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Report to the Ranking Member, Committee on Science, Space, and Technology, House of Representatives

January 2012

ENERGY-WATER NEXUS

Information on the Quantity, Quality, and Management of Water Produced during Oil and Gas Production

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Highlights

Highlights of GAO-12-156, a report to the Ranking Member, Committee on Science, Space, and Technology, House of Representatives

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ENERGY-WATER NEXUS

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Why GAO Did This Study

Water is a significant byproduct associated with oil and gas exploration and production. This water, known as "produced water," may contain a variety of contaminants. If produced water is not appropriately managed or treated, these contaminants may present a human health and environmental risk.

GAO was asked to describe (1) what is known about the volume and quality of produced water from oil and gas production; (2) what practices are generally used to manage and treat produced water, and what factors are considered in the selection of each; (3) how produced water management is regulated at the federal level and in selected states; and (4) what federal research and development efforts have been undertaken during the last 10 years related to produced water. To address these objectives, GAO reviewed studies and other documents on produced water and interviewed federal and state regulatory officials, federal scientists, officials from oil and gas companies and water treatment companies, and other experts. GAO focused its review on the nine states that generate nearly 90 percent of the produced water, and conducted site visits in three states.

What GAO Recommends

GAO is not making any recommendations. A draft was provided to the Departments of Energy and the Interior, and EPA for review. None of these agencies provided written comments. EPA and Interior provided technical comments, which we incorporated as appropriate.

View GAO-12-156. For more information, contact Anu Mittal or Frank Rusco at (202) 512-3841 or mittala@gao.gov or ruscof@gao.gov.

What GAO Found

A significant amount of water is produced daily as a byproduct from drilling of oil and gas. A 2009 Argonne National Laboratory study estimated that 56 million barrels of water are produced onshore every day, but this study may underestimate the current total volume because it is based on limited, and in some cases, incomplete data generated by the states. In general, the volume of produced water generated by a given well varies widely according to three key factors: the hydrocarbon being produced, the geographic location of the well, and the method of production used. For example, some gas wells typically generate large volumes of water early in production, whereas oil wells typically generate less. Generally, the quality of produced water from oil and gas production is poor, and it cannot be readily used for another purpose without prior treatment. The specific quality of water produced by a given well, however, can vary widely according to the same three factors that impact volume—hydrocarbon, geography, and production method.

Oil and gas producers can choose from a number of practices to manage and treat produced water, but underground injection is the predominant practice because it requires little or no treatment and is often the least costly option. According to federal estimates, more than 90 percent of produced water is managed by injecting it into wells that are designated to receive produced water. A limited amount of produced water is disposed of or reused by producers in other ways, including discharging it to surface water, storing it in surface impoundments or ponds so that it can evaporate, irrigating crops, and reusing it for hydraulic fracturing. Managing produced water in these ways can require more advanced treatment methods, such as distillation. How produced water is ultimately managed and treated is primarily an economic decision, made within the bounds of federal and state regulations.

The management of produced water through underground injection is subject to the Safe Drinking Water Act's Underground Injection Control program, which is designed to prevent contamination of aquifers that supply public water systems by ensuring the safe operation of injection wells. Under this program, the Environmental Protection Agency (EPA) or the states require producers to obtain permits for their injection wells by, among other things, meeting technical standards for constructing, operating, and testing and monitoring the wells. EPA also regulates the management of produced water through surface discharges under the Clean Water Act. Other management practices, such as disposal of the water into surface impoundments, irrigation, and the reuse of the water for hydraulic fracturing, are regulated by state authorities.

Several federal agencies, including EPA; the Department of Interior's Bureau of Reclamation and U.S. Geological Survey; and a number of Department of Energy national laboratories, have undertaken research and development efforts related to produced water. These efforts have included sponsoring and issuing studies that describe the volume and quality of produced water, options for managing produced water and associated regulatory issues, as well as options for improving existing technologies for treating produced water and developing new technologies, such as more cost-effective filters.

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Abbreviations

BLM	Bureau of Land Management
DOE	Department of Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
NETL	National Energy Technology Laboratory
USGS	U.S. Geological Survey

United States Government Accountability Office
Washington, DC 20548

January 9, 2012

The Honorable Eddie Bernice Johnson
Ranking Member
Committee on Science, Space,
and Technology
House of Representatives

Dear Ms. Johnson:

The exploration for and production of oil and gas to meet our nation's energy needs also results in the production of large quantities of water as a byproduct.[1] This water, which is produced from wells during exploration and production, is known as "produced water." Because produced water may contain a variety of contaminants, such as salts and minerals, it is often considered to be a waste stream that oil and gas producers must appropriately manage and treat before this water can be disposed of. If it is not appropriately managed or treated, the contaminants present in produced water discharged from oil and gas operations may threaten human health and the environment.

Oil and gas—known as hydrocarbons—are found in a variety of geologic formations. Oil can be found in deep, porous rock or reservoirs that can flow under natural pressure to the surface after drilling, as well as other geologic formations, including shale and oil sands, in which other processes must be used to extract the oil, such as injecting liquid into the formation or applying heat or steam. Similarly, gas can be found in porous rock or reservoirs, in coal seams (known as coalbed methane), and in tighter geologic formations, including tight sands and shale formations. Extracting oil and gas from any of these reserves can result in produced water as a byproduct because water can exist naturally along with oil and gas in geologic formations (known as formation water) or it can be added to the well to stimulate oil and gas production (known as injected water). Formation water and injected water can return to the surface as produced water along with the oil or gas that is being extracted from the well. In

[1]Most of the balance of the nation's energy is supplied by coal, nuclear power, and hydropower and renewable resources.

other circumstances, such as when oil and gas are extracted from certain shale formations, water, sand, and chemicals are injected at high pressure to create fractures in the formation—a process known as hydraulic fracturing—thereby allowing the oil or gas to flow easier and be brought to the surface.[2] Some of this mix of water, sand, and chemicals returns to the surface when production starts (this type of produced water is known as flowback water). Over time, the quantity of produced flowback water generally diminishes, but smaller amounts of water will continue to be produced from the well.

Because of the inextricable link between energy production and water, you asked us to undertake a series of studies reviewing the energy-water nexus.[3] This is the fifth and final study in this series and provides information on (1) what is known about the volume and quality of produced water from oil and gas production; (2) what practices are generally used to manage and treat produced water, and what factors are considered in the selection of each; (3) how the management of produced water is regulated at the federal level and in selected states; and (4) what federal research and development efforts have been undertaken during the last 10 years related to produced water.

While oil and gas production comes from onshore and offshore operations, the focus of this review is onshore because produced water from onshore sources has the potential to affect surface and groundwater quality, and a greater variety of practices are employed to manage produced water. To address these objectives, we conducted a literature review of studies and other documents on produced water quality and volume, management, and regulations issued by federal agencies and laboratories, state agencies, the oil and gas industry, and academic institutions. These documents included peer-reviewed scientific and

[2]Ceramic beads are sometimes used in lieu of sand when hydraulically fracturing a well. Both are used to prevent the fractures from closing when the injection has stopped.

[3]GAO, *Energy-Water Nexus: Improvements to Federal Water Use Data Would Increase Understanding of Trends in Power Plant Water Use*, GAO-10-23 (Washington, D.C.: Oct. 16, 2009); *Energy-Water Nexus: Many Uncertainties Remain about National and Regional Effects of Increased Biofuel Production on Water Resources*, GAO-10-116 (Washington, D.C.: Nov. 30, 2009); *Energy-Water Nexus: A Better and Coordinated Understanding of Water Resources Could Help Mitigate the Impacts of Potential Oil Shale Development*, GAO-11-35 (Washington, D.C.: Oct. 29, 2010); *Energy-Water Nexus: Amount of Energy Needed to Supply, Use, and Treat Water Is Location-Specific and Can Be Reduced by Certain Technologies and Approaches*, GAO-11-225 (Washington, D.C.: Mar. 23, 2011).

industry periodicals, government-sponsored research, and reports from nongovernmental research organizations. We believe we have included the key studies and have qualified our findings, where appropriate. However, it is possible that we may not have identified all of the studies with findings relevant to our objectives.

In addition, we interviewed stakeholders such as federal and state regulatory officials; federal scientists from the Environmental Protection Agency's (EPA) Office of Research and Development and the Department of Energy's (DOE) Argonne National Laboratory, Los Alamos National Laboratory, National Energy Technology Laboratory (NETL), Oak Ridge National Laboratory, and Sandia National Laboratories; officials from oil and gas exploration and production companies; officials from water treatment companies; and other experts with experience related to produced water. The federal and state regulatory officials included those with responsibility over oil and gas regulation, as well as clean water and drinking water regulation. We focused our review of management techniques and produced water regulation on nine states—California, Colorado, Kansas, Louisiana, New Mexico, Oklahoma, Pennsylvania, Texas, and Wyoming. These states account for nearly 90 percent of produced water generated.

We supplemented our literature review and stakeholder discussions with site visits to selected locations in Pennsylvania, Texas, and Wyoming, where we met with oil and gas producers and officials from produced water treatment facilities and discussed issues related to produced water management and treatment and the factors that influence these decisions. We selected these states because of the current and potential volumes of produced water generated, the range of hydrocarbons produced, and the different management and treatment practices employed. We also visited hydraulic fracturing drilling operations, underground injection control well sites, and a number of different treatment facilities employing a variety of technologies. To determine what federal research and development efforts have been undertaken during the last 10 years related to produced water, we analyzed information supplied by and conducted interviews with federal officials from DOE and select national laboratories, EPA, and the Department of the Interior's U.S. Geological Survey (USGS), Bureau of Land Management (BLM), and Bureau of Reclamation.

We conducted this performance audit from October 2010 to January 2012, in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

Background

The domestic production of oil and gas is essential to the nation's energy portfolio. According to DOE's Energy Information Administration (EIA), the United States consumed approximately 6.7 billion barrels of oil and 24 trillion cubic feet of gas in 2010. Together, oil and gas production supply over 60 percent of the nation's total energy demand, and demand is expected to grow in the future. While domestic drilling for oil and gas can present risks to the environment, it also results in the creation of jobs and economic growth, as well as payments to the government in the form of royalties.[4]

The U.S. oil and gas reserves located onshore are extensive, with proven onshore oil reserves of approximately 18 billion barrels and proven onshore gas reserves of approximately 271 trillion cubic feet as of December 2009, according to the EIA.[5] These reserves are located across the country, primarily in 31 key oil- and gas-producing states, and include a range of different types of hydrocarbons. These hydrocarbons include both conventional and unconventional oil and gas sources. Although there is no clear and consistently agreed upon distinction between conventional and unconventional oil and gas, conventional sources of oil and gas are generally produced using traditional methods of drilling and pumping, whereas unconventional oil and gas sources generally require more complex and expensive technologies for production. For example, in some instances heavy oils produced using steam injection are considered unconventional, while in other situations they are considered conventional. For this reason, in this report we generally do not distinguish between conventional and unconventional oil

[4]The federal government issues leases for federal lands and waters to oil and gas operators who in turn pay royalties to the government on the oil and gas they produce. These royalty payments totaled approximately $9 billion in 2009.

[5]Proven, or proved, reserves are defined as oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. While the United States also has extensive offshore oil and gas reserves, the focus of this report is limited to onshore oil and gas production.

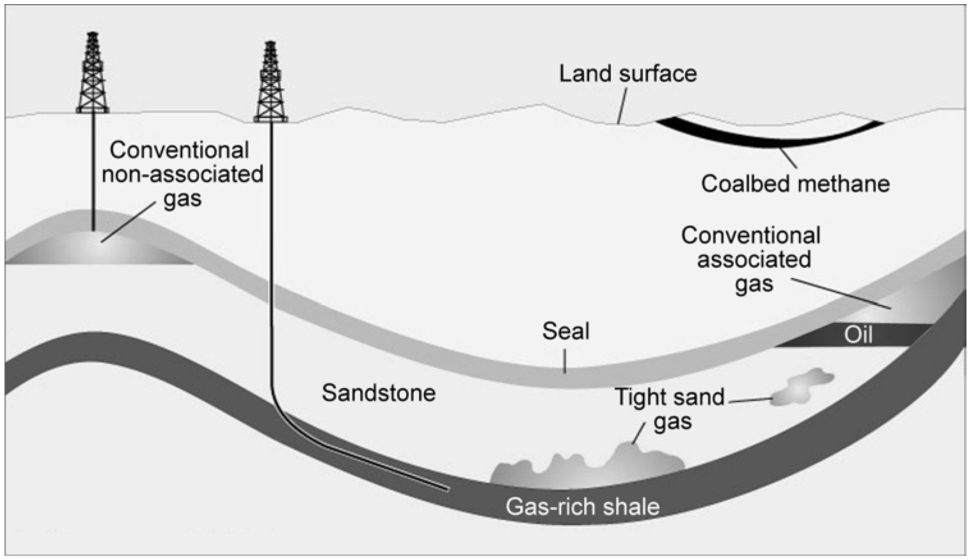
and gas except in instances when supporting documentation or information we use from other sources makes this distinction necessary; in such cases, we provide the relevant definition in a footnote.[6]

Oil and gas is found within underground layers of rock referred to as formations. The geologic characteristics of the formations in which the various hydrocarbons are found vary widely, along with the characteristics of the hydrocarbons themselves. For example, shale oil and gas formations are generally tighter and much less permeable than other formations, causing the oil and gas to be much less free flowing. Coalbed methane formations, located at shallow depths of 1,000 to 2,000 feet, are more permeable formations through which gas can flow more freely than through shale formations. In addition, heavy oil, due to its higher viscosity, has much less ability to flow freely through a formation compared to lighter oil.[7] Figure 1 below provides examples of differing geologies for various gas hydrocarbons.

[6]This report includes oil and gas currently produced onshore in the United States. It excludes some kinds of oil production from shale formations that are not generally being produced commercially at the current time, as well as oil sands, which are primarily produced in Canada.

[7]Viscosity is a measure of the resistance of a fluid to flow.

Figure 1: Geology of Gas Resources



Sources: U.S. Energy Information Administration and U.S. Geological Survey.

Note: "Associated gas" is gas that accumulates in conjunction with oil in a formation. "Non-associated gas" is gas that accumulates separately from oil in a formation.

As a result of these geologic differences, the methods used to produce hydrocarbons vary widely. Some oil and gas can be produced by drilling a well and relying on the natural pressure in the formation to push the oil or gas to the surface. Heavy oil, on the other hand, may require the injection of an additive such as steam into the formation to stimulate the flow of oil—a process known as enhanced recovery. Similarly, some hydrocarbons are produced through the use of hydraulic fracturing. Hydraulic fracturing involves the injection of liquid under pressure to fracture the rock formation and to prop open the fractures to allow hydrocarbons to flow more freely from the formation into the well for collection. The liquids used in this process consist primarily of water, but also include chemicals, as well as sand or other propping agents for holding open the fractures (proppant). Hydraulic fracturing is commonly used to facilitate the production of many hydrocarbons, including oil, shale gas, tight gas, and coalbed methane. Recent improvements in hydraulic fracturing, combined with horizontal drilling technologies, have prompted a boom in shale oil and gas production.

The process of producing oil and gas is complicated and yields several byproducts that must be managed as part of the oil and gas operation's waste stream. Key among these byproducts is the produced water that comes to the surface along with the oil or gas during production. Produced water may include water that occurs naturally in the formation, water or other liquids that were injected into the formation to enhance recovery during the drilling or production process, and flowback water, which is the water, proppants, and chemicals used for hydraulic fracturing (fracturing fluids).

EPA regulates water primarily through two federal laws: the Safe Drinking Water Act and the Clean Water Act. The Safe Drinking Water Act was originally passed by Congress in 1974 to protect public health by ensuring a safe drinking water supply.[8] Under the act, EPA is authorized to set standards for both naturally-occurring and man-made contaminants that may be found in drinking water. The Safe Drinking Water Act also regulates the placement of wastewater and other fluids underground through the Underground Injection Control program. This program provides safeguards to ensure that wastewater injected underground does not endanger drinking water supplies. There are six classes or categories of wells regulated through the Underground Injection Control program. For example, class II wells are for the management of fluids associated with oil and gas production, and they include wells used to dispose of wastewater and those used to enhance oil and gas production.[9] EPA may grant, or approve by rule, primary enforcement authority for the Underground Injection Control program to a state, which means that the state assumes responsibility for executing the program, including permitting, monitoring, and enforcement for operations within the state. To be approved for this authority, state programs must be at least as stringent as the federal program and show that their regulations contain effective minimum requirements. To obtain this authority over class II wells only, states with existing oil and gas programs may make an optional demonstration that their program is effective in protecting underground sources of drinking water.

[8]Pub. L. No. 93-523 (1974), codified as amended at 42 U.S.C. §§ 300f–300j-26.

[9]The other classes of Underground Injection Control program wells are as follows: class I wells are used for the disposal of hazardous and certain nonhazardous waste; class III wells are used to inject fluids for mineral extraction; class IV wells are used to dispose of hazardous or radioactive wastes, into or above an underground source of drinking water; class V wells are used to dispose of other nonhazardous wastes; and class VI wells are used for carbon sequestration. Class IV wells are currently banned.

The Clean Water Act was enacted by Congress in 1972 to protect surface waters by regulating discharges of pollutants into those waters.[10] Pursuant to the water-quality-based pollution control program mandated by the act, states establish and EPA approves water quality standards for contaminants in surface waters. The Clean Water Act also regulates the discharge of wastewaters, including produced water, through the National Pollutant Discharge Elimination System permit program, which requires all facilities that discharge pollutants from any point source into surface waters to be permitted.[11] EPA may delegate primary enforcement authority to a state for this program if a state demonstrates that its program requirements are as stringent as those set by EPA. Once EPA delegates this authority, the state is responsible for permitting, monitoring, and enforcing these permits.

Oil and gas producers who would like to drill on federal lands managed by BLM must also obtain permits from BLM. The Federal Land Policy and Management Act of 1976 requires BLM to develop resource management plans, which, among other things, identify parcels of federal land that will be available for oil and gas development and leasing. Producers who have obtained a lease from BLM for oil and gas production on public lands must submit an application to BLM for a permit to drill before beginning to prepare the land or drilling any new oil or gas wells. The complete permit application package must include, among other things, a reclamation plan that details the steps operators propose to take to reclaim the site, including redistribution of topsoil, configuring the reshaped topography, and seeding or other steps to re-establish vegetation. In some circumstances, approval from state officials may also be required before operators can begin drilling and production.

[10]The Federal Water Pollution Control Act Amendments of 1972, Pub. L. No. 92-500, § 2, 86 Stat. 816, codified as amended at 33 U.S.C. § 1251 et seq. (commonly referred to as the Clean Water Act).

[11]Surface waters refer to navigable waters, tributaries to navigable waters, interstate waters, the oceans out to 200 miles, and intrastate waters that are used by interstate travelers, for recreation or other purposes, as a source of fish or shellfish sold in interstate commerce, or for industrial purposes by industries engaged in interstate commerce. Point sources are wastes discharged from discrete sources such as pipes. The Clean Water Act defines point source as "any discernible, confined and discrete conveyance, including but not limited to any pipe, ditch, channel, tunnel, conduit, well, discrete fissure…or vessel or other floating craft from which pollutants are or may be discharged."

In addition to obtaining permits for underground injection, discharge, and drilling, oil and gas producers may also be required to obtain permits from state or regional authorities to withdraw water from a river basin or underground. For example, producers in the Susquehanna River Basin must obtain a permit from the Basin Commission to withdraw surface water or groundwater. This water may be blended with recycled or produced water and used for hydraulic fracturing. Alternately, producers in Colorado and Wyoming must obtain groundwater permits from their State Engineer's Office to drill for coalbed methane. State officials consider the drilling to be a beneficial use of water since producers must withdraw water from underground to obtain the gas and this classification means a permit is required.

Oil and Gas Wells Generate a Significant Amount of Produced Water, but the Volume and Quality of the Water Produced at a Given Well Varies

A significant amount of water is produced daily as a byproduct from onshore drilling of oil and gas, but the volume produced by a given well will vary depending on the type of hydrocarbon being produced, the geographic location of the well, and the method of production used. Overall, most produced water is of poor quality and cannot be used for other purposes without prior treatment; however, produced water quality can also vary greatly depending on the hydrocarbon, geography, and production method.

Millions of Barrels of Produced Water Are Generated Daily, but the Volume Produced at a Given Well Is Dependent on Several Factors

An estimated 56 million barrels of produced water are generated every day as a byproduct of onshore oil and gas production in the United States. This estimate is based on an Argonne National Laboratory study of produced water volumes generated during 2007—the most recent year for which such data were collected—and was derived from data collected from state agencies in 31 oil- and gas-producing states.[12] The study is considered by agency officials, researchers, and other experts with whom we spoke to be the most comprehensive and accurate assessment of produced water volumes to date. However, because the Argonne study is based on limited and, in some cases, incomplete data, it likely underestimates the current total volume of produced water being

[12]Argonne National Laboratory, *Produced Water Volumes and Management Practices in the United States*, ANL/EVS/R-09/1 (Argonne, Ill.: September 2009).

generated by oil and gas operations today. Specifically, we noted the following limitations in the Argonne estimate:

- The reporting time frame for the study largely occurred prior to the recent, dramatic increase in shale gas production in the United States, which had an average annual growth rate of 48 percent from 2006 to 2010, according to the EIA. In 2010, EIA had estimated that shale gas accounted for approximately 23 percent of all gas production in the United States.

- The study is based on state data that were collected and maintained using a variety of methods, making them difficult to compare and aggregate at a national level. For example, in some states, producers are required to report produced water volumes as measured by flow meters, whereas in other states, producers are required to estimate produced water volumes using a method of their choosing, which may limit the precision of the data. Furthermore, in other states, producers are only required to report produced water volumes they dispose of in injection wells, which may not reflect the total produced water generated. Lastly, some states do not collect data on produced water volumes at all. In such cases, Argonne generated estimates of produced water volumes based on available information on oil and gas production in the state and made certain assumptions about water volumes based on produced water data from neighboring states.

Although the Argonne study clearly demonstrates that a large amount of produced water is generated daily, the volume generated by a specific oil and gas well can vary significantly according to three key factors: the type of hydrocarbon being produced, the geographic location of the well, and the method of production used. First, according to literature we reviewed and stakeholders we spoke with, the type of hydrocarbon influences not only how much water a well generates, but also when the water is produced over the life of the well. This is because the geological formations for different hydrocarbons have different attributes, thus influencing the amount of water that is produced from a particular well. For example, coalbed methane wells produce large volumes of water in the early stages of production, because coal beds are essentially aquifers that contain coal rock and gas bound together from the pressure of the water present in the aquifer.[13] By pumping out water, the resulting drop in

[13]An aquifer is a natural underground layer, often of sand or gravel, that contains water.

pressure allows the gas to detach from the coal and flow to the surface. In contrast, one producer noted that their conventional gas wells produce much less water than their coalbed methane wells because the formations from which conventional gas is drawn contain much less water.[14] Oil wells, on the other hand, typically generate less water during the first years of production, when formation pressure is high enough to allow the oil to flow freely to the surface. As these oil wells age, however, water volumes increase, as oil taken out is displaced by water flowing in from the surrounding formation. One producer that we spoke with noted that their older oil fields produce more than five times the volume of water produced by their younger oil fields.

Second, according to the literature we reviewed and stakeholders we spoke with, the geographic location of a well also influences the volume of produced water it generates, due to differences in geology. For example, stakeholders noted that the Barnett Shale formation in Texas is generally known to be a "wetter" formation than the Marcellus Shale formation in the Northeast, with shale gas wells in the Barnett typically producing three to four times more water than shale gas wells in the Marcellus. Similarly, USGS reported that coalbed methane wells in the Powder River Basin in Wyoming and Montana produce, on average, 16 times more water than coalbed methane wells in the San Juan Basin in Colorado and New Mexico. In addition, produced water volumes can vary among wells in close proximity with one another. For example, at one site we visited in Wyoming, some gas wells were producing two to three times more water than other gas wells in the same field, for reasons that were, in general, not clear to the operator of those wells.

Lastly, the method of production used to extract oil and gas also influences the volume of water generated, according to the literature we reviewed and stakeholders we spoke with. Specifically, stakeholders reported that methods of production that rely on the injection of water and other fluids into the formation in order to stimulate oil and gas production can generate more produced water than in cases in which oil and gas comes to the surface under existing pressure. For example, one stakeholder reported that the use of enhanced oil recovery methods such as steam injection can generate eight to nine barrels of water for every

[14]In this example, conventional gas well is used to refer to formations typically consisting of porous sandstone that can be produced using traditional drilling methods.

barrel of oil produced. At one enhanced oil recovery field we visited, produced water comprised more than 95 percent of the total liquids produced, with oil comprising the remainder. Similarly, the use of hydraulic fracturing to produce oil or gas can result in larger volumes of produced water than production in more porous formations, although the larger volumes associated with hydraulic fracturing are limited to the initial flowback of water and fracturing fluids. For example, with shale gas production, stakeholders reported that flowback volumes can range from approximately 10,000 to 60,000 barrels per well for each hydraulic fracture.[15] However, once the initial flowback ceases, the volume of water produced by shale gas production may be relatively small, sometimes decreasing to just a few barrels per day.

Produced Water Is Generally of Poor Quality, with the Levels of Contaminants Varying Widely

The quality of produced water from oil and gas production is generally poor, and in most situations, it cannot be readily used for other purposes without prior treatment. According to the literature we reviewed and stakeholders we spoke with, produced water may contain a wide range of contaminants in varying amounts. Most of the contaminants occur naturally in the produced water, but some are added through the process of drilling, hydraulic fracturing, and pumping oil and gas. The range of contaminants found in produced water can include, but is not limited to

- salts, which include chlorides, bromides, and sulfides of calcium, magnesium, and sodium;
- metals, which include barium, manganese, iron, and strontium, among others;
- oil, grease, and dissolved organics, which include benzene and toluene, among others;
- naturally occurring radioactive materials; and
- production chemicals, which may include friction reducers to help with water flow, biocides to prevent growth of microorganisms, and additives to prevent corrosion, among others.

[15] An individual shale gas well is typically fractured between 10 and 16 times.

Exposure to these contaminants at high levels may pose risks to human health and the environment. For example, according to EPA, a potential human health risk from exposure to high levels of barium is increased blood pressure, and potential human health risks from exposure to high levels of benzene are anemia and increased risk of cancer. From an environmental standpoint, research indicated that elevated levels of salts can inhibit crop growth by hindering a plant's ability to absorb water from the soil. Additionally, exposure to elevated levels of metals and production chemicals, such as biocides, can contribute to increased mortality among livestock and wildlife.

The specific quality of water generated by a given well, however, can vary widely according to the same three factors that impact the volume of water produced from the well: the hydrocarbon being produced, the geographic location of the well, and method of production used. First, according to stakeholders we spoke with, the type of hydrocarbon is a key driver of produced water quality, due to differences in geology across the formations in which the hydrocarbons are found. Specifically, the depth at which the hydrocarbons are found influences the salt and mineral content of produced water, and, in general, the deeper the formation is, the higher the salt and mineral content will be. For example, produced water from shale gas wells drilled at depths generally ranging from 5,000 to 8,000 feet have salt and mineral levels 20 times higher than produced water from coalbed methane wells drilled at depths of 1,000 to 2,000 feet. Additionally, the amount of oil or gas that is mixed in with the produced water brought to the surface can also vary. For example, produced water typically blends more easily with oil than with gas. As a result, produced water from oil wells generally contains levels of oil, grease, and other organic compounds that are four to five times higher than water from gas wells.

Second, the quality of produced water also varies depending on the well's geographic location, also because of differences in geology. For example, producers we spoke with said that produced water from wells in the Marcellus Shale formation in the Northeast has higher levels of radionuclides than water from shale gas wells in the Barnett Shale formation in Texas. Similarly, according to research, produced water from coalbed methane wells in the Raton Basin in Colorado and New Mexico has a salt content, on average, roughly two and a half times higher than produced water from the Powder River Basin in Wyoming and Montana. In addition, produced water quality can vary within a given region, according to producers we spoke with. For example, some coalbed methane wells in the Powder River Basin in Wyoming contain barium levels five to six times higher than the barium levels found in wells less than 50 miles away. Additionally, produced water from wells in one oil field in California contains levels of boron four to five times higher than produced water from oil wells in neighboring fields.

Lastly, the method of production can affect the quality of the water produced. These differences are largely attributable to the chemicals and other substances added during drilling or production processes, according to stakeholders we spoke with. Specifically, methods of production that rely on hydraulic fracturing or enhanced recovery methods can result in poorer quality produced water than other methods. For example, according to stakeholders, the range of chemicals, sand, and water that are added to facilitate the hydraulic fracturing process can lower the overall quality of the produced water from these kinds of operations. Similarly, the use of chemicals during enhanced recovery can also affect the quality of water produced. Stakeholders noted that enhanced recovery involves the addition of production chemicals such as biocides, corrosion inhibitors, and friction reducers, along with steam or carbon dioxide. For example, one stakeholder estimated that wells produced using these enhanced recovery methods can yield produced water with levels of some production chemicals three to four times higher than produced water from wells that do not use enhanced recovery techniques.

A Number of Practices Are Available to Manage and Treat Produced Water, with Cost Being the Primary Determining Factor

Oil and gas producers have a number of options on how to manage produced water, but underground injection is the predominant practice. In addition to underground injection, a limited amount of produced water is managed by discharging it to surface water, storing it in surface impoundments, and reusing it for irrigation or hydraulic fracturing. With regard to treatment options, most produced water is minimally treated, although more advanced treatment methods are available if the end use of the water requires a higher level of treatment. Ultimately, cost is the primary driver in producers' decisions about how to manage and treat produced water generated by oil and gas producers.

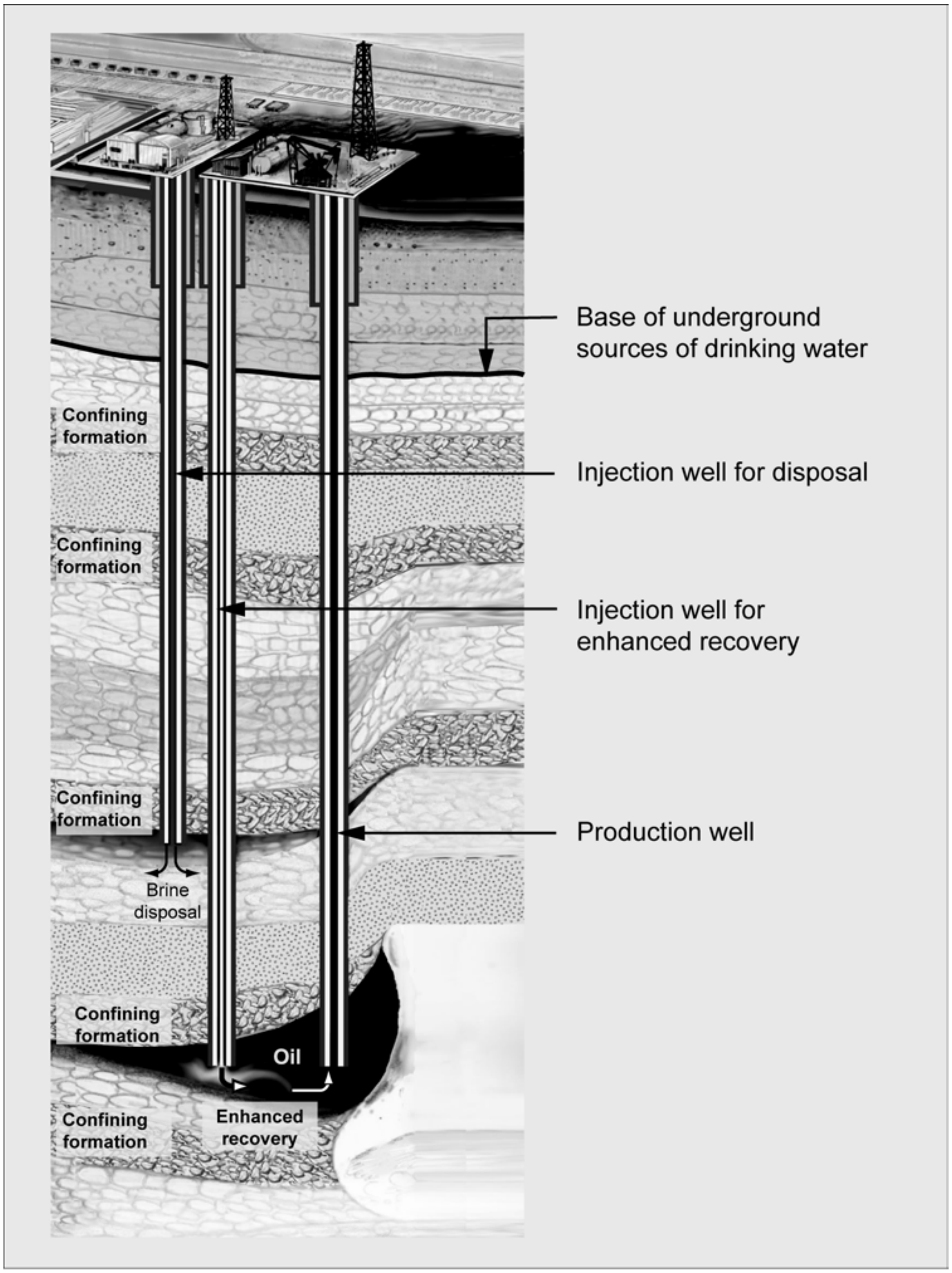
Produced Water Can Be Managed in a Number of Ways, although Underground Injection Is the Most Common Practice

Over 90 percent of the water produced during oil and gas operations is managed through underground injection practices; the remaining water is generally discharged to surface water, stored in surface impoundments, reused for irrigation, or reused for hydraulic fracturing. In its 2009 report,[16] Argonne National Laboratory estimated, and EPA officials that we spoke with concurred, that most produced water is managed by injecting it underground into wells that are designated to receive this water.[17] These wells, known as injection wells, must be constructed to protect underground sources of drinking water, and they are tested and monitored periodically to ensure no drinking water is being contaminated by well operations (see fig. 2). Injection wells can be used for enhanced recovery or permanent disposal of the water. When producers reuse produced water for enhanced recovery, they inject it into wells in the same producing formation to recover additional oil and, in limited applications, gas, thus prolonging the life of the production well. Some of this water will come back up as produced water in subsequent well operations. When producers inject produced water for permanent disposal into an underground formation, they inject it into wells in the same formation or a formation that is similar to the one the produced water was extracted from.

[16]Argonne National Laboratory, *Produced Water Volumes and Management Practices in the United States*.

[17]Argonne National Laboratory reported that more than 98 percent of produced water generated from onshore oil and gas wells in 2007 was injected underground. EPA officials we spoke with estimated that over 90 percent of produced water generated from onshore wells is still injected underground but could not provide a precise figure for current volumes.

Figure 2: Injection Wells for Produced Water



Source: EPA.

According to EPA records, in 2010 there were 150,855 injection wells authorized for the injection of fluids brought to the surface during oil and gas production, including produced water, although EPA officials told us that not all are currently operating.[18] About four-fifths of the wells—124,837—are located in the nine states we reviewed (see table 1).

Table 1: Number of Injection Wells in Selected States

State	Number of injection wells
Texas	52,016
California	29,505
Kansas	16,658
Oklahoma	10,629
Wyoming	4,978
New Mexico	4,585
Louisiana	3,731
Pennsylvania	1,861
Colorado	874
Total in selected states	**124,837**

Source: GAO analysis of EPA data.

According to state regulators we interviewed in the nine states, underground injection is common in most, but not all, of their states. Specifically, regulators in five states told us that all or almost all of the produced water is managed through underground injection, and in three other states, most of the produced water is managed this way. In the ninth state—Pennsylvania—many producers use underground injection for enhanced recovery, but the practice is not widely used for disposal, according to EPA officials.[19]

[18]Although approximately 80 percent of these injection wells are used for enhanced recovery and the remaining 20 percent are used for disposal, only about 59 percent of produced water is injected into these wells for enhanced recovery, and about 40 percent is injected for disposal.

[19]According to EPA officials, there are currently only six active injection wells for produced water disposal in Pennsylvania. As a result, producers that want to dispose of produced water through underground injection would generally have to transport the water to authorized injection wells in Ohio or West Virginia, and trucking can be expensive. However, EPA officials we interviewed said that in the past 2 years producers have shown interest in drilling additional injection wells for disposal in Pennsylvania, and EPA has received permit applications for new wells.

Produced water that is not injected into underground injection wells is disposed of or reused by producers in other ways, including the following.[20]

Discharge to surface water. According to Argonne National Laboratory's report, less than 1 percent of produced water generated from onshore oil and gas operations in 2007 was managed by discharging it to surface water.[21] Surface discharges of produced water directly from oil and gas production sites are prohibited in much of the United States, but produced water may be discharged from an off-site treatment facility.[22] According to Argonne's report, discharges of produced water to surface water are primarily limited to the western United States and generally occur only when the salt content of the water is low. While a current national estimate of this practice is not available, EPA officials and regulators in seven of the nine states we reviewed told us that surface discharges of produced water are limited or are nonexistent in their states. For example, officials we spoke with from Colorado said that a very small portion of the produced water generated in that state is discharged to surface water and only 24 of the approximately 9,900 discharge permits they have issued are for oil and gas producers. Among the states we reviewed, Wyoming and Pennsylvania were the only two where producers commonly use surface discharges to manage produced water.[23] For example, an oil producer we spoke with in Wyoming told us his company discharges a small portion of the produced water from some of its fields directly to a nearby creek because the water quality is high enough to meet the state's discharge limits without prior treatment; however, the majority of the water generated from these fields has a much higher salt concentration and cannot be discharged into surface waters.

[20]Other less commonly used management practices, such as reusing the produced water in industrial settings for dust control or cooling water, may also be options for producers.

[21]Argonne National Laboratory, *Produced Water Volumes and Management Practices in the United States*.

[22]There are limited exceptions to this prohibition. For example, produced water from onshore oil and gas production sites located west of the 98th meridian that will be put to beneficial use for agriculture or wildlife watering can be discharged directly from the production site.

[23]Pennsylvania regulatory officials told us that almost all conventional oil and gas producers use surface discharges to manage produced water, following treatment; however, almost all shale gas producers in Pennsylvania stopped using this practice after the state's surface discharge standards were made more stringent in 2011.

Surface impoundment. Surface impoundments are lined or unlined ponds used primarily to facilitate evaporation of produced water, and in the case of unlined ponds, allow it to infiltrate into the ground.[24] According to DOE's NETL, drier climates are favorable for evaporation and spray nozzles may be used to increase the rate of evaporation. The National Research Council reported that, in 2008, surface impoundments were used to manage about 64 percent of produced water generated by coalbed methane producers in the Wyoming portion of the Powder River Basin.[25] According to the report, the water was generally untreated, but in some cases water was treated to meet requirements for discharging to the impoundment. For example, a coalbed methane producer we visited in Wyoming treats the produced water at a treatment facility to first remove barium to meet state water quality standards, then disposes of most of it in a surface impoundment, where it evaporates or infiltrates to the subsurface. Officials we spoke with from California, Colorado, and New Mexico also said that surface impoundments are used to manage produced water in those states, but it is not a significant practice in any of them.

Irrigation. Some produced water from coalbed methane is reused for irrigation in certain parts of Wyoming and Colorado because the water is generally of high enough quality that it does not require extensive treatment in order to avoid damage to the crops or soil. According to the National Research Council,[26] about 13 percent of the produced water generated from coalbed methane producers in Wyoming's Powder River Basin was reused for managed irrigation or subsurface drip irrigation.[27] For example, a coalbed methane production operation we visited in Wyoming disposes of almost all of its produced water from the Powder River Basin using a managed irrigation system, following minimal

[24]Surface impoundments are also used for the temporary storage of produced water prior to managing it in some other way.

[25]National Research Council, *Management and Effects of Coalbed Methane Produced Water in the Western United States* (Washington, D.C.: 2010).

[26]National Research Council, *Management and Effects of Coalbed Methane Produced Water in the Western United States*.

[27]Managed irrigation combines irrigation using produced water with preventative or intervention soil management, such as the addition of gypsum and elemental sulfur to improve the soil structure. Managed irrigation is necessary to prevent substantial deterioration of the soil structure caused by the salts and sodium present in produced water.

treatment of the water. Because its wells produce more water than can be disposed of under its surface discharge permit, it is a fairly economical option, and is allowable under state regulations. While there are examples of irrigation with produced water occurring elsewhere, it is not a widely used management practice. According to NETL, a significant challenge to using produced water for irrigation is the salt content of the water, which can decrease crop yields and damage the soil. In addition, the National Research Council reported that while reusing coalbed methane produced water for beneficial purposes such as irrigation would seem to be a desirable and relatively easy objective, in reality it is potentially economically and environmentally burdensome, complex, and challenging. The suitability of water for irrigation depends on a number of factors including the type of crops grown, the soil type, irrigation methods, and the types and quantity of salts dissolved in the water. In addition, the reliability of the produced water supply over time, proximity to the irrigation site, and costs also present challenges.

Hydraulic fracturing. In recent years, some shale gas producers have begun reusing produced water for hydraulic fracturing of additional wells at their operations. The water is typically treated first, either on-site or off-site, and then mixed with freshwater if salt concentrations remain high. Although no national estimate of producers' use of this practice is available, a 2009 report on shale gas development reported that interest in this type of reuse for produced water was high.[28] However, the report also noted that certain water treatment challenges needed to be overcome to make this type of reuse more widespread. According to NETL, in order for reuse of produced water to become widespread, low-cost treatment technologies must be developed. In the last couple of years, reusing produced water for hydraulic fracturing has become more common among shale gas producers in Pennsylvania, according to state regulators and producers we spoke with in the state. The shift was motivated, in part, by a change in the state's surface discharge standards that ultimately made treatment and discharge a comparatively more expensive practice. For example, one shale gas production site we visited in Pennsylvania currently reuses all of its produced water for hydraulic fracturing, although it had used other practices in the past. Other shale gas producers in the state are also adopting this approach, according to

[28]Ground Water Protection Council and ALL Consulting, *Modern Shale Gas Development in the United States: A Primer* (Oklahoma City, Okla.: April 2009).

agency officials and an academic expert we spoke with. In addition, regulators in five of the other states we reviewed told us that producers in these states are reusing produced water for hydraulic fracturing, although generally to a lesser extent than in Pennsylvania.

Most Produced Water Is Minimally Treated, but More Advanced Treatment Methods Are Available

Because most produced water is managed through underground injection wells, it is minimally treated; however, if produced water is going to be reused or disposed of in some other manner, then more advanced treatment methods are available, depending on the level of treatment required.

Treatment methods for produced water managed through underground injection. Produced water managed through underground injection generally does not need to be treated because injection wells are designed to confine the produced water to the receiving formation and prevent it from migrating to underground sources of drinking water. In some cases, however, to meet an injection well's operating requirements or prevent premature "plugging" of the formation, the water may be treated to control excessive solids, dissolved oil, corrosion, chemical reactions, or the growth of bacteria and other microbes, according to NETL. Such treatment is generally minimal and can include storing the water in a tank to allow solids to settle out and passing the water through a screen or filter to remove additional solids. Chemicals may also be added to prevent corrosion of the injection well equipment and filtration or biocides may be used to prevent bacteria, algae, or fungi present in the water from clogging equipment or encouraging corrosion.

Treatment methods for produced water reused for hydraulic fracturing. Producers who reuse produced water for hydraulic fracturing told us they treat the water to meet their own operating requirements. While producers we spoke with said that they had previously treated the water to a very high quality before reusing it for hydraulic fracturing, they are currently experimenting with lower levels of treatment. For example, one producer told us that 2 years ago his company treated the water so that it was nearly as clean as freshwater, but based on internal research, the company no longer removes salt from the produced water that it reuses for hydraulic fracturing. This lower level of treatment has reduced operating costs, and the producer is considering eliminating other treatment steps as long as doing so will not cause operational problems, such as equipment corrosion.

Treatment methods for produced water discharged to surface water bodies or reused for irrigation. If produced water is going to be discharged to surface water or reused for irrigation, then treatment is often necessary to reduce hardness, salts, and other contaminants, in addition to settling and filtration methods to remove solids. Solids and hardness removal are sometimes referred to as "pretreatment" steps. Hard water contains dissolved constituents, mainly calcium and magnesium ions, which can cause scaling of pipes and equipment. Hardness is typically removed prior to removing salts by adjusting the pH of the water and adding chemicals that cause dissolved calcium and magnesium to form small solids, or precipitates, which then settle out or are filtered out of the water with the aid of additional processes.[29] Alternatively, when produced water is going to be reused for irrigation, calcium or magnesium may be added to the water to address sodium levels. Treatment technologies, including distillation, reverse osmosis, and ion exchange, are then used to remove salt and other contaminants from produced water.[30] Distillation is a treatment process that essentially boils produced water to evaporate and then condense the clean water, leaving behind concentrated brine. Reverse osmosis is a filtration process that forces water through a semi-permeable membrane, allowing water to pass through but trapping salt on the other side. Reverse osmosis generally requires a high level of pretreatment to prevent fouling of the membranes, and it is only feasible when salt concentrations in the produced water are less than approximately 25,000 parts per million, according to a study by the Colorado School of Mines.[31] For example, produced water from a gas operation we visited in Wyoming had to first undergo pretreatment to remove solids, hardness, and other contaminants before being put through three stages of reverse osmosis. A third treatment technology, ion exchange, selectively captures sodium ions from produced water and

[29]pH is a measure of how acidic or basic the water is. Excessively high or low pH can be detrimental for the use of water.

[30]The ratio of sodium to calcium and magnesium ions in produced water is an important property affecting the infiltration and permeability of the soil. The sodium adsorption ratio is an index used to measure the hazard related to sodium abundance in the soil.

[31]Colorado School of Mines, *An Integrated Framework for Treatment and Management of Produced Water* (Golden, Colo.: November 2009). The Colorado School of Mines also reported that total dissolved solids (i.e., salt concentrations) in produced water from conventional oil and gas in the western United States range from 1,000 to 400,000 parts per million. Producers we interviewed in other parts of the United States told us total dissolved solids in their produced water range from 40,000 to 300,000 parts per million.

replaces them with others.[32] The water is passed through a large bed of resin beads and sodium ions are adsorbed to (i.e., concentrate on the surface of) the resin. Similar to reverse osmosis, ion exchange faces upper limits on salt concentrations of approximately 7,000 parts per million, according to the Colorado School of Mines.[33] Each of the technologies to remove salt typically generates concentrated brine, which must then be properly disposed of as well.

Cost Is the Primary Factor That Determines How Produced Water Is Managed and Treated

While a variety of factors influence how produced water is managed and the level to which it is treated, cost is the primary factor that oil and gas producers consider when making these decisions. According to producers and agency officials we spoke with, how produced water is managed and treated is primarily an economic decision, made within the bounds of federal and state regulations. In most cases, underground injection is the lowest-cost option and producers we spoke with said that their costs for underground injection range from $0.07 to $1.60 per barrel of produced water.[34] However, if a producer is not operating in close proximity to injection wells, transporting the water via truck or pipeline can significantly increase these costs. Furthermore, producers told us that trucking is one of the most significant cost factors they face, and they seek to minimize this cost by managing the water closer to the production site when possible. For example, according to one producer, trucking costs in Texas range from $0.50 to $1.00 per barrel because injection wells in the area are plentiful, whereas costs in Pennsylvania range from $4.00 to $8.00 per barrel because injection wells are scarce, and the produced water often must be transported out of state. As a result, once trucking is factored in, underground injection may in fact become more costly than other management practices.

Another significant component of cost is whether treatment will be required as part of the management practice being employed. Treatment costs depend heavily on the technologies used, which in turn depend on the quality of the produced water being treated and the level of treatment

[32]Ion exchange can also be used to remove hardness.

[33]Colorado School of Mines, *An Integrated Framework for Treatment and Management of Produced Water.*

[34]The costs presented in this report generally do not include construction costs for the injection well or treatment facility.

needed for the disposal or reuse option being considered. For example, there are a number of treatment methods to remove salt from produced water, but each option has a different cost and differing level of effectiveness. Distillation, while effective at removing salts, has significantly higher costs, and representatives from water treatment facilities and producers we spoke to said it can cost from $6.35 to $8.50 per barrel, on average. Reverse osmosis and ion exchange are less costly treatment options for removing salt, but their use is limited by the level of salt content they can remove from produced water, and reverse osmosis can require extensive pretreatment, which can significantly drive up costs. Producers we spoke with who use reverse osmosis and ion exchange to treat produced water told us that their costs range from $0.20 to $0.60 per barrel. In some cases, producers may be able to change the management practice they use to minimize their treatment costs. For example, state regulators told us that when more stringent discharge limits were put into place in Pennsylvania, many shale gas producers in the state stopped discharging produced water to the surface and started to reuse it for hydraulic fracturing because the latter requires a simpler, and less expensive, level of treatment.

In addition to cost, according to our review of the literature and stakeholders we spoke with, produced water management decisions are also influenced by a number of other factors including the following:

- Poor water quality is a key reason most produced water is managed through underground injection, rather than reused or discharged to the surface. However, when water quality is relatively good, as some of it is in the Powder River Basin of Wyoming, management practices such as irrigation and infiltration from surface impoundments may become viable options. Nonetheless, adequate quantities of produced water are needed for irrigation to be a sustainable practice, and the water must be in close proximity to the land it will be used on or producers can face high transportation costs.

- Proximity and region-specific factors, such as geology, also influence which management practices are feasible in a given area. For example, some oil and gas producers are not located in close proximity to injection wells, or the number of available wells is limited by the underlying geology of the area, and therefore producers must manage their produced water some other way. An oil producer we spoke to told us his company would prefer to manage all of its produced water through underground injection for enhanced recovery and disposal. However, opportunities for enhanced recovery at one of the producer's sites are limited by its level of oil production and disposal is constrained by the geology in the area. As a result, the producer told us he manages about 20 percent of the produced water from this site through treatment and discharge, which is significantly more costly and technically challenging than underground injection.

- Climate is also a factor in the decision-making process. Arid climates are favorable for managing produced water using surface impoundments for evaporation, and limited water supplies in certain regions can motivate producers to make the water available for other purposes, such as irrigation.

- Regulatory requirements at the federal or state level can also influence producers' management decisions. As discussed earlier, the changes in discharge limits in Pennsylvania led to a change in management practices by shale gas producers in the state.

- Producers' risk management policies can also influence how they manage the water. For example, regulators we spoke with from California told us that liabilities associated with surface discharges and impoundments are a driving factor in moving away from those practices and toward underground injection. According to these regulators, surface impoundments were commonly used in California to manage produced water in the past, but in the last few years hundreds of them have closed down and they are no longer widely used.

EPA and the States We Reviewed Regulate the Management of Produced Water through a Variety of Means

The management of produced water is regulated by EPA and the states we reviewed through a variety of means, depending on how the water is disposed of or reused. EPA regulates the management of produced water that is injected underground under the Safe Drinking Water Act, while it regulates the management of produced water that is discharged into surface waters under the Clean Water Act. Other management practices, such as disposal of the water into surface impoundments, irrigation, and reuse of the water for hydraulic fracturing, are primarily regulated by the state authorities.

Underground Injection Is Regulated under the Safe Drinking Water Act

The management of produced water through underground injection is subject to the Safe Drinking Water Act's Underground Injection Control program. This program is designed to prevent contamination of aquifers that supply, or could supply in the future, public water systems by ensuring the safe operation of injection wells. Under this program, EPA or authorized states generally require producers to obtain permits for their injection wells by, among other things, meeting technical standards for constructing, operating, and testing and monitoring wells.[35] Of the nine states we reviewed, all but Pennsylvania have received approval authority from EPA to implement this program for class II wells, including issuing permits and conducting oversight. In most of these states, the agency that oversees oil and gas activities is responsible for implementing this program. Regardless of whether EPA or the state has authority for implementing the program, EPA regional offices periodically review each state's program and require states to submit an annual report on program activity, according to EPA officials from the regions we spoke with.

As part of the Underground Injection Control program, producers generally must apply for a permit to drill an injection well and supply information, including the location and depth of the proposed well. Furthermore, once EPA or the state has issued an Underground Injection Control permit, producers must observe and record the injection pressure, flow rate, and cumulative volume each month and report this information to the permitting agency annually. In addition, the injection well permit also requires producers to conduct mechanical integrity tests on the wells at least once every 5 years, although EPA and some states require testing to be performed more often, according to officials we spoke with. Officials at many of the state agencies we spoke with said that they observe these tests in person to ensure that the well is mechanically sound. According to officials in each of the eight states we contacted, the state can levy penalties for noncompliance for violations ranging from a failure to submit a report to exceeding the pressure permitted in the well. Enforcement response to noncompliance can range from a warning letter to a fine. EPA can commence a separate action for penalties if it believes that a state's imposition of penalties is insufficient, although EPA officials we spoke with stated that this is rare.

[35] Certain existing injection wells were authorized by rule if the well was properly inventoried within 1 year after the effective date of the applicable Underground Injection Control program.

Discharge of Produced Water Is Regulated under the Clean Water Act

The management of produced water through discharge into surface waters is regulated under the Clean Water Act's National Pollutant Discharge Elimination System. Under this program, all facilities that discharge pollutants to surface waters must obtain a permit from EPA or the designated state agency, which is generally the agency responsible for environmental protection or quality. Permits can be tailored to individual facilities or cover multiple facilities within a specific geographic region. To obtain a permit, producers must complete an application that, among other things, describes the waste that will be discharged, where the discharge will take place, and the method of treatment or containment, if applicable. Once the state or EPA has issued a permit, producers must report any discharges, including the volume of effluent and the amount of each pollutant specified in the permit, to the permitting authority at least once per year. EPA has issued regulations establishing Effluent Limitations Guidelines for some onshore oil and gas extraction including shale gas, but these regulations do not apply to coalbed methane extraction.[36]

Of the nine states we reviewed, all but New Mexico have received approval authority from EPA to implement this program for industrial and municipal facilities. EPA requires states with approval authority to submit annual reports on program activity in their state and conduct program reviews every 2 to 5 years. Of these eight states, four—California, Colorado, Pennsylvania, and Wyoming—have issued permits for the discharge of produced water. This is in part because discharging produced water directly from a production site is generally prohibited by regulations implementing the Clean Water Act for locations east of the 98th meridian, which, in the United States, runs from near the eastern border of North Dakota through the eastern portion of Texas, passing near the Dallas-Ft. Worth area. Discharge of produced water from an off-site treatment plant, however, is allowed under the Clean Water Act provided the treated water meets applicable water quality standards, and some states have permitted this activity. For example, a commercial water treatment facility we visited in Pennsylvania treats produced water from shale gas to meet the state's new, more stringent discharge limits

[36]On October 20, 2011, EPA announced it is developing standards for wastewater discharges produced by natural gas extraction from underground coalbed and shale formations. No comprehensive set of national standards exists at this time for the disposal of wastewater discharged from natural gas extraction activities. The agency plans to propose wastewater rules for coalbed methane in 2013 and for shale gas in 2014.

and then releases it to a municipal sewer system. In addition, one producer we spoke with in Wyoming told us his company takes some of its produced water to a treatment facility, where it is treated with reverse osmosis and then discharged to a ravine that flows into the Powder River. The eight states that have approval authority to administer the discharge program may levy penalties if they find producers are not complying with their permit, or if they are discharging without a permit, according to officials we spoke with. As with the Underground Injection Control program, EPA may commence a separate action for penalties if it believes a state's penalty determination to be inadequate, but EPA officials we spoke with stated that this is rare.

Other Management Practices Are Regulated by State Authorities

The management of produced water through disposal into a surface impoundment or reuse for irrigation is regulated at the state level in the four states we reviewed where producers employ these practices. For example, the Oil and Gas Conservation Commissions in Colorado and Wyoming are among the state regulatory agencies that allow for disposal in surface impoundments; however, these states have set different standards for the quality of the water that may be placed in the ponds. For example, Colorado generally does not require these ponds to be lined, while Wyoming requires any pond with a total dissolved solids level of 10,000 parts per million or more to be lined. In addition, Wyoming also allows produced water to be used for irrigation or as water for livestock with approval from the Wyoming Department of Environmental Quality.

Some of the states we reviewed also regulate other practices to reuse produced water. For example, regulations in Colorado, Pennsylvania, and Wyoming allow for the application of produced water to roads in certain circumstances. Specifically, Colorado regulations allow produced water to be spread on roads as long as it meets certain requirements and is authorized by the owner of the road. In addition, reuse of produced water for hydraulic fracturing is regulated at the state level for some states.[37] Specifically, some states have regulations that apply to the temporary

[37]In general, the process of hydraulic fracturing is not directly regulated at the federal level at this time. Congress exempted most hydraulic fracturing activities from EPA's jurisdiction in the 2005 Energy Policy Act amendments to the Safe Drinking Water Act; however, the agency has authority to regulate hydraulic fracturing when diesel fuels are used in fracturing fluids or propping agents. EPA is currently studying the impacts of hydraulic fracturing and plans to issue an interim report on the potential impacts of hydraulic fracturing on drinking water resources in 2012 and a final report in 2014.

storage of hydraulic fracturing fluids, including flowback water, on drilling sites. For example, Oklahoma has recently adopted standards for the construction, operation, location, and maintenance of noncommercial ponds used for temporary storage of flowback water. In addition, some states have begun to require producers to disclose the chemical composition of their hydraulic fracturing fluids. Of the nine states we reviewed, four states—Louisiana, Pennsylvania, Texas, and Wyoming—currently require this disclosure.

Federal Research Efforts Have Focused on Describing the Characteristics of and Uses for Produced Water, Management Options, and Treatment Methods

Over 100 federal research studies conducted during the last 10 years have addressed various aspects of using, managing, and treating produced water. Many federal research projects have focused on describing the characteristics of produced water, such as the volume of water produced from oil and gas activities and the quality of that water. Other research efforts have focused on describing strategies producers could use to manage produced water and the regulatory context for doing so. Federal research also has focused on developing and describing new and existing technologies for treating produced water. Appendix II of this report includes a compilation of the studies we identified.

Federal Research Efforts Have Examined the Characteristics of Produced Water

Several federal agencies, including USGS, the Bureau of Reclamation, a number of DOE national laboratories, and EPA, have issued or sponsored studies describing the characteristics of produced water from oil and gas operations—particularly the volume and quality of produced water. For example, in 2009, USGS published a fact sheet that, among other things, described water disposal issues associated with gas production in the Marcellus Shale.[38] More recently, in 2010, USGS published an article describing the quality of produced water from coalbed methane production, and how untreated or partially treated produced water from these operations may threaten fish and aquatic resources.[39] USGS also maintains a database that provides the location, geologic

[38]Daniel J. Soeder and William M. Kappel, *Water Resources and Natural Gas Production from the Marcellus Shale*, USGS Fact Sheet 2009-3032 (May 2009).

[39]Aida M. Farag, David D. Harper, Anna Senecal, and Wayne A. Hubert, “Potential Effects of Coalbed Natural Gas Development on Fish and Aquatic Resources,” chap. 11 in *Coalbed Natural Gas: Energy and Environment* (Nova Science Publishers, Inc., 2010).

setting, and chemical composition of produced water samples from locations throughout the United States.

The Department of the Interior's Bureau of Reclamation participated in a study published in 2008 that describes the quantity of produced water generated and specific contaminants it contains from oil and gas production in the western United States.[40] The study was designed to assist producers and others in determining viability of this water for beneficial reuse and for selecting appropriate treatment processes.

Several DOE national laboratories have also sponsored or published research describing the volume and quality of produced water. Argonne National Laboratory has published two studies—a 2004 study that provided basic information about how much produced water is generated and what contaminants are in it,[41] and a 2009 study that describes produced water volumes and management practices in every oil- or gas-producing state in the United States.[42] Oak Ridge National Laboratory has conducted a number of produced water research studies designed to characterize and evaluate the soluble organic compounds that contaminate the water. In addition, NETL cosponsored several such studies, including a 2003 project that provided information about radioactive materials from hydrocarbon production in Mississippi.[43] Another NETL project, completed in 2005, provided a means by which interested stakeholders could access a large quantity of produced water chemistry data for New Mexico oil wells.[44] NETL is currently engaged in

[40]Katie L. Benko and Jörg E. Drewes, "Produced Water in the Western United States: Geographical Distribution, Occurrence, and Composition," *Environmental Engineering Science*, vol. 25, no. 2 (2008):.239 – 246.

[41]John A. Veil, Markus G. Puder, Deborah Elcock, and Robert J. Redweik, Jr., Argonne National Laboratory, *A White Paper Describing Produced Water from Production of Crude Oil, Natural Gas, and Coal Bed Methane* (January 2004).

[42]Argonne National Laboratory, *Produced Water Volumes and Management Practices in the United States*.

[43]*Evaluations of Radionuclides of Uranium, Thorium, and Radium Associated with Produced Fluids, Precipitates, and Sludges from Oil, Gas, and Oilfield Brine Injection Wells in Mississippi*, a study cosponsored by the National Energy Technology Laboratory, 2002-2003.

[44]*NM WAIDS: A Produced-Water Quality and Infrastructure GIS Database for New Mexico Oil Production*, a study sponsored by the National Energy Technology Laboratory, project start: 2002, project end: 2005.

two other projects. The first is designed to differentiate produced water from surface water or shallow groundwater in the Marcellus shale area. The other is a multiagency effort with industry, EPA, and USGS, among others, to establish baseline water quality data at a Marcellus drilling site that will be monitored 1 year prior to development and compared to data acquired for 1 year after production begins.

Finally, EPA's Office of Research and Development initiated a study in January 2010 to examine the potential impacts of hydraulic fracturing on drinking water resources and the quality of flowback and produced water. The study plan is currently being reviewed by EPA's Science Advisory Board, and the agency anticipates issuing an interim report on the potential impacts of hydraulic fracturing on drinking water resources in 2012 and a final report in 2014.

Federal Research Has Examined Options for Managing Produced Water and Associated Regulatory Issues

Federal research has also focused on providing information about options producers can use to manage their produced water and the regulations they must follow in doing so. For example, the Energy Policy Act of 2005 mandated that the Department of the Interior, in consultation with EPA, engage the National Academy of Sciences to conduct a study on the effect of coalbed methane production on surface and groundwater resources in selected northern and western states. The study was issued in 2010.[45] Several DOE laboratories have also conducted studies or partnered with industry, universities, and other labs to provide information about managing produced water and associated regulations. For example, in May 2009, NETL, in cooperation with the Ground Water Protection Council, published a report summarizing produced-water-related regulations enacted by states for the purpose of protecting water resources.[46] NETL is also currently partnered with Clemson University and Chevron to study the efficacy of constructing wetlands to provide a low-cost, effective technology for the treatment and potential reuse of produced water. In addition, NETL has partnered with other DOE laboratories to conduct research on management of produced water. For example, from 2001 through 2004,

[45]National Research Council, *Management and Effects of Coalbed Methane Produced Water in the Western United States*.

[46]Ground Water Protection Council, *State Oil and Natural Gas Regulations Designed to Protect Water Resources*, a report funded by the Department of Energy and prepared for the National Energy Technology Laboratory, May 2009.

NETL collaborated with Idaho National Laboratory and others to analyze coalbed methane production on an Indian reservation and to evaluate options for managing the associated produced water in an effort to minimize the environmental impacts of the water.

Other DOE national laboratories also have undertaken studies related to the management and regulation of produced water. For example, Argonne National Laboratory published a study in 2002 that described regulatory issues affecting the management of produced water from coalbed methane production.[47] This was followed by a 2004 study that provided information on how produced water is managed and regulated, and the cost of various management practices.[48] More recently, Argonne National Laboratory published a series of studies describing produced water management practices in different energy-producing regions, including the Marcellus formation in the Appalachians and the Fayetteville Shale in Arkansas. In addition, Sandia National Laboratories partnered with a producer to study options for managing produced water from coalbed methane, and published its analysis in 2008.[49] Also, Oak Ridge National Laboratory has developed new approaches for produced water sampling, analysis, and remediation, and Los Alamos National Laboratory is currently conducting research to provide information about how produced water can be used to cultivate algae for biofuel production.

Other federal agencies have also contributed to research on the management and regulation of produced water. Specifically, the Bureau of Reclamation partially funded a publication containing the proceedings from an April 2006 workshop on produced water,[50] and the agency presented information about the beneficial use of produced water at the

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[47]John A. Veil, Argonne National Laboratory, *Regulatory Issues Affecting Management of Produced Water from Coal Bed Methane Wells* (February 2002).

[48]John A. Veil et al., Argonne National Laboratory, *A White Paper Describing Produced Water from Production of Crude Oil, Natural Gas, and Coal Bed Methane*.

[49]Malynda Cappelle, Randy Everett, William Holub, Richard Kottenstette, and Allan Sattler, Sandia National Laboratories, *Coal Bed Natural Gas Produced Water Preliminary Pilot Plant Operation and Results* (August 2008).

[50]Colorado Waters Resources Research Institute, Colorado State University, *Produced Water Workshop* (April 4-5, 2006).

2007 International Petroleum Environmental Conference.[51] In addition, in 2006, USGS issued a bibliography of studies from across oil- and gas-producing areas that it had compiled from the last 80 years. These studies describe the effects of produced water on soils, water quality, and ecosystems.[52]

Federal Research Has Explored New Ways and Existing Alternatives for Treating Produced Water

Federal research efforts, primarily conducted by DOE's national laboratories, have also focused on new technologies and treatment methods for produced water. Sandia National Laboratories, for example, has partnered with a producer to conduct pilot testing of a new treatment system to lower the salt content of produced water from coalbed methane sources.[53] NETL has partnered with Los Alamos National Laboratory, the New Mexico Institute of Mining and Technology, and the University of Texas on a long-term project to develop and test a prototype for a new treatment system that uses an innovative filtration method to remove problem contaminants and that would facilitate on-site treatment of produced water. From March 2003 through the end of 2005, NETL also partnered with Oak Ridge National Laboratory and industry to develop and test novel liquid solvents to remove organic substances from produced water. In addition, NETL is currently sponsoring a project to develop high-temperature nanofiltration technology to remove contaminants from produced water. According to the agency, the goal of this project is to minimize environmental impacts from coalbed methane and shale gas operations and allow cost-effective reuse of produced water that will reduce freshwater consumption and disposal costs. More recently, NETL sponsored research that led to the development of a new treatment system that, according to the agency, successfully treated flowback water from a hydraulic fracturing site in Pennsylvania. According to NETL, the treatment system significantly reduced the producer's disposal costs.

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[51] Steve Dundorf and Katie Benko, *Geographical Assessment of Potential for Beneficial Use of Produced Water* (presented at the International Petroleum Environmental Conference, Houston, 2007).

[52] James K. Otton, Department of the Interior, U.S. Geological Survey, *Environmental Aspects of Produced-water Salt Releases in Onshore and Coastal Petroleum-producing Areas of the Conterminous U.S. – A Bibliography*, Open-File Report 2006-1154.

[53] Malynda Cappelle et al., Sandia National Laboratories, *Coal Bed Natural Gas Produced Water Preliminary Pilot Plant Operation and Results*.

Other federal research efforts have been designed to improve existing techniques to treat produced water. For example, NETL partnered with Texas A&M, Argonne National Laboratory, and industry to develop improved reverse osmosis membrane filtration technology for the removal of salt from produced water. The desalination technology developed through this project led to the construction of a large-scale mobile unit and the development of a commercial oilfield treatment system at a site in Texas, according to NETL officials. Similarly, NETL has partnered with industry to develop a process that, when combined with existing reverse osmosis treatment, will facilitate the reuse of produced water by lowering energy requirements needed to treat produced water and by reducing membrane fouling.

Agency Comments

We provided a draft of this report to the Department of Energy, the Department of the Interior, and the Environmental Protection Agency for review and comment. None of these agencies provided written comments to include in our report; however, the Environmental Protection Agency and the Department of the Interior provided technical comments, which we incorporated as appropriate.

As agreed with your office, unless you publicly announce the contents of this report earlier, we plan no further distribution until 30 days from the report date. At that time, we will send copies of this report to the appropriate congressional committees, the Secretary of Energy, the Secretary of the Interior, the EPA Administrator, and other interested parties. In addition, the report will be available at no charge on the GAO website at http://www.gao.gov.

If you or your staff members have any questions about this report, please contact us at (202) 512-3841 or mittala@gao.gov or ruscof@gao.gov. Contact points for our Offices of Congressional Relations and Public Affairs may be found on the last page of this report. GAO staff who made major contributions to this report are listed in appendix III.

Sincerely yours,

Anu K. Mittal
Director, Natural Resources and Environment

Frank Rusco
Director, Natural Resources and Environment

Appendix I: Scope and Methodology

Our objectives for this review were to describe (1) what is known about the volume and quality of produced water from oil and gas production; (2) what practices are generally used to manage and treat produced water, and what factors are considered in the selection of each; (3) how the management of produced water is regulated at the federal level and in selected states; and (4) what federal research and development efforts have been undertaken during the last 10 years related to produced water.

To address each of these objectives, we conducted a literature review of studies and other documents on produced water quality and volume, management, and regulation issued by federal agencies and laboratories, state agencies, the oil and gas industry, and academic institutions. These documents included peer-reviewed scientific and industry periodicals, government-sponsored research, and reports from nongovernmental research organizations. We identified this literature through a systematic search of databases such as ProQuest, EconLit, and BioDigest, and used an iterative process to identify the most relevant studies for our review. We believe we have included the key studies and have qualified our findings, where appropriate. However, we may not have identified all of the studies with findings relevant to our objectives. In addition, we reviewed studies that fit the following criteria for selection: (1) the research was of sufficient breadth and depth to provide observations or conclusions directly related to our objectives; (2) the research was targeted specifically toward the volume and quality of produced water, available management practices and treatment methods, regulation of produced water broadly and in selected states, and undertaken by the federal government; and (3) the research was typically published in the last 10 years. We examined key assumptions, methods, and relevant findings of major scientific articles primarily related to water volumes and quality, and treatment methods. Where applicable, we assessed the reliability of the data we obtained and found them to be sufficiently reliable for our purposes.

In addition, we interviewed federal and state regulatory officials; federal scientists from the Environmental Protection Agency's (EPA) Office of Research and Development and the Department of Energy's (DOE) Argonne National Laboratory, Los Alamos National Laboratory, National Energy Technology Laboratory, Oak Ridge National Laboratory, and Sandia National Laboratories; officials from oil and gas exploration and production companies; officials from water treatment facilities; and other experts with experience related to produced water. The federal and state regulatory officials included those with responsibility over oil and gas regulation, as well as clean water and drinking water regulation. We focused our review of management techniques and produced water regulation on nine states—California, Colorado, Kansas, Louisiana, New Mexico, Oklahoma, Pennsylvania, Texas, and Wyoming. We selected eight of these states because the volume of produced water generated within their borders accounts for nearly 90 percent of the produced water generated in the United States as of 2007, the most recent year for which there were available data. In addition, we selected Pennsylvania because of the recent growth in shale gas development in the Marcellus shale formation and the expected potential for large-scale produced water management approaches in this area. While oil shale production has expanded and continues to expand in Texas, North Dakota, and other states, we did not look specifically at produced water from oil shale as part of this review. Furthermore, GAO will be conducting future work on the development of shale gas resources and the use of hydraulic fracturing for oil and gas development and will address these topics more fully in subsequent reports.

We supplemented our literature review and stakeholder discussions with site visits to selected locations in Pennsylvania, Texas, and Wyoming, where we met with oil and gas producers and officials from produced water treatment facilities and discussed issues related to produced water management and treatment and the factors that influence these decisions. We selected these states because of the current and potential volumes of produced water generated, the range of hydrocarbons produced, and the different management and treatment practices employed. We also visited hydraulic fracturing drilling operations, underground injection control sites, and a number of different treatment facilities employing a variety of technologies. To determine what federal research and development efforts have been undertaken during the last 10 years related to produced water, we analyzed information supplied by and conducted interviews with federal officials from DOE and select national laboratories, EPA, and the Department of the Interior's U.S. Geological Survey, Bureau of Land Management, and Bureau of Reclamation.

We conducted this performance audit from October 2010 to January 2012, in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

Appendix II: List of Ongoing and Completed Federal Produced Water Research Efforts Undertaken during the Last 10 Years

The following is a list of federally sponsored research efforts undertaken in the last 10 years that we identified in consultation with officials from the Department of Energy and select national laboratories, the Department of the Interior, the Environmental Protection Agency, and the National Research Council. These research efforts include those related to the quantity, quality, management, treatment, and use of produced water.

Department of Energy

Argonne National Laboratory

The following studies were published by or prepared for Argonne National Laboratory.

Analysis of Data from a Downhole Oil/Water Separator Field Trial in East Texas. February 2001.

Clark, C.E and J.A. Veil. *Produced Water Volumes and Management Practices in the United States*. September 2009.

Harto, Christopher. *Shale Gas – The Energy Water Nexus*. April 2011.

Argonne National Laboratory. *An Introduction to Slurry Injection Technology for Disposal of Drilling Wastes.* September 2003.

Puder, Markus G., Bill Bryson, and John A. Veil. *Compendium of Regulatory Requirements Governing Underground Injection of Drilling Wastes.* February 2003.

Puder, M.G. and J. A. Veil. *Offsite Commercial Disposal of Oil and Gas Exploration and Production Waste: Availability, Options, and Costs.* August 2006.

Veil, John A. and John J. Quinn. *Downhole Separation Technology Performance: Relationship to Geologic Conditions.* November 2004.

Veil, John A. and Maurice B. Dusseault. *Evaluation of Slurry Injection Technology for Management of Drilling Wastes.* May 2003.

Veil, J.A. and M.G. Puder. *Potential Ground Water and Surface Water Impacts from Oil Shale and Tar Sands Energy-Production Operations.* October 2006.

Veil, John A. *Regulatory Issues Affecting Management of Produced Water from Coal Bed Methane Wells.* February 2002.

Veil, J., J. Gasper, M. Puder, and P. Leath. *Summary of DOE/PERF Water Program Review.* January 2006.

Veil, John A. *Thermal Distillation Technology for Management of Produced Water and Frac Flowback Water.* Water Technology Brief #2008-1. May 13, 2008.

Veil, J.A. and J.J. Quinn. *Water Issues Associated with Heavy Oil Production.* November 2008.

Veil, John A. "Water Management Practices Used by Fayetteville Shale Gas Producers." *Oil & Natural Gas Technology* (June 2011).

Veil, John A. "Water Management Technologies Used by Marcellus Shale Gas Producers." *Oil & Natural Gas Technology* (July 2010).

Veil, John A., Markus G. Puder, Deborah Elcock, and Robert J. Redweik, Jr. *A White Paper Describing Produced Water from Production of Crude Oil, Natural Gas, and Coal Bed Methane.* January 2004.

Los Alamos National Laboratory

The following studies were published by or prepared for Los Alamos National Laboratory.

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Kwon, Soondong, Enid J. Sullivan, Lynn E. Katz, Robert S. Bowman, and Kerry A. Kinney. "Laboratory and Field Evaluation of a Pretreatment System for Removing Organics from Produced Water." *Water Environment Research*, vol. 83 (2011).

Ranck, J. Michael, Robert S. Bowman, Jeffrey L. Weeber, Lynn E. Katz, and Enid J. Sullivan. "BTEX Removal from Produced Water Using Surfactant-Modified Zeolite." *Journal of Environmental Engineering* (March 2005).

Sullivan, E.J., C.A. Dean, T.M. Yoshida, B. Cordova, M. Rearick, P. Laur, A. Viszolay, L. Brown, and J. Brown. *Chemical Quality Impacts of Oil and Gas Produced Water as a Growth Medium for Nannochloropsis Grown at Pilot Scale for Biofuel Production.* LA-UR-11-11017.

National Energy Technology Laboratory

The following studies were published by or prepared for the National Energy Technology Laboratory.

Billingsley, R.L. *Identifying and Remediating High Water Production Problems in Basin-Centered Formations.* December 2005.

Brown, Terry, Carol D. Frost, Thomas D. Hayes, Leo A. Heath, Drew W. Johnson, David A. Lopez, Demian Saffer, Michael A. Urynowicz, John Wheaton, and Mark D. Zoback. *Final Report: Produced Water Management and Beneficial Use.* January 2009.

Burnett, David B. and Mustafa Siddiqui. *Recovery of Fresh Water Resources from Desalination of Brine Produced During Oil and Gas Production Operations.* September 2003–December 2006.

COAL BED METHANE PRIMER—New Source of Natural Gas – Environmental Implications: Background and Development in the Rocky Mountain West. February 2004.

DOE Oil and Natural Gas Water Resources Program. December 2009.

Feasibility Study of Expanded Coal Bed Natural Gas Produced Water Management Alternatives in the Wyoming Portion of the Powder River Basin Phase One. January 2006.

A Guide to Practical Management of Produced Water from Onshore Oil and Gas Operations in the United States. October 2006.

Handbook on Best Management Practices and Mitigation Strategies for Coal Bed Methane in the Montana Portion of the Powder River Basin. April 2002.

Handbook on Coal Bed Methane Produced Water: Management and Beneficial Use Alternatives. July 2003.

Modern Shale Gas Development in the United States: A Primer. April 2009.

Policy Analysis of Produced Water Issues Associated With In-Situ Thermal Technologies. January 2011.

Remson, Don J. *Produced Water in the Rocky Mountain Region—Quantity and Quality*. November 2005.

Review of the U.S. Department of Energy's Environmental Program. July 1, 2010.

Siting, Design, Construction and Reclamation Guidebook for Coalbed Natural Gas Impoundments. May 2006.

Ground Water Protection Council, *State Oil and Natural Gas Regulations Designed to Protect Water Resources.* May 2009.

Use of Produced Water in Recirculated Cooling Systems at Power Generating Facilities. September 2006.

Wang, Xixi, Bethany A. Kurz, and Marc D. Kurz. *Subtask 1.18 – A Decision Tool for Watershed-Based Effluent Trading.* February 2007.

Welch, Robert A. and Dwight F. Rychel. *Produced Water from Oil and Gas Operations in the Onshore Lower 48 States.* December 2004.

National Energy Technology Laboratory

The following are past and current projects funded by the National Energy Technology Laboratory, but for which no studies have been published.

Advanced Membrane Filtration Technology for Cost-Effective Recovery of Fresh Water from Oil and Gas Produced Brine. Project start: 2003. Project end: 2006.

Anti-Fouling Reverse Osmosis Desalination System. Project start: 2009. Project end: 2010.

Barnett and Appalachian Shale Water Management and Reuse Technologies. Project start: 2009. Estimated project end: 2011.

Cleaning Agents for Produced Water Membrane Filters. Project start: 2004. Project end: 2006.

Coal Bed Methane Best Management Practices Workshop. Project start: 2003. Project end: 2004.

Coalbed Methane Research. Project start: 2006. Project end: 2008.

Coalbed Natural Gas Produced-Water Treatment Using Gas Hydrate Formation at the Wellhead. Project start: 2005. Project end: 2009.

Coalbed Natural Gas Produced-Water Treatment Using Gas Hydrates. Project start: 2006. Project end: 2008.

Coalbed Natural Gas Research. Project start: 2003. Project end: 2006.

Comprehensive Lifecycle Planning and Management System for Addressing Water Issues Associated with Shale Gas Development in New York, Pennsylvania and West Virginia. Project start: 2009. Estimated project end: 2012.

Cost Effective Recovery of Low-TDS Frac Flowback Water for Re-use. Project start: 2009. Project end: 2011.

Cost-Effective Treatment of Produced Water Using Co-Produced Energy Sources for Small Producers. Project start: 2008. Original project end: 2010 (extended).

Effects of Irrigating with Treated Oil and Gas Product Water on Crop Biomass and Soil Permeability. Project start: 2008. Project end: 2010.

Energy in the Environment-Initiatives 2004-09. Project start: 2004. Project end: 2009.

Evaluations of Radionuclides of Uranium, Thorium, and Radium Associated with Produced Fluids, Precipitates, and Sludges from Oil, Gas, and Oilfield Brine Injection Wells in Mississippi. Project start: 2002. Project end: 2003.

Field Validation of Toxicity Tests to Evaluate the Potential for Beneficial Use of Produced Water. Project start: 2004. Project end: 2008.

GIS and Web-Based Water Resource Geospatial Infrastructure for Oil Shale Development. Project start: 2008. Estimated project end: 2012.

Handbooks for Preparing, Evaluation Development, Environmental Plans and Background Development Pertinent to Coal Bed Methane Production. Project start: 2002. Project end: 2005.

Hypoxia, Program Review, and Total Petroleum Hydrocarbon Workshop. Project start: 2006. Project end: 2008.

Identification, Verification, & Compilation of Produced-Water Best Management Practices for Conventional Oil & Gas Production Operations. Project start: 2004. Project end: 2007.

Improving Science-Based Methods for Assessing Risks Attributable to Petroleum Residues in Soil Transferred to Vegetation. Project start: 2002. Project end: 2005.

Innovative Water Management Technology to Reduce Environmental Impacts of Produced Water. Project start: 2008. Estimated project end: 2012.

An Integrative Framework for the Treatment and Management of Produced Water. Project start: 2008. Estimated project end: 2011.

An Integrated Water Treatment Technology Solution for Sustainable Water Resource Management in the Marcellus Shale. Project start: 2009. Estimated project end: 2011.

Integration of Water Resource Models with Fayetteville Shale Decision and Support Systems. Project start: 2009. Estimated project end: 2012.

Life Cycle Assessment, Produced Water, and Waste Management Analyses. Project start: 2004. Project end: 2007.

Long-term field Deployment of a Surfactant Modified Zeolite Vapor Phase Bioreactor System. Project start: 2004. Project end: 2007.

Long Term Field Development of a Surfactant-Modified Zeolite/Vapor-Phase Bioreactor System for Treatment of Produced Waters for Power Generation. Project start: 2004. Project end: 2007.

Management of Produced Water. Project start: 2003. Project end: 2006.

Managing Coalbed Natural Gas Produced Water for Beneficial Uses, Initially Using the San Juan and Raton Basins as a Model. Project start: 2003. Project end: 2008.

Membrane Technology for Produced Water at Lea County, NM. Project start: 2008. Estimated project end: 2011.

Microbial Ecology of Shale Gas Production Waters. Project start: 2011. Estimated project end: not established.

Modified Reverse Osmosis System for Treatment of Produced Water. Project start: 2000. Project end: 2004.

Modeling of Water-Soluble Organic Content in Produced Water. Project start: 2002. Project end: 2005.

NMWAIDS: A Produced-Water Quality and Infrastruture GIS Database for New Mexico Oil Production. Project start: 2002. Project end: 2005.

Northeast National Petroleum Reserve-Alaska Reconnaissance-Level Airborne Contaminants Study. Project start: 2001. Project end: 2006.

Northern Cheyenne Indian Reservation (NCIR) Coalbed Natural Gas Resource Assessment and Analysis of Produced-Water Disposal Options. Project start: 2001. Project end: 2004.

Novel Cleanup Agents for Membrane Filters Used to Treat Oilfield Produced Water for Beneficial Purposes. Project start: 2004. Project end: 2007.

Novel Fouling—Reducing Coatings for Ultrafiltration, Nanofiltration and Reverse Osmosis Membranes. Project start: 2004. Project end: 2008.

Pilot Testing: Pretreatment Options to Allow Re-Use of Frac Flowback and Produced Brine for Gas Shale Resource Development. Project start: 2009. Estimated project end: 2011.

Pretreatment and Water Management for Frac Water Reuse and Salt Production. Project start: 2009. Estimated project end: 2011.

Produced Water Management and Beneficial Use. Project start: 2005. Project end: 2007.

Produced Water Management and Beneficial Use/15549 Colorado School of Mines. Project start: 2005. Project end: 2007.

Produced Water Management and Beneficial Use/15549 Colorado School of Mines. (Different portion of the preceding project with distinct project identification.) Project start: 2005. Project end: 2007.

Produced Water Treatment and Decision Tool. Project start: 2008. Estimated project end: 2012.

Provide Support to Produced Water: Osage-Skiatook Petroleum Environmental Research Project. Project start: 2001. Project end: 2006.

Range Resources Baseline Monitoring Site for Marcellus Shale Gas. Project start: 2011. Estimated project end: not established.

Recovery of More Oil-in-Place at lower Production Costs While Creating a Beneficial Water Resource. Project start: 2002 Project end: 2006.

Research and Development Concerning Coalbed Natural Gas—Congressional Mandate. Project start: 2006. Project end: 2008.

Research to Enhance Oil and Gas Development and Environmental Protection on Federal Lands: Joint Montana Regional Coalbed Natural Gas Ground-Water Monitoring Program. Project start: 2005. Project end: 2008.

Risk Based Data Management System (RBDMS) and Cost Effective Regulatory Approaches (CERA) Related to Hydraulic Fracturing and

Geologic Sequestration of CO-2. Project start: 2009. Estimated project end: 2012.

Subsurface Drip Irrigation. Project start: 2007. Estimated project end: 2014.

Sustainable Management of Flowback Water during Hydraulic Fracturing of Marcellus Shale for Natural Gas Production. Project start: 2009. Estimated project end: 2012.

Treating Coalbed Natural Gas Produced Water for Beneficial Use by MFI Zeolite Membranes. Project start: 2004. Project end: 2008.

Treatment and Beneficial Reuse of Produced Waters Using a Novel Pervaporation-Based Irrigation Technology. (NETL in-house project not yet awarded.)

Treatment of Produced Water by FARADAVIC Electrodialysis and Reverse Osmosis. Project start: 2009. Project end: 2010.

Treatment of Produced Waters using a Surfactant Modified Zeolite/Vapor-Phase Bioreactor. Project start: 2002. Project end: 2006.

Treatment of Produced Waters Using a Surfactant-Modified Zeolite/Vapor-Phase Bioreactor System. Project start: 2003. Project end: 2006.

Treatment of Produced Waters Using a Surfactant-Modified Zeolite/Vapor-Phase Bioreactor System. (Next phase.) Project start: 2004. Project end: 2006.

Unconventional High Temperature Nanofiltration for Produced Water Treatment. (Phase I.) Project start: 2009. Project end: 2010.

Unconventional High Temperature Nanofiltration for Produced Water Treatment. (Next phase.) Project start: 2010. Project end: 2012.

Use of Ionic Liquids in Produced-Water Clean-up. Project start: 2003. Project end: 2005.

Use of Stable Isotopes to Discern Marcellus Produced Water When Commingled with Surface Water or Shallow Groundwater. Project start: 2011. Estimated project end: not established.

Use of Wetland Plant Species and Communities for Phytoremediation of Coalbed Natural Gas Produced Water and Waters of Quality Similar to that Associated with Coalbed Natutral Gas Deposits of the Powder River Basin. Project start: 2001. Project end: 2008.

Using Helicopter Electromagnetic Surveys to Determine the Hydrologic Fate of Coalbed Methane Produced Water. Project start: 2002. Project end: 2004.

Water Management Strategies for Improved Coalbed Methane Production in the Black Warrior Basin. Project start: 2009. Estimated project end: 2012.

Water-Related Issues Affecting Conventional Oil and Gas Recovery and Potential Oil Shale Development in the Uinta Basin, Utah. Project start: 2008. Estimated project end: 2011.

Water & Waste Regulatory Analysis. Project start: 2006. Project end: 2008.

Zero Discharge Water Management for Horizontal Shale Gas Well Development. Project start: 2009. Estimated project end: 2011.

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McFarlane, Joanna. *Measurement, Characterization and Prediction of Organic Solubility in Produced Water*. Presentation at Gas Technology Institute Natural Gas Technologies II Conference and Exhibition, February 8-11, 2004.

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Sandia National Laboratories

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Cappelle, Malynda, Randy Everett, William Holub, Richard Kottenstette, and Allan Sattler. *Coal Bed Natural Gas Produced Water Preliminary Pilot Plant Operation and Results*. August 2008.

Department of the Interior

Bureau of Reclamation

The following studies were published by or prepared for the Bureau of Reclamation.

Benko, Katie L. “Ceramic Membranes for Produced Water Treatment.” *World Oil* (April 2009): 1-3

Benko, Katie L and Jörg E. Drewes. “Produced Water in the Western United States: Geographical Distribution, Occurrence and Composition.” *Environmental Engineering Science*, vol. 25, no. 2 (2008): 239-246.

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U.S. Geological Survey

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Peterman, Zell E., Joanna N. Thamke, Kiyoto Futa, and Thomas A. Oliver. *Strontium Isotope Detection of Brine Contamination in the East Poplar Oil Field, Montana.* Open-File Report 2010-1326.

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Environmental Protection Agency

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National Research Council

Committee on Management and Effects of Coalbed Methane Development and Produced Water in the Western United States, Committee on Earth Resources, Board on Earth Sciences and Resources, Water Science and Technology Board, Division on Earth and Life Studies, National Research Council of the National Academies. *Management and Effects of Coalbed Methane Produced Water in the Western United States.* 2010.

Appendix III: GAO Contacts and Staff Acknowledgments

GAO Contacts

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Staff Acknowledgments

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