Emerging Issues for Fossil Energy and Water

DOE/NETL-2006/1233

Investigation of Water Issues Related to Coal Mining, Coal to Liquids, Oil Shale, and Carbon Capture and Sequestration

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Executive Summary

The National Energy Technology Laboratory (NETL) is a leader in evaluating the relationship between water and energy. The Environmental Water Resources program and Geological Sciences Division at NETL have evaluated the impact of energy development on water quality and availability and pioneered means of decreasing water consumption and resource impairment. To date, NETL's research has focused on evaluating water use and consumption in thermoelectric power plants, quantifying legacy acid mine drainage, advancing water management options for resource extraction, and developing creative solutions to remediate water quality—leading the way with research to support the National Laboratories Energy-Water Nexus Roadmap to Congress. This activity involves all the national laboratories in the development of a research and development plan for technologies and methodologies that reduce the impact of energy development on water and water demands in energy production. NETL has a portfolio of innovative technologies, expertise, and knowledge to continue minimizing the impact of fossil energy use on water quality and availability and ensure the success of the Energy-Water Nexus.

In the following chapters, NETL's Office of Systems, Analyses and Planning provides four brief introductions to critical water-energy issues that are arising with continued development of energy resources. This work examines the relationship between water and coal extraction, novel fuel options including coal-to-liquids (CTL) production and oil shale development, and actions to reduce carbon dioxide (CO_2) emissions and ambient concentrations via biological and geological carbon capture and storage. The development of these technologies has local and global impacts on water supply. For example, development of oil shale can result in a localized effect on water quality and availability in Colorado and Wyoming, while carbon capture and sequestration can reduce climate change and thus diminish its influence on rainfall, runoff, and quality of fresh and saltwaters.

Due to the prospective nature of this work, each chapter is a survey of the water-energy issues for each topic and is presented with the goal of fostering further discussion and investigation of the relationship among fossil fuel extraction and conversion, technology, and water. Where available, estimates of water use, consumption, and quality are provided. Additional data collection and analyses are needed to fully understand the quantity and application of water used, as well as the extent of damage or beneficence resulting from technology implementation.

This report begins with a discussion of coal mining, followed by CTL technology, oil shale development, and carbon capture and sequestration. In all, it discusses fuel throughout its entire life cycle—from extraction to treatment of end use emissions. It is anticipated that readers will find these brief studies to be a suitable platform for further questioning and discussion of the relationship between water and emerging fossil fuel technologies.

The withdrawal and consumption of water in regions where water is not abundant for coal mining, CTL production, and oil shale development necessitates competition with other industries and public consumption. Additionally, all the energy issues discussed in this report have the potential to negatively and positively affect water quality. The true nature of these impacts to water quality and availability must be analyzed to further address potential shortages and environmental concerns. This report identifies areas in which NETL can add value, recognizing that the laboratory is a leader in addressing water-energy issues.

NETL expertise in systems and situational analyses supports the evaluation of water needs for fuel development and the identification of more efficient uses of water. The Pennsylvania Environmental Council has recognized the NETL Clean Water Team for its groundbreaking research and demonstration of technologies that address mine water quality. NETL continues to contribute to the understanding of water quality, through development and demonstration of technologies that can be transferred to other applications. For instance, NETL's watershed imaging techniques could easily be used to create images of underground reservoirs to better understand their relationship to overlying coal reserves and determine coal mining's impact on water availability. Another application of NETL's expertise could be found in developing process analyses of fuel development, such as coal liquefaction and oil shale production, and new technologies, such as carbon capture and sequestration.

Anticipating new issues for fossil energy and water is critical to adequately managing water quality and availability. With foresight, it is possible to develop creative approaches to increasing water supply while increasing energy and fuel technologies. In the past, NETL has been at the forefront of addressing the relationship between water and energy; it will continue to offer knowledge and solutions in the future.

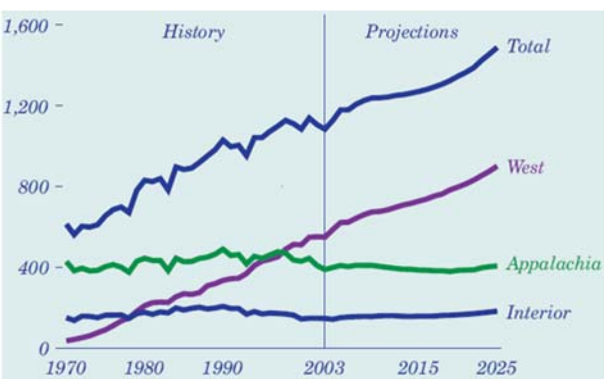
Chapter 1: Water and Coal Mining

Background

As coal continues to be a major source of energy in the United States, it is necessary to consider the amount of water used in the coal extraction process, as well as the impact of mining practices on local water quality. The relationship between water and coal varies across the country, as water quality impacts are related to the geology and chemical composition of the rock, proximity to local water resources, and mining method used. Similarly, the amount of water used throughout the mining process is dependent on the type of coal and the extraction process used in each region.

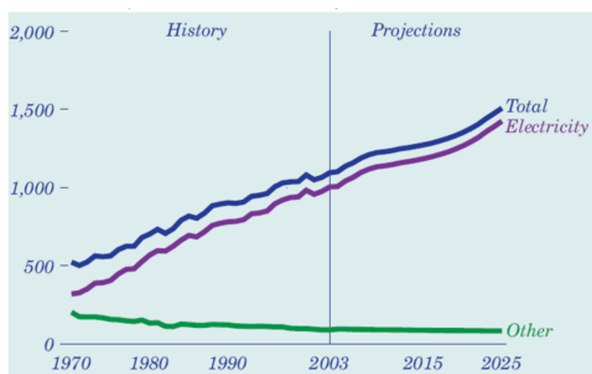
Continued reliance on domestic fossil energy resources will require ongoing mining of coal. To meet U.S. coal demand, the 2006 DOE/Energy Information Administration (EIA) Annual Energy Outlook projects continued growth in annual coal production. Electricity generation consumed 92 percent of the coal produced and is expected to account for 94 percent of the coal market in 2025 (EIA 2005a). The increase in coal production is driven in large part by sulfur emission regulations, with significant production increases in the low-sulfur western coal that has lower heating value than eastern coal. More coal is needed to make up the energy penalty of using western coals in electricity generation. Figures 1-1 and 1-2 show expected increase in coal production and continued reliance on coal for electricity production.

Figure 1-1. Coal Production by Region, 1970–2025.



Source: EIA 2005a.

Figure 1-2. Electricity and Other Coal Consumption, 1970–2025 (million short tons).

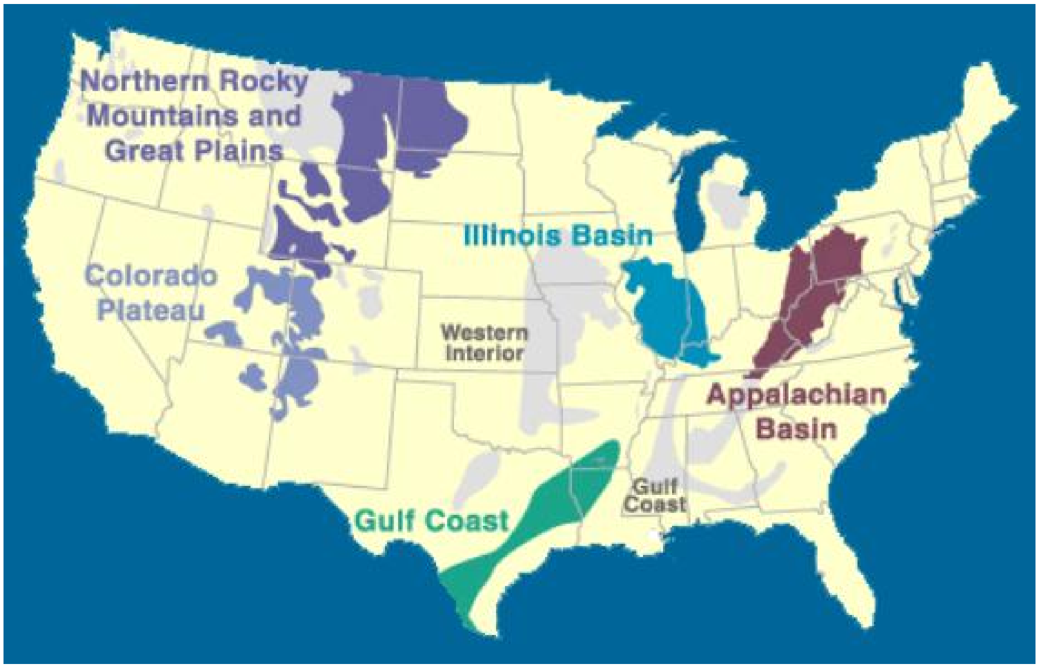


Source: EIA 2005a.

Coal Resources

There are five major coal-producing regions in the United States, as shown in Figure 1-3: the Appalachian Basin, the Illinois Basin, the Gulf Coast, the Northern Rocky Mountains and Northern Great Plains, and the Rocky Mountains and Colorado Plateau. The United States Geological Survey (USGS) and EIA maintain estimates of economically recoverable coal reserves per region. USGS performs detailed assessments of coal depth, thickness, structure, and mined-out areas, while EIA records prices and productivity and forecasts future demand, price, and production per region. According to the EIA, 1.2 billion short tons of coal were produced in the United States in 2004.

Figure 1-3. U.S. Coal-Producing Regions.



Source: http://geology.usgs.gov/connections/blm/energy_intro.htm

Coal quality varies by region. In general, Appalachian and Illinois Basin coals have higher heating value than coal mined from the western coal basins. However, mining in the Appalachian and Illinois Basins is now a mature industry and beginning to decline. Although Powder River Basin coal has a lower calorific value than coals from the Appalachian and Illinois Basins, its low sulfur content makes it a popular fuel of choice to comply with the sulfur dioxide (SO_2) emissions restrictions of the Clean Air Act Amendments of 1990.

Just as coal varies by region, so does the depth of the deposit and the height of the seam. Mining methods must be chosen to cost effectively extract the coal. In general, coal located at depths greater than 100 feet are extracted by underground methods. Due to the shallow nature of western coal deposits, surface mining methods dominate western mining. On the other hand, underground mining techniques are used throughout Appalachia. Coal production and average prices per region are shown in Table 1-1. Both methods of mining are shown in Figures 1-4 and 1-5.

Table 1-1. Coal Production and Price by Region, 2004.

	Production (million short tons)			Average Open Market Sales Price ($)
	Underground	**Surface**	**Total**	
Appalachia	251.6	138.3	389.3	31.85
Illinois	56.7	89.3	145.8	24.20
Western	59.2	515.9	575.2	14.85
Total	**367.5**	**743.5**	**1,111.5**	**23.63**

Source: EIA 2005b.

Figure 1-4. Surface Mining Operation.

Source: NETL.

Figure 1-5. Underground Mining Operation.

Source: NETL.

Water Requirements During Mining Operations

Water needs for coal mining can vary by mining method, whether it is surface (approximately 90 percent of current western coal mining) or underground (approximately 65 percent of current Appalachian coal mining) mining (EIA 2004). Typical mining processes that require water include coal cutting in underground mines, coal washing to increase heat content and partially remove sulfur, and dust suppression for mining and hauling activities. In addition, reclamation and revegetation of surface mines also require water, and those requirements can be highly variable depending on a variety of factors (e.g., coal properties, mining waste disposal methods, and mine location). Estimates of water requirements for mining activities range from 10 gallons per ton to more than 150 gallons per ton of coal mined, with the lower range applicable to western coals with minimal revegetation activities and the higher end applicable to underground mining of eastern coals (Gleick 1994). Recycling of water in underground mining process can dramatically reduce water consumption. Coal washing is applicable to eastern and interior coals, while western coals are typically not washed due to homogeneous seams with low sulfur content. An estimated 80 percent of eastern and interior coal is washed (Toole-O'Neil 1999). Water requirements for coal washing are also quite variable, with estimates of roughly 20–40 gallons per ton of coal washed (Gleick 1994; Lancet 1993).

Based on 2003 national coal production statistics, a rough estimate of overall water required for coal extraction (mining and washing) could range roughly from 86 to 235 million gallons per day, approximately 4–12 percent of freshwater withdrawals for the mining water-use sector in 2000. However, in 1995, the USGS estimated that approximately 30 percent of the freshwater withdrawn was consumed by mining operations (USGS 2004; USGS 1996). Overall, the USGS estimates that for 2000 the mining sector freshwater withdrawals were approximately 2 billion gallons per day, 20 percent less than reported for the more complete estimate in 1995. The cause for this decrease is likely due to the change in reporting practices described below.

The USGS provides estimates of water use for mining, which include the mining of solids (e.g., coal, iron, sand, and gravel) and the extraction of petroleum and natural gas resources. While the mining water-use category contains a variety of resource extraction activities, there is no quantification of water use for extraction of individual resources, such as coal, oil, or gas. USGS relies heavily on surveys of mining operations and State and Federal agencies that collect water withdrawal or discharge data. USGS data for 2000 are not as detailed as 1995 estimates because no 2000 data were collected for 27 states that reported some water use for the mining sector in 1995. The 27 states that did not have data collected included several large coal-producing states, such as West Virginia and Kentucky. In 2003, those two states combined produced more than half of the coal mined east of the Mississippi River and nearly one-quarter of the total tonnage mined in the United States.

Water Quality

Local water quality may be affected during and after coal mining activity. Underground and surface mines require the removal of material, topsoil, soil, and rocks to access the coal. This material and waste coal are stored in piles that are exposed to the elements, allowing for oxidation of trace elements into acids or alkyls that can be leached into surface waters by water runoff from rain or snow. When the life of the mine is over, there may still be problems related to the coal extraction activity. Mine drainage issues at the end of life vary according to mining method used, geology, climate, and rainfall.

Due to differences in geology, eastern and western aquifers are affected in different ways. Impacts on western water are typically attributed to high levels of salts and alkaline materials, whereas eastern water pollution is due to acid formation. Western coals are often part of a local aquifer, such that water flows through crevices in the coal. Removal of the coal disrupts the natural aquifer recharge rate. In the East, water from precipitation flows through crevices and cracks in soil to recharge ground water resources. Thus, coal extraction activity affects water quality and availability in the West and East.

The Surface Mining Conservation and Recovery Act of 1977, enforced by the Office of Surface Mining, requires affected resources to be returned to a condition that is suitable for post-mining use. In the West, where the climate is arid, typical end-of-life reclamation practice is to refill mined areas with the stored soils and other materials to match pre-mined contours as best as possible. Since this material has been stored in the open, it may be oxidized, aerated, and mixed and no longer have the same composition it did before mining activity began. When it rains, the reclaimed area may be more porous, allowing percolating water to leach pollutants through soil into underground aquifers (NRC 1990). However, compressing fill materials to reduce the level of contaminants that leach through a reclaimed surface mining area may result in lower recharge rates to local groundwater resources and reduced water availability in the region.

In the East, underground mining requires coal to be cut in order to be removed. This practice exposes the coal face. Pyrite, iron, aluminum, and manganese may contact and react with water and oxygen to form acids. Acid may form during active operations and after coal production has ended since metals remain to be leached from the exposed coal surface. Iron is a strong indicator of acidity because it represents the potential for acid formation. First, some acid may be formed when pyrite, an iron and sulfur compound, is oxidized. Dissolved ferric iron released from pyrrhic oxidation serves to further oxidize any remaining pyrite. Second, pH alone is not an adequate indicator of acidity. Water with near-neutral pH with high concentrations of dissolved iron can become acidic after complete oxidation and precipitation of the iron.

Water Management

Water quality issues may be treated in a number of ways. As described above, water impacts vary by type of coal, and therefore, by region of the country. In the West, where water availability is impacted by disruption of water recharge, surface water quality can be affected by runoff from storage of topsoil and other overlying material. To reduce these impacts from western coal mining, it is necessary to extract the overlying material and soil in layers and store them separately. The Environmental Protection Agency (EPA) and the Office of Surface Mining (OSM) have recommended best management practices for reducing the leaching of minerals and nutrients from these materials and the placement of these materials after the coal has been extracted in order to best simulate original land characteristics.

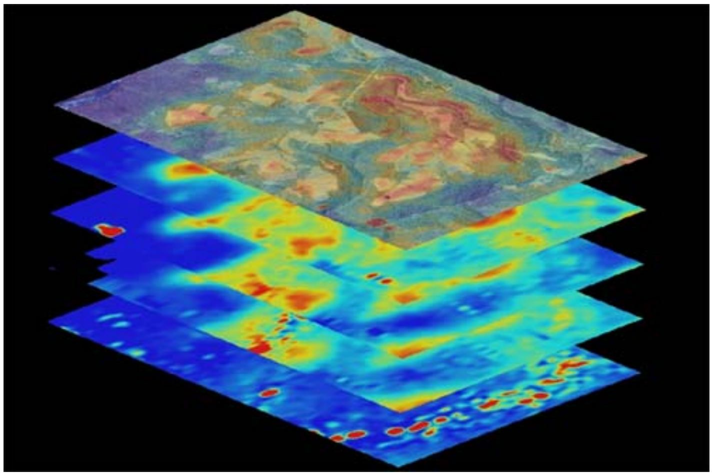
In the East, where acid mine drainage is a prevalent problem, treatment options include the addition of alkaline to neutralize acids and the prevention of acid formation preventing exposure of the cut coal face to air and water. To date, several methods have been developed with these strategies in mind. Water can be actively pumped and caustic material can be added to reduce acidity of mine discharges or the discharge can be allowed to passively flow through a constructed wetland so that the minerals are absorbed by soils and plants (Figure 1-6). The added benefits of a constructed wetland include aesthetic improvements through vegetation and low maintenance cost. A mine can be grouted to prevent contact between the coal face and air and water; mines that lie below the water table can be flooded to achieve the same effect.

Figure 1-6. Constructed Wetland for Mine Water Discharge Treatment.

Source: NETL Clean Water Team.

NETL has expertise and experience in examining water quality and treating mine discharges. Over the years, NETL has developed a multitude of watershed assessment tools and means of reducing pollution from coal extraction. The NETL Clean Water Team has worked extensively to collect data about coal mine discharges to surface and underground water resources and to present these data in formats that ease planning for mine remediation. Figure 1-7 is an example of a three-dimensional watershed profile, created by NETL, to diagnose pollutant concentrations. Geologic features are represented to a depth of 300 feet, which can be used to select technologies for targeted treatment. In addition to watershed characterization, NETL has worked with USGS, EPA, and various community groups to create successful systems to address specific needs.

Figure 1-7. Three-Dimensional Model of Groundwater Within a WV Watershed.



Source: NETL Clean Water Team.

NETL pioneered the development of environmentally benign water treatment methods for coal mines. NETL experts work in the field to demonstrate that mines can be reliably grouted to prevent acid formation and are developing technologies to treat acidified waters. Besides the award-winning projects that resulted in passive water treatments, such as constructed wetlands and anoxic lime drain treatments, NETL has patented the In-Line System that treats flows up to 3,000 gallons per minute, uses no electricity, and reduces treatment costs by more than 30 percent (Figure 1-8).

Figure 1-8. In-Line System to Treat Acid Mine Drainage.

Source: NETL Clean Water Team.

Conclusions

The relationship between water and coal mining is complex—between the need for water in coal preparation and coal miner safety and the impact that mining activities have on local water availability and quality. NETL's expertise in systems and situational analyses can support the evaluation of water needs for coal mining and the identification of more efficient uses of water. The Pennsylvania Environmental Council has recognized the NETL Clean Water Team for its groundbreaking research and demonstration of technologies addressing mine water quality. In the future, NETL will continue to contribute to the understanding of water quality. For instance, the watershed imaging techniques could easily be used to create images of underground reservoirs to better understand their relationship to overlying coal reserves and determine coal mining's impact on water availability.

In addition to providing the knowledge necessary to improve water availability and quality in coal mining, NETL is leading the way with research to support the National Laboratories Energy-Water Nexus Roadmap to Congress. This multilaboratory activity, lead by Sandia National Laboratory, is developing a research and development plan for technologies and methodologies that reduce the impact of energy development on water, as well as reduce water demands in energy production. NETL has a portfolio of innovative technologies, expertise, and knowledge to continue minimizing impact of coal mining on water quality and availability, as well as ensure the success of the Energy-Water Nexus.

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Chapter 2: The Availability of Water Resources to Support Coal-to-Liquid Fuels Plants

Introduction

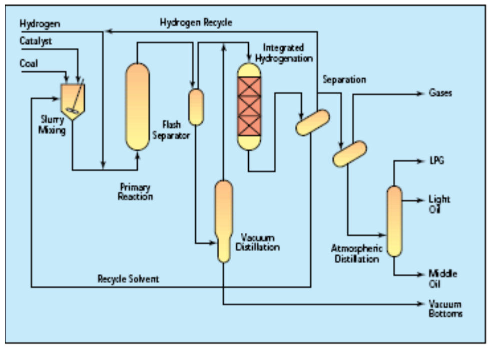
Coal resources are abundant throughout the United States, and given the high prices and volatility in the oil and natural gas markets and the Administration's vision to reduce foreign oil imports, coal-to-liquid (CTL) fuels plants are becoming a more common topic of discussion for decision makers in business and government alike. Three factors influencing the site location of such plants are (1) the availability of the coal resource, (2) the process used by the plant (direct or indirect liquefaction), and (3) the accessibility of water. Overlying these factors are the plant's environmental impact and the impact mitigation plan for water acquisition and disposal. Before coal liquefaction can make a significant contribution to meeting the demand for liquid fuels, it will be necessary to ensure that sufficient water resources are available at proposed plant sites. This section examines three coal-rich regions of the United States and their coals—Pennsylvania/West Virginia's eastern coals, Illinois' midwest coals, and Wyoming/Montana's western coals—and provides a cursory review of the CTL-water relationship.

Background

The technology for converting coal into synthetic crude oil (syncrude) has been available for many years. Following World War II, there was a strong domestic program aimed at commercializing coal liquefaction processes, and a number of pilot plants were built and operated. However, starting about 1980, there began a de-emphasis of coal liquefaction, driven primarily by the relatively low price of petroleum (Kent 2003).

There are two major approaches to liquefying coal: direct liquefaction and indirect liquefaction. In direct liquefaction, finely ground coal is mixed with a process-derived solvent and heated at relatively high temperature and pressure in the presence of hydrogen. Upon pressure letdown, the liquefied coal is separated, the solvent is recycled, and any unconverted coal is fed to the hydrogen production unit. The product produced by direct liquefaction tends to be relatively high in aromatics. The schematic shown in Figure 2-1 illustrates an updated version of the single-stage direct liquefaction process used in Germany until 1945, called the Kohleoel Process (DTI, 1999). This process was updated to increase the production of lighter oils.

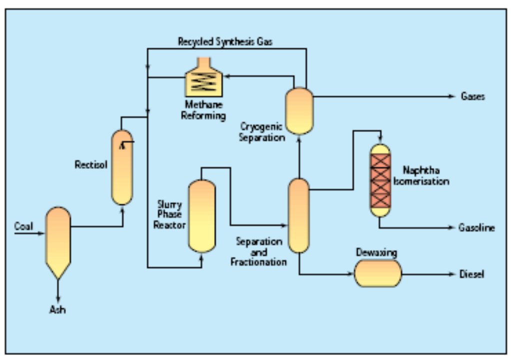
Figure 2-1. Kohleoel Process.



Source: DTI 1999.

In indirect coal liquefaction, the coal is first gasified to produce syngas—a mixture of carbon monoxide (CO) and hydrogen. The syngas is sent to a Fischer-Tropsch (F-T) reactor, where it is converted to a wide boiling point range of mainly paraffinic hydrocarbons. Figure 2-2 is a schematic diagram of the Sasol Process for indirect coal liquefaction. The design was updated in 1980 to produce roughly 50,000 barrels per day (bbl/d) of products at Sasol's plant in South Africa (DTI 1999).

Figure 2-2. Sasol Process for a 50,000 bbl/d Plant in 1980.



Source: DTI 1999.

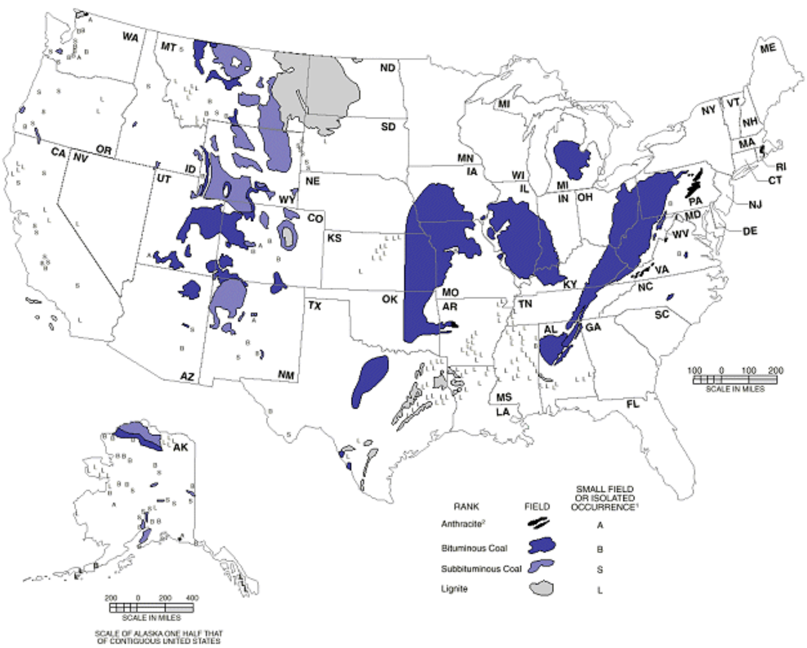
Both direct and indirect liquefaction are relatively expensive processes, and studies have indicated that the cost to produce syncrude is about \$50–\$60/bbl (barrel of 42 gallons). These costs make coal liquefaction unattractive in a time of "cheap oil," but price trends for petroleum in the \$60–\$70+/bbl range are beginning to renew interest in coal liquefaction.

Resources

According to the EIA, the 2003 coal resource base was estimated at approximately 268,000 million short tons within the United States, including Alaska. The EIA recoverable reserves for 2003 in the three areas of interest were as follows: for the Eastern United States (Pennsylvania/West Virginia) recoverable reserves of 2,033 million short tons, for the Midwest (Illinois) 913 million short tons, and for the Western United

States (Wyoming/Montana) 7,904 million short tons. The largest concentration of high-quality bituminous coals occurs in the Eastern and Midwestern United States, while the western coals are younger and range in quality from lignite to subbituminous and bituminous (Figure 2-3).

Figure 2-3. Coal Rank and Location.



Source: http://www.eia.doe.gov/cneaf/coal/reserves/chapter1.html

Water Requirements for Liquefaction Technologies

There are three major requirements for water in a typically sized 50,000 barrels per steam day (BPSD) liquefaction plant:

- *Process Water.* Process water is water that is intimately involved in the liquefaction process and sometimes even plays a part in chemical reactions. Examples include water in coal gasifiers that reacts with carbon to form CO and hydrogen and water in water-gas-shift reactors. Process water may also be used in scrubbers for the purpose of removing ammonia and hydrogen chloride from syngas. Some process water is consumed in the liquefaction process and must be replaced with additional makeup water. It can also be lost through evaporation into process gas streams or in waste slurry streams, such as flue gas desulfurization sludge or gasifier slag.

- *Boiler Feed Water.* Boiler feed water is used to produce steam. Much of this water is recovered as condensate and returned to the boiler, but there is some loss due to leakage and the occasional need for a blowdown to purge impurities from the system. Also, steam may need to be injected at a specific step in the process, in which case the boiler feed water is converted to process water.

- *Cooling Water.* Chemical plants, refineries, power plants, etc., often require cooling of process streams, and a CTL plant is no different in this regard. Such cooling is typically accomplished using circulating water. After absorbing heat, the cooling water is sent to a cooling tower, where evaporation of part of the water cools the remaining portion so that it can be recirculated. Typically, cooling water loss through evaporation in the tower is *the most significant* factor in total overall water consumption.

The amount of water required to operate a coal liquefaction plant is a function of many variables, including the design of the liquefaction unit, the type of gasifier used to provide the syngas or hydrogen, the coal properties, and the average ambient temperature and humidity. In the 1990s, Bechtel performed a series of studies for DOE in which they evaluated a variety of coal liquefaction schemes for indirect liquefaction (Bechtel 1998) and determined the following water needs:

For eastern coal	7.3 gal of water/gal F-T liquid
For western coal	5.0 gal of water/gal F-T liquid

The above differences in water requirements between eastern and western coals probably reflect the higher moisture content of western coal and lower humidity. For example, if a gasifier such as the GE Energy (Texaco) gasifier (which uses slurry feed) is used, then the coal does not need to be dried and the inherent moisture in the coal can serve as part of the process water. Of the total water requirements, it is estimated that about 1 gal/gal of F-T product is needed for process water in the gasifier (Bechtel 1998).

For a direct liquefaction plant based on Illinois No. 6 coal, Bechtel (Bechtel 1993a) estimated water requirements of about 6.1 gal/gal of liquid product. Over 70 percent (4.5 gal/gal product) of this was for makeup water to the cooling tower. Approximately 0.5 gal/gal product was used for boiler feed water, 0.7 gal/gal product for process water to the coal gasifier used for hydrogen production, and 0.4 gal/gal product for miscellaneous purposes (Bechtel 1993b). Three to five percent of the water being circulated in a cooling tower is lost to evaporation, leaks, and blowdown. Thus, for every 1,000 gallons circulated, 30–50 gallons of makeup water is needed. Most steam is condensed, and the condensate is re-circulated to the boiler. In modern designs, there is very little discharge of waste water to the environment. Blowdown streams can be used as part of the coal feed slurry water, with the impurities they contain ending up in the gasifier slag.

In a recent study, Parsons provided estimates of water usage for integrated gasification combined cycle (IGCC) power plants based on a variety of gasifiers (Parsons 2005). Water usage ranged from 678 gallons per megawatt-hour (gal/MWh) for E-Gas to 830 gal/MWh for GE Energy Quench. It is estimated that the amount of syngas required to produce one barrel of F-T liquids would generate about 1.2 MWh of electric power if burned in an IGCC system.

To put things in perspective, Table 2-1 presents the approximate water requirements for some typically sized coal liquefaction plants. The amount of water required to operate a coal liquefaction plant is impacted by many variables, including the design of the liquefaction unit, the type of gasifier used to provide the syngas or hydrogen, the coal properties, and the average ambient temperature and humidity. The table presents the approximate water requirements in gallons per minute (GPM) and billion gallons per year (Bgal/yr) for some reasonably sized 50,000 BPSD for coal liquefaction plants.

Table 2-1. Water Requirements for Coal Liquefaction Plants.

Technology	Coal	Size	Water Requirement
Indirect Liquefaction	Eastern	50,000 BPSD	10,500 GPM (4.966 Bgal/yr)
Indirect Liquefaction	Western	50,000 BPSD	7,300 GPM (3.453 Bgal/yr)
Direct Liquefaction	Midwestern	50,000 BPSD	7,900 GPM (3.737 Bgal/yr)
Coproduction (F-T Liquids Plus Electric Power)	Eastern	25,000 BPSD plus 1,250 MW	20,800 GPM (9.839 Bgal/yr)

Source: Parsons 2005.

Water Quality Requirements

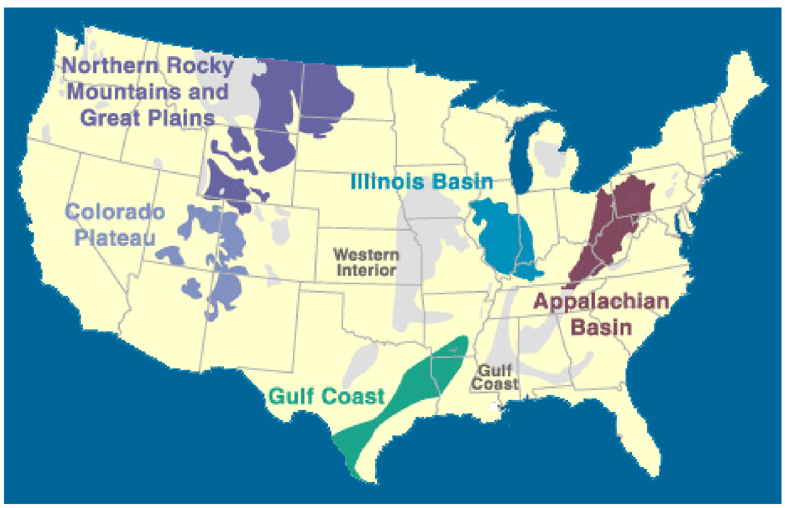
The water used to slurry the feed coal to the gasifier does not need to be of high quality, impurities in the water are removed along with the coal ash in the gasifier slag. Boiler feed water, of course, has to be high quality to prevent deposition of scale in boilers, so the makeup water to the boiler feed water system must be treated. The cost of this treatment increases as the quality of the raw water decreases. Cooling water needs to be of reasonable quality to prevent corrosion and deposit formation in heat exchangers, and additives are typically added to the cooling water to control corrosion and scaling in the system. Due to the wide variation in water chemistry, a professional water treatment consultant is needed to evaluate the makeup water and operating conditions of the cooling tower and recommend appropriate water treatment chemicals and pretreatment (e.g., softening, pH adjustments). Both boiler feed water and cooling tower systems employ a blowdown stream to prevent the buildup of impurities in the system. These blowdown streams can be used as coal slurry water; with the impurities they contain ultimately leaving the system with the gasifier slag.

Because water purification is critical to the operation of refineries, chemical plants, power generation plants, and CTL plants, numerous industrial processes have been developed to remove impurities from the water needed by these facilities. Among the processes in use are filtration to remove suspended solids, activated carbon filters to remove dissolved organics, and demineralization using ion exchange resins to remove undesirable minerals. While it is technically possible to clean up almost any water stream to make it usable in a CTL plant, the cost will increase as the impurity levels in the raw water increase.

Regional River Basins and Their Proximity to Coal Mining

The major coal basins span most of the United States (Figure 2-4), and their proximity to sources of water for resource extraction, processing, and consumption operations can impact the feasibility and cost associated with those operations. A wide variety of industrial operations, from coal washing to water injection for enhanced oil recovery, require large quantities of water, with thermoelectric power plants responsible for the largest amount of water withdrawal. According to a USGS report, thermoelectric generation accounted for 39 percent of the freshwater withdrawn from watersheds in the United States in 2000 (USGS 2004).

Figure 2-4. Display of Major Coal Basins.

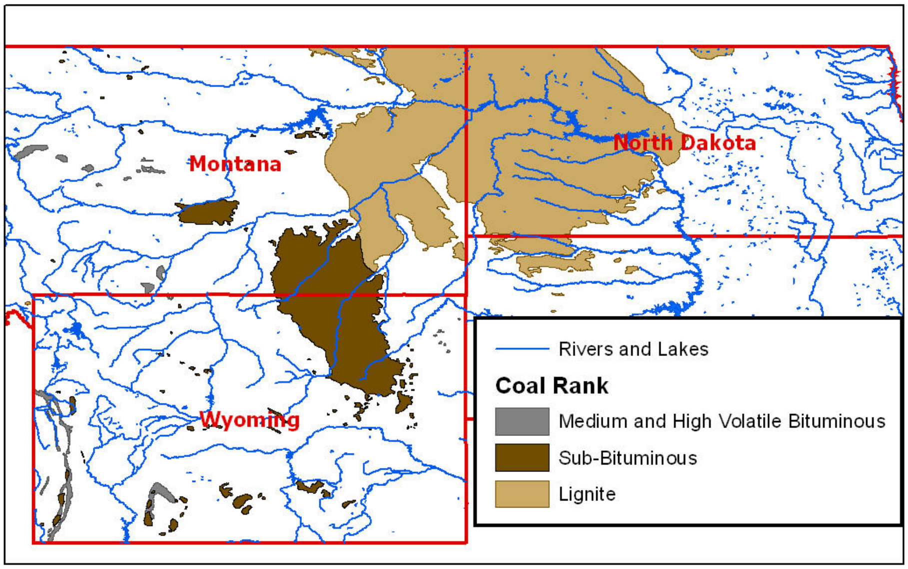


Source: http://geology.usgs.gov/connections/blm/energy_intro.htm

In regard to CTL plants, consideration must be given to the availability of water for use, surface and groundwater sources, the total water consumption, and the effect of the remaining discharge of waste water. Figures 2-5 through 2-7[1] display the locations of surface water sources and coal resources in the Wyoming/Montana area (Powder River Basin); the Illinois Basin, and the Appalachian Basin. All of these regions include both surface water resources and active coal mining operations.

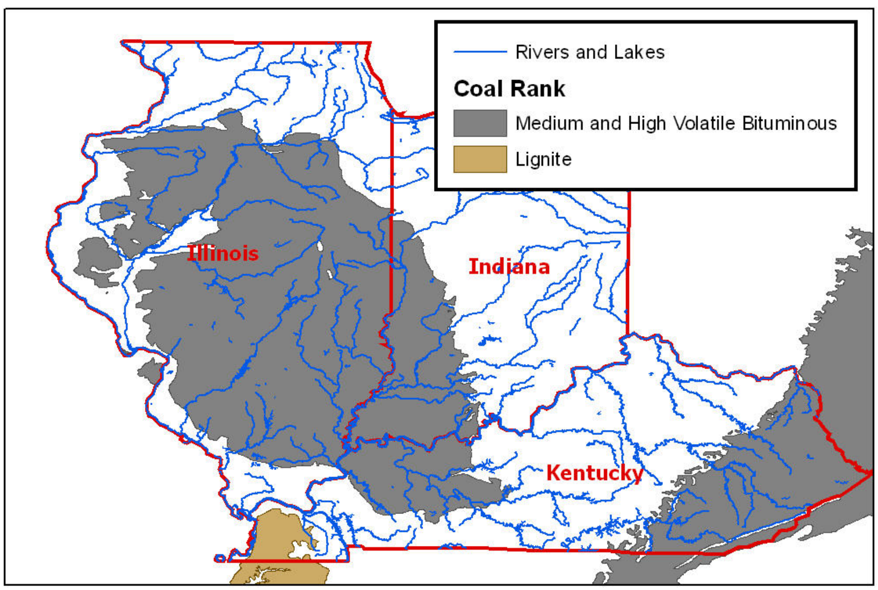
[1] Figures 5 through 7 were generated using ArcMap 9.1. Coal data layer was downloaded from the USGS GEODE website at http://geode.usgs.gov/. States, rivers, and lakes are from ESRI standard layers at www.esri.com.

Figure 2-5. Northern Rocky Mountain Region Coal and Surface Water.



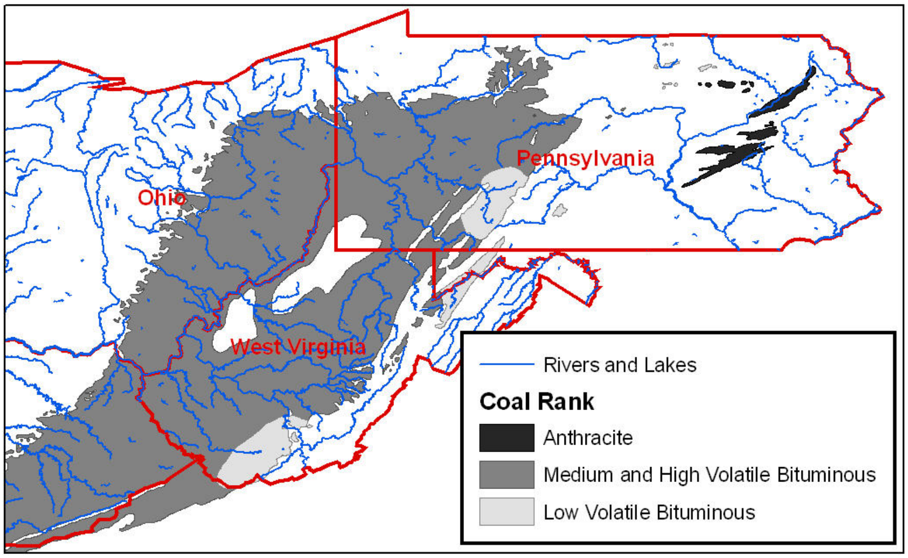
Source: Figure generated using ArcMap 9.1 and data from http://geode.usgs.gov/ and www.esri.com.

Figure 2-6. Illinois Basin Coal and Surface Water.



Source: Figure generated using ArcMap 9.1 and data from http://geode.usgs.gov/ and www.esri.com.

Figure 2-7. Appalachian Region Coal and Surface Water.



Source: Figure generated using ArcMap 9.1 and data from http://geode.usgs.gov/ and www.esri.com.

Competing Regional Water Usage and Impact to CTL Placement

An understanding of how water in each region is currently used and forecasted to be used allows for a better understanding of competing uses of water. Data from the USGS "Estimated Use of Water in the United States in 2000" (USGS 2004) report were used to create Table 2-2. For each of the three regions in 2000, the first column gives surface freshwater withdrawals by sector; the second column shows groundwater withdrawals; and the third shows total withdrawals.

Table 2-2. Freshwater Usage in 2000.

Region	**Wyoming/Montana**			**Illinois Basin**			**Pennsylvania/West Virginia**		
Usage by Sector, %	**Surface**	**Ground-water**	**Total**	**Surface**	**Ground-water**	**Total**	**Surface**	**Ground-water**	**Total**
Public Supply	1.1	20.2	2.0	8.6	44.5	10.7	8.2	38.7	9.2
Domestic	0.0	5.2	0.2	0.1	15.2	0.9	0.0	31.7	1.1
Irrigation	95.1	60.2	93.5	0.4	9.2	0.9	0.1	0.1	0.1
Livestock	0.0	0.0	0.0	0.1	2.9	0.2	0.0	0.0	0.0
Industrial	0.2	8.9	0.4	10.6	27.2	11.4	15.0	17.0	15.4

Mining	0.2	5.4	0.8	0.3	0.2	0.3	0.1	12.2	0.9
Thermo-electric Power	3.4	0.1	3.1	79.9	0.8	75.6	76.6	0.3	73.3
Water Usage, million gal/day	12,500	730	13,230	26,300	1,660	27,960	14,350	750	15,100

Source: USGS 2004.

This table reveals that water usage issues can vary significantly among the Western (Wyoming/Montana), Midwest (Illinois Basin) and Eastern (Pennsylvania/West Virginia) regions. The largest withdrawals of surface and groundwater in the Western United States are for crops and livestock irrigation, due to the semiarid environment. The competition for water withdrawals for a CTL plant in the Illinois Basin and Pennsylvania/West Virginia regions is due to thermoelectric power generation (for surface water) and public supply requirements (for groundwater). Any new industry developed in any of these three regions would compete with the established users for water withdrawals from a finite surface and subsurface water resource.

To fully understand the competition among water users in each region, an understanding of how much water is available, ownership of water rights, the cost of purchasing water rights (where applicable), the stability of groundwater tables, and the feasibility of using brine instead of fresh water is needed. A study of this magnitude is beyond the scope of this report. In general, however, competing uses will be more significant in western states, where water rights are established and water is considered a valuable commodity. In eastern states, water shortages are only beginning to become issues of concern, and in most cases water rights have not been established, making competing uses less of a problem.

Environmental impact within each region is also a concern. Each state within the areas researched has performed an assessment of water bodies within respective state boundaries. The results of those studies (current as of 2002) are presented in Table 2-3, which is based on information from EPA's "Surf Your Watershed" (EPA 2006).

The quality ranking of a water body determines how sensitive it is to pollution and influences the activities that each state is likely to approve. In the following description, the terms "good," "threatened," and "impaired" are used. As defined by the EPA (2006):

> "Water may be assessed for several different uses. In order to be considered 'good,' it must meet all the uses for which it was assessed. It is considered 'threatened' if it is meeting all assessed uses but water quality conditions appear to be declining. It is considered 'impaired' if any one of its assessed uses is not met."

Table 2-3. Surface Water Quality Data.

State	Water Body	Ranking			Impairment Cause*	Impairment Source**
		Good	Threat-ened	Impaired		
Wyoming	Rivers, streams	62.5%	12.4%	25.1%	p, f, s, y, w, x, o, q	Z, R,A, E, Q, M, G, U, S
	Lakes, ponds, reservoirs	0.0%	99.5%	0.5%	f, s	R
Montana	Rivers, streams	23.9%	0.1%	76.1%	f, d, x, v, m, b, a	A, M, E, I, H, F, O, B
	Lakes, ponds, reservoirs	10.7%	0.8%	88.5%	i, l, g, m, x, bb, h, t	Y, A, O, D, I, P, F
Illinois	Rivers, streams	46.7%	0.2%	53.1%	m, h, f, t, x, r, bb, k	A, Z, E, B, P
	Lakes, ponds, reservoirs	7.3%	0.0%	92.7%	m, x, bb, n, r, l, k	E, A, H, X, T
Indiana	Rivers, streams	59.5%	0.0%	40.5%	t, p, i, g, h, m, w	R, Z, J, P, M, AA, H, D,
	Lakes, ponds, reservoirs	3.7%	0.0%	96.3%	i, bb, t, n, l	Z, J, R, O
Kentucky	Rivers, streams	53.3%	1.7%	45.0%	x, p, t, f, m, h	Z, H, U, M, P, L
	Lakes, ponds, reservoirs	55.3%	0.0%	44.7%	i, j, t, u, m, h	Z, A, J, P, L, W
Pennsylvania	Rivers, streams	82.3%	0.0%	17.7%	x, j, m, q, z, e, f, i	O, A, AA, G, N, E
	Lakes, ponds, reservoirs	47.2%	0.0%	52.8%	i, m, z, bb, cc, q	Z, A, Y, AA, W, P
West Virginia	Rivers, streams	29.1%	26.5%	44.4%	p, c, j, x, q, f, m, aa	Z, O, A, L, M, U, P
	Lakes, ponds, reservoirs	14.6%	24.1%	61.3%	x, l, m	C, H, V, X

*Impairment Causes: [a]Bank erosion, [b]Dewatering, [c]Fecal coliform, [d]Flow alteration, [e]Flow variability, [f]Habitat alteration, [g]Lead, [h]Low dissolved oxygen, [i]Mercury, [j]Metals, [k]Nitrogen/ammonia, [l]Non-native aquatic plants, [m]Nutrients, [n]Odor, [o]Oil & grease, [p]Pathogen, [q]pH, [r]Phosphorous, [s]Physical degradation, [t]Polychlorinated biphenyls, [u]Priority organics, [v]Riparian degradation, [w]Salinity, [x]Sedimentation/siltation, [y]Selenium, [z]Sewage, [aa]Sulfates, [bb]Suspended solids, [cc]Water temperature
**Impairment Sources: [A]Agriculture, [B]Channelization, [C]Construction, [D]Contaminated sediments, [E]Crop production, [F]Flow alteration, [G]Grazing, [H]Habitat modification, [I]Hydromodification, [J]Industrial point source discharge, [K]Irrigation, [L]Land disposal, [M]Livestock, [N]Loss of riparian habitat, [O]Mine drainage, [P]Municipal point source discharge, [Q]Natural sources, [R]Non-point source, [S]Oil & natural gas production, [T]Recreational activities, [U]Resource extraction, [V]Roadway runoff, [W]Septic systems, [X]Stream bank destabilization, [Y]Toxic rain, [Z]Unknown source, [AA]Urban runoff

Source: EPA 2006.

From the information provided in the table, one can conclude that the greater portion of the surface water quality in all three regions is ranked as threatened or impaired.

Environmental concerns and the likely need to purify any water discharged from a CTL plant will remain important issues for decision makers.

Regional Discharge and Treatment Issues and CTL Impacts

A common complication when examining water-energy issues is the fact that boundaries do not match. Water quality and availability is delineated by the watershed; energy issues are delineated by coal, oil, and gas deposits within each sedimentary basin or by electricity utility domain; and regulations are delineated by state borders. Allowable methods of water disposal vary regionally within each state depending on specific water quality issues in each water body. Website references to water disposal regulations and water quality regulations for the various states of interest are available at the following websites:

Wyoming	http://www.epa.gov/waterscience/standards/wqslibrary/wy/wy.html.
Montana	http://www.epa.gov/waterscience/standards/wqslibrary/mt/mt.html.
Illinois	http://www.epa.gov/waterscience/standards/wqslibrary/il/il.html.
Indiana	http://www.epa.gov/waterscience/standards/wqslibrary/in/in.html
Kentucky	http://www.epa.gov/waterscience/standards/wqslibrary/ky/ky.html.
Pennsylvania	http://www.epa.gov/waterscience/standards/wqslibrary/pa/pa.html.
West Virginia	http://www.epa.gov/waterscience/standards/wqslibrary/wv/wv.html.

If treatment costs could be ignored, CTL plants could be located anywhere. However, to determine the feasibility of locating a plant in a specific location, cost analysis of the treatment necessary to meet the specific requirements of particular water body would need to be performed. The cost of treatment will vary depending on the quality of the water being examined. For example, water with larger amounts of biological content would require larger doses of chlorine or other biocides to minimize biological growth, which would increase treatment costs. To minimize scaling issues, waters with such compounds as calcium carbonate, calcium sulfate, calcium phosphate, magnesium carbonate, and magnesium phosphate will require treatment via chemical addition to precipitate the compounds before the water enters the system or by use of precipitation suppressing chemicals, both of which will increase the cost of treatment. Waters with higher-than-average total dissolved solids (TDS) concentrations will require additional chemical corrosion inhibitors to reduce the corrosion exacerbated by high TDS concentrations, also increasing the cost of treatment (Metcalf & Eddy Inc. 2003). In general, the lower the quality of the water, the more it will cost to treat it. According to EPA, costs for cooling tower makeup water treatment and disposal of blowdown water range from $0.50 to $3.00 per 1,000 gallons (EPA 2001). This range is defined based on the use of surface versus gray water for makeup water and the disposal of blowdown water in a pond or sewer line.

Conclusions

Two issues in the placement of a CTL plant will be (1) availability of water and (2) the environmental concerns related to the discharge of water after use.

The withdrawal and consumption of water in regions where water is not abundant and where the plant would be competing with other users (e.g., thermoelectric power generation and agriculture) must be analyzed to further address potential shortages and environmental concerns. NETL could add value by initiating a process design analysis for the building of a “green” plant that will optimize water consumption. This could be part of a design optimization process focusing on four objectives: (1) minimizing water withdrawal and consumption, (2) maximizing conversion efficiency, (3) minimizing environmental impact, and (4) minimizing capital cost.

In 2006, NETL will initiate a design study for a 50,000 bbl/day CTL plant located in the Illinois Basin using Illinois No. 6 coal as feedstock. The technical evaluation will include a complete energy and material balance. Air, liquid, and solid emissions will be tracked and a full water balance will be performed. In addition to the technical evaluation, a capital cost estimate, an operating cost estimate, and a financial analysis will be developed.

Another potential NETL study could evaluate options for onsite refining of CTL products (e.g., hydrotreating of the reactor product wax). A cost optimization analysis with options to transport various CTL products to a refinery versus the creation of end products onsite could be performed.

The focus of environmental concerns in future studies will be on the contaminants in discharged water. Currently, the management of water produced in conjunction with coalbed methane is a primary concern in Montana and Wyoming. In this case, the discharge water is very saline and needs to be treated prior to surface discharge or must be re-injected. The discharge water from a CTL plant would be more similar to that of a thermoelectric plant or refinery—not brine but possibly contaminated with organics. However, the environmental risk could be mitigated by incorporating into the process design the need for activated carbon filters to remove any dissolved organics in the waste water before disposal. This cost could be included as an option for minimizing the environmental impact of a CTL plant in any of the three regions evaluated.

High energy prices have ignited sudden consideration of CTL plant development to help increase the supply of and thus reduce the cost for transportation fuels. A more detailed study of site specific locations, could further address concerns related to the factors underlying the development of a CTL plant, including not only the availability of the coal but also the availability of water and the environmental concerns regarding how the demand for water will affect the environment around the plant.

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Chapter 3: Oil Shale Development—Water Resources and Requirements

Summary

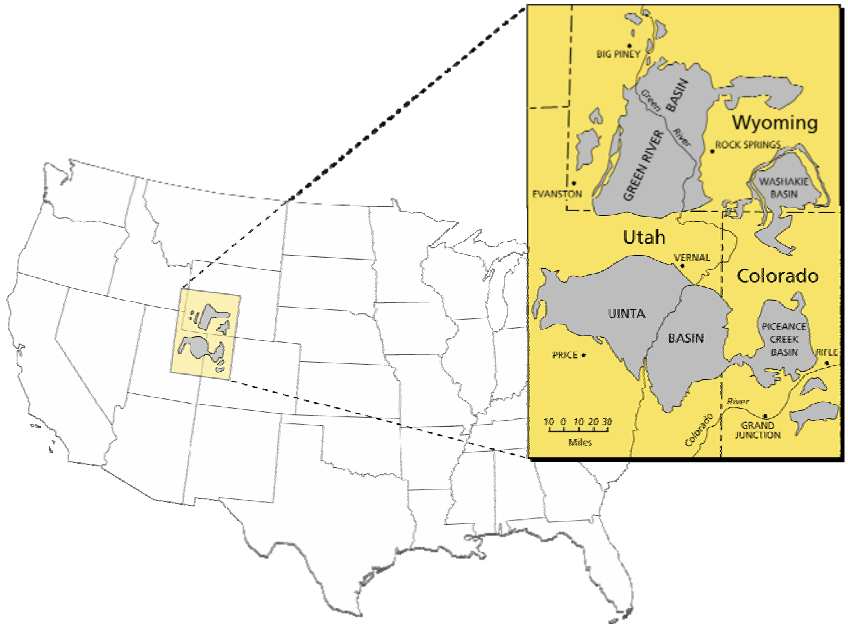
The vast oil shale resources of Colorado, Utah, and Wyoming will undoubtedly be the initial target for industry development. These resources lie within the Upper Colorado River Basin where several years of drought have raised public awareness regarding the river's ability to sustain long-term regional development and meet rising water demands. Water availability and water quality concerns influenced past oil shale development in the 1970s and 1980s and are likely to do so again as industry proceeds with renewed development plans in the Western United States.

This chapter of the report investigates the relationship between oil shale development and the water resources of the Upper Colorado River Basin. Specifically, water requirements for the development of oil shale are discussed within the context of current and forecasted demand for water. Water quality issues and the potential impact of an oil shale industry are also addressed. As oil shale research and development proceeds, numerous opportunities will emerge to reduce water consumption and ensure that the region's water quality is not jeopardized. This section addresses some of these challenges and opportunities.

Oil Shale Resources

The oil shale resources of the United States are estimated at over 2 trillion barrels. Three-quarters of this resource lies within the Green River Formation underlying Colorado, Wyoming, and Utah (Figure 3-1). Development will likely focus initially on high-grade oil shale yielding 25 or more gallons per ton. Resources in this range have been estimated between 400 and 750 billion barrels. More than 80 percent of this rich resource is located in a remarkably small area of the Piceance Basin in western Colorado. In some portions of the basin, the oil shale is over 1,500 feet thick with the potential of yielding over 2.5 million barrels per acre. While smaller than the Colorado resource base, the high-grade oil shale resources in Utah's Uinta Basin are significant, generally close to the surface, and in seams often several hundred feet thick. Initial commercial oil shale operations would likely occur in both Colorado and Utah. The Wyoming oil shale resources—located in the Green River and Washakie Basins—are generally of lower quality and therefore are not likely to be targeted until a mature industry has been developed. Significant deposits also occur in the eastern and midwestern states. These deposits are also not likely candidates for initial development due primarily to lower grade and generally thinner beds less than 100 feet thick.

Figure 3-1. Oil Shale Resources of the Western United States.



Source: RAND Corporation 2005.

Water Resources

The rich oil shale deposits of the Western United States are located within the Upper Colorado River Basin. The Colorado River and its tributaries are critical resources in the semiarid region. These surface waters are used for municipal purposes, agriculture, mining and energy development, industry, and recreation. Flows on the Colorado River vary seasonally, increasing with spring snowmelts and heavy rainstorms in the late summer and fall and declining during the rest of the year.

Management of water resources from the Colorado River is governed by numerous interstate agreements, State and Federal laws, and international treaties, known collectively as the "Law of the River" (see side bar). The foundation of these governing agreements is the Colorado River

Law of the River

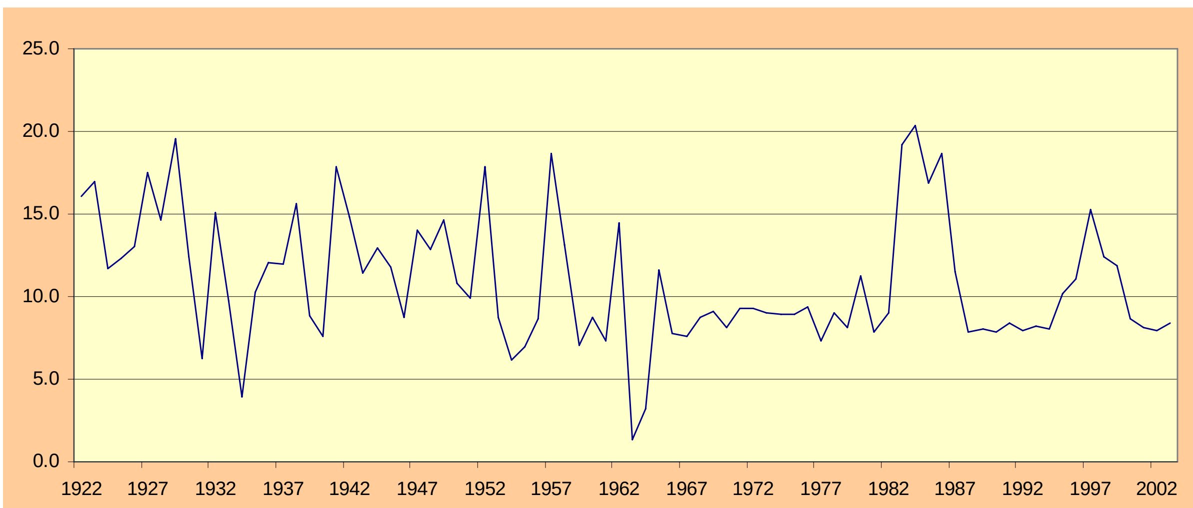
- Colorado River Compact of 1922—divided water 50:50 between Upper and Lower Basins.
- Boulder Canyon Project Act of 1928—allocations between Lower Basin States and provided for the construction of the Hoover Dam and the All-American Canal.
- California Limitation Act of 1929—required California to reduce annual consumption to 4.4 million acre-feet plus not more than half the surplus water provided to the Lower Basin.
- Mexican Water Treaty of 1944—guaranteed delivery of 1.5 million acre-feet per year to Mexico.
- Upper Colorado River Basin Compact of 1948—allocations between Upper Basin States.
- Colorado River Storage Project Act of 1956—provided for new storage reservoirs to assist the Upper Basin states in meeting their obligation to the Lower Basin.
- Colorado River Basin Project Act of 1968—coordinated long-range reservoir operations.
- Colorado River Basin Salinity Control Act of 1974 (as amended)—authorized the construction, operation, and maintenance of facilities to control the salinity of water delivered to Mexico.

www.usbr.gov/lc/region/g1000/lawofrvr.html

Compact of 1922, which divided the river system into the Upper and Lower Basins and allocated 7.5 million acre-feet (58 billion barrels) per year to each basin for beneficial consumptive use. The Lower Basin was also given the right to increase its annual use by 1 million acre-feet. Though no specific volumes were established until 1944, the compact provided the framework for supplying surplus waters to Mexico. The Mexican Water Treaty of 1944 guaranteed annual delivery of 1.5 million acre-feet, with the volume being borne equally from the allocations of the Upper and Lower Basins.

Because flows in the Colorado River also vary from year to year, the 1922 water allocation, based on absolute volumes, has been the cause of continued controversy between the Upper and Lower Basins. Figure 3-2 shows the annual flow of the Colorado River as measured at Lees Ferry, AZ, which divides the Upper and Lower Colorado Basins.

Figure 3-2. Colorado River Flow at Lees Ferry, AZ: 1922–2003 (million acre-feet/year).



Source: USGS 2006.

The Upper Colorado River Basin Compact of 1948 established water allocations among the Upper Basin states. This compact recognized the problems of allocating water on a quantity basis. As a result, water was apportioned on a percentage basis accordingly: Colorado (51.75 percent), New Mexico (11.25 percent), Utah (23.00 percent), and Wyoming (14.00 percent). The one exception, Arizona, was guaranteed 50,000 acre-feet per year. Water allocations in the Lower Basin—California, Nevada, and Arizona—were determined in the Boulder Canyon Project Act of 1928 and upheld in the 1964 Supreme Court case *Arizona v. California*.

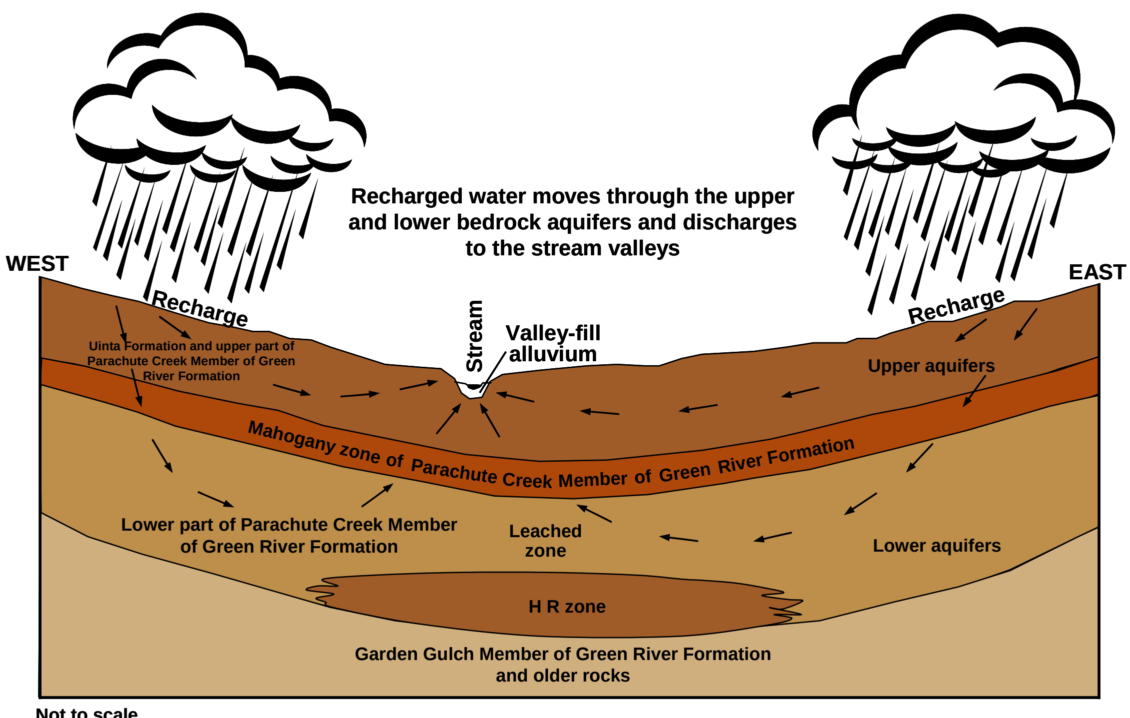
The western basins also have substantial groundwater resources that occur near the surface in alluvial aquifers and more deeply buried in bedrock aquifers. There is, however, limited information available regarding the deep bedrock aquifer resources in the Upper Basin because little development has occurred due to the typically poor quality of the water and because sufficient surface-water supplies are usually available.

The Piceance Basin contains a very productive unconsolidated alluvial aquifer that supplies water to the city of Meeker, CO. Two important bedrock aquifers are also present above and below the relatively impermeable, oil shale-rich Mahogany Zone (Figure 3-3). The upper aquifer system is about 700 feet thick and consists of several permeable zones. The lower aquifer system is about 900 feet thick and consists of a fractured dolomitic marlstone. It has been estimated that as much as 25 million acre-feet of water is stored in these two aquifers. This is nearly twice the annual flow of the Colorado River at Lees Ferry and is equivalent to the storage capacity of Lake Powell. Wells in these two bedrock aquifer systems typically range in depth from 500 to 2,000 feet and commonly produce between 2–500 gallons per minute of water (USGS 1984).

Water quality in the Piceance Basin is generally poor, owing to nahcolite (sodium bicarbonate) deposits and salt beds within the basin. Water in the lower aquifer is reported to contain several hundred milligrams per liter (mg/L) of chloride. Only very shallow waters are used for drinking water. In general, the potable water wells in the Piceance Basin extend no further than 200 feet in depth, based on well records maintained by the Colorado Division of Water Resources.

Figure 3-3. Piceance Creek and Yellow Creek Drainage Basins.

OIL SHALE, WATER RESOURCES, VALUABLE MINERALS, PICEANCE BASIN, COLO.



Piceance and Yellow Creek Drainage Basins

Source: EPA 2004 (recreated NETL 2006).

The aquifer system within the Uinta Basin is estimated to contain at least 80,000 acre-feet. The older and deeper aquifers generally contain very saline to briny water, with TDS values greater than 10,000 mg/L.

The right to utilize water is, in general, similar among the Upper Basin states and is based on the doctrine of prior appropriation and the principle of "first in time, first in right." Water rights are apportioned to a particular party, for a specified amount of water, at a specified location, and for specified uses. The doctrine applies to both surface water and tributary groundwater connected hydrologically to the surface water system. In times of water shortage, senior water rights have priority and are met before junior rights. Each state has also established a preference system to apportion water among different beneficial uses during times of shortage. Under these provisions, drinking water and municipal users have first preference, agriculture is second, and industry is third.

Many potential oil shale developers already hold water rights acquired directly through filings of the prior appropriations system or purchased from agricultural users; the latter typically being senior rights. The extent of developer's water rights is difficult to ascertain because the information is considered proprietary. In 1980, the Office of Technology Assessment (OTA) estimated oil industry water rights on the order of 1 million acre-feet (7.8 billion barrels) per year. These rights included storage rights and direct diversion flows from the Colorado River. Most were conditional decrees, meaning that the owner must show due diligence in perfecting the appropriation to beneficial use before an application for absolute water rights can be filed. An area for further investigation is the extent to which industry has demonstrated reasonable diligence over the past 2 decades.

Water Requirements

Accurate water volumes necessary to support a commercial oil shale industry are not known, but they are considered to be substantial. Water is needed for mining and oil shale retorting and upgrading; dust control during materials extraction, crushing, and transport; cooling and reclaiming spent shale; revegetation; and various plant utilities associated with power production and environmental control. Water will also be needed for final refining. Whether water requirements add to regional demands will depend on where refining occurs and whether new grassroot refineries are built. If shale oil merely displaces conventional feedstocks currently processed by refineries, no significant additional water should be required.

In 1980, OTA analyzed four different basic retorting configurations to determine likely water requirements for a commercial shale oil industry. These included:

- Direct-heated Aboveground Retorting (AGR)
- Indirect-heated AGR
- Modified In-Situ (MIS)
- Combination of MIS and Indirect-heated AGR

As shown in Table 3-1, retorting and upgrading require the most water. All of the technologies need comparable amounts of water for upgrading. Therefore, the differences among alternate technologies reflect differences in retorting efficiencies. Water requirements for mining, dust control, spent shale disposal, and revegetation are considerably higher for AGR retorting because of the large amount of material that must be mined. MIS techniques were assumed to produce sufficient quantities of low-Btu gas to produce power using open-cycle gas turbines, which do not need to be cooled and therefore require little or no water. For most AGR techniques, cooling water is required because solid-fuel steam cycle systems were assumed to be used. With the advancement of IGCC for power generation, water requirements for AGR could be significantly reduced.

Table 3-1. Water Requirements for Various Oil Shale Unit Operations (percent of total).

Subprocess	Direct AGR	Indirect AGR	MIS/AGR	MIS
Mining and Handling	13–18	9–10	6	10
Power Generation	0*–10	8–12	0*	0*
Retorting and Upgrading	41–44	35–43	54–62	51
Disposal and Revegetation	26	33–40	19–26	23
Municipal	10-12	5-7	13-14	16

** Assuming low-Btu gases are burned in an open-cycle gas turbine that does not require cooling water.*

Source: Data from OTA 1980 and Nowacki 1981.

No reliable data regarding true in-situ techniques existed at the time of a 1980 OTA study. Today, Shell Oil is developing their In-Situ Conversion Process. Though data is still limited, Shell's process is anticipated to reduce overall water requirements, but water will still be needed for drilling and extraction, post-extraction cooling, product upgrading and refining, environmental control systems, and power production. Reliable estimates of water requirements for Shell's process will not be available until the technology reaches the scale-up and confirmation stage.

Based on the OTA study data, Table 3-2 shows the estimated water requirements for a 50,000 bbl/d facility. These estimates range between 4,900 and 11,800 acre-feet per year or the equivalent of 2.1–5.0 barrels of water consumed (net) for each barrel of shale oil produced. Given this range, a 1 million bbl/d industry would consume 100,000 to 240,000 acre-feet (0.8–1.8 billion barrels) per year. Actual requirements will vary depending on the mix of technologies deployed and, clearly, are a subject for further analysis given the age of the data. Developers of potential oil shale technologies claim that advancements have drastically reduced water requirements. These claims will be followed closely as research, development, and demonstration (RD&D) proceeds on Federal lands as a result of the Bureau of Land Management's (BLM) recent RD&D lease awards (BLM 2006).

Table 3-2. Water Requirements for Oil Shale Facilities Producing 50,000 Barrels per Day of Shale Oil.

	Direct AGR	Indirect AGR	MIS/AGR	MIS
Acre-feet per year	5,300–6,400	9,900–11,800	5,700–5,800	4,900
Barrels of water per barrel of oil	2.3–2.7	4.2–5.0	2.4–2.5	2.1

Source: Data from OTA 1980 and Nowacki 1981.

Based on the above water requirement estimates, OTA found that available supplies of surface water in the Upper Basin could support production utilizing mining and surface retorting techniques of around 2 million barrels of shale oil per day. This estimate was contingent on the construction of additional reservoirs and pipelines and is highly dependent on where an oil shale industry develops and projections of annual stream flow in the Colorado River.

Table 3-3 shows water use and surplus surface water available for the three Upper Basin states where oil shale development is likely to occur. The water allocation estimates assume two scenarios for the annual virgin flow in the Colorado River. The first scenario assumes flow of 15 million acre-feet per year; split evenly between the Upper and Lower Basins. Of the 7.5 million acre-feet allocated to the Upper Basin, 750,000 acre-feet are made available to Mexico and 50,000 acre-feet to Arizona. The remaining 6.7 million acre-feet are allocated to the other four Upper Basin states (Colorado, Utah, Wyoming, and New Mexico) in accordance with the Compact of 1948.

Table 3-3. Upper Basin Water Use and Surplus Surface Water (thousand acre-feet per year).

	Colorado		Utah		Wyoming	
Virgin Flow [1]	15,000	14,250	15,000	14,250	15,000	14,250
Water Allocation	3,467	3,079	1,541	1,369	938	833
	Average 2001-2003 Water Use					
Water Use[2]	2,393	2,393	930	930	486	486
Surplus	1,074	686	611	439	452	347
	2010 Forecast Water Use					
Water Use[2]	2,870	2,870	1,095	1,095	590	590
Surplus	597	209	446	274	348	243
	2020 Forecast Water Use					
Water Use[2]	2,970	2,970	1,190	1,190	644	644
Surplus	497	109	351	179	294	189

1 Virgin flow is the flow that would occur in the absence of human activity.
2 Includes evaporative losses

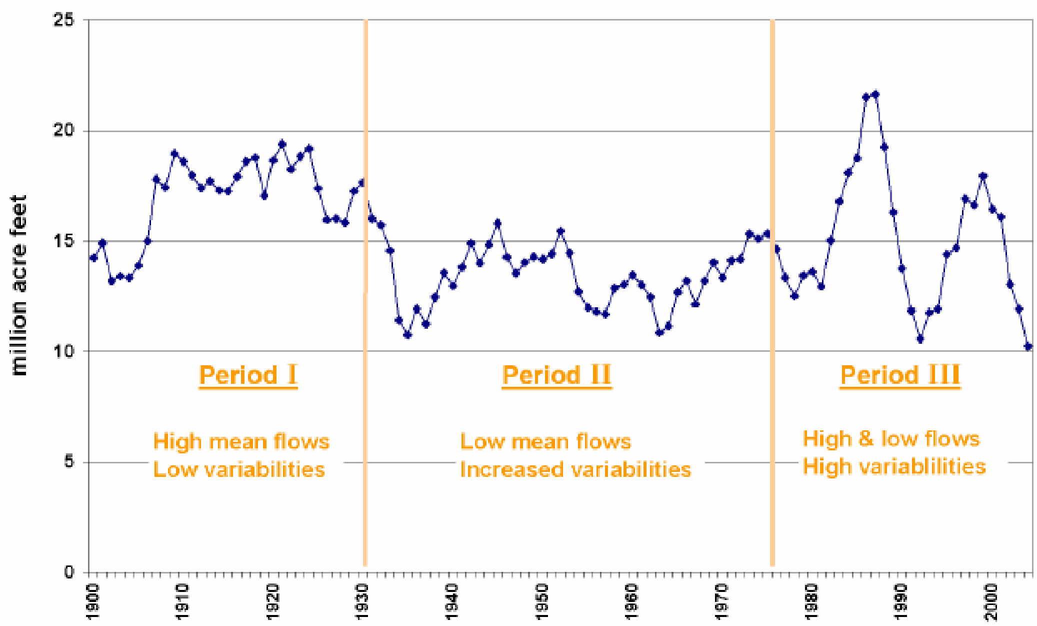
Source: Data from Kuhn 2005a and Ostler 2005.

The second scenario is based on the Department of Interior's 1988 hydrologic determination, which found that after meeting Lower Basin's obligation of 7.5 million acre-feet per year and the 750,000 acre-feet obligation for Mexico, only 6 million acre-feet remained for beneficial use in the Upper Basin or a virgin flow of 14.25 million acre-feet per year. As seen, surplus surface water is estimated to be available beyond 2020 under both scenarios. However, by 2020 available surplus water could constrain industry growth, particularly under the low-flow scenario, which is more reflective of the flows experienced in recent years.

Demands placed on the Upper and Lower Basins have risen considerably over the past 2 decades. With a rise in the population, especially in the Southwest, there has been a rise in demand for water for electric power and recreational use and in maintaining and restoring the river's ecosystems. In recent years, water availability has become particularly acute due to an extended drought resulting in low river flows (Figure 3-4) and subsequent drawdown of reservoirs. Annual inflow to Lake Powell has been reduced by approximately 50 percent between 2,000 and 2004, with levels dropping over 100 feet. Significant water withdrawals to supply an oil shale industry may conflict with other uses downstream and exacerbate current water supply problems.

The availability of groundwater for oil shale development and to alleviate already tight supplies is uncertain. The amount available would be determined by the location of the aquifers relative to potential plant sites, the water quality, and physical characteristics such as the depth and the recharge rate. The physical characteristics determine the quantity of water that can be stored or extracted, the rate at which water can be added or withdrawn, and the change in water levels that will result from withdrawing a given volume of water. Additional investigation is necessary to adequately assess the groundwater resources in the region, especially those found within deeper aquifer systems. Shallow aquifers are generally considered surface water diversions. That is, the waters drawn from shallow aquifers are typically diverted away from surface water stream flows.

Figure 3-4. Lees Ferry Virgin Flow 5-Year Running Average (1900–2004).



Source: Kuhn 2005a.

Water Quality Impacts

As with any mineral extraction and upgrading process, water produced during oil shale processing will become degraded and could affect surface and groundwater if effective management systems are not employed. Table 3-4 lists some of the major constituents and their wastewater point sources. The most significant effluent streams (volumetrically) are retort and gas condensates and cooling tower blowdown. Retort condensates for AGR systems can be reduced significantly or even eliminated if operating temperatures are adjusted properly. Indirect-heated AGR systems have no combustion within the retort unit itself, producing less gas and therefore less gas condensate. In general, control of major water pollutants from point sources is neither expected to be a problem nor a limiting factor in the development of an oil shale industry. The largest uncertainty exists for excess mine drainage, which is highly site dependent. This may be a particular concern for in-situ operations as they are likely to be sited in the rich center of the Piceance Basin, which has significant groundwater.

Table 3-4. Types and Sources of Oil Shale Contaminants.

Contaminant	Waste Stream
Suspended Solids	Mine drainage Retort condensate Cooling tower blowdown
Oil and Grease and Dissolved Gases	Retort condensate Gas condensate Coking condensate
Dissolved Organics	Retort condensate Gas condensate Coking condensate Hydrotreating
Dissolved Inorganics	Mine drainage Retort condensate Gas condensate Cooling tower blowdown Ion exchange regenerants
Trace Elements and Metals	Retort condensate Gas condensate
Trace Organics and Toxics	Retort condensate Gas condensate Upgrading condensate

Source: OTA 1980 and Nowacki 1981.

The major potential nonpoint sources are leachates from aboveground storage of spent or raw shale and from in-situ operations that have ceased. For aboveground retorting, leachate may be reduced by proper disposal methods and by capturing and treating leachate that does occur. A number of experimental processes have been tested in the past to control leaching from in-situ operations. These strategies have yet to be proven at commercial scale, and thus long-term monitoring will be required to assure that contaminants are not released during and after in-situ development.

Salinity or TDS has long been recognized as one of the major problems of the Colorado River. The salinity increases as the river flows downstream, and an average of 9 million tons of salt pass the Hoover Dam annually. Approximately 53 percent of the salinity results from various human activities. Irrigation and other agricultural activities account for the largest share of the salt concentration. Development of an oil shale industry is not expected to greatly alter the salinity of the Colorado River, but strict concentration criteria will need to be observed.

The effects on aquifers and hydrologic modification resulting from oil shale development, especially in-situ operations, and other energy and mineral development operations are another water quality issue that will require careful monitoring and could benefit from further research.

Conclusion

The Upper Colorado River Basin is experiencing a period of drought conditions. The reduced flow resulting from these drought conditions, coupled with increased population growth in the Upper and Lower Basins, has raised the level of public awareness and concern regarding the long-term sustainability of surface waters from the Colorado River to meet demands. As industry proceeds with renewed interest to develop the rich oil shale resources of the Upper Colorado River Basin, there will be many issues debated regarding water availability and water quality.

Very little research has been conducted over the past 20 years on oil shale technologies. Advances that have been made over the past 2 decades, those in particular by Shell Oil on their In-situ Conversion Process, are proprietary and little information has been made public. Past data suggest that for each barrel of shale oil produced, 2–5 barrels of water will be required. Even if these volumes were cut in half, water requirements could constrain long-term oil shale development. Opportunities exist to develop improved water management practices and innovative water recovery and reuse technologies for oil shale processing. For example, innovative approaches should be sought to beneficially reuse the vast quantities of produced water resulting from oil and gas (including coalbed natural gas) development for subsequent development of oil shale in the same region. With respect to in-situ techniques, improvements in groundwater characterization and monitoring are needed to ensure against potential groundwater contamination and long-term damage to subsurface aquifers.

On January 17, 2006, BLM announced eight RD&D lease awards. The proposed technologies offer the potential to advance the knowledge of oil shale recovery and processing. A key component of the technology proposals is their ability to successfully show that they can manage the environmental impacts of oil shale development to land, air, and water. As industry development efforts proceed, opportunities for government cooperation and government-sponsored research will likely emerge. DOE's Office of Fossil Energy is well positioned to respond to such a challenge as a result of ongoing energy-water research efforts that cut across its coal, oil, and natural gas programs.

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Additional Web-Based Resources

Colorado River Salinity Control Forum. Available at http://www.coloradoriversalinity.org/

Colorado River Water Users Association Bureau of Reclamation. Available at http://www.crwua.org/colorado_river/reclamation.htm

Drought, Climate Variability, and Water Supply Workshop: Water Supply Challenges and New Tools for Water Managers, sponsored by the U.S. Geological Survey, January 24, 2005. Available at http://co.water.usgs.gov/drought/workshop200501/

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Chapter 4: Potential Impacts of Climate Change on Water Resources—Will Sequestration Strategies Compound Problems?

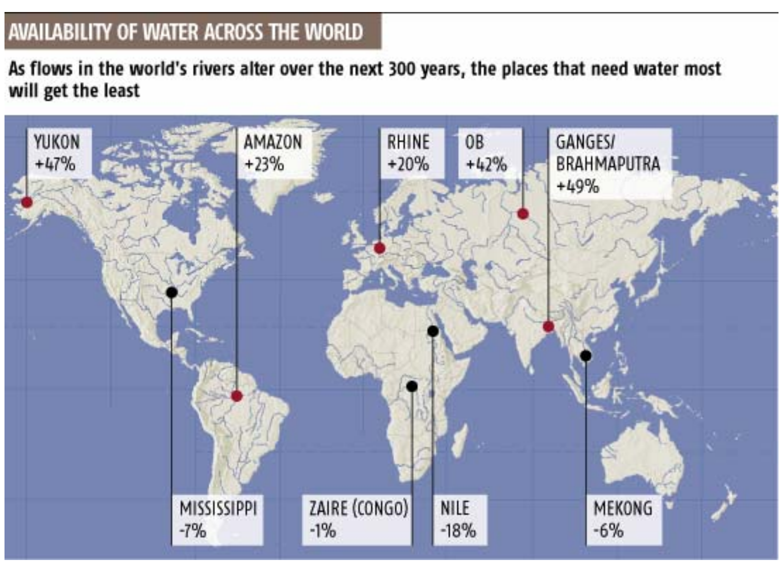
There is a recognized correlation between reliable energy and clean water. Climate change and ensuing regulations of CO_2 emissions will impact the energy industry in many ways. This section of the report outlines the overall impact that climate change will have on water resources and highlights the specific impact that carbon sequestration technologies may have on the Energy-Water Nexus.

How Climate Change Might Impact Water Resources

Environment

Water availability is a global concern. Climate change compounds the issue through a variety of feedback mechanisms within the carbon and water cycles. For example, higher temperatures increase evaporation rates and changes in precipitation impact stream flow and runoff rates. A November 2005 study (Milly) used 12 climate models to project stream flow and water availability in the 21st century. The projected changes are significant: 10–40 percent increases in runoff in areas that are water rich (including high-latitude North America) and 10–30 percent decreases in runoff in arid regions (including mid-latitude western North America) by 2050. Changes of this magnitude would have significant, far-reaching impacts. Expectations include increasing floods and worsening drought.

Figure 4-1. Availability of Water Across the World.

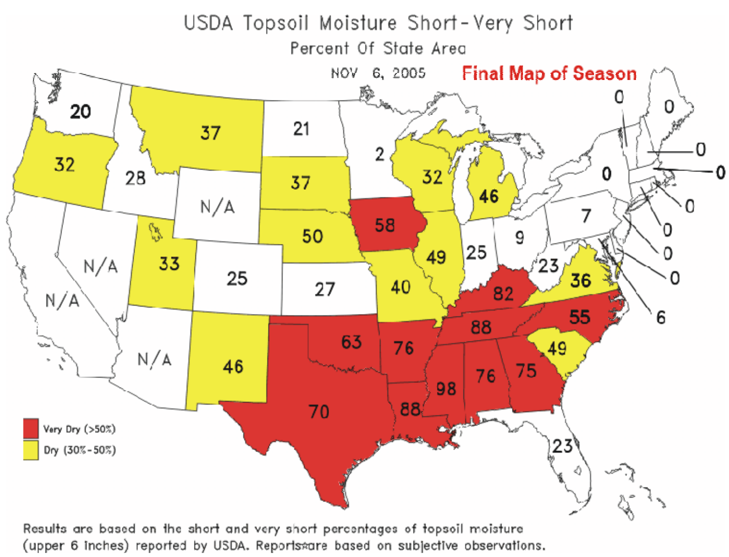


Source: http://www.newscientist.com/article.ns?id=dn5011

Water quality is also likely to be affected by climate change. The ocean, like the terrestrial ecosystem, serves as a natural sink for CO_2. Today, the pH of the ocean is 0.1 unit lower than pre-industrial levels and predictions are that under a business-as-usual scenario it will drop another 0.3–0.4 units—which corresponds to a 100–150 percent increase in hydrogen ions. A September 2005 *Nature* article (Orr 2005) highlights the potential impact on marine organisms and finds that ecosystems in the Southern and subarctic Pacific Oceans will likely show response to increases in acidification within decades rather than centuries as previously reported. In addition to impacts seen in the ocean, changes in water quality are also expected in the Great Lakes and other surface waters. For example, the combination of lower water levels and warmer temperatures may accelerate the accumulation of mercury in fish (Ecological Society 2005).

Soil moisture is another area of concern, and arid regions are predicted to be particularly at risk. The mechanism is simple, increased temperatures increase evaporation and the already dry soil looses the little water it has. According to a recent article in *Climate Change* (Manabe 2004) soil moisture will fall by up to 40 percent in the Southern United States. Changes in soil moisture of this magnitude would have a significant impact on agriculture. In fact, crop production could vary by greater than 50 percent (Thomson 2005).

Figure 4-2. USDA Topsoil Moisture (Short – Very Short)—Percent of State Area.



Source: http://www.cpc.noaa.gov/products/monitoring_and_data/soilmmap.gif

Ecosystem changes are another anticipated impact of climate change, with expected shifts in species distribution and migration patterns. Alpine ecosystems are particularly at risk because of the reliance of organisms on the runoff from the glaciers and snow pack or the permafrost. Greater impacts are expected at higher latitudes. A 2001 study (Jorgenson et al.) of the impact of warming trends on permafrost in Alaska demonstrates a relationship between the disappearance of permafrost and a shift from birch forests to bog ecosystems. The researchers predict that if current trends continue, the lowland birch forests will disappear by the end of the century.

Changes in precipitation and temperature also have the potential to impact drinking water availability from both groundwater and surface water, and the incidence of water-borne diseases like Cryptosporidium could increase (Patz 2000). Current regulatory frameworks and planning for drinking water should consider the possibilities of impacted stream flow, groundwater levels, and runoff rates.

Table 4-1. Water-Related Issues and Potential U.S. Impact.

Water-Related Issue	Potential Impact (U.S. Focus)
Stream flow changes	10–30% decrease in Western U.S. 10–40% increase in Eastern U.S.
Ocean acidification	0.3–0.4 pH unit decrease
Soil moisture	40% decrease in Southern U.S.
Ecosystem change	Loss of birch forest ecosystem in Alaska
Drinking water compromised	Decreased water in arid regions and increased disease incidence

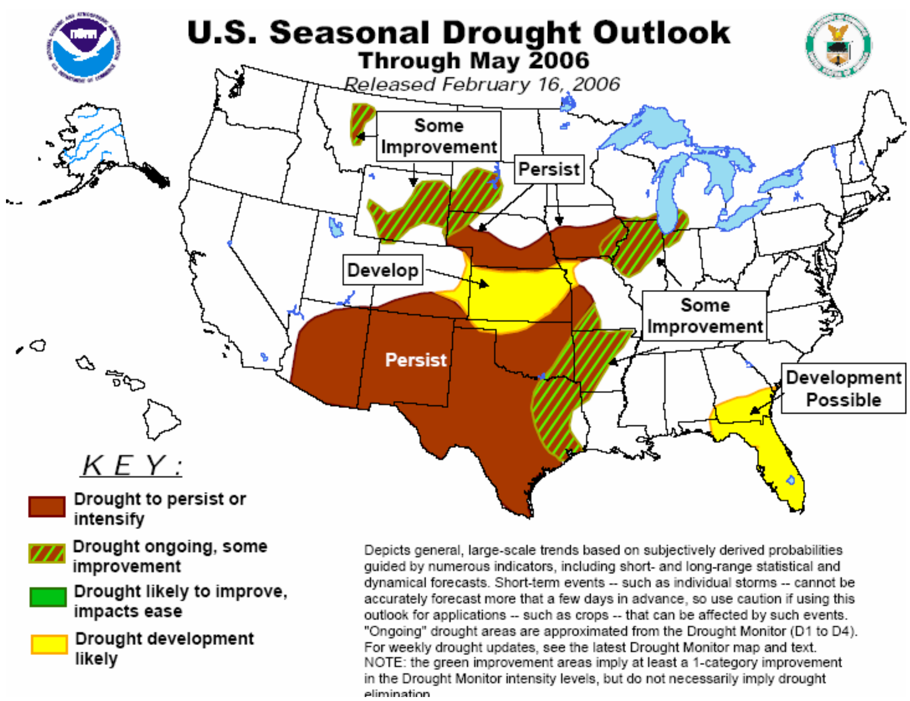
Source: Created by author.

Economies

Environmental changes of the magnitude predicted would impact socioeconomic activity in a number of ways, and there are costs and benefits associated with actions taken to adapt or mitigate those changes. Planning for water needs is often conducted based on historical records, a practice which does not take the potential impacts of climate change into account. The Intergovernmental Panel for Climate Change (IPCC) and others (Ramaker 2005) are urging planners to design new systems with the flexibility to adapt to or mitigate potential climate impacts.

The electricity sector is vulnerable to impacts associated with climate change on many levels (potential CO_2 regulation, direct impacts of increased temperature on equipment, etc.). Water is no exception, as changes in precipitation could change hydropower resource availability. This is of particular concern to areas like the Pacific Northwest, which rely heavily on water resources for power. If the regional drought continues to worsen, this area with a current surplus of power may experience shortages. States are responding to this challenge by implementing electricity conservation programs and developing a better understanding of future drought projects (NETL 2005). Changes in precipitation (e.g., drought) also impact nonhydro plants because of the large amounts of water withdrawals needed for cooling. This affects the siting of new fossil plants and the operation of existing plants. For example, due to severe drought in 2002, the Public Services Company of New Mexico established a “shortage sharing agreement” with others in the region to enable their San Juan Generating Station, a 1,800-MW coal-fired facility, to operate at its full capacity.

Figure 4-3. U.S. Seasonal Drought Outlook—Through May 2006.



Source: http://www.cpc.noaa.gov/products/expert_assessment/seasonal_drought.pdf

Will Sequestration Strategies Compound Problems?

Biological Sequestration

Enhancing natural carbon sinks is a greenhouse gas mitigation strategy that has received a great deal of attention both domestically and in international circles. Vegetation and soils naturally store carbon, and biological (or terrestrial) sequestration is any technique that enhances that natural storage. The United States emits 1.4 billion tons per year, but carbon sinks absorb one-fourth to one-half of that carbon or 330–638 million tons of carbon (Pacala 2001). Reforestation of degraded lands could increase this storage and offset emissions from fossil energy use. Recognizing this potential, utilities and other CO_2 emitters have actively invested in carbon sequestration projects. Projects must demonstrate that there is no leakage (carbon lost from another natural system) or additionality (a project that would have happened anyway) and address the relative permanence of the carbon storage through effective monitoring and verification of carbon stored.

A December 2005 paper in *Science* (Jackson) highlights the potential negative impact of biological sequestration. Sequestration plantations decreased stream flow by 52 percent globally, with 13 percent of streams drying up completely. The article recognizes the positive climate implications of sequestration plantings for CO_2 absorption and groundwater recharge but reminds us that the full ecological picture needs to be included.

In the Eastern United States, many biological sequestration projects have focused on increasing carbon storage on abandoned and post-mining lands. These areas traditionally have poor vegetative growth. By planting trees and grasses on abandoned or partially reclaimed surface mines to capture and store CO_2, we can also reduce the runoff, sedimentation, siltation, and acid mine discharge into rivers and lakes in the region. In doing so, higher-quality waters become available for residential and agricultural use.

Contemporary agricultural practices have depleted soil carbon stores, particularly in the Midwest. There is an opportunity for farmers to dramatically increase soil carbon and reduce the life cycle of greenhouse gas emissions of their operation by switching to no-till farming. In addition to increasing soil carbon storage, no-till practices also decrease sedimentation and runoff-related pollutants, especially nitrogen which is of particular concern because the long-term ecological consequences of eutrophication. Reducing the pollutant loading from these nonpoint sources can have major beneficial impacts on local watersheds. One challenge that exists is the increased use of fertilizer and subsequent nitrogen oxide emissions associated with no-till farming.

One of the most potent examples of the protection forests and surrounding wetlands offer watersheds is the New York City water supply story. City planners faced with a decision to either construct a water filtration plant ($6–$8 billion with $300 million annual maintenance fees) or take action to conserve the 200 square miles forests and wetlands in upstate New York that make up the watershed chose to invest in the conservation effort. The conservation effort cost $1.5 billion, resulting in substantial savings for the city.

Geologic Storage

CO_2 also can be captured from a stationary source (e.g., a power plant) and then stored underground. Suitable geologic formations for carbon storage include unmineable coal seams, depleted oil and gas wells, and saline aquifers. The technology for pumping CO_2 into these underground storage sites is not new. Industrial practices for enhanced oil recovery and coalbed methane production employ CO_2 flooding as a mechanism for recovering hard-to-reach oil and gas. There are several industrial-scale operations injecting waste CO_2 from natural gas reprocessing into formations under the seabed.

Figure 4-4. Photo of Statiol's Sleipner Project (Injecting CO_2 in a Reservoir Beneath the North Sea Since 1999).

Source: Photo courtesy of USGS.

Storing CO_2 in geological formations has the potential to displace significant volumes of water. Most of the potential storage sites for CO_2, such as coal mines, saline aquifers, and secondary-gas recovery, are located in the regions of the country that would be most affected by a greenhouse gas regulation. Carbon storage combined with an enhanced oil recovery or coalbed methane operation is viewed as value-added sequestration. When these value-added sequestration techniques are employed, brackish water is often produced. (Carbon storage in saline aquifers can also result in produced waters.) Characterizing, treating, and reusing produced waters could increase the availability of water for residential, agricultural and industrial use in the Eastern and Western United States. As water availability declines (particularly in the western states) sequestration sites where water is produced may be colocated with refineries and electric generating plants.

The plume of injected CO_2 may migrate over time, and researchers are investigating the appropriate tools for monitoring injection sites. Princeton researchers have expressed concern over the potential of migrating CO_2 interacting with groundwater supplies and mobilizing heavy metals. Although this possibility is remote because geologic storage sites under consideration are not located in areas where interactions with groundwater are believed possible, it is essential that we have a thorough understanding of the potential implications of large-scale carbon storage on our groundwater supplies. A primary concern is that undetected faults may exist and CO_2 would accumulate between the surface and the top of the water table. Groundwater might be impacted if CO_2 were to leak directly into the aquifer or by brackish water entering the aquifer after being displaced by the injected CO_2. Monitoring and leak remediation technologies are being developed through research (IPCC n.d.).

Carbon Capture

NETL and others are developing new sorbents and other technologies for capturing CO_2 from stationary sources. These technologies have the potential to affect water availability both directly and indirectly. Several of the capture technologies currently under development require additional water, which will directly increase the water intake needed for power production, compounding problems associated with impingement and entrainment of aquatic organisms.

There is a high energy penalty associated with current carbon capture technologies. Any significant reduction in plant efficiency will increase the amount of water needed on a per kilowatt-hour basis. Future selection of carbon capture technologies may depend, in part, on the amount of water available and the capture system's impact on local and regional watersheds.

Conclusion

The global carbon and water cycles are interconnected. For example, changes in temperature may increase evaporation, decreasing water availability on a global scale. Also, increased levels of CO_2 in the atmosphere may increase plant growth, affecting the rate of water uptake and availability on landscape scales. Climate change mitigation strategies like carbon sequestration, although designed to decrease atmospheric CO_2 levels, will also impact water resources. Each carbon sequestration strategy has a unique impact on water resources:

- Terrestrial/biologic carbon sequestration has the ancillary benefit of improving water quality but the potential of decreasing stream flows.
- In the case of produced waters, geologic carbon storage has the potential to increase water availability in areas with limited resources.
- There are environmental issues associated with underground carbon storage and potential interactions with groundwater that need to be understood before carbon storage is adopted on large scales.
- Technologies for carbon capture may increase the energy industry's water use both directly and indirectly.

Developing an awareness of these potential interactions is critical to the success of carbon sequestration technologies.

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