SPE 119898

Marcellus Shale Water Management Challenges in Pennsylvania

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This paper was prepared for presentation at the 2008 SPE Shale Gas Production Conference held in Fort Worth, Texas, U.S.A., 16–18 November 2008.

Abstract

The management of water resources poses considerable challenges to the Pennsylvania Oil and Gas Industry as it begins to expand the development of the Marcellus Shale. Although the play overlies a seemingly water-rich region the sourcing of fresh water for drilling and completions operations are far from straight forward due to regulatory restrictions. Development companies planning to operate in the state must seek to understand an evolving regulatory landscape that is struggling to create a framework specific to shale gas development. The current regulatory status limits conventional methods of surface water withdrawals from streams and rivers and forces industry to search out alternative water sources from groundwater wells, municipalities, private sources and recycled waters. In addition to the challenge of fresh water sourcing, operators are also limited in the options for disposing waste-waters generated during drilling, flowback and production. The current methodology of pre-treatment and discharge via NPDES permit has a finite capacity which is projected to be insufficient in a short time as the level of drilling activity increases. There is very limited potential for underground injection of fluids into permitted disposal wells and virtually no need for weighted brines for well control. Alternative disposal and recycling options which could potentially process the waste-waters into recycled fresh water and concentrated brine or salt cake are being actively studied by individual operating companies and the industry as a whole.

Introduction

The Appalachian Shale Basin encompasses several large natural gas plays in the U.S. that geographically cover significant areas of five states in the Eastern U.S. including Pennsylvania, West Virginia, Ohio, New York and Kentucky, as shown in Figure A. As long as 10 year NYMEX strip prices for natural gas remain above $8/mmBtu, well drilling activity in the Appalachian Basin is expected to escalate throughout the next decade. Within this region, one of the major shale plays where development activity is greatest is the Marcellus Shale.

Many of the logistical problems associated with the development of shale gas stem from the large amounts of water associated with the completion and operation of shale gas wells that must be transported, stored and disposed of in a manner that is protective of human health and the environment. In the course of developing shale gas in the Appalachian Basin, thousands of wells will be drilled and completed. Hydraulic fracturing ("fracing") is a necessary step for the completion of each of these wells in order to achieve economic well performance in terms of natural gas production; this step requires between 1 and 4 million gallons (3,800 and 15,200 m^3) of water for successful completion of each well. Vertical wells (representing approximately 10% of the wells drilled in the Barnett Shale) require approximately 1 million gallons (3,800 m^3) and horizontal wells (representing the remaining 90% of Barnett wells) require 3-4 million gallons (11,400 to 15,200 m^3) according to a recent survey among Barnett Shale Producers (Galusky, 2007). Similar volumes of water per well will be required in the drilling and completion of Marcellus Shale gas wells.

The challenge ahead for Marcellus Shale gas developers is to identify techniques to deliver the water required for drilling and completion and to develop methods for the disposal of brines represented by flowback and produced water that comply with applicable environmental regulations. The purpose of this paper is to outline a number of considerations and potential alternatives associated with meeting this challenge in Pennsylvania.

Water Consumption

Current Practice

The process of developing Marcellus Shale gas wells typically requires larger volumes of water than is necessary for conventional gas wells. The bulk of the water required for the successful development of Marcellus Shale gas wells is utilized in the fracing process. Fracing is necessary to obtain economically viable flows of natural gas from Marcellus Shale gas wells.

Prior to fracing, fresh water is typically stored in constructed storage impoundments or a large number of tanks located in close proximity to well sites. That water can either be pumped directly to such impoundments from water sources or hauled by truck from water sources. Bulk hauling over public roadways is not the preferred method to supply source water for fracing as it can cause roadway damage, increased traffic congestion, air and noise pollution and increased safety risk.

Currently, the preferred source of frac water is surface water (e.g. water from rivers, ponds, lakes, etc.). The preferred method for delivery of water to the wellhead is to pump water directly from a withdrawal point on a surface water source through pipelines to an impoundment or tank battery near the well completion location. In order to pump efficiently, the surface water withdrawal point should be located within one mile of the storage. Direct pumping is the preferred method because it substantially reduces the risks and costs associated with bulk hauling by truck.

Projections

The Appalachian Shale Water Conservation Management Committee (ASWCMC) recently conducted a survey which quantified the projected water use in the region for the development of the Marcellus Shale. The survey data was collected from 12 ASWCMC member operating companies and detailed the projected rig activity, specific water use and water sources through 2013. The survey forecasts a growth in rig activity from 64 rigs drilling 857 wells in 2009 to 171 rigs drilling 2,243 wells in 2013. The daily water consumption associated with drilling and completions activity is projected to increase from 6.1 million gpd to 18.7 million gpd over the same period. Multi-stage hydraulic fracturing was identified as the main consumptive use activity accounting for nearly 95% of all water used in drilling and completions operations. Surface waters are identified as the main source of waters planned for this purpose comprising 60-70 percent of the total water demand with groundwater serving as a very minor source for well completions (less than 4 percent of the total water demand) (ASWCMC, 2008). The remaining portions of source water are municipal supplied and forecasted recycling efforts.

The projected increase in fresh water for Marcellus Shale development is large relative to the conventional sandstone exploration and development activity which has dominated the region for more than a century. However, in comparison to other industries it is a small amount. In the Susquehanna River Basin alone the consumptive use of fresh water for the power generation industry is nearly 150 million gpd in comparison to the projected total demand for Marcellus Shale activity of 8.4 million gpd. An additional comparison can be made with the recreation or golf course industry which utilizes more than 50 mgpd.

Regulatory

Environmental regulation of flowback and produced waters associated with shale gas development is addressed in three federal laws and a compliment of laws administered by the states. Regulatory control of the injection of flowback and produced waters is governed by the Underground Injection Control Program (UIC) of the Federal Safe Drinking Water Act. The purpose of this act is to ensure that injected produced waters are confined in the injection zone in a manner that does not contaminate fresh water bearing formations which presently or may in the future serve as an Underground Source of Drinking Water (USDW).

Produced waters which are discharged to surface waters or the U.S. are regulated under the Federal Clean Water Act. Under this act, no effluent from an industrial operation may be discharged to surface waters except in accord with the provisions of a permit issued by the National Pollutant Discharge Elimination System (NPDES); NPDES permits are usually administered by the states. Since more than 90 percent of the projected drilling activity is aimed at areas within the State of Pennsylvania (ASWCMC, 2008), much of the natural gas industry's attention has centered on the regulatory requirements of that state related to shale gas development.

In addition to the regulation of effluents, regional and state laws also affect the delivery of water to the wellhead for completion in terms of the source, amounts of water utilized, and tracking involving a tapestry of state and regional regulatory organizations. Waters used for well completion will be mostly sourced from surface waters. Under the common law system of water rights, surface water is subject to the riparian rights doctrine which states that landowners with property adjacent to or crossed by a natural body of water with defined banks have the right to use these waters. Riparian doctrine, however, does not provide the right to divert or consume a certain amount of water, nor does it grant ownership of a specific quantity of water to the riparian landowner. In most cases, the natural gas developers will not be in the position of a riparian land owner, though it may seek to purchase water from such landowners. Clearly, added guidelines were needed from regulatory organizations regarding water sourcing for natural gas development.

Recent developments in the permitting process for new Marcellus Shale wells have opened an ongoing dialogue between the Pennsylvania Department of Environmental Protection (PaDEP) and the Oil & Gas Industry. Companies attempting to explore and develop the Marcellus Shale in Pennsylvania are faced with regulatory challenges specifically related to water withdrawal from surface waters.

The PaDEP has added an addendum to its drilling permit application specific to the Marcellus shale. The addendum requires the operator to submit a Water Management Plan (WMP) detailing water sources and safe yield calculations for surface water withdrawals for each new well. The objective of the WMP is to ensure that Best Management Practices (BMP) are utilized to which guarantee that anti-degradation requirements are fulfilled and that the specified existing and designated uses of the surface waters are protected. Debate remains on what guidelines are relevant and applicable to each region of the state and how the industry can practically withdraw surface water without degrading or jeopardizing the existing and designated use of the streams.

Other pieces of the water management regulatory tapestry include those related to the river basins. The Delaware and Susquehanna River Basins cover the eastern two-thirds of the State of Pennsylvania. The western third of the state is principally in the Ohio River Basin. In the 1960's and 1970's, the federal government created two interstate river basin commissions to manage water interests in the Susquehanna and Delaware River Watersheds. These organizations were named the Susquehanna River Basin Commission (SRBC) and the Delaware River Basin Commission (DRBC). Both of these organizations have the power to issue permits for surface and groundwater withdrawals that exceed certain maximum levels. In most cases, the water required for drilling and completion of shale gas wells (amounting to several million gallons within a 2-month period) will make it necessary for shale gas developers to work with the SRBC and DRBC to obtain the necessary consumptive water use and water withdrawal permits.

Alternative Sources

In certain locations within the Marcellus Play and in other shale gas development regions in Appalachia, the delivery of water supplies to the wellhead may encounter the constraints of long distances from suitable surface water sources or inadequate aquifers to support a useful water delivery flow of 50 gpm or more. Because of the logistical likelihood of these problems, it is necessary to find acceptable alternative water sources; this may also be necessary in order to sustain ongoing operations and to ensure that drilling permit approvals are not withheld due to debates over surface water withdrawal guidelines. Acceptable alternative water sources are understood to be source waters that could be withdrawn and used with beneficial or minimal environmental impact. Alternative water sources should be evaluated on availability, accessibility and economics as well as standard analysis of water chemistry and additive compatibility.

Municipal Suppliers

Municipal water suppliers are an expedient source of fresh water. Certain considerations need to be taken into account when using municipal water supplies. The most important considerations are the water withdrawal allocation, demand rates and system capacity of the municipal supplier. The allocation and demand rates are critical parameters when listing a municipal water supply as a potential source on a drilling permit application. The municipal water supplier has an obligation to provide water to residential and commercial customers ahead of intermittent industrial customers such as the Oil & Gas Industry. If the municipal supplier does not have enough excess withdrawal allocation in relation to its average and peak demands and system capacity then it may not have the ability to provide sufficient amounts and rates of water to meet oilfield demands.

The location of access points, transmission lines, booster pumps and water towers are of special interest in Pennsylvania due to the varying topography of the region. Obviously, the closer the access point is to the field operation and the higher the capacity the easier it is to transfer water via pipeline at high rates over elevated terrain. The option of pumping water may not be available in all cases. Operators may find that hauling water from an access point with sufficient capacity rather than pumping is the only solution.

Additionally, the type and quality of water being supplied should be evaluated. In most cases raw water provides sufficient water quality characteristics to be used for hydraulic fracturing operations with little to no treatment; however, municipal suppliers do not always provide raw water as an option for industrial use and may limit the water supplied to finished or treated water. Finished water exceeds water quality criteria but could represent an un-necessary cost in comparison to raw water.

The cost associated with municipal supplied water can vary greatly from one municipality to another. The current rates quoted in Pennsylvania range from $1 to $14 per 1000 gal. In the case that the water is hauled the total cost of municipal supplied water per well can be considered negligible in comparison to the cost of trucking.

Groundwater

The development of groundwater supply wells in close proximity to impoundments or storage facilities is another alternative water source which has the potential to minimize the cost associated with transporting water over the road. This assumes that target formations exist in and around Marcellus Shale development areas and provide sufficient yields with zero impact to surface waters and offset wells. This may not be the case in all areas and detailed hydrological study of target formations would be required to determine the actual feasibility of extensive groundwater supply well development.

The potential impact of groundwater supply wells on surface waters and offset wells could lead to further regulatory requirements in a WMP for analysis and safeguards. This raises questions similar to surface water withdrawals concerning safe yield definitions and anti-degradation guidelines.

Acid Mine Drainage

The most common form of water pollution in Pennsylvania is Acid Mine Drainage (AMD). This is attributed to the extensive development of the coal mining industry in the state. AMD is water which has been contaminated by contact with coal or mining activity. AMD water results from water contact with pyrite in strip-mine, refuse piles or abandoned deep mines resulting in the formation of sulfuric acid and iron hydroxide. The general characteristics of AMD water are elevated acidity and high concentrations of metals, sulfates and suspended solids.

A great deal of effort and investment has been made by PaDEP and the coal industry to identify, characterize and treat AMD water. Each AMD stream has unique characteristics and treatment processes which are customized to adjust pH and drop out metals prior to discharge. There are numerous AMD treatment facilities overlaying the Marcellus Shale which represent an overhead cost to the coal industry and a large scale environmental concern to PaDEP. The beneficial use of AMD water for Marcellus Shale development could provide a win-win solution for the coal and natural gas industries along with the PaDEP.

Initial analysis and additive compatibility testing of treated AMD water samples from Southwest Pennsylvania indicate that the treated effluent has the potential to meet minimum water quality requirements for hydraulic fracturing. As each AMD discharge is unique, similar water analysis and additive compatibility testing should be conducted on each potential source.

Private Suppliers

The PaDEP considers privately owned farm ponds, lakes, springs and reservoirs as “waters of the Commonwealth” that fall under PaDEP regulation and would require the same evaluation of anti-degradation and habit impact as other surface water withdrawals.

Recycled Waters

Water recovered from the chemical and mechanical processing of flowback water and produced brine could soon become a leading source of fresh water for Marcellus Shale development. Significant volumes of recycled water would reduce the demand for surface water withdrawal and conventional waste water discharge capacity at the same time.

There are many technical solutions being offered by a countless number of waste water treatment and chemical processing companies to recycle flowback water and produced brine. The actual effectiveness of each technical process depends on several factors with the most important factor being the characteristics of the waste water influent. A review of these technical solutions is given later in this paper.

It is worth noting that there is a technical limit to the amount of water that could be recycled. The technical limit exists because only a fraction of the water used to fracture a Marcellus Shale well is recovered during flowback. This fraction is estimated at 35% of the volume pumped. Depending upon the recovery factor of the process used to treat the flowback fluid and recover fresh water this fraction drops. A high-end mult-stage zero liquid discharge process is estimated to recover 70% of the wastewater treated. This sets a technical limit of 25% for the amount of fresh water which is recoverable from the initial volume of fluid used to fracture the well and would require an additional volume of fresh water as make up volume for a subsequent operation.

Waste Water Disposal

Current Practice

The primary conventional method for disposing of oil field waste water is through pre-treatment facilities which use clarification and filtration processes coupled with direct discharge to surface waters or sewage treatment plants. The NPDES program allows for permitted discharge of these treated industrial waste waters under controlled conditions and takes into account the assimilative capacity of the receiving water and ensures that subsequent downstream withdrawal points meet national drinking water quality standards.

As an alternative, an exceptionally small amount of disposal capacity exists in Class II injection wells. There are 8 permitted disposal wells in the state of Pennsylvania. The average injection rate of these wells is less than 1,000 bpd. The US Environmental Protection Agency (EPA) administers the permitting and operating of disposal wells in Pennsylvania.

As of 2008, the Marcellus Shale development is still in its infancy and the rate of drilling and completion of wells has been relatively low; many counties in Pennsylvania have seen less than a half a dozen wells completed over the past year. As a result the existing infrastructure for oilfield waste water disposal has been able to absorb the modest increase in waste volume. However, as the development of the Marcellus Shale continues to grow the disposal requirements will very shortly exceed the capacity of existing facilities and disposal wells.

Projections

Assuming well development activity similar to the effort to develop the Barnett Shale region, it is projected that water use for well completion in the Appalachian Shale gas plays could approximate 8.4 million gallons per day before reaching a plateau and declining. In the completion of many of the wells under development to date, it appears that the fraction of flowback water that is generated may only be a modest fraction of the water injected to perform each of the frac jobs. It may not be inconceivable that in the Appalachian setting, the amount of brine requiring disposal may be less than 4 million gallons per day; this is still equivalent to over 95,000 barrels per day of flowback water that will require management and disposal. It needs to be stressed, however, that this level of brine generation depends on the rate of shale gas development. For any given shale gas play, this category of brine generation will increase over a finite time period, will plateau over a finite period and will decline as well completions in that play are diminished in number each year. The nature of the brine water disposal challenge is temporal in nature and is closely related to the annual rate of well completions in the shale gas fields.

Chemistry

The general nature of produced water production composition environmental issues and current practices associated with the management of produced water streams associated with conventional oil and gas production are covered in several recent reviews (Veil, et al., 2004; Boysen, et al., 2002; Doran and Leong, 2000). Typical measurements from three samples of shale gas flowback water streams are presented in Table A (Champion, 2007). As shown in the table, total dissolved solids levels (reflecting the soluble salt content) in flowback water can range from a few thousand mg/l to over 200,000 mg/l (> 20% salt content). The wide range of salt concentrations in flowback water may be due to natural variation of formation conditions, but may also be due to the tendency of flowback water to increase in salt content as it flows from the well after fracturing (i.e. salt concentration in flowback water increases with time of residence down-hole).

A breakdown of constituents of flowback and produced water is shown in Figure B. Constituents can be considered to be divided into organic and inorganic compounds. Inorganic constituents in produced water generated in the field are either insoluble (examples include scale, precipitates, grit, inorganic colloids, etc.) or soluble. Soluble salts are comprised of anions and cations. Some examples of cations in produced water include the monovalent cations of sodium and potassium and the multivalent cations of iron, calcium and magnesium. Major anions include chloride, sulfate, carbonate and bicarbonate. Non-charged soluble inorganic species are also present; examples of these include silicate (H4SiO2) and Borate (H3BO3).

Organic compounds are either separable with gravimetric and deoiling technologies (oils and greases fall into this category), or they are soluble, requiring more complicated processing for removal. Soluble organic constituents can be divided into compounds that are dissociable into the ionic form (examples include phenol, mono-carboxylic acids and di-carboxylic acids) and into compounds that are not dissociable (such as non-ionic soluble oils and glycols).

In general, most flowback and produced waters are circum-neutral with pH values between 6 and 8. Buffering is usually provided through the presence of bicarbonate. In the normal storage and handling of produced waters, pH values will remain neutral unless caustics or acids are added in the course of treatment. Additives placed into the well during hydraulic fracturing and completion will also be present in flowback water and some produced waters at measureable levels. These additives include friction reducers, corrosion inhibitors, scale inhibitors and biocides. All of these classes of compounds are obtained from wellfield service companies and are well-known commercial products with material safety data sheet (MSDS) information that can be made available upon request. Friction reducers are polyacrylamide compounds that have been used in the paper industry as flocculants but are employed in the hydraulic fracturing procedure to achieve fractures in shale rock at reduced horsepower requirements.

Disposal Options

The central objectives in the management of water associated with shale gas well completion and operation include protection of the environment and the minimization of trucking requirements for water transportation. When a number of wells are completed in a localized project area, good progress toward both of these objectives can be realized through potentially beneficial management options that include:

1. Segregation of low TDS early flowback water that first emerges following a frac job; the low TDS water is used for future well completions and only the medium to high TDS water fractions are taken from the project area.
2. Transportation of the medium to high TDS flowback water and produced waters to a central disposal facility that could utilize one or more final disposal alternatives of deepwell injection (usually through Class II wells) or discharge under a National Pollutant Discharge Elimination System (NPDES) permit to surface waters either directly into a receiving water body or indirectly through a controlled discharge to a publicly owned treatment works (POTW).
3. Water processing near the project area to recover demineralized product water for blending with surface water and early flowback water for reuse in conducting future frac jobs within the project area.

In view of these water management options, there has been growing interest among energy companies and the regulatory community in the conversion of produced water to water streams suitable for flowback/produced water reuse and for reliable disposal using deepwell injection and/or discharge under NPDES permit. In support of these options, treatment needs could include one or more of the following:

- Reduction in brine volumes requiring transportation and disposal
- Oil and grease removal
- TDS reductions in product water
- Decreased concentrations of benzene
- Decreased concentrations of biological oxygen demand arising from soluble organics
- Control of suspended solids

Over the past decades, numerous treatment processes have been successfully used to achieve the above objectives in the processing of conventional produced waters. Since a good approximation may be that the shale gas flowback waters resemble conventional produced waters with a higher level of well-known commercial products (including friction reducers) present, it would be reasonable to assume that many of these treatment processes would be applicable to the management of brines in the development of Appalachian Shale gas. The categories of treatment systems and their applications to conventional produced water have been described in the literature (Hayes and Arthur, 2004). These categories and their capability in reaching water treatment objectives are described in Table B.

In the management of Appalachian Shale gas waters, the most pressing issues are how to deal with the disposal of large volumes of brines that are anticipated from the completion of wells. Certain disposal alternatives and treatment systems have already been begun to be critically evaluated for the Appalachian Shale gas region. Some initial thoughts on the potential of certain options are described below.

Pre-Treatment Process under NPDES permits

At many locations in the Appalachian region, there are a number of industrial and municipal facilities that have received permits under the National Pollutant Discharge Elimination System (NPDES) to treat waters and to discharge these waters at an allowable loading into a receiving waterbody. Many of these facilities have sufficient capacity to receive a controlled flow of flowback and produced waters while maintaining an effluent quality that meets NPDES guidelines. Ancillary steps required to successfully develop this option would include the construction of surge tanks, pretreatment processing which may include some deoiling, and controlled metering of waters into the plant with closed loop control with respect to conductivity of the influent stream into the POTW. Many treatment facilities would receive added revenues for allowing discharges of flowback and produced waters into the treatment plants and the natural gas industry would realize savings in transportation costs if local POTWs could be utilized for controlled water disposal. As noted earlier, however, there is a finite capacity for discharging treated brine into surface waters and subsequently a limited number of new facilities that will be approved to accept flowback water and produced brine.

Deep well injection

Underground injection is usually provided by waste disposal service companies that are regulated by “Underground Injection Control” programs that have been established in compliance with the Federal Safe Drinking Water Act of 1974. Under this act, primacy of regulatory control can be either State or Federal-based, depending upon agreements between each of the states and the USEPA. Class I wells are used for hazardous waste fluid disposal. Brines from oil and gas operations (which are normally considered to be non-hazardous) can be disposed of using Class II wells, a category of well disposal reserved for the oil and gas industry. Currently, the capacity of Class I and II disposal wells is not sufficient to handle the anticipated brine flows that may total several million gallons per day requiring disposal. If underground injection is to be used for the disposal of flowback and produced waters, additional capacity of Class II wells will need to be developed in the shale gas plays of the Appalachian Region. This will require additional characterization of formations proximal to shale gas plays that could be used for brine disposal. Service companies could potentially partner with water treatment entities to provide central flowback and produced water processing that would recover a water stream for reuse while concentrating the brine to reduced volumes of water requiring deepwell injection. Water recovered from this operation would be transported back to wellfields for use in performing future hydraulic fracturing in completing additional wells (frac jobs).

Demineralization Systems

Another approach to easing the challenge of brine volume disposal is to concentrate the salts into smaller volumes of brine while recovering a demineralized stream of water that can be reused for beneficial purposes, such as the performance of future frac jobs in the completion of new gas wells. Demineralization treatment systems for brines typically consist of pretreatment often involving filtration, followed by a demineralization step to concentrate the salts into a small volume of brine, followed by disposal of the concentrated brines (usually by deepwell injection as described above). Demineralization is at the heart of facilities that are dedicated to water reuse and brine volume reduction.

Thermal Evaporation/Condensation

Currently, the demineralization processes that are commercially applied for brine reduction or that are being evaluated in the field as experimental test units rely heavily on thermal evaporation/condensation processing. Several commercial designs rely on mechanical vapor compression. Many thermal evaporation condensation systems include the heating of the brine to promote evaporation in the evaporation chamber, the use of a compressor to compress the water vapor and pass the vapor through a heat exchanger that captures the heat and transfers the heat to the liquid phase of the evaporation chamber. In the handling of influent brines of 75,000 mg/l TDS, the process results in a water recovery efficiency greater than 70% with a nearly 4:1 reduction in brine volume. Practical limitations for the handling of influent concentrations of most thermal evaporation/condensation systems is approximately 150,000 mg/l TDS; under this condition, about 50% of the water can be recovered with a concomitant brine reduction of about 2:1. The challenge in applying thermal systems to brine demineralization includes heat exchanger fouling with organic deposits. However, these problems can be reduced through the use of properly-designed pretreatment to remove oils and greases, polyacrylamide friction reducers, and other problematic constituents. Another challenge is the formation of precipitates that occur in the concentrated brine that is circulated for heat recovery in the heat exchanger, which can cause scouring and corrosion of the heat exchanger surface and may lead to mineral scale plugging requiring frequent cleaning of the heat exchanger. Some companies have addressed this challenge with proprietary heat exchanger designs that allow a very rapid disassembly, cleaning and reassembly procedure to be implemented on modular units. Other companies are exploring the use of new surface coatings that impede the formation of scale. One company is using a scour-resistant titanium heat exchanger that maintains a turbulent regime for the concentrated brine that is circulated through the heat exchanger, making it difficult for scale to form on heat exchanger surfaces. Further, a manufacturer of mechanical vapor recompression (MVR) evaporation/condensation technology is exploring the use of seeded precipitate formation to encourage the formation of precipitates into suspended precipitates to avoid deposition of scale onto heat exchanger surfaces. These and other features will continue to improve the capability and cost of evaporation/condensation as an option for the recovery of water for reuse and for the reduction of brine volumes requiring final disposal.

Reverse Osmosis

Reverse osmosis is another type of process that is capable of demineralizing brines. Reverse osmosis (RO) is a treatment process that uses high pressure (600-900 psig) to force a brine through a membrane that retains salts on one side and allows demineralized water to flow through to the other side. The RO process is commonly used in industry and in community water supply systems for the removal of salts. As of 1997, there were approximately 2,000 RO plants in the world treating a total of 800 million gallons of water per day (MGD). Most of these plants treat brackish water and seawater to supplement water supplies for municipalities and industry. Under ideal conditions, RO should be capable of treating influent brines of up to 40,000 mg/l TDS (about the strength of seawater).

In the treatment of produced waters, there is a conspicuous lack of published information showing a period of satisfactory performance in the treatment of produced or flowback waters for more than 30 days (Hayes and Arthur, 2004). For produced waters, pilot tests have shown that although a 3:1 reduction of brine volume could be achieved over a short term; and a deionized product stream of good quality water could be initially produced, many operational problems involving membrane fouling have surfaced in the initial attempts in the field to deploy the technology (Lawrence, et al., 1995; Doran and Leong, 2000). These operational problems arise from the complex composition of the produced water and the effects of certain constituents on the membrane material. Free and dissolved oils collect on RO membranes causing them to lose their permeability. Particulates, including inorganic precipitates, tend to scour the surface of the membrane causing the filter material to break down mechanically. Soluble hydrocarbons including volatile acids and BTEX can promote the growth or microbial films on reverse osmosis membrane surfaces, causing them to lose their separation performance. These fouling problems are largely responsible for the lack of deployment success of RO in the oil and gas industry. Recent advances in applying meticulous preprocessing of produced water show potential of improving the reliability of RO in achieving economical brine reduction; successful preprocessing involving extensive filtering and softening (i.e. calcium, magnesium and silica removal) is often complex and site specific. Rigorous pretreatment and future advancements in polymeric coatings and ceramics in the design of RO membranes hold promise in increasing the capability as well as improving the performance and cost of this technology in the demineralization of produced and flowback waters.

Natural Evaporation

Unlike many of the states of the Western U.S., the Appalachian Region does not have the land area or the climate (i.e. temperature/humidity) conditions necessary to support the rapid evaporation of flowback waters.

Freeze Thaw

Freeze thaw evaporation (FTE) technology is a water treatment process in which water is sprayed under freezing conditions (i.e. ambient temperatures under 32° F) onto a freezing pad to create an ice pile. Under subfreezing conditions, runoff from the ice pile will have elevated concentrations of salts compared to the feed water. The runoff can be diverted to a storage tank for concentrated brines. At temperatures over 32° F, the runoff from the freezing pad will contain relatively low concentrations of TDS. Thus, natural freezing and thawing conditions are used to promote a separation of salts from demineralized product water. Recently, freeze thaw evaporation has been commercially introduced at a number of sites where conventional produced waters are treated for brine reduction (Boysen, et al., 2002). The obvious limitation of this technology is that it must be deployed in the region U.S. with sufficient days of freezing weather; all of the Appalachia fits easily in that region favorable for FTE application. However, the most obvious limitation is the very large requirement for land area. Land area requirements for a 1,000 barrel per day facility that could process the flowback water from several wells in one winter can require tens of acres; footprint requirements of this order of magnitude would no doubt make this process impractical for many counties of the Appalachian Region.

Crystallization

A process of precipitating salts in a water stream has been combined with falling film evaporators and MVR technology to achieve a further concentration of brines beyond the capability of conventional thermal evaporators, thereby allowing the recovery of near-solid salts or highly concentrated brine suspensions that can be recycled for other uses (such as kill fluids for oil and gas wellfield purposes, road salt, etc.) with a concomitant production of demineralized water for reuse. This type of system is often described as a zero liquid discharge ("ZLD") treatment system. These units have been applied in the chemicals industry for the recovery of specialty constituents of high value and in the power industry for demineralization of water streams. In application to shale gas fields, the process, when coupled with MVR, has the potential of recovering freshwater and a salt cake from produced waters and flowback waters. One challenge for crystallization application to shale gas waters is represented by the large sizes of equipment required for the handling of modest flows may limit the ability to modularize this technology to the extent of making it mobile. More testing and development will be needed to resolve issues that will determine the technical and economic feasibility of applying the technology to shale gas waters.

Additional considerations for ZLD should include handling of the solid saltcake material in an environmentally acceptable manner. Two potential options for handling the residual salt cake are solid waste disposal by landfilling or further processing to achieve a marketable by-product such as road salt.

Filtration

An essential pretreatment for nearly any demineralization step will include filtration. If not removed, polyacrylamide polymers have the potential of accumulating on heat exchangers or membranes used in demineralization. The adjustment of pH and the addition of chemicals to promote agglomeration of polymers, and suspended solids will be a first step, followed by sedimentation and rough filtration through pressurized rapid sand filtration and cartridge filters. These processes will also aid the removal of some levels of suspended oil and grease to about 10 µm (diameter). These steps may be followed by ultra filtration to achieve further removal of suspended solids and oils and greases down to 2 nm. Using chemical enhancements for ultrafiltration, these filtration steps have the potential of reducing suspended solids to less than 10 mg/l and oil and grease to less than 2 mg/l markedly reducing potential fouling problems. Note: these filtration processes will remove suspended solids and oils and grease but will not achieve concentration of soluble salts as is achieved in demineralization.

Ozone

The addition of ozone has been proposed to enhance the removal of soluble organics (including volatile acids, BTEX and napthenic acids), oils and greases, and heavy metals when coupled with the above-mentioned filtration steps. Ozone enhanced filtering has shown potential for achieving efficient (> 80%) removal of organic constituents in laboratory trials through oxidation; a number of heavy metals (such as iron) were also oxidized to form insoluble species that were easily removed with filtering. Pilot experiments are currently under way to evaluate the process under actual field conditions. One factor that may determine the economic feasibility of this approach is the cost of ozone delivered to the process.

Integrated Hybrid Processing

Given the complexity of shale gas flowback and produced waters, it is highly likely that multiple processes will need to be linked to achieve the treatment goals for water reuse and for reducing brine volumes destined for final disposal. Pretreatment involving filtering followed by some kind of demineralization will generally be involved when achieving the goal of recovering water for reuse and when reducing brines to significantly smaller volumes. Opportunities arise when considering the "regional" flowsheet where decisions are made as to what separations can be performed with mobile units in proximity to gas well project areas and what separations are best performed by larger regional processing plants that are located in proximity to final disposal facilities (such as Class II wells).

Implementation Considerations

The management of water for shale gas development will involve a strategic plan involving goals for brine volume reduction, water reuse, compatibility of blending reused water with other water streams, and attention to specifications on the minimum quality of water required to perform frac jobs for future well completions. Some considerations to this challenge are given in the following sections.

Transportation

Overarching goals may include minimization of water transportation since this achievement also reduces impact to the environment, reduces air emissions (including dust), lowers traffic congestion, and lessens the hydrocarbon footprint of well completions. About 300 truckloads are needed to move a million gallons of water assuming each truck is limited to 80 bbls per truck. Therefore, in the design of regional approaches to water management, it will be beneficial to identify strategies to minimize truck traffic by reducing the movement of large volumes of water across substantial distances. One alternative to trucking is the use of pumps and pipes. This method of water transfer works best when moving water over distances of thousands of feet to a few miles to deliver water from a central water source or blending area to wells within a project area. Such a system would consist of storage, piping, pumps and lift stations that would move water from a central water supply or from a reuse facility to a near-by project area where numerous wells are being constructed and completed. The feasibility of this option largely depends on terrain, rights of way, and other site or area specific factors.

Mobility

One strategy that can substantially reduce truck traffic is to bring processing equipment to the brine rather than transporting large volumes of brine long distances to treatment systems and disposal facilities. This can be achieved by utilizing mobile treatment units that are capable of concentrating brines in facilities located near wellfields. Many of the thermal treatment system proposed for flowback and produced water are packaged in skid mounted units that are highly mobile. Membrane based systems are even more amenable for mobile applications.

Modular Capacity

Commercial penetration into shale gas water management will be benefited by treatment systems that can be added or subtracted in terms of capacity since the flows from a single well or from the multiple wells of a project area will vary with the maturity of the wellfield. Already, thermal treatment units are available that are modularized to handle 500, 2,000 or 3,000 barrels per day. Combining skids in a parallel manner can provide considerable flexibility in handling water flows from hundreds to tens of thousands barrels of water per day.

Conclusion

Pennsylvania is blessed to have the opportunity to benefit from development of the Marcellus Shale. The economic and energy indepence potentials for the state are huge. However, from an operator's standpoint a comprehensive, muli-pronged water management plan is a necessity. Any such plan should incorporate an understanding of the regulatory landscape, various alternatives for sourcing water and a combination of disposal options with an emphasis on recycling and reuse. Each facet of the water management plan is integrated based upon regional logistics and regulatory supervision.

Technology in the form of water treatment needs to come to the forefront of any discussion on shale development. Current capacity constraints cannot be expanded to the levels necessary and as such, water treatment advancements must take place or Marcellus Shale development will be hindered. All of the above-mentioned technologies are, in general, proven, but each has limitations either logistically, capacity, TDS or economic. A flexible, hybrid system, both portable and stationary, would seem a logical choice of technology development. Such processes would pull from all facets of water treatment including oilfield, municipal waste and industrial treatment processes.

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Figures

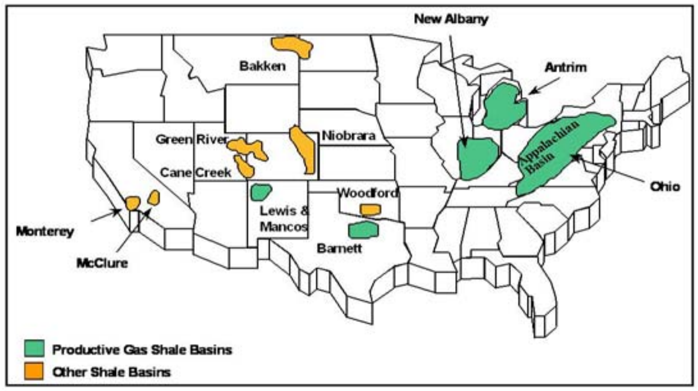

Figure A. Locations of the Shale Gas Basins of the U.S.

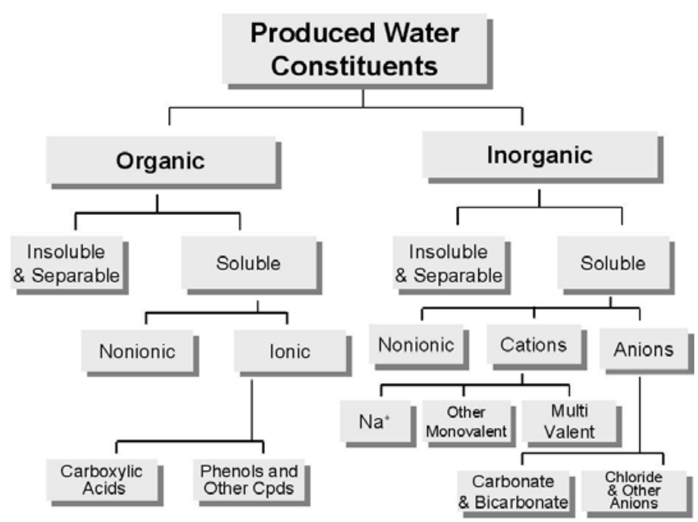

Figure B. Breakdown of Produced Water Chemical Constituents.

Tables

Table A. Typical Composition Data from Several Randomly Selected Flowback Water Streams.

Measurement	--- Randomly Selected Flowback Water Samples ---				
	A	B	C	D	E
pH	5.89	5.83	5.95	5.93	7.0
Sodium, mg/l	54,629	1,477	34,548	43,108	3,310
Calcium, mg/l	15,200	15,680	6,800	3,600	241
Magnesium, mg/l	4,730	1,707	899	6,062	49
Barium, mg/l	98	112	127	547	1
Iron, mg/l	92	60	105	1,274	4
Manganese, mg/l	1.8	1.4	1.7	99.6	na
Bicarbonate, mg/l	195	183	348	415	1,098
Sulfate, mg/l	60	10	20	10	48
Chloride, mg/l	125,000	35,000	68,000	93,000	5,000
Sulfide, mg/l	na	na	na	na	na
Total Dissolved Solids, mg/l	200,006	54,230	110,847	148,016	9,751

Table B. Unit Processes and Their Application to Produced Water Treatment.

Treatment Method	De-Oiling	Suspended Solids Removal	Iron Removal	Ca & Mg Removal Softening	Soluble Organic Removal	Trace Organics Removal	Desalination & Brine Volume Red	Adjust-ment of SAR*	Silicate & Boron Removal
API Separator	✓	✓							
Deep Bed Filter	✓	✓							
Hydroclone	✓	✓							
Induced Gas Flotation	✓	✓							
Ultra-filtration	✓	✓							
Sand Filtration		✓							
Aeration & Sedimentation		✓	✓						
Precipitation Softening				✓					✓
Ion Exchange			✓	✓					✓
Biological Treatment					✓				
Ozonation	✓		✓		✓	✓			
Activated Carbon						✓			
Reverse Osmosis							✓		
Distillation							✓		
Freeze Thaw Evaporation					✓		✓		
Electrodialysis					✓		✓		
Chemical Addition								✓	

✓ = Indicates that the technology is applicable as a potential remedy as indicated by data collected from pilot or commercial scale units.

* SAR= Sodium Absorption Ratio = $Na^{+}/((Ca^{+2} + Mg^{+2})/2)^{0.5}$