Exhibit 29

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United States Environmental Protection Agency
Office of Water
Washington, DC 20460
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Technical Development Document for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction

United States Environmental Protection Agency

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U.S. Environmental Protection Agency
Office of Water (4303T)
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ABBREVIATIONS

AO	Administrative Order
API	American Petroleum Institute
Bcf	billion cubic feet
BDL	below method detection limit
BOD_5	biochemical oxygen demand
BPD	barrels per day
BPT	best practicable control technology currently available
$CaCO_3$	calcium carbonate
CBM	coalbed methane
Ci	curie
CIU	categorical industrial user
COD	chemical oxygen demand
COG	conventional oil and gas
CWA	Clean Water Act
CWT	centralized waste treatment
DBP	disinfection byproduct
DMR	discharge monitoring report
DOE	Department of Energy
EIA	Energy Information Administration
ELGs	Effluent Limitations Guidelines and Standards
EPA	U.S. Environmental Protection Agency
EUR	estimated ultimate recovery
gpd	gallons per day
IU	industrial user
LTPW	long-term produced water
MG	million gallons
MGD	million gallons per day
mg/L	milligrams per liter
MI DEQ	Michigan Department of Environmental Quality
NORM	naturally occurring radioactive material
OH DNR	Ohio Department of Natural Resources
ORD	Office of Research and Development
PA DEP	Pennsylvania Department of Environmental Protection
pCi	picocurie
PESA	Petroleum Equipment Suppliers Association
POTW	publicly owned treatment works
SIU	significant industrial user
SRB	sulfate-reducing bacteria
TDD	technical development document
TDS	total dissolved solids
TENORM	technologically-enhanced naturally occurring radioactive material
THM	trihalomethane
TOC	total organic carbon
TRR	technically recoverable resource

ABBREVIATIONS (Continued)

UIC	underground injection control
UOG	unconventional oil and gas
USGS	U.S. Geological Survey
UV	ultraviolet
WV DEP	West Virginia Department of Environmental Protection

GLOSSARY[1]

Base fluid	The primary component of fracturing fluid to which proppant (sand) and chemicals are added. Base fluids are typically water-based; however there are cases of non-aqueous fracturing fluids (e.g., compressed nitrogen, propane, carbon dioxide). Water-based fluid can consist of only fresh water or a mixture of fresh water, brackish water and/or reused/recycled wastewater.
Biochemical oxygen demand (BOD_5)	The amount of oxygen consumed by biodegradation processes during a standardized test. The test usually involves degradation of organic matter in a discarded waste or an effluent. Standard Method 5210 B-2001, USGS I-1578-78, and an AOAC method.
Centralized waste treatment (CWT) facility	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 offsite.
Chemical oxygen demand (COD)	The amount of oxygen needed to oxidize reactive chemicals in a water system, typically determined by a standardized test procedure. Standard Method 5220 (B-D)-1997, ASTM D1252-06 (A), EPA Method 410.3 (Rev. 1978), USGS I-3560-85, and an AOAC method.
Class II UIC disposal well	A well that injects brines and other fluids associated with the production of oil and natural gas or natural gas storage operations. Class II disposal wells can only be used to dispose of fluids associated with oil and gas production.
Class II UIC enhanced recovery well	A well that injects brine, water, steam, polymers, or carbon dioxide into oil-bearing formations to recover residual oil and—in some limited applications—natural gas. This is also known as secondary or tertiary recovery.
Conventional oil and gas (COG) resources	Crude oil and natural gas that is produced by a well drilled into a geologic formation in which the reservoir and fluid characteristics permit the oil and natural gas to readily flow to the wellbore
Drill cuttings	The particles generated by drilling into subsurface geologic formations and carried out from the wellbore with the drilling fluid.
Drilling fluid	The circulating fluid (e.g., mud) used in the rotary drilling of wells to clean and condition the hole and to counterbalance formation pressure.
Drilling wastewater	The liquid waste stream separated from recovered drilling fluid (e.g., mud) and drill cuttings.

[1] The definitions of terms in the Glossary are only meant to apply to the terms as used throughout the *Technical Development Document for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction (TDD)* and the TDD supporting documentation.

GLOSSARY (Continued)

Flowback	The produced water generated in the initial period after hydraulic fracturing prior to production (i.e., fracturing fluid, injection water, any chemicals added downhole, varying amounts of formation water). See long-term produced water.
Formation water	Water that occurs naturally within the pores of rock.
Hydraulic fracturing	Fracturing of rock at depth with fluid pressure. Hydraulic fracturing at depth may be accomplished by pumping water or other liquid or gaseous fluid into a well at high pressures.
Hydraulic fracturing fluid	The fluid, consisting of a base fluid and chemical additives, used to fracture rock in the hydraulic fracturing process. Hydraulic fracturing fluids are used to initiate and/or expand fractures, as well as to transport proppant into fractures. See base fluid.
Long-term produced water (LTPW)	The produced water generated during the production phase of the well after the initial flowback process (includes increasing amounts of formation water).
Naturally occurring radioactive material (NORM)	Material that contains radionuclides at concentrations found in nature. See also technologically-enhanced radioactive material (TENORM)
Non-TDS removal technologies	Technologies that remove non-dissolved constituents from wastewater.
Produced sand	The slurried particles used in hydraulic fracturing, the accumulated formation sands, and scales particles generated during production. Produced sand also includes desander discharge from the produced water waste stream, and blowdown of the water phase from the produced water treating system.
Produced water (brine)	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.
Proppant	A granular substance (e.g., sand grains, aluminum pellets) that is carried in suspension by the fracturing fluid and that serves to keep the cracks open when fracturing fluid is withdrawn after a fracture treatment.
Publicly owned treatment works (POTW)	Any device and system used in the storage, treatment, recycling and reclamation of municipal sewage or industrial wastes of a liquid nature that is owned by a state or municipality. This definition includes sewers, pipes, or other conveyances only if they convey wastewater to a POTW providing treatment.
Source water	Water used to make up base fluid in hydraulic fracturing operations. Examples include surface water (e.g., ponds, rivers, lakes), ground water, reused/recycled oil and gas extraction wastewater, and treated industrial and municipal wastewater.

GLOSSARY (Continued)

TDS removal technologies	Technologies capable of removing dissolved constituents (e.g., sodium, chloride, calcium) in addition to the constituents removed by non-TDS removal technologies.
Technologically-enhanced naturally occurring radioactive material (TENORM)	Naturally occurring radionuclides that human activity has concentrated or exposed to the environment.
Total dissolved solids (TDS)	A measure of the matter, including salts (e.g., sodium, chloride, nitrate), organic matter, and minerals dissolved in water. Standard Method 2540C-1997, ASTM D5907-03, and USGS I-1750-85.
Total organic carbon (TOC)	The concentration of organic material in a sample as represented by the weight percent of organic carbon. Standard Method 5310 (B-D)-2000, ASTM D7573-09 and D4839-03, an AOAC method, and a USGS method.
Total suspended solids (TSS)	The matter that remains as residue upon evaporation. Suspended solids include the settable solids that will settle to the bottom of a cone-shaped container in a 60 minute period. Standard Method 2540 D-1997, ASTM D5907-03, and USGS I-3765-85.
Unconventional oil and gas (UOG)	Crude oil and natural gas produced by a well drilled into a low porosity, low permeability formation (including, but not limited to, shale gas, shale oil, tight gas, tight oil). For the purpose of the proposed rule, the definition of UOG does not include CBM.
UOG extraction wastewater	Wastewater sources associated with production, field exploration, drilling, well completion, or well treatment for unconventional oil and gas extraction (e.g., drilling muds, drill cuttings, produced sand, produced water).

Chapter A. INTRODUCTION

1 BACKGROUND ON OIL AND GAS EXTRACTION

Recent advances in well development that combine hydraulic fracturing and horizontal drilling have dramatically improved the technical and economic feasibility of oil and gas extraction from unconventional resources. As a result, in 2012, United States (U.S.) crude oil and natural gas production reached their highest levels in more than 15 and 30 years, respectively. The U.S. Department of Energy (DOE) reports these increases to be a direct result of advances in hydraulic fracturing and horizontal drilling. Further, the DOE projects that natural gas production in the U.S. will increase by 56 percent by 2040, compared to 2012 production levels. Similarly, the DOE projects that by 2019, crude oil production in the U.S. will increase by 48 percent compared to 2012 production levels (31 DCN SGE00989).

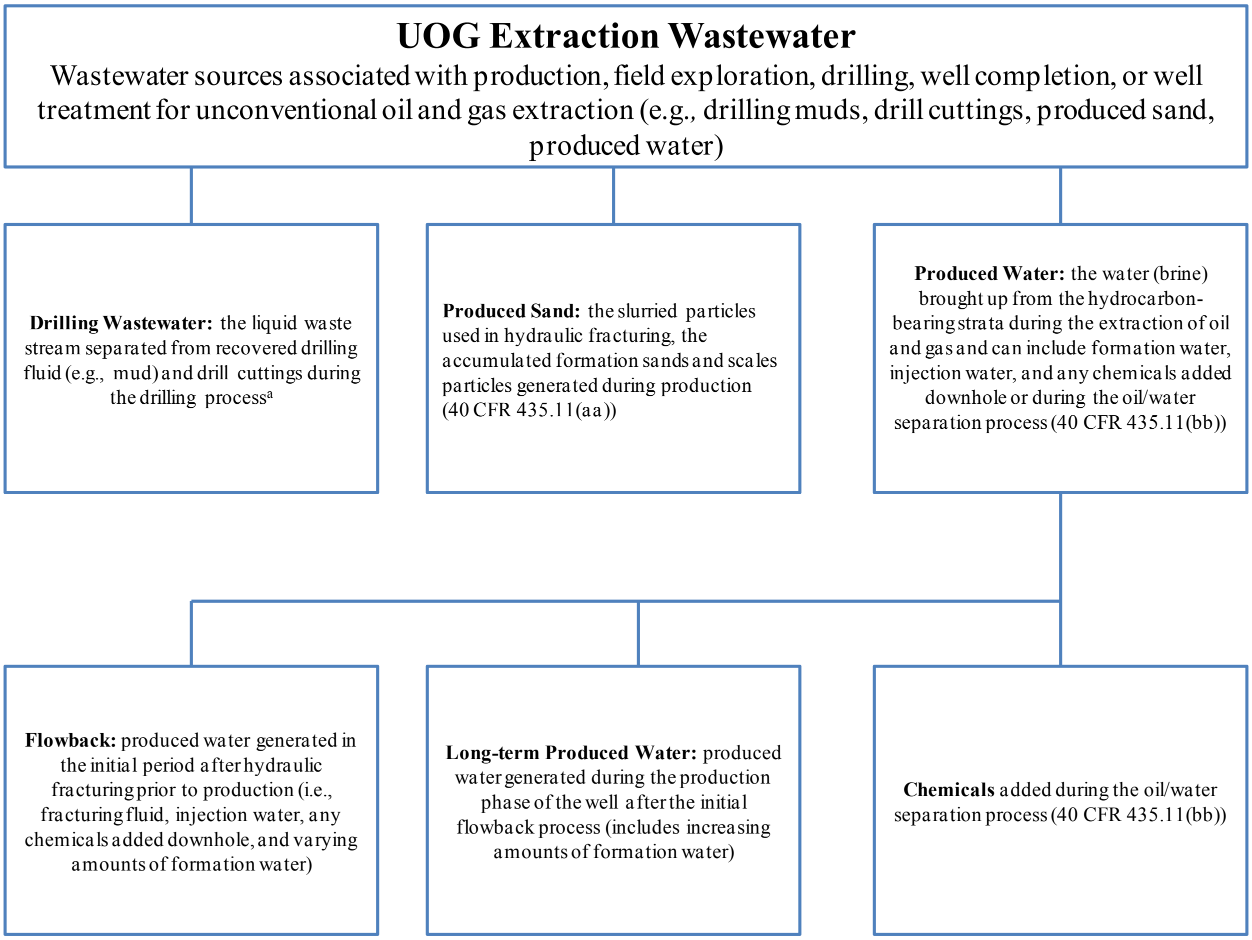
This technical development document (TDD) provides background information and data considered in the development of revised effluent limitations guidelines and standards (ELGs) proposed for the Oil and Gas Extraction point source category to address discharges from unconventional oil and gas (UOG) extraction facilities to municipal wastewater treatment plants. UOG consists of crude oil and natural gas[2] produced by wells drilled into a low porosity, low permeability formation. UOG resources include shale oil and gas, resources that were formed, and remain, in low-permeability shale. UOG resources also include tight oil and gas, resources that were formed in a source rock and migrated into a reservoir rock such as sandstone, siltstones, or carbonates. As explained in the preamble to the proposed rule, although coalbed methane (CBM) would fit the definition of UOG in the proposed rule, the proposed rule would not apply to pollutant discharges to POTWs associated with CBM extraction.[3] The remainder of the information presented in this document is specific to the UOG resources subject to the proposed rule and therefore excludes CBM unless explicitly indicated otherwise.

Development of UOG resources typically requires hydraulic fracturing of the reservoir rock by injecting fracturing fluid at high pressures to create a network of fissures in the rock formations, giving the oil and/or natural gas a pathway to travel to the well for extraction. Pressure within the low-permeability formations forces a portion of these fracturing fluids back to the surface. The fluid that returns is typically referred to as "flowback." Produced water consists of flowback that flows from the well initially and the long-term produced water that flows from the well during oil and gas production. Produced water also includes any chemicals that are added downhole or added to fracturing or drilling fluids that are then injected downhole, as well as chemicals that are added during the process of separating the oil and/or gas from the wastewater.

[2] Natural gas can include "natural gas liquids," components that are liquid at ambient temperature and pressure.

[3] EPA notes that the requirements in the existing effluent guidelines for direct dischargers also do not apply to coalbed methane extraction, as this industry did not exist at the time that the effluent guidelines were developed and was not considered by the Agency in establishing the effluent guidelines (160 DCN SGE00761). To reflect the fact that neither the proposed pretreatment standards nor the existing effluent guideline requirements apply to coalbed methane extraction, EPA is expressly reserving a separate unregulated subcategory for coalbed methane in the proposed rule. For information on coalbed methane, see http://water.epa.gov/scitech/wastetech/guide/oilandgas/cbm.cfm.

As depicted in Figure A-1, produced water, drilling wastewater, and produced sand are collectively referred to as UOG extraction wastewater.



a – Drilling fluid (mud) is the circulating fluid used in the rotary drilling of wells to clean and condition the hole and to counterbalance formation pressure. Drill cuttings means the particles generated by drilling into subsurface geologic formations and carried out from the wellbore with the drilling fluid.

Figure A-1. UOG Extraction Wastewater

This document supports the EPA's development of pretreatment standards for UOG extraction wastewater. The remainder of this chapter describes existing discharge regulations for UOG extraction wastewater. Subsequent chapters provide additional detail on UOG resources, extraction processes, and wastewater generation. They describe the quantity and quality of wastewater generated and the practices industry uses to manage and/or dispose of UOG extraction wastewater.

The pretreatment standards for UOG extraction wastewater are based on data generated or obtained in accordance with EPA's Quality Policy and Information Quality Guidelines. EPA's quality assurance (QA) and quality control (QC) activities for this rulemaking include the development, approval, and implementation of Quality Assurance Project Plans for the use of environmental data generated or collected from sampling and analyses, existing databases, and literature searches.

References cited in this document are listed in Chapter E and are identified in the body of the document by reference ID numbers (e.g., 149) and DCN (e.g., DCN SGE00586). Information presented in this document was taken from existing data sources, including state and federal agency databases, journal articles and technical papers, technical references, vendor websites, and industry/vendor telephone calls, meetings, and site visits. The EPA classified the quality of the data sources with a "data source quality flag", assigning ratings from "A" for peer-reviewed journal articles and documents prepared by or for a government agency to "D" for documents prepared by a source that could not be verified and that do not include citation information, such as some newspaper articles and conference presentations. For each source cited in this document, the reference list in Chapter E includes the reference ID number, document control number (DCN), source citation, and data source quality flag.

Appendix F.1 includes two tables with more information about where to find more data about certain topics, tables, and/or figures contained in the TDD. Table F-1 lists supporting memoranda along with their associated DCNs and a brief description of the type of information covered in the memoranda. Each supporting memorandum includes a section about QC activities related to the data and/or analyses discussed in the given memoranda. Table F-1 also lists the relevant TDD sections associated with each memorandum. Table F-2 contains additional information about each table and figure in the TDD, including the original source(s) of information for the data presented in the table or figure and the relevant memorandum and attachments, where relevant.

2 EXISTING DISCHARGE REGULATIONS FOR OIL AND GAS EXTRACTION FACILITY WASTEWATER

Wastewater discharges from oil and gas extraction facilities are subject to federal, state, and local regulations. Section A.2.1 describes federal regulations affecting the discharge of oil and gas extraction wastewater directly into waters of the United States and indirectly to municipal wastewater treatment plants (known as publicly owned treatment works, or POTWs), including ELGs for the Oil and Gas Extraction point source category (40 C.F.R. part 435) as well as the national pretreatment program (40 C.F.R. part 403). In addition to applicable federal requirements, some states specifically regulate the management, storage, and disposal of UOG extraction wastewater. Section A.2.2 discusses state-specific requirements that the EPA has identified that relate to UOG extraction wastewater pollutant discharges to POTWs.

2.1 Federal Regulations

The national clean water industrial regulatory program is authorized under Sections 301, 304, 306, and 307 of the Clean Water Act (CWA). These sections direct the EPA to promulgate categorical regulations through six levels of control:

- Best practicable control technology currently available (BPT)
- Best available technology economically achievable (BAT)
- Best conventional pollutant control technology (BCT)

- New source performance standards (NSPS)
- Pretreatment standards for existing sources (PSES)
- Pretreatment standards for new sources (PSNS)

For point sources that discharge pollutants directly into the waters of the United States (direct dischargers), the national-level ELGs promulgated by the EPA (i.e., BPT, BAT, BCT, and NSPS) are implemented through National Pollutant Discharge Elimination System (NPDES) permits[4] as authorized by CWA Sections 301(a), 301(b), and 402. For sources that discharge to POTWs, the EPA promulgates national categorical pretreatment standards (i.e., PSES and PSNS) that apply to discharges to POTWs and are enforced by local, state, and federal authorities. See CWA Sections 307(b) and (c) for the EPA's authority to develop pretreatment standards.

The EPA issues ELGs for categories of dischargers—groups with common characteristics, such as a manufacturing process or commercial activity (e.g., battery manufacturing, airport deicing). The EPA may divide a point source category into groupings called "subcategories" to provide a method for addressing variations among products, processes, and other factors, which result in distinctly different effluent characteristics that affect the determination of the technology basis for categorical regulations. ELGs are national in scope and apply to all facilities within a category or subcategory[5] that discharge wastewater. In establishing these controls, the EPA assesses, among other things:

- The performance and availability of the best pollution control technologies or pollution prevention practices for the category or subcategory as a whole.
- The economic achievability of those technologies, which can include consideration of the affordability of achieving reductions in pollutant discharges.

40 C.F.R. part 403.5(b) notes eight categories of pollutant discharge prohibitions:

1. Pollutants that create a fire or explosion hazard in the POTW
2. Pollutants that will cause corrosive structural damage to the POTW
3. Solid or viscous pollutants in amounts that will obstruct the flow in the POTW, resulting in interference
4. Any pollutant, including oxygen-demanding pollutants (e.g., BOD), released in a discharge at a flow rate and/or pollutant concentration that will interfere with the POTW
5. Heat in amounts that will inhibit biological activity in the POTW resulting in interference
6. Petroleum oil, nonbiodegradable cutting oil, or products of mineral oil origin in amounts that will cause interference or pass through
7. Pollutants that result in the presence of toxic gases, vapors, or fumes within the POTW in a quantity that may cause acute worker health and safety problems
8. Any trucked or hauled pollutants, except at discharge points designated by the POTW

2.1.1 The National Pretreatment Program (40 C.F.R. Part 403)

The 1972 CWA established the National Pretreatment Program to address wastewater discharged from industries to POTWs. POTWs collect wastewater from

[4] Facilities that do not discharge or propose not to discharge (zero dischargers) may apply for permit coverage for upset or bypass defense to cover discharges resulting from unforeseen incidents that otherwise would cause a violation of CWA Section 301 (i.e., discharge without a permit) (82 DCN SGE00531).

[5] The EPA may subcategorize a category based on appropriate factors, including facility size. See CWA Section 304(b)(2)(b)a. These factors may affect the availability and affordability of pollution control technologies.

homes, commercial buildings, and industrial facilities via a series of pipes, known as a collection system, to a treatment plant. In some cases, dischargers may haul wastewater to the treatment plant by tanker truck. Industrial wastewater, commingled with domestic wastewater, is treated by the POTW and discharged to a receiving water body. Under the CWA, in order to discharge wastewater, the POTW must have a NPDES permit that may limit the type and quantity of pollutants that it may discharge.

To implement the National Pretreatment Program, the EPA developed the General Pretreatment Regulations to protect POTW operations. As described in Chapter 2 of the EPA's introduction to the program (171 DCN SGE00249), these regulations apply to all non-domestic sources that introduce pollutants into a POTW. Non-domestic sources are referred to as industrial users (IUs). To distinguish small, simple IUs (e.g., coin-operated laundries, commercial car washes) from larger, more complex IUs (e.g., oil refineries, steel mills), the EPA has established a category called significant IUs (SIUs). The General Pretreatment Regulations apply to all nondomestic sources that introduce pollutants into a POTW and are intended to protect POTW operations from "pass through" and "interference." See the textbox for a list of prohibited pollutant discharges, as defined by 40 C.F.R. part 403.

Pretreatment Program Implementation

Most of the responsibility for implementing the National Pretreatment Program rests on local municipalities. For example, 40 C.F.R. part 403.8(a) requires that POTWs designed to treat more than 5 million gallons per day (MGD) of wastewater and receiving pollutants from IUs that pass through or interfere with the POTW's operation must establish a local pretreatment program.[6] The POTW's NPDES permit will include requirements for developing a local pretreatment program that will control the wastewater discharged to the POTW by IUs.

The National Pretreatment Program regulations identify specific requirements that apply to IUs, additional requirements that apply to all SIUs, and certain requirements that apply only to categorical industrial users (CIUs). There are three types of national pretreatment requirements:

- Prohibited discharge standards that include general and specific prohibition on discharges
- Categorical pretreatment standards
- Local limits

Prohibited discharge standards.

The prohibited discharge standards are not technology-based and are intended to prevent the POTW from receiving pollutants(s) that may cause pass through or interference. All IUs—regardless of whether they are subject to any other national, state, or local pretreatment requirements—are subject to the general and specific prohibitions identified in 40 C.F.R. parts 403.5(a) and (b), respectively.

[6] POTWs designed to treat less than 5 MGD may be required by their Approval Authority to develop a local pretreatment program if the nature or volume of the industrial influent, treatment process upsets, violations of POTW effluent limitations, contamination of municipal sludge, or other circumstances warrant in order to prevent interference with the POTW or pass through.

- General prohibitions prohibit the discharge of substances that pass through the POTW or interfere with its operation. Note that under the definition of “pass through,” only pollutants that are limited in the POTW’s NPDES permit are prohibited from pass through by the general prohibitions.
- Specific prohibitions in 40 C.F.R. part 403.5(b) prohibit eight categories of pollutant discharges that will harm POTW workers or the POTW, including the collection system. Pollutant discharges outside these defined categories are not specifically prohibited.

Categorical pretreatment standards.

As discussed in Section A.2.1, the CWA authorizes the EPA to promulgate national categorical pretreatment standards for industrial sources that discharge to POTWs. Developed by the EPA on an industry-specific basis, categorical pretreatment standards are based on the best available technology that is economically achievable for that industry on a national level, and set regulatory requirements based on the performance of that technology. These requirements limit discharges of toxic and nonconventional pollutants that could cause pass through or cause interference.[7] Categorical pretreatment standards represent a baseline level of control that all IUs in the category must meet, without regard to the POTW they discharge to. IUs subject to categorical pretreatment standards are known as CIUs. The EPA establishes two types of categorical pretreatment standards for CIUs: PSES and PSNS.

Local limits.

Developed by individual POTWs, local limits address the specific needs and concerns of the POTW, its sludge, and its receiving waters. Typically, POTWs develop local limits for discharges from all SIUs, not just CIUs. To evaluate the need for local limits, the POTW will survey the IUs subject to the pretreatment program, determine the pollutants discharged and whether they present a reasonable potential for pass through or interference, evaluate the capability of the POTW system to address pollutants received by all users (IUs and residential sources), and implement a system to control industrial discharges. Additional information can be found in the EPA’s 2004 *Local Limits Development Guidance* (165 DCN SGE00602*)*.

Responsibilities of POTWs and IUs

The POTW controls the discharges from the IU through an individual control mechanism, often called an IU permit. The POTW may also issue general permits under certain conditions if it has adequate legal authority and approval. POTWs with approved local pretreatment programs must have procedures for:

- Identifying all possible IUs, and the character and volume of pollutants from IUs introduced to the POTW

[7] In determining whether a pollutant would pass through POTWs for categorical pretreatment standards, EPA generally compares the percentage of a pollutant removed by well-operated POTWs performing secondary treatment to the percentage removed by a candidate technology basis. A pollutant is determined to pass through POTWs when the median percentage removed nationwide by well-operated POTWs is less than the median percentage removed by the candidate technology basis.

- Communicating applicable standards and requirements to IUs
- Receiving and analyzing reports
- Inspecting IUs, including annual inspections of SIUs
- Sampling in certain cases
- Investigating noncompliance with pretreatment standards and requirements
- Reporting to the Approval Authority (i.e., state or regional pretreatment program)

Each IU of a POTW is responsible for compliance with applicable federal, state, and local pretreatment standards and requirements.

Approval Authority

POTWs establish local pretreatment programs to control discharges from non-domestic sources. These programs must be approved by the Approval Authority*,* which is also responsible for overseeing implementation and enforcement of the programs (171 DCN SGE00249). The Approval Authority is the director in a NPDES authorized state with an approved state pretreatment program, or the appropriate EPA regional administrator in a non-NPDES authorized state or NPDES state without an approved state pretreatment program. A state may have an NPDES permit program but lack a state pretreatment program. One example is Pennsylvania, which the EPA has authorized for the NPDES program but not for the pretreatment program. EPA Region 3 is the Approval Authority for POTW pretreatment programs in Pennsylvania.

Hauled Wastewater

As discussed in the EPA's *Introduction to the National Pretreatment Program* (171 DCN SGE00249), in addition to receiving wastewater through the collection system, many POTWs accept trucked wastewater. IUs may truck their wastewater to the POTW when the facility is outside the POTW's service area (e.g., located in a rural area) and is not connected to the collection system. Just like wastewater received through the collection system, trucked wastewater is subject to the General Pretreatment Regulations and may also be subject to categorical pretreatment standards. Therefore, the POTW must regulate hauled wastewater from CIUs or hauled wastewater that otherwise qualifies the discharger as an IU in accordance with the requirements of the General Pretreatment Regulations and any applicable categorical pretreatment standards, including any applicable requirements for permitting and inspecting the facility that generates the wastewater.

Section 403.5(b)(8) of the General Pretreatment Regulations specifically prohibits the introduction of any trucked or hauled pollutants to the POTW, except at discharge points designated by the POTW. As explained in *Introduction to the National Pretreatment Program* (171 DCN SGE00249), Section 403.5(b)(8) of the General Pretreatment Regulations is the only pretreatment requirement specifically addressing hauled wastewater. POTWs are not required to have waste hauler control programs. However, POTWs that accept any hazardous waste by truck, rail, or dedicated piping at the POTW facility are considered treatment, storage, and disposal facilities (TSDFs) subject to management requirements under the Resource Conservation and Recovery Act (RCRA). Consequently, a POTW should not accept hauled waste without consideration of the implications of its acceptance (see 40 C.F.R. part 260).

2.1.2 ELGs for the Oil and Gas Extraction Point Source Category (40 C.F.R. Part 435)

The EPA promulgated the Oil and Gas Extraction ELGs (40 C.F.R. part 435) in 1979, and amended the regulation in 1993, 1996, and 2001. The Oil and Gas Extraction industrial category is subcategorized[8] as follows:

- Subpart A: Offshore
- Subpart C: Onshore
- Subpart D: Coastal
- Subpart E: Agricultural and Wildlife Water Use
- Subpart F: Stripper Wells

The existing subpart C and subpart E regulations cover wastewater discharges from field exploration, drilling, production, well treatment, and well completion activities in the onshore oil and gas industry. Although oil and gas resources occur in unconventional formations in offshore and coastal regions, recent development of UOG resources in the United States has occurred primarily onshore in regions to which the regulations in subpart C (onshore) and subpart E (agricultural and wildlife water use) apply and thus, only the regulations that apply to onshore oil and gas extraction are described in more detail here.

Note that the scope of the existing Oil and Gas Extraction ELG does not similarly apply to privately owned wastewater treatment facilities that accept oil and gas extraction wastewater from offsite that are also not engaged in production, field exploration, drilling, well completion, or well treatment. Discharges from such facilities are not subject to 40 C.F.R. part 435, but rather are subject to requirements in 40 C.F.R. part 437, the Centralized Waste Treatment category (see Section D.4 for more information).

Direct Discharge Requirements for Onshore Oil and Gas Extraction Facilities

Subpart C: Onshore Subcategory

Applicability. As set forth in 40 C.F.R. part 435.30, subpart C applies to facilities engaged in production, field exploration, drilling, well completion, and well treatment in the oil and gas extraction industry, located landward of the inner boundary of the territorial seas—and not included in the definition of other subparts, including subpart D (Coastal) at 40 C.F.R. part 435.40.

Direct discharge requirements. The regulations at 40 C.F.R. part 435.32 specify the following for BPT:

> *…there shall be no discharge of waste water pollutants into navigable waters from any source associated with production, field exploration, drilling, well completion, or well treatment (i.e., produced water, drilling muds, drill cuttings, and produced sand).*

The existing regulations do not include national categorical pretreatment standards for discharges to POTWs.

[8] Subpart B is reserved.

Subpart E: Agricultural and Wildlife Use Subcategory[9]

Subpart E applies to onshore facilities located in the continental United States and west of the 98th meridian for which the produced water has a use in agriculture or wildlife propagation when discharged into waters of the United States.

Applicability. As set forth in 40 C.F.R. part 435.50, subpart E applies to onshore facilities located in the continental United States and west of the 98th meridian for which the produced water has a use in agriculture or wildlife propagation when discharged into navigable waters. Definitions in 40 C.F.R. part 435.51(c) explain that the term "use in agricultural or wildlife propagation" means:

- The produced water is of good enough quality to be used for wildlife or livestock watering or other agricultural uses; and
- The produced water is actually put to such use during periods of discharge.

Direct discharge requirements. Subpart E prohibits the discharge of waste pollutants into navigable waters from any source (other than produced water) associated with production, field exploration, drilling, well completion, or well treatment (i.e., drilling muds, drill cuttings, produced sands). Therefore, the only allowable discharge under this subpart is produced water[10] that meets the "good enough quality" and actual use requirements described above, with an oil and grease concentration not exceeding 35 mg/L.

2.2 State Pretreatment Requirements That Apply to UOG Extraction Wastewater

In addition to applicable federal requirements, some states regulate the management, storage, and disposal of UOG extraction wastewater, including regulations concerning pollutant discharges to POTWs from oil and gas extraction facilities. In addition to pretreatment requirements, some states have indirectly addressed the issue of pollutant discharges to POTWs by limiting the management and disposal options available to operators. Table A-1, beginning on the next page, summarizes how Pennsylvania, Ohio, West Virginia, and Michigan responded to UOG extraction wastewater discharges into their POTWs.

The Groundwater Protection Council's (GWPC) 2014 report *Regulations Designed to Protect State Oil and Gas Water Resources* describes that, as part of their study, GWPC "surveyed the study states[11] regarding the use of POTWs for discharging production fluids including flowback water. Of the states responding, three indicated this practice was banned by

[9] While pollutant discharges from onshore oil and gas extraction produced water are allowed under subpart E in certain geographic locations for use in agriculture or wildlife propagation, EPA has not found that these types of permits are typically written for unconventional oil and gas extraction wastewater (as defined for the proposed rule).

[10] Produced water is not defined in subpart C (onshore) or subpart E (agricultural and wildlife use). For subparts A (offshore) and D (coastal), produced water is defined 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."

[11] GWPC reviewed data for the following 27 oil and gas producing states: Alabama, Alaska, Arkansas, California, Colorado, Florida, Illinois, Indiana, Kansas, Kentucky, Louisiana, Michigan, Mississippi, Montana, Nebraska, New Mexico, New York, North Dakota, Ohio, Oklahoma, Pennsylvania, South Dakota, Texas, Utah, Virginia, West Virginia, and Wyoming.

regulation, five states did not have a regulation covering this disposal method but would not allow it as a matter of policy, and nine indicated it was either regulated by another state agency or would otherwise be allowed under certain circumstances…. [A]s of 2013, six state oil and gas agencies had permitting requirements for POTWs accepting this waste" (77 DCN SGE01077).

Table A-1. Summary of State Regulations

State	Relevant State Authority (s)	State Authority Website(s)	Description of State's Relevant Requirements
Pennsylvania	EPA Region 3, PA DEP	PA DEP: http://www.depweb.state.pa.us/ PA Code, Chapter 95: http://www.pacode.com/secure/data/025/chapter95/chap95toc.html	Pennsylvania amended 25 Pennsylvania Code Ch. 95.10 on August 21, 2010. According to PA Bulletin, Doc. No. 10-1572 (130 DCN SGE00187) (available at http://www.pabulletin.com/secure/data/vol40/40-34/1572.html) *This final form rulemaking ensures the continued protection of this Commonwealth's water resources from new and expanded sources of TDS. Most importantly, the final-form rulemaking guarantees that waters of this Commonwealth will not exceed a threshold of 500 mg/L.* In addition, the bulletin specifies *A higher standard of 500 mg/L is being applied specifically to the natural gas sector, based on several factors.* The bulletin also explains the following, regarding existing authorized discharges, addressed in Section 95.10(a)(1) *This section makes it clear that discharge loads of TDS authorized by the Department, under NPDES permits or other authority that were issued or reissued prior to the effective date of this final-form rulemaking, are exempt from the regulation until the net load is to be increased. It is important to note that only an increase in net TDS load is considered to be a new or expanding discharge loading.* The bulletin also explains the pretreatment requirements described in Section 95.10(b)(3)(ii), including *the final rule establishes that POTWs may accept these wastewaters only if the wastes are first treated at a CWT facility and meet the end-of-pipe effluent standards imposed by the rule. In effect, the final rule regulates these indirect discharges in a manner consistent with direct discharges of these wastes.* On April 19, 2011, PA DEP requested that *Marcellus Shale natural gas drillers voluntarily cease delivering their wastewater to 15 wastewater treatment plants which currently accept it and have "grandfathered" status with respect to PA DEP's Total Dissolved Solids regulations* (170 DCN SGE00982). On April 20, 2011, the Marcellus Shale Coalition wrote a response to PA DEP that stated *I write to you today to express our commitment to meet the call of the Department of Environmental Protection (DEP) to halt the delivery of flowback and produced water from shale gas extraction to the facilities that currently accept it under special provisions of last year's Total Dissolved Solids (TDS) regulations. Our members are carefully reviewing their operations and support achieving this milestone by May 19, 2011* (111 DCN SGE00545).

Table A-1. Summary of State Regulations

State	Relevant State Authority (s)	State Authority Website(s)	Description of State's Relevant Requirements
Ohio	OH EPA, OH DNR	OH EPA: http://www.epa.state.oh.us/ OH DNR: http://ohiodnr.gov/ Ohio R.C. 15, Chapter 1509: http://codes.ohio.gov/orc/1509	Ohio R.C. Title 15, Chapter 1509, part 22(C)(1) (128 DCN SGE00983), includes the provision that *brine[12] from any well except an exempt Mississippian well[13] shall be disposed of only as follows: by injection into an underground formation, including annular disposal if approved by rule of the chief, which injection shall be subject to division (D) of this section; by surface application in accordance with section 1509.226 of the Revised Code; in association with a method of enhanced recovery as provided in section 1509.21 of the Revised Code; [or] in any other manner not specified in divisions (C)(1)(a) to (c) of this section that is approved by a permit or order issued by the chief.*
West Virginia	WVDEP	WVDEP: http://www.dep.wv.gov/Pages/default.aspx	A WVDEP guidance document about POTWs accepting oil and gas wastewater (218 DCN SGE00767) notes that *The USEPA and WVDEP discourage POTWs from accepting wastewater from oil and gas operations such as coal bed methane and Marcellus Shale wastewaters because these wastewaters essentially pass through sewage treatment plants and can cause inhibition and interference with treatment plant operations.*

[12] The Ohio EPA defines brine as "all saline geological formation water resulting from, obtained from, or produced in connection with the exploration, drilling, or production of oil or gas, including saline water resulting from, obtained from, or produced in connection with well stimulation or plugging of a well."

[13] OH R.C. Section 1509.01 defines an "exempt Mississippian well" as a well that (1) was drilled and completed before January 1, 1980; (2) is in an unglaciated part of the state; (3) was completed in a reservoir no deeper than the Mississippian Big Injun sandstone in areas underlain by Pennsylvanian or Permian stratigraphy, or the Mississippian Berea sandstone in areas directly overlain by Permian stratigraphy; and (4) is used primarily to provide oil or gas for domestic use.

Table A-1. Summary of State Regulations

State	Relevant State Authority (s)	State Authority Website(s)	Description of State's Relevant Requirements
Michigan	MI DEQ	MI DEQ: http://www.michigan.gov/deq Michigan Oil and Gas Regulations: http://www.michigan.gov/documents/deq/ogs-oilandgas-regs_263032_7.pdf	Michigan's Oil and Gas Regulations, part 324.703 (120 DCN SGE00254), state that *A permittee of a well shall inject oil or gas field fluid wastes, or both, into an approved underground formation in a manner that prevents waste. The disposal formation shall be isolated from fresh water strata by an impervious confining formation.*

Sources: 130 DCN SGE00187; 120 DCN SGE00254; 104 DCN SGE00545; 198 DCN SGE00766; 218 DCN SGE00767; 170 DCN SGE00982; 128 DCN SGE00983

Abbreviations: PA DEP—Pennsylvania Department of Environmental Protect; OH EPA—Ohio Environmental Protection Agency; OH DNR—Ohio Department of Natural Resources; R.C.—Revised Code; WVDEP—West Virginia Department of Environmental Protection; MI DEQ—Michigan Department of Environmental Quality

3 RELATED FEDERAL REQUIREMENTS

As required by the Safe Drinking Water Act Section 1421, the EPA has promulgated regulations to protect underground sources of drinking water through underground injection control (UIC) programs that regulate the injection of fluids underground. These regulations are found at 40 C.F.R. parts 144 through 148, and specifically prohibit any underground injection not authorized by UIC permit (40 C.F.R. part 144.11). They classify underground injection into six classes; wells that inject fluids brought to the surface in connection with oil and gas production are classified as Class II UIC wells (see Section D.2 for more information). Thus, an onshore oil and gas extraction facility that seeks to meet zero discharge requirements through underground injection of wastewater must dispose of the wastewater in a well with a Class II UIC disposal well permit.

Chapter B. BACKGROUND ON UNCONVENTIONAL OIL AND GAS EXTRACTION

To provide context for discussions of UOG extraction wastewater volumes and characteristics (Chapter C) and management and disposal practices (Chapter D), this chapter describes the following:

- What UOG resources are in context of the proposed rule, differences between unconventional and conventional resources, differences between types of UOG resources, and where UOG resources are located
- How UOG wells are developed and the development processes that generate wastewater
- Historical, current, and projected future UOG well drilling activity

Relevant national economic information about the UOG industry is included in a separate memorandum to the record, titled *Profile of the Oil and Gas Extraction (OGE) Sector, with Focus on Unconventional Oil and Gas (UOG) Extraction* (2 DCN SGE00932).

Oil and gas resources are defined as the total in-place hydrocarbon contained in porous rock formations. There are several ways to classify oil and gas resources. Throughout this TDD, the EPA typically classifies resources into conventional and unconventional resources. For purposes of the proposed rule, the EPA is proposing to define "unconventional oil and gas" (UOG) as "crude oil and natural gas[14] produced by a well drilled into a low porosity, low permeability formation (including, but not limited to, shale gas, shale oil, tight gas, tight oil)." As explained in the preamble to the proposed rule and in Section A.1, although CBM would fit the definition of UOG in the proposed rule, the proposed rule would not apply to pollutant discharges to POTWs associated with CBM extraction.

The different types of unconventional resources (shale, tight) and how they differ from conventional resources are discussed in more detail in Section B.2.1. UOG and conventional oil and gas (COG) resources can be further classified by the type of hydrocarbon: oil, natural gas, and natural gas condensates. Literature often refers to formations that co-produce natural gas condensates[15] along with oil and/or natural gas as liquid rich formations. Formations that primarily produce oil also co-produce natural gas known as "associated gas" (206 DCN SGE00623). Formations that only produce dry natural gas are known as non-associated gas resources.

1 OVERVIEW OF UOG RESOURCES

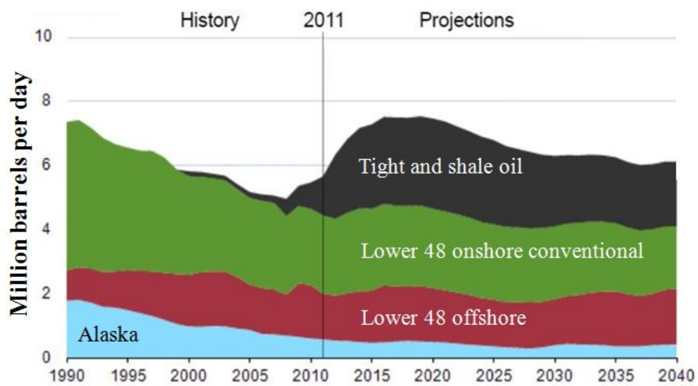
The Energy Information Administration (EIA) publishes historical and projected future oil and gas production by resource type in its Annual Energy Outlooks (AEOs). Beginning around 2000, advances in technologies such as horizontal drilling and advances in hydraulic fracturing made it possible to economically produce oil and natural gas from tight and shale

[14] Natural gas can include "natural gas liquids," components that are liquid at ambient temperature and pressure.

[15] Natural gas condensates include light hydrocarbons such as ethanes, propanes, and butanes. When gas condensates are depressurized at the wellhead, they condense into a liquid phase. When processed at the refinery, the finished byproducts of natural gas condensates are referred to as natural gas liquids and have high market value.

resources (209 DCN SGE01095). The EIA's 2014 AEO projects that, in the next 30 years, the majority of the country's natural gas will come from unconventional resources and that unconventional oil production will continue to increase substantially (31 DCN SGE00989). Figure B-1 and Figure B-2 show the historical and future profiles of COG and UOG production in the United States by resource type according to the EIA.[16] CBM and COG are included in some of the figures in this chapter, but are identified separately within each figure. Section B.3 summarizes historical and current trends in UOG drilling in more detail on a well basis.

Figure B-3 and Figure B-4 show the major shale and tight UOG resources, respectively, in the lower 48 states. Appendix F (Table F-3 and Table F-4) provides an updated and more thorough list of UOG formations by basin as the EIA maps shown below only show major UOG formations as of May 2011. Geological characteristics of UOG resources shown in Figure B-3 and Figure B-4 are described in detail in Section B.1.2.[17]

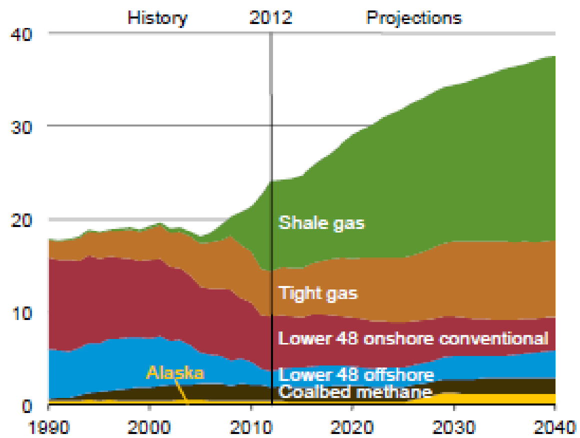


Source: 158 DCN SGE00487

Figure B-1. Historical and Projected Oil Production by Resource Type

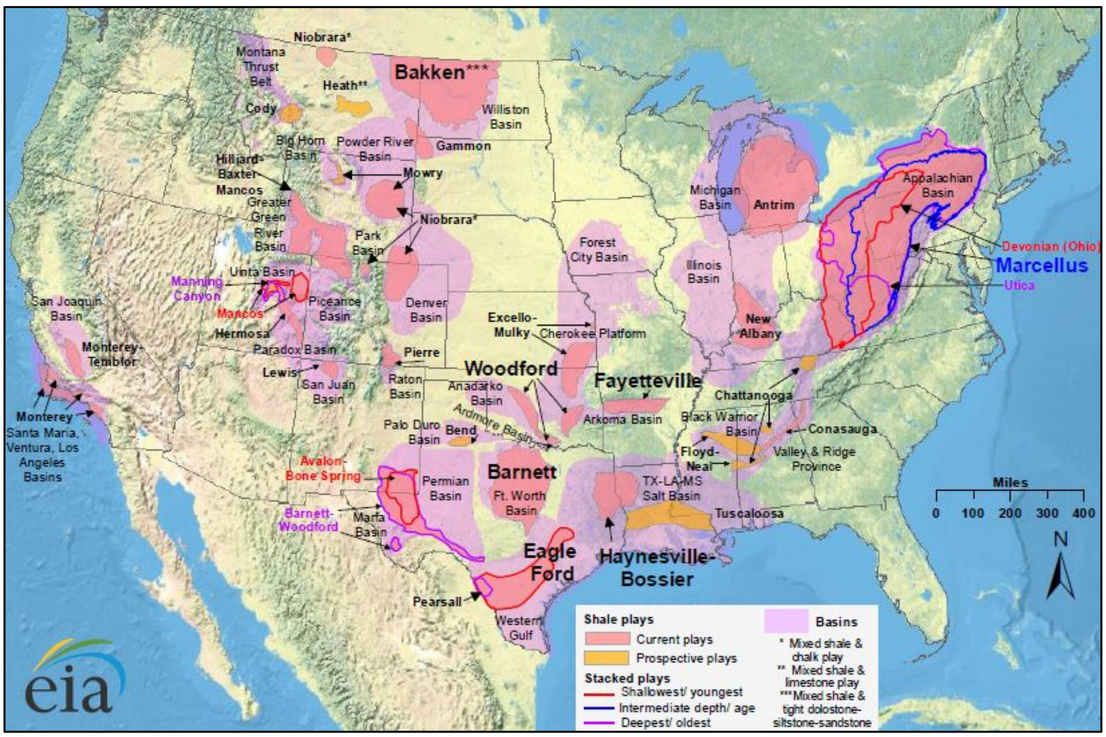
[16] In Figure B-1, the EIA refers to all types of unconventional oil including shale as "tight oil." As explained in Section B.1, EPA differentiates between shale and tight oil for the purpose of this TDD.

[17] The EIA uses the term "play" to describe subsets of UOG resources in Figure B-3 and Figure B-4, which are similar to the term "formation" as used in this TDD.



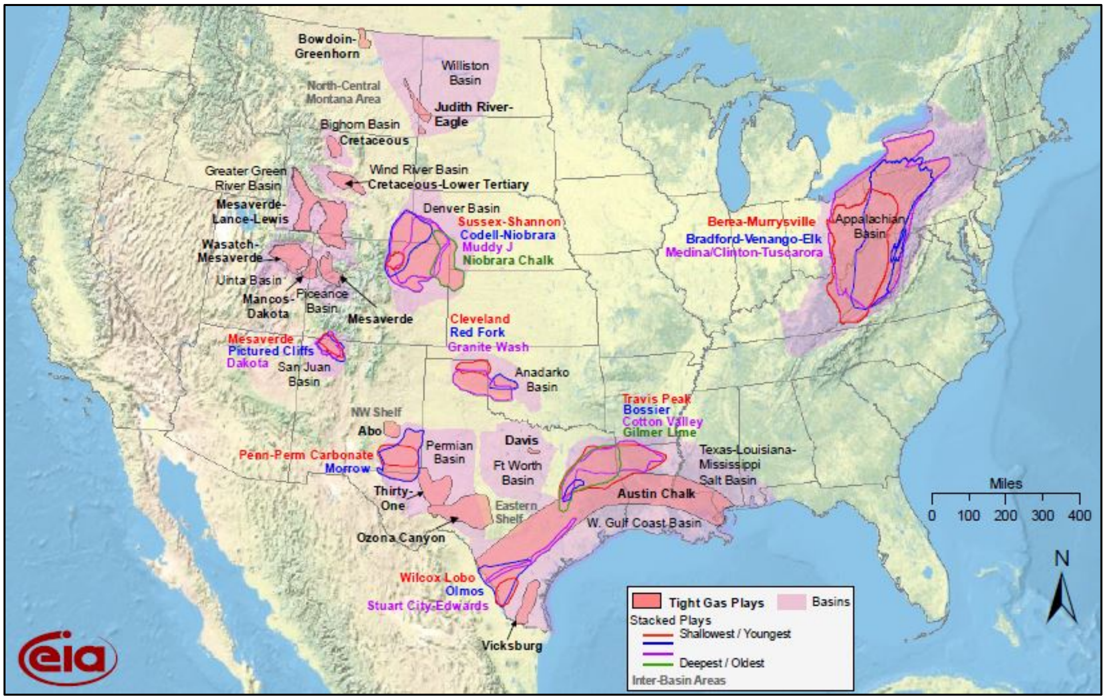
Source: 31 DCN SGE00989

Figure B-2. Historical and Projected Natural Gas Production by Resource Type



Source: 157 DCN SGE00153

Figure B-3. Major U.S. Shale Plays (Updated May 9, 2011)



Source: 156 DCN SGE00155

Figure B-4. Major U.S. Tight Plays (Updated June 6, 2010)

The key differences between UOG and COG resources are the geological characteristics of the formations that contain the resources. UOG resources include shale oil and gas resources that were formed, and remain, in low-permeability shale. UOG resources also include tight oil and gas resources that were formed in a source rock and migrated into a reservoir rock such as sandstone, siltstones, or carbonates. The permeability and porosity of tight oil and gas reservoirs are lower than that of COG reservoirs, but generally higher than that of shale oil and gas reservoirs (100 DCN SGE00527). As mentioned above, while CBM is sometimes referred to as an unconventional resource, the proposed rule does not apply to CBM, and therefore the scope of this document does not include CBM.

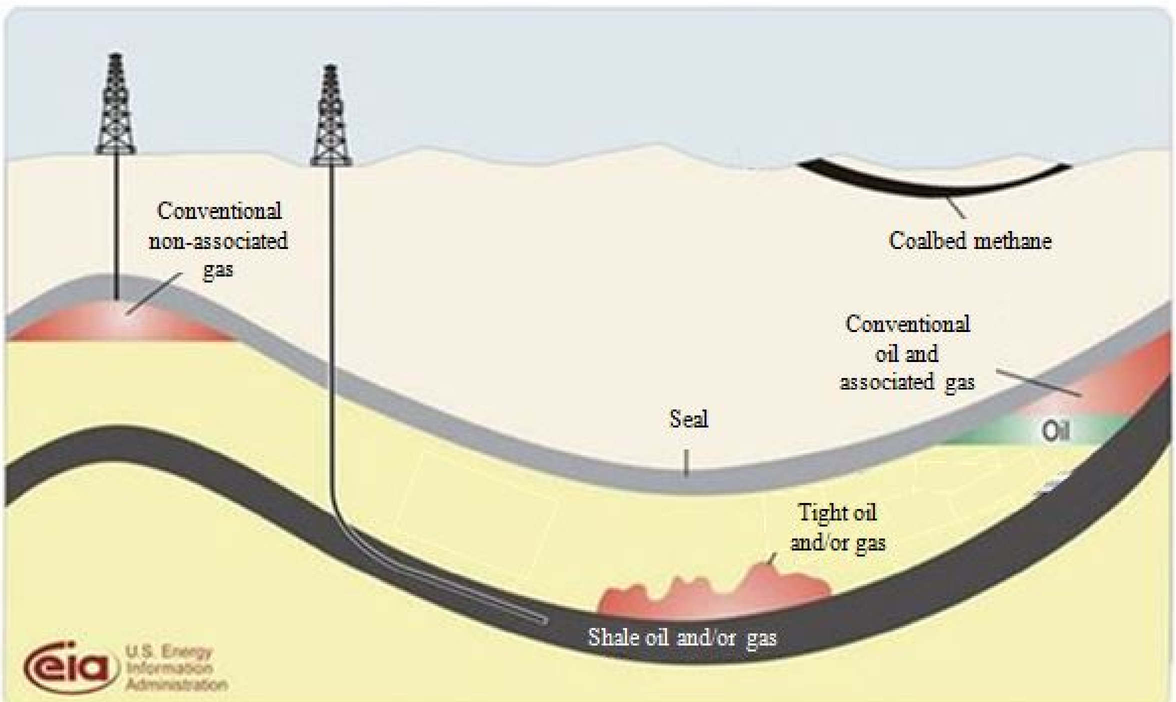
1.1 <u>How UOG Resources Were Formed</u>

Differences in how conventional and unconventional resources were formed can be explained in terms of the source and resource rock.[18] The following explains these differences, which are also illustrated in Figure B-5 (100 DCN SGE00527; 113 DCN SGE00547; 211 DCN SGE00114).

- Oil and gas in **conventional** resources were formed in a source rock, migrated through the surrounding permeable rock, and eventually became trapped by a confining rock layer forming non-continuous accumulations. The final reservoir rock has high permeability and porosity.

[18] The source rock is the type of rock in which the oil and/or gas formed. The reservoir rock is the type of rock in which the oil and/or gas is contained at the time of production.

- Oil and gas in **tight** resources, similar to conventional resources, were formed in a source rock and migrated until they reached a confining layer of rock. Tight resources occur in a mixture of continuous and non-continuous accumulations. They differ from conventional resources in that the oil and gas accumulated in a reservoir rock with relatively low permeability and porosity.[19]
- Oil and gas in **shale** resources were formed in and remained in the source rock, making it also the reservoir rock. Consequently, shale reservoirs occur in continuous accumulations over large geographic areas. Shale reservoirs have the lowest permeability and porosity out of all resource types (see Section B.2.2 for more information about hydraulic fracturing).



Source: 155 DCN SGE00594

Figure B-5. Geology of Formations Containing Various Hydrocarbons[20]

1.2 Geological Characteristics of UOG Resources

UOG resources are typically developed using advanced completion and well drilling techniques because they have unique geologic characteristics that differ from conventional resources. These are summarized in Table B-1. COG reservoirs have relatively high porosities and permeabilities, so economical oil and gas production typically relies on natural pressure

[19] Because tight oil and gas exists in multiple types of reservoir rocks, EPA refers to it generally as "tight" oil and gas in this report as opposed to "tight sands" because that reference is not all inclusive of the different types of tight formations.

[20] "Associated" gas accumulates with oil in a formation. "Non-associated" gas accumulates separately from oil in a formation (206 DCN SGE00623).

gradients with open-hole completion techniques (see Section B.2.2 for more information about well completion). UOG reservoirs have extremely low porosity and permeability, typically requiring rigorous stimulation (e.g., hydraulic fracturing) during well completion to produce oil and gas economically (113 DCN SGE00547; 100 DCN SGE00527; 211 DCN SGE00114). Although it is not necessary to create fractures to obtain oil and gas from conventional reservoirs, hydraulic fracturing can still be used to increase production from COG wells (100 DCN SGE00527; 146 DCN SGE00291)[21]. UOG formations are also more likely to occur in continuous accumulations, as explained in Section B.1.1. As a result, UOG wells are more likely to be drilled horizontally.

Table B-1. Characteristics of Reservoirs Containing UOG and COG Resources

Reservoir Characteristic	COG Resources	UOG Resources	
		Tight	Shale
Reservoir rock type	Sandstones, siltstones, or carbonates	Sandstones, siltstones, or carbonates	Shales
Source rock	No	No	Yes
Accumulation type	Non-continuous	Continuous or non-continuous	Continuous
Porosity	High (>10%)	Low (<10%)	Low (<10%)
Permeability	High (>100 mD)[a]	Low (<0.1 mD)[a]	Low (<0.001 mD)[a]
Well trajectory[b]	Mostly vertical	Mixture of vertical and horizontal	Mostly horizontal
Completion method	Open hole completions and natural reservoir pressure[c]	Hydraulic fracturing and/or acidization[d]	Hydraulic fracturing

Sources: 211 DCN SGE00114; 86 DCN SGE00533; 100 DCN SGE00527; 109 DCN SGE00345

a—The millidarcy (mD) is a measurement of permeability (i.e., ability for fluid flow within a rock). Higher permeability means fluids flow more readily.
b—Well trajectories are described in more detail in Section B.2.1.
c—As COG wells age, operators may also use enhanced recovery techniques such as water or steam injection to enhance production. COG wells may also be hydraulically fractured.
d—Acidization is the process of dissolving undesired rocks from the wellbore using acidic fluids in order to improve fluid flow from the reservoir (18 DCN SGE00966).

2 UOG Well Development Process

UOG well development includes the following processes: well pad construction, well drilling and construction, well completion, and production. UOG well completion includes well stimulation such as hydraulic fracturing, acidization, or a combination of hydraulic fracturing and acidization. The return of injected fluids to the surface, commonly referred to as the "flowback process," is also part of the UOG well completion process. Before UOG well development, operators conduct exploration and obtain surface use agreements, mineral leases, and permits. These steps can take a few months to several years to complete. When they are

[21] A survey conducted by American Petroleum Institute (API) and the American Natural Gas Alliance (ANGA), included well completion information for 5,307 well completions in 2010, consisting of a mixture of conventional and unconventional wells. The survey also showed that 69 percent of conventional wells were hydraulically fractured.

completed, operators begin the well development process, as described in the following subsections.

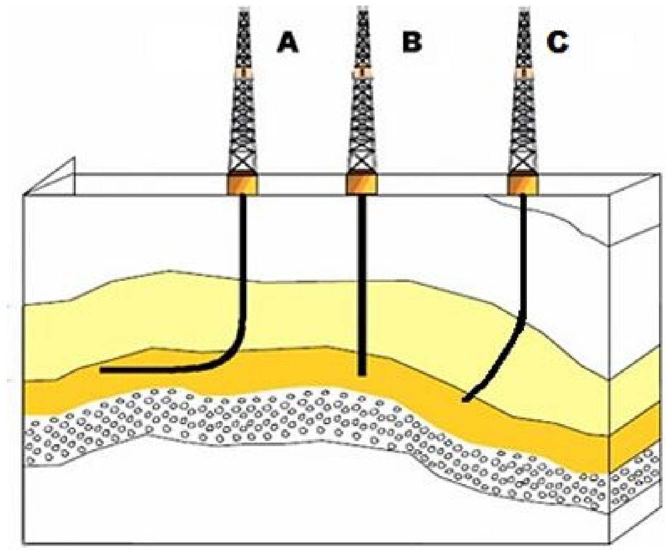
The largest UOG extraction wastewater volumes generated during the UOG well development process are flowback and long-term produced water (see Section C.2 for characteristics of each). UOG well drilling also generates drilling wastewater. Throughout the well development process, many materials are transported to the well pad. These materials include well casing and tubing, fuel (e.g., diesel or liquefied natural gas), and base fluid, sand, and chemicals for hydraulic fracturing. Operators must also transport UOG extraction wastewater from the well to the ultimate wastewater management or disposal location—e.g., a centralized waste treatment (CWT) facility, an underground injection well for disposal, another well for reuse. Sand, chemicals, and construction materials are typically transported to the well pad by truck, but fracturing base fluid (e.g., fresh water, recycled UOG produced water) and UOG extraction wastewater may be transported via truck or temporary piping (191 DCN SGE00625; 178 DCN SGE00635; 179 DCN SGE00275).

2.1 UOG Well Drilling and Construction

Drilling occurs in two phases: exploration and development. Exploration involves the drilling of wells to locate hydrocarbon-bearing formations and to determine the size and production potential of hydrocarbon reserves. Development involves drilling production wells once a hydrocarbon reserve has been discovered and delineated. The following discussion will focus on the drilling of production wells.

After the well pad is constructed, operators drill and construct the well. Operators use one of the three drilling trajectories below to drill for UOG (see Figure B-6). See Table B-3 for a breakdown of active UOG wells as of 2011 by drilling trajectory.

- **Vertical drilling** is the drilling of a wellbore straight down into the ground. In UOG well drilling, vertical well drilling is more commonly used for tight wells than shale wells (100 DCN SGE00527). For shale, vertical drilling is used by operators during the exploration phase of field development (178 DCN SGE00635), in shallow formations (e.g., Antrim shale), or by small entity operators who may be unable to make large investments in horizontal wells (39 DCN SGE00283). Vertical drilling has historically been used for COG wells.
- **Directional drilling** is the drilling of a wellbore at an angle off the vertical to reach an end location not directly below the well pad. Directional drilling is used where a well pad cannot be constructed directly above the resource (e.g., in rough terrain). Directional drilling is common in conventional and unconventional tight formations that occur as accumulations as illustrated in Section B.1.
- **Horizontal drilling,** the most advanced drilling technique, allows operators to drill vertically down to a desired depth, about 500 feet above the target formation (called the "kickoff point"), and then gradually turn the drill 90 degrees to continue drilling laterally. Horizontal drilling exposes the producing formation via a long horizontal lateral, which can vary in length between 1,000 and 5,000 feet (154 DCN SGE00593; 206 DCN SGE00623). Horizontal drilling is the most commonly used method in continuous shale and tight formations (24 DCN SGE00354; 78 DCN SGE00010).



Source: 154 DCN SGE00593 (edited by the EPA)

Figure B-6. Horizontal (A), Vertical (B), and Directional (C) Drilling Schematic

Because shale reservoirs occur in continuous accumulations over large geographic areas, operators drilling in these resources typically drill multiple horizontal wells on each well pad (191 DCN SGE00625; 178 DCN SGE00635; 179 DCN SGE00275). However, tight reservoirs occur in both continuous and non-continuous accumulations; therefore, operators may drill multiple horizontal wells or a single directional or vertical well on a well pad, depending on the location and accumulation type of the tight reservoir. Directional and horizontal well configurations give operators access to more of the producing formation and therefore reduce surface disturbance (24 DCN SGE00354; 212 DCN SGE00011). Operators may drill one or two horizontal wells on a well pad initially and move on to the next pad. When this happens, the operator typically comes back to drill out the remaining wells on the pad after the initial wells show economical production and favorable conditions.[22]

Drilling for oil and gas is generally performed by rotary drilling methods, which involve the use of a rotating drill bit that grinds through the earth's crust as it descends. Well drilling is an iterative process that includes several sequences of drilling, installing casing, and cementing of succeeding sections of the well (178 DCN SGE00635). During drilling, operators inject drilling fluids down the wellbore to cool the drill bit, to circulate fragments of rock (i.e., drill cuttings) back to the surface so they do not clog the wellbore, and to control downhole pressure. Operators use one of the following types of drilling fluids depending on which portion of the well they are drilling (55 DCN SGE00740):

- **Compressed gases:** During the beginning phase of drilling an UOG well (i.e., the initial drilling close to the surface), compressed gases may be used to minimize costs. Dry air, nitrogen gas, mist, foam, and aerated fluids are included in this category.

[22] Favorable conditions include sufficient oil and/or gas prices, available drilling rigs, available fracturing crews, and permits.

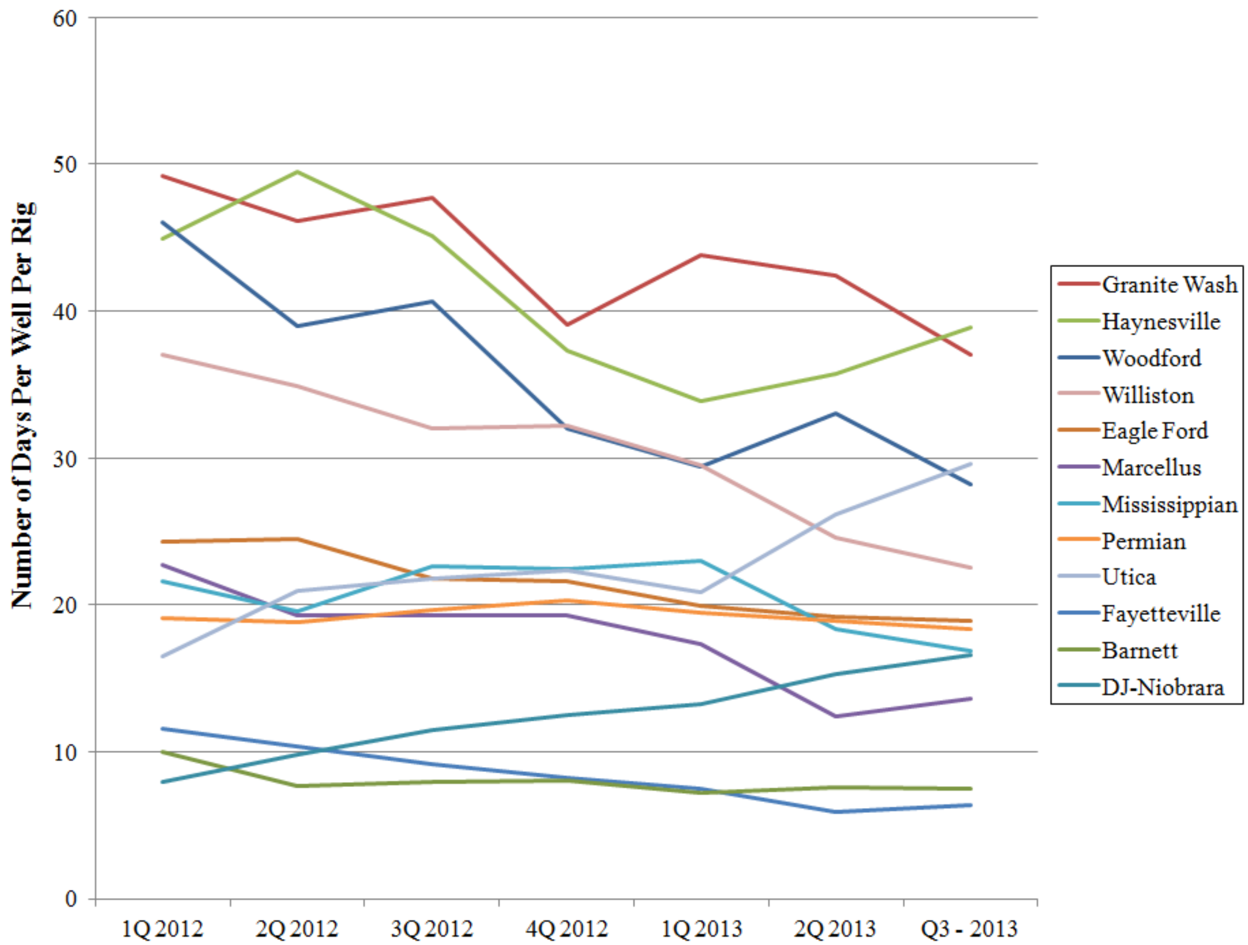
- **Water-based:** At several thousand feet deep, operators typically use water-based drilling fluids (i.e., drilling mud), which provide more robust fluid properties at these depths than compressed gases. Water-based drilling fluids may contain salts,[23] barite, polymers, lime, and gels as additives.
- **Oil-based:** For drilling at deep depths and/or the horizontal laterals of wells, operators may use oil-based mud to maintain more consistent fluid properties at the higher temperatures and pressures that are associated with deeper depths. Oil-based drilling fluids may use diesel oil and/or mineral oils and contain emulsifiers, barite, and gels as additives.
- **Synthetic-oil-based:** For drilling at deep depths and/or the horizontal laterals of wells, operators may also use synthetic-oil-based fluids which are similar to oil-based fluids. However, instead of using diesel oil and/or mineral oils, synthetic oil-based fluids use organic fluids (e.g., esters, polyeolefins, acetal, ether, and linear alkyl benzenes) that exhibit similar fluid properties as diesel and mineral oils. Synthetic-oil-based fluids have been referred as more environmentally friendly[24] than oil-based fluids but are also more expensive (162 DCN SGE01006; 17 DCN SGE01009).

When returned to the surface, drill cuttings (solids) are removed from the drilling fluids using shakers, desilters, and centrifuges. This results in drill cuttings and a wastewater stream, referred to as drilling wastewater. Drilling wastewater is either reused/recycled in a closed loop process or otherwise managed (e.g., transferred to a CWT facility) (124 DCN SGE00090; 178 DCN SGE00635).

Well drilling and construction typically lasts between five days and two months, depending on well depth and how familiar operators are with the specific formation. Figure B-7 shows that drilling time generally decreases as UOG operators become more familiar and efficient at drilling in a UOG formation (9 DCN SGE00503; 178 DCN SGE00635; 26 DCN SGE00516). Figure B-7 also compares drilling phase durations among UOG formations (e.g., Granite Wash requires 40 to 50 days for drilling while Barnett requires 10 or fewer days).

[23] The UOG industry may refer to water-based drilling fluids that contain salts as "salt mud."

[24] Using synthetic-oil-based drilling fluids results in a lower volume of wastewater that must be disposed of. They also have lower toxicities, lower concentrations of certain priority pollutants, lower bioaccumulation potential, and faster biodegradation rates than oil-based drilling fluid.



Source: 48 DCN SGE00693

Figure B-7. Length of Time to Drill a Well in Various UOG Formations as Reported for the First Quarter of 2012 through the Third Quarter of 2013

2.2 UOG Well Completion

After the well is drilled and constructed, the well completion process begins. "Well completion" is a general term used to describe the process of bringing a wellbore into production once drilling and well construction are completed (33 DCN SGE00984). The UOG well completion process involves many steps, including cleaning the well to remove drilling fluids and debris, perforating the casing that lines the producing formation,[25] inserting production tubing to transport the hydrocarbon fluids to the surface, installing the surface wellhead, stimulating the well (e.g., hydraulic fracturing), setting plugs in each stage, and eventually drilling the plugs out of the well. It also includes the flowback process, in which fluids injected during well stimulation return to the surface. The following two subsections describe the well stimulation and flowback processes that are common for UOG well completion.

[25] In some instances, open-hole completions may be used, where the well is drilled into the top of the target formation and casing is set from the top of the formation to the surface. Open-hole well completions leave the bottom of the wellbore uncased.

2.2.1 UOG Well Completion: Well Stimulation

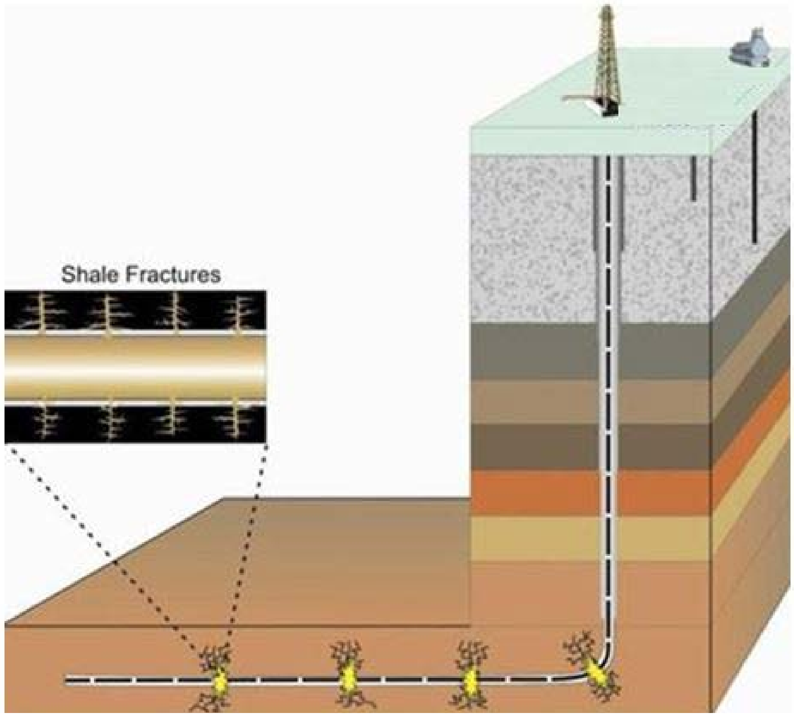
Because UOG resources are extracted from formations with low porosity and permeability, UOG wells are typically developed using more advanced stimulation technologies than traditionally used on COG wells to create higher permeability in the reservoir that allows operators to produce oil and gas economically. UOG well stimulation techniques include but are not limited to hydraulic fracturing, acidization, or a combination of fracturing and acidization (18 DCN SGE00966). The most common technique for UOG wells is hydraulic fracturing, discussed in the rest of this subsection (see Section B.3.3) (78 DCN SGE00010). Hydraulic fracturing of COG wells is becoming more common, but traditionally COG wells have been completed with open-hole techniques allowing the oil and/or gas resources to flow naturally (109 DCN SGE00345; 86 DCN SGE00533).

Operators typically fracture UOG wells in multiple stages to maintain the high pressures necessary to fracture the reservoir rock. Stages are fractured starting with the stage at the end of the wellbore and working back toward the wellhead. The number of stages depends on lateral length. Because horizontal laterals are 1,000 to 5,000 feet long, operators may use between eight and 23 stages for horizontal wells (177 DCN SGE00276). Vertical wells are typically only fractured with one stage (78 DCN SGE00010). A fracturing crew can typically fracture two to three stages per day when operating 12 hours per day or four to five stages per day when operating 24 hours per day.[26] Consequently, a typical well may take two to seven days to complete (87 DCN SGE00239; 124 DCN SGE00090). The following processes are performed for each stage:

- **Perforation**—Operators lower a perforation gun into the stage using a line wire. The perforation gun releases an explosive charge to create holes that penetrate approximately 1 foot into the formation rock in a radial fashion. These perforations create a starting point for the hydraulic fractures.
- **Hydraulic fracturing**—Operators inject fracturing fluids (e.g., water, sand, and other additives) down the wellbore to highly pressurize the formation to the point where small fractures are created in the rock (see Figure B-8).[27] See Section C.1 for information about fracturing fluid volumes and characteristics.
- **Stage plugging**—Once the stage is hydraulically fractured, a stage plug is inserted down the wellbore, separating it from additional stages until all stages are completed.

[26] The hours per day depends on the operator, local ordinances, and weather.

[27] The first stage is fractured with what is known as the pad fracture. The pad is the injection of high-pressure water and chemical additives without proppant (i.e., solid material designed to keep fractures open to allow gas to flow from the producing formation) to create the initial fractures into the formation. After the pad is pumped downhole, proppant is introduced to the fracturing fluid for the additional stages.



Source: 168 DCN SGE00604

Figure B-8. Hydraulic Fracturing Schematic

The components of fracturing fluid (i.e., base fluid, sand, chemical additives) are typically stored on the well pad before hydraulic fracturing begins. (See Section C.1 for a more detailed description of the fracturing fluid composition.) Operators may store fresh water in storage impoundments (see Figure B-9) or fracturing tanks that typically range from 10,500 to 21,000 gallons (250 to 500 barrels) in size (see Figure B-11) (190 DCN SGE00280; 179 DCN SGE00275; 177 DCN SGE00276). Operators that reuse/recycle UOG produced water in subsequent fracturing jobs typically store the reused/recycled wastewater in fracturing tanks and/or pits (190 DCN SGE00280). Operators typically have sand trucks and pump trucks onsite during the hydraulic fracturing process. The sand trucks contain the sand prior to mixing in the fracturing fluid and the pump trucks pump the fracturing fluid down the wellbore during each stage of fracturing.

Source: 179 DCN SGE00275

Figure B-9. Freshwater Impoundment

2.2.2 UOG Well Completion: Flowback Process

After all of the stages of a well have been hydraulically fractured, the stage plugs are drilled out of the wellbore and the pressure at the wellhead is released. Releasing the pressure allows a portion of produced water to return to the wellhead; this waste stream is often referred to as "flowback." Industry commonly refers to this as the flowback process (178 DCN SGE00635). The flowback consists of a portion of the fluid injected into the wellbore combined with formation water. At the wellhead, a combination of flowback water, sand, oil, and/or gas is routed through phase separators, which separate products from wastes. Industry uses different types of separators depending on a number of factors (e.g., formation, resource type). Figure B-10 shows an example of a separator used for dry gas production (i.e., only requires gas and water separation because there is no oil production).

Higher volumes of flowback water are generated in the beginning of the flowback process; flowback rates decrease as the well goes into the production phase. Operators typically store flowback in fracturing tanks onsite before treatment or transport offsite.[28] In addition to flowback, small quantities of oil and/or gas may be produced during the initial flowback process. The small quantities of produced gas may be flared; if the operator is using "green completions,"

[28] Fracturing tanks cannot be transported from one site to another when they contain wastewater. Wastewater is typically transported via trucks with capacities of about 4,200 to 5,000 gallons (100 to 120 barrel) or via pipe (178 DCN SGE00635).

the gas may instead be captured.[29] If oil is produced, oil/water separators may be used[30] or the oil may be recovered from the flowback water after it is transported offsite.

Source: 191 DCN SGE00625

Figure B-10. Vertical Gas and Water Separator

Flowback typically lasts from a few days to a few weeks (78 DCN SGE00010; 212 DCN SGE00011; 204 DCN SGE00622; 153 DCN SGE00592; 80 DCN SGE00286). At some wells, the majority of fracturing fluid may be recovered within a few hours (78 DCN SGE00010; 212 DCN SGE00011; 204 DCN SGE00622; 153 DCN SGE00592; 80 DCN SGE00286). A 2009 report published by the Ground Water Protection Council and ALL Consulting stated that operators recover between 10 and 70 percent of the fracturing fluid that they inject down the wellbore (78 DCN SGE00010; 153 DCN SGE00592; 80 DCN SGE00286). Section C.3.1 provides more details on flowback generation rates over time and fracturing fluid recovery percentages for specific UOG formations.

[29] On April 17, 2012, the U.S. EPA issued regulations, required by the Clean Air Act, requiring the natural gas industry to reduce air pollution by using green completions, or reduced emission completions. EPA has identified a transition period until January 1, 2015, to allow operators to locate and install green completion equipment (40 C.F.R. part 60 and 63).

[30] Operators sometimes use chemicals during the oil/water phase separation process.

Source: 191 DCN SGE00625

Figure B-11. Fracturing Tanks

2.3 <u>Production</u>

After the flowback process, the well begins producing oil and/or gas. During this production phase, UOG wells produce oil and/or gas and water. This water, called "long-term produced water" in this report, consists primarily of formation water and continues to be produced throughout the lifetime of the well, though typically at much lower rates than flowback (153 DCN SGE00592). Long-term produced water rates range from less than a barrel up to 4,200 gallons (100 barrels) per day (see Chapter C) and gradually decrease over the life of the well.[31] The rates vary with each well because they are dependent on formation characteristics and the completion success of the given well (see Chapter C for information about flowback and long-term produced water volumes and characteristics).

When the well enters the production phase, operators typically remove the fracturing tanks that were used during flowback and store long-term produced water in permanent above-ground storage tanks referred to as produced water tanks with capacities that range from 4,200 to 33,600 gallons (100 to 800 barrels) (see Figure B-12) (190 DCN SGE00280; 179 DCN SGE00275; 183 DCN SGE00636). The number of produced water tanks depends on the number of wells that are producing on the well pad and the volume of water produced by each well. Most operators configure water piping on the well pad so that each well has a designated produced water tank (178 DCN SGE00635; 177 DCN SGE00276).

[31] The life of an UOG well varies significantly by well. Some wells are expected to produce up to 40 years without further stimulation, while others may only produce economically for 10 years (80 DCN SGE00286).

Source: 179 DCN SGE00275

Figure B-12. Produced Water Storage Tanks

3 UOG WELL DRILLING AND COMPLETION ACTIVITY

The following subsections describe historical, current, and projections of future UOG drilling activity, including:

- Historical and current UOG well drilling activity
- Total estimated UOG resource potential
- Current and projections of future UOG well completions

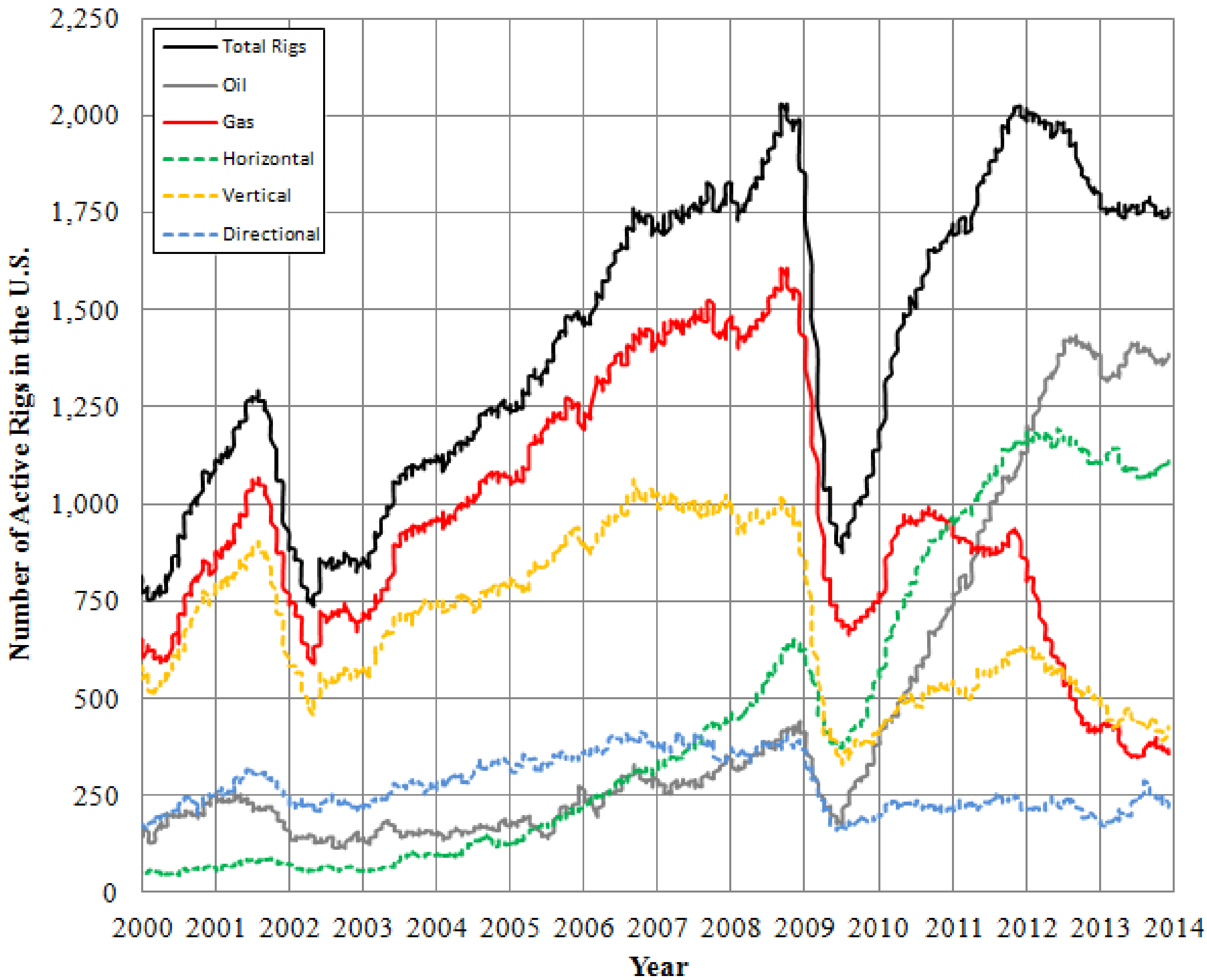
3.1 Historical and Current UOG Drilling Activity

Since 2000, hydraulic fracturing coupled with drilling directional and horizontal wellbores in unconventional formations has increased (209 DCN SGE01095). More recently, drilling has also increased in liquid-rich formations.[32] Baker Hughes, one of the world's largest oilfield services companies, periodically publishes location and other data for active U.S. rigs.[33] Figure B-13 shows Baker Hughes' estimates of total number of active drilling rigs in the United

[32] Liquid-rich formations are those that either primarily produce oil or primarily co-produce natural gas with gas condensates (i.e., hydrocarbons such as ethanes, propanes, and butanes). When gas condensates are depressurized at the wellhead, they condense into a liquid phase.

[33] Baker Hughes obtains data in part from RigData, a company that sells rig and well data. Rig data Baker Hughes publishes are reported in major newspapers and journals (e.g., *Oil and Gas Journal*) and are used by the industry as an indicator for demand of oil and gas equipment.

States between January 2000 and November 2013 and shows drilling trajectory (i.e., directional, horizontal, vertical) and product type (i.e., oil, gas). These counts include rigs that are drilling for CBM and COG. Both horizontal drilling and oil well drilling have increased since 2000. (As of November 15, 2013, 63 percent of rigs were drilling horizontal wells compared to 6 percent in January 2000.[34]) In 2009, horizontal well drilling surpassed vertical well drilling for the first time in the United States. Shortly after, in 2011, oil well drilling surpassed gas for the first time since 1993 (7 DCN SGE00504).



Source: 48 DCN SGE00693

Figure B-13. Number of Active U.S. Onshore Rigs by Trajectory and Product Type over Time[35]

Table B-2 shows the active drilling rigs in the United States by formation or basin, broken down by well trajectory and resource type, as of November 2013. Based on data reported by Baker Hughes and rig counts reported in other literature, the majority of rigs were drilling

[34] Another 13 percent of wells were being drilled directionally in the United States as of November 8, 2013.

[35] The sharp decrease in active drilling rigs observed in 2009 is likely attributed to the sudden drop in natural gas and crude oil prices also experienced in 2009 (31 DCN SGE00989).

into unconventional formations at this time (8 DCN SGE00502; 159 DCN SGE00595). Where Baker Hughes did not specify the formation being drilled, counts may include a mixture of rigs that are drilling for UOG, CBM, and COG. In 2012, nearly 1,800 active rigs drilled about 36,000 wells (9 DCN SGE00503).

Table B-2. Active Onshore Oil and Gas Drilling Rigs by Well Trajectory and Product Type (as of November 8, 2013)

Basin[b]	Formation[b]	Resource Type[b]	Gas Rigs by Well Trajectory				Oil Rigs by Well Trajectory[a]				Total Rigs
			Directional	Horizontal	Vertical	Total Gas	Directional	Horizontal	Vertical	Total Oil	
Permian	—[c]	Mix	0	6	1	7	21	206	235	462	469
Other[d]	—[c]	Mix	48	20	20	88	55	139	85	279	367
Western Gulf	Eagle Ford	Shale	0	26	0	26	17	174	9	200	226
Williston	—[c,e]	Mostly shale[e]	0	0	0	0	16	155	4	175	175
Appalachian	Marcellus	Shale	10	67	8	85	0	0	0	0	85
Anadarko	Mississippi Lime	Tight	0	9	0	9	2	58	6	66	75
Anadarko	Granite Wash	Tight	0	8	0	8	0	50	2	52	60
Denver J.	Niobrara	Shale	0	18	0	18	3	25	5	33	51
Anadarko	Woodford[f]	Shale	1	17	0	18	2	27	3	32	50
TX-LA-MS Salt	Haynesville	Shale	0	38	0	38	0	2	0	2	40
Fort Worth	Barnett	Shale	0	18	0	18	0	9	9	18	36
Appalachian	Utica	Shale	2	17	0	19	0	15	2	17	36
Arkoma	Fayetteville	Shale	0	9	0	9	0	0	0	0	9
Total			**61**	**253**	**29**	**343**	**116**	**860**	**360**	**1,336**	**1,679**

Sources: 48 DCN SGE00693

a—Oil rigs include six “miscellaneous” rigs reported by Baker Hughes (8 DCN SGE00502).

b—Baker Hughes (8 DCN SGE00502) reported a mixture of basins and formations. The EPA classified them by resource type (i.e., shale, tight) when specific formations were reported. When formations were not reported, the EPA classified the resource type as a “mix” of resources (conventional, tight, shale).

c—Baker Hughes reported basin as opposed to formation for these areas. Therefore, these areas may include rigs drilling in conventional and unconventional formations.

d—The majority of the “Other” rigs were drilling in Texas, Louisiana, Wyoming, California, Utah, and Colorado. The remaining rigs in the “Other” category were distributed evenly throughout the United States.

e—The majority of these rigs are expected to have been drilling in the Bakken shale formation based on rig counts reported by the EIA (159 DCN SGE00595).

f—This formation includes the Woodford-Cana, Arkoma Woodford, and Ardmore Woodford formations.

3.2 UOG Resource Potential

Assessments by the U.S. Geological Survey (USGS) and the EIA show substantial potential for new UOG wells. Using the USGS and EIA assessments, this section quantifies how many new UOG wells may be drilled in the future (i.e., new well potential) to estimate the potential number of new UOG extraction wastewater sources. The EIA also calculates new well potential in its AEO but only for several sub-formations.[36] The EPA used the EIA methodology to calculate new well potential for all UOG formations.[37] This analysis is documented in more detail in a separate memorandum titled *Data Compilation Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction* (48 DCN SGE00693; 50 DCN SGE00693.A02).

The two EIA-reported parameters that the EPA used to calculate new well potential are described below. The EIA's estimates of resource potential are primarily based on geological characteristics published by the USGS, which in turn rely on historical production data from existing wells and the technology deployed at the time of assessment. However, the EIA adjusts these estimates annually to account for the ongoing changes in drilling and completion practices and to account for formations not yet assessed by the USGS (32 DCN SGE00988; 31 DCN SGE00989).

- **Estimated ultimate recovery per well (EUR)**—EUR is the quantity of oil and/or gas that is produced by a single well over its life.
- **Technically recoverable resources (TRR)**—The TRR is the quantity of oil and/or gas producible from a geological formation using current drilling and completion technology. The EIA's TRR estimates are functions of total formation geographic area (square miles), the portion of formation land area that can be developed for oil and gas extraction, average well spacing assuming that the formation is fully developed, and EUR per well. TRR is the sum of proven reserves and unproven resources.[38]

To evaluate new well potential, the EPA calculated new well potential for each formation or sub-formation by dividing the TRR by the EUR. Table B-3 summarizes the total new well potential the EPA calculated for the four UOG resource types.[39] It also shows the approximate number of current wells based on the EPA's analysis of Drillinginfo's (DI) Desktop® well database (29 DCN SGE00520). Appendix F provides EUR and TRR on a formation basis based on this analysis. To calculate total TRR and new well potential by resource type, the EPA

[36] For example, the Assumptions to the 2014 AEO reported new well potential for several, but not all, Bakken sub-formations: 29,186 wells. The EPA estimated approximately 28,562 new Bakken wells for the same Bakken sub formations. Differences between EIA and EPA new well potential are due to rounding (32 DCN SGE00988).

[37] These estimates do not factor in future changes to TRR estimates by the EIA, advances in drilling technology, or economic conditions that ultimately affect how many wells UOG operators drill over time (31 DCN SGE00989; 32 DCN SGE00988).

[38] Proven reserves are resources that are currently developed commercially or have been demonstrated with reasonable certainty to be recoverable in future years under existing economic conditions and current technologies. Unproven resources are resources that have been confirmed by exploratory drilling but are not yet commercially developed.

[39] These estimates only include shale and tight oil and gas resources. It does not include CBM or COG.

summed the TRR and the new well potential for all formations in each resource type shown in Table F-2 and Table F-3. The results presented in Table B-3 show that the UOG new well potential is much greater than the active well count. The EPA estimates that approximately 2.2 million potential new UOG wells—with associated extraction wastewater—may be drilled in the future.

Table B-3. UOG Potential by Resource Type as of January 1, 2012

Resource Type	Weighted Average Oil EUR (MMbls per well)	Weighted Average Gas EUR (Bcf per well)	Total Oil TRR (MMbls)	Total Gas TRR (Bcf)	Total New Well Potential (Beginning in 2012)	2010-2011 Active Well Count[b]
Shale gas	0.007	0.543	6,200	501,500	923,000	H: 22,400 D: 1,820 V: 15,100 U: 15,300
Shale oil	0.079	0.099	26,300	33,100	333,000	
Tight gas	0.006	0.483	4,200	352,200	729,000	H: 5,620 D: 9,230 V: 59,600 U: 32,800
Tight oil	0.105	0.076	22,500	16,400	215,000	
All UOG	0.027	0.411	59,200	903,200	2,200,000	H: 28,000 D: 11,100 V: 74,700 U: 48,100

Sources: 48 DCN SGE00693

a—Gas production from shale and tight oil resources is associated gas that is produced simultaneously with oil.
b—Well counts are based on ERG's *Analysis of DI Desktop*® memorandum (45 DCN SGE00963). These well counts may not be all-inclusive.

Abbreviations: MMbls-million barrels; Bcf-billion cubic feet of gas; EUR—estimated ultimate recovery (per well); TRR—technically recoverable resources; H—horizontal; D—directional; V—vertical; U—trajectory unknown

3.3 Current and Projections of Future UOG Well Completions

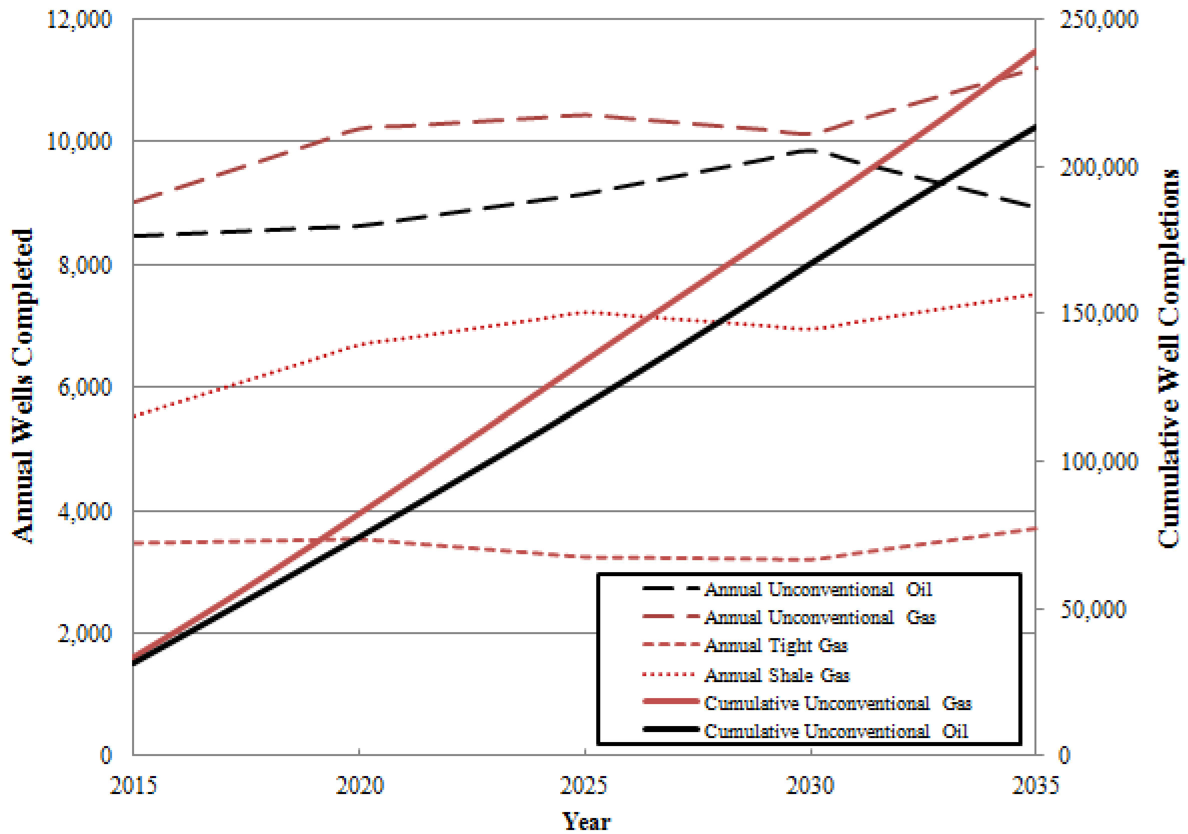
In 2012 alone, more than 22,000[40] oil and gas wells were hydraulically fractured nationwide (199 DCN SGE00585). As previously explained, hydraulic fracturing is currently the most popular well stimulation technique for UOG wells. A survey conducted by the American Petroleum Institute (API) and the American Natural Gas Alliance (ANGA) shows that, as of 2010, nearly all unconventional wells were being completed using hydraulic fracturing (146 DCN SGE00291).[41] Operators may also refracture existing oil and gas wells. Based on a national database maintained by IHS, Inc., 0.13 to 0.35 percent of well completions involving hydraulic fracturing from 2000 to 2010 were reported as refracturing of existing oil and gas wells (210

[40] The actual number of wells fractured in 2012 is greater than 22,000 because this number is based on FracFocus data and some states where fracturing is common (e.g., Michigan) did not yet require reporting to FracFocus in 2012.

[41] This survey included well completion information for 5,307 well completions in 2010, consisting of a mixture of conventional and unconventional wells. The survey results showed that more than 96 percent of tight gas wells and 99 percent of shale gas wells surveyed were hydraulically fractured. The survey also showed that 69 percent of conventional wells were hydraulically fractured.

DCN SGE01095.A09). A more recent survey of 205 UOG operators conducted by the Petroleum Equipment Suppliers Association (PESA)[42] shows that in 2012 and 2013 approximately 10 percent of well completions involving hydraulic fracturing were refracturing of existing oil and gas wells (136 DCN SGE00575).

In 2012, IHS, Inc. estimated the total number of UOG wells that UOG operators may complete through 2035 (94 DCN SGE00728). The EPA generated Figure B-14 using data published by IHS (48 DCN SGE00693). The figure shows the projected number of UOG wells[39] completed annually and cumulatively. Unconventional gas is further broken down into tight gas and shale gas. The projections estimated by IHS show a gradual increase in annual UOG well completions through 2035.



Source: 48 DCN SGE00693

Figure B-14. Projections of UOG Well Completions

[42] The PESA represents the energy industry's manufacturers and oilfield service and supply companies. Its mission is to promote and advocate for policies that will support the oilfield service sector's continued job creation, technological innovation, and economic stability.

Chapter C. UNCONVENTIONAL OIL AND GAS EXTRACTION WASTEWATER VOLUMES AND CHARACTERISTICS

Since 2000, horizontal drilling and hydraulic fracturing of UOG resources has increased dramatically (209 DCN SGE01095). The EIA, in its 2014 AEO, projects that, within the next 30 years, the majority of the country's natural gas will come from unconventional resources and unconventional oil production will continue to increase substantially (31 DCN SGE00989). Consequently, industry experts expect UOG produced water volumes to continue to increase (34 DCN SGE00708; 98 DCN SGE00479; 95 DCN SGE00722; 141 DCN SGE00768.A01; 72 DCN SGE00768.A25).

This chapter discusses UOG extraction wastewater volumes and characteristics. The EPA is proposing to define "UOG extraction wastewater" as sources of wastewater pollutants associated with production, field exploration, drilling, well completion, or well treatment.[43] This includes the following sources:

- Produced water—the water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas. This can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process. Based on the stage of completion and production the well is in, produced water can be further broken down into the following components:
  - Flowback—the wastewater generated by UOG wells during the flowback process of well completion. After the hydraulic fracturing procedure is completed and pressure is released, the direction of fluid flow reverses, and the fluid flows up through the wellbore to the surface. The water that returns to the surface is commonly referred to as "flowback."
  - Long-term produced water—the wastewater generated by UOG wells during the production phase after the initial flowback process. Long-term produced water continues to be produced throughout the lifetime of the well.
- Drill cuttings—the particles generated by drilling into subsurface geologic formations and carried out from the wellbore with the drilling fluid (mud).
- Drilling wastewater—the liquid waste stream separated from recovered drilling fluid (mud) and drill cuttings during the drilling process. Drilling fluid is the circulating fluid used in the rotary drilling of wells to clean and condition the hole and to counterbalance formation pressure.
- Produced sand—the slurried particles used in hydraulic fracturing, the accumulated formation sands, and scales particles generated during production. Produced sand also includes desander discharge from the produced water waste stream, as well as blowdown of the water phase from the produced water treatment system.

[43] Stormwater is not considered a source of UOG extraction wastewater. In general, no permit is required for discharges of stormwater from any field activities or operations associated with oil and gas production, except as specified in 40 C.F.R. part 122.26(c)(1)(iii) for discharges of a reportable quantity or that contribute to a violation of a water quality standard.

The EPA identified drilling wastewater and produced water as the major sources of wastewater pollutants associated with UOG extraction, so these wastewaters are described further below. The following subsections discuss volumes and chemical constituents found in fracturing fluid typically used by UOG operators and volumes and characteristics of drilling wastewater, flowback, and long-term produced water generated by UOG operations. The EPA identified this information from existing data sources, including state and federal agency databases, journal articles and technical papers, technical references, industry/vendor telephone calls, industry site visits, and meetings with industry. The EPA reported the data exactly as reported in existing literature throughout Chapter C. In some instances, the EPA compiled the existing data into a separate document to compile and analyze the data. These separate memoranda, referenced throughout Chapter C, are titled *Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation* (56 DCN SGE00724) and *Data Compilation Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction* (48 DCN SGE00693).

Section C.1 discusses the characteristics of fracturing fluid,[44] Section C.2 discusses typical volumes of UOG extraction wastewater, and Section C.3 presents constituents that are typically found in UOG extraction wastewater. Section C.3 extensively discusses TDS, a parameter that is often used to characterize UOG extraction wastewater because it provides a measure of dissolved matter including salts (e.g., sodium, chloride, nitrate), metals, minerals, and organic material (1 DCN SGE00046). Data in Section C.3 show that sodium chloride makes up the majority of TDS in UOG produced water. The data also show that chloride contributes heavily to the makeup of TDS in UOG drilling wastewater. TDS is not a specific chemical, but is defined as the portion of solids that pass through a filter with a nominal pore size of 2.0 µm or less as specified by Standard Method 2540C-1997.[45] Because TDS in UOG produced water primarily consists of inorganic salts and other ionic species, conductivity measurements may also be used to estimate TDS.[46] High measurements of specific conductivity are indicative of high TDS concentrations.

TDS and chloride are potential concerns in the management of UOG extraction wastewater because of the high concentrations of these parameters in the wastewater. UOG produced water can have TDS concentrations up to 400,000 mg/L, which is over 10 times the concentration of TDS typically found in seawater (i.e., 35,000 mg/L). Chapter D discusses UOG extraction wastewater management and disposal practices. Section D.3 discusses reusing/recycling UOG extraction wastewater in hydraulic fracturing and the different factors (e.g., pollutant concentrations) that operators consider when reusing/recycling UOG extraction wastewater. Section D.5 discusses the problems that a POTW may experience if high concentrations of TDS and other UOG extraction wastewater constituents are present in POTW influent.

[44] The type of fracturing fluid and total fracturing fluid volume may dictate the characteristics of UOG produced water and are therefore described in this chapter.

[45] 40 C.F.R. part 136 lists standard method 2540C as an approved test method for TDS.

[46] The electrical conductivity of water is directly related to the concentration of dissolved ionized solids in the water.

1 FRACTURING FLUID CHARACTERISTICS

As discussed in Section B.2.2, most UOG resources (e.g., tight oil, shale gas) are stimulated using hydraulic fracturing. Hydraulic fracturing of UOG resources typically requires high volumes of fracturing fluid, consisting of a base fluid mixed with proppant (e.g., sand) and chemicals. The quantity of each fracturing fluid component varies by operator, basin, formation, and resource type. The remainder of this subsection discusses the sources used for base fluid, concentrations of chemical additives, and observed constituents in fracturing fluids.

1.1 Base Fluid Composition

The primary component of fracturing fluid is the base fluid to which proppant (sand) and chemicals are added. Fracturing fluids are typically water-based, though cases of non-aqueous fracturing fluids are documented in the literature (e.g., compressed nitrogen, propane) (209 DCN SGE01095). Base fluid typically consists of only fresh water (surface, groundwater, or municipal water) or a mixture of fresh water, reused/recycled UOG produced water, and/or other sources (e.g., treated municipal wastewater, groundwater) (126 DCN SGE00639; 136 DCN SGE00575). The PESA reports the following percentages of UOG operators using each water source as fracturing fluid in the United States (136 DCN SGE00575):

- Surface water (e.g., rivers, lakes) (40 percent)
- Groundwater (36 percent)
- City/ municipal water[47] (16 percent)
- Recycled UOG produced water (7 percent)[48]
- Industrial wastewater (1 percent)

Table C-1 shows the composition of base fluid for basins and/or formations with available data. Fresh water sources are those generally characterized by having low concentrations of dissolved salts and other TDS (e.g., ponds, lakes, rivers, certain underground aquifers). Brackish sources are those with more salinity than freshwater, but not as much as seawater (e.g., other industrial wastewater, certain groundwater aquifers). Fresh water is the most common source of base fluid across all basins. As shown in Table C-1, brackish sources are used more often in arid regions (e.g., the Permian and Gulf Coast basins in Texas and New Mexico). For basins/formations where the EPA identified projected data in addition to historic data, the EPA created a separate set of columns for each basin/formation combination. Projected percentages for the year 2020 are reported parenthetically in Table C-1.

In general, the fraction of base fluid that can be composed of UOG produced water is limited by two factors (125 DCN SGE00556; 148 DCN SGE00710):

[47] The PESA does not specify whether this water source is potable drinking water or treated municipal effluent (136 DCN SGE00575).

[48] The amount of UOG wastewater that is reused/recycled in fracturing fluid varies significantly by UOG formation. See Section D.2 for more information about UOG wastewater reuse/recycle.

- **Produced water volume**—When large volumes of flowback and long-term produced water are generated by other UOG wells in the area, reuse/recycle wastewater can make up a larger portion of base fluid water on average.
- **Produced water quality**—When the concentration of TDS in UOG produced water rapidly increases after fracturing, it may have less potential for reuse/recycle as a source of base fluid to fracture another well (148 DCN SGE00710).

Table C-1. Sources for Base Fluid in Hydraulic Fracturing

Basin	UOG Formation	Resource Type	Percentage of Total Base Fluid Used for Hydraulic Fracturing[a]		
			Fresh Water[b]	Brackish Water[b]	Reused/Recycled UOG Produced Water
All California Basins	All formations	shale and tight	96	0	4
Anadarko	All formations	shale and tight	50 (40)	30 (30)	20 (30)
Appalachian	Marcellus (PA)	shale	82 to 90	0	10 to 18
	Marcellus (WV)	shale	77 to 83[c,d]	--[c]	6 to 10
Arkoma	Fayetteville	shale	70	0	30
Fort Worth	Barnett	shale	92 (75)	3 (15)	5 (10)
Gulf Coast	Eagle Ford	shale	80 (50)	20 (40)	0 (10)
Permian (Far West)	All formations	shale and tight	20 (20)	80 (30)	0 (50)
Permian (Midland)	All formations	shale and tight	68 (35)	30 (40)	2 (25)
TX-LA-MS	All formations	shale and tight	95 (90)	0 (0)	5 (10)
Nationwide	All formations	shale and tight	40	53	7

Sources: 48 DCN SGE00693

a— Projected data for the year 2020 are shown parenthetically which were reported as the "most likely" scenario by Nicot et al. 2012 (126 DCN SGE00639).

b— Fresh water is naturally occurring water on the Earth's surface. Examples include ponds, lakes, rivers and streams, and certain underground aquifers. Fresh water is generally characterized by having low concentrations of dissolved salts. Brackish water is water that has more salinity than fresh water, but not as much as seawater. Example sources include certain underground aquifers, effluent from publicly owned treatment plants (POTWs), and wastewater from other industries.

c—In addition to the 77 to 83 percent fresh water reported for the Marcellus shale in WV, 6 to 17 percent of base fluid was reported as "purchased water" and 1 to 3 percent was reported as groundwater both of which could be fresh or brackish. Neither of these values are included in this table.

d—Hansen et al. 2013 (84 DCN SGE00532) reported this data as "surface water".

"—" indicates no data.

1.2 Additives

In addition to base fluid, operators add proppant and chemicals to adjust the fracturing fluid properties. Proppant generally makes up 10 percent or less of the total fracturing fluid by mass. Chemical additives in total typically make up less than 0.5 percent of the total fracturing fluid by mass (78 DCN SGE00010). The additives and the quantity of additives used in fracturing fluid depend on the formation geology, base fluid characteristics, and UOG operator (201 DCN SGE00721; 3 DCN SGE00070; 70 DCN SGE00780; 73 DCN SGE00781). Fracturing fluid additives are constantly evolving as UOG operators determine the most efficient composition to use for each fracture job. There are two general types of water-based fracturing fluids:

- **Slickwater fracturing** fluids consist of small quantities of friction reducer, biocides, scale inhibitors, surfactants, and propping agents. Operators generally use slickwater designs to fracture dry natural gas producing formations (148 DCN SGE00710; 40 DCN SGE00705).
- **Gel fracturing** fluids include higher quantities of gels to increase fluid viscosity that enables the fluid to carry higher concentrations of propping agents into the formation. Using gel fracturing fluids requires less total base fluid volume than using slickwater fracturing fluids, but gel fracturing fluids contain more additives and proppant. Consequently, gel fracturing fluids are more complex than slickwater fracturing fluids and are more sensitive to the quality of base fluid (148 DCN SGE00710; 40 DCN SGE00705). Operators generally use gel fracturing fluids to fracture liquid-rich formations (40 DCN SGE00705).

In 2015, the EPA's Office of Research and Development (ORD) released a report summarizing additives used by operators based on public disclosures to FracFocus[49] (201 DCN SGE00721). In addition, several sources have published information regarding fracturing fluid additives and their uses in hydraulic fracturing (3 DCN SGE00070; 70 DCN SGE00780; 73 DCN SGE00781; 18 DCN SGE00966). Table C-2 shows specific additives used by operators categorized by purpose. Many additives can have multiple purposes depending on the exact design of the fracturing fluid. Table C-3 shows concentrations of the most common chemicals identified by operators in the FracFocus public disclosures, summarized in the EPA report, for hydraulically fractured gas and oil wells.

Table C-2. Fracturing Fluid Additives, Main Compounds, and Common Uses

Additive Type[a]	Common Compound(s)[b]	Purpose
Acid	Hydrochloric acid; Muriatic acid	Removes cement and drilling mud 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	Peroxydisulfates; salts	Reduces the viscosity of the fluid by "breaking down" the gelling agents in order to release proppant into fractures and enhance the recovery of the fracturing fluid.

[49] Operators submit reports for individual wells to FracFocus. These reports include date of completion, well type (oil, gas), total fracturing fluid volume, well API number, well depth, location coordinates, and the concentrations of additives. These reports mostly represent wells completed in UOG formations but may also include some in conventional and coalbed methane formations.

Table C-2. Fracturing Fluid Additives, Main Compounds, and Common Uses

Additive Type[a]	Common Compound(s)[b]	Purpose
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; methanol	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	Adjusts and controls the pH of the fluid in order to maximize the effectiveness of other additives such as crosslinkers.
Proppant	Quartz; sand; silica	Used to hold open the hydraulic fractures, allowing the gas or oil to flow to the production well.
Scale inhibitor	Ethylene glycol	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: 201 DCN SGE00721; 3 DCN SGE00070; 70 DCN SGE00780; 73 DCN SGE00781; 18 DCN SGE00966

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.

Table C-3. Most Frequently Reported Additive Ingredients Used in Fracturing Fluid in Gas and Oil Wells from FracFocus (2011-2013)

Specific Constituents	CAS Number	Maximum Concentration in Hydraulic Fracturing Fluid (% by mass)					
		Gas[a]			Oil[b]		
		Number of Reported Uses	Median Concentration	5th to 95th Percentile Concentration	Number of Reported Uses	Median Concentration	5th to 95th Percentile Concentration
Hydrochloric acid	7647-01-0	12,351	0.078	0.0063–0.67	10,029	0.29	0.013–1.8
Guar gum	9000-30-0	3,586	0.10	0.00057–0.38	9,110	0.17	0.027–0.43
Phenolic resin	9003-35-4	—	—	—	3,109	0.13	0.019–2.0
Distillates, petroleum, hydrotreated light	64742-47-8	11,897	0.017	0.0021–0.27	10,566	0.087	0.00073–0.39
Ethylene glycol	107-21-1	5,493	0.0061	0.000080–0.24	10,307	0.023	0.00086–0.098
Potassium hydroxide	1310-58-3	—	—	—	7,206	0.013	0.000010–0.052
Methanol	67-56-1	12,269	0.0020	0.000040–0.053	12,484	0.022	0.00064–0.16
Ethanol	64-17-5	6,325	0.0023	0.00012–0.090	3,536	0.026	0.000020–0.16
Saline	7647-14-5	3,608	0.0091	0–0.12	3,692	0.0071	0–0.27
Sodium hydroxide	1310-73-2	4,656	0.0036	0.000020–0.088	8,609	0.010	0.00005–0.075
Glutaraldehyde	111-30-8	5,635	0.0084	0.00091–0.023	5,927	0.0065	0.00027–0.020
Peroxydisulfuric acid, diammonium salt	7727-54-0	4,618	0.0045	0.000050–0.045	10,350	0.0076	0.00028–0.067
Solvent naphtha, petroleum, heavy arom.	64742-94-5	3,287	0.0044	0.000030–0.030	3,821	0.0060	0–0.038
2-Butoxyethanol	111-76-2	3,325	0.0035	0.000010–0.041	4,022	0.0053	0–0.17
Isopropanol	67-63-0	8,008	0.0016	0.000010–0.051	8,031	0.0063	0.00007–0.22
Acetic acid	64-19-7	3,563	0.0025	0–0.028	4,623	0.0047	0–0.047
Citric acid	77-92-9	4,832	0.0017	0.000050–0.011	3,310	0.0047	0.00016–0.024
2,2-Dibromo-3-nitrilopropionamide	10222-01-2	3,668	0.0018	0.000070–0.022	—	—	—
Naphthalene	91-20-3	3,294	0.0012	0.0000027–0.0050	—	—	—
Propargyl alcohol	107-19-7	5,811	0.000070	0.000010–0.0016	5,599	0.00022	0.000030–0.0030

Source: 48 DCN SGE00693

a—Represents 17,035 FracFocus disclosures for gas wells.
b—Represents 17,640 FracFocus disclosures for oil wells.

"—" indicates this additive was not commonly reported.

1.3 Fracturing Fluids

Fracturing fluid is the final mixture of base fluid and additives. Its total volume depends on the well trajectory (i.e., vertical, directional, horizontal) and the type of fracturing fluid used (e.g., gel, slickwater) (209 DCN SGE01095). Operators fracture UOG wells using 50,000 to over 10 million gallons (1,200 to over 238,000 barrels) of fracturing fluid per well along with up to millions of pounds of sand (i.e., proppant). Operators typically fracture horizontal wells in eight to 23 stages, using between 250,000 and 420,000 gallons (6,000 and 10,000 barrels) of fracturing fluid per stage (190 DCN SGE00280). Literature reports that tight oil and gas wells typically require less fracturing fluid than shale oil and gas wells (86 DCN SGE00533). Typical volumes of fracturing fluid vary by UOG formation, well trajectory, number of stages, and resource type and are provided in Section C.2.

The concentrations of TDS in fracturing fluid are often low (<20,000 mg/L) compared to levels found in UOG produced water, which suggests that the majority of the TDS in UOG produced water is contributed by the formation (see Section C.3) (16 DCN SGE00110, 85 DCN SGE00414). Other constituents, such as total organic carbon (TOC) and biochemical oxygen demand (BOD_5), have been found at higher concentrations in fracturing fluid than in flowback and long-term produced water. For example, one study of Marcellus UOG produced water found median concentrations of BOD_5 in fracturing fluid of about 1,700[50] mg/L but BOD_5 in the corresponding flowback and long-term produced water of 300[51] mg/L or less on average (85 DCN SGE00414). As indicated in Table C-2 and Table C-3, organic materials (which contribute to BOD_5 and TOC) are typical chemical additives in fracturing fluid (85 DCN SGE00414).

2 UOG Extraction Wastewater Volumes

As explained previously, UOG wells generate three main types of wastewater over the life of the well: drilling wastewater, flowback, and long-term produced water (these latter two are collectively referred to as produced water). These wastewater streams' flow rates and total volumes generated per well vary based on several factors, including:

- Time since flowback commenced
- Resource type (e.g., shale oil, tight gas)
- Specific geology properties (e.g., presence of naturally occurring water)
- Well trajectory (i.e., horizontal, directional, vertical)

The following two subsections quantify wastewater volumes generated during the UOG well development process. Section C.2.1 summarizes general trends in UOG extraction wastewater volumes for each part of the well development process by resource type and well

[50] This study reported 1,700 mg/L as the median concentration based on 19 samples. The overall range of BOD was 4.3 to 47,400 mg/L.

[51] This study reported 330 mg/L as the median concentration based on 19 flowback samples. The overall range of BOD was 30 to 1,440 mg/L.

trajectory. Section C.2.2 provides detailed produced water volumes by UOG formation and well trajectory.[52]

2.1 UOG Extraction Wastewater Volumes by Resource and Well Trajectory

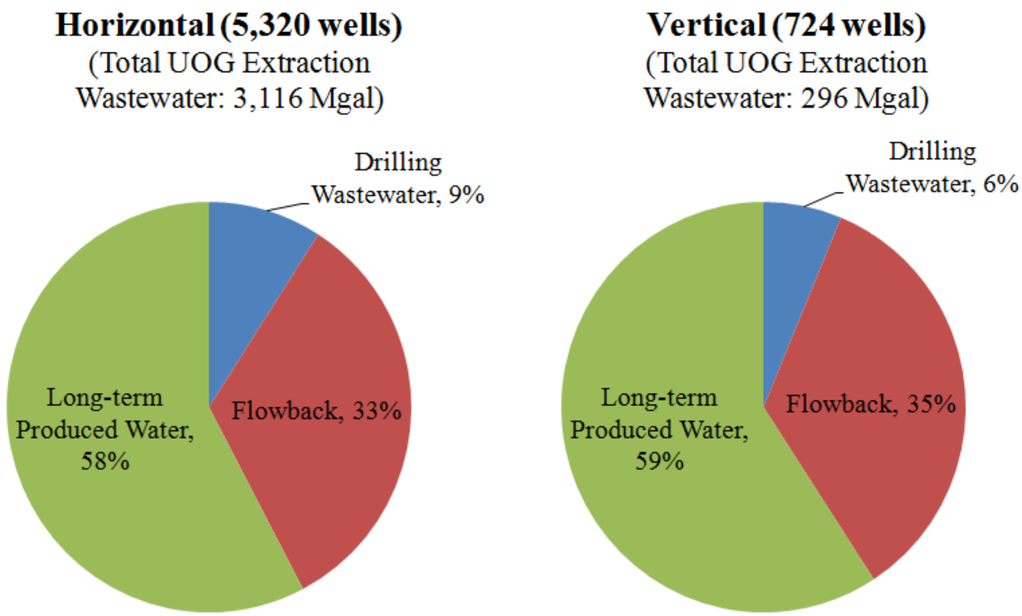
This section quantifies the volumes of UOG extraction wastewater generated, on a per well basis, for the following three wastewater components:

- Drilling wastewater
- Flowback
- Long-term produced water

Flowback and long-term produced water are the largest volumes of UOG extraction wastewater. Figure C-1 shows a breakdown of UOG extraction wastewater volumes generated from Marcellus shale wells in Pennsylvania based on data from PA DEP's statewide waste production reports for all wells active between 2004 and 2013 (46 DCN SGE00739). This trend varies by formation and, sometimes, within formations. However, a general rule of thumb for all UOG formations is that the total volume of UOG produced water (i.e., flowback, long-term produced water) generated by a well over its lifetime is approximately 50 percent flowback and 50 percent long-term produced water—despite the fact that flowback is generated over less than 30 days and long-term produced water is generated over the well life, which may be more than 10 years (94 DCN SGE00728).[53]

[52] Section C.2.2 does not include drilling wastewater volumes by formation and drill type because EPA identified less detailed data for drilling wastewater volumes compared to UOG produced water volumes.

[53] Figure C-1 shows that long-term produced water is more than 50 percent of total UOG produced water for Marcellus shale wells likely because Marcellus wells generate relatively lower flowback volumes compared to other UOG formations (see Table C-8).



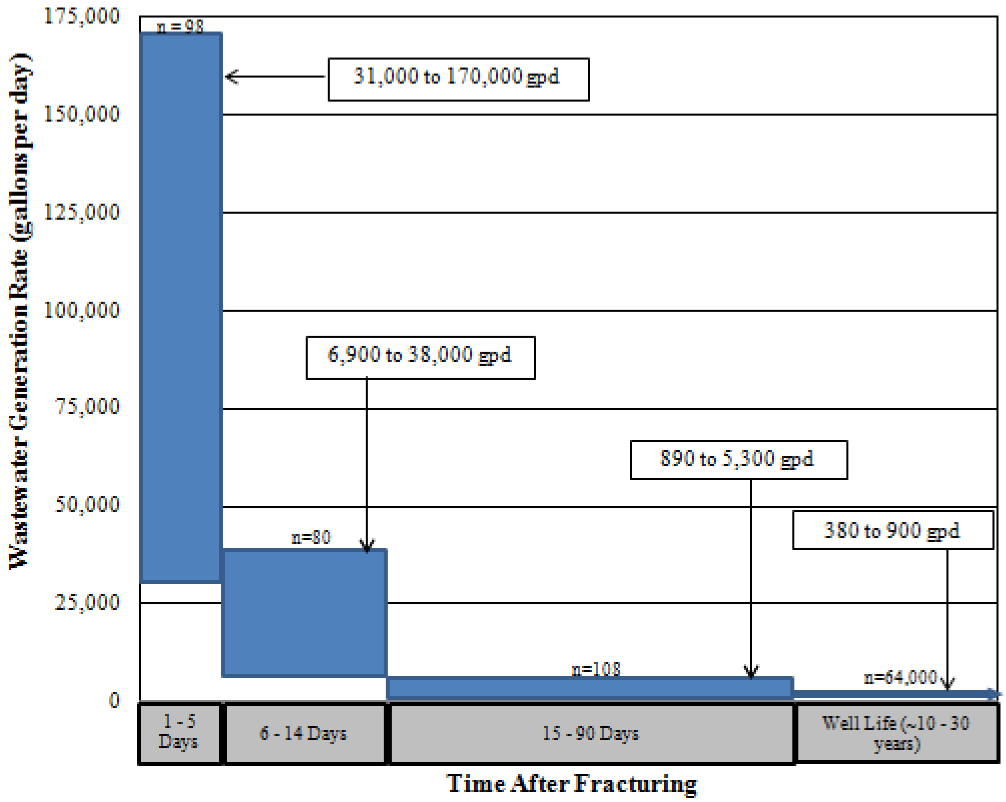
Sources: 46 DCN SGE00739

Figure C-1. UOG Extraction Wastewater Volumes for Marcellus Shale Wells in Pennsylvania (2004–2013)

Figure C-2 shows the quantities of produced water (i.e., flowback, long-term produced water) generated from UOG wells from the time of well completion to the end of the well life. The produced water generation rates reflect aggregated data from multiple UOG formations;[54] "n" is the number of data points for each time period.[55] As shown in the figure, UOG produced water generation rates are highest immediately after well completion, when there is little or no oil and gas production (flowback). During the transition from the flowback process to production (within weeks of well completion), produced water generation rates decrease significantly and eventually level out. During production, produced water generation rates gradually decrease over the life of the well (long-term produced water).

[54] As explained in Chapter B, the length of the flowback process is variable. Literature generally reports it as 30 days or less (83 DCN SGE00532). Other operators report it as only lasting five days (151 DCN SGE00350).

[55] Data for the first 90 days represent the Marcellus, Barnett, Woodford, Codell-Niobrara, Bakken, and Fayetteville UOG formations. Data beyond 90 days (long-term produced water) are from Table C-8.



Source: 56 DCN SGE00724

Figure C-2. Ranges of Typical Produced Water Generation Rates over Time After Fracturing

2.1.1 Drilling Wastewater

Volumes of drilling wastewater typically increase with the length of the wellbore. For example, a vertical well will typically produce a smaller volume of drilling wastewater than a horizontal well drilled into the same formation, because the latter requires additional drilling fluid to complete the horizontal lateral (46 DCN SGE00739). Table C-4 illustrates this trend for UOG wells drilled into the Marcellus formation in Pennsylvania.

Table C-4. Median Drilling Wastewater Volumes for UOG Horizontal and Vertical Wells in Pennsylvania

Well Trajectory	Median Drilling Fluid Volume per Well (gallons)	Range of Drilling Fluid Volume per Well (gallons) [a]	Typical Total Measured Depth [b]	Number of Data Points
Horizontal	46,000	3,200–210,000	10,000–11,000	3,055
Vertical	37,000	5,000–210,000	6,000–7,000	209

Source: 46 DCN SGE00739

a— These ranges are based on the 10th and 90th percentile of volumes reported for individual wells.
b— Total measured depth is the true length of wellbore drilled (i.e., sum of the vertical and horizontal).

The EPA collected information on volumes of drilling wastewater generated per well. Table C-5 shows typical volumes generated by UOG wells by resource type and formation. Operators report that nearly all of the drilling fluid used per well is recovered as wastewater at the end of drilling.[56] Therefore, where it had information on drilling fluid volumes but not the resulting drilling wastewater volume, the EPA assumed the former is representative of the latter.

Table C-5. Drilling Wastewater Volumes Generated per Well by UOG Formation

Resource Type	Formation	Range (gallons)	Median (gallons)	Typical Total Measured Depth[a] (feet)	Number of Data Points
Shale	Haynesville	420,000–1,100,000	600,000	13,000 – 19,000	5
Tight	Anadarko Basin[b]	222,000–420,000	310,000	--[c]	2
Shale	Niobrara	—[c]	300,000	7,500 – 13,000	1
Shale	Barnett	170,000–500,000	250,000	8,500 – 14,000	6
Shale	Permian Basin[b]	95,200–420,000	210,000	--[c]	8
Tight	Granite Wash	—[c]	200,000	--[c]	1
Tight	Cleveland	—[c]	200,000	--[c]	1
Shale	Eagle Ford	130,000–420,000	160,000	6,000 – 16,000	7
Shale	Utica	—[c]	100,000	6,000 – 19,000	1
Tight	Mississippi Lime	—[c]	100,000	--[c]	1
Shale	Marcellus	2,400 – 170,000	92,000	7,300 – 13,000	2,072

Source: 55 DCN SGE00740

a—Total measured depth is the true length of wellbore drilled (i.e., sum of the vertical and horizontal).
b—Specific formation was not reported.
c—The EPA identified only one data point for these formations. Therefore, there is no range to display.

2.1.2 Produced Water: Flowback

As described above, for purposes of this document, produced water includes flowback in addition to long-term produced water. Table C-6 quantifies the portion of fracturing fluid returned as flowback.[57] Because the volume of fracturing fluid used during well stimulation affects flowback quantities, fracturing fluid volumes are also listed. Given data in the table,[58] total flowback volumes typically range between 26,000 to 300,000 gallons (620 to 7,000 barrels) per well. On average, horizontal shale wells generate the highest volumes of flowback. In terms of wastewater management, operators must consider that the flowback process generates large volumes of wastewater in a short period of time (e.g., 30 days) compared to long-term produced water that is generated in small volumes over a long period of time.

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[56] Some drilling fluid volume may be lost downhole and/or to moisture in the cuttings, but these losses account for a relatively small percentage of the total volume (191 DCN SGE00625).

[57] The EPA explains how it differentiated between flowback and long-term produced water volumes in literature in its memorandum *Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation* (56 DCN SGE00724).

[58] Approximate flowback volumes can be estimated by multiplying total fracturing volume by the percent of fracturing fluid returned during flowback. However, EPA does not show this calculation in Table C-6 because not all data sources report both fracturing fluid volume and percent of fracturing fluid recovered as flowback.

Table C-6. UOG Well Flowback Recovery[59] by Resource Type and Well Trajectory

Resource Type	Trajectory	Fracturing Fluid (MG)[a]			Flowback (Percent of Fracturing Fluid Returned)[a]		
		Median	Range	Number of Data Points	Median	Range	Number of Data Points
Shale	H	4.0	0.13–15	50,053	6	1–50	6,488
	D	1.6	0.051–12	124	14	4–31	19
	V	1.2	0.015–22	4,152	24	7–75	18
Tight	H	2.2	0.042–9.4	765	7	7–60	39
	D	0.60	0.056–4.0	693	6	0–60	263
	V	0.31	0.019–4.0	1,287	8	1–83	48

Source: 56 DCN SGE00724 (Data are based on aggregated data from Table C-8, which contains volumes by formation)

a—Most of the underlying fracturing fluid volume data and percentages of fracturing fluid returned as flowback were reported in different sources. To avoid representing the data incorrectly, the EPA did not calculate total flowback volume for Table C-6.

Abbreviations: MG—million gallons; H—horizontal well; D—directional well; v—vertical well

2.1.3 Produced Water: Long-Term Produced Water

Long-term produced water rates remain relatively constant[60] over the well life compared to flowback rates (178 DCN SGE00635). Table C-7 quantifies long-term produced water rates in gallons per day by UOG resource and well trajectory. Median long-term produced water rates range from about 380 to 900 gallons (9 to 21 barrels) per day. A comparison of median long-term produced water rates for shale formation wells, as listed in the table, shows that horizontal shale wells have higher median generation rates than directional and vertical shale wells. On the other hand, median long-term produced water rates for tight formation wells in Table C-7 show that vertical tight wells have higher generation rates than directional and horizontal tight wells, but horizontal wells have the highest maximum generation rate.

[59] Flowback recovery is the percent of total fracturing fluid injected during hydraulic fracturing that returns to the wellhead during the flowback process.

[60] Note that long-term produced water rates typically gradually decrease over the well life. However, the change is small relative to flowback.

Table C-7. Long-Term Produced Water Generation Rates by Resource Type and Well Trajectory

Resource Type	Trajectory	Long-Term Produced Water Generation Rates (gpd per well)[a]		
		Median	Range	Number of Data Points
Shale	H	900	0–19,000	22,222
	D	480	22–8,700	695
	V	380	0–4,600	12,393
Tight	H	620	0–120,000	2,394
	D	750	12–1,800	3,816
	V	570	0–4,000	21,393

Sources: 56 DCN SGE00724

a—Based on aggregated data from Table C-8, which contains volumes by formation.

Abbreviations: gpd—gallons per day; H—horizontal well; D—directional well; V—vertical well

2.2 UOG Produced Water Volumes by Formation

Table C-8 shows the underlying UOG produced water volumes by formation and well trajectory used to generate the summary statistics in Section C.2.1. The data in Table C-8 are specific to UOG formations and are sorted alphabetically by basin and then from highest median fracturing fluid volume to lowest within each formation. Because the EPA identified less detailed data by formation for drilling wastewater, Table C-8 does not include drilling wastewater volumes.

Data in Table C-8 illustrate that volumes of flowback and flow rates of long-term produced water vary by formation. For example, UOG horizontal wells drilled into the Barnett shale formation in the Fort Worth basin generate 920 gallons (22 barrels) per day of long-term produced water compared to 110 gallons (3 barrels) per day for horizontal wells drilled into the Eagle Ford shale formation in the Western Gulf basin (206 DCN SGE00623). In some cases, produced water even varies geographically within the same formation, which is not evident in Table C-8. For example, operators report that wells drilled in the northeast portion of the Marcellus shale formation (in Pennsylvania) generate less produced water than wells drilled in the southwest portion of the Marcellus shale formation (in West Virginia) (178 DCN SGE00635).

Table C-8. Produced Water Volume Generation by UOG Formation

Basin	UOG Formation	Resource Type	Drill Type	Fracturing Fluid (MG)			Flowback (% of Fracturing Fluid Returned)			Long-Term Produced Water Rates (gpd)		
				Median	Range[b]	Number of Data Points[a]	Median	Range[b]	Number of Data Points[a]	Median	Range[b]	Number of Data Points[a]
Anadarko	Granite Wash	tight	H	6.2	0.20–9.4	77	—	7–22	2	1,300	0–2,200	273
			V	0.56	0.050–3.0	26	—	—	2	500	170–1,300	2,413
	Woodford	shale	H	4.7	1.0–12	2,239	34	20–50	3	5,500	3,200–6,400	198
	Mississippi Lime	tight	H	1.8	0.82–2.4	428	—	50	1	—	37,000–120,000	4
	Cleveland	tight	H	0.81	0.20–4.0	144	—	12–40	2	82	20–300	571
			V	0.69	0.11–3.0	4	—	—	2	32	6.6–170	390
Appalachian	Marcellus	shale	H	4.4	0.90–11	14,010	7	4–47	4,374	860	54–13,000	4,984
			V	2.6	0.53–6.6	66	40	21–60	7	230	100–1,200	714
	Utica	shale	H	4.0	1.0–11	150	4	2–27	73	510	210–1,200	82
Arkoma	Fayetteville	shale	H	5.1	1.7–11	1,668	—	10–20	2	430	150–2,300	2,305
Denver J.	Niobrara	shale	H	2.6	0.73–3.4	69	13	6–25	16	680	260–810	250
			V	0.32	0.27–3.3	367	11	7–35	9	340	240–600	5,474
	Codell-Niobrara	tight	H	2.6	0.15–2.7	62	7	—	32	34	19–140	32
			D	0.45	0.21–0.47	116	—	—	0	—	—	0
			V	0.30	0.13–0.46	592	—	—	0	29	13–65	1,677
	Muddy J	tight	D	0.59	0.25–0.62	162	—	—	0	230	64–390	3
			V	0.28	0.16–0.62	292	—	—	0	55	9.3–500	129
	Codell	tight	D	0.28	0.21–0.46	78	—	—	0	—	—	0
			V	0.27	0.13–0.46	185	—	—	0	—	—	0

Table C-8. Produced Water Volume Generation by UOG Formation

Basin	UOG Formation	Resource Type	Drill Type	Fracturing Fluid (MG)			Flowback (% of Fracturing Fluid Returned)			Long-Term Produced Water Rates (gpd)		
				Median	Range[b]	Number of Data Points[a]	Median	Range[b]	Number of Data Points[a]	Median	Range[b]	Number of Data Points[a]
Fort Worth	Barnett	shale	H	3.6	1.0–7.3	23,917	30	21–40	11	920	160–4,200	10,349
			V	1.3	0.4–1.9	3,589	—	—	0	250	170–580	3,318
Green River	Hilliard-Baxter-Mancos	shale	H	1.7	1.0–5.6	2	—	—	0	37	15–58	7
	Lance	tight	V	1.3	0.81–3.5	29	3	1–50	31	410	250–580	1,050
			D	1.2	0.76–1.9	180	6	1–17	170	860	360–1,200	1,140
	Mesaverde (Green River)	tight	D	0.23	0.16–0.31	73	8	0–37	61	190	150–440	445
			V	0.17	0.081–0.29	14	21	6–83	11	290	140–610	1,081
Illinois	New Albany	shale	H	—	—	0	—	—	0	—	2,900	2
Michigan	Antrim	shale	V	—	0.050	1	—	25–75	2	—	4,600	1
Permian	Avalon & Bone Spring	shale	D	2.2	0.94–4.5	20	13	5–31	16	950	220–2,400	183
		shale	H	1.1	0.73–2.8	17	—	—	0	0	0–2,300	37
	Barnett-Woodford	shale	H	2.1	0.5–4.5	2	—	—	0	—	—	0
	Wolfcamp	shale	H	1.4	1.1–3.9	55	—	—	0	3,000	210–19,000	104
			D	1.3	0.26–1.7	12	16	15–20	3	310	22–8,700	259
			V	0.81	0.078–1.7	60	—	—	0	910	130–1,700	926
	Spraberry	tight	V	—	1.0	1	—	—	0	870	100–4,000	66
	Devonian (TX)	shale	H	0.32	0.13–0.89	10	—	—	0	880	310–1,800	381
			V	0.27	0.12–1.0	16	—	—	0	400	150–3,000	162
San Juan	Mesaverde (San Juan)	tight	D	—	—	0	—	—	0	18	12–260	48

Table C-8. Produced Water Volume Generation by UOG Formation

Basin	UOG Formation	Resource Type	Drill Type	Fracturing Fluid (MG)			Flowback (% of Fracturing Fluid Returned)			Long-Term Produced Water Rates (gpd)		
				Median	Range[b]	Number of Data Points[a]	Median	Range[b]	Number of Data Points[a]	Median	Range[b]	Number of Data Points[a]
	Dakota	tight	V	0.2	0.063–0.22	19	—	—	0	65	29–120	6
			D	0.12	0.070–0.30	52	4	1–40	30	160	41–370	379
TX-LA-MS	Haynesville	shale	H	5.3	0.95–15	3,222	5	5–30	3	1,700	84–1,800	1,249
			V	0.61	0.14–3.5	9	—	—	0	210	56–850	263
	Cotton Valley	tight	H	4.2	0.25–6.0	30	—	<60	2	770	130–2,700	335
			D	0.48	0.084–4.0	24	—	<60	2	950	630–1,800	1,801
			V	0.28	0.019–0.94	76	—	<60	2	640	370–1,800	10,717
	Travis Peak	tight	H	3.0	0.25–6.0	2	—	—	0	200	39–1,700	5
			V	0.90	0.20–4.0	2	—	—	0	980	330–1,800	1,380
	Bossier	shale	H	2.7	1.7–3.6	2	—	—	0	750	610–1,200	25
			V	0.40	0.19–1.7	16	—	—	0	470	180–1,100	1,203
			D	0.28	0.13–0.80	21	—	—	0	320	130–1,300	253
Western Gulf	Austin Chalk	tight	H	0.94	0.58–1.3	15	—	—	0	720	290–2,400	1,097
	Eagle Ford	shale	H	5.0	1.0–14	2,485	4	2–8	1,800	110	9.1–250	498
			V	2.9	2.0–4.1	9	—	—	0	—	—	0
	Pearsall	shale	H	3.7	3.3–4.1	2	—	—	0	200	54–370	12
	Wilcox Lobo	tight	H	2.1	0.66–2.6	4	—	—	0	330	62–740	77
			V	0.21	0.06–0.60	14	—	—	0	620	330–1,400	1,514
			D	0.058	0.056–0.076	3	—	—	0	—	—	0

Table C-8. Produced Water Volume Generation by UOG Formation

Basin	UOG Formation	Resource Type	Drill Type	Fracturing Fluid (MG)			Flowback (% of Fracturing Fluid Returned)			Long-Term Produced Water Rates (gpd)		
				Median	Range[b]	Number of Data Points[a]	Median	Range[b]	Number of Data Points[a]	Median	Range[b]	Number of Data Points[a]
	Vicksburg	tight	V	0.16	0.084–0.60	20	—	—	0	1,000	650–1,900	937
			D	0.11	0.10–0.13	4	—	—	0	—	—	0
	Olmos	tight	V	—	0.15	2	—	—	0	—	—	0
Williston	Bakken	shale	H	2.0	0.35–10	2,203	19	5–47	206	680	380–1,500	1,739
			V	1.1	0.35–2.9	12	—	—	0	1,000	340–3,100	222

Sources: 56 DCN SGE00724

a—For some formations, the number of data points was not reported in the data source. In these instances, this table reports that number as 1, except if the source reported a range in which case this table reports the number of data points as 2.

b—For some formations, if only one data point was reported, the EPA reported it in the range column and did not report a median value.

"—" indicates no data.

Abbreviations: MG—million gallons; H—horizontal well; D—directional well; V—vertical well

3 UOG EXTRACTION WASTEWATER CHARACTERIZATION

As discussed in Chapter B, UOG operations generate wastewater that includes drilling wastewater, flowback, and long-term produced water. Drilling wastewater is generated during the initial drilling of the well and typically maintains the characteristics of the drilling fluid, but also contains additional solids (i.e., drill cuttings) that are generated during the well drilling process. Flowback may contain the specific fracturing fluid composition (e.g., chemical additives, base fluid) used by each UOG operator as well as chemical constituents present in the UOG formation (80 DCN SGE00286; 16 DCN SGE00110). Long-term produced water typically mimics the characteristics of the UOG formation, which often contributes, in part, to high concentrations of select naturally occurring ions (124 DCN SGE00090). The volumes and characteristics of UOG extraction wastewater may vary significantly between basins, between formations, and sometimes between wells within the same formation (see Section C.2 for a discussion of UOG extraction wastewater volumes) (153 DCN SGE00592). The following subsections describe the characteristics of UOG extraction wastewater.

3.1 Availability of Data for UOG Extraction Wastewater Characterization

The EPA identified concentration data for constituents commonly found in UOG extraction wastewater. These constituents include, primarily, total dissolved solids (TDS), anions/cations, metals, hardness, and radioactive constituents. The EPA presents summarized UOG extraction wastewater characterization data in the following subsections, which are organized into five constituent categories: classical and conventional, organic, metal, radioactive, and other. Table C-9 shows relative quantities of data found for each constituent category. The number of stars indicates the amount of data available, where one star indicates less data and five stars indicates more data.

Table C-9. Availability of Data for UOG Extraction Wastewater Characterization

Constituent Category	Examples of Constituents Included Within Category	Amount of Available Produced Water Data	Amount of Available Drilling Wastewater Data
Classical and conventional[a]	TDS, TSS, COD, BOD_5, pH, conductivity, *chloride, sodium, calcium*	★★★★★	★★
Organic	Ethylbenzene, toluene	★★★	★
Metal	Barium, strontium, magnesium, potassium, iron, copper, zinc	★★★★★	★★
Radioactive	Radium-226, radium-228, gross alpha, gross beta	★★	★
Other	Guar gum, microorganisms	★	★

a—The classical and conventional constituent category also includes a discussion of the anions and cations that contribute to TDS. These anions and cations are italicized in the examples column.

For all of the constituent categories, data on concentrations are less available for 1) produced water specifically generated from tight oil and gas wells and 2) drilling wastewater generated at all UOG wells. The EPA presents available data in the following subsections.

3.2 UOG Extraction Wastewater Constituent Categories

The data in the following subsections are representative of UOG extraction wastewater characteristics as presented in the literature for the entire UOG industry.[61] The data show combined characterization data for shale and tight reservoirs as well as for oil and gas resources. Regarding UOG produced water, the EPA sometimes presents the data as flowback and long-term produced water individually. In other instances, the data are presented as UOG produced water, which includes both flowback and long-term produced water.

3.2.1 Classical and Conventional Constituents in UOG Extraction Wastewater

Table C-10 presents typical concentrations of select classical and conventional constituents that are present in UOG drilling wastewater. According to one CWT facility operator, TSS is high in returned drilling fluid before cuttings are removed. Depending on how well the cuttings are removed by the operator, solids can be as high as 50 percent by mass in drilling wastewater (37 DCN SGE00245) (see Section B.2.1). The EPA identified the following limitations to the data presented in Table C-10:

- Fewer data points (i.e., less than 30 data points) were available for each parameter.
- All of the data came from the Marcellus shale formation.

Table C-11 presents typical concentrations of select classical and conventional constituents that are present in UOG produced water. The EPA identified the following limitations to the data presented in Table C-11:

- Fewer data points (i.e., less than 30 data points) were available for ammonia and phosphate.
- The majority of data associated with alkalinity, BOD_5, chemical oxygen demand (COD), specific conductivity, TOC, and TSS came from the Marcellus shale formation.
- The majority of data associated with chloride and TDS came from the Eagle Ford shale formation.
- The majority of data associated with pH came from the Woodford-Cana-Caney shale formation.

[61] Note that the lack of data for select constituents may not necessarily imply that those constituents are not present in the wastewater, but rather that they were not measured and/or reported in the existing literature. Refer to 56 DCN SGE00724 for additional details on the parameters reported in the literature reviewed. The accompanying database includes non detect, below detection, or zero values that were reported in the literature reviewed.

Table C-10. Concentrations of Select Classical and Conventional Constituents in UOG Drilling Wastewater from Marcellus Shale Formation Wells[62]

Parameter	Units	Range	Median	Number of Data Points	Number of Detects	Formation Represented
Alkalinity	mg/L	110–42,000	1,600	11	11	Marcellus
Ammonia	mg/L	0.98–35	7	8	8	Marcellus
BOD_5	mg/L	80–1,100	390	8	8	Marcellus
Chloride	mg/L	160–23,000	12,000	12	12	Marcellus
COD	mg/L	150–9,300	1,800	8	8	Marcellus
Hardness as $CaCO_3$	mg/L	1,400–46,000	4,400	12	12	Marcellus
Oil and grease	mg/L	ND[a]–150	2.5	8	8	Marcellus
pH	SU	6.8–12	9.0	12	12	Marcellus
Phosphate	mg/L	—[b]	16	4	4	Marcellus
Specific conductivity	µS/cm	1,100–60,000	19,000	10	10	Marcellus
TDS	mg/L	560–80,000	31,000	14	14	Marcellus
TSS	mg/L	120–600,000	28,000	16	16	Marcellus

Source: 55 DCN SGE00740

a—Source did not report detection limit.
b—Source only reported median value.

Abbreviations: mg/L—milligrams per liter; ND—non detect; SU—standard units; µS/cm—microsiemens per centimeter

[62] Drilling wastewater may contain differing amounts of drill cuttings depending on how the operator chooses to remove drill cuttings from drilling wastewater.

Table C-11. Concentrations of Select Classical and Conventional Constituents in UOG Produced Water

Parameter	Units	Range	Median	Number of Data Points[a]	Number of Detects	Formations Represented[a]
Alkalinity	mg/L	7.5–1,600	140	265	265	Barnett (29); Eagle Ford (1); Marcellus (232); Woodford-Cana-Caney (3)
Ammonia	mg/L	39–350	110	13	13	Marcellus (5); Niobrara (5); Woodford-Cana-Caney (3)
Bicarbonate	mg/L	0 – 19,000	290	6,352	6,352	Bakken (398); Barnett (6); Cleveland (11); Cotton Valley/Bossier (3); Dakota (3); Eagle Ford (2,925); Lansing Kansas City (16); Marcellus (154); Mesaverde/Lance (5); Morrow (1); New Albany (1); Oswego (5); Pearsall (3); Spraberry (26); Woodford-Cana-Caney (2,795)
BOD_5	mg/L	2–12,000	160	154	153	Barnett (28); Marcellus (122); Medina/Clinton-Tuscarora (1); Woodford-Cana-Caney (3)
Carbonate	mg/L	0 – 13,000	0	59	59	Bakken (20); Barnett (4); Cotton Valley/Bossier (2); Dakota (3); Eagle Ford (4); Spraberry (26)
Chloride[b]	mg/L	64–230,000	73,000	2,190	2,190	Bakken (22); Barnett (144); Cleveland (11); Cotton Valley/Bossier (25); Dakota (3); Eagle Ford (1651); Granite Wash/Atoka (1); Marcellus (287); Mesaverde/Lance (5); New Albany (1); Niobrara (5); Pearsall (3); Spraberry (26); Utica (1); Woodford-Cana-Caney (5)
COD	mg/L	99–37,000	3,200	149	149	Barnett (23); Marcellus (122); Medina/Clinton-Tuscarora (1); Woodford-Cana-Caney (3)
Hardness as $CaCO_3$	mg/L	160–110,000	21,000	80	80	Barnett (15); Marcellus (65)
Oil and grease	mg/L	0.21–1,500	5.6	134	99	Barnett (23); Marcellus (108); Woodford-Cana-Caney (3)
pH	SU	3.9–12	6.5	5,233	5,233	Bakken (420); Barnett (30); Cleveland (4); Cotton Valley/Bossier (3); Dakota (3); Eagle Ford (1600); Fayetteville (2); Lansing Kansas City (16); Marcellus (300); Medina/Clinton-Tuscarora (3); Mesaverde/Lance (5); Morrow (1); Oswego (5); Spraberry (26); Woodford-Cana-Caney (2815)
Phosphate	mg/L	12–88	31	4	4	Barnett (1); Marcellus (1); Woodford-Cana-Caney (2)
Specific conductivity	µS/cm	0.11–760,000	120,000	162	162	Bakken (9); Barnett (25); Dakota (3); Marcellus (103); Spraberry (19); Woodford-Cana-Caney (3)

Table C-11. Concentrations of Select Classical and Conventional Constituents in UOG Produced Water

Parameter	Units	Range	Median	Number of Data Points[a]	Number of Detects	Formations Represented[a]
TDS	mg/L	320–400,000	100,000	2,164	2,164	Bakken (11); Barnett (38); Bradford-Venango-Elk (5); Cleveland (11); Cotton Valley/Bossier (3); Dakota (3); Devonian (11); Eagle Ford (1647); Fayetteville (4); Green River (1); Haynesville/Bossier (2); Marcellus (373); Mesaverde/Lance (5); Mississippi Lime (3); New Albany (1); Niobrara (8); Pearsall (3); Spraberry (26); Utica (1); Woodford-Cana-Caney (8)
TOC	mg/L	1.2–5,700	65	129	124	Bakken (2); Barnett (28); Marcellus (96); Woodford-Cana-Caney (3)
TSS	mg/L	4–14,000	130	150	150	Bakken (2); Barnett (29); Eagle Ford (1); Marcellus (113); Woodford-Cana-Caney (5)

Source: 56 DCN SGE00724

a—In some instances the sum of the number of data points associated with individual formations does not equal the total number of data points. In these instances, there were data points reported in existing literature for which an associated shale or tight oil and gas formation was not identified.
b—The EPA assumed values reported as "Cl" in the wastewater characterization data were meant to represent "chloride" values.

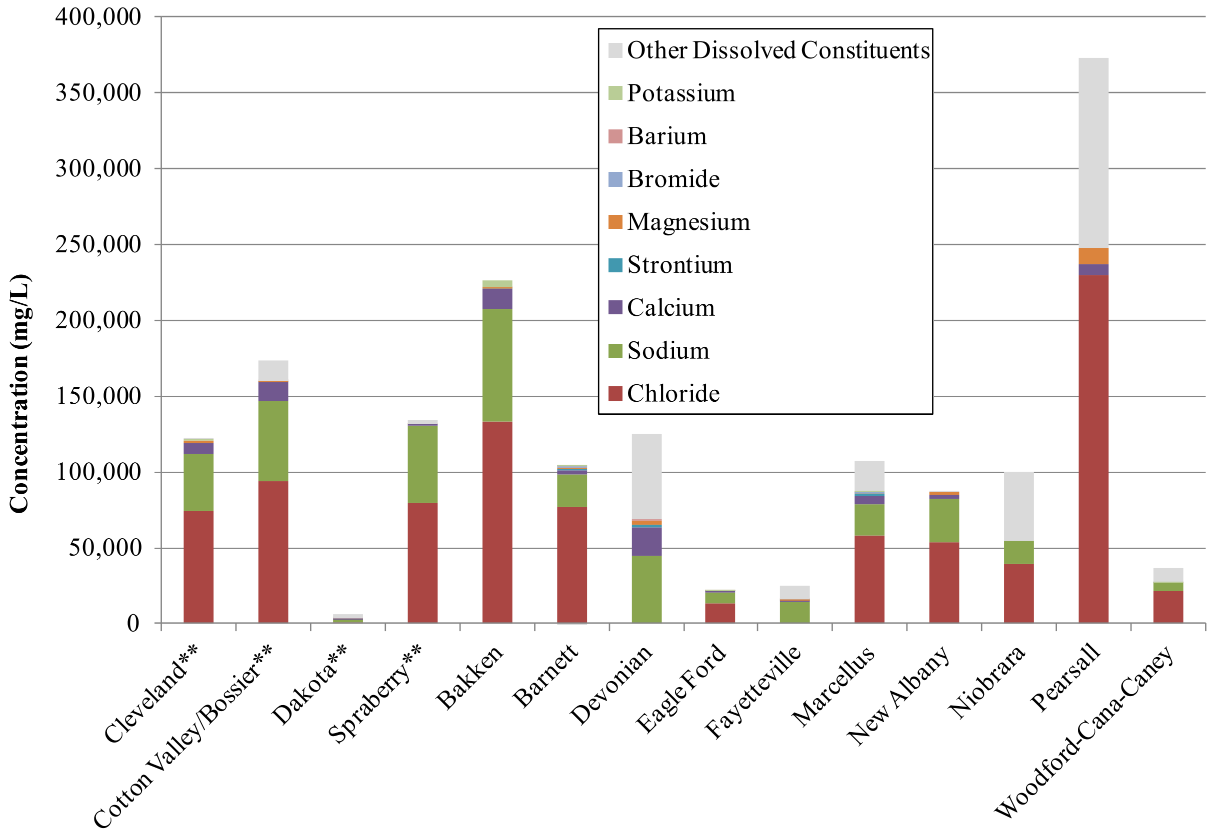
Abbreviations: mg/L—milligrams per liter; SU—standard units; µS/cm—microsiemens per centimeter

COD is a measure of the amount of oxygen needed to oxidize organic matter in wastewater using a strong chemical oxidant; therefore, it is an indicator of the presence of organic constituents in wastewater. As reported in Table C-11, the median COD concentration found in UOG produced water is 3,200 mg/L. However, researchers have shown that concentrations of COD may be influenced by chloride, bromide, alkaline earth metals (e.g., barium, calcium), and reduced inorganic constituents (e.g., sulfide, nitrite). As shown in Table C-13, the median concentrations of sulfide and nitrite in UOG produced water are less than 10 mg/L, indicating that they are not likely to have an influence on the COD concentrations. However, chloride, bromide, and alkaline earth metals are present at higher concentrations than reduced inorganic constituents in UOG produced water and may interfere with COD sample measurements (227 DCN SGE00725). In Table C-11, the relatively low median TOC concentration (65 mg/L) and BOD_5 concentration (160 mg/L) compared to the COD concentration likely indicates that some of the COD measurements reported in existing literature experienced interference from high concentrations of chloride, bromide, and group II alkaline earth metals. Therefore, reported COD concentrations may be higher than actual COD concentrations in UOG produced water.

TDS, which is regularly measured in UOG produced water, provides a measure of dissolved matter including salts (e.g., sodium, chloride, nitrate), metals, minerals, and organic material (1 DCN SGE00046). TDS is not a specific chemical, but is defined as the portion of solids that pass through a filter with a nominal pore size of 2.0 µm or less (Standard Method 2540C-1997, ASTM D5907-03, and USGS I-1750-85). Salts are the majority of TDS in UOG produced water, and sodium chloride often constitutes approximately 50 percent of the TDS in UOG produced water (1 DCN SGE00046). As reported in Table C-11, the concentration of TDS in UOG produced water is approximately 10 percent by weight.

Calcium and other group II alkaline earth metals (e.g., strontium, barium, magnesium) also contribute to the TDS in UOG produced water.

Figure C-3 shows the primary anions and cations that contribute to TDS in UOG produced water in various shale and tight oil and gas formations. Data for all of the anions and cations contributing to TDS were not available for all formations. For example, the EPA did not identify any sodium concentration data in the Pearsall formation. Similarly, the EPA did not identify any chloride concentration data in the Spraberry formation. These missing data will account for some of the remaining TDS concentrations that are currently shown as “other dissolved constituents” in Figure C-3.



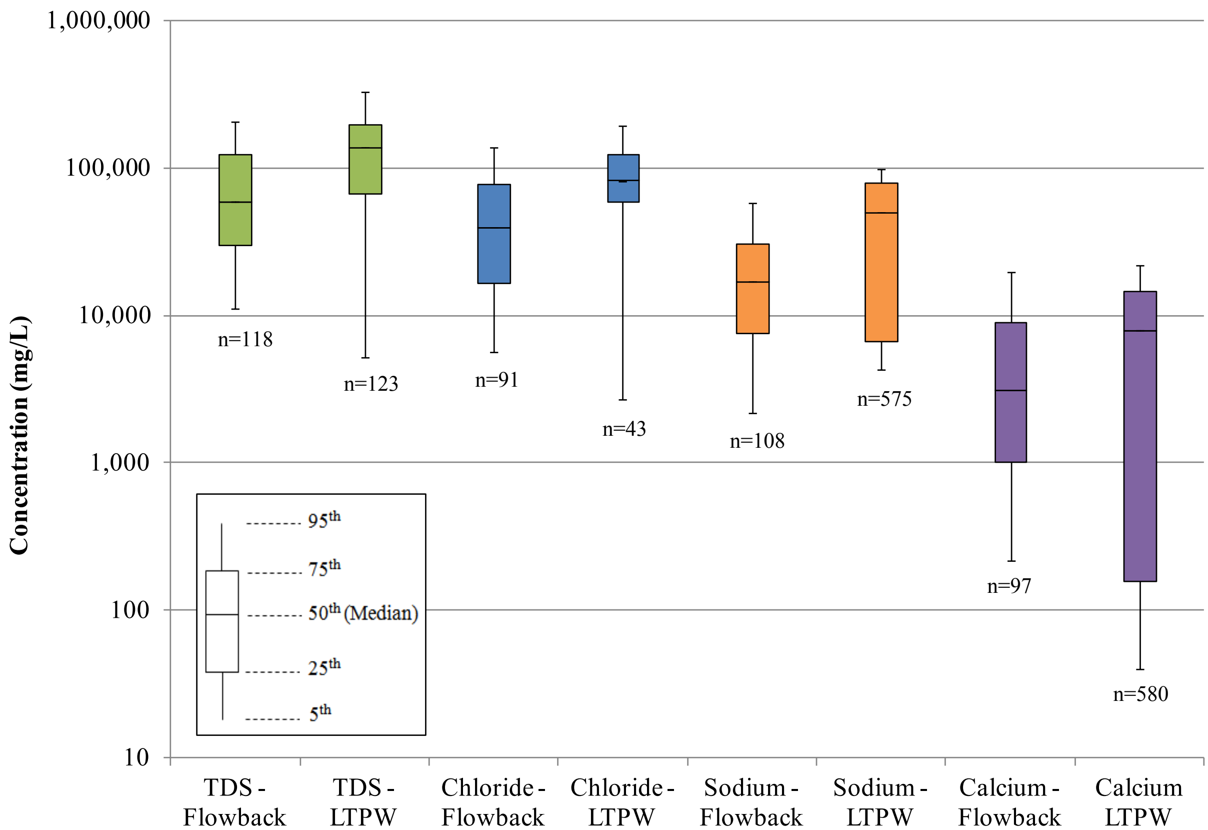
EPA assumed values reported as "Cl" in the wastewater characterization data were meant to represent "chloride" values and were reported as such in Table C-11.

Source: 56 DCN SGE00724

Figure C-3. Anions and Cations Contributing to TDS Concentrations in Shale and Tight Oil and Gas Formations[63]

As shown in Figure C-3, of those chemicals specifically identified as contributing to TDS, sodium, chloride, and calcium ions make up the majority of TDS in UOG produced water. Additional ions that may contribute to the TDS in UOG produced water include bromide, fluoride, nitrate, nitrite, phosphate, and sulfate. Figure C-4 shows ranges of concentrations of sodium, chloride, and calcium contributing to TDS in UOG flowback and long-term produced water. The data used to create this figure include constituent concentration data from flowback or long-term produced water generated at a shale or tight oil and gas well. The data show that concentrations of these constituents are typically higher in long-term produced water than in flowback.

[63] In Figure C-3, the EPA indicates tight oil and gas formations by "**" after the formation name. The EPA assumed values reported as "Cl" in the wastewater characterization data were meant to represent "chloride" values and has reported them as such in Figure C-3.



EPA assumed values reported as "Cl" in the wastewater characterization data were meant to represent "chloride" values and were reported as such in Table C-11.

Source: 56 DCN SGE00724

Figure C-4. Chloride, Sodium, and Calcium Concentrations in Flowback and Long-Term Produced Water (LTPW) from Shale and Tight Oil and Gas Formations

Table C-12 presents typical concentrations of additional constituents that may contribute to TDS in drilling wastewater. The EPA identified the following limitations to the data presented in the table:

- Fewer data points (i.e., less than 30 data points) were available for all parameters.
- All of the data came from the Marcellus shale formation.

Table C-13 presents typical concentrations of additional constituents that may contribute to TDS in UOG produced water. The EPA identified the following limitations to the data presented in the table:

- Less data (i.e., less than 30 data points) were available for nitrite and phosphate.
- All of the available data for nitrite and sulfide came from the Marcellus shale formation.
- The majority of the data associated with nitrate came from the Bakken shale formation.

- The majority of the data associated with bromide and fluoride came from the Marcellus shale formation.
- The majority of the data associated with sulfate came from the Woodford-Cana-Caney shale formation.

Table C-12. Concentrations of Select Anions and Cations Contributing to TDS in UOG Drilling Wastewater from Marcellus Shale Formation Wells

Parameter	Units	Range	Median	Number of Data Points	Number of Detects	Formation Represented
Bromide	mg/L	23–210	110	5	5	Marcellus
Sulfate	mg/L	ND–1,600	220	13	10	Marcellus

Source: 55 DCN SGE00740

Abbreviation: mg/L—milligrams per liter

Table C-13. Concentrations of Select Anions and Cations Contributing to TDS in UOG Produced Water

Parameter	Units	Range	Median	Number of Data Points	Number of Detects	Formations Represented (Number of Associated Data Points)[a]
Bromide	mg/L	0.20–3,100	510	111	111	Barnett (23); Marcellus (85); Woodford-Cana-Caney (3)
Fluoride	mg/L	0.045–390	2.5	99	97	Barnett (23); Marcellus (73); Woodford-Cana-Caney (3)
Nitrate	mg/L	0.30–920	0.30	110	110	Bakken (107); Marcellus (3)
Nitrite	mg/L	5.0–5.0[b]	5.0	2	2	Marcellus (2)
Phosphate	mg/L	12-88	31	4	4	Barnett (1); Marcellus (1); Woodford-Cana-Caney (2)
Sulfate	mg/L	0–7,200	270	4,711	4,687	Bakken (424); Barnett (31); Cleveland (9); Cotton Valley/Bossier (1); Dakota (3); Devonian (4); Eagle Ford (1,166); Fayetteville (2); Lansing Kansas City (15); Marcellus (301); Medina/Clinton-Tuscarora (2); Mesaverde/Lance (4); Morrow (1); New Albany (1); Niobrara (5); Oswego (4); Pearsall (3); Spraberry (26); Woodford-Cana-Caney (2,709)
Sulfide	mg/L	0.80–30	3.0	76	69	Marcellus (76)

Source: 56 DCN SGE00724

a—In some instances the sum of the number of data points associated with individual formations does not equal the total number of data points. In these instances, there were data points reported in existing literature for which an associated shale or tight oil and gas formation was not identified.
b—Only two data points were identified for nitrite concentrations in UOG produced water and both data points reported the same value.

Abbreviation: mg/L—milligrams per liter

3.2.2 Organic Constituents in UOG Extraction Wastewater

Table C-14 presents concentration data from existing literature on organic constituents in UOG drilling wastewater. The EPA identified the following limitations to the data presented in the table:

- Fewer data points (i.e., less than 30) were available for each parameter.
- All of the data came from the Marcellus shale formation.

Table C-15 presents concentration data from existing literature on organic constituents in UOG produced water. The EPA identified the following limitations to the data presented in the table:

- All of the available data for carbon disulfide, ethanol, methanol, methyl chloride, and tetrachloroethylene came from the Marcellus shale formation.
- The majority of the data associated with each of the organic constituents presented in the table came from the Marcellus shale formation.

Table C-14. Concentrations of Select Organic Constituents in UOG Drilling Wastewater from Marcellus Shale Formation Wells

Parameter	Units	Range	Median	Number of Data Points	Number of Detects	Formation Represented
Benzene	µg/L	ND[a]–40	ND[a]	20	5	Marcellus
Ethylbenzene	µg/L	—[b]	9.6	4	4	Marcellus
Ethylene glycol	mg/L	—[b]	500	1	1	Marcellus
Toluene	µg/L	ND[a]–80	ND[a]	20	8	Marcellus
Xylene (m,p)	µg/L	—[b]	88	4	4	Marcellus
Xylene (o)	µg/L	—[b]	22	4	4	Marcellus

Source: 55 DCN SGE00740

a—Source did not report detection limit.
b—Source only reported median value.

Abbreviations: ND—non detect; mg/L—milligrams per liter; µg/L—micrograms per liter

Table C-15. Concentrations of Select Organic Constituents in UOG Produced Water

Parameter	Units	Range	Median	Number of Data Points	Number of Detects	Formations Represented (Number of Associated Data Points)[a]
1,2,4-trimethylbenzene	µg/L	0.54–4,000	5.0	92	89	Barnett (25); Marcellus (67)
1,3,5-trimethylbenzene	µg/L	0.64–1,900	5.0	85	81	Barnett (18); Marcellus (67)
Acetone	µg/L	5.9–160,000	40	96	86	Barnett (22); Marcellus (74)
Benzene	µg/L	0.99–800,000	8.5	144	122	Barnett (25); Marcellus (111); Niobrara (5); Woodford-Cana-Caney (3)
Carbon disulfide	µg/L	5.0–7,300	5.0	68	67	Marcellus (68)
Chlorobenzene	µg/L	0–500	5.0	72	70	Marcellus (69); Woodford-Cana-Caney (3)
Chloroform	µg/L	0–500	5.0	77	75	Barnett (5); Marcellus (69); Woodford-Cana-Caney (3)
Ethanol	µg/L	1,000–230,000	10,000	53	53	Marcellus (53)
Ethylbenzene	µg/L	0.63–8,900	5.0	130	104	Barnett (18); Marcellus (108); Medina/Clinton-Tuscarora (1); Woodford-Cana-Caney (3)
Isopropylbenzene	µg/L	0.53–500	5.0	83	69	Barnett (16); Marcellus (67)
Methanol	µg/L	3,200–4,500,000	10,000	55	55	Marcellus (55)
Methyl chloride	µg/L	2.0–500	5.0	95	69	Marcellus (95)
Naphthalene	µg/L	0.50–1,400	5.0	129	103	Barnett (39); Marcellus (90)
Phenol	µg/L	0.70–460	2.0	111	83	Barnett (17); Marcellus (91); Woodford-Cana-Caney (3)
Pyridine	µg/L	1.1–2,600	86	91	90	Barnett (24); Marcellus (67)
Tetrachloroethylene	µg/L	5.0–5,000	5.0	95	68	Marcellus (95)
Toluene	µg/L	0.91–1,700,000	6.0	149	125	Barnett (25); Marcellus (115); Medina/Clinton-Tuscarora (1); Niobrara (5); Woodford-Cana-Caney (3)
Xylenes	µg/L	3.0–440,000	15	136	111	Barnett (20); Marcellus (112); Medina/Clinton-Tuscarora (1); Woodford-Cana-Caney (3)

Source: 56 DCN SGE00724

a—In some instances the sum of the number of data points associated with individual formations does not equal the total number of data points. In these instances, there were data points reported in existing literature for which an associated shale or tight oil and gas formation was not identified.

Abbreviation: µg/L—micrograms per liter

Table C-3 includes concentration data for ethanol, methanol, and naphthalene, suggesting that a portion of the concentrations of these constituents found in UOG produced water (see Table C-15) may have originated from the fracturing fluid. Methanol is typically used in fracturing fluid as a biocide, corrosion inhibitor, crosslinker, and surfactant; ethanol is also used as a biocide and surfactant (see Table C-2).

Operators may use methanol as an antifreezing agent at UOG operations in areas with seasonal temperature fluctuations. Methanol may be used at the wellhead to avoid freezing in the wellbore or at compressor stations to prevent equipment from freezing.

The EPA did not identify any quantitative information about diesel-range organics or total petroleum hydrocarbons in UOG produced water. However, Table C-3 shows that petroleum distillates are typically used in fracturing fluid at 0.0021 to 0.27 percent by mass. The EPA ORD's 2015 *Evaluation of Hydraulic Fracturing Fluid Data from the FracFocus Chemical Disclosure Registry 1.0* contains additional information about these constituents (201 DCN SGE00721).

3.2.3 Metals in UOG Extraction Wastewater

UOG extraction wastewater contains varying concentrations of numerous metals.

Table C-16 presents concentration data from existing literature for the metals most common in UOG drilling wastewater. The EPA identified the following limitations to the data presented in the table:

- Fewer data points (i.e., less than 30) were available for each parameter.
- All of the data came from the Marcellus shale formation.

Table C-17 presents concentration data from existing literature for the metals most common in UOG produced water. The EPA identified the following limitations to the data presented in the table:

- Fewer data (i.e., less than 30 data points) were available for vanadium.
- All of the available data for vanadium came from the Marcellus shale formation.
- The majority of the data associated with aluminum, antimony, arsenic, beryllium, boron, cadmium, cobalt, copper, iron, lead, lithium, manganese, mercury, molybdenum, nickel, selenium, silver, strontium, thallium, tin, titanium, and zinc came from the Marcellus shale formation.
- The majority of the data associated with calcium, magnesium, potassium, and sodium came from the Eagle Ford and Woodford-Cana-Caney shale formations.
- The majority of the data associated with chromium came from the Bakken shale formation.

Table C-16. Concentrations of Select Metal Constituents in UOG Drilling Wastewater from Marcellus Shale Formation Wells

Parameter	Units	Range	Median	Number of Data Points	Number of Detects	Formation Represented
Aluminum	mg/L	1.7–6,900	38	12	12	Marcellus
Arsenic	mg/L	ND[a]–4.2	ND[a]	12	6	Marcellus
Barium	mg/L	2.6–2,000	13	14	14	Marcellus
Beryllium	mg/L	ND[a]–0.018	ND[a]	8	2	Marcellus
Boron	mg/L	ND[a]–2.7	0.17	8	4	Marcellus
Cadmium	mg/L	ND[a]–0.0050	ND[a]	8	1	Marcellus
Calcium	mg/L	150–15,000	1,300	13	13	Marcellus
Chromium	mg/L	ND[a]–11	0.010	12	8	Marcellus
Cobalt	mg/L	ND[a]–1.8	ND[a]	8	3	Marcellus
Copper	mg/L	ND[a]–17	0.83	8	6	Marcellus
Iron	mg/L	4.2–18,000	86	12	12	Marcellus
Lead	mg/L	ND[a]–8.0	0.35	12	10	Marcellus
Lithium	mg/L	ND[a]–1.2	ND[a]	8	1	Marcellus
Magnesium	mg/L	ND[a]–3,600	290	12	11	Marcellus
Manganese	mg/L	ND[a]–350	4.3	12	11	Marcellus
Mercury	mg/L	ND[a]–0.029	ND[a]	8	2	Marcellus
Molybdenum	mg/L	—[b]	0.10	1	1	Marcellus
Nickel	mg/L	ND[a]–16	0.55	12	9	Marcellus
Potassium	mg/L	—[b]	8,800	4	4	Marcellus
Selenium	mg/L	ND[a]–0.11	ND[a]	8	3	Marcellus
Silver	mg/L	ND[a]–0.010	ND[a]	8	1	Marcellus
Sodium	mg/L	170–16,000	2,900	12	12	Marcellus
Strontium	mg/L	1.8–1,500	21	13	13	Marcellus
Zinc	mg/L	ND[a]–38	2.1	12	10	Marcellus

Source: 55 DCN SGE00740

a—Source did not report detection limit.
b—Source only reported median value.

Abbreviation: mg/L—milligrams per liter; ND—non detect

Table C-17. Concentrations of Select Metal Constituents in UOG Produced Water

Parameter	Units	Range	Median	Number of Data Points	Number of Detects	Formations Represented (Number of Associated Data Points)[a]
Aluminum	mg/L	0.048 - 47	0.45	159	128	Bakken (4); Barnett (31); Marcellus (116); Woodford-Cana-Caney (3)
Antimony	mg/L	0.0089 - 0.5	0.047	112	79	Barnett (9); Marcellus (103)
Arsenic	mg/L	0.004 - 0.5	0.057	132	96	Barnett (15); Marcellus (114); Woodford-Cana-Caney (3)
Barium	mg/L	0 - 16,000	19	1,097	1,096	Bakken (312); Barnett (38); Cotton Valley/Bossier (2); Dakota (3); Devonian (4); Eagle Ford (8); Fayetteville (2); Lansing Kansas City (7); Marcellus (209); Medina/Clinton-Tuscarora (1); Morrow (1); Utica (1); Woodford-Cana-Caney (508)
Beryllium	mg/L	0.0009 - 420	0.04	114	72	Barnett (2); Marcellus (112)
Boron	mg/L	0.018 - 150	14	148	134	Bakken (8); Barnett (32); Eagle Ford (1); Marcellus (102); Niobrara (5)
Cadmium	mg/L	0 - 1.2	0.0086	134	92	Barnett (16); Marcellus (115); Woodford-Cana-Caney (3)
Calcium	mg/L	13 - 130,000	6,700	5,336	5,335	Bakken (426); Barnett (39); Cleveland (11); Cotton Valley/Bossier (3); Dakota (3); Devonian (4); Eagle Ford (1644); Fayetteville (2); Lansing Kansas City (15); Marcellus (342); Medina/Clinton-Tuscarora (2); Mesaverde/Lance (5); Morrow (1); New Albany (1); Oswego (5); Pearsall (3); Spraberry (26); Woodford-Cana-Caney (2804)
Chromium	mg/L	0.0066 - 260	0.3	383	349	Bakken (234); Barnett (26); Marcellus (115); Woodford-Cana-Caney (3)
Cobalt	mg/L	0.0045 - 25	0.5	124	92	Barnett (16); Eagle Ford (1); Marcellus (103)
Copper	mg/L	0 - 4.2	0.14	147	107	Bakken (2); Barnett (22); Marcellus (115); Woodford-Cana-Caney (3)
Iron	mg/L	0.95 - 810	39	407	380	Bakken (22); Barnett (35); Cotton Valley/Bossier (2); Dakota (3); Eagle Ford (10); Fayetteville (2); Marcellus (300); Spraberry (26); Utica (1); Woodford-Cana-Caney (6)
Lead	mg/L	0 - 5	0.03	133	96	Bakken (1); Barnett (15); Marcellus (113); Woodford-Cana-Caney (3)
Lithium	mg/L	0.5 - 430	52	120	120	Barnett (31); Marcellus (89)
Magnesium	mg/L	3 - 27,000	670	3,562	3,549	Bakken (426); Barnett (39); Cleveland (11); Cotton Valley/Bossier (3); Dakota (3); Devonian (4); Eagle Ford (1621); Fayetteville (2); Lansing Kansas City (15); Marcellus (326); Medina/Clinton-Tuscarora (2); Mesaverde/Lance (5); Morrow (1); New Albany (1); Oswego (5); Pearsall (3); Spraberry (26); Woodford-Cana-Caney (1069)
Manganese	mg/L	0.12 - 43	1.7	235	221	Bakken (7); Barnett (37); Cotton Valley/Bossier (2); Dakota (3); Eagle Ford (6); Fayetteville (2); Marcellus (155); Spraberry (19); Woodford-Cana-Caney (3)
Mercury	mg/L	0 - 0.3	0.0002	115	85	Barnett (11); Marcellus (101); Woodford-Cana-Caney (3)
Molybdenum	mg/L	0.003 - 13	0.038	140	118	Bakken (1); Barnett (29); Marcellus (105)
Nickel	mg/L	0.007 - 4	0.12	151	121	Barnett (27); Eagle Ford (1); Marcellus (116); Woodford-Cana-Caney (3)

Table C-17. Concentrations of Select Metal Constituents in UOG Produced Water

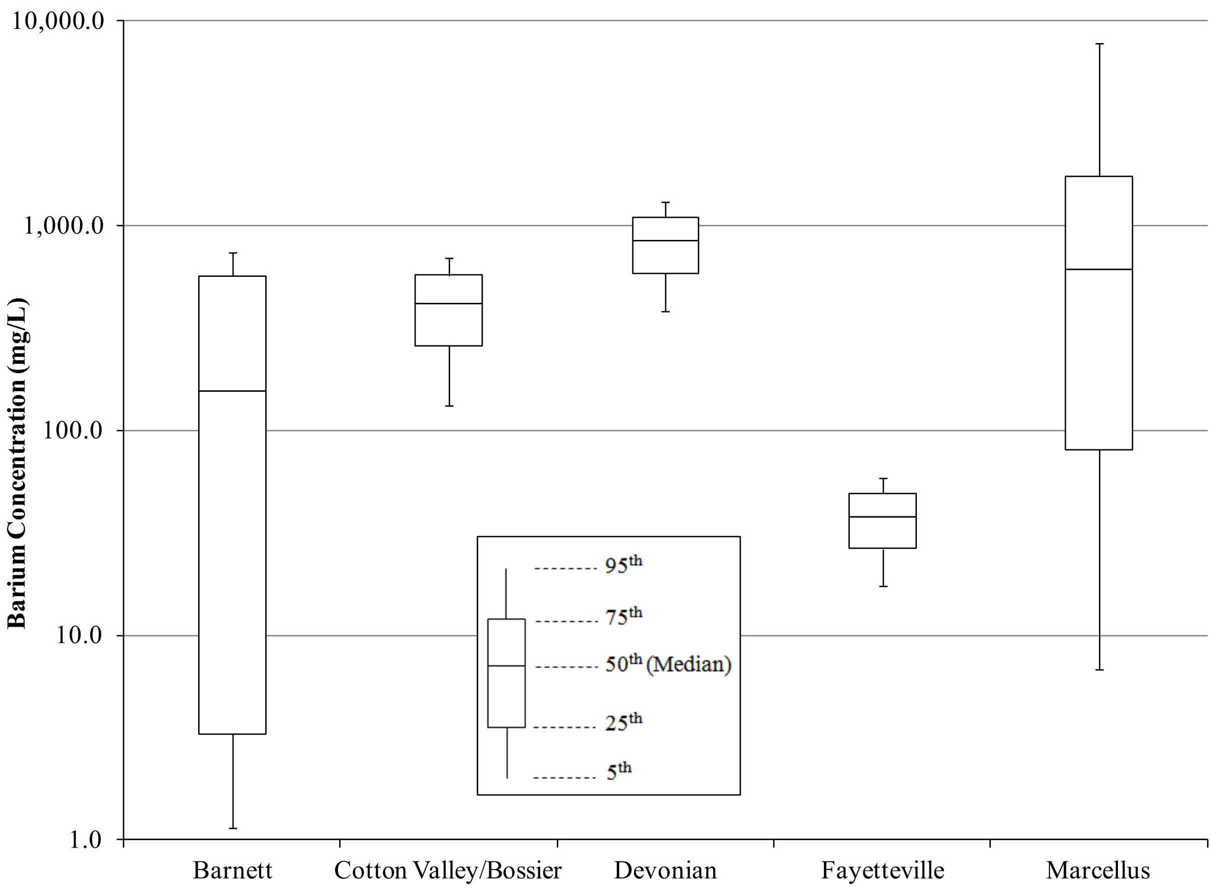
Parameter	Units	Range	Median	Number of Data Points	Number of Detects	Formations Represented (Number of Associated Data Points)[a]
Potassium	mg/L	0 - 8,500	3,100	715	699	Bakken (382); Barnett (36); Cleveland (3); Cotton Valley/Bossier (3); Eagle Ford (149); Marcellus (136); Medina/Clinton-Tuscarora (2); Mesaverde/Lance (1); Woodford-Cana-Caney (3)
Selenium	mg/L	0.0043 - 0.5	0.05	110	75	Barnett (7); Marcellus (103)
Silver	mg/L	0.00073 - 0.5	0.05	115	75	Marcellus (112); Woodford-Cana-Caney (3)
Sodium	mg/L	64 - 430,000	39,000	3,449	3,448	Bakken (426); Barnett (38); Cleveland (11); Cotton Valley/Bossier (3); Dakota (3); Devonian (4); Eagle Ford (1631); Fayetteville (2); Lansing Kansas City (16); Marcellus (202); Medina/Clinton-Tuscarora (2); Mesaverde/Lance (5); Morrow (1); New Albany (1); Niobrara (5); Oswego (5); Spraberry (26); Woodford-Cana-Caney (1068)
Strontium	mg/L	0 - 8,000	750	253	251	Bakken (10); Barnett (35); Cotton Valley/Bossier (2); Dakota (3); Devonian (4); Eagle Ford (8); Fayetteville (2); Marcellus (183); Medina/Clinton-Tuscarora (2); Utica (1); Woodford-Cana-Caney (3)
Thallium	mg/L	0.0049 - 1	0.1	120	83	Barnett (13); Marcellus (104); Woodford-Cana-Caney (3)
Tin	mg/L	0.0038 - 3	1	80	78	Barnett (10); Marcellus (69)
Titanium	mg/L	0 - 8	0.19	111	80	Barnett (16); Marcellus (94)
Vanadium	mg/L	0.063 - 40	0.63	27	2	Marcellus (26)
Zinc	mg/L	0 - 250	0.2	160	135	Bakken (2); Barnett (32); Eagle Ford (1); Fayetteville (2); Marcellus (116); Woodford-Cana-Caney (3)

Source: 56 DCN SGE00724

a—In some instances the sum of the number of data points associated with individual formations does not equal the total number of data points. In these instances, there were data points reported in existing literature for which an associated shale or tight oil and gas formation was not identified.

Abbreviation: mg/L—milligrams per liter

As discussed in Section C.3.2.1, sodium and calcium are two of the primary constituents that contribute to TDS in UOG produced water. Other metals with median concentrations between 100 mg/L and 750 mg/L are magnesium and strontium, which are group II alkaline earth metals. Low-solubility salts of these metals (e.g., barium sulfate) commonly precipitate in pipes and valves, forming scale. Barium is commonly found in higher concentrations in produced water from the Marcellus and Devonian shale formations than in produced water from other UOG formations. Figure C-5 shows the concentrations of barium in UOG produced water from various shale and tight oil and gas formations on a log scale. Median concentrations of heavy metals (e.g., chromium, copper, nickel, zinc, lead, mercury, arsenic) in UOG produced water are less than 1 mg/L, much lower than the concentrations of the alkaline earth metals.



Source: 56 DCN SGE00724

Figure C-5. Barium Concentrations in UOG Produced Water from Shale and Tight Oil and Gas Formations

3.2.4 Radioactive Constituents in UOG Extraction Wastewater

Oil and gas formations contain varying levels of naturally occurring radioactive material (NORM) resulting from uranium and thorium decay, which can be transferred to UOG produced water. Radioactive decay products typically include radium-226 and radium-228 (54 DCN SGE00933). The EPA identified limited available data (primarily from the Marcellus Shale formation) on some radioactive constituents in UOG extraction wastewater, including radium-226, radium-228, gross alpha, and gross beta, and therefore focused the radioactive constituent discussion and data presentation on these parameters. ERG's *Radioactive Materials in the Unconventional Oil and Gas (UOG) Industry* memorandum (54 DCN SGE00933) contains a more detailed discussion of this topic.

The EPA identified limited radioactive constituent concentration data for UOG drilling wastewater. Table C-18 shows the available data from the Marcellus shale formation.

Table C-18. Concentrations of Select Radioactive Constituents in UOG Drilling Wastewater from Marcellus Shale Formation Wells

Parameter	Units	Range	Median	Number of		
Gross alpha	pCi/L	17–3,000	130	5	5	Marcellus
Gross beta	pCi/L	32–4,200	1,200	5	5	Marcellus

Sources: 55 DCN SGE00740

Abbreviation: pCi/L—picocuries per liter

Similarly, the EPA identified limited radioactive constituent concentration data for UOG produced water. As presented in Table C-19, most available data characterize produced water from the Marcellus formation; limited data were available from the Niobrara formation. Radium-226 and radium-228 are both found in UOG produced water, with radium-226 concentrations generally two to five times greater than radium-228 concentrations.

The EPA identified the following limitations to the data presented in the table:

- Limited or no radioactive constituent concentration data were available for the majority of shale and tight formations.
- Many EPA methods are known to experience interference from high TDS concentrations or the presence of Group II elements, which are typical of UOG extraction wastewater, and may result in an underestimation of reported values. ERG's *Radioactive Materials in the Unconventional Oil and Gas (UOG) Industry* memorandum (54 DCN SGE00933) discusses potential interference issues associated with various EPA methods and notes that the following methods may experience interference from UOG extraction wastewater: 900.0 Gross Alpha and Gross Beta Radioactivity, 903.0 Alpha-Emitting Radium Isotopes, and 903.1 Radium-226, Radon Emanation Technique.

Table C-19. Concentrations of Select Radioactive Constituents in UOG Produced Water

Parameter	Formation	Method(s)	Range (pCi/L)	Median (pCi/L)	Number of Data Points	Number of Detects
Gross alpha	Marcellus	900.0	8.7 - 120,000	8,700	74	74
Gross alpha	Niobrara	900.0	620–4,000	1,800	3	3
Gross beta	Marcellus	900.0	6.8 - 21,000	1,600	73	72

Table C-19. Concentrations of Select Radioactive Constituents in UOG Produced Water

Parameter	Formation	Method(s)	Range (pCi/L)	Median (pCi/L)	Number of Data Points	Number of Detects
Gross beta	Niobrara	900.0	250–1,200	760	3	3
Radium-226	Marcellus	901.1 Mod., 903.0, 903.1, γ-spectrometry	0.16 - 27,000	1,700	103	101
Radium-226	Niobrara	901.1 Mod.	170–900	620	3	3
Radium-228	Marcellus	901.1. 903.0, 904.0, γ-spectrometry	0 - 1,900	470	94	92
Radium-228	Niobrara	901.1 Mod.	100–460	330	3	3

Sources: 56 DCN SGE00724

Abbreviations: pCi/L—picocuries per liter; NA—not available

As a point of comparison, Table C-20 includes data from a 2014 International Atomic Energy Agency report (96 DCN SGE00769) that included radium isotope concentrations in rivers, lakes, groundwater, and drinking water. Data for radium-228 were limited, but the average of measured concentrations of radium-226 found in U.S. rivers and lakes was 0.56 pCi/L (21 mBq/L). The median concentrations of radium-226 and radium-228 in UOG produced water in at least one of the formations presented in Table C-19 was above the maximum naturally occurring concentration in U.S. rivers, lakes, groundwater, or drinking water presented in Table C-20. Radium in groundwater may originate from rocks, soil, and other naturally occurring materials, which are likely also the origins of a portion of the radium in UOG produced water.

Table C-20. Concentrations of Radioactive Constituents in Rivers, Lakes, Groundwater, and Drinking Water Sources Throughout the United States (pCi/L)

Parameter	Location Description	Minimum	Maximum	Average
Radium-226	Boise, Idaho—well water	—	—	0.10
	Florida—groundwater	ND	76	—
	Florida—well water	0.20	3.3	—
	Hudson River	—	—	0.032
	Illinois—well water	0.020	23	—
	Illinois Lake	0.059	1.3	—
	Iowa—well water	0.10	48	—
	Iowa—well water	1.8	25	—
	Joliet, Illinois—well water	—	—	6.5
	Lake Ontario	0.04	1.7	—
	Memphis, Tennessee—well water	—	—	0.21
	Miami, Florida—well water	—	—	0.48
	Mississippi River	0.010	1.1	—
	Ottawa County, OK—well water	0.10	15	—
	Sarasota, Florida—groundwater	1.5	24	—
	South Carolina—well water	2.7	27	—

Table C-20. Concentrations of Radioactive Constituents in Rivers, Lakes, Groundwater, and Drinking Water Sources Throughout the United States (pCi/L)

Parameter	Location Description	Minimum	Maximum	Average
	South Texas—groundwater	0.40	170	—
	Suwannee River	—	—	0.20
	U.S. drinking water	0.011	4.9	—
	Utah—well water	1.0	20	—
	Wichita, Kansas—groundwater	—	—	0.23
Radium-228	Iowa—well water	0.60	6.3	—
	South Carolina—well water	4.7	12	—
	U.S. drinking water	0	0.014	—

Source: 96 DCN SGE00769

"—"—Data were not reported.

Note: Data are presented as they were reported, either as a range (i.e., minimum, maximum) or as an average value.

Abbreviations: pCi/L—picocuries per liter; ND—non detect

In January 2015, PA DEP announced the results of a study of radioactive elements in UOG extraction wastewater, sludge, and drill cuttings. Although PA DEP concluded "…[t]here is little potential for radiological exposure to workers and members of the public from handling and temporary storage of [flowback fluid and] produced water on natural gas well sites," they did conclude "…[t]here is a potential for radiological environmental impacts from spills of produced water [and flowback fluid] on natural gas well sites and from spills that could occur from the transportation and delivery of …[these] fluid[s]" (135 DCN SGE01028).

3.2.5 Other Constituents in UOG Extraction Wastewater

UOG produced water may also contain guar gum, which is a polymer that is commonly used in fracturing fluid to transport the proppant to the end of the wellbore (see Table C-2 and Table C-3). Guar gum may be found in UOG produced water at concentrations between 100 mg/L and 20,000 mg/L (193 DCN SGE00616). Guar gum treatment requires a breakdown of the polymer and is a consideration for UOG operators who are reusing/recycling wastewater for fracturing.

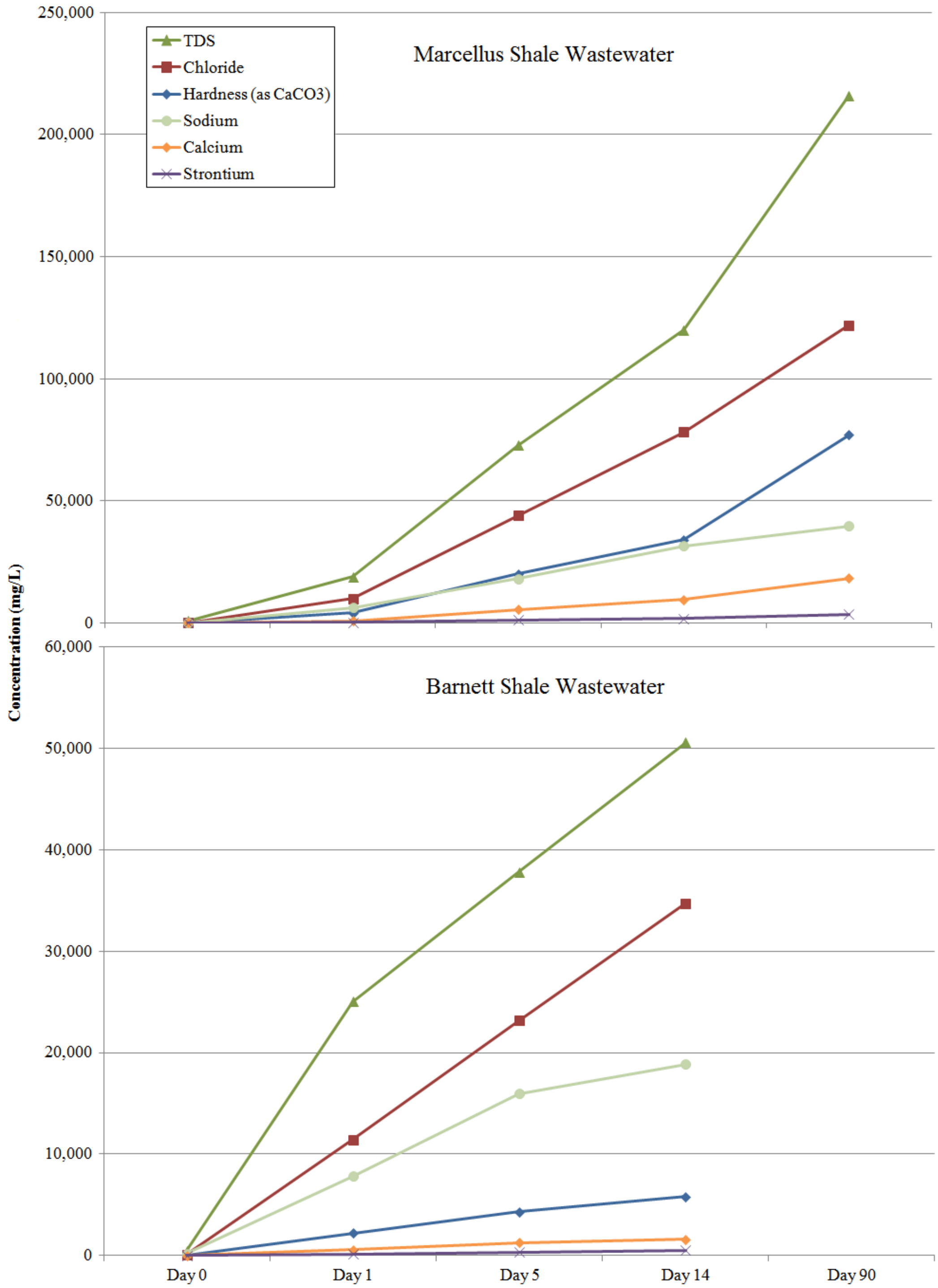
Microorganisms are also found in UOG drilling wastewater and produced water. Microorganisms may be present in concentrations as high as 1×10^9 organisms per 100 mL in UOG produced water (193 DCN SGE00616). Sulfate-reducing bacteria (SRB) are one classification of a naturally occurring microorganism that may be found in UOG produced water and drilling wastewater. SRB can cause problems during reuse/recycle of UOG produced water because they can reduce and/or precipitate metals and ions, potentially causing scale in the wellbore. They can also create hydrogen sulfide,[64] a potential human health concern that is also highly corrosive and can harm the well casing and wellbore (201 DCN SGE00721).

[64] Exposure to low concentrations of hydrogen sulfide may cause difficulty breathing and/or irritation to the eyes, nose, or throat. Exposure to high concentrations of hydrogen sulfide may cause headaches, poor memory, unconsciousness and death (4 DCN SGE00723).

3.3 UOG Produced Water Characterization Changes over Time

Concentrations of TDS, radioactive elements, and organic compounds vary across different formations and over time. However, for the vast majority of formations for which data are available, the data demonstrate that flowback and long-term produced water are both influenced by constituents present in the formation. For example, concentrations of select naturally occurring constituents commonly found in shale formations (e.g., bromide, magnesium) are found in elevated concentrations in flowback compared to hydraulic fracturing fluid. The elevated concentrations indicate that the formation is contributing concentrations of these constituents to the flowback. Similarly, concentrations of TDS and TDS-contributing constituents (e.g., sodium, chloride, calcium) increase over time as formation water and the dissolution of constituents out of the formation contribute to long-term produced water.

RPSEA's 2012 Characterization of Flowback Waters from the Marcellus and the Barnett Shale Regions (85 DCN SGE00414) presents sampling data from 19 sites in the Marcellus shale and five sites in the Barnett shale. The sampled constituents include a wide array of classicals, conventionals, organics, and metals. Where possible, these constituents were sampled at day 0, day 1, day 5, day 14, and day 90. Figure C-6 presents median data for select constituents as reported in the RPSEA report. Figure F-1 in the appendices presents median data for additional constituents as reported in the RPSEA report.



Source: The EPA generated this figure using data from 85 DCN SGE00414.

Figure C-6. Constituent Concentrations over Time in UOG Produced Water from the Marcellus and Barnett Shale Formations

Chapter D. UOG EXTRACTION WASTEWATER MANAGEMENT AND DISPOSAL PRACTICES

During the lifetime of a well, UOG extraction generates large volumes of UOG extraction wastewater that contain constituents potentially harmful to human health and the environment, as discussed in Chapter C. This creates a need for appropriate wastewater management infrastructure and disposal practices. Except in limited circumstances,[65] the existing effluent guidelines for oil and gas extraction prohibit the onsite direct discharge of wastewater into waters of the United States. Historically, operators primarily managed their wastewater via underground injection (where available). This section discusses the methods used by UOG operators to manage and dispose of UOG extraction wastewater.

1 OVERVIEW OF UOG EXTRACTION WASTEWATER MANAGEMENT AND DISPOSAL PRACTICES

For management of UOG produced water, UOG operators primarily use the three methods listed below and shown in Figure D-1 (188 DCN SGE00613; 177 DCN SGE00276; 76 DCN SGE00528).

- Dispose of wastewater via underground injection, using Class II UIC disposal wells ("disposal wells")
- Reuse/recycle wastewater in subsequent fracturing jobs
- Transfer wastewater to a CWT facility

Across the United States, operators most often manage their produced water via disposal wells. For management of drilling wastewater, which includes drill cuttings and drilling fluids, operators primarily use the methods listed below and shown in Figure D-2 (55 DCN SGE00740).

- Disposal via disposal wells
- Reuse/recycle in subsequent drilling and/or fracturing jobs
- Transfer to a CWT facility
- Onsite burial[66]
- Disposal via landfill
- Land application

In select areas, UOG operators also use evaporation ponds for disposal of UOG produced water and drilling wastewater. However, there are certain requirements for using evaporation ponds, including very dry climates, which mainly occur in the western United States (148 DCN

[65] While the existing oil and gas extraction ELG allows onshore oil and gas extraction wastewater generated west of the 98th meridian to be permitted for discharge when the water is of good enough quality for agricultural and wildlife uses (see 40 C.F.R. part 435 subpart E), the EPA has not found that these types of permits are typically written for UOG extraction wastewater (as defined for the proposed rule).

[66] Onsite burial involves temporary fluid storage in on-site open earthen or lined pits with burial of residual solids after fluids are solidified, removed from the top, or evaporated.

SGE00710). Evaporation ponds also require a large, flat site, and they perform best only during select months of the year (e.g., May through October) (114 DCN SGE00779.A24).

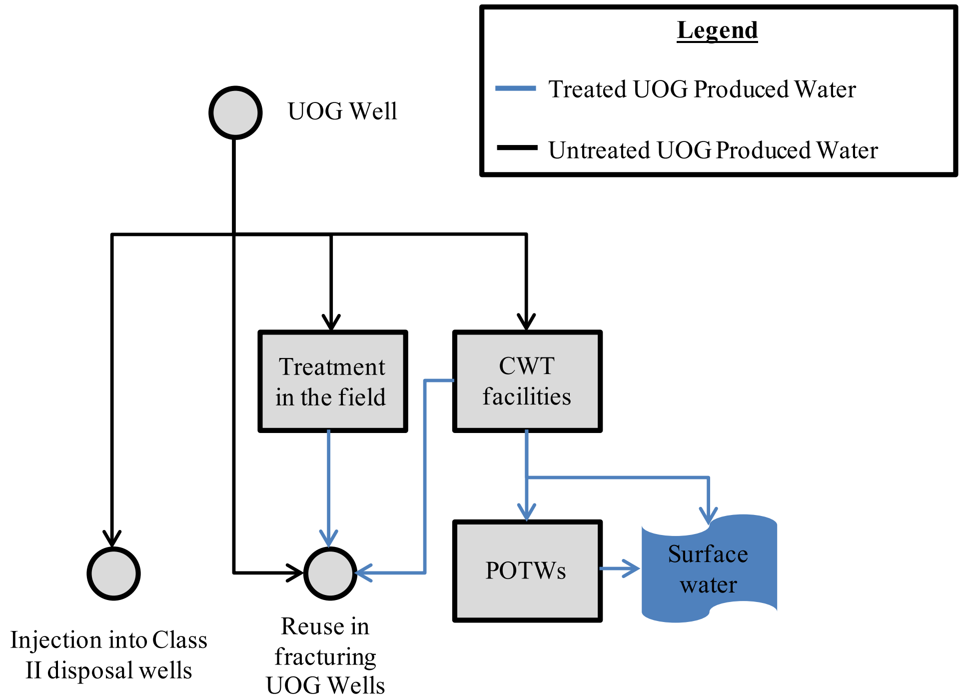


Figure D-1. UOG Produced Water Management Methods

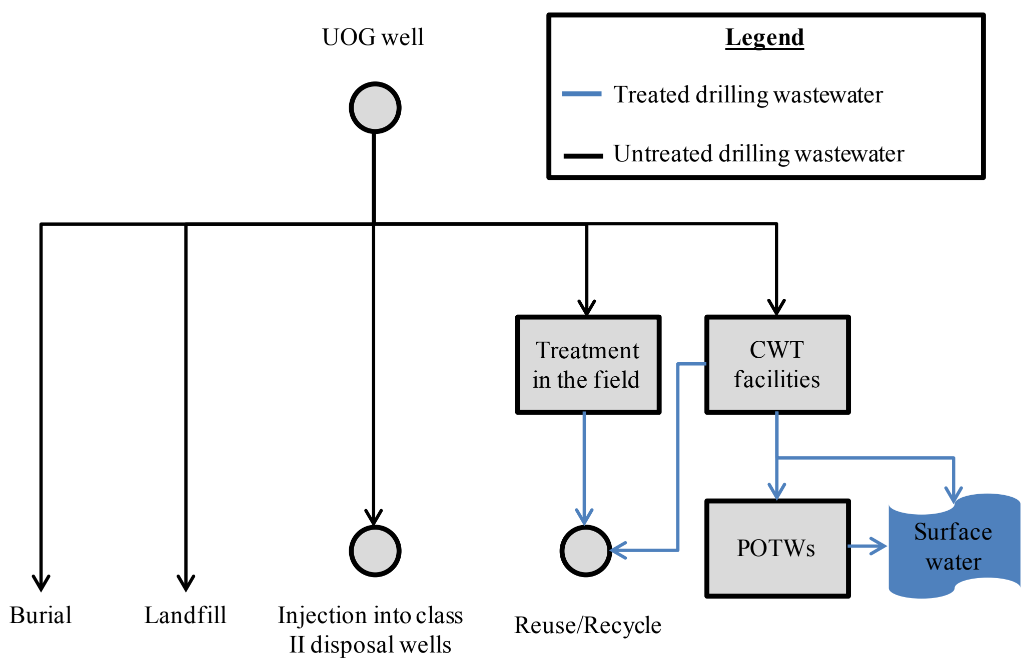


Figure D-2. UOG Drilling Wastewater Management Methods

UOG operators' frequency of use of each of the aforementioned UOG extraction wastewater management options varies by operator, by formation, and sometimes within each region of the formation (139 DCN SGE00579; 177 DCN SGE00276; 178 DCN SGE00635; 55 DCN SGE00740). Table D-1 describes how UOG operators manage produced water specifically in basins containing major UOG formations, which varies by basin and formation. As detailed above, historically, the oil and gas industry has most commonly managed produced water by underground injection (25 DCN SGE00182), but the industry is increasingly turning to reuse/recycle and, in some geographic areas, transferring to CWT facilities to manage growing volumes of wastewater (see Section D.3 and Section D.4) (43 DCN SGE00596; 92 DCN SGE00707; 34 DCN SGE00708).

The literature does not contain the same level of detailed information about drilling wastewater management practices as is provided for produced water management in Table D-1. However, the EPA did identify comprehensive data for management of drilling wastewater generated by Marcellus shale wells located in Pennsylvania. Figure D-3 shows management practices used by UOG operators in Pennsylvania for managing their UOG drilling wastewater from 2008 to 2013. In recent years (2010 to 2013), transfer to CWT facilities, reuse/recycle in drilling or fracturing, and injection for disposal—in that order—were the most common practices (46 DCN SGE00739) for UOG drilling wastewater management in Pennsylvania. In addition to this detailed information about drilling wastewater management in Pennsylvania, the EPA obtained information from a large UOG operator regarding its Fayetteville shale operations. This operator reported that it reuses/recycles the majority of its drilling wastewater in drilling subsequent wells and the remainder is disposed of via disposal wells (191 DCN SGE00625).

To illustrate how management practices used by UOG operators vary geographically, the EPA mapped the locations of known CWT facilities and disposal wells in the Appalachian basin (containing the Utica and Marcellus shale formations).[67] Figure D-4 compares the east and west portions of the basin, thus illustrating basin and formation differences in wastewater management practices. The east side of the basin contains very few underground disposal wells, but contains a high density of CWT facilities that have accepted or plan to accept UOG produced water from operators. In contrast, the west side has an abundance of disposal wells and injection for disposal is the primary wastewater management practice.

The remaining subsections in Chapter D describe UOG produced water management practices: how disposal in disposal wells is the most common practice, how reuse/recycle in fracturing fluid is increasing, and how increasing numbers of CWT facilities are accepting UOG produced water and drilling wastewater where disposal wells are limited. Although operators have discharged UOG extraction wastewater to POTWs, these discharges were discontinued in 2011 (46 DCN SGE00739; 80 DCN SGE00286; 109 DCN SGE00345; 139 DCN SGE00579). After describing the three management alternatives that the UOG industry uses (i.e., injection into disposal wells, reuse/recycle in fracturing, transfer to CWT facility), Chapter D ends with a discussion of POTWs and how they cannot remove some of the constituents in UOG extraction wastewater and drilling wastewater. The end of Chapter D also presents EPA-collected data

[67] The EPA obtained information about CWT facilities accepting UOG extraction wastewater from publicly available sources. Therefore, the list of CWT facilities the EPA identified may not be complete.

indicating that POTWs have not received any UOG extraction wastewater between 2011 and the present (data are current up through the end of 2013).

Table D-1. UOG Produced Water Management Practices

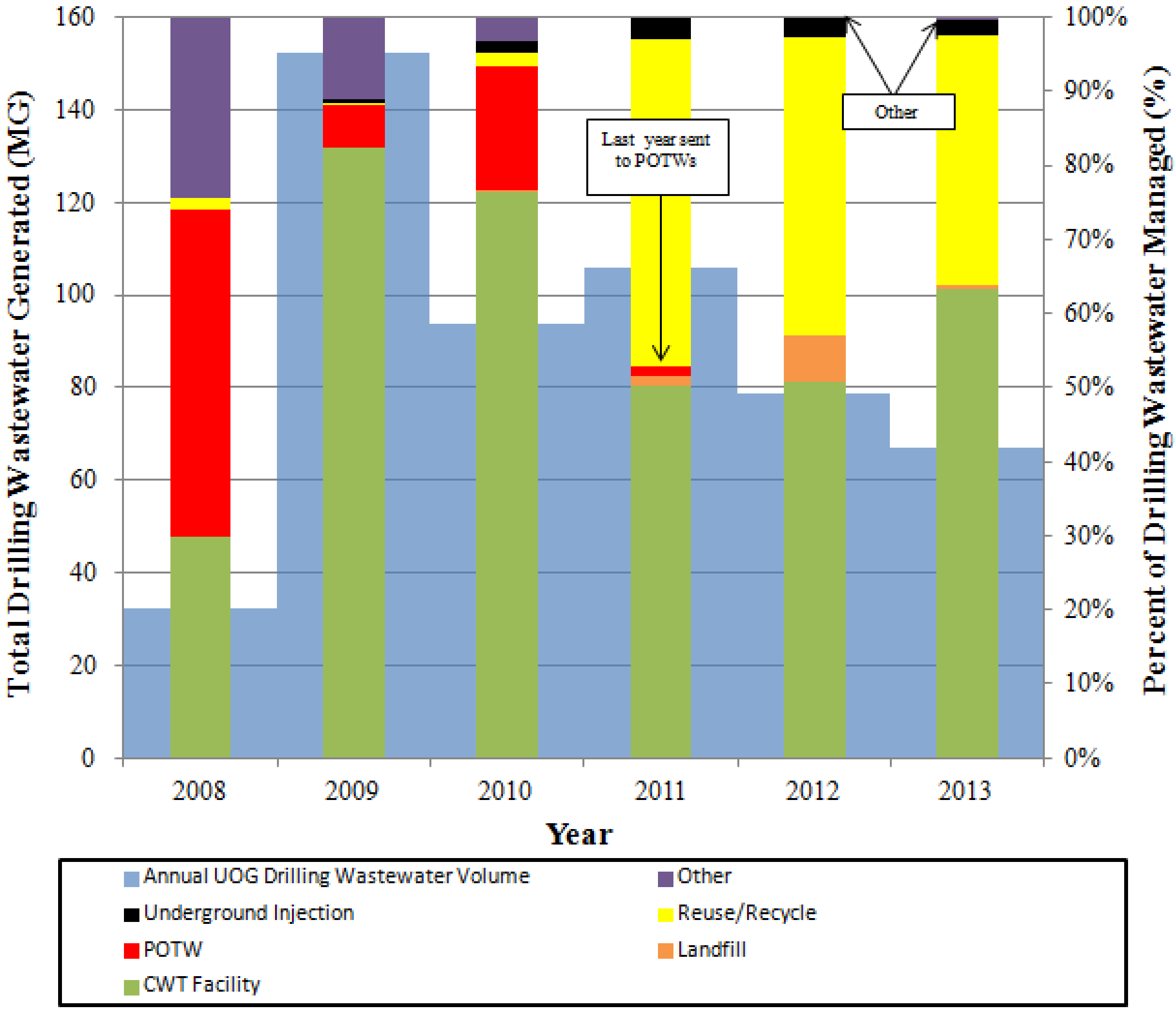
Basin	UOG Formation	Resource Type	Reuse or Recycle	Injection for Disposal	CWT Facilities	Notes	Available Data[b]
Michigan	Antrim	Shale gas		XXX			Qualitative
Appalachian	Marcellus/Utica (PA)	Shale gas	XXX	XX	XX		Quantitative
	Marcellus/Utica (WV)	Shale gas/oil	XXX	XX	X	Limited disposal wells in east	Quantitative
	Marcellus/Utica (OH)	Shale gas/oil	XX	XXX	X		Mixed
Anadarko	Granite Wash	Tight gas	XX	XXX	X[a]		Mixed
	Mississippi Lime	Tight oil	X	XXX		Reuse/recycling limited but is being evaluated	Qualitative
	Woodford, Cana, Caney	Shale gas/oil	X	XXX	X[a]		Qualitative
Arkoma	Fayetteville	Shale gas	XX	XX	X[a]	Few existing disposal wells; new CWT facilities are under construction	Mixed
Fort Worth	Barnett	Shale gas	X	XXX	X[a]	Reuse/recycle not typically effective due to high TDS early in flowback and abundance of disposal wells	Mixed
Permian	Avalon/Bone Springs, Wolfcamp, Spraberry	Shale/tight oil/gas	X	XXX	X[a]		Mixed
TX-LA-MS Salt	Haynesville	Tight gas	X	XXX		Reuse/recycle not typically effective due to high TDS early in flowback and abundance of disposal wells	Mixed
West Gulf	Eagle Ford, Pearsall	Shale gas/oil	X	XXX	X		Mixed
Denver Julesburg	Niobrara	Shale gas/oil	X	XXX	X		Mixed
Piceance; Green River	Mesaverde/Lance	Tight gas	X	XX	X	Also managed through evaporation to atmosphere in ponds in this region	Qualitative
Williston	Bakken	Shale oil	X	XXX		Reuse/recycling limited but is being evaluated	Mixed

Sources: 48 DCN SGE00693

a—CWT facilities identified in these formations are all operator-owned.

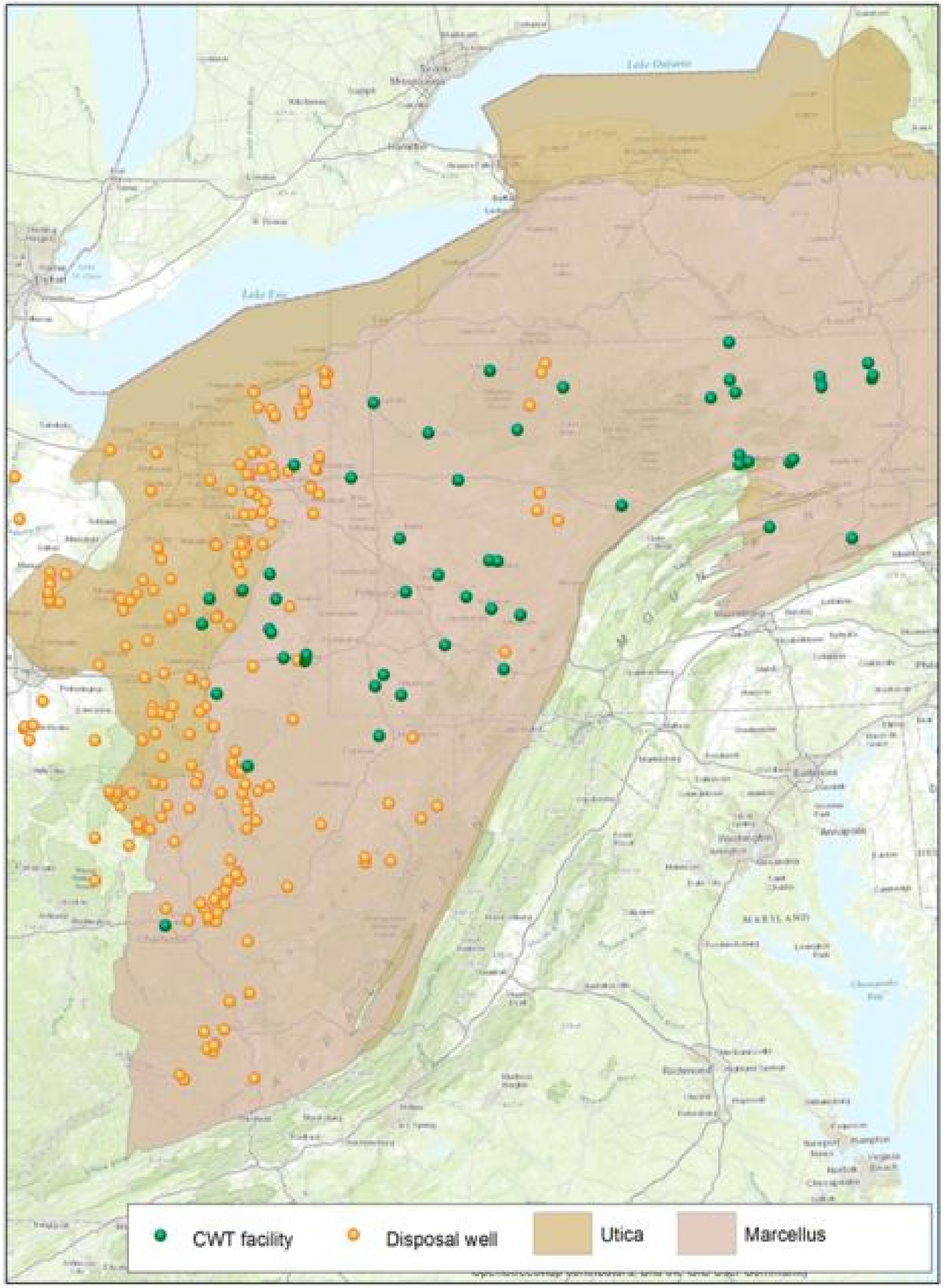
b—This column indicates the type of data the EPA based the number of Xs on. In most cases, the EPA used a mixture of qualitative and quantitative data sources along with engineering judgment to determine the number of Xs.

XXX—The majority (≥50%) of wastewater is managed with this management practice; XX—A moderate portion (≥10% and <50%) of wastewater is managed with this management practice; X—This management practice has been documented in this location, but for a small (<10%) or unknown percent of wastewater.



Sources: 46 DCN SGE00739

Figure D-3. Management of UOG Drilling Wastewater Generated by UOG Wells in Pennsylvania (2008–2013)



Sources: Generated by the EPA using data from 43 DCN SGE00596 and 41 DCN SGE00736

Figure D-4. Active Disposal Wells and CWT Facilities Identified in the Appalachian Basin[68]

[68] The active disposal wells data for New York were last updated in September 2009 for New York and December 2013 for Pennsylvania. The last update for the active disposal wells data in Ohio and West Virginia is unknown. The EPA accessed the Ohio data in February 2013 and the West Virginia data in December 2013. The CWT facility data were last updated at the end of 2013, based on publicly available information.

2 INJECTION INTO DISPOSAL WELLS

Historically, underground injection has been the most common wastewater management method among UOG operators. In 2010, the EPA and industry stakeholders estimated that over 90 percent of oil and gas produced water (conventional and unconventional) was disposed of via Class II injection wells (207 DCN SGE00623). Underground injection involves pumping wastes into an underground formation with a confining layer of impermeable rock. The formation must also be porous enough to accept the wastewater. In its underground injection well control program codified in 40 C.F.R. parts 144 to 148, the EPA established six classes of underground injection wells (173 DCN SGE00132):

- Class I industrial and municipal waste disposal wells
- Class II oil and gas related injection wells
- Class III mining wells
- Class IV shallow hazardous and radioactive injection wells (banned)
- Class V any not covered in Class I through IV (e.g., leach fields)
- Class VI carbon dioxide storage or sequestration

Class II injection wells serve three major purposes:

- Injection of hydrocarbons for storage
- Injection of fluids for disposal (i.e., disposal wells)
- Injection of fluids for enhanced recovery (i.e., enhanced recovery wells)

Approximately 20 percent of Class II wells in the United States are disposal wells; the remaining 80 percent are mostly enhanced recovery wells (173 DCN SGE00132). Injection for disposal typically involves injecting wastewater into a porous and non-oil-and-gas-containing reservoir. Industry does not use enhanced recovery wells for disposing of UOG extraction wastewater because most enhanced recovery projects consist of a closed-loop system with two or more wells: at least one producing well and at least one enhanced recovery well. Operators of enhanced recovery projects typically route the wastewater generated by the producing well directly back to the adjacent enhanced recovery well (206 DCN SGE00623; 173 DCN SGE00132; 188 DCN SGE00613). Available literature and communication with industry indicates that industry only hauls UOG extraction wastewater to Class II disposal wells and does not use Class II enhanced recovery wells. In fact, the leading method of UOG extraction wastewater management throughout the United States is injection into a Class II disposal well (51 DCN SGE00693.A03). However, all types of oil and gas extraction wastewater (e.g., conventional, CBM, UOG) may be disposed of in Class II disposal wells.

2.1 Regulatory Framework for Underground Injection

The EPA's regulations on underground injection wells are described in Chapter A. States, territories, and tribes have the option of requesting primacy, or primary enforcement authority, from the EPA for the Class II wells within their boundaries. In order to receive primacy, the state underground injection program must meet the EPA's regulatory requirements to prevent underground injection that endangers drinking water sources, or have a program determined to be effective as the federal standards. Currently, the EPA has delegated Class II primacy to 39 states, three territories and two tribes. The EPA has authority over the Class II UIC programs in the remaining 11 states, two territories and all other tribes (184 DCN SGE00611).

2.2 Active Disposal Wells and Volumes

The availability of underground injection for disposal varies by state. Some states have a large number of Class II injection wells (e.g., Texas, Oklahoma, Kansas) while others have few (e.g., Virginia, South Dakota). The EPA tabulated active Class II disposal wells using data from state agencies and EPA direct implementation programs. More information about how the EPA compiled data from state agencies is documented in a separate memorandum titled *Analysis of Active Underground Injection for Disposal Wells* (41 DCN SGE00736; 42 DCN SGE00736.A01).

Table D-2 presents the number of active Class II disposal wells by state (41 DCN SGE00736; 42 DCN SGE00736.A01). It also includes average daily disposal rates for disposal wells on a gallon-per-well-per-day basis for each state. Daily disposal rates of individual disposal wells vary significantly, reflecting the geology of the underlying formation (176 DCN SGE00279). The average disposal rate per well estimates in the table are not exact but rather are general approximations based on a number of assumptions which are described in detail in ERG's memorandum *Analysis of Active Underground Injection for Disposal Wells* (41 DCN SGE00736). Lastly, Table D-2 presents the total state disposal rate based on the active number of disposal wells and average daily disposal rates per well. States are first sorted by geographic region, then by the total state disposal rate. States with no disposal rate data are sorted by highest to lowest count of active Class II disposal wells.

Table D-2. Distribution of Active Class II Disposal Wells Across the United States

Geographic Region (from the EIA)	State	Number of Active Disposal Wells[a]	Average Disposal Rate Per Well (gpd/well)[b]	Total State Disposal Rate (MGD)
Alaska	Alaska	45	182,000	8.2
East	Illinois	1,054	—[c]	—[c]
	Michigan	779[g]	16,600	13
	Ohio	188	8,900	1.7
	Indiana	183	3,580	0.66
	West Virginia	66	7,180	0.47
	Virginia	12	17,500	0.21
	Kentucky	58	1,750	0.10
	Pennsylvania	9	6,380	0.057
	New York	10[d]	3,530	0.035
	Tennessee	0	0	0
	Maryland	0	0	0
	Minnesota	0	0	0
	North Carolina	0	0	0
Gulf Coast/Southwest	Texas	7,876	54,200	430

Table D-2. Distribution of Active Class II Disposal Wells Across the United States

Geographic Region (from the EIA)	State	Number of Active Disposal Wells[a]	Average Disposal Rate Per Well (gpd/well)[b]	Total State Disposal Rate (MGD)
	Louisiana	2,448	42,100	100
	New Mexico	736	48,600	36
	Mississippi	499	69,500	35
	Alabama	85	44,200	3.8
Mid-Continent	Oklahoma	4,622[g]	35,900	170
	Kansas	5,516	20,900	120
	Arkansas	611[e]	30,900	19
	Nebraska	113	18,100	2.0
	Missouri	11	1,270	0.014
Northern Great Plains	North Dakota	395	31,600	12
	Montana	199	31,100	6.2
	South Dakota	21	10,200	0.21
Rocky Mountains	Wyoming	330	—[c]	—[c]
	Colorado	294	50,200	15
	Utah	109	74,400	8.1
	Arizona	0	0	0
West Coast	California	826	77,800	64
All other states (NV, FL, OR, IA, and WA)[f]		42	89,400	3.8
Total		**27,137**	**40,400**	**1,040**

Sources: 41 DCN SGE00736

a—Number of active disposal wells is based primarily on data from 2012 to 2014.
b—Typical injection volumes per well are based on historical annual volumes for injection for disposal divided by the number of active disposal wells during the same year (primarily data 2007 to 2013). These approximations are based on a number of assumptions which are detailed in ERG's *Analysis of Active Underground Injection for Disposal Wells* memorandum (41 DCN SGE00736).
c—Disposal rates and/or number of disposal wells is unknown.
d—These wells are not currently permitted to accept UOG extraction wastewater (source: 186 DCN SGE00726).
e—Only 24 of the 614 active disposal wells in Arkansas are in the northern half of the state, close to the Fayetteville formation (6 DCN SGE00499).
f—These are states that have minimal oil and gas activity. The number of wells shown for these states may include all types of Class II wells (e.g., Class II enhanced recovery wells) and therefore is an upper estimate (167 DCN SGE00138). All other states not listed in this table have minimal oil and gas activity and no active disposal wells.
g—With the exception of Oklahoma and Michigan, wells on tribal lands have not been intentionally included. Wells on tribal lands may be counted if state databases contained them.
Abbreviations: gpd—gallons per day; MGD—million gallons per day

2.3 Underground Injection Considerations

In many UOG formations, distances from the average producing well to the nearest disposal well are short and disposal capacity is abundant, making it the least expensive UOG extraction wastewater management practice (178 DCN SGE00635). There is no widespread discussion in the industry about lack of injection well disposal capacity (188 DCN SGE00613) nationally, suggesting that there is enough capacity in place and; therefore, potential for continued acceptance of UOG extraction wastewater. However, as illustrated above, underground injection for disposal capacity in close proximity is much less available in certain portions of the United States. Another consideration is freshwater availability. In some areas with plentiful underground injection for disposal capacity where water scarcity is a problem, there is a concern about permanently disposing of UOG produced water underground rather than using it to supplement freshwater needs in subsequent hydraulic fracturing jobs (75 DCN SGE00760; 142 DCN SGE00583).

Commercial injection for disposal well operators may surcharge operators to dispose of flowback (176 DCN SGE00279). Injection well operators impose the surcharge because flowback has a lower density than long-term produced water. Injection of high-density wastewater requires less power (i.e., pumping) than injecting less-dense wastewater,[69] and the injection rate (i.e., barrels per day per well) is inversely proportional to the injection pressure due to technical and permit limitations. As a result, disposal well operators must inject lower-density flowback at a lower flow rate and more power.

3 REUSE/RECYCLE IN FRACTURING

As of 2013, many operators evaluate reusing/recycling UOG extraction wastewater before deciding to manage it via another method (i.e., disposal well or CWT facility) (188 DCN SGE00613; 38 DCN SGE00521; 177 DCN SGE00276). Reuse/recycle involves mixing flowback and/or long-term produced water from previously fractured wells with other source water[70] to create the base fluid[71] used in a subsequent well fracture (1 DCN SGE00046). Operators typically transport the wastewater, by truck or pipe, from storage to the fracturing site just before and during hydraulic fracturing. Operators typically store the wastewater in 10,500- to 21,000-gallon (200- to 500-barrel) fracturing tanks onsite until they are ready to blend it with other source water during the hydraulic fracture. When hydraulic fracturing begins, they pump the stored UOG produced water for reuse and other source water to a blender to form the base fluid. The blending usually occurs upstream of other steps such as fracturing chemical addition or pressurization by the pump trucks (191 DCN SGE00625).

Since the late 2000s, UOG operators have increased wastewater reuse/recycle (188 DCN SGE00613). In the early development of UOG (i.e., the early to mid-2000s), most operators believed that reuse/recycle was not technically feasible because high TDS concentrations in UOG extraction wastewater adversely affected fracturing chemical additives and/or formation geology (188 DCN SGE00613). As a result, operators used only fresh water as base fluid for fracturing. One of the changes that contributed to more widespread reuse of wastewater as a base fluid is that fracturing service providers were able to design fracturing additives to tolerate base fluids with higher concentrations of TDS (194 DCN SGE00691; 38 DCN SGE00521; 188 DCN SGE00613; 208 DCN SGE00095).

[69] The density of flowback is typically close to that of fresh water (8 pounds per gallon), while the density of produced water can be greater than 10 pounds per gallon (176 DCN SGE00279).

[70] Source water is any fluid that makes up fracturing base fluid. See Section C.1.1.

[71] Base fluid is the primary component of fracturing fluid to which proppant and chemicals are added. See Section C.1.1.

To date, slickwater fracturing fluid designs (defined in Section C.1) are the most accommodating for using base fluid that contains the high end of the TDS criteria ranges (see Table D-4 in section D.3.2 for these ranges) (188 DCN SGE00613; 40 DCN SGE00705; 193 DCN SGE00616). Gel designs (defined in Section C.1), which are typically used to fracture liquid rich plays (e.g., Bakken), are more complex and industry currently finds them to be less compatible with high concentrations of TDS than slickwater designs (40 DCN SGE00705; 188 DCN SGE00613; 193 DCN SGE00616). As a result, at present, gel designs require base fluid that meets the low end of the TDS criteria ranges (see Table D-4 in section D.3.2 for these ranges). This is primarily because TDS interferes with the properties of the cross-linked gels inherent to gel fracturing fluid designs. Industry also reports that boron is a constituent of concern for reuse/recycle when using gel recipes because it interferes with the intended delayed activation of cross-linked gels (193 DCN SGE00616; 40 DCN SGE00705). This may be changing: industry has recently demonstrated the use of higher-TDS base fluid in gel fracturing as new chemical additives are becoming available for gel designs that tolerate higher TDS concentrations[72] (110 DCN SGE00667; 40 DCN SGE00705).

PESA surveyed 205 UOG operators about their wastewater management practices in 2012 (136 DCN SGE00575).[73] Table D-3 presents the survey results. Nationally, UOG operators reported reusing/recycling 23 percent of total produced water generated. The results also showed that most operators anticipate reusing/recycling higher percentages of their produced water in the two to three years following the survey. Other research firms that gather data on UOG extraction wastewater management report similar findings (34 DCN SGE00708; 122 DCN SGE00709). For example, IHS Inc. estimates that in 2013 operators reused/recycled 16 percent of UOG produced water nationwide and expects this number to double by 2022 (34 DCN SGE00708). The EPA participated in several site visits and conference calls with operators in several formations that have been able to reuse/recycle 100 percent of their produced water under certain circumstances (178 DCN SGE00635; 179 DCN SGE00275; 191 DCN SGE00625; 183 DCN SGE00636).

Table D-3. Reuse/Recycle Practices in 2012 as a Percentage of Total Produced Water Generated as Reported by Respondents to 2012 Survey

Basin	UOG Formation	Resource Type	Percent of Wastewater Reused/Recycled for Fracturing	Percent of Wastewater Managed Using Other Methods[a]	Percent of Respondents Planning to Increase Reuse/Recycle
Appalachian	Marcellus/Utica	Shale gas/oil	74	26	50
TX-LA-MS Salt	Haynesville	Shale gas	30	70	67
Arkoma	Fayetteville	Shale gas	30	70	67
Western Gulf	Eagle Ford	Shale gas/oil	16	84	60
Fort Worth	Barnett	Shale gas	13	87	86
Permian	Avalon; Barnett-Woodford	Shale gas/oil	7	93	67
Williston	Bakken	Shale oil	5	95	56

[72] One vendor reported that testing of new additives for gel designs that allow the use of high-TDS base fluid is underway. This vendor expected the cost for these chemicals to initially be high (40 DCN SGE00705).

[73] Out of the 205 respondents, 143 represented operators active in major U.S. UOG plays.

Table D-3. Reuse/Recycle Practices in 2012 as a Percentage of Total Produced Water Generated as Reported by Respondents to 2012 Survey

Basin	UOG Formation	Resource Type	Percent of Wastewater Reused/Recycled for Fracturing	Percent of Wastewater Managed Using Other Methods[a]	Percent of Respondents Planning to Increase Reuse/Recycle
Gulf Coast (Austin Chalk, Cotton Valley, Vicksburg)[b]		Unknown	10	90	100
Mid-Continent (Woodford, Cana, Caney, Granite Wash)[b]		Unknown	25	75	68
Rockies (Niobrara, Mancos)[b]		Unknown	14	86	100
Weighted average			23	77	55

Source: 136 DCN SGE00575

a—PESA (136 DCN SGE00575) reported this as "disposal" but did not clearly describe what it means.
b—PESA (136 DCN SGE00575) did not specify basin or formation for these areas. The EPA provided formation names that are present in these areas if not already previously listed above.

3.1 Reuse/Recycle Strategies

Operators can reuse/recycle UOG extraction wastewater for fracturing through different strategies. An operator's choice of strategy depends on many factors, which Section D.3.2 describes in detail. The following subsections discuss direct reuse/recycle without treatment and reuse/recycle after treatment.

3.1.1 Direct Reuse/Recycle for Fracturing Without Treatment

Many operators reuse/recycle their wastewater for fracturing without any treatment (i.e., only blending with fresh water) or with minimal treatment such as sedimentation or filtration to remove suspended solids. The primary purpose of the blending is to control TDS concentrations (193 DCN SGE00616; 194 DCN SGE00691). When using this strategy, operators either transport UOG extraction wastewater directly to the next well they are fracturing or transport it to a temporary storage area offsite until they are ready to fracture the next well.

Reuse/recycle without treatment accounts for a large portion of all wastewater that industry reuses/recycles. In PESA's 2012 survey (136 DCN SGE00575), UOG operators reported that 54 percent of produced water reused/recycled by the UOG industry in 2012 for fracturing requires minimal or no treatment. In addition, the EPA conducted several site visits and conference calls with operators that have increasingly reused/recycled wastewater with no treatment (178 DCN SGE00635; 179 DCN SGE00275; 191 DCN SGE00625; 183 DCN SGE00636; 177 DCN SGE00276).

3.1.2 Reuse/Recycle in Fracturing After Treatment

Operators also reuse/recycle UOG extraction wastewater after some type of treatment. Where treatment is employed, the UOG industry typically uses one of two levels of treatment:

- **Non-TDS removal technologies**—technologies that remove non-dissolved[74] constituents from wastewater, including suspended solids, oil and grease, bacteria, and/or certain ions that can cause scale to form on equipment and interfere with fracturing chemical additives. These technologies are not designed to reduce the levels of dissolved constituents, which are the majority of compounds that contribute to TDS in UOG extraction wastewater.
- **TDS removal technologies**—technologies capable of removing dissolved constituents that contribute to TDS (e.g., sodium, chloride, calcium) as well as the constituents removed by non-TDS removal technologies. Treatment systems with these treatment technologies include non-TDS removal technologies for pretreatment (e.g., TSS, oil and grease).

Each of these levels of treatment is described in more detail below. Also see the EPA's report titled *Unconventional Oil and Gas (UOG) Extraction Wastewater Treatment Technologies* (203 DCN SGE00692), which discusses treatment technologies used to treat UOG produced water.

Non-TDS Removal Technologies

As discussed in Section D.3, there are constituents in UOG extraction wastewater other than TDS that operators may need to remove or destabilize before reuse/recycle. In particular, they may need to reduce constituents that may cause scale, formation damage, and/or interference between chemical additives and the formation geology (203 DCN SGE00692). These constituents include suspended solids, oil and grease, bacteria, and certain ions (e.g., iron, calcium, magnesium, and barium). Non-TDS removal technologies used to treat UOG extraction wastewater for reuse/recycle include (188 DCN SGE00613; 208 DCN SGE00095):

- Solids removal (e.g., sedimentation, filtration, dissolved air flotation)
- Chemical precipitation
- Electrocoagulation
- Advanced oxidation precipitation

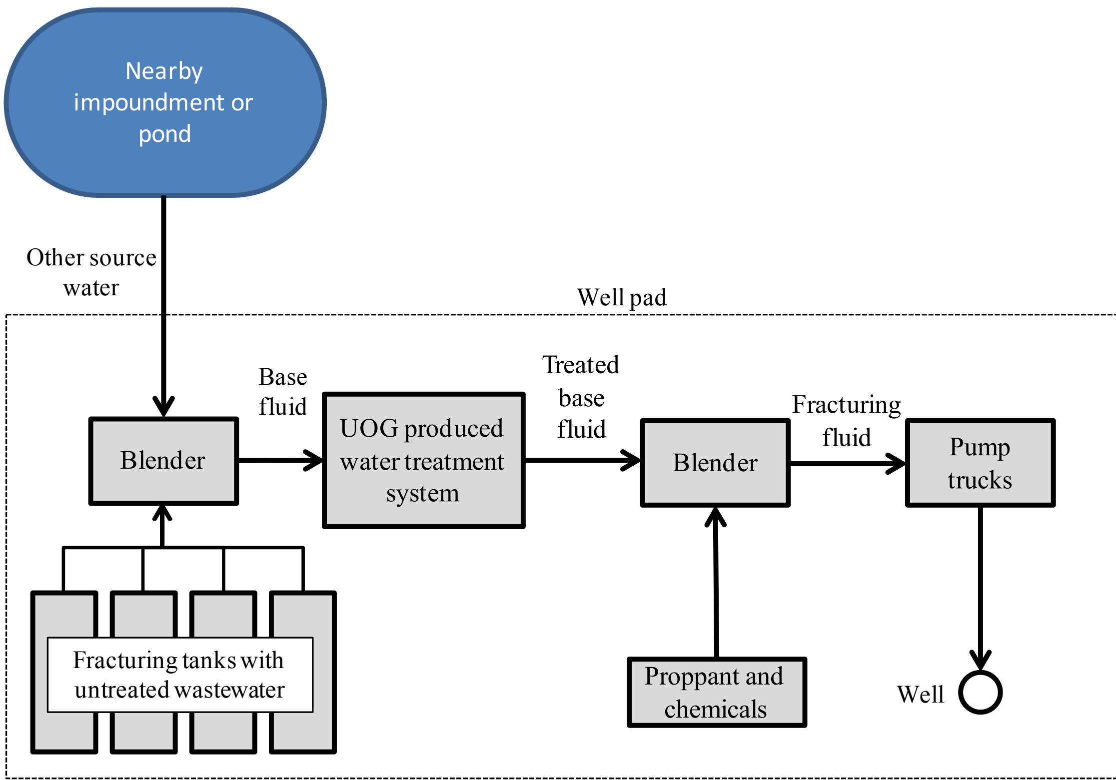
Industry often uses non-TDS removal technologies to remove or destabilize the aforementioned constituents. This treatment may be done in the field at the well site or off-site at a CWT facility. One method used in the field to treat UOG extraction wastewater is referred to as "on the fly" treatment, where the wastewater is treated as fluids are mixed for hydraulic fracturing.

Figure D-5 shows a simplified flow diagram of on-the-fly treatment of UOG produced water for reuse/recycle. In this practice, the operator treats the mixture of UOG produced water and other source water concurrently with the hydraulic fracturing process. Therefore, wastewater

[74] EPA has categorized treatment technologies into two categories in this document: those that are designed to remove dissolved constituents and those that are not designed to remove dissolved constituents. However, it should be noted that some of the technologies in the non-TDS removal category do in fact remove some dissolved constituents. For example, chemical precipitation will remove certain metals. However, these technologies typically will not remove salts and hardness, which are the primary components of TDS in UOG extraction wastewater.

treatment occurs at relatively high flow rates equivalent to the rate of hydraulic fracturing.[75] Other than the treatment unit, there is no additional equipment required in this setup that is not already required for hydraulic fracturing (e.g., additional storage typically required for treated wastewater). This eliminates or reduces the following (30 DCN SGE00331):[76]

- Transporting wastewater for reuse/recycle to a CWT facility and then transporting it again to the next well for fracturing
- Procuring the services of a CWT facility
- Purchasing or renting storage containers, and renting space on which to keep the storage containers, for treated wastewater



Source: Generated by EPA using 30 SGE00331.

Figure D-5. Flow Diagram of On-the-Fly UOG Produced Water Treatment for Reuse/Recycle

TDS Removal Technologies

In general, TDS removal technologies convert influent wastewater into two streams: concentrated brine and low-TDS water (i.e., distillate). As discussed in the introduction to

[75] Operators typically hydraulically fracture wells at rates of 2,520 to 5,040 gallons (60 to 120 barrels) per minute. On-the-fly treatment technologies must be capable of treating wastewater at the same rate (203 DCN SGE00692).

[76] The most common technology for on-the-fly treatment is advanced oxidation. This technology eliminates the need to add biocide to the fracturing fluid to prevent bacteria growth.

Section D.3, operators have learned that low-TDS base fluid is not necessarily required for fracturing. However, some operators may still use TDS removal technologies to treat wastewater for reuse/recycle in fracturing. TDS removal technologies that UOG operators have used to treat UOG extraction wastewater for reuse/recycle include (188 DCN SGE00613; 208 DCN SGE00095) reverse osmosis (when TDS is less than approximately 50,000 mg/L) and evaporation/condensation and crystallization (203 DCN SGE00692). Some vendors currently offer skid-mounted mobile TDS removal units for reuse/recycle in the field (203 DCN SGE00692). The EPA also identified several CWT facilities owned by operators that use TDS removal technologies (e.g., evaporation/condensation) (84 DCN SGE00284).

3.2 Reuse/Recycle Drivers

The reuse/recycle strategy operators choose depends on many different factors. The following subsections describe the two biggest drivers (148 DCN SGE00710):

- Pollutant concentrations in UOG extraction wastewater compared to maximum acceptable pollutant concentrations for base fluid (described in more detail in Section D.3.2.1)
- Volume of UOG extraction wastewater available for reuse/recycle compared to total volume of base fluid required for fracturing a new well (described in more detail in Section D.3.2.2)

These factors vary by formation and operator; therefore, the potential for reusing/recycling UOG extraction wastewater for fracturing also varies by formation and operator. These two drivers ultimately affect the level of treatment required, if any, and the total cost for reuse/recycle. Operators always consider the total cost per barrel for reuse/recycle as compared to other management alternatives.

3.2.1 Pollutant Concentrations in Available UOG Extraction Wastewater for Reuse/Recycle

Operators typically consider TDS when they evaluate whether they can reuse/recycle their wastewater and, if so, what level of treatment is required prior to reuse/recycle (148 DCN SGE00710). Operators are more likely to reuse/recycle UOG extraction wastewater with low TDS and high volumes to avoid TDS treatment and/or minimize freshwater usage. As explained in Section C.3.2.1 and shown in Figure C-6, TDS concentrations increase over time as the flow rate decreases after fracturing (148 DCN SGE00710, 85 DCN SGE00414, 27 DCN SGE00357, 151 DCN SGE00350, 191 DCN SGE00625). Therefore, operators are more likely to reuse/recycle flowback than long-term produced water because concentrations of TDS in flowback, on average, are lower than concentrations in long-term produced water (see Section C.3.2.1) (148 DCN SGE00710).

Some operators are able to reuse/recycle long-term produced water with no or minimal TDS treatment, as observed by the EPA in the Marcellus and Fayetteville shale formations (183 DCN SGE00636; 178 DCN SGE00635; 191 DCN SGE00625). However, this may not be possible in all UOG formations. As shown in Chapter C, the maximum concentration of TDS and the rate at which that concentration is reached are functions of the underlying geology. This means that, in some basins, the TDS concentrations for long-term produced water may be lower than the TDS concentrations for flowback in other basins. For example, in the Bakken formation, TDS concentrations in flowback increase rapidly to levels as high as 200,000 mg/L (within five days after fracturing), which may limit the volume of this wastewater capable of being used for reuse/recycle (151 DCN SGE00350).[77] On the other hand, the Fayetteville shale formation generates a maximum of 40,000 mg/L TDS in long-term produced water (191 DCN SGE00625).[78]

If operators reuse/recycle UOG extraction wastewater that contains too much of certain constituents, the fracturing fluid, well, and/or formation may undergo one or more of the following problems (3 DCN SGE00070):

- Fluid instability (change in fluid properties)
- Well plugging (restriction of flow)
- Well bacteria growth (buildup of bacteria on casing)
- Well scaling (accumulation of precipitated solids)
- Formation damage (restriction of flow in the reservoir)

Table D-4 shows ranges of observed or recommended constituent concentration criteria for the fracturing base fluid and the associated effect that the fluid or well may experience with concentrations in excess of the criteria. These ranges represent general values that industry reports, not values specific to one UOG formation. The exact criteria an operator uses depend on operator preference, geology, and the fracturing fluid chemistry (e.g., slickwater, gel), but the selected criteria typically fall within the ranges shown in Table D-4.

[77] This report determined that only the initial five percent of the injected fracturing fluid volume that returns to the surface contains TDS less than 60,000 mg/L in the Bakken, based on sampling data for 62 wells.

[78] This operator reported that they are able to reuse all of their UOG wastewater due to low TDS concentrations.

Table D-4. Reported Reuse/Recycle Criteria

Constituent	Reasons for Limiting Concentrations	Recommended or Observed Base Fluid Target Concentrations (mg/L,[a] After Blending)
TDS	Fluid stability	500–70,000
Chloride	Fluid stability	2,000–90,000
Sodium	Fluid stability	2,000–5,000
Metals		
Iron	Scaling	1–15
Strontium	Scaling	1
Barium	Scaling	2–38
Silica	Scaling	20
Calcium	Scaling	50–4,200
Magnesium	Scaling	10–1,000
Sulfate	Scaling	124–1,000
Potassium	Scaling	100–500
Scale formers[b]	Scaling	2,500–2,500
Phosphate	Not reported	10
Other		
TSS	Plugging	50–1,500
Oil	Fluid stability	5–25
Boron	Fluid stability	0–10
pH (SU)	Fluid stability	6.5–8.1
Bacteria (counts/mL)	Bacterial growth	0–10,000

Sources: 48 DCN SGE00693

a—Unless otherwise noted.
b—Includes total of barium, calcium, manganese, and strontium.

Abbreviations: mg/L—milligrams per liter; SU—standard units; mL—milliliter

3.2.2 Base Fluid Demand for Fracturing

The amount of wastewater used in fracturing fluid make up depends not just on wastewater pollutants and concentrations but also on wastewater quantity compared to the amount of water required for the base fluid.

Water Demand at the Well Level

The volume of fracturing fluid required per well for fracturing may also influence the level of treatment or blending ratio necessary to meet the base fluid pollutant criteria in Table D-4. The blending ratio is the volume of reused/recycled wastewater as a percent of the total base fluid volume used to fracture a specific well. The blending ratio depends on the wastewater pollutants and concentrations as well as on the volume of UOG extraction wastewater available and the total volume of base fluid required. Operators must consider how much wastewater is generated by nearby wells with respect to how much fracturing fluid is required to fracture a subsequent well. In areas where produced water volume generation is high and/or the required total base fluid volume for fracturing is low, operators may use a high blending ratio. As explained above, this high ratio may require more treatment depending on TDS and other constituent concentrations. On the other hand, in formations where produced water volume generation is low and total base fluid fracturing volume is high, operators may use a low blending ratio. A low blending ratio can typically be used with little to no treatment (179 DCN SGE00275; 178 DCN SGE00635; 188 DCN SGE00613). Table D-5 shows observed blending ratios for various formations. This table also includes theoretical upper end blending ratios as presented in literature which are based on the typical fracturing fluid volume and produced water volume generated per well[79] for each formation (215 DCN SGE00627; 126 DCN SGE00639; and 194 DCN SGE00691).

Table D-5. Reported Reuse/Recycle Practices as a Percentage of Total Fracturing Volume

Basin	Formation	Resource Type	Observed Blending Ratio[a] (%)	Estimated Maximum Potential Blending Ratio[b] (%)
Anadarko	Cleveland	Tight	—	10–40
	Granite Wash	Tight	—	10–40
	Mississippi Lime	Tight	—	50
Appalachian	Marcellus	Shale	10–12	10–40
	Utica	Shale	—	10–40
Arkoma	Fayetteville	Shale	6–30	—
Denver J.	Niobrara	Shale	—	10–40
Fort Worth	Barnett	Shale	4–6	10–40
Permian	—[c]	Shale/tight	2–40	50
TX-LA-MS Salt	Haynesville	Shale	5	5–10
	Tuscaloosa Marine	Shale	25	—
Western Gulf	Eagle Ford	Shale	—	10–40

Sources: 48 DCN SGE00693

Note: Data years represented range from 2009 to 2013.
a— Actual observed volumes of reused/recycled UOG extraction wastewater as a percentage of fracturing fluid volume.
b— Estimated maximum blending ratio based on typical flowback volume per well compared to typical fracturing volume per well as presented in 215 DCN SGE00627; 126 DCN SGE00639; and 194 DCN SGE00691.
c— References do not specify a specific formation.
"—" indicates no data.

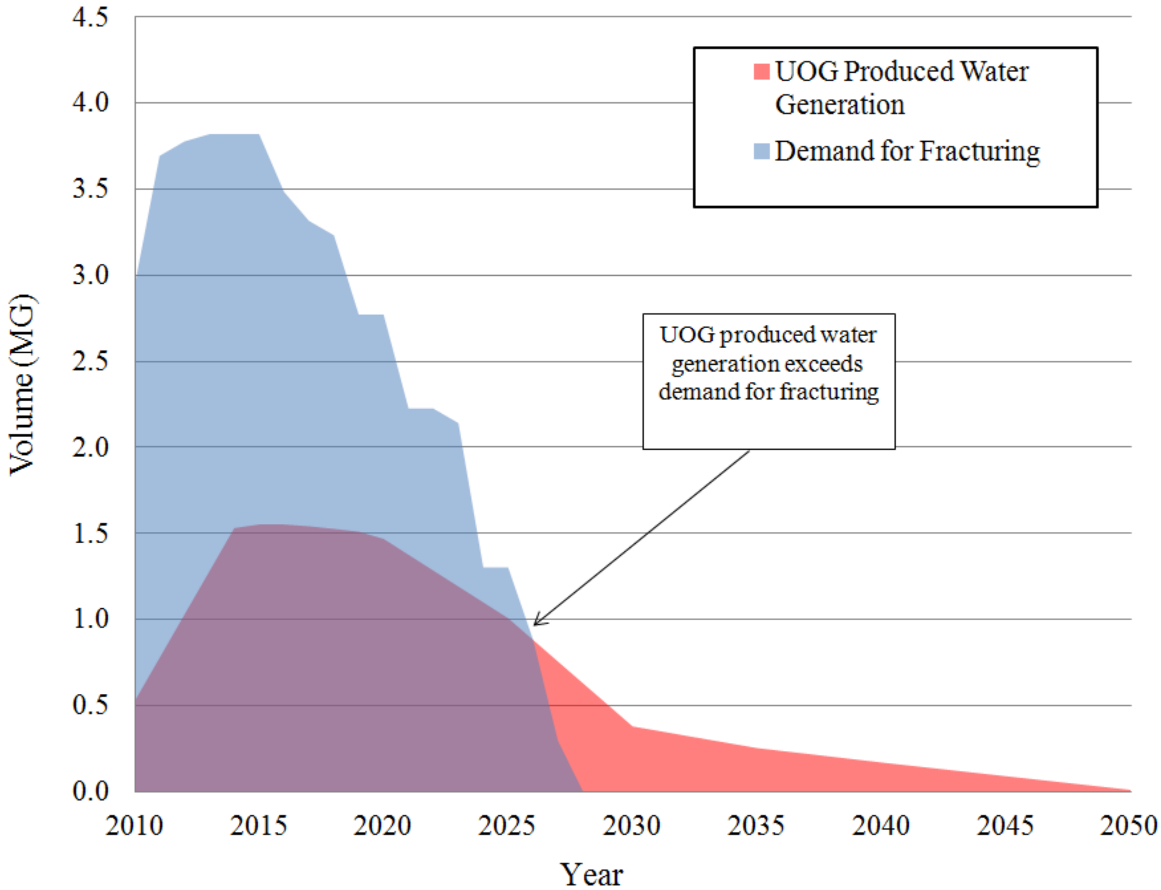
Water Demand at the Formation Level

Although reuse/recycle has become popular as a way to manage UOG extraction wastewater, it is anticipated to become less attractive as a formation matures and the operator drills and fractures fewer wells (148 DCN SGE00710). As a formation matures, the volume of base fluid needed to fracture new wells may be less than the volume of produced water generated by producing wells in the area (191 DCN SGE00625). Figure D-6 illustrates this concept[80] with a hypothetical situation for an operator in a single formation as reported by an operator (20 DCN SGE00305.A03). During early years of development, the base fluid demand for fracturing wells

[79] This theoretical value reported in literature is irrespective of constituent concentrations.

[80] This concept assumes that operators do not typically share wastewater for reuse in fracturing.

always exceeds the volume of produced water generated. This provides favorable conditions for reuse/recycle. As drilling decreases, the volume of base fluid needed decreases below the volume of produced wastewater generated. Consequently, the operator must find an alternative for at least some portion of the produced water (e.g., disposal well).



Source: 48 DCN SGE00693 (Generated by the EPA based on figure in 20 DCN SGE00305.A03)

Figure D-6. Hypothetical UOG Produced Water Generation and Base Fracturing Fluid Demand over Time

3.3 Other Considerations for Reuse/Recycle

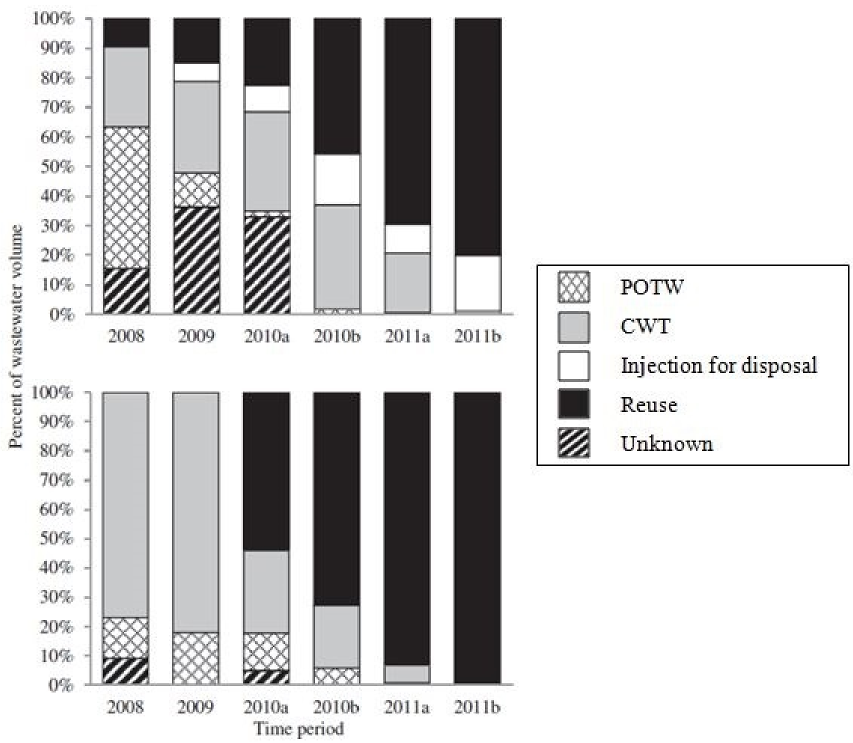
In addition to the level of treatment required for reuse/recycle, operators consider the following as they decide whether to reuse/recycle their wastewater:

- Wastewater transportation
- Wastewater storage
- Source water availability and cost

3.3.1 Transportation

Transportation requirements affect the wastewater reuse/recycle potential in a specific area. While not explicitly stated above, the location of the producing well(s) relative to the location of disposal well(s), CWT facilities, and/or a subsequent well(s) to be drilled is also a consideration. Operators must determine and compare the cost (dollars per barrel) to transport the wastewater for all management scenarios.

Further, when an UOG well generating wastewater is far from alternative management approaches such as a disposal well or CWT facility, reuse/recycle may also be more economical. The distance between disposal wells and CWT facilities from the UOG well generating the wastewater can vary by formation and even within formations. For example, Figure D-7 shows how operators in the northeast region of the Marcellus reused/recycled a higher percentage of wastewater compared to the southwestern region between 2008 and 2011 (139 DCN SGE00579). This is due to the fact that Marcellus wells in the southwestern part of Pennsylvania are closer to disposal wells in Ohio, whereas Marcellus wells in the northeast portion of Pennsylvania are more than 200 miles from disposal wells in Ohio. As a result, it is typically less expensive per barrel to reuse/recycle the wastewater in the northeast than to transport it to a disposal well in Ohio because transportation alone can cost as much as $13 per barrel (180 DCN SGE00300).



Source: Graphic reprinted with permission from Brian Rahm (139 DCN SGE00579)
Note: "a" and "b" for 2010 and 2011 represent the first and second half of the year, respectively.

Figure D-7. UOG Extraction Wastewater Management Practices Used in the Marcellus Shale (Top: Southwestern Region; Bottom: Northeastern Region)

3.3.2 Storage

Storage requirements and the number of wells the operator is drilling per unit time under its drilling program may also dictate when operators can reuse/recycle wastewater. In general, the effective storage cost to the operator increases the longer UOG extraction wastewater is stored before reuse in a subsequent well[81] (179 DCN SGE00275). For example, an operator who is considering reusing extraction wastewater for fracturing that fractures 12 wells per year in an area will need to store wastewater for approximately one month before the next fracturing job. In comparison, an operator who fractures 50 wells per year in an area may only need to store wastewater for a week before they can reuse/recycle it in the next fracturing job (39 DCN SGE00283). Section B.2.1 explains UOG extraction wastewater storage options in more detail.

3.3.3 Source Water Availability

Operators that successfully reuse/recycle their wastewater can reduce the total volume of other types of source water they need to use for base fluids, creating an offset in costs associated with source water (208 DCN SGE00095). Fresh water from rivers and streams is relatively abundant and inexpensive in some areas, but in others it can be a stressed resource. Seasonal droughts can cause a high demand for resources and operators can experience inflated acquisition costs. Reuse/recycle is more likely to be driven by these reasons for operators in arid or drought-prone regions than for operators in regions where freshwater and groundwater resources are abundant and inexpensive (142 DCN SGE00583; 148 DCN SGE00710). This is because as the cost of fresh water and groundwater increases, the offset in costs from reusing/recycling wastewater to replace other source water also increases.[82] Examples of such areas include California, the Denver Julesburg and Permian basins, and the Eagle Ford shale formation (148 DCN SGE00710). In addition, as mentioned above, a lack of disposal wells in some areas may be another driver behind wastewater reuse/recycle activity in some areas (e.g., Marcellus shale).

4 TRANSFER TO CWT FACILITIES

Some operators manage UOG extraction wastewater by transporting it to CWT facilities. Treated UOG extraction wastewater at CWT facilities is either discharged[83] or returned to the operator for reuse/recycle in fracturing. Operators may choose to use CWT facilities primarily when other wastewater management options (e.g., disposal wells) are not available where they are operating (148 DCN SGE00710; 138 DCN SGE00139; 25 DCN SGE00182).

This section provides a general overview of the types of CWT facilities that exist and that UOG operators may use for wastewater management, typical CWT facility treatment processes, CWT facilities that EPA is aware of that have in the past or currently accept UOG extraction wastewater, and considerations for using CWT facilities to manage UOG extraction wastewater.

4.1 Types of CWT Facilities

A CWT facility is 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 offsite (40 C.F.R 437.2(c)). CWT facilities that accept UOG extraction wastewater are sometimes run by the UOG operator and are sometimes

[81] This is primarily because many operators rent fracturing tanks on a per-tank-per-day basis. Even if operators purchase fracturing tanks instead, the effective cost to the operator still increases as storage time increases.

[82] Transportation distances may also affects costs.

[83] Discharge includes both indirect discharge (to a POTW) and direct discharge (to surface water).

run by an entity not engaged in the oil and gas extraction business. Since UOG development ramped up in the late 2000s, new CWT facilities that accept extraction wastewater from operators have become available (43 DCN SGE00596), mostly in areas with less underground injection capacity. In addition, many UOG operators have vertically integrated their companies by purchasing or constructing their own CWT facilities (see Section D.2.2) (43 DCN SGE00596). Some CWT facilities accept only oil and gas wastewater while others accept a variety of industrial wastewater. They follow different discharge practices:

- Zero discharge (treated wastewater is typically reused in fracturing or disposed of in an Class II disposal well)
- Discharge (to surface waters or POTWs)
- Multiple discharge options (a mix of discharge and zero discharge)

Pollutant discharges to surface waters or to POTWs from CWT facilities are not subject to the Oil and Gas Extraction ELGs (40 C.F.R. part 435). Rather, they are subject to the Centralized Waste Treatment ELGs promulgated in 40 C.F.R. part 437. Unlike the Oil and Gas Extraction ELGs, 40 C.F.R. part 437 includes limitations and standards for both direct and indirect dischargers.

The level of treatment CWT facilities use depends on the fate of the treated wastewater. The two primary types of treatment technologies are non-TDS removal technologies[84] and TDS removal technologies[85], defined in Section D.3. In general, CWT facilities typically use non-TDS removal technologies for treatment before reuse/recycle and TDS removal technologies for treatment before indirect or direct discharge.

4.1.1 Zero Discharge CWT Facilities

After treatment, a zero discharge CWT facility does not discharge the wastewater to surface water or a POTW. Instead, it typically returns the wastewater to UOG operators for reuse/recycle in fracturing.[86] CWT facilities that accept UOG extraction wastewater from operators and fall into this category typically allow them to unload a truckload of wastewater for treatment and take a load of treated wastewater on a cost-per-barrel basis (37 DCN SGE00245). Others may allow an operator to unload a truckload of wastewater for a surcharge without taking a load of treated wastewater, as long as other operators need additional treated wastewater. Most of these CWT facilities provide minimal (i.e., non-TDS removal) treatment, but some also use TDS-removal technologies.

4.1.2 Discharging CWT Facilities

Some CWT facilities discharge treated wastewater either indirectly to a POTW or directly to surface waters. As discussed in Section A.2.1.1, discharges from the CWT facility to

[84] Examples of CWT facilities using this level of treatment are described in 191 DCN SGE00625; 178 DCN SGE00635, 37 DCN SGE00245, 116 DCN SGE00481, and 89 DCN SGE00379.

[85] Examples of CWT facilities using this level of treatment are described in 93 DCN SGE00476, 23 DCN SGE00366, 19 DCN SGE00367, and 140 DCN SGE00374.

[86] Zero discharge CWT facilities may also evaporate the wastewater or send it to underground injection wells (205 DCN SGE00374).

the POTW are controlled by an Industrial User Agreement that must incorporate the pretreatment standards set out in 40 C.F.R. part 437 and requirements set out in 40 C.F.R. part 403. Surface water discharges from CWT facilities are controlled by NDPES permits that include pollutant discharge limitations based on water-quality-based limitations and the technology-based limitations set out in 40 C.F.R. part 437. The level of treatment typically depends on the requirements in the NPDES permit, which may or may not include restrictions on TDS. Direct-discharging CWT facilities use a mixture of TDS and non-TDS removal technologies. However, new state regulations in Pennsylvania, for example, have led direct-discharging CWT facilities to use more TDS removal technologies (43 DCN SGE00596).

4.1.3 CWT Facilities with Multiple Discharge Options

Some discharging[83] CWT facilities may also recycle a portion of the treated wastewater. Consequently, these types of CWT facilities may employ both non-TDS and TDS removal technologies. One such facility is Eureka Resources in Williamsport, Pennsylvania. The Eureka CWT facility holds a General Permit (WMGR123NC005)[87] from PA DEP that includes limits[88] for TDS (500 mg/L), chloride (25 mg/L), and radium-226 + radium-228 (5 pCi/L), among others. The Eureka CWT facility uses a non-TDS removal technology (chemical treatment) followed by a TDS removal technology (evaporation/condensation) (180 DCN SGE00300). Operators may take a load of treated wastewater for reuse/recycle that the facility treated using the non-TDS removal technology train or using the entire treatment train (both non-TDS and TDS removal technologies). There are no permit limits that must to be met for wastewater that is treated for reuse. The level of treatment is based on the operators' specifications.

4.2 Active CWT Facilities Accepting UOG Extraction Wastewater

To date, the EPA has identified 73 CWT facilities that have accepted or plan to accept UOG extraction wastewater. Most of them accept only oil and gas wastewater, not wastewater from other industries. Table D-6 shows the total number of CWT facilities, by state, that have accepted or plan to accept UOG extraction wastewater. The table includes a breakdown by treatment level and facility discharge type (described in Section D.4.1). The majority of these facilities can treat between 87,000 and 1,200,000 gallons (2,100 and 29,000 barrels) per day (43 DCN SGE00596).[89]

To generate Table D-6, the EPA used information from state agencies (e.g., PA DEP statewide waste reports), CWT facility websites, and news articles. The collected information is documented in a separate memorandum titled *Analysis of Centralized Waste Treatment (CWT) Facilities Accepting UOG Extraction Wastewater* (43 DCN SGE00596), which lists known CWT facilities along with information such as permit number, location, treatment capacity, and treatment level when available. Because few states keep comprehensive lists of CWT facilities,

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[87] More information available online at: http://files.dep.state.pa.us/Waste/Bureau%20of%20Waste%20Management/WasteMgtPortalFiles/SolidWaste/Residual_Waste/GP/WMGR123.pdf.

[88] In addition to setting discharge limitations to the nearby POTW, Eureka's General Permit allows it to treat wastewater for reuse purposes only, in which case there are no actual limits.

[89] To exclude outliers, the EPA presents the 10th and 90th percentiles of reported treatment capacities at CWT facilities.

Table D-6 likely underestimates the number of CWT facilities accepting UOG extraction wastewater.[90]

Table D-6. Number, by State, of CWT Facilities That Have Accepted or Plan to Accept UOG Extraction Wastewater

State	UOG Formation(s) Served	Zero Discharge CWT Facilities[a]		CWT Facilities That Discharge to a Surface Water or POTW[a]		CWT Facilities with Multiple Discharge Options[a]		Total Known Facilities
		Non-TDS Removal	TDS Removal	Non-TDS Removal	TDS Removal	Non-TDS Removal	TDS Removal	
AR	Fayetteville	2	0	0	0	0	1	**3**
CO	Niobrara, Piceance Basin	3(1)	0	0	0	0	0	**3**
ND	Bakken	0	1 (1)	0	0	0	0	**1**
OH	Utica, Marcellus	10 (7)	0	1	0	0	0	**11**
OK	Woodford	2	0	0	0	0	0	**2**
PA	Utica, Marcellus	23	7(3)	6	0	0	3 (1)	**39**
TX	Eagle Ford, Barnett, Granite Wash	1	3	0	0	0	0	**4**
WV	Marcellus, Utica	4 (2)	0	0	0	1	1	**6**
WY	Mesaverde and Lance	0	2	0	0	0	2	**4**
Total		**45**	**13**	**7**	**0**	**1**	**7**	**73**

Sources: 43 DCN SGE00596

a—Number of facilities includes facilities that have not yet opened but are under construction, pending permit approval, or are in the planning stages. Facilities that are not accepting UOG extraction wastewater but plan to in the future are noted parenthetically.

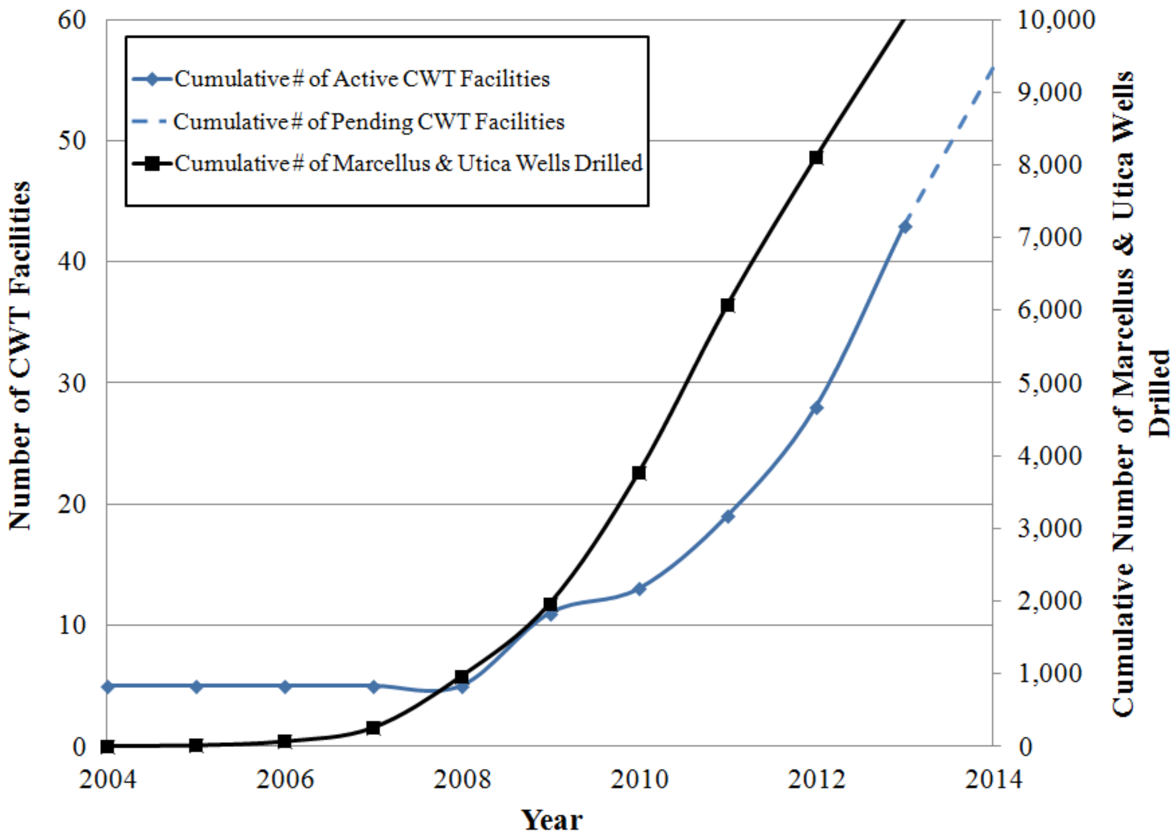
This information shows that CWT facilities have developed in regions of increasing oil and gas production, especially in areas where capacities for other management practices are less available (138 DCN SGE00139). To illustrate this, the EPA analyzed the number of active CWT facilities available to Marcellus shale and Utica shale operators where there are few disposal wells in some parts of the region.[91] Figure D-4 illustrates how the eastern half of the Appalachian basin contains many CWT facilities and few disposal wells and the western half contains many disposal wells and few CWT facilities. Figure D-8 shows the trend over time of active CWT facilities available to operators in the Marcellus and Utica shales,[92] along with the number of UOG wells drilled. The number of CWT facilities available to operators in the Marcellus and Utica shales has increased with the number of wells drilled. The EPA observed a similar trend in the Fayetteville shale formation in Arkansas. Although Arkansas has several hundred active disposal wells, only 24 wells are located in the northern half of the state in close proximity to Fayetteville shale wells (41 DCN SGE00736). As a result, the largest active operator in the Fayetteville shale has constructed three CWT facilities. The EPA anticipates that

[90]The information in Table D-6 is current as of 2013; it is possible that since 2013 some listed CWT facilities have closed and/or some CWT facilities not listed have begun operation.

[91] This analysis included Pennsylvania, West Virginia, and Ohio.

[92] The Marcellus and Utica shale formations are in the Appalachian basin.

more CWT facilities will become available near UOG formations where access to disposal wells is limited as additional UOG wells are drilled.



Sources: 43 DCN SGE00596

Figure D-8. Number of Known Active CWT Facilities over Time in the Marcellus and Utica Shale Formations

5 Discharge to POTWs

In locations where disposal wells and CWT facilities are limited or transportation distances are a factor, operators have, in the past, managed UOG extraction wastewater by discharge to POTWs. This practice can be problematic because POTWs do not use technologies that can remove some UOG extraction wastewater constituents (e.g., TDS). Also, constituents in UOG extraction wastewater such as TDS may interfere with POTW operations and may increase pollutant loads in receiving streams to the detriment of downstream water use (80 DCN SGE00286; 109 DCN SGE00345; 139 DCN SGE00579; 82 DCN SGE00531; 226 DCN SGE00633; 77 DCN SGE01077).[93]

[93] GWPC, 2014 (77 DCN SGE01077) states, “For a POTW to accept a waste stream for treatment, the facility must show that the accepted waste will not interfere with the treatment process or pass through the facility untreated. Since POTWs are typically not designed to treat fluids with constituents found in produced water (e.g., high TDS concentrations, hydrocarbons, etc.), problems have occurred as a result of produced water being sent to POTWs including impacts to the treatment process or the discharge of constituents at levels detrimental to the receiving water body.”

This section provides an overview of typical treatment processes used at POTWs, a discussion of how constituents commonly found in UOG extraction wastewater interact with POTWs (including examples of POTWs that have been used to manage UOG extraction wastewater), a review of POTWs that have accepted UOG extraction wastewater, and the current status of UOG extraction wastewater discharges to POTWs.

5.1 POTW Background and Treatment Levels

40 C.F.R. part 403.3(q) defines a POTW as "a treatment works as defined by section 212 of the [Clean Water] Act,[94] which is owned by a State or municipality." POTWs are designed to treat residential, commercial, and industrial wastewater, focusing on the removal of suspended solids and dissolved organic constituents. Table D-7 presents concentrations of weak, moderate, and strong domestic wastewater as would be typically experienced by a POTW (i.e., influent).

Table D-7. Typical Composition of Untreated Domestic Wastewater

Constituent	Concentrations (mg/L)		
	Weak	Moderate	Strong
TDS	270	500	860
COD	250	430	800
TSS	120	210	400
BOD_5	110	190	350
TOC	80	140	260
Oil and grease	50	90	100
Chlorides	30	50	90
Nitrogen, total	20	40	70
Sulfate	20	30	50
Phosphorus, total	4	7	12
Nitrates	0	0	0
Nitrites	0	0	0

Source: 119 DCN SGE00167

Abbreviation: mg/L—milligrams per liter

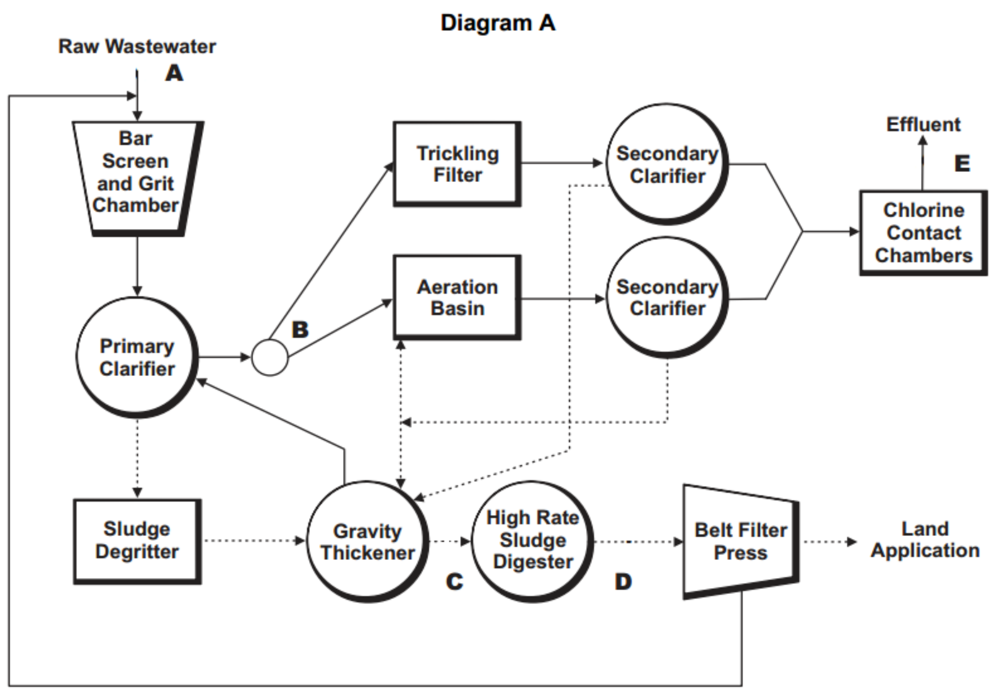
Typical treatment processes used at POTWs are categorized into the following levels:

- **Primary treatment,** capable of removing some suspended solids and organic matter from influent wastewater using unit operations such as screening and clarification.
- **Secondary treatment,** capable of removing additional suspended solids and biodegradable organic matter from influent wastewater using biological treatment processes, such as activated sludge and trickling filters. Secondary treatment is sometimes followed by chlorination or ultraviolet (UV) disinfection to reduce microbial pathogens.

[94] Section 212 of the CWA defines the term "treatment works" as "any devices and systems used in the storage, treatment, recycling, and reclamation of municipal sewage or industrial wastes of a liquid nature."

- **Tertiary (advanced) treatment,** capable of removing other pollutants, such as nutrients, not removed in secondary treatment using processes such as nitrification/denitrification and activated carbon adsorption (119 DCN SGE00167).

Figure D-9 shows a typical process flow diagram for a POTW. The processes shown include primary treatment (screen, grit chamber, primary clarifier), secondary treatment (trickling filter, aeration, secondary clarifier), and disinfection (chlorine). The diagram also shows sludge treatment (gravity thickening, digestion, filter press) before use/disposal (e.g., land application).



Source: 165 DCN SGE00602

Figure D-9. Typical Process Flow Diagram at a POTW

In general, the average POTW in the United States has primary and secondary treatment. In addition to treated wastewater, POTW treatment processes produce residual solids (sludge), including biosolids generated during biological treatment and other suspended material removed in clarifiers. Most POTWs apply additional treatment to the sludge, typically gravity thickening followed by stabilization (e.g., anaerobic digestion) and dewatering (e.g., filter press). After this additional treatment, most sludge is either put to a beneficial use (e.g., land application, soil enrichment) or disposed of in a landfill or incinerator (161 DCN SGE00599).

Table D-8 shows typical removal percentages for various constituents. As discussed, removal rates for suspended solids are high (90 percent for TSS) and removal rates for metals and salts are low (6 percent for cobalt, 8 percent for TDS).

Table D-8. Typical Percent Removal Capabilities from POTWs with Secondary Treatment

Constituent	POTW Percent Removal (%)	Constituent	POTW Percent Removal (%)
Aluminum	91	Mercury	72
Ammonia as nitrogen	39	Molybdenum	19
Antimony	67	Naphthalene	95
Arsenic	66	Nickel	51
Barium	16	Oil and grease (as HEM)	86
Beryllium	72	Phenol	95
BOD_5	89	Phenolics, total recoverable	57
Boron	30	Phosphorus, total	57
Cadmium	90	Pyridine	95
Calcium	9	Selenium	34
Carbon disulfide	84	Silver	88
Chloride	57	Sodium	3
Chlorobenzene	96	Sulfate	85
Chloroform	73	Sulfide	57
Chromium	80	TDS	8
Cobalt	6	Thallium	72
COD	81	Tin	42
Copper	84	Titanium	92
Cyanide	70	TOC	70
Ethylbenzene	94	Toluene	96
Fluoride	61	Total petroleum hydrocarbons	57
Iron	82	TSS	90
Lead	77	Vanadium	10
Magnesium	14	Xylenes (m+p, m, o+p, o)	65 to 95
Manganese	36	Zinc	79

Source: 164 DCN SGE00600
Note: 164 DCN SGE00600 references data from the November 5, 1999, updated 50-POTW study and the RREL database compiled for the CWT effluent guidelines.

Table D-9 shows the breakdown of U.S. POTWs categorized according to their level of treatment. As of 2008, secondary treatment was the most common level of treatment at POTWs.

Table D-9. U.S. POTWs by Treatment Level in 2008

Treatment Level	Percent of Facilities (%)	Number of Facilities	Design Capacity (MGD)
Less than secondary (e.g., primary)	0.2	30	546
Secondary	49.4	7,302	17,765
Greater than secondary (e.g., tertiary, advanced)	34.3	5,071	23,710
No discharge	15.2	2,251	2,557
Partial treatment[a]	0.8	115	287
Total	**99.9**	**14,769**	**44,866**

Source: 166 DCN SGE00603

a—These facilities provide some treatment to wastewater and discharge their effluent to other wastewater facilities for further treatment and discharge.

Abbreviation: MGD—million gallons per day

5.2 History of POTW Acceptance of UOG Extraction Wastewater

As operators began extracting oil and gas from unconventional formations, UOG operators discharged wastewater to POTWs in some cases (80 DCN SGE00286; 109 DCN SGE00345; 139 DCN SGE00579).[95] The EPA located the most comprehensive data about this practice in Pennsylvania. Therefore, this subsection primarily discusses data from PA DEP, though it also includes discussions about a few POTWs in West Virginia and New York. The PA DEP data indicate that the majority of UOG operators in Pennsylvania who decided to discharge to POTWs did so by 2008[96] (127 DCN SGE00188). To identify POTWs that accepted wastewater from UOG operations,[97] the EPA reviewed the following sources:

- Notes from calls with regional and state pretreatment program coordinators (182 DCN SGE00742, 192 DCN SGE00743)
- Notes from an EPA-state implementation pilot project with the Environmental Council of the States in coordination with the Association of Clean Water Administrators (196 DCN SGE00762)
- EPA Region 3's website (174 DCN SGE00368)
- Site visits, conference calls, and meetings with industry representatives (188 DCN SGE00613; 38 DCN SGE00521), UOG operators (191 DCN SGE00625; 178 DCN SGE00635; 179 DCN SGE00275; 190 DCN SGE00280), CWT facilities (181 DCN SGE00299; 180 DCN SGE00300; 37 DCN SGE00245; 36 DCN SGE00244), and Native American tribal groups (202 DCN SGE00785).
- PA DEP's statewide waste report data[98] (127 DCN SGE00188; 46 DCN SGE00739)
- The U.S. DOE's 2010 *Water Management Technologies Used by Marcellus Shale Gas Producers* report (212 DCN SGE00011)
- Publicly available data sources identified through Internet searches

The EPA compiled and analyzed much of these existing data in a separate document, *Publicly Owned Treatment Works (POTW) Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction* (52 DCN SGE00929). This memorandum is referenced throughout Section D.5.

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[95] EPA acknowledges that COG operators are still using POTWs as a viable option for disposal of COG wastewater.

[96] EPA did not identify any information indicating when POTWs in New York began accepting of UOG extraction wastewater. EPA also could not definitely determine when UOG operators in Pennsylvania began discharging UOG extraction wastewater at POTWs because the 2007 PA DEP Waste Report data are incomplete.

[97] EPA could not determine the date when POTWs began accepting UOG wastewater in all instances. The EPA has documentation that all POTWs in Pennsylvania stopped accepting UOG extraction wastewater by the end of 2011.

[98] PA DEP's waste report data provide wastewater volumes by well over time and management/disposal information as it was reported by the oil and gas well operator to PA DEP. ERG's memorandum titled *Analysis of Pennsylvania Department of Environmental Protection's (PA DEP) Oil and Gas Waste Reports* provides more detail (46 DCN SGE00739).

The EPA identified POTWs that, at one time, accepted wastewater from UOG operators generated by Marcellus shale wells. Table D-10 presents information about POTWs that have accepted UOG extraction wastewater directly from onshore UOG operators.

Table D-10. POTWs That Accepted UOG Extraction Wastewater from Onshore UOG Operators

Facility Name	NPDES Permit No.	City	State	POTW Currently Accepting UOG Wastewater from UOG Operator?	Year POTW Stopped Accepting UOG Wastewater from UOG Operator
Allegheny Valley Joint Sewer Authority	PA0026255	Cheswick	PA	No	2008
Altoona Water Authority—Easterly WWTP	PA0027014	Altoona	PA	No	2011
Belle Vernon Borough	PA0092355	Belle Vernon	PA	No	2009
Borough of Jersey Shore	PA0028665	Jersey Shore	PA	No	2010
Brownsville Municipal Authority	PA0022306	Brownsville	PA	No	2008
California Borough	PA0022241	California	PA	No	2009
Charleroi Borough	PA0026891	Charleroi	PA	No	2008
City of Auburn	NY0021903	Auburn	NY	No	2008
City of Johnstown Redevelopment Authority—Dornick Point	PA0026034	Johnstown	PA	No	2010
City of McKeesport	PA0026913	McKeesport	PA	No	2011
City of Watertown	SPDES NY 002 5984	Watertown	NY	No	2010
Clairton Municipal Authority	PA0026824	Clairton	PA	No	2011
Clearfield Municipal Authority	PA0026310	Clearfield	PA	No	2009
Dravosburg	PA0028401	Dravosburg	PA	No	2008
Lock Haven City STP	PA0025933	Lock Haven	PA	No	2008
Mon Valley Sewage Authority	PA0026158	Donora	PA	No	2008
Moshannon Valley Authority STP	PA0037966	Rush Township	PA	No	2009
Reynoldsville Sewer Authority	PA0028207	Reynoldsville	PA	No	2011
Ridgway Borough	PA0023213	Ridgway	PA	No	2011
Waynesburg Borough Water System	PA0020613	Waynesburg	PA	No	2008

Source: 52 DCN SGE00929

Based on data collected through June 2014, the EPA concluded that none of the POTWs listed in Table D-10 currently accept wastewater directly from UOG operations. That is, no UOG extraction wastewater is currently being managed by discharging to any of the POTWs in this table. This is, in large part, a result of UOG operators' compliance with PA DEP's April 2011 request that they stop discharging UOG extraction wastewater to POTWs (see Section A.2.2). PA DEP data indicate that UOG operators in Pennsylvania stopped sending their waste to POTWs in 2011 (127 DCN SGE00188). Furthermore, the EPA has not been able to identify any POTW in any state that is accepting UOG extraction wastewater directly from an operator. In addition, the EPA collected data about UOG operations on tribal reservations, UOG operators that are affiliated with Indian tribes, and POTWs owned or operated by tribes that may accept industrial wastewater (202 DCN SGE00785). According to this information, there are no tribes operating UOG wells that discharge wastewater to POTWs, nor are there any tribes that own or operate POTWs that accept UOG extraction wastewater. As such, the EPA concludes that operators have determined that discharge to a POTW is not a necessary and/or appropriate option for managing UOG extraction wastewater.

The EPA is aware of a few cases where UOG operators discharge wastewater to CWT facilities for treatment and those CWT facilities discharge to POTWs. As explained in Section A.2.1.2, such discharges are not subject to the ELGs for the oil and gas extraction category which is the subject of the proposed rule. Rather, discharges to POTWs from CWT facilities are subject to ELGs for the Centralized Waste Treatment Category (40 C.F.R. part 437).

The EPA reviewed PA DEP statewide waste reports (46 DCN SGE00739) and discharge monitoring report (DMR) data (175 DCN SGE00608) to identify the total volumes of UOG extraction wastewater and average total influent wastewater for each POTW. Using these data sources, the EPA calculated the maximum annual average daily[99] percentage of UOG extraction wastewater accepted by the POTW as shown in Table D-11. The EPA found that discharges of UOG extraction wastewater from UOG operators to POTWs peaked in 2008 and the last known discharge was in 2011.

Table D-11 also presents the year in which the maximum annual average daily volume occurred and the corresponding UOG extraction wastewater volume being accepted by the POTW during that year. The contribution of UOG extraction wastewater out of the total volume of wastewater treated at the POTW is typically a small percentage (less than 1 percent). However, based on the data presented in Table D-11, the contribution of UOG extraction wastewater was much higher (e.g., up to 21 percent) for some POTWs for some years.

[99] PA DEP waste reports provided the total volume of UOG extraction wastewater delivered to the POTW each year. The EPA divided the annual volume by 365 to calculate the annual average daily flow of UOG extraction wastewater accepted at the POTW.

Table D-11. Percentage of Total POTW Influent Wastewater Composed of UOG Extraction Wastewater at POTWs Accepting Wastewater from UOG Operators

POTW Name	NPDES Permit No.	Maximum Annual Average Daily UOG Extraction Wastewater Volume Accepted (gpd)	Corresponding Total Annual Average Daily Influent Flow to POTW (MGD)[a]	Maximum Annual Average Daily UOG Extraction Wastewater Percent of POTW Influent (%)	Year of Maximum Annual Average Daily UOG Extraction Wastewater Volume
Belle Vernon Borough	PA0092355	93,000	0.44	21[b]	2008
California Borough	PA0022241	84,000	0.60	14	2008
Charleroi Borough	PA0026891	180,000	1.74	10	2008
Waynesburg Borough Water System	PA0020613	56,000	0.58	9.7	2008
Mon Valley Sewage Authority	PA0026158	67,000	3.47	1.9	2008
City of Johnstown Redevelopment Authority—Dornick Point	PA0026034	130,000	9.47	1.4	2008
Brownsville Municipal Authority	PA0022306	9,400	0.88	1.1	2008
City of Auburn	NY0021903	1,800	0.20	0.91	2008
Borough of Jersey Shore	PA0028665	6,000	0.69	0.88	2008
Allegheny Valley Joint Sewer Authority	PA0026255	30,000	4.30	0.69	2008
Ridgway Borough	PA0023213	4,500	0.97	0.47	2010
Dravosburg	PA0028401	1,300	0.33	0.39	2008
Clairton Municipal Authority	PA0026824	12,000	4.15	0.30	2009
Moshannon Valley Authority STP	PA0037966	3,400	2.29	0.15	2008
Reynoldsville Sewer Authority	PA0028207	930	0.80	0.12	2010
City of McKeesport	PA0026913	11,000	16.25	0.07	2009
Bellefonte Water Treatment Plant	PA0020486	1,400	1.99	0.07	2008
Lock Haven City STP	PA0025933	1,800	2.84	0.06	2008
Altoona Water Authority	PA0027014	2,500	6.86	0.04	2011

Sources: 52 DCN SGE00929

a—This is the total influent wastewater flow to the POTW (domestic sewage and UOG extraction wastewater) in the year associated with the maximum UOG extraction wastewater volume received by the POTW.
b—The average total flow through the POTW (MGD) in 2008 was calculated using the average of four months of available data (September 2008 through December 2008).

Abbreviations: gpd—gallons per day; MGD—million gallons per day

5.3 How UOG Extraction Wastewater Constituents Interact with POTWs

POTWs are likely effective in treating only some of the pollutants in UOG extraction wastewater. Most POTWs are designed to primarily treat domestic wastewater. They typically provide at least secondary-level treatment and, thus, are designed to remove suspended solids and organic material. However, secondary treatment technologies are not designed to treat the high concentrations of TDS, radioactive constituents, metals, chlorides, sulfates, and other dissolved inorganic constituents found in UOG extraction wastewater.[100] Because they are not typical of POTW influent wastewater, UOG extraction wastewater constituents:

- May be discharged, untreated, from the POTW to the receiving stream
- May disrupt the operation of the POTW (e.g., by exceeding permit limits for BOD_5 or TSS in discharges, by inhibiting sludge settling)
- May accumulate in sludge, limiting its use
- May facilitate the formation of disinfection byproducts (DBPs)

Where available, the EPA reviewed the following information related to POTWs that have accepted UOG extraction wastewater:

- Local limit evaluations completed by POTWs' pretreatment program coordinators
- Technical evaluations of the impact of oil and gas wastewater pollutants on POTW unit processes completed in response to Administrative Orders (AOs)[101] issued to a number of POTWs by PA DEP
- Pass through analyses completed by POTWs
- DMR data from times when POTWs accepted UOG extraction wastewater

In many cases, POTWs that accepted UOG extraction wastewater also accepted COG extraction wastewater. Because the UOG extraction wastewater constituents that are discussed in this chapter are also present in COG extraction wastewater (205 DCN SGE00956; 18 DCN SGE00966), information and studies on the treatability of these constituents by POTWs (or their impacts on POTWs) are similarly relevant when those POTWs are accepting only COG extraction wastewater and/or a combination of COG and UOG extraction wastewater. In most of the case studies presented in this chapter, the POTWs that were accepting UOG extraction wastewater were also accepting COG wastewater.

The EPA also reviewed common textbooks on wastewater treatment technology effectiveness. These textbooks indicated that POTWs would likely be ineffective for treatment of certain pollutants in UOG extraction wastewater, such as TDS and many pollutants that

[100] Some POTWs provide tertiary treatment, which removes additional nutrients as well as constituents targeted for removal using secondary treatment. Similar to secondary treatment, tertiary treatment processes are not designed to treat the high concentrations of TDS, radioactive constituents, metals, chlorides, sulfates, and other dissolved inorganic constituents found in UOG extraction wastewater.

[101] PA DEP issued AOs to many POTWs in Pennsylvania that were accepting or suspected to begin accepting wastewater from UOG operations.

contribute to TDS (164 DCN SGE00600). The EPA used all of this information to evaluate treatment effectiveness at POTWs, primarily for TDS.

In addition to information about POTWs accepting oil and gas extraction wastewater, the EPA collected available information about other discharges to POTWs from industrial sources containing pollutants found in UOG extraction wastewater. The case studies presented in Sections D.5.3.1.2 and D.5.3.2.2 involve discharges to POTWs from CWT facilities that accepted oil and gas extraction wastewater. To the extent that a CWT facility discharges to a POTW and also lacks technologies that remove some oil and gas extraction pollutants (e.g., TDS), information on resulting POTW effluent concentrations (and/or inhibition) can be used as a proxy for UOG extraction operator discharges to a POTW.

Table D-12 summarizes the POTW studies and analyses that are presented in Section D.5.3.1 and Section D.5.3.2. Section D.5.3.1 discusses the potential for UOG pollutants to be discharged, untreated, from POTWs. Section D.5.3.2 discusses the potential for UOG wastewater pollutants to cause or contribute to inhibition and disruption at POTWs.

Table D-12. Summary of Studies About POTWs Receiving Oil and Gas Extraction Wastewater Pollutants

POTW	Summary of Study Findings
POTWs Accepting Wastewater from Oil and Gas Operators	
Clairton, PA, POTW	Treatment system influent and effluent samples show minimal or no TDS and chloride removals. See Section D.5.3.1.1.
McKeesport, PA, POTW	Treatment system influent and effluent samples show less than 10% removal of TDS, chloride, sulfate, and magnesium at the POTW. See Section D.5.3.1.1.
Ridgway, PA, POTW	TDS and chloride concentrations in effluent from the POTW were highest when the POTW was accepting the greatest volume of oil and gas extraction wastewater (including UOG extraction wastewater). Local limits analysis assumed zero percent removal of TDS, chloride, and sulfate at the POTW. See Section D.5.3.1.1.
Charleroi, PA, POTW	Treatment system influent and effluent samples show minimal or no TDS removal. The POTW rejects influent oil and gas wastewater with TDS greater than 30,000 mg/L and/or chloride greater than 15,000 mg/L. See Section D.5.3.1.1. Higher concentrations of TSS and BOD_5 in POTW effluent when the POTW was accepting UOG extraction wastewater. See Section D.5.3.2.1.
Clarksburg, WV, POTW	The POTW accepted UOG extraction wastewater, but chlorides were not removed, merely diluted. It also exceeded the desired effluent chloride concentrations during dry weather flows. See Section D.5.3.1.1.
Johnstown, PA, POTW	Higher concentrations of TSS and BOD_5 in POTW effluent, including 52 permit limit exceedances, when the POTW was accepting UOG extraction wastewater. See Section D.5.3.2.1.
California, PA, POTW	Higher concentrations of TSS and BOD_5 in POTW effluent, including four permit limit exceedances, when the POTW was accepting UOG extraction wastewater. See Section D.5.3.2.1.
Waynesburg, PA, POTW	High-salinity UOG produced water impacted biological growth in trickling filter. See Section D.5.3.2.1.

Table D-12. Summary of Studies About POTWs Receiving Oil and Gas Extraction Wastewater Pollutants

POTW	Summary of Study Findings
POTWs Accepting Wastewater Containing UOG Extraction Wastewater Pollutants from Other Industrial Sources (e.g., CWT Facilities)	
Franklin, PA, POTW	The Franklin POTW received industrial discharges from the Tri-County CWT facility (which received oil and gas extraction wastewater). The CWT facility targeted removal of TSS and oil and grease by filtration, flocculation, and skimming. TDS and chloride concentrations in effluent from the POTW were higher when the POTW was accepting industrial wastewater from the Tri-County CWT facility and decreased after it stopped accepting wastewater from this CWT facility. See Section D.5.3.1.2.
Wheeling, WV, POTW	The Wheeling POTW received oil and gas extraction wastewater from operators as well as industrial wastewater discharges from the Liquid Asset Disposal (LAD) CWT facility. The LAD CWT facility uses ultra-filtration, ozonation, and reverse osmosis to target the removal of chlorides prior to discharge to the Wheeling POTW. The POTW experienced higher concentrations of chloride in POTW effluent while accepting UOG extraction wastewater from UOG operators and from the LAD CWT facility (which receives oil and gas extraction wastewater). See Section D.5.3.1.2. The POTW experienced interference with biological treatment from accepting UOG extraction wastewater pollutants via the LAD CWT facility's industrial discharge. The POTW also experienced an upset that required the introduction of a "seed" sludge to maintain microbial activity in treatment processes. See Section D.5.3.2.2.
Warren, OH, POTW	The Warren POTW receives industrial wastewater discharges from the Patriot CWT facility. The Patriot CWT facility uses primary treatment processes (e.g., settlement tanks, clarifier tanks) to target the removal of suspended solids and metals from UOG extraction wastewater before discharge to the Warren POTW. Influent and effluent TDS and chloride concentrations at the Warren POTW show minimal or no TDS or chloride removals. See Section D.5.3.1.2.
Brockway, PA, POTW	The Brockway POTW received natural-gas-related wastewater treated by the Dannic Energy Corporation CWT facility.[102] The POTW experienced higher concentrations of TDS in POTW effluent while accepting industrial discharges from the CWT facility containing oil and gas extraction wastewater pollutants. See Section D.5.3.1.2. The POTW experienced scum formation on clarifiers as well as increased sludge generation and high concentrations of barium in the sludge, while treating industrial discharges from the CWT facility. See Section D.5.3.2.2.
New Castle, PA, POTW	The New Castle POTW received industrial wastewater from the Advanced Waste Services CWT facility (which treats oil and gas wastewater). The CWT facility uses the following treatment processes: solids settling, surface oil skimming, pH adjustment, and (occasional) flocculation. The POTW experienced numerous effluent TSS permit limit exceedances while accepting industrial discharges from the CWT facility. The CWT facility discharge was associated with adverse impacts on sludge settling in final clarifiers at the POTW. See Section D.5.3.2.2.

[102] EPA could not find information about the treatment processes used by the Dannic Energy Corporation CWT facility.

5.3.1 UOG Extraction Wastewater Constituents Discharged Untreated from POTWs

As described in Section D.5.3, the EPA reviewed studies and analyses relevant to POTWs accepting wastewater containing pollutants found in UOG extraction wastewater. Consistent with wastewater treatment literature, the POTWs described in these studies demonstrated that some UOG extraction wastewater pollutants are not removed by POTWs and are discharged untreated to receiving streams.

5.3.1.1 Case Studies of POTWs Accepting Oil and Gas Extraction Wastewater

Clairton, PA, POTW

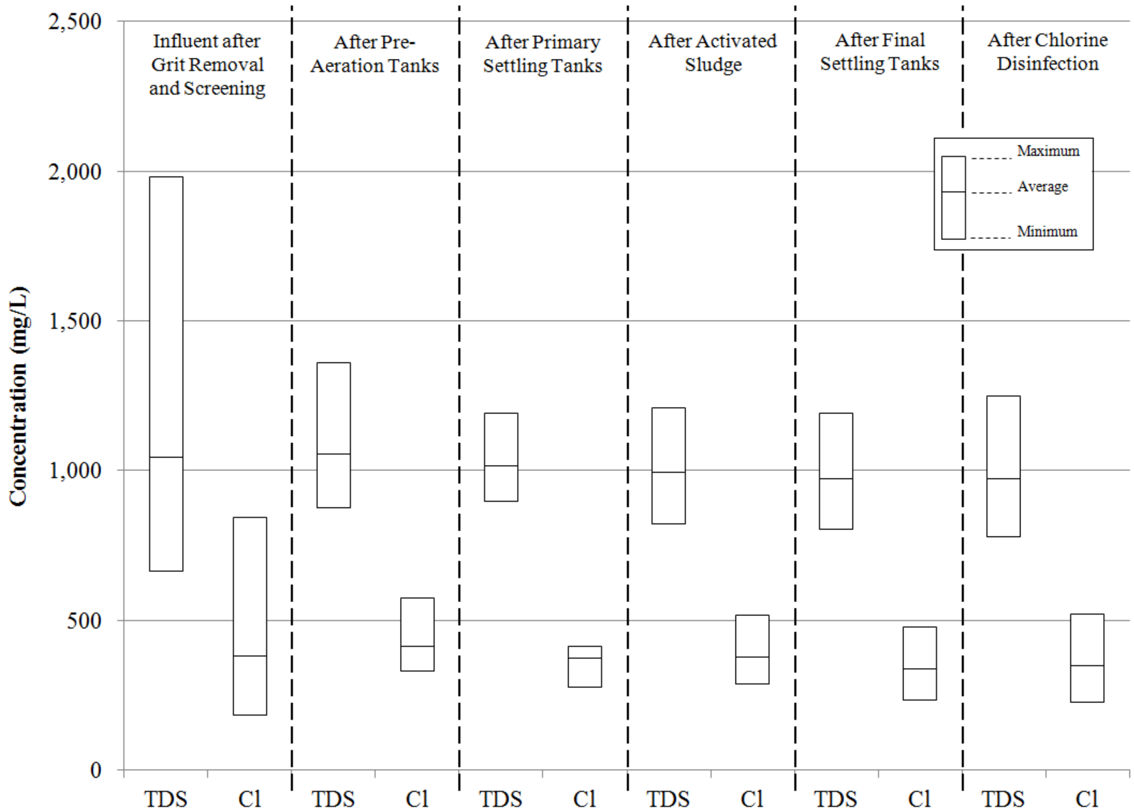
The Clairton POTW discharges to Peters Creek, which flows into the Monongahela River and treats influent wastewater using screening and grit removal, comminutors (i.e., grinders),[103] aeration basins, clarifiers, activated sludge, aerobic digestion, and chlorine disinfection. The Clairton POTW is permitted to treat a maximum of 6 MGD (107 DCN SGE00758).

On October 23, 2008, PA DEP issued an AO to the Clairton POTW that established requirements for its acceptance of oil and gas wastewater. The AO required the Clairton POTW to restrict the volume of oil and gas wastewater it accepts to a flow rate no greater than 1 percent of the average daily flow. The AO also required the POTW to evaluate the potential impacts of oil and gas production wastewater on its treatment processes. The technical evaluation noted (107 DCN SGE00758):

> *The results of the samples taken and analyzed through the CMA [Clairton Municipal Authority] WWTP indicate that there is little to no reduction in concentration of TDS and chlorides through the plant processes. This is not unexpected as conventional sewage treatment facilities are not designed to remove dissolved constituents such as TDS and chlorides.*

Figure D-10 shows the results from the 24-hour composite sampling that occurred over five days in December 2008. According to PA DEP data (46 DCN SGE00739), in 2008, the Clairton POTW was accepting oil and gas wastewater amounting to an average of 0.05 percent of the POTW flow. Looking at the average measured concentrations, the results indicate little or no removal of TDS or chloride.

[103] A comminutor is a machine that reduces the particle size of wastewater solids using a cutting device.



Sources: 52 DCN SGE00929

Note: The data presented in this figure are based on five 24-hour composite samples taken from December 8, 2008, through December 12, 2008.

Figure D-10. Clairton POTW: Technical Evaluation of Treatment Processes' Ability to Remove Chlorides and TDS

Clairton POTW's consultant completed a pass through analysis in August 2009 (137 DCN SGE00748). Having collected two sets of influent concentration data from two different oil and gas wells, the consultant stated that the O&G Well No. 2 wastewater "was not characteristic of the oil and gas wastewater routinely accepted by the CMA POTW." Therefore, the EPA only included the wastewater characteristic data for O&G Well No. 1, as reported in the pass through analysis (see Table D-13). The pass through analysis assumes zero percent removal of TDS at the POTW and concludes that (137 DCN SGE00748):

> *The result of the mass balance analyses clearly indicates that TDS is untreated resulting in a "pass-through" to receiving waters…The hypothetical mass balance review…indicates that if higher concentrations of TDS are introduced into the POTW, the concentration and loading of TDS to the receiving waters increases proportionally.*

Table D-13. Clairton Influent Oil and Gas Extraction Wastewater Characteristics

Parameter	Wastewater Concentrations (mg/L)
	O&G Well No. 1
Barium	294
Calcium	3,060
Chloride	44,700
Magnesium	1,210
Sodium	84,500
TDS	76,000
TSS	1,600

Source: 137 DCN SGE00748

Abbreviation: mg/L—milligrams per liter

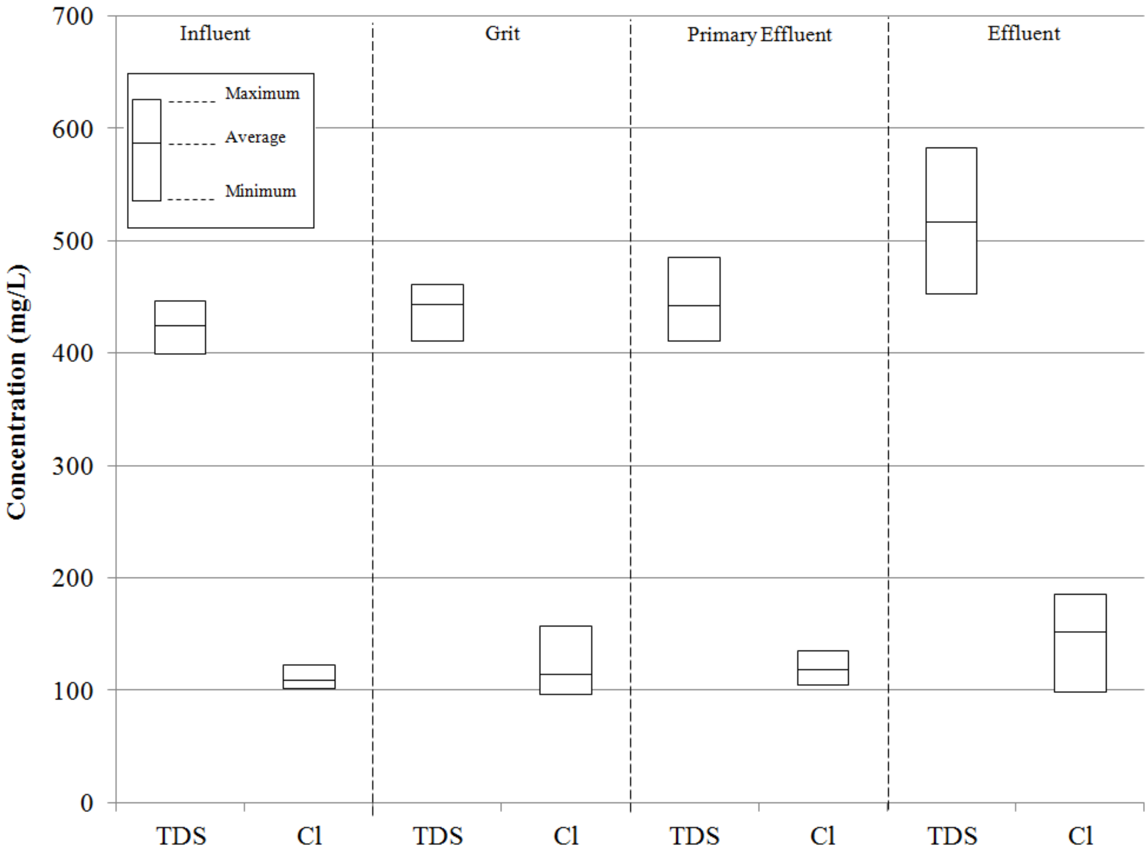
McKeesport, PA, POTW

The McKeesport POTW discharges to the Monongahela River and treats wastewater using screening and grit removal, aeration, clarification, activated sludge, aerobic digestion, and chlorine disinfection (108 DCN SGE00745). The McKeesport POTW began accepting COG wastewater in 2008 and UOG extraction wastewater in 2009. The POTW stopped accepting both COG and UOG extraction wastewater in December 2011 (46 DCN SGE00739).

On October 23, 2008, PA DEP issued an AO to the McKeesport POTW that allowed it to accept oil and gas wastewater in amounts no greater than 1 percent of its average daily flow, among other requirements. The AO also required the POTW to evaluate the potential impacts of oil and gas production wastewater on its treatment processes. The POTW conducted this technical evaluation in November 2008. According to PA DEP data (46 DCN SGE00739), in 2008, the McKeesport POTW was accepting only COG wastewater. The evaluation (106 DCN SGE00757) noted:

> *The results of the samples taken and analyzed through the MACM [Municipal Authority of the City of McKeesport] WWTP indicate that there is no reduction in concentration of TDS and chlorides through the plant processes. This is not unexpected as conventional sewage treatment facilities are not designed to remove dissolved constituents such as TDS and chlorides.*

Figure D-11 shows the results from 24-hour composite sampling over seven days in November 2008. The results indicate no removal of TDS or chloride. According to the manifests included in the technical evaluation (106 DCN SGE00757), McKeesport treated trucked wastewater from conventional wells during the seven-day sampling period. These wastewater sources are summarized in Table D-14, below.



Sources: 52 DCN SGE00929

Note: The data presented in this figure are based on seven 24-hour composite samples taken from November 1, 2008, through November 7, 2008.

Figure D-11. McKeesport POTW: Technical Evaluation of Treatment Processes' Ability to Remove Chlorides and TDS

Table D-14. Trucked COG Extraction Wastewater Treated at McKeesport POTW from November 1 Through 7, 2008

Date	Waste Type[a]	Volume (gallons)	Chlorides (mg/L)	Chlorides (lbs)
November 3, 2008	Brine	3,780	155,000	4,886
November 4, 2008	Flow-back	3,780	145,000	4,571
November 6, 2008	Flow-back	3,780	155,000	4,886
November 6, 2008	Frac	4,620	20,000	771
November 7, 2008	Frac	4,620	20,000	771

Source: 108 DCN SGE00745

a—According to data from the technical evaluation, some waste streams were referred to as "frac" and "flow-back," indicating that the conventional wells were hydraulically fractured.

Abbreviations: mg/L—milligrams per liter; lbs—pounds

McKeesport POTW's consultant completed a headworks loading analysis in March 2011 (108 DCN SGE00745). As part of the analysis, the consultant completed monthly sampling of the influent and effluent of the POTW from February 2010 through January 2011 and determined the average removal percentages based on the sampling results. During the time of sampling, a combination of UOG and COG wastewater contributed no more than 1 percent of the average daily flow and municipal wastewater made up the remaining influent to the McKeesport POTW. Table D-15 presents the percent removals calculated during this analysis and shows that the POTW removed less than 7 percent of the influent TDS and less than 5 percent of the influent chloride. Effluent TDS concentrations ranged from 600 to 1,500 mg/L while the facility accepted both UOG and COG wastewater during the sampling period (108 DCN SGE00745).

Table D-15. McKeesport POTW Removal Rates Calculated for Local Limits Analysis

Parameter	Removal Rates (%)
Sulfate	3.94
Chloride	4.44
TDS	6.43
Magnesium	6.62
Strontium	18.47
Bromide	26.99
Barium	71.64

Source: 108 DCN SGE00745

Note: The data presented in this table are based on timed composite samples obtained once a month for 12 months from February 2010 through January 2011.

A 2013 study by Ferrar et al. (71 DCN SGE00525) analyzed constituents in effluent wastewater discharged from two POTWs in Pennsylvania, first while the POTWs accepted industrial discharges containing UOG extraction wastewater pollutants (either from a CWT facility or from a UOG operator) and again after the POTWs stopped accepting those industrial discharges. The study included effluent sampling at the McKeesport POTW in 2010 while the POTW was accepting UOG extraction wastewater. The study specifically reported that the facility was accepting UOG extraction wastewater during the sampling but did not mention COG wastewater. Based on PA DEP data, the EPA is aware that the POTW accepted both UOG and COG wastewater in 2010; however, details were not available concerning whether COG wastewater was accepted on the specific days of the sampling. The UOG extraction wastewater, received from operators via tanker trucks, was stored in holding tanks, then mixed with municipal wastewater in the primary clarifier. The study sampled POTW effluent in October 2010, when the POTW was accepting UOG extraction wastewater and again in December 2011, after the POTW had stopped accepting COG and UOG extraction wastewater.[104] The study also collected one sample in November 2010 of UOG extraction wastewater before it was mixed with the municipal influent[105] (see Table D-16).

On October 19, 2010, when Ferrar et al. collected their POTW effluent sample, they reported that the McKeesport POTW treated 13,020 gallons of UOG extraction wastewater, and the average daily flow of the POTW was 9.6 MGD, indicating that the UOG extraction

[104] The PA DEP waste reports data (46 DCN SGE00739) show that the McKeesport POTW stopped accepted COG and UOG wastewater after 2011.

[105] Note that the one-time sample of influent UOG extraction wastewater was not collected at the same time as either of the effluent sampling events.

wastewater accounted for 0.14 percent of the total influent.[106] The remaining influent wastewater consisted of municipal wastewater typically treated by the POTW (see Table D-7 for typical constituent concentrations in municipal wastewater).

Table D-17 shows the range and mean effluent concentrations, as measured by Ferrar et al., at the McKeesport POTW while they were accepting UOG extraction wastewater and after they had stopped accepting UOG extraction wastewater. As noted above, the study reported that the McKeesport POTW accepted an average daily flow of 9.6 MGD during the October 2010 sampling event. However, they did not report the average daily flow during the December 2011 sampling event. Although they reported that the facility was accepting UOG extraction wastewater on the first effluent sampling date (October 19, 2010), sampling data for that influent UOG extraction wastewater (like the data presented in Table D-16) were not available. Therefore it is not possible to know whether the data presented in Table D-16 are representative of the UOG extraction wastewater influent on the date of the effluent sampling presented in Table D-17. As discussed in Section C.3, UOG extraction wastewater characteristics vary over time and from well to well.

Table D-16. Constituent Concentrations in UOG Extraction Wastewater Treated at the McKeesport POTW Before Mixing with Other Influent Wastewater

Analyte[a]	Concentrations in UOG Extraction Wastewater Treated at McKeesport POTW (mg/L)[b]
Barium	106
Calcium	1,690
Magnesium	203
Strontium	324
Bromide	151
Chloride	17,000
Sulfate	53.1
TDS	24,200

Source: 71 DCN SGE00525

a—Organic analytes were not detected in samples.
b—Sample date: 11/10/2010. Reported values are based on only one sample taken for each analyte. Samples were collected from a UOG extraction wastewater holding tank before mixture and dilution with influent municipal wastewater.

Abbreviation: mg/L—milligrams per liter

[106] Ferrar et al. (71 DCN SGE00525) noted that since the total volume of UOG wastewater was released at one time, the actual dilution might have been 0.81 percent UOG wastewater in the effluent when it was discharged (8–12 hours later).

Table D-17. McKeesport POTW Effluent Concentrations With and Without UOG Extraction Wastewater

Analyte[a]	Effluent Concentrations Measured While POTW Was Accepting UOG Extraction Wastewater (mg/L)[b]		Effluent Concentrations Measured After POTW Had Stopped Accepting UOG Extraction Wastewater (mg/L)[c]	
	Mean	Range	Mean	Range
Barium	0.55	0.21–0.81	0.036	0.034–0.039
Calcium[d]	50.3	42.4–55.9	58.8	56.6–63.4
Magnesium[d]	10.3	8.96–11.2	13.61	13.2–14.4
Strontium	1.63	0.924–2.26	0.228	0.219–0.237
Bromide	0.600	0.231–0.944	0.119	0.08–0.43
Chloride	228.7	150–377	136.8	133–142
Sulfate	98.1	81.2–139	65.9	64.4–67.2
TDS	562.2	466–648	494.2	464–524

Source: 71 DCN SGE00525

a—Organic analytes were not detected in samples.
b—Sample date: 10/19/2010. Reported values are based on the mean, minimum, and maximum of 24 samples taken for each analyte taken over 24 hours. Effluent samples were collected just before mixing with surface water.
c—Sample date: 12/1/2011. Reported values are based on the mean, minimum, and maximum of nine samples taken for each analyte taken over 24 hours. Effluent samples were collected just before mixing with surface water.
d—The effluent concentrations of calcium and magnesium increased after the POTW had stopped accepting UOG extraction wastewater. Ferrar et al. (71 DCN SGE00525) suggest that the increased concentrations of these ions may be from high influent calcium and magnesium concentrations in other wastewater treated by the McKeesport POTW (e.g., COG wastewater).

Abbreviation: mg/L—milligrams per liter

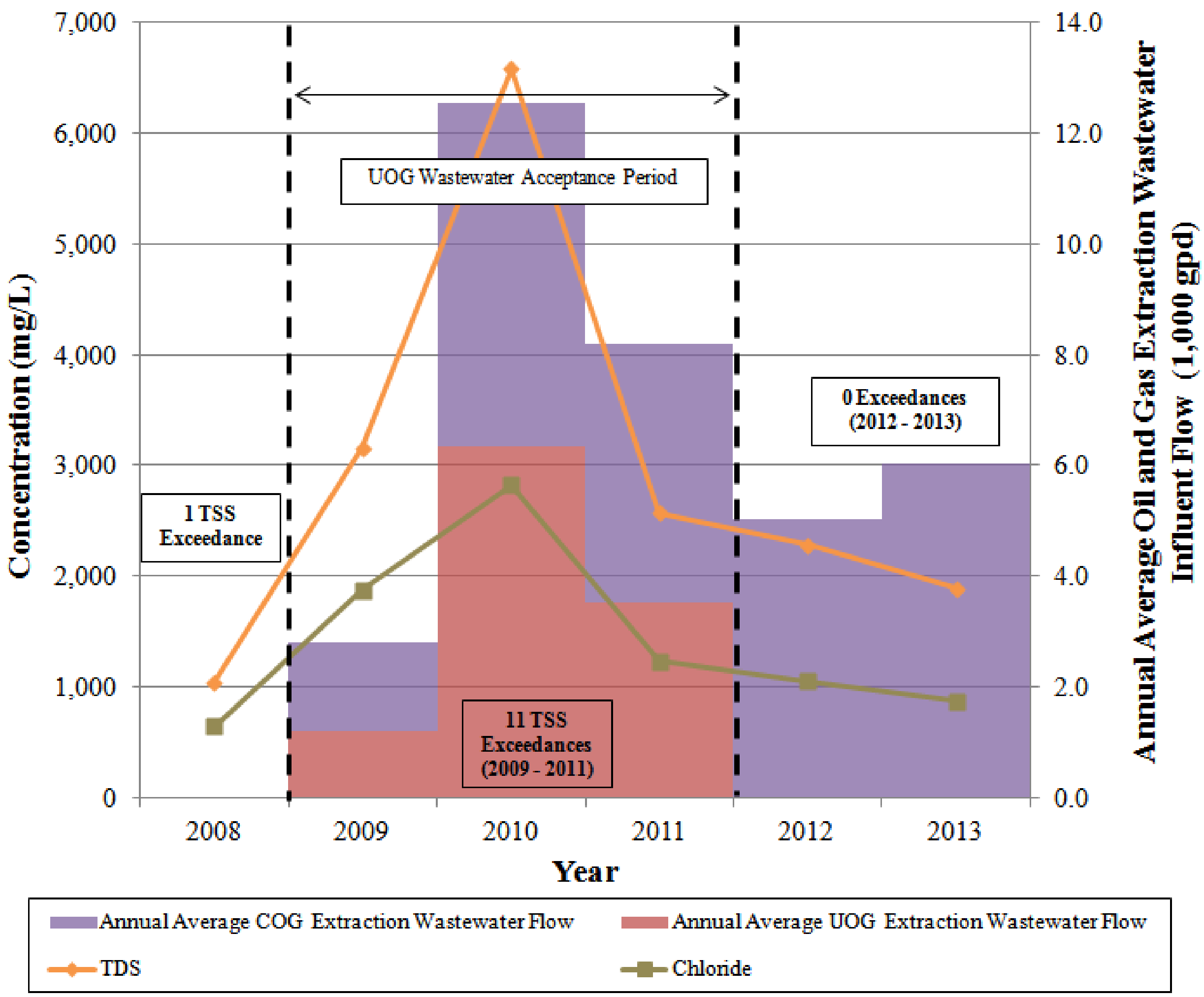
Ridgway, PA, POTW

Ridgway Borough operates a POTW that discharges to the Clarion River and has a maximum monthly average design rate of 2.2 MGD. The Ridgway POTW uses screening and grit removal, an equalization tank, aeration tanks, clarifiers, a chlorination feed system, a chlorine contact tank, aerobic digesters, and a belt filter press. This POTW began accepting both COG and UOG extraction wastewater in 2009. It stopped accepting UOG extraction wastewater in 2011 but continued accepting COG wastewater, and still was as of the end of 2013.[107] The total oil and gas wastewater volume accounted for less than 2 percent of the total POTW influent volume during 2009 through 2011 on average (46 DCN SGE00739). The POTW's total annual average daily flow rate ranges between 0.8 and 1.3 MGD, based on 2008 to 2013 DMR data (175 DCN SGE00608).

The EPA created Figure D-12 using the sampling data submitted in the EPA's DMR Loading Tool (175 DCN SGE00608) and PA DEP waste reports data (46 DCN SGE00739). Each effluent concentration data point represents the average of 12 monthly average data points as calculated and reported by the DMR Loading Tool. PA DEP waste reports provided the total

[107] Ridgway's October 2011 NPDES permit (131 DCN SGE00755) notes that "no more than 20,000 gallons/day of natural gas wastewater from shallow well operations shall be treated at the facility. The acceptance of wastewater generated from shale oil extraction activities is prohibited."

volume of UOG and COG wastewater delivered to the POTW each year. The EPA divided the annual volume by 365 to calculate the annual average daily flow. As shown in Figure D-12, in 2010, the Ridgway POTW experienced effluent TDS concentrations greater than 6,000 mg/L on average and effluent chloride concentrations greater than 2,500 mg/L on average while it was accepting the greatest volume of oil and gas wastewater, including that from UOG operators. As a point of comparison, in 2008, before accepting any oil and gas wastewater, the POTW experienced effluent TDS and chloride concentrations around 1,000 mg/L.



Sources: 52 DCN SGE00929

Figure D-12. Ridgway POTW: Annual Average Daily Effluent Concentrations and POTW Flows

To comply with the requirements of the Ridgway Borough Pretreatment Program, the Ridgway POTW completed a local limits analysis in January 2014 that included paired POTW influent and effluent data. The samples were collected for 10 consecutive days in October and November 2013 after the POTW stopped accepting UOG extraction wastewater but was still accepting COG wastewater. Of particular interest is the fact that Ridgway POTW's contractor estimated zero percent removals for TDS, chloride, and sulfate. All three of these constituents are found in UOG extraction wastewater (88 DCN SGE00756).

Charleroi, PA, POTW

The Charleroi POTW uses an equalization tank, screening and grit removal, sedimentation, activated sludge, and chlorine disinfection. It began accepting both COG and UOG extraction wastewater in January 2005 and stopped accepting it in 2008 (11 DCN SGE00751; 46 DCN SGE00739). The total oil and gas wastewater accounted for up to 32 percent of the total POTW influent volume during 2008, on average. UOG extraction wastewater accounted for 10 percent of total POTW influent during 2008 on average (46 DCN SGE00739). The POTW's average annual flow rate ranges between 1.4 and 1.9 MGD based on 2008 through 2013 DMR data (175 DCN SGE00608). The EPA identified case studies showing potential for both pass through (Section D.5.3.1.1) and inhibition/disruption (Section D.5.3.2.1) at the Charleroi POTW.

In 2008, PA DEP issued an AO requiring the Charleroi POTW to evaluate how accepting oil and gas production wastewater affects its treatment processes, among other things (11 DCN SGE00751). Charleroi's technical evaluation noted that the POTW typically rejects influent oil and gas wastewater with TDS concentrations greater than 30,000 mg/L or chloride concentrations greater than 15,000 mg/L. As part of the technical evaluation, Charleroi sampled influent wastewater (including UOG extraction wastewater) and effluent wastewater over a 24-hour period. The total oil and gas wastewater treated during this period was 150,650 gallons (3,587 barrels) and the total wastewater treated was 1,559,000 gallons (37,120 barrels). Therefore, the oil and gas wastewater accounted for 9.7 percent of the total influent to the plant during the sampling period (11 DCN SGE00751). Table D-18 shows the results of the sampling and the calculated removal rates. The data show that TDS is not removed by the Charleroi POTW treatment processes.

Table D-18. Charleroi POTW Paired Influent/Effluent Data and Calculated Removal Rates

Parameter	Influent Concentration (mg/L)	Effluent Concentration (mg/L)	Removal Rate (%)
Aluminum	2.34	0.656	72
Ammonia, as N	14.4	4.52	68.6
Barium	0.177	0.171	3.4
BOD_5	84	1.00	98.8
Hardness, as $CaCO_3$	265	260	1.9
Oil and grease	29	5	82.8
Phosphorus	0.49	0.3	38.8
TDS	1,020	1,030	0
TSS	116	21	81.9

Source: 11 DCN SGE00751

Abbreviation: mg/L—milligrams per liter

Clarksburg, WV, POTW

The Clarksburg POTW has a maximum capacity of 8 MGD and uses screening, a cyclone hydrogritter, clarifiers, aeration basins, and chlorine disinfection. The Clarksburg POTW started accepting "gas well wastewater" (i.e., brine) in July 2008 on a trial basis and continued through at least March 2009. Three frac tanks were set up on the treatment plant site and the brine (i.e., oil and gas extraction wastewater) was metered into the POTW's pump station wet well at a constant continuous flow rate. Total POTW flow was at least 5 MGD. The amount of brine metered to the POTW was gradually increased to evaluate the effect it would have on the POTW performance. Clarksburg provided the following non-comprehensive data about the quantity and chloride concentration of the brine metered to the POTW:

- July 2008, week 1: 10,000 gpd @ 50,000 mg/L chloride
- July 2008, week 2: 15,000 gpd @ 50,000 mg/L chloride
- July 2008, week 3: 17, 280 gpd @ 50,000 mg/L chloride
- July 2008, week 4: 25,000 gpd @ 50,000 mg/L chloride
- November 2008: 50,000 gpd @ 18,500 mg/L chloride

During the initial trial period in July 2008, the Clarksburg POTW superintendent noted that effluent chloride concentrations "exceeded the desired quantity of 235 mg/L a couple of times due to dry weather flows being below 5 MGD." He also noted that they would need to adjust the volume of brine in the influent to the POTW during low flow conditions, and that "Chlorides are not removed at the facility, merely diluted to acceptable levels." This statement further supports the concept that TDS, of which the primary contributing ions in UOG extraction wastewater are chloride and sodium, passes through POTWs untreated.

After the trial period, Clarksburg contacted the WV DEP about modifying its NPDES permit to allow acceptance of gas wastewater. The DEP told the Clarksburg POTW that they could continue accepting the gas wastewater as long as they were not violating their existing effluent limitations (21 DCN SGE00749; 121 DCN SGE00552). In July 2009, WV DEP sent a letter to the Clarskburg Sanitary Board with a list of requirements that would be imposed, if they decided to accept oil and gas related wastewater (221 DCN SGE01113). The letter also stated that

> *…WVDEP discourages POTWs from accepting wastewater from oil and gas operations such as…marcellus shale wastewaters because these wastewater essentially pass through sewage treatment plants and can cause inhibition and interference with treatment plant operations. The wastewaters from these types of operations contain high levels of chloride, dissolved solid, sulfate, and other pollutants. POTWs provide little to no treatment of these pollutants and could potentially lead to water quality issues in the receiving stream.*

In April 2013, WV DEP verified that no POTWs in WV were accepting UOG extraction wastewater (196 DCN SGE00762; 198 DCN SGE00766).

5.3.1.2 Case Studies About POTWs Accepting Wastewater from Other Industrial Sources Containing UOG Pollutants

Franklin Township, PA, POTW

The Franklin Township POTW discharges to the lower fork of Ten Mile Creek, a tributary to the Monongahela River, and treats influent wastewater using aeration, rotating biological contactors, clarification, filtration, and chlorination (74 DCN SGE00746). The Franklin Township POTW accepted industrial wastewater from the Tri-County Wastewater CWT facility until March 2011. During that time, the Tri-County CWT facility was accepting oil and gas extraction wastewater. The CWT facility targeted removal of TSS and oil and grease by filtration, flocculation, and skimming, but certain pollutants in the UOG extraction wastewater such as TDS remained in the treated effluent from the CWT facility. The industrial wastewater received from Tri-County Wastewater accounted for approximately 5.4 percent of the Franklin POTW’s 0.982 MGD effluent by volume in November 2010 (71 DCN SGE00525).

On December 4, 2008, the Franklin POTW entered into a Consent Order and Agreement with PA DEP[108] regarding effluent discharges containing elevated levels of TDS. Paragraph G of the order notes that

Neither the STP [Franklin POTW] nor the Pretreatment Facility [Tri-County CWT Facility] currently has treatment facilities for the removal of Total Dissolved Solids.

Ferrar et al. (71 DCN SGE00525) analyzed constituents in effluent wastewater discharged from the Franklin Township POTW during the period before and after it accepted industrial wastewater from the Tri-County Wastewater CWT facility. Table D-19 shows the mean and range of effluent concentrations at the Franklin Township POTW during the period it accepted industrial wastewater from the CWT facility and after they stopped. Ferrar et al. analyzed pollutants typically found in UOG extraction wastewater; they report a mean effluent TDS concentration of 3,860 mg/L from the Franklin Township POTW while it was accepting wastewater from the Tri-County CWT facility and a mean effluent TDS concentration of 398 mg/L from the POTW after it stopped. The mean effluent concentrations for all pollutants presented in Table D-19 were higher when the POTW was accepting the industrial discharge from the Tri-County CWT facility, suggesting that pollutants were discharged from the POTW without treatment. Based on the treatment technologies currently in place at the Franklin Township POTW, one would expect little to no treatment of the common constituents in UOG extraction wastewater. Ferrar et al. concluded:

This research provides preliminary evidence that these and similar WWTPs may not be able to provide sufficient treatment for this wastewater stream, and more thorough monitoring is recommended.

[108] PA DEP had issued an AO to the Franklin POTW in October 2008, but the Consent Order and Agreement superseded that order.

Table D-19. Franklin Township POTW Effluent Concentrations With and Without Industrial Discharges from the Tri-County CWT Facility

Analyte[a]	Effluent Concentrations from Franklin Township POTW Measured While POTW Was Accepting Wastewater from CWT Facility (mg/L)[b]		Effluent Concentrations from Franklin Township POTW Measured After POTW Had Stopped Accepting Wastewater from CWT Facility (mg/L)[c]	
	Mean	Range	Mean	Range
Barium	5.99	4.27–7.72	0.141	0.124–0.156
Calcium	231	207–268	40.6	38.8–43.5
Magnesium	32.6	29.1–36.6	8.63	8.04–9.11
Manganese	0.228	0.204–0.249	0.112	0.102–0.144
Strontium	48.3	41.8–56.1	0.236	0.226–0.249
Bromide	20.9	14.3–28.0	<0.016	<0.016
Chloride	2,210	1,940–2,490	61.9	57.5–64.6
Sulfate	137	117–267	65.6	60.0–75.0
TDS	3,860	3,350–4,440	398	376–450

Source: 71 DCN SGE00525

a—Organic analytes were not detected in samples.
b—Sample date: 11/10/2010. Reported values are based on the mean, minimum, and maximum of 24 samples taken for each analyte taken over 24 hours. Effluent samples were collected just before mixing with surface water.
c—Sample date: 11/7/2011. Reported values are based on the mean, minimum, and maximum of nine samples taken for each analyte taken over 24 hours. Effluent samples were collected just before mixing with surface water.

Abbreviation: mg/L—milligrams per liter

Wheeling, WV, POTW

The Wheeling POTW has primary and secondary treatment operations, including primary clarification, solids and floatable materials removal, and disinfection (115 DCN SGE00999). The Wheeling POTW accepted industrial wastewater from the Liquid Asset Disposal (LAD) CWT facility through August 2009[109] and wastewater directly from UOG operators in 2008[110]. The LAD CWT facility accepted a variety of wastewater from the following sources: sewage facilities, storm water from an international airport, and gas well development and production wastewater, among others. The LAD CWT facility is a SIU and was authorized to discharge into the Wheeling, WV POTW (SIU Permit No. 0014) (219 DCN SGE00485). The LAD CWT facility uses ultra-filtration, ozonation, and reverse osmosis to target the removal of chlorides prior to discharges to the Wheeling POTW (101 DCN SGE00996).

The EPA analyzed sampling data submitted in its DMR Loading Tool (175 DCN SGE00608) and PA DEP waste reports data (46 DCN SGE00739) and found that the effluent concentrations of chloride experienced by the Wheeling POTW in 2008 were higher when it was accepting UOG extraction wastewater and industrial discharges from the LAD CWT facility than

[109] EPA did not identify the date on which the Wheeling POTW began accepting wastewater from the LAD CWT facility. However, the LAD CWT SIU Permit No. 0014 was issued in August 2004 (22 DCN SGE01000).

[110] The Wheeling POTW may have accepted UOG extraction wastewater directly from operators in years other than 2008, but EPA only identified acceptance directly from operators in 2008 (127 DCN SGE00188).

after it stopped. In 2008, the POTW accepted an average of 5,400 gallons/day of UOG extraction wastewater and had an average effluent chloride concentration of 650 mg/L. Comparatively, in 2011, the POTW did not accept any UOG extraction wastewater and had an average effluent chloride concentration of 130 mg/L.[111] Data from an August 2009 letter from WV DEP to the City of Wheeling states (222 DCN SGE01114)

> *The agency has determined that the following pollutants are of concern associated with oil and gas related wastewaters and may have a potential for inhibition, interference, and pass through: total dissolved solids (TDS), sulfate, chloride…zinc…copper…barium …total suspended solids, iron…benzene…strontium…gross alpha radiation, gross beta radiation, and radium 226 + radium 228. In addition to the potential for inhibition, interference, and pass through, these pollutants may also have an impact on sludge disposal requirements.*

Additional data from a 2011 Consent Order from WV DEP to the Wheeling POTW indicates that the LAD CWT facility exceeded its 9,000-pound daily chloride limitation, in violation of its SIU permit, 50 times between January 8, 2009, and February 4, 2010 (219 DCN SGE00485). Therefore, the UOG extraction wastewater and the industrial wastewater accepted by the Wheeling POTW from the LAD CWT facility likely contributed to the elevated effluent chloride concentrations.

Warren, OH, POTW

The city of Warren operates a 16 MGD POTW that discharges to the Mahoning River. The POTW employs screening and grit removal, primary settling, activated sludge aeration, final clarification, chlorination, dechlorination, and post-aeration treatment processes. Solid residuals are thickened by dissolved air flotation, dewatered using a belt filter press, stabilized with lime, and disposed of by land application or by distribution and marketing of usable end products.

In May 2009, the Warren POTW and its customer, the Patriot Water Treatment CWT facility,[112] began discussions with the Ohio EPA about accepting UOG produced water. Patriot planned to accept UOG produced water from shale gas operations, treat the wastewater to remove heavy metals and other constituents, and discharge the treated industrial wastewater to the Warren POTW. In preparation for acceptance of treated industrial wastewater from the CWT facility that would contain pollutants found in UOG produced water, the Warren POTW undertook a pilot study to show that accepting wastewater containing pollutants found in UOG produced water would not cause any problems with Mahoning River water quality. Patriot's treatment of UOG produced water includes reduction in heavy metal concentration, but not TDS or chloride. The Ohio EPA worked with Patriot and the Warren POTW to develop a pilot treatment study that evaluated the effects of pretreated UOG produced water on the POTW. The

[111] The data about quantities of UOG extraction wastewater accepted by the Wheeling POTW are from the PA DEP waste report data and are reflective of volumes of UOG extraction wastewater accepted from UOG operators in Pennsylvania. The Wheeling POTW may be accepting additional UOG extraction wastewater from UOG operators in West Virginia or other nearby states; these volumes of wastewater are not captured in this discussion.

[112] The Patriot CWT facility uses primary treatment processes (e.g., settlement tanks, clarifier tanks) to target the removal of suspended solids and metals prior to discharge.

study also evaluated the receiving stream (Mahoning River) water quality, upstream and downstream of the POTW discharge (5 DCN SGE00497; 35 DCN SGE00522).

The pilot study began on February 9, 2010, and ran for eight weeks. It focused on collecting data from the Warren POTW and did not include sampling at the Patriot CWT facility. The summarized TDS and chloride data from the study are presented in Table D-20. The Warren POTW reported typical flow rates of 13.38 MGD and accepted the following volumes of wastewater from the Patriot CWT facility over the eight weeks (percentage of total POTW flow accounted for by Patriot CWT facility's industrial wastewater is noted parenthetically)[113] (193 DCN SGE00616):

- Week 1: 5 days @ 20,000 gallons (0.15 percent)
- Week 2: 5 days @ 40,000 gallons (0.30 percent)
- Week 3: 5 days @ 60,000 gallons (0.45 percent)
- Week 4: 5 days @ 80,000 gallons (0.60 percent)
- Week 5: 5 days @ 100,000 gallons (0.75 percent)
- Week 6: 5 days @ 100,000 gallons (0.75 percent)
- Week 7: 5 days @ 100,000 gallons (0.75 percent)
- Week 8: 5 days @ 100,000 gallons (0.75 percent)

Table D-20 shows the average paired influent and effluent TDS concentrations measured prior to start up and during the pilot study. Baseline samples were collected when the POTW was not accepting wastewater from the Patriot CWT facility. The pilot study description states that the influent samples (baseline and pilot study) include only municipal influent and do not include any wastewater from the Patriot CWT facility.[114] The data show that TDS and chloride concentrations increased in the influent and effluent samples over time both during the baseline sampling and after the Warren POTW accepted wastewater from the Patriot CWT facility. The effluent concentrations of TDS and chloride increased at higher percentages over the influent concentration during the pilot study, when the POTW was accepting wastewater from the Patriot CWT facility (193 DCN SGE00616), suggesting that TDS and chloride were not removed by the POTW.

[113] All flows were introduced into the Warren POTW over an eight-hour period.

[114] The Warren POTW pilot study description states that "Raw [influent] does not have any Patriot influence or plant return flows." The report author also noted increases in the TDS and chloride concentrations over the period of the study and suggested that "these increases are most likely due to seasonal fluctuations within the collection system as a result of user operations or seasonal runoff from spring rains" (193 DCN SGE00616).

Table D-20. TDS Concentrations in Baseline and Pilot Study Wastewater Samples at Warren POTW

Sample Type	Influent Concentration (mg/L)	Effluent Concentration (mg/L)	Percent Increase (%)
Baseline Samples			
TDS	584	599	2.6
Chloride	143	157	9.8
Eight-Week Pilot Study Samples			
TDS	679	885	30.3
Chloride	239	348	45.6

Source: 193 DCN SGE00616

Abbreviation: mg/L—milligrams per liter

From September 12 through 16, 2011, EPA Region 5 inspected and collected wastewater samples at the Warren POTW and noted that (193 DCN SGE00616)

the POTW had not experienced any of the following conditions since accepting the brine waste water from the Patriot CWT facility:

- *Diminished or inhibited performance of the biological treatment processes*
- *Adverse impacts to the downstream water quality*
- *Adverse impacts to the quality of the facility's biosolids*

The compliance inspection indicated that the Warren POTW was in compliance with all of its NPDES permit limitations. Table D-21 shows the results of EPA Region 5's wastewater sample analyses conducted during their September 2011 inspection. The compliance inspection data show minimal to no TDS removals by the POTW and minimal chloride removals.

Table D-21. EPA Region 5 Compliance Inspection Sampling Data

Pollutant	Warren POTW Influent Concentration (mg/L)[a]		Warren POTW Effluent Concentration (mg/L)[a]	
	Average	Range	Average	Range
TDS	726	686–748	726	648–778
Chloride	361	345–374	213	191–252
Sulfate	250	243–256	77	68–84
TSS	95.0	67.0–112	<4	NA[b]
BOD_5	33.3	27.7–39.0	<2	NA[b]
Bromide	5.25	5.01–5.43	1.57	1.40–1.89
Fluoride	3.62	3.36–4.13	1.83	1.40–2.14

Source: 193 DCN SGE00616

a—Samples were taken on four days (9/12/2013, 9/13/2013, 9/14/2013, and 9/15/2013).
b—All four samples were reported as below the detection limit.

Abbreviation: mg/L—milligrams per liter

As of June 2014, the Warren POTW was still accepting wastewater from the Patriot CWT facility (200 DCN SGE00786). Its NPDES permit allows it to accept a maximum of 100,000 gallons of "wastewater from a regulated CWT facility that is tributary to the City's collection system" per day (0.67 percent of its maximum total daily flow) at a maximum TDS concentration of 50,000 mg/L (217 DCN SGE00295).

Brockway, PA, POTW

The Brockway POTW treats industrial and domestic wastewater using screens, aerated basins, oxidation ditches, clarifiers, aerobic sludge digestion, UV disinfection, and post-aeration. Its NPDES permit (issued on July 3, 2012, and expiring on July 31, 2017) allows it to accept up to 14,000 gpd of "natural gas related wastewater," none of which may be from "Shale Gas Extraction related activities" (132 DCN SGE00931). As of June 2014, the Brockway POTW was still accepting natural-gas-related wastewater treated by the Dannic Energy Corporation CWT facility. The Brockway POTW is sampling and reporting the required parameters on PA DEP's electronic DMR system (eDMR) (132 DCN SGE00931). The permit includes limits for pH, carbonaceous BOD_5, TSS, fecal coliform, ammonia-nitrogen, TDS, and osmotic pressure. The permit also included reporting requirements for flow, barium, strontium, uranium, chloride, bromide, gross alpha, and radium-226/228.

The Brockway POTW saw increases in the effluent concentrations of TDS, which were below 400 mg/L before the acceptance of COG wastewater and increased to between 2,500 and 3,000 mg/L during the acceptance of COG wastewater. Typical COG wastewater accepted by the Brockway POTW may have TDS concentrations over 200,000 mg/L (99 DCN SGE00753).

5.3.2 UOG Extraction Wastewater Constituents and POTW Inhibition and Disruption

In addition to the discharge of pollutants not treated by a POTW, the presence of certain pollutants in industrial wastewater discharges can have the following effects on the receiving POTW:

- Inhibition or disruption of the POTW's treatment processes and/or operations
- Inhibition or disruption of the POTW's sludge processes, including sludge disposal processes
- Harm to POTW workers

The EPA investigated how pollutants in industrial wastewater discharges, which may contain constituents found in UOG extraction wastewater, might inhibit the performance of typical POTW treatment processes. Table D-22 presents inhibition threshold levels for activated sludge and nitrification, two treatment processes commonly used at POTWs, for select UOG constituents identified in Section C.3.[115] The EPA recognizes that POTW treatment processes will not be exposed to UOG constituents at the concentrations they are found in UOG produced water (i.e., flowback, long-term produced water).

[115] EPA also presents specific inhibition thresholds for anaerobic digestion and trickling filters, but the UOG constituent concentrations are not as likely to exceed the thresholds, so they were not included in Table D-22.

As discussed in Section A.2.1.1, POTWs establish local limits to control pollutant discharges that present a reasonable potential for pass through or interference with POTW operations. The inhibition levels presented in the EPA's guidance represent concentrations that would reduce the effectiveness or otherwise interfere with the treatment operations for treatment commonly used at POTWs. Inhibition of activated sludge processes at a POTW could impair BOD_5 removal and TSS removal (particularly if sludge settling is affected). Inhibition of nitrification, a process that some POTWs use to convert ammonia to nitrate/nitrite (which may be part of the activated sludge process or a separate biological treatment stage), may impair the POTW's ability to remove ammonia and nutrients in the wastewater.

Table D-22. Inhibition Threshold Levels for Various Treatment Processes[a]

Pollutant	Reported Range of Activated Sludge Inhibition Threshold Levels (mg/L)[a]	Reported Range of Nitrification Inhibition Threshold Levels (mg/L)[a]
Ammonia	480	NA
Arsenic	0.1	1.5
Benzene	100–500, 125–500	NA
Cadmium	1–10	5.2
Chloride	NA	180
Chloroform	NA	10
Chromium, total	1–100	0.25–1.9, 1–100 (trickling filter)
Copper	1	0.05–0.48
Ethylbenzene	200	NA
Lead	1–5, 10–100	0.5
Mercury	0.1–1, 2.5 as Hg(II)	NA
Naphthalene	500, 500, 500	NA
Nickel	1–2.5, 5	0.25–0.5, 5
Phenol	50–200, 200, 200	4, 4–10
Sulfide	25–30	NA
Toluene	200	NA
Zinc	0.3–5, 5–10	0.08–0.5

Source: 165 DCN SGE00602

a—Where multiple values are listed (divided by commas), the data were reported individually in 165 DCN SGE00602 by different sources.

Abbreviations: mg/L—milligrams per liter; NA—not available

Because all POTWs are required to control TSS and BOD_5, they are designed for the effective removal of these two parameters. Elevated concentrations of TSS and BOD_5 in POTW discharges suggest inhibition/disruption of treatment processes. As some of the studies described in the following sections indicate, POTWs have linked TSS and/or BOD_5 permit limit exceedances with the acceptance of oil and gas extraction wastewater.

The following subsections present case studies that discuss inhibition/disruption at POTWs that accepted wastewater containing pollutants found in UOG extraction wastewater. The purpose of these subsections is to identify instances of inhibition/disruption, or potential inhibition/disruption, at POTWs associated with the acceptance of UOG extraction wastewater pollutants.

5.3.2.1 Case Studies About POTWs Accepting Wastewater from Oil and Gas Extraction Facilities

Johnstown, PA, POTW

The Johnstown POTW uses screening, grit removal, high-purity oxygen activated sludge aeration with integrated fixed-film activated sludge, final clarification, and chlorination (133 DCN SGE00930). The Johnstown POTW accepted both UOG and COG wastewater before 2008 and stopped accepting both in 2011 (46 DCN SGE00739). The total oil and gas wastewater accounted for less than 3 percent of the total POTW influent volume during the acceptance period on average. The POTW's annual average daily flow rate ranges between 9.0 and 10.5 MGD based on 2008 through 2013 DMR data (175 DCN SGE00608).

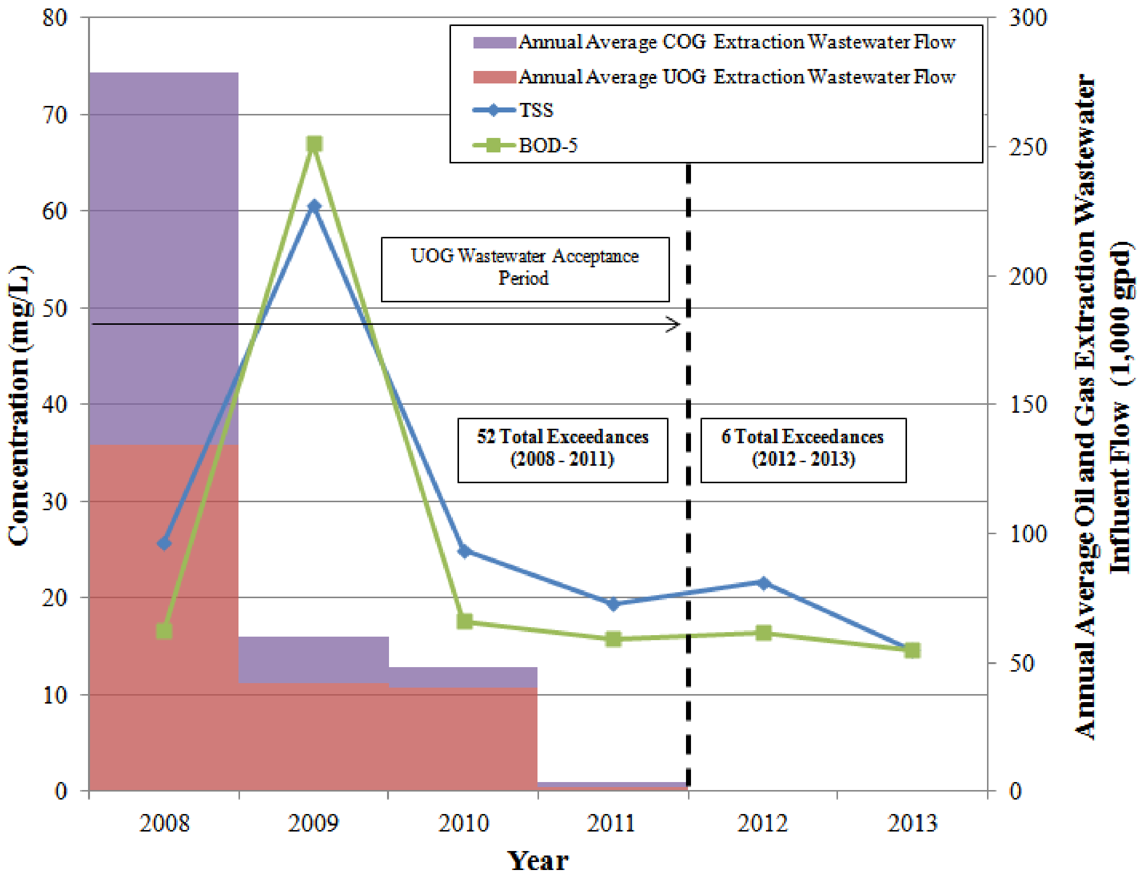
The EPA created Figure D-13 using the sampling data submitted in its DMR Loading Tool (175 DCN SGE00608) and PA DEP waste reports data (46 DCN SGE00739). Each effluent concentration data point represents the average of 12 monthly average data points as calculated and reported by the Loading Tool. PA DEP waste reports provided the total volume of UOG and COG wastewater delivered to the POTW each year. The EPA divided the annual volume by 365 to calculate the annual average daily flow. As shown in Figure D-13, the Johnstown POTW experienced a much larger number of permit limit exceedances during the period when they were accepting the greatest volume of oil and gas extraction wastewater. In a December 2012 letter regarding the 2011 annual pretreatment report, Johnstown's pretreatment coordinator stated,

> *[We] know that the treatment plant no longer accepts gas drilling waste,*[116] *and we anticipate that the number of violations will decrease.*

Further, Section C.3.2.1 presents data showing that TSS concentrations in drilling wastewater may be higher than TSS concentrations in UOG produced water.[117] The PA DEP waste reports data show that the Johnstown POTW accepted more drilling wastewater than any other POTW in Pennsylvania from 2008 through 2011. The POTW accepted the largest volume of drilling wastewater in 2009 and 2010, which totaled over 15 million gallons and accounted for over 40 percent of the total influent oil and gas wastewater accepted by the POTW. In total, the Johnstown POTW experienced 27 TSS permit limit exceedances from 2008 through 2011, 18 of which were in 2009 and 2010. The POTW also experienced elevated effluent TSS concentrations in 2009 (61 mg/L).

[116] The EPA assumes that this phrase refers to both COG wastewater and UOG extraction wastewater.

[117] Drilling wastewater initially includes cuttings (i.e., solids) that are partially removed by the operator before management or disposal. Any cuttings that remain may contribute to elevated TSS concentrations.



Sources: 52 DCN SGE00929

Figure D-13. Johnstown POTW: Annual Average Daily Effluent Concentrations and POTW Flows

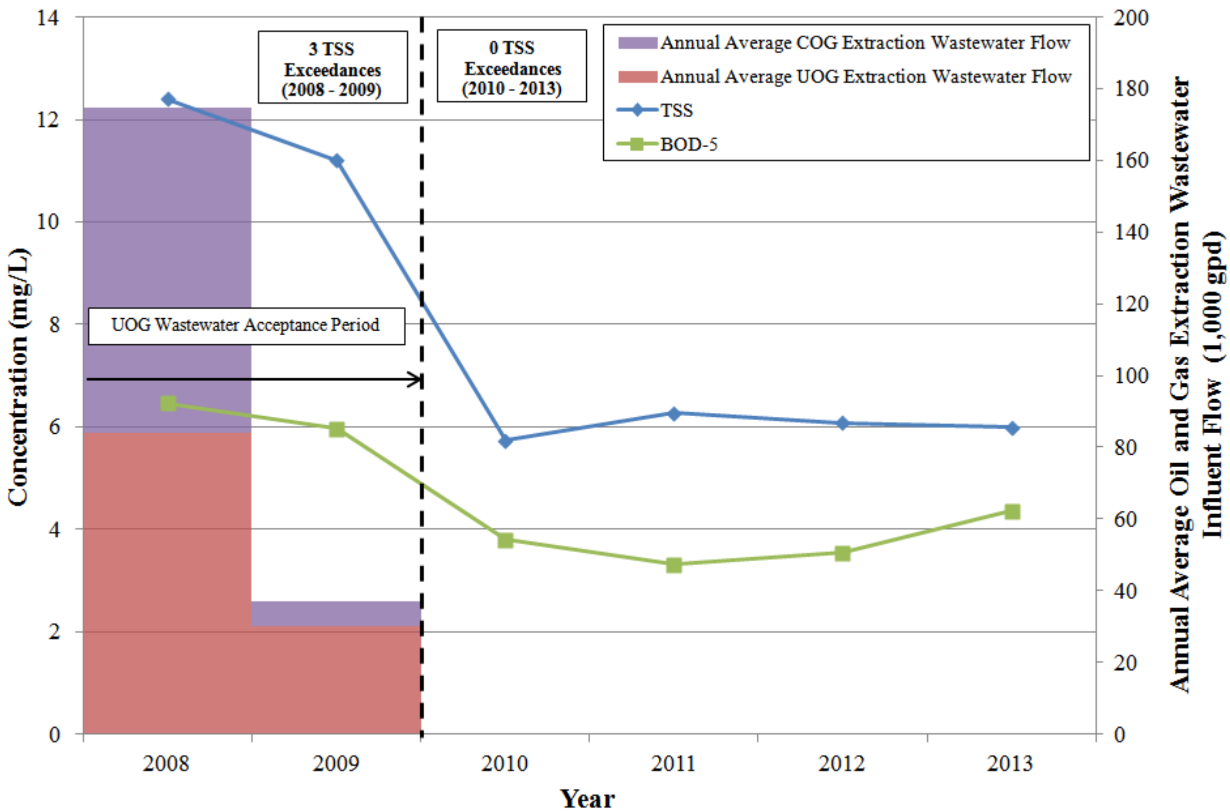
California, PA, POTW

The California POTW uses a contact stabilization[118] process to treat influent wastewater (10 DCN SGE00787). In 2008 and 2009, the California POTW accepted both UOG and COG wastewater. The total oil and gas wastewater accounted for up to 33 percent of the total POTW influent volume during 2008, on average. UOG extraction wastewater accounted for 14 percent of total POTW influent during 2008, on average (46 DCN SGE00739). The POTW's average annual daily flow rate ranges between 0.5 and 0.8 MGD based on 2008 through 2013 DMR data (175 DCN SGE00608).

The EPA created Figure D-14 using the sampling data submitted in its DMR Loading Tool (175 DCN SGE00608) and PA DEP waste reports data (46 DCN SGE00739). Each effluent concentration data point represents the average of 12 monthly average data points as calculated

[118] Contact stabilization is a two-stage activated sludge process, consisting of a 30 to 60 minute absorptive phase followed by a one to two hour oxidation phase. Aeration volume requirements are half of those for conventional activated sludge (119 DCN SGE00167).

and reported by the DMR Loading Tool. PA DEP waste reports provided the total volume of UOG and COG wastewater delivered to the POTW each year. The EPA divided the annual volume by 365 to calculate the annual average daily flow. As shown in Figure D-14, the California POTW experienced elevated concentrations of TSS and BOD_5 while accepting oil and gas wastewater. Figure D-14 also shows that the California POTW experienced three exceedances of its TSS permit limits[119] and one exceedance of its BOD_5 permit limits.[120]



Sources: 52 DCN SGE00929

Figure D-14. California POTW: Annual Average Daily Effluent Concentrations and POTW Flows

Charleroi, PA, POTW

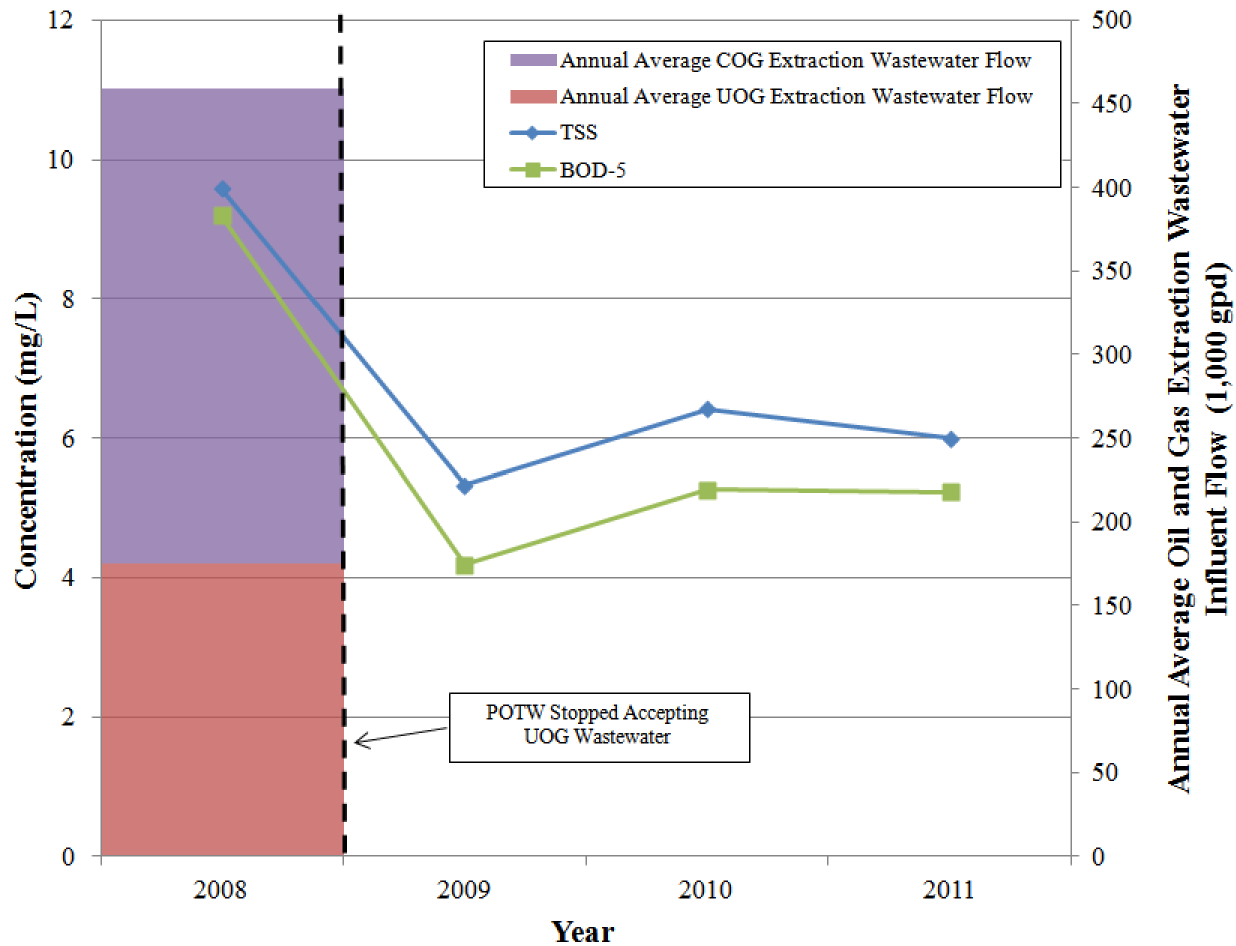
The Charleroi POTW was introduced and described in more detail in Section D.5.3.1 of this TDD.

The EPA created Figure D-15 using the sampling data submitted in its DMR Loading Tool (175 DCN SGE00608) and PA DEP waste reports data (46 DCN SGE00739). Each effluent

[119] The California POTW had a monthly average TSS limit of 30 mg/L and a daily maximum TSS limit of 45 mg/L from 2008 through 2013.

[120] The California POTW had a monthly average BOD_5 limit of 25 mg/L and a daily maximum BOD_5 limit of 37.5 mg/L from 2008 through 2012. In 2013, its daily maximum BOD_5 limit changed to 40 mg/L.

concentration data point represents the average of 12 monthly average data points as calculated and reported by the Loading Tool. PA DEP waste reports provided the total volume of UOG and COG wastewater delivered to the POTW each year. The EPA divided the annual volume by 365 to calculate the annual average daily flow. As shown in Figure D-15, the Charleroi POTW experienced elevated concentrations of TSS and BOD_5 while accepting UOG extraction wastewater.



Sources: 52 DCN SGE00929

Figure D-15. Charleroi POTW: Annual Average Daily Effluent Concentrations and POTW Flows[121]

Waynesburg, PA, POTW

The Borough of Waynesburg POTW accepted gas-exploration-related wastewater, hauled directly from operators, from June 2006 to November 2008. Gas well wastewater made up about 2 percent of total inflow in 2006. The percentage increased to 8.1 percent in 2007 and 9.5 percent

[121] Figure D-15 only shows data for 2008 through 2011 because there is no PA DEP waste report data or DMR Loading Tool data for the Charleroi POTW for 2012 or 2013.

in 2008. The Waynesburg POTW's average annual daily flow rate ranged between 0.37 and 0.62 MGD over those three years. The treatment process at Waynesburg POTW is as follows: two primary clarifiers, a trickling filter, a bio-tower, a final clarifier, and chlorine disinfection (12 DCN SGE00997, 13 DCN SGE00997.A01).

The Waynesburg POTW received a CWA §308 Request for Information from EPA Region 3 in February 2009. In March 2009, the Waynesburg POTW responded with a "Process Impact Evaluation" (14 DCN SGE00750), which stated that:

> *The amount of well water that was being accepted to the treatment facility has had no adverse effects on the trickling filter and the bio-tower except on one occasion in 2007. A hauler delivered a batch of well water that impacted the biological growth within the trickling filter. The water was believed to be frac water which possesses a high salinity which in turn impacted the biological growth in the trickling filter.*

5.3.2.2 Case Studies About POTWs Accepting Wastewater from Other Industrial Sources Containing UOG Pollutants (e.g., CWT Facilities)

New Castle, PA, POTW

The New Castle POTW accepted industrial wastewater from the Advanced Waste Services CWT facility, which treats oil and gas wastewater. Advanced Waste Services CWT facility treats "pretreated brine" (industrial wastewater) using solids settling, surface oil skimming, and pH adjustment. If influent wastewater does not meet Advanced Waste Services' pretreatment permit requirements, the facility applies additional treatment with flocculants (223 DCN SGE00554).

In its 2009 annual report to EPA Region 3, the New Castle POTW identified numerous violations of its NPDES permit limits for discharges of TSS. It also identified significant increases in the volume of industrial wastewater that it was receiving (see Table D-23) from Advanced Waste Services. New Castle's 2009 annual report does not include the total volume of wastewater it treated, but its 2013 NPDES permit indicates that all permit limits were based on an effluent discharge rate of 17 MGD (223 DCN SGE00554; 134 DCN SGE00573).

Table D-23. Industrial Wastewater Volumes Received by New Castle POTW (2007–2009)

Year	Industrial Wastewater Volume (gpd)	Percent of Total Volume Treated by POTW[a]
2007	74,278	0.44%
2008	130,608	0.77%
2009	331,381	1.95%

Source: 223 DCN SGE00554

a—Assuming 17 MGD is the total volume treated.

The 2009 annual report (223 DCN SGE00554) states that:

> *It is believed that pretreated brine wastewater from the developing oil & gas industry is adversely affecting the ability of the final clarifiers to separate solids via gravity settling.*

This has resulted in higher sludge blanket levels that are more easily upset and washed out during rainfall-induced high flow events. The Authority has begun using polymer flocculation to enhance settling with some success. However, there were numerous effluent TSS violations in 2009.

As noted in the annual report, instability in sludge blanket levels can cause increased washouts during large rain events, which may cause interference with biological treatment. New Castle reported 19 violations of its NPDES permit limits for TSS, believed to be caused by the acceptance of UOG extraction wastewater via the Advanced Waste Services CWT facility's industrial discharge (223 DCN SGE00554). The EPA compared the violations in 2009 to the violations that occurred in 2011, after the New Castle POTW stopped accepting industrial discharges from the CWT facility (i.e., violations between May and December 2011). The EPA identified two TSS violations during this nine-month time frame. Table D-24 shows detailed information about the violations in 2009 and 2011, including when they occurred, the measured values, and the percentage over the NPDES permit limit. The decrease in the number of TSS violations from 2009 to 2011, after the POTW stopped accepting industrial discharges from the Advanced Waste Services CWT facility, suggests that the UOG extraction wastewater pollutants were a contributing cause of the violations. However, the two violations in 2011 indicate that the UOG extraction wastewater was likely not the sole cause of interference with treatment processes at the POTW.

Table D-24. NPDES Permit Limit Violations from Outfall 001 of the New Castle POTW (NPDES Permit Number PA0027511)

Month, Year	Parameter	Sample Type	NPDES Permit Limit (mg/L)	Measured Value (mg/L)	Percentage Over Permit Limit (%)
March 2009	TSS	Weekly maximum	45	58	29
March 2009	TSS	Monthly average	30	37	23
May 2009	TSS	Monthly average	30	34	13
June 2009	TSS	Monthly average	30	38	27
July 2009	TSS	Weekly maximum	45	64	42
July 2009	TSS	Monthly average	30	45	50
August 2009	TSS	Weekly maximum	45	61	36
August 2009	TSS	Monthly average	30	50	67
September 2009	TSS	Monthly average	30	37	23
October 2009	TSS	Weekly maximum	45	46	2
October 2009	TSS	Monthly average	30	31	3
January 2010	TSS	Weekly maximum	45	60	33
January 2010	TSS	Monthly average	30	40	33
February 2010	TSS	Monthly average	30	33	10
March 2010	TSS	Monthly average	30	38	27
March 2010	TSS	Weekly maximum	45	55	22
November 2010	TSS	Monthly average	30	34	13
November 2010	TSS	Weekly maximum	45	55	22
December 2010	TSS	Weekly maximum	45	56	24
November 2011	TSS	Monthly average	30	35	17

Table D-24. NPDES Permit Limit Violations from Outfall 001 of the New Castle POTW (NPDES Permit Number PA0027511)

Month, Year	Parameter	Sample Type	NPDES Permit Limit (mg/L)	Measured Value (mg/L)	Percentage Over Permit Limit (%)
November 2011	TSS	Weekly maximum	45	64	42

Sources: 169 DCN SGE00620; 185 DCN SGE00612

Abbreviation: mg/L—milligrams per liter

Wheeling, WV, POTW

The Wheeling POTW, introduced in Section D.5.3.1, accepted industrial wastewater from the LAD CWT facility, which treats oil and gas wastewater[122]. A 2011 Consent Order issued to the Wheeling POTW by the WV DEP indicates that the POTW experienced interference with biological treatment from accepting UOG extraction wastewater via the CWT facility's industrial discharge. The Order describes the following timeline of events (219 DCN SGE00485):

- July 21, 2009—the Wheeling POTW experienced an upset that required several weeks of "vigilant action to recover" and included the introduction of a "seed" sludge from a nearby POTW. Plant upset conditions occurred during periods when the POTW exceeded discharge limits for fecal coliform and TSS.
- August 21, 2009—Meeting minutes from a meeting between Wheeling POTW and LAD CWT facility stated that Wheeling was accepting oil and gas wastewater "well above the 1% that is allowed." The minutes also said that Wheeling was concerned about the lack of diversity in microorganisms and that the wastewater from LAD was the cause of the lack of microbial diversity.
- November 17, 2009—WVDEP inspected Wheeling POTW and noted that "[t]he discharge from Wheeling was slightly turbid and causing a crispy white foam in the receiving stream." In addition, the Wheeling POTW experienced operational interference, inefficiency, or possible upset indicated by several factors including an increased chlorine demand, loss in effluent clarity, UV disinfection failures, and suspicious odors.
- May 6, 2010—Wheeling POTW representatives met with WV DEP representatives to discuss the draft Consent Order. The Order included numerous requirements including one that stated, "Upon entry of this Order, Wheeling shall continue to cease and desist acceptance of all oil and gas wastewater."

Brockway, PA, POTW

The Brockway POTW, introduced in Section D.5.3.1, was still accepting natural-gas-related wastewater treated by the Dannic Energy Corporation CWT facility as of June 2014. Before accepting COG wastewater, Brockway POTW installed an oil/solids separator and aerated equalization tank. The POTW began accepting COG wastewater starting in November

[122] As described in Section D.5.3.1, the Wheeling POTW accepted industrial wastewater from the LAD CWT facility through August 2009 and wastewater directly from UOG operators in 2008.

2008 and noticed an increase in sludge generation.[123] The POTW operators noticed a scum layer forming on the clarifiers because of a combination of calcium in the oil and gas wastewater and soaps/fats in the typical POTW influent wastewater. In addition to the scum layer on the clarifiers, the POTW experienced increased sludge generation and high concentrations of barium in the sludge (sludge barium content = 1,490 mg/kg). However, the POTW ran a hazardous waste determination and found that the barium content was below the hazardous waste classification threshold (99 DCN SGE00753).

5.3.2.3 POTW Sludge and Scale Formation

UOG extraction wastewater is also a concern in the disruption of POTW sludge processes, including sludge disposal, and the disruption of POTW operations as a result of excessive scale formation. For example, POTWs that accept and treat wastewater high in heavy metals (e.g., nickel, copper, zinc) face the potential for heavy metals accumulation in sludge. A POTW accepting wastewater with high metals concentrations may no longer be able to land-apply its sludge because it may violate sludge disposal rules.

While UOG extraction wastewater does not typically contain concentrations of heavy metals at levels that would likely prohibit the POTW from land-applying its sludge (see Table C-17), the EPA has identified the potential for elevated concentrations of radium-226 and -228 in sludge (172 DCN SGE00136; 135 DCN SGE01028). State and federal regulations for the transport and disposal of radioactive waste may limit the POTW's options for managing sludge contaminated with radium and other radioactive materials derived from UOG extraction wastewater. POTWs with sludge containing radioactive materials may resort to underground injection in a Class I well[124], disposal at a hazardous waste landfill[125], or disposal at a low-level radioactive waste landfill[126] (189 DCN SGE00615).

In addition to inhibiting the performance of treatment operations, UOG extraction wastewater may disrupt POTW operations as a result of excessive scale formation. Scale typically accumulates on valves, pipes, and fittings and, therefore, may interfere with POTW operation (e.g., restrict flow to unit processes). Scale is produced from deposits of divalent cations (e.g., barium, calcium, magnesium) that precipitate out of wastewater. Figure D-16 shows an example of barium sulfate scaling in an oil and gas pipe in the Haynesville shale formation.

[123] The EPA is not aware of any time when the Brockway POTW accepted UOG extraction wastewater.

[124] Class I underground injection wells are used to inject hazardous wastes, industrial non-hazardous liquids, or municipal wastewater beneath the lowermost underground source of drinking water.

[125] Hazardous waste landfills are regulated under RCRA Subtitle C. Some hazardous waste landfills are permitted to accept TENORM waste, while others have to request state approval before accepting TENORM waste.

[126] Low-level radioactive waste landfills are licensed by the U.S. Nuclear Regulatory Commission or by a state under agreement with the Commission. These landfills provide a disposal option for wastes with radionuclide concentrations that are unable to be disposed of at municipal, industrial, or hazardous waste landfills.

Source: 152 DCN SGE00768.A26

Figure D-16. Barium Sulfate Scaling in Haynesville Shale Pipe

Table C-17 shows typical concentrations of barium, calcium, and strontium in UOG extraction wastewater, which suggest that UOG extraction wastewater may cause scale accumulation at POTWs. Because radium[127] behaves like other divalent cations, it may also accumulate in scale and form TENORM: technologically-enhanced naturally occurring radioactive material, defined 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 (e.g., in treatment processes at a POTW). PA DEP's 2015 study report[128] (135 DCN SGE01028) provides the following examples of solids that may contain TENORM: drill cuttings, filter sock residuals, impoundment sludge, tank bottom sludge, pipe scale, wastewater treatment plant sludge, and soils[129]. The PA DEP TENORM study report concludes that "There is little potential for radiological exposure to workers and members of the public from handling and temporary storage of filter cake at POTWs. However, there is a potential for radiological environmental impacts from spills and the long-term disposal of POTW filter cake." The PA DEP TENORM study report includes the following recommendations for future action:

- "Perform routine survey assessment of areas impacted with surface radioactivity to determine personal protective equipment (PPE) use and monitoring during future activity that may cause surface alpha and beta radioactivity to become airborne."

[127] Radium is a naturally occurring radioactive element that ionizes in water to a divalent cation with chemical properties similar to barium, calcium, and strontium.

[128] PA DEP initiated a study to collect data related to TENORM associated with oil and gas operations in Pennsylvania, including assessment of potential worker and public radiation exposure, TENORM disposal, and other environmental impacts.

[129] PA DEP's 2015 TENORM study sampled the following types of solids: surface soil impacted by sediments, filter cakes, soils, sludge, drill cuttings, drilling muds, proppant sand, and filter socks. PA DEP identified pipe scale as a source of TENORM, but did not sample for pipe scale in their 2015 TENORM study.

- "Conduct additional radiological sampling and analyses and radiological surveys at all WWTPs accepting wastewater from O&G operations to determine if there are areas of contamination that require remediation; if it is necessary to establish radiological effluent discharge limitations; and if the development and implementation of a spill policy is necessary."

The Marcellus shale formation is known to contain radium and, therefore, is of particular concern for TENORM generation (172 DCN SGE00136; 28 DCN SGE00519; 150 DCN SGE00587).

Rowan et al. (145 DCN SGE00241) report a positive correlation between TDS concentrations and radium activity based on data for produced water from the Marcellus shale and conventional formations in the Appalachian basin. Therefore, UOG formations containing higher concentrations of TDS will likely also contain higher radium activity and, therefore, a higher chance for TENORM accumulation in sludge. However, the existing literature contains limited sampling data measuring radioactive constituents in UOG extraction wastewater (see Table C-19). Therefore, the potential for TENORM accumulation in scale from UOG extraction wastewater and the subsequent health risks to worker safety at POTWs are not fully known.

The 2015 PA DEP TENORM Study (135 DCN SGE01028) also looked into potential worker exposure, TENORM disposal options, and environmental impacts. PA DEP analyzed liquid and solid samples for alpha, beta, and gamma radiation and gas samples for radon. PA DEP sampled the following types of facilities, among others, as part of their study:

- Well sites – PA DEP sampled 38 well sites (4 conventional wells and 34 unconventional wells) from June 2013 through July 2014; and

- Wastewater treatment plants – PA DEP sampled 29 wastewater treatment plants (10 POTWs, 10 CWT facilities, and 9 zero liquid discharge (ZLDs) facilities).

PA DEP presents sample data of filter cakes from POTWs receiving oil and gas wastewater that showed "Ra-226 and Ra-228 present above typical background concentrations in soil. The average Ra-226 result was 20.1 pCi/g with a large variance in the distribution, and the maximum result was 55.6 pCi/g. The average Ra-228 result was 8.32 pCi/g, and the maximum result was 32.0 pCi/g Ra-228." (135 DCN SGE01028)

PADEP concluded, "…[t]here is little potential for radiological exposure to workers and members of the public from handling and temporary storage of filter cake at POTW-I's[130]. However, there is a potential for radiological environmental impacts from spills and the long-term disposal of POTW-I filter cake" (135 DCN SGE01028). ERG's *Radioactive Materials in the Unconventional Oil and Gas (UOG) Industry* memorandum (54 DCN SGE00933) provides additional information and results from the PA DEP study.

[130] PA DEP defines a "POTW-I" as a POTW that was considered to be influenced by having received wastewater from the oil and gas industry.

5.3.3 Potential Impacts of DBP Precursors in UOG Extraction Wastewater

Disinfection, especially chlorination of drinking water and wastewater, is used to reduce outbreaks of waterborne disease. As well as killing pathogenic microbes, though, disinfection can produce a variety of toxic halo-organic compounds called DBPs. UOG extraction wastewater often contains elevated levels of bromide (see Table C-13) and chloride, which is a precursor of several toxic DBPs (15 DCN SGE00509; 214 DCN SGE00754). Brominated DBPs are reported to have greater health risks (e.g., higher risk of cancer) than chlorinated DBPs (118 DCN SGE00800).

UOG extraction wastewater discharged to POTWs would be a potential source of DBPs in two scenarios:

- When UOG extraction wastewater is disinfected at a POTW (90 DCN SGE00535)
- When a POTW discharges wastewater including UOG extraction wastewater pollutants to a river that is used as a source water for a downstream drinking water treatment plant where disinfection is used (150 DCN SGE00587)

5.3.3.1 UOG Extraction Wastewater Disinfection at POTWs

DBPs can form within a POTW when disinfectants (e.g., chlorine, chloramine), natural organic matter, and bromide or iodide react. Because UOG extraction wastewater contains high concentrations of bromide (see Section C.2.2), treatment of UOG extraction wastewater at POTWs with disinfection processes can create DBPs. Hladik et al. investigated whether POTW treatment of wastewater from COG and UOG operations (hereafter referred to as “oil and gas wastewater”) could create DBPs, particularly brominated DBPs (90 DCN SGE00535).

Hladik et al. sampled effluent from three Pennsylvania POTWs, one POTW that did not accept oil and gas wastewater (POTW 1) and two that accepted oil and gas wastewater from oil and gas operators (POTW 2, POTW 3). The daily average discharge for POTW 1 was approximately 1,200 MGD. The daily average discharges for POTWs 2 and 3 were not reported, but the amount of oil and gas wastewater accepted at the POTWs was reported as ranging from 2.3 million gallons to 2.9 million gallons in 2012. Grab samples were collected in the river where the POTW effluent entered and were analyzed for 29 DBPs.

Table D-25 presents sampling results showing higher concentrations of DBPs in the majority of the effluent samples from POTWs that had accepted oil and gas wastewater from oil and gas operators. Hladik et al.’s results show that COG and UOG extraction wastewater may contribute to the formation of DBPs in chlorinated POTW effluent.

Table D-25. Concentrations of DBPs in Effluent Discharges at One POTW Not Accepting Oil and Gas Wastewater and at Two POTWs Accepting Oil and Gas Wastewater (µg/L)

Facility Identifier	POTW 1	POTW 1	POTW 2	POTW 3	MDL[a]
Sample Date	8/20/2012	11/28/2012	4/17/2013	4/17/2013	
Accepted Oil and Gas Wastewater	No	No	Yes	Yes	
Bromochloroiodomethane	ND	ND	0.10	0.12	0.02
Bromodichloromethane	BDL[b]	ND	BDL[b]	BDL[b]	0.10
Bromodiiodomethane	ND	ND	0.09	0.20	0.02
Bromoform	0.03	0.04	10.1	9.2	0.02
Chloroform	0.02	0.05	0.20	0.13	0.02
Dibromo-chloro-methane	0.05	0.05	0.83	0.51	0.02
Dibromoiodomethane	ND	ND	0.98	1.3	0.02
Dichloroiodomethane	ND	ND	BDL[b]	BDL[b]	0.04

Source: 90 DCN SGE00535

Note: The EPA presents data for eight DBPs in Table D-25. Hladik et al. (90 DCN SGE00535) collected data for 29 DBPs. The concentrations of DBPs in the effluent of POTWs that had accepted oil and gas wastewater were higher than the concentrations in POTWs that had not accepted oil and gas wastewater in all but three samples.
a—Method detection limits (MDLs) in surface water samples, as reported by Hladik et al. (90 DCN SGE00535).
b—Below method detection limit (BDL) indicates a value reported by Hladik et al. that was lower than the MDL. The EPA reported these values as BDL instead of reporting the values from Hladik et al. (90 DCN SGE00535).

Abbreviation: ND—non detect

5.3.3.2 Drinking Water Treatment Disinfection Downstream of POTWs

DBPs form when disinfectants (e.g., chlorine), natural organic matter, and bromide or iodide react. Therefore, they can form in drinking water treatment plants that use disinfection processes. Beginning in 2008, researchers in Pennsylvania detected high concentrations of bromide, a pollutant that facilitates the formation of toxic DBPs (e.g., brominated trihalomethanes), downstream of POTWs that accepted UOG extraction wastewater (81 DCN SGE00567; 150 DCN SGE00587).

Wilson and Van Briesen (226 DCN SGE00633) also investigated whether effluent discharges from POTWs were causing high TDS and bromide concentrations that would negatively impact drinking water treatment plants. They note that

> *Like TDS, bromide is not removed at drinking water treatment plants. Thus, produced water management that leads to increased concentrations of bromide in source waters for drinking water treatment plants can lead to increased concentrations of DBPs in drinking water.*

Wilson and Van Briesen later conclude that

> *Produced water management decisions should be informed by the potential contribution of this wastewater to the formation of disinfection by-products in downstream drinking water treatment plants.*

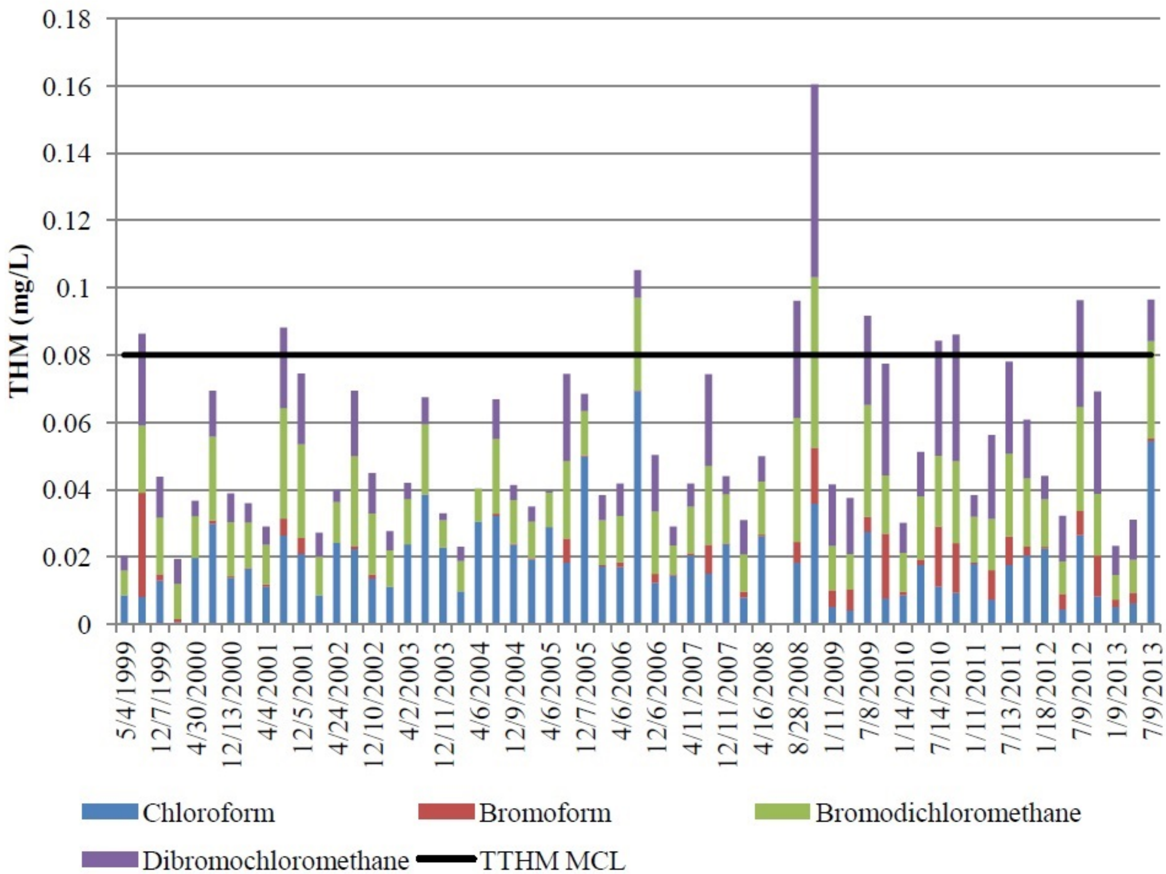
States et al. (150 DCN SGE00587) conducted a drinking water treatment plant survey and investigated bromide concentrations in the untreated river water intake and trihalomethanes (THMs) (i.e., chloroform, bromoform, dibromochloromethane, bromodicholoromethane) in the treated, "finished" drinking water. States et al. drew the following conclusions from their study:

- Elevated bromide concentrations in the influent to the studied drinking water treatment plant resulted in increased concentrations of certain DBPs, particularly brominated THMs, in the drinking water.
- Drinking water treatment plants cannot effectively remove bromide from intake water.
- POTWs discharging treated UOG extraction wastewater (specifically from the Marcellus shale formation) were major contributors to the increase in bromide in the drinking water treatment plant intake during the period of the study.

In February 2013, Eshelman and Elmore published a report for the Maryland Department of the Environment titled *Recommended Best Management Practices for Marcellus Shale Gas Development in Maryland* (69 DCN SGE00735). The report discussed POTW management of UOG extraction wastewater and specifically noted that this is not a best management practice. They further reported that the discharge of high-TDS loads into surface waters that could be drinking water treatment intakes should be prohibited. Eshelman and Elmore state that,

> *Higher chloride levels cause taste and odor problems in finished water. High bromide levels lead to increased formation of carcinogenic disinfectant by-products that can persist in the water to the point of consumption. Treatment of produced water by POTWs and other conventional wastewater treatment methods that do not remove salts should be prohibited in Maryland.*

McTigue et al. published an article about the occurrence and consequences of bromide in drinking water sources (118 DCN SGE00800). They note that UOG extraction wastewater may contribute to recent increases in bromide-containing waste upstream of drinking water utilities, and thus to the increase in DBPs reported by the drinking water utilities. The authors provide an example of an unnamed water treatment plant (WTP E) that began experiencing influent water with high TDS concentrations in 2008, around the same time that UOG extraction operations began in the area. Figure D-17 shows the average quarterly total THM speciation from 1999 through 2013, which shows a decrease in chlorinated DBPs and an increase in brominated DBPs starting around 2008.



Abbreviations: TTHM MCL – total trihalomethane maximum contaminant level
Source: 118 DCN SGE00800.

Figure D-17. THM Speciation in a Water Treatment Plant (1999–2013)

Another example of concerns about DBP formation from oil and gas wastewater is shown in PA DEP's response to a comment on Ridgway POTW's NPDES permit renewal. The comment, from the University of Pittsburgh, stated that, "bromide can create trihalomethane byproducts." PA DEP's response noted that trihalomethanes are made up of one of the following (followed parenthetically by measured effluent concentrations from the Ridgway POTW):

- Chloroform (non detect)
- Bromodichloromethane (non detect)
- Dibromochloromethane (non detect)
- Bromoform (74 µg/L)

PA DEP noted that the effluent concentration of bromoform was low enough not to be of concern compared to water quality limits. However, it is studying the impact of bromides on surface waters. PA DEP recognizes that UOG extraction wastewater has the potential to contribute to the formation of DBPs.

In August 2013, EPA Region 3 issued a letter (187 DCN SGE00935) informing the NPDES permitting authorities in the Mid-Atlantic region that

> *…conventional and nonconventional pollutants, such as bromide, must be tested by existing dischargers as part of the permit application process if such pollutants are expected to be present in effluent.*

The letter goes on to state that EPA Region 3 has reason to believe that industrial discharges (including UOG extraction wastewater discharges) containing bromide contributed to elevated levels of bromide in rivers and streams that resulted in downstream impacts at drinking water treatment plants, including increased occurrence of DBPs. Therefore, if the parameter is not limited in an applicable ELG, NPDES permit applicants must either describe why the parameter is expected in their discharges or include quantitative data for the parameter. These requirements apply to the following parameters of interest in UOG extraction wastewater, among others (195 DCN SGE00935.A01):

- TDS
- Chloride
- Bromide
- Sulfate
- Fluoride
- Aluminum, total
- Barium, total
- Iron, total
- Manganese, total
- Radium-226/228
- Arsenic, total
- Selenium, total
- Benzene
- Bromoform
- Chlorobenzene
- Chloroform
- Ethylbenzene
- Toluene
- Phenol
- Naphthalene
- Alpha-BHC
- Beta-BHC

Parker et al. published an article in September 2014 (129 DCN SGE00985) that evaluated the minimum volume of UOG produced water from Marcellus shale and Fayetteville shale wells that, when diluted by fresh water, would generate and/or alter the formation and speciation of DBPs after chlorination, chloramination, and ozonation treatment.

Parker et al. suspect that, due to the increased salinity of UOG produced water, elevated bromide and iodide in UOG produced water may promote the formation of DBPs. The results show that UOG produced water dilution as low as 0.01 percent could result in altered speciation toward the formation of brominated and iodinated DBPs. The results also show that UOG produced water dilution as low as 0.03 percent increases the overall formation of DBPs. Parker et al. suggest either eliminating UOG produced water discharges or installing halide-specific removal techniques in CWT facilities and/or POTWs that are accepting UOG produced water for treatment.

Chapter E. Reference Flags and List

The EPA reviewed existing data sources, including state and federal agency databases, journal articles and technical papers, technical references, industry/vendor telephone queries, and vendor websites to gather information for the TDD. The EPA identified all of the information described in this TDD from these types of existing data sources, which are listed in Table E-1.

The EPA assigned one of the following data source quality flags to each of the sources referenced in this TDD:

- **Source quality flag "A":** Journal articles and documents prepared by or for a government agency (e.g., EPA site visit reports, industry meeting notes)
- **Source quality flag "B":** Documents prepared by a verified source that include citation information (e.g., operator reports, vendor documents, university publications)
- **Source quality flag "C":** Documents prepared by a verified source that do not include citation information (e.g., operator reports, vendor documents, conference presentations)
- **Source quality flag "D":** Documents prepared by a source that could not be verified and that do not include citation information

Table E-1. Source List

ID	DCN	Source Citation	Source Flag
1	SGE00046	Abdalla, Charles W.; Drohan , Joy R.; Blunk, Kristen S.; Edson, Jessie. 2011. Marcellus Shale Wastewater Issues in Pennsylvania—Current and Emerging Treatment and Disposal Technologies. Penn State Cooperative Extension, College of Agricultural Sciences.	B
2	SGE00932	Abt Associates. 2015. Profile of the Oil and Gas Extraction (OGE) Sector, with Focus on Unconventional Oil and Gas (UOG) Extraction. (February 18).	A
3	SGE00070	Acharya, Harish; Matis, Hope; Kommepalli, Hareesh; Moore, Brian; Wang, Hua. 2011. Cost Effective Recovery of Low-TDS Frac Flowback Water for Re-use. Prepared by GE Global Research. Prepared for US DOE NETL. Morgantown, WV. (June).	A
4	SGE00723	Agency for Toxic Substances & Disease Registry (ATSDR). 2006. Hydrogen Sulfide ToxFAQs. (July).	A
5	SGE00497	Angelo, Tom. 2013. From Pilot Study to Daily Processing: Warren, Ohio's Documentary to Hydraulic Fracturing Water Treatment. City of Warren, Ohio, Water Pollution Control Department. Presentation at EPA's Study of Hydraulic Fracturing and Its Potential Impact on Drinking Water Resources: Wastewater Treatment and Related Modeling Technical Workshop. April 18, 2013.	A
6	SGE00499	Arkansas Oil and Gas Commission (AOGC). 2013. Welcome to the Arkansas Oil and Gas Commission Online Production and Well Information. Accessed on 6/14/2013.	A

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8	SGE00502	Baker Hughes. 2013. North America Rotary Rig Count Pivot Table (Feb 2011–Current). (November 8). Downloaded on 11/11/2013. Available online at: http://phx.corporate-ir.net/phoenix.zhtml?c=79687&p=irol-reportsother	B
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10	SGE00787	Borough of California. 2009. Borough of California Response to 308 Request for Information. (March 18).	A
11	SGE00751	Borough of Charleroi. 2008. Re: Authority of the Borough of Charleroi Administrative Order. (November 21).	A
12	SGE00997	Borough of Waynesburg. 2009. Clean Water Act Section 308 Request for Information.	A
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15	SGE00509	Brown, Daniel; Bridgeman, John; West, John R. 2011. Predicting Chlorine Decay and THM Formation in Water Supply Systems. Reviews in Environmental Science and Bio/Technology 10:79–99.	A
16	SGE00110	Bruff, Matthew. 2011. An Integrated Water Treatment Technology Solution for Sustainable Water Resource Management in the Marcellus Shale. Prepared by Altela, Inc., Argonne National Laboratory, BLX, Inc., and CWM Environmental, Inc. DE-FE0000833.	A
17	SGE01009	Caen, R., Darley, H.C.H., and G. R. Gray. 2011. Composition and Properties of Drilling and Completion Fluids. 6th edition. Gulf Professional Publishing: Waltham, MA.	B
18	SGE00966	California Council on Science and Technology (CCST). 2014. Advanced Well Stimulation Technologies in California: An Independent Review of Scientific and Technical Information. Sacramento, CA.	A
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21	SGE00749	City of Clarksburg. 2009. Re: Clean Water Act Section 308 Request for Information. (March 2).	A
22	SGE01000	City of Wheeling Water Pollution Control Division. 2007. Wheeling Effluent Data.	A
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25	SGE00182	Clark, C.E.; Veil, J.A. 2009. Produced Water Volumes and Management Practices in the United States. ANL/EVS/R-09/1. Argonne National Laboratory. (September)	A
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27	SGE00357	Cramer, John. 2011. Post-frac Flowback Analysis and Reuse Implications. Superior Well Services.	B
28	SGE00519	Davies, Peter J. n.d. Radioactivity. Cornell University.	B
29	SGE00520	Drillinginfo. 2011. DI Desktop® December 2011 Download. Drillinginfo, Inc.	B
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31	SGE00989	Energy Information Administration (EIA). 2014. Annual Energy Outlook 2014 with Projections to 2040. DOE/EIA-0383(2014).	A
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33	SGE00984	Energy Information Administration (EIA). 2014. Glossary. Retrieved from http://www.eia.gov/tools/glossary	A
34	SGE00708	Environmental Leader. 2013. Unconventional E&P "$8 Billion of US Water Services Market." (November 11).	B
35	SGE00522	Environmental Review Appeals Commission, State of Ohio. 2012. Patriot Water Treatment, LLC, and City of Warren v. Chris Korleski, Director of Environmental Protection, and Scott Nally, Director of Environmental Protection: 2012 Decision.	A
36	SGE00244	ERG. 2012. Camp, Meghan; Bicknell, Betsy; Ruminski, Brent. Notes on Conference Call with 212 Resources on 4 January 2012. (January 9).	A
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38	SGE00521	ERG. 2012. Camp, Meghan; Ruminski, Brent. Notes for Shale Gas Industry Meeting Held on 29 February 2012. (April 20).	A
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40	SGE00705	ERG. 2014. Ruminski, Brent. Notes on Call with Hydrozonix, LLC on 7 February 2014. (March 7.)	A
41	SGE00736	ERG. 2015. Analysis of Active Underground Injection for Disposal Wells.	A
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43	SGE00596	ERG. 2015. Analysis of Centralized Waste Treatment (CWT) Facilities Accepting UOG Extraction Wastewater.	A
44	SGE00596.A01	ERG. 2015. Analysis of Centralized Waste Treatment Facilities (CWTs) Accepting UOG Wastewater Attachment 1: UOG CWT List and Analysis.	A
45	SGE00963	ERG. 2015. Analysis of DI Desktop® Memorandum.	A
46	SGE00739	ERG. 2015. Analysis of Pennsylvania Department of Environmental Protection's (PA DEP) Oil and Gas Waste Reports.	A
47	SGE00739.A03	ERG. 2015. Analysis of Pennsylvania Department of Environmental Protection's (PA DEP) Oil and Gas Waste Reports.	A
48	SGE00693	ERG. 2015. Data Compilation Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction. Office of Water Engineering and Analysis Division.	A
49	SGE00693.A01	ERG. 2015. Data Compilation Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction —Attachment 1: Onshore Oil and Gas Drilling Activity.	A
50	SGE00693.A02	ERG. 2015. Data Compilation Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction —Attachment 2: EIA UOG Resource Potential.	A
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52	SGE00929	ERG. 2015. Publicly Owned Treatment Works (POTW) Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction	A
53	SGE00929.A01	ERG. 2015. Publicly Owned Treatment Works (POTW) Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction —Attachment 1: POTWs Data for TDD.	A
54	SGE00933	ERG. 2015. Radioactive Materials in the Unconventional Oil and Gas (UOG) Industry Memorandum.	A
55	SGE00740	ERG. 2015. Unconventional Oil and Gas (UOG) Drilling Wastewater Memorandum.	A
56	SGE00724	ERG. 2015. Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation Memorandum.	A
57	SGE00724.A01	ERG. 2015. Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation —Attachment 1: UOG Produced Water Data Compilation.	A
58	SGE00724.A02	ERG. 2015. Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation —Attachment 2: DI Desktop Long-term Produced Water Rates.	A

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59	SGE00724.A03	ERG. 2015. Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation —Attachment 3: DI Desktop Long-term Produced Water Rates.	A
60	SGE00724.A04	ERG. 2015. Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation —Attachment 4: FracFocus Fracturing Fluid Volume.	A
61	SGE00724.A05	ERG. 2015. Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation —Attachment 5: FracFocus Fracturing Fluid Volume.	A
62	SGE00724.A06	ERG. 2015. Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation —Attachment 6: Bakken Flowback Water Rates.	A
63	SGE00724.A07	ERG. 2015. Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation —Attachment 7: New Mexico Flowback Water Rates.	A
64	SGE00724.A08	ERG. 2015. Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation —Attachment 8: Utica Flowback and Produced Water.	A
65	SGE00724.A09	ERG. 2015. Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation —Attachment 9: Niobrara Produced Water Rates.	A
66	SGE00724.A10	ERG. 2015. Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation —Attachment 10: Wyoming Flowback Water Rates.	A
67	SGE00724.A11	ERG. 2015. Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation —Attachment 11: Wattenberg Produced Water Rates.	A
68	SGE00724.A12	ERG. 2015. Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation —Attachment 12: Colorado Flowback Water Rates.	A
69	SGE00735	Eshelman, Keith N.; Elmore, Andrew. 2013. Recommended Best Management Practices for Marcellus Shale Gas Development in Maryland. University of Maryland Center for Environmental Science. Prepared for Maryland Department of the Environment. (February 18).	A
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71	SGE00525	Ferrar, Kyle J.; Michanowicz, Drew R.; Christen, Charles L.; Mulcahy, N.; Malone, Samantha L.; Sharma, Ravi K. 2013. Assessment of Effluent contaminants from Three Facilities Discharging Marcellus Shale Wastewater to Surface Waters in Pennsylvania. Environmental Science & Technology 47:3472–3481.	A
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74	SGE00746	Franklin Township Sewer Authority. 2008. Franklin Township WWTP Fact Sheet/Statement of Basis (NPDES PA0046426). (June 2).	A
75	SGE00760	Freyman, Monika. 2014. Hydraulic Fracturing & Water Stress: Water Demand by the Numbers. Ceres. (February).	B
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82	SGE00531	Hanlon, James. 2011. Natural Gas Drilling in the Marcellus Shale: NPDES Program Frequently Asked Questions. (March 16).	A
83	SGE00532	Hansen, Evan; Mulvaney, Dustin; Betcher, Meghan. 2013. Water Resource Reporting and Water Footprint from Marcellus Shale Development in West Virginia and Pennsylvania. (October 30).	B
84	SGE00284	Hayes, Thomas et al. 2012. Barnett and Appalachian Shale Water Management and Reuse Technologies. Research Partnership to Secure Energy for America (RPSEA).	A
85	SGE00414	Hayes, Thomas; Severin, Blaine F. 2012. Characterization of Flowback Waters from the Marcellus and the Barnett Shale Regions Report No. 08122-05.09. Research Partnership to Secure Energy for America (RPSEA).	A
86	SGE00533	Heffernan, Kevin. 2012. Unconventional Resource Development and Hydraulic Fracturing. Red Deer River Watershed Alliance. (October 25).	B
87	SGE00239	Hefley, William, et al. 2011. The Economic Impact of the Value Chain of a Marcellus Shale Well. University of Pittsburgh. (August).	B

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90	SGE00535	Hladik, Michelle; Focazio, Michael J.; Englae, Mark. 2014. Discharges of Produced Waters from Oil and Gas Extraction via Wastewater Treatment Plants Are Sources of Disinfection By-products to Receiving Streams. Science of the Total Environment 466–467:1085–1093.	A
91	SGE00333	Horn, Aaron. 2009. Breakthrough Mobile Water Treatment Converts 75% of Fracturing Flowback Fluid to Fresh Water and Lowers CO_2 Emissions. SPE SPE-121104-PP. Presentation at 2009 SPE Americas E&P Environmental & Safety Conference.	B
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93	SGE00476	Hydro Recovery, LP. 2013. Company Info. Downloaded on 5/20/2013.	C
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96	SGE00769	International Atomic Energy Agency (IAEA). 2014. The Environmental Behaviour of Radium: Revised Edition. Technical Report Series No. 476. (March 1).	A
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98	SGE00479	Kadramas, Lee & Jackson, Inc. 2012. Power Forecast 2012: Williston Basin Oil and Gas Related Electrical Load Growth Forecast.	**B**
99	SGE00753	Keister, Timothy. 2010. Marcellus Hydrofracture Flowback and Production Wastewater Treatment, Recycle, and Disposal Technologies. Presentation at The Science of Marcellus Shale. (January 29).	B
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101	SGE00996	Kicinski, J. 2007. Wheeling POTW Analysis 4.	A
102	SGE00775	Kieler, Janet. 2012. CDPS General Permit for Discharges Associated with Produced-Water Treatment Facilities. (January 30).	A
103	SGE00540	Kiski Valley Water Pollution Control Authority. 2011. Letter to McCutcheon Enterprises, Inc. (April 21).	A
104	SGE00545	Klaber, Kathryn. 2011. Letter to Michael Krancer, PA DEP. Marcellus Shale Coalition. (April 20).	C

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105	SGE00759	KLH Engineers. 2006. City of Wheeling: Water Pollution Control Division Headworks Loading Analysis. (November).	A
106	SGE00757	KLH Engineers. 2008. Technical Evaluation of the Impact of Oil and Gas Well Wastewaters on the Municipal Authority of the City of McKeesport Wastewater Treatment Facility. (November).	A
107	SGE00758	KLH Engineers. 2009. Technical Evaluation of the Impact of Oil and Gas Well Wastewaters on the Clairton Municipal Authority Wastewater Treatment Facility. (February).	A
108	SGE00745	KLH Engineers. 2011. Municipal Authority of the City of McKeesport: Headworks Loading Analysis for Natural Gas Drilling Wastewater Pollutants. (March).	B
109	SGE00345	Lewis, Aurana. 2012. Wastewater Generation and Disposal from Natural Gas Wells in Pennsylvania. Duke University.	B
110	SGE00667	Lord, R. LeBas; Luna, D.; Shahan, T. 2013. Development and Use of High-TDS Recycled Produced Water for Crosslinked-Gel-Based Hydraulic Fracturing. SPE 163824. Society of Petroleum Engineers.	B
111	SGE00543	Macormac, Zach. 2011. Wheeling Fined for Taking Frack Water. The Intelligencer/Wheeling News-Register. (October 15).	D
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113	SGE00547	Massachusetts Institute of Technology (MIT). 2011. The Future of Natural Gas: An Interdisciplinary MIT Study.	B
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116	SGE00481	McCutcheon Enterprises. 2013. Waste Reduction: A Greener Alternative for Treating Drilling Muds. (April).	C
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118	SGE00800	McTigue, Nancy; Graf, Katherine; Brown, Richard. 2014. Occurrence and Consequences of Increased Bromide in Drinking Water Sources. Environmental Engineering & Technology, Inc.	A
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123	SGE00644	New Mexico Energy, Minerals and Natural Resources Department (NMEMND). 2014. OCD Permitting: Well Search.	A
124	SGE00090	New York State Department of Environmental Conservation (NYSDEC). 2011. Supplemental Generic Environmental Impact Statement on the Oil, Gas, and Solution Mining Regulatory Program: Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs. Preliminary Revised Draft.	A
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126	SGE00639	Nicot, Jean-Philippe; Reedy, Robert C.; Costley, Ruth A.; Huang, Yun. 2012. Oil & Gas Water Use in Texas: Update to the 2011 Mining Water Use Report. University of Texas at Austin, Bureau of Economic Geology. (September).	A
127	SGE00188	O'Connell, James, ERG. 2014. Pennsylvania Department of Environmental Protection’s (PA DEP) Statewide Oil and Gas Waste Reports. (December).	A
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129	SGE00985	Parker, Kimberly M.; Zeng, Teng; Harkness, Jennifer; Vengosh, Avner; Mitch, William A. 2014. Enhanced Formation of Disinfection Byproducts in Shale Gas Wastewater-Impacted Drinking Water Supplies. Environmental Science & Technology 48(19):11161–11169.	A
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136	SGE00575	Petroleum Equipment Suppliers Association (PESA). 2012. Outlook for Domestic Unconventional Resources. Presentation at PESA Annual Meeting.	B
137	SGE00748	PG Environmental, LLC. 2009. Clairton Municipal Authority POTW Pass-Through Analysis Appendices. (August 19).	A
138	SGE00139	Puder, M.G.; Veil, J.A. 2006. Argonne National Laboratory. Offsite Commercial Disposal of Oil and Gas Exploration and Production Waste: Availability, Options, and Costs. Prepared for U.S. DOE NETL. (August). Available online at: http://www.evs.anl.gov/pub/doc/ANL-EVS-R-06-5.pdf	A
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144	SGE00987	Rost, J. November 2010. Municipal Authority of the City of McKeesport Analysis of Gas Well Wastewaters as Required Under the PA DEP Administrative Order Dated October 23, 2008.	A
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149	SGE00586	State Review of Oil and Natural Gas Environmental Regulations (STRONGER). 2003. West Virginia Follow-Up and Supplemental Review. (January).	A
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156	SGE00155	U.S. Energy Information Administration (EIA). 2010. Tight Sands Gas Plays, Lower 48 States. Prepared by EIA Office of Oil and Gas. (June).	A
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158	SGE00487	U.S. Energy Information Administration (EIA). 2013. Annual Energy Outlook 2013 with Projections to 2040. DOE/EIA-0383(2013). (April).	A
159	SGE00595	U.S. Energy Information Administration (EIA). 2013. Drilling Productivity Report: For Key Tight Oil and Shale Gas Regions. (October).	A
160	SGE00761	U.S. EPA. 1989. Letter from T.P. O'Farrell (EPA) to C.B. Harriman (Steptoe & Johnson) about applicability of 40 C.F.R 435 Subpart C to CBM operations.	A
161	SGE00599	U.S. EPA. 1999. Biosolids Generation, Use, and Disposal in the United States. EPA 530-R-99-009. (September).	A
162	SGE01006	U.S. EPA. 2000. Development Document for Final Effluent Limitations Guidelines and Standards for Synthetic-Based Drilling Fluids and Other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category. EPA-821-B-00-013. (December).	A
163	SGE00601	U.S. EPA. 2001. Small Entity Compliance Guide: Centralized Waste Treatment Effluent Limitations Guidelines and Pretreatment Standards (40C.F.R 437). EPA 821-B-01-003.	A
164	SGE00600	U.S. EPA. 2003. Development Document for the Final Effluent Limitations Guidelines and Standards for the Metal Products and Machinery Point Source Category. EPA 821-B-03-001. (February).	A
165	SGE00602	U.S. EPA. 2004. Local Limits Development Guidance Appendices. EPA 833-R-04-002B. (July). Available online at: http://www.epa.gov/npdes/pubs/final_local_limits_appendices.pdf	A
166	SGE00603	U.S. EPA. 2008. Clean Watersheds Needs Survey: 2008 Report to Congress. EPA 832-R-10-002. Available online at: http://water.epa.gov/scitech/datait/databases/cwns/upload/cwns2008rtc.pdf	A

Table E-1. Source List

ID	DCN	Source Citation	Source Flag
167	SGE00138	U.S. EPA. 2010. 2010 UIC Well Inventory 2010. Available online at: http://water.epa.gov/type/groundwater/uic/class2/index.cfm	A
168	SGE00604	U.S. EPA. 2010. Hydraulic Fracturing Research Study. EPA 600-F-10-002. (June).	A
169	SGE00620	U.S. EPA. 2011. (Region 3) Administrative Order for Compliance and Request for Information, EPA Docket No. CWA-03-2011-0272DN. (September 28).	A
170	SGE00982	U.S. EPA. 2011. (Region 3) Letter to PA DEP regarding disposal of Marcellus Shale wastewater. (May 12).	A
171	SGE00249	U.S. EPA. 2011. Introduction to the National Pretreatment Program. EPA 833-B-11-001. (June).	A
172	SGE00136	U.S. EPA. 2011. Oil and Gas Production Wastes. http://www.epa.gov/radiation/tenorm/oilandgas.html	A
173	SGE00132	U.S. EPA. 2011. Underground Injection Control Program: Class II Wells—Oil and Gas Related Injection Wells (Class II). Downloaded on 8/31/2011. Available online at: http://water.epa.gov/type/groundwater/uic/class2/	A
174	SGE00368	U.S. EPA. 2012. (Region 3). Key Documents About Mid-Atlantic Oil and Gas Extraction. (November 26). Available online at: http://www.epa.gov/region3/marcellus_shale/	A
175	SGE00608	U.S. EPA. 2012. Discharge Monitoring Report (DMR) Pollutant Loading Tool. Downloaded on 1/28/2013. Available online at: http://cfpub.epa.gov/dmr/	A
176	SGE00279	U.S. EPA. 2012. Meeting Summary: Conference Call with North Star Disposal, Inc Regarding Underground Injection Operations in Ohio. (July 2).	A
177	SGE00276	U.S. EPA. 2012. Meeting with XTO Energy, Inc. about Unconventional Oil and Gas Sanitized.	A
178	SGE00635	U.S. EPA. 2012. Site Visit Report: Chesapeake Energy Corporation Marcellus Shale Gas Operations Sanitized.	A
179	SGE00275	U.S. EPA. 2012. Site Visit Report: Citrus Energy Corporation Marcellus Shale Gas Operations. (January 22).	A
180	SGE00300	U.S. EPA. 2012. Site Visit Report: Eureka Resources, LLC Marcellus Shale Gas Operations. (February 25).	A
181	SGE00299	U.S. EPA. 2012. Site Visit Report: US Gas Field Fluids Management (formerly Clean Streams) Marcellus Shale Gas Operations. (October 9).	A
182	SGE00742	U.S. EPA. 2012. States Pretreatment Coordinators' Quarterly Conference Call: Summary. (August 8).	A
183	SGE00636	U.S. EPA. 2012. Talisman Marcellus Operations Overview. (July 23).	A
184	SGE00611	U.S. EPA. 2012. UIC Program Primacy. Downloaded on 10/24/2013. Available online at: http://water.epa.gov/type/groundwater/uic/Primacy.cfm	A
185	SGE00612	U.S. EPA. 2013. DMR Loading Tool Download for New Castle POTW (NPDES No. PA0027511). Downloaded on 11/ 22/2013.	A

Table E-1. Source List

ID	DCN	Source Citation	Source Flag
186	SGE00726	U.S. EPA. 2013. Email Chain between Jacqueline Rios, Frank Brock, and Lisa Biddle About UICs in NY Taking Oil and Gas Wastewater. (November 13).	A
187	SGE00935	U.S. EPA. 2013. Letter to Lee McDonnell, PA DEP, Informing NPDES Permitting Authorities of Testing as Part of the Permit Application Process. (August 28).	A
188	SGE00613	U.S. EPA. 2013. Meeting Summary: Meeting with Industry Representatives About the Unconventional Oil and Gas Effluent Guideline Rulemaking. (February 28).	A
189	SGE00615	U.S. EPA. 2013. Radionuclides in Drinking Water: Waste Disposal Options. (November 26).	A
190	SGE00280	U.S. EPA. 2013. Site Visit Report: Anadarko Petroleum Corporation Marcellus Shale Gas Operations. (January 9).	A
191	SGE00625	U.S. EPA. 2013. Site Visit Report: Southwestern Energy (SWN) Fayetteville Shale Gas Operations Sanitized.	A
192	SGE00743	U.S. EPA. 2013. States Pretreatment Coordinators' Bi-monthly Conference Call. (August 14).	A
193	SGE00616	U.S. EPA. 2013. Summary of the Technical Workshop on Wastewater Treatment and Related Modeling. (April 18).	A
194	SGE00691	U.S. EPA. 2013. Summary of the Technical Workshop on Water Acquisition Modeling: Assessing Impacts Through Modeling and Other Means. (September).	A
195	SGE00935.A01	U.S. EPA. 2013. Toxic Screening Analysis Spreadsheet.	A
196	SGE00762	U.S. EPA. 2013. US EPA Technology Innovation Project: ECOS/ACWA Conference Call. (April 25).	A
197	SGE00585	U.S. EPA. 2014. FracFocus Database. Office of Research and Development (ORD).	A
198	SGE00766	U.S. EPA. 2014. Lockhart, John V. Email Correspondence between WV DEP and EPA. (June 3).	A
199	SGE00783	U.S. EPA. 2014. Thorium. (February 28). Available online at: http://www.epa.gov/radiation/radionuclides/thorium.html	A
200	SGE00786	U.S. EPA. 2014. UOG Workgroup—Warren, OH POTW Info Request. (June 19).	A
201	SGE00721	U.S. EPA. 2015. Evaluation of Hydraulic Fracturing Fluid Data from the FracFocus Chemical Disclosure Registry 1.0. (March).	A
202	SGE00785	U.S. EPA. 2015. Summary of Tribal Outreach Regarding Pretreatment Standards for Unconventional Oil and Gas (UOG) Extraction Wastewater.	A
203	SGE00692	U.S. EPA. 2015. Unconventional Oil & Gas (UOG) Extraction Wastewater Treatment Technologies.	A
204	SGE00622	U.S. Geological Survey (USGS). 2013. Water Resources and Shale Gas/Oil Production in the Appalachian Basin—Critical Issues and Evolving Developments. (August). Available online at: http://pubs.usgs.gov/of/2013/1137/pdf/ofr2013-1137.pdf	A

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ID	DCN	Source Citation	Source Flag
205	SGE00956	U.S. Geological Survey (USGS). 2014. National Produced Waters Geochemical Database v2.0 (Provisional).	A
206	SGE00623	U.S. Government Accountability Office (GAO). 2012. Energy-Water-Nexus: Information on the Quantity, Quality, and Management of Water Produced During Oil and Gas Production. (January). GAO-12-156.	A
207	SGE00624	University of Michigan. 2013. Hydraulic Fracturing in the State of Michigan. Graham Sustainability Institute Integrated Assessment Report Series. (September).	B
208	SGE00095	URS. 2011. Water-Related Issues Associated with Gas Production in the Marcellus Shale. (March 25).	B
209	SGE01095	USGS. 2015. Trends in Hydraulic Fracturing Distributions & Trt Fluids, Additives, Proppants, & Water Volumes Applied to US Wells Drilled, 1947-2010.	A
210	SGE01095.A09	USGS. 2015. Trends in Hydraulic Fracturing Distributions & Trt Fluids, Additives, Proppants, & Water Volumes Applied to US Wells Drilled, 1947-2010: Attachment 9: Frac_Trtm_Type.xlsx	A
211	SGE00114	Van Dyke, Staffan. 2010. Tight Gas Sandstone: Is It Truly Unconventional? Oil & Gas Evaluation Report. (October).	C
212	SGE00011	Veil, John A. 2010. Water Management Technologies Used by Marcellus Shale Gas Producers. Prepared by Argonne National Laboratory. Prepared for U.S. DOE NETL. (July). Available at: http://www.mde.state.md.us/programs/Land/mining/marcellus/Documents/WaterMgmtinMarcellusfull.pdf	A
213	SGE00093	Veil, John; Puder, Markus G.; Elcock, Deborah; Redweik, Robert J. 2004. A White Paper Describing Produced Water from Production of Crude Oil, Natural Gas, and Coal Bed Methane. Prepared by Argonne National Laboratory. Prepared for U.S. DOE NETL. (January).	A
214	SGE00754	Vengosh, A.; Jackson, Robert B.; Warner, N.; Darrah, Thomas H.; Kondash, A. 2014. A Critical Review of the Risks to Water Resources from Unconventional Shale Gas Development and Hydraulic Fracturing in the United States. Environmental Science & Technology 48(15):8334–8348.	A
215	SGE00627	Vidic, Radisav; Brantley, S.L.; Vandenbossche, J.M.; Yoxtheimer, D.; Abad, J.D. 2013. Impact of Shale Gas Development on Regional Water Quality. Science 340(6134).	B
216	SGE00629	Warner, Nathaniel R.; Christie, Cidney A.; Jackson, Robert B.; Vengosh, Avner. 2013. Impacts of Shale Gas Wastewater Disposal on Water Quality in Western Pennsylvania. Environmental Science & Technology 47(20):11849–11857.	A
217	SGE00295	Warren Water Pollution Control Facility. 2011. Fact Sheet for NPDES Permit Renewal, Warren Water Pollution Control Facility, 2011–2012. City of Warren.	A
218	SGE00767	West Virginia Department of Environmental Protection (WV DEP). 2010. Letter to City of Follansbee Re: WV/NPDES Permit No. WV0020273 Accepting Oil and Gas Wastewater. (December 15).	A

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ID	DCN	Source Citation	Source Flag
219	SGE00485	West Virginia Department of Environmental Protection (WV DEP). 2011. Consent Order Issued Under the Water Pollution Control Act, West Virginia Code, Chapter 22, Article 11.	A
220	SGE00488	West Virginia Department of Environmental Protection (WV DEP). 2012. NPDES Water Pollution Control Permit WV0116441. Reserved Environmental Services CWT Permit.	A
221	SGE01113	West Virginia Department of Environmental Protection (WV DEP). 2009. WV/NPDES Permit No WV0023302 Clarksburg Sanitary Board Accepting Oil and Gas Wastewater.	A
222	SGE01114	West Virginia Department of Environmental Protection (WV DEP). 2009. WV/NPDES Permit No, WV0023230 City of Wheeling Accepting Oil and Gas Wastewater.	A
223	SGE00554	Widmer Engineering, Inc. 2010. New Castle Sanitation Authority, New Castle, Lawerance County, Pennsylvania: Annual Pretreatment Report, 2009 Operating Year. Prepared for New Castle Sanitation Authority.	A
224	SGE00064	Williams, John. 2011. Marcellus Shale-Gas Development and Water-Resource Issues. USGS: New York Water Science Center.	A
225	SGE00632	Williams, John. n.d. The Marcellus Shale Gas Play: Geology, Development, and Water-Resource Impact Mitigation. USGS: New York Water Science Center.	A
226	SGE00633	Wilson, Jessica; Van Briesen, Jeanne. 2013. Oil and Gas Produced Water Management and Surface Drinking Water Sources in Pennsylvania. Environmental Practice 14(4):288–300.	A
227	SGE00725	Wolford, Robert. 2011. Characterization of Organics in the Marcellus Shale Flowback and Produced Waters. Pennsylvania State University. Master's Thesis. (August).	B
228	SGE00774	Ziemkiewicz, Paul. 2013. Water Quality Literature Review and Field Monitoring of Active Shale Gas Wells. Phase I: Assessing Environmental Impacts of Horizontal Gas Well Drilling Operations. West Virginia Department of Environmental Protection. (February 15).	A

Chapter F. APPENDICES

APPENDIX F.1 REFERENCE FILES IN FDMS

Table F-1. TDD Supporting Memoranda and Other Relevant Documents Available in FDMS

DCN	Title	Description	Relevant TDD Section(s)
SGE00596	Analysis of Centralized Waste Treatment (CWT) Facilities Accepting UOG Extraction Wastewater	Describes the various data sources used to identify CWT facilities that have accepted UOG wastewater and explains the different CWT facility analyses that are presented in Section D.4 of the TDD.	D.1, D.4
SGE00692	Unconventional Oil and Gas (UOG) Extraction Wastewater Treatment Technologies	Summarizes technologies that are currently used to treat UOG wastewater at full-scale operations and technologies not currently used to treat UOG extraction wastewater, but which may be applied in the future.	D.3
SGE00693	Data Compilation Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction	Explains various data analyses presented in Chapters B, C, and D of the TDD, involving well drilling and construction, historical and current drilling activity, UOG resource potential, fracturing fluid chemical additives, and reuse/recycle.	B.3, C.Intro, C.1, C.2, D.1, D.2, D.3
SGE00724	Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation	Describes the various data sources used to identify UOG wastewater volumes and characteristics data and explains the process that was used to standardize and summarize the data.	B.3, C.Intro, C.2, C.3
SGE00736	Analysis of Active Underground Injection for Disposal Wells	Explains the compilation of underground injection wells data from various sources.	D.1, D.2, D.4
SGE00739	Analysis of Pennsylvania Department of Environmental Protection's (PA DEP) Oil and Gas Waste Reports	Explains the PA DEP waste reports data and explains the processes that were used to analyze the data.	C.2, D.1, D.5
SGE00740	Unconventional Oil and Gas (UOG) Drilling Wastewater	Explains the well drilling process in more detail, with focus on drilling wastewater volumes and constituent concentrations.	B.2, C.2, C.3, D.1

Table F-1. TDD Supporting Memoranda and Other Relevant Documents Available in FDMS

DCN	Title	Description	Relevant TDD Section(s)
SGE00785	Summary of Tribal Outreach Regarding Pretreatment Standards for Unconventional Oil and Gas (UOG) Extraction Wastewater	Summarizes the data collected as part of the tribal outreach efforts associated with the proposed rule.	D.5
SGE00929	Publicly Owned Treatment Works (POTW) Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction	Describes the various data sources used to identify POTWs that have accepted UOG wastewater and explains the different POTW analyses that are presented in Section D.5 of the TDD.	D.5
SGE00932	Profile of the Oil and Gas Extraction (OGE) Sector, with Focus on Unconventional Oil and Gas (UOG) Extraction	Provides economic background information about the oil and gas industry.	B.Intro
SGE00933	Radioactive Materials in the Unconventional Oil and Gas (UOG) Industry	Provides background information about radioactive elements in the UOG industry, with focus on radium-226 and radium-228.	C.3, D.5
SGE00963	Analysis of DI Desktop®	Summarizes the DI Desktop® data source and where it is cited throughout the proposed rule analyses.	B.3.2
SGE01016	Conventional Oil and Gas (COG) Memorandum for the Record	Summarizes COG extraction wastewater characteristics and management and disposal practices used for COG extraction wastewater.	N/A

N/A—Not Applicable

Table F-2. Crosswalk Between TDD and Supporting Memoranda

TDD Table or Figure Number	TDD Table/Figure Title	In a Supporting Memo (Y/N)?[a]	Source or Supporting Memo DCN(s)	Supporting Memo Title(s)
Figure A-1	UOG Extraction Wastewater	No (Created by the EPA)	—	—
Table A-1	Summary of State Regulations	No	SGE00187, SGE00254, SGE00545, SGE00766, SGE00767, SGE00982, SGE00983	—
Figure B-1	Historical and Projected Oil Production by Resource Type	No	SGE00487	—
Figure B-2	Historical and Projected Natural Gas Production by Resource Type	No	SGE00989	—
Figure B-3	Major U.S. Shale Plays (Updated May 9, 2011)	No	SGE00153	—
Figure B-4	Major U.S. Tight Plays (Updated June 6, 2010)	No	SGE00155	—
Figure B-5	Geology of Formations Containing Various Hydrocarbons	No	SGE00594	—
Figure B-6	Horizontal (A), Vertical (B), and Directional (C) Drilling Schematic	No	SGE00593	—
Figure B-7	Length of Time to Drill a Well in Various UOG Formations	Yes	SGE00693	Data Compilation Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction
Figure B-8	Hydraulic Fracturing Schematic	No	SGE00604	—
Figure B-9	Freshwater Impoundment	No	SGE00275	—
Figure B-10	Vertical Gas and Water Separator	No	SGE00625	—
Figure B-11	Fracturing Tanks	No	SGE00625	—
Figure B-12	Produced Water Storage Tanks	No	SGE00275	—
Figure B-13	Number of Active U.S. Onshore Rigs by Trajectory and Product Type over Time	Yes	SGE00693	Data Compilation Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction

Table F-2. Crosswalk Between TDD and Supporting Memoranda

TDD Table or Figure Number	TDD Table/Figure Title	In a Supporting Memo (Y/N)?[a]	Source or Supporting Memo DCN(s)	Supporting Memo Title(s)
Figure B-14	Projections of UOG Well Completions	Yes	SGE00693	Data Compilation Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction
Table B-1	Characteristics of Reservoirs Containing UOG and COG Resources	No	SGE00114, SGE00345, SGE00527, SGE00533	—
Table B-2	Active Onshore Oil and Gas Drilling Rigs by Well Trajectory and Product Type (as of November 8, 2013)	Yes	SGE00693	Data Compilation Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction
Table B-3	UOG Potential by Resource Type as of January 1, 2012	Yes	SGE00693	Data Compilation Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction
Figure C-1	UOG Extraction Wastewater Volumes for Marcellus Shale Wells in Pennsylvania (2004–2013)	Yes	SGE00739	Analysis of Pennsylvania Department of Environmental Protection's (PA DEP) Oil and Gas Waste Reports
Figure C-2	Ranges of Typical Produced Water Generation Rates over Time After Fracturing	Yes	SGE00724	Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation
Figure C-3	Anions and Cations Contributing to TDS Concentrations in Shale and Tight Oil and Gas Formations	Yes	SGE00724	Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation
Figure C-4	Chloride, Sodium, and Calcium Concentrations in Flowback and Long-Term Produced Water (LTPW) from Shale and Tight Oil and Gas Formations	Yes	SGE00724	Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation
Figure C-5	Barium Concentrations in UOG Produced Water from Shale and Tight Oil and Gas Formations	Yes	SGE00724	Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation

Table F-2. Crosswalk Between TDD and Supporting Memoranda

TDD Table or Figure Number	TDD Table/Figure Title	In a Supporting Memo (Y/N)?[a]	Source or Supporting Memo DCN(s)	Supporting Memo Title(s)
Figure C-6	Constituent Concentrations over Time in UOG Produced Water from the Marcellus and Barnett Shale Formations	No	SGE00414	—
Table C-1	Sources for Base Fluid in Hydraulic Fracturing	Yes	SGE00693	Data Compilation Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction
Table C-2	Fracturing Fluid Additives, Main Compounds, and Common Uses	No	SGE00070, SGE00721, SGE00780, SGE00781, SGE00966	—
Table C-3	Most Frequently Reported Additive Ingredients Used in Fracturing Fluid in Gas and Oil Wells from FracFocus (2011-2013)	Yes	SGE00693	Data Compilation Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction
Table C-4	Median Drilling Wastewater Volumes for UOG Horizontal and Vertical Wells in Pennsylvania	Yes	SGE00739	Analysis of Pennsylvania Department of Environmental Protection's (PA DEP) Oil and Gas Waste Reports
Table C-5	Drilling Wastewater Volumes Generated per Well by UOG Formation	Yes	SGE00740	Unconventional Oil and Gas (UOG) Drilling Wastewater
Table C-6	UOG Well Flowback Recovery by Resource Type and Well Trajectory	Yes	SGE00724	Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation
Table C-7	Long-Term Produced Water Generation Rates by Resource Type and Well Trajectory	Yes	SGE00724	Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation
Table C-8	Produced Water Volume Generation by UOG Formation	Yes	SGE00724	Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation
Table C-9	Availability of Data for UOG Extraction Wastewater Characterization	No (Created by the EPA)	—	—
Table C-10	Concentrations of Select Classical and Conventional Constituents in UOG Drilling Wastewater from Marcellus Shale Formation Wells	Yes	SGE00740	Unconventional Oil and Gas (UOG) Drilling Wastewater

Table F-2. Crosswalk Between TDD and Supporting Memoranda

TDD Table or Figure Number	TDD Table/Figure Title	In a Supporting Memo (Y/N)?[a]	Source or Supporting Memo DCN(s)	Supporting Memo Title(s)
Table C-11	Concentrations of Select Classical and Conventional Constituents in UOG Produced Water	Yes	SGE00724	Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation
Table C-12	Concentrations of Select Anions and Cations Contributing to TDS in UOG Drilling Wastewater from Marcellus Shale Formation Wells	Yes	SGE00740	Unconventional Oil and Gas (UOG) Drilling Wastewater
Table C-13	Concentrations of Select Anions and Cations Contributing to TDS in UOG Produced Water	Yes	SGE00724	Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation
Table C-14	Concentrations of Select Organic Constituents in UOG Drilling Wastewater from Marcellus Shale Formation Wells	Yes	SGE00740	Unconventional Oil and Gas (UOG) Drilling Wastewater
Table C-15	Concentrations of Select Organic Constituents in UOG Produced Water	Yes	SGE00724	Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation
Table C-16	Concentrations of Select Metal Constituents in UOG Drilling Wastewater from Marcellus Shale Formation Wells	Yes	SGE00740	Unconventional Oil and Gas (UOG) Drilling Wastewater
Table C-17	Concentrations of Select Metal Constituents in UOG Produced Water	Yes	SGE00724	Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation
Table C-18	Concentrations of Select Radioactive Constituents in UOG Drilling Wastewater from Marcellus Shale Formation Wells	Yes	SGE00740	Unconventional Oil and Gas (UOG) Drilling Wastewater
Table C-19	Concentrations of Select Radioactive Constituents in UOG Produced Water	Yes	SGE00724	Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation
Table C-20	Concentrations of Radioactive Constituents in Rivers, Lakes, Groundwater, and Drinking Water Sources Throughout the United States (pCi/L)	No	SGE00769	—
Figure D-1	UOG Produced Water Management Methods	No (Created by the EPA)	—	—

Table F-2. Crosswalk Between TDD and Supporting Memoranda

TDD Table or Figure Number	TDD Table/Figure Title	In a Supporting Memo (Y/N)?[a]	Source or Supporting Memo DCN(s)	Supporting Memo Title(s)
Figure D-2	UOG Drilling Wastewater Management Methods	No (Created by the EPA)	—	—
Figure D-3	Management of UOG Drilling Wastewater Generated by UOG Wells in Pennsylvania (2008–2013)	Yes	SGE00739	Analysis of Pennsylvania Department of Environmental Protection's (PA DEP) Oil and Gas Waste Reports
Figure D-4	Active Disposal Wells and CWT Facilities Identified in the Appalachian Basin	No (Created by the EPA)	—	—
Figure D-5	Flow Diagram of On-the-Fly UOG Produced Water Treatment for Reuse/Recycle	No	SGE00331	—
Figure D-6	Hypothetical UOG Produced Water Generation and Base Fracturing Fluid Demand over Time	Yes	SGE00693	Data Compilation Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction
Figure D-7	UOG Extraction Wastewater Management Practices Used in the Marcellus Shale (Top: Southwestern Region; Bottom: Northeastern Region)	No	SGE00579	—
Figure D-8	Number of Known Active CWT Facilities over Time in the Marcellus and Utica Shale Formation	Yes	SGE00596	Analysis of Centralized Waste Treatment (CWT) Facilities Accepting UOG Extraction Wastewater
Figure D-9	Typical Process Flow Diagram at a POTW	No	SGE00602	—
Figure D-10	Clairton POTW: Technical Evaluation of Treatment Processes' Ability to Remove Chlorides and TDS	Yes	SGE00929	Publicly Owned Treatment Works (POTW) Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction
Figure D-11	McKeesport POTW: Technical Evaluation of Treatment Processes' Ability to Remove Chlorides and TDS	Yes	SGE00929	Publicly Owned Treatment Works (POTW) Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction

Table F-2. Crosswalk Between TDD and Supporting Memoranda

TDD Table or Figure Number	TDD Table/Figure Title	In a Supporting Memo (Y/N)?[a]	Source or Supporting Memo DCN(s)	Supporting Memo Title(s)
Figure D-12	Ridgway POTW: Annual Average Daily Effluent Concentrations and POTW Flows	Yes	SGE00929	Publicly Owned Treatment Works (POTW) Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction
Figure D-13	Johnstown POTW: Annual Average Daily Effluent Concentrations and POTW Flows	Yes	SGE00929	Publicly Owned Treatment Works (POTW) Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction
Figure D-14	California POTW: Annual Average Daily Effluent Concentrations and POTW Flows	Yes	SGE00929	Publicly Owned Treatment Works (POTW) Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction
Figure D-15	Charleroi POTW: Annual Average Daily Effluent Concentrations and POTW Flows	Yes	SGE00929	Publicly Owned Treatment Works (POTW) Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction
Figure D-16	Barium Sulfate Scaling in Haynesville Shale Pipe	No	SGE00768.A26	—
Figure D-17	THM Speciation in a Water Treatment Plant (1999–2013)	No	SGE00800	—
Table D-1	UOG Produced Water Management Practices	Yes	SGE00693	Data Compilation Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction
Table D-2	Distribution of Active Class II Disposal Wells Across the United States	Yes	SGE00736	Analysis of Active Underground Injection for Disposal Wells
Table D-3	Reuse/Recycle Practices in 2012 as a Percentage of Total Produced Water Generated as Reported by Respondents to 2012 Survey	No	SGE00575	—

Table F-2. Crosswalk Between TDD and Supporting Memoranda

TDD Table or Figure Number	TDD Table/Figure Title	In a Supporting Memo (Y/N)?[a]	Source or Supporting Memo DCN(s)	Supporting Memo Title(s)
Table D-4	Reported Reuse/Recycle Criteria	Yes	SGE00693	Data Compilation Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction
Table D-5	Reported Reuse/Recycle Practices as a Percentage of Total Fracturing Volume	Yes	SGE00693	Data Compilation Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction
Table D-6	Number, by State, of CWT Facilities That Have Accepted or Plan to Accept UOG Extraction Wastewater	Yes	SGE00596	Analysis of Centralized Waste Treatment (CWT) Facilities Accepting UOG Extraction Wastewater
Table D-7	Typical Composition of Untreated Domestic Wastewater	No	SGE00167	—
Table D-8	Typical Percent Removal Capabilities from POTWs with Secondary Treatment	No	SGE00600	—
Table D-9	U.S. POTWs by Treatment Level in 2008	No	SGE00603	—
Table D-10	POTWs That Accepted UOG Extraction Wastewater from Onshore UOG Operators	Yes	SGE00929	Publicly Owned Treatment Works (POTW) Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction
Table D-11	Percentage of Total POTW Influent Wastewater Composed of UOG Extraction Wastewater at POTWs Accepting Wastewater from UOG Operators	Yes	SGE00929	Publicly Owned Treatment Works (POTW) Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction
Table D-12	Summary of Studies About POTWs Receiving Oil and Gas Extraction Wastewater Pollutants	No (Created by the EPA)	—	—
Table D-13	Clairton Influent Oil and Gas Extraction Wastewater Characteristics	No	SGE00748	—
Table D-14	Trucked COG Extraction Wastewater Treated at McKeesport POTW from November 1 Through 7, 2008	No	SGE00745	—

Table F-2. Crosswalk Between TDD and Supporting Memoranda

TDD Table or Figure Number	TDD Table/Figure Title	In a Supporting Memo (Y/N)?[a]	Source or Supporting Memo DCN(s)	Supporting Memo Title(s)
Table D-15	McKeesport POTW Removal Rates Calculated for Local Limits Analysis	No	SGE00745	—
Table D-16	Constituent Concentrations in UOG Extraction Wastewater Treated at the McKeesport POTW Before Mixing with Other Influent Wastewater	No	SGE00525	—
Table D-17	McKeesport POTW Effluent Concentrations With and Without UOG Extraction Wastewater	No	SGE00525	—
Table D-18	Charleroi POTW Paired Influent/Effluent Data and Calculated Removal Rates	No	SGE00751	—
Table D-19	Franklin Township POTW Effluent Concentrations With and Without Industrial Discharges from the Tri-County CWT Facility	No	SGE00525	—
Table D-20	TDS Concentrations in Baseline and Pilot Study Wastewater Samples at Warren POTW	No	SGE00616	—
Table D-21	EPA Region 5 Compliance Inspection Sampling Data	No	SGE00616	—
Table D-22	Inhibition Threshold Levels for Various Treatment Processesa	No	SGE00602	—
Table D-23	Industrial Wastewater Volumes Received by New Castle POTW (2007–2009)	No	SGE00554	—
Table D-24	NPDES Permit Limit Violations from Outfall 001 of the New Castle POTW (NPDES Permit Number PA0027511)	No	SGE00612, SGE00620	—
Table D-25	Concentrations of DBPs in Effluent Discharges at One POTW Not Accepting Oil and Gas Wastewater and at Two POTWs Accepting Oil and Gas Wastewater (μg/L)	No	SGE00535	—
Figure F-1	Constituent Concentrations over Time in UOG Produced Water from the Marcellus and Barnett Shale Formations	No	SGE00414	—

Table F-2. Crosswalk Between TDD and Supporting Memoranda

TDD Table or Figure Number	TDD Table/Figure Title	In a Supporting Memo (Y/N)?[a]	Source or Supporting Memo DCN(s)	Supporting Memo Title(s)
Table F-1	TDD Supporting Memoranda and Other Relevant Documents Available in FDMS	No (Created by the EPA)	—	—
Table F-2	Crosswalk Between TDD and Supporting Memoranda	No (Created by the EPA)	—	—
Table F-3	UOG Resource Potential: Shale as of January 1, 2012	Yes	SGE00693	Data Compilation Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction
Table F-4	UOG Resource Potential: Tight as of January 1, 2012	Yes	SGE00693	Data Compilation Memorandum for the Technical Development Document (TDD) for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction

a—Unless otherwise noted, figures and/or tables not included in a supporting memorandum were taken directly from a source without calculation or interpretation.

APPENDIX F.2 UOG RESOURCE POTENTIAL BY SHALE AND TIGHT FORMATIONS

Table F-3. UOG Resource Potential: Shale as of January 1, 2012

EIA Region	EIA Basin	UOG Formation Name	Resource Type	Oil EUR (MMbls per well)	Gas EUR (Bcf per well)	Oil TRR (MMbls)	Gas TRR (Bcf)	New Well Potential
1—East	Appalachian	Devonian	Shale gas	0.000	0.058	0	20,800	358,600
		Marcellus	Shale gas	0.000	1.317	0	118,900	90,300
		Utica	Shale gas	0.000	0.330	0	37,400	113,500
			Shale oil	0.063	0.057	1,000	900	15,900
	Illinois	New Albany	Shale gas	0.000	1.721	0	41,700	24,200
	Michigan	Antrim	Shale gas	0.000	0.157	0	15,300	97,500
2—Gulf Coast	Black Warrior	Floyd-Neal/Conasauga	Shale gas	0.000	1.520	0	4,300	2,800
	TX-LA-MS Salt	Haynesville-Bossier	Shale gas	0.000	3.455	0	70,900	20,500
	Western Gulf	Eagle Ford	Shale gas	0.177	1.549	6,100	53,400	34,500
			Shale oil	0.101	0.212	3,300	6,900	32,500
		Pearsall	Shale gas	0.000	1.090	0	7,800	7,200
		Tuscaloosa	Shale oil	0.092	0.019	2,900	600	31,600
		Woodbine	Shale oil	0.108	0.054	600	300	5,600
3—Midcontinent	Anadarko	Cana Woodford	Shale gas	0.014	1.232	100	8,900	7,200
			Shale oil	0.038	0.415	100	1,100	2,700
	Arkoma	Caney	Shale gas	0.000	0.330	0	1,100	3,300
		Fayetteville	Shale gas	0.000	1.284	0	29,800	23,200
		Woodford	Shale gas	0.000	1.422	0	6,700	4,700
	Black Warrior	Chattanooga	Shale gas	0.000	0.970	0	1,600	1,600
4—Southwest	Barnett	Shale Gas	Shale gas	0.000	0.377	0	20,300	53,900
	Permian	Wolfcamp	Shale oil	0.068	0.217	3,400	10,900	50,200
		Barnett-Woodford	Shale gas	0.000	1.513	0	15,800	10,400
		Avalon/BoneSpring	Shale oil	0.080	0.000	2,000	0	25,000
5—Rocky Mountain	Denver	Niobrara	Shale oil	0.011	0.073	400	2,700	37,000
	Greater Green River	Hilliard-Baxter-Mancos	Shale gas	0.000	0.293	0	10,500	35,800

Table F-3. UOG Resource Potential: Shale as of January 1, 2012

EIA Region	EIA Basin	UOG Formation Name	Resource Type	Oil EUR (MMbls per well)	Gas EUR (Bcf per well)	Oil TRR (MMbls)	Gas TRR (Bcf)	New Well Potential
5—Rocky Mountain	Montana Thrust Belt	All tight oil plays	Shale oil	0.113	0.075	600	400	5,300
	Powder River	All tight oil plays	Shale oil	0.035	0.040	2,100	2,400	60,000
	San Juan	Lewis	Shale gas	0.000	2.200	0	9,800	4,500
	Uinta-Piceance	Mancos	Shale gas	0.000	0.880	0	10,900	12,400
	Williston	Gammon	Shale gas	0.000	0.440	0	3,400	7,700
		Bakken	Shale oil	0.142	0.096	9,300	6,300	65,500
6—West Coast	Columbia	Basin Centered	Shale gas	0.000	1.400	0	12,200	8,700
	San Joaquin/Los Angeles	Monterey/Santos	Shale oil	0.502	0.502	600	600	1,200

Sources: 48 DCN SGE00693

Abbreviations: EUR—estimated ultimate recovery (per well); MMbls—million barrels; Bcf—billion cubic feet of gas; TRR—technically recoverable resources

Table F-4. UOG Resource Potential: Tight as of January 1, 2012

EIA Region	EIA Basin	UOG Formation Name	Resource Type	Oil EUR (MMbls per well)	Gas EUR (Bcf per well)	Oil TRR (MMbls)	Gas TRR (Bcf)	New Well Potential
1—East	Appalachian	Clinton-Medina	Tight gas	0.003	0.060	500	11,700	195,000
		Tuscarora	Tight gas	0.000	2.172	0	4,400	2,000
	Michigan	Berea Sand	Tight gas	0.000	0.143	0	8,100	56,600
2—Gulf Coast	TX-LA-MS Salt	Cotton Valley	Tight gas	0.009	1.472	900	152,700	103,700
	Western Gulf	Olmos	Tight gas	0.005	1.093	100	23,600	21,600
		Vicksburg	Tight gas	0.000	1.473	0	3,900	2,600
		Wilcox Lobo	Tight gas	0.000	1.404	0	10,100	7,200
		Austin Chalk	Tight oil	0.086	0.048	7,600	4,300	88,800
		Buda	Tight oil	0.108	0.070	3,700	2,400	34,300
3—Midcontinent	Anadarko	Cleveland	Tight gas	0.036	0.394	100	1,100	2,800
		Granite Wash	Tight gas	0.046	0.948	600	12,300	13,000

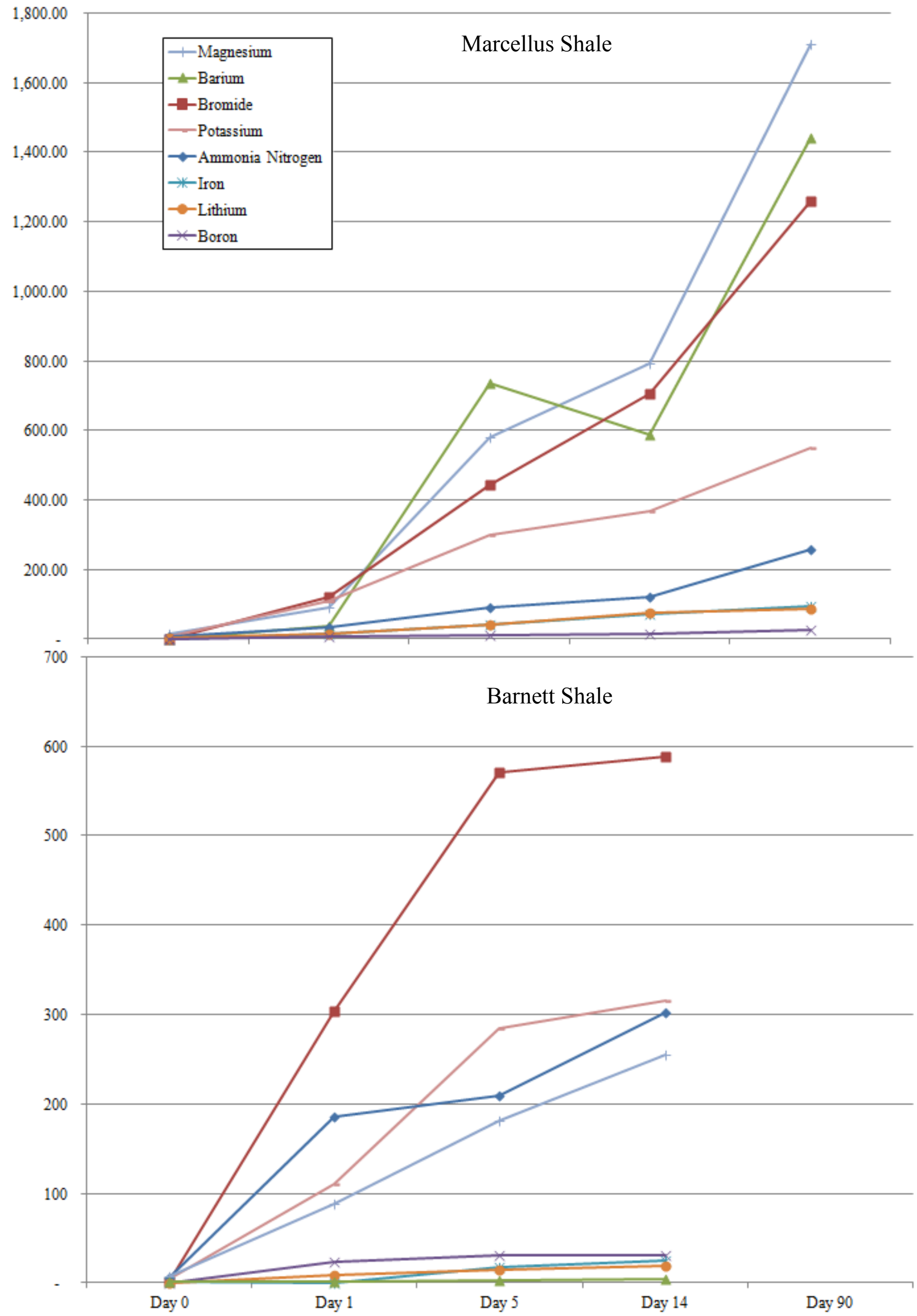
Table F-4. UOG Resource Potential: Tight as of January 1, 2012

EIA Region	EIA Basin	UOG Formation Name	Resource Type	Oil EUR (MMbls per well)	Gas EUR (Bcf per well)	Oil TRR (MMbls)	Gas TRR (Bcf)	New Well Potential
		Red Fork	Tight gas	0.000	0.593	0	1,000	1,700
4—Southwest	Permian	Abo	Tight gas	0.101	0.182	1,000	1,800	9,900
		Canyon	Tight gas	0.002	0.209	100	10,900	52,200
		Spraberry	Tight oil	0.108	0.113	8,100	8,500	75,200
5—Rocky Mountain	Denver	Muddy	Tight gas	0.000	0.182	0	11,500	63,200
	Greater Green River	All Tight Oil Plays	Tight oil	0.135	0.015	900	100	6,700
	North Central Montana	Bowdoin-Greenhorn	Tight gas	0.000	0.151	0	300	2,000
	Paradox	Fractured Interbed	Tight oil	0.543	0.434	1,000	800	1,800
	San Juan	Dakota	Tight gas	0.000	0.416	0	6,100	14,700
		Mesaverde	Tight gas	0.000	0.464	0	5,800	12,500
		Pictured Cliffs	Tight gas	0.000	0.397	0	200	500
	SW Wyoming	Fort Union-Fox Hills	Tight gas	0.000	1.047	0	15,800	15,100
		Frontier	Tight gas	0.009	0.273	200	6,200	22,700
		Lance	Tight gas	0.016	1.012	300	18,700	18,500
		Lewis	Tight gas	0.000	0.248	0	7,700	31,000
		All Tight Oil Plays	Tight oil	0.165	0.015	1,100	100	6,700
	Uinta-Piceance	Iles-Mesaverde	Tight gas	0.000	0.502	0	17,100	34,100
		Wasatch-Mesaverde	Tight gas	0.023	0.463	400	8,200	17,700
		Williams Fork	Tight gas	0.000	0.456	0	7,600	16,700
		All Tight Oil Plays	Tight oil	0.056	0.111	100	200	1,800
	Williston	Judith River-Eagle	Tight gas	0.000	0.158	0	1,000	6,300
	Wind River	Mesaverde/Frontier Shallow	Tight gas	0.000	0.768	0	4,400	5,700

Sources: 48 DCN SGE00693

Abbreviations: EUR—estimated ultimate recovery (per well); MMbls—million barrels; Bcf—billion cubic feet of gas; TRR—technically recoverable resources

APPENDIX F.3 CONSTITUENT CONCENTRATIONS OVER TIME IN UOG PRODUCED WATER FROM MARCELLUS AND BARNETT SHALE FORMATIONS



Source: The EPA generated this figure using data from 85 DCN SGE00414.

Figure F-1. Constituent Concentrations over Time in UOG Produced Water from the Marcellus and Barnett Shale Formations