

**STATE OF NEW MEXICO
BEFORE THE WATER QUALITY CONTROL COMMISSION**

IN THE MATTER OF PROPOSED NEW
RULE 20.6.8 NMAC –
*Ground and Surface Water Protection –
Supplemental Requirements For Water Reuse*

No. WQCC 23 - 84 (R)

NEW MEXICO ENVIRONMENT DEPARTMENT,
WATER PROTECTION DIVISION,

Petitioner.

**WILDEARTH GUARDIANS’ NOTICE OF INTENT
TO PRESENT REBUTTAL TESTIMONY**

WildEarth Guardians submits this Notice of Intent to Present Rebuttal Testimony, submitted through its undersigned counsel. As required by NMAC 20.1.6.202 and the Hearing Officer’s February 13, 2024 Pre-hearing Order (“PHO”), WildEarth Guardians provides the following:

1. In response to parties’ direct written testimonies, Melissa Troutman provides rebuttal testimony on behalf of WildEarth Guardians, enclosed here as **Exhibit WG-8**.
2. Ms. Troutman’s qualifications, including a description of her education and work background were enclosed as Exhibit WQ-1 with WildEarth Guardians’ Notice of Intent to present technical Testimony, filed April 15, 2024.
3. Pursuant to the PHO, Ms. Troutman will provide a summary of her direct and rebuttal testimony during the hearing on this matter.
4. WildEarth Guardians intends to offer the exhibits listed below, which are attached to this Notice of Intent:
 - **Exhibit WG-8:** May 6, 2024 Rebuttal Testimony of Melissa Troutman on behalf of WildEarth

Guardians.

- **Exhibit WG-9:** Cawelo Water District (CA) Recycled Produced Water webpage
- **Exhibit WG-10:** US EPA: "Detailed Study of the Centralized Waste Treatment Point Source Category for Facilities Managing Oil and Gas Extraction Wastes" (EPA-821-R-18-004)
- **Exhibit WG-11:** Lauer study of stream sediments near treatment disposal sites
- **Exhibit WG-12:** Warner study of treated produced water impacts on water quality
- **Exhibit WG-13:** Investigative report on Pennsylvania Dept. of Environmental Protection's 2016 study of o&g wastewater treatment efficacy
- **Exhibit WG-14:** California Food Safety Expert Panel white paper on risks associated with produced water crop irrigation

Respectfully submitted this 6th day of May 2024,

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Certificate of Service

I hereby certify that on May 6, 2024 a copy of the foregoing Rebuttal Testimony & Exhibits of Melissa Troutman was emailed to the persons listed below. A copy will be mailed first class upon request.

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EXHIBIT WG - 8

STATE OF NEW MEXICO
BEFORE THE WATER QUALITY CONTROL COMMISSION

IN THE MATTER OF PROPOSED NEW
RULE 20.6.8 NMAC –
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No. WQCC 23 - 84 (R)

NEW MEXICO ENVIRONMENT DEPARTMENT,
WATER PROTECTION DIVISION,

Petitioner.

REBUTTAL TESTIMONY AND EXHIBITS

OF

MELISSA TROUTMAN

ON BEHALF OF

WILDEARTH GUARDIANS

May 6, 2024

I. Introduction

My name is Melissa Troutman, and I am offering this rebuttal testimony on behalf of WildEarth Guardians in response to parties' April 15th direct testimony in the matter of Proposed New Rule 20.6.8 NMAC – *Ground and Surface Water Protection – Supplemental Requirements For Water Reuse*.

The commission received direct written testimonies from parties who claim that the use of treated produced water is tried, tested, and truly safe for discharge to surface waters and for uses such as crop irrigation. States like California and Pennsylvania were offered as examples. For example, in his direct testimony on behalf of the New Mexico Produced Water Research Consortium, Michael Hightower claimed that “[t]he data available on produced water overwhelmingly shows that it can be treated and used safely. Pennsylvania, California, and Colorado have used treated produced water for surface water discharge and land applications for many years.” (page 2 of Hightower’s April 15 testimony)

However, these parties have either omitted or are unaware of well-documented **cases of contamination from treated produced water discharge in states like Pennsylvania**, and they have also failed to mention **key data gaps that currently exist for reuse applications in states like California**.

Anyone claiming that produced water can be treated safely and effectively in real-world, long-term applications must show, not tell. To protect water quality in New Mexico, the Commission must rely on science supported by verifiable, peer-reviewed data that shows the safety and efficacy of produced water treatment technologies in the real world over the long-term. This is a necessity, because it’s the large-scale application of these technologies over time that pose problems in other states. Furthermore, showing that something works in a laboratory is not enough – lab and bench-scale experiments do not translate to “safe” and “effective” for real world applications.

Below, I offer documented examples of treated produced water reuse in other states, including California and Pennsylvania, that plainly show the problems that exist. They also reveal the limited framing of so-called successes in other states by those who attempt to use these other states as justification for reuse in New Mexico. Specifically, I cover:

- 1) crop irrigators in California don't allow the use of produced water from hydraulic fracturing,
- 2) discharge of treated produced water has created pollution in waterways in Pennsylvania and other states, and
- 3) treatment of produced water in Pennsylvania at leading treatment facilities has actually increased, not decreased, the amount of contaminants in the treated effluent.

I will also address chemical disclosure as a necessary prerequisite for the reuse of treated produced water, citing disclosure uses and recommendations in California as an example.

II. Rejecting produced water from hydraulic fracturing

In California, water districts that allow treated produced water for crop irrigation do not allow the use of produced water from hydraulic fracturing for this use. This is stated specifically on the "Recycled Produced Water" webpage of Cawelo Water District. The screenshot below from Cawelo Water District's website (<https://www.cawelowd.org/recycled-produced-water/>) highlights the prohibition on produced water from hydraulic fracturing. **(Exhibit WG-9)**

Recycled Oilfield Produced Water Program

Cawelo Water District has been relying on produced water from oil operations for more than two decades — a reliable additional source of water that helps offset severe restrictions imposed due to the drought and environmental measures.

Kern County has a rich history in oil production, responsible for generating nearly three-quarters of California's oil production under some of the nation's most stringent environmental standards. Every barrel of oil produced also naturally generates approximately 15 barrels of water, called produced water.

Cawelo's produced water is treated by oil producers, filtered and then delivered to Cawelo, where it is blended with other supplies for agricultural use. Our District has a long history of complying with the water quality standards and testing/monitoring protocols established by the Central Valley Regional Water Quality Control Board (Regional Board).

It's important to note and clarify, water generated during hydraulic fracturing (also known as "fracking") is not used for agricultural purposes — a point that has been incorrectly reported in certain publications and promoted by opponents of oil production. Cawelo does not accept, use, or deliver water generated from hydraulic fracturing.

The caveat here is that people often make a distinction between “flowback” liquids that return to the surface during and closely after hydraulic fracturing and “produced water” that returns after a manner of weeks. While there is certainly a level of rationality to this distinction, many engineers admit that there is **no hard and fast stop to the return of the chemicals in fracturing fluids**, which can resurface in produced water after other hydraulic fracturing constituents, such as sand, cease to return. Additionally, chemical additives are also used during drilling and maintenance operations that can influence produced water quality as well. All chemicals should be considered, not just ones used for hydraulic fracturing.

III. Water pollution from discharges of treated produced water

In a study released May 2018, the United States Environmental Protection Agency found **“direct and measurable impacts on downstream surface waters and sediment”** from facilities treating and discharging unconventional and conventional oil and gas produced water. **(Exhibit WG-10)** In this study, the agency reported elevated levels of contaminants downstream of permitted discharges of treated produced water that **“can negatively affect human health or aquatic life.”** (pg. 9-18) (emphasis added) Specifically, EPA found that “concentrations in the surface water for TDS, chloride, bromide, metals, and TENORM [radioactive material]” were significantly higher downstream compared to upstream concentrations. Downstream concentrations also exceeded “applicable aquatic and/or drinking water thresholds.”

Another study published January 2018 in *Environmental Science Technology* by Lauer, N. et al. **(Exhibit WG-11)** identified surface water discharge of “treated conventional [produced water]” as **“the source of high [radium] in stream sediments”** downstream of wastewater treatment facilities in Pennsylvania. (emphasis added) Downstream radiation levels “found in stream sediments at the disposal sites was about 650 times higher than radiation in upstream sediments.” These disposal sites operate under discharge permits issued by the state that include testing for radioactive materials, yet problems still occurred.

A similar study published 2013 in *Environmental Science Technology* by Warner, N. et al. **(Exhibit WG-12)** found that **even though produced water treatment worked as expected, contaminants accumulated over time and pollution still occurred** at a site in Pennsylvania. Specifically, “[b]arium and radium were substantially (>90%) reduced in the treated effluents” and yet carcinogenic “[radium 226] levels in stream sediments (544–8759 Bq/kg) at the point of discharge were

~200 times greater than upstream...posing potential environmental risks of radium bioaccumulation in localized areas of shale gas wastewater disposal.”

These are just a few of many peer-reviewed studies on the impacts of discharging of treated produced water. I encourage the Commission to seek comprehensive study of all such research available in addition to the creation of new data specific to New Mexico.

III. Increase in radioactivity as a result of treatment

In 2016, the Pennsylvania Department of Environment Protection (DEP) released a study of the efficacy of oil and gas wastewater treatment facilities across the state. The raw data collected by the Department revealed that **treatment actually increased radiation levels at some facilities, while treatment failed to significantly clean produced water at others.**

A 2022 investigation by Public Herald, for which I was a lead editor, released the names and locations of the facilities studied by the Department, linked to the raw data collected, in order to map where discharges may be impacting rivers. The analysis of DEP’s data found that oil and gas wastewater tested higher on average for radium levels after treatment at three facilities. **“At two facilities, treated waste tested over 200% higher on average for radium than before treatment:** McCutcheon Enterprises (Apollo, Armstrong Co.) and Covanta (New Castle, Lawrence Co.). Only five [centralized waste treatment facilities] were able to remove on average over 50% of the radioactivity, and only two out of 11 facilities managed to cut down radium on average by more than 90%.” **(Exhibit WG-13)** A table of the Department’s raw data showing produced water analyses before and after treatment at the facilities referenced above is included here:

CWT (Treatment Facility)	Avg. Unfiltered Influent Radium	Avg. Filtered Effluent Radium	Radium Content Change	Percent Change
Hart Resource (Creekside)	3,641.7 pCi/L	88.0 pCi/L	-3,553.7 pCi/L	-97.58%
Pa. Brine Treatment, Inc. (Josephine)	2,981.3 pCi/L	203.0 pCi/L	-2,778.3 pCi/L	-93.19%
Pa. Brine Treatment, Inc. (Franklin)	625.7 pCi/L	233.0 pCi/L	-392.7 pCi/L	-62.76%
Tunnelton Liquids	167.3 pCi/L	69.6 pCi/L	-97.7 pCi/L	-58.38%
Dannic Energy (Punxsutawney)	979.0 pCi/L	448.0 pCi/L	-531.0 pCi/L	-54.24%
Waste Treatment Corp.	388.3 pCi/L	250.7 pCi/L	-137.7 pCi/L	-35.45%
Eureka Resources	9,590.0 pCi/L	8,762.8 pCi/L	-827.2 pCi/L	-8.63%
TerrAqua Resource Management	10,060.0 pCi/L	11,281.7 pCi/L	1,221.7 pCi/L	12.14%
McCutcheon Enterprises	1,815.7 pCi/L	6,287.7 pCi/L	4,472.0 pCi/L	246.30%
Covanta Environmental Solutions	54.0 pCi/L	202.7 pCi/L	148.7 pCi/L	275.31%
Dannic Energy (Brockway)		2,854.5 pCi/L		

The raw data collected by the Pennsylvania Department of Environmental Protection, from facilities that had been operating for years, gave a clearer picture of the efficacy of oil and gas wastewater treatment to reduce radium contamination over time. **This level of temporal data collection is essential for drawing any conclusions on the safety of produced water treatment and any potential risks to humans and the environment.** Therefore, I encourage the Commision to to base its decisions on the matter of produced water treatment for reuse on a similar level of clear, verifiable temporal data.

IV. Chemical disclosure as a necessary prerequisite for produced water treatment

In 2021, the Food Safety Expert Panel released a white paper on the safety of treated produced water for crop irrigation in California’s Central Valley. It revealed that the panel could not evaluate the potential long-term impacts to soil and plants and that **“the potential for recurring reuse of produced water for irrigation to adversely impact the soil and / or plants is not known.”** (emphasis added) (Exhibit WG-14)

Furthermore, the expert panel discourages the use of produced water that contains unknown chemical additives, stating that **“the use of additives that lack sufficient characterization to undertake a hazard evaluation or risk assessment should be discouraged.”** (emphasis added) The panel

recommends that water purveyors “continue to require the disclosure of additives used in oil production that supply produced water for agriculture. The disclosure of additives that are used during petroleum exploration and production, **including chemicals used in the treatment of produced water**, enabled the review completed by the Panel. Continued chemical disclosure will support risk management in the face of changing oil and gas production practices. Additives should be disclosed with their corresponding Chemical Abstract Services Registry Numbers (CASRN).”

The expert paper also determined that “[c]**hemicals or constituents that do not have toxicity data or an approved analytical method may have the potential to pose a threat to crop safety and human health**. Since these chemicals or constituents cannot be analyzed or do not have a known toxicity threshold, there are **potentially significant unknowns** associated with these chemicals or constituents.”
(page 19)

As noted by this panel, produced water reuse comes with inherent unknown toxic risk in light of two factors: 1) the lack of toxicity data or analytical methods for known chemical additives, and 2) the unknown risks associated with unknown chemicals. Many scientific studies and reviews echo these warnings.

It is imperative that the Commission require the full disclosure of all chemicals that could potentially be present in any produced water used for any reuse, including demonstration and industrial projects that create waste streams where these chemicals can be present and accumulate at disposal sites where there is potential for discharge of leachate into surface waters.

V. Conclusion

In conclusion, the Commission cannot with any degree of scientific integrity fulfill its duty to

protect water quality if it relies upon mere statements about the safety and efficacy of produced water treatment. **Any conclusion about safety and efficacy must be backed by verified, peer-reviewed research that has studied the full-scale, real-world impacts over time.** Summaries of laboratory-scale experiments, like the ones provided in Mr. Hightower's testimony exhibits, are not sufficient to base decisions upon. To prevent unintended pollution impacts from treated produced water, rules approved by the Commission must be based on vetted, well-documented conclusions based on verifiable data.

Lastly, **the Commission should never allow discharge of treated produced water unless all chemicals are disclosed, identified, and have known toxicity data and analytical methods attached.** General toxicity tests, such as WET testing, are insufficient for the detection of unknown chemicals and their potential real-world impacts to aquatic life, humans, and the environment. Studies revealing the limitations and pitfalls of WET testing in particular are cited in my direct testimony submitted April 15.

EXHIBIT WG - 9

Recycled Produced Water

Recycled Oilfield Produced Water Program

Cawelo Water District has been relying on produced water from oil operations for more than two decades – a reliable additional source of water that helps offset severe restrictions imposed due to the drought and environmental measures.

Kern County has a rich history in oil production, responsible for generating nearly three-quarters of California's oil production under some of the nation's most stringent environmental standards. Every barrel of oil produced also naturally generates approximately 15 barrels of water, called produced water.

Cawelo's produced water is treated by oil producers, filtered and then delivered to Cawelo, where it is blended with other supplies for agricultural use. Our District has a long history of complying with the water quality standards and testing/monitoring protocols established by the Central Valley Regional Water Quality Control Board (Regional Board).

It's important to note and clarify, water generated during hydraulic fracturing (also known as "fracking") is not used for agricultural purposes – a point that has been incorrectly reported in certain publications and promoted by opponents of oil production. Cawelo does not accept, use, or deliver water generated from hydraulic fracturing.

As the use of produced water expands, the Regional Board requested additional analysis from water districts relying on produced water – requiring testing for nearly 70 additional elements in order to evaluate water quality. Cawelo proactively engaged a third-party environmental toxicologist to analyze the data submitted to the Regional Board – studying levels of organic compounds in the irrigation water.

The third-party environmental toxicologist found that detected organic compounds were well within safe drinking water standards and Cawelo's produced water is safe for agricultural use. Initial water quality laboratory analysis reported the levels of acetone in Cawelo's produced water were 280 times below the maximum concentration considered safe for drinking water; and the level of petroleum hydrocarbons in Cawelo's produced water were 750 times below the maximum concentration considered safe for drinking water. What's more, the third-party environmental toxicologist conducted preliminary crop testing and found that crops irrigated with Cawelo's produced water had the same chemical composition as crops irrigated with other water supplies.

Cawelo is committed to working with the Regional Board and its expert panel in the next steps in this process to do its part and ensure produced water is governed within a strict regulatory framework and is a safe, reliable supply for California agriculture.

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RPW INFORMATION	REPORTS	MEETING INFORMATION, FOOD SAFETY EXPERT PANEL
Recycled Produce Water Information	Citrus Crop Sampling Report, October 11, 2016	Food Safety Expert Panel, Central Valley Regional Water Quality Control Board
Fact Sheet	Water Quality Testing Results Presentation	Food Safety Panel Presentation, October 28, 2017
Root Crop Study Statement, Nov 2016	Irrigation Water Quality Evaluation Report	
Citrus Study Statement	Root Crop Sampling and Analysis Report Technical Memorandum, November 2, 2016	
In Case You Missed It, Oct 2016		
In Case You Missed It, July 2016		

EXHIBIT WG - 10

**Detailed Study of the
Centralized Waste Treatment
Point Source Category
for Facilities Managing
Oil and Gas Extraction Wastes
EPA-821-R-18-004**

U.S. Environmental Protection Agency

Engineering and Analysis Division

Office of Water

1200 Pennsylvania Avenue, NW

Washington, D.C. 20460

www.epa.gov/eg

May 2018

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LIST OF ACRONYMS AND ABBREVIATIONS

BAT	Best available technology economically achievable
bbl	Barrels
BCT	Best conventional control technology
BOD	Biochemical oxygen demand
bpd	Barrels per day
BPJ	Best professional judgment
BPT	Best practicable control technology currently available
BTEX	Benzene, toluene, ethylbenzene and xylenes
CBM	Coalbed methane
CFR	Code of Federal Regulations
COD	Chemical oxygen demand
CWA	Clean Water Act
CWT	Centralized waste treatment
D&B	Dun & Bradstreet
DI	Drillinginfo
DMR	Discharge Monitoring Reports
DOE	Department of Energy
DOI	Department of Interior
ECHO	Enforcement and Compliance History Online
EIA	Energy Information Administration
ELGs	Effluent Limitations Guidelines and Standards
EPA	Environmental Protection Agency
FRS	Federal Registry System
GWPC	Ground Water Protection Council
HEM	Hexane Extractable Material
LM-HT	Low momentum – high turbulence
MBR	Membrane bioreactor
ME	Multiple effect
MGD	Million gallons per day
MVC	Mechanical vapor compression
MWCO	Molecular weight cutoff
NAICS	North American Industry Classification System
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
O&G	Oil and gas extraction
O&M	Operating and maintenance
PA DEP	Pennsylvania Department of Environmental Protection
POTW	Publicly owned treatment works
PSES	Pretreatment standards for existing sources
PSNS	Pretreatment standards for new sources
RO	Reverse osmosis
RS	Rapid spray
SBA	Small Business Association

SGT- HEM	Silica Gel Treated N-Hexane Extractable Material
SIC	Standard Industrial Classification
SUSB	Statistics of U.S. Businesses
TDD	Technical Development Document
TDS	Total dissolved solids
TENORM	Technologically Enhanced Naturally Occurring Radioactive Materials
TOC	Total organic carbon
TPH	Total petroleum hydrocarbons
TRI	Toxics Release Inventory
TSS	Total suspended solids
TVC	Thermal vapor compression
TWF	Toxic weighting factors
TWPE	Toxic-weighted pound equivalent
USGS	United States Geological Survey
WQBEL	Water-quality based effluent limitations
ZLD	Zero liquid discharge

1. EXECUTIVE SUMMARY

The U.S. Environmental Protection Agency (EPA) regulates discharges from centralized waste treatment (CWT) facilities through the existing effluent limitations guidelines and pretreatment standards (ELGs) found at 40 CFR Part 437. CWT facilities accept for treatment, recovery or reuse a variety of wastes and wastewaters. EPA first promulgated the CWT ELGs in 2000. At that time, while EPA was aware that some CWT facilities were accepting wastes from oil and gas extraction activities, this practice was not prevalent.

Since 2000, CWT facilities have been increasingly used to manage wastes such as produced water, drilling wastes and hydraulic fracturing fluids generated by oil and gas extraction operations. This is due to a number of factors, such as the increased utilization of hydraulic fracturing to extract oil and gas. Given changes in the industry since 2000, particularly with respect to management of oil and gas extraction wastes, EPA has undertaken a detailed study of the CWT industry. A primary goal of the study is to determine if the existing CWT regulations should be updated given changes in the industry, specifically related to facilities that accept oil and gas extraction wastes.

As part of this study, EPA has evaluated several aspects of the CWT industry. This report details several areas, including:

- The current universe of 40 CFR Part 437 CWT facilities that EPA is aware of that accept oil and gas extraction wastes for discharge either directly to waters of the United States or indirectly via publicly-owned treatment works (POTWs). A lesser focus are facilities that accept oil and gas extraction wastes and discharge under a different effluent guideline (such as the Oil and Gas Extraction ELGs at 40 CFR Part 435) and facilities that accept oil and gas extraction wastes but do not discharge (i.e., facilities that treat for recycle or reuse).
- The current regulatory status of these facilities, including the basis for National Pollutant Discharge Elimination System (NPDES) permits issued to these facilities, factors such as the wastewater parameters contained in these permits, and the types and quantities of wastes accepted for management.
- Characteristics of wastewaters from oil and gas extraction activities that are currently or could potentially be managed by CWT facilities.
- Technologies applicable to treatment of wastewaters from oil and gas extraction activities, including their cost and performance.
- Economic and financial characteristics of the CWT industry and facilities that manage oil and gas extraction wastes.
- Documented and potential human health and environmental impacts of discharges from CWT facilities managing oil and gas extraction wastewater.

- Generation and management of treatment residuals at CWT facilities, and transfer of pollutants to other media (solid waste, air emissions).

EPA has collected data from a variety of sources, including publicly-available information (facility permits, literature), Clean Water Act (CWA) section 308 data collection, and wastewater sampling.

EPA has made the following observations regarding the CWT industry and CWT facilities that manage oil and gas extraction wastes:

- Although EPA has identified many existing CWT facilities, little information is readily available to determine whether some of these facilities would be affected by changes to EPA’s existing regulations at Part 437. A primary data gap is knowledge about the types of wastewaters accepted, specifically whether wastewater from oil and gas extraction facilities are accepted, and the basis for NPDES permits issued to these facilities.
- EPA identified 11 facilities that accept oil and gas extraction wastes as of 2017, discharge those wastes after treatment and are subject to the Part 437 ELGs (or information available to EPA indicates will be subject to Part 437 when permits are re-issued). These are the facilities considered to be “in-scope” for the purpose of this study.
- Oil and gas extraction wastes can contain a variety of constituents, including biochemical oxygen demand (BOD), bromide, chloride, chemical oxygen demand (COD), specific conductivity, sulfate, total dissolved solids (TDS), total suspended solids (TSS), barium, potassium, sodium, strontium, benzene, ethylbenzene, toluene, xylenes, sulfide, gross alpha, gross beta, radium 226, and radium 228.
- The pollutants present in and characteristics of oil and gas extraction wastes can vary greatly. Factors that can influence the pollutants contained in and the characteristics of these wastes include the source formation for the oil and gas, the type of drilling and whether stimulation methods are used, the types and quantities of additives used during drilling and well development, and the age of the well.
- The range of pollutants present in these wastes typically require the use of a multi-step treatment train to meet discharge standards.
- Of those facilities that are in-scope for this study, variation exists in types of treatment technologies employed. Some facilities employ multi-step treatment systems specifically designed to remove pollutants commonly found in oil and gas extraction wastes. Other facilities use treatment, such as chemical precipitation, that remove specific pollutants but provide little or no removal of the many other pollutants commonly found in these wastes. As a result, some facilities discharge much greater quantities of pollutants, such as total dissolved solids and chlorides, than others.
- Costs for technologies to remove TDS can be high, but nonetheless can be cost-competitive when factors such as transportation to alternate treatment or disposal methods (such as to

injection wells) are considered. In addition, technologies (such as evaporation) are available that use waste heat from other industrial sources that, where co-located, can significantly reduce costs of treatment.

- EPA approved analytical methods do not exist for many constituents found in oil and gas extraction wastes. In addition, some constituents (such as total dissolved solids) found in oil and gas extraction wastes can interfere with EPA approved analytical methods and significantly affect the ability to detect and quantify the level of some analytes.
- The current ELGs at 40 CFR Part 437 do not contain limitations for many of the pollutants commonly found in oil and gas extraction wastes. Many of these pollutants are not included on the current list of priority pollutants.
- The manner in which permitting and control authorities have permitted facilities that accept oil and gas extraction wastes for discharge varies. Some facilities are permitted under Part 437 while others are not. As a result, discharge limitations in permits are not consistent across the industry. A number of facilities operate under expired permits that do not contain limitations for many of the pollutants found in oil and gas extraction wastes; several facilities are in the process of permit renewals that may change the limitations contained in future permits.
- A lack of clarity exists among the regulated community regarding applicability of the current CWT effluent guidelines to facilities that treat oil and gas extraction wastes. Some of this is centered on the interpretation of what constitutes “off-site” in the context of oil and gas operations and whether Part 437 or Part 435 effluent limitations should be applied to facilities treating oil and gas extraction wastes. While EPA has provided clarification of this for operations in the Marcellus Shale region, questions still arise.
- The cyclical market for commodities, including the recent drop in oil and gas prices from 2014 through 2016, has affected the CWT industry that accepts oil and gas extraction wastes. Data available to EPA indicates that some facilities have reduced operations or ceased operating, in part because producers have also reduced operations or ceased operating, or sought cheaper wastewater management solutions. In addition, several new discharge permits have been issued for facilities that have yet to be constructed, in part because of the reduced demand for treating wastewater for discharge. It is not clear if or when these facilities may be constructed or begin operations.
- The demand for CWT services is directly related to the amount of wastewater requiring management. If increased oil and gas exploration occurs in the future, an increase in the volume of wastes produced would also be expected. It is difficult to predict whether the demand for oil and gas CWT services will increase or decrease in the future, as that demand is directly tied to commodities that are subject to market fluctuations. In addition, competition exists from other management options, such as disposal wells. However, concerns regarding induced seismicity and reduced disposal well capacity may result in greater demand for CWT facilities treating these wastes.

- Removal of barium and co-precipitation of radium may create a solid waste management issue at CWT facilities treating oil and gas extraction wastes. More efficient barium removal from the wastewater in the presence of sufficient radium may result in solid waste that exhibits radioactivity at levels that preclude disposal in most landfills. In addition, it is plausible that radioisotopes in wastewater treatment residuals disposed in landfills may subsequently be released to the environment through leachate. The level of radioactivity present in oil and gas extraction wastes is a function of source formation characteristics.
- Management of brines and salts produced from technologies such as reverse osmosis, evaporators, and crystallizers may present a solid waste management issue. Disposal of these residuals in landfills has the potential to increase salinity of landfill leachate. Residuals that have marketable characteristics can be produced at CWT facilities. Producing saleable residuals or materials that can be beneficially reused may offset treatment costs. Other management options for these residuals include injection into disposal wells.
- CWT effluents may have elevated levels of TDS, halides, metals, and technologically enhanced naturally occurring radioactive materials (TENORM) relative to the receiving streams into which they are discharged dependent upon the treatment technology utilized by the CWT. These elevated concentrations are detectable in samples collected downstream of CWT facility discharge points. The distance over which these elevated concentrations are detectable depends on site-specific factors such as source formation, CWT facility discharge volume, upstream concentrations of constituents, and river flow.
- Documented and potential impacts to both aquatic life and human health related to discharges from CWT facilities treating oil and gas extraction wastewater exist due to the prevalence of some pollutants. Levels of pollutants downstream from CWT facility discharges have been reported to exceed applicable thresholds, such as primary and secondary drinking water standards and acute and chronic water quality criteria for protection of aquatic life.
- In a number of cases, CWT effluents have been shown to adversely affect downstream aquatic life and, in one case, have been shown to affect survival of riffleshell mussels, a federally-listed endangered species (e.g., Patnode et al., 2015).
- Multiple drinking water intakes are situated downstream of CWTs accepting oil and gas extraction wastewater within distances at which impacts to drinking water from CWTs have previously been identified. Drinking water treatment plants downstream of CWT facilities treating oil and gas extraction wastewater have noted a shift in the composition of DBPs from mostly chlorinated DBPs to mostly brominated DBPs (McTigue et al., 2014), which are more toxic than their chlorinated analogues. These shifts could affect human health from consumption of treated waters.

2. INTRODUCTION

Recent advances in horizontal drilling, hydraulic fracturing, and other enhanced exploration and production technologies have made the extraction of oil and natural gas from certain formations more technically achievable and economically viable than in past decades. These advanced drilling and production techniques have resulted in dramatic increases in the number of oil and gas wells drilled in the United States. For example, the number of hydraulically fractured wells increased from approximately 36,000 in 2010 to over 300,000 in 2015 (U.S. DOE, 2016). From 1990 to the late 2000s, the United States' dependence on imports of petroleum and other liquid fuels rose as domestic crude oil production declined. Similarly, natural gas production rose slightly during the 1990s and then began to decline in the early part of the last decade. However, following these advances in drilling and production techniques, both oil and natural gas production have risen dramatically, transforming the U.S. oil and gas industry (U.S. DOE, 2014).

The increase in domestic oil and gas extraction has caused higher demand for centralized waste treatment (CWT) services. This has led to both the creation of startup CWT companies and to larger, established waste management companies augmenting their offerings for oil and gas water and waste management services. For example, in 2013, Waste Management (a large waste management company) acquired two energy service companies operating in the Bakken Shale of North Dakota (Reuters, 2014; Waste Management, 2013). In addition, established oil and gas service companies have become involved in CWT services. As evidenced by these changes, the business and technical operation models for providing wastewater management services are evolving rapidly with new service models and technologies emerging. Wastewater management services for oil and gas operations, which may include CWT-type services, are being provided by businesses that lie outside of the traditional CWT industry.

The rise in the number of oil and gas wells and the new types of oil and gas exploration utilized in the United States have led to changes in the volumes and characteristics of solid waste and wastewater that require management. Oil and gas extraction wastewaters can vary greatly depending on the oil and gas source formation, the direction of oil and gas extraction (i.e., vertical, horizontal, or diagonal), the additives being used, and the age of the well.

The current ELGs at 40 CFR Part 437 were promulgated in 2000 (and amended in 2003) and were developed prior to these recent changes in the oil and gas extraction industry. As a result, the pollutants regulated in the ELGs may not include pollutants that exist in oil and gas extraction wastewaters and the technology basis for the ELGs may not address these pollutants. Therefore, CWT facilities accepting oil and gas extraction wastes may not currently install adequate treatment for these wastes, and discharges from CWT facilities accepting oil and gas extraction wastes have the potential to contribute to a range of human health and environmental impacts.

In addition, treatment of oil and gas extraction wastewaters may create solid waste management issues. Solid wastes from these facilities may contain high levels of radioactivity,

which would preclude them from being disposed of at most landfills. In addition, solid wastes generated by oil and gas extraction wastewater treatment may have high levels of salts.

CWT facilities accepting oil and gas extraction wastewater may be regulated under the current CWT ELGs or regulated using other methods, including under 40 CFR Part 435 or local limits using best professional judgement. There is some room for interpretation as to what constitutes “off-site” in the context of oil and gas operations and whether Part 437 or Part 435 ELGs should be applied to facilities treating oil and gas extraction wastes (this issue is described in Section 3.4).

EPA developed this study to help the Agency determine if any action should be taken to address CWT facilities’ treatment of oil and gas extraction wastes. These actions may include (but are not limited to) revising the existing CWT regulations at 40 CFR Part 437 or further evaluating the industry. The study will inform EPA’s determination of future steps by providing information on the following questions:

- What regulations currently apply to CWT facilities in general, and specifically CWT facilities treating oil and gas extraction wastes? Do these current regulations adequately address the pollutants generated by the oil and gas extraction industry?
- How many CWT facilities treating oil and gas extraction wastes currently exist? How many of them discharge to surface waters or to POTWs? How many of them have no discharge, for example because they recycle wastewater or inject wastewater into disposal wells?
- How are facilities treating oil and gas extraction wastes currently permitted? How many are permitted under 40 CFR Part 437 or 40 CFR Part 435? What other methods are used to regulate these facilities?
- How many oil and gas extraction wells exist in the United States? Are these wells located in proximity to CWT facilities?
- What are the types and characteristics of oil and gas extraction wastewater? What pollutants are present in these types of wastewater? How much wastewater is generated by the industry?
- What technologies can be used to treat oil and gas extraction wastewaters? How do these technologies work? How much do these technologies cost? How effectively do these technologies treat the pollutants found in oil and gas extraction wastes?
- What are the pollutant loads generated by CWT facilities that treat and discharge oil and gas extraction wastes? What quantity of toxic pollutants are discharged by these facilities as a function of the volume of wastewater treated?
- What are the economic business models used by CWT facilities treating oil and gas extraction wastes and what are their financial performance and condition? What are the operating market and competition characteristics of the relevant CWT service market?
- What is the industry outlook for both CWT facilities and oil and gas extraction operations?

- What are the documented and potential human health and environmental impacts from discharges from CWT facilities managing oil and gas extraction wastes? What are the impacts of disposal of treatment residuals?

The remainder of this report presents EPA’s investigations, analyses, and findings, organized as follows:

- Section 3 summarizes the existing CWT ELGs found at 40 CFR Part 437 and the existing oil and gas extraction ELGs at 40 CFR Part 435. This section also describes important interrelationships between these two regulations, such as applicability and definitions specific to each regulation.
- Section 4 presents a profile of the CWT industry. This profile describes the data sources EPA used to identify existing CWT facilities and other oil and gas wastewater treatment facilities across the country. EPA provides available information on in-scope facilities, which are the subset of facilities that are permitted for discharge under the 40 CFR Part 437 regulations and that accept oil and gas extraction wastes. Section 4 also provides a limited profile of the number and location of oil and gas extraction wells to provide a basis for understanding the industry’s potential need for CWT services.
- Section 5 presents data and information on characteristics of wastes generated by oil and gas extraction activities. These data are primarily from exploration and production (E&P) activities. EPA has not included data on characteristics of wastes from midstream and downstream activities, although some of these wastes are managed at CWT facilities. Section 5 also presents waste characterization data specific to CWT facilities treating oil and gas extraction wastes, including sampling conducted by EPA specifically for this detailed study.
- Section 6 describes wastewater management practices that are applicable to oil and gas extraction wastes and therefore may be relevant to CWT facilities managing these wastes. Information and data on performance, costs and treatment residuals produced are presented, where available.
- Section 7 presents estimates of the pollutant loadings discharged by in-scope CWT facilities, based on Discharge Monitoring Report (DMR) data for directly discharging facilities and data collected by EPA for indirectly discharging facilities.
- Section 8 presents an economic profile of the CWT industry for facilities that accept oil and gas extraction wastewater and describes the industry outlook.
- Section 9 discusses documented and potential human health and environmental impacts from discharges from CWT facilities managing oil and gas extraction wastes. Discussion of treatment residuals is also included in this section.
- Section 10 details the data sources used throughout EPA’s analyses.

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3. EXISTING EFFLUENT LIMITATIONS GUIDELINES FOR OIL AND GAS EXTRACTION WASTES

This section describes the existing ELGs that may apply to discharges of oil and gas extraction wastes. Section 3.1 provides background on the effluent guidelines program and process. Section 3.2 describes the ELGs that apply to the CWT point source category, which is the primary focus of this detailed study. ELGs that apply to the oil and gas extraction category are described in Section 3.3. While this study is not specifically evaluating the existing oil and gas extraction ELGs, this information is presented as a basis of comparison to the requirements applicable to CWT facilities treating those wastewaters. In addition, it is important to characterize the interrelationships between these two rules to understand the instances where the CWT ELGs apply and the instances where the oil and gas ELGs apply.

3.1 Effluent Guidelines Background

ELGs are national wastewater discharge standards that are developed by EPA on an industry-by-industry basis. These are technology-based regulations and are intended to represent the greatest pollutant reductions that are economically achievable for an industry. The standards for **direct dischargers** are incorporated into NPDES permits issued by states and EPA regional offices, and standards for **indirect dischargers** are incorporated into permits or other control mechanisms issued by pretreatment authorities.

When developing ELGs, EPA identifies the best available technology that is economically achievable for that industry and sets regulatory requirements based on the performance of that technology. The ELGs do not require facilities to install the specific technology identified by EPA; however, the regulations do require facilities to achieve the same level of pollutant reductions. ELGs can apply to both existing dischargers and new dischargers. ELGs also establish different levels of control for specific classes of pollutants (**priority pollutants**, **conventional pollutants** and **nonconventional pollutants**).

The direct discharge pollution control guidelines that are developed by EPA in ELGs include: best practicable control technology currently available (BPT), best conventional pollutant control technology (BCT), best available technology economically achievable (BAT), and new source performance standards (NSPS). The indirect discharge pollution control standards that are developed by EPA in ELGs include pretreatment standards for existing sources (PSES) and

Direct Discharger

A point source that discharges pollutants to waters of the United States.

Indirect Discharger

A facility that discharges pollutants to a publicly-owned treatment works (municipal sewage treatment plant).

Priority Pollutants

A list of 126 toxic pollutants, last modified in 1981, that are frequently found in water samples, produced in significant quantities and have approved EPA methods for detection.

Conventional Pollutants

Biochemical oxygen demand, total suspended solids, fecal coliform, pH and oil and grease.

Nonconventional Pollutants

All other pollutants not considered priority or conventional pollutants.

pretreatment standards for new sources (PSNS). Table 3-1 illustrates the types of dischargers and the different levels of control in ELGs. Table 3-2 illustrates the classes of pollutants addressed by different levels of control in ELGs.

Table 3-1. Applicability of Effluent Guidelines Levels of Control to Types of Discharger

Type of Discharger Regulated	BPT	BCT	BAT	NSPS	PSES	PSNS
Existing Direct Dischargers	•	•	•			
New Direct Dischargers				•		
Existing Indirect Dischargers					•	
New Indirect Dischargers						•

Table 3-2. Pollutant Classes Regulated by Effluent Guidelines Levels of Control

Pollutants Regulated	BPT	BCT	BAT	NSPS	PSES	PSNS
Priority Pollutants	•		•	•	•	•
Conventional Pollutants	•	•		•		
Nonconventional Pollutants	•		•	•	•	•

3.2 Centralized Waste Treatment Point Source Category Effluent Guidelines

Discharges from CWT facilities are regulated under 40 CFR Part 437. CWT facilities accept waste from off-site for disposal, recovery or recycling. CWT facilities may also treat on-site generated wastes. EPA defines off-site as “outside the boundaries of a facility” (40 CFR 437.2(n)).

The CWT category does not apply to discharges of wastewater from facilities that are subject to other categorical discharge standards when they receive wastes from off-site for treatment or recovery that are subject to the *same ELGs* as the on-site generated wastes. Similarly, the CWT category does not apply to discharges of wastewater from facilities that receive off-site wastes whose nature and treatment are compatible with the treatment of on-site (non-CWT) wastes. The CWT category does not apply to operations engaged exclusively in landfilling and/or the treatment of landfill wastewaters, whether generated on- or off-site. See 40 CFR Part 437.1 for additional details regarding the applicability of the CWT category.

40 CFR part 437 defines a CWT facility as: “any facility that treats (for disposal, recycling or recovery of material) any hazardous or nonhazardous industrial wastes, hazardous or non-hazardous industrial wastewater, and/or used material received from off-site.”

CWT wastewater means any wastewater generated as a result of CWT activities. CWT wastewater sources may include liquid waste receipts, solubilization water, used oil-emulsion breaking wastewater, tanker truck/drum/roll-off box washes, equipment washes, air pollution control scrubber blow-down, laboratory-derived wastewater, on-site landfill wastewaters, and contaminated storm water.

The guidelines at 40 CFR Part 437 categorize CWT facilities into four subparts:

- Subpart A: Metals Treatment and Recovery
- Subpart B: Oils Treatment and Recovery
- Subpart C: Organics Treatment and Recovery
- Subpart D: Multiple Wastestreams

The technologies considered BPT in the CWT ELGs include primary precipitation, liquid-solid separation, secondary precipitation, clarification, and sand filtration for Subpart A; emulsion breaking/gravity separation, secondary gravity separation, and dissolved air flotation for Subpart B; and equalization and biological treatment for Subpart C. For Subpart D, the limitations were derived by combining BPT limitations from the three other subparts, selecting the most stringent values where they overlap. Therefore, the technology basis for Subpart D limitations reflects the technology basis for the applicable subparts. EPA adopted BCT and BAT effluent limitations for all subparts of the CWT industry based on the same technologies selected as the basis for BPT for each subpart.

EPA promulgated NSPS Subpart B and C limitations based on the same technology basis as BPT/BCT/BAT. However, for Subpart A, the NSPS technology basis includes selective metals precipitation, liquid-solid separation, secondary precipitation, and tertiary precipitation and clarification. As was the case for BPT/BCT/BAT, the technology basis for Subpart D NSPS limitations reflects the technology basis for the applicable subparts.

In addition to the direct discharge limitations, 40 CFR Part 437 established pretreatment standards for indirect discharges from CWT facilities to POTWs. For Subpart A and Subpart C, EPA based the PSES on the same technology basis as BPT. For Subpart B, EPA based PSES on emulsion breaking/gravity separation and dissolved air flotation. As was the case for BPT/BAT, the technology bases for pretreatment standards for Subpart D reflect the technology bases for the applicable subparts.

EPA based the PSNS for Subpart B and Subpart C on the same technology basis as NSPS. EPA based Subpart A PSNS on the same technology basis as BPT. As was the case for PSES, the technology basis for Subpart D PSNS reflects the technology basis for the applicable subparts.

Since the pollutants present and the technology basis varies by subpart, the pollutants regulated within each subpart vary. Table 3-3 shows the pollutant categories that are regulated under each of the subparts in the CWT rule for both direct and indirect discharging facilities. Appendix A lists the individual pollutants contained in the effluent limitations and pretreatment standards in the rule. The pollutant categories that are regulated under Subpart D reflect the categories for the applicable subparts making up the multiple wastestreams.

Table 3-3. Pollutant Categories Regulated Under Each Subpart of the CWT Effluent Guidelines and Standards

Pollutant Category	Subpart A		Subpart B		Subpart C	
	Direct	Indirect	Direct	Indirect	Direct	Indirect
BOD ₅					•	
Oil and Grease	•		•			
TSS	•		•		•	
Metals	•	•	•	•	•	
Organics			•	•	•	•
Cyanide	•	•				

3.3 Oil and Gas Extraction Point Source Category Effluent Guidelines

Discharges from oil and gas extraction activities are subject to ELGs at 40 CFR Part 435. These regulations are subcategorized based on the location where the activities take place (onshore, offshore and in coastal areas), and the levels of control vary for each subpart. Table 3-4 shows the levels of control that are contained in the oil and gas extraction ELGs. These regulations address wastewater discharges from activities such as field exploration, drilling, production, well treatment and well completion activities.

Table 3-4. Levels of Control by Subcategory in the Oil and Gas Extraction Effluent Guidelines

Type of Discharger Regulated	BPT	BCT	BAT	NSPS	PSES	PSNS
Offshore Subcategory	•	•	•	•		
Onshore Subcategory ^a	•				•	•
Coastal Subcategory	•	•	•	•	•	•

^a PSES and PSNS for the onshore category were promulgated in June 2016 for unconventional oil and gas extraction activities. Pretreatment standards currently do not exist for onshore conventional extraction activities.

Table 3-5 provides additional details on the applicability and limitations contained in these subparts. Additional details are provided in Appendix A.

Some of the waste streams addressed by the guidelines for 40 CFR Part 435 include:

- Produced water which is brought up from the hydrocarbon-bearing strata during the extraction of oil and gas;
- Produced sand which is the slurried particles used in hydraulic fracturing, the accumulated formation sands and scales particles generated during production;
- Drilling fluids which are the circulating fluids used in the rotary drilling of wells;

- Drill cuttings generated from drilling into subsurface geologic formations and carried out from the wellbore with the drilling fluid;
- Well treatment fluid which is any fluid used to restore or improve productivity by physically or chemically altering the hydrocarbon-bearing strata after a well has been drilled;
- Workover fluid which are additives used in a producing well for maintenance, repair, or abandonment; and
- Well completion fluids which are additives used to prevent damage to the well bore during operations which prepare the drilled well for production.

Table 3-5. Subparts of 40 CFR Part 435 and their Applicability and Limitations

Subpart	Title	Applicability	Description
A	Offshore Subcategory	Facilities located in waters that are seaward of the inner boundary of the territorial seas as defined in 502(g) of the CWA.	Both numeric and zero discharge.
C	Onshore Subcategory	Facilities located landward of the inner boundary of the territorial seas as defined in 40 CFR 125.1(gg) and which are not included within subpart D, E, or F	BPT regulations require zero discharge of produced water for direct dischargers. PSES and PSNS require zero discharge for unconventional oil and gas extraction facilities.
D	Coastal Subcategory	Facilities located in or on a water of the United States landward of the inner boundary of the territorial seas, or as defined at 40 CFR 435.40(b)(1)	Zero discharge as BAT for the coastal subcategory (except for Cook Inlet) and zero discharge pretreatment standards.
E	Agricultural and Wildlife Water Use Subcategory	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 navigable waters.	Subpart E requires no discharge of waste pollutants into navigable waters from any source other than produced water. Produced water discharges have a daily maximum limitation of 35 mg/L for oil and grease by the application of the BPT.
F	Stripper Subcategory	Onshore facilities which produce 10 barrels per well per calendar day or less of crude oil and which are operating at the maximum feasible rate of production and in accordance with recognized conservation practices.	This subcategory has no limitations. Technology-based limitations are developed on a case-by-case basis or in a state-wide general permit.

Note: Subpart B and H (Coalbed Methane) requirements are reserved. Subpart G requirements prevent moving effluent produced in one subcategory to another subcategory for disposal under less stringent requirements.

In general, 40 CFR Part 435 prohibits the discharge of pollutants from oil and gas extraction facilities, with a few exceptions. Appendix A contains additional details on the limitations and standards contained in the oil and gas ELGs.

3.4 Interrelationship Between the CWT and Oil and Gas Extraction Effluent Guidelines

As described above, CWT facilities typically receive wastes from a variety of sources with different characteristics. A facility must receive waste from off-site to be regulated under

the CWT ELGs. EPA has published several resources to help permit writers and control authorities determine applicability of the CWT ELGs¹. When determining whether it is appropriate to apply the CWT ELGs to a particular facility, the permit writer or control authority considers a number of factors, including: (1) the location of the facility in relation to where the wastes are generated to determine if wastes are received from off-site; (2) the number of generators of the waste; (3) the nature of the wastes, and in particular whether all of the wastes are from a single ELGs category; and (4) the method(s) of delivery of the wastes (e.g., via pipeline, conduit, or truck, rail car, etc.).

When a CWT facility accepts waste from a single ELGs category from off-site (which may be the case with CWT facilities that accept waste exclusively from oil and gas extraction activities), the CWT regulations do apply to those wastes. However, if the CWT facility receives wastewater on a continuous basis from five or fewer generators with consistent profiles, the permit writer or control authority could set alternative limits that are based on the limitations and standards applicable to the waste where it was generated. If the wastes are from the oil and gas sector, and since the oil and gas ELGs are generally zero discharge (for onshore facilities), the permit writer or control authority could set zero discharge standards for the CWT facility.

Another key question that arises with respect to oil and gas extraction activities and CWT facilities is how to determine if a facility is located off-site. EPA defines *site* at 40 CFR 122.2 as “the land or water area where any ‘facility or activity’ is physically located or conducted, including adjacent land used in connection with the facility or activity.” *Facility or activity* means any NPDES “point source” or any other facility or activity (including land or appurtenances thereto) that is subject to regulation under the NPDES program.”

EPA issued a compliance guide and associated frequently asked questions (FAQs) to explain, among other things, the relationship between the CWT ELGs and the oil and gas extraction ELGs for natural gas drilling in the Marcellus shale (U.S. EPA, 2011a, 2011b). In the FAQs, EPA indicates that for gas drilling activities:

(T)he land identified in the drilling permit; including the locations of wells, access roads, lease areas, and any lands where the facility is conducting its exploratory, development or production activities, or adjacent lands used in connection with the facility or activity, would constitute the site. Land that is outside the boundaries of that area is considered to be “off-site.”

While these FAQs provide clarity on the question of what constitutes off-site in the context of Marcellus shale gas extraction activities, EPA has not provided any additional information or guidance beyond what is contained in the existing CWT ELGs record and the CWT Small Entity Compliance guide and FAQs for other oil and gas extraction activities across the country. As a result, there may be questions from both industry and regulatory entities about

¹ See the EPA Small Entity Compliance Guide and FAQ addenda at <https://www.epa.gov/eg/centralized-waste-treatment-effluent-guidelines-documents>.

whether the oil and gas ELGs or the CWT ELGs should apply to a specific facility treating oil and gas extraction wastes.

3.5 References

1. U.S. EPA. 2001. Small Entity Compliance Guide: Centralized Waste Treatment Effluent Limitations Guidelines and Pretreatment Standards (40 CFR 437) and addenda. EPA-821-b-001-003. DCN CWT00144
2. U.S. EPA. 2011a. Regulating Natural Gas Drilling in the Marcellus Shale under the NPDES Program. Memorandum from James A. Hanlon, Director, Office of Wastewater Management to Water Division Directors, Regions 1-10. (March 17). DCN CWT00540
3. U.S. EPA. 2011b. Natural Gas Drilling in the Marcellus Shale NPDES Program Frequently Asked Questions. (March 16). DCN CWT00541

4. INDUSTRY PROFILE

Oil and gas exploration and production activities generate a variety of waste materials requiring management. These waste materials include produced waters, spent drilling fluids, used drilling muds and drill cuttings. Many waste materials, such as produced waters, are recycled and reused in exploration and production operations. However, in many instances disposal of these materials is needed. Many disposal options are available, including injection in Class II UIC wells, stabilization and solidification and subsequent disposal in landfills, and transfer to CWT facilities. The options selected depend on factors such as cost and proximity to the source generating the waste. CWT facilities provide a valuable service to the oil and gas industry, particularly in areas where certain disposal options (such as underground injection) may be limited.

To better understand the scope and extent to which CWT facilities are used by the oil and gas extraction industry to manage wastes, EPA prepared a profile of the CWT industry. This industry profile is intended to:

- Identify CWT facilities nationwide, including a summary of facilities' discharge status, location, permitting methods, and whether or not they accept oil and gas extraction wastewaters.
- Provide further details about the subset of facilities that accept oil and gas extraction wastes and discharge wastewater. For facilities EPA determined to be “in-scope” of this study, the profile describes characteristics of these facilities, such as type of treatment, discharge status and volume, and types and characteristics of wastes accepted.
- Present a limited evaluation of the oil and gas extraction industry, including the current universe of oil and gas extraction wells and summary data on wastewater production and management, where available.
- Evaluate the proximity of oil and gas extraction wells to all CWT facilities and the “in-scope” facilities to determine the potential market for CWT services for oil and gas extraction wastewater.

4.1 **Overview of the CWT Industry and the Segment Receiving and Treating Oil and Gas Extraction Wastewaters**

The CWT industry is composed of facilities that treat and/or recover nonhazardous or hazardous waste, wastewater, and/or other used materials generated by industrial facilities. Based on previous EPA regulatory analysis for the CWT industry, CWT activity has traditionally occurred in three North American Industry Classification System (NAICS) sectors: Hazardous Waste Treatment and Disposal (NAICS 562211), Other Nonhazardous Waste Treatment and Disposal (NAICS 562219) and Materials Recovery Facilities (NAICS 562920) (U.S. EPA,

2010).² Detailed information on the CWT industry can be found in the "Development Document for Final Effluent Limitations Guidelines and Standards for the Centralized Waste Treatment Industry" (U.S. EPA, 2016f; EPA-821-R-00-020) and in the Economic Analysis of Final Effluent Limitations Guidelines and Standards for the Centralized Waste Treatment Industry" (U.S. EPA, 2001; EPA-821-R-00-024).

In recent years, an increase in production of oil and gas utilizing hydraulic fracturing has changed the character and quantity of wastewaters that must be managed as part of oil and gas extraction. As a result, the business and technical operation models for providing wastewater management services to the oil and gas extraction industry are evolving rapidly with new service models and technologies emerging in some regions. Wastewater management services for oil and gas extraction operations, including CWT-type services, are being provided by businesses that lie outside the definition of the traditional CWT industry.

Table 4-1 lists NAICS codes for (1) the three traditional CWT industry segments, and (2) NAICS codes for other sectors which may provide services to oil and gas operations. It is possible, given the evolving business models for oil and gas wastewater services, that some facilities providing CWT services to the oil and gas extraction industry may fall into one or more of these sectors. More information on this table is provided in Chapter 8.

Based on research of trade publications, company websites, and general online searches, EPA identified five business classifications that provide wastewater management services to the oil and gas extraction industry, as described in Table 4-2.

Diversified waste management firms provide general environmental and waste management services, including transportation or hauling of waste, landfill services, and other waste services, and include such firms as Waste Management, the largest provider of waste management environmental services in North America. Firms in these industry segments provide wastewater treatment and management services to oil and gas operations, but these services are only part of the company's overall business.

² For the 2000 Final Centralized Waste Treatment Rule, EPA relied on information gathered from a 1990 survey questionnaire and comments to the 1996 Notice of Data Availability (NODA) to determine the universe of CWT facilities. Based on these two data sources, EPA determined that there were 223 CWT facilities in scope of the 2000 rule. The majority of respondents identified their industry as SIC 4953: Refuse Systems. This SIC code maps to five NAICS codes, three of which were determined to be in scope: NAICS 562211, NAICS 562219, and NAICS 562920. In a 2010 Regulatory Flexibility Act analysis, EPA assumed that facilities in these three NAICS industry segments represented the entire CWT industry and were all subject to the 2000 Final CWT Rule (U.S. EPA, 2010).

Table 4-1. NAICS Codes of Centralized Waste Treatment Industry and Other Industries Providing Wastewater Services to Oil and Gas Extraction Operations

NAICS	Facilities Included
Traditional CWT Industry Sectors	
562211	Hazardous Waste Treatment and Disposal
562219	Other Nonhazardous Waste Treatment and Disposal
562920	Materials Recovery
Other Sectors Providing Wastewater Services to Oil and Gas Operators	
211111	Crude Petroleum and Natural Gas Extraction
212321	Construction Sand and Gravel Mining
213111	Drilling Oil and Gas Wells
213112	Support Activities for Oil and Gas Operations
237110	Water and Sewer Line and Related Structures Construction
237310	Highway, Street, and Bridge Construction
325180	Other Basic Inorganic Chemical Manufacturing
333132	Oil and Gas Field Machinery and Equipment Manufacturing
333318	Other Commercial and Service Industry Machinery Manufacturing
424720	Petroleum and Petroleum Products Merchant Wholesalers
454390	Other Direct Selling Establishments
484230	Specialized Freight Trucking, Long-Distance
488390	Other Support Activities for Water Transportation
541611	Administrative Management and General Management Consulting Services
541620	Environmental Consulting Services
541712	Research and Development in the Physical, Engineering, and Life Sciences (except Biotechnology)
551112	Offices of Other Holding Companies
561210	Facilities Support Services

Source: U.S. EPA, 2017a; U.S. Census, 2016.

Table 4-2. Business Models for Firms Offering Wastewater Management Services to the Oil and Gas Extraction Industry

Business Classification	Example Firm-Level NAICS Codes
Diversified Waste Management	562211 (Hazardous Waste Treatment and Disposal); 562219 (Other Nonhazardous Waste Treatment and Disposal); 562920 (Materials Recovery)
Engineering and Environmental Services	541330 (Engineering Services); 333318 (Other Commercial and Service Industry Machinery Manufacturing)
Wastewater Management and Environmental Services for Oil and Gas Extraction	541611 (Administrative Management and General Management Consulting Services); 541620 (Environmental Consulting Services)
Traditional Energy/Oilfield Services	213112 (Support Activities for Oil and Gas Operations); 333132 (Oil and Gas Field Machinery and Equipment Manufacturing)
Oil and Gas Extraction Operators	213112 (Support Activities for Oil and Gas Operations); 211111 (Crude Petroleum and Natural Gas Extraction)

Engineering and environmental services companies are those that focus on areas such as construction, engineering design, and technology development and do not limit their services primarily to the oil and gas industry. The firms that fall in this category, such as Aquatech, provide logistics support, wastewater technologies, and facility planning to both oil and gas firms and CWT firms. In many cases, these firms sell their technology or services to other firms, or provide onsite wastewater management and treatment services. However, in some cases, these firms may own or operate a CWT facility as well. An example of this type of firm is Veolia.

In addition to engineering and environmental services firms, there are traditional wastewater management firms, for which wastewater management services and environmental services in the oil and gas industry is their primary business. These firms provide services such as waste and wastewater hauling, treatment, storage, and disposal to oil and gas producers, and, in some cases, were started to serve the growing need for wastewater treatment specifically within this industry. One such firm, Eureka Resources, began in 2008 and serves oil and gas producers operating in the Marcellus shale in Pennsylvania (Eureka Resources, 2016).

Firms in the traditional energy/oilfield services category, such as National Oilwell Varco, provide field services to oil and gas companies. These services have traditionally involved a range of technical and engineering/construction-type services, including reservoir characterization, drilling, downhole, and production and gathering services. While many of these firms have historically provided waste management services to operators, the recent rise in the use of water for oil and gas production has seen these companies take on a new role in wastewater management services. For these firms, oil and gas exploration and production companies serve as the primary customers. An example of this type of firm is Chesapeake Energy.

A number of oil and gas operators, such as Encana, manage their own wastewater treatment. These firms may purchase wastewater treatment technologies from other companies or rely on other firms for management and operation services but own their wastewater treatment services. In addition, a number of joint ventures, strategic alliances, and agreements have emerged among oilfield and environmental service firms to either develop treatment technologies and systems or to offer expanded water services. These ventures involve businesses with primary operations that fall in a range of industry sectors.

4.2 Profile of CWT Facilities

EPA regulates discharges from CWT facilities pursuant to ELGs under 40 CFR Part 437, as discussed in Section 3. EPA defines a CWT facility in part 437 as “any facility that treats (for disposal, recycling or recovery of material) any hazardous or non-hazardous industrial waste, hazardous or non-hazardous industrial wastewater, and/or used material received from off-site.”

The operations of CWT facilities are quite varied. As noted in the Technical Development Document (TDD) for the 2000 CWT ELGs (U.S. EPA, 2000), some CWT facilities treat used materials or wastes from a few generating facilities while others treat wastes from dozens or more generators. Some treat non-hazardous wastes exclusively while others treat hazardous and non-hazardous wastes. Some primarily treat concentrated wastes while others primarily treat dilute wastes. Some primarily perform either wastewater treatment or materials recovery and recycling, while others perform both.

EPA identified 223 CWT facilities (U.S. EPA, 2000) as part of the 2000 rulemaking (65 FR 81267). Of these 223 facilities, 14 were identified as direct dischargers to waters of the U.S., 151 were indirect dischargers and 58 were zero or alternative dischargers.³ Figure 4-1 shows a map of the CWT facilities that were identified in the public record for the 2000 rulemaking.

Using EPA’s DMR Pollutant Loading Tool, EPA identified 21 direct discharging facilities associated with the CWT point source category that submitted DMR data for the reporting year 2016. These facilities are listed in Table 4-3 and shown on Figure 4-2. [Note that the DMR Pollutant Loading Tool typically assigns facilities to point source categories based on NAICS Code (i.e., facilities are not required to report point source categories in their DMRs). Because the CWT point source category does not align directly with NAICS codes, CWT facilities are identified through their prior association with the CWT category, such as their inclusion in the 2000 rulemaking. Therefore, this list may not be complete for the reasons described in Section 4.1.] In addition, indirect discharging CWT facilities are not required to submit DMRs and therefore EPA has no national data set to identify the current universe of these facilities. For these reasons, EPA developed a list of CWT facilities to be used for this study, as described below.

³ Zero and alternative discharge methods include deep well injection, incineration, evaporation, transfer to another off-site facility (such as another CWT facility), and facilities that generate no wastewater.



Note: This figure excludes one facility located in Hawaii.

Figure 4-1. CWT Facilities Identified for 2000 Rulemaking

Table 4-3. Direct Discharging CWT Facilities in 2016, Identified by the DMR Pollutant Loading Tool

Facility Name	City	State
Clean Harbors Baton Rouge, LLC	Baton Rouge	LA
Clean Harbors PPM, LLC	Ashtabula	OH
Clean Harbors White Castle, LLC - White Castle Landfarm	White Castle	LA
CWM Chemical Services - Model City Site	Model City	NY
Envirite of Illinois Inc. - Harvey	Harvey	IL
Fort Martin Power Station	Maidsville	WV
Harford Waste Disposal Center	Street	MD
Max Environmental - Yukon Facility	Yukon	PA
Montgomery Co. Resource Recovery Facility	Dickerson	MD
North Kansas City Sewer LDF	Kansas City	MO
North Regional Treatment Plant	Beaumont	TX
Oiltanking Houston, Inc.	Houston	TX
Reserve Environmental Services	Ashtabula	OH
Rush Township Treatment Plant	Moshannon	PA
SET Environmental	Houston	TX
SID #8 Saunders County Waste Water Treatment Facility	Fremont	NE
Encycle/Texas Inc.	Corpus Christi	TX

Table 4-3. Direct Discharging CWT Facilities in 2016, Identified by the DMR Pollutant Loading Tool

Facility Name	City	State
US Ecology	Robstown	TX
Vopak Logistics Services - Deer Park Terminal	La Porte	TX
Waste Control Specialists	Andrews	TX
Waste Treatment Corp.	Warren	PA

**Figure 4-2. Direct Discharging CWT Facilities in 2016, Identified by the DMR Pollutant Loading Tool**

In identifying facilities potentially in-scope of this study, EPA evaluated the list of CWT facilities from the 2000 CWT rulemaking. EPA expects that some of the CWT facilities identified as part of the 2000 rulemaking are no longer in business. EPA also expects that additional facilities have begun operation since 2000. EPA also expects that some facilities have changed ownership, name, or discharge status. Given these factors, and that the 2000 rulemaking list of facilities did not in some cases identify whether those facilities accepted waste from oil and gas extraction activities, EPA did not consider the 2000 list to be the best source of data to identify current CWT facilities that accept oil and gas extraction wastes. Rather, EPA relied

primarily on other data sources to identify potentially in-scope facilities for this detailed study. These data sources include:

- The rulemaking record supporting EPA’s ELGs rulemaking activities for Unconventional Oil and Gas Extraction (40 CFR 435, Subpart C);
- The record supporting the Effluent Guidelines Program Plans under section 304(m) of the CWA;
- State NPDES and oil and gas permitting agencies and on-line databases;
- Literature and periodicals;
- Information from facilities and technology vendors (for example, through websites, newsletters, or contact via site visits or phone conversations);
- Input from trade groups and industry stakeholders;
- Conference proceedings; and
- EPA data systems such as Envirofacts⁴ and Enforcement and Compliance History Online (ECHO).⁵

EPA combined information from these data sources into one dataset and reviewed this dataset for duplicate records and accuracy. EPA collected information on facility location, treatment capacity, and treatment type when available, as well as information such as facility addresses, NPDES permit numbers, and Federal Registry System (FRS) identification numbers. As a result of this effort, EPA prepared an updated CWT facility list (ERG, 2018). In total, EPA identified 426 facilities nationwide⁶. For each of these facilities, EPA attempted to identify whether the facility accepts oil and gas extraction wastes, such as produced water, fracturing fluids, drilling fluids, drilling cuttings, etc. For those eight facilities where information indicated that the facility does accept (or previously had accepted) oil and gas extraction wastes, EPA then further evaluated whether each facility discharges process wastewater and how the facility is permitted for discharge (e.g., under an effluent guideline or some other mechanism). Based on this information, the list of 426 CWT facilities was organized by the following categories of facilities (ERG, 2018):

- Facilities permitted for discharge under the CWT ELGs at 40 CFR Part 437;
- Facilities permitted for discharge under 40 CFR 435, Subpart E or F;
- Facilities that do not discharge process wastewater but may be permitted to discharge other wastewater (such as stormwater);

⁴ Envirofacts is available online at: <https://www3.epa.gov/enviro/>.

⁵ ECHO is available online at: <https://echo.epa.gov/>.

⁶ Note EPA did not devote significant resources towards obtaining updated information on the status of facilities identified for the 2000 rulemaking since EPA did not expect most of these facilities to be in-scope of EPA’s detailed study of CWTs accepting oil and gas extraction wastes. As a result, some of these facilities are likely no longer in operation and/or information contained in U.S. EPA, 2017a is likely not current.

- Facilities that discharge wastewater from coalbed methane (CBM) extraction⁷;
- Facilities permitted for discharge under other authority, such as Best Professional Judgement or general permits;
- Facilities with unknown discharge status and/or unknown basis for permitting⁸;
- Zero discharge facilities located at oil and gas extraction wells and off-site⁹;
- Facilities that applied for NPDES permits, but as of late 2016 had not installed treatment and were not discharging oil and gas extraction wastewaters;
- Facilities that ceased operations; and
- Facilities with incomplete information and therefore it is not known whether oil and gas extraction wastes are accepted for treatment.

Figure 4-3 shows information EPA has obtained on the 426 facilities identified. This information should be considered a snapshot in time as of June 2017. EPA identified 210 facilities that potentially accept oil and gas extraction wastes. This includes 12 facilities that accept only CBM wastes. Excluding CBM facilities, the number of facilities is 198. EPA has little data available on the types of wastes accepted at many of these facilities, and therefore it is likely that some of these facilities accept waste from activities such as crude oil storage rather than from oil and gas extraction activities. EPA identified eight facilities that do not accept oil and gas extraction wastes. EPA also identified 192 facilities for which information was not readily available to determine whether oil and gas extraction wastes are accepted. Most of these facilities are likely oil recyclers and facilities that provide CWT services for other (non-oil and gas extraction) industrial waste sources. It is important to acknowledge that this list is limited because EPA has incomplete information on existing indirect discharging CWT facilities, as these facilities are not required to report to EPA. Additional data collection would be needed to determine the types of wastes that are accepted at these facilities.

Of the 198 facilities identified as accepting oil and gas extraction wastes, 98 discharge wastewater from waste treatment activities (also called process wastewater); 100 facilities do not discharge process wastewater (but may have other discharges, such as stormwater or sanitary waste); and discharge status is not known for 12 facilities.

⁷ Although EPA identified some CBM treatment facilities as part of this data gathering exercise, this was not a primary purpose of this effort and the list prepared is not comprehensive.

⁸ Additional research will be needed to determine whether any of these facilities would be affected by changes to EPA's CWT ELGs.

⁹ EPA was able to identify little information from public sources on many of these facilities. Therefore, the list identified by EPA should not be considered comprehensive. In addition, some of these facilities are temporary facilities located at well sites, and therefore may no longer be in operation.

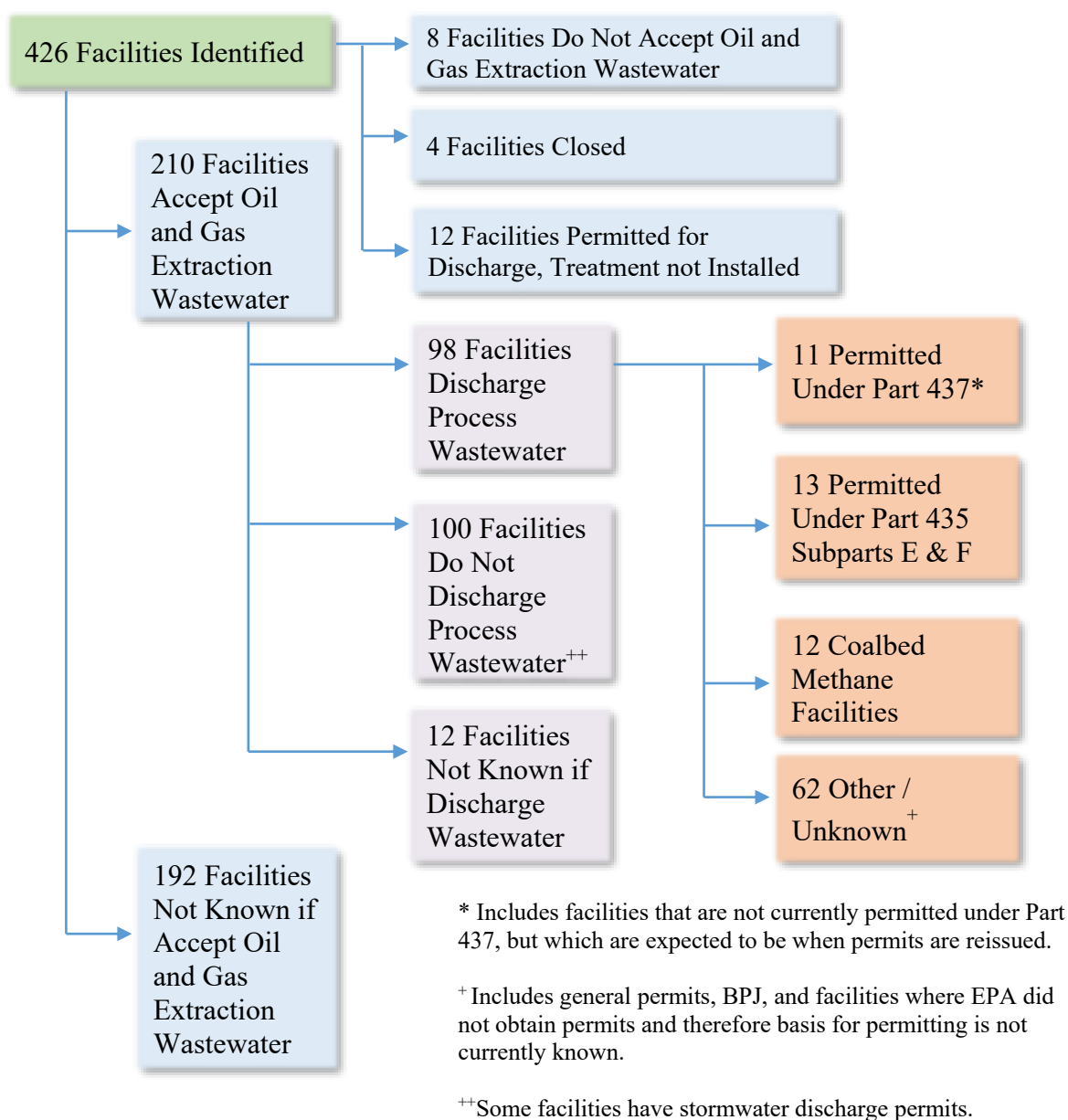


Figure 4-3. CWT and Oil and Gas Wastewater Treatment Facilities by Permit Type and Discharge Status

Some facilities are permitted for discharge, but do not discharge wastewater from oil and gas extraction waste treatment. Rather, the oil and gas extraction wastes are segregated from other waste streams for treatment and/or management and are not discharged. EPA collected information on some of these facilities to assess the broader CWT market. Additionally, EPA identified several facilities that had obtained NPDES permits to discharge; however, information available to EPA indicates that these facilities had not yet been constructed or had not yet installed necessary treatment to meet effluent limitations as of late 2016.

EPA identified 13 facilities that are permitted for discharge under the oil and gas ELGs at 40 CFR Part 435¹⁰. EPA collected information (such as type of treatment in place) from some of these facilities. EPA also identified 12 coalbed methane treatment facilities (EPA did not collect any additional information on these facilities because EPA evaluated CBM and determined in 2013 not to pursue a rulemaking for this industry). There were 62 facilities for which EPA did not identify the permitting mechanism and did not identify any information indicating that these facilities are in-scope of this study. Limitations on available information regarding the discharge status and nature of the wastes accepted at facilities possibly caused EPA to mischaracterize some proportion of facilities; additional data collection will be needed to make determinations about facilities' activities and applicability. For the purposes of this study, EPA only considered facilities in-scope if the wastewater accepted, discharge status, and permitting mechanism could all be confirmed.

For this study EPA is primarily interested in those facilities that accept wastes from oil and gas extraction activities and that are permitted for discharge (and are or have discharged) under the CWT ELGs at 40 CFR Part 437. EPA has focused most of its data collection activities on this subset of facilities. In addition, there are some facilities that are not currently permitted under Part 437, but information available to EPA indicates that these facilities will be subject to the CWT ELGs when permits are re-issued. These facilities are also in-scope for this study since these facilities may be affected by any changes to Part 437 requirements in the future. EPA has identified 11 facilities that accept oil and gas extraction wastes and are either currently permitted under Part 437 or information available to EPA indicates will be permitted under Part 437 when NPDES permits are reissued. These 11 facilities are the primary focus of this study. Table 4-4 lists the facilities that EPA has identified as being in-scope, or potentially in-scope, for this study.

For each of the potentially in-scope facilities identified in Table 4-4, EPA attempted to obtain additional information, such as types and quantities of wastes accepted, and treatment technologies utilized. EPA collected information and data using a variety of methods, including internet searches and review of NPDES permits. EPA held teleconferences with personnel at some facilities to obtain details of the operations at those facilities. In addition, EPA conducted site visits at select in-scope facilities, as well as other facilities that manage oil and gas extraction wastewaters, to collect information about each facility's operations, wastewater management practices and treatment technologies. Table 4-5 lists the facilities that EPA visited as part of this study. EPA prepared a Site Visit Report for each of the facility site visits; these references are also listed in the table.

¹⁰ These facilities were identified incidentally during EPA's search for Part 437 facilities; therefore, this is not a comprehensive list and there may be more Part 435 facilities.

Table 4-4. Summary of In-Scope Discharging CWT Facilities Treating Oil and Gas Extraction Wastes

Facility Name	City	State	Discharge Type	Facility Notes
Byrd/Judsonia Water Reuse/Recycle Facility	Judsonia	AR	Direct	Facility is permitted for discharge, but operates almost exclusively as a recycle facility and discharges infrequently.
Clarion Altela Environmental Services (CAES)	Clarion	PA	Direct	Facility is permitted for discharge, but as of late 2016 facility was not accepting wastewater for discharge.
Eureka Resources, Standing Stone Facility	Wysox	PA	Direct	
Eureka Resources, Williamsport 2 nd Street Plant	Williamsport	PA	Indirect	
Fairmont Brine Processing, LLC	Fairmont	WV	Direct	
Fluid Recovery Services: Franklin Facility (Aquatech)	Franklin	PA	Direct	Facility is not currently permitted under part 437, but revised permit expected to contain part 437 limitations.
Fluid Recovery Services: Josephine Facility (Aquatech)	Josephine	PA	Direct	Facility is not currently permitted under part 437, but revised permit expected to contain part 437 limitations.
Fluid Recovery Services: Creekside Facility (Aquatech)	Creekside	PA	Direct	Facility is not currently permitted under part 437, but revised permit expected to contain part 437 limitations
Max Environmental Technologies, Inc - Yukon Facility	Yukon	PA	Direct	Accepts drilling muds and cuttings for stabilization and solidification along with other industrial wastes. Facility is permitted for discharge of CWT wastes.
Patriot Water Treatment, LLC	Warren	OH	Indirect	
Waste Treatment Corporation	Warren	PA	Direct	

Note: EPA identified one additional facility, the Cares McKean facility in Pennsylvania, that was previously permitted under Part 437. However, the most recent permit for this facility issued in 2016 no longer includes the CWT ELGs indicating that this facility no longer discharges process wastewater from Part 437-regulated activities.

Table 4-5. List of Facilities Visited by EPA

Facility Name	Location	Date of Visit	Site Visit Report Citation
Anticline Disposal	Pinedale, WY	August 29, 2016	ERG, 2016b
Fluid Recovery Services, Josephine Facility	Indiana, PA	June 2, 2016	ERG, 2016a
Eureka Resources, Standing Stone Facility	Wysox, PA	June 1, 2016	ERG, 2017b
Fairmont Brine Processing, LLC	Fairmont, WV	December 8, 2015	ERG, 2016d
Patriot Water Treatment, LLC	Warren, OH	October 28, 2014	U.S. EPA, 2015b
Seneca Resources Corporation	Covington, PA	August 6, 2014	U.S. EPA, 2015d
Nuverra Appalachian Water Services	Masontown, PA	July 29, 2014	U.S. EPA, 2014
Reserved Environmental Services, LLC	Mt. Pleasant, PA	July 28, 2014	U.S. EPA, 2015c
McCutcheon Enterprises Inc.	Apollo, PA	July 28, 2014	U.S. EPA, 2015a

4.3 In-Scope CWT Facility Summaries

The following discussion summarizes information obtained by EPA for each of the potentially in-scope facilities identified in Table 4-4. A series of tables is presented that includes relevant information collected for each facility. In addition, a discussion of each facility presents key information and findings.

Table 4-6 shows the address and latitude/longitude for each potentially in-scope facility. As can be seen, with the exception of the Byrd/Judsonia facility in Arkansas, all of the potentially in-scope facilities are located near the Marcellus shale region. The locations of in-scope facilities are shown in Figure 4-4.

Table 4-7 shows the type of discharge (either direct or indirect) for each potentially in-scope facility, as well as the NPDES permit number, applicable subpart of the CWT ELGs that forms the basis of the technology-based effluent limitations in each permit and the receiving water body each facility discharges to. Two of the facilities, the Eureka Resources 2nd Street plant and the Patriot Water Treatment, LLC plant are indirect dischargers while the remaining facilities are permitted for direct discharge.

Table 4-8 shows the types of wastes accepted at each facility, based on various data sources. One source, the Pennsylvania Department of Environmental Protection Oil and Gas reporting website¹¹, uses reports of waste disposition provided by producers. As this data is self-reported by the producers of the waste, it is possible that producers may indicate an incorrect waste type. EPA has not verified the accuracy of these reports.

Table 4-9 lists some of the treatment technologies utilized at each facility, taken from publicly available sources such as NPDES permit fact sheets or internet searches. It is noteworthy that the level of treatment in-place at facilities varies, with some facilities using

¹¹ <https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/Welcome/Agreement.aspx>.

technologies such as evaporation or distillation that are capable of removing dissolved solids (such as chlorides) while others provide only limited treatment such as chemical precipitation.

There are pollutants that are found in oil and gas extraction wastes that are not currently regulated by the CWT ELGs. Permits for some facilities contain limitations for some of these pollutants, which are based on water quality criteria or other factors. Table 4-10 and Table 4-11 show the permit limitations for select pollutants that are not contained in the current CWT ELGs at 40 CFR part 437, but that are commonly associated with certain oil and gas extraction wastes such as produced waters. Pollutants include barium, strontium, bromide, gross alpha and beta radiation, radium (226 and/or 228) TDS, chlorides and osmotic pressure. As can be seen in these tables, some of the permits for in-scope facilities contain numeric effluent limitations or monitoring requirements for these pollutants, while others do not.

Table 4-6. In-Scope Facility Summary – Location Information

Facility Name	Facility Address ^a	Latitude	Longitude ^b
Byrd/Judsonia Water Reuse/Recycle Facility	4301 Highway 157 N Judsonia, AR	35.443	-91.691
Clarion Altela Environmental Services (CAES)	3099 Piney Dam Rd Clarion, PA	41.170	-79.437
Eureka Resources, Standing Stone Facility	34640 Route 6 Wysox, PA	41.748	-76.332
Eureka Resources, Williamsport 2 nd Street Plant	419 2 nd Street Williamsport, PA	41.237	-77.008
Fairmont Brine Processing, LLC	168 AFR Drive Fairmont, WV	39.507	-80.126
Fluid Recovery Services: Franklin Facility	5148 U.S. Route 322 Franklin, PA	41.373	-79.798
Fluid Recovery Services: Josephine Facility	931 Bells Mill Rd. Josephine, PA	40.482	-79.171
Fluid Recovery Services: Creekside Treatment Facility	5035 U.S. Route 110 West Creekside, PA	40.677	-79.186
Max Environmental Technologies, Inc - Yukon Facility	233 Max Lane Yukon, PA	40.212	-79.699
Patriot Water Treatment, LLC	2840 Sferra Ave Warren, OH	41.261	-80.824
Waste Treatment Corporation	123 West Harmar Street Warren, PA	41.839	-79.161

^a Addresses obtained from permit documents, may be approximate or may be office location, not facility location.

^b Latitude/Longitude may be for permitted outfall or facility.



Figure 4-4. In-Scope Facility Map

Table 4-7. In-Scope Facility Summary – Permit and Discharge Information

Facility Name	Type of Discharge	Discharge Permit Number	CWT ELGs Subpart	Receiving Water or POTW
Byrd/Judsonia Water Reuse/Recycle Facility	Direct	AR0052051	B	Unnamed tributary of Holcomb Branch
Clarion Altela Environmental Services (CAES)	Direct	PA0103632	D	Piney Creek
Eureka Resources, Standing Stone Facility	Direct	PA0232351	D	Susquehanna River
Eureka Resources, Williamsport 2 nd Street Plant	Indirect to POTW	NDWD C-20 ^b	C	City of Williamsport, PA
Fairmont Brine Processing, LLC	Direct	WV0116408	D	Monongahela River
Fluid Recovery Services: Franklin Facility	Direct	PA0101508	N/A ^a	Allegheny River
Fluid Recovery Services: Josephine Facility	Direct	PA0095273	N/A ^a	Blacklick Creek
Fluid Recovery Services: Creekside Treatment Facility	Direct	PA0095443	N/A ^a	McKee Run
Max Environmental Technologies, Inc - Yukon Facility	Direct	PA0027715	A	Sewickley Creek
Patriot Water Treatment, LLC	Indirect to POTW	N/A ^b	C	City of Warren, OH
Waste Treatment Corporation	Direct	PA0102784	A	Allegheny River

^a Current NPDES permit does not contain 40 CFR Part 437 ELGs.

^b Indirect discharging facilities do not hold NPDES permits, but instead comply with pretreatment standards which are generally implemented through control agreements issued by the POTW.

Table 4-8. In-Scope Facility Summary – Wastes Accepted

Facility Name	Types of Wastes Accepted	Data Source(s)
Byrd/Judsonia Water Reuse/Recycle Facility	Treated fluids from the exploration, production and development of oil and/or gas operations.	Site Visit; NPDES permit; Questionnaire
Clarion Altela Environmental Services (CAES)	Drilling fluid waste, fracturing fluid waste, produced fluid, servicing fluid.	PA DEP Oil and Gas Reporting Website – Waste Reports
Eureka Resources, Standing Stone Facility	Drilling fluid waste, fracturing fluid waste, produced fluid, other oil and gas wastes (unspecified).	PA DEP Oil and Gas Reporting Website – Waste Reports; Site Visit and Questionnaire
Eureka Resources, Williamsport 2 nd Street Plant	Drilling fluid waste, fracturing fluid waste, produced fluid, servicing fluid.	PA DEP Oil and Gas Reporting Website – Waste Reports
Fairmont Brine Processing, LLC	Drilling fluid waste, fracturing fluid waste, produced fluid.	PA DEP Oil and Gas Reporting Website – Waste Reports; Site Visit and Questionnaire
Fluid Recovery Services: Franklin Facility	Drilling fluid waste, fracturing fluid waste, produced fluid, servicing fluid.	PA DEP Oil and Gas Reporting Website – Waste Reports
Fluid Recovery Services: Josephine Facility	Drilling fluid waste, fracturing fluid waste, produced fluid, servicing fluid.	PA DEP Oil and Gas Reporting Website – Waste Reports; Site Visit and Questionnaire
Fluid Recovery Services: Creekside Treatment Facility	Drilling fluid waste, fracturing fluid waste, produced fluid.	PA DEP Oil and Gas Reporting Website – Waste Reports
Max Environmental Technologies, Inc - Yukon Facility	Drill cuttings, drilling fluid waste, flowback fracturing sand, fracturing fluid waste, produced fluid.	PA DEP Oil and Gas Reporting Website – Waste Reports
Patriot Water Treatment, LLC	Drill cuttings, drilling fluid waste, fracturing fluid waste, other oil and gas wastes (unspecified), produced fluid, servicing fluid.	PA DEP Oil and Gas Reporting Website – Waste Reports; Site Visit and Questionnaire
Waste Treatment Corporation	Drill cuttings, drilling fluid waste, fracturing fluid waste, produced fluid, servicing fluid.	PA DEP Oil and Gas Reporting Website – Waste Reports; Questionnaire

Table 4-9. In-Scope Facility Summary – Treatment Technologies Utilized

Facility Name	Treatment Technologies Utilized	Design or Permitted Treatment Capacity (gallons/day)
Byrd/Judsonia Water Reuse/Recycle Facility	Sedimentation basins, induced gas flotation, bag filter, mechanical vapor recompression.	168,000 (permitted)
Clarion Altela Environmental Services (CAES)	Sedimentation basins, chemical precipitation, thermal distillation (AltelaRain®).	62,500 (permitted)
Eureka Resources, Standing Stone Facility	Clarification, chemical precipitation, mechanical vapor recompression, membrane biological reactors, ion exchange, reverse osmosis.	420,000 (pretreatment for recycle) 210,000 (crystallization)
Eureka Resources, Williamsport 2 nd Street Plant	Clarification, chemical precipitation, mechanical vapor recompression.	337,500 (permitted)
Fairmont Brine Processing, LLC	Chemical precipitation, oil/water separation, bag filter, granulated activated carbon filter, evaporation and crystallization, ion exchange.	210,000
Fluid Recovery Services: Franklin Facility	Aeration, oil/water separation, chemical precipitation, clarification.	300,000 (permitted)
Fluid Recovery Services: Josephine Facility	Oil/water separation, aeration, chemical precipitation, clarification, bag filtration.	155,000 (permitted)
Fluid Recovery Services: Creekside Treatment Facility	Oil/water separation, chemical precipitation, clarification, bag filtration.	63,000 (permitted)
Max Environmental Technologies, Inc - Yukon Facility	Lime neutralization, flocculation, sedimentation.	173,000 (average)
Patriot Water Treatment, LLC	Settling, chemical precipitation, clarification.	100,000
Waste Treatment Corporation	Chemical precipitation, filtration, oil/water separation, mechanical vapor recompression.	213,000 (permitted)

Note: Information obtained from facility permits, fact sheets or internet searches.

Table 4-10. In-Scope Facility Summary – Effluent Limitations for Select Parameters Not Currently Regulated at 40 CFR Part 437 (Monthly Averages)

Facility Name	Monthly Average Effluent Limitations									
	Outfall	Barium (mg/L)	Strontium (mg/L)	Bromide (mg/L)	Gross A (pCi/L)	Gross B (pCi/L)	Radium 226 + 228 (pCi/L)	TDS (mg/L)	Chlorides (mg/L)	Osmotic Pressure (mOs/kg)
Byrd/Judsonia Water Reuse/Recycle Facility	001	--	Monitor*	--	--	Monitor*	Monitor (Ra226)*	354	94	--
Clarion Altela Environmental Services (CAES)	501	10	10	Monitor	Monitor	--	Monitor	500	250	3,571
Eureka Resources, Standing Stone Facility	002	10	10	--	--	--	--	500	250	--
Eureka Resources, Williamsport 2 nd Street Plant	1	2.0	2.0	Monitor	Monitor*	Monitor*	Monitor*	250	125	--
Fairmont Brine Processing, LLC	001	Monitor	Monitor	Monitor	7.5	498	2.5	Monitor	Monitor	--
Fluid Recovery Services: Franklin Facility	001	Monitor	Monitor	--	--	--	--	Monitor	147**	--
Fluid Recovery Services: Josephine Facility	001	114	--	--	--	--	--	Monitor	Monitor	Monitor
Fluid Recovery Services: Creekside Treatment Facility	401	14.64	--	--	--	--	--	Monitor	Monitor	483
	501	13.78	--	--	--	--	--	Monitor	Monitor	4,128
Max Environmental Technologies, Inc - Yukon Facility	001	4.0	--	--	--	--	--	--	--	1,000
	201	--	--	--	--	--	--	--	--	--
Patriot Water Treatment, LLC	--	--	--	--	--	--	--	--	--	--
Waste Treatment Corporation	001	--	--	--	--	--	--	--	Monitor	Monitor

-- No effluent limitation listed in permit.

* Quarterly.

** Mass-based limitation (lbs/min).

Table 4-11. In-Scope Facility Summary – Effluent Limitations for Select Parameters Not Currently Regulated at 40 CFR Part 437 (Daily Maximums)

Facility Name	Daily Maximum Effluent Limitations									
	Outfall	Barium (mg/L)	Strontium (mg/L)	Bromide (mg/L)	Gross A (pCi/L)	Gross B (pCi/L)	Radium 226 + 228 (pCi/L)	TDS (mg/L)	Chlorides (mg/L)	Osmotic Pressure (mOs/kg)
Byrd/Judsonia Water Reuse/Recycle Facility	001	--	--	--	--	--	--	534	141	--
Clarion Altela Environmental Services (CAES)	501	20	20	--	--	--	--	1,000	500	7,142
Eureka Resources, Standing Stone Facility	002	20	20	--	--	--	--	1,000	500	--
Eureka Resources, Williamsport 2 nd Street Plant	1	3.0	3.0	--	--	--	--	375	188	--
Fairmont Brine Processing, LLC	001	--	--	--	15	1000	5	--	--	--
Fluid Recovery Services: Franklin Facility	001	--	--	--	--	--	--	--	245**	--
Fluid Recovery Services: Josephine Facility	001	228	--	--	--	--	--	--	--	--
Fluid Recovery Services: Creekside Treatment Facility	401	29.28	--	--	--	--	--	--	--	980***
	501	27.56	--	--	--	--	--	--	--	5,879***
Max Environmental Technologies, Inc - Yukon Facility	001	8.0	--	--	--	--	--	--	--	2,000
	201	--	--	--	--	--	--	--	--	--
Patriot Water Treatment, LLC	--	--	--	--	--	--	--	50,000*	--	--
Waste Treatment Corporation	001	--	--	--	--	--	--	--	--	--

-- No effluent limitation listed in permit.

* Maximum allowable TDS in indirect discharge is 50,000 mg/L or 41,700 lbs/day. Facility pays a surcharge for TDS above 1,500 mg/L.

**Mass-based limitation (lbs/min).

*** Instantaneous maximum.

4.3.1 Byrd/Judsonia Water Reuse/Recycle Facility

This facility began operating in 2013 and manages wastewater from wells operated by Southwestern Energy's Fayetteville shale operations. The facility is permitted for discharge; however, it is EPA's understanding from discussions with representatives of Southwestern Energy that the facility rarely discharges treated wastewater. Instead, wastewater is reused in other oil and gas operations. EPA conducted a site visit at the Judsonia facility in September 2013 (U.S. EPA, 2015e) as part of EPA's unconventional oil and gas extraction rulemaking (81 FR 41845). In addition, in 2016 the facility completed a technical and an economic questionnaire obtained under authority of section 308 of the Clean Water Act. At the time of the 2013 site visit, the treatment technologies utilized included sedimentation, oil skimming, aeration, Purestream Services' induced gas flotation (IGF) technology to remove suspended solids and oils, bag filtration and evaporation using Purestream Services' mechanical vapor recompression (MVR) technology. The condensate from the MVR is stored in holding tanks until recycled for reuse in well development or discharged. Concentrated brine is stored in a brine tank prior to disposal or reuse.

The facility is permitted under the CWT ELGs, with direct discharge limitations from Subpart B, NSPS (40 CFR 437.24). The technology-based effluent limitations serve as the basis of the permit limits for some metals (arsenic, chromium, cobalt and tin) as well as all organic parameters found at 437.24. The permit contains limits that are more stringent than the CWT NSPS limitations for TSS, oil and grease and several metals (cadmium, copper, lead, mercury and zinc). In addition, the permit contains limitations for several parameters not included in the CWT Subpart B ELGs (carbonaceous biochemical oxygen demand (BOD), ammonia-nitrogen (NH₃-N), dissolved oxygen (DO), chlorides, sulfates, total dissolved solids (TDS), chromium (III), chromium (VI), nickel, silver and cyanide). The permit also contains monitoring requirements, but no limitations, for radium-226, strontium-90, gross beta radiation, and chronic whole effluent toxicity (WET).

See Figure 4-5 for an aerial view of the facility. The sedimentation basins, the aerated impoundment and the holding tanks are clearly visible. U.S. EPA, 2015e contains additional details on this facility.



Figure 4-5. Aerial View of Judsonia Treatment Facility

4.3.2 Clarion/Altela Environmental Services (CAES)

This commercial facility is co-located with a power plant and permitted to discharge several wastestreams including treated shale gas extraction wastewater. EPA did not conduct a site visit at this facility, but did have a phone call with representatives of Altela, Inc. (Altela) in November 2015 to obtain additional facility information. The facility operates the AltelaRain® evaporative technology. The technology was developed with Department of Energy funding and described in a series of reports including NETL, 2011 and U.S. DOE, 2014. The facility also includes technologies to pretreat the wastewater prior to the evaporative technology, described at U.S. EPA, 2017b.

The facility is permitted under the CWT ELGs, with direct discharge limitations from Subpart D, NSPS (40 CFR 437.45(b)). There is an internal monitoring point (IMP) 501 in the permit that contains the limitations for the treated shale gas extraction wastewater. The CWT ELGs serve as the basis of the permit limits for all parameters regulated at 40 CFR 437.45(b), with the exception of oil and grease. The oil and grease limitations in the permit are more stringent than the technology-based limitations at 40 CFR 437.45(b). IMP 501 also includes

limitations for several additional parameters not regulated at 40 CFR 437.45(b) (TDS, osmotic pressure, barium, strontium and chloride) and also requires monitoring and reporting for ammonia-nitrogen, total uranium, bromide, gross alpha, and radium 226/228. Figure 4-6 shows an aerial view of the CAES facility. Several impoundments are visible, as well as a building that houses the treatment system and evaporators.



Figure 4-6. Aerial View of CAES Facility

4.3.3 Eureka Resources, Standing Stone Facility

Eureka Resources operates two commercial CWT facilities in Pennsylvania – the Standing Stone facility located in Bradford County and the Reach Road facility located in the city of Williamsport. EPA conducted a site visit of the Standing Stone facility in June 2016. In addition, in 2016 the facility completed a technical and an economic questionnaire obtained under authority of section 308 of the Clean Water Act. EPA also conducted wastewater sampling at the Standing Stone facility in 2016. A discussion of the sampling data collected is included in Sections 5 and 7 of this report.

Eureka Resources utilizes a variety of technologies at their facilities, including oil/water separation, chemical precipitation, distillation and crystallization using mechanical vapor recompression, biological treatment utilizing membrane biological reactors, and reverse osmosis. Eureka also employs methanol rectification to recover methanol and reduce the organic content of the wastewater. Eureka Resources recovers marketable by-products during treatment, such as methanol, sodium chloride and calcium chloride. See Figure 4-7 for an aerial view of the Standing Stone facility.

The Standing Stone facility is permitted under the CWT ELGs, with direct discharge limitations from Subpart C, NSPS (40 CFR 437.34). The technology-based effluent limitations serve as the basis of the permit limits for all pollutants regulated at 437.34. In addition, there are discharge limitations for pollutants not contained in the CWT ELGs at 437.34 (TDS, chloride, oil and grease, $\text{NH}_3\text{-N}$, barium, iron and strontium). The permit also contains monitoring requirements, but no effluent limitations, for nitrogen compounds and phosphorus.

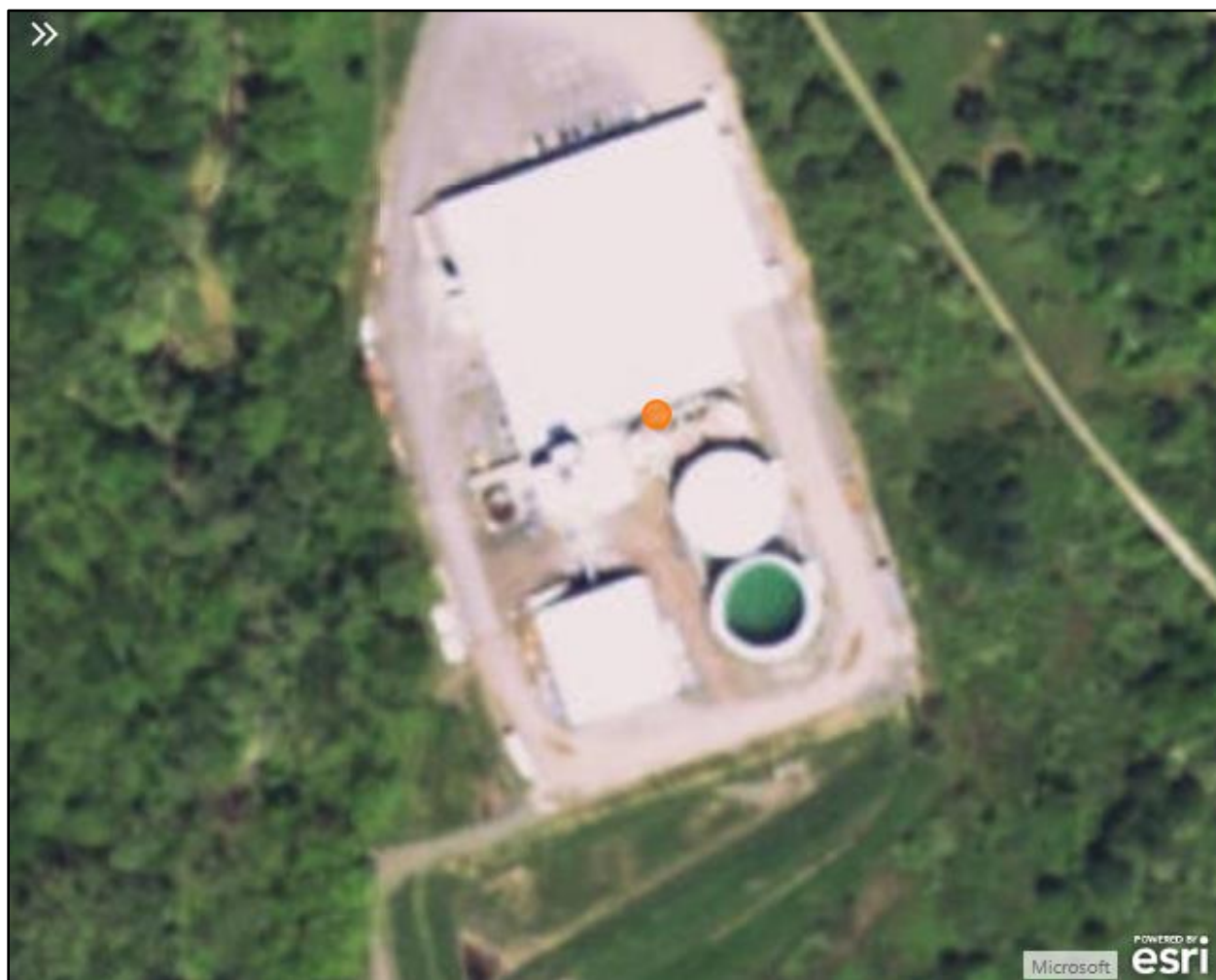


Figure 4-7. Aerial View of Eureka Standing Stone Facility

4.3.4 Eureka Resources, Williamsport 2nd Street Plant

Eureka Resources operates a commercial CWT facility in Williamsport, PA servicing operators in the Marcellus Shale region. EPA conducted a site visit at the Eureka Williamsport facility in June 2012 as part of EPA’s unconventional oil and gas extraction rulemaking (81 FR 41845). At that time, the facility was permitted to accept wastewaters from drilling, fracturing and production. The facility offers treated wastewater for reuse to operators, and also can discharge indirectly to the Williamsport, PA POTW. Treatment technologies utilized at the facility include chemical precipitation, clarification, and evaporation/condensation using mechanical vapor recompression. See the Eureka Site Visit Report for additional information obtained during the EPA site visit of the facility (U.S. EPA, 2012).

The facility is permitted under the CWT ELGs, with indirect discharge limitations from Subpart C, PSNS (40 CFR 437.36). The technology-based effluent limitations serve as the basis of the permit limits for all pollutants regulated at 437.36. In addition, the facility is subject to numeric local limits for TDS, chloride, COD, arsenic, barium, copper, lead, strontium, sulfates, and oil and grease. The facility is also subject to monitoring requirements for a range of other pollutants, notably bromide, surfactants, methanol, glycols, gross alpha/beta radiation, and radium 226/228. Figure 4-8 shows an aerial view of the facility.



Figure 4-8. Aerial View of Eureka 2nd Street Facility

4.3.5 Fairmont Brine Processing, LLC

Fairmont Brine Processing, LLC (Fairmont) operates a commercial CWT facility in Fairmont, WV that provides wastewater treatment services for producers in the Marcellus Shale region. EPA conducted a site visit at the Fairmont facility in December 2015. See U.S. EPA,

2015d for additional details on this facility. In addition, in 2016 the facility completed an economic questionnaire obtained under authority of section 308 of the Clean Water Act.

The treatment system at the facility incorporates a number of technologies, including oil water separation, chemical precipitation for barium and metals removal, bag filtration for solids removal, granulated activated carbon filtration for organics control, evaporation/crystallization for TDS and chlorides removal, and ion exchange for final polishing for ammonia. The evaporative system uses a multiple-effect process and the facility recovers marketable by-products during treatment, such as sodium chloride crystals and calcium chloride solutions.

The Fairmont Brine facility is permitted under the CWT ELGs, with direct discharge limitations from Subpart D NSPS with combined wastes from Subpart A and B (40 CFR 437.45(c)). The technology-based effluent limitations serve as the basis of the permit limits for all parameters regulated under this subpart. In addition, there are more stringent daily limitations for total copper and bis(2-ethylhexyl) phthalate in the permit. The permit also contains numeric effluent limitations for several pollutants not included in the CWT ELGs (ammonia-nitrogen, residual chlorine, gross alpha and gross beta radiation, radium 226/228 and chronic toxicity) and monitoring requirements, but no limitations, for a number of additional pollutants (including chloride, barium, strontium, lithium and bromide).

See Figure 4-9 for an aerial view of the facility. The unloading area, process building, and impoundments are clearly visible.

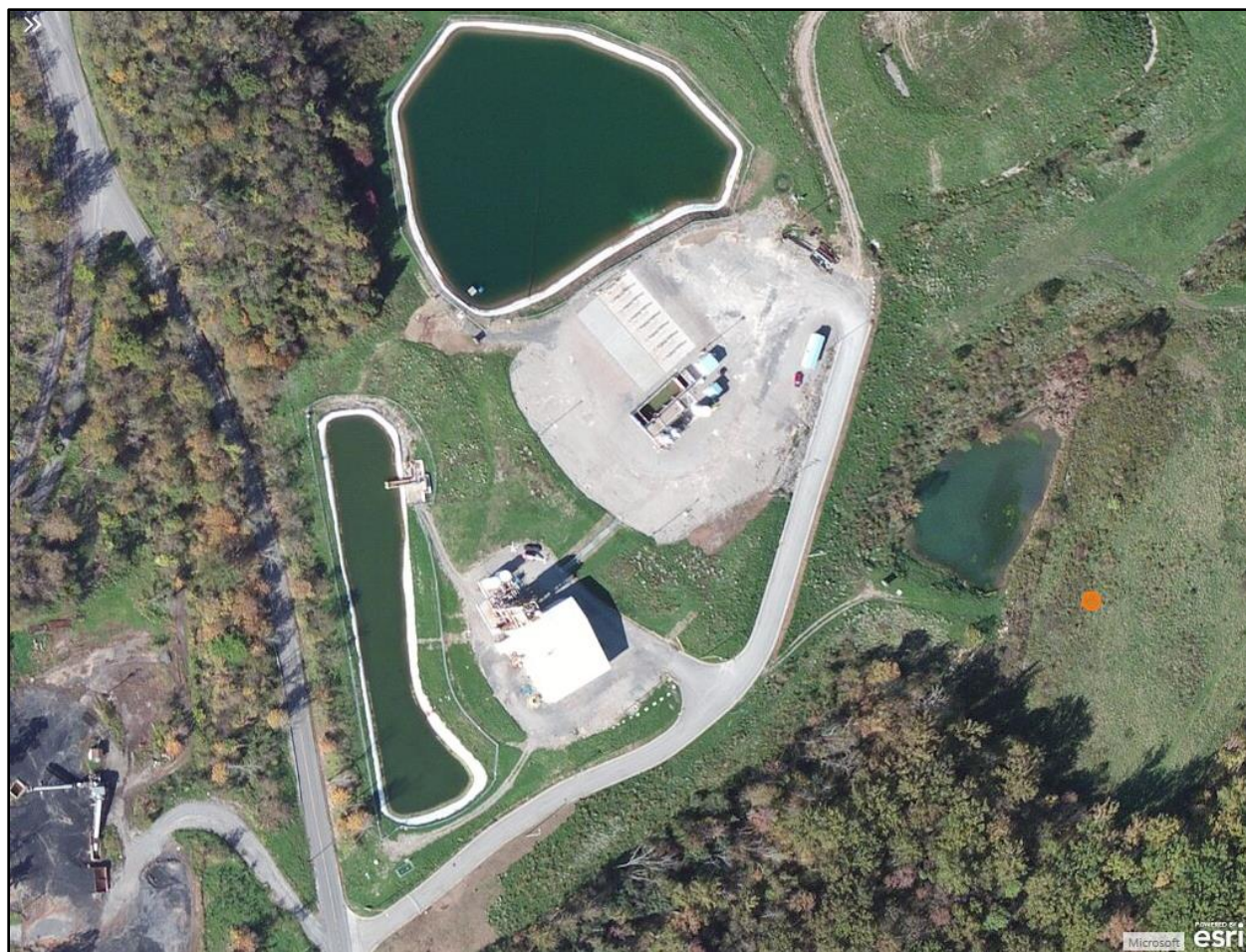


Figure 4-9. Aerial View of Fairmont Brine Facility

4.3.6 Fluid Recovery Services: Franklin Facility

Fluid Recovery Services (FRS) operates four commercial CWT facilities servicing operators in and around Pennsylvania. The parent company of FRS is Aquatech International LLC. As of late 2016, three of the FRS facilities were discharging wastewater. A fourth facility (the Rouseville facility), was not discharging wastewater and was being used only as a waste transfer facility as treatment necessary to meet discharge limitations had not yet been installed¹².

The Franklin facility utilizes treatment technologies including aeration, oil/water separation, chemical precipitation and clarification (PA DEP, 2008a). As of April 2017, the facility does not have treatment in place to remove TDS or chlorides. The discharge permit does not contain the CWT effluent limitations – discharge limitations are based on BPJ and water quality criteria. However, it is EPA’s understanding that the facility will be subject to the CWT

¹² The Rouseville facility is permitted for discharge under the CWT ELGs with direct discharge limitations from Subpart D NSPS with combined waste receipts from Subparts A, B and C (40 CFR 437.45(b)). The permit also contains limitations for TDS and chloride. See NPDES permit number PA0263516.

ELGs when the permit is reissued at some point in the future. The current NPDES permit includes limitations for oil and grease, TSS, iron, copper and silver. The permit also contains a mass-based limitation on chloride. The permit restricts discharge to a maximum of 0.30 MGD, and the daily maximum chloride limitation is 245 pounds per minute. The permit also includes additional monitoring requirements, notably for barium, strontium and TDS. The NPDES permit expired in February 2015, and the facility is currently operating under an administratively continued permit. Figure 4-10 shows an aerial view of the facility.



Figure 4-10. Aerial View of Fluid Recovery Services Franklin Facility

4.3.7 Fluid Recovery Services: Josephine Facility

EPA conducted a site visit at the Josephine facility in June of 2016. In addition, the facility completed a technical and an economic questionnaire obtained under authority of section 308 of the Clean Water Act. At the time of the site visit, the facility was operating a treatment system consisting of oil/water separation, aeration, chemical precipitation, clarification and bag filtration (PA DEP, 2008b). As of April 2017, the facility does not have treatment in place to remove TDS or chlorides. Similar to the Franklin facility, the discharge permit for the Josephine facility does not contain the CWT effluent limitations. However, it is EPA's understanding that

the facility will be subject to the CWT ELGs when the permit is reissued at some point in the future. The current NPDES permit includes limitations for oil and grease, TSS, iron and barium. The permit does not contain any limitation on chlorides or TDS, although it does contain monitoring requirements for TDS, chlorides and osmotic pressure. The permit restricts discharge to a maximum of 0.155 MGD. The NPDES permit expired in June 2013, and the facility is currently operating under an administratively continued permit. See Figure 4-11 for an aerial view of the facility.

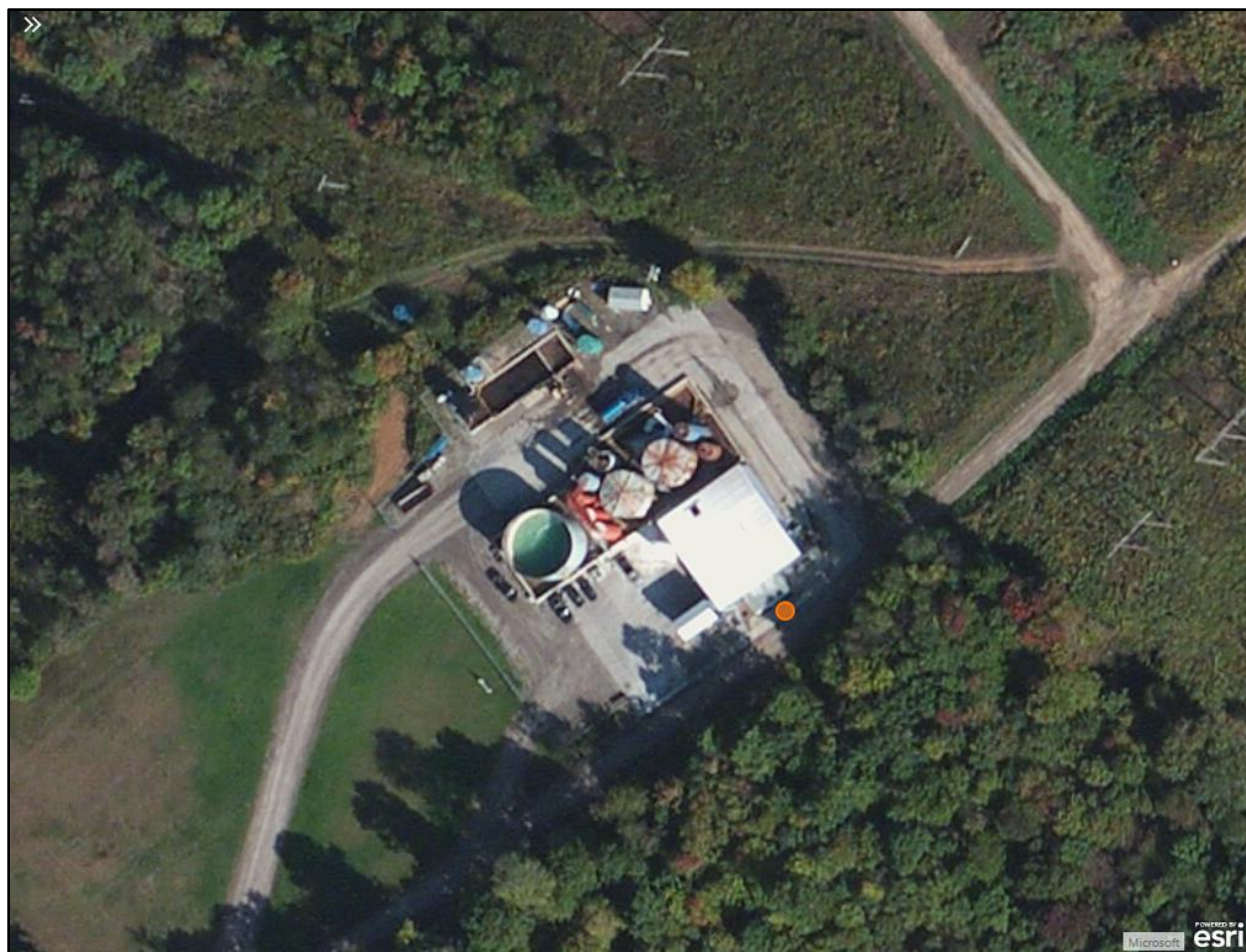


Figure 4-11. Aerial View of Fluid Recovery Services Josephine Facility

4.3.8 Fluid Recovery Services: Creekside Treatment Facility

The Creekside facility utilizes treatment technologies including aeration, oil/water separation, chemical precipitation and clarification (PA DEP, 2013). As of April 2017, the facility does not have treatment in place to remove TDS or chlorides. Similar to both the Josephine and Franklin facilities, the discharge permit does not contain the CWT effluent limitations. However, it is EPA's understanding that the facility will be subject to the CWT ELGs when the permit is reissued at some point in the future. The current NPDES permit includes limitations for oil and grease, TSS, iron, barium and osmotic pressure. The permit does

not contain any limitation on chloride or TDS, although the permit does contain monitoring requirements for these parameters. The permit restricts discharge to a maximum of 0.045 MGD. The NPDES permit expired in July 2013, and the facility is currently operating under an administratively continued permit. Figure 4-12 shows an aerial view of the facility.

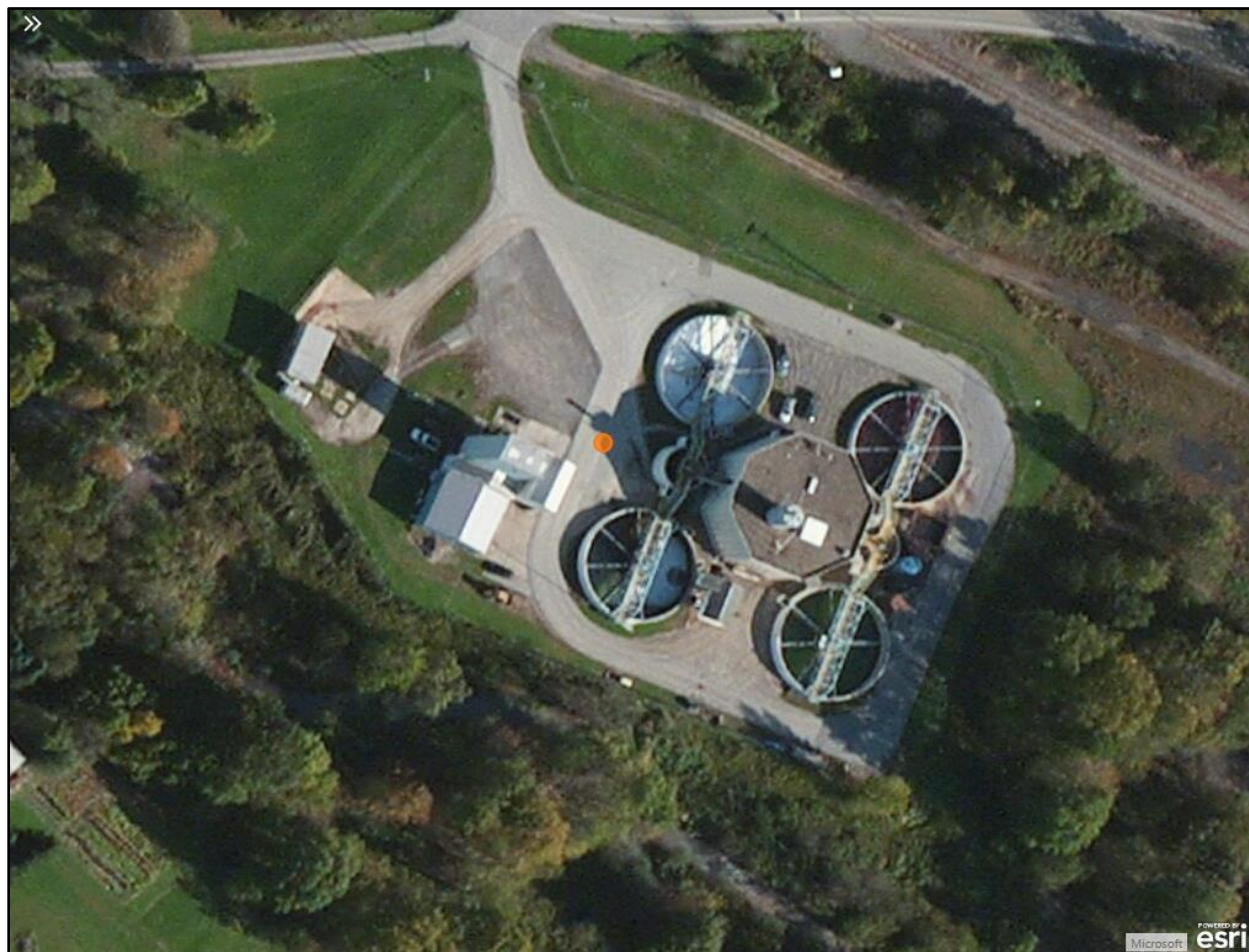


Figure 4-12. Aerial View of Fluid Recovery Services Creekside Facility

4.3.9 Max Environmental Technologies, Inc - Yukon Facility

This facility includes a landfill and on-site hazardous waste treatment system. The most recent NPDES permit was issued in July 2004. The permit expired in July 2009 and has been administratively continued. This site is permitted to accept several different wastes and contains several permitted outfalls. Internal outfall 201 is for the hazardous liquid slurry treatment system, and the effluent limitations are based on 40 CFR 437 subpart A.

The pollution report for the facility (PA DEP, 2004) indicates that the average discharge of outfall 201 is 173,000 gpd and that this is an intermittent discharge. The pollution report also indicates that the facility discharges continuously thorough outfall 001 at an average discharge of 280,000 gpd. Outfall 001 includes several waste streams, such as treated pickle liquor

wastewater from iron and steel manufacturing, treated waste storage area storm water, mine drain wastewater, and leachate from the co-located landfill. Effluent limitations for outfall 001 are based on various sources.

While the facility accepts waste from oil and gas extraction activities, and the PA DEP oil and gas reporting website indicates producers have utilized the facility for management of several different waste types, information obtained from the Pennsylvania Department of Environmental Protection indicates that these wastes are not discharged under the NPDES permit, but rather are solidified for disposal. Therefore, while the facility is currently permitted under Part 437, and the facility does accept oil and gas extraction wastes, the facility would not be affected by any changes to Part 437 given EPA's current understanding of operations.



Figure 4-13. Aerial View of Max Environmental Technologies, Inc. Yukon Facility

4.3.10 Patriot Water Treatment, LLC

This facility is a commercial facility permitted for indirect discharge to the City of Warren, Ohio POTW. EPA conducted a site visit of the Patriot Water Treatment, LLC (Patriot) facility on October 28, 2014. In addition, the facility completed a technical and an economic

questionnaire obtained under authority of section 308 of the Clean Water Act. At the time of the site visit, the facility was treating oil and gas extraction wastewater, industrial wastewater and oil and gas drilling muds. Treatment for oil and gas extraction wastewater at the facility consists of settling, chemical precipitation and clarification. The facility does not have technologies for TDS or chlorides removal. The permit with the City of Warren allows for a daily discharge up to 100,000 gallons per day at 50,000 mg/L (or approximately 41,700 pounds per day) of TDS from treating oil and gas extraction wastewaters. The facility also accepts wastewater from industrial sources, which is treated through a parallel treatment train consisting of chemical precipitation and clarification. Drilling muds are centrifuged to separate solids and liquids, or else mixed with sawdust to absorb water. Additional details of the facility can be found at U.S. EPA, 2015b.

The facility's permit contains pretreatment standards from the CWT ELGs, Subpart C, PSNS (40 CFR 437.36) and the limitations for copper, zinc, acetone, acetophenone, 2-butanone, phenol and pyridine that apply to direct discharging facilities as well (40 CFR 437.31). In addition, the permit incorporates ordinance effluent limitations for additional pollutants including metals, free cyanide, ammonia, pH, COD, TDS, and TSS. Effluent concentrations exceeding daily maximum discharge limitations for COD, TDS, and TSS (600 mg/L, 1,500 mg/L, and 250 mg/L, respectively) are subject to additional surcharge. The permit also contains monitoring requirements but no limitations for cadmium, lead, silver and total cyanide. Figure 4-14 shows an aerial view of the Patriot facility.

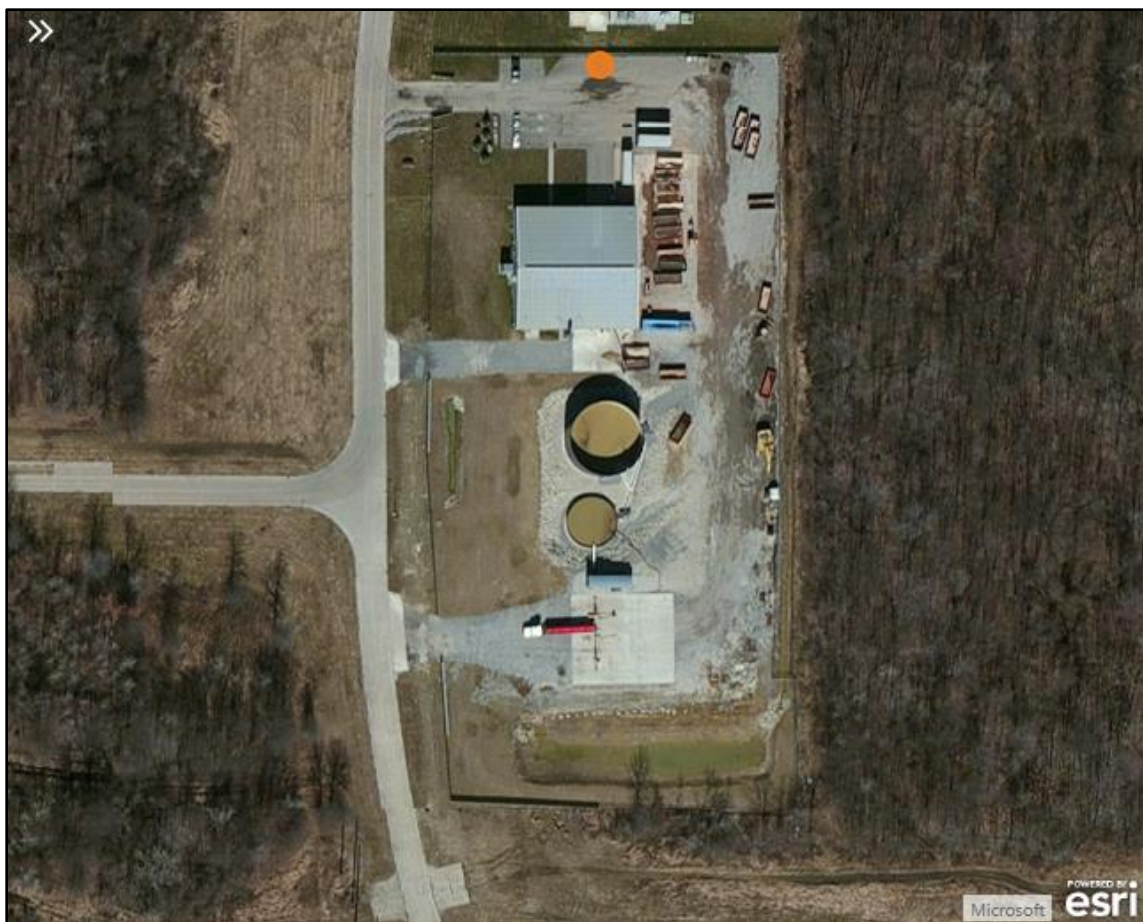


Figure 4-14. Aerial View of Patriot Water Treatment, LLC Facility

4.3.11 Waste Treatment Corporation

Waste Treatment Corporation operated a commercial CWT facility in Warren, PA¹³. EPA did not conduct a site visit at this facility; however, the facility did provide details regarding operations and treatment technologies utilized at the facility (Roddy, 2016). The facility accepted wastewater for discharge from wells defined as conventionally drilled according to Pennsylvania. The facility indicated that, as of June 2016, wastewater from unconventionally (as defined by Pennsylvania) drilled wells was not being discharged¹⁴. Technologies used at the site include

¹³ This facility closed in November, 2017.

¹⁴ Pennsylvania defines an unconventional formation as “A geological shale formation existing below the base of the Elk Sandstone or its geologic equivalent stratigraphic interval where natural gas generally cannot be produced at economic flow rates or in economic volumes except by vertical or horizontal well bores stimulated by hydraulic fracture treatments or by using multilateral well bores or other techniques to expose more of the formation to the well bore.”

In April 2011, the Pennsylvania Secretary of Environmental Protection requested that all unconventional oil and gas developers cease taking wastewater to processing facilities and sewage treatment plants.

oil/water separation, chemical precipitation, clarification, filtration and mechanical vapor recompression for TDS and chlorides removal.

The facility is permitted under the CWT ELGs, with direct discharge limitations for internal outfalls 101 and 201 from Subpart A, BAT (40 CFR 437.13). The permit also includes BAT cyanide limitations. The technology-based effluent limitations serve as the basis of the permit limits for all metals and cyanide found at 437.13. The permit also contains limitations for oil and grease, TSS, iron, aluminum and selenium for outfalls 101 and 201, and CBOD₅ and total residual chlorine for outfall 201. Outfall 001, which receives wastewater from internal outfalls 101 and 201 as well as stormwater, includes limitations for cadmium, fecal coliform and acrylamide, and monitoring requirements for chlorides, osmotic pressure and toxics. The permit for this facility expired in November of 2008 and has been administratively continued. Figure 4-15 shows an aerial view of the facility.



Figure 4-15. Aerial View of Waste Treatment Corporation Facility

4.4 Other Facilities Treating Oil and Gas Extraction Wastes

Although EPA identified 11 facilities as being potentially in-scope of this study, there are a number of other facilities in the country that are managing oil and gas extraction wastes. These facilities may be treating wastewater for discharge under the beneficial reuse provisions of 40 CFR 435 Subpart E, treating wastewater for uses such as irrigation or groundwater recharge, treating wastewater for reuse in oil and gas operations, or evaporating wastewater as a means of disposal.

As these facilities are not the focus of this study, EPA did not collect comprehensive information about these facilities. EPA identified only a few state data systems that are available on-line that can be used to identify these facilities, and there is limited information available from these data systems to indicate characteristics of these facilities, such as the types of waste accepted and whether any process wastewater is discharged. Information collected about these facilities is included in the CWT facility list (ERG, 2018).

The information collected by EPA indicates that there are a variety of treatment systems in use across the country at these not-in-scope facilities. While these facilities are likely not subject to the CWT ELGs, information about these facilities (such as the type, cost and performance of treatment technologies) is relevant to this study as this information is potentially transferrable to in-scope facilities. Therefore, Table 4-12 summarizes select facilities that are not in-scope, but identified as having relevant information on treatment technology cost and performance. This table is limited to facilities that include technologies for TDS removal.

Table 4-12. Select Oil and Gas Wastewater Treatment Facilities with TDS Removal Technologies

Facility Name	Location	Facility Notes	Source
Chevron, San Ardo Water Reclamation Facility	San Ardo, CA	This facility discharges to shallow groundwater recharge basins. The facility is not permitted to discharge to surface water. Treatment includes induced gas flotation, walnut shell filtration, ion exchange, and reverse osmosis.	Webb, 2009
Anticline Disposal	Boulder, WY	This facility is permitted to discharge produced water under the beneficial reuse provisions of the oil and gas ELGs (40 CFR 435 Subpart E). Treatment includes anaerobic and aerobic biological treatment, coagulation, flocculation, sand filters, ultrafiltration, reverse osmosis and ion exchange. EPA conducted wastewater sampling at the Anticline Disposal facility. A discussion of the sampling data collected is included in Sections 5 and 7 of this report. In addition, the facility completed a technical and an economic questionnaire obtained under authority of section 308 of the Clean Water Act.	ERG, 2016b
Freeport-McMoRan Oil and Gas Produced Water Reclamation Facility	Arroyo Grande, CA	This facility is permitted to discharge produced water to Pismo Creek. Treatment includes microfiltration, reverse osmosis and ion exchange.	Facility Permit (CA0050628)

4.5 Demand for CWT Services for Managing Oil and Gas Extraction Wastes

As the level of exploration, development, and production activity by oil and gas firms increases, so does the generation of wastes requiring management. Many factors affect the amount of wastes generated, the amount requiring disposal and how oil and gas firms decide to manage those wastes. These factors include:

- **The amount of wastewater that is able to be reused or recycled.** Wastewater can be treated on- or offsite and reused or mixed with freshwater and reused to drill or fracture new wells. This use may require various levels of treatment, depending on the quality of the produced water and operational needs in a particular oil or gas formation (Veil, 2015). Reuse depends on the number of new wells being drilled. As drilling activity slows, so does the need for recycled wastewater. Consequently, the need for other management options may increase in these instances.
- **The amount of wastewater that is injected underground for disposal.** Underground injection for disposal is a common onshore practice, but requires presence of suitable injection wells. Most Class II wells suitable for oil and gas wastewater injection are in Texas, California, Oklahoma, and Kansas (U.S. EPA, undated). Where access to disposal wells is limited, demand for other wastewater management options (including CWT services) may be higher. In addition, concerns over induced seismicity may limit injection well capacity in certain areas, resulting in increased demand for alternative management options.
- **Transportation Costs of Alternatives.** A number of economic factors can influence relative costs of alternative waste and wastewater management services. For example, trucking is a principal form of transportation of wastewater, and may account for 65 to 80 percent of total wastewater management costs (Warlick, 2014). Reuse or recycle of wastewater can be an economical wastewater management solution, especially if transport is not needed or trucking distances are limited. Other important considerations include the location of the wastewater relative to new oil and gas wells, underground injection wells, or CWT facilities, as proximity might make treatment or disposal a more economical option. Also, piping wastewater, where permissible, can reduce transportation costs.
- **Other technical factors.** The quantity and quality of produced water depends on the location of drilling (producing formation), as does the quality and quantity of water needed for drilling and fracturing (U.S. EPA, 2015).

As the number of producing wells increases, it is likely that the demand for CWT services will increase as well. This is particularly true in areas where other disposal options or reuse options are limited. The demand for CWT services depends on both the type and quantity of producing wells as well as the level of drilling activity. Demand also depends on crude oil and

natural gas prices. Between their peak of \$105.79 per barrel in June 2014 and April 2016, crude oil spot prices fell about 60 percent (U.S. DOE, 2016a). In the first quarter of 2014, Henry Hub gas prices averaged \$5.20 per million Btu (mmBtu) before falling as much as 66 percent to \$1.76 per mmBtu in April 2016 (U.S. DOE, 2016b). This decrease in oil and gas prices has led to a drop in drilling activity, with rig counts falling 73 percent between October 2014 and April 2016 (Zborowski, 2016). With fewer opportunities for reuse/recycle, increasing volumes have been sent to CWT facilities for treatment and discharge services (Litvak, 2016). More recently, crude oil and Henry Hub prices have recovered slightly but remain below their 2014 peaks. In November 2017, the Henry Hub price averaged \$3.01 per mmBtu, and crude oil spot prices averaged \$56.64 per barrel (U.S. DOE, 2017a; U.S. DOE, 2017b). In addition, drilling activity has recovered, with the rig count as of the week ending December 8, 2017 at 931, up from the all-time low of 480 in March 2016 (OGJ, 2017; Zborowski, 2016).

4.6 Competition and Cost Pass-Through Potential in OGE/UOG Activity Basins

As stated above, proximity to oil and gas operations is an important consideration for firms providing CWT services. Demand and the types of services needed vary across market areas tied to natural resource basins. Large diversified waste management companies often compete with smaller regional companies for wastewater volumes.

Generally, CWT facilities are one of several options for wastewater management. Certain regional and local areas may have constraints on the total number of options available for wastewater management, and CWT facilities must interact with potential competitors in that market structure. The market share for CWT facilities differs across these different regional and local areas giving CWT facilities different abilities to adjust price in relation to prospective competition, oil and gas operations density and proximity, and regulatory requirements.

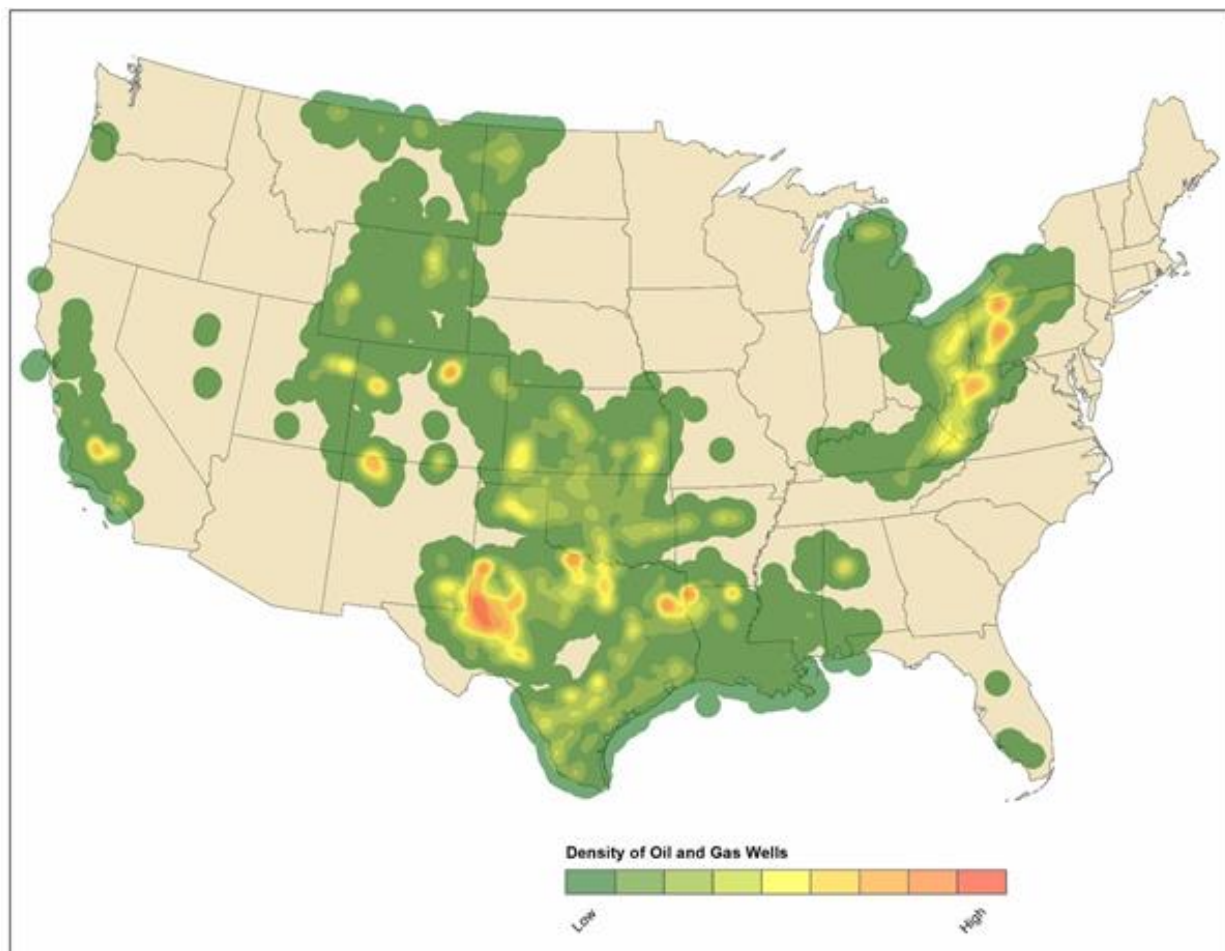
4.7 Location and Number of Onshore Oil and Gas Extraction Wells

EPA evaluated the number and location of existing onshore¹⁵ oil and gas extraction wells (excluding CBM) to provide an overview of potential wastewater sources that might be managed by CWT facilities. For this evaluation, EPA used Drillinginfo's (DI) Desktop® Well File Database, a nationwide database of all oil and gas wells (ERG, 2016e) to develop a list of all active oil and gas wells (excluding CBM wells) by basin (as defined by DI Desktop®). This list was developed in March 2015 and reflects 2014 well counts.

Appendix B presents the total number of active wells within each oil and gas basin (as of 2014), as well as the number of wells by state. Over 1.1 million wells were identified in the DI Desktop® database. The Permian basin had the largest number of wells with almost 300,000 wells.

¹⁵ EPA's analysis did not consider the number and location of offshore or coastal wells.

Figure 4-16 is a map illustrating the concentration of onshore wells throughout the country. As can be seen from Figure 4-16, there are several locations where oil and gas wells are clustered around the U.S. For example, Texas has a large number (nearly 519,000) of oil and gas wells.

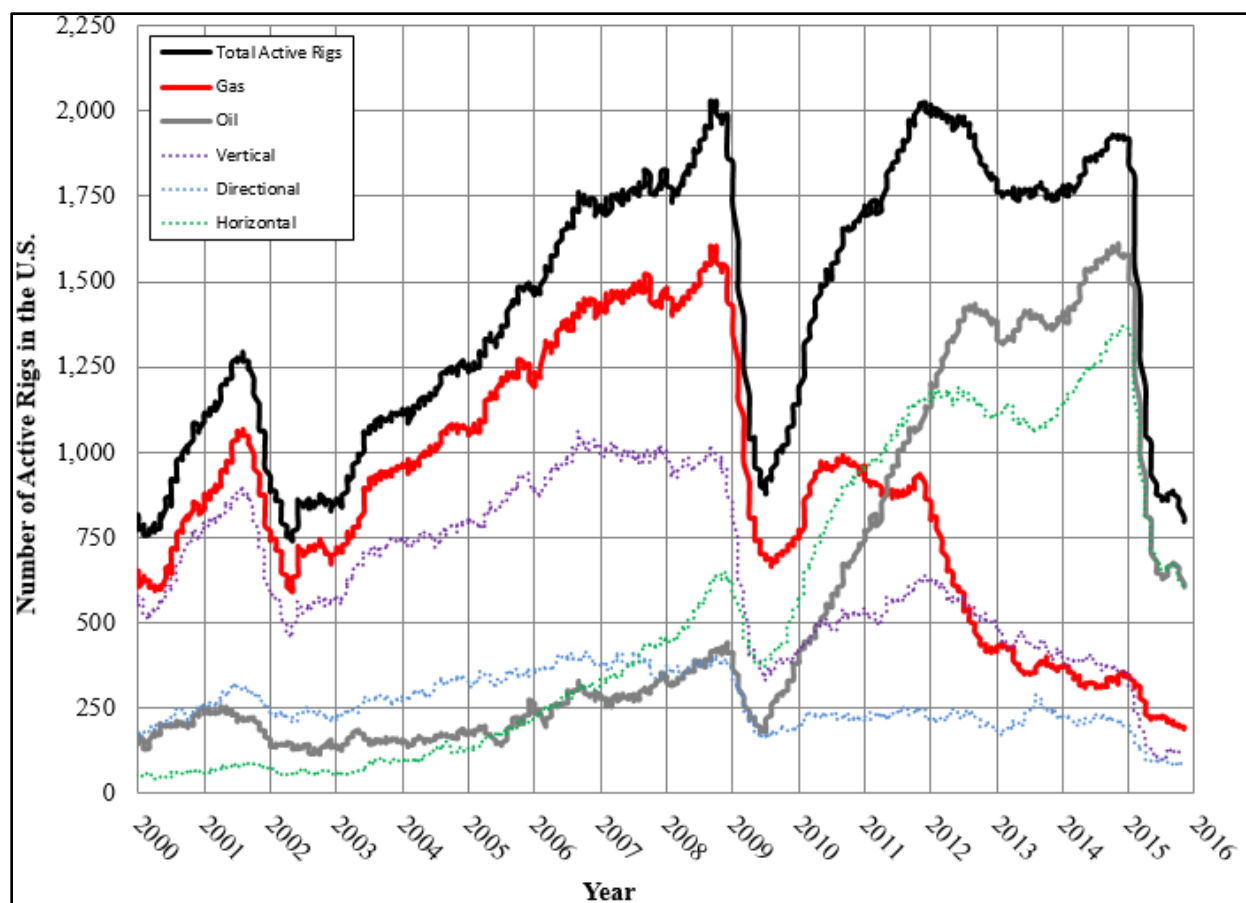


Source: Based on 2014 data from Drillinginfo's Desktop® Well File Database, obtained in 2015.

Note: The lowest density locations on the map have up to 0.2 wells per square kilometer, the highest density locations have more than 3.9 wells per square kilometer.

Figure 4-16. Density of U.S. Onshore Oil and Gas Well Locations

Figure 4-17 shows the estimated total number of active drilling rigs in the United States between January 2000 and October 2015 and shows drilling trajectory (i.e., directional, horizontal, vertical) and product type (i.e., crude oil, natural gas). While these counts include rigs that are drilling for CBM, it paints an overall picture of oil and gas activities in the United States. The sharp decreases in active drilling rigs observed in 2009 and 2015 are likely attributed to the sudden drop in natural gas and crude oil prices experienced in those years. (U.S. EPA, 2016f)



Source: U.S. EPA, 2016f (Section B.3.1, Figure B-13)

Figure 4-17. Number of Active U.S. Onshore Rigs by Trajectory and Product Type over Time

4.8 Proximity of Production Wells to CWT Facilities

To understand the potential market for CWT services for oil and gas extraction wastes, EPA evaluated the number of active oil and gas wells that are located proximally to known CWT facilities (ERG, 2017c). In conducting this evaluation, EPA evaluated proximity of all wells to the 11 in-scope facilities and performed a second analysis of the proximity of all wells to all Part 437 facilities in the CWT facility list. It is important to acknowledge that this analysis is limited because EPA has incomplete information on existing indirect discharging CWT facilities, as these facilities are not required to report to EPA. However, this evaluation does provide a useful screening to evaluate the number of wells that could potentially utilize CWT facilities for management of their wastes and identify areas that are currently not well served by CWT facilities.

For this analysis, EPA compared the CWT facility lists (in-scope and all Part 437) to a list of active oil and gas wells obtained from the DI Desktop® Well File Database. The total count of wells is based on the "Active Oil and Gas Wells" table of DI Desktop database, refined to include only wells with "Property Type" COM (completion), LEASE, and WELL that have

non-zero latitude and longitude values. EPA assumed that a separation of 100 miles or less between a well and a CWT facility constitutes a reasonable estimate of a generally economical transport distance for when a CWT facility could potentially be a viable alternative to treat wastes from a given well.

With respect to the 11 in-scope facilities, EPA estimates that approximately 148,500 active wells (or 13 percent of the total number of wells) are located within 100 miles of at least one in-scope facility (see Table 4-13). Of the over 1.1 million active wells considered in this analysis on the national scale, EPA estimates that approximately 280,000 (or 25 percent of the total number of wells) are located within 100 miles of at least one part 437 CWT facility. Results by state are summarized in Table 4-13 (ERG, 2017c).

Table 4-13. Counts of Total Oil and Gas Extraction Wells and Oil and Gas Extraction Wells within 100 Miles of a CWT Facility, by State

State	Total Well Count	Wells Within 100 Miles of a Part 437 CWT Facility		Wells Within 100 Miles of an In-Scope CWT Facility	
		Count	Percentage	Count	Percentage
AL	6,458	548	8.49%	0	0.00%
AK	1,825	0	0.00%	0	0.00%
AZ	25	0	0.00%	0	0.00%
AR	10,077	8,906	88.4%	5,638	56.0%
CA	23,187	5,327	23.0%	0	0.00%
CO	39,884	0	0.00%	0	0.00%
FL	60	60	100%	0	0.00%
KS	101,541	5,608	5.52%	0	0.00%
KY	14,505	13,798	95.1%	0	0.00%
LA	35,677	3,220	9.03%	0	0.00%
MD	3	3	100%	3	100%
MI	11,904	798	6.70%	0	0.00%
MS	3,361	1,754	52.2%	0	0.00%
MO	7	0	0.00%	0	0.00%
MT	9,839	0	0.00%	0	0.00%
NE	1,764	66	3.74%	0	0.00%
NV	60	0	0.00%	0	0.00%
NM	44,319	0	0.00%	0	0.00%
NY	8,979	8,978	99.9%	8,957	99.8%
ND	11,776	0	0.00%	0	0.00%
OH	39,170	37,999	97.0%	35,751	91.3%
OK	59,553	27,123	45.5%	0	0.00%
OR	15	14	93.3%	0	0.00%
PA	65,609	65,609	100%	65,609	100%

Table 4-13. Counts of Total Oil and Gas Extraction Wells and Oil and Gas Extraction Wells within 100 Miles of a CWT Facility, by State

State	Total Well Count	Wells Within 100 Miles of a Part 437 CWT Facility		Wells Within 100 Miles of an In-Scope CWT Facility	
		Count	Percentage	Count	Percentage
SD	220	0	0.00%	0	0.00%
TN	1,742	525	30.1%	0	0.00%
TX	518,939	54,494	10.5%	0	0.00%
UT	12,450	0	0.00%	0	0.00%
VA	6,195	6,195	100%	0	0.00%
WV	48,365	38,983	80.6%	32,552	67.3%
WY	31,239	0	0.00%	0	0.00%
Total	1,108,748	280,008	25.3%	148,510	13.4%

As seen in the table, many states appear underserved in terms of their access to CWT facilities, but some of these states might not have a need for CWT facilities, depending on other disposal options. For example, Texas has almost 519,000 oil and gas extraction wells, but only about 10 percent of those wells are within 100 miles of a CWT facility. However, Texas has over 32,000 active disposal wells (Railroad Commission of Texas, 2014). This availability of disposal wells reduces the demand for waste management at CWT facilities. In contrast, all of Pennsylvania's oil and gas extraction wells are within 100 miles of a CWT facility. This is true for the subset of in-scope facilities as well. Since Pennsylvania has few brine disposal wells (only eight brine disposal wells were permitted in Pennsylvania at the time of the study (McCurdy, 2015)), CWT services may be in higher demand in that state.

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5. WASTEWATER CHARACTERIZATION AND MANAGEMENT

To understand whether the current CWT ELGs are adequately managing wastewater discharges from CWT facilities accepting oil and gas extraction wastes, EPA collected and evaluated data regarding oil and gas wastewater characteristics, as well as data characterizing discharges from CWT facilities accepting oil and gas extraction wastes. These data are primarily taken from publicly available sources. EPA also conducted sampling at two facilities that discharge treated oil and gas extraction wastewater. Section 5.1 presents data broadly characterizing oil and gas extraction wastes and wastewater. Section 5.2 presents data on wastewater received at and discharged from in-scope CWT facilities, as well as data collected during EPA's sampling activities. Section 5.3 presents information about the volumes of wastewater generated by the oil and gas extraction industry and how that wastewater is currently managed.

5.1 Types of Oil and Gas Extraction Waste and Wastewater Characteristics

The exploration, development and production of oil and gas reserves vary markedly from region to region (U.S. Congress, 1992). There are a number of solid and liquid waste materials generated during oil and gas exploration, extraction and production, and these waste materials may be managed by CWT facilities. The nature and characteristics and quantity of the wastes generated depend upon a number of factors, such as the type of drilling, the characteristics of the formation, the depth of the well and the type and quantity of chemical additives used during drilling, production and well maintenance activities.

During drilling activities conducted for exploratory purposes and for production wells, solid and slurry materials such as drill cuttings and drilling muds are generated. These materials contain rock removed by the drill bit as well as water or oil-based fluids and additives, such as barite, that are pumped down the drilling pipe for purposes such as lubrication and to counteract the pressure contained in the formation.

Many wells generate large volumes of produced water, which is natural water contained in the oil or gas-bearing rock formations. Produced water can be very saline depending on the formation. In addition, depending on the source rock of the formation and the hydrocarbons present, produced water may contain pollutants such as TENORM¹⁶ and benzene. Other constituents of produced water include chemicals added for well treatment, such as corrosion inhibitors (U.S. Congress, 1992).

¹⁶ Technologically enhanced Naturally Occurring Radioactive material, or TENORM, is defined by EPA as "Naturally occurring radioactive materials that have been concentrated or exposed to the accessible environment as a result of human activities such as manufacturing, mineral extraction, or water processing."

"Technologically enhanced" means that the radiological, physical, and chemical properties of the radioactive material have been concentrated or further altered by having been processed, or beneficiated, or disturbed in a way that increases the potential for human and/or environmental exposures.

In wells that are hydraulically fractured, fracturing fluid - typically consisting of water, a number of chemical additives and a proppant (such as sand) - is pumped down the well bore under pressure to create and hold open fractures in the target formation that allow for the flow of oil and gas. Some fracturing fluid, as well as water from the formation, returns to the surface as flow-back.

Chemicals used in well servicing and maintenance, such as work-over fluids, can be contained in wastewaters that are generated by wells. Other waste sources include well completion, treatment and stimulation fluids; sediment, water and other tank bottoms; oily debris; contaminated soils; produced sands; and residuals from wastewater treatment systems located at the well site.

Once oil and gas enter the distribution system, wastes such as compressor station water are generated. Wastes generated from these mid-stream operations may also be managed at CWT facilities. In addition, downstream operations such as refining, storage and oil recycling may generate a number of wastes that may be transferred to CWT facilities for management. However, these wastes are not the focus of this study. The existing CWT regulations contain an oily wastes subcategory that are applicable to these downstream wastes.

The amount of characterization data available in the literature varies by waste and wastewater type, as well as location. For some waste types and for some basins, little data are available. In addition, wastes received at CWT facilities typically originate from many different well locations that are in various stages of development. As a result, wastes may contain mixtures of several different waste streams from various sources. For purposes of this study, EPA is most interested in drilling fluid wastes, fracturing fluid wastes and produced waters as these are the primary waste materials (by volume) reported as being accepted at CWT facilities.

5.1.1 Drilling Wastes

Drilling activities generate a number of waste materials, such as drill cuttings and spent drilling fluids. The solid materials are typically separated from the liquid materials using separation technologies such as shakers and centrifuges. Some of the muds may remain on the cuttings, depending on the degree of separation accomplished. These solid materials are typically treated or solidified/stabilized and then buried on-site, sent off-site to landfills, or diverted to other uses. These materials may also be managed by CWT facilities. Liquid wastes separated from the cuttings and spent drilling fluids may also be solidified/stabilized, or diverted to treatment either on-site or off-site. Off-site management options also include transfer to CWT facilities.

There are two main types of drilling fluids: water-based and non-aqueous systems. Water-based fluids consist of water (either fresh or brackish) with various additives to achieve the desired characteristics. Non-aqueous systems use a non-water soluble base fluid with water or brine dispersed within the base fluid. Non-aqueous drilling fluids include diesel, mineral oils, and synthetic-based fluids. There are a variety of materials added to drilling fluids. Materials

such as barite, clay, salts, polymers, diesel and synthetic oils, alkalines, surfactants, organic polymers, and droplets of emulsified oil are common constituents of drilling fluids (National Petroleum Council, 2011; Caen and Darley, 2011). Many of these materials would be expected to be found in wastewaters generated from drilling activities. Drilling fluids may also contain priority pollutants, such as polynuclear aromatic hydrocarbons.

EPA has identified data describing drilling wastewater and fracturing fluid characteristics. These data include technical evaluations of the impact of oil and gas extraction wastewater pollutants on POTW unit processes completed in response to Administrative Orders issued to a number of POTWs by PA DEP (Rost, 2010a and Rost, 2010b). All the data identified by EPA was specific to the Marcellus Shale. It should be noted that drilling wastewater commonly contains recycled produced water that has been minimally treated to make it suitable for re-use. As a result, drilling wastewater from wells using recycled water will differ from other wells where fresh water is utilized to formulate the drilling fluids.

Huffmyer (2013) examines the various techniques of drilling fluid waste treatment, including treatment of well head fluid, drill cuttings, drilling mud, and wastewater, and provides examples of reuse potential ranging from hydrocarbon use for energy recovery to drill cuttings incorporated into road base material. The author also provides a brief analysis of an example facility in the Marcellus shale region to highlight common influent contaminants and reuse applications. Typical drilling waste characteristics described include highly variable levels of strontium (10 – 1,400 mg/L), sulfate (0 – 1,500 mg/L), barium (25 – 2,000 mg/L), TSS (200 – 2,000 mg/L), and TDS (3,000 – 80,000 mg/L).

The PA DEP TENORM Study (PA DEP, 2016) conducted radiological surveys to assess the potential for exposure to TENORM by the general public and people working with wastes from O&G exploration. The study encompassed well sites, wastewater treatment plants, landfills, gas distribution and end use, and brine-treated roads and included sampling of solids, liquids, natural gas, air, and surface radioactivity. The study found notable activity in many samples of drilling fluids (Table 5-1) and fracturing fluids (Table 5-2).

Table 5-1. Ra-226, Ra-228, K-40, Gross Alpha and Gross Beta Activity in Drilling Fluids (PA DEP, 2016)

Parameter	Minimum	Maximum	Median	Number of Samples	Number of Non-Detects or Zero Values
Gross Alpha (pCi/L)	ND	3,820	2,700	5	3
Gross Beta (pCi/L)	ND	3,940	2,600	5	3
Radium 226 (pCi/L)	1,510	4,940	2,010	5	0
Radium 228 (pCi/L)	162	466	216	5	0
Potassium 40 (pCi/L)	420	11,400	5,220	5	0

ND = Non-Detect.

Table 5-2. Ra-226, Ra-228, K-40, Gross Alpha and Gross Beta Activity in Fracturing Fluids (PA DEP, 2016)

Parameter	Minimum	Maximum	Median	Number of Samples	Number of Non-Detects or Zero Values
Gross Alpha (pCi/L)	<1.39	54,100	5,020	11	0
Gross Beta (pCi/L)	<1.63	14,900	1,010	11	0
Radium 226 (pCi/L)	64	21,000	2,160	11	0
Radium 228 (pCi/L)	<9	1,640	218	11	0
Potassium 40 (pCi/L)	<21	456	283	11	0

Rost, 2010a and Rost 2010b are letters from the City of McKeesport to PA DEP in response to PA DEP’s Administrative Order on October 23, 2008, and each present analytical results from samples of wastes, including drilling waste. The McKeesport POTW analytical data was collected because the facility accepted wastewater from oil and gas extraction operations. Select parameters from samples of drilling wastes (identified as “drill water” and “pit water” in the references) are summarized in Table 5-3. These data show high dissolved solids, as well as varying concentrations of other pollutants such as barium, strontium and sulfate. Samples also exhibited radioactivity measured as gross alpha and gross beta.

Table 5-3. Concentrations of Select Pollutants in Drilling Wastewater (Rost, 2010a and 2010b)

Source	Parameter	Minimum	Maximum	Units	Number of Samples
Rost, 2010a	Aluminum	1.7	6,916	mg/L	7
	Ammonia	0.98	34.98	Mg/L	7
	Barium	2.55	471	mg/L	7
	BOD ₅	79.8	1,119	Mg/L	7
	Chloride	158	23,469	mg/L	7
	COD	153	9,270	mg/L	7
	Gross Alpha	16.6	3,022	pCi/L	5
	Gross Beta	32.49	4,172	pCi/L	5
	Sodium	167	15,726	mg/L	7
	Strontium	1.8	65	mg/L	7
	Sulfate	ND	525	mg/L	7
	TDS	557	39,500	mg/L	7

ND: Non-Detect.

U.S. EPA, 2013 is the supporting technical document for the Oil and Gas Exploration and Production Waste Exemption. This source includes analyses of drilling fluid wastewater in Pennsylvania in 2009. Drilling fluid wastewater contained high levels of salts, as well as high levels of strontium and barium (see Table 5-4 for example data).

Table 5-4. Concentrations of Select Pollutants in Drilling Wastewater (U.S. EPA, 2013)

Parameter	Value (mg/L)
Barium	20.9
Benzene	ND
Bromide	205
Chloride	17,500
COD	947
Sodium	12,200
Strontium	20.8
Sulfate	663
TDS	36,100
Toluene	ND
TSS	168

ND: Non-Detect.

Ziemkiewicz, 2013 conducted a Phase 1 study titled *Assessing Environmental Impacts of Horizontal Gas Well Drilling Operations*, endeavoring to identify any potential health effects of oil and gas exploration in the Marcellus Shale Formation on nearby communities. This report contains a literature review of drilling waste as well as a liquid waste stream characterization. The study characterized drilling mud, cuttings, and other fluids, identifying high levels of sodium, potassium and chloride. Results of analysis of drilling wastewater samples for select parameters are shown in Table 5-5. The reference provided one value for each parameter, which was the average of four samples. Note that the samples taken during this study were collected prior to the well reaching the Marcellus Shale formation.

Table 5-5. Concentrations of Select Pollutants in Drilling Wastewater

Parameter	Value	Units
Aluminum	1,208	mg/L
Barium	12.8	mg/L
Benzene	40.3	µg/L
Bromide	22.5	mg/L
Chloride	14,640	mg/L
Ethylbenzene	9.55	µg/L
Potassium	8,792	mg/L
Sodium	2,859	mg/L
Strontium	40.2	mg/L
Sulfate	1,568	mg/L
TDS	34,550	mg/L
Toluene	80.4	µg/L
TSS	47,300	mg/L
Xylene (total m, p and o)	109.7	µg/L

Source: (Ziemkiewicz, 2013)

5.1.2 Produced Water

Produced water is the largest wastewater source by volume generated during oil and gas extraction¹⁷. Produced water is the fluid (often called brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas and includes, where present, formation water, injection water, and any chemicals added downhole or during drilling, production or maintenance processes. Naturally occurring constituents include bromide, magnesium, and radioactive materials (U.S. EPA, 2016b). Materials added down-hole include hydraulic fracturing chemicals, well stimulation chemicals and well maintenance chemicals.

EPA defines produced water at 40 CFR 435.11(bb) as “the water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas, and can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process.”

The purpose, quantity and characteristics of materials utilized during well development, stimulation and maintenance are diverse. For example, EPA identified some 692 unique ingredients reported for additives, base fluids and proppants contained in more than 39,000 FracFocus¹⁸ disclosures provided by the Groundwater Protection Council (GWPC) (U.S. EPA, 2015a).

Table 5-6 describes the types and purposes of additives used in hydraulic fracturing, well development and well maintenance activities.

¹⁷ Coalbed methane extraction often generates produced water as a by-product of the gas extraction process. EPA is not aware of any Part 437 CWT facilities that are managing large quantities of CBM produced water. Rather, facilities managing CBM wastewater are permitted for discharge using best professional judgement. As a result, EPA does not discuss CBM wastewater further in this report. See U.S. EPA, 2010 for additional information on CBM wastewaters.

¹⁸ FracFocus is a publicly accessible website managed by GWPC and the Interstate Oil and Gas Compact Commission (IOGCC) where oil and gas production well operations can disclose information about ingredients used in hydraulic fracturing fluids at individual wells.

Table 5-6. Type and Purpose of Additives used in Well Development, Stimulation and Maintenance

Category of Additive ^a	Example Constituents ^b	Purpose
Acid	Hydrochloric acid; muriatic acid	Removes cement and drilling fluid from casing perforations prior to fracturing fluid injection.
Biocide	Glutaraldehyde; 2,2-dibromo-3-nitrilopropionamide	Inhibits growth of organisms that could produce gases (particularly hydrogen sulfide) that could contaminate methane gas; prevents the growth of bacteria that can reduce the ability of the fluid to carry proppant into the fractures by breaking down the gelling agent.
Breaker	Peroxydisulfate salts	Reduces the viscosity of the fluid by breaking down the gelling agents to release proppant into fractures and enhance the recovery of the fracturing fluid.
Clay Stabilizer	Potassium chloride	Creates a brine carrier fluid that prohibits fluid interaction (e.g., swelling) with formation clays; interaction between fracturing fluid and formation clays could block pore spaces and reduce permeability.
Corrosion Inhibitor	Ammonium bisulfite	Reduces rust formation on steel tubing, well casings, tools, and tanks (used only in fracturing fluids that contain acid).
Crosslinker	Borate salts; potassium hydroxide	Increases fluid viscosity to allow the fluid to carry more proppant into the fractures.
Friction Reducer	Petroleum distillates	Minimizes friction, allowing fracturing fluids to be injected at optimum rates and pressures.
Gel	Guar gum; hydroxyethyl cellulose	Increases fracturing fluid viscosity, allowing the fluid to carry more proppant into the fractures.
Iron Control	Citric acid	Sequestering agent that prevents precipitation of metal oxides, which could plug the formation.
pH Adjusting Agent	Acetic acid; potassium or sodium carbonate; sodium hydroxide	Adjusts and controls the pH of the fluid to maximize the effectiveness of other additives such as crosslinkers.
Proppant	Quartz; sand; silica	Used to hold open the hydraulic fractures, allowing the natural gas or crude oil to flow to the production well.
Scale Inhibitor	methylene phosphonic acid, polyacrylate	Prevents the precipitation of carbonate and sulfate scales (e.g., calcium carbonate, calcium sulfate, barium sulfate) in pipes and in the formation.
Surfactant	Isopropanol; naphthalene	Reduces the surface tension of the fracturing fluids to improve fluid recovery from the well after fracture is completed.

Sources: U.S. EPA, 2015; Acharya, 2011; FracFocus, 2014; CCST, 2014; ExxonMobil Corporation, 2014.

^a Operators do not use all of the chemical additives in hydraulic fracturing fluid for a single well: they decide which additives to use on a well-by-well basis.

^b The specific compounds used in a given fracturing operation will vary depending on company preference, base fluid quality, and site-specific characteristics of the target formation.

Data describing produced water sometimes differentiates between the initial flowback period and long-term produced water. Generally, produced water generated in the initial time period after hydraulic fracturing would be expected to contain a higher proportion of additives, while subsequent produced water would be expected to more closely approximate the formation water. For purposes of this study, EPA is generally not concerned with differentiation of wastewater characteristics between the initial flowback period and longer-term produced water.

This is because a typical CWT facility would be expected to receive wastewater from a variety of wells in various stages of exploration and production. Wastewater from various wells and from various producers are typically mixed prior to treatment.

Table 5-7 lists data sources EPA identified that contain data on produced water. For each reference, a brief description of the content of each data source is provided. Some of these sources present original data, and some also present data from other sources. References that contain data from other sources are indicated.

Table 5-7. Identified Data Sources for Produced Water Characteristics

Reference	Content
Acharya, 2011 ^a	Developed a cost-effective water recovery process for low TDS produced water from the Woodford formation of Oklahoma. Details in the study include fracturing fluid composition.
Benko, 2008 ^a	Literature review of approximately 33,000 data records, including data housed by USGS. Noted highly variable levels of TDS and identified common pollutants present in produced water in the western U.S.
Boschee, 2014 ^a	Reports options for reuse and recycling of produced water. Reports average TDS by producing region.
Bruff, 2011	Performed pre- and post-treatment water quality analysis of produced water in Pennsylvania. Reported significant radium and TDS in produced water before treatment.
Campbell, 2012	Used isotope investigation to determine characteristics of produced water TDS in northeastern and southwestern Pennsylvania.
Coleman, 2011	Reviewed analytical results for produced water from four shale plays. Reports that produced water characteristics are highly variable within and between formations.
Dunkel, 2012	Discusses options for improved water management in Texas. Details of study include analytical results of produced water from the Permian basin.
Gradient, 2009	Conducted exposure analysis of produced water waste to microbial POTW treatment processes. Reported that no disruption of biological treatment was expected to occur.
Haluszcak, 2012 ^a	Conducted chemical analysis of late-stage produced water from Marcellus wells in Pennsylvania. Determined high concentrations of TDS, chloride, bromide, sodium, calcium, barium, radium-226 and radium-228.
Hansen et al, 2013 ^a	Review of WVDEP, PADEP, and FracFocus Chemical Database Download records for Marcellus gas wells, focusing on water use and reuse. Also includes a discussion of waste generation in Pennsylvania.
Harju, 2009	Discusses water quality of Bakken produced water (North Dakota, Montana), noting salinity as high as 200,000 mg/L.
Havics, 2011	Study of fracturing fluid composition in Colorado. Noted high levels of salts, and detected benzene and low levels of radioactivity.
Hayes et al., 2012	Report characterizing flowback waters from 19 sites in Pennsylvania and West Virginia, and 5 sites in northern Texas. Noted high concentrations of TDS, COD, and high hardness in Pennsylvania/ West Virginia; noted lower levels of TDS and COD in Texas.
Hayes, 2011; Hayes et al., 2012	Presents characterization of flowback waters and produced waters West Virginia, Pennsylvania and Texas.
Horn, 2009	Describes a technology for mobile treatment of produced water for reuse. Notes that the process would be ineffective at high chloride levels.
Johnson & Harry, 2014	Produced water reuse feasibility study in the Uinta region. Noted relatively low levels of TDS in untreated water.

Table 5-7. Identified Data Sources for Produced Water Characteristics

Reference	Content
Kimball, 2012	Provides an analysis of produced water treatment and reuse systems. Includes review of TDS levels across 10 regions of the U.S.
Maguire-Boyle & Barron, 2014	Study reporting organic compounds found in produced water. Determined that shale produced water contains fewer organic constituents than CBM produced water.
Mantell, 2011	Technical workshop for hydraulic fracturing water management. Highlights variations in produced water quality between shale plays.
Mazoch, 2012	Study of Fayetteville shale region in Arkansas and Oklahoma. Notes low concentrations of TDS and metals.
McElreath, 2011	Comparison of western and eastern U.S. fracturing fluid composition. Noted no significant difference in conventional parameters, but some higher gross beta in the eastern U.S.
NYSDEC, 1999	Presents radioactivity analysis with 49 data points in New York for oil and gas waste.
NYSDEC, 2009	Draft proposed regulatory action regarding Marcellus shale, with full scale environmental review for New York. Includes produced water characteristics based on samples from West Virginia and Pennsylvania.
NYDEC, 2011	Revision of NYSDEC, 2009. Includes produced water characteristics, noted as high in TDS, surfactants, and metals.
ORD, 2014	Hydraulic fracturing data public record to support EPA ORD's Hydraulic Fracturing Study.
PADEP, 2016	TENORM evaluated for exposure to workers and public, primarily in northwestern Pennsylvania. Noted high levels of radium from unconventional wells and low levels of radium from conventional wells.
Palacios, 2012 ^a	Review of produced water quality testing in south Texas. Contains comparison of produced water and groundwater TDS content (produced water being on average 86,000 mg/L higher in concentration).
Rimassa, 2009	Laboratory produced water analysis from samples in northeast Texas and northwest Colorado. Result for Texas showed much higher TDS (147,000 mg/L) than Colorado (33,100 mg/L).
Rowan, 2011 ^a	Study of radium content in produced water in Pennsylvania and New York. Indicates wide range of radium content within Marcellus produced waters. Also indicated a correlation between TDS and radium content in Pennsylvania.
Silva et al., 2013	Reviews pretreatment targets for barium and radium for produced water in Pennsylvania. Notes high levels of TDS, and higher levels of radium and barium in central and eastern Pennsylvania.
Slutz, 2012	Notes strategies for produced water management. Contains characterization data for flowback from several shale plays.
Stepan, 2010	Outlines treatment and reuse opportunities in Bakken region (northwest U.S.). Details flow and concentration of pollutants over time.
Tipton, 2012	Outlines Oklahoma and Arkansas produced water reuse. Notes moderate to high TDS.
U.S. DOE, 2013	Report from U.S. DOE on produced water management options. Notes relative levels of salinity.
U.S. EPA, 1976	Supporting document for oil and gas effluent guidelines rulemaking effort. Noted high TDS for 7 regions in California, Texas, Louisiana, and Wyoming.
USGS, 2014 ^a	USGS Produced Waters Geochemical Database, updated version of 2002 USGS Produced Waters Database. Draws from 25 databases, publications, or reports.
Volz, 2011 ^a	Produced water characterization in western Pennsylvania. Noted high levels of barium, benzene, and high TDS.
Warner, 2013 ^a	Study of impact of produced water disposal on water quality in western Pennsylvania. Noted substantially higher levels of radium 226 in sediments at point of discharge than at upstream sediments.
Williams, 2011 ^a	Reviewed measurements of radionuclides of produced waters in the Marcellus region. Noted increasing TDS, chlorides, barium, and radioisotope concentrations as flowback volumes increased.

Table 5-7. Identified Data Sources for Produced Water Characteristics

Reference	Content
Williams, unknown ^a	This presentation describes the geology, development, and impact on water-resources of hydraulic fracturing in the Marcellus shale.
WY OGCC, 2015	Database of well analytical test results in Wyoming. Five produced water results above 100,000 mg/L TDS, and 51 results less than 100,000 mg/L TDS.
Yoxtheimer, 2012	Presentation on produced water treatment and reuse strategies. Notes water quality results for Bakken, Eagle Ford, Permian, and Utica formations.
Ziemkiewicz, 2013	Final Report for West Virginia DEP on the water quality literature review and field monitoring of active shale gas wells. Includes results of the literature review, water and waste stream monitoring including the plan, data analysis, and results.

^a Reference presents data from another source.

EPA selected a subset of these sources to describe in further detail and summarize the produced water characteristics. These sources were selected because of their data quality and quantity and their ability to represent a range of oil and gas produced water characteristics and constituents across the countries. More detailed summaries of these reports are presented below.

The USGS National Produced Waters Geochemical Database (USGS database) contains geochemical data for produced water and other deep formation waters from wells in the United States. The USGS created the database by compiling data from existing databases, publications, and reports; removing duplicates; and performing quality control procedures (USGS, 2014). The database is periodically updated (Version 2.1 includes data for almost 60,000 wells in 36 states¹⁹, sampled between 1900 and 2012). Data for select parameters from Version 2.2 of the USGS, database is shown in Figure 5-1 as box and whisker plots, showing the minimum (excluding non-detect values), 25th percentile, median, 75th percentile and maximum values for each parameter²⁰. For each constituent, the total number of samples as well as the number of samples with values greater than the detection limit are shown in parentheses (for example, there were 18,387 samples for barium, 11,369 of which were greater than the detection limit). As illustrated in Figure 5-1, the concentration of these select parameters varies greatly across the country. An example is TDS, which can vary significantly by basin. Figure 5-2 shows the box and whisker plots with TDS concentration data for the 10 basins with the greatest number of samples contained in Version 2.2 of the USGS database (TDS values below 10 mg/L are not shown in this plot). As illustrated by these data, TDS concentrations for samples contained in the database vary greatly, both within a specific basin and across different basins.

¹⁹ States include: Alabama, Alaska, Arizona, Arkansas, California, Colorado, Florida, Georgia, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Montana, Nebraska, Nevada, New Mexico, New York, North Dakota, Ohio, Oklahoma, Oregon, Pennsylvania, South Dakota, Texas, Utah, Virginia, Washington, West Virginia, and Wyoming.

²⁰ These plots were generated by extracting all data from the database for conventional hydrocarbon, shale gas, tight gas and tight oil well types. Zero values and entries listed as unknown were excluded from the counts and statistics.

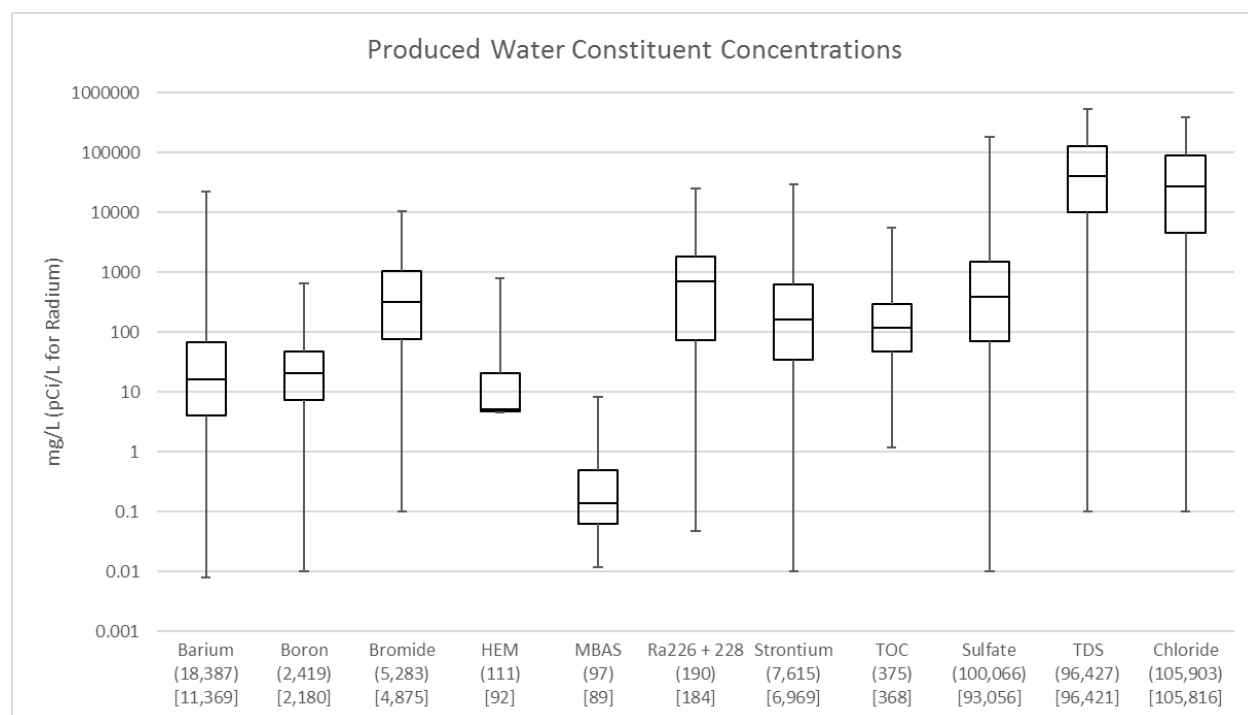


Figure 5-1. Oil and Gas Produced Water Constituent Concentration Data (USGS National Produced Waters Geochemical Database, V2.2)

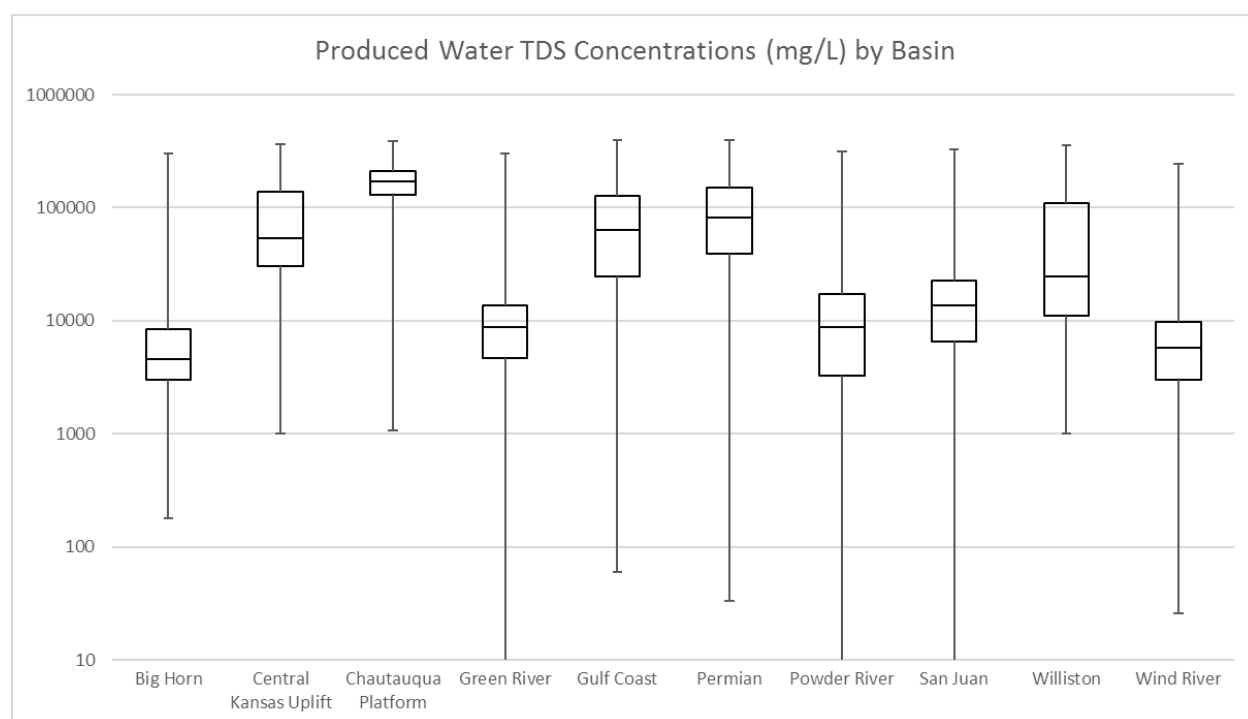


Figure 5-2. Oil and Gas Produced Water TDS Concentration by Basin (USGS National Produced Waters Geochemical Database, V2.2)

It should be noted that the USGS database has limitations. The earliest reported data included in the database are from the early 1900s. Analytical methods have evolved since that time, and the older data may not be as accurate or directly comparable to the newer data. In addition, not all of the records have a sample collection date. Also, analytical methods are not provided for all reported values.

Another data source (ORD, 2014) included produced water sampling results for Hogback, Conoco Phillips, Williams Production, and Clayton Williams Energy operators from 2004 to 2010. Data was collected for the U.S. EPA Office of Research and Development's general solicitation of data related to hydraulic fracturing. The public docket for that effort contains all related data and documents (EPA-HQ-ORD-2010-0674). The non-CBI data used in this report contains over 4,500 data points, with 2,690 of those reported results above detection limits. An average of 34,506 mg/L of TDS was recorded. Data for other select pollutants, such as radium, bromide, barium, and strontium, are shown in Table 5-8.

Table 5-8. Concentrations of Select Pollutants in Produced Water (ORD, 2014)

Parameter	Minimum	Maximum	Units	Number of Samples	Number of Zero Values*	Number of Non-Detects
Barium	0.963	787	mg/L	34	9	0
Benzene	0.0015	1.7	mg/L	9	0	0
BOD	244	2,120	mg/L	8	0	0
Bromide	270	798	mg/L	8	0	0
Chloride	698	141,200	mg/L	152	0	0
COD	1,360	3,070	mg/L	8	0	0
Ethylbenzene	ND	0.035	mg/L	8	0	6
Potassium	0	2,190	mg/L	28	5	0
Sodium	733	63,284	mg/L	61	0	0
Specific Conductivity	4,880	198,100	uS/cm	32	0	0
Strontium	ND	4,370	mg/L	32	0	1
Sulfate	ND	3,350	mg/L	45	0	1
TDS	2,861	226,733	mg/L	45	0	0
Toluene	0.0016	1	mg/L	9	0	0
TSS	57	353	mg/L	8	0	0
Xylenes	ND	0.39	mg/L	10	0	6

ND – Non-Detect

* Some values were reported by producers as being zero, but may in fact be non-detects.

As discussed in Section 5.1.1, the PA DEP conducted a study (PA DEP, 2016) evaluating TENORM at several facilities associated with oil and gas extraction activities, including CWTs. Samples were collected of several waste materials, including produced water. The report for this study noted significant activity in some produced water samples. Filtering produced water had no significant effect on radioactivity, indicating the radium was likely soluble. Results of TENORM in produced water samples presented in this study are summarized in Table 5-9.

Table 5-9. Ra-226, Ra-228, K-40, Gross Alpha and Gross Beta Activity in Unfiltered Produced Water (PA DEP, 2016)

Parameter	Minimum	Maximum	Median	Number of Samples	Number of Non-Detects or Zero Values
Gross Alpha (pCi/L)	<465	41,700	9,760	13	4
Gross Beta (pCi/L)	<225	7,600	2,300	13	4
Radium 226 (pCi/L)	<81	26,600	4,490	13	1
Radium 228 (pCi/L)	26	1,900	636	13	0
Potassium 40 (pCi/L)	<31	852	220	13	1

WY OGCC, 2015 is the underlying data set for the “Water Analysis” data provided on the WY OGCC website (<http://wogcc.state.wy.us/warchoiceMenu.cfm>). The data set contains monitoring data for chloride, potassium, sodium, sulfate, and TDS for produced waters in Wyoming from 1940 to 2014.

Table 5-10. Concentrations of Select Pollutants in Wyoming Produced Water (WY OGCC, 2015)

Parameter	Minimum	Maximum	Units	Number of Samples	Number of Non-Detects or Zero Values
Chloride	478	29,197	mg/L	3,077	NR
Potassium	18	2,200	mg/L	2,639	NR
Sodium	1,475	18,500	mg/L	3,057	NR
Sulfate	8	390	mg/L	2,757	NR
TDS	4,017	64,800	mg/L	3,071	NR

NR – Not reported

Havics, 2011 evaluated several media associated with hydraulic fracturing activities in Colorado. Havics collected 25 flowback and 10 produced water samples (plus duplicates and QA samples) from four basins in Colorado: Piceance, Denver-Julesburg, San Juan, and Raton.

Barium, benzene, boron, chloride, ethylbenzene, naphthalene, nickel, toluene, total xylenes, trimethylbenzene (TMB), and TEPH were detected in 100 percent of the flowback fluid samples. Barium, boron, chloride, and nickel were detected in 100 percent of produced water samples. The author noted that barium, boron, chloride and nickel are naturally occurring in the formation waters, and therefore at least a portion of the concentration of these constituents in samples can be attributed to the formation (as opposed to additives used during fracturing). Havics also reported maximum gross alpha and gross beta activity for flowback fluids of 274 and 4,030 pCi/L, respectively.

Comparing data from this reference, it is notable that concentrations of select constituents are much higher in samples identified as flowback than in those identified as produced water. Table 5-11 shows select data from this reference.

Table 5-11. Flowback and Produced Water Constituents from Hydraulically Fractured Colorado Wells (Havics, 2011)

Parameter	Minimum	Maximum	Units	Number of Samples	Number of Non-Detects
Barium	0.009	180	mg/L	35	0
Benzene	ND	9.7	mg/L	46	8
Chloride	17	32,000	mg/L	48	0
Ethylbenzene	ND	7.1	mg/L	46	11
Gross Alpha	ND	274	pCi/L	48	38
Gross Beta	ND	4,030	pCi/L	48	27
Naphthalene	ND	6	mg/L	48	11
Toluene	ND	110	mg/L	47	10
m+p-Xylene	ND	120	mg/L	47	10
o-Xylene	ND	17	mg/L	47	10
1,2,4-Trimethylbenzene	ND	17	mg/L	46	11
1,3,5-Trimethylbenzene	ND	12	mg/L	47	10

ND – Non-detect

McElreath, 2011 is a study from Chesapeake Energy comparing hydraulic fracturing fluid composition to constituent concentrations in produced waters following hydraulic fracturing from the Western and Eastern U.S. The author presents a time series of produced water characterization data for specified intervals following hydraulic fracturing, showing how the concentration of constituents changes over time. The produced water analytical results include volatile and semi-volatile organic compounds, metals, radionuclides, chloride and TDS. Select results from the study are shown in Table 5-12.

Table 5-12. Produced Water Constituents from Hydraulically Fractured Wells (McElreath, 2011)

Parameter	Minimum	Maximum	Units	Number of Samples	Number of Non-Detects
Benzene	1	797	µg/L	12	0
Chloride	126	81,500	mg/L	12	0
Gross Alpha	620	6,600	pCi/L	6	0
Gross Beta	ND	2,400	pCi/L	5	1
Radium 226	167	1,050	pCi/L	6	0
Radium 228	101	867	pCi/L	6	0
Sodium	95	38,100	mg/L	12	0
Sulfate	2	162	mg/L	12	0

Table 5-12. Produced Water Constituents from Hydraulically Fractured Wells (McElreath, 2011)

Parameter	Minimum	Maximum	Units	Number of Samples	Number of Non-Detects
TDS	1,500	153,000	mg/L	18	0
Toluene	1	1,650	µg/L	12	0

ND – Non detect

Stepan, 2010 is a treatment and reuse study of produced water from the Bakken oil formation in North Dakota. The project analyzed fracturing flowback water data from five different oil producers operating at various locations in the Bakken. Calculated TDS levels in the produced water were as high as 219,000 mg/L. Select produced water data collected from this study are presented in Table 5-13.

Table 5-13. Produced Water Constituents from Bakken Oil Formation Wells (Stepan, 2010)

Parameter	Minimum	Maximum	Units	Number of Samples	Number of Non-Detects
Barium	ND	24.6	mg/L	7	2
Chloride	500	133,000	mg/L	7	0
Potassium	ND	5,770	mg/L	7	1
Sodium	540	74,600	mg/L	7	0
Specific Conductivity	3,000	205,000	uS/cm	5	0
Strontium	4	1,010	mg/L	6	0
Sulfate	300	1,000	mg/L	7	0
TDS (calculated)	150,000	219,000	mg/L	3	0

ND – Non detect

The preceding discussion presented select data on produced water characteristics contained in several references. As can be seen from these data, the concentration and prevalence of constituents varies greatly across the country. This is expected, since formation characteristics and the type and quantity of additives utilized by producers during well development varies. This has implications for proper management of produced waters at CWT facilities, as the choice of treatment technology must be appropriate to treat the wastewater to meet discharge standards and to protect receiving water quality. Additional data on produced water characteristics can be found in ERG, 2018a, which is a compilation of multiple original data sources; the presentation of information summarized in the compilation and presented here may not include all the data included in each reference, but only those relevant to the study.

5.2 CWT Wastewater Characteristics

EPA utilized several data sources to characterize wastewater discharged by CWT facilities that manage oil and gas extraction wastes. These include data contained in facility discharge monitoring reports (DMRs), data collected from CWA 308 letters sent to select facilities, and sampling conducted by EPA. EPA also evaluated the Toxics Release Inventory (TRI); however, none of the in-scope facilities reported data to TRI.²¹

5.2.1 *DMR Data*

EPA used the EPA DMR Pollutant Loading Tool (U.S. EPA, 2016a) to characterize concentrations of pollutants in process wastewater discharges²² reported by in-scope CWT facilities. Data reported in DMRs include pollutants that are regulated in NPDES permits, including technology-based and water quality-based effluent limitations. Discharges reported in DMRs may not include all pollutants of interest for this industry as facilities report only those pollutants required to be monitored by their NPDES permit. DMR data are available only for direct dischargers with NPDES permits and not for facilities discharging indirectly via publicly owned treatment works (POTW). Also, DMR data may not be available for permitted direct dischargers classified as “minor sources”.

EPA extracted data from the DMR Pollutant Loadings Tool for calendar year 2016. Eight of the 11 in-scope CWT facilities submitted DMRs for 2016; however, some DMR data submitted was not for process wastewater, and was instead for discharges such as stormwater or sanitary waste.

The eight facilities submitting 2016 DMR data were:

- *Byrd/Judsonia Water Reuse/Recycle Facility*: This facility submitted data for all 12 months in 2016. However, only one month (February) reported non-zero flow. These data are summarized in Table 5-14.
- *Clarion Altela Environmental Services (CAES)*: This facility submitted data for one month, and the data did not contain process wastewater.
- *Eureka Resources, Standing Stone Facility*: This facility submitted process wastewater data for one month in 2016 (December). These data are summarized in Table 5-14.

²¹ Facilities report discharges to EPA’s TRI program only if they meet the employee criteria (i.e., 10 or more employees) and TRI chemical threshold(s).

²² Some permits include reporting requirements for stormwater discharges. EPA did not include data from outfalls that were comprised solely of stormwater in the data summaries presented in this section.

- *Fairmont Brine Processing, LLC*: This facility submitted process wastewater data for six months in 2016. For one of these months, the facility reported zero flow. Data for months with reported flow are summarized in Table 5-14.
- *Fluid Recovery Services: Franklin Facility (Aquatech)*: This facility submitted process wastewater data for each month in 2016. These data are summarized in Table 5-14.
- *Fluid Recovery Services: Josephine Facility (Aquatech)*: This facility submitted process wastewater data for each month in 2016. These data are summarized in Table 5-14.
- *Max Environmental Technologies, Inc. – Yukon Facility*: This facility submitted process wastewater data for each month in 2016. However, these data did not include data from the internal outfall that received wastewater from the centralized waste treatment portion of the facility. It is EPA’s understanding that the facility does not currently discharge wastewater from such operations.
- *Waste Treatment Corporation*: This facility reported data for each month in 2016. Non-zero flow was reported for 7 of the 12 months. As noted in Section 4.3.11, this facility has a permit to discharge; however, this facility reported only minimal discharge (e.g., 543 pounds of chloride) on DMRs in 2016. This facility closed in 2017, which may have influenced the limited data reported in 2016. In comparison, the facility reported in excess of 34 million pounds of chloride in 2014 and 7.8 million pounds of chloride in 2015 DMRs.

The three facilities with no 2016 DMR data were:

- *Eureka Resources, Williamsport 2nd Street Plant*: This facility discharges indirectly and therefore does not report DMR data.
- *Fluid Recovery Services: Creekside Facility*: As noted in Section 4.3.8, this facility has a permit to discharge; however, this facility did not report any discharge on DMRs in 2016 (perhaps because this facility is classified as a minor source).
- *Patriot Water Treatment, LLC*: This facility discharges indirectly and therefore does not report DMR data.

The concentration data for select pollutants for each of the facilities reporting DMR data in 2016 is presented in Table 5-14. Values are the average of all reported values for the monitoring year. For facilities with more than one month of data available, EPA used ½ of the detection limit for reported non-detect values in calculating the average for the reporting year. If all reported values were non-detects, EPA did not calculate an average concentration but rather indicated that all values were reported as non-detect. The complete DMR dataset for 2016 can be found in ERG, 2018b.

Table 5-14. Average Concentration of Select Pollutants in Process Wastewater Reported in 2016 Discharge Monitoring Reports for In-Scope CWT Facilities

Pollutant	Units	Facility				
		Byrd/Judsonia Water Reuse/Recycle Facility	Eureka Resources, Standing Stone Facility	Fairmont Brine Processing	Fluid Recovery Services: Franklin Facility	Fluid Recovery Services: Josephine Facility
Barium, total (as Ba)	mg/L		0.05	2.99	2.93	6.86
Bromide (as Br)	mg/L			14.71		
Chloride (as Cl)	mg/L	76.93	5	781.2	72,339	74,975
Nitrogen, ammonia total (as N)	mg/L	0.147	2.77	2.86		
Oil & grease	mg/L	ND	ND		ND	3.57
Radiation, gross alpha	pCi/L			16.39		
Radium 226 + radium 228, total	pCi/L			15.17		
Solids, total dissolved	mg/L	191.9	ND	847.8	107,522	151,713
Strontium, total (as Sr)	mg/L		0.11	16.73	149.35	
Sulfate, total (as SO ₄)	mg/L	13.03		16.32		
# of Months with Non-Zero Flow		1	1	5	12	12

Note: This table presents the average concentration of pollutants as reported in DMRs calculated with non-detects set equal to half the detection limit. Averages were not calculated if all data for a particular pollutant were non-detects.

ND: All values reported were non-detects.

Blank values indicate that the facility did not report any data for that pollutant in process wastewater discharges.

Notable observations from the DMR data are the low concentration of barium, which is expected since all facilities reporting barium incorporate chemical precipitation into their treatment trains. The two Fluid Recovery Services facilities report high chloride and TDS, which is expected since these facilities do not incorporate TDS removal technologies. This is in comparison to the Eureka Resources and Fairmont Brine facilities, which have much lower TDS owing to the utilization of evaporation/crystallization technologies. The only facility reporting radium and gross alpha radiation, Fairmont Brine, showed low activity in reported samples. Strontium was also markedly lower in the Eureka Resources and Fairmont Brine facilities as opposed to the Franklin Facility. None of the facilities reporting oil and grease showed appreciable concentrations of this pollutant. Additional DMR data can be found in ERG, 2018b.

5.2.2 EPA Sampling Data

EPA collected sampling data at the Pinedale Anticline Waste Treatment Facility (Anticline) in Pinedale, WY and the Eureka Resources, Standing Stone Facility (Eureka) in Wysox, PA. Both facilities were fully operational and active commercial CWT facilities that treat oil and gas extraction wastewaters and directly discharged their treated effluent at the time of sampling in 2016. The sampling team collected a grab sample from various stages of

treatment at both facilities to characterize untreated wastewater, treated effluent, intermediate treatment points, and treatment residuals generated at these facilities.

Both facilities accept wastewater from multiple oil and gas producers, have NPDES permits authorizing direct discharge of treated effluent, discharge their treated water on an as needed basis depending upon alternate users of the treated water, and have treatment technologies that are designed to reduce TDS and other pollutants of interest in the final effluent. Anticline operates a multi-stage treatment system that includes oil/water separation, chemically-assisted clarification, media filtration, biological treatment, reverse osmosis (RO), and boron ion exchange (Schafer, 2010). The Eureka facility operates a multi-stage treatment system that includes chemical precipitation, evaporation/crystallization, biological treatment, ion exchange, and RO (U.S. EPA, 2017b).

EPA selected a comprehensive list of analytes for testing provided in Table 5-15 along with the test methods. These included classical wet chemistry, anions, metals, gasoline and diesel range organics, volatile organics, semi-volatile organics, alcohols, radiological measurements, and WET tests. Several of these parameters were analyzed using multiple methods, including anions, volatile organics, and semi-volatile organics to determine if any particular method had fewer interferences with the high TDS wastewater. For details on the sampling methods, facility treatment technology, and analytes tested for, see each facility's respective Sampling and Analysis Plans (U.S. EPA, 2017c; U.S. EPA, 2017d)

Table 5-15. Analytical Methods for the CWT Study Sampling Program

Analyte	Method (Technique)
Group I Classical Wet Chemistry	
Total Dissolved Solids (TDS)	SM 2540 C-1997 (Gravimetric)
Total Suspended Solids (TSS)	SM 2540 D-1997 (Gravimetric)
Specific Conductance	SM 2510 B-1997 (Conductivity Meter)
Alkalinity	SM 2320 B-1997 (Titration)
Group II Classical Wet Chemistry	
Chemical Oxygen Demand (COD)	EPA 410.4 (Spectrophotometric)
Total Organic Carbon (TOC)	SM 5310 B-2000 (Combustion)
Ammonia	EPA 350.1 (Colorimetric)
Other Classical Wet Chemistry	
n-Hexane Extractable Material (HEM) and Silica Gel Treated n-Hexane Extractable Material (SGT-HEM)	EPA 1664A (Gravimetric)
Biochemical Oxygen Demand (BOD ₅)	SM 5210 B-2001
Total Hardness	SM 2340 C-1997 (Titrimetric)
Anions	
Fluoride, Chloride, Nitrite, Ortho-Phosphate, Bromide, Nitrate, Sulfate	ASTM D4237 (Suppressed Ion Chromatography)
Fluoride, Chloride, Nitrite, Ortho-Phosphate-p, Bromide, Nitrate, Sulfate, Bromate, Chlorite, Chlorate	EPA 300.0 (Ion Chromatography)

Table 5-15. Analytical Methods for the CWT Study Sampling Program

Analyte	Method (Technique)
Total Metals	
Trace Elements	EPA 200.8
Mercury	EPA 245.1 or 245.2 (Cold Vapor Atomic Absorption)
Hexavalent Chromium	SM 3500-Cr B-2009 (Colorimetric)
Organics	
Diesel Range	EPA 3520C (sample preparation), EPA 8015C (analysis) (Gas Chromatography)
Gasoline Range	EPA 5030B (sample preparation), EPA 8015C (analysis) (Gas Chromatography)
Volatile Organic Compounds	EPA 5030 or EPA 5035/8260C (Gas Chromatography/Mass Spectroscopy)
Volatile Organic Compounds	EPA 624 (Gas Chromatography/Mass Spectroscopy)
Semivolatile Organic Compounds	EPA 3520C/8270D (Gas Chromatography/Mass Spectroscopy)
Semivolatile Organic Compounds	EPA 625 (Gas Chromatography)
Alcohols	EPA 8260C, 8270D, and 8015C (Gas Chromatography/Mass Spectroscopy)
Radioactives	
Total Radium 226 (Liquid Samples)	EPA 903.1 (Radon Emanation)
Total Radium 228 (Liquid Samples)	EPA 904.0 (Radiochemical/Precipitation)
Total Radium 226 and 228 (Solid Samples)	EPA 901.1 (Gamma Spectroscopy)
Gross Alpha/Beta (Liquid Samples)	EPA 900.0
Gross Alpha/Beta (Solid Samples)	EPA 900.0
Whole Effluent Toxicity (WET)	
Acute Nonvertebrate	<i>Ceriodaphnia dubia</i> EPA 2002.0
Acute Vertebrate	<i>Pimephales promelas</i> EPA 2000.0
Chronic Nonvertebrate	<i>Ceriodaphnia dubia</i> EPA 1002.0
Chronic Vertebrate	<i>Pimephales promelas</i> EPA 1000.0

Table 5-16 presents the effluent sampling results for Anticline and the influent and effluent sampling results for Eureka. [Note that because Anticline has claimed their influent and all in-process sampling results as confidential, only their effluent data are presented.] The table presents all analytes that were detected at either facility for all methods, as well as a general indication of percent reduction for the Eureka facility. In addition, this table indicates whether a specific analyte is currently regulated under the CWT effluent guidelines at 40 CFR Part 437.

Table 5-16. EPA Sampling Results for Anticline and Eureka Facilities

Analyte	Unit	Regulated under 40 CFR 437			Anticline	Eureka		
		Subpart A	Subpart B	Subpart C	Effluent	Influent	Effluent	Percent Reduction
Classical Wet Chemistry								
Alkalinity, Total as CaCO ₃	mg/L				11	76	9.23	87.9%
pH	S.U.	Yes	Yes	Yes	9.2	6.03	7.15	NC
Biochemical Oxygen Demand (BOD ₅)	mg/L			Yes	1.53	80	3.72	95.4%
Chemical Oxygen Demand (COD)	mg/L				12.7	15,700	16.1	99.9%
Conductivity	µmhos/cm				177	180,000	34.6	>99.9%
Hardness as CaCO3	mg/L				3.89	74,400	283	99.6%
n-Hexane Extractable Material (HEM)	mg/L	Yes	Yes		ND (1.14)	88.1	ND (1.14)	≥98.7%
Nitrogen, Ammonia	mg/L				ND (0.017)	124	0.0578	>99.9%
Silica Gel Treated n-Hexane Extractable Material (SGT-HEM)	mg/L	Yes	Yes		ND (1.14)	62.2	ND (1.14)	≥98.2%
Total Dissolved Solids (TDS)	mg/L				78.6	174,000	14.3	>99.9%
Total Organic Carbon (TOC)	mg/L				0.419	829	0.59	99.9%
Total Suspended Solids (TSS)	mg/L	Yes	Yes	Yes	ND (0.633)	545	ND (0.633)	≥99.9%
Anions Method 300.0								
Bromide	mg/L				0.327	725	ND (0.067)	≥99.9%
Chloride	mg/L				45.1	95,500	2.05	>99.9%
Nitrate	mg/L				ND (0.033)	ND (33)	0.977	NC
Sulfate	mg/L				ND (0.133)	63.2	0.265	99.6%
Anions Method ASTM D4237								
Bromide - UV	mg/L				0.265	839.7	ND (NR)	NC
Bromide - Conductivity	mg/L				0.291	834.5	ND (NR)	NC
Nitrate - Conductivity	mg/L				ND (NR)	ND (NR)	4.215	NC
Nitrate - UV	mg/L				ND (NR)	ND (NR)	4.441	NC
Sulfate - Conductivity	mg/L				ND (NR)	ND (NR)	ND (NR)	NC
Sulfate - UV	mg/L				ND (NR)	ND (NR)	ND (NR)	NC

Table 5-16. EPA Sampling Results for Anticline and Eureka Facilities

Analyte	Unit	Regulated under 40 CFR 437			Anticline	Eureka		
		Subpart A	Subpart B	Subpart C	Effluent	Influent	Effluent	Percent Reduction
Total Metals								
Antimony*	µg/L	Yes			ND (1)	ND (100)	ND (1)	NC
Arsenic	µg/L	Yes	Yes		ND (1.7)	440	ND (1.7)	≥99.6%
Barium	µg/L				78.4	11,000,000	15.4	>99.9%
Boron	µg/L				ND (7.5)	3,710	81.6	97.8%
Cadmium	µg/L	Yes	Yes		ND (0.3)	12.1	ND (0.3)	≥97.5%
Calcium	µg/L				442	21,700,000	204	>99.9%
Chromium*	µg/L	Yes	Yes		ND (3)	ND (60)	ND (3)	NC
Cobalt	µg/L	Yes	Yes		ND (0.1)	20.3	ND (0.1)	≥99.5%
Copper	µg/L	Yes	Yes	Yes	ND (0.35)	1,430	1.21	99.9%
Cyanide	µg/L	Yes			NS	NS	NS	NC
Iron	µg/L				ND (33)	117,000	ND (33)	>99.9%
Lead	µg/L	Yes	Yes		ND (0.5)	3.53	ND (0.5)	≥85.8%
Lithium	µg/L				9.53	185,000	9.01	>99.9%
Magnesium	µg/L				ND (10)	1,240,000	ND (10)	≥99.9%
Manganese	µg/L				1.21	9,520	ND (1)	≥99.9%
Mercury*	µg/L	Yes	Yes		ND (0.067)	ND (0.67)	ND (0.067)	NC
Molybdenum	µg/L				ND (0.3)	6.34	ND (0.3)	≥95.3%
Nickel	µg/L	Yes			ND (0.5)	210	ND (0.5)	≥99.8%
Phosphorous	µg/L				ND (15)	736	ND (15)	≥98.0%
Potassium	µg/L				275	282,000	ND (80)	≥99.9%
Selenium	µg/L	Yes			ND (2)	1,660	ND (2)	≥99.9%
Silica	µg/L				238	10,800	97.2	99.1%
Silver	µg/L	Yes			ND (0.4)	9.72	ND (0.4)	≥95.9%
Sodium	µg/L				36600	43,700,000	7,910	>99.9%
Strontium	µg/L				39.6	5,670,000	34.7	>99.9%

Table 5-16. EPA Sampling Results for Anticline and Eureka Facilities

Analyte	Unit	Regulated under 40 CFR 437			Anticline Effluent	Eureka		
		Subpart A	Subpart B	Subpart C		Influent	Effluent	Percent Reduction
Tin*	µg/L	Yes	Yes		ND (1)	ND (20)	ND (1)	NC
Titanium*	µg/L	Yes			ND (2)	ND (40)	ND (2)	NC
Vanadium*	µg/L	Yes			ND (4.5)	ND (450)	ND (4.5)	NC
Zinc	µg/L	Yes	Yes	Yes	ND (3.5)	2,820	7.4	99.7%
Diesel Range Organics								
Diesel Range Organics	µg/L				ND (20)	173,000	83.5	>99.9%
Gasoline Range Organics								
Ethylbenzene	µg/L				ND (1)	ND (10)	ND (1)	NC
o-Xylene	µg/L				ND (1)	ND (10)	ND (1)	NC
TPH as Gasoline	µg/L				ND (20)	6,460	ND (20)	≥99.7%
Volatile Organic Compounds Method 8260C								
1,2,4-Trimethylbenzene	µg/L				ND (0.3)	0.8	ND (0.3)	≥62.5%
2-Butanone*	µg/L			Yes	ND (3)	ND (3)	ND (3)	NC
Acetone	µg/L			Yes	26.3	33.3	ND (3)	≥91.0%
Chlorobenzene	µg/L				0.38	ND (0.3)	ND (0.3)	NC
Ethylbenzene	µg/L				ND (0.3)	ND (0.3)	ND (0.3)	NC
m,p-Xylenes	µg/L				ND (0.3)	0.72	ND (0.3)	≥58.3%
o-Xylene	µg/L				ND (0.3)	0.48	ND (0.3)	≥37.5%
Volatile Organic Compounds Method 624								
Chlorobenzene	µg/L				ND (0.333)	ND (0.333)	ND (0.333)	NC
Ethylbenzene	µg/L				ND (0.333)	0.34	ND (0.333)	≥2.06%
Isopropyl Alcohol	µg/L				ND (16.7)	291	ND (16.7)	≥94.3%

Table 5-16. EPA Sampling Results for Anticline and Eureka Facilities

Analyte	Unit	Regulated under 40 CFR 437			Anticline	Eureka		
		Subpart A	Subpart B	Subpart C	Effluent	Influent	Effluent	Percent Reduction
Semivolatile Organic Compounds Method 625								
2,4,6-Trichlorophenol*	µg/L			Yes	ND (3)	ND (30)	ND (2.75)	NC
Acetophenone*	µg/L			Yes	ND (3)	ND (30)	ND (2.75)	NC
Bis(2-ethylhexyl)phthalate	µg/L		Yes		ND (3)	ND (30)	ND (2.75)	NC
Butylbenzylphthalate*	µg/L		Yes		ND (3)	ND (30)	ND (2.75)	NC
Carbazole*	µg/L		Yes		ND (0.3)	ND (3)	ND (0.275)	NC
Fluoranthene*	µg/L		Yes		ND (0.3)	ND (3)	ND (0.275)	NC
m,p-Cresols*	µg/L			Yes	ND (3.7)	ND (37)	ND (3.39)	NC
n-Decane*	µg/L		Yes		ND (3)	ND (30)	ND (2.75)	NC
n-Octadecane*	µg/L		Yes		ND (3)	ND (30)	ND (2.75)	NC
o-Cresol*	µg/L			Yes	ND (3)	ND (30)	ND (2.75)	NC
Phenol*	µg/L			Yes	ND (3)	ND (30)	ND (2.75)	NC
Pyridine*	µg/L			Yes	ND (3)	ND (30)	ND (2.75)	NC
Semivolatile Organic Compounds Method 3520C/8270D								
2,4,6-Trichlorophenol*	µg/L			Yes	ND (2)	ND (20)	ND (2)	NC
2-Butoxyethanol	µg/L				ND (1)	566	ND (1)	≥99.8%
Bis(2-ethylhexyl)phthalate	µg/L		Yes		ND (2)	ND (20)	3.33	NC
Butylbenzylphthalate*	µg/L		Yes		ND (1)	ND (10)	ND (1)	NC
Carbazole*	µg/L		Yes		ND (3)	ND (30)	ND (3)	NC
Fluoranthene*	µg/L		Yes		ND (1)	ND (10)	ND (1)	NC
Phenol*	µg/L			Yes	ND (2)	ND (20)	ND (2)	NC
Pyridine*	µg/L			Yes	ND (1)	ND (10)	ND (1)	NC
Alcohols								
Ethanol	µg/L				ND (3000)	31,800	ND (3,000)	≥90.6%
Methanol	µg/L				ND (250)	91,400	ND (250)	≥99.7%

Table 5-16. EPA Sampling Results for Anticline and Eureka Facilities

Analyte	Unit	Regulated under 40 CFR 437			Anticline	Eureka		
		Subpart A	Subpart B	Subpart C	Effluent	Influent	Effluent	Percent Reduction
Radioactives (Liquid)								
Gross Alpha	pCi/L				ND (3)	5,900	ND (3)	≥99.9%
Gross Beta	pCi/L				ND (4)	6,000	ND (4)	≥99.9%
Total Radium 226	pCi/L				ND (1)	10,300	0.16	>99.9%
Total Radium 228	pCi/L				1.1	1,320	0.74	99.9%
Radioactives (Solid)								
Gross Alpha	pCi/g				6.3	NS	9.2	NC
Gross Beta	pCi/g				6.1	NS	4	NC
Total Radium 226	pCi/g				5.69	NS	451	NC
Total Radium 228	pCi/g				3.06	NS	40.3	NC

NS is Not Sampled; ND is Not Detected (value in parenthesis is detection limit); NC is Not Calculated; NR is Not Reported

* Indicates a 40 CFR 437 regulated pollutant that was not detected in any samples.

The Table 5-16 results exclude tentatively identified compounds and any analytes where all results were below the detection limit, with the exception of 40 CFR 437 regulated pollutants. A more comprehensive discussion of Eureka's intermediate sampling results based on each treatment step can be found in Chapter 6.

Of the 34 CWT regulated pollutants at 40 CFR 437, 18 regulated pollutants were not detected in any of the samples from Anticline or Eureka using any test method. These are indicated with an asterisk (*) in Table 5-16. Note that cyanide is the only 40 CFR 437 regulated pollutant (under subpart A) that was not analyzed for at any sampling point at either facility; cyanide was not analyzed for because it was not reasonably expected to be present in oil and gas extraction wastewater.

The influent wastewater at Eureka contained particularly high levels of four classical wet chemistry pollutants: COD, conductivity, hardness, and TDS. There were high levels of the common ions, chloride, sodium, calcium, magnesium, and to a lesser extent sulfate, along with elevated concentrations of bromide, as well as most of the metals, such as barium and strontium. As would be expected for wastewater from the Marcellus, there are elevated levels of radium in the influent. Most of the organics were at low concentrations to below detection levels. The exceptions being organics in the diesel and gasoline range as well as high levels of alcohols, ethanol and methanol, the alcohols being added as part of the recovery process. The Eureka sampling data results indicate a significant reduction in the concentration of all detected pollutants. Lastly, in comparing the effluents from the two facilities, the Anticline data is fairly similar to Eureka's in terms of analytes detected and concentrations reported. Any comparison between the two facilities is difficult to make due to the different treatment trains employed and the different wastewater being treated, Anticline being located in Wyoming and Eureka in Pennsylvania.

Whole effluent toxicity testing was also performed on the effluent samples from both facilities. The results showed that both facilities generated effluent discharges that were not acutely toxic to *C. dubia* or fathead minnows, nor were they chronically toxic to *C. dubia*. However, while Anticline's effluent was not chronically toxic to fathead minnows (NOEC of 100 percent), the effluent from Eureka was found to be slightly chronically toxic to fathead minnows (NOEC of 50 percent). For the two chronic tests conducted on Eureka's effluent sample, the second and third renewal samples were shipped with inadequate ice and arrived at the testing laboratory well above the recommended 0-6°C range. As a result, EPA decided to not use the second renewal sample but continue with the test using the third renewal sample on day 3, 4, 5, and 6. It is unknown what effect this might have had, if any, on the toxicity tests.

Anions, volatile organics, and semi-volatile organics were all analyzed using two separate analytical methods for both facilities to determine if any particular method had fewer interferences from the high TDS wastewater. For the analysis of anions, bromide and nitrate were detected in the same samples using either test method (Method 300.0 or Method ASTM D4237) and procedure (UV or conductivity). However, Method 300.0 detected concentrations of sulfate in the Anticline effluent and the Eureka influent that were not detected by the ASTM

D4237 Method. Additional testing would be required to determine which constituents may have been responsible for the observed differences and at what concentrations they become a problem.

Four volatile organic analytes were measured using two methods: Method 8260C and Method 624. Ethylbenzene was detected only by Method 624. Chlorobenzene and o-xylene were detected by only Method 8260C. Generally speaking, Method 8260C and Method 624 had similar detection limits, but the methods have different lists of compounds that are measured. For example, isopropyl alcohol is detected by Method 624 but only appears as a tentatively identified compound in Method 8260C. For semi-volatile organics, which were analyzed using Method 625 and Method 3520C/8070D, bis(2-ethylhexyl) phthalate was detected by Method 3520C/8070D and not by Method 625. Once again, additional testing would be required to determine which constituents may have been responsible for the observed differences and at what concentrations they become a problem. Since the techniques and instruments used to analyze for organics differs from those employed for inorganics, it may be possible that the component responsible for the observed difference in organics may be different from that for inorganics.

Refer to the Sampling Episode Reports for these two sampling events for the complete dataset generated by these two sampling episodes, analysis of all sampling points, residual sample results, and data quality discussion (US. EPA, 2017a and U.S. EPA, 2017b).

5.3 Oil and Gas Extraction Wastewater Volumes and Management Practices

Limited national data currently exist on the volume of wastewater generated by oil and gas extraction activities and the volumes being managed at CWT facilities. As discussed earlier in this report, EPA has identified only 11 CWT facilities nationally that accept oil and gas extraction wastes and discharge wastewater and are therefore in-scope for this study. As noted, there are a number of facilities that accept oil and gas extraction wastes nationally but do not discharge. These facilities instead treat wastewater for reuse in hydraulic fracturing or other uses. There are national data sets on the volumes of wastewater managed at these facilities, which are outside the scope of this study.

According to the U.S. DOI's 2011 report entitled "Oil and Gas Produced Water Management and Beneficial Use in the Western United States", between 7 to 10 barrels (294 to 420 gallons) of water are produced for every barrel of crude oil produced. Reservoirs have naturally existing formation water, with oil reserves containing larger volumes of water than gas reserves. As the oil and gas reserves deplete over time and wells age, the volume of produced water generated can increase relative to the amount of oil or gas produced (U.S. DOI, 2011).

The oil and gas industry has most commonly managed produced water by underground injection (Clark & Veil, 2009). For example, disposal of oil and gas extraction wastewaters in Texas is primarily through disposal wells - there were over 32,000 active disposal wells in Texas in 2014 (Railroad Commission of Texas, 2014). In contrast, Pennsylvania has only eight permitted brine disposal wells as of 2011 (McCurdy, 2011). Where other management options exist, such as injection or reuse in hydraulic fracturing, there may be little need for CWT

facilities that treat and discharge wastewater. However, where other management options are limited, there may be greater demand for CWT services for managing oil and gas extraction wastes. In some geographic areas, the industry may rely on CWT facilities, in part, to manage growing volumes of wastewater. (Horn et al., 2013; Environmental Leader, 2013)

A comprehensive study of U.S. oil and gas extraction produced water volumes and management practices was published in 2009 called “Produced Water Volumes and Management Practices in the United States” (U.S. DOE, 2009). This study used oil and gas industry data from the year 2007. The study collected data by sending information requests to state agencies asking them to report precise and accurate data for oil and gas wells. Data from each state were compiled, and the resulting dataset estimated that approximately 21 billion barrels of produced water were generated in 2007 (U.S. DOE, 2009).

In 2015, the DOE study was updated to include 2012 data (GWPC, 2015). The 2012 data estimated that oil production in the U.S. increased by about 29 percent between 2007 and 2012 and gas production by 22 percent; however, water production increased by only one percent. Table 5-17 lists the ten states with the highest volumes of wastewater generation by oil and gas extraction operations, as reported by GWPC, 2015. Texas and California generated about 50 percent of all the produced water generated in 2012.

Table 5-17. Ten States with the Highest Oil and Gas Produced Water Volumes in 2012

State	Volume of Oil and Gas Extraction Wastewater in 2012 (million bbl/yr)	Percentage of Total U.S. Oil and Gas Extraction Wastewater (%)
Texas	7,435	35
California	3,074	15
Oklahoma	2,325	11
Wyoming	2,178	10
Kansas	1,061	5
Louisiana	927	4
Alaska	769	4
Colorado	358	2
North Dakota	291	1
Mississippi	231	1
U.S. Total (million bbl/yr)	21,180	

Source: GWPC, 2015.

Table 5-18 shows quantities of wastewater reported in the 2015 GWPC report for on-shore facilities. The majority of water from onshore wells is injected for enhanced recovery or disposal. The next most common management technique for onshore produced water is offsite commercial disposal.

Table 5-18. Produced Water Management Practices and Volumes for 2012

Management Practice	Onshore Total (million bbl/yr)	Percentage of Onshore (%)
Injection for Enhanced Recovery	9,230	46.2
Injection for Disposal	7,950	39.8
Surface Discharge	605	3.0
Evaporation	691	3.5
Offsite Commercial Disposal	1,370	6.9
Beneficial Reuse	126	0.6
Total Produced Water Managed	20,000	100

Source: GWPC, 2015.

While the GWPC 2015 report (and the U.S. DOE, 2009 report) are the most comprehensive studies analyzing national trends in wastewater volumes from oil and gas extraction, there are other resources that EPA reviewed. For example:

- *DrillingInfo (DI) Desktop® database.* Although the DI Desktop® database includes annual oil, gas, and produced water production records for all oil and gas wells (including inactive wells and underground injection wells that do not produce oil and/or gas), the DI Desktop® database has incomplete wastewater volume data, including inconsistent naming conventions, spelling errors and wells with an “N/A”, “0”, “N”, or blank as basin type (U.S. EPA, 2016b).
- *USGS National Produced Waters Geochemical Database.* EPA evaluated the USGS database, which includes geochemical data for almost 60,000 wells in the 36 states where O&G exploration occurs. However, the database does not include wastewater flow volumes.
- *Office of Technology Assessment.* A congressional report detailing the management technologies and practices as of 1992. Surface impoundments, landfiling, land application, discharges to surface waters, and waste reduction were possible practices. Sixty-two percent of produced water was injected for enhanced oil recovery, while 29 percent was injected into a disposal well. Only 6 percent of produced water was discharged.
- *State Data.* No federal regulatory agency requires producers or states to track oil and gas extraction wastewater volume data or its submission. Consequently, most states do not collect or maintain produced water information. Of the few states that do maintain datasets, water production or management information is not reported consistently from state to state, making it difficult to compile into a single database. Databases from Ohio, Colorado, New Mexico, North Dakota, and Wyoming state agencies include monthly or annual produced water volumes per well (depending on the state), and include well API number, formation name, well completion date, and/or well trajectory.

- *PA DEP*. Statewide data downloads (i.e., waste reports data) are published in six-month reporting periods (i.e., January to June, July to December). For each reporting period, the data downloads include the following types of information: API number of the well that generated waste, waste quantity and type, and waste management information. The data downloads also provide information about the facility where the waste was disposed, including the facility name, permit number, and location.
- *Texas Railroad Commission (TX RRC)*. List of permitted commercial recycling and surface waste facilities with permit number and expiration date information. Commercial recycling and surface waste facilities are organized into the following groups: Recycling, Pits, Stationary Treatment Facilities, Landfarm/Landtreatment Facilities, and Reclamation Plants.

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6. WASTEWATER MANAGEMENT PRACTICES

CWT facilities that manage oil and gas extraction wastewaters use a variety of treatment technologies, depending on characteristics of the wastewater received and the treatment objectives. Facilities that treat oil and gas extraction wastewater for reuse treat the water so that it is “just clean enough” to be reused in fracturing (Dale, 2013). This primarily consists of disinfection, and removal of suspended solids (TSS), oil and grease, and other constituents that can interfere with fracturing fluid chemicals, damage the formation, cause scaling down the wellbore and in equipment, or otherwise interfere with well production and integrity. Over the years, the oil and gas extraction industry has progressed toward the understanding that total dissolved solids (TDS) removal is not necessary for reuse (ERG, 2014; Papso et al., 2010; Lord et al., 2013; Horn et al., 2013). When treating for reuse, facilities typically use chemical precipitation and/or filtration/flotation/sedimentation. These treatment techniques do not reduce TDS.

At facilities that are treating water for discharge, the limitations in NPDES permits or control agreements drive the selection of technology. Effluent limitations for individual parameters may be based on categorical discharge limitations contained in 40 CFR 437 and/or water-quality based effluent limitations (WQBELS), state derived limits, local limits, or other regulatory requirements.

The following subsections present an overview of wastewater treatment technologies that are applicable to the treatment of oil and gas extraction wastes and that are used at CWT facilities managing these wastes. Information and data provided for each of the technologies includes the process description, treatment costs, and vendors that EPA is currently aware of that market the technology for the treatment of oil and gas extraction wastewater. In addition, EPA provides treatment capabilities and limitations, including the ability to remove select pollutants commonly found in oil and gas extraction wastewaters, including BOD, bromide, chloride, COD, specific conductivity, sulfate, TDS, TSS, barium, potassium, sodium, strontium, benzene, ethylbenzene, toluene, xylenes, sulfide, gross alpha radiation, gross beta radiation, radium 226, and radium 228.

EPA estimated the pollutant removal efficiencies²³ of these technologies using paired influent and effluent concentrations (i.e., performance data) reported in literature, where possible. Sampling data collected by EPA at two oil and gas wastewater treatment facilities are also provided, if those facilities used that specific technology. If effluent concentration was

²³ For purposes of this report, EPA calculates the removal efficiency of technologies as (influent concentration – effluent concentration)/(influent concentration). Where an effluent value was reported as a non-detect, EPA calculated the removal efficiency using the reported detection limit and qualified the removal efficiency with a “>” indicator indicating that the removal efficiency was greater than the calculated value. The reported detection limit was used in this report for calculating removal efficiencies specifically due to the variety of different data sources referenced in Chapter 6. This approach using the detection limit may differ from other approaches used by EPA to calculate removal efficiencies of technologies in other documents. In the remainder of this report, ½ of the detection limit was used for calculations such as estimating the average effluent concentration and estimating pollutant loads discharged at facilities based on DMR data.

reported as not detected, EPA used the reported detection level in calculating the removal efficiency when possible.

6.1 **Chemical Precipitation**

6.1.1 *Principle and Process Description*

In chemical precipitation, chemicals are added to wastewater to change the physical properties of dissolved and suspended pollutants, so they can be removed by settling, flotation, or filtration. This is accomplished by adding a treatment chemical (precipitant) to the wastewater that reacts with the targeted pollutant and forms an insoluble solid (precipitate). The insoluble solids are suspended in the wastewater, then removed through settling, flotation, and/or filtration. Chemical precipitation can be used to treat oil and gas extraction wastewater prior to reuse, or as a component of a treatment train prior to discharge.

Table 6-1 lists some chemical precipitants and the pollutants they remove. In oil and gas extraction wastewater applications, the targeted pollutants include TSS, multivalent cations, and heavy metals (U.S. EPA, 2016c). The most commonly used chemical precipitants include calcium hydroxide (i.e., lime) and sodium hydroxide (i.e., caustic soda). One of the underlying principles dictating chemical precipitation design and operation is that a precipitate's solubility is correlated to pH. Each precipitate has a different solubility at different pH ranges (Metcalf and Eddy, 2003). As a result, a chemical precipitation operation involves careful control of pH to optimize pollutant removal. Since different precipitates have different solubilities at different pH levels, it may not be possible to remove all pollutants in a one-step precipitation process. To maximize pollutants removed, multiple stages of precipitation may be necessary, using different pH levels and chemical precipitants (U.S. EPA, 2000a).

Table 6-1. Chemical Precipitants and Targeted Pollutants

Chemical Precipitant	Targeted Pollutants	Reference
Caustic Soda (sodium hydroxide)	Noncarbonate hardness and TSS	Acharya, 2011
Hydrogen peroxide	Iron, TSS	ERG, 2016b
Lime (calcium hydroxide)	Carbonate hardness and TSS	Acharya, 2011; Silva, 2012
Sodium Sulfate and Caustic Soda	Barium, calcium, metals, TSS	JS Meyer Engineering, 2015
Sodium Sulfate	Barium, strontium, radium.	Silva, 2012

6.1.2 *Capabilities and Limitations*

The primary pollutants removed by chemical precipitation with respect to treatment of oil and gas extraction wastewaters include barium, radium and strontium. Radium and strontium are naturally occurring constituents in some source rock formations, while barium is found in both the drilling fluid as well as the source rock formation. All three of these constituents can be contained in produced water from these formations.

EPA collected samples in September 2016 at Eureka Resources, where chemical precipitation is part of its treatment train. The values reported for influent and effluent in Table 6-2 represent samples taken from storage tanks prior to and after treatment by chemical precipitation. As can be seen from these data, certain trends are readily observable, such as the lower effluent concentrations for n-hexane extractable material (HEM), barium and radium. While the removal of barium and radium were expected, the system also produced notable removal of HEM. Also to be expected is the relatively poor removal of the alcohols and the total organic carbon (TOC). One other item of note is the apparent poor removal of strontium, a component can be readily removed by this treatment process (additional data can be found in U.S. EPA, 2017).

Table 6-2. EPA Chemical Precipitation Sampling Data at Eureka Resources

Constituent	Units	Influent Concentration	Effluent Concentration	Calculated Removal Efficiency
HEM	mg/L	88.1	1.85	97.9%
SGT-HEM	mg/L	62.2	ND (1.18)	>98.1%
TOC	mg/L	829	424	48.9%
Barium	mg/L	11,000	3,280	70.2%
Strontium	mg/L	5,670	4,770	15.9%
DRO	mg/L	173	52.7	69.5%
TPH	mg/L	6.46	0.658	89.8%
Radium-226	pCi/L	10,300	2,170	78.9%
Radium-228	pCi/L	1,320	311	76.4%
Gross Alpha	pCi/L	5,900	1,320	77.6%
Gross Beta	pCi/L	6,000	1,160	80.7%
Ethanol	mg/L	31.8	15.6	50.9%
Methanol	mg/L	91.4	79.2	13.3%

ND—Not detected (number in parenthesis is sample detection limit, which was used to calculate removal efficiency).

Source: U.S. EPA, 2017

While data are available in the literature on the performance of chemical precipitation in managing industrial wastewater, a more limited dataset exists specifically for oil and gas extraction wastewaters. For example, Acharya et al. (2011) conducted bench-scale treatability tests of flowback water from wells in the Woodford shale in Oklahoma. The testing included chemical precipitation using lime and soda ash (sodium carbonate). Results of these treatability tests for pollutants of interest are shown in Table 6-3. Hayes et al. (2012) conducted full-scale testing of treatment of wastewater from Barnett Shale wells in Texas. The testing included a preconditioning step using caustic and polymer, with clarification in a lamella separator, with the primary purpose being removal of iron. TPH was also reported to be removed, with the author attributing this to co-removal with TSS. In addition, benzene, toluene, ethylbenzene, and xylene (BTEX) removal was reported, likely through surface volatilization in the rapid mix tank. EPA

did not present this data here because the report qualifies that the data were impacted by an upset event. Papso et al. (2010) conducted chemical treatment and sedimentation of flowback fluid from eastern Marcellus shale wells prior to reuse in fracturing operations. The primary purposes of treatment were reducing scale-formers (such as iron), suspended solids and microorganisms. Specific chemical additives were not identified by the authors. Reported reductions are presented in Table 6-4.

A constituent in some oil and gas wastewaters is TENORM, from elements such as radium. For example, Rowan et al. (2011) described high radium activity in Marcellus shale waters up to 18,000 picocuries per liter. The three references described above do not provide data on the performance of chemical precipitation in reducing radium concentrations. However, there are other studies in the literature describing radium removal through chemical precipitation. For example, Zhang et al. (2014) evaluated the equilibria and kinetics of co-precipitation of radium with barium and strontium sulfate under varying ionic strength conditions that are representative of brines generated during unconventional oil and gas extraction activities. Sivla et al. (2012a) describes several approaches for pretreating produced water to reduce barium and radium prior to evaporation and crystallization, including sulfate precipitation. In addition, chemical precipitation for barium removal via sulfate precipitation (with co-precipitation of radium) is a technology used at several of the CWT facilities that EPA reviewed as part of this study.

Table 6-3. Bench-Scale Chemical Precipitation Data

Constituent	Units	Influent Concentration	Effluent Concentration	Calculated Removal Efficiency
HEM	mg/L	2,100	ND (6)	>99.7%
TOC	mg/L	18.4	6	67.4%
Barium	mg/L	30.7	0.147	99.5%
Strontium	mg/L	152	6.43	95.8%

Source: Acharya et al., 2011

ND—Not detected (number in parenthesis is sample detection limit, which was used to calculate removal efficiency).

Table 6-4. Full-Scale Chemical Treatment Data

Constituent	Units	Influent Concentration	Effluent Concentration	Reported Removal Efficiency
Barium	mg/L	596	43	93%
Calcium	mg/L	736	540	28%
Magnesium	mg/L	127	49	61%
Iron, total	mg/L	7.9	1.0	87%
Strontium	mg/L	228	174	25%

Source: Papso et al., 2010

6.1.2.1 Residuals

Chemical precipitation generates sludge that is typically dewatered before landfill disposal. Levels of radioactivity in treatment residuals from chemical precipitation vary depending on the source of the wastewater and may exceed landfill acceptability limits, depending on state regulations and applicable permits. For example, Zhang et al. (2014) estimated that given an initial radium and barium concentration in produced water of 3,000 picocuries per liter and 685 mg per liter, respectively, the estimated level of radium activity in precipitates would range from 2,571 to 18,087 picocuries per gram of barium sulfate precipitate produced. TENORM limits for municipal waste landfills typically range from 5 to 50 picocuries per gram (Zhang et al., 2014). While the radium activity calculated by Zhang et al. does not correct for entrained water and other sulfates that would be expected to precipitate at a CWT facility, the numbers are indicative of high activity measured in sludge. CWT operators at facilities that EPA contacted or visited stated that it is common to screen residuals for radioactivity prior to transport to landfills (U.S. EPA, 2014; U.S. EPA, 2012; ERG, 2012a; U.S. EPA, 2015f; U.S. EPA, 2016b).

EPA found that CWT facilities typically operate barium sulfate precipitation systems only to a level sufficient to meet discharge permit limitations, as more efficient operation can result in the generation of sludge with radium activity exceeding landfill disposal thresholds. With this in mind, more efficient removal of barium, radium and strontium from wastewaters using sulfate precipitation may produce treatment residuals that are costly to manage. An alternative is to use a treatment process that does not concentrate radium in sludge. Silva et al. (2012) describe a modified lime-soda process that precipitates both barium and radium as carbonates, which can then be treated with concentrated hydrochloric acid to produce a barium and radium chloride solution that can be managed via underground injection.

Table 6-5 shows estimated sludge generation rates from chemical precipitation units treating oil and gas extraction wastewater. In general, for properly designed and operated facilities, higher influent wastewater TDS and TSS concentrations result in higher sludge generation rates (Silva, 2012). The treatment systems associated with the data in Table 6-5 are operated to remove barium, strontium, magnesium, calcium, radium, and TSS from oil and gas extraction wastewater.

Table 6-5. Sludge Generation Rates from Chemical Precipitation Units Treating Oil and Gas Extraction Wastewater

Type of Precipitation	Influent TDS Concentration (mg/L)	Influent Flow Rate (bpd)	Total Waste Generation (tons per day)	Waste Generation (pounds per barrel of wastewater treated)	Reference
Caustic Addition	45,000 – 80,000	4,000 – 6,000	5 – 6	1.7 – 3	Hayes et al., 2012
Lime-Soda	34,000 – 59,000	NR	NR	3.68 – 7.84	Acharya, 2012
Sulfate Precipitation	132,000	NR	NR	3.69 – 8.21	Silva, 2012
Lime-Soda	132,000	NR	NR	14.07 - 25	Silva, 2012
Modified Lime-Soda	132,000	NR	NR	1.49 – 8.23	Silva, 2012
Sodium Sulfate and Lime-Soda	100,000	4,000	10 – 30	5 – 15	U.S. EPA, 2012

NR—Not Reported

6.2 Costs

Capital costs of chemical precipitation include costs for mixing tanks, a settling tank (clarifier) and/or filtration system, chemical feed systems, piping, low-pressure pumps, and monitoring equipment. Advanced monitoring equipment may be necessary to improve system control and reliability. In addition, chemical precipitation may require investment for wastewater equalization and storage (e.g., impoundments, tanks).

The operating costs associated with chemical precipitation include energy to operate low-pressure pumps and mixers, chemical precipitants, and labor costs. Operating costs also depend on the quality of influent wastewater and the desired quality of the effluent wastewater, which will impact the type and quantity of the chemical precipitants and therefore the chemical cost. One of the largest operating costs is the cost of the chemical precipitant. Another large operating cost is sludge management and disposal.

Table 6-6 shows approximate capital and operating and maintenance (O&M) costs for purchased or rented chemical precipitation treatment systems, as reported in the literature. Table 6-7 shows approximate costs incurred by oil and gas extraction operators for chemical precipitation treatment of produced water at a CWT facility. One commercial CWT facility stated that when influent TDS concentrations are higher than 150,000 mg/L, they charge operators extra to cover the increased chemical demand (U.S. EPA, 2012).

Table 6-6. Chemical Precipitation Capital and O&M Costs for Oil and Gas Extraction Wastewater Applications

Vendor and Technology Name	System Description	Cost Basis	Capacity (MGD)	Capital Cost (\$ per gpd)	O&M Cost (\$ per bbl)	Rental or Effective Cost (\$ per bbl) ^a	Reference
Fountain Quail Water Management, LLC's Rover	Mobile System	Rental	0.420	N/A	N/A	1.00 – 4.00	Hayes et al., 2012; Hefley et al., 2011
JS Meyer Engineering	Mobile System	NR	NR	NR	2.10	NR	JS Meyer Engineering, 2015
Not Specified	Plant	Purchase	1.200	5 to 6 ^b	NR	NR	U.S. EPA, 2015f
Not Specified	System	Purchase	NR	NR	0.15 - 0.30	< 2.00	Acharya, 2011
Not Specified	Unit	Purchase	0.022	20.8	NR	0.50 – 3.00	URS, 2011
			0.720	1.4			

N/A—Not applicable; NR—Not reported

^a Represents rental cost if the cost basis was rental and is inclusive of O&M. Represents total effective cost when cost basis is purchase, which includes amortized capital costs and O&M costs combined. When the cost basis is purchased, total effective cost is included only when a reference reported amortized capital costs.

^b This is the estimated capital cost for the entire treatment plant. Costs for just the chemical precipitation treatment system were not provided.

Table 6-7. Chemical Precipitation Costs at CWT Facilities

CWT Facility Name ^a	Type of Service	Commercial CWT Price for Treatment (\$ per bbl)	Reference
Eureka Resources, LLC	Reuse Only	7 to 9 ^b	U.S. EPA, 2012
Clean Streams, LLC		15 to 18 ^b	U.S. EPA, 2014
Reserved Environmental Services, LLC		7 ^c	ERG, 2012a
Nuverra Appalachian Water Services		4 to 7 ^c	U.S. EPA, 2015d
Patriot Water Treatment	Discharge to POTW	3.36 to 21 ^c	U.S. EPA, 2015e

NR—Not reported

^a All facilities listed are located in the Appalachian Basin where Marcellus and Utica gas are produced.

^b Cost of treatment.

^c Price quoted to users.

6.2.1 Vendors

Table 6-8 lists vendors of chemical precipitation technologies that EPA has identified that offer treatment systems designed specifically for oil and gas extraction wastewater, along with capacity information on available systems.

Table 6-8. Chemical Precipitation Technology Vendors for Oil and Gas Extraction Wastewater

Vendor	Technology Name	System Description	Surface Footprint (ft ²) ^a	Capacity (bpd)	Reference
Anguil Aqua Systems	NR	NR	NR	NR	Anguil Aqua Systems, 2016
AquaTech International Corporation	MoTreat	Mobile System	Unit fits on mobile trailer	1,700 – 6,900	All Consulting, 2011b
CoilChem, LLC	CoilChem	Mobile System	640	20,000	ERG, 2016b
Fountain Quail Water Management, LLC	Rover	Mobile System	1,100	10,000	Hayes et al., 2012
Gradiant Corporation	Selective Chemical Extraction	Fixed System	NR	12,000	Gradiant, 2016
JS Meyer Engineering	JSM	Mobile System	NR	NR	JS Meyer Engineering, 2015
MI-SWACO	Frac Water Reclamation System	Mobile System	NR	3,000	M-I SWACO, 2009

NR—Not reported

^a Includes only the primary treatment unit, not storage for wastewater, chemicals, or sludge (solid waste).

6.3 Filtration/Flotation/Sedimentation

CWT facilities often use physical separation technologies including filtration, flotation, and sedimentation to remove free oil and TSS. CWT facilities most often use filtration/sedimentation/flotation to treat oil and gas extraction wastewater prior to reuse, or as a component of a treatment train prior to other physical, chemical or biological treatment. In addition, filtration or sedimentation is typically a component of a chemical precipitation system to remove precipitates.

6.3.1 *Principle and Process Descriptions*

6.3.1.1 **Filtration**

Filtration works by routing wastewater through a porous media composed of rock, glass, walnut shell, sand, or other suitable material to separate oil and suspended solids. Gravity, centrifugal force, pressure, or a vacuum forces the wastewater through the media, which may be a single fixed bed, multiple fixed layers, or a moving bed (U.S. EPA, 1998). Suspended solids are trapped in the pores between the grains of the media (typically greater than 3 µm) and remain as the water passes through. As the media filter captures increasing amounts of solids, the pressure drop across the filter bed increases until it reaches a threshold at which point a backwash cycle is used to remove the accumulated solids. Filter backwash is typically recycled

to the first unit of the treatment system, such as a sedimentation basin. Other filter types, such as disposable bags or cartridges, do not use a backwash cycle and instead are replaced when spent.

Wastewater may also be filtered through ceramic or polymeric membranes using a pressure differential. Membrane filtration systems include media with pore sizes 0.1-3 μm (microfiltration), 0.01-0.1 μm (ultrafiltration), 0.01-0.001 μm (nanofiltration) and 0.001-0.0001 μm (reverse osmosis). Microfiltration removes conventional clays, humic acids, bacteria, algae, cysts, and other suspended solids. Ultrafiltration also removes viruses, color, odor, and some colloidal natural organic matter. Microfiltration and ultrafiltration require trans-membrane pressure of 1-30 pounds per square inch (psi) to operate (Colorado School of Mines, 2009). Nanofiltration fills the gap between ultrafiltration and reverse osmosis, operating at intermediate pressures to remove multivalent ions and small molecules. Reverse osmosis operates at applied pressures ranging from 250 to 1,180 psi to push water through the membrane while blocking ions and other dissolved material (TDS) from passing (Hayes, 2004). Reverse osmosis for TDS removal is described in Section 6.6 and not further discussed in this section.

Many applications for oil and gas extraction wastewater treatment use multiple stage filtration where each subsequent stage uses a smaller pore size than the previous stage to optimize performance. For example, one facility that EPA visited treats oil and gas extraction wastewater using 100, 50, 25, and 10-micron filters sequentially to remove suspended solids (U.S. EPA, 2014). In addition, at another facility, an operator reported they use 100 followed by 20-micron filters prior to reuse (U.S. EPA, 2015b).

6.3.1.2 Sedimentation

Sedimentation removes suspended solids by gravity settling. Sedimentation works by adjusting holding times, either by batch process or controlled flow through an impoundment or tank, that provides sufficient time for suspended solids to settle to the bottom. Dispersed oil and grease may also float to the surface for simultaneous removal. Various tank configurations, such as inclined plate settler or lamella clarifier can be used to increase efficiency. Sedimentation is most effective in removing suspended solids with specific gravities significantly greater than 1.0.

6.3.1.3 Flotation

Gas flotation is the process of using fine bubbles to induce oil and suspended particles to rise to the surface of a tank where they can be collected and removed. Gas bubbles are introduced into the wastewater and attach to the particles. With the bubbles and particles attached, the effective specific gravity of the two combined is less than that of water, allowing the suspended particles to rise to the surface with the bubbles (U.S. EPA, 1998). The gas bubbles are typically air, nitrogen, or other inert gases (Colorado School of Mines, 2009).

Two categories of gas flotation technologies are used to treat oil and gas extraction wastewater: dissolved gas flotation and induced gas flotation. These two categories differ by the

method used to create the bubbles. Consequently, the bubble sizes differ for each method (Colorado School of Mines, 2009).

- **Dissolved Gas Flotation** – Gas is injected into wastewater in a pressurized retention tank or pipe, allowing the gas to dissolve into the wastewater. When the wastewater enters the flotation tank, the pressure is reduced, causing fine air bubbles to be released.
- **Induced Gas Flotation** – Bubbles are generated or injected near the bottom of the flotation unit by mechanical means such as a propeller or diffuser.

6.3.2 Capabilities and Limitations

Filtration/sedimentation/flotation technologies primarily remove suspended solids and dispersed oil and grease (Colorado School of Mines, 2009; U.S. EPA, 2015a). EPA identified one reference with performance data for filtration in oil and gas extraction applications (Ziemkiewicz et al., 2012). In this study, bench-scale testing was first done to evaluate different filter media. Performance data from the bench-scale testing for pollutants of interest is shown in Table 6-9. The table includes untreated influent pollutant concentrations, effluent pollutant concentrations, and the calculated pollutant removal efficiencies. A full-scale 5,000 barrels per day multi-media filtration mobile treatment unit was then evaluated using mixtures of Utica and Marcellus produced waters along with other sources such as collected rain water. The goal of the treatment was to provide treated water for reuse in fracturing operations. Demonstration-scale performance data for this system for one site treating Marcellus flowback water was reported which showed a TSS reduction from 360 to 244 mg/L or 32% reduction.

Table 6-9. Bench-Scale Filtration Treatment Performance Data

Constituent	Influent Concentration Range (mg/L)	Effluent Concentration Range (mg/L)	Calculated Removal Efficiency Range (%)
Barium	172 – 2,290	93 – 1,520	34 – 56
TSS	99 - 882	81 -681	20 – 23
Sulfate	0 - 414	0 – 101	0 – 76

Source: Ziemkiewicz et al., 2012

Note: EPA used the reported detection level in calculating the removal efficiency when value was reported.

Flotation demonstrated the following removal efficiency when treating oil and gas extraction wastewater on multiple scales (e.g., bench and field) (Colorado School of Mines, 2009):

- Oil and grease: 93 percent removal efficiency;
- Chemical Oxygen Demand (COD): 75 percent removal efficiency; and
- Suspended solids: Removal of suspended solids down to 25 microns in size.

6.3.2.1 Residuals

Filtration

As noted earlier, solids collected in the filtration media during filtration periodically need to be removed to restore optimum removal efficiency. This can be achieved by backwashing the filter, with the backwash water typically recycled to the treatment system inlet, or by replacing and disposing the filter bag or cartridge. A small fraction of wastewater may be lost during backwash cycles or entrained in sludge (Colorado School of Mines, 2009). With bag or cartridge filters, once the filter capacity is spent, the bag or cartridge is typically disposed of in a landfill.

Sedimentation

The frequency with which solids must be removed from a sedimentation basin depend upon concentration in the influent. But regardless of the concentration, at some point solids must be removed from the bottom of the basin. In cases where solids must be removed from an impoundment, they are typically dredged from the bottom of the impoundment on a periodic basis and disposed of offsite, commonly at a landfill. With lamella clarifiers, solids are removed from the bottom of the clarifier and dewatered prior to disposal, usually by landfilling. Typically, all the influent is recovered as treated wastewater. However, some volume may be entrained in sludge or, depending on the region, lost to evaporation (Colorado School of Mines, 2009).

Flotation

During flotation, air bubbles, particulates, and free oil droplets form foam on the surface. This foam may be skimmed off for disposal. Note that flotation does not remove soluble oil constituents, which remain in the effluent (Colorado School of Mines, 2009). Free oil, if present in sufficient quantity and quality, can be separated and sold.

6.3.3 Costs

Capital costs of filtration, sedimentation, and flotation include costs for settling tanks, basin liners, pressurized gas tanks, piping, low-pressure pumps, monitoring equipment, membrane systems, and filters. Operating costs associated with filtration, sedimentation, and flotation include energy to pump water and pressurize the system, replacement filters, additive chemicals, disposal of generated solids, and labor costs.

Table 6-10 shows approximate capital and O&M costs for purchased or rented flotation, sedimentation, and filtration treatment systems, as reported in the literature. One facility (Clean Streams, LLC) reported that oil and gas extraction operators paid CWT facilities \$1.00 per barrel to treat oil and gas extraction wastewater with 100,000 mg/L TDS for reuse using filtration, sedimentation, and flotation treatment (U.S. EPA, 2014).

Table 6-10. Filtration/Sedimentation/Flotation Capital and O&M Costs for Oil and Gas Extraction Wastewater Applications

Technology	Vendor	Cost Basis	Capacity (MGD)	Capital Cost (\$ per gpd) ^a	O&M Cost (\$ per barrel)	Rental or Effective Cost (\$ per barrel) ^b	Reference
Filtration	NR	Purchase	0.025	12.00	Low	NR	URS, 2011
Sedimentation	NR	Purchase or Rental	0.63	NR	NR	0.15-0.40	Smith, 2014
Gas Flotation	Purestream	Purchase or Rental	0.11	2.40-3.80	NR	0.50	Purestream, 2011; U.S. EPA, 2013b

NR—Not reported; MGD—million gallons per day; gpd—gallons per day; bbl—barrels.

^a Capital costs are based on the MGD capacity of the facility.

^b Represents rental cost if the cost basis was rental and is inclusive of O&M. Represents total effective cost when cost basis is purchase, which includes amortized capital costs and O&M costs combined.

6.3.4 Vendors

Table 6-11 lists vendors of filtration, sedimentation, and floatation technologies that EPA has identified that offer treatment systems designed specifically for oil and gas extraction wastewater.

Table 6-11. Filtration/Sedimentation/Flotation Technology Vendors for Oil and Gas Extraction Wastewater

Vendor	Technology	Technology Name	Surface Footprint (ft ²) ^a	Capacity (bpd)	Reference
Anguil Aqua Systems	Sedimentation ^b	NR	NR	NR	Anguil Aqua Systems, 2016
FilterSure	Media Filtration	NR	Trailer mounted	5,000	Ziemkiewicz, 2012
Purestream	Gas Flotation	IGF and IGF+	Trailer mounted	2,500	U.S. EPA, 2013b

NR—Not reported; IGF—induced gas flotation separator; IGF+—induced gas flotation separator plus.

^a Only includes the primary treatment unit, not storage for wastewater, chemicals, or sludge (solid waste).

^b This vendor offers a chemical precipitation treatment technology that incorporates tube settlers into the process.

6.4 Evaporation/Condensation

Evaporation/condensation is used by CWT facilities to separate high TDS wastewater into distilled water and concentrated brine. Evaporation/condensation may be used when very pure treated water is desired (e.g., to meet requirements for discharging to streams or POTWs) (Metcalf and Eddy, 2003) or when costs for alternative disposal are high (e.g., in the Marcellus because of limited availability of disposal wells) (U.S. EPA, 2012, Colorado School of Mines, 2009, U.S. EPA, 2015a; Kasey, 2009). Evaporation/condensation is also useful where TDS exceeds approximately 50,000 mg/L, as other TDS removal technologies such as reverse osmosis become ineffective (see Section 6.6). At higher TDS concentrations, evaporation/condensation

remains an effective treatment process, especially if low-cost energy is available (e.g., waste heat or waste methane from co-located facilities).

6.4.1 Principle and Process Description

The evaporation/condensation treatment process removes water from wastewater through evaporation (converting liquid to vapor), reducing the wastewater volume and concentrating wastewater pollutants in the brine. The evaporated water vapor is either vented to the atmosphere or condensed as a clean distillate/condensate. For evaporation to occur, the liquid water molecules at the surface must have vapor pressure greater than the vapor pressure of the surrounding gas. Most of the pollutants present in the wastewater are unable to evaporate.²⁴ As a result, they remain in the wastewater that has not evaporated, creating concentrated brine. As evaporation continues, the pollutants in the brine become more concentrated. When pollutant concentrations reach their solubility limits, dissolved material will precipitate out of the concentrated stream (which is not desired for normal operation).

Evaporation/condensation technologies differ in the method used for evaporation. For vapor pressure to become greater than atmospheric pressure, vapor pressure can be increased, atmospheric pressure can be decreased, or both. Factors used to increase the rate of evaporation for wastewater treatment are listed below:

- **Pressure** – If atmospheric pressure decreases, the rate of evaporation increases. This can be accomplished by technologies that operate under partial vacuum.
- **Temperature** – As temperature increases, the rate of evaporation increases. This can be accomplished using technologies that increase the temperature of the wastewater.
- **Surface Area** – As the surface area of the water that is in contact with the air increases, the rate of evaporation increases. This can be accomplished by spraying the wastewater into droplets.
- **Air Movement** – As the flow rate of air at the liquid surface increases, the rate of evaporation increases. This can be accomplished using fans to push or pull air through the unit.

Three types of evaporation/condensation processes are used for oil and gas extraction wastewater treatment: vapor compression; multiple stage flash and multiple effect; and rapid spray. A discussion of each type follows.

²⁴ Some pollutants, such as solvents and light hydrocarbons, may evaporate along with the water vapor. These may pass through the treatment or be recovered using a hydrocarbon recovery unit.

6.4.1.1 Vapor Compression (VC) Evaporation/Condensation

Two types of vapor compression processes are mechanical vapor compression (MVC) and thermal vapor compression (TVC). The difference between these two types is how the water vapor pressure is increased. MVC primarily uses a mechanical compressor²⁵ to add energy into the system, while TVC uses a heat source to add energy, such as a gas burner. Both types of vapor compression technologies are used in oil and gas extraction wastewater applications, but mechanical compressors have some advantages:

- Mechanical compressors start up more quickly, run on electricity, and are less expensive than thermal vapor compression (U.S. EPA, 2012).
- Thermal vapor compression requires a closed loop system consisting of a working fluid (e.g., steam, oil) and boiler. This configuration increases the overall size of the system.

6.4.1.2 Multiple Stage Flash (MSF) and Multiple Effect (ME) Evaporation/Condensation

In MSF and ME evaporation/condensation, the main evaporation vessel operates at reduced pressure to facilitate evaporation. When the pressure decreases, preheated wastewater can be evaporated at temperatures lower than 212 ° F (Colorado School of Mines, 2009). The primary difference between MSF and ME evaporation/condensation is that the reduced pressure and high temperatures are carried out in separate vessels in ME evaporation, but in only one main vessel in MSF evaporation. Although decreasing the pressure requires energy input, less energy is then required to increase the temperature of the influent wastewater.

6.4.1.3 Rapid Spray (RS) Evaporation/Condensation

In RS evaporation, wastewater is evaporated by spraying it in small droplets into a heated air stream. The evaporation generates water vapor and concentrated brine as with other evaporation technologies. The specific configuration differs by manufacturer, but in a typical system the exhaust/brine mixture enters an entrainment separator where the concentrated brine is separated from the exhaust and drains into a sump located under the separator. A sump pump transfers brine and solids from the sump to a thickener tank, where salt solids/brine settle to the bottom and are removed, while the lower-density supernatant liquid (lower salt content) is recycled back to the evaporator section. The supernatant recycle rate is adjusted to achieve the target brine salt concentration. Water vapor (steam) is typically released directly to the atmosphere from the separator. However, as an option, the steam can be routed to a shell and

²⁵ Mechanical vapor compression also typically includes a heat source (e.g., a gas-fired boiler) but it only operates during startup operations and then periodically during steady state operation. The boiler runs approximately two percent of operational time, according to one CWT operator (U.S. EPA, 2012a). Because mechanical vapor compression does not rely on heat, it does not require steam or a boiler, making MVC more suitable for mobile treatment units than TVC.

tube heat exchanger to condense it into distillate. Cooling water for the heat exchanger is provided by wastewater feed.

6.4.2 Capabilities and Limitations

6.4.2.1 Targeted Pollutants and Treatment Effectiveness

Evaporation/condensation technologies can remove a wide range of wastewater pollutants, including suspended solids, dissolved organic matter, dissolved inorganic matter, biological contaminants (e.g., bacteria and viruses), and radioactive elements (Metcalf and Eddy, 2003). With respect to oil and gas extraction wastewaters, evaporation/condensation can be used to concentrate anions such as chloride and bromide, and metals such as barium, boron, calcium, iron, lithium, potassium, sodium and strontium into the brine solution, resulting in significant reductions in TDS in the treated effluent.

Typical influent TDS concentrations for cost effective operation can range from 20,000 mg/L to 125,000 mg/L, and effluent concentrations can be less than 10 mg/L (U.S. EPA, 2012; U.S. EPA, 2015a; All Consulting, 2011h; Colorado School of Mines, 2009). Influent TDS concentrations, in theory, can be as high as the supersaturation concentration for TDS (approximately 300,000 mg/L),²⁶ but at the expense of higher energy input and lower distilled water recovery. One CWT facility that uses evaporation/condensation suggested that the economics of the technology become unfavorable when TDS concentrations reached 125,000 mg/L (U.S. EPA, 2012). Case studies in the literature demonstrate that evaporation/condensation units can operate with TDS concentrations as high as 195,000 mg/L (Bruff, 2011). The Heartland Technologies Partners (Heartland) low momentum – high turbulence (LM-HT®) Concentrator is able to treat water with TDS concentrations of up to 235,000 mg/L (U.S. EPA, 2015c).

Constituents with evaporation temperatures lower than water could evaporate and exit the system in the water vapor stream. Examples include ammonia (U.S. EPA, 2015a) and light hydrocarbons (ERG, 2012a). Light hydrocarbons can be separated from the water vapor using a dedicated recovery unit prior to water vapor condensation. The hydrocarbons recovered from this add-on unit have the potential to be sold (ERG, 2012a).

EPA identified two references with field-scale performance data on evaporation/condensation of oil and gas extraction wastewaters. The first (Bruff, 2011) evaluated the performance of an Altela ARS-4000 thermal distillation system treating Marcellus well wastewater. This study included both bench-scale and field-scale testing. In the field-scale testing, the system was operated from August 2010 through April 2011. Pretreatment prior to the evaporation system consisted of a 100-micron bag filter to remove suspended solids. Performance data for pollutants of interest are presented in Table 6-12. These results are calculated averages from four reported sampling events. The system demonstrated removal of

²⁶ This is the approximate supersaturation concentration for sodium chloride, the primary component of TDS found in oil and gas extraction wastewater. Several vendors indicated that supersaturation occurs at approximately 300,000 mg/L TDS (Mertz, 2011; ERG, 2011d; Wilson, 2011).

TDS and chloride, COD, barium and strontium, radium, bromide and acetone. A second reference (Hayes et al., 2012) evaluated the performance of an MVR system treating shale gas wastewater from wells in the Barnett Shale in Texas. Water samples were collected twice weekly during a 60-day period in 2011, yielding 18 days of samples. Pretreatment prior to the MVR consisted of clarification using caustic as well as addition of anti-foam agents and corrosion control and a five-micron bag filter. Performance data from the system for pollutants of interest is presented in Table 6-13. Influent data were collected after the clarifier and bag filter, and the paper presented median influent data collected from a combined dataset from three MVRs operated at the site. EPA calculated that the MVR system achieved a 99% reduction in TDS, a 98% reduction in barium, a 95% reduction in BTEX and a nearly 100% reduction in strontium.

Table 6-12. Treatment Performance Data, Thermal Distillation

Constituent	Unit	Average Influent Concentration	Average Effluent Concentration	Calculated Average Removal Efficiency
TDS	mg/L	27,891	160	99.4%
TSS	mg/L	66	3	94.6%
COD	mg/L	280	36.4	86.7%
Chloride	mg/L	12,256	75.2	99.3%
Sodium	mg/L	5,772	34.6	99.3%
Barium	mg/L	321	1.9	99.3%
Strontium	mg/L	299	1.6	99.3%
Gross Alpha	pCi/L	357	2.4	99.0%
Gross Beta	pCi/L	323	0.7	99.4%
Radium 226	pCi/L	150	1.4	99.0%
Radium 228	pCi/L	59	0.6	98.8%
DRO	mg/L	5	2.8	38.7%
Bromide	mg/L	125	0.7	99.4%
Acetone	mg/L	10,958	576	94.9%

Source: Bruff, 2011

Table 6-13. Treatment Performance Data, MVR

Constituent	Median Influent Concentration (mg/L)	Median Effluent Concentration (mg/L)	Calculated Removal Efficiency
Ammonia	84	64	23.8%
Barium	6	0.1	98.3%
Boron	16	0.4	97.5%
BTEX	2.1	0.1	95.2%
Calcium	2,705	0.8	100%
Iron	2	0.1	95.0%
Lithium	11	0.1	99.1%
Magnesium	296	0.1	100%
Phosphorous	2	0.1	95.0%
Potassium	349	0.1	100%
Sodium	12,100	3.6	100%
Strontium	483	0.1	100%
Sulfates	205	5	97.6%
TDS	46,900	103	99.8%
TPH	4	4	0%
TSS	132	4	97.0%

Source: Hayes et al., 2012

Note: EPA used the detection level in calculating the removal efficiency when value was reported.

6.4.2.2 Design and Operation Considerations

One of the challenges with evaporation/condensation is the tendency for heat exchange surfaces (e.g., piping) to lose their heat transfer quality due to scaling. When these surfaces have diminished heat transfer capabilities, more energy input is required, making the overall process less energy efficient. Scaling occurs when inorganic salts precipitate onto pipes and equipment. Major contributors to scaling are salts of multivalent cations (e.g., calcium, barium, magnesium).

Prior to evaporation/condensation, oil and gas extraction wastewater is typically pretreated by chemical precipitation and filtration to reduce scale-causing constituents, which are present in high concentrations. Rigorous pretreatment can be avoided if the evaporation/condensation unit is operated at higher than atmospheric pressures, as increased pressure allows inorganic salts to remain dissolved in the water at higher temperatures, reducing the tendency for scaling (Mertz, 2011; URS, 2011). One exception is the Heartland LM-HT® technology that is designed to operate at supersaturated concentrations without the need for pretreatment or operating under pressure (U.S. EPA, 2015c).

6.4.2.3 Residuals

Evaporation/condensation processes generate a concentrated brine stream. Because chemical precipitation is typically used for pretreatment in oil and gas extraction applications, a solid waste stream will also be generated (see 6.1 for solid waste generation from chemical

precipitation). Both Bruff, 2011 and Hayes, 2012 include data on constituent concentrations in the concentrated brine generated by evaporation/condensation. The concentrated brine stream contains all the salt products contained in the influent water, but at higher concentrations than the influent. This includes any radioactive elements present in the influent wastewater that are not removed by pretreatment. The brine can be managed in several ways. Options may include:

- Injection into a disposal well;
- Use as well kill fluid;
- Use as additive for drilling fluid; and
- Further treatment via crystallization (U.S. EPA, 2012; U.S. EPA, 2014; URS, 2011).

6.4.2.4 Energy Use

Evaporation/condensation is an energy-intensive treatment technology. TVC systems require a burner or boiler (Colorado School of Mines, 2009). MVC units require compressors that run on electricity (Mertz, 2011); however, most MVC systems still require a small boiler or burner to assist in startup operations (U.S. EPA, 2012). In some field applications, electricity is generated using natural gas fired generators that use gas produced at the well site.

Evaporation/condensation systems can be designed to use waste or low-grade energy. One example was the CARES facility near Mt. Jewett, Pennsylvania that treated oil and gas extraction wastewater (CARES, unknown date). This facility was adjacent to the McKean County landfill and used landfill gas²⁷ to power specifically-designed boilers to generate steam for their AltelaRain® treatment system (NETL, unknown date). Another source for low-grade energy in oil and gas extraction wastewater applications is waste heat from compressor stations (e.g., as is used at the Heartland LM-HT® system located in Covington, PA) (Heartland Technology Partners, 2014; U.S. EPA, 2015c).

Table 6-14 reports energy usage per barrel of influent wastewater for some pilot- and full-scale projects using evaporation/condensation to treat oil and gas extraction wastewater. Table 6-14 includes the associated influent TDS concentrations of the wastewater being treated and resulting water recovery percentages. Since many of the units require both electricity and some type of fuel, the energy requirement is presented in three columns: electrical (e.g., pumps, compressors), fuel (e.g., natural gas for a burner), and the total energy required, if reported.

²⁷ Landfill gas is low-grade natural gas (approximately 52 percent methane) produced from decomposition of organic materials within the landfill.

Table 6-14. Evaporation/Condensation Influent TDS Concentration, Energy Consumption, and Water Recovery

Pilot- or Full-Scale Project	Vendor	Technology Name	Evaporator Type	Influent TDS Concentration (mg/L)	Energy Consumption			Water Recovery (%)	Power Source	Reference
					Electrical (kWh/bbl)	Fuel Energy (MCF)	Total (kWh/bbl)			
Full-Scale Project	Purestream	AVARA	Mechanical Vapor	20,000 – 40,000	6	N/A	6	80	Electrical	U.S. EPA, 2015a
	212 Resources	Vacom	Multiple Effect	~30,000	1.3	NR	1.3	90	Electricity or Wellhead Natural Gas	Colorado School of Mines, 2009; Mertz, 2011
	Fountain Quail Water Management, LLC	NOMAD	Mechanical Vapor	60,000–80,000	NR	0.07	4.6	60–90	50 kW Generator ^a	Hayes et al., 2012; Roman, 2011
	Heartland Technology Partners	LM-HT®	Rapid Spray	Up to 235,000	NR	NR	NR	NR	Uses Waste Heat from Compressor Stations or Runs on Natural Gas	Heartland Technology Partners, 2014; U.S. EPA, 2015c
	NR	NR	Mechanical Vapor	110,000–130,000	NR	NR	6.5–7.5	50	Wellhead Gas Generator	Shaw, 2011
Pilot-Scale Project	Altela Inc.	AltelaRain™	Multiple effect	25,300–195,000	2–2.5	5–10	NR	45–90	Electricity, Natural Gas, Onsite Waste Heat, Solar Panels	Bruff, 2011
	GE Water & Process Technologies	NR	Mechanical Vapor	<128,000	NR	NR	2.1–2.9	60–95	Electricity or Natural Gas	Colorado School of Mines, 2009; Wilson, 2011

N/A—Not available; NR—Not reported; mg/L—milligrams per liter; MCF—million cubic feet; kWh—kilowatt-hour; bbl—barrel.

^a Runs on natural gas directly from well head or electricity.

6.4.3 Costs

Capital costs of evaporation/condensation include costs for the pretreatment system, the evaporation/condensation unit, low-pressure pumps, and monitoring equipment. Operating costs include energy for low-pressure pumps, energy for evaporation, brine management and disposal, and labor (Wilkerson, 2013; Dale, 2013). The technology is energy-intensive; however, several studies concluded that if waste heat (e.g., low-grade steam or low-grade natural gas) is used, the technology remains effective and cost is significantly reduced (Beckman, 2008, Colorado School of Mines, 2009, Bruff, 2011).

Table 6-15 shows approximate capital and O&M costs for evaporation/condensation reported in the literature for purchased and rented treatment systems. The costs do not include pretreatment systems such as precipitation and filtration. Table 6-16 shows approximate prices charged by three CWT facilities that use(d) evaporation/condensation and the TDS concentration of the influent water that the evaporation/condensation system treated. All of the facilities use electricity or natural gas to power the evaporation/condensation treatment unit.

Table 6-15. Evaporation/Condensation Capital and O&M Costs for Oil and Gas Extraction Wastewater Applications

Vendor and Technology Name	System Description	Influent TDS Concentration (mg/L) ^a	Unit Capacity (MGD)	Cost Basis	Capital Cost (\$ per gpd)	O&M Cost (\$ per bbl)	Rental or Effective Cost (\$ per bbl) ^b	Reference
AltelaRain	Plant	25,300 – 195,000	NR	Purchase	8	0.14 – 0.89	5.24	Bruff, 2011
212 Resources	Plant	~20,000	0.168	Purchase	30	0.30 – 0.50 ^c	3.00 – 5.00	212 Resources, 2011; ERG, 2012a; Mertz, 2011
Heartland Technology Partners LM-HT®	Plant	235,000	0.03	Purchase	93 to 127	2.0 – 3.0	NR	Heartland, 2014; U.S. EPA, 2015c
Fountain Quail NOMAD	Plant	45,000 – 80,000	0.315	Purchase	NR	NR	2.57 – 4.50	Hayes et al., 2012; Jay, 2008; U.S. EPA, 2013a
	Mobile system	NR	0.105	Purchase	38	0.94	5.00 – 6.00	Hefley, 2011
NR	Mobile system	110,000 – 130,000	0.060	Purchase	100	2.40	5.40	Shaw, 2011
Purestream	Mobile System	NR	0.053	Purchase	22 to 44	1.29	2.00 – 3.00	Purestream, 2011; U.S. EPA, 2013b
GE	Mobile system	<128,000	0.072	Purchase or Rental	34	NR	2.50 – 6.50	Purestream, 2011. U.S. EPA, 1998, ERG, 2016c

NR—Not reported

^a Data are sampling data/characteristic of source water from each reference.^b Represents rental cost if the cost basis was rental and is inclusive of O&M. Represents total effective cost when cost basis is purchase, which includes amortized capital costs and O&M costs combined. When the cost basis is purchased, total effect cost is only included when a reference reported amortized capital costs.^c Electricity costs only.

Table 6-16. Evaporation/Condensation Costs at CWT Facilities

CWT Facility Name	Treated Wastewater	Influent TDS Concentration (mg/L)	Type of Service	Price for Treatment (\$ per bbl)	Year of Cost	Reference
Clean Streams, LLC ^a	Shale Gas	100,000	Reuse	6.30 – 8.25	2012	U.S. EPA, 2014
212 Water Services ^a	Tight Gas	~30,000	Discharge to Surface Water or Reuse	3.00 – 4.00	2012	Colorado School of Mines, 2009; ERG, 2012b; Wilson, 2011
Eureka Resources, LLC	Shale Gas	100,000	Discharge to POTW or Reuse	6.5 – 10.00	2012	U.S. EPA, 2012

^a Indicates that facility has since closed.

6.4.4 Vendors

Table 6-17 lists vendors of evaporation/condensation technologies that EPA identified that offer treatment systems designed specifically for oil and gas extraction wastewater.

Table 6-17. Evaporation/Condensation Technology Vendors for Oil and Gas Extraction Wastewater

Vendor	Technology Name	Surface Footprint (ft ²) ^a	Capacity (bpd)	Reference
212 Resources	Vacom	2,400	2,500 – 3,000	Mertz, 2011; ERG, 2012a; 212 Resources, 2011
Altela, Inc.	AltelaRain™	NR	100 – 600	All Consulting, 2011a; Bruff, 2011
AquaTech International Corporation	MoVap	420	1,000 – 1,700	All Consulting, 2011g; All Consulting, 2011b
Fountain Quail Water Management, LLC	NOMAD	2,500	2,500	Purestream, 2011; Hayes et al., 2012
GE Water & Process Technologies	NR	NR	1,700	Purestream, 2011, Wilson, 2011
Gradient Corporation	Carrier Gas Extraction	NR	12,000	Gradient, 2016
Purestream	AVARA	Trailer mounted	1,000 – 2,500	Purestream, 2011
Heartland Technology Partners	LM-HT®	NR	750	U.S. EPA, 2015c
Veolia	NR	NR	~6,000	Shaw, 2011

NR—Not reported

^a Only includes the primary treatment unit, not storage for wastewater, chemicals, or sludge (solid waste).

6.5 Crystallization

Crystallization converts high TDS wastewater into distilled water (low TDS) and solid salt crystals. Unlike evaporation/condensation that generates concentrated brine, as described in Section 6.4, crystallization can be used as a zero-liquid discharge (ZLD) technology if the distilled vapor is vented, rather than condensed. This technology may also be used for treating oil and gas extraction wastewater when very pure treated water is desired (e.g., to meet requirements for discharging to streams or POTWs) (Metcalf and Eddy, 2003) or when costs for alternative disposal are high (e.g., in the Marcellus because of limited availability of disposal wells) (U.S. EPA, 2012, Colorado School of Mines, 2009; U.S. EPA, 2015a; Kasey, 2009).

6.5.1 *Principle and Process Description*

Crystallization is similar to evaporation/condensation. Both technologies evaporate water from wastewater by manipulating temperature and pressure. Crystallization differs from evaporation/condensation in that sufficient water is evaporated that the brine stream becomes “supersaturated” with salts, causing the salts to precipitate out of the solution, forming solid salt crystals (Colorado School of Mines, 2009).

In crystallization systems designed for oil and gas extraction wastewater treatment, the evaporated water vapor is either recovered through condensation or vented into the atmosphere. According to the literature, both MVC and TVC technologies are used. EPA is also aware of one facility that uses RS technology for crystallization (see the description of the Heartland LM-HT® Concentrator in Section 6.4.2).

6.5.2 *Capabilities and Limitations*

6.5.2.1 Targeted Pollutants and Treatment Effectiveness

Crystallizers are capable of treating oil and gas extraction wastewaters with extremely high TDS concentrations (All Consulting, 2011g). Crystallization treatment technologies operate most efficiently when the influent wastewater is already near its supersaturation concentration for TDS (300,000 mg/L for sodium chloride). EPA did not identify detailed data in the literature on pollutant removal for crystallization. Given the similarity of the process to evaporation/condensation, pollutant removal for crystallization is also likely similar (see Section 6.4). Evaporation/condensation typically produces effluent (condensate) TDS concentrations of less than 50 mg/L (All Consulting, 2011g).

EPA collected samples in September 2016 at Eureka Resources, which incorporates crystallization as part of its treatment train. Table 6-18 shows the EPA crystallization sampling data collected at this facility for select pollutants of interest. As can be seen from these data, the crystallization removed constituents found in oil and gas extraction wastewaters, including bromide, COD, TOC, barium, strontium, boron, TDS, chloride, and radium 226 and 228. In addition, the alcohols ethanol and methanol increased in concentration after crystallization since

these components evaporate and exit the system in the water vapor stream. Additional performance data can be found in U.S. EPA, 2017.

Table 6-18. EPA Crystallization Sampling Data at Eureka Resources

Constituent	Units	Influent Concentration	Effluent Concentration	Calculated Removal Efficiency
Bromide ^a	mg/L	796	0.186	100%
Bromide ^b	mg/L	882	ND (NR)	NC
Bromide ^c	mg/L	855	ND (NR)	NC
COD	mg/L	12,500	ND (895)	>93%
TOC	mg/L	424	121	71.5%
Barium	mg/L	3,280	0.837	100%
Strontium	mg/L	4,770	0.966	100%
DRO	mg/L	52,700	17.7	66%
TPH	mg/L	0.658	0.341	48.2%
Ra-226	pCi/L	2,170	0.550	100%
Ra-228	pCi/L	311	ND (1)	100%
Gross Alpha	pCi/L	1,320	3.00	100%
Gross Beta	pCi/L	1,160	ND (4)	100%
TDS	mg/L	187,000	14.3	100%
Ammonia	mg/L	147	41.1	72.0%
Chloride	mg/L	102,000	11.4	100%
Sulfate	mg/L	127	0.583	100%
Boron	mg/L	2.74	0.143	94.8%
Calcium	mg/L	24,000	5.380	100%
Lithium	mg/L	174	0.0482	100%
Sodium	mg/L	47,900	3.62	100%
Ethanol	mg/L	15.6	22.3	NC
Methanol	mg/L	79.2	150	NC

NC – Not Calculated; NR – Not Reported; ND – Not Detected (Detection Limit value in parenthesis).

Source: U.S. EPA, 2017

Note: EPA used the reported detection level in calculating the removal efficiency.

^a Using EPA method 300.0.

^b Using ASTM method D4237 conductivity.

^c Using ASTM method D4237 UV.

6.5.2.2 Design and Operation Considerations

In oil and gas extraction wastewater treatment applications, crystallizers have been added to existing evaporation/condensation treatment systems. In these designs, the concentrated brine generated by evaporation/condensation becomes the influent to the crystallization unit (U.S. EPA, 2012). However, in some cases, stand-alone crystallization units are used to treat oil and

gas extraction wastewaters. In either case, the influent wastewater is typically pretreated to reduce concentrations of multivalent cations (e.g., calcium, magnesium, strontium, barium) (Shaw, 2011; U.S. EPA, 2012). Removal of these cations has three benefits (Shaw, 2011):

- **Reduced Corrosion and Capital Costs** – Multivalent cations are corrosive to equipment. Pretreatment to reduce corrosion allows downstream equipment, such as the crystallization unit, to be constructed of less expensive materials, reducing capital costs.
- **Reduced Operating Costs** – Removing multivalent cations allows for a lower operating temperature, resulting in energy savings. This is because the solubility limit of concentrated brine that contains multivalent cations is higher than that of concentrated brine that does not contain multivalent cations.
- **Purity of Solid Crystals** – When multivalent cations and other pollutants are removed prior to crystallization, the salt crystal is very pure sodium chloride. One CWT facility suggested the solid crystals are 98 percent pure sodium chloride, which has potential value in industrial applications (U.S. EPA, 2012).

Regardless of the type of crystallizer used, equipment is affected by scaling and corrosion in the same way that evaporation/condensation units are affected (All Consulting, 2011g). Common pretreatment alternatives include settling, chemical precipitation, and filtration to remove suspended solids and other undesired constituents (e.g., iron) (Colorado School of Mines, 2009; Adams, 2011; U.S. EPA, 2012).

An alternative to removing multivalent cations before crystallization is to operate the crystallization unit at reduced pressure using a vacuum and chilling system, which decreases the boiling temperature of the solution (Shaw, 2011). Since the solubility limit of multivalent cations will not be reached at decreased boiling temperature, the unit can be constructed of less expensive materials (due to reduced corrosion), reducing capital costs. This alternative design eliminates the need to pretreat the influent wastewater to remove multivalent cations (Shaw, 2011). However, pretreatment may still be needed to remove other constituents such as TSS and iron (Adams, 2011).

Ambient temperature can also be a design consideration. Because crystallization is a thermal technology, low winter temperatures increase energy requirements. A fixed heat exchange capacity and lower temperatures result in a lower rate of evaporation and capacity (i.e., barrels treated per day). For example, one vendor reported that capacity may be as low as 200 barrels per day (bpd) in the winter and as high as 450 bpd in the summer for a specific mobile system (Adams, 2011).

6.5.2.3 Residuals

If the crystallization unit is operated so that the water vapor is collected and condensed, recovered treated wastewater (condensate) can be reused for hydraulic fracturing or other

purposes by oil and gas operators. Crystallization can recover more than 80 percent of the influent wastewater (U.S. EPA, 2012).

Crystallization of oil and gas extraction wastewater can produce a solid crystal residue of high quality sodium chloride (up to 98 percent purity) (U.S. EPA, 2012). Several options exist for disposing of the solid crystals or recovering them as saleable byproducts, including:

- Hauling to landfill for disposal;
- Returning to operators to use as an additive in drilling fluid²⁸;
- Selling for use as highway deicer; and
- Selling for use as a raw material for industrial processes.

States may regulate the use of the crystallized solids. For example, Pennsylvania requires that all salts generated by oil and gas facilities that are used for deicing or as a raw material in an industrial process meet applicable standards in Pennsylvania Department of Environmental Protection's (PA DEP) General Permit. This permit provides 21 specific quality standards for salt crystals, including maximum levels of two radioactive constituents: thorium 232 (2 pCi/kg) and uranium 238 (2 pCi/g) (PA DEP, 2012).

Crystallization will also generate a brine purge stream that must be managed. For example, a crystallizer treating 210,000 gallons per day of oil and gas extraction wastewater with a TDS concentration of 100,000 mg/L could generate approximately 38,000 gallons per day of purge (U.S. EPA, 2012; U.S. EPA, 2013a). Depending on the composition of the original wastewater the concentration of calcium chloride could be high enough to be a valuable byproduct. One CWT facility reported that if the calcium chloride concentration is at least 35 percent, the purge stream would be a saleable byproduct for other industrial applications (U.S. EPA, 2012).²⁹ Sodium chloride is sold as road salt, pool salt, and for specific industrial uses. Calcium chloride could also be used for road salt, and there are some oil and gas uses (e.g., brining agent), among other uses. The Fairmont Brine Processing facility produces up to 80 tons a day of rock salt which is used for de-winterizing operations (Fairmont Brine Processing, 2015).

6.5.2.4 Energy Use

Crystallization is an energy-intensive treatment technology because of the large amount of energy required to evaporate the influent wastewater to generate solid crystals (URS, 2011). Most units use natural gas burners as an energy source, but a variety of alternatives have been tested.

²⁸ Salt may be used as an additive in drilling fluid to increase density and/or increase the fluid's electrical conductivity.

²⁹ Calcium chloride may be added to drilling fluid to increase density and/or increase electrical conductivity.

Vendors attempt to offset energy demand by designing units that can use alternative energy sources, such as waste heat from compressor stations and solar energy (U.S. EPA, 2015b and Adams, 2011). For example, Epiphany Solar Water Systems offers a crystallizer treatment unit that uses concentrated solar energy³⁰ (Pettengill, 2012). Consol Energy, Inc. pilot tested the system in 2012. Epiphany’s company website states that its technologies were treating produced water as of 2016, but no information was provided about facilities using the technologies (Epiphany Water Solutions, 2016).

Table 6-19 reports energy use per barrel of influent wastewater based on data reported by vendors. Table 6-19 also includes TDS concentrations of untreated water entering the treatment system, and resulting water recovery percentages. Because many of the units require both electrical energy and fuels, the energy requirement is presented in three columns: electrical (e.g., pumps, compressors), fuel (e.g., natural gas for a burner to produce steam), and the total energy required, if reported.

³⁰ In this technology, solar thermal energy is collected using mirrors and reflected onto a central point. A working fluid with high thermal energy capacity (e.g., antifreeze) passes through this central point to be heated by the concentrated solar energy.

Table 6-19. Crystallization Influent TDS Concentration, Energy Use per Barrel of Influent Wastewater, and Water Recovery

Vendor	Technology Name	Influent TDS Concentration (mg/L)	Energy Consumption			Water Recovery (%)	Additional Notes	Reference ID
			Electrical (kWh/bbl)	Steam (tons) ^a	Total (kWh/bbl)			
INTEVRAS	EVRAS™	NR	NR	N/A	1.9 – 2.1 ^b	NR	Uses waste heat from compressor stations or runs on natural gas.	INTEVRAS, 2011
Epiphany Solar Water Systems	E3H	NR	NR	N/A	NR	80	Uses concentrated solar energy.	Pettengill, 2012
Heartland Technology Partners, LLC	LM-HT®	NR	NR	N/A	NR	NR	Uses waste heat from compressor stations or runs on natural gas.	Heartland, 2014
Not Specified	Not Specified	132,000	0.5–1.7	~14	NR	NR	Assuming waste steam is available.	Shaw, 2011
Not Specified	Not Specified	>40,000	NR	NR	4.2–11	NR	None.	Colorado School of Mines, 2009

N/A—Not available; NR—Not reported; TDS—total dissolved solids; mg/L—milligrams per liter; kWh—kilowatt-hour; bbl—barrel.

^a Waste steam from other industrial processes may be used to improve economics.

^b Vendor reported the power requirement for the pumps and fans alone as 30 kW to treat 325 barrels per day, assuming waste heat is available. Assuming a 90- to 95-percent capacity, electrical consumption is between 1.9 and 2.1 kWh per barrel of influent wastewater. Additional energy is required if waste heat is not available.

6.5.3 Costs

Capital costs of crystallization include costs for the pretreatment system, evaporation/condensation unit, low-pressure pumps, and monitoring equipment. The operating costs associated with crystallization include energy for low-pressure pumps and evaporation and labor costs (Wilkerson, 2013; Dale, 2013). The energy costs are highest among all technologies used to treat oil and gas extraction wastewater, unless low-grade or waste energy is used (e.g., waste heat from compressor stations, solar energy) (Beckman, 2008; Colorado School of Mines, 2009; Bruff, 2011). Management and disposal of residuals is another operating cost. Factors that affect the costs for crystallization include feed water quality, energy source, and disposition of residuals.

Table 6-20 shows approximate capital and O&M costs for crystallization when a treatment system is purchased or rented. Table 6-21 shows approximate prices charged by CWT facilities for crystallization. Another facility estimated that the crystallization process would cost operators \$15 to \$18 per barrel (\$0.36 to \$0.43 per gallon), including pretreatment (U.S. EPA, 2014). However, other facilities in the Marcellus have multiple facilities already operating that use crystallization (U.S. EPA, 2012; U.S. EPA, 2016, U.S. EPA, 2016a).

Table 6-20. Crystallization Capital and O&M Costs for Oil and Gas Extraction Wastewater Applications

Vendor or Technology Name	System Description	Influent TDS Concentration (mg/L) ^a	Cost Basis	Capacity (MGD)	Capital Cost (\$ per gpd)	O&M Cost (\$ per bbl)	Rental or Effective Cost (\$ per bbl) ^b	Reference
NOMAD	Unit	250,000 to 300,000 ^c	Purchase	0.21	33	NR	NR	U.S. EPA, 2012
NR	Plant	110,000 – 130,000	Purchase or Rental	0.25	120	3.50	11 to 22	Shaw, 2011
NR	System	40,000 – 150,000	Purchase	0.25	45	3.70	NR	Keister, 2012
GE	Plant	~130,000	NR	1.0	NR	NR	5.00 to 6.80	Tinto, 2012
NR	System	NR	Rental	NR	N/A	N/A	1.00 – 3.00 more than evaporation/condensation	ERG, 2014

N/A—Not available; NR—Not reported;

^a These concentrations are examples provided in the sources.

^b Represents rental cost if the cost basis was rental and is inclusive of O&M. Represents total effective cost when cost basis is purchase, which includes amortized capital costs and O&M costs combined. When the cost basis is purchased, total effective cost is only included when a reference reported amortized capital costs.

^c The typical influent to the plant has a TDS concentration around 100,000 mg/L. The TDS concentration presented in the reference is the author's assumed concentration for the actual influent to the crystallization unit, which is the effluent wastewater from an evaporator.

Table 6-21. Crystallization Costs at Commercial CWT Facilities

CWT Facility Name	Treated Wastewater	Influent TDS Concentration (mg/L)	Type of Service	Commercial CWT Price for Treatment (\$ per bbl)	Year of Cost	Reference
Fairmont Brine Processing	Shale gas	250,000 to 300,000	Discharge to surface water or reuse.	5.50 – 8.00	2014	Litvak, 2014; ERG, 2016a
Eureka Resources, LLC Williamsport	Shale gas	250,000 to 300,000 ^a	Discharge to POTW or reuse.	10.80 – 11.00 ^b	2013	U.S. EPA, 2012a
NR	NR	>100,000	Reuse only.	5.00 – 6.80 ^c	1998	Tinto, 2012

NR—Not reported

^a The typical influent to the plant has a TDS concentration around 100,000 mg/L. The TDS concentration presented in the reference is the author's assumed concentration for the actual influent to the crystallization unit, which is the effluent wastewater from an evaporator.

^b Cost may be as low as \$7 per barrel to the operator if the residuals can be sold for beneficial use to other industries.

^c Costs were reported by the source; the author assumed that the hypothetical CWT facility is owned and operated by the vendor, and that the operator brings wastewater to the plant for treatment on a contractual basis.

6.5.4 Vendors

Table 6-22 lists vendors of crystallization technologies that EPA is aware of that offer treatment systems designed specifically for oil and gas extraction wastewater.

Table 6-22. Crystallization Technology Vendors for Oil and Gas Extraction Wastewater

Vendor	Technology Name	System Description	Surface Footprint (ft ²) ^a	Capacity (bpd)	Other Notes	Reference
Epiphany Solar Water Systems	E3H	Non-mobile	NR, fits on well pad	10 – 100	Each unit is sized for one well, but can be scaled up for a multi-well pad. Uses concentrated solar energy in lieu of fuel.	Pettengill, 2012
Fountain Quail Energy Services	NOMAD	Non-mobile	1,500	2,000	Multiple units may be deployed at a single location.	Hayes et al., 2012
Heartland Technology Partners, LLC	LM-HT®	Mobile	NR	1,000	Can be designed for low-grade waste heat use.	New Mexico, 2014; U.S. EPA, 2015c
		Stationary	NR	6,300		
INTEVRAS Technologies, LLC.	EVRAS™	Semi-mobile	820	200 – 400	Can be designed for low-grade waste heat use.	All Consulting, 2011d; Adams, 2011; INTEVRAS, 2011
Veolia	CoLD®	Mobile	NR	~6,000	The collected distillate from the crystallizer can be returned to the drill operator as water to be used in additional fracking operations	Shaw, 2011

NR—Not reported; bpd—barrels per day; ft²—square feet.

^a Only includes the primary treatment unit, not storage for wastewater, chemicals, or sludge (solid waste).

6.6 Reverse Osmosis

6.6.1 *Principle and Process Description*

In reverse osmosis (RO), pressure is used to force water through semi-permeable membranes that allow water, but not dissolved solids, to flow through. The RO membrane separates constituents from wastewater based not only on size differences but also based on electrostatic charge. RO membranes will repel most charged particles (ions) but allow neutral molecules like water and dissolved gases to pass through. Since TDS is primarily composed of ions such as sodium (Na⁺) and chloride (Cl⁻) that are repelled by RO membranes, RO is well suited for desalination provided the TDS concentration is not too high (Weber, 1972).

The name “reverse osmosis” derives from osmosis, the spontaneous flow of water from a dilute solution to a concentrated solution, which occurs when the two solutions are separated by a semi-permeable membrane (Weber, 1972). In “reverse” osmosis, water flows from a concentrated solution to a dilute solution. This is accomplished when a pressure greater than the osmotic pressure is applied to the concentrated water, driving water through the membrane to the

dilute solution. The membrane prevents ions from passing, leaving a concentrated solution behind (Metcalf and Eddy, 2003).

In a typical wastewater treatment RO unit, hydraulic pumps apply pressure to the influent wastewater. The process requires pressures ranging from 250 to 1,180 psi, depending on the osmotic pressure (related to TDS concentration) of the influent wastewater (Hayes, 2004). The applied pressure pushes the water through the membrane while the membrane blocks the ions (TDS) from passing. The influent wastewater separates into two streams: treated wastewater and concentrated brine. In the literature, the treated wastewater is referred to as permeate and the concentrated brine is referred to as concentrate (Colorado School of Mines, 2009).

6.6.2 Capabilities and Limitations

6.6.2.1 Targeted Pollutants and Treatment Effectiveness

RO is used to remove dissolved organic and inorganic constituents, such as ions, acids, sugars, dyes, natural resins, salts, BOD, COD, and radioactive elements from wastewater (Colorado School of Mines, 2009). The typical upper limit of TDS concentration in the wastewater for cost-effective operation is 45,000 to 50,000 mg/L (All Consulting, 2011h; Alexander, 2011). Higher TDS concentrations increase osmotic pressure to the point where excessive energy is required to generate enough applied pressure to reverse the osmotic flow, making the process prohibitively expensive. RO can achieve effluent TDS concentrations less than 200 mg/L, depending on the composition of the influent wastewater (URS, 2011). One vendor suggests that RO is the most cost-effective treatment for oil and gas extraction wastewater when TDS is less than 30,000 mg/L (Alexander, 2011).

EPA collected samples in September 2016 at Eureka Resources, which incorporates RO as part of its treatment train. Table 6-23 shows the EPA RO sampling data collected at this facility for pollutants of interest. As can be seen from these data, the system removed constituents found in oil and gas extraction wastewaters, including COD, TDS, barium, strontium, and DRO (additional data can be found in U.S. EPA, 2017). In this case, RO is a final polishing step after the wastewater had already been treated by chemical precipitation, crystallization, membrane bio-reactor, and ion exchange.

Table 6-23. EPA Reverse Osmosis Sampling Data at Eureka Resources

Constituent	Influent Concentration	Effluent Concentration	Calculated Removal Efficiency
COD (mg/L)	489	16.1	96.7%
TDS (mg/L)	150	14.3	90.5%
Barium (mg/L)	0.589	0.0154	97.4%
Strontium (mg/L)	1.32	0.0347	97.4%
DRO (mg/L)	0.828	0.0835	89.9%

NC – Not Calculated

Source: U.S. EPA, 2017

Note: EPA used the reported detection level in calculating the removal efficiency when possible.

EPA identified several references in the literature that contain data on the performance of RO in treating oil and gas extraction wastewater, these data sources are summarized below, and their performance data are presented in the next 5 tables.

- All Consulting (2006) reported pilot-study data on the feasibility of membrane filtration technologies of a GE system for the treatment of produced water in California near Bakersfield, shown in Table 6-24. Calculated percent removals of the RO component are 97 percent for sodium and 98 percent for chloride. The report also shows the intermediate performance data of the whole physical/chemical treatment system, which incorporated demineralization, ultrafiltration, followed by nanofiltration, and then RO.
- Data from Newpark Environmental Services cited in All Consulting (2006) from three locations treating produced water from CBM facilities are shown in Table 6-25. The data labeled as influent to RO is wastewater that had undergone physical/chemical pretreatment. The calculated percent reductions in TDS for these three locations ranged from 96.9 to 99.5 percent.
- Horn (2009) provided data on the performance of a pilot-scale treatment system combining an advanced oxidation process with RO for treating produced waters in the Woodford Shale from Newfield Exploration. Data for the entire system is provided in Table 6-26 (the reference did not provide data for just the RO portion of the system). The system removed TDS, chloride, organics, barium and radium 226.
- Ecolotron (2012) provided data on the performance of an electrocoagulation system with a subsequent RO unit treating wastewaters from three locations. Table 6-27 provides performance data for the RO membrane treatment portion of this system. Removal of barium, strontium, sodium and chloride was reported.
- Shafer (2010) reported on the performance of the Anticline Disposal treatment system in Pinedale, Wyoming that uses RO. Although this reference did not provide data for just the RO portion of the system, data for the entire treatment system are shown in Table 6-28. The system begins with an API separator, followed by anaerobic then aerobic basins, leading into a clarifier. After a sand filter, the wastewater flows to an MBR, and then to the RO unit. Additional treatment is then used: electrocoagulation, another RO unit, and then ion exchange before discharge.

Table 6-24. GE Pilot Membrane Filtration and RO Performance Data

Constituent	RO Influent ^a Concentration (mg/L)	RO Permeate Concentration (mg/L)
Sodium	5,250	144
Calcium	163	5
Magnesium	115	2
Potassium	77	2
Ammonium	68	2
Chloride	4,710	114
Sulfate	ND	ND
Oil	ND	ND

ND – Not Detected

Source: All Consulting, 2006

^a Permeate from ultrafiltration followed by nanofiltration, prior to RO.**Table 6-25. Newpark Environmental Services Reverse Osmosis Performance Data**

Constituent	Concentrations (mg/L)					
	Pinedale, WY		Big Hills, TX		Gillette, WY	
	Influent	Effluent	Influent	Effluent	Influent	Effluent
Chloride	-	-	8,922	355	-	-
Sodium	-	-	5,140	217	-	-
TDS	3,004	93	19,053	93.1	1,358	46

Source: Newpark Environmental Services cited in ALL Consulting, 2006

Table 6-26. Newfield Exploration Advanced Oxidation Process/Reverse Osmosis Performance Data

Constituent	Units	Influent Concentration	Effluent Concentration	Reported Removal Efficiency
TDS	mg/L	13,833	128	99.1%
Chloride	mg/L	8,393	27	99.7%
Chemical Oxygen Demand	mg/L	248	2	99.3%
BOD - 5 Day	mg/L	196	9	95.4%
Total Organic Carbon	mg/L	65.4	3.0	95.4%
Ammonia as N	mg/L	39.9	1.1	97.2%
Barium	mg/L	34.9	0.0	99.9%
Sulfate	mg/L	23.5	0.0	100%
Oil & Grease	mg/L	13.8	1.1	92.3%
Phenolics	mg/L	0.111	0.051	54.4%
Phenol	µg/L	38.6	0.0	100%
Bis(2-chloroethyl)ether	µg/L	38.3	0.0	100%
Xylenes, total	µg/L	24.3	0.0	100%
Toluene	µg/L	5.62	0.97	82.7%
Benzene	µg/L	4.73	0.00	100%
Ethylbenzene	µg/L	4.25	0.00	100%
Gross Alpha	pCi/L	265	0	100%
Gross Beta	pCi/L	72.0	0.0	100%
Radium 226	pCi/L	81.8	0.0	100%
Radium 228	pCi/L	7.34	0.00	100%

Source: Horn, 2009

Table 6-27. Ecolotron RO Membrane Performance Data

Constituent	Units	Influent Concentration	Effluent Concentration	Calculated Removal Efficiency
Eagle Ford				
Barium	mg/L	5.96	0.2	96.6%
Sodium	mg/L	8,630	88.3	99.0%
Strontium	mg/L	24.1	0.0987	95.9%
Chlorides	mg/L	18,400	93.6	99.5%
Eagle Ford				
Barium	mg/L	3	0.1	96.7%
Sodium	mg/L	23,100	906	96.1%
Strontium	mg/L	352	5.8	98.4%
Chlorides	mg/L	42,700	985	97.7%
Colorado				
Barium	mg/L	14	5	64.3%
Chlorides	mg/L	25,080	600	97.6%

Source: Ecolotron, 2012

Table 6-28. Anticline Disposal Performance Data for Treatment System Incorporating Reverse Osmosis

Constituent	Units	Typical Influent Concentration	Effluent Concentration	Calculated Removal Efficiency
TDS	mg/L	8,000 - 15,000	41	99.5% - 99.7%
Boron	mg/L	15 - 30	0.750	95.0% - 97.5%
Chloride	mg/L	3,600 - 6,750	18	99.5% - 99.7%
Sulfates	mg/L	10 - 100	ND	NC
BTEX	µg/L	28,000 - 80,000	ND	NC
DRO	µg/L	77,000 - 1,100,000	ND	NC
Gasoline Range Organics	µg/L	88,000 - 420,000	ND	NC
Methanol	mg/L	40 - 1,500	ND	NC
Oil & Grease	mg/L	50 - 2,400	ND	NC

ND – Not Detected; NC – Not Calculated

Source: Shafer, 2010

6.6.2.2 Design and Operation Considerations

RO is most efficient and cost-effective when treating wastewater with TDS concentrations less than 50,000 mg/L; therefore, it is generally only used to treat flowback or produced waters from formations that generate relatively low TDS concentrations (Ely, 2011). Additionally, RO may be used as a polishing step. The most challenging problem with RO is

that, even with proper pretreatment, membranes are subject to fouling.³¹ Constituents that contribute to fouling include metal hydroxides, colloidal and particulate foulants, precipitates or salts, organic materials (e.g., oil, humic acids), and biologicals (e.g., microbes, bacteria) (Alexander, 2011; Colorado School of Mines, 2009). Membrane fouling will lead to reduced treatment efficiency and higher volumes of concentrated brine. To minimize scaling and reduce membrane fouling, pretreatment and chemical addition are typically required (Colorado School of Mines, 2009, All Consulting, 2011h). Usually scale control occurs first and can include pH adjustment or antiscalant addition. After scale control, the wastewater is filtered to remove particulate matter (TSS). Finally, wastewater may also be disinfected to reduce biofouling of the membrane (Crittenden, 2005). Even with proper pretreatment, periodic chemical cleaning is needed to remove foulants from the membrane. Cleaning chemicals may include hydrochloric acid and sodium hydroxide (Colorado School of Mines, 2009). Examples of pretreatment prior to RO specifically used in oil and gas extraction applications include advanced oxidation and precipitation, induced gas flotation, filtration, and electrocoagulation.

6.6.2.3 Residuals

RO generates concentrated brine. At higher influent TDS concentrations, water recovery decreases, resulting in a larger volume of concentrate and higher disposal costs (URS, 2011; Colorado School of Mines, 2009; Asano, 2007). High water recovery (75 to 90 percent) and reduced concentrated brine generation is possible if influent TDS is below approximately 25,000 mg/L (URS, 2011). One vendor estimated that water recovery drops to 60 percent when influent TDS concentration reaches 30,000 mg/L, and to 25 percent when influent TDS concentration reaches 50,000 mg/L (Alexander, 2011). Disposal methods for concentrated brine include evaporation in ponds (Red Dessert, 2013; Themaat, 2012) and injection to a Class II disposal well (Themaat, 2012).

6.6.2.4 Energy Use

RO requires electrical energy to run the pumps that pressurize the influent wastewater (Hayes, 2004). A general rule of thumb in industry is that for every 100 mg/L increase of influent TDS concentration, an additional 1 psi of applied pressure is required (Alexander, 2011). When the required applied pressure increases, energy requirement also increases. In general, RO pumps are powered by electricity purchased from off-site generation (i.e., the grid). Burnett (2011) suggested alternative methods of powering RO units. These methods include microturbines (which require low grade gas), solar panels (if the system has low pressure requirements), and wind turbines. Burnett (2011) described a mobile wind turbine unit that is capable of providing enough power for pretreatment operations such as media filtration, but not enough to run the high-pressure hydraulic pumps required for RO.

³¹ Membrane fouling occurs when dissolved and suspended solids deposit onto a membrane surface, degrading overall performance. Specific declines in performance include a decrease in permeate quality and water recovery percentage.

Table 6-29 reports energy use for RO per barrel of influent wastewater. Influent and effluent TDS concentrations are also included, together with the final water recovery percent.

Table 6-29. Reverse Osmosis Influent TDS Concentration, Energy Use, and Water Recovery

Vendor	Technology Name	Influent TDS Concentration (mg/L)	Energy Use (kWh per bbl)	Water Recovery (%)	Reference
Ecosphere Technologies, Inc.	Ozonix™, includes AOP for pretreatment.	13,800	2.184	75	Colorado School of Mines, 2009; Horn, 2013
Not Specified	NR, includes filtration for pretreatment.	500–25,000	0.02–0.4	60–85	Asano, 2007; Horn, 2013
Not Specified	Mobile unit designed by Chevron, includes electrocoagulation for pretreatment.	45,000	1	NR	Panu et al., 2013
Not Specified	N/A, includes softening and filtration for pretreatment.	20,000–47,000	0.5–1.6	30–60	Asano, 2007; Horn, 2013

NR—Not reported

6.6.3 Costs

The major capital costs associated with RO are the RO unit and hydraulic pumps that can withstand the corrosivity of the high TDS in oil and gas extraction wastewater. A major operating cost associated with RO is membrane replacement, which is expected to occur every three to seven years for oil and gas extraction wastewater applications, according to Colorado School of Mines (2009). According to Burnett (2011), unconventional oil and gas wastewater treatment requires annual membrane replacement. Energy required for the pumps and brine management and disposal are the other major operating costs (Colorado School of Mines, 2009).

Table 6-30 shows approximate RO capital and O&M costs. The reported data show that overall cost of RO units depends on influent wastewater quality. As influent TDS concentrations increase, the capital and operational costs increase. This is because larger and more robust pumps and membranes are required as the applied pressure increases (with the increase of TDS). Table 6-31 shows approximate prices CWT facilities charge to oil and gas extraction operators for treatment including RO. Costs do not include pretreatment steps.

Table 6-30. Reverse Osmosis Capital and O&M Costs for Oil and Gas Extraction Wastewater Applications

Vendor and Technology Name	System Description	Influent TDS Concentration (mg/L)	Capacity (MGD)	Cost Basis	Capital Cost (\$ per gpd)	O&M Cost (\$ per bbl)	Rental or Effective Cost (\$/bbl) ^a	Reference
General	Mobile System with Electro-coagulation and Dissolved Air Flotation	~50,000	0.063	Purchase and Rental	17.7	1.51	4.38	Panu et al., 2013
Ecosphere Energy Services, Inc.	Mobile System	20,000 – 30,000	0.144	NR	NR	NR	3.50 – 4.00	212 Resources, 2011
Siemens	Mobile System	~30,000	NR	Purchase	1.0 – 4.0	NR	NR	Alexander, 2011
General	Mobile System with Filtration	20,000 – 47,000	NR	Purchase	3.0 to 7.0	0.08	NR	Colorado School of Mines, 2009

NR—Not reported

^a Represents rental cost if the cost basis was rental and is inclusive of O&M. Represents total effective cost when cost basis is purchase, which includes amortized capital costs and O&M costs combined. When the cost basis is purchased, total effective cost is only included when a reference reported amortized capital costs.

Table 6-31. Reverse Osmosis Treatment Cost at CWT Facilities

CWT Facility Name	Type of OG	Influent TDS Concentration (mg/L)	Type of Service	Commercial Price for Treatment (\$ per bbl)	Year of Cost	Reference
Anticline Disposal, LLC	Tight Gas	~20,000	Discharge treated wastewater to surface water.	2.50 – 3.50	2006	Puder, 2006
Red Desert Reclamation, LLC ^a	Tight Gas	<30,000	Reuse treated wastewater in fracturing and evaporate concentrated brine in ponds.	2.00 – 3.00	2013	Red Desert, 2013

^a Facility is no longer in commercial operation.

6.6.4 Vendors

Table 6-32 lists vendors of reverse osmosis technologies that EPA is aware of that offer treatment systems designed specifically for oil and gas extraction wastewater.

Table 6-32. Reverse Osmosis Technology Vendors for Oil and Gas Extraction Wastewater

Vendor	Technology Name	System Description	Surface Footprint (ft ²) ^a	Capacity (bpd)	Other Notes	Reference
Ecosphere Technologies, Inc.	Ozonix™	Mobile	380	7,200	Includes Advanced Oxidation Process (AOP) as pretreatment.	Ecosphere Technologies, Inc., 2011; Horn, 2009
GeoPure Hydrotechnologies	NR	NR	NR	5,000	None.	All Consulting, 2011c
M-I SWACO	GPRI Designs™	NR	NR	5,000	None.	All Consulting, 2011e
Omni Water Solutions, Inc.	HIPPO®	Mobile	NR	2,500 – 10,000	Includes pretreatment.	Omni Water Solutions, 2014
Siemens Water Technologies	FracTreat	Mobile	NR	NR	Includes pretreatment.	Alexander, 2011; Asano, 2007
Veolia Water Solutions & Technologies	OPUS™	Mobile or stationary	NR	10,000	Includes chemical softening, degasification, and media filtration.	CO Department of Public Health and Env, 2011, 2011; All Consulting, 2011f

NR—Not reported

^a Only includes the primary treatment unit, not storage for wastewater, chemicals, or sludge (solid waste).

6.7 Biological Treatment

Biological treatment is a broad category of treatment which includes many different technologies. This section provides an overview of biological treatment and discusses the specific technologies most commonly used for oil and gas extraction wastewater.

6.7.1 *Principle and Process Description*

Biological wastewater treatment systems use microorganisms to consume biodegradable soluble organic contaminants and bind the less soluble portions into flocculant, which is removed from the system typically in a clarifier. Biological treatment may be aerobic, anaerobic, anoxic, or a combination of these technologies. Aerobic biological treatment is the degradation of organic impurities by bacteria that can thrive in the presence of oxygen (also called aerobes) (Mittal, 2011); this treatment takes place in an aerobic bioreactor which is typically aerated. Anaerobic biological treatment is the degradation of organic impurities by bacteria that thrive only in the absence of oxygen (also called anaerobes) (Mittal, 2011). Anoxic systems are typically used for denitrification (conversion of nitrate to nitrogen gas) using facultative bacteria that thrive in the absence of dissolved oxygen and instead use oxygen in the form of nitrous oxides.

One type of biological treatment system used to treat oil and gas extraction wastewater is a membrane bioreactor (MBR). In an MBR the wastewater from a bioreactor passes through membranes for solid-liquid separation instead of clarifiers. The membrane separation processes typically used in an MBR are microfiltration or ultrafiltration. The membranes are usually made of plastic or ceramic materials but can be made of metal (Radjenovic et al., 2008). Similar to RO, the effluent from the membrane is called permeate and the rejected fluid is called the concentrate (Sutton, 2006).

Anticline Disposal's Jensen facility uses both anaerobic and aerobic biological treatment to treat produced waters. Wastewater flows from a large anaerobic lagoon to an aerated lagoon and then to a clarifier where added chemicals aid in flocculation, coagulation, and settling of biomass. From the clarifier, the wastewater flows to sand filters (Shafer, 2010). Effluent from this process can be reused by oil and gas extraction operations, or further processed through an activated sludge bioreactor, an MBR, and other subsequent treatment for discharge to surface waters (Shafer, 2010). Eureka Resources also incorporates MBR into their treatment train for discharge of produced waters (McManus et al., 2015).

6.7.2 Capabilities and Limitations

Biological treatment is mainly used to remove suspended organics, dissolved/colloidal organic matter, and possibly nutrients. However, other wastewater constituents may be removed by biological treatment because they are either biologically degraded (e.g., methanol) or collected in the flocculent and removed from the wastewater with the other solids (e.g., particulate metals).

EPA collected samples in September 2016 at Eureka Resources that incorporated MBRs as part of the treatment train. Table 6-33 shows the data collected at this facility for pollutants of interest. As can be seen from these data, the systems removed constituents found in oil and gas extraction wastewaters, including oil and grease/hexane extractable material, diesel range organics, total petroleum hydrocarbons, and alcohols (additional data can be found in U.S. EPA, 2017).

Table 6-33. EPA MBR Sampling Data at Eureka Resources

Constituent	Influent Concentration	Effluent Concentration	Calculated Removal Efficiency
Ammonia (mg/L)	41.1	0.259	99.4%
TOC (mg/L)	121	2.540	97.9%
DRO (mg/L)	17.7	10.2	42.4%
2-Butoxyethanol	1.08	ND (0.001)	>99.9%
Ethanol (mg/L)	22.3	ND (3)	>86.5%
Methanol (mg/L)	150	ND (0.25)	>99.8%

ND – Not Detected (Detection Limit value in parenthesis)

Source: U.S. EPA, 2017

Note: EPA used the reported detection level in calculating the removal efficiency.

EPA identified limited performance data for biological treatment specific to oil and gas extraction wastewater treatment in the literature. Kose et al. (2012) evaluated the performance of a submerged MBR in the laboratory for the treatment of brackish oil and natural gas field produced water in Turkey. Table 6-34 presents the results of this study. Reductions in COD, oil and grease and TPH were reported.

Table 6-34. MBR Laboratory Performance Data

Constituent	Reported Influent Range (mg/L)	Reported Effluent Range (mg/L)	Reported Removal Efficiency (%)
COD	1,500 – 3,000	<500	80 - 85
Oil and Grease	31 - 50	7 - 15	60 - 85
TPH	1,030 – 2,210	<8 - 185	82 - 99

Source: Kose et al., 2012

6.7.2.1 Design and Operation Considerations

Biological processes can be sensitive to variations in influent flow and organic loads. Also, sludge buildup can be a concern, especially in aerobic treatment processes, which generate more sludge than anaerobic treatment processes. Biological treatment has a high energy requirement for aeration which increases with wastewater strength (high concentration of organics). Also, the efficiency of this treatment process is temperature dependent, so the systems may need to be heated, which adds to energy costs. Aerobic processes only operate within a fixed pH range of 6.5 to 8.5 (U.S. EPA, 2000b). If there is insufficient alkalinity to buffer the system, the pH must be maintained by chemical addition, which adds to the treatment cost.

A significant concern with MBR is membrane fouling, which can cause a decrease in permeate flux rate. Fouling may be the result of material adsorbing to the membrane, biofilm growing on the membrane, precipitation of inorganic material, or membrane aging (Radjenovic et al., 2008). Fouling may be controlled by a variety of management techniques, including a regular physical and chemical cleaning regimen. Physical cleaning of the membranes may consist of either back flushing or rinsing the membranes and scouring with air bubbles. Chemical cleaning methods include the use of either alkaline or acidic chemicals.

6.7.2.2 Residuals

In most biological treatment systems, the clarifier separates the biomass from the treated wastewater. Sludge is removed regularly from the system, sometimes continuously. Landfilling is a typical method of disposal. In anaerobic lagoons, there is minimal generation of solids. Solids are typically removed infrequently by dredging the lagoon. Depending on the design of the lagoon, this cleanout may occur every several years or even less frequently.

6.7.3 Costs

Capital costs for biological treatment include costs for a bioreactor or lagoon, clarifier and/or filtration system, pumps, and monitoring equipment. Operation and maintenance costs include electricity, sludge disposal costs, plant maintenance costs and labor costs. Electricity costs account for the energy required to operate the aeration tanks as well as the pumps and mixers. The energy requirements depend upon the device employed, but range from 1 to 4 kWh/day (U.S. EPA, 2000b). Operating costs are directly proportional to the quality of wastewater supplied for treatment. Labor costs are also a factor due to maintenance performed by semi-skilled personnel and/or operational problems for onsite blower, mechanical aerator tanks, pump and pipe clogging, electrical, motor failure, corrosion and/or failure of controls, and electrical malfunctions (U.S. EPA, 2000b).

Capital costs for MBRs include the items listed above for other activated sludge systems, and in addition, the costs of the membranes. Operating costs, in addition to those listed above, include the chemical and labor costs for cleaning the membranes and increased power requirements for pumping water through the membranes.

The cost effectiveness of an anaerobic biological treatment depends upon many factors such as ability to use biogas, power costs, and sludge disposal costs (U.S. EPA, 2000b). Capital costs of general anaerobic biological treatment mainly include the cost of construction and costs for the pretreatment system or monitoring equipment. Operational costs include costs for pH control chemicals and nutrients, and labor costs for periodic sludge removal.

6.7.4 Vendors

Lagoons and activated sludge systems may be designed and constructed by facilities without the use of a vendor. MBR systems are more complex and require specific vendors. Table 6-35 lists some vendors of MBR technology.

Table 6-35. Biological Treatment Technology Vendors for Oil and Gas Extraction Wastewater

Vendor	Technology Name	System Description	Surface Footprint (ft ²) ^a	Capacity (bpd)	Reference
General Electric-Zenon Environmental	ZeeWeed ZW-500	Submerged Membrane	495.14	NR	Radjenovic, 2008
Koch Membrane Systems	PURON® MBR	Submerged Membrane	3,552 – 19,375	NR	Koch Membrane Systems, 2015
KUBOTA Corporation	Kubota Submerged Membrane Unit® (SMU)	Submerged Membrane	86 – 6,243	NR	KUBOTA Corp., 2015
ADI System Inc.	ADI-AnMBR	Anaerobic Membrane Bioreactor	NR	NR	ADI Systems Inc., 2015

NR—Not reported

^a Only includes the primary treatment unit, not storage for wastewater, chemicals, or sludge (solid waste).

6.8 Summary

The preceding discussions described technologies that EPA identified that are currently being used at CWT facilities to treat oil and gas extraction wastewaters. In addition to those technologies previously described, there are additional technologies that are or have been used as part of a treatment train at these facilities, for example for polishing of treated effluent prior to discharge or as pretreatment steps prior to other technologies. An example of such a technology is ion exchange. Additionally, other technologies have been used or researched for treating oil and gas extraction wastewaters, either in the laboratory or at other (non-CWT) facilities that may be applicable to CWT facilities. These include electrocoagulation, electrodialysis reversal, capacitative deionization, membrane distillation and forward osmosis. Many of these technologies are described by Ahmadun et al. (2009).

6.9 Performance Data Reference Information

EPA reviewed multiple data sources to produce the data contained in this section. These data sources include journal articles and technical papers, technical references, industry/vendor telephone queries, facility site visits, technology fact sheets, and vendor websites. Table 6-36 lists the performance data sources in this section along with notes on the scale of the study (if applicable). The scale may be bench, pilot, demonstration, or full, as described below. In some cases, the data source included multiple studies which represented multiple scales. In cases where the data source summarized and presented data or information from other studies, or presented only data from other studies, the type of scale was reported as not applicable (N/A).

- Bench – very small scale, in-laboratory testing;
- Pilot – larger than bench, but still small scale; sometimes in a laboratory;
- Demonstration – large scale, not full-size; and
- Full – full-sized; usually operating at a facility.

Table 6-36 also contains a Source Type number that indicates the type of reference the information was obtained from. These numbers correspond to the following:

1. Journal articles, documents prepared by or documents prepared for a government agency (e.g., EPA site visit reports, industry meeting notes).
2. Documents prepared by a source³² that include verifiable information (e.g., operator reports, vendor documents, university publications).
3. Documents prepared by a verified source that do not include citation information (e.g., operator reports, vendor documents, conference presentations).

Table 6-36. Performance Data Quality Review

Author, Year	Study Scale	Source Type	Author, Year	Study Scale	Source Type
212 Resources, 2011	Full Scale	3	Horn et al., 2013	Full Scale	2
Acharya, 2011	Bench Scale	1	Horn, 2009	Pilot Scale	2
ADI System Inc., 2015	Full Scale	3	INTEVRAS Technologies, LLC, 2011	Full Scale	3
All Consulting, 2006	Multiple	2	JS Meyer Engineering, 2015	Full Scale	2
All Consulting, 2011a	Full Scale	3	Keister, 2012	Pilot Scale	2
All Consulting, 2011b	Full Scale	3	Kose et al., 2012	Bench Scale	1
All Consulting, 2011c	Full Scale	3	KUBOTA Corporation, 2015	Full Scale	3

³² The EPA considered sources as verifiable if we were able to find information about the author outside of the reference document. For example, EPA primarily verified information by looking for company/organization websites that confirmed the author's affiliation with the oil and gas extraction industry.

Table 6-36. Performance Data Quality Review

Author, Year	Study Scale	Source Type	Author, Year	Study Scale	Source Type
All Consulting, 2011d	Full Scale	3	Litvak, 2014	Pilot Scale	3
All Consulting, 2011e	Full Scale	3	Lord et al., 2013	Bench Scale	2
All Consulting, 2011f	Full Scale	3	Mittal, 2011	Pilot Scale	1
Anguil Aqua Systems, 2016	Full Scale	3	M-I SWACO, 2009	Full Scale	3
Asano, 2007	Pilot Scale	1	Papso et al., 2010	Full Scale	2
AquaTech International Corporation, 2011	Full Scale	3	Puder, 2006	Full Scale	2
Beckman, 2008	Pilot Scale	2	Radjenovic, 2008	Multiple	3
Bruff, 2011	Multiple	2	Roman, Jaime, 2011	Full Scale	3
CARES, Unknown	Full Scale	3	Shafer, 2010	Full Scale	2
CO Department of Public Health and Env, 2011	Full Scale	1	Shaw, 2011	Full Scale	3
Colorado School of Mines (CSM), 2009	Multiple	1	Silva, 2012	Full Scale	3
Crittendon et al., 2005	Multiple	1	Smith, 2014	Pilot Scale	1
Dale, 2013	Pilot Scale	3	Sutton, 2006	Demonstration Scale	2
ERG, 2016a	N/A	1	U.S. EPA, 1998	Multiple	3
ERG, 2016b	Full Scale	1	U.S. EPA, 2000a	Multiple	1
ERG, 2016c	Multiple	1	U.S. EPA, 2013a	Full Scale	1
ERG, 2014	Full Scale	1	U.S. EPA, 2013b	Multiple	1
ERG, 2012a	Full Scale	1	U.S. EPA, 2014	Full Scale	1
ERG, 2012b	Full Scale	1	U.S. EPA, 2015a	Pilot Scale	1
Ecolotron, 2012	Demonstration Scale	2	U.S. EPA, 2015c	Full Scale	1
Ecosphere Technologies Inc., 2011	Full Scale	2	U.S. EPA, 2015d	Full Scale	1
Fairmont Brine Processing, 2015	Full	2	U.S. EPA, 2015e	Full Scale	1
Gradient, 2016	Full Scale	3	U.S. EPA, 2015f	Full Scale	1
Hayes, 2004	Pilot Scale	1	URS, 2011	Full Scale	3
Hayes et al., 2012	Full Scale	3	Ziemkiewicz et al., 2012	Bench Scale	2
Heartland Technology Partners, LLC, 2014	Full Scale	3			

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7. POLLUTANT DISCHARGE LOADINGS

EPA estimated the quantity of pollutants discharged from in-scope facilities for the 2016 reporting year. To develop these estimates, EPA used a combination of Discharge Monitoring Report (DMR) data from 2016 and responses to EPA’s data request under section 308(a) of the Clean Water Act.³³ As described in Section 4.3, EPA is aware of nine in-scope direct discharging and two in-scope indirect discharging CWT facilities. These facilities are listed in Table 7-1, which also notes whether a facility is a major or non-major discharger under NPDES³⁴. As noted previously, the Max Environmental Technologies, Inc. Yukon Facility does not discharge oil and gas extraction wastes under the CWT effluent guidelines and therefore the pollutants reported in the DMRs are reflective of other discharges from the facility. Therefore, EPA has not summarized DMR data for this facility.

As described in Section 5.2.1, DMR data from treating oil and gas extraction process wastewater is available from five facilities for reporting year 2016. For each of these five facilities, EPA estimated the total pounds of pollutants discharged from treating oil and gas extraction wastewater. In addition, EPA estimated the toxicity of these wastewater discharges using pollutant-specific toxic weighting factors (TWFs) to account for the relative toxicity of different pollutants. (TWF values and a discussion of their development are available in ERG, 2005.). EPA calculated pollutant toxic weighted pound equivalents (TWPEs) for each pollutant by multiplying the pollutant load (in pounds) by its TWF.

Table 7-1. In-Scope Facilities Accepting Oil and Gas Extraction Wastes

Name of the Facility	City, State	Status (Major/Minor)
Byrd/Judsonia Water Reuse/Recycle Facility	Judsonia, AR	Minor
Clarion Altela Environmental Services (CAES)	Clarion, PA	Minor
Eureka Resources, Standing Stone Facility	Wysox, PA	Minor
Fairmont Brine Processing, LLC	Fairmont, WV	Minor
Fluid Recovery Service: Franklin Facility	Franklin, PA	Major
Fluid Recovery Service: Josephine Facility	Josephine, PA	Major
Fluid Recovery Services: Creekside Treatment Facility	Creekside, PA	Minor
Max Environmental Technologies, Inc. Yukon Facility	Yukon, PA	Minor
Waste Treatment Corporation*	Warren, PA	Major
Eureka Resources, Williamsport 2 nd Street Plant	Williamsport, PA	N/A (indirect discharge)
Patriot Water Treatment, LLC	Warren, OH	N/A (indirect discharge)

*Note this facility has closed as of November, 2017.

³³ TRI data were not available for any of the nine facilities. Only facilities meeting specific size and discharge thresholds are required to report to TRI.

³⁴ Major or federally-reportable facilities are those for which states must submit compliance and enforcement data to EPA. See <https://echo.epa.gov/tools/data-downloads/icis-npdes-download-summary> for more information.

7.1 **Direct Discharges**

EPA reviewed the 2016 DMR data to estimate the pollutant loadings discharged by each in-scope CWT facility that accepts oil and gas extraction wastewater and directly discharges treated wastewater. EPA obtained 2016 DMR pollutant data for seven of the nine facilities that discharge directly. Only minimal data were available for Waste Treatment Corporation in 2016 DMRs, and therefore EPA did not calculate annual loads for this facility. The Byrd/Judsonia Water Reuse/Recycle Facility has a NPDES permit to discharge but rarely discharges and instead primarily reuses water in other oil and gas operations. EPA did not calculate annual loadings for this facility. The Fluid Recovery Services: Creekside Facility has an NPDES permit, but the facility did not report any discharge on DMRs in 2016. EPA was unable to identify any publicly-available sources of data to estimate discharge loadings for the Creekside Facility in 2016; therefore, EPA did not calculate the pollutant loadings for the Creekside facility for 2016.

EPA’s DMR Pollutant Loading Tool calculates pollutant loadings discharged using the pollutant concentrations and wastewater flows and/or pollutant loadings reported by facilities on their DMRs. The tool also estimates toxic weighted pound equivalents (TWPEs) by multiplying the loadings by toxic weighting factors (TWFs). EPA developed TWFs for use in the ELGs development program to allow comparison of pollutants with varying toxicities (ERG, 2005). More information about the DMR Pollutant Loading Tool calculations is available in the tool’s user guide.³⁵

Table 7-2 and Table 7-3 present these 2016 pollutant loadings discharged in pounds and TWPE, respectively, as calculated by the DMR Pollutant Loading Tool (ERG, 2018). Note that the tool will only calculate loadings for pollutants included in a facility’s NPDES permit for which monitoring is required. For these calculations, EPA downloaded monitoring period data from the DMR Pollutant Loading Tool. EPA calculated loads only for outfall locations associated with process wastewater, as defined in the facility permits. Calculated loads that incorporate at least one non-detect value are indicated in the table. If a pollutant was reported as non-detect values for some months but had detected values in other months, the loadings were calculated with the non-detects set equal to half the detection limit. If a pollutant was reported as non-detect for all reported months for a particular facility, EPA did not calculate a load for that pollutant for that facility. Note that both Fluid Recovery Services facilities reported 12 months of data, Fairmont Brine reported five months, and Eureka Resources Standing Stone reported only one month of data.

³⁵ DMR Pollutant Loading Tool user guide: <https://echo.epa.gov/trends/loading-tool/resources/technical-support-document>.

Table 7-2. Annual Pollutant Loading Discharges in Pounds for In-Scope CWT Facilities Calculated Using DMR Pollutant Loading Tool Output with 2016 Reported Data

Pollutant	Pollutant Loadings, Pounds per Year				
	Eureka Resources, Standing Stone Facility	Fairmont Brine Processing	Fluid Recovery Services: Franklin Facility	Fluid Recovery Services: Josephine Facility	Total Reported
Acidity, total (as CaCO ₃)	NR	NR	4,660	6,050	10,700
Alkalinity, total (as CaCO ₃)	NR	NR	14,000 ^b	20,800	34,800
Aluminum, total recoverable	NR	0.911	NR	NR	0.911
Arsenic, total recoverable ^a	NR	0.027	NR	NR	0.027
Barium, total (as Ba)	0.647	164	1,050	2,340	3,550
Benzene	NR	0.089	NR	NR	0.089
Beryllium, total recoverable (as Be)	NR	0.001	NR	NR	0.001
BOD, 5-day, 20 deg. C ^a	25.9	NR	NR	NR	25.9
Boron, total recoverable	NR	29.4	NR	NR	29.4
Bromide (as Br)	NR	868	NR	NR	868
Chloride (as Cl)	64.7	45,700	26,000,000	25,000,000	51,000,000
Chlorine, total residual	NR	0.090	NR	NR	0.090
Chloroform	NR	0.023	NR	NR	0.023
Chromium, hexavalent dissolved (as Cr)	NR	0.011	NR	NR	0.011
Copper, total recoverable ^a	ND	0.603	ND	NR	0.603
Dibromochloromethane	NR	0.014	NR	NR	0.014
Fluoride, total (as F)	NR	14.0	NR	NR	14.0
Iron, total recoverable	ND	34.0	ND	ND	34.0
Lithium, total (as Li)	NR	24.6	NR	NR	24.6
Nickel, total recoverable ^a	NR	1.03	NR	NR	1.03
Nitrogen, ammonia total (as N)	35.8	146	NR	NR	182
Oil & grease ^a	ND	NR	ND	1,190 ^b	1,190
Phthalate esters	NR	0.018	NR	NR	0.018
Selenium, total recoverable	NR	0.038	NR	NR	0.038
Solids, total dissolved	ND	46,000	37,700,000	50,600,000	88,300,000
Solids, total suspended ^a	ND	NR	1,720 ^b	2,360 ^b	4,080
Strontium, total (as Sr)	1.42	917	53,500 ^b	NR	54,400
Sulfate	NR	728	NR	NR	728
Vanadium, total (as V) ^a	NR	0.027	NR	NR	0.027
Zinc, total (as Zn) ^a	0.259	NR	NR	NR	0.259
Zinc, total recoverable ^a	NR	0.672	NR	NR	0.672

^a Indicates a pollutant is regulated under 40 CR Part 437.^b Indicates a pollutant that had some months of non-detected values included in the loadings calculation (and set equal to half the detection limit).

ND = Non-Detect

NR = Not reported by that facility.

Pollutants where all reported data were non-detects are not included in the table.

Table 7-3. Annual Pollutant Loading Discharges in TWPE for In-Scope CWT Facilities Calculated Using DMR Pollutant Loading Tool Output with 2016 Reported Data

Pollutant	Pollutant Loadings, Pounds per Year				
	Eureka Resources, Standing Stone Facility	Fairmont Brine Processing	Fluid Recovery Services: Franklin Facility	Fluid Recovery Services: Josephine Facility	Total Reported
Aluminum, total recoverable	NR	0.055	NR	NR	0.055
Arsenic, total recoverable ^a	NR	0.095	NR	NR	0.095
Barium, total (as Ba)	0.001	0.326	2.09	4.66	7.08
Benzene	NR	0.003	NR	NR	0.003
Beryllium, total recoverable (as Be)	NR	0.001	NR	NR	0.001
Boron, total recoverable	NR	0.245	NR	NR	0.245
Chloride (as Cl)	0.002	1.11	632	606	1,240
Chlorine, total residual	NR	0.045	NR	NR	0.045
Chloroform	NR	0.000	NR	NR	0.000
Chromium, hexavalent dissolved (as Cr)	NR	0.006	NR	NR	0.006
Copper, total recoverable ^a	ND	0.376	ND	NR	0.376
Dibromochloromethane	NR	0.001	NR	NR	0.001
Fluoride, total (as F)	NR	0.420	NR	NR	0.420
Iron, total recoverable	NR	0.191	ND	ND	0.191
Lithium, total (as Li)	NR	0.246	NR	NR	0.246
Nickel, total recoverable ^a	NR	0.103	NR	NR	0.103
Nitrogen, ammonia total (as N)	0.040	0.162	NR	NR	0.202
Selenium, total recoverable	NR	0.042	NR	NR	0.042
Strontium, total (as Sr)	0.00003	0.020	1.19 ^b	NR	1.21
Sulfate	NR	0.004	NR	NR	0.004
Vanadium, total (as V) ^a	NR	0.008	NR	NR	0.008
Zinc, total (as Zn) ^a	0.010	NR	NR	NR	0.010
Zinc, total recoverable ^a	NR	0.027	NR	NR	0.027

^a Indicates a pollutant is regulated under 40 CR Part 437.

^b Indicates a pollutant that had some months of non-detected values included in the loadings calculation (and set equal to half the detection limit). Pollutants with all months of non-detected values are not included in the table. NR = Not reported by that facility.

7.2 Indirect Discharges

Indirect discharging facilities do not report monitoring data on DMRs, so EPA attempted to identify other sources of information to estimate pollutant loadings discharged by these facilities. Patriot Water Treatment, LLC provided 2015 monthly monitoring concentration data

in response to EPA’s data request under section 308 of the Clean Water Act. EPA averaged these monthly monitoring data, then multiplied the average concentrations by annual wastewater flows reported by the facility in their response to EPA’s 308 data request to calculate annual pollutant loadings discharged (ERG, 2018). If a pollutant was reported as non-detect values for some months but had detected values in other months, the loadings were calculated with the non-detects set equal to half the detection limit. If a pollutant was reported as non-detect in all months, loadings were not calculated for that pollutant; pollutants with non-detects every month include antimony, arsenic, cadmium, cyanide, mercury and selenium. The pounds of pollutant loadings per year were multiplied by the pollutant TWFs to calculate TWPE per year. Table 7-4 presents the estimated 2015 pollutant loadings for Patriot Water Treatment, LLC to the POTW. EPA notes that the POTW would be expected to remove some portion of these pollutant loadings prior to discharge to the receiving waters.

Table 7-4. 2015 Pollutant Loadings Discharged by Indirect Discharger Patriot Water Treatment, LLC

Pollutant Name	Indirect Discharge Loadings (Pounds/Year)	Indirect Discharge Loadings (TWPE/Year)
TDS	7,740,000	-
COD	262,000	-
Barium	27,200	54.2
Bromide ^b	23,800	-
TSS ^a	26,100	-
Ammonia (as N)	5,840	6.48
Copper, total ^a	152	94.7
Lead, total ^a	33.4	74.8
Zinc, total ^{a, b}	27.0	1.08
Molybdenum, total	23.0	4.60
Silver, total ^a	8.69	143
Nickel, total ^{a, b}	8.59	0.859
Chromium, hexavalent total ^b	5.51	2.81
Chromium, total ^{a, b}	4.85	0.340

^a Indicates a pollutant is regulated under 40 CR Part 437.

^b Indicates a pollutant that had some months of non-detected values included in the loadings calculation (and set equal to half the detection limit). Pollutants with all months of non-detected values are not included in the table.

Eureka Second Street facility also responded to EPA’s data request; however, the facility did not provide discharge monitoring data as part of their response. EPA was unable to identify other publicly-available data to estimate loadings for this facility.

7.3 Summary of Pollutant Loadings for Discharging CWT Facilities Accepting Oil and Gas Extraction Wastewater

Multiple pollutants with the highest loadings in pounds per year are not regulated under 40 CFR Part 437, such as TDS, chloride, ammonia, COD, and strontium. Several of the

pollutants with the highest TWPE per year are also not regulated under 40 CFR Part 437, such as ammonia, chloride, silver, barium, and molybdenum.

Note that this pollutant loadings analysis has the following limitations:

- This analysis does not include all facilities, since EPA did not have data to calculate annual loads from all facilities. The one notable direct discharging facility missing from the analysis is the Creekside treatment facility. This facility does discharge, and currently does not incorporate TDS removal technologies. One indirect discharging facility (Eureka Resources, Williamsport) is also known to be operating and discharging
- Only pollutants being monitored and reported are included, so different facilities monitor different pollutants, and there may be other pollutants present in the wastewater that are not accounted for in this estimate.
- In some cases, annual pollutant loadings discharged are calculated based on less than 12 months of data.
- Some of the direct discharging facilities did not report any (or minimal) discharges on DMRs in 2016 because they did not discharge in 2016 (such as the Byrd/Judsonia Water Reuse/Recycle Facility, which is known to rarely discharge), or the DMR data may have been missing from the DMR Pollutant Loadings Tool for other reasons.
- While setting non-detect values equal to half the detection limit may create an over or under estimate of actual pollutant loadings discharged from a facility, this approach is reasonable given that the actual concentration of pollutant in the discharge would be expected to be between zero and the reported detection limit.

7.4 References

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8. ECONOMIC PROFILE

As described in Chapter 4, EPA has identified eleven facilities that accept oil and gas extraction wastes and are either currently permitted under Part 437 or information available to EPA indicates will be permitted under Part 437 when NPDES permits are reissued. More broadly, EPA identified many facilities that accept these wastes but do not discharge, and numerous facilities that are currently permitted under Part 437 but do not accept these wastes. EPA also identified a number of facilities where incomplete information is currently available to EPA to determine if these facilities are in-scope of this study (although EPA’s preliminary review of these facilities indicates the few, if any, are likely to be in-scope of this study).

In preparing an economic profile of the industry, EPA has evaluated the subset of facilities that are known by EPA to be in-scope of this study, meaning current 40 CFR Part 437 facilities (or those that will likely be subject to Part 437 when permits are reissued) that accept oil and gas extraction wastes and discharge treated wastewater, as well as trends within the broader set of facilities known to accept oil and gas wastes. EPA discusses the subset of in-scope facilities and the subset’s trends in this profile chapter, followed by broader industry trends in Appendix C.

EPA is also interested in the economics of the broader industry defined by the three NAICS codes in which CWT activity has traditionally occurred, as described in Section 4.1, because facilities that currently do not provide oil and gas extraction wastewater treatment services may decide to enter the market in the future. However, these industry sectors reflect much broader industry activity and capture firms and facilities that are not CWT firms and facilities. A profile of these NAICS codes is provided in Appendix C.

EPA notes that the increase in investment of technologically advanced CWT facilities, or investment to build new ones, shows an emergence of new business models for provision of wastewater and other water-related services for oil and gas operations. This may have come about given how the CWT industry is affected by the expansion of the oil and gas industry and the resulting increase and change in characteristics of oil and gas extraction wastewater. Given these factors, EPA continues to study and review data that may provide insight into the potential economic impacts that might result from changes to the CWT effluent limitations guidelines (ELGs). The CWT industry’s ability to withstand compliance costs in general is primarily influenced by two factors: (1) the extent to which the industry may be expected to shift compliance costs to its customers through price increases and (2) the financial health of the industry and its general business outlook.

8.1 Facilities and Firms Receiving and Treating OGE Wastewater

As described in Section 4.2, EPA identified 198 facilities that are known to accept OGE wastewater (excluding facilities that only accept CBM wastewater). Of these, 98 discharge process wastewater. Parent and/or facility information was obtained from Hoover’s for 66 of these facilities (D&B, 2016). No information was available for the remaining 32 facilities. Table

8-1 presents basic summary statistics of the set of 66 CWT facilities, by NAICS code and as totals.

Table 8-1. Facilities Known to Provide OGE-Related CWT Services

NAICS	NAICS Description	Number of Facilities	Number of Firms	Total Firm Employment	Average Employment per Firm	% Small Business	Total Estimated Revenue (\$ millions)
562211	Hazardous Waste Treatment and Disposal	2	2	13,000	6,500	100%	\$15,042.2
562219	Other Nonhazardous Waste Treatment and Disposal	29	3	47,396	15,799	33%	\$15,042.2
562920	Materials Recovery	3	3	3,882	1,294	33%	\$1,697.6
211111	Crude Petroleum and Natural Gas Extraction	9	5	11,304	2,261	20%	\$17,215.3
212321	Construction Sand and Gravel Mining	1	1	1	1	100%	\$0.1
213111	Drilling Oil and Gas Wells	1	1	61	61	100%	\$13.4
213112	Support Activities for Oil and Gas Operations	4	3	2,752	917	67%	\$4,421.7
237110	Water and Sewer Line and Related Structures Construction	1	1	12	12	100%	\$1.3
237310	Highway, Street, and Bridge Construction	1	1	15	15	100%	\$9.1
325180	Other Basic Inorganic Chemical Manufacturing	1	1	25	25	100%	\$1.2
333132	Oil and Gas Field Machinery and Equipment Manufacturing	1	1	50,197	50,197	0%	\$14,760.0
333318	Other Commercial and Service Industry Machinery Manufacturing	3	1	500	500	100%	\$141.6
424720	Petroleum and Petroleum Products Merchant Wholesalers	1	1	3,100	3,100	0%	\$1,680.0
454390	Other Direct Selling Establishments	1	1	1	1	100%	\$0.0
484230	Specialized Freight Trucking, Long-Distance	2	1	17	17	100%	\$3.2
488390	Other Support Activities for Water Transportation	1	1	17	17	100%	\$0.9
541611	Administrative Management and General Management Consulting Services	2	1	50	50	0%	\$10,100.0
541620	Environmental Consulting Services	2	2	34	17	100%	\$3.0
541712	Research and Development in the Physical, Engineering, and Life Sciences (except Biotechnology)	1	1	9	9	100%	\$0.7
551112	Offices of Other Holding Companies	1	1	34	34	100%	\$3.9
561210	Facilities Support Services	1	1	3	3	0%	\$0.2
Total		66	33	132,410	4,012	64%	\$65,095.4

Source: D&B, 2016; ERG, 2016.

8.1.1 40 CFR Part 437 In-Scope CWT Facilities that Treat Oil and Gas Extraction Wastes

As described in Section 4.3, EPA received economic questionnaire responses from 6 facilities: Byrd/Judsonia Water Reuse/Recycle Facility; Eureka Resources, Standing Stone Facility; Fairmont Brine Processing, LLC; Fluid Recovery Services, Josephine Facility; Patriot Water Treatment, LLC; and Waste Treatment Corporation. The majority of facilities claimed CBI for their financial data. Without a minimum of three data points with which to mask the data within an average, EPA is unable to publish any data identified as CBI or any calculations using said data. This is consistent with Statistical Policy Working Paper 22: Report on Statistical Disclosure Limitation Methodology (Federal Committee on Statistical Methodology, 2005) which describes the limitations on reporting data when it does not meet the threshold of three or more data points. Since much of the data obtained in the economic questionnaires does not meet this threshold, EPA decided to not include the economic questionnaire data in this report. Instead, the reader may view the blank copy of the financial form in the record of the study docket to see what kind of information was requested from these facilities (U.S. EPA, 2016).

8.1.2 Other Facilities that Treat Oil and Gas Extraction Wastes

Based on information in EPA's CWT facility list, 187 facilities accept oil and gas extraction wastes but are not in-scope of the current study. An additional 12 facilities only accept CBM wastes, and are also not in-scope of the current study. These numbers may be underestimated because other facilities may accept wastes that could potentially be oil and gas extraction wastes, but EPA lacks information for these facilities. In addition, there may be additional facilities that were not identified by EPA.

As discussed in Section 4.4, EPA received financial information from one non-in-scope facility. Again, given that this facility requested their information be CBI, and the threshold of 3 or more data points required for reporting sensitive data, EPA decided to not include this information in this report. Instead, the reader may view the blank copy of the financial form in the record of the study docket to see what kind of information was requested from these facilities.

Table 8-2 lists the top eight states with the largest number of facilities treating oil and gas extraction wastewater. The states in Table 8-2 account for 90 percent of the 210 facilities treating oil and gas extraction wastewater. Pennsylvania and Texas have the highest number of facilities treating oil and gas extraction wastewater, accounting for almost 50 percent of the total number. For a full list of States that have facilities treating oil and gas wastewater, see Table B-2.

Table 8-2. States with the Highest Number of Facilities Treating Oil and Gas Extraction Wastewater

State	Facilities Accepting Oil and Gas Extraction Wastes ^a	
	Number of Facilities	Percentage of Total
Pennsylvania	57	27%
Texas	47	22%
Wyoming	21	10%
Ohio	16	8%
Colorado	15	7%
Louisiana	14	7%
North Dakota	11	5%
West Virginia	5	2%

^a Includes the 189 of the 210 facilities on EPA's CWT facility list known to accept oil and gas extraction wastes.

8.1.3 Commercial and Non- Commercial CWT Facilities

EPA was able to identify only 85 (40 percent) of CWT facilities as being either commercial or non-commercial. Conclusive information was not available for the remaining facilities. Of these 85 facilities, 51 facilities (60 percent) were commercial and 40 percent were non-commercial. Non-commercial facilities include those owned by an oil and gas operator that do not accept waste from other operators.

8.2 Demand for CWT facilities that Treat Oil and Gas Wastewater and Output Projections

Increasing extraction and production of oil and gas resources will likely lead to increased need for wastewater management options, including treatment at CWTs. Natural gas production has increased substantially since 2005 due to shale gas production, and crude oil production has increased substantially since 2008 due to tight oil and shale oil production. In 2008, shale gas and tight oil plays was the third largest source for natural gas production (lower 48 onshore conventional production and tight gas were the leading sources), and by 2010 became the number one source of U.S. production (U.S. DOE, 2016a). Most of this increase has come since 2010 from the Marcellus formation, which is now by far the biggest U.S. producer of shale gas (U.S. DOE, 2017b). Likewise, between 2008 and 2015, tight and shale oil production grew almost ten times, due mostly to increased production in the Eagle Ford and Bakken formations (U.S. DOE, 2016e).

However, crude oil prices have fallen considerably since the summer of 2014. The 60 percent fall in crude oil prices since they peaked in June 2014, along with low natural gas prices, has had significant adverse effects on OGE firms. In the short term, this is likely to continue, as prices are expected to recover slowly. U.S. crude oil production, which averaged 9.4 million barrels per day (bpd) in 2015 and 8.9 million bpd in 2016, is projected to average 8.7 million bpd in 2017 and 9.3 million bpd in 2018 (U.S. DOE, 2017a). U.S. rig counts continued to fall through

2016, and a significant recovery was not expected until the end of 2016 (Zborowski, 2016). Recovery has occurred in 2017, with the rig count as of the week ending December 8, 2017 at 931, up from the all-time low of 480 in March 2016 (OGJ, 2017; Zborowski, 2016).

The long-term outlook is more favorable. Henry Hub natural gas prices are forecast to increase through 2030 then remain relatively flat through 2040, and Brent crude oil prices are forecast to increase more quickly than gas prices, through 2040 (U.S. DOE, 2017a). And while many factors will affect further development, and forecasts inevitably involve considerable uncertainty, U.S. crude oil production is expected to continue to increase through 2025, and U.S. natural gas production is projected to increase through 2040 (U.S. DOE, 2017a). This growth, along with an increasing water cut (the ratio of produced water to oil production), environmental regulations, and water scarcity, is expected to drive capital expenditures on equipment for treating produced water (Stanic, 2014). Growth depends on the production profile of individual wells, the cost of drilling and operating the wells, and the revenue generated.

Wastewater generation, and therefore demand for CWT services, will not only depend on overall oil and gas production, but also on the type of production. For conventional vertical well production, there is little water used for drilling, but lifetime produced water volumes can be high. The opposite is typically the case with horizontal drilling and hydraulic fracturing, which can require large amounts of water. At hydraulically fractured wells, initial flowback is high but lifetime produced water is much lower (Veil, 2015). In 2005, tight and shale oil production totaled approximately 136 million barrels, representing 7 percent of total crude oil production in the United States. In 2015, tight and shale oil production increased to approximately 1,658 million barrels, or 48 percent of total crude oil production (U.S. DOE, 2016c; U.S. DOE, 2016f). This ratio is expected to remain relatively constant, with tight and shale oil projected to represent about 45 percent of total crude oil production in 2040 (U.S. DOE, 2015). In 2005, shale gas production totaled approximately 1,134 billion cubic feet (bcf), or 6 percent of total U.S. natural gas marketed production. In 2015, shale gas production increased to 15,252 bcf, 53 percent of total natural gas marketed production (U.S. DOE, 2016b; U.S. DOE, 2016d). This fraction increases when tight gas is considered in addition to shale gas. By 2040, tight and shale gas production is projected to represent 75 percent of total U.S. dry production (U.S. DOE, 2015).³⁶

8.3 Regional Trend/Outlook Discussion for CWT facilities that Treat Oil and Gas Wastewater

Due to the variability of oil and gas reservoirs by region, the changes in OGE activities and the need for wastewater treatment will also likely vary by region. EIA predicts that U.S. dry natural gas production will continue to increase through 2040, and crude oil production will increase through 2025 and then decline (U.S. DOE, 2017a).

³⁶ EIA reports historical shale gas production as marketed production, but projects natural gas production as dry production in its Annual Energy Outlook. Dry natural gas production equals marketed production less extraction losses.

Lower 48 onshore crude oil production will show the strongest growth in the Dakotas/Rocky Mountain region, which includes the Bakken formation, followed by the Southwest region, which includes the Permian basin. Lower 48 onshore dry natural gas production will show the strongest growth in the East region, which includes the Marcellus Shale and Utica Shale, followed by the Gulf Coast region and Dakotas/Rocky Mountain region. Between 2013 and 2040, more than half of the projected growth in shale gas production comes from the Haynesville and Marcellus formations (U.S. DOE, 2015).

Whether an increase in wastewater generation translates to an increase in demand for CWT services depends on the feasibility and relative cost of alternative management options. Though underground injection has historically been the preferred method for managing wastewater in the majority of shale gas plays, in the Marcellus play, for example, only a few areas provide suitable underground injection zones (Arthur et al., 2009). Faced with high trucking costs to transport wastewater to injection wells in Ohio or West Virginia, oil and gas operators in Pennsylvania may turn to treatment for reuse/recycle or other CWT services. These circumstances, along with the projected growth in Marcellus shale gas production, may favor higher growth in demand for CWT services in that region than in other areas.

Wyoming may also be a potential location for growth in demand for CWT services. While produced water can be managed through injection in permitted disposal or enhanced recovery wells or evaporated in surface ponds, the state does also allow discharge to surface waters (Still et al., 2012)³⁷. Demand for CWT services may also increase in Ohio and Oklahoma, due to concerns over induced seismicity from underground injection of oil and gas extraction wastes (Ohio DNR, undated, Rubenstein and Mahani, 2015).

8.4 Financial Outlook for CWT facilities that Treat Oil and Gas Extraction Wastewater

Generally, EPA has noted that the more recent increase in oil prices (from 2016 onward), along with the ability for some in-scope CWT facilities to learn their business better (e.g., work out technology and process matters, or incentivize with by-product sales) has allowed the CWT industry to improve its financial outlook. The drop in oil prices in 2015 and early 2016 reduced the financial well-being of these facilities, but the more recent price increasing trends have helped to now change some of this narrative. With the price of oil projected to continue to increase (U.S. DOE, 2017a), EPA will continue to review the cyclical market's financial outlook.

8.5 References

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³⁷ Since Wyoming is located west of the 98th meridian, discharges may be authorized under 40 CFR 435 Subpart E. Therefore, the need for 40 CFR Part 437 facilities is unknown.

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9. ENVIRONMENTAL IMPACTS

Centralized waste treatment facilities accepting oil & gas extraction (O&G) wastewaters can release pollutants into the environment that impact aquatic ecosystems and human health. Potential pollutants can reach the environment (1) through effluent discharging to surface waters either directly from a CWT facility or indirectly from publicly owned treatment works (POTWs) accepting treated CWT effluent; (2) during managed use of wastewater, such as irrigation; and (3) by releases from storage impoundments and spills. Direct discharges of treated effluent from CWT facilities accepting O&G wastewater have caused environmental impacts, particularly on water quality, drinking water, and aquatic health. This chapter addresses the documented and potential human health and environmental impacts associated with CWT facilities accepting O&G wastewater and presents specific case studies to illustrate these impacts.

Section 9.1 of this chapter discusses pollutants associated with CWTs accepting O&G wastewater and their origins, including total dissolved solids (TDS), halides, metals, radionuclides (primarily radium), and other chemicals in hydraulic fracturing (HF) injection fluids. Section 9.2 explores the pathways through which pollutants in O&G wastewater accepted by CWTs can interact with the environment. Section 9.3 analyzes the downstream impact to water quality from CWT effluent containing treated O&G wastewater. Section 9.4 discusses documented and potential human health impacts from CWTs accepting O&G wastewater. Section 9.5 discusses documented and potential aquatic life impacts. Section 9.6 describes other environmental impacts from CWTs accepting O&G wastewater, such as impacts to POTW efficiency, impacts to irrigation or livestock watering uses, and impacts to air. Finally, Section 9.7 addresses data gaps that exist in the literature on environmental impacts from CWTs accepting O&G wastewaters.

9.1 Constituents in O&G Wastewater at CWT Facilities

Effluents from CWT facilities treating O&G wastewater have been associated with alterations in downstream surface water quality in individual receiving streams (e.g., Warner et al., 2013; Ferrar et al., 2013) as well as at the watershed level (e.g., Wilson and VanBriesen, 2012; Olmstead et al., 2013; Vidic et al., 2013). Extraction techniques, such as hydraulic fracturing (HF), became a major source of O&G wastewater in the early 2000s (Wilson and VanBriesen, 2012; U.S. EPA, 2016c). HF wastewater has been characterized as either flowback water or produced water in some references. Some pollutants of potential concern from an environmental or human health perspective in O&G wastewater include TDS; halides (e.g., bromide, chloride, and iodide); metals; technologically enhanced naturally occurring radioactive materials (TENORM); and a wide range of poorly characterized chemicals in injected fluids including surfactants, biocides, wetting agents, scale inhibitors, and organic compounds.

9.1.1 TDS

TDS is a quantitative measure of the amount of dissolved inorganic and organic substances in water. Compounds constituting TDS include ionic salts (e.g. carbonate,

bicarbonate, chloride, fluoride, sulfate, phosphate, nitrate, calcium, magnesium, sodium, potassium), dissolved metals (e.g., boron, copper, lead, zinc), and small amounts of organic matter. TDS is commonly used as a parameter to assess water quality, and can be regulated (e.g., Pennsylvania Code, 2011).

Wastewaters from O&G operations commonly have high concentrations of TDS. TDS is contributed to these wastewaters from the targeted formation either from brines in the formation or from interaction of injected fluid with the formation. Previous work cites two possible mechanisms that increase TDS levels in produced waters from HF. The first mechanism is ion dissolution from the underground rock formation upon interaction with the injected HF fluid (Blauch et al., 2009). The second mechanism is that brines trapped within sedimentary rock pore space dissolve into the HF fluid during the HF process (Dresel and Rose, 2010; Haluszczak et al., 2013). A variety of processes can create brines in rock pore space, resulting in brine chemical composition that varies among rock formations (Dresel and Rose, 2010). Because each major oil or gas play has a distinctive rock and brine composition, the range of TDS concentrations in produced waters varies by extraction location. For example, O&G wastewater from the Fayetteville shale has been reported to have a TDS range of 3,000–80,000 mg/L (Alleman, 2011), while water from the Marcellus Shale has been reported to have a range of 10,000–300,000 mg/L (e.g., Wilson et al., 2014). TDS concentrations in non-HF O&G wastewater have similar ranges to HF wastewaters; Wilson et al. (2014) report a median TDS concentration from conventional O&G plays of about 238,000 mg/L, with a standard deviation of about 63,000 mg/L.

If CWT facilities lack TDS removal technologies such as RO or distillation, these facilities will not remove the ions that contribute to TDS concentrations, and these constituents become part of the CWT waste stream. High concentrations of TDS degrade the potability of drinking water, generally on the basis of taste, and can corrode water transport pipes. Based on results from panels of tasters rating the palatability of drinking water, taste begins to degrade at TDS levels above approximately 300 mg/L, and taste becomes unacceptable at concentrations greater than ~1,200 mg/L (Bruvold and Ongerth, 1969). High levels of TDS can also negatively affect aquatic biota through increases in salinity, loss of osmotic balance in tissues, and toxicity of individual ions. Increases in salinity cause shifts in biotic communities, limit biodiversity, exclude less-tolerant species and cause acute or chronic effects at specific life stages (Weber-Scannell and Duffy, 2007). High TDS levels can also adversely affect agriculture irrigation and livestock watering.

9.1.2 Halides

High concentrations of halides (e.g., bromide, chloride, iodide) are often present in produced water and in the discharged effluents from CWT facilities treating O&G wastewater that lack specific technologies for their removal (Ferrar et al., 2013; Parker et al., 2014). As one component of TDS, halides originate from the rock and brine formations (Dresel and Rose, 2010). Haluszczak et al. (2013) note that in the Marcellus region, halide concentrations in produced water are similar to those from conventionally drilled O&G wells, and the elevated

concentrations are likely from brine in the rock formation. While HF injection fluids generally have low chloride concentrations (~ 82 mg/l) (Haluszczak et al., 2013), the median chloride concentration from flowback from 8 wells (taken at 14 days after injection) was 98,300 mg/L (Haluszczak et al., 2013).

At high concentrations, halides such as chloride can be directly toxic to aquatic organisms (Corsi et al., 2010). Halides also pose potential drinking water concerns due to their reactivity and potential to form disinfection byproducts (DBPs) that can have adverse effects on human health (e.g., Hladik et al., 2014; McTigue et al., 2014; Harkness et al., 2015). See Section 9.3.3 for a detailed description of DBP formation.

9.1.3 Metals

O&G wastewaters treated at CWT facilities commonly have high concentrations of metals, including barium, calcium, iron, magnesium, manganese, and strontium (e.g., Haluszczak et al., 2013). These metals occur naturally in the brines located within O&G formations. EPA has established chemical-specific national recommended water quality criteria for some of these metals (e.g., Ba, Mn, Fe) based on a variety of human health or ecological benchmarks. Produced waters and CWT facility effluent have been reported to routinely exceed many of these criteria (e.g., Ferrar et al., 2013).

9.1.4 TENORM

Naturally occurring radioactive materials primarily come from uranium-thorium decay sequences (e.g., Ra^{226} , Ra^{228}) and are present in virtually all environmental media, including rocks and soils. These radionuclides can become mobilized through the O&G extraction and wastewater treatment processes, and as such are technologically enhanced or TENORM. Soluble radionuclides are commonly present in produced water, with the specific makeup of nuclides and isotopic composition dependent on the geological formation (Rowan et al., 2011). For many O&G producing formations, this distinct isotopic “signature” is discernible even after facility treatment, and can be a useful tracer for O&G wastes in downstream waters and sediments (Rowan et al., 2011; Warner et al., 2013).

HF and shale gas drilling operations bring TENORM to the surface during production operations because subsurface geologic formations commonly contain higher amounts of radioactive isotopes than surface rock or soil (Haluszczak et al., 2013) and radioactive isotopes desorb into solution at high salinity (Sturchio et al., 2001). TENORM can be present in CWT effluent and can, under favorable environmental conditions, precipitate out in receiving waters or be incorporated into downstream sediment. TENORM can also concentrate in waste sludge generated by CWT processes, resulting in materials that have radioactivity levels exceeding the ambient levels in the geologic formations. When not handled correctly, TENORM contamination may pose potential human health concerns for wastewater plant staff or landfill operators (PA DEP, 2015).

9.1.5 Other Constituents

Other potential pollutants in O&G wastewater include chemicals contained in injection fluids, such as surfactants, biocides, wetting agents, scale inhibitors, and organic compounds. The composition of some HF chemicals are disclosed to the public, while others are considered confidential business information (CBI) and HF service companies have not released information on those chemicals to the public or regulatory agencies (U.S. EPA, 2012; Elliott et al., 2017). EPA released a report on HF effects on drinking water resources, “Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources,” in 2012 (U.S. EPA, 2012). The report provides a list of known chemicals that HF service companies use in HF activities and additional chemicals that have been detected in flowback and produced water. Elliott et al. (2017) reviewed the reported list of 925 chemicals to determine their impacts to human health. They found that 76% of the chemicals do not have toxicity information. For the 240 chemicals with toxicity information, 65% are associated with developmental or reproductive toxicity.

Stringfellow et al. (2014) reviewed 81 known fracturing fluid chemicals for potential toxicity to humans and effects on water treatment. They categorized the chemicals into functional classes (Table 9-1) defined by the intended use or purpose. Not all chemicals analyzed are used at every well. Stringfellow et al. (2014) concluded that biocides in HF fluid are a high concern because many of those chemicals are classified as toxic to human health or the environment. Additionally, many fracturing chemicals (such as gelling agents) that have high or moderate chemical oxygen demand (COD) can cause problems to wastewater treatment processes. Stringfellow et al. (2014) estimated that HF wastewater has high COD and can cause treatment challenges.

Table 9-1. Chemical Categories in HF Fluids

Chemical category	Purpose
Gelling agents	Increases the viscosity to better transport into fractures
Friction reducers	Reduces fluid surface tension to help remove HF fluid from the geologic formations
Crosslinkers	Binds molecules to increase viscosity and elasticity for better HF fluid transport
Breaker	Chemicals used to “break” the gelling agent used in fracking that decrease solution viscosity and improve flow
pH adjuster	Adjusts pH to improve effectiveness of other chemicals in HF fluid
Biocides	Controls bacteria to prevent chemical degradation and damage to well materials
Corrosion inhibitors	Creates protective layer on well materials to prevent corrosion from HF fluid chemicals
Scale inhibitors	Prevents scaling to reduce blockages
Iron control	Prevents iron precipitates from forming within the fractures; helps increase permeability and well productivity
Clay stabilizers	Prevents clays within formation from swelling
Surfactants	Controls viscosity and helps improve fluid recovery after fracturing

Because of the information gap in the chemical make-up of HF fluids and the information gap for 76% of the known HF fluid chemicals, this chapter does not contain specific impacts analyses on water quality, aquatic life, or human health from HF fluid chemicals.

9.2 Exposure Pathways for CWT Waste Streams

Environmental and human exposure to pollutants in O&G wastewater can occur through multiple pathways related to treatment at CWT facilities. Environmental releases and human interactions with pollutants can occur from discharge of treated effluent to the environment, during transport to CWT treatment facilities, during CWT treatment itself, or through other waste streams such as sludge, spills, and fugitive emissions. Rozell and Reaven (2012) estimated that wastewater disposal at treatment facilities had the highest environmental contamination risk and potential environmental harm when compared to other potential exposure pathways (e.g., transportation spills, well casing leaks, leaks through fractured rock, drilling site discharge). This section summarizes these exposure pathways for CWT waste streams (Figure 9-1). The remainder of the document describes in more detail the concentrations of constituents in CWT effluents and the effects of these constituents on downstream water quality, when CWT facilities discharge directly to surface water.

9.2.1 *Discharge of CWT Effluent to Rivers and Streams*

CWT facilities that hold direct discharge permits can release wastewater directly to rivers and streams after treatment. Treatment processes do not always effectively remove all of the constituents that originate from O&G extraction. As a result, the effluent from these facilities can contain high concentrations of O&G related compounds, and therefore discharge of treated effluent can represent a significant pathway for potential releases to the environment. Section 9.3 summarizes the concentrations of pollutants in CWT effluent and the effects of these discharges on downstream water quality. Sections 9.4 and 9.5 describe the human health and aquatic life impacts from these discharges in receiving waters.

9.2.2 *Solid Waste and Sludge*

TENORM can be present in sediments and particulates from O&G operations, and dissolved TENORM co-precipitates with other ions during certain treatment processes such as chemical precipitation. As a result, TENORM and associated radioactivity tends to become concentrated in the residual solids or sludge produced by the treatment unit. Solid residual waste enriched in TENORM can also be generated during storage of flowback and produced waters in impoundments prior to treatment (Zhang et al., 2015). CWT operators must periodically remove, dewater, and dispose of sludge. The dewatering process creates filter cakes, which can contain elevated levels of radium. Handling of these produced water treatment sludge poses potential human health and environmental concerns (e.g., Belcher and Resnikoff, 2013; Brown, 2014), although a recent evaluation of the human health implications of this pathway suggest that exposure of workers may not be a significant concern (PA DEP, 2015).

Different wastewater treatment methods for O&G wastewaters can result in varying levels of TENORM in solid residual waste (sludge) (PA DEP, 2015). The ability to dispose sludge in landfills depends on the level of radioactivity, as states have different regulations on what constitutes radioactive waste and how and where it can be disposed. This situation is complicated by the non-uniformity in regulatory language, administrative codes, and regulating authorities (e.g., Litvak, 2016). For some states, there is little or no regulatory language, while other states prohibit disposal of TENORM, and still others indicate that disposal decisions are made on a case-by-case basis (Abt Associates, 2016). TENORM-enriched sludge disposed in landfills can produce TENORM-enriched leachate, therefore leaching of solid residual waste in landfills may also be a concern (Zhang et al., 2015).