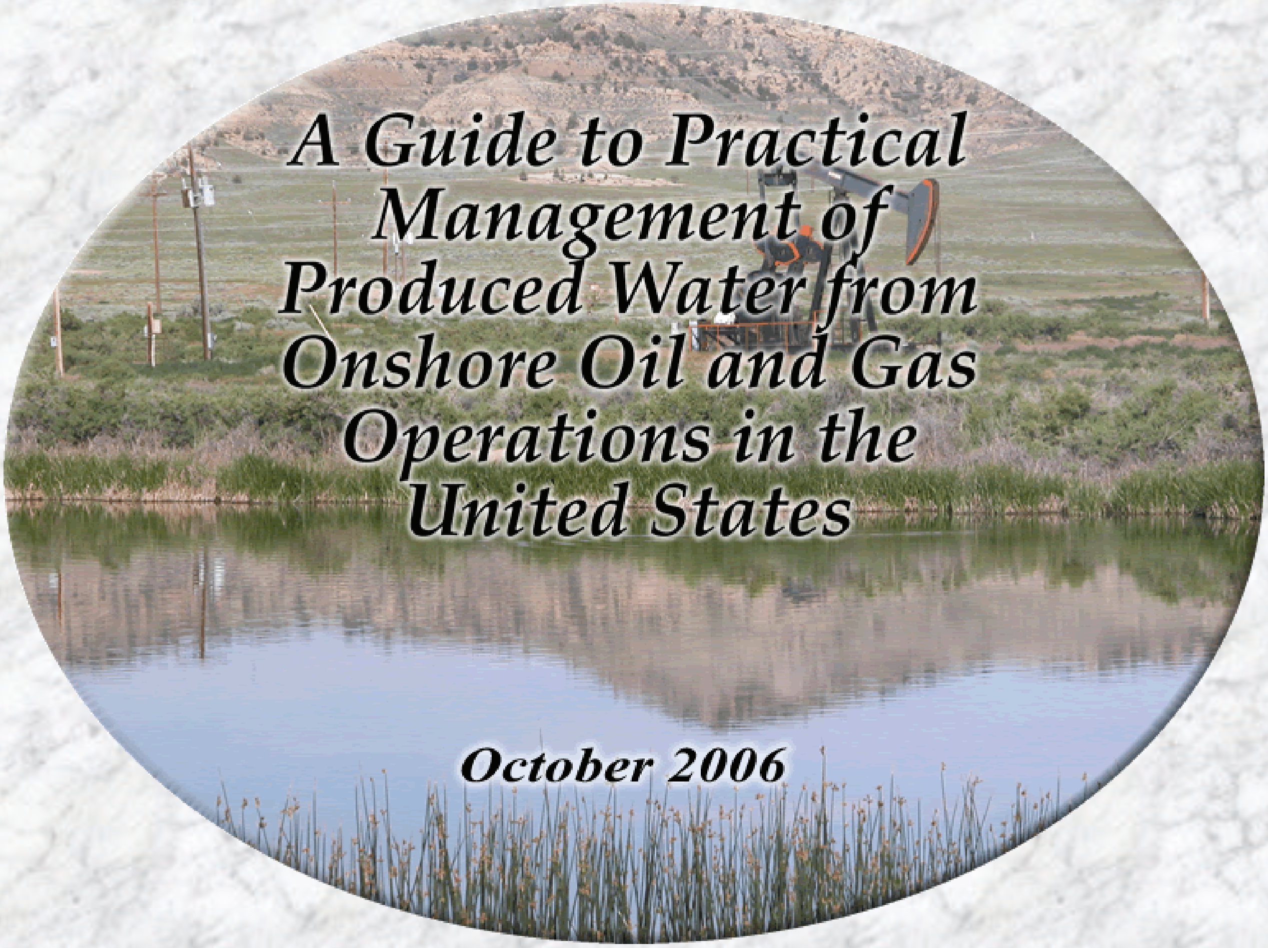
A Guide to Practical Management of Produced Water from Onshore Oil and Gas Operations in the United States

October 2006



Prepared For:
U.S. Department of Energy
National Petroleum Technology Office

Prepared By:
Interstate Oil and Gas Compact Commission
and
ALL Consulting

In Cooperation with:

Montana Board of Oil & Gas Conservation
Wyoming Oil and Gas Conservation Commission
Alaska Oil and Gas Conservation Commission
Oklahoma Corporation Commission
Kansas Corporation Commission

ACKNOWLEDGEMENTS

This project was funded by the National Energy Technology Laboratory (NETL) of the U.S. Department of Energy (DOE) program ***"Focused Research in Federal Lands Access and Produced Water Management in Oil and Gas Exploration and Production"***. The project was developed under the ***Area of Interest 2: Produced Water Management Practices,*** and ***Topic 3: Produced Water Best Management Practices***.

The Interstate Oil and Gas Compact Commission (IOGCC) and ALL Consulting (ALL) conducted this study as co-researchers in cooperation with the oil and gas agencies of Alaska (Alaska Oil and Gas Conservation Commission), Montana (Montana Board of Oil and Gas Conservation), Wyoming (Wyoming Oil and Gas Conservation Commission), Kansas (Kansas Corporation Commission), and Oklahoma (Oklahoma Corporation Commission).

The effort was overseen by NETL's, National Petroleum Technology Office in Tulsa, Oklahoma. The National Petroleum Technology Office project manager for this effort was Mr. John Ford. The research team also extends its appreciation to those companies operating in the Powder River, Big Horn, Williston, North Central Montana, Anadarko, Arkoma, Alaska North Slope, Cook Inlet, Permian and Fort Worth Basins, and the staffs of the Department of the Interior, Environmental Protection Agency, and the various state agencies who provided the technical input and assistance that enabled DOE to improve the scope and quality of the analysis.

DE-PS26-04NT15460-02

DISCLAIMER

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

ACRONYM LIST

AC	Alternating Current
API	American Petroleum Institute
ARI	Advanced Resource International
ASR	Aquifer Storage and Recovery
Ba	Barium
BAT	Best Available Technology
BCT	Best Conventional Pollutant Control Technology
BER	Board of Environmental Review
BLM	Bureau of Land Management
BOPD	Barrels of Oil Per Day
BPT	Best Practicable Control Technology
BTEX	Benzene, Tolulene, Ethylbenzene, Xylene
Ca	Calcium
CaCO3	Calcium Carbonate
CAFO	Concentrated Animal Feeding Operations
CBNG	Coal Bed Natural Gas
CDT	Capacitive Deionization Technology
Cl	Chloride
COOH	Carboxylic Acid
CWA	Clean Water Act
DC	Direct Current
DOE	Department of Energy
DOWS	Downhole Oil/Water Separation Technology
ECA	Electrochemical Activiation
ED	Electrodialysis
EDI	Electro-deionization
EDR	Électrodialysis Reversal
EIA	United States Energy Information Administration
ESPs	Electric Submersible Pumps
FTE®	Freeze Thaw Evaporation
GAC	Granular Activated Carbon
GTI	Gas Technology Institute
GWPC	Ground Water Protection Council
H+	Hydronium
HCO3	Bicarbonate
HEED™	High Efficiency Electodialysis
HERO™	High Efficiency Reverse Osmosis
HSWA	Hazardous & Solid Waste Amendments
HUC	Hydrologic Unit Code
HTC	Hydrotalcite
IID	Class II Injection Disposal Wells
IIR	Class II Injection Recovery Wells
IOGCC	Interstate Oil and Gas Compact Commission
kg/m2h	kilograms per meters squared-hour
KSU	Kansas State University
MBOGC	Montana Board of Oil and Gas Conservation

MCF	Thousand Cubic Feet
MMCF	Million Cubic Feet
MDEQ	Montana Department of Environmental Quality
MF	Microfiltration
Mg	Magnesium
MPDES	Montana Pollutant Discharge Elimination System
MWCO	Molecular Weight Cutoff
Na	Sodium
NaCl	Sodium Chloride
NaOH	Concentrated Sodium Hydroxide
NETL	National Energy Technology Laboratory
NF	Nanofiltration
NO3	Nitrate
NORM	Naturally Occurring Radioactive Materials
NPDES	National Pollutant Discharge Elimination System
NPR-3	Naval Petroleum Reserve No. 3
NRCS	National Resource Conservation Service
NSPS	New Source Performance Standards
PAC	Project Advisory Council
PCPs	Progressive Cavity Pumps
POD	Project Plan of Development
POTWs	Publicly Owned Treatment Works
PRRC	Petroleum Recovery and Research Center
ppm	Parts Per Million
psi	Pounds Per Square Inch
RCCD	Reverse Circulation Center Discharge
RCRA	Resource Conservation and Recovery Act
RO	Reverse Osmosis
RMOTC	Rocky Mountain Oilfield Testing Center
RSE	Rapid Spray Evaporation™
SAC	Strong Acid Cation
SAR	Sodium Absorption Radio
SDI	Subsurface Drip Irrigation
SDWA	Safe Drinking Water Act
SEO	State Engineer's Office
SNL	Sandia National Laboratory
SO3H	Sufonic Acid Group
TCEQ	Texas Commission of Environmental Quality
TCF	trillion cubic feet
TDS	Total Dissolved Solids
TMDL	Total Maximum Daily Load
TPH	Total Petroleum Hydrocarbons
UBD	Underbalanced Drilling
UF	Ultrafiltration
UIC	Underground Injection Control
USDW	Underground Sources of Drinking Water
USEPA	United States Environmental Protection Agency
USGS	United States Geological Survey

VSEP	Vibratory Shear Enhanced Processing
WAC	Weak Acid Cation
WDEQ	Wyoming Department of Environmental Quality
WGR	Water to Gas Ratios
WGS	Wyoming Geological Survey
WOGCC	Wyoming Oil and Gas Conservation Commission
WOR	Water to Oil Ratios
WWQRR	Wyoming Water Quality Rules and Regulations

SECTION 1.0 INTRODUCTION

The make-up of the oil and gas industry in the United States today is different than it was 25 years ago. The domestic oil and gas sector is no longer dominated by large oil and gas companies. Currently, 65 percent of the natural gas and 40 percent of the oil produced in the United States is produced by small independent oil and gas companies which typically employ no more than 10 full-time employees (DOE, 2006 and API, 2006). This core of independent producers might not have the financial aptitude to conduct the research required to make the technological advances necessary to continue to economically produce domestic energy resources, but the domestic oil and gas industry cannot sustain itself without the critical development of new technologies. This is a major concern that is addressed by the United States Department of Energy (DOE) National Energy Technology Laboratory (NETL) through research grants targeted to fill this void.

Along with Congress, President George W. Bush set forth an Energy Bill in 2005 that focuses on increasing our nation's ability to be more reliant on domestic sources of energy and less reliant on foreign oil and gas. President Bush stated the following in an address to the Sandia National Laboratory in Albuquerque, NM:

> *"Meeting the needs of our growing economy also means expanding our domestic production of oil and natural gas, which are vital fuels for transportation and electricity and manufacturing."*

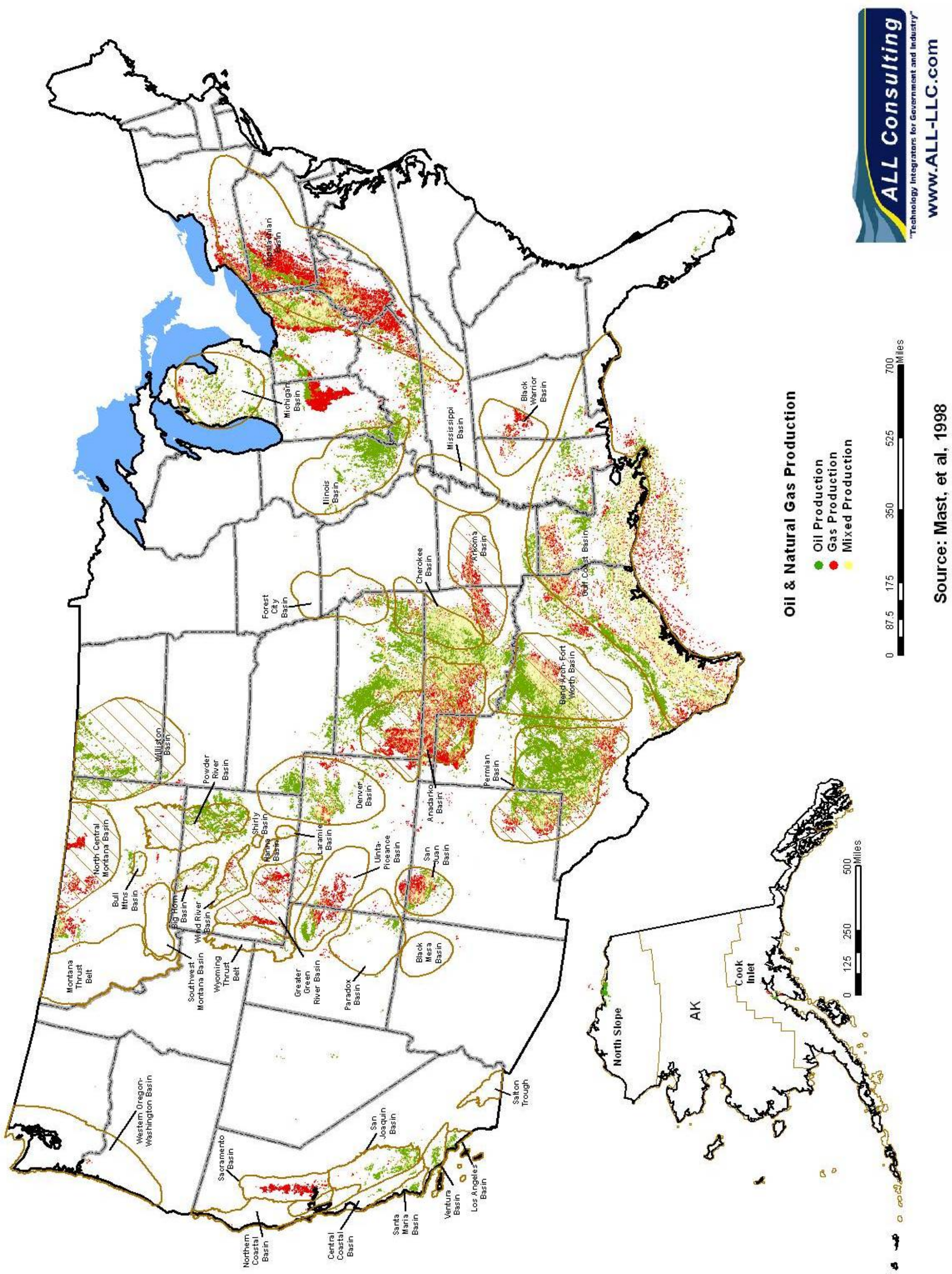
To meet the goals of the President, NETL has focused research funding to develop oil and natural gas technologies and technology transfer projects to enhance the ability of domestic producers to extract energy resources while continuing to protect the environment (DOE, 2006). Produced water management is widely recognized as a core issue that may be a barrier to continued economical and environmentally sensitive oil and gas development in the United States. Figure 1.1 is a map of the United States showing the distribution of oil and natural gas producing regions across the country. The distribution of producing areas is not uniform across the United States, as there are distinct regions where oil and gas production occurs. These regions include, but are not limited to: the Mid-Continent, Gulf Coast, the Rocky Mountain Region, Appalachian Mountain Region, California, and Alaska. The increased demand for energy resources in the United States has caused increases in oil and gas prices, which have led to a renewed interest in previously uneconomical or marginally economic areas. These once marginal, or high risk, plays include tertiary recovery projects, continuous reservoirs and other conventional and unconventional oil and gas plays that often have high water to oil ratios (WOR) and/or high water to gas ratios (WGR). Many of these new unconventional plays are under development and have resulted in a broad spectrum of new produced water management challenges.

Various technological advances such as improved water reduction procedures that lower the WOR and/or WGR at the wellhead and cutting edge produced water management alternatives that can treat large volumes of marginal quality water to beneficial use standards are constantly being developed. The benefit of these technological advances typically results in extending the productive life of a well, or in some cases an entire field. The benefits are not likely to be attained, however, if the technological advances are not widely available to the public and industry via technology transfer.

Advanced technology also might allow development of resources that were not previously economically viable, such as unconventional natural gas (e.g., coal bed natural gas, oil shales, tight sands, regionally extensive-highly permeable reservoirs) and mature oil and gas fields ("stripper" wells). More than 75 percent (423,000 out of 555,000) of our nation's oil wells are classified as "stripper" wells, or wells that produce less than 10 barrels per day (BOPD), or 60 million cubic feet (MMCF) of gas per day (IOGCC, 2005). On average, these stripper wells produce about 2 BOPD, but collectively, they account for nearly 15 percent of domestic oil production (API, 2006). The WOR on stripper wells can be as high as 40 barrels of water to 1 barrel of oil produced (API, 2006). The economic and environmental benefit to lowering the WOR on stripper wells is wide reaching and can affect the industry on a nationwide basis.

Water produced during oil and gas operations constitutes the industry's most prolific product. By volume, water production represents approximately 98 percent of the non-energy related fluids produced from oil and gas operations, yielding approximately 14 billion barrels of water annually (Veil, 2004). When compared to the annual oil (1.9 billion barrels, EIA, 2006) and gas (23.9 TCF, EIA, 2006) production across the United States, the argument could be made that the oil and gas produced would be more appropriately identified as a byproduct to production of water.

Figure 1.1 Oil and Natural Gas Production in the United States



Source: Mast, et al, 1998 and ALL Consulting, 2006

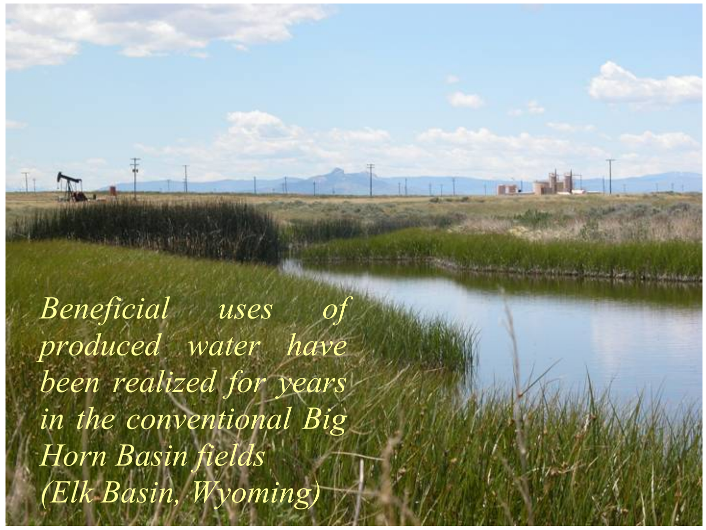
In recent years, the oil and gas industry's view on water production has changed dramatically. Produced water has historically been viewed by most as a waste stream that must simply be disposed of in the most cost efficient and environmentally sound manner possible. This outdated viewpoint has and is continuing to evolve in the upstream energy industry and in the eyes of many other stakeholders (e.g., landowners, government regulatory agencies, and non-governmental organizations). The evolving view on produced water has stemmed from many issues the industry and our nation have faced, including lengthy droughts in areas of the western United States; water shortages for power generation; and many other environmental challenges facing our nation. This evolving viewpoint has led some to the belief that produced water is not a waste stream at all, rather it has created a desire to beneficially use the water opposed to simply disposing of it as a waste (ALL, 2006).

Adding gypsum to produced water prior to discharge to meet discharge permit criteria (PRB, Wyoming)

The large volumes of high quality water produced today have resulted in operators looking for alternative means of managing this water in a cost-effective and environmentally safe manner. A common misconception is that there is one produced water management practice that will work throughout the United States. Quite the opposite is true. In fact, produced water management practices vary widely across the United States and in some instances across a single oil and gas field. A few examples of produced water management practices currently in use are:

- **Water Treatment**: Water treatment (purification or composition adjustment) technologies are advancing and expanding into oilfield use in many areas. The area that has led the drive to implement water treatment technologies is the coal bed natural gas development in the Powder River Basin located in northeastern Wyoming and southeastern Montana. Other areas have expanded the use of water treatment technologies for temperature correction, solids removal, oil and grease removal, and purification to facilitate drilling and stimulation.
- **Enhanced Recovery**: Produced water has long been used for enhanced oil recovery or even for pressure maintenance through waterflooding. The majority of injection wells used in the United States in association with the energy industry are used for enhanced recovery.
- **Deep Well Injection**: In some cases, oilfield wastes do not meet the criteria to be injected into a Class II injection well and must be disposed of via a Class I industrial or hazardous waste disposal well. For instance, reject water from some water treatment facilities is disposed of in Class I injection wells.
- **Sustainable Development Practices**: In some areas of the country, water is difficult to obtain and operators are forced to make the best overall use of the water produced. In these areas, operators store and save produced water for drilling activities, dust suppression, stimulation, clean-up, and other uses to avoid acquiring water from substantial distances.

- **Water Reduction**: Technology continues to play a tremendous role in natural gas and oil development. In some reservoirs, water production poses tremendous problems for economic production of hydrocarbons. Many alternatives have been and are continuing to be used more prolifically. Water reduction alternatives such as downhole oil/water separation technology (DOWS) have a great potential to save money and reduce the environmental impacts of managing produced water at the surface (Veil, et al. 1999).



Beneficial uses of produced water have been realized for years in the conventional Big Horn Basin fields (Elk Basin, Wyoming)

- **Beneficial Uses**: High quality water with a total dissolved solids (TDS) concentration of less than 10,000 parts per million (ppm) may be employed for an assortment of beneficial uses, providing recreational opportunities, drinking water for stock and wildlife, irrigation water in arid regions, and a supplemental source for municipal water supplies. In some basins, such as the Big Horn, in north-central Wyoming and south-central Montana, landowners have come to depend on the produced water for farming and ranching.

The above mentioned practices are discussed in more detail in Section 4, along with several other practices and water treatment alternatives that are currently being tested, researched, and implemented on pilot scale studies to further the potential for beneficial use of produced water that normally would be considered as marginal to poor quality.

Section 1.1 Purpose and Need

Industry operators and state regulators share two goals: to effectively and efficiently manage produced water while 1) remaining protective of the environment and 2) continuing to economically develop domestic energy resources. This document aids in achieving these goals by compiling various sources of data and providing an analysis for how the data can be used to create innovative produced water management solutions. The data include:

- **Produced Water Management Practices:** A catalogue of water management practices, treatment technologies, and water reduction techniques is presented for use as a reference of water management practices currently available to operators. Leading edge technologies that have not yet been widely applied are also identified and discussed. Operational parameters of each water management practice are identified as well.
- **Produced Water Quality**: The quality of produced water from various onshore oil and gas producing basins of the United States is presented in terms of TDS. TDS is a good indicator of salinity, which can be used to determine appropriate produced water management practices, because many practices might become uneconomical or impractical based on the salinity of the water. Case studies of water management

practices currently used to handle a wide range of water qualities in various basins are presented to provide examples of success stories and lessons learned.

- **Socio-economic Setting and Climate:** The ability to beneficially use water can be dependant on the socio-economic setting and the weather trends of the area from which it is produced. Arid areas with a high population density or areas highly dependant on agricultural activities to sustain their population are most likely to be interested in utilizing the produced water. Water quality data are geospatially presented along with average rainfall, evapotranspiration, and population density. The result is identification of areas of the United States where water management is considered of utmost importance because any beneficial use might improve the sustainability of that area.
- **Availability of Injection Zones:** The ability to economically inject produced water may dictate the feasibility of marginal wells with extremely high salinity water that has no redeemable beneficial use other than enhanced recovery. A statistical analysis of permitted injection wells and their disposal rates is presented on a state-by-state basis to identify areas where injection is most common.

The analyses of these datasets include technology transfer recommendations by matching the applicable water management practices to relevant basins of the United States that meet or exceed the critical operational parameters. While each state is responsible for regulating the produced water management techniques implemented in their state, this analysis may prove to be instrumental to state and federal regulators' decision-making process in regards to produced water regulations that are protective of the environment while avoiding economic impacts caused by the disruption of domestic oil and natural gas supply and delivery.

This Guidebook may be utilized by operators during the planning phase for determining produced water management options as they move into areas of the United States that might be unfamiliar to them. Operators also can take advantage of the technology transfer recommendations by evaluating alternative options for water management as they seek to maintain economic production from older fields that have progressed to higher WORs and WGRs. This Guidebook also provides operators with a valuable reference to lead them as they pursue unconventional oil and gas plays that can involve large volumes of produced water and unusually high WOR and/or WGRs.

Section 1.2 Overview of Research

This document contains the results of research conducted to provide an overview of current issues as they relate to produced water and produced water management. This research focused on developing inter-basin technology transfer recommendations based on the findings. The following list presents the topics researched and presented in this document:

- **Current and Emerging Trends:** Where available, researchers compiled production data from the 37 oil and gas producing states. Nationwide production trends associated with produced water were noted and documented to support the growing concern that annual domestic produced water volumes continue to rise as annual domestic oil and gas production volumes decline.
- **Existing and Emerging Regulations:** Researchers examined the applicable and relevant regulatory literature as it applies to produced water management of onshore oil and gas exploration and production sites. To expedite the process, the research team interviewed various state agencies that govern produced water issues of the oil and gas industry. Industry personnel also were interviewed in various states to determine what issues, if any, are relevant and germane to industry in terms of impacting the economic viability of oil and gas production. The Project Advisory Council (PAC) described in Section 1.3 was instrumental in identifying various regulatory issues and challenges that warranted further research.
- **Produced Water Management Alternatives:** Researchers examined various produced water management practices, water treatment technologies, and water reduction techniques to identify the operational requirements of each. Operational requirements may include water quality and quantity, environmental impacts, operational costs, applicability per resource type, regional setting, and basin statistics, among others. Strengths and weaknesses of the various management alternatives analyzed were noted and categorized for ease of technology transfer between regions of the United States.
- **Case Studies:** Several case studies were performed to gain further insight into produced water management alternatives in various basins. Industry personnel were interviewed as a part of the case study process, and the research team documented success stories and lessons learned.
- **Watershed Based Permitting:** Watershed based permitting is a relatively new concept intended to protect the environment while maintaining reasonable discharge limits based on the assimilative capacity of the watershed as a whole. The Wyoming Department of Environmental Quality (WDEQ) began implementation of a watershed based permitting program in the Powder River Basin in 2005. Members of the research team followed the progress of the WDEQ and attended various public meetings to gain input from various stakeholders. As part of the research phase of the project, the results of these meetings and the pending outcomes are documented in this report.

Section 1.3 Project Advisory Council

The research herein was conducted under the direction of the Interstate Oil and Gas Compact Commission, with oversight and direction from the PAC. The PAC is comprised of a diverse group with interests related to produced water management associated with oil and gas development that includes: oil and gas agency directors, state and federal agency representatives, industry representatives, and other stakeholders. Because the PAC includes such a diverse group, input actively was sought at various stages of the research to provide direction and to help identify issues that are relevant to the success of the research. The diversity of the PAC has resulted in the research obtaining rare perspectives into the produced water management issues associated with oil and gas development.

SECTION 2.0 CURRENT INDUSTRY TRENDS

Water production within the domestic oil and gas industry has increased with the industry's efforts to increase production from existing fields (such as the de-watering projects in the Anadarko Basin) and from non-conventional fields (such as the Barnett shales in Northern Texas and the coal bed natural gas (CBNG) plays in various basins of the western United States). Furthermore, the past few years have seen a drastic increase in the price of crude oil and natural gas while demand for these resources has continued to rise. Operators in the United States have attempted to alleviate the shortage by increasing domestic production. Although production statistics typically lag a few years on a nationwide scale, indicators present in state data such as that from the Montana Board of Oil and Gas Conservation's records show that oil production is increasing (as a result of the expansive development of the non-conventional Bakken shale oil fields), while other aging fields in Montana are producing less oil and more water (MBOGC, 2006). In general, this trend is correlative to the oil and gas industry across the United States. As a result, to increase daily oil and gas production, operators of these older fields also must increase daily water production. This ultimately leads to an increase in the production ratios of water to oil (WOR) and/or water to gas (WGR).

In addition to the common aging trend, technological advances have allowed the oil and gas industry to focus on several new non-conventional plays that have intrinsically higher water production rates to facilitate the yield of oil and gas:

- **CBNG** often requires de-pressurization of the producing coal seam by pumping large volumes of high quality water (<10,000 mg/L TDS) to facilitate the production of natural gas.
- **Shales and diatomites** such as the Barnett Formation of north-central Texas require high-volume hydraulic fracture treatments that produce water back to wells for a long period of time. This water can be fairly high quality but because of state and federal regulations, the water must be managed as an oil and gas waste.
- **Dewatering** of old reservoirs aims to drain the water from competing permeability systems to allow oil into the borehole. These projects require pumping of prodigious amounts of water as evidenced by the high rate disposal permits obtained in recent years within mid-continent fields in Oklahoma, Texas, and Kansas.

The quality and quantity of produced water varies across the United States. Section 2.1 explains how the water quality varies from region to region; introduces a scientific theory that explains why these differences may have come to be; and presents oil, gas, and water production trends across the United States that show how the average WOR and WGR have been increasing over the last few years.

The production trends noted in Section 2.1 are representative of the WOR and WGR of the nation on average. This is useful information, but it does not necessarily explain what is impacting the increase in these ratios. Section 2.2 looks closer at individual state production trends, permitting activity, and completion activity to determine the key aspects that are impacting water production volumes, energy prices, and new technologies.

Section 2.1 Domestic United States Overview

As previously mentioned, the quality and quantity of produced water varies across the United States. Section 2.1.1 provides an illustration of how the quality of produced water varies and Section 2.1.2 provides a discussion that explains why these differences may have come to be. Section 2.1.3 demonstrates the nationwide impact of produced water quantities in terms of WOR and WGR.

Section 2.1.1 Produced Water Quality Trends Across the United States

Produced water quality data on a national level are available from the DOE-USGS Produced Water Database (USGS, 2002) and state-specific data are collected by some of the oil and gas producing states and stored in the producing states' databases for oil and gas production. Figure 2.1 presents a summary map of the data from the USGS produced water database. The colored data points shown in Figure 2.1 represent a range of salinity (as represented by TDS) values collected from the produced water from oil and gas boreholes. TDS ranges are indicated by color, with the data ranges indicated in the legend of Figure 2.1.

This database consists of approximately 53,000 individual produced water samples from 35 states. Water quality information comes from the analysis of water taken from the boreholes during oil and gas production, from production tests, and from drill-stem tests. Data quality may vary across the sample set due to evaporation from surface tanks and contamination from rainwater or mud filtrate. The DOE-USGS database contains descriptors of sample type. Water chemistry data in the database vary from sample to sample with many samples consisting only of TDS while other samples include detailed cation and anion concentrations. Although individual ions may affect beneficial use, suitability for most beneficial uses can be ascertained by total salinity (as represented by TDS). The water quality from this database is analyzed in more detail for various basins in the United States in Section 6.

Section 2.1.2 Understanding the Science of Produced Water Quality

Water may be produced from oil and gas reservoirs as a part of routine operations. In the subsurface, water exists in the pores or other openings of the reservoir. Reservoir rocks can contain predominantly hydrocarbons, predominantly water, or a mixture of the two, but in each case the water is a part of the dynamic rock-fluid system. After sediments are laid down, subsequent movement of water and other fluids is largely lateral, driven by hydraulic pressure differences. However, net movement of water is consistently towards the surface, driven by induration, compaction, and maturation of the rock frame. As vertical movement continues, filter-pressing through shales rich in chemically active clay minerals can retard the passage of dissolved constituents, thereby increasing the salinity of the water in deeper reservoirs. The phenomenon of natural filter-pressing by shales is analogous to nano-filtration desalination (Cohen, et. al., 2001). If upward migrating water has reduced salinity, the pore water left behind will have higher salinity. In this way, the vertical flux of migrating water will give rise to a salinity gradient within the sedimentary column from shallow strata with pore water much like sea water (approximately 32,000 mg/L) to very strong brines (up to a saturated solution of approximately 350,000 to 400,000 mg/L) at depth. This, in general, is what is seen in many sedimentary basins, where the oldest sedimentary rocks have pore water that is nearly saturated and the younger, shallow strata contain water of lesser salinity. A diagram depicting this process of water movement is shown on the right-hand side of Figure 2.2.

Figure 2.1 Total Dissolved Solids from the USGS Produced Water Database in the United States

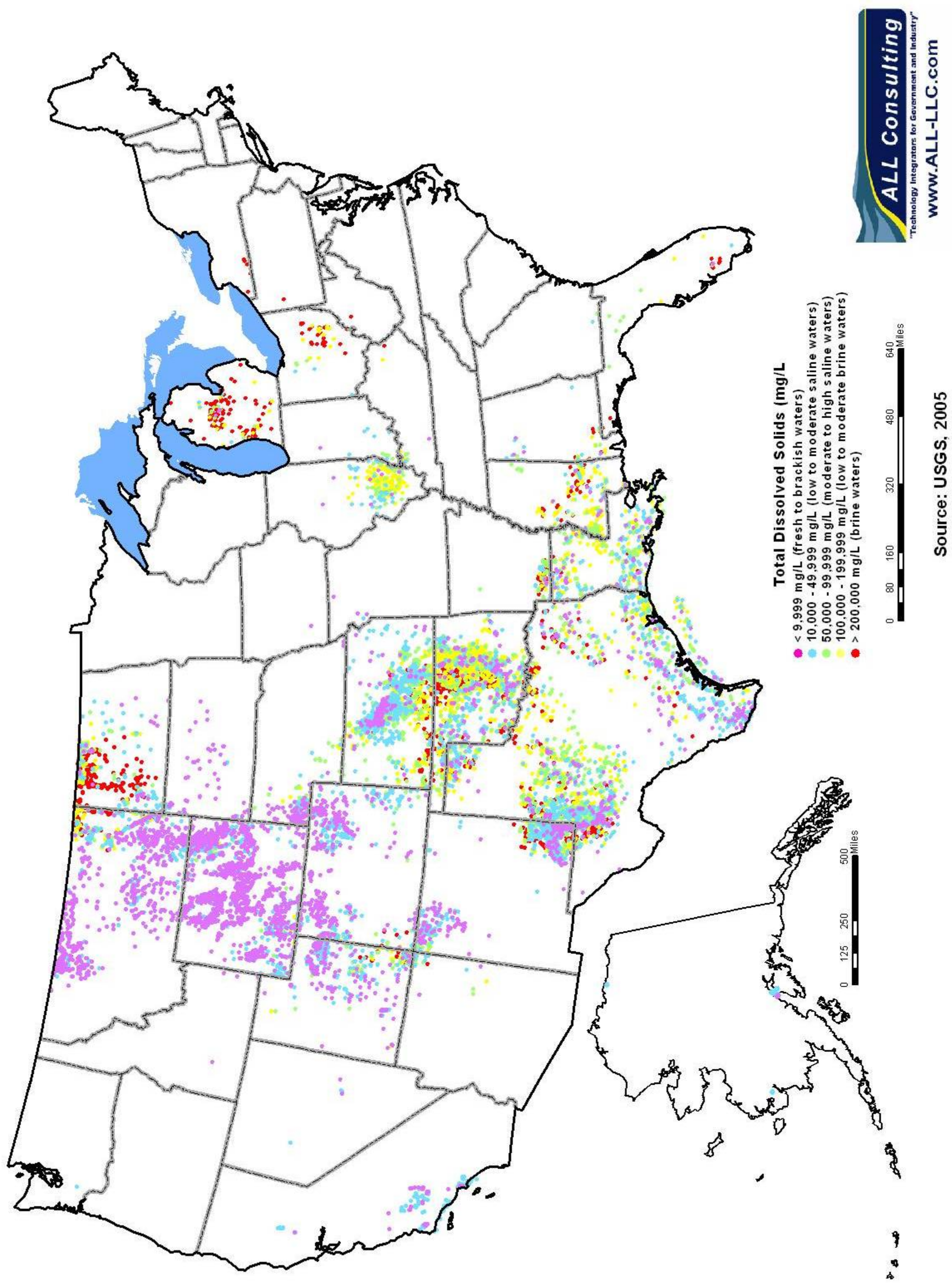
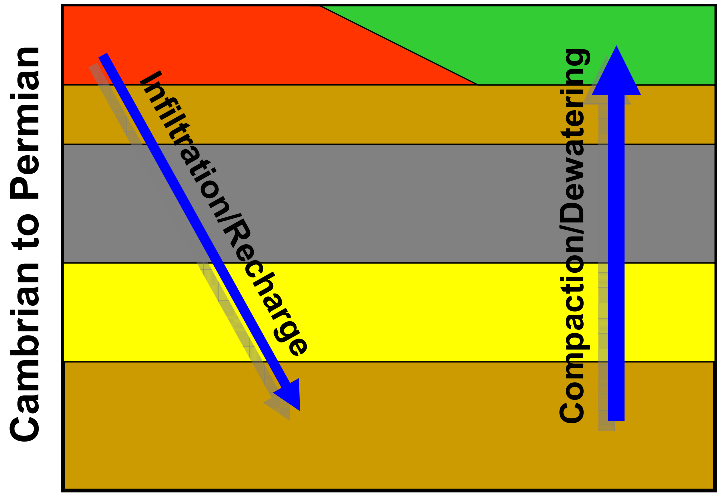


Figure 2.2 Natural Water Progression in Basins Such as the Anadarko or Permian Basin



The general trend of increasing salinity can be modified by several more or less local processes including long-range, dip-wise migration of fresh water from the outcrop, driven by surface recharge. Surface recharge can be occurring at the present time in those areas near the outcrop belt on uplifted areas, or historical recharge could have occurred during times of uplift and deep erosion. It is unknown how far recharge with meteoric water can extend, but Tertiary-aged recharge of Mississippian Madison Formation under the Great Plains of Wyoming and Montana extends many miles down-dip from the outcrop. Recharge is driven by hydraulic pressure generated by elevation of the outcropping recharge area, causing downward flow of the lighter meteoric water column. Meteoric water begins at the surface as high quality rain water, but over time the comparatively fresh water infiltrates and obtains added salinity from soluble minerals within the strata overlying the reservoir rock. The downward progression of recharge water is depicted on the left-hand side of Figure 2.2.

In addition to general upward flux of subsurface water and recharge from outcrops, reservoir rocks are subject to water variations caused by original water chemistry and fluid invasion from maturing, transforming shale masses (Hunt, 1979). As temperatures increase due to increasing burial, shales can expel water and entrained hydrocarbons. Simple compaction of the shale will drive out native pore water as the shales' porosity decreases from an original 80%. At some point, however, clay minerals within the shale begin to change, driving out water of crystallization, which can have a very different chemical composition from the pore water. Near the same point (in terms of temperature), organic material within the shale begins to give off large volumes of hydrocarbons. This charge of fluids can migrate throughout the sedimentary basin, depending upon permeability connections.

As an example, the Silurian-Devonian Hunton Formation is a prolific reservoir in the Anadarko Basin. Hunton oils found in Oklahoma fields have been geochemically correlated with overlying Woodford shales (Comer, 1992). On the other hand, thick, over-pressured Springer/Chester shales of the deep basin may be in connection with deep Hunton reservoirs by way of major regional faults, changing the water chemistry. It would be difficult to predict the salinity and chemistry of expelled water from the Woodford or Springer/Chester shales; that water would likely be a combination of pore water squeezed physically out of the shales and water of crystallization displaced by clay mineralogy changes.

Reservoir water chemistry in ancient sediments can be a product of original water chemistry. Some sediments, such as the Tertiary coals of the Powder River Basin, appear to have been laid down in fresh water, not sea water; this may be one of the reasons that the coals produce high quality, low TDS water. Other sediments such as the Permian Aged formations of the Anadarko Basin contain inter-bedded evaporates suggesting that deposition was in hypersaline environments resulting in reservoir waters that are very high in TDS.

A comprehensive paper (Bein and Dutton, 1993) describes interpreted formation waters in the southern Mid-Continent from the Delaware Basin to the Anadarko Basin, throughout the Paleozoic section. With the help of detailed chemical analyses, including stable isotopes, the authors saw the presence of several migrating brines that have modified the characteristics of formation waters. The authors saw the influence of meteoric water reacting with strata containing halite, gypsum, clays and other minerals. Downward leaching gave rise to saturated brines and low salinity brines, depending upon the local intervening strata. The authors observed high salinity brines in reservoirs adjacent to the Wichita Uplift, presumed to be caused by meteoric waters leaching through thick Permian evaporites. The complex geological history of these basins has produced complex varieties of produced water that often can be resolved only on a local basis.

Section 2.1.3 Nationwide Trends in Produced Water Quantities

The IOGCC consists of 30 member states and seven associate member states representing the regions of domestic oil and gas production of the United States. Available data were collected from each state and then aggregated to determine the United States domestic production trends (oil, gas, and produced water) as a whole. Trends may vary on a state-by-state basis, but the overwhelming tendency for the nation is shown to be increasing volumes of water, while oil and gas production is decreasing. As a result, industry has been experiencing higher WOR and WGR than in recent history. Figure 2.3 presents the water and oil production and the WOR since 2000, and Figure 2.4 presents the water and gas production and the WGR since 2000. The WOR has an upward trend with a high at around 9.8 barrels of water per 1 barrel of oil produced in 2005. The WGR also has an upward trend from 2000-2005; the high in 2005 was approximately 1 barrel of water produced per 1.0 MCF of natural gas.

Please note that if a state's production data were not available for any of the three components (oil, gas or water), all data for that state were not included in the analysis. States not included as a result of these data gaps were: Missouri, New York, Nevada, West Virginia, Virginia, Tennessee, Texas, and Utah. Furthermore, some states did not have data available for 2004 and/or 2005 (Arkansas, Mississippi, New Mexico, North Dakota, Ohio, and Pennsylvania), and the states that did have data for 2005 or only had partially complete datasets (Alaska, California, Colorado, Florida, Michigan, Montana, Nebraska, South Dakota, and Wyoming). Although this skews the total 2004 and 2005 production volumes of the oil, gas, and water produced, the oil/water and oil/gas ratios are believed to be representative of a complete dataset, which stresses the importance of the WOR and WGR versus actual production volumes when performing the comparative analysis. In general, the data support the notion that over time operators have had to produce more water to get the same amount (or less) of oil and gas production from a reservoir.

Figure 2.3 Water and Oil Production Volumes in the United States Since 2000

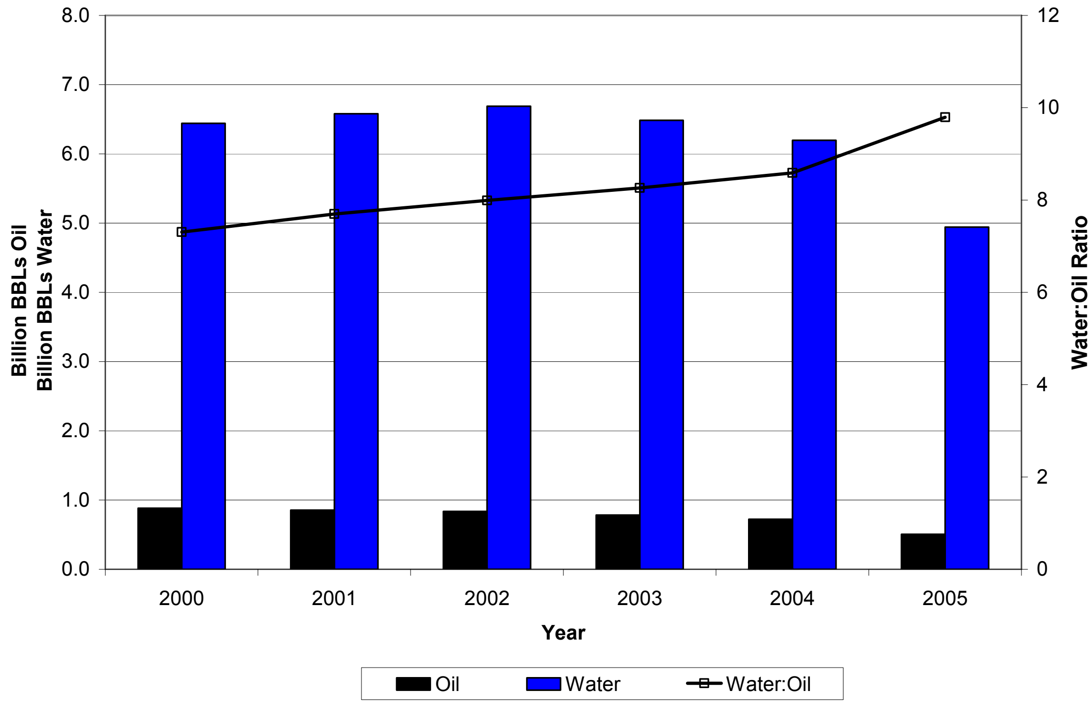
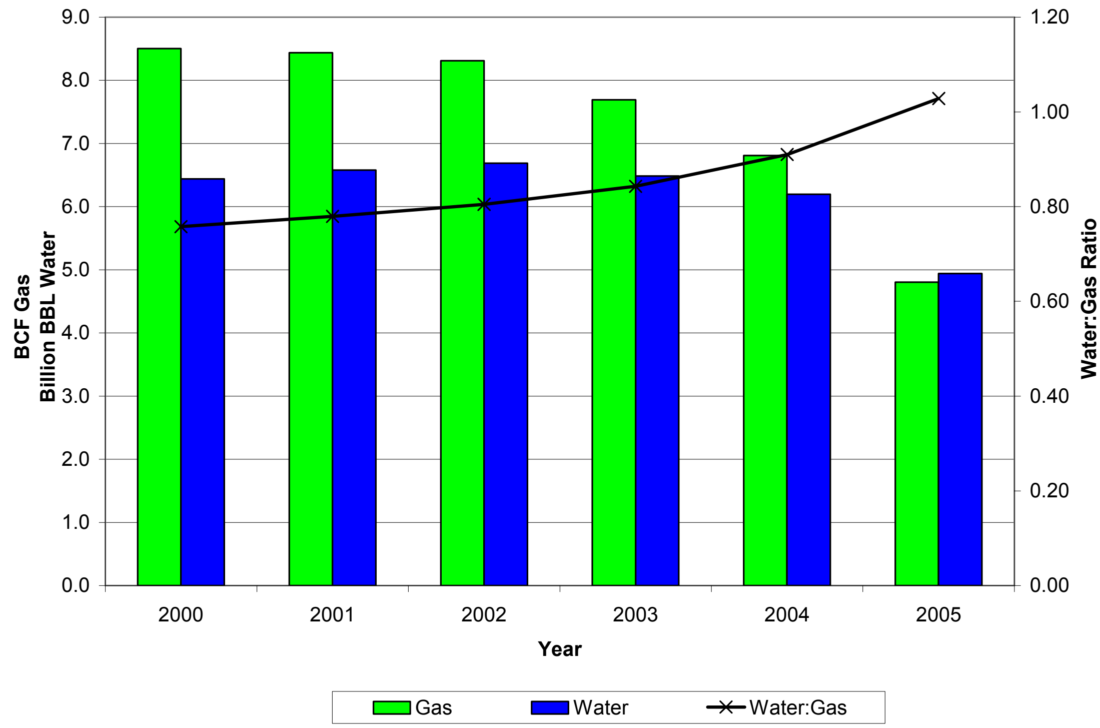


Figure 2.4 Water and Gas Production Volumes in the United States Since 2000



Note: Data for Figures 2.3 and 2.4 were compiled from the following state agencies:
2000 - 2003 – AK, AR, CA, CO, FL, MI, MS, MT, NM, ND, NE, OH, PA, SD, and WY
2004 – AK, AR, CA, CO, FL, MI, MS, MT, ND, NE, SD, and WY
(partial) 2005 – AK, CA, CO, FL, MI, MT, NE, SD, and WY

Section 2.2 Production Trends in Select States

Oil, gas and produced water databases were analyzed from Montana, Wyoming, Alaska, and Kansas to identify and evaluate production trends and the driving forces behind those trends (i.e. hot play exploited within the state, new technologies incorporated, and energy price fluctuations). The primary driver that impacts domestic oil and gas production trends is the market price of oil and gas, which is driven by a number of factors, one of which is demand. Over the last few years domestic energy demands have reached new heights and as a result, oil and gas prices have continued to rise. Section 2.2.1 discusses how the rise in oil and gas prices has lead to a push for domestic oil and gas exploration and production to increase to lessen the need for foreign imports. Section 2.2.2 shows how the push for increased domestic oil and gas production has lead to unprecedented advances in the use of new technologies, such as horizontal drilling and horizontal re-completions. The end result is a net increase in produced water across much of the nation. However, the new technologies employed are not necessarily responsible for an increase in WOR and WGRs. Section 2.2.3 provides discussion of how new drilling technologies increase water production while also decreasing the WOR. With rising energy prices, this example of employing new technologies might now prove to be economical because the increased revenue from oil and gas production might offset or exceed the incremental increase in capital drilling costs and operational water management costs.

Section 2.2.1 Energy Prices Impact Trends

The price of oil and gas either can stimulate or chill domestic oil and gas exploration and production. Figures 2.5, 2.7, 2.9, and 2.11 illustrate the effect of pricing on permit activity in Montana, Wyoming, Alaska, and Kansas respectively. Likewise, Figures 2.6, 2.8, 2.10, and 2.12 illustrate the effect of pricing on well completion activity in Montana, Wyoming, Alaska, and Kansas respectively. The data presented is for oil and gas wells in the representative state compared to the average oil and gas prices for the United States on an annual basis. The figures generally show that there is a positive correlation between oil and gas prices, permits issued, and well completion activity from 1990 to 2005. Alaska is the one state that does not appear to follow this trend directly, as can be seen in Figures 2.9 and 2.10.

As oil prices declined and gas prices remained steady in the early 1990s the well permit activity in Montana, Wyoming, and Kansas declined, from nearly 400 permits in 1990 to a little over 200 permits by 1993 in Montana, from over 1100 permits in 1990 to about 1000 permits in 1993 in Wyoming, and from almost 4000 permits in 1990 to less than 1500 permits in 1995 in Kansas. As energy prices have increased over the last 10 – 12 years, well permit activity also has increased for these three states. As oil and gas prices reached new highs in 2005, permit activity in Montana and Wyoming also reached new highs, with more than 1,300 well permits approved in Montana in 2005 and around 10,000 permits approved in Wyoming that same year. Kansas was also up in permits in 2005 with over 3500 permits approved. Figures 2.5, 2.7, and 2.11 show the permit application data in terms of the primary energy resource extracted from the well from Montana, Wyoming, and Kansas respectively, while Figures 2.6, 2.8, and 2.12 show the well completion data broken down in the same manner for these three states. The data presented in these figures show how new technologies (advances in horizontal well borings) and new developments (CBNG and the Bakken play) are impacting production of oil and gas resources in these states.

Figure 2.5 Well Permitting Activity in Montana, by Resource Compared to Average Oil and Gas Prices 1990 - 2005

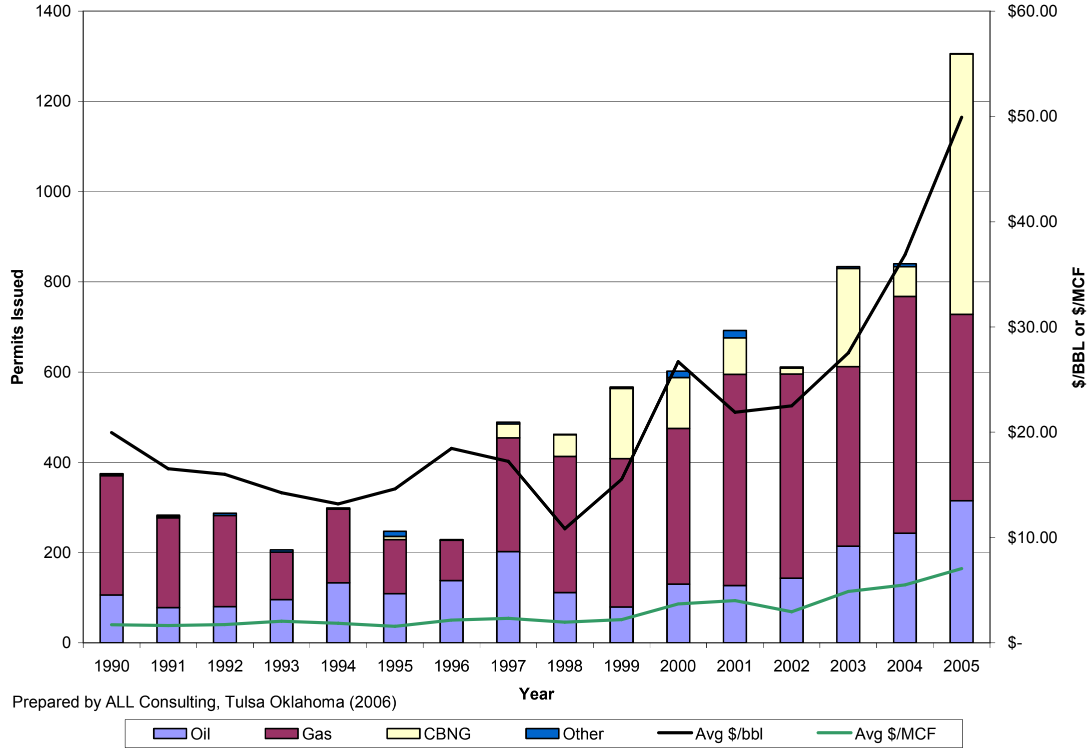


Figure 2.6 Well Completion Activity in Montana, by Resource Compared to Average Oil and Gas Prices 1990 - 2005

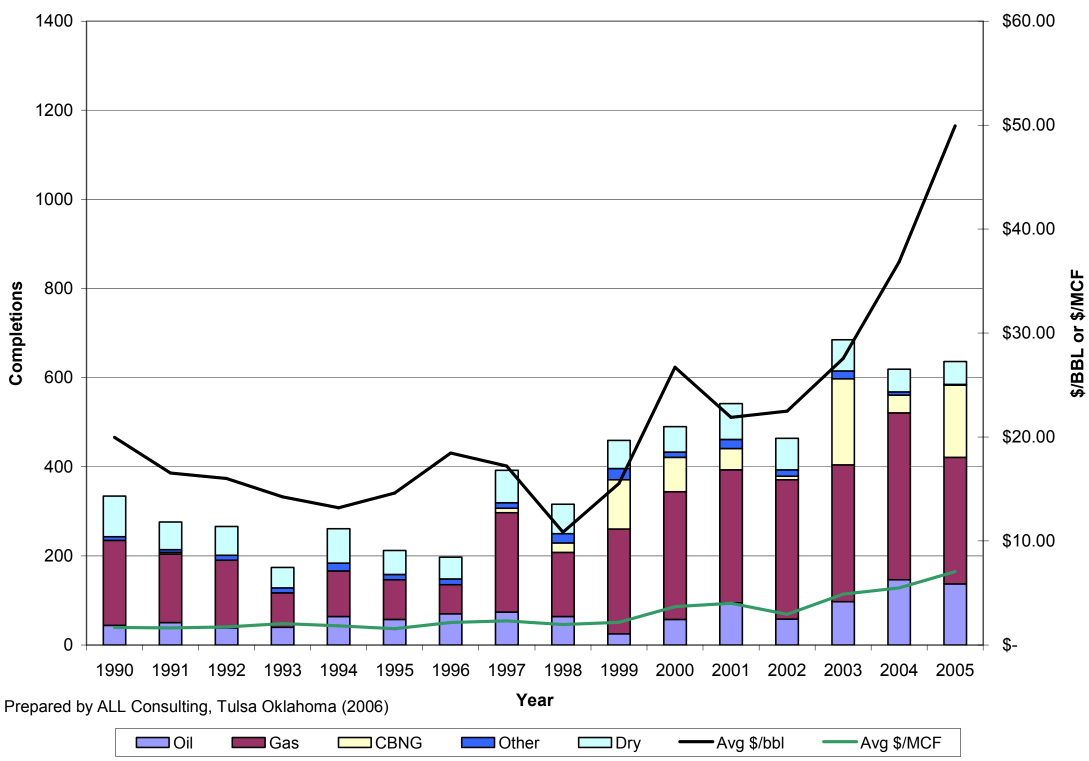


Figure 2.7 Well Permitting Activity in Wyoming, by Resource Compared to Average Oil and Gas Prices 1990 - 2005

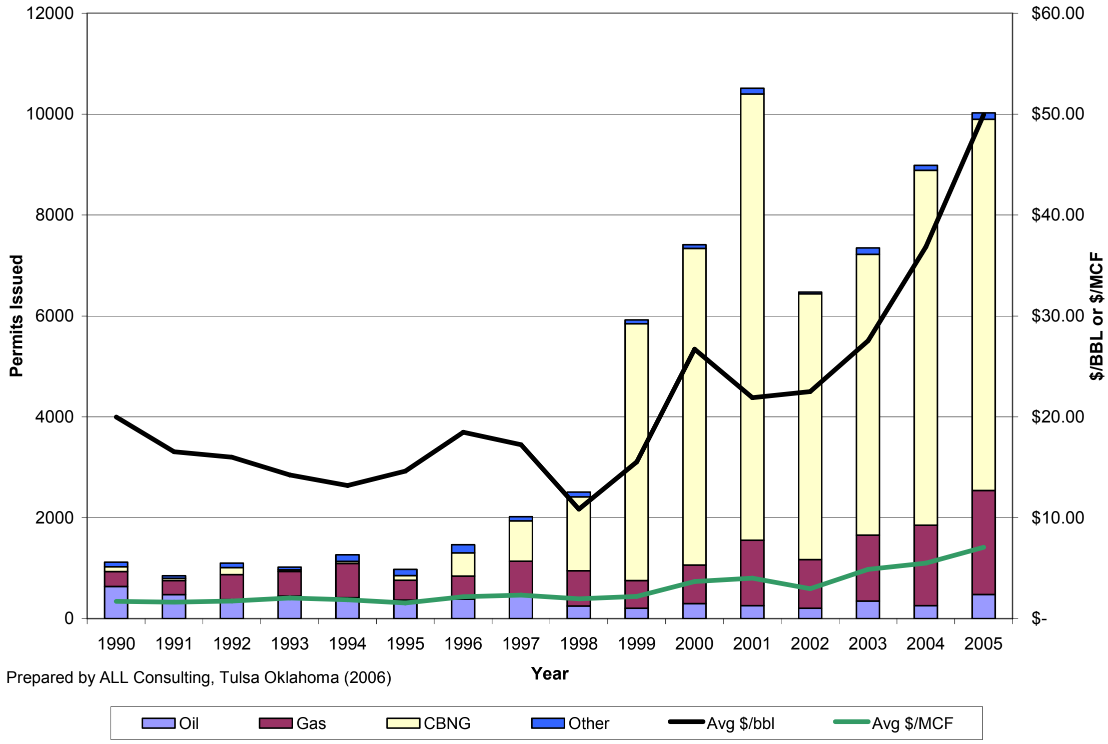


Figure 2.8 Well Completion Activity in Wyoming, by Resource Compared to Average Oil and Gas Prices 1990 - 2005

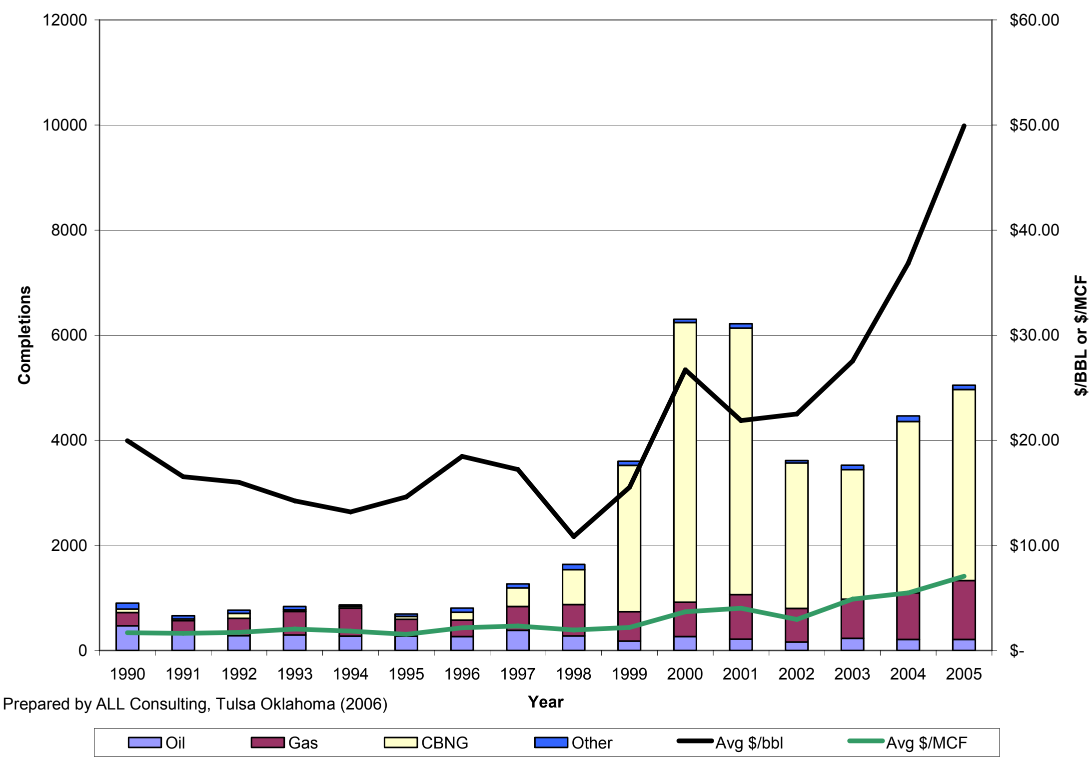


Figure 2.9 Well Permitting Activity in Alaska, by Resource Compared to Average Oil and Gas Prices 1990 - 2005

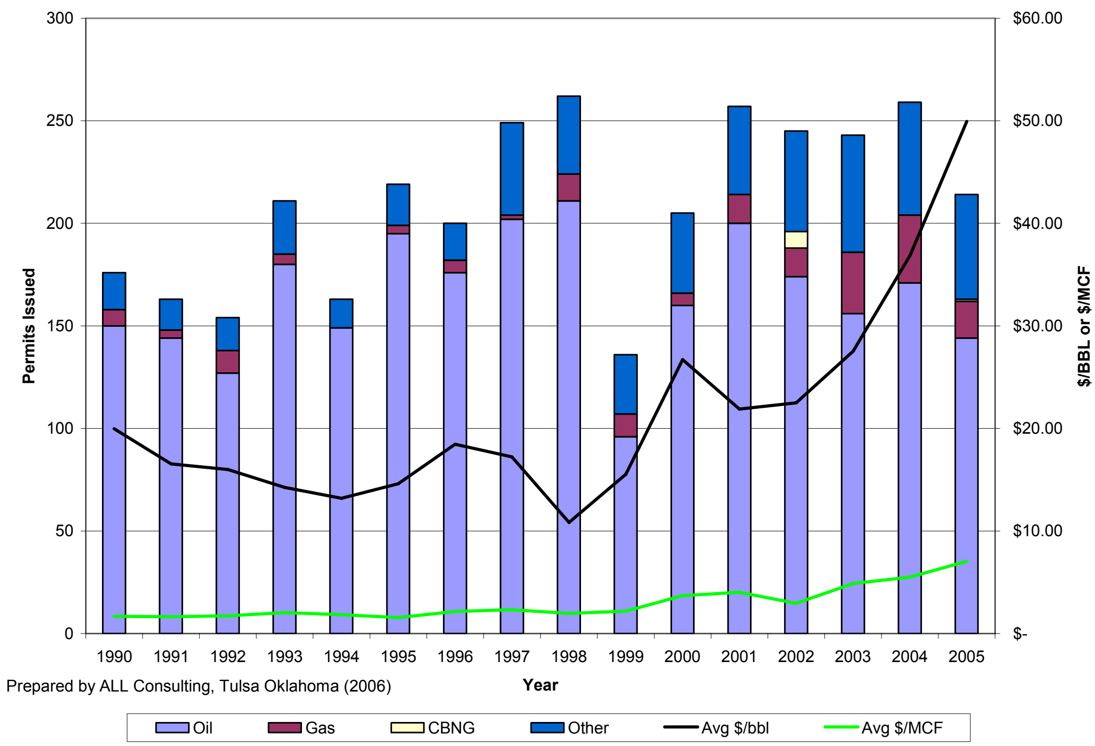


Figure 2.10 Well Completion Activity in Alaska, by Resource Compared to Average Oil and Gas Prices 1990 - 2005

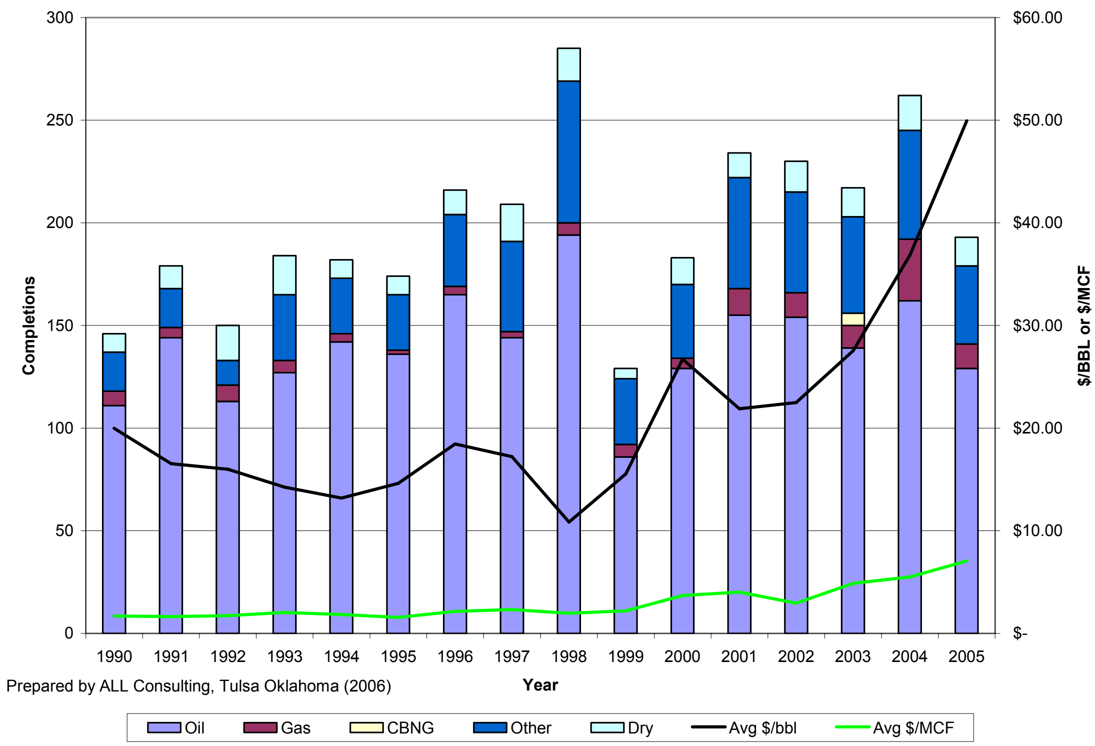


Figure 2.11 Well Permitting Activity in Kansas, by Resource Compared to Average Oil and Gas Prices 1990 - 2005

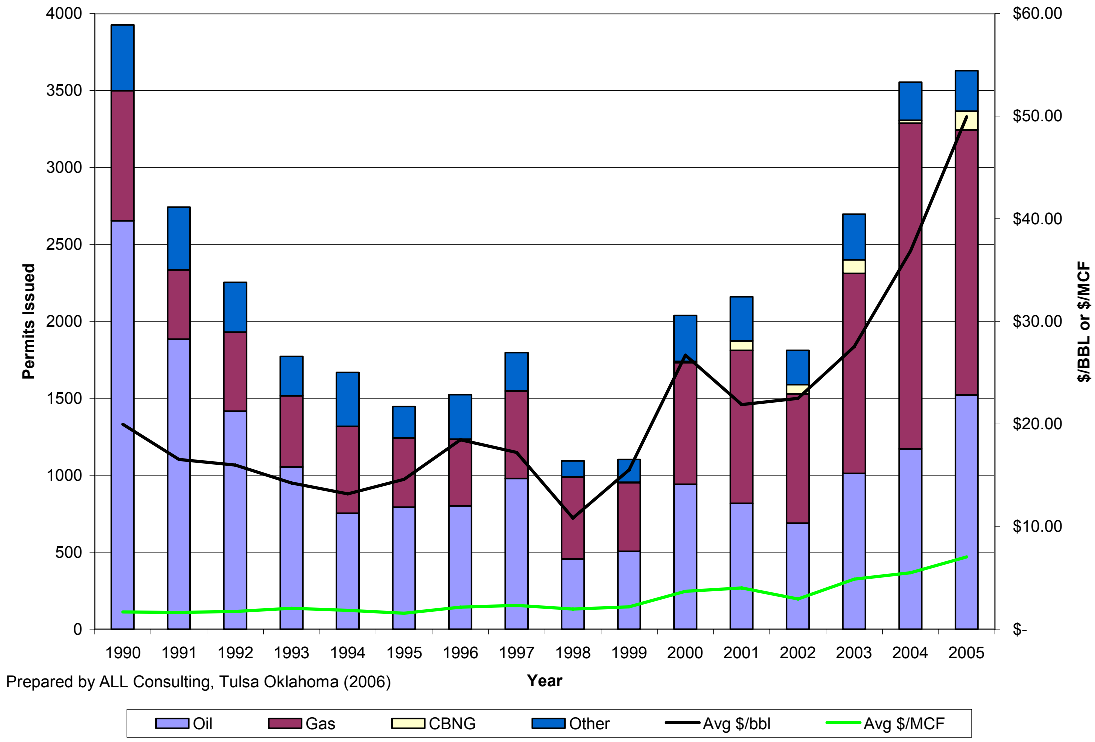
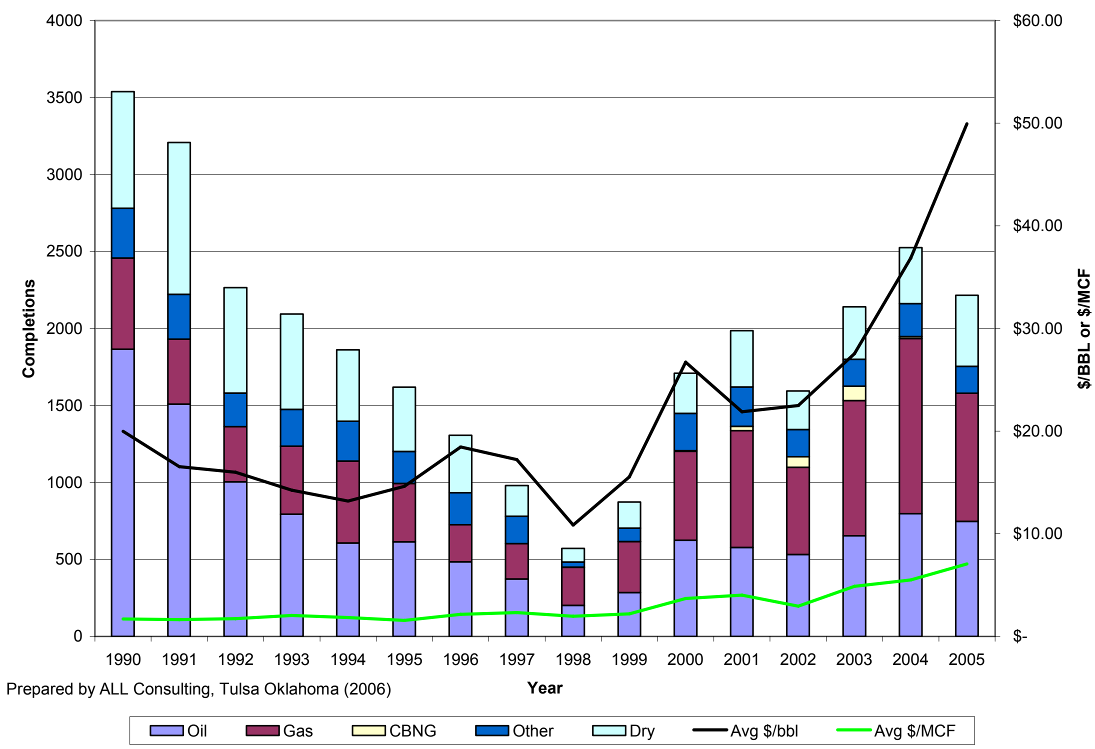


Figure 2.12 Well Completion Activity in Kansas, by Resource Compared to Average Oil and Gas Prices 1990 - 2005

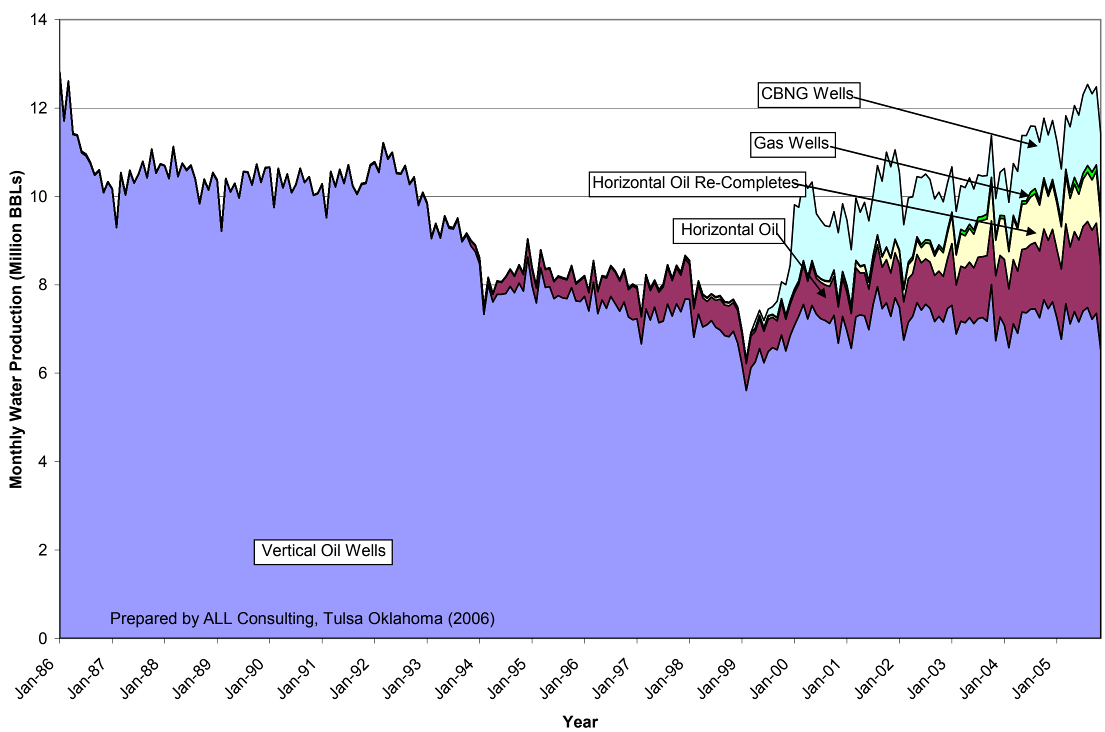


Section 2.2.2 New Technologies Impact Trends

As previously mentioned, increases in domestic and worldwide energy demand has driven up the price of oil and gas, which has stimulated domestic exploration and production programs. Higher prices can allow operators to explore the use of experimental and new technologies, which can increase domestic exploration and production and allow for the development of new plays that previously might have been uneconomical or technologically unattainable. Figures 2.6 and 2.8 document the affect the rise in energy prices had on the onset and increases in CBNG development, which was once considered uneconomical.

Figure 2.13 presents the volume of water produced in the state of Montana per month from 1986 through 2005 for different well classifications. Figure 2.13 shows the impact of new technologies such as horizontal wells on water production presenting the total Montana water production by month for horizontal oil, horizontal re-completed oil, vertical oil, conventional gas, and CBNG wells. Water production from conventional gas wells appears to be a minor percentage in relationship to the other well types. Furthermore, Figure 2.13 breaks down the water production for oil wells using different completion technologies, showing the decline in water production from conventional vertical oil wells, while horizontal oil and horizontal oil re-completion wells are all showing increasing volumes of water production. Horizontal oil wells allow for increased areas of the reservoir to be exposed to production, which results in increased oil and water output.

Figure 2.13 Water Produced in Montana from Oil and Gas Wells by Type, 1986 - 2005



CBNG is not the only new play in Montana. The Bakken oil shale play in Richland County also has received attention due to the new horizontal development technologies applied as a result of the high oil and gas prices. When Figure 2.13 is compared to Figure 2.14 and Figure 2.15,

Figure 2.14 Impact of New Technologies on Oil Production in Montana

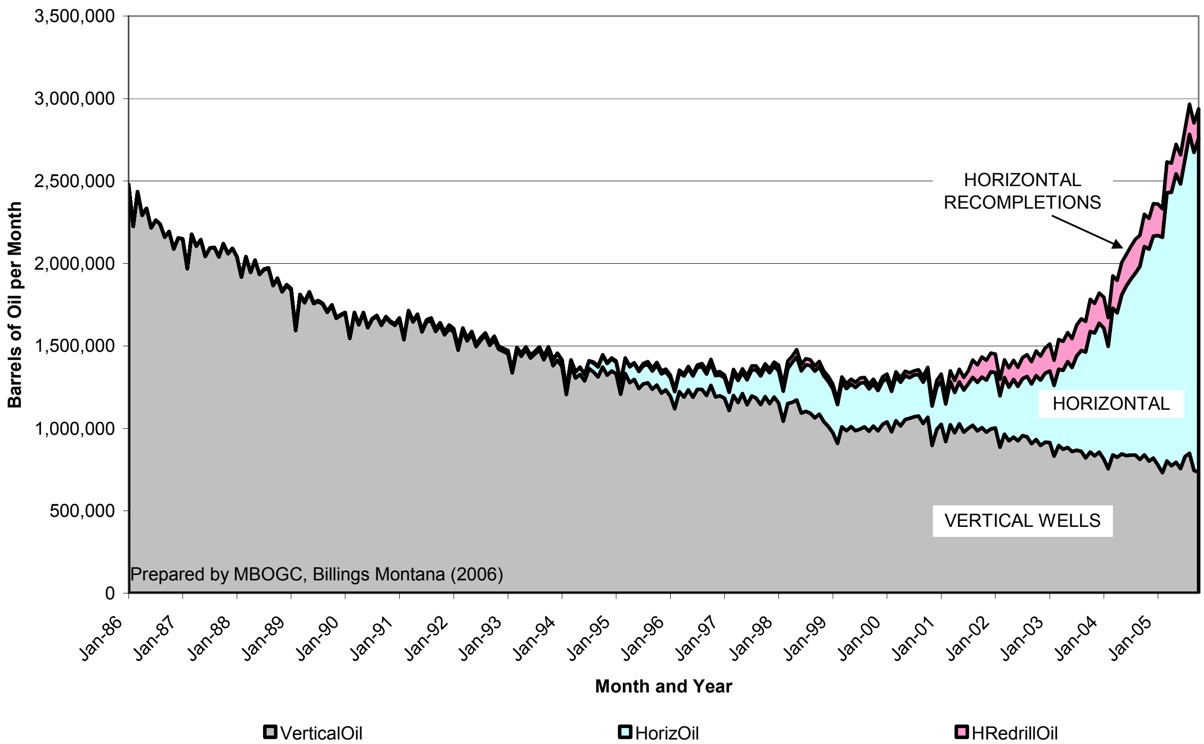
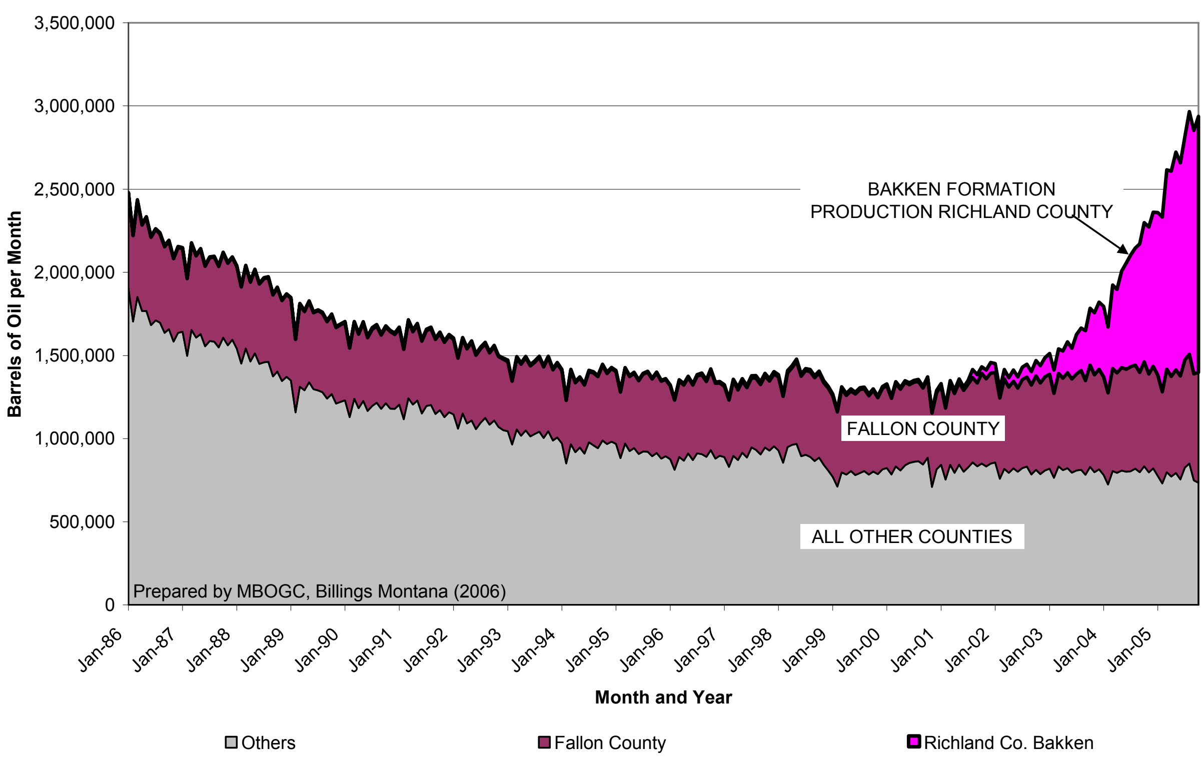


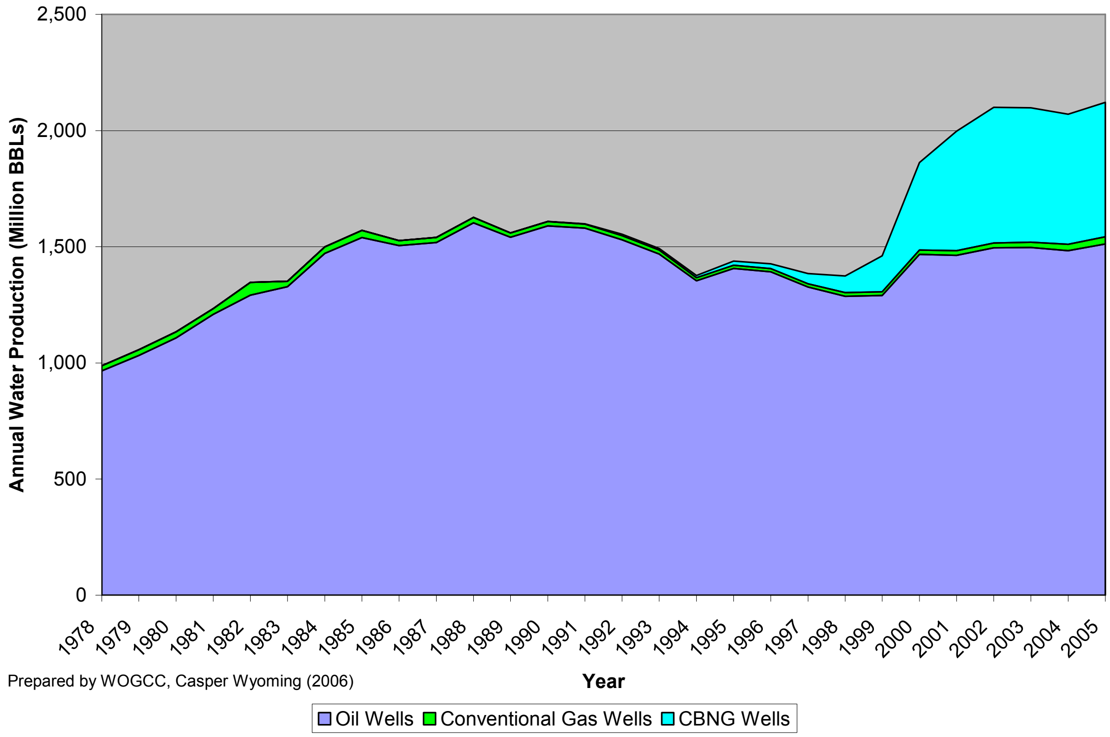
Figure 2.15 The Impact of the Recent Development of the Bakken Formation on Oil Production in Montana



the economic impact to the state of Montana from the new technology is evident as the horizontal completions in the Bakken play and the horizontal completions and re-completions in the Cedar Creek Anticline of Fallon County have led to a 20-year peak in annual oil production in Montana. The evidence that this peak has occurred as a result of these technological advances can be seen in Figure 2.14 and 2.11 where despite the fact that oil production from the rest of the state (as shown by vertical well completions in Figure 2.14 and by the other counties' line in Figure 2.15) has shown a decline for the last 20 years.

Figure 2.16 presents the volume of water produced in the state of Wyoming per year from 1978 through 2005 for oil, gas, and CBNG wells. Figure 2.16 shows the impact of new CBNG production since 1998. Water production from conventional gas wells appears to be a minor percentage in relationship to oil and CBNG.

Figure 2.16 Water Produced in Wyoming from Oil, Gas, and CBNG Wells, 1978 - 2005

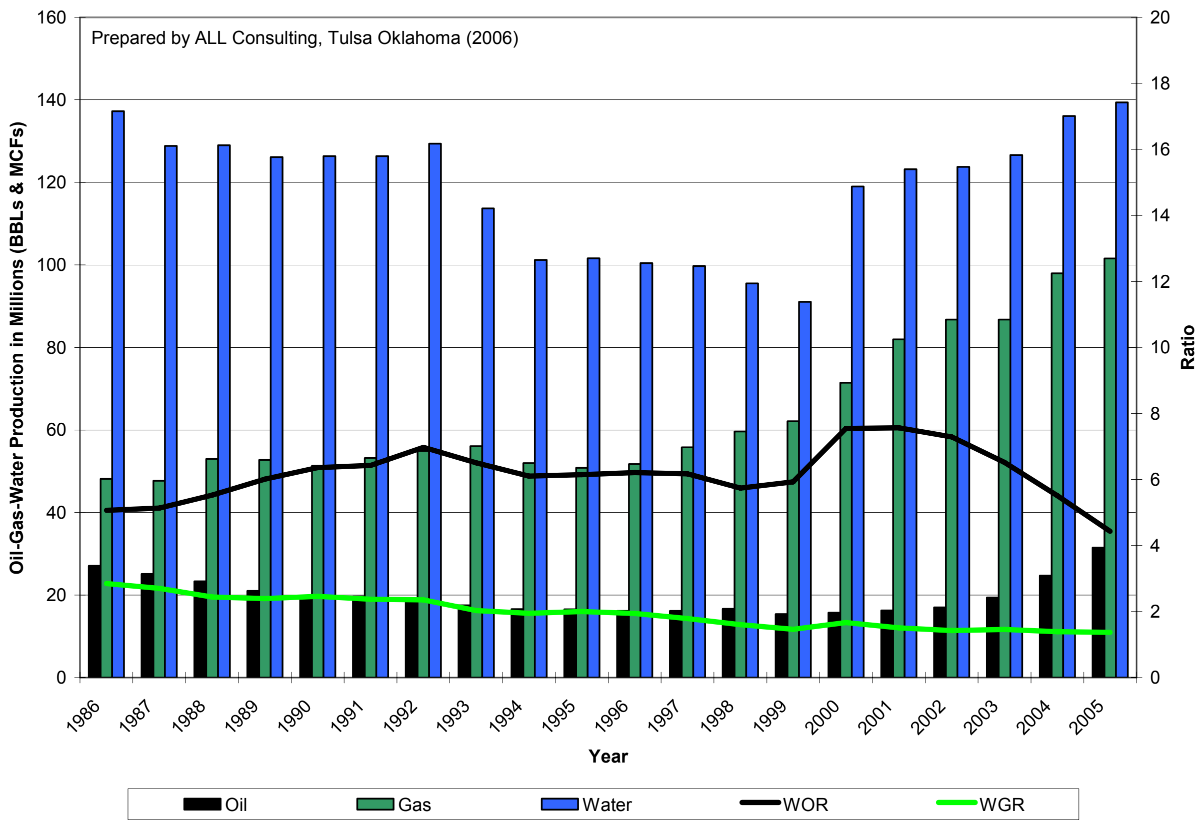


Section 2.2.3 How Trends Impact Produced Water Management

As development evolves with the introduction of new technologies and increased production from new oil and gas plays, produced water management also must evolve to meet the needs of the volumes of water being produced. This section provides some analysis of observed trends in oil and gas produced water and how they affect management of it. The first example documents produced water management within the state of Montana and provides analysis related to the trends of the last 20 years of reported production data. The data analyzed in this section look at the gross production numbers for oil, gas and produced water as well as the WORs and WGRs.

Figure 2.17 presents the gross production for oil, gas and water in Montana from 1986 through partial year data for 2005. Figure 2.17 also presents the WORs and WGRs over the same period of time. Analysis of the gross production trends for water in the state shows that water production had been on the decline from 1986 through 1999 with totals dropping from approximately 137 million barrels in 1986 to approximately 90 million barrels in 1999 (Figure 2.17). Since 1999, water production in Montana has been increasing with output in 2005 approaching 140 million barrels --- a volume greater than production in 1986 (Figure 2.17). Analysis of the gross oil production trends in the state of Montana shows a similar trend to the gross water production, with a decline in oil production from 1986 to 1999 from approximately 28 million barrels to approximately 15 million (Figure 2.17). Since 1999, oil production has increased to greater than 30 million barrels in 2005 (Figure 2.17). Analysis of the gross production trends for gas shows that production has been increasing steadily from 1986 through 2005 with total annual production rising from approximately 48 MMCF to greater than 100 MMCF.

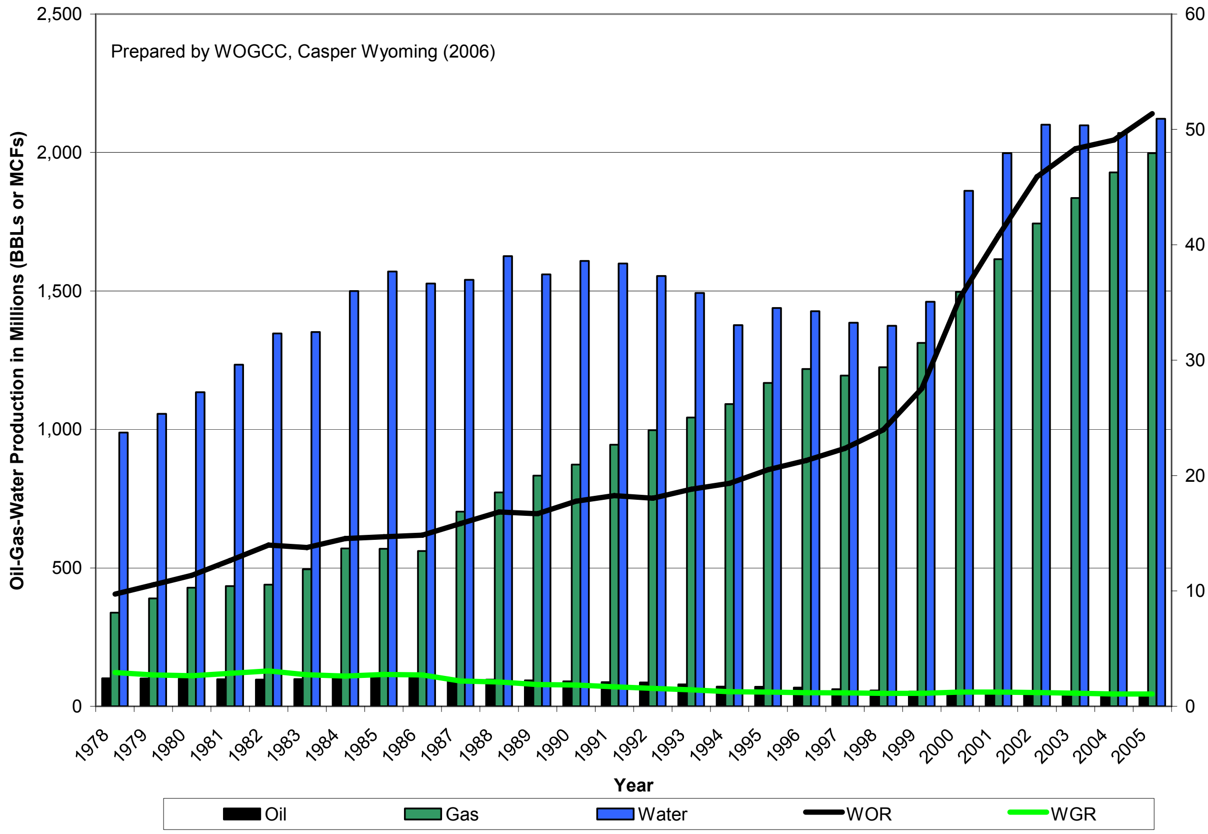
Figure 2.17 Oil, Gas, and Water Production Trends for Montana from 1986 to 2005



Analysis of WOR and WGR for the 1986 to 2005 time frame for Montana is also shown in Figure 2.17. While the WGR shows a relatively steady decline from 1986 to 2005, the WOR shows several fluctuations from 1986 to 2005. WOR rose during two intervals --- from 1986 to 1992, and from 1998 to 2000 --- while there was a leveling off and slight decrease from 1993 to 1998. Data from 2001 to 2005 show the WOR to be declining.

Figure 2.18 presents the gross production for oil, gas and water in Wyoming from 1978 through 2005. Figure 2.18 also presents the WORs and WGRs over the same period of time. Analysis of the gross production trends for water in the state shows that water production had been on the decline from 1990 through 1998 with totals dropping from approximately 1.6 billion barrels in 1990 to approximately 1.4 billion barrels in 1998 (Figure 2.18). Since 1998, water production in Wyoming has been increasing with output in 2005 over 2.1 billion barrels --- a volume greater than production in any year since 1978 (Figure 2.18). Analysis of the gross oil production trends in the state of Wyoming shows a decline in oil production from 1978 from approximately 101 million barrels to approximately 41 million barrels in 2005 (Figure 2.18). Analysis of the gross production trends for gas shows that production has been increasing steadily from 1978 through 2005 with total annual production rising from approximately 338 MMCF to almost 2 BCF.

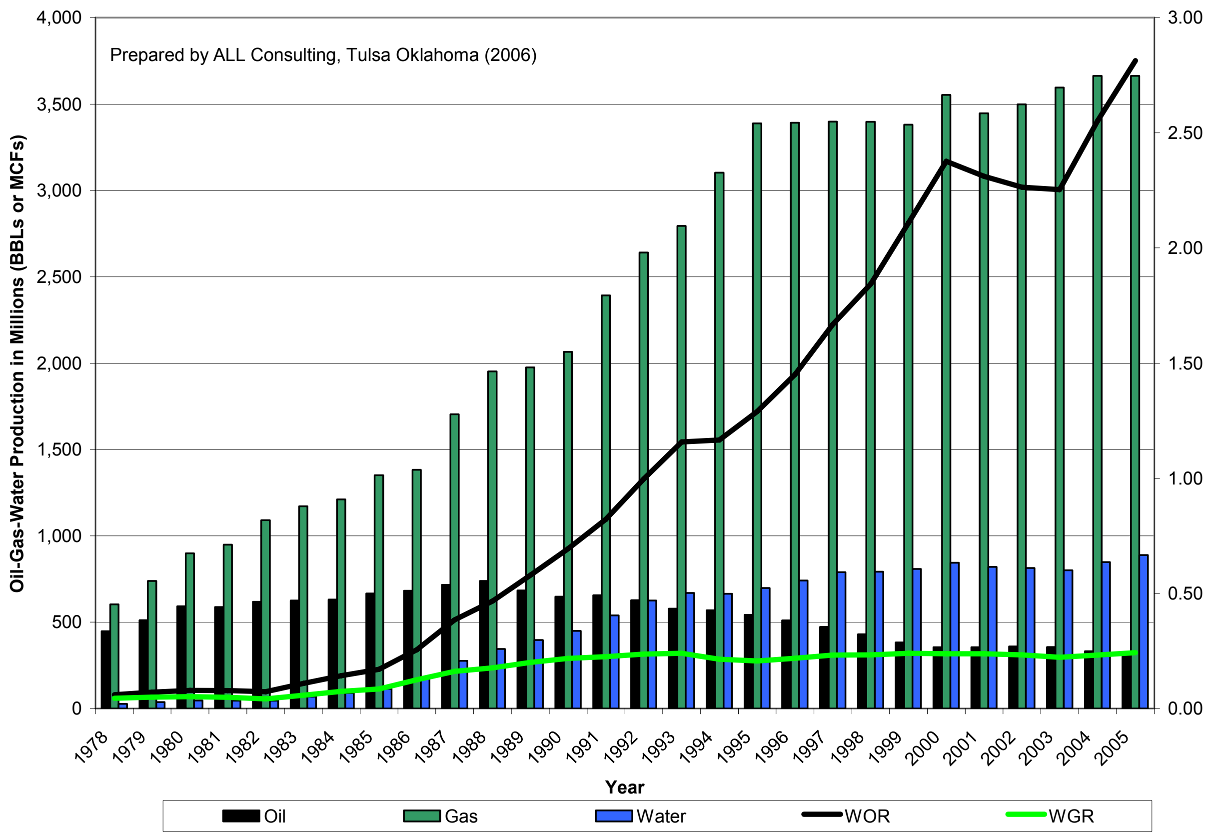
Figure 2.18 Oil, Gas, and Water Production Trends for Wyoming from 1978 to 2005



Analysis of WOR and WGR for the 1978 to 2005 time frame for Wyoming is also shown in Figure 2.18. While the WGR shows a relatively steady decline from 1978 to 2005, the WOR shows a steady climb from 1978 to 1998, and then a sharp increase from 1998 to 2003 while stabilizing somewhat from 2003 to 2005.

Figure 2.19 presents the gross production for oil, gas and water in Alaska from 1978 through 2005. Figure 2.19 also presents the WORs and WGRs over the same period of time. Analysis of the gross production trends for water in the state shows that water production has been on the steady incline from 1978 through 1998 with totals coming up from approximately 26 million barrels in 1978 to approximately 800 million barrels in 1998 (Figure 2.19). Since 1998, water production in Alaska has been increasing slightly with output in 2005 just over 880 million barrels --- a volume greater than production in any year since 1978 (Figure 2.19). Analysis of the gross oil production trends in the state of Alaska shows a rise in oil production from 1978 to 1988 from approximately 450 million barrels to approximately 740 million barrels in 1988, and then a steady decline to 2005 where totals are approximately 315 million barrels (Figure 2.19). Analysis of the gross production trends for gas shows that production has been increasing steadily from 1978 through 1995 with total annual production rising from approximately 600 MMCF to over 3.3 BCF in 1995, and then a slight incline to 2005 where totals are approximately 3.6 BCF (Figure 2.19). .

Figure 2.19 Oil, Gas, and Water Production Trends for Alaska from 1978 to 2005



Analysis of WOR and WGR for the 1978 to 2005 time frame for Alaska is also shown in Figure 2.19. While the WGR shows a relatively steady incline from 1978 to 1991 at which point it stabilizes to 2005, the WOR shows a steady climb from 1978 to 2000, and then a slight dip from 2000 to 2003, and then a sharp increase from 2003 to 2005.

THIS PAGE INTENTIONALLY LEFT BLANK

SECTION 3.0 CURRENT REGULATORY CHALLENGES

Water produced in association with oil and natural gas production comprises 80 percent of the oil and gas industry's residual waste requiring management and disposal. It contributes to the overall cost of energy production (GTI, 2002). Management costs associated with produced water can impact the economics of oil and natural gas developments; thus, newly promulgated regulations and policies that have the potential to limit water management options possibly could halt some existing production operations that are marginally profitable. Approximately 60% of produced water is managed via deep injection disposal wells at costs ranging from $0.50 to $1.75/bbl in wells that cost $400,000 to $3 million to install (Argonne National Laboratory, 2002). Other methods of management, such as beneficial use and discharge to surface waters, cost considerably less but may be limited by proposed regulations. Due to an increase in future expenses and disposal limitations resulting from proposed regulations, some existing water management options might become economically impractical.

Management of produced water from the oil and gas industry is regulated under rules enacted federally by the Clean Water Act (CWA) and the Safe Drinking Water Act (SDWA). Recent research related to how produced water is regulated and managed has covered a wide range of topics such as how new natural gas developments are impacted by existing regulation as well as identifying alternative means (typically beneficial uses) of managing the water (ALL Consulting, 2003; ALL Consulting and MBOGC, 2004; Argonne National Laboratory, 2002; Jackson and Meyer, 2002; Jackson and Meyer, 2003; Reynolds, 2003; Veil, 1997). This section discusses how existing and proposed regulations are affecting the management of water produced from conventional production activities. Furthermore, the intent of this section is not to describe various state produced water regulations, or the history of their promulgation, but to focus on evolving regulatory challenges that could have long-reaching impacts on how produced water is managed.

The prolific development of coal bed natural gas and other continuous reservoirs has prompted regulators to reconsider produced water management rules and policies to the point that the rules soon might be affecting conventional oil and gas operations. The proposed rule and policy changes are making it increasingly difficult to manage the produced water through traditional procedures at the same time policy is moving toward limiting the potential for many beneficial uses of this valuable resource. Beneficial use of produced water has become the mantra of many local, state, and federal agencies to avoid what these agencies consider to be wasting a valuable resource. These agencies are demanding that produced water of any redeemable quality be used beneficially and that uses such as irrigation, stock water, and wetlands maintenance be incorporated into all oil and gas operations where water quality is appropriate. At the same time, what could be one of the largest beneficial uses, discharge to downstream water users, is becoming more difficult for operators to get permitted.

Section 3.1 Regulatory Synopsis

The United States Environmental Protection Agency's (EPA) regional offices typically initiate policy and the direction of enforcement actions under the Clean Water Act and Safe Drinking Water Act in an effort to protect human health and the environment. These two federal regulations are the basis for other federal and state regulatory programs that control the management of water produced during oil and gas development. The federal government has established several regulatory water classifications and standards. In some regulatory programs, federal classifications and/or standards may be adopted by applicable state regulatory agencies. Water can be classified according to its characteristics, use, source, location, and other criteria. Water classifications generally take into consideration the use and value of water for public supplies; protection and propagation of aquatic wildlife; recreation in and on the water; and other potential uses (e.g., agricultural, industrial, municipal). Standards also might be established to maintain the quality of water as well as current and potential beneficial uses. In addition to federal programs, individual states also can have classifications and standards to account for local or regional environmental issues.

Although the EPA acts at the federal level to set national standards, states and tribal governments can acquire primacy for Underground Injection Control (UIC) and National Pollutant Discharge Elimination System (NPDES) by meeting the EPA's primacy requirements. A state that meets the primacy requirements is allowed to set more stringent state specific standards for these programs. Since individual states can acquire primacy over their respective programs, it is not uncommon to have varying requirements for these programs from state to state. This variation can affect how the oil and gas industry manages produced water within a basin that crosses between two states.

Section 3.1.1 Clean Water Act and NPDES

The Clean Water Act was established to protect water quality, which includes regulation of the NPDES permitting process. NPDES establishes, through a permit, pollutant limits on the discharge of produced water that generally include a volume (quantity) and concentration (quality) (U.S. EPA, 2004). Pollutants under the NPDES program fall into one of three categories: conventional, toxic, and non-conventional. There are two types of permits under the NPDES program that allow for the discharge of pollutants from point sources, individual permits, which are specific to an individual facility, and general permits, which cover multiple facilities within a specific permit category.

There are two controls which are the basis for NPDES permit limit: 1) the EPA effluent limitation guidelines for a particular industry (which are technology based and vary by industry), and 2) water quality based limits (U.S. EPA, 2004). Effluent limitation guidelines developed by the EPA under the Clean Water Act include three guidelines for existing discharges and one for new discharges:

- Best conventional pollutant control technology (BCT) for conventional pollutants and applicable to existing discharges.
- Best practicable control technology currently available (BPT) for conventional, toxic, and non-conventional pollutants and applicable to existing discharges.
- Best available technology economically achievable (BAT) for toxic and non-conventional pollutants and applicable to existing discharges.
- New source performance standards (NSPS) for conventional pollutants and applicable to new sources.

In addition to the controls on pollutant discharge established by the effluent limitation guidelines, the Clean Water Act has additional controls on pollutant discharges to water bodies that have been identified as currently being impaired because these waters do not meet water quality standards. The Total Maximum Daily Load (TMDL) program specifies the maximum amount of a pollutant that can be discharged to a body of water without exceeding established water quality standards and provides an allocation of the pollutant among the existing point and non-point sources of the pollutant (U.S. EPA 2005a).

Section 3.1.2 Safe Drinking Water Act and Underground Injection Control

The Safe Drinking Water Act was established to protect public health by regulating public drinking water supplies and to protect sources of drinking water. Through the Safe Drinking Water Act, the Underground Injection Control (UIC) Program was established to protect underground sources of drinking water from potential contamination from injection wells. Injection is responsible for approximately 60% of the produced water management activities for the oil and gas industry. The EPA's classification of UIC wells defines a separate well class (Class II) for oil and gas brine injection wells, which includes disposal and enhanced recovery wells used in conventional oil and gas production (U.S. EPA, 2005b). Historically, Class I injection wells also have been used for disposal of oil and gas produced water.

Class I injection wells typically are technologically sophisticated deep injection wells isolated by a confining zone from underground sources of drinking water; the injection formations typically are below the lowest underground source of drinking water (U.S. EPA, 2005b). Class I injection is sometimes identified as "deep" disposal injection when discussed relative to the oil and gas industry because the formations used for Class I injection are typically thousands of feet below the land surface and the injection of the fluids do not result in enhanced oil or gas recovery. The number of Class I injection wells in the United States is small relative to the number of Class II and Class V injection wells.

Not all oil and gas produced water management injection wells are Class I and II wells. Recent activities associated with the management of produced water have started to utilize Class V wells. The Class V injection well category was created to categorize all the injection wells that did not fit into the more easily defined categories of Class I through Class IV. Class V wells can range from technologically simple septic systems to technologically advanced injection well systems. Simply put, the EPA defines Class V injection wells as any shallow well that is a bored, drilled, driven, or dug hole that is deeper than its width at its widest point. Class V wells typically are shallow wells which are used to place non-hazardous fluids below the land surface (U.S. EPA, 2005b).

Section 3.2 Beneficial Use of Produced Water

The beneficial use of produced water has become a popular water management alternative for regulators, operators, and landowners alike. Beneficial use in western states is considered a priority to prevent the potential wasting of a groundwater resource, and in many cases, oil and gas operators find beneficial uses to be a cost effective water management alternative. Additionally, the western United States' climate is arid, and therefore water quality impacts and water wasting issues are a great concern. As a result, developers and resource managers are requested to find beneficial uses for produced water while minimizing potential impacts to the environment.

Oil and gas operators are feeling pressure from both regulators and activist groups to find beneficial uses for the water produced with conventional oil and gas development activities. In general, some produced water is suitable for livestock and wildlife watering, agriculture, and other industrial uses. Beneficial uses of produced water have expanded in recent years with the invention of new treatment technologies. This has allowed more flexible management options for regulators to meet regional or local water needs. Examples of treatment technologies already in use are included in Section 4, and a discussion of cutting edge technologies currently being considered by the oil and gas industry is included in Section 5.

Conventional oil and gas produced water can be of varying quality with lower quality produced water having TDS concentrations >200,000 mg/l, where some of the produced water from shallower oil and gas development can range from 100's mg/l to 10,000's mg/l TDS. A discussion of the water quality in various domestic oil and gas basins is included in Section 4.

Higher TDS water typically will have more limited beneficial uses and treatment becomes more difficult and more expensive as TDS increases. Typically, water treatment technologies are limited to treating specific constituent types concentrated in water, e.g., dissolved solids, organics, conductive ions, etc. Depending on the eventual use of the water and the desired constituent concentrations, treatment processes are often coupled to achieve required water use objectives. For this reason, an integral aspect of the treatment process is the performance of water analysis to ascertain the presence of specific constituents for any given water source. This step provides various entities such as government agencies, oil and gas companies, or landowners the ability to choose a treatment technology (or technologies) best suited to achieve the necessary water quality objectives for beneficial use.

Although states typically will define what they consider a beneficial use (generally incorporating the EPA's beneficial use definition of livestock watering, wildlife watering, agricultural uses, and wetlands enhancement), other beneficial uses can include:

- **Agriculture** (impoundment stock water, irrigation, wildlife and waterfowl habitat, fish hatcheries, water leased)
- **Municipal** (domestic, fire protection, recreation uses)
- **Industrial/Commercial** (power, geothermal, mining, sediment control, erosion control, pollution abatement, navigation)

In most cases, state regulations do not require that produced water be used for beneficial use, but instead mandate water quality standards specific to state water classification schemes that must be satisfied prior to the water's beneficial use. The EPA, under 40 CFR Part 435, subpart E, provides the beneficial use exception rule to no discharge of produced water from oil and gas activities. This rule applies to the continental United States west of the 98th meridian, and allows for discharges of produced water if the produced water is clean enough to be used for wildlife and livestock watering or other agricultural use. Subpart E allows produced water of "good enough quality to be used for wildlife or livestock watering or other agricultural uses" but the water "must actually be put to such use during periods of discharge" (40 CFR Part 435, subpart E). However, Subpart E does not require beneficial use of good quality water nor does it require treatment of produced waters to meet the beneficial use options defined in Subpart E.

Section 3.3 NPDES Discharge Challenges

The evolution of CBNG development and other continuous type reservoirs has resulted in the need to manage large quantities of produced water that are considered to be of high quality. One of the most economical means of managing high quality produced water is through direct discharge to surface waters, which also provides benefit to downstream users.

Section 3.3.1 Challenges in Wyoming

As the number of direct discharge outfalls from CBNG increases in the Wyoming portion of the Powder River Basin, Wyoming regulatory agencies and the EPA have begun to scrutinize Wyoming's surface water quality and discharge regulations. Wyoming has primacy over their NPDES discharges, including produced water from both CBNG and conventional oil and gas operations. Currently, most of the discharges from conventional oil and gas development occur in watersheds that are Class 4, as defined by the Wyoming Chapter 1 surface water quality rules. Generally, Class 4 waters are those not designated as Class 1, where it has been determined that aquatic life uses are not attainable pursuant to the reclassification and site-specific criteria provisions (WDEQ, 2001). Some of the surface waters in which conventional oil and gas produced water is being discharged have developed into perennial streams, which could result in their ability to support some species of fish. Conventional oil and gas operators have developed concerns that such a scenario is occurring. As a result, the EPA might reclassify these surface waters to Class 3 or better, which would prevent continued discharge of produced water (WOGCC Staff Personal Communication, 2005). This would negatively impact the ability to discharge, which could affect the ability of downstream users to beneficially use the water and damage the stream's ability to support fish that have become acclimated to it.

Personnel with the oil and gas operators in the Bighorn Basin have expressed concerns that a reclassification of waters from Class 4 to Class 3 or higher would require discharges of produced water to meet the Chapter 1 Water Quality Criteria for Priority Pollutants of Aquatic Life. Oil and gas operators believe the produced water being discharged from the actively permitted outfalls would not be capable of meeting the Chapter 1 standards without treatment.

Draft changes currently available on the WDEQ Water Quality Division website for the Chapter 1 Surface Water Standards might be the cause of some of the concerns that operators are having specific to the Priority Pollutant - chloride. The draft Chapter 1 regulation changes have in part been created to address concerns from the high salinity discharges from CBNG that have resulted in the development of Acute Aquatic Life Criteria for chloride of 230 ppm and Chronic Aquatic Life Criteria of 860 ppm. These changes, if applied to the current Chapter 1 water classifications, would be applicable to Class 3 surface waters in Wyoming, and thus could affect existing discharges to surface waters. However, the changes that are proposed in the draft version of the Chapter 1 standards for chloride currently are applicable only to certain surface water classifications. The proposed chloride standards are for surface waters in Class 1, 2AB, 2B and 2C (WDEQ, 2005a). Therefore, the adoption of the draft three version of the Chapter 1 Surface Water Standards, even if accompanied by a lowering of classification of the surface waters to which oil and gas operators in the Bighorn Basin are discharging into, would not result in an implementation of the chloride standard unless those waters change from Class 4 waters to a Class 1, 2AB, 2B or 2C classification.

Section 3.3.2 Inter-State Challenges between Wyoming and Montana

Further complicating the management of CBNG produced water in the PRB is the fact that many of the significant watersheds in the basin flow in a northerly direction from Wyoming into Montana. This is the case with some of the major watersheds where CBNG development is occurring, including the Tongue and Powder River watersheds. In fact, much of the production from one of the thickest producing coal seams in the Wyoming portion of the basin, the Big George Coal, falls mainly within the Powder River Watershed.

In an effort to limit impacts to watersheds flowing into Montana, Wyoming and Montana are working together and have generally agreed to manage CBNG produced water in such a fashion to avoid any changes in quality and quantity of the various applicable watersheds. More recently, Montana has proposed new rules presently being considered by the Montana Department of Environmental Quality's (MDEQ's) Board of Environmental Review (BER) to further restrict discharges of CBNG produced water. These proposed rules would change the way water would be managed throughout the entire PRB. Two of the more significant proposed amendments include Rules II and VIII.

Proposed Rule II is a "zero discharge" requirement applicable to the Montana Pollutant Discharge Elimination System (MPDES) program. This proposed new rule requires that "*(1) except as provided in [New Rules III through IX], point-sources of methane wastewater shall achieve zero discharge of pollutants, which represents the minimum technology-based requirement. Zero discharge shall be accomplished by reinjection [sic] of methane wastewater into suitable geologic formations in the project area in compliance with all other applicable federal and state laws and regulations*." The rule does provide a means to obtain an exemption from the injection requirement, but timeframes to obtain an exemption may be greater than 12 months as the rule is currently proposed.

Proposed Rule VIII establishes "*treatment-based effluent limitations*" for CBNG produced water. The proposed rule requires that "*(1) If the department grants a waiver from the zero discharge requirement for all or a portion of the wastewater pursuant to [New Rules II and III], the amount of wastewater that obtains the waiver shall achieve the following minimum technology-based effluent limitations at the end of the pipe prior to discharge*:

(a) calcium average concentration between 0.1 mg/L and 0.2 mg/L;
(b) magnesium average concentration between 0.1 mg/L and 0.6 mg/L;
(c) sodium average concentration of 10 mg/L;
(d) bicarbonate average concentration of 30 mg/L and instantaneous maximum concentration of 115 mg/L;
(e) sodium adsorption ratio instantaneous maximum of 0.5;
(f) electrical conductivity average concentration of 233 µmhos/cm;
(g) total dissolved solids average concentration of 170 mg/L;
(h) ammonia average concentration of 0.1 mg/L and instantaneous maximum concentration of 0.3 mg/L; and
(i) arsenic concentration of <0.0001 mg/L."

Evaluation of the proposed amendments suggests that implementation of the new rules would significantly impede and/or likely cause the cessation of current and future CBNG development in the Wyoming portion of the PRB. Implementing a zero discharge requirement likely would reduce production by 25 percent immediately upon enforcement of the rule. Within one year of implementation, production rates are expected to decrease by as much as 50 percent. Within five years, production likely would decline by 90 percent, eliminating much (if not all) of the potential production in the region.

Section 3.4 UIC Program Challenges

UIC wells for the management of produced water from conventional oil and gas activities are typically EPA Class II injection wells. Increasingly, however, produced water is being managed by way of Class V and Class I wells.

Section 3.4.1 The Evolution of Class V Wells

As oil and gas development expands into continuous reservoirs, the quality of water produced with the resources increases. As a result, water management options increasingly have begun to include the use of Class V injection wells. Class V injection wells have been used for aquifer recharge and aquifer storage and recovery in parts of the Rocky Mountain West as a means to beneficially manage produced water for future uses, including public water supply and as irrigation water. Class V wells are being used to manage large volumes of produced water from oil and gas production, something Class V was never meant to do. Class V wells that inject large volumes of produced water could be regulated as Class II wells by Class II agencies. If water is not being directly injected into active USDWs, the Class II agency has the background and regulatory framework to oversee wells that manage high volumes of low-toxicity wastes.

Another question that has been raised by industry is whether subsurface irrigation could be considered to be a Class V injection activity. Subsurface irrigation facilities have the ability to manage large volumes of produced water, enabling ranchers and farmers to grow large amounts of hay and grain. The facilities share construction details with infiltration trenches that do not require Class V permits. Permitting subsurface irrigation in a reasonable manner will be a challenge for UIC regulators in the near future. Steps recently have been taken in Texas to allow for an authorization by rule; thus Class V approvals for subsurface drip irrigation have been streamlined to take no longer than 60 days (TCEQ, 2006). Similar steps can be taken in other states as well, as appropriate.

Section 3.4.2 Classification of Brine

Water produced with oil and gas can be treated to beneficial use standards. In the process of treatment, concentrated brine often is generated as a by-product. In respect to regulatory concerns, the brine is no longer considered as oil and gas production waste, and therefore does not qualify for the oil and gas exemption provided in the federal Resource Conservation and Recovery Act (RCRA). The brine can represent as little as 1% of the produced water volume, or as much as 70% of the produced water volume, depending on the quality of the produced water and the treatment process; however, it is considered an industrial process waste once the produced water has been treated. Currently, this brine can be determined to be either a Class I or Class II industrial process waste, and different states might have different criteria for making this determination. Classification of the brine appears to be sensitive to a number of things such as the physical arrangement of the treatment plant, the corrosiveness of the brine, and the use of the treated water. The classification may need to be standardized across the country to prevent the brine from being classified differently in the same basin, based on in which state the brine is generated.

Section 3.5 Watershed Based Permitting

The primary objectives of watershed based permitting are to develop an improved permitting process for surface discharges, improve environmental protection, and provide for more informed permitting decisions within a watershed by the governing regulatory agency. The approach is intended to: 1) provide a clear understanding of the limits and constraints of discharging produced waters; 2) provide equitable distribution of finite assimilative capacity; and 3) improve the mechanism to hear and address concerns of the stakeholders and understand the competing interests involved with the discharge of produced water. The holistic approach of looking at the impacts to an entire watershed allows the governing regulatory agency to make more informed decisions with regard to permitting discharges into the watershed.

Until recently, watershed based permitting had not been attempted. However, in 2005 the WDEQ implemented a watershed based approach to permitting discharge of CBNG produced waters into the Powder River watershed. Therefore, the steps the WDEQ has taken to implement watershed based permitting are included in Section 3.5.1 as a template for other state agencies to use in determining whether or not watershed based permitting would benefit their state. Advantages and disadvantages of watershed based permitting are discussed in Section 3.5.2.

WDEQ's approach was intended to address concerns over the increasing quantities and decreasing quality of produced water from CBNG development. A heightened concern by stakeholders over the cumulative impacts also spurred the process. These stakeholders include the landowners in Wyoming and downstream states of Montana and South Dakota, regulatory agencies in these states, and environmental interest groups.

Parallel to the watershed based permitting process, the WDEQ developed an assimilative capacity allocation and control process for the Powder River mainstem to further preserve and protect the Powder River. The assimilative capacity control process has not been implemented at this time, but is expected to be in place soon. The Program Policy was issued for public comment and was presented in a September 2005 meeting of the Wyoming Water and Wastewater Advisory Board. The assimilative capacity control process will control the amount of TDS and sodium that can be discharged by CBNG produced water by using the calculated assimilative capacity of the Powder River and 'credits' calculated from coal volumes under an operator's leased acreage. A description of the policy is included in Section 3.5.3 along with the implications of the calculated credits.

Section 3.5.1 The Process

The watershed based permitting process is a holistic approach that looks at surface water uses and processes within an entire watershed. The process can first be initiated by identifying all the stakeholders within a pre-defined watershed. These stakeholders may include government agencies, operators, landowners and users, and environmental interest groups. An initial public meeting can be held to discuss the watershed based permitting process.

The next step can be collection of information about the surface water uses within the watershed. This information may be collected from sources that include the operators, landowners, USGS, EPA, BLM, Wyoming State Engineer's Office (SEO), WDEQ, WOGCC, Wyoming Game and Fish Department, and the conservation districts. The data collected might include information on seasonal stream flow quantity and quality, irrigation use, channel capacity, topography, erosion, and produced water quality and quantity. These data can be analyzed and summarized to identify water quality objectives. Water quality objectives may include:

- Target flow volume limit, determined for each watershed.
- Target concentrations of constituents of concern, determined for each watershed.
- Potential water users.

Based on these water quality objectives, discharge options can be evaluated, selected, and discussed with all area stakeholders at a public meeting. Current discharge options may include irrigation, on- and off-channel storage, direct discharge, treatment and discharge, re-injection, and consolidation of outfalls.

Monitoring locations can be established within the watershed and a monitoring plan can be developed. The monitoring plan may address the constituents of concern, sampling and reporting frequency, responsibilities, and contingencies. Permitees can be held responsible for monitoring and reporting, and can conduct these activities independently, or they can collaborate with other permit holders within the watershed.

The governing agency might then develop permit conditions and draft the permit. It is up to the area stakeholders involved whether a general permit will be issued for the watershed or if individual permits will be required. If a general permit is issued, a notice to the public may be published and the permit made available for public review and comment. The governing agency can respond to public comments, if any, and then issue the permit. The general permit can define TDS and sodium limits within the watershed at the monitoring points. The permit can also establish cumulative discharge limits for all the discharge points above the monitoring points. These discharge limits may be year-round limits or vary month-by-month, but are not to be exceeded.

Any operator wishing to discharge under a general permit must submit a notice of intent to discharge to the governing agency prior to discharge. The notice of intent will specify the location of discharge points and the maximum discharge volume. The notice of intent also will supply analyses of the proposed discharge water to demonstrate its similarity to prevailing produced water quality standards.

If stakeholders require individual permits, then a permit application must be filed by the operator and reviewed by the governing agency. The agency would then draft an individual permit, issue it for public review and comment, and then prepare a final permit after the comment period.

Currently, the watershed based permitting process is underway for the undeveloped hydrologic unit code (HUC) 10 watersheds within the Powder River Drainage. As existing WPDES discharge permits for CBNG produced water expire, they will be rolled into a watershed based permit, either general or individual, based on the preference of the watershed stakeholders. CBNG produced water discharges within the Tongue and the Belle Fourche drainages in Wyoming will be subject to watershed based permitting in the future (WDEQ, 2005b).

Section 3.5.2 Advantages and Disadvantages

The primary advantage of watershed based permitting is the involvement of all stakeholders and management of assimilative capacity within the watershed. Each stakeholder is given the opportunity to voice concerns and be included in decision making during the permitting process. As such, one disadvantage is the process may be exhaustive and can prolong the permitting process.

Section 3.5.3 Assimilative Capacity Allocation and Control System

Parallel with the watershed based permitting process, the WDEQ has developed an Assimilative Capacity Allocation and Control System for protecting and managing the surface water quality of the Powder River consistent with both Wyoming and Montana conditions while providing for the development of the CBNG resources of Wyoming. A draft Program Policy was developed and issued for public comment. The WDEQ worked toward implementation of the policy, and believed it would be in effect in early 2006 (WDEQ, 2005b). Implementation of the assimilative capacity and control system on the Powder River mainstem involves five principle parts:

1) **Determine the assimilative capacity of the Powder River mainstem.** The WDEQ will use ambient water quality data collected at the USGS gauging station near Moorehead, Montana, in predictive models to assess the assimilative capacity of the Powder River. The available load will be calculated in pounds per day for each month and will be reduced by 5 percent to allow a reasonable margin of safety.
2) **Establish credits for assimilative capacity.** The modeled assimilative capacity will be divided into credits representing 10 pounds of total dissolved solids or sodium. The credits will be calculated from the CBNG operator's share of mineral lease acreage multiplied by the calculated coal volume under the lease. Each credit is valid only for the month in which it is calculated and issued. Historical monthly flows of the Powder River are used for monthly allocation of credits.
3) **Regulate credits through issuance of a general permit.** A general permit will be the vehicle used to regulate and allocate the calculated available mass loading of TDS and sodium for discharges of CBNG produced water in the entire Powder River mainstem watershed. The WDEQ will issue this permit after public notice and comment.
4) **Establish a Credit Registration procedure.** The Wyoming Geological Survey (WGS) will act as the Registrar and will implement the registration procedures. The WGS will issue a map and list calculated coal thicknesses, by section, of the Powder River watershed. For the purposes of the assimilative capacity allocation and control policy, it will be assumed that all coal seams will produce the same volume of water per measured unit of thickness.
5) **Establish a Credit Tracking Mechanism, or credit bank.** Permitted discharges based on appropriated credits will be debited from the appropriate CBNG operator's credit bank account, which will be managed by the WDEQ. Individual and/or watershed permits will continue to regulate limits required by Chapter 1 and Chapter 2 (WWQRR) and as necessary to protect local and watershed conditions in addition to TDS and sodium for the Powder River mainstem.

General Powder River Mainstem Permit and Credits

All CBNG produced water discharging into the Powder River mainstem, tributaries, and on-channel reservoirs will require an applicable general, individual, or watershed permit in accordance with the Chapter 2, WWQRR. Upon implementation of the Assimilative Capacity Policy, new and renewed CBNG produced water discharge permits will be issued in conformance with available credits authorized by the Powder River Mainstem General Permit. Dischargers will continue to comply with their existing permit until reopened, renewed, or a major modification is made, at which time the individual permit will be brought into conformity with the Assimilative Capacity Policy.

Upon application for a new permit, a major modification to an existing permit, or a permit renewal, the permittee must submit a water management plan that describes how the produced water will be discharged/managed through the use of credits, treatment, impoundment, or other means. The WDEQ will then verify through the credit bank that the applicant has sufficient credits or facilities to implement its water management plan.

THIS PAGE INTENTIONALLY LEFT BLANK

SECTION 4.0 PRODUCED WATER MANAGEMENT PRACTICES

It is paramount that produced water be managed in innovative ways that will both reduce the operational cost to produce oil and gas reserves as well as be protective of the environment. A common misconception is that there is one management practice that will work throughout the United States to manage the produced water in a responsible way. Quite the opposite is true. In fact, produced water management practices vary widely across the United States, and in some instances across a single oil and gas field. Produced water management falls under two broad categories: underground injection and surface management. Water treatment is also a produced water management practice, but the end result of a water treatment facility is 1) a higher quality stream of water that must be managed at the surface, and 2) a concentrated stream of wastewater that must be disposed through underground injection. Therefore, water treatment is discussed at the end of this section as a means of transforming the water quality to make best use of the water as a resource, and not as a "management practice".

Underground Injection encompasses a wide range of water management practices. The EPA classifies five different injection well categories, and three of them are applicable in one way or another to the management of produced water from oil and gas development. In general, oil and gas produced water is an exempt waste and therefore can be injected in Class II or Class V injection wells. Operators of Class II wells inject fluids associated with oil and natural gas production (EPA, 2005). Class II injection wells can either be classified as disposal wells (IID) or as enhanced recovery wells (IIR). The process wastewater that is the result of produced water treatment, however, does not carry the same exemption; therefore it must be disposed of in a Class I injection well. The EPA defines Class I wells as technologically sophisticated wells that inject hazardous and non-hazardous wastes below the lowermost underground source of drinking water (USDW). Injection occurs into deep, isolated rock formations that are separated from the lowermost USDW by layers of impermeable clay and rock (EPA, 2005). Class V wells (i.e. shallow injection, subsurface drip irrigation) are injection wells that are not included in the other classes, and generally their simple construction provides little or no protection against possible groundwater contamination; therefore, it is important to control what goes into them (EPA, 2005).

Surface Management includes all water management practices where the water (whether it be raw produced water, or treated produced water) is managed at the surface by either discharging directly into a water course, into an impoundment, or to the land for some beneficial use. Once the water has been brought to the surface, a number of techniques, processes, approaches, and/or beneficial uses can be applied to enhance the management of the water and lower the associated costs for the operator. These include, but are not limited to, surface impoundments (i.e. stock watering/irrigation storage ponds, evaporation ponds, enhanced evaporation/aeration ponds, recreational ponds, constructed wetlands) and industrial uses (i.e. cooling tower water, dust suppression, truck wash station, oil and gas completion activities).

As noted above, there is a wide range of water management practices and alternatives that fall under these two categories. This section provides a more detailed description of these water management practices and alternatives. Class I wells are discussed in terms of the applicability and constraints for managing the process wastewater from water treatment processes. Class II wells, Class V wells, and the various surface management practices are discussed in terms of their applicability and their constraints for managing produced water.

Section 4.1 Class I Injection

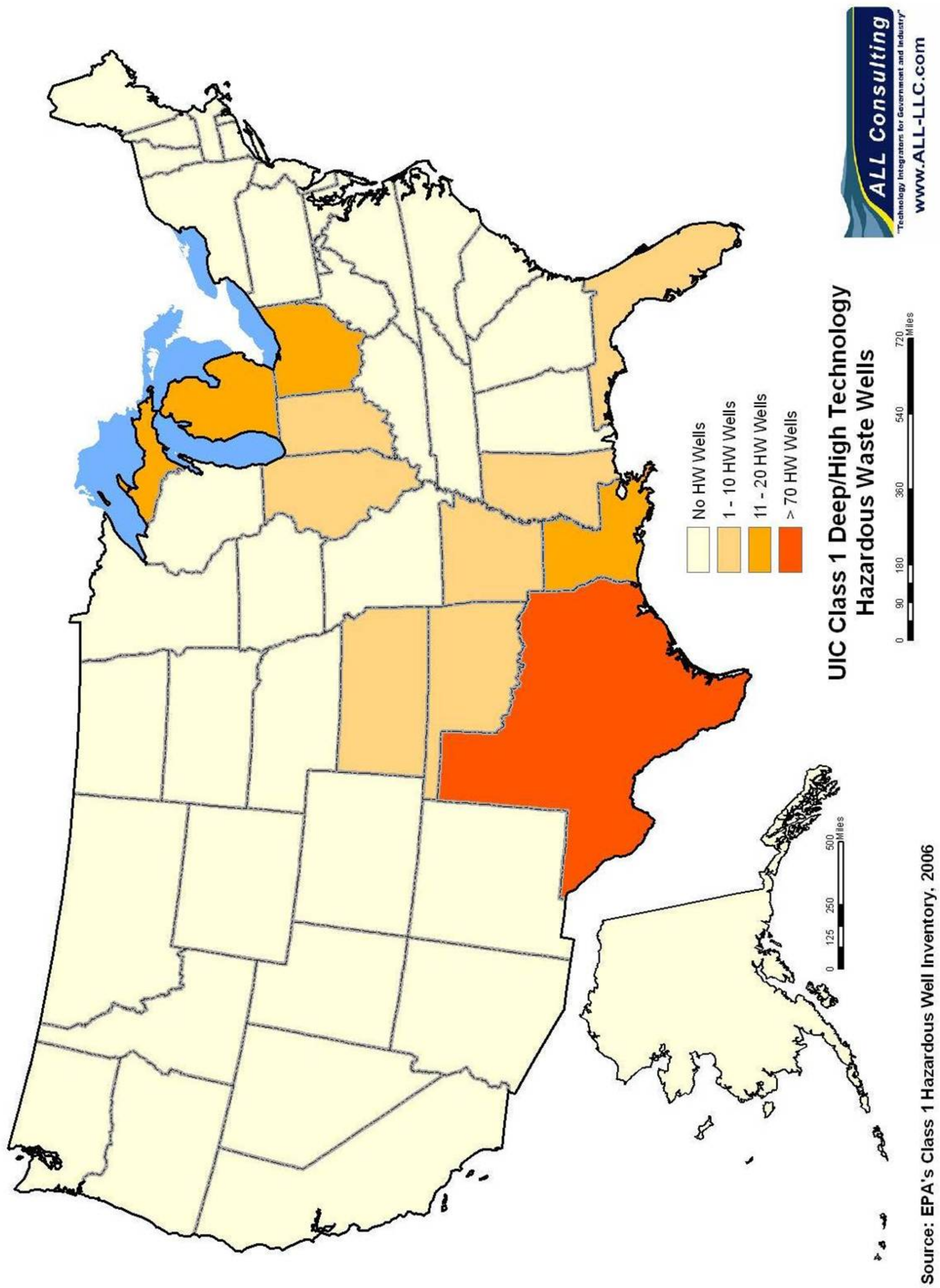
Class I injection wells are technologically sophisticated wells that inject large volumes of industrial hazardous or non-hazardous wastes into deep, isolated rock formations that are separated from the lower most USDW by layers of impermeable clay and rock. Although most hazardous waste fluids are treated and released to surface waters, Class I wells account for 89 percent of the hazardous waste fluids disposed of on land (GWPC, 2006). Class I wells are classified as hazardous or non-hazardous, depending on the characteristics of the wastewaters injected. For instance, municipal waste is classified as non-hazardous. The EPA regulates Class I underground injection wells under the Safe Drinking Water Act (SDWA) and the Hazardous and Solid Waste Amendments of the Resource Conservation and Recovery Act (RCRA). These regulations establish siting, design, construction, and monitoring requirements for these injection wells to ensure protection of USDWs from injected wastewater (EPA, 2001a).

Underground injection of wastewater began in the 1930s when oil companies began disposing of oilfield brines and other oil and gas waste products into depleted reservoirs. Most of the early injection wells were oil production wells converted for wastewater disposal. In the 1950s, injection of hazardous chemical and steel industry wastes began. At that time, four Class I wells were reported; by 1963, there were 30 wells. In the mid 1960s and 1970s, Class I injection began to increase sharply, growing at a rate of more than 20 wells per year (EPA, 2001a).

Currently, under the UIC Program, the EPA and the states regulate more than 400,000 injection wells. Class I wells comprise less than 1% of the injection wells in the U.S. (GWPC, 2006). There are 272 active Class I injection facilities nationwide. Of these, 51 are hazardous and 221 are non-hazardous. These 272 facilities maintain approximately 529 Class I injection wells that are scattered throughout the U.S. in 19 states (EPA, 2006). The 51 hazardous injection facilities are composed of 163 Class I hazardous waste injection wells, most of which are located in Texas (78) and Louisiana (18) (see Figure 4.1). Eleven of the facilities are commercial hazardous waste injection facilities. These are the only facilities that can accept hazardous waste generated offsite for injection. Ten of them are located in the Gulf Coast region while one is located in the Great Lakes region. There are 366 Class I non-hazardous injection wells nationwide. While these wells are scattered through 19 states, most of them are found in the states of Florida (112) and Texas (110) (EPA, 2006).

Class I wells are used mainly in the petroleum refining, metal production, chemical production, pharmaceutical production, commercial disposal, and municipal disposal industries (EPA, 2006). However, almost half of the fluids injected into non-hazardous and municipal waste injection wells are manufacturing wastes; municipal effluent accounts for approximately 28% of the Class I non-hazardous wastes (GWPC, 2006).

Figure 4.1 Approximate Class I Well Count in Each State



Applicability

The use of Class I injection wells for produced water management has limited applicability to the oil and gas industry. However, certain circumstances may arise that will require or dictate disposal via Class I injection. If produced water is used for industrial purposes, then the disposal of the water could be required by use of a Class I injection well (ALL and MBOGC, 2002). Additionally, concentrated produced water waste streams generated as a byproduct from certain treatment technologies (e.g., reverse osmosis, ion exchange, distillation, etc.) could require disposal using Class I injection wells.

Constraints

Class I wells must be sited so that wastewaters are injected into a formation that is below the lowermost formation containing, within one-quarter mile of the well, a USDW (EPA, 2001a). Typically, Class I fluids are injected deep into geologic formations thousands of feet below the land surface composed of brine-saturated formations or non-freshwater zones. In the Great Lakes region, for example, injection well depths typically range from 1,700 to 6,000 feet; in the Gulf Coast, depths range from 2,200 to 12,000 feet or more (EPA, 2001a). Fluids at these depths move very slowly, on the order of a few feet per hundred or even thousand years, meaning that fluids injected into the deep subsurface are likely to remain confined for a long time (EPA, 2001a).

EPA requires that Class I wells be located in geologically stable areas that are free of transmissive fractures or faults through which injected fluids could travel to drinking water sources (EPA, 2001a). Well operators must also show that there are no wells or other artificial pathways between the injection zone and USDWs through which fluids can travel. Extensive pre-siting geological tests can be used to confirm that the injection zone is of sufficient lateral extent and thickness, as well as sufficiently porous and permeable, so that the fluids injected through the well can enter the rock formation without an excessive build-up of pressure and possible displacement of injected fluids outside of the intended zone (EPA, 2001a). In addition this "injection zone" should be overlain by one or more layers of relatively impermeable rock that will hold injected fluids in place and not allow them to move vertically toward a USDW (confining zone)(EPA, 2001a).

In 1984, Congress enacted the Hazardous and Solid Waste Amendments (HSWA) to RCRA that banned the land disposal of hazardous waste, unless the hazardous waste is treated to meet specific standards. EPA amended the UIC regulations in 1988 to address the Hazardous and Solid Waste Amendments. Operators of Class I wells are exempt from the ban if they demonstrate that the hazardous constituents of the wastewater will not migrate from the disposal site for 10,000 years or as long as the wastewater remains hazardous. This demonstration is known as a no-migration petition (EPA, 2001a and EPA, 2006).

Section 4.2 Class II Injection

Injection wells used for disposal or enhanced recovery below any USDW are classified by the EPA as Class II wells, and they commonly are used for managing produced water in conventional oil and gas operations. Class II wells have to follow strict construction and conversion standards except when historical practices in the state and geology allow for different standards. A Class II well that follows EPA federal standards is built very much the same as a Class I well. There are approximately 167,000 oil and gas injection wells in the United States, most of which are used for the secondary recovery of oil. The majority of the oil and gas injection wells are located in the Southwest, with Texas having the largest number (53,000) and California, Oklahoma, and Kansas following some distance behind with 25,000, 22,000, and 15,000 wells, respectively. Figure 4.2 shows the approximate count for Class II injection wells in each state.

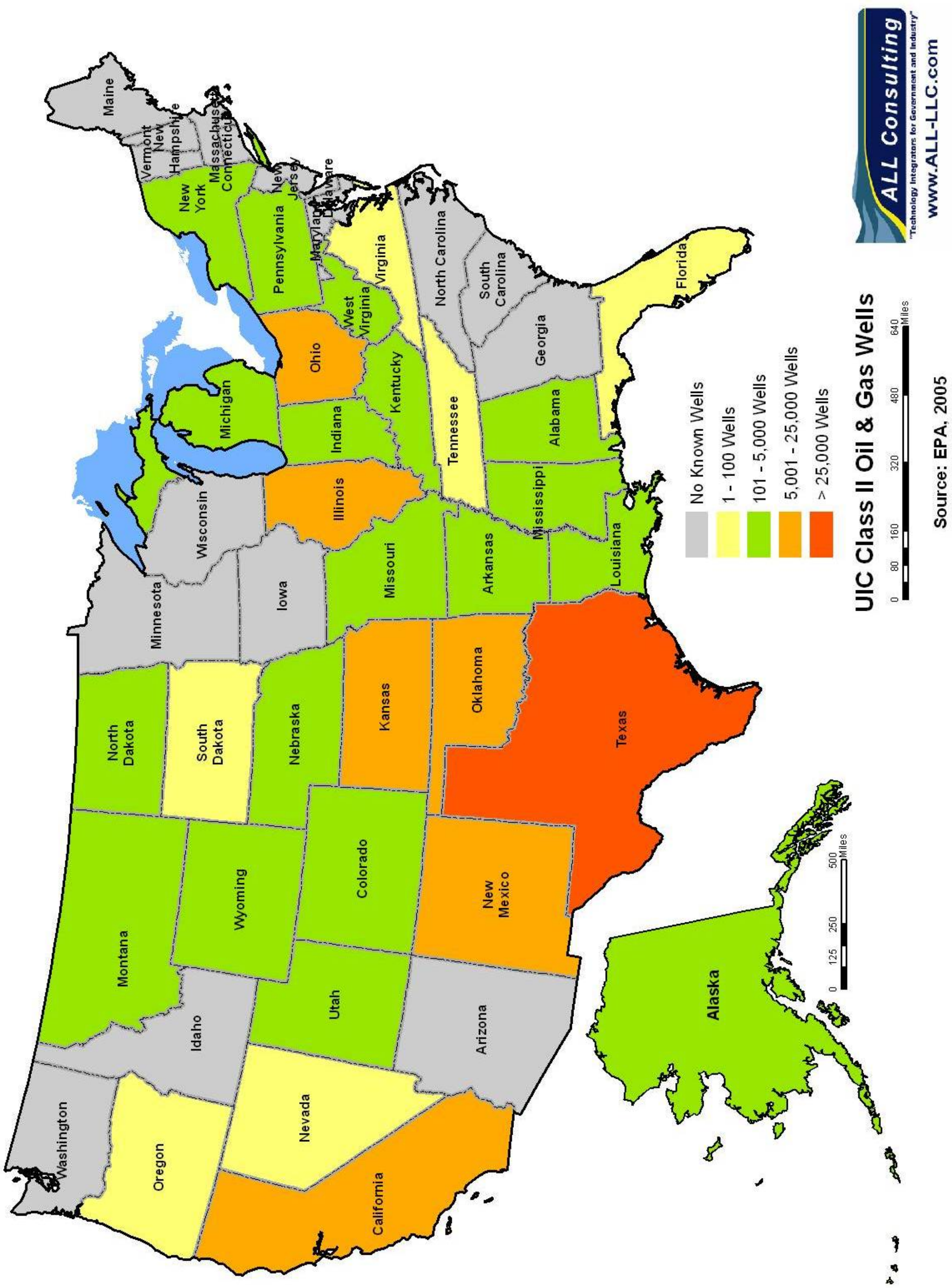
Class II injection wells are subdivided as either IID (for disposal) or IIR (for secondary oil recovery). Over 2 billion gallons of produced water are injected daily into Class II injection wells in the United States (EPA, 2005). The largest portion of the water is injected into Class IIR wells. In a common configuration, one injection well is surrounded by four or more extraction wells. The recovered fluid is sent to a phase separator where the oil, gas, and water can be separated. In Class IID wells, excess water from production and some other activities directly related to the production process are injected solely for the purpose of disposal.

Applicability

Class II injection is applicable for a wide range of produced water quality in terms of TDS; however, for produced water that is of high quality (i.e. TDS less than 10,000 mg/L) Class II may not be a reasonable option as the water resource may be wasted through injection into a lower quality aquifer. Successful Class II wells may be able to accept more than 50,000 barrels of water per day while unsuccessful wells will take little or no water.

Class IIR injection is applicable in many conventional oil fields. Waterfloods consist of a number of injection wells in a particular field that are coordinated to move the oil that remains in the target reservoir toward the producing wells in the subject field. A waterflood project can consist of less than a dozen wells or several hundred wells. Each of the operating waterfloods uses injection wells to inject water back into the oil reservoir to maintain reservoir energy and drive more oil toward the producing wells. The injected water can be water produced from the field being waterflooded, or it can be "make-up" water obtained from another source. In some cases the original field wells do not produce enough water with the oil to support a flood project and in those cases the operator will either postpone the flood project or will find make-up water from nearby production, surface water, or groundwater produced through water supply wells. As the waterflood continues, the reservoir fills up and eventually the injected water and additional oil will be seen at the producing wells. As production continues, the water produced in the oil wells replaces make-up water and the flood becomes more or less self-sustaining so no outside water is needed.

Figure 4.2 Approximate Class II Well Count in Each State



Class IID injection is applicable into underground reservoirs that are greater than 10,000 mg/L TDS or are identified as an exempted aquifer. Deep aquifers that could be suitable for injection may contain less than 10,000 mg/L TDS and would require an aquifer exemption in order to receive injectate. Aquifer exemptions are written in federal EPA regulations and are meant to avoid giving full protection to aquifers that will never be used for public water supply because of the cost of producing and treating the water. It would be risky to put a depth limit or water quality limit on an aquifer before it might qualify for an aquifer exemption; if the aquifer is deeper than 10,000 feet, it is unlikely that it would be an economic source of drinking water for a public water supply. These deep Class IID wells are generally expected to be able to inject large volumes of water in an environmentally safe and unobtrusive manner. These injection zones can be very deep and isolated by thick, impermeable confining zones safely confining the injectate away from drinking water aquifers. Wells will be inherently safe, thus providing minimal environmental concerns.

Technological advances in the use of Class II wells has lead to the development of horizontal disposal and enhanced recovery wells that have opened up new fronts in once marginal fields. In the Oklahoma City field of the Arkoma Basin, once thought depleted, a process known as "de-watering" has proven to be effective in recovering oil and gas along with high volumes of water. The process is economical due to the efficient water management system that runs the water through a high volume phase separator prior to injection of the water in a horizontal disposal well capable of handling 60,000 barrels of water per day.

High Volume Phase Separator Used in a "De-watering" Project (Oklahoma)

Constraints

Feasibility of underground injection as a tool for managing produced water involves several technical considerations including geologic, economic, and engineering questions. These may vary significantly by operator and location. There are, however, a common set of questions that must be answered for any proposed injection well (ALL, 2006), including:

- **Formation Suitability**: Selection of a suitable injection zone potentially might include reservoir characteristics; depth; relative location to producing wells and locally important aquifers; significance of local fracturing and faulting; condition of active and abandoned wells within the area; as well as other artificial penetrations.

- **Isolation**: The receiving formation must be vertically and laterally separated or otherwise confined from other USDWs. The well must also be equipped to isolate the receiving zone from other porous zones in the well to avoid unauthorized fluid movement into zones that are not permitted for injection.

- **Porosity**: Porosity is the percentage of void spaces or openings in a consolidated or unconsolidated material (EPA, 1999). Reservoir rocks are typically high in porosity, while confining zone rocks range from high to very low porosity.

- **Permeability**: Permeability is defined as a measure of the relative ease with which a porous medium can transmit a liquid under a potential gradient (EPA, 1999). A reservoir rock will have sufficiently high permeability to allow fluid movement. Confining zone rocks will have very low permeability and will act as seals rather than zones of fluid movement. Often porosity and permeability are not correlative; highly porous sands can have very low permeability while low porosity sands can be highly permeable due to natural fractures.

- **Storage Capacity**: The storage capacity of a geologic unit can be estimated using a simplistic approach by estimating the pore volume of the entire injection zone.

- **Reservoir Pressure**: The reservoir pressure is the static pressure within the receiving formation expressed either as pound per square inch or fluid head. Reservoir pressure may limit the rate at which fluids can be injected and/or may limit the total volume of fluid that can be injected.

- **Water Quality**: The quality and chemistry of water of the injectate and water within the receiving formation will determine the type of injection well to be used. The chemical compatibility of their fluids will also play a part in the feasibility assessment of the injection plan. Compatibility tests can be run prior to installing necessary pipelines to deliver the water. In order to be reliable, the test will require sidewall or full-hole cores of the reservoir; these are usually obtained when an oil operator is beginning to exploit a new field. Important aspects of a compatibility test will be pore-throat size range to determine the filter system and the presence of clays and other mineral grains that can react, swell, or become mobile when exposed to the injected water. If incompatibility is discovered, the testing contractor will be able to recommend a chemical additive that may prevent the reaction.

Technically feasible injection requires that the injection rate is sufficient for the operator's needs without exceeding the fracture pressure of the confining zone. The operator can test the injection zone to verify fracture pressure and injectivity – the injection rate as it is related to the injection pressure. Injection pressure can exceed the fracture pressure in the injection zone but cannot exceed the fracture pressure of the confining zone. This is best determined by step-rate tests. Prior to use, the injection zone may need to be stimulated by way of acidization or fracturing. This might involve pumping small amounts of weak acid or large volumes of fluid with sand to prop open the fractures in the injection zone (ALL, 2006).

Class IID deep wells must be demonstrated to be safe and protective of the environment. Mechanical and engineering integrity must be shown prior to the well being used; the injection zone must be isolated from other aquifers and USDWs. The operator must show that the deep injection zone is isolated from other permeable zones away from the borehole and the injection perforations are isolated from the long-string casing in the well. The former – stratigraphic isolation – can be demonstrated by wire-line log cross-sections through the proposed injection well and nearby wells; stratigraphy can illustrate local and regional isolation. At the same time, integrity of the injection tubing and packer on top of the injection perforations can be tested by pressuring up on the long-string casing to check for leaks.

Section 4.3 Class V Injection

Class V injection wells are defined by the EPA as any well that does not fit under the other four classes (I, II, III, and IV). Typically, Class V injection wells are shallow "wells," such as septic systems and drywells, used to place non-hazardous fluids directly below the land surface. The minimum requirements for a Class V injection well have been set by Volume 40 of the Code of Federal Regulations (40 CFR) Sections 144-147, as well as within state promulgated Rules and Regulations. The EPA estimates there are more than 650,000 Class V wells in the United States (EPA, 2001b). Examples of Class V injection wells used to manage produced water include:

> **Subsurface Drip Irrigation (SDI)** supplies water to crops by a system of hoses and pipes buried in a network of trenches under the field within the root zone of the crops. SDI allows enhanced crop production without negative environmental impacts associated with leaching or runoff. Water can be applied year-round instead of just during the typical growing season of most crops, allowing for more water to be beneficially used, and reducing or eliminating the need to store produced water during winter months. SDI application of water during non-growing months may not represent irrigation but may be seen as a beneficial use in the aid of the soil and subsoil, flushing the salts below the root zone. An added benefit is an increase in crop production for the surface landowner.
>
> **Aquifer Storage and Recovery (ASR)** is the process of injecting water into an aquifer for storage and subsequent recovery for beneficial use using the same well. Beneficial uses include, but are not limited to, public drinking water, agricultural uses, future recharge, and industrial uses. The storage aquifers may be the primary drinking water source for a region, a secondary drinking water source, or may be used for agricultural or industrial purposes. ASR is regularly used in areas with no drinking water source, areas undergoing seasonal depletions, and in areas where salt water is intruding into the fresh water aquifer (EPA, 1999). When injection is considered using Class V type wells for beneficial uses, pre-treatment of the produced water may be required before it is injected into an aquifer for either recharge or ASR. For example, treatment of water may be required to prevent the injection of bacteria contaminated water when the water has been temporarily stored in an impoundment.

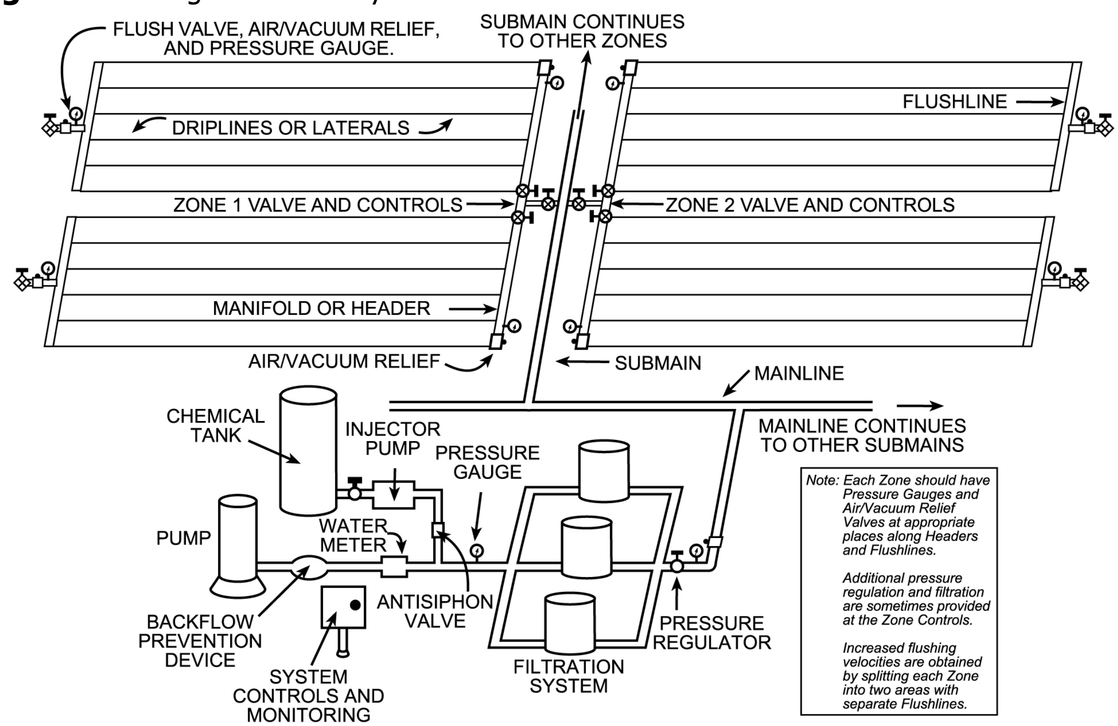
Section 4.3.1 Subsurface Drip Irrigation (SDI)

Irrigation is a common and proven beneficial use of produced water when the water quality is sufficient and compatible with soil conditions. In arid regions, good sources of water for irrigation are not abundant except near rivers and reservoirs; therefore, good sources of usable water are desirable for farmers and ranchers for irrigation use. Some of the problems associated with typical surface irrigation include soil crusting on the surface, dispersion, and salt accumulation in the root zone. SDI supplies water to crops by a system of hoses and pipes buried in a network of trenches under the field. The water enters the soil below the soil surface avoiding these problems. Subsurface drip irrigation has long been used in Israel and Australia with high quality and saline water (KSU, 2005). Figure 4.3 illustrates a typical SDI system.

Applicability

SDI appears to be a well suited type of irrigation available for use with produced water as it avoids some of the drawbacks of surface irrigation. There is increased flexibility in matching field shape and field size, and SDI's pressure compensating systems are not as limited as surface irrigation in regard to the slope. Furthermore, since the SDI process applies irrigation water to the subsurface, operators might be able to pump water year round; field operations can occur during irrigation; less irrigation equipment is exposed to vehicular damage; there is no surface soil crusting; any salt accumulation is below the root zone; there is less or no runoff into streams; and reduced weather-related application constraints (especially high winds and freezing temperatures). Other advantages include decreased energy costs as compared to other irrigation systems; improved in-field uniformities, resulting in better control of the water, nutrients and salts; and the SDI system can be easily and economically sized to the available water supply.

Figure 4.3 Diagram of SDI System



Source: KSU, 2005

Crop selection is also important with the use of SDI. Optimum plant species will vary with different regions of the United States. Perennial crops are the most suited for SDI, with alfalfa and refined grasses as some of the better candidates. Alfalfa, a forage crop, has high crop water needs and, thus, can benefit from highly efficient irrigation systems such as SDI. In some regions, the water allocation is limited by physical or institutional constraints, so SDI can effectively increase alfalfa production by increasing the crop transpiration while reducing or eliminating soil evaporation. Since alfalfa is such a high-water user and has a very long growing season, irrigation labor requirements with SDI can be reduced relative to less efficient alternative irrigation systems that would require more irrigation events. Currently, SDI is used to irrigate a number of alfalfa fields in the Powder River Basin of Wyoming, and it is estimated that about 60 inches of water can be applied annually, with the crop using 40 inches of that water through evapotranspiration (Zupancic, 2005). Continuation of irrigation reduces the amount of water stress on the alfalfa and, thus, can increase forage production that is generally linearly related to transpiration. Salt tolerant or moderately tolerant grass species such as halophytes or mixes of grass should be chosen for use with SDI.

Constraints

Constraints that may limit the attractiveness of utilizing a SDI system include, but are not limited to:

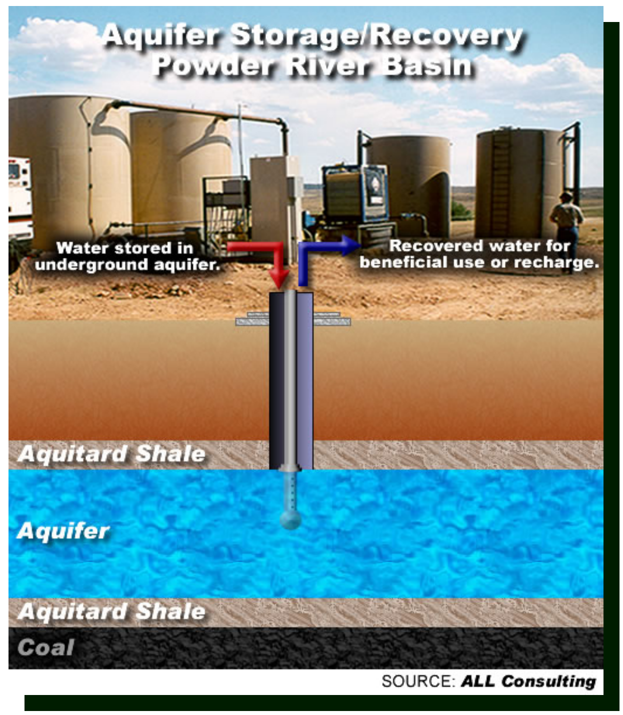
- **Regulatory -** Permits vary from state to state. The permitting process can add to the time required before the operator can start using SDI irrigation with oil and gas produced water and can add to the cost of implementation.
- **Water Pre-Treatment –** Proper leaching leads to flushing salts below the root zone by applying more water than the plant needs. There is a potential for salt accumulation to occur above the root zone if appropriate leaching is not performed during irrigation. Often this leaching process can be facilitated by natural rainfall. However, gypsum, or other amendments, might need to be used to help reduce SAR in the soil.
- **Operational Challenges –** Various operational issues exist that may cause constraints to the installation of a SDI system. Examples include limitations to soil tillage options, lack of ability to visually inspect the system to troubleshoot malfunctions leading to more difficult subsurface repairs, and root intrusion into drip lines.
- **Groundwater Impacts –** If the groundwater in alluvial aquifers is shallow, there could be a possibility that saline water could affect the aquifer. For groundwater to be impacted by SDI systems, saturated flow must exist through the soil/unsaturated zone to the point where water is moving in a continuous wetting front under gravity to the groundwater table. If produced water is applied in accordance with crop needs, soil water holding capacities, climatic characteristics, soil infiltration rates, and leaching requirements, the aquifer should not be affected. It may be necessary to perform modeling to avoid this situation, especially if the water is applied on a continual basis throughout the year.

Section 4.3.2 Aquifer Storage Recovery Wells

Underground injection into shallow aquifers offers a potential means for managing water produced from oil and gas wells. This type of injection uses boreholes drilled into shallow formations, such as sands, that are classified as USDWs, and then involves the pumping of the produced water into those formations to replenish depleted aquifers that might have experienced several years of pumping for domestic or municipal supply.

Applicability

The use of ASR wells for produced water management is applicable in areas where the quality of the produced water is of a useable nature, or can be easily treated to a useable level. Furthermore, this management practice is most likely to be applicable in arid regions where the water supply can be heavily impacted by droughts. Existing non-productive wells may be nearby and available to the operator at low cost with minimal pipeline costs, making this type of water management practice even more practical. Applicability further depends on the ability of the formation to accept water at a rate commensurate with the cost to implement this management practice.



Perhaps the most prominent example of an ASR project was where the City of Gillette, Wyoming's well field had been locally depleted. The well field was completed in Lower Fort Union sands at a depth of approximately 1,500 feet. These sands had been pumped for a number of years to supply water for public use and consumption. Over time, water levels in the city's wells had decreased considerably. The city coordinated with a CBNG operator to install Class V aquifer recharge wells that were sufficient to manage all of the produced water from a small, CBNG producing project. In this example, the best injection well averaged more than 1 million barrels per year for more than three years (Olson, 2005). Although this example is unique, it does illustrate the potential capability of ASR Class V shallow injection wells.

Constraints

The most serious constraint for ASR Class V wells appears to be the loss of permeability over time. Permeability losses could be caused by plugging of reservoir pores with fines suspended in the water or by clay swelling (Olson, 2005). These problems are common to all types of injection wells that require careful pre-injection tests to determine the vulnerability of the aquifer's rock-frame to plugging by fines and to chemical effects. Injection testing might involve either full-hole or sidewall cores through the aquifer and lab tests of pore-throat sizes and water-rock compatibility analysis. Tests might be necessary on each injection well due to aquifer variations and other issues that have the potential to negatively impact placing water underground.

Permeability constraints may be overcome by injecting at higher pressures. In Class V wells, this might mean pressures over the local fracture pressure. High pressure injection can be difficult to permit but might allow the disposal of large volumes of produced water.

Water also might need to be treated before injection to insure that it meets water quality constraints that can be part of state permit requirements, or otherwise required by a water user. Treatment of the water is dependant upon the quality of the water, the proposed use of the water, and the storage history of the water, if any.

Section 4.4 Surface Discharge

Surface discharge involves release of produced water onto the earth's surface, either to surface water or to a watercourse. Surface discharge is a water management option that allows water to augment stream water flow. Increasing stream water flow can enhance riparian areas and provide additional water resources to support agriculture. Releases to surface water resources must be carefully managed, however, to maintain state specified water quality standards and to avoid excessive riparian erosion. The specific amount of water that can be managed by surface discharge will depend upon the existing characteristics of the stream and the quality of the produced water.

Applicability

Surface discharges are applicable in a variety of instances, such as:

- Direct discharge to surface waters. In this situation, water is delivered to a stream by pipeline or dry drainage where it mixes with existing stream flow.
- Discharge to surface impoundments with possible infiltration into the subsurface and surface water. This is further discussed in Section 4.5.
- Discharge to surface soil with possible runoff to surface water. This involves the release and management of water through different irrigation techniques. Specific management and site conditions will determine the rate of water that can be discharged to the surface, as well as the possibility of any runoff and subsequent discharge to surface water. If irrigation and runoff rates are high, significant volumes of water can enter and mix with surface water. This is further discussed in Section 4.6.

Surface discharges can be managed through evaporation and infiltration into subsoil and bedrock aquifers. When water enters a shallow aquifer, the water could migrate to surface water. Management of this water allows operators to discharge significant volumes of water that can be available for beneficial use with minimal impact on the environment. Additionally, the discharge of produced water can bolster seasonal flows of local rivers and accommodate more beneficial uses. Various discharge scenarios can be considered based on the quantity and quality of the produced water and the receiving water. Discharges directly to surface waters, such as streams and rivers, can be accomplished by the use of pipelines. The pipeline method avoids erosion and the incorporation of suspended sediments, which can impact stream water quality. Pipeline use prevents interaction of produced water with local soil and bedrock.

Water has successfully been managed through this technique for several years in the Big Horn Basin of Wyoming and Montana, as well as in the Belle Creek Field in the Powder River Basin of Montana. Prior to discharge the water is separated from fugitive oil and grease, but the quality of the water in many instances is such that it provides a tremendous source of beneficial uses to downstream water users.

Constraints

The quality of the produced water is a major constraint on the ability to discharge to the surface. If the quality of the produced water is such that it negatively impacts the receiving water quality, then surface discharge is not an option without treating the water to an acceptable quality.

The flow rate of the produced water stream in relation to the receiving stream may also limit the ability to discharge to the surface. If the produced water stream flow rate is considerably high relative to the receiving stream, then erosion may be a serious cause for concern as the additional flow may cause the side slopes and bed of the stream to be transported downstream, causing sedimentation issues at downstream reservoirs and low energy points along the stream.

Section 4.5 Surface Impoundments

A surface impoundment is an excavation or diked area that is typically used for the treatment, storage, or disposal of liquids (EPA, 1991) and can vary from less than one acre in size to several hundred acres. Impoundments are usually constructed in low permeable soils, with the possible exception of recharge ponds, to prevent or decrease raw water loss due to subsurface infiltration or percolation. Based upon an EPA national impoundment survey that characterized more than 180,000 impoundments, the oil and gas industry is considered one of the largest users of this technology. A breakdown of applied impoundment uses by this industry includes storage (29%), disposal (67%), and treatment (4%) (EPA, 1991).

The impoundment of produced water from oil and gas production can be an option utilized by operators as part of their water management practices. In some producing basins, impoundments play a large role in water management practices, while in other basins impoundments might be used only during drilling operations.

The impoundment of produced water is the placement of water produced during operations at the surface in a pit or pond. There are a variety of ways in which operators can impound produced water at the surface. Impoundments can be constructed on- or off-channel, and the regulatory authority in some states varies based on whether the impoundments are on- or off-channel.

Impoundments can be used for a variety of water management options, including disposal by evaporation and/or infiltration; storage prior to other water management options such as injection or irrigation; or for beneficial use such as a fishpond, livestock and wildlife watering ponds, or a recreational pond. The impoundment of water can be performed in any area where there is sufficient construction space. Impoundments can be constructed to provide a single management option, or a combination of management options that include livestock and wildlife watering from wetlands, fisheries and recreational ponds, recharge and evaporation ponds, or other combinations.

The purpose of the discussion in this section is to provide a brief overview for the management of produced water via impoundments. Operators, landowners, or other entities interested in the use of impoundments to receive produced water should contact their appropriate state authority, including Departments of Environmental Quality, State Engineer's Office, Oil and Gas Commission, and Fish and Wildlife, for additional information, pertinent statutes, or clarification of the information provided within.

Section 4.5.1 Evaporation and Aeration

Evaporation ponds are usually off-channel constructed impoundments designed to store water at the surface so that natural evaporative processes can move the water from the land surface into the atmosphere. As evaporation occurs, pure water is removed from the pond, resulting in an increase in the TDS for the remaining water. Over time, as more water is lost to the atmosphere, the water remaining in the pond may become concentrated brine.

Applicability

Evaporation and aeration (enhanced evaporation) is applicable in arid regions where the average annual rainfall is relatively low and the average annual evaporation is relatively high. If the evaporation pond is constructed solely for evaporative loss (no infiltration), the ponds are generally designed to be broad shallow pools that maximize the surface area allowing for increased evaporation rates. Additional consideration is given to exposure; areas with high winds and few natural windbreaks could provide additional evaporative potential, which would include finding areas with low-level vegetation.

In the Battle Creek Field of Montana a zero-discharge system of managing produced water has been developed by utilizing enhanced evaporation ponds through aeration coupled with recycling the produced water for oilfield uses (such as well completions and dust prevention).

Constraints

Climate conditions may provide constraints that interfere with the effectiveness of evaporation. In colder regions evaporation might be effective for only short periods throughout the year, making it an ineffective year round water management practice. In wet regions there may be more water provided to the pond via rainfall than can be managed via evaporation.

Water quality and geological setting also can impact the ability to use evaporation as a water management practice. Depending on the quality of the water and the soil at the bottom of the evaporation pond, the bottom and toe areas may need to be lined to prevent infiltration and migration of the water. Lining the evaporation pond may make this an uneconomical water management option; however, it has proven to be cost effective in the Bowdoin Field in Montana by master planning the phased construction of several lined ponds adjacent to each other to ensure capacity while not over-designing the water management system.

In geologic settings where a suitable material is available to prevent infiltration, the ponds may be placed on natural confining layers such as bentonite rich clay soils, or exposed shales that prevent the downward migration of the groundwater.

Section 4.5.2 Wildlife and Stock Watering

Wildlife watering ponds are typically small off-channel reservoirs that are used to help supplement wildlife or livestock water demands in semi-arid to arid regions. There are many types of watering facility designs available and choosing the correct one depends on proper evaluation of the situation to ensure landowner needs are satisfied.

The Natural Resource Conservation Service (NRCS) provides nationwide standards and technical guidelines for wildlife watering facilities (NRCS, 1982) to help facilitate the decision process and assure proper recommendations are presented to landowners. State NRCS offices in some cases have customized these standards to meet the demands or requirements for their particular region.

Applicability

Where water quality allows, wildlife watering ponds function to improve, or enhance watering places and systems for wildlife, to provide adequate drinking water during drought periods, to create or expand suitable habitat for wildlife, and, in some cases, to improve water quality. Wildlife watering ponds are commonly constructed in areas of the western United States to enhance habitat limited by water supplies. In some areas, watering ponds provide wintering areas for migrating waterfowl, neotropical birds, or other transient species. In severe drought conditions, watering ponds are used to provide water to mule deer, coyotes, bobcats, badgers, and other wildlife (U.S. Fish and Wildlife, 2002).

Watering ponds should be located in habitats that can provide food and shelter for as many wildlife species as possible and should include water level control devices or a means for escape to prevent drowning (ALL, 2003). Other important considerations include aesthetics, accessibility for periodic maintenance, and the control of noxious weeds. In some cases, natural watering areas can be improved to function in the same manner as constructed watering ponds. Natural watering areas are often found where run-off water accumulates in depressions. These areas can be improved by deepening the catchments, by trenching run-off waters to the basin, or developing the springs and seeps (ALL, 2003).

In general, surface impoundments for wildlife should have gentle slopes to reduce erosion and suspended solids (Rumble, 1989). The surface area and depth of the pond would depend on the climate and the species expected to utilize it. Ponds expected to sustain waterfowl populations should have a surface area of 0.4 to 4.0 ha (1 to 10 ac) (Proctor et. al., 1983) and at least 25% of the pond should have a depth of 3 meters (10 ft) (Rumble, 1989). Watering ponds of this size and depth could also be used to sustain populations of shore and upland birds and fish. Ponds with a surface area less than 0.4 ha (1 ac) would likely not be able to support fish populations without management (Marriage and Davison, 1971).

A successful wildlife watering pond known as Custer Lake is located in the Oregon Basin of Wyoming. Approximately 30,000 barrels of water per day are discharged to what would normally be a seasonal playa lake. Wildlife such as waterfowl and big game flourish in the area as a result.

Constraints

As with many beneficial uses, the quality of the produced water can prove to disallow the use of this water management practice. Typically water with TDS above 10,000 ppm is not of sufficient quality for wildlife consumption. Water quantity can also be a concern if this water management practice is employed, and it is likely that additional water management practices such as enhanced recovery would need to be used in conjuncture with this practice to manage all of the water produced.

Section 4.6 Managed Irrigation and Land Application

This management option involves either the discharge of raw produced water directly to the land surface, or pre-treating the water with amendments just prior to applying the water to the land surface by way of irrigation methods. The common methods of irrigation include center-pivots, side-rolls, and fixed or mobile water-guns.


Surface Irrigation in the Hamilton Dome (Wyoming)

Applicability

The direct discharge of water to the land surface can be a viable practice for operators, depending upon site-specific conditions. Under this management strategy, water can be discharged to fields and pastures in order to support plant growth, and disposed of through evaporation, transpiration by way of plant tissue, and infiltration into the soil. However, factors such as the quality of produced water, existing land uses, landowner's future plans for use, soil type, vegetative cover, and other factors all affect the land's ability to accept surface discharge produced water. Although it should be assumed that this management option could lead to runoff that reaches surface water, depending upon local conditions, many control or mitigation practices exist to minimize this effect.

Constraints

As mentioned before, the quality of the produced water can prove to disallow the use of this water management practice. Typically water with high salinity and/or high SAR values can damage plant life and make soil unusable in the future. In this instance, water quality can be improved by adding amendments either to the soil or to the water prior to application of the water to the soil. The required amendments would be site specific depending on the soil, water, and plant that the water would be irrigated with.

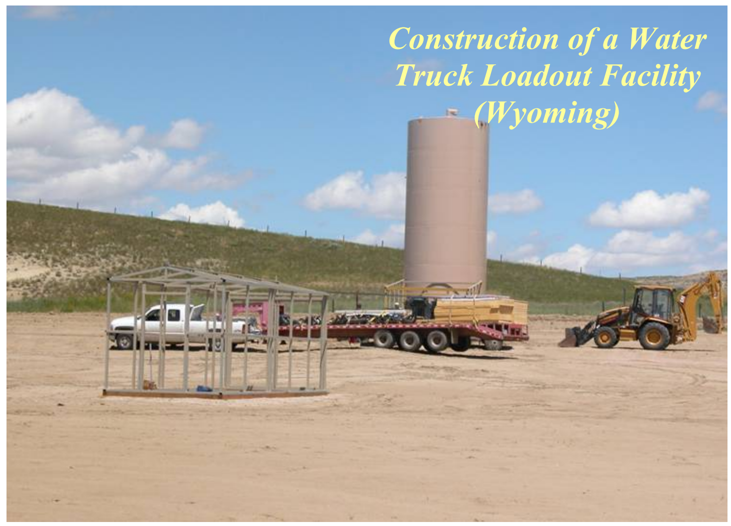
Water quantity can also be a concern if this water management practice is employed, and it is likely that additional water management practices such as enhanced recovery would need to be used in conjuncture with this practice to manage all of the water produced.

Section 4.7 Industrial Uses

There are various beneficial industrial uses that may be applicable for produced water management depending on site-specific conditions and economics. Some examples discussed here include the use of the water in oil and gas operations (i.e. truck wash station, well completions, fracturing), use of the produced water for the cooling needs of a power plant, and dust suppression (i.e. at coal mines or on unpaved county roads). The applicability and constraints of these industrial uses are discussed here, along with examples of where these practices have already been employed.

Section 4.7.1 Oil and Gas Operations

Water is used for various things in the day-to-day operations of the oil and gas industry. Some uses such as truck washing, well completions, and fracture water may not require the water to be of high quality. Therefore produced water generated from oil and gas development can be used for these activities with little to no regard for the quality of the water. By utilizing produced water in this fashion, operators not only lower the cost to dispose of the produced water, but eliminate the cost to acquire the water necessary for operations.


Construction of a Water Truck Loadout Facility (Wyoming)

Applicability

The use of produced water in oil and gas operations is applicable in several regions under various scenarios. One example in the PRB of Wyoming is a water truck load-out facility that utilizes produced water to supply oil and gas activity with the water necessary for operations, thus taking some pressure off the local water supply to meet this demand.

In the Barnett Shale play in Texas as much as 2 million of gallons of make-up water is required for a fracture job. This water is subsequently produced back to the surface in the early stages of development. To reduce the cost of fracturing wells, efforts are being made to reclaim and recycle this water as it is produced by utilizing it to fracture the next well.

Another example previously discussed is in the Battle Creek Field of Montana. A zero-discharge system has been developed to manage produced water through enhanced evaporation ponds coupled with recycling the produced water for operational uses (such as well completions and dust prevention). The central evaporation ponds are used as a water supply source. Water trucks haul water from these ponds to the site where water is required.

Constraints

The main constraint to using produced water for oil and gas operations is the fact that the volume of water used may be nominal when compared to the total volume of water produced, and therefore it may be uneconomical to put practices in place solely to recycle the produced water for operational uses. This can be overcome by applying a portfolio of water management practices, such as in the Battle Creek Field example, where the water is readily available when needed for operations, but operations is not the sole source of managing the water.

Section 4.7.2 Power Plant Cooling Water

Electric generating power plants can have a considerable need for water for cooling. Nationally, water availability has been a limiting factor in the development of new power plants. With the current and projected over-abundance of produced water from development when combined with existing and potential future power plants in the United States, consideration of using produced water for cooling at power plants is reasonable.

Applicability

In general, power plants have the capacity to individually generate between 80 and 2,110 Megawatts (MW). As an integral part of the power generating process, these power facilities must employ water, air, mist, or a combination of these for cooling. Produced water could be used for cooling at power plants in several states, thus avoiding the need for costly air cooling, potentially reducing overall power generation costs. Further, the presence of a water surplus could be used to attract power generating facilities for exporting power.

Water usage volumes can vary widely among power plants, with ranges from approximately 20,000 bpd to more than 400,000 bpd (Schultz, 2005). As an example, Basin Electric operates a large power facility near Wheatland, Wyoming. Designed as a water-cooled facility, this plant has a capacity of 1,650 MW and requires approximately 400,000 bpd of water for cooling. Currently, its water comes from the Grey Rocks Reservoir on the North Platte watershed. This reservoir does not have an adequate supply of water to support its cool water fishery. Further, the entire watershed lacks sufficient water to support irrigation and to fulfill commitments to the Platte River Compact (Lawson, 2005).

Constraints

Several technical constraints may exist for supplying produced water to power plants. These include water quality, water quantity, consistency of water quality and quantity, water treatment issues, distance from the producing area to the usage area, water transportation issues, and the length of time the water would be available.

Plants are generally designed to accommodate cooling water of a relatively high and consistent quality. These issues are of particular concern with respect to produced water since considerable variations exist in both produced water quality and consistency of quality and volume across the nation. These issues would need to be considered and addressed when further pursuing the use of produced water for cooling at power plants.

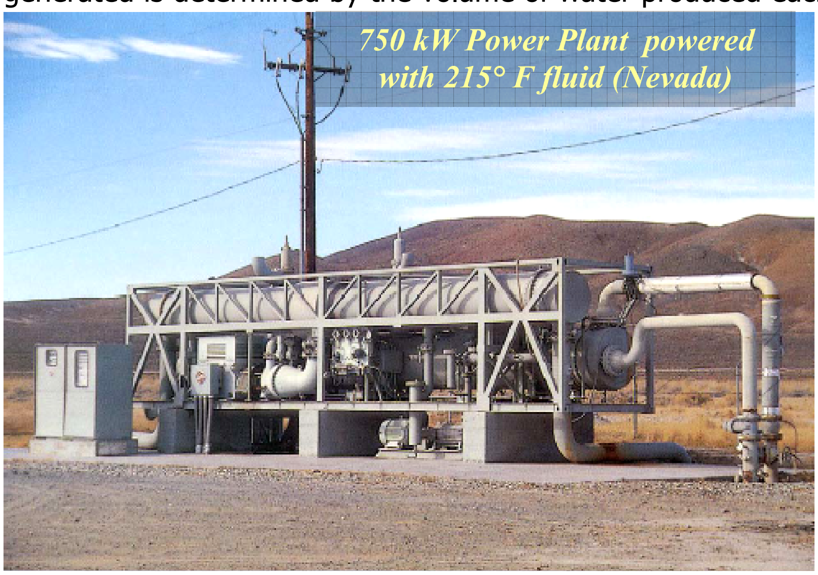
The issue of a single operator being able to commit to long-term supply needs of a power plant has been challenging (Cline, 2005). Furthermore, the costs of this water management strategy would include significant up-front capital costs and long-term operational costs for the water transportation pipelines. Therefore, to economically meet the short- and long-term water supply needs of a power plant, it is likely that a consortium of operators would need to cooperate for this management practice to be feasible.

There has been some small-scale usage of produced water for cooling by power plants. This usage has been short-lived and minor from the standpoint of the power plants (Stafford, 2005). In all of the historical cases where produced water has been used, the usage point was very close to the production area, thus minimizing transportation costs (ALL, 2006). Unfortunately, due to rapid water production declines, the cases evaluated were unable to meet plant quantity requirements for an extended time, thus forcing the plant to seek cooling water from alternative sources.

Water rights issues may provide additional constraints through public perception and outcry in the event that produced water is transported long distances over state and basin boundaries. Inter-basin transfer of water can involve complex water ownership issues that could delay or restrict the implementation of oil and gas projects.

Section 4.7.3 Geothermal Power Generation

Produced water that is at/above a temperature of approximately 215°F can be utilized for the economic generation of electric power (Blackwell, 2004). The electric power generated can 1) be used by the operator to supply the operational needs of the development, 2) be sold either to local end-users or to the local utility company. The amount of potential electric power generated is determined by the volume of water produced each day and the temperature of the water as it reaches the surface. The geothermal generation process does not interfere with the other management options discussed elsewhere in this chapter. For example, after running through the generator, the water may be put to further beneficial use if the water is of high quality, the water may subsequently be re-injected into the subsurface into a disposal zone, or into the original subsurface reservoir to maintain reservoir pressure and enhance oil production.



Applicability

Given the right conditions, electrical power can be generated as part of an oil or natural gas development. Efficient and cost effective power generation requires high volumes of water production and high water temperatures. Current state-of-the-art technology generators require at least 15,000 barrels of water per day with a minimum temperature of 215°F (Blackwell, 2004). This volume of water is frequently exceeded by medium and large oil and gas fields in the United States where 100 producing wells may average 200 to 500 barrels of water per day each. Further, water of the required temperature can be found in many deep fields in the United States as shown in Figures 4.4 and 4.5. Figure 4.4 is a map of the United States showing estimated temperatures at a depth of approximately 9,800 feet (3 km), and Figure 4.5 depicts estimated temperatures at a depth of approximately 16,400 feet (5 km).

Figure 4.4 Temperature (°F) at 3 km (~9,800 ft) for the Continental United States

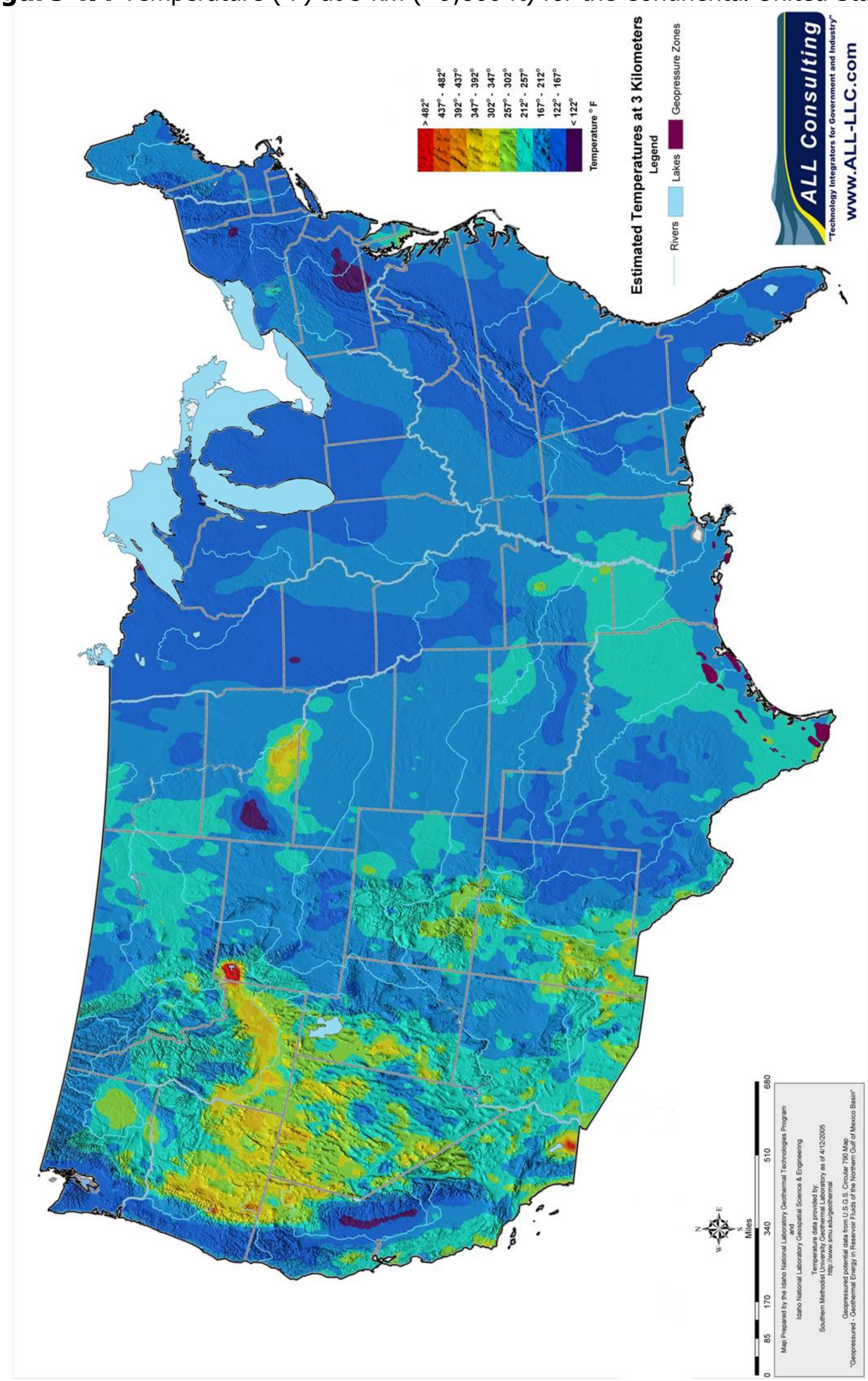


Figure 4.5 Temperature (^oF) at 5 km (~16,400 ft) for the Continental United States

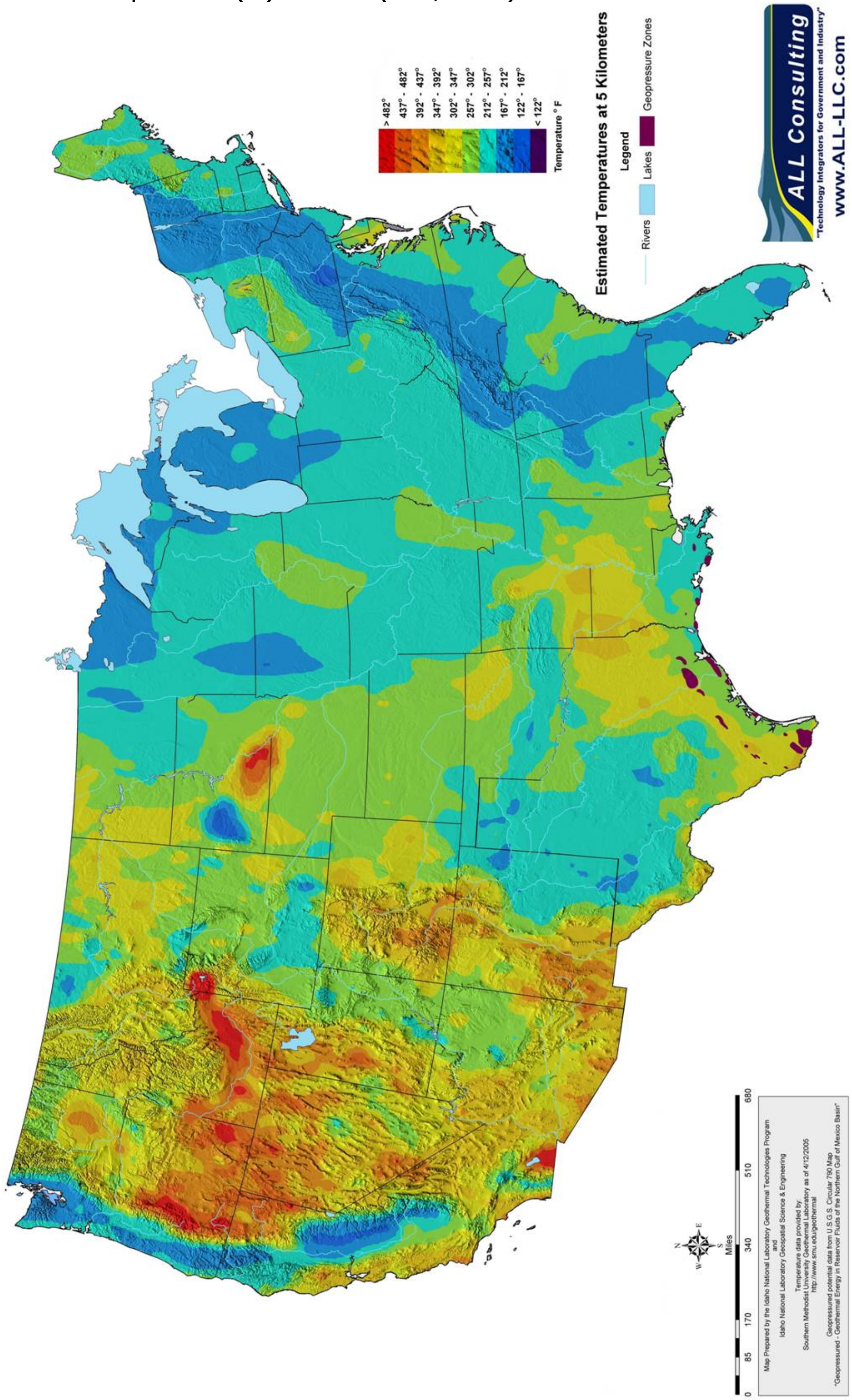


Figure 4.4 shows promising areas in East Texas and some spots in the Rocky Mountains at a depth of 9,800 feet (3 km). At deeper depths, a large percentage of the area shown in Figure 4.5 is underlain by strata in excess of 212°F at a depth of 16,400 feet (5 km), the approximate point of economic geothermal power generation.

Several manufacturers can supply generators on an on-the-shelf basis. The 750 kW Nevada facility shown in this section can be assembled in a short time and moved to another location if production characteristics change. A facility like this may be located on the grounds of a water plant at a large producing field between separators and the water injection plant (Thomsen, 2006). The generator shown requires a flow of 500 gpm (approximately 17,000 bpd) of water at 215°F to generate 750 kW. The power for this specific facility is sold to Sierra Pacific Power under a long term agreement.

Constraints

The biggest constraint on the development of geothermal power generation at traditional oil and gas sites is the temperature of the produced water as it reaches the surface. Given that the minimum temperature for efficient and economic power generation is 215°F, and that the geothermal gradient throughout the petroleum basins of the United States ranges between 1.0 and 1.2°F/100 feet, then the requisite temperature would be available at depths between 12,100 feet (70°F surface temperature and 1.2°F/100 feet) and 16,500 feet (50°F surface temperature and 1.0°F/100 feet) below the surface. These depths are attainable in many states, however, oil and gas wells are more commonly produced from depths shallower with associated waters less than the required 215°F. Temperature constraints may change in the future as the technology of geothermal power generation continues to advance.

Another serious constraint on the feasibility of generating efficient and economic power is the tendency of strata to lose porosity and permeability with increasing depth. When depth and pressures increase, both matrix porosity and fractures tend to close. Unless extraordinary forces keep pathways open, either by the action of local tectonic stresses or abnormally high fluid pressures, reservoir rocks at great depths will have limited ability to deliver the necessary volume of water to the power plant. Downhole permeability can be accurately measured by examining reservoir performance from oil, gas, and water production records. An operator with an interest in utilizing geothermal generators may be able to use historical production data to assess the feasibility.

The presence of secondary or tertiary recovery facilities will not constrain the operator’s ability to install geothermal generation. The space requirements are small and water production is in no way hampered (Thomsen, 2006). Scaling can develop within the generator from some produced water chemistries; which will be similar to the scaling experienced by the operator in existing water handling facilities. Scaling can be controlled by existing chemical treatments.

Section 4.7.4 Dust Suppression

Fugitive dust impacts to local or regional air quality are important issues (ALL, 2006). Some industrial sites, such as coal mines, constantly need to control fugitive dust. Some areas are facing dust levels that may require curtailment of mining and other industrial activity. Truck traffic in coal mine operations can be heavy, depending on the number of active pits, and they can travel as much as 15 miles on gravel roads for each pit (mine) (Hutchinson, 2005). As this is done, loaded trains leave for power plants while empty trains arrive at loading docks. All of this activity goes on continually year-round and almost all of this activity generates copious amounts of fugitive dust. The demand for water for dust suppression at mines is site-specific and dependant on the season; therefore, it can range anywhere from 2,400 bpd to 100,000 bpd (Murphree, 2005 and Hutchinson, 2005). Depending on the availability and cost of the water used to control the dust, produced water from oil and gas operations could be a viable option to supply this water. Produced water also can be used for washing trucks and other large equipment.

Applicability

Coal mines require more water for dust control during the dry periods of the summer and fall. During other times, water can be stored on-site in pits and settling ponds. A typical large coal mine can have storage approaching 5.0 million bbls (Murphree, 2005). Helping area coal mines control dust by supplementing their water sources for dust control can benefit the mining sector, help all industrial interests in the basin, and improve air quality issues. In addition, reducing dust with supplemental produced water can give operators a low-cost, year-round option for managing the water.

Several operators supply water to numerous coal mines, especially in Wyoming and Montana. The Spring Creek mine near Decker, Montana, receives between 200 and 800 gpm from the CX Ranch CBNG field in the area (Williams, 2005) and several mines near Gillette have previously received small amounts of water from adjacent CBNG fields (Stearns, 2005).

Constraints

Technical constraints of this option involve water quality requirements that may limit usage. However, there are differing impressions of the quality limits for dust control water applied to roads. Some operators are concerned about the buildup of salt at the side of coal mine roads and have a self-imposed limit of 10 SAR (Murphree, 2005) while other companies have a corporate policy about using high quality water for dust control and emphasize the use of poor quality water (Stearns, 2005). Some operators add Magnesium Chloride (MgCl) to dust control water and, thus, are unconcerned about water quality for dust control (Hutchinson, 2005).

The proximity of oil and gas operations to an industrial area where dust suppression is required is also a potential constraint from an economic standpoint. The cost to haul the water to the industrial site may preclude this as a viable option, and the capital cost required to construct a water pipeline would make it difficult for any operator to justify. As mentioned before, this option may become more viable if multiple operators collaborate in establishing the infrastructure necessary to transport the water from the wellhead to the site where it can be used for dust suppression.

Section 4.7.5 Concentrated Animal Feeding Operations (CAFO)

Livestock watering is one of the most common and proven beneficial uses of produced water. Most range and pasture used for livestock watering would require relatively minute quantities compared to the amounts of water produced; therefore, to support a concentrated animal feeding operation (CAFO) where large numbers of animals are confined and fed would manage a larger volume of produced water. The water needs of a CAFO could include animal consumption, irrigation of forage crops, and waste management. Current feedlot operators will already have sources of water; therefore, water would have to be provided at a very low cost for this to be economically feasible for them. Costs associated with the beneficial use of produced water for feedlots mainly would include transporting the water to the feedlot facility.

Applicability

Finishing cattle consume from 8 to 20 gallons of water per day, depending on the time of year and outdoor temperature (Guyer, 1977). For a larger feedlot handling 5,000 head, this would require a maximum volume of about 100,000 gallons, or 2,380 bpd of drinking water. The average size feedlot in the Great Plains is about 500 head (Davies and Widawsky, 1995); therefore, water use for livestock drinking would be about 240 bpd for an average size feedlot. Water requirements for waste management would increase this amount slightly. If produced water were to also supply irrigation for hay and grain adjacent to the feedlot, much more water would be required.

Table 4.1 shows the acceptable quality of water for livestock. Water with a TDS below 10,000 mg/L (EC <16 mmhos/cm) is generally considered acceptable.

Table 4.1 Water Quality Guide for Livestock Use

TDS (mg/L)*	Livestock Watering Comments
Less than 1,000 (EC < 1.5 mmhos/cm)	Excellent for all classes of livestock.
1,000 to 2,999 (EC = 1.5-5 mmhos/cm)	Very satisfactory for all classes of livestock. May cause temporary and mild diarrhea in livestock not accustomed to them.
3,000 to 4,999 (EC = 5-8 mmhos/cm)	Satisfactory for livestock, but may cause temporary diarrhea or be refused at first by animals not accustomed to them.
5,000 to 6,999 (EC = 8-11 mmhos/cm)	Can be used with reasonable safety for dairy and beef cattle, sheep, swine, and horses. Avoid use for pregnant or lactating animals.
7,000 to 10,000 (EC = 11-16 mmhos/cm)	Considerable risk in using for pregnant or lactating cows, horses or sheep, or for the young of these species. In general, use should be avoided although older ruminants, horses, poultry, and swine may subsist on them under certain conditions.
Over 10.000 (EC > 16 mmhos/cm)	This water is considered unsatisfactory for all classes of livestock.

(Source: NAS, 1974)
Note: Electrical conductivity (EC) expressed in micromhos per centimeter at 25°C can be substituted for total dissolved solids without introducing a great error in interpretation.

Constraints

The quality of the produced water most likely would present the biggest constraint for use of this water management practice. As stated above, water with a TDS of 10,000 is considered unsatisfactory for animal consumption. Furthermore, transporting the water from the producing areas to the CAFO would be another difficult aspect of this water management practice. Either trucking the water or building pipelines would be the most feasible solutions, but cost may be prohibitive, depending on the distances.

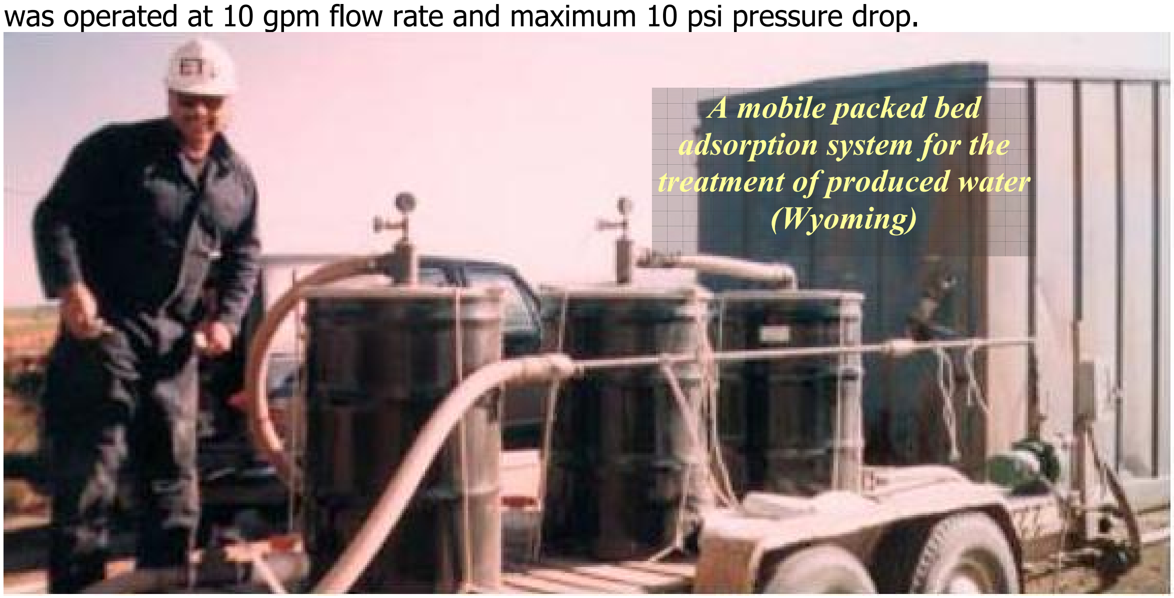
The issue of a single operator being able to commit to long-term supply needs of feedlot could be challenging. Therefore, to meet short- and long-term water supply demands, it is likely that a consortium of operators would need to cooperate to make this a viable produced water management option.

Section 4.8 Water Treatment Technologies

Various water treatment technologies are available to the oil and gas industry. The options can differ in their inherent facility requirements, capital costs, operating expense, and waste streams; all three factors can be important to the oil and gas operator. Some technologies may have large space requirements that may not be possible in some oil and gas installations. Some technologies may be commercially available as small, skid-mounted units that easily can be relocated as production conditions change. Equipment costs are obviously important in some installations where a large amount of dedicated equipment must be purchased just for managing produced water. Higher power costs and chemical expenses could be unsupportable early in the life of an oil and gas development. Treatment wastes derived from produced water might no longer be classified as oil and gas wastes and might be more difficult and more expensive to manage. This section discusses various produced water technologies along with examples of how they are being implemented in the field.

Section 4.8.1 Packed Bed Adsorption

ET Ventures, L.L.C., South Carolina, field tested its new ET #1 produced water treatment system at Rocky Mountain Oilfield Testing Center (RMOTC) in July 1996 to determine its effectiveness in adsorbing hydrocarbons from produced water (Doyle, et al., 1997). Water produced from the Tensleep formation was atmospherically cooled (to 90°F) and flowed through a three-stage packed bed adsorption treatment system. Higher temperature affects the removal efficiency of the adsorbent. The first two stages contained ET #1, a sodium bentonite modified organoclay adsorbent. The final stage contained granular activated carbon (GAC). The picture below shows a mobile treatment trailer used for the operation. The system was operated at 10 gpm flow rate and maximum 10 psi pressure drop.



The samples of inlet feed, effluent from ET #1 columns, and effluent from the GAC column were analyzed by a standard EPA (EPA 1664-A) analytical testing method. Table 4.2 shows the results obtained for one of the trials during the treatment. ET #1 treatment was sufficient to remove Total Petroleum Hydrocarbons (TPH) below detectable limits. Oil and grease values were below detectable levels after ET #1 adsorption treatment. Benzene, toluene, ethylbenzene, and xylene (BTEX) were removed to below detectable levels after GAC adsorption treatment.

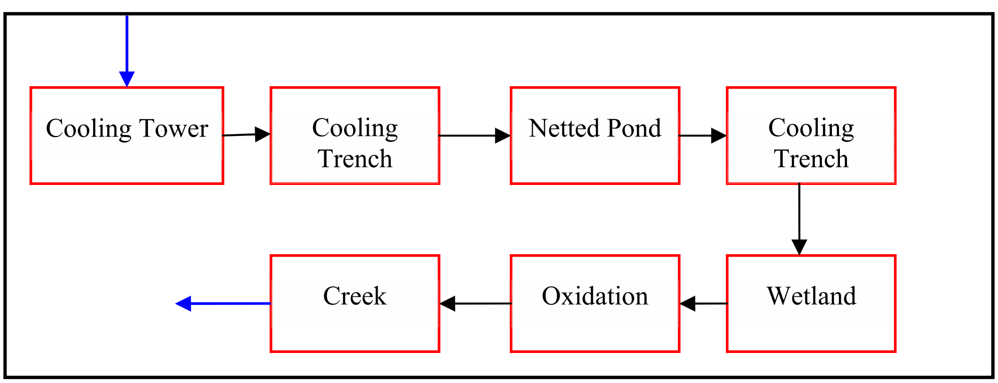
Table 4.2 Results from ET Venture's mobile produced water treatment system

Contents	Before Treatment (ppm)	After Treatment (ppm)
TPH	148	1.1
Oil and Grease	151	1.2
Benzene	3.14	<0.5
Toluene	4.97	<0.5
Ethylbenzene	4.95	<0.5
Xylene	29.7	<1

Section 4.8.2 Decomposition in Constructed Wetland

The DOE's Naval Petroleum Reserve No. 3 (NPR-3) bio-treatment facility with average throughput of 35,000 bpd of water is located in Natrona County in east-central Wyoming (Myers, et al., 2001). The wetlands treatment facility started in January 1996 to provide a cheaper alternative to reinjection and to benefit local wildlife by way of water discharge. Wetlands are thin film bioreactors that utilize various species of plants and microbes along with sands that oxidize contaminants present in the water. A schematic of treatment process is shown in Figure 4.6.

Figure 4.6 DOE Naval Petroleum Reserve's bio-treatment process



The process undergoes the following steps:

1. Cooling tower followed by a shallow cooling trench to reduce the temperature of produced water from 180 – 200°F to below 100°F. Higher temperatures reduce the performance of plants in the subsequent wetlands pond.

2. Netted pond or skimming pond further cools the water and also removes suspended solid and oil under gravity effects. Dispersed oil on the top surface is skimmed off.
3. Specially developed flora and fauna, including hydrocarbon decomposing bacteria, sulfate reducing bacteria, nitrifying and denitrifying bacteria, iron related bacteria, algae, etc. biodegrade various contaminants present in produced water.
4. Microorganisms in wetlands degrade most of the hydrocarbons and the remaining traces of hydrocarbons are removed in an oxidation process.

The produced water from the Tensleep formation was blended with the produced water from other formations before the treatment. The blending process reduced the level of some of the contaminants and also lowered the temperature. While TDS was not affected, certain persistent contaminants such as organics, alkalinity, and ammonia were greatly attenuated. Table 4.3 shows the result obtained using the bio-treatment facility.

Table 4.3 Summary of the performance of NPR-3 Bio-treatment facility which included wetland treatment

Constituents	Before treatment (ppm)	After treatment (ppm)	Overall removal (%)
NH_3	2.03	0.54	73
NO_3	<0.1	<0.1	-
Phosphorus	1.83	0.46	75
BOD	28	2.3	92
COD	48	29	40
TOC	32.7	3.6	90
TPH	112	5.8	95
Oil & Grease	71.9	4.2	94
Benzene	0.143	<0.001	100
Toluene	0.135	<0.001	100
Ethlybenzene	0.035	<0.001	100
Xylene	0.162	<0.001	100
Turbidity	45.4	4.76	90
TDS	4380	4010	9
Alkalinity	713	190	73

Section 4.8.3 Ion Exchange

The ion exchange process effectively removes arsenic, heavy metals, nitrates, radium, salts, uranium, and other elements from the produced water. Ion exchange is a reversible chemical reaction wherein positively or negatively charged ions present in the water are replaced by similarly charged ions present within the resin. The resins immersed in the water are either naturally occurring inorganic zeolites or synthetically produced organic resins. When the replacement ions on the resin are exhausted, the resin is recharged with more replacement ions.

Ion Exchange Resins

Ion exchange resins are classified as cation exchangers, which exchange positively charged ions, and anion exchangers, which exchange negatively charged ions. The resins are further classified as:

Strong Acid Cation (SAC) Resins:

The hydrogen or sodium forms of the cation resins are highly dissociated and H^+ or Na^+ ions are readily exchangeable over the entire pH range. Equation 1 shows an example of salt removal with SAC.

$$2(R - SO_3H) + NiCl_2 \rightarrow (R - SO_4)Ni + 2HCl \qquad ..(1)$$

Equation 2 shows an example of Ca^+ softening with SAC.

$$2(R - SO_3H) + Ca^+ \rightarrow (R - SO_3)^2 Ca + 2H^+ \qquad ..(2)$$

These resins would be used in the hydrogen form for complete deionization (Na, Ca, Mg, Ba, etc. removal); they are used in the sodium form for water softening (Ca and Mg removal). After exhaustion, the resin is regenerated to the hydrogen form by contact with a strong acid solution, or to the sodium form with a sodium chloride solution.

Weak Acid Cation (WAC) Resins:

Weak acid resin has carboxylic acid (COOH) group as opposed to the sulfonic acid group (SO_3H) used in strong acid resins. These resins behave similarly to organic acids that are weakly dissociated. WAC has high affinity for divalent salts. Equation 3 shows an example of Ca^+ softening with WAC. Alkalinity present in bicarbonate form also can be removed by WAC.

$$2(R - COOH) + Ca^+ \rightarrow (R - COO)_2 Ca + 2H^+ \qquad ..(3)$$

Free H^+ ions can react with bicarbonate (present as hardness, $Ca(HCO_3)_2$) to form carbonic acid. The carbonic acid decomposes in carbon dioxide as shown in equation 4. Removal of carbon dioxide or decarbonation (Moftak, 2002) is necessary during the water treatment process.

$$HCO_3^- + H^+ \rightarrow H_2CO_3 \rightarrow CO_2 + H_2O \qquad ..(4)$$

Weak acid resins exhibit a much higher affinity for hydrogen ions compared to strong acid resins. This characteristic allows regeneration to the hydrogen form with significantly less acid than is required for strong acid resins. Almost complete regeneration can be accomplished with stoichiometric amounts of acid. The degree of dissociation of a WAC is strongly influenced by the solution pH. Consequently, resin capacity depends in part on solution pH.

Strong Base Anion Resins:

Strong base resins are highly ionized and can be used over the entire pH range. These resins are used in the hydroxide (OH^-) form for water deionization. They will react with anions in solution and can convert an acid solution to nearly pure water. Equation 5 shows the reaction involved in an anion exchange step.

$$(R - NH_3OH) + HCl \rightarrow (R - NH_3Cl) + HOH \qquad ..(5)$$

Regeneration with concentrated sodium hydroxide (NaOH) converts the exhausted resin to the hydroxide form.

Weak Base Anion Resins:

Weak base resins exhibit minimum exchange capacity above a pH of 7. The weak base anion resins sorbs anions associated with weak acid.

Applications

Ion exchange has several applications in water treatment processes such as hardness removal, desalination, alkalinity removal, radioactive waste removal, ammonia removal, and heavy metal removal. Since divalent ions (Ca, Mg, etc.) are favored over monovalent (Na, etc.) ions by the resin for replacement, secondary treatment for SAR (sodicity) is required.

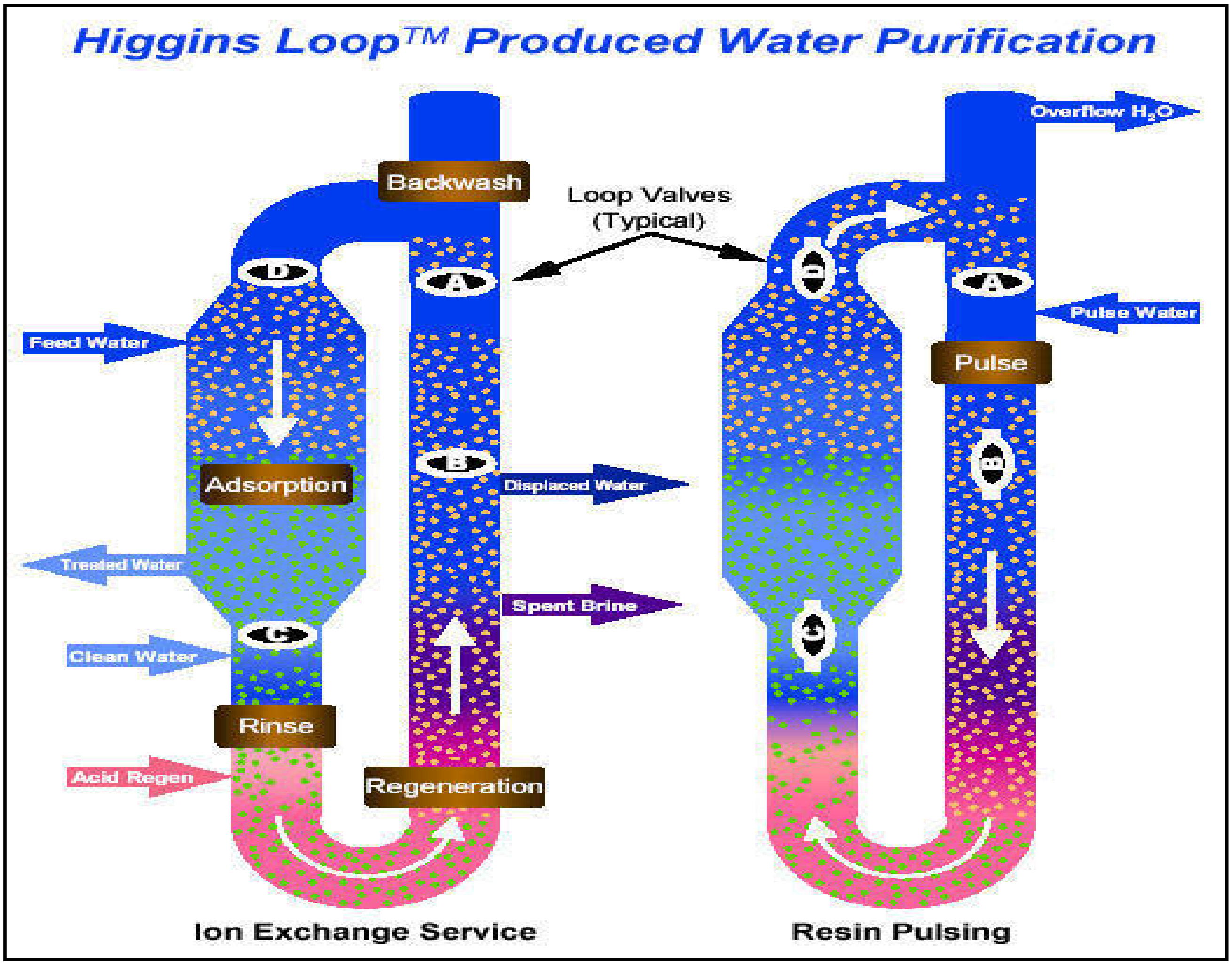
Powder River Gas, LLC

In 2002 Powder River Gas, LLC proposed a Project Plan of Development (POD) (Bopst and Reid, 2002) to drill and test for CBNG in eight federal and eight fee wells at eight locations (two wells per location) in an area northeast of the Tongue River Reservoir, Big Horn County of southeastern Montana.

Higgins Loop in operation (Montana)

Part of their *NO FEDERAL ACTION* alternative is to treat water produced from the wells using a Higgins Loop (continuous counter-current ion exchange) treatment facility prior to discharging to the Tongue River. The stationary Higgins Loop facility was constructed along with a series of impoundments and chemical storage tanks. All chemical storage tanks are surrounded by a shallow spill containment berm to prevent any accidental chemical spills.

Figure 4.7 Higgins Loop schematic (Source: Seven Trent Services)

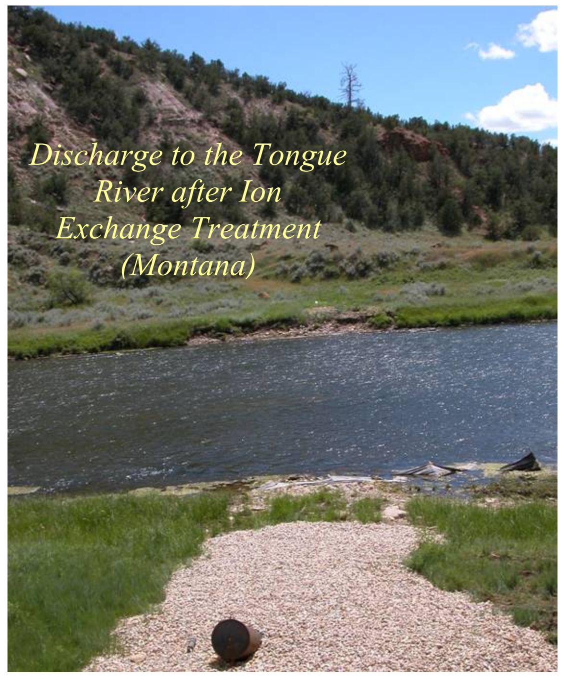


Produced water from CBNG wells is to be treated stepwise within the treatment facility. Settling of suspended sediments and releasing of residual gas will be within the impoundment. Na^+, barium and other heavy metals from produced water will be removed using SAC resins in the Higgins Loop. Removal of CO_2 produced during the ion exchange process and adjustment of pH will be achieved by adding calcium hydroxide. CO_2 can be removed by air-stripping or membrane degasification. The physical law governing this process is the equilibrium between the gas phase and the concentration of the solute gas in the liquid phase.

The schematic is shown in Figure 4.7. The Higgins Loop is a vertical cylindrical loop containing a packed bed of strong acid ion exchange resin that is separated into four operating zones by butterfly (loop) valves. These operating zones (Adsorption, Regeneration, Backwashing and Pulsing) function like four separate vessels.

The Higgins Loop treats liquids in the adsorption zone with resin while the ions are being removed from loaded resin in the regeneration zone simultaneously. Intermittently, a small portion of resin is removed from the respective zone and replaced with regenerated or loaded resin at the opposite end of that zone. This is accomplished hydraulically by pulsing of the resin through the loop. The result is continuous and countercurrent contacting of liquid and resin. The cations (Ca^+, Na^+ etc.) are replaced by hydronium (H^+) ions from resin beads. The hydronium ions are released in the treated water, which lowers the pH of the water. Cations are stripped from the resin in the regeneration zone concurrent with ion exchange in the adsorption zone. Dilute hydrochloric acid is injected into the loop and moves counter-current to the resin and the spent brine discharge, leaving the resin restored to the hydronium form.

Concentrated brine volumes average approximately 1.0% of the total loop feed volume, depending on the cation loading that is removed from the treated water. Excess brine that is not recycled to other beneficial uses is proposed to be transported offsite by truck for disposal by injection into a permitted Class I, deep disposal well located in Wyoming. The waste stream from the treatment process, at maximum flow, will generate approximately 60 barrels of brine or reject water per day. The treatment unit would discharge a total of 250 gpm of treated water.



EMIT Water Discharge Technology, LLC

EMIT Water Discharge Technology, LLC (Dow, 2003) developed a new treatment process that uses DOWEX G-26 (strong acid cation exchange resin manufactured by DOW Chemical Company). G-26 resin has a sulfonic acid (SO_3H^+) group that exchanges Na^+, Ba^+, Ca^{2+}, and $Mg2^+$ ions with H^+ ion. The ion exchange process is accomplished in a Higgins Loop. The Higgins Loop operation is followed by calcium addition to adjust pH, balance SAR, and increase calcium concentration. Table 4.4 shows the results of a field trial for the treatment of produced water from Powder River Basin, Wyoming. The process focused on the removal of sodium ions and reduction of SAR using a combination of Higgins loop and calcium addition.

The increment in calcium, chloride and sulfate levels were due to chemical addition during SAR adjustment. The field trial was conducted with throughput of 200 gpm. The treatment cost ranges from $0.05 to $0.20 per barrel of treated water depending on the influent composition, SAR, and availability of resources. The ion exchange treated water may then be discharged to the environment and the residue disposed of (ALL, 2003).

Table 4.4 Performance of Higgins Loop treatment for a field trial at Powder River Basin site

Constituents	Influent Produced Water	Treated Water	Removal %
Na, ppm	486	12	97.53
Ca, ppm	22.2	113	-409
Mg, ppm	13.2	<1	>93
K, ppm	13.5	<1	>93
Ba, ppm	0.72	ND	100
Carbonate, ppm	<1	<1	-
Bicarbonate, ppm	1430	311	78.52
Chloride, ppm	18	42	-133.33
Sulfate, ppm	1	1.1	-10
SAR	20.2	0.3	98.51
pH	8.1	6.5	19.75

Sandia Ion Exchange/Sorption Process

Sandia National Laboratory (SNL) reported use of Hydrotalcite (HTC) as anion exchanger and Permutite as cation exchanger (Sattler, et al., 2004). These ion exchangers are comprised of durable inorganic oxides that provide stability over a large range of pH. Based on the results of various experiments, SNL reported average ion exchange capacity of HTC and Permutite as 2.5 mEq/gram (measured with Na_2So_4), and 1.7-2.7 mEq/gram (measured with NaOH), respectively.

Anions in the inlet water are replaced by hydroxide ions (HTC anion exchange) and cations are replaced by hydrogen ions (Permutite cation exchange). Lime softening pretreatment is an optional stage.

Ion exchangers are regenerated after they are exhausted. In the regeneration process ion exchangers regain their ion exchange capacity. It might not be possible to regain 100% ion exchange capacity during the regeneration process. SNL attempted to determine effects of regeneration on the ion exchange capacity of above mentioned ion exchangers and concluded that Permutite can regain ion exchange capacity without significant loss. Regeneration of HTC at low temperatures was not promising, and at high temperatures regeneration became costly.

Section 4.8.4 Electrodialysis (ED) and Electrodialysis Reversal (EDR)

Electrodialysis (ED)

Most salts dissolved in water are ionic, being positively (cationic) or negatively (anionic) charged. These ions are attracted to electrodes with an opposite electric charge.

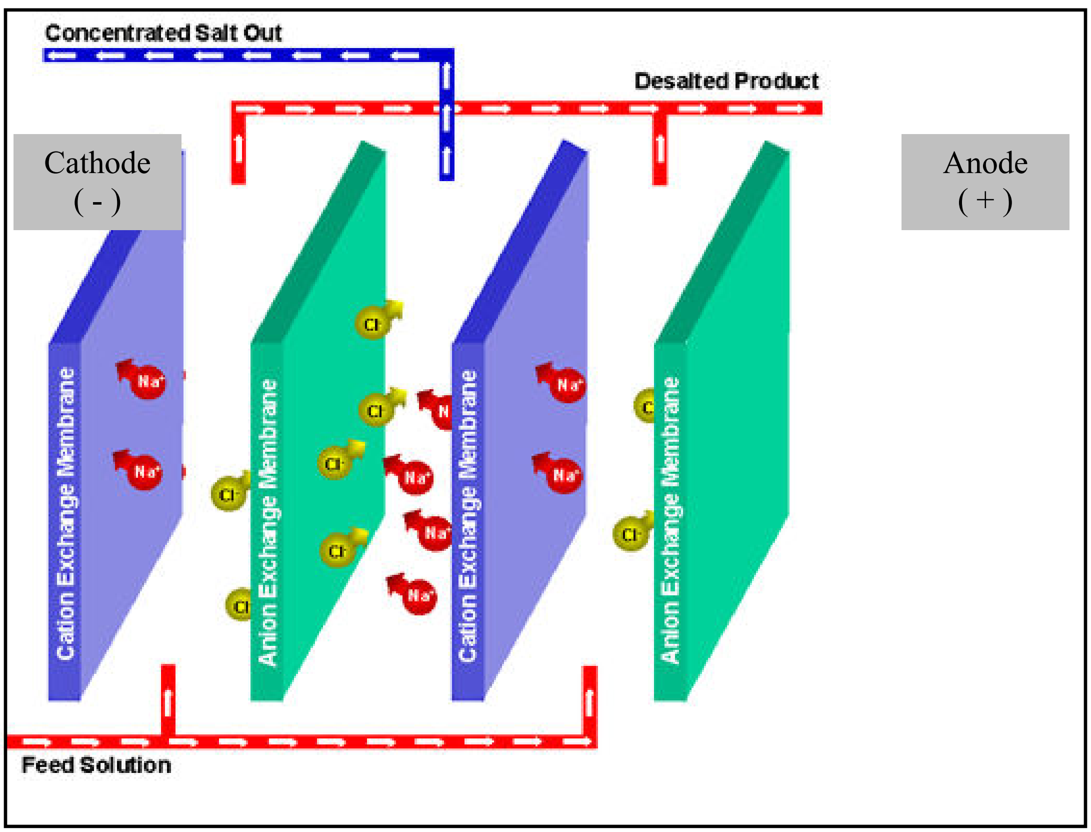
In ED, membranes that allow either cations or anions (but not both) to pass are placed between a pair of electrodes. These membranes are arranged alternately. A spacer sheet that permits feed water to flow along the face of the membrane is placed between each pair of membranes. Figure 4.8 shows an ED assembly with feed spacer and ion exchange membrane placed between oppositely charged electrodes. Positively charged ions (Na^+ etc) migrate to cathode and negatively charged ions (Cl^- etc) migrate to anode.

During migration the charged ions are rejected by similarly charged ion exchange membranes. As a result, water within the alternate compartment is concentrated leaving desalted water within the next compartment of the ED unit. The concentrate and desalted water are continuously removed from the unit. The basic electrodialysis unit consists of several hundred cell pairs bound together with electrodes on the outside and is referred to as a membrane stack.

Feed water passes simultaneously in parallel paths through all of the cells to provide a continuous flow of desalted water and brine to emerge from the stack. The feed water is circulated through the stack with a low-pressure pump with enough power to overcome the resistance of the water as it passes through the narrow passages. The raw feed water must be pretreated to remove materials that could harm the membranes or clog the narrow channels in the cells from entering the membrane stack. A rectifier is generally used to transform alternating current (AC) to the direct current (DC) supplied to the electrodes on the outside of the membrane stacks.

Post-treatment consists of stabilizing the water and preparing it for distribution. This post-treatment might consist of removing gases such as hydrogen sulfide and adjusting the pH.

Figure 4.8 An ED unit in operation (Source: Electrosynthesis Company, Inc)



Electrodialysis Reversal Process (EDR)

An EDR unit operates on the same general principle as a standard electrodialysis plant except that both the product and the brine channels are identical. At intervals of several times an hour, the polarity of the electrodes is reversed and the flows are simultaneously switched so that the brine channel becomes the product water channel and the product water channel becomes the brine channel.

The result is that the ions are attracted in the opposite direction across the membrane stack. Immediately following the reversal of polarity and flow, enough of the product water is dumped until the stack and lines are flushed out and the desired water quality is restored. This flush takes about 1 or 2 minutes, and then the unit can resume producing water. The reversal process is useful in breaking up and flushing scales, slimes, and other deposits in the cells before they can build up and create a problem. Flushing allows the unit to operate with fewer pretreatment chemicals minimizing membrane fouling. The charges of the electrodes are reversed by a motorized valve.

Applications

Electrodialysis is conducted at low pressure drops across the process (usually less than 25 psi). The pressure drop across the typical Reverse Osmosis (RO) membrane ranges from 400 – 1400 psi, which indicates higher energy consumption.

Wind River Basin, Lysite, Wyoming

The produced water from a conventional well in Wind River Basin of Wyoming (Hayes, 2004) contains H_2S, oil, acid, BTEX, dissolved solids, etc. About 93% of total TDS (8,300 to 10,000 ppm) is accounted for as sodium, chloride, calcium, and bicarbonates. Oil and grease content was about 65 ppm and BOD value was more than 330 ppm (contributed by acetates and volatile acids). The treatment trailer consists of the following units:

1. De-oiling via induced gas floatation unit.
2. Dissolved organics removal via two fluidized bed reactors. First was the anaerobic and nitrate consuming reactor for reducing large amounts of organics. The second was the aerobic reactor ensuring oxidation of dissolved organics.
3. Desalting/Demineralization using an ED unit.

ED provided economical demineralization in this case. The feed water had approximately 9,000 ppm TDS. As usual, the cost of the ED unit operation increases as the required TDS removal increases. Table 4.5 shows the overall removal of contaminants using different treatment technologies. The ED removed approximately 89% of TDS from the produced water.

Table 4.5 Produced water treatment performance at Wind River Basin, Wyoming

Parameter	Influent (ppm)	Effluent (ppm)	Overall Removal (%)
Oil and Grease	90	4	95.5
BOD	330	51	84.5
BTEX	11	0.1	99.1
TDS (using ED)	9,100	1,000	88.9

High Efficiency Electrodialysis (HEED^{TM}), Frac Water, Inc.

Frac Water, Inc. developed mobile ED treatment units for treating CBNG produced water and reusing it in fracturing treatment. Several case studies suggest that the mobile treatment units treat the produced water with TDS ranges from 11,400 to 27,000 ppm and sulphates from 4,000 to 14,000 ppm (Spitz, 2003). ED provides the following benefits over RO:

1. ED can sustain high temperature; in fact higher temperature of produced water from the wellhead (140°F) improved the conductivity and reduced resistance during the ED process, which leads to lesser voltage usage. Also, higher temperature reduces viscosity.
2. ED accepts feed water with Silt Density Index (SDI) value of 12 compare to SDI value of 3 for RO. Less SDI value indicates the necessity of pretreatment steps. The membranes are susceptible to fouling if feed water has high SDI.
3. Certain levels of fouling also occur in ED operations. ED membranes can be cleaned or regenerated using weak acid treatment.
4. Plate and frame configuration of the ED system enables easier maintenance and cleaning.

The picture below shows mobile ED treatment units from Frac Water, Inc. ED treatment primarily recovers 80 to 90% of brackish water. The patents-pending electrodialysis HEEDTM stack configuration with dual or multiple side-by-side ion exchange membrane cells and improved gasket design results in greater separation efficiencies and affords greater flexibility in unit design. The improved design requiring up to 40% less membrane area resulted in an increase in energy efficiency of more than 70%.


Mobile ED treatment trailer developed by Frac Water Inc (Wyoming)

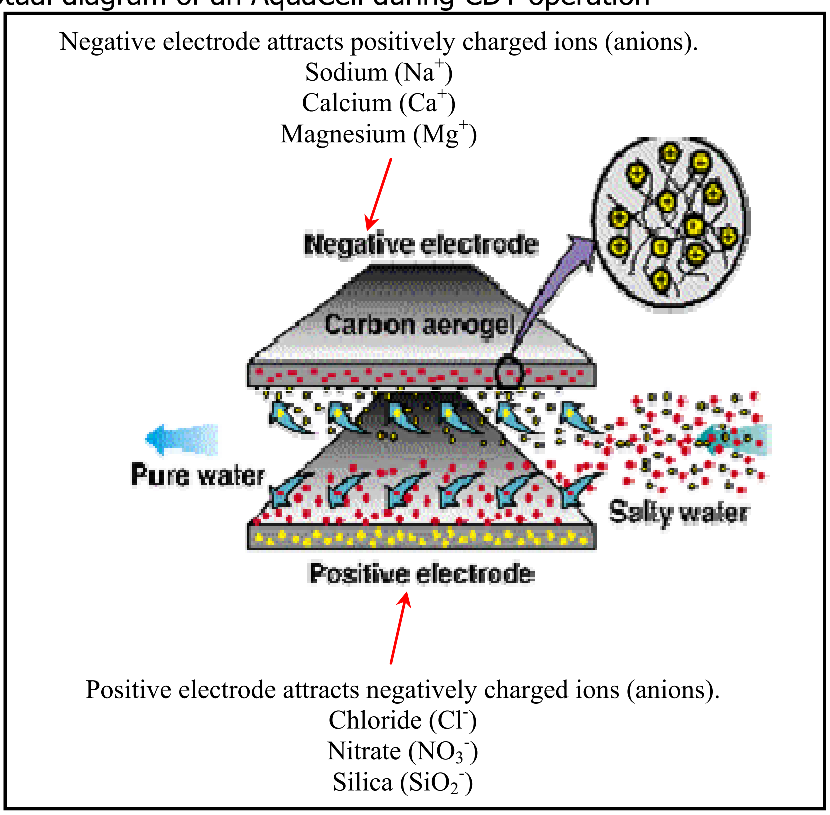
Section 4.8.5 Capacitive Deionization Technology (CDT)

Capacitive deionization technology (CDT) is a new technology being developed for the purification of ocean and brackish groundwater. A constant voltage is applied and soluble salts are collected on the surface of porous carbon electrodes, thus purifying the water for human consumption or industrial processes. In CDT, a brackish water stream flows between pairs of high surface area carbon electrodes that are held at a potential difference of 1.2 V. The ions and other charged particles (such as microorganisms) are attracted to and held on the electrode of opposite charge. The negative electrode attracts positively charged ions (cations) such as calcium (Ca), magnesium (Mg), and sodium (Na) while the positively charged electrode attracts negative ions (anions) such as chloride (Cl) and nitrate (NO_3). Eventually, the electrodes become saturated with ions and must be regenerated. The applied potential is removed and the electrodes are flushed to release attached ions from the system producing the more concentrated brine stream.

The current carbon aero gel electrodes provide approximately 500 m^2/g surface area. They provide high electrical conductivity and high ion permeability. Carbon aero gel electrodes are expensive and their ion storage capacity is relatively low. The main problem is that the cost of the electrodes is high due the high cost of the resorcinol (Resorcinol Fluoride, RF) from which the electrodes are made. TDA Research, Inc. developed electrodes that provide higher surface area. CDT System, Inc. is developing an impregnate of carbon nanotubes on the RF resins.

Figure 4.9 shows a conceptual diagram of CDT. Exchange of ions does not occur; ions are adsorbed within the pores of charged electrodes under the effect of capacitance.

Figure 4.9 A conceptual diagram of an AquaCell during CDT operation



(Source: TDA Research, Inc.)

Applications

Desalination of produced water

Table 4.6 shows the result of the treatment of produced water from a CBNG well in Wyoming using CDT.

Table 4.6 Performance of CDT for the CBNG produced water treatment

Constituent	Before Treatment	After Treatment
Conductivity (micro s/m)	2,100	< 800
Sodium ions (ppm)	280	84
Bicarbonate ions (ppm)	520	144

CDT Mobile Systems also can be used to produce drinking water and water for agriculture purposes at a low cost. Table 4.7 shows the throughput capacity of a 28-foot mobile CDT unit that includes 30 AquaCells with the capability to be field expanded to 88 AquaCells. The expected quality of treated water is fixed at 500 ppm TDS for drinking water and 1000 ppm TDS for agriculture water.

Table 4.7 Treatment capacity of CDT unit

Feed Water TDS (ppm)	Capacity, Potable Water	Capacity, Agriculture Water
< 1,500	30,000 GPD	30,000 GPD
2,500	20,000 GPD	27,000 GPD
3,500	10,000 GPD	17,000 GPD
4,000	5,000 GPD	12,000 GPD

Source: CDT Inc, Dallas, TX

Section 4.8.6 Electrochemical Activation (ECA) Technology

Electrochemical Activation (ECA) technology is an innovative water disinfection technology that involves the exposure of water, and the natural salts, to a substantial electrical potential difference. As an anode (+) and a cathode (-) are placed in pure water and direct current is applied, electrolysis of water occurs at the poles leading to the breakdown of water into its constituent elements. If sodium chloride (NaCI), or table salt, is used as a solution, the dominant electrolysis end product is hypochlorite, a chlorine based reagent that is commonly used to disinfect water and kill microorganisms. This disinfection technology is currently used in series with the capacitive deionization technology in an activated water type of application. With this technology the natural water chemistry is used to produce highly effective disinfection agents that would destroy viruses and bacteria.

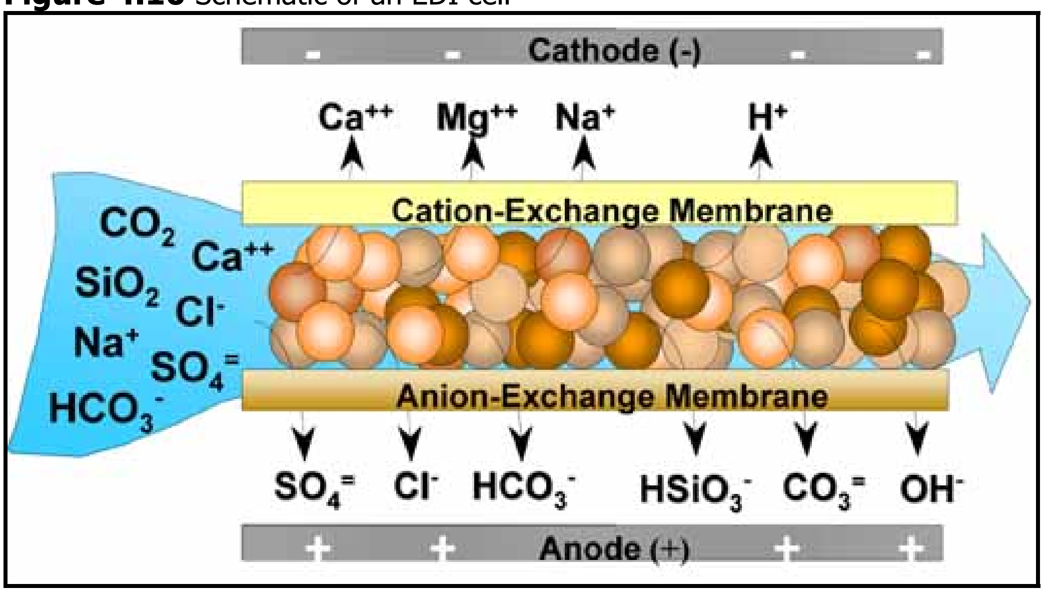
Typically, activated water would be dosed before and after the CDT AquaCells. Dosage before reduces the overall organic load into the AquaCells and also disinfects the feed stream, preventing biofouling. The dosage after the CDT AquaCells would then mainly serve as a final disinfection step specifically for potable water applications. Another benefit of the activated water technology is that the dosage before the AquaCells would also serve as a surfactant, thus reducing fouling - for example, membrane fouling by $CaCO_3$ (Calcium Carbonate) precipitation.

Section 4.8.7 Electro-deionization (EDI)

Weakly-ionized species such as carbon dioxide, boron, and ammonia are difficult to remove via such membrane processes as RO and EDR. EDI (Hernon, et al., 1999) is an electrically-driven membrane process. EDI combines ion-exchange resins, ion-exchange membranes, and a DC electrical field. In EDI, ionized species are removed much like conventional ED with the rate of ion removal greatly increased by the presence of the ion-exchange resins in the cell. In the cell, the DC electrical field splits water at the surface of the ion-exchange beads producing hydrogen and hydroxyl ions that act as continuous regenerants of the ion-exchange resins. This allows a portion of the resins in the EDI to always be in the fully regenerated state. Once ionized, these species are quickly removed under the influence of the DC electrical field. In effect, ionized species are removed in one area of an EDI stack, and weakly ionized species are removed in a second area.

Figure 4.10 shows the removal of ions as water travels through the EDI cell. Strongly ionized species are removed first in the flow path and weakly ionized species are removed as the water moves down the flow path. Removal of ionized species such as sodium, chloride, sulfate, and calcium by EDI is usually well over 99% and has been well documented previously. Removal of weakly ionized species is an area where a properly designed EDI can also achieve extremely high removal rates.

Figure 4.10 Schematic of an EDI cell



(Source: Ionics, Inc.)

Applications

Ionics, Inc. has installed EDI units in various power plants and semiconductor plants in the U.S. Table 4.8 shows the average removal of weakly ionized ions using EDI in such plants. The results are based on the EDI operation only and no pretreatment or post treatment results are included. For example, EDI was able to remove approximately 97% of boron from the RO permeate. In this case, RO was unable to effectively remove boron from the produced water.

Table 4.8 Average percentage removal of weakly ionized species using EDI

Treatment	Performance % removal (avg.)	Comments
Silica	> 99.2	
CO2	> 99.5	
Boron	> 97.0	Post RO treatment only
Ammonia	> 97.4	

The advantage of EDI is that it doesn't require addition of chemicals to remove weakly ionized species from the produced water.

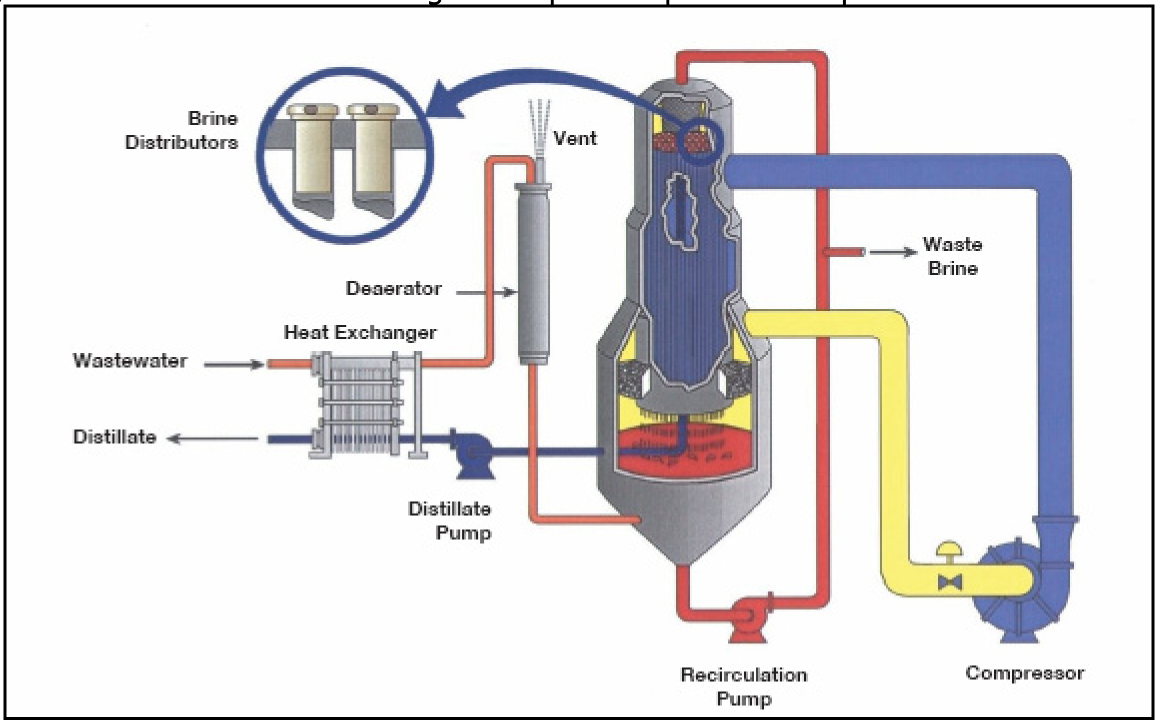
Section 4.8.8 Evaporation

Direct treatment of the produced water in an evaporation system eliminates majority of chemical/physical treatment. The principle of this technique is to provide latent heat to the feed water to generate vapor that can be condensed into pure water form. The remaining stream contains high concentrations of salts/solids.

Falling Film Vertical Tube Evaporators

Falling film vertical tube evaporators (Heinz and Peterson, 2003) have the highest heat transfer coefficient, which is required to save energy (see Figure 4.11). It also minimizes chances of fouling by keeping tubing surface wetted during operations. Produced water is de-oiled and the pH is adjusted. Next, a pre-heater increases the temperature of the produced water/brine. Hot brine goes to de-aerator, which removes non-condensable gases. Hot de-aerated brine enters the evaporator sump where it combines with the re-circulating brine slurry. The slurry is pumped to the top of a bundle of heat transfer tubes and flows down into each tube through a liquid distributor. As the brine flows down the tubes, a small portion evaporates and the rest falls into the sump to be re-circulated. The vapor travels down the tubes with the brine and goes to a compressor through mist eliminators. Compressed vapor flows to the outside of the heat transfer tubes where its latent heat is transferred to the cooler brine slurry falling inside. As a result, vapor gets condensed into pure water form that is pumped back through the heat exchanger where it gives up sensible heat to the incoming wastewater. A small amount of concentrated slurry from the evaporator sump is continuously discarded through a blowdown valve to maintain density of the slurry in the evaporator. The concentrated blowdown can be disposed through a class I injection well or can be converted into solid waste in a crystallizer.

Figure 4.11 A vertical tube falling film vapor compression evaporator



(Source: Ionics, Inc.)

Rapid Spray Evaporation (RSE)

AquaSonics International has developed a Rapid Spray Evaporation™ (RSE) system of ejecting contaminated water at high velocities through a specialized injector-nozzle into waste heat. The unit uses a heating element for a heat source across which air is blown into the evaporation chamber. As the heated air moves along the evaporation chamber, nebulized wastewater is injected into the evaporation chamber. The moving vapor and brine droplets pass through a mechanical filter that traps the brine droplets. The pure vapor phase then passes on to a condenser. The brine droplets are periodically flushed from the filter with the water being treated.

As the water vaporizes within milliseconds of ejection, the solids in the solution flash or separate out. The water vapor is condensed and collected while the precipitated solids form isolated crystalline particles that are collected through a vacuum process and sold as a byproduct. RSE ejects the salt water through a nozzle into a stream of heated air forming a mist of droplets that vaporize almost instantly. The minute flakes of solid salt left behind fall to the bottom of the evaporation chamber where they can be collected. The best success comes from developing nozzles that allow the process to work with hydraulic pressure.

Applications

Tests on the RSE system (Turner, 2002) carried out by Westwater Resources, Albuquerque, New Mexico, confirmed that it can process water containing up to 16% salt. The operating costs for RSE are about one-third of the cost of conventional desalination methods alone, producing 1,000 liters of fresh water for between 16 and 27 cents. AquaSonics claims to attain nearly 100% salt conversion of salt water into fresh water. Table 4.9 shows the results obtained during the testing phase.

Table 4.9 Rapid Spray Evaporation testing results (Source: WestWater Resources)

Solute	Untreated (ppm)	Treated (ppm)	Concentrate (ppm)
Calcium	79	1.6	20
Magnesium	490	1.7	600
Sodium	25,000	160	57,000
Potassium	610	1.9	1,100
Chloride	5,000	90	8,400
Sulfate	31,000	150	35,000
Bicarbonate	5,700	20	2,900
Phosphate	1,200	0	-
Carbon Dioxide	3,100	0	-
TDS	130,000	440	180,000

Freeze Thaw Evaporation (FTE)

Freeze thaw evaporation (FTE®) is a process whereby produced water is first stored in a holding pond until air temperatures drop below 0°C (32°F). The water is then removed from the pond using pumps and sprayed onto a separate freezing pad which consists of an elevated pipe grid with strategically placed sprinklers. These sprinklers can be raised as the ice builds up on the pipe grid. The unfrozen brine water drains from the ice grid and is separated using conductivity-controlled valves.

The concentrated brine water is then transported to separate storage ponds for either secondary treatment or for disposal. The picture below shows a Spray Freezing unit with sprinklers. The alternate to Spray Freezing process involves allowing the holding reservoir to freeze, and draining the brine that forms below the ice. The ice in the pond melts in the spring leaving fresh water.

Source: Hart Energy Publications

Applications

Crystal Solutions, LLC, a joint venture of Gas Technology and BC Technologies, utilized FTE (Lang, 2000) for produced water treatment at its first major commercial treatment facility near Wamsutter, Wyoming. The FTE uses naturally occurring ambient temperature swings to alternately freeze and thaw produced water, concentrating the dissolved solids and producing fresh water suitable for various beneficial uses.

During the 1999-2000 cycle, produced water with 14,000 ppm of TDS was converted to a concentrated brine of approximately 64,300 ppm TDS and the fresh water (melt from ice) having 924 ppm TDS. Roughly 55% of the feed was converted to melt water; about 30% is lost to evaporation and/or sublimation; and only about 15% of the original feed remains as concentrated brine. In this case, due to the concentrated brine having a potassium chloride concentration in excess of 2% it was a usable product for drilling applications.

Section 4.8.9 Pressure Driven Membrane Separation Technologies

Microfiltration (MF), Ultrafiltration (UF), Nanofiltration (NF) and Reverse Osmosis (RO) utilize high pressure across the membranes to accomplish filtration of contaminants from the produced water. These technologies are the most common techniques of water purification. The membranes also are continuously being upgraded or modified for superior performance. Various applications of the pressure driven membrane technologies are listed in Table 4.10. Molecular Weight Cutoff (MWCO) is the ability of a membrane to reject the species of certain molecular weight measured as Daltons.

Table 4.10 Applications of advanced membrane filtration technologies

Membrane Filtration	**Separation Specifications**	**Applications/Removal**
Microfiltration (MF)	>100,000 Daltons 10 - 0.1µm	bacteria, viruses, suspended solids etc
Ultrafiltration (UF)	10,000 to 100,000 Daltons 0.05 - 5 e-3 µm	proteins, starch, viruses, colloid silica, organics, dyes, fats, paint solids etc
Nanofiltration (NF)	1,000 to 100,000 Daltons 5 e-3 - 5 e-4 µm	starch, sugar, pesticides, herbicides, divalent ions, organics, BOD, COD, detergents etc
Reverse Osmosis (RO)	salts and lower MWCO 1 e-4 - 1 e-5 µm	metal ions, acids, sugars, aqueous salts, dyes, natural resins, monovalent salts, BOD, COD, ions etc
Gas Liquid Membrane	CO2, H2S	decarbonation, hydrogen sulfide removal

MF, UF and NF are based on the principle of rejection of species higher than the pore size of the membrane under pressure. RO uses the operating pressure higher than the osmotic pressure of salt present in the water to drive pure water through the membrane, thereby rejecting the salts. It is reversal of the osmosis process where water flows from the higher concentration solution to the lower concentration solution to attain natural equilibrium. The notion of these filtration technologies is discussed in the literature ("Membrane Filtration", 1999).

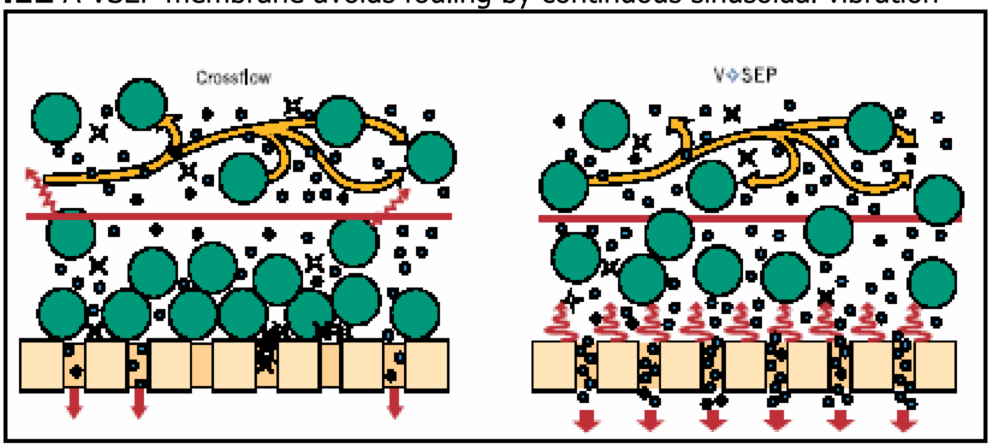
In gas-liquid separation, the pressure difference across a selective membrane is with pore size of about 0.03 micrometers (small enough to prevent water from leaking out, but large enough to allow CO_2 to pass through) is applied. Gas penetrates into the membrane at a rate that depends on diffusivity and solubility of molecules in order to attain the equilibrium between the gas phase and the solute gas in liquid. The pressure difference is created by either vacuum or gas sweep through the membrane.

Oil and gas operators exploit the clear advantages of using mobile produced water treatment units. GE Osmonics, one of the leading manufacturers of membranes focusing on produced water treatment applications, has been developing high performance compact membrane (such as spiral wound membrane) modules (GE, 2006). These membrane modules are easy to utilize in mobile systems. The spiral wound membrane offers the most efficient packing of membrane area to provide higher membrane contact area in limited space. The performance of these membranes is reduced by higher temperature; the upper limit for operating temperature is 113 to 122°F, but some of the spiral wound elements it can be used up to 194°F. Higher temperature operations require more pressure differential across the membranes and so more energy is required to achieve desired separation. However, higher temperature reduces the viscosity of the solution which somewhat offsets the temperature effect (Barrufet, et al., 2004).

The pH of the solution is also an important factor during the membrane filtration operations. High pH RO operation effectively removes boron if the membrane can sustain high pH.

Membrane fouling is a common problem in the various membrane filtration processes. Higher flow rate through the membrane module can produce enough shears near the membrane to avoid accumulation of oil and fouling agents. A hydrophilic membrane is less prone to oil fouling as it has a higher affinity for water and ability to reject oil and grease. New Logic Research developed a vibrating membrane mechanism to avoid membrane fouling caused by free oils and scaling agents (New Logic Research, 2003). The sinusoidal vibration of the membrane avoids the migration of colloids onto the membrane surface. The colloids are washed away with reject in the cross-flow configuration. The anionic membrane repels anions (monovalent, divalent, or multivalent) and associated cations (sodium, magnesium, copper, zinc, iron etc.). Figure 4.12 shows a conceptual picture of Vibratory Shear Enhanced Processing (VSEP) membrane.

Figure 4.12 A VSEP membrane avoids fouling by continuous sinusoidal vibration



(Source: New Logic Research Inc)

Petroleum recovery and research center (PRRC) of New Mexico Institute of Mining and Technology has developed inorganic membranes for the produced water treatment focusing on the treatment of high salinity produced water (> 50,000 ppm in San Juan and > 100,000 ppm in Permian basin). The inorganic membranes made up from zeolite provided higher flux, pH compatibility, and thermal and chemical stability. Table 4.11 shows the higher removal efficiency, even lower differential pressure, and higher flux operations. Each row is for different membranes.

Table 4.11 Performance of various zeolite membranes (Source: PRRC, NMIMT)

Membrane	Ions in feed	TDS (ppm)	Pressure (psi)	Flux ($kg/m^2.h$)	Rejection (%)
1	Na^+, K^+, Ca^{2+}, Mg^{2+}, NH_4^+, Cl^-	39,000	350	0.112	74.5
2	Na^+, Cl^-	5,500	300	0.135	89.2
3	Mg^{2+}, Cl^-	9,400	300	0.081	68.6
4	Ca^{2+}, Cl^-	11,000	300	0.096	57.6
5	Na^+, SO_4^-	14,200	300	0.097	57.4
6	Na^+, Cl^-	5,000	300	0.24	76.8

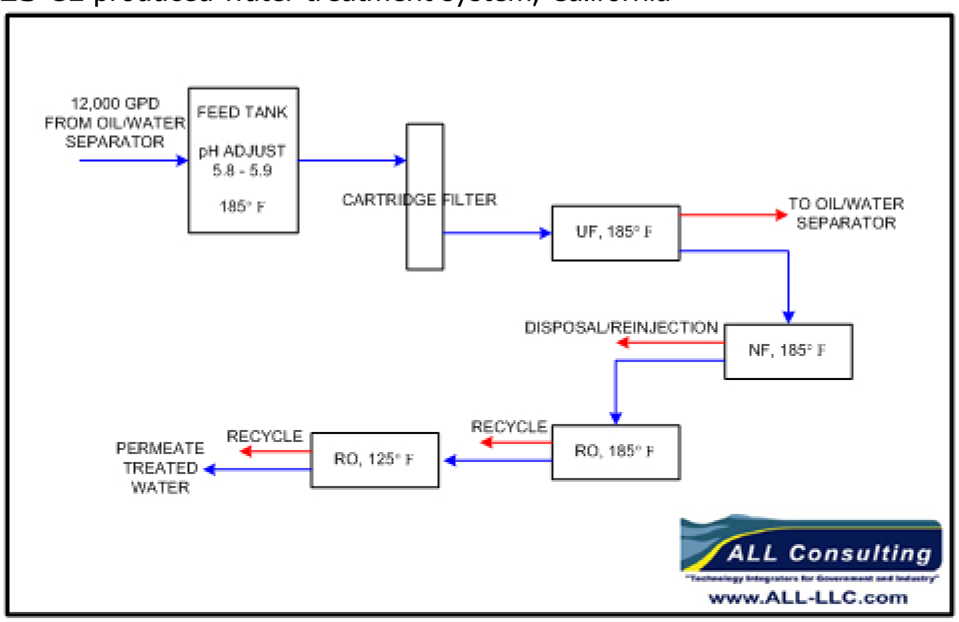
Applications

GE Pilot Study, California

In 2001, GE Osmonics performed a pilot study (GE, 2001) to evaluate feasibility of membrane filtration technologies for the treatment of produced water in California near Bakersfield. The produced water came to the surface at 185°F with approximately 10,000 ppm of salt, a high level of suspended solids, and free oil.

The three-step membrane separation combined with an ion exchange step proved to be sufficient to yield water suitable for irrigation (< 1,000 ppm TDS). The treated water contained 5 to 10 ppm boron, which is higher than the 0.75 ppm limit for irrigation water. Purification of treated water using ion exchange produced boron levels below the 0.75 ppm limit. The schematic of produced water treatment is shown in Figure 4.13.

Figure 4.13 GE produced water treatment system, California



The pH of the produced water from the oil separators was adjusted to 5.8 with sulfuric acid. The suspended solids were allowed to settle in a tank with a conical bottom. CO_2 and H_2S were degassed from the top of the tank and feed from the middle of the tank is discharged to a cartridge filter to remove smaller particles and oil. The effluent from the cartridge filter is passed through high temperature UF, NF and RO units followed by cooling operation and a low temperature RO unit. The overall system recovery was more than 80% considering the recycling of the UF concentrate and the use of the RO concentrate for various purposes. Table 4.12 shows the results of the produced water treatment system composed of membrane filtration units.

Table 4.12 GE pilot water treatment plant results

Constituent	Feed (ppm)	UF Permeate (ppm)	NF Permeate (ppm)	RO Permeate (ppm)
Sodium	9,610	9,610	5,250	144
Calcium	715	715	163	5
Magnesium	412	412	115	2
Potassium	174	174	77	2
Ammonium	110	110	68	2
Chloride	8,010	8,010	4,710	114
Sulfate	1,090	1,090	Non-detectable	Non-detectable
Oil	10 – 50	< 1	Non-detectable	Non-detectable
Recovery, %	-	90 – 95 %	90 – 95 %	80 – 90 %

Placerita Canyon Oil Field, California

The pilot water treatment unit at Placerita Canyon oilfield (Funston, et al., 2002) consisted of warm softening, coconut shell filtration, cooling (fin-fan), trickling filter, ion exchange, and reverse osmosis. The warm softening process removed approximately 95% hardness from the produced water. Silica levels in the softening effluent were 80 and 20 mg/l at a pH of 8.5 and 9.5, respectively. Silica level decreased to 3 mg/l when 400 mg/l of $MgCl_2$ were added. More than 95% of TDS was removed by RO. Approximately 90% removal of boron was achieved at a pH of 10.5 or above. Ammonia removal was 80% at a pH of 8.7 or below. The capital cost of the treatment varied from $3.4 million to $13.2 million. The annual estimated operation and maintenance cost varied from 6¢ to 27¢/barrel of water treated. Table 4.13 shows the summary of produced water treatment system. Figure 4.14 shows the schematic diagram of the produced water treatment system.

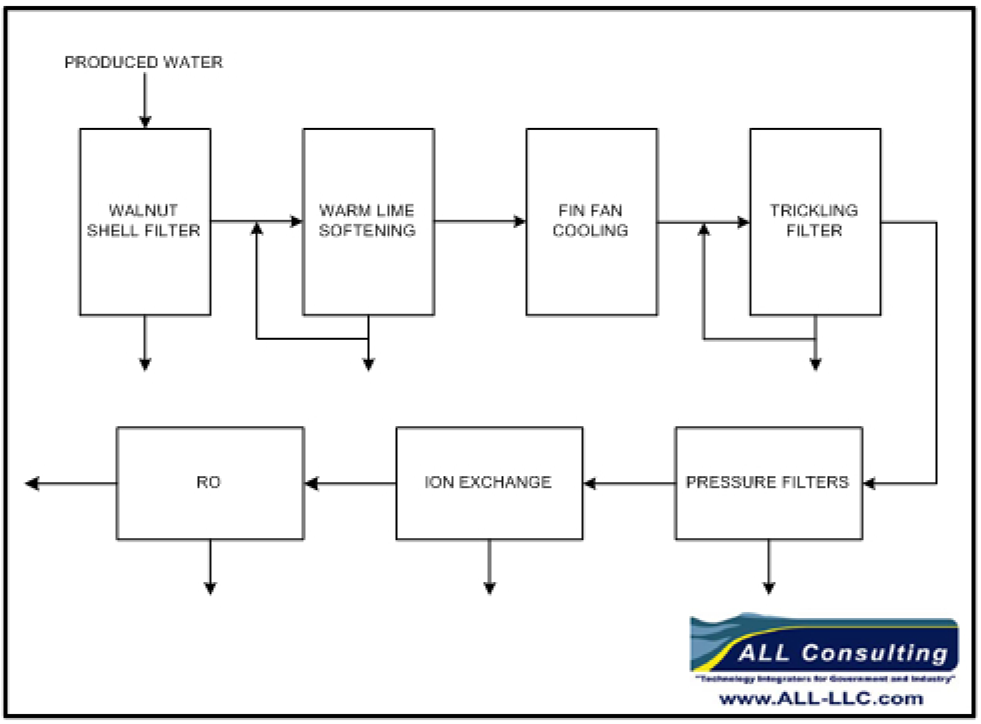
The first step was the Warm Softening process in which lime, $MgCl_2$ and ionic polymer were added to the produced water to precipitate calcium and magnesium hardness. Equation 6 shows the removal of bicarbonate hardness by addition of lime.

$$Ca(HCO_3)_2 + Ca(OH)_2 \rightarrow 2CaCO_3 + 2H_2O \quad ..(6)$$

Table 4.13 A summary of utilized water treatment processes

Process	Specifications	Treatment	Comments
Warm Softening	100 gpm throughput with 10 gpm/ft2 precipitate rising rate	Hardness, Boron, Silica, Ammonia removal	sodium hydroxide/ polymer MgCl2 addition
Cooling	Fin-fan heat exchanger	cooling effluent from softening unit	necessary to prevent damage of the downstream units
Trickling Filter	400 ft3 of polypropylene packing 2.5 gpm/ft2 Hydraulic loading	Biological oxidation of organic carbon	effluent with < 2 ppm TOC
Ion Exchange	5 ft3 of Ionac C-249 resin with capacity of 25-30 grains/ft3	Pretreatment to RO stage residual hardness removal	cation exchange membranes
RO	4 X 40 spiral wound membrane	TDS, Boron, Silica removal	high pH for Boron removal
GAC Adsorber	activated carbon packing	organics removal	post trickling filter treatment

Figure 4.14 Schematic of produced water treatment process



Boron, silica, and ammonia were removed to some extent in the Lime Softening process. The effluent from the softening process was discharged to a fin-fan type heat exchanger to cool the water from more than 150°F to just above ambient air temperature as the units downstream of the softening unit were susceptible to damage at temperatures above 100°F.

The next step was the trickling filter for biological oxidation of organics (U.S. EPA, 2000). A trickling filter is a plastic or rock packed system with large diameter to depth ratio. Influent water is trickled through from the top in the presence of air (oxygen). The microorganisms in the produced water attach on the surface of packed media to form a biological film. Subsequently, the organic materials are degraded by the biological film. As the biological film thickens through microbial growth, oxygen penetration to the packed media is affected. Also, portions of the film lose their ability as they are used to degrade organics. This causes the used layer to fall off from the packed media, known as sloughing process. Next the sloughed solids are removed in pressure filters. During most stages of testing, the trickling filter was bypassed to allow the microbes produced to acclimate to the water organics. When bypassing the trickling filter, the water was sent directly from the heat exchanger.

Next, the processed water passed through the ion exchange softeners to remove any residual hardness. Finally, RO was used to remove TDS, boron, and additional organics. The RO permeate was sent to a 2,000-gallon polyethylene tank for storage and the concentrated reject stream was sent to the system drain. pH adjustment is the most important step in the treatment system because boron, silica, ammonia, and hardness removal depends on pH of the solution. The relationships among the constituents are not monotonous, which required careful pH adjustment during the process. For example, as the pH of the solution increases more silica gets ionized and that increases silica solubility, which may increase membrane leakage and deteriorates the silica removal. Opposite to that, as the silica solubility increases the chances of membrane fouling due to silica precipitation decreases, which improves RO membrane performance. As the pH of the solution increases ammonia solubility decreases, which diminishes ammonia removal by RO.

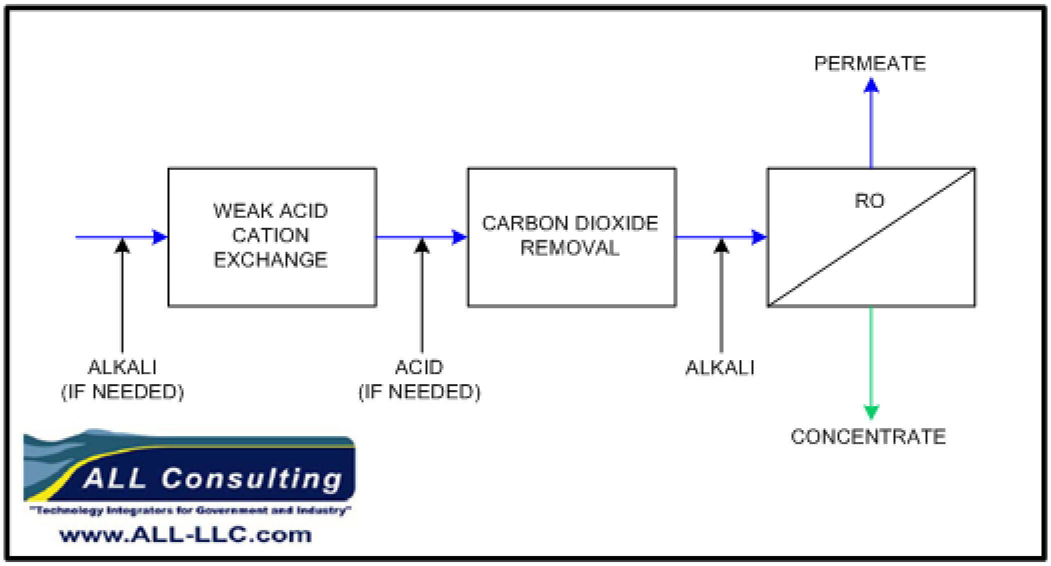
High Efficiency Reverse Osmosis (HERO™)

GE Ionics developed HERO™ (Hayter et al., 2004) to provide higher water recovery, higher quality permeate, higher operating flux, and lower overall cost than conventional RO treatment. The most important stage of HERO is pretreatment of the feed water before RO operation to raise the pH of feed water that enables higher efficiency. As discussed earlier, increase in pH improves boron removal and avoids membrane fouling.

As shown in Figure 4.15, HERO is a three step process.

1. *Hardness removal*: Calcium and Magnesium hardness can precipitate on RO membranes at high pH, which causes membrane fouling. Alkali is added to balance alkalinity and hardness which improves weak acid cation exchange (WAC) softening process efficiency. WAC resins exchange hardness from the produced water as discussed earlier. The H+ addition increases pH enabling conversion of bicarbonate alkalinity into carbon dioxide.
2. *Carbon dioxide removal*: As discussed in earlier sections, degasification using air stripping removes carbon dioxide from the water. The carbon dioxide removal further increases pH of the produced water.
3. *High pH RO*: High pH water increases solubility of silica and destroys biological organisms that cause membrane fouling. Dissolved solids are removed by the RO process.

Figure 4.15 A schematic of HERO system developed by GE Ionics



The biggest advantage of the HERO system is the reduced capital cost (~15%) at higher flux rate (50 GPM). Because of reduced fouling and scaling of the RO membrane, the operating and energy costs for HERO are also less than conventional RO. The increase in water recovery is obvious with HERO systems due to the high performance of membrane. The shortcomings of HERO are the treatment chemical requirements and the higher costs at lower flux operations.

GE Ionics tested a HERO system to upgrade the water purification plant of Sandia National Laboratories at Albuquerque, New Mexico. The system produced approximately 94% water recovery. The reported power usage was approximately 17 kWh per 1000 gallons of treated water. The reported operating cost was approximately $0.064 per gallon of treated water.

Oxidation Reactor

Newpark Environmental Services offers an innovative treatment system consisting of several components and is based on aggressive oxidation followed by precipitation of the contaminants present in the produced water (Lincz, 2004). Oxidation of contaminants is the most important part, which is accomplished in the Armel Reactor, a proprietary design of Newpark Environmental Services. The Armel Reactor is part of the chemical/physical treatment stage of this multi-stage technology. The chemical/physical stage is often adequate to achieve many water treatment requirements on its own. Dissolved contaminants such as monovalent salts are extremely resistant to oxidation/precipitation and may not be removed during the chemical/physical treatment stage. Such contaminants can be removed in the demineralization stage, which consists of MF, UF and/or RO units. The chemical/physical treatment stage before the demineralization stage removes contaminants that can plug the membrane and improves efficiency of the demineralization stage.

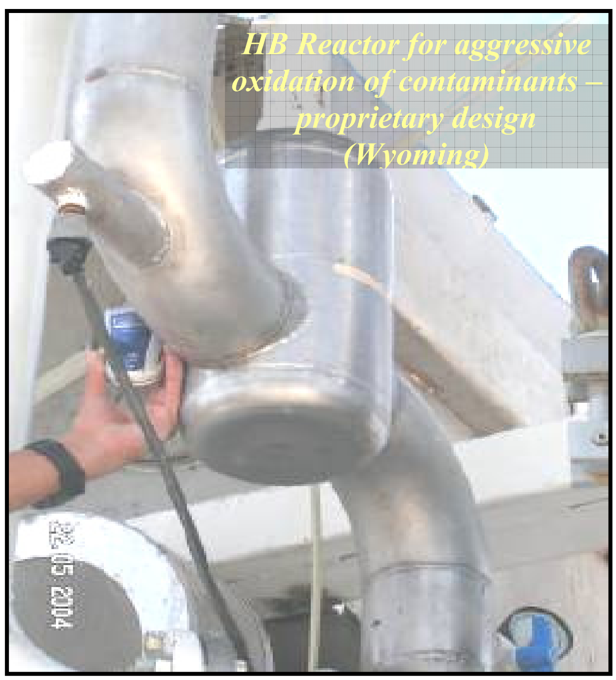
The Newpark system contains three separate stages that can be used separately or in tandem: the chemical/physical stage, the demineralization stage, and the waste disposal stage.

Chemical/Physical Stage

The chemical/physical stage consists of the following elements:

- *Degasification* – recovery of methane gas from produced water inflow from CBNG well and removal of CO2 from produced water.
- *Solids Removal* – water from degasification unit flows through patented Clasiker equipment that removes suspended solids ranging from debris to micro fines.
- *pH Adjustment* – pH of the water is adjusted to as neutral as possible, which would maximize the efficiency of oxidation reactor.
- *Liquid Ring Blower* – high volume, low pressure air is pumped into the water stream just prior to the HB.
- *Armel Reactor (sonic oxidation)* – the water/air mixture then flows through the reactor and is aggressively oxidized/energized. Water/air mixture then enters the reactor where millions of small micro-bubbles are generated from the entrained air by mechanical means (5 to 10 psi pressure drop). The micro-bubbles carry positive charge and repel other micro-bubbles, but attract negatively charged ions (these negatively charged ions are associated with positively charged ions) in the form of a contaminant (Ca+CO3-, Na2+SO4-2 etc.).

The charged micro-bubbles attract more oppositely charged contaminants and become thicker, which increases their surface tension. Due to ever increasing surface tension, the size of the micro-bubble decreases and the pressures and temperatures inside the bubble significantly increase, which creates points of highly localized temperature. Under the effects of increased pressure and temperature, contaminants attached to micro-bubbles are violently reacted with O_2 associated with atmospheric air inside the micro-bubble. The energy associated with this reaction results in ultrasonic wave and a very aggressive oxidation of contaminants. Those contaminants not oxidized are highly energized and in a very reactive state. The water (along with the oxidized and energized ions/contaminants) flows out of the reactor to the next stage.



- *Degasser* – at this stage all O_2 has been consumed but a significant amount of N_2 remains trapped in the water. Degasser removes the trapped N_2.
- *Coagulation/Flocculation* – a coagulant (lime) and flocculent (anionic polymer) is mixed into the water to precipitate out the treated contaminants in the form of flocculants.
- *Frictioning* – frictioner settles and removes the larger flocculants.
- *High Rate Clarification* – a series of tubes settles out and removes the smaller flocculants.
- *Sand/Activated Carbon Filtration* – the water is then filtered through a sand and activated carbon to remove the smallest flocculants. The water becomes clear through this process.

Demineralization Stage

Complete removal of dissolved contaminants can be achieved in the demineralization stage by further treatment of effluent water from the chemical/physical treatment system. The demineralization stage consists of the following elements:

- *MF Unit* – sub-micron size particles or contaminants are removed in MF unit. This ensures that undissolved sub-micron particles do not enter the RO system and plug the membranes.
- *RO Unit* – the water is then pumped at high pressure through a series of reverse osmosis membranes for the concentration and further removal of remaining dissolved contaminants.

Waste Disposal

Permeate from the RO unit can be utilized as a fresh water source with or without further treatment. Concentrate is generally hauled to the nearest disposal facility. Large volumes of concentrate, transportation costs, and limited capacity of disposal sites encourage further treatment of concentrate. Concentrate can be dried into a solid phase, which would be easier to handle.

- *Crystallizer and Evaporator* – Crystallizer further concentrates the RO concentrate stream by extracting water. Total volume of the concentrate is reduced while the associated TDS increases significantly. The water (extract phase) is re-circulated through the RO and concentrate (sludge-water) flows through evaporators. Water gets evaporated and the dissolved solids remain in sludge state. Handling and disposal of reduced volume of waste in sludge form is easier.

Figure 4.16 shows a schematic of produced water treatment system designed by Newpark Environmental Services. Newpark has tested this system for the treatment of produced water from various sources on the pilot scale.

Table 4.14 shows the performance of Newpark's system for the treatment of produced water from three facilities. The quality of effluent or treated water at the end of both the chemical/physical treatment stage and demineralization stage was supervised. The Pinedale and Gillette plants are company-owned facilities that process operators' water on a contract basis.

Section 4.8.10 NORM Treatment

Naturally occurring radioactive materials (NORM), such as radium, are mobilized from the oil or gas formations because of the solubility in the presence of chloride ions which are present in the water within formation (Tenorm Page, 2004). Low solubility of the sulfate species is a factor in redeposition of NORM. The low solubility precipitates scale containing high concentrations of radium in the form of barium sulfate or barite [Equation 7] under the effects of varying temperature and pressure during the production operations.

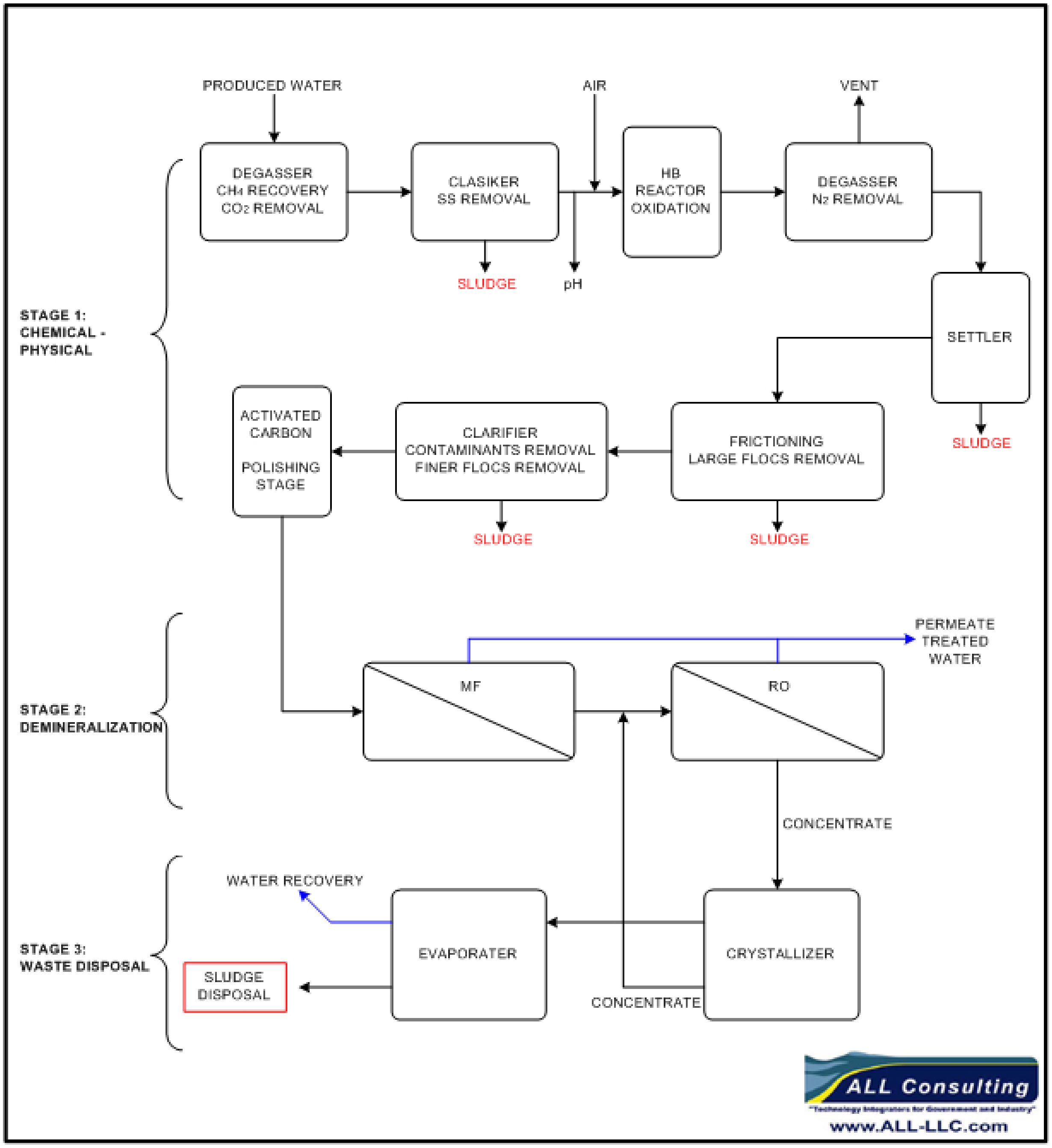
$$Ba^{+} + Ra^{+} + SO_4^{\ -} \rightarrow Ba[Ra]SO_4 \qquad ..(7)$$

The handling and treatment of the precipitated sulfate deposits containing decaying radioactive materials is an absolute necessity because of the dangers of radioactivity. BPF Inc., Texas (Mickley, 2001), developed a mobile automated treatment system that includes separation of

NORM solids from other oilfield waste (produced water) containing less than 30 pCi/g (picocuries per gram, a measurement of radioactivity) radium and dissolving it into aqueous solutions. Extraction of radionuclides from the scale is done by dissolving the radioactive material in one or more aqueous solvents in the hydroclone, which separates solids with no NORM from the solution. The NORM containing solution is transported to class II injection sites and reinjected into the formation (Smith, et al., 1997).

Radioactive materials also occur in natural gas in the form of radon. One of the methods to treat the gas is packed bed adsorption of radon with activated charcoal. Monitoring of radioactivity is an essential part of NORM treatment, which is accomplished by in-situ radioassay capability.

Figure 4.16 Newpark Environmental Services produced water treatment system



(Source: Newpark Environmental Services)

Table 4.14 Results from field test with a produced water treatment system

	Pinedale, WY (Pinedale Field Produced Water)			**Big Hills, TX (Conventional Oil and Gas Produced Water)**			**Gillette, WY (CBNG Water)**		
Parameter mg/L or ppm	Influent	Effluent		Influent	Effluent		Influent	Effluent	
		Chemical/ Physical	After RO		Chemical/ Physical	After RO		Chemical/ Physical	After RO
Carbonate (CO_3)	< 1	-	-	< 1	< 1	< 1	< 1	-	< 1
Bicarbonate (HCO_3)	842	-	-	312	156	7.3	2,782	-	12.2
Calcium	68	-	-	2,388	303	0.96	43.67	-	1
Chloride	4,589	-	56.5	70,978	8,922	355	115	-	18
Magnesium	9	-	-	90	93	0.3	32.87	-	< 0.1
Sodium	3,324	-	36.6	49,590	5,140	217	1,076	-	21.5
Sulfates	1	-	-	6	280	< 1	< 1	-	<0.1
Alkalinity as $CaCO_3$	582	-	-	210	118	6	2,110	-	10
TDS	11,957	3,004	93	174,452	19,053	93.1	3,203	1,358	46
TPH	5	-	-	8	2	1	1	-	1

(Source: Newpark Environmental Services)

A summary table of the various treatment technologies included in here is presented in Table 4.15 for ease of use. The table describes advantages, disadvantages, and ranges of field applicability for each treatment technology evaluated. The table is segmented by treatment objective (for example "De-oiling"), and within each objective technologies can be compared in terms of their advantages, disadvantages, resulting waste stream, and applications to oil and gas fields. Advantages and disadvantages are described in comparative terms rather than absolute figures that are subject to change; the aim is to compare technological options for a given objective. Durability and cost are important factors that will depend on site-specific conditions and the specific commercial version picked by the operator. Comparisons of inherent durability can be made within each objective but these are only generalizations. No attempt was made to ascribe economic factors to these technologies since costs will vary from location to location and may be dependent upon commercial configurations and innovations.

Waste products are specific to each technology; for example desalinization can result in a residue consisting of 20% of the input stream or a residue made up of 1% of the input. The 1% residue will be a more concentrated brine than the 20% residue. However, both may no longer be classified as oil and gas wastes because they are a result of a treatment process. "Raw" produced water can be disposed of by way of an exemption from standard industrial waste regulations under the federal Resource Conservation and Recovery Act (RCRA) as described in Section 3. The oil and gas exemption means that "raw" produced water can be sent to deep disposal wells that inject the water back into deep, salt water bearing reservoirs with minimal regulatory requirements and cost. Industrial brines, however, are subject to increased regulatory compliance costs because the brines are a result of a treatment process. The challenges associated with the UIC process are discussed in more detail in Section 3, and the disposal options are discussed in Section 4.9.

Table 4.15 Advantages, Disadvantages, and Applicability of Produced Water Treatment Technologies

TREATMENT	DESCRIPTION	ADVANTAGES	DISADVANTAGES	WASTE STREAM	OIL AND GAS PRODUCED WATER APPLICATIONS
De-oiling					
Corrugated plate separator	separation of free oil from water under gravity effects enhanced by flocculation on the surface of corrugated plates	No energy required, cheaper, effective for bulk oil removal and suspended solid removal, with no moving parts, this technology is robust and resistant to breakdowns in the field.	inefficient for fine oil particles, requirement of high retention time, maintenance	suspended particles slurry at the bottom of the separator	Oil recovery from emulsions or water with high oil content prior to discharge. Produced water from water-drive reservoirs and water flood production are most likely feed-stocks. Water may contain oil & grease in excess of 1000 mg/L.
Centrifuge	separation of free oil from water under centrifugal force generated by spinning the centrifuge cylinder	efficient removal of smaller oil particles and suspended solids, lesser retention time-high throughput	energy requirement for spinning, high maintenance cost	suspended particles slurry as pre-treatment waste	
Hydroclone	free oil separation under centrifugal force generated by pressurized tangential input of influent stream	compact modules, higher efficiency and throughput for smaller oil particles	energy requirement to pressurize inlet, no solid separation, fouling, higher maintenance cost		
Gas floatation	oil particles attach to induced gas bubbles and float to the surface	no moving parts, higher efficiency due to coalescence, easy operation, robust and durable	generation of large amount of air, retention time for separation, skim volume	skim off volume, lumps of oil	
Extraction	removal of free or dissolved oil soluble in lighter hydrocarbon solvent	no energy required, easy operation, removes dissolved oil	use of solvent, extract handling, regeneration of solvent	solvent regeneration waste	Oil removal from water with low oil and grease content (< 1000 mg/L) or removal of trace quantities of oil and grease prior to membrane processing. Oil reservoirs and thermogenic natural gas reservoirs usually contain trace amounts of liquid hydrocarbons. Biogenic natural gas such as CBNG may contain no liquids in the reservoir but when pumped to the surface, the water takes up lubricating fluids from the pumps.
Ozone/hydrogen peroxide/oxygen	strong oxidizers oxidize soluble contaminant and remove them as precipitate	easy operation, efficient for primary treatment of soluble constituents	on-site supply of oxidizer, separation of precipitate, byproduct CO_2 etc.	solids precipitated in slurry form	
Adsorption	porous media adsorbs contaminants from the influent stream	compact packed bed modules, cheaper, efficient	high retention time, less efficient at higher feed concentration	used adsorbent media, regeneration waste	

TREATMENT	DESCRIPTION	ADVANTAGES	DISADVANTAGES	WASTE STREAM	OIL AND GAS PRODUCED WATER APPLICATIONS
Disinfection					
UV light/ozone	passing UV light or ozone produce hydroxyl ions that kills microbial	simple and clean operation, highly efficient disinfection	on-site supply of ozone, other contaminants reduce efficiency	small volumes of suspended particles at the end of the treatment	Microbes may exist in the subsurface reservoir or can be introduced during production or during water treatments. Disinfection may need to be done to protect potability or to or to prevent fouling of the reservoir, tubulars, and surface equipment.
Chlorination	chlorine reacts with water to produce hypochlorous acid which kills microbial	cheaper and the simplest method	does not remove all types of microbial		
Desalinization					
Lime softening	addition of lime to remove carbonate, bicarbonate etc. hardness	cheaper, accessible, can be modified	chemical addition, post treatment necessary	used chemical and precipitated waste	These technologies typically require less power and less pre-treatment than membrane technologies. Suitable produced waters will have TDS values between 10,000 and 1,000 mg/L. Some of the treatments remove oil and grease contaminants and some of them require oil and grease contaminants to be treated before these operations.
Ion exchange	dissolved salts or minerals are ionized and removed by exchanging ions with ion exchangers	low energy required, possible continuous regeneration of resin, efficient, mobile treatment possible	pre and post treatment require for high efficiency, produce effluent concentrate	regeneration chemicals	
Electrodialysis	ionized salts attract and approach to oppositely charged electrodes passing through ion exchange membranes	clean technology, no chemical addition, mobile treatment possible, less pretreatment	less efficient with high concentration influent, require membrane regeneration	regeneration waste	
Electro-deionization	Enhanced electrodialysis due to presence of ion exchange resins between ion exchange membranes	removes of weakly ionized species, high removal rate, mobile treatment possible	regeneration of ion exchange resins, pre/post treatment necessary	regeneration waste, filtrate waste from post-treatment stage	
Capacitive deionization	ionized salts are adsorbed by the oppositely charged electrodes	low energy required, higher throughput	expensive electrodes, fouling	regeneration waste	
Electrochemical Activation	ionized water reacts with ionized chloride ion to produce chlorite that kills microbial	simultaneously salt and microbial removal, reduce fouling	expensive electrodes	regeneration waste	
Rapid spray evaporation	injecting water at high velocity in heated air evaporates the water which can be condensed to obtained treated water	high quality treated water, higher conversion efficiency	high energy required for heating air, required handling of solids	waste in sludge form at the end of evaporation	

TREATMENT	DESCRIPTION	ADVANTAGES	DISADVANTAGES	WASTE STREAM	OIL AND GAS PRODUCED WATER APPLICATIONS
Freeze thaw evaporation	utilize natural temperature cycles to freeze water into crystals from contaminated water and thaw crystals to produce pure water	no energy required, natural process, cheaper	lower conversion efficiency, long operation cycle		
Membrane Treatment					
Microfiltration	membrane removes micro-particles from the water under the applied pressure	higher recovery of fresh water, compact modules	high energy required, less efficiency for divalent, monovalent salts, viruses etc.	concentrated waste from membrane backwash during membrane cleaning, concentrate stream from the filtration operation	Removal of trace oil and grease, microbial, soluble organics, divalent salts, acids, and trace solids. Contaminants can be targeted by the selection of the membrane. The size distribution of the removable species for membrane filtration technologies is shown in Table 4.10.
Ultrafiltration	membrane removes ultra-particles from the water under the applied pressure	higher recovery of fresh water, compact modules, viruses and organics etc. removal	high energy, membrane fouling, low MW organics, salts etc		
Nanofiltration	membrane separation technology removes species ranging between ultrafiltration and RO	low MW organics removal, hardness removal, divalent salts removal, compact module	high energy required, less efficient for monovalent salts and lower MW organics, membrane fouling		
Reverse Osmosis	pure water is squeezed from contaminated water under pressure differential	removes monovalent salts, dissolved contaminants etc., compact modules	high pressure requirements, even trace amounts of oil & grease can cause membrane fouling		Removal of sodium chloride, other monovalent salts, and other organics. Some organic species may require pre-treatment. While energy costs increase with higher TDS, RO is able to efficiently remove salts in excess of 10,000 mg/L.
Miscellaneous Treatment					
Trickling Filter	develops film of microbial on the surface of packed material to degrade contaminants within water	cheaper, simple and clean technology	oxygen requirement, large dimensions of the filter	sludge waste at the end of the treatment	Removal of suspended and trace solids, ammonia, boron, metals etc. Post-treatment is normally required to separate biomass, precipitated solids, dissolved gases etc.
Constructed wetland treatment	natural oxidation and decomposition of contaminants by flora and fauna	cheaper, efficient removal of dissolved and suspended contaminants	retention time requirement, maintenance, temperature and pH effects		
SAR adjustment	addition of Ca or Mg ions	cheaper option	chemical addition		Balance high SAR and very low TDS (higher percentage of sodium salts) after membrane processes.

TREATMENT	DESCRIPTION	ADVANTAGES	DISADVANTAGES	WASTE STREAM	OIL AND GAS PRODUCED WATER APPLICATIONS
NORM Treatment					
NORM treatment	extraction of radioactive material with aqueous solution	efficient for reducing radioactive waste volume	extracted radioactive materials need further treatment or disposal		Produced waters containing high levels of Uranium or Thorium. Unless treatment is accomplished, radioactive scale can form in surface equipment extensive remediation.
Natural Gas Recovery					
Air stripping	stripping of dissolved gas from water	concurrent or countercurrent operations, cheaper	post treatment, lower efficiency		

Source: ALL, 2005

Section 4.9 Handling of Water Treatment Waste/Concentrate

Produced water treatment technologies convert poor quality produced water into good quality water by removing contaminants and impurities. As discussed earlier, many such treatment technologies decontaminate inlet produced water producing a waste stream with higher concentration of contaminants and a treated water stream. For example, membrane systems separate influent water into cleaner product water and a more concentrated stream that is called concentrate in RO, NF, and EDR systems and backwash in UF and MF systems. Considering large scale of produced water treatment, the amount of concentrated waste volume needs to be considered when planning water treatment facilities.

The selection of concentrate disposal practice depends on several factors such as regional disposal availability (geology, geographical, climate, etc), local availability (existence of suitable disposal site, distance, compatibility, etc), volume of concentrate stream, applicable environmental regulations (NPDES, underground injection control regulations, and underground water resource regulations, etc. are imposed by local, state, or federal agencies), environmental impacts, public reception, cost, etc. Along with cost contributing factors such as transportation, treatment, development of disposal site, etc., environmental regulations also have major impacts on the feasibility of any particular concentrate disposal method.

Disposal to surface water:

Membrane wastes may be discharged to surface waters and ultimately reside within large receiving water bodies. Direct discharge to water bodies must have an NPDES permit (states' authority), which requires meeting CWA regulations for effluent limitations. Large volumes of concentrate waste and level of contaminants in it are some of the limiting factors for this practice.

Disposal to Publicly Owned Treatment Works (POTWs):

An NPDES permit is not required for the disposal into publicly owned treatment works (POTWs). However, POTWs may enforce pre-treatment before disposal according to federal regulations to control the level of wastewater pollutants entering the sewage system.

Disposal with injection well:

Injection of concentrated waste through a Class I injection well beneath the lowermost underground source of drinking water requires meeting UIC regulations according to state and federal standards. Research is being attempted to evaluate disposal of concentrate into depleted oil or gas fields through Class I wells (Nicot and Dutton, 2004). Formation damage, scaling, etc., are some of the concerns for using depleted oil or gas fields.

Evaporation ponds:

Evaporation ponds utilize solar energy to evaporate water into the atmosphere in vapor form leaving behind solids/salts in sludge form. This technology is limited to regions where solar irradiation is high. Permits may be required if a potential of leakage into surface water or drinking water aquifers exists.

Spray evaporation:

An NPDES permit may be required for spray evaporation if the potential of waste runoff to a receiving water body exists.

Zero liquid discharge:

The objective of zero liquid discharge is to eliminate any liquid waste at the end of the water treatment process. Evaporators or concentrators can be utilized to concentrate the waste stream. Conversion of concentrated sludge into solids/salts form can be accomplished by using a crystallizer. Disposal of solid waste from a crystallizer must avoid contamination of surface or groundwater.

THIS PAGE INTENTIONALLY LEFT BLANK

SECTION 5.0 PRODUCED WATER REDUCTION TECHNIQUES

A white paper studying the applicability of various water reduction techniques to the coalbed natural gas development of the Powder River Basin in Montana and Wyoming was prepared as part of a research project funded by the National Energy Technology Laboratory (NETL) of the DOE. This section presents a summary of the findings of this research as they may apply to various basins across the United States. The title of the white paper is: *Reducing Produced Water Volumes from Coal Bed Natural Gas in the Powder River Basin* (ALL, 2005).

Across the CBNG industry, the following were identified as the more promising technologies for minimizing produced water on the surface:

1) Downhole Water Separation and Injection – avoids producing the groundwater to the surface as it separates water from gas downhole and injects the water into underground disposal/injection zones.
2) Advanced Production and Completion Techniques – controls unconfined fracture propagation and reduces hydraulic connectivity between water bearing formations other than the resource bearing formation near the producing well.
3) Horizontal Drilling – improves resource recovery (often without stimulation) per barrel of produced water and appears to be a way to reduce net water production.

The technologies listed above are commonly used in the development of oil and gas reservoirs but are not applicable to every field. Each technology has geotechnical limitations and operational pros and cons that are described in Section 5.1 for downhole water separation and injection; Section 5.2 for advanced production and completion techniques; and Section 5.3 for horizontal drilling.

Section 5.1 Downhole Water Separation and Injection

Downhole separators separate water from oil or gas within the well bore; oil or gas with little or no water is then produced to the surface. Significant amounts of water are disposed into a non-producing formation above or below the oil or gas producing formation using injection tools within the well bore. The performance of downhole separators is influenced by the geology of disposal zone. The small amount of water produced to the surface along with oil or gas requires appropriate handling or treatment, or disposal in accordance with the existing regulations. The downhole separator assembly comprises a number of various compact elements installed within the actual well bore.

1) Separation Tool – Separates water from incoming fluids from the reservoir. The tool is not a necessity for a gas producing wells, but is required for oil producing wells.
2) Pump – Pressurizes large amounts of water from the separator and injects the water into the disposal zone. Sucker rod pumps, plunger pumps, progressive cavity pumps (PCPs) or electric submersible pumps (ESPs) are utilized depending on the requirements of injection pressure and volume.

3) Motor – Heavy duty compact motor-modules are required to perform desired pumping duty.
4) Miscellaneous – Downhole monitoring equipment, cables, surface controls, etc. may also be required for better controlled operations.

The evaluation of both engineering and economic feasibility varies significantly by operator and location. Some of the technical issues of concern for downhole separation are the following:

Producing and Receiving Formation Suitability
Selection of a suitable injection zone/area within the producing formation may depend upon several criteria, including reservoir characteristics, depth, relative location to producing wells, and possible contamination of underground sources of drinking water (USDW). To be a suitable candidate for downhole separation, the productive zone would have to produce very few fines that could plug the receiving zone.

Zonal Isolation
The receiving formation must be vertically and laterally separated or otherwise confined from producing formations and other USDWs. Suitability analyses also would require the examination of local fracturing and faulting as the fractures may be able to hydraulically connect injection and producing zones; this could cause recycling of produced water in the vicinity of the well bore.

Porosity
Injection formation must have sufficient porosity to adequately hold the injected formation fluids.

Permeability
A productive reservoir or an attractive injection zone will have sufficiently high permeability to allow sufficient fluid movement. Confining zones should have very low permeability in order to act as seals rather than zones that will allow fluid movement.

Storativity
The storage capacity of a geologic unit can be estimated using a simplistic approach by estimating the pore volume of the entire injection zone. For instance, a permeable unit that has 10% porosity, is 20 feet thick, and is homogenous and regionally extensive would have a storage capacity of 2 million barrels if the injectate front extended for ¼ mile. Higher storativity is desired and contributes to the success of injection.

Injection Pressure
Reservoir pressure may limit the rate at which fluids can be injected and/or may limit the injectivity. Injection pressures may be so high that fracture-propagation could be initiated and augmented; fractures within and outside the injection zone could cause real problems at the injection site leading to injected fluids moving out of the zone into a nearby producing zone or USDW.

Fractures
Natural fracture or fractures created during injection can be helpful if they are confined to the injection zone and do not create conduits for flow across the confining zones. Fractures can reduce the impacts of near well bore damage and improve injectivity. However, unconfined vertical fractures extending from the producing formation to an USDW can cause problems.

Water Quality
The chemical compatibility of the injectate fluids also plays a part in the feasibility assessment of the injection plan. If the injected water is incompatible with the underground water of the injection zone it can cause scaling problems (from the precipitation of minerals) that could damage or reduce the hydraulic conductivity of the formation.

Injectivity Loss
Water being separated downhole and injected is not filtered in the same manner that water brought to the surface and then re-injected is filtered. Clogging of pores of the injection formation by sand or fine solid particles, scale, biological slimes, and precipitates can reduce the rate a formation can receive injectate. The processes that cause injectivity loss can reduce the success of the downhole water separation installation more than any other effect, especially if a large volume of water is being injected every day. The build-up of fines across the perforations can act as a cement. For example, if the injectate contains as little as 50 mg/L suspended fines, injecting 1000 bpd will result in approximately 70 lbs of fines being forced into the formation opposite the perforations every day of operation. Over a very short time, plugging can lead to irreparable damage to an injection zone.

Section 5.2 Advanced Production and Completion Techniques

Improvements to production and completion techniques are being attempted by operators to reduce the production of water to the surface during the production of oil and gas resources. Some of the new techniques that operators are trying to utilize are described below.

Section 5.2.1 Reverse Circulation Center Discharge

A recent innovation is a unique drilling program developed by Calgary-based K2 Energy Corp (Evergreen, 2002). The process is called "reverse circulation center discharge" (RCCD). The company, in conjunction with Midnight Sun Drilling of Whitehorse, Yukon, has recently completed nine shallow gas wells in northern Montana. RCCD creates minimum drilling damage to the formation, thus allowing shallow, low pressure gas to flow to the surface during drilling operations. RCCD drilling consists of three basic components: double-wall drillpipe, an air hammer, and a downhole blowout prevention system. The drillpipe has 4.5-inch outer and 2.875-inch inner diameter tubulars. Air circulates between the two strings, drives the air hammer, and at the same time reverse circulates the formation cuttings back up the inner pipe to the surface. K2 reports that the well bore is perfectly straight from top to bottom, with no fill at the bottom of the well. The well can flow gas as it is drilled.

Section 5.2.2 Cavitation

As a stimulation or clean-up treatment, the cavitation process uses dynamic pressure changes to break apart the rock face and to widen the effective borehole across the producing zone. Air or foam is pumped into the well to increase the pressure in the reservoir followed by a sudden release that blows out the air/gas along with rock fragments (Oil and Gas Accountability, 2004).

This action is sometimes referred to as "surging," and it is accompanied by a jet engine-like noise that can last up to 15 minutes. The rock fragments, foam, water, and gas that escape from the well are directed at an earthen berm to prevent the materials from entering the greater environment. Some of the loose rock material remains in the well. It is cleaned out by circulating water or foam in the well and pumping the material into the recovery pit or steel tank.

Cavitation Inc. developed a new cavitation and cleaning tool specifically for CBNG completion. The cavitation and cleaning tool is engineered and designed for enlarging hole size, completion, and work over uses. The cavitation and cleaning tool can be used with air, water, and drilling foam, or just water and foam. An air compressor can be sized to the depth of a well. For example, a 950 cfm and 350 psi air compressor can be used on a well as deep as 1,200 feet, according to how much water the well makes. The tool can be adjusted to depth and hole size. The advantages of this technology include enlargement and cleaning of the well bore in one run and replacement of "water enhancement" activities that could create unconfined fractures responsible for higher water production. Limitations of cavitation may include shortening the production life of the CBNG well.

Section 5.2.3 Well Stimulation

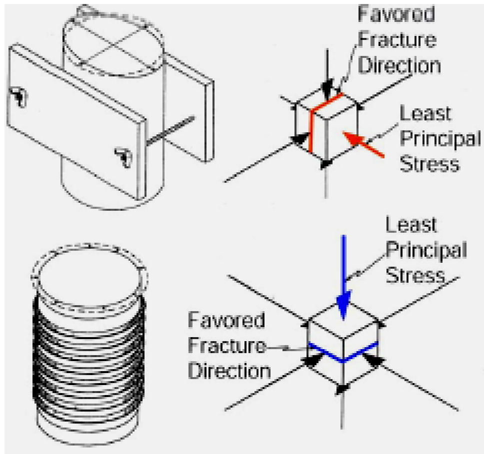
After the producing well is completed either in one open hole zone or one or more zones opened by perforations through casing, the well is often stimulated by the injection of a fluid under pressure. Stimulation is achieved by one of several technologies – hydraulic fracturing, propellant fracturing, and various other techniques.

Hydraulic Fracturing:

One option for the operator is to complete producing wells with high pressure hydraulic fracture stimulation. Hydraulic fracturing is often avoided to prevent fracturing the confining formations adjacent to the producing zones, which can significantly increase water production. If the fracture is confined within the producing zone, for example, horizontal fractures in a vertical well within the zone contribute to increased gas production. If the fracture extends in vertical direction it can possibly contact the overlying or underlying water bearing formations or even extend into those aquifers. The vertical fractures then have the possibility of increasing the volume of produced water because water will be drawn not only from the productive zone but also from the water saturated sands around it. Typically, operators are aware of this possibility and go to great lengths to avoid this scenario so as to protect valuable water resources and to preserve the economics of their development.

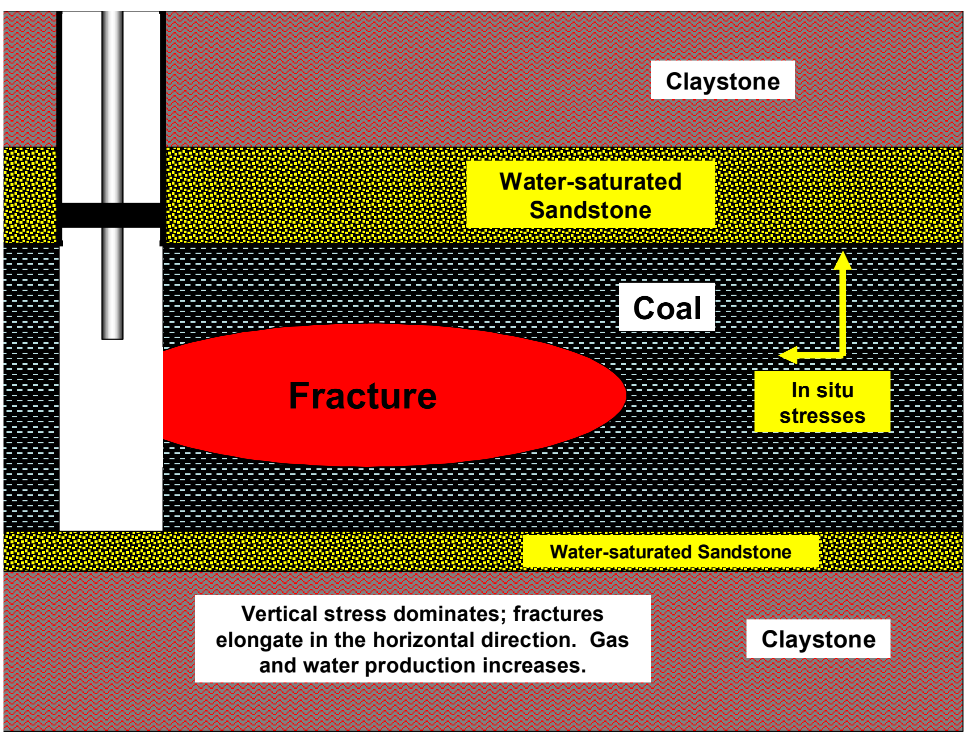
Research related to the stress analysis of earthen materials has determined that an individual fracture extends or propagates perpendicular to the least principal stress. If the least principal stress is vertical or overburden then the hydraulic fractures propagate in the horizontal direction. If the least principal stress is horizontal, then fractures propagate in vertical direction (perpendicular to minimum of all horizontal stresses). This is illustrated in Figure 5.1, which shows the application of principal stresses to a cone of earthen material, the directions of least principal stress and the favored fracture development direction for the two previously discussed scenarios.

Figure 5.1 A fracture propagates perpendicular to the minimum principal stress.



An additional concern for hydraulic fracturing practices is unconfined fracture propagation. Figure 5.2 illustrates an example of the possible results from fracturing a coal under a vertically-dominated stress field. This example holds true for conventional oil/gas hydraulic fracturing as well. In this case, if fractures are initiated and enlarged, they would tend to elongate in the horizontal direction; that is, stay within the producing coal seam. This may augment both natural gas and water production from the well. Although gas production may increase, water production rates may increase also, and the water to gas ratios may change as a result of the fracturing.

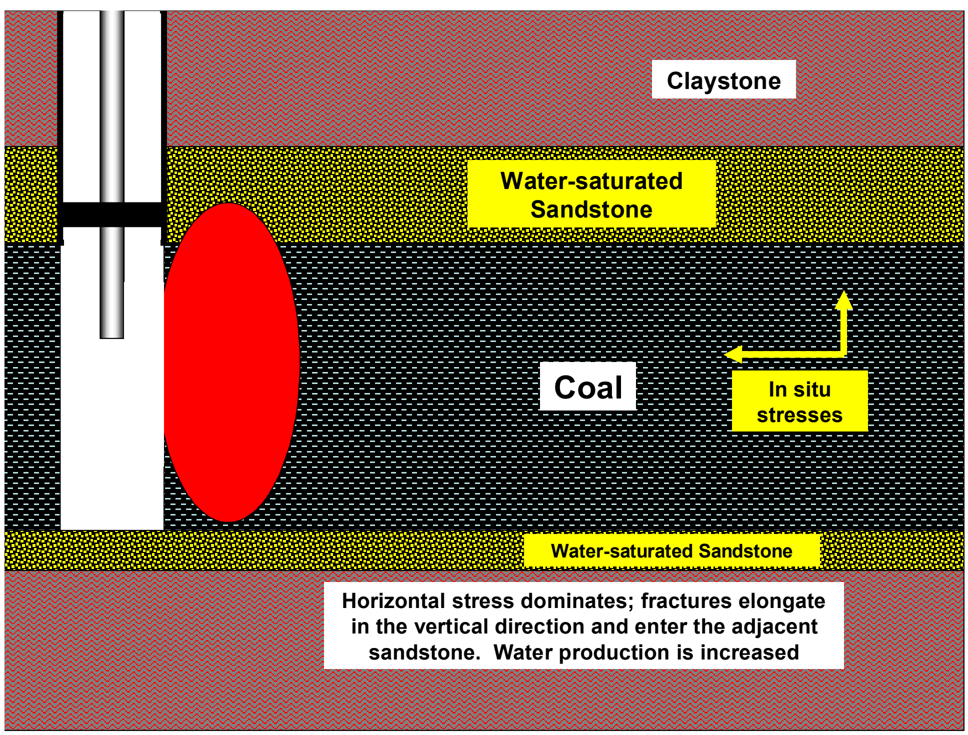
Figure 5.2 Hydro-fracturing a CBNG well. Possible results under conditions of a vertical-dominated stress field; horizontal fractures can be formed.



If the horizontal stresses predominate in an area, fracture treatment of the coal may result in fractures elongated in a vertical direction (Figure 5.3) moving toward the overlying water-saturated sandstone reservoirs. Depending upon the relative fracture gradients of the coal and the sandstone, the vertical fractures may extend up to the contact with the sandstone or may actually enter the sandstone bed. In either case, the borehole may be opened to the adjacent sandstones that contain only water. If these fractures are created, water production may be increased while not increasing natural gas production rates. Natural fractures might exist locally in the coals but can be difficult to detect. These fractures might be oriented in the same directions as the local cleat or may be at different orientations. These natural fractures may be vertical and might already connect some coal seams to adjacent sands; therefore, this may be a factor as to why some coals produce more water than others. If natural fractures exist in a CBNG development zone, they may be augmented by hydro-fracturing treatments.

Real time fracture height measurement can help in mapping fractures. Hydraulic fracturing models can be calibrated with real-time data to optimize treatment designs and to prevent undesired propagation of vertical fractures that could increase water production. Several diagnostic technologies are commercially available to map hydraulic fracture growth. Surface tilt meters can be used to measure fracture orientation, but there can be surface access issues.

Figure 5.3 Hydro-fracturing a CBNG well. Possible results under conditions of a horizontal-dominated stress field; vertical fractures can be formed.



Various downhole tilt meter instruments are run into the well bore prior to beginning the treatment (Stutz and Fisher, 2004). The tools are coupled to the well bore with magnetic decentralizers. Pumping begins, and induced tilt is measured at each tool allowing fracture height to be measured in real time. Fracture geometry is directly measured as a function of actual treatment parameters. The result is a calibrated fracture model that enables optimized fracturing treatment design. The accurate treatment designing helps to avoid uncontrollable fracture propagation, which can cause higher water production volumes.

Hydraulic Fracturing – Case Study

Anadarko's CBNG production at Copper Ridge field in the PRB of Wyoming is a good example of real time fracture mapping used to optimize the fracture treatment design while avoiding excessive water production. The coals are present in 2-foot to 12-foot stringers spread over 100–foot to 300-foot gross intervals at depths ranging from 2,600 to 3,000 feet. The most prolific seams are perforated and fracture stimulated using cross-linked gel with a combination of 16/30 and 20/40 sands as proppant. The Ericsson sand zone, used for water disposal, underlies the coal sections while higher permeability water sands overlay the sections.

Fracture mapping occurred on six wells, and fracture engineering and modeling were performed. Where fractures were mapped, growth was measured in real time. The measured fracture growth was then incorporated into the software program, FracproPT, along with pressures, volumes, and injection rates. This allowed on-site adjustments to prevent fracturing into the adjacent water sands. The fracturing model was quickly optimized and used on all subsequent wells.

The objectives that led Anadarko to obtain real time data and use them to model the fracture treatment were to:

- Stay out of overlying and underlying water zones;
- Minimize the number of stages while still achieving complete interval stimulation;
- Create long fractures with adequate conductivity.

Tilt meter data were obtained in real time while the proppant was being pumped. Previously, data had been gathered only during proppant-free stages, such as with mini-fracturing, acid fracturing, and water-only fracturing. Safe operating bounds for pumping rate, viscosity, sand concentration, and job duration, within which the tools and wire-line can be safely operated, were determined during pilot treatment.

This treatment showed some tendency for upward fracture growth toward the overlying water sands. The proppant ramp was adjusted, accordingly, to be more aggressive early in the treatment. This ensured adequate conductivity if the treatment needed to be halted early due to the fracture top getting too close to the water sands. The propped treatment was pumped to completion while monitoring fracture height in real time. Treatment avoided growth into the overlying water sand.

Fracturing treatments were optimized to avoid propagation into permeable water sands. Savings from reduced water production were $1.3 million in the first year. Research into such carefully monitored fracture jobs should include costs for the treatments as well as water management costs over time.

Propellant Fracturing:
Propellant fracturing (ARI, 1994) is a controlled pulse fracturing, tailored pulse loading, or high energy gas fracturing that involves the use of a wire-line run, electrically ignited propellant (similar to solid rocket fuel) placed across the formation to create a high pressure pulse. This pulse of gas creates multiple short (5 foot to 20 foot) radial fractures in the formation that connect to the well bore and are confined close to the zone stimulated. In addition, propellant fracturing avoids the resulting well bore damage often associated with explosive fracturing.

In addition to minimizing near-well bore damage, propellant fracturing also controls vertical fracture growth. Fracture cracks are restricted to about one-half the horizontal length of the fracture. This is because the fracture growth is gas-dynamic, and there is not time nor energy available for the unrestricted height growth that can occur with a large hydraulic fracture. Therefore, knowing the distance to the reservoir cap, a propellant treatment can be designed to virtually guarantee that breakthrough will not occur. With recent concerns over the possibility that hydraulic fracturing could contaminate aquifers, this technique could be used to ensure that the fracture does not communicate with the overlying aquifers.

By restricting or avoiding fracture propagation into the over- or under-lying water bearing formations, this technique can control excessive water production.

One of the disadvantages of propellant technology is that the created fractures are left unpropped, and hence are susceptible to closure and plugging. It can be applied as an effective near-well bore damage removal technique.

Miscellaneous:
Utilization of coil tube fracturing, multi-zone completions (DOE-NETL, 2003), hydraulic fracturing with high performance slurry, etc. improves gas recovery by means of improved accuracy in fracturing, reducing near-well-bore damage, improved connectivity, and other factors that contribute to enhance fracturing results in terms of gas production. However, on the basis of this literature search it is not clear that these techniques can reduce excessive water production during operations.

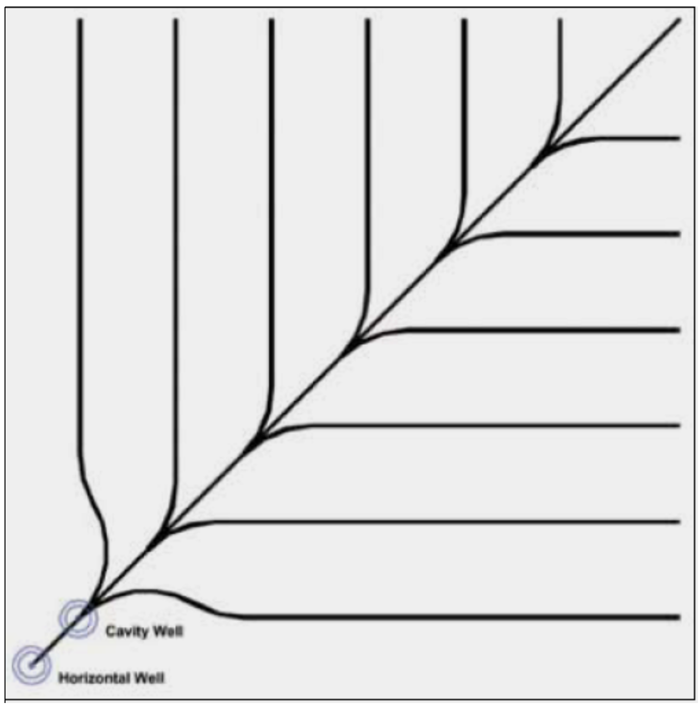
Section 5.3 Horizontal Drilling

The advantages of horizontal drilling typically are noted as higher recovery at accelerated rates and more uniform reservoir drainage.

The Dallas-based company, CDX, has developed and demonstrated a Z-pinnate horizontal drilling and completion system as illustrated in Figure 5.4. Using horizontal laterals, CDX can access up to 1,200 acres from a single well site, significantly reducing surface impacts. (Vertical CBNG wells are often drilled on 80-, 40- or even 20-acre spacing.) CDX's pinnate drilling pattern accelerates gas recovery allowing as much as 85% of the gas in place to be produced within 36 months.

The first step of pinnate drilling involves drilling a vertical well to the target producing zone. If producing zones are stacked, it is possible to extend the vertical well downward to pierce multiple zones. A cavity is reamed in the vertical well at each zone to create an accumulation chamber, or sump, for water collection. Next, a directional well is drilled nearby and steered to intersect the cavity horizontally, then continuing to pierce the producing zone laterally. Laterals totaling as much as 25,000 feet are drilled off the main lateral to procure a roughly square drainage pattern. Subsequently, as many as three additional pinnates can be drilled from a single surface location in a "quad-pinnate" pattern. This provides 360° of drainage, optimizing production. Comparing a 500 MMcf horizontal pinnate well with a 500 MMcf fracture stimulated well, the pinnate well produces at a high initial rate and depletes in approximately 6 years; whereas, the conventional well will deplete at a lower rate in approximately 15 years. A one-mile radius drainage pattern from each well can cover up to 1,200 acres from a single drilling location. In CBNG fields, maximal reservoir contact, as would be realized in a horizontal well, speeds up the depressurizing process meaning that first production is achieved more quickly and at greater rates.

Figure 5.4 A schematic of Z-pinnate drilling

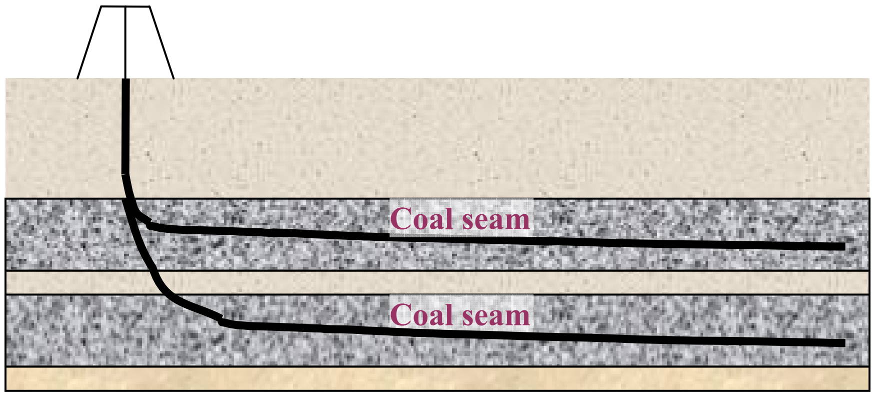


Source: CDX technology

The pinnate drilling program is not without problems. Its applicability to each field and the economics of drilling such an expensive well need to be evaluated against the cost of conventional completions.

The typical well bore construction for a horizontal well involves going from vertical to horizontal mode in two phases. The first portion of the curve is achieved above the uppermost portion of the producing zone. Typically, the well is drilled out vertically below surface casing to a kickoff point, depending on the proximity of the uppermost zone. Then directional tools are conveyed into the well bore, and a curve is built with a 6°/100-foot to 8°/100-foot build rate so as not to create too severe a dogleg. A dogleg is a particularly crooked place in a well bore where the trajectory of the well bore in three-dimensional space changes rapidly. Minimizing the dogleg is important because artificial lift equipment may need to be run through this section. When the well bore reaches a tangent angle between 60° and 75°, that tangent is held constant and laterally drilled through the entire producing zone, extending approximately 150 feet beneath the deepest zone to be completed. This drilling geometry for a CBNG project is illustrated in Figure 5.5.

Figure 5.5 Multi horizontal wells penetrate through multiple coal seams



Improved ultimate gas recovery, higher gas production rates, greater effective drainage, and less surface disturbance are the major advantages of horizontal drilling. The chief limitation to using horizontal laterals in any field is to find suitable formations that will have sufficient drillability and borehole stability. Additional research is required to understand and evaluate the effects on water production and WGRs from horizontal wells. Success of horizontal drilling in eastern and central hard coal basins has been reported. Fracturing may not be needed with horizontal wells, even at later stages of production. This factor alone could reduce the chances for uncontrolled vertical fracture propagation and, hence, reduce the chances for unnecessary, higher water production.

Weatherford International offers an underbalanced drilling (UBD) technique for creation of horizontal wells. UBD provides a non-damaging alternative for horizontal drilling within producing zones. UBD requires that the circulating bottom-hole pressure remain below reservoir pore pressure while, at the same time, the hole be cleaned as it is drilled. For soft formations it is possible to drill, even horizontally, at a rate higher than the cuttings can be cleaned from the well bore (Saikat and Heinz, 2004). This requires controlled drilling to keep the hole clean, and also to monitor and maintain the circulating pressure environment to continue to drill in an underbalanced fashion.

Well bore stability remains the greatest barrier to horizontal drilling in many fields. For example, the Tertiary-age Fort Union Formation low-rank coals of the PRB are notoriously low in strength and have a tendency to slough into the borehole even in vertical wells. Only limited horizontal drilling has been attempted in the PRB, but those attempts have been failures because of sloughing. Horizontal boreholes in weak producing zones may not be able to stay open without a liner and may not even be drillable. This question is very important when considering horizontal drilling and completions. If the producing zone cannot be successfully drilled, then this water reduction technique is not applicable. Horizontal drilling innovations could eventually increase the drillability of soft formations. Currently, two innovative products may supply much needed information – designer mud systems forming a "stress-cage" within the borehole and borehole stability modeling.

Stress-cage designer muds have been demonstrated on low-strength materials (Aston, 2004). The mud is designed to be an ultra low fluid loss system that builds and maintains a bridge across the fractures in the borehole allowing the hole to stay open until a screen or liner can be installed. The stress-cage muds would then be dispersed prior to production. Economics of this horizontal technique are unknown at present time.

STABView (McLelland and Hawkes, 2002) is a commercial well bore modeling program designed to use wire-line and core information to model borehole stability in low-strength rocks. The model uses log derived data, core analyses, and borehole stress measurements to predict borehole deformation and collapse. Work on Canadian coals suggests that results are depth sensitive and that mapping borehole deformation in vertical holes can predict stability in deflected holes and horizontal laterals. Borehole stability models could have application in selecting potential candidates in weak producing zones and predicting favorable depth ranges for horizontal drilling.

THIS PAGE INTENTIONALLY LEFT BLANK

SECTION 6.0 ANALYSIS OF SELECT OIL & GAS BASINS

In early years of oil and gas production, oily water was pumped into shallow ponds so that crude oil could be skimmed off and sold. The brine water in the ponds often seeped into the subsoil, causing salt scars that proved difficult to remediate. Around this same time, the oil and gas industry discovered a beneficial use for high-salinity produced water – secondary oil recovery via subsurface water floods. Individual states began to pass laws prohibiting pollution in general and the release of deleterious materials to air, water, and soil. Oil and gas producing states set up rules and regulatory agencies to control the production of crude oil, natural gas, and salt water by the petroleum industry. The regulatory process is designed to safeguard the physical environment, prevent the waste of the hydrocarbon resource, and protect correlative property rights on the land surface and in the subsurface.

Oil and gas environmental regulation became a federal issue with the passage of the Safe Drinking Water Act in 1974 that included nationwide underground injection regulations. The federal regulations established a number of classes of injection wells with construction and operating requirements relevant to the various classes of wells. Most oil and gas injection and disposal wells fall under the Class II regulations.

The produced water data presented in this report was assessed relative to Total Dissolved Solids (a representation of the produced waters salinity) to illustrate the range and distribution of the produced water salinities for each of the basins. Produced water quality data is also presented in two ways – numerically and geographically. The water classifications presented in the bar graphs for the individual basins use ranges based on classifications of groundwater quality and salinity expressed as TDS and were modified to reflect the relative management options for the waters. The ranges are 0 mg/L to 9,999 mg/L TDS (fresh to brackish waters in USGS classification), 10,000 mg/L to 49,999 mg/L TDS (low to moderate saline waters), 50,000 mg/L to 99,999 mg/L TDS (moderate to high saline waters), 100,000 mg/L to 199,999 mg/L TDS (low to moderate brine waters), and 200,000 mg/L to 460,000 mg/L TDS (brine waters).

Basic statistics are listed in the bar graphs to show the distribution of produced water quality samples collected within the individual basins for each of the classification groups listed above. While these statistics are calculated from the various reservoirs sampled within the basins, it is assumed for this report that these statistics approximate the distribution of salinities within the basin and within the total water volume produced each year, unless otherwise noted. Median TDS (salinity) as well as the lowest and highest TDS samples are presented for each chart to provide additional information of the variability of water salinity for each basin. The data is also plotted on maps to provide spatial analysis of the produced water quality distribution within the basins.

Section 6.1 Alaska North Slope and Cook Inlet

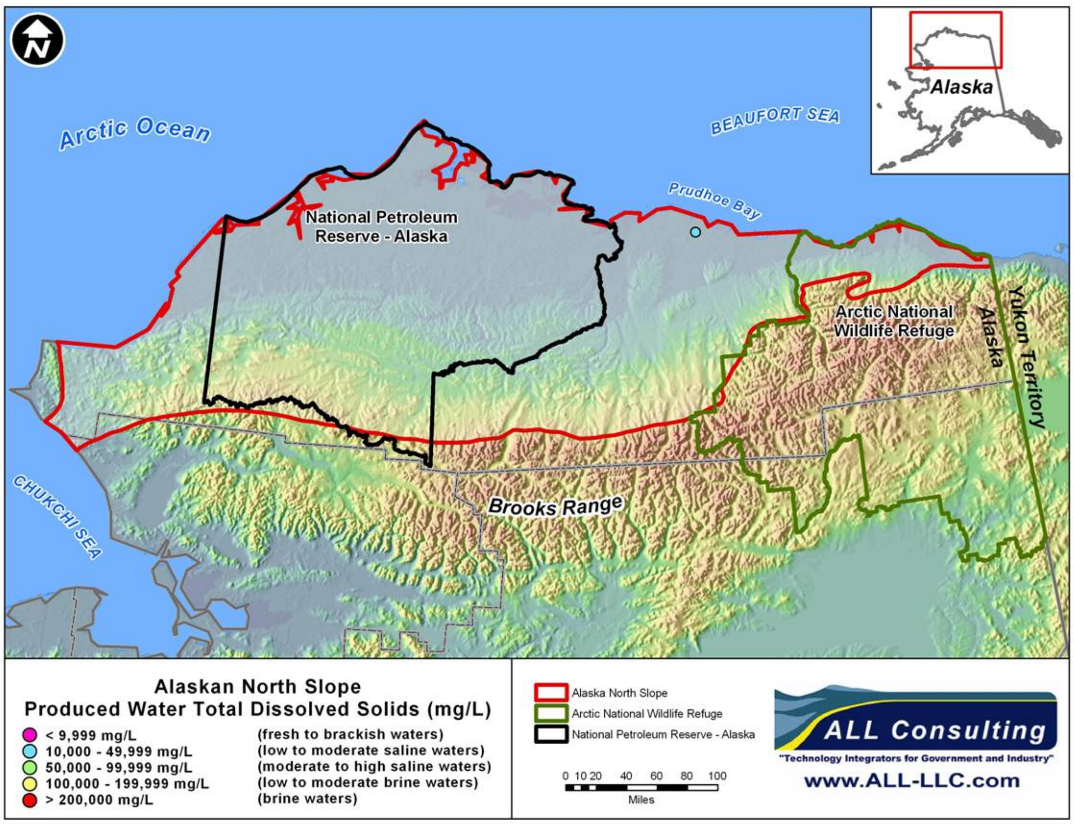
North Slope

The Alaska North Slope, which covers approximately 88,000 square miles, is the region of Alaska located on the northern slope of the Brooks Range foothills to the coast of the Arctic Ocean. The region contains the major petroleum reserves of Alaska, including Prudhoe Bay, which is North America's largest oil and gas field. The region also contains the Arctic National

Wildlife Refuge. Prudhoe Bay is a coastal feature of the Beaufort Sea approximately 250 miles north of the Arctic Circle and 1,300 miles south of the North Pole (Alyeska Pipeline, 2006). Prudhoe Bay includes 3,898 exploratory wells, 170 drilling pads, 500 miles of road, 1,100 miles of pipeline, 5 docks, and 25 production, processing, sea-water treatment, and power plants.

The state of Alaska receives about 85% of its revenues from oil and gas activity. Most of these revenues come from the 1.5 million bpd production of the Prudhoe Bay field on the North Slope. Figure 6-1 depicts the location of the Alaska North Slope (red line) and defines the National Petroleum Reserve in Alaska (black line) and the Arctic National Wildlife Reserve (ANWR) as the green line; the water quality data presented on Figure 6.1 is from the Prudhoe Bay field which is located east of the National Petroleum Reserve and west of ANWR.

Figure 6.1 Geologic Setting and Produced Water Quality Distribution of the Alaska North Slope



(Source: USGS, 2005)

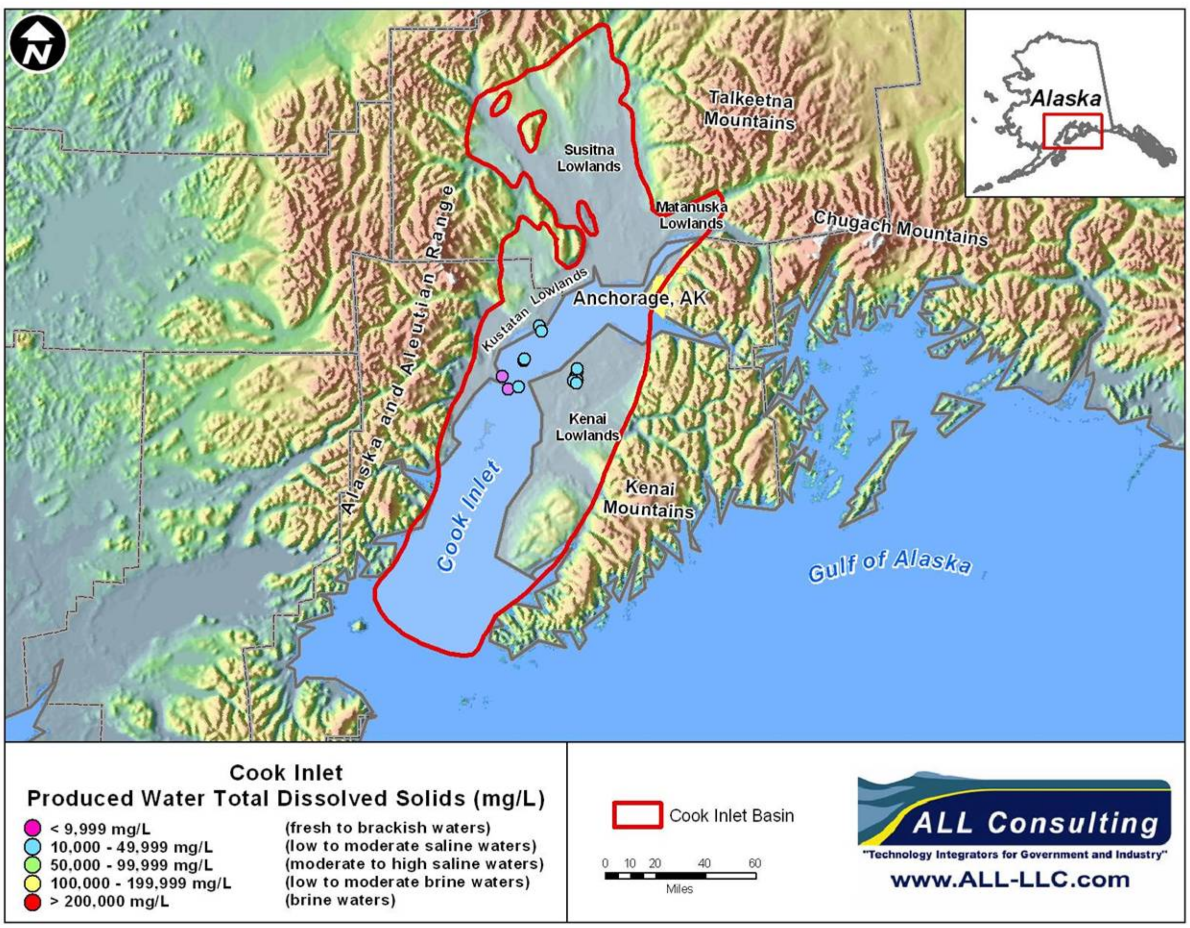
Cook Inlet

The Cook Inlet basin is about 380 km long and about 80 km wide and is bordered to the west and north by the Alaska and Aleutian Ranges and to the northeast and east by the Talkeetna, Chugach, and Kenai Mountains. Cook Inlet and its extensions, Turnagain Arm and Knik Arm, form a major marine re-entrant of the south-central Alaska coastline and subdivide the Cook Inlet Lowland into several natural subunits (Alaska Department of Natural Resources, 2003). These include the Kenai Lowland, which fronts the Kenai Mountains to the east; the Kustatan Lowland, a narrow coastal shelf fronting the Aleutian and Alaskan Ranges to the west; the

Susitna Lowland, a broad lowland between the Alaska Range and the Talkeetna Mountains that is drained by the Susitna River, which in turn flows into Cook Inlet from the north; and the lower Matanuska Lowland, drained by Knik Arm, which lies between the Talkeetna and Chugach Mountains to the northeast (Alaska Department of Natural Resources, 2003).

The origins of the Alaska oil and gas industry began in Cook Inlet with the discovery of Alaska's first commercially viable oil find in the Swanson River field in 1957. After the Swanson River finding, additional wells were developed in Cook Inlet and more leases were approved throughout the basin. By 1959, 187,000 barrels of crude oil were produced annually in Cook Inlet (Alaska Department of Natural Resources, 2004). The Cook Inlet or Kenai Peninsula watershed is located in south-central Alaska and is approximately 47,000 square miles in size, lying generally below an elevation of 1,000 feet (Alaska Department of Natural Resources, 2003). Figure 6.2 defines the boundary and geologic setting of the Cook Inlet Basin.

Figure 6.2 Geologic Setting and Produced Water Quality Distribution of the Alaska Cook Inlet Basin/ Kenai Peninsula



(Source: USGS, 2005)

SIGNIFICANT GEOLOGIC FEATURES

North Slope

The North Slope of Alaska is a major hydrocarbon-producing region of North America, but its geologic setting is still not completely understood (Alyeska Pipeline, 2006). This is in part due to the tectonic history of northern Alaska, where there is a complex interplay between the formation of the Brooks Range collisional orogen and the development of the nearby north Alaska rifted continental margin (Wallace and Hanks, 2005).

In general, the North Slope consists of the Carboniferous Lisburne Group, a thick, heterogeneous and highly fractured sequence of carbonate rocks that acts as the reservoir horizon for some oilfields located in the North Slope (Wallace and Hanks, 2005). The Lisburne Group also is widely exposed throughout northern Alaska as an important element of the Brooks Range fold-and-thrust belt. The Lisburne Group was recognized as a potential reservoir horizon very early during petroleum exploration of northern Alaska and was considered by many to be the primary exploration target during the early phases of drilling on the North Slope (Wallace and Hanks, 2005). As in many carbonate reservoirs, naturally occurring fractures in the Lisburne Group play a major role in hydrocarbon production by providing both porosity and permeability. However, the distribution, density, and character of fractures within the Lisburne are highly variable and difficult to predict, and may depend on the lithology of the host rock, the structural setting of the reservoir, and/or other unidentified factors (Wallace and Hanks, 2005).

Cook Inlet

The present topography of Cook Inlet and adjoining areas is primarily the product of at least five major Pleistocene glaciations and two minor post-Pleistocene glacial advances (Karlstrom, 1964). These are recorded by the distribution of moraines and ice scoured landforms, by discordant drainage relations, and by stratigraphic evidence of multiple drift sheets separated by major unconformities and weathering profiles (Karlstrom, 1964). The Cook Inlet basin occupies a structural trough, is underlain at variable depths by rocks of Middle Jurassic through early Cretaceous sediments (2,700 m), 4,300 m of Early and Late Cretaceous flysch, and up to 6,500 m of Tertiary fluvial sediment (Alaska Department of Natural Resources, 2004).

Semi-consolidated coal-bearing formations of Tertiary age crop out at the surface or occur at relatively shallow depth at the southwest end of the Kenai Lowland and along the flank of the Alaska Range between Tyonek and Peters Creek (Alaska Department of Natural Resources, 2003).

OIL AND GAS PRODUCTION

North Slope

Petroleum reserves in Prudhoe Bay were discovered in 1968 with initial recoverable reserves estimated at 9.6 billion barrels of oil and 26 trillion cubic feet of gas (Alaska Department of Natural Resources, 2004). Production was initially restricted to small quantities used to fuel field operations until the Trans Alaska Pipeline System (TAPS) was completed in July 1977. Until this, operators injected surplus crude and residual oil back into the Prudhoe Bay reservoir.

North Slope gas production began near Barrow in the mid-1940s. Gross gas production on the North Slope in 2000 was 3.2 trillion cubic feet (8.7 billion cubic feet (BCF)) per day, but 93% of this volume was injected into oil producing reservoirs (Alaska Department of Natural Resources, 2004). The remaining net gas production, equal to 297 BCF in 2003, is consumed locally on the North Slope to fuel oilfield equipment, operations, and pipelines. North Slope industrial yearly gas consumption is approximately equal to annual gas produced in Cook Inlet (Alaska Department of Natural Resources, 2004).

From the beginning of Prudhoe Bay production, dissolved gas and water were separated from the crude oil and injected back into the reservoir. Over time the proportion of both produced gas and water to oil increased. Eventually, oil production was constrained by the rate at which the separating plants could process gas and water. The North Slope has produced 14.4 billion barrels of oil and natural gas liquids (NGLs) by the end of 2003; nearly all from the large Prudhoe Bay and Kuparuk fields (Alaska Department of Natural Resources, 2004). NGLs produced on the North Slope are blended with oil and shipped down TAPS or used to make miscible injectant for enhanced oil recovery projects. Today, incremental oil production from new fields brought on-line since 1995 account for about 27% of total yearly Alaska North Slope production. Oil production in the bay has slowed considerably and at the present time an average of 680,000 barrels per day is produced (Alaska Department of Natural Resources, 2004).

Cook Inlet

The Cook Inlet watershed contains more than 225 miles of active oil pipelines and more than 690 miles of active natural gas pipelines, approximately 100 miles of active oil and natural gas gathering lines in several onshore production fields, and numerous miles of active natural gas distribution pipelines, particularly in the Anchorage area. First commercial production from an Alaska oilfield began at Swanson River, Cook Inlet in 1959. Five other Cook Inlet fields began production between 1965 and 1972. Most recently, West McArthur River began production in 1993 and Redoubt in 2002. All Cook Inlet oil is currently shipped to the Tesoro refinery at Nikiski on the Kenai Peninsula. Oil from fields on the west side of Cook Inlet is transported by pipeline to the Drift River terminal, and then transported to Nikiski (Alaska Department of Natural Resources, 2004). Oil from the eastside fields is shipped by pipeline directly to the refinery. By year-end 2003, the Cook Inlet had produced almost 1.3 billion barrels of oil, including 10 million barrels of NGLs (Alaska Department of Natural Resources, 2004).

Cook Inlet gas production began in 1959 as a by-product of Swanson River oil development. As more oil and gas fields were discovered, nearby markets for the gas were developed in Anchorage and Kenai to supply space heat and electricity generation. In 1968 Unocal started up the ammonia-urea plant at Nikiski to take advantage of the abundance of cheap stranded natural gas (Alaska Department of Natural Resources, 2004). In recent years, NGL exports to Japan accounted for about 33% of total Cook Inlet gas production. Industrial use of Cook Inlet gas has remained fairly constant since 1983; production has increased in step with the growing residential and commercial demand for space heating and electric power generation (Alaska Department of Natural Resources, 2004). By 1984, net annual natural gas production reached 305 BCF per year and peaked at 311.5 BCF in 1990. Cook Inlet natural gas production has remained relatively stable at an average of 217 BCF per year from 1998 to 2005.

PRODUCED WATER MANAGEMENT

North Slope

The numerical distribution of produced water quality for the Alaskan North Slope area is shown in Figure 6.3. The USGS produced water database contains 22 individual samples of produced water quality for the Alaskan North Slope; the Alaska Oil and Gas Conservation Commission also had two individual water quality samples from the area. Produced water salinity in the Alaskan North Slope included only two produced water quality ranges identified for analysis in this study; from 0 mg/L to 9,999 mg/L and 10,000 mg/L to 49,999 mg/L TDS. Median produced water salinity for the Alaskan North Slope was 28,230 mg/L TDS (saline). The range of salinity values for the Alaskan North Slope ranged from 786 mg/L to 45,640 mg/L with a median of 28,320 mg/L (Figure 6-3). From the small sample set (24 total samples), the majority of samples (92%) indicate TDS results that fall within the 10,000 mg/L to 49,999 mg/L group; the remaining 8% of the samples fall in the group 0 to 9,999 mg/L. Additionally, no collected samples indicate results greater than 49,999 mg/L.

Figure 6.3 Produced Water Quality from the Alaska North Slope

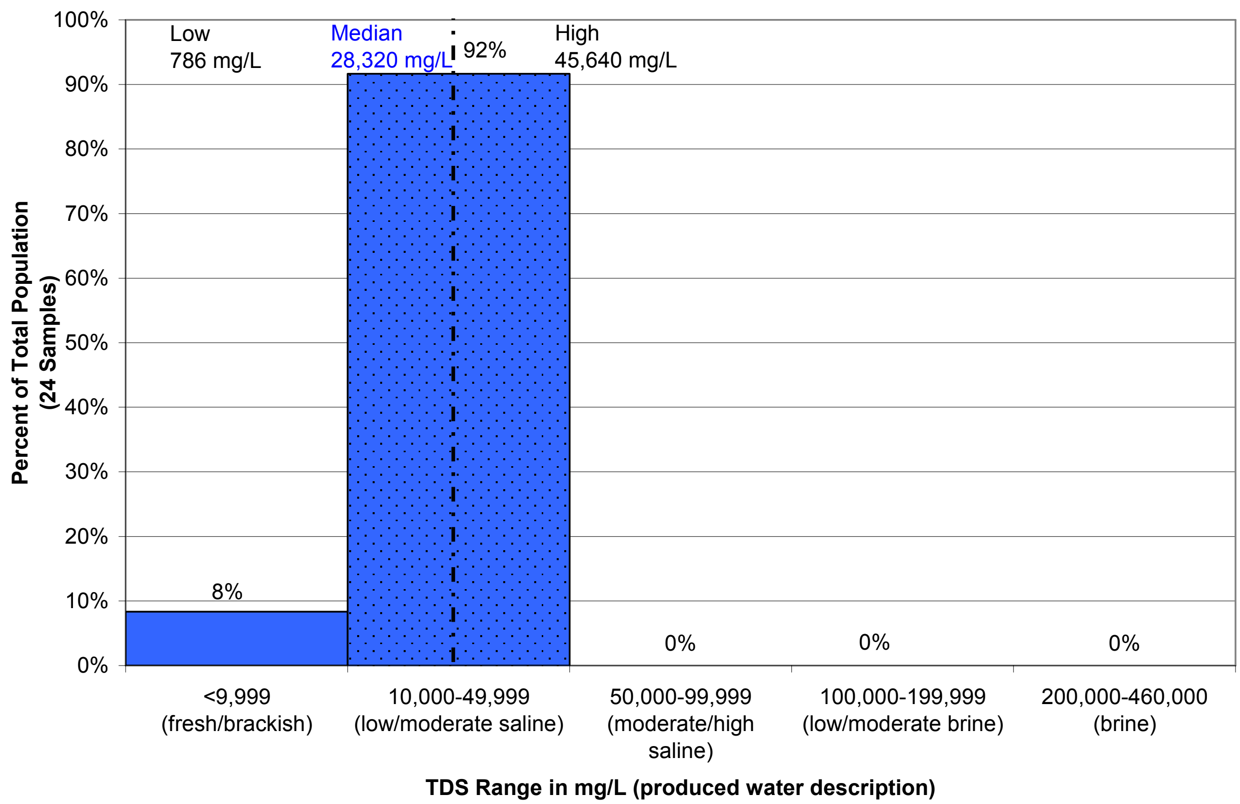


Figure 6.1 documents the spatial distribution of the water quality samples from the USGS produced water database across the Alaskan North Slope showing that the produced water samples were all located in a single area, Prudhoe Bay. While Figure 6.1 graphically delineates the location of the 22 samples as all falling in a single production area, assessment of produced water quality in other regions cannot assume all produced water quality for the Alaskan North Slope would be of the same quality. Produced water from the Alaskan North Slope area is

either injected into the producing reservoirs for pressure maintenance and secondary recovery or into Cretaceous formations for injection disposal (ConocoPhillips, 2006). Secondary recovery and pressure maintenance is also being supplemented by make-up water collected by pumping sea water into the reservoir (Alyeska Pipeline, 2006).

Cook Inlet

The numerical distribution of produced water quality for the Cook Inlet Basin is depicted in Figure 6.4. The USGS produced water database contains 37 individual samples of produced water quality for the Cook Inlet Basin; the Alaska Oil and Gas Conservation Commission also had 38 individual water quality samples from the area. Produced water salinity in the Cook Inlet Basin included three produced water quality ranges identified for analysis in this study; from 0 mg/L to 9,999 mg/L, 10,000 mg/L to 49,999 mg/L, and 50,000 mg/L to 99,999 mg/L TDS. Median produced water salinity for the Alaskan North Slope was 9,605 mg/L TDS (brackish). The range of salinity values for the Cook Inlet Basin ranged from 178 mg/L to 75,717 mg/L (Figure 6.4). Nearly all of the produced water quality samples from the Cook Inlet Basin (99%) have TDS concentrations below 50,000 mg/L (Figure 6.4). Fifty-one percent and 48% of the produced water from this basin fall within TDS results of 0 to 9,999 mg/L or 10,000 to 49,999 mg/L, respectively. Additionally, 1% of the produced water is described within the 50,000 to 99,999 mg/L TDS group.

Figure 6.4 Produced Water Quality from the Alaska Kenai Peninsula/Cook Inlet

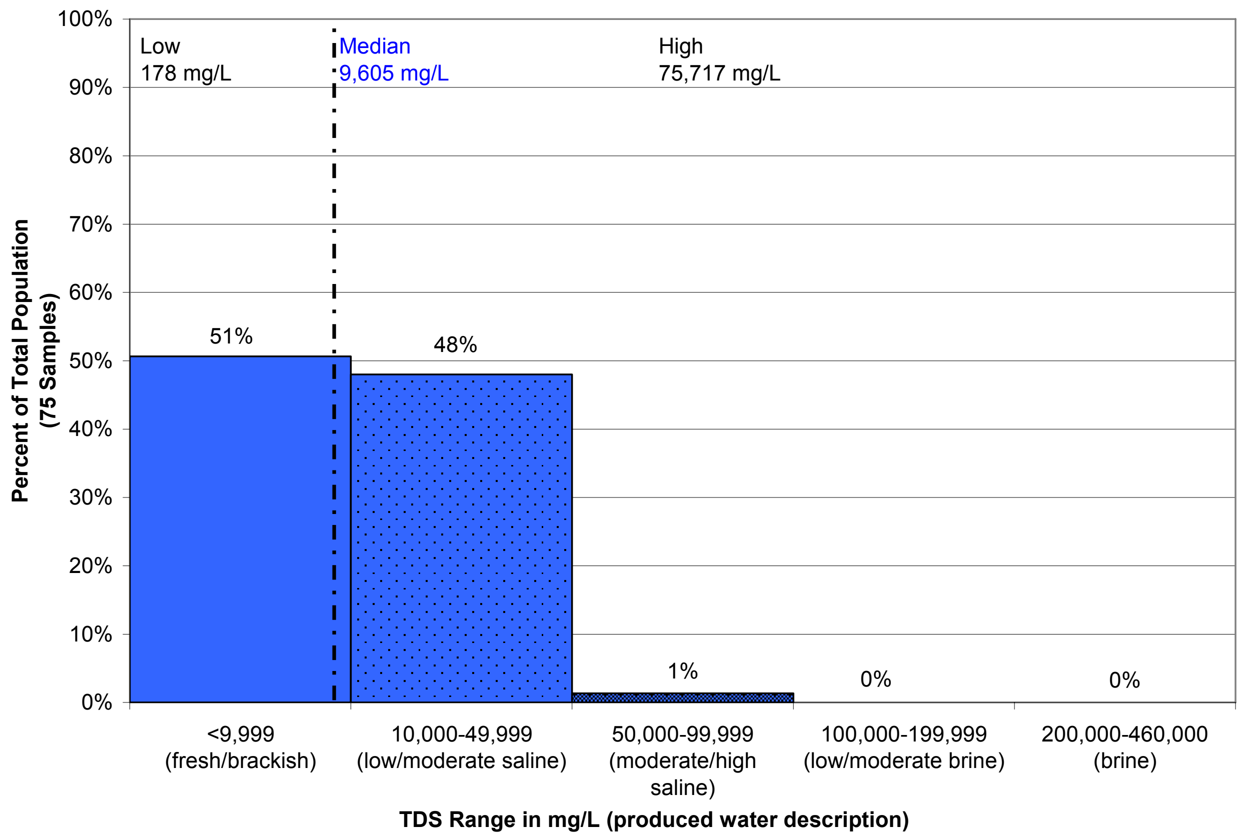


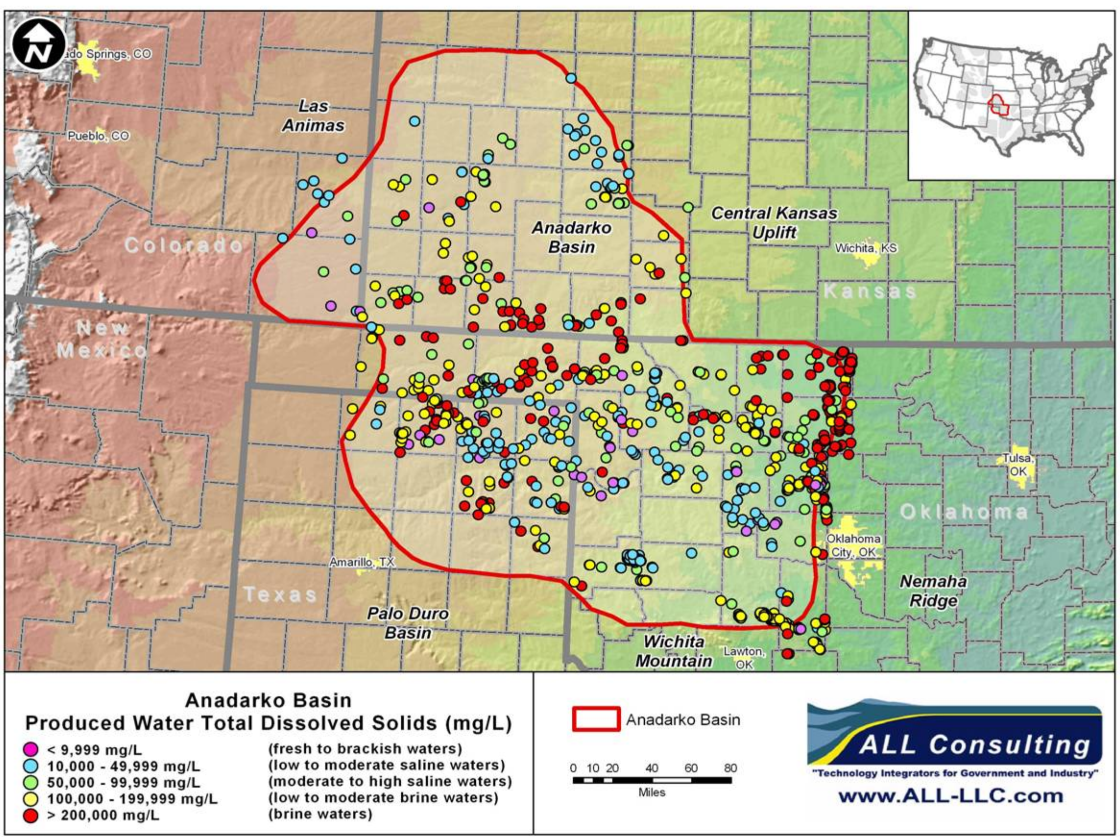
Figure 6.2 documents the spatial distribution of the water quality samples from the USGS produced water database across the Cook Inlet Basin showing that the produced water samples

were concentrated in only a few areas. While Figure 6.2 graphically delineates the location of the 37 samples as all falling in a few production areas, assessment of produced water quality in other regions of this basin cannot assume all produced water quality for the Cook Inlet Basin would be of the same quality. In general, produced water from onshore oil and gas facilities in Cook Inlet Basin is disposed of via Class II disposal wells or is used for enhanced recovery. Since 1968, the produced water volume in the Swanson River Field has consistently fluctuated near 0.2 bbls/day, with a spike in volume between 1972 and 1973.

Section 6.2 Anadarko Basin

The Anadarko Basin covers a large portion of the Southern Great Plains; the majority of the basin is located in western Oklahoma and the basin extends into the northeastern Texas panhandle, southeastern Colorado, and southwestern Kansas (Henry and Hester, 1995). Figure 6.5 shows the approximate extents of the basin, lying in a northwest to southeast orientation, with the Wichita Mountains to the south; the axis and deepest portion of the basin lying just north of the mountains. The basin is further bounded by the Palo Duro Basin to the southwest, Las Animas Arch to the northwest, the Central Kansas Uplift to the northeast, and Nemaha Ridge to the southeast. The Anadarko Basin covers an area of approximately 50,000 square miles (Henry and Hester, 1995).

Figure 6.5 Geologic Setting and Produced Water Quality Distribution of the Anadarko Basin



(Source: USGS, 2005)

Significant Geological Features

The Anadarko Basin contains strata of Cambrian through Permian age with a thin veneer of Tertiary continental sediments. Most of the basin-fill volume is taken up with the Ordovician through Permian sediments that accumulated in the ancient seaway. The sources of the older sediments were the Paleozoic outcroppings to the north and the ancestral Rocky Mountains to the west. The important strata in the basin include the Lower Ordovician Arbuckle Formation, which is the same age and similar in lithology to the massive Knox carbonates of the Appalachians and the Ellenberger of Texas. The Upper Ordovician through Mississippian section is present as thickened versions of thinner strata that blanketed most of the Mid-Continent. During the Pennsylvanian and Permian eras the Wichita Mountains to the south began to emerge from the seaway as the Anadarko basin began to vanish.

The result of this long history of sedimentation is the thick sedimentary column over 40,000 feet thick in some places that holds a variety of hydrocarbon-bearing reservoirs. In addition, the sedimentary column holds several zones that make thick, permeable injection zones that are able to serve as disposal reservoirs. Formations such as the Permian Red Cave and Ordovician Arbuckle can receive water at rates of thousands of barrels per day on a long-term basis.

Oil and Gas Production

Oil and gas has been produced from the basin's shallow, prolific oil pools and deep, high-pressured gas reservoirs. First production from the basin was in the 1890's with more than 2.3 billion barrels of oil (BBO) and more than 65.5 trillion cubic feet of gas (TCFG) having been produced to date. Since the conception of oil and gas activity in the Anadarko Basin, wells have produced low quality water, commonly referred to as brine.

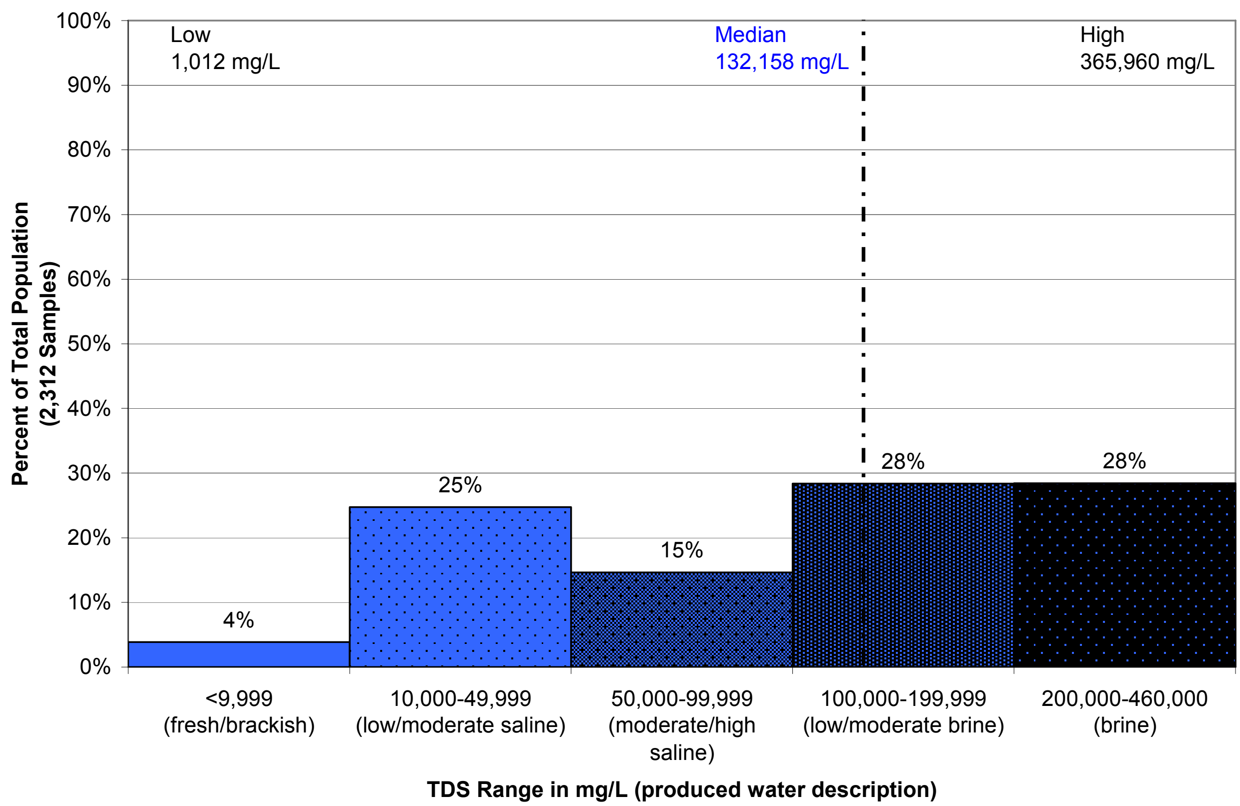
Earliest petroleum production was from shallow reservoirs that had prominent surface expression such as the Oklahoma City Field and Cement Field. As the technology progressed, deeper reservoirs could be exploited so that by the 1960's, exploratory wells were being drilled below 30,000 feet in the Anadarko Basin. Currently, production in the basin is on the decline although the number of feet of exploratory holes drilled each year remains high. Among the plays generating interest are deep reservoirs near the center of the basin, stratigraphic traps throughout the basin, existing continuous reservoirs in the Permian Hugoton Gas Field, and new unconventional, continuous reservoir accumulations in the Woodford-Chattanooga sequence. These plays have implications for produced water management in the Anadarko Basin.

Produced Water Management

Oil and gas operators in the Anadarko Basin have utilized several options for the management of produced water. Typically oil and gas production in the Anadarko Basin has utilized injection as the primary management practice for produced water. The presence of permeable disposal zones at readily drillable depths has helped the oil and gas industry in the Anadarko Basin to manage produced salt water volumes. Early in the production life of a field, operators are typically disposing of produced water in an injection zone not connected to the producing reservoir. As oil and gas fields in the basin age, production declines and operators have the option of initiating a water flood with their produced water.

Produced water quality data for this basin is presented in two ways – numerically and geographically. The numerical distribution of produced water quality is shown in Figure 6.6. The USGS produced water database contains 2,312 individual samples of produced water quality for the Anadarko Basin. Produced water salinity in the Anadarko Basin includes all of the ranges identified for analysis in this study, from <10,000 mg/L to >200,000 mg/L TDS. Median salinity expressed as TDS is relatively high at 132,158 mg/L (low to moderate brine waters). The range of salinity values for the Anadarko Basin ranged from 1,012 mg/L (slightly brackish) to 365,960 mg/L (brine) (Figure 6.6). More than half (56%) of the produced water samples collected from the Anadarko Basin had TDS concentrations greater than 100,000 mg/L, which would be classified as brines. Approximately 4% of the samples in the USGS produced water database had salinity values less than 10,000 mg/L (brackish waters). Produced water varies across the basin from saturated (approximately 350,000 mg/L) brines to waters less than 10,000 mg/L (Bein and Dutton, 1993). While most of this produced water is used in secondary oil recovery operations, some water is disposed of into scattered commercial disposal wells.

Figure 6.6 Produced Water Quality from the Anadarko Basin



(Source: USGS, 2002)

Figure 6.5 documents the geographical distribution of water quality samples across the basin showing that produced water quality varies randomly. This map indicates that the small amount of high quality produced water with TDS less than 10,000 mg/L is widely scattered from the deep basin to the Anadarko Shelf on the north side of the basin. Figure 6.5 shows that 4% of the water quality samples from the reservoirs held brackish quality water less than 10,000 mg/L TDS. Some of this high quality water is shallow, the result of fresh water that has entered oil reservoirs from the surface; this water could have a beneficial use if the oil and grease content was appropriate or could be removed prior to beneficial use. Water less than 10,000 mg/L would appear to be of minor importance in the Anadarko Basin because of the relatively small percentage (4%) it represents of the produced water from the basin.

Figure 6.5 shows that 25% of the produced water in the Anadarko Basin falls in the water quality range from 10,000 to 49,999 mg/L TDS (low to moderate saline waters). Although for most surface beneficial uses this water is of insufficient quality, there are some options for the treatment of this water to enable it to be used. Figure 6.5 shows the distribution of the majority of the water produced (TDS >50,000 mg/L) in the basin is scattered across the basin. This produced water can be used for secondary recovery in water floods of local oil reservoirs. Many times the water is filtered and treated and pumped back into the reservoir it came from. Other water is transported to another water flood in the area that is in need of "make-up" water to begin or maintain a flood. Often at the initiation of a flood, insufficient water volume exists in the field and outside water will need to be supplied. Oil and gas operators ensure that the outside water is fully compatible with the water chemistry of the flooded reservoir and that the water is free of suspended sediment. Material either dissolved or suspended in the flood water injected into the reservoir can cause plugging either in the injection wells or within the reservoir itself, thereby reducing flow and production.

There are areas where water floods are not utilized, commonly in gas-producing areas; produced waters that are not able to be used for surface uses are disposed of by injection into saltwater-bearing reservoirs. Injection disposal is discussed in more detail in Section 4.

Many parts of the Anadarko Basin have only minor oil production and, therefore, the need for secondary recovery water flood injection is not great. One of these areas is the giant Hugoton gas field in parts of Kansas, Oklahoma, and Texas. This shallow, continuous gas field was initially developed in the 1940's and has been in operation since then. As the wells increase in age, they could begin to produce more water. In the Hugoton, the primary option for produced water management is to use dedicated disposal wells, either owned by the oil and gas operator or commercial wells. The expense of managing the increasing volumes of produced water from these wells can be enough to cause early abandonment of the producing well. Some operators have installed disposal wells but with the wide spacing of wells in the field, the disposal wells may be long distances from the producing wells, requiring additional transportation costs.

A produced water reduction alternative is to use Downhole Gas/Water Separators (DGWS) and the injection of the produced water into a separate water-bearing zone perforated within a producing gas well. Produced water from nearby wells can also be accommodated in these wells if the receiving zone is capable of accepting the additional volume of water. Several gas wells have been equipped with DGWS in the Oklahoma and Kansas portions of the Hugoton. One of the benefits of DGWS technology is its hygiene; if water does not get to the surface for storage and filtering, it is less likely to pick up impurities, including sulfate-reducing bacteria. In parts of the Kansas portion of the Hugoton, H_2S is being produced where none had been produced historically. This apparently has been caused by operators introducing surface waters into the reservoir formations where they have proliferated to liberate enough H_2S gas to reduce the natural gas value and make it potentially harmful to livestock and humans. DGWS completions may have applicability in other gas fields as a way of efficiently managing produced water.

Similar completions have been used in water floods to rapidly achieve fill-up of the reservoir. "Dump-flood" wells can produce saltwater from a prolific, non-hydrocarbon bearing zone and pump it directly into the flood zone without drawing the water to the surface. Such wells must be carefully engineered to convey clean water to the flooded reservoir and avoid suspended material that may plug the reservoir. Such wells in Oklahoma can move thousands of barrels of produced water every day at very low costs.

Several "de-watering" projects are underway in Oklahoma and Kansas that utilize high rates of water production in a different setting. These projects produce large volumes of water from previously watered-out fields. Producing wells utilize large electric submersible pumps to produce high volumes of saltwater every day until oil begins to move to the wellbore. Produced water is disposed into injection wells utilizing thick, continuous injection zones such as the Arbuckle Formation.

Section 6.3 Arkoma Basin

The Arkoma Basin is a medium-sized interior basin located in southeastern Oklahoma and west-central Arkansas (Perry, 1995). Figure 6.7 shows the approximate extents of the basin. The Arkoma Basin is bisected by the Oklahoma-Arkansas border and lies in slight southwest to northeast orientation (Figure 6-10). The basin is bounded by the Ozark uplift to the northeast, the Cherokee Basin to the northwest, and the Ouachita Foldbelt to the south as shown in Figure 6.7. The Arkoma Basin covers an area of approximately 33,800 square miles (Perry, 1995).

Significant Geological Features

The Arkoma Basin is filled with Cambrian through Pennsylvanian sediments that have been folded, faulted, and heated to such an extent that the traps contain only dry gas. The basin contains nearly all of the early to middle Pennsylvanian section (Perry, 1995). The sedimentary rocks present in the basin range from 3,000 to 20,000 feet in thickness and are composed of pre-Mississippian carbonate shelf deposits, Mississippian marine shales and Pennsylvanian fluvial deposits (Perry, 1995).

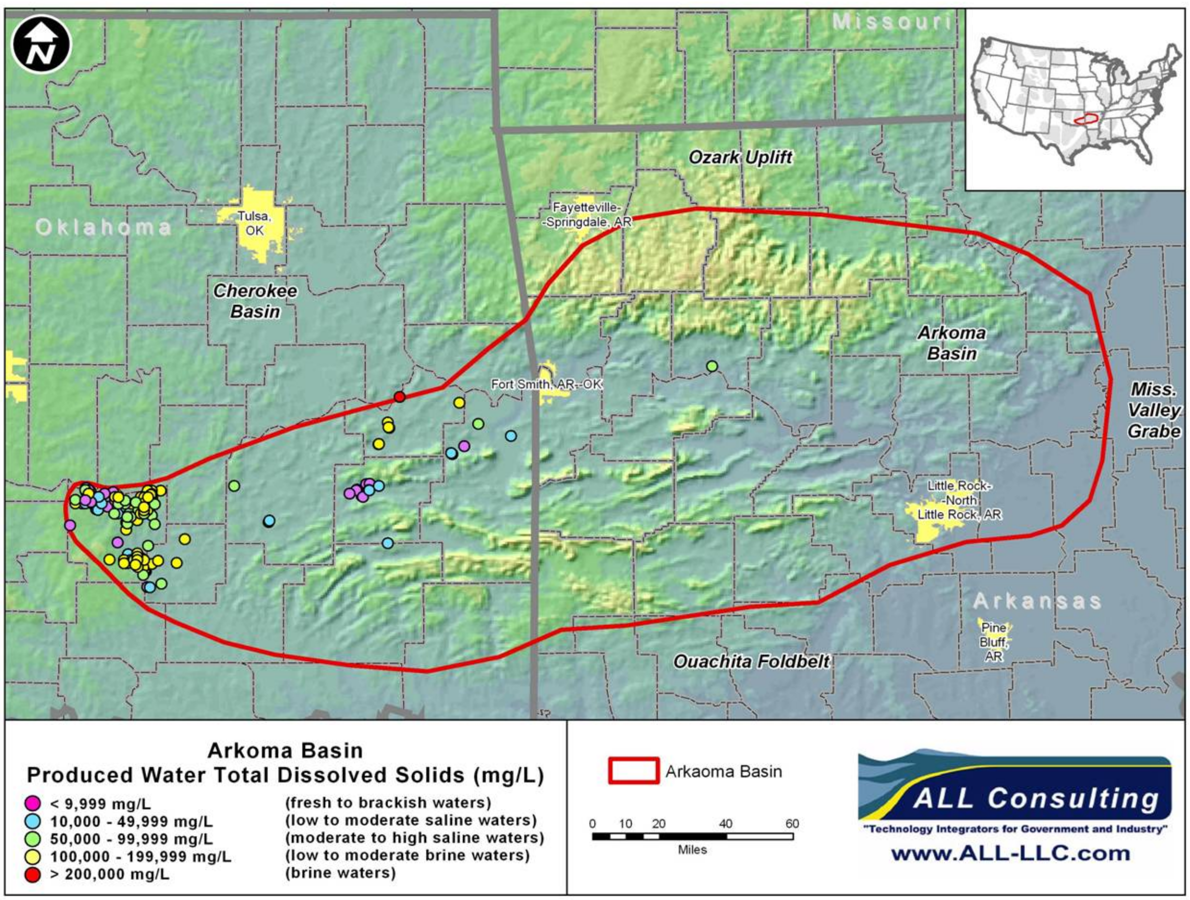
Heating that the area has undergone has driven out much of the pore water within the basin; only minor amounts of water are produced in conventional gas wells. Groundwater is present only in alluvium within the basin and any water wells will be sourced by this alluvium.

Oil and Gas Production

Natural gas has been produced in this basin since 1910 (Perry, 1995) and continues to the present. The geology of the basin indicates that little or no formation water is present in any of the oil and gas reservoirs. Gas is trapped in large structural reservoirs, in small- and medium-sized stratigraphic traps, and in coal bed natural gas accumulations. CBNG wells make only small amounts of formation water while conventional gas wells produce no formation water, but do produce small volumes of water that exist in the gas reservoir as water vapor entrained with the natural gas. When the natural gas is produced, the water vapor condenses at the surface. In high-flowing gas wells, the condensed vapor can represent a large volume. This water is typically very high quality and locally would have beneficial uses if the regulatory environment would allow its use.

At the present time, the Mississippian Fayetteville shale is being developed as a source of unconventional shale gas similar to the Barnett play in the Fort Worth Basin. Drilling and production of gas from the Fayetteville could become as important as the Barnett play. The Mississippian Fayetteville is a thick, highly bituminous shale that can produce natural gas as a continuous reservoir. To date, approximately 82 wells have been completed, 53 are producing gas, and others are drilling or are awaiting completion. Of the 82 completed wells, 31 are horizontal wells; 13 of these have been completed and have an average production off 2.5 mmcf per day. These wells are scattered over seven counties in Arkansas (Southwest Energy, 2006). Like the Barnett wells, the Fayetteville wells are fracture treated before the wells produce sizable gas volumes. Fracturing has been done using high pressure nitrogen, although some wells have used water and sand. It is possible that in the future these shale-gas wells will be similar to Barnett wells in that they may receive large water-fracs that could cause the wells to produce large volumes of water with the natural gas.

Figure 6.7 Geologic Setting and Produced Water Quality Distribution of the Arkoma Basin

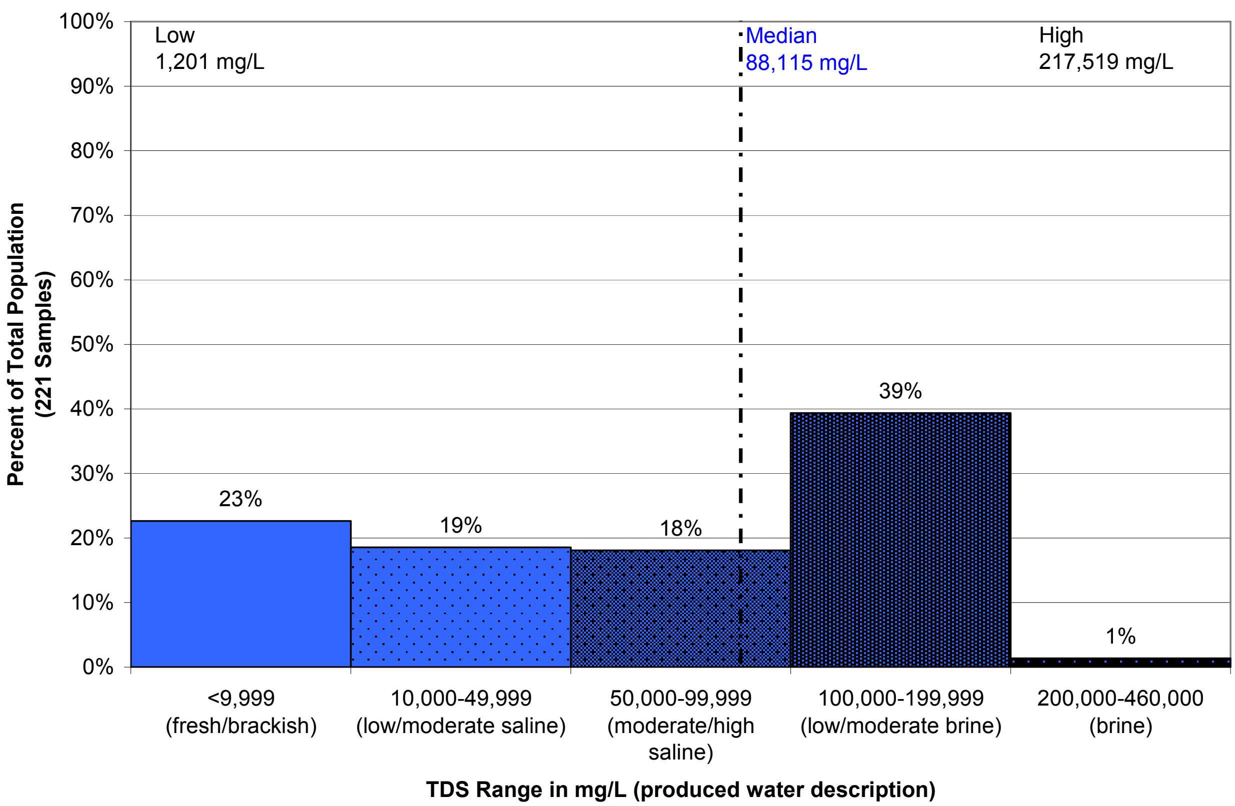


(Source: USGS, 2005)

Produced Water Management

The USGS produced water database lists 221 samples of produced water from the Arkoma Basin, and includes samples from a variety of formations and depths. Figure 6.8 documents the quality of the produced water from the USGS produced water database for the Arkoma basin. The produced water from this basin appears to be relatively poor in quality with 1% of the samples having TDS concentrations greater than 200,000 mg/L (brine waters), 39% of the samples having TDS concentrations between 100,000 and 199,999 mg/L (low to moderate brine waters), and 18% of the samples having TDS concentrations between 50,000 and 99,999 mg/L (moderately saline to saline waters). The median produced water quality for the Arkoma Basin was saline water with a TDS of 88,115 mg/L. The salinity values for the basin range from a low of 1,201 mg/L (slightly brackish) to a high of 217,519 mg/L (moderate brine) (Figure 6.8). Approximately 23% of the samples in the USGS produced water database had a TDS less than 10,000 mg/L (brackish waters); this is water of sufficient quality that it may have some beneficial uses.

Figure 6.8 Produced Water Quality from the Arkoma Basin



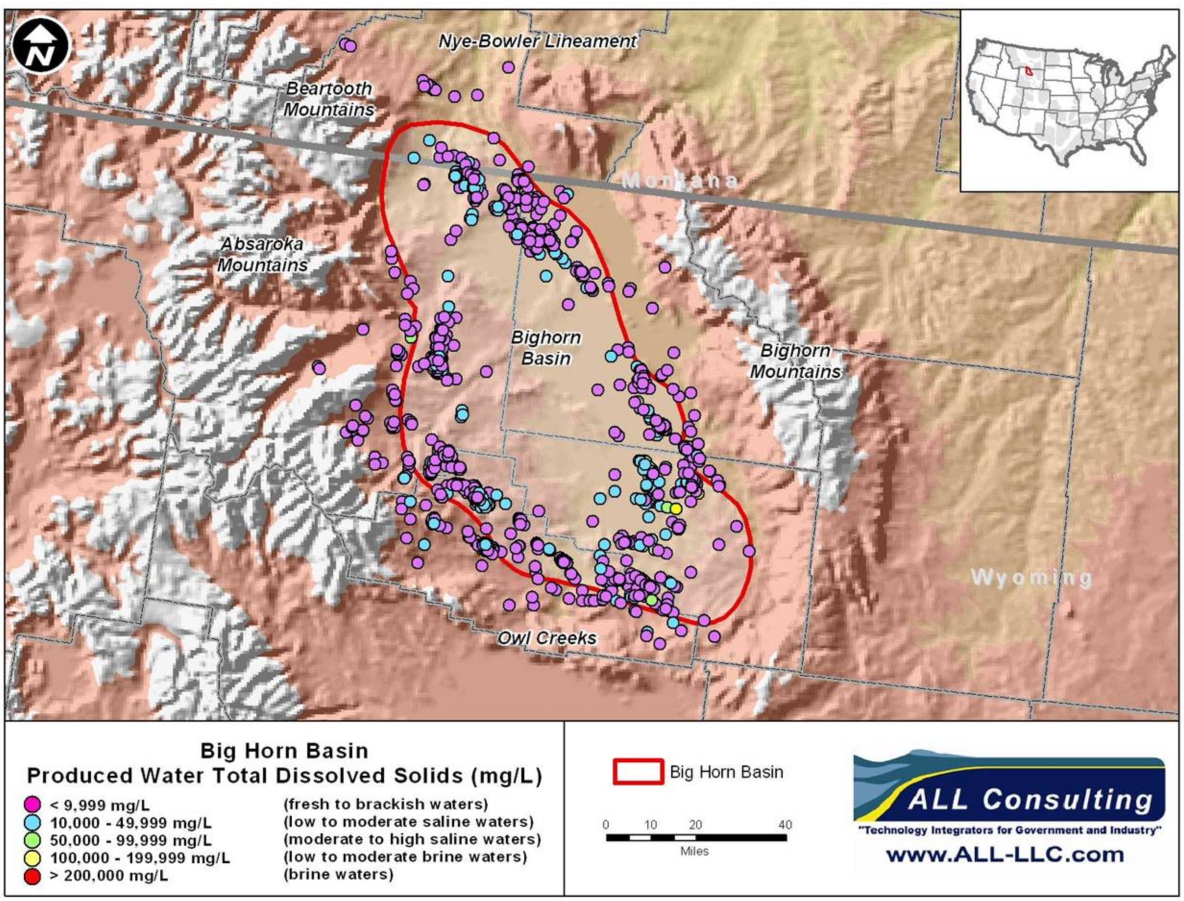
(Source: USGS, 2002)

Figure 6.7 documents the distribution of USGS produced water quality samples across the Arkoma Basin showing the produced water quality distribution across the basin. The geographical distribution of water salinity as shown in Figure 6.7 indicates that the brackish quality produced water with TDS <10,000 mg/L (23% of the total) is scattered from the western edge of the basin to the center portion of the basin. Water volumes from conventional natural gas production are minor and scattered. Other brackish quality water is recovered from deep, high-flowing natural gas wells where the water comes to the surface as vapor entrained in the natural gas and condenses at the surface. Some of this water is produced in water-starved areas such as southeastern Oklahoma and could have important beneficial uses if the regulatory framework would allow (Baker, 2005). Most of the produced water is not a viable beneficial use source except for localized uses, unless Fayetteville shale-gas development becomes as prolific as the Barnett play and large volumes of water are produced from these wells. Oil and gas operators in the Arkoma Basin have utilized several options for the management of produced water. Typically oil and gas producers in the Arkoma Basin have utilized injection as the primary management practice for produced water. The presence of permeable disposal zones at readily drillable depths has helped the oil and gas industry in the Arkoma Basin to manage produced saltwater volumes.

Section 6.4 Bighorn Basin

The Bighorn Basin covers north-central Wyoming extending into south-central Montana (Fox and Dolton, 1995a). Figure 6.9 shows the approximate extents of the asymmetric heart-shaped Bighorn Basin which lies in a northwest to southeast orientation located between the Bighorn Range and the Rocky Mountain Range. Surrounding the basin are the Bighorn Mountains to the east, the Beartooth and Absaroka Mountains to the west, the Nye-Bowler Lineament to the north, and the Owl Creeks to the south. The Bighorn Basin covers an area of approximately 13,200 square miles (Fox and Dolton, 1995a).

Figure 6.9 Geologic Setting and Produced Water Quality Distribution of the Bighorn Basin



(Source: USGS, 2005)

Significant Geological Features

The Bighorn Basin contains strata of Cambrian through Tertiary age. The sources of the sediment are the fault bounded Laramide uplifts that surround the basin (Fox and Dolton, 1995a). The important strata for oil and gas development in the basin are the Permian and Cretaceous source rocks and reservoirs, which include the Pennsylvanian Tensleep Sandstone, Permian Phosphoria, and Upper Cretaceous Frontier sandstones.

Oil and Gas Production

Oil and gas has been produced from the basin margin anticlinal structures since their discovery in 1906 and 1907 (Fox and Dolton, 1995a). Oil and gas production in the Bighorn Basin has occurred from formations ranging in age from Cambrian to Late Cretaceous.

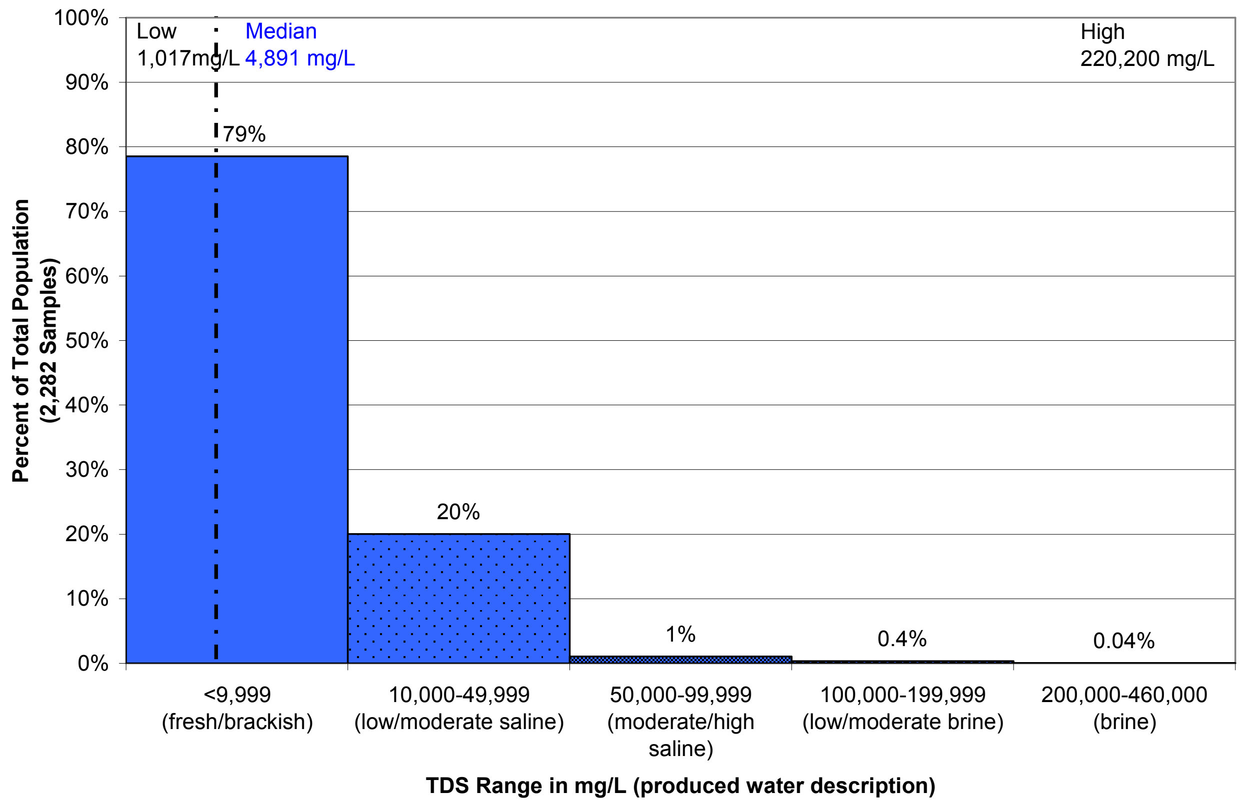
Produced Water Management

Oil and gas operators in the Bighorn Basin have utilized both enhanced recovery and agricultural beneficial use for the management of produced water. Typically, oil and gas production in the Bighorn Basin has utilized injection for enhanced oil recovery as the primary management practice for produced water.

The numerical distribution of produced water quality for the Bighorn Basin is shown in Figure 6.10. The USGS produced water database contains 2,282 individual samples of produced water quality. Produced water salinity in the Bighorn Basin includes all of the ranges identified for analysis in this study, from <10,000 mg/L to >200,000 mg/L TDS. Median produced water salinity is relatively good at 4,891 mg/L (moderately brackish). The range of salinity values for the Bighorn Basin ranged from 1,017 mg/L (slightly brackish) to 220,200 mg/L (moderate brine) (Figure 6.10). Most of the produced water quality samples from the Bighorn Basin (79%) have TDS concentrations less than 10,000 mg/L, which would be classified as brackish waters with the potential for beneficial uses. The USGS produced water database also includes nearly 20% of the samples for the Bighorn Basin in the next highest water quality category from >10,000 mg/L to <50,000 mg/L TDS. The three remaining produced water quality distributions discussed in this report contained less than 1.5% of total number of samples in the USGS produced water database (Figure 6.10).

Figure 6.9 documents the spatial distribution of water quality samples across the Bighorn Basin indicating that the low TDS produced water is widely distributed. The higher salinity produced water (that produced water with TDS >100,000 mg/L) from the USGS produced water database is located in the southeastern portion of the basin in Washakie County, Wyoming (Figure 6.9). Some of the high quality water is from shallow reservoirs with fresh water recharging these zones from the surface, while the low quality water is from deeper reservoirs in the deeper portions of the basin. The Bighorn Basin contains a large portion of low salinity water that is widely distributed as shown in Figure 6.9. Once the oil and gas have been separated from the water, this low salinity water can have important beneficial uses in addition to enhanced recovery of resources; the water can be utilized by local landowners for livestock watering, irrigation, and other beneficial uses.

Figure 6.10 Produced Water Quality from the Wyoming and Montana Portions of the Bighorn Basin



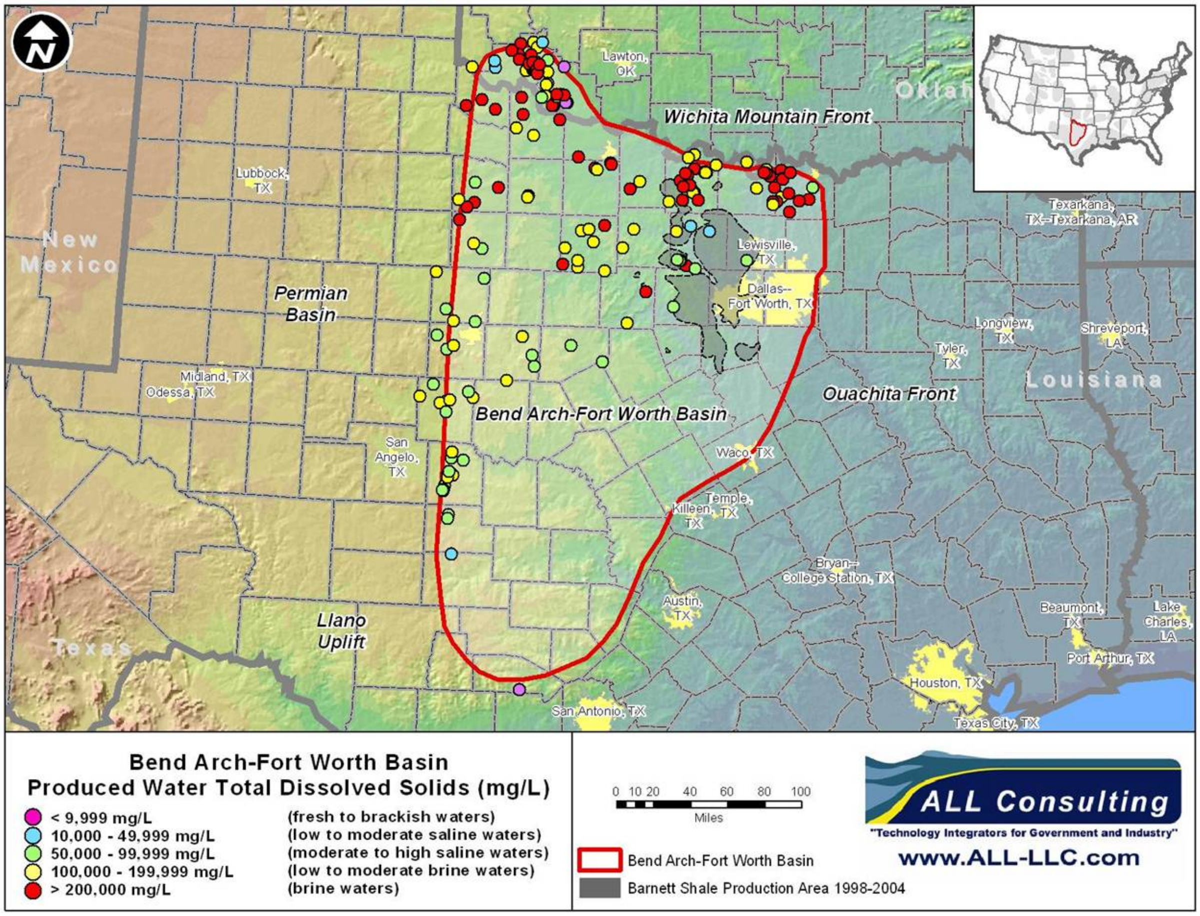
Source: USGS, 2002

Within the Bighorn Basin, water quality varies by producing formation; typically produced water quality decreases with depth in a basin. Produced water quality for the Madison, Phosphoria, and Tensleep formations of the Bighorn Basin from the Wyoming Oil and Gas Conservation Commission (WOGCC) are presented below. Produced water from the WOGCC for the Madison Formation varies from less than 500 mg/L to 4,000 mg/L TDS (WOGCC, 2006). The Phosphoria Formation produces water ranging from less than 500 mg/L to more than 80,000 mg/L TDS. The Tensleep Formation produces water ranging from less than 2,000 to more than 4,000 mg/L TDS. The majority of produced water from this basin is used in secondary recovery operations while some volumes are used for agricultural purposes.

Section 6.5 Fort Worth Basin

The Fort Worth Basin covers a large portion of north-central Texas and small portion of southwestern Oklahoma. The basin is bounded by the Wichita Mountains to the north, the Ouachita Front to the east and south, the Permian Basin to the west, and the Llano Uplift to the south (Ball and Perry, 1995). Figure 6.11 shows the approximate extents of the basin. The Fort Worth Basin has a similar geological history to the Anadarko Basin to the north and the Permian Basin to the south. Figure 6.11 shows the basin to lie in a north to south orientation along its western edge where it junctions with the Permian Basin (Ball and Perry, 1995). The Fort Worth Basin covers an area of approximately 54,000 square miles.

Figure 6.11 Geologic Setting and Produced Water Quality Distribution of the Fort Worth Basin



Source: USGS, 2005

Significant Geological Features

The sedimentary strata filling the Fort Worth Basin are mostly Paleozoic in age from Ordovician through Permian. A thin veneer of Cretaceous sediments hold the drinking water aquifers of the area and covers the older section containing oil, gas, and saltwater reservoirs. The total thickness of sediments in the Fort Worth Basin is approximately 12,000 feet or less. Some faulting is present on the edges of the basin. Conventional oil and gas development have taken place in the basin for a long time, but recently the development of unconventional gas in the Barnett shale has dominated the drilling in this basin. The Barnett gas play is currently the most active development in the United States.

Oil and Gas Production

The Fort Worth Basin has produced commercial quantities of oil and gas for most of the 20th Century. First production from the basin was in the early 1900's with more than 2.3 BBO and more than 65.5 TCFG having been produced to date. Productive reservoirs include the

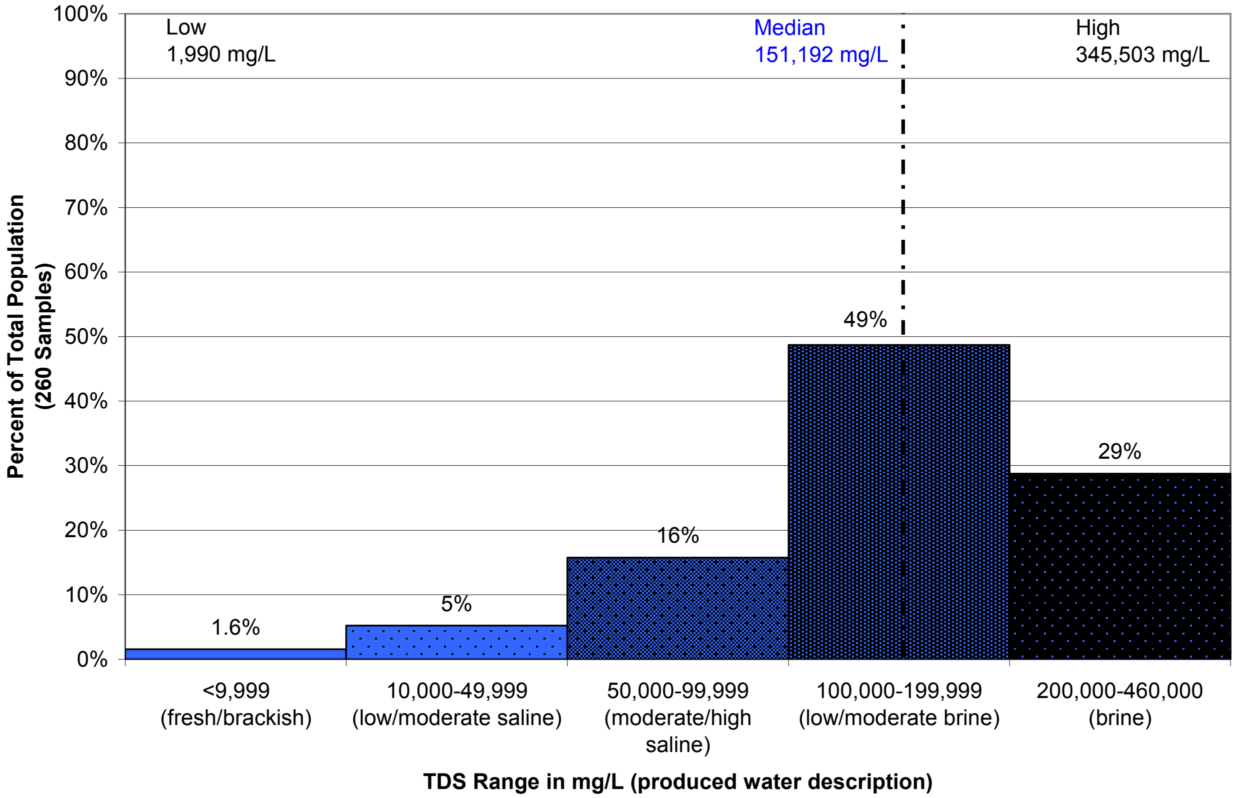
Ellenberger, Mississippian, and prolific Pennsylvanian/Permian sands. Fields developing these formations have been producing mostly oil since the 1960's. The biggest play at the present time is the Mississippian Barnett shale, a thick, highly organic, siliceous fine-grained rock laid down over most of the basin. The Barnett is a self-sourced reservoir that holds large quantities of dry natural gas that can be produced if the reservoir rock is fractured. Figure 6.11 shows the extent of the Barnett play in the basin. Horizontal wells have become prolific dry gas Barnett producers in the past few years. After drilling, the horizontal wells are fractured with huge volumes of water to open permeability in the fine-grained rock. Once natural gas production has been established, the water used to fracture the reservoir is produced back to the surface. Therefore, the Barnett wells produce large volumes of frac water that needs to be managed.

The Newark East Barnett field (noted on Figure 6.11 as the Barnett Shale production area from 1998 – 2004) is currently the largest gas field in Texas and the most active drilling area in the nation. Total production from the Barnett through October 2005 was 5.6 million barrels of oil and 1.6 TCFG. At the end of 2005 there were approximately 4,500 producing Barnett wells with total daily gas production rates of approximately 9.62 BCF and approximately 3,367 barrels of oil per day. There is an estimated 26 TCF of gas recoverable in the play (Rushworth, 2006).

Produced Water Management

Most oil and gas production has associated water production in the basin, but other than the frac water from the Barnett wells, the volumes are not large. Management historically has been by way of water floods or injection disposal wells. Figure 6.12 charts the numerical distribution of water quality across the basin from the USGS produced water database, which contains 768 individual samples of produced water quality for the Fort Worth Basin. Produced water salinity in the Fort Worth Basin includes the ranges from <10,000 mg/L to >200,000 mg/L TDS. Median salinity expressed as TDS is high at 151,192 mg/L (moderate brine). The range of salinity values for the basin ranged from 1,990 mg/L (brackish) to 345,503 mg/L (brine) (Figure 6.12). The distribution is quite similar to the Permian and Anadarko basins suggesting their similar geological history. Of the 768 produced water quality samples from the Fort Worth Basin, the largest portion of the produced water quality samples (49%) for the Fort Worth Basin were reported in the 100,000 mg/L to 199,999 mg/L range (Figure 6-18). The next largest distribution of produced water quality for the basin (29%) was the 200,000 mg/L to 460,000 mg/L TDS range (Figure 6-18). The large percentage (80%) of produced water in the brine quality ranges suggests that few beneficial uses exist for the produced water from this basin other than for water flood projects.

Figure 6.12 Water Quality Distribution in the Fort Worth Basin



(Source: USGS, 2002)

Figure 6.11 documents the distribution of water quality samples across the Fort Worth Basin showing how the produced water quality varies throughout the basin. The geographic distribution of water salinity shown in Figure 6.11 reflects higher TDS water is more prevalent in the northern and western portions of the basin, and the lower TDS water is present in the central and eastern portions of the basin. Produced water with greater than 100,000 mg/L TDS is more prevalent in the northern portion of the basin, near the Texas-Oklahoma border (Figure 6.11). The produced water quality samples with TDS less than 100,000 mg/L are more predominant in the central and eastern portions of the basin with some associated produced water samples of higher TDS present in this area (Figure 6-19).

Currently the Barnett production has taxed the water management options when the water used to fracture the well is produced to the surface. Few disposal wells existed in the basin before the hundreds of Barnet wells were drilled. Over most of the basin, the Pennsylvanian sands and the Ellenberger carbonates water-bearing permeable units traditionally have been used for disposal by Class II disposal wells. The Ellenberger has more capacity, consisting of thick carbonates that often are naturally fractured and cavernous. Pennsylvanian sands are present above the Barnett and are drilled through by each producing well. The Ellenberger, however, is situated beneath the Barnett shale and is not drilled by the Barnett field wells.

Produced water from the Barnett development is a challenge for operators in the basin. A fracture job on a horizontal well can utilize more than 2 million gallons of water that is then produced back to the surface during the productive life of the well. Operators often use water from municipal water systems to be sure that the water is clean and contains no live bacteria that could be introduced into the formation. The fracture water that is brought back to the surface during production has picked up some oil and grease, dissolved salts, and may contain >100,000 mg/L TDS. Water of this quality could be treated to drinking water or irrigation quality, but to date the water has not been treated. However, some of this produced water is re-used by operators for fracturing other wells in the field. Most of the produced water is sent to disposal wells in the basin.

In January 2005, the Texas Railroad Commission approved a pilot project to be conducted by Fountain Quail Water Management to treat fracture-job flow-back water in the Barnett Shale trend on a lease held by Devon Energy in North Texas for the purposes of recycling the fluid. The approval given by the Commission allows the recycling operations to go forward without the need to obtain certain permits or additional financial assurance for the operation. A skid-mounted device located at the site of a Barnett well to be fracture stimulated is utilized to distill produced water brought in from off-site. The produced water is distilled through a series of heat exchangers yielding 2,000 barrels of distilled water for every 2,350 barrels of produced water put into the system. The remaining 350 barrels of saltwater and waste require off-site disposal at a conventional Class I injection facility. Once a sufficient volume of distilled water is produced, the water may be used for fracture stimulating a Barnett well on Devon's lease (Forbis, 2005).

In addition to using commercial injection wells, Class II (oil and gas) injection wells are also used for disposal of produced water in the Fort Worth Basin. Class II injection well permits can be difficult to obtain and the permit process can be delayed by citizen protests. One aspect of the Barnett play that is different from other oil and gas plays is the fact that oil and gas activity in the Barnett is centered on and around the city of Fort Worth, Texas, and its suburbs. Because the Barnett play is located near an urban area, development is often surrounded by residential homes with residents that may not be familiar with oil and gas production facilities. Because of the large urban population and their water needs, injection pressure gradients incorporated into disposal permits are curtailed in some areas for the shallow Pennsylvanian sands in order to prevent impact to overlying drinking water aquifers. At these lower injection pressures, Class II disposal wells completed into the Pennsylvanian sands often cannot inject enough water to make the wells economical to operate. One option is for operators to complete wells in the deeper Ellenberger zone where higher pressure gradients can be permitted to inject and large quantities of water can usually be injected. However, Barnett wells are completed at shallower depths than the Ellenberger zone; because of this, operators who wish to use an Ellenberger disposal well will need to drill a different well for this purpose. The necessity of drilling a separate disposal well to the Ellenberger adds considerably to the expense of the injection well installation.

Section 6.6 Greater Green River Basin

The Greater Green River Basin is located in the Rocky Mountain Foreland from western to south-central Wyoming and extends into northeastern Utah and northwestern Colorado (Law, 1995). Figure 6.13 shows the basin to lie in a northwest to southeast orientation located between the Uinta Uplift to the southwest and the Hanna and Wind River Basins to the northeast and east. The Greater Green River Basin is further bounded by the Medicine Bow and Park Range Uplifts to the south-southeast, Wyoming-Utah-Idaho Thrust Belt to the northwest, and the Absaroka Mountains to the north. The Greater Green River Basin covers an area of approximately 19,700 square miles (DeJarnett et. al., 1997).

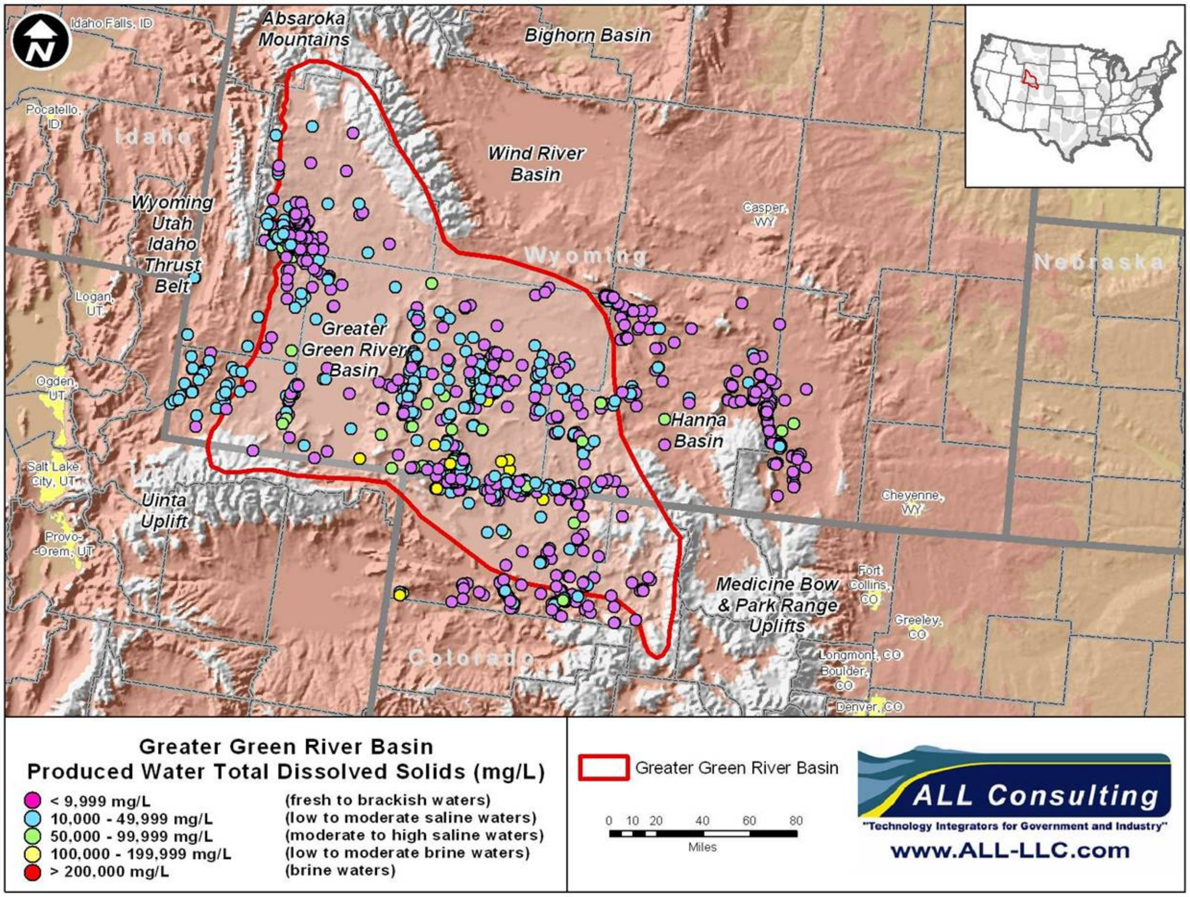
Significant Geological Features

The Greater Green River Basin contains strata of Cambrian through Tertiary age, which are believed to have been deposited in three stages (Law, 1995). The first stage of deposition is referred to as the shelf in which the area was inundated by shallow seaways from the Middle Cambrian to Middle Jurassic. The middle stage is the foreland stage in which sediments were supplied to the basin from uplift areas to the west (Idaho and Utah). The final stage is the inter-basin sedimentation stage in which sediments were derived from the uplift of local areas. The result of these three stages of deposition is an accumulated thickness of sediments in the northern part of the basin that approaches 32,000 feet (Law, 1995). The important strata for oil and gas development in the basin range from Paleozoic to Tertiary in age, with recent production focusing on tight sands of Cretaceous aged Almond and Frontier Formations (DeJarnett et. al., 1997).

Oil and Gas Production

Oil and gas production has been ongoing in the basin since discovery of the Lost Soldier field in 1916 with the first gas play discovery in 1922 on the Rock Springs Uplift (Law, 1995 and Gibson, 1997). To date, more than 0.17 BBO and more than 13.75 TCFG have been produced from the Greater Green River Basin (Gibson, 1997 and WOGCC, 2006). The basin has seen sporadic testing of CBNG resources since the mid 1980's into the early 1990's. Much of the gas production has been occurring in tight sandstone formations in the center of the basin, which have resulted in large volumes of produced water co-produced with the gas.

Figure 6.13 Geologic Setting and Produced Water Quality Distribution of the Greater Green River Basin

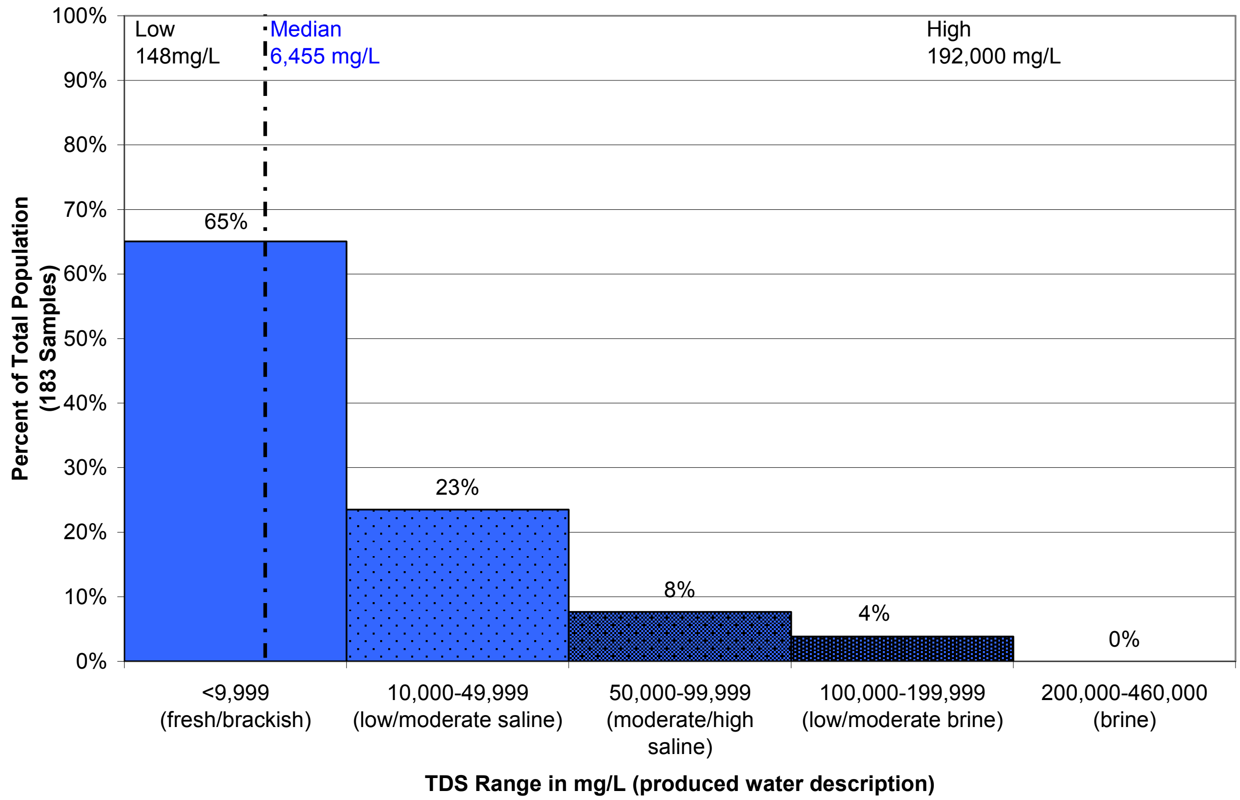


(Source: USGS, 2005)

Produced Water Management

The numerical distribution of produced water quality data from the USGS produced water database for the Greater Green River Basin is shown in Figure 6.14. The database contains 183 individual samples of produced water quality. Produced water salinity in the basin includes ranges from <10,000 mg/L to <200,000 mg/L TDS; there were no samples in the database for the 200,000 mg/L to 460,000 mg/L range (Figure 6-21). Median salinity expressed as TDS for the Greater Green River Basin was low at 6,455 mg/L (brackish water). The range of salinity values for the basin ranged from 148 mg/L (fresh water) to 192,000 mg/L (moderate brine). More than half of the produced water samples (65%) reported for the basin have TDS concentrations <10,000 mg/L. The next highest grouping of produced water quality samples (23%) was the 10,000 mg/L to 49,999 mg/L TDS (saline waters). The moderately saline (8%) to moderate brine (4%) categories contain the remaining 12% of the produced water quality samples. (Figure 6.14).

Figure 6.14 Water Quality Distribution in the Greater Green River Basin



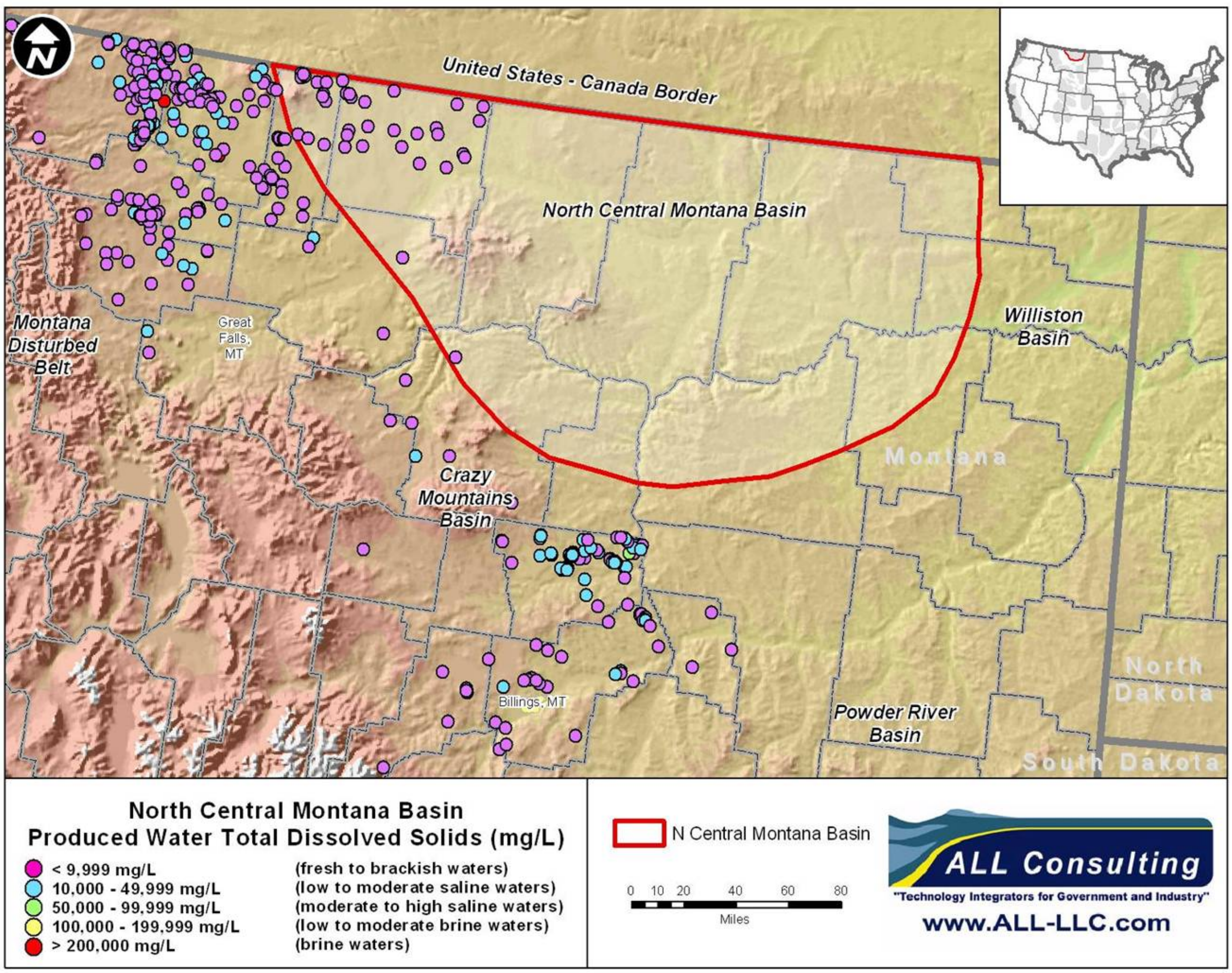
(Source: USGS, 2002)

Figure 6.13 documents the distribution of water quality samples across the Greater Green River Basin and shows that fresh to brackish quality produced water (TDS <10,000 mg/L) is scattered across the basin. Similarly, the two groupings of saline produced water (10,000 mg/L to 49,999 mg/L and 50,000 to 99,999 mg/L TDS) are also scattered across the basin (Figure 6.14). The one grouping of brine waters (100,000 mg/L to 199,999 mg/L TDS) identified for the basin from the USGS produced water database is present along the Wyoming-Colorado state line (Figure 6.13). This grouping is likely indicative of production occurring in a deeper portion of the basin in formations that are not receiving fresh water recharge from the surface.

Section 6.7 North Central Montana Basin

The North Central Montana Basin covers a large portion of the center of the state of Montana (Figure 6-23). The U.S. portion of the basin is bounded by the United States-Canadian border to the north, the Williston Basin to the east, the Powder River Basin to the southeast, the Crazy Mountain Basin to the southwest, and the Montana Disturbed Belt to the west (Figure 6.15). Several geological features are present in the basin, including: Sweetgrass Arch, Kevin-Sunburst and Bowdoin Domes, Bearpaw Uplift, and Central Montana Trough (Dyman, 1995). The North Central Montana Basin is approximately 250 miles long and 250 miles wide and covers an area of approximately 60,000 square miles (Dyman, 1995).

Figure 6.15 Geologic Setting and Produced Water Quality Distribution of the North Central Montana Basin



(Source: USGS, 2005)

Significant Geological Features

The North Central Montana Basin contains strata of Cambrian through Tertiary age, which are present both at the outcrop and in the subsurface throughout the basin (Dyman, 1995). Much of the active oil and gas production in the basin comes from the Cretaceous sandstones from the Kootenai Formation and the Madison Group carbonates. Other formations with potential plays include the Cambro-Ordivician and Jurassic-Cretaceous sandstones, carbonates of the Devonian-Mississippian, and shallow Cretaceous biogenic gas (Dyman, 1995). Recent activity includes the Bakken Shale play, which extends from the Williston Basin into the North Central Montana Basin.

Oil and Gas Production

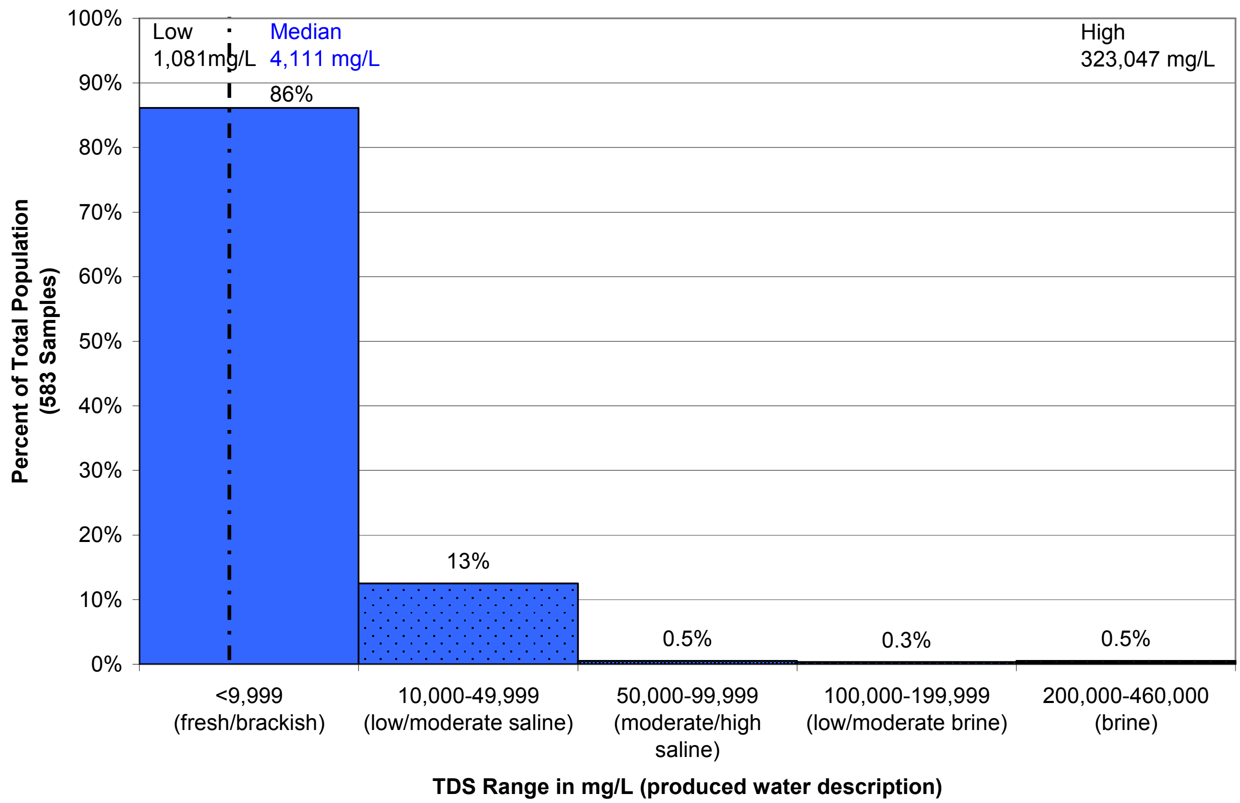
Oil and gas production in the North Central Montana Basin has been ongoing since the early 1900's from the Bowdoin Field and the Cutbank oil field (Dyman, 1995). Both crude oil and natural gas are produced from Cretaceous through Devonian aged reservoirs across the North Central Montana Basin, with more than 0.46 BBO and more than 1.67 TCFG having been produced from the basin to date (Dyman, 1995 and MBOGC, 2006).

Produced Water Management

The numerical distribution of produced water quality samples from the USGS produced water database for the North Central Montana Basin is shown in Figure 6.16. The USGS produced water database contains 583 individual samples of produced water quality for the North Central Montana Basin. Produced water salinity includes all ranges identified for analysis in this study from <10,000 mg/L to >200,000 mg/L TDS. Median salinity expressed as TDS is low at 4,111 mg/L (brackish). The range of salinity values for the basin ranged from 1,081 mg/L (slightly brackish) to 323,047 mg/L (brine) (Figure 6.16). Produced water from this basin is very high quality with 86% of the samples in the USGS database having less than 10,000 mg/L TDS. Another 13% of the produced water samples were reported in the range from 10,000 mg/L to 49,999 mg/L TDS. The remaining percentage (approximately 1.3%) were relatively evenly distributed through the remaining three water quality groupings analyzed in this report (Figure 6.16).

Figure 6.15 documents the distribution of water quality samples across the basin showing that the high quality produced water is distributed across the producing regions. Since there is such a small percentage of low quality produced water (>50,000 mg/L TDS) it is difficult to assess the distribution of these samples within the basin. While the low quality water (<10,000 mg/L TDS) appears to be focused along several features close to the Montana-Canadian border, some scattered production reaches into the central part of Montana (Figure 6.15). The low salinity water might have beneficial uses that include enhanced recovery of oil and gas resources and agricultural. The majority of these low salinity samples are from production wells at depths less than 5,000 feet below the surface where fresh surface waters are recharging these zones. Many of the low TDS produced water quality samples were taken from the Mississippian aged Madison Formation, although many other formations were sampled.

Figure 6.16 Water Quality Distribution of the North Central Montana Basin



(Source: USGS, 2002)

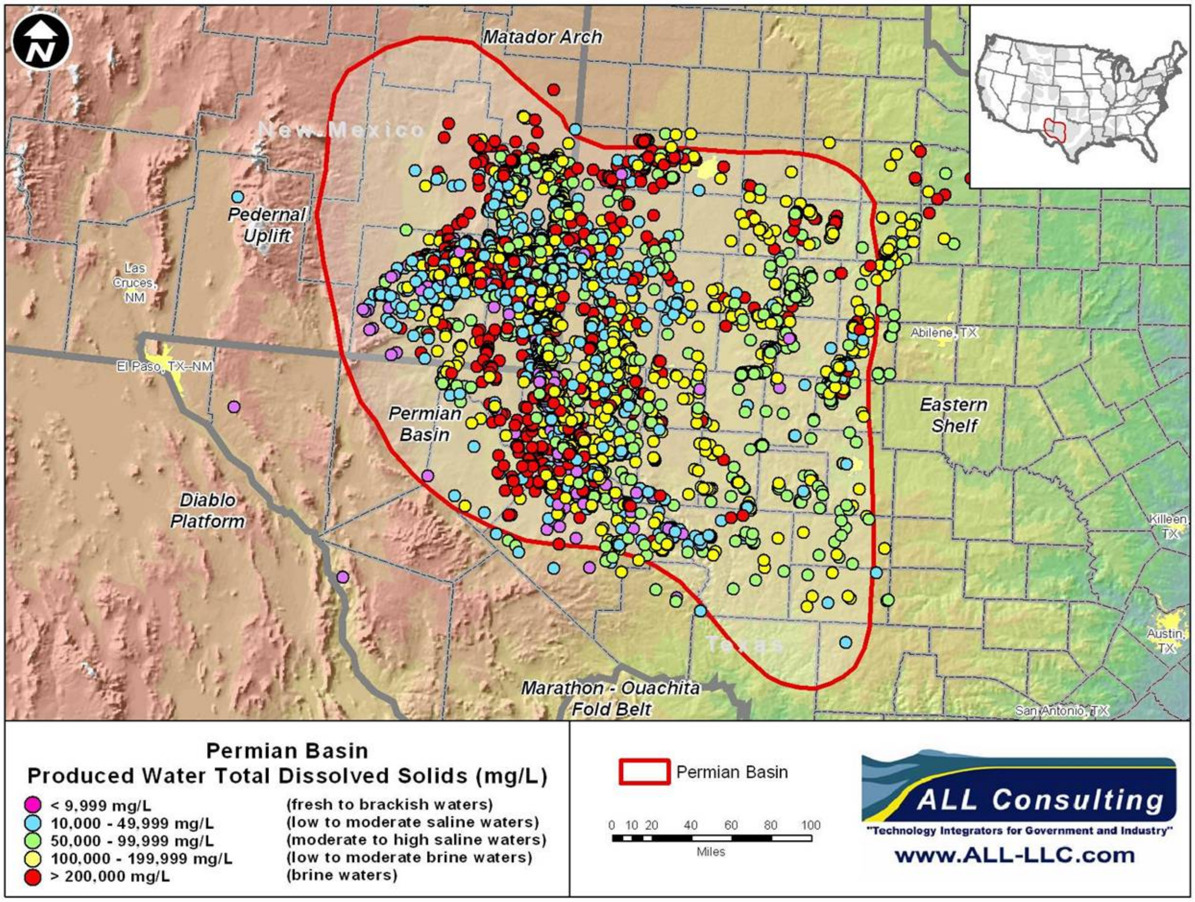
Section 6.8 Permian Basin

The Permian Basin covers a large portion of western Texas and southeastern New Mexico. The majority of the basin is located in western Texas as seen in Figure 6.17. The basin contains a variety of hydrocarbon reservoirs that also produce water (Steuber, 1998). Figure 6.17 shows the Permian Basin to lie in a north to south orientation, with the Matador Arch to the north, the Eastern Shelf of the Midland Basin to the east, the Marathon-Ouachita Fold Belt to the south, and the Pedernal Uplift and Diablo Platform to the west (Ball, 1995). The Permian Basin is approximately 260 miles by 300 miles with a total surface area exceeding 86,000 square miles.

Significant Geological Features

The Permian Basin contains strata of predominantly Paleozoic in age with thinner extent of younger sediments; the basin's current structural features developed from the Late Mississippian to Early Pennsylvania time (Dutton et. al., 2004). Most of the basin-fill volume is taken up with the Paleozoic strata with oil and gas production from rocks ranging from the Cambrian through Cretaceous age sediments. The important strata in the basin include the Ordovician Ellenburger carbonates, which are the same age and similar in lithology to the massive Knox carbonates of the Appalachians and the Arbuckle Formation of the Anadarko Basin. The stratigraphy of the Permian Basin includes a thick sequence of Paleozoic age rocks, which can be greater than 25,000 feet in thickness (Ball, 1995).

Figure 6.17 Geologic Setting and Produced Water Quality Distribution of the Permian Basin



(Source: USGS, 2005)

Oil and Gas Production

The Permian Basin continues to be one of most prolific and largest oil production basins in the United States. As of 2002, the Permian Basin production was 17% of the total United States oil production (BEG, 2002). Oil and gas production occurs in rocks dating from the Cambrian to the Cretaceous with most production coming from reservoirs of Paleozoic age (Ball, 1995). More than 35 BBO, 5.5 BBNGL, and 90.7 TCFG had been produced from the basin as of the early 1990's (Ball, 1995).

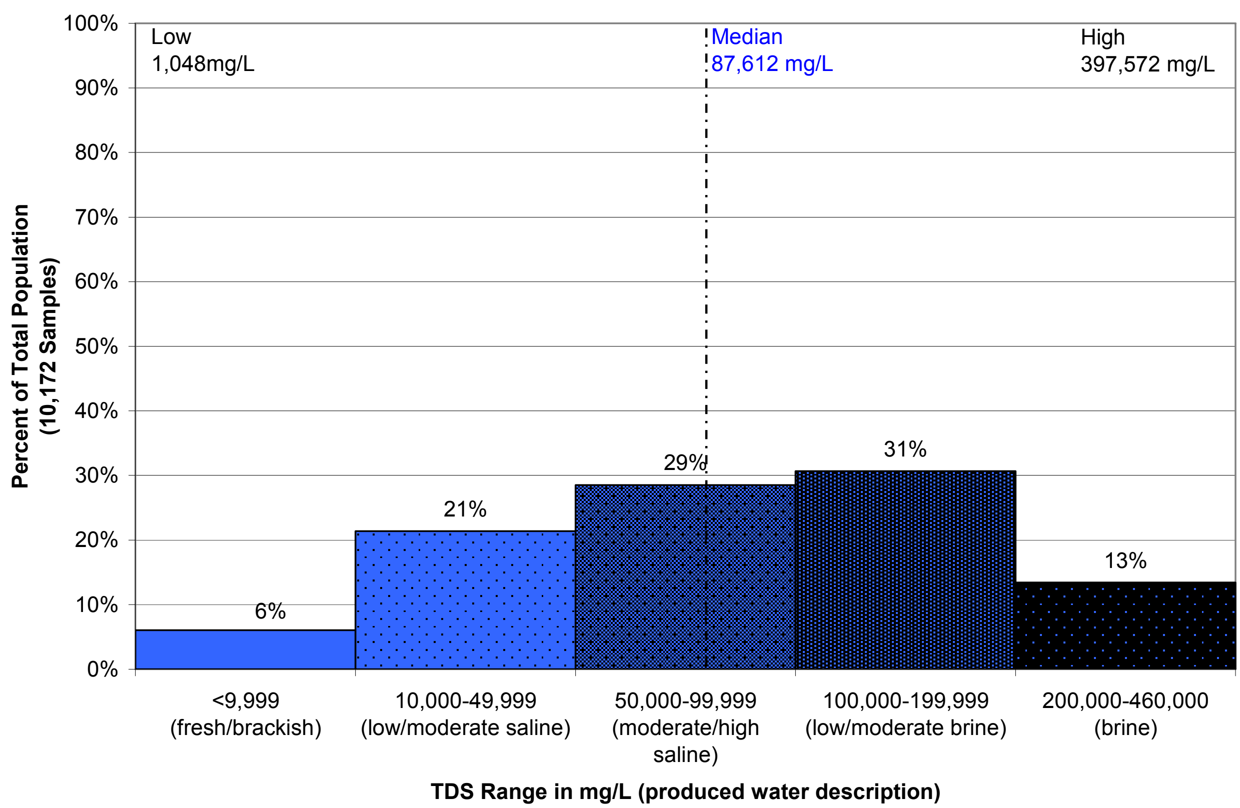
Produced Water Management

The numerical distribution of produced water for the Permian Basin is presented in Figure 6.18. The USGS produced water database contains more than 10,000 individual samples for the Permian Basin. Produced water salinity in the basin includes all ranges identified for analysis in this study from <10,000 mg/L to >200,000 mg/L TDS (Figure 6-27). Median salinity expressed as TDS was 87,612 mg/L with the range of salinity values ranging from 1,048 mg/L (slightly brackish) to 397,572 mg/L (brine). Approximately 6 percent of the water samples in the database were below 10,000 mg/L TDS and could have local beneficial uses; this high quality water is reported from shallow aquifers that do not produce hydrocarbons (USGS, 2002), but scattered wells have sampled productive formations that locally contain high quality water.

Depths of those samples less than 10,000 mg/L range from 25 feet to more than 19,000 feet. Most of these low salinity water samples were taken less than 4,000 feet deep. Water this deep probably cannot be economically exploited by wells drilled expressly for water, but could be exploited as a by-product of oil and gas production.

The largest grouping of produced water for the Permian Basin (31%) was reported in the 100,000 mg/L to 199,999 mg/L TDS grouping, with slightly fewer samples (29%) in the 50,000 mg/L to 99,999 mg/L TDS category (Figure 6.18). Figure 6.17 shows the distribution of produced water salinity values, showing that produced water quality varies randomly throughout the basin. The geographic distribution of the produced water salinity values show the high quality water samples (TDS <10,000 mg/L) to be located along the western boundary of the basin (Figure 6.17). This water may be able to satisfy some uses in its raw state without treatment while uses such as industrial and municipal water supply may require treatment. The other classifications of produced water appear to be much more evenly distributed with most of the produced water currently utilized for extensive secondary recovery operations in the basin's oil fields.

Figure 6.18 Water Quality Distribution in the Texas and New Mexico Portions of the Permian Basin

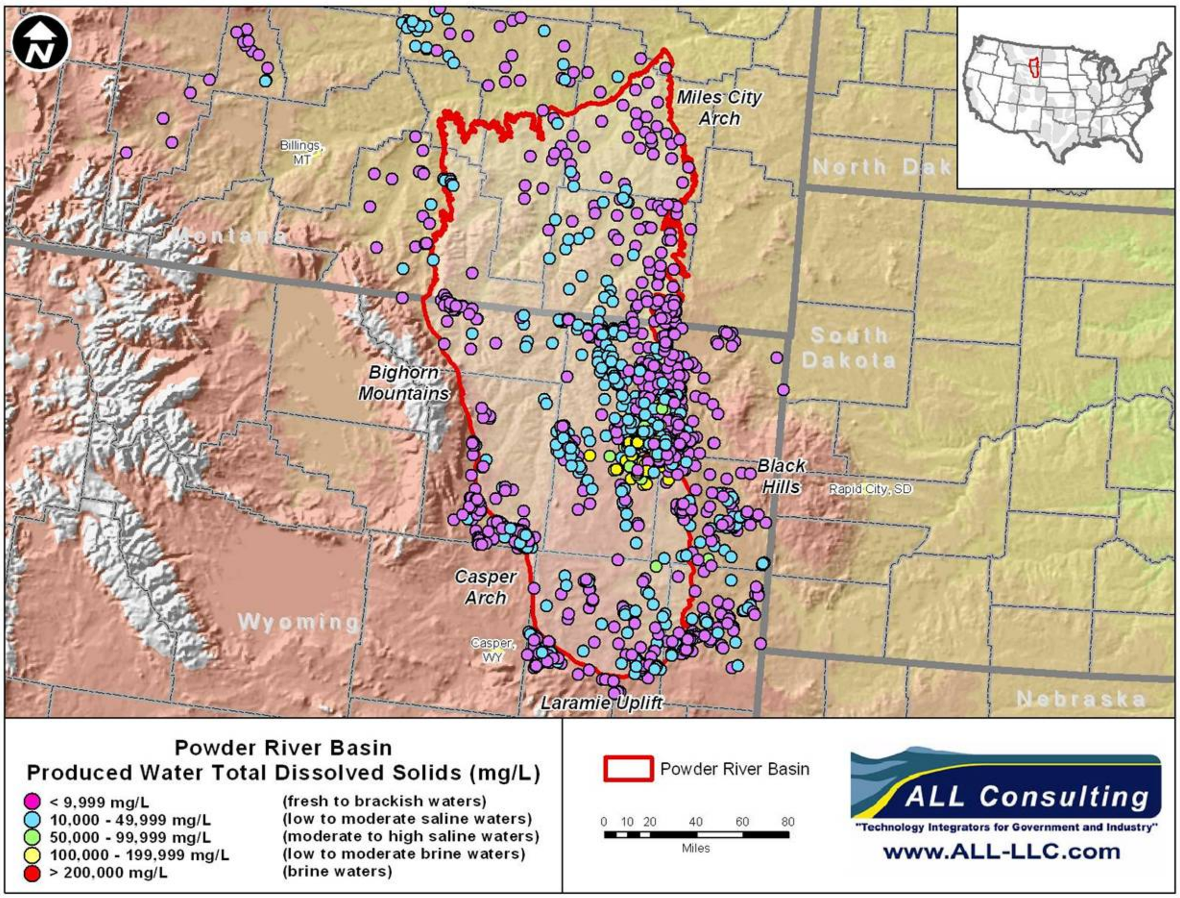


Source: USGS, 2002

Section 6.9 Powder River Basin

The Powder River Basin forms part of the Unglaciated Missouri Plateau section of the Great Plains province. It extends from northeastern Wyoming into southeastern Montana and contains strata of Cambian to Tertiary age (Figure 6.19). On the surface of the basin, there are several watersheds while outcropping formations are primarily Tertiary in age. Figure 6.19 shows the Powder River Basin to lie in a northwest to southeast orientation that is bound by the Miles City Arch to the north, the Black Hills to the east, the Laramie Uplift and Casper Arch to the south, and the Bighorn Mountains to the west (Dolton and Fox, 1995). The Powder River Basin covers an area of approximately 34,000 square miles (Dolton and Fox, 1995).

Figure 6.19 Geologic Setting and Produced Water Quality Distribution of the Powder River Basin



(Source: USGS, 2005)

Significant Geological Features

The basin is filled with a thick sequence of sediments from the Cambrian to Tertiary in age. The sediments result from accumulations of Paleozoic shelf carbonates, sandstones, and shales, overlain by a thick sequence of Mesozoic to Tertiary sediments that accumulated during the time of the Western interior seaway, with recent sediments for local uplifted areas (Dolton and Fox, 1995). Formations within the Powder River Basin important to oil and gas development range from the shallow Tertiary coal beds to conventional oil and gas reservoirs from the Mississippian to lower Cretaceous. The stratigraphy of the basin includes a thick sequence of Phanerozoic strata, which can be greater than 18,000 feet in thickness near the basin's axis (Dolton and Fox, 1995).

Oil and Gas Production

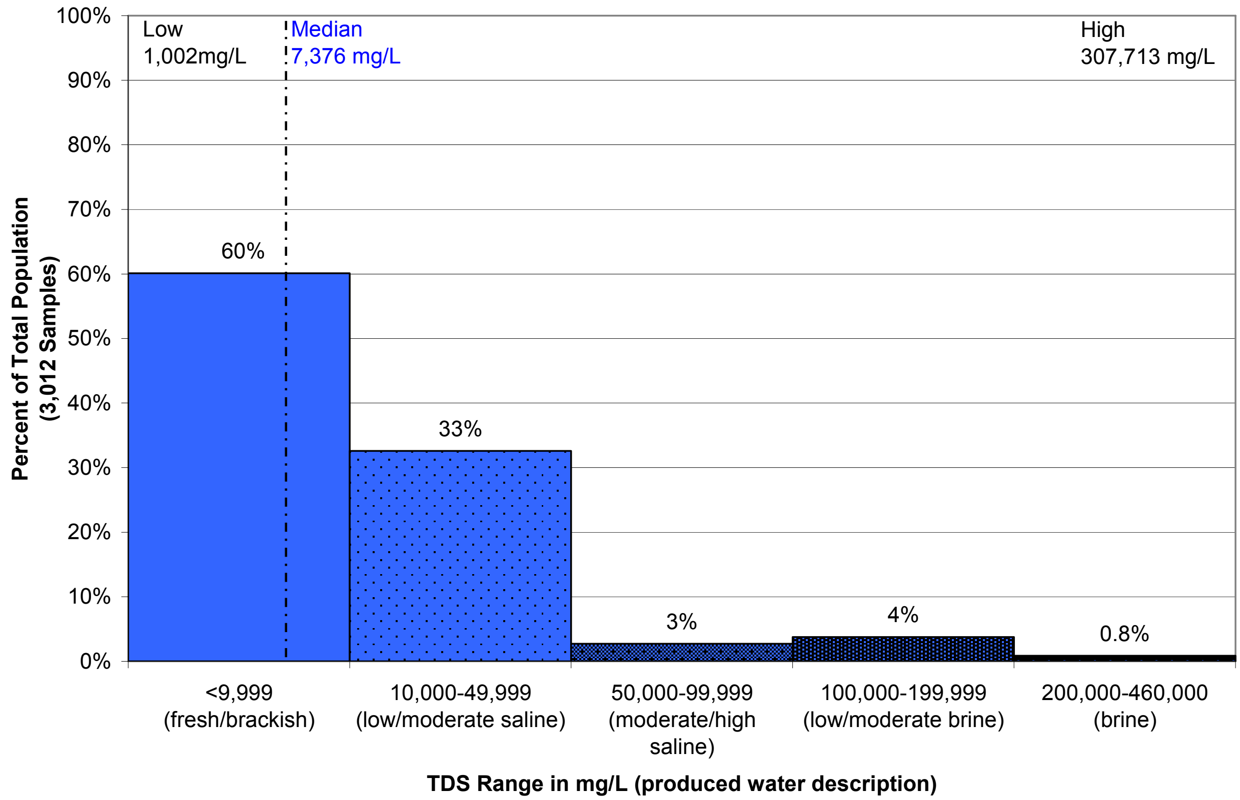
Oil and gas has been developed in the Powder River Basin since the discovery of the Salt Creek field in 1908 (Dolton and Fox, 1995). Since this initial discovery, recoverable resources have been estimated at 2.7 BBO and 2.3 TCFG within the basin (Dolton and Fox, 1995). Conventional oil and gas exploration has been declining in the Montana portion, with considerable decreases in oil production since 1986; natural gas production had been declining in the Powder River Basin until the start of CBNG production in 1990's. Since then, the basin increasingly has become a larger source of natural gas revenues for Montana and Wyoming, with production of CBNG contributing to the majority of the increase in production.

Produced Water Management

The numerical distribution of produced water quality for the Powder River Basin is presented in Figure 6.20. The USGS produced water database contains 3,012 individual samples for the Powder River Basin. Produced water salinity in the basin includes all ranges identified for analysis in this study from <10,000 mg/L to >200,000 mg/L TDS. Median salinity expressed as TDS is moderately brackish at 7,376 mg/L (Figure 6-30) with a range of salinity values from 1,002 mg/L (slightly brackish) to 307,713 mg/L (brine). More than half the produced water quality samples (60%) in the USGS database for the basin have TDS concentrations of less than 10,000 mg/L. Another 33% of the produced water samples were reported in the range from 10,000 mg/L to 49,999 mg/L TDS. The majority of the remaining percentage (approximately 7%) was distributed between the 50,000 mg/L to 99,999 mg/L (3%) and the 100,000 mg/L to 199,999 mg/L (4%) groupings. Less than one percent (0.8%) of the produced water quality samples were reported in the highest salinity grouping from 200,000 mg/L to 460,000 mg/L (Figure 6.20). Formation water varies from strong brines in deep reservoirs, higher quality water trapped in Tertiary and Cretaceous reservoirs, and fresh meteoric water that has entered some of the aquifers at their outcrop and migrated into the basin.

Figure 6.19 documents the distribution of water quality samples across the Powder River Basin showing how the produced water quality varies across the basin. The geographical distribution of water salinity as shown in Figure 6.19 indicates that the water quality reflects the geometry of the basin. Produced water of the fresh to brackish quality (0 mg/L to 9,999 mg/L TDS) is located along the basin margins with some scattering of this higher quality water into the center of the basin. The produced water quality of low-to-moderate salinity (10,000 mg/L to 49,999 mg/L TDS) are predominately located toward the center of the basin inside the area of the fresh to brackish quality samples (Figure 6.19). The lower quality produced water samples (>50,000 mg/L TDS) are located toward the deeper portion of the basin as shown in Figure 6.19.

Figure 6.20 Water Quality Distribution of the Entire Powder River Basin of Montana and Wyoming



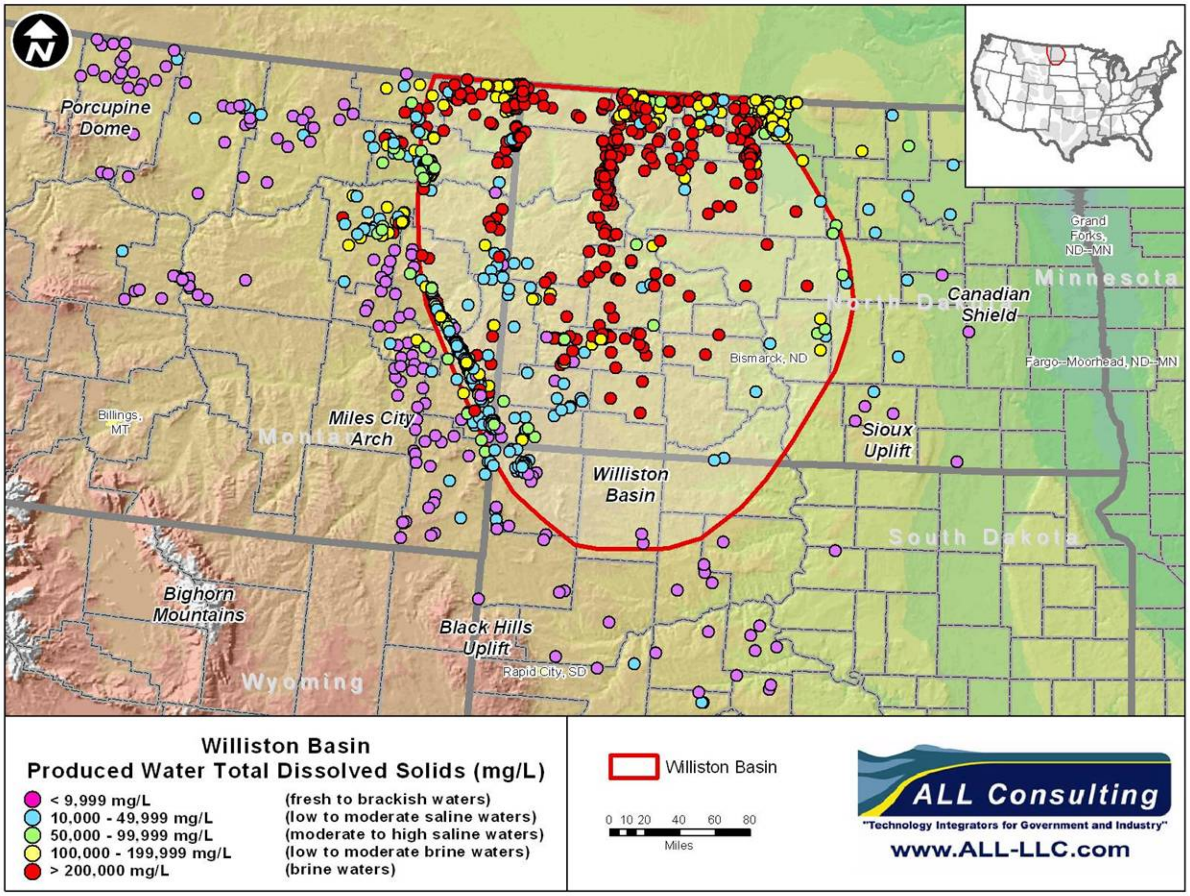
(Source: USGS, 2002)

Within the Powder River Basin, produced water varies by reservoir type and depth. CBNG produced water typically has a TDS between approximately 1,000 mg/L and 4,000 mg/L. CBNG fields are prodigious water producers and account for approximately 50% of all produced water in the basin (WOGCC, 2006). Water from the Muddy/Newcastle Formations varies from less than 2,000 mg/L to more than 50,000 mg/L; water from the Nugget Formation ranges from 50,000 mg/L to 70,000 mg/L; water from the Madison Formation varies from less than 1,000 mg/L to 8,000 mg/L; Dakota Formation water ranges between 2,000 mg/L to 8,000 mg/L; and the Minnelusa Formation contains water in excess of 150,000 mg/L TDS.

Section 6.10 Williston Basin

The Williston Basin is located at the northern end of the Great Plains and covers approximately 143,000 square miles within the United States, including parts of eastern Montana and North and South Dakota (Figure 6.21). The Williston Basin is bound in the east by the Canadian Shield, the southeast by the Sioux Uplift, to the southwest by the Black Hills Uplift, and to the west by the Miles City Arch and Porcupine Dome (Peterson, 1995). The Williston Basin is the result of subsidence, which is believed to have started as early as the Ordovician Period and continues today (Heck et al. 2002). The Williston Basin contains a nearly complete rock record reflecting the numerous transgressive/regressive sequences that have occurred in the basin (Heck et al. 2002).

Figure 6.21 Geologic Setting and Produced Water Quality Distribution of the Williston Basin



(Source: USGS, 2005)

Significant Geological Features

The sediments within the basin range from the Cambrian through Tertiary strata, with the maximum thickness of Phanerozois rocks being greater than 16,000 feet in the North Dakota portion of the basin (Peterson, 1995). Outcrops within the Williston Basin consist primarily of the Tertiary sediments from the Fort Union Formation, Cretaceous sediments from the Hell Creek Formation, and Quaternary Alluvium along the various river valleys. Oil and gas have been developed from Cretaceous, Mississippian, Devonian, Silurian, and Ordovician reservoirs within the basin (MBOGC, 2005). The Tertiary deposits contain sediments including various coals and lignites which to date have been sporadically tested for only CBNG in North Dakota. The Williston Basin contains several significant geologic features relative to oil and gas development, including the Cedar Creek Anticline, Nesson Anticline, the Poplar Dome, and the Bakken Formation.

Oil and Gas Production

Oil and gas has been produced from the Williston Basin since the 1910's with production of shallow gas resources from the Cretaceous Eagle Sandstone on the Cedar Creek Anticline in Montana, and major oil production on the Nesson Anticline in North Dakota starting after World

War II (Peterson, 1995). Much of current activity in the Williston basin is focused on the Cedar Creek Anticline, which is currently experiencing exploration and production in the Siluro-Ordovician with recent horizontal water-floods getting the most attention in the basin. Other recent oil and gas development in the Williston Basin has been focused on the continuous Bakken play of east central Montana and west central North Dakota.

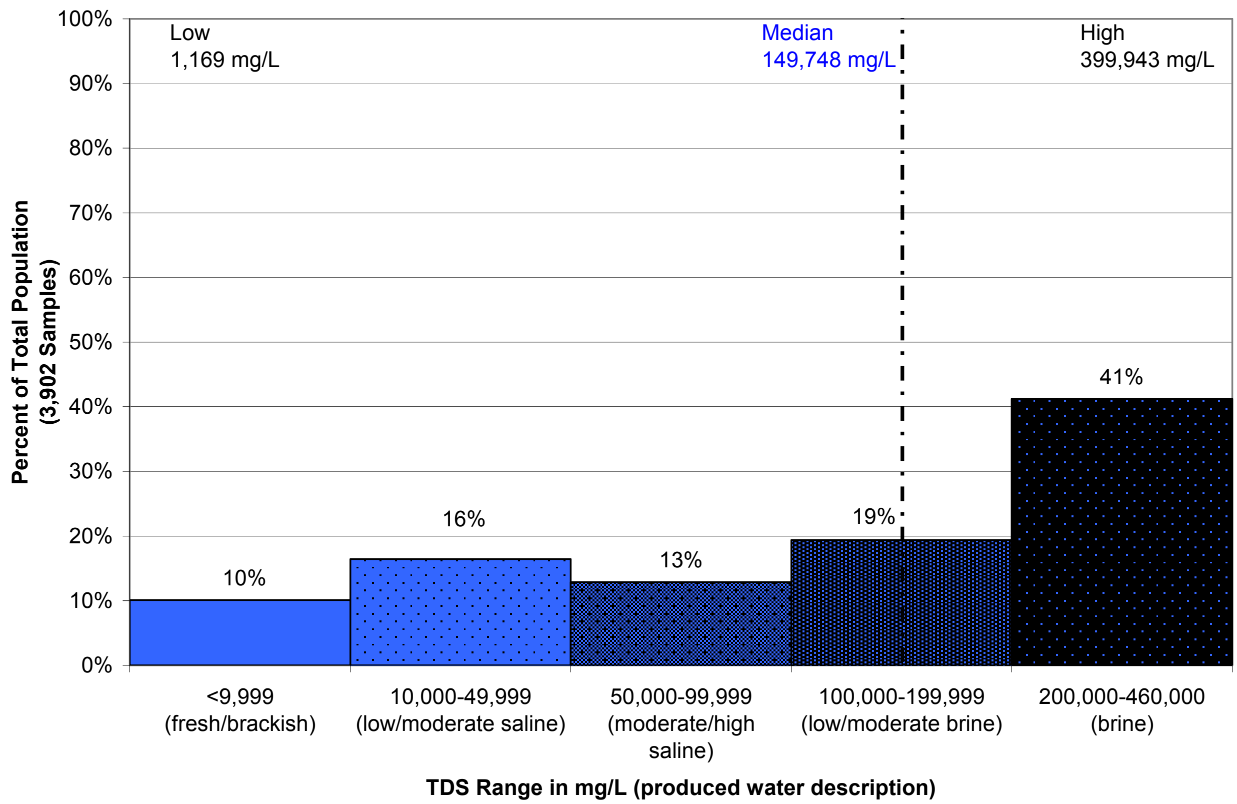
Produced Water Management

The numerical distribution of produced water quality for the Williston Basin is shown in Figure 6.22. The USGS produced water database contains 3,902 individual samples for the Williston Basin. Produced water salinity for the Williston Basin includes all ranges identified for analysis in this study from <10,000 mg/L to >200,000 mg/L TDS. Median salinity expressed as TDS for the basin is relatively high at 149,748 mg/L (moderate brine waters) as shown in Figure 6.22. The range of salinity values for the Williston Basin ranged from 1,169 mg/L (slightly brackish) to 399,943 (brine). The largest percentage (41%) of the water quality samples from the USGS produced water database for the Williston Basin had TDS concentrations between 200,000 mg/L and 460,000 mg/L. The next highest distribution percentage (19%) was the 100,000 mg/L to 199,999 mg/L range. The remaining 39% are distributed between the 50,000 mg/L to 99,999 mg/L (13%), the 10,000 mg/L to 49,999 mg/L (16%), and the <10,000 mg/L (10%) ranges.

Figure 6.21 documents the distribution of water quality samples across the Williston Basin, showing how the produced water quality varies geographically. The distribution of water salinity as shown in Figure 6.21 indicates that the water quality reflects the geometry of the basin. Produced water of the fresh to brackish quality (0 mg/L to 9,999 mg/L TDS) is located along the basin margin with most of the higher quality water located along the southwestern edge of the basin. The low-to-moderate saline waters (10,000 mg/L to 49,999 mg/L) are predominately located inside of the fresh to brackish quality samples. The lower quality produced water samples (>50,000 mg/L) are located toward the deeper central portion of the basin as shown in Figure 6.21.

Because most of this water is not of beneficial use quality (<10,000 mg/L TDS), the majority is utilized in secondary oil recovery operations or disposed of commercially. Almost 90% of the produced water from the Williston Basin is high in TDS and lacks any other use. Some reservoirs (Tertiary aged) within the Williston Basin do produce water low enough in TDS to support some uses, but at the present time no water is being produced from lignite coalbeds in the Tertiary Fort Union Formation. If these lignites ever prove productive of CBNG, this water may be of sufficient quality and quantity to sustain beneficial uses such as irrigation, cattle, or support of coal mining and power generation operations as is seen in the Powder River Basin.

Figure 6.22 Water Quality Distribution in the United States Portion of the Williston Basin



(Source: USGS, 2002)

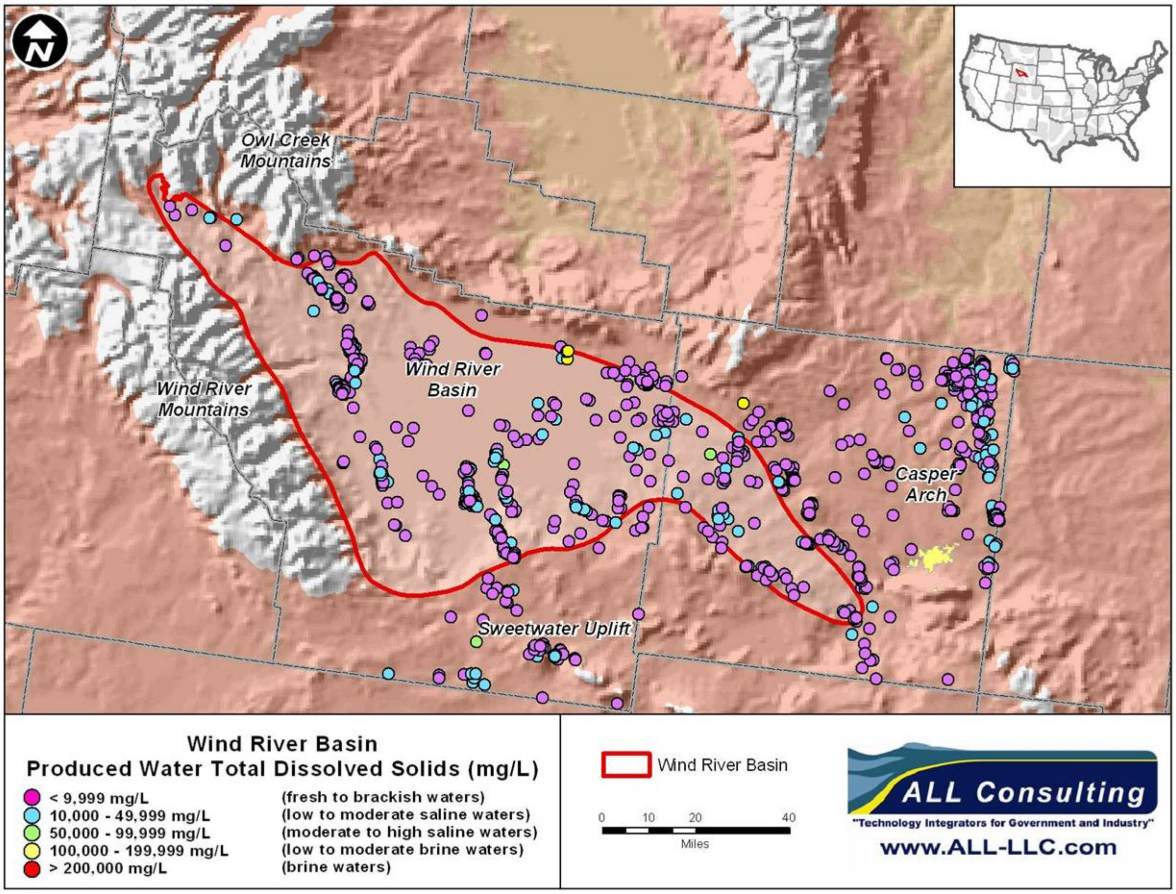
Section 6.11 Wind River Basin

The Wind River Basin is a major foreland basin in the Wyoming Rockies located in central Wyoming, south of the Bighorn Basin. The Wind River Basin is an asymmetric basin with a southeast-northwest orientation and contains major structures related to the bounding structural uplifts (Figure 6.23). The basin is bound by the Sweetwater Uplift to the south, the Wind River Mountains to the west, the Owl Creek Mountains to the north, and the Casper Arch to the east as shown in Figure 6.23 (Fox and Dolton, 1995b). The Wind River Basin covers an area of approximately 11,700 square miles (Fox and Dolton, 1995b).

Significant Geological Features

The basin has produced oil and gas since 1884 when Wyoming's first oil well was completed in the Wind River Basin. The basin is split between oil and gas production with oil dominating production until the 1950's when natural gas became more important. The basin is currently one of the most important natural gas producing areas in the state. Both crude oil and natural gas are produced from Cretaceous through Devonian aged reservoirs across the North Central Montana Basin, with more than 0.59 BBO and more than 4.73 TCFG having been produced from the basin to date (Fox and Dolton, 1995b and WOGCC, 2006).

Figure 6.23 Geologic Setting and Produced Water Quality Distribution of the Wind River Basin



(Source: USGS, 2005)

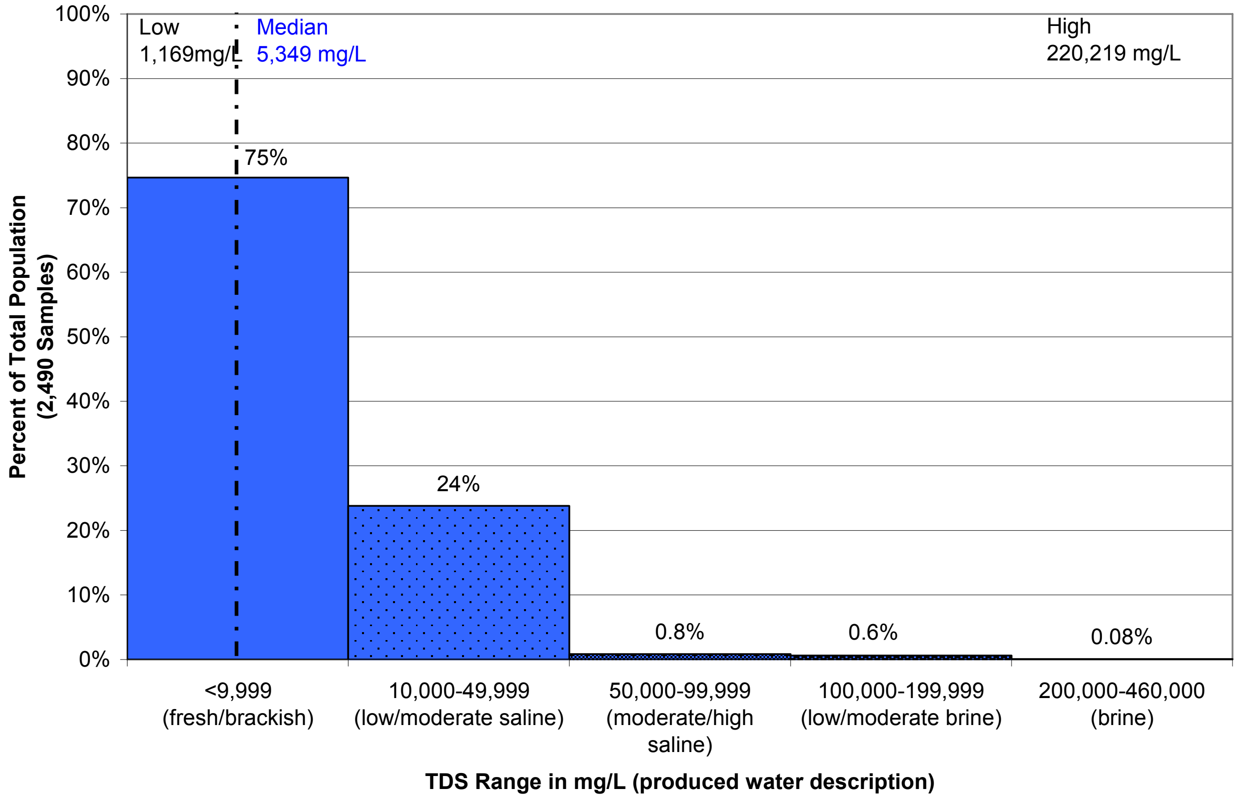
In 2005, the Wind River Basin produced 3.95 million bbls of oil, 245.8 BCF of gas, and 209 million bbls of water (WOGCC, 2006). No CBNG is currently produced in the basin.

Produced Water Management

The numerical distribution of produced water quality for the Wind River Basin is shown in Figure 6.24. The USGS produced water database contains 2,490 individual samples for the Wind River Basin. Produced water salinity in the basin includes all of the ranges identified for analysis in this study from <10,000 mg/L to >200,000 mg/L TDS. Median salinity expressed as TDS was low at 5,349 mg/L (brackish water) (Figure 6.24). Salinity values for the Wind River Basin ranged from 1,169 mg/L (slightly brackish) to 220,219 (brine). The largest percentage (75%) of the water quality samples have TDS concentrations <10,000 mg/L. The next highest distribution percentage (24%) was the 10,000 mg/L to 49,999 mg/L range. The remaining 1.5% was distributed between the 50,000 mg/L to 99,999 mg/L (0.8%) range, the 100,000 mg/L to 199,999 mg/L (0.6%) range, and the 200,000 mg/L to 460,000 mg/L (0.08%) range.

Figure 6.23 documents the distribution of water quality samples across the Wind River Basin showing how the produced water quality varies. The geographical distribution of water salinity indicates that the highest produced water quality samples are distributed all across the basin. Produced water of the fresh to brackish quality (0 mg/L to 9,999 mg/L TDS) is located throughout the basin with most of this higher quality water likely located in shallow formations receiving recharge from the surface (Figure 6.23). Much of this water could have local beneficial uses. The produced water quality of low-to-moderate saline waters (10,000 mg/L to 49,999 mg/L) similarly are distributed across the basin and are likely produced from the deeper formations. The lower quality produced water samples (>50,000 mg/L) are located toward the north-central portion of the basin, but represent only a small percentage of the total samples (<2%).

Figure 6.24 Water Quality Distribution in the Wind River Basin



(Source: USGS, 2002)

The large volumes of water are of varying quality ranging from less than 300 mg/L to much stronger brines. Deep gas reservoirs typically produce very high quality water that likely represents condensed water present as vapor in the subsurface; this water could have local beneficial uses for agriculture and livestock watering. Oil reservoirs produce water at rates up to 100 times the rate of crude oil production; this water is most often injected back into the oil reservoirs to support oil production.

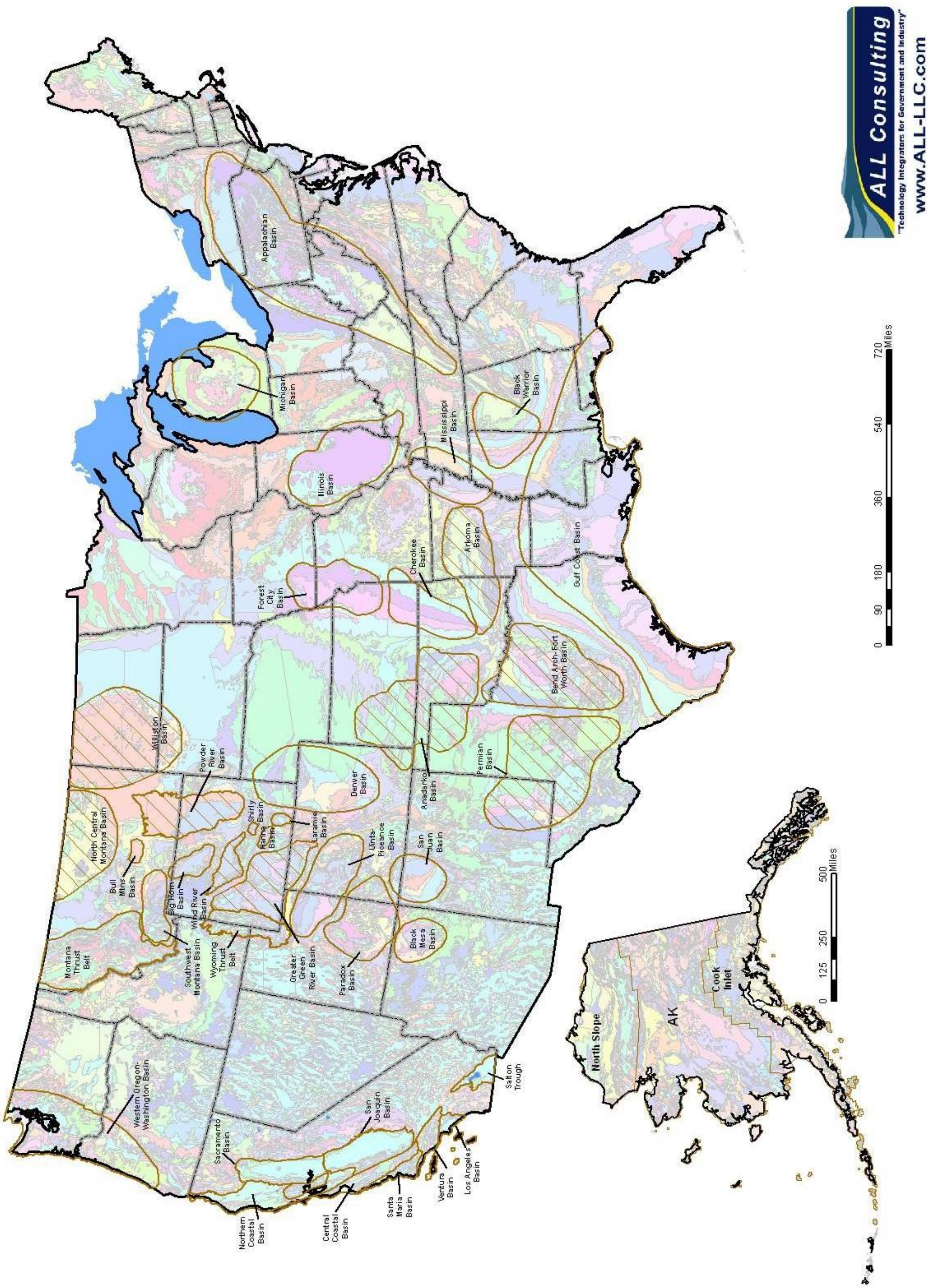
THIS PAGE INTENTIONALLY LEFT BLANK

SECTION 7.0 REGIONAL IMPLICATIONS TO PRODUCED WATER MANAGEMENT IN THE UNITED STATES

Section 6 presents a detailed analysis of several hydrocarbon producing basins located primarily in Alaska, Montana, Wyoming, Kansas, Oklahoma, and Texas. Several other major basins exist in the United States, as shown in Figure 7.1. The basins discussed in Section 6 provide a varied cross section of produced water issues sufficient to document the majority of proven water management practices utilized across the United States in the other basins shown in Figure 7.1. These issues include, but are not limited to:

- **Produced Water Characteristics –** The range in water quality is extreme across the United States. Produced water with TDS less than 10,000 mg/L may have significant beneficial uses for industrial and agricultural activities while water with a TDS greater than 50,000 mg/l has limited use other than enhanced recovery and will likely require injection disposal for proper management. Water quantity is difficult to predict because it is likely to change from well to well over time. Conventional wells typically yield more water as production progresses, while non-conventional plays, such as CBNG, may yield less water as production progresses. Regardless, understanding the water quality and quantity of a site is important when determining an appropriate water management practice.
- **Socio-economic and Political Setting –** Socio-economic setting can be quantified by population density and industrial activity. Areas with a higher population density will typically yield more complicated water management issues than areas of low population density, and areas with a high level of industrial activity might have use for water that is low in quality, or water demand may be high enough to offset the cost to treat the water to a usable level. Political setting is a concept that is best considered qualitatively; however, it can be noted that regions where split estate is common, (i.e. surface ownership has been severed from mineral ownership) the political setting can be detrimental for oil and gas development as the produced water management options may be limited by legal issues.
- **Climate Zones –** Annual rainfall and evapotranspiration (ET) are two elements of the weather that may play a role in the effectiveness of different produced water management practices. In areas where the average rainfall is close to, or less than, the average ET, produced water beneficial use (for produced water less than 10,000 mg/L TDS) can help to sustain farmers and ranchers through irrigation and water supply for livestock. Furthermore, these areas might be able to capitalize on marginal produced water (with a TDS less than 50,000 mg/L) by treating the water for beneficial use and disposing of the lower quantity waste stream.

Figure 7.1 Major Hydrocarbon Producing Basins of the United States



The culmination of these issues often dictates regional-specific problems and solutions that are not always shared outside that region. However, various regions can benefit from sharing problems experienced in other regions, and how operators have met with success (and failure) when solutions to these problems are employed in the field. This section attempts to close the information gap between hydrocarbon producing regions by identifying and sharing applicable produced water management practices that may have implications outside of their current region. Furthermore, in light of recent concerns that produced water can and should be treated as a resource rather than as a waste, this section provides a forward looking discussion in terms of treating and beneficially using produced water of marginal quality (i.e. with a TDS value greater than 10,000 mg/l, but less than 50,000 mg/l) versus wholesale disposal of this resource.

Section 7.1 Water Quality and Quantity

The range in water quality across the United States is great, as shown in Figure 7.2, which suggests that produced water has many possible origins, as described in Section 2. For example, large areas within the arid Great Plains and adjacent to recharge areas in the Rocky Mountains contain water that is low in TDS and has potential beneficial uses. The low TDS produced water often represents infiltrated meteoric water that enters porous strata at the outcrops on the edge of large basins.

Water quality may be the single most important factor when considering the water management practice selected. Table 7.1 illustrates a numerical summary of the water quality statistical analyses in the oil and gas basins discussed in Section 6. Produced water less than 10,000 mg/L might have significant beneficial uses for industrial and agricultural activities, and produced water less than 50,000 mg/L may have the potential to be treated and beneficially used in the same manner. Figure 7.3 is a graphical representation of the same data that shows how the basins compare to one another in terms of water quality. In Figure 7.3 the basins are ranked by percent of produced water that is either usable in the raw form (less than 10,000 mg/L) or marginal quality water that is treatable (less than 50,000 mg/L).

Of the basins analyzed, the following basins had a high percentage of high to marginal quality produced water that may be used or treated for beneficial uses: Alaska North Slope (100%), North Central Montana (99%), Bighorn (99%), Wind River (99%), Alaska Cook Inlet (99%), Powder River (93%), and Greater Green River (88%). The Arkoma Basin has a moderate percentage of usable or treatable water (42%). In many instances, the water from these basins is already being put to beneficial uses such as irrigation, stock and wildlife watering, supplemental public water supply, and fish hatcheries, to name a few. However, the actual implementation of these beneficial uses might not be realized to the fullest extent possible for a number of reasons (i.e. regulatory barriers, public outcry, economic barriers). It is important for produced water that is fresh or marginal in quality be recognized and utilized as a resource across the entire United States, especially in arid regions where water is not always in abundance.

Water with salinity above 50,000 mg/L is either cost prohibitive or technologically incapable of being treated for traditional beneficial uses. However, this water can be used for enhanced recovery water injection projects or recycled for multiple hydraulic fracturing jobs. As discussed in Section 6, this is a common practice is most basins, and more notably so in older fields that have been exploited for many years.

Figure 7.2 Total Dissolved Solids of Produced Water in the United States

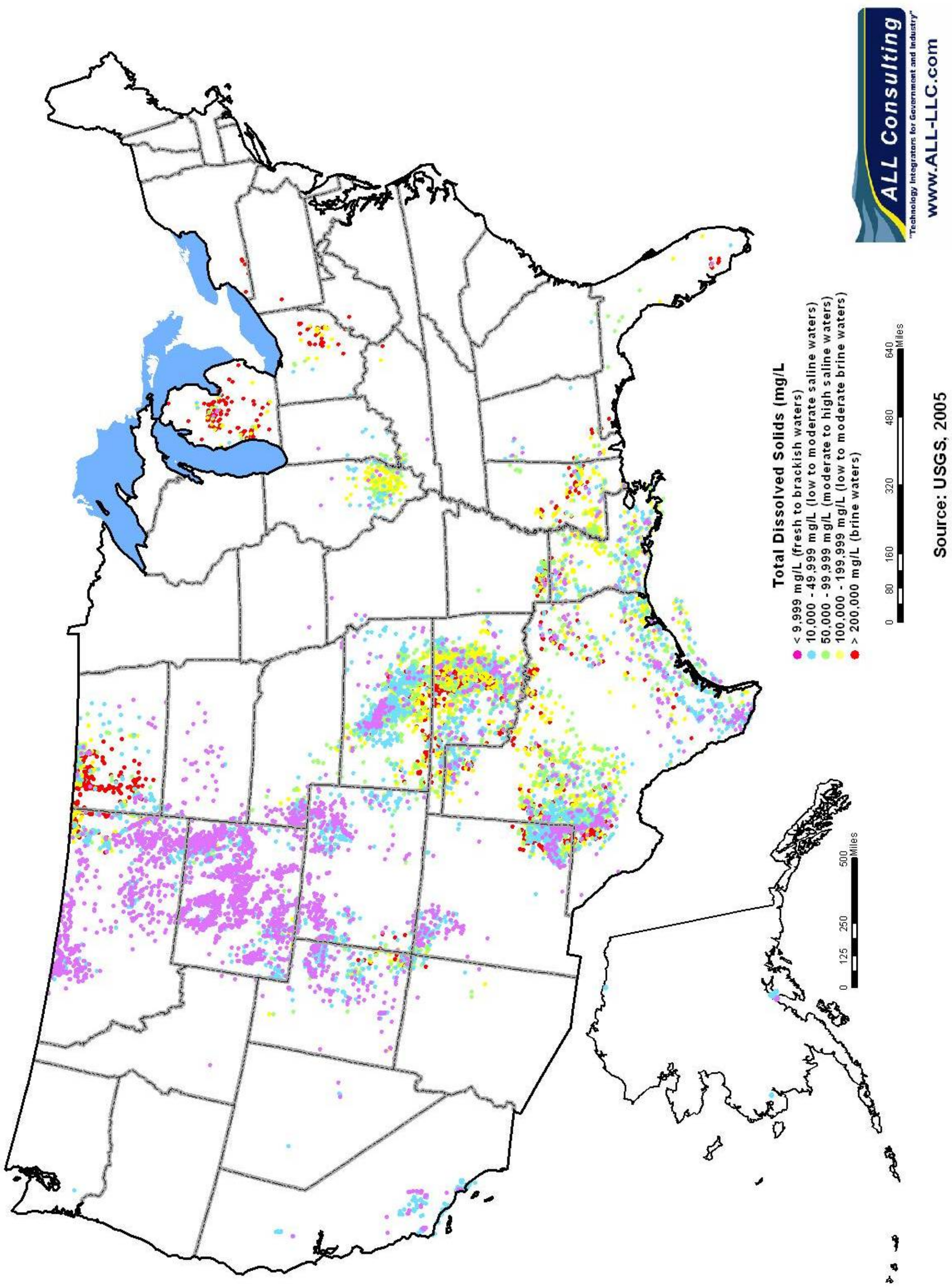
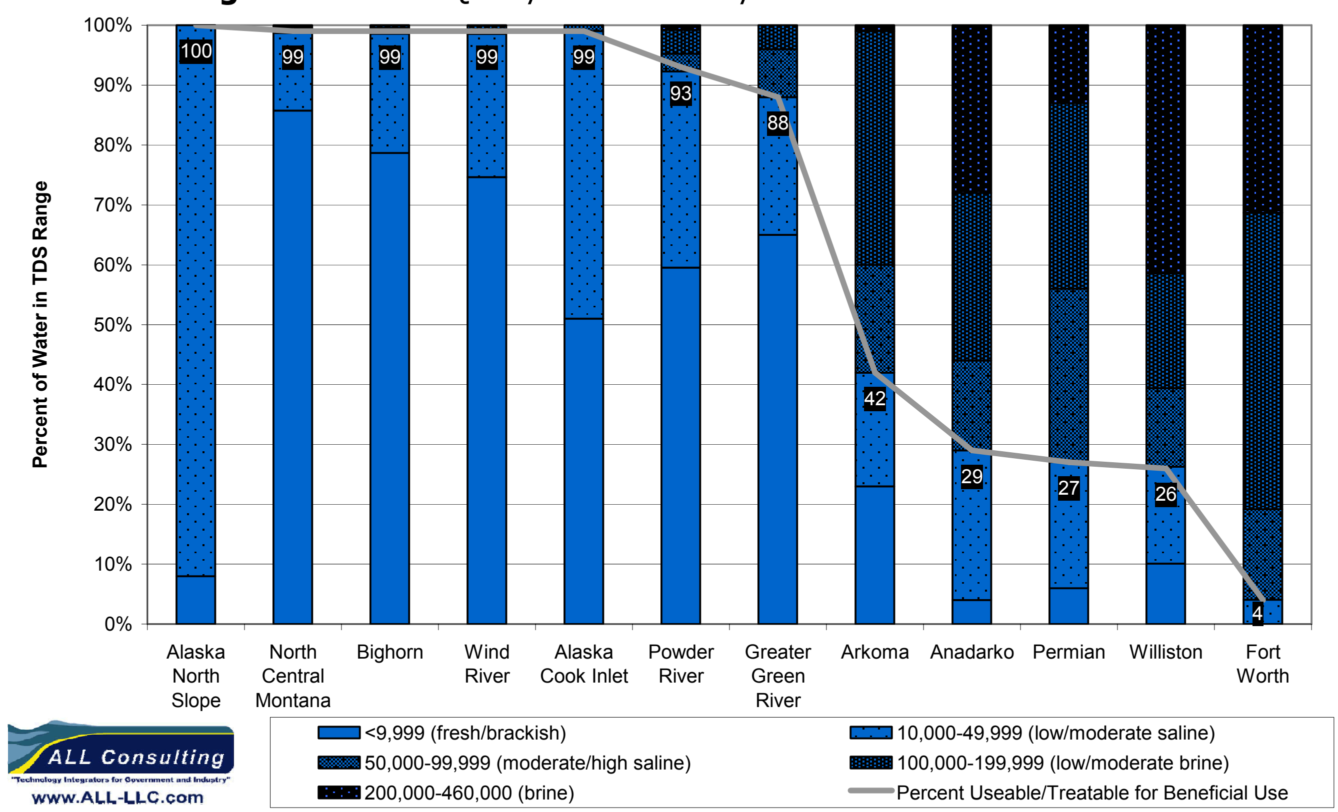


Table 7.1 Summary of Produced Water Quality Statistics

Basin Name	Produced Water Quality Percentage for Ranges (mg/L TDS)				
	0 – 9,999	**10,000 – 49,999**	**50,000 – 99,999**	**100,000 – 199,999**	**200,000 – 460,000**
Alaska North Slope	8	92	0	0	0
Alaska Cook Inlet	51	48	1	0	0
Anadarko Basin	4	25	15	28	28
Arkoma Basin	23	19	18	39	1
Bighorn Basin	79	20	1	0.4	0.04
Fort Worth Basin	0	4	15	49	31
Greater Green River	65	23	8	4	0
North Central Montana	86	13	0.5	0.3	0.5
Permian Basin	6	21	29	31	13
Powder River Basin	60	33	3	4	0.8
Williston Basin	10	16	13	19	41
Wind River Basin	75	24	0.8	0.6	0.08

Figure 7.3 Water Quality Statistical Analysis of Select Oil and Gas Basins



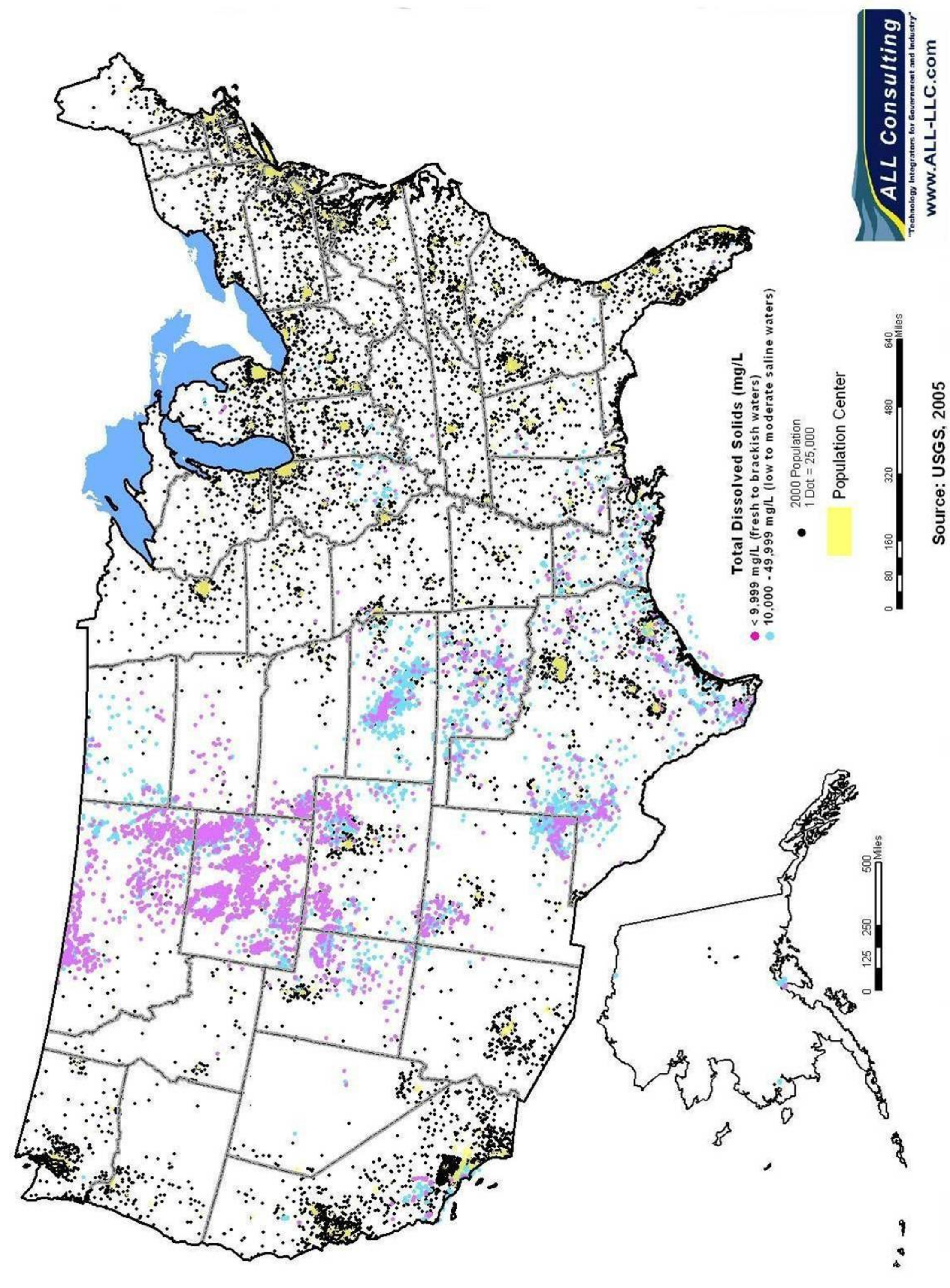
Water quantity also can play a role in deciding how best to manage produced waters. Some potential industrial applications of produced water, such as cooling water for a power generation facility, need a reliable source of water in terms of daily quantity, longevity, and quality. Some industrial sites would prefer to pay for a reliable source of water that they know will be available to them rather than rely on a free source of water that may diminish or be cut off over time. This stems from the fact that water quantities are highly variable from field to field; therefore making broad generalizations about water quantities for different basins is not recommended. Furthermore, the dynamics of produced water quantities can vary as the field is developed. Conventional fields typically yield more water as production progresses, while non-conventional plays such as CBNG might yield less water as production progresses. However, operators can develop a site-specific understanding of their projected water quantities by tracking the water they produce, and therefore instill a better understanding of their water management options that can utilize the water in a beneficial manner and be more economical in the future.

Section 7.2 Socio-Economic Setting

The socio-economic setting of a region can influence the options for how produced water is managed in that region. For purposes of exploring this idea further, socio-economic setting is quantified by population density and potential industrial uses. Areas with a higher population density typically will yield more complicated water management issues than areas of lower population density; however, the high population density areas may have a greater demand for water supply. Figure 7.4 provides a geographical distribution of water that is generally considered treatable (TDS < 50,000 mg/L) and population density across the contiguous United States. Areas can be identified from this map that might provide suitable water management solutions in high population areas. For example, the city of Denver is located near sources of usable and treatable produced water.

The impact of socio-economic setting is also evident when dealing with low quality water in areas such as the de-watering project in the Oklahoma City field of the Anadarko basin and the Barnett Shale play in and around Fort Worth, Texas. Surface use of the land in these densely populated areas precludes the drilling of wells at several well pad sites. Rather, multiple horizontal wells can be drilled from one well pad in various horizontal directions, which in turn can raise the costs of drilling when compared to similar projects in rural Oklahoma and Texas. In the Anadarko Basin the water is either re-injected for enhanced recovery, or it is injected into a horizontal disposal well capable of handling more than 60,000 barrels of water per day. In the Barnett Shale play the water may be recycled for use on fracturing additional wells in the area, thus saving the operator money on the cost of water for the fracture job, and saving local residents the burden on their local water supply.

Figure 7.4 Oil and Gas Basins compared to Population Density of the Contiguous United States



Another factor that population density can be a predictor of is qualified and available work force. In general, highly populated areas have a larger pool of potential workers, and therefore it can be easier to find a suitable labor force. Rural areas may not have immediate work force available, which in turn can raise the cost of a drilling program if the work crew is transported in from another region. This does not necessarily impact the water management options available, but it can impact the overall cost of the drilling program, which indirectly can impact the ability to economically treat and beneficially use produced water of marginal quality.

In regions where split estate is a common occurrence, (i.e. surface ownership has been severed from mineral ownership) the political setting might be unfavorable for oil and gas development because the produced water management options might be limited by legal issues between surface and mineral owners. This has been an issue with the CBNG resources in the Powder River Basin of Montana where federal mineral ownership is a common occurrence.

Section 7.3 Annual Rainfall and Evapotranspiration

Annual rainfall and evapotranspiration (ET) are two elements of the weather that can play a role in the effectiveness of different produced water management practices. Figures 7.5 and 7.6 provide estimates for the annual average rainfall and annual average lake evaporation rates, and Figure 7.7 provides a state-by-state estimate of the water available for ET in the United States. The water available for ET was calculated on a state-by-state basis by examining statewide water budgets:

Precip. + Surf. In-flow – Surf. Out-flow –Consumption = Water Available for ET

These figures can be used together to identify areas with a net zero or negative supply of water. For example, in the Big Horn and Powder River Basins the annual lake evaporation is between 40 and 50 inches per year (Figure 7.6); however, there is less than 10 inches per year available for ET (Figure 7.7). Therefore, the region in general is in need of water for irrigation as the evaporation rate is 4 to 5 times greater than the water available for ET.

If the produced water in these water starved areas is sufficient in quality for beneficial use (TDS less than 10,000 mg/L) the water can help to sustain farmers and ranchers through irrigation and water supply for livestock. Furthermore, these areas also might have the ability to use produced water that is marginal in quality (TDS less than 50,000 mg/L) by treating the water for beneficial use and disposing of a lower quantity waste stream.

Figure 7.5 Annual Average Rainfall in the Contiguous United States and Alaska

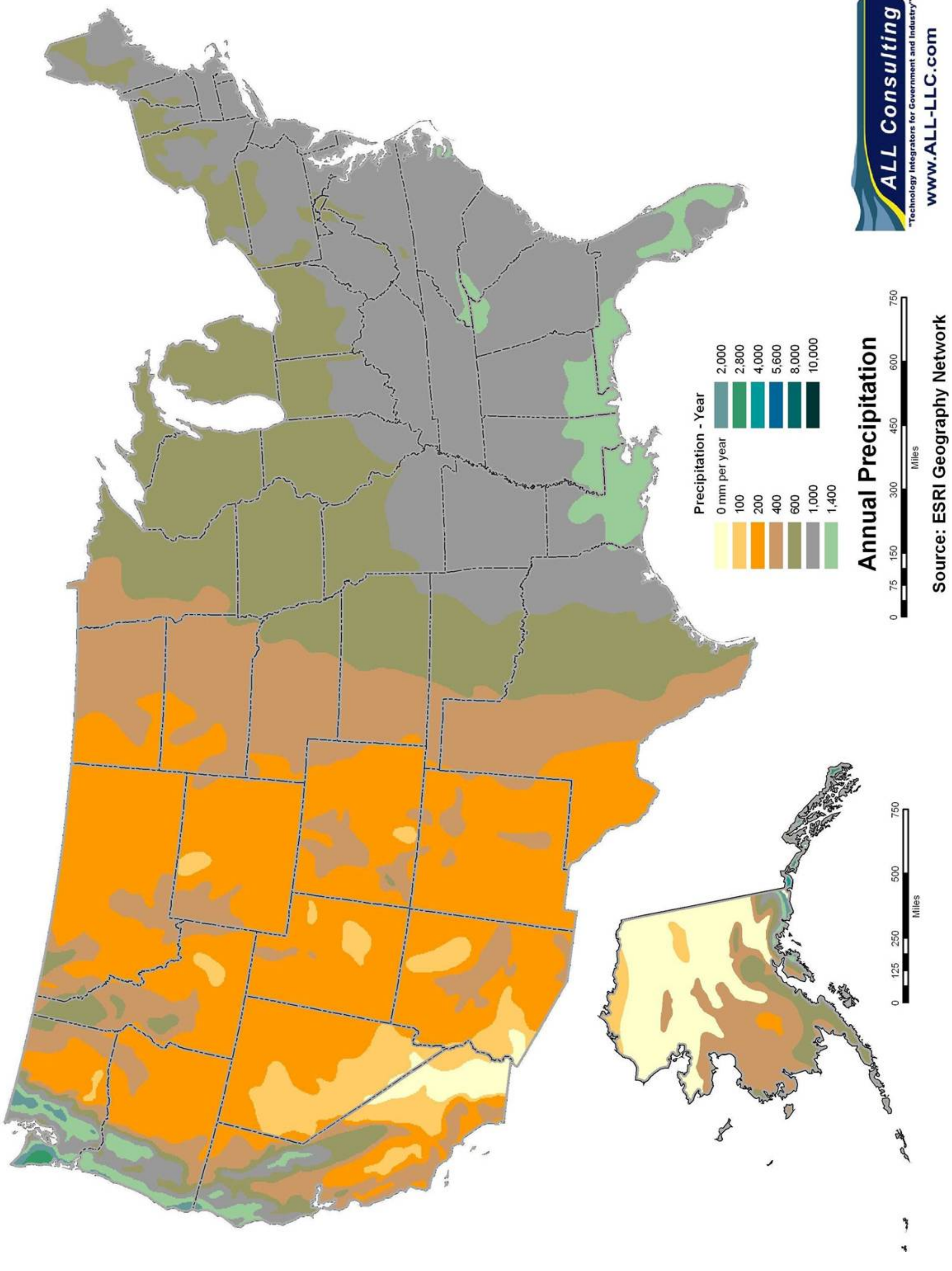


Figure 7.6 Annual Average Lake Evaporation in the United States

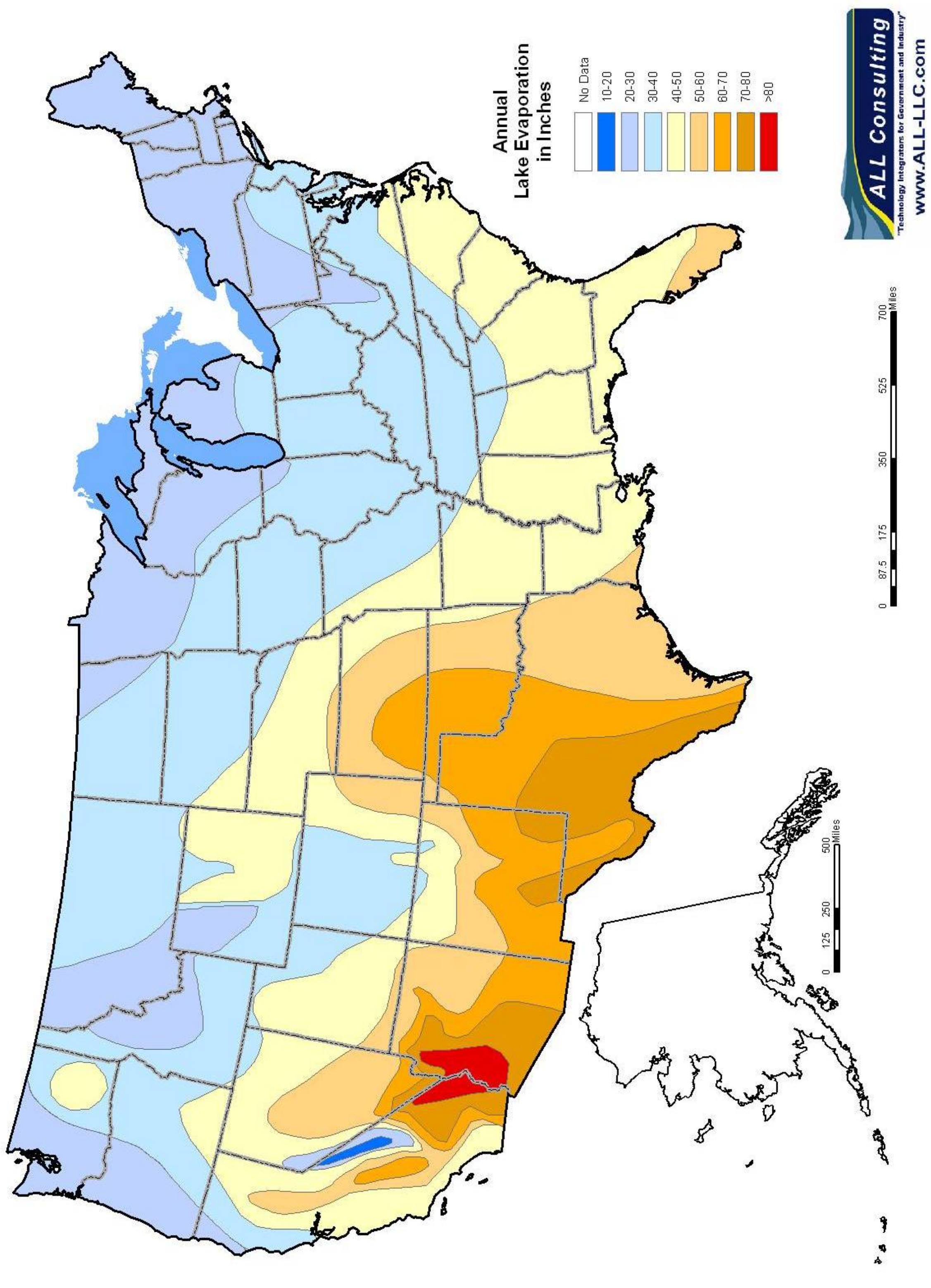
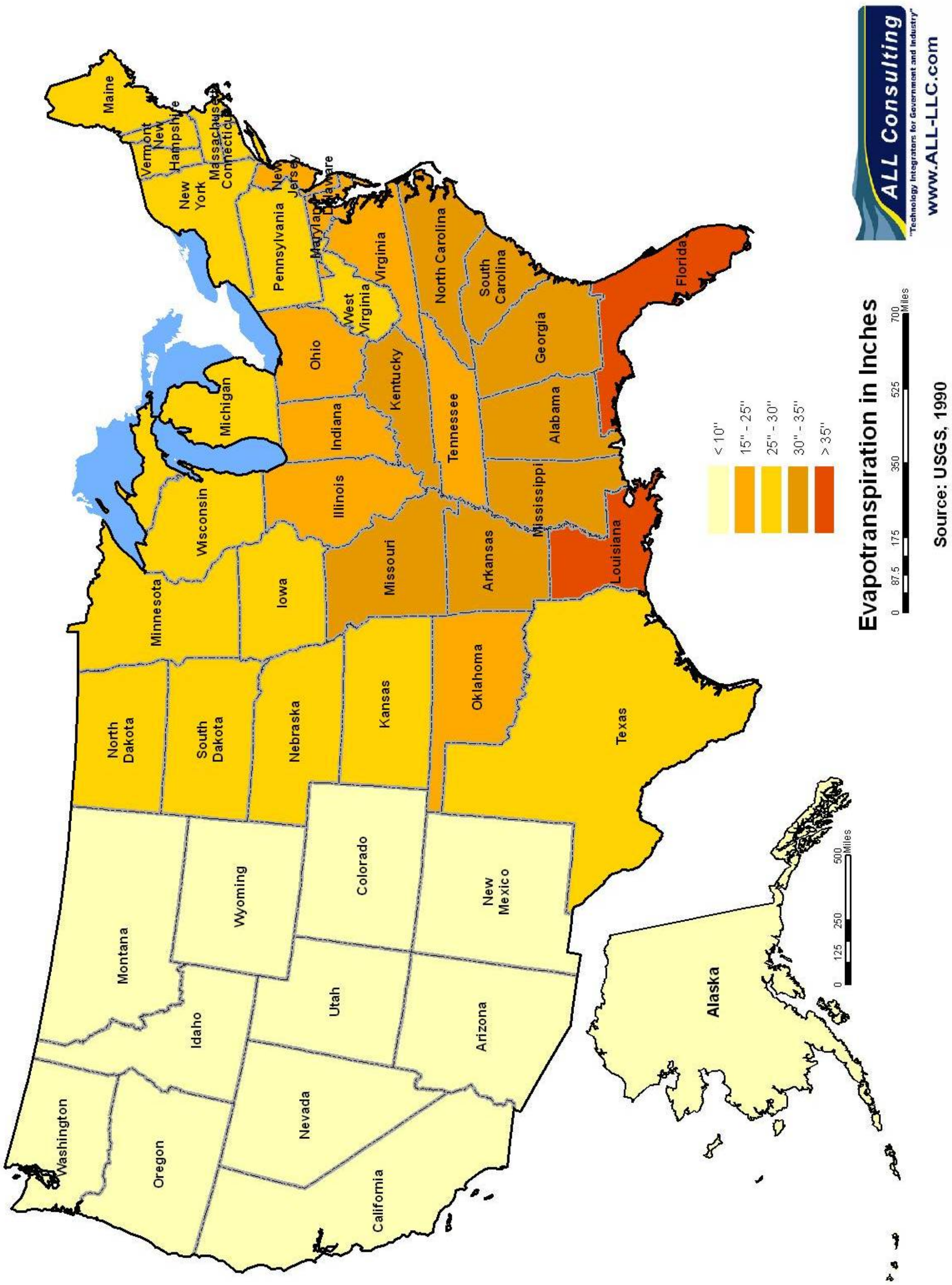


Figure 7.7 Annual Average Water Available for Evapotranspiration in the United States



The arid Western states provide several other examples where evaporation rates far exceed the water available for ET. In general, the water available for ET in these states is less than 10 inches per year; however, several basins intersect areas where evaporation is as high as 60 inches per year and rainfall is not more than 20 inches per year. These include several basins where beneficial uses of the water are common, and have been for several years, such as the Big Horn Basin, the North Central Montana Basin, the Powder River Basin, and the San Joaquin Basin in California. Other areas that might not be as obvious include the Arkoma Basin of Arkansas and Oklahoma. The water available for ET (25-35 inches per year) is relatively high, but when compared to the average annual lake evaporation (between 40 and 60 inches per year) a potential need for irrigation water can be identified because the evaporation rate can be as much as twice the amount available for ET. Furthermore, the water quality in some portions of the Arkoma Basin is of sufficient quality for beneficial uses such as flood irrigation and livestock watering; however, a large percentage of this high quality water is being disposed of in commercial disposal wells. BP has initiated a pilot program to use this water beneficially in coordination with the Oklahoma Corporation Commission and the local landowners in the Red Oak field. Similar programs may be feasible in the basin where water can be economically managed while providing an asset to landowners.

Historic annual precipitation and evapotranspiration ratios have changed in the past few years with a widespread drought in the upper Great Plains (Handwerk, 2005). This drought has lowered average annual precipitation and could be a cyclic phenomenon or a manifestation of Global Climate Change (Linden, 2006). Over the last century, the average temperature in Laramie, Wyoming, has increased 1.5°F. Precipitation has decreased by up to 20% in many parts of the state. Over the 21st Century, climate in the Great Plains may change even more due to the increases in greenhouse gases. By 2100, for example, temperatures in Wyoming could increase by 4°F in spring and fall, 5°F in summer, and 6°F in the winter. If temperatures and evaporation increase as forecast and the drought continues, surface water resources could be reduced drastically across the Great Plains. This could lead to severe competition for groundwater resources, including lesser quality groundwater that may require pre-use treatment.

If this drought is a long-term climatic development for the Great Plains and adjacent areas, potential beneficial uses for produced water gain importance. If precipitation is indeed to be lower throughout the future, produced water may become valuable for augmenting base-flow in streams and supplying water to cities and towns. Competition for scarce water resources might lead to increased value for higher quality produced water and may lead to large scale treatment of lower quality water prior to its use. Important uses might include protection of habitat within the riparian zone, supplement to irrigation and animal husbandry, or supplement to drinking water systems in towns and cities of the Great Plains. If global climate change is occurring, beneficial use of the water produced with oil and gas will become more important.

Section 7.4 Potential for New and Innovative Beneficial Uses

As previously mentioned, the culmination of water quality, quantity, socio-economic setting, and climatic conditions often lead to the development of regional-specific produced water management solutions. The potential exists for implementing new and/or innovative management solutions for produced water by identifying and sharing applicable produced water management practices that may have implications outside of their current region. The purpose of this document is to serve as a tool for achieving this goal.

In light of recent drought concerns and water shortages in many western states, produced water can be treated as a resource rather than as a waste product. In Section 7.2, basins were identified where a large portion of the produced water had quality that is currently deemed as "usable" (TDS values <10,000 mg/l) or "treatable" (TDS values >10,000 mg/l, but <50,000 mg/l) versus wholesale disposal of this resource. The identified basins include the Alaska North Slope, North Central Montana, Bighorn, Wind River, Alaska Cook Inlet, Powder River, Greater Green River, and the Arkoma. Basins identified as having a small percentage of beneficially usable or treatable water were the Anadarko, Permian, Williston, and Fort Worth, where the current practice of injection, whether it be for enhanced oil recovery, or strictly for disposal, seem to be the most practical options in these basins. Furthermore, of the basins with a large percentage of beneficially usable or treatable water, the socio-economic setting and climatic conditions were not favorable for taking advantage of the quality of the water in the two Alaskan basins (North Slope and Cook Inlet).

Marginal to Low Quality Water Basins

The Anadarko, Permian, Williston, and Fort Worth Basins fall within a scattering of population and industry ranging from large cities to strictly rural expanses. The precipitation regime of the basin is largely semiarid with an average rainfall between 15 and 30 inches per year (Figure 7.5), suggesting that surface water is a scarce commodity in these basins. There are a number of population centers as shown on Figure 7.4. Besides the historic petroleum industry, other forms of industry would include ranching and agriculture, which use copious amounts of water. The relatively low quality of the produced water of the basins, however, mitigates against its widespread use even for livestock watering. With low percentages of the reported produced water samples having less than 10,000 mg/L, it is unlikely that water in these basins would have industrial uses. A large percentage of the produced water quality samples from these basins was of poor quality with a TDS greater than 50,000 mg/L. If technologically possible, the costs of treating this water would be fairly high. Most industry users would prefer to use higher quality groundwater obtained locally if it can be attained economically.

Another use that may become more important if the current drought discussed in Section 7.4 continues is that produced water could be used for brush fire control. Brush fires have become more prevalent in the past several years across the United States. Depending upon their location, the large grass-fires and the need for water to control them may place undue stress on local reservoirs and aquifers that may have a higher use in support of agriculture or municipal water supply. High quality to marginal quality water produced through oil and gas operations could be used for fire suppression with minimal treatment. However, the means for transporting that water from the producing field where it is produced to the actual location of the fire may prove to be logistically complicated unless plans were made in advance to use the water in this manner.

High Quality Water Basins with Unfavorable Water Re-Use Conditions

As previously mentioned, the Alaskan North Slope and Cook Inlet have high percentages of beneficially usable and/or treatable quality water. However, these basins have other conditions that are unfavorable in regards to using the produced water. The low population density and the less than favorable annual climatic conditions lead to the conclusion that the current practice of injection, whether it be for enhanced oil recovery, or strictly for disposal, may be the most practical for Alaskan basins.

High Quality Water Basins with Favorable Water Re-Use Conditions

By considering water quality, socio-economic setting, and climatic conditions, the following basins have favorable characteristics for beneficially using produced water: North Central Montana, Bighorn, Wind River, Powder River, Greater Green River, and the Arkoma.

All of the basins in this category are almost predominantly rural with small cities dispersed throughout. They include some of the driest regions in the country with several locations averaging less than 5 inches of rain per year. In addition to the arid conditions, the basins in Montana and Wyoming have been in a prolonged drought since 1999 (NCDC, 2006) where precipitation has averaged only 84% of the historic annual value.

In the Bighorn Basin it is mostly agricultural users and local ranchers who have come to rely upon produced water for irrigation. The reliance is especially important during times of drought when rainfall can be very low. The basin appears to produce large volumes of high quality water that can be used for both stock watering and irrigation. The Bighorn Basin is similar in characteristics to other basins in Wyoming and Montana but unlike the others it has developed a system for utilizing produced water in the furtherance of agriculture. Therefore, the other basins in Montana and Wyoming have the potential for beneficially using the produced water in a way that can further the ability of farmers and ranchers.

The Arkoma Basin is spread across forested portions of eastern Oklahoma and western Arkansas. It is an area with small population centers and ample rainfall of 30 to 50 inches per year. Agriculture is the common industrial activity including confined animal feeding operations (CAFO). As discussed in Section 4, water requirements are greater at CAFO facilities when compared to range livestock; therefore, there might be a local demand for water that could be satisfied with produced water. The quality of the local produced water may mean that treatment is required and the demand for water might allow the user to pay for the treatment. Over 20% of the water tested from this basin is less than 10,000 mg/L and a smaller portion is high enough in quality to use for irrigation. These minor volumes of produced water have begun to play a local role in the Red Oak field, but due to the low volumes of the water produced it appears to have minimal affect on the economics of the region.

Population Centers Drive Water Demand

Southern California is a good example of how high density population centers can drive water demand to the point that new and innovative ways to treat and use water become a necessity. Municipal water district planners in Southern California predict that future water supply in the region will fall short of urban demand by 2020 without development of new water resources and increased conservation savings (UCR, 1999). Figure 7.4 shows that the produced water generated from nearby basins, such as the San Joaquin Basin, may be of suitable quality that it can either be treated for human consumption or it may continue to be used for irrigation purposes on orchards to offset the demand for treated water. Basins upstream of Southern California near the Colorado River (Unita-Piceance, San Juan, Paradox) also might be suitable to discharge water to the Colorado River system, thus providing additional water resources to downstream users in California. Other potential markets that might couple well with oil and gas producing basins include the Denver Basin with the Denver Metro Area, the Uinta-Piceance or the Greater Green River Basins with the Salt Lake City metro area, and the Forest City Basin with the Kansas City Metro area.

Section 8.0 References

AAPG, 1992. Geothermal Map of the United States.

AAPG, 2006: *Barnett Shale a Stimulating Play,* in AAPG Explorer, Feb 2006.

Alyeska Pipeline, 2006: Pipeline Facts: North Slope. accessed on March 7, 2006 @ http://www.alyeska-pipe.com/Pipelinefacts/North%20Slope.html.

Alaska Department of Natural Resources, 2003: Cook Inlet Oil & Gas. Department of Natural Resources. Division of Oil and Gas. Prepared by Tim Ryherd, Geologist, State of Alaska. July 29, 2003.

Alaska Department of Natural Resources, 2004: Oil and Gas Report. Division of Oil and Gas. accessed at: http://www.dog.dnr.state.ak.us/oil/products/publications/annual/2004_annual_report/Section1.pdf

Alaska Department of Natural Resources, 2006: Alaska Oil and Gas Activities. Division of Oil and Gas. Prepared by William Van Dyke, Acting Director, Alaska Department of Natural Resources. January 17, 2006. Advanced Resource International (ARI) for the U.S. EPA, 1994, 68-W-00-094. "Fracturing Technologies for Improving CMM/CBNG Production".

ALL Consulting (ALL) and Montana Board of Oil and Gas Conservation (MBOGC), 2002. Handbook on Best Management Practices and Mitigation Strategies for Coal Bed Methane in the Montana Portion of the Powder River Basin, prepared for United States Department of Energy – National Petroleum Technology Office, April 2002.

ALL Consulting (ALL), July 2003. Handbook on Coal Bed Methane Produced Water: Management and Beneficial Use Alternatives. Prepared For the Ground Water Protection Research Foundation, U.S. Department of Energy - National Petroleum Technology Office, Bureau of Land Management.

ALL Consulting (ALL), 2005. "Reducing Produced Water Volumes from Coal Bed Natural Gas in the Powder River Basin".

ALL Consulting (ALL), 2005. Technical Summary of Oil and Gas Produced Water Treatment Technologies.

ALL Consulting (ALL), 2006. "Feasibility Study of Expanded Coal Bed Natural Gas Produced Water Management Alternatives in the Wyoming Portion of the Powder River Basin: Phase I".

ALL Consulting (ALL), 2006. "Phase One: Feasibility Study of Expanded Coal Bed Natural Gas Produced Water Management Alternatives in the Wyoming Portion of the Powder River Basin".

ALL Consulting and MBOGC, 2004. Coal Bed Methane Primer: New Source of Natural Gas – Environmental Implications, Background and Development in the Rocky Mountain West, Prepared for: U.S. DOE National Petroleum Technology Office.

Argonne National Laboratory, 2002. Regulatory Issues Affecting Management of Produced Water from Coal Bed Methane Wells, Argonne National Laboratory, prepared for U.S. DOE Office of Fossil Energy.

American Petroleum Institute (API), 2006. "Where does the U.S. produce oil and natural gas?" Accessed online at: http://www.api.org

Aston, M.S., et al, SPE Paper 87130, March 2004. "Drilling Fluids for Well-bore Strengthening".

Barrufet M.A., Iglesias-Silva G., Petriciolet A., Patel C.V., and Burnett D., 2004. "A Modular Design And Implementation of A Brine Conversion Process: Oil Removal and Desalting Units," paper presented at the 11th IPEC, Albuquerque, NM.

Baker, Tim, 2005. Personal conversation between Dr. Langhus and Jake Crissup of ALL Consulting and Tim Baker of the Oklahoma Corporation Commission.

Ball, Mahlon, 1995. Permian Basin Province (044), in Gautier, D. L., Dolton, G.I., Takahashi, K.T., and Varnes, K.L., eds., 1995 National assessment of United States oil and gas resources--Results, methodology, and supporting data: U.S. Geological Survey Digital Data Series DDS-30.

Ball, M., and W. Perry, 1995. Bend Arch-Fort Worth Basin Province (045), in Gautier, D. L., Dolton, G.I., Takahashi, K.T., and Varnes, K.L., eds., 1995 National assessment of United States oil and gas resources--Results, methodology, and supporting data: U.S. Geological Survey Digital Data Series DDS-30.

Bein, A. and A. R. Dutton, 1993. Origin, distribution, and movement of brine in the Permian Basin: A model for displacement of connate brine. GSA Bull., vol. 105, pp. 695-707.

Blackwell, D. D., and M. C. Richards, 2004. Geothermal Map of North America, scale 1:5,000,000, AAPG, Map Code #423, April 2004.

Blackwell, D.D. et al, 2006. Geothermal Resources in Sedimentary Basins, 2006 SMU Geothermal Conference, Dallas, March 2006.

Bost A.L., and Reid T., 2004. "Powder River Gas L.L.C. Coal Creek CNBG POD – Hydrology Technical Report," BLM Montana (November 2004).

Bureau of Economic Geology, 2002. Play Analysis and Digital Portfolio of Major Oil Reservoirs in the Permian Basin: Application and Transfer of Advanced Geological and Engineering Technologies for Incremental Production Opportunities. Performed in cooperation with the New Mexico Bureau of Geology and Mineral Resources.

Cline, J., December 13, 2005. Personal conversation between Dr. Langhus and Jeff Cline of Anadarko Petroleum.

Cohen, Y., J. Glater, A. Tsao and R-W Lee, September 9-13, 2001. "Nanofiltration Membranes for Agricultural Drainage Water Reclamation," Paper published in the proceedings of the International Conference on Membrane Technology for Wastewater Reclamation and Reuse, Tel-Aviv, Israel.

Comer, J.B., 1992. Organic geochemistry and paleogeography of Upper Devonian formations in Oklahoma and northwestern Arkansas, in K.S. Johnson and B.J. Cardott, eds., Source rocks in the southern Mid-Continent, 1990 symposium: OGS Circular 93, p. 70-93.

Davies, S. and D. Widawsky, 1995. The Impact of the Changing Size of Feedlots on Corn Marketing in Colorado. Journal of the American Society of Farm Managers and Rural Appraisers, Volume 59, No. 1: Pg 120-127.

DeJarnett, B., F. Lim, and D. Calogero, 1997: Greater Green River Basin Production Improvement Project, prepared for the U.S. Department of Energy's Federal Energy Technology Center and Union Pacific Resources Company.

Dolton G., and J.E. Fox, 1995: Powder River Basin Province (033), in Gautier, D. L., Dolton, G.I., Takahashi, K.T., and Varnes, K.L., eds., 1995 National assessment of United States oil and gas resources--Results, methodology, and supporting data: U.S. Geological Survey Digital Data Series DDS-30.

The Dow Chemical Company (Dow), 2003. "A Low Cost Option to Reduce Sodium Levels in Coal Bed Methane Coproduced Wastewater using DOWEX G-26 Resin," DOWEX Ion Exchange Resins.

Doyle D.H., Daniel F., and Brown A.B., 1997. "Field Test of Produced Water Treatment with Polymer Modified Bentonite," paper SPE 38353 presented at the 1997 Rocky Mountain Regional Meeting, Casper, Wyoming.

Dutton, S., E. Kim, R. Broadhead, C. Breton, W. Raatz, S. Ruppel, and C. Kerans, 2004: Play Analysis and Digital Portfolio of Major Oil Reservoirs in the Permian Basin: Application and Transfer of Advanced Geological and Engineering

Technologies for Incremental Production Opportunities. Prepared by the Texas Bureau of Economic Geology and New Mexico Bureau of Geology and Mineral Resources.

Dyman, T.S., 1995: North-Central Montana Province (028), in Gautier, D. L., Dolton, G.I., Takahashi, K.T., and Varnes, K.L., eds., 1995 National assessment of United States oil and gas resources--Results, methodology, and supporting data: U.S. Geological Survey Digital Data Series DDS-30.

Evergreeen Resources Inc., CBM-1: A Supplement to the Oil & Gas Investor, December 2002. "Opportunities in CBNG".

Forbis, P., February 2006. *Agency Approves Fluid Recycling of Frac Fluids in Pilot Project,* in Texas Drilling Observer Newsletter, vol 7, Issue 4.

Fox, J.E., and G. Dolton, 1995a. Bighorn Basin Province (034), in Gautier, D. L., Dolton, G.I., Takahashi, K.T., and Varnes, K.L., eds., 1995 National assessment of United States oil and gas resources--Results, methodology, and supporting data: U.S. Geological Survey Digital Data Series DDS-30.

Fox, J.E., and G. Dolton, 1995b. Wind River Basin Province (035), in Gautier, D. L., Dolton, G.I., Takahashi, K.T., and Varnes, K.L., eds., 1995 National assessment of United States oil and gas resources--Results, methodology, and supporting data: U.S. Geological Survey Digital Data Series DDS-30.

Funston R., Ganesh R., and Leong Lawrence Y.C., 2002. "Evaluation of Technical and Economic Feasibility of Treating Oilfield Produced Water to Create a "New" Water Resource," paper presented at the 2002 Ground Water Protection Council (GWPC) meeting.

GE Infrastructure Water & Process Technologies (GE), 2006. "Membrane Filtration of Oil and Gas Field Produced Water".

GE Infrastructure Water & Process Technologies (GE), 2001. "Produced Water Pilot Study".

Groundwater Protection Council (GWPC), 2006. About Class I Injection Wells. accessed on March 2, 2006. http://www.gwpc.org/UIC/Well-Types/classi.htm

Gas Technology Institute (GTI), 2002. accessed at: http://www.gtionline.org/gti/main/main.cfm

Gibson, R.I., 1997. Greater Green River Basin: online at http://www.gravmag.com/grnriv.htm.

Guyer, P.Q. 1977. Water Requirements for Beef Cattle. University of Nebraska Cooperative Extension Service Bulletin G77-371-A.

Handwerk, B, June 14, 2005. Plains Drought Cycle Has Long History, Ominous Future, National Geographic News

Hayes T., 2004. "The Electodialysis Alternative for Produced Water Management," Gas Technology Institute (2004).

Hayter S., Tanner S., Urbatsch E., and Zuboy J., June 2004. "Saving Energy, Water, and Money with Efficient Water Treatment Technologies," DOE/EE-0294, A New Technology Demonstration Publication, Federal Energy Management Program.

Heck, Thomas J., R.D. LeFever, D.W. Fischer, and J. LeFever, 2002. Overview of the Petroleum Geology of the North Dakota Williston Basin, N.D. Geological Survey

Heins W., and Peterson D., June 2003. "Use of Evaporation for Heavy Oil Produced Water Treatment", a paper presented at the 4th Canadian International Petroleum Conference held in Calgary, Canada.

Henry, M. and T. Hester, 1995. Anadarko Basin Province (058), in Gautier, D. L., Dolton, G.I., Takahashi, K.T., and Varnes, K.L., eds., 1995 National assessment of United States oil and gas resources--Results, methodology, and supporting data: U.S. Geological Survey Digital Data Series DDS-30.

Hernon B., Zanapalidou H., Prato T., and Zhang L., 1999. "Removal of Weakly-Ionized Species by EDI," Ionics Inc.

Hutchinson, W., November 21, 2005. Personal conversation between Dr. Langhus and Wendy Hutchinson of Arch Coal Company.

Hunt, J. M., 1979. *Petroleum Geochemistry and Geology*: W. H. Freeman and Sons, San Francisco, 617.

Interstate Oil and Gas Compact Commission (IOGCC), 2005. "Marginal Oil and Natural Gas : American Energy for the American Dream"

Jackson, L., and J. Myers, October 16-17, 2002. "Alternative Use of Produced Water in Aquaculture and Hydroponic Systems at Naval Petroleum Reserve No. 3," presented at the 2002 Ground Water Protection Council Produced Water Conference, Colorado Springs, CO. (Paper available at http://www.gwpc.org/Meetings/PW2002/Papers-Abstracts.htm.)

Jackson, L.M., and J.E. Myers, October 2003. "Design and Construction of Pilot Wetlands for Produced Water Treatment," SPE 84587, presented at the SPE Annual Technical Conference and Exhibition, Denver, CO.

Kansas State University (KSU), November 2005. Kansas State University Research and Extension Department Website http://www.oznet.ksu.edu/sdi/Photos/Photos.htm.

Karlstrom, Thor N.V., 1964: Quaternary Geology of the Kenai Lowland and Glacial History of the Cook Inlet Region, Alaska. U.S. Department of the Interior. Geological Survey Professional Paper-443.

Lang K., 4th Quarter 2000. "Managing Produced Water", Hart Energy Publications Excerpts in Petroleum Technology Transfer Council Network News.

Law, Ben E., 1995, Southwestern Wyoming Province (037), in Gautier, D. L., Dolton, G.I., Takahashi, K.T., and Varnes, K.L., eds., 1995 National assessment of United States oil and gas resources--Results, methodology, and supporting data: U.S. Geological Survey Digital Data Series DDS-30.

Lawson, J., November 18, 2005. Personal conversation between Dr. Langhus and John Lawson of the United States Bureau of Reclamation.

Lincz R., December 2004. "Newpark's HB Reactor Water Treatment Technology Used for Anadarko Coal Bed Methane Produced Water Treatment for Discharge County Line Production Field", prepared by Newpark Environmental Services for DEQ-Water Quality Division.

Linden, E. 2006. *The Winds of Change*, Simon and Schuster, New York.

Marriage, L.D., Davison, V.E., 197.. Fish Ponds-Construction and Management. in: Teague, R.D., ed. A Manual of Wildlife Conservation. Washington D.C.. The Wildlife Society: 100-102.

"Membrane Filtration," Tech Brief, National Drinking Water Clearinghouse Fact Sheet (1999).

Mickley M., September 2001. "Membrane Concentrate Disposal: Practices and Regulation", prepared by Mickley & Associates for U.S. Department of The Interior under agreement no. 98-FC-81-0054, Desalination and Water Purification research and Development Program Report No. 69.

Moftah K., October 2002. "High pH RO for Wastewater Treatment," Pollution Engineering.

Murphree, P., 2005. Personal conversation between Dr. Langhus and Mr. Murphree of Peabody Coal Company.

Myers J.E., Jackson L.M., Bernier R.F., and Miles D.A., 2001. "An Evaluation of the Department of Energy Naval Petroleum Reserve No. 3 Produced Water Bio-Treatment Facility," paper SPE 66522 presented at the 2001 SPE/EPA/DOE Exploration and Production Environmental Conference, San Antonio, Texas.

Mast, R.F., Root, D.H., Williams, L.P., Beeman, W.R., and Barnett, D.L., 1998. Areas of historical oil and gas exploration and production in the conterminous United States: U.S. Geological Survey Geologic Investigations Series I-2582, one sheet.

McLelland, P. and Hawkes, C., October 2002. "Assessing Bore-hole Instability Risks for Horizontal Wells in Coals and Fractured Shales". 4th Annual Unconventional Gas and CBM Conference, Calgary

Montana Board of Oil and Gas (MBOGC), 2005. Montana Board of Oil and Gas Conservation online database, http://bogc.dnrc.state.mt.us/OnlineData.htm

Montana Board of Oil and Gas (MBOGC), 2006. Data compilation and analysis.

NCDC, March 2006. Climate of 2005 - June , Wyoming Division 4 Drought, National Climate Data Center website, http://www.ncdc.noaa.gov/oa/climate/research/2005/jun/st048dv04pcp200506.html

New Logic Research, 2003. "Using VSEP to Treat Produced Water – An effective and economical solution".

Nicot Jean-Philippe, and Dutton A.R., September 2004. "Please Pass the Salt: Using Oil Fields for the Disposal of Concentrate from Desalination Plants," a report presented to the U.S. Bureau of Reclamation.

Olson, J., November 8, 2005. Personal conversation between Dr. Langhus and Joe Olson of Williams Production.

Oil & Gas Accountability Project, April 2004. "Oil and Gas at Your Door – A Landowner's Guide to Oil and Gas Development".

Perry, William J., 1995. Arkoma Basin Province (062), in Gautier, D. L., Dolton, G.I., Takahashi, K.T., and Varnes, K.L., eds., 1995 National assessment of United States oil and gas resources--Results, methodology, and supporting data: U.S. Geological Survey Digital Data Series DDS-30.

Peterson, James A., 1995. Williston Basin Province (031), in Gautier, D. L., Dolton, G.I., Takahashi, K.T., and Varnes, K.L., eds., 1995 National assessment of United States oil and gas resources--Results, methodology, and supporting data: U.S. Geological Survey Digital Data Series DDS-30.

Proctor, B.R., Thompson, R.W., Bernin, J.E. et al, 1983. Practices for Protecting and Enhancing Fish and Wildlife on Coastal Surface Mined land in The Powder River-Ft. Union Region. United States Department of the Interior, Fish and Wildlife Service, FWS/OBS-83/10: 246.

Reynolds Rodney R., 2003. "Produced Water and Associated Issues," a manual for independent operator, *Petroleum Technology Transfer Council*.

Rumble, Mark, 1989. United States Department of Agriculture Forest Service, Surface Mine Impoundments as Wildlife and Fish Habitat.

Rushworth, S. and M. Manning, Decmeber 12, 2005. *Local Play Brings Business and New Technology*, in Fort Worth Business Press.

Saikat, Mazumder and Karl-Heinz, Wold A., Third Quarter, 2004. "A Different Direction for CBNG Wells". Weatherford W Magazine.

Stutz, Lloyd and Fisher, Kevin, PTTC Archive, June 2004. "Fracture mapping and modeling optimize CBNG fracture treatments".

Sattler A., Hightower M., Nenoff T., Pless J., Phillips M., Brister B., Arnold R., Cather M., and McPherson B., 2004. "Managing Coal Bed Methane Produced Water for Beneficial Uses, Initially Using The San Juan and Raton Basins as a Model", Interim Progress Report prepared for NETL, Sandia National Laboratory.

Shultz, J., December 9, 2005. Personal conversation between Dr. Langhus and John Shultz of Basin Electric Power Coop.

Smith K.P., Williams G.P., Blunt D.L., and Arnish J.J., 1997. "Radiological Dose Assessment of NORM Disposal in Class II Injection Wells," U.S. DOE contract W-31-109-Eng-38.

Southwest Energy Company, February 2006. Home Page/Operations/Fayetteville Shale Gas, http://www.swn.com/

Spitz L.R., 2003. "Advanced Mobile Water Treatment Systems for Treating Coal Bed Methane Produced Water," a paper presented at the 2003 Ground Water Protection Council meeting.

Stafford, B., December 9, 2005. Personal conversation between Dr. Langhus and Bill Stafford of Basin Electric Power Coop

Stearns, M., November 11, 2005. Personal conversation between Dr. Langhus and Marty Stearns of Kennecott Energy Company.

The Tenorm Page, 2004. "Mobilization and Redeposition of NORM".

Texas Commission of Environmental Quality (TCEQ), January 24, 2006. Personal communication between Jake Crissup of ALL Consulting and Bryan Smith of TCEQ.

Thomsen, Paul, A., 2006. New Technologies for Modular Geothermal Power Plants in Oil and Gas Settings, 2006 SMU Geothermal Conference, March 2006.

Turner W., 2002. "Report on Treatment of Power Plant Waste Water Using The Aquasonics Rapid Spray Desalination Process," WestWater Resources, NM.

United States Department of Agriculture and National Resource Conservation Service (NRCS), 1982. Agriculture Handbook Number 590, Ponds – Planning, Design, Construction. Revised 1997.

United States Department of Energy Office of Fossil Energy and National Energy Technology Laboratory-Strategic Center for Natural Gas, DOE/NETL-2003/1193, September 2003. "Multi-Seam Well Completion Technology: Implications for Powder River Basin Coalbed Methane Production".

United States Department of Energy (DOE), 2006. "Oil and Natural Gas Supply, Technology Transfer." Accessed online at: http://www.netl.doe.gov

United States Energy Information Administration (EIA), 2006. "United States Crude Oil and Natural Gas Supply & Disposition". Accessed online at: http://www.eia.doe.gov

United States Environmental Protection Agency (EPA), September 1988. Climate Change and Wyoming, EPA 236-F-98-007n.

United States Environmental Protection Agency (EPA), 1991. Industrial Surface Impoundment Study in the United States. EPA 530-R-01-005. Washington, DC.

United States Environmental Protection Agency (EPA), September 1999. "Class V Underground Injection Control Study", U.S. EPA/816-R-99-014.

United States Environmental Protection Agency (U.S. EPA), September 2000. "Wastewater Technology Fact Sheet – Trickling Filters," 832-F-00-014.

United States Environmental Protection Agency (EPA), March 2001a. Class I Underground Injection Control Program: Study of the Risks Associated with Class I Underground Injection Wells. EPA 816-R-01-007

United States Environmental Protection Agency (EPA), April 2001b. "EPA Proposes to Continue with its Existing Approach for Managing Class V Injection Wells". Accessed online at: http://www.epa.gov/safewater/uic/classvdetermination.html

United States Environmental Protection Agency (EPA), 2004. Water Permitting 101, NPDES Permit Program Basics, available on the U.S. EPA website at http://www.epa.gov/npdes/pubs/101pape.pdf

United States Environmental Protection Agency (EPA), 2005a, Overview of Current Total Maximum Daily Load- TMDL- Program and Regulations, available on the U.S. EPA website at http://www.epa.gov/owow/tmdl/overviewfs.html

United States Environmental Protection Agency (EPA), 2005b, Underground Injection Control Program, available on the U.S. EPA website at http://www.epa.gov/safewater/uic/index.html

United States Environmental Protection Agency (EPA), February 14, 2005. "Oil and Gas Injection Wells (Class II)". Accessed online at: http://www.epa.gov/safewater/uic/classii.html

United States Environmental Protection Agency (EPA), March 1, 2006. Underground Injection Control Program. Deep Wells (Class I). Accessed. http://www.epa.gov/OGWDW/uic/classi.html

United States Fish and Wildlife Service (U.S. Fish and Wildlife), October 2002. Buffalo Lake National Wildlife Refuge. http://southwest.fws.gov/refuges/texas/buffalo.html.

United States Geological Survey (USGS), December 2004. "A Tapestry of Time and terrain: The Union of Two Maps – Geology and Topography" http://tapestry.usgs.gov/physiogr/physio.html.

United States Geological Survey (USGS), April 2002. "Produced Waters Database" Accessed online at: http://energy.cr.usgs.gov/prov/prodwat/intro.htm

United States Geological Survey (USGS), May 2002. United States Geological Survey Produced Waters Database, compiled by George N. Breit, Provisional Release, online at: http://energy.cr.usgs.gov/prov/prodwat/index.htm

United States Geological Survey (USGS), December 2004. "A Tapestry of Time and terrain: The Union of Two Maps – Geology and Topography" http://tapestry.usgs.gov/physiogr/physio.html

United States Geological Survey (USGS), 2005. United State Geological Survey National Oil and Gas Assessment, online at: http://energy.cr.usgs.gov/oilgas/noga/

United States Geological Survey (USGS), 2005. United States Geological Survey National Oil and Gas Assessment Interactive Map Page, online at: 'http://certmapper.cr.usgs.gov/noga/servlet/MapWindowServ

University of California Riverside (UCR), August 1999. "California Water Demand Snapshot", UCRTRAC Newsletter

Veil, J. A., February 1997. Surface Water Discharge from Onshore Stripper Wells, Prepared for United States Department of Energy, Office of Fossil Energy.

Veil, J.A., Langhus, B.G., and Belieu, S., January 1999. "Feasibility Evaluation of Downhole Oil/Water Separation Technology," U.S. DOE Report.

Veil, J.A., Puder M.G., Elcock D., and Redweik R. Jr. J., January 2004. "A White Paper Describing Produced Water from Production of Crude Oil, Natural Gas, and Coal Bed Methane," USDOE, W-31-109-Eng-38.

Wallace, W. K., and C. L. Hanks, 2005. Structural Geology of the Brooks Range. University of Fairbanks. Department of Geology and Geophysics. Accessed at: http://www.uaf.edu/geology/Research/research/structure.html.

Williams, B., 2005. Personal conversation between Dr. Langhus and Bruce Williams of Fidelity.

Wyoming Department of Environmental Quality (WDEQ), 2001, Chapter 1 Wyoming Water Quality Rules and Regulations; Wyoming Surface Water Quality Standards, Wyoming Department of Environmental Quality-Water Quality Division.

Wyoming Department of Environmental Quality (WDEQ), 2005a, Chapter 1 Wyoming Surface Water Quality Standards, Draft Three of the proposed changes to the Chapter 1 Regulations.

Wyoming Department of Environmental Quality (WDEQ), December 2005b, Personal communication between Heidi Kaiser of ALL Consulting and Jason Thomas of WDEQ.

Wyoming Oil and Gas Conservation Commission (WOGCC), June 27, 2005. Personal communication between Jake Crissup of ALL Consulting and Craig Eggerman of WYOGCC.

Wyoming Oil and Gas Conservation Commission (WOGCC), 2006. Online Production Data available at: http://wogcc.state.wy.us/grouptrpMenu.cfm?Skip='Y'&oops=49.

Zupancic, J., October 31, 2005. Personal conversation between Dr. Langhus and John Zupancic of BeneTerra.

THIS PAGE INTENTIONALLY LEFT BLANK

Appendix A – Site Visit Summaries

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF
PRODUCED WATER MANAGEMENT PRACTICES
FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE INFORMATION

OFFICE ADDRESS: VARIOUS SITES VISITED

CITY: GARDEN CITY STATE: KS COUNTY: FINNEY, HASKELL

BASIN: HUGOTON FIELD: STEWART

CONTACT NAME/TITLE: PETE KUNEYL – PRODUCTION FOREMAN/ PETROSANTANDER

CONTACT NUMBER: (620)275-2388

CONTACT NAME/TITLE: JIM HOLLAND & KEN JELHICK/ REGULATORY TECHNICIANS-KCC

CONTACT NUMBER: (620)225-8888

WATER MANAGEMENT TECHNOLOGIES/PRACTICES IN PLACE

DESCRIPTION: THE FIRST SITE VISITED WAS THE PETROSANTANDER WATER FLOOD IN THE STEWART FIELD JUST NORTHEAST OF GARDEN CITY A FEW MILES. PETROSANTANDER TOOK THE WATER FLOOD OVER ABOUT 10 YEARS AGO, AND HAS WORKED WITH THE DOE AND KANSAS GEOLOGICAL SURVEY (KGS) TO STUDY THE FLOOD AND IMPROVE EFFICIENCIES. IN TERMS OF WATER MANAGEMENT, PETROSANTANDER REINJECTS 100% OF THE WATER PRODUCED BACK INTO THE MORROW FORMATION FOR ENHANCED RECOVERY. PRIOR TO REINJECTION THE WATER IS FIRST RUN THROUGH A PHASE SEPARATOR, WHICH SEPARATES THE WATER FROM THE OIL AND GAS. CHEMICAL AMENDMENTS ARE THEN ADDED TO THE WATER (SCALE AND BACTERIA INHIBITORS) AND IT IS PUMPED TO A SERIES OF TANKS. THE WATER IS PUMPED CENTRIFUGALLY INTO THE TANKS TO PREVENT STAGNATION AND INCREASE RESIDENCE TIME IN EACH TANK. OIL IS SKIMMED OUT OF EACH TANK, AS NECESSARY. THE WATER IS THEN PUMPED THROUGH A 50 MICRON SOCK FILTER TO REMOVE SOILDS THAT MAY PLUG THE REINJECTION WELLS. THE WATER IS PUMPED BACK OUT INTO THE FIELD AND REINJECTED ALONG WITH ANY MAKEUP WATER THAT IS ADDED AS NECESSARY.

THE SECOND SITE VISITED WAS A WATER FLOOD OPERATED BY CHESAPEAKE. A NEARBY WELL (ONCE OPERATED BY MESA AND BOUGHT BY PIONEER) THAT WAS NOT PLUGGED PROPERLY HAD SEEPED SALTWATER INTO THE OGALLALA AQUIFER, WHICH IS A MAJOR DRINKING WATER AQUIFER. IN ORDER TO CONTAIN THE SALTWATER SEEP, SEVERAL WELLS WERE INSTALLED TO CAPTURE THE SALTWATER AND THEN REINJECT THE CONTAMINATED WATER AT A CENTRAL INJECETION WELL INTO A DEEPER AQUIFER. THE CENTRAL INJECTION WELL WAS PRESSURING UP, AND THEREFORE PIONEER WAS LOOKING TO CONTRUCT A SECOND INJECTION WELL. CHESAPEAKE WAS LOOKING TO INSTALL SEVERAL MORE WATER SUPPLY WELLS TO SUPPLY WATER TO THEIR WATER FLOOD. INSTEAD, PIONEER WAS ABLE TO SUPPLY CHESAPEAKE WITH THE OGALLALA WATER, AND PREVENT THE NEED FOR A SECOND INJECITON WELL, AND CHESAPEAKE DID NOT HAVE TO BUILD ADDITIONAL WATER

SUPPLY WELLS. CHESAPEAKE CURRENTLY USES ABOUT 2,200 BBLS/DAY OF THE CONTAMINATED OGALLALA WATER TO 1,400 BBLS/DAY OF WATER FROM SUPPLY WELLS.

THE THIRD SITE VISITED WAS A SERIES OF COMMERCIAL DISPOSAL WELLS. EACH DISPOSAL WELL CONSISTED OF A SERIES OF TANKS THAT ARE USED TO STORE THE WATER AS IT IS OFF LOADED FROM HAUL TRUCKS, AND SEPARATES ANY REMAINING OIL FROM THE WATER. THE WATER IS TYPICALLY STORED AT THE WELL HEAD IN CLOSED TANKS THAT MINIMIZE EVAPORATION (CRYSTALIZATION IS A CONCERN DUE TO HIGH TDS VALUES IN WATER) AND PREVENT WILDLIFE FROM COMING IN CONTACT WITH THE HIGH TDS WATER.

ENVIRONMENTAL IMPACTS/BENEFITS: OTHER THAN ENHANCED RECOVERY/WATER FLOOD, THERE ARE NO KNOWN BENEFICIAL USES FOR THE LOW QUALITY PRODUCED WATER IN WESTERN KANSAS. THE ONLY OTHER OPTION IS TO DISPOSE OF THE WATER IN DISPOSAL WELLS.

APPLICABILITY: ENHANCED RECOVERY/WATER FLOODING IS APPLICABLE WHERE THE QUALITY OF THE PRODUCED WATER IS LOW (AKA HIGH TDS) AND THE NEED FOR ENHANCED RECOVERY IN PRESENT DUE TO THE NATURE OF MATURE OIL AND GAS FIELDS.

COST: NO INFORMATION WAS COLLECTED ON COST.

ADDITIONAL NOTES: NONE

DATE: 7/29/2005____ INFORMATION COLLECTED BY: _JAKE CRISSUP

PHOTO LOG

VIEW OF A THREE PHASE SEPARATOR TANK AT PETROSANTANDER

VIEW OF THE CHEMICAL INJECTION TANKS THAT TREAT THE WATER BEFORE STORAGE

VIEW OF THE STORAGE TANKS AND ONE OF THE PUMPS

VIEW OF THE SOCK FILTER THAT REMOVES SOLIDS FROM THE WATER BEFORE REINJECTION

VIEW OF THE HEATER TREATER THAT SEPARATES THE WATER FROM THE OIL

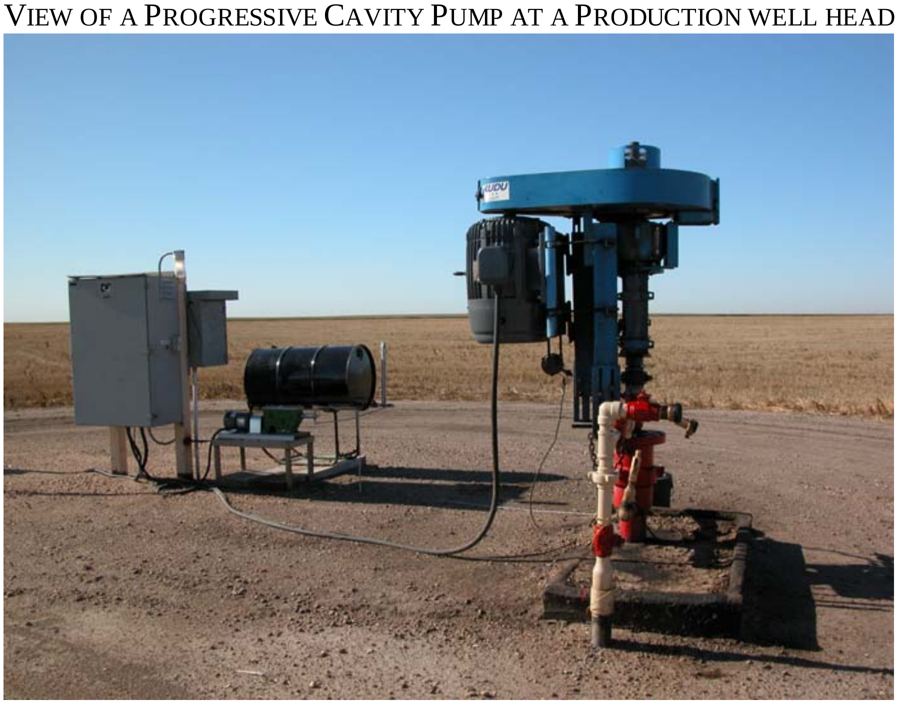
VIEW OF A WATER SUPPLY WELL THAT PROVIDES MAKEUP WATER

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF
PRODUCED WATER MANAGEMENT PRACTICES
FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

VIEW OF A TYPICAL PRODUCTION WELL

VIEW OF A PROGRESSIVE CAVITY PUMP AT A PRODUCTION WELL HEAD



VIEW OF A TYPICAL STORAGE TANK AT A WELL HEAD

VIEW OF THE STORAGE TANKS THAT ARE USED IN THE REMEDIATION OF CONTAMINATED WATER

VIEW OF STORAGE TANKS AT A COMMERCIAL DISPOSAL SITE

VIEW OF A COMMERCIAL DISPOSAL WELL HEAD

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF

PRODUCED WATER MANAGEMENT PRACTICES

FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

Site Visit Summary

Identification, Verification, and Compilation of
Produced Water Management Practices
for Conventional Oil and Gas Production Operations

Site Information

Office Address: PO Box 1645

City: Havre State: MT County: Blaine

Basin: Battle Creek Field: North Battle Creek

Contact Name/Title: Mark Hedstrom/ Field Supervisor – Helis Oil and gas

Contact Number: (406)357-3639

Contact Name/Title: Gary Klotz/ Field Inspector – MBOGC

Contact Number: (406)698-4871

Water Management Technologies/Practices in Place

Description: Visited two centralized evaporation/aeration pits and several well sites that have both lined and unlined evaporation/aeration pits adjacent to the well heads. The producing gas wells (approximately 130 wells operated by Helis) discharge water directly to a pit adjacent to the well head. Pits that are more remote (ie not easily accessible with a vacuum truck) have larger pits adjacent to the well head and aerators in the pit to enhance evaporation. This minimizes the need to haul the water away. For lined and unlined pits that have a smaller capacity, vacuum trucks are employed on an as needed basis to haul the water to a central evaporation/aeration pit. There are approximately 21 aerators on each of the central evaporation/aeration pits. The aerators move approximately 150 gpm (cummulative) on the centralized pits, and about 5 gpm on the remote pits. This circulation and spraying of the water enhances the evaporation rate. The level of enhancement is dependant on weather conditions (temp, wind speed, cloud cover, etc).

Environmental Impacts/Benefits: All water is either evaporated at the well head, or evaporated at the central evaporation/aeration pits. All pits are fenced to prevent entrance of live stock and wildlife from consuming the water. No oil is present in the water, so harm to birds and migratory waterfowl is not a concern.

Applicability: This particular technology is applicable to gas fields, producing low volumes of water, in an arid environment that encourages evaporation.

Cost: Costs were not collected on the operating cost for hauling water. The capital cost for installing the aerators is around $4,000, with the biggest

SINGLE TICKET ITEM BEING THE CIRCULATOR PUMP, WHICH IS ABOUT $1,500. THE MONTHLY ELECTRIC COSTS FOR OPERATING THE PUMP AND AERATORS ON ONE OF THE EVAPORATION/AERATION PITS IS ESTIMATED TO BE $150/MONTH.

ADDITIONAL NOTES: NONE.

DATE: 7/14/2005 INFORMATION COLLECTED BY: JAKE CRISSUP

PHOTO LOG

VIEW OF CENTRALIZED EVAPORATION/AERATION PIT

VIEW OF EVAPORATION PIT ADJACENT TO EVAPORATION/AERATION PIT

VIEW OF AN UNLINED INDIVIDUAL EVAPORATION/AERATION PIT AT REMOTE WELL HEAD

CLOSER VIEW OF INDIVIDUAL AERATOR AT REMOTE WELL HEAD

VIEW OF SOLAR PANEL AT REMOTE WELL LOCATION

VIEW OF A LINED EVAPORATION PIT ADJACENT TO A WELL HEAD

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF

PRODUCED WATER MANAGEMENT PRACTICES

FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF

PRODUCED WATER MANAGEMENT PRACTICES

FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE INFORMATION

OFFICE ADDRESS: SOUTHEAST OF BROADUS OFF OF 544

CITY: BELL CREEK STATE: MT COUNTY: POWDER

BASIN: BELL CREEK FIELD: BELL CREEK

CONTACT NAME/TITLE: DARRELL HYSTAD/ FIELD INSPECTOR – MBOGC

CONTACT NUMBER: (406)698-4861

WATER MANAGEMENT TECHNOLOGIES/PRACTICES IN PLACE

DESCRIPTION: VISITED THE BELL CREEK FIELD WHERE 40-50 OIL WELLS ARE CURRENTLY PRODUCING. BELL CREEK HAS 27 INJECTION WELLS CURRENTLY ONLINE FOR ENHANCED RECOVERY. OF THE 13,000 BBLS/DAY OF WATER THAT IS PRODUCED, APPROXIMATELY 8,000 BBLS/DAY IS RE-INJECTED FOR ENHANCED RECOVERY AND 5,000 BBLS/DAY IS DISCHARGED THROUGH A SERIES OF TANKS AND PITS TO SEPARATE OIL FROM THE WATER PRIOR TO DISCHARGE.

ENVIRONMENTAL IMPACTS/BENEFITS: DISCHARGED WATER IS CONSUMED BY CATTLE, DEER, AND OTHER WILDLIFE, AND HABITAT IS CREATED FOR WILDLIFE WHERE NONE WOULD BE PRESENT DUE TO THE SEASONAL CONDITION OF THE DRAINAGE.

APPLICABILITY: THE COMBINATION OF INJECTION FOR ENHANCED RECOVERY AND DISCHARGE TO THE SURFACE IS APPLICABLE DUE TO THE QUALITY OF THE WATER OF THE MATURE NATURE OF THIS OIL FIELD TO REQUIRE ENHANCED RECOVERY.

COST: NO INFORMATION WAS COLLECTED ON COST.

ADDITIONAL NOTES: NONE.

DATE: 7/12/2005 INFORMATION COLLECTED BY: JAKE CRISSUP

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF

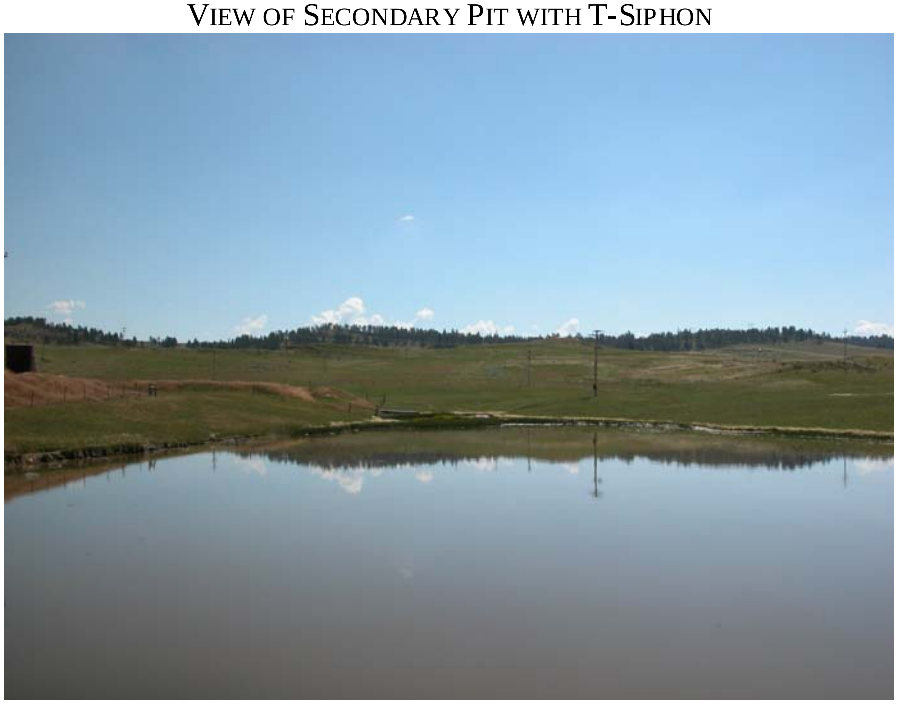
PRODUCED WATER MANAGEMENT PRACTICES

FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

PHOTO LOG

VIEW OF THE FIRST OIL/WATER SEPARATOR PIT

VIEW OF SECONDARY PIT WITH T-SIPHON



VIEW OF SECONDARY PIT T-SIPHON TO PREVENT OIL FROM DISCHARGING

VIEW OF SECONDARY PIT DISCHARGE TO BELL CREEK

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF

PRODUCED WATER MANAGEMENT PRACTICES

FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE INFORMATION

OFFICE ADDRESS: VISITED CENTRALIZED EVAPORATION PIT NORTH OF SACO

CITY: NORTH OF SACO STATE: MT COUNTY: PHILLIPS

BASIN: BOWDOIN FIELD: BOWDOIN

CONTACT NAME/TITLE: BOB SCHMIDT/ FIELD INSPECTOR – MBOGC

CONTACT NUMBER: (406)698-5266

WATER MANAGEMENT TECHNOLOGIES/PRACTICES IN PLACE

DESCRIPTION: VISITED A CENTRALIZED EVAPORATION PIT CONSTRUCTED AND OPERATED BY FIDELITY. WATER IS COLLECTED AT INDIVIDUAL EVAPORATION PITS ADJACENT TO EACH WELL HEAD. AS THE INDIVIDUAL EVAPORATION PITS FILL WITH WATER, A VACUUM TRUCK COLLECTS THE WATER AND TRANSPORTS IT TO THE CENTRALIZED EVAPORATION PIT THAT IS LINED WITH A GEOSYNTHETIC LINER. THE CENTRAL EVAPORATION PIT WAS A SEPARATOR BOX THAT PREVENTS SOLIDS (SOIL, ROCKS, ETC) FROM DISCHARGING TO THE EVAPORATION PIT, THUS EXTENDING THE LIFE OF THE LINER. FIDELITY HAS THREE ADDITIONAL CELLS THAT CAN BE LINED, AS NECESSARY, ONCE THE FIRST EVAPORATION PIT REACHES CAPACITY. THE EVAPORATION PIT IS A FEW FEET DEEP, THUS ENHANCING THE HEATING AND EVAPORATION OF THE WATER, WHICH IS SPREAD OVER A LARGE AREA (APPROXIMATELY 100 FEET WIDE BY 300 FEET LONG).

ENVIRONMENTAL IMPACTS/BENEFITS: ALL WATER IS EITHER EVAPORATED AT THE WELL HEAD, OR EVAPORATED AT THE CENTRAL EVAPORATION PIT. ALL PITS ARE FENCED TO PREVENT ENTRANCE OF LIVE STOCK AND WILDLIFE FROM CONSUMING THE WATER. NO OIL IS PRESENT IN THE WATER, SO HARM TO BIRDS AND MIGRATORY WATERFOWL IS NOT A CONCERN.

APPLICABILITY: THIS PARTICULAR TECHNOLOGY IS APPLICABLE TO GAS FIELDS, PRODUCING LOW VOLUMES OF WATER, IN AN ARID ENVIRONMENT THAT ENCOURAGES EVAPORATION.

COST: COSTS WERE NOT COLLECTED ON THE EVAPORATION PIT OR THE TRUCKING COSTS FOR HAULING WATER.

ADDITIONAL NOTES: NONE.

DATE: 7/13/2005 INFORMATION COLLECTED BY: JAKE CRISSUP

IDENTIFICATION, VERIFICATION, AND COMPILATION OF
PRODUCED WATER MANAGEMENT PRACTICES
FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

PHOTO LOG

VIEW OF EVAPORATION PIT ADJACENT TO A PRODUCING GAS WELL

CLOSER VIEW OF EVAPORATION PIT ADJACENT TO PRODUCING GAS WELL

IDENTIFICATION, VERIFICATION, AND COMPILATION OF
PRODUCED WATER MANAGEMENT PRACTICES
FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

VIEW OF CENTRALIZED EVAPORATION PIT THAT IS LINED

VIEW OF CELL ADJACENT TO EVAPORATION PIT FOR FURTHER EXPANSION OF THE SYSTEM

VIEW OF TRUCK OFF-LOADING AREA WHERE WATER IS OFF-LOADED INTO THE EVAPORATION PIT FROM TRUCKS

CLOSER VIEW OF DISCHARGE WEIR WHERE SOLIDS ARE SEPARATED OUT AS THE TRUCK IS OFF-LOADED PRIOR TO DISCHARGE TO THE EVAPORATION PIT

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF

PRODUCED WATER MANAGEMENT PRACTICES

FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF
PRODUCED WATER MANAGEMENT PRACTICES
FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE INFORMATION

OFFICE ADDRESS: 115 N. MAIN (BURLINGTON RESOURCES)

CITY: BAKER STATE: MT COUNTY: FALLON

BASIN: CEDAR CREEK ANTICLINE FIELD: EAST LOOKOUT BUTTE

CONTACT NAME/TITLE: DALE HINTON/ ENCORE

CONTACT NUMBER: (406)

CONTACT NAME/TITLE: JIM ARMENTROUT/ BURLINGTON RESOURCES

CONTACT NUMBER: (406)778-6401

CONTACT NAME/TITLE: DARRELL HYSTAD/ FIELD INSPECTOR – MBOGC

CONTACT NUMBER: (406)698-4861

WATER MANAGEMENT TECHNOLOGIES/PRACTICES IN PLACE

DESCRIPTION: VISITED THE CEDAR CREEK ANTICLINE FIELD WHERE WATER IS PRIMARLY INJECTED FOR DISPOSAL AND ENHANCED RECOVERY. WATER THAT IS ENTRAINED WITH OIL IS RUN THROUGH A MOBILE OIL RECOVERY UNIT THAT FURTHER SEPARATES THE OIL FROM THE WATER. SOLIDS REMOVED FROM THE OIL RECOVERY PROCESS ARE APPLIED TO AN ALKALINE FLAT LANDFARM WHERE THE PROPERTIES OF THE SOIL ARE IMPROVED FROM THE LANDFARMING TECHNIQUE. WATER REMOVED IS INJECTED AND OIL REMOVED IS SOLD TO RECOVER THE COST OF THE OIL RECOVERY PROCESS.

ENVIRONMENTAL IMPACTS/BENEFITS: ALL WATER IS INJECTED FOR EITHER ENHANCED RECOVERY OR DISPOSAL.

APPLICABILITY: THE INJECTION FOR DISPOSAL AND ENHANCED RECOVERY IS APPLICABLE DUE TO THE QUALITY OF THE WATER AND THE MATURE NATURE OF THIS OIL FIELD TO REQUIRE ENHANCED RECOVERY.

COST: NO INFORMATION WAS COLLECTED ON COST.

ADDITIONAL NOTES: NONE.

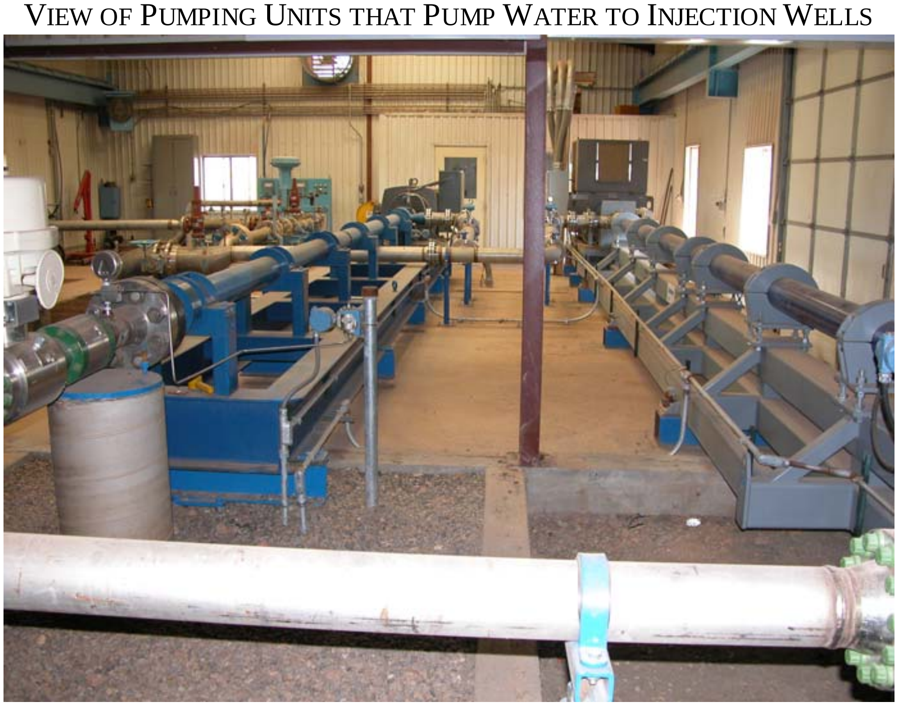
DATE: 7/12/2005 INFORMATION COLLECTED BY: JAKE CRISSUP

IDENTIFICATION, VERIFICATION, AND COMPILATION OF
PRODUCED WATER MANAGEMENT PRACTICES
FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

PHOTO LOG

VIEW OF AN INJECTION WELL

VIEW OF PUMPING UNITS THAT PUMP WATER TO INJECTION WELLS



VIEW OF PRODUCING WELL WITH AN EVAPORATION PIT ADJACENT TO IT

CLOSER VIEW OF THE EVAPORATION PIT

VIEW OF A MOBILE OIL RECOVERY UNIT

VIEW OF A BIN THAT COLLECTS SOLIDS FROM THE MOBILE OIL RECOVERY UNIT

VIEW OF LANDFARM WHERE ALKALINE SOILS ARE RECLAIMED

VIEW OF NATURAL ALKALINE SOILS ADJACENT TO LANDFARM

Site Visit Summary

Identification, Verification, and Compilation of
Produced Water Management Practices
for Conventional Oil and Gas Production Operations

Site Information

Office Address: Various Disposal Sites Visited

City: Sydney and Medicine Lake State: MT County: Richland and Sheridan

Basin: Various Field: Various

Contact Name/Title: Bob Schmidt/ Field Inspector – MBOGC

Contact Number: (406)698-5266

Contact Name/Title: Darrell Hystad/ Field Inspector – MBOGC

Contact Number: (406)698-4861

Water Management Technologies/Practices in Place

Description: Visited three disposal sites.

Landtech, just northwest of Sydney (approximately 12 miles) was visited. Landtech has been allowed to maintain the netted concrete pit system due to grandfather laws. Landtech has three concrete pits in series that separate the oil from the water. They also have several tanks onsite for temporary storage prior to disposal injection. Landtech disposes about 2,000-5,000 BBLs of water/day.

Nance operates a commercial disposal well just north of Medicine Lake. The Nance disposal operation has a separation pit that is netted and is used to separate the oil from the water. Both Nance and Landtech utilize the Mobile Oil recovery Units to further separate water from oil and sell the oil commercially.

The third site visited was a disposal well that services 6 producing oil wells. This site had no surface pits as all of the water is contained in tanks prior to disposal. The well house is connected to the final tank to prevent freezing of the pipes during winter months.

Environmental Impacts/Benefits: All water is injected for disposal.

Applicability: The injection for disposal is applicable due to the quality of the water.

Cost: Disposal costs vary based on the quality of the water.

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF

PRODUCED WATER MANAGEMENT PRACTICES

FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

ADDITIONAL NOTES:_NONE.

DATE: 7/13/2005____ INFORMATION COLLECTED BY: _JAKE CRISSUP

PHOTO LOG

VIEW OF CONCRETE SEPARATION PITS IN SERIES AT LANDTECH

VIEW OF INSTRUMENTS USED TO DETERMINE WATER QUALITY AT LANDTECH

VIEW OF TANKS AND NETTED PIT AT NANCE

VIEW OF INJECTION WELLHEAD AT NANCE

VIEW OF A OILFIELD AND TANKS AT A "NO PIT" DISPOSAL SITE NEAR MEDICINE LAKE

VIEW OF A TANK WITH THE WELL HEAD HOUSED NEXT TO IT

IDENTIFICATION, VERIFICATION, AND COMPILATION OF
PRODUCED WATER MANAGEMENT PRACTICES
FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE INFORMATION

OFFICE ADDRESS: SITES VISITED IN CX FIELD AND COAL CREEK EXPLORATORY POD

CITY: NORTHEAST OF DECKER STATE: MT COUNTY: BIG HORN

BASIN: POWDER RIVER FIELD: PRB CBM

CONTACT NAME/TITLE: STEVE SASAKI/ DRILLING INSPECTOR- MBOGC

CONTACT NUMBER: (406)656-0040

WATER MANAGEMENT TECHNOLOGIES/PRACTICES IN PLACE

DESCRIPTION: THE CX FIELD WAS VISITED AND AN EMIT WATER TREATMENT PLANT WAS VISITED NORTH OF THE TONGUE RIVER RESERVOIR JUST NORTH OF COAL CREEK. THE CX FIELD HAS SEVERAL DISCHARGE POINTS INTO THE TONGUE RIVER THAT HAVE BEEN GRANDFATHERED AS MDPES DISCHARGE POINTS. 1600 GPM IS CUMMULATIVELY DISCHARGED INTO THE TONGUE RIVER FROM THE CX FIELD. FIDELITY HAS REQUESTED TO ALTER THE MPDES DISCHARGE PERMITS TO ALLOW FOR HIGHER DISCHARGE RATES DURING HIGH FLOW PERIODS OF THE TONGUE RIVER. THE EMIT PLANT VISITED WAS FROM THE COAL CREEK EXPLORATORY PLAN OF DEVELOPMENT (POD). ALL OF THE WATER PRODUCED FROM THE COAL CREEK EXPLORATORY POD IS PUMPED TO A CENTRAL TANK WHERE ANY GAS IS VENTED OFF. THE WATER IS THEN RUN THROUGH THE EMIT PLANT AS DESCRIBED BELOW. AFTER THE EMIT PLANT, THE WATER IS RUN THROUGH A LIMESTONE REACTOR BED, AND THEN THROUGH A RENTENTION PIT AND THEN AN AERATOR PIT PRIOR TO DISCHARGE. THE WATER IS THEN DISCHARGED TO THE TONGUE RIVER THROUGH A PERFORATED PIPE THAT IS TRENCHED BELOW THE BED OF THE RIVER. THE TRENCHED PIPE HAS A CLEAN OUT PIPE OF BOTH SIDES OF THE RIVER THAT DAYLIGHT SO THE TRENCHED PIPE CAN BE EASILY CLEANED OUT AS NEEDED.

THE FOLLOWING PROCESS DESCRIPTION WAS TAKEN FROM THE EMIT TECHNOLOGIES WEBSITE, WWW.EMITTECHNOLOGIES.COM :

COMMERCIALLY AVAILABLE CATION & ANION RESINS ARE USED TO PURIFY PRODUCED WATER OF SODIUM, CHLORIDE, SULFATE AND OTHER IONS IN BOTH A CONTINUOUS AND COUNTERCURRENT OPERATING MODE. THESE CHEMICAL ENGINEERING PRINCIPLES OF MASS TRANSFER MAXIMIZE THE RESINS' ABILITIES IN PURIFYING WATER WITH A CONSISTENT QUALITY. THEY ALSO OPTIMIZE THE USE OF ACID AND ALKALI REGENERANTS, MINIMIZE THEIR VOLUMES AND GENERATE A DENSE BRINE SOLUTION THAT MAY HAVE VALUE AS A CLEAR BRINE FLUID WITHIN THE OIL AND GAS INDUSTRY. THE KEY TO THE HIGGINS LOOP FEATURES IS ITS ABILITY TO MOVE THE RESIN THROUGH THE LOOP VIA INCREMENTAL "PULSING". THE PULSE VESSEL SERVES AS A RESIN FLOW METER TO ENSURE ITS FLOW IS IN PROPORTION TO THE WATER TREATED AND THE AMOUNT OF REGENERANT CONSUMED.

PRODUCED WATER CONTAINING HIGH NA LEVELS IS FED TO THE ADSORPTION ZONE WITHIN THE HIGGINS LOOP WHERE IT CONTACTS STRONG ACID CATION RESIN WHICH LOADS NA^+ IONS IN EXCHANGE FOR HYDROGEN (H^-) IONS. TREATED WATER EXITS THE LOOP CONTAINING LESS THAN 10 MG/L NA.

CONCURRENT WITH ADSORPTION AND IN THE LOWER SECTION OF THE HIGGINS LOOP, NA-LOADED RESIN IS REGENERATED WITH EITHER HYDROCHLORIC OR SULFURIC ACID TO PRODUCE A SMALL, CONCENTRATED SPENT BRINE STREAM. REGENERATED RESIN IS RINSED WITH WATER PRIOR TO REENTERING THE ADSORPTION ZONE TO REMOVE ACID FROM ITS PORES.

AS RESIN IN THE UPPER LAYER OF THE ADSORPTION ZONE BECOMES LOADED WITH NA, THE FLOWS TO THE HIGGINS LOOP ARE MOMENTARILY INTERRUPTED TO ALLOW ADVANCEMENT OF THE RESIN BED (PULSING) THROUGH THE LOOP IN THE OPPOSITE DIRECTION OF LIQUID FLOW. LIQUID FLOWS ARE RESTARTED AFTER RESIN PULSING IS COMPLETE.

TREATED WATER IS SLIGHTLY ACIDIC DUE TO ITS INCREASED H^- ION STRENGTH, AND IT IS NEUTRALIZED WITH LIMESTONE, WHICH ALSO INCREASES ITS CALCIUM CONCENTRATION SO THAT THE WATER'S SODIUM ADSORPTION RATIO (SAR) IS LESS THAN 1.0. SPENT BRINE CONTAINING REMOVED NA^+ IONS HAS A DENSITY HIGH ENOUGH FOR USE AS A KILL FLUID.

ENVIRONMENTAL IMPACTS/BENEFITS: TREATING PRODUCED WATER WITH THIS TECHNOLOGY PROVIDES ENVIRONMENTAL BENEFITS BY ALLOWING FOR THE WATER TO BE BENEFICIALLY USED BY IMPROVING THE SAR AND LOWERING THE TDS. ONCE THE WATER IS TREATED, IT CAN BE PUT BACK INTO A SURFACE STREAM FOR USE BY LIVESTOCK, WILDLIFE, AND DOWNSTREAM WATER RIGHTS HOLDERS, OR IT CAN BE IRRIGATED IMMEDIATELY.

APPLICABILITY: THE HIGGINS LOOP HAS BEEN IN USE SINCE WWII, AND THE USE OF THE EMIT TECHNOLOGY IS GROWING IN THE POWDER RIVER BASIN ON BOTH THE WYOMING AND MONTANA SIDE. THIS TECHNOLOGY IS USEFUL IN LOWERING SODIUM, BICARBONATES, SAR VALUES, AND OVERALL TDS TO BELOW NPDES PERMIT REQUIREMENTS.

COST: NO INFORMATION WAS COLLECTED ON COST. THE WEBSITE STATES THAT COST IS A FIXED COST AND IS CHEAPER THAN SEVERAL OF THE CURRENT TREATMENT ALTERNATIVES.

ADDITIONAL NOTES: NONE

DATE: 7/11/2005 ____ INFORMATION COLLECTED BY: _JAKE CRISSUP

PHOTO LOG

VIEW OF THE ENTRANCE TO CX RANCH

VIEW OF A MPDES DISCHARGE POINT ON CX RANCH

VIEW OF THE DISCHARGE POINT INTO THE TONGUE RIVER

CLOSER VIEW OF THE DISCHARGE POINT

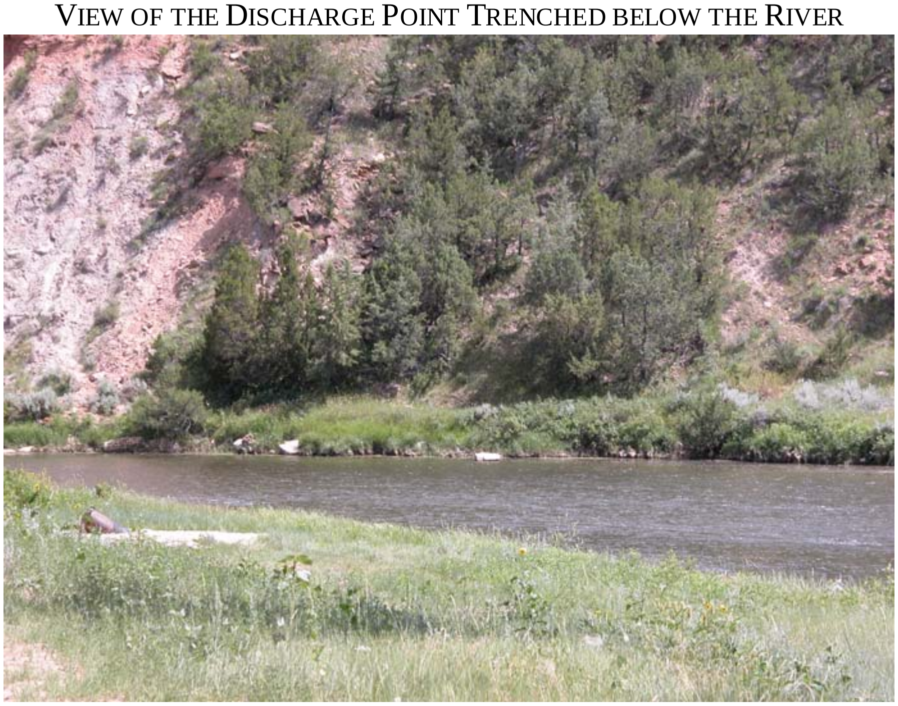
VIEW OF THE COAL CREEK EMIT PLANT

VIEW OF A LIME REACTOR BED WITH AN AERATOR

CLOSER VIEW OF THE AERATOR PRIOR TO DISCHARGE TO RETENTION PIT

VIEW OF THE RETENTION AND AERATION PITS

VIEW OF THE DISCHARGE POINT TRENCHED BELOW THE RIVER



CLOSER VIEW OF THE DISCHARGE POINT TRENCHED BELOW THE RIVER

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF

PRODUCED WATER MANAGEMENT PRACTICES

FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF

PRODUCED WATER MANAGEMENT PRACTICES

FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE INFORMATION

OFFICE ADDRESS: NONE AVAILABLE (SUMMIT RESOURCES WAS THE OPERATOR)

CITY: NORTH OF CHINOOK STATE: MT COUNTY: BLAINE

BASIN: RABBITT HILLS FIELD: RABBITT HILLS

CONTACT NAME/TITLE: GARY KLOTZ/ FIELD INSPECTOR – MBOGC

CONTACT NUMBER: (406)698-4871

WATER MANAGEMENT TECHNOLOGIES/PRACTICES IN PLACE

DESCRIPTION: VISITED A SURFACE DISCHARGE POINT AT THE RABBITT HILLS OIL FIELD. SIMILAR OIL/WATER SEPARATION PITS WERE USED, ALONG WITH NETTING ON THE PRIMARY PIT TO PROTECT BIRDS AND WILDLIFE. A FILTER SOCK, WHICH IS FREQUENTLY CHANGED OUT, IS ALSO EMPLOYED JUST AFTER THE SECONDARY SEPARATION PIT TO ENHANCE THE OIL AND SOLIDS REMOVAL FROM THE DISCHARGE PRIOR TO DISCHARGING TO THE STOCK POND. FURTHERMORE, A 20-30 FOOT FLEXIBLE PLASTIC TUBE HAS BEEN CONNECTED TO THE PIPE SPILLWAY OF THE STOCK POND TO MINIMIZE EROSION DURING STORM EVENTS AND PERIODS OF HIGH FLOW. THE STOCK POND WAS NOT DISCHARGING OVER THE SPILLWAY AT THE TIME OF THE VISIT.

ENVIRONMENTAL IMPACTS/BENEFITS: DISCHARGED WATER IS CONSUMED BY CATTLE, DEER, AND OTHER WILDLIFE, AND HABITAT IS CREATED FOR WILDLIFE WHERE NONE WOULD BE PRESENT DUE TO THE SEASONAL CONDITION OF THE DRAINAGE.

APPLICABILITY: THE DISCHARGE TO THE SURFACE IS APPLICABLE DUE TO THE QUALITY OF THE WATER AND THE ABILITY OF THE PROCESS TO REMOVE OIL FROM THE WATER PRIOR TO SURFACE DISCHARGE.

COST: NO INFORMATION WAS COLLECTED ON COST.

ADDITIONAL NOTES: NONE.

DATE: 7/14/2005 INFORMATION COLLECTED BY: JAKE CRISSUP

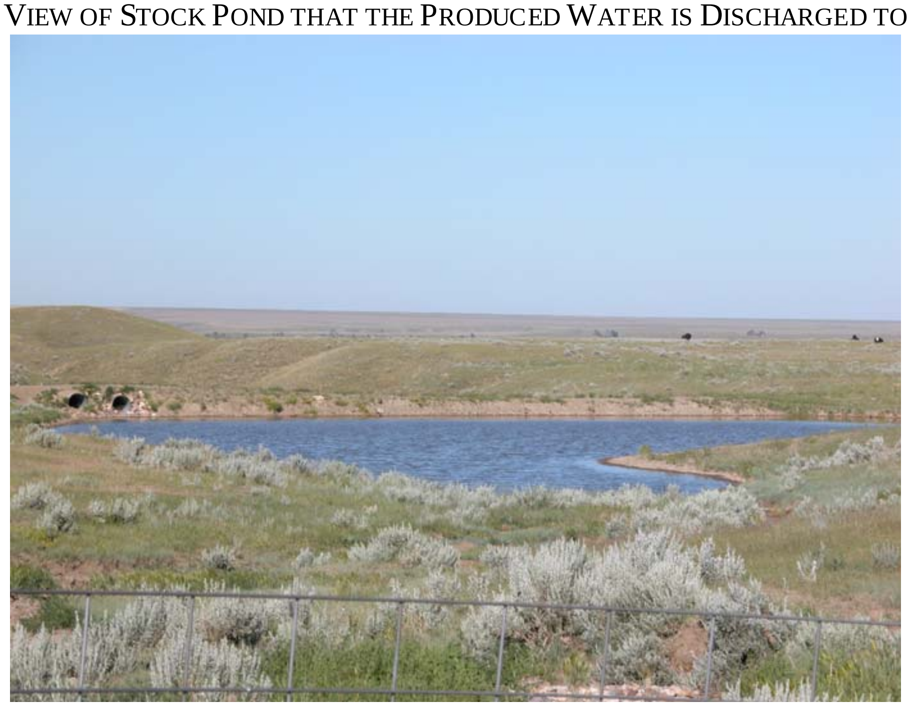
PHOTO LOG

VIEW OF PRIMARY SEPARATION PIT THAT IS NETTED

VIEW OF SECONDARY SEPARATION PIT ENCLOSED WITH A FENCE AND A CATTLE GUARD

VIEW OF DISCHARGE POINT WITH SOCK FILTERS TO REMOVE OILY SOLIDS

VIEW OF STOCK POND THAT THE PRODUCED WATER IS DISCHARGED TO



VIEW OF STOCK POND DAM WITH PRIMARY SPILLWAY PIPES

CLOSER VIEW OF ENERGY DISSIPATION DEVICE AT DISCHARGE POINT TO REDUCE EROSION

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF

PRODUCED WATER MANAGEMENT PRACTICES

FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF
PRODUCED WATER MANAGEMENT PRACTICES
FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE INFORMATION

OFFICE ADDRESS: SOUTH OF HAVRE IN/AROUND BEAR PAW MOUNTAINS

CITY: HAVRE STATE: MT COUNTY: HILL

BASIN: TIGER RIDGE FIELD: TIGER RIDGE

CONTACT NAME/TITLE: GARY KLOTZ/ FIELD INSPECTOR – MBOGC

CONTACT NUMBER: (406)698-4871

WATER MANAGEMENT TECHNOLOGIES/PRACTICES IN PLACE

DESCRIPTION: VISITED TWO CENTRALIZED EVAPORATION PITS AND SEVERAL WELL SITES THAT HAVE LINED, UNLINED, AND OPEN TUB EVAPORATION PITS ADJACENT TO THE WELL HEADS. ONE LOCATION VISITED HAD AN OPEN RING TANK AND A COMPRESSOR TO INCREASE THE GAS PRESSURE TO PIPELINE QUALITY. ANOTHER LOCATION HAD AN ENCLOSED TANK ADJACENT TO THE WELL HEAD. IT WAS UNCLEAR WHY THE TANK HAD BEEN INSTALLED AS THE SITE WAS VERY REMOTE, AND A VACUUM TRUCK WOULD NOT BE ABLE TO EASILY ACCESS THE SITE FOR HAULING WATER. FOR LINED AND UNLINED PITS, VACUUM TRUCKS ARE EMPLOYED ON AN AS NEEDED BASIS TO HAUL THE WATER TO A CENTRAL EVAPORATION PIT. THE CENTRAL EVAPORATION PITS ARE FENCED AND NETTED TO PREVENT WILDLIFE FROM ENTERING THEM.

ENVIRONMENTAL IMPACTS/BENEFITS: ALL WATER IS EITHER EVAPORATED AT THE WELL HEAD, OR EVAPORATED AT THE CENTRAL EVAPORATION PITS. ALL PITS ARE FENCED AND NETTED TO PREVENT ENTRANCE OF LIVE STOCK AND WILDLIFE FROM CONSUMING THE WATER.

APPLICABILITY: THIS PARTICULAR TECHNOLOGY IS APPLICABLE TO GAS FIELDS, PRODUCING LOW VOLUMES OF WATER, IN AN ARID ENVIRONMENT THAT ENCOURAGES EVAPORATION.

COST: COSTS WERE NOT COLLECTED.

ADDITIONAL NOTES: NONE.

DATE: 7/14/2005 INFORMATION COLLECTED BY: JAKE CRISSUP

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF

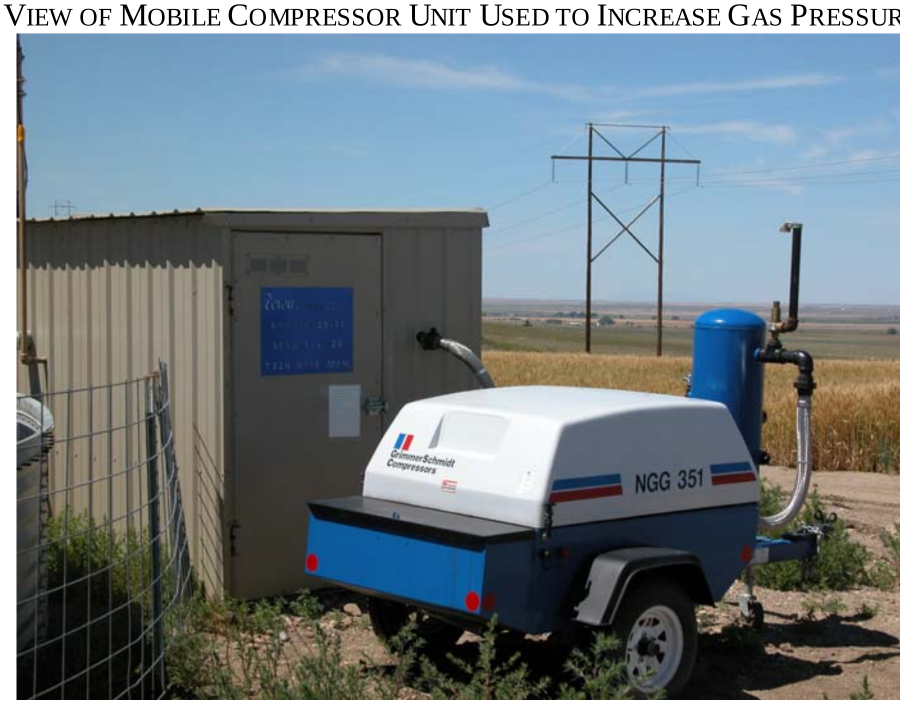
PRODUCED WATER MANAGEMENT PRACTICES

FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

PHOTO LOG

VIEW OF 30' RING TANK THAT IS USED TO STORE PRODUCED WATER ADJACENT TO THE WELL HEAD

VIEW OF MOBILE COMPRESSOR UNIT USED TO INCREASE GAS PRESSURE



VIEW OF A CENTRALIZED EVAPORATION PIT OFF-LOADING AREA

CLOSER VIEW OF CENTRALIZED EVAPORATION PIT

VIEW OF A LINED PIT ADJACENT TO A WELL HEAD

VIEW OF AN EVAPORATION TUB ADJACENT TO WELL HEAD

IDENTIFICATION, VERIFICATION, AND COMPILATION OF

PRODUCED WATER MANAGEMENT PRACTICES

FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

VIEW OF A WELL HEAD WITH A TANK ADJACENT TO IT TO HOLD PRODUCED WATER

IDENTIFICATION, VERIFICATION, AND COMPILATION OF
PRODUCED WATER MANAGEMENT PRACTICES
FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

CLOSER VIEW OF PRODUCED WATER TANK ADJACENT TO WELL HEAD

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF
PRODUCED WATER MANAGEMENT PRACTICES
FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE INFORMATION

OFFICE ADDRESS: 111 WEST 5TH STREET, SUITE 1000 (MAIN OFFICE)

CITY: TULSA STATE: OK COUNTY: OKLAHOMA

BASIN: OKLAHOMA CITY FIELD: OKLAHOMA CITY

CONTACT NAME/TITLE: JANET MCGEHEE/ PRODUCTION MANAGER – NEW DOMINION

CONTACT NUMBER: (918)465-4167

CONTACT NAME/TITLE: TIM BAKER/ POLLUTION ABATEMENT MANAGER-OCC

CONTACT NUMBER: (405)522-2763

WATER MANAGEMENT TECHNOLOGIES/PRACTICES IN PLACE

DESCRIPTION: A DEEP INJECTION WELL, NAMED "DEEP THROAT" HAS BEEN CONSTRUCTED IN THE MATURE OKLAHOMA CITY FIELD IN ORDER TO DISPOSE OF LARGE VOLUMES OF WATER THAT ARE PRODUCED AS A RESULT OF THE DEWATERING TECHNIQUE THAT IS BEING EMPLOYED BY NEW DOMINION, LLC. DEEP THROAT IS COMPLETED AS A MULTI-LATERAL HORIZONTAL DISPOSAL WELL IN THE LOWER ARBUCKLE FORMATION (OVER 8,000' TOTAL DEPTH), AND IT IS PERMITTED TO DISPOSE OF 60,000 BBLS/DAY. THE OIL AND GAS IS BEING PRODUCED FROM THE UPPER PORTION OF THE ARBUCKLE FORMATION (~6,000' DEPTH). THE WATER PRODUCED IS EXTREMELY HIGH IN TDS, AND THE OKLAHOMA CITY FIELD IS IN THE MIDDLE OF A HIGHLY POPULATED AREA DUE TO THE GROWTH OF OKLAHOMA CITY, THEREFORE THE ONLY FEASIBLE OPTION TO MANAGE THE HIGH VOLUMES OF WATER IS TO INJECT IT.

ENVIRONMENTAL IMPACTS/BENEFITS: THERE ARE NO KNOWN BENEFICIAL USES FOR THE HIGH TDS WATER, AND DUE TO THE PROXIMITY TO RESIDENTIAL AREAS, THE MAJOR ENVIRONMENTAL CONCERN IS FOR HUMAN SAFETY FOR THE SURROUNDING NEAIGHBORHOODS. PIPELINES CARRYING THE OIL, WATER, AND GAS ARE ALL BELOW GRADE, AND CARE HAS BEEN TAKEN TO RESTORE ALL PIPELINE CORRIDORS. DUE TO THE PROXIMITY OF HUMAN INHABITANCE, THE DRILLING SITES HAVE BEEN CONDENSED TO A SMALL AREA (~6 CONTIGUOUS ACRES FOR 8 DRILLING SITES). MULTI-LATERAL HORIZONTAL DRILLING TECHNOLOGY IS UTILIZED TO COMPLETE THE WELLS IN VARIOUS FORMATIONS, OVER A LARGE AREA, WHILE ONLY DISTURBING THIS SMALL SURFACE AREA.

APPLICABILITY: MULTI-LATERAL DEEP WELL INJECTION IS BEST SUITED FOR HIGHLY POPULATED AREAS, WHERE THE VOLUME OF WATER IS CONSIDERABLY LARGE, AND/OR THE QUALITY OF THE WATER IS SUCH THAT NO BENEFICIAL USE CAN BE REALIZED.

COST: NO INFORMATION WAS COLLECTED ON THE CAPITAL COST TO DRILL "DEEP THROAT". THE COST TO HAVE IT WORKED ON, AS IT WAS BEING WORKED ON DURING THE SITE VISIT, IS APPROXIMATELY $15,000/DAY.

ADDITIONAL NOTES: NONE

DATE: 7/6/2005____ INFORMATION COLLECTED BY: _ JAKE CRISSUP

IDENTIFICATION, VERIFICATION, AND COMPILATION OF
PRODUCED WATER MANAGEMENT PRACTICES
FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

PHOTO LOG

VIEW OF THE WELL HEAD FOR "DEEP THROAT" THE DEEP MULTI-LATERAL DISPOSAL WELL

VIEW OF THE DRILL RIG SETTING UP TO WORK ON "DEEP THROAT"

VIEW OF THE WELL HEAD OF A PRODUCING WELL

VIEW OF THE 3 PHASE SEPARATOR THAT IS SPECIALLY DESIGNED FOR A HIGH SEPARATION EFFICIENCY OF WATER, OIL, AND GAS

VIEW OF A FOUNDATION THAT HAS BEEN CONSTRUCTED FOR AN ADDITIONAL 3 PHASE SEPARATOR

VIEW OF TRANSMISSION LINES CONSTRUCTED TO ALLOW FOR FUTURE GROWTH

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF

PRODUCED WATER MANAGEMENT PRACTICES

FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF
PRODUCED WATER MANAGEMENT PRACTICES
FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE INFORMATION

OFFICE ADDRESS: 1110 W. STOVALL ROAD

CITY: WILBURTON STATE: OK COUNTY: LATIMER

BASIN: RED OAK FIELD: RED OAK

CONTACT NAME/TITLE: JAY EUBANKS/ FIELD ENV. COORD. – BP AMERICA

CONTACT NUMBER: (918)465-4167

CONTACT NAME/TITLE: TIM BAKER/ POLLUTION ABATEMENT MANAGER-OCC

CONTACT NUMBER: (405)522-2763

WATER MANAGEMENT TECHNOLOGIES/PRACTICES IN PLACE

DESCRIPTION: CURRENTLY, BP ESTIMATES THAT THEY HAVE 450 ACTIVE PRODUCING WELLS IN THE RED OAK FIELD. IN 2004, A PILOT PROGRAM WAS INITIATED BY BP TO PROMOTE FLOOD IRRIGATION AROUND WELL SITES USING THE PRODUCED WATER TO IRRIGATE THE LAND VERSUS HAVING THE WATER HAULED OFF FOR DISPOSAL. CURRENTLY, 13 WELLS ARE PERMITTED, WITH LANDOWNER APPROVAL, TO UTILIZE THE WATER FOR FLOOD IRRIGATION. BP PLANS TO HAVE AS MANY AS 100 WELLS PERMITTED, WITH LANDOWNER APPROVAL, USING THE SAME TECHNIQUES BY THE END OF 2005.

AN AVERAGE OF ½ BBL OF WATER IS PRODUCED FOR EVERY 100,000 CUBIC FEET (CF) OF GAS PRODUCED. THE WATER IS TYPICALLY LOW IN OIL AND GREASE (<1,000 PPM) AND LOW IN TOTAL SUSPENDED SOLIDS (TSS) (<5,000 PPM). THE WATER HAS AN AVERAGE CHLORIDE VALUE BETWEEN 250 AND 500 PPM.

THE OKLAHOMA CORPORATION COMMISSION HAS A REQUIRED APPLICATION FOR SURFACE DISCHARGE THAT SHOULD BE FILED AND APPROVED FOR EACH WELL SITE PRIOR TO FLOOD IRRIGATION ACTIVITIES. THE PERMIT REQUIRES LANDOWNER NOTIFICATION AND APPROVAL, SOIL AND WATER SAMPLES TO BE COLLECTED AND ANALYZED, AND A CALCULATION OF THE APPLICATION RATE BASED ON THE MAXIMUM TSS AND THE MAXIMUM OIL AND GREASE THAT CAN BE APPLIED TO THE LAND ON A PER ACRE BASIS. THE LIMITING CONCENTRATION IS THEN DETERMINED TO BE EITHER TSS OR OIL AND GREASE, DEPENDING ON WHICH CALCULATION IS MORE CONSERVATIVE. THE MAXIMUM TSS THAT CAN BE APPLIED OVER TIME IS 6000 LBS/ACRE, AND THE MAXIMUM OIL AND GREASE THAT CAN BE APPLIED OVER TIME IS 500 LBS/ACRE.

ONCE THE WELL SITE HAS BEEN PROPERLY PERMITTED AND APPROVED, BP CAN THEN COMMENCE THE FLOOD IRRIGATION OF THAT SITE. THE FLOOD IRRIGATION SYSTEM CONSISTS OF CONNECTING A HOSE TO THE DRAIN OF THE STORAGE TANK AT THE WELL SITE (EACH WELL SITE HAS A TANK WITH TEMPORARY STORAGE OF BETWEEN 100 AND 150 BBLS

OF WATER). WHEN THE TANK NEARS CAPACITY, A HOSE IS CONNECTED TO THE DRAIN OF THE TANK, AND A T-FITTING IS CONNECTED TO THE OPPOSITE END OF THE HOSE. TWO PERFORATED HOSES ARE THEN RUN IN OPPOSITE DIRECTIONS INTO THE AREA THAT WILL BE IRRIGATED. THE VALVE AT THE TANK DRAIN IS THEN OPENED AND THE WATER IN THE TANK IS THEN DRAINED INTO THE FIELD, THUS IRRIGATING THE FIELD. BP KEEPS RECORDS OF HOW MUCH WATER IS DISCHARGED, AND WHERE THE WATER IS DISCHARGED TO, SO THAT ONCE THE PERMIT LIMITS HAVE BEEN MET THEY WILL NO LONGER DISCHARGE TO THAT FIELD. THE TANKS TYPICALLY FILL UP IN ABOUT 6 WEEKS. DEPENDING ON THE SOIL AND WATER ANALYTICAL RESULTS, THE FIELDS CAN ACCEPT A WIDE RANGE OF WATER VOLUMES OVER TIME. FOR EXAMPLE, IF A 1 ACRE FIELD IS CALCULATED TO ACCEPT 30,000 BBLS/ACRE, THEN AT A RATE OF 100 BBLS IRRIGATED EVERY 6 WEEKS, THE FIELD CAN BE FLOOD IRRIGATED FOR THE NEXT 34 YEARS BEFORE THE PERMIT LIMITS ARE REACHED. THIS IS A CONSERVATIVE ESTIMATE AS MOST FIELDS CAN ACCEPT MORE THAN 30,000 BBLSS/ACRE, AND MOST FIELDS HAVE MORE THAN 1 ACRE THAT IS ACCESSIBLE TO IRRIGATE.

SOME SITES ARE NOT ACCEPTABLE FOR THIS FLOOD IRRIGATION PRACTICE DUE TO THE TOPOGRAPHY OF THE WELL SITE. GENERALLY, THE WELL NEEDS TO BE LOCATED IN AN AREA WHERE THERE IS A LARGE FLAT (< 3:1 GRADE) AREA TO PREVENT EROSION, AS THE LOAMY SOILS IN THIS AREA CAN BE EROSIVE AT STEEPER GRADES.

ENVIRONMENTAL IMPACTS/BENEFITS: BY UTILIZING THE WATER FOR FLOOD IRRIGATION, IMPROVEMENTS ARE REALIZED BY INCREASED LIVESTOCK AND WILDLIFE FORARING, AND GREATER YIELDS OF HAY.

APPLICABILITY: THE FLOOD IRRIGATION EMPLOYED IN THIS AREA IS ENABLED BY THE QUALITY OF THE WATER (LOW TSS AND LOW OIL AND GREASE), QUALITY OF THE SOIL (LOW TSS), SITE TOPOGRAPHY (< 3:1 GRADE), AND WILLINGNESS OF THE LANDOWNER TO ALLOW THE FLOOD IRRIGATION. SOME LANDOWNERS ARE RELUCTANT TO ALLOW THE FLOOD IRRIGATION TO TAKE PLACE ON THEIR PROPERTY WITHOUT MONETARY COMPENSATION, AT WHICH POINT BP OPTS TO HAVE THE WATER DISPOSED OF THROUGH INJECTION. FURTHERMORE, WATER IS NOT USED FOR FLOOD IRRIGATION IS WEATHER DOES NOT PERMIT DUE TO INCLEMENT CONDITIONS, AT WHICH POINT, THE WATER IS THEN CONTRACTED TO BE HAULED AND DISPOSED THROUGH INJECTION.

COST: THERE IS LITTLE COST ASSOCIATED WITH DISCHARGING THE WATER THROUGH FLOOD IRRIGATION OTHER THAN THE CAPITAL COST OF FABRICATING THE HOSES AND THE OPERATING COST OF THE LABOR HOURS ASSOCIATED WITH MANAGING THE FLOOD IRRIGATION. THE ALTERNATIVE (DISPOSAL INJECTION) IS MORE COSTLY ON A PER BBL BASIS.

ADDITIONAL NOTES: NONE

DATE: 7/7/2005____ INFORMATION COLLECTED BY: _JAKE CRISSUP

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF
PRODUCED WATER MANAGEMENT PRACTICES
FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

PHOTO LOG

VIEW OF A WELL HEAD IN THE RED OAK FIELD THAT USES FLOOD IRRIGATION

VIEW OF THE 150 BARREL TANK THAT WATER IS STORED IN

VIEW OF PERFORATED HOSE THAT IS USED TO FLOOD IRRIGATE

VIEW OF THE TEMPORARY INSTALLATION OF THE FLOOD IRRIGATION SYSTEM

VIEW OF THE DEPLOYMENT OF TEMPORARY FLOOD IRRIGATION SYSTEM

VIEW OF A FLOOD IRRIGATION SYSTEM AS WATER IS DRAINED FROM THE STORAGE TANK

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF

PRODUCED WATER MANAGEMENT PRACTICES

FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE INFORMATION

OFFICE ADDRESS: 16 MILES NORTH HIGHWAY 295

CITY: POWELL STATE: WY COUNTY: PARK

BASIN: BIG HORN FIELD: ELK BASIN

CONTACT NAME/TITLE: JEFF SCHWEIGHART/SENIOR REGULATORY ANALYST –ANADARKO

CONTACT NUMBER: (307) 754-7314

CONTACT NAME/TITLE: CRAIG EGGERMAN/ SENIOR ENV. ANALYST-WYOGCC

CONTACT NUMBER: (307)234-7147

WATER MANAGEMENT TECHNOLOGIES/PRACTICES IN PLACE

DESCRIPTION: VISITED THE SOUTH WATER FLOOD BATTERY 8 (AVG 2100 BBLS WATER/DAY MANAGED), NORTH WATER FLOOD BATTERY 7 (AVG 4400 BBLS WATER/DAY MANAGED), AND NW ELK BASIN (IN MONTANA, 35 GPM WATER MANAGED). A SCALE INHIBITOR IS APPLIED TO THE WATER PRIOR TO PUTTING THE WATER INTO THE TREATMENT SYSTEMS FOR THE TWO WATER FLOOD BATTERIES. THE TREATMENT SYSTEM TREATS THE WATER PRIOR TO DISCHARGE BY RUNNING THE WATER THROUGH SEVERAL PITS/BASINS WHERE BOOMS ARE EMPLOYED TO SEPARATE THE OIL ON THE SURFACE OF THE WATER AND OIL IS SKIMMED OFF OF THE TOP OF THE WATER (PHYSICAL TREATMENT). THE DISCHARGE WATER FLOWS FROM THROUGH A T-SYPHON AND DISCHARGES TO THE SILVER TIP CREEK, WHICH FLOWS NORTH, INTO MONTANA. THE CONFLUENCES WITH SILVER TIP CREEK WERE ALSO VISITED, ALONG WITH THE "SAFETY PITS" THAT ARE USED TO PREVENT SPILLS FROM MIGRATING FURTHER DOWNSTREAM (ADDITIONAL T-SYPHONS AT CRITICAL POINTS SUCH AS ROAD CROSSINGS). THE NW ELK BASIN DISCHARGE IS ON THE MONTANA SIDE OF ELK BASIN, AND IT DISCHARGES JUST UPSTREAM OF A WASHED OUT DAM ALONG SILVER TIP CREEK. THE WASHED OUT DAM IS CURRENTLY AWAITING APPROVAL FROM MDEQ FOR THE WORKPLAN THAT HAS BEEN DEVELOPED TO REMEDIATE THE SITE AFTER A SPILL THAT OCCURRED EARLIER THIS YEAR. THE DAM WASHED OUT DURING A STORM EVENT AS IT HAD NO PRIMARY/EMERGENCY SPILLWAY TO ELEVIATE THE FLOOD CONDITIONS.

ENVIRONMENTAL IMPACTS/BENEFITS: DISCHARGED WATER IS CONSUMED BY CATTLE, DEER, AND OTHER WILDLIFE, AND HABITAT IS CREATED FOR WILDLIFE WHERE NONE WOULD BE PRESENT DUE TO THE SEASONAL CONDITION OF THE DRAINAGE (ONLY FLOWS DURING STORM EVENTS). THE WATER IS ALSO USED FOR IRRIGATION BY LOCAL FARMERS FOR WATERING CROPS.

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF

PRODUCED WATER MANAGEMENT PRACTICES

FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

APPLICABILITY: THE IRRIGATION INFRASTRUCTURE IN THE BIG HORN BASIN ALLOW FOR MUCH OF THE PRODUCED WATER TO BE USED BY LOCAL FARMERS AND RANCHERS FOR IRRIGATING CROPS AND KEEPING STOCK PONDS FULL OF WATER.

COST: NO INFORMATION WAS COLLECTED ON COST, BUT ANADARKO INDICATED THAT IF THE WYPDES REQUIREMENTS BECOME ANY MORE STRINGENT IT WILL BE MORE COST EFFECTIVE TO DISPOSE OF THE WATER THROUGH INJECTION.

ADDITIONAL NOTES: EROSION IS A PROBLEM AT DISCHARGE POINTS, DUE TO THE SOIL CONDITIONS AND THE DIFFICULTY WITH ESTABLISHING VEGETATION THAT IS NOT CONSIDERED NOXIOUS WEEDS.

THE EPA (JANE NACKETT) HAS HAD A DIFFICULT TIME ACCEPTING THE "SAFETY PIT" PRACTICE FRO SPILL PREVENTION AND MANAGEMENT. WYOGCC AND ANADARKO POINTED OUT THAT IT IS UNREALISTIC TO BUILD BERMS IN THIS TERRAIN (LOTS OF HILLS AND STEEP GRADES) THAT WILL HOLD THE AMOUNT OF WATER THAT MAY BE DISCHARGED IN THE EVENT OF A SPILL (UNTREATED OILY WATER IS THE MAIN CONCERN FOR SPILLS AT THIS FIELD).

THE 230 PPM CHLORIDE RULE IS ALSO A CONCERN IF A WAIVER IS NOT EXTENDED TO THE OIL AND GAS INDUSTRY AS IT WILL MAKE IT UNFEASIBLE TO DISCHARGE AND MEET THE WYPDES REQUIREMENTS.

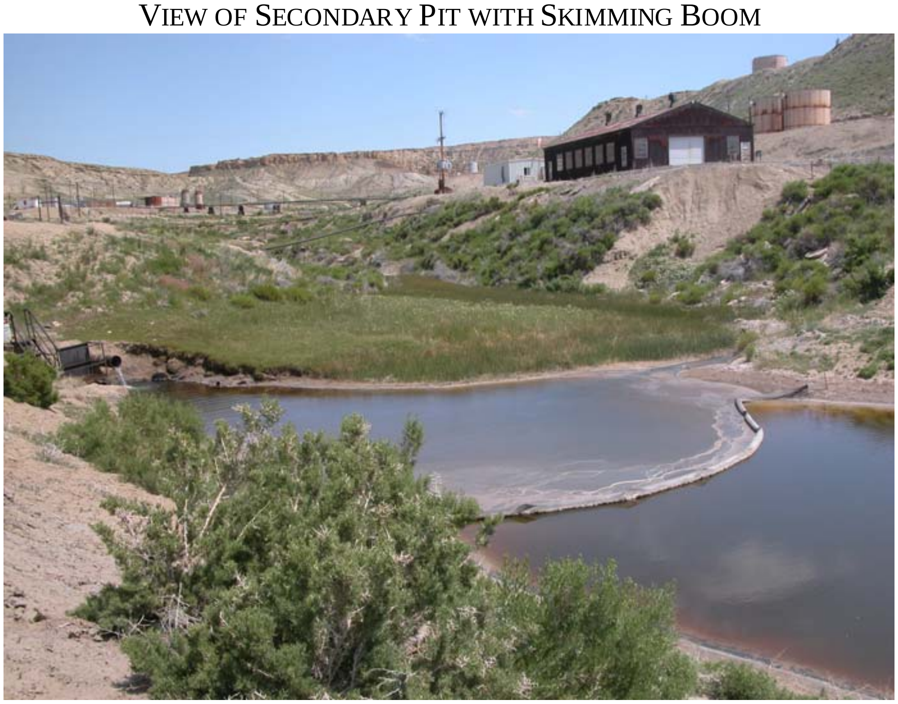
DATE: 6/27/2005____ INFORMATION COLLECTED BY: _JON SEEKINS, JAKE CRISSUP

IDENTIFICATION, VERIFICATION, AND COMPILATION OF
PRODUCED WATER MANAGEMENT PRACTICES
FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

PHOTO LOG

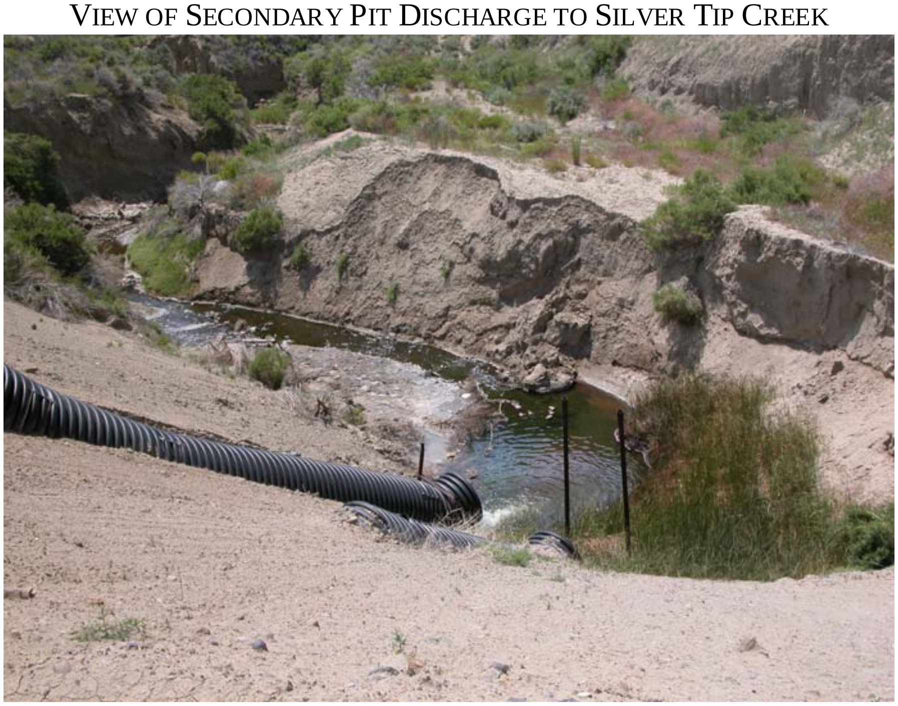
VIEW OF ELK BASIN FIELD ENTRANCE

VIEW OF SECONDARY PIT WITH SKIMMING BOOM



VIEW OF SECONDARY PIT T-SIPHON TO PREVENT OIL FROM DISCHARGING

VIEW OF SECONDARY PIT DISCHARGE TO SILVER TIP CREEK



IDENTIFICATION, VERIFICATION, AND COMPILATION OF
PRODUCED WATER MANAGEMENT PRACTICES
FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

VIEW OF T-SIPHONS IN SILVER TIP CREEK DRAINAGE TO
PREVENT OIL SPILLS FROM MIGRATING DOWNSTREAM

VIEW OF A PRIMARY PIT WITH NETTING TO PROTECT WILDLIFE

IDENTIFICATION, VERIFICATION, AND COMPILATION OF
PRODUCED WATER MANAGEMENT PRACTICES
FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

VIEW OF A SURFACE DISCHARGE AFTER OIL HAS BEEN SKIMMED FROM WATER

VIEW OF A LIVESTOCK/WILDLIFE WATER HOLE SUPPLIED BY PRODUCED WATER

VIEW OF A PIT WHERE OIL IS SEPARATED FROM THE DISCHARGE WITH A T-SIPHON

CLOSER VIEW OF A PIT WHERE OIL IS SEPARATED FROM THE DISCHARGE WITH A T-SIPHON

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF

PRODUCED WATER MANAGEMENT PRACTICES

FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF
PRODUCED WATER MANAGEMENT PRACTICES
FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE INFORMATION

OFFICE ADDRESS: 1501 STAMPEDE AVE.

CITY: CODY STATE: WY COUNTY: PARK

BASIN: BIG HORN FIELD: GARLAND

CONTACT NAME/TITLE: MARVIN BLAKESLEY/HES PROFESSIONAL – MARATHON

CONTACT NUMBER: (307) 527-2127

CONTACT NAME/TITLE: RON ???/TECHNICIAN? – MARATHON

CONTACT NAME/TITLE: CRAIG EGGERMAN/ SENIOR ENV. ANALYST-WYOGCC

CONTACT NUMBER: (307)234-7147

WATER MANAGEMENT TECHNOLOGIES/PRACTICES IN PLACE

DESCRIPTION: VISITED THE ARNOLDUS LAKE WHERE AN AVERAGE OF 80,000 BBLS WATER/DAY IS DISCHARGED. PRIOR TO DISCHARE, THE WATER IS PRETREATED TO SKIM OIL IN FOUR GRAVITY FLOW BASINS/PITS. ALL FOURS PITS ARE COVERED WITH NETTING TO PREVENT BIRDS FROM COMING INTO CONTACT WITH THE WATER PRIOR TO DISCHARGE. BETWEEN THE THIRD AND FOURTH BASIN THERE IS A CONCRETE DITCH THAT IS SEVERAL HUNDRED YARDS LONG THAT ACTS TO FURTHER AERATE THE WATER. HYDROGEN SULFIDE IS A CONCERN. IN ADDITION TO THE WATER DISCHARED TO ARNOLDUS LAKE, THERE ARE 8 INJECTION WELLS THAT ALSO DISPOSE OF WATER INTO THE MADISON FORMATION. ONE OF THE WELLS IS CAPABLE OF DISPOSING 50,000 BBLS/DAY.

ENVIRONMENTAL IMPACTS/BENEFITS: THE LAKE IS A LOW SPOT IN THE TOPOGRAPHY, AND WOULD BE A PLAYA LAKE IF NOT FOR THE PRODUCED WATER DISCHARGE. SEVERAL WATER FOWL USE THE LAKE AS HABITAT, AND THE WATER FOWL IS HUNTED FOR RECREATIONAL PURPOSES AS WELL.

APPLICABILITY: THE IRRIGATION INFRASTRUCTURE IN THE BIG HORN BASIN ALLOW FOR MUCH OF THE PRODUCED WATER TO BE USED BY LOCAL FARMERS AND RANCHERS FOR IRRIGATING CROPS AND KEEPING STOCK PONDS FULL OF WATER.

COST: NO INFORMATION WAS COLLECTED ON COST, BUT MARATHON INDICATED THAT IF THE WYPDES REQUIREMENTS BECOME ANY MORE STRINGENT IT WILL BE MORE COST EFFECTIVE TO DISPOSE OF THE WATER THROUGH INJECTION.

ADDITIONAL NOTES: THE EPA (JANE NACKETT) HAS HAD A DIFFICULT TIME ACCEPTING THE "SAFETY PIT" PRACTICE FOR SPILL PREVENTION AND MANAGEMENT. WYOGCC AND MARATHON POINTED OUT THAT IT IS UNREALISTIC TO BUILD BERMS THAT WILL HOLD THE

AMOUNT OF WATER THAT MAY BE DISCHARGED IN THE EVENT OF A SPILL (UNTREATED OILY WATER IS THE MAIN CONCERN FOR SPILLS AT THIS FIELD).

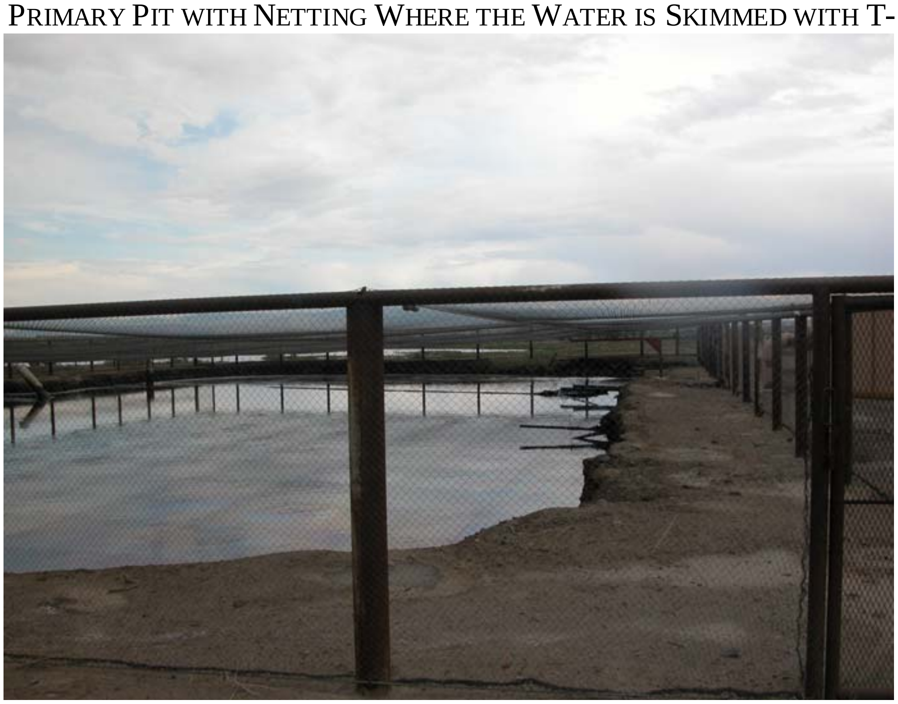
THE 230 PPM CHLORIDE RULE IS ALSO A CONCERN IF A WAIVER IS NOT EXTENDED TO THE OIL AND GAS INDUSTRY AS IT WILL MAKE IT UNFEASIBLE TO DISCHARGE AND MEET THE WYPDES REQUIREMENTS.

DATE: 6/27/2005____ INFORMATION COLLECTED BY: _JON SEEKINS, JAKE CRISSUP

PHOTO LOG

VIEW OF ARNOLDUS LAKE WHERE AND AVERAGE OF 80,000 BBLS/DAY IS DISCHARGED

VIEW OF PRIMARY PIT WITH NETTING WHERE THE WATER IS SKIMMED WITH T-SIPHONS



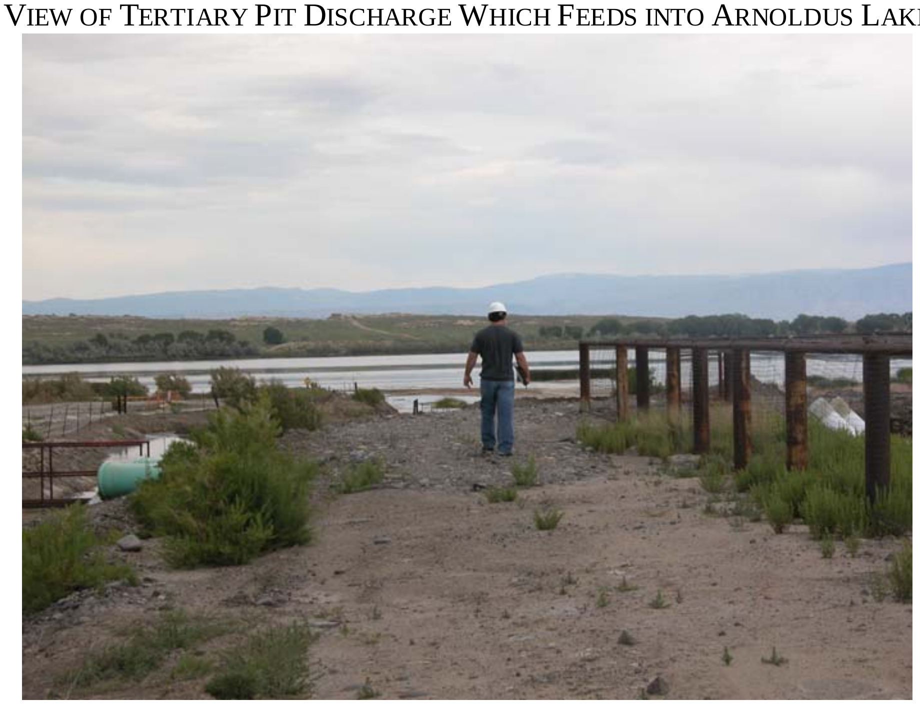
VIEW OF SECONDARY PIT WITH NETTING WHERE THE WATER IS POLISHED FURTHER WITH T-SIPHONS

VIEW OF SECONDARY PIT DISCHARGE WHERE WATER IS AERATED

VIEW OF WATER CHANNEL AFTER SECONDARY PIT, WHICH FEEDS INTO THE TERTIARY PIT

VIEW OF TERTIARY PIT WHERE FINAL POLISHING IS COMPLETED WITH A T-SIPHON

VIEW OF TERTIARY PIT DISCHARGE WHICH FEEDS INTO ARNOLDUS LAKE



CLOSER VIEW OF TERTIARY PIT DISCHARGE WHICH FEEDS INTO ARNOLDUS LAKE

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF

PRODUCED WATER MANAGEMENT PRACTICES

FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF

PRODUCED WATER MANAGEMENT PRACTICES

FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE INFORMATION

OFFICE ADDRESS: ______________________________

CITY: HAMILTON DOME__________ STATE: WY__ COUNTY: HOT SPRINGS___________

BASIN: BIG HORN_________FIELD: HAMILTON DOME____

CONTACT NAME/TITLE: ROGER HART/FIELD TECHNICIAN – MERIT

CONTACT NUMBER: (307)_________

CONTACT NAME/TITLE: CRAIG EGGERMAN/ SENIOR ENV. ANALYST-WYOGCC

CONTACT NUMBER: (307)234-7147

WATER MANAGEMENT TECHNOLOGIES/PRACTICES IN PLACE

DESCRIPTION: VISITED THE TWO DISCHARGES AT HAMILTON DOME. BOTH DISCHARGES ARE WYPDES DISCHARGE POINTS, AND HAVE PITS THAT ARE UTILIZED TO SKIM OIL FROM THE SURFACE OF THE WATER PRIOR TO DISCHARGE. IN 2004, WYPDES PERMIT # WY0000680, ALSO KNOWN AS THE "PLACER RATHVON", DISCHARGED AN AVERAGE OF 128,000-130,000 BBLS/DAY AND INJECTED ANYWHERE FROM 0-4700 BBLS/DAY. MEANWHILE, WYPDES PERMIT # WY0000175, ALSO KNOWN AS THE "CEMENT PIT", DISCHARGED AN AVERAGE OF 50,000-68,000 BBLS/DAY AND INJECTED ANYWHERE FROM 43,000-69,000 BBLS/DAY. BOTH DISCHARGES ARE BENEFICIALLY USED FOR IRRIGATION PURPOSES BY LOCAL LANDOWNERS. THE PLACER RATHVON SYSTEM IS CHANNELIZED AND PIPED INTO AN EXTENSIVE IRRIGATION SYSTEM THAT IRRIGATES SEVERAL THOUSAND ACRES OF ALFALFA FIELDS, AND THE CEMENT PIT SYSTEM IS CHANNELIZED AND HAS SEVERAL DIVERSION BOXES ALONG THE CHANNEL WHERE THE LOCAL LANDOWNER DIVERTS THE WATER AS NEEDED TO FLOOD IRRIGATE HIS LAND. ALL WATER NOT DIVERTED IS DISCHARGED TO A DOWNSTREAM WATER RIGHTS HOLDER ON THE COTTONWOOD CREEK TO ENHANCE RIPRARIAN HABITAT AND WATER LIVESTOCK. DURING NON-GROWING SEASON WHEN IRRIGATION IS NOT NECESSARY, THE WATER FROM THE PLACER RATHVON DISCHARGE IS DIVERTED TO LAKE CHARLIE, WHICH HAS T-SIPHONS TO PREVENT A SPILL FROM REACHING COTTONWOOD CREEK. MERIT HAS 250 OIL PRODUCING WELLS IN THIS FIELD, AND UTILIZES 80 INJECTION WELLS.

ENVIRONMENTAL IMPACTS/BENEFITS: IF NOT FOR THE PRODUCED WATER DISCHARGES, THERE WOULD NOT BE ENOUGH WATER TO IRRIGATE THE LAND IN THE HAMILTON DOME FIELD, AND THE FARMERS WOULD NOT BE ABLE TO ACHIEVE THE SAME LEVEL OF SUCCESS THEY ARE CURRENTLY EXPERIENCING.

APPLICABILITY: THE IRRIGATION INFRASTRUCTURE IN THE BIG HORN BASIN ALLOW FOR MUCH OF THE PRODUCED WATER TO BE USED BY LOCAL FARMERS AND RANCHERS FOR IRRIGATING CROPS AND KEEPING STOCK PONDS FULL OF WATER.

Identification, Verification, and Compilation of
Produced Water Management Practices
for Conventional Oil and Gas Production Operations

Cost: No information was collected on cost, but Merit indicated that if the WYPDES requirements become any more stringent (notably for chlorides) it will be more cost effective to dispose of the water through injection. This would deny the farmers from utilizing the beneficial use of irrigation with the produced water.

Additional Notes: The EPA (Jane Nackett) has had a difficult time accepting the "safety Pit" practice for spill prevention and management. WYOGCC and Merit pointed out that it is unrealistic to build berms that will hold the amount of water that may be discharged in the event of a spill (untreated oily water is the main concern for spills at this field).

The 230 ppm chloride rule is also a concern if a waiver is not extended to the oil and gas industry as it will make it unfeasible to discharge and meet the WYPDES requirements. It is believed that the 230 ppm for chlorides has been established to protect certain aquatic life. WY is the only state that has a chloride standard for class III waters.

Date: 6/28/2005____ Information Collected by: _Jon Seekins, Jake Crissup

PHOTO LOG

VIEW OF "PLACER RATHVON" SECONDARY PIT WHERE WATER IS POLISHED WITH A T-SIPHON BEFORE DISCHARGE TO IRRIGATION FIELD

VIEW OF "PLACER RATHVON" SECONDARY PIT DISCHARGE TO IRRIGATION FIELD

VIEW OF WATER IN CHANNEL GRAVITY FLOWING TO IRRIGATION FIELD

VIEW OF ALFALFA FIELDS THAT BENEFIT FROM IRRIGATION IN HAMILTON DOME

VIEW OF LAKE CHARLIE (BYPASS RESERVOIR DURING NON-GROWING SEASON)

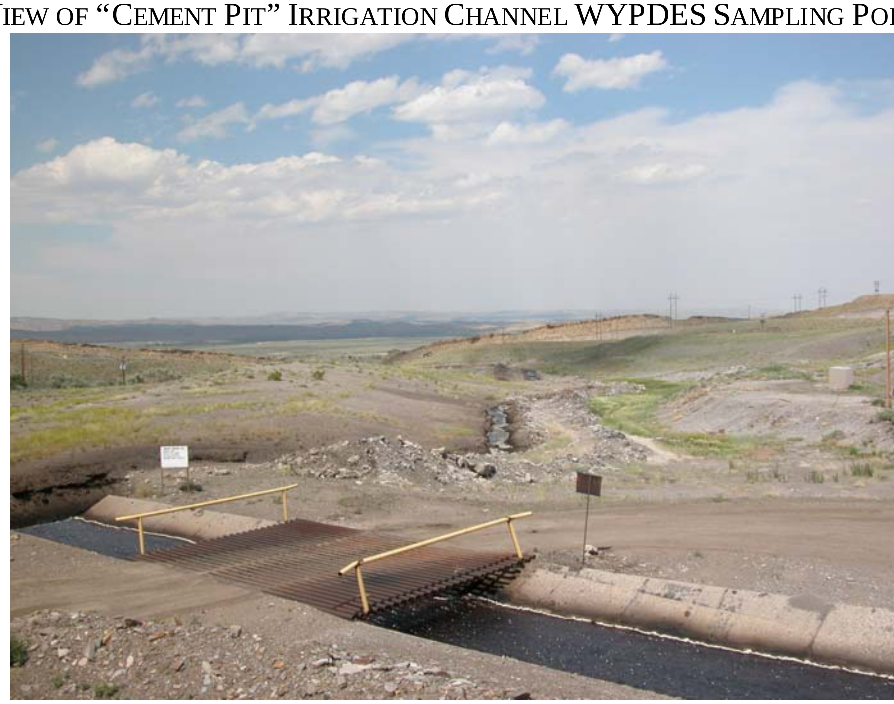
CLOSER VIEW OF LAKE CHARLIE T-SIPHONS USED TO PREVENT

SPILLS FROM ENTERING COTTONWOOD CREEK DRAINAGE

VIEW OF "CEMENT PIT" PRIMARY PIT INPUT WITH NETTING TO PROTECT WILDLIFE

VIEW OF "CEMENT PIT" PRIMARY PIT DISCHARGE TO IRRIGATION CHANNEL

VIEW OF "CEMENT PIT" IRRIGATION CHANNEL WYPDES SAMPLING POINT



SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF

PRODUCED WATER MANAGEMENT PRACTICES

FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

VIEW OF "CEMENT PIT" IRRIGATION CHANNEL DIVERSION BOX USED FOR FLOOD IRRIGATION

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF
PRODUCED WATER MANAGEMENT PRACTICES
FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE INFORMATION

OFFICE ADDRESS: PO BOX 127

CITY: MEETEETSE STATE: WY COUNTY: PARK

BASIN: BIG HORN FIELD: LITTLE BUFFALO BASIN

CONTACT NAME/TITLE: KEITH LARSON/PRODUCTION FOREMAN – CITATION

CONTACT NUMBER: (307) 868-9300

CONTACT NAME/TITLE: LARRY PUTNEY/FIELD TECHNICIAN – CITATION

CONTACT NAME/TITLE: CRAIG EGGERMAN/ SENIOR ENV. ANALYST-WYOGCC

CONTACT NUMBER: (307)234-7147

WATER MANAGEMENT TECHNOLOGIES/PRACTICES IN PLACE

DESCRIPTION: VISITED THE TWO DISCHARGES INTO BUFFALO CREEK. BOTH DISCHARGES ARE WYPDES DISCHARGE POINTS, AND HAVE SEVERAL PITS THAT ARE UTILIZED TO SKIM OIL FROM THE SURFACE OF THE WATER PRIOR TO DISCHARGE. CITATION HAS 70 OIL PRODUCING WELLS IN THIS FIELD, AND UTILIZES 140 INJECTION WELLS, WHICH ARE MOSTLY CONVERTED OIL WELLS THAT WERE NON-PRODUCING. OF THE 116,500 BBLS OF WATER PRODUCED DAILY, APPROXIMATELY 72,000 BBLS OF WATER IS REINJECTED FOR SECONDARY RECOVERY. 2,800 BBLS WATER/DAY IS THE MOST A WELL WILL ACCEPT IN THEIR FIELD, AND SOME WELLS ACCEPT AS LITTLE AS 50 BBLS/DAY.

ENVIRONMENTAL IMPACTS/BENEFITS: IF NOT FOR THE PRODUCED WATER DISCHARGES, BUFFALO CREEK WOULD BE AN INTERMITTENT STREAM THAT WOULD BE DRY MOST OF THE YEAR. THE PRODUCED WATER HAS CREATED SOME RIPRARIAN HABITAT WHICH PROMOTES ANTELOPE, DEER, WATERFOWL, AMONG OTHER WILDLIFE SPECIES.

APPLICABILITY: THE IRRIGATION INFRASTRUCTURE IN THE BIG HORN BASIN ALLOW FOR MUCH OF THE PRODUCED WATER TO BE USED BY LOCAL FARMERS AND RANCHERS FOR IRRIGATING CROPS AND KEEPING STOCK PONDS FULL OF WATER.

COST: NO INFORMATION WAS COLLECTED ON COST, BUT CITATION INDICATED THAT IF THE WYPDES REQUIREMENTS BECOME ANY MORE STRINGENT (NOTABLY FOR CHLORIDES) IT WILL BE MORE COST EFFECTIVE TO DISPOSE OF THE WATER THROUGH INJECTION.

ADDITIONAL NOTES: THE EPA (JANE NACKETT) HAS HAD A DIFFICULT TIME ACCEPTING THE "SAFETY PIT" PRACTICE FOR SPILL PREVENTION AND MANAGEMENT. WYOGCC AND CITATION POINTED OUT THAT IT IS UNREALISTIC TO BUILD BERMS THAT WILL HOLD THE

AMOUNT OF WATER THAT MAY BE DISCHARGED IN THE EVENT OF A SPILL (UNTREATED OILY WATER IS THE MAIN CONCERN FOR SPILLS AT THIS FIELD).

THE 230 PPM CHLORIDE RULE IS ALSO A CONCERN IF A WAIVER IS NOT EXTENDED TO THE OIL AND GAS INDUSTRY AS IT WILL MAKE IT UNFEASIBLE TO DISCHARGE AND MEET THE WYPDES REQUIREMENTS. IT IS BELIEVED THAT THE 230 PPM FOR CHLORIDES HAS BEEN ESTABLISHED TO PROTECT CERTAIN AQUATIC LIFE. WY IS THE ONLY STATE THAT HAS A CHLORIDE STANDARD FOR CLASS III WATERS.

DATE: 6/28/2005____ INFORMATION COLLECTED BY: _JON SEEKINS, JAKE CRISSUP

PHOTO LOG

VIEW OF LITTLE BUFFALO BASIN FIELD OFFICE ENTRANCE

VIEW OF INJECTION WELL UTILIZED FOR ENHANCED RECOVERY

VIEW OF FIRST PIT WITH T-SIPHON TO PREVENT OIL FROM DISCHARGING

VIEW OF FIRST PIT'S DISCHARGE TO BUFFALO CREEK

VIEW OF SECOND PIT WITH TWO T-SIPHONS TO PREVENT OIL FROM DISCHARGING

VIEW OF SECOND PIT'S DISCHARGE TO BUFFALO CREEK

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF
PRODUCED WATER MANAGEMENT PRACTICES
FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE INFORMATION

OFFICE ADDRESS: 1501 STAMPEDE AVE.

CITY: CODY STATE: WY COUNTY: PARK

BASIN: BIG HORN FIELD: OREGON BASIN

CONTACT NAME/TITLE: MARVIN BLAKESLEY/HES PROFESSIONAL – MARATHON

CONTACT NUMBER: (307) 527-2127

CONTACT NAME/TITLE: CRAIG EGGERMAN/ SENIOR ENV. ANALYST-WYOGCC

CONTACT NUMBER: (307)234-7147

WATER MANAGEMENT TECHNOLOGIES/PRACTICES IN PLACE

DESCRIPTION: VISITED THE CUSTER LAKE WHERE AN AVAERAGE OF 30,000 BBLS OF WATER/DAY IS DISCHARGED TO. THERE WERE NO DISCHARGES TODAY, AND MARATHON INDICATED THAT SOME WORK WAS PROBABLY BEING DONE. THE WATER IS PRE-TREATED PRIOR TO DISCHARGE INTO CUSTER LAKE BY RUNNING THE WATER THROUGH SEVERAL PITS THROUGH GRAVITY FLOW AND SKIMMING OIL OFF OF THE SURFACE OF THE WATER THROUGH A SERIES OF BOOMS. A T-SYPHON IS EMPLOYED AT EACH PIT TO MINIMIZE OIL PROGRESSION TO THE NEXT PIT. APPROXIMATELY 500,000 BBLS OF WATER/DAY IS PRODUCED IN THIS FIELD, AND 400,000 BBLS/DAY OF IT IS REINJECTED INTO THE MADISON FORMATION FOR SECONDARY RECOVERY. LOCH CATRIN IS FURTHER DOWNSTREAM FROM CUSTER LAKE, AND PORTIONS OF LOCH CATRIN HAVE DRIED UP BECAUSE THE WATER HAS NOT MADE IT THAT FAR DOWNSTREAM FOR SOME TIME.

ENVIRONMENTAL IMPACTS/BENEFITS: SEVERAL SPECIES OF WILDLIFE AND WATER FOWL USE THE LAKE AS HABITAT, AND THE WATER FOWL IS HUNTED FOR RECREATIONAL PURPOSES AS WELL.

APPLICABILITY: THE IRRIGATION INFRASTRUCTURE IN THE BIG HORN BASIN ALLOW FOR MUCH OF THE PRODUCED WATER TO BE USED BY LOCAL FARMERS AND RANCHERS FOR IRRIGATING CROPS AND KEEPING STOCK PONDS FULL OF WATER.

COST: NO INFORMATION WAS COLLECTED ON COST, BUT MARATHON INDICATED THAT IF THE WYPDES REQUIREMENTS BECOME ANY MORE STRINGENT (NOTABLY FOR CHLORIDES) IT WILL BE MORE COST EFFECTIVE TO DISPOSE OF THE WATER THROUGH INJECTION. MARATHON HAS ESTIMATED THAT BASIN WIDE IT WOULD COST THEM 12-15 MILLION DOLLARS IN CAPITAL COSTS TO CONVERT TO A 100% DISPOSAL OPTION THROUGH REINJECTION, AND ABOUT 1-2 MILLION IN OPERATING COSTS PER YEAR.

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF

PRODUCED WATER MANAGEMENT PRACTICES

FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

ADDITIONAL NOTES: THE EPA (JANE NACKETT) HAS HAD A DIFFICULT TIME ACCEPTING THE "SAFETY PIT" PRACTICE FOR SPILL PREVENTION AND MANAGEMENT. WYOGCC AND MARATHON POINTED OUT THAT IT IS UNREALISTIC TO BUILD BERMS THAT WILL HOLD THE AMOUNT OF WATER THAT MAY BE DISCHARGED IN THE EVENT OF A SPILL (UNTREATED OILY WATER IS THE MAIN CONCERN FOR SPILLS AT THIS FIELD).

THE 230 PPM CHLORIDE RULE IS ALSO A CONCERN IF A WAIVER IS NOT EXTENDED TO THE OIL AND GAS INDUSTRY AS IT WILL MAKE IT UNFEASIBLE TO DISCHARGE AND MEET THE WYPDES REQUIREMENTS. IT IS BELIEVED THAT THE 230 PPM FOR CHLORIDES HAS BEEN ESTABLISHED TO PROTECT CERTAIN AQUATIC LIFE. WY IS THE ONLY STATE THAT HAS A CHLORIDE STANDARD FOR CLASS III WATERS.

DATE: 6/28/2005____ INFORMATION COLLECTED BY: _JON SEEKINS, JAKE CRISSUP

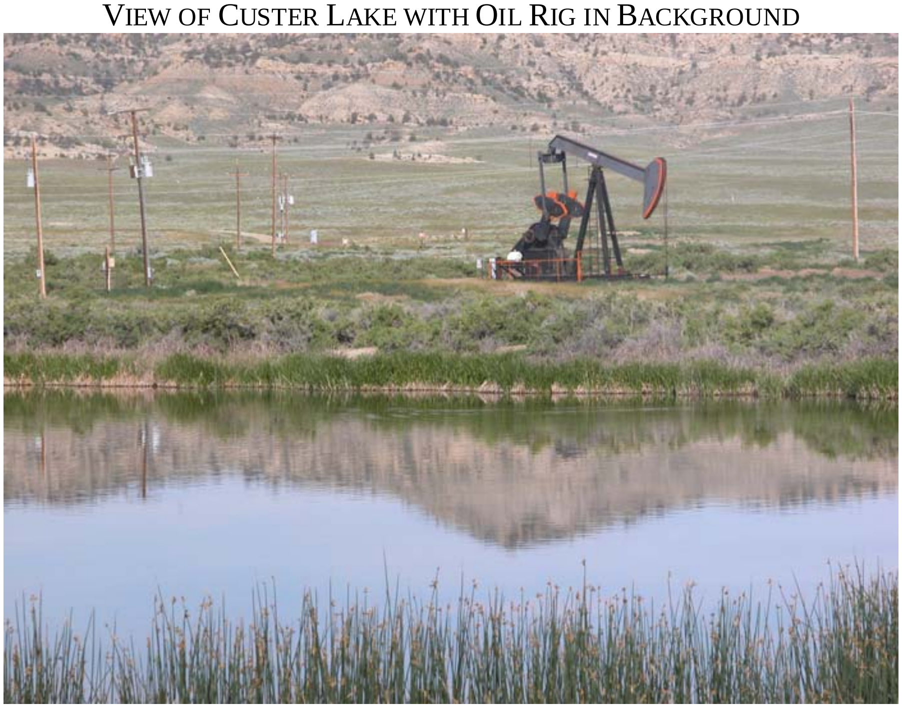
SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF
PRODUCED WATER MANAGEMENT PRACTICES
FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

PHOTO LOG

VIEW OF ENTRANCE TO OREGON BASIN FIELD

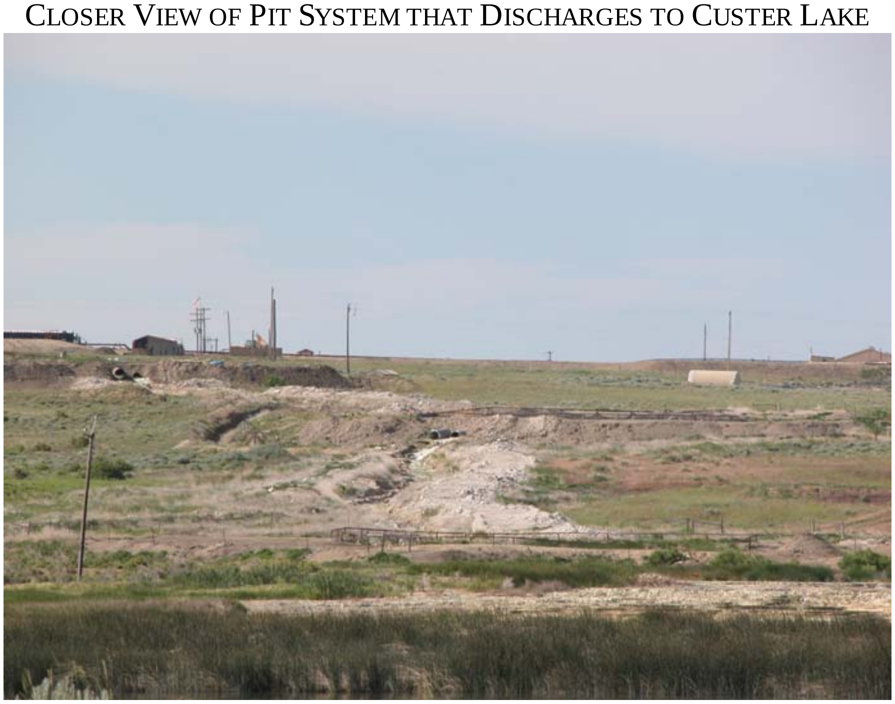
VIEW OF CUSTER LAKE WITH OIL RIG IN BACKGROUND



IDENTIFICATION, VERIFICATION, AND COMPILATION OF
PRODUCED WATER MANAGEMENT PRACTICES
FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

VIEW OF CUSTER LAKE WITH PIT SYSTEM IN BACKGROUND

CLOSER VIEW OF PIT SYSTEM THAT DISCHARGES TO CUSTER LAKE



SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF

PRODUCED WATER MANAGEMENT PRACTICES

FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE INFORMATION

OFFICE ADDRESS: SITE VISITED NORTH OF I-90

CITY: BETWEEN GILLETTE AND BUFFALO STATE: WY COUNTY: JOHNSON

BASIN: POWDER RIVER FIELD: PRB CBM

CONTACT NAME/TITLE: RICK WAAS/ DRILLING INSPECTOR-WYOGCC

CONTACT NUMBER: (307)358-4101

WATER MANAGEMENT TECHNOLOGIES/PRACTICES IN PLACE

DESCRIPTION: AN EMIT WATER TREATMENT PLANT WAS VISITED NORTH OF I-90 JUST OFF OF THE POWDER RIVER. THE WATER TREATMENT PLANT WAS NOT DISCHARGING AT THE TIME OF THE VISIT. THE FOLLOWING PROCESS DESCRIPTION WAS TAKEN FROM THE EMIT TECHNOLOGIES WEBSITE, WWW.EMITTECHNOLOGIES.COM :

COMMERCIALLY AVAILABLE CATION & ANION RESINS ARE USED TO PURIFY PRODUCED WATER OF SODIUM, CHLORIDE, SULFATE AND OTHER IONS IN BOTH A CONTINUOUS AND COUNTERCURRENT OPERATING MODE. THESE CHEMICAL ENGINEERING PRINCIPLES OF MASS TRANSFER MAXIMIZE THE RESINS' ABILITIES IN PURIFYING WATER WITH A CONSISTENT QUALITY. THEY ALSO OPTIMIZE THE USE OF ACID AND ALKALI REGENERANTS, MINIMIZE THEIR VOLUMES AND GENERATE A DENSE BRINE SOLUTION THAT MAY HAVE VALUE AS A CLEAR BRINE FLUID WITHIN THE OIL AND GAS INDUSTRY. THE KEY TO THE HIGGINS LOOP FEATURES IS ITS ABILITY TO MOVE THE RESIN THROUGH THE LOOP VIA INCREMENTAL "PULSING". THE PULSE VESSEL SERVES AS A RESIN FLOW METER TO ENSURE ITS FLOW IS IN PROPORTION TO THE WATER TREATED AND THE AMOUNT OF REGENERANT CONSUMED.

PRODUCED WATER CONTAINING HIGH NA LEVELS IS FED TO THE ADSORPTION ZONE WITHIN THE HIGGINS LOOP WHERE IT CONTACTS STRONG ACID CATION RESIN WHICH LOADS NA^{+} IONS IN EXCHANGE FOR HYDROGEN (H^{-}) IONS. TREATED WATER EXITS THE LOOP CONTAINING LESS THAN 10 MG/L NA.

CONCURRENT WITH ADSORPTION AND IN THE LOWER SECTION OF THE HIGGINS LOOP, NA-LOADED RESIN IS REGENERATED WITH EITHER HYDROCHLORIC OR SULFURIC ACID TO PRODUCE A SMALL, CONCENTRATED SPENT BRINE STREAM. REGENERATED RESIN IS RINSED WITH WATER PRIOR TO REENTERING THE ADSORPTION ZONE TO REMOVE ACID FROM ITS PORES.

AS RESIN IN THE UPPER LAYER OF THE ADSORPTION ZONE BECOMES LOADED WITH NA, THE FLOWS TO THE HIGGINS LOOP ARE MOMENTARILY INTERRUPTED TO ALLOW ADVANCEMENT

OF THE RESIN BED (PULSING) THROUGH THE LOOP IN THE OPPOSITE DIRECTION OF LIQUID FLOW. LIQUID FLOWS ARE RESTARTED AFTER RESIN PULSING IS COMPLETE.
TREATED WATER IS SLIGHTLY ACIDIC DUE TO ITS INCREASED H^- ION STRENGTH, AND IT IS NEUTRALIZED WITH LIMESTONE, WHICH ALSO INCREASES ITS CALCIUM CONCENTRATION SO THAT THE WATER'S SODIUM ADSORPTION RATIO (SAR) IS LESS THAN 1.0. SPENT BRINE CONTAINING REMOVED NA^+ IONS HAS A DENSITY HIGH ENOUGH FOR USE AS A KILL FLUID.

ENVIRONMENTAL IMPACTS/BENEFITS: TREATING PRODUCED WATER WITH THIS TECHNOLOGY PROVIDES ENVIRONMENTAL BENEFITS BY ALLOWING FOR THE WATER TO BE BENEFICIALLY USED BY IMPROVING THE SAR AND LOWERING THE TDS. ONCE THE WATER IS TREATED, IT CAN BE PUT BACK INTO A SURFACE STREAM FOR USE BY LIVESTOCK, WILDLIFE, AND DOWNSTREAM WATER RIGHTS HOLDERS, OR IT CAN BE IRRIGATED IMMEDIATELY.

APPLICABILITY: THE HIGGINS LOOP HAS BEEN IN USE SINCE WWII, AND THE USE OF THE EMIT TECHNOLOGY IS GROWING IN THE POWDER RIVER BASIN ON BOTH THE WYOMING AND MONTANA SIDE. THIS TECHNOLOGY IS USEFUL IN LOWERING SODIUM, BICARBONATES, SAR VALUES, AND OVERALL TDS TO BELOW NPDES PERMIT REQUIREMENTS.

COST: NO INFORMATION WAS COLLECTED ON COST. THE WEBSITE STATES THAT COST IS A FIXED COST AND IS CHEAPER THAN SEVERAL OF THE CURRENT TREATMENT ALTERNATIVES.

ADDITIONAL NOTES: NONE

DATE: 6/30/2005____ INFORMATION COLLECTED BY: _JON SEEKINS, JAKE CRISSUP

IDENTIFICATION, VERIFICATION, AND COMPILATION OF
PRODUCED WATER MANAGEMENT PRACTICES
FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

PHOTO LOG

VIEW OF A EMIT ION EXCHANGE PLANT

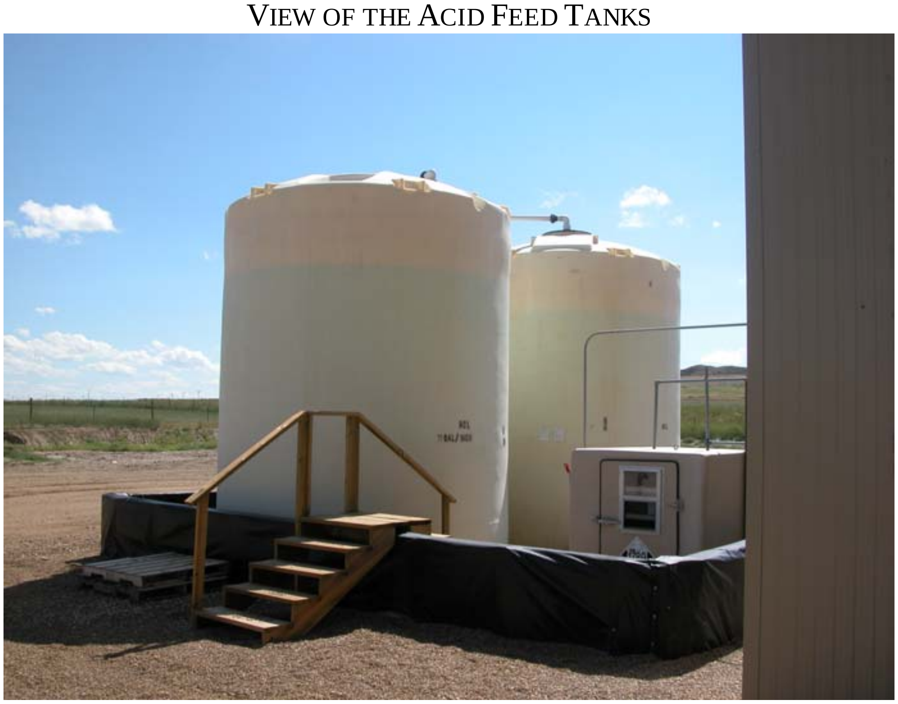
VIEW OF A PULSE AND ADSORPTION TANK

VIEW OF A PULSE WATER TANK

VIEW OF THE BACK WASH LOOP

VIEW OF THE RESIN RECOVERY TANK

VIEW OF THE ACID FEED TANKS



VIEW OF A LIME REACTOR BED TO ADJUST PH PRIOR TO DISCHARGE

VIEW OF A POND THAT THE EMIT PLANT DISCHARGES TO PRIOR TO ENTERING THE POWDER RIVER

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF

PRODUCED WATER MANAGEMENT PRACTICES

FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF
PRODUCED WATER MANAGEMENT PRACTICES
FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE INFORMATION

OFFICE ADDRESS: VARIOUS SITES VISITED SOUTH OF I-90

CITY: BETWEEN GILLETTE AND BUFFALO STATE: WY COUNTY: JOHNSON

BASIN: POWDER RIVER FIELD: PRB CBM

CONTACT NAME/TITLE: RICK WAAS/ DRILLING INSPECTOR-WYOGCC

CONTACT NUMBER: (307)358-4101

WATER MANAGEMENT TECHNOLOGIES/PRACTICES IN PLACE

DESCRIPTION: VARIOUS CBM SITES WERE VISISTED, AND VARIOUS TYPES OF PRODUCED WATER MANAGEMENT TECHNIQUES AND TECHNOLOGIES WERE VIEWED. THE FIRST STOP WAS AT THE CONSTRUCTION SITE OF A FUTURE WATER TRUCK LOAD OUT FACILITY AND TRUCK WASH OUT STATION THAT WILL USE PRODUCED WATER AS THE SOURCE OF WATER FOR THE FACILITY. THE SITE WAS CONVENIENTLY LOCATED OFF OF I-90 BETWEEN GILLETTE AND BUFFALO.

ALSO NOTED JUST NORTH OF I-90 WAS A DRILL RIG THAT IS DRILLING A 14,250 FT DEEP INJECTION WELL FOR DEEP INJECTION DISPOSAL OF PRODUCED WATER.

THE NEXT WATER MANAGEMENT TECHNIQUE NOTED WAS A WATER TANK FOR CATTLE THAT WAS MADE FROM A TRACTOR TIRE AND HAS PRODUCED WATER "ON TAP". THE WATER DOES NOT FLOW FREELY INTO THE WATER TANK, BUT RATHER, THE HYDRANT CAN BE TURNED ON AT THE RANCHERS DISCRETION. THE WATER IS PIPED TO THE WATER TANK AND IS UNDER PRESSURE SO THAT IT WILL FLOW. THIS IS A GOOD USE OF THE WATER BY ALLOWING A SOURCE OF WATER TO BE AVAILABLE IN A REMOTE LOCATION TO PROMOTE CATTLE FORAGING IN OTHER AREAS.

THE NEXT SITE VISITED WAS A POND WITH SPRAY EVAPORATION ATOMIZERS. THE TECHNOLOGY WAS NOT BEING OPERATED AT THE TIME WITH THE REASON CITED BY THE OPERATOR THAT THE EVAPORATION WAS NOT ENHANCED AS MUCH AS WAS EXPECTED. WATER FROM THE 12 PRODUCING WELLS IN THIS AREA IS CURRENTLY BEING DISCHARGED INTO A SHALLOW AQUIFER AT A RATE OF 11,000 BBLS/DAY INTO 6 INJECTION WELLS THAT ARE ALL AROUND 100 FEET DEEP. CHLORINE TABLETS ARE ADDED TO THE WATER PRIOR TO INJECTION TO KILL BACTERIA AND PREVENT HYDROGEN SULFIDE ACCUMULATION. NO GAS HAS BEEN PRODUCED FROM THE 12 PRODUCING WELLS YET, AND THE OPERATOR IS WAITING FOR PRODUCTION TO INCREASE IN NEARBY LEASES TO HELP DRAW DOWN THE PRESSURE GRADIENT ON THE COAL SEAM.

ENVIRONMENTAL IMPACTS/BENEFITS: PROVIDING A CONSISTENT SOURCE OF WATER FOR LIVESTOCK AND WILDLIFE AND PROVIDING HABITAT FOR FISH AND WATERFOWL AND THE

PRIMARY ENVIRONMENTAL BENEFITS ACHIVED BY THESE TREATMENT TECHNOLOGIES. FURTHERMORE, BY UTILIZING THE PRODUCED WATER FOR INDUSTRIAL PURPOSES AT THE WATER TRUCK LOADOUT STATION, IT HELPS TO CONSERVE WATER FOR OTHER HUMAN USES SUCH AS CONSUMPTION.

APPLICABILITY: THE CBM WATER FROM THIS PORTION OF THE PRB CAN BE USED FOR INDUSTRIAL APPLICATIONS, STOCK AND WILDLIFE WATERING, AND RECREATION PURPOSES. TREATMENT PROCESSES OBSERVED (ZEOLITE, REVERSE OSMOSIS, AND INO EXCHANGE) ARE DISCUSSED INDIVIDUALLY IN SEPARATE SITE SUMMARIES.

COST: NO INFORMATION WAS COLLECTED ON COST.

ADDITIONAL NOTES: NONE

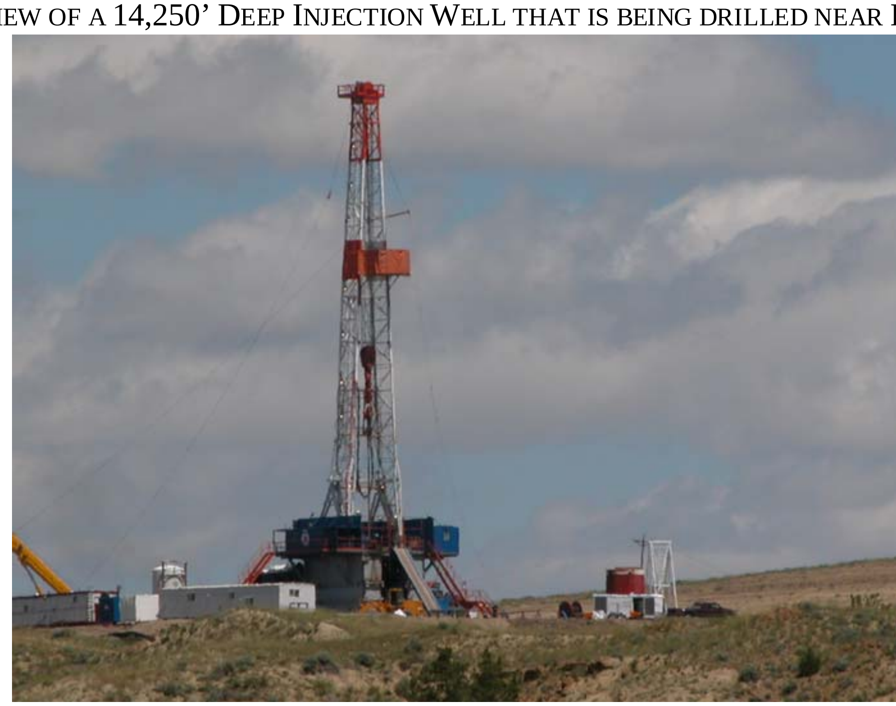
DATE: 6/30/2005____ INFORMATION COLLECTED BY: _JON SEEKINS, JAKE CRISSUP

PHOTO LOG

VIEW OF THE ENTRANCE TO A WATER TRUCK LOADOUT/WASH FACILITY JUST OFF OF I-90 THAT WILL USE CBM PRODUCED WATER

VIEW OF THE WATER TRUCK LOADOUT/WASH FACILITY UNDER CONSTRUCTION

VIEW OF A 14,250' DEEP INJECTION WELL THAT IS BEING DRILLED NEAR I-90



VIEW OF A TIRE STOCK TANK THAT IS SUPPLIED BY CBM PRODUCED WATER ON DEMAND

VIEW OF ATOMIZER OPERATED BY MCCARTNEY ENGINEERING ON JONES PIT 41-18

VIEW OF A SHALLOW INJECTION WELL ON THE JONES RANCH OPERATED BY MCCARTNEY

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF

PRODUCED WATER MANAGEMENT PRACTICES

FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF

PRODUCED WATER MANAGEMENT PRACTICES

FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE INFORMATION

OFFICE ADDRESS: VARIOUS SITES VISITED

CITY: WRIGHT, SIOUX RANCH STATE: WY COUNTY: CAMPBELL

BASIN: POWDER RIVER FIELD: PRB CBM

CONTACT NAME/TITLE: RICK WAAS/ DRILLING INSPECTOR-WYOGCC

CONTACT NUMBER: (307)358-4101

WATER MANAGEMENT TECHNOLOGIES/PRACTICES IN PLACE

DESCRIPTION: VISITED A CBM DISCHARGE INTO HAYS CREEK WHERE THE PRODUCED WATER IS USED TO IRRIGATE A GOLF COURSE NEAR THE TOWN OF WRIGHT, WY. ALSO VISITED THE 13,000 ACRE SIOUX RANCH14 MILES SOUTH OF WRIGHT ON HWY 59 AND VIEWED SEVERAL PONDS THAT HAVE BEEN REJUVENATED WITH CBM PRODUCED WATER. ACCORDING TO THE LAND OWNER, EDDIE RENO, THE PONDS WERE DRYING UP DUE TO THE DROUGHT, AND THEY HAD NO WATER TO IRRIGATE WITH. THEY HAD TO STOP RUNNING CATTLE ON THE LAND IN ORDER TO ALLOW THE GRASS TO RECOVER FROM THE DROUGHT PERIOD. NOW THAT WATER IS READILY AVAILABLE FROM CBM PRODUCTION THE PONDS ARE FULL AGAIN AND WILDLIFE IS FLOURISHING, THE PONDS ARE USED FOR RECREATIONAL PURPOSES, AND THEY PLAN TO PUT CATTLE BACK ON THE LAND AS SOON AS NEXT YEAR.

ENVIRONMENTAL IMPACTS/BENEFITS: ACCORDING TO THE LAND OWNER AT SIOUX RANCH, EDDIE RENO, THE EXISTING STOCK PONDS WERE DRYING UP DUE TO THE DROUGHT, AND THEY HAD NO WATER TO IRRIGATE WITH. THEY HAD TO STOP RUNNING CATTLE ON THE LAND IN ORDER TO ALLOW THE GRASS TO RECOVER FROM THE DROUGHT. NOW THAT WATER IS READILY AVAILABLE FROM CBM PRODUCTION THE PONDS ARE FULL AGAIN AND WILDLIFE IS FLOURISHING, THE PONDS ARE USED FOR RECREATIONAL PURPOSES, AND THEY PLAN TO PUT CATTLE BACK ON THE LAND AS SOON AS NEXT YEAR.

APPLICABILITY: THE CBM WATER FROM THIS PORTION OF THE PRB IS FRESH, SO IT CAN READILY BE USED FOR IRRIGATION, STOCK AND WILDLIFE WATERING, AND RECREATION PURPOSES. NO TREATMENT IS REQUIRED.

COST: NO INFORMATION WAS COLLECTED ON COST.

ADDITIONAL NOTES: NONE

DATE: 6/29/2005 INFORMATION COLLECTED BY: JON SEEKINS, JAKE CRISSUP

PHOTO LOG

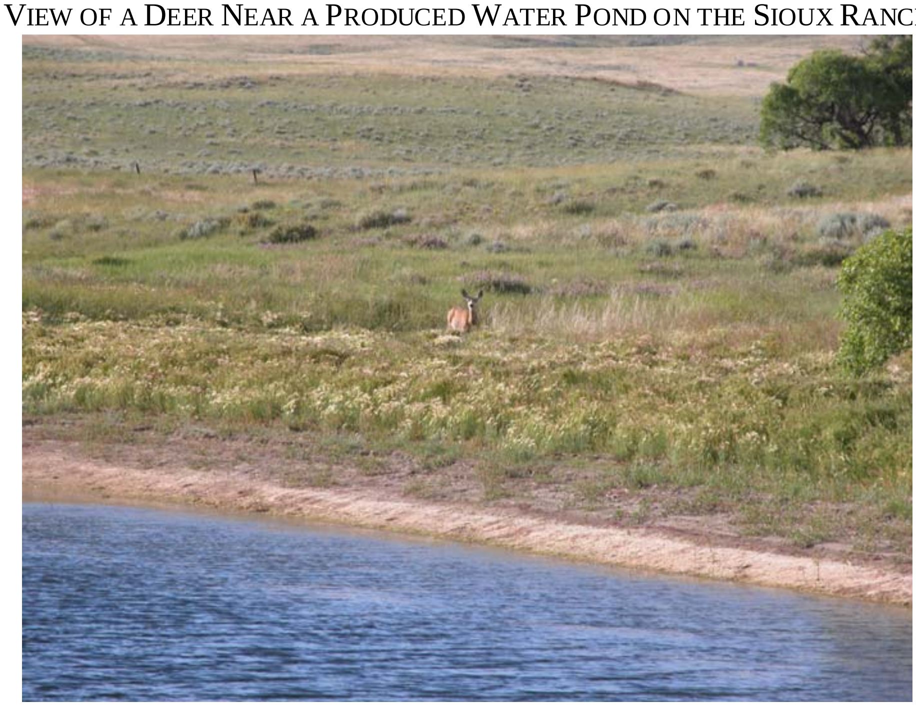
VIEW OF CBM PRODUCED WATER DISCHARGE TO HAYS CREEK, NEAR GOLF COURSE IN WRIGHT, WY

VIEW OF A IRRIGATION POND ON GOLF COURSE WITH A FOUNTAIN TO AERATE THE WATER

VIEW OF A TIRE LIVESTOCK WATER TANK DISCHARGING TO AN EXISTING POND ON THE SIOUX RANCH

VIEW OF A PRODUCED WATER POND USED FOR FLOOD IRRIGATION ON THE SIOUX RANCH

VIEW OF A DEER NEAR A PRODUCED WATER POND ON THE SIOUX RANCH



VIEW OF A COMPRESSOR STATION ON THE SIOUX RANCH

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF

PRODUCED WATER MANAGEMENT PRACTICES

FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF
PRODUCED WATER MANAGEMENT PRACTICES
FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE INFORMATION

OFFICE ADDRESS: SITE VISITED SOUTH OF I-90

CITY: BETWEEN GILLETTE AND BUFFALO STATE: WY COUNTY: JOHNSON

BASIN: POWDER RIVER FIELD: PRB CBM

CONTACT NAME/TITLE: RON LINCZ/ NEWPARK ENVIRONMENTAL WATER SOLUTIONS

CONTACT NUMBER: (403)861-4075

CONTACT NAME/TITLE: RICK WAAS/ DRILLING INSPECTOR-WYOGCC

CONTACT NUMBER: (307)358-4101

WATER MANAGEMENT TECHNOLOGIES/PRACTICES IN PLACE

DESCRIPTION: NEWPARK ENVIRONMENTAL WATER SOLUTIONS (NEWS) IS CONSTRUCING AND HAS PLANS FOR OPERATING A 20,000 BBLS/DAY WATER TREATMENT PLANT TO REDUCE SAR VALUES TO BELOW WYPDES PERMIT LEVELS AND ALLOW DISCHARGE TO THE SURFACE. THE WATER TREATMENT PLANT UTILIZES REVERSE OSMOSIS TECHNOLOGY TO REMOVE THE CHARGED IONS AND LOWER THE SAR AND THE TDS IN THE WATER, HOWEVER, IT ALSO EMPLOYS A PATENTED TECHNOLOGY TO TREAT THE WATER BEFORE THE RO UNIT TO MINIMIZE FOULING OF THE RO MEMBRANES.

THE PATENTED TECHNOLOGY IS BASED ON THE EMERGING SCIENCE OF SONOCHEMISTRY. NEWS IS APPLYING THIS TECHNOLOGY INITIALLY TO WASTEWATER TREATMENT. HIGH-FREQUENCY SOUND WAVES ARE USED TO POWER PHYSICAL-CHEMICAL REACTIONS. THESE ULTRASONIC SOUND WAVES, IN LIQUIDS, CAUSE THE FORMATION OF MICRO BUBBLES THAT COLLAPSE AT EXTREMELY HIGH TEMPERATURES AND PRESSURES AT THE MOLECULAR LEVEL GENERATING NOVEL CHEMICAL REACTIONS WITH MINIMAL EFFECT ON AMBIENT TEMPERATURES.

AT THE CORE OF THE NEWS WASTEWATER TREATMENT PROCESS IS AN INSTRUMENT REFERRED TO AS AN ARMEL ACTIVATOR. IT MANAGES THE FLOW DYNAMICS OF THE WASTEWATER STREAM BY PRESSURE AND SOUND FREQUENCY VARIATIONS. THIS PROVIDES TURBULENT MIXING, ULTRASONIC PRESSURE WAVES AND CAVITATION. INTERMOLECULAR DISTANCES ARE SHORTENED AMONG MOLECULES WITH AN INCREASE IN SPECIFIC CONTACT SURFACES.

THE RESULTS ARE THAT DESIRED REACTIONS DOWNSTREAM OF THE ARMEL ACTIVATOR (SUCH AS COAGULANT ADDITION AND FLOCCULATION) OCCUR WITH VERY SHORT RETENTION TIMES AND WITHOUT EXCESSIVE USE OF CHEMICAL ADDITIVES.

A SMALLER PLANT HAS BEEN CONSTRUCTED AND IS CURRENTLY IN USE TO REMOVE

DISSOLVED SOLIDS FROM THE WASTEWATER GENERATED BY OIL AND GAS PRODUCTION ACTIVITIES IN THE PINEDALE/JONAH FIELDS IN THE GREATER GREEN RIVER BASIN OF WYOMING. CONSTITUENTS WILL BE LOWERED TO LEVELS THAT WILL ALLOW DISCHARGE UNDER AN NPDES PERMIT INTO THE COLORADO RIVER BASIN.

ENVIRONMENTAL IMPACTS/BENEFITS: TREATING PRODUCED WATER WITH THIS TECHNOLOGY PROVIDES ENVIRONMENTAL BENEFITS BY ALLOWING FOR THE WATER TO BE BENEFICIALLY USED BY IMPROVING THE SAR AND LOWERING THE TDS. ONCE THE WATER IS TREATED, IT CAN BE PUT BACK INTO A SURFACE STREAM FOR USE BY LIVESTOCK, WILDLIFE, AND DOWNSTREAM WATER RIGHTS HOLDERS, OR IT CAN BE IRRIGATED IMMEDIATELY.

APPLICABILITY: THIS TREATMENT TECHNOLOGY IS EMERGING. THE SUCCESS OF THIS TECHNOLOGY WILL BE CLOSELY TIED TO THE SUCCESS OF THE TECHNOLOGY TO EFFECTIVELY AND EFFICIENTLY TREAT WATER FROM THE PINEDALE/JONAH FIELD AS WELL AS CBM WATER FROM THE POWDER RIVER BASIN TO BELOW THEIR PERMIT LIMITS.

COST: COST IS EXTREMELY VARIABLE BASED ON THE WATER QUALITY AND THE LEVEL OF THE DESIRED WATER QUALITY.

ADDITIONAL NOTES: NONE

DATE: 6/30/2005____ INFORMATION COLLECTED BY: _JON SEEKINS, JAKE CRISSUP

PHOTO LOG

VIEW OF A REVERSE OSMOSIS PLANT UNDER CONSTRUCTION

VIEW OF A SKID MOUNTED REVERSE OSMOSIS SYSTEM

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF
PRODUCED WATER MANAGEMENT PRACTICES
FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE INFORMATION

OFFICE ADDRESS: VARIOUS SITES VISITED OF OFF I-90

CITY: BETWEEN GILLETTE AND BUFFALO STATE: WY COUNTY: JOHNSON

BASIN: POWDER RIVER FIELD: PRB CBM

CONTACT NAME/TITLE: RICK WAAS/ DRILLING INSPECTOR-WYOGCC

CONTACT NUMBER: (307)358-4101

WATER MANAGEMENT TECHNOLOGIES/PRACTICES IN PLACE

DESCRIPTION: TWO EXISTING ZEOLITE FACILITIES WERE VISITED, AND ONE ZEOLITE FACILITY THAT IS UNDER CONSTRUCTION WAS VISITED. OF THE TWO EXISTING ZEOLITE FACILITIES, ONLY ONE WAS CURRENTLY BEING DISCHARGED TO.

ZEOLITE IS A NATURALLY OCCURING MINERAL THAT CAN BE MINED, CRUSHED, AND MODIFIED TO ENHANCE THE CATION EXCHANGE CAPACITY OF THE MINERAL. THE ZEOLITE IS THEN PLACED IN A COLUMN, OR A PIT, AND PRODUCED WATER IS PASSED THROUGH IT TO ALLOW FOR THE CHARGED IONS IN THE WATER (SUCH AS SODIUM) TO BE EXCHANGED FOR THE CHARGED IONS IN THE ZEOLITE (SUCH AS CALCIUM AND MAGNESIUM). THE EXCHANGE OF SODIUM FOR CALCIUM AND MAGNESIUM ALLOWS FOR THE SODIUM ADSORPTION RATIO (SAR) TO BE LOWERED, WHICH IN EFFECT RENDERS THE WATER CAPABLE FOR USE IN IRRIGATION, OR FOR A DIRECT DISCHARGE TO A STREAM/CREEK.

ENVIRONMENTAL IMPACTS/BENEFITS: TREATING PRODUCED WATER WITH ZEOLITE PROVIDES ENVIRONMENTAL BENEFITS BY ALLOWING FOR THE WATER TO BE BENEFICIALLY USED BY IMPROVING THE SAR. ONCE THE WATER IS TREATED, IT CAN BE PUT BACK INTO A SURFACE STREAM FOR USE BY LIVESTOCK, WILDLIFE, AND DOWNSTREAM WATER RIGHTS HOLDERS, OR IT CAN BE IRRIGATED IMMEDIATELY.

APPLICABILITY: ZEOLITE IS AN EFFECTIVE TREATMENT TECHNOLOGY FOR USE ON WATER CONTAINING HIGH LEVELS OF SODIUM, AS IT IMPROVED THE SAR VALUES BY EXCHANGING SODIUM FOR CALCIUM AND MAGNESIUM.

COST: NO INFORMATION WAS COLLECTED ON COST.

ADDITIONAL NOTES: NONE

DATE: 6/30/2005 INFORMATION COLLECTED BY: JON SEEKINS, JAKE CRISSUP

PHOTO LOG

VIEW OF A ZEOLITE WATER TREATMENT SYSTEM

VIEW OF A ZEOLITE PLANT UNDER CONSTRUCTION

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF

PRODUCED WATER MANAGEMENT PRACTICES

FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE INFORMATION

OFFICE ADDRESS: SALT CREEK OPERATION CENTER, 1 MILE SOUTH OF MIDWEST

CITY: MIDWEST STATE: WY COUNTY: NATRONA

BASIN: POWDER RIVER FIELD: SALT CREEK

CONTACT NAME/TITLE: JOHN FARRELL/ ANADARKO

CONTACT NUMBER: (307)437-9568

CONTACT NAME/TITLE: RICK WAAS/ DRILLING INSPECTOR-WYOGCC

CONTACT NUMBER: (307)358-4101

WATER MANAGEMENT TECHNOLOGIES/PRACTICES IN PLACE

DESCRIPTION: VISITED TWO RECREATION PONDS THAT ARE SUPPLIED BY PRODUCED WATER FROM THE SALT CREEK FIELD. THE FIRST POND HAS AN EARTHEN SPILLWAY THAT REQUIRES SOME ADDITIONAL EARTHWORK DUE TO EROSION PROBLEMS THAT HAVE OCCURRED. THE SECOND POND HAS A PIPE SPILLWAY AND AN EARTHEN EMERGENCY SPILLWAY. THE TWO PONDS ARE SUPPLIED BY PRODUCED WATER AT A RATE OF 5 GPM. WATER DISCHARGES FROM THE RECREATION PONDS TO THE SALT CREEK, WHICH EVENTUALLY FEEDS INTO THE POWDER RIVER. A TOTAL OF APPROXIMATELY 350 BBLS OF WATER/DAY IS DISCHARGED TO THE TWO PONDS, AND THE REMAINDER OF THE WATER PRODUCED (CLOSE TO 600,000 BBLS/DAY) IS RE-INJECTED INTO ENHANCED RECOVERY WELLS AND DISPOSAL WELLS. THE SALT CREEK FIELD IS THE SECOND LARGEST WATER PRODUCING FIELD IN WYOMING.

ENVIRONMENTAL IMPACTS/BENEFITS: THE RECREATION PONDS ARE STOCKED WITH FISH AND ARE WIDELY USED BY SPORT FISHERMAN. WILDLIFE SUCH AS WATERFOWL AND ANTELOPE ALSO USE THE RECREATION PONDS FOR WATER AND HABITAT.

APPLICABILITY: THE INJECTION OF THE WATER FOR ENHANCED RECOVERY IS A BENEFICIAL USE, AS WELL AS THE RECREATION USE OF THE WATER FOR FISHING AND WILDLIFE HABITAT. A PIPELINE TO PIPE CBM PRODUCED WATER FROM THE POWDER RIVER CBM FIELDS IS ALSO UNDER CONSIDERATION FOR USE IN ENHANCED RECOVERY AND INJECTION DISPOSAL INO THE MADISON FORMATION TO COOL THE FORMATION.

COST: NO INFORMATION WAS COLLECTED ON COST.

ADDITIONAL NOTES: NONE

DATE: 6/29/2005 INFORMATION COLLECTED BY: JON SEEKINS, JAKE CRISSUP

PHOTO LOG

VIEW OF ENTRANCE TO RECREATION POND SUPPLIED BY SALT CREEK PRODUCED WATER

VIEW OF A PVC PIPE THAT DELIVER PRODUCED WATER TO RECREATION POND

SITE VISIT SUMMARY

IDENTIFICATION, VERIFICATION, AND COMPILATION OF
PRODUCED WATER MANAGEMENT PRACTICES
FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

SITE INFORMATION

OFFICE ADDRESS: ______________________________

CITY: TEAPOT DOME__________ STATE: WY__ COUNTY: NATRONA___________

BASIN: POWDER RIVER_________FIELD: TEAPOT DOME____

CONTACT NAME/TITLE: RICK WAAS/ DRILLING INSPECTOR-WYOGCC

CONTACT NUMBER: (307)358-4101

WATER MANAGEMENT TECHNOLOGIES/PRACTICES IN PLACE

DESCRIPTION: VISITED THE ROCKY MOUNTAIN OILFIELD TESTING CENTER'S (RMOTC) TESTING LABORATORIES WHERE PRODUCED WATER IS USED TO RAISE SHRIMP AND TILAPIA IN LARGE TANKS. A GREENHOUSE IS ALSO ONSITE TO TEST THE ABILITY OF DIFFERENT SPECIES OF PLANTS TO BE IRRIGATED WITH PRODUCED WATER THAT HAS HIGHER SALINITY. THE TEAPOT NAVAL RESERVE IS ALSO A WORKING OIL AND GAS FIELD THAT PRODUCES ABOUT 700 BBLS OF OIL/DAY AND ABOUT 50,000 BBLS OF WATER/DAY. THE PRODUCED WATER IS MANAGED THROUGH RE-INJECTION FOR ENHANCED RECOVERY AS WELL AS A SURFACE DISCHARGE TO THE TEAPOT CREEK. SEVERAL PITS ARE IN PLACE TO SEPARATE THE OIL FROM THE WATER PRIOR TO THE PERMITTED DISCHARGE POINT.

ENVIRONMENTAL IMPACTS/BENEFITS: THE FIELD COVERS APPROXIMATELY 10,000 ACRES AND WILDLIFE ABOUNDS THROUGHOUT THE FIELD. THE PRODUCED WATER DISCHARGE TO TEAPOT CREEK IMPROVES THE RIPRARIAN HABITAT, WHICH WOULD BE SEASONAL AT BEST WITHOUT THE PRODUCED WATER.

APPLICABILITY: THE RMOTC LABORATORIES IS AN EXCELLENT PLACE TO PROVE NEW TECHNOLOGIES AND EXPERIMENT WITH EMERGING TECHNIQUES FOR PRODUCED WATER MANAGEMENT AND BENEFICIAL USE.

COST: NO INFORMATION WAS COLLECTED ON COST.

ADDITIONAL NOTES: NONE

DATE: 6/29/2005____ INFORMATION COLLECTED BY: _JON SEEKINS, JAKE CRISSUP

IDENTIFICATION, VERIFICATION, AND COMPILATION OF
PRODUCED WATER MANAGEMENT PRACTICES
FOR CONVENTIONAL OIL AND GAS PRODUCTION OPERATIONS

PHOTO LOG

VIEW OF TANKS WHERE TILAPIA AND SHRIMP ARE RAISED WITH PRODUCED WATER

VIEW OF A TILAPIA FISH THAT WAS RAISED IN PRODUCED WATER

VIEW OF STEAM GENERATED FROM A NETTED PRIMARY SEPARATOR PIT

VIEW OF SECONDARY AND TERTIARY PITS PRIOR TO DISCHARGE TO TEAPOT CREEK