9-2008

ELR NEWS & ANALYSIS

38 ELR 10661

Fitting a Square Peg in a Round (Drill) Hole: The Evolving Legal Treatment of Coalbed Methane-Produced Water in the Intermountain West

by Colby Barrett

Editors' Summary: Groundwater resources in the intermountain West (Colorado, Montana, New Mexico, Utah, and Wyoming) continue to dwindle while populations expand. In the 1950s, states set up oil and gas conservation commissions to regulate the disposal of small amounts of highly saline water produced during conventional oil and gas extraction. Beginning in the mid-1980s, however, energy producers began extracting methane trapped in coal seams too deep to mine conventionally. Today, this coalbed methane (CBM) comprises nearly 10% of total domestic natural gas production. To extract CBM, large quantities of often high-quality water must be removed and disposed. Traditionally, that water is exempted from western states' groundwater laws requiring it to be beneficially used and subject to senior uses. But states are now recognizing this produced water should not belong in the regulatory schemes of mining waste governed solely by state oil and gas conservation commissions. In this Article, Colby Barrett examines Colorado's recent shift from the byproduct waste model to a groundwater resource model and proposes specific legislative changes that would integrate mining-produced water into western water law.

At a time when water demand in western states is rising beyond available supply, an effective regulatory framework for the large volumes of water pumped from coal seams during coalbed methane (CBM) extraction is crucial to meeting the region's current and future needs.[1] Current regulation is based on a complex and inefficient system established in the 1950s to deal with traditional oil- and gas-waste disposal.[2] Although much of the CBM-produced water is near drinking water standards, most is wasted through surface dumping or pumped deep underground into high-saline aquifers. This Article examines the West's legal history and developing trends in the industry. Focusing on Colorado, the Article will examine the trend from produced water regulated by oil and gas commissions (as in Montana, New Mexico, and Utah) to concurrent regulation by the State Engineer (as in Wyoming) after the *Vance v. Simpson*[3] decision. This Article posits that recent legal, scientific, and technological developments may 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.

Colby Barrett is a 2008 graduate of Yale Law School. He thanks Prof. Thomas Merrill for his assistance and encouragement, as well as Sen. Greg Brophy, Thomas F. Darin, and Dave Stewart for their comments and suggestions. The author would like to extend special thanks to Dick Wolfe and Dave McElhaney at the Colorado State Engineer's Office and to Sarah Klahn and Ken Wonstolen for the diverse perspectives they provided.

1. *See* More Water, More Energy, and Less Waste Act of 2007, S. 1116, 110th Cong. §1 (2007) (similar bill passed by the U.S. House of Representatives, H.R. 902, 110th Cong. (2007)):

> [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 . . . .

2. Denver Post Editorial Bd., *Rocky Mountain States Drop Ball on Water Rules*, Denv. Post, Aug. 17, 2007, *available at* http://www.denverpost.com/search/ci_6643530 ("This 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.").

3. No. 2005CW063 (Colo. Dist. Ct., Water Div. 7, July 2, 2007). Colorado is likely to pass legislation on the subject soon. E-mail from Sen. Greg Brophy, Colo. Dist. 1, to author (Nov. 30, 2007) (on file with author).

I. CBM Production and Extraction

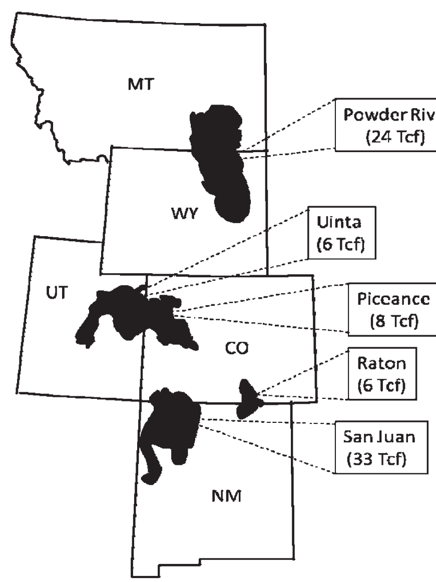
Coal seams are found in 38 states, and nearly one-eighth of the country lies over coalbeds.[4] However, 90% of these deposits are unmineable.[5] All coal seams contain some amount of methane. Methane was formerly viewed as a mine safety hazard[6] but now represents more than 9.6% of total domestic natural gas production.[7] Unlike traditional coal mining, CBM 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 relative 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 is 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.[8] 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,[9] can yield up to 8,000 cubic feet of methane gas,[10] and typically contains six to seven times the gas of an equivalent mass of rock in a conventional gas reservoir.[11] Unlike coals in the eastern United States, which 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 deposits may be mined conventionally for their coal, but deeper deposits can only be exploited for their methane. Conservative estimates for total CBM reserves in the coterminous United States are 700 trillion cubic feet (Tcf)[12] with up to 186 Tcf technically recoverable.[13] 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.[14] Figure 1 shows the location of major basins in the intermountain West, as well as their projected volumes of economically recoverable methane.[15]

Figure 1: Estimated Economically Recoverable Coalbed Methane Reserves in the Intermountain West Over Five Tcf[16]



4. American Coal Found., *All About Coal: FAQs About Coal*, http://www.teachcoal.org/aboutcoal/articles/faqs.html (last visited June 24, 2008).
5. Office of Fossil Energy, U.S. Dep't of Energy (DOE), *Coalbed Natural Gas*, Pol'y Facts, Feb. 2005, at 2, *available at* http://www.netl.doe.gov/publications/factsheets/policy/Policy019.pdf.
6. The worst mine disaster in American history, the 1907 Fairmont Coal Methane Explosion near Monongah, West Virginia, killed over 362 miners. CBM 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 CBM explosions. Mine Safety & Health Admin., 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 (last visited June 24, 2008); U.S. Mine Rescue Ass'n, *Fatalities Occurring at Underground Coal Mine Disasters Since 1980*, http://www.usmra.com/disasters_80on.htm (last visited June 24, 2008).
7. 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. Energy Info. Admin., U.S. DOE, *Natural Gas Navigator*, http://tonto.eia.doe.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm (last visited June 24, 2008).
8. *Id.*
9. Scott R. Reeves, Enhanced Coalbed Methane Recovery (2003), *available at* http://www.adv-res.com/pdf/Reeves%20DL%20Presentation.pdf.
10. Interstate Oil & Gas Compact Comm'n & ALL Consulting, A Guide to Practical Management of Produced Water From Onshore Oil and Gas Operations in the United States 6 (2006), *available at* http://www.all-llc.com/IOGCC/PDF/PWGuideFinal-LowRes.pdf.
11. U.S. Geological Survey (USGS), Coalbed Methane—An Untapped Energy Resource and an Environmental Concern 1 (1997) (USGS FS-019-97), *available at* http://pubs.usgs.gov/fs/fs123-00/fs123-00.pdf.
12. *Id.*
13. 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* Energy Info. Admin., U.S. DOE, *Coalbed Methane Proved Reserves and Production*, http://tonto.eia.doe.gov/dnav/ng/ng_enr_cbm_a_EPG0_r51_Bcf_a.htm (last visited June 24, 2008); Potential Gas Comm., *Announcing the 2006 PGC Natural Gas Resource Estimates and Biennial Report*, http://www.mines.edu/research/pga/ (last visited June 24, 2008).
14. Energy Info. Admin., U.S. DOE, Annual Energy Outlook 2008, at 12 (2007), *available at* http://www.eia.doe.gov/oiaf/aeo/pdf/earlyrelease.pdf.
15. 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. *Compare* Scott R. Reeves et al., Nature and Importance of Technology Progress for Unconventional Gas (2007), *available at* http://www.adv-res.com/pdf/ARI%20GJ%204%20Unconventional%20Gas%20Technology%207_24_07.pdf *with* Energy Info. Admin., *supra* note 13.
16. Ted McCallister, Unconventional Gas: Challenges, Successes, and Future Outlook Unconventional Gas Production Projections in the Annual Energy Outlook 2005: An Overview (2005).

In addition to having a large amount of estimated economically recoverable CBM, Colorado is home to the highest amount of proved CBM reserves[17] in the continental United States (6.34 Tcf), followed by New Mexico (4.89 Tcf), and Wyoming (2.45 Tcf).[18] In 2006, annual production was greatest in New Mexico (0.51 Tcf), Colorado (0.48 Tcf), and Wyoming (0.38 Tcf).[19]

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.[20] 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 higher saline water.

Water quality for CBM-produced water is often given in terms of total dissolved solids (TDS), 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 milligrams per liter (mg/L))[21] or higher, due to the filtering effect of overlying strata. TDS levels of 350,000 to 400,000 mg/L (10 to 11 times saltier than seawater) have been reported with extraction of traditional oil and gas reserves in deep formations.[22]

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17. 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.

Energy Info. Admin., U.S. DOE, *Natural Gas Navigator: Definitions, Sources, and Explanatory Notes*, http://tonto.eia.doe.gov/dnav/ng/TblDefs/ng_enr_cbm_tbldef2.asp (last visited June 24, 2008).

18. *See* Energy Info. Admin., *Natural Gas Navigator*, *supra* note 7 (2006 values).

19. *Id.*

20. *See* Interstate Oil and Gas Compact Comm'n & ALL Consulting, *supra* note 10, at 10.

21. Ruckelshaus Inst. of Env't & Nat. Resources & Univ. of Wyo., Water Production From Coalbed Methane Development in Wyoming: A Summary of Quantity, Quality, and Management Options 27 (2005), *available at* http://www.uwyo.edu/enr/ienr/CBMWaterFinalReportDec2005.pdf.

22. *Id.*

Table 1: Selected Water Quality

	Average Depth of Potable Water Wells (ft)	Depth of reserves (ft) Range (Typical)	TDS (mg/L) Range (Typical)
EPA secondary drinking water standard[23]	N/A	N/A	500
Lake Mead[24]	Surface	N/A	640
San Pellegrino mineral water[25]	Surface	N/A	960
Livestock Watering[26]	N/A	N/A	0-6,600
Powder River		200-1,800[27]	270-4,000[28] (947)[29]
Raton		400-4,000[30]	530-6,000[31] (1,500)[32]
San Juan	Less than 400[33]	550-4,000[34] (2,500)	300-25,000[35] (8,000)[36]
Uinta[37]		1,000- 7,000 (4,300)	9,286-31,000 (15,000)[38]
Piceance[39]	200	4,000-12,000 (6,000)	15,000
Atlantic Ocean[40]	N/A	N/A	35,000
Great Salt Lake[41]	N/A	N/A	230,000
Conventional Oil and Gas	N/A	Varies	5,000-410,000[42]

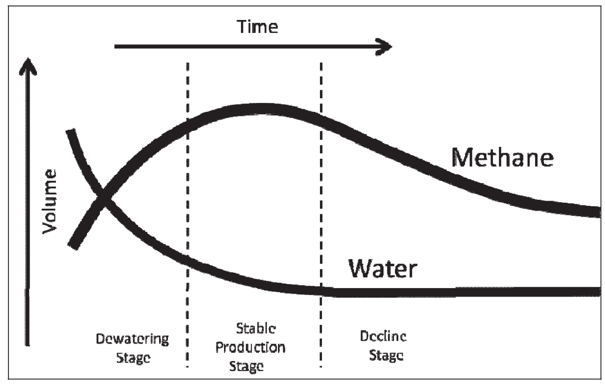
23. National Secondary Drinking Water Regulations, 40 C.F.R. §143.3 (2007).
24. *See* Ruckelshaus Inst. of Env't & Nat. Resources & Univ. of Wyo., *supra* note 21.
25. San Pellegrino, *Chemical Structure*, http://www.sanpellegrino.com (last visited June 24, 2008) (click "Water Essence" tab, click "Chemical Structure" subtab, and follow on-screen directions).
26. R.S. Ayers & D.W. Westcot, Water Quality for Agriculture Review 1 (Food & Agriculture Org. of the United Nations 1976, reprinted in 1994), *available at* http://www.fao.org/DOCREP/003/T0234E07lhtm#26note1 (note that 1 dS/m = 600 mg/L). The U.S. Environmental Protection Agency's (EPA's) limit for livestock watering is 2,000 mg/L. *See* Ruckelshaus Inst. of Env't & Nat. Resources & Univ. of Wyo., *supra* note 21, at 21.
27. ALL Consulting, *Coalbed Methane: What Is It and How Do You Get It?*, http://www.all-llc.com/CBM/pdf/CBMIntro2004IOGCC_11-20.pdf (last visited June 24, 2008).
28. Jim Otton, Estimated Volume and Quality of Produced Water Associated With Projected Energy Resources in the Western U.S. 26, 30 (2005), *available at* http://cwrri.colostate.edu/Produced%20Waters/Proceedings%20Final%20PDF.pdf.
29. Ruckelshaus Inst. of Env't & Nat. Resources & Univ. of Wyo., *supra* note 21, at 21.
30. ALL Consulting, *supra* note 27.
31. Otton, *supra* note 28, at 30.
32. Mike Hightower, *Managing Coal Bed Methane Produced Water for Beneficial Uses, Initially Using the San Juan and Raton Basins as a Model*, at 2, http://wrri.nmsu.edu/conf/forum/CBM.pdf [hereinafter Sandia Report]; *see also* U.S. EPA, Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs A9-3 (2004) (EPA 816-R-04-003), *available at* www.epa.gov/safewater/uic/pdfs/cbmstudy_attach_uic_attach09_raton.pdf.
33. Telephone Interview with Dick Wolfe, State Eng'r, Colo. (Dec 28, 2007) [hereinafter Wolfe Interview].
34. U.S. EPA, Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs, at A1-1, *available at* http://www.epg.gov/ogwdcw/uic/pdfs/cbmstudy_attach_uic_attach01_sanjuan.pdf.
35. *Id.*
36. Sandia Report, *supra* note 32.
37. *Id.*
38. *Id.*
39. *Id.*
40. Ruckelshaus Inst. of Env't & Nat. Resources & Univ. of Wyo., *supra* note 21, at 21.
41. *Id.*
42. Otton, *supra* note 28, at 30.

Water quantity is another important aspect of CBM methane extraction. Water produced during oil and gas operations constitutes the industry's most prolific product: 98% of waste fluids, a total of 14 billion barrels, of water were produced in 2004.[43] When compared to 2006 annual domestic production volumes of oil and gas (1.9 billion barrels and 23.9 Tcf, respectively), it is no wonder why some analysts characterize oil and gas as byproducts to the production of water.[44] 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).[45]

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[46] or stimulated[47] to increase coal seam permeability and gas recovery. A submersible pump is run into the well to pump the water from the coal seam to release the methane held in place by water pressure. Analogous to opening a soda can,[48] 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."[49] Unlike in traditional oil and gas extraction, water production in CBM wells is high at the outset and then drops off dramatically.[50] 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 CBM Over Time



D. Is CBM Dewatering "Beneficial Use?"

Each state in the intermountain West regulates water resources through the doctrine of prior appropriation born in Colorado in 1882,[51] and judicially or statutorily recognized within 20 years of the that decision in all eight Rocky Mountain States.[52] The prior appropriation doctrine provides that an intentional diversion of water with subsequent application to beneficial use[53] constitutes an appropriation.[54] Water rights are based on the date of the appropriation, with the first appropriators holding superior (senior) rights to later (junior) appropriators. In 1983, the U.S. Court of Appeals for the Ninth Circuit proclaimed that there were "differ-

43. *See* Interstate Oil & Gas Compact Comm'n & ALL Consulting, *supra* note 10, at 2.

44. *Id*.

45. This is a compilation of data from the Wyoming Oil and Gas Conservation Commission, which lists production statistics on its website. Wyoming, Oil and Gas Conservation Commission, *Homepage*, http://wogcc.state.wy.us/ (last visited June 26, 2008) (follow "statistics" hyperlink to data sources).

46. In cavitation, air, water, gel, 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 Plata County Energy Council, *Gas Facts: Production Overview*, http://www.energycouncil.org/gasfacts/prodover.htm.

47. 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 groundwater 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 [Underground Source of Drinking Water] USDWs" and that "[c]ontinued investigation . . . is not warranted at this time." *See* U.S. EPA, *supra* note 32.

48. Hal Clifford, *Drilling Method Pumps Up Floods of Conflict*, Christian Sci. Monitor, Jan. 3, 2002, *available at* http://www.csmonitor.com/2002/0103/p3s1-usgn.html.

49. ALL Consulting, Handbook on Coalbed Methane Produced Water: Management and Beneficial Use Alternatives 2-11 (2003), *available at* http://www.all-llc.com/CBM/BU/index.htm.

50. *Id.* at 1-8. 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.*

51. Coffin v. Left Hand Ditch Co., 6 Colo. 443 (1882).

52. George Vranesh, Vranesh's Colorado Water Law: Revised Edition 9 (James N. Corbridge & Teresa A. Rice eds., Univ. Press of Colo. 2000) (1987).

53. "Beneficial use" is mentioned in the constitutions of Colorado, Montana, New Mexico, Utah, and Wyoming. 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.").

54. *See* Vranesh, *supra* note 52, at 32.

ences 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."[55] Until the commercial exploitation of CBM, 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 groundwater diverted in the process of extracting CBM was an "appropriation" requiring CBM producers to comply with state water laws.[56] Central to the court's inquiry was whether CBM dewatering constituted an (1) intentional (2) diversion of (3) state waters, with subsequent (4) application to (5) a beneficial use (6) without waste.[57]

The first three issues were not in serious contention. Removing groundwater by pumping constitutes a "diversion" under a relatively clear statutory definition.[58] In Colorado, "waters of the state" means "all surface and underground water in or tributary to all natural streams within the state of Colorado" outside designated groundwater basins.[59] Appropriations also require intent. Although the CBM producers sought methane, not water, the court found that their actions demonstrated intent to divert the water.[60]

The primary issue in *Vance* was whether dewatering coal seams to release gas was a beneficial use of the produced water. 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 . . . ."[61] Before this codification, beneficial use was historically defined by Colorado courts on a case-by-case basis. The generality of the statute, which does not define "waste,"[62] implies that there may be no difference in interpretation of beneficial use under the statute or under the common law.[63] 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 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).[64] 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[65] and aquaculture.[66] Other jurisdictions have attempted to maximize water use by excluding certain wasteful uses as beneficial that could be accomplished without water, including drowning gophers,[67] softening a field for plowing,[68] flushing debris during the irrigation season,[69] and using the water to deposit gravel for mining.[70] A case in Colorado found that pumping groundwater simply to test a well pump was not beneficial use.[71] 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 the speculative nature of the purported beneficial use.[72]

British Petroleum (BP) America (the operator of most CBM wells in the San Juan Basin) and the Colorado State Engineer's Office (SEO) 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 or transport the produced gas . . . ."[73] Simply stated, the water wasn't doing anything—it was just 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.[74]

The strongest argument put forth by BP America and the SEO was from a Colorado statute, which said that for some mine dewatering, "[n]o well permit shall be required unless the . . . groundwater being removed will be beneficially used,"[75] implying that dewatering, in itself, is not a benefi-

55. 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)).

56. Brief for Plaintiff at 2, *Vance*, No. 2005CW063 (Colo. Dist. Ct., Water Div. 7, July 2, 2007).

57. *See* Vranesh, *supra* note 52, at 32.

58. *See* Colo. Rev. Stat. §37-92-103(7) (2007).

59. *See id*. §37-92-103(13). Designated groundwater basins are geographically defined nontributary aquifers primarily on the plains portion of Colorado and are subject to the jurisdiction of Colorado Groundwater Commission. *See generally id.* §§37-90-103 to -108.

60. In *Three Bells Ranch Ass'n v. Cache La Poudre Water Users Ass'n*, 758 P.2d 164, 170-73 (Colo. 1988), 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. *Id.* at 173 ("[P]ersons intend the reasonable, natural, and probable consequences of their actions.").

61. Colo. Rev. Stat. §37-92-103(4).

62. 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." *Id*. §37-90-103(20). But, because dewatering is necessary to extract methane, this definition presumably is inapplicable while methane extraction is underway.

63. *See* Vranesh, *supra* note 52, at 44.

64. Janet C. Neuman, *Beneficial Use, Waste, and Forfeiture: The Inefficient Search for Efficiency in Western Water Use*, 28 Envtl. L. 919 (1998).

65. Larimer & Weld Reservoir Co. v. Fort Collins Milling & Elevator Co., 152 P. 1160 (Colo. 1915).

66. Denver v. Sheriff, 96 P.2d 836 (Colo. 1939).

67. Tulare Irrigation Dist. v. Lindsay-Strathmore Irrigation Dist., 45 P.2d 972 (Cal. 1935).

68. Hennings v. Water Resources Dep't, 622 P.2d 333 (Or. 1981).

69. In re Water Rights of Deschutes River & Tributaries, 286 P. 563 (Or. 1930). The court allowed use during winter as long as it did not interfere with storage requirements for irrigation. *Id.* at 578.

70. Joslin v. Marin Mun. Water Dist., 429 P.2d 889 (Cal. 1967).

71. Danielson v. Milne, 765 P.2d 572 (Colo. 1988).

72. *Id.*

73. Brief of Defendant-Intervenor at 10, *Vance*, No. 2005CW063 (Colo. Dist. Ct., Water Div. 7, July 2, 2007).

74. The court seemed to struggle with this concept, citing the dictionary definition of "application" without further elaboration. *Id*. at *16.

75. Colo. Rev. Stat. §37-90-137(7).

cial use. The court seemingly painted itself into 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, requiring deference to their intent in those cases, but "beneficial use," although codified, was essentially a common-law concept best interpreted by the courts without reliance on a somewhat vague expression of legislative intent.

The plaintiff-ranchers contended that the water was "used" to allow gas extraction and then "used up" by reinjection into deep, saline aquifers.[76] Plaintiffs promoted a definition of "used" as "removed from the [groundwater] system and made physically unavailable to senior vested water rights," leaving only two options: (1) either the water was "beneficially used"; or (2) the water was "wasted."[77] Under either scenario, the SEO had a nondiscretionary duty to regulate the diversion.[78] The relevant statute states that

> [e]ach 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.[79]

BP America 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.[80] Simply stated, there are some water displacements outside the purview of the SEO that were neither beneficial use nor waste.[81] 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. 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 Article, 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

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.[82]

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.[83]

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; the type of use; and the costs 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)[84] but there are a number of rivers that meet the demand for the few mostly rural consumers. As the table below shows, the opportunity for beneficial use is low in most parts of the basin. Consequently, nearly 99% of produced water in the San Juan Basin is injected into deep formations.[85] Where water demand and quality are higher, as in the Raton Basin of Colorado, opportunities for beneficial use increase.[86] 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 put to beneficial use.[87]

76. Brief for Plaintiff at 2, *Vance*, No. 2005CW063.
77. *Id.* at 4.
78. *Id.*
79. Colo. Rev. Stat. §37-92-502(2)(a) (emphasis added).
80. Brief for Defendant-Intervenor BP America at 22-23, *Vance*, No. 2005CW063.
81. *Id.*
82. *Id.* at 27.
83. *Id.* at 5.
84. *See* S.S. Papadopulos & Assocs. & Colo. Geological Survey, Coalbed Methane Stream Depletion Assessment Study—Northern San Juan Basin, Colorado (2006), *available at* http://water.state.co.us/pubs/pdf/CMSDA_Study.pdf.
85. Gary Bryner, Coalbed Methane Development in the Intermountain West: Primer (2002), *available at* http://www.colorado.edu/Law/centers/nrlc/CBM_Primer.pdf.
86. In the Raton Basin 70% of water is discharged to the surface and some of this water is used beneficially. *Id.*
87. *Id.*

Table 2: Requirements and Potential for Beneficial Use of CBM-Produced Water in the San Juan Basin in Colorado[88]

Beneficial Use	Approximate TDS Requirements	Area Meeting TDS Requirements	Local Use or Via Conveyance	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 area < 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
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[89]	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[90]	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.[91] The city's well field, located in a sandy formation at approximately 1,500 feet, was 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.[92] 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 CBM gas production with regular drinking water to stretch the city's supply in the face of a projected water shortage.[93] CBM operators note that they would be willing to help the city out if the cost of treatment and transportation does not exceed the current injection disposal costs.[94]

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 the following:

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, ensuring against negative impacts;
4. Surface discharges with water treatment as required, resulting in improved stream flows with adequate mitigations against negative impacts.[95]

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 impact aquatic life, downstream users, or result in loss of resource.[96]

Deep injection may be "sustainable" or not depending on the quality of the produced water, the quality of the receiv-

88. S.S. Papadopulos & Assocs. & Colo. Geological Survey, *supra* note 84, tbl.7.1.
89. 5 Colo. Code Regs. §1002-34 (2007) (giving the classifications and numeric standards for the San Juan and Dolores River Basins but not stating a specific TDS limit). The TDS limit above was calculated from BLM TDS numbers for local streams and assumes that CBM water should not degrade stream quality. See S.S. Papadopulos & Assocs. & Colo. Geological Survey, *supra* note 84.
90. S.S. Papadopulos & Assocs. & Colo. Geological Survey, *supra* note 84.
91. ALL Consulting, Feasibility Study of Expanded Coalbed Natural Gas Produced Water Management Alternatives in the Wyoming Portion of the Powder River Basin: Phase One 11 (2006), *available at* http://www.fossil.energy.gov/programs/oilgas/publications/coalbed_methane/Final_WY_CBNG_FS.pdf.
92. *Id.*
93. 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.
94. *Id.*
95. James R. Kuipers et al., Presentation to the CBNG Research, Monitoring, and Applications Conference, Coalbed Methane-Produced Water: Management Options for Sustainable Development (Aug. 19, 2004).
96. *Id.*

ing formation, and the region's water demand. The government of British Columbia states that deep injection is the best management practice available in North America,[97] 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.[98] Conversely, injecting low-quality brine into a low-quality receiving aquifer, avoiding contamination of surface or shallow aquifers, would be a "sustainable" means of disposal.

II. Current Regulation of Produced Water

A. Agencies and Courts

Colorado's approach to water within oil and gas regulation is typical of western states, and is overseen by three agencies. The SEO is tasked with overseeing the distribution of the waters of the state,[99] including groundwater well permitting outside of designated groundwater basins.[100] 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 dates, and approving plans for augmentation. The Colorado Water Quality Control Division (CWQCD) has authority over pollutant discharges into the state waters (including CBM-produced water). The Colorado Oil and Gas Conservation Commission (COGCC) is tasked by the legislature to broadly regulate the oil and gas industry, including all exploration and production waste from oil and gas operations.[101] Exploration and production waste includes produced water.[102] The Colorado Supreme Court has interpreted the statute creating the COGCC 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."[103]

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 the following:

> 1. Injection into a Class II well (permitted by the COGCC);
> 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).[104]

Option 1 subjects operators to regulation from a single agency and is currently the most common disposal method in Colorado. Most surface discharges, under option 2, require an additional permit from the CWQCD. Traditional beneficial uses are allowed through options 3 and 4, although neither section provides much incentive for this type of use.[105]

All underground injection is overseen by the U.S. Environmental Protection Agency (EPA) pursuant to the Safe Drinking Water Act, which includes five classifications of wells (three of which are applicable to CBM-produced water).[106] 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.[107] New Mexico, Utah, and Wyoming have pri-

97. The B.C. government does not allow any surface discharge of CBM-produced water. *See* B.C. Ministry of Energy, Mines & Petroleum Resources, The BC Energy Plan: A Vision for Clean Energy Leadership 29 (2007), *available at* http://www.energyplan.gov.bc.ca/PDF/BC_Energy_Plan.pdf.

98. *Cf. id.* Like evaporation, deep injection would lose water for both current and future users.

99. Colo. Rev. Stat. §37-80-102(h).

100. This would be regulated by the Colorado Groundwater Commission. *Id.* §37-90-137(1).

101. Colorado defines "oil and gas operations" broadly:

> 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. *Id.* §34-60-106(2)(a), -106(9), -106(17)(e).

102. *Id.* §34-60-103(6.5).

103. Board of County Comm'rs v. Bowen/Edwards Ass'n, 830 P.2d 1045, 1057 (Colo. 1992) (interpreting §34-60-105(1)).

104. 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. COGGC R. 907(c)(2) (Colo. Oil & Gas Conservation Comm'n, 2006), *available at* http://www.oil-gas.state.co.us/RR_Docs/rules_new2.html.

105. The shortcomings of Option 3 are discussed below. Option 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 . . . . *Id.* R. 907(c)(4). This provides 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 the "[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." *Id.*

106. 42 U.S.C. §§300f to 300j-26, ELR Stat. SDWA §§1401-1465.

107. U.S. EPA, *Classes of Wells*, http://www.epa.gov/safewater/uic/wells.html (last visited June 25, 2008).

macy over each type of well,[108] while Colorado and Montana only regulate Class II wells[109] and leave other categories to EPA.[110]

Class I wells have the strictest requirements: the waste must be injected below any underground source of drinking water (USDW)[111] with sufficient confinement layers above the injection zone ensuring "no reasonable possibility of contamination" exists.[112] Although there are currently no Class I wells in the intermountain West, treatment of produced water would result in a relatively small amount 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.[113]

Class II injection wells are regulated by the states, and are the primary means of disposal for oil and gas wastes. As an example, Colorado allows Class II injections into any formation that is not a USDW,[114] unless the aquifer is exempted.[115] 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).[116]

C. Colorado Groundwater Regulation

In Colorado, the Colorado Ground Water Commission has primary authority over the administration of "designated" groundwater.[117] However, most of the state's groundwater lies outside designated basins and is administered by the SEO, including "tributary" groundwater (hydrologically connected to a natural stream system either by surface or underground flows) and "nontributary" groundwater; 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 one percent of the annual rate of withdrawal."[118] Both types are administered using a permit system.

Tributary groundwater is integrated with surface waters and managed through the doctrine of prior appropriation as outlined in the Colorado Constitution.[119] All groundwater is presumed to be a tributary to a stream unless proven otherwise.[120] New water wells require a permit from the SEO,[121] who must determine that unappropriated water is available for withdrawal and that the vested water rights of others will not be materially injured by the proposed well.[122] Both must be substantiated by hydrological and geological facts.[123] 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 groundwater is "fully appropriated" and any withdrawal causes material injury to senior appropriators by definition.[124] 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.[125] 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 "new" water will be added to the stream system, including transfer of other senior rights or the use of nontributary groundwater to augment the surface stream.[126]

Nontributary groundwater is not part of the "waters of the state" and the Colorado Legislature has plenary power over its administration and distribution.[127] 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.[128] 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.[129]

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* . . . ."[130] 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

108. U.S. EPA, *UIC Program Primacy*, http://www.epa.gov/safewater/uic/primacy.html (last visited June 25, 2008).

109. Montana has expressed interest in regulating Class V wells but no application has yet been submitted. Mont. Dep't of Nat. Resources Conservation, Montana Board of Oil & Gas Conservation, *Homepage*, http://bogc.dnrc.state.mt.us/BoardSummaries.asp (last visited June 25, 2008).

110. *See* U.S. EPA, *UIC Program Primacy*, *supra* note 108.

111. *See* 40 C.F.R. §144.3 (defining Underground Source of Drinking Water (USDW) as an aquifer which supplies the public a sufficient quantity of potable water).

112. *See* U.S. EPA, *supra* note 32.

113. *See* ALL CONSULTING, *supra* note 49.

114. Underground Injection Control Program, 40 C.F.R. §144.3.

115. A water-bearing formation may be exempted if it is not a source of drinking water and it is not expected to become one because it contains commercially viable hydrocarbons, practically unrecoverable water, or water too polluted by TDS or other contaminants. COGCC R. 324B(a) (Colo. Oil & Gas Conservation Comm'n 2006), *available at* http://www.oil-gas.state.co.us/RR_Docs/rules_new2.html.

116. *See* INTERSTATE OIL & GAS COMPACT COMM'N & ALL CONSULTING, *supra* note 10, at 4.

117. COLO. REV. STAT. §§37-90-107 to -109. Because these types of water lie in defined basins with little overlap with CBM reserves, they are outside the scope of this paper.

118. *Id*. §37-90-103(10.5).

119. *Id*. §§37-90-101 to -602; COLO. CONST. art. XVI, §6.

120. *See* Platte Valley Irrigation Co. v. Buckers Irrigation, Milling, & Improvement Co., 53 P. 334 (Colo. 1898).

121. COLO. REV. STAT. §37-90-137(1).

122. *Id*. §37-90-137(2)(b)(I).

123. *Id.*

124. *See* Hall v. Kuiper, 510 P.2d 329 (Colo. 1973).

125. 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).

126. *See* Hall v. Kuiper, 550 P.2d at 303.

127. *See* Kuiper v. Lundvall, 575 P.2d 372 (Colo. 1978).

128. COLO. REV. STAT. §37-90-137(4).

129. *Id.*

130. *Id*. §37-90-103(21)(a).

nontributary groundwater followed §37-90-137(7) of the Colorado Revised Statute, which states:

> 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 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.[131]

Simply stated, a producer could obtain a well permit to use nontributary water from CBM operations, even in an overappropriated 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 SEO to regulate CBM water diversions, including issuing water well permits for CBM wells and requiring augmentation plans when tributary groundwater was diverted in overappropriated groundwater basins.

The case centered on who was in 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 SEO?

The water court began by finding that COGCC is granted exclusive authority over oil and gas operations, including the disposal of wastes from exploration and production, such as produced water.[132] 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."[133] 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, nondiscretionary 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."[134] Those acts also vested the SEO with the duty to issue permits for water wells constructed outside designated groundwater basins,[135] and the court found that CBM wells fell within the definition of water well.[136] Although the purpose of the wells was to produce gas, the effect was water production for beneficial use.[137] The court noted that because the legislature had provided permit exceptions in the case of mine dewatering of nontributary groundwater[138] the doctrine of *expresio unius est exclusio alterius* dictated that for tributary groundwater, a permit was required.[139] Finally, the court dismissed the SEO's agency deference argument because the SEO's position was not a permissible construction of the statute.[140]

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 SEO, and existing wells will likely require permitting as well.[141] In fully appropriated basins, no permit will be issued by the SEO without a plan for augmentation.[142] 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 statutes permitting requirement would be invoked requiring even nontributary CBM wells to be permitted.[143] Taken further, if *any* mine dewatering is beneficial use, then even traditional oil and gas wells (almost exclusively located in nontributary aquifers) may require water well permits.

The costs of these outcomes could be significant. While a water well permit is only $100,[144] no permit may be issued in a fully appropriated tributary basin without first obtaining a water right and filing a plan for augmentation with a Colorado Water Court (an additional $467 fee).[145] This process generally requires a water attorney and a water resources engineer.[146] Applications are public, and anyone may file

131. *See id*. §37-90-137(7).

132. *See id*. §34-60-105.

133. COGCC R. 209 (Colo. Oil & Gas Conservation Comm'n, 2006), *available at* http://www.oil-gas.state.co.us/RR_Docs/rules_new2.html.

134. Colo. Rev. Stat. §37-92-501(1).

135. *See id*. §37-90-137(1).

136. "Water well" is defined as any structure "used for the purpose or with the effect of obtaining groundwater for beneficial use from an aquifer." *Id*. §37-90-103(21)(a).

137. *Id.*

138. *Id*. §37-90-137(7)(a) ("[n]o well permit shall be required unless the nontributary groundwater being removed will be beneficially used").

139. Vance, No. 2005CW063, at *18.

140. *Id*. (citing Chevron, U.S.A., Inc. v. National Research Defense Council, 467 U.S. 837, 843, 14 ELR 20507 (1984)).

141. Permitting existing wells would likely be accomplished in stages and over a series of years. E-mail from Sarah Klahn, attorney for plaintiffs in *Vance*, to author (Nov. 26, 2007) (on file with author).

142. *See* Colo. Rev. Stat. §37-90-137(2).

143. *See id.* §37-90-137(7).

144. *Id*. §37-90-137(2).

145. Division of Water Resources, Colo. Dep't of Nat. Resources, Guide to Colorado Well Permits, Water Rights, and Water Administration 4 (2008), *available at* http://water.state.co.us/pubs/wellpermitguide.pdf.

146. *Id.*

statements in opposition.[147] In opposed cases, the water referee will often conduct an informal hearing and either approve, deny, or modify the permit; or may refer the matter to the water court judge.[148] Any person may protest a referee's ruling, requiring it to be referred to de novo review by a water court judge.[149] In water court proceedings, the applicant carries the burden of showing absence of injury to senior water rights holders.[150] As a matter of practice, the water court allows other parties to intervene.[151] Water court rulings are subject to appeal in the Colorado Supreme Court.[152] The entire process takes from four months to two years, depending on the complexity of the case and the level of opposition.[153]

In addition to fees and attorney and engineering costs, an augmentation plan generally requires the purchase of replacement water. Although initially a plan could include use of the CBM-produced water during the years the well is active, an augmentation plan would likely require the CBM producer to purchase water to cover post-pumping depletions as well.[154] BP America claims that the total costs of the decision could top $100,000 per well[155] 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."[156] Increasing permit requirements also raises doubts about the State Engineer's ability to process all the applications.[157] Currently, the SEO plans to wait until all appeals to *Vance* are decided before approaching the legislature for more funding to meet an increased workload.[158]

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 augmentation plans would be required unless the producers can demonstrate through hydrologic modeling that this water is nontributary.[159] 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 nontributary permit statute.[160]

To date in Colorado, the only well permit obtained through the nontributary dewatering statute was for the Wellington oil field, which sought to treat water produced during oil extraction to sell to residential developers. The Wellington oil field is located north of Fort Collins near the Wyoming border. As a "stripper well" operation, it produces more water than oil: of the approximately 3,000 barrels produced each day, only 50 barrels are oil.[161] 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.[162] 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.[163] The economics of the operation seemed promising. On the oil side, treatment would produce more oil from the water that was currently injected underground. Of the 35 wells on the site currently dedicated to water reinjection, 19 could be used for additional oil extraction, and the costs of reinjection pumping would be avoided.[164] On the water side, a treatment plant could be constructed for $1.4 million,[165] and could be operated for approximately $350 per acre-foot, putting the total cost of capacity at $2,000 to $4,000 per acre-foot.[166] Water rights in the expanding eastern slope of Colorado run anywhere from $20,000 to $35,000 per acre-foot.[167] The water would eventually end up as drinking water for the town of Wellington, increasing their drinking water supplies by 300%. Also, 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 produced was nontributary and a traditional byproduct of oil and gas mining, 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 wa-

147. *See* Colo. Rev. Stat. §37-92-302(1)(b).

148. *See* Vranesh, *supra* note 52, at 148.

149. *See id.* at 149.

150. Colo. Rev. Stat. §37-92-304(3).

151. *See* Vranesh, *supra* note 52, at 150.

152. Colo. Rev. Stat. §13-4-102(1)(d) (2007).

153. Colo. Div. of Water Res., *supra* note 145, at 16.

154. *See* Wolfe Interview, *supra* note 33.

155. Kim McGuire, *Battle Looms Over Water Quality*, Denv. Post, Aug. 14, 2007, *available at* http://www.denverpost.com/headlines/ci_6616176.

156. Kim McGuire, *Farmers Win Water Ruling on Methane Gas*, Denv. Post, July 3, 2007, *available at* http://www.denverpost.com/news/ci_6285559.

157. Mark Jaffe, *Water Ruling May Burden Regulators, Official Says*, Denv. Post, Aug. 16, 2007, *available at* http://www.denverpost.com/ci_6633328?source=rssdp.

158. *See* Wolfe Interview, *supra* note 33.

159. *Id.*

160. *Id.*

161. *See* Cherry Sokoloski, *Oil, Water Mix Well in Wellington*, N. Forty News, Mar. 1, 2006, *available at* http://www.northfortynews.com/Archive/A200603oilWaterMix.htm.

162. Kim McGuire, *Unchartered Waters for Wellington: No Precedent for Rights to Abundant Coal-Bed Runoff*, Denv. Post, Aug. 13, 2006, *available at* http://www.denverpost.com/headlines/ci_6608638.

163. *See* Sokoloski, *supra* note 161.

164. *See id.*

165. *See id.*

166. E-mail from Dr. David R. Stewart, President & CEO of Stewart Envtl. Consultants, Inc. (Dec. 18, 2007) (on file with author) [hereinafter Stewart E-mail]. Dr. Stewart designed the treatment facility for the Wellington oilfield project and was instrumental in all stages of the process.

167. *Id.*

ter."[168] In this case, the "applicable state statute" is §37-90-137(7) of the Colorado Revised Statute, outlined above. In issuing this permit, the State Engineer only had to determine that (1) the water was nontributary and (2) the withdrawal would not cause material injury to the vested water rights of others.[169] 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.[170] However, because the permit would cover only 1 of the 15 producing wells, only 1/15th of the water might have been put to beneficial use, and the permit was conditioned on continued oil production.[171] It took two and one-half years for the Wellington operators to gather the required proof, submit it, and for the SEO to then verify that the water was nontributary.[172]

Once the company had a permit from the SEO, 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: (1) the COGCC, who regulates produced water discharges into lined pits; (2) the Colorado Water Quality Control Division, who regulates surface discharges; and (3) EPA, who regulates Colorado's Class V injection wells (including aquifer storage/recharge wells). 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 . . . ."[173] 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 . . . ."[174] which would presumably invoke the authority of the CWQCD.[175] Surprisingly, the attorney for the CWQCD (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 made into "surface waters."[176] 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 . . . ,"[177] 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."[178] 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 . . . ."[179] 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.[180] The total cost for permitting, engineering, and hydrological studies was over $1 million but because the state agencies have now clarified their respective responsibilities, future projects should be closer to $500,000.[181]

The treatment plant went online in mid-April 2006,[182] but the final hurdle for the Wellington group came in the Division One Water Court on January 15, 2008.[183] Nine statements of objection were originally filed, most by landowners that overlay the aquifer Wellington pumps from (as well as from the SEO), but only one objector (a bank trust) remained when the case went to court.[184] Wellington had originally sought a water right in the produced water under §37-90-137(7) of the Colorado Revised Statute, but later modified its request to a decreed use right based on the permit obtained by the SEO.[185] The court noted that when oil production ceased, Wellington could pursue a traditional water right in the same water under §37-90-137(4) (which governs most groundwater withdrawals) but this right would be based on the amount of land they owned or had consent from the landowner.[186] 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 nontributary water/oil mixture. If the oil component of the water becomes depleted, Wellington will only need to file a timely request with the court to gain rights under §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 lacking mineral rights and mineral producers who have §37-90-137(7) permits. First, the court noted that until a well is constructed or a water right is adjudicated, rights in underlying nontributary water are inchoate and are neither considered a vested present interest nor a constitutionally protected property interest.[187] The court went on to state that §137(7) permits trumped inchoate rights but failed to explain how those permit withdrawals would be balanced against vested rights in nontributary water.[188]

168. COGCC R. 907(a)(3), 907(c)(2)(E)(2) (Colo. Oil & Gas Conservation Comm'n, 2006), *available at* http://www.oil-gas.state.co.us/RR_Docs/rules_new2.html.

169. Colo. Rev. Stat. §37-90-137(7) (2007).

170. *See id.*.

171. In re Water Rights of Wellington Water Works LLC, No. 2005CW343, 5 (Colo. Dist. Ct., Water Div. 1, Mar. 10, 2008).

172. *See* Sokoloski, *supra* note 161. The average review time at the State Engineer's office for each submission was less than three months. E-mail from Dave McElhaney, P.G., Colorado SEO (Mar. 3, 2008) (on file with author).

173. Underground Injection Control Program, 40 C.F.R. §144.3 (2008).

174. §25-8-103(19).

175. *See* §25-8-501(1) ("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 , . . .).

176. In re Request to Allow the Discharge of Treated Produced Water into the Box Elder Creek Alluvium, No. 1-108 (Colo. Oil & Gas Conservation Comm'n, Aug. 15, 2005).

177. §25-8-202(7).

178. §25-8-202(7)(a).

179. §25-8-202(7)(b)(I) (emphasis added).

180. In re Discharge Request, No. 1-108 (Colo. Oil & Gas Conservation Comm'n Aug. 15, 2005).

181. Stewart E-mail *supra* note 161.

182. *See* Cherry Sokoloski, *Water Users Contesting Wellington Oil Field Plan*, N. Forty News, May, 2006, *available at* http://www.northfortynews.com/Archive/A200605waterUsersContesting.htm.

183. Stewart E-mail *supra* note 166.

184. Water Rights of Wellington Water Works, Ltd. Liab. Co., No. 2005CW343 (Colo. Dist. Ct., Water Div. 1, Mar. 10, 2008).

185. *Id.* at 2.

186. *Id.* at 6.

187. *Id.* at 11.

188. *Id.* at 12.

E. Comparative Approaches

1. Wyoming

As in Colorado, the Wyoming SEO 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, which adjudicates water rights similar to the Colorado water court system.[189]

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 . . . ."[190] 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.[191]

Interestingly, Wyoming does not consider CBM water to be byproduct water, and in 1997 the Wyoming State Engineer also recognized that CBM dewatering was a beneficial use. The position was clarified in a 2004 memo:

> 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 groundwater 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 groundwater.[192]

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,[193] and permits are granted as a matter of course.[194] 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.[195]

Recently, Wyoming has shown willingness to crack down on CBM producers whose wells are producing little or no gas.[196] Current Colorado statutes would presumably prohibit this kind of waste as well,[197] although Colorado has no official guidelines like the Wyoming threshold water-to-gas ratio of 10 barrels per thousand cubic feet.[198]

2. 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.[199] All appropriations of groundwater in "declared basins" require a permit from the State Engineer,[200] 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."[201] 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

> (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;

189. *Id.*

190. Wyo. Stat. Ann. §41-3-901(a)(ii) (2007).

191. *Id.* §41-3-903.

192. Wyo. SEO, Guidance: CBM/Ground Water Permits (2004), *available at* http://seo.state.wy.us/PDF/GW_CBM%20Guidance.pdf.

193. Patrick T. Tyrrell, State Engineer's Office Permitting Requirements for Water Produced During the Recovery of Coalbed Methane (CBNG) (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 . . . .). 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, No. 170-63 (1st Dist. Wyo., filed June 14, 2007).

194. Wyo. Stat. Ann. §41-3-931.

195. 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 No. 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:

> No 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 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.

Id. at 3 (Andarko Petroleum), *available at* http://seo.state.wy.us/scans/GW_Docs/GW_Permits/Permits/D_P00164824_UW_003.pdf.

196. Press Release, Wyo. SEO (Dec. 18, 2007), *available at* http://seo.state.wy.us/Press/2007/121807.aspx.

197. The Colorado Groundwater Management Act defines waste as "causing, suffering, or permitting any well to discharge water unnecessarily above or below the surface of the ground." Colo. Rev. Stat. §37-90-103(20). 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."

198. This ratio must be achieved in the first two to three years of water production. *See* Wyo. SEO, *supra* note 196.

199. N.M. Stat. Ann. §72-12-1 (LexisNexis 2007).

200. *Id.* §72-12-20.

201. *Id.* §72-12-25.

> (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 . . . .[202]

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."[203] 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.[204] 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.[205] Notably, if replacement water is required, the operator may propose that the produced water be the source.[206]

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 §70-2-12 by the Oil Conservation Division of the energy minerals and natural resources department."[207] The referenced statute is broad, allowing the division 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 . . . ."[208] The division's disposal rules are also broad, allowing disposal by injection wells, pits, reuse, or "use in accordance with a division-issued use permit or other division authorization."[209]

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 impair existing rights. In any case, dewatering may continue with a replacement plan, for which the produced water may be a source. With the Oil Conservation Division's approval, CBM operators may use the water for traditional beneficial uses without any further oversight from the State Engineer. Presumably the CBM producers could apply for water rights in the produced waters, but this additional step is not required to beneficially use produced water.

III. A Cost-Benefit Analysis

A. The Costs of CBM-Produced Water Regulation

New regulations on CBM-produced water can have three economic effects: (1) immediate, direct, and quantifiable effects; (2) long-term and indirect, or nonquantifiable, effects; and (3) secondary effects, such as behavior changes of stakeholders. For example, a statute mandating that produced water be treated to reduce TDS levels to a specific value would have the direct effect of increasing production costs for CBM producers, possibly leading to lower production volumes, federal royalties, and state severance collections. Production decreases may indirectly cause 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 industrywide.

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.[210]

202. *Id*. §72-12A-2(A)(1)-(4).
203. *Id*. §72-12A-5(A).
204. *Id*. §72-12A-7.
205. *Id.*
206. *Id.*
207. *Id*. §70-2-12.1.
208. *Id*. §70-2-12(15).
209. *Id*. §19.15.2.52(B)(2).
210. Ruckelshaus Inst. of Env't & Nat. Resources & Univ. of Wyo., *supra* note 21; Interstate Oil & Gas Compact Comm'n & ALL Consulting, *supra* note 10, at 27.

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 impacts from surface discharge	Water not immediately available for additional beneficial surface use Some injection zones have limited capacity	Capital: $6,500-$15,000 (reworking of existing well); $100,000 new 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's basinwide rules that would allow for zero surface discharges of produced water unless the water was treated to contain less than 170 parts per million (ppm) TDS,[211] industry-sponsored experts predicted that

> [i]mplementation 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 per-

211. 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 time frames 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

> [i]f 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 technology-based effluent limitations at the end of the pipe prior to discharge: . . . total dissolved solids average concentration of 170 mg/L . . . .

See Interstate Oil & Gas Compact Comm'n & ALL Consulting, *supra* note 10, at 32-33.

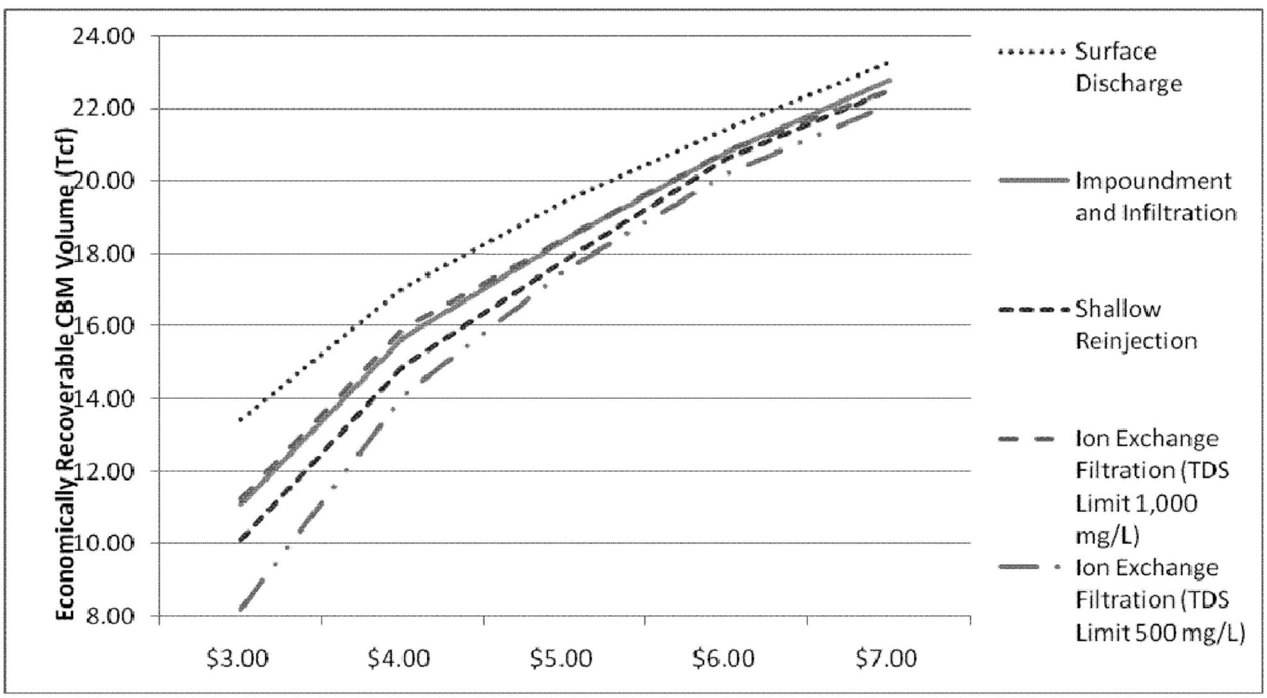
cent, eliminating much (if not all) of the potential production in the region.[212]

A 2006 study in Wyoming prepared for the U.S. Department of Energy (DOE) was slightly less alarmist, but echoed studies in other states in finding that

> [t]he 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.[213]

However, the study recognized that these negative economic effects did not vary linearly with gas price: "At 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."[214] As the figure below shows, stringent water disposal regulation, i.e., treatment versus 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.[215]

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[216]



212. *Id.*

213. Gregory C. Bank & Vello A. Kuuskraa, The Economics of Powder River Basin Coalbed Methane Development (2006), *available at* http://www.netl.doe.gov/technologies/coalpower/ewr/pubs/netl%20Cost%20of%20Produced%20Water%20Treatment%200106.pdf.

214. *Id.*

215. Wellhead prices for October, 2007 were $6.25/Mcf. Energy Info. Admin., U.S. DOE, *U.S. Natural Gas Wellhead Price*, http://tonto.eia.doe.gov/dnav/ng/hist/n9190us3M.htm (last visited June 26, 2008). DOE expects well head prices to hover between $5.42 and $6.60 between 2008 and 2030. *See infra* note 221.

216. *Id.*

In 2001, the Montana Coalbed Natural Gas Alliance presented a study of how CBM 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 other agencies; and $1.3 billion in purchases of local goods and services.[217] 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."[218]

The Powder River Basin studies are compelling, and the negative economic effects 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 regulation's effects (both direct and indirect) may only slow, rather than preclude gas extraction. Assuming gas prices will continue to rise, and recovery and treatment technologies will advance, regulation's short-term economic impact 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. 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 than 50% for the most common types), while U.S. gross domestic product has tripled, energy consumption has increased by 50%, and vehicle use has increased by 200%.[219]

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 (CO_2) or nitrogen) to increase methane desorption. Analysts have estimated that this process may allow for the additional recovery of 150 Tcf of methane in the United States and would sequester over 90 billion tons (Gt) of CO_2.[220] In 2004, global CO_2 emissions totaled 26.9 Gt.[221] The process requires a pattern of injection wells drilled into a producing coal seam around a central production well. The mechanics of ECBM recovery depend on which gas is used; CO_2 has a strong affinity for coal, followed by methane and then nitrogen.[222] When nitrogen is introduced into coal fractures, it displaces methane and lowers the partial pressure of the methane gas.[223] This disequilibrium strips methane from the coal, and the nitrogen/methane mixture can be removed and separated.[224] In CO_2 ECBM recovery, the CO_2 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.[225] CO_2 sorption lowers the permeability of the coal seams, which helps to explain why equivalent volumes of the two gases injected into two test sites in the San Juan Basin increased daily methane recovery for nitrogen by 57%, but increased recovery only by 29% when using CO_2.[226] Although the nitrogen process is faster and more productive than the CO_2 process, the CO_2 process does not require expensive gas separators on production wells and sequesters large amounts of greenhouse gases. However, 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 regulations.[227]

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 with other investment opportunities; therefore, if the gas risk/reward is too high, we go to other investments with lower risk/reward.[228]

Cline identifies two key concepts in his comments. First, oil and gas development exists in a highly volatile energy

217. Anderson ZurMuehlen & Co., Coalbed Methane Development, Powder River Basin of Montana: Economic and Social Impacts of Proposed Development (2001), *available at* http://www.deq.state.mt.us/CoalBedMethane/pdf/cbm2.pdf.

218. *Id.*

219. U.S. EPA, *Understanding the Clean Air Act: Plain English Guide to the Clean Air Act*, http://epa.gov/oar/caa/peg/understand.html (last visited Apr. 9, 2008).

220. *Id.*

221. Energy Info. Admin., U.S. DOE, International Energy Outlook 2007 (2007) (DOE/EIA-0484), *available at* http://www.eia.doe.gov/oiaf/archive/ieo07/index.html.

222. *See* Scott R. Reeves, Assessment of CO_2 Sequestration and ECBM Potential of U.S. Coalbeds (2003) (DE-FC26-00NT40924), *available at* http://www.adv-res.com/Carbon-Sequestration.asp.

223. *Id.*

224. *Id.*

225. *Id.*

226. *Id.*

227. *See* Green Car Congress, *Factors and Impacts for CO_2 Storage in Coalbed Seams*, http://www.greencarcongress.com/2007/06/factors-and-imp.html (June 24, 2007).

228. Jeff Cline, *Opportunities and Liabilities for Produced Waters* 36, 39 (Produced Water Workshop) (unpublished manuscript) (on file with author).

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 increase 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:

Table 4

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

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* . . . .[229]

Regulatory uncertainty may help to explain why producers would choose to spend $3 to $4 million to drill a Class II injection well and spend $0.50 to $1.75 per barrel of water rather than to build a treatment plant for $450,000 to $1.270 million with operation costs between $0.26 and $0.34 per barrel[230]—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 with long permitting time frames have direct economic impacts on produced water disposal options, possibly precluding the most desirable choice.

B. Benefits of CBM-Produced Water Regulations

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-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.[231] In 2004, economists with the Science and Environmental Health Network[232] conducted a study examining the effects of CBM development on the Powder River Basin.[233] The authors believed that the precautionary principle[234] 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 a loss of water resources valued at $2.1 to $10.1 billion and cost households $50 million in well deepening made necessary by lower groundwater tables. The study also identified the federal tax credits and subsidies producers would receive over the next five years, including:

> §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

This study, and the precautionary principle in general, are not without their critics.[235] 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 substan-

229. *Id.*

230. *See supra* tbl. 3.

231. *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.

232. Science and Environmental Health Network describes itself as

> 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.

Science & Envtl. Health Network, *About SEHN: History and Mission*, http://www.sehn.org/about.html (last visited June 26, 2008).

233. Joshua Skov & Nancy Myers, Easy Money, Hidden Costs, Applying Precautionary Economic Analysis to Coalbed Methane in the Powder River Basin (2004), *available at* http://www.sehn.org/tccpdf/coalbed%20methane%20costs%20Powder%20River.pdf.

234. 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.*

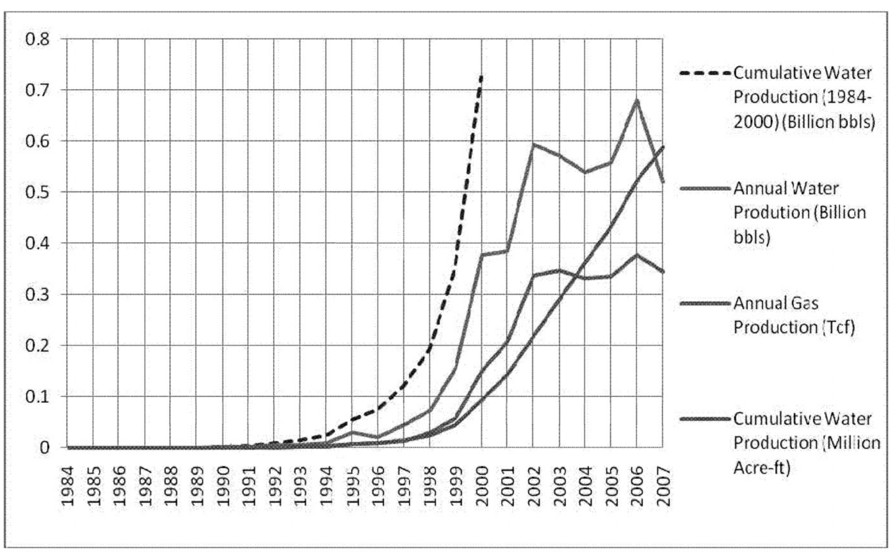
235. Julian Morris of the International Policy Network in London was quoted as saying: "If someone had evaluated the risk of fire right after it was invented they may well have decided to eat their food raw." Steven G. Gilbert, A Small Dose of Toxicology: The Health Effects of Common Chemicals 238 (CRC Press 2004).

> tially 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.[236]

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[237] would be a resource loss of nearly $4 million. This number is nowhere near $10.1 billion, but still shows that the numbers involved are not trivial. Significant increases in water 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 CBM's 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: 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.[238] 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 commercially viable CBM fields. The first wells came online in the mid-1980s, and have production lives of 10 to 40 years.[239]

Figure 4: CBM Water and Gas Production in the Powder River Basin (1984-2007)[240]



236. Roger Coupal, Review of Economic Issues Associated With CBM Development (2005), *available at* http://www.uwyo.edu/enr/ienr/Projects/Coupal2005.pdf.

237. *See infra* fig. 4.

238. Thomas J. Schneider, Coalbed Methane Produced Water Reinjection (2001), *available at* http://www.deq.state.mt.us/CoalBedMethane/pdf/SchneiderPaper5-16-01.PDF.

239. Black Diamond Energy, a producer in the basin, states:

> The 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 et al., *Coalbed Methane in Wyoming*, http://blackdiamondenergy.com/coalbed2.html (last visited June 26, 2008).

240. Oil & Gas Conservation Comm'n, Wyoming, *Homepage*, http://wogcc.state.wy.us/ (last visited June 26, 2008) (follow "statistics" hyperlink to data sources).

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 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.[241] 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 years into the future. Indeed, a recent report by Sandia National Laboratories concluded that

> [w]hile 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.[242]

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. One study modeled a hypothetical field in the Powder River Basin.[243] Although the regional study was not meant as a comprehensive statewide analysis, the authors did compare benefits (labor income and local tax revenues during production) to costs (production costs, local government costs of the extra economic activity, estimated opportunity costs of lost water on potential economic development, 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).[244] 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.[245]

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 extraction of oil and gas 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, New Mexico, and Utah treat CBM-produced water similarly to traditional oil and gas waste, but Colorado (after *Vance*) and Wyoming 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.[246] The "beneficial use" model (with concurrent regulation by the SEO) fails to account for the massive quantities of produced water that often cannot be beneficially used in the traditional sense[247]; and assumes mine dewatering is a "beneficial use," implying the water cannot be waste, which may present state constitutional issues.[248]

There is little reason to believe that a legislative solution that could avoid both sets of problems is impossible.[249] Be-

241. *See* fig. 4. 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.

242. Sandia Nat'l Labs., Technical Review of Proposed Changes in Montana Water Quality Standards for Coalbed Natural Gas Produced Water 19 (2006) (SAND-2006-0312), *available at* http://www.fossil.energy.gov/programs/oilgas/publications/coalbed_methane/sandia_report.pdf.

243. 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), *cited in* Roger Coupal, Review of Economic Issues Associated With CBM Development 10 (2005), *available at* http://www.uwyo.edu/enr/ienr/Projects/Coupal2005.pdf.

244. Stewart E-mail, *supra* note 161.

245. *Id.* ("Wyoming has a law that prevents the movement of over 1,000 [acre-fee per year of water] out of state. This will need to be modified in the future to utilize this resource.").

246. *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 (2002).

247. Darin noted:

> The 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.

248. *Id.*

249. 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:*

cause the specific statutory regimes for administering water and handling produced water vary between western states, examining specific states' regulatory frameworks is most appropriate. In this Article, Colorado is chosen as an example state.[250] Two potential statutory changes and one COGCC rule change are proposed and evaluated in terms of their economic, legal, and political merit.

A. Colorado Statutory Changes

Just as the doctrine of prior appropriation first emerged in Colorado, a legislative solution to CBM-produced water may emerge there as well. In any case, the state will pass legislation on the subject soon.[251] The *Vance* case has highlighted the issue, and legislators are authorized to implement a solution to the CBM-produced water by 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."[252] The three proposals below may provide a partial solution to the problem.

1. Codify CBM Dewatering as "Beneficial Use" to Force Cost Internalization and to 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 of CBM-produced water depleted surface streams by 156 acre-feet annually.[253] Depletion in this basin will not drop below 50 acre-feet annually until after 2300.[254] In the Raton Basin, the losses are much higher: 16,000 acre-feet of annual dewatering depletes surface streams by 2,500 acre-feet annually.[255] Because the water withdrawn is currently 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 value).[256] The first step in any statutory reform would be forcing producers to bear the cost of depletions. Despite recent reforms to the COGCC,[257] this would best be accomplished utilizing the existing state water administration regime.[258] 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.[259] Because of the uncertainties in scope of the *Vance* holding,[260] a statute limiting beneficial use to CBM dewatering is required to exclude the approximately 30,000 conventional oil and gas wells in the state from the SEO's jurisdiction and the appropriation system.[261]

Producing Energy and Protecting Water, 4 Wyo. L. Rev. 541, 555-57 (2004).

250. Colorado was chosen as this Article's focus 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.

251. In September 2007, Sen. Jim Isgar, chairman of the Colorado Water Resources Review Committee, said: "For 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, Sept. 13, 2007, *available at* http://durangoherald.com/asp-bin/article_generation.asp?article_type=news&article_path=/news/07/news070913_3.htm; *see also* Wolfe Interview, *supra* note 33.

252. Colo. Const. art. XVI, §3.

253. *See* S.S. Papadopulos & Assocs. & Colo. Geological Survey, *supra* note 84.

254. *Id.*

255. *Update on Coal Bed Methane Produced Water Litigation Before the Colo. Water Resources Review Comm.* (Sept. 12, 2007) (statement of Dick Wolfe, Ass't State Eng'r, Div. of Water Resources) [hereinafter Wolfe Testimony].

256. 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* S.S. Papadopulos & Assocs. & Colo. Geological Survey, *supra* note 84.

257. Colorado House Bill No. 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. (Colo. 2007) (enacted). Colorado House Bill No. 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. (Colo. 2007) (enacted).

258. 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.

259. 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 nontributary situations. Colo. Rev. Stat. §37-90-137(7).

260. 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.

261. *See* Hanel, *supra* note 251.

2. Introduce a Tributary/Nontributary Distinction 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 nontributary if*
>
> > *(1) the top of the aquifer is at a depth of 2,500 feet or more below the ground's surface at any location at which a well is drilled; and*
> > *(2) the aquifer contains water not less than 10,000 ppm 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 produced water is like surface water (high quality, easily accessible, and fit for various uses), but the logic breaks down when the produced water starts to resemble traditional oil and gas wastewater (low quality, difficult to extract, and unfit for most traditional uses). At some point, the produced water shifts from an asset to 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 nontributary mine dewatering statute, which still requires that 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.[262]

Currently, all Colorado groundwater is presumed to be tributary unless proven otherwise with hydrologic facts.[263] Unless the aquifer in question has already been proven to be nontributary, 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 nontributary areas—produced water with TDS higher than 10,000 mg/L[264] and well below the range of most domestic or livestock watering wells (2,500 feet)[265] would carry a presumption of being nontributary. This TDS/depth limit would also mirror hydrologic facts: in general, nontributary 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 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.[266] The provision is also unpopular with some legislators—a 2007 bill that would close the loophole failed in the state 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 [Oil Conservation Division] to authorize injection into deep aquifers . . . ."[267]

Neither of New Mexico's concerns would apply in Colorado. The SEO and the COGCC already have concurrent jurisdiction over all nondesignated aquifers, so introducing a statutory definition of nontributary 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.

3. Allow for Class V Injection

New COGCC Rule 907(c)(2) (listing disposal methods for produced water) add[268]:

> *"(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 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

262. *See* Colo. Rev. Stat. §37-90-137(7).

263. *See* Platte Valley Irrigation Co. v. Buckers Irrigation, Milling & Improvement Co., 53 P. 334 (Colo. 1898).

264. 10,000 mg/L is the number typically cited for "usable" or high-quality water. *See* Interstate Oil & Gas Compact Comm'n & ALL Consulting *supra* note 10, 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.").

265. Most domestic water wells in the San Juan Basin do not exceed 400 feet. Wolfe Interview, *supra* note 33.

266. Staci Matlock, *Nature Holds Trump Card with Water Rights*, New Mexican (Sept. 15, 2007), *available at* http://www.freenewmexican.com/news/68605.html.

267. 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.

268. COGCC R. 907(c)(2) (Colo. Oil & Gas Conservation Comm'n 2006), http://www.oil-gas.state.co.us/RR_Docs/rules_new2.html.

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 2006, the owner of the Wellington oilfield doubted that he would have undertaken the project if he would have fully understood its complexities.[269] If a highly profitable and arguably desirable project that will produce marketable water for 300 to 500 years[270] 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? As shown earlier in Section 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 four 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 nontributary areas; and (4) CBM operators in tributary areas.

In the first example, 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.[271] 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 startup time would be reduced significantly. They could show that their produced water was nontributary without extensive hydrologic modeling, and the SEO review would be considerably shorter. Lower capital costs would allow for treatment of lower quality produced water.

In the third example, CBM producers in statutorily defined nontributary areas, §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.

Finally, 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 nontributary, 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[272] (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.[273] 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,[274] 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.[275] 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.[276] 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 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,[277] and nontributary operators would only

269. 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]." Brad Pomeroy, The Wellington Oil Field: A Case Study of the Beneficial Use of Produced Water From an Oil Field in Colorado 98, 98 (2006) (Produced Water Workshop) (on file with author).

270. *See* Cherry Sokoloski, *Udall Bill Could Help Oil-Rich, Water-Poor West*, N. Forty News, Apr. 2007, *available at* http://www.northfortynews.com/Archive/A200704UdallBill.htm.

271. *See supra* note 104.

272. *See* Wolfe Interview, *supra* note 33.

273. *See* Wolfe Testimony, *supra* note 255.

274. 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.

275. *See* Wyo. SEO, *supra* note 196.

276. *See* Colo. Rev. Stat. §37-92-502(2)(a).

277. Through the augmentation plan approval.

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.[278]

C. The Political Feasibility of CBM-Produced Water Legislation

Politically, these statutory changes can be characterized as a sort of trade: CBM producers would be subject to additional regulations 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 management regulation.[279] 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.[280] 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 Colorado Constitution states that "[t]he right to divert the unappropriated waters of any natural stream to beneficial uses shall never be denied."[281] Nontributary groundwater is not part of the "natural stream" and thus outside constitutional water provisions. Landowners could argue that some waters falling under the statutory nontributary exemption were in fact tributary, and hence part of the "natural stream."[282] Because the CBM operators would be making these waters unavailable, the landowners 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

CBM reserves are extensive in the intermountain West and are an important part of the U.S. 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, relaxing 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.

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278. *See* Bryner, *supra* note 249, at 555-57.

279. Ken Wonstolen states that "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." E-mail from Ken Wonstolen, Gen. Counsel and Senior Vice President, Colo. Oil & Gas Ass'n (Nov. 26, 2007) (on file with author).

280. 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 182.

281. Colo. Const. art. XVI, §6.

282. *Id.*