Chapter 5

Natural Gas

Natural gas – long an important part of the US energy mix – is on the ascendance. Recent extraction methods, known as “fracking,” have made domestically produced natural gas widely available and relatively inexpensive.

Many predict that natural gas, already widely used for commercial/residential heating and in industrial applications, will replace coal in power plants in this country and might even become the fuel of choice in transportation.

According to the energy “input/output” chart (below), natural gas as of 2013 constitutes about 26.7% of the total U.S. energy consumed.

Chapter collaborators:
Brodie Erwin (WF ’12)
Derrick Lankford (WF ’12)
Lea Ko (WF ’13)
Wade Sample (WF ’12)
Kyle Simon (WF ’12)
Craig Harasimowicz (WF ’13)
Doug Winn (WF ’13)
William Hester (WF ’13)
Tim Stewart (WF ’12)
Ben Winikoff (WF ’15)
Ben Zich (WF ’14)

In this chapter, you will learn about:

• The basics of natural gas -- including its chemical makeup, production, and how it gets to its users

• How the natural gas industry has evolved since 1900 – including the history of gas prices
  o How economic, environmental, and social factors influence the price of and demand for natural gas
  o How the spot and futures markets in natural gas have been manipulated by short-term investors and speculators

• The legal rights of surface owners and mineral owners and who prevails when gas extraction damages surface land
  o How the common law treats split estates, where surface and subsurface rights are separated
  o How the common law has sought to accommodate the rights of surface owners, while accepting the dominance of subsurface owners

• The convoluted federal and state regulation that governs the extraction and pricing of natural gas – including gas stored in coal (aka coalbed methane)

• The regulation (and de-regulation) of the transportation of natural gas under the Natural Gas Act and Natural Gas Policies Act
  o The effect of Order 636 (an order by the Federal Energy Regulatory Commission that forces gas pipelines to unbundle transportation) on natural gas prices and availability
  o The industry restructuring caused by gas deregulation, including effects on gas pipelines and producers under take-or-pay-contracts (and looking at California energy crisis)

• The impact of liquefied natural gas (LNG) and the regulation of onshore and offshore LNG terminals

• The significance of fracking – as well as its environmental and social externalities, along with current and proposed regulation
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Sources:
5.1 Natural Gas Basics

Natural gas is an odorless, nontoxic, gaseous mixture of hydrocarbons – predominately methane (CH$_4$). It forms whenever organic material mixes with water in an airtight space, often underground. Natural gas accounts for about a quarter of the energy used in the United States, with about one-third used for residential and commercial purposes such as heating and cooking, another one-third used for industrial purposes, and one-third for electric power production. Natural gas is a popular fuel source because it burns cleaner, hotter and brighter than other fossil fuels, like coal and oil. Besides being an important fuel source, natural gas is also a major feedstock for fertilizers. Natural gas is often informally referred to as simply gas, especially when compared to other energy sources such as oil or coal. Recently, 80% to 90% of the natural gas used in the United States was domestically produced. Natural gas is found in deep underground natural rock formations or associated with other hydrocarbon reservoirs, in coal beds, and as methane clathrates. Most natural gas is drawn from wells or extracted in conjunction with crude oil (aka petroleum) production.

How is natural gas created? Most natural gas is created over time by two mechanisms: biogenic and thermogenic. Biogenic gas is created by methanogenic organisms in marshes, bogs, landfills, and shallow sediments. Deeper in the earth, at greater temperature and pressure, thermogenic gas is created from buried organic material. Before natural gas can be used as a fuel, it must undergo processing to remove almost all materials other than methane. The by-products
of that processing include ethane, propane, butanes, pentanes, and higher molecular weight hydrocarbons, elemental sulfur, carbon dioxide, water vapor, and sometimes helium and nitrogen. Wikipedia, “Natural Gas.”

For many years the federal government heavily controlled natural gas prices, unlike crude oil prices, with profound effects on the industry. Further, while oil pipelines have always been considered a common carrier, gas pipelines did not become common carriers until the 1970s and 1980s; thus this difference further affected natural gas prices in the past.

5.1.1 Physical Flow through Four Entities

Natural gas as used today flows through a continuous chain of links between four types of entities:

**Producers**: The producers of natural gas are the operators of wells in oil and gas fields. For the most part, they are the same companies that also drill for oil. Gas comes from two types of fields: associated gas (also called casinghead gas) is a gas that is produced along with oil from oil wells, separated from oil, and then sent into gas pipelines. See Britannica, “Associated Gas.” Other gas wells produce gas from gas-only fields that have no accompanying oil production.

**Transmission Pipelines**: Transmission pipelines are used to transport crude oil and natural gas from their respective gathering systems to refining, processing, or storage facilities. US Dept. of Transportation, “Fact Sheet: Transmission Pipelines.” These large pipelines of high-strength steel form an interstate highway system of over 28,000 square miles for natural gas to travel. The safety of construction, operation, and maintenance of transmission pipeline systems is regulated by the Pipeline and Hazardous Materials Safety Administration’s Office of Pipeline Safety under 49 CFR Parts 192 and 195. US Dept. of Transportation, “Fact Sheet: Transmission Pipelines.” The Federal Energy Regulatory Commission (FERC) regulates natural gas transportation in interstate commerce. FERC, “Overview of FERC.” In large producing and consuming states, many intrastate pipelines also exist -- regulated by a state agency, often the public utility commission.

**Distributors or LDCs**: Distribution is the final step in delivering natural gas to customers. Local distribution companies (LDCs) are regulated utilities involved in the delivery of natural gas to consumers within a specific geographic area. There are two basic types of natural gas utilities: those owned by private investors and public gas systems owned by local governments. LDCs typically transport natural gas from delivery points located on interstate and intrastate pipelines to households and businesses through transmission pipelines. NaturalGas.Org, “Natural Gas Distribution.”

**Industrial Users and Power plants**: Gas is used as fuel in many industrial processes like boilers and blast furnaces. During the 1990s, due to economic, environmental and technological changes, natural gas became the fuel of choice for new power plants. NaturalGas.Org, “Electric
Thus, the fate of both gas and electricity restricting became intertwined. Industrial users, unlike residential and commercial users who buy gas from the area’s LDC, may take gas directly from the pipeline, a practice known as “industrial bypass.” In 2013, the industrial sector used about 33.4% of all natural consumed in the United States, slightly more than commercial and residential uses. Institute for Energy Research, “Natural Gas.”

### 5.1.2 Pipeline Operations and Rates

Natural gas rates – and pipeline demand – varies based on the season of the year. In Northern states during the winter when heating is needed, the use of residential gas is 7x greater than in the summer. Thus, pipelines must have enough excess capacity to meet customer demand on peak days. Natural gas companies deal with this variability in usage in two ways. First, reservoirs near consuming areas are often converted into storage units of natural gas that can be tapped during peak usage days. Natural gas can be stored for an indefinite period of time in storage facilities for later consumption. Wikipedia, “Natural Gas Storage.” Second, many industrial users are large enough to maintain alternative coal or fuel oil facilities to which they can switch if gas is not available or becomes too expensive during peak times. To attract such customers, pipeline companies designate “interruptible” rates, which allow industrial users to buy gas at lower rates on the condition that they can be cut-off if the pipeline space is needed, say, for residential gas heating on very cold days.

The firm (or residential customers) pays a two-part rate for gas. Id. The first part is based on actual gas used. Id. Second, the customers pays for the right to demand services on the even the coldest days—thus this second charge is termed a “reservation” or “demand” charge because the pipelines reserves space to meet these customers needs all of the time. Id. If weather becomes too severe, the gas company will provide less gas to the customers who will suffer the least. Id.

### 5.1.3 Changing Industry Landscapes

Historically, pipelines bought gas from producers, transported it to the markets where the gas was needed, and sold it to distributors and industrial users. The physical flow of gas went from “upstream” wells to “downstream” consumers. The energy shocks in the 1970s changed this landscape. Today, the gas still flows from wellhead to the end-users, but the buy/sell financial transactions involve new players and risks – as detailed below.

### 5.1.4 Gas Prices over the Years

Between 1949 and 1973, gas prices stayed very low. But prices began to increase after the embargo-induced shortage in oil supplies and oil’s exponential price increase. In 2000, gas prices rose as the economy boomed – however prices crashed with the global financial crisis and recession in mid-2008. While prices recovered some, the shale oil boom over the past four years has flooded the market and continues to drive down the price of natural gas.
5.1.5 Gas as Resource over the Years

From By-Product to Regulation (1900-1978). For many years, gas was an unwanted by-product of the oil extraction process. In the 1920s and 1930s, large amounts of oil were discovered in the Oklahoma and the Texas Panhandle, but the gas was too far from the populated East. It sold for only 1/3 to 1/7 the price of heating oil.

After World War II, during which crude oil was in short supply, natural gas became much more popular. See The Role of Synthetic Fuel in World War II Germany. Gas is about 30x more expensive to transport than oil (on an energy equivalent basis); thus the price of natural gas is largely dependent on how good the transportation infrastructure is to transport natural gas.

The passage of the Clear Air Act in 1970 elevated gas to a premium fuel, as it is a “cleaner” fuel than coal. See EPA, “Clean Air Act.” During the oil crisis of the 1970s, natural gas was hard to get as interstate pipelines were forced to curtail and ration gas to end-users on the East Coast. In response, Congress passed the Natural Gas Energy Policy Act – a good part of which involved policies (such as price controls) to solve natural gas shortages. See US EIA, “Natural Gas Policy Act of 1978.”

Natural Gas Markets (1978-present): As price controls were gradually lifted on natural gas production after 1978, more producers began to generate natural gas. Producers drilled more wells, invested in newer technologies and produced more gas. In 1978, Congress passed the Powerplant and Industrial Fuel Use Act (PIFUA), which prohibited the use of natural gas or oil as a fuel for power plants or large industrial boilers. This was done in an effort to reserve this scarce resource for heating and in an effort to promote nuclear power plants. Thus, during the early 1980s, the demand for natural gas substantially declined, which contributed to a significant oversupply of gas for much of the decade. US EIA, “Repeal of the Powerplant and Industrial Fuel Use Act (1987).” Because of this surplus of natural gas, the PIFUA was repealed in 1987.
The repeal of the PIFUA set the stage for a dramatic increase in the use of natural gas for electric generation and industrial processing. US EIA, “Repeal of the Powerplant and Industrial Fuel Use Act (1987).” By 1990, gas prices settled at about $2.00 per thousand cubic feet of natural gas (MCF), a relatively low price considering the clean environmental benefits of burning gas compared to coal. Thus, gas became the “golden fuel,” eagerly sought by the new generation of merchant power plants built to compete in deregulated energy markets.

**CO₂ Emissions**

Gas has a big advantage over coal combustion in electric power generation because it emits less carbon dioxide (“CO₂”), one of the primary greenhouse gasses contributing to global warming. If the Kyoto Protocol on climate change -- an international, binding agreement that commits members to emission reduction targets -- were to become an effective, it could further increase the demand for gas as a substitute for coal. See United Nations Framework Convention on Climate Change, “Kyoto Protocol.” The United States signed the Kyoto Protocol, but did not ratify it. Before the Protocol was agreed to, the US Senate passed the Byrd-Hagel Resolution, which prevented the United States from entering a emissions reduction treaty that 1) would not bind developing countries to the same greenhouse emissions standards for the same compliance period, or 2) “would result in serious harm to the economy of the United States.” Byrd-Hagel Resolution.

The modern gas-powered generating plants of the 1990s often used a new, sleek technology: the combined-cycle gas turbine, which converts natural gas into electricity. See NaturalGas.Org, “Electric Generation Using Natural Gas.” In these types of generating facilities, there is both a gas turbine and a steam turbine. The gas turbine operates in much the same way as a normal gas turbine, using the hot gases released from burning natural gas to turn a turbine and generate electricity. In combined-cycle plants, the excess heat from the gas-turbine process is directed toward generating steam, which is then used to generate electricity much like a steam unit. Because of this efficient use of the heat energy released from the natural gas, combined-cycle plants are much more efficient than steam units or gas turbines alone. In fact, combined-cycle plants can achieve thermal efficiencies of up to 60%.

**Future of Natural Gas**

Thus, by the early 2000s, gas seemed poised for a bright future. For example, in 1999, the Environmental Law Institute, studied the feasibility of switching from dirty coal to clean natural gas. It concluded that gas could be used as an abundant energy sources for centuries, depending on technology improvements and the price of natural gas. If the price dropped below $2, technology advances would slow. If prices jumped above $4, would make many gas fields able to come to market because they are currently too expensive to produce and transport, but if the price of gas is above $4, then it would be feasible.
Between 2000 and 2003, the price of natural gas sky-rocketed. As prices increased, some users of natural gas in industrial capacities began to look for other sources of gas. Further, as prices increased some worries about the future of natural gas became to be revised. For example, the National Petroleum Council in 2003 issued a gloomy report that concluded the following: (i) the prior estimates greatly underestimated the explosion in gas-powered power plans, (ii) many sources of natural gas were subject to leasing moratoria and thus could not be used to produce gas, and (iii) the drilling booms simply could not replace rapidly depleting supplies from existing wells. See National Petroleum Council. For example, in April 2004, DuPont, a large chemical company laid off 3,500 workers in order to reduce costs and stay competitive against companies with lower gas prices abroad. See DuPont.

However, by 2006 these fears became unfounded. This spike in natural gas prices led oil and gas companies to invest into unconventional gas sources for extraction. An unconventional source refers to producing gas from any source that does not readily flow into a well bore, such as shale gas, coal bed methane and tight sands gas. Primarily, the process of hydraulic fracturing (fracking) was no longer used only to recover trapped oil, but now “dry wells” were created to solely collect trapped natural gas. This process allows for drilling companies to reach natural gas that was previously unreachable. It has led to a modern day “shale rush” and the extraction of natural gas by hydraulic fracturing is one of the fastest growing trends in American onshore domestic oil and gas production. By 2008, U.S. natural gas production reached peak 1973 levels. Unconventional natural gas extraction has led to a boom in domestic natural gas production and has led the U.S. Energy Information Administration to predict a 113% increase in shale gas production from 2011 to 2040.

Extensive research and development has been ongoing for fuel cells powered by natural gas. Fuel cells are electrochemical devices in which electric current is created directly by the combination of oxygen and hydrogen ions without the need for a mechanical generator.

In addition to these technological advancements, different types of natural gas may be collected in the future.
**Stranded Gas.** Stranded gas refers to gas fields that have no pipeline access. About half of the world’s natural gas reserves were stranded in 2005. Gas can be stranded for either physical or economic reasons. Physically stranded gas refers to a gas field that is too deep to drill for, or is beneath an obstruction. [Wikipedia, “Stranded Gas Reserve.”](https://en.wikipedia.org/wiki/Stranded_gas) Economically stranded gas refers to a gas reserve that is either too remote from a market for natural gas, making construction of pipelines prohibitively expensive or a reserve that is in a region where demand for gas is saturated and the cost of exporting gas beyond this region is excessive. [Wikipedia, “Stranded Gas Reserve.”](https://en.wikipedia.org/wiki/Stranded_gas) The stranding problem may be solved by Gas-to-Liquids (GTL) technology that can convert natural gas to synthetic petroleum, which can then transported by pipeline tanker, barge, or truck. The virtue of GTL technology is that the synthetic liquid can be used as a clean burning transportation fuel.

**Methane Hydrates.** R&D continues on harvesting the methane hydrates lying at the outer edges of the ocean’s continental shelf, just beneath the ocean floor to be used as energy. Methane hydrate is a cage-like lattice of ice inside of which are trapped molecules of methane, the chief constituent of natural. [US Dept. of Energy, “Methane Hydrate.”](https://energy.gov/eere/hydrogenandfuelcells/methane-hydrates) When warmed or depressurized, methane hydrate will revert back to water and natural gas. [US Dept. of Energy, “Methane Hydrate.”](https://energy.gov/eere/hydrogenandfuelcells/methane-hydrates) These hydrates may contain more carbon than all of the world’s fossil fuels combined. Hydrates are also trapped in the Arctic. The US Department of Energy’s (“DOE”) methane hydrate program aims to develop the tools and technologies to allow environmentally safe methane production from arctic and domestic offshore hydrates. [US Dept. of Energy, “Methane Hydrate.”](https://energy.gov/eere/hydrogenandfuelcells/methane-hydrates) The program includes R&D in production feasibility, research and modeling, climate change, and international collaboration. [US Dept. of Energy, “Methane Hydrate.”](https://energy.gov/eere/hydrogenandfuelcells/methane-hydrates) The DOE is working with energy companies to map, quantify, and assess the feasibility of producing gas from the North Slope gas hydrates and international consortium including the U.S. Geological Survey, the DOE, Canada, Japan, India, and Germany.

**Gasification.** As discussed in the Coal chapter, an integrated gasification combined cycle (IGCC) is another carbon reducing (also referred to as carbon capture) technology that turns coal into gas—synthesis gas (syngas) – that can be used to generate electricity. It then removes impurities from the coal gas before it is combusted and attempts to turn any pollutants into re-usable byproducts. [Wikipedia, “Integrated Gasification Combined Cycle.”](https://en.wikipedia.org/wiki/Integrated_gasification_combined_cycle) This results in lower emissions of sulfur dioxide, particulates, and mercury. [Wikipedia, “Integrated Gasification Combined Cycle.”](https://en.wikipedia.org/wiki/Integrated_gasification_combined_cycle) Excess heat from the primary combustion and generation is then passed to a steam cycle, similarly to a combined cycle gas turbine, which results in improved efficiency compared to conventional pulverized coal. [Wikipedia, “Integrated Gasification Combined Cycle.”](https://en.wikipedia.org/wiki/Integrated_gasification_combined_cycle)

5.2 **Ownership and Externalities**
5.2.1 Split Estates

Split estates are common in the United States. In a split estate, the surface rights and subsurface rights (such as the rights to develop minerals) for a piece of land are owned by different parties. Dept. of the Interior Bureau of Land Management, “Split Estate.” These split estates are often a source of conflict between the surface and mineral owners. To resolve split-estate conflicts, U.S. courts have adopted British common law principles to govern such disputes. In these situations, mineral rights are considered the dominant estate, meaning they take precedence over other rights associated with the property, including those associated with owning the surface. Dept. of the Interior Bureau of Land Management, “Split Estate.”

**Dominance of Mineral Estate.** The early case of *Grimes v. Goodman Drilling Co.* (Tex. Civ. App. 1919), illustrates the dominance of the mineral estate. In *Grimes*, the court held that the owner of a town lot (who had bought the lot subject to an oil and gas lease) could not obtain an injunction when the leaseholder erected a derrick in his front yard. The court ruled the owner was presumed to have known that the subsurface mineral rights were already owned by another party, potentially making use of the home “disagreeable, inconvenient, and perhaps dangerous.”

This dominant mineral estate granted oil and gas companies a wide rage of activities against the wishes of the surface owner. These included: seismic tests, storage tanks, roads, and even the use of the surface owners’ freshwater for drilling or secondary recovery operations.

**Accommodation Doctrine.** However, the courts began to chip away at the common law dominance of the mineral estate. The court in *Getty Oil Co. v. Jones*, 470 S.W.2d 618 (Tex. 1971) held that the mineral owner must show due regard for the interests of the surface estate owner and occupy only those portions of the surface that are “reasonably necessary” to develop the mineral estate. Dept. of the Interior Bureau of Land Management, “Split Estate.” This protection has been termed the accommodation doctrine, which requires the mineral owner to accommodate the surface owner’s existing use of the land if the mineral owner has reasonable alternatives. Houston Business Journal, “Surface Rights vs. Mineral Rights Conflicts are Bound to Increase.” In later cases, courts have lessened this protection by holding that a lessee could never be forced to go off the leased premises to develop an alternative that would mitigate damage to the surface area. *Sun Oil v. Whitaker*, 483 S.W.2d 808 (Tex. 1972).

**Surface Damage Acts.** State legislatures have also tried to restrict the dominance of the common law mineral estate. Many farming and ranching states passed surface damage acts that require mineral operators to pay for the loss of the use of a surface. While the common law requires no compensation, surface damages acts require the operator to give the surface owner adequate notice of the commencement of drilling operations and compensation for actual damages such as loss of crops, loss of land value, and lost use of the surface or any surface improvements. These statutes have been sustained against challenges that they are an unconstitutional taking of the mineral estate owner’s rights.
Surface Development Statutes. Some states, particularly those with growing populations, have also enacted statutes that offer some protection from backyard wells to housing developments. For example, in Texas, the surface developer in populated counties can bind the mineral owner to specific designated plats to accommodate the residential community. In Colorado, surface owners can request that the Colorado Oil and Gas Conservation Commission conduct an onsite inspection to determine if a proposed well site is reasonably located.

5.2.2 Coalbed Methane Ownership

When the resources under the surface don’t cause a great deal of disruption to the land on top, there are relatively few disputes over the ownership of those resources. This is often the case with oil and gas. However, when the extraction of the underlying resource destroys the surface, as in the case of coal or iron ore, more disputes arise. One such dispute was over the production of coalbed methane (CBM), a form of natural gas extracted from coal beds. [Wikipedia, “Coalbed Methane.”]

On Public Lands. Situations may occur where private parties and the government have rights over the same tract of land, where one owns the surface and the other owns what is underneath. Two federal agencies, the U.S. Forest Service (USFS) and the Bureau of Land Management (BLM), oversee a great deal of land in the western United States. Over time, land acts gave rights to these lands to private persons but reserved the mineral rights for the federal government. In such situations, the rights to the underlying minerals go to the government or a federal lessee. The opposite may occur when private parties own the mineral rights underlying federal claims to the surface. An example is the Padre Island National Seashore in Texas where privately owned oil and gas is drilled, but those drilling take training programs to protect wildlife in the area along with other conditions to the operation of the oil wells. See [National Park Service, “Padre Isalnd.”]

In Amoco Production Co. v. Southern Ute Indian Tribe (US 1999), the Court faced the issue whether CBM attached to coal rights under land owned by the Ute Indian Tribe. In 1938 the Southern Ute Tribe had been granted title to underlying coal resources underneath the lands within its reservation. At the time, CBM was considered a hazardous waste of coal mining. In the 1970s, however, CBM became a valuable resource, and in 1991, the Ute Tribe brought an action claiming ownership of the CBM as against those who claimed rights to the underlying resources as successors in interest from claims to the land before 1938. The issue before the Court depended on whether Congress had viewed CBM as a “constituent of coal” in prior acts in 1909 and 1910. If CBM were determined to be part of coal, then the CBM rights to the coal would be with the government. The Court held that Congress did not intend for “coal” to encompass CBM, which was regarded as a “distinct substance that escaped from coal as the coal was mined, rather than as a part of the coal itself.”
The *Amoco* case is an example of a split-estate case in which those with surface rights prevailed. Many states have adopted rules that favor those with surface rights where extraction of the minerals would be harmful to the surface. Such rules illustrate the economic policy questions that lie behind, including economic value, short and long term use, and environmental factors.

**On Private Lands.** As in *Amoco*, courts have decided how coalbed methane ought to be regarded in cases concerning private deeds rather than public land controversies. A number of rules have been developed from the common law:

1. **CBM is Gas:** Under this rule, CBM is defined as a gas within the ordinary meaning of the term as used in standard mineral conveyances. A problem with regarding CBM in this way is that coal owners have to vent the gas while mining which may open them up to suit by owners of the gas who will want to prevent that venting.

2. **CBM is Coal:** On the other hand, some courts have determined that CBM is coal since it is physically present in coal. A problem with this approach is that not all CBM released during mining comes from the coal, but rather comes from other layers that may collapse during the mining process. CBM not derived from the coal would have to be separated from CBM derived from the coal.

3. **Priority at Severance:** Commentators have suggested a first in time approach in which rights accrue in the order in which the competing deeds or leases were created. This approach has been criticized as basing the result on an arbitrary consideration.

4. **Analysis of the Parties’ Intent:** Rather than simply classifying CBM as coal or gas, and instead of looking only at priority at severance, there is a focus on the language of the deed or lease along with any other evidence that tends to show intent.

5. **Successive ownership:** Under this rule, the owner of the coal also has title to CBM absorbed in the coal, but not to any CBM that escapes to other strata or that enters the gob zone from longwall mining.

6. **Mutual simultaneous rights:** This approach gives the rights to the coal to coal owners and CBM to gas owners, but allows the coal owner to capture the CBM as incidental mining rights. Incidental mining rights are those that are “reasonably necessary to facilitate extraction of coal” and are based on the need for ventilation to keep mining safe.

**Ownership of Depleted Reservoirs.** Depleted gas reservoirs are formations that have already been tapped of recoverable natural gas. NaturalGas.Org, “Storage of Natural Gas.” This leaves an underground formation, geologically capable of holding natural gas. NaturalGas.Org, “Storage of Natural Gas.” They are the most prominent and common form of underground
storage and the least expensive way to store natural gas closer to population centers. By storing natural gas nearby population centers, distribution during times of peak demand (such as cold snaps or heat waves) becomes easier. There are over 400 depleted reservoirs in the United States – which also may be used for the storage of carbon dioxide.

Questions arise when the mineral source below the surface is depleted in split estate situations. Typically, the underground paths made by mining operations become owned by the surface owner, but the situation with gas is different since the pore spaces left behind are much different and specific to gas storage. Although little case law exists on the topic, commentators believe that the proper owner is the surface owner. The reasoning analogizes the storage business to opening a service station, which is more appropriate to belong to a surface estate than a mineral one.

5.2.3. Coalbed Methane Externalities and Mineral Dominance.

The externalities of gas production are similar to those present in oil production with one key difference: gas does not spill. Instead, gas is leaked into the air or combests, thus gas mishaps mostly pose safety hazards to people rather than pollution hazards to the environment. Like oil and gas production, CBM production brings about roads, drilling pads, noise and air pollution, disruption of habitats, and general intrusion of otherwise uninhabited areas. A common problem with CBM production is that the wells are placed much closer together. While conventional gas wells might be put at the center of a 640-acre section, CBM wells are often spaced within 40 or 80 acres of each other.

Excess water is the key externality involved in CBM production, especially in the arid western states.

Source: MBMG Energy
Coalbed methane gas cannot be released from coal until the water pressure that traps it there is released. Therefore, CBM drillers must first de-water the coal seams by producing large amounts of water from the coal bed. This creates serious issues about groundwater depletion, contamination, and disposal of the produced water when it is separated from the methane. The biggest problem with the extracted groundwater is not pollution (the most common contaminant is salt), but the volume of the water produced. In fact, some water removed from coal beds can be as clean as bottled water.

While clean water is normally not seen as an issue, in arid states there are not enough livestock, industries, or people in the state that can drink or use the millions of gallons of water produced. For example, in the Wyoming Powder River Basin the CBM wells can produce 700 million gallons of water a day. This is enough for 45 million cows or 325 million sheep. However, the basin currently only has 500,000 of these animals. Therefore, the majority of the water is released by surface discharge, which has resulted in a host of problems including increased erosion of ditches and banks, salt concentration in the soil, and the overproduction of stock ponds for livestock. While stock ponds themselves are not dangerous, so many have been built in semi-arid, CBM areas that mosquitoes bearing the West Nile virus have become a health problem to people and animals in the region.

5.3. Natural Gas Regulation: Price Controls.

Generally speaking, the transportation of natural gas tends to create natural monopolies. Efficient pipeline systems are characterized by high barriers of entry and large economies of scale, much like railroads or electric grids. When the natural gas industry first came on line, individual states, through their state public utility commissions, attempted to regulate the production and transportation of the fuel. This arrangement subjected gas firms to inconsistent obligations as they began to trade across state lines. In the 1920s, a series of Supreme Court opinions held that the dormant Commerce Clause barred states from regulating the interstate transportation or wholesale of gas. See Pub. Utils. Comm’n of R.I. v. Attleboro Steam & Elec. Co. (US 1927); Missouri v. Kansas Gas Co. (US 1924); Pennsylvania v. West Virginia (US 1923). The Court’s more expansive reading of the Commerce Clause in the 1930s, however, changed the regulatory landscape.

5.3.1 Natural Gas Act of 1938

Faced with the need for a uniform, comprehensive regulatory regime, Congress enacted the Natural Gas Act of 1938 (NGA), 15 USC § 717. See US EIA, "Natural Gas Act of 1938," Congress could have chosen to regulate the gas pipelines as if they were common carriers, as it did to interstate oil pipelines. This would have given the federal government the power to require pipeline companies to transport gas for third parties at rates equivalent to their own. However, the industry successfully lobbied against a common carrier policy in favor of being treated like a public utility. Regulation of public utilities involves state utility commissions using cost-of-
service ratemaking in an effort to approximate as close as possible the “fair market price” of the service. The theory behind this regulation is that it prevents monopolies from reaping excessive profits off the captive consumer.

In 1954, the Supreme Court held that the NGA required the Federal Power Commission (FPC) to set price controls on gas sold by producers in interstate commerce. See Phillips Petroleum Co. v. Wisconsin (US 1954). However, while the transportation of natural gas tends to be monopolistic, the production of gas displays all the characteristics of a thriving, competitive market. Thousands of firms are able to compete with one another to produce gas because the activity presents low barriers to entry and does not involve large economies of scale. In essence, the Supreme Court’s Phillips decision assigned the FPC an impossible task. No agency can adequately impose price controls on a competitive market without a shortage of regulated product or service.

In response to the Phillips Petroleum decision, the FPC first attempted to set a maximum rate applicable to each producer, not unlike how utility commissions set maximum rates for electric companies. But because the volume of producers was so large and the task of rate setting so complex and fact-intensive, the FPC became hopelessly backlogged. As a practical matter, the FPC adopted broad rates applicable to entire regions based on historic costs in a given area. The market interference brought about by the FPC’s regulatory approach created painful supply shortages.

In 1959, the Court modified the Phillips decision in Atlantic Refining Co. v. Pub. Serv. Comm’n of N.Y., 360 U.S. 378 (1959). In Atlantic Refining the Court created a new system of rates applicable to all gas produced in each producing area based on the agency’s estimate of the average historical cost of finding and producing a unit of gas in each area. However, in the 1970s a particularly harsh winter led to a shortage so great that gas was no longer able to reach most new customers. This forced thousands of manufacturing plants and schools to close because of service curtailments and over 1 million workers were laid off because of their employers’ inability to obtain gas. To address the shortages, Congress enacted the Natural Gas Policy Act of 1978 (NGPA), 60 USC § 3301 et seq. See US EIA, “Natural Gas Policy Act of 1978.”

5.3.2 Natural Gas Policy Act of 1978.

The NGPA attempted to deregulate the gas market slowly over a span of decades while substituting a complex new price control formula in the meantime. Congress assumed that the quantity of gas demanded and supplied would change slowly in response to changes in the price of gas. However, this did not reflect the actual market of natural gas. Instead, as the price of gas increased, the quantity of gas demanded fell rapidly, the quantity of gas supplied rose rapidly, and the market price of gas plummeted to well below the statutory ceiling prices. The plan was ultimately met with mixed success, and the market continued to be plagued by high gas prices.

5.4. Restructured Pipeline Industry
In 1985, the FPC, now called the Federal Energy Regulatory Commission (FERC) issued Order 436, which coerced pipeline companies into becoming common carriers obligating them to carry third party gas at competitive rates. See NaturalGas.Org, “The History of Regulation – FERC Order No. 436.” In effect, the Commission for the first time imposed the duties of common carriers upon interstate pipelines. See Associated Gas Distributors v. FERC, 824 F.2d 981, 997 (D.C. Cir. 1987) (AGD I), cert. denied, 485 U.S. 1006 (1988).

Order 436 used regulatory incentives to encourage pipelines to voluntarily agree to become common carriers. Congress ratified this approach in 1989 when it enacted the Natural Gas Wellhead Decontrol Act, which amended the NGPA to repeal all remaining regulated prices on wellhead sales. NaturalGas.Org, “The History of Regulation – The Natural Gas Wellhead Decontrol Act of 1989.”

A year after Order 436, FERC issued Order 451, which changed the maximum rate rules in an effort to allow pipelines and producers to take advantage of flexible pricing. Together, these remedial measures brought gas prices down to reasonable levels that reflected real market conditions.

Among other things, the Natural Gas Policy Act had required the elimination of all price ceilings by a certain date. In 1992, FERC completed the process of deregulating the gas sales market by issuing Order 636, which required pipelines to unbundle their services and provide full open access. See NaturalGas.Org, “The History of Regulation – FERC Order No. 636.” Through these actions, FERC carried out the congressional decree to end federal price controls on all gas as of 1993.

5.4.1. Deregulation

Consider the history of natural gas regulation. Natural gas regulation began as a state-based conservation effort to manage natural resources and direct commerce. While the Supreme Court has made it clear that the Commerce Clause prevents states from regulating the sale of interstate gas, it remains unclear to what extent state conservation laws are preempted by the federal scheme. See Transcontinental Gas Pipe Line Corp. v. State Oil & Gas Board of Mississippi (US 1986) (holding that the NGPA pre-empted Mississippi’s “ratable-take order” which required pipelines to take gas from all producers in a field).

Prior to price deregulation at the federal level, pipelines entered into “take-or-pay contracts” with wellhead producers. The contracts required the pipelines to purchase all the gas a producer could extract or else make up the difference on the gas left in the ground. When deregulation hit and prices began to fall, pipelines with take-or-pay contracts stood to lose billions of dollars on their commitments. To protect themselves, the pipelines adopted a litigation strategy designed to stall the implementation of deregulation and shift some of the long-term contract losses to other market participants. The litigation lasted until well into the 1990s.
Technological innovation, industry growth, and improved service have all followed in the wake of deregulation. What lessons, if any, should other energy sectors learn from the history of the NGA and NGPA? Some scholars argue that the electricity industry should adopt the gas industry’s market-based approach. See Richard J. Pierce, *The Evolution of Natural Gas Regulatory Policy*, NATURAL RESOURCES AND ENVIRONMENT 53-55, 84-85 (1995).

5.4.2. Order 636

**Functional Unbundling and Affiliates.** Implementing Order 636 has created plenty of problems. One problem has been the “functional unbundling” requirements mandated by the Order. As discussed earlier, Order 636 mandated that the newly created pipeline marketing entities not receive or share information from the pipeline companies themselves that was not also made available to new competitors. This partition became known as the “Chinese Wall” requirement. However, achieving this compliance was understandably difficult. The employees of the newly created marketing entities were often long-time former employees of the pipeline company. These employees possessed a long “institutional memory” and thus had knowledge regarding the pipeline that could not possibly be made available to new competitors.

Implicit in the policies surrounding the restructuring of the natural gas industry was that unbundling or separating services traditionally performed by the pipeline company was desirable as a matter of economic efficiency. Pipeline companies historically found it extremely efficient to provide both sales and transportation under the same umbrella corporation. However, the FERC reasoned that unbundling would minimize distortions in the sales market facilitated by the market power the pipelines wielded over gas transportation. The switch to a competitive gas market became possible because so many pipelines had been built that most market areas had reasonably good access to more than one pipeline and because pipeline capacity had largely caught up with demand. Thus, unlike in the electricity sector, there are a few natural monopolies in the natural gas market.

After the enactment of Order 636 shippers filed a number of complaints with the FERC alleging violations by pipelines and their marketing affiliated of the “Chinese Wall” requirements. Most were resolved through negotiations. But several complaints resulted in the assessment of penalties against the pipelines. See *Amoco Prod. Co. v. Natural Gas Pipeline Co. of Am.*, 82 F.E.R.C. ¶ 61, 038 (1998). In the *Amoco* case, shippers alleged that the pipeline had violated the Order and FERC agreed. FERC found that the pipeline had created a system in which employees had day-to-day duties consisting of carrying out gas related operations in both sales, marketing, and transportation. The crossover between sales and transportation duties clearly violated the Order’s “Chinese Wall” requirement.

**Rate Design - Rolled-in Rates.** Another contentious issue after Order 636 is whether to have a rate design "rolled in" or have incremental rates. The big question here is whether or not costs of new pipeline construction should be paid solely be the customers who are to be served be the
new section or should the costs be “rolled in” to the overall rate base and distributed among all of the pipeline’s customers.

The answer to this problem came in 2000 in *Midcoast Interstate Transmission, Inc. v. FERC* (D.C. Cir. 2000). In that case, the court held that FERC had properly authorized “rolling in” the cost of new pipeline construction into the company’s system-wide rate because there would be system wide benefits to consumers and because the impact on system wide rates would be minimal. However, “rolling in” can be to the detriment of smaller companies looking to compete and expand in markets controlled by larger pipeline companies. The larger companies are able to keep their rates low while expanding because they are able to disperse the cost across a large system. A smaller company is not able to keep the rates as low because they do not have enough system-wide customers to completely subsidize the new construction.

**Spot and Futures Markets.** Lastly, over-reliance on short term contracts in the spot and futures markets are another problem that has arisen in the wake of Order 636. See Wikipedia, “Spot Market.” Today, most natural gas is purchased through contracts on the spot market. These transactions are short term, usually for only thirty days, and are generally interruptible. These contracts respond to current market prices, but also expose the parties to the risks of price volatility or service interruption. Before the restructuring of the natural gas industry, companies negotiated twenty-year service contracts. The restructuring and Order 636 have caused the companies to have to learn the ways of commodity exchanges.

The development of the spot markets in physical sales of gas directly correlated with the creation of a natural gas futures market on the New York Mercantile Exchange. See Wikipedia, “New York Mercantile Exchange.” This exchange allows buyers and sellers of physical volumes of gas to hedge their price risks and thus reduce their exposure to price volatility. The exchange quotes prices of gas daily and provides price signals to all market participants. The futures markets also allow speculators to invest in complex financial derivatives tied to commodity prices. Speculators willingly take on price risks in hopes that they can somehow “beat the market.” Unlike the hedgers in spot markets, speculators have no interest in owning actual physical volumes of natural gas. These derivative traders can create a more efficient market by transferring risk from hedgers to speculators, promoting information dissemination and price discover, and by creating a more liquid market.

This new array of financially-tradable products created after Order 636 can help large users of natural gas insure their operations against losses from rapid fluctuations in the price of natural gas. The value of these new financial risk management tools went untested See Wikipedia, "California Energy Crisis of 2000." The California energy crisis in combination with the Enron scandal led to an increased push for more government regulation in financial trading of natural gas. The new regulations are discussed in the following section. See Wikipedia, "Natural Gas Prices."
5.4.3 Has Restructuring Succeeded?

By 1995, restructuring had brought a $5 billion annual improvement in aggregate efficiency, cleaner air, commercial and technical innovations, and competitive markets. In 2004 FERC asserted its “State of the Markets Report for Natural Gas” that gas markets were functioning well, but that natural gas prices had risen 63% in 2003 and 7% in 2004, resulting in a public concern over price manipulation. In response to the FERC report, Congress passed the Energy Policy Act of 2005, 42 USC § 13201 et seq., and amended the Natural Gas Act to increase public confidence in natural gas markets and trading. The EPA directed the FERC to “facilitate price transparency in markets for the sale of transportation of physical natural gas in interstate commerce.” 15 USC § 717T-2; See EPA, “Summary of the Energy Policy Act.” The FERC was also given the power to obtain pricing information from market participants, if the gas industry and price publishers do not police themselves. Still, there was public concern over a lack of transparency in price reporting in derivative trading.

More recently, in the wake of the 2008 financial crisis, the Obama Administration sought to regulate derivatives trading by requiring trades to be made on a regulated exchange that has a duty to report prices (rather than the “over the counter” method currently employed) to promote more transparent reporting and reduce speculation. This new financial data is meant to enable FERC to launch investigations of manipulated rates charged by interstate pipeline companies. In 2009, FERC found three pipelines had earned rates of return of more than 20%, while the national average was only 12%. This disparity signaled to the FERC that manipulation was occurring. The FERC was able to initiate an investigation, instead of waiting and being reactionary, because of the new financial reporting standards. On a brighter note, natural gas infrastructure is burgeoning with gas pipelines adding 43.9 billion cubic feet per day in new projects (2008 numbers). These new additions are allowing unconventional gas supplies from the Rockies and new shale gas reservoirs to come to market.

5.5 LNG Imports

Liquefied natural gas (LNG) is a natural gas that has been converted to liquid form for ease of storage or transport. Wikipedia, “Liquefied Natural Gas.” LNG is natural gas cooled to minus 260 degrees Fahrenheit. In liquid form, natural gas may be shipped by tanker across thousands of miles of ocean. When an LNG tanker arrives at an LNG receiving terminal, its LNG cargo is regasified. The natural gas is then placed into pipelines for distribution consumers.

It is likely that more natural gas power plants will be built in the future? Technological improvements continue to make the construction of natural gas liquefaction plants and tankers much more efficient and less costly. Since 1990, costs of LNG shipments have decreased by as much as 30%. In light of these developments, LNG is becoming increasingly attractive to potential investors. And as the LNG market becomes more open and accessible, questions about the safety and regulation of LNG have become more pressing. In the early 2000s LNG imports
were seen as the solution to a growing gap in US future demand and supply for natural gas projected in all energy forecasts. It was projected that by 2020, the US would import 20% of natural gas by LNG shipments from Russia and the Middle East. But the shale oil boom of 2008 completely eliminated this concern. In 2013, the EIA projected that the United States could cut its dependence on natural gas imports entirely.

We next discuss how LNG markets and business models developed. Then we examine the onshore regulation of LNG by the Federal Energy Regulatory Commission (FERC), as well as the offshore regulation of LNG by the United States Maritime Administration (MARAD). See US Dept. of Transportation Maritime Administration. Finally, we provide an overview of the safety issues associated with LNG and its distribution.

### 5.5.1. Regulation of LNG Terminals

LNG’s development as a global fuel began with Japan’s efforts to reduce air pollution. In the United States, LNG imports were called on to bridge the gap between future demand and supply for natural gas projected by virtually all energy analysts. LNG is still considered a key supply source in the meeting of the demand for natural gas. FERC, “LNG.”

The early LNG trade developed using a business model called the “LNG paradigm.” Under this early paradigm, specific natural gas reserves in a host country were tied to long-term contracts. These contracts required that the host country’s natural gas be sent to capital intensive liquefaction plants. From there, the LNG would be placed in tankers that would then transport the LNG to receiving terminals. Long-term contracts were necessary under this “LNG paradigm.” Due to LNG’s enormous capital costs (roughly $3-10 billion per project), no one would invest in LNG supply facilities unless the demand for LNG was guaranteed.

**Onshore Regulation.** FERC is the lead federal agency for licensing and regulating onshore LNG terminals. See Natural Gas Act, 15 USC § 717B(e). FERC restructured the old “LNG
paradigm” and that model soon gave way to a more competitive, open access LNG network. Short-term contracts and spot LNG markets soon arose. The tension between the old “LNG paradigm” and the newer “LNG paradigm” resulted in a number of important policy questions:

- Should LNG receiving terminals be “open access” and available to any importer? Or should these terminals be considered “proprietary” and open only to those investors who built them?
- Should terminal rates be regulated by FERC under cost-of-service ratemaking or should FERC allow rates to be set by market forces?
- Should FERC guarantee profitability to those who invest billions in such terminals?

In the National Energy Act of 2005, Congress answered a few of those policy questions. The Act states that, until January 2015, FERC may not deny an LNG terminal application solely because the applicant chooses to use the terminal exclusively or partially for its own gas. Section 311 of the Act further prohibits FERC from regulating the “rates, charges, terms or conditions of service” of an LNG terminal.

These regulations were largely passed to expedite the importation of natural gas in the face of declining US natural gas reserves. However, the shale gas production boom has reversed the reasoning for additional LNG terminals. Instead of importing natural gas, US companies now want to export LNG to take advantage of the increased prices in the global market. In May 2013, two Japanese conglomerates and a big French energy player signed agreements to invest up to $7 billion in a liquefied natural gas project in Louisiana. The US Department of Energy has been reluctant to authorize a general export of natural gas. However, in September of 2013 the DOE approved Dominion Cove Point LP’s application to export LNG from its terminal in Calvert County, Maryland to countries that do not have a free-trade agreement with the US.

**Offshore Regulation.** Technology now allows for the construction of offshore terminals located in deep water beyond a state’s jurisdiction. These terminals re-gasify the LNG offshore and transport the gas to shore by pipeline. A division of the U.S. Department of Transportation, the Maritime Administration (MARAD), regulates these offshore LNG terminals. FERC has no jurisdiction over such terminals. See [The Marine Transportation Security Act of 2002, 46 USC 70101 et seq.](https://www.gpo.gov/fdsys/pkg/USCODE-2002-title46-part3/content-detail.html) Instead, MARAD and the Coast Guard are in charge of deepwater LNG ports.

Both FERC and MARAD’s major concern is to ensure that the country’s need for natural gas is met. To advance this end, the licensing process for LNG terminals has been streamlined and, to some degree, expedited.

On the other hand, state and local governments are often more concerned with the safety and environmental impacts of such offshore LNG terminals. Given these local concerns, state governments have been given some say in the construction of certain offshore LNG terminals. For example, the governor of any state adjacent to an LNG terminal has an absolute veto power over any application for a federal permit. See [33 USC § 1508.](https://www.gpo.gov/fdsys/pkg/USCODE-2015-title33-part2/content-detail.html) It has faced opposition from a
variety of sources including commercial and sport fishing interests and environmental groups. See *Gulf Restoration Network v. USDOT* 452 F.3d 362 (5th Cir. 2006).

### 5.5.2. Safety Issues

Natural gas is a potentially dangerous substance even when used in a standard fashion. When liquefied into LNG, the gas is concentrated at six hundred times its normal volume. This makes the LNG extremely volatile. While the LNG will not burn, if it is released into the air, mixed with oxygen at a certain ratio, and encountered by a spark, a disaster is almost sure to ensue. The resulting fire will emit so much heat and radiation that it will completely scour the area around it, melting plastic and burning skin.

These risks are well known to companies that deal with LNG. In general, these companies and other players in the LNG market have established international safety standards for all stages of the LNG process. As of the beginning of 2005, around 33,000 shipments of LNG by tanker have been made. In the course of those shipments, there has not been a single cargo explosion or fire.

In addition to shipping the LNG safely, the companies in the LNG market have also liquefied and regasified the natural gas in a relatively safe manner with one notable exception. In January 2004, a huge explosion occurred at a liquefaction plant in Skikda, Algeria. Unfortunately, the catastrophic nature of the explosion made it difficult to determine how the original leak occurred and why it was not immediately detected.

The intersection of LNG and terrorism is particularly interesting. The outbreaks of terrorism since 2000 have raised fears that LNG tankers and terminals are highly volatile, easily accessible targets. These concerns have resulted in the closure of an LNG terminal at least once. After 9/11, an import LNG terminal was closed near Boston Harbor. Dr. James A. Fay, an MIT scientist, argued that an accident on an LNG tanker headed for the terminal in Boston Harbor would result in catastrophic damage and the uncontrollable spread of fire throughout the area. James A. Fay, *Spills and Fires from LNG and Oil Tankers in Boston Harbor* (Cambridge, MA, Mar. 26, 2003).

Homeland Security adviser Richard A. Clarke was particularly concerned with LNG facilities located in urban areas. Discussing the costs and benefits of LNG imports in parts of New England, Clarke determined there would be no way to prevent a terrorist attack on an LNG tanker located in Narragansett Bay, Massachusetts. In a different May 2005 report, Clarke stated:

If...governments decide to proceed with the proposed urban location because of [a] cost differential, then the cost trade off can be precisely measured. Governments would be deciding that avoiding the possible financial cost to the LNG operator...is more important public policy than avoiding the additional risk
of a catastrophic attack. . .which does accompany a decision to permit an urban LNG facility.


While LNG companies have a near flawless safety record, in April 2014 an explosion at a LNG facility in Washington State injured five workers and sent shrapnel as heavy as 250 pounds flying over 300 yards. Everyone within a two-mile radius of the facility was evacuated. Fortunately the local responders were able to control the situation and no other damage was reported. This accident continues the debate over the safety of LGN centers, especially ones near large cities in the US.

5.6 Fracking

Hydraulic fracturing, referred to as “fracking,” is a method of natural gas production in which operators drill down vertically, and then drill horizontally along a productive strata of oil or gas. Fracking is accomplished by pumping fluid down a well at high pressure in order to force natural gas out. The expanded use of this technique by drillers in the United States over the past decade has drastically increased the estimated amount of recoverable natural gas deposits. In fact, it is now estimated that there is 2,384 million cubic feet of recoverable natural gas deposits in the United States, which is twice the amount estimated nine years ago when fracking was not being widely utilized Natural Gas Resources Seen at Record in U.S. on Fracking.

The practice of fracking allows gas producers to expand their ability to recover natural gas from underground shale deposits. Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays at pg. 4. The United States is home to large tracks of underground shale. The map below illustrates where the shale deposits are located in the United States:

![Map of U.S. shale gas and shale oil plays](image-url)
These shale deposits represent a tremendous resource, which over the past few years have started to be tapped. As a result, U.S. production of natural gas has increased significantly. Since 2005, the amount of natural gas production from within U.S. territory has increased 19.5 billion cubic feet of gas to 25.6 billion in 2013. U.S. Natural Gas Production. As the law of supply and demand suggest, this increase in production has led to significant decreases in natural gas prices. Current natural gas prices are at around $4 per thousand cubic feet, which represents a price level that when taken in context with historical prices, is relatively low Natural Gas Prices.

5.6.1 Production gains from fracking

Fracking allows producers to extract substantial amounts of natural gas because the technique allows for exploitation of shale resources that extend horizontally from the wellhead. This allows drillers to access a greater portion of natural gas deposits than would be available to traditional operations. The diagram below provides a pictorial explanation of this process (note the horizontal direction of the drill within the gas-rich shale).

![Fracking Diagram](image)

5.6.2 Fracking and common law

Since the horizontal portion of the well may extend for more than a mile, the issue of trespass again arises. In Coastal Oil and Gas Corp. v. Garza Energy Trust, the Texas Supreme Court ruled that the rule of capture applied in this setting as well, when it reversed and remanded a jury award for $1 million to the Salinas family when Coastal extended its fracking operation into property owned by the Salinas, thus depriving them of their royalties.

Rejecting the Salinas’ argument that the rule of capture does not apply to fracking because it is unnatural, the court reasoned that fracking is no more unnatural than drilling wells, and that the “law affords…ample relief” because Salinas could use hydraulic fracturing to stimulate production of his own wells and drain the gas to his own property. The court listed
four reasons for not altering the rule of capture with respect to fracking: 1) the law affords the owner full recourse in the form of allowing an owner to drill a well to offset the drainage from his property, 2) allowing recovery in these situations would usurp the authority of the Railroad Commission to regulate oil and gas production, 3) the litigation process is not equipped to handle determining the value of oil and gas drained by fracking, and 4) no one in the oil and gas industry wants or needs the rule of capture to be changed.

5.6.3 Regulatory framework govern fracking

As with conventional oil and gas extraction, hydraulic fracturing is governed primarily by state level regulators, except in the case where such operations take place on federally controlled lands. Therefore, individual states enjoy a relatively high amount of flexibility in creating a regulatory regime that governs unconventional gas extraction. See California Fracking Regulations, Illinois Issues Long-Awaited Fracking Rules. The figure below illustrates the wide variety in how states have decided to regulate the disclosure of chemicals used in fracking.

On federal lands, the Department of Interior (DOI) is responsible for regulating fracking operations. In May 2013, the DOI proposed a new set of rules to regulate fracking on federal and Indian lands. These proposed rules require drillers to, among other things, disclose the chemicals that are used in the fracking process DOI Fracking Rules. The DOI proposal was met with resistance from industry group, who feel the new regulations are an unnecessary burden, and environmental groups, who feel that the rules do not go far enough, especially in protecting groundwater from such chemicals Reaction to DOI Fracking Rules. In response, the House passed a bill in November 2013 that would prohibit Interior Department rules in states that
already regulate the process. The Obama administration has stated that it plans to unveil the final rules in September 2014.

5.6.4 Future of fracking

What does the future hold? The use of fracking and the subsequent increase in U.S. natural gas production will likely continue into the foreseeable future. However, whether this increased level of production will continue to result in depressed natural gas price, as in the recent past, is not certain. The EIA estimates that although production will remain high, the cost of developing new incremental production will likely increase, resulting in upward pressure on prices as drillers pass through these increased costs to consumers EIA Annual Energy Outlook 2013 at 76.

Because the price of energy inputs has a significant impact on end-user consumption patterns, this projected price increase could have significant impact on the industrial, commercial and residential and electric power sectors of the economy. Time will tell how the fracking story plays out.