A White Paper Describing Produced Water from Production of Crude Oil, Natural Gas, and Coal Bed Methane

Prepared for:
U.S. Department of Energy
National Energy Technology Laboratory
Under Contract W-31-109-Eng-38

Prepared by:
Argonne National Laboratory
John A. Veil
Markus G. Puder
Deborah Elcock
Robert J. Redweik, Jr.

January 2004

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Executive Summary

Produced water is water trapped in underground formations that is brought to the surface along with oil or gas. It is by far the largest volume byproduct or waste stream associated with oil and gas production. Management of produced water presents challenges and costs to operators. This white paper is intended to provide basic information on many aspects of produced water, including its constituents, how much of it is generated, how it is managed and regulated in different settings, and the cost of its management.

Chapter 1 provides an overview of the white paper and explains that the U.S. Department of Energy (DOE) is interested in produced water and desires an up-to-date document that covers many aspects of produced water. If DOE elects to develop future research programs or policy initiatives dealing with various aspects of produced water, this white paper can serve as a baseline of knowledge for the year 2003.

Chapter 2 discusses the chemical and physical characteristics of produced water, where it is produced, and its potential impacts on the environment and on oil and gas operations. Produced water characteristics and physical properties vary considerably depending on the geographic location of the field, the geological formation with which the produced water has been in contact for thousands of years, and the type of hydrocarbon product being produced. Produced water properties and volume can even vary throughout the lifetime of the reservoir. Oil and grease are the constituents of produced water that receive the most attention in both onshore and offshore operations, while salt content (expressed as salinity, conductivity, or total dissolved solids [TDS]) is also a primary constituent of concern in onshore operations. In addition, produced water contains many organic and inorganic compounds that can lead to toxicity. Some of these are naturally occurring in the produced water while others are related to chemicals that have been added for well-control purposes. These vary greatly from location to location and even over time in the same well. The white paper evaluates produced water from oil production, conventional natural gas production, and coal bed methane production.

The many chemical constituents found in produced water, when present either individually or collectively in high concentrations, can present a threat to aquatic life when they are discharged or to crops when the water is used for irrigation. Produced water can have different potential impacts depending on where it is discharged. For example, discharges to small streams are likely to have a larger environmental impact than discharges made to the open ocean by virtue of the dilution that takes place following discharge. Regulatory agencies have recognized the potential impacts that produced water discharges can have on the environment and have prohibited discharges in most onshore or near-shore locations.

Chapter 3 provides information on the volume of produced water generated. According to the American Petroleum Institute (API), about 18 billion barrels (bbl) of produced water was generated by U.S. onshore operations in 1995 (API 2000). Additional large volumes of produced water are generated at U.S. offshore wells and at thousands of wells in other countries. Khatib and Verbeek (2003) estimate that for 1999, an average of 210

million bbl of water was produced each day worldwide. This volume represents about 77 billion bbl of produced water for the entire year. As part of this white paper, an effort was made to generate contemporary estimates of onshore produced water volume in the United States (for the year 2002). This was challenging in that many of the states did not have readily available volume information. The 2002 total onshore volume estimate of 14 billion bbl was derived directly from the applicable state oil and gas agencies or their websites, where data were available. If volume estimates were not available from a state agency or website, an estimated volume was calculated for that state by multiplying 2002 crude oil production by the average historic water-to-oil ratio for that state.

The volume of produced water from oil and gas wells does not remain constant over time. The water-to-oil ratio increases over the life of a conventional oil or gas well. For such wells, water makes up a small percentage of produced fluids when the well is new. Over time, the percentage of water increases and the percentage of product declines. Lee et al. (2002) report that U.S. wells produce an average of more than 7 bbl of water for each barrel of oil. For crude oil wells nearing the end of their productive lives, water can comprise as much as 98% of the material brought to the surface. Wells elsewhere in the world average 3 bbl of water for each barrel of oil (Khatib and Verbeek 2003). Coal bed methane (CBM) wells, in contrast, produce a large volume of water early in their life, and the water volume declines over time. Many new CBM wells have been drilled and produced since the last national estimate was made via API's 1995 study. CBM wells quickly produce much water but will not be counted through the estimation approach used in this white paper (2002 crude oil production ´ historical water-to-oil ratio). The actual total volume of produced water in 2002 is probably much higher than the estimated 14 billion bbl.

Chapter 4 describes the federal and state regulatory requirements regarding discharge and injection. In 1988, the U.S. Environmental Protection Agency (EPA) exempted wastes related to oil and gas exploration and production (including produced water) from the hazardous waste portions of the Resource Conservation and Recovery Act. Produced water disposal generally bifurcates into discharge and injection operations. Most onshore produced water is injected into Class II wells for either enhanced recovery or for disposal. Injection is regulated under the Underground Injection Control (UIC) program. The EPA has delegated UIC program authority to many states, which then regulate injection activities to ensure protection of underground sources of drinking water.

Most offshore produced water is discharged under the authority of general permits issued by EPA regional offices. These permits are part of the National Pollutant Discharge Elimination System (NPDES). They include limits on oil and grease, toxicity, and other constituents. Under a few circumstances, onshore produced water can be discharged. Generally these discharges are from very small stripper oil wells, CBM wells, or from other wells in which the produced water is clean enough to be used for agricultural or wildlife purposes.

Chapter 5 discusses numerous options for managing produced water. The options are grouped into those that minimize the amount of produced water that reaches the surface, those that recycle or reuse produce water, and those that involve disposal of produced water. The first group of options (water minimization) includes techniques such as mechanical blocking devices or water shut-off chemicals that allow oil to enter the well bore while blocking water flow. Also included in this group are devices that collect and separate produced water either downhole or at the sea floor. Examples include downhole oil/water or gas/water separators, dual-completion wells, and subsea separators.

The second group of options (reuse and recycle) includes underground injection to stimulate additional oil production, use for irrigation, livestock or wildlife watering and habitat, and various industrial uses (e.g., dust control, vehicle washing, power plant makeup water, and fire control). When the first two groups of management options cannot be used, operators typically rely on injection or discharge for disposal. The last portion of Chapter 5 describes various treatment technologies that can be employed before the produced water is injected or discharged.

Chapter 6 offers summary data on produced water management costs. Produced water management is generally expensive, regardless of the cost per barrel, because of the large volumes of water that must be lifted to the surface, separated from petroleum product, treated (usually), and then injected or disposed of. The components that can contribute to overall costs include: site preparation, pumping, electricity, treatment equipment, storage equipment, management of residuals removed or generated during treatment, piping, maintenance, chemicals, in-house personnel and outside consultants, permitting, injection, monitoring and reporting, transportation, down time due to component failure or repair, clean up of spills, and other long-term liabilities. The cost of managing produced water after it is already lifted to the surface and separated from the oil or gas product can range from less than $0.01 to at least several dollars per barrel. The white paper includes discussion of several references that provide ranges or produced water management costs.

The white paper is supported by more than 100 references, many of which have been published in the past three years.

1 Introduction

One of the key missions of the U.S. Department of Energy (DOE) is to ensure an abundant and affordable energy supply for the nation. As part of the process of producing oil and natural gas, operators also must manage large quantities of water that are found in the same underground formations. The quantity of this water, known as produced water, generated each year is so large that it represents a significant component in the cost of producing oil and gas.

1.1 What Is Produced Water?

In subsurface formations, naturally occurring rocks are generally permeated with fluids such as water, oil, or gas (or some combination of these fluids). It is believed that the rock in most oil-bearing formations was completely saturated with water prior to the invasion and trapping of petroleum (Amyx et al. 1960). The less dense hydrocarbons migrated to trap locations, displacing some of the water from the formation in becoming hydrocarbon reservoirs. Thus, reservoir rocks normally contain both petroleum hydrocarbons (liquid and gas) and water. Sources of this water may include flow from above or below the hydrocarbon zone, flow from within the hydrocarbon zone, or flow from injected fluids and additives resulting from production activities. This water is frequently referred to as "connate water" or "formation water" and becomes produced water when the reservoir is produced and these fluids are brought to the surface. Produced water is any water that is present in a reservoir with the hydrocarbon resource and is produced to the surface with the crude oil or natural gas.

When hydrocarbons are produced, they are brought to the surface as a produced fluid mixture. The composition of this produced fluid is dependent on whether crude oil or natural gas is being produced and generally includes a mixture of either liquid or gaseous hydrocarbons, produced water, dissolved or suspended solids, produced solids such as sand or silt, and injected fluids and additives that may have been placed in the formation as a result of exploration and production activities.

Production of coal bed methane (CBM) involves removal of formation water so that the natural gas in the coal seams can migrate to the collection wells. This formation water is also referred to as produced water. It shares some of the same properties as produced water from oil or conventional gas production, but may be quite different in composition.

1.2 Purpose

DOE's Office of Fossil Energy (FE) and its National Energy Technology Laboratory (NETL) are interested in gaining a better understanding of produced water, constituents that are in it, how much of it is generated, how it is managed in different settings, and the cost of water management. DOE asked Argonne National Laboratory to prepare a white paper that compiles information on these topics. If DOE elects to develop future research programs or policy initiatives dealing with various aspects of produced water, this white paper can serve as a baseline of knowledge for the year 2003.

Thousands of articles, papers, and reports have been written on assorted aspects of produced water. Given enough time and money, it would be possible to develop a detailed treatise on the subject. However, DOE preferred a quick-turn-around evaluation of produced water and provided only a moderate budget. Therefore, this document is written to provide a good overview of the many issues relating to produced water. It includes a lengthy list of references that can lead the reader to more detailed information.

1.3 Layout of White Paper

The white paper contains five chapters that discuss various aspects of produced water:

- Chapter 2 discusses the chemical and physical characteristics of produced water, where it is produced, and its potential impacts on the environment and on oil and gas operations.

- Chapter 3 provides information on the volume of produced water generated in the United States. To the extent possible, the data is segregated by state and by major management option.

- Chapter 4 describes the federal and state regulatory requirements regarding discharge and injection.

- Chapter 5 discusses numerous options for managing produced water. The options are grouped into those that minimize the amount of produced water reaching the surface, those that recycle or reuse produce water, and those that involve disposal of produced water.

- Chapter 6 offers summary data on produced water management costs.

1.4 Acknowledgments

This work was supported by DOE-FE and NETL under contract W-31-109-Eng-38. John Ford was the DOE project officer for this work. We also acknowledge the many state officials that provided information for the produced water volume and regulatory sections of the white paper. The authors thank Dan Caudle for his review of and comments on the white paper.

2 Produced Water Characteristics

Produced water is not a single commodity. The physical and chemical properties of produced water vary considerably depending on the geographic location of the field, the geological formation with which the produced water has been in contact for thousands of years, and the type of hydrocarbon product being produced. Produced water properties and volume can even vary throughout the lifetime of a reservoir. If waterflooding operations are conducted, these properties and volumes may vary even more dramatically as additional water is injected into the formation.

This chapter provides information on the range of likely physical and chemical characteristics of produced water, how much they vary, and why they vary. The chapter also discusses the potential impacts of discharging produced water, particularly to the marine environment.

Understanding a produced water's characteristics can help operators increase production. For example, parameters such as total dissolved solids (TDS) can help define pay zones (Breit et al. 1998) when coupled with resistivity measurements. Also, by knowing a produced water's constituents, producers can determine the proper application of scale inhibitors and well-treatment chemicals as well as identify potential well-bore or reservoir problem areas (Breit et al. 1998).

2.1 Major Components of Produced Water

Knowledge of the constituents of specific produced waters is needed for regulatory compliance and for selecting management/disposal options such as secondary recovery and disposal. Oil and grease are the constituents of produced water that receive the most attention in both onshore and offshore operations, while salt content (expressed as salinity, conductivity, or TDS) is a primary constituent of concern in onshore operations. In addition, produced water contains many organic and inorganic compounds. These vary greatly from location to location and even over time in the same well. The causes of variation are discussed in a later section.

2.1.1 Produced Water from Oil Production

Table 2-1 shows typical concentrations of pollutants in treated offshore produced water samples from the Gulf of Mexico (EPA 1993). These data were compiled by EPA during the development of its offshore discharge regulations and are a composite of data from many different platforms. The first column of data represents the performance for a very basic level of treatment (best practicable technology, or BPT) while the second column of data represents a more comprehensive level of treatment (best available technology, or BAT). The data show that many constituents are present. The organic and inorganic components of produced water discharged from offshore wells can be in a variety of physical states including solution, suspension, emulsion, adsorbed particles, and particulates (Tibbetts et al. 1992).

In addition to its natural components, produced waters from oil production may also contain groundwater or seawater (generally called "source" water) injected to maintain reservoir pressure, as well as miscellaneous solids and bacteria. Most produced waters are more saline than seawater (Cline 1998). They may also include chemical additives used in drilling and producing operations and in the oil/water separation process. Treatment chemicals are typically complex mixtures of various molecular compounds. These mixtures can include:

- Corrosion inhibitors and oxygen scavengers to reduce equipment corrosion;
- Scale inhibitors to limit mineral scale deposits; biocides to mitigate bacterial fouling;
- Emulsion breakers and clarifiers to break water-in-oil emulsions and reverse breakers to break oil-in-water emulsions;
- Coagulants, flocculants, and clarifiers to remove solids; and
- Solvents to reduce paraffin deposits (Cline 1998).

In produced water, these chemicals can affect the oil/water partition coefficient, toxicity, bioavailability, and biodegradability (Brendehaug et al. 1992). With increased development of subsea oil fields in the North Sea and the Gulf of Mexico, many of these additives will be required in larger amounts, to assure flow assurance in subsea pipelines (Georgie et al. 2001).

2.1.2 Produced Water from Gas Production

Produced water is separated from gas during the production process. In addition to formation water, produced water from gas operations also includes condensed water. Produced waters from gas production have higher contents of low molecular-weight aromatic hydrocarbons such as benzene, toluene, ethylbenzene, and xylene (BTEX) than those from oil operations; hence they are relatively more toxic than produced waters from oil production. Studies indicate that the produced waters discharged from gas/condensate platforms are about 10 times more toxic than the produced waters discharged from oil platforms (Jacobs et al. 1992). However, for produced water discharged offshore, the volumes from gas production are much lower, so the total impact may be less. The chemicals used for gas processing typically include dehydration chemicals, hydrogen sulfide-removal chemicals, and chemicals to inhibit hydrates. Well-stimulation chemicals that may be found in produced water from gas operations can include mineral acids, dense brines, and additives (Stephenson 1992). Significant differences between offshore oilfield produced water and offshore gas produced water exist for other parameters as well. For example, Jacobs et al. (1992) report that, in the North Sea, ambient pH is 8.1 and chlorides are about 19 g/L. Produced water discharges from oil platforms in that area have pH levels of 6-7.7, while those from gas platforms are more acidic (about 3.5-5.5). Chloride concentrations range from about 12 to 100 g/L in produced water associated with crude oil production and from less than 1 to 189 g/L in produced waters associated with natural gas production.

2.1.3 Produced Water from Coal Bed Methane (CBM) Production

CBM produced waters differ from conventional oil and gas produced waters in the way they are generated, their composition, and their potential impact on receiving environments. Beneath the earth's surface, methane is adsorbed onto the crystal surfaces of coal due to the hydrostatic pressure of the water contained in the coal beds. For the methane to be removed from the crystalline structure of the coal, the hydrostatic head, or reservoir pressure, in the coal seam must be reduced. CBM produced water is generated when the water that permeates the coal beds that contain the methane is removed. In contrast to conventional oil and gas production, the produced water from a CBM well comes in large volumes in the early stages of production; as the amount of water in the coal decreases, the amount of methane production increases. CBM produced water is reinjected or treated and discharged to the surface.

The quality of CBM produced water varies with the original depositional environment, depth of burial, and coal type (Jackson and Myers 2002), and it varies significantly across production areas. As CBM production increases and more water is produced, concern about the disposition of these waters on the receiving environment is increasing, since uncertainties abound regarding the impact of these waters, as regulators and operators try to ensure protection of the environment. CBM constituent data are growing, and many states maintain files with produced water data. Sources include the Colorado Oil and Gas Conservation Commission, the Groundwater Information Center at the Montana Bureau of Mines and Geology, the Utah Division of Oil, Gas, and Mining, and the Wyoming Oil and Gas Conservation Commission. In addition, the U.S. Geological Survey (USGS) Produced Waters Database contains data on the composition of produced water and general characteristics of the volume of water produced from specific petroleum-producing provinces in the United States (Breit et al. 1998). The data were originally compiled by DOE and the Bureau of Mines, and the USGS has reviewed, verified, and evaluated the reliability and quality of the data. However, information on the actual impacts of CBM discharges — which depend not only on produced water characteristics, but also on the characteristics of the receiving environment — are not well understood.

2.2 Specific Produced Water Constituents and Their Significance

This section describes constituents typically found in produced waters, and, to the extent that information is available, why they are of concern. Constituents typically associated with produced waters from conventional oil and gas production are described first, followed by those associated with CBM produced waters.

2.2.1 Constituents in Produced Waters from Conventional Oil and Gas Production

Organic constituents are normally either dispersed or dissolved in produced water and include oil and grease and a number of dissolved compounds.

2.2.1.1 Dispersed Oil

Oil is an important discharge contaminant, because it can create potentially toxic effects near the discharge point. Dispersed oil consists of small droplets suspended in the aqueous phase. If the dispersed oil contacts the ocean floor, contamination and accumulation of oil on ocean sediments may occur, which can disturb the benthic community. Dispersed oils can also rise to the surface and spread, causing sheening and increased biological oxygen demand near the mixing zone (Stephenson 1992). Factors that affect the concentration of dispersed oil in produced water include oil density, interfacial tension between oil and water phases, type and efficiency of chemical treatment, and type, size, and efficiency of the physical separation equipment (Ali et al. 1999). Soluble organics and treatment chemicals in produced water decrease the interfacial tension between oil and water. Water movement caused by vertical mixing, tides, currents, and waves can affect the accumulation cycle. Also, because precipitated droplets are often 4–6 microns in size, and current treatment systems typically cannot remove droplets smaller than 10 microns, the small droplets can interfere with water processing operations (Bansal and Caudle 1999).

2.2.1.2 Dissolved or Soluble Organic Components

Deep-water crude has a large polar constituent, which increases the amount of dissolved hydrocarbons in produced water. Temperature and pH can affect the solubility of organic compounds (McFarlane et al. 2002). Hydrocarbons that occur naturally in produced water include organic acids, polycyclic aromatic hydrocarbons (PAHs), phenols, and volatiles. These hydrocarbons are likely contributors to produced water toxicity, and their toxicities are additive, so that although individually the toxicities may be insignificant, when combined, aquatic toxicity can occur (Glickman 1998).

Soluble organics are not easily removed from produced water and therefore are typically discharged to the ocean or reinjected at onshore locations. Generally, the concentration of organic compounds in produced water increases as the molecular weight of the compound decreases. The lighter weight compounds (BTEX and naphthalene) are less influenced by the efficiency of the oil/water separation process than the higher molecular weight PAHs (Utvik 2003) and are not measured by the oil and grease analytical method.

Volatile hydrocarbons can occur naturally in produced water. Concentrations of these compounds are usually higher in produced water from gas-condensate-producing platforms than in produced water from oil-producing platforms (Utvik 2003).

Organic components that are very soluble in produced water consist of low molecular weight (C2-C5) carboxylic acids (fatty acids), ketones, and alcohols. They include acetic and propionic acid, acetone, and methanol. In some produced waters, the concentration of these components is greater than 5,000 ppm. Due to their high solubility, the organic solvent used in oil and grease analysis extracts virtually none of them, and therefore, despite their large concentrations in produced water, they do not contribute significantly to the oil and grease measurements (Ali et al. 1999).

Partially soluble components include medium to higher molecular weight hydrocarbons (C6 to C15). They are soluble in water at low concentrations, but are not as soluble as lower molecular weight hydrocarbons. They are not easily removed from produced water and are generally discharged directly to the ocean. They contribute to the formation of sheen, but the primary concern involves toxicity. These components include aliphatic and aromatic carboxylic acids, phenols, and aliphatic and aromatic hydrocarbons. Aromatic hydrocarbons are substances consisting of carbon and hydrogen in benzene-like cyclic systems. PAHs are hydrocarbon molecules with several cyclic rings. Formed naturally from organic material under high pressure, PAHs are present in crude oil. Naphthalene is the most simple PAH, with two interconnected benzene rings and is normally present in higher concentrations than other PAHs. (In Norwegian fields, for example, naphthalenes comprise 95% or more of the total PAHs in offshore produced water.) PAHs range from relatively “light” substances with average water solubility to “heavy” substances with high liposolubility and poor water solubility. They increase biological oxygen demand, are highly toxic to aquatic organisms, and can be carcinogenic to man and animals. All are mutagenic and harmful to reproduction. Heavy PAHs bind strongly to organic matter (e.g., on the seabed) contributing to their persistency (Danish EPA 2003). Higher molecular weight PAHs are less water soluble and will be present mainly in or associated with dispersed oil. Aromatic hydrocarbons and alkylated phenols are perhaps the most important contributors to toxicity (Frost et al. 1998). Alkylated phenols are considered to be endocrine disruptors, and hence have the potential for reproductive effects (Frost et al. 1998). However, phenols and alkyl phenols can be readily degraded by bacterial and photo-oxidation in seawater and marine sediments (Stephenson 1992).

A greater understanding is needed of the chemistry involved in the production and toxicity of soluble compounds. A Petroleum Environmental Research Forum (PERF) project is under way to characterize and evaluate water-soluble organics to help understand the production of these substances. The results may help develop means to reduce production of such organics (McFarlane et al. 2002).

2.2.1.3 Treatment Chemicals

Treatment chemicals posing the greatest concerns for aquatic toxicity include biocides, reverse emulsion breakers, and corrosion inhibitors. However, these substances may undergo reactions that reduce their toxicities before they are discharged or injected. For example, biocides react chemically to lose their toxicity, and some corrosion inhibitors may partition into the oil phase so that they never reach the final discharge stream (Glickman 1998). Nonetheless, some of these treatment chemicals can be lethal at levels as low as 0.1 parts per million (Glickman 1998). In addition, corrosion inhibitors can form more stable emulsions, thus making oil/water separation less efficient.

2.2.1.4 Produced Solids

Produced water can contain precipitated solids, sand and silt, carbonates, clays, proppant, corrosion products, and other suspended solids derived from the producing formation and from well bore operations. Quantities can range from insignificant to a solids slurry, which can cause the well or the produced water treatment system to shut down. The solids can influence produced water fate and effects, and fine-grained solids can reduce the removal efficiency of oil/water separators, leading to exceedances of oil and grease limits in discharged produced water (Cline 1998). Some can form oily sludges in production equipment and require periodic removal and disposal.

2.2.1.5 Scales

Scales can form when ions in a supersaturated produced water react to form precipitates when pressures and temperatures are decreased during production. Common scales include calcium carbonate, calcium sulfate, barium sulfate, strontium sulfate, and iron sulfate. They can clog flow lines, form oily sludges that must be removed, and form emulsions that are difficult to break (Cline 1998).

2.2.1.6 Bacteria

Bacteria can clog equipment and pipelines. They can also form difficult-to-break emulsions and hydrogen sulfide, which can be corrosive.

2.2.1.7 Metals

The concentration of metals in produced water depends on the field, particularly with respect to the age and geology of the formation from which the oil and gas are produced. However, there is no correlation between concentration in the crude and in the water produced with it (Utvik 2003). Metals typically found in produced waters include zinc, lead, manganese, iron, and barium. Metals concentrations in produced water are often higher than those in seawater. However, potential impacts on marine organisms may be low, because dilution reduces the concentration and because the form of the metals adsorbed onto sediments is less bioavailable to marine animals than metal ions in solution (Stephenson 1992). Besides toxicity, metals can cause production problems. For example, iron in produced water can react with oxygen in the air to produce solids, which can interfere with processing equipment, such as hydrocyclones, and can plug formations during injection (Bansal and Caudle 1999) or cause staining or deposits at onshore discharge sites.

2.2.1.8 pH

Reduced pH can disturb the oil/water separation process and can impact receiving waters when discharged. Many chemicals used in scale removal are acidic.

2.2.1.9 Sulfates

Sulfate concentration controls the solubility of several other elements in solution, particularly barium and calcium (Utvik 2003).

2.2.1.10 Naturally Occurring Radioactive Material (NORM)

NORM originates in geological formations and can be brought to the surface with produced water. The most abundant NORM compounds in produced water are radium-226 and radium-228, which are derived from the radioactive decay of uranium and thorium associated with certain rocks and clays in the hydrocarbon reservoir (Utvik 2003). As the water approaches the surface, temperature changes cause radioactive elements to precipitate. The resulting scales and sludges may accumulate in water separation systems. In the North Sea, where ambient concentrations of Ra-226 are 0.027-0.04 Bq/L, measured concentrations in produced waters range from 0.23 to 14.7 Bq/L (Utvik 2003). Radium contamination of produced water has generated enough concern that some states have placed additional requirements on National Pollution Discharge Elimination System (NPDES) permits that limit the amount of radium that can be discharged. Compounding the NORM concern is that chemical constituents in many produced waters can interfere with conventional analytical methods, and, as a result, radium components can be lost, leading to a false negative result for samples that may contain significant amounts of NORM (Demorest and Wallace 1992).

2.2.2 Constituents in Produced Waters from CBM Production

The mix of constituents that characterizes CBM produced waters differs from that characterizing conventional produced waters. This is not surprising, since produced water from oil production has been in direct contact with crude oil for centuries and is probably at a chemical equilibrium condition. In comparison, CBM water has been in direct contact with coal seams. Therefore, different compounds are likely to enter the water.

Much of the CBM produced water may be put to beneficial use, but some of the constituents and their concentrations may limit the use of these waters in certain areas. The final determination of whether a CBM produced water can be used for agricultural purposes (generally irrigation or stock watering), for example, will depend not only on the quality of the produced water but also on the conditions of the receiving areas. These conditions include soil mineralogy and texture, amount of water applied, sensitivity of plant species, and the length of time the water has been stored in impoundments prior to use (ALL 2003). Some of the important characteristics of CBM produced water of potential concern are salinity, sodicity, and toxicity from various metals. This is discussed further in Chapter 5.

2.2.2.1 Salinity

Salinity refers to the amount of total dissolved salts (TDS) in the water and is frequently measured by electrical conductivity (EC), because ions dissolved in water conduct electricity and actual TDS analyses are expensive to conduct. Waters with higher TDS concentrations will be relatively conductive. TDS is measured in parts per million or mg/L and EC is measured in micro-Siemens per centimeter (μS/cm). Irrigation waters that are high in TDS can reduce the availability of water for plant use, diminish the ability of plant roots to incorporate water, and reduce crop yield. Studies have identified the tolerance of various crops to salinity (Horpestad et al. 2001). EC levels of more than 3,000 μS/cm are considered saline (ALL 2003). However, determining salinity threshold values depends on additional factors such as the leaching fraction. Thus, salinity threshold values of 1,000 μS/cm have been calculated for the Tongue and Little Bighorn Rivers and Rosebud Creek, while salinity thresholds of 2,000 μS/cm have been determined for the Powder and Little Powder Rivers and Mizpah Creek (Horpestad et al. 2001).

2.2.2.2 Sodicity

Sodicity refers to the amount of sodium in the soil. Irrigation water with excess amounts of sodium can adversely impact soil structure and plant growth. The sodium adsorption ratio (SAR) is the standard measure of sodicity. It is a calculated parameter that relates the concentration of sodium to the sum of the concentrations of calcium and magnesium. The higher the SAR, the greater the potential for reduced permeability, which reduces infiltration, reduces hydraulic conductivity, and causes surface crusting. Irrigation waters with SAR levels greater than 12 are considered sodic (ALL 2003).

2.2.2.3 Other Constituents

Also important for determining the suitability of CBM produced water for irrigation are the concentrations of iron, manganese, and boron, which are often found in CBM produced water (ALL 2003). Table 2-2 shows concentration ranges of several constituents in CBM produced waters in the Powder River Basin.

Besides crops, CBM produced waters may also affect native riparian and wetlands plants. The SAR thresholds developed to protect irrigation uses, which apply seasonally, may or may not protect the riparian uses, which are continually exposed to water. Because of the lack of data and the site-specific nature of these potential impacts, specific threshold values for protecting riparian plant communities have not been developed.

In some cases, CBM may be considered for domestic supplies and drinking water. However, CBM produced waters from coal seams that are greater than 200 feet in depth often have water that exceeds salinity levels appropriate for domestic uses. This level is about 3,000 mg/L. Also, water with high metals contents can stain faucets and drains. Water used by municipalities with treatment systems may have some of the harmful constituents removed or their concentrations reduced by existing processes in those treatment systems (ALL 2003).

2.3 Impacts of Produced Water Discharges

The previous sections outline the many chemical constituents found in produced water. These chemicals, either individually or collectively, when present in high concentrations, can present a threat to aquatic life when they are discharged or to crops when the water is used for irrigation. Produced water can have different potential impacts depending on where it is discharged. For example, discharges to small streams are likely to have a larger environmental impact than discharges made to the open ocean by virtue of the dilution that takes place following discharge. Numerous variables determine the actual impacts of produced water discharge. These include the physical and chemical properties of the constituents, temperature, content of dissolved organic material, humic acids, presence of other organic contaminants, and internal factors such as metabolism, fat content, reproductive state, and feeding behavior (Frost et al. 1998). The following sections discuss the potential impact based on where the discharges occur and the type of produced water.

2.3.1 Impacts of Discharging Produced Water in Marine Environment

Impacts are related to the exposure of organisms to concentrations of various chemicals. Factors that affect the amount of produced water constituents and their concentrations in seawater, and therefore their potential for impact on aquatic organisms, include the following (Georgie et al. 2001):

- Dilution of the discharge into the receiving environment,
- Instantaneous and long-term precipitation,
- Volatilization of low molecular weight hydrocarbons,
- Physical-chemical reactions with other chemical species present in seawater that may affect the concentration of produced water components,
- Adsorption onto particulate matter, and
- Biodegradation of organic compounds into other simpler compounds.

Within the marine environment, it is necessary to distinguish between shallow, poorly flushed coastal areas and the open ocean. For coastal operations, the receiving environments can include shallow, nearshore areas, marshes, and areas with moderately flushed waters. Numerous studies have been conducted on the fate and effects of produced water discharges in the coastal environments of the Gulf of Mexico (Rabalais et al. 1992). These have shown that produced waters can contaminate sediments and that the zone of such contamination correlates positively with produced water discharge volume and hydrocarbon concentration (Rabalais et al. 1992). Recognizing the potential for shallow-water impacts, EPA banned discharges of produced water in coastal waters with a phase-out period starting in 1997, except for the Cook Inlet in Alaska, where offshore discharge limits apply. Note that Cook Inlet has deep water and swift currents, thereby providing more than adequate dilution. However, although sediment contamination is evident at most studied locations, impacts on the benthic communities may be localized or not evident.

For offshore operations, key factors include concentration of constituents and other characteristics of the constituents such as toxicity, bioavailability, and form. Actual fate and effects vary with volume and composition of the discharge and the hydrologic and physical characteristics of the receiving environment (Rabalais et al. 1992). The details of the regulations and relevant discharge permits are described in Chapter 4.

A key concern is the potential for toxicity effects on aquatic organisms resulting from produced water discharges to marine and estuarine environments. Numerous toxicity studies have been conducted, and EPA continues to require a series of toxicity tests by each produced water discharger on the Outer Continental Shelf.

A constituent may be toxic, but unless absorbed or ingested by an organism at levels above a sensitivity threshold, effects are not likely to occur. A more detailed discussion of the relationships, interactions, and uncertainties associated with bioconcentration, bioavailability, and bioaccumulation is beyond the scope of this paper. However, it is important to understand that translating produced water constituents into actual impacts is not a trivial exercise.

2.3.1.1 Acute Toxicity

The main contributors to acute toxicity (short-term effects) of produced water have been found to be the aromatic and phenol fractions of the dissolved hydrocarbons (Frost et al. 1998). In addition, sometimes, particularly with deep offshore operations, existing separation equipment cannot remove all of the oil and grease to meet regulatory limits. In these cases, chemicals are used, but some of these chemicals can have toxic effects. The impacts of produced water and produced water constituents in the short term depend largely on concentration at the discharge point.

They also depend on the discharge location. Deep-water discharges, for example, where there is rapid dilution, may limit the potential for detrimental biological effects and for bioaccumulation of produced water constituents. Several studies have indicated that the acute toxicity of produced water to marine organisms is generally low, except possibly in the mixing zone, due to rapid dilution and biodegradation of the aromatic and phenol fractions (Frost et al. 1998; Brendehaug 1992). Actual impacts will depend on the biological effect (e.g., toxicity, bioaccumulation, oxygen depletion) of the produced water at the concentrations that exist over the exposure times found in the environment (Cline 1998).

2.3.1.2 Chronic Toxicity

Most of the EPA permits for offshore oil and gas operations require chronic toxicity testing. The results of this testing do not indicate any significant toxicity problem in U.S. waters. Some of the North Sea nations have focused their attention more heavily on the combined impact of many chemical constituents and have followed a different approach to produced water control. As an example, Johnsen (2003) and Johnsen et al. (2000) report on the various programs used in Norway to promote "zero environmental harmful discharges." The latest in a series of developments is the environmental impact factor (EIF), which employs a risk-based approach to compare the predicted environmental concentration for each constituent with the predicted no-effect concentration. The EIF can be calculated using the Dose-related Risk and Effect Assessment Model (DREAM).

This approach involves a great deal of quantitative work to evaluate each discharge. However, since there are relatively few offshore discharges in the Norwegian sector of the North Sea, this approach is viable there. In contrast, several thousand offshore discharges occur in the Gulf of Mexico, and such an approach would probably not be workable here. The Gulf of Mexico approach of chronic toxicity testing with limits provides acceptable controls.

2.3.2 Impacts of Discharging CBM Produced Waters

In areas where CBM produced waters have dissolved constituents that are greater than those in the receiving water, stream water quality impacts are possible. The impacts of CBM produced water have not been studied to the same extent as those of conventional oil and gas produced waters. However, potential water quality impacts of CBM produced waters include the following:

- Surface discharges of CBM produced water can cause the infiltration of produced water contaminants to drinking water supplies or sub-irrigation supplies.

- Surface waters and riparian zones can be altered as a result of CBM constituents. Here, the specific ionic composition is a greater determinant than total ion concentration (EPA 2001).

- New plant species may take over from native plants as a result of changes in soils resulting from contact with CBM produced water.

- Salt-tolerant aquatic habitats in ponded waters and surface reservoirs may increase.

- Local environments can be altered as a result of excess soluble salts, which can cause plants to dehydrate and die. The impacts of salinity on the environment are related to the amount of precipitation. Where rainfall is relatively abundant, most of the salts are flushed to the groundwater or surface streams and do not accumulate in soils. However, where precipitation levels are low, salts may be present at high concentrations in the soils and in the surface and groundwater.

- Local environments can be altered as a result of excess sodicity. Excess sodicity can cause clay to deflocculate, thereby lowering the permeability of soil to air and water, and reducing nutrient availability.

- Oxygen demand in produced water can overwhelm surface waters and reduce the oxygen level enough to damage aquatic species.

2.3.3 Other Impact Issues

Produced water constituents can affect both the environment and operations. Produced water volumes can be expected to grow as onshore wells age (the ratio of produced water to oil increases as wells age) and coal bed methane production increases to help meet projected natural gas demand. In addition, deep offshore production is expected to increase, and treating produced water prior to discharge may become increasingly difficult due to space limitations and motion on the rigs, which limit the use of conventional offshore treatment technologies. This growth will increase produced water management challenges for which a knowledge and understanding of the constituents of produced water and their effects will be critical.

As the amount of produced water increases, the amount of produced water constituents entering the water will increase, even assuming concentration discharge limits are met. Also, because actual impacts of produced water constituents will depend on the produced water as a whole in the context of the environment into which it is released, it will be important to understand effects of site-specific produced waters rather than addressing individual components. A variety of potential additive, synergistic, and antagonistic effects of multiple constituents can affect actual impacts.

Cross-media impacts can occur when technologies designed to address one environmental problem (e.g., discharge of produced water to the marine or onshore environment) create other problems (e.g., increased energy use, air emissions, contamination of aquifers from CBM reinjection), which could result in a greater net impact to the environment.

TABLE 2-1 Produced Water Characteristics Following Treatment

Constituent	**Concentration after BPT-Level Treatment (mg/L)**[a]	**Concentration after BAT-Level Treatment (mg/L) – Gas Flotation Treatment**[b]
Oil and grease	25	23.5
2-Butanone	1.03	0.41
2,4-Dimethylphenol	0.32	0.25
Anthracene	0.018	0.007
Benzene	2.98	1.22
Benzo(a)pyrene	0.012	0.005
Chlorobenzene	0.019	0.008
Di-n-butylphthalate	0.016	0.006
Ethylbenzene	0.32	0.062
n-Alkanes	1.64	0.66
Naphthalene	0.24	0.092
p-Chloro-m-cresol	0.25	0.010
Phenol	1.54	0.54
Steranes	0.077	0.033
Toluene	1.901	0.83
Triterpanes	0.078	0.031
Total xylenes	0.70	0.38
Aluminum	0.078	0.050
Arsenic	0.11	0.073
Barium	55.6	35.6
Boron	25.7	16.5
Cadmium	0.023	0.014
Copper	0.45	0.28
Iron	4.9	3.1
Lead	0.19	0.12
Manganese	0.12	0.074
Nickel	1.7	1.1
Titanium	0.007	0.004
Zinc	1.2	0.13
Radium 226 (in pCi/L)	0.00023	0.00020
Radium 228 (in pCi/L)	0.00028	0.00025

[a] BPT = best practicable technology.
[b] BAT = best available technology.
Source: EPA (1993).

TABLE 2-2 CBM Produced Water Characteristics in the Powder River Basin

Constituent	Minimum (mg/L)	Maximum (mg/L)	Mean (mg/L)
TDS	270	2,010	862
SAR	5.7	32	11.7
Sodium	110	800	305
Calcium	5.9	200	36
Magnesium	1.6	46	16
Iron	0.02	15.4	0.8
Barium	0.1	8	0.6
Chloride	3	119	13
Sulfate	0.01	17	2.4

Source: EPA (2001).

3 Produced Water Volumes

In the United States, produced water comprises approximately 98% of the total volume of exploration and production (E&P) waste generated by the oil and gas industry and is the largest volume waste stream generated by the oil and gas industry. According to the American Petroleum Institute (API), about 18 billion barrels (bbl) of produced water was generated by U.S. onshore operations in 1995 (API 2000). Additional large volumes of produced water are generated at U.S. offshore wells and at thousands of wells in other countries. Khatib and Verbeek (2003) estimate that, in 1999, an average of 210 million bbl of water was produced each day worldwide. This volume represents about 77 billion bbl of produced water for the entire year.

Natural gas wells typically produce much lower volumes of water than oil wells, with the exception of certain types of gas resources such as CBM or Devonian/Antrim shales. Within the Powder River Basin, the CBM produced water volume increased almost seven-fold during the period of 1998 through 2001 to more than 1.4 million bbl/day. Between 1999 and 2001, the volume of water produced per well dropped from 396 bbl/day to 177 bbl/day (Advanced Resources 2002). However, as discussed below, these differences in the produced water volumes are to be expected because of how the CBM is produced.

3.1 Water-to-Oil Ratio

Lee et al. (2002) report that U.S. wells produce an average of more than 7 bbl of water for each barrel of oil. API's produced water surveys in 1985 and 1995 (see Table 3-1) also demonstrated that the volume of water produced increases with the age of the crude oil production. In these surveys, API had calculated a water-to-oil ratio of approximately 7.5 barrels of water for each barrel of oil produced. For the survey of 2002 production prepared for this white paper, the water-to-oil ratio was calculated to have increased to approximately 9.5. For crude oil wells nearing the end of their productive lives, Weideman (1996) reports that water can compromise as much as 98% of the material brought to the surface. In these stripper wells, the amount of water produced can be 10 to 20 bbl for each barrel of crude oil produced.

Wells elsewhere in the world average 3 bbl of water for each barrel of oil (Khatib and Verbeek 2003). The volume of produced water from oil and gas wells does not remain constant over time. The water-to-oil ratio increases over the life of a conventional oil or gas well. For such wells, water makes up a small percentage of produced fluids when the well is new. Over time, the percentage of water increases and the percentage of petroleum product declines. For example, Khatib and Verbeek (2003) report that water production from several of Shell's operating units has increased from 2.1 million bbl per day in 1990 to more than 6 million bbl per day in 2002. At some point, the cost of managing the water becomes so high that the well is no longer profitable.

In contrast, production of CBM, a growing source of natural gas in North America, follows a different pattern. CBM is produced by drilling into coal seams and pumping off the water as quickly as possible to lower the hydrostatic pressure in the seam. This allows the methane trapped in the coal to move to the well bore, where it can be collected. The water production cycle for CBM starts out high as the hydrostatic pressure is reduced in the coal seam and gradually declines. Methane production starts low, then rises after water production peaks and declines.

3.2 Factors Affecting Produced Water Production and Volume

A discussion of the factors affecting produced water production is important because of the economic burden that it places on oil and gas operators. Produced water is an inextricable part of the hydrocarbon recovery process (Khatib and Verbeek 2003), so if an operator cannot optimize water management, a valuable resource may be lost or diminished. Management of produced water is a key issue because of its sheer volume and its high handling cost. In addition, even though produced water is naturally occurring, its potential environmental impacts could be substantial if not properly managed.

The following factors can affect the volume of produced water during the life cycle of a well (Reynolds and Kiker 2003). This is not intended to be an all-inclusive list but merely a demonstration of the potential impacts.

- Type of well drilled – A horizontal well can produce at higher rates than a vertical well with a similar drawdown or can produce at similar rates with a lower drawdown, thus delaying the entry of water into the well bore in a bottom water drive reservoir.

- Location of well within reservoir structure – An improperly drilled well or one that has been improperly located within the reservoir structure could result in earlier than anticipated water production.

- Type of completion – A perforated completion offers a greater degree of control in the hydrocarbon-producing zone. Specific intervals can either be targeted for increased hydrocarbon production or avoided or plugged to minimize water production.

- Type of water separation and treatment facilities – Historically, surface separation and treatment facilities have been used for produced water management. However, this type of operation involves lifting costs to get the water to the surface as well as equipment and chemical costs for treatment of the water. Once on the surface, introduction of oxygen into the produced water treatment environment requires that corrosion and microbial issues be addressed. Alternatives to surface treatment could be downhole separation equipment that allows the produced water to remain downhole, thereby avoiding some of the lifting, surface facility, and corrosion costs and issues.

- Water flooding for enhanced oil recovery – The basic purpose of water flooding is to put water in the reservoir where the oil is located so that it will be driven to a producing well. As the water flood front reaches a producing well, the volume of produced water will be greatly increased. In many instances, it is advantageous to shut in these producing wells or convert them to injection wells so as not to impede the progression of the water front through the reservoir.

- Insufficient produced water volume for water flooding – If insufficient produced water is available for water flooding, additional source waters must be obtained to augment the produced water injection. For a water flood operation to be successful, the water used for injection must be of a quality that will not damage the reservoir rock. In the past, freshwater was commonly used in water floods. Because of increasing scarcity, freshwater is typically no longer used as a viable source water for water flooding. Regardless of the source, the increased addition of this water to the reservoir will result in an increased volume of produced water.

- Loss of mechanical integrity – Holes caused by corrosion or wear and splits in the casing caused by flaws, excessive pressure, or formation deformation can allow unwanted reservoir or aquifer waters to enter the well bore and be produced to the surface as produced water.

- Subsurface communication problems – Near-well bore communication problems such as channels behind casing, barrier breakdowns, and completions into or near water can result in increased produced water volumes. Additionally, reservoir communication problems such as coning, cresting, channeling through higher permeability zones or fractures, and fracturing out of the hydrocarbon producing zone can also contribute to higher produced water volumes.

Each of the above factors can greatly affect the volume of produced water that is ultimately managed during the life cycle of a well and project. With increased produced water volumes, the economic viability of a project becomes an issue, due to the loss of recoverable hydrocarbons, the added expense of lifting water versus hydrocarbons, the increased size and cost of water treating facilities and associated treatment chemicals, and the disposal cost of the water. With the consideration of water impacts to a project, proper planning and implementation can minimize these expenses or at least delay their impact.

3.3 Volume of Produced Water Generated Onshore in the U.S.

According to the API website (www.api.org), exploration and production activities take place at nearly 900,000 separate locations in 33 states and on the Outer Continental Shelf (OCS. Unfortunately, no single mechanism exists for tabulating the volume of produced water generated by the oil and gas industry. Although some states have started to track this information and have this information available electronically on their websites, most do not. The majority of states do track the volume of produced water that is injected, but do not track the volume of produced water that is managed in ways other than injection. Hence, produced water volume figures are generally available for enhanced recovery or disposal in injection wells, but these data are not typically readily available for the other management techniques such as:

- Treatment and discharge (under the National Pollutant Discharge Elimination System [NPDES] program),
- Evaporation and percolation ponds,
- Beneficial uses such as irrigation, livestock/wildlife watering, and industrial,
- Injection into aquifer storage and recovery wells (domestic use),
- Land application, and
- Roadspreading.

Although the states do regulate the management of produced water under this set of techniques, the volumes are typically not recorded in a single location for easy tracking.

With the advent of major CBM developments during the recent decade, it was also difficult to distinguish between produced water volumes from conventional oil and gas production operations versus CBM operations. Because of the differences between conventional and CBM operations and the limitations placed on the preparation of this report, the produced water volumes documented in this report may be somewhat distorted because of how the estimates were made for those states that did not provide data.

API (1988 and 2000) had similar data collection issues when it conducted a survey of the oil and gas industry to gather information about E&P wastes in 1985 and then again for its 1995 update. As a result, API was forced to conduct a statistical survey to gather the E&P waste data (including produced water volume) that it needed for its study. These studies examined the volume of produced water and other wastes generated as a result of oil and gas E&P in the U.S. and how those wastes were managed and disposed of. Due to the differences between onshore and offshore management of produced water (i.e., injection versus discharge), the API studies are focused on the onshore area. Currently, the vast majority of produced water generated at OCS locations is discharged overboard in accordance with NPDES discharge permits.

For this report, an update of the volume figures was prepared for produced water generated in the year 2002 (see Table 3-1). For those states that did not have data available, estimates were prepared based on the average water-to-oil ratios that were calculated for each applicable state from the 1985 and 1995 API studies. Table 3-2 shows crude oil production by state and is provided to aid in the calculation of these average water-to-oil ratios so that the produced water volumes could be estimated for each state that did not provide this data.

Table 3-1 provides a summary of the onshore produced water volumes for 1985, 1995, and 2002. The 1985 and 1995 data were taken from the API surveys while the 2002 numbers were obtained directly from the applicable state oil and gas agencies or their websites. If numbers were not available from the state agency or website, an estimated volume was calculated as described above based on the average historic water-to-oil ratio for that state. The final column in Table 3□1 indicates which produced water volume numbers were calculated estimates and which were obtained directly from the states.

Since the produced water estimates were made based on historic water-to-oil ratios from API's 1985 and 1995 studies, the estimates for 2002 do not reflect the fact that while CBM operations generate produced water, they did not produce any crude oil. In addition, since CBM wells generate the greatest amount of produced water early in the life cycle of the well (the opposite of conventional oil and gas operations), the 2002 estimates are likely somewhat lower than the actual volume of produced water generated. For example, data from Kansas (see Tables 3-1 and 3-2) indicated a steady decline in both crude oil and produced water production. However, despite a continued decline in crude oil production in 2002, the volume of produced water nearly doubled from the 1995 figures. Further analysis of the data indicated the start of CBM operations in Kansas during the 2000/2001 timeframe, thus explaining the tremendous increase in produced water volume. We acknowledge this shortcoming for the 2002 data, but for the purposes of this white paper, we did not have the resources or time to develop more sophisticated estimates.

The crude oil production volumes in Table 3-2 offer an indication of the direction in which the oil and gas industry is heading. In the decade between 1985 and 1995 (as documented in API's studies), crude oil production declined a total of 15%, or an average of about 1.5% per year. However, in the period between 1995 and 2002 (as documented in this report), crude oil production declined at an even greater rate by 37%, or by an average of about 6% per year. As anticipated, oil production within the U.S. is declining at an increasing rate. Between 1985 and 2002, U.S. crude oil production had declined a total of 46%.

Table 3-1 shows that between 1985 and 1995, the volume of produced water generated declined 13% (average of 1.3% per year). Between 1995 and 2002, the volume of produced water continued to decline but at a lesser rate than the decline in crude oil production. If the produced water from CBM operations could be segregated and excluded from these figures, the decline in produced water production would have likely been as steep as the crude oil production decline during this same period. However, since the states do not typically track these numbers separately, the different types of produced water could not be segregated for this report. A more in-depth analysis would likely be able to provide segregated CBM and conventional oil and gas produced water volume data.

API's 1995 study indicated that the management and disposal of E&P wastes was following a trend toward less discharge and more reuse, recycling, and reclamation (API 2000). With the advent of no discharge criteria for produced water in coastal areas, nearly all produced water from conventional oil and gas operations onshore is being injected. API's study indicated that approximately 71% of all produced water is being injected for enhanced recovery (beneficial use) while 21% is being injected for disposal. Hence, a total of 92% of all produced water generated is being returned to the subsurface from whence it came. For the remaining produced water volume, 5% is either treated and discharged or beneficially used for irrigation, livestock/wildlife watering, and other uses. For the last 3% of the produced water, percolation and evaporation ponds are the identified method of disposal.

The 2002 onshore volume of approximately 14 billion barrels of produced water demonstrates that the oil and gas industry continues to generate a tremendous volume of water that must be properly managed.

3.4 Volume of Produced Water Generated Offshore in the U.S.

We were not able to get an accurate current count of produced water generation in the U.S. Outer Continental Shelf. Some previously unpublished data shed some light on the subject. In a PowerPoint presentation, Intek (2001) offers some general statistics for offshore produced water volume in 1999 based on an analysis of Minerals Management Service data. In that year, there were 2,399 offshore oil wells and 1,228 offshore gas wells that produced water. A very large percentage of these wells were located in water depths less than 200 meters (oil 93%; gas 98%). Nearly all of the gas wells were very low water producers, generating less than 10 bbl/day of water. The oil wells showed considerably more variation, with most wells reported in several volume groupings ranging from 50 to 1,000 bbl/day. The median oil well produced water volume was approximately 200 bbl/day. A rough estimate of the typical produced water generation rate can be derived by multiplying the median oil well volume by the total number of oil wells producing water. This estimate is about 480,000 bbl/day, or 175 million bbl/year. This estimate is only an order-of-magnitude approximation as it omits consideration of the wells in water depth greater than 200 meters and all gas wells and some of the data are extrapolated from bar graphs. It is included in this white paper only for informational purposes.

TABLE 3-1 Annual Onshore Produced Water Generation by State (1,000 bbl)

State	1985[a]	1995[b]	2002[c]	Source
Alabama	87,619	320,000	99,938	State
Alaska	97,740	1,090,000	813,367	State
Arizona	149	100	88	Estimate
Arkansas	184,536	110,000	90,331	Estimate
California	2,846,078	1,684,200	1,290,050	Estimate
Colorado	388,661	210,600	133,005	Estimate
Florida	No data available	76,500	48,990	Estimate
Illinois	1,282,933	285,000	212,098	Estimate
Indiana	No data available	48,900	34,531	Estimate
Kansas	999,143	683,700	1,174,641	State
Kentucky	90,754	3,000	2,411	Estimate
Louisiana	1,346,675	1,346,400	1,079,805	State
Michigan	76,440	52,900	33,207	Estimate
Mississippi	318,666	234,700	286,532	State
Missouri	No data available	100	1,200	State
Montana	223,558	103,300	104,501	Estimate
Nebraska	164,688	61,200	51,191	State
Nevada	No data available	6,700	2,765	Estimate
New Mexico	445,265	706,000	112,934	State
New York	No data available	300	844	State
North Dakota	59,503	79,800	78,236	Estimate
Ohio	No data available	7,900	6,416	State
Oklahoma	3,103,433	1,642,500	1,252,870	Estimate
Pennsylvania	No data available	2,100	5,842	State
South Dakota	5,155	4,000	3,293	State
Tennessee	No data available	400	275	Estimate
Texas	7,838,783	7,630,000	5,031,945	State
Utah	260,661	124,600	84,791	Estimate
Virginia	No data available	300	550	Estimate
W. Virginia	2,844	6,000	4,284	Estimate
Wyoming	785,221	1,401,000	2,119,394	State
TOTAL	20,608,505	17,922,200	14,160,325	

[a] 1985 produced water volume (barrels) from API (1988).
[b] 1995 produced water volume (barrels) from API (2000).
[c] 2002 produced water volume data from state oil and gas agencies/websites unless estimated based on historic water-to-oil ratio.

TABLE 3-2 Annual Crude Oil Production by State (1,000 bbl)

State	1985[a]	1995[b]	2002[c]
Alabama	21,581	18,731	8,631
Alaska	651,599	541,654	359,335
Arizona	175	71	63
Arkansas	19,044	8,910	7,344
California	353,550	350,686	258,010
Colorado	30,246	27,976	17,734
Florida	11,458	5,693	3,656
Illinois	30,265	16,190	12,051
Indiana	No data available	2,778	1,962
Kansas	75,407	43,767	32,721
Kentucky	7,790	3,492	2,679
Louisiana	158,806	426,322	93,477
Michigan	27,300	11,383	7,219
Mississippi	30,641	19,911	18,015
Missouri	No data available	120	95
Montana	29,768	16,529	16,855
Nebraska	6,943	3,794	2,779
Nevada	No data available	1,342	553
New Mexico	78,530	64,508	67,041
New York	No data available	304	165
North Dakota	50,857	29,335	30,993
Ohio	No data available	8,258	6,004
Oklahoma	162,739	87,491	66,642
Pennsylvania	No data available	1,939	2,233
South Dakota	1,596	1,344	1,214
Tennessee	No data available	382	275
Texas	867,122	600,527	411,985
Utah	40,792	19,988	13,676
Virginia	No data available	12	22
W. Virginia	3,555	1,948	1,382
Wyoming	128,514	78,884	54,717
TOTAL	2,788,278	2,394,269	1,499,528

[a] 1985 crude oil production from API (1988).
[b] 1995 crude oil production from API (2000).
[c] 2002 crude oil production from IPAA data.

4 Regulatory Requirements Governing Produced Water Management

4.1 Introductory Remarks

In 1980, Congress conditionally exempted oil and gas E&P wastes, including produced water, from the hazardous waste management requirements of Subtitle C of the Resource Conservation and Recovery Act (RCRA) — RCRA Sections 3001(b)(2)(A), 8002(m). In addition to directing the U.S. Environmental Protection Agency (the EPA or the Agency) to study these wastes and submit a report to Congress on the status of their management, Congress required the Agency either to promulgate regulations under Subtitle C of RCRA or make a determination that such regulations were unwarranted. In 1988, the EPA published its regulatory determination in the Federal Register (FR) at 53 FR 25447 (July 6, 1988). Produced water ranks first on the list of wastes that are generally exempt and warrant no regulation under Subtitle C of RCRA. The EPA states in the Code of Federal Regulations (CFR) that "produced wastewater" is among "[s]olid wastes which are not hazardous wastes" (40 CFR §261.4(b)(5)). The federal E&P RCRA Subtitle C exemption did however not preclude these wastes from control under other federal and state regulations (including oil and gas conservation programs and some hazardous waste programs) (EPA 2002).

Produced water management generally bifurcates into discharge and injection operations. Most of onshore produced water is injected, while most of the offshore produced water is discharged and only some is injected. Section 4.2 discusses regulatory requirements for surface discharge of produced waters. Section 4.3 covers subsurface disposal of produced waters.

4.2 Discharge of Produced Waters

The Clean Water Act (CWA) requires that all discharges of pollutants to surface waters (streams, rivers, lakes, bays, and oceans) must be authorized by a permit issued under the National Pollutant Discharge Elimination System (NPDES) program. The two basic types of NPDES permits issued are individual and general permits. Individual NPDES permits are specifically tailored to individual facilities. General NPDES permits cover multiple facilities within a certain category located in a specific geographical area.

Under the CWA, the EPA has the authority to implement the NPDES program. The Agency may authorize states — as well as territories and tribes — to implement all or parts of the national program. Once approved, a state gains the authority to issue permits and administer the program. However, the EPA retains the opportunity to review the permits issued by the state and formally object to elements deemed in conflict with federal requirements. Absent approval of a state, the EPA operates the NPDES program in direct implementation.

4.2.1 Calculation of Effluent Limits

Numerical effluent limits present the primary mechanism for controlling discharges of pollutants to receiving waters. The EPA has grouped pollutants into three categories under the NPDES program: conventional pollutants (five-day biochemical oxygen demand, total suspended solids, pH, fecal coliform, and oil and grease), toxic or priority pollutants (including metals and manmade organic compounds), and nonconventional (including ammonia, nitrogen, phosphorus, chemical oxygen demand, and whole effluent toxicity). The effluent limits describe the pollutants subject to monitoring as well as the appropriate quantity or concentration of pollutants. Permit writers derive effluent limits from the applicable technology-based effluent limitation guidelines (ELGs) and water quality-based standards. The more stringent of the two will be written into the permit.

4.2.1.1 Effluent Limitation Guidelines (ELGs)

ELGs are national technology-based minimum discharge requirements. These standards are developed by EPA on an industry-by-industry basis and represent the greatest pollutant reductions that are economically achievable for an industry sector or portion of the industry (e.g., offshore oil and gas platforms). The selection of ELGs involves consideration of technologies that have already been demonstrated in industrial applications, costs and economic impacts, and non-water quality environmental impacts. ELGs are applied uniformly to every facility within the industrial sector, regardless of the location of the facility or the condition of the water body receiving the discharge. Existing facilities must meet a level of performance known as best available technology economically achievable (BAT) for toxic and nonconventional pollutants.

The EPA has defined the BAT as the performance associated with the best control and treatment measures that have been, or are capable of being, achieved. While the EPA must still consider the cost of attainability in the context of BAT, it is not required to balance the implementation cost against the pollution reduction benefit. (For conventional pollutants only, BAT is replaced by best conventional pollutant control technology [BCT].) New facilities must meet new source performance standards (NSPS). NSPS reflect the most stringent limits based on performance of the state-of-the-art technologies.

The EPA has developed ELGs for most major industrial categories. For the oil and gas industry, EPA developed separate ELGs for onshore activities in 1979, offshore activities in 1993, and coastal activities in 1996. The terms onshore, offshore, and coastal may be illustrated by drawing an imaginary line that runs along the coast of a country. The line crosses the mouth of rivers, bays, and inlets. Any facility to the ocean side of the line is an offshore facility. Any facility to the land side of the line and located on land is classified as an onshore facility. Any facility in or on the water or in wetlands on the land side of the line is a coastal facility. For example, a facility located in a marsh or inside a river mouth or bay is a coastal facility. The EPA has codified the ELGs in the Code of Federal Regulations (CFR) at 40 CFR Part 435 — oil and gas extraction point source category.

4.2.1.1.1 Onshore Activities

Pursuant to Subpart C of 40 CFR Part 435, oil and gas activities located onshore may not discharge produced waters into navigable waters. However, two other subcategories provide for tailored exceptions to the onshore rule. Subpart E of 40 CFR Part 435 presents the agricultural and wildlife water use subcategory. The regulations apply to those onshore facilities located in the continental United States and west of the 98th meridian for which produced water is clean enough for use in agriculture or wildlife propagation when discharged into navigable waters. The 98th meridian extends from near the eastern edge of the Dakotas through central Nebraska, Kansas, Oklahoma, and Texas. Produced water with a maximum oil and grease limit of 35 mg/L may be discharged from such sites. However, this subcategory requires that the produced water is of good enough quality to be used for wildlife or livestock watering or other agricultural uses and that the produced water is actually put to such use during periods of discharge. An undetermined number (believed to be a small number) of Western oil and natural gas operators are discharging under NPDES permits that conform to the ELGs. Veil (1997a) notes that four states (California, Colorado, South Dakota, and Utah) indicated that they issued NPDES permits to facilities that could be classified under the agricultural and wildlife water use subcategory.

The second exception that allows for onshore discharges is offered in Subpart F for the stripper subcategory. It applies to facilities that produce 10 barrels per day or less of crude oil. The EPA has published no national discharge standards for this subcategory, effectively leaving any regulatory controls to the primacy states or the EPA's regional offices for direct implementation programs. The EPA's decision to provide a window for small oil wells reflects the consideration to minimize the economic burden imposed by an across-the-board zero-discharge standard. The stripper subcategory appears inconsistent because it gives relief only to small oil wells and not to marginal gas wells (typically 60 thousand cubic feet per day or less). In the absence of any regulatory exception for marginal gas well discharges, such discharges fall under the general onshore standards of Subpart C. Veil (1997a) reports that, in 1997, six states (Kentucky, Nebraska, New York, Pennsylvania, Texas, and West Virginia) issued NPDES permits for produced water discharges from stripper wells. All six states limited oil and grease and pH, and some of the states placed limits on different combinations of total suspended solids, iron, chlorides, and other pollutants.

4.2.1.1.2 Coastal Subcategory

Oil and gas activities located in coastal waters may not discharge produced waters to the marine environment. This discharge prohibition does not apply to the Cook Inlet, Alaska (which is treated in the same manner as offshore waters). Table 4-1 presents the ELGs for the coastal subcategory.

TABLE 4-1 ELGs for Coastal Subcategory

Stream	Pollutant Parameter	BAT	NSPS
Produced water – all coastal areas except Cook Inlet	—	No discharge	No discharge
Produced water – Cook Inlet	Oil and grease	42 mg/L (daily maximum); 29 mg/L (monthly average)	42 mg/L (daily maximum); 29 mg/L (monthly average)

4.2.1.1.3 Offshore Subcategory

Offshore oil and gas facilities are allowed to discharge produced waters to the sea. The ELGs are presented in Table 4-2.

TABLE 4-2 ELGs for Offshore Subcategory

Stream	Pollutant Parameter	BAT	NSPS
Produced water	Oil and grease	42 mg/L (daily maximum); 29 mg/L (monthly average)	42 mg/L (daily maximum); 29 mg/L (monthly average)

4.2.1.2 Discharges from CBM Operations

CBM production activities are somewhat different from conventional gas production. The EPA did not consider CBM production when it established its ELGs and has not yet revised its ELGs to include CBM discharges. Thus, state regulatory agencies have been able to issue NPDES permits allowing discharges of CBM water using their own "best professional judgment." Veil (2002b) describes the regulations that govern water discharges from CBM wells as wells as those that do not apply. That report also describes the permitting procedures and limitations used by Alabama, Wyoming, Montana, and Colorado. Each state follows somewhat different permitting procedures and has different discharge standards. The states place limits on or require monitoring for oil and grease, salinity (e.g., chlorides, TDS, or conductivity), pH, total suspended solids, and toxicity. They also require limits or monitoring for other contaminants. In most situations, those CBM producers that are currently discharging are able to provide a minimal degree of treatment and meet the permit limits.

The regulatory requirements for discharging CBM produced water have been evolving along with the increased demand for CBM production and water discharges. Elcock et al. (2002) discuss the current and potential regulatory issues and requirements for managing CBM water as CBM production expands in the United States. EPA Region 8 has been developing a set of best professional judgment discharge guidelines for CBM water discharges on tribal lands. During a September 2001 public meeting, EPA discussed several water management options: discharge with erosion control and iron removal, discharge following treatment with reverse osmosis, and injection (EPA 2001). EPA has not yet issued its final guidance for this topic.

4.2.1.3 Water Quality-Based Limits

The Clean Water Act prohibits the discharge of toxic substances in toxic quantities. This goal is accomplished through water quality-based effluent limits designed to ensure that ambient receiving water concentrations are low enough to maintain the designated use of the waters (e.g., fishing).

4.2.1.4 Calculation of Effluent Limits

ELGs serve as a foundation for the effluent limits included in a permit, but the ELGs are based on the performance of a technology and do not address the site-specific environmental effects of discharges. In certain instances, the technology-based controls may not be strict enough to ensure that the aquatic environment will be protected against toxic quantities of substances. In these cases, the permit writer must include additional, more stringent water quality-based effluent limits in NPDES permits. These water quality-based limits may be numeric (the EPA has published numeric water quality criteria for more than 100 pollutants that can be used to calculate water quality-based limits) or narrative (e.g., "no toxic substances in toxic quantities"). The process for establishing the limits takes into account the designated use of the water body, the variability of the pollutant in the effluent, species sensitivity (for toxicity), and, where appropriate, dilution in the receiving water (including discharge conditions and water column properties).

4.2.2 Regional General Permits

Four of the EPA's regional offices have issued permits to facilities discharging into ocean waters beyond the three-mile limit of the territorial seas and may also issue permits to facilities in the territorial sea if the adjoining state does not have an approved NPDES program. Regional NPDES permits impose additional operational, monitoring, testing, and reporting requirements. The following describes the five most important general permits for oil and gas exploration, development, and production operations issued for the Eastern Gulf of Mexico (Region 4), Western Gulf of Mexico (Region 6), California (Region 9), and North Slope and Cook Inlet, Alaska (Region 10) (Veil 2001a).

4.2.2.1 Region 4 — Eastern Gulf of Mexico

General Permit GMG280000 applies to operators of lease blocks located in the Outer Continental Shelf (OCS) federal waters seaward of 200 meters in the Eastern Planning Area and seaward of the outer boundary of the territorial seas in the Central Planning Area with existing or new source discharges originating from oil and gas exploration or development and production operations. The general permit includes the following additional requirements related to produced water discharges:

- No discharge allowed within 1,000 meters of Area of Biological Concern,

- Toxicity: 96-hour LC50 (concentration of test material that is lethal to 50% of the test organisms in a toxicity test after 96 hours of constant exposure) must not exceed critical concentrations,

- Testing using two species:
  Mysid shrimp (Mysidopsis bahia)
  Inland silverside minnow (Menidia beryllina),

- Critical dilutions based on water depth, pipe diameter, and flow rate,

- Dilution calculated using CORMIX 2 model, and

- Dilution can be increased by using a diffuser, adding seawater, or installing multiple discharge ports.

4.2.2.2 Region 6 — Western Portion of the Outer Continental Shelf of the Gulf of Mexico

General Permit GMG290000 applies to discharges from new and existing sources in the offshore subcategory of the oil and gas extraction point source category to the federal waters of the Gulf of Mexico seaward of the outer boundary of the territorial seas offshore off Louisiana and Texas. The general permit includes:

- No discharge within Area of Biological Concern,

- Toxicity: 7-day no observed effect concentration (NOEC) must not exceed concentration determined by using critical dilutions,

- Testing using two species:
  Mysid shrimp (Mysidopsis bahia)
  Inland silverside minnow (Menidia beryllina),

- Critical dilutions based on water depth, discharge depth, pipe diameter, and flow rate,

- Dilution calculated using CORMIX model,

- Dilution can be increased by using a diffuser, adding seawater, or installing multiple ports,

- Frequency of testing based on volume of discharge.

4.2.2.3 Region 6 — Territorial Seas of Louisiana

General Permit LAG260000 applies to discharges from new and existing sources in the offshore subcategory of the oil and gas extraction point source category to the territorial seas of Louisiana. The general permit, which has expired, but is administratively extended, includes:

- No discharge allowed:
  - To areas intermittently exposed
  - In parks or wildlife refuges
  - Within 1,300 feet of oyster or sea grass bed,

- Toxicity similar to Region 6 (>3 miles offshore),

- Other chemical monitoring:
Benzene, lead, phenol, thallium, radium 226, radium 228, and

- Limits based on dilution.

4.2.2.4 Region 9 — California

General Permit CAG280000 applies to discharges from oil and gas exploration, development, and production operations in federal waters offshore of California. The general permit, which is being reissued, includes:

- Sample produced water for 26 chemicals and effluent toxicity to determine if those substances are likely to cause a water quality problem,

- Determine available dilution using PLUMES-UM model,

- Dilution can be increased by using a diffuser or adding seawater,

- The EPA has already set limits on selected chemicals at some platforms,

- Discharge volume limits are set for each platform,

- Conduct study of on-line oil and grease monitors,

- Toxicity requirements:
  Quarterly chronic testing with red abalone (Haliotis rufescens)
  Annual chronic testing with plant (giant kelp – Macrocystis pyrifera) and fish (topsmelt – Atherinops affinis),

- The EPA will set separate NOEC limits for each platform based on dilution:

If limits are exceeded, must sample more frequently

If limits are still exceeded, must undertake a toxicity reduction evaluation
Identify sources of toxicity
Take actions to mitigate toxicity
Retest to confirm results, and

- Study of impacts of produced water discharges on fish.

4.2.2.5 Region 10 — Alaska Cook Inlet

General Permit AKG285000 applies to discharges from oil and gas development and production facilities into state waters north of the Forelands in the Upper Cook Inlet and from exploratory facilities to all state and federal waters in Cook Inlet north of the line between Cape Douglas on the west and Port Chatham on the east. The general permit includes:

- Study of impacts of produced water discharges on fish,

- NOEC toxicity limits set for each platform, and

- Annual chronic testing using three species:
  Inland silverside minnow (Menidia beryllina)
  Mysid shrimp (Mysidopsis bahia)
  Mussel (Mytilus sp.) or Pacific oyster (Crassostrea gigas)

  If limits are exceeded, must sample more frequently
  If limits are still exceeded, must undertake a toxicity reduction evaluation
  Identify sources of toxicity
  Take actions to mitigate toxicity
  Retest to confirm results.

4.2.3 Ocean Discharge Criteria Evaluation

Discharges into territorial seas, contiguous zone, and the oceans must undergo an additional level of review to ensure that they do not cause unreasonable degradation of the marine environment. The review is based on the EPA's ocean discharge criteria regulations codified at Subpart M of 40 CFR Part 125.

Before issuing an NPDES permit for discharges to the territorial seas, contiguous zone, and the oceans, the EPA must consider various factors, including: the quantities, composition, and potential for bioaccumulation or persistence of the pollutants to be discharged; the potential transport of such pollutants by biological, physical, or chemical processes; the composition and vulnerability of the biological communities that may be exposed to such pollutants; the importance of the receiving water area to the surrounding biological community (including the presence of spawning sites, nursery areas, and

migratory pathways); the existence of special aquatic sites such as marine sanctuaries and refuges, parks, national and historic monuments, national seashores, wilderness areas, and coral reefs; the potential impacts on human health through direct and indirect pathways; existing or potential recreational and commercial fishing; and numeric water quality criteria for specific pollutants.
NPDES permits for facilities discharging into marine waters are required to include limits that prevent unreasonable degradation of the marine environment. In certain cases, that may mean a discharge prohibition. If insufficient information is available to conduct the degradation assessment, the EPA will determine whether the discharge will cause irreparable harm to the marine environment and whether reasonable alternatives to onsite disposal exist. When assessing the potential for irreparable harm, the EPA determines whether the facility is likely to cause permanent and significant harm to the environment on the basis of additional information collected during a monitoring period. If the potential for irreparable harm is low, the EPA may allow a monitoring program to demonstrate that the discharge will not cause unreasonable degradation. If the data gathered through monitoring indicate that continued discharge may cause unreasonable degradation, the discharge must be halted or additional permit limitations must be established.

President Clinton's Executive Order (E.O.) 13158, issued on May 26, 2000, states that the EPA "shall expeditiously propose new science-based regulations, as necessary, to ensure appropriate levels of protection for the marine environment." In the wake of the E.O., the EPA developed a proposal that would have made the ocean discharge regulations more stringent. However, in early 2001, the EPA withdrew the proposal.

4.2.4 Other NPDES Permit Conditions

Facilities are responsible for taking the steps necessary to demonstrate compliance with NPDES permit limits. Permits instruct each facility operator regarding the frequency for collecting wastewater samples, the location for sample collection, the pollutants to be analyzed, and the laboratory procedures to be used in conducting the analyses. Detailed records of these "self-monitoring" activities must be retained by the facility for at least three years. Furthermore, each facility is required to submit the results of these analyses to the regulators on a periodic basis. For most facilities, the reporting frequency is monthly or quarterly, but in no case may it be less than once per year. NPDES permits may also require operational or environmental effects monitoring. This includes the preparation of best management practices plans or spill prevention plans.

Inspectors from the EPA visit the offshore platforms occasionally to monitor their discharges and make sure that all operations are in compliance with permit requirements. Failure to meet the permit limits can result in fines or loss of the permit.

4.3 Injection of Produced Water

The Safe Drinking Water Act of 1974 (Part C, Sections 1421-1426) gave the EPA the authority for Underground Injection Control (UIC) regulation. The UIC program is

designed to protect underground sources of drinking water (USDWs). A USDW is an aquifer or portion of an aquifer that supplies any public water systems or contains sufficient quantity of groundwater to supply a public water system; currently supplies drinking water for human consumption or contains fewer than 10,000 milligrams/liter total dissolved solids; and is not an aquifer exempted from UIC regulations.
For regulatory control purposes, underground injection is grouped into five classes of injection wells. An injection well is defined as any bored, drilled or a driven shaft or a dug hole, where the depth is greater than the largest surface dimension that is used to inject fluids underground. Class I wells are used for the emplacement of hazardous and nonhazardous fluids (industrial and municipal wastes) into isolated formations beneath the lowermost underground source of drinking water. Class I operations are the most strictly regulated by the SDWA and are further controlled by the Resource Conservation and Recovery Act. Class II wells inject brines and other fluids associated with oil and gas production. Class III wells inject fluids associated with solution mining of minerals. Class IV wells, which involve the injection of hazardous or radioactive wastes into or above a USDW, are banned unless authorized under other statutes for groundwater remediation. Class V wells include underground injection wells not included in Classes I through IV. Class V governs wells that inject nonhazardous fluids into or above a USDW — typically shallow, onsite disposal systems, such as floor and sink drains discharging directly or indirectly to ground water, dry wells, leach fields, and similar types of drainage wells.

Wells used for injecting produced water are considered Class II wells. Class II subclasses include enhanced recovery wells (Class II-R) and disposal wells (Class II-D). Numerous fields are operated under an enhanced recovery mode when water, steam, or other substances are injected to a producing formation to help move the crude oil to wells for collection. These are typically water-flood or steam-flood operations. The application of enhanced recovery can prolong the productive life of certain hydrocarbon deposits (i.e., water-drive reservoirs) and increases the resource yield. In this scenario, produced water ceases being a waste and becomes a beneficial resource. Produced water can also be injected solely for disposal. In this case, the water is typically injected to a formation other than the producing formation.

The EPA's regulations establish minimum standards for state programs prior to receiving primary responsibility (primacy) for the UIC program under Section 1422 of the SDWA. (A state program can always be more stringent than the federal blueprint.) In 1981, Congress added Section 1425 to the SDWA, which relieves oil and gas-related injection well programs in the states from having to meet the technical requirements in the federal UIC regulations. (This reinforced the statutory instruction that the EPA not interfere with the production of oil and gas unless the requirements are essential for the protection of USDWs.) Instead, the demonstration can be made that the state has an effective program (including adequate oversight, record-keeping, and reporting) in place to prevent the endangerment of USDWs by underground injection operations. The EPA thus can approve delegation of the UIC program to the states in several ways, including for (1) all well classes under Section 1422 of the SDWA, (2) oil and gas injection wells under Section 1425 of the SDWA, and/or (3) all but oil and gas injection wells under Section

1422 of the SDWA. A state could have full delegation of the UIC program and have one portion for oil and gas injection wells approved under Section 1425 and another for the other types of wells under Section 1422 of the SDWA. Because the Section 1425 approval route offers greater flexibility, most states have obtained UIC primacy in this manner. The EPA's website reports that the Agency has approved program primacy for all well classes in 34 states, that it shares responsibility in six states, and that it directly implements the program for all well classes in 10 states. The Agency provides grant funds to all delegated programs to help pay for program costs. States must provide a 25% match on EPA funds (EPA 2003).

4.3.1 Federal UIC Program

The application, construction, operating, monitoring, and reporting requirements for Class II wells are found in 40 CFR 144 and 146. Some key features of the EPA's federal regulations are highlighted below.

All Class II-D wells existing on the effective date of the UIC program implementation were required to apply for a permit during the first years (40 CFR §144.21). Class II-R wells existing at the effective date of the UIC program implementation maintain rule authorization for the life of the well, if the owner/operator complies with the regulations governing rule authorization (40 CFR §144.22). Every new Class II-D and Class II-R well must be permitted prior to construction or injection. The owner/operator must file a permit application with the UIC Director containing the specific information listed in 40 CFR Part 146 (Kobelski 2003).

4.3.1.1 Area of Review (40 CFR § 144.55 & 146.6)

Applicants for new Class II injection well permits must identify the location of all known wells within the injection well's area of review (AOR) that penetrate the injection zone, or in the case of Class II wells operating over the fracture pressure of the injection formation, all known wells within AOR penetrating formations affected by the increase in pressure. If the review of the available completion and plugging records for all wells within the AOR yields conditions or pathways suggesting the potential for migration of formation or injection fluids out of the injection zone, corrective or preventive action must be taken before using the injection well.

The AOR analysis allows the permitting authorities to determine whether a proposed injection has the potential to contaminate USDWs through wells, faults, or other pathways penetrating the injection zone. For permit applications, the AOR is referenced through computing the zone of endangering influence or through determining a fixed radius of at least one quarter of a mile.

4.3.1.2 Mechanical Integrity (40 CFR §§146.8 & 146.23(b)(3))

Owners/operators must demonstrate the internal and external integrity of their injection wells. This includes the absence of significant leakage in the casing, tubing, or packer of

the injection wells. Moreover, operators must show that there is no significant fluid movement into a USDW through vertical channels adjacent to the well bore. The regulations specify the types of mechanical integrity test (MIT) methods that are approved by the EPA.
The methods used to evaluate the absence of leaks include:

- Following an initial pressure test, monitoring of the tubing-casing annulus pressure with sufficient frequency to be representative, as determined by the Director, while maintaining an annulus pressure different from atmospheric pressure measured at the surface;

- Pressure test with liquid or gas; or

- Records of monitoring showing the absence of significant changes in the relationship between injection pressure and injection flow rate for the following Class II-R wells:

o Existing wells completed without a packer, provided that a pressure test has been performed and the data is available and provided further that one pressure test shall be performed at a time when the well is shut down and if the running of such a test will not cause further loss of significant amounts of oil or gas; or
o Existing wells constructed without a long string casing, but with surface casing that terminates at the base of freshwater provided that local geological and hydrological features allow such construction and provided further that the annular space shall be visually inspected.

The methods used to evaluate the absence of significant fluid movement include:

- The results of a temperature or noise log, or

- For Class II only, cementing records demonstrating the presence of adequate cement to prevent such migration.

The Director may approve alternative mechanical integrity test methods. Mechanical integrity must be demonstrated at least every five years.

4.3.1.3 Plugging and Abandonment (40 CFR §146.10)

Injection wells that have not been in operation for two years must be plugged and abandoned unless special precautions are taken to avoid endangerment of USDWs. Prior to abandonment, Class II wells must be plugged with cement in a manner that will not allow movement of fluids into or between USDWs. Owner/operators must maintain bonds or other financial instruments to assure that a well that is no longer needed can be appropriately plugged and abandoned.

4.3.1.4 Construction Requirements (40 CFR §146.22)

All new Class II wells must be sited to inject into a formation that is separated from a USDW by a confining zone free of known open faults or fractures within the AOR. Class II wells must be cased and cemented to prevent fluid movement into or between USDWs. The regulations list several criteria that must be considered in determining casing and cementing requirements. Logs and other tests are required during the drilling and construction of new Class II wells. Moreover, a report interpreting the logs and tests must be submitted to the regulator. The regulations prescribe minimum requirements for the logs and tests.

4.3.1.5 Operating Requirements (40 CFR §146.23(a))

The operating requirements in UIC Class II permits must specify a maximum injection pressure that will not initiate new fractures or propagate existing fractures in the confining zone adjacent to the USDWs. Injection pressure must not cause the movement of fluids into USDWs. Injection into the space between the outermost casing protecting USDWs and the well bore is prohibited.

4.3.1.6 Monitoring and Reporting Requirements (40 CFR §146.23(b) & (c))

Owner/operators must monitor the nature of injected fluids (at least once within the first year of authorization, and thereafter whenever changes are made to the injection fluid); injection pressure, flow rate, and cumulative volume at various frequencies specified in the regulations (weekly for disposal wells and monthly for enhanced recovery wells); mechanical integrity (at least once every five years), and other operational statistics. Owner/operators must submit at least an annual report of the monitoring results. In addition, well failures or other well-specific activities (including corrective action) must be reported.

4.3.2 State UIC Programs

State regulations are similar to the federal regulations, but not necessarily exact replications. While state programs must be at least as stringent as the federal blueprint, states are free to impose more stringent requirements. In this light, UIC regulations administered by the states exhibit differences in regulatory definitions and technical standards when compared to the federal minimum standards established by the EPA. The variations stem from historic reasons, differing geologies, and other factors. Many states have been active in the regulation of underground injection operations long before the EPA promulgated the technical UIC regulations. Most state UIC Class II programs were approved under the alternative effectiveness route made available under Section 1425 of the SDWA. The states with the largest number of oil and gas injection wells are Texas (53,000) and California (25,000). The following presents information for Texas, California, Alaska, and Colorado.

4.3.2.1 Texas

In Texas, the Railroad Commission of Texas (the RRC) enjoys primacy over the UIC Class II program. The main differences between the RRC and EPA's UIC programs relate to AOR and MIT regulation. While the EPA prescribes checking all plugging and completion reports for cement across the injection zone, the RRC does not conduct full AOR checks in all cases. Due to staffing limitations, full AOR checks are done only in specific problem areas. The RRC MIT program is generally based on a five-year testing interval. However, the RRC requires annual testing for wells that do not meet the new construction standard for well construction and groundwater protection. The regulations governing Class II-D wells and Class II-R wells are almost identical. Minor differences stem from the groundwater depth jurisdiction language in the Texas Water Code for Class II-D and the Texas Natural Resources Code for Class II-R. All groundwater depth recommendations are made by the Texas Commission on Environmental Quality (TCEQ). The Class II-D groundwater depth recommendation (from TCEQ) includes a review of geologic separation for shallowest allowed disposal (250 feet of cumulative clay/shale between the disposal zone and deepest groundwater). In the case of Class II-R, the TCEQ groundwater recommendation does not consider the geologic separation issue. Instead, RRC staff review the geologic separation. In the event of inadequate separation, the permit will include a fluid source limit allowing re-injection only of the produced water from the same zone. In addition to groundwater depth, the requirements for Class II-D wells and Class II-R wells differ with respect to the packer setting depth. Class II-D packers must be set within 100 feet of the disposal zone. Class II-R packers are typically placed subject to the same 100-foot limit, but may be set further away if well construction, proximity to groundwater, and impermeable intervening strata allow (De Leon 2003).

4.3.2.2 California

In California, the Division of Oil, Gas, and Geothermal Resources (the Division) in the Department of Conservation enjoys primacy over the UIC Class II program. California has adopted a much narrower E&P waste exemption than at the federal level, expressly exempting only geothermal E&P wastes from the scope of its hazardous waste program. The exemption applies in California if the waste displays the toxicity characteristic for hazardous wastes based solely on the Toxicity Characteristic Leaching Procedure (TCLP). The exemption does not apply if the toxicity is determined based on criteria other than the TCLP or if the waste meets any of the other three characteristics of hazardous waste—ignitability, corrosivity, and reactivity.

In consequence, E&P wastes that exhibit a hazardous characteristic or contain a hazardous waste may be regulated as hazardous wastes. In this light, the Division carefully reviews what fluids are deemed Class II fluids. This is especially important in enhanced recovery operations (for example, using polymers to seal off zones with fluid loss). Moreover, the Division prescribes shorter MIT time intervals. Water-disposal wells must be tested at least once each year, water flood wells every two years, and steam flood wells every five years. For purposes of testing external integrity, the Division does not allow cement bond logs but generally requires radioactive tracer surveys (Stettner 2003b).

4.3.2.3 Alaska

In Alaska, the Alaska Oil and Gas Conservation Commission (the AOGCC) enjoys primacy over the UIC Class II program. As such, AOGCC regulation of produced water injection does not differentiate between injection for purpose of disposal and injection for enhanced recovery. Any differences relative to AOR, MIT, plugging and abandonment, construction, operation, monitoring, and reporting are driven by the presence or absence of a USDW. For example, on the North Slope of Alaska, the AOGCC has the ability to relax some of the mechanical integrity and construction requirements for injection wells because there are no USDWs. Occasionally circumstances may call for a larger AOR than the typical ¼-mile radius around an injector, but the determination is not driven by produced water operations. In practice, the AOGCC rarely deviates from the ¼-mile radius, even when a USDW is not present. AOGCC regulators emphasize that the "real sticking points" enter the picture when one contrasts Class I wells and Class II wells in terms of the types of fluids eligible to be injected into Class II wells (Regg 2003).

4.3.2.4 Colorado

In Colorado, the Oil and Gas Conservation Commission (the COGCC) enjoys primacy over the UIC Class II program. As part of the AOR regulation, the COGCC, unlike many other states, requires the identification of all oil and gas wells currently producing from the proposed injection zone within ½ mile of the disposal zone. In terms of produced water injection regulation, the COGCC may make a distinction between Class II-D wells and Class II-R wells when it comes to the allowable maximum operating pressure, which will be established by the COGCC upon approval (Kobelski 2003).

4.3.3 Bureau of Land Management Regulations

The Bureau of Land Management (the BLM) in the U.S. Department of the Interior has jurisdiction over onshore leasing, exploration, development, and production of oil and gas on federal lands. In addition, the BLM approves and supervises most oil and gas operations on American Indian lands. The BLM regulations governing onshore oil and gas operations are codified at 43 CFR Part 3160 (onshore oil and gas operations). Onshore oil and gas orders (OOGOs) implement and supplement the regulations found at 43 CFR Part 3160 for conducting oil and gas operations on federal or Indian lands. Notices to lessees (NTLs) implement and supplement the OOGOs and the regulations. Disposal of produced water is governed by Onshore Oil and Gas Order (OOGO) No. 7, published in the Federal Register on November 2, 1993, at 58 FR 58506. It applies to disposal of produced water from completed wells on federal and Indian (except Osage) oil and gas leases. It does not apply to approval of disposal facilities on lands other than federal or Indian lands. Separate approval under the OOGO is not required if the disposal method has been covered under an enhanced recovery project approved by the authorized officer.

Operators of onshore federal and Indian oil and gas leases may not dispose of produced water unless and until approval is obtained from the authorized officer. All produced water from federal and Indian leases must be disposed of (1) by injection into the subsurface; (2) into lined or unlined pits; or (3) by other acceptable methods approved by the authorized officer, including surface discharge under NPDES permits. Injection is generally the preferred method of disposal.

Operators shall submit a Sundry Notice Form 3160 when they request approval for on-lease disposal of produced water in injection wells and in lined or unlined pits. When requesting approval for removal of water and off-lease disposal on leased or unleased federal and Indian lands in a pit, operators shall submit a Sundry Notice Form 3160. If the water is to be disposed of in injection wells, operators must also submit a copy of the UIC permit (unless the well is authorized by rule). Off-lease disposal on state and privately owned lands requires submission of a Sundry Notice Form 3160-5, along with a copy of the UIC permit for injection wells or pit permit, as required.

In addition, OOGO No. 7 identifies informational requirements for injection wells and pits; requirements governing pit design, construction, maintenance, abandonment, and reclamation; requirements for other disposal methods; and reporting requirements for disposal facilities. Operators may request variances from the standards of the OOGO.

4.3.4 Minerals Management Service Requirements

The Outer Continental Shelf Lands Act (OCSLA) established federal jurisdiction over submerged lands on the Outer Continental Shelf (OCS) seaward of state boundaries. Under the OCSLA, the Secretary of the U.S. Department of the Interior (DOI) is responsible for the administration of mineral exploration and development of the OCS. The Minerals Management Service (MMS), a DOI bureau, manages the nation's natural gas, oil, and other mineral resources on the OCS. The Offshore Minerals Management program features three regions: Alaska, Gulf of Mexico, and the Pacific.

Because no USDWs exist below the seabed of the OCS, the EPA's UIC program does not apply. Instead, the MMS has regulated sub-seabed disposal separately. The MMS regulations governing oil and gas operations in the OCS are codified at 30 CFR Part 250 (oil and gas and sulphur operations in the Outer Continental Shelf). Each application for underground waste disposal must be authorized on a case-by-case basis by the MMS (see 30 CFR §250.300(b)(2)). Notices to lessees (NTLs) clarify, describe, or interpret offshore regulations or standards. NTLs also may provide guidelines on special lease stipulations, explain the MMS's interpretation of requirements, or transmit administrative information. There are two types of NTLs, those issued at the regional level pertinent to a particular region and those issued nationally that are effective nationwide for all MMS regions. The MMS Gulf of Mexico OCS Region (GOMR) has published NTL No. 99-G22, "Guidelines for the Sub-Seabed Disposal and Offshore Storage of Solid Wastes." If operators plan to inject produced waters through underground injection wells for purposes of disposal, the receiving formation must be located below the deepest underground source of drinking water, must be isolated above and below by shale layers, and may not contain any producing wells. Operators must demonstrate that injection wells have mechanical integrity. In contrast to disposal operations, reinjection of produced water for enhanced recovery is considered part of processing not subject to the NTL. MMS officials note that most produced water is discharged overboard (subject to all applicable requirements) and that enhanced recovery operations are in the majority of cases conducted through gas injection.

5 Produced Water Management Options

There are many approaches to managing produced water; some of these are discussed in this chapter. The most appropriate option for a given location will be a function of several factors, including site location, regulatory acceptance, technical feasibility, cost, and availability of infrastructure and equipment. The primary alternatives being used today are underground injection, discharge, and beneficial reuse, although some other options are used at selected locations. Historically, produced water was managed in ways that were the most convenient or least expensive. Today, many companies recognize that water can be either a cost or a value to their operations. For example, Shell has established a formal Water-to-Value program through which the company attempts to minimize the production of water, reduce the costs of water treatment methods, and look for ways in which existing facilities can handle larger volumes of water (Khatib and Verbeek 2003). Greater attention to water management allows production of hydrocarbons and the concomitant profits to remain viable.

The commonly used approaches for managing CBM water are somewhat different than those used for other onshore conventional gas and crude oil production. This is a function of different regulations and the disparate nature of the constituents in the produced water from the two types of production. The discussions in this chapter help to point out the various approaches used.

This chapter discusses water management technologies and strategies in terms of a three-tiered waste management or pollution prevention hierarchy (Veil 2002a). In the first tier (water minimization), processes are modified, technologies are adapted, or products are substituted so that less water is generated. When feasible, water minimization can often save money for operators and results in greater protection of the environment. For the water that is still produced following water minimization, operators next move to the second tier, in which water is reused or recycled. Some water cannot be recycled or reused and must be disposed of by injection or discharge.

5.1 Water Minimization Options

Within a producing formation, water and petroleum hydrocarbons are not fully mixed; they exist as separate adjacent fluid layers, with the hydrocarbon layer typically lying above the water layer by virtue of its lower specific gravity. Operators try their best to design wells to produce from the hydrocarbon layer. As hydrocarbons are removed from the formation, the pressure gradient changes so that the water layer often rises up in the vicinity of the well, creating a coning effect. As production continues, an increasing portion of the produced fluids will be water.

It is challenging to minimize the amount of water produced into the well, but there are some strategies that can be used to restrict water from entering the well bore. These involve mechanical blocking devices or chemicals that “shut off” water-bearing channels or fractures within the formation and prevent water from making its way to the well.

Although they help to avoid production of water and its associated environmental impacts, they are generally considered to be in the realm of reservoir and production engineering activities rather than environmental management tools.

5.1.1 Options for Keeping Water from the Wells

5.1.1.1 Mechanical Blocking Devices

Operators have used various mechanical and well construction techniques to block water from entering the well. Seright et al. (2001) offer several examples of these techniques:

- Straddle packers,
- Bridge plugs,
- Tubing patches,
- Cement,
- Well bore sand plugs,
- Well abandonment,
- Infill drilling,
- Pattern flow control, and
- Horizontal wells.

These have been used for many years, but do not work well in all applications. Operators often do not put forth the time or expense to diagnose the cause of their overabundant water. Consequently, incorrect solutions are not uncommon. For example, Seright et al. (2001) identify 13 types of events that lead to excess water; these are divided into four categories of most viable remedies. Seright et al. (2001) recommend that mechanical approaches can be used to block casing leaks or flow behind pipe without flow restrictions and unfractured wells with barriers to cross flow. Those approaches may not be effective in solving other types of water production problems.

5.1.1.2 Water Shut-Off Chemicals

Another approach to shutting off water production while allowing continued production of oil involves the use of chemicals that are injected into the formation. In its most basic sense, the process of waste minimization would not generally support introduction of new chemicals into the ground. In this case, however, the chemicals are introduced deep in the earth where they are unlikely to affect the biosphere, and they have a net beneficial impact. Therefore, this option is included under the water management options discussion.

Most of these products are polymer gels or their pre-gel forms (gelants). Gel solutions selectively enter the cracks and pathways that the water follows and displace the water. When the gels set up in the cracks, they block most of the water movement to the well while allowing oil to flow to the well. Many different types of gels can be prepared, depending on the specific type of water flow that is being targeted. Thomas et al. (2000), Mack (2003), Seright et al. (2001) and Green et al. (2001) offer thoughts on the key factors to be considered when designing and conducting a gel treatment. Some important considerations include:

- The component ingredients:
  - o Type of gel polymer (often a polyacrylamide polymer; also microbial products or lignosulfonate have been tried)
  - o Type of crosslinking agent (metal ion or organic)
  - o Fluid used to mix the gel (freshwater or produced water)

- The properties of the gel (these may vary in several stages throughout gel treatment):
  - o Concentration of polymer
  - o Molecular weight of polymer
  - o Degree of crosslinking
  - o Viscosity (affects the size of cracks or fractures that can be penetrated at a given pressure; can inject as pre-mixed gel or as gelant)
  - o Density (if density is too heavy, gel can sink too far into the water layer and lose effectiveness)
  - o Set-up time (this determines how far into the cracks or fractures the gel will penetrate)

- The treatment procedure:
  - o Preparation of well before treatment
  - o Volume of gel used
  - o Injection pressure
  - o Injection rate.

In the United States, most of the polymer gel treatments are made in wells producing from fractured carbonate or dolomitic formations that operate under a natural water drive (Reynolds et al. 2002). Mack (2003) and Reynolds et al. (2002) suggest the following criteria for selecting candidate wells for gel treatments:

- Wells already shut-in or near the end of their economic life,
- Significant remaining mobile oil in place,
- High water-oil ratio,
- High producing fluid level,
- Declining oil and flat water production,
- Wells associated with active natural water drive, and
- High-permeability contrast between oil- and water-saturated rock.

The results of many successful gel treatment jobs have been reported in the literature. Seright et al. (2001) report on 274 gel treatments conducted in naturally fractured carbonate formations. The median water-to-oil ratio (WOR) was 82 before the treatment, 7 shortly after the treatment, and 20 a year or two after treatment. The oil production increased following treatment and remained above pretreatment levels for 1 to 2 years. Thomas et al. (2000) report that an initial investment of $231,000 for gel treatments resulted in incremental profits of $1.7-2.3 million over a two-year period. Green et al. (2001) report that following a series of gel treatments at four Kansas wells, which cost $14,000 to $18,000 per well, including polymer and well servicing costs, total oil production increased by about 30 barrels per day (bpd) while water production dropped by about 1,000 bpd. Lifting costs associated with the lower fluid volume were reduced about $300/month/well. With less stress on the lifting equipment, well servicing costs were also reduced about $2,400/year/well. Through mid-2000, about 37,500 bbl of incremental oil were economically recovered, representing about $1.60 per incremental bbl to date — and several years of production is still anticipated. The gel polymer treatments extended the lease economic life at least seven years.

5.1.2 Options for Keeping Water from Getting to the Surface

Lifting water to the surface represents a substantial expense for operators. The process of lifting and managing the water at the surface puts the water in a location where it can harm the land surface and surface or ground water resources. A variety of technologies have been developed that attempt to manage water either in the well bore itself or at a remote location like the sea floor. Although these technologies do not minimize the volume of water entering the well, they do minimize the volume of water that comes to the surface. Thus, they are also included under the water minimization discussion in this chapter.

5.1.2.1 Dual Completion Wells

Oil production can decline in a well because water forms a cone around the production perforations, limiting the volume of oil that can be produced. This situation can be reversed and controlled by completing the well with two separate tubing strings and pumps. The primary completion is made at a depth corresponding to strong oil production, and a secondary completion is made lower in the interval, at a depth with strong water production. The two completions are separated by a packer. The oil collected above the packer is produced to the surface, and the water collected below the packer is injected into a lower formation (Shirman and Wojtanowicz 2002; Wojtanowicz et al. 1999). This technology has also been called a downhole water sink. In another version of the process, the water can be separately produced to the surface for management there.

Swisher (2000) reports on the performance of a dual-completion well compared to three wells with conventional completions in a north Louisiana field. Although the dual-completion well cost about twice as much to install, it took the same or fewer number of months to reach payout as the other wells. At payout, it was producing 55 bpd of oil compared to about 16 bpd from the other three wells. The net monthly earnings at payout for the dual completion well were nearly $26,000 compared to $5,000 to $8,000 for the other wells. Wojtanowicz (2003) offers some additional examples from more complicated geological settings.

5.1.2.2 Downhole Oil/Water Separators

Downhole oil/water separators (DOWS, also referred to as DHOWS) separate oil from water in the well bore itself. DOWS technology reduces the quantity of produced water that is handled at the surface by separating it from the oil downhole and simultaneously injecting it underground. A DOWS system includes many components, but the two primary ones are an oil/water separation system and at least one pump to lift oil to the surface and inject the water. Two basic types of DOWS have been developed—one type using hydrocyclones to mechanically separate oil and water and one relying on gravity separation that takes place in the well bore.

Hydrocyclones use centrifugal force to separate fluids of different specific gravity without any moving parts. A mixture of oil and water enters the hydrocyclone at a high velocity from the side of a conical chamber. The subsequent swirling action causes the heavier water to move to the outside of the chamber and exit through one end, while the lighter oil remains in the interior of the chamber and exits through a second opening. The water fraction, containing a low concentration of oil (typically less than 500 mg/L), can then be injected, and the oil fraction along with some water is pumped to the surface. Hydrocyclone-type DOWS have been designed with electric submersible pumps, progressing cavity pumps, gas lift pumps, and rod pumps.

Gravity separator-type DOWS are designed to allow the oil droplets that enter a well bore through the perforations to rise and form a discrete oil layer in the well. Most gravity separator tools are vertically oriented and have two intakes, one in the oil layer and the other in the water layer. This type of gravity separator-type DOWS uses rod pumps. As the sucker rods move up and down, the oil is lifted to the surface and the water is injected. During the past few years, three North Sea-based companies collaborated to develop a new class of gravity-separation DOWS that works by allowing gravity separation to occur in the horizontal section of an extended reach well. The downhole conditions allow for rapid separation of oil and water. Oil is lifted to the surface, while water is injected by a hydraulic submersible pump (Almdahl et al. 2000).

DOE (FE and National Petroleum Technology Office [NPTO]) have actively promoted DOWS technology. Through DOE funding, Argonne National Laboratory conducted an independent evaluation of the technical feasibility, economic viability, and regulatory applicability of DOWS technology in 1999 (Veil et al. 1999). Only a modest number of DOWS systems have been installed throughout the world. Veil et al. (1999) provide information on the geology and performance of 37 of these installations, representing most of the installations that had been made through 1998. Some of the key findings from those installations are summarized below:

- More than half of the installations were hydrocyclone-type DOWS (21 compared with 16 gravity separator-type DOWS).

- Twenty-seven installations were in Canada and 10 were in the United States.

- Of the 37 DOWS trials described, 27 were in four producing areas—southeast Saskatchewan, east-central Alberta, the central Alberta reef trends, and East Texas.

- Seventeen installations were in 5.5-inch casing, 14 were in 7-inch casing, 1 was in 8.625inch casing, and 5 were unspecified.

- Twenty of the DOWS installations were in wells located in carbonate formations, and 16 were in wells located in sandstone formations. One trial did not specify the lithology. DOWS appeared to work better in carbonate formations, showing an average increase in oil production of 47% (compared with an average of 17% for sandstone formations) and an average decrease in water brought to the surface of 88% (compared with 78% for sandstone formations).

- The rate of oil production increased in 19 of the trials, decreased in 12, stayed the same in 2, and was unspecified in 4. The top three performing hydrocyclone-type wells showed oil production increases ranging from 457% to 1,162%, while one well lost all oil production. The top performing well improved from 13 to 164 bpd. The top three gravity separator-type wells showed oil production increases ranging from 106% to 233%, while one well lost all oil production. The top performing well in this group improved from 3 to 10 bpd.

- All 29 trials for which both pre-installation and post-installation water production data were provided showed a decrease in water brought to the surface. The decrease ranged from 14% to 97%, with 22 of 29 trials exceeding a 75% reduction.

Argonne later ran a program for two years under which funds were offered to companies to subsidize the cost of installing DOWS systems in exchange for receiving detailed operating data. Only two companies participated in this program. The data from a gravity-separator-type DOWS trial in New Mexico (Veil 2000) and a hydrocyclone-type DOWS trial in Texas (Argonne and ALL 2001) are available on Argonne's website at http://www.ead.anl.gov/
project/dsp_topicdetail.cfm?topicid=18.

Several organizations have worked to develop a DOWS unit that separates fluids using a centrifuge. DOE funded development of a centrifugal DOWS by Oak Ridge National Laboratory (Walker and Cummins 1999), but this technology has not been tested in a full-scale field application. Chachula (2003) reported on a separate research effort that was expected (as of April 2003) to complete a prototype centrifugal DOWS by the fourth quarter of 2003.

Since 1999, DOWS have been used sparsely, although several new designs have been tested (Veil 2001b). Two papers summarize the status of DOWS as of early 2003 (Veil 2003; Chachula 2003). During the first half of 2004, Argonne will review the status of

DOWS and downhole gas/water separators for DOE and try to identify the types of geological formations in which DOWS perform most effectively.

One of the applications for which DOWS could be used is to improve the water handling and production rate on a field-wide basis. To date, DOWS have not been used for this purpose. The following examples lead in that direction.

In 1999, DOE awarded a large grant to Venoco, Inc., a southern California offshore producer, to conduct a pilot application using downhole water separation units attached to electric submersible pumps. The goal was to improve field economics and minimize water disposal in the South Ellwood Field, offshore from Santa Barbara, California. Venoco continues to work on reservoir and fracture characterization but does not plan to install a DOWS until one of its wells receives a workover about the first quarter of 2004 (Horner 2003).

A second application involves an innovative approach to recover more oil from a field in a shorter amount of time. The so-called π-mode production strategy (Ehlig-Economides and Economides 2000; Guerithault and Ehlig-Economides 2001) relies heavily on the use of downhole oil/water separators to reinject water into the same formations from which the fluids originated and maintain formation pressure. This process accelerates the rate of recovering the available oil.

Chachula (2003) discusses use of a DOWS as part of a "smart well" system that would control real-time choking, plugging, isolation, and monitoring. He acknowledges that this is an expensive, complex, and unproven technology.

5.1.2.3 Downhole Gas/Water Separators

Several companies have marketed devices similar to DOWS for gas wells. These are known as downhole gas/water separators. The Gas Research Institute (now known as Gas Technology Institute) funded Radian International Corporation to prepare a "consumer guide" to downhole gas/water separation. The study was released in CD format in 1999 (GRI 1999). GRI found 53 commercial field tests involving 34 operators in the U.S. and Canada. Sixty percent of the tests used modified plunger rod pumps, while another 32% used bypass tools. Gas production rates were increased in 57% of the tests with 47% of the field tests termed successful, confirming that there is still significant risk. Half of the 42% failures were attributed to water cycling or poor injectivity issues.

Produced water rates and well depth exert the primary influence on which the DWGS tool is appropriate. Bypass tools are appropriate for water volumes from 25 to 250 bpd and depths in the 2,000 to 8,000-foot range. Modified plunger rod pumps can handle 250-800 bpd at depths in this range. Fully burdened costs for bypass tools and modified plunger rod pumps are about the same, in the $0.30 to $1.10/bbl range. For higher water rates above 800 bpd, electric submersible pumps are typically the most cost effective ($0.20-0.40/bbl), especially at depths greater than 6,000 ft.

5.1.2.4 Subsea Separation

This technology involves remote oil/water separation at the sea floor rather than downhole. A Norwegian company developed a subsea separation and injection system (SUBSIS) that separates the produced fluids from an offshore well at a treatment module located on the sea floor. Because size is not limited to the dimensions of a well bore, the SUBSIS equipment is much larger than the DOWS tools previously described. The SUBSIS module weighs 400 tons and is 17 meters long and wide and 6 meters high. The SUBSIS began full operation in August 2001 at Norsk Hydro's Troll field, in water at a depth of 350 meters and about 4 kilometers from the Troll C platform. Initial results indicated that 23,000 bpd of produced fluids were separated into 16,000 bpd of oil and gas and 7,000 bpd of water. The water was injected into a dedicated injection well directly from the SUBSIS unit (Wolff 2000; Offshore 2000). Von Flatern (2003) reports the results of a year-long trial of the SUBSIS. During the trial, the SUBSIS handled a maximum flow of 60,000 bpd and a typical flow of 20,000 bpd. The oil concentration in the separated water stream dropped from an initial level of about 600 ppm to a much lower 15 ppm. Because the water injected from the SUBSIS did not need to come to the surface at the Troll platform and occupy some of its water handling capacity, the Troll platform was able to produce an additional 2.5 million bbl of oil during the year-long trial (von Flatern 2003).

5.2 Water Recycle and Reuse Options

In many cases, produced water can be put to other uses. Sometimes the water can be used without treatment, particularly when the produced water is very clean to start with (e.g., many samples of CBM water) or the end use does not require high water quality (e.g., some water flood projects). In many other cases, the water must be treated before it can be reused. The cost of treating the water to meet an end use is an important factor in determining the types of reuse options that will be considered. This section describes a variety of approaches to recycling and reusing produced water. A recent report that focuses on beneficial reuse of CBM produced water (ALL 2003) provides more detail on many of the options described throughout Section 5.2.

5.2.1 Underground Injection for Increasing Oil Recovery

The most commonly used approach for managing onshore produced water is reinjection into an underground formation. Although some produced water is injected solely for disposal, most produced water (71%) is injected to maintain reservoir pressure and to hydraulically drive oil toward a producing well. This practice is referred to as water flooding, or if the water is heated to make steam, as steam flooding. When used to improve oil recovery, produced water ceases being a waste and becomes a resource. Without that produced water to use, operators would need to use other surface or groundwater supplies as sources of water for the water or steam flood. Typically, for water flooding, sufficient produced water volumes may not be available for injection. In these instances, other sources of water must be used to supplement the water flooding operation. Historically, freshwater sources have been used for this purpose. However, due to the increasing scarcity of this resource, other brines or water sources are now typically used in lieu of freshwater resources.

5.2.1.1 Examples of Produced Water Use for Increasing Recovery

Significant volumes of produced water are injected in the United States. Recent data, summarized below, were collected through interviews with staff from three state oil and gas agencies. Note that the volume estimates reported here vary somewhat from the volume estimates shown in Table 3-1 for these three states. Table 3-1 data are based on a later round of interviews, and may have involved different state officials. We have not been able to rectify the difference between the values.

Although this section of the white paper focuses on reuse, the volume of water injected for disposal in the three states is included in the same discussions for the sake of comparison. The ratio of produced water volume injected for water and steam flooding to the volume injected for disposal ranges from 1.8:1 to 4.0:1 for these three states.

California: California has nearly 25,000 produced water injection wells. The annual injected volume is approximately 1.8 billion bbl, distributed as follows: disposal wells – 360 million bbl; water flood – 900 million bbl; and steam flood – 560 million bbl (Stettner 2003a).

New Mexico: As of February 2003, New Mexico has 903 permitted disposal wells, with 264 of them active. It has an additional 5,036 wells permitted for enhanced recovery, with 4,330 of those active. The approximate volume of produced water injected for disposal is 190 million bbl, and the volume injected for enhanced recovery is about 350 million bbl (Stone 2003).

Texas: As of February 2003, Texas has 11,988 permitted disposal wells, with 7,405 of them active. It has an additional 38,540 wells permitted for enhanced recovery, with 25,204 of those active. The approximate volume of produced water injected in 2000 (there were similar well counts in 2000 and 2003) was 1.2 billion bbl disposed into nonproducing formations, 1 billion bbl disposed into producing formations, and 5.3 billion bbl injected for enhanced recovery (Ginn 2003).

5.2.2 Injection for Future Use

Some types of produced water are relatively fresh and can be used directly with little or no treatment. This is particularly true for produced water from some CBM fields. This water may be used immediately for beneficial reuse or it can be injected into an aquifer where it can be recovered for later use. This process is known as aquifer storage and recovery (ASR). The EPA treats ASR wells as Class V injection wells. In a 1999 survey, the EPA identified at least 130 ASR wells in use throughout the country (EPA 1999), although these were not injecting produced water. ALL (2003) suggests that ASR

wells could be potentially used for CBM produced water, but does not indicate if they are actually being used for that purpose.
Brost (2002) describes an operation in the Kern River field of California in which a blend of produced water and treated groundwater is filtered then sent to the local water district for use in both irrigation and aquifer recharge. That paper offers no details on how the water is further treated or injected.

5.2.3 Use by Animals

Some produced water is clean enough to be used directly or after some degree of treatment by animals (i.e., livestock or wildlife) as a source of drinking water or, in the case of fish and waterfowl, as habitat. This section describes several possible alternatives for beneficial reuse for animals.

5.2.3.1 Livestock Watering

Livestock can tolerate a range of contaminants in their drinking water. At some concentrations, the animals, although still able to survive, will begin to show some impairment. ALL (2003) provides a table showing the total dissolved solids (TDS) levels that are appropriate for livestock watering. In general, animals can often tolerate a higher degree of TDS if they are gradually acclimated to the elevated levels. Water with TDS less than 1,000 ppm is considered to be an excellent source water. Water with TDS from 1,000 up to 7,000 ppm can be used for livestock but may cause some diarrhea (ALL 2003). Some CBM projects on ranch land have created impoundments or watering stations to provide CBM produced water as a drinking water source for livestock. ALL (2003) describes an example from the 7 Ranch near Gillette, Wyoming, in which livestock are watered by using small reservoirs and old heavy-vehicle tires as watering tanks.

5.2.3.2 Wildlife Watering and Habitat

Some Rocky Mountain area CBM projects have created impoundments that collect and retain large volumes of produced water. In some cases, these may have surface areas of at least several acres. These impoundments provide a source of drinking water for wildlife and offer habitat for fish and waterfowl in an otherwise arid environment. It is important to make sure that the quality of the impounded water will not create health problems for the wildlife. The impoundments can also provide additional recreational opportunities for hunting, fishing, boating, and bird watching.

5.2.3.3 Aquaculture and Hydroponic Vegetable Culture

Jackson and Myers (2002) report on greenhouse experiments to raise vegetables (not a use by animals, but placed in Section 5.2.3 for convenience) and fish using produced water or potable water as the water source. The system used a combination of hydroponic plant cultivation (no soil) and aquaculture. Tomatoes grown with produced water were smaller than those grown in potable water. The produced water tank grew a larger weight of tilapia fish (Orechromis niuloticus/aureus), although some of the fish died. None of the fish in the potable water tank died. The tests showed that produced water could serve as a water source for vegetables and fish when other potable water sources are not available.

5.2.4 Irrigation of Crops

Many parts of the United States and around the world have limited freshwater resources. Crop irrigation is the largest single use of freshwater in the United States, making up 39% of all freshwater withdrawn, or 150 billion gallons per day (USGS 1998). If produced water has low enough TDS and other characteristics, it can be a valuable resource for crop irrigation.

ALL (2003) summarizes crop irrigation water quality requirements, noting that the three most critical parameters are salinity (affects crops), sodicity (affects soil), and toxicity (affects crops). Salinity is expressed as electrical conductivity in units of mmhos/cm or more currently in micro□Siemens per cm (µS/cm). Crops have varying susceptibility to salinity; as salinity rises above a species-specific salinity threshold, crop yields decrease.

Excess sodium can damage soils. Higher SAR values lead to soil dispersion and a loss of soil infiltration capability. When sodic soils are wet, they become sticky, and when dry, they form a crusty layer that is nearly impermeable. Paetz and Maloney (2002) describe an approach for treating CBM water to mitigate its salinity and sodicity problems so it can be used in a managed irrigation program.

Some trace elements in produced water can cause harmful effects to plants when present in sufficient quantities. ALL (2003) suggests that the most common sources of plant toxicity are chloride, sodium, and boron.

Another source of information on the effects of applying produced water to soils is a manual developed for the American Petroleum Institute on remediation of soils that had experienced produced water spills (API 1997). The authors of that manual have subsequently taught a series of workshops on the same subject. The manual is a detailed guide with much useful technical information on the impacts of salinity and sodium on soils and vegetation.

Texas A&M University established a program to develop a portable produced water treatment system that can be moved into oil fields to convert produced water to potable or irrigation water. The goal is to produce water suitable for agricultural use (less than 500 mg/L of total dissolved solids and less than 0.05 mg/L of hydrocarbons). Such a system not only augments scarce water supplies in arid regions, but also provides an economic payback to operators that could allow the well to produce longer (Burnett et al. 2002; Burnett and Veil 2004).

5.2.4.1 Examples of Use of Produced Water for Irrigation

Wyoming: ALL (2003) provides two case examples from Wyoming of irrigation using CBM water. The first project was conducted by Fidelity Exploration and Production. They irrigated livestock forage using pure CBM water on some plots and CBM water blended with surface water on other plots. Both pure and blended irrigation water created adequate crop production. When pure CBM water was used, it needed to be applied at a higher rate because the plants could not utilize it as efficiently as the surface water.

The second project was conducted by Williams, a CBM producer. Large land were irrigated areas that previously had supported only the local drought-tolerant vegetation. Following irrigation with CBM produced water, the land was able to support healthy grass crops to serve as feed for livestock. Williams provided gypsum and other soil supplements between waterings to counteract the high SAR in the produced water.

A third project is described by DeJoia (2002). CBM produced water was used in a managed irrigation project. After two years of applying soil amendments and CBM water, the test sites were converted from overgrazed range land to highly productive grasslands with both livestock and wildlife benefits.

California: Brost (2002) describes a complex system used by ChevronTexaco to treat produced water in the Kern River field in central California. The treatment system provides about 480,000 bpd of water that is used for irrigation of fruit trees and other crops and for recharging shallow aquifers. An additional 360,000 bpd of water is further purified and used to make steam at a cogeneration facility.

Powder River Basin (state not specified): Paetz and Maloney (2002) describe a project using 12,500 bpd of CBM water to irrigate 100 acres of arid land to produce a forage crop using a carefully managed approach. The project successfully produced, harvested, and sold the forage crop.

5.2.5 Industrial Uses of Produced Water

In areas where traditional surface and groundwater resources are scarce, produced water may be substituted in various industrial practices as long as the quality of the produced water meets the needs of the industrial process with or without treatment. Produced water is already being used for several industrial uses and may be suitable for others. These are discussed in this section.

5.2.5.1 Dust Control

In most oil fields, the lease roads are unpaved and can create substantial dust. Some oil and gas regulatory agencies allow operators to spray produced water on dirt roads to control the dust. This practice is generally controlled so that produced water is not applied beyond the road boundaries or within buffer zones around stream crossings and near buildings.
CBM produced water may be generated in areas with active surface coal mining. Surface mining, processing, and hauling are inherently dusty activities. Produced water can be used for dust suppression at those locations, too, if regulators allow the practice (Murphree 2002).

5.2.5.2 Vehicle and Equipment Washing

ALL (2003) notes that some state and federal agencies recommend that vehicles and equipment leaving production sites be washed to control the possibility of distributing seeds of undesirable weed species. ALL does not state if CBM produced water is actually being used for this purpose at the present time.

5.2.5.3 Oil Field Use

Peacock (2002) describes a program in New Mexico through which produced water is treated to remove hydrogen sulfide and then is used in drilling operations. This beneficial reuse saves more than 4 million bbl per year of local groundwater.

5.2.5.4 Use for Power Generation

In at least one case, produced water is used to supply water to make steam. About 360,000 bpd of produced water from a ChevronTexaco facility in central California is softened and sent to a cogeneration plant as a source of boiler feed water (Brost 2002).

Another potential use of produced water is cooling water. The electric power industry is the second largest user of freshwater in the United States, making up 38% of all freshwater withdrawn, or 150 billion gallons per day (USGS 1998). Conventional surface and ground water sources are no longer sufficient to meet increasing power plant needs in many parts of the country. Produced water represents a large-volume source of water that could potentially serve as make-up water for a power plant. In August 2003, DOE/NETL announced that it had awarded a contract to a group of researchers led by the Electric Power Research Institute to study the feasibility of using water produced from CBM production to meet up to 25% of the cooling water needs at the San Juan Generating Station in northwestern New Mexico. The researchers will evaluate the quality, quantity, and location of the produced water. They will also evaluate the existing produced water collection, transportation, and treatment systems for possible use in

delivering cooling water to the generating station. The results are expected in about two years.
Argonne National Laboratory recently completed a study that evaluates the use of another alternative type of water supply for power plant cooling (Veil et al. 2003). Although that study considers underground pools formed in abandoned coal mines, many of the report's discussions concerning water quality, water quantity, and mode of operation are relevant for using produced water as a cooling source.

5.2.5.5 Fire Control

Fires often break out during the driest portions of the year and in areas experiencing drought conditions. In many cases, only limited surface and ground water resources are available for fire fighting in these areas. Although application of large volumes of saline produced water can have an impact on soils, this impact is far less devastating than a large fire. ALL (2003) reports that firefighters near Durango, Colorado, used CBM produced water impoundments as sources of water to fill air tankers (helicopters that spray water onto fires) during the summer of 2002.

5.2.6 Other Uses

When water is scarce, its value increases. In water-poor areas, it may be cost-effective to treat produced water for use in many applications. It is likely that the range of potential uses will be expanded in the future. This is clearly an area where additional research could be fruitful.

5.3 Water Disposal Options

Ideally, operators will find cost-effective produced water management approaches that employ water minimization, recycling, or reuse. However, much of the world's produced water is not managed in those ways. Instead, it is disposed of through either discharge to surface water bodies or by underground injection. Although there certainly are exceptions, the following premises generally apply:

- Most U.S. onshore oil and natural gas well operators inject their produced water for either enhanced recovery or for disposal. To a large extent, this is necessary because discharge from most onshore wells is prohibited.

- Many U.S. CBM well operators try to discharge produced water to surface water bodies if they can obtain permission to do so. Section 5.2 outlined many ways in which CBM water can be reused. Future requirements to treat CBM water to meet more restrictive discharge standards may change the mix of options used.

- Most U.S. offshore operators discharge produced water to the ocean if they are permitted to do so. Offshore produced water is also typically discharged in other parts of the world. Not surprisingly, different countries employ different discharge standards. A small percentage of offshore produced water is used for enhanced recovery operations.

Occasionally disposal of untreated produced water is possible. In most cases, however, it is necessary to treat the produced water first. The type and extent of treatment are determined by a variety of factors:

- Where the water is going (e.g., freshwater surface water body, ocean, ground),
- The applicable regulatory requirements and allowable options,
- The cost to transport and treat the water,
- Site-specific factors (e.g., climate, availability of infrastructure),
- The potential for long-term liability, and
- A company's familiarity with or preference for specific options.

The remainder of this section describes different types of injection and discharge situations and the treatment technologies that are typically used before the produced water can be disposed of in those ways.

5.3.1 Separation of Oil, Gas, and Water

When reservoir fluids are produced to the surface, it is first necessary to segregate the oil, gas, and water into separate streams to maximize salable product. This is typically accomplished by gravity separation in a horizontal or vertical separator. A common type of separator is known as a free-water knockout tank. The gas stream is first removed. Historically, gas was often burned (flared) or, at many wells, it was provided to the landowner for domestic use. Today, the gas is often collected and sent to market where gathering lines are available. The marketable gas is generally treated to meet pipeline-quality standards at a gas processing plant.

The separated oil stream may contain some water, and the water stream may contain additional dissolved hydrocarbons or emulsified oil. These generally cannot be removed through basic gravity separation and require additional treatment. One common oil field treatment method used to break emulsions is the application of heat generated by burning gas and passing the hot exhaust gas through a pipe running through the middle of a tank known as a heater-treater. This treatment helps to break emulsions, thereby allowing gravity separation to take place. Other approaches that are used to break emulsions involve electrostatic precipitation and emulsion-breaking chemicals (demulsifiers).

At some point, the oil is sent to market and the water is left for management or disposal. The next treatment steps, if needed, are dictated by the intended fate of the water. The next several sections describe some of the disposal modes and treatment processes that can be used to manage water that will be injected or discharged. Within these two broad categories, further subdivision is necessary based on the pollutants of concern for the environment into which the water will be disposed of.

5.3.2 Treatment before Injection

It is important to ensure that the water being injected is compatible with the formations receiving the water, to prevent premature plugging of the formation or other damage to equipment. It may be necessary to treat the water to control excessive solids, dissolved oil, corrosion, chemical reactions, or growth of microbes.

Solids are usually treated by gravity settling or filtration. Reynolds (2003) reports that a common rule of thumb for solids control is that all particulate matter larger than one-third the average pore-throat size of the receiving formation should be removed.

Residual amounts of oil in the produced water not only represent lost profit for producers but also can contribute to plugging of formations receiving the injectate. Various treatment chemicals are available to break emulsions or make dissolved oil more amenable to oil removal treatment.

Corrosion can be exacerbated by various dissolved gases, primarily oxygen, carbon dioxide, and hydrogen sulfide. Oxygen scavengers and other treatment chemicals are available to minimize levels of undesired dissolved gases.

The water chemistry of a produced water sample is not necessarily the same as that of the formation that will receive the injected water. Various substances dissolved in produced water may react with the rock or other fluids in the receiving formation and have undesired consequences. It is important to analyze the constituents of the produced water before beginning a water flood operation to avoid chemical reactions that may form precipitates. If necessary, treatment chemicals can minimize undesired reactions.

Bacteria, algae, and fungi can be present in produced water or can be introduced during water handling processes at the surface. These are generally controlled by adding biocides or by filtration.

5.3.3 Onshore Wells

5.3.3.1 Discharges under the Agricultural and Wildlife Water Use Subcategory

Little information is available on the treatment methods used before discharging produced water from oil and conventional gas wells under this subcategory.

5.3.3.2 Discharges from CBM Operations

Some CBM water is clean enough that it can be discharged without treatment. Other produced water is bubbled over rocks to aerate it and allow iron to precipitate out before it is discharged to a stream. When more rigorous treatment is required, operators have sometimes used reverse osmosis. Reverse osmosis is an effective water pollution treatment method that passes a dirty water stream across a semipermeable membrane. Fresh water diffuses through the membrane, leaving behind a concentrated waste stream. Reverse osmosis has only been used sparingly in the hydrocarbon-production field because it is expensive and the membranes can be fouled or damaged by constituents in raw produced water. Often, produced water must be pretreated before it can be treated with reverse osmosis. Lee et al. (2002) describe several pretreatment methods that are being tested at Sandia National Laboratories and the Petroleum Recovery Research Center at New Mexico Tech. These include chemical treatment, filtration, biological treatment, polymeric absorbents, and macroporous polymer extraction.

Other researchers have been investigating the use of natural clays for ion-exchange (Janks and Cadena 1992) or electrostatic precipitation (Atlas 2002; Welgemoed 2002). ALL (2003) provides short descriptions of these and several other water treatment technologies that are either already being used or may be applicable for treating CBM water. That study summarizes nine types of treatment processes and indicates the relative effectiveness of reducing different produced water contaminants.

5.3.3.3 Discharges from Stripper Wells

Low oil production volumes do not contribute much income to stripper well operators. Consequently, they are not able to undertake complicated or expensive treatment. Adewumi et al. (1992) describe a simple, low-cost system used for produced water treatment in Pennsylvania. It involves separation, pH adjustment, aeration, solids separation, and filtration. DOE has funded a Stripper Well Consortium through Pennsylvania State University that supports research on ways to produce stripper wells and manage the water most cost-effectively. For more information on specific projects, see the Stripper Well Consortium's website at: http://www.energy.psu.edu/swc/index.html.

5.3.3.4 Other Onshore Options

Rather than dealing with treatment of water from numerous small-volume wells, many stripper-well or other onshore operators pay a contractor to remove the water for offsite disposal. This is generally accomplished by having a pump truck visit the well locations periodically and remove the accumulated water. The truck hauls the water to a disposal facility. Veil (1997b) compiled information on offsite commercial facilities that accepted produced water for disposal. Those facilities were located in nine oil-producing states. The predominant disposal method was injection, although some facilities in arid areas relied on evaporation pits. Several companies in Pennsylvania and one company in Wyoming treated the produced water and then discharged it to a stream via NPDES permit or to a municipal sewer system.

Boysen et al. (2002) describe numerous approaches for managing produced water in the Rocky Mountain region. Some involve recycle and reuse, but one that is appropriate for discussion in this section is evaporation by portable misting towers. These are essentially spray nozzles at the top of vertical pipes. The water is sprayed into the air and evaporates before hitting the ground. Boysen et al. (2002) report that one operator was able to evaporate at a rate of 30 gallons per minute during the warm, dry Wyoming summer.

Constructed wetlands can be used to treat produced water (Myers 2000). Over the past few years, researchers have studied the feasibility of treating produced water using constructed wetlands at the Rocky Mountain Oilfield Testing Center (Jackson and Myers 2003). After two years of a three-year study, the authors noted that the wetlands improved water quality, good plant growth was observed, and wetland functions were similar to those found in natural wetlands. The treatment performance of the wetlands was affected by temperature.

Boysen et al. (1996) describe an innovative process that relies on natural freezing and thawing coupled with evaporation to treat produced water (Freeze/Thaw Evaporation). This results in a concentrated brine stream and a clean water stream. Unless artificial refrigeration is employed, this process is limited to cold climates during cold times of the year.

5.3.4 Offshore Wells

The large majority of offshore produced water is discharged to the ocean. The primary pollutant of concern is oil and grease, which is regulated by EPA's national ELGs for offshore activities and is made part of all U.S. offshore discharge permits. Unlike onshore discharges, for which salinity is a key consideration, offshore discharges need not worry about that parameter. Depending on the EPA region, operators must meet various other discharge limitations, including restrictions on flow rate, toxicity testing, and monitoring for several toxic metals, organics, and naturally occurring radioactive material (NORM). Most of the treatment technology for offshore produced water is geared toward removing oil and grease. The next section discusses some important issues concerning oil and grease, how it is measured, and the influence of measurement on permit compliance.

5.3.4.1 What Is Oil and Grease?

Oil and grease is not a single chemical compound, but a measure of many different types of organic materials that respond to a particular analytical procedure. Different analytical methods will measure different organic fractions and compounds. Therefore, the specific analytical method used is important in determining the magnitude of an oil and grease measurement. This is particularly important because of the phasing out of the use of Freon-113 as an extraction solvent (EPA Method 413.1) over the past decade. That longstanding standard-approved method (which was used to collect all the effluent data used in establishing the statistically derived ELGs limit for oil and grease) has been replaced by EPA Method 1664, which uses n-hexane as the extraction solvent. Raia and Caudle (1999) report on a study sponsored by the American Petroleum Institute to compare the results of the two methods. The standard deviations of the results were in the same order of magnitude or larger than the means, thereby making it difficult to determine if the results are comparable. Most of the samples showed higher values when measured by the new method. This raises some concern over compliance. For example, if the new method measures 44 mg/L while the old method measures 40 mg/L for the same sample, this is the difference between compliance and noncompliance with the maximum ELGs limit for oil and grease of 42 mg/L.

Subsequent papers have debated the use of alternative types of solvents (for example Keathley and Konrad 2000; Wilks 2001). These are highly technical chemical discourses that are outside of the scope of this white paper. Nevertheless, analytical measurement continues to be an important topic. It is also worth noting that the standard oil and grease method approved for measuring North Sea discharges is different from the two methods mentioned above (Yang and Tulloch 2003).

Although there are many different oil and grease methods, only Method 1664 is approved for official NPDES compliance purposes. Some of the other methods may be quicker or less expensive. Some of them can be utilized in continuous on-line devices for process monitoring purposes, but those other methods cannot be substituted for the official permit samples.

A second point is that not all produced waters contain the same constituents even if they have the same oil and grease content. Oil and grease is made up of at least three forms:

- Free oil (this is in the form of large droplets that are readily removable by gravity separation methods),
- Dispersed oil (this is in the form of small droplets that are more difficult to remove), and
- Dissolved oil (these are hydrocarbons and other similar materials that are dissolved in the water stream; they are often challenging to remove).

For example, take two untreated produced water samples, both of which contain 100 mg/L of oil and grease. Produced water A has primarily free oil whereas produced water B has primarily dissolved oil. In order to meet the maximum discharge limit of 42 mg/L, the types of treatment processes and the cost of those processes would be vastly different. This is the challenge faced by offshore operators. McFarlane et al. (2002) report on a collaborative project between Oak Ridge National Laboratory and several major oil companies to better characterize and predict the types of water-soluble organics that are present in offshore produced water.

With this background, the following sections describe different treatment processes that have been used to treat offshore produced water.

5.3.4.2 Offshore Treatment Technology

Offshore produced water treatment can be challenging because offshore facilities do not have abundant space or weight capacity for treatment equipment. In addition, offshore environments are remote and typically harsh; equipment and processes that operate there must be designed for those environments. For the past 13 years, a group of offshore water specialists has gathered in Houston each January for the Produced Water Seminar. This gathering is informal yet highly informative for learning about new produced water management technologies and analytical and regulatory issues. Many of the references cited in this section are papers presented at the seminars. In recent years, this group has formed the Produced Water Society. Information about the society and ordering seminar papers is available at www.producedwatersociety.net. Other organizations in the United States and Europe have also held useful meetings focused on offshore produced water.

Many authors have described programs for produced water treatment at offshore facilities (for example, Favret and Doucet 1999; Tyrie 2000; Caudle 2000; Robinson 2003; Greenwood 2003). The water is first pretreated by skimmers or other basic separation equipment to remove oil droplets greater than 100 microns in size. Devices to promote coalescence of small oil droplets into larger droplets may be used here, too. Tulloch (2003) describes a pre-coalescer device that consists of a bundle of oleophilic fibers placed inside of a flow line. The fibers serve to aggregate small oil droplets for easier downstream removal.

Next, the water receives primary treatment to remove additional free oil. The types of equipment used for primary treatment include liquid/liquid hydrocyclones, corrugated plate separators, and centrifuges. Faucher and Sellman (1998) describe the use of centrifuges to remove oil and solids.

Secondary treatment to remove emulsified oil and suspended solids is the next stage of treatment. Flotation cells, adsorption, ion exchange, filtration, and organic extraction are used in secondary treatment.

Cline (2000) offers a useful overview of flotation technology. The principle of flotation is to create many very small air or gas bubbles that rise through a vessel filled with produced water and carry small oil droplets and solids particles to the surface of the vessel where they can be skimmed off. Chemicals may be added to help break emulsions. Cline reviews the flotation equipment offered by several different vendors, and discusses efficiencies, advantages, and disadvantages. Jahnsen and Vik (2003) report on North Sea trials of a compact flotation unit that combines separation, gas flotation, and centrifugal separation in the same device. Several years of trials showed very low oil and grease in the effluent.

There are several types of filtration devices used for produced water treatment (Tyrie 1998). Some utilize membrane filters that are often deployed as cartridges, which can be replaced when filled. Nicolaisen and Lien (2003) provide an overview of membrane filter applications and suggest that membranes in the ultrafiltration size range are appropriate for offshore produced water. Nanofiltration and reverse osmosis membranes have smaller pore size and can be deployed downstream of the ultrafiltration filters, if needed. Some operators use media filters that are backwashed periodically. Kozar (2000) reports on filters filled with crushed walnut shells. Brock et al. (2003) describes another type of media filter that features a radial flow design to allow on-line cleaning of the media without having to stop for backwashing.

Meijer and Kuijvenhoven (2002) describe an approach to removing dissolved organics from offshore produced water using fluid extraction. The process, known as Macro Porous Polymer Extraction (MPPE), takes place in the pores of polymer particles, and the particles can be regenerated in place with low-pressure steam. Grini et al. (2003) describe trials using the MPPE and another type of extraction process, the CTour, which utilizes gas condensate as the extraction fluid.

Frankiewicz (2001) presents an overview of factors that lead to poor produced water quality. His presentation describes 12 common causes and groups them into 4 main categories:

- Presence of inorganic or organic solids,
- Excessive or highly varying fluid flow rates,
- Gas breakout or slugging in or into process equipment, and
- Improper chemical treatment programs.

Frankiewicz (2001) provides a useful table that helps in selecting treatment equipment based on the size of the particles that need to be removed. That information is shown in Table 5-1.

TABLE 5-1 Particle Size Removal Capabilities

Technology	Removes Particles Greater Than Size Indicated (in microns)
API gravity separator	150
Corrugated plate separator	40
Induced gas flotation without chemical addition	25
Induced gas flotation with chemical addition	3-5
Hydrocyclone	10-15
Mesh coalescer	5
Media filter	5
Centrifuge	2
Membrane filter	0.01

Source: Frankiewicz (2001).

6 The Cost of Produced Water Management

There are many sources of site-specific costs in the literature. For the purposes of this white paper, it is impractical to list hundreds of single-cost values from different references. Instead, this chapter discusses the components that contribute to water management costs, and gives a few examples from references that report data from multiple sources.

It is well understood that for conventional oil and gas production, the volume of water produced by a well and a field will increase over time and the volume of oil and gas produced will decline. At some time, the revenue from the oil and gas is not sufficient to cover the costs of operation (a growing portion of those costs will be water management) and the well will be shut in.

6.1 Components of Cost

Produced water management is generally expensive, regardless of the cost/barrel, because of the large volumes of water that must be lifted to the surface, separated from the petroleum product, treated (usually), and then injected or disposed of. The previous chapter outlined a wide array of options for managing wastes. These all are driven by minimizing some or all of the individual cost components. The following list includes many of the components that can contribute to overall costs:

- Site preparation
- Pumping
- Electricity
- Treatment equipment
- Storage equipment
- Management of residuals removed or generated during treatment
- Piping
- Maintenance
- Chemicals
- In-house personnel and outside consultants
- Permitting
- Injection
- Monitoring and reporting
- Transportation
- Down time due to component failure or repair
- Clean up of spills
- Other long-term liability.

As an example of how a large, multinational company looks at cost, Shell's cost distribution is reported by Khatib and Verbeek (2003) as pumping (27.5%), deoiling (21%), lifting (17%), separation (15%), filtration (14%), and injecting (5%).

6.2 Cost Rates ($/bbl)

The cost of managing produced water after it is already lifted to the surface and separated from the oil or gas product can range from less than $0.01 to at least several dollars per barrel. The following sections offer several examples of costs.

6.3 Offsite Commercial Disposal Costs

In 1997, Argonne National Laboratory compiled information on costs charged by offsite commercial disposal companies to accept produced water, rain water, and other "water-type wastes" (Veil 1997b). The reported costs are assumed to be lower than or comparable to the costs available for onsite management by the operators themselves. Costs for disposing of these wastes are listed in Table 6-1. Overall, disposal costs are $0.01-$8/bbl, although most are $0.25-$1.50/bbl. The highest cost, $8/bbl, is charged at one facility in Wyoming for particularly dirty wastes that need pretreatment before injection. The same facility charges as low as $0.75/bbl for cleaner wastes. The lowest cost is charged by a nonprofit facility in California that operates as a cooperative for several member users. These costs are solely disposal costs; the cost of transporting the water to the facilities is additional.

By far, the most common commercial disposal method for produced water is injection. The range of costs for injection is the same as that described in the previous paragraph. Ten companies in Wyoming, five companies in Utah, and four companies in New Mexico use evaporation to dispose of produced water. The cost is $0.25-$2.50/bbl. Another New Mexico company uses a combination of evaporation and injection, at a cost of $0.69/bbl. The nonprofit California company described above, which also uses a combination of evaporation and injection, charges $0.01-$0.09/bbl.

Six companies in Pennsylvania utilize surface water discharge options. Three of these companies treat and blend produced water and discharge it directly through an NPDES permit. Another company treats the waste and discharges it to a sanitary sewer that leads to a municipal wastewater treatment plant. They charge $1-$2.10/bbl. Two municipal wastewater treatment plants accept water-type wastes but not produced water. They charge $0.65-$1.50/bbl. Another company in Pennsylvania spreads produced water on roads in the summer and discharges to a municipal wastewater treatment plant in the winter. This company charges $1.30-4.20/bbl.

6.4 Costs for Rocky Mountain Region Operators

Jackson and Myers (2002, 2003) provide cost estimates for many produced water disposal methods that might be used in the states of Wyoming, Colorado, Utah, and New Mexico. Table 5-2 is based on data from that paper. The majority of their reported costs range from $0.01/bbl for surface discharge or evaporation to more than $5.50/bbl for commercial waste haulers. The magnitude of the cost depends on the water chemistry, the regulatory requirements imposed, and the amount of treatment needed.

Boysen et al. (2002) summarize the results of many interviews with operators in the San Juan, Powder River, and Greater Green River Basins concerning water management and disposal costs. In the Power River Basin, most CBM operators reported water management costs ranging from $0.01/bbl to $2/bbl. The low end of that range covered the costs for a pipeline and impoundment while the upper end of the range represented the cost of a commercial hauling company. Costs were somewhat different for the San Juan Basin, based on three separate surveys conducted in 1998 ($0.04/bbl to $1.88/bbl), early 2001 ($0.30/bbl to $2.80/bbl), and late 2001 ($0.50/bbl to $4.20/bbl). Note that different groups of operators were interviewed for the two 2001 surveys.

Surveys were conducted in 1998 and 2001 in the Greater Green River Basin. The 1998 results ranged from $0.40/bbl to $4/bbl, and the 2001 results were even higher, ranging from $0.50/bbl to $10/bbl.

6.5 Perspective of an International Oil Company

Khatib and Verbeek (2003) estimate that Shell Oil's worldwide produced water management costs are more than $400 million per year. This translates to a cost rate of from $0.02/bbl to as much as $2.50/bbl, depending on the location and volume. Khatib and Verbeek suggest that the average cost for produced water management in the U.S. is about $0.10/bbl.

TABLE 6-1 Disposal Costs for Produced Water at Offsite Commercial Facilities

State	Number of Facilities Using This Process	Type of Disposal Process	Cost[a]
CA	1	Evaporation/injection	\$0.01-\$0.09/bbl
KY	1	Injection	\$1/bbl
LA	23	Injection	\$0.20-\$4.50/bbl
NM	4	Evaporation	\$0.25-\$0.81/bbl
NM	1	Evaporation/injection	\$0.69/bbl
NM	1	Injection	\$0.69/bbl
OK	1	Injection	\$0.30/bbl
PA	3	Treat/discharge	\$1-\$2.10/bbl
PA	1	Treat/POTW	\$1.25-\$1.80/bbl
PA	1	POTW/road spread	\$1.30-\$4.20/bbl
PA	2	POTW	\$0.65-\$1.50/bbl
TX	9	Injection	\$0.23-\$4.50/bbl
UT	5	Evaporation	\$0.50-\$0.75/bbl
WY	10	Evaporation	\$0.50- \$2.50/bbl
WY	1	Treat/injection or discharge	\$0.96/bbl
WY	3	Injection	\$0.60-\$8.00/bbl

[a] Costs are those reported by disposal company operators in 1997.
Source: Veil (1997b).

TABLE 6-2 Produced Water Management Costs

Management Option	Estimated Cost ($/bbl)
Surface discharge	0.01-0.80
Secondary recovery	0.05-1.25
Shallow reinjection	0.10-1.33
Evaporation pits	0.01-0.80
Commercial water hauling	1.00-5.50
Disposal wells	0.05-2.65
Freeze-thaw evaporation	2.65-5.00
Evaporation pits and flowlines	1.00-1.75
Constructed wetlands	0.001-2.00
Electrodialysis	0.02-0.64
Induced air flotation for deoiling	0.05
Anoxic/aerobic granular activated carbon	0.083

Source: Jackson and Myers (2002, 2003).

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