FITTING A SQUARE PEG IN A ROUND [DRILL] HOLE: THE EVOLVING LEGAL TREATMENT OF COALBED METHANE PRODUCED WATER IN THE INTERMOUNTAIN WEST

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ABSTRACT

Groundwater resources in the Intermountain West (Colorado, Montana, New Mexico, Utah, and Wyoming) continue to dwindle while populations expand. Oil and natural gas production in the region continues to increase, with a corresponding increase in production waste (mostly water). In the 1950s, each state set up an oil and gas conservation commission to regulate the disposal of the relatively small amounts of highly saline water produced during conventional oil and gas extraction. Beginning in the 1980s, however, energy producers began extracting methane trapped in coal seams that were too deep to mine conventionally. Today, this coalbed methane comprises nearly 10% of total domestic natural gas production. In order to extract coalbed methane, large quantities of water—often high-quality water—must be removed and disposed. That water does not fit into the regulatory scheme of byproduct waste to be governed solely by state oil and gas conservation commissions, nor is it extracted and used in the same manner as traditional groundwater resources subject to state groundwater laws. This paper examines Colorado's recent shift from the byproduct waste model to a groundwater resource model and proposes specific legislative changes that would recognize coalbed methane produced water as a unique resource. Those changes would help slow the waste of high-quality groundwater resources without unduly burdening energy producers, and would encourage treatment and traditional uses of the water. Colorado's approach may then serve as a template for other states in the region who are attempting to meet their water and energy needs while preserving groundwater resources for future generations.

INTRODUCTION

Methane (commonly called natural gas) trapped in coal seams historically was viewed as a waste product that had to be removed prior to mining, but as energy supplies dwindle, this resource has become increasingly important. In order to extract coalbed methane (CBM), large volumes of water must be pumped from coal seams and disposed. At a time when water demand in western states is rising beyond available supply, an effective regulatory framework for the water involved in CBM extraction is crucial to meeting the region's current and future needs.[1] Currently, regulation is based on a complex and inefficient system set up in the 1950s to deal with traditional oil and gas waste disposal.[2] Although much of the CBM produced water approaches drinking water quality standards, most is wasted through surface dumping or pumped deep underground into highly saline aquifers. This paper examines the historical and developing legal trends in the industry. Colorado is used as a representative state to examine the shift from oil and gas commission regulation (as in New Mexico, Utah, and Montana) to concurrent regulation by the State Engineer (as in Wyoming) after the *Vance v. Simpson* decision.[3] This paper posits that recent legal, scientific, and technological developments may

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[1] The "More Water, More Energy, and Less Waste Act of 2007" as passed by the House and currently on the Senate Calendar states that "[the] development of energy resources, including . . . coalbed methane . . . frequently results in bringing to the surface water extracted from underground sources; . . .most of the water is returned to the subsurface or otherwise disposed of as waste . . . . [I]t is in the national interest . . . to limit the quantity of produced water disposed of as waste; . . . and to remove or reduce obstacles to use of produced water for irrigation or other purposes . . . ." S. 1116, 110th Cong. § 1 (2007).

[2] The need for a legislative solution was the subject of a recent Denver Post Editorial, which stated that the "water problem seems to have taken the five Rocky Mountain states by surprise. It's high time their legislatures clarified their state laws . . . to protect the economy, environment and agriculture of the Rocky Mountain West." Denver Post Editorial Board, *Rocky Mountain States Drop Ball on Water Rules*, DEN. POST, August 17, 2007, *available at* http://www.denverpost.com/search/ci_6643530.

[3] No. 2005CW063 (Colo. Dist. Ct., Water Div. 7, July 2, 2007). In any case, Colorado is likely to pass legislation on the subject soon. Email from Sen. Greg Brophy, Colo. Dist. 1, to author (Nov. 30, 2007 15:01:00 EST) (on file with author).

encourage an alternate disposal system for this “byproduct” water focused on treatment and beneficial use rather than disposal by injection into deep wells or surface dumping. Minor legislative changes could codify these developments and better conform to market forces, encourage new technology, and protect the interests of current and future residents of the region.

Part I of this paper introduces how coalbed methane is formed and the location of major reserves in the intermountain west, including an overview of resource quantity, depth, water quality, and extraction techniques. The current controversy over whether CBM dewatering constitutes “beneficial use” is outlined. Each state in the region follows the prior appropriation doctrine, but Montana, New Mexico, and Utah have determined that CBM dewatering is not a “beneficial use” of water and thus exclude it from the appropriation system. Wyoming is the only state that recognizes CBM dewatering as a “beneficial use.” Colorado’s move to find CBM dewatering a “beneficial use” is examined through the July 2007 Durango Water Court ruling in *Vance v. Simpson*.[4] Finally, current disposal methods are outlined and evaluated based on their long term sustainability.

Part II sets out the regulatory background in for oil, gas, and groundwater extraction. Colorado’s approach (before *Vance*) is outlined, including the responsible state agencies and the specific regulations dealing with produced water disposal and groundwater appropriation. As a byproduct waste, most CBM produced water falls under the sole jurisdiction of the oil and gas conservation commissions. This model treats relatively high quality water as a “waste,” similar to the low quality brine associated with conventional oil and gas extraction which may be up to eleven times saltier than

[4] *Id.*

seawater. In Wyoming and in Colorado after *Vance*, removing the water is an appropriation that invokes the jurisdiction of the State Engineer. In Colorado, this may cause jurisdictional problems between the oil and gas conservation commission and the State Engineer. The Wellington oilfield project, where oil producers treat produced water in order to augment municipal drinking water supplies is discussed to highlight current deficiencies in Colorado's regulatory scheme. Finally, Wyoming and New Mexico's approach to CBM produced water management are shown. Specific solutions adopted by each state are applicable to Colorado, but neither state has fully addressed the problem.

Part III examines CBM development and regulation in terms of economic and technologic feasibility. Stringent produced water regulations restrict resource development and may decrease royalty and tax collection. This may impact local communities and may discourage certain technological advances. However, many of these impacts are mitigated as gas prices rise and more resources become economically recoverable. Constant legislative changes and schemes that involve long permitting timeframes also have a direct economic impact on produced water disposal options, precluding the most desirable choice. Part III also examines the benefits of produced water regulation. Much like oil and gas reserves, high-quality groundwater is an increasingly valuable and finite resource in the west. Stringent regulation slows withdrawal and waste of groundwater resources, which in the future may become even more valuable than its associated natural gas. However, forcing producers to fully internalize the costs of wasting groundwater may be economically and technologically infeasible.

Part IV introduces a proposed legislative solution for Colorado that would codify the *Vance* decision, legislatively stating that CBM dewatering *is* beneficial use, but introducing a distinction between produced water from deep, saline aquifers (which resembles conventional oil and gas waste) and produced water from shallow, high quality aquifers (which resembles surface water). Setting a depth/water quality threshold would recognize that some of the produced water can and should be beneficially used, while much is of such low quality that "waste" regulations are more appropriate. This distinction would strike the appropriate balance between gas extraction and water resource preservation, and would protect existing water rights. Subjecting CBM operators to the jurisdiction of the State Engineer would prevent waste of this increasingly valuable resource, and may serve as a model for other states in the region.

I. CBM PRODUCTION AND EXTRACTION

Coal seams are found in thirty-eight states, and nearly one-eighth of the country lies over coalbeds.[5] However, 90% of these deposits are unmineable.[6] All coal seams contain some amount of natural gas, or methane, which historically was viewed as a mine safety hazard,[7] but now represents more than 9.6% of total domestic natural gas production.[8]

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[5] American Coal Foundation: FAQs about coal, http://www.teachcoal.org/aboutcoal/articles/faqs.html.
[6] U.S. Dep't of Energy, *Policy Facts: Coalbed Natural Gas* (Feb. 2005) *available at* http://www.netl.doe.gov/publications/factsheets/policy/Policy019.pdf.
[7] The worst mine disaster in American history, the 1907 Fairmont Coal Methane Explosion near Monogah, West Virginia, killed over 362 miners. Coalbed methane is also a current danger – of the 197 fatalities in underground coal mines in the United States from August 1980 to August 2007, 104 were due to coalbed methane explosions. U.S. Dep't of Labor, *Mining Disasters - An Exhibition: 1907 Fairmont Coal Company Mining Disaster Monongah, West Virginia*, http://www.msha.gov/disaster/monongah/monon1.asp; U.S. Mine Rescue Ass'n, *Fatalities Occurring at Underground Coal Mine Disasters Since 1980*, http://www.usmra.com/disasters_80on.htm.

Unlike traditional coal mining, coalbed methane is produced by drilling and dewatering unmineable coal seams to allow the methane to escape. Due to the nature of coal deposition and depth compared to traditional oil and gas reserves, the water produced in CBM extraction is generally of much higher quality than that produced in traditional oil and gas production. Because of its relatively high quality, CBM water is often discharged onto the surface and may be used for irrigation, stock watering, or other uses with little or no treatment, unlike produced water waste from traditional oil and gas extraction which generally injected underground into deep, highly saline formations.

A. Formation and Location of Reserves in the Intermountain West

Coal formation and consolidation produces large amounts of methane over time.[9] Instead of escaping, the methane binds (adsorbs) to coal surfaces. The microstructure of coal provides tremendous surface area for gas adsorption: one ton of coal contains 200 million to 2 trillion square feet of surface area,[10] can yield up to 8,000 cubic feet of methane gas,[11] and typically contains six to seven times the gas of an equivalent mass of rock in a conventional gas reservoir.[12] Unlike coals in the Eastern United States (which

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[8] Total domestic CBM production in 2005 was 1.732 trillion cubic feet (Tcf) of gas while total domestic natural gas production was 18.051 Tcf. U.S. Energy Information Administration Natural Gas Navigator, http://www.eia.doe.gov/oil_gas/natural_gas/info_glance/natural_gas.html [hereinafter EIA].
[9] *Id.*
[10] Scott Reeves, *Enhanced Coalbed Methane Recovery*, (2003) (Presentation at the Soc. of Petroleum Eng. Distinguished Lecture Series) *available at* http://www.adv-res.com/pdf/Reeves%20DL%20Presentation.pdf
[11] Interstate Oil and Gas Compact Comm'n and ALL Consulting, *A Guide to Practical Management of Produced Water from Onshore Oil and Gas Operations in the United States* (Prepared for the U.S. Dep't of Energy Nat'l Petroleum Technology Office) (Oct. 2006) [hereinafter ALL 2006] at 6, *available at* http://www.all-llc.com/IOGCC/PDF/PWGuideFinal-LowRes.pdf.
[12] U.S. Geological Survey, Coalbed Methane—An Untapped Energy Resource and an Environmental Concern, FS-019-97 (1997) http://pubs.usgs.gov/fs/fs123-00/fs123-00.pdf.

generally lie in narrow, impermeable seams with low CBM recovery), coals in the West typically lie in thick and highly fractured seams that allow for excellent gas recovery.

Shallow coal deposit may be mined conventionally for their coal, but deeper deposits can only be exploited for the methane they contain. Conservative estimates for total CBM reserves in the coterminous United States are 700 trillion cubic feet (Tcf)[13] with up to 186 Tcf technically recoverable.[14] To put these figures in context, total U.S. natural gas consumption in 2006 was 21.78 Tcf, and is slated to hover between 23 and 24 Tcf annually between now and 2030.[15] Figure 1 shows the location of major basins in the Intermountain West, as well as their projected volumes of estimate economically recoverable methane, in trillion cubic feet (Tcf).[16]

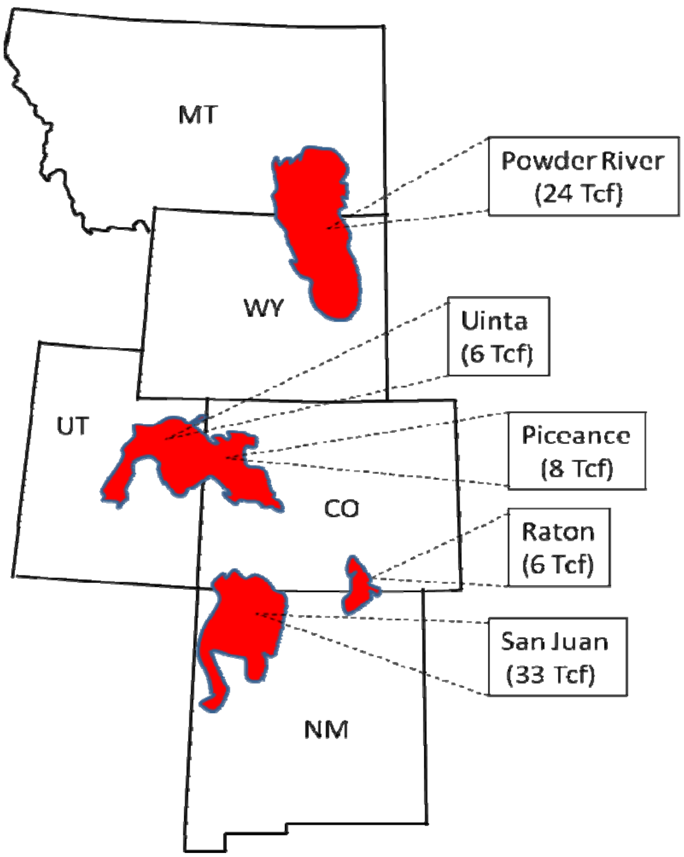
[13] *Id.*

[14] This number is the sum of the U.S. Energy Information Administration's 2005 proved CBM reserves (19.9 Tcf) plus the Potential Gas Committees 2006 estimate of 166.1 Tcf that may be found and produced in the future. *See* U.S. Energy Information Administration, Coalbed Methane Proved Reserves and Production, http://tonto.eia.doe.gov/dnav/ng/ng_enr_cbm_a_EPG0_r51_Bcf_a.htm; Potential Gas Comm., Announcing the 2006 PGC Natural Gas Resource Estimates and Biennial Report, http://www.mines.edu/research/pga/.

[15] U.S. Energy Information Administration, *Annual Energy Outlook 2008 Overview* at 12 *available at* http://www.eia.doe.gov/oiaf/aeo/pdf/earlyrelease.pdf.

[16] There are various measures of CBM reserves from different groups and with different methodologies that vary wildly. For example, some estimate the Greater Green River basin to contain over 314 Tcf of CBM reserves, but of this amount only 2.7 Tcf are estimated to be economically recoverable. *Cf.* Scott R. Reeves; George J. Koperna; & Vello A. Kuuskraa, *Nature and Importance of Technology Progress for Unconventional Gas* (July 24, 2007) *available at* http://www.adv-res.com/pdf/ARI%20GJ%204%20Unconventional%20Gas%20Technology%207_24_07.pdf and U.S. Energy Information Administration, *supra* note 14.

Figure 1: Estimated Economically Recoverable Coalbed Methane Reserves in the Intermountain West over 5 Tcf[17]



In addition to having a large amount of estimated economically recoverable CBM, Colorado is home to the highest amount of proved[18] CBM reserves in the continental

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[17]Modified after Ted McCallister, *Unconventional Gas: Challenges, Successes, and Future Outlook Unconventional Gas Production Projections in the Annual Energy Outlook 2005: An Overview*, (April 12, 2005) (Presented at the U.S. Energy Information Administration Midterm Energy Outlook and Modeling Conference in Washington, DC).

[18] The U.S. Energy Information Administration defines "proved reserves" as "the estimated quantities which analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Reservoirs are considered proved if economic producibility is supported by *actual production* or *conclusive formation test* (drill stem or wire line), or if economic producibility is supported by core analyses and/or electric or other log interpretations." U.S. Energy Information Administration, Natural gas Navigator: Definitions, Sources,

United States (6.34 Tcf), followed by New Mexico (4.89 Tcf) and Wyoming (2.45 Tcf).[19] In 2006, annual production was greatest in New Mexico (0.51 Tcf), Colorado (0.48), and Wyoming (0.38 Tcf).[20]

B. Water Quality and Quantity

Nearly all underground coal seams exist at a saturated condition, and the water quantity and quality is often related to the depth of the coal seam. Shallow, younger coals like those found in the Western United States are highly porous, and contain large amounts of relatively clean water (often associated with original deposition or subsequent meteoric groundwater infiltration). As coals mature and consolidate, their porosity decreases, and water is driven into surrounding strata. Consolidation causes net water movement toward the ground surface, with overlying clays and shales serving as filters, trapping salts from migrating upward and increasing the salinity of deeper formations.[21] The net effect of these phenomena is a general salinity gradient that increases with depth, and a water to coal volume ratio that decreases with depth (i.e., shallow, young coals contain large amounts of high quality water, and deep, older coals contain smaller amounts of saline water).

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and Explanatory Notes, http://tonto.eia.doe.gov/dnav/ng/TblDefs/ng_enr_cbm_tbldef2.asp (emphasis added).

[19] *See* EIA *supra* note 7 (values are for 2006).

[20] *Id.*

[21] *See* ALL 2006 *supra* note **Error! Bookmark not defined.** at 10.

Water quality for CBM produced water is often given in terms of total dissolved solids (TDS),[22] a measure of all dissolved salts or *salinity*. When used for irrigation or livestock watering, saline water can stress or kill crops and animals. Saline irrigation water can present an especially serious problem in arid regions, where limited leaching and evapoconcentration can cause salts to build up near the root zones of plants, limiting their ability to absorb water.

Unlike coal seams, traditional oil and gas reserves are usually associated with marine depositions. As a consequence, the water associated with their production often has TDS measures as high as seawater (approximately 35,000 mg/L)[23] or higher, due to the filtering effect of overlying strata. TDS levels of 350,000 to 400,000 mg/L (10 to11 times saltier than seawater) have been reported with extraction of traditional oil and gas reserves in deep formations.[24]

Table 1: Selected Water Quality

	Average Depth of Potable Water Wells (ft)	Depth of reserves (ft) Range and (Typical)	TDS (mg/L) Range and (Typical)

[22] Sodium Absorption Ratio (SAR) and concentrations of other toxic components are also measures of CBM produced water quality. Dissolved solids in water are a combination of sodium (as found in table salt) and other salts. The sodium hazard of soil, or *sodicity*, is expressed as the sodium adsorption ratio (SAR) – the proportion of sodium ions to calcium plus magnesium ions. Sodic irrigation water may cause clay soils to swell and soil aggregates to disperse, clogging soil pores which results in decreased infiltration and soil permeability. Soil damage from sodic irrigation water is most pronounced when the salinity is low (i.e., water with low salinity (TDS) but a high relative concentration of sodium to other ions (SAR) will damage clay soils the most).

[23] The Ruckelshaus Inst. of Env. & Nat. Res. & The Univ. of Wyoming, *Water Production from Coalbed Methane Development in Wyoming: A Summary of Quantity, Quality, and Management Options*, Prepared for the Office of the Governor (Dec. 2005) [hereinafter Wyoming Governor's Report] at 27, *available at* http://www.uwyo.edu/enr/ienr/cbm.asp

[24] *Id.*

EPA secondary drinking water standard[25]	N/A	N/A	500
Lake Mead[26]	Surface	N/A	640
San Pellegrino mineral water[27]	Surface	N/A	960
Livestock Watering[28]	N/A	N/A	1,000-7,000
Powder River		200-1,800[29]	270-4,000[30]
Raton		400-4,000[31]	530-6,000[32] (1,000)[33]
San Juan	Less than 400[34]	500-4,000[35] (2,500)	300-25,000[36]
Uinta[37]		1,000- 7,000 (4,300)	9,286-31,000
Piceance[38]	200	4,000-12,000 (6,000)	15,000
Atlantic Ocean[39]	N/A	N/A	35,000
Great Salt Lake[40]	N/A	N/A	230,000
Conventional Oil and Gas	N/A	Varies	5,000-410,000[41]

[25] 40 C.F.R. § 143.3.
[26] *See* Wyoming Governor's Report, *supra* note 23.
[27] San Pellegrino, Chemical Structure, http://www.sanpellegrino.com.
[28] R.S. Ayers & D.W. Westcot, *Water Quality for Agriculture*, (Food and Agriculture Organization of the United Nations, Rome, 1976). The EPA limit for livestock watering is 2,000 mg/L. *See* Wyoming Governor's Report, *supra* note 23.
[29] ALL Consulting, Coalbed Methane: What is it and How do you Get it Out?, http://www.all-llc.com/CBM/pdf/CBMIntro2004IOGCC_11-20.pdf.
[30] Jim Otton, *Estimated Volume and Quality of Produced Water Associated with Projected Energy Resources in the Western U.S.*, Produced Water Workshop 26, 30, *available at* http://cwrri.colostate.edu/Produced%20Waters/Proceedings%20Final%20PDF.pdf.
[31] *See* ALL Consulting, *supra* note 29.
[32] Otton, *supra* note 30, at 30.
[33] U.S. Env. Protection Agency, *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*, EPA 816-R-04-003 (June 2004) [hereinafter EPA] *available at* www.epa.gov/safewater.
[34] Telephone Interview with Dick Wolfe, State Eng'r, State of Colo. (Dec. 28, 2007) [hereinafter Wolfe interview].
[35] *See* EPA, *supra* note 33.
[36] *Id.*
[37] *Id.*
[38] *Id.*
[39] *See* Wyoming Governor's Report, *supra* note 23.
[40] *Id.*
[41] Otton, *supra* note 30, at 30.

Water quantity is another important aspect of coalbed methane extraction. Water produced during oil and gas operations constitutes the industry's most prolific product (98 percent of waste fluids; a total of 14 billion barrels of water were produced in 2004).[42] While these figures are impressive in themselves, when compared to 2006 annual domestic production volumes of oil and gas (1.9 billion barrels and 23.9 trillion cubic feet, respectively) it is no wonder why some analysts characterize oil and gas as a byproduct to the production of water.[43] CBM produced water is a significant and increasing portion of this total – the Powder River basin alone produced over 670 million barrels of water in 2006 (even though less than 5% of the basin CBM reserves have been exploited).[44]

C. *Extraction Processes*

In a typical CBM well, the operator drills a hole from the surface into the coal seam, casing and cementing the drill hole as it progresses to protect shallower aquifers from becoming contaminated or leaking into the drill hole. The coal seam is then drilled out to open up more coal face to production. In areas where the coal is not naturally fractured, the seam may be cavitated[45] or stimulated[46] to increase coal seam permeability

[42] *See* ALL 2006, *supra* note 8 at 2.
[43] *Id*.
[44] This is a compilation of data from the Wyoming Oil and Gas Conservation Commission, which lists production statistics on its website. http://wogcc.state.wy.us/ under "statistics."
[45] Two means are commonly used to increase coal seam permeability: cavitation and stimulation through fracturing. In cavitation, air, water, gel or foam (or a combination thereof) is pumped into the well to increase the pressure in the reservoir, followed by a sudden release that blows out the mixture along with coal fragments. This "surge" in pressure enlarges and cleans the well bore by as much as 16 feet in diameter in the coal seam and propagates fractures that extend from the well bore. If the cavitation fractures connect to natural fractures in the coal, they provide channels for gas to more easily flow to the well. La

and gas recovery. A submersible pump is run into the well to pump the water from the coal seam in order to release the methane held in place by water pressure. Analogous to opening a soda can,[47] dewatering reduces hydrostatic pressure and allows for methane desorption to occur. The methane flows up both the casing of the well and is sent via pipe to a gas-water separator at the compression station. The methane is then compressed for shipment to the natural gas sales pipeline.[48] Unlike in traditional oil and gas extraction, water production in CBM wells is high at the outset and then drops off dramatically.[49] Gas production does not begin until the pressure is reduced, and typically increases over the life of the well before finally dropping off.

Figure 2: Typical Production Curves of Water and Coalbed Methane over Time

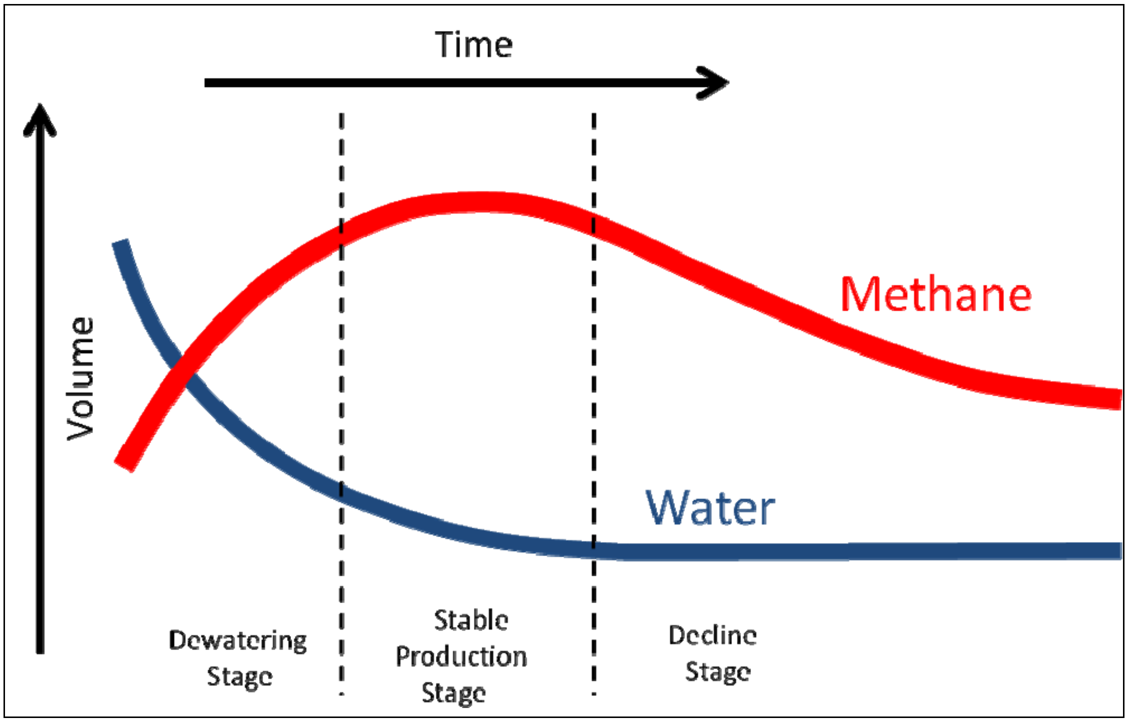
Plata County Energy Council, *Gas Facts - Production Overview*, http://www.energycouncil.org/gasfacts/prodover.htm.

[46] In stimulation through hydraulic fracturing, fluids and sand are forced into the coal formation at very high pressures to hydraulically fracture the coal seams. Sand particles in the hydraulic fluid prop up the widened and newly created fractures in the coal allowing more methane gas to escape after much of the hydraulic fluid and ground water have been pumped out of the well. Hydraulic fracturing was thought to introduce harmful contaminants into underground aquifers. After a multiyear study, the EPA concluded that "the injection of hydraulic fracturing fluids into CBM wells poses little or no threat to USDWs" and that "Continued investigation . . . is not warranted at this time." *See* EPA, *supra* note 33.

[47] Hal Clifford, Drilling Method Pumps up Floods of Conflict, CHRISTIAN SCIENCE MONITOR, Jan. 3, 2002, *available at* http://www.csmonitor.com/2002/0103/p3s1-usgn.html.

[48] ALL Consulting, *Handbook on Coalbed Methane Produced Water: Management and Beneficial Use Alternatives*, (July 2003) [hereinafter ALL 2003] (prepared for the Ground Water Protection Research Foundation; U.S. Department of Energy; National Petroleum Technology Office; Bureau of Land Management) *available at* http://www.all-llc.com/CBM/BU/index.htm.

[49] Traditional oil and gas wells produce primarily hydrocarbons at the outset and then increasing amounts of water. Oil wells approaching the end of their useful life are sometimes known as "stripper" wells, which commonly produce as much as 40 barrels of water for each barrel of oil. *Id.* at 2.



D. Is CBM dewatering "Beneficial Use?"

Each state in the intermountain west regulates water resources through the doctrine of prior appropriation – judicially born in Colorado in 1882 after *Coffin v. Left Hand Ditch Company*,[50] and judicially and/or statutorily recognized within 20 years of the that decision in all eight Rocky Mountain States.[51] The prior appropriation doctrine provides that an intentional diversion of water with subsequent application to beneficial use[52]

[50] 6 Colo. 443 (1882).
[51] GEORGE VRANESH, VRANESH'S COLORADO WATER LAW: REVISED EDITION 9, (Univ. Press of Colo., James N. Corbridge & Teresa A. Rice, Rev. eds. 1999) (1987).
[52] "Beneficial use" is mentioned in the Constitutions of Colorado, Montana, Utah, Wyoming, and New Mexico. See Colo. Const. art. XVI, § 6 ("The right to divert the unappropriated waters of any natural stream to beneficial uses shall never be denied."); Mont. Const. art. IX, § 3 (making water available for appropriation for beneficial use); Utah Const. art. XVII, § 1 (confirming existing rights to use water for beneficial purposes); Wyo. Const. art. VIII, § 3 ("Priority of appropriation for beneficial uses shall give the better right."); N.M. Const. art. XVI, § 1 ("All existing rights to the use of any waters in this state for any useful or beneficial purpose are hereby recognized and confirmed.").

constitutes an appropriation.[53] Water "rights" are based on the date of the appropriation, with the first appropriators holding senior rights to later (junior) appropriators. In 1983, the Ninth Circuit proclaimed that there were "differences in water law among the various western states" but that "on the point of what is beneficial use the law is general and without significant dissent."[54] Until the commercial exploitation of coalbed methane, this statement was generally true. Today, however, the concept of beneficial use for CBM dewatering varies between the states, with Wyoming recognizing CBM dewatering as beneficial use, and Montana, New Mexico, and Utah finding that beneficial use is only subsequent to diversion. Prior to July 2007, Colorado did not recognize CBM dewatering as a beneficial use.

In November 2005, two ranchers in the San Juan Basin of southwest Colorado filed a declaratory relief action seeking a determination that tributary ground water diverted in the process of extracting CBM was an "appropriation" requiring CBM producers to comply with state water laws.[55] Central to the court's inquiry was whether CBM dewatering constituted an (1) intentional (2) diversion of the waters of the state with subsequent (4) application to (5) a beneficial use (6) without waste.[56]

Whether CBM extraction constituted a diversion of the waters of the state was not in serious contention. Removing groundwater by pumping constitutes a "diversion" under a relatively clear statutory definition.[57] In Colorado, "waters of the state" means "all surface and underground water in or tributary to all natural streams within the state of

[53] *See* VRANESH, *supra* note 51, at 32.
[54] United States v. Alpine Land & Reservoir Co., 697 F.2d 851, 854 (9th Cir. 1983) (citing 1 WATERS AND WATER RIGHTS 19.2 (R. Clark ed., 1967).
[55] Brief for Plaintiff at 2, Vance v. Simpson, No. 2005CW063 (Colo. Dist. Ct., Water Div. 7, July 2, 2007).
[56] *See* VRANESH, *supra* note 51, at 32.
[57] *See* Colo. Rev. Stat. § 37-92-103(7) (2007).

Colorado" outside designated groundwater basins.[58] Appropriations also require intent. Although the CBM producers sought methane, not water, the court found that their actions demonstrated intent to divert the water.[59]

The primary issue in *Vance* was whether dewatering coal seams to release gas was "beneficial use" of the produced water without which there could be no appropriation. In Colorado, beneficial use is statutorily defined in the Water Right Determination and Administration Act of 1969 as "the use of that amount of water that is reasonable and appropriate under reasonably efficient practices to accomplish without waste the purpose for which the appropriation is lawfully made . . . .[60]

Before this codification, beneficial use was historically defined by Colorado courts on a case-by-case basis. The generality of the statutory definition (both explicitly and due to the fact that "waste" is not defined anywhere in the Act)[61] implies that there may be no difference in interpretation of beneficial use under the statute or under the common law.[62] In examining beneficial use cases, courts have recognized three main goals of the beneficial use concept: (1) avoiding speculation and monopoly of water resources (only actual, bona-fide uses would trigger an appropriation); (2) maximizing

[58] *See* Colo. Rev. Stat. § 37-92-103(13) (2007). Designated groundwater basins are geographically defined non-tributary aquifers primarily on the plains portion of Colorado and are subject to the jurisdiction of Colorado Groundwater Commission. See generally Colo. Rev. Stat. §§ 37-90-103 to 108 (2007).

[59] In *Three Bells Ranch Associations v. Cache La Poudre Water Users Association*, owners of gravel pits were required by the State to reclaim land after mining operations concluded. The reclamation plan included the creation of recreation and fishing ponds (a beneficial use) fed by tributary groundwater. The gravel pit operators argued that because their intent was not to appropriate water, but to mine gravel, no appropriation had occurred. The court disagreed, finding that "intent" was evidenced by digging the gravel pits and reclaiming the land, regardless of the fact that the pit operators were forced to do so by the Mined Lands Reclamation Act. 758 P.2d 164, 70-73 (Colo. 1988) ("persons intend the reasonable, natural, and probable consequences of their actions").

[60] Colo. Rev. Stat. § 37-92-103(4) (2007).

[61] The Colorado Groundwater Management Act does define "waste" as "causing, suffering, or permitting any well to discharge water unnecessarily above or below the surface of the ground." C.R.S. 37-90-103(20) (2007). Because dewatering is "necessary" to extract methane, this definition is presumably not applicable as long as methane extraction is underway.

[62] *See* VRANESH, *supra* note 51, at 44.

water use (wasteful practices would not constitute beneficial use); and (3) providing flexibility to the water user (a loosely defined concept could change over time as new uses for water are established).[63] In keeping with the flexibility of the concept, Colorado courts have recognized uses unknown when the state constitution was written as beneficial, including power generation[64] and aquaculture.[65] Other jurisdictions have attempted to maximize water use by excluding certain wasteful uses from the beneficial category that could be accomplished without using water (such as drowning gophers,[66] softening a field for plowing,[67] flushing debris during the irrigation season,[68] and using the water to deposit gravel for mining[69]). A case in Colorado found that pumping groundwater simply to test a well pump was not beneficial use.[70] Although this seems to fall into the wasteful category (the tester could have used other means to test the pump) the court's reasoning was centered on speculative nature of the purported beneficial use.[71]

British Petroleum America (the operator of most CBM wells in the San Juan Basin) and the Colorado State Engineer both filed briefs in *Vance*. They argued that beneficial use required an "application" of the water to some purpose to constitute beneficial use, and although dewatering was necessary for CBM extraction, the water was not "used to force or draw natural gas from the target formation . . . [nor] used to process

[63] Janet C. Neuman, *Beneficial Use, Waste, and Forfeiture: The Inefficient Search for Efficiency in Western Water Use*, 28 ENVTL. L. 919 (1998).
[64] City & County of Denver v. Sheriff, 96 P.2d 836 (Colo. 1939).
[65] Larimer & Weld Reservoir Co. v. Ft. Collins Milling & Elevator Co., 152 P. 1160 (Colo. 1915).
[66] Tulare Irrigation Dist. v. Lindsay-Strathmore Irrigation Dist., 45 P.2d 972 (Cal. 1935).
[67] Hennings v. Water Resources Dep't, 622 P.2d 333 (Or. 1981).
[68] In re Water Rights of Deschutes River & Tributaries, 286 P. 563 (Or. 1930). The court did allowed the use during winter as long as it did not interfere with storage requirements for irrigation. *Id.* at 578.
[69] Joslin v. Marin Mun. Water Dist., 429 P.2d 889 (Cal. 1967).
[70] Danielson v. Milne, 765 P.2d 572 (Colo. 1988).
[71] *Id.*

or transport the produced gas . . . ."[72] Simply stated, the water wasn't doing anything – it was just something that was in the way, and if it magically disappeared, all the better. The court disagreed, finding that because the dewatering was essential to the process, there was an application of the water.[73]

The strongest argument put forth by BP and the SEO was Colo. Rev. Stat. § 37-90-137(7), which states that for some types of mine dewatering, "[n]o well permit shall be required unless the . . . ground water being removed will be beneficially used" which implies that dewatering, in itself, is not a beneficial use. The court seemingly painted itself in a corner – it had already used that exact subsection to show that the legislature had intended permit exceptions to apply only in certain instances. Interestingly, the argument was not addressed by the court. Perhaps the court felt that permitting exceptions were within the competency of the legislature, so deference to their intent was appropriate in those cases, but beneficial use, though codified, was a common law concept best interpreted by the courts, and that reliance on a somewhat vague expression of legislative intent was inappropriate.

The ranchers contended that the water was "used" to allow gas extraction and then "used up" by reinjection into deep saline aquifers.[74] Because the water was *used* (defined by the plaintiffs as "removed from the [groundwater] system and made physically unavailable to senior vested water rights") there were only two options: either the water was "beneficially used" or the water was "wasted."[75] Under either scenario, the

[72] Brief for Defendant-Intervenor (BP America) at 10, Vance v. Simpson, No. 2005CW063 (Colo. Dist. Ct., Water Div. 7, July 2, 2007).
[73] The court seemed to struggle with this concept, citing the dictionary definition of "application" without further elaboration. Vance v. Simpson, No. 2005CW063 at 16 (Colo. Dist. Ct., Water Div. 7, July 2, 2007).
[74] Brief for Plaintiff at 2, Vance v. Simpson, No. 2005CW063 (Colo. Dist. Ct., Water Div. 7, July 2, 2007).
[75] *Id.* at 4.

State Engineer's Office (SEO) had a non-discretionary duty to regulate the diversion.[76] The relevant statute states that

> Each division engineer shall order the total or partial discontinuance of any diversion in his division to the extent that the *water being diverted is not necessary for application to a beneficial use*; and he shall also order the total or partial discontinuance of any diversion in his division to the extent that the water being diverted is required by persons entitled to use water under water rights having senior priorities, but no such discontinuance shall be ordered unless the diversion is causing or will cause material injury to such water rights having senior priorities.[77]

BP argued that classifying any movement of water as either beneficial use or waste would, in some cases, forbid dewatering construction sites, allowing trees to grow on a riverbank, or plowing snow.[78] Simply stated, there are some water displacements outside the purview of the SEO that were neither beneficial use nor waste.[79] While this is certainly true, it may be more due to SEO custom rather than statutory reasoning; each of the instances cited except for the natural tree growth would qualify as a diversion and potentially implicate the waste statute. In any case, because the court found CBM dewatering to be a beneficial use there was no need to rule on the issue of waste.

As later noted in this paper, viewing CBM dewatering as an appropriation rather than a byproduct waste is both legally and economically significant, involving major shifts in costs and regulatory structure.

E. Produced Water Disposal and Use

[76] *Id.*
[77] Colo. Rev. Stat. § 37-92-502(2)(a) (2007) (emphasis added).
[78] Brief for Defendant-Intervenor (BP America) at 22-23, Vance v. Simpson, No. 2005CW063 (Colo. Dist. Ct., Water Div. 7, July 2, 2007).
[79] *Id.*

After water is brought to the surface, CBM extractors either discharge the water on the surface or inject it deep underground, depending on basin geology, demand for water, and water quality. Approximately 60% of all oil and gas industry produced water is managed via deep injection disposal wells.[80]

CBM produced water is also disposed of on the surface. Typical disposal methods include placement in lined pits (to allow for evaporation) unlined pits (to allow the water to seep into shallow aquifers), dust suppression, air spraying (which allows for evaporation), or traditional beneficial uses such as irrigation, stock watering, wildlife habitat enhancement, and even use as municipal drinking water, In some basins, landowners have come to depend on the produced water for farming and ranching.[81]

Opportunity for beneficial use varies across basins and depends on the quality of the produced water, the demand for water (which may be related to the aridity of the basin); and the type of use and cost of treatment, transportation, and permitting. Table 2 outlines the potential beneficial uses for CBM water in Colorado's San Juan Basin. Produced water in the basin varies from 410 to 170,000 mg/L TDS, with a small quantity of high quality water near the Fruitland outcrop and much lower values throughout the basin. The basin is arid (average annual precipitation is between 12 and 28 inches)[82] but there are a number of rivers that meet much of the demand for the few, mostly rural consumers. As the table shows, opportunity for beneficial use is low in most parts of the basin.

[80] *Id.* at 27
[81] *Id.* at 5
[82] *See* S.S. Papadopulos & Colo. Geological Survey, *Coalbed Methane Stream Depletion Assessment Study – Northern San Juan Basin, Colorado* (Feb. 2006), *available at* http://water.state.co.us/pubs/pdf/CMSDA_Study.pdf.

Consequently, nearly 99% of produced water in the San Juan Basin is injected into deep formations.[83] Where demand and water quality are higher, as in the Raton basin of Colorado, opportunities for beneficial use increase (in the Raton Basin 70% of water is discharged to the surface and some of this water is used beneficially).[84] In areas such as the Powder River Basin where water quality is high but demand is low, 99.9% of the produced water is discharged on the surface, with little actually put to beneficial use.[85]

Table 2: Requirements and Potential for Beneficial Use of CBM Produced Water in the San Juan Basin in Colorado[86]

Beneficial Use	Approximate TDS Requirements	Area Meeting TDS Requirements1	Local Use or Via Conveyance2	Estimated Demand/Economic Viability
Domestic water Supply	<500 mg/L (up to 1000 mg/L occurs)	Only adjacent to outcrop	Local use	Low-moderate demand; locally viable in very small area
Municipal water Supply	<500 mg/L	Only adjacent to outcrop	Conveyance	Low demand and economic viability due to available surface water
Industrial use or mining	Varies, treatment often required	260 sq mi are <10,000 mg/L	Conveyance (or local if new development)	Low demand and economic viability without new industrial development/coal mining
Irrigation	<3000 mg/L	25 sq mi	Local use or minimal conveyance	Unknown, possibly medium to high demand; is locally viable
Livestock Watering	<7000 mg/L	90 sq mi	Local use or minimal conveyance	Unknown, possibly medium demand; is locally viable

[83] Gary Bryner, *Coalbed Methane Development in the Intermountain West: Primer* (2002), *available at* http://www.colorado.edu/Law/centers/nrlc/CBM_Primer.pdf.
[84] *Id.*
[85] *Id.*
[86] Modified from Papadopulos, *supra* note 82 at Table 7.1.

Fire protection and dust Suppression	NA	All of basin	Local use	Demand is seasonal, and probably low overall
Minimum stream flow	Est. <600 mg/L[87]	Only adjacent to outcrop	Local use or Conveyance	Low, not an issue in the basin
Augmentation	Based on use and point of discharge	Unknown, depends on use	Local use or Conveyance	Currently low; potentially high if CBM water production is regulated.
Interstate compact compliance	Est. <600 mg/L[88]	Only adjacent to outcrop	Local use or Conveyance	Very low

In Gillette, Wyoming, high quality CBM water is reinjected into depleted sandy aquifers that serve the city as a source of drinking water.[89] The city's well field, located in a sandy formation at approximately 1,500 feet, had been locally depleted, so the city coordinated with a CBM operator to install aquifer recharge wells sufficient to manage all of the produced water from a small CBM producing project.[90] Some of the injection wells averaged over one million barrels per year for over three years. The city is currently studying direct use of these waters by mixing water pumped during coalbed methane gas production with regular drinking water to stretch the city's supply in the face of a projected water shortage.[91] CBM operators note that they would be willing to help the

[87] 5 Code. Colo. Regs. § 1002-34 gives the classifications and numeric standards for the San Juan and Dolores river basins, but does not include a specific TDS limit. The TDS limit above was calculated from BLM TDS numbers for local streams, and assuming that CBM water should not degrade stream quality. *See* Papadopulos, *supra* note 82.
[88] *Id.*
[89] ALL Consulting, *Feasibility Study of Expanded Coalbed Natural Gas Produced Water Management Alternatives in the Wyoming Portion of the Powder River Basin: Phase One*, (Jan. 2006) at 11 (Prepared for the U.S. Department of Energy, National Energy Technology Laboratory, Wyoming State Planning Office) *available at* http://www.fossil.energy.gov/programs/oilgas/publications/coalbed_methane/Final_WY_CBNG_FS.pdf .
[90] *Id.*
[91] Associated Press, *Gillette Studies CBM Water Use*, BILLINGS GAZETTE, Nov. 8, 2007, *available at* http://www.billingsgazette.net/articles/2007/11/08/news/wyoming/32-gillette.txt.

city out provided the cost of treatment and transportation would not exceed the current injection disposal costs.[92]

Disposal options may be placed into two categories based on their effects on future water resource availability, and potential for long term harm to the environment. The most "sustainable" practices include:

1. Reinjection into aquifers depleted or otherwise affected by CBM production;
2. Injection or percolation into depleted aquifers with water treatment as required, protecting and/or enhancing water quality;
3. Crop, livestock, municipal or industrial use with water treatment and other mitigations as required, insuring against negative impacts;
4. Surface discharges with water treatment as required, resulting in improved stream flows with adequate mitigations against negative impacts.[93]

The least sustainable practices are:

1. Evaporation of water resulting in loss of resource;
2. Injection or percolation into aquifers where water quality is deteriorated and negative hydrological impacts occur;
3. Land application that creates negative impacts on soils and water quality;
4. Direct discharges that degrade water quality and negatively impacts aquatic life, downstream users or result in loss of resource.[94]

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[92] *Id*.
[93] James R. Kuipers, *Coalbed Methane-Produced Water: Management Options for Sustainable Development*, (Aug. 19, 2004) (Presented at the CBNG Research, Monitoring, and Applications Conference) *available at* http://www.cbmclearinghouse.info/research.html.
[94] *Id.*

Deep injection may be "sustainable" or not depending on the quality of the produced water, the quality of the receiving formation, and the region's water needs. The government of British Columbia states that deep injection is the best management practice available in North America,[95] but placing high quality CBM water into deep, highly saline aquifers precludes later extraction without extensive treatment, and can hardly be viewed as a "best management practice" in the arid west.[96] Conversely, injecting low quality brine into a low quality receiving aquifer and thus avoiding surface or shallow aquifer contamination would be a "sustainable" means of disposal.

II. CURRENT REGULATION OF PRODUCED WATER

A. Agencies and Courts

Colorado's approach to water and oil and gas regulation is typical of Western States, and is overseen by three agencies. The State Engineer's Office (SEO) was tasked with overseeing the distribution of the waters of the state,[97] including ground water well permitting outside designated groundwater basins.[98] Unlike most western states, Colorado also has a water court system that works in conjunction with the SEO. The seven district water courts are responsible for adjudicating water rights, setting priority

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[95] The B.C. government does not allow any surface discharge of CBM produced water. *See* British Columbia Ministry of Energy, Mines and Petroleum Resources, *The BC Energy Plan: A Vision for Clean energy Leadership*, (Feb. 27, 2007) *available at* http://www.energyplan.gov.bc.ca/PDF/BC_Energy_Plan.pdf.

[96] In this case, deep injection would resemble evaporation in that the water would be lost to both current and future users.

[97] Colo. Rev. Stat. § 37-80-102(h) (2007).

[98] This would be regulated by the Colorado Groundwater Commission. Colo. Rev. Stat. § 37-90-137(1) (2007).

dates, and approving plans for augmentation. The Colorado Water Quality Control Division has authority for discharges of pollutants into the waters of the state (including CBM produced water). The Colorado Oil and Gas Conservation Commission (COGCC) was tasked by the legislature to broadly regulate the oil and gas industry, including all exploration and production waste from oil and gas operations.[99] Exploration and production waste includes produced water.[100] The Colorado Supreme Court has interpreted the statute creating the Commission as "an effort to clarify that the only state administrative body with regulatory authority over oil and gas activities is the Oil and Gas Conservation Commission."[101]

B. Colorado Oil and Gas Regulation

The typical permitting process for CBM operators in Colorado can be a relatively streamlined process, depending on the source and disposal method of the produced water. An applicant first contacts the COGCC for a permit to drill. After the well is constructed, an additional well permit is obtained from the COGCC. Once the well is constructed, COGCC rule 907 governs the disposal of produced water, allowing eight methods of disposal, including:

1. Injection into a Class II well (permitted by the COGCC);

[99] Colorado defines "oil and gas operations" broadly as "exploration for oil and gas, . . . the siting, drilling, deepening, recompletion, reworking, or abandonment of an oil and gas well, underground injection well, or gas storage well; production operations related to any such well . . . ; the generation, transportation, storage, treatment, or disposal of exploration and production wastes; and any construction, site preparation, or reclamation activities associated with such operations. Colo. Rev. Stat. § 34-60-103 (6.5) (2007). The COGCC has extensive power to regulate oil and gas operations. Colo. Rev. Stat. § 34-60-106(2)(a) & (9) & (17)(e) (2007).

[100] Colo. Rev. Stat. § 34-60-103 (6.5) (2007).

[101] Board of County Comm'rs v. Bowen/Edwards Assoc., 830 P.2d 1045, 1057 (Colo. 1992) (interpreting Colo. Rev. Stat. § 34-60-105(1)).

2. Discharging into state waters, in accordance with the Water Quality Control Act and the rules and regulations promulgated thereunder (permitted by the CWQCD);
3. Beneficial use in accordance with applicable state statutes and regulations governing the use and administration of water (requires a well permit from the SEO, may require Water Court adjudication, as well as a CWQCD permit);
4. May be used to provide an alternate domestic water supply to surface owners within the oil or gas field (permitted by the CWQCD).[102]

Option 1 subjects operators to regulation from a single agency and is currently the most common disposal method in Colorado. Most surface discharges require an additional permit from the CWQCD. Traditional beneficial uses are allowed through 3 and 4, although neither section provides much incentive for this type of use.[103]

All underground injection is overseen by the EPA pursuant to the Safe Drinking Water Act, which includes five classifications of wells (three of which are applicable to

[102]Other methods include evaporation/percolation in a properly permitted lined or unlined pit; disposal at permitted commercial facilities (permitted by the COGCC); disposal by road spreading on lease roads outside sensitive areas for produced waters with less than 5,000 mg/l TDS when authorized by the surface owner (subject to regulation by the COGCC); and reinjection into producing zones for enhanced recovery, drilling, and other uses in a manner consistent with existing water rights and in consideration of water quality standards and classifications established by the WQCC for waters of the state; Colo. Oil & Gas Conservation Comm'n, Rules and Regulations 907 (2007), http://www.oil-gas.state.co.us.

[103] The shortcomings of 3 are discussed below. 4 also provides little incentive for operators to offer water for domestic use. The rules deem such use "shall be to the benefit of the surface owner within the oil and gas field and may not be sold for profit or traded . . ." providing little incentive for operators to go through the CWQCD permitting process, other than to gain the good graces of locals. The rule is, however, carefully crafted to avoid regulation by the SEO. First, because the use is for the benefit of the surface owner, any beneficial use is not attributable to the operator but rather to the local surface user. Because the water is still waste from the operator's perspective, COGCC jurisdiction is retained. If the beneficial use was that of the operator, then the state engineer's office would acquire jurisdiction. Second, the rule denies any implication of material injury to surface holder's rights, stating that "[p]rovision of produced water for domestic use . . . shall not constitute an admission by the operator that the well is dewatering or impacting any existing water well."

CBM produced water).[104] Class I wells are used to inject industrial waste, class II wells are used for produced water and other fluids associated with oil and gas operations, and class V wells are used for shallow injection of non-hazardous fluids into or above aquifers.[105] Wyoming, Utah, and New Mexico have primacy over each type of well,[106] while Colorado and Montana only regulate Class II wells[107] and leave other categories to the EPA.[108]

Class I wells have the strictest requirements: the waste must be injected below any underground source of drinking water (USDW)[109] with sufficient confinement layers above the injection zone that "no reasonable possibility of contamination" exists.[110] Although there are currently no Class I wells in the Intermountain West, treatment of produced water would result in a relatively small amounts of concentrated waste. As a byproduct of industrial activity (rather than oil and gas activities) disposal by injection could only occur in a class I well.[111]

Class II injection wells are regulated by the states, and are the primary means of disposal for oil and gas activities. As an example, Colorado allows Class II injections into

[104] 42 U.S.C. § 300f et seq.
[105] U.S. Environmental Protection Agency, *Classes of Wells*, http://www.epa.gov/safewater/uic/wells.html.
[106] U.S. Environmental Protection Agency , *UIC Program Primacy*, http://www.epa.gov/safewater/uic/primacy.html.
[107] Montana has expressed interest in regulating Class V wells but no application has yet been submitted. Mont. Dep't of Nat. Res. Conservation, *Montana Board of Oil & Gas Conservation*, http://bogc.dnrc.state.mt.us/BoardSummaries.asp
[108] See EPA, *supra* note 106.
[109] Underground Source of Drinking Water (USDW) means an aquifer or its portion:
(a) (1) Which supplies any public water system; or
(2) Which contains sufficient quantity of ground water to supply a public water system; and
(i) Currently supplies drinking water for human consumption; or
(ii) Contains fewer than 10,000 mg/l total dissolved solids; and
(b) Which is not an exempted aquifer. 40 Code Fed. Reg. § 144.3.
[110] See EPA, *supra* note 33.
[111] See ALL 2003, *supra* note 48.

any formation that is not a USDW,[112] unless the aquifer is exempted.[113] The majority of class II injection wells serve the dual purposes of disposal and recovery of additional minerals (enhanced oil recovery; or pressure maintenance through water flooding to recover additional natural gas in conventional reserves).[114]

C. Colorado Groundwater Regulation

In Colorado, the Colorado Ground Water Commission has primary authority over the administration of "designated" ground water.[115] However, most of the state's groundwater lies outside designated basins and is administered by the State Engineer's Office (SEO), including "tributary" groundwater (hydrologically connected to a natural stream system either by surface or underground flows) and "nontributary" ground water; defined as "ground water . . . the withdrawal of which will not, within one hundred years, deplete the flow of a natural stream . . . at an annual rate greater than one-tenth of

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[112] 40 CFR § 144.3.

[113] A water-bearing formation may be exempted if:

> (1) It does not currently serve as a source of drinking water; and either subparagraph (2) or (3) below apply:
> (2) It cannot now and will not in the future serve as a source of drinking water because:
> A. It is . . . or can be demonstrated . . . to contain minerals or hydrocarbons that … are expected to be commercially producible; or
> B. It is situated at a depth or location which makes recovery of water for drinking water purposes economically or technologically impractical; or
> C. It is so contaminated that it would be economically or technologically impractical to render the water fit for human consumption;
> (3) The total dissolved solids content of the ground water is more than three thousand (3,000) and less than ten thousand (10,000) milligrams per liter and it is not reasonably expected to supply a public water system.

Colo. Oil & Gas Conservation Comm'n, Rules and Regulations 325 (2007), http://www.oil-gas.state.co.us.

[114] *See* ALL 2006, *supra* note 8 at 4.

[115] Colo. Rev. Stat. § 37-90-107 – 109 (2007) Because these types of water lie in defined basins with little overlap with CBM reserves, they are outside the scope of this paper..

one percent of the annual rate of withdrawal."[116] Both types are administered using a permit system.

Tributary ground water is integrated with surface waters and managed through the doctrine of prior appropriation as outlined in the Colorado Constitution.[117] All groundwater is presumed to be tributary to a stream unless proven otherwise.[118] New water wells require a permit from the SEO,[119] who must determine that there is unappropriated water available for withdrawal and that the vested water rights of others will not be materially injured by the proposed well.[120] Both must be substantiated by hydrological and geological facts.[121] Tributary well permits are more difficult to obtain than surface diversions; if a surface body is fully appropriated *at any time during the year* the tributary ground water is "fully appropriated" and any withdrawal causes material injury to senior appropriators by definition.[122] After a permit is granted, a diverter may then petition the water court for a priority date and a water right in the tributary groundwater. Permits may be issued in fully appropriated basins pursuant to an augmentation plan.[123] These plans are approved by a water court, and detail how, when, and where an appropriator will increase the water in a stream system to prevent injury to senior appropriators. Although not always required, most augmentation plans detail how

[116] Colo. Rev. Stat. § 37-90-103(10.5) (2007).
[117] Colo. Rev. Stat. § 37-90-101 – 602 (2007); Colo. Const. Art. XVI, §6.
[118] *See* Platte Valley Irrigation Co. v. Buckers Irrigation, Milling, & Improvement Co., 53 P. 334 (Colo. 1898).
[119] Colo. Rev. Stat. § 37-90-137(1) (2007).
[120] Colo. Rev. Stat. § 37-90-137(2)(b)(I) (2007).
[121] *Id.*
[122] *See* Hall v. Kuiper, 510 P.2d 329 (Colo. 1973).
[123] A plan for augmentation is "a detailed program . . . to increase the supply of water available for beneficial use . . . by development of new or alternate means or points of diversion, by pooling water resources, by water exchange projects, by providing substitute supplies of water, by the development of new sources, or by any other appropriate means." Colo. Rev. Stat. § 37-90-103(9) (2007).

"new" water will be added to the stream system, including transfer of other senior rights or the use of non-tributary groundwater to augment the surface stream.[124]

Nontributary groundwater is not part of the "waters of the state" and the Colorado legislature has plenary power over its administration and distribution.[125] The legislature has authorized "mining" of the resource – well permits are required from the SEO, but the rate of withdrawal is based on overlying land ownership and an aquifer life of 100 years, not the rate of aquifer recharge.[126] Although the SEO must determine that pumping will not cause material injury to other vested nontributary appropriators, "the reduction of either hydrostatic pressure or water level in the aquifer" is not deemed material injury.[127]

Prior to the *Vance* ruling, CBM and oil and gas producers sidestepped most water well permitting requirements. "Wells" subject to permitting are "structure[s] or device[s] used for the purpose or with the effect of obtaining ground water *for beneficial use* . . . ."[128] Because production of water during oil and gas operations was not assumed to be a beneficial use, there was no requirement for a permit. If the producers subsequently applied the produced water to beneficial use, the general rules applied for tributary groundwater, but nontributary groundwater followed Colo. Rev. Stat. § 37-90-137(7), which states that

> In the case of dewatering of geologic formations by removing nontributary ground water to facilitate or permit mining of minerals:
> (a) No well permit shall be required unless the nontributary ground water being removed will be *beneficially used*; and
> (b) In the issuance of any well permit pursuant to this subsection (7), . . . in considering whether the permit shall issue, the requirement that the state

[124] *See* Hall v. Kuiper, 550 P.2d at 303.
[125] *See* Kuiper v. Lundvall, 575 P.2d 372 (Colo. 1978).
[126] Colo. Rev. Stat. § 37-90-137(4) (2007).
[127] *Id.*
[128] Colo. Rev. Stat. § 37-90-103(21)(a) (2007).

> engineer find that there is unappropriated water available for withdrawal . . . shall not apply. The state engineer shall allow the rate of withdrawal stated by the applicant to be *necessary to dewater the mine*; except that, if the state engineer finds that the proposed dewatering will cause material injury to the vested water rights of others, the applicant may propose, and the permit shall contain, terms and conditions which will prevent such injury. The reduction of hydrostatic pressure level or water level alone does not constitute material injury.

Simply stated, a producer could obtain a well permit to use nontributary water from CBM operations, even in an over-appropriated basin, without a plan for augmentation, and may remove any amount of water necessary to dewater the mine.

D. Agency Overlap Problems

The *Vance* case outlined earlier highlights conflicts between COGCC and SEO jurisdiction. In *Vance*, the ranchers contended that the Water Right Determination and Administration Act of 1969 and the Colorado Ground Water Management Act required the State Engineer to regulate CBM water diversions, including issuing water well permits for CBM wells and requiring augmentation plans when tributary ground water was diverted in over-appropriated groundwater basins.

The case centered on who was in responsible charge of the water pumped from coal seams during CBM extraction. Did the legislature vest sole authority in the COGCC to regulate produced water as a waste generated in gas operations, or was the removal of water an appropriation of the tributary waters of the state that required oversight by the State Engineer?

The water court began by examining the statutory authority of the COGCC and the SEO, finding that COGCC had exclusive authority over oil and gas conservation and operations, including the disposal of exploration and production waste such as produced water.[129] The agency did not, however, have the authority to regulate the *diversion* of water except pursuant to COGCC Rule 209 ("Protection of Coal Seams and Water-bearing Formations") which provides that "[i]n the conduct of oil and gas operations each owner shall exercise due care in the protection of coal seams and water-bearing formations as required by the applicable statutes of the State of Colorado."[130] The court reasoned that the "applicable statutes of the State of Colorado" included the Water Right Determination and Administration Act of 1969 and the Colorado Ground Water Management Act, which state that the SEO has a broad, non-discretionary duty to "administer, distribute, and regulate the waters of the state in accordance with the constitution of the state of Colorado" and that "no other official, board, commission, department, or agency . . . has jurisdiction and authority with respect to said administration, distribution, and regulation.[131] Those acts also vested the SEO with the duty to issue permits for water wells constructed outside designated groundwater basins,[132] and the court found that CBM wells fell within the definition of "water well."[133] Although the "purpose" of the wells was to produce gas, the "effect" was water production for beneficial use.[134] The court noted that because the legislature had provided permit exceptions in the case of mine dewatering of non-tributary ground water ("[n]o

[129] *See* Colo. Rev. Stat. § 34-60-105 (2007).
[130] Colo. Oil & Gas Conservation Comm'n, Rules and Regulations 209 (2007), http://www.oil-gas.state.co.us.
[131] Colo. Rev. Stat. § 37-92-501(1) (2007).
[132] *See* Colo. Rev. Stat. § 37-90-137(1) (2007).
[133] "Water well" is defined as any structure "used for the purpose or with the effect of obtaining ground water for beneficial use from an aquifer." Colo. Rev. Stat. § 37-90-103(21)(a) (2007).
[134] *Id.*

well permit shall be required unless the nontributary ground water being removed will be beneficially used") the doctrine of *expresio unius est exclusio alterius* dictated that for tributary groundwater, a permit was required.[135] Finally, the court dismissed the SEO's agency deference argument because the SEO's position was not a permissible construction of the statute.[136]

Lingering doubt exists as to how far the *Vance* decision extends. Certainly, where CBM extractors are dewatering a tributary coal seam, water well permits must now be obtained from the State Engineer, and existing wells will likely require permitting as well.[137] In fully appropriated basins, no permit will be issued by the SEO without a plan for augmentation.[138] The real question, however, is how far the concept of "beneficial use" defined by the case extends. If dewatering to permit CBM extraction is a beneficial use, then presumably the permitting requirement of C.R.S. 37-90-137(7)(a) would be invoked ("[n]o well permit shall be required unless the nontributary ground water being removed will be beneficially used") requiring even non-tributary CBM wells to be permitted. Taken further, if *any* mine dewatering is beneficial use, then even traditional oil and gas wells (almost exclusively located in non-tributary aquifers) may require water well permits.

The costs of these outcomes could be significant. While a water well permit is only $100,[139] no permit may be issued in a fully appropriated tributary basin without first

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[135] Colo. Rev. Stat. § 37-90-137(7)(a) (2007); Vance v. Simpson, No. 2005CW063 at 18 (Colo. Dist. Ct., Water Div. 7, July 2, 2007).
[136] Vance v. Simpson, No. 2005CW063 at 18 (Colo. Dist. Ct., Water Div. 7, July 2, 2007).
(citing Chevron U.S.A. Inc. v. Natural Resources Defense Council Inc., 467 U.S. 837, 843 (1984)).
[137] Permitting existing wells would likely be accomplished in stages and over a series of years. Email from Sarah Klahn, attorney for plaintiffs in Vance v. Simpson to author (Nov. 26, 2007 11:13:00 EST) (on file with author).
[138] *See* Colo. Rev. Stat. § 37-90-137(2) (2007).
[139] *See* Colo. Rev. Stat. § 37-90-137(2) (2007)

obtaining a water right and filing a plan for augmentation with a Colorado Water Court (an additional $467 fee).[140] This process generally requires a water attorney and a water resources engineer.[141] Applications are public, and anyone may file statements in opposition.[142] In opposed cases, the Water Referee will often conduct an informal hearing, and will approve, deny, or modify the permit, and may also refer the matter to the Water Court Judge.[143] Any person may protest a referee's ruling, in which case the case would be referred to a *de novo* review by the Water Court Judge.[144] In water court proceedings, the applicant carries the burden of showing absence of injury to senior water rights holders.[145] As a matter of practice, the Water Court will allow other parties to intervene.[146] Water court rulings are subject to appeal in the Colorado Supreme Court.[147] The entire process takes from four months to two years, depending on the complexity of the case and the level of opposition.[148]

In addition to fees and attorney and engineering costs, an augmentation plan generally requires the purchase of replacement water. Although initially the plan could include use of the CBM produced water during the years the well is active, any augmentation plan would likely require the CBM producer to purchase water to cover post pumping depletions as well.[149] BP America claims total costs of the decision could top $100,000

[140] Colorado Division of Water Resources, *Guide to Colorado Well Permits, Water Rights, and Water Administration*, (Mar. 2006 & Rev. July 2007) *available at* http://water.state.co.us/pubs/wellpermitguide.pdf.
[141] *Id.*
[142] *See* Colo. Rev. Stat. § 37-92-302(1)(b) (2007).
[143] *See* VRANESH, *supra* note 88, at 148.
[144] *See* VRANESH, *supra* note 88, at 149.
[145] Colo. Rev. Stat. § 37-92-304(3) (2007).
[146] *See* VRANESH, *supra* note 88, at 150.
[147] Colo. Rev. Stat. § 13-4-102(1)(d) (2007).
[148] Colorado Division of Water Resources, *supra* note 140 at 16.
[149] *See* Wolfe interview, *supra* note 34.

per well[150] while the Plaintiff's attorney has argued that "[p]aying $200 for a well permit or the expense associated with an augmentation plan is hardly catastrophic for this industry . . . they're going to continue to get gas out of the ground. They're just going to do it in a way now that protects landowners."[151] Increased permitting requirements also raise serious doubts about the ability of the State Engineer to process all the applications.[152] Currently, the SEO plans to wait until *Vance* is decided before approaching the legislature for more funding to meet an increased workload.[153]

i. COGCC and Other State Agencies

Agency conflict can also arise when oil and gas producers attempt to put produced water to traditional beneficial use. In Colorado, the statutory mechanisms outlined above seem simple. Most produced water (especially from deep conventional oil and gas extraction) would fall into the "nontributary" category and the lenient nontributary mine dewatering permit requirements would apply. This statute seems to encourage traditional beneficial use of produced water, but has so far rarely been utilized. A few CBM producers in the Raton basin have applied for permits to restore aspen groves and other vegetation destroyed in the 2002 wildfires and for water storage for fire suppression, but each permit has been returned: current SEO modeling shows the entire Raton basin CBM field as tributary, so unless the producers can demonstrate through

[150] Kim McGuire, *Battle Looms Over Water Quality*, DEN. POST, Aug. 14, 2007, *available at* http://www.denverpost.com/headlines/ci_6616176.
[151] Kim McGuire, *Farmers Win Water Ruling on Methane Gas*, DEN. POST, July 3, 2007, *available at* http://www.denverpost.com/news/ci_6285559.
[152] Mark Jaffe, *Water Ruling May Burden Regulators, Official Says*, DEN. POST, Aug. 16, 2007, *available at* http://www.denverpost.com/ci_6633328?source=rssdp.
[153] *See* Wolfe interview, *supra* note 34.

hydrologic modeling that this water is non-tributary, augmentation plans would be required.[154] Conventional gas producers have shown interest in using produced waters from the Republican River basin, as well as near Wellington, Colorado, but no permits have yet been issued to either CBM or conventional gas producers under the non-tributary permit statute.[155]

To date in Colorado, the only well permit obtained through the non-tributary dewatering statute was for the Wellington oil field, who sought to treat water produced in oil extraction to sell to residential developers. The Wellington oil field is located north of Fort Collins near the Wyoming border. As a typical "stripper" well operation, it produces more water than oil: of the approximately 3,000 barrels of production per day, only 50 barrels are oil.[156] The field's owner was spending over $1 per barrel to inject the saline byproduct water into a Class II well when a local developer approached him with a plan to treat and sell the water.[157] The plan seemed simple: rather than inject the water 5,000 feet underground into the same formations he was retrieving oil from, treat it and use it beneficially.[158] The economics of the operation seemed promising. On the oil side, treatment would produce more oil from the water that was currently injected underground. Nineteen of the 35 wells on the site that were currently dedicated to water reinjection could be used for oil extraction, and the costs of reinjection pumping would be avoided.[159] On the water side, a treatment plant could be constructed for 1.4 million

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[154] *See* Wolfe interview, *supra* note 34.
[155] *Id.*
[156] *See* Cherry Sokoloski, *Oil, Water Mix Well in Wellington*, NORTH FORTY NEWS, March, 2006, *available at* http://www.northfortynews.com/Archive/A200603oilWaterMix.htm.
[157] Kim McGuire, *Unchartered Waters for Wellington: No Precedent for Rights to Abundant Coal-Bed Runoff*, DEN. POST, Aug. 13, 2006, *available at* http://www.denverpost.com/headlines/ci_6608638.
[158] *See* Sokoloski, *supra* note 156.
[159] *See id.*

dollars,[160] and could be operated for approximately $350 per acre/ft, putting the total cost of capacity at $2,000 to $4,000 per acre/ft.[161] Water rights in the expanding Eastern Slope of Colorado run anywhere from $20,000 to $35,000 per acre/ft.[162] The water would eventually end up as drinking water for the town of Wellington, increasing their drinking water supplies by 300 percent, and increased royalties on oil extraction would help fund local government. Economically, the project seemed feasible, but the oil field operator and the developer had no idea how complex (and expensive) permitting this type of operation would be.

Although the water involved was non-tributary traditional oil and gas byproduct water, the permitting process invokes many of the same statutes at issue in the *Vance* case. COGCC rule 907 states that "[t]o encourage and promote waste minimization" produced water "may be put to beneficial use in accordance with applicable state statutes and regulations governing the use and administration of water."[163] In this case, the "applicable state statute" is Colo. Rev. Stat. § 37-90-137(7), outlined above. In issuing this permit, the State Engineer only had to determine that (1) the water was non-tributary and (2) the withdrawal would not cause material injury to the vested water rights of others.[164] The Wellington operators would be entitled to a yearly withdrawal of "the amount necessary to dewater the mine" regardless of their land ownership, the appropriated water available, and the aquifer volume.[165] However, because the permit

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[160] *See id.*
[161] Email from Dr. David R. Stewart, President and CEO of Stewart Environmental Consultants, Inc. to author (Dec. 18, 2007 17:13:00 EST) (on file with author) [hereinafter Stewart email]. Dr. Stewart designed the treatment facility for the Wellington oilfield project and was instrumental in all stages of the process.
[162] *Id.*
[163] Colo. Oil & Gas Conservation Comm'n, Rules and Regulations 907(a)(3); 907(c)(2)(E)(2) (2007) *available at* http://www.oil-gas.state.co.us.
[164] Colo. Rev. Stat. § 37-90-137(7) (2007).
[165] *See* Colo. Rev. Stat. § 37-90-137(7) (2007).

covered only one of the 15 producing wells, only 1/15th of the water may be put to beneficial use, and the permit is conditioned on continued oil production.[166] It took two and a half years for the Wellington operators to gather the required proof, submit it, and for the State Engineer to then verify that the water was non-tributary.[167]

Once the company had a permit from the State Engineer, they sought a permit to discharge the treated water into unlined pits, which would serve as shallow aquifer recharge points. This discharge potentially implicated three different agencies: the COGCC (who regulates produced water discharges into lined pits), the Colorado Water Quality Control Division (who regulates surface discharges) and the EPA (who regulates Class V injection wells (including aquifer storage/recharge wells) in Colorado). The EPA defines a "well" as any "bored, drilled, or driven shaft whose depth is greater than the largest surface dimension; or, a dug hole whose depth is greater than the largest surface dimension . . . ."[168] because the pits were shallow and wide, an EPA permit was not required. The discharge would be into "state waters" defined as "any and all surface and subsurface waters which are contained in or flow in or through this state . . ."[169] which would presumably invoke the authority CWQCD.[170] Surprisingly, the attorney for the WQCD (after conferring with the attorney for the COGCC) took the position that the COGCC had jurisdiction over discharge into groundwater of water produced from oil and gas operations, and that the CWQCD would only have jurisdiction if the discharges were

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[166] Water Rights of Wellington Water Works LLC, No. 2005CW343, 5 (Colo. Dist. Ct., Water Div. 1, Mar. 10, 2008).
[167] *See* Sokoloski, *supra* note 156. The average review time at the State Engineer's office for each submission was less than 3 months. Email from Dave McElhaney, P.G., Colorado State Engineer's Office, to author (Mar. 3, 2008 10:43:00 EST) (on file with author).
[168] 40 C.F.R. 144.3 (2008).
[169] Colo. Rev. Stat. § 25-8-103(19) (2007).
[170] *See* Colo. Rev. Stat. § 25-8-501(1) (2007) ("No person shall discharge any pollutant into any state water from a point source without first having obtained a permit from the division for such discharge . . . .").

made into “surface waters.”[171] The CWQCD attorney reasoned that because the division was required by statute to “recognize water quality responsibilities of . . . “implementing agencies” [including] . . . the oil and gas conservation commission . . .,”[172] the CWQCD was only responsible for setting appropriate discharge standards, while actual implementation would be left to the COGCC “after consultation with the [CWQCD] through their own programs.”[173] The CWQCD was not, however, entitled to delegate any permitting responsibility for “the issuance and enforcement of permits authorizing point source discharges to *surface waters* of the state . . . ,”[174] so any disposal not utilizing a pit or a well would require a CWQCD permit. After granting a variance to allow for the pit to be unlined, the COGCC granted the discharge permit.[175] The total cost for permitting, engineering, and hydrological studies was over $1,000,000, but because the state agencies have now clarified their respective responsibilities, future projects should be on the order of $500,000.[176]

The treatment plant went online in mid April 2006,[177] but the final hurdle for the Wellington group was overcome in the Division One Water Court on January 15, 2008.[178] Nine statements of objection were originally filed, most by landowners that overlay the aquifer Wellington pumps from (as well as from the State Engineer), but only

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[171] In the Matter of a Request to Allow the Discharge of Treated Produced Water from the Wellington Muddy 108 Unit into the Box Elder Creek Alluvium, Larimer County, Colorado, No. 1-108 (Colo. Oil & Gas Conservation Comm’n Aug. 15, 2005).
[172] Colo. Rev. Stat. § 25-8-202(7) (2007).
[173] Colo. Rev. Stat. § 25-8-202(7)(a) (2007).
[174] Colo. Rev. Stat. § 25-8-202(7)(b)(I) (2007) (emphasis added).
[175] In the Matter of a Request to Allow the Discharge of Treated Produced Water from the Wellington Muddy 108 Unit into the Box Elder Creek Alluvium, Larimer County, Colorado, No. 1-108 (Colo. Oil & Gas Conservation Comm’n Aug. 15, 2005).
[176] Stewart email *supra* note 161.
[177] *See* Cherry Sokoloski, *Water Users Contesting Wellington Oil Field Plan*, NORTH FORTY NEWS, May, 2006, *available at* http://www.northfortynews.com/Archive/A200605waterUsersContesting.htm.
[178] Stewart email *supra* note 161.

one objector (a bank trust) remained when the case went to court.[179] Wellington had originally sought a water right in the produced water under Colo. Rev. Stat. § 37-90-137(7), but later modified its request to a decreed use right based on the permit obtained by the State Engineer.[180] The court noted that when oil production ceased, Wellington could pursue a traditional water right in the same water under Colo. Rev. Stat. § 37-90-137(4) (which governs most groundwater withdrawals) but this right would be based on the amount of land they owned (or land where they had consent from the landowner).[181] Regardless of these constraints, Wellington will still control the produced water for the foreseeable future. Because they own the mineral estate, no surface landowner can withdraw any of the non-tributary water/oil mixture. If, in a few hundred years the oil component of the water becomes depleted, Wellington will only need to file a timely request with the court to gain rights under Colo. Rev. Stat. § 37-90-137(4), ensuring their right to pump this groundwater until it is fully depleted.

Perhaps the most interesting aspect of the case was the precedent it set in conflicts between overlying landowners who do not own the mineral rights and mineral producers who have permits under Colo. Rev. Stat. § 37-90-137(7). First, the court noted that until a well is constructed or a water right is adjudicated, rights in underlying non-tributary water are inchoate, and not considered a vested present interest, and not a constitutionally protected property interest.[182] The court went on to state that 137(7) permits trumped

[179] Water Rights of Wellington Water Works LLC, No. 2005CW343 (Colo. Dist. Ct., Water Div. 1, Mar. 10, 2008).
[180] *Id.* At 2.
[181] *Id.*at 6.
[182]*Id.* at 11.

inchoate rights, but failed to address how 137(7) permit withdrawals would be balanced against vested rights in non-tributary water.[183]

E. Comparative Approaches

i. Wyoming

As in Colorado, the Wyoming State Engineer's Office is also responsible for the regulation and administration of water. Each water division has its own Water Superintendent; these superintendents and the State Engineer compose the Wyoming Board of Control (BOC), which adjudicates water rights and is the nearest analogue to the Colorado water court system.[184]

Wyoming defines underground water as "any water . . . under the surface of the land or the bed of any stream, lake, reservoir, or other body of surface water . . ."[185] A subset of groundwater is "byproduct water" defined as

> water which has not been put to prior beneficial use, and which is a by-product of some non water-related economic activity and has been developed only as a result of such activity. By-product water includes, but is not limited to, water resulting from the operation of oil well separator systems or mining activities such as dewatering of mines.[186]

Interestingly, Wyoming does not consider CBM water to be "byproduct water," and in 1997 the Wyoming State Engineer also recognized that CBM

[183] *Id.* at 12.
[184] *Id.*
[185] Wyo. Stat. Ann. § 41-3-901(a)(ii) (2007).
[186] Wyo. Stat. Ann. § 41-3-903 (2007).

dewatering was a beneficial use. The position was clarified in a 2004 memo, stating that

> CBM production is different than traditional natural gas production. It is similar in that the water is not the object of production; the methane reserve is the target. CBM production is different than conventional gas production due to the necessity for production of water for the production of the gas resource, thus the production of water is a requirement of the production cycle. The intentional production, or appropriation, of ground water for the CBM production led to the designation of CBM as a *beneficial use* of water and subsequently, to a requirement for a permit to appropriate the ground water.[187]

Although the state has recognized CBM dewatering as a beneficial use, CBM operators benefit from a relatively streamlined well permitting process. The Wyoming SEO considers most CBM water to be unappropriated,[188] and permits are granted as a matter of course.[189] Although the permits are evaluated every five years and expire after gas production ceases, there is no limit to the amount of water that may be pumped.[190]

[187] Wyoming State Engineer's Office, *Guidance: CBM/Ground Water Permits* (Mar. 2004) *available at* http://seo.state.wy.us/PDF/GW_CBM%20Guidance.pdf.

[188] Patrick Tyrell, *SEO policy: State Engineer's Office Permitting Requirements for Water Produced During the Recovery of Coalbed Methane (CBNG),* (Apr. 26, 2004) (stating that "water produced in the production of coalbed methane gas has no other implied use and is considered to be un-appropriated waters of the state of Wyoming.") This streamlined permitting process has not escaped attention. In June 2007 two ranching families filed suit against the Wyoming State Engineer, alleging that "[t]he SEO categorically declares appropriation and production of ground water for CBM a 'beneficial use' of water . . . which allows junior ground water diverters to obtain permits for CBM production . . . . The SEO does not require applicants for CBM ground water or reservoirs to make a showing of no injury to vested water rights . . . . [And] [t]he majority of CBM ground water wells are never adjudicated before the [Wyoming Board of Control]." West v. Tyrrell, Civil Action No. 170-63 (1st Dist. Wyo. filed June 14, 2007).

[189] Wyo. Stat. Ann. § 41-3-931 (2007).

[190] Form U.W. 5 is used for CBM wells. The phrase "[t]he amount of appropriation shall be limited to the quantity to which permittee is entitled as determined at time of proof of application to beneficial use" is crossed out for CBM permits. Permit # 164824 at 2 (Andarko Petroleum) *available at* http://seo.state.wy.us/scans/GW_Docs/GW_Permits/Permits/D_P00164824_UW_002.pdf. Additionally, the CBM "additional conditions and limitations" section states that "[n]o Proof of Appropriation and Beneficial Use of Ground Water form is required under this permit for the production of water associated with the production of natural gas. Beneficial use of ground water for the production of natural gas will be assumed as of the well completion date. In the event that water from this well is beneficially utilized for some purpose after natural gas production has ceased, the permittee is required to submit the appropriate

Recently, Wyoming has shown willingness to crack down on CBM producers whose wells are producing little or no gas.[191] Current Colorado statutes would presumably prohibit this kind of waste as well,[192] although Colorado has no official guidelines like the Wyoming threshold water-to-gas ratio of 10 barrels per Mcf.[193]

ii. New Mexico

Although New Mexico law classifies water used in the "prospecting, mining or drilling operations designed to discover or develop the natural resources of the state" as a beneficial use of the water, the state has never recognized CBM dewatering as a beneficial use.[194] All appropriations of groundwater in "declared basins" require a permit from the State Engineer,[195] but declared basins do not include any aquifer "the top of which . . . is at a depth of twenty-five hundred feet or more below the ground surface . . . and which aquifer contains water containing not less than one thousand parts per million of dissolved solids."[196] This provision excludes most New Mexico CBM operations. In 2004 the legislature further moved to define how CBM dewatering "fit" into the state's water regulation rules, finding that

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form(s) and documentation, as determined by the State Engineer, pertinent to the remaining use(s) specified under this permit. Such form(s) and documentation shall be submitted to the State Engineer within two (2) years of the cessation of natural gas production." Permit # 164824 at 3 (Andarko Petroleum) *available at* http://seo.state.wy.us/scans/GW_Docs/GW_Permits/Permits/D_P00164824_UW_003.pdf.

[191] Wyoming State Engineer's Office, *Press Release*, (Dec. 18, 2007) *available at* http://seo.state.wy.us/Press/2007/121807.aspx.

[192] The Colorado Groundwater Management Act does defines "waste" as "causing, suffering, or permitting any well to discharge water unnecessarily above or below the surface of the ground." C.olo. Rev. Stat. 37-90-103(20) (2007). Dewatering without methane extraction would presumably not be "necessary," but no limit has yet been set on how much methane would need to be extracted to avoid statutory "waste."

[193] This ratio must be achieved in the first two to three years of water production. *See* Wyoming State Engineer's Office, *supra* note 191.

[194] N.M. Stat. Ann. § 72-12-1 (LexisNexis 2007).

[195] N.M. Stat. Ann. § 72-12-20 (LexisNexis 2007).

[196] N.M. Stat. Ann. § 72-12-25 (LexisNexis 2007).

> (1) the production of minerals in New Mexico at times requires the diversion and associated treatment of large quantities of water;
> (2) the diversion of water to permit mineral production is affected with a public interest;
> (3) existing principles of prior appropriation, beneficial use and impairment of water rights, when applied to the diversion of water to permit mineral production, may cause severe economic hardship and impact to persons engaged in mineral production, to the owners of water rights and to the citizens of New Mexico;
> (4) such hardship and impact are threats to the public health, safety and welfare and can be averted or minimized . . .

The act explicitly states that mine dewatering is not “an appropriation of water nor waste . . .” and that “[n]o water rights may be established solely by mine dewatering.[197] However, any mine dewatering in a designated basin *does* require a permit from the state engineer, who will examine existing water rights and determine if the dewatering would impair these rights.[198] If no impairment exists, the permit shall issue, but if there would be some impairment the State Engineer would notify the applicant, who may propose a plan for replacement.[199] Notably, if replacement water is required, the operator may propose that the produced water be the source.[200]

Another bill in 2004 created a loophole that allows produced water to be used beneficially without obtaining a water right from the State Engineer. The provision states that “[n]o permit shall be required from the state engineer for the disposition of produced water in accordance with rules promulgated pursuant to section 70-2-12 NMSA by the Oil Conservation Division [OCD] of the energy minerals and natural resources

[197] N.M. Stat. Ann. § 72-12A-5(A) (LexisNexis 2007).
[198] N.M. Stat. Ann. § 72-12A-7 (LexisNexis 2007).
[199] *Id.*
[200] *Id.*

department."[201] The referenced statute is broad, allowing the OCD to "regulate the disposition of [produced] water . . . to direct surface or subsurface disposal . . . in a manner that will afford reasonable protection against contamination of fresh water supplies . . . ."[202] OCD disposition rules are also broad, allowing disposal by injection wells, pits, or reuse, as well as "use in accordance with a division-issued use permit or other division authorization."[203]

In sum, New Mexico allows dewatering of brackish water below 2,500 feet without regulation from the State Engineer. If the dewatering takes place above 2,500 feet, or is high quality water, a permit is required from the State Engineer, who will determine if the dewatering would cause any impairment to existing rights. In any case, dewatering may continue with a replacement plan, of which the produced water may be a source. With NMOCD approval, CBM operators may use the water for traditional beneficial uses without any further oversight from the SEO. Presumably the CBM producers could apply for a water right in the produced waters, but this additional step is not required in order to beneficially use produced water.

III. A COST BENEFIT ANALYSIS

A. The Costs of CBM Produced Water Regulation

New regulations on CBM produced water have three economic effects: (1) immediate, direct, quantifiable effects; (2) long term, indirect, or non-quantifiable effects;

[201] N.M. Stat. Ann. § 70-2-12.1 (LexisNexis 2007).
[202] N.M. Stat. Ann. § 70-2-12(15) (LexisNexis 2007).
[203] N.M. Admin. Code § 19.15.2.52(B)(2) (2007).

and (3) secondary effects (such as behavior changes of stakeholders). For example, a statute mandating that produced water be treated to a low TDS level would have the direct effect of increasing production costs for CBM producers, possibly leading to lower production and lower federal royalty and state severance collection. Production decreases may cause the indirect effect of layoffs and depression of local economies. However, treatment mandates may also cause greater demand for treatment facilities and technology, with a secondary effect of lowering the cost of treatment industry-wide.

Direct effects of CBM water regulation include increased production costs and corresponding reductions in economically recoverable resources. If these costs result in decreased production, tax revenues and royalties also decline. These types of direct economic impacts are generally quite easy to quantify. Table 3 lists the advantages and disadvantages of different water management options as well as their associated costs.[204]

Table 3. Summary of Common Water Management Options

Option	Advantages	Disadvantages	Cost
Direct Surface Discharge	Increased stream flows Increased riparian habitat Available for supplemental irrigation Available for livestock and wildlife	Riparian erosion Deposition of salt Adverse effects on cropland Potential to alter natural surface water Impact to native aquatic species	Capital: $1,400 per well Operation and Maintenance (O&M): $0.02/bbl
Surface Impoundments (lined or unlined pits)	Available for stock use Shallow aquifer recharge Increased wildlife habitat Recreation Fisheries	Mobilization of salts Potential for degradation of shallow aquifer Evaporation increases salinity Water source is temporary	Capital: $10,000-$20,000 per impoundment in the Powder River Basin O&M: $0.06/bbl
Shallow Injection (Class V)	Aquifer recharge Aquifer storage No environmental	Water not immediately available for additional beneficial	Capital: $6,500-$15,000 (reworking of existing well); $100,000 new

[204] Modified from Wyoming Governor's Report, *supra* note 26 and ALL 2006, *supra* note 8 at 27.

	impacts from surface discharge	surface use Some injection zones have limited capacity	well O&M: $0.05-$0.40/bbl
Deep Injection (Class II)	Avoids environmental impacts for surface discharge Provides a source of water for enhanced oil/gas recovery projects	If not properly completed water could migrate and impact higher quality aquifers Requires additional surface disturbance for well site, gathering systems, and surface storage	Capital: $35,000-$63,000 (reworking of existing well) $3,000,000-$4,000,000 for new well (drilling and completion) O&M: $0.50-$1.75/bbl
Reverse Osmosis Treatment	High quality water Produced	Generation of concentrated brine (2-4% of Influent) Energy- intensive process	Capital: $450,000-$1,025,000 for treatment plant with commercial (off-site) disposal of brine; $750,000-$1,270,000 for treatment and onsite brine injection O&M: $0.19-$0.73/bbl with commercial disposal; $0.26-$0.34/bbl with brine injection
Treatment (Ion Exchange)	Removal of cations and bicarbonate Greater than 98% water recovery	Generation of acidic brine (1-2% of influent) Does not remove anions	O&M: $0.25/bbl-$2.00/bbl (includes capital and permitting costs)

Industry participants often have a good picture of disposal costs, production costs, and expected income based on forecast market prices and risks. For example, when Montana proposed Powder River Basin-wide rules that would allow for zero surface discharge of produced water unless the water was treated to contain less than 170 ppm TDS,[205] industry-sponsored experts predicted that

[205] Proposed Rule II is a "zero discharge" requirement applicable to the Montana Pollutant Discharge Elimination System (MPDES) program. This proposed new rule requires that "(1) except as provided in [New Rules III through IX], point-sources of methane wastewater shall achieve zero discharge of pollutants, which represents the minimum technology-based requirement. Zero discharge shall be accomplished by reinjection of methane wastewater into suitable geologic formations in the project area in compliance with all other applicable federal and state laws and regulations." The rule does provide a means to obtain an exemption from the injection requirement, but timeframes to obtain an exemption may be greater than 12 months as the rule is currently proposed. Proposed Rule VIII establishes "treatment-based effluent limitations" for CBNG produced water. The proposed rule requires that "If the department grants a waiver from the zero discharge requirement for all or a portion of the wastewater pursuant to [New Rules II and III], the amount of wastewater that obtains the waiver shall achieve the following minimum

> Implementation of the new rules would significantly impede and/or likely cause the cessation of current and future CBNG development in the Wyoming portion of the [Powder River Basin]. Implementing a zero discharge requirement likely would reduce production by 25 percent immediately upon enforcement of the rule. Within one year of implementation, production rates are expected to decrease by as much as 50 percent. Within five years, production likely would decline by 90 percent, eliminating much (if not all) of the potential production in the region."[206]

A 2006 study in Wyoming prepared for the Department of Energy was slightly less alarmist, but echoed studies in other states in finding that

> The choice of the water disposal and management option directly impacts the volume of economically producible CBM from the Powder River Basin . . . . Progressively more stringent water disposal and management options also reduce federal, state and local tax receipts that would accrue from royalty and production tax payments on CBM production.[207]

However, the study recognized that these negative economic effects did not vary linearly with gas price; "[a]t lower wellhead natural gas prices, the impact of progressively more stringent water disposal options is more severe; at higher wellhead natural gas prices, the impact is less severe as progressively more costly water management practices can be accommodated at the economic threshold used in the model."[208] As the figure below shows, stringent water disposal regulation (i.e. treatment

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technology-based effluent limitations at the end of the pipe prior to discharge: . . . total dissolved solids average concentration of 170 mg/L . . . ." *See* ALL 2006 *supra* note **Error! Bookmark not defined.** at 32-33.

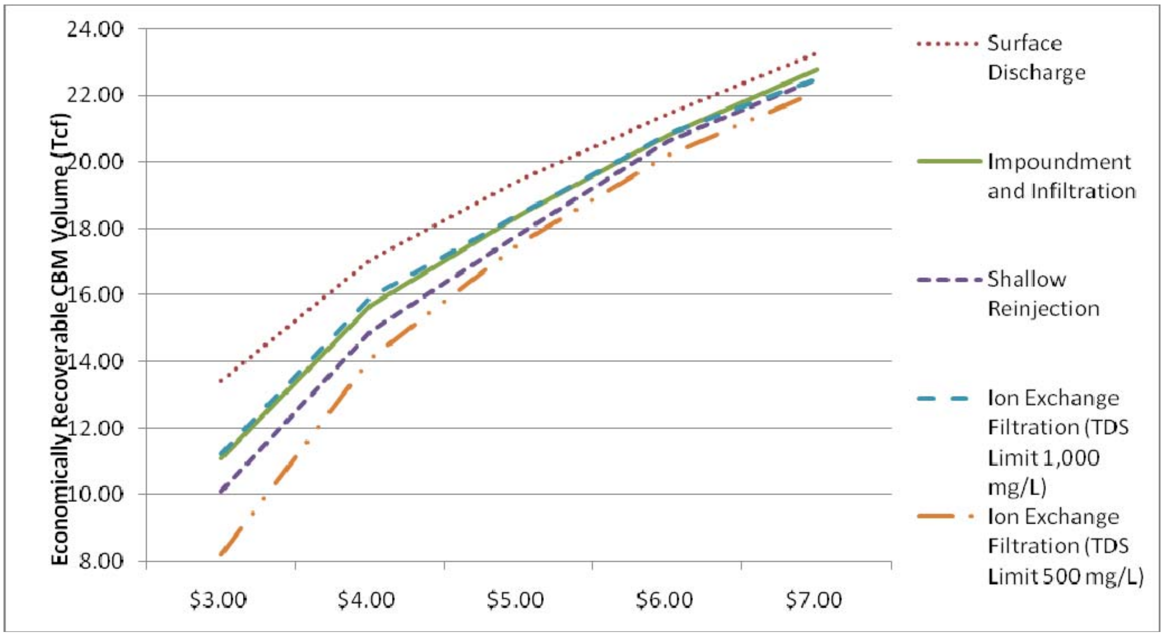
[206] *Id.*

[207] Gregory C. Bank & Vello A. Kuuskraa, *The Economics of Powder River Basin Coalbed Methane Development* (Jan. 2006) (Prepared for the U.S. Department of Energy) *available at* http://www.netl.doe.gov/technologies/coalpower/ewr/pubs/netl%20Cost%20of%20Produced%20Water%20Treatment%200106.pdf.

[208] *Id.*

vs. surface discharge) lowers the amount of gas that can be economically recovered, but as gas prices rise, nearly the same amount of gas is economically recoverable regardless of the water disposal option.[209]

Figure 3. Estimated Relationship of Wellhead Natural Gas Prices to Economically Recoverable CBM Volumes from the Powder River Basin, Assuming a 15% Cost of Funds Rate[210]



In 2001, the Montana Coalbed Natural Gas Alliance presented a study of how CBM production would affect the area from 2000 through 2022. The report concluded that the economic benefits to Montana would include $253.5 million in royalties to Montana schools; $426 million in royalties to the Montana state general fund, $982 million in production tax paid to Montana for schools, state and local governments and

[209] Wellhead prices for October, 2007 were $6.25/Mcf. U.S. Energy Information Administration, U.S. Natural Gas Wellhead Prices, http://tonto.eia.doe.gov/dnav/ng/hist/n9190us3M.htm. The U.S. Department of Energy expects well head prices to hover between $5.42 and $6.60 between 2008 and 2030. *See supra* note 215.
[210] *Id.*

other agencies; and $1.3 billion in purchases of local goods and services.[211] The development would create up to 736 jobs worth $326 million in total wages and benefits, for a total economic benefit of $4.1 billion. While the study was comprehensive in its examination of benefits, many costs were addressed less thoroughly. Under the "environmental impacts" section, the study noted that "[t]he environmental impacts of the development are currently under evaluation. Any impacts identified would require mitigation. All costs of mitigation would be the responsibility of the producers."[212]

The Powder River Basin studies are compelling, and the negatives associated with stringent water regulation take more force when coupled with indirect negative effects on local communities. Lower resource exploitation decreases employment and tax revenues to local communities, something state politicians should be keenly aware of. However, the negative effects (both direct and indirect) may only slow, rather than preclude gas extraction. Assuming gas prices will continue to rise in the future and recovery and treatment technology will advance, the negative effect may only be temporary. As prices rise, more gas becomes economically recoverable, more wells will be drilled, more jobs are created, and more taxes collected. The net direct effects of stringent regulation on the already established CBM industry may be temporarily significant but relatively minor in the long term. In addition, U.S. industry voiced similar woes in 1970 over the passage of the Clean Air Act. Since that time, air pollutants have been significantly decreased (more

[211] Anderson ZurMuehlen and Co., P.C, *Coalbed Methane Development, Powder River Basin of Montana: Economic and Social Impacts of Proposed Development*, (June 1, 2001) (prepared for the Montana Coalbed Natural Gas Alliance) *available at* http://www.deq.state.mt.us/CoalBedMethane/pdf/cbm2.pdf.
[212] *Id.*

than 50% for the most common types) while U.S. gross domestic product has tripled, energy consumption had increased by 50%, and vehicle use had increased by 200%.[213]

Stringent regulation may, however, slow the development of new recovery technology. One of the most interesting recovery technologies to emerge in the last decade is enhanced CBM (ECBM) recovery, which uses gas injection (carbon dioxide or nitrogen) to increase methane desorption. Analysts have estimated that this process may allow for 150 Tcf additional recovery of methane in the United States and would sequester over 90 billion tons (90Gt) of carbon dioxide[214] (in 2004, global carbon dioxide emissions totaled 26.9 Gt[215]). The process requires a pattern of injection wells drilled into a producing coal seam around a central production well. The mechanics of the recovery depend on which gas is used: Carbon dioxide has a strong affinity for coal, followed by methane and then nitrogen.[216] When nitrogen is introduced into coal fractures, it displaces methane and lowers the partial pressure of the methane gas.[217] This disequilibrium "strips" methane from the coal, and the nitrogen/methane mixture can be removed and separated.[218] In carbon dioxide ECBM recovery, the carbon dioxide replaces methane due to differences in affinity for the coal surface, this produces large amounts of methane that would not otherwise be recoverable, but the process is much slower than with nitrogen.[219] Carbon dioxide sorption lowers the permeability of the coal seams, which helps to

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[213] U.S. Env. Protection Agency, Understanding the Clean Air Act, http://epa.gov/oar/caa/peg/understand.html (last visited Apr. 9, 2008).
[214] *Id.*
[215] U.S. Dep't of Energy, *International Energy Outlook 2007*, DOE/EIA-0484 (May 2007) *available at* www.eia.doe.gov/oiaf/ieo/index.html.
[216] *See* Scott Reeves, *Assessment of CO2 Sequestration and ECBM Potential of U.S. Coalbeds* DE-FC26-00NT40924, (Feb. 2003) (Prepared for the U.S. Dep't of Energy) *available at* http://www.adv-res.com/Carbon-Sequestration.asp.
[217] *Id.*
[218] *Id.*
[219] *Id.*

explain why equivalent volumes of the two gases injected into two test sites in the San Juan Basin yielded a 57% increased daily recovery for nitrogen, but only a 29% increase for carbon dioxide.[220] Although the nitrogen process is faster and more productive than the carbon dioxide process, the carbon dioxide process does not require expensive gas separators on production wells and has the added benefit of sequestering large amounts of greenhouse gases. Because ECBM technology has little effect on produced water volumes (and may even cause the produced water to contain higher concentrations of some contaminants) the technology may be stifled by stringent produced water regulation.[221]

The final piece in understanding the economics of produced water regulation has to do with time and risk. Oil and gas extraction requires significant capital costs, and treatment and disposal increase these costs. Delays in permitting can pose extensive costs to operators, and risks (both market and regulatory) are factored into decisions. In a produced waters workshop held in 2006, Dr. Jeff Cline**,** the Water Programs Manager at Anadarko Petroleum Corporation (one of the largest CBM producers in Wyoming) said:

> Oil and gas development is an investment. That's important to keep in perspective. . . . One thing that's very difficult and costly is the time required – years – to obtain the authorizations. Time is money. It can take sometimes several years to get an NPDES permit, and then the permit requirements change because of moving regulatory requirements. . . . It's a risky business for us. High price volatility for the product [also] equals high economic risk. For coalbed natural gas . . . the price has varied from $0.80 to $7.00 per thousand cubic feet during the last three years. That's high risk. You have to make all this investment up front, well before you know what price you're going to get for your product. CBNG competes

[220] *Id.*
[221] *See* Green Car Congress, *Factors and Impacts for CO2 Storage in Coalbed Seams*, (June 24, 2007) *available at* http://www.greencarcongress.com/2007/06/factors-and-imp.html.

> with other investment opportunities; therefore, if the gas risk/reward is too high, we go to other investments with lower risk/reward.[222]

Cline identifies two key concepts in his comments. First, oil and gas development exists in a highly volatile energy market, which means that administrative delays make projects more costly (which may then preclude expensive water disposal techniques). Second, regulatory uncertainty is a risk that can increases the projected cost of water treatment technology. The following table represents the relative cost and risk associated with different water disposal options from Cline's perspective:

Option	**Cost**	**Economic Risk**
Injection	Med-High	Low
Impoundment	Low-Med	Med-High
Irrigation	Med	Med
Minor Treatment/Discharge	Low	High
Major Treatment/Discharge	Very High	Low-Med

In support of the above framework, Cline offered the following explanation:

> . . . I consider minor treatment and discharge as a high economic risk [because] the regulations are changing constantly.. . . . A production engineer will first opt for injecting the coalbed natural gas produced water and conventional produced water when it's feasible. That's the lowest risk option. It's the only thing he can take advantage of. We want to support the local community and help out ranchers by giving them water, we really do. But, it must be a low-risk strategy. If the regulatory environment makes it higher risk, it does not make sense to do it. *We need to really have certainty here [in order to] manage beneficial use water as a resource, not a waste . . . .*[223]

[222] Jeff Cline, *Opportunities and Liabilities for Produced Waters*, Produced Water Workshop 36, 39 (emphasis added), *available at* http://cwrri.colostate.edu/Produced%20Waters/Proceedings%20Final%20PDF.pdf.
[223] *Id.*

Regulatory uncertainty may help to explain why producers would choose to spend $3 to 4 million dollars to drill class II injection well and spend $0.50 to $1.75 per barrel to operate the well rather than building a treatment plant for $450,000 to $1,270,000 with operation costs between $0.26 and $0.34 per barrel.[224] There is little chance that class II well requirements would change, but water quality discharge standards might, leaving producers with an obsolete treatment plant.

The above examples show the complexity in evaluating the costs of CBM produced water regulation. Direct and indirect costs are generally quantifiable and immediately apparent, but may be mitigated by rising natural gas prices. Beneficial carbon sequestration projects may also be hindered by stringent regulation. Finally, constant legislative changes, or schemes that involve long permitting timeframes have a direct economic impact on produced water disposal options, possibly precluding the most desirable choice.

B. Benefits of CBM Produced Water Regulation

The direct benefits of regulating CBM produced water include environmental protection and protection of vested water rights. Because regulation can slow or stop CBM development, groundwater resources are also preserved, which is a major benefit in the arid west.

Due to the slow recharge of many aquifers, the removal of relatively high quality water with subsequent injection into deep saline aquifers or surface dumping is a long

[224] *See* table 3, *supra*.

term consequence of CBM development. Because CBM has been commercially exploited only recently, many of the negative effects (especially those relating to aquifer depletions) are not fully understood, and many of the scientific studies on the subject remain highly controversial.[225] In 2004, economists with the Science and Environmental Health Network[226] conducted a study examining the effects of CBM development on the Powder River Basin.[227] The authors believed that the precautionary principle[228] dictated that all costs of CBM development be examined, including the value of lost water resources and state and federal subsidies to the oil and gas industry. The study concluded that CBM development would result in loss of water resources valued at $2.1 to $10.1 billion and $50 million for household well deepening due to lower groundwater tables. The study also identified the federal and state tax credits producers would receive over the next five years, including:

> Section 29 tax credit: $676 million – $1.57 billion
> Percentage depletion credit: $9.8 million – $38.1 million
> Expensing development costs: $21.4 million – $42.8 million
> Research subsidies: $11 million
> *Total federal tax breaks: $707 million – $1.65 billion*

[225] *See* Memorandum from Deborah Hathaway, & Bryan Grigsby to Dick Wolfe, *Responses to Review Comments of Coalbed Methane Stream Depletion Assessment Study, February 2006* (Sept. 27, 2006) *available at* http://www.water.state.co.us/pubs/pdf/CBMCommentsResponses.pdf

[226] SEHN (Science and Environmental Health Network) was founded in 1994 by a consortium of North American environmental organizations (including the Environmental Defense Fund, The Environmental Research Foundation, and OMB Watch) concerned about the misuse of science in ways that failed to protect the environment and human health. SEHN has been the leading proponent in the United States of the Precautionary Principle as a new basis for environmental and public health policy. About SEHN: History and Mission, http://www.sehn.org/about.html.

[227] J. Skov and N. Myers, *Easy Money, Hidden Costs, Applying Precautionary Economic Analysis to Coalbed Methane in the Powder River Basin* (June, 2004) *available at* http://www.sehn.org/tccpdf/coalbed%20methane%20costs%20Powder%20River.pdf.

[228] The authors define the principle as stated in the Wingspread Conference of 1998:
"Where an activity raises threats of harm to the environment or human health, precautionary measures should be taken even if some cause and effect relationships are not fully established scientifically." *Id.*

This study (and the precautionary principle in general) are not without their critics.[229] Roger Coupal, of the University of Wyoming Department of Agricultural and Applied Economics summarized the problems with the use of the precautionary principle in the study as follows:

> The principle, as usually applied, claims to balance risk with economic efficiency issues. This analysis does not do that . . . . in this case the risk of running out of water is not balanced with the risk associated with substantially depressed economies from the loss of gas production, the fiscal losses in providing education and public services, and the poverty that comes with it. So to be balanced . . . there should [be a] comparison of the risks associated with non-development, or poverty-based development, that would come with non-mineral development. It is important to consider that there are risks inherent in development and risks inherent in not developing.[230]

Coupal also took issue with valuing water that may be of poor quality using market prices (the study assumed local prices of $258 to $600 per acre-foot). Although these prices may be excessive, even assuming that local prices for agricultural water are on the order of $25 per acre-foot (much lower than the $65 Coupal uses for his calculations) and only 25% of the water is of high enough quality to use for agriculture, the cumulative 589,000 acre-feet of water taken out of the Powder River Basin by the end of 2007[231] would be a resource loss of over 3.68 million dollars. This number is nowhere near $10.1 billion, but still shows that the numbers involved are not trivial. Significant

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[229] Julian Morris of the International Policy Network in London was quoted as saying "[i]f someone had evaluated the risk of fire right after it was invented they may well have decided to eat their food raw." STEVEN G. GILBERT, A SMALL DOSE OF TOXICOLOGY: THE HEALTH EFFECTS OF COMMON CHEMICALS 238 (CRC Press 2004).

[230] Roger Coupal, *Review of Economic Issues Associated with CBM Development* (2005) (Technical Support Document prepared for the University of Wyoming's Ruckelshaus Institute of Environment and Natural Resources) *available at* http://www.uwyo.edu/enr/ienr/Projects/Coupal2005.pdf. *See also supra* note 23.

[231] *See* Figure 4.

increases in demand (caused by increasing populations), reductions in supply (caused by climate changes and drought), and decreased cost of treatment (caused by new technology) seem to indicate that the resource loss may well be in the billions, and in any case, should be a factor in any cost benefit analysis.

Because the effect of aquifer depletion is unknown and potentially severe, some have called for CBM producers to bear the burden of fully restoring aquifers after gas extraction. This would presumably be accomplished with "immediate reinjection" of produced waters back into coal seam aquifers. Some commentators have touted this as the solution to the produced water problem because it would eliminate the full range of discharge/disposal issues, including surface damage to drainage ecosystems, waters, and soils as well as loss of coalbed aquifer pressure, which has been linked to methane seeps, coalbed fires, and surface subsidence.[232] Essentially, "immediate reinjection" would completely solve CBM water issues, but it is both technologically and economically infeasible in most instances. First, in order to produce methane, coal seams must be dewatered. Immediate reinjection into the same coal seam would effectively preclude methane extraction, so "reinjection" into the producing coal seam would have to occur at geologically distant locations. Because most CBM coal seams exist at a saturated state, the only possible reinjection sites would be spent production wells (converted into coal seam injection wells). Although this would require extensive piping, the real problem is the timing of CBM water production. Consider the Powder River Basin, one of the first

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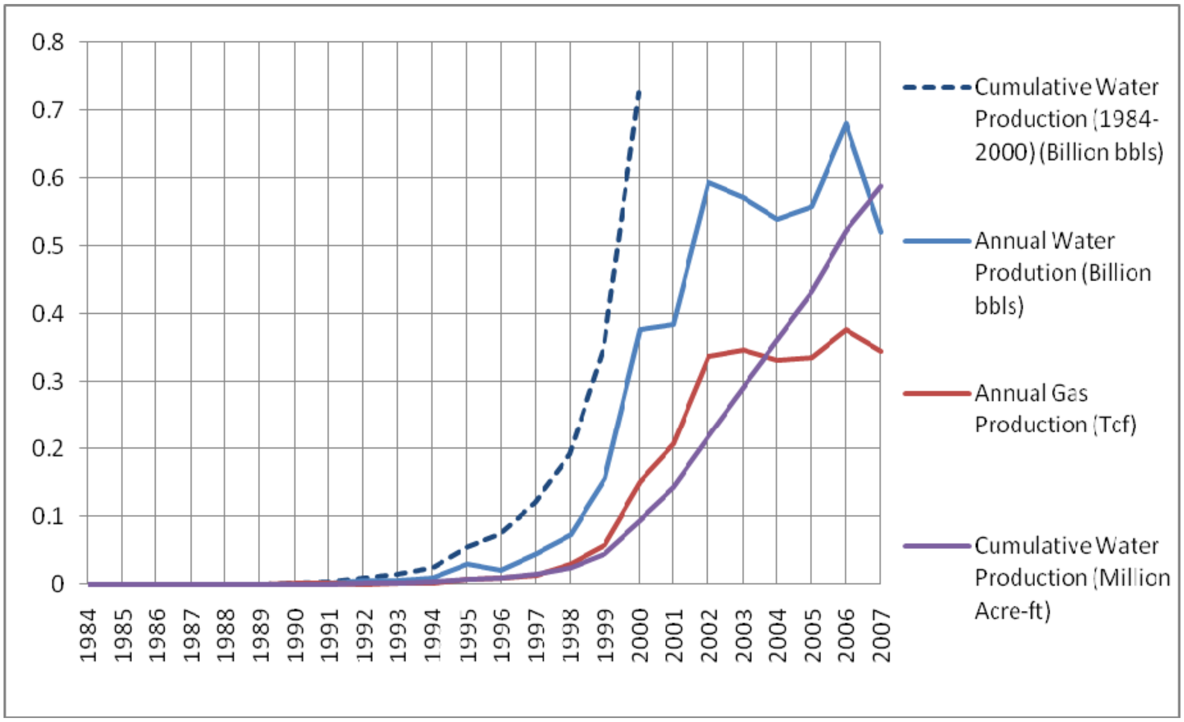
[232] Thomas J. Schneider, *Coalbed Methane Produced Water Reinjection*, (May 16, 2001) (prepared for the Northern Plains Resource Council) *available at* http://www.deq.state.mt.us/CoalBedMethane/pdf/SchneiderPaper5-16-01.PDF

commercially viable CBM fields. The first wells came online in the mid 1980s, and have a production life of 10-40 years.[233]

Figure 4: CBM Water and Gas Production in the Powder River Basin (1984-2007).[234]



As figure 4 demonstrates, assuming a best case scenario where (1) all wells stop producing and can be converted to injection wells after 10 years; (2) each injection well

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[233] Black Diamond Energy, a producer in the basin states that "[t]he life of a coalbed methane well depends on the distance from its neighboring wells (spacing of the well field), how wells communicate with each other in the subsurface, and the amount of gas available to each well. These and other factors for Wyoming low rank coals are not entirely understood and are still being studied. Most of the producers in the Powder River Coal Field expect that a coalbed methane well can produce for 10 to 12 years. As a coalbed in the original production zone is drained of its methane, the well often can be reworked to produce gas from lower coalbeds. Depending on the situation, multiple coalbeds could extend the life of a well site by 10 to 30 years." Rodney H. De Bruin, Robert M. Lyman, Richard W. Jones, & Lance W. Cook, *Coalbed Methane in Wyoming*, http://blackdiamondenergy.com/coalbed2.html#.

[234] This is a compilation of data from the Wyoming Oil and Gas Conservation Commission, which lists production statistics on its website. http://wogcc.state.wy.us/ "statistics"

can receive the same amount of water it produced; and (3) piping within the basin is possible; immediate reinjection does not become a viable solution until 2010 or later.[235] While immediate reinjection may be a partial solution at present, natural recharge, piping costs, injection issues and longer well life would preclude it from being a total solution until many years into the future. Indeed, a recent report by Sandia National Laboratories concluded that

> While some reinjection in the Montana and Wyoming Powder River Basins is feasible, the overall success is . . . less than 30% . . . . [This] would require roughly three injection wells drilled for one successful injection well with very substantial environmental disturbance in the form of surface disturbance, air emissions, noise, and vehicle traffic.[236]

The above examples all relate to economic and technological feasibility and accurate cost benefit analyses to quantify the impact of CBM extraction on the region. In some cases, however, the total public value of the CBM produced water may be more than the value of the gas itself, especially with rising water prices in the West. A study conducted by Coupal and Peck in 2003 modeled a hypothetical field in the Powder River Basin.[237] Although the study was regional and not meant to be a comprehensive statewide analysis, the authors did compare benefits (labor income over the life of the play and local tax revenues) to costs (production costs, local government costs of the extra economic activity, an estimate of overall opportunity cost of lost water in terms economic

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[235] First, draw a horizontal line from the cumulative water production line at any given date and project it forward ten years. Where the annual water production line is at or below the projected line, total immediate reinjection is theoretically feasible.

[236] Sandia National Laboratories, *Technical Review of Proposed Changes in Montana Water Quality Standards for Coalbed Natural Gas Produced Water,* SAND2006-0312 (Jan. 2006) at 19, *available at* http://www.fossil.energy.gov/programs/oilgas/publications/coalbed_methane/sandia_report.pdf.

[237] Roger Coupal & D. Peck, *Coalbed Methane Development in the Powder River Basin, Northeast Wyoming: A Regional Investment Analysis.*(2003), (Unpublished report for Johnson and Campbell Counties, Wyoming).

development potential, spillover effects on surface owners, and economic impacts on wildlife seasonal range). The analysis concluded that the public benefits in terms of labor income and tax revenue exceeded the costs of development, including the opportunity cost of water at present. Based on the same factors, however, the study estimated that the breakeven value of water was just under $700 per acre-foot. This value implies that if there is a willing buyer of the water for $700 per acre-foot or higher, then given the assumptions of the model it is worth more for the region to develop the water than the gas. Although not a perfect comparison, this model would seem to explain the Wellington oilfield project. By using a discount rate of 4-10%, and viewing the $700 as a perpetual annuity, the figure may be converted to a water right with a value from $7,000 to $21,000, which is below the range of water right prices in the Wellington area ($16,000 to $33,000 after treatment costs).[238] Indeed, the chief constraint of the Coupal study was the assumption that there would always be a willing buyer for the produced water (unlikely inside the Powder River Basin). Anecdotal evidence indicates that finding a willing buyer of water from Wyoming, especially in Colorado's front range, may not be that difficult.[239]

IV. A LEGISLATIVE SOLUTION?

The current statutes regulating produced water from oil and gas operations were mostly written in the 1950s to handle highly saline wastewater from conventional oil and

[238]Stewart email, *supra* note 161.
[239] In correspondence with Dr. Dave Stewart, the author posed the question "[a]re there any ways the laws could be improved to make this type of beneficial use more attractive to Oil and Gas companies?" to which he replied "Wyoming has a law that prevents the movement of over 1,000 af/yr out of state. This will need to be modified in the future to utilize this resource." *Id.*

gas extraction from deep formations. As the *Vance* case and the Wellington oilfield example demonstrate, applying these statutes to beneficial uses of produced water can be problematic, especially when the produced water is relatively high quality CBM water from shallower aquifers. Montana, Utah, and New Mexico treat CBM produced water similarly to traditional oil and gas waste, but Wyoming and Colorado (after *Vance*) view CBM dewatering as a beneficial use. Treating the water the same as traditional oil and gas waste (with regulation by the Oil and Gas Conservation Commission) is problematic for three reasons: (1) oil and gas conservation commissions are concerned with preventing waste of oil and gas, not the waste of water resources; (2) these commissions are not equipped to adjudicate water rights or protect the water rights of senior appropriators; and (3) classifying water that often meets drinking water quality with highly saline oilfield waste makes little sense.[240] The "beneficial use" model (with concurrent regulation by the State Engineer) (1) does not account for the fact that the massive quantities and sometimes marginal quality of the produced water could never be beneficially used in the traditional sense;[241] and (2) assuming this is a "beneficial use" means that it cannot be "waste" which may present state constitutional issues.[242]

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[240] *See* Thomas F. Darin, *Waste or Wasted? - Rethinking the Regulation of Coalbed Methane Byproduct Water in the Rocky Mountains: A Comparative Analysis of Approaches to Coalbed Methane Produced Water Quantity Legal Issues in Utah, New Mexico, Colorado, Montana and Wyoming*, 17 J. ENVTL. L. & LITIG. 281 (Fall 2002).
[241] Darin noted that "[t]he Powder River Basin has a total of 500,000 cattle and sheep. As previously discussed, one cow, or seven sheep, drinks about 14.5 gallons per day. At peak production of 51,000 wells at 9.5 gpm, this will amount to nearly 700 million gallons per day. At this rate, for this use alone to account for all of the produced water, the Powder River Basin would be overrun with over 45 million cows or 325 million sheep." *Id.* at 330.
[242] *Id.*

There is little reason to believe that a legislative solution that would avoid both sets of problems is impossible.[243] Because the specific statutory regimes for administering water and handling produced water vary between western states, examining specific states' regulatory frameworks is most appropriate. For the purpose of this paper (and for the sake of brevity) Colorado is chosen as an example state.[244] Two statutory changes and one COGCC rule change are outlined and evaluated in terms of their economic, legal, and political feasibility.

A. Colorado Statutory Changes

Just as the doctrine of prior appropriation first emerged in Colorado, a legislative solution to coalbed methane produced water will may emerge there as well. In any case, the state will pass legislation on the subject soon.[245] The *Vance* case has highlighted the

[243] Gary Bryner took Darin's ideas a step further and proposed legislative recommendations that would encourage subsequent beneficial use of CBM produced water in western states: (1) clarify instances where producers would own rights in the produced water (which would encourage producers to find beneficial uses of the water in order to market it); (2) require water management plans as part of every major CBM development to ensure that water rights are protected and that produced water is not wasted; (3) establish standards for protecting surface waters and aquifers to ensure that the quality of CBM water is equal to or better quality than that which it impacts; and (4) specify beneficial uses of CBM water, such as bolstering seasonal flows of rivers, irrigation, and aquifer recharge. Gary Bryner, *Article: Coalbed Methane Development in the Intermountain West: Producing Energy and Protecting Water*, 4 WYO. L. REV. 541, 555-57 (2004).

[244] Colorado was chosen for five reasons: (1) the *Vance* case discussed earlier presents the applicable statutes in depth; (2) the state will likely pass legislation on the subject in 2008; (3) the values and perceptions of the stakeholders are similar to each of the western states (i.e. a Colorado rancher is much like a Wyoming rancher and a Colorado CBM producer is much like a Utah CBM producer); (4) Colorado is home to multiple CBM basins that vary in depth and water quality, so a CBM solution there could serve as a model for other states with less variety; (5) Colorado is a central state, with most of its CBM basins crossing into other states (i.e. a solution to the CBM produced water from the Raton basin could be a model for New Mexico, and a solution for the Uinta could serve as a model for Wyoming and Utah).

[245] In September 2007, Sen. Jim Isgar, chairman of the Colorado Water Resources Review Committee, said, "[f]or years, we've tossed around whether we should do legislation . . . maybe the time has come." Joe Hanel, *Local Well Ruling Looms Over State: Order Could Affect Thousands*, DURANGO HERALD, September 13, 2007, *available at* http://durangoherald.com/asp-

issue, and the authority of legislators to implement a solution to the coalbed methane produced water problem is enshrined in the Colorado Constitution, which provides that "[t]he general assembly may make such regulations from time to time, as may be necessary for the proper and equitable drainage of mines."[246] The three proposals below may provide a partial solution to the problem.

i. Codify CBM Dewatering as "Beneficial Use" in Order to Force Cost Internalization and Protect Vested Rights

New Colo. Rev. Stat. § § 37-92-103(4): "Beneficial use" shall also include the reasonable diversion of groundwater to facilitate the production of coalbed methane."

In a comprehensive hydrologic study completed for the San Juan Basin, engineers determined that the estimated 3,000 acre-feet or produced water depleted surface streams by 156 acre-feet annually.[247] Depletion will not drop below 50 acre-feet annually until after 2300.[248] In the Raton Basin, the numbers are much higher: 16,000 acre-feet of annual dewatering depletes surface streams by 2,500 acre-feet annually.[249] Because the water withdrawn is classified as waste and regulated solely by the COGCC, producers do not bear the cost of these depletions (or, as mentioned above, the loss of resource

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bin/article_generation.asp?article_type=news&article_path=/news/07/news070913_3.htm; *See also* Wolfe interview, *supra* note 34.

[246] Colo. Const. Article XVI §3.

[247] *See* Papadopulos, *supra* note 82.

[248] *Id.*

[249] Dick Wolfe, Colorado State Engineer, before the Colorado Water Resources Review Committee (Sep. 12, 2007) *available at* *http://www.state.co.us/gov_dir/leg_dir/lcsstaff/2007/comsched/07WaterResources0912agd.htm.*

value).[250] The first step in any statutory reform would be forcing producers to bear the cost of depletions. Despite recent reforms to the COGCC, [251] this would best be accomplished utilizing the existing state water administration regime.[252] In *Vance*, the court invoked the jurisdiction of the SEO and the state water court system. These two bodies are uniquely competent in this area and are the only acceptable choice to determine injury to senior rights and adjudicate methods to prevent such injury.[253] Because of the uncertainties in scope of the *Vance* holding,[254] a statutory definition limiting beneficial use to CBM dewatering is required to exclude the approximately

[250] Valuing this resource is troublesome. The stream depletion study notes that "[v]ery little CBM water is used for beneficial purposes, in part because the quality of the water in the Fruitland-Pictured Cliffs aquifer in most of the Colorado portion of the San Juan Basin is too poor for most uses that involve a sizeable and relatively continuous supply of water . . . . [and] because of the relatively low demand for water for local municipal and industrial supply purposes, it is unlikely that the construction of the necessary infrastructure to treat/transfer water to points of use in the basin will be economically feasible in the near future." Based on this analysis, the water may have a low or even negative value, but what is the value of the resource in the year 2300? *See* Papadopulos, *supra* note 82.

[251]Colorado House Bill 1341 Reforms the composition of the oil and gas commission so that the oil and gas industry is no longer guaranteed a majority of seats and requires the commission to avoid and minimize damage to the environment, wildlife resources and public health. The two new members include the executive director of the Department of Natural Resources and the executive director of the Colorado Department of Public Health and Environment. The remaining seven members include: Three from the oil and gas industry (of which two shall have college degrees in petroleum geology or petroleum engineering); one local government official; one with a background in environmental or wildlife protection; one with a background in soil conservation or reclamation; and one with a background in agriculture who is also a royalty owner (read: rancher with CBM operators on his property). H.R. 1341, 66th Leg., 1st Sess. (2007). Colorado House Bill 1298 makes protecting wildlife resources part of the Oil and Gas Conservation Commission's mission and ensures that the Division of Wildlife plays a more prominent role in protecting wildlife in the face of oil and gas development. H.R. 1298, 66th Leg., 1st Sess. (2007).

[252] While single agency oversight is certainly desirable, augmentation plans are complex matters, requiring replacement water to be delivered in the correct manner, time, and location. Although recent reforms have made the COGCC more sympathetic to environmental and water concerns, water administration is simply not the role of the COGCC. The COGCC does allow for public participation in drill permitting decisions, but the Commission is not the appropriate forum for determinations of material injury to vested water rights.

[253] Forcing internalization of costs was likely one of the motivations of the court in *Vance*, where the court found CBM dewatering to be a beneficial use despite relatively clear statutory evidence that the legislature never intended this outcome, at least in non-tributary situations. Colo. Rev. Stat. § 37-90-137(7) (2007).

[254] By classifying dewatering as an "appropriation," the jurisdiction of the SEO and the water courts are invoked, but this outcome potentially subjects all oil and gas operations that produce any water to this same jurisdiction. This is hardly what the legislature had in mind when it created the COGCC, and one would have a hard time arguing that the SEO and water courts should have any oversight for traditional oil and gas operations that produce and immediately reinject brine from deep formations.

30,000 conventional oil and gas wells in the state from the SEO's jurisdiction and the appropriation system.[255]

ii. Introduce a Tributary/Non-Tributary Distinction in Order to Reduce Administrative Hurdles for Desirable Projects

New Colo. Rev. Stat. § 37-90-137(7)) would contain the following exception:

"(c) For the purposes of this subsection (7), groundwater from the following aquifers shall be presumed to be non-tributary:

(1) the top the aquifer is at a depth of twenty-five hundred feet or more below the ground surface at any location at which a well is drilled; and

(2) the aquifer contains water not less than ten thousand parts per million of dissolved solids."

In order to increase sustainable development and beneficial use, statutory exemptions for CBM operators are required. After legislatively clarifying the *Vance* holding, CBM operators withdrawing tributary water would be on equal footing with traditional appropriators. They would need well permits and plans to replace any water required to prevent material injury to senior appropriators. Conceptually, requiring this type of cost internalization makes sense when the water is like surface water (high quality, easily accessible, and fit for a variety of uses), but the logic breaks down when the produced water starts to resemble traditional oil and gas waste (low quality, difficult to extract, and unfit for most traditional uses). At some point, the produced water shifts from an asset to

[255] *See* Hanel, *supra* note 245.

a liability, which should be captured in any proposed legislation. The simplest way to accomplish this is to define instances when CBM operators may be afforded the benefit of the more generous non-tributary mine dewatering statute, which still requires the SEO determine that there be no material injury to senior appropriators, but not that augmentation plans be filed as a matter of course in fully appropriated basins.[256]

Currently, all Colorado groundwater is presumed to be tributary unless proven otherwise with hydrologic facts.[257] Unless the aquifer in question has already been proven to be non-tributary, this generally involves a costly report from a hydrologic engineer and a lengthy review by the SEO. The entire process could take years and cost hundreds of thousands of dollars, and was a major hurdle in the Wellington oilfield project. The TDS/depth limit described above would better delineate tributary and non-tributary areas – produced water with TDS higher than 10,000 mg/L[258] and well below the range of most domestic or livestock watering wells (2,500 ft)[259] would carry a presumption of being non-tributary. This TDS/depth limit would also mirror hydrologic facts: in general, non-tributary groundwater is deeper and of lower quality than tributary groundwater.

Recall that New Mexico has a provision similar to the one proposed above: aquifers below 2,500 feet that contain nonpotable water are outside the jurisdiction of the State Engineer. If appropriators can prove the water is of low quality, below 2,500 feet, and

[256] *See* Colo. Rev. Stat. § 37-90-137(7) (2007).
[257] *See* Platte Valley Irrigation Co. v. Buckers Irrigation, Milling, & Improvement Co., 53 P. 334 (Colo. 1898).
[258] 10,000 mg/L is the number typically cited for "usable" or "high" quality water. *See* ALL 2006 *supra* note **Error! Bookmark not defined.** at 5 ("High quality water with a total dissolved solids (TDS) concentration of less than 10,000 parts per million (ppm) may be employed for an assortment of beneficial uses, providing recreational opportunities, drinking water for stock and wildlife, irrigation water in arid regions, and a supplemental source for municipal water supplies.").
[259] Most domestic water wells in the San Juan Basin do not exceed 400 ft. Wolfe interview, supra note 34.

unconnected to shallower aquifers, they may mine the water without oversight. The loophole is unpopular with the New Mexico State Engineer, however, who fears that unregulated mining of these aquifers by developers and water-hungry municipalities could impact shallower aquifers in the future.[260] The provision is also unpopular with some legislators – a 2007 bill that would close the loophole failed in the Senate 11-31 after the State Oil Conservation Division stated that the bill would involve "hazards of agency conflict" and interfere with "[t]he authority of OCD to authorize injection into deep aquifers . . ."[261]

Neither of New Mexico's concerns would apply in Colorado. The SEO and the COGCC already have concurrent jurisdiction over all non-designated aquifers, so introducing a statutory definition of non-tributary dewatering would not raise jurisdictional concerns. Further, if the TDS/depth limitation was qualified as applicable only for mine dewatering, there would be no means for municipalities or developers to use the distinction to their advantage.

iii. Allow for Class V Injection

New COGCC Rule 907(c)(2) (listing disposal methods for produced water) add:[262]

[260] Staci Matlock, *Nature Holds Trump Card with Water Rights*, THE NEW MEXICAN (Sep. 15, 2007) *available at* http://www.freenewmexican.com/news/68605.html.
[261] S. 1169, 48th Leg. 1st Sess. (N.M. 2007) (Fiscal Impact Rep.) *available at* http://legis.state.nm.us/Sessions/07%20Regular/firs/SB1169.html.
[262] Colo. Oil & Gas Conservation Comm'n, Rules and Regulations 907(c)(2) (2007), http://www.oil-gas.state.co.us.

"(F) Injection into a properly permitted Class V well in accordance with the rules and regulations of the Water Quality Control Division ("WQCD") and the U.S. Environmental Protection Agency ("EPA")."

In the Wellington example, COGCC permitted percolation pits are used for aquifer recharge, but this technique may not work in all areas. Under current regulations, there is no mechanism for injecting high quality water (treated or otherwise) into high quality aquifers (which would include shallow aquifer recharge wells or even some coal seam reinjection). If a project like Wellington wished to inject treated water, or a CBM operator wanted to conduct aquifer recharge (perhaps as part of an augmentation plan) the current COGCC rules would not allow it. Not only would an operator require a Class V permit from the EPA, they would have to request a variance from the COGCC. Rather than subjecting aquifer recharge projects to the same problems Wellington faced, the COGCC should modify their rules to allow class V reinjection subject to EPA oversight.

B. Economic Feasibility

The Wellington oil example and the *Vance* case highlight the current statutory deficiencies in Colorado and many states in the intermountain west for encouraging sustainable practices and beneficial use of produced waters. At a produced waters workshop held at Colorado State University in February 2007, the owner of the Wellington oilfield doubted that he would have undertaken the project if he would have fully understood its complexities.[263] If a highly profitable and arguably desirable project that will produce marketable water for 300 to 500 years[264] is viewed with some degree of regret by its founder, why would CBM producers, whose wells may produce decreasing amounts of water for only 10 years ever undertake similar projects (or even hope to recoup their costs)? As shown in part III, the answer lies in the economics; statutory changes should decrease the costs of desirable projects for oil and gas producers, as well as increase the burden on producers who would waste high quality water. With the proper economic incentives in place, both producers and other stakeholders will come to see both gas *and* water as valuable resources, which may fuel additional conflict but will likely encourage efficient exploitation of both resources.

Let us examine how the proposed statutory scheme outlined so far would treat three different operators: (1) a conventional oil and gas operator who will reinject his produced water; (2) the Wellington oilfield owner; (3) CBM producers in statutory non-tributary areas; and (4) CBM operators in tributary areas.

Because conventional oil and gas extraction does not constitute beneficial use, the SEO would have no jurisdiction and conventional producers would continue to dispose of their produced water through reinjection or other means according to COGCC rule 907 with single agency oversight.[265] Nothing would change for these producers. If, however, conventional producers wished to treat and beneficially use the produced water, as in the Wellington field, their capital costs and start up time would be reduced significantly. They could show that their produced water was non-tributary without extensive

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[263] Brad Pomeroy stated that "[i]f I'd known then what I know now, I'd have realized we probably can't, but we're way too far down the road [now]. . . ."
[264] *See* Cherry Sokoloski, *Udall Bill could Help Oil-Rich, Water-Poor West*, NORTH FORTY NEWS, April, 2007, *available at* http://www.northfortynews.com/Archive/A200704UdallBill.htm.
[265] *See* Colo. Oil & Gas Conservation Comm'n, *supra* note 102 at 907.

hydrologic modeling, and the SEO review would be considerably shorter. Lower capital costs would allow for treatment of lower quality produced water.

For CBM producers in statutorily defined non-tributary areas, C.R.S. 37-90-137(7) would apply. A well permit would be required from the SEO, as well as a determination that dewatering would not constitute material injury to the vested rights of others. Presumably, the chances that pumping deep, saline water would cause injury is unlikely, but the inquiry would still be completed. The rate of withdrawal would be set to dewater the mine, and the water could then be disposed of according to COGCC rules or put to some beneficial use without further oversight from the SEO (state water quality rules would still apply to any surface discharge). If the operators wished to then obtain a water right in order to market the produced water, they could then apply to the water court using the SEO permit as the basis for the right. Because of basin geology, this would cover most CBM operators in Colorado, especially in the Piceance and San Juan Basins.

CBM operators in tributary areas (such as the Raton Basin and near the Fruitland outcrop of the San Juan) would be on equal footing with traditional appropriators. Unless they could meet the statutory exemption, or prove by modeling that their dewatering was in fact non-tributary, they would require a well permit from the SEO, but in fully appropriated basins (most of Colorado), this permit would not issue without a plan for augmentation. Augmentation plans may only be approved by the water court in conjunction with a water right proceeding, so in order to dewater mines the operators would need an approved augmentation plan and a water right in the produced water.

This plan would slow CBM development and would involve extensive additional permitting from the SEO. The proposed legislation would cause direct economic impact to CBM producers in Colorado, which would not be borne uniformly across basins. Production in the Raton Basin, which is almost exclusively tributary[266] (even using the proposed delineation) would be significantly impacted. Producers in the Piceance Basin (where water is of low quality and relatively deep), however, would not be significantly affected. This outcome makes sense when viewed in a cost internalization model. In the Raton Basin, 16,000 acre-feet of water is produced each year, causing 2,500 acre-feet of depletions to the stream system.[267] In the Piceance, however, 1,200 acre-feet of production resulted in less than 1 acre-foot of depletion (cumulative to date). Further, some wells, especially if completed improperly,[268] produce large amounts of water and small amounts of gas. Wyoming has moved to curtail these types of wells under their waste statutes and by introducing a upper limit water to gas ratio.[269] Under the above statute, however, an upper limit ratio would not be required, as these wells would be very costly to permit in tributary areas and may be capped voluntarily, without the SEO resorting to Colorado's waste prevention statutes.[270] The net result again would be preservation of shallow high quality water and little change in deep saline water extraction.

Indirect benefits may include increased treatment, especially in tributary areas, due to the fact that augmentation water sources would be required. Initially, this water may

[266] *See* Wolfe interview, *supra* note 34.
[267] *See* Wolfe, *supra* note 249.
[268] Improper casing or fracturing allows water from shallow aquifers to enter the wellbore, increasing water production and precluding pressure relief which in turn causes low methane yields.
[269] *See* Wyoming State Engineer's Office, *supra* note 191.
[270] *See* Colo. Rev. Stat. § 37-92-502(2)(a) (2007).

come from the dewatering itself, which would likely require some treatment. In the San Juan Basin, for instance, this would decrease the use of class II reinjection in favor of traditional beneficial uses.

In Colorado, the instances where CBM producers have a right to their produced water is relatively clear and would not require statutory changes. The statutory proposal outlined above does not clarify rights but rather "forces" rights. All CBM producers would require a water well permit and cannot cause material injury with their pumping. Tributary operators would already have gained water rights in their produced water,[271] and non-tributary operators would only need to apply to a water court to perfect their rights. Because "rights forcing" statutes place produced water inside the appropriation system (which in Colorado allows for sale and transfer) the value of produced water to the producer may increase, which in turn may increase incentives for treatment, beneficial use, and marketing of the water as an asset.[272]

C. The Political Feasibility of Coalbed Methane Produced Water Legislation

Politically, these statutory changes can be characterized as a sort of trade: CBM producers would be subject to additional regulation in exchange for more defined water rights. Because of the scarcity and high value of water rights in the arid West, this exchange has merit, but water rights are not valued the same by all stakeholders. CBM producers generally do not see water rights as a valuable resource, and it may be difficult to convince them that gaining those rights would be a fair exchange for additional water

[271] Through the augmentation plan approval.
[272] *See* Bryner, *supra* note 243, at 555-57.

management regulation.[273] Ranchers or other parties that would generally support more stringent water management legislation might react negatively to granting CBM producers water rights over produced waters, even to encourage beneficial use of these waters.[274] However, legislators could reframe the argument, offering CBM producers partial relief from a possible (and costly) *Vance* affirmation, while at the same time offering ranchers protection of their water rights statewide. Equitably, some Industry concessions make sense after the rules are changed: prior to *Vance* (or its proposed codification) CBM producers were unable to gain water rights in their produced water if they did not find subsequent beneficial uses apart from the initial dewatering. Meanwhile, most basins in Colorado had become fully appropriated, leaving producers with extremely junior water rights and increasingly expensive augmentation sources.

Constitutional concerns of the proposed legislation are minor. As mentioned earlier, the legislature has a plausible constitutional basis to pass legislation on the subject. Further, the Constitution states that "[t]he right to divert the unappropriated waters of any natural stream to beneficial uses shall never be denied."[275] Non-tributary groundwater is not part of the "natural stream" and thus outside constitutional water provisions. Landowners could argue that some waters falling under the statutory non-tributary exemption were in fact tributary, and hence part of the "natural stream."[276] Because the CBM operators would be making these waters unavailable, the landowners

[273] Ken Wonstolen, General Counsel and Senior Vice President of the Colorado Oil and Gas Association states "CBM producers . . . are not interested in obtaining water rights. They would just like to be able to surface discharge and let the stream administration system take it from there." Email from Ken Wonstolen, to author (Nov. 26, 2007 14:08:00 EST) (on file with author).
[274] Although CBM producers place little value on water rights, that perception is not shared by most western state residents. JoAnn Blehm, a resident near the Wellington oilfield was asked to sign over rights in her nontributary water in exchange for part of the Wellington's profits. "That's a joke," she said. "If I had my choice between gold and water, I'd take water." *See* Sokoloski *supra* note 177.
[275] Colo. Const. art. XVI, § 6.
[276] *Id.*

would be “denied” from diverting the waters. This argument fails for two reasons. First, if appropriation of water from a stream was “denying” later users the right to use it, the entire prior appropriation system would be unconstitutional. Second, if the denial by appropriation injured existing, vested rights, the dewatering would not be approved by the SEO (who in all cases must prevent material injury in issuing well permits).

V. CONCLUSION

Coalbed methane reserves are extensive in the intermountain west and are an important part of the United States’ energy supply. Extraction of these reserves produces great amounts of high quality water that is typically injected into deep, saline formations or dumped on the ground surface. Unlike water produced in conventional oil and gas operations, CBM water is often of high quality and may come from shallow formations. Statutes written in the 1950s to deal with conventional oil and gas production waste are inadequate to address CBM specific concerns, including the loss of water resource value and the protection of vested water rights. While each state has a different method of addressing CBM produced water, none has effectively solved the problem. In Colorado, the *Vance* case and the Wellington oilfield example have highlighted the issue, and the legislature will likely pass legislation soon. Based on a comprehensive economic analyses and a detailed examination of Colorado water law, the best solution for the state would be to declare CBM extraction a beneficial use, subjecting CBM operators to State Engineer jurisdiction and protecting existing water rights holders. At the same time, relaxed permitting standards for deep, low quality CBM dewatering would recognize that much of the produced water is a liability rather than a resource. This compromise strikes the appropriate balance between gas extraction, existing water rights, and water resource preservation. Other states in the region may then use Colorado as a model for their own regulation, increasing the opportunity for treatment and traditional beneficial use of an increasingly scarce resource in the intermountain west.