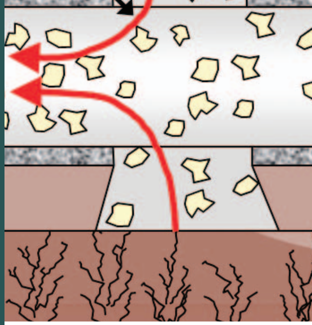

Water Management Challenges Associated with the Production of Shale Gas by Hydraulic Fracturing

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Development of unconventional, onshore natural gas resources in deep shales is rapidly expanding to meet global energy needs. Water management has emerged as a critical issue in the development of these inland gas reservoirs, where hydraulic fracturing is used to liberate the gas. Following hydraulic fracturing, large volumes of water containing very high concentrations of total dissolved solids (TDS) return to the surface. The TDS concentration in this wastewater, also known as "flowback," can reach 5 times that of sea water. Wastewaters that contain high TDS levels are challenging and costly to treat. Economical production of shale gas resources will require creative management of flowback to ensure protection of groundwater and surface water resources. Currently, deep-well injection is the primary means of management. However, in many areas where shale gas production will be abundant, deep-well injection sites are not available. With global concerns over the quality and quantity of fresh water, novel water management strategies and treatment technologies that will enable environmentally sustainable and economically feasible natural gas extraction will be critical for the development of this vast energy source.

Keywords: shale gas, hydraulic fracturing, produced water, flowback

INTRODUCTION

Natural gas plays a central role in meeting the demand for energy around the world. This versatile, readily transportable fossil fuel has long been used for residential and industrial heating, steam production, and thermoelectric power production. While coal remains the dominant fuel source for electric power production, economic, technological, regulatory, and environmental drivers have shifted the focus of new electrical power generation towards natural gas. Currently, natural gas is the fuel source for 21% of electricity production and for 24% of the total energy demand in the United States (EIA 2011). Over the next 25 years, these proportions are expected to remain constant or increase. Global demand for natural gas is on the rise as well. For example, natural gas currently provides 4% of China's energy, and that country's goal is to increase the amount of natural gas used to 8% of the energy supply by 2020 (Peoples Daily Online 2010).

The main advantages of natural gas are its widespread availability, its ease of transport, and its efficient and clean combustion. Also, natural gas combustion yields lower emissions of greenhouse gases and other pollutants relative to coal combustion for equivalent amounts of power generation (Jaramillo et al. 2007).

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To meet the growing demand for natural gas, energy companies have greatly expanded their exploration and development of unconventional natural gas resources, such as coalbed methane, tight sands, and shale gas. The fastest-growing source of natural gas is shale gas, which is projected to be the largest contributor to growth in natural gas production in the United States for the next 25 years (EIA 2011). The same is true in many other nations, as recent assessments of global shale gas resources indicate substantial technically recoverable resources in many countries, including China, Argentina, Mexico, South Africa, and others (Fig. 1).

SHALE GAS DEVELOPMENT

Shale gas is natural gas entrapped in shale and is distinct from gas in other low-permeability reservoirs and from "conventional" gas (Fig. 2). Shale is a fine-grained, clastic sedimentary rock composed of clay minerals and silt-sized particles, and may contain other minerals such as quartz, calcite, and pyrite. The shale formation is both the source and the reservoir for the natural gas, which is predominantly methane (~90%) but may also contain other hydrocarbons, CO_2, nitrogen, H_2S, and rare gases (Lapidus et al. 2000). The gas is held in natural fractures and pore spaces or adsorbed onto the organic material and minerals in the formation (Jenkins and Boyer 2008). Shale lacks sufficient natural permeability for the recovery of gas at rates suitable for large-scale production. Therefore, wellbores must be lengthened and fractures must be engineered to enable commercial viability (Jenkins and Boyer 2008).

New drilling and well-completion technology for gas production from shale formations evolved in the Barnett Shale in Texas, and its economic success has led to the rapid exploration of shale formations in many countries and has greatly increased the estimates of global natural gas reserves in the world (EIA 2011). Estimated reserves in the United States increased 35% between 2006 and 2009, largely the result of revised estimates of recoverable gas from shale formations, in particular the Marcellus Shale in the Appalachian Basin (Navigant Consulting 2008). With recoverable gas quantities nearing 500 trillion cubic feet (Tcf) (14 trillion cubic meters) (Engelder and Lash 2008) and estimated production rates near 30 billion cubic feet (Bcf) per day by 2030 (Moniz et al. 2010), the Marcellus

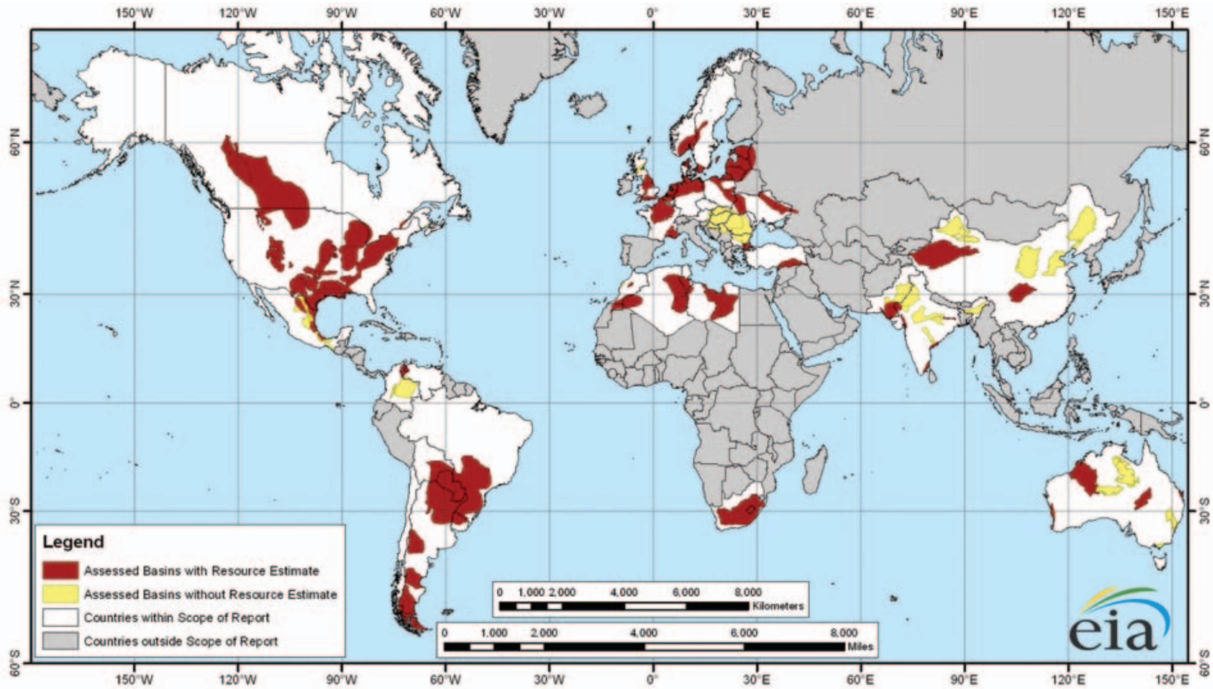

FIGURE 1 Map of world shale gas resources assessed by the United States Energy Information Administration. FROM EIA 2011

Shale has the greatest economic potential among the shale formations in the United States.

The technological and economic feasibility of gas production from the Barnett Shale in Texas has led to a rapid development of natural gas resources in the United States. Annual production volume has increased from 0.2 Tcf in 1998 to 4.9 Tcf in 2010 (FIG. 3), and is expected to grow more than threefold over the next decade and eventually represent 24% of the total natural gas production in the United States (EIA 2011).

DRILLING AND HYDRAULIC FRACTURING

Economically viable gas production from shale is achieved by horizontal drilling followed by hydraulic fracturing (FIG. 4). Horizontal drilling greatly increases the length of contact between the shale gas formation and the wellbore relative to a conventional vertical well, and a single horizontal well may replace 3 or 4 vertical wells (Arthur et al. 2008). Decreasing the number of wells decreases production costs and environmental risks associated with pad-site construction, drilling, and well development, and contributes to the economic feasibility of shale gas production. Hydraulic fracturing, or "fracking," involves the introduction of aqueous fracturing fluid at a rate sufficient to raise the downhole pressure above the fracture pressure of the formation rock. The stress induced by the pressure creates fissures and interconnected cracks that increase the permeability of the formation and enable greater flow rates of gas into the well. After hydraulic fracturing is performed, the pumping pressure is relieved and the fracture fluid returns to the surface through the well casing. This water is referred to as "flowback." Hydraulic fracturing is commonly a one-time event, performed in stages. However, additional hydraulic fracturing may be performed over the lifetime of the well if necessary and economically viable.

FIGURE 4 provides an overview of the hydraulic fracturing process used in a typical shale formation. A typical hydraulic fracturing procedure in the Marcellus Shale uses 7000 to 18,000 cubic meters of fracturing fluid (Arthur et al. 2008). Fracturing fluid for shale gas is most commonly a mixture of water, "proppant," and chemical modifiers (TABLE 1). Proppants are small particles of sand or engineered materials, such as resins or ceramics, that flow with the fracturing fluid and hold the fractures open, maintaining porosity as the pressure decreases in the formation with the return of fracturing fluid and gas to the surface (FIG. 4, INSET). The mixture of chemical modifiers is determined by site characteristics. It is important to note that the constituents listed in TABLE 1 are never all used simultaneously during hydraulic fracturing. Recent hydraulic fracturing in the Marcellus Shale has included only three

TABLE 1 VOLUMETRIC COMPOSITION AND PURPOSES OF THE TYPICAL CONSTITUENTS OF HYDRAULIC FRACTURING FLUID. DATA COMPILED FROM VARIOUS SOURCES (EPA 2004; API 2009)

Constituent	Composition (% by vol)	Example	Purpose
Water and sand	99.50	Sand suspension	"Proppant" sand grains hold microfractures open
Acid	0.123	Hydrochloric or muriatic acid	Dissolves minerals and initiates cracks in the rock
Friction reducer	0.088	Polyacrylamide or mineral oil	Minimizes friction between the fluid and the pipe
Surfactant	0.085	Isopropanol	Increases the viscosity of the fracture fluid
Salt	0.06	Potassium chloride	Creates a brine carrier fluid
Scale inhibitor	0.043	Ethylene glycol	Prevents scale deposits in pipes
pH-adjusting agent	0.011	Sodium or potassium carbonate	Maintains effectiveness of chemical additives
Iron control	0.004	Citric acid	Prevents precipitation of metal oxides
Corrosion inhibitor	0.002	n,n-dimethyl formamide	Prevents pipe corrosion
Biocide	0.001	Glutaraldehyde	Minimizes growth of bacteria that produce corrosive and toxic by-products

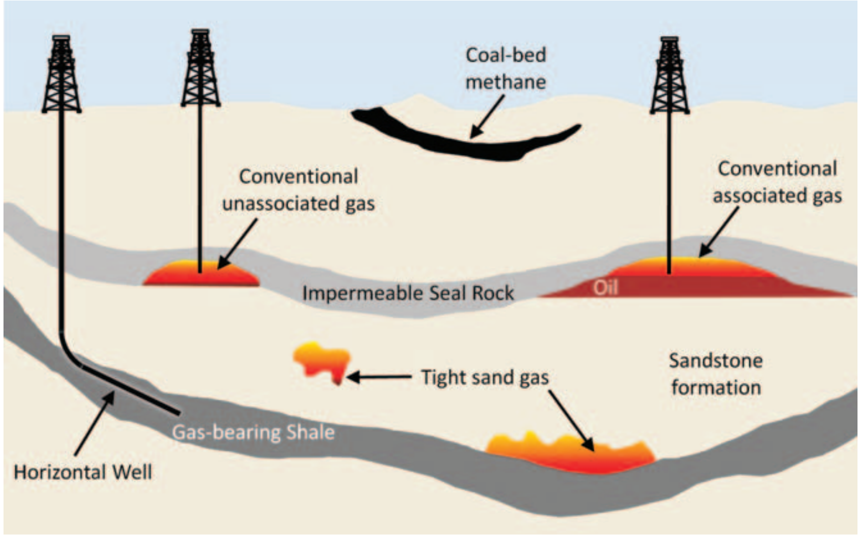

Figure 2 The types and common orientations of onshore natural gas resources. Modified after USGS National Assessment of Oil and Gas Fact Sheet, http://pubs.usgs.gov/fs/fs-0113-01/fs-0113-01.pdf

of these constituents: a friction reducer, a scale inhibitor, and an antimicrobial agent.

During the flowback period, which usually lasts up to two weeks, approximately 10 to 40% of the fracturing fluid returns to the surface (Arthur et al. 2008). The volume of flowback depends on the formation characteristics and operating parameters during development of the well. Once active gas production has begun, aqueous and nonaqueous liquid continues to be produced at the surface in much lower volumes (2–8 m^3/day) over the lifetime of the well. This wastewater, known as "produced water," contains very high TDS concentrations, as well as heavy and light petroleum hydrocarbons that may be separated and recovered (GWPC and ALL Consulting 2009).

ENVIRONMENTAL CHALLENGES AND WATER MANAGEMENT OPTIONS

The grand challenge that natural gas producers must address is how to preserve the favorable economics of shale gas production while maintaining responsible stewardship of natural resources and protecting public health. The goals of the natural gas developers and the goals of those responsible for human and environmental health protection are intimately connected by water, including its use, management, and disposal.

Water Resources

The drilling and completion of wells require large quantities of water. Drilling of the vertical and horizontal components of a well may require 400–4000 m^3 of water for drilling fluids to maintain downhole hydrostatic pressure, cool the drillhead, and remove drill cuttings. Then, 7000–18,000 m^3 of water are needed for hydraulic fracturing of each well. These large volumes of water are typically obtained from nearby surface waters or pumped from a municipal source. In regions where local, natural water sources are scarce or dedicated to other uses, the limited availability of water may be a significant impediment to gas resource development.

Management of Flowback Water

Flowback of the fracturing fluid occurs over a few days to a few weeks following hydraulic fracturing, depending on the geology and geomechanics of the formation. The highest rate of flowback occurs on the first day, and the rate diminishes over time; the typical initial rate may be as high as 1000 m^3/d (GWPC and ALL Consulting 2009). The composition of the flowback water changes as a function of the time the water flowing out of the shale formation was in contact with the formation. Minerals and organic constituents present in the formation dissolve into the fracturing water, creating a brine solution that includes high concentrations of salts, metals, oils, greases, and soluble organic compounds, both volatile and semivolatile (Table 2). The flowback water is typically impounded at the surface for subsequent disposal, treatment, or reuse. Due to the large water volume, the high concentration of dissolved solids, and the complex physicochemical

Table 2 TYPICAL RANGE OF CONCENTRATIONS FOR SOME COMMON CONSTITUENTS OF FLOWBACK WATER FROM NATURAL GAS DEVELOPMENT IN THE MARCELLUS SHALE. The data were obtained from flowback water from several production sites in western Pennsylvania[1].

Constituent	Low[2] (mg/L)	Medium[2] (mg/L)	High[3] (mg/L)
Total dissolved solids	66,000	150,000	261,000
Total suspended solids	27	380	3200
Hardness (as $CaCO_3$)	9100	29,000	55,000
Alkalinity (as $CaCO_3$)	200	200	1100
Chloride	32,000	76,000	148,000
Sulfate	ND[5]	7	500
Sodium	18,000	33,000	44,000
Calcium, total[4]	3000	9800	31,000
Strontium, total	1400	2100	6800
Barium, total	2300	3300	4700
Bromide	720	1200	1600
Iron, total	25	48	55
Manganese, total	3	7	7
Oil and grease	10	18	260
Total radioactivity	ND[5]	ND	ND

1 Data compiled by Elise Barbot, University of Pittsburgh, and Juan Peng, Carnegie Mellon University

2 "Low" concentrations are from early flowback at one well. "Medium" concentrations are from late flowback at the same well for which the "low" concentrations are reported.

3 "High" concentrations are the highest concentrations observed in late flowback from several wells with similar reported TDS concentrations.

4 Total concentration = dissolved phase + suspended solid phase concentrations.

5 Not detected

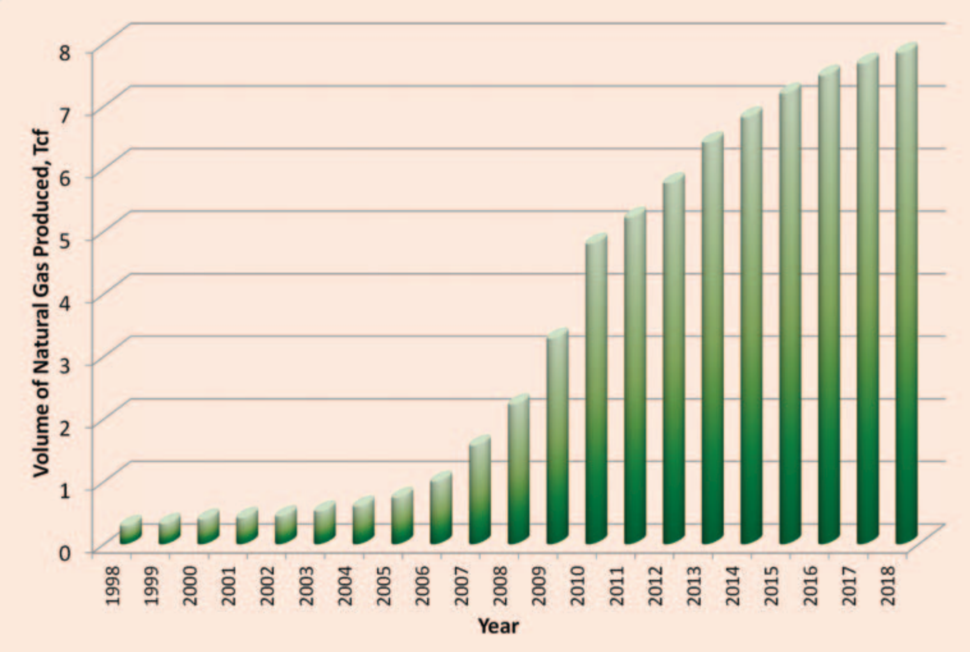

Figure 3 Actual and projected production of natural gas from shale in the United States in trillions of cubic feet (Tcf). 1 Tcf = 28 trillion liters. Data from U.S. Department of Energy Information Administration 2011 (EIA 2011)

composition of the flowback water, there is growing public concern about management of this water because of the potential for human health and environmental impacts associated with an accidental release of flowback water into the environment (Kargbo et al. 2010).

Treatment technologies and management strategies for flowback water are based on constraints established by governments, economics, technology performance, and the appropriateness of a technology for a particular water. Past experience with produced and flowback waters is used to guide developers towards treatment and management options in regions of new production (Kargbo et al. 2010). Flowback water management options for some shale plays, such as the Marcellus, are confounded by high concentrations of total dissolved solids in the flowback water, geography, geology, and a lack of physical infrastructure (Arthur et al. 2008; Kargbo et al. 2010).

Underground Injection

Most produced water from oil and gas production in the United States is disposed of through deep underground injection (Clark and Veil 2009). When underground injection is utilized, such operations are performed using Class II (disposal) underground injection control wells as defined by the U.S. Environmental Protection Agency (Veil et al. 2004). However, the availability of adequate deep-well disposal capacity can be an important constraining factor for shale gas development. In Texas, there were over 11,000 Class II disposal wells in 2008, or slightly more than one disposal well per gas-producing well in the Barnett Shale (Tintera 2008). In contrast, the whole state of Pennsylvania has only seven Class II disposal wells available for receiving flowback water. The Marcellus Shale is a large resource that will eventually be exploited by a large number of producing wells. Although the number of underground-injection disposal wells in Pennsylvania is expected to increase, shale gas development is currently occurring in many areas where insufficient disposal wells are available, and the construction of new disposal wells is complex, time consuming, and costly (Arthur et al. 2008). As a result, other solutions for flowback water management are necessary.

Discharge to Publicly Owned Treatment Works (POTWs) for Dilution Disposal

Although discharge and dilution of flowback water into publicly owned municipal wastewater treatment plants (POTWs) has been utilized (e.g. Penn Future 2010), this is not an adequate or sustainable approach for managing flowback water. The amount of high-TDS flowback water that can be accepted by POTWs is usually limited by regulation. For example, in many POTWs in Pennsylvania, the amount of oil and gas wastewater must not exceed 1% of the average daily volume of waste handled by the POTW. In addition, discharge limits in Pennsylvania for TDS are set at 500 mg/L to insure the quality of the processed product. In general, the volume of flowback water that can be sent to POTWs is small compared to the volume of flowback water generated during rapid well drilling and well development.

Reverse Osmosis

Reverse osmosis (RO) is a well-known treatment method for producing drinking water and high-purity industrial water. In the RO process, water is passed through a semipermeable membrane under pressure and a treated water of high quality is produced, along with a concentrate that requires disposal. This separation process removes material ranging from suspended particulates down to organic molecules and even monovalent ions of salt (Xu and Drewes 2006). In trials of RO treatment of flowback water, the volume of concentrate for disposal has been reduced to as low as 20% of the initial volume of flowback water (ALL Consulting 2003). Driven by mechanical pressure, RO is energy intensive. Even with favorable energy prices, the treatment of flowback water using RO is considered to be economically infeasible for waters containing more than 40,000 mg/L TDS (Cline et al. 2009). For high-TDS waters, vibratory shear-enhanced processing (VSEP) has been applied to membrane technologies (Jaffrin 2008). In VSEP, flat membranes are arranged as parallel discs separated by gaskets. Shear is created by vibrating a leaf element tangent to the membrane surface. The created shear lifts solids and fouling material off the membrane surface, thereby reducing colloidal fouling and polarization of the membrane (New Logic Research 2004). VSEP technology has been used successfully in the treatment of produced water from offshore oil production (Fakhru'l-Razi et al.

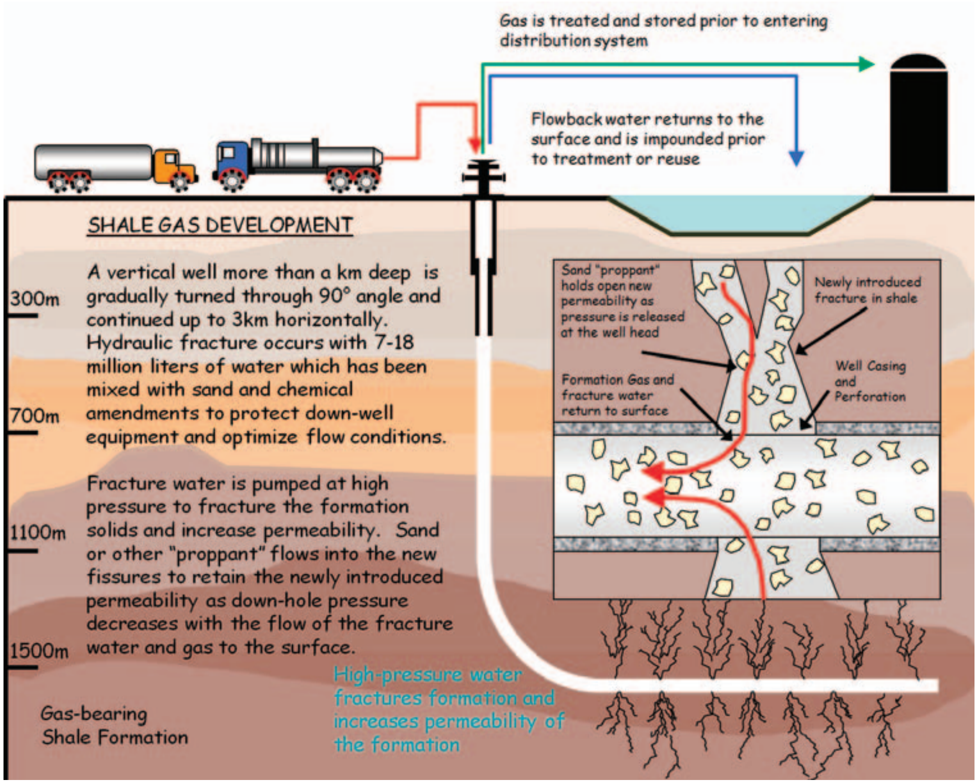

Figure 4 Overview of how hydraulic fracturing is used to produce natural gas from shale. The inset box illustrates the process at the horizontal well. Modified after a graphic by Al Granberg for ProPublica

2009). However, the salt concentrations in offshore produced waters are far lower than those expected during shale gas extraction.

Thermal Distillation and Crystallization

The high concentrations of TDS in flowback water may limit the use of membrane technology, but such water is well suited to treatment by distillation and crystallization (Doran and Leong 2000). Distillation and crystallization are mature technologies that rely on evaporating the wastewater to separate the water from its dissolved constituents. The vapor stream is passed through a heat exchanger to condense the gas and produce purified water. Distillation removes up to 99.5% of dissolved solids and has been estimated to reduce treatment and disposal costs by as much as 75% for produced water from shale oil development (ALL Consulting 2003). However, as with RO, distillation is an energy-intensive process. Thermal distillation may treat flowback water containing up to, and in some cases even exceeding, 125,000 mg/L of TDS, but even the most modern technology is limited to low flow rates (300 m^3/d), necessitating the construction of large storage impoundments (Veil 2008). For example, flowback water from the Marcellus Shale gas sites can be produced at rates of 3000 m^3/d or higher. Recent developments include using mechanical vapor-recompression systems to concentrate flowback water, which can be done at a fraction of the cost of conventional distillation because the heat of the compressed vapor is used to preheat the influent. Further water evaporation to create dry mineral crystals (i.e. crystallization) will improve water recovery and create salt products that might be reused as industrial feed stocks. Crystallization is a feasible approach for treating flowback water with TDS concentrations as high as 300,000 mg/L, but it has high energy requirements and large capital costs.

Other Treatment Options

Several other technologies have been or are being developed for treating flowback water, but each has its limitations. Falling into this category are ion exchange and capacitive deionization (Jurenka 2007), which are limited to the treatment of low-TDS water; freeze–thaw evaporation, which is restricted to cold climates; evaporation ponds, which are restricted to arid climates; and artificial wetlands and agricultural reuse (Veil et al. 2004), which are greatly limited by the salinity tolerance of plant and animal life.

On-Site Reuse for Hydraulic Fracturing

One of the most promising technologies for management of flowback water is its reuse in subsequent hydraulic fracturing operations. Flowback water is impounded at the surface and reused either directly or following dilution or pretreatment. Reuse is particularly attractive in regions where deep-well disposal options are limited or where the availability of make-up water for hydraulic fracturing is limited. The reuse of flowback water has the benefit of minimizing the volume of such water that must be treated or disposed of and greatly reduces environmental risks while enhancing the economics of shale gas extraction.

Potentially limiting factors for reuse are the chemical stability of the viscosity modifiers and other constituents of hydraulic fracture water in the brine solution and the potential for precipitation of divalent cations in the wellbore. The effectiveness of friction reducers may be decreased at high TDS concentrations (Kamel and Shah 2009). The development of additives that retain their effectiveness in brine solutions are likely to expand the opportunity for reuse of flowback water for subsequent hydraulic fracturing.

The divalent cations in the flowback water are solubilized from formation minerals and can form stable carbonate and sulfate precipitates in the wellbore if the flowback water is reinjected. This may potentially reduce gas production from the well. In particular, barium and strontium form very low-solubility solids with sulfate, while high calcium concentrations may lead to calcite formation. Depending on the quality of the flowback water, pretreatment to reduce the divalent cation concentration by precipitation may be necessary.

OUTLOOK

Natural gas production from deep shale formations by hydraulic fracturing has been growing exponentially in the United States. With growing global energy demands and expanding discovery of global shale resources, similar trajectories for global shale gas production are expected. Hydraulic fracturing uses thousands of cubic meters of water for fracturing fluid at each well and therefore has the ability to strain local freshwater resources. The water that returns to the surface is a brine solution with very high concentrations of salts, metals, oils, and greases, and it is commonly impounded at the surface prior to treatment, reuse, or disposal. If not responsibly managed, the release of flowback water into the environment can have a range of impacts.

While many options are available for the treatment of flowback water, many are limited by high capital and operating costs. The most widely used option for management of flowback water is deep-well injection disposal. However, in regions where deep-well injection sites are not available, a widely practiced alternative is precipitation softening for a partial reduction of TDS, followed by reuse of the flowback in subsequent hydraulic fracturing procedures.

While shale gas appears to be an abundant resource in many countries, it will remain untapped without favorable economics for its production. The economics of shale gas development is a complex multivariate optimization, with water resource management as a critical input. It is important to note that optimized strategies for one basin or locality may not apply in others. Environmental, geographical, geological, economic, social, and political considerations will ultimately determine the water management solutions that will enable production of shale gas resources while protecting that locality's other natural resources.

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