Chapter 2

Coal

Coal fueled the Industrial Revolution and continues to be the principal energy source for power generation throughout the world, including the United States.

This chapter first examines the history of coal in the United States and its continued use as a fuel for power production. The chapter then looks at the four steps coal takes in its journey from mining, processing and transportation to combustion – and the legal regimes that apply along the way.

According to the energy “input/output” chart (below), coal constituted about 20% of total U.S. primary energy in 2013 – down from 22% in 2012. Coal is devoted almost entirely to power production.

Chapter collaborators:
Brian Dorwin (WF ’13)
Bethany Corbin (WF ’14)
William Hester (WF ‘13)
Andy Rinehart (WF ‘13)
Lea Ko (WF ‘13)
Marc Rigsby (WF ‘12)
Tim Stewart (WF ‘12)
Danielle Stone (WF ’12)

In this chapter, you will learn about:

- The historical role of coal in the Industrial Revolution and its continuing use as an energy source

- The different methods of coal mining and specifically how and where they have developed in the United States
  - The regulation of underground mining, given the safety, environmental and health dangers associated with such mining
  - The regulation of (and litigation concerning) surface mining and mountaintop removal, given the ecological risks of these extraction methods
  - The nature of mineral rights in the United States, specifically as they relate to coal mining

- The nature and regulation of coal transportation, particularly by train from western mines to eastern market

- The regulation of coal as a fuel in power generations
  - Regulation under the Clean Air Act of “new sources” of air pollution and the grandfathering of older power plants
  - The Clean Air Act regulations that deal with specific pollutants caused by coal combustion – including sulfur dioxide, nitrogen oxides and mercury

- The concept of “clean coal” and how environmental, safety, and fuel shortage concerns shape the future of coal
# Chapter 2 – Coal

## 2.1 Coal in Perspective
- 2.1.1 What is Coal?
- 2.1.2 Coal in the World

## 2.2 Coal in America
- 2.2.1 Sources
- 2.2.2 Extraction Methods
- 2.2.3 Coal Markets
- 2.2.4 Mineral Rights

## 2.3 Coal Mining
- 2.3.1 Underground Mining
- 2.3.2 Surface Mining

## 2.4 Coal Transportation
- 2.4.1 Coal Transportation by Rail
- 2.4.2 Coal Transportation by Pipeline

## 2.5 Coal Combustion
- 2.5.1 Clean Air Act – Regulation of “New Sources”
- 2.5.2 Regulation of Specific Pollutants

## 2.6 Future of Coal
- 2.6.1 Coal Usage Trends
- 2.6.2 Carbon Capture Storage

**Sources:**
- U.S. Department of Energy, Energy Information Agency [website]
2.1 Coal in Perspective

2.1.1 What is Coal?

Coal is a non-renewable resource (EIA, “Nonrenewables”) composed of combustible sedimentary rock containing carbon and hydrocarbons. EIA, “Coal”. Formed under intense heat and pressure, coal represents the “altered remains of prehistoric vegetation.” World Coal Organization, “What is Coal?”. In other words, the energy released from coal today was actually energy from the sun that was absorbed by plants millions of years ago.

Beginning with the Carboniferous Period (sometimes called the first coal age), which spanned 360 to 290 million years ago, tectonic movements buried swamps and bogs. As this movement occurred, plants became trapped within the earth and subjected to high temperatures and pressure. The pressure and heat caused chemical changes in the vegetation and disrupted the plants natural decay process. As a result, solar energy was never released from these plants, but was instead transformed into coal, a highly combustible, non-renewable resource.

HOW COAL WAS FORMED

![Diagram showing how coal was formed](https://example.com/coalFormationDiagram.png)

2.1.2 Coal in the World

Coal is plentiful around the world. Here is a chart showing proven energy reserves around the world, with a comparison to other energy reserves:
2.2 Coal in America

The importance of coal in American history cannot be understated. During the Industrial Revolution, coal provided a concentrated form of energy, which the steam engine then converted into movement. In the mid-19th Century coal replaced wood as the primary source of energy in the United States. Over time, the location of accessible coal reserves in the United States has shifted, as well as the methods used to extract coal and the markets in which coal is ultimately used. This section describes these changes.

2.2.1 Sources

Coal represents the largest domestically produced source of energy in the United States, and generates nearly half of the nation’s electricity. EIA, “Energy in Brief”. As of 2013, coal constituted 20% of the U.S. primary energy flow. EIA, Primary Energy Production by Source.
Historically, coal was found mostly in the Appalachian Mountains, particularly in Pennsylvania and West Virginia. As the nation developed, coal mines opened in the Midwestern and Rocky Mountain areas of the United States. Today, there are around 500 billion tons of readily extractable coal in the United States, approximately half of which is located in the Rocky Mountain area.

**Different categories of coal.** Coal’s wide geographical spread also means that not all coal is created equal. Four principal categories of coal exist, with each category differing in the mercury, sulfur, and heat energy content contained within the coal. EIA, “Energy in Brief”.

**Anthracite**, the first category of coal, is mined primarily in northeastern Pennsylvania and contains the highest carbon content at approximately 86-97%. Despite its high carbon content, anthracite accounts for less than 0.5% of all coal mined in the United States. EIA, “Energy Explained”.

**Bituminous**, the second category, contains 45-86% carbon and was formed between 100 and 300 million years ago. Bituminous is the most abundant coal in the United States, with West Virginia, Kentucky, and Pennsylvania the largest producers.

**Subbituminous**, the third category, is at least 100 million years old and contains only 35-45% carbon. Wyoming leads production of this coal.

**Lignite**, the final category, is a relatively young form of coal and has not been subjected to the extreme heat and pressure typically required for coal formation. As such, lignite contains only 25-35% carbon and represents 7% of U.S. coal. Lignite is found mainly in Texas and North Dakota. The chart below shows the shifts in coal mining industry regarding the different types of coal mined over the past sixty years in the United States.
What is the importance of these differences in coal? Coal in the eastern United States has high heat and high sulfur contents, meaning that this coal produces more heat but releases high volumes of sulfur dioxide during combustion. In contrast, coal in the western United States has lower heat and sulfur contents, meaning this coal does not release as much sulfur dioxide when burned, but must increase the quantity burned to produce the same amount of energy. These regional differences in coal production have had a significant political impact in the United States. For example, eastern Congressional representatives tend to support requirements for the installation of power plant scrubbers, which allows plants to continue to burn high-sulfur coal, while western Congressional representatives tend to support laws that promote shipment of low-sulfur Western coal to power plants in the East and Midwest.

Even as annual U.S. coal production has been on the rise—from 890 million tons in 1986 to 1.094 million tons in 2011—the number of coal mines has decreased. EIA, Annual Energy Review (2011). For example, in the span of one year, from 2009 to 2010, the total number of mines in the United States decreased from 1,407 to 1,285. EIA, Annual Coal Report (2010).

The future of coal to generate electricity, however, is uncertain. There has been slow growth in electricity demand, and proposed regulations make new coal powerplants infeasible. In addition,
more renewable technologies and price competition from natural gas suggest coal’s heyday is over. For example, coal’s share of US power generation has declined significantly in the last few years, from nearly 50% in 2007 to 39% in 2013, as many power producers have switched to lower-priced natural gas. EIA, “Energy in Brief: What is role of coal in United States?”

### 2.2.2 Extraction Methods

Historically, underground mining in the eastern United States was the primary method for extracting coal, but today over half of the coal mined in the United States is obtained by surface mining (aka strip mining), mostly in the western United States. EIA, “Energy Explained”. The choice between mining methods is determined principally by the geology of the coal deposit. As its name suggests, surface coal mining can only be used when the coal seam is near the surface, less than 200 feet underground. All coal deposited more than 200 feet below the ground must be extracted through underground mining techniques. These two mining processes, along with their pros and cons, are discussed next.

**Underground mining.** This type of mining involves the digging of shafts and tunnels into the ground to reach buried coal. A mineshaft is drilled down to the coal seam, and tunnels are excavated through the seam. The following diagram illustrates this process:

![Diagram of underground mining](photo.png)

Although the above diagram describes a generalized version of underground mining, two specific types of underground mining techniques have emerged. The first -- room and pillar mining -- involves cutting a network of rooms into the coal. Miners then extract the available coal but leave the pillars intact to support the mine roof. The result of this technique is that only 60% of all available coal within that mine can be extracted. EIA, “Coal Mining”. In contrast, longwall mining employs mechanical shearsers and hydraulically-powered supports to hold up the
mining area while coal is extracted. Once extraction is complete, the pillars collapse. This procedure enables miners to obtain 75% of the available coal.

**Surface mining.** In contrast to underground mining, surface mining involves the removal or stripping of land surfaces – including vegetation, dirt, or even layers of bedrock – to reach buried coal. Surface mining produces most of the coal in the United States because it is less expensive than underground mining. EIA, “Coal Explained.” Additionally, surface coal mining permits recovery of 90% of the available coal. World Coal. Therefore, within the past forty years there has been a dramatic shift in the United States away from underground mining.

While surface mining does not require underground digging below 200 feet, the process nonetheless remains complex. The overburden of soil (essentially the top layer) must first be broken up by explosives, and then removed by shovels and trucks. Only then is the coal exposed. Once exposed, the coal must be drilled, fractured, and mined in strips. The diagram below offers a comparison of underground and surface mining:
Mountaintop removal. In addition to underground and traditional surface mining, a third process for extraction exists: mountaintop removal. Mountaintop removal is a type of surface coal mining in which soil and rock upon a mountain are blasted away to expose buried coal. The picture below illustrates the impact of mountaintop removal.

The illustration below shows coal basins in the Northern Rockies region. The Powder River Basin is labeled number 2:

![Coal basins in the Northern Rockies region](https://example.com/coal-basins.png)

Photo - [Paleontological Research Institution](https://www.example.com/paleo-research).

This chart shows the dramatic shift that the Black Thunder Mine has had in shifting coal mining away from the east coast:

![Coal mining chart](https://example.com/coal-chart.png)
2.2.3 Markets

Historically, coal was primarily consumed by the iron and steel industries in the form of coke. Coke, made by heating coal in a high temperature oven without contact with the air until all impurities evaporated, was then used in smelting iron ore to create steel.

Today, coal is used to create almost half of all electricity generated in the United States, with about 92% of the coal consumed in the U.S. used in electricity generation. EIA, “Coal Explained.” Although coal production has shifted to the West, the East (from Pennsylvania to Missouri) remains the heaviest user of coal.

One reason for this shift to western production is the discovery of low-sulfur coal in the Northern Great Plains states of Wyoming, Montana, and North Dakota. Low-sulfur coal has assumed increasing importance in light of the more stringent air pollution regulations adopted by the EPA. Thus, coal from the western United States (despite the transportation costs) is a more cost-effective choice than coal from the eastern United States.

Coal exports. Although coal is primarily consumed within its country of origin, there exists a significant international market in coal, with 15% of coal used globally coming from imports. World Coal Organization, “Coal Mining”. The United States has been a net exporter of coal. During the 20th Century, U.S. coal was exported in significant amounts to other countries, but export levels declined between 2000 and 2012, with the United States exporting only 5% of its coal production. EIA, “Energy in Brief”.

Lately, though, U.S. coal exports have been on the rise. In 2013, the United States exported 12% of its coal production, the highest in two decades. EIA, “Energy in Brief”. The destination of US coal exports has varied. In 2011, a significant proportion went to Australia, because of flooding that limited that country’s coal production. In 2013, most US coal exports went to Brazil. The sustained demand for high-quality coal in developing countries, with domestic coal consumption falling, has led to an increase in US coal exports. EIA, “Energy in Brief”; EIA, “Coal Exports.”

The following graph details U.S. coal exports and imports between 2005 and 2012.
Of the coal exported from the United States, approximately 76% entered the European and Asian markets in 2011. EIA, “Coal Exports”. European markets have historically received a significant portion of U.S. coal exports, but exports to Asia have increased since 2009 due to increases in sales to South Korea, India, and China. Within Europe, the Netherlands typically purchases the most coal exported from the United States -- receiving 11 million short tons in 2011, compared to 7 million short tons exported to the United Kingdom. EIA, “Coal Exports”. In Asia, South Korea dominates imports from the U.S., receiving 10 million short tons of coal in 2011.

What is the market price of coal? The market price for coal, as one would expect, varies significantly based on the type of coal. For example, in 2010, the average sale price of lignite coal was $18.76 per ton, while the average price of bituminous was $60.88 per ton. EIA, “Coal Prices”. Additionally, a spot purchase for a single shipment of fuel costs on average $2.41 more than the coal purchased by power plants. Moreover, surface-mined coal typically fetches a lower price than underground-mined coal due to the simpler technology and reduced risks to human life and health. Finally, coal used to make coke must be low in sulfur, and therefore is priced higher. In 2010, the average price of coal used for coke was $153.59.

### 2.2.4 Mineral Rights

In the United States, mineral rights constitute an estate in real property. Wikipedia, “Mineral Rights.” Thus, owners of mineral rights hold a legal interest in the property. In general, mineral rights give the owner the right to exploit, mine, and/or produce any or all of the underlying minerals below the surface of the property.

Mineral rights are severable from surface rights, and the surface owner may sell or lease these rights to another party. Coal mining companies typically obtain only mineral rights, not surface rights, from landowners because the companies do not want responsibility for surface uses, and mineral rights can be obtained at a lower price than buying or leasing the property as a whole.

Does owning mineral rights include the right to surface mine? As the prevalence of surface coal mining increases, an interesting question arises whether a coal company that holds mineral rights also possesses the right to mine the surface for coal. Although underground coal mining companies were often given broad authority to use the surface “to the extent necessary,” several courts have limited the scope of this authority in regards to surface mining. See, e.g., *Smith v. Moore*, 474 P.2d 794 (Colo. 1970); *Benton v. U.S. Manganese Corp.*, 313 S.W.2d 839 (Ark. 1958); and *Campbell v. Campbell*, 199 S.W.2d 931 (Tenn. App. 1946). These courts noted that if the original instrument did not expressly describe the extraction methods to be used, then coal companies were limited to using the extraction methods commonly in use at the time the mineral rights instrument was executed.
For example, the Supreme Court of Virginia held that the deed under which appellants were permitted to mine coal did not give appellants the right to use surface mining methods. *Phipps v. Leftwich*, 222 S.E.2d 536 (Va. 1976). The court reasoned that the owner of mineral rights should not be permitted to destroy the surface and interfere with the surface owner’s rights unless the owner of the surface estate clearly waived his rights to the land. The effect in the Eastern United States of cases like *Phipps v. Leftwich* has been to diminish surface mining, which became prevalent only in the 1950s. Courts have made clear that disputes between surface and mineral owners places a heavy burden on the mineral owner to prove that the deed intended to convey surface mining rights along with mineral rights. See also *Ward v. Harding*, 860 S.W.2d 280 (Ky. 1993) (*‘neither fair nor just to permit surface mining contrary to the wishes of the surface owner and beyond the contemplation of the original parties*).

What is the legal arrangement between surface owners and the holders of mineral rights? Today, the mining company leases mineral rights from the surface owner for a modest cash rental, plus a significant percentage of the extracted minerals—known as a “royalty interest.” In addition, the lease details the parties’ obligations concerning (1) the mineral owner’s right to use the surface for related uses, such as mine openings and roads, (2) the mine operator’s liability for land subsidence, (3) the mineral rights owner’s obligation to explore and develop mineral rights within a particular time. Complications arise, however, when the mineral rights owner, who is not the surface rights owner, leases its rights to a mining company. In this situation, the mining company often must obtain permission both from the mineral rights owner and the surface rights owner to operate machinery on the property.

### 2.3 Coal Mining

Coal mining is labor-intensive and heavily regulated because of its safety concerns, environmental risks, and health dangers. The two methods of coal extraction—underground mining and surface mining—present different externalities and thus regulatory challenges.

#### 2.3.1 Underground Mining

In underground mining, shafts and tunnels extend below the surface from a minehead. While underground mining does not present the same environmental land concerns as surface mining, it presents its own risks and problems. These risks include the health and safety of mineworkers in underground mines, subsidence of the ground above these mines, and acid drainage from underground mine refuse.

**Health and safety risks.** Working in underground mines presents unique and often dangerous health and safety concerns.

Black lung disease, caused by extended exposure to coal dust, has plagued underground miners. Black lung is a fatal disease that causes a progressive loss of lung capacity. When inhaled, the coal dust builds in the lungs and cannot be removed by the body. As a result, the lungs become inflamed, leading to fibrosis and necrosis. Although during the past 30 years stricter mine safety
laws have decreased the prevalence of black lung disease, it is again on the rise as of 2011. Huffington Post, “Black Lung Disease on the Rise Again.”

Methane gas in underground mines is potentially explosive and can cause asphyxiation. Many deadly underground mine explosions have been caused by improper ventilation of methane gas. For example, in April 2010 twenty-nine miners died and two were injured in a blast at the Upper Big Branch mine in West Virginia. See The New York Times, “No Survivors Found After West Virginia Mine Disaster.”

Another safety risk to underground miners is the danger of mineshift collapse. For example, in October 2011 two miners died and several were injured after tons of rock fell from a high-wall collapse at the Equality Boot Mine in Kentucky See 14 News, “Two miners dead after wall collapse in Ohio County.”

It is important to note that many of the health issues raised by underground mining are not raised by surface mining, which now accounts for more than 60% of US coal mining. Strip mining, which involves the use of huge shovels the size of a multistory buildings, is less labor-intensive and does not create the same health and safety issues for mine workers – and the mine industry -- as underground mining.

**Legal protections for miners.** What legal protections are there for miners? It was not until the 1960s that public attention focused on the hazards of coal mining and the need for federal regulation. In response to the hazards associated with coal mining, Congress passed both the Federal Coal Mine Health and Safety Act of 1969 and the Black Lung Benefits Act of 1972. The 1969 Coal Act requires multiple annual safety inspections of every coal mine, and imposes monetary, civil, and criminal penalties for violations. As a result of the Coal Act, black lung disease decreased by 90%. The 1972 Black Lung Benefits Act requires coal companies to pay lifetime benefits to miners and their families who have contracted the disease. This Act was wide reaching and also required companies to pay benefits even to the miners who had contracted the disease but had left the company prior to the act. See Usery v. Turner Elkhorn Mining Co., 428 U.S. 1 (1976) (upholding retroactive application of Act). In addition, many of the union contracts negotiated between mining companies and the United Mine Workers included provisions for lifetime health benefits and company obligations to pay into a benefit fund for miners.

In addition, to protect the health and safety of miners, Congress in 1978 established the Mine Safety and Health Administration (MSHA), located within the Department of Labor. The Federal Mine Safety and Health Act of 1977 (MINE Act), which consolidated all federal health and safety regulations of the mining industry under a single statutory scheme, governs all MSHA activities. The MINE Act provides mandatory safety and health standards and also strengthened and enhanced the rights of miners. In 2006, Congress passed the Mine Improvement and New Emergency Response Act (MINER Act), which amended the MINE Act by requiring minespecific emergency response plans in underground coalmines, among other things. See U.S. Dept. of Labor, MSHA, “History of Mine Safety and Health Legislation”.

**Retroactivity of mining company duties.** Because black lung disease and other work-related illnesses manifest themselves long after the miner stops working, attributing the injury to a
particular employer has been a problem, especially with mining companies going out of business. In 1992 Congress passed The Coal Industry Retiree Health Benefit Act of 1992, to require mining companies to pay lifetime medical benefits to miners. Under the Act, coal mining companies were made retroactively liable for these health benefits if they had been in the coal business after the “general understanding” between the industry and the United Mine Workers that lifetime health benefits would be paid.

This retroactivity was challenged by Eastern Enterprises, a company that had gotten out of the coal business in 1966, but found itself responsible for the medical costs of retired miners under the 1992 law. In 1998, the case reached the Supreme Court, which held the Act unconstitutional as applied to Eastern. Eastern Enterprises v. Apfel, 524 U.S. 498 (1998). The Court considered three constitutional theories: the Ex Post Facto Clause (which generally is limited to criminal statutes); the Due Process Clause (which includes the once-popular “substantive due process” requirement that laws be fair); and the Takings Clause (which commonly applies to laws that burden real property). Four justices found that the Act constituted a taking of property without just compensation. One justice, Justice Kennedy, found that there was no taking, but concluded the Act violated substantive due process as applied to Eastern Enterprises. Four dissenters would have upheld the Act as neither a taking nor unfair under substantive due process.

Therefore, Eastern Enterprises invalidated part of a statute but without a consistent rationale. Was the Act valid as to companies that had undertaken contractually to pay into a health-benefits fund, but then terminated those payments as permitted under their contracts? In Unity Real Estate Co. v. Hudson, 178 F.3d 649 (3d Cir. 1999), the court found coal mine operators liable under the Act that had signed coal benefit agreements in 1978, reflecting their reasonable expectation that they would pay for miners' lifetime health benefits. Thus, the court held them retroactively liable under the Act even though the companies' contractual obligations to make health benefit payments had terminated. The Act, in effect, closed "the gap between the contracts and the needs of the benefit funds." Further, given the extensive government regulation of the coal industry, the court concluded it was not fundamentally unfair for Congress to make the former coal companies (which in 1978 had assumed contractual responsibility for paying into a benefit fund) responsible for paying these benefits, even if they were no longer contractually obligated to do so. In the words of the court, the companies' "recourse must be to Congress rather than to the courts."

Since the Unity decision, no plaintiff has shown a taking or substantive unfairness. See, e.g., A.T. Massey Coal Co., Inc. v. Massanari, 305 F.3d 226 (4th Cir.2002). Perhaps this understandable. The 1992 Coal Act does not involve the acquisition of property by the government, but instead requires coal companies to pay money directly into a fund for coal miners. Thus, rather than a taking the question is fairness under the Due Process Clause.
See John V. Orth, Taking from A and Giving to B: Substantive Due Process and the Case of the Shifting Paradigm, 14 Constitutional Commentary 337 (1997).

**Subsidence.** Underground coal mining not only poses dangers to miners, but also to surrounding landowners. Subsidence has challenged the courts, which are forced to balance economic development and fair compensation for those whose land is damaged by coal mining.

Subsidence is the lowering of strata (including land surface) above a coal mine caused by the extraction of underground coal. Subsidence is an inevitable (and not well understood) consequence of underground mining. Subsidence can cause damage to foundations and structural components of houses, buildings and roads. It can also create sinkholes and troughs, which may make land difficult or impossible to develop or farm, and loss of groundwater or surface ponds.

Regulation of mining subsidence, like regulation of damming of waterways, has faced constitutional challenges. In 1922, the Supreme Court struck down a Pennsylvania statute that prohibited coal companies from mining in a way that caused subsidence. *Pennsylvania Coal Co. v. Mahon*, 260 U.S. 393 (1922). It was the first time in American history that the Court held that a regulation could be tantamount to a constitutional taking. Justice Holmes, writing for the majority, justified the conclusion that the state regulation constituted an uncompensated taking by balancing the public interest, which in his view was limited and largely private, with the extent of the taking, which was great because it made commercial mining virtually impossible.

The *Pennsylvania Coal* case, however, has been limited. In 1987, the Supreme Court upheld a similar Pennsylvania anti-subsidence statute. *Keystone Bituminous Coal Ass’n v. DeBenedictis*, 480 U.S. 470 (1987). The Court distinguished the newer statute from the one struck down in *Pennsylvania Coal* on the ground that the newer statute was limited to preventing subsidence to roads, schools, and other public facilities. Therefore, according to the Court, the public interest was public safety, and the extent of the taking was limited and did not make it “impossible for [coal companies] to profitably engage in their business.” Therefore, unlike the *Pennsylvania Coal* case, this statute did not merely attempt to restrict the economic interests of coal companies to the benefit of private surface owners. It only held that important public interests are served by enforcing a policy that is designed to minimize subsidence in certain areas.

After *Keystone* does denial of a mining permit constitute a taking? Most lower courts have said no, holding that companies denied a permit because of risks to public safety (potential cracking of the ground, collapsing structures, and breaks in underground utility lines) are not deprived of beneficial use of the “owner’s estate.” Given the companies’ “prescribed use interests were not part of the title to begin with,” the permit denials took away nothing the companies already had. *M&J Coal Co. v. United States*, 47 F.3d 1148 (Fed. Cir. 1995). Thus, this seems to reinforce the notion that so long as the permit denial did not eliminate all benefit to the coal company, then it did not constitute a taking. But see *Machipongo Land and Coal Company, Inc. v. Commonwealth*, 719 A.2d 19 (Pa. Comm. Ct. 1998) (discussing various theories for measuring the extent to which the regulation diminishes the company’s interest) and *Eastern Minerals International, Inc. v. United States*, 36 Fed. Cl. 541 (1996) (holding that an inexcusable delay in issuing a mining permit may constitute a taking).
In 1992 Congress attempted to clarify the legal rights and duties related to subsidence by passing the Energy Policy Act of 1992, which added anti-subsidence provisions to the Federal Surface Mining Control and Reclamation Act (SMCRA), 30 U.S.C. § 1309A. New SMCRA § 720 requires underground mines operating after October 24, 1992 to:

1. Promptly repair, or compensate for, material damage resulting from subsidence caused to any occupied residential dwelling and structures related thereto, or non-commercial building due to underground coal mining operations; and
2. Promptly replace any drinking, domestic, or residential water supply from a well or spring in existence prior to the application for a surface coal mining and reclamation permit, which has been affected by contamination, diminution, or interruption resulting from underground coal mining operations.

In addition, mining companies must attempt to mitigate the damage caused by subsidence. According to the rules promulgated under the SMCRA, mines “must either adopt measures consistent with known technology that prevent subsidence from causing material damage to the extent technologically and economically feasible, maximize mine stability, and maintain the value and reasonably foreseeable use of surface lands or adopt mining technology that provides for planned subsidence in a predictable and controlled manner.” 30 CFR § 817.121.

The SMCRA regulations were challenged by the National Mining Association (NMA). National Mining Ass’n v. Babbitt (D.C. Cir. 1999). The NMA argued that the Energy Policy Act’s “repair or compensate” requirement (that mining permittees promptly repair or compensate for material damages caused by subsidence) was unreasonable. Mine operators often purchased pre-subsidence waivers of rights from potentially affected landowners, and the NMA contended that allowing landowners to benefit from both pre-subsidence agreements and the post-mining damages constituted double compensation. The D.C. Circuit rejected these arguments. The court pointed out that, under the government’s interpretation of the regulations, the cost of the waiver would be subtracted from the post-mining damage amount. It upheld the regulations as a valid exercise of regulatory power because “legislation [that] disregards or destroys existing contractual rights does not always transform the regulation into an illegal taking.” Thus, coal companies are now responsible for most damage caused by subsidence – perhaps making the Pennsylvania Coal case appear to be obsolete.

**Acid mine drainage.** Acid mine drainage (affectionately known as AMD) occurs when surface and shallow subsurface waters react with rocks that contain sulfur-bearing minerals. This reaction creates highly acidic water that can also leach heavy metals from rocks. The resulting fluids are often toxic and can have detrimental effects on humans, fish, and wildlife. Due to the acidity and metal content of AMD, affected waters are often unsuitable for human consumption and recreation. [EPA: “Acid Mine Drainage”](https://www.epa.gov/waterscience/acid-mine-drainage).

Under the Clean Water Act (CWA) the discharge of any pollutant into navigable waters by any person is unlawful, except when in compliance with the statute. 30 U.S.C. § 1311. “Discharge of a pollutant” is defined as the addition of a pollutant to “navigable waters” from a point source, which is defined broadly to include pipes and tunnels. 33 USC § 1362. Thus, introducing any
pollutant into US waters from almost any source will constitute the “discharge of a pollutant” under the CWA. Nonetheless, as respects coal mining, the CWA defines a “pollutant” not to include fluids used to facilitate production from oil or gas wells, which (supposedly) are covered under other statutes.

In 1992, the Fourth Circuit applied the CWA to acid mine drainage from a West Virginia mine, upholding the convictions of Lewis R. Law and Mine Management, Inc. (MMI) for violations of the CWA. \textit{United States v. Law} (4th Cir. 1992). Law, the sole owner and stockholder of MMI, had purchased 241 acres from New River Company, which included “gob piles” (masses of coal refuse) and a water treatment system designed to reduce the acidity and metal content of the drainage from the gob pile. When MMI purchased the property, this water treatment system was required to have a National Pollution Discharge Elimination System (NDPES) permit. However, despite notice of the need to apply, Law and MMI did not re-apply for or receive an NDPES permit for the water treatment system. On at least 16 occasions over a four-year period, MMI’s mining operation resulted in acid mine drainage into two creeks. A jury convicted Law and MMI for violating the CWA. On appeal, they argued that the pollutants were preexisting in the waters of the United States and they merely diverted the flow of the water. The Fourth Circuit rejected this argument and stated that the runoff and leachate collected in the water treatment system were not part of the “waters of the United States” and that the treatment system was a “point source,” as defined by the CWA.

\textbf{2.3.2 Surface Mining}

In contrast to the safety and health concerns associated with underground mining, debates over surface mining tend to revolve around the potential environmental damage created by the excavation activity. Surface mining regulation targets reclamation as its overarching goal in an effort to control and lessen its environmental effects. Below is an image of the effect of surface mining in the Powder River Basin in Wyoming.

![Photo - Plains Justice Today](image_url)

\textbf{SMCRA}. Under the \textit{Surface Mining Control and Reclamation Act of 1977} (SMCRA), mining companies engaged in surface mining are required to perform a variety of tasks: restore the soil,
re-contour the surface, revegetate the site, and so on. The amount of restoration a company is obligated to perform varies according to the original condition of the land. For instance, land suitable for farming prior to the mining must be returned to a like condition afterward.

Congress passed SMCRA to “establish a nationwide program to protect society and the environment from the adverse effects of surface coal mining operations” and to “assure that the coal supply essential to the Nation’s energy requirements… is provided.” 30 USC § 1202(a), (f). Thus, the SMCRA aims to “strike a balance between protection of the environment… and the Nation’s need for coal as an essential source of energy.” 30 USC § 1202(f).

The coal industry initially challenged the SMCRA as an abuse of federal power under the Commerce Clause, and district courts in Indiana and Virginia initially held the statute invalid. In Indiana v. Andrus, 501 F.Supp. 452 (1980), the court held (1) that the sections of SMCRA designed to protect prime farmland are directed at facets of surface coal mining with no substantial and adverse effects on interstate commerce; (2) that the prime farmland provisions are not related to the removal of air and water pollution and are, therefore, not reasonably and plainly adapted to the legitimate end of removing any substantial adverse effect on interstate commerce; and (3) that all of these sections are not within powers delegated to Congress and contrary to the Tenth Amendment to the Constitution.

On appeal, the Supreme Court reversed and upheld the validity of the statute. Hodel v. Virginia Surface Mining & Reclamation Ass’n, Inc., 452 U.S. 264 (1981), and Hodel v. Indiana, 452 U.S. 314 (1981). The Supreme Court held that Congress was “concerned about preserving the productive capacity of mined lands and protecting the public from health and safety hazards that may result from surface coal mining. All the provisions invalidated by the court below are reasonably calculated to further these legitimate goals.” Therefore, it did not exceed federal power under the Commerce Clause. The Court also rejected that statute was invalid under the Tenth Amendment, concluding that the statute only regulates private individuals and businesses, and the district court’s conclusion that the statute directly regulates the States is “untenable.”

Who enforces the SMCRA? The regulatory scheme laid out in the SMCRA assume cooperation between the federal and state governments to control surface mining, with the federal role administered by the Office of Surface Mining (OSM) in the Department of the Interior (DOI). Once a state obtains permission from the Secretary of the Interior to enforce SMCRA compliance, the OSM takes on an oversight role with limited authority. Modification of state SMCRA programs requires federal approval.

To enforce the SMCRA, mine operators must post a bond calculated to meet their reclamation obligations. 30 USC § 1259(a). The bond secures funding for reclamation and ensures that the regulation’s environmental goals will be met even in the event that the mining company goes insolvent. Once the company completes the reclamation work and the government inspects it, the bond is released and the company is no longer subject to SMCRA jurisdiction.

SMCRA also provides for inspection of and enforcement against permitted mines. SMCRA requires that at least one full, on-site inspection be performed each quarter and one partial
inspection be performed, without prior notice, each month. The penalties for violations vary depending on their severity. In the case of a violation that poses an imminent danger to the public or a significant, imminent threat to the environment, inspectors (both OSM and state authorized inspectors) have the legal authority to force the mine to shut down immediately. In the case of violations that do not pose imminent danger to either humans or the environment, the inspector must issue a Notice of Violation (NOV). Should the mine operator fail to abate the violation within the time proscribed by the inspector, the inspector is required to issue a Cessation Order (CO) and impose affirmative actions in order to ameliorate the violations. 30 U.S.C. §1271.

Citizens can also request SCMRA inspections, either orally or in writing, if they have reason to believe such an inspection is necessary. Upon receipt of such a request, the regulating agency must perform an inspection (unless it has reason to believe that the information supplied was false) and report whether or not any enforcement action has been taken. If the agency refuses to perform an inspection, the citizen can request that the head of the agency review the decision. 30 C.F.R. § 842.15. Citizens affected by SMCRA noncompliance can also bring suit against violators and recover damages. Citizens need not have economic interests to bring suit since SMCRA recognizes aesthetic and recreational interests, as well.

**Termination of SMCRA jurisdiction.** SMCRA outlines a number of steps that mine operators must take upon termination of a mining operation. The operator must restore all disturbed lands to conditions capable of supporting the uses they were capable of supporting before any mining or restore them to conditions capable of supporting ‘higher or better’ uses. 30 C.F.R. § 816.133. SMCRA also requires that the operator:

1. Restore the approximate original contour (AOC) of the land by backfilling, grading, and compacting;
2. Minimize disturbances to the hydrologic system by avoiding acid mine drainage and preventing additional contributions of suspended solids (sediments from erosion) to nearby streams and other water bodies;
3. Reclaim the land as soon as practicable after the coal has been extracted, and even as the mining operation moves forward; and
4. Establish a permanent vegetative cover in the affected area. Strip Mining Handbook, “A Brief Overview of SCMRA”.

One interesting point is that SMCRA jurisdiction over a surface mining site terminates after a certain amount of time has passed, regardless of whether or not reclamation efforts were in fact successful. In 1991, the National Wildlife Federation (NWF) brought suit against the Secretary of the Interior challenging rules regarding reclamation bonds that had been promulgated by the Office of Surface Mining Reclamation and Enforcement (OSMRE). *National Wildlife Federation v. Lujan*, 928 F.2d 453 (D.C. Cir. 1991). Under the then-existing regulatory framework, mine operators had to wait a certain number of years before their bond was returned, to ensure that the reclamation efforts had taken hold. The number of years varied between 5 years for eastern lands to 10 years for arid, western lands. Once the time passed, on the assumption the land had been restored, the government would release the bond, thus terminating regulatory jurisdiction over the mine operators. As a practical matter, this regulation freed
operators from SMRCA jurisdiction once the performance bond had expired, whether or not the operator’s land has actually been restored to its previous useable condition as required by SMRCA.

The NWF challenged the termination provisions included in the OSMRE rules, arguing the agency did not have the authority to terminate SMRCA jurisdiction over mine operators, but had a continuing duty to ensure SMRCA requirements were being met. The DC Circuit disagreed with NWF and sided with the agency. It concluded the statute only required the government to enforce SMRCA “during mining and reclamation operations.” Once reclamation operations are completed, according to the court, the Act no longer applied, even if the reclamation efforts were not actually successful. The court reasoned that the Act’s purpose was to promote two conflicting policies: “protect the environment and… ensure an adequate supply of coal to meet the nation’s energy requirements.” If mine operators were forever liable for surface reclamation, then the second purpose of the Act would be thwarted.

However, not all bond releases are unreviewable. SMCRA regulations provide authority for regulators to reassert jurisdiction over mining sites when the bond release “was based upon fraud, collusion, or misrepresentation of a material fact.” 30 C.F.R. § 700.11(d). See Cheyenne Sales Co., Inc. v. Norton, 2007 WL 773904 (N.D. W.V. 2007) (holding that misrepresentation of material fact standard does not require intentional wrongdoing).

Mountaintop removal mining. Mountaintop removal mining, a form of surface mining prevalent in Southern Appalachia, is controversial – on one hand, it is a cost-effective method of coal extraction; on the other hand, it creates significant environmental and other harms.

The EPA defines mountaintop removal mining as the “removal of mountaintops to expose coal seams, and disposing of the associated mining overburden [layers of rock and dirt that sit above the coal] in adjacent valleys – valley fills.” EPA, “Mid-Atlantic Mountaintop Mining”. According to the EPA, mountaintop mining and valley fills have been known to cause the following environmental impacts:

• Water: increase in minerals in the water may negatively impact fish, leading to less diverse and more pollutant-tolerant species; streams are sometimes covered up
• Forests: forests may become fragmented (broken into sections); regrowth of trees and woody plants on affected land may be slowed due to compacted soils
• Social, economic and heritage issues: Neither EPA nor the source cited by EPA list the social, economic or heritage issues specifically; however, these likely refer to things like changes in the landscape, loss of hunting grounds, reduction in the quality of fishing, degradation of roads as a result of mining trucks, and strains placed on small towns as a result of the mining operation.
The deposit of overburden in mountaintop removal is regulated by Sections 402 and 404 of the CWA and the permit and reclamation provisions of the SMCRA, 30 USC § 1265, § 1258. The Army Corps of Engineers exercises permitting jurisdiction over the deposit of fill into wetlands and has traditionally granted approval for these activities under Nationwide Permit 21 (“NWP 21”), which specifically authorizes discharges of dredged or fill material into waters of the United States for surface coal mining activities. Although this practice has been challenged as inconsistent with the CWA, most challenges have failed. See e.g. *Kentuckians for the Commonwealth v. Rivenburgh*, 317 F.3d 425 (4th Cir. 2003) (upholding fill activities under the nationwide permit); *Ohio Valley Environmental Coalition v. Bulen*, No. 04-2129 (4th Cir. 2005) (overturning and remanding district court decision finding nationwide permit inconsistent with the Clean Water Act) *But see Ohio Valley Envtl. Coalition v. Hurst*, 2009 WL 972610 (S.D. W. Va 2009) (issuance of nationwide permit was arbitrary and capricious).

How much recent regulatory action has there been to reign in mountain mining? In 2010, the Obama Administration imposed an effective moratorium on mountaintop mining. In June 2010, the Army Corp of Engineers suspended use of NWP 21, thus effectively prohibiting mountaintop removal operations that involve the discharges of fill material into waters of the United States in six states in the Appalachian Region. The purpose of this suspension was twofold: (1) to prohibit NWP 21’s use to authorize surface coal mining activities in the Appalachian region of Kentucky, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia and (2) to modify NWP 21 to make the prohibition permanent until NWP expires on March 18, 2012. *U.S. Army Corps of Engineers, “Suspension and Modification of Nationwide Permit 21.”* However, in February 2012, the Army Corps of Engineers reissued NWP 21, with revisions to impose new limits on stream impacts and to prohibit valley fills. *U.S. Army Corps of Engineers, News Release.*

In addition to this moratorium on new permits, the EPA used its authority under the CWA to revoke prior-issued permits. For example, in January 2011, the EPA denied a water permit to the Spruce No. 1 Mine in Logan County, West Virginia – what was to have been one of the nation’s largest mountaintop removal mining projects, covering nearly 2,300-acres and burying nearly seven miles of streams. The EPA’s decision was based on “several major environmental, water quality, and wildlife concerns.” *TriCities, "EPA decision on Spruce No. 1 Mine big news in coalfields, beyond."* The EPA invoked its authority under the CWA to rescind the mine’s permit that had been granted by the Army Corps of Engineers, an action it had taken only twice in 40 years and never for a coal mine. However, in March 2012, a US District Court judge reversed the EPA’s decision to retroactively revoke the waste disposal permit, holding it exceeded the agency’s authority and violated federal law. *The New York Times, “Court Reverses EPA on Big Mining Project.”*

### 2.4 Coal Transportation

Coal is relatively high in energy, with one ton of coal equivalent to 16-26 million BTU, while one ton of wood is only 9-17 million BTU. But coal is also costly to transport. Railroads and barge lines handle 75% of coal shipments, especially long-distance shipments, with about 71% of coal in the United States transported by train. *EIA, “Coal Explained.”* These trains are often 100 cars in length, and dominate coal transportation in the Western United States. Trucks and conveyor systems often handle shorter-distance shipments. The price of coal to the consumer is
largely affected by the distance from its markets and the method and efficiency of its transportation.

2.4.1 Coal transportation by rail

Despite their symbiotic relationship, the coal and railroad industries have a love-hate relationship: as railroads become more efficient, they allow coal companies to compete in an increasing number of markets (such as, western coal companies in the eastern markets). On the other hand, as railroad industries consolidate, industry competition decreases and transportation rates increase – though the railroad companies argue that in the long-run, consolidation produces economies of scale. In the early 1980s, for example, the railroad industry was deregulated, and coal transportation rates fell by 42% between 1984 and 2001. More recently, however, railroads have increased base transportation rates, with the price of coal transportation rising 6% from 2004 to 2005. EIA, “Coal Transportation”.

Although a number of factors contribute to increasing rail rates, the biggest factors are railroad profitability, increased fuel expenses, and the need to create additional infrastructure. Railroads maintain that during deregulation, the railroads were able to pass savings on to consumers that resulted from consolidation of redundant infrastructure. However, these savings are no longer attainable. Instead, railroads today must add infrastructure to meet increasing transportation demands. EIA, “Coal Transportation”.

So why exactly are railroad prices so difficult to regulate? Railroads often have “bottleneck” monopoly position – that is, when a railroad track segment leads to a single-served facility. The question is whether railroads that control such “bottlenecks” can exploit their monopoly position. In 1999, the Eighth Circuit sided with the railroad industry, allowing railroads to charge “bottleneck” rates on lines for which there was no competition. MidAmerican Energy Co. v. Surface Transportation Board, 169 F.3d 1099 (8th Cir. 1999). MidAmerican and similarly positioned coal companies were looking for competitive transportation rates between their mines and generating facilities. MidAmerican found a railroad offering a competitive rate for a significant portion of the route, but the final 90 miles to the generating station were exclusively serviced by one railroad carrier. The Surface Transportation Board determined that under the Interstate Commerce Clause, a railroad company need not provide a rate exclusively for its so-called “bottleneck segments” serviced by the other carrier. The Court affirmed the Board’s decision, noting that “the Act protects both shippers and carriers. It guarantees that shippers will receive rail service at reasonable rates, and it allows carriers to provide such service in a manner that achieves revenue adequacy.” The Board determined that “exploiting bottlenecks by refusing to provide separately challengeable bottleneck rates also assists carriers in achieving revenue adequacy.” The decision of the Board, according to the Court, was consistent with the national railroad policy of maximizing carrier discretion in setting routes and rates.

2.4.2 Coal transportation by pipeline

In addition to rail, coal can also be transported by pipelines. Pipelines transport coal from the location where it is mined directly to the plant that consumes it. Although the use of trains and
barges is preferable for long-distance shipping, pipelines present economical advantages when no suitable railway or waterway exists to transport the coal.

The principle type of pipeline, known as slurry pipeline, produces a mixture of water and pulverized coal. The ratio of coal to water is approximately 1:1. The drawback of slurry pipelines is that the coal must be relatively dry prior to burning efficiently. Thus, coal transported by slurry pipelines requires extensive drying periods. Failure to dry the coal completely results in substantial inefficiencies during electricity generation. Wikipedia, “Coal Pipeline”.

Thus, the type of transportation method utilized for coal from the point of extraction to its end use location, for example a power plant, depends primarily on the distance between the mining site and operational facility, and the existence of easily accessible railroads or water passages.

2.5 Coal Combustion

Once coal has been transported and delivered to the production facility, the facility is ready to engage in the process of coal combustion. Combustion includes drying, heating, devolatilisation, and oxidation. As is well know, these combustion processes result in the formation and destruction of gaseous and solid pollutants. Because of the danger associated with these gaseous byproducts, Congress heavily regulates the coal combustion process. This section explores the federal regulations associated with coal combustion, and the dangers posed by the gaseous byproducts that are emitted.

2.5.1 Clean Air Act – “New Source” Regulation

The treatment of the Clean Air Act (CAA) of “new source” emitters has been a major cause of coal industry litigation since its enactment. The CAA applies only to new sources of air pollution, specifically requiring “new source” permitting standards for those sources constructed or modified after 1971. 42 USC § 7411. As a result, hundreds of stationary sources (coal-powered generating plants) have been grandfathered from CAA compliance unless they were modified or reconstructed after 1971. Energy Law in a Nutshell, 341.

Central to the regulation of coal-burning power plants is the grandfathering of coal-burning power plants that began operation before 1978. According to an important 2012 Government Accountability Office (GAO) report about electricity generators, much of our air pollution is due to these older power-generating units. GAO, Air Emissions and Electricity Generation at US Power Plants (May 18, 2012); see also Legal Planet, “Out With the Old, In With the New.” In 2010 these older power plants generated 45% of carbon-generated electricity, but produced a disproportionate share of emissions – contributing 75% of sulfur dioxide emissions, 64% of nitrogen oxides emissions, and 54% of carbon dioxide emissions from fossil fuel units.

Moreover, according to the GAO report, for each unit of electricity generated, older units collectively emitted about 3.6 times as much sulfur dioxide, 2.1 times as much nitrogen oxides, and 1.3 times as much carbon dioxide as newer units. The survival of these older plants is partly due to the grandfathering provisions of the CAA, which makes it easier to maintain old plants rather than build new ones.
Why are the older plants so much worse? According to the GAO there are three main reasons:

First, 93% of the electricity produced by older fossil fuel units in 2010 was generated by coal-fired units. Compared with natural gas units, coal-fired units produced over 90 times as much sulfur dioxide, twice as much carbon dioxide and over five times as much nitrogen oxides per unit of electricity, largely because coal contains more sulfur and carbon than natural gas.

Second, fewer older units have installed emissions controls, which reduce emissions by limiting their formation or capturing them after they are formed. Among coal-fired units—which produce nearly all sulfur dioxide emissions from electric power generation—approximately 26% of older units used controls for sulfur dioxide, compared with 63% of newer units.

Third, lower emissions among newer units may be attributable in part to improvements in the efficiency with which newer units convert fuel into electricity.

The treatment of the Clean Air Act (CAA) of “new source” emitters has been a major cause of coal industry litigation since its enactment.

The EPA, however, can regulate these older, dirtier plants when the plants are “modified,” a term that has been the subject of much litigation. A 1978 EPA rule defined a modification to mean “physical change” excluding “routine maintenance, repair, and replacement.” But in 1990, the Seventh Circuit concluded “any physical change” should be interpreted more broadly. See WEPCO v. Reilly, 893 F.2d 901 (7th Cir. 1990). A narrow definition of “physical change” would essentially exempt existing coal-powered plants from CAA regulation. Subsequent courts have interpreted “modification” as work that increases the emissions from a particular plant. The determination of whether an emissions increase has taken place (or will take place) as the result of any physical change in the plant is not straightforward. Interpreted strictly, it could be any hourly increase in emissions experience by a particular plant based on some physical change. More broadly, however, is that the increase should be gauged annually. See, e.g., United States v. Ala. Power Co., 372 F. Supp. 2d 1283 (N.D. Ala. 2005).

Supreme Court weigh in. The debate over how the EPA should decide whether emissions have increased was finally settled in 2007 when the Supreme Court held that the EPA must conform Prevention of Significant Deterioration standards (PSD) to the New Source Performance Standards (NSPS) counterparts in the CAA. Environmental Defense v. Duke Energy Corp., 549 U.S. 561 (2007). Thus, a grandfathered plant could avoid CAA regulation so long as it satisfied the NSPS. The Court held that the EPA had erred in trying to enforce more stringent PSD standards against a plant that increased its operational hours. The Court found that under the NSPS, a simple increase in hours of operation alone would not constitute a modification allowing CAA regulation. Thus, deciding whether emissions have increased to justify “new source” regulation remains unclear. Section 111 of the Clean Air Act gives the EPA significant
discretion to identify the facilities that should be regulated and the level of that regulation. EPA, “Background on NSPS”.

**Recent action to address power plant emissions.** In 2009, under the Obama administration, the EPA initiated new enforcement actions against energy companies charging that past modifications of older facilities triggered new source review. Then in March 2012, the EPA proposed a Carbon Pollution Standard for New Power Plants under the CAA, which would for the first time set national limits on carbon pollution new power plants can emit. EPA, Fact Sheet.

These actions are a first wave of regulations likely to have a dramatic impact on the coal industry. According to a Duke University study, pending regulations governing air-quality standards would likely increase the cost of coal-fired power plants to make them as expensive to run as plants powered by natural gas. The goal of the Obama administration is to decrease pollutants by, first, placing stricter regulations on coal power plants and, second, to encourage a migration to lower-CO₂ natural gas power plants because of the increased regulatory costs for coal power plants. Duke Study, “New Emissions Standards Could Increase the Cost of Coal”.

In June 2014, the EPA proposed additional (and controversial) new rules to regulate GHG emissions from US power plants. EPA, Clean Power Plan Proposed Rule. The proposed rule would create emission guidelines, with state-specific rate-based goals, for states to follow in developing plans to address GHG emissions from existing fossil fuel-fired electric generating units. Here is the EPA’s overview of the proposed rule, for which hearings around the country are currently underway:

- Our climate is changing, and we’re feeling the dangerous and costly effects right now.
  - Average temperatures have risen in most states since 1901, with seven of the top 10 warmest years on record occurring since 1998.
  - Climate and weather disasters in 2012 cost the American economy more than $100 billion.

Although there are limits at power plants for other pollutants like arsenic and mercury, there are currently no national limits on carbon.

- Children, the elderly, and the poor are most vulnerable to a range of climate-related health effects, including those related to heat stress, air pollution, extreme weather events, and others.

Nationwide, the Clean Power Plan will help cut carbon pollution from the power sector by 30 percent from 2005 levels.

- Power plants are the largest source of carbon pollution in the U.S., accounting for roughly one-third of all domestic greenhouse gas emissions.
• The proposal will also cut pollution that leads to soot and smog by over 25 percent in 2030.

Americans will see billions of dollars in public health and climate benefits, now and for future generations.

• The Clean Power Plan will lead to climate and health benefits worth an estimated $55 billion to $93 billion in 2030, including avoiding 2,700 to 6,600 premature deaths and 140,000 to 150,000 asthma attacks in children.

States and businesses have already charted the path toward cleaner, more efficient power.

• States, cities and businesses are already taking action.

• The Clean Power Plan puts states in the driver’s seat to a cleaner, more efficient power fleet of the future by giving them the flexibility to choose how to meet their goals.

With EPA’s flexible proposal, we can cut wasted energy, improve efficiency, and reduce pollution – while still having all the power we need to grow our economy and maintain our competitive edge.

• The agency’s proposal is flexible—reflecting the different needs of different states.

• The proposal will put Americans to work making the U.S. electricity system less polluting and our homes and businesses more efficient, shrinking electricity bills by roughly 8 percent in 2030.

• It will keep the United States—and more importantly our businesses—at the forefront of a global movement to produce and consume energy in a better, more sustainable way.

As a result of the rule, many observers of the electric power industry have concluded that it unlikely any new coal-fired power plants will be built in the United States. Marlo Lewis, “EPA’s ‘Carbon Pollution’ Standard for Power Plants: Four Ways Weird”

2.5.2 Pollutant Emissions

Coal generates 54% of our nation’s electricity and is the single biggest air polluter in the United States. Coal pollutes when it is mined, transported, stored, and burned. There are about 600 coal plants in the United States, with a typical coal plant burning up to 1.4 million tons of coal each year. Burning coal causes smog, soot, acid rain, global warming, and toxic air emissions. In an average year, a typical coal plant generates 3,700,000 tons of carbon dioxide (CO₂), 10,000 tons of sulfur dioxide (SO₂), 10,200 tons of nitrogen oxide (NOₓ), 720 tons of carbon monoxide (CO),
and 170 pounds of mercury. Union of Concerned Scientists, “Environmental Impacts of Coal Power: Air Pollution.” Each of these pollutants is discussed further below.

**Sulfur Dioxide.** Coal-fired power plants are the largest human-caused source of sulfur dioxide, a pollutant gas that causes acid rain. Source Watch, “Sulfur Dioxide and Coal.” Prior to the 1900s downwind states form large sulfur neighboring polluters had little recourse to corral their neighbors. However, the Clean Air Act amendments of 1990 mandated a sharp, staged decrease in sulfur dioxide emissions from coal fired power plants, including the sources grandfathered in (and thus exempt) by the Act’s new source permitting requirements. The CAA now prohibits emissions that “contribute significantly” to the National Ambient Air Quality Standards (NAAQS) in other states. Sulfur dioxide from coal combustion contributes to downwind acid rain in states near polluters and is currently regulated through a cap and trade system administered by the EPA.

How does cap and trade work? Cap and trade serves as an environmental policy tool that delivers results with a mandatory cap on emissions while providing sources flexibility in determining compliance. EPA, “Cap and Trade.” This tool provides an economic incentive for reduction in pollution. Under this program, a governmental agency determines a limit (cap) on the amount of pollution that can be emitted from any individual plant. This cap is then sold (or given) to each company, and the agency requires the companies and plants to hold a certain number of permits (also called allowances) that is equivalent to their emissions. For example, the Acid Rain Program of the CAA, a successful cap-and-trade program, created a market for pollution reduction in sulfur dioxide “allowances.” Wikipedia, “Emissions Trading”.

Allowances gained by a particular plant could be sold, traded, or used to further pollute. This created incentivizes for firms to reduce their emissions so they could sell excess allowances to plants unable to meet the sulfur dioxide requirements. Thus, those plants with the ability to cheaply reduce their sulfur dioxide emissions are able to sell their excess allowances to plants that cannot and, theoretically, would see a return on their pollution-preventing investments. To address concerns that the program could lead to pollution hotspots, especially where the coal is lower quality and contains more sulfur, allowances are slowly “taken off the market” over time to force an industry-wide sulfur dioxide decrease.

Why has the sulfur dioxide cap and trade system created problems for the states? Sulfur dioxide allowances have created problems for state regulations. States that rely on cost-of-service rate setting present uncertainty for plant owners in knowing where their rates will be set based on their “income” and investments from allowances. Further, prohibitions on shareholder returns imposed by state utilities commissions make the risk of investing in sulfur dioxide emissions prevention one-sided. While capital losses are not managed by the state, the gains are. Despite the drawbacks of sulfur dioxide allowances, the picture is not completely bleak: sulfur dioxide emissions between 2004 and 2009 decreased from 10.3 million tons to 5.7 million tons. Energy Law in a Nutshell, 336.

The biggest downside of the 1990 Clean Air Act amendments was felt by states having high-sulfur coal mines. The cheapest alternative for power companies to comply with the CAA amendments was to simply use coal with less sulfur. In response, many states passed laws to
discourage local electric utilities from switching from local high-sulfur coal to low-sulfur out-of-state coal. For example, Illinois enacted a law that required the installation of scrubbers to allow the continued burning of high-sulfur Illinois coal. When low-sulfur coal producers sued alleging that this violated the “dormant” commerce clause, the Seventh Circuit agreed and stated, “The obvious intent was to eliminate western coal use by Illinois generating plants, thus effectively discriminating against western coal. The Commerce Clause compels us to invalidate this statute.” *Alliance for Clean Coal v. Miller*, 44 F.3d 591 (7th Cir. 1995).

**Nitrogen oxides (ozone).** Nitrogen oxides, commonly known as ozone, are essential for absorbing and reflecting radiation from the sun in the upper atmosphere. However, nitrogen oxide emissions are a precursor of both acid rain and ground level ozone, an extremely dangerous pollutant. Because of these risks, the acid rain program of the 1990 amendments to the CAA also mandates reduction in nitrogen oxide emissions from the largest coal-fired power plants, even though these plants represent a relatively small percentage of the nation’s nitrogen oxide emissions. On July 6, 2011, the (EPA) finalized a the Cross-State Air Pollution Rule (CSAPR), “requires states to significantly improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states.” [EPA](http://www.epa.gov). CSAPR requires a total of 28 states to reduce annual emissions, including nitrogen oxide emissions, in order to assist the states in attaining the National Ambient Air Quality Standards that the EPA has set.

**Mercury.** Coal-burning power plants are the largest source of mercury emissions related to human activity in the United States, accounting for roughly 40% of all mercury emissions nationwide. [Environment News Service, “Mercury Emissions Up at Coal-Burning Power Plants.”](http://www.environmentnewswire.org) The CAA’s treatment of mercury, a toxic pollutant, differs from sulfur dioxide and nitrogen oxides, which are regulated as conventional pollutants. Mercury is regulated as a “hazardous air pollutant” (HAP) and is subject to a stricter technology-based standard. Where the standards for sulfur dioxide and ozone are subject to the feasibility of decreased emissions, mercury and other HAPs are regulated based on “maximum achievable control technology” (MACT). Further, unlike conventional pollutants, HAPs are regulated in new sources and old sources alike, despite any grandfathering provisions.

The mercury MACT standards have been controversial. In 2005, the Bush Administration reversed the conclusion it was “appropriate and necessary” for mercury to meet MACT standards. Instead the Bush EPA created the Clean Air Mercury Rule (CAMR) to impose a cap-and-trade system for mercury emissions from power plants. In a challenge to this regulatory change, the DC Court of Appeals held the EPA lacked the authority to reverse its prior conclusion by failing to make specific findings as to why mercury is not a HAP. *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008). Thus, today mercury from coal-fired power plants is regulated as a HAP -- subject to maximum achievable control technology standards.

**Carbon dioxide.** Coal combustion represents the largest contributor to human-made CO₂ increases in the earth’s atmosphere. For example, electricity generation from coal creates nearly two times the amount of greenhouse gases compared to electricity generation that uses natural gas. The average emission rate for carbon dioxide from coal-fired generation is 2,249 lbs/MWh,
while emissions from oil are 1,672 lbs/MWh and from natural gas 1,135 lbs/MWh. EPA, “Carbon Dioxide Emissions”.

One main source of CO₂ reduction results from the creation of more modern and efficient coal plants to replace the older and ineffective plants currently in existence. Modern coal plants emit 40% less CO₂ than the average coal plant currently in use. By improving the efficiency of the oldest and most inefficient plants, CO₂ emissions would drop by 25%, reducing global CO₂ levels by 6%. Even improving efficiency levels of coal plants by 1 percentage point will result in a 2-3% reduction in total CO₂ emissions. World Coal Organization, “Coal Use”. The charts below illustrate the potential benefits of CO₂ reduction by increasing facility efficiency.

2.6 Future of Coal

As an energy source, coal has some major advantages and some serious disadvantages for society. The availability of coal throughout the world makes it easy and cost effective for developing economies to harness energy from coal to fuel expansion and growth. Among the disadvantages of coal is that it is a relatively dirty fuel, imposing additional unrealized costs on society in the form of pollution. Further, both underground mining and surface mining have unique externalities that have serious adverse impacts on people outside of the coal industry (i.e. subsidence). Our greater understanding about the true economic and environmental costs of coal has resulted in two key trends.

First, developed economies are shifting away from coal in favor of alternative energy sources. And second, industry, governments, and environmentalists have researched and developed technology to mitigate the carbon dioxide emissions resulting from coal burning.
2.6.1 Coal usage trends

Knowledge about the environmental impact of coal use has impacted the way in which countries are utilizing coal for their energy needs, primarily in developed economies. The World Energy Council has estimated that fossil fuels, including coal, will supply the world with 82% of its commercial energy needs in 2030, and 64% in 2050. One of the reasons for this decline is the implementation of the Kyoto Protocol in 2005.

Global response. In response to the impact of coal on climate change, Kyoto Protocol (an international treaty that the United States has not ratified) set binding targets to reduce greenhouse gas emissions for 37 industrialized nations and the European community. Under the Protocol, countries must meet their emissions targets primarily through internal efforts, which include changes in the consumption of fossil fuels and implementations of cleaner technologies. Additionally, the Protocol created several mechanisms for international collaboration in the reduction of emissions: the global carbon market, the Clean Development Mechanism, and the Joint Implementation Mechanism.

Global carbon market. The global carbon market created by the Kyoto Protocol, also referred to as emissions trading, is an international market. Nations committed to the Protocol have accepted targets to limit or reduce their emissions of greenhouse gases, which are expressed as levels of allowed emissions or “assigned amounts.” Allowed emissions are divided into “assigned amount units” (AAUs). If a country manages to reduce its emissions so much as to exceed its targets, then it has spare AAUs that may be sold to any other nation under the Protocol. This has created a market where AAUs are exchanged and priced like any other commodity. Additionally, other units are commonly traded on the carbon market. The units are expressed as the equivalent of a ton of emitted carbon dioxide, and include removal units (RMUs are created by land use, land-use change and forestry activities like reforestation), emission reduction units (ERUs are generated by joint implementation projects), and certified emission reductions (CERs are produced by clean development mechanism projects). The carbon market essentially provides nations with flexibility in how best meet their emissions targets and provides incentives for exceeding those goals.

Clean Development Mechanism (CDM). The CDM allows a nation to implement a project in a developing country (which is not a party to the Protocol) designed to reduce carbon emissions for the purpose of earning CERs that can be subsequently traded on the carbon market. The CDM is the first global, environmental investment and credit scheme of its kind. It provides Protocol nations with additional options in how to best meet their emissions targets and incentivizes the development and implementation of projects in emerging economies to reduce carbon emissions. There are currently 4,626 registered CDM projects that have resulted in the issue of 1,004,715,659 CERs (the equivalent of preventing over one billion tons of carbon dioxide emissions).

Joint Implementation Mechanism (JI). The JI allows a Protocol nation to undertake an emissions-reducing project in another Protocol nation for the purpose of earning ERUs which
may then be applied to the former nation’s emissions targets. Similar to the CDM and the carbon market, joint implementations provide countries with another option in how to best meet emissions targets, and they incentivize international collaboration.

The Kyoto Protocol was a major effort in the global reduction of greenhouse gas emissions. However, the Protocol is by no means a comprehensive or a final solution. Developing nations are not included in the agreement, and the emissions from those countries (which will likely be utilizing coal as a primary source of energy, given its relatively low cost compared to cleaner options) will amount to 60-70% of the total carbon emissions globally by 2050. Just as coal fueled the Industrial Revolution in the United States and Europe, coal is currently on track to serve as a key factor in the industrialization of less developed nations in other parts of the world.

What are we doing here to reduce CO2 emissions? Within the United States, there is currently no official government policy in effect that seeks to systemically reduce the amount of coal used for energy production. The most significant effort to do so occurred in 2009, when the U.S. House of Representatives approved the American Clean Energy and Security Act of 2009. The bill died in the U.S. Senate, but it represented the most aggressive attempt to revamp American energy policy in modern history. The bill proposed a cap and trade system for carbon emissions that would have created a carbon market in the U.S. similar to the international market of the Kyoto Protocol. The system would have placed a cap on the total amount of greenhouse gases that could be emitted on a national level, and would have required companies to purchase permits to emit those gases into the atmosphere. An initial allowance of permits would have been granted to emitting entities (such as utilities), and parties would then be allowed to buy and sell permits between themselves.

While Congress may have stalled, the Clean Power Plan of 2014 (mentioned above) is the EPA’s current plan to cut carbon pollution from the power sector by 30% in the US.

8.4.2 Carbon Capture and Storage

Efforts to reduce the harmful emissions resulting from the burning of coal and other fossil fuels have led to the development of carbon capture and storage (CCS) technologies. CCS systems appear in many different forms, but they share the same goal of attempting to prevent the carbon dioxide that is produced by burning coal from being released into the atmosphere. CCS systems collect carbon emissions and sequester them in a storage medium. Until cleaner sources of energy become as cost-effective as coal, CCS will serve as an important bridging technology that will permit continued use of coal for energy production and simultaneously mitigate further environmental harm.

Details of the CCS process. CCS is not a single technology. Rather, it describes a process that can be implemented by several different techniques and technologies. The basic steps of the CCS process are (1) carbon separation, where carbon dioxide is removed from the gas produced by burning coal; (2) compression, where the carbon dioxide is rendered into a form that can be transported away from the combustion site; and (3) sequestration, where the carbon dioxide is transported and stored elsewhere. While technologies exist that are capable of performing all of these steps, they are in varying stages of maturity and efficiency. Currently, no commercial-scale
CCS technology has been deployed in the U.S. on a coal-fired electrical facility. CBO, “Federal Efforts to Reduce the Cost of Capturing and Storing Carbon Dioxide”

What are the different methods for capturing CO2 emissions? There are four methods for capturing carbon dioxide emissions:

1. *Post-combustion separation* is a process where carbon emissions are separated from the flue gas generated by burning coal. The carbon gases are usually absorbed into an amine solution and then separated by increasing the temperature of the solution.

2. *Pre-combustion separation* involves the use of a physical solvent that is applied after coal has been reacted at high temperature, but prior to combustion. The solvent separates the carbon dioxide from the resulting syngas. *Integrated gasification combined cycle* (IGCC) power plants take advantage of pre-combustion separation as it is a cheaper and easier method.

3. *Oxy-fuel combustion* uses oxygen rather than air for combustion and produces a concentrated stream of carbon dioxide exhaust that does not require separation from other gases.

4. *Natural gas purification* and other industrial processes can capture limited amounts of carbon dioxide where fuel, such as coal, is not actually combusted.

How is captured CO2 compressed? The compression step of CCS is necessary to make the transportation of captured carbon dioxide cost effective. Similar to the way natural gas is compressed into a liquid, trapped carbon emissions are liquefied and transported for storage. This step of the CCS process is relatively mature compared to capturing carbon emissions as a result of industry experience with natural gas. The transportation of liquefied carbon dioxide involves a combination of pipelines, tanker trucks, and shipping. Carbon dioxide has been transported across the U.S. since the early 1970’s via pipeline for use in the process of enhanced oil. One such pipeline, already in pace, is the Cortez pipeline, which is 502 miles long reaches from Denver City to West Texas. Kinder Morgan, “Cortez Pipeline and Southwest Colorado CO2 Supply.” However, to make a demonstrable impact on carbon emissions, significant amounts of transportation capacity must be added to accommodate the amount of carbon dioxide that will be captured when large-scale CCS technologies are implemented.

What is the final step in the sequestration process? The final step comprises the injection of liquefied carbon emissions into deep reservoirs like depleted oil and gas fields, or saline aquifers. Most estimates of U.S. sequestration potential describe an available capacity of anywhere between 2 trillion to 11 trillion tons of liquid carbon dioxide. Globally, sequestration poses a unique challenge because different regions of the world have different amounts of sequestration capacity. For example, the U.S., Canada, and Australia have significant capacity, while South Korea and Japan do not. This report describes the geologic storage issues involved with CCS.

**Barriers to CCS implementation.** A key challenge to CCS implementation is that any capture system will require additional energy to function. This energy penalty reduces the power produced by burning coal which moves the turbine used to generate electricity, requiring larger amounts of coal to be used as fuel in order to generate the same amount of electricity. In other
words, CCS makes a coal-fired plant friendlier to the environment and less efficient economically (and consequently more expensive). This acts as a significant deterrent for the deployment of CCS on a commercial scale. However, in spite of the high implementation costs, several CCS projects outside of the U.S. that have reached industrial levels of capacity.

The Sleipner facility off the coast of Norway was the first commercial carbon capture site, storing carbon emissions from gas production in a saline aquifer beneath the North Sea. Another site, in Canada, the Weyburn enhanced oil recovery site, uses captured carbon emissions from a North Dakota coal gasification plant to assist in the recovery of oil from underground oilfields. These two projects represent some of the most advanced implementations of CCS technology.

**Roadblocks to putting in place CCS regulatory mandates.** While the benefits of CCS are promising, there is an unaddressed need for an underlying regulatory framework, both domestically and abroad, to address the various issues that can arise. First, CCS requires the extraction of carbon emissions from a site, transportation, and storage. Since carbon emitting facilities are not always located near promising storage sites, the CCS process commonly spans a significant amount of territory, and may even cross international borders, such as in the case with the Weyburn project. These necessities create jurisdictional issues and require the collaboration of governments and agencies at different regulatory levels. For instance, Canada is a federal state that comprises ten provinces and three territories. While the Canadian federal government has jurisdiction over foreign affairs, including its responsibilities under treaties like the Kyoto Protocol, the provincial governments have exclusive jurisdiction over natural resources and economic development. CCS projects naturally require the collaboration of the provincial and federal governments, but difficulties can arise if two different provinces have different priorities over the use and storage of captured carbon emissions. The province of Quebec, for example, derives the majority of its energy from hydroelectric plants and has limited space for the storage of carbon dioxide, whereas Alberta uses and produces coal heavily and has a significant amount of storage potential. IEA, “Legal Aspects of Storing CO₂.”

**What are some other challenges?** Additional challenge to CCS exist and, although are basic, are by no means less complicated. For instance, how should captured carbon dioxide be classified? Is it a pollutant, industrial waste, or a resource? Captured carbon emissions can be used for enhanced oil recovery, and in that context there is value in capturing and liquefying carbon dioxide for industrial use. On the other hand, in regions where there is no oil production, captured carbon emissions are little more than the byproduct of burning fossil fuels. In countries like the United States, where all of these situations exist, formulating a national definition for the purpose of regulating the sequestration of carbon emissions will prove to be a challenge in the future, particularly as scientists are discovering new applications for carbon dioxide.

The property rights issues of CCS are an equally complicated puzzle. Legal systems in different parts of the world create a patchwork of approaches to determining basic questions such as where captured emissions may be sequestered and for how long an investor has the right to access those sites. For instance, in the U.S. a property owner inherently owns the subsurface rights to a particular plot of lot. In Australia, however, subsurface rights are vested in the government. Furthermore, the question of who owns captured emissions after sequestration can
be equally daunting, since the owner will likely be responsible for monitoring the storage site and be held liable in the event that a leak or failure of containment occurs.

Currently, CCS is a promising and speculative means of reducing the adverse environmental effects of coal use. However, as the developing world relies more and more on coal for energy production over the next fifty years, CCS will be a crucial component of global efforts to prevent further destabilization of the environment while still making energy available and accessible for the planet.