Briefing Paper 2

How Energy Choices Affect Fresh Water Supplies: A Comparison of U.S. Coal and Natural Gas

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I. Introduction

Water and energy are critical and interdependent resources. The production and use of energy requires both the withdrawal and consumption[a] of water and represents one of the largest demands on fresh water in the United States. In 2005, U.S. power plant cooling systems withdrew 143 billion gallons of fresh water per day, accounting for 41 percent of domestic fresh water withdrawals. Mining and fuel extraction withdrew an additional 2 billion gallons per day. [1] Fresh water in turn requires energy to be pumped, treated, and transported before it can be used.

In a 2003 study by the Government Accountability Office, water managers in 36 of 47 surveyed U.S. states predicted that their states or regions would face water shortages by 2013.[2] The study warned that the depletion of groundwater aquifers, the rising demand for fresh water, and the potential impacts of climate change could all reduce water availability.

Declining water availability is already limiting energy choices. Over the past decade, concerns about water availability have halted power plant construction or operation in the U.S. states of Arizona, California, Colorado, Georgia, Massachusetts, Missouri, New Mexico, North Carolina, Pennsylvania, Rhode Island, South Dakota, Tennessee, Texas, and Washington.[3] As state and local governments around the country plan their electricity generation mix for the coming years, they will need to consider the water dimension of their decisions.

A shift from reliance on coal-fired steam-turbine generators (which provided about 44 percent of U.S. electricity generation in 2009) to combined-cycle plants fueled by natural gas (about 19 percent of generation) could have a profound effect on the power sector's water demands.[4] The relatively high efficiency of natural gas combined-cycle (NGCC) plants means that they generate electricity using less fuel and creating less than half the greenhouse gas emissions that coal plants do.[5] Moreover, NGCC plants consume one-tenth to one-half as much fresh water as conventional coal plants do to generate each unit of electricity—a critical advantage in regions where water shortages present as urgent a concern as air pollution and climate change.[6]

A newfound abundance of economically viable natural gas from unconventional reservoirs, combined with tightening air-quality standards and/or carbon constraints, could enable natural gas to claim a large share of the U.S. power market from coal.[7] This should reduce water demand at the power plant. However, complete comparisons of coal- and natural gas-generated electricity must account for water demands during the full fuel cycle. For example, extracting unconventional natural gas, including shale gas, tight gas, and coalbed methane, often requires

[a] Withdrawal refers to the removal of water from a natural source, which may be either returned to the source or consumed.

significantly more water than conventional natural gas extraction because of the use of hydraulic fracturing, a water-intensive well-stimulation technique.[8]

This paper examines the impacts on U.S. fresh water resources of generating electricity from coal and natural gas, from the point of fuel extraction through the fuel's use at the power plant. Although fuel extraction can require locally significant quantities of water, by far the largest water consumer in the life cycle of electricity is power plants—which can be responsible for more than 90 percent of the water consumed to produce a kilowatt-hour of electricity.[9]

NGCC power plants generally use less water per unit of electricity generated than coal power plants due to higher efficiency and less need for emissions controls (which in many cases represent an extra water use at coal plants). Thus, shifting generation from coal to natural gas should reduce the electricity sector's water needs whether unconventional or conventional natural gas is used.

This paper also finds that coal extraction has higher potential for long-term degradation of water resources than does natural gas extraction. However, the quantitative and qualitative water impacts of fuel extraction vary by site and method. Using natural gas instead of coal will likely involve less damage to the fresh water system, with localized exceptions.

Although this paper focuses on water, water is not the only resource affected by the extraction, processing, transport, and use of coal and natural gas; air, land, and communities also face impacts. All of these impacts must be considered in a holistic comparison of the effects of coal and natural gas production and use. (See Table 1.)

Table 1. Lifecycle Environmental Impacts of Coal and Natural Gas Production and Use

	Coal	Natural Gas
Land use	• Land intensive • Reclamation can be difficult	• Well pads are relatively small, especially for horizontal wells
Solid waste	• Large volumes of processing waste and combustion byproducts must be disposed of	• Limited volumes of drill cuttings
Air emissions	• CO_2 emissions when combusted; some methane leakage • Emissions of particulates, sulfur, nitrogen, mercury, other metals at power plant	• CO_2 emissions (less than half those of coal) when combusted; methane leakage • Other emissions from drilling site, pipelines, and service trucks
Water pollution and disturbance	• Chemical pollution from mining and processing • Minewater discharge and groundwater pumping at mines disturbs stream and groundwater flows • Thermal pollution from power plants	• Chemical pollution from accidental spills or faulty well completions • Briny flowback and produced water often has high solids content and sometimes has naturally occurring radioactive material (NORM) • Thermal pollution from power plants
Water consumption	• Limited water use during mining • Steam-turbine power plants require large amounts of water for cooling	• Water used for drilling and hydraulic fracturing • Combined-cycle and gas-turbine power plants use less water for cooling

II. Water Impacts from Fuel Extraction, Processing, and Transport

Evaluating the water impacts of displacing coal with natural gas in the power sector requires a clear understanding of these fuels' demands on water. Coal and natural gas must be extracted, processed, and transported before they reach power plants. Each of these stages uses and affects the supply and quality of water. (See Figure 1.) Unfortunately, quantitative data on how resource extraction affects water quality and demand are scarce, as water impacts are site-specific depending on how and where the extraction occurs. In particular, the quality of a coal or natural gas resource and how close it is to water affects its need for water and its potential to pollute.

Coal

The two main methods for mining coal are surface mining and underground mining. For surface mining, miners uncover coal by removing the rock at the surface, known as the overburden; for underground mining, they dig beneath the overburden and work under a rock roof. In the United States, surface mines account for 69 percent of total coal production, and underground mines for 31 percent.[10]

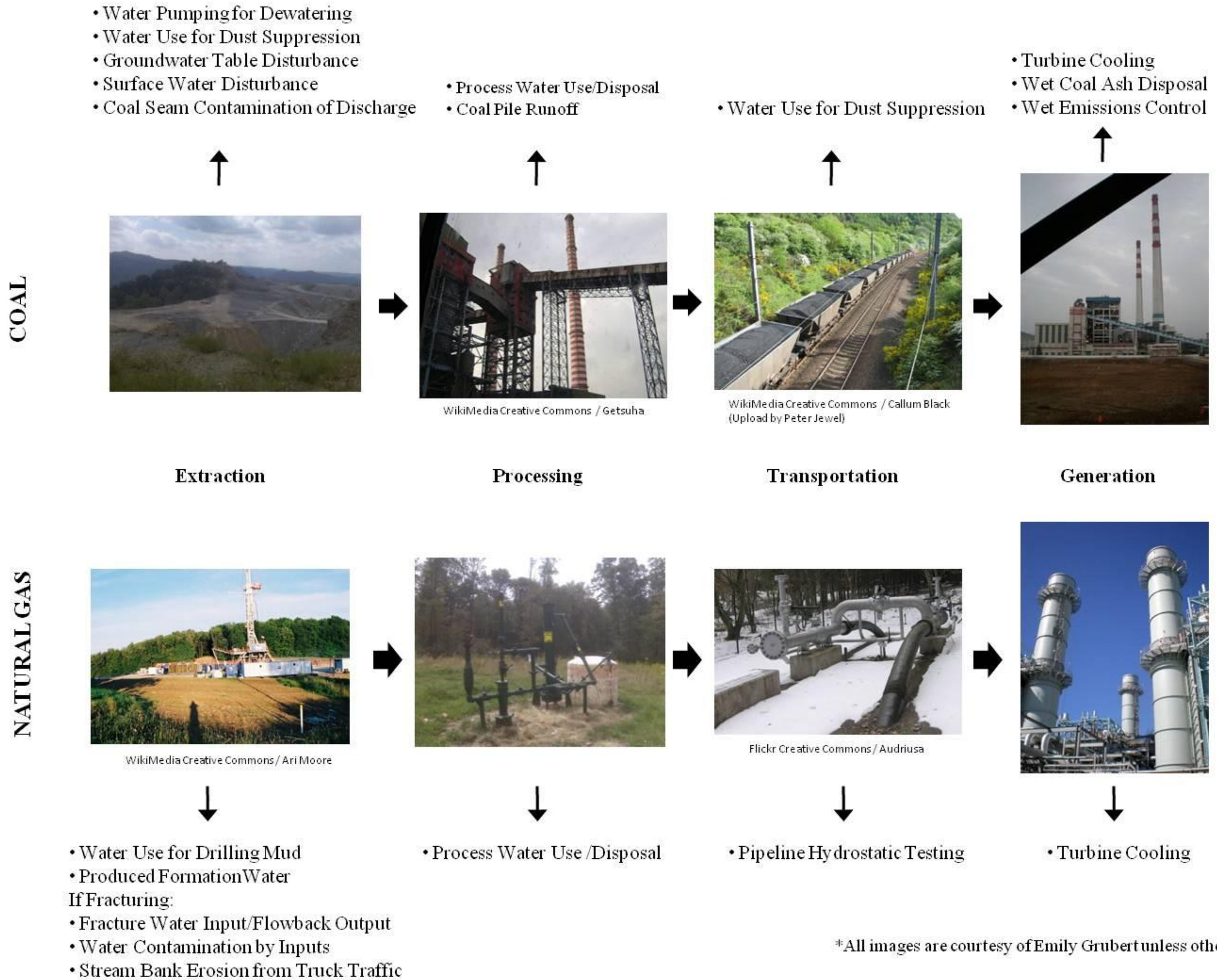
Both underground and surface mines are often situated at least partially below the water table, so miners must pump out water from the working area during much of the mining process (from pre-excavation until the mine is abandoned). This "mine dewatering" includes removing water from rain or snow in addition to water that is already in the coal formation. Dewatering equipment discharges most of the water at the surface, although some operations capture or treat this water for reuse for dust suppression and other needs.

Mine dewatering can lower water tables for decades, affecting groundwater levels and flow patterns around the mine for miles. But it can also prevent the long-term exposure of water to any contaminants in the coal. Coal is highly heterogeneous, with the full range of the world's coals containing 76 of the 92 naturally occurring elements.[11] Both the combustion of coal and its exposure to water can release contaminants to the environment, making remediation difficult.

Most U.S. coal mining takes place in two regions: the Appalachian Mountains in the mid-Atlantic (33 percent) and the Powder River Basin in the Western states of Wyoming and Montana (42 percent).[12] Appalachian coals are characterized by high energy density and relatively high sulfur content, whereas Western coals are typically lower energy density and low in sulfur. The United States is expected to obtain a rising share of its coal from the West in the future, in part because of the lower sulfur emissions released during combustion.

In addition to the coal that can be used for energy, mining involves removing large volumes of waste rock from the ground. Removal of this rock can disrupt surface and groundwater flows, and waste rock disposal can bury streams. Rock surfaces that are inert when surrounded by other rock can oxidize and leach material into water when they are exposed to air and water.

Figure 1. Water Usage and Impacts in the Fuel Cycles of Coal and Natural Gas*



*All images are courtesy of Emily Grubert unless otherwise noted.

Coals and waste rock in the eastern United States are particularly problematic, not just because they release higher sulfur emissions during combustion, but because the sulfur compounds are reactive when exposed to air and water. Waste rock generally contains more of these contaminating compounds than coal, and Appalachia's thin coal seams are often associated with more waste rock than Western seams, which can be 10 times as thick. And because Appalachian coal is located in wet, mountainous areas with many streams, coal-related contamination is more likely to affect the water in this region than in the semi-arid West.

Environmental regulations require that most Eastern coals be processed before they are used in power plants. Companies remove impurities by crushing the coal into smaller pieces in water, which adds 1–2 gallons of water demand per million Btu of coal.[13] Once used, this water is discharged to holding ponds and often contains fine coal particles that are difficult to remove.[14] Since coals in the West usually have fewer impurities as well as lower energy densities than those in the East, such preparation before use is often not considered worthwhile for Western coals.[15]

Most U.S. coal is transported by rail, barge, or truck, so water usage for transportation is low. At mine sites, water consumption is usually limited to domestic services such as toilets and showers for workers and dust suppression, which involves spraying water from the mine on coal piles and roads to reduce airborne dust. Because contamination from this dust is typically transferred to the water, the associated pollution is often moved but not eliminated, presenting a major challenge for mitigation. Coal is usually stored in open piles, so precipitation can become contaminated runoff as well.

One of coal mining's greatest impacts on water quality comes from abandoned mines, as water moves through pits or tunnels in rock surfaces that remain chemically active. Abandoned surface mines often turn into lakes, whereas underground mines experience groundwater seepage. Without control measures, new water continuously enters abandoned mines and piles of waste rock, which means that a poorly remediated mine can contaminate water for decades or even centuries. Such contamination is a bigger problem in the eastern United States than the West, so the expected continued shift to Western coals could reduce the negative impacts on fresh water quality.[16] But because water associated with Western coals is often of high quality, containing few contaminants, mining in the region can deplete already-scarce water resources that could be used for other purposes.

After mining ceases, reclaimed mine sites continue to consume water to reestablish vegetation, although the amount varies by climate. In the U.S. West, estimates of this usage range from 616,000 liters to 925,000 liters of high-quality water per acre of reclaimed land annually, over a 10-year period.[17]

In 2009, **Central Appalachia** produced some 196 million short tons of *high-sulfur, bituminous coal*—18 percent of the U.S. coal supply—from 399 underground and 403 surface mines.[18] Because coal seams in the region are thin—between 3 and 15 feet—mining companies may use mountaintop removal to access seams that are less than 30 inches thick. This involves stripping the tops of mountains and pushing waste rock into adjacent valleys. Mountaintop removal generates large volumes of waste rock that may be stored in impoundment slurry dams or large tailings piles, which can bury or eliminate streams.

Water flow following mountaintop removal can liberate contaminants such as pyrite and heavy metals, creating acid mine drainage (AMD) and other contaminated runoff.[19] AMD is associated with certain sulfur compounds and is highly damaging to water quality, particularly since the acid can dissolve other contaminants into water. AMD is also persistent: rocks containing sulfur can produce AMD as long as air and clean water are in contact with an exposed coal seam.

Wyoming and Montana's **Powder River Basin** is the largest U.S. source of coal, with only 17 mines accounting for 496 million short tons, or 42 percent, of domestic production.[20] The basin is expected to provide an even larger share in the future.[21] Extremely thick seams (up to 150 feet) of *low-sulfur, sub-bituminous coal* are exploited through open-pit surface mines.

Because coal-mining areas in the U.S. West are less mountainous than in the East, there are fewer headwater streams that can be affected by mining. Even when Powder River Basin coal does impinge on water resources, it does not pose as great a risk of contamination as Appalachian coals because it contains lower levels of sulfur, heavy metals, and other contaminants.[22] In some areas, the coal even acts as a natural filter and holds potable water—creating a tension between developing coal resources and preserving high-quality water supplies for drinking, livestock, and irrigation.

Some of the water in Western mines has high levels of sodium, which can negatively affect soils when the water is discharged.[23] The potential negative impact on agriculture from pumping water and sodium contamination is one reason that Montana has restricted mining in its portion of the Powder River Basin.[24]

Natural Gas

The United States produced 21 trillion cubic feet (tcf) of natural gas in 2009.[25] Up until 2008, most of the nation's natural gas was produced from "conventional" reservoirs, which have relatively high permeability, enabling natural gas to flow easily to drilled wells. More recently, production in less-permeable "unconventional" reservoirs, including tight sands, deep shales, and natural gas-bearing coalbeds, has overtaken conventional production and is projected to grow through 2030 at least.[26] As with coal, the water needs and risks of natural gas extraction depend on geology and geography. In general, natural gas production from unconventional reservoirs requires more water than production from conventional reservoirs.

Both conventional and unconventional natural gas drilling use water to lubricate and cool the drill bit, consuming hundreds of thousands of gallons per well. The "drilling mud" that results can contain toxins, posing a disposal challenge: it may be injected underground; treated and then reused or released; or dried and disposed of. Similarly, both conventional and unconventional wells can produce naturally occurring water from the reservoir rock. This "formation water" has typically spent millions of years in contact with ancient rock formations and can therefore contain high concentrations of salts, naturally occurring radioactive material (NORM), and other contaminants including arsenic, benzene, and mercury.[27] Produced water volumes vary by basin: they are generally low for deep shale wells, due to the extreme temperature and pressure, and high for coalbed methane wells, which must be dewatered.

All natural gas wells are subject to accidents such as blowouts, improper well construction and abandonment, and contamination associated with the disposal of drilling mud and produced water. Any structure that penetrates water aquifers, such as a well, has the potential to contaminate these water sources.

After it is extracted, natural gas must be processed, transported, and stored for use. Natural gas processing uses about two gallons of water per million Btu of natural gas, removing liquid hydrocarbons, acid gases, carbon dioxide, and water vapor to produce a nearly pure methane stream.[28] Transportation in pipelines requires an additional one gallon of water per million Btu.[29] Natural gas can be stored in oil or gas reservoirs, aquifers, or salt caverns. Salt cavern storage has the highest water impact, as salt must be dissolved with a one-time use of 500–600 gallons of water per million Btu of capacity, yielding a briny waste stream. This represents 4 percent (and growing) of U.S. natural gas storage volume.[30] Other storage options for natural gas use little water.

For unconventional natural gas production, the major additional water need is associated with "hydraulic fracturing," a commonly used technique that enables drillers to extract natural gas from rock with low permeability, or interconnected spaces. The goal is to give natural gas molecules a pathway to the wellbore by stimulating and propping open fractures in the rock formation containing the natural gas. The fracturing is accomplished by pumping 2–4 million gallons of water mixed with sand and chemical additives into the gas-bearing layer of rock at high pressures.[31] The water used for fracturing is often transported in trucks and stored in tanks at drilling sites. The substantial transportation needs associated with moving water can stress nearby stream banks, contributing to erosion and adding sediment to surface water.[32]

Once in the ground, a large portion of the fracturing fluid may be trapped in the target formation.[33] The rest is pumped to the surface as "flowback," combined with any water "produced" from the formation itself.[34] Both flowback and produced water represent large waste streams that must be disposed of in injection wells or evaporation pits, or municipal treatment plants, or treated and reused to fracture future wells. Where injection or evaporation are not locally tenable, waste water must be trucked to a treatment or disposal site (which increases truck traffic) or recycled and reused in other fracture jobs. Numerous efforts to make produced water reusable for fracturing are under way.[35] If flowback and produced water are disposed of improperly, or if the well is poorly constructed, waste water or natural gas (methane) can contaminate surface water, threatening public and environmental health.[36]

With shale gas production, the two major pathways to water contamination are activities at the surface and errors below ground. At the surface, water resources—particularly stream banks—can be disturbed by truck traffic associated with wellpad construction, day-to-day industrial activity, and in particular, trucking water to and from the site for fracturing and then disposal. Other surface risks include chemical spills and leaching from produced water and flowback stored above ground. Mitigation options do exist, however. Good road planning and reduced truck traffic can protect stream banks. Using more benign chemicals or stricter handling standards reduces the risk of harmful chemical spills. And better water-disposal practices, including lining storage pits and treating water on site, can reduce contamination risk from produced water.

Errors below ground can endanger water resources during shale gas production as well. Properly casing wells mitigates substantially the risk of contamination when an aquifer is penetrated. One element of this is identifying zones that need to be isolated in order to prevent potential shallow pockets of natural gas in formations above the target layer from entering into ground water.[37] Another way to mitigate the risk of contamination during aquifer penetration is by using horizontal wells rather than vertical wells: horizontal wells allow drillers to produce natural gas from a much larger region using fewer wells, thus penetrating aquifers less frequently. When multiple horizontal wells are drilled from one well pad, the risk of contamination is reduced even further since any problems will be localized to that area.[38]

Conventional natural gas has a low extraction-related water footprint, largely because conventional wells do not require hydraulic fracturing. Shale gas, tight gas, and coalbed methane, however, can use and affect much larger amounts of water during their extraction, raising concerns that switching from coal to natural gas could be less benign for water supplies if an increasing share of natural gas is produced from unconventional formations.

Unconventional natural gas has rapidly gained importance in the United States. Estimates of potential **shale gas** resources have increased dramatically in the past two years and now stand at 616 tcf, or 33 percent of potential U.S. natural gas resources.[39] Most natural gas-bearing shales in the United States are located thousands of feet below the Earth's surface, and all have very low permeability, necessitating horizontal drilling and hydraulic fracturing. Approximately 163 tcf of potential natural gas resources are thought to exist in coal seams as **coalbed methane**.[40] Coalbed methane basins are generally shallower than shales and can be located in drinking water aquifers, meaning that wells must be dewatered rapidly and that hydraulic fracturing can pose a greater risk of water contamination.

The **Barnett Shale** in Texas has served as a testing ground for hydraulic fracturing and horizontal drilling techniques in shales. One concern in this region, which is highly urbanized, is the high quality of water used for natural gas wells: potable water from both fire hydrants and the Dallas-Fort Worth airport is used for drilling and fracturing. Barnett wells use an average of 250,000 gallons of drilling water per well and 3.8 million gallons of fracturing water each time a well is hydraulically fractured.[41] Water is disposed of through injection wells or recycled for further fracturing jobs.[42] Barnett wells produce very little formation water and an average of 2.7 billion cubic feet (bcf) of natural gas over their lifetimes.[43]

The **Marcellus Shale** underlying much of Appalachia presents challenging terrain in sensitive watersheds. Marcellus wells are drilled with air mists and water- or oil-based muds, requiring some 80,000 gallons of water for drilling and 3.8 million gallons for hydraulic fracturing per well.[44] Recovered fracture fluids are disposed of primarily through treatment and discharge or recycling, although water treatment plants already are proving inadequate to deal with the volumes and high salinity flowback.[45] Safe fluid disposal is likely a greater challenge than water availability, especially since few injection wells for water disposal exist in the Marcellus due to challenging geology: water must be treated and recycled or discharged, which poses a contamination risk for surface and ground water.[46] However, water availability can be a barrier when stream flows are low, as in the summer, and even relatively small withdrawals can affect aquatic life. Marcellus wells produce about 3.7 bcf of natural gas over their lifetimes and almost no formation water.[47]

The **San Juan Basin** is a mature coalbed methane field in the Four Corners area of the U.S. Southwest. Unlike shale and tight gas reservoirs, coalbeds must be dewatered to reduce pressure and maximize natural gas production.[48] Water content and quality varies throughout the San Juan

Basin, with wells producing between zero and 10,000 gallons of water (average 1,000 gallons) each day and produced water qualities ranging from potable to as saline as ocean water.[49] Produced water is disposed of in injection wells and evaporation ponds.[50] San Juan Basin coalbed methane wells are historically vertical, long-lived, and almost all hydraulically fractured, with individual well productivity ranging from as little as 1,000 to as much as 500,000 cubic feet per day.[51] Each fracturing job requires 55,000 to 300,000 gallons of water-based fluid, which can be difficult to recover.[52] Estimates for average lifetime recovery vary, with typical values between 2 and 4 bcf per well.[53]

The **Powder River Basin** of Wyoming and Montana is a long-term target for coalbed methane production. As with the region's coal mines, water produced from some of the basin's coalbed methane wells could have been suitable for municipal consumption, so expansion of this production in the Powder River Basin could contribute to rapid depletion of high-quality ground water.[54] Wells in the basin generally do not have to be hydraulically fractured and produce an average of 17,000 gallons (but up to some 170,000 gallons) of high-quality water per day.[55] This water is usually discharged to surface waters, stock ponds, or reservoirs.[56] Wells are small, with average reserves of 0.4 bcf.[57]

III. Water Impacts at the Power Plant

Natural gas and coal are both used in thermoelectric power stations to generate electricity. Just as the water implications of fuel extraction, processing, and transport are different for these two fuels, so too are the water implications at the power plant.

Thermoelectric power represents a significant share of U.S. water usage. In 2005, it accounted for 143 billion gallons (41 percent) of fresh water withdrawals per day and 58.1 billion gallons (95 percent) of saline water withdrawals per day.[58] Most of the water that is withdrawn is not consumed: a power plant may take water from the ocean, add heat to it, and return it to the ocean, withdrawing large amounts but consuming almost none. Even so, returning heated water to its source can have negative environmental impacts.

In 2009, thermoelectric power plants were responsible for generating about three-quarters of U.S. electricity.[59] Steam-electric generation operates roughly the same way whether it is fueled by coal, natural gas, biomass, nuclear, solar, or something else: the fuel is used to heat water to steam using a circulatory system of tubes. This steam converts much of its heat energy to mechanical energy by expanding through a turbine, which turns a generator that produces electricity. The steam passes to a heat exchanger or "condenser," where it is cooled and condensed to a liquid so it can be moved back easily to be reheated by fuel combustion in the boiler.

Power plants generally use one of three main types of cooling systems to condense steam: open-loop and closed-loop cooling (both of which use water), and dry cooling (which uses air). Some plants use a hybrid dry-wet system to accommodate seasonal variability in water availability and the plant's cooling needs. The selection of a cooling technology has impacts on a plant's water withdrawal and consumption, construction costs, and efficiency. In general, cold-water cooling systems allow for more efficient operation.[60]

Figure 2a. Schematic of a Open-Loop Cooling System

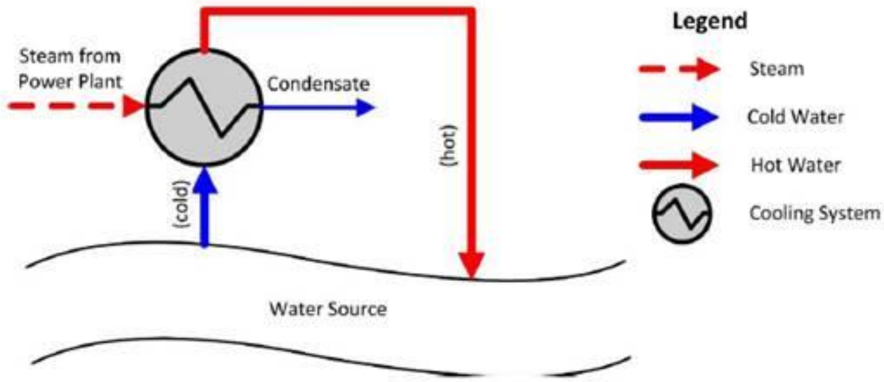


Figure 2b. Schematic of a Closed-Loop System with a Wet Cooling Tower

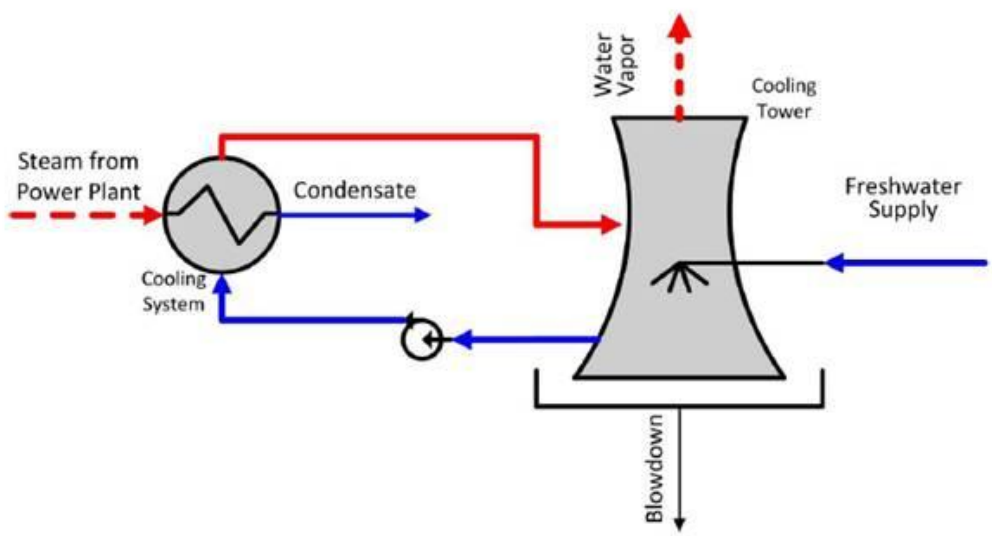
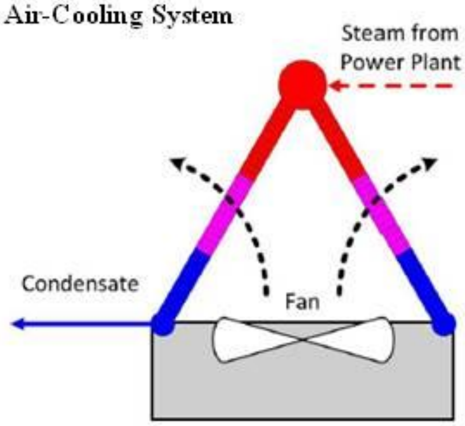


Figure 2c. Schematic of an Air-Cooling System



Source: Stillwell et al.

Plant efficiency, or the amount of usable energy a plant creates from the chemical energy contained in its fuel, also depends on the generating technology, fuel, elevation, age, ambient temperature, and many other factors. No plant can convert 100 percent of its fuel's energy into electricity, and typical efficiencies are between 30 and 40 percent. The rest of the energy is lost from the system as heat in flue gas or cooling water.[61]

Before 1970, most U.S. thermoelectric power plants used **open-loop cooling**, where water is withdrawn from a lake, river, ocean, or other body of water, passed through the condenser, and then discharged back to its source.[62] (See Figure 2.) About 31 percent of current U.S. generating capacity uses open-loop cooling, responsible for 92 percent of water withdrawals for thermoelectric power.[63] Although water withdrawals for open-loop cooling are high, the amount of water consumed is generally minor.

However, open-loop cooling systems can damage aquatic ecosystems. Warm water is a form of thermal pollution, as it reduces the amount of dissolved oxygen available to fish and other species. Since the passage of the U.S. Clean Water Act in 1972, open-loop cooling systems have become much less common in new power plants—only about 10 such systems have been built in the United States since 1980.[64] Open-loop cooling systems can also use seawater where it is available.

Most new U.S. power plants today use **closed-loop cooling**, a system in which water is pumped to a cooling tower or pond, where it is stored and cycled through the heat exchanger. Heat is dissipated through evaporation from cooling towers, which replenish their water supply from a nearby water source. Closed-loop cooling withdraws much less water than open-loop cooling, but half or more of the water it uses is lost through evaporation.[65] As a result, water consumption is actually higher for closed-loop systems, although withdrawals and impacts on aquatic ecosystems are lower.[66] Using seawater in cooling towers reduces stress on fresh water resources, but it also introduces maintenance challenges related to corrosion and mineral build-up.[67]

Dry cooling systems use air instead of water to cool power plants. After the steam is collected in a condenser, the condenser's tubes are cooled using air that is typically blown across the condenser with a fan. Dry cooling enables plants to operate in regions where water availability is extremely limited for all or part of the year.[68] However, air is less able to absorb heat than water, so air cooling reduces overall plant efficiency. This means that more fuel must be consumed and more emissions created for each unit of electricity.[69]

Different plant types in the existing U.S. fleet may be more likely to have one type of cooling system or another. For example, coal-fired generation uses a greater share of open-loop or "once-through" cooling systems than does natural gas combined-cycle generation, in large part because these facilities are more likely to predate the 1972 Clean Water Act.[70]

In addition to cooling systems, coal-fired power plants may use water in "wet" or "dry" flue gas desulfurization (FGD) devices. These devices remove sulfur dioxide—an air pollutant that can lead to smog and acid rain—from boiler exhaust. The use of an FGD device has been estimated to add some 43 liters of water per megawatt-hour (MWh) for a dry system and 257 liters per MWh for a wet system to a plant's withdrawals, virtually all of which is consumed.[71] The incremental water consumption attributable to FGD might be equivalent to almost 50 percent of all water consumption in a plant with a wet FGD process and an open-loop cooling system, whereas it might be less than 10 percent of all water consumption in a plant with a dry FGD process and a cooling tower.[72] (FGD is not necessary in natural gas-fired power plants since natural gas has its relatively low sulfur content stripped out at gas processing facilities.)

Combusting coal in a power plant produces solid wastes such as coal ash, the noncombustible portion of coal. About 10 percent of the volume of coal burned becomes ash.[73] The ash is landfilled, recycled, or mixed with water and stored in impoundments, creating large reservoirs of sometimes-toxic ash suspended in water.[74] Ash must be isolated from aquifers and precipitation to prevent leaching. Spills from impoundment dams can be damaging to surface waters and the surrounding environment. In 2008, the breach of an impoundment dam at a Tennessee coal plant released an estimated 5.4 million cubic yards of wet coal ash, destroying three houses, flooding roads and rails with sludge, and contaminating drinking water with lead and thallium.[75] By contrast, natural gas combustion produces almost no ash.

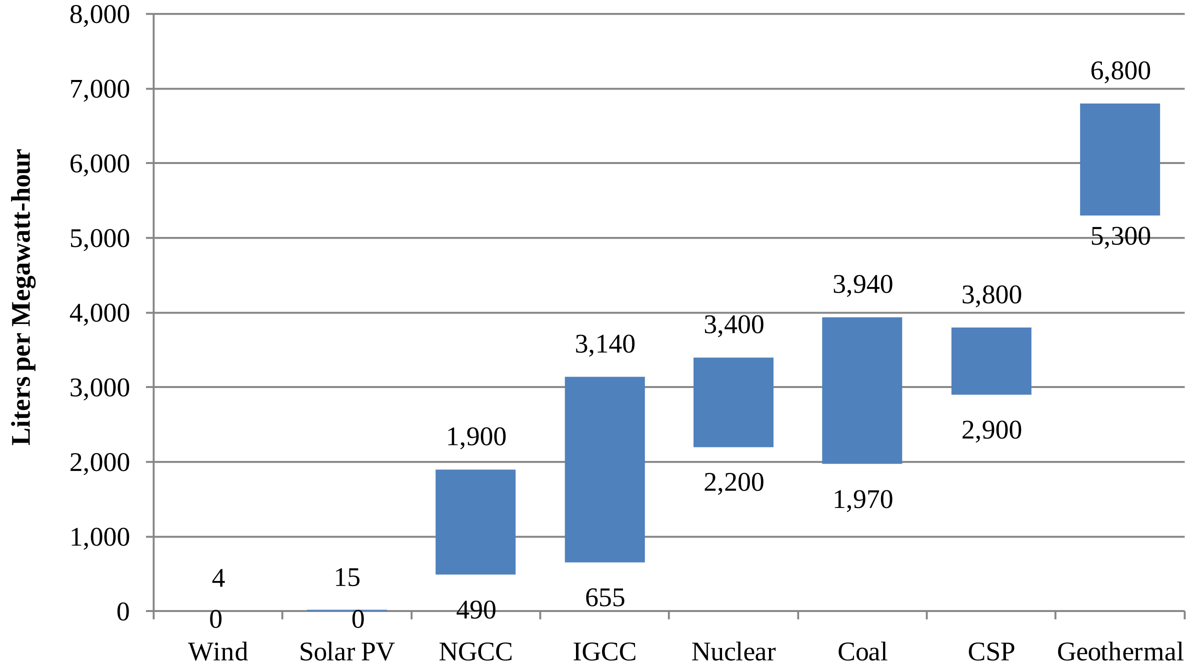
The type of generating technology also affects a plant's overall water requirements. U.S. coal-fired power plants are almost all single-cycle steam-turbine plants that run most of the time. Natural gas combined-cycle plants are much more efficient and may emit more than 60 percent less CO_2 per kilowatt-hour generated than the average U.S. coal plant.[76] Although the United States has installed some 142 GW of NGCC plants since 2000, these facilities have been underutilized, due largely to the relatively high prices of natural gas and the persistent use of coal plants for baseload generation. In 2008, NGCC plants ran at 41 percent of their capacity, while coal steam-turbine plants ran at almost 73 percent, although this gap narrowed substantially during 2009 and the first half of 2010.[77]

Coal-fired steam turbines are the most common power-plant generator technology, accounting for some 44 percent of U.S. electricity generation in 2009.[78] They dominate baseload electricity generation in many parts of the country, and they historically have been expensive to build but cheap to run, since coal prices recently have been lower and more predictable than natural gas prices and the original loans on many older coal plants have now been paid in full. Pulverized coal is combusted in a boiler, and the resulting heat is used to create steam, which powers a steam turbine to generate electricity. The boiler operating temperature affects the plant's efficiency; supercritical boilers operate at higher temperatures and with consequently higher plant efficiencies than subcritical boilers.

Some 81 percent of U.S. natural gas generation today takes place in combined-cycle plants, which generate about 19 percent of the country's electricity.[79] In NGCC systems, a gas turbine is used to generate electricity, and the waste heat is recovered and used to heat water in a heat recovery steam generator. The steam is then used to power a steam turbine. Because a portion of the gas turbine's waste heat is captured and utilized, NGCC plants often have high thermal efficiencies, approaching 50 percent. Water is required to condense steam from the steam turbine, but because the plant also utilizes a gas turbine, which is air-cooled, the water used to generate a kilowatt-hour of electricity is only about one-third of that required by a subcritical pulverized coal plant.[80]

Figure 3 summarizes the estimated water needs for different generating technologies.[81]

Figure 3. Water Consumed in Electricity Generation, by Power Plant Type



Note: Figures assume that plants are equipped with wet cooling tower systems. PV = Photovoltaic; NGCC = natural gas combined-cycle; IGCC = integrated gasification combined-cycle; CSP = Concentrating Solar Power. Source: Fthenakis and Kim.

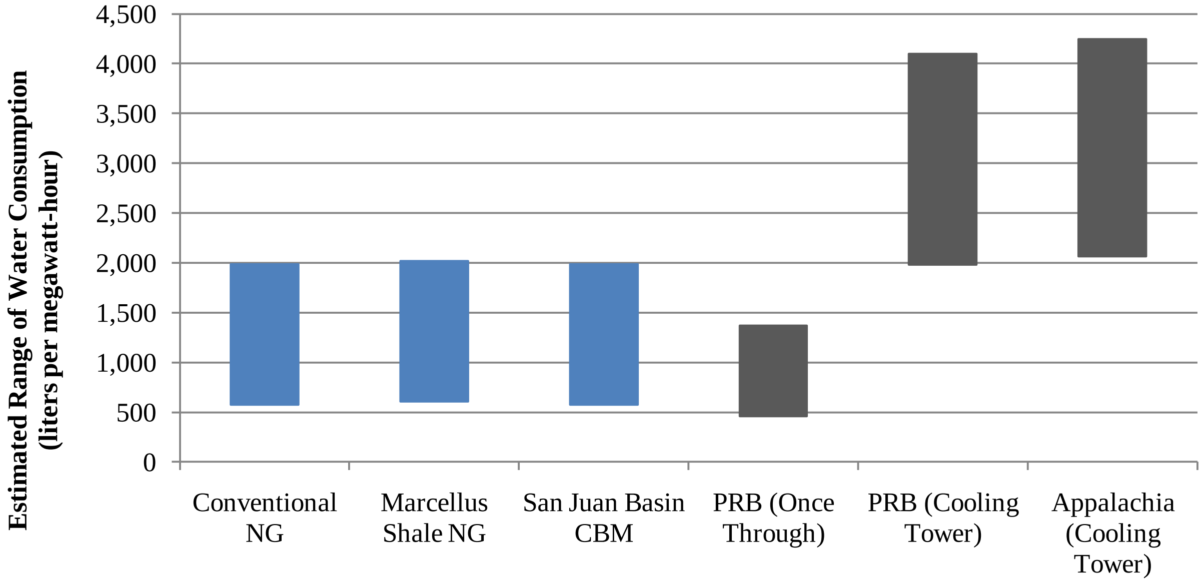
IV. Analysis

Using basic assumptions about the heat rates of different power plant technologies makes it possible to estimate the lifecycle water impacts associated with the electricity generated in coal and natural gas power plants. This allows for a first-order comparison between the two plant types from a water perspective.[82] (See Figure 4 and Table 2.)

Figure 4 compares the water consumption from a range of coal and natural gas power plant technologies equipped with wet cooling towers, the most common cooling systems for new plants. With cooling towers, power plant cooling represents the largest point of water consumption throughout the life cycle of a unit of electricity from coal or natural gas, regardless of the type of plant or fuel used. On balance, the analysis suggests that, for electricity generation, using natural gas consumes less water than using coal. In other words, the water savings from NGCC plants relative to coal steam-turbine plants overwhelm differences in water consumption from extraction, processing, and transportation.

The choice of cooling technology has a large impact on the overall water required to generate a kilowatt-hour of electricity. NGCC plants have lower withdrawal and consumption rates than their coal counterparts when cooling systems are held constant. However, many older U.S. coal plants have once-through cooling systems. As Figure 4 illustrates, a unit of electricity generated at one of these plants could require lower water consumption than a unit of electricity generated at an NGCC power plant. Thus, the type of cooling system employed plays an important role in determining the overall water implications of choosing to generate electricity from coal or natural gas.

Figure 4. Estimated Total Lifecycle Water Consumption for Selected Fuel–Plant Combinations



Note: Blue bars represent natural gas combined-cycle power plants; gray bars represent coal steam-turbine power plants. Assumed plant heat rates based on U.S. averages in EIA's Electric Power Annual 2008. All power plants assumed to be equipped with cooling towers unless noted otherwise. NG = Natural Gas; CBM = Coal Bed Methane; PRB = Powder River Basin. Source: See Endnote 85.

Table 2. Estimated Water Consumption Throughout Fuel Cycle of Coal and Natural Gas

Plant/Cooling System/Fuel	Estimated Water Consumption (Liters per Megawatt-hour)				
	Extraction	**Processing**	**Transport**	**Generation**	**Total**
Coal steam turbine, cooling tower, PRB	11–53	0–109	Negligible	1,970–3,940	1,981–4,102
Coal steam turbine, once-through, PRB	11–53	0–109	Negligible	450–1,210	461–1,372
Coal steam turbine, cooling tower, Appalachia	11–200	82–109	Negligible	1,970–3,940	2,063–4,249
NGCC, cooling tower, conventional natural gas	Negligible	57.5	28.8	490–1,900	576–1,986
NGCC, cooling tower, Marcellus Shale	29.4	57.5	28.8	490–1,900	606–2,016
NGCC, cooling tower, SJB coalbed methane	0.8-2.1	57.5	28.8	490–1,900	577–1,988

Note: PRB = Powder River Basin Coal; NGCC = Natural Gas Combined Cycle; SJB = San Juan Basin.

Many of the water impacts associated with fuel extraction, such as potential long-term contamination or altered hydrology, do not represent water consumption and are difficult to measure and compare. Coal mining likely has a greater potential for long-term water disturbance than does natural gas extraction due to the large footprint of coal mines, acid mine drainage, and other contamination from abandoned mines. However, fresh water impacts from extraction of either fuel must be considered in a local context as well as a national context to obtain a true sense of how energy choices affect fresh water supply and quantity. It is also important to note that risks are not static: for natural gas in particular, near-term technological development may mitigate many risks. Technologies for treating produced water, as well as less harmful additives for hydraulic fracturing, are under active development. As drilling and fracturing techniques improve, the water needs per well might decline as well.

Produced water represents the largest waste stream associated with natural gas extraction, as well as one of the most significant potential sources of contamination. The volume and chemical characteristics of produced water vary by geological formation. Coalbed methane wells in particular produce a lot of water when they are first drilled but less and less over their lifetime.[83] In some cases, produced water is of high-enough quality that it may be used for irrigation, such as in the Powder River Basin. However, produced water from most conventional natural gas and deep shale reservoirs is highly saline, can be toxic, and must be disposed of.

So far, most of the water produced by the U.S. oil and natural gas industry has been reinjected into underground formations or evaporated. But these methods will not be viable on the scale that shale gas drilling is anticipated to reach in the Marcellus Shale because of land constraints for evaporation ponds and geology poorly suited to injection wells. The safe disposal or effective treatment of produced water will be a significant challenge to natural gas development as it moves into new regions.

Of course, the energy choices confronting the United States in the coming years are much broader than whether the country will use coal or natural gas in steam turbines or combined-cycle power plants. The United States is supporting extensive research and development into "clean coal" technologies that will enable electricity to be generated from coal without the steep CO_2 emissions that conventional coal plants produce. One proposed alternative is to gasify coal and use it in a combined-cycle plant. Because such Integrated Gasification Combined Cycle (IGCC) plants are more efficient, they use about a third of the water that their steam turbine counterparts do.[84]

Another potential solution to the large CO_2 emissions associated with coal-fired electricity generation is carbon capture and sequestration (CCS). However, CO_2 capture technology generally adds a significant parasitic load, reducing overall plant efficiency and indirectly increasing the water intensity of generation through additional fuel needs. It can also directly require additional water for cooling and other processes. A 2007 National Energy Technology Laboratory study estimated that the use of CO_2 capture technology increased water consumption per kilowatt-hour by about 95 percent for pulverized coal plants and 37 percent for IGCC plants.[85] Although less frequently proposed, CCS can be used with NGCC plants as well, but this could raise their water consumption by more than 80 percent.[86] The significant water requirements of carbon capture could make CCS-based "clean coal" generation an unsustainable option for water-constrained parts of the world.

Other power plant technologies have negligible water needs—including solar photovoltaic panels, wind turbines, and gas turbines.[87] If these technologies become more prevalent, they are likely to further reduce the per-kilowatt-hour water needs of the U.S. power system.

V. Recommendations

Water and energy are valuable resources whose fates are closely linked. As the United States—and the world—enter a 21st century marked by carbon, energy, and water constraints, managing these two resources in isolation will become ever more challenging. Promoting technologies that are less water intensive—and that have fewer negative impacts on water quality and quantity—will become increasingly important as the demand for energy, clean air, and clean water grows. Choosing natural gas over coal for electricity generation might be an option that simultaneously reduces air emissions and water demand.

Energy production is only one of many competing consumers of limited fresh water supplies. Fresh water is also needed to irrigate crops, supply households, and sustain aquatic ecosystems, among other uses. Moreover, fresh water availability is not distributed evenly in time or space, and even relatively small volumes of water may be locally significant. Decision makers should consider both local impacts and their larger context. For example, using a more water-intensive fuel might be a good choice if that fuel can be extracted in a water-rich region and reduce water needs at a power plant in a water-scarce region.

A range of technologies can reduce water demand throughout the fuel cycle of electricity. At the point of fuel extraction, recycling water simultaneously mitigates the need for fresh water supplies and wastewater disposal. Both the coal and natural gas industries are exploring methods for treating and reusing waste water. One Pennsylvania power plant is investigating the possibility of using treated acid mine drainage water from local abandoned mines for cooling water and boiler feedwater.[88] And numerous natural gas companies are filtering their produced water onsite for reuse in future fracturing jobs.[89] Producers should work with communities and local water authorities as well to shift their water usage to coincide with periods of relatively high water availability.

Finally, improved efficiency can lower the cooling water requirements of any power plant technology. One application that provides substantial efficiency gains is cogeneration, the capture and utilization of the excess heat created during electricity generation. Often, cogeneration supplies heat in the form of hot water or low-temperature steam, so the net water impact depends on the application. Cogeneration may increase water use at the plant level, for example, if waste heat in flue gas is captured in water for heat delivery, thereby displacing heat from a natural gas furnace that was not using water. But cogeneration can save water if a hot water discharge from a power plant is used to directly replace a separately fueled hot water heating system. Cogeneration also mitigates the need for other energy sources to supply heat, reducing water impacts associated with fuel extraction, processing, and transportation.

Decisions about energy resource use and policy should value both the quantity and quality of water. Valuing water quality impacts is often subjective, however, and the short- and long-term needs of communities should be considered. Water is inherently a fungible resource, and considering its full context might improve overall resource utilization.

As energy extraction in the United States and elsewhere continues to affect water resources, restoring these resources will require additional energy usage, which in turn will require greater water demand for energy production. Utilities and policy makers considering natural gas as an alternative to coal in the power sector should take into account the sizable difference in the fuels' water footprints.

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