GROUNDWATER PROTECTION COUNCIL

PRODUCED WATER REPORT

Regulations, Current Practices, and Research Needs

NMOGA Exhibit 92

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Dear Reader:

I would like to express my deep appreciation to all the people who contributed to the Produced Water Report. I especially want to thank those who served on the leadership team for their dedication and effort in bringing the report to fruition. To produce a balanced report, we engaged geologists, engineers, lawyers, toxicologists, soil experts, public health experts, the petroleum industry, and state regulators, from whom we sought ideas and advice on the report development and conclusions. Researching facts, reviewing thousands of papers and studies, conducting dozens of meetings, writing, editing and final production — all required a myriad of experts on a variety of critical topics.

This report is a seminal work about produced water regulation and reuse. It contains the most current information available about regulatory frameworks, produced water use in oil and gas operations, and potential future uses of produced water outside of oil and gas operations.

While we believe the report is exhaustive, it is by no means the final word with respect to produced water reuse. We expect future efforts to continue developing a more mature understanding of produced water characteristics and reuse potential. We trust that our report will provide a solid base of reference for these efforts.

We are grateful for the funding provided by several organizations including the U.S. Department of Energy, Ground Water Research and Education Foundation, Environmental Defense Fund and American Petroleum Institute.

Mike Paque
Executive Director
GWPC

Preface

The Ground Water Protection Council (GWPC) is the national association of state groundwater protection and underground injection control agencies. GWPC has served as a valuable forum for communication on oil and gas issues between state government, federal government, industry, academia, environmental advocacy groups, and other interested parties. The mission of the GWPC addresses "the protection of groundwater resources for all beneficial uses." It covers all groundwater resources that are or may be used for beneficial purposes, including oil and gas produced water.

This report is part of an effort by the GWPC to promote consideration of appropriate beneficial reuses of produced water. While produced water is currently being used in applications both within and outside of oil and gas operations, many potential applications remain. Further research will be needed to assure that these potential applications are both suitable and safe.

As a direct byproduct of oil and gas production, produced water is a natural area of interest for GWPC, which places a strong emphasis on energy and water interactions. The process of regulation of underground injection of fluids (the Safe Drinking Water Act's Underground Injection Control or UIC program) is one of GWPC's major programmatic concerns.

Given its longstanding working relationship with federal agencies including the Environmental Protection Agency and Department of Energy, as well as with industry stakeholders and non-governmental organizations, GWPC is uniquely positioned to explore the current and future beneficial reuse of produced water. Recognizing that produced water has the potential to be an important contributor to water resources in the United States, the GWPC brought together scientists, regulatory officials, members of academia, the oil and gas industry, and environmental groups to explore roles produced water might play in developing greater water certainty. Their research has been synthesized in this report, which is designed to support policy makers, regulators, and the public in making informed decisions, driving additional research, and analyzing practical opportunities and challenges of beneficially reusing produced water.

This report considers produced water to be a "potential resource" rather than a "waste." Although most produced water has never had any use before it is brought to the surface, the term "reuse" is commonly assigned to produced water that is or will be used for a beneficial purpose.

This report consists of three modules.

Module 1: Current Legal, Regulatory, and Operational Frameworks of Produced Water Management. This module focuses on the multifaceted regulation of produced water, including long established federal laws and programs as well as areas where additional regulatory clarity may be needed to further advance the beneficial use or reuse of produced water. It also discusses the legal and operational aspects of produced water reuse such as ownership, water rights, liability, and standard practices. These topics define the framework under which produced water reuse may be accomplished and the challenges limiting its current implementation as a water source.

Module 2: Produced Water Reuse in Unconventional Oil and Gas Operations. This module presents information on how produced water is used within oil and gas operations, with a focus on unconventional operations. Through literature reviews, interviews with oil and gas companies, and data requests, information has been gathered on the current state of oil and gas operational reuse of produced water and on future potential reuse options and dynamics.

Module 3: Produced Water Reuse and Research Needs Outside Oil and Gas Operations. The most forward-looking part of this report, this module looks at current and needed research to properly and safely use produced water in applications outside oil and gas operations. It also discusses the range of reuse options currently available along with potential reuse options that may one day become practical.

The GWPC hopes readers will find this report informative and useful. It offers a realistic assessment of the contribution produced water could make to the national water resource portfolio and state water planning efforts. This report offers a solid base for building upon and improving the knowledge and use of produced water. It is expected that ever-changing technology and statutory transformations will only further the use of produced water in the future.

Leadership in Addressing Oil and Gas Water Management

The Ground Water Protection Council has taken the lead role in oil and gas water management issues during recent years. Examples include:

- Creating the highly acclaimed Risk Based Data Management System (RBDMS), used by more than 24 state agencies to track oil and gas data
- Implementing the FracFocus system with its unique hydraulic fracturing chemical disclosure registry, developed in collaboration with the Interstate Oil and Gas Compact Commission (IOGCC)
- Conducting several annual national conferences on energy/water interactions
- Publishing the groundbreaking primer *Modern Shale Gas Development in the United States* (April 2009), prepared in conjunction with ALL Consulting for the U.S. Department of Energy and National Energy Technology Laboratory
- Organizing the first-of-its-kind national conference on stray gas issues in 2012
- Initiating discussions on induced seismicity related to hydraulic fracturing and disposal wells in 2013, leading to formation of an induced seismicity work group and publishing of the 2015 and updated 2017 primer on *Technical and Regulatory Considerations Informing Risk Management and Mitigation*
- Sponsoring a 2015 report on national produced water volumes and management practices.

For more information on these and other efforts, see the Groundwater Protection Council website at www.gwpc.org.

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TABLE OF CONTENTS

MODULE 1: Current Legal, Regulatory, and Operational Frameworks of Produced Water Management

MODULE 2: Produced Water Reuse in Unconventional Oil and Gas Operations

MODULE 3: Produced Water Reuse and Research Needs Outside Oil and Gas Operations

APPENDIXES MODULE 1

APPENDIXES MODULE 2

APPENDIXES MODULE 3

Executive Summary

Water is closely intertwined with oil and gas production, including **sourced water** (water supplied to support operations) and **produced water** (formation water brought to the surface during well completion and oil and gas production). Determining how to find sourced water and manage produced water efficiently and cost effectively is an important component of producing oil and gas. Produced water can be managed within an individual lease area or over a larger field that incorporates many wells and leases and extends over more than one county, river basin, or state.

In a 2015 Ground Water Protection Council (GWPC) report, which analyzed 2012 data, about 45 percent of produced water was used within conventional oil and gas enhanced recovery operations, leaving about 55 percent to be disposed of in permitted underground injection control (UIC) wells with a small percentage managed in other ways including evaporation and discharge.

Produced water varies widely in quality. Most produced water is highly saline and may contain a mix of mineral salts; organic compounds; hydrocarbons, organic acids, waxes, and oils; inorganic metals and other inorganic constituents; naturally-occurring radioactive material; chemical additives; and other constituents and byproducts.

GWPC recognizes that, as fresh water resources become more constrained, the ability to use produced water to offset freshwater demands both inside and outside of oil and gas operations will offer opportunities and challenges. This report is part of an effort by the GWPC to work with a variety of stakeholders to identify those opportunities and challenges and provide suggestions that policy makers, researchers, regulators, and others can use to address them. To that end, the report focuses on three key areas:

- Regulatory and legal frameworks for produced water reuse
- Current and future potential for produced water reuse in unconventional oil and gas production
- Opportunities and research needs for future reuse of produced water for purposes outside of the oil and gas industry

About This Report

This report addresses the drivers and potential benefits for increasing produced water reuse both in unconventional oil and gas operations and outside the industry, as well as complex economic, scientific, regulatory, and policy considerations, specifically with respect to risk management. It also identifies research that will be needed to enable informed decision-making on produced water reuse, as well as regulatory and policy initiatives that would facilitate reuse.

An overriding theme of this report is that opportunities for increased produced water reuse will vary greatly depending on:

- **Local conditions**, including the quality and quantity of produced water available, the profile of regional water supply and demand, geological and demographic characteristics, the cost and availability of permitted UIC disposal, and the existence or lack of infrastructure for transporting, storing, and treating produced water; and
- **The envisioned end-use scenario** and specific cost, environmental, operational, policy, regulatory, and public perception considerations, especially the level of treatment required to make the produced water suitable for the intended end use, or “fit for purpose.”

Reflecting the paramount importance of local considerations and a “fit-for-purpose” approach, this report includes:

- **Profiles of the top seven basins/regions based on oil and gas production and current unconventional drilling activity:** the Permian, Appalachian, Bakken, Niobrara/ Denver-Julesburg (DJ), Oklahoma, Haynesville, and Eagle Ford basins/regions.

- **Data on water management from 18 producing companies**, with operations summarized for these seven major unconventional regions.
- **A summary — developed with the Louisiana State University School of Law —evaluating how selected states regulate produced water**, focusing on differing regulatory frameworks for produced water management, agencies responsible for regulating these processes, and produced water ownership and liability.
- **A four-phase conceptual research framework designed to assist decision-makers in assessing and reducing risks associated with a given reuse scenario where produced water is considered for uses outside of oil and gas operations**, incorporating the traditional concepts of risk-based decision-making — research, risk assessment, and risk management — as applied to produced water treatment and reuse.
- **An overview of various treatment technologies** that exist or are being actively researched today within academic, governmental, and industrial arenas.
- **A literature review** identifying hundreds of published, peer-reviewed studies and referencing other reports, which may be relevant to assessing produced water reuse or identifying knowledge gaps and current limitations.

Opportunities and Challenges

Increasing produced water reuse holds promise for making available a substantial volume of water that could potentially offset, or supplement, fresh water demands in some areas. Reuse also can be beneficial to oil and gas producers as an alternative to disposal in UIC wells, which can be costly, locally unavailable, or subject to volume restrictions. States and regulators may want to investigate reuse for reasons ranging from drought and groundwater depletion to disposal-related induced seismicity.

For the end user, in addition to considerations related to the quality of treated produced water, the economic attractiveness of reuse depends on whether the supply of produced water is predictable, whether it can be delivered reliably to the point of use, and how the cost compares to other available sources of water after factoring in the costs of its treatment and transportation as well as the disposal of treatment residuals. If local water supplies of fresh water are adequate or abundant, there is less incentive to consider beneficial reuse of treated produced water, especially given its potential associated risks.

Reuse in Unconventional Oil and Gas Operations

The multi-stage hydraulic fracturing of a single horizontal well can use an average of about 12 million gallons of water. Growth in the volumes of sourced and produced water required in hydraulic fracturing operations has raised sustainability concerns in unconventional regions, prompting greater emphasis on long-term water planning. In regions where either source water or disposal capacities are limited, produced water reuse may become economically viable and operationally practical. The area where reuse is highest, Pennsylvania and West Virginia (Appalachia), and the area where reuse is growing fastest, West Texas and New Mexico (Permian), are regions where disposal options have been or may become limited and disposal costs have been high or are increasing. In addition, several of the top basins are in arid regions with limited availability of sourced water.

Water treatment requirements for reusing produced water in hydraulic fracturing are far less demanding than for uses outside the industry. Advances in hydraulic fracturing chemistry allow operators to use produced water with minimal treatment, addressing only a few specific constituents to create “clean brine.” The approach is significantly less costly than more advanced treatment regimes such as those necessary to remove salts. However, in limited cases, advanced treatment is still done to provide an option that could meet discharge water quality requirements or reduce the potential risk from a spill.

The high costs of transporting and storing produced water, particularly in areas lacking an established water pipeline infrastructure, remain a barrier to reuse in most regions. Achieving significant levels of produced water use in unconventional producing regions will require capital investment in storage, transportation, and treatment capacity; a predictable supply of produced water; ongoing demand for source water for nearby production operations; and a supportive regulatory framework. Managing environmental risk related to transporting and storing produced water for reuse requires minimizing and remediating spills and leaks, managing residuals, controlling air emissions, and taking actions to protect wildlife. These considerations must be paramount in production operations, as well as in the design and construction of storage impoundments or tanks and permanent or temporary pipelines.

The recent emergence of water midstream solutions (coordinating water sourcing for completion operations with produced water reuse across multiple producing companies) holds promise for smoothing out the peaks and valleys of individual company water demands, reducing transportation and disposal, and reducing demands on infrastructure through shared use. The scale of water midstream could allow reuse to grow steadily, especially in the most active areas in the Permian, Appalachia, and Oklahoma.

Reuse Outside the Oil and Gas Industry

Potential options for treatment and reuse of produced water outside the oil and gas industry include land application (e.g., irrigation, roadspreading), introduction to water bodies (e.g., discharges to surface water, injection or infiltration to ground water) and industrial uses (e.g., industrial feed streams, product or mineral mining). While some options, such as surface water discharge, are in limited use today, most remain theoretical.

Currently, the feasibility of reuse is significantly greater in unconventional oil and gas operations than in applications outside the oil and gas industry, where the costs of transporting and storing produced water and, particularly, of treating it to a “fit for purpose” level can be limiting. Potential risks to health and the environment must be well understood and appropriately managed in order to prevent unintended consequences of reuse. Produced water is complex, and in most cases further research and analysis is needed to better understand and define the “fit for purpose” quality goals for treatment and permitting programs. Environmental considerations beyond direct health or ecosystem impacts include emissions from treatment, managing waste materials from treatment, cumulative ecosystem impacts, or other localized issues.

Overview of Research Needs

Most research needs identified for this report pertain to produced water treatment and reuse outside the oil and gas industry. Managing potential risks with such applications requires improved understanding of the composition of a specific produced water source and identification of the health and environmental risks of reuse or release. This information is then used to determine the standards of quality that must be met to make the produced water fit for purpose. Finally, a user must evaluate the costs, benefits, and risks entailed in achieving those standards.

Produced water is a subject on which research is rapidly advancing, including the development of knowledge and tools for produced water characterization, treatment, risk assessment, and feasibility for reuse. Yet many knowledge gaps remain to be tackled. Strategic advancements in data and analysis will be needed to inform risk-based decisions and support the development of reuse programs that are protective of human health and the environment.

A central challenge will be researching and designing effective and economical treatment trains for specific reuse scenarios, which can entail analyzing the complex character of a specific produced water; managing variability; significantly reducing high total dissolved solid levels, organic constituents, metals, and naturally occurring radioactive material; and handling residuals. The most purposeful and actionable research and development strategy will be to identify and focus on specific reuse options where circumstances align to make reuse a potential need or opportunity in the near-future, in specific regions, taking into account the volume and quality of produced water potentially available and the needs of nearby water users.

For reuse within the oil and gas industry, research needs are more modest, addressing such areas as optimized leak detection systems, water treatment technologies to cost effectively address specific water quality challenges related to scale buildup or a specific analyte or other component, improvements in enhanced evaporation or desalination, development of automated treatment systems that can be operated remotely with little or no human intervention, and methods for separation of saleable products during treatment.

Overview of Regulatory and Legal Challenges and Opportunities

Nearly every aspect of produced water — including management practices, construction standards, and operational requirements — is regulated by federal, state, or local agencies. Disposal of produced water through surface discharges or injection in underground wells is subject to two key federal permitting programs — the National Pollutant Discharge Elimination System (NPDES) program and the Underground Injection Control (UIC) program — both of which are administered primarily at the state level.

Presently, regulatory frameworks for overseeing beneficial use of produced water, particularly reuse outside the oil and gas industry, are not well developed. As interest in beneficial reuse of produced water grows, agencies could be expected to develop new regulatory programs to authorize and manage those activities. Legal and regulatory considerations include determining state water rights as well as applicable regulations such as those relating to water quality standards and permitting. The determination of a specific beneficial use would depend on federal and state jurisdiction and the circumstances of each case.

Similarly, midstream water operations and other forms of water sharing are often outside traditional state oil and gas regulatory frameworks and require state authorization and oversight for activities that are not associated with other permitted oil and gas operations. Expanding midstream and other water-sharing opportunities may require state-level regulatory or legislative solutions to several issues, including management of risk associated with commercial management of large volumes of produced water from multiple sources at one facility, ownership of produced water, transfer of ownership, surface storage, and determination of liability if there is a spill or other environmental damage.

There are also other concerns regarding ownership and legal liability. In many cases, the lease holder, typically an oil and gas company, is the owner of the produced water and has the legal liability to properly treat, transport, and dispose of it. Reuse within the oil and gas industry is typically not subject to additional regulations other than tracking the flow and disposition of the produced water. However, if treated produced water is being reused outside the oil and gas industry, there must be a clear understanding of the current and future liability and transfer point of the liability and ownership.

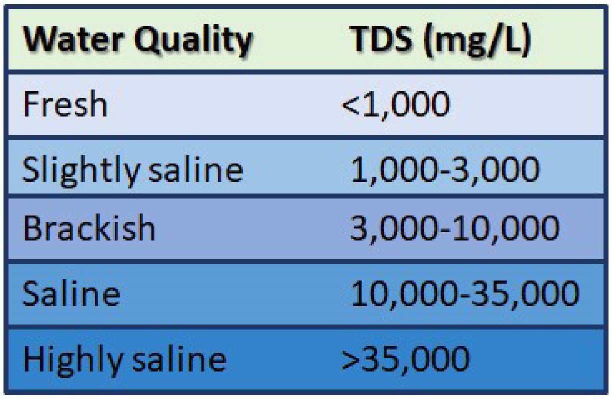
Conclusions

Operators and regulators alike are rethinking the economics and long-term sustainability of traditional produced water management practices. Many operators are reusing more produced water than ever. As water becomes scarcer, the increasing benefits of reusing produced water in some regions may outweigh the costs of managing, treating, storing, and transporting it if health and environmental risks can be understood and appropriately managed. While most near-term alternatives focus on reuse of produced water to reduce fresh water consumption in unconventional oil and gas operations, interest is growing in the potential for reuse outside the oil and gas industry.

Produced water is not uniform, and neither are the circumstances of its potential treatment and reuse. Research, treatment decisions, risk management strategies, and in some cases even approval processes should be tailored to address the reuse of a particular produced water for a particular type of reuse. Identifying specific reuse options that address current or emerging needs or drivers in specific regions is an important next-step opportunity in order to prioritize investment in purposeful and actionable research and development with a defined set of facts and circumstances. Additional regulations to protect public health and the environment may apply or be developed in response to increased beneficial reuse outside the oil and gas industry.

Introduction

Produced water, a byproduct of oil and gas production, is water in underground formations that is brought to the surface during oil and gas production. It is sometimes referred to as “brine” or “saltwater” within the industry, as it is typically saline to highly saline (Figure I-1).



Water Quality	TDS (mg/L)
Fresh	<1,000
Slightly saline	1,000-3,000
Brackish	3,000-10,000
Saline	10,000-35,000
Highly saline	>35,000

Figure I-1. Produced Water Quality

Source: After USGS and Compendium of Hydrogeology

Produced water salinities range from fresh to highly saline.

While most produced water is groundwater naturally occurring deep in the reservoir, it also can include water previously injected into the formation during well treatment or secondary recovery to increase oil and gas production, as well as residuals of any chemicals added during the production processes. A third source of produced water is “flowback water” that returns to the surface after a well is hydraulically fractured.

Produced water is classified as an “exempt” oil and gas waste stream, meaning it is not subject to the Subtitle C (hazardous waste) provisions of the Resource Conservation and Recovery Act (RCRA). Its management is subject to two key federal permitting programs—the National Pollutant Discharge Elimination System (NPDES) program and the Underground Injection Control (UIC) program—both of which are administered primarily at the state level.

Produced water is either disposed of as a wastewater or beneficially reused (Figure I-2). In cases where it is determined to be fit for a beneficial reuse, produced water then becomes a resource rather than a waste product. Over the past decade, interest has grown in increasing the beneficial reuse of produced water both inside the oil and gas industry and elsewhere, an approach that holds promise for making available a substantial volume of water that could potentially offset, or supplement, fresh water demands in some areas.

The GWPC anticipates that as states and regions look to become more water resilient, the role of produced water will expand. To encourage this expansion, this report compiles information regarding produced water and identifies areas of needed legal or regulatory action and where research needs exist to potentially increase the amount of produced water utilized. It is hoped that over time this report will be used to:

- Educate the public on produced water and how the oil and gas industry uses water
- Encourage the oil and gas industry, state and federal regulatory agencies, and other parties that gather data on produced water to make the data more readily available
- Inform new research in the chemical characterization of produced water
- Inform new research to determine appropriate quality objects for reuse of produced water
- Inform new research in the development and testing of technologies for the treatment of produced water
- Expand the use of produced water in a manner that is protective of the environment and public health.

What Is Driving the Discussion of Produced Water Reuse?

Several factors are driving the discussion about the reuse of produced water, including stress on fresh water resources, limitations on underground formation storage capacities and pressures, concerns about induced seismicity, and localized need for large volumes of water for unconventional oil and gas operations such as hydraulic fracturing.

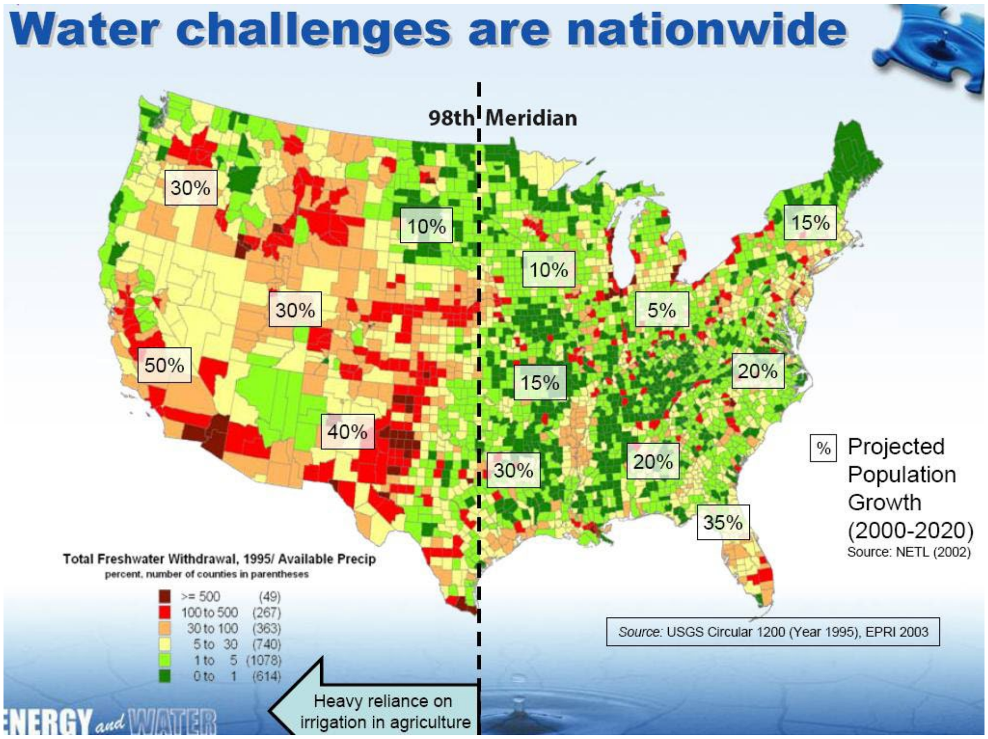
From a technical standpoint, “fresh water” is defined by both the U.S. Geological Survey (USGS) and the Compendium of Hydrogeology[1] as water that contains less than 1,000 milligrams per liter of dissolved solids (TDS). The USGS goes on to note that “generally, more than 500 mg/L of TDS is undesirable for drinking and many industrial uses”,[2] and the EPA has established a secondary drinking water standard of 500 mg/L TDS.

Fresh water stress is driven by rising populations and regional droughts, which have created challenges to meet demands for fresh water resources in some areas across the country. According to the U.S. Census Bureau, the U.S. population is expected to increase by more than 50 million between 2000 and 2020. Where surface water is scarce, communities and industries typically turn to groundwater to meet their freshwater needs. Currently, there are concerns about the amount of groundwater being used regionally and nationally. For example, as of 2015, storage in the

DIFFERING STATE DEFINITIONS OF FRESH WATER

Legal/regulatory definitions of fresh water differ by state. For example, the Pennsylvania Department of Environmental Protection defines fresh water as “Water in that portion of the generally recognized hydrologic cycle which occupies the pore spaces and fractures of saturated subsurface materials.” The Texas Water Development Board defines fresh groundwater as water with less than 1,000 mg/L of Total Dissolved Solids (TDS), while the Wyoming Oil and Gas Conservation Commission defines fresh water as “water currently being used as a drinking water source or having a total dissolved solids (TDS) concentration of less than 10,000 milligrams per liter (mg/l) and which can reasonably be expected to be used for domestic, agricultural, or livestock use; or is suitable for fish or aquatic life.”

Determining what is considered “fresh water” depends on the quality of the water, the state in which the water resides, and the use of the water. Since it is not possible to use a single definition for fresh water, the term “fresh water” in this report must be viewed within the context of the narrative in which it appears.



Source: NETL (2002)

Source: USGS Circular 1200 (Year 1995), EPRI 2003

Figure I-2. Fresh Water Withdrawals and Population Growth Estimates

Source: https://myweb.rollins.edu/jsiry/Waterbasics.html

This figure shows the total freshwater withdrawal divided by the available precipitation in different parts of the country. The anticipated percentage population increases in different regions is overlain on the map. Much of this growth is projected to occur in the already water-stressed areas of the Southwest. The 98th Meridian shown on the map illustrates an important distinction for the management of produced water.

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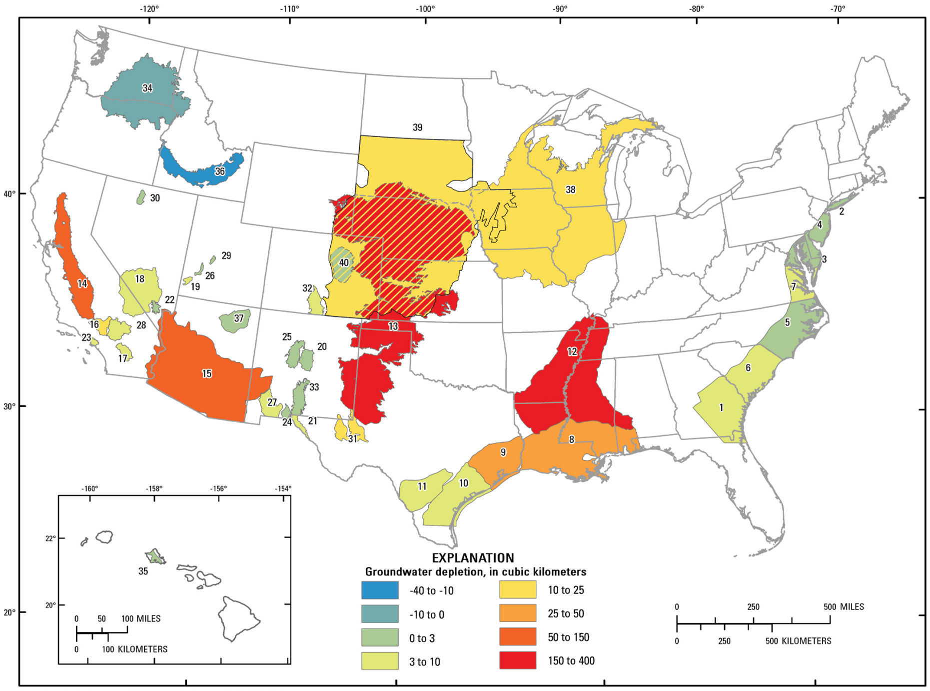
[1] Robert F. Porges and Mathew J. Hammer, *The Compendium of Hydrogeology* (Westerville, Ohio: National Ground Water Association, 2001).

[2] “Water Science Glossary of Terms,” The USGS Water Science School, U.S. Geological Survey, https://water.usgs.gov/edu/dictionary.html.



Base from U.S. Geological Survey digital data, 1972,1:2,000,000
Albers Equal-Area Conic Projection
Standard parallels 29° 30' N and 45° 30' N, central meridian 96° 00' W

Figure I-3. Cumulative Groundwater Depletion, 1900 through 2008, in 40 Assessed Aquifer Systems or Subareas in the United States (excluding Alaska)

Source: Groundwater Depletion in the United States (1900-2008), USGS Scientific Investigations Report 2013-5079

Fresh water withdrawals coupled with population growth have resulted in an increased reliance on groundwater resources, causing depletion of aquifers to varying degrees. This depletion (often referred to as aquifer mining) is resulting in a shortage of fresh groundwater available for use. In this figure, colors are hatched in the High Plains aquifer (area 39) where the aquifer overlaps with other aquifers having different values of depletion.

High Plains aquifer was about 2.91 billion acre-feet or more. This represents a decline of about 273.2 million acre-feet, or 9 percent, since significant groundwater irrigation development began around 1950.[3] On a national scale, approximately 1,000 cubic kilometers (km^3) of groundwater, or about 811 million acre-feet, were depleted between 1900 and 2008.[4] Once depleted, this water is not easily or quickly recharged naturally.

How Much Produced Water Is Generated?

Currently, the volume of produced water is small compared to total U.S. daily water use, but these volumes can be locally significant.[5] Based on the best available data from 2012, the nearly 1 million producing oil and gas wells in the United States generate approximately 21.2 billion barrels (bbl.) of produced water each year. Expressed in other units, this volume equals 58 million bbl./day, 890 billion gallons/year, 2.4 billion gallons/day, or 2.7 million acre-feet/year.

Produced water flow rate varies throughout the lifetime of an oil or gas well. Most unconventional hydraulically fractured wells show a high produced water flow rate initially as the flowback of fracturing fluids is occurring, followed by a decline in flow rate until it levels off at a relatively steady lower level.

Based on the best available data from 2012, the nearly 1 million producing oil and gas wells in the United States generate approximately 21.2 billion barrels of produced water each year.

Conventional oil and gas wells show little or no produced water initially, with the flow rate increasing over time. Total lifetime water production is typically higher for conventional wells than for unconventional wells.

Although this report does not include water production from coalbed methane wells, it is worth noting

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[3] USGS, "High Plains Aquifer Groundwater Levels Continue to Decline" (News Release, June 16, 2017), https://www.usgs.gov/news/usgs-high-plains-aquifer-groundwater-levels-continue-decline.

[4] Leonard Konikow, *Groundwater Depletion in the United States 1900-2008, USGS Scientific Investigations Report 2013-5079* (Reston, Virginia: U.S. Geological Survey, 2013), https://pubs.usgs.gov/sir/2013/5079/SIR2013-5079.pdf.

[5] John Veil, *U.S. Produced Water Volumes and Management Practices in 2012* (Groundwater Protection Council, April 2015), (accessed June 16, 2016) http://www.gwpc.org/sites/default/files/Produced%20Water%20Report%202014-GWPC_0.pdf.

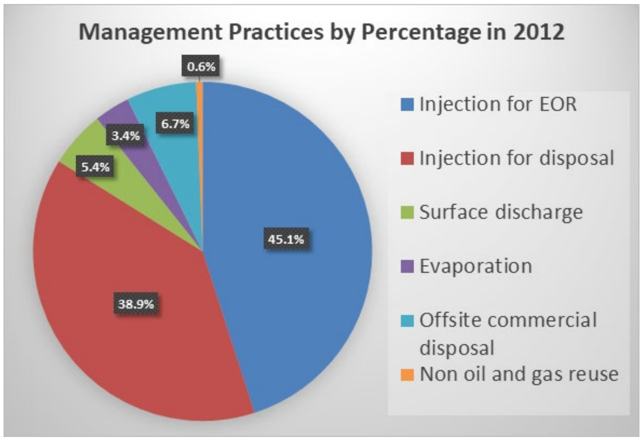

Figure I-4. Management Practices of Produced Water by Percentage in 2012

Source: GWPC 2015 Produced Water Report

In 2012, the amount of produced water generated from oil and natural gas development onshore and offshore in the United States was estimated to be 21 billion barrels. The GWPC estimates this produced water was managed as shown above.

that initial water production from these wells can be quite substantial, tapering off as gas begins to flow into the wellbore.[6]

What Does Produced Water Contain?

The physical and chemical properties of produced water vary considerably depending on the geographic location of the field, the geologic formation, and the type of hydrocarbon product being produced. Because the water has been in contact with hydrocarbon-bearing formations for millennia, it generally contains some of the chemical characteristics of the formations and the hydrocarbons in those formations.

Produced water can contain many different constituents. In collecting data for its 2016 hydraulic fracturing study, the U.S. Environmental Protection Agency (EPA) found literature reports showing the detection of about 600 different chemicals in some produced water samples.[7] Some of these chemicals are monitored routinely, while others may rarely be measured. Although hundreds of chemicals could be used as additives, only a limited number are routinely used in well treatment operations. While it is relatively easy to characterize some constituents in produced water, it is more difficult to characterize others, especially in highly saline matrices. Produced water characterization is an evolving science.

Produced water may contain:

- Mineral salts including cations and anions dissolved in water (often expressed as salinity, conductivity, or total dissolved solids [TDS])
- Organic compounds including volatile and semi-volatile organics, hydrocarbons, organic acids, waxes, and oils
- Inorganic metals and other inorganic constituents including compounds such as sulfate and ammonia
- Naturally-occurring radioactive material (NORM) that leached into the produced water from some formations or precipitated due to water mixing
- Chemical additives to improve drilling and production operations
- Transformational byproducts that can form from the interaction between added chemicals and formation water.

Another concern are constituents resulting from chemical reactions that can occur when produced water from one formation is introduced into a different formation. Additionally, naturally occurring elements, including metals, can leach out of the geologic formation into the produced water because of this change in the formation waters.

In collecting data for its 2016 hydraulic fracturing study, the U.S. Environmental Protection Agency found literature reports of about 600 different chemicals in some produced water samples.

Although some produced waters have a low salt content, most is highly saline. TDS in different produced waters ranges from less than 3,000 mg/L to over 300,000 mg/L. Waters with very high salinity are difficult to treat, and treatment results in a large quantity of very concentrated waste products that require appropriate disposal. High salinity also can

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[6] Cynthia Rice and Vito Nuccio, "Water Produced with Coalbed Methane," USGS Fact Sheet FS-156-00 (November 2000), https://pubs.usgs.gov/fs/fs-0156-00/fs-0156-00.pdf.

[7] USEPA, *Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States, Main Report* (EPA/600/R-16/236fa), https://cfpub.epa.gov/ncea/hfstudy/recordisplay.cfm?deid=332990.

be troublesome when analyzing many constituents in produced water, since some traditional analytical methods do not work accurately in saline water. Further, adequate analytical methods may not exist for other chemicals that are not monitored frequently or are unknown at this time.

Produced water, especially from unconventional wells, will show varying concentrations of constituents over time. This consideration is important when designing treatment processes and in assessing the suitability of the produced water to be used or reused for a beneficial purpose.

What Opportunities Exist for Beneficial Reuse?

Currently, about 45 percent of produced water generated from onshore activities in the United States is reused within conventional oil and gas operations, where it is injected into formations to enhance recovery. Enhanced recovery techniques include injecting water or steam into the formation to maintain pressure and help sweep more oil to the production well ("water flooding" or "steam flooding"). Produced water is typically used for these operations, along with additional water.

Most of the remaining produced water, approximately 55 percent (488 billion gallons per year), is handled as a wastewater. Additional potential opportunities exist both within and outside of the oil and gas industry to make beneficial reuse of some of this water.

Within the oil and gas industry, operators and regulators are seeking ways to increase the beneficial reuse of produced water not only in enhanced recovery in conventional oil and gas operations, but also in well drilling and hydraulic fracturing operations in unconventional oil and gas production.

Several factors make beneficial reuse within the industry appealing in many cases. One major driver is a desire to minimize disposal of produced water. Disposal through underground injection is a costly operation that can be subject to capacity limitations. Underground injection may also create the potential for induced seismicity, which has resulted in further limitations on injection volumes and rates in some states. Disposal through discharge to surface water may be subject to volume limitations and entail costly treatment in a wastewater treatment facility or a centralized industrial wastewater treatment plant. There are also costs and risks associated with transportation of produced water. In contrast, beneficial reuse within the oil and gas operations eliminates or reduces treatment and some transportation of the produced water.

Another driver to consider is local water needs. Drought conditions in recent years have created serious water availability problems for some communities. For example, parts of the southeastern United States faced summer brown-outs due to inadequate cooling water for electrical generation, and numerous cities and towns, especially in California, Oklahoma, and Texas, have been forced to ration water. One possibility for dealing with fresh water shortages may be to supplement or replace fresh water use in unconventional oil and gas operations with produced water. (In contrast, disposal of produced water through deep injection can exacerbate water shortages since water is effectively removed from the ecosystem.)

CONVENTIONAL VS. UNCONVENTIONAL OIL AND GAS OPERATIONS

Historically, most oil and gas wells were drilled to intercept pools of oil and gas trapped in underground geologic structures. Typically, the oil and gas had migrated from their original source rock formations to other formations that had enough pore space to hold economic quantities of the hydrocarbons. These are known as "conventional" plays and the wells drilled in such areas are called conventional wells, representing historic oil field activities.

Geologists knew for decades that source rock formations, like shale, held extensive quantities of oil and gas. Because of the low permeability in the shale source rock, the historic technology for drilling wells and producing the oil and gas did not generate enough quantities to justify the cost of the wells. A few decades ago, the technologies of horizontal drilling (drilling a vertical well until just above a target formation, then turning the well so it runs horizontally or laterally within the target formation) and hydraulic fracturing (using pressure to create new cracks in a formation to allow the oil and gas to move to a well) were combined. This approach allowed wells to produce enough oil and gas from the shale formations to justify the cost of drilling and completing the wells. This type of geologic formation play is known as an "unconventional" or "tight" formation, and the wells drilled in these formations are called unconventional wells.

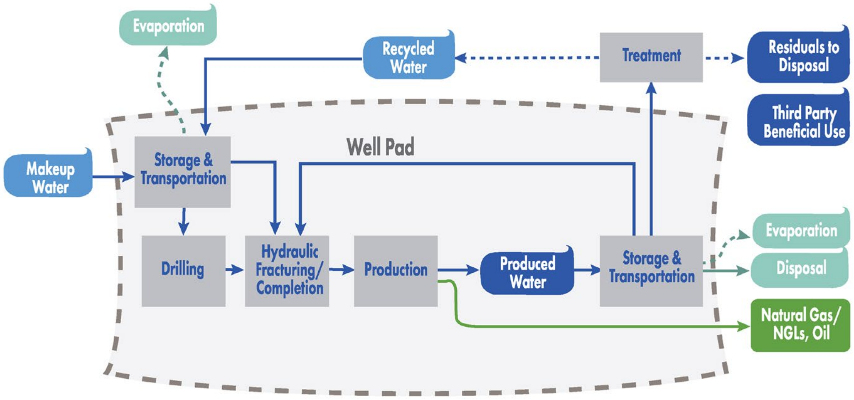

Figure I-5. Water Lifecycle for Unconventional Oil and Gas Production

Source: Energy Water Initiative (an effort by members of the U.S. oil and gas Industry to study and Improve lifecycle water use and management in upstream unconventional exploration and production)

Water is required to conduct various steps in the production of unconventional oil and gas resources. Water is needed to make up drilling and completion fluids and to assist in site washing and dust control activities. After wells are drilled, they may undergo hydraulic fracturing as part of completing the well, which requires additional water to make up the fluids used for fracturing (frac fluids).

Outside the oil and gas industry, produced water is used in a few limited applications such as livestock watering, stream augmentation, and irrigation of selected crops. Less than one percent of produced water is currently reused in such ways. Wider uses may also become practical and cost-effective with further research. As the volume of available fresh water continues to diminish, there is a growing need to reduce the use of freshwater for industrial, municipal, and agricultural activities, especially for consumptive uses that do not return water to usable water sources. Possibilities include applications in drought relief, fire protection, dust suppression, irrigation of additional crops, irrigation of public access areas such as golf courses and parks, industrial cooling or process water, mining, municipal water needs, and recreational uses.

Generally, beneficial reuse outside the oil and gas industry will be less economically attractive than reuse within the industry, since the produced water usually must be transported greater distances and treated more extensively. (See Module 3 for more information about reuse outside of oil and gas operations.)

What Factors Determine the Feasibility of Beneficial Reuse?

Because produced water resides at the surface, it makes sense to determine whether there is a cost-effective and environmentally friendly way to treat and reuse it instead of disposing of it by underground injection. Several factors determine whether and where beneficial reuse is feasible.

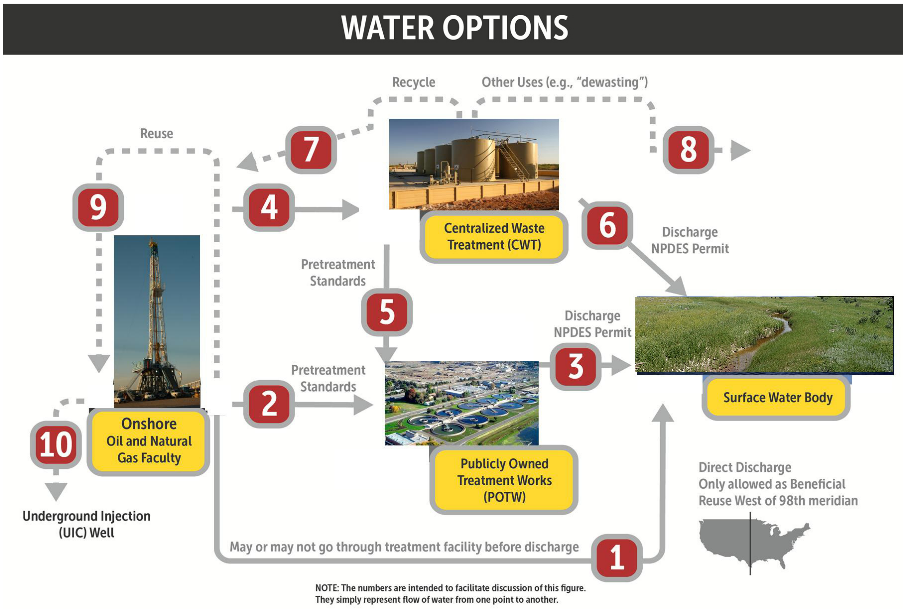

Figure I-6. Options for Produced Water Management

Source: After American Petroleum Institute (Modified)

This figure illustrates the range of alternate options for managing produced water. Options 1 through 6 show some form of discharge to surface waters, either directly or after treatment in a wastewater treatment facility or a centralized industrial wastewater treatment plant. Produced water can be used again in the oil and gas process without treatment (option 9) or after treatment (option 7). Produced water can also be put to some other use (option 8) after treatment. Option 10 shows produced water directed to injection wells. A more substantive discussion of these practices is included in Modules 1 and 2.

Currently, more than 90 percent of the produced water brought to the surface from the production of oil and gas is injected underground through Class II injection wells such as the one shown here to aid in future oil and gas production or for disposal.

Water quality. The quality of produced water will determine its potential suitability for specific uses. A major water quality consideration is the feasibility and cost of treating the produced water to be fit for the intended purpose. In some cases, research may be necessary to define quality goals. Produced water from different sources varies greatly in quality and its reuse requires accurately characterizing the constituents and their concentrations in a specific produced water supply, identifying the health and environmental risks of their release, determining the standards of quality that must be met to make the produced water fit for purpose, and evaluating the costs, benefits, and risks entailed in achieving those standards. Management of treatment residuals is a major cost factor and can present a substantial barrier to water treatment based on its characteristics, volumes, and disposal options.

Water quality presents a lesser challenge for reuse within oil and gas operations, because this option presents limited exposure pathways, operators have a good understanding of quality needs or objectives, and there are reduced treatment requirements.

Water volumes and longevity. The amount of produced water and its long-term availability can affect the desirability of its reuse. While desirability may be high in an area with large amounts of produced water and limited alternate water supplies, that is not likely to be the case where produced water volumes are low, and supplies are unpredictable. Longevity of supply is especially important in making the case for beneficial reuse outside the oil and gas industry. For example, a typical production well may last from 20 to 30 years, while a typical coal fired power plant has a lifespan of 50 years or more. Unless the operator(s) can guarantee a quantity of deliverable water of a specific quality over the life of the power plant, it may not be advantageous for the power plant to use produced water as a source of supply unless a separate guaranteed backup source of supply can be arranged.

Logistics and infrastructure. Logistical and transportation costs may limit the potential reuse of produced water. Considerations include the availability of treatment facilities and the costs of transporting the produced water to the facilities as well as to the point of end use. Moving water can be expensive. Trucking costs for a typical trip from a tank battery to a salt water disposal (SWD) well can range from \$1 to \$3 per barrel.[8] The cost of constructing permanent pipelines currently averages about \$1.45 million per mile depending on pipe size, terrain, right of way costs, and other factors.[9] The use of temporary pipe, sometimes

FIT FOR PURPOSE

The level of treatment necessary when considering reuse of produced water depends on the quality needs for the intended use. Treatment is typically designed to be “fit for purpose.”

If salinity reduction or removal of other constituents of concern is needed to meet a regulatory standard (e.g., discharge to a river) or if the end use requires water with a specific set of parameters, advanced treatment may be necessary to meet those end goals.

If the produced water will be injected into a disposal well or back into a formation to produce more oil, less or possibly no treatment is needed. The main treatment goals are to remove any free oil or large solids to keep the injected water from blocking the pores in the formation or damaging the injection equipment and to remove any other constituents that may interfere with drilling or completion.

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[8] One barrel (bbl.) equals 42 gallons.

[9] State of Oklahoma Water Research Board (OWRB), *Oklahoma Water for 2060 Produced Water Reuse and Recycling* (Tulsa, Oklahoma: April 2017), https://www.owrb.ok.gov/2060/PWWG/pwwgfinalreport.pdf.

referred to as "lay flat pipe", is less expensive than permanent pipe but comes with its own set of problems, including increased maintenance needs and higher leakage rates. Remote locations may require the use of modular treatment facilities where the logistics of transporting water to a centralized facility may be both difficult and cost prohibitive. The extent to which this affects beneficial use depends on the availability and cost of modular treatment, accessibility to the site, number of treatment units needed, maintenance needs of the treatment equipment, and other factors.

Market considerations. The economic attractiveness of beneficial reuse depends on whether the supply of produced water is predictable, if it can be delivered reliably to the point of use, and how the cost compares to other available sources of water after factoring in the costs of its treatment and transportation as well as the disposal of treatment residuals. If local water supplies of freshwater are adequate or abundant, there is less incentive to consider beneficial reuse of treated produced water, especially given its associated risks. Also, when other water sources, such as locally available brackish groundwater, can be delivered cost effectively, that may also depress reuse of produced water.

Legal and regulatory. These considerations include determining state water rights as well as applicable regulations. The determination of a specific beneficial use depends on federal and state jurisdiction, and the circumstances of each case.[10] Another concern is the legal liability. In many cases, the lease holder, typically an oil and gas company, has the legal liability to properly treat, transport, and dispose of the produced water. However, if treated produced water is being used or reused outside of the oil and gas processing areas, there must be a clear understanding of the current and future liability and transfer point of liability.

What Are Future Implications for Water Planning?

Realizing the promise of increased beneficial reuse of produced water will not be a simple matter. It will require addressing substantial economic, technical, regulatory, and environmental challenges.

Given these complex factors, it would be unrealistic to suggest that all produced water can be put to beneficial reuse. Yet it is important for policymakers to recognize all the potential sources of water in an area to meet user needs. When considered as an integral part of water planning, treated produced water can be utilized to help relieve reliance on fresh water.

Based on the location, volume, and availability of fresh water, treated wastewater and produced water can, and likely will, play a larger role in future water supplies. However, until further research is completed, opportunities to reuse produced water more widely may be limited. Additional research on the characteristics of produced water in specific locations and evaluation of the environmental and health risks that could be associated with produced water use will be necessary to help inform both producers and potential end users of the possibilities for expanded produced water reuse.

In addition to research, challenges to be addressed range from defining regulatory frameworks to gaining public acceptance of produced water use in new applications. Presently, regulatory frameworks for overseeing beneficial use of produced water are not well developed. GWPC anticipates that as interest in beneficial use of produced water grows, agencies will develop new regulatory programs to authorize and manage those activities.

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[10] Modified from "Produced Water Treatment and Beneficial Use Information Center" website, Colorado School of Mines / Advanced Water Technology Center, http://aqwatec.mines.edu/produced_water/intro/what/index.htm.

Why Isn't Coalbed Methane Produced Water Included in this Report? Water from coalbed methane production is not included in the report for several reasons:

- Because the volume of coalbed methane produced water falls off rapidly after initial production, it is not a reliable potential long-term source of water for reuse, except for hydraulic fracturing of other coalbed methane wells.
- Coalbed methane production operations are generally distant from major oil and gas producing basins, making its use in exploration and production activities impractical except for fracturing of other coalbed methane wells.
- Coalbed methane produced water is not covered by the oil and gas Effluent Limitation Guidelines (ELGs) promulgated at 40 CFR Part 435 and is frequently fresh enough to be considered for surface discharge with minimal treatment. Reuse can be logistically more difficult and costlier than such discharge.
- Contributions of produced water from coalbed methane would likely be statistically insignificant. Volumes of coalbed methane production continue to decline nationally and are small (< 3% annually) compared to natural gas production.

Studies on coalbed methane produced water are acknowledged in this report where relevant but are not extensively analyzed.

MODULE 1

Current Legal, Regulatory, and Operational Frameworks of Produced Water Management

MODULE SUMMARY

This module explores the use of water in the oil and gas industry from a national overview perspective and describes the regulatory frameworks surrounding management of produced water. Essential points about regulatory management of produced water include the following:

Water is critical to oil and gas production.
Water plays an integral role in oil and gas production, including use for drilling fluids, fracturing fluids, and water flooding. Produced water is generated from producing wells and must be managed. Historically, more than 90 percent of produced water is injected underground for disposal or to help produce more oil.

States regulate oil and gas activity.
The entire oil and gas exploration and production process is regulated in many ways by different agencies, with most oil and gas regulation occurring at the state level. The principal purpose of these regulations is to protect the environment. While some produced water management activities are subject to regulatory standards, others are subject to operational standards set by operators or end users. There are more than 30 states with oil and gas production, and each state has its own regulations. Even within individual states, more than one agency may regulate the management of produced water, as shown in Table 1-3.

Water rights and responsibilities vary from state to state.
Produced water is groundwater and is subject to individual state water rights laws. Each state has a different set of laws governing the management and allocation of surface and groundwater. Views on reuse of produced water vary depending on which state is involved, as shown in Table 1-4.

It is important to identify how and when ownership changes occur and to understand that these changes in ownership may differ based on local or state regulations or laws. Understanding the role of water rights, mineral rights, and surface ownership in the exploration and production of oil and gas is critical in addressing how and when there is compensation for or liability related to the beneficial use of produced water.

Produced water reuse requires careful thought.
Reuse of produced water is possible and may be cost effective in the right situations. When specific reuse projects are being considered, oil and gas companies and end users must work together. Regulators can look for ways to allow reuse projects to move forward but should ensure that these practices can be done with proper environmental and public health protection.

Expanding reuse opportunities may require regulatory or legislative solutions to several issues, including ownership of produced water, transfer of ownership, and determination of liability if there is a spill or other environmental damage.

Background

Water is closely intertwined with oil and gas production, including water supplied to support operations and byproducts (produced water) from the production process. Determining how to find source water and manage produced water efficiently and cost effectively is an important component of producing oil and gas.

Nearly every aspect of produced water—including management practices, construction standards, and operational requirements—is regulated by federal, state, or local agencies. Federal laws and regulations govern the disposal of produced water through surface discharges or injection in underground wells.

Oil and gas companies are required to obtain numerous permits, licenses, and certificates, conduct monitoring and reporting to the agencies, and operate in compliance with the regulations. Produced water can be managed within an individual lease area or over a larger field that incorporates many wells and leases. Depending on the size of fields or plays, more than one oil and gas company may be involved, and geographic boundaries can include more than one county, river basin, or state.

Following are examples of regulatory involvement throughout the oil and gas water cycle.

- **Sourcing, including ownership of water.** State water rights laws or regulations determine who has legal rights to water sources. Many states require permits to withdraw water from surface or groundwater sources. Under drought conditions, permits may be delayed or denied temporarily, or allocations may be reduced. If water is obtained from a municipal drinking water supplier, municipal wastewater treatment facility, or other alternate source, contracts or some other legal mechanisms are utilized.
- **Transportation of water.** Trucks used to haul water must obtain permits and licenses. When pipelines are used, they typically are long, linear structures that may cross over areas owned by multiple landowners, requiring multiple easements to be purchased or leased. Where pipelines intersect roadways, streams, railways, or other existing structures, additional permits and approvals are typically needed.
- **Storage of water.** In some states, permits are required to build and operate storage pits which are subject to construction criteria, including surface water and groundwater contamination prevention. When tanks are used, they typically are authorized as part of the Application for Permit to Drill or by rule. Although most states do not have specific design and construction requirements for tanks, secondary containment requirements are required in almost all cases. Spill prevention, control, and countermeasure (SPCC) plans may be required. Additionally, stormwater management permits may be required for the storage at the well site.
- **Hydraulic fracturing**. Hydraulic fracturing is typically regulated under state oil and gas programs. Reporting of information relating to pressures, volumes, depths, duration, materials, etc., must be made for each hydraulic fracturing job. In many states, companies conducting fracturing jobs must keep information available, submit information to the state regulatory agency, or enter data on water and chemical usage into the National Hydraulic Fracturing Chemical Registry (FracFocus). Transportation and storage of chemicals used in fracturing fluids may be regulated by federal, state, and local agencies.
- **Disposition of produced water**. Produced water disposed by discharge directly to surface water must be authorized by a National Pollutant Discharge Elimination System (NPDES) permit and/or a state discharge permit. Produced water sent to a municipal wastewater treatment facility must follow NPDES regulations for pretreatment and meet any additional standards imposed by the wastewater treatment facility. Currently, this is only allowed when produced water is pretreated at a centralized treatment facility or is generated through conventional oil and gas activities. Produced water sent to a centralized treatment facility must meet any standards established by the treatment

facility, and the centralized treatment facility must meet standards established in its NPDES or state discharge permit. Wells used to inject produced water for enhanced recovery must be permitted under the Underground Injection Control (UIC) program as Class II-R UIC wells. Produced water sent to Class II disposal wells may be subject to state tracking regulations. The disposal wells themselves must be permitted as Class II-D UIC wells. If water is placed in pits and disposed of by evaporation, there may be construction, operational, and air quality permits required.

- **Beneficial use of produced water.** Beneficial use within the oil and gas industry is typically not subjected to additional regulations other than tracking the flow and disposition of the produced water. Existing beneficial uses of water in applications outside of the oil and gas industry may be subject to permits. For example, several states allow for and regulate the spreading of produced water on roads during winter months for snow and ice control. In Ohio, for example, minimum state standards for produced water spreading are established, but spreading must be authorized by resolution of the local authority that has jurisdiction over road maintenance. Local authorities can adopt standards that are more stringent than the state standards and may rescind authorization. Use of produced water for irrigation or industrial use may be subject to state regulations. As beneficial use of produced water is considered for more applications such as crop irrigation, stream augmentation, industrial cooling towers, etc., it is likely that additional regulations will be adopted.

This module describes the major federal laws and regulations affecting produced water, specifically the NDPES and UIC programs, as well as the cooperative relationship between federal and state governments to administer these laws and regulations. In addition, it discusses regulations at the state level that cover produced water reuse practices. Some states have such regulations, but most do not. States often differ in their regulatory approaches, reflecting geologic or other physical differences among states. This module is not intended to be a comprehensive compilation of state produced water management regulations. Rather, it is designed to provide the reader a sense of the scope of regulatory, operational, and legal standards that apply to produced water in regions of the United States.

WASTEWATER TREATMENT FACILITIES

Most communities operate facilities to treat sewage, with such names as municipal sewage plant, wastewater treatment plant, publicly owned treatment works (POTWs), water resource recovery plant, and water reclamation facility. In this report, the term “wastewater treatment plant” is used in most instances. In a few situations, the term POTW is used because it is noted as such in related documents. Readers should understand that these are the same type of facility.

There are also industrial wastewater treatment facilities and centralized treatment facilities that treat produced water prior to disposal, discharge, or reuse. These often employ different types of treatment equipment than traditional municipal wastewater facilities because they are designed to treat industrial wastewater.

The U.S. Legal/Regulatory System

The federal legal/regulatory system in the United States consists of three tiers. The interrelationships of these tiers can be seen in the example of regulation governing the discharge of produced water to rivers, lakes, and streams. At **Tier 1**, Congress passed the Federal Water Pollution Control Act, later known as the Clean Water Act (CWA), which created the National Pollutant Discharge Elimination System (NPDES) program to regulate any discharge of wastewater to water bodies that are waters of the United States. As the designated federal agency, the EPA established comprehensive regulations (**Tier 2**) for implementing the NPDES program. NPDES water quality permits (**Tier 3**) are either issued by the EPA itself (in Massachusetts, New Hampshire, New Mexico, the District of Columbia, and U.S. territories, as well as on federal and tribal trust lands) or by states that have been delegated by EPA to issue their own permits, including for produced water discharges.[11]

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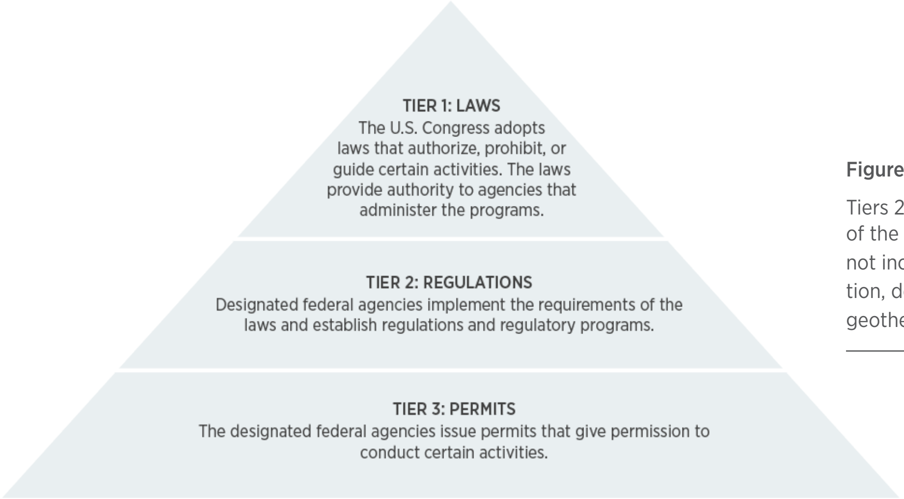
[11] USEPA, Map of NPDES Program Authorizations (July 2015), https://www.epa.gov/sites/production/files/2015-10/documents/state_npdes_program_status.pdf.



TIER 1: LAWS
The U.S. Congress adopts laws that authorize, prohibit, or guide certain activities. The laws provide authority to agencies that administer the programs.

TIER 2: REGULATIONS
Designated federal agencies implement the requirements of the laws and establish regulations and regulatory programs.

TIER 3: PERMITS
The designated federal agencies issue permits that give permission to conduct certain activities.

Figure 1-1. U.S. Federal Legal/Regulatory System

Tiers 2 and 3 are dependent on the basic authority of the CWA. NPDES delegation in some states does not include activities associated with the exploration, development, or production of oil or gas or geothermal resources.

Federal Laws and Regulatory Programs

Two federal regulatory programs are historically associated with management of produced water:

- **The National Pollutant Discharge Elimination System (NPDES) program.** Through the Clean Water Act (CWA), the U.S. Congress directs the EPA to create an NPDES permitting, compliance, and enforcement program that regulates discharges of produced water to rivers, lakes, and streams. The CWA also allows the EPA to delegate authority to states and tribes that demonstrate financial, managerial, and technical competency. States customize the NPDES program based on state specific laws, hydrology, weather conditions, and other factors. When states are authorized to operate the program, typically it is renamed to identify the state and include any state specific requirements. For example, the NPDES program in Oklahoma is the Oklahoma Pollutant Discharge Elimination System program (OPDES). In this report, "NPDES permits" includes those permits issued by a state under the delegated authority.
- **The Underground Injection Control (UIC) program**. Through the Safe Drinking Water Act (SDWA), Congress directs the EPA to develop the UIC program to regulate disposal in injection wells and provides for its delegation to states under agreements with the EPA. Most oil and gas producing states have received the authority to implement UIC

Table 1-1. Comparison of ELGs for the Oil and Gas Extraction Industry

Subcategory	Parameter	Limits on Produced Water Discharges
Onshore	n/a	Zero discharge
Stripper Wells[a]	n/a	No nationwide federal discharge standards
Agricultural and Wildlife Water Use[b]	oil and grease	35 mg/L
Coastal	oil and grease	Zero discharge except for Cook Inlet, AK, which has the same limits as offshore wells
Offshore	oil and grease	29 mg/L monthly or 30-day average 42 mg/L daily maximum

a Applies to wells producing less than 10 bbl./day of crude oil. There is no comparable subcategory for small gas wells.

b Applies to onshore facilities located in the continental United States and west of the 98th meridian for which the produced water has a use in agriculture or wildlife propagation when discharged into waters of the United States. The term "use in agricultural or wildlife propagation" means the produced water is of good enough quality to be used for wildlife or livestock watering or other agricultural uses and is actually put to such use during periods of discharge.

Class II programs. In the few states where the agencies have not received authority to administer those programs, the programs are administered by the regional office of the EPA.

Delegated NPDES and UIC programs operate independently but are subject to federal oversight.

Overview of the NPDES Program

The NPDES program requires that any discharge of wastewater to waters of the United States be authorized by a permit. Permits can either be individual permits to authorize and establish regulatory controls from a single facility or general permits for multiple facilities with similar operations and discharges.

The permit specifies both narrative and numerical limits on one or more constituents in the discharged wastewater to protect the designated beneficial uses of the receiving water body. Permit limits are determined using technology-based standards and water-quality-based standards. The most protective value becomes the permit limit. In the case of permit renewals, the anti-degradation provision of Water Quality Standards may apply.

The permit writer first calculates technology-based limits, considering such factors as the constituents in the discharge, the types of treatment commonly used for the type of wastewater, and the cost of treatment. For many major industrial categories, the EPA has already done much of this work and has published national minimum discharge standards that must be met unless more restrictive state standards or water quality standards exist. These national discharge standards are known as effluent limitations guidelines (ELGs). The ELGs for the oil and gas extraction industry are published in the Code of Federal Regulations (CFR) at 40 CFR Part 435 and are shown in Table 1-1.

Further definition of the limits shown in Table 1-1 are as follows:

- Although onshore wells are subject to a national zero discharge requirement for produced water, there are several exceptions to this regulation. For example, EPA declined to establish a national discharge standard for stripper wells. Permit writers in states or EPA regional offices have discretion to allow these discharges.
- Particular limits apply to wells located west of the 98th meridian (Figure 1-2) with produced water that "is of good enough quality to be used for wildlife or livestock watering or other agricultural uses and that the produced water

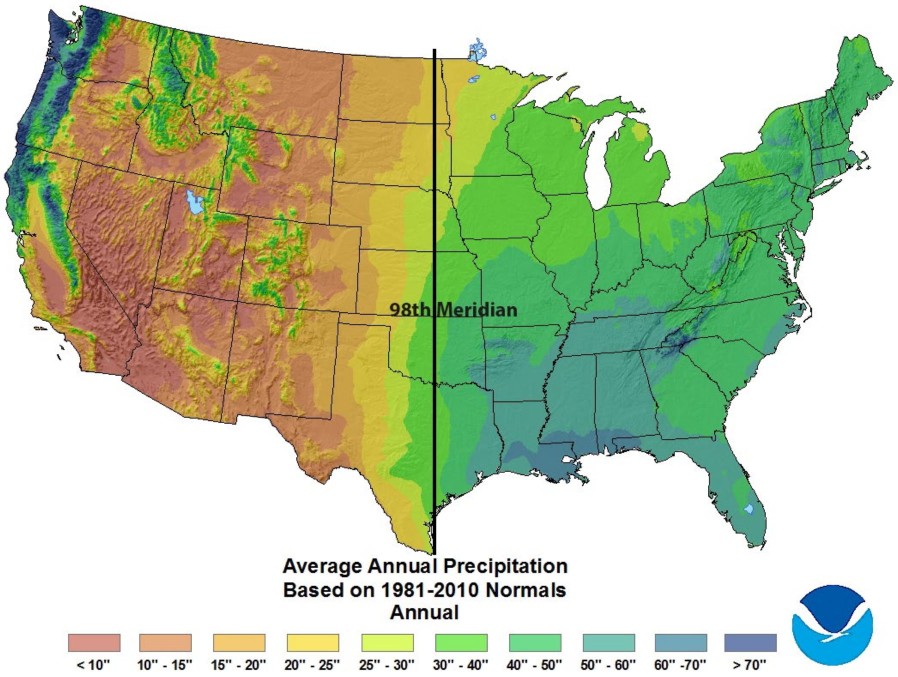


Figure 1-2. Map Showing 98th Meridian Overlain on Annual Precipitation Map
Source: Modified from National Oceanographic and Atmospheric Administration https://www.ncdc.noaa.gov/climateatlas/

The 98th meridian extends from near the eastern edge of the Dakotas through central Nebraska, Kansas, Oklahoma, and Texas.

is actually put to such use during periods of discharge."[12] Permit writers must follow the minimum oil and grease limit of 35 mg/L but can also place limits on other parameters.

- Coalbed methane (CBM) generates a lot of produced water. In many CBM fields, the water is too salty to discharge. In other places, the salinity is lower (e.g., Powder River Basin in Wyoming) or the available dilution in the local rivers is very high (e.g., Black Warrior Basin in Alabama). CBM produced waters are not subject to the oil and gas ELG.
- Most produced water east of the 98th meridian cannot be discharged directly from an oil and gas well site. It can be treated offsite in a centralized wastewater treatment facility and then discharged if the facility has been issued an NPDES (or state equivalent) permit. In a few instances, centralized facilities in cities have obtained permission to discharge treated water to the municipal sanitary sewer where it will receive additional treatment at the city's wastewater treatment facility.

Although technology-based limits and ELGs serve as a baseline for the effluent limits included in a permit, the technology-based controls may not ensure that all designated beneficial uses of the surface water will be protected. In these cases, the permit writer must include additional, more stringent water-quality-based effluent limits in NPDES permits. These limits may be numeric[13] or narrative (e.g., "no toxic substances in toxic quantities"). The process for establishing the limits considers the designated beneficial use of the water body; the amount of the pollutant in the effluent, toxicity, and assimilative capacity; and, where appropriate, dilution in the receiving water (including discharge conditions and water column properties).

Appendix 1-A describes the NPDES permitting process undertaken by an oil and gas company in Arkansas for a centralized produced water treatment facility.

UNDERGROUND SOURCES OF DRINKING WATER (USDW)

The code of Federal Regulations at 40 CFR 144.3 defines a USDW as an aquifer or part of an aquifer which:

- Supplies any public water system, or contains a sufficient quantity of groundwater to supply a public water system and currently supplies drinking water for human consumption or contains fewer than 10,000 milligrams/liter of Total Dissolved Solids (TDS); and
- Is not an exempted aquifer as defined in 40 CFR Section 146.4 as part or all of an aquifer which meets the definition of a USDW, but which has been exempted according to the criteria in 40 CFR Section 146.4.

Overview of the UIC Program

The UIC program is designed to protect underground sources of drinking water (USDWs). This protection is provided through the regulation of injection wells. An injection well is defined as any bored, drilled, or driven shaft or a dug hole, where the depth is greater than the largest surface dimension that is used to inject fluids underground. Underground injection is grouped into six classes of injection wells (Table 1-2).

Wells used for injecting produced water are Class II wells. When fluids are injected into a hydrocarbon-bearing formation to help produce additional oil (water flood, steam flood) the injection wells are Class II-R, enhanced recovery wells. Produced water can also be injected solely for disposal. In this case, the water is typically injected into a formation below the USDW other than the producing formation. These wells are known as Class II-D disposal wells. A third group of Class II wells are used to inject fluids associated with hydrocarbon storage wells (Class II-S). These are not directly related to produced water and are not discussed further here.

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[12] Specialized Definitions 40 CFR 435.51, *Code of Federal Regulations*, Title 40 (2003), https://www.govinfo.gov/content/pkg/CFR-2003-title40-vol27/pdf/CFR-2003-title40-vol27-sec435-51.pdf.

[13] Most states have published water quality standards for many pollutants that can be used to calculate water quality-based limits. These are enforceable regulations. Where state standards are not available, permit writers can look at EPA's published numeric water quality criteria for more than 100 pollutants. These criteria are technical recommendations but are not enforceable unless they are specified in a permit.

Table 1-2. Classification of UIC Wells

Sources: USEPA and State Primacy Agencies

Underground Injection Control Well Classification Chart

Well Class	Purpose	Active Wells*
I	Injection of hazardous, non-hazardous, and municipal wastes below the lowermost USDW	817
II	Injection of fluids associated with the production of oil and natural gas resources for disposal or enhanced oil and gas recovery	180,344
III	Injection of fluids for the extraction of minerals	29,617
IV	Injection of hazardous or radioactive wastes into or above a USDW**	127
V	Injection into wells not included in the other well classes but generally used to inject non-hazardous waste	650,000 to 1.5 Mil.
VI	Injection of supercritical carbon dioxide for storage	2***

* All numbers estimated from state agency surveys and a USEPA inventory published for Federal Fiscal Year 2017.

** Class IV wells are banned except where used for remediation of USDWs

*** Existing commercial wells with permits issued under the Class VI program

Following are key elements of Class II UIC permits.

- **Well location**. This can include conditions such as depth, wellhead location, and setback distances.
- **Construction requirements.** This can include details like the size and setting depths for different layers of casing, cementing requirements, and other well hardware.
- **Area of Review evaluation.** This element includes an evaluation of the area surrounding the proposed injection well to identify any pathways for the injected fluids to migrate from the targeted injection zone.
- **Operations.** This typically includes restrictions on parameters like pressure, flow rate, and daily injected volume.
- **Monitoring and reporting to the permitting agency.** This element includes routine and periodic logging and mechanical integrity testing to ensure that wells are not leaking. Other types of monitoring and reporting may be required, including operating restrictions.
- **Closure requirements.** This element includes requirements for plugging and abandonment.

Over 90 percent of produced water generated in the United States is injected into underground geologic formations through injection wells permitted under the UIC Class II program. Under sections 1422 and 1425 of the Safe Drinking Water Act (SDWA), the EPA may delegate primary enforcement authority (primacy) to states, territories, and tribes for the UIC program. To date 43 states, territories, and tribes have obtained primacy for portions of the UIC program. Of these, 25 states and 2 tribes have obtained primacy over the Class II UIC program in areas where oil and gas exploration and production occur.

Over 90 percent of produced water generated in the United States is injected into underground geologic formations through injection wells permitted under the UIC Class II program.

The E&P Waste Exemption

EPA made an important regulatory determination in 1988 that clarified that oil and gas exploration and production (E&P) wastes, including produced water, would not be subject to Subtitle C (the hazardous waste section) of the Resource Conservation and Recovery Act (RCRA).[14] This determination was important in allowing the oil and gas industry to manage produced water in ways that made sense and were cost-effective. The determination stated in part, "USEPA's review… found that imposition of Subtitle C regulations for all oil and gas wastes could subject billions of barrels of waste to regulation under Subtitle C as hazardous wastes and would cause a severe economic impact on the industry and on oil

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[14] USEPA, "Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes," Federal Register 53, no. 129 (July 6, 1988): 25447, https://archive.epa.gov/epawaste/nonhaz/industrial/special/web/pdf/og88wp.pdf.

and gas production in the U.S." The determination also stated that "EPA found most existing State regulations are generally adequate for protecting human health and the environment." Each state can set up its own regulatory programs for this waste if they do not interfere with existing authorities such as the NPDES and UIC programs.

Additionally, states routinely evaluate their existing regulatory programs through such efforts as the State Oil and Gas Regulatory Exchange (the Exchange) and the State Review of Oil and Natural Gas Environment Regulations (STRONGER) processes. These reviews help states update their programs to remain current with technological, legal, and other changes.

The extent to which the RCRA exemption expands to include produced water, its treatment, and treatment residuals in the context of new reuse scenarios outside of oil and gas operations presents a question worth considering.

The RCRA exemption applies to wastes, including produced water, that are "intrinsically derived from the primary field operations." The extent to which the exemption expands to include produced water, its treatment, and treatment residuals in the context of new reuse scenarios outside of oil and gas operations presents a question worth considering. This is an area of evolving understanding and there are currently no clear answers, primarily because the exemption has not been tested in practice and questions, to date, remain theoretical. As options to treat and reuse produced water expand, it is likely that more attention may be paid to this subject to bring further clarity.

Regulatory Roles of State Governments

With a few exceptions, oil and gas activities relating to management of oil field wastes, including produced water, are regulated at the state level rather than directly by federal agencies or regulations. When states receive primacy to administer the NPDES or UIC programs, the state regulations do not need to be identical to the federal regulations but must include conditions that offer at least the same level of protection. States can customize regulatory programs to reflect state-specific practices and laws. They can be more restrictive than federal regulations and can include regulations for activities not covered by federal regulations. This creates a scenario in which each of the approximately 31 oil and gas producing states has flexibility to regulate oil and gas operations and management of E&P wastes, including produced water, in similar but slightly different ways. For example, as of January 2018, the Texas Commission on Environmental Quality (TCEQ) had NPDES authority for most types of discharges, but not for oil and gas industry produced water. That authority remains with EPA Region 6. The Texas Railroad Commission (RRC) manages oil and gas produced water through delegated UIC Primacy for Class II wells.

Most produced water regulatory programs are assigned to oil and gas agencies or state environmental protection agencies. However, in some cases, public health agencies, state engineers, or regional water planning commissions such as the Susquehanna River Basin Commission and the Delaware River Basin Commission may play some role in regulating produced water. State wastewater programs may also cover discharges to state waters, including non-federal surface waters, groundwater, and land application. Some states have prohibitions on moving water from one river basin to another. As new produced water reuse projects are considered, the topic of inter-basin transfer of water may become important. Additionally, some states have developed wellhead or source water protection programs that apply to all potential sources of pollution. These states may have requirements for setbacks or other requirements on a case-by-case basis.

Evolution of State Regulatory Programs

After regulating produced water for many decades, states have developed similar, but somewhat different, regulations and requirements. Differences in regulations between states reflect factors such as geography, geology, and hydrology; climate; state statutory authority and state court interpretations; infrastructure; and historical practices.

Differences in regulations between states reflect factors such as geography, geology, and hydrology; climate; state statutory authority and state court interpretations; infrastructure; and historical practices.

State agencies that regulate produced water participate in national organizations like GWPC, the Interstate Oil and Gas Compact Commission (IOGCC), and others. Through these organizations they become aware of the types of regulatory revisions and updates being made by their fellow states. Over time, states tend to make their regulatory programs more comprehensive.[15]

With the introduction of new technologies, entry into new resources areas, or the use of technologies in innovative ways, state regulatory agencies must evaluate and respond to changes in oil and gas operations to provide additional environmental and public health protection. For example, some state agencies have responded to the rapid growth of hydraulic fracturing, which has resulted in significant changes in truck traffic, industrial activity, job opportunities, leasing revenue, and water demand.

Although most oil and gas development activities are conducted safely, in some instances poor well construction, spills, leaks, accidents, and other events have resulted in produced water releases to the environment or have impacted drinking water. State agencies respond to these events by developing or modifying regulatory controls to mitigate and minimize the impacts. Each state establishes priorities on which activities are most deserving of additional controls based on state-specific concerns. Sometimes regulatory updates are done as single large efforts, while in others several rounds of incremental revision takes place.

State agencies have taken various actions to reduce or eliminate seismic impacts. Both industry and the regulatory agencies learned a great deal in a short time about earthquakes, their possible causes, and methods for mitigation.

Local residents, environmental groups, and the media have raised concerns about real or perceived risks regarding produced water management. They may contact agencies at the state and federal level and request additional controls. Although state agencies have the lead role in overseeing and regulating most oil and gas activities, federal agencies may also have a role. Solutions are often worked out on a case-by-case basis.

An example of unanticipated events that have led to a new regulatory response is an increase in seismic activity (earthquakes) associated with produced water disposal wells in parts of the country. Although numerous disposal wells had been in operation in states like Oklahoma, Texas, Arkansas, and Ohio for decades without significant seismic impacts, a few years ago the frequency and magnitude of earthquakes increased noticeably in some areas. Figure 1-3 illustrates this increase in seismicity. Many of these earthquakes seemed to be associated with injection wells used to dispose of produced water from unconventional oil and gas development. State agencies have taken various actions to reduce or eliminate seismic impacts. Both industry and the regulatory agencies learned a great deal in a short time about earthquakes, their possible causes, and methods for mitigation. GWPC took a leadership role in initiating discussions on induced seismicity related to hydraulic fracturing

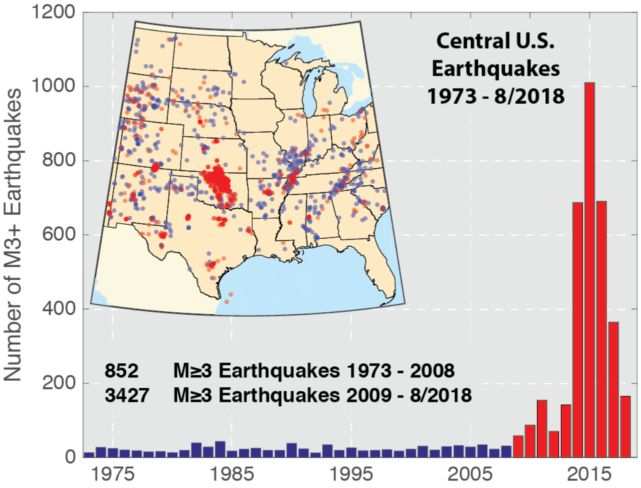

Figure 1-3. The Number of Earthquakes M 3.0 and Greater in the Central United States, 1973–8/2018

Source: USGS 2018, https://earthquake.usgs.gov/research/induced/overview.php

Although numerous disposal wells had been in operation in states like Oklahoma, Texas, Arkansas, and Ohio for decades without significant seismic impacts, a few years ago the frequency and magnitude of earthquakes increased noticeably in some areas. Figure 1-3 illustrates this increase in seismicity. Many of these earthquakes seemed to be associated with injection wells used to dispose of produced water from unconventional oil and gas development.

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[15] Ground Water Protection Council, *State Oil and Natural Gas Regulations Designed to Protect Water Resources, Third Edition* (November 2017), http://www.gwpc.org/sites/default/files/State%20Regulations%20Report%202017%20Final.pdf.

Table 1-3. Regulatory Management of Produced Water by Method and Agency in Six States

State	Underground Injection Control (Class II)	Land Application	Water Discharge via NPDES	Recycling
New Mexico	NMOCD	NMDOT[1]	USEPA[2]	NMOCD
North Dakota	NDIC	NDDoH[3]	NDDoH	NDSWC
Oklahoma	OCC	OCC/ ODEQ[4]	ODEQ	
Pennsylvania	USEPA		PADEP	
Texas	TRRC	TRRC	USEPA[5]	TRRC
Wyoming	WOGCC	WOGCC[6]	WDEQ	WDEQ

Agency Acronyms

NDDoH—North Dakota Department of Health
NDIC—North Dakota Industrial Commission
NDSWC—North Dakota State Water Commission
NMDOT—New Mexico Department of Transportation
NMED—New Mexico Environment Department
NMOCD—New Mexico Oil Conservation Division
OCC—Oklahoma Corporation Commission, Oil and Gas Division
ODEQ—Oklahoma Department of Environmental Quality
PADEP—Pennsylvania Department of Environmental Protection
TCEQ—Texas Commission on Environmental Quality
TRRC—Railroad Commission of Texas
USEPA—United States Environmental Protection Agency
WOGCC—Wyoming Oil and Gas Conservation Commission
WDEQ—Wyoming Department of Environmental Quality Agency Specific Provisions

1 The NMDOT may have jurisdiction over the use of produced water for road de-icing, http://www.emnrd.state.nm.us/OCD/education.html#OGProd4.
2 The NMED conducts compliance evaluation inspections on behalf of USEPA and reviews federal permits through certification.
3 The NDDoH has guidelines regarding use of certain produced water in dust and ice control. (NDDoH, supra Note 11)
4 The OCC regulates land application of produced water.
5 The TCEQ is not authorized to issue permits for activities associated with the exploration, development, or production of oil or gas or geothermal resources.
6 One-time land spreading on the well site is regulated by WOGCC. Other road spreading, land-spreading and land-farming operations are regulated by WDEQ and require a permit (Chapter 3 Permit Requirements for Treatment of CBM, Oil or Gas Produced Water, Wyoming Department of Environmental Quality, 7-8).

and disposal wells in 2013. As part of a joint effort with the IOGCC, the GWPC, in concert with state regulatory agencies, formed an induced seismicity work group. In 2015, this workgroup developed a primer on *Technical and Regulatory Considerations Informing Risk Management and Mitigation*, which was updated in 2017.

Examples of State Produced Water Regulations and Rights in 2017

For this report, the GWPC contracted with the Louisiana State University School of Law to evaluate how selected states regulate produced water, focusing on regulatory frameworks concerning methods of produced water management, agencies responsible for regulating these methods, and produced water ownership and liability. The states—New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas, and Wyoming—were chosen based on their representativeness of a region; the geologic variability of production areas within the state; geographic, climatologic, and water need diversity; and the availability of geologic, hydrologic and water quality data. The results of this legal research are summarized below.

Regulatory Frameworks for Produced Water Management

As shown in Table 1-3, even within individual states, more than one agency may regulate the management of produced water. While underground injection control often falls under the jurisdiction of a state oil and gas agency, board, or commission, other management options such as NPDES discharge are typically regulated by either a state environmental quality agency, health agency or, in some cases, the EPA.

Such shared regulatory control may complicate produced water reuse outside of the oil and gas industry, requiring new levels of coordination between state agencies and even across state and federal agencies. This is particularly true when regulatory requirements differ substantially between multiple states that exert regulatory authority. For example, a project involving application on roadways for deicing of produced water produced in Permian basin operations would require coordination between regulating agencies in New Mexico and Texas: the NMDOT in New Mexico and the TRRC in Texas. Some agencies that may be involved in new produced water reuse options may not normally coordinate their regulatory management activities, and developing the appropriate MOUs or MOAs, etc., can take time.

Frameworks for Produced Water Rights, Ownership, and Liability

In the United States, designation and distribution of water rights are done separately by each state and in some cases tribes, interstate agencies, and compacts. While there are some general trends, each state has slightly different rules. Understanding these varying state rules and requirements is important to the oil and gas industry in obtaining water to use for drilling and fracturing fluids and in managing produced water. Table 1-4 shows the various groundwater rights doctrines and produced water ownership and liability provisions that apply in six states. Appendix 1-B provides more information on surface and groundwater rights.

Although individual state laws vary, two general doctrines apply to surface water rights: prior appropriation and reasonable use.

- Under the **prior appropriation** doctrine, the first user of the water for a beneficial reuse such as agricultural or industrial use is considered to have a right to continued use of the water. Subsequent users may utilize water from the same source but may not impinge on the original user's right to use the water.
- Under the **reasonable use** doctrine, riparian users of a water source may use water provided it does not impinge on the use of the water by other riparian users. A riparian user is defined as someone situated along the path of the water.

With respect to groundwater, states generally follow one of five common law "rules" for groundwater rights: the Absolute Dominion rule (the Absolute Ownership rule or English rule) (11 states), the Reasonable Use rule (the American rule or Rule of Reasonableness) (17 states), the Correlative Rights doctrine (five states), the Restatement (Second) of Torts rule (the Beneficial Purpose doctrine) (two states) and the Prior Appropriation doctrine (First in Time, First in Right seniority system) (13 states). However, states increasingly supplement or alter common law rules with state statutes ("regulated riparianism").

- Under the Absolute Dominion Rule (also known as the Absolute Ownership Rule), a landowner has a right to take for use or sale all the water that he can capture from below his land, regardless of the effect on wells of adjacent owners.
- The Reasonable Use Rule limits a landowner's use to beneficial uses having a reasonable relationship to the use of his overlying land.[16] As long as the use of the water is reasonable, the landowner can withdraw all the water, even to the detriment of others, without liability.
- The Correlative Rights doctrine is based on the Reasonable Use rule, but does not prohibit off-site uses and uses a proportionality rule. A landowner must limit use of groundwater to prevent interference with use of the water by adjacent landowners. The Correlative Rights doctrine does not envision an absolute right of access to groundwater or an unlimited right to pump.[17] Rather, this doctrine maintains that the authority to allocate water is held by the courts.[18] A major feature of the Correlative Rights doctrine, however, is the concept that adjoining lands can be served by a single aquifer.[19] Therefore, the judicial power to allocate water protects both the public's interest and the interests of private users.[20]

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[16] "Ground Water: Louisiana's Quasi-Fictional and Truly Fugacious Mineral," 44 *La. L. Rev.*, 1123, 1133 (1984).

[17] Id.

[18] Id.

[19] Id.

[20] Id.

Table 1-4. Produced Water Ownership and Liability Findings in Six States

Disclaimer: This table should not be considered a legal opinion regarding the ownership of or liability for produced water under all circumstances. It is merely a compilation of general research conducted on behalf of the GWPC.

State	Groundwater Rights Doctrine	Produced Water Ownership		Produced Water Liability	
		Operator	Landowner	Operator	Other Persons
New Mexico	Prior appropriation		X[6]	X	X
North Dakota	Prior appropriation		X[1]	X[2]	X
Oklahoma	Reasonable use	X[3]		X	
Pennsylvania	Reasonable use	[5]	[5]	X	
Texas	Absolute Ownership Rule		X	X	X[4]
Wyoming	Prior appropriation		X[1]	X	

Specific provisions that may apply to or modify the information contained in Table 1-4 include the following:

1 Water is not owned but pore space is the property of the surface rights owner.

2 Operator is immunized from liability if transferred to a commercial oilfield special waste recycling facility.

3 Produced water ownership in Oklahoma resides with the oil and gas operator except that landowners have "domestic use" of water flowing across the property. (Mack Oil Co. v. Laurence, 389 P.2d 955 (Okla. 1964)).

4 Texas limits tort liability for sellers or transferors of recycled produced water. 3 Tex. Nat. Res. Code Ann. § 122.003(a) (2015) ("Responsibility in Tort").

5 The Pennsylvania legislature has not explicitly defined who owns produced water. As a result, produced water is likely owned by either the landowner or the oil and gas operator. However, use of groundwater off of the premises is considered unreasonable and unlawful per se if other users' rights are interfered with. Pamela Bishop, PADEP, A Short Review of Pennsylvania Water Law, 4 (2006); R. Timothy Weston & Joel R. Burcat, Legal Aspects of Pennsylvania Water Management, in Water Resources in Pennsylvania: Availability, Quality and Management 219, 220 (Shyamal K. Majumdar et al. eds., 1990).

6 In New Mexico the term "possession" is often used because actual water ownership is by contract only.

- The Restatement of Torts rule (the Beneficial Purpose doctrine) merges the English concept of nonliability with the American standard of Reasonable Use. "The result merges prior groundwater law into a standard intended to more equitably meet growing demands on water resources."[21]
- Under the Prior Appropriation doctrine, the first landowner to beneficially use or to divert water from a water source is granted priority of right. The quantity of groundwater a senior appropriator may withdraw may be limited based on reasonableness and beneficial purposes is used in several western states.[22]

Produced water ownership is not clearly defined and may present challenges. However, ownership varies in each state. For example, in New Mexico, there is no water right associated with produced water at the point of production. Later, if the water is used and mixed with water that has defined rights, this can change. In contrast, produced water ownership in Colorado is differentiated as being either tributary or non-tributary.

In the United States, designation and distribution of water rights are done separately by each state and in some cases tribes, interstate agencies, and compacts.

Typically, the company bringing the produced water to the surface has been responsible for its disposal. However, as produced water moves from waste to resource and potentially final disposal, ownership of the water may change.

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[21] Juliane Matthews, "A Modern Approach to Groundwater Allocation Disputes: Cline v. American Aggregates Corporation," 7 *J. Energy L. & Pol'y*, 361 (1986).

[22] Id.

It is important to identify how and when ownership changes occur and to understand that these changes in ownership may differ based on local or state regulations or laws. Understanding the role of water rights, mineral rights, and surface ownership in the exploration and production of oil and gas is critical in addressing the how and when there is compensation for or liability of the beneficial use of produced water.

When produced water is used within the industry for a beneficial use, liability remains with the companies. If companies provide produced water (treated or untreated) to external entities for a beneficial use, which party (company or end user) holds the liability can be less clear. For example, if an oil or gas company treats its produced water, then gives or sells the water to a rancher, the company may later be sued by the rancher if a ranch employee or a farm animal suffers ill effects.

If oil and gas companies transfer ownership of produced water to another party, the oil and gas companies assume that at least partial if not complete liability is also transferred. But this is not necessarily the case. In 2013, Texas Governor Rick Perry signed HB 2767, which partially addressed this issue. HB 2767 allowed the ownership of produced water for the purpose of treatment and reuse to be transferred from the generator (the oil and gas producer) to a person who treats for use or disposes of the produced water (a treater) and from the treater to another person who reuses the treated produced water for beneficial reuse or disposal. HB 2767 also provided some limitation for tort liability for the "treater" who later sells/gives the treated produced water to another person for use "in connection with the drilling for or production of oil or gas." The limit on liability is specific to "a consequence of the subsequent use of that treated product by the person to whom the treated product is transferred or by another person." HB 2767 does not transfer all liability, including liability to comply with TRRC regulations. In cases where produced water is sold or provided free of cost to another party, a contract may specify the party responsible for treating and monitoring the produced water, the party with ultimate responsibility for the produced water, and the point at which contractually that responsibility changes, but generally the contract will not affect a regulator's determination of liability to the state.

If a surface owner or mineral right holder expects payment for the produced water generated from oil and gas E&P, the expectation of transfer of full or partial liability if any spills or damage occurs likely exists. Additionally, entities that receive produced water for beneficial use must understand and accept the potential legal liabilities. The issues of water rights and liability were presented to a Congressional committee more than a decade ago.[23] Congress has not taken any action. Any progress on resolving these issues will likely come from state action taken to increase the likelihood of beneficially reusing produced water.

It is important to identify how and when ownership changes occur and to understand that these changes in ownership may differ based on local or state regulations or laws. Understanding the role of water rights, mineral rights, and surface ownership in the exploration and production of oil and gas is critical in addressing the how and when there is compensation for or liability of the beneficial use of produced water.

To facilitate produced water use, states may need to make statutory or regulatory changes. Texas was one of the first states to formally recognize the potential opportunities for beneficial use of produced water. For example, the TRRC, the oil and gas agency in Texas, amended its commercial and non-commercial recycling rules effective April 15, 2013[24] to remove barriers. Major rule changes encourage further conservation, reuse, and recycling of solids and liquids produced by oil and gas operators that would otherwise be considered waste. Appendix 1-C is a presentation prepared by the TRRC that describes the changes that were made. Similarly, New Mexico promulgated recycling rules to protect fresh water

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[23] John Veil, *Testimony*, Hearing before the U.S. House of Representatives Committee on Science and Technology, Subcommittee on Energy and Environment, regarding "Research to Improve Water-Use Efficiency and Conservation: Technologies and Practice" (Washington, DC: October 30, 2007), http://www.veilenvironmental.com/publications/pw/testimony_veil_final.pdf.

[24] Texas Administrative Code, Title 16, Part 1, Chapter 3, Rule 3.8 (16 TAC § 3.8) relating to Water Protection, and 16 TAC Chapter 4, Subchapter B, relating to Commercial Recycling.

and encourage recycling of produced water. These rules became effective on March 31, 2015. Appendix 1-D details the history of the process used by New Mexico to develop its recycling rule.

Operational Standards for Produced Water Management

Not all produced water activities are subject to regulatory controls. However, they may be subject to operational standards established by the end user to meet such needs as protection of infrastructure and facilities.

For example, the quality of produced water needed as make-up water for new fracturing fluids is not subject to EPA or state water quality standards. Rather, the operator sets operational standards for specific chemical constituents to protect pumps, valves, and piping from excessive corrosion and prevent scaling, biofilm growth, and accelerated crosslinking of polymers. Companies want to ensure that the quality of water used to fracture a well is compatible with the goal of achieving the greatest possible oil and gas production.

Similarly, fluids injected into Class II disposal wells do not need to meet any regulatory standards in terms of how clean the water must be. However, the water must be a Class II fluid under the provisions of the EPA 1988 regulatory determination and cannot be altered in such a way as to make it subject to RCRA requirements. The injected water is given adequate treatment to avoid damage to the injection well and the receiving formation. The actual treatment is chosen by the operator.

In some states, when produced water is treated and used for crop irrigation, the farmer or rancher may determine the water quality standards needed to protect crops and soil structure. In other states, such as Oklahoma, specific land application standards are required by regulation. Guidelines on irrigation water quality are often available from agricultural agencies, conservation agencies or districts but these may be recommendations, not enforceable standards. These standards relate to land application of produced water rather than discharge of produced water.

Best Practices and Guidance for Produced Water Management

Companies, individually and through industry associations, have documented various best practices for managing produced water. For some activities, highly technical standards (e.g., tank construction guidelines) are available from organizations like the American Society for Testing and Materials (ASTM) and the American Petroleum Institute (API). In other cases, design and operational best practices have been developed by government agencies such as the Bureau of Land Management and other organizations.

There are a variety of resources available to the public on produced water, its regulation, best practices, etc., some of which are listed in Appendix 1-E. Also see Appendix 1-F for an example of regulatory changes in the management of produced water in the Marcellus Shale play in Pennsylvania circa 2009.

Produced Water as Part of the State Water Planning Process

As states begin evaluating long-term water needs, water planning plays an important role. More states and regions are experiencing water shortages due to drought, population shifts, and increased usage. Water plans are used to evaluate the quality, quantity, and geographic location of water versus where the water is needed. These plans may be broad in nature and cover an entire state, a watershed, or some combination.

States have various statutory, regulatory, and recommendations for water planning. Only three of the six states reviewed in the legal research referenced previously include produced water as a component in their state water plans. One possible reason for its exclusion is that produced water has not traditionally been considered a potential source of water. As treatment technology advances, populations grow, and water scarcity becomes more pronounced, the view of produced water may change over time and result in a broader look at produced water as a resource that could add to a state's water balance sheet.

Oklahoma, which has developed a comprehensive water plan for the entire state based on 13 geographic regions, considered produced water in the water planning process. The comprehensive water plan and the 13 regional reports can be viewed on the Oklahoma

Water Resources Board (OWRB) website using the following links:

- https://www.owrb.ok.gov/supply/ocwp/pdf_ocwp/WaterPlanUpdate/draftreports/OCWP%20Executive%20Rpt%20FINAL.pdf
- https://www.owrb.ok.gov/supply/ocwp/ocwp.php#regionalreports

These planning regions can use their report as a starting point to develop their own more localized water plans. The water plan(s) can be used to assess water quality or quantity or to meet some other established goal. In the case of Oklahoma, a goal was established by the legislature in a bill that became known as Water for 2060 Act.[25] This legislative action created a goal for the state to use no more fresh water in 2060 than in 2010. To achieve this goal, all water sources were considered, including brackish groundwater, produced water, and the reuse of reclaimed water from municipal or industrial processes, along with conservation methods.

In another example, the State of Kansas has completed regional water plans and included goals for effectively using produced water. In the Red Hills Regional Advisory Committee report, two of the four water goals were related to produced water and recycling in the production of oil and gas. Goal #3 is to "Reduce the amount of freshwater used in oil and gas completion operations by 4% annually" and Goal #4 is to "Work with oil and gas industry, beginning in 2040, to have 10,000 barrels a day of fresh water to be recycled from oil production for regional use in the Red Hills." More information can be found at https://kwo.ks.gov/docs/default-source/regional-advisory-committees/red-hills-rac/red-hills-rac-action-plan.pdf?sfvrsn=2.

In California, the State Water Resources Control Board (SWRCB or State Board) and the nine Regional Water Quality Control Boards (RWQCBs or Regional Boards) are responsible for the protection and, where possible, the enhancement of the quality of California's waters. The SWRCB sets statewide policy and, together with the RWQCBs, implements state and federal laws and regulations. Each of the nine Regional Boards adopts a Water Quality Control Plan, or Basin Plan, which recognizes and reflects regional differences in existing water quality, the beneficial uses of the region's ground and surface waters, and local water quality conditions and problems.[26] California's Porter-Cologne Water Quality Control Act (1969), which became Division Seven ("Water Quality") of the State Water Code, establishes the responsibilities and authorities of the nine RWQCBs (previously called Water Pollution Control Boards) and the SWRCB. The Porter Cologne Act names these Boards "... the principal State agencies with primary responsibility for the coordination and control of water quality" (Section 13001). Each Regional Board is directed to "... formulate and adopt water quality control plans for all areas within the region." A water quality control plan for the waters of an area is defined as having three components: beneficial uses which are to be protected, water quality objectives which protect those uses, and an implementation plan which accomplishes those objectives."[27] Although the current regional water plans in California do not specifically address produced water as a component of the water system for purposes of water resource planning, the regional boards process requests for produced water beneficial use and have developed a fact sheet related to the use of recycled produced water for crop irrigation.[28]

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[25] *Oklahoma Water for 2060 Act*; Enrolled House Bill 3055 by Steele, Lockhart and Raon of the House and Fields of the Senate; Codified in the Oklahoma State Statutes as Section 1088.11 of Title 82.

[26] California Water Boards, Santa Ana Region, "The Water Quality Control Plan (Basin Plan) for the Santa Ana River Basin," (February 2008), https://www.waterboards.ca.gov/santaana/water_issues/programs/basin_plan/docs/chapter1.pdf.

[27] Central Coast Regional Water Quality Control Board, "Water Quality Control Plan for the Central Coastal Basin, September 2017 Edition," California Environmental Protection Agency (September 2017), https://www.waterboards.ca.gov/centralcoast/publications_forms/publications/basin_plan/docs2017/2017_basin_plan_r3_complete.pdf.

[28] California State Water Resources Control Board, "Fact Sheet: Frequently Asked Questions About Recycled Oilfield Water for Crop Irrigation" (April 5, 2016), https://www.waterboards.ca.gov/publications_forms/publications/factsheets/docs/prod_water_for_crop_irrigation.pdf.

Historically, produced water has been viewed as a waste product. With broader understanding of water volumes and the types of treatment available, produced water may become a potential resource and an integrated part of a water plan in the future. Water planning can assist states or regions in identifying where the produced water is located, the current and projected amount of produced water in the area, and the projected need for water. The ability to treat produced water to the level necessary for other uses may leave more potable water for other more restrictive uses and could be a factor in a water plan. The availability of additional water can bolster plans for economic development, increased or maintained recreation, and a more sustainable drinking water supply.

Produced water currently has limited use because of actual and perceived risk, cost of transportation, treatment and distribution, and location of the produced water versus where the water is needed, among other factors. As water becomes scarcer, the benefits of produced water use may outweigh the costs of managing, treating, storing, and transporting the water and more opportunities for produced water use may occur. Research and investigation into risks and opportunities for produced water reuse will be necessary to inform decision making, as discussed further in Module 3 of this report. Additional regulations to protect public health and the environment may apply or be developed in response to increased beneficial reuse outside the oil and gas industry.

MODULE 2

Produced Water Reuse in Unconventional Oil and Gas Operations

MODULE SUMMARY

Reuse varies by region.
Substantial differences in reuse of produced water exist based on a variety of factors both above and below the surface. For this report, data from 18 producing companies were collected on water reuse, produced water, and source water by basin. The data was aggregated by basin, or region, to determine an indicative water reuse percentage as shown in Figure 2-1. The weighted average national reuse was 10 percent but varied from 0 to 67 percent across the seven basins considered.

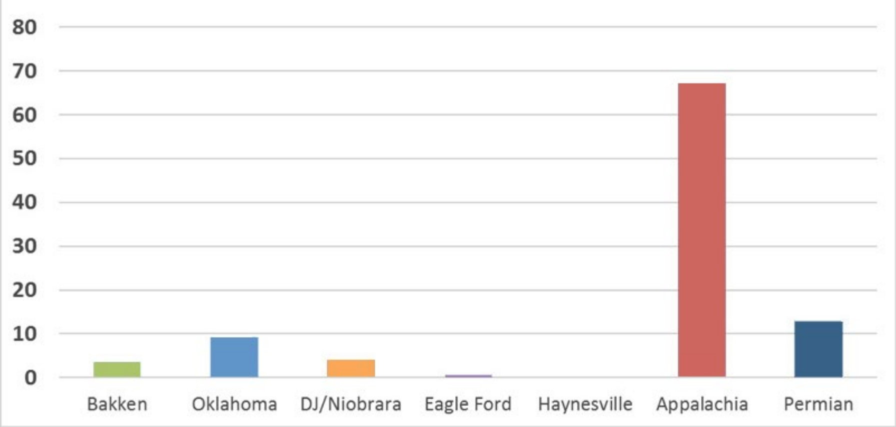


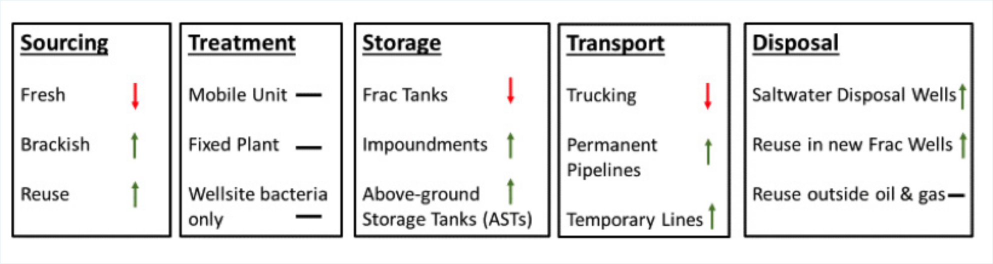
Figure 2-1: Reuse Percentage for Key Basins (18 Companies Reporting)

Source: Jacobs Engineering

Cost is the key driver of water management and reuse.
In most of the regional discussions conducted for this report, cost was the dominant driver for water reuse, although by no means the only factor companies consider. Most companies interviewed are publicly traded and have a legal obligation to conduct operations in a cost-effective way that delivers value to their stockholders. Costs were particularly emphasized with the downturn in the prices of oil and natural gas starting in 2015. Transportation costs are also a significant factor in produced water reuse evaluations.

Water management and water reuse are evolving.
Water management and water reuse are continuing to evolve in most regions. As the market demands that companies maximize efficiencies in their operations, an increasing number of companies are building pipelines for source water, pipelines to connect to disposal wells, or to other water facilities for treatment and reuse. Water management practices are also evolving in areas where local demand for source water and disposal are driving up water costs. When sourcing and disposal costs rise, reuse becomes more economically attractive and cost competitive.

MODULE 2



Sourcing	Treatment	Storage	Transport	Disposal
Fresh ↓	Mobile Unit —	Frac Tanks ↓	Trucking ↓	Saltwater Disposal Wells ↑
Brackish ↑	Fixed Plant —	Impoundments ↑	Permanent Pipelines ↑	Reuse in new Frac Wells ↑
Reuse ↑	Wellsite bacteria only —	Above-ground Storage Tanks (ASTs) ↑	Temporary Lines ↑	Reuse outside oil & gas —

Figure 2-2: Trends in Water Management

Source: Jacobs Engineering

Companies weigh risks in water management and reuse.

Increasing water reuse can reduce company exposure to some risks but increase risk in other areas. The qualitative assessment of risks is weighed against tangible cost considerations to make water reuse plans.

Water midstream solutions are emerging.

Water midstream is a recent development involving the gathering and distribution of source water for hydraulic fracturing as well as the gathering and disposal of produced water. Although there are both positive and negative drivers for water midstream development, increasingly, third-party midstream solutions are emerging. Water midstream companies have acquired water systems and developed new projects over the last couple of years. While water midstream is generally provided by an independent company for multiple producing companies, producers are also exchanging produced water in certain situations.

Water midstream involves the management of produced water in the field, usually by a third party, between the point of production and the point of final processing, treatment or disposal.

Data on reuse volumes is not widely available.

Neither federal regulators nor most states require reporting of the source of water used for completions, or hydraulic fracturing. Companies often report on their websites if they are reusing produced water in a specific region, but volumes are usually not reported. The *Journal of Petroleum Technology* concluded that "Improved reporting is needed to guide the industry and regulators as they look for solutions and figure out how to manage scarce resources, particularly the limited capacity of subsurface formations used for water injection."[29]

State regulation variations impact reuse practices.

Most producers and state regulators agree that states are better able to craft regulations that address regional conditions instead of applying a blanket federal regulatory framework on operations. The corollary of states having varying rules is that companies must understand all the variations for the states where they operate. If state regulators consider water reuse in crafting new and updating existing regulations, they can encourage reuse. Statutes and regulations that optimize and balance both flexibility and environmental protection will encourage reuse.

Operators should also be aware of any relevant local land use restrictions or permitting processes that may impact their ability to reuse water. This may occur at the town or county level, depending on the state.

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[29] Stephen Rassenfoss, "Rising Tide of Produced Water Could Pinch Permian Growth," *Journal of Petroleum Technology*, June 12, 2018, https://www.spe.org/en/jpt/jpt-article-detail/?art=4273.

Background

Managing produced water is a normal cost of doing business for oil and gas producing companies. While produced water is most commonly disposed of into permitted salt water disposal (SWD) wells within deep saline underground formations, it is also frequently reinjected into conventional reservoirs for enhanced oil recovery (EOR) operations. An additional opportunity for managing produced water is reusing it in unconventional oil and gas plays, particularly in hydraulic fracturing of wells or other well completion operations. Currently, reuse of produced water in unconventional plays is limited, primarily by cost and logistical barriers.

This module focuses on the potential for increasing the rates of produced water reuse in unconventional oil and gas operations. It addresses the evolution of produced water management and reuse practices in unconventional operations; available data on water volumes and produced water quality; operational and environmental challenges related to produced water reuse; and opportunities to facilitate water reuse through new business models as well as legislative, regulatory, policy, and research initiatives. The module also characterizes top-producing unconventional basins or regions and the similarities and differences among these basins/regions that may impact water management practices. Case studies illustrating trends in water management and reuse in the unconventional oil and gas industry are provided in Appendix 2-A.

Information for this module was gathered from public sources as well as from stakeholders specifically for this report. Research methodologies included analysis of public data and company web sites; regional discussions with groups of producing companies about water management practices; discussions with regulators, industry groups, and other non-governmental organizations; data requests to producing companies relayed through the American Petroleum Institute; and special requests to IHS Energy Group, which provides industry data on produced water and the cost of source water. Notes from discussions are included in Appendix 2-B.

Water management practices, including produced water reuse, vary substantially from region to region. All told, data on water management was gathered for this report from 18 producing companies, with operations summarized for seven of the major unconventional regions, shown in Figure 2-3. It is important to consider that, while this data set is the best available, it still represents a very small subset of the overall industry. As an indication of sample size, the 18 producing companies contributing data for this report accounted for 29 percent of the total water sourced in the seven basins in 2017.

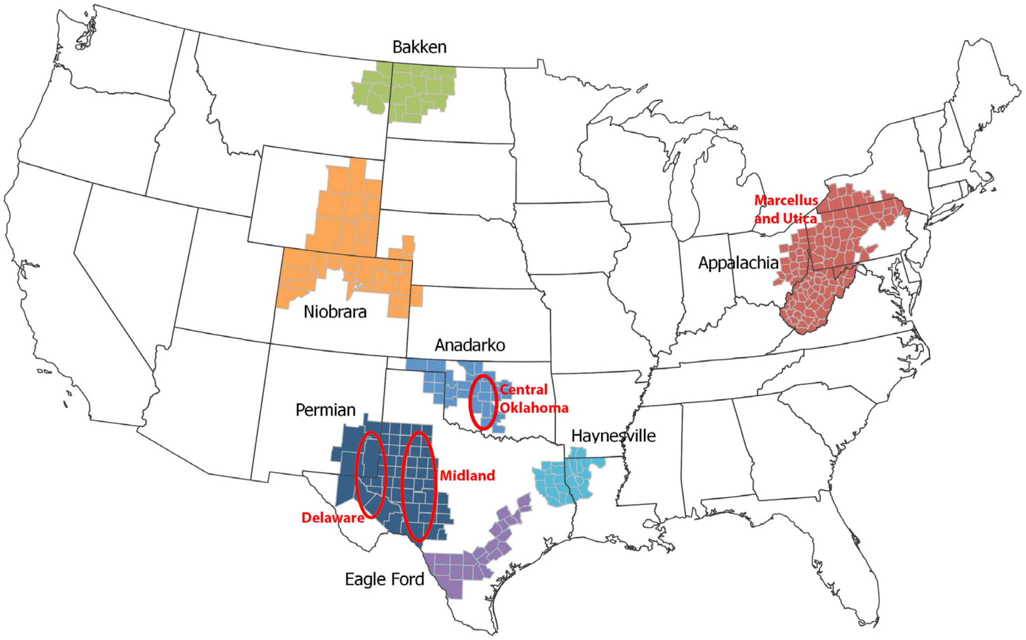

Figure 2-3: Select Oil and Gas Producing Basins/Regions in the Continental U.S.

Source: EIA https://www.eia.gov/petroleum/drilling/

This report focuses on the top seven basins/regions based on oil and gas production and current drilling activity: the Permian, Appalachian, Bakken, Niobrara, Anadarko, Haynesville, and Eagle Ford basins/regions, shown in Figure 2-3. In this report, the Permian is sometimes referred to as its component Midland and Delaware sub-basins, and the Appalachia as the Marcellus/Utica play. Central Oklahoma is a sub-basin of the Anadarko.

Water Management in Unconventional Oil and Gas Operations

This section examines the changing dynamics of water management in unconventional oil and gas operations, the potential for increasing the rate of produced water reuse in hydraulic fracturing or other well completion operations, and how this potential varies across major producing regions.

Overview of Water Management

The water lifecycle for unconventional oil and gas operations can be complex because water management practices vary widely across the United States. Figure I-5 in the Introduction charts the possible pathways for water in normal operations. The water lifecycle graphic could apply to a wellpad, an entire county, or a region. If transportation is available, the system can balance produced water with the water needed for completions more effectively. As drilling and completions move from area to area within a county or region, an integrated water system would facilitate water reuse. However, once drilling and completions activities slow down or are discontinued in a region, reuse becomes more difficult due to the distance between the location of the producing wells and the nearest completion activity.

Figure 2-4 is a simplified comparison of the infrastructure requirements for produced water disposal and reuse. The reuse graphic shows how water reuse changes the water lifecycle.

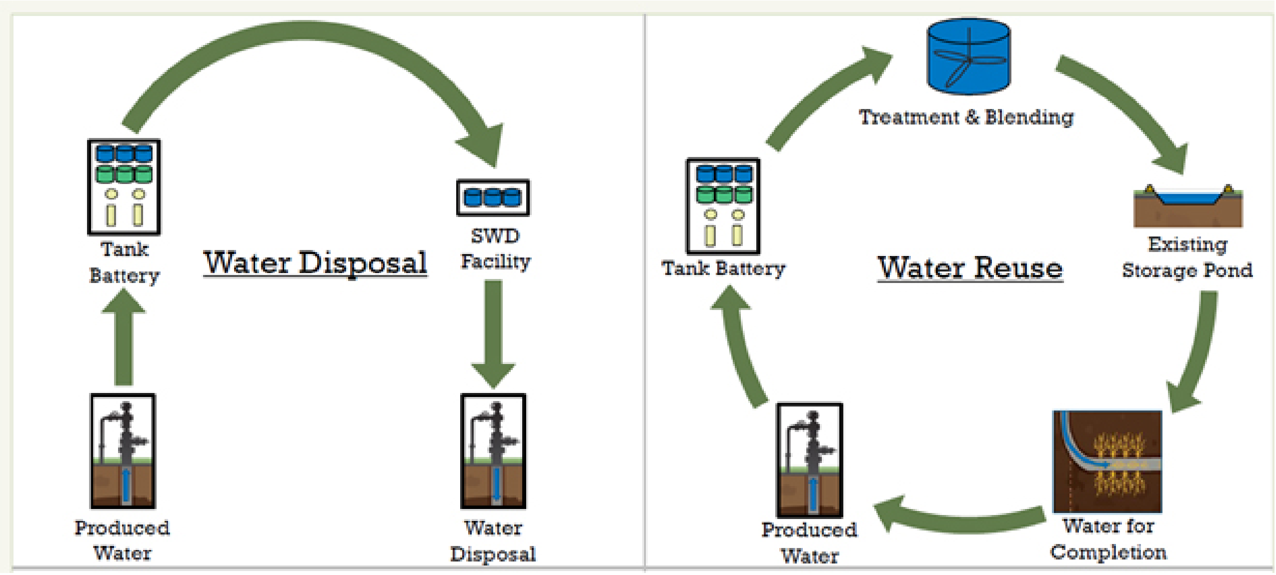

Figure 2-4: Simplified Flow Diagrams for Water Reuse vs. Disposal

Source: Pioneer Natural Resources http://investors.pxd.com/static-files/5aebb0b7-50e1-4c75-a10b-711ce71422c4

The active unconventional producing regions of the United States have substantially different water management characteristics. This variability is discussed in detail in *Water Management and Produced Water Reuse by Region*. Some areas have significant surface water available for sourcing for completions, while other areas are more arid. Water injection disposal capacity varies based on the availability of adequate geologic formations and disposal wells. When either source water or disposal capacities are limited, produced water reuse becomes more economically viable and operationally practical. The volume of water produced from an oil or gas well also varies by region and formation. These variables affect water management practices and the potential to reuse produced water.

Importantly, the reuse system must have enough storage, transportation, treatment capacity, and ongoing needs for source water, to ensure higher levels of water reuse. The logistics of transferring water from the production site to where it can be reused in another completion are critical. Often, the cost to transport water by truck can exceed the treatment and storage costs. It is usually not practical to transport water long distances by truck due to the high transport cost.[30] Storage is often needed for reuse since water production may be at a steady lower rate, but the volumes needed during hydraulic fracturing are comparatively high and intermittent. Treatment of produced water, when necessary to make it suitable for reuse, may also create residual liquids and solids that must be disposed of properly.

While it is possible to reuse produced water outside of oil and gas operations, this practice is currently limited due to the cost of treating produced water for other applications, environmental risks, regulatory restrictions, and operational factors. Produced water typically has TDS levels that are very high compared to state water quality standards for surface water bodies. If produced water discharges are allowed under an NPDES permit, the discharge will be required to meet applicable state and federal standards.[31] In most cases, treatment would be required to meet the constituent limits. Further, most potential reuse opportunities for produced water outside the oil and gas industry would require extensive treatment to lower salt content of the water. Most, though not all, produced water has at least as much salinity as seawater and commonly may have three to eight times the salinity of seawater. There are a few fields from which the produced water has a low TDS content. For example, in Texas, there are numerous fields that produce from formations with sufficiently low TDS content that the produced water can be discharged under an NPDES permit. In addition, produced water from coalbed methane (CBM) formations can be an exception to the high TDS norm. There are instances where CBM operations discharge produced water after minimal treatment due to the low salinity of the water. Produced water reuse outside of the oil and gas operations is the subject of Module 3 of this report.

Waterfloods and enhanced oil recovery (EOR) projects use produced water differently from unconventional oil and gas developments. Waterfloods have historically been performed exclusively in conventional formations, with fewer starting up in recent years. It is only in the initial years of the waterflood that makeup water is needed. Most waterfloods in the United States have reached a maturity where the produced water is reinjected back into the formation in a steady state. Figure 2-5 shows the typical water flow paths in waterfloods or EOR projects. The GWPC estimated that 45 percent of all produced water in 2012 (conventional and unconventional) was reused for EOR or waterflooding.[32] Therefore, waterfloods are independent of unconventional water management and are not likely to factor into produced water reuse for unconventional development.

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[30] OWRB, *Oklahoma Water for 2060 Produced Water Reuse and Recycling* (April 2017), https://www.owrb.ok.gov/2060/PWWG/pwwgfinalreport.pdf.

[31] USEPA, "Oil and Gas Extraction Effluent Limitation Guidelines and Standards," 40 CFR Part 435, https://www.epa.gov/eg/oil-and-gas-extraction-effluent-guidelines.

[32] John Veil, *U.S. Produced Water Volumes and Management Practices in 2012*, (Ground Water Protection Council, April 2015), http://www.veilenvironmental.com/publications/pw/final_report_CO_note.pdf.

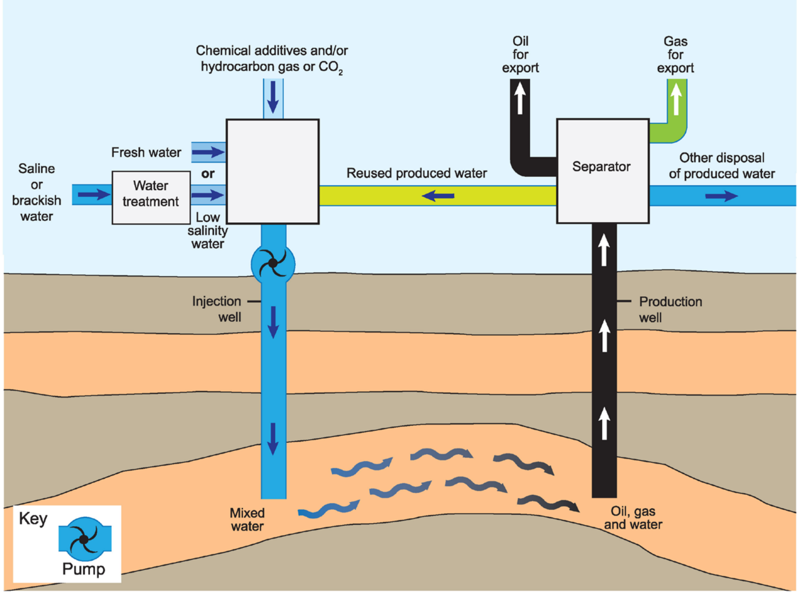

Figure 2-5: Secondary Recovery Process

Source: BP https://www.bp.com/content/dam/bp/pdf/sustainability/group-reports/BP-ESC-water-handbook.pdf

In some cases, especially in the Permian Basin and Oklahoma, conventional produced water may be available in the same region as unconventional operations. In these non-waterflood fields, it may be possible to reuse the conventional produced water as a source for hydraulic fracturing of unconventional formations.

Evolution of Water Management in Unconventional Oil and Gas Regions

Horizontal well and hydraulic fracturing technologies have had an unparalleled impact on the growth of U.S. oil and natural gas production, making it economically feasible to produce shale oil and gas resources. The multi-stage hydraulic fracturing of a single horizontal shale gas well can use an average of about 12 million gallons of water. Sourcing and managing the large quantities of water used in unconventional production is a central challenge for operators.

Currently, produced water reuse in unconventional oil and gas operations is relatively uncommon, representing about 10 percent of produced water volumes overall. However, the rate of produced water reuse and the potential for increasing it vary significantly from region to region, depending largely on the economics of reuse compared to alternatives for water sourcing and disposal.

Produced water reuse, where feasible, can play a role to meaningfully reduce the use of fresh or brackish water for unconventional oil and gas operations and reduce the need for deep injection of produced water. Reuse represents an opportunity to improve the balance of water in specific areas of the United States and to support the sustainable, economic development of important U.S. energy resources. Achieving significant levels of produced water use in unconventional producing regions will require capital investment in storage, transportation, and treatment capacity; a predictable supply of produced water; ongoing demand for source water for nearby production operations; and a supportive regulatory framework.

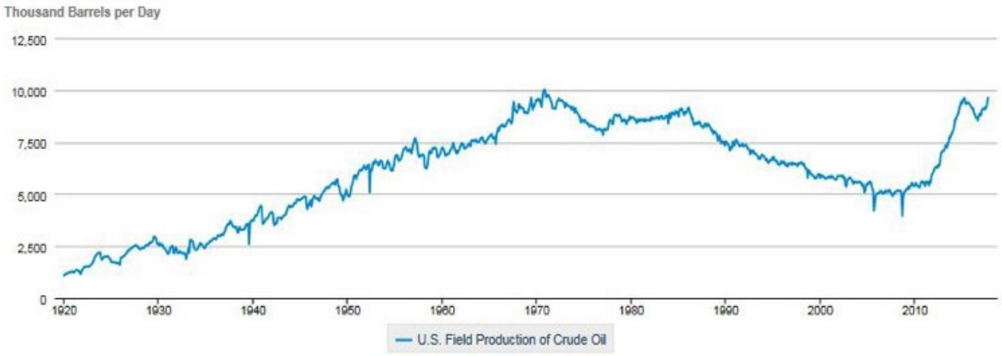

Figure 2-6: U.S. Field Production of Crude Oil

Source: U.S. Energy Information Administration (EIA)

It took roughly 25 years, from the late 1940s to the early 1970s, for oil production to increase from 5 million barrels per day to 10 million barrels per day. Over the next 35 years, production declined back to 5 million barrels per day by 2009. However, in nine years, from 2009 to 2018, oil production recovered to over 10 million barrels per day. This reversal is due to the combined technological advances in hydraulic fracturing and horizontal well development that were not economical with earlier technologies. The impact on natural gas production has been similarly significant, increasing approximately 50 percent from 2007 to 2018 (Figure 2-7).

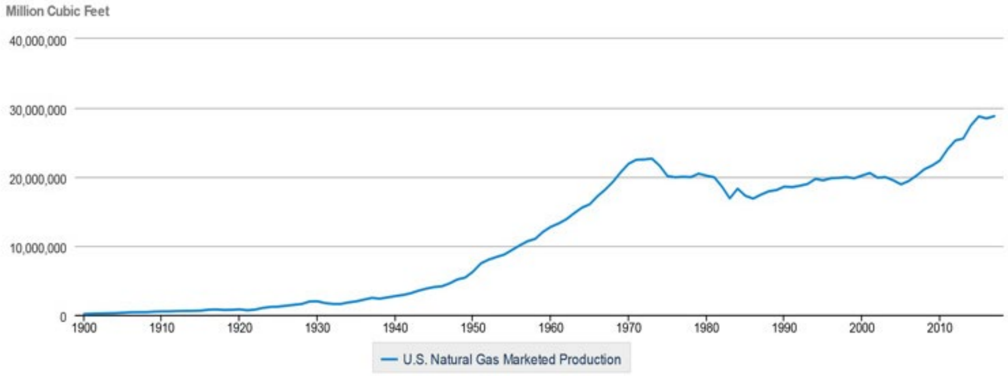

Figure 2-7: U.S. Natural Gas Marketed Production

Source: EIA

Unconventional shale development started in the Barnett Shale in the 1980s; however, significant drilling activity did not begin until gas prices increased in the late 1990s. Devon Energy acquired Mitchell Energy in 2002 and established itself as the leading producer from the Barnett Shale.*

*Texas Railroad Commission

A Decade of Change

Just as large-scale unconventional oil and gas development is relatively new, so are the practices of water planning and management within shale plays. In the early days, unconventional development required widespread, highly dispersed, and rapidly changing drilling schedules, and the priority for operators was to prove a new area would produce effectively.[33] Water planning was challenged by the limited scale of production and uncertainty over long-term drilling plans. Typically, water was sourced locally from groundwater or surface sources and, because water volumes were small compared to those used in today's hydraulic fracturing operations, there was little or no impact on local resources.

In the past decade, producing companies successfully demonstrated the technical and economic viability of hydraulic fracturing in horizontal wells. This led to a dramatic increase in unconventional production, with the U.S. horizontal rig count climbing above 900 for the first time in 2010.[34] The growing volumes of sourced and produced water required in these operations raised sustainability concerns in unconventional regions, prompting greater emphasis on long-term water planning. Stakeholders from Pennsylvania to Texas were increasingly concerned about potential groundwater contamination or use of source water for hydraulic fracturing. At the mandate from Congress, the Environmental Protection Agency (EPA) announced in March 2010 that it would conduct a research study investigating the potential impacts of hydraulic fracturing on drinking water resources.[35] In 2011 and 2012, both Texas and Oklahoma experienced extreme drought.[36] State officials and stakeholders were concerned that water use by oil and gas operations was depleting critical resources. The investor organization, Ceres, published a report in 2014 mapping unconventional development in water-stressed areas.[37]

Over time, producers began practicing water reuse in some unconventional regions to help address sourcing demand and disposal challenges. Some successful efforts to manage water more effectively are documented in the Energy Water Initiative Case Studies report from 2015.[38]

Technology developments were important in driving down costs and making such produced water reuse more feasible. Advances in hydraulic fracturing chemistry allowed operators to use produced water with minimal treatment, compared to early reuse projects.[39] In addition, drilling multiple wells from a single pad allowed water managers to better optimize water transportation infrastructure. However, the high costs of transporting produced water, particularly in areas lacking an established water pipeline infrastructure, remained a significant barrier to water reuse in most regions.

Recent Trends in Water Management and Reuse

Water management and reuse are continuing to evolve in most regions. In recent years, both the Permian Basin and Oklahoma have had rising water source and disposal costs, making reuse more economically attractive and cost competitive. Self-reporting by companies in the Permian Basin suggests that reuse has increased there in the last two years, and several producers in Oklahoma also recently announced new reuse projects. In addition, operators in the Marcellus Shale in Pennsylvania and West Virginia have pioneered large-scale water recycling technologies.[40]

Another factor driving interest in water reuse has been induced seismicity, often defined as earthquakes triggered by human activity. Induced seismicity is a concern in parts of Ohio, Arkansas, Texas, Oklahoma, and Kansas. While each situation was unique, regulators and other experts linked deep well injection of

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[33] Michael R. Dunkel, *Sustainability Aspects of Water Infrastructure*, SPE Paper 184445-MS, April 2017.

[34] Rig Count Overview and Summary Count," Baker Hughes Rig Count, Baker Hughes, Inc., http://phx.corporate-ir.net/phoenix.zhtml?c=79687&p=irol-rigcountsoverview.

[35] USEPA, *Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States, Main Report* (EPA/600/R-16/236fa), https://cfpub.epa.gov/ncea/hfstudy/recordisplay.cfm?deid=332990.

[36] Bradley R. Rippey, *The U.S. Drought of 2012*, USDA, Office of the Chief Economist, World Agricultural Outlook Board (Washington D.C.: 2015).

[37] Monika Freyman, *Hydraulic Fracturing & Water Stress: Water Demand by the Numbers* (CERES Report: February 2014), https://www.researchgate.net/publication/306199871_Hydraulic_Fracturing_and_Water_Stress_Water_Demand_by_the_Numbers.

[38] Energy Water Initiative (EWI), *U.S. Onshore Unconventional Exploration and Production Water Management Case Studies*, prepared by CH2M HILL ENGINEERS, INC. (January 2015), https://www.anadarko.com/content/documents/apc/Responsibility/EWI_Case_Studies_Report.pdf

[39] OWRB, *Oklahoma Water for 2060 Produced Water Reuse and Recycling* (April 2017), https://www.owrb.ok.gov/2060/PWWG/pwwgfinalreport.pdf.

[40] "Water," Marcellus Shale Coalition™, http://marcelluscoalition.org/marcellus-shale/production-processes/water/.

produced water as the potential cause.[41] Regulatory authorities have taken a variety of risk-mitigation actions to lessen or prevent potential seismic impacts. Examples have included establishing seismic monitoring networks, installing instruments to monitor surface particle motion, suspending well operations, requiring modifications to well construction or operational parameters, requiring well tests, reducing injection pressure, or reducing water injection volumes. These actions can have the effect of increasing disposal costs and making water reuse a more economically attractive alternative.

Transportation costs have remained a major limitation on reuse in most regions. Additionally, volatility in oil and natural gas prices has constrained the ability of producers to invest in capital-intensive water systems that allow reuse. In the second half of 2014, oil prices fell from more than $100 per barrel to about $30 per barrel, slowing unconventional drilling activities and reducing producing companies' overall capital budgets. However, as oil prices recovered in 2017 and 2018, companies became more confident in planning and building water projects in order to maximize their operational efficiencies. An increasing number of companies are building temporary or permanent pipelines to transport sourced water, to connect to disposal wells, or to connect to facilities for water treatment and reuse. Such large infrastructure investments are possible due to large, contiguous acreage positions.

For example:

- **Pioneer Natural Resources** is building a pipeline network that will span 100 miles north to south and about 60 miles east to west over many of the counties in the heart of the Midland Basin (Figure 2-8). The largest water system for shale plays in the United States, the system will have line sizes up to 30- to 36-inch diameter and will distribute effluent water from municipal sources, brackish water, and treated produced water for reuse. The company was expected to spend $135 million in capital in 2018 for the Midland wastewater treatment plant upgrade, additional subsystems, produced water ponds, and produced water reuse. Pioneer is several years into the system development.[42]

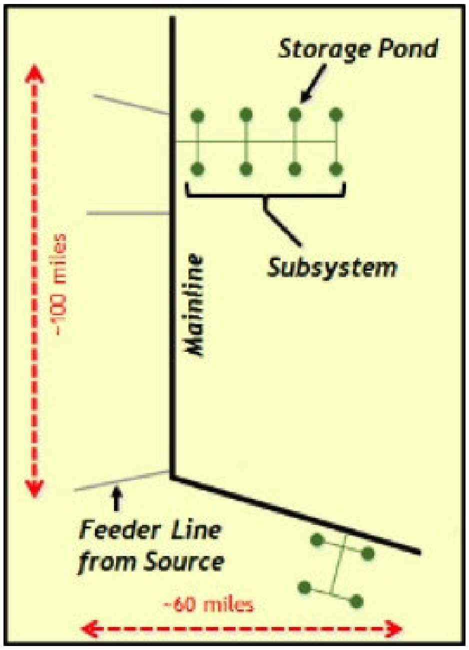

Figure 2-8: Simplified Diagram of Pioneer Water System Components

Source: Pioneer Natural Resources

Pioneer Natural Resources is constructing the largest water system for shale plays in the United States. The system will distribute effluent water from municipal sources, brackish water, and treated produced water for reuse.

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[41] Ground Water Protection Council and Interstate Oil and Gas Compact Commission, *Potential Injection-Induced Seismicity Associated with Oil & Gas Development: A Primer on Technical and Regulatory Considerations Informing Risk Management and Mitigation*, Second Edition (2017), http://www.gwpc.org/sites/default/files/ISWG%20Primer%20Second%20Edition%20Final%2011-17-2017.pdf.

[42] Pioneer Natural Resources, JP Morgan Energy Conference, June 19, 2018.

- **Antero Resources** has the largest desalination plant for produced water reuse in the industry. The 60,000 barrels per day capacity plant in West Virginia cost approximately $500 million. The company has a water system to gather produced water and distribute the treated water for reuse (Figure 2-9).

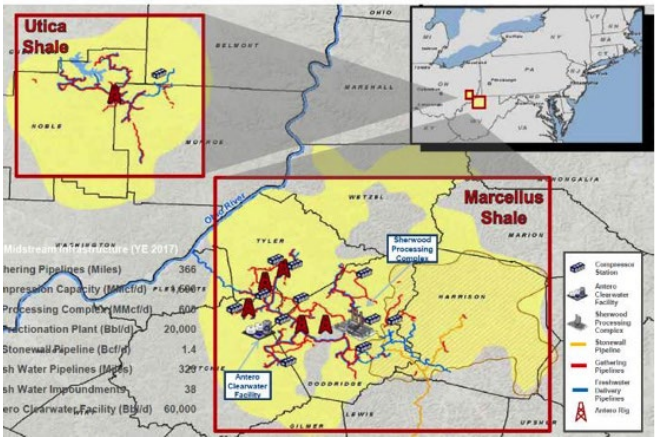

Figure 2-9: Map Showing Antero, Inc. Water Systems

Source: Antero, Inc.

This map shows the water system of Antero Resources, which operates the largest desalination plant for produced water reuse in the industry.

- **Anadarko** implemented a water recycling and closed-loop water-on-demand (WOD) system in Colorado, consisting of more than 150 miles of pipeline (Figure 2-10). The WOD system uses automation and consolidates equipment to conserve water, reduce traffic by more than 2,000 vehicles per day, and reduce greenhouse gas emissions. The system transports about 98 percent of this water via these pipelines. The WOD system has the added benefit of reducing the number of water storage tanks needed onsite, which further reduces surface impacts. Anadarko also partnered with **Western Gas**, which has a 90,000 barrels per day water system in Loving and Reeves Counties in the Delaware Basin of west Texas to enable large scale reuse of produced water.[43,44]
- In the Midland Basin, **Concho** built a 90-mile pipeline that transports more than 90 percent of its water via pipelines. The pipeline, which includes water storage facilities and can accommodate up to 125,000 barrels /day, transports treated effluent to Concho's areas of operation in the Midland Basin.

The emergence of water midstream solutions is a recent development involving efforts to coordinate water sourcing for completion operations with produced water reuse across multiple producing companies. While water midstream solutions generally are provided by an independent third-party company, producers themselves are also directly involved in exchanging produced water in certain situations. Sharing produced water among producing companies is most common in the Marcellus and Utica plays of Pennsylvania and West Virginia where operations are far from disposal wells. It has also been reported in Colorado and Oklahoma. Produced water may be transferred from a company that lacks sufficient disposal options to another nearby company that reuses the water in its completion operations. Agreements to exchange water can potentially reduce costs for both companies, while reducing truck miles driven and reducing disposal. However, if sharing of produced water triggers a commercial designation and requires additional permitting, it can be a deterrent to reuse.

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[43] Western Gas Partners, LP, Operations, http://www.westernmidstream.com/Operations/.

[44] "Water Management," Anadarko, Inc., (2017), https://www.anadarko.com/Responsibility/Sustainable-Development/HSE/Water-Management/.

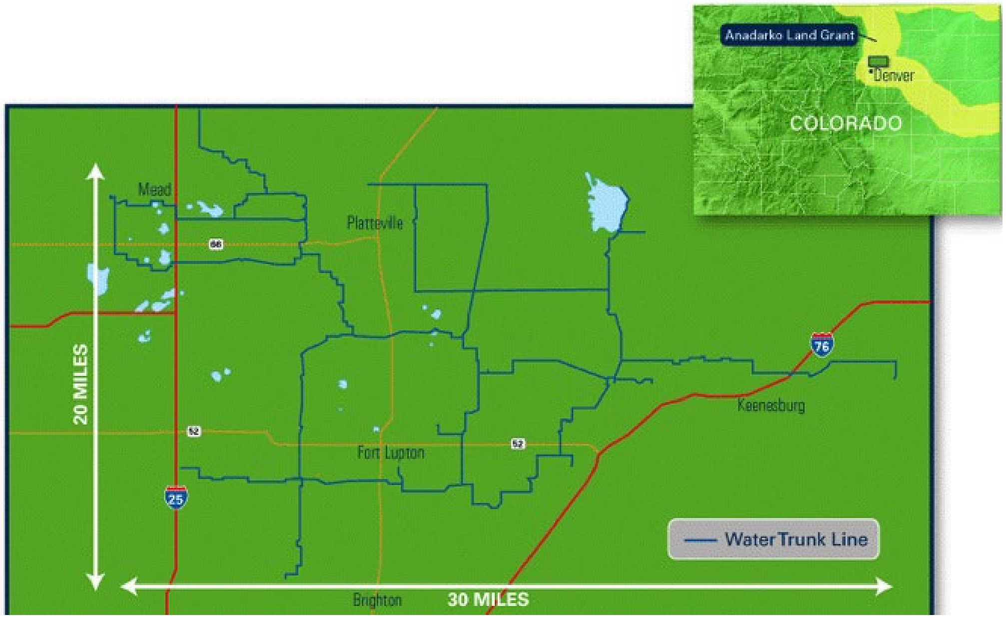

Figure 2-10: Map of Anadarko Water System in Colorado

Source: Anadarko, Inc.

Anadarko's water recycling and closed-loop water-on-demand system in Colorado consists of more than 150 miles of pipeline.

Considerations for Operators

Today, most mid and larger sized producing companies have corporate goals to reduce sourcing from fresh water, leaving more fresh water for agriculture, human consumption, aquatic life, and other industries. All 10 of the larger companies surveyed for this report had stated efforts to decrease fresh water use. (These efforts are discussed on websites for ExxonMobil, Shell, Chevron, BP, ConocoPhillips, EOG, Oxy, Anadarko, Pioneer, and Concho.) Discussions with producers' water managers confirmed this priority and identified the most commonly used non-fresh water sources as brackish surface or groundwater, produced water, and municipal wastewater effluent. In some regions, especially the Permian and Eagle Ford, brackish water is preferentially used over fresh water by many companies. Other companies in Texas and Oklahoma are sourcing brackish water when available. Areas with abundant fresh water may not be sourcing brackish water to the same extent.

Economic considerations—as outlined in the following section, Evaluating the Economics of Produced Water Reuse—are paramount in decisions made by operators in weighing reuse potential. In addition, companies weigh other relative risks and benefits of investing in produced water reuse.

Increasing water reuse can reduce company exposure to the following risks:

- Water disposal limitations caused by localized induced seismicity or over-pressuring of the disposal formation, or lack of appropriate geologic formations for disposal
- Restrictions to normal sourced water due to drought or other reasons
- Increased cost for source water and disposal capacity
- Increased trucking costs for water sourcing and disposal and other transportation restrictions
- Regulatory or stakeholder initiatives
- Reputation risks from external perceptions that the company does not support water conservation
- Missing an opportunity to shape how reuse infrastructure, technologies, and regulations develop.

Risks associated with increased water reuse may include:

- Spills associated with the additional transport and storage if required

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* Upstream" refers to operations involved with the drilling, completion, and production of oil and gas wells, while "downstream" operations include refineries and gas stations. "Midstream" includes the processes of treating natural gas for sale, gas pipelines, and oil pipelines to the refineries.

- Underutilization of pipelines, storage, and treatment facilities intended for reuse as a result of decreasing oil or natural gas prices that curtail drilling plans
- Over spending on water reuse capital projects that might not be warranted by ongoing or projected future development
- Additional cost and potential liability concerns associated with storing, transporting, and treating water for reuse
- Company risks from public perception that storage, transportation, and reuse infrastructure constitute an increased footprint rather than a greener alternative
- Increased logistics challenges and costs associated with moving high salinity water through temporary infrastructure
- Concern over environmental liability in the case of produced water sharing
- Produced water ownership and custody transfer of treated produced water
- Potential formation damage from incompatible fluids
- Residuals handling and disposal from treatment system.

Recent Developments in Multi-Company Sharing and Water Midstream

Sharing produced water among producing companies is most common in the Marcellus and Utica plays of Pennsylvania and West Virginia where operations are often far from disposal wells. It has also been reported in Oklahoma. In these cases, water may be transferred from one company without enough nearby completion operations to another company needing produced water for reuse. Agreements to exchange water can potentially reduce costs for both companies, while reducing truck miles driven and water disposal. In other areas with more available disposal capacity, produced water transfers are less common. Concerns have arisen in some states about whether surface owners may make a monetary claim on water transferred among operators. A second concern is whether the liability for spills is fully passed to the receiving company. Despite these concerns, water sharing among producers has the effect of smoothing out the peaks and valleys of individual company water demands.

Another more substantial method of sharing water is the trend for midstream companies to own and operate a water system for multiple operators. The midstream ownership concept in oil and gas was developed decades ago as midstream companies developed oil pipelines and gas plants to allow the

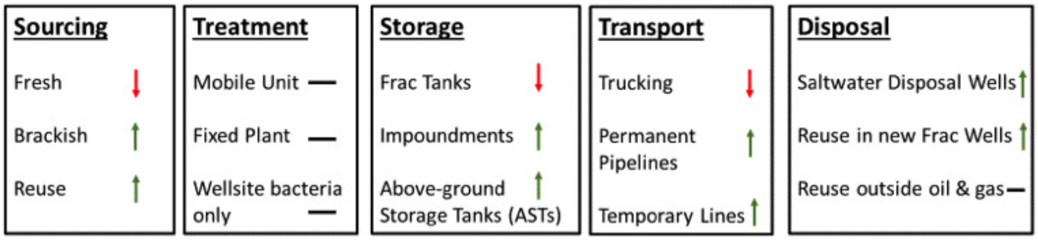

Figure 2-11: Trends in Water Management
Source: Jacobs Engineering

Figure 2-11 summarizes key trends in water management, as derived from discussions with operators for this report, and may not be accurate for all U.S. regions. Red downward arrows indicate activities that have decreased in recent years and green upward arrows indicate activities that have increased. A horizontal line indicates no clear trend.

Sourcing. Many operators have expressed a commitment to reduce fresh water sourcing. They have identified the most commonly used non-fresh water sources as brackish surface or groundwater, produced water, and municipal wastewater effluent.

Treatment. It is now widely recognized that companies do not need to remove total dissolved solids (TDS) to reuse water in oil and gas operations. Most water treatment for reuse in completions removes limited solids or a few specific constituents such as iron or scale forming cations. (In contrast, for produced water to be used outside of the oil and gas operations, most TDS must be removed, along with other constituents of concern.) The trend of using poorer quality water has reduced the level of treatment needed for produced water reuse. Most areas are using a combination of mobile treatment units and permanent plants, depending on the forecast for additional drilling and amount of the produced water to be treated.

Storage. Several states (Texas, New Mexico and Oklahoma) have been moving towards the use of larger impoundments as the scale of water operations has increased. In some cases, state regulations are more restrictive for impoundments, reducing their applicability.

Transport. Pipeline transportation of water has grown in many areas, most notably in the Permian Basin, resulting in reduced truck traffic. However, lack of a critical volume of produced water or difficult terrain reduce the feasibility of permanent water piping in some basins. For example, the Appalachian Basin has little piping of produced water, but there have been projects to install permanent piping for sourcing water. Often, temporary “layflat hose” is used to convey the water the last mile or so to the well site, where it is not usually practical to run permanent lines.

Disposal. Reuse has grown as an option to disposal in SWD wells in many areas. However, as drilling activity remains high in many areas like the Permian, it is possible that water disposal in SWD wells could continue to increase, even while reuse of produced water increases.[*]

Nationwide total withdrawals of water in the mining category, which includes oil and gas use, were about 1 percent of total withdrawals in 2015.[**] Texas’ water withdrawals in the mining category (including oil and gas) are estimated to be 1 percent of total withdrawals in 2016, the most recent data available.[†] In three states that track state-wide water use data—Colorado, New Mexico, and Wyoming—oil and natural gas activities use less than 1 percent of the total water in the state. However, the percentage of water use by oil and gas operations in some individual counties will be much higher than the state-wide average.[‡]

[*] Paul Wiseman, “Water, Water Everywhere in the Permian,” *The Permian Basin Petroleum Association Magazine*, May 8, 2018, https://pboilandgasmagazine.com/water-water-everywhere-in-the-permian/.

[**] Cheryl A. Dieter, et al., *Estimated Use of Water in the United States in 2015*, U.S. Geological Survey (USGS) Circular 1441, Supersedes USGS Open-File Report 2017-1131 (Reston, Virginia: USGS, 2018), https://pubs.usgs.gov/circ/1441/circ1441.pdf.

[†] Texas Water Development Board (TWRB), “Texas Water Use Estimates, 2016 Summary,” August 2018, http://www.twdb.texas.gov/waterplanning/waterusesurvey/estimates/data/2016TexasWaterUseEstimatesSummary.pdf?d=1532722565244.

[‡] Western Energy Alliance, *Oil and Natural Gas Exploration and Production Water Sources and Demand Study: Colorado, Montana, New Mexico, North Dakota, Utah and Wyoming* (July 14, 2014), https://www.westernenergyalliance.org/sites/default/files/WesternWaterUseStudy.pdf.

products to move to market. Natural gas is treated near the area of production at gas plants then put into regional sales lines. Water midstream is a relatively new industry, created since unconventional oil and gas development began in select plays. Only in the last few years has water midstream begun to have significant scale. Most water midstream development has been focused in the Permian, a relatively "wet" play that continues to produce water over time.

Water midstream companies may originate from producing companies forming subsidiaries or independent companies (e.g., Pioneer, EQT, Anadarko). In other cases, they are new startups specifically focused on water midstream (e.g., WaterBridge, H2O Midstream, Solaris). Other participants include companies providing salt water disposal solutions that build gathering pipelines to expand into water midstream (e.g., Oilfield Water Logistics, Goodnight Midstream), as well as oil and gas midstream companies or other water companies that expand into water midstream (e.g., Layne Christensen, Crestwood Midstream).

Recent publicly announced projects demonstrate that water midstream solutions are poised to grow.

- **WaterBridge Resources** announced a partnership with Fort Stockton, Texas to purchase water resources for oil and gas (July 2017); acquired Arkoma Water Resources LLC with 110 miles of water pipelines (October 2017); and acquired EnWater's assets in Permian including 100 miles of pipelines and SWDs (August 2017).
- **Layne Christensen** built a 20-mile water pipeline system to water sources to deliver up to 200,000 barrels/day from their water storage facility (June 2017).

Figure 2-12: Layne Christensen's Water Storage Facility in Reeves County, Texas

Photo courtesy of Layne

- **H2O Midstream** announced the first truck-less produced water hub in Permian with pipelines, storage, and disposal (June 2018), and acquired produced water assets from Encana Oil and Gas in Permian (June 2017).
- **Solaris Midstream** acquired Vision Resources water sources and its 200+ miles of water pipelines (June 2018) to complement Solaris nearby water reuse and disposal system in southeast New Mexico; it commenced operations on the new Pecos Star System reuse system in New Mexico (May 2018).
- **EQT** (Producer) spun off its midstream company that operates Appalachian assets, including water midstream (February 2018).
- **Oilfield Water Logistics** completed a 30-mile produced water pipeline with a capacity of 150,000 barrels/day (July 2016).
- **Goodnight Midstream** added 50 miles of produced water gathering and five additional SWDs to its North Dakota water system (March 2018), which now has 24 SWDs and 250 miles of water pipelines. The company announced it is planning a 200,000 barrels/day produced water system in Lea County, New Mexico (February 2018), and that is has formed a multi-year partnership to gather and dispose produced water for producer Callon Petroleum (September 2017).
- **Waterfield Midstream**, formed with a private equity commitment of $500 million, has a focus on the Permian Basin.
- **Lagoon Water Solutions** announced backing of $500 million from private equity (September 2018) and has a focus on Oklahoma.

Pipelines can reduce variable transportation cost sufficiently to enable large-scale reuse of produced water. Yet networks built by and for a single operator may suffer from the volatility of that producer's completion schedule and produced water volumes. When larger systems are built for multiple companies, individual company's needs can be balanced more effectively. The scale of water midstream will allow reuse to grow steadily, especially in the most active areas in the Permian, Appalachia, and Oklahoma.

Table 2-1: Water Midstream Drivers

Source: Jacobs Engineering

Water Midstream Drivers	
Positives:	Negatives:
• Reduce overall costs with economics of scale	• Producer's loss of absolute control of system
• Reduce upfront capital costs for producer	• Commitment needed to Midstream to build system
• Allow producers to focus on high return completions and production	• Water mixing problems or different source quality criteria
• Allow a better overall water balance (supply and demand)	• Complexity of system allocation and working with other companies

Although there are both positive and negative drivers for water midstream development, third-party midstream solutions are increasingly emerging. Water midstream companies have acquired water systems and developed new projects in recent years.

Potential for Basin-to-Basin Produced Water Transfer

Since some formations and basins produce significantly more water than others, transferring produced water from basin to basin potentially could facilitate water reuse. For example, the Delaware Basin in Texas and New Mexico, probably the most prolific water-producing basin on a per well basis, is also one of the most active areas for drilling. This makes it more likely that Delaware Basin disposal could become restricted even if water reuse continues to grow. Meanwhile, the Midland Basin has substantial drilling and completion activity, but typically produces lower volumes of water over the life of the well than the Delaware Basin. Constructing a pipeline or series of pipelines to carry produced water from the Delaware Basin to the Midland Basin might be feasible if the Midland basin could reuse additional produced water.

A similar situation exists in Oklahoma, although at a smaller scale. The Mississippi Lime area of north central Oklahoma produces more water than can be reused and has been limited by water disposal capacity due to seismicity. The STACK play in central Oklahoma will likely need sourced water for a long time, even if it continues to ramp up water reuse. An evaluation of a 200,000 barrel per day transfer pipeline conducted as part of CH2M's water study for the Oklahoma Water Resources Board (OWRB) suggested that a pipeline could potentially be economically feasible. In a second ongoing study, OWRB is making a more in-depth review of the pipeline potential, including non-economic factors.[45] Several major uncertainties remain, including water quality differences that could increase completion costs or create formation damage in the hydraulically fractured well.

Evaluating the Economics of Produced Water Reuse

Unconventional oil and gas development is capital-intensive. An unconventional well is generally considerably more expensive to drill and complete than a conventional well due to technical factors such as the need for hydraulic fracturing. Sourcing water for the hydraulic fracturing of unconventional wells is a significant portion of the capital for drilling and completing a new well.

After the well is put on production, the management and disposal of the produced water is an operating cost that typically lasts for the life of the well. The "default" water management strategy is to source water as locally as possible and reuse it or dispose of it in nearby injection wells.

In most of the regional discussions conducted for this report, cost was the dominant driver for water reuse, although by no means the only factor companies consider. Most companies interviewed were publicly traded with a legal obligation to conduct operations in a cost-effective way that delivers value to their stockholders. Costs were particularly emphasized with the downturn in the prices of oil and natural gas starting in 2015. Within individual companies, U.S. regional operations constitute a business unit that must compete against other domestic and international business units. Not surprisingly, water managers and asset executives must demonstrate that water reuse competes economically with alternatives for that business unit.

Reusing produced water has the potential to reduce or eliminate the costs of sourcing water for well completion and of disposing of it in permitted SWD injection wells. However, decisions about water reuse involve complex determinations about both operating costs and capital investments. If low-cost

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[45] OWRB, *Oklahoma Water for 2060 Produced Water Reuse and Recycling* (April 2017), https://www.owrb.ok.gov/2060/PWWG/pwwgfinalreport.pdf.

sourcing and disposal are available, water reuse is not likely to be a competitive option. In contrast, if sourcing and disposal are limited and expensive, reuse may be economically attractive, provided that any necessary capital investments in transportation, storage, and treatment infrastructure can be justified. The area where reuse is highest, Pennsylvania and West Virginia, and the area where reuse is growing fastest, the Permian Basin, are regions where disposal options have been limited and disposal costs have been high or are increasing. In addition, several of the top basins are in arid regions resulting in limited availability of sourced water.

Primary water lifecycle costs for unconventional oil and gas operations can be simplified, as shown below, when produced water is not reused.

When produced water is reused, the water lifecycle cost for unconventional oil and gas operations changes (Figure 2-13). Commonly, additional sourced water is blended with reused produced water in a hybrid of Figures 2-13 and 2-14.

AREAS OF HIGHEST REUSE

The area where reuse is highest, Pennsylvania and West Virginia, and the area where reuse is growing fastest, the Permian Basin, are regions where disposal options have been limited and disposal costs have been high or are increasing. In addition, several of the top basins are in arid regions.

Comparing Lifecycle Water Costs

In evaluating the potential for produced water reuse, most operators compare the total lifecycle water costs of sourcing and disposing locally to water reuse. Comparing costs on a per-barrel basis requires considering the costs of source water acquisition, sourced water transportation, produced water transportation, produced water treatment and storage, and produced water disposal. These water cost components vary by region and even down to the individual well.

- **Sourced water acquisition.** Water source costs vary with local water availability, local and regional market demand and commercial considerations, availability of water source permits (which is more important in some states than others), water quality (fresh water and brackish water may be valued differently), and volumes purchased (larger volume contracts usually have a lower price per barrel.) Several of the top unconventional basins are in arid regions with limited availability of sourced water.

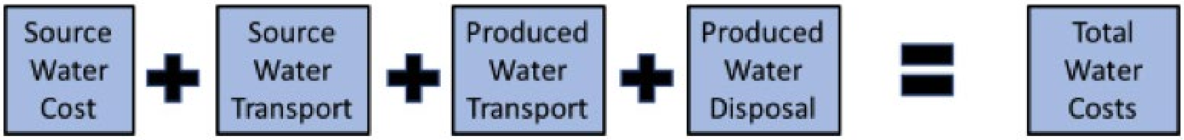

Figure 2-13: Water Lifecycle Costs without Reuse
Source: Jacobs Engineering

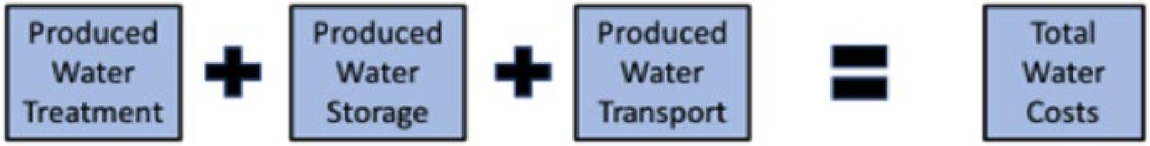

Figure 2-14: Water Lifecycle Costs with Reuse
Source: Jacobs Engineering

- **Water transportation.** Transportation costs per barrel will differ significantly depending on whether produced water is moved by trucks or pipelines. Often the most expensive component of produced water reuse, transportation can be complicated by continual changes in well locations as the drilling rig moves from well to well, and by the changing volumes of produced water, which typically decline over time as wells mature. Due to the high cost, water is rarely transported over 50 miles, so most sourcing and disposal is performed locally, normally within 10 miles.
- **Produced water treatment.** With the technical advancements in hydraulic fracturing chemistry, minimal water treatment is required for reuse within the oil and gas operations. Treatment of produced water, when necessary to make it suitable for reuse, may also create residual liquids and solids that must be disposed of properly.
- **Produced water storage.** Storage is often needed for reuse since water production may be at a steady lower rate, while the volumes needed during hydraulic fracturing are comparatively high and intermittent. Storage cost per barrel can be low if the storage system is used for large volumes of water over time. Transportation and storage costs can be reduced using on-site water treatment.
- **Produced water disposal.** Disposal costs can vary significantly by region. Costs are largely determined by the availability or scarcity of appropriate geologic formations for water disposal through injection and the number of permitted SWD wells.

Justifying Capital Investments

Water infrastructure is built in a specific area with the expectation that intensive drilling and production will follow in that location. If companies decide to discontinue drilling in the area because a new area has better performance, oil price drops make production infeasible or for any other reason, the capital invested in water pipeline, storage, and treatment facilities will be underutilized and project economics will be negatively impacted.

Before investing in the pipelines, storage, and treatment infrastructure to support produced water reuse in an area, producers need to ensure that the supply of produced water and demand for sourced water merit the investment. Considerations include produced water volumes and longevity, the concentration of development activity in the area, and the existence of nearby ongoing drilling and completions in which to reuse produced water. Unless the producing company has acreage continuity from the point of water production to the sites of reuse, landowner permission must be obtained to cross the area. Obtaining such right-of-way access takes time and resources.

Decision making is complicated by uncertainties about oil and gas prices, drilling and hydraulic fracturing forecasts in the area of concern, technology changes in completion operations, changes in regulations related to water management, and changes in

Table 2-2: Water Acquisition Costs per Barrel for Seven Counties in the Permian Basin

Source: Sourcewater https://www.sourcewater.com/

State	Data Points	County	Price High	Price Low	Price Average	Price Median	Today's Volume Median
TX	36	Reeves	$2.00	$0.30	$0.58	$0.57	50,000
TX	33	Yoakum	$1.00	$0.45	$0.77	$1.00	20,572
TX	33	Martin	$1.40	$0.35	$1.06	$0.50	8,572
TX	31	Midland	$3.00	$0.10	$0.52	$0.50	6,857
TX	14	Howard	$0.65	$0.30	$0.48	$0.48	30,000
NM	60	Lea	$1.00	$0.50	$0.80	$1.00	17,142
NM	21	Eddy	$1.25	$1.00	$1.02	$1.00	27,428

Sourcewater provided the data in Table 2-2 from their water source marketplace in July 2018, showing the asking prices for acquiring fresh and brackish water at the source in seven counties of the Permian Basin. The variation of the average cost ranges from $0.48/barrel to $1.02/barrel, over a factor of two within a single basin. The column "Today's Volume Median" is the median volume of the water offered, in barrels.

the availability of sourced water or disposal capacity and associated pricing. Typically, producing companies may only have specific well forecasts for 12 to 18 months, even if corporate financial models project drilling unspecified locations for multiple years.

Companies have indicated that a regulatory framework that reduces the cost of storage, transportation, and/or transfer costs (for example, by facilitating the use of on-site water treatment, and produced water sharing among companies operating in an area) supports increasing water reuse. Of course, all these items must be evaluated within the constraint of protecting public health and the environment.

Evaluating Water Midstream Options

The emergence of water midstream solutions may change the economics of produced water reuse for some producers. Producers may have better financial returns on producing wells than on water infrastructure, depending on the nature of the individual plays. By leveraging infrastructure investments made by water midstream companies, these producers can focus their investments on producing wells and improve their cashflows. This option allows them to respond to pressure from energy investors who encourage upstream companies to limit borrowing.

Nevertheless, producers may be reluctant to commit to a midstream solution for several reasons. First, if producing companies own and operate their own water system, they may have more control over sourcing and disposal of water. Water midstream is a developing business and the relatively new producer water teams are still figuring out this new option. Second, companies may be concerned that long-term, volume-based, take-or-pay commitments to the midstream company may be required to allow the system to be built. Third, in peak times there may be complexity with allocation of the system capacity among producers. Fourth, water mixing problems and differing water quality needs for various water sources could be an issue. Finally, regulatory and other business risks may inhibit midstream growth.

Figure 2-15: Oil Prices Since 2000

Volatile oil and gas prices have had a profound effect on unconventional drilling activity and, in turn, on water reuse investments. Leading up to the 2007 peak of oil prices, industry was just getting started with shale plays and unconventional development. The price crash of 2008 and 2009 during the great recession reminded a new generation how volatile oil prices can be. From 2010 to 2014, prices were remarkably stable, until another price collapse in 2015. In 2015 and 2016, market conditions forced numerous companies to reduce the size of their workforce and their capital budgets, which created uncertainty for longer-term planning and capital investment. As drilling levels declined in most basins, constraints on water sourcing and disposal eased, making capital investments in water projects difficult to justify.

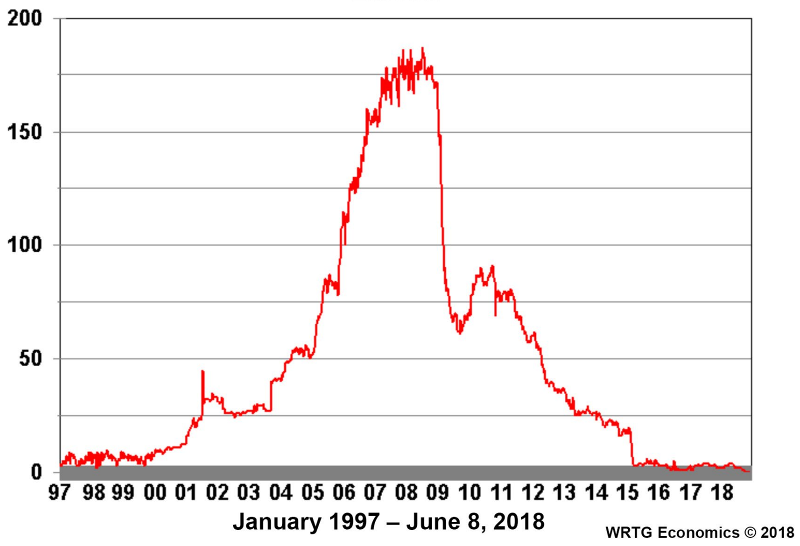

Figure 2-16: Rotary Rig Count in the Barnett Shale

Source: WTRG Economics

Rig count in the Barnett Shale, the first major region developed with horizontal wells and hydraulic fracturing, has been quite volatile. Had Barnett producers built substantial water infrastructure in peak drilling years, the infrastructure would have been largely unused. Rig count in the region has reflected not only changes in oil prices but also improving economics for other basins (Permian and Appalachia).

Operational Challenges of Produced Water Management

Operational challenges related to produced water reuse include the logistics of moving water from source to well site for use; storing produced water for reuse; regulatory and permitting requirements relative to all aspects of reuse and sourcing; landowner agreements and permissions needed, including right-of-way; and water quality requirements for completion and the need to dilute produced water.

Transporting Water for Reuse

Produced water can be transported by permanent pipelines, temporary pipelines, or trucks, or by a combination of these modes. Transportation was named by water managers interviewed for this report as the top operational challenge affecting produced water reuse.

The operating cost of moving water by existing pipelines is substantially less than the cost of trucking the water, often the difference between cents per barrel and dollars per barrel. However, if permanent pipelines do not exist, installing them typically requires companies to commit to a multi-year capital investment plan that can only be justified by the need to transport large volumes of water over an extended period of time.

The Marcellus and Utica plays in Pennsylvania, Ohio, and West Virginia are the exception to building pipelines to establish reuse. Due to regulations, hilly terrain, and the relatively small volumes of water, most water reused in Appalachia is trucked from the gathering points to the next completion site. The cost of trucking is highly dependent on the distance water must be transported, which may limit produced water reuse when the closest hydraulic fracturing site is farther away than the closest disposal well.

Permanent and Temporary Pipelines

Permanent pipelines are typically buried and are usually 18 inches or larger in diameter. Evaluations of when and where to install permanent lines to transport water must weigh uncertainties about oil and natural gas prices that impact drilling activity, capital investments, and water needs. The lead time to design, permit, and install buried water pipelines may be six to 18 months. This lag time from decision to operation is another complicating factor since drilling plans by companies are often revised monthly or even weekly.

Often, the location where the treated produced water is needed changes over time. In the simple "default" scenario, a single water line may connect a group of wells to a disposal well. However, for reuse, a complex network of water pipelines may be needed to move the water to within a few miles of the well site for reuse. Short transfers of water simplify logistics. Often, the sourced water can be conveyed with temporary surface lines while permanent water lines link produced water to disposal wells.

Designing a permanent pipeline infrastructure must take into account physical and operating conditions including normal operating pressures and flows, pipeline material, pump station spacing, and control and isolation valves. Special considerations must be given to rights of way, the crossing of roads, railroad tracks, water bodies, and environmentally sensitive areas which may require a permit. Equally important is construction oversight to ensure construction meets design specifications and addresses any required field modifications during construction. Once the pipelines are installed, monitoring of operating conditions incorporating leak detection and routine inspections is important.

In order to improve reliability of layflat hose and prevent against possible leaks, the American Petroleum Institute has a standards committee looking at this issue.

Temporary pipelines are typically laid across the surface (such as "layflat pipe" or "layflat hose") and may be smaller in diameter (4 to 12 inches) than permanent pipelines. These lines can be reliably deployed for short periods of time. Steel-reinforced (or similarly reinforced) flexible pipe is available for use as temporary pipelines. This piping is routinely available in long lengths of 600 feet or more in order to minimize connecting joints, which are a common source of pipeline leaks. Pressure ratings for temporary pipelines are well in excess of typical pipeline transfer operating pressures. More sophisticated leak detection systems are not designed for temporary pipelines. Therefore, more dependence is placed on flow and pressure monitoring and visual inspection during fluid transfer operations. In order to improve reliability of layflat hose and prevent against possible leaks, the American Petroleum Institute has a standards committee looking at this issue.

Permanent Pipelines for Water Reuse

Challenges

- High upfront capital cost
- Time required to obtain right-of-way access from landowner
- Hilly terrain and rocky soils making installation more complex and costly
- Uncertainties in oil and natural gas prices and drilling forecasts combined with the longer term payout of a water system
- Monitoring for leaks and spills and effectively responding when they occur
- Companies owning a low concentration of acreage which may lack a critical mass
- Automating pumping and storage systems where possible to ensure smooth operations and reduce labor costs
- Measuring and reporting water volumes for better transparency

Opportunities

- Lower costs to move water once the system is installed
- Potential to link storage, treatment, and disposal capacities into an efficient flexible system
- Dramatic reduction of truck traffic for water hauling and reduced accidents and road damage
- Enabling produced water reuse at a large scale
- Reducing fresh and brackish water sourcing and water disposal through increased reuse

Temporary (transfer) Pipelines for Water Reuse

Challenges

- Obtaining permits and right of way
- Infrastructure engineering and construction costs
- Monitoring and leak detection
- Routine inspection and maintenance costs
- Potential regulatory constraints

Opportunities

- Efficient movement of fluids while alleviating dependence on tracking
- Implementing robust leak detection and inspection procedures to reduce potential for leaks and spills
- Ability to quickly deploy and move the piping based on factors such as need, site conditions, etc.

Trucking

Legislators and regulators in key oil and gas producing states report hearing more complaints about truck traffic than all other industry issues. The impacts of trucking in oil and gas operations are documented in a report by The Academy of Medicine, Engineering and Science of Texas.[46] In addition to wanting to reduce impacts on stakeholders, producing companies also often want to minimize trucking due to its high costs. Yet it is unlikely that trucking can be entirely eliminated for water transport. When produced water volumes are low or the terrain is difficult, it becomes impractical to install a water pipeline. In some basins where wells are widely spaced, or the volumes of water are small, trucking the produced water is the most common transport choice (Appalachia and Eagle Ford).

Some producing companies and service companies are using GPS to track truck locations and direct them in a more efficient process. This optimization can track where the water loads should be obtained, and which nearby salt water disposal wells have the shortest wait time. The same systems can also track vehicle speed for safety purposes. These systems have aided oil and gas companies in managing their water trucking operations. For example, Pioneer Natural Resources has a sophisticated control room for water trucking operations and other logistics.[47]

TRUCKING MILEAGE MATH

Hydraulic fracturing operations at a well site may require approximately 50,000 barrels of water per day.

Trucks typically have a capacity of 120 barrels.

Thus, if a truck is making a 20-mile round trip to deliver 120 barrels of water and all of the water is delivered by truck, the trucks would drive about 8,300 miles per day.

If the loading, unloading, and roundtrip driving took two hours, the ongoing operations would require 35 trucks 24 hours per day.

For these reasons, sourced water for operations is largely provided by a series of permanent and/or temporary water pipelines.

Trucking Produced Water

Challenges

- Minimizing trucking to reduce community impacts and costs
- Consistently maintaining safe trucking operations even when industry activity is at a crescendo
- Local road conditions and weight limits
- Producer responsiblities and liabilities associated with road maintenance and repairs
- Truck fleet availability and scheduling difficulties

Opportunities

- Using technology to improve the efficiency of trucking timing and routes
- Improving methods to record and track volumes of water trucked

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[46] The Academy of Medicine, Engineering and Science of Texas (TAMEST), Task Force on Environmental and Community Impacts of Shale Development in Texas, "Environmental and Community Impacts of Shale Development in Texas" (Austin, Texas: TAMEST, 2017), doi:10.25238/TAMESTstf.6.2017, https://tamest.org/wp-content/uploads/2017/07/Final-Shale-Task-Force-Report.pdf.

[47] Pioneer Natural Resources, Operations.

Produced Water Storage

Produced water must be stored before it is reused. This intermediate storage is needed because water normally is produced at low flow rates compared to the high, variable flow rates used during fracturing operations (up to 75,000 barrels per day). Water storage systems used in operations include frac tanks, in-ground impoundments, and above-ground storage tanks. The type selected is based on how long storage will be needed, regulations, space available, terrain, and soil/rock conditions. Measures taken during design, construction, and operations to minimize leaks and spills from storage facilities include:

- Using qualified individuals and properly designing facilities to meet specific storage needs and siting conditions
- Conducting construction oversight to ensure construction meets design specifications, addressing any required field modifications during construction
- Using spill prevention and containment at fluid loading and off-loading points
- Using secondary containment around above-ground storage (frac tanks and ASTs) with enough volume to contain a release from a potential tank failure
- Insuring proper leak detection and prevention systems for in-ground impoundments are installed and monitored appropriately.

Frac tanks

Frac tanks typically have a small capacity (450 to 500 barrels) relative to the average need of wells (180,000 to 350,000 barrels). They are used for mixing of fluids before being pumped downhole but may also be used to store water before completion. Most commonly, multiple frac tanks (six to eight) are used as buffers to supply consistent flow rates during hydraulic fracturing. Regulations in some states have restricted impoundments or make them difficult to be permitted, thus encouraging the use of frac tanks. Some regions like the Marcellus/Utica use frac tanks almost exclusively.

Figure 2-17: Frac Tanks Lined up Side by Side in Oklahoma

Photo courtesy of Chesapeake Energy

While frac tanks such as these can be moved fairly easily, they are relatively expensive to rent for the volume of water stored. The tanks can be easily inspected and leaks are easily spotted.

Figure 2-18: Covered Tank

Photo courtesy of EJS Graham ©2016

This covered frac tank is set up by layering rings of metal to the correct height and then placing the liner. Best practices would be to place the tank in a lined secondary containment area with appropriate berms or dikes to capture any leaks; regulations may require secondary containment in some states. This type of tank has a series of valves for trucks to unload into the tank. The height helps provide hydraulic head to route the produced water to nearby facilities. These constructed tanks can be moved from site to site with relative ease.

Impoundments

Impoundments are the lowest cost option for storage over a period of years. New impoundments in the Permian and Oklahoma areas may have capacities up to 1,000,000 barrels, which is 2,000 times the capacity of an individual frac tank. Most states have regulations for the design and permitting of impoundments. One of the major risks to impoundments storage of produced water is potential leaks of the liners. Most in industry consider the dual lined impoundments with leak detection a reliable way to store treated produced water that is awaiting reuse. Permitting and construction of large impoundments can take from two to 12 months or more and may require additional permitting under other regulatory programs such as dam safety.

Figure 2-19: A Pioneer Drilling Rig Behind the Lined Containment Berm of a Water Storage Pond

Source: Pioneer Natural Resources

Impoundments to store produced water are usually dual-lined with leak detection. The height of the berm, the earthen wall, may commonly be 12 feet.

Above-ground storage tanks

Above-ground storage tanks (ASTs) are often rented for short and medium time frames (months vs. years) because they can be set up quickly and easily moved to a new site. These tanks can range from 4,500 to 62,000 barrels in capacity.[48,49] They are often 10 feet tall, with steel or plastic sides and open tops, and are lined with polyethylene liners to prevent leaks. ASTs have a reduced footprint compared to frac tanks for the same water volume.

Figure 2-20: Muscle Wall Above-Ground Storage Tank in Permian

Photo courtesy of Muscle Wall Holdings, LLC

Above-ground storage tanks have a reduced footprint compared to frac tanks for the same water volume.

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[48] David Nightingale, Rockwater Energy Solutions, "Water Storage Issues Bring Benefits of Above-Ground Storage Tanks to Surface," *E&P Mag: Look Outside the Tank*, June 2014, http://www.rockwaterenergy.com/ep-mag-look-outside-the-tank/.

[49] "Containment," Select Energy Services, http://selectenergyservices.com/content/uploads/2014/04/Containment.pdf.

Water Storage for Reuse

Challenges

- Permitting, bonding, and closure of impoundments
- Longer lead time for constructing impoundments
- Solids buildup including normally occurring radioactive material (NORM)
- Keeping costs low enough to compete against local disposal of produced water
- Preventing leaks and maintaining monitoring standards of produced water
- Preventing air emissions, especially volatile organic compounds (VOCs)

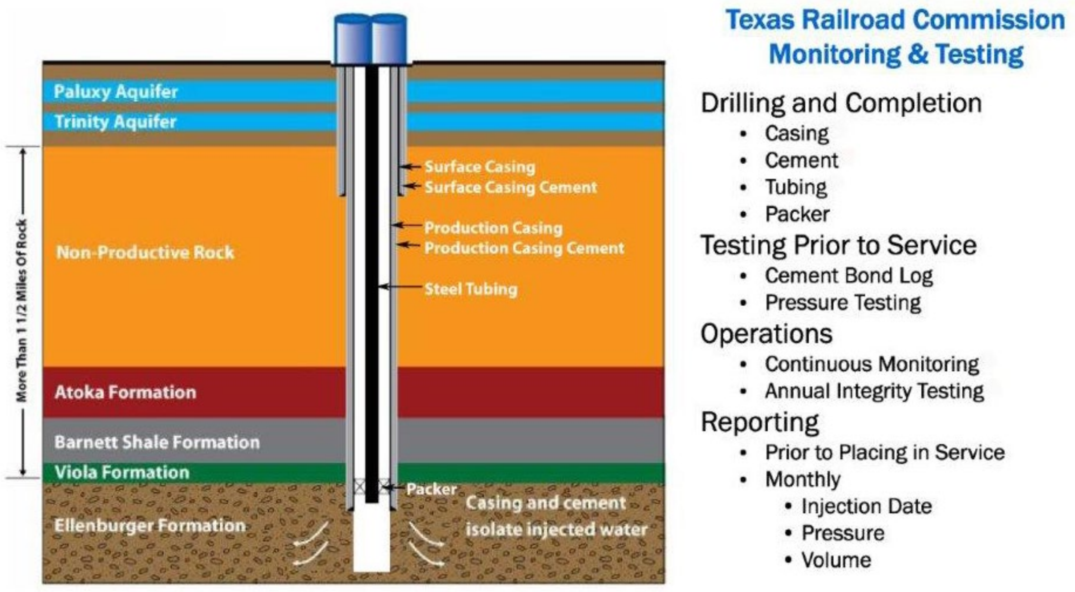
Opportunities

- Regulations that allow all types of water storage, including impoundments, as well as an effective permitting process and timeline (Example: A change in Texas impoundments rules by the Texas Railroad commission in 2013 greatly improved the adoption of large impoundments that led to additional water reuse.)*
- Reducing the difficulty for operators to share produced water and store in impoundments, whether by facilitating commercial permits or some other regulatory change

* Rick McCurdy, *Underground Injection Wells For Produced Water Disposal*, Chesapeake Energy Corporation (2011), https://www.epa.gov/sites/production/files/documents/21_McCurdy_-_UIC_Disposal_508.pdf.

Water Disposal in Injection Wells

Water disposal in injection wells has proven to be a reliable method for disposal of waste water from oil and gas operations since the 1930s. Disposal wells are typically regulated by the states under delegated authority from the EPA. Wells are designed with multiple strings of steel casing separated by cement layers to ensure that the wellbore fluids do not contaminate groundwater. Typically, produced water is injected into saline formations that were more saline than ocean water before the process started. Approximately 80 percent of the Class II injection wells are for enhanced oil recovery and the remainder are for disposal.



Texas Railroad Commission Monitoring & Testing

Drilling and Completion
- Casing
- Cement
- Tubing
- Packer

Testing Prior to Service
- Cement Bond Log
- Pressure Testing

Operations
- Continuous Monitoring
- Annual Integrity Testing

Reporting
- Prior to Placing in Service
- Monthly
  - Injection Date
  - Pressure
  - Volume

Figure 2-21: Well Monitoring and Testing Diagram

Source: After TRRC

In a typical water disposal well, thousands of feet (sometimes 10,000 or more) separate the USDWs from the disposal formation.

Discussions with water managers from producing companies indicate that having disposal capacity is a bigger concern in the Permian, Oklahoma, Haynesville, and Bakken basins/regions than in other areas.

While reuse of produced water within the industry is important where possible in order to save fresh water resources, having an option to dispose is also important.

Deep Well Disposal of Produced Water

Challenges

- Having appropriate permeable formations that allow sufficient injection rates
- Knowing whether disposal in a particular area could create induced seismicity
- Increasingly difficult and complex permitting in some states and regions
- Loss of a potentially valuable water resource

Opportunities

- Complementing water reuse sytems when produced water volume exceeds what is reusable
- Allowing an outlet for produced water when reuse is impractical
- Reducing disposal to increase reuse and reduce fresh water use
- Potentially recharging pressures in depeleted formations, allowing water intended for disposal to be used for enhanced oil recovery

Treatment of Produced Water for Reuse in Hydraulic Fracturing

Prior to about 2010 or 2011, most reused produced water for hydraulic fracturing was treated to reduce total dissolved solids (TDS) to a fresh level. This desalination was necessary because hydraulic fracture chemistries in use at the time required high quality water to create a highly viscous gel to carry the sand to formation. In 2004, Devon Energy established the first commercial reuse in the Barnett Shale using desalinated produced water.[50,51]

The Energy Water Initiative report in 2015 documented a trend toward more robust hydraulic fracturing chemistry allowing the use of lower quality water with high salinity.[52] Today, most reused produced water is minimally treated due to these advances in fracture fluid chemistry. This minimal approach—which treats only a few specific constituents to create “clean brine”— is significantly less costly than desalination. The most common items treated are bacteria, total suspended solids, iron, and a few other constituents. In some cases, only bacteria are treated.

Desalination

In limited cases, desalination is still done to provide an option that could meet discharge water quality requirements or reduce the potential risk from a spill. Companies using this treatment include Antero, Eureka, and Fairmont. Southwestern Energy had a desalination facility in its Fayetteville Shale operations, but that site is not currently treating produced water. Desalination of high salinity produced water tends to be very expensive and creates substantial solid waste that requires disposal. For example, a 20,000 barrel per day desalination plant processing 150,000 mg/L TDS brine could produce approximately 350 tons per day of solids.

The technology and operational efficiency of water treatment in oil and gas operations has improved markedly over the last 10 years. These improvements have helped facilitate the economic reuse of produced water in more situations by reducing costs for a variety of clean brine and desalination treatments.

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[50] “Water,” Devon Energy, https://www.devonenergy.com/sustainability/environment.

[51] “History,” Fountain Quail Energy Services, https://www.fountainquail.com/our-company/history.

[52] EWI, *U.S. Onshore Unconventional Exploration and Production Water Management Case Studies*, prepared by CH2M HILL ENGINEERS, INC. (January 2015), https://www.anadarko.com/content/documents/apc/Responsibility/EWI_Case_Studies_Report.pdf.

A related trend has been the development of permanent plants to sell some of the separated solids such as salt, calcium chloride, and iodine. The revenue from selling separated material has also helped offset treatment costs.[53,54]

One of the challenges to water treatment costs has been the lack of consistently available large volumes of water. Smaller volumes of water, less than 5,000 to 10,000 barrels per day, have fewer barrels over which to spread the fixed costs. The economies of large-scale systems that transport and treat large volumes of water (perhaps 50,000 barrels per day and up) offer lower costs per barrel. As the water pipeline infrastructure projects grow larger, the economies of scale should continue to reduce treatment costs.

Desalination Treatment of Produced Water

Challenges

- Reducing water treatment costs for smaller volumes of water
- Finding methods to dramatically reduce costs as pipeline systems aggregate larger volumes of water
- Determining the optimal blend of permanent plants and mobile treatment facilities to meet changing water volumes and pace of activity
- Developing sustainable water agreements to align with typical pace and changes in operational activity (i.e., ability to commit to plants without having committed water volumes)
- Managing treatment solids and residuals, including potential NORM and TENORM constituents, that pose regulatory and disposal challenges
- Regulatory constraints or prohibitions on discharge of treated produced water
- Ambiguous ownership of produced water in some states

Opportunities

- Reducing energy requirements to operate treatment facilities
- Improving separation of saleable solids such as salts and calcium chloride
- Finding effective methods to treat scale and other challenges associated with mixing different quality water sources
- Optimizing water quality for reuse
- Demonstrating that commercially viable treatment technologies can treat to discharge standards
- Resource preservation

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[53] Rick McCurdy, Chesapeake Energy Corporation, *Produced Water Treatment–A Look at Current Technologies, Challenges and Opportunities*, U.S. Department of Energy, Advanced Manufacturing Office (July 10, 2017), https://www.energy.gov/sites/prod/files/2017/08/f35/2017%20-%20Jul%20-%20AMO%20Clean%20Water%20-%20McCurdy.pdf.

[54] Rick McCurdy, Chesapeake Energy Corporation, "Treating Produced Water for Beneficial Use–Current Challenges and Potential Future Advances," Ground Water Protection Council 2016 UIC Conference (2016), http://www.gwpc.org/sites/default/files/event-sessions/McCurdy_Rick.pdf.

Enhanced evaporation

As an alternative to water reuse or SWD disposal, natural evaporation has been used to reduce produced water volumes in limited cases. The method is most widely reported in Wyoming (seven companies), followed by Colorado (four companies), Utah (four companies), and New Mexico (three companies). Disposal costs using enhanced evaporation ranged from $0.40 to $3.95 per barrel.[55] Using natural evaporation to reduce produced water disposal has generally not been effective because the rate of evaporation from a large impoundment is small compared to the amount of produced water. Natural evaporation is more cost effective in arid to semi-arid conditions. Ponds should be kept shallow as evaporation occurs only at the surface.

Some treatment companies offer enhanced evaporation as an alternative to desalination and discharge. A 2017 survey found costs to be 39 to 54 percent of desalination costs.[56] Enhanced evaporation may be most feasible when disposal and reuse are already fully employed. If the choice is between desalination and evaporation, evaporation may have more positives in some situations.

Figure 2-22: Evaporator

Photo courtesy of Logic-ES

Evaporation technologies range from thermal treatment to spraying pretreated water in the air in a contained area.

Enhanced Evaporation of Produced Water

Challenges

- Typically more costly than disposal if available
- Disposing of significant volumes of solids (unless evaporation is done simply to concentrate brine for disposal)
- Minimizing the risk of salt in evaporated steam (critical to local soil conditions)
- Need for quick startup (in months) when rigs and completions are restricted due to oil or gas price pullback
- Air emissions and emission control processes
- Lack of direct reuse opportunity

Opportunities

- Competitive costs (may be roughly half cost of desalination)
- Less rigorous permitting criteria and no water quality criteria for discharge
- Potential for new efficiencies as technologies and operations progress with more regular operations
- Reduced disposal volumes

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[55] National Energy Technology Laboratory, Fact Sheet–Offsite Commercial Disposal, https://netl.doe.gov/node/3179.

[56] OWRB, *Oklahoma Water for 2060 Produced Water Reuse and Recycling* (April 2017), https://www.owrb.ok.gov/2060/PWWG/pwwgfinalreport.pdf.

Environmental Challenges of Produced Water Management

The production, transport, storage, reuse, and disposal of produced water involves environmental risk. Because of its high saline content and other constituents, produced water can create numerous potential environmental impacts if it contacts soil or water bodies, including impacts on ecosystems and wildlife. In comparison to disposal options, reuse requires storing produced water in greater volumes for longer periods of time and transporting it from points of generation to the well site and in some instances to treatment facilities between the two. As water transfers increase, so do the risks of spills. Other potential environmental impacts can result from mismanagement of residuals generated from produced water treatment as well as air emissions.

Upstream oil and gas operations are typically regulated by several federal and state agencies, including state departments of environmental quality or natural resources or, in cases of federal or tribal lands, the Bureau of Land Management.

Managing the environmental challenges of produced water management requires minimizing and remediating spills and leaks, managing residuals, controlling air emissions, and taking actions to protect wildlife.

Minimizing Spills and Leaks

Surface spills and well casing leaks near the surface are the most likely pathways for oil and gas activities to contaminate drinking water sources and cause environmental damage. The depth separation between oil-bearing zones and drinking water-bearing zones in many areas makes direct fracturing into drinking water zones unlikely.

Methods of minimizing leaks and spills vary by the types of storage and transportation used.

- **Storage.** Key elements for surface impoundments may include double lining with leak detection and freeboard requirements, while for ASTs they are secondary containment, leak detection and overfill control, and fluid loading and off-loading operations to catch and retain potential spills.
- **Permanent pipeline infrastructure.** Permanent pipelines require appropriate design, considering physical and operating conditions including normal operating pressures and flows, pipeline material, pump station spacing, and control and isolation valves. Special considerations must be given to the crossing of roads, water courses, and environmentally sensitive areas. Equally important is construction oversight to ensure that construction meets design specifications and addresses any required field modifications during construction. Isolation valves are recommended on either end of a water or road crossing and at the boundaries of environmentally sensitive areas to allow the isolation and depressurization of these pipe segments in the event of a leak. Additionally, isolation valves should be located at defined distances along pipe segments. Leak detection for pipelines can be accomplished in many ways. A reliable standard method involves monitoring of pressure and flow and comparing the results to a system model of what pressures should be. Routine visual inspection of the pipeline route and right-of-way are likely to catch small leaks that the system monitoring may not find. In addition, continuous monitoring leak detection systems provide relatively quick and accurate identification of a leak and its location. These systems include negative pressure wave, real-time transient model, and statistical corrected volume balance.[57]
- **Temporary pipeline infrastructure.** The primary method of minimizing leaks and spills is routine inspection of the lines.

The design and construction of an impoundment, tank, or pipeline is a project encompassing not just design by qualified individuals but oversight and quality assurance during construction. Design plans and specifications should be developed and may need to be sealed by a professional engineer. However, that is not where the involvement of design personnel ends. Construction oversight by qualified individuals must also occur during construction.

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[57] Tina Olivero, “Drastically Reducing Pipeline Oil Spills,” *OGM™* (Our Great Minds Online Magazine: 2017), https://theogm.com/2018/05/16/drastically-reducing-pipeline-oil-spills/.

This oversight will include documenting all field modifications to address conditions encountered that were not accounted for during design, checking field modifications against design parameters and getting sign-off by the designer if needed, verifying field quality control requirements are met, and developing final as-built plans documenting the facility as it was constructed.

An effective way to ensure proper construction oversight is by developing and implementing a Construction Quality Assurance (CQA) plan. A formal CQA establishes procedures to document that construction is in accordance with the approved engineering plans and specifications and meets appropriate regulatory requirements. It also provides a paper trail to verify that specified activities are properly completed. Verification is achieved through a CQA report documenting the extent to which construction was performed in compliance with design drawings and specifications.

Ongoing inspection and maintenance are required throughout the course of operating impoundments, tanks, or pipelines. Elements include routine inspection, the use of remote sensing technology, and a program to correct identified issues and verify repairs are completed properly. A checklist is an effective tool in both conducting and documenting this effort. For in-ground impoundments, inspections of the berms and liners are important. For steel tanks, corrosion monitoring is appropriate.

At the end of a facility's service life, any impacts from operation must be addressed (starting with identification and followed by remediation and verification of completeness of any response action). Tools and programs will be different but typically include a level of financial assurance to provide for future closure/decommissioning costs.

Remediating Spills

Oil and gas produced water is often much saltier than sea water and can damage soil if large amounts spill or leak during storage or transport. In fact, a produced water spill can cause much more long-term damage to land than an oil spill. Various studies of reported spills of produced water indicate that the majority are small spills. The typical small spill may have limited impact and can be remediated a variety of ways. These small spills can however persist for decades and rarely naturally remediate, primarily as a result of the high salinity that impacts both vegetation and soil structure. Remediation of the brine impacts typically includes flushing of the soil to reduce the salt content in the plant root zone and rebuild the soil structure (addressing the cation and anion imbalance), and revegetation to re-establish the ecosystem and counter erosion. Revegetation can take multiple years, depending on severity of the spill.

Beyond salt, produced water can contain many chemicals[58] that are either present in formation water or known to be used in the well completion or maintenance processes. Chemicals may range from ethylene glycol (antifreeze) to hydrochloric acid and could include radionuclides (from NORM). Regulator-approved chemical detection methods only exist for about a quarter of the potential chemicals.[59]

Minimizing and Remediating Spills

Challenges

- Minimizing large and small spills in all aspects of water management and reuse
- Developing cleanup standards and remediation techniques for various environmental media (surface water, ground water, drinking water, soil, pad materials, wetlands and other environments) for a variety of spill types including produced water

Opportunities

- Limit risk and impact of water spills using automation and leak detection technologies
- Limit risk and impact of water spills using proper design and operating practices in containment and transport

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[58] Karl Oetjen, Colorado School Mines, "Emerging analytical methods for the characterization and quantification of organic contaminants in flowback and produced water," *Trends in Environmental Analytical Chemistry 15* (2017), 12–23.

[59] Dan Mueller, "Water Management Associated with Oil and Gas Development and Production," *EM*, August 2017, http://blogs.edf.org/energyexchange/files/2017/09/emaug17.pdf.

Residuals Management

The most common residuals with minimally treated produced water are suspended solids that may be separated in the treatment process or settle in the water storage impoundments or tanks. These solids must be disposed of according to state regulations. Often the solids will be sent to landfills. If the solids contain NORM that is concentrated through industrial processes, they may be classified as "technologically enhanced naturally occurring radioactive material" (TENORM) and must be disposed of in hazardous waste landfills designed for such materials. Management of the solids creates an additional cost to the reuse process and may introduce separate risks. Typically, the residuals may contain salts that will potentially create risks to groundwater if they leak from the landfill. Transporting any elevated concentrations of NORM or TENORM from the treatment site to the special landfill also introduces potential risks. In some cases, residual solids may have a marketable value that can help offset the costs of treatment. However, it sometimes is not clear who owns these saleable solids.

In some treatment processes, a residual concentrated brine may be produced. This brine would normally be disposed in a disposal well. The disposal of concentrated brine can reduce the volume of solids needing disposal.

Residuals Management

Challenges

- Designing processes that limit solid waste
- Handling solids appropriately and preventing environmental impacts from residuals
- Being particularly cautious with NORM and TENORM management and disposal, which is becoming an increasingly regulated aspect of oil and gas operations

Opportunities

- Selling marketable products from residuals when possible to offset treatment costs

Managing Air Emissions

Air emissions from produced water in tons per year would vary depending on what type of storage is being used and the throughput that storage can accommodate. Some produced water could be transported to a large impoundment in volumes that result in permit/notice triggering levels of volatile organic compounds (VOCs) being released. Emissions must be managed in accordance with state and federal regulations. For example, methanol is a common additive in hydraulic fracturing and production operations. It is considered a VOC. Methanol emissions from water impoundments have been an issue infrequently. One conclusion of a whitepaper examining the use of methanol in hydraulic fracturing was that "Because of methanol's low tendency to volatilize out of water and into air, methanol will practically not volatize from flowback ponds."[60] However, since methanol has a boiling point much lower than water, thermally enhanced evaporation or distillation processes will allow methanol to volatize before water vapor, which may require that it be trapped or scrubbed from the emissions.

Water treatment, especially desalination, may involve heating produced water with natural gas. The burned natural gas will increase CO_2 emissions and may increase emissions of other gasses such as sulfur dioxide (SOx) and nitrogen dioxide (NOx), which may change permitting criteria for a facility.

Hydrogen sulfide (H_2S) is naturally present in some producing formations or can be a byproduct from bacteria growth in stored produced water, especially during hotter months. The amount generated from an impoundment is typically low, but H_2S is a potential safety and health concern if concentrated. Low levels of H_2S can create a bad smell and a nuisance. Most producing companies have established operations to prevent H_2S growth in impoundments, including relatively simple methods of circulating the water and aerating the ponds. Additionally, there are mechanical and chemical methods available to remove higher levels of H_2S from water.

Air Emissions Management

Challenges

- Preventing VOCs, H_2S or other air emissions that could create any risk to health or safety
- Effectively monitoring air emissions from water reuse operations

Opportunity

- Establishing water reuse operations and systems that minimize air emissions and keep overall emissions from upstream energy operations as low as possible

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[60] Tarek Saba, et al., "White Paper: Methanol Use in Hydraulic Fracturing Fluids" (Methanol Institute: Alexandria, Virginia, January 20, 2012), http://www.methanol.org/wp-content/uploads/2016/06/White-Paper-Methanol-Use-in-Hydraulic-Fracturing-Jan-11.pdf.

Preventing Potential Impacts to Wildlife

State and federal regulations apply to protect wildlife around oil and gas operations. Federal statutes, such as the Migratory Bird Treaty Act,[61] provide substantial penalties for the death of many species of birds that could occur from contact with oil in an open top tank or impoundment. Some states require bird abatement for produced water storage. Common forms of prevention may involve netting or a sound source to prevent birds from landing. Netting is not typically practical for large impoundments.

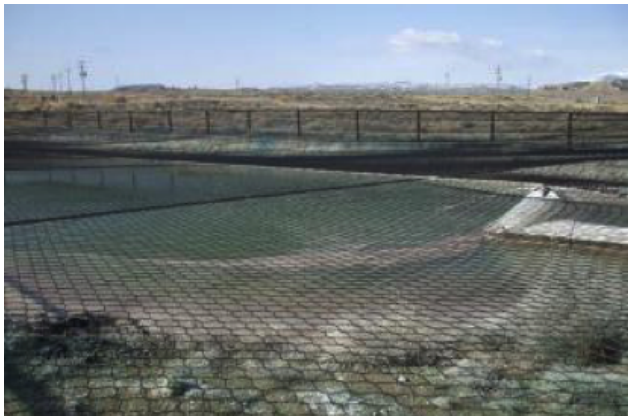

Figure 2-23: Netting over Impoundment

Photo courtesy of American Netting, LLC

Netting can be used over open tanks or impoundments to prevent birds from landing.

It is important to keep animals from being trapped in an impoundment due to a slippery liner. Often, fences around the impoundment secure the area and protect walking wildlife. Companies also want to prevent deer and cattle from walking on the liner, since their hooves may puncture the liner and trigger the leak detection system.

Protecting Wildlife

Challenges

- Preventing any occurance of wildlife impact over the long life of an oil and gas development
- Deterring birds from produced water impoundments and tanks, which may be attractive to them as water sources
- Preventing trucking hazards to deer and other wildlife

Opportunities

- Building water pipeline systems that can have less impact on wildlife than trucking
- Protecting and enjoying wildlife

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[61] *Migratory Bird Treaty Act of 1918* (16 U.S.C. 703-712; Ch. 128; July 3, 1918; 40 Stat. 755) as amended by: Chapter 634; June 20, 1936; 49 Stat. 1556; P.L. 86-732; September 8, 1960; 74 Stat. 866; P.L. 90-578; October 17, 1968; 82 Stat. 1118; P.L. 91-135; December 5, 1969; 83 Stat. 282; P.L. 93-300; June 1, 1974; 88 Stat. 190; P.L. 95-616; November 8, 1978; 92 Stat. 3111; P.L. 99-645; November 10, 1986; 100 Stat. 3590 and P.L. 105-312; October 30, 1998; 112 Stat. 2956 https://www.fws.gov/laws/lawsdigest/migtrea.html.

Regulatory and Legal Challenges and Opportunities

Management of produced water is subject to a complex set of federal, state, and sometimes local regulations that may address a wide range of topics (permitting, siting criteria, bonding, water acquisition, temporary storage alternatives, facility construction, facility operations, liabilities for misuse, discharge reporting and response, environmental monitoring transport, infrastructure, land disturbance, reclamation, treatment technologies, beneficial use, recycling, reporting site closure, and decommissioning). The purpose of state and federal regulations is to allow for orderly and efficient development of resources while ensuring protection of the environment, public health, and safety.

Regulations evolve over time in response to such factors as emerging practices, new technologies, and identified risks that are not adequately addressed by existing regulations. In the case of produced water management, the emergence of unconventional resource development has led to new midstream approaches to water gathering, storage, treatment, and distribution for use. These midstream operations are often outside of traditional state regulatory frameworks and require state authorization and oversight for activities that are neither associated with permitted oil and gas operations, nor facilities at Class II underground injection operations. For example, the surface storage of produced water may entail the use of impoundments, which may be regulated by a state agency other than the state oil and gas agency. Determining how these impoundments would be regulated and by which state agency or agencies will require a thorough review of current statutes and authorities. State laws typically establish broad performance objectives and empower one or more state agencies to promulgate more specific regulatory standards, with authority to enter properties and enforce state standards. This process will need to be repeated with respect to midstream water management companies and will take time. In the meantime, rapid growth of such companies could lead to potential problems for which no or only a limited regulatory response is available.

In response to the emergence of a midstream produced water industry, some state legislative bodies have passed laws to authorize these emerging practices. For example, in 2014, the Ohio General Assembly enacted Am. Substitute House Bill 59, authorizing the Ohio Division of Oil and Gas Resources Management to develop new rules to establish requirements for permitting and operating new facilities that will temporarily store, recycle, treat, and/or process produced water not associated with sites permitted for drilling and completion of oil and gas wells or Class II injection wells. By law, Ohio now authorizes new facilities by permit until such time that rules are enacted.

In recent years, some states have enacted rules that address specific components of the challenges posed by emerging practices. For example, prior to 2013, Texas producers were having difficulty obtaining permits for impoundments to store produced water to facilitate reuse. The issue was often just the difference in time to obtain a permit as compared to the fast-changing drilling plans. The Railroad Commission of Texas changed the requirements for permitting to allow permits by rule under certain conditions. The revised Statewide Rule 8 (16 Tex. Admin. Code §3.8) allowed companies to implement water reuse impoundments in a timelier fashion and reuse has grown over time.

The Ground Water Protection Council and Interstate Oil and Gas Compact Commission can facilitate the exchange of applied research, emerging standards, and continually improving regulations to assist states in developing and implementing effective regulatory frameworks. The State Oil and Gas Regulatory Exchange program provides a process for the exchange of ideas as state regulations evolve.

The Oklahoma Corporation Commission (OCC) has revised bonding requirements associated with storage impoundments to support produced water reuse. This bonding provides the state with the funds necessary to close any water impoundments left behind in the event of a bankruptcy. In this regard, the Oklahoma Corporation Commission (OCC) requires bonding on a per barrel of water storage capacity at a water treatment facility. The trend in water storage is to construct impoundments to accommodate the larger hydraulic fracturing completions being performed. Typically, multiple impoundments will be necessary to effectively reuse produced water in a service area of a recycling facility, potentially leading to multi-millions of dollars of bonding requirements in a relatively small play area. This bonding requirement has been identified by producing companies as a potential deterrent to produced water reuse. The OCC has been working cooperatively with industry on this issue so as not to discourage recycling of produced water, while at the same time remaining environmentally protective. The OCC will review new application bonding requirements on a case-by-case basis with an eye toward potential use of blanket bonding for multiple recycling facilities by producers.

Most producers and state regulators agree that states are better able to craft regulations that address regional conditions instead of applying a blanket federal regulatory framework on operations. The corollary of states having varying rules is that companies must understand all the variations for the states where they operate. Statutes and regulations that optimize and balance both flexibility and environmental protection will encourage reuse. Where reuse of produced water is important to an individual state, evaluating the differences between its laws and regulations with those of similarly situated states might result in changes that could encourage reuse.

The Case for Improved Reporting

Neither federal regulators nor most states require reporting of the source of the water used for completions or hydraulic fracturing. Companies often report on their websites if they are reusing produced water in a specific region. Most states require that operators report water volumes and chemicals used during hydraulic fracturing in their FracFocus® reports by well. It is not a requirement to report the source or the quality of the water used, which may be surface water, groundwater, treated wastewater effluent or produced water (reuse).

State regulators continually balance the need for data to evaluate compliance with the risk of increasing operating costs and potentially reducing economic activity. The lack of full information about reuse frequency and produced water availability will limit policymakers' understanding of the issue when it may become more important. For example, in the event of a drought or disposal problem, regulators may have a limited ability to determine how important reuse could be in helping with a potential solution.

INFORMATION IS CRITICAL

The lack of full information about reuse frequency and produced water availability will limit policymakers' understanding of the issue when it may become more important.

Produced water reuse is a relatively new priority in this fast developing and changing industry. The *Journal of Petroleum Technology* concluded that "Improved reporting is needed to guide the industry and regulators as they look for solutions and figure out how to manage scarce resources, particularly the limited capacity of subsurface formations used for water injection."[62]

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[62] Stephen Rassenfoss, "Rising Tide of Produced Water Could Pinch Permian Growth," *Journal of Petroleum Technology*, June 12, 2018, https://www.spe.org/en/jpt/jpt-article-detail/?art=4273.

Research Needed to Facilitate Produced Water Reuse

Most producing companies interviewed for this report do not see significant research needs or opportunities related to water reuse within oil and gas operations. Breakthroughs in water transport, a major operational and cost barrier to reuse, are viewed as unlikely, since pipelines and pumps for produced water are mature technologies. However, the interviews identified the following areas as potentially valuable.

- **Leak detection**. Optimization of leak detection is potentially promising. Monitoring systems for real-time detection of leaks in saltwater pipelines flag pressure changes that are inconsistent with the rate of pumping. This technology for large high-rate saltwater systems is immature and research may help improve operational efficiencies. More sophistication with controls from the impoundments and pumping may also be beneficial.
- **Addressing specific water treatment challenges**. Some producing companies identified water treatment as an area where technology improvements could potentially be very beneficial. They noted that, while service providers have already substantially reduced water treatment costs in recent years, technical challenges are periodically encountered due to unique water quality or mixing. Problems may relate to scale buildup or a specific analyte such as barium, sulfate, iron, or some other component. Research by universities and water treatment companies to improve solutions for specific treatment problems could help reduce costs for reuse and increase reuse volumes.
- **Improvement in enhanced evaporation or desalination**. Advances in enhanced evaporation technologies could be beneficial in reducing the risk of salt carry over into the steam or spray. Also, enhanced evaporation or desalination that concentrates the brine to near saturation without creating solids would reduce the potential impact of managing large amounts of solids in landfills.
- **Automation in treatment systems**. Research on treatment systems that can be operated remotely with little or no human intervention offer the potential for labor cost savings.
- **Separation of saleable products during treatment**. Water treatment costs can be partially offset when treatment companies separate out saleable products. Analytes such as iodine or lithium may be separated when in higher concentrations, even without full desalination of the produced water. For example, Iofina—a company involved in the exploration and production of iodine, iodine specialty chemical derivatives, and produced water and natural gas—is separating iodine found in higher-than-normal concentrations in the produced water of one Oklahoma operator. Research could further the separation of saleable products by determining the best saleable products, and processes to create the products.
- **Water treatment research needs**. Companies also touched on water treatment research needed to facilitate water reuse outside the oil and gas industry through discharge or use in another industry. To date, the discharge of produced water has been rare, hindered by the high costs of required desalination and other treatments. Yet, from an operational perspective, some producers contend that discharge may need to be integrated into long-term water management strategies, especially in plays with limited disposal compared to the volume of produced water (e.g., the Marcellus in Pennsylvania, the STACK in Oklahoma, and the Delaware Basin in New Mexico and Texas). Discharge also might be built into water planning for periods when drilling and completion activities drop. In those periods, the same water network that normally moves water to where it is needed for reuse within the oil and gas industry could transport it to a desalination treatment facility that allows the water to be used in another industry or discharged. Research into automation, low energy treatment options, and low-cost capital facilities will be important.

Another potential route to offsetting costs is the separation of saleable products during treatment processes. Separation of products has even more potential when treating for discharge rather than for reuse in the oil and gas industry, since desalination is involved. Research is needed to determine what useful products can be created and which processes are best to create the materials. Module 3 discusses this further.

- **Regulatory changes needed to facilitate discharge**. Enabling the surface discharge of appropriately treated produced water will require regulatory changes, which may include modifications to storage requirements, NPDES discharge permitting, transportation requirements, and others.

REGULATORY UPDATE NEEDS

Enabling the surface discharge of appropriately treated produced water will require regulatory changes, which may include modifications to storage requirements, NPDES discharge permitting, transportation requirements, and others.

Policy Initiatives to Facilitate Reuse

Producers interviewed for this report raised several consistent themes when discussing how state and local policies may support or inhibit increased water reuse.

- **Tracking water transfers**. Regulators in some areas of the Marcellus/Utica region could facilitate reuse by reducing requirements to track produced water moved from site to site by actual barrels. The barrels cannot be definitively tracked when they are mixed together in storage.
- **Commercial designation**. In some states, water management requirements for non-commercial reuse are more flexible than for commercial reuse. While the commercial regulations usually set a higher standard, sometimes they prevent companies from working together efficiently to reuse produced water. With the trend toward larger reuse systems and water sharing, regulations should be reviewed to assure they strike the right balance between resource protection and reuse
- **Storage**. Companies want the flexibility to use the best operational option for the situation. In some cases, states limit or prohibit impoundments for storing treated produced water. In many situations, the alternate produced water storage options are substantially more expensive and deter reuse.
- **Temporary layflat lines**. If temporary layflat hose is not permitted to transport produced water the last mile or two to the well site, the alternatives are less feasible. Trucking water for the last short run or running permanent pipe to every well site may increase costs dramatically and increase the impacts related to truck traffic.
- **Right-of-way on county roads**. Right-of-way on county roads can enable water transport via permanent or temporary pipelines. Water reuse is hampered in counties that prohibit this possibility.
- **Timely permitting**. If operators encounter lengthy permit approval times for reuse operations, they will tend to default to local sourcing and disposal to meet completion schedules. Speeding up approval times will support greater water reuse. Some companies have been critical of the historically slow process of obtaining an NPDES permit to discharge produced water, reporting that in some cases it can take two years, which is much longer than the companies' well planning cycle. It should be noted that there are many reasons why the permitting process may take longer than expected including insufficient program funding, problems with the application, communication and response time-lags, and others. Also, Bureau of Land Management (BLM) water-related permitting processes are reportedly much slower than state processes.
- **Clarity of regulations**. Companies mentioned that variation of rules from state to state can complicate their efforts to understand and comply with the intentions of the regulations.

- **Incentives**. Some companies mentioned that incentives such as state or federal tax deductions for water reuse would be helpful. However, any incentives should consider possible unintended consequences and the associated administrative effort to implement the plan.
- **Produced water ownership**. Companies cite ambiguity related to produced water ownership as a potential impediment to produced water sharing and reuse. In some states, they report it is not clear that the producer can sell or transfer water to another producer. In most basins, produced water does not have any value if one tries to sell it. If it has value, it is often less than the cost to treat and transfer the water. In some instances, surface owners may claim a right to a royalty to any water that is treated and sold.

Water Management and Produced Water Reuse by Region

Water management practices, including produced water reuse, vary substantially from region to region. This section focuses on the top seven basins/regions based on oil and gas production and current drilling activity: the Permian, Appalachian, Bakken, Niobrara, Anadarko, Haynesville, and Eagle Ford basins/regions, shown in Figure 2-24. In this report, the Permian is sometimes referred to as its component Midland and Delaware sub-basins, and the Appalachia as the Marcellus/Utica play. Central Oklahoma is a sub-basin in the Anadarko.

Overview of Regional Differences

Significant variables affect water management across these regions. Some have appropriate geology for water disposal and wide availability of permitted underground injection control (UIC) wells, while others have very limited access to disposal. Some areas have abundant supplies of surface water or groundwater, while others are relatively arid. Some are primarily rural regions, others more urban. The amount of produced water from a typical well varies by region, as does the quality of the produced water. Differences in topography determine the feasibility and cost effectiveness of developing water pipeline systems. Applicable state and local regulations vary by region, as do landowner and mineral lease requirements relating to the use of water. Some regions are affected by potential seismicity concerns associated with disposal well injection into specific formations.

Currently, the Appalachia basin with its Marcellus and Utica formations of Pennsylvania and West Virginia has the highest rate of produced water reuse. Primary drivers for the Appalachian region's reuse have been the extremely limited number of regionally available disposal wells and the high costs of transporting water to these distant wells. Pennsylvania has less than 10 permitted disposal wells for produced water; in comparison, Texas has over 8,000 permitted and operating disposal wells.[63,64]

The second highest level of reuse is occurring in the Permian Basin of west Texas and New Mexico. Despite its large disposal capacity, the Permian Basin has had significant increases in reuse projects over the last two years, driven by rising costs for other source water and increasing costs for disposal injection wells due to high demand.

Figures 2-25 to 2-41 highlight the relative production of the top basins and contrast differences in their water use and management.

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[63] "Injection and Disposal Wells," Railroad Commission of Texas (RRC), http://www.rrc.state.tx.us/about-us/resource-center/faqs/oil-gas-faqs/faq-injection-and-disposal-wells/.

[64] Rick McCurdy, *Underground Injection Wells For Produced Water Disposal*, Chesapeake Energy Corporation (2011), https://www.epa.gov/sites/production/files/documents/21_McCurdy_-_UIC_Disposal_508.pdf.

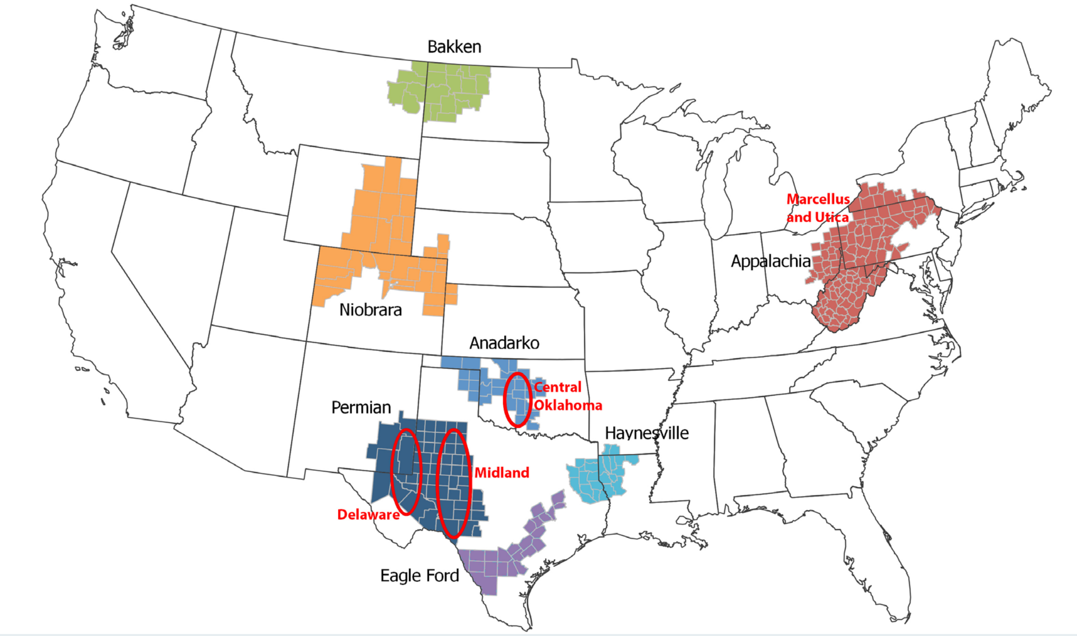

Figure 2-24: Select Oil and Gas Producing Basins/Regions in the Continental U.S.

Source: EIA https://www.eia.gov/petroleum/drilling/

The top seven basins/regions based on oil and gas production and current drilling activity are the Permian, Appalachian, Bakken, Niobrara, Anadarko (includes Central Oklahoma), Haynesville, and Eagle Ford.

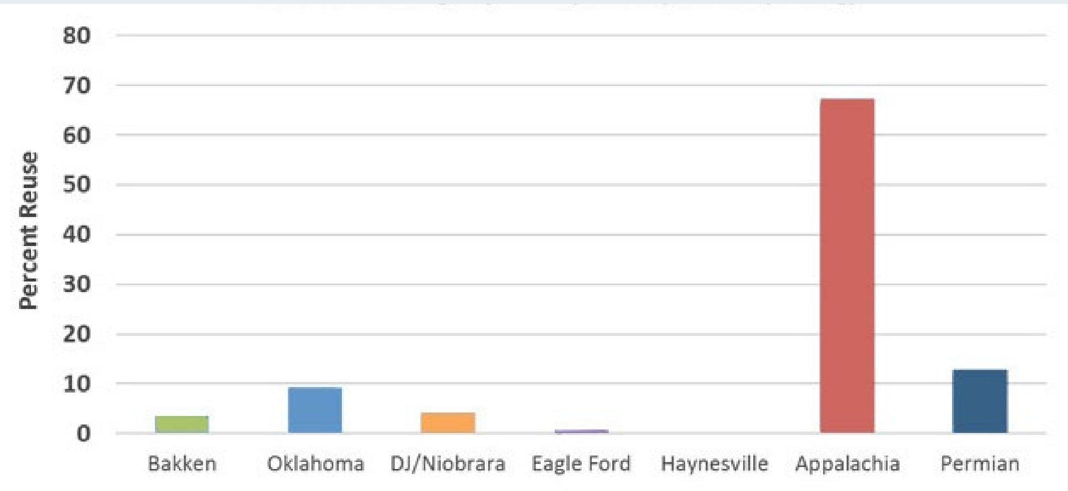

Figure 2-25: Reuse Percentage for Key Basins (18 Companies Reporting)

Source: Jacobs Engineering

Produced water reuse is highest in the Appalachia and Permian Basins. This figure is based on data collected for this report from 18 producing companies and aggregated by basin/region with help from the American Petroleum Institute. The weighted average reuse was 10 percent but varied from 0 to 67 percent across the seven basins considered. The reuse volume was divided by the lower of the water sourced or water produced in the basin. The sourced water was higher than the produced water in four of seven basins. The 18 producing companies contributing data for this report accounted for 29 percent of the total water sourced in the seven basins in 2017.

Top Producing Basins

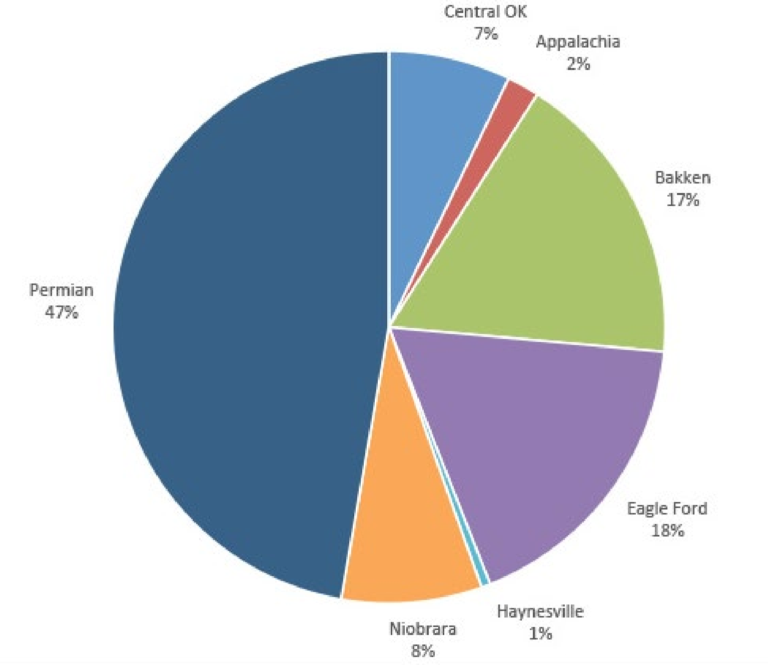

Figure 2-26: U.S. Onshore Oil Production by Basin December 2018

Source: After EIA

The Permian is the leading onshore oil-producing basin, followed by Eagle Ford and Bakken.

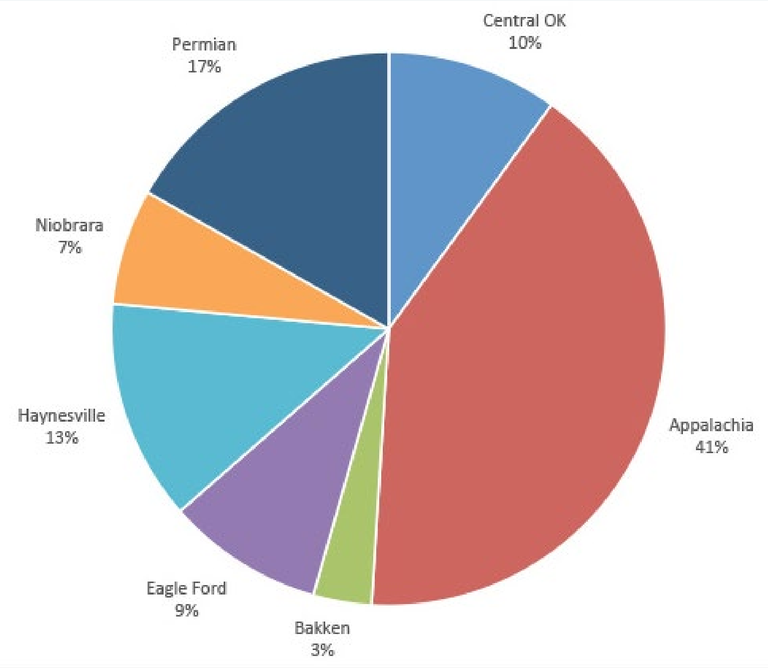

Figure 2-27: U.S. Onshore Natural Gas Production by Basin December 2018

Source: After EIA

In natural gas production, the Appalachia is the leading basin, followed by Permian and Haynesville. Generally, the higher the oil or gas production, the more drilling and well completions have occurred. Higher activity will correlate to higher water source demands and, to some extent, to produced water production rates. Higher activity may also correlate to higher produced water reuse opportunities.

Trends in Production for Leading U.S. Basins

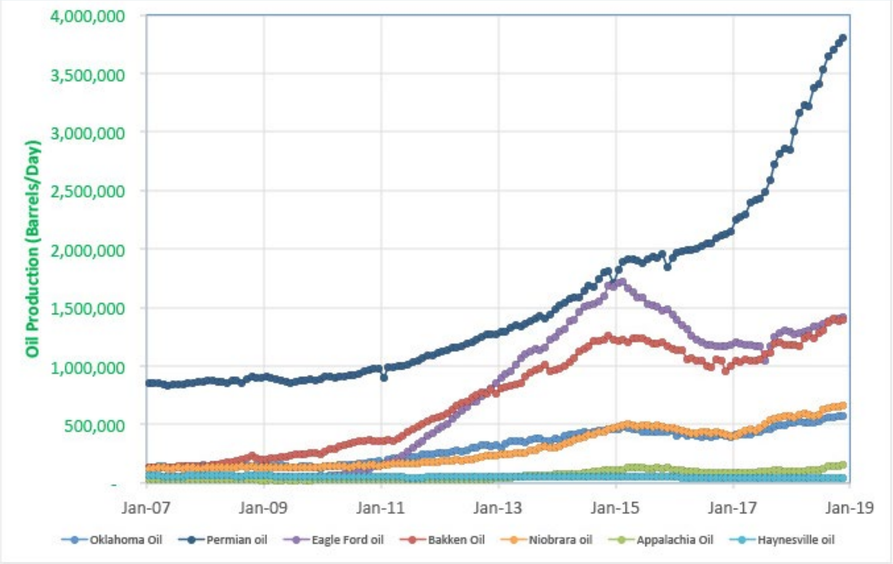

Figure 2-28: Oil Production for Major Basins/Regions

Source: After EIA

Well completion activity and oil production growth rates have varied over time based on changing technical understandings of the economic viability of the basins. Oil production in the Permian was high in 2007 from conventional production. The Bakken grew faster than the other areas from 2007 to 2011. The Eagle Ford production grew dramatically from 2011 to 2015. The Permian Basin is the only oil producing basin that continued to grow when oil prices fell in late 2014 and early 2015. Production dipped in the other basins, then resumed a growth trend around January 2017 as oil prices recovered.

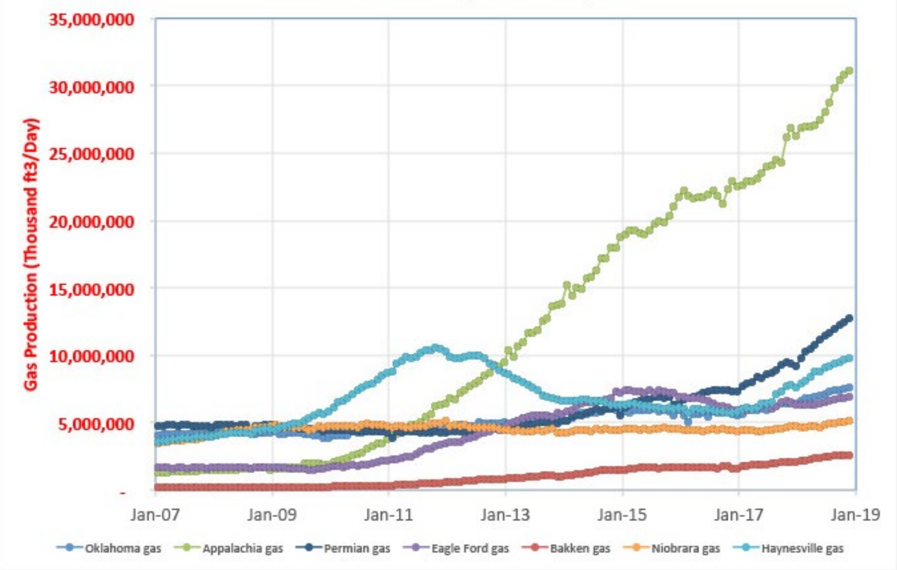

Figure 2-29: Natural Gas Production for Major Basins/Regions

Source: After EIA

Natural gas production has grown dramatically in Appalachia, driven by high-rate well production and proximity to the East Coast gas market. The other basins resumed their increasing production trend starting around January 2017. The Appalachia and Haynesville areas are the only pure gas plays. The others are primarily oil plays with associated gas that is produced with the oil.

Rig Counts Across Major Basins

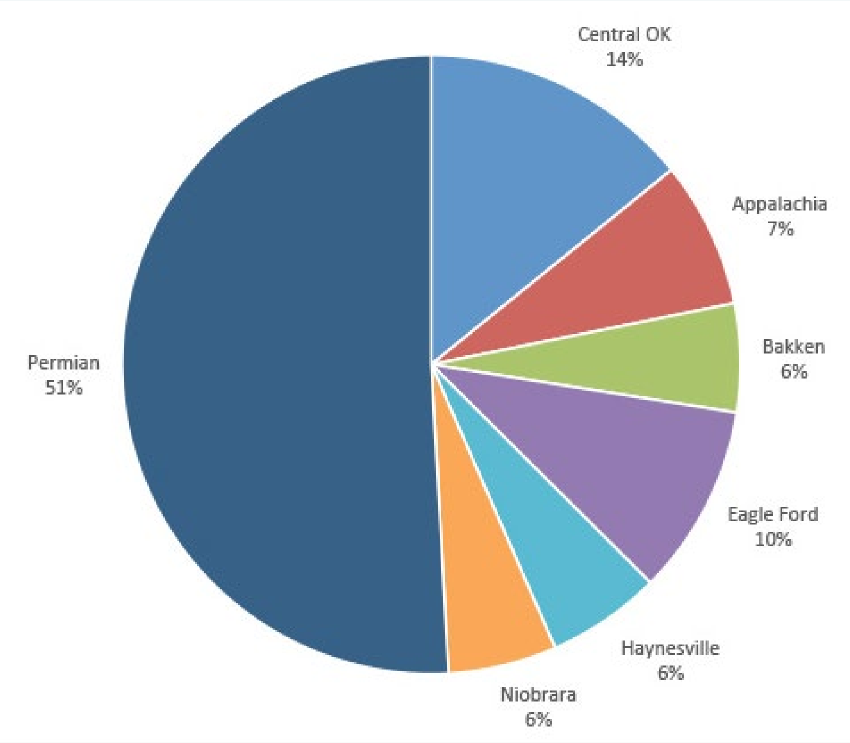

Figure 2-30: U.S. Onshore Rig Count by Basin December 2018

Source: EIA

The Permian basin had just over half of the U.S. onshore rigs in December 2018. High rig count is an indicator of a region's having economically viable wells and foretells potential production growth. Higher rig counts increase demand for sourced water for hydraulic fracturing which, in turn, will eventually lead to higher water production.

Distribution of Water Use for Hydraulic Fracturing

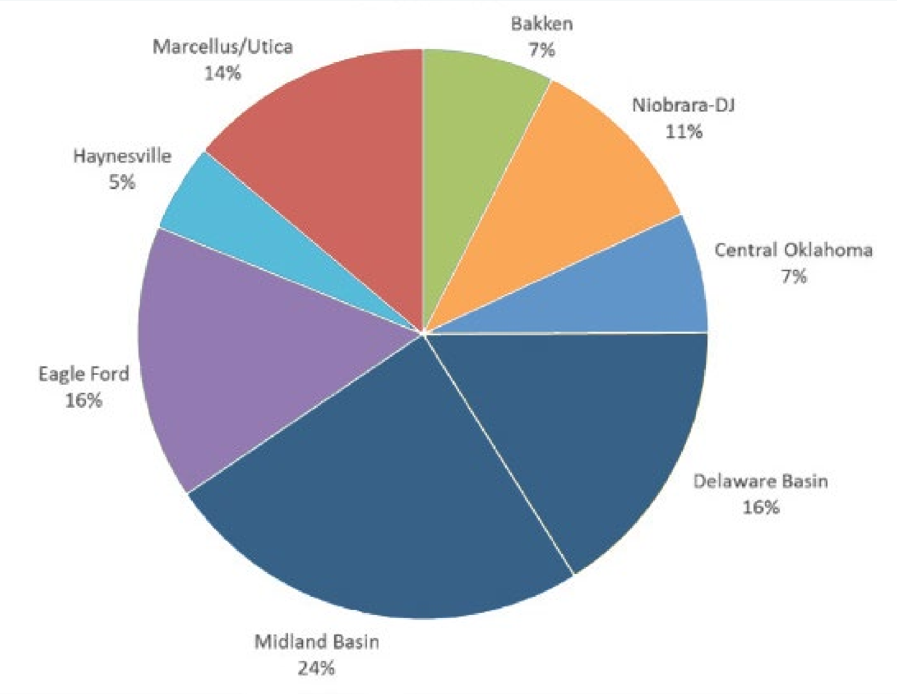

Figure 2-31: Water used in Hydraulic Fracturing for Top Basins/Regions in 2017

Source: After FracFocus® http://www.fracfocus.org

The Permian, Eagle Ford, and Appalachia regions accounted for 70 percent of the water used for hydraulic fracturing in 2017 across the key basins. The Permian (Delaware and Midland sub-basins) accounted for the greatest volumes, using 40 percent of the total across the key basins.

Water Disposal by County (Based on Available Data)

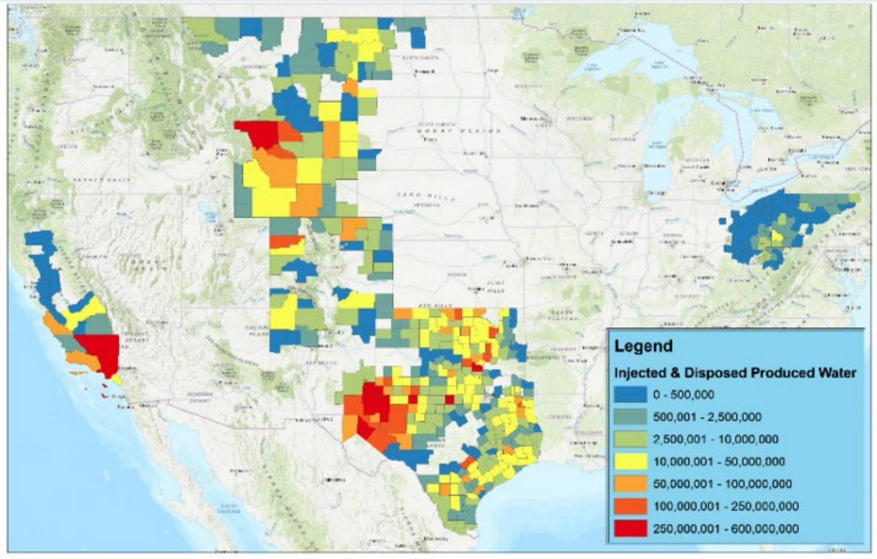

Figure 2-32: Injected Produced Water by County (bbl.) in 2017

Source: IHS Energy Group

Counties with high water disposal volumes—a proxy for high water production—are highlighted in red, orange, and yellow and are mostly concentrated in Texas and Oklahoma. This figure shows the estimated volume of injected produced water in barrels generated at a county level in 2017, where available. These volumes are a proxy for water production, but do not account for reuse or water crossing county lines.

Water Use for Hydraulic Fracturing per Well

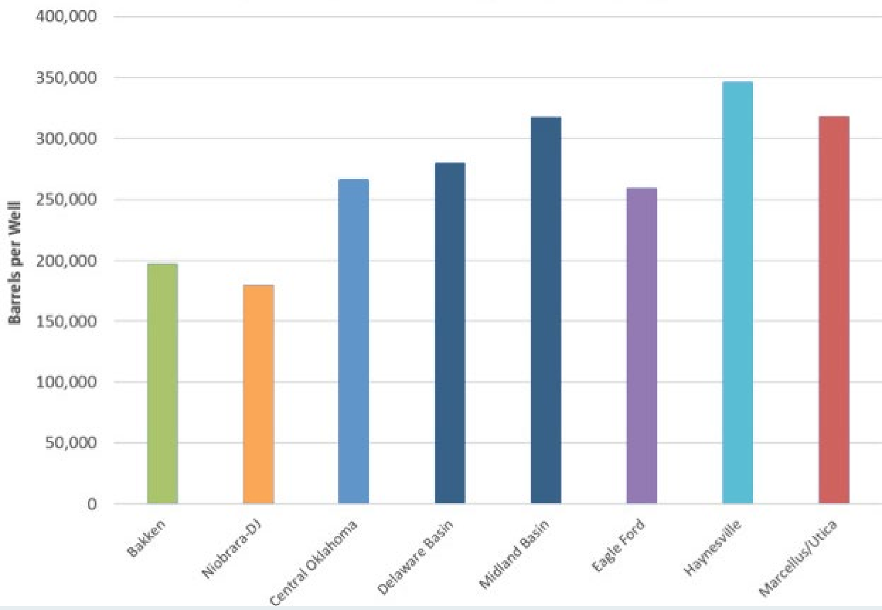

Figure 2-33: Water Use per Well in Hydraulic Fracturing for Key Basins/Regions in 2017

Source: After FracFocus®, http://www.fracfocus.org

The Haynesville and Marcellus natural gas-producing formations and the oil-producing Midland Basin used the highest water volumes per well in 2017. Per-well water use for hydraulic fracturing varies by formation properties and the length of the horizontal. Larger volumes of water needed and produced can provide the economics of scale to make reuse more viable. The multi-year trend has been for wells to use more water in their completion than previously required.

Typical Water Production by Well

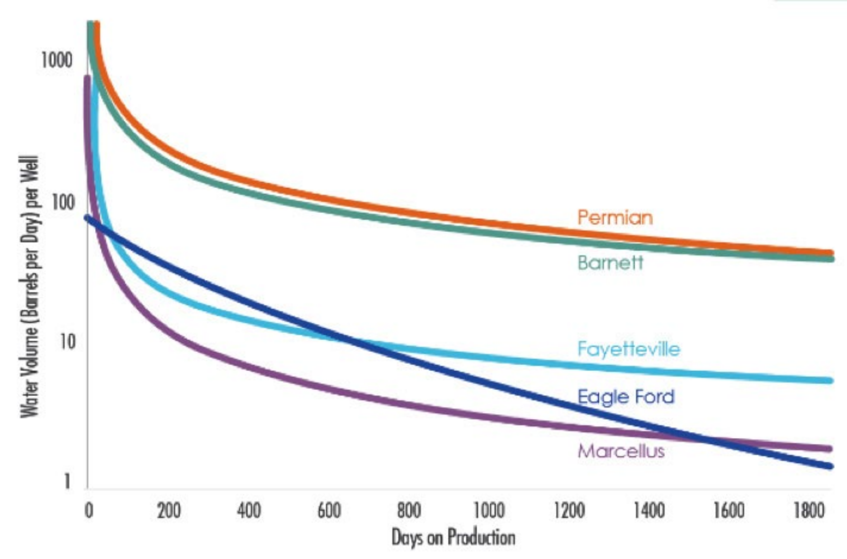

Figure 2-34: Typical Water Production by Well

Source: Energy Water Initiative 2015 Case Studies Report https://www.anadarko.com/content/documents/apc/Responsibility/EWI_Case_Studies_Report.pdf

While water production generally increases over time in conventional wells, it usually declines in unconventional wells in line with the well's oil and gas production. Declining water production can make single sourcing of reused water challenging or less viable.

Ratios of Produced Water to Sourced Water by Basin

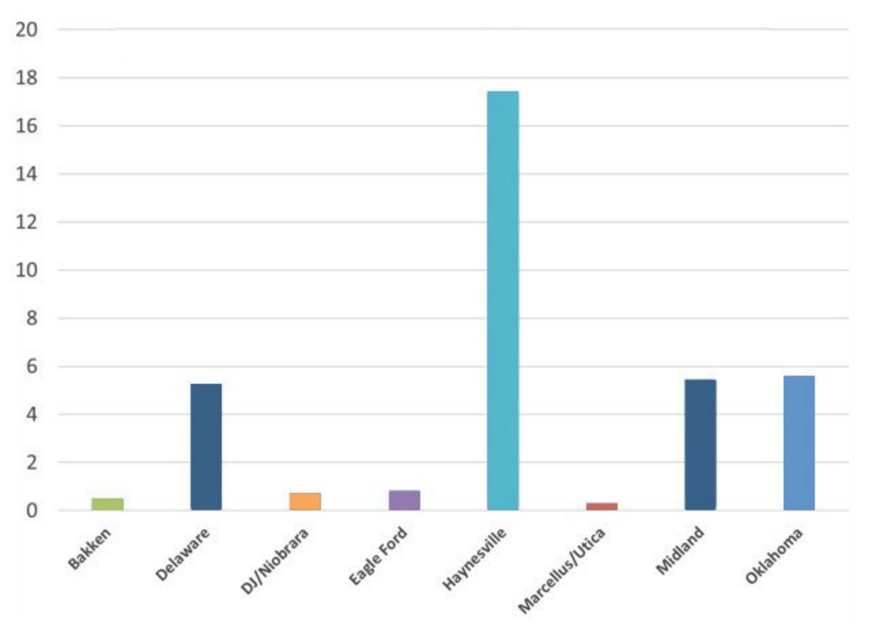

Figure 2-35: Produced Water to Sourced Water Ratio by Region for 2017

Source: After FracFocus®, http://www.fracfocus.org *and IHS Energy Group*

Haynesville, Permian, and Oklahoma have much more produced water than sourced water in 2017.* Produced water volumes in some regions far exceed the water volumes sourced for hydraulically fracturing of wells. Other regions, in contrast, produce less water than water sourced for hydraulic fracturing. The average amount of produced water over the life of a well varies from basin to basin and is influenced by the development maturity of an area, coupled with the number of wells drilled historically. The Haynesville area produced roughly 18 times as much water as was used in hydraulic fracturing in the area. Haynesville has conventional production that has substantial produced water and its water needs for hydraulic fracturing are relatively small. Comparing water volumes needed for hydraulic fracturing to the volume of produced water illuminates the potential balance of water for reuse.

* The produced water data is from IHS Energy Group, a company specializing in business information, and the sourced water data from FracFocus®. Counties with less than 100,000 barrels of sourced water in 2017 were excluded. Importantly, the produced water includes water from conventional production and enhanced oil recovery.