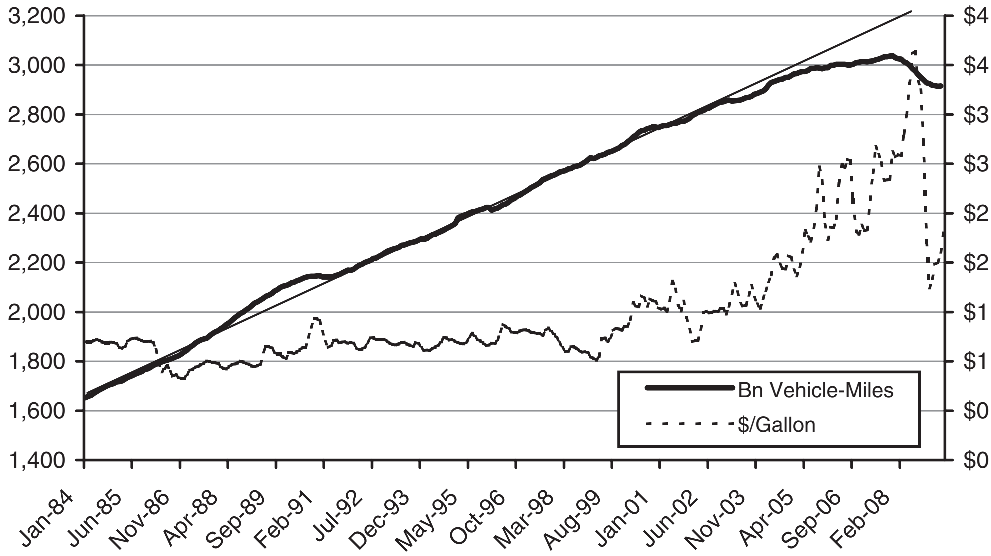
short-distance delivery with rail for long-distance hauling. A higher price for diesel fuel would provide an economic incentive to get some of the trucks off the road and their payloads on a train. This would reduce oil consumption and highway congestion.

In addition, the United States consumes about 10 million bpd of gasoline for automobiles. This amounts to 420 million gallons per day (42 gallons in a barrel) or 150 billion gallons per year. A $1 tax on each gallon of gasoline will support $150 billion in annual war expenditures in the Middle East. It would probably take a few dollars per gallon tax to internalize the external cost of military activity in the Middle East. Such a high price on gasoline affects both mileage driven and type of automobile purchased. It also supports the development of alternative fuels. All these would help to extricate the United States from dependence on Middle East crude. Figure 6.4 shows the impact of gasoline prices on the average number of miles driven by U.S. automobiles.

In round terms, the average miles driven per year fell about 10 percent during the era of high-priced gasoline during the late 1970s and early 1980s. People were not deprived of the driving experience, they just thought more carefully about how they drove their cars. Carpooling, taking the bus or train to work, not visiting the shopping mall every day, letting the kids take the bus from school rather than picking them up, and shortening the distance traveled for family vacations can have a significant impact on the number of miles driven in a year. In addition to driving less, people were incentivized to buy fuel-efficient Toyotas and other Japanese cars at the expense of gas-guzzling American made automobiles. All this happened again in recent years when gas prices briefly passed $4 per gallon. Figure 6.5 shows the relationship between motor vehicle-miles and gasoline since 1984. Motor vehicle-miles reflect an aggregate measure of miles driven per vehicle and the population of vehicles prices, both growing throughout most of this period.[24]

Low gasoline prices do not affect aggregate motor vehicle-miles. But the long-term trend in motor vehicle-miles was broken before gasoline prices spiked at $4 per gallon in 2008. As shown more clearly in Figure 6.6, the long-term trend changed in the fall of 2005 when gasoline prices approached $3 per gallon.

Figure 6.5 **12-Month Moving Average Billion Vehicle-Miles versus Gasoline Prices** (1984–2009)

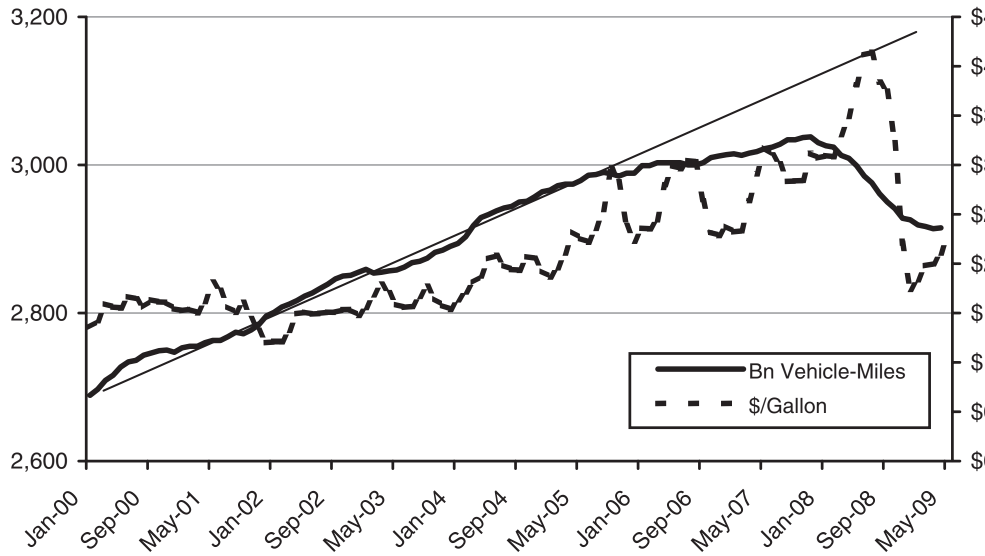


Thus, it appears that $3 per gallon gasoline can suppress driving activity. At higher prices between $3 and 4 per gallon, people not only drove less, but switched from gas-guzzling SUVs to hybrids. It has been observed that sales for SUVs increase and sales for hybrids decrease whenever gasoline prices fall below $3 per gallon. Notice that the peak price of $4 per gallon occurred after the downturn in motor vehicle-miles. Thus, the actual fall-off in motor vehicle-miles was more the result of the economy collapsing from the global financial meltdown than from high gasoline prices.

Suppose that $3–4 per gallon gasoline is sufficient to cut mileage driven per year and encourage the switch from SUVs to fuel-efficient hybrids to reduce gasoline consumption by 10 percent. A 10 percent savings on 10 million bpd of gasoline consumed by automobiles is one million bpd of gasoline, which requires about 2.5 million bpd of crude oil assuming 40 percent weighted average output of gasoline between U.S. and European refineries. (The United States depends on European refineries to fill some of its gasoline needs.) Two-and-a-half million bpd savings in crude imports would have to be apportioned between Europe and the United States, depending on which refineries were affected. Nevertheless, 2.5 million bpd is close to what the United States and Canada import from the Middle East. A gasoline tax that brings the price of gasoline between $3–4 per gallon can, in time, drastically reduce the demand for Middle East oil. Parenthetically, 1.5 million bpd of West African crude is exported to Asia. Diverting a portion of this to the United States would decrease our Arabian Gulf imports commensurately, hastening the day when we can eliminate the need to meddle militarily in the Middle East.

Of course some time has to pass to allow energy-efficient automobiles to replace gasoline-hogs. But with incremental crude from oil sands production in Canada and greater imports from regions in the Atlantic basin showing promise of higher oil production such as Brazil and West

Figure 6.6 **12-Month Moving Average Billion Vehicle-Miles versus Gasoline Prices** (2000–2009)



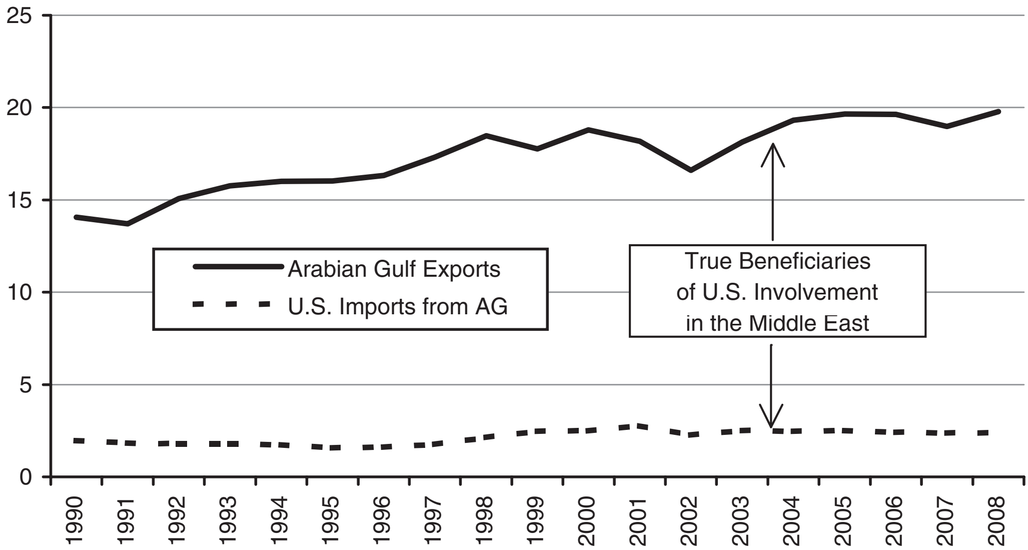
Source: For retail gasoline prices http://www.eia.gov/emeu/petro.html. For vehicle distance billion miles U.S. Department of Transportation, Federal Highway Administration at http://www.fhwa.dot.gov/ohim/tvtw/tvtpage.cfm

Africa, and allowing more bioethanol to enter the United States by eliminating the discriminatory tax against Brazilian ethanol, we are within reach of eliminating Middle East imports to North America altogether in a few years. Figure 6.7 shows that the United States accounts for relatively little of Arabian Gulf exports. We have been on the line since the late 1970s to defend the interests of the oil-importing world for trillions of taxpayer dollars with nearly five thousand dead and countless others without limbs and suffering from the consequences of wounds, physical and mental, for the rest of their lives. Yet the true beneficiaries have barely paid a dime for our effort. When will we learn?

IS THIS POLITICALLY ACCEPTABLE?

Of course reducing our dependence on oil from the Middle East by hiking gasoline prices is not politically acceptable, but what relevance is that? If we do nothing, we will be doing our part to ensure that the world remains dangerously close to supply not being able to satisfy demand. The problem with being on the razor's edge is that one can easily fall off. In the world of oil, an extended supply disruption in Nigeria or Venezuela or Iran, or any number of other possibilities can reduce the oil supply below demand. Once this happens, there is no upper limit on oil prices. This is what was experienced in 2008 when oil peaked at $147 per barrel with forecasts at that time of $200 per barrel up to $300 per barrel. Supply hardly was able to meet demand. While some blamed hedge funds and speculators for loading up on oil futures for high oil prices, the general consensus is that this only exaggerated the underlying price movement. The real reason why prices were strong was a lack of spare capacity. Six months later in early 2009, oil was in the

Figure 6.7 **Arabian Gulf Oil Exports and U.S. Imports from the Arabian Gulf** (MM Bpd)



Source: http://tonto.eia.doe.gov/dnav/pet/hist/mttimuspg1m.htm

low-$30s with forecasts of $30 per barrel down to $20 per barrel. From this low point, oil prices increased to $70–$80 per barrel by late 2009. So much for forecasts and those who depend on price forecasts to establish government energy policies! Unlike the oil crisis in the 1970s when a sharp decline in economic activity from high-energy prices reduced demand to eventually cause prices to fall, this time it was a global financial meltdown stemming from the subprime mortgage fiasco. What we should learn from the high oil prices in 2008 is that a gasoline price of $3–4 per gallon appears sufficient to persuade U.S. drivers to drive less and buy fuel-efficient automobiles. This in turn will eventually allow us to extricate ourselves from the Middle East saving billions, if not trillions, of dollars and many lives, increasing the availability of oil for the rest of the world, and in so doing, easing the strain on global oil supplies.

Stated in the most simplistic way, we have a choice of paying $3–4 per gallon or paying $3–4 per gallon. The choice is only differentiated by when and where the money flows: to the U.S. government to ease the budget deficit or to the coffers of the oil exporters. Either way, there will be an economic incentive for the development of alternative fuels, but it may be too late to save the economy if we continue to procrastinate. The time to wean our dependence on oil imports in favor of alternative fuels was yesterday, but nothing can be done about that. The time is now before the next crisis strikes.

We had our first warning in the 1970s oil crisis that life will not be the same, and we managed to do nothing in the subsequent four decades to deal with a highly explosive situation. Matters are not getting better, and each subsequent oil crisis will bring even higher prices that will last longer. It is about time that we do something to at least reduce the growth in demand and our dependence on Middle East oil and become more serious about developing alternative motor vehicle fuels. The old saw that alternative fuels cannot be developed because of our enormous vested interest in the infrastructure of oil-production facilities, refineries, and associated processing plants, pipelines, ships, storage tanks, and distribution facilities is not going to carry much weight when that infrastructure goes dry.

NOTES

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7

NATURAL GAS

With reserves to production ratio of natural gas 50 percent larger than oil and with plenty of potential for expansion, the "oil and gas industry" may one day be dubbed the "gas and oil industry." This chapter covers the history of natural gas from its beginning as a manufactured gas made from coal. It is the most regulated of fossil fuels because only one natural gas pipeline can be connected to a house, just as a house can have only one electrical cable. Like electricity, natural gas is in the midst of deregulation (liberalization). How natural gas travels from the earth to consumption point is discussed, along with the growth of the international trade in natural gas and the possibility of developing nonconventional sources of methane.

BACKGROUND

Natural gas is made up of primarily methane, a carbon atom surrounded by four hydrogen atoms. It is the cleanest-burning fossil fuel with only water and carbon dioxide as products of combustion. Carbon monoxide emissions, if any, are caused by insufficient oxygen to support combustion. Nitrous oxides stem from nitrogen in the air reacting with the heat of a flame. Natural gas produces far less nitrous oxides than oil and coal, which contain nitrogen within their molecular structures. Burning natural gas produces virtually no sulfur oxides and no particulate or metallic emissions. A greater ratio of hydrogen to carbon atoms releases less carbon dioxide per unit of energy than coal and oil. Moreover, cogeneration plants fueled by natural gas have a higher thermal efficiency than coal and oil, further lowering carbon dioxide emissions for the same output of electricity.

Natural gas fields have about double the reservoir recovery (70–80 percent) than oil (30–40 percent), which lessens the need to continually find new gas fields. Unlike oil, natural gas requires relatively little processing to become "pipeline-quality." On the minus side, natural gas has always been a logistical challenge. In the beginning decades of the oil age, much of the natural gas produced in association with crude oil was flared (burned) or vented to the atmosphere. The primitive state of pipeline technology restricted natural gas to the local market. Large amounts of natural gas associated with oil production were available with the development of oil and gas discoveries in the U.S. Southwest. With no nearby markets to consume the gas and no means to get the gas to distant markets, vast quantities of natural gas associated with crude oil production were vented to the atmosphere. This waste of a "free" energy source and the waning of natural gas fields in Appalachia provided a strong incentive to improve pipeline technology to connect suppliers with consumers over long distances in a safe, reliable, and cost-effective manner.

Another drawback is that leaking natural gas can asphyxiate the occupants of a building or trigger a fire or an explosion that can level a building or, on occasion, a city block. Fires fueled by broken gas mains in the aftermath of earthquakes, such as occurred in San Francisco in 1906 and Kobe, Japan, in 1995, exacerbated the damage and suffering. Unlike liquid petroleum products, consumers have no way of storing natural gas. Natural gas delivery systems must be designed to handle extreme vagaries in demand.

Most pipelines are largely confined to a single nation or region, such as North America, where they connect producers and consumers in Canada, the United States, and Mexico. The United States alone has 300,000 miles of transmission pipelines and about 1 million miles each of gathering and distribution pipelines. Russia has a well-developed natural gas pipeline system to serve its domestic needs and exports large volumes to the European pipeline grid. The grid crosses national borders, much as pipelines cross state borders in the United States, connecting European consumers to gas fields in Russia, the Netherlands, the North Sea, and Algeria via two undersea trans-Mediterranean pipelines. One pipeline from Algeria crosses Morocco and the Mediterranean Sea to Spain (near Gibraltar) and the other crosses Tunisia, the Mediterranean, Sicily, and the Strait of Messina to mainland Italy. Another undersea trans-Meditteranean natural gas pipeline connects Libya and Sicily.

There are limits to pipeline transmission that leave enormous reserves of stranded gas beyond the reach of consumers. With limited domestic consumption, natural gas associated with oil production in the Middle East, Southeast Asia, and West Africa is either flared or vented to the atmosphere or reinjected into oil fields. Flaring and venting are a horrendous waste of energy, equivalent to burning money in this world of high-energy prices. Reinjection maintains the pressure of oil fields and preserves a valuable energy resource. In recent decades a new method of shipping natural gas in a liquefied state aboard highly specialized tankers has emerged. Liquefied natural gas (LNG) export plants, coupled with specialized import terminals and LNG carriers, have monetized these reserves of stranded gas by making them available to consumers. Since LNG cargoes can be shipped from exporting terminals in North and West Africa, Latin America, the Middle East, Southeast Asia, and Australia to receiving terminals in the United States, Europe, and Asia, natural gas is in the beginning stages of being transformed from a regional to a globally traded commodity like oil. Furthermore, technological progress has been made in converting natural gas to liquid motor vehicle fuels, giving natural gas access to the same delivery system that serves petroleum.

A long-standing and complex relationship exists between natural gas and electricity as the proliferation of electric and gas utilities suggests. Gas both supplies fuel to generate electricity and competes with electricity to supply consumers with a means to cook, heat water and living spaces, and run appliances. Both became federally regulated commodities in the 1930s as a result of interstate transmission. Later on, natural gas regulation was expanded to include natural gas suppliers of regulated interstate transmission pipelines. This experiment in total regulation of an industry turned into a bureaucratic quagmire with internal contradictions and undesired consequences plaguing the regulators. The final solution to the problems induced by regulation was deregulation of natural gas production, transmission, and distribution, beginning in the late 1970s. Again, the link between electricity and natural gas can be seen in the parallel deregulation of electricity generation, transmission, and distribution. While the breakdown of the monopoly status of natural gas and electricity is quite advanced in the United States and the United Kingdom, it is still an ongoing process. Deregulation (liberalization) is actively being pursued elsewhere in the world.

Natural gas as an energy source looks extremely promising for the coming decades and has a number of advantages working in its favor. However, natural gas, like oil, will eventually become another depleting resource, a fact that the world will eventually have to contend with. Some say that day, while admittedly further away than that for oil, may not be that far in the future.

EARLY HISTORY OF COAL GAS

The beginning of the natural gas industry was not natural gas from the first oil wells in western Pennsylvania, but manufactured gas from coal—a case of a synthetic or manufactured fuel preceding the natural fuel. In 1609, a Belgian physician and chemist reduced sixty-two pounds of coal to one pound of ash and speculated about what had happened to the missing sixty-one pounds, the first published account of coal gas. While burning coal in the presence of air reduces it to ash, heating coal in a closed environment, without a fresh supply of air, produces coke, tar, and gas. Coke, primarily carbon, is burned as a fuel or consumed in steel production. Coal tar was originally a waste product, dumped willy-nilly in streams, rivers, ponds, and on land adjacent to manufactured gas plants. "Free" coal tar, as a potential raw material for useful products, became the cornerstone of the chemical industry by first being transformed to creosote, tar, pitch, wood preservatives, mothballs, and carbon black. Later on the chemical industry learned to extract benzene, toluene, and xylene, which can be used as gasoline components or feedstock for the petrochemical industry. Other products included phenol and polynuclear aromatic hydrocarbons found in synthetic fibers, epoxies, resins, dyes, plastics, disinfectants, germicides, fungicides, pesticides, and pharmaceuticals. Unfortunately, a large amount of the early coal tar was not processed. When natural gas replaced manufactured gas, the thousands of abandoned manufactured gas plants became classified as hazardous and toxic waste dumpsites whose cost of cleanup is under the Superfund Program of the U.S. Environmental Protection Agency (an example of the consumer not paying the full cost for a service).

The purpose of manufactured gas plants was not to make coke or coal tar, but coal gas, a mixture of hydrogen, carbon monoxide, carbon dioxide, and methane. The heat content of coal gas, made up partially of noncombustible carbon dioxide, is half that of natural gas. The first demonstration of coal gas as an energy source occurred in 1683 when an English clergyman stored coal gas in an ox bladder; when he was ready to use it, he pricked the bladder and lit the outgoing gas. The first demonstration of coal gas as a means of illumination occurred a century later, in 1785, when a professor of natural philosophy lit his classroom by burning coal gas in a lamp. In 1801, a French engineer used coal gas to light and heat a Parisian hotel. William Murdoch, an engineer working for Boulton and Watt, the manufacturer of James Watt's steam engines, produced coal gas that passed through seventy feet of copper and tin pipe to light a room in his house in 1792 and, in 1802, to light a foundry. He experimented with various types of coal heated to different temperatures for varying lengths of time, which led to the first major commercial use of coal gas: to light the Manchester cotton mills for round-the-clock operation. For his pioneering work, Murdoch was called the father of the gas industry.[1]

Other advances included purifying coal gas by passing it through limewater and devising meters to measure its usage. Friedrich Albrecht Winzer, a German entrepreneur, proposed the first centralized gas works where gas would be made in large quantities and pipelined to customers for lighting and heating. Germany was not ready for the idea, so he anglicized his name to Fredrick Albert Winsor and sold the concept to the Prince of Wales, a fellow German of the house of Hanover, who had gaslights installed for celebrating King George III's birthday in 1805. In 1812 the Westminster Gas Light and Coke Company was chartered by Parliament, and by 1815 the company was supplying London from a centralized coal gas producing plant via twenty-six miles of gas mains of the same three-quarters-inch pipe used to make rifle barrels. This placed England in the forefront of a new industry and a font of technological know-how for the introduction of gas lighting in Europe and America.

Two sons of Charles Peale, a well-known portrait painter of Revolutionary War heroes (including fourteen of George Washington), played important roles in what would lead to the formation of the Gas Light Company of Baltimore in 1816. In 1817, the company received a franchise from Baltimore to provide gas lighting. Progress was slow, and only two miles of gas mains were supplying 3,000 private and 100 public lamps by 1833. The company's activities spread into manufacturing and repair of gas meters, along with producing chandeliers, pipes, and fittings in order to be able to sell coal gas for illumination. The spread of manufactured gas in major cities for lighting was not particularly rapid, beginning with Baltimore in 1817, New York City in 1825 (the Great White Way of Broadway was first lit with gas, not electricity), Philadelphia in 1836 (the first municipal-owned gas works), Cincinnati, St. Louis, and Chicago in the 1840s, San Francisco in 1854, Kansas City and Los Angeles in 1867, and Minneapolis and Seattle in the 1870s. The advantage of coal gas was easy shipment of coal to manufactured gas-producing plants strategically located in the center of their markets. This minimized the cost of laying pipes causing coal gas plants to proliferate. The slow adoption of manufactured gas for lighting was its cost, which ranged between $2.50–$3.50 per thousand cubic feet (Mcf). In twenty-first-century dollars, this would be equivalent to about $60 per Mcf compared to $6.80 per Mcf for the average price of natural gas delivered to residential consumers during the 1990s and $11.85 from 2000–2008.

Consumers have a choice of oil companies when buying liquid petroleum products, the hallmark of a competitive market. Manufactured gas began as a natural monopoly because laying multiple gas mains to give consumers a choice of supplier was not deemed cost-effective. Moreover, manufactured gas companies required municipal assistance, support, and cooperation to get into business including a franchise to be sole supplier, permits to lay gas mains under city streets, and a contract to light city streets. All these were necessary for a manufactured gas company to assure potential investors of sufficient revenue for a satisfactory return on their investment. Once the gas mains were laid for city lighting, it was a relatively simple matter to connect to residences and businesses. While municipal authorities recognized that a single company could provide gas at a lower cost than two competing companies with twice the investment in facilities and pipelines, they also recognized that a single company, once ensconced in a market as a natural monopoly, would not be cheaper. Thus, a franchise that granted a monopoly also specified municipal oversight on entry, expansion, exit, safety, and rates to protect the public interest.

Local or municipal regulation worked well with manufactured gas providers whose plant and distribution system were within the legal jurisdiction of a municipality. Things changed when natural gas began to displace manufactured gas because natural gas fields were normally outside of a municipality's legal jurisdiction. This complicated regulation for the municipalities, a problem that was solved when state governments replaced municipal regulation. Since a natural gas field generally served several municipalities, the natural gas industry opted for statewide rather than municipal regulation, a situation that promised greater consistency of rules and rates and reduced the number of regulators to be dealt with (or influenced).

HISTORY OF NATURAL GAS

Sacred fires in Persia and elsewhere were natural gas seeps that may have been ignited by lightning. The temple of Delphi was built around a "burning spring." Around 400 BCE the Chinese discovered natural gas bubbling through brine, which they separated and burned to distill salt. Around 200 CE the Chinese learned to tap natural gas deposits and route the gas through bamboo pipes to distill salt from seawater and cook food. The earliest reference to natural gas in the United States was in the 1600s when explorers noted certain Indian tribes burning gaseous emissions from the earth. In 1821, a more organized approach to capturing escaping or seep gas started in Fredonia, New

York, when a gunsmith piped seep gas to nearby buildings for lighting. In 1827, another source of naturally occurring seep gas was harnessed to supply a lighthouse on Lake Erie. In 1840, the first industrial use of natural gas occurred in Pennsylvania, where gas was burned to heat brine to distill salt, the same thing the Chinese had done more than two millennia earlier.

While natural gas provided the lift for Drake's well, for the most part, natural gas found along with oil was vented to the atmosphere. Drilling for oil and discovering natural gas was equivalent to a dry hole. Natural gas was normally out of reach of municipalities and was unable to compete with manufactured gas protected by municipal franchises. In 1872 the Rochester Natural Gas Light Company was formed to provide natural gas to Rochester, New York, from a field twenty-five miles away. Pipes made of two- to eight-foot segments of hollowed-out Canadian white pine logs reflected the primitive state of pipeline technology. The problems associated with a rotting and leaking wooden pipeline eventually led to the company's demise. In the same year a five-and-a-half-mile, two-inch-wide wrought-iron pipeline was successfully constructed to carry waste gas from oil wells near Titusville to 250 townspeople.

But cast- and wrought-iron pipelines were plagued by breaks and leaking connections held together by screws. Before the day of compressors, transmission distance was limited by gas well pressure. In 1870, Pittsburgh became the first city to start consuming natural gas as a substitute for manufactured gas from coal to clean up its smoke-laden atmosphere. The Natural Gas Act, passed in 1885 by the Pennsylvania legislature, permitted natural gas to compete with manufactured gas. This proved to be the driving wedge that enabled natural gas to penetrate the manufactured coal gas business and resulted in the formation of Peoples Natural Gas, which by 1887 was serving 35,000 households in Pittsburgh. Another Pittsburgh natural gas distributor, Chartiers Valley Gas, was the first company to telescope pipe from an initial eight to ten and finally twelve inches in diameter to reduce gas pressure before it entered a home, business, or industrial plant. By this time, screws had given way to threaded pipe to hold pipe segments together. Dresser and Company, formed in 1880, specialized in pipe couplings, and in 1887 received a patent for a leak-proof coupling that incorporated a rubber ring in the pipe joints; an invention that would dominate the market until the 1920s.

George Westinghouse, inventor of the compressed-air railroad brake, became interested in natural gas and decided to drill for natural gas. He selected, of all places, his backyard and, lo and behold, he struck natural gas as one might expect for the rich to get richer. He became one of the largest gas distributors in Pittsburgh, and relied on the natural gas produced from one hundred wells in and around Pittsburgh, including his backyard. Westinghouse was well-versed in the dangers associated with natural gas such as gas users not turning off their gas appliances (lamps, stoves, heaters) when natural gas pipelines were shut down for repair of breaks and leaks. When pipeline service was restored, a nearly odorless and colorless gas seeped into homes and shops, threatening to kill those within from asphyxiation, fire, or explosion. Westinghouse put his experience with compressed air to good use and originated a number of patents for enclosing main gas lines in residential areas with a conducting pipe to contain gas leaks, introducing pressure regulators to reduce gas pressure before it entered residences and commercial establishments, and cutoff values to prevent any further flow of gas once gas pressure fell below a set point.

These improvements made Pittsburgh the center of the natural gas industry by the late 1880s, with 500 miles of pipeline to transport natural gas from surrounding wells to the city and another 230 miles of pipeline within the city limits. Andrew Carnegie, the steel magnate, promoted the use of natural gas in steelmaking. Natural gas became the fuel of choice not only for steel mills, but also glassmaking plants, breweries, businesses, homes, and a crematorium. Hundreds of natural gas companies were formed to sell gas to municipalities in Pennsylvania, West Virginia, Ohio, and

Indiana with a local supply of natural gas. Some of these gas fields were rapidly depleted, forcing a switch back to manufactured gas. Early customers were simply charged a monthly rate for a hookup without a means to measure the amount of gas consumed. When meters were eventually installed, a new business sprang up: renting “gas dogs” to greet meter readers on their days of visitation.

John D. Rockefeller entered the natural gas business in 1881. True to form, through mergers with existing pipeline companies and expanding their business activities once they were under his control, Standard Oil established a major market presence in the gas-producing states in Appalachia. Rockefeller’s success at monopolization led to the passage of the Hepburn Act in 1906, which was intended to give the Interstate Commerce Commission (ICC) regulatory authority over interstate natural gas pipelines, even though very few existed at the time. In the end, the Hepburn Act exempted natural gas and water pipelines from regulatory oversight, but growing concern over Rockefeller’s hold on the oil industry led to the U.S. Department of Justice filing suit under the Sherman Antitrust Act against Standard Oil. Curiously, in the Standard Oil breakup in 1911, the company’s natural gas properties and activities remained intact within Standard Oil of New Jersey, enabling the company to maintain its standing as a major natural gas player in the Midwest and Northeast and, eventually, the Southwest.

The Battle Over Lighting

Manufactured gas commanded the market for lighting in urban areas while kerosene continued to be used in rural areas and towns not hooked up to manufactured gas. Though vulnerable to penetration by natural gas, coal gas was given a new lease on life by the discovery of a technique for making “water gas” by injecting steam into anthracite coal or coke heated to incandescence. This produced a flammable mixture of hydrogen and carbon monoxide that was sprayed with atomized oil (a new market for oil) to increase its heat content to match that of coal gas. Less costly to make than coal gas, water gas had 75 percent of the manufactured gas market by 1900.

Although water gas could temporarily hold natural gas at bay, a new competitive threat entered the lighting business, affecting both manufactured and natural gas: electricity. In 1880, Edison rigged Broadway for illumination by electricity and lost no time attacking gas lighting for its odors, leaks, fires, explosions, and transport in “sewer pipes,” ignoring, of course, the risk of electric shock, electrocution, and fires from exposed wires. In 1882, the Pearl Street generating station provided electricity to 1,284 lamps within one mile of the plant. Edison used existing gas statutes for permission to install electric wiring under streets and set up a system to supply electricity that mirrored gas as closely as possible to make it easier for customers to switch. The gas-distribution companies knew that electricity would replace gas for lighting and responded with a two-pronged program to meet the new competitive threat. The first was to shift the emphasis of gas from lighting to cooking and heating, and the second was to pursue corporate consolidation to strengthen their position.

As the availability of electricity spread throughout the nation, it did not take long for managers of consolidated gas companies to see the virtue of expanding their merger activities to include electricity-generating firms (“if you can’t beat the enemy, embrace him”). The coke byproduct from coal gas production could be burned to make electricity, and mergers would result in major savings in corporate overhead. The first merger occurred in Boston in 1887, setting the example for the creation of innumerable gas and electric or electric and gas utility companies across the nation. Consolidating gas companies and merging with electricity-generating companies into independent gas and electric utilities further evolved into the public holding company, which owned controlling interests in independent electric and gas companies.

The first public holding company was formed by Henry L. Doherty, who started out as an office boy and rose to chief engineer of a natural gas company. Noticing that poorly designed gas stoves were a drag on natural gas sales, Doherty increased gas sales by working with stove manufacturers to improve their product. He switched to marketing, where he was an instant success because of his ability to motivate and lead salespeople, initiating all sorts of promotional activities, and setting high standards of customer service. Doherty then established his own company to provide advice on the reorganization, management, and financing of public utility companies. He began to attract investor interest and in 1910 formed Cities Service Company, the first public holding company. As the name suggested, the company was to serve cities across the nation with gas and electricity and, by 1913, Cities Service controlled fifty utilities in fourteen states.

Cities Service was a model for a much larger public utility empire created by Samuel Insull, who started out as the English representative of a U.S. bank handling Thomas Edison's interests in London. He ended up working directly for Edison as his private secretary by day and learned the electricity-generating business at the Pearl Street plant by night. He eventually rose to third place in the newly formed General Electric, a merger involving Edison Electric, then to chief executive of Chicago Edison, and finally to chairman of Peoples Gas in Chicago, where he managed a corporate turnaround. This string of successes led to the 1912 founding of Middle West Utilities and later to Insull Utility Investments, both holding companies for electric and gas utilities. By 1926 Insull's utility empire encompassed 6,000 communities across thirty-two states, and by 1930 it had grown to 4 million customers controlling 12 percent of the nation's electricity-generating and gas-distribution capacity.

The War Industries Board encouraged the formation of nationwide industrial organizations to carry out its mandate to coordinate the nation's industrial activities during the First World War. Natural gas suppliers responded by combining several predecessor organizations into the American Gas Association (AGA) in 1918 to centralize the exchange of information, set industry-wide standards, and encourage cooperation and coordination among its members. The AGA also represented the industry viewpoint to the public at Congressional hearings and before natural gas regulatory bodies. The complete conversion of natural gas from lighting to cooking and heating took place at this time, symbolized by natural gas being sold in units of energy (British thermal units) rather than units of illumination (candlepower).

Long-Distance Transmission

The discovery of huge natural gas fields in the Southwest, the Panhandle Field in northern Texas in 1918, followed by the Hugoton gas fields in the Kansas, Oklahoma, and Texas border areas in 1922, changed the nature of the gas business. Both fields covered over 1.6 million acres and accounted for much of the nation's reserves. Exploiting oil found in these fields resulted in venting enormous quantities of associated natural gas to the atmosphere. The discovery of natural gas fields in the Southwest occurred just as natural gas fields in Appalachia were beginning to wane. The promise of commercial reward to be gained by substituting "free" Southwest gas for valuable Appalachian gas spurred R&D efforts in long-distance pipeline transmission resulting in thin-walled, high tensile strength, large diameter, seamless pipe segments joined together by electric arc welding, gas compressors for moving large volumes of natural gas at high pressures, and in ditch digging and filling machinery for laying pipe. An indication of the progress in gas transmission can be seen in pipeline diameters and design working pressures. In the 1920s and 1930s, large transmission pipelines were between twenty and twenty-six inches in diameter and could sustain up to 500 pounds working pressure; in the 1940s, diameters were up to thirty inches, and working pressure was up to 800 pounds; by the 1960s, up to thirty-six inches in diameter and 1,000 pounds; in the 1970s, diameters up to forty-two inches and 1,260 pounds; and after 1980, pipelines were fifty-six inches in diameter and working pressure up to 2,000 pounds.

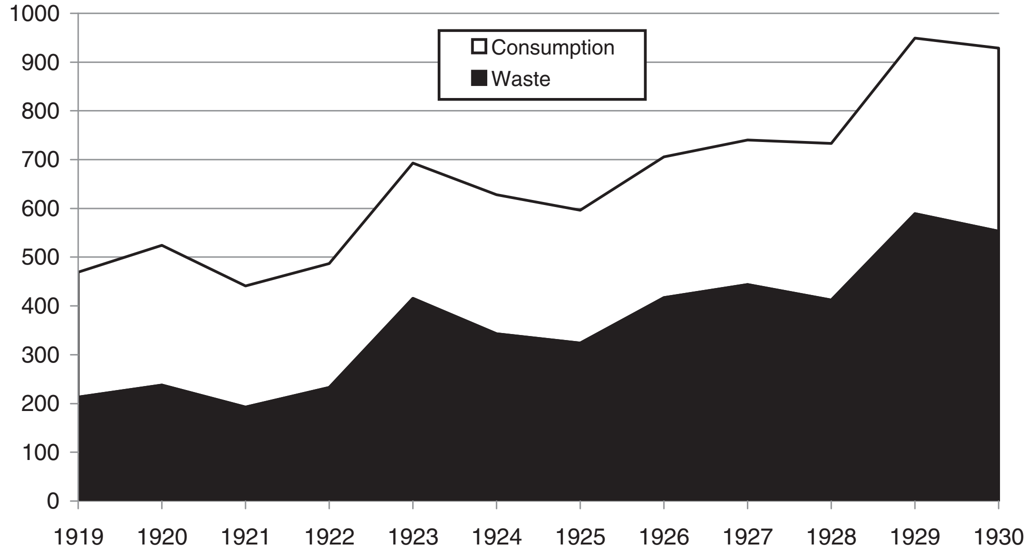
Manufactured coal gas companies financed many of the first long-distance pipelines built in the 1920s for mixing cheap natural gas into water gas to raise its heat content. The first long-distance pipeline was 250 miles long and made of twenty-inch diameter pipe built by Cities Service in 1927/28 to connect the Panhandle field with Kansas City. This was quickly followed by Standard Oil of New Jersey's 350-mile, twenty-two-inch line from the Texas-New Mexico border to Denver. In 1929, natural gas was pipelined 300 miles from the San Joaquin Valley to San Francisco, the first metropolitan area to switch from manufactured to natural gas. These pipelines carried a considerable amount of gas that had to find a "home," spawning an intense marketing effort to induce consumers to buy gas-powered appliances such as space and water heaters, stoves, and clothes dryers. Individual burners for manufactured gas had to be adjusted to handle the higher heat content of natural gas, no small effort when a city had hundreds of thousands of individual burners. In 1930, the industry accepted a standard and distinctive mercaptan odorant to detect escaping gas.

A consortium of companies controlled by Doherty, Insull, and Standard Oil of New Jersey built the first 1,000-mile pipeline (actually 980 miles) from north Texas to Chicago, called the Chicago Line. The twenty-four-inch diameter pipeline, started in 1930 and completed one year later, primarily served Insull's Chicago area utilities. The pipeline transmitted a sufficient volume of attractively priced gas to eventually convert Chicago from manufactured to natural gas. The three principal partners to varying degrees owned and controlled the natural gas fields and the pipeline transmission and distribution systems. A similar arrangement was behind the Northern Natural Gas 1,110-mile, twenty-six-inch pipeline from the Hugoton gas field to Omaha, then continuing on to Minnesota. Essentially the same power trust, but with different shareholdings and minority participants, controlled both pipelines. With no competition between the two pipeline systems in their respective "territories," and the same partners owning the natural gas fields, the pipeline transmission and distribution systems, consumers were at the mercy of a natural monopoly whose operations were far beyond the purview of state regulatory authorities.

The Panhandle Eastern pipeline was intended to introduce competition in the "territories." The power trusts then in existence employed various legal shenanigans to stop the building of the pipeline, including putting pressure on financial institutions not to fund the project. While ultimately unsuccessful, the trusts did succeed in drawing public attention to their power to thwart competition. Yet, it was in the public interest to build more long-distance gas pipelines to reduce the wasteful practice of venting natural gas to the atmosphere. As seen in Figure 7.1, venting amounted to over half of natural gas production in the Southwest.

An average of a little under 400 billion cubic feet were vented to the atmosphere per year for the eleven years shown in Figure 7.1; perhaps in no small way contributing to the buildup of methane, a greenhouse gas, in the atmosphere. To understand what this waste means in terms of oil, a cubic foot of natural gas contains 1,026 Btu, whereas a barrel of crude oil contains 5.8 million Btu. One Btu is the amount of energy to increase the temperature of one pound of water by 1°F; it is a small measure of energy equivalent to burning a blue-tip kitchen match. One barrel of oil is energy-equivalent to 5,653 cubic feet of natural gas, or one barrel of oil per day for one year is energy-equivalent to 2.063 million cubic feet of natural gas. Thus, 1 trillion cubic feet of gas per year is energy-equivalent to 484,648 barrels of oil per day or, in round numbers, 0.5 million barrels per day. The waste of, say, 0.4 trillion cubic feet of gas per year vented to the atmosphere was energy-equivalent to throwing away about 200,000 barrels of crude oil per day for a year, at a time when energy consumption was a minuscule fraction of current levels.

Figure 7.1 **Consumption versus Waste of Natural Gas** (Billion Cubic Feet)



This waste was primarily natural gas associated with oil production. A lower oil production rate would result in less waste. Unfortunately, the common-law principal applicable to the ownership of underground hydrocarbons is the rule of capture, which simply states that whoever draws the oil out of the ground owns the oil (assuming vertical wells!). If three individuals or companies own the land and mineral rights over an oil reservoir, and only one drills wells on his or her property and, over time, drains the entire reservoir dry, the other two have no claim on the revenue or profits of the driller. The rule of capture forces everyone whose land lies over an oil reservoir to drill as many wells as possible and to pump as hard as possible to get their "rightful" share. Under these conditions, natural gas associated with oil production had no way to go but up into the atmosphere.

Federal Regulation

The construction of long-distance natural gas pipelines came to an abrupt end with the Great Depression of the 1930s, when only three pipelines of less than 300 miles in length were built. Existing natural gas pipelines and electric utilities operated far below capacity and many could no longer produce enough revenue to support their operating and capital costs. Insull Utility Investments, the darling of the Roaring Twenties, had issued bonds galore to finance the takeover of many of the nation's utilities at stock prices inflated by investor enthusiasm and overvalued assets. The Great Depression wrung the last drop of excess out of the stocks in Insull's empire and the discovery of accounting irregularities hastened its demise in 1932, incurring the wrath of shareholders, bondholders, the Federal Power Commission (FPC), and Franklin Delano Roosevelt.

While criticism of the monopolistic corporate structure of public utilities was voiced before the 1929 stock market crash, the collapse of Insull's house of cards led to a 1935 ninety-six-volume FPC report assailing the electricity and natural gas industries. With regard to natural gas, the report focused on the waste of venting natural gas to the atmosphere, the monopolistic control by the same corporate entities over natural gas production, transmission, and distribution, and reckless financial manipulation. The report pointed out the practice common among natural gas and electricity-generating companies of inflating book values to increase the rate base for pricing electricity, and their unrelenting pressure to influence state regulators to get higher rates and protect their "territories." The report noted only four companies, one being Standard Oil of New Jersey, controlled 60 percent of natural gas pipelines in terms of mileage and a like amount of the nation's natural gas production. With natural gas in interstate trade passing through thirty-four states serving 7 million customers, the report concluded that it was high time for the public utility industry to come under public scrutiny.

The passage of the Public Utility Holding Act of 1935 dismantled the pyramid utility holding companies. The public utility business would henceforth be organized into single, locally managed entities providing electricity and gas and serving a specific area. Although electricity and gas operations were still allowed under one corporate umbrella, they were housed in separate organizations. The Act essentially put the utility business back to where it was before Doherty and Insull started building their pyramids.

In 1937, an explosion in a Texas high school from natural gas leaking into the basement killed nearly 300 students and teachers. Although it was industry practice to put an odorant in natural gas to detect accumulation of gas in a closed space, the particular source of natural gas for the high school did not have an odorant. Perched on top of the wreckage was part of a blackboard with the intact inscription: "Oil and natural gas are East Texas' greatest mineral blessings. Without them this school would not be here, and none of us would be here learning our lessons." This tragedy hastened the passage of the Natural Gas Act of 1938, which empowered the FPC to regulate interstate natural gas pipelines. Viewed as an extension of its 1930 mandate to regulate the interstate transmission of electricity, the Act gave the FPC authority to approve natural gas pipeline rates based on a just and reasonable return, to require regulated pipeline companies to submit extensive documentation on operational and financial matters, and to order actions to be taken on a variety of matters if deemed necessary.

No interstate pipeline could be constructed without a Federal Certificate of Public Convenience and Necessity. To obtain this certificate, the promoting company or companies had to have a twenty or so year contract for an adequate supply of natural gas, must demonstrate a sound and proven ability to attract the necessary financing, and propose a rate based on a just and reasonable return on its investment. Moreover, the granting of the certificate had to take into consideration the impact of the proposed pipeline on other natural gas suppliers serving the intended market. The wording of this last point would prove to be a regulatory sticking point for certifying natural gas pipelines intended for areas without existing natural gas services. As bizarre as this sounds, the inability to measure the impact of a natural gas pipeline in a market not already served by natural gas pipelines would end up being an effective way for opponents of natural gas to obstruct the building of natural gas pipelines.

Before the passage of the Act, the owning corporations decided who had access to the pipeline and what rates would be charged. After the passage of the Act, interstate pipelines would be common carriers charging the same FPC-approved rates to all users without restrictions to access. The certificate, once granted, was a franchise for a natural gas pipeline company to exclusively serve a specified market. Thus, the concept of the franchise survived, but who determined the franchise had changed. Before the passage of the Act, corporations set up an exclusive "territory" where only the members of the cartel had access to the market. After the passage of the Act, the regulators would determine the "territory" where a pipeline transmission company had an exclusive franchise. The franchise was protected from competition by government fiat rather than corporate connivance. Having a chief executive with an "in" with the FPC regulators could be a natural gas pipeline's greatest asset.

Curiously, the Act did not grant the right of eminent domain to pipeline companies for building natural gas pipelines. Coal-carrying railroads, coal-mining companies, and manufactured gas producers would be able to obstruct the building of natural gas pipelines by taking advantage of the lack of a right of eminent domain and the requirement to evaluate the impact of a pipeline on other natural gas providers serving an area that had none. Standard Oil of New Jersey's response to this massive government intrusion into the natural gas business was to distribute shares in its natural gas and pipeline subsidiaries to its stockholders and abandon the natural gas business.

The War Years

The Second World War significantly boosted demand for natural gas to fuel factories and armament plants. This stimulated the building of new pipelines to tap Southwest gas to replace declining production in Appalachia. Despite wartime needs, a proposal to build a natural gas pipeline from the Southwest to New York was thwarted by coal-mining companies, railroads, and manufactured gas producers. As an alternative, a newly organized company, Tennessee Gas and Transmission, made a proposal to build a pipeline from Louisiana to Tennessee. The application failed because the company could not demonstrate how the pipeline would affect other natural gas suppliers in an area that had none! Attempts to correct this legislative imbroglio were bitterly opposed by railroads, coal companies, and manufactured coal gas producers.

When reason finally prevailed and appropriate legislative changes were made to modify this obstructive requirement, the railroads, coal mining, and manufactured gas companies were granted the right to intervene directly in natural gas pipeline certification hearings. Having lost one means to obstruct the building of natural gas pipelines, they were awarded another. The saga for granting the Certificate of Public Convenience and Necessity to build the Tennessee Gas pipeline involved political intrigue right on up to the office of the President along with major changes in the source of natural gas, changes in the financing, changes in the corporate structure of the company, and changes in its ownership. Appeals were made to the War Production Board to support the pipeline application in order to alleviate the growing shortage of natural gas in Appalachia, which was critical to fueling wartime industries. Perhaps the exigency of military industrial enterprises running out of natural gas or perhaps the rare triumph of reason over vested interests finally prevailed, and the FPC granted the required certification for building this twenty-four-inch pipeline.

Opening Up the Northeast

Manufactured gas companies, along with the coal-mining industry and the coal-carrying railroads, were intent on maintaining their last market bastion in the Northeast, the population center of the nation. All they had to do was obstruct the building of any natural gas pipeline. The Tennessee Gas pipeline extended the market reach of Southwest gas to Appalachia but not to the Northeast.

During the Second World War, tankers transported oil from the U.S. Gulf to the Northeast as the first step in shipping oil to Europe in support of the war effort. The eastern seaboard cities refused to turn off their lights at night, and the silhouetted tankers passing against their skylines became easy targets for U-Boats. As a countermeasure, the U.S. government built two oil pipelines, the Big Inch (twenty-four-inch) and the Little Inch (twenty-inch), from Texas to Pennsylvania and New Jersey. After the war, the oil companies reverted to tanker shipments and the pipelines, now under the Surplus Property Administration, were put up for sale. Congressmen representing the coal-producing states joined the railroads, coal companies, and manufactured gas producers to prevent the sale of these pipelines to a natural gas pipeline company. Proponents of natural gas pointed to the prospect of the continuing waste of venting natural gas to the atmosphere in the Southwest if these oil pipelines were not converted to natural gas. Opponents pointed to the millions of tons of coal that would be displaced to the detriment of the coal-mining industry and the transporting railroads if these oil pipelines were converted.

The winning bid at the first auction was Tennessee Gas, which obtained a one-year lease to pipeline natural gas to Ohio, with the promise that it would not to try to move gas into the Northeast. This converted the oil pipelines to gas transmission. At the expiration of the lease in 1947, a second auction was held and another fledging company, Texas Eastern, won with a bid of $143 million, about equal to the government's cost of construction. Later that year, a bill granting eminent domain to the natural gas pipeline industry quietly slipped through Congress. Philadelphia was the first northeastern city to convert to natural gas in 1948, and within a decade its manufactured gas industry was gone. The FPC then approved the building of the Transcontinental pipeline from Texas to New York City. Begun in 1949, the thirty-inch, 1,000-mile pipeline, including the "Costliest Inch" connection under Manhattan to five receiving gas utilities in New York City and Long Island, was completed in 1951.

The conversion of New York City and Long Island from manufactured to natural gas made New England the last bastion of manufactured gas in the United States. Progress, once underway, was hard to stop. A two-year dispute between Texas Eastern and Tennessee Gas before the FPC ended up with Texas Eastern being the supplier to Algonquin pipeline to provide service to Connecticut, Rhode Island, and eastern Massachusetts, including Boston. A subsidiary of Tennessee Gas was given permission to pipeline gas from a connection in Buffalo through upstate New York to western Massachusetts. Natural gas flowing into New England in 1953 marked the end of a century of domination by manufactured gas producers.

Last Stop Before Total Regulation

The Natural Gas Act of 1938 split the natural gas business into three entities: the unregulated natural gas producers, interstate pipelines regulated by the FPC, and local distribution companies (LDCs) regulated by state or municipal authorities. In the 1940s, Panhandle Eastern attempted to sell gas directly to a Detroit utility, bypassing the LDC. The irate LDC decided not to object, but to build a competitive pipeline to cut out Panhandle Eastern. Now it was Panhandle Eastern's turn to object to the granting of a certificate for building a competing pipeline. Despite legal maneuvering, Panhandle Eastern lost the case. The alternative pipeline had contracted with Phillips Petroleum for its entire gas supply. The pipeline fell behind schedule in 1950, forcing a renegotiation of the contract. Phillips exercised its monopolistic hold over the pipeline's gas supply by hiking the price by 60 percent, raising the hackles of those in Congress representing the pipeline's consumers. The upshot was the "Phillips Decision" by the U.S. Supreme Court that brought natural gas producers selling gas to interstate pipelines under regulatory control.

Now the FPC had jurisdiction not only over 157 interstate gas pipeline companies but also over tens of thousands of independent producers. While arriving at a just and reasonable tariff for pipelines was a regulatory possibility (because pipeline projects were relatively few in number with well-documented costs), now the FPC had to deal with tens of thousands of independent producers who owned hundreds of thousands of individual wells each with its unique cost structure. What is a fair and reasonable price for natural gas coming from a deep well, drilled at great expense with high operating costs, and drawing gas from a reservoir with a short life versus the fair and reasonable price for gas coming from a shallow well with low operating costs tapping a field that will last for decades? Pricing gas on a well-by-well basis proved impossible and the FPC resorted to the "fair field" method to regulate natural gas prices in interstate trade, which was challenged and overturned in a 1955 court decision. In 1960 the FPC, facing a monumental backlog of applications for price increases by independent natural gas producers selling gas to interstate pipelines, decided to establish common prices for five geographic areas. In 1965, five years later, the FPC published its first area price; another five years were to pass before the second area price was published.

The never-ending regulatory wrangling prevented price increases for natural gas sold to interstate pipelines. The availability of cheap surplus gas in the Southwest encouraged the building of interstate pipelines. California began to suffer from a decline in local supplies of natural gas and interstate pipelines were built to its border for transfer to intrastate pipelines (California prohibits the building of interstate pipelines within its borders). Another large natural gas market was tapped by building an interstate pipeline to Florida. The new gas pipelines absorbed excess production in the Southwest, eliminating the wasteful practice of venting, but the continued building of interstate pipelines began to outstrip supply. Ignoring the lessons of Economics 101, the FPC set a regulated price for natural gas in interstate commerce at a level that encouraged consumption but discouraged investment in developing new gas fields. With a price set too low, proven reserves started to decline after 1970 and an impending natural gas shortage was looming when the oil crisis struck in 1973.

Unraveling Natural Gas Regulation

The 1973 oil crisis sent oil prices spiraling, which, in turn, caused the prices of all forms of energy to rise sharply, with the exception of regulated interstate natural gas. Though prices for regulated interstate gas remained unchanged, prices for unregulated intrastate natural gas jumped. Natural gas producers sold all they could to intrastate pipelines and reduced the volume sold to interstate pipelines to the absolute minimum contractual amounts. Natural gas shortages amounting to 1 trillion cubic feet in the Midwest and Northeast started in 1973 and continued to worsen. They became particularly severe during a long and cold winter in 1976–1977, reaching a peak shortfall of 3.8 trillion cubic feet with New York State declaring a state of emergency.

The FPC was at its wit's end trying to cope with the deteriorating situation, with its primary focus more on how to prevent an owner of an existing regulated well from enjoying a windfall profit than solving the natural gas shortage. Cracks in the regulatory facade started to occur in 1975 when the FPC allowed LDCs to make direct contract with producers to buy gas at higher than regulated prices. Interstate pipeline owners opposed this scheme because it threatened their merchant status, which allowed them to be the sole buyers and sellers of natural gas carried by their pipelines. The interstate pipeline owners initiated an advance payment program to natural gas producers that was essentially a five-year interest-free loan to encourage exploration, but this was abrogated by the FPC. Finally, the FPC abandoned area pricing and set a nationwide price for regulated gas 50 percent below intrastate gas prices. When this failed to stimulate exploration, the FPC announced a price menu that authorized higher prices for "new" gas and lower prices for "old" gas.

The Iranian Revolution of 1979–1980 worsened the natural gas situation with another spike in oil prices. The Synthetic Fuels Corporation, formed under Carter's Energy Security Act of 1978, was to make America energy independent. With vast deposits of coal, the most promising solution was a return to manufactured, or synthetic, gas made from coal. The Fischer-Tropsch process employed in Europe and South Africa produced nearly pure methane from coal without the adverse environmental consequences of the bygone era of manufactured gas. All but one of the proposed synfuel projects failed for a variety of environmental, commercial, and legal reasons. The one that succeeded came onstream in 1984, with four interstate pipelines companies forced to buy its output of synthetic gas made from coal at a resounding $6.75 per million Btu, nearly fifteen times the price of wellhead "old" gas when the project was conceived.

The second response to increasing natural gas supplies without increasing the price of old gas was to exploit the huge natural gas reserves found along with oil at Prudhoe Bay in Alaska. Three proposals were offered to tap this gas. One was a 2,500-mile, forty-eight-inch pipeline from Prudhoe Bay, along the coast of the Beaufort Sea, into Canada to the Mackenzie River Delta, also a source of natural gas. The pipeline would then proceed south along the Mackenzie River to pipeline connections in Alberta for delivery of the natural gas to customers in the Midwest and California. Environmentalists successfully opposed this project on the basis of potential damage to the Arctic National Wildlife Refuge. Although this project failed, two pipelines built in anticipation of its approval now carry Alberta gas to the Midwest and California.

A second proposal was to build a parallel natural gas pipeline to the existing crude oil pipeline that carried Prudhoe Bay oil to Valdez for shipment in tankers to U.S. markets. The natural gas would be liquefied at Valdez and shipped in LNG carriers to California. President Carter did not favor this project and preferred a third proposal: building a 1,600-mile pipeline from Prudhoe Bay parallel to the crude oil pipeline and then south parallel to the Alcan Highway through Canada, reentering the United States in Montana. Financing problems plagued the project until it was shelved in 1982.

The third response to increase natural gas supply was LNG imports. LNG production already existed in the United States since 1969 with Phillips Petroleum and Marathon Oil exporting LNG from Cook Inlet in Alaska to Japan. Anticipating natural gas shortages, Distrigas, a subsidiary of Cabot Corporation at the time and now part of the Suez LNG, built a terminal near Boston to receive LNG from Algeria to satisfy peak winter demand. An early proposal to import LNG from the Soviet Union failed for political reasons. In 1969, before the oil crisis and also anticipating natural gas shortages, El Paso Natural Gas organized a major LNG project with Sonatrach, the Algerian state-owned oil and gas company. Sonatrach would receive an export price for LNG that reflected the then low value for natural gas in the United States. El Paso built a fleet of nine LNG carriers and contracted with three east coast gas companies to receive the gas at specially built LNG terminals along the eastern seaboard. Panhandle Eastern entered into a similar agreement for Algerian LNG deliveries at a terminal built at Lake Charles, Louisiana, to feed Trunkline, a pipeline subsidiary that was running low on natural gas. (If a pipeline is running out of gas supplies and LNG can be delivered to either end of the pipeline, why have LNG fill the pipeline?)

The El Paso project survived only the first shipments when Sonatrach unilaterally repriced LNG to fit market realities, giving El Paso the opportunity to walk away from the deal. The Trunkline failure took a bit longer because its deal with Sonatrach had tied the price of LNG to fuel oil. Whereas El Paso walked away from the project when Sonatrach repriced LNG, here Trunkline customers did the walking. The price they had to pay was a blended price of relatively cheap interstate gas and expensive LNG. Faced with opportunities to buy lower-priced gas from other sources, one Trunkline customer after another took their business elsewhere. As its customer base eroded, the rising portion of expensive Algerian gas in Trunkline's pipeline increased the price of the blended gas, encouraging others to walk. From 1982–1984, customer defection halved pipeline volume forcing Trunkline to walk away from the Sonatrach contract. Sonatrach successfully sued Panhandle Eastern for partial restitution.

All in all, natural gas regulation was a bitter lesson for the regulators, who seemed to forget the lessons of Economics 101. By pricing gas too low starting in the late 1960s, the regulators encouraged growth in demand while simultaneously discouraging growth in supply. Their reaction to the energy crisis—proposing esoteric solutions such as synfuels, developing isolated reserves, and using LNG rather than raising the price of old gas—simply exacerbated the situation.

The Road to Deregulation

The 1976 Carter campaign for the presidency pledged the "moral equivalent of war" on the ongoing energy crisis. Following through on his campaign pledge, Carter created the Department of Energy as part of the National Energy Act of 1978, which was preceded by Congress reorganizing the harassed Federal Power Commission as the Federal Energy Regulatory Commission (FERC). The Natural Gas Policy Act of 1978 permitted FERC to price natural gas that came into production in and after 1978 into nine categories with subcategories depending on well depth, source, and other factors, until 1985 when all post-1978 gas would be deregulated. Old gas in production prior to 1978 would be indefinitely regulated with three price tiers. The significantly higher-priced new gas flowing into the system had "unexpected" Economics 101 consequences—it provided an incentive for consumers to reduce demand by switching to other sources of energy and taking steps to conserve energy, at the same time providing an incentive for producers to expand supply. New gas prices dropped when controls were lifted in 1985 because the gas shortage of too little supply chasing too much demand had been transformed to a gas "bubble" of too much supply chasing too little demand. The word bubble was intentionally used to describe what FERC thought would be a transient state of oversupply, but "transient" was a situation that lasted for nearly two decades. Natural gas prices fell to the point where synthetic gas, Alaskan gas, and LNG were far from being economically viable. The fall in natural gas prices as a result of letting the market work its magic (higher prices spurring exploration to expand supply and conservation and energy-switching to dampen demand) made it easy for Congress to pass the Natural Gas Wellhead Decontrol Act of 1989 abrogating price controls on all wellhead gas.

Unfortunately, the pipeline companies had arranged for twenty-year, back-to-back, take-or-pay, fixed-price contracts between electric utilities and natural gas suppliers at the prevailing high natural gas prices of the late 1970s. The growing presence of lower-priced gas during the first half of the 1980s placed a great deal of pressure on utilities to break their high-priced gas contracts. FERC bent to their demands and, through various rulings, allowed utilities to walk away from these contracts and buy natural gas directly from producers at lower prices and pay a fee to the pipeline companies for transmission services. This started the transformation of natural gas-transmission companies from merchants to transporters, the first step in breaking a monopoly in which a consumer had no choice but to buy from the transmission company.

Once the utilities were allowed to break their contracts with pipeline companies, the pipeline companies were stuck with the other side of the take-or-pay contracts to buy natural gas at high prices. Faced with multi-billion dollar liabilities, in 1987 FERC issued Order 500, the first step toward breaking take-or-pay contracts with natural gas producers, allowing pipeline companies to set up a system of pipeline transmission credits against producers' take-or-pay claims. While not an entirely satisfactory resolution of the matter, Order 500 turned out to be the precursor to a series of orders that ended up with Order 636 in 1992, which mandated the final solution to the national gas regulatory problem: deregulation.

To its credit, regulation either fostered or, at least, did not prevent the building of hundreds of thousands of miles of interstate gas pipelines linking natural gas producers to consumers throughout the nation. Under the sanction of the FPC, natural gas pipeline merchants acquired natural gas, transmitted the gas through their pipelines, and sold the gas in their respective franchised territories. The pipeline merchants generally made more money buying and selling gas than transmitting it. This system ended with Order 636. The whole natural gas system was unbundled into three distinct activities: natural gas producers, pipeline transmitters, and the end-use buyers—either LDCs or major consumers such as utilities or industrial plants.

Order 636 restricted the service offered by interstate pipeline companies to transmission of natural gas at a regulated rate that provided a just and reasonable return on their investments. LDCs and major consumers would be responsible for arranging their own supplies by contracting with natural gas producers to cover their needs. This created a marketing opportunity for companies to acquire natural gas production or represent the interest of natural gas producers and sell to end users. The pipeline transmission carriers were reduced to contract carriers and were obligated to set up Electronic Bulletin Boards in order for buyers and sellers to keep track of gas flows and pipeline allocations.

In 1983, 95 percent of all interstate commerce gas was purchased by the pipeline companies from natural gas producers and sold to LDCs and major consumers. By 1987 the pipeline companies arranged for the buying and selling of less than half of the gas going through their pipelines, and by 1994, they were fully converted to common carriers. Thus ended the world of the pipeline companies where they dealt with producers for a supply of gas and then marketed the gas to LDCs and large end users. Now the pipeline company was no longer a gas merchant but a common contract carrier like a railroad. Marketing firms were the intermediaries between natural gas producers and LDCs and large end users. However, pipeline carriers were free to set up marketing organizations to compete with independent marketers in arranging and brokering deals between natural gas buyers and sellers. By 1993 the marketing arms of pipeline companies had more than a 40 percent share of the market, but they had to operate independently of the pipeline transmission organization; any collusion between the two, or less than arm's-length transactions, were subject to heavy fines.

This process of unbundling of services is not complete. LDCs buy natural gas from producers and pay a toll to an interstate natural gas pipeline as a common carrier at a rate determined to provide a reasonable return and supply the gas to their customers. This principle can be expanded to include customers of the LDCs, in theory down to individual households, who can arrange for their natural gas needs directly with producers, pay the interstate pipeline company one toll for the use of its transmission system, and then pay another toll to the LDC for the use of its distribution system at a rate that represents a fair return.

FROM SOURCE TO CONSUMER

Natural gas comes from the well as a mixture of hydrocarbons. For instance, Southwest natural gas has average proportions of 88 percent methane, 5 percent ethane, 2 percent propane, 1 percent butane, plus heavier hydrocarbons and impurities. A methane molecule is one carbon atom and four hydrogen atoms; ethane is two carbon atoms and six hydrogen atoms; propane has three carbon atoms and eight hydrogen; butane, four carbon and ten hydrogen. Heavier hydrocarbons of pentane (with five carbon atoms and twelve hydrogen atoms), hexane (with five carbon atoms and fourteen hydrogen), and heptane (seven carbon atoms and sixteen hydrogen) are in a gaseous state when in a natural gas reservoir, but "fall out," or condense, to a liquid called condensates when brought to the surface. Condensates are separated from natural gas and sold separately to refiners. Ethane is fairly expensive to separate with its low liquefying temperature, and normally remains in the natural gas stream. Propane and butane are more easily separated by fractionation, or a cooling of the natural gas, and are sold separately as liquefied petroleum gases (LPG). Impurities such as hydrogen sulfide, carbon dioxide, nitrogen, and water have to be removed. "Pipeline-quality" natural gas is primarily methane with some ethane, cleaned of impurities and stripped of condensates and petroleum gas liquids, with a heat content of 1,000–1,050 Btus per cubic foot at standard atmospheric conditions.[2]

The cleaning and stripping functions are performed in the pipeline-gathering system connecting the producing wells with transmission pipelines; the last step is raising the pressure of natural gas to transmission system pressure. Transmission pipelines typically are twenty-four- to thirty-six-inch diameter operating between 600 and 1,200 psi pressure, although there are wider diameter pipelines operating at higher pressures. Compressor stations are located about every seventy miles and the speed of the gas varies between fifteen and thirty miles per hour, depending on the gas pressure, compressor capacity, and pipeline diameter. Monitoring devices and shutoff values are strategically placed about every five to twenty miles to deal with potential pipeline ruptures and routine pipe maintenance. Both the inner and outer pipe surfaces are coated to protect against corrosion. The inner surface is kept clean by running a "pig" through the pipeline for routine maintenance; a "smart pig" can also transmit data on the internal condition of the pipeline. There are also routine maintenance inspections of the external condition of pipelines to detect leaks and other potential problems.

Storage facilities are available along a pipeline. In the Gulf region, natural gas is stored under pressure in salt caverns where the salt has been leached out. In other areas of the nation, abandoned or played-out natural gas reservoirs are used for storage. Natural gas is reinjected into these reservoirs under pressure during times of weak demand and lower prices to be withdrawn during times of strong demand and higher prices. Before deregulation, natural gas was stored during the summer and drawn out during the winter. Since deregulation, natural gas in storage is recycled several times a year in response to changing prices, not necessarily related to times of peak demand. The 300,000 miles of transmission pipelines have an inherent storage capacity that can be increased by increasing the gas pressure. Metering is a vital operation as gas enters and leaves the gas transmission system and associated storage facilities for both accurate paying of suppliers, charging of customers, and system control.

Gas planning for a transmission company depends on long- and short-term forecasting models. Long-term forecasts determine investments in order for the pipeline system to meet future demand. Short-term forecasts ensure that the volume of gas can accommodate current demand. Nominations are made one to two days in advance to ensure that enough gas enters the system upstream to match demand downstream without exceeding pipeline capacity. Scheduling acceptances of gas from thousands of suppliers and deliveries of gas to thousands of consumers, each with their specific needs and different contractual arrangements, is both complex and crucial to the smooth operation of the system. A system of allocation cuts based on a previously arranged and agreed-on priority ranking is activated when nominations exceed the limits of pipeline capacity.

In today's deregulated climate, natural gas can be drawn from storage or obtained directly from natural gas producers or from other interstate transmission companies via hubs. Hubs connect various interstate pipelines in a common system whereby natural gas consumers connected into one interstate pipeline can obtain supplies from natural gas suppliers hooked into other interstate pipelines. There are about a dozen major hubs in the United States, the most important being Henry Hub in Louisiana, where a multitude of pipelines connect natural gas suppliers and interstate pipelines into what amounts to one huge common system. Hubs not only allow for common distribution, but also common pricing. The Henry Hub is the most important distribution and pricing hub in the United States; its price is the base price for the nation. Other hubs are generally priced at the

Henry Hub price plus transmission costs with local market-related variations. As an example, three interstate pipelines serve New York City. Through local interconnections, major gas purchasers can bargain for natural gas from suppliers in three different Southwest natural gas regions. These continual negotiations for the best price create a pricing hub in New York City, where price does not vary much regardless of which transmission company is actually supplying the gas. If a gap in price does appear among the transmission companies, then consumers' continual quest for the cheapest source of natural gas tends to close the gap. Another pricing hub is in Boston, where gas from two interstate pipelines from the Southwest and two pipelines from the western and eastern provinces of Canada are interconnected, providing major customers with the opportunity to buy gas for the best price from suppliers in four different natural gas-producing regions. The search by large consumers for the best price ends up with a more or less common price in Boston, regardless of the source. Natural gas prices in New York and Boston are not the same. The New York basis price reflects the price in Henry Hub plus transmission costs. The presence of Canadian producers in the Boston market affects the basis price of Boston gas and its relationship with the New York basis price and the price in Henry Hub. It is possible for Canadian gas to penetrate the New York market by reversing the Algonquin pipeline between New York and Boston. Deregulation has introduced a dynamic in the natural gas business that was lacking under regulation.

The simple days when gas producers sold to interstate pipeline companies which then sold to LDCs selling to residential, commercial, industrial, and electricity-generating customers at a regulated price based on costs are gone. Natural gas suppliers are no longer regulated. Pipeline transmission companies have lost their status as natural monopolies. No longer merchants, they have become common carriers with regulated long-term transmission rates. Life is now more complex for customers because they must examine many options such as buying direct from gas producers via independent marketing firms, the marketing arms of transmission companies, from storage providers, or from other gas transmission pipelines and their natural gas suppliers via hubs.

While natural gas consumers are doing their best to buy at the lowest cost, natural gas producers are doing their best to sell at the highest price. Producers look at the basis price at every hub that they have access to and net the basis price of the transmission cost to obtain the netback value for their gas and then sell to the pricing hub with the highest netback value. The enormous number of individual transactions among buyers seeking the lowest delivered cost and sellers seeking the highest netback price, in a market where no individual dominates and where buy-and-sell transactions are simplified, transferable, and transparent, leads to commoditization. Natural gas prices are set by market conditions that reflect supply and demand, not regulated cost plus pricing. The regulators' role is to ensure that no one tries to manipulate the price, reduce the transparency of transactions, or in any way attempts to control the market. In a commodity market, where the providers are all selling at the same approximate price, differentiation among natural gas providers becomes one of value-added services. A buyer selects a provider based not only on price, but also on reliability, dependability, and behind-the-meter services. Behind-the-meter services can include maintenance and repair of natural gas equipment owned by the buyer or advice on how to utilize natural gas more efficiently. In the future, companies may provide a bundled service in which gas is combined with other utility services such as electricity and water, or even communication, to woo customers away from competitors.

Deregulation has not made life easy for transmission companies because increasing revenue means attracting more customers by, perhaps, cutting rates on spare capacity, reducing operating expenses and capital commitments, and providing value-added services behind the meter. Nor is life easier for the consumer. With natural gas prices fluctuating widely and long-term contracts becoming less available, there is a greater exposure to adverse price fluctuations in the spot and short-term markets. Independent gas marketers can also be at great risk if their buy-and-sell commitments do not match up either in volume or time duration, which exposes them to the potential of huge financial losses from an adverse change in natural gas prices.

The risk of adverse price changes generates a need for risk mitigation among natural gas suppliers, consumers, and marketers. Banks and other financial institutions provide an active over-the-counter market for swaps tailored to meet the particular needs of suppliers and consumers. A swap protects a supplier from a low price and consumers from a high price that can threaten their financial well-being. NYMEX is the nation's leading center for buying and selling natural gas futures contracts. In addition to traditional hedging, the public trading of natural gas futures contracts opens up the opportunity for individuals (including hedgers turned gamblers) to speculate on the future price of natural gas, which is why the futures volume far exceeds the physical volume. Speculators add depth to the market by accepting the risk that hedgers are trying to shed. However, not all risks can be mitigated by financial instruments such as volume risk (a customer uses more or less than the nominated amount), counterparty risk (one of the parties to a transaction does not honor its commitment), execution risk (a transaction is not properly concluded), regulatory risk (the possibility of a change in the rules after a transaction has been signed), operational risk (system failure), and basis risk (the possibility of the price at a hub such as Boston moving differently than expected from the price used to hedge a risk such as Henry Hub).

The demarcation point between transmission and distribution is the citygate where regulators reduce the gas pressure; scrubbers and filters remove any remaining traces of contaminants and water vapor, and mercaptan is added as an odorant to detect gas leaks. The nation's million-mile distribution system is made up of two- to twenty-four-inch pipe with pressures from 60 psi down to one-quarter psi (above atmospheric) for natural gas entering a home or business, and higher for industrial and electricity-generating customers. Though distribution pipe had traditionally been made of steel, nowadays plastic or PVC is used for its flexibility, resistance to corrosion, and lower cost.

To ensure an adequate supply of natural gas, LDCs contract with the transmission companies for pipeline volume capacity that meets peak demand. The rate charged to LDCs is the regulated rate that ensures a fair and reasonable return on the interstate pipeline investment. However, during times of less than peak demand, LDCs are free to sell their spare transmission capacity to third parties. While these rates are generally less than what the LDCs are paying, the revenue so earned reduces LDC transmission costs. This creates a market for interstate pipeline capacity that generally disappears during times of peak demand. But if a LDC finds itself in a position with spare capacity during times of peak demand, it can sell this spare capacity at either the market rate or a maximum rate imposed by government regulations.

In addition to the marketing of spare transmission capacity, another opportunity has opened up to address nomination imbalances. Major customers of transmission pipelines (LDCs, utilities, industrial plants) must address an imbalance between their nominated and actual usage of more than 10 percent either way or face a monetary penalty. Rather than face a monetary penalty, customers can contact a marketing outfit that specializes in finding other users with the opposite imbalance.

The unbundling of services has created a plethora of marketing opportunities and commercial dealings that has commodized natural gas, natural gas transmission and storage capacity, nomination imbalances, and risk mitigation. The buying and selling of natural gas has become just like any other commodity such as grain or metals. Yet, there is still a great deal of regulation in the natural gas industry. FERC establishes services to be provided by interstate pipelines, determines rates based on a fair and reasonable return, and approves construction of new interstate pipelines. LDCs

Table 7.1

World Natural Gas Consumption in Trillion Cubic Feet (Tcf)

	# Tcf	% World Total
North America	29.0	27
Europe	20.3	19
FSU	20.0	19
Asia	17.1	16
Middle East	11.5	11
South America	5.0	5
Africa	3.4	3

are regulated by the states and, in some cases, municipalities, where no two state or municipal regulators issue the same set of regulations for conducting business, determining rate structures, approving construction of new facilities, and addressing complaints by users.

Rates charged by LDCs are based on covering operating and capital costs including the purchase of natural gas. Consistent with interstate transmission companies, a fair and reasonable return for LDCs is based on determining the appropriate rate of return that induces shareholders to invest in plant and equipment consistent with the inherent risk of the business and the opportunity to invest elsewhere. A balancing account keeps track of the difference between required and actual revenue, which eventually leads to upward or downward rate adjustments. Rates also reflect customer categories to take into account the peculiarities associated with each. The capital and service requirements for hundreds of thousands of residential and commercial customers in a local distribution system are quite different than those for a few industrial and utility customers.

Various states are experimenting with unbundling LDC services, but progress is slow. It is possible that regulation may not be deregulated but transformed to incentive regulation, which gives the regulated LDC an opportunity to profit from exceptional performance. One form of incentive regulation is performance-based regulation in which the LDC's cost of procuring gas for residential customers is compared to an index value for other LDCs. If the cost is lower than the index value, then the LDC shareholders and ratepayers benefit by splitting the savings. If higher, the incremental cost is again split and the shareholders suffer along with ratepayers. Incentive regulation can take the form of benchmarking with adjustments for both inflation and productivity gains. If productivity gains exceed the impact of inflation, then both shareholders and ratepayers share the benefit; if not, both suffer. Another alternative is rate caps, a method whereby shareholders either suffer or benefit from actual rates being above or below the cap. Incentive regulation provides an opportunity for LDCs to enhance their profitability by becoming more astute in gas purchases and more eager to pursue productivity gains.

NATURAL GAS AS A FUEL

Natural gas provides nearly 24 percent of world energy demand excluding biofuels. The consuming regions of natural gas in Table 7.1 are ranked in terms of trillion cubic feet (tcf) per year.[3] Consumption of 1 tcf per year is roughly equivalent to 0.5 million barrels of oil per day. North America and Europe account for 46 percent of world consumption. Whereas the United States is at the brink of becoming an importer of natural gas, Russia has long been a major exporter to Europe.

Under communism, natural gas in the Soviet Union was free, obviating the need for meters and thermostats. Torridly hot rooms were cooled by a blast of frigid Arctic air through an opened window. Since the fall of communism, meters and thermostats have been installed and natural gas usage is now charged to stop this wasteful practice, freeing up supplies for hard-currency exports. However, gas sold within Russia is only a fraction of the value received from European importers. The conflict between Russia and the Ukraine that took place in 2006 and 2009 was exactly on this point.

The categories of use for any energy source are transportation, residential, commercial, industrial, and electricity generation. Natural gas as a vehicle fuel is extremely clean-burning, emitting a small fraction of the precursors to ozone formation (organic gases and nitrous oxides) and carbon monoxide compared to oil-based motor fuels. Moreover, there are no particulates (soot), virtually no sulfur oxides, and less carbon dioxide emissions. The most difficult hurdle for natural gas to overcome to be an acceptable motor vehicle fuel is the logistics of refueling. For this reason, very little natural gas is actually consumed in transportation with most compressed natural gas-fueled vehicles owned by natural gas pipeline and distribution companies.

Using projected 2010 figures for the United States, about 20 percent of consumption is consumed by over 60 million residential customers for space and water heating, cooking, clothes drying, pool heating, and gas fireplaces. Residential demand peaks during winter months, accounting for as much as 70 percent of annual gas consumption, which of itself can vary greatly between cold and mild winters. Residential customers pay the highest rates for natural gas because they support a distribution system connected to each individual home capable of handling peak winter needs. Moreover, residential customers consume the greatest volume of natural gas when natural gas prices are high, which, of course, are high because of increased residential demand (the chicken-and-egg syndrome). Five million commercial customers use about 15 percent of total demand, paying the second highest price for natural gas. The commercial sector consists of restaurants, motels and hotels, retail establishments, hospitals and healthcare facilities, and office and government buildings. Though their natural gas usage is similar to that of residential customers, there is less of a swing in demand between summer and winter from space cooling fueled by natural gas. In addition to the weather, consumption in the commercial sector is sensitive to general business activity.

The industrial sector is the largest consumer at about 35 percent of total demand, with over 200,000 customers. Natural gas supplies the energy needs of a host of manufacturing industries plus waste treatment, incineration, drying and dehumidification processes, and is a feedstock for the fertilizer, chemical, and petrochemical industries. Natural gas prices directly affect food prices because natural gas is a raw material for making ammonia-based nitrogen fertilizers and is used for drying crops, pumping irrigation water, and processing food. While seasonal variations are less than those of residential and commercial users, the industrial sector experiences significant fluctuations in demand from changes in economic activity. Moreover, one-third of industrial users can switch to propane and fuel oil if natural gas prices get out of line with these alternative fuels. The industrial sector ranks third in what is paid for natural gas, while plants that generate electricity pay the lowest price. This sector consists of only 5,700 customers that account for nearly 30 percent of total demand. Electricity generation was the fastest growing market segment, with approximately 5,000 natural gas-fueled electricity-generating plants, not counting the cogeneration units run by commercial and industrial customers, until cheap natural gas went away with the natural gas bubble in 2000. Up until the bursting of the bubble, nearly all incremental electricity-generating capacity was fueled by natural gas. Since then, coal has been in the ascendancy, although many natural gas plants are still being built. Natural gas usage in electricity generation is affected by seasonal factors, changes in economic activity, and the relative cost of electricity generated from natural gas compared to coal, oil, and nuclear and hydropower. Some dual-fueled electricity-generating plants can easily switch between natural gas and fuel oil, depending on their relative costs. On a global scale, the residential sector consumes 17 percent of natural gas, commercial sector 6 percent, industrial sector 43 percent, and transportation sector 1 percent. The remaining share is the electricity-generating sector, whose share of 33 percent is expected to grow in the future at the expense of the other sectors.[4]

Natural gas in electricity generation employs a variety of technologies including conventional steam generators, combustion turbines, and combined-cycle plants. Natural gas burned in a steam generator is similar in context to burning coal or oil to produce steam that passes through a turbine that drives an electricity generator. Efficiency is about 35–40 percent for new plants and about 25–35 percent for older plants, regardless of the fuel. Most of the remaining energy passes to the environment as the latent heat of vaporization (the heat consumed for water to change to steam). Combustion turbines are basically modified jet engines attached to turbines to generate electricity for peak shaving. Peak shaving occurs for relatively short periods of time such as air-conditioning demand during a heat wave. Combustion turbines are best for peak shaving because their low capital cost minimizes a utility's investment in equipment that is run only for short periods of time. However, combustion turbines have a high operating cost since a large portion of the energy input is released to the environment as turbine exhaust.

A combined-cycle plant directs the escaping exhaust gases from a combustion turbine through a steam generator to drive an electricity-generating turbine. A combined-cycle plant can increase thermal efficiency up to 50 percent, higher than that of an oil- or coal-fired steam-generating plant, by the inclusion of a combustion turbine. A combined-cycle plant has lower capital costs than coal or nuclear plants, shorter construction times, greater operational flexibility, and is the preferred choice for smaller capacity plants. With a higher fuel cost, natural gas plants of various generating capacities are built to meet the variable needs of electricity-generating utilities, leaving base-load generation to large coal and nuclear plants. Hydro plants would be ideal for base-load generation since the fuel cost (water) is free. But it is difficult to ramp coal and nuclear plants up and down—they are best employed for base-load demand. Hydro plants, on the other hand, can be easily ramped up or down by changing the amount of water flowing through the turbine. In nations where hydro is a principal source of power, hydro satisfies both base and variable needs whereas in other nations such as the United States, hydro and natural gas plants primarily satisfy variable needs. As a general rule, natural gas plants satisfy variable needs because of higher fuel costs and the relative ease to respond to changing electricity demand.

Many companies need large quantities of hot water and have historically purchased electricity for both power and for heating water. These companies are increasingly installing cogeneration plants that do not necessarily have to be fueled by natural gas. When fueled by natural gas, a cogeneration plant is a combined-cycle plant with both a combustion turbine and a steam turbine to produce electricity, with none of the line losses associated with offsite electricity generation. Moreover, water containing the latent heat of vaporization from the steam turbine condenser can be substituted for the hot water that had previously been heated with electricity. Being able to utilize the "free" hot water raises the overall efficiency of cogenerating plants to 60 percent or higher.

For global electricity generation, the natural gas share as an energy source grew from 13 percent in 1971 to 20 percent in 2005 and is expected to increase to 22 percent in 2010 and continue to increase to 25 percent in 2030, outpacing growth in electricity and essentially making up for the falloff in the share of electricity generated by nuclear energy. Coal is expected to maintain its share, meaning of course, that consumption will follow growth in electricity demand.

THE EUROPEAN VERSION OF DEREGULATION

Europe never had a regulatory regime similar to that of the United States. European nations carried out their respective energy policies through "championed" energy companies. Championed energy companies had the support of their respective governments to dominate a nation's electricity or natural gas business. Governments exercised control over these companies by either having seats on the board of directors and/or approving the appointment of top executives. This comfortable relationship resulted in European governments being assured of a secure supply delivered in a dependable and reliable manner, in championed companies that operated profitably in a secure business environment, and in consumers who paid a high price for energy.

The first European leader to react against high-priced energy was Prime Minister Thatcher, who cut subsidies to coal companies, privatized national energy companies, and started the process of major consumers having direct access to energy providers to negotiate electricity and natural gas supplies. The ability to choose suppliers introduced competition to what had previously been a natural monopoly. Thus, the two paths taken by the United States and the United Kingdom were basically parallel and arrived at the same destination. For the United States, the path was deregulation of a regulated industry; for the United Kingdom, the path was cutting the umbilical cord to subsidized energy companies, privatizing previously nationalized companies, and giving major consumers third-party access to natural gas and electricity-transmission systems in order to be able to select suppliers. Both paths led to the introduction of a competitive marketplace where buyers can negotiate with suppliers to lower electricity and natural gas costs.

Although the unbundling of the UK natural gas and electricity markets in the late 1990s is very similar to what happened in the United States, it stands apart from Europe. European nations have been reluctant to liberalize their energy markets and give buyers the ability to negotiate with suppliers. While high-cost energy was widely recognized as a deterrent to European economic growth in the mid-1980s, the first EU directives for liberalizing electricity and natural gas did not appear until the latter half of the 1990s. These directives established a time frame for specified percentages of natural gas and electricity that had to be satisfied in a competitive marketplace. In 2003, another EU directive was issued to accelerate the process of liberalization. Independent transmission and distribution system operators were to be created to separate services formerly provided by integrated transmission and distribution companies, with a target year of 2007 for the unbundling of the gas and electricity markets.

With regard to natural gas, the objectives were to give major consumers access to gas-transmission networks with the ability to negotiate firm or interruptible, short- or long-term service contracts not only with gas suppliers, but also with operators of gas storage facilities and LNG terminals. Natural gas charges were to reflect actual costs, thereby avoiding cross-subsidies, and capacity allocation was to be transparent and nondiscriminatory. Interconnecting pipeline hubs and pricing hubs were to be established to give buyers access to various suppliers so they could negotiate price and terms. Yet in the 2000s, despite some liberalization, competition in Europe is limited in scope with gas prices still linked primarily to oil prices, which thwarts price competition, and transactions being more opaque than transparent. Existing long-term take-or-pay contracts between customers and integrated energy companies impede the pace of unbundling as do high transmission costs. Liberalization is not heartily endorsed by national governments; in particular, Germany, the powerhouse of Europe, sees no need to unbundle the services of its championed integrated energy companies. These companies have worked well in the past, providing security of supply, which to the German government is more important than cost.

Yet for competition to be effective, the number of natural gas supply sources must be increased, a market for physical and financial trading of natural gas has to be developed, the link between gas and oil pricing has to be severed, new entrants must be permitted in the energy business, and governments have to become more supportive of liberalization and less willing to shield their championed companies from competition. This foot-dragging by European nations is at variance with the EU energy bureaucrats in Brussels. In 2005, the EU warned a number of nations within the European Union that they will be brought before the European Court of Justice and face stiff fines unless they open up their energy markets.

Spain and Italy have taken steps to adopt an infrastructure of freedom of choice for consumers, with less progress being made in Austria, Ireland, Sweden, Belgium, and the Netherlands, and still less in Denmark, France, and Germany. A lack of uniformity of approach to the problem of dealing with supply, transmission, storage, and liquefied natural gas (LNG) terminals in a common natural gas pipeline grid among the various nations of Europe is the focus of the Gas Transmission Europe, an association of forty-five European companies in thirty countries. This organization not only deals with proposals concerning the hardware of interconnections between pipelines, storage facilities, and LNG terminals for improved network access, but also in the software of internal controls, gas flow and transaction information systems, nomination procedures, and other operational matters.[5]

Even with unbundling, natural gas prices may remain high if the primary sources of natural gas (the North Sea, the Netherlands, Russia, and Algeria) form a common front against lower prices. Natural gas buyers with access to LNG terminals may be able to break this common front were it to occur. LNG suppliers in Latin America, West Africa, and the Middle East are less controllable than traditional European gas suppliers. For instance, they may be tempted to get rid of excess production by selling low-priced cargoes into Europe. With third-party access to LNG terminals, a surfeit of LNG cargoes may exert sufficient commercial pressure on the traditional suppliers to break any common front and create a truly competitive market.

LPG: PRELUDE TO LNG

Liquefied petroleum gases (LPG) are primarily propane and butane. LPG is formed as a byproduct of oil refining and is stripped out of a natural gas stream by a fractionating unit. In the 1910s light-end gases from a barrel of crude were kept in a liquid state under pressure and fueled early automobiles, then blowtorches for metal cutting, and, in 1927, gas stoves. Butane was one of the propulsion fuels for dirigibles until the market for butane-fueled dirigibles crashed in 1937 with the *Hindenburg*. An entrepreneur began selling unwanted bottles of butane as fuel for gas stoves in Brazil. All went well until he ran out of dirigible fuel. To replace the butane, he began to import cylinders of pressurized butane on the decks of cargo liners, thus marking the humble beginning of the international trade of LPG.[6]

A 1927 court decision made the fractionating process available to industry, which opened the door for the development of the LPG business. With an increased availability of supply came the opportunity to develop a new market. The industry grew slowly, with bobtail trucks delivering pressurized propane in a liquid state to refill cylinders that fueled stoves, water heaters, clothes dryers, and space heaters in rural areas and towns not served by natural gas pipelines. LPG was also used for crop drying. Propane was a preferred fuel for bakeries and glassmaking facilities and other commercial and industrial enterprises that required a greater degree of control over temperature and flame characteristics. Cleaner-burning propane became a motor fuel of choice over gasoline for forklift trucks and other vehicles that operated in semiclosed environments such as terminals and warehouses. Butane eventually found a home as fuel for cigarette lighters and taxicabs. LPG became a gasoline blending stock and a feedstock for steam crackers to make ethylene, the precursor to plastics, and other petrochemicals. Railroad tank cars were the primary means of moving LPG over long distances until they were replaced by pipelines in the late 1960s.

Wells drilled into a salt dome at Mont Belvieu in Texas leached out the salt to form a cavern to store LPG. This would eventually become the nation's principal storage hub and central marketplace for LPG, with extensive gas liquids pipeline connections to major suppliers and buyers in the Gulf Coast, Midwest, and Northeast. Another storage hub in Kansas served the upper Midwest via pipeline. LPG was carried in pressurized tanks mounted on vessels and barges along the eastern seaboard and the Mississippi River. In 1971 President Nixon put price controls on oil, which happened to include LPG. Not surprisingly, this encouraged the consumption of LPG because of its lower cost compared to other fuels.

In the United States, refinery-produced LPG is generally consumed internally for gasoline blending or pipelined as feedstock to an associated petrochemical plant. The commercial market for LPG was primarily supplied by stripping gas liquids from natural gas. In contrast, LPG development in Europe was based on refinery operations and rail-car imports from the Soviet Union because there were no indigenous supplies of natural gas until the late 1970s, when the North Sea natural gas fields came onstream. LPG consumption was primarily propane in the north and butane in the south because propane vaporized more easily in warm climates. In the 1970s, Italy promoted the use of butane as a motor vehicle fuel. Small shipments in pressurized tanks installed on vessels carried LPG from refineries in Rotterdam to destinations in northern Europe and from refineries in Italy, Libya, and Algeria to southern Europe and the eastern Mediterranean.

In Japan, the LPG market grew out of the desires of Japanese housewives and restaurant owners to cook with propane rather than kerosene. Switching from kerosene to propane was a sign of a rising standard of living. Japan also encouraged the use of butane-fueled taxicabs. Unlike the United States and Europe, Japan had to import much of its LPG aside from that produced as a byproduct in domestic refineries. Shipping LPG at sea was costly because LPG was carried in cargo tanks built to withstand the pressure necessary to keep LPG liquid at ambient temperatures. The weight of the steel in the cargo tanks was about the same as the weight of the cargo, restricting the cargo-carrying capacity of the vessel.

To counter high shipping costs, Japanese shipyards developed and began building fully refrigerated LPG carriers in the 1960s. The temperature of the cargo was reduced to keep LPG liquid at atmospheric pressure (–43°C for propane and–1°C for butane). The cargo tanks had to withstand a lower-temperature cargo and had to be insulated to minimize heat transfer from the outside environment. An onboard cargo refrigeration unit kept the cargo at the requisite temperature to prevent pressure buildup in the cargo tanks. Fully refrigerated cargoes made it possible to use a simpler design for the cargo tanks, which could be built to conform to the shape of the hull, because they did not have to satisfy the structural requirements of a pressurized cargo. This allowed an order of magnitude increase in the carrying capacity from several thousand cubic meters to 30,000–50,000 cubic meters. Parenthetically, with a specific gravity of about 0.6, a cubic meter of LPG weighs about 0.6 metric tons, compared to close to 1 metric ton for a cubic meter of crude oil. A fully loaded LPG carrier transports less cargo weight-wise than a crude carrier of an equivalent cargo volume. The first large-sized LPG carriers were employed shipping LPG between Kuwait and Japan. By 1970, the Japanese LPG carrier fleet numbered a dozen vessels with the largest being 72,000 cubic meters.

The United States was primed for large-scale imports with adequate storage at Mont Belvieu, inland pipeline connections (the Little Inch was converted from natural gas to gas liquids), and LPG terminals, originally built for export in the U.S. Gulf, with importing terminals in the Northeast.

All that was missing was an LPG shortage, the appearance of a major new export source, and a means of transport. All the missing elements fell into place following the oil crisis of 1973. Shortages in natural gas stemming from the consequences of government price regulations of natural gas in interstate commerce reduced the domestic supply of LPG. Fractionating plants built in the Middle East and Europe to strip out gas liquids from natural gas greatly increased the overseas supply. Transport was available as more shipyards began building large-sized, fully refrigerated LPG carriers.

While all the elements fell in place for the United States to become a major LPG importer, large-scale imports never quite got off the ground. The appearance of new supplies of natural gas, along with deregulation of "new" gas, increased the domestic availability of LPG. LPG demand slackened when oil (and LPG) price controls were partially lifted, and finally dismantled, by President Reagan in 1981. Increased availability, coupled with a decline in demand from higher prices, reduced the need for large-scale imports. Without the U.S. import market developing to any significant degree, the enormous capacity of new LPG export plants in Saudi Arabia and elsewhere in the Middle East and in Europe created a glut. There is nothing like a glut to present an opportunity for entrepreneurs to develop a market, as had already happened with the glut created by discoveries of huge reserves of natural gas in the U.S. Southwest.

The international price for LPG swung between a premium or a discount from the price of crude oil on an energy-equivalent basis and thus was more volatile than oil. These price swings reflected the success or failure of entrepreneurs in finding a home for the new supplies of LPG. Those who bought a cargo of Middle East LPG and loaded it on a ship without a firm commitment from someone to buy the cargo when delivered in the United States or Europe were at the mercy of a fickle market while the vessel was at sea. Millions of dollars could be made or lost during a single voyage, depending on whether the buyer was on the right or wrong side of a price swing. Some of the founding firms instrumental in developing the international LPG market were merged or liquidated when they eventually found themselves on the wrong side. The same thing happened to independent LPG carrier owners when more vessels were delivered from shipyards than there were cargoes to fill the vessels. Lining up long-term deals between suppliers and buyers, along with the ships to carry the cargoes, would drastically reduce the degree of commercial risk; but long-term deals were not always available, and, when they were available, they were not always to the liking of either the buyer or the seller.

While Western firms were enjoying a financial bonanza or going bust, the Japanese LPG players just kept rolling along in a secure business environment, the result of how business is conducted in Japan. Of course, steady growth in propane consumption as a substitute for kerosene and as a substitute for naphtha for steam crackers to produce petrochemicals would provide an element of stability anywhere. But the Japanese are particularly adept at calming the financial waters. In the case of LPG, they developed a fully integrated logistics supply chain consisting of long-term contracts arranged with Middle East exporters, vessels to move the cargoes, terminals to unload the vessels, storage facilities to store the cargoes, and cylinder bottles to distribute LPG to consumers. The Ministry of International Trade and Industry (MITI) coordinated activities with the cooperation of an industry made up of a relatively few participants who respected each other's "territories." MITI was also in a position to dictate the amount of LPG to be consumed by the petrochemical industry, which smoothed out any bumps and wrinkles in the supply chain. LPG carriers received a "regulated" rate to cover costs and ensure an adequate return on vested funds over the life of the vessel. The modest return on investment reflected little risk of unemployment for vessels built to serve a single trade for the duration of their physical lives. This investment philosophy was shared by the other elements of the supply chain. The price of LPG sold in Japan took into consideration the cost of acquiring the LPG, and the capital and operating costs of transmission (by ship, not pipeline), storage, and local distribution. The Japanese people, accustomed to paying a high price for energy, did not object to this arrangement. There was no political advantage for a Japanese government body that guided an industry to curry the favor of the electorate by underpricing a fuel. Government guidance of energy policy in Japan proved to be superior to the regulatory experience in the United States, where energy policies seem to be a series of "fits and starts" that eventually have to be scrapped. Managing LPG imports on a systems, or supply chain, basis would turn out to be the prelude to LNG imports.

The history of LPG consumption is a series of developing markets that started at a point in time and reached maturity at another. The U.S. market began in earnest in 1950 and reached maturity around 1975; for Europe the growth stage spanned 1960 to around 1980, for Japan from 1965 to 1985, and for Korea from 1980 to the late 1990s. In the early 2000s, China entered the growth phase of a new LPG market, with India slated to be next. Although the rate of growth in aggregate LPG consumption is somewhat constant, its center of activity travels around the world as one market begins to be developed and another matures. Thus, what appears to be a stable business growing at a modest rate to outsiders is, in reality, a continual opening up of new opportunities by insiders including entrepreneurs, marketers, traders, and suppliers. The LPG business, like so much of the energy business, is a challenge for those who like to be on the cusp of change where money can be made by correctly assessing its twists and turns.

In 2000, the United States was the world's leading LPG consumer at 51 million tons annually and was essentially self-sufficient, importing and exporting only about 1 million tons annually. The second-largest consumer was Europe at 31 million tons, exporting 7 million tons from the North Sea to the Mediterranean and Brazil and importing 15 million tons from Algeria, Venezuela, and the Middle East. While simultaneous importing and exporting may not make immediate sense, LPG is made of two distinct products, propane and butane, each of which can be long or short on a regional basis. Furthermore, it may pay to export from one location and import into another, rather than ship directly between the two, to take advantage of price disparities. The third-largest consumer was Japan, at 19 million tons, of which 15 million tons were imported primarily from the Middle East and the remainder produced in domestic refineries. Saudi Arabia was by far the world's largest LPG-exporting nation, followed by Algeria, Abu Dhabi, Kuwait, and Norway.

In the mid-2000s the fastest growing importers were China, followed by Korea, both having negligible consumption in 1980. Korea consumed about 7 million tons in 2000 and China over 13 million tons, each importing about 5 million tons mainly from the Middle East. While Korea is reaching maturity, China is far from maturity and India is just beginning to move into the growth stage. In a way, Korea, China, and India mimic Japan. Burning propane for cooking is a status symbol and indicates a rising standard of living. In Japan, propane displaced kerosene, while in Korea propane displaced charcoal briquettes, and in China propane is displacing coal and biofuels (charcoal, wood, and agricultural waste such as straw and animal dung). The next market to be developed is India, where coal and biofuels also dominate home cooking.

Substituting LPG for coal and biofuels is a big step toward a cleaner environment because it does not emit air particulate (smoke), carbon monoxide, nitrous oxides, and, in the case of coal, sulfur oxides and metal (arsenic and mercury) emissions. However, a high price for oil becomes a high price for LPG. For millions of the world's poor, high-priced LPG means continued cooking with coal and biofuels, ingesting the pollution along with the food.

Natural gas liquids in international trade in the mid-2000s required an LPG carrier fleet of a hundred large carriers over 60,000 cubic meters (most between 70,000–80,000 cubic meters) and another seventy vessels between 40,000–60,000 cubic meters. There are also more than sixty

Table 7.2

International Natural Gas Pipeline Movements in Billion Cubic Meters (Bcm)

Importer	Domestic Consumption	Pipeline Imports	Supplier	Percent of Importer's Consumption
Europe*	576	154	Russia	27
United States**	657	89	Canada	14
Europe*	576	46	Algeria and Libya***	8

* Europe, excluding the Russian Federation.
** Net of U.S. exports to Canada.
*** Via trans-Mediterranean pipelines to Spain and Italy.

semirefrigerated LPG carriers between 10,000–20,000 cubic meters in size, used more for local distribution than long-haul trading, in which the cargoes are cooled, but not enough for the gas to remain liquid at atmospheric pressure. LPG carriers can also carry liquid cargoes of ammonia, butadiene, and vinyl chloride monomer (VCM). Another twenty ethylene carriers carry liquefied ethylene at a much lower temperature than LPG, but not low enough to carry LNG. While ethylene carriers can carry LPG as backup when no ethylene cargoes are available, they make their real money carrying ethylene cargoes that cannot be carried by LPG carriers.

LIQUEFIED NATURAL GAS

As mentioned repeatedly in this text, natural gas is constrained by logistics. The development of long-distance pipeline transmission was crucial to natural gas becoming a commercial energy resource. Pipelines are fixed installations connecting a specific set of suppliers with a specific set of consumers and are an inflexible mode of transmission. Most pipelines are within a single nation because political considerations enter the picture when pipelines cross national borders. A proposed pipeline from Iran to India that would cross Pakistan was, for many years, considered impossible because of the rivalry and bitter feelings between Pakistan and India. However, in the 2000s progress was made in advancing this proposal in response to Pakistan's own need for energy and the potential earnings from transit fees. A pipeline connection between Turkey and Greece, long-time bitter foes, has been completed. Another example of long-time foes cementing better relationships through energy is a pipeline supplying Egyptian gas to Israel.

A major pipeline project nearing final approval is the Nabucco pipeline project that will ultimately transport 31 bcm per year of Caspian natural gas in a 3,300 kilometer, 56 inch pipeline stretching from the Caspian region across Turkey, Bulgaria, Romania, Hungary, and Austria where it will connect into the European pipeline distribution system. If approved as expected, construction will start in 2010 and the pipeline will be completed in 2013. When in full operation, Nabucco pipeline will give Europe a major alternative source of natural gas that does not involve the Russian natural gas pipeline system. Table 7.2 shows that there is a healthy international natural gas pipeline trade.[7]

Total world reserves are 185 trillion cubic meters (tcm) in 2008, up from 110 tcm in 1988 and 148 tcm in 1998. With world consumption at 3.0 trillion cubic meters in 2008, the reserve-to-consumption ratio is sixty years as compared to forty years for oil. Forty-one percent of natural gas reserves are in the Middle East, of which 16 percent of world's reserves are in Iran and 14 percent in Qatar. Russia possesses 23 percent of world reserves. These three nations account for 53 percent of world's reserves; all other nations pale in comparison (for instance, the United States accounts for only 4 percent of the world's reserves).

Reserves can be misleading. For instance, proven reserves in Alaska exclude potentially vast gas fields in the North Slope that have not been sufficiently assessed to classify them as proven. With the exception of Russia and the United States, much of the world's natural gas reserves would be stranded if pipelines were the only means of transmission. Construction of long-distance undersea pipelines to connect remote fields in Iran, Qatar, Nigeria, Venezuela, Indonesia, and Malaysia with industrially developed nations, with pumping stations every 50–100 miles, is prohibitively expensive. Even Australia's natural gas fields in the northwest part of the nation are too remote from the principal cities in the southeast for economic pipeline transport. The natural gas reserves for these nations remained stranded with no commercial value until a new means of transmission was devised.

Compressed natural gas (2,000–4,000 psi) can be transported in specially built tanks. The problem is the cost of building large-capacity cargo tanks that can withstand this magnitude of pressure with a cargo still four times greater in volume than in a liquefied state. However, there are special circumstances in which compressed natural gas carriers are feasible such as small natural gas fields in remote areas of the Amazon River, where reserves are not sufficient to justify building a long-distance pipeline or a liquefaction plant or for natural gas delivery to Caribbean islands whose consumption is far too small to sustain an LNG import terminal.

Just as liquefied gas liquids (propane and butane) are refrigerated for transport as a liquid at ambient pressure, so too can natural gas. As a liquid, natural gas takes up 600 times less volume than at ambient conditions with a specific gravity a little less than LPG. The problem is that natural gas is a liquid at atmospheric pressure at a much colder temperature of –161°C (–258°F). This imposes severe constraints on tank design and insulation to prevent the cargo from coming in contact with the hull. Conventional steel in ship hulls, if exposed to the cold temperature of LNG, is subject to instantaneous cracking, known as brittle fracture. A huge tank 50 feet wide and 90 feet wide containing 2.3 million gallons of molasses split apart from brittle fracture on a cold January day in 1919 in Boston; it is memorialized as the Great Molasses Flood. A few mass-produced Liberty freighters during the Second World War sunk while transiting the cold Atlantic waters when their hulls split open from brittle fracture. A belt of steel welded around succeeding vessels resulted in no further losses from this cause. Better-quality steel can prevent brittle fracture at freezing temperatures but not from the cold of liquefied natural gas.

A much greater technological challenge in tank design and insulation than LPG carriers had to be faced before natural gas could be transported as a liquid. The success of independent research efforts in the 1950s led to the first LNG delivery in 1964 from a liquefaction plant in Algeria to a regasification terminal on an island in the Thames River. From this time forward, Algeria would remain a major force in the LNG business, expanding its export capacity in 1973, 1978, 1980, and 1981. Small-scale LNG plants were built to export LNG from Alaska (Cook Inlet) to Japan in 1969 and from Libya to Europe in 1970. Brunei was the first large-scale LNG export project to serve Japan, starting in 1972, and was followed by other large-scale LNG export projects in Indonesia and Abu Dhabi in 1977, Malaysia in 1983 (a second in 1994), Australia in 1989, Qatar in 1997 (a second in 1999), Trinidad and Nigeria in 1999, Oman in 2000, and Egypt in 2005. Many of these nations are currently expanding their LNG-production capacity. The relative importance of LNG-importing nations in the mid-2000s can be ranked by the number of receiving terminals, with Japan in first place with twenty-six, Europe with thirteen, Korea with six, the United States with four (now undergoing rapid expansion), Taiwan with two, and Puerto Rico with one.[8]

In the wake of the energy crisis in the 1970s, Japan adopted an energy policy of diversifying its energy sources to reduce its dependence on Middle East crude oil. The first generation of large-scale LNG projects were long-term contractual arrangements of twenty or more years for the entire output of a liquefaction plant dedicated to a small group of Japanese utilities. LNG carriers were assigned to a project for their entire serviceable lives. As such, the first LNG export projects were as inflexible as long-distance pipelines and were organized similarly to LPG projects as totally integrated supply chains.

The price of LNG sold in Japan was based on the delivered cost of crude oil. Low crude oil prices during the latter part of the 1980s and much of the 1990s kept a lid on LNG prices and, consequently, on the value of stranded gas. New LNG projects were few and far between until the passing of the natural gas bubble in the United States. This was the dawn of a new day for LNG projects because it was perceived that the United States might become a major LNG importer, spurring new LNG projects in Egypt, Qatar, Nigeria, Oman, and Trinidad. But this time building new or expanding existing LNG export plants was not in response to an energy policy to diversify energy sources, as in Japan and later Korea and Taiwan, but to the commercial opportunities associated with the prospect of large-scale LNG imports into the United States. Ironically, as with LPG, the United States has not yet become a large-scale LNG importer. One reason is that natural gas production has increased, reducing the need for imports. The other is that natural gas prices are less in the United States than in Europe and Asia, abrogating the commercial incentive to import large volumes of LNG. Alternative LNG markets are being developed in Europe as a means to reduce dependence on Russia gas pipeline imports and in Asia to meet the burgeoning demand for energy.

The LNG business is unique in several aspects. One is the sheer size of the investment. Unlike oil, coal, and other commodity businesses that start small and become large through accretion, LNG starts out as a large multi-billion-dollar project. LNG projects are rivaled in size, complexity, and capital requirements only by nuclear power plants. But unlike a nuclear power plant connected to a local electricity grid, an LNG project involves two sovereign powers—the nation with stranded gas reserves and the nation in need of natural gas. Though an LNG project is like a long-distance pipeline, which requires that suppliers and consumers be lined up before the pipeline can be built, an LNG Sales and Purchase Agreement (SPA) is more akin to a commercial agreement between two sovereign powers. One is the nation with the gas supply, whose interests are pursued by its national energy company, and the other is the nation with an energy policy that calls for greater consumption of natural gas, whose interests are pursued by its receiving utilities. In both cases, a sovereign power has made a policy decision to either export or import LNG and has delegated oversight to a national energy company or the receiving utilities.

The SPA establishes the commercial link between the buyer (the receiving utilities) and the seller (the national energy company), laying the foundation for the financial structure of the project. Laying the foundation for the physical structure is the engineering, procurement, and construction (EPC) contract. The EPC contract selects a consortium of companies with the requisite skill sets in project management and technical expertise to design the plant, procure the necessary equipment, build a liquefaction plant in a rather remote part of the world, and put it in operation. Shipping contracts have to be arranged, with the delivery of ships timed to the startup and the step-ups in liquefaction plant output. It can take as long as four years for a multi-train liquefaction plant to reach its full capacity.

For Japan, and later Korea and Taiwan, it was not a simple matter of building a receiving terminal with sufficient storage capacity and berths to off-load the LNG carriers, along with a regasification plant to convert LNG back to a gas. These nations had to create a market for natural gas. The first customers were electricity-generating plants located near the receiving facilities. Eventually an entire natural gas pipeline distribution infrastructure, replete with customers, had to be organized, designed, and built for natural gas to become an important contributor to a nation's energy supply. Getting approvals for the requisite permits to build a natural gas pipeline grid would have been impossible if the government had not endorsed the LNG project.

The LNG supply chain consists of three major segments. The first segment is the upstream end of natural gas fields with their wells and gathering system. A gas-treatment facility removes undesirable elements (nitrogen, carbon dioxide, hydrogen sulfide, sulfur, and water) and separates gas liquids and condensates from the natural gas stream. These, along with any sulfur, are sold to third parties to provide additional revenue. A pipeline delivers the treated natural gas from the gas fields to the second segment, the downstream end, which consists of the liquefaction plant and the LNG carriers. After the last remaining contaminants are removed, a mixed refrigeration process cools methane to its liquefaction temperature using various refrigerants, starting with propane and switching to butane, pentane, ethane, methane, and finally nitrogen. Terminal storage capacity at the liquefaction plant is about two shiploads of cargo plus berthing facilities and a sufficiently sized fleet of LNG carriers to ship the desired throughput from the loading to the receiving terminals. The third segment is the market end of the supply chain, which is made up of the receiving and storage facilities and the regasification plant at the importing nation to warm and feed LNG into a natural gas pipeline distribution system. The receiving facilities must have sufficient storage for unloading a vessel plus extra storage to ensure sufficient quantities for transient and seasonal fluctuations in demand and delays in vessel arrivals. The regasification plant must be connected to a natural gas-distribution pipeline grid with sufficient customers to consume the LNG.

Organizing and Financing the LNG Supply Chain

The three segments of the LNG supply chain can have different organizational structures. The simplest is to have the same participants throughout the supply chain. This "seamless" structure avoids the need for negotiating transfer price and sales conditions as natural gas or LNG passes through each segment of the chain. But this form of organization can lead to management by committee in which representatives of each segment of the supply chain vote on critical matters for a particular segment. This can have undesirable repercussions if the representatives are not well versed in the technical aspects of each segment. Moreover, funding of the project may be in jeopardy if a participant in one segment does not desire or does not have sufficiently deep pockets to fund its share of the entire project.

The second alternative with regard to ownership is the upstream and downstream segments of the project (natural gas fields and the liquefaction plant) being a separate profit center that sells LNG either free on board (FOB) at the loading terminal or delivered at the receiving terminal, where the price of the LNG includes cargo, insurance, and freight (CIF). The profit for the upstream and downstream portions of an LNG supply chain is the revenue from selling LNG less all operating and capital costs, the acquisition cost of the natural gas, taxes, and royalties. A floor price for the LNG may be incorporated in the SPA to ensure a positive cash flow and a minimum value for the natural gas. The third alternative is using the liquefaction plant as a cost center that simply receives a toll for services rendered that covers its operating and capital costs. These last two alternatives can have different participants with different shares within each segment of the LNG supply chain. Segmented ownership arrangements among the participants can create interface problems in transfer pricing and risk sharing. A conflict-resolution mechanism should be established to resolve potentially contentious issues as, or preferably before, they arise. Splitting the ownership of the various supply chain segments has the advantage of having participants who are interested in dedicating their financial and technical resources to a particular segment.

An LNG project can be entirely funded by equity. The return on equity is determined by the cash flow (revenue less operating costs, taxes, royalties, and acquisition costs). The advantage of equity funding is that the participants are not beholden to outside financial institutions. The disadvantage is that the participants must have deep pockets. The dedication of funds to a single multi-billion-dollar project may preclude becoming involved in other LNG projects. At the other extreme, an LNG project can be financed entirely by debt. The debt may be supplied by the sovereign nation that borrows on the basis of its creditworthiness or provides a sovereign guarantee. Revenue is funneled into a special account from which debt service charges are drawn off first and what remains pays for operating costs, royalties, and taxes; whatever is left determines the value of the natural gas.

The proceeds of an LNG project from a government's perspective are its receipts of royalties and taxes and what the national oil company, normally wholly owned by the government, earns on its natural gas sales to the LNG project plus the return on its investment in the project. The split in government payments in the form of royalties and taxes on profits is critical for LNG project participants in the event of a drop in LNG prices. Royalty payments remain fixed and independent of the price of LNG. Taxes on profits, on the other hand, decline as the price of LNG falls. The risk of a negative cash flow can be better dealt with by favoring taxes over royalties. The cost of mitigating this risk is that more money will be paid to the government when LNG prices are high.

A popular form of raising capital is project financing. Here the LNG supply chain is set up to be self-financing, with debt holders looking only to the financial wherewithal of the project itself, not the project sponsors, for interest and debt repayment. Debt issued by an LNG supply chain project is initially limited recourse debt—the sponsors assume full liability for funds advanced only during construction. Once the plant operates at its defined specifications, the debt becomes nonrecourse and the project sponsors assume no liability for debt service obligations; debt repayment relies exclusively on the financial performance of the project.

Project financing is usually equity and debt whose mix is determined by a cash flow analysis that takes into account the value of crude oil and other determinants on the price for LNG, the operating costs of the liquefaction plant and the upstream natural gas field, the acquisition cost of the natural gas, the LNG carriers (if part of the project), royalties and taxes, and debt-servicing requirements. Project financing exposes the LNG supply chain to the scrutiny of third parties when they exercise due diligence prior to making a commitment. Sponsors and host governments are more likely to agree to an organizational and legal structure imposed by a third party because of the benefit of external sourcing of capital. In this sense, project financing has been a healthy influence because it discourages a sponsor from insisting on conditions that would not only be detrimental to others, but would also jeopardize the external funding of the project.

Project financing removes the necessity for the sponsors to have sufficient internal funds to finance the entire project by equity alone. By reducing funding requirements, the sponsors are free to participate in other LNG projects, spreading their risk and expanding their presence in the LNG business. Project financing also allows the importing nation to participate directly in an LNG supply chain by purchasing a meaningful portion of the debt. These benefits of project financing have to be balanced by the costs of satisfying third-party due diligence requirements, managing lender-project relationships, and arranging creditor agreements with various financial institutions.

Underwriters for project financing face the challenge of making an internationally oriented

LNG project attractive to prospective buyers of the underlying debt. In packaging the securities, underwriters must deal with the sovereign risk of the host country (e.g., a Middle East nation), a variety of contractual arrangements with several receiving utilities from one or more nations (e.g., Europe), vessel chartering agreements involving a number of legal jurisdictions (e.g., Korea as shipbuilder, London as center of operations, Bermuda as shipowner, Liberia as ship registry), and multiple equity participants incorporated in different nations with unequal shares in various segments of an LNG project. Financial institutions funding LNG projects include pension funds seeking long-term maturities, and commercial banks and private investors interested in short- and medium-term maturities. Another source of debt funding is low-interest credits issued by governments to finance exports.

Depending on the distance between the liquefaction plant and the receiving facility, LNG carriers may account for 25–40 percent of the total investment in an LNG project, the same general magnitude of investment as the liquefaction plant. The remaining investment is primarily the development of the natural gas fields. The regasification system is usually the responsibility of the receiving utility, but for Japan, Korea, and Taiwan, a natural gas pipeline distribution system also had to be built. The development of the natural gas fields, the construction of the liquefaction plant, the building of the ships, and the receiving terminal, including the regasification plant and a natural gas distribution system with a sufficient number of consumers to absorb the LNG imports, have to be coordinated on a fairly tight schedule for all the elements of an LNG project to fall into place in a synchronous fashion. As large and as complex as LNG projects are, a number have been completed and the LNG trade has blossomed. As a point of reference, in 2008 the total volume of the international trade by pipeline of natural gas is 587 bcm compared to 226 bcm of LNG.

The world's largest suppliers of LNG are Qatar (18 percent), Malaysia (13 percent), Indonesia (12 percent), Algeria (10 percent), Nigeria and Australia (9 percent each), Trinidad (8 percent) with smaller shares from Egypt, Oman, Brunei, and UAE (United Arab Emirates). Japan, South Korea, and Taiwan consume 62 percent of the world's LNG and absorb nearly the entire output of LNG export plants in Brunei, Indonesia, and Malaysia, plus much of the output of LNG export plants in Australia, Qatar, Oman, and UAE. Europe receives 24 percent of the world movement of LNG with Spain and France being the primary importers, most of which comes from Algeria, Nigeria, and Egypt. Over 40 percent of Trinidad's LNG production is shipped to the United States, almost 30 percent to Europe with the remainder mainly to Mexico and the Caribbean, and a little to Asia. Unlike most LNG plants whose production is largely fixed by contractual arrangements, Trinidad is more oriented to commercial sales and the destructions of LNG can vary greatly from year to year. Much of the remainder of U.S. LNG imports is from Egypt, Nigeria, and Algeria. The United States is also a minor exporter of LNG from Alaska (Cook Inlet) to Japan. Between 2007 and 2012, LNG production capacity is expected to grow by nearly 60 percent with the largest incremental gain in Qatar, which is projected to supply 25 percent of world LNG production with other major capacity additions in Australia, Russia, and Indonesia.

Despite best intentions, LNG projects, if not organized properly, can fail. The El Paso and Trunkline projects are prime examples with another in India. The largely completed $3 billion Dabhol project foundered with a change in the local government in 2001. The winners of an election campaigned on a platform that the Enron-sponsored project was rife with political corruption and lacked competitive bidding and transparency. They opposed a local state government contract to purchase nearly all the electricity produced from the imported LNG at a price that consumers could not afford. The project was abandoned as a result of the election. Negotiations began for the possible purchase of the largely completed plant with the intent to bring it into operation in a manner that would have both government and popular support. The plant was eventually purchased by

Ratnagiri Gas and Power and was expecting its first shipment of LNG in early 2009. The terminal will run at 20–30 percent of its 5 million ton capacity until a breakwater is completed in 2011.[9]

LNG Carriers

LNG carriers can be owned by the project for delivered sales where the price at the receiving terminal includes insurance and freight or they can be owned by the buyer for purchase at the loading terminal for free on board sales. Alternatively, the vessels do not have to be owned by either the buyer or seller but can be chartered from third parties (independent shipowners, energy companies, or financial institutions) under a variety of arrangements. Charters shift the responsibility for raising capital to finance the vessels from the LNG project to the vessel owners.

LNG carriers are classified by their containment systems: spherical or membrane. In the spherical containment system, a thick aluminum spherical shell covered by insulation and an outer steel shell is supported by a freestanding skirt that accommodates expansion or contraction of the cargo tank. Propagation of a crack, should any occur, is very slow, with little chance of leakage. While there is no need for a full secondary barrier, a partial barrier prevents any LNG leakage from coming in contact with the hull. The spherical tanks limit sloshing of the cargo when at sea for improved ship stability, but their protrusion above the main deck affects visibility from the bridge. The principal disadvantage of spherical tanks is the inefficient utilization of space within a ship's hull. Spherical tanks are also used for storage at loading and receiving terminals.

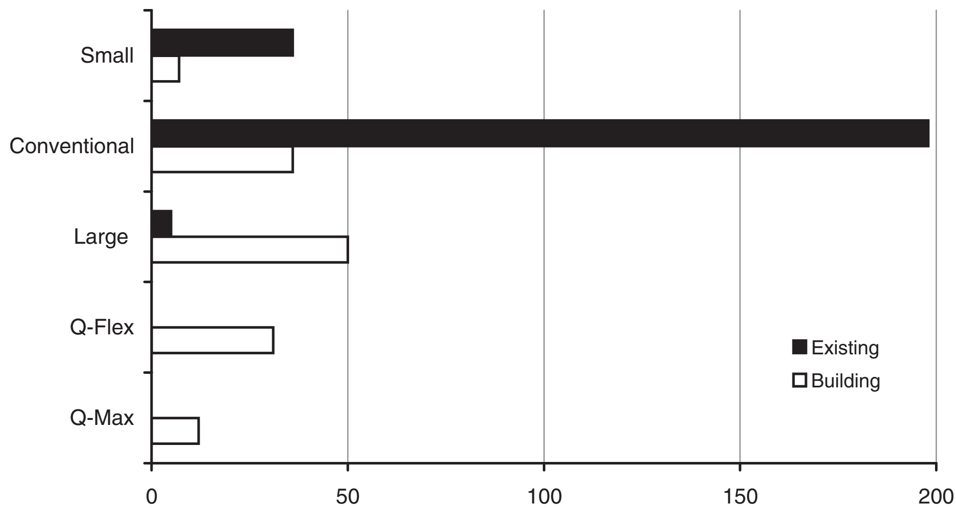
The alternative containment system is the membrane design in which the cargo tanks conform to the shape of the ship's hull, increasing a vessel's cargo-carrying capacity. Rather than thick aluminum, the membrane is a thin primary barrier covering insulation installed on the inner hull surface of the ship. This considerably reduces the weight of the metal in an LNG tank. Membrane tanks are not self-supporting, but an integral part of the ship's hull that directly bears the weight of the cargo. The structure holding the insulation material must be strong enough to transfer the weight of the cargo to the inner hull, be an effective insulator in its own right, and prevent any liquid gas from coming in contact with the ship's hull.

The membrane for the Gaz Transport system is made of a special stainless steel alloy called invar of 36 percent nickel with a very low coefficient of thermal expansion, eliminating the need for expansion joints. Both the primary and secondary insulation consists of a layer of thin (0.7mm) invar membrane covering plywood boxes filled with perlite, a naturally occurring insulating material made from volcanic glass. The primary and secondary insulation provides 100 percent redundancy. The membrane for Technigaz system is thin (1.2mm), low-carbon corrugated stainless steel with a relatively high coefficient of thermal expansion. The corrugation is designed to accommodate expansion and contraction of the metal caused by temperature changes. Earlier LNG carriers of this design used balsa wood as insulation material. Now two layers of reinforced polyurethane panels, separated by a secondary membrane made of a thin sheet of aluminum between two layers of glass cloth, form the primary and secondary insulation. The latest membrane system (CS1) combines the Gaz Transport and Techigas technologies with a membrane of invar and insulation of reinforced polyurethane panels.

The membrane design requires less material, but construction is more labor-intensive. Spherical tanks require more material, but their construction is more automated. Thus, the comparative cost of LNG carriers of the spherical or membrane design depends on shipyard labor costs. An LNG carrier of spherical tank design costs less in Japan than membrane design because labor costs are high; the opposite prevails in Korea, where labor costs are lower.

The first generation of LNG carriers built in the 1970s was 75,000 cubic meters, but these

Figure 7.2 **Number of Existing and Newbuilding LNG Carriers**



were quickly followed by what turned out to be a standard size of 125,000 cubic meters. The 1980s was not an active time for new LNG projects with little demand for new LNG carriers, but vessels built in the 1990s were typically 135,000 cubic meters (cbm). The anticipated growth in LNG imports in the 2000s spurred new building orders that will significantly expand the carrying capacity of the fleet. In mid-2007, the existing fleet consisted of 239 vessels dominated by the conventional-sized vessel of between 120,000 and 150,000 cbm. As seen in Figure 7.2, there were 136 vessels on order in 2007 spread over five size categories, but concentrated in the large size category of 150,000–180,000 cbm along with the Qatar Gas Transport orders for Q-Flex vessels of 200,000–220,000 cbm and Q-Max vessels of 266,000 cbm.[10] Whereas 55 percent of the existing fleet was built with the membrane design, 80 percent of the fleet under construction incorporates this design. Shipyards capable of building LNG carriers are in Korea, Japan, Spain, France, and China (a newcomer), with an aggregate capacity of delivering over forty LNG carriers a year of which Korea accounts for half.

Heat passing through the insulation can warm the cargo and increase the pressure within the cargo tank. Unlike LPG cargoes where a refrigeration plant keeps the cargo cool enough to remain liquid at atmospheric pressure, an LNG cargo is kept liquefied by boil-off, which removes the heat transmitted through the insulation into the cargo. The better the insulation, the less the boil-off; typical boil-off rates for modern vessels are about 0.15 percent of the cargo volume per day. While nearly all merchant vessels have diesel engine propulsion plants that burn heavy fuel oil, existing LNG carriers have dual fuel steam turbine propulsion systems that burn either heavy fuel oil or LNG boil-off, which typically provides 60 percent of the fuel requirements. This avoids wasting boil-off by flaring or venting to the atmosphere. Not all the LNG cargo on a vessel is discharged at the receiving terminal. A heel or small amount of LNG is left in the cargo tanks to keep the tanks cold via boil-off on the ballast voyage to the loading port. This eliminates the necessity of cooling the cargo tanks before loading the next cargo and minimizes stress from repeated thermal cycling. The ship is charged for the boil-off burned for ship propulsion on an energy-equivalent basis with heavy fuel oil.

Of the ships on order, only 40 percent are steam turbine with the remainder somewhat split between diesel engines with reliquefaction units to keep boil-off as part of the cargo and the rest dual fuel diesel-electric engines that burn boil-off or heavy fuel oil. The choice of engine is the result of an economic analysis of benefits and costs. The benefit of diesel engines with a reliquefaction unit is discharging a larger cargo of LNG and having smaller bunker costs from using only heavy fuel cargo; the cost is the necessity of having a reliquefaction unit on board the vessel. The benefit of dual fuel diesel-electric engines that burn either boil-off or heavy fuel oil is not having a reliquefaction unit on board; the cost is a smaller cargo to be discharged and higher bunker costs. The Q-Flex vessels can trade commercial cargoes of Qatar LNG cargoes to existing terminals large enough to accommodate these vessels. The Q-Max vessels are built for long-term contracts where the receiving terminals will be built specifically to handle these larger sized vessels. Both vessel types have significant shipping cost savings of the order of 20–30 percent from the economies of scale of larger-sized vessels and the fuel economy inherent in diesel engines compared to steam turbines.

The LNG cargo is pumped into LNG storage tanks at the receiving terminal. LNG has to be warmed to a gaseous state before entering natural gas pipelines for distribution to consumers. The most common way to heat LNG is to pass it through a seawater heat exchanger where the seawater is cooled and the LNG warmed to about 5°C (41°F). A gas-fired vaporizer is available if needed. A few Japanese import terminals tap the "waste cold" of LNG to cool brine or Freon for freezing food and for chemical and industrial processes that require cooling water.

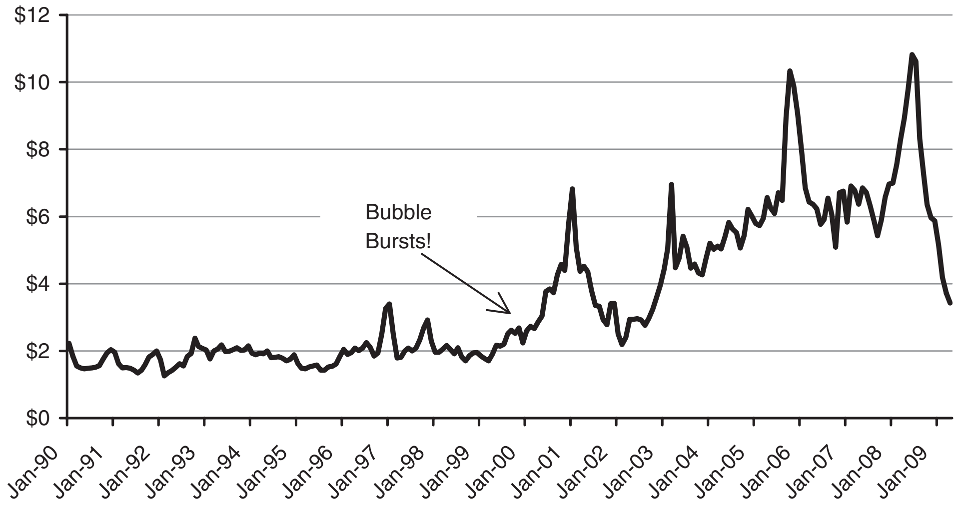
LNG Pricing

Pricing LNG in Japan is formula-based on the blended cost of crude oil imports (Japan Customs Cleared Crude) on an energy-equivalent basis, later adopted by South Korea and Taiwan. Thus the natural-gas exporting nation received for its natural gas a price that reflected the blended cost of crude delivered in Japan less the operating and capital costs associated with the natural gas gathering system, the liquefaction plant, and the LNG carriers (regasification facilities are owned by the receiving nation's gas utility). A minimum floor on the LNG price, if incorporated in the SAP contract, assured the exporting nation of a minimum price for its gas exports and the debt providers of a positive cash flow. The price relationship between LNG and crude oil is tempered to partially protect LNG importers from oil price shocks. Pricing of LNG imported into Europe is based on a formula reflecting the prices of European pipeline gas from natural gas fields, Brent crude, high- and low-sulfur fuel oil, and coal. The pricing of LNG imported into the United States is based on the price of natural gas at Henry Hub as indicated by near-term futures trading of natural gas contracts on the New York Mercantile Exchange (NYMEX).

The early LNG projects were based on fixed-quantity, twenty-or-more-year contracts between importers and exporters. Beginning in the latter part of the 1990s, spot LNG cargoes began to appear. These cargoes were the result of liquefaction plants producing more LNG than their nominal nameplate capacity (from conservative design features), improved productivity, and debottlenecking (the removal of constraints that restrict production). The first liquefaction plants were eventually able to produce 25 percent more than their indicated design capacity at a time of retrenchment in Asian economic activity, particularly in South Korea, which could not absorb its contractual volumes. Now there were cargoes without a home. The third element was the availability of laid-up LNG carriers from the failed El Paso and Trunkline projects plus a few built on speculation. The fourth element that caused the emergence of a spot trade in LNG was sufficient market demand in Europe and the United States to absorb these cargoes.

Since then other factors have come into play, transforming the LNG business from fixed

Figure 7.3 **U.S. Average Natural Gas Wellhead Price** ($/MMBtu)



Source: http://tonto.eia.doe.gov/dnav/ng/hist/n9190us3a.htm

long-term contracts based on the price of oil to a more commercially oriented business like oil and coal where the market realities of supply and demand play an important role in determining price. One was the continual decline in the cost of LNG carriers. In 1995, the cost of building a large LNG carrier was three times that of a large crude oil carrier ($280 million). Since an LNG carrier can only transport about one-third as much energy as a large crude carrier of the same cargo volume, LNG shipping costs were nine times higher than crude oil on a Btu basis. By the 2000s, the shipbuilding cost had fallen to $150–$160 million, or a 50–60 percent premium over large crude carriers, knocking down the premium on an energy basis to about five times. Lower shipyard costs were partially caused by moving down the learning curve where repetition tends to iron out or eliminate problems that were previously encountered. Gains in shipyard productivity from automation also contributed to lower shipbuilding costs. Whereas only a few shipyards were capable of building LNG carriers in the 1970s, in the 2000s there were a dozen. Increased competition to keep building berths busy narrows shipyard profit margins and provides an incentive to further improve shipbuilding technology. Lower shipyard prices, combined with the economies of scale of larger-sized LNG carriers, have reduced shipping costs.

Greater output and improved system design of liquefaction trains built in the 2000s have resulted in a one-third reduction in capital and operating costs for liquefying natural gas. Two or three engineering, procurement, and construction (EPC) consortia capable of undertaking a massive and complex LNG project in the 1970s increased to about five in the 2000s. Energy companies with the requisite project-management skills, technical expertise, and the financial wherewithal to organize LNG supply-chain projects have grown from three or four in the 1970s to about ten in the 2000s. Project funding has become more sophisticated and innovative with project managers and financial underwriters well-versed on how to structure LNG projects in order to make their underlying debt attractive to potential investors. Greater reliance on debt in the financial structure of LNG projects reduces capital costs. Although all these factors have lowered the delivered cost of LNG, there has also been a concomitant rise in natural gas prices, illustrated in Figure 7.3.

The average wellhead price of natural gas was about $2 per million Btu in the 1990s and tripled in the early 2000s. The significant rise in natural gas prices, coupled with a significant fall in the cost of producing and shipping LNG, has made LNG projects commercially attractive without the need for fixed long-term contractual arrangements to cover the entire output. Contemporary LNG sponsors are not so much interested in protecting against the commercial risk of an LNG project as in taking advantage of commercial opportunities. LNG project sponsors look to a mix of long-term commitments to cover the minimum financial requirements with a portion of total capacity dedicated to short-term deals to enhance profitability. The willingness of LNG sponsors to accept commercial risk and the desire of buyers not to have to commit to twenty-year, take-or-pay-contracts have encouraged the emergence of spot and short-term markets.

LNG buyers, no longer contractually chained to a single supplier for twenty years at a fixed formula-based price, can now select their LNG providers on a variety of short- and medium-term deals, creating a diversified portfolio of LNG purchases at prices that reflect market realities. The possibilities of commercial opportunities have led to the construction or expansion of liquefaction facilities in Australia, Algeria, Angola, Egypt, Equatorial Guinea, Indonesia, Malaysia, Nigeria, Oman, Peru, Qatar, Russia, Trinidad, and Yemen. Nonproducing LNG nations seriously contemplating monetizing their stranded gas by building LNG liquefaction plants include Iran, Venezuela, and Bolivia.

The Future of LNG

The LNG market with the greatest potential of growth is the United States. The U.S. government recognizes the need to build LNG terminals to avert a potential shortage of natural gas. Various projections call for the United States to be importing from 12–20 percent of its natural gas needs as LNG by 2025. U.S. reserves have been in a general decline reaching a low point of 4.65 trillion cubic meters in 1998, but have subsequently been rising to 6.7 trillion cubic meters in 2008 for a reserve to production ratio of 11.6 years. U.S. natural gas production and reserves have been increasing largely from nonconventional gas sources since 2005, delaying the incursion of the anticipated large-scale imports of LNG. Nevertheless, the industry has been gearing up for large-scale imports by building LNG terminals.

Until 2004, there were only four receiving terminals (Lake Charles in Louisiana, Elba Island in Georgia, Cove Point in Maryland, and Everett, Massachusetts). The first three were built in response to the energy crisis in the 1970s and were idle. The terminal in Everett has been active, receiving seasonal deliveries of LNG to meet peak winter demand in New England. As a consequence of the anticipation of large-scale LNG imports, the three receiving terminals were reactivated and another four terminals had been built by 2009 (Gulf of Mexico, Offshore Boston, Freeport, Texas, and Sabine, Louisiana) plus two in Mexico (Altamira and Baja California).There are another 28 LNG projects that have been approved of which 7 are under construction. Unless there is a major shift in near-term LNG prospects, it is problematic whether the approved projects not under construction will be built.

The LNG terminal on the Mexican Atlantic coast (Altamira) will supply Mexico with natural gas which will back out U.S. exports to Mexico to increase U.S. domestic supply. The LNG terminal in Baja California sidesteps the regulatory hassle of siting an LNG receiving facility in California. LNG can enter California via Mexico as pipeline natural gas or electricity generated from natural gas. Natural gas from the LNG terminal in eastern Canada can be shipped via an underutilized pipeline carrying eastern Canadian gas into New England.

Building LNG terminals in Mexico and eastern Canada reflect the difficulty of siting LNG terminals in the United States. Licenses are required from the Department of Transportation, the

Coast Guard, and the Maritime Administration, along with permissions from the Research and Special Programs Administration, which enforces deepwater-port pipeline regulations, and the Department of the Interior for pipeline right-of-way. The Fish and Wildlife Service is concerned with the ramifications of an LNG receiving terminal on endangered species; the Minerals Management Service with potential hazards and underwater artifacts of archeological interest; and the Environmental Protection Agency with carrying out the provisions of the Clean Air Act. The Department of Energy must issue an import certificate and the FERC must issue a Certificate of Public Convenience and Necessity. Other Federal agencies involved are the Department of Defense, the Department of State, the Department of Commerce, the National Oceanic and Atmospheric Administration, the Bureau of Oceans, the Army Corps of Engineers, and the Advisory Council on Historic Preservation. Besides these, various state bodies involved with coastal zone management, pollution control, wildlife and fisheries, and historical preservation present their own hurdles for building a receiving terminal. Most importantly, an LNG receiving terminal cannot be built without a permit from the municipality within which the receiving terminal would be located. For this to occur, the local population must be in support of an LNG facility built in their midst.[11]

Proposed terminals in California and the Northeast have to combat the “not in my backyard” or “Nimby” syndrome represented by local citizens who can exert sufficient political clout to stop a municipality from issuing a permit. Where once “Nimby” was concerned with the sight and smells and sounds of having an industrial plant in one’s backyard, now there are concerns over potential terrorist actions against an LNG facility. Resolution of these issues not only determines the future volume of LNG trade, but also the prospects of owners who have ordered LNG carriers on speculation without any commitment for employment by either an LNG supplier or buyer.

An innovative approach to bypass “Nimby” occurred in 2005 when an LNG terminal of a radically different design was inaugurated for service. A normal LNG terminal is located in a port with a storage facility and a regasification unit for transforming LNG to natural gas as needed. The Gulf Gateway Deepwater Port, located 116 miles off Louisiana, is a floating buoy connected to an already existing and underutilized natural gas pipeline. Located outside municipal and state jurisdictions, approvals are federal only. Specially constructed LNG carriers with built-in regasification units tie up to the buoy for about five days to regasify their cargoes prior to discharge into the natural gas pipeline. The pipeline is connected to several transmission pipeline systems that can contract for the natural gas. Without associated storage facilities, the regasified natural gas must enter a pipeline transmission system directly from the ship, which can cause operational problems with other natural gas suppliers. This, of course, can be corrected if access can be gained to a storage facility or an accommodation can be worked out with the suppliers. The additional cost of $25 million per vessel for an installed regasification unit and the extended discharge time increases shipping costs in relationship to direct discharge to a U.S. Gulf LNG terminal. But it is an alternative way to import LNG when it is not possible to build an onshore LNG terminal.

Another development to move LNG terminals out of ports into offshore waters is the proposed building of a gravity-based terminal that will be sunk about ten miles offshore from Venice, Italy. The terminal is to be built in a graving dock in Spain, and, when completed, the graving dock will be flooded to float the terminal. Then the terminal will be towed to offshore Venice, and, when onsite, the terminal is sunk by filling its empty ballast tanks with water. Later, heavier material will be added to permanently ballast the terminal. LNG carriers will off-load their cargoes into the terminal’s storage tanks. LNG will be regasified at the terminal and pipelined to onshore natural gas connections. The development of such terminals can bring LNG directly into populated areas where it is needed, bypassing local opposition to building LNG terminals and storage tanks within the confines of populated areas.

Imports of LNG into the United States were expected to grow rapidly from 0.6 trillion cubic feet in 2005 to 2.1 trillion cubic feet in 2015. However, actual imports are trailing this projection because of climbing domestic gas production. Having the world's lowest priced natural gas, some thought has been given to converting a newly constructed and idle import LNG terminal to an export terminal by adding an LNG liquefaction plant. However by the time the permitting process is completed, the U.S. will probably be importing large quantities of LNG, which would defeat the purpose of such a project. While the United States' appetite for LNG imports is temporarily waning, this is not true for the rest of the world. The United Kingdom is facing declining production and reserves of its North Sea oil and gas finds. The Interconnecter, a natural gas pipeline between the United Kingdom and Europe, was built for two-way flow, exporting gas to Europe during the summer and importing gas during the winter. One might expect that the Interconnecter will be flowing in one direction from Europe to the U.K. as output from North Sea gas fields dwindles, but this may not happen. A pipeline is being built to connect the United Kingdom with a Norwegian gas field, LNG terminals in the United Kingdom are being expanded to handle a higher throughput, and depleted natural gas fields are being converted to storage facilities as in the United States. How these developments play out will determine the future direction of flow through the Interconnecter.

Italy, Spain, and France are expanding their LNG terminals as Europe becomes more committed to natural gas to meet its carbon dioxide emission obligations under the Kyoto Protocol. The interruption of Russian gas supplies to Europe in 2009 as a result of a dispute between Russia and the Ukraine over pricing, the second such occurrence (the first occurred in 2006), is a clear warning to Europe not to become too reliant on the Russian Bear for its natural gas supplies. The expansion of European LNG terminals will allow imports of LNG from the Atlantic basin and the Middle East to supplement natural gas supplies. It is anticipated that LNG imports may grow by several orders of magnitude as Europe reduces its reliance on Russian natural gas for energy security reasons.

China has a huge thirst for energy, including LNG imports and, through its balance-of-trade surplus, has the capital to invest in LNG terminals and build a natural gas infrastructure. India is another nation with an enormous thirst for energy, but that nation is stymied by balance-of-trade deficits and relatively limited capital reserves. Nevertheless, a number of companies are investigating the possibility of LNG projects in India with at least one company expressing a willingness to accept payment in Indian rupees rather than U.S. dollars. The enormous expansion of LNG-producing capacity may turn out to be necessary to satisfy energy security concerns in Europe and energy needs in Asia, even if U.S. LNG imports fail to meet expectations.

LNG terminals in Japan serve regional needs with no interregional pipelines. Yet the natural gas price is essentially the same throughout Japan because the price of LNG imported into each region refers to the same pricing formula on a delivered basis. Without price differentials, there is no economic justification to build interregional pipelines in Japan. With this thought in mind, LNG terminals will have a major impact on basis pricing of natural gas in the United States. For instance, there is a newly built LNG terminal in New England. The LNG export plant in Trinidad, or possibly one built in Venezuela, has nearly the same shipping distance to the U.S. Gulf as to the U.S. Northeast. Thus, it is conceivable for LNG to enter both regions at the same delivered price. If sufficient volumes were imported at both locations, the price differential between the two regions would shrink, raising havoc with tolls for the pipelines connecting the U.S. Gulf with the Northeast.

An LNG plant in Nigeria has about the same shipping distance to the U.S. Gulf, the U.S. Northeast, and Europe. This permits arbitrage trading that would tend to equalize natural gas prices in all three regions. If price differentials were large enough to absorb the extra shipping costs, LNG cargoes from Trinidad or Venezuela (if an LNG plant were built there) could also be sold in Europe and LNG cargoes from Murmansk (if an LNG plant were built) could also be sold in the United States. Moreover, LNG terminals in the Middle East with excess capacity could sell cargoes west or east (Atlantic or Pacific basins), depending on netback values. The upshot of spot trading of sufficient volumes of LNG cargoes is that the price of natural gas in Europe and the United States and Asia might not be materially different, making natural gas a globally traded commodity similar to oil.

The price of natural gas may remain closely tied to oil on an energy-equivalent basis. The price of LNG in Japan, Korea, and Taiwan is directly tied to oil. The price of LNG imported into Europe is partly tied to the price of Brent crude and fuel oil. The price of natural gas in the United States was only weakly related to oil prices during the 1990s when natural gas was in surplus. With the passing of the natural gas bubble, a closer relationship between natural gas and crude oil prices on an energy-equivalent basis has been established. Thus, spot trading in LNG may not only equalize the price of natural gas on a global basis but also maintain parity between the price of natural gas and crude oil. This has significant ramifications for natural gas consumers if crude oil supply cannot keep up with demand, resulting in another spiking of oil prices.

Gas to Liquids (GTL) Technology

Reservoirs of stranded gas too remote for access by pipeline, and lacking sufficient reserves to support an LNG export project, can be made accessible to the market through gas to liquids (GTL) technology. Combining methane with air at high temperatures produces a mixture of carbon monoxide and hydrogen, which, via the Fischer-Tropsch process, in the presence of iron or cobalt catalysts, can create long hydrocarbon chains. These are then broken down to produce a combination of naphtha, kerosene, diesel fuel, lubricating oil, and wax.[12] The Fischer-Tropsch process is very versatile as it can also create liquid hydrocarbon fuels from coal and biofuels (wood and other plant life).

Diesel fuel produced by the GTL process is very clean-burning with significantly less nitrous oxide and particulate emissions and virtually no sulfur oxide emissions. Shell Oil has been in the forefront of GTL development and has been producing over 14,000 bpd of liquid petroleum products from its Bintula plant in Malaysia for a number of years. Qatar has been actively seeking joint venture partners to build GTL plants. The Oryx GTL plant, a joint venture between Qatar and Sasol of South Africa, began operations in 2006. The plant consumes 330 million cubic feet of natural gas per day, producing 34,000 bpd of petroleum products (24,000 bpd of diesel fuel, 9,000 bpd of naphtha, and 1,000 bpd of LPG). Shell, utilizing its experience from the Bintula plant, is building the Pearl GTL plant in a joint venture with Qatar. The plant is anticipated to be completed in 2010 and will produce 140,000 bpd of naphtha, kerosene, diesel fuel, lubricating oils, and paraffin plus 120,000 bpd of natural gas liquids and ethane stripped from the 1.6 million cubic feet per day of natural gas feedstock. Chevron, utilizing its experience in a GTL project with Sasol, is building a 34,000 bpd GTL plant in Escravos, Nigeria, in partnership with the Nigerian National Oil Company, to be completed in 2010. There are plans for this plant to be expanded to 120,000 bpd within ten years of completion. Russia is looking into GTL production for isolated gas fields in Siberia and to capture the value lost by gas flaring. A proposal has been made to build barge-mounted GTL plants to reach isolated gas fields located near water in Southeast Asia and elsewhere.

Selling GTL petroleum products is a virtually unlimited market from the perspective of natural gas producers, whereas LNG is ultimately limited by the throughput capacity of LNG receiving terminals. One drawback to GTL production is the cost of the GTL plant, which could be reduced with further technological advances and by economies of scale in building larger-sized plants much as the cost of building LNG liquefaction plants has fallen over time. Another drawback is that the GTL process is about twice as thermally inefficient as an LNG liquefaction plant. This means that a lot more of the original energy content of natural gas is lost when natural gas is converted to petroleum products than to LNG. In addition, the Fischer-Tropsch process produces a great deal of carbon dioxide as a waste product (the process has been dubbed a carbon dioxide production plant by critics). While the petroleum products made by the Fischer-Tropsch process are cleaner-burning than those made from crude oil, the carbon footprint is larger when emissions from the production process are taken into account. The carbon footprint would be smaller if the GTL plant were consuming natural gas that would otherwise be flared. Earlier projections of the contribution of GTL as a source of motor vehicle fuels may not materialize from a combination of higher capital costs for building a GTL plant, the thermal inefficiency of the process, and a larger perceived growth in LNG exports to Europe and Asia. This reduces the need for gas-exporting nations to diversify their exports by transforming natural gas to oil products and may be behind the cancellation of a proposed GTL project involving Exxon-Mobil and Qatar.

NONCONVENTIONAL GAS

Nonconventional gas refers to natural gas whose production requires special stimulation and drilling techniques to release the gas trapped in reservoirs. The principal sources of nonconventional gas are coalbed methane and tight gas shale and sand formations. It is difficult to estimate the reserves of nonconventional gas because of the nature of their geological structures and the ultimate recovery of gas from these reservoirs. At this time, the global estimate is over 900 tcm as compared to conventional global natural gas reserves of 177 tcm. Although reserves of nonconventional gas dwarf conventional sources, actual recovery may be only 10–15 percent because of the difficulty of removing gas embedded in coal seams and impermeable rock. Nonconventional gas fields are concentrated with 25 percent in the United States and Canada and 15 percent each in China, India, and the former Soviet Union. Nonconventional gas is a rapidly growing source of gas in the United States and to a lesser extent in Canada.

While not considered nonconventional, sour gas reserves are plentiful, amounting to 40 percent of global and 60 percent of Middle East gas reserves. Sour gas is natural gas with a significant content of either hydrogen sulfide or carbon dioxide or both. The presence of either gas poses a number of technical challenges as these gases must be separated from natural gas and disposed in an acceptable manner. Hydrogen sulfide is normally converted to sulfur and sold to industrial enterprises. However, sour gas containing hydrogen sulphide requires special alloys for the steel pipe used in natural gas production to prevent corrosion. There is no effective and economical way of disposing of carbon dioxide. The 1.3 tcm Natuna gas field in Indonesia, Southeast Asia's largest gas field, has a carbon dioxide concentration of over 70 percent. Disposal of this amount of carbon dioxide has prevented the development of this field for over two decades. However, there are a few examples of successful sequestration of gas fields with high carbon dioxide content. One such gas field in Norway and another in Algeria have successfully separated and injected the carbon dioxide content into nearby depleted gas fields, providing useful data and experience on carbon sequestration. But there is a cost that has to be taken into account of separating carbon dioxide from natural gas and in compressing, transporting, and injecting the carbon dioxide into underground formations.

Methane from Coal

Methane found with coal has been responsible for the death of many miners. Coal bed methane (CBM) is "mining" coal beds not for their coal, but for their methane. CBM works best for mines that are too deep for mining (below 3,000 feet) with fractured methane-rich coal beds that are submerged in water. Water surrounding the coal absorbs and retains methane as long as the water is under pressure. Methane has a low solubility in water and readily comes out of solution when the water pressure is dropped.

A well is drilled to the coal seam to allow the water to rise to the surface, where it is capped and kept under pressure. From time to time water is pumped out of the well to lower its pressure. The released methane is collected and diverted to a gathering system that serves a number of wells. The gathering system is connected to a natural gas pipeline. After the release of methane, pumping stops and the well is capped to increase its internal pressure. Once the concentration of methane is restored, the well is pumped again to lower the pressure and release the methane. The principal region for CBM wells in the United States is the San Juan basin encompassing the Four Corners region (northwestern New Mexico, northeastern Arizona, southwestern Colorado and southeastern Utah), Powder River Basin (southeastern Montana and northeastern Wyoming), and other basins and regions such as Appalachia. CBM already contributes about 10 percent of the nonassociated natural gas production in the United States, 5 percent of Canada's gas production, 7 percent of Australia's gas production with Indonesia, India, and China in the early stages of developing CBM production. CBM is expected to continue growing rapidly, particularly with the rise in natural gas prices.

Environmentalists object to the pristine Western wilderness being crisscrossed with gathering pipelines and its quiet disturbed by the noise of equipment pumping water out of wells and compressors moving gas in pipelines. Much of the water from CBM wells is saline and can damage agricultural and natural plant life. Saline water is kept in ponds, but some can seep into the surface groundwater. Reinjecting saline water into the CBM well avoids the risk of surface water contamination, but at the present time, relatively little is reinjected.[13] Enhanced coal-bed methane involves injection of carbon dioxide into the coal bed. Fractures in a coal bed can absorb twice as much carbon dioxide as methane. The carbon dioxide remains trapped in the coal bed displacing the methane. This has the double benefit of sequestering carbon dioxide while enhancing methane production. Between 0.1 and 0.2 tons of methane can be recovered for every ton of injected carbon dioxide. Experimentation of enhanced CBM is being undertaken in the United States, China, Japan, and Poland. Sequestering carbon dioxide in coal beds would require separating carbon dioxide from flue gases and pipelining it from an electricity-generating plant to a CBM site, which, as one might expect, would be quite costly at this time.

Methane from Tight Shale

Vertical drilling for conventional sources of oil and gas sometimes penetrated thick layers of shale rock hundreds of meters thick. This rock could not be economically exploited because of its low permeability. In recent years, technological advances have been made to tap this resource. Horizontal drilling can collect natural gas in shale if there are vertical fractures in the rock for the gas to flow into the well bore. "Hydraulic fracturing" or "hydrofracing" has been developed to increase the productivity of a horizontal well by increasing the number of fractures in a well bore. To do this, a portion of the well bore is sealed off and water or gel is injected under very high pressure (3,500 psi) to fracture the rock and expand existing fractures. Tons of sand or other "propant" is pumped down the well and into the pressurized portion of the hole to force millions of grains of sand into the fractures. If enough sand grains are trapped in the fractures, the fractures will remain propped open when the pressure is reduced. This increases the permeability of the rock, which allows a greater flow of gas into the well bore. This technique was first applied in the Barnett shale formation in north central Texas. Other promising formations under development are Marcellus shale in West Virginia, eastern Ohio, western Pennsylvania, and southern New York; Haynesville shale in northwestern Louisiana and eastern Texas; and Fayetteville shale in Arkansas. Thirty-five percent of the estimated global shale-gas reserves of 450 tcm are in North America with an equal sharing in the Asia-Pacific region and 15 percent in the Middle East. The United States is the only large-scale producer of shale gas, accounting for nearly 5 percent of total gas production, but shale gas is under development at the Horn River basin in northeastern British Columbia.

Methane from Tight Sands

Tight gas sands are sandstone with a low permeability, and extracting methane is similar to that of tight shale formations. Tight sand formations are found mainly in the Rocky Mountain region but also in the Gulf coast, midcontinent, and northeast regions. World tight gas sand recoverable reserves are about 200 tcm, of which about 40 percent is in North America, 25 percent in Asia-Pacific with other deposits in former Soviet Union, Middle East, and Africa. The United States and Canada have been leaders in tight gas sands development. In 2006, 40 percent of new gas wells were in tight gas sands formations, accounting for nearly 30 percent of natural gas production. By 2009, nonconventional gas production was equal to conventional gas production, raising the issue of whether the descriptive term "nonconventional gas" was appropriate. However wells in tight shale and sands have a relatively short life, and drilling activity must be continuous to sustain production. But their high cost and short lives require a high price for natural gas. A fall-off in the price of natural gas, such as the one that occurred in late 2008/09, will have deleterious effects on natural gas production from nonconventional sources, leading to a greater dependence on imported LNG.

Methane Hydrates

Methane hydrates are essentially natural gas molecules trapped in a lattice of ice whose structure is maintained in a low-temperature and moderate-to-high-pressure environment. Methane hydrates look like ice crystals. An ice ball of methane hydrates looks like those carefully sculpted by Calvin in the "Calvin and Hobbs" comic strip to throw at Suzie. The only difference is that the methane hydrate ice ball can be ignited. One cubic meter of methane hydrates contain 160 cubic meters of embedded natural gas. Methane hydrates are found beneath large portions of the world's permafrost as well as in offshore sediments. They are thought to have been formed by migrating natural gas or seep gas that came in contact with cold seawater at sufficient depths to form hydrates or by the decay of marine life in bottom sediments. Cold and pressure keep the methane entrapped in the ice lattice but it is released if warmed or the pressure reduced. Some climatologists fear that global warming of the tundra regions could release methane now entrapped as methane hydrates in the permafrost. This would lead to runaway global warming because methane is twenty times more effective than carbon dioxide in reflecting back infrared radiation from the earth. The challenge is how to "mine" methane hydrates considering their inherent instability.[14]

Methane hydrates are not limited to the arctic regions. Large deposits of methane hydrates have been found in coastal regions around Japan, both coasts of the United States, Central and South

America, and elsewhere. The known world reserves of natural gas are over 6,500 tcf, while the worldwide estimate of methane in methane hydrates is over 100 times greater at 700,000 tcf. For the United States, the estimate is 200,000 tcf versus natural gas reserves of 238 tcf, over 800 times larger. There is an awful lot of methane locked up in methane hydrates, and such a potential cannot be ignored. Research efforts are being conducted in Japan, Canada, Korea, the United States, China, and India to better understand the nature of methane hydrate deposits as a first step toward dealing with the technological challenge of how to mine them.

It is thought that ships lost in the Bermuda Triangle may have actually been caught in a gigantic bubble of methane released from methane hydrates and floundered from a loss of buoyancy. Aircraft passing through a cloud of methane-enriched air might suffer from a loss of power by methane displacing oxygen or from an explosion or fire from methane coming in contact with the hot engine exhaust. As an aside, brine pools with an extreme concentration of salt have been found in certain areas of the ocean. These pools are also rich sources of methane surrounded by colonies of mussels, which have formed a symbiotic relationship with methane-metabolizing bacteria that live on their gills. Methane-metabolizing bacteria have also been found living symbiotically with worms in methane hydrate deposits at the bottom of the Gulf of Mexico. Methane hydrate deposits and brine pools are fairly recent discoveries as is methane in the atmosphere of Saturn's moon, Titan, which appears to have lakes of LNG. These newly discovered sources of methane show that we live in an amazing world in an equally amazing universe.

NOTES

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