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Topical Report

POLICY ANALYSIS OF PRODUCED WATER ISSUES ASSOCIATED WITH IN-SITU THERMAL TECHNOLOGIES

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POLICY ANALYSIS OF PRODUCED WATER ISSUES ASSOCIATED WITH IN-SITU THERMAL TECHNOLOGIES

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ABSTRACT

Commercial scale oil shale and oil sands development will require water, the amount of which will depend on the technologies adopted and the scale of development that occurs. Water in oil shale and oil sands country is already in scarce supply, and because of the arid nature of the region and limitations on water consumption imposed by interstate compacts and the Endangered Species Act, the State of Utah normally does not issue new water rights in oil shale or oil sands rich areas. Prospective oil shale and oil sands developers that do not already hold adequate water rights can acquire water rights from willing sellers, but large and secure water supplies may be difficult and expensive to acquire, driving oil shale and oil sands developers to seek alternative sources of supply. Produced water is one such potential source of supply.

When oil and gas are developed, operators often encounter ground water that must be removed and disposed of to facilitate hydrocarbon extraction. Water produced through mineral extraction was traditionally poor in quality and treated as a waste product rather than a valuable resource. However, the increase in produced water volume and the often-higher quality water associated with coalbed methane development have drawn attention to potential uses of produced water and its treatment under appropriations law. This growing interest in produced water has led to litigation and statutory changes that must be understood and evaluated if produced water is to be harnessed in the oil shale and oil sands development process. Conversely, if water is generated as a byproduct of oil shale and oil sands production, consideration must be given to how this water will be disposed of or utilized in the shale oil production process.

This report explores the role produced water could play in commercial oil shale and oil sands production, explaining the evolving regulatory framework associated with produced water, Utah water law and produced water regulation, and the obstacles that must be overcome in order for produced water to support the nascent oil shale and oil sands industries.

EXECUTIVE SUMMARY

Eastern Utah is home to vast oil shale and oil sands resources. If economically feasible and environmentally responsible means of tapping these resources can be developed, these resources could provide a safe and stable domestic energy source for decades to come. Controversial issues with respect to oil shale and oil sands development involve development's demand for water and the availability of water in this generally arid region. Some prospective oil shale and oil sands developers have previously secured water supplies, but many have not and will need to secure water supplies before development can proceed. While water resources within eastern Utah are already fully allocated, some of these resources have not been developed and water could, theoretically, be reallocated to support oil shale and oil sands development. Where prospective oil shale and oil sands developers are unable to acquire water rights or the cost of acquisition is prohibitive, developers will seek out alternative water sources. Water produced as a byproduct of energy development represents such a source.

When oil and gas are developed, operators often encounter ground water that must be removed and disposed of to facilitate hydrocarbon extraction. Water produced as a byproduct of oil and gas production represents a potential source of supply for the nascent oil shale and oil sands industries. Likewise, oil shale development is expected to produce water as a byproduct of the retorting process (though less water than required for commercial operations). If water is generated as a byproduct of oil shale and oil sands production, consideration must be given to how this water will be utilized in the shale oil production process or otherwise disposed of.

Produced water management poses a challenge to western appropriative water law because produced water's principal value, to the oil and gas operator, is in its removal from the hydrocarbon bearing formation. Produced water withdrawn from the hydrocarbon bearing formation is a depletion of (or consumptive loss to) the source aquifer, but unlike ground water withdrawals for agricultural or domestic uses, primary production of oil and gas does not consume the water withdrawn. Unlike more conventional water uses where excess water can be returned to the source of supply, returning produced water to the source aquifer can impede hydrocarbon production and is therefore counterproductive, unless carefully controlled to enhance hydrocarbon recovery.

Produced water was traditionally treated as a waste product because if it has little if any value to the operator and is often poor in quality. Water rights were generally not required for water produced as a byproduct of hydrocarbon extraction because it was considered a waste product. Growing interest in water generated as a byproduct of natural gas production has lead to litigation and statutory changes that must be addressed if produced water is to be harnessed. Litigation and legislation respond to two significant concerns. First, that the withdrawal of water to facilitate hydrocarbon production is a beneficial use of water and requires operators to obtain a state issued water right at the outset of development, thereby ensuring that produced water withdrawals do not impair the valid existing water rights or harm ecological processes. Second, that state law prohibitions against the waste of water limit disposal options to methods that do not make useable water unavailable to other water users or cause water to run to waste. These two theories are not mutually exclusive and their application depends on evolving matters of state law as well as site-specific factors such as the amount and quality of water withdrawn, continuity between the source of supply and other water sources, treatment and disposal options, and opportunities to put produced water to secondary uses. While neither theory has been tested in a Utah court, with respect to either oil shale or oil sands development, arguments made with respect to natural gas and in neighboring states' courts may be predictors of challenges to come.

Operators' responses to these uncertainties are straightforward. Oil and gas operators have a clear incentive to reduce the volume of produced water brought to the surface as part of their development operations. Every gallon of withdrawal avoided is a permitting and disposal issue avoided, and lowering water production reduces the chance of causing impairment to other water right holders. Limiting withdrawals to no more than needed and making unused produced water available to other water users also addresses the potential for challenges that oil and gas operators should not waste produced water. Additionally, reducing produced water volume means fewer disposal wells, infiltration galleries, evaporation ponds, associated pumps and pipelines, and the permitting requirements they entail.

When produced water generation cannot be avoided, operators have a strong incentive to use the water produced as a byproduct of their operations for their own operational requirements. While a water right is likely required for reuse, reuse moderates the need to obtain additional scarce and expensive external water sources, moderates disposal costs, and reduces the amount of water subject to potential back-end beneficial use requirements. Recognizing that elimination of byproduct water generation is unlikely and reuse may not completely eliminate disposal requirements, operators should look for disposal options that avoid waste and make water available to others. Where water quality allows, produced water can be used to irrigate crops and reclaim disturbed areas, to water livestock and wildlife, to augment stream flows, and to recharge ground water.

Efforts by oil and gas operators to reduce produced water generation and to increase produced water reuse limit produced water as a source of supply for prospective oil shale and oil sands developers. However, even with the most aggressive reduction and reuse programs, some level of excess produced water generation is likely. The oil shale and oil sands industry may benefit, as they would represent a market for a product that is of limited use to the operator and which would otherwise represent a disposal challenge. Aside from non-legal concerns (e.g., produced water quality, treatment costs, transportation costs, and stability of supplies), prospective third-party produced water users will need to comply with state appropriations law. Provided that the produced water generator has satisfied with all applicable water law requirements, availability to third-party users will likely require a water right change authorization (or a water right if one was not required for formation dewatering).

Produced water generators, prospective produced water users, and government regulators alike must be flexible in adapting to site-specific issues and constraints, a rapidly evolving legal framework, and a resource that may change over time. Foreseeable increases in energy production will likely drive more stringent disposal and appropriations requirements and all involved must be flexible in responding to these challenges.

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List of Acronyms

AF	Acre-Foot
BBL	Barrel
BLM	Bureau of Land Management
BPD	Barrel per Day
CBM	Coalbed Methane
CWA	Clean Water Act
DGWS	Downhole Gas/Water Separator
DOGM	Utah Division of Oil, Gas, and Mining
DOWS	Downhole Oil/Water Separator
EIS	Environmental Impact Statement
EHR	Enhanced Hydrocarbon Recovery
GPD	Gallons per Day
ICSE	[University of Utah] Institute for Clean and Secure Energy
MBOGC	Montana Board of Oil and Gas Conservation
MG/L	Milligrams per Liter
PPM	Parts Per Million
SDWA	Safe Drinking Water Act
TDS	Total Dissolved Solids
UIC	Underground Injection Control [Well]

1. Introduction – Why Produced Water Matters

Much attention has been given to water demand associated with commercial oil shale and oil sands development.[1] Under reasonable assumptions, commercial oil shale development will require between 1.5 and 3.0 units of water per unit of shale oil produced.[2] Water use estimates associated with oil sands development are more wide-ranging, but generally in the range of 2.4 to 7.0 barrels of water for each barrel of oil produced.[3]

The Uinta Basin, which is shown in Figures 1 and 2, is home to all of Utah's commercially developable oil shale resources. Oil sands deposits, which are shown in Figure 3, are geographically more dispersed, but eastern Utah is also home to all major domestic oil sands resources.[4] Within much of the Uinta Basin, precipitation averages less than ten inches annually, and the arid nature of oil shale and oil sands bearing regions may make water a limiting factor for development. Precipitation within the region is shown in Figure 4. Because of existing water allocations, interstate agreements apportioning water, and Endangered Species Act requirements, new surface water rights within the Uinta Basin are generally not available.[5] Surface and ground water are presumed to be connected so new ground water rights are generally not available unless discontinuity can be shown. Accordingly, prospective oil shale and oil sands developers must already possess valid water rights, or acquire existing water rights and obtain permission to change the use associated with those rights. As discussed in earlier Institute for Clean and Secure Energy (ICSE) reports, the State of Utah holds water rights on the White River and Green River, some of which may be available for oil shale and oil sands development.[6] While these conventional water sources are likely to represent the most desirable sources of supply, existing water allocations and requirements for federally protected species will limit the extent to which these sources can be developed and alternatives to conventional sources could fill an important need.

Figure 1
Oil Shale Location Map

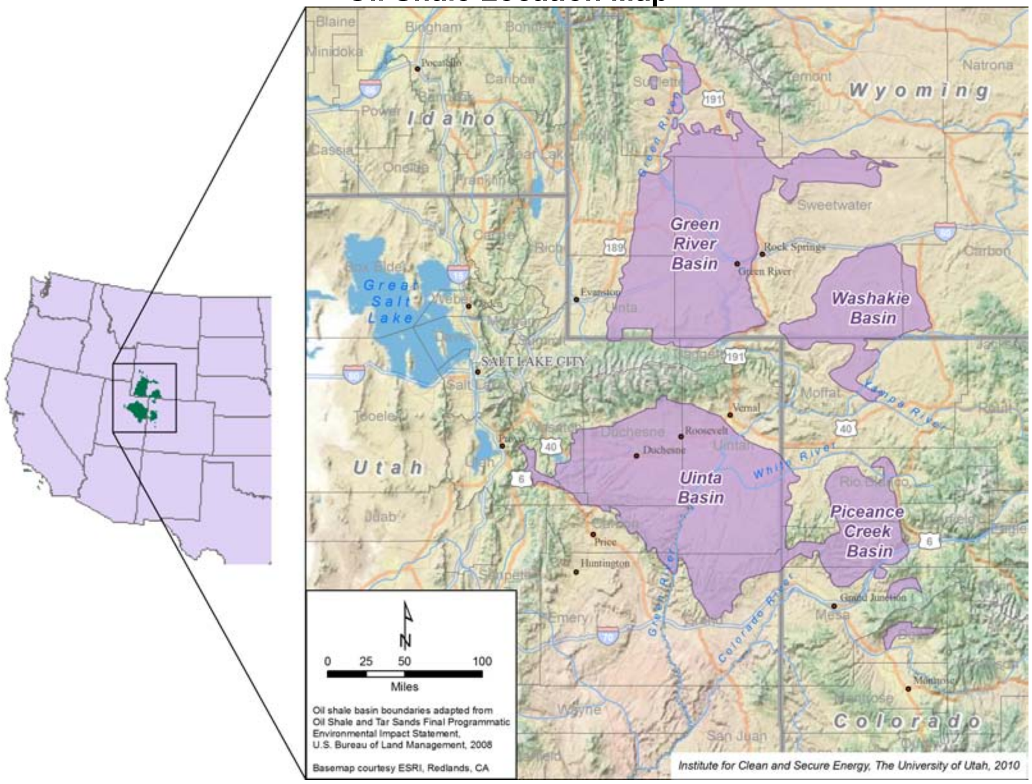


Figure 2
Oil Shale Resources Within the Uinta Basin

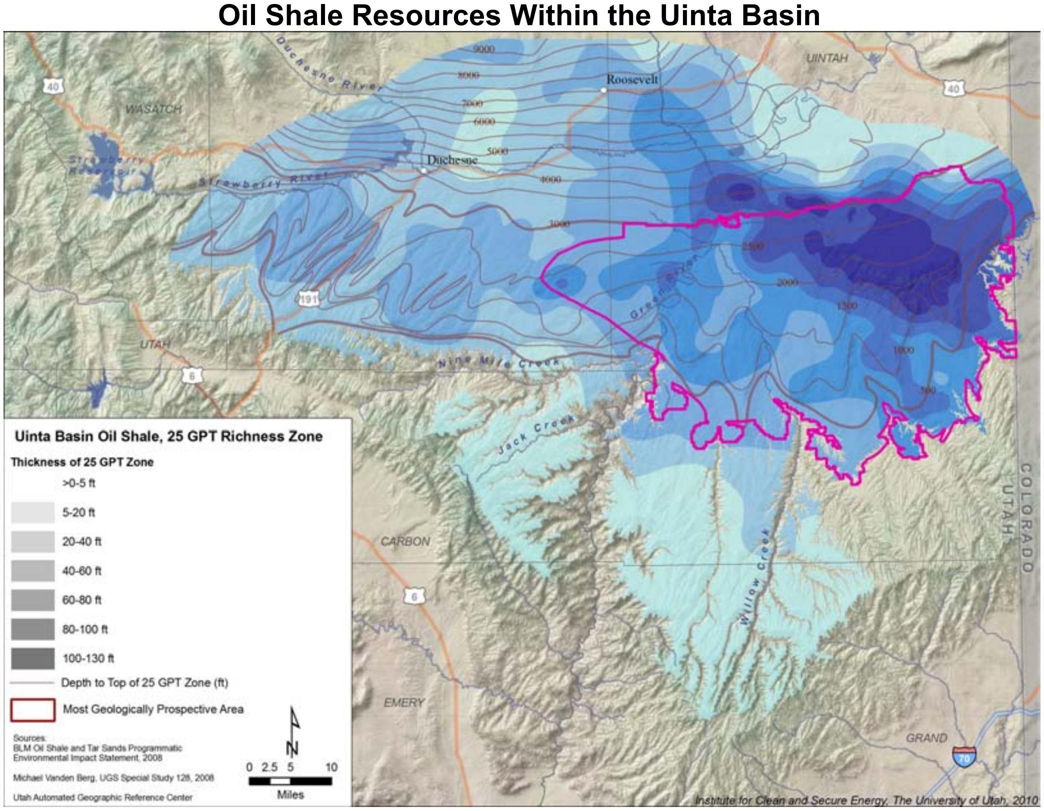


Figure 3
Special Tar Sands Areas

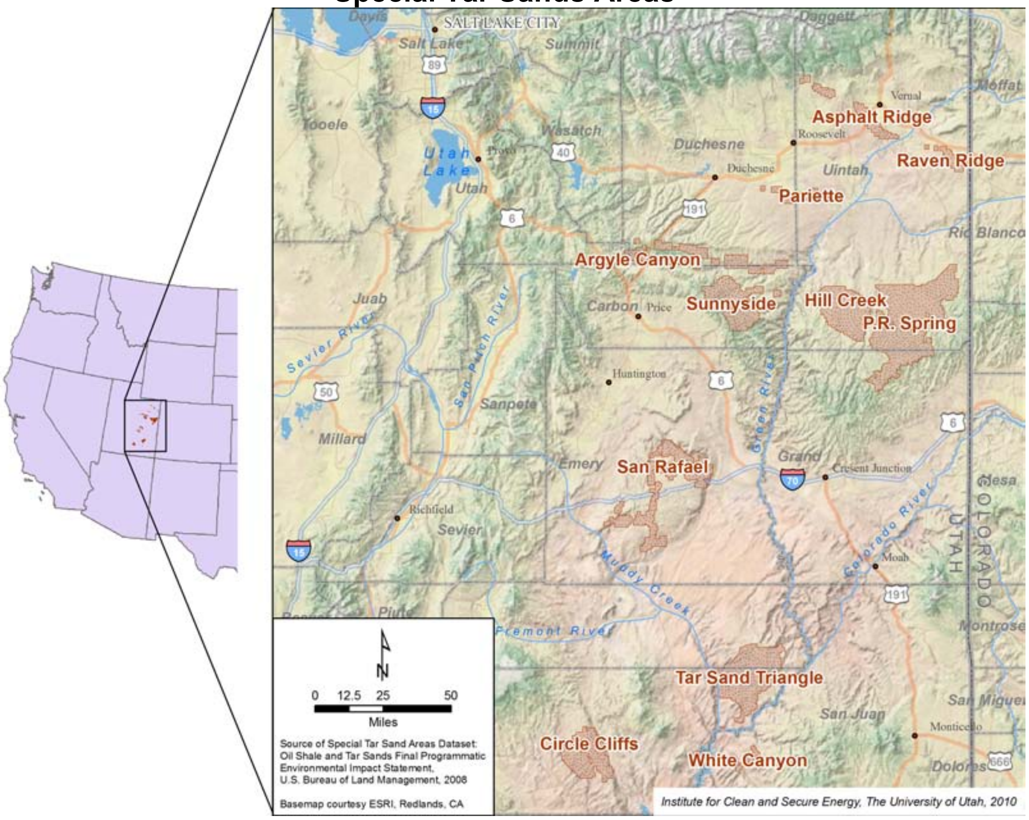
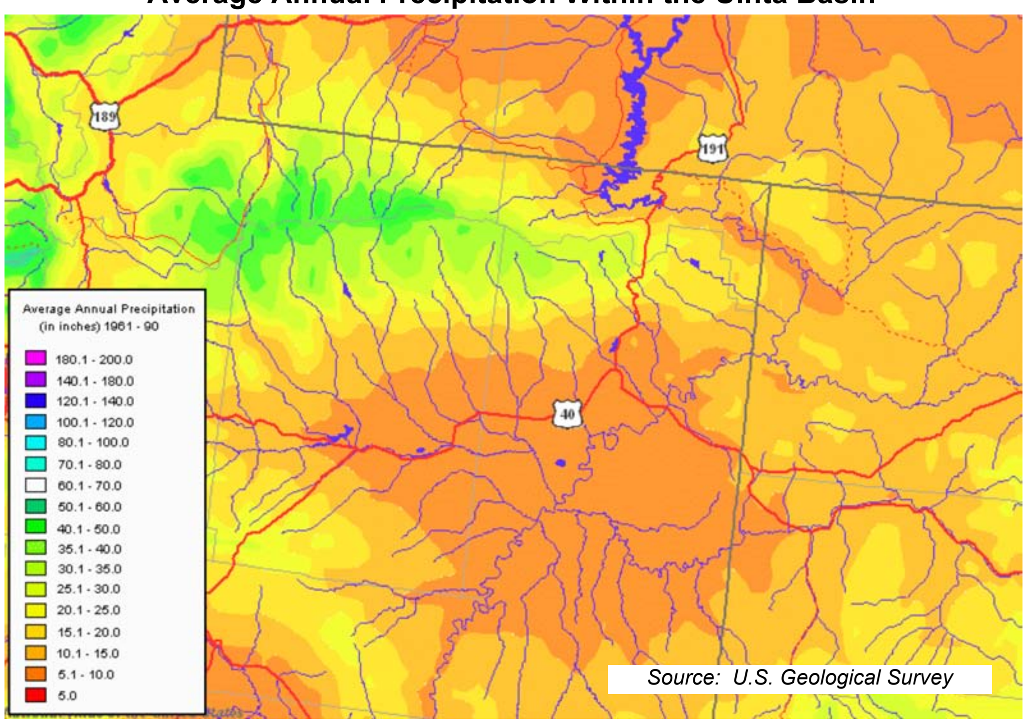


Figure 4
Average Annual Precipitation Within the Uinta Basin



Source: U.S. Geological Survey

If prospective oil shale and oil sands developers do not currently possess valid water rights and cannot find an existing water right holder willing to convey water, water resource availability could impede development. Prospective developers may find an alternative source of supply in water produced as a byproduct of oil, natural gas, or coalbed methane (CBM) production (referred to as produced water or byproduct water in this report). Within Uintah County, approximately 46.5 million barrels (BBLs) (5,989 acre-feet (AF)) of produced water[7] were generated during 2009, the most recent year for which statistics are available.[8] Much of this water was disposed of as a waste product. If stable supplies of produced water could be treated to support application to a beneficial use and regulatory hurdles can be overcome, produced water could represent an alternative source of supply for the nascent oil shale and oil sands industries while simultaneously reducing disposal costs for produced water generators.

While putting produced water to a beneficial use may represent a proverbial win-win situation, produced water is not free for the taking. Under Utah law, all water within the state is public property[9] and administered by the state to maximize benefits to the state's citizens.[10] Water, even wastewater, cannot be used without first obtaining a water right. The emerging trend whereby western states treat the withdrawal of water to facilitate energy production as a beneficial use poses several challenges for both produced water generators and those hoping to capture and utilize the produced water resource. Where the withdrawal of water is considered a beneficial use, the producer must obtain a right to appropriate water before operations can proceed. Obtaining a water right can prove problematic if the water withdrawn comes from aquifers in continuity with surface or ground water resources that are already appropriated. Growing recognition of the potential value of produced water may also limit options for its disposal, precluding disposal processes that are wasteful or pose risks to other water users.

Complicating matters, oil shale and oil sands operators are produced water generators. At the upper bounds of short to mid-term oil shale production estimates (50,000 BBLs per day or

BPD), in-situ processing would generate an estimated 1,882 AF of produced water annually.[11] The quality of produced water depends on the geologic formation from which the water and associated hydrocarbons are withdrawn, as well as the production processes used to recover the oil shale resource. Produced water that cannot be put to a beneficial use cost effectively must be disposed of in accordance with applicable federal and state laws. Disposal costs will depend on disposal methods and the level of treatment needed prior to disposal. Disposal requirements aside, produced water generators will need to find available disposal facilities. Since evaporation is disfavored,[12] producers would normally turn to injection wells. However, geology limits which formations can be injected into and the capacity of the Birds Nest Aquifer, proximate to Utah's oil shale resources, is under investigation.[13] Safe Drinking Water Act (SDWA) requirements also restrict injections in order to protect underground sources of drinking water.

Western water law is poorly equipped to deal with produced water generation and disposal. While conventional water users divert or withdraw only what they intend to consume, produced water generators withdraw as needed to capture the oil or gas resources without consuming the water withdrawn. And unlike conventional water users, unconsumed produced water cannot be easily returned to its source. Produced water generators are therefore in the unique position of possessing a potentially valuable resource with limited means of avoiding resource depletions. Reconciling produced water management with conventional objectives of maximizing development, preventing waste, and avoiding injury to third parties has resulted in litigation impacting both produced water generators and those interested in subsequent produced water management.

Section Two looks in more detail at produced water's potential role in oil shale and oil sands development. Against this factual backdrop our analysis turns to produced water regulation, focusing primarily on recent developments within the CBM extraction industry. We conclude with a discussion of the practical impact of recent litigation and what prospective oil shale and oil sands producers can anticipate with respect to produced water management within Utah.

2. Produced Water and Its Role in Commercial Oil Shale and Oil Sands Development

> "Many of the oil shale and tar sands deposits in Utah are located near existing oil and gas activities where produced water is generally trucked from the site or replaced through injection wells. With injection well siting providing its own set of challenges and water removal transport requiring additional roadway activity, the environmental benefits of utilizing local produced water extend beyond minimization of fresh water requirements. Solutions such as recycling of produced water from conventional oil and gas production could be utilized to help offset water requirements for oil shale production."
>
> – Utah Mining Ass'n (2008).

Water produced through mineral extraction has traditionally been treated as a waste product rather than a valuable resource and therefore, regulated under disposal laws rather than water appropriations law. If available for appropriation, produced water presents a largely untapped source of water. Produced water is of particular import within Utah's Uintah County because the County is home to all of Utah's commercially viable oil shale resources and some of the state's richest oil sands resources. See Figures 2 and 3. While rich in energy resources, Uintah County has limited water resources, and most water resources were fully appropriated long ago. Although short on conventional water resources, Uintah County generates more produced water than any other county in the state. The prospect of a substantial volume of water that could be used for commercial oil shale or oil sands development is understandably exciting to many.

This section begins with a discussion of water needs for oil shale and oil sands production, the availability of conventional water sources, and produced water's potential as an alternative source of supply. From these front-end concerns, we turn briefly to produced water disposal and water generated as a byproduct of oil shale and oil sands development. These discussions form the factual backdrop for the regulatory discussions to come.

2.1. Produced Water as a Source of Supply

Oil shale and oil sands development will require water; the amount will depend upon the technologies utilized and the size of oil shale and oil sands developments. While water demands are not currently susceptible to precise quantification, it is universally recognized that water is scarce in areas containing Utah's oil shale and oil sands resources. With water resources constrained by existing appropriations and the need to protect threatened or endangered fishes, water produced as a byproduct of oil and gas production represents a potential source of supply that, if developed, could reduce current pressure on produced water disposal operations.

2.1.1. <u>Water Needs for Oil Shale and Oil Sands Development</u>

The amount of water required for commercial oil shale and oil sands development is the subject of heated debate. The nascent nature of the oil shale industry limits the ability to accurately quantify water demand, forcing resource planners to make assumptions regarding the nature and scale of future developments. While limited domestic oil shale development occurred during the 1970s and 1980s and some development has occurred internationally differences between domestic and international resources, technological differences, and evolving environmental requirements complicate efforts to extrapolate from past projects.[14] Likewise, while a significant body of oil sands related information is available based on development within Canada, caution should be used in extrapolating water use figures from Canada because of differences between the resources in Alberta and Utah and the technologies that may be needed to process these different sands.[15]

An earlier ICSE report reviewed a number of water use estimates, adopting what we described as a conservative assumption that three units of water would be required for each unit of shale oil produced.[16] Estimates available at the time indicated that water use associated with oil shale development could be substantially lower than we assumed, but a lack of transparency regarding the assumptions inherent in these low estimates cautioned against their adoption. This report retains the three to one water to oil ratio as an upper estimate of water demand, and we adopt 1.5 units of water per unit of oil produced as a lower estimate. This lower estimate reflects the low estimate of direct and indirect energy use for in-situ retorting reported by AMEC Earth and Environmental as part of Colorado's Water for the Twenty-First Century planning process.[17] Water use estimates for oil sands are based on information contained in the Bureau of Land Management's (BLM) 2008 Final Environmental Impact Statement (FINAL EIS) for Oil Shale and Tar Sands.[18] Table 1 shows a reasonable range of short to mid-term water demand estimates for oil shale and oil sands development. While these estimates are based on a smaller industry than many assume will eventually develop,[19] these projections reflect recent industry statements regarding production over the next decade that have been scaled up to provide a margin of safety.[20] Information obtained as oil shale and oil sands producers scale up from bench and pilot scale experiments to commercial scale operations will facilitate more accurate assessments and provide the foundation for the more detailed plans needed to accommodate large scale development.[21]

Table 1
Estimated Water Demand for Commercial Oil Shale and Oil Sands Development[22]

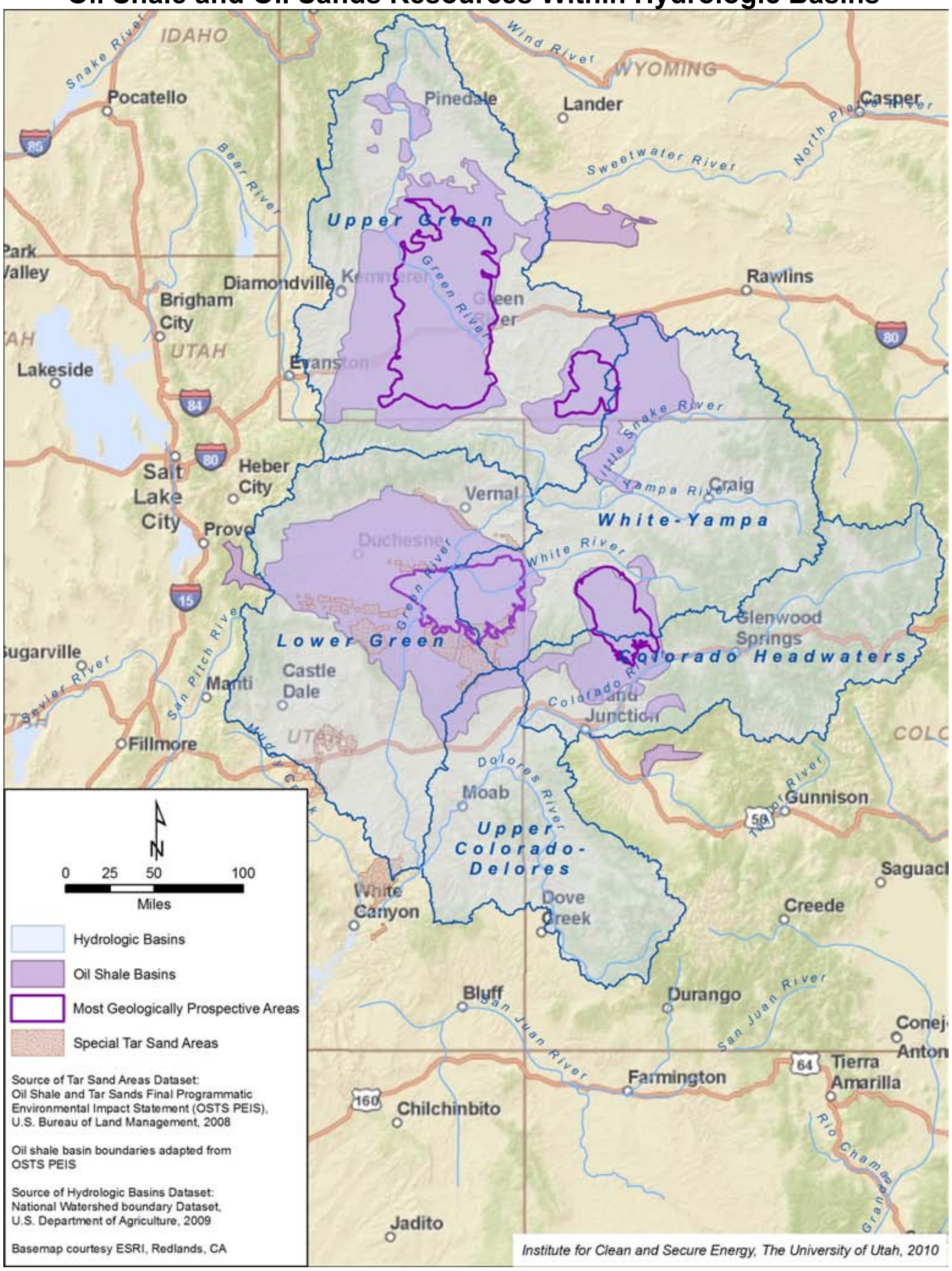
	10,000 BBL/day Production	50,000 BBL/day Production
Oil Shale (1.5 - 3.0:1)	706 to 1,411 AF	3,528 to 7,057 AF
Oil Sands (2.4 - 7.0:1)	1,129 to 3,293 AF	5,646 to 16,466 AF

In considering future water needs, policy makers should bear in mind that oil shale and oil sands production are not the only energy-related demand on water resources. Utah's Uinta Basin is experiencing unprecedented natural gas permitting activity and decisions to forego or proceed with oil shale or oil sands development will occur in the context of other energy development decisions. Water resource planning must therefore consider whether oil shale and oil sands development will displace, be displaced by, or occur in addition to other forms of energy development. If oil shale or oil sands development occurs in addition to conventional oil and natural gas production, direct and indirect strains on water resources will increase. If conventional and unconventional hydrocarbon production cannot be co-located, conventional mineral development will likely displace oil shale and oil sands production as conventional resources are already undergoing rapid development, while oil shale and oil sands have yet to achieve commercial scale production.

2.1.2. <u>Conventional Water Availability</u>

Oil shale resources are located in portions of Colorado, Utah, and Wyoming that are tributary to the Colorado River. The Colorado River is heavily regulated and water resources within the river basin are fully allocated between the seven basin states. Oil shale and oil sands resources and major river basins are shown in Figure 5.

Figure 5
Oil Shale and Oil Sands Resources Within Hydrologic Basins



The State of Utah has not utilized its full apportionment of Colorado River system water and some water from the White River or Green River (both of which are part of the Colorado River system) may be available. However, the ability to utilize these water sources is constrained by Endangered Species Act requirements that protect habitat for four federally protected fish species. Utah's growing population and a changing climate are also likely to increase stress on water resources, the severity of which will increase with time.[23] Oil sands resources also exist within the Colorado River Basin and are subject to the same constraints. While this section discusses water availability within Utah to provide context for the growing interest in produced water, supply constraints are evident throughout the broader intermountain region.

Water is public property under Utah law,[24] and the right to use surface or ground water can be obtained only through an application approved by the State Engineer.[25] Water rights are a form of property and can be transferred between buyers and sellers, subject to State Engineer approval.[26] Some prospective oil shale and oil sands developers have already secured water rights to support planned oil shale or oil sands development.[27] Those who have not already secured water rights will need to obtain them.

Within Utah, water resources are managed in resource areas defined by major hydrologic basins. Area 49 (shown in Figure 6) contains Utah's richest oil shale resources. Within Area 49, surface waters are fully appropriated and ground water resources are generally limited to domestic or temporary supplies, when they are available at all.[28] Utah's oil

Figure 6
Water Resource Area 49

Source: Division of Water Rights, Utah Department of Natural Resources.

sands resources are spread over a broader geographic range, but are subject to similar water scarcity concerns.[29] Some of the existing appropriations are held by the Utah Division of Water Resources, which has not developed these rights and may be willing to convey appropriations to others.[30]

For prospective transferees, the most desirable water rights reflect stable sources of supply and allow for consumptive use of large quantities of water. Relatively large and secure water rights include senior irrigation rights and rights to water stored in the Flaming Gorge Reservoir.[31] The Ute Tribe of Indians also holds claims to very large quantities of water, and their claims are among the most senior in the Uinta Basin.[32] Competition for limited water resources will increase as the arid west's population continues to increase, making "new" sources of water very attractive.

2.1.3. Water Potentially Available from Oil, Gas, and CBM Development

Water produced as a byproduct of oil and gas development is of no small consequence due to the volume of water involved. In Utah, the Division of Oil, Gas, and Mining (DOGM) reports that during 2009, oil and gas wells generated over 20,000 AF of produced water statewide.[33] In Uintah County, oil and gas operators reported production of 46.5 million BBLs (5,989 AF) of produced water during 2009.[34] This number is likely to increase substantially if proposed oil and gas developments are approved.

As of 2006, the three primary means of produced water disposal within Utah were water flooding (also referred to as enhanced hydrocarbon recovery or EHR) associated with secondary oil and gas production (44.7 percent), deep injection disposal wells (Underground Injection Control or UIC wells regulated under the SDWA) (37.4 percent), and discharges to surface waters under Utah Pollution Discharge Elimination System permits (14.7 percent).[35] Evaporation pits are used to dispose of only 2.5 percent of produced water statewide.[36] Quantification of disposal methods is not available at the county level, but DOGM indicates that evaporative pits may be the dominant disposal method within the Uinta Basin.[37] The prevalence of evaporation pits within the Uinta Basin reflects limited disposal well capacity rather than a preference for evaporation.[38]

Produced water generation and disposal will become increasingly problematic if oil and gas development occurs as proposed. As of July 2010, DOGM reported 6,017 active oil and natural gas wells within Uintah County.[39] Figure 7 shows oil and gas fields near oil shale and oil sands resources. However, as of November 2010, there were at least ten oil and gas field developments proposed or recently approved within the Uinta Basin. Project locations, which are shown in Figure 8, extend beyond known field boundaries, indicating that Figure 7 may under represent the scope of both energy resources and development conflicts. If approved as proposed, these projects would authorize development of over 25,000 additional wells. A brief description of these projects and their anticipated means of produced water disposal follow. In some cases, the projects are in the early stages of permitting and environmental review and little information is currently available. Most, if not all of these projects will not use produced water for dust suppression or revegetation because of high total dissolved solids (TDS) levels and salinity control requirements.[40] Some produced water will be used for EHR or other downhole activities, but large quantities of produced water will require disposal if development proceeds as proposed.

Figure 7
Oil and Gas Fields

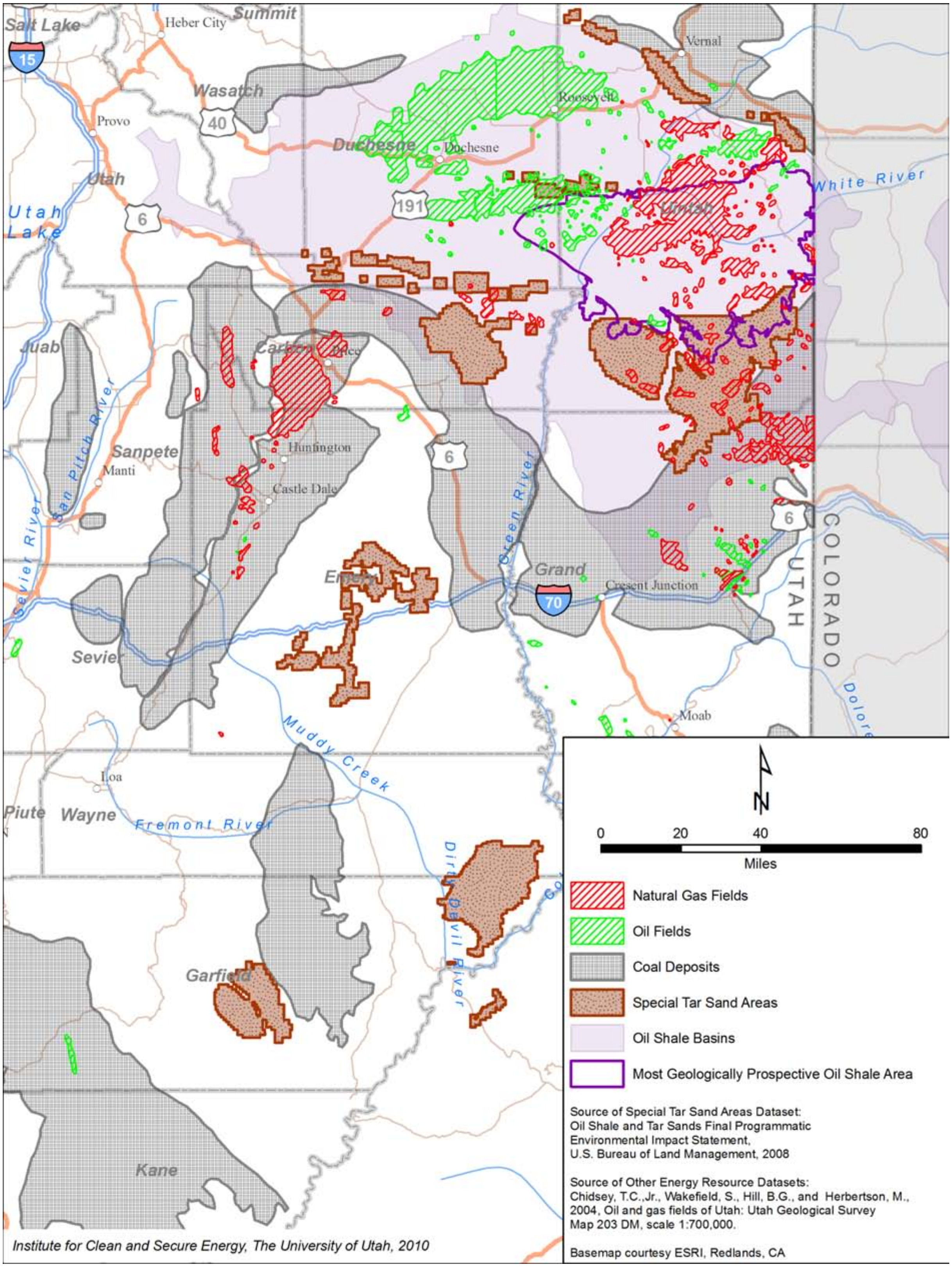
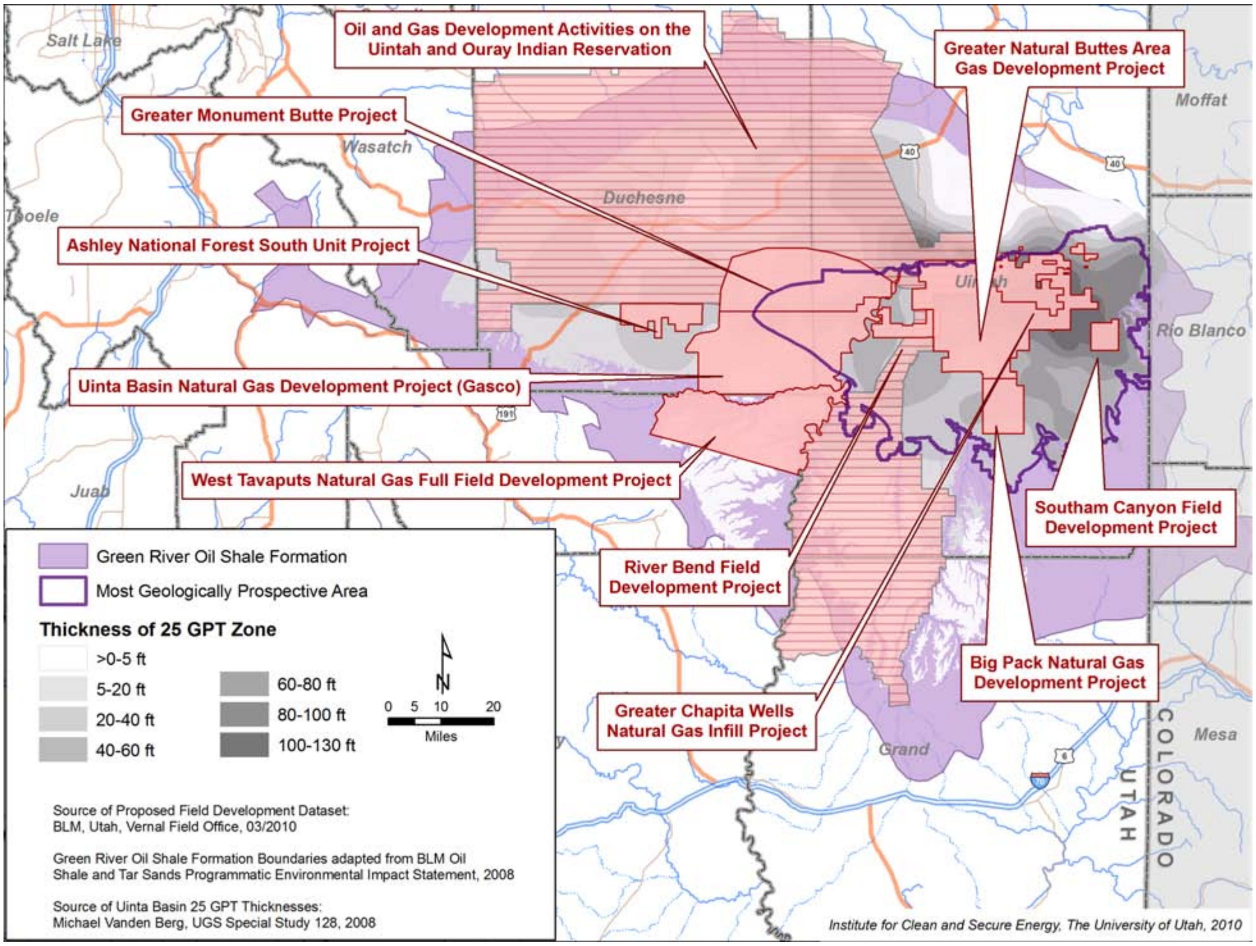


Figure 8
Pending Oil and Gas Development Projects



The West Tavaputs Natural Gas Full Field Development Project was recently approved to develop 626 new wells across 137,930 acres (216 square miles) of federal and state lands. Existing gas wells within the project area produce approximately eight BPD (336 gallons) of water; assuming comparable produced water generation rates, new wells are likely to produce 5,008 BPD of water (216,370 gallons per day (GPD) or 236 AF per year). Produced water will be disposed of with three new water management / disposal facilities and seven saltwater disposal wells.[41]

The Uinta Basin Natural Gas Development Project (also known as the GASCO project) calls for 1,491 new wells over 206,826 acres (323 square miles) of federal, state, and private lands. Based on the Draft Environmental Impact Statement (Draft EIS) for the project, the proposed action would produce approximately 30,000 BPD of water (1,260,000 GPD or 1,412 AF of water per year). Produced water would likely be unsuitable for reuse and would be disposed of in up to thirty 450 by 650 foot evaporation ponds (total pond surface area would be approximately 200 acres). Injection wells could also be used if suitable receiving aquifers can be found.[42]

The Greater Natural Butte Area Gas Development Project proposes 3,675 wells across 162,911 acres (255 square miles) of federal, state, private, and tribal lands. Based on the Draft EIS for the project, the proposed action would produce approximately 29,500 BPD of water (1,239,000 GPD or 1,388 AF per year). Produced water would be used for hydraulic fracturing, reused, injected into disposal wells, or disposed of in evaporation ponds.[43]

The South Unit Oil and Gas Development Project proposes up to 400 new oil and gas wells across 25,900 acres (40 square miles) of National Forest System land.[44] The Draft EIS for the project does not disclose anticipated produced water volumes, but states that approximately seventy percent of produced water would be reused for drilling and completions of new wells, and for off-site EHR. The remaining produced water would be trucked to an off-site injection or evaporation facility.[45]

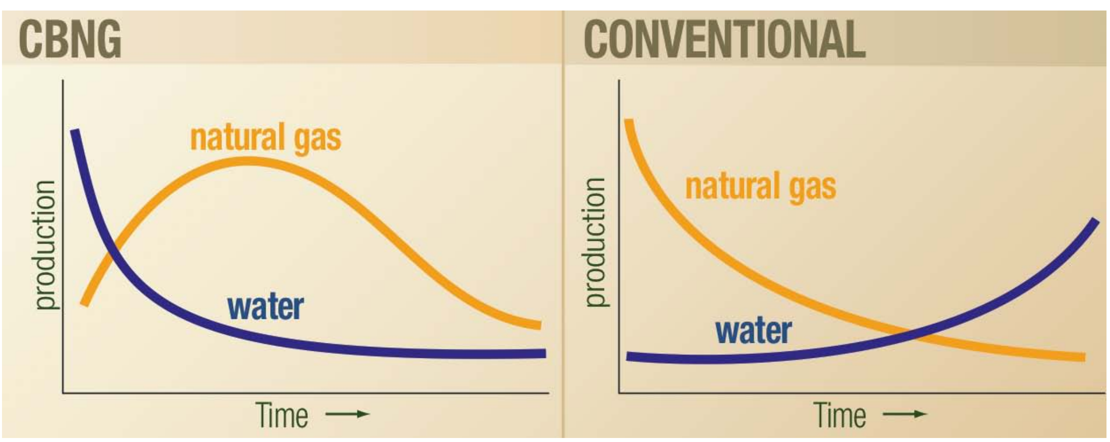
Three additional projects are beginning the EIS process, and thus far only minimal information is available regarding anticipated byproduct water production levels and disposal processes. The Greater Chapita Wells Natural Gas Infill Project proposes 7,028 new wells over 48,027 acres (75 square miles) of federal, state, tribal, and private lands. Existing produced water treatment and disposal facilities would support the project, with new injection wells drilled as needed. The Greater Monument Butte project proposes 5,570 new wells over 119,850 acres (187 square miles) of federal, state, private, and tribal lands. Existing treatment facilities would be utilized and augmented by construction of eight new injection facilities. The Bureau of Indian Affairs is evaluating proposed development of 4,899 new wells across 18,866,770 acres (2,948 square miles) of the Uintah and Ouray Indian Reservation. Information regarding produced water management for this project is not currently available.

Three more projects are being reviewed in Environmental Assessments. The River Bend Field Development Project proposes 484 wells across 16,719 acres (twenty-six square miles) of federal, state, and tribal lands. Produced water volumes have not been quantified, but the operator proposes to dispose of produced water through injection wells.[46] The Big Pack Natural Gas Development would drill 664 new wells across 34,471 acres (54 square miles) of federal, state, and private lands[47] and the Southam Canyon Field Development would drill 249 wells across 10,575 acres (17 square miles) of federal, state, and private lands.[48] Anticipated produced water volumes have not been quantified for either project and the operators propose to truck produced water to off-site disposal facilities.

It is unlikely that these projects will be approved as proposed. The West Tavaputs Natural Gas Full Field Development Project was recently approved for 626 wells on 160 well pads, resulting in 1,603 acres of short-term surface disturbance; the project was initially proposed as a 807 well development that would have resulted in construction of 538 well pads and 3,656 acres of short-term surface disturbance.[49] If the West Tavaputs project is any indication, pending projects are likely to decrease in size between the proposal and final approval. It is also likely that additional projects will be proposed in the coming months and years. Therefore the projects discussed above should be seen as a broad indicator of interest in hydrocarbon production rather than as a quantitative prediction of future development. However, regardless of the exact level of development that occurs, it is uncertain whether commercial produced water disposal facilities have sufficient capacity to dispose of all produced water generated by these proposed projects. It is also unclear whether there will be sufficient oil and gas production to utilize large quantities of produced water for EHR. Therefore, produced water management is likely to be a significant issue in forthcoming EISs.

All of the pending projects appear to involve conventional natural gas as opposed to CBM,[50] and it is important to note the difference between produced water generated by conventional natural gas production and CBM production. With conventional natural gas production, water withdrawals increase as easily separable water and gas are withdrawn, and operators typically produce more water as the field ages. In a CBM reservoir, methane is adsorbed to the coal cleats and water must be removed to reduce reservoir pressure before the methane can desorb and begin to flow. Therefore in a CBM reservoir the water production is highest at the outset and falls over time,[51] as shown in Figure 9. For prospective oil shale and oil sands developers looking for a stable and predictable source of water that will increase as unconventional fuel production expands, conventional natural gas production better matches water production to the needs of a growing industry. However, water production will continue only for the lifetime of the oil or gas well, which may not correspond to the operational needs of oil shale or oil sands facilities.

Figure 9
Water Production Over Time



From: Tom Osborne & Joel Adams, HydroSolutions, Inc., *Coal Bed Natural Gas and Water Management in the Powder River Basin*, SOUTHWEST HYDROLOGY 19 (Nov./Dec. 2001).

Assuming that roughly half of the produced water currently generated within Uintah County is available for use by oil shale and oil sands developers and that transportation and treatment costs are not prohibitively expensive, there appears to be sufficient ongoing produced water generation to support as many as four pilot scale (10,000 BPD) oil shale facilities or one to two pilot scale oil sands facilities. If natural gas production increases as proposed and byproduct water production occurs at the same per-well rate, more than five times the produced water would be generated and a much larger oil shale and oil sands industry could be supplied.

Produced water appears to be a promising source of supply, but it is important to note that while natural gas development is a potential source of water for unconventional fuel development, oil and gas development will simultaneously compete with unconventional fuel development for other scarce resources. In fact, intensive oil and gas development is likely incompatible with commercial scale oil shale and oil sands development.[52] Surface facilities associated with conventional mineral development could complicate or preclude siting of facilities needed for oil shale and oil sands development, and down-hole infrastructure could contaminate co-located resources or preclude oil shale and oil sands extraction. Even if natural gas development does not directly displace oil shale and oil sands development, statutory protections afforded to sensitive resources may limit the overall amount of development that can occur. For example, the cumulative impact to air quality related values might indirectly limit development, barring slower developing industries.[53] This report proceeds on the assumption that at least some level of concurrent production is possible, however, that assumption will need to be revisited as permitting decisions are made and new information becomes available. Reevaluation will be necessary to assess the extent of the conflicts and opportunities presented by oil and gas development.

Those contemplating produced water as a potential source of supply must also bear in mind the quality of the water produced, the requirements of the industrial uses, and the cost of treating water to appropriate discharge or reuse standards. Water quality data for oil and gas produced water is not readily available, but published reports indicate that within Utah, oil and gas produced water averages around 12,000 MG/L of TDS and can reach as high as 20,000 MG/L.[54] Within the Uinta Basin, TDS levels range from 6,350 to 42,700 MG/L.[55] By way of comparison, secondary standards under the SDWA allow for no more than 500 MG/L TDS and

Wyoming livestock watering standards allow for up to 5,000 MG/L TDS.[56] Produced water may also contain trace elements of aluminum, arsenic, barium, boron, cadmium, chromium, copper, iron, lead, manganese, molybdenum, selenium, or zinc.[57] Additional information regarding the qualitative requirements of different oil shale and oil sands technologies will help in estimating water treatment costs and in evaluating the viability of produced water as a source of supply.

2.1.4. Water Potentially Available from Oil Shale Development

In recognition of increased water demand attributed to population growth, energy development, and other pressures, the Colorado Legislature funded a comprehensive assessment of Colorado River Basin water resources. As part of this process, the White River, Yampa River, and Colorado River basins are preparing long-range assessments of water availability that specifically consider water demands associated with commercial scale oil shale development. Based on information provided by industry, consultants estimate that in-situ oil shale retorting will produce 0.8 gallons of water per gallon of oil produced and that above ground retorting will produce 0.3 gallons of water per gallon of oil produced.[58] Table 2 shows estimated water production for 10,000 and 50,000 BPD oil shale facilities. These estimates should be considered preliminary due both to the small sample size and nascent nature of the industry.[59] In considering the implications of various oil shale development scenarios, "methods using combustion heating can be expected to produce more byproduct water than methods using electrical heating or solvents."[60]

Table 2
Estimated Produced Water Generated by Commercial Oil Shale Development

	10,000 BBL/day Production	50,000 BBL/day Production
In-Situ Production	376 AF	1,882 AF
Surface Retorting	141 AF	706 AF

Water use estimates for oil shale and oil sands developments often fail to explicitly state whether produced water reuse is already reflected in operational requirements. Nonetheless, it is almost certain that prospective oil shale and oil sands producers plan to reuse produced water to the extent practicable. However, even with 100 percent produced water reuse, most oil shale and development technologies are likely to require outside water sources. Therefore, prospective oil shale and oil sands producers will need to obtain external sources of water as noted above.

2.2. Produced Water as a Waste Product

Produced water also represents a back-end consideration for oil shale and oil sands producers. Oil shale retorting will produce byproduct water, the amount and quality of which depend on the geologic formations that are exploited and the technology deployed. Byproduct water reuse represents the preferable option as it reduces the need for outside sources of water while minimizing waste stream volumes. Where it is uneconomical or infeasible to treat produced water to a level sufficient to support the intended use, operators must dispose of produced water in accordance with applicable federal and state laws.

Assuming in-situ retorting will produce 0.8 units of water for each unit of shale oil produced and that above ground retorting will generate 0.3 units of water per unit of shale oil produced,[61] a 50,000 BPD in-situ processing operation would generate 1,882 AF (14,600,000 BBL) of produced water annually. A similarly scaled above ground retort would generate approximately 706 AF (5,475,000 BBL) of produced water annually.[62]

Water produced as a byproduct of oil shale and oil sands development may be qualitatively different from water produced as a byproduct of conventional hydrocarbon production. During conventional hydrocarbon production, formation water is extracted as part of hydrocarbon withdrawal. The hydrocarbons contained in oil shale and oil sands cannot be removed passively; heat must be applied to the shale or solvents to the sands to release the hydrocarbons. The shale oil production process can liberate connate water and chemically created water as well as formation water. The same thermal or chemical processes that free hydrocarbons from oil shale and oil sands can impact water quality by releasing hydrocarbons and trace minerals into the water. While more technology specific information regarding oil shale and oil sands produced water quality and intended end uses will be needed to develop appropriate treatment programs, in-situ thermal processing of oil sands does not appear to present an insurmountable hurdle. Steam flooding is currently used to produce high viscosity oil from the Kern River, California field and much of that water is captured and reused.[63] A summary of predicted oil shale leachate characteristics is reprinted in Table 3.

Table 3
Summary of Leachate Characteristics from In-Situ and Above Ground Retorts (MG/L)[64]

	Simulated In-Situ Retorts	Surface Retorts
General Water Quality Measures		
pH	7.8 – 12.7	7.8 – 11.2
TDS	80 – >2,100	970 – 10,011
Major Inorganics		
Bicarbonate	22 – 40	20 – 38
Carbonate	30 – 215	21
Hydroxide	22 – 40	N/A
Chloride	5.5	5 – 33
Fluoride	1.2 – 4.2	3.4 – 60
Sulfate	50 – 130	600 – 6,230
Nitrate (NO_3)	0.2 – 2.6	5.1 – 5.6
Calcium	3.6 – 210	42 – 114
Magnesium	0.002 – 8.0	3.5 – 91
Sodium	8.8 – 235	165 – 2,100
Potassium	0.76 – 18	10 – 625
Organics		
Total Organic Carbon	0.9 - 38	N/A
Trace Elements		
Aluminum	0.095 – 2.8	N/A
Arsenic	N/A	0.10
Boron	0.075 – 0.14	2 – 12
Barium	N/A	4.0
Chromium	0.002 – 1.8	N/A
Iron	0.0004 – 0.042	N/A
Lead	0.014 – 0.017	N/A
Lithium	0.020 – 0.42	N/A
Molybdenum	Trace	2 – 8
Selenium	N/A	0.05
Silica	25 – 88	N/A
Strontium	0.004 – 8.7	N/A
Zinc	0.001 – 0.025	N/A

Different qualitative requirements are associated with the various reuse and disposal options presented. Multiple technologies are available to meet these qualitative requirements and the cost of treatment will depend upon the quantity of water being treated, its level of contamination, its intended use, and the standard to which water must be treated.[65] Where the cost of treatment is prohibitively high, oil shale and oil sands producers will need to focus on disposal. While this report focuses on produced water as a source of supply, a brief discussion of disposal options is included. Some of these options are best described as waste disposal while others likely constitute a beneficial use of the water. The appropriate classification is important because of permitting concerns which are discussed further in section three.

2.2.1. Disposal Methods

Produced water management falls into two general categories: disposal as a waste product, and application to a beneficial use. Where management involves disposal as a waste product, produced water can be subject to surface disposal or underground injection. Surface disposal involves evaporation or discharge to surface waters. Underground disposal includes either deep or shallow injection or infiltration. Management options are not mutually exclusive and can be combined as local conditions dictate. The choice of which disposal method to use depends on the quantity and quality of water being disposed of, the sustainability of supplies over time, legal and economic factors, as well as local conditions and demand. Disposal and beneficial use are addressed in turn. Underground injection is generally the preferred disposal option, but evaporation is widely used within the Uinta Basin due to limited injection capacity.

2.2.1.1. Surface Disposal

Aside from application to a beneficial use, there are two main options for surface disposal of produced water: evaporation and discharge to surface waters. Each alternative has advantages and disadvantages that vary with local conditions. Evaporation involves discharging to a shallow, lined surface impoundment where solar radiation causes water to evaporate. Minerals and contaminants are left behind and disposed of as residual wastes. Evaporation rates may be enhanced by high pressure spraying of produced water into the atmosphere above the impoundments, but fan guns and atomizers are susceptible to clogging where salts and dissolved solid levels are elevated. Surface storage or disposal can also prove problematic where water contained in the evaporation ponds presents a hazard to wildlife. Migrating waterfowl can be attracted to surface impoundments and succumb to the effects of hydrocarbons, minerals, or other contaminants found in the water. Waterfowl entrapment has been problematic in Canada and ponds containing non-potable water should incorporate bird deterrent devices to minimize the risk of violating the Migratory Bird Treaty Act or other laws.[66]

Produced water can, under certain conditions, be discharged to surface streams. Surface discharges are regulated under the Clean Water Act (CWA) and will require National Pollution Discharge Elimination System permits or the state-issued equivalent. These permits may require pre-discharge treatment to address mineralization and other contaminants.[67] Where discharge to surface streams is feasible, discharge can provide valuable indirect benefits in terms of aquatic and riparian habitat maintenance and restoration, wildlife and livestock watering, aquifer recharge, and flow augmentation for downstream users.

Water users may grow accustomed to enhanced water availability and ecosystems may develop based on produced water discharges that increase surface flows. Therefore, whenever produced water discharges provide longer-term surface flow augmentation, cessation of discharges is likely to result in increased water demand to the detriment of appropriators or natural processes that have come to depend on augmented flow levels. While Utah law imposes no obligation to continue a diversion or use of water[68] and this rule likely extends to continued discharge to surface waters, years of reliance upon surface water discharges may create policy challenges. The high quality of CBM produced water in the Powder River Basin led to expansion of surface discharges and interested parties should monitor management within the Powder River Basin to identify means of minimizing impacts of produced water discharge cessation. While there does not appear to be any obligation to continue discharges, minimizing ecological impacts may help avoid other regulatory and policy challenges.

2.2.1.2. Underground Injection

Underground injection of produced water fits into two general categories: deep and shallow injection, both of which are regulated under the SDWA. Deep injection normally involves injection below the lowermost potential underground source of drinking water (USDW) and often can utilize abandoned oil or gas wells. Deep injection has two primary advantages to the producer: first, pre-injection treatment is not generally required because produced water is injected below the lowermost USDW and the risk of contamination is very low. The lack of a treatment requirement is particularly important where the cost of treatment is high. The second advantage is that produced water injected into deep formations isolated from potable water sources may also facilitate EHR by increasing the pressure within oil and gas reservoirs and driving hydrocarbons towards producing wells.

Shallow injection (infiltration) involves discharge to unlined surface impoundments or infiltration galleries. Infiltration may provide indirect benefits by recharging aquifers and improving native vegetation. Infiltration is regulated under the SDWA to ensure protection of existing and potential sources of potable ground water, and infiltration viability will depend on the quality of the water being disposed of, proximity to potential underground sources of drinking water, intermittent geology, and the nature of pre-discharge water quality treatment.[69]

On most federal and tribal lands, injection is the generally preferred method of disposal.[70] However, poorly understood ground water hydrology and limited aquifer capacity within portions of the Uinta Basin limit deployment of disposal well technologies, driving other technologies and limiting the overall level of oil and gas development.[71]

2.2.1.3. Beneficial Use

Traditionally, beneficial uses of water have included mining, irrigation, stock watering, power production, domestic, municipal, and industrial uses. In short, beneficial uses traditionally involved domestic uses and uses that directly generated economically quantifiable value. For commercial scale oil shale or oil sands development, there are numerous possible beneficial uses of produced water. For example, conventional mining and surface retorting require water for dust control during materials extraction, crushing, transport, storage and disposal; for cooling, reclaiming, and revegetating spent shale; for upgrading raw shale oil into a pumpable oil suitable for refinery feedstock; and for various plant uses including sanitary waste systems and environmental controls such as exhaust gas scrubbing.[72] Like conventional mining and surface retorting, in-situ retorting may require water for oil and synthesis gas extraction, post extraction cooling, product upgrading and refining, environmental control system operation, power production, and post-production site reclamation and revegetation. Industrial applications associated with conventional hydrocarbon production are also possible and include enhanced hydrocarbon recovery and subsidence prevention in addition to many of the uses noted above. Beneficial reuse of produced water minimizes the need for external water supplies while simultaneously reducing disposal obligations. As process water is already located on site, expensive diversion and transport facilities are unnecessary. Recycling and reuse may represent a cost-effective disposal strategy.

Where production-related uses of water are unavailable, CBM producers have been able to dispose of produced water in EHR operations, by irrigating crops and native vegetation, augmenting instream flows, and augmenting ground water recharge, as well as watering livestock and wildlife. Indirect benefits may include: increased hydrocarbon yields, increased crop production, habitat and disturbed lands maintenance or restoration, flow augmentation, shallow aquifer recharge, and supply stabilization. Pre-disposal treatment may be required depending on the quality of the water produced, the intended use, and applicable permitting requirements. Treatment may involve filtration, chlorination, pH adjustments, blending, or other measures to address salinity, hydrocarbon, or heavy metal levels.[73] Those considering beneficial land application of produced water must recognize that produced water can be high in dissolved salts. As noted in ICSE's WATER RESOURCES TOPICAL REPORT, concerns over elevated salinity within the Colorado River Basin led to enactment of the Colorado River Salinity

Control Act.[74] Consequently, salinity reduction may be required before produced water can be used for dust suppression or site reclamation, and land disposal should incorporate components to control the leaching of salts from the soil.

Applying produced water to these or similar secondary beneficial uses involves another level of regulatory complexity (discussed in section three) and may reflect more stringent water quality requirements. However, such opportunities may provide valuable secondary benefits to the community in addition to avoiding some or all of the costs associated with traditional disposal methods.

2.2.2. Disposal Capacity

Produced water disposal capacity has been described as "the single most pressing issue with regard to increasing petroleum and natural gas production in the Uinta Basin."[75] Oil and gas production within the Uinta Basin has increased significantly over the last decade, and with it, the volume of produced water that requires disposal. According to the Utah Geological Survey:

> Current water-disposal wells are near capacity and permitting for new wells is being delayed because of a lack of technical data regarding potential disposal aquifers and questions concerning contamination of freshwater sources. Many Uinta Basin operators claim that crude oil and natural gas production cannot reach its full potential until a suitable, long-term saline water disposal system is developed.[76]

While underground injection is the preferred method of produced water disposal,[77] "[m]any companies are reluctantly resorting to evaporation ponds as a short-term solution, but these ponds have limited capacity, are prone to leakage, and pose potential risks to birds and other wildlife."[78]

If natural gas production increases as proposed, or if oil shale development occurs and produces byproduct water as anticipated, the demand for produced water disposal will increase significantly. The Birds Nest Aquifer is the most promising aquifer for produced water disposal in Utah. However, "the Birds Nest Aquifer is located in the oil shale zone of the Green River

Formation's Parachute Creek Member and is 200 to 300 ft above the kerogen rich Mahogany Zone."[79] Federal and state programs regulate the sub-surface discharge or injection of fluids in order to provide that discharged or injected substances do not degrade ground water quality. The efficacy of permitting programs depends in large part on knowledge of geologic conditions and pathways by which injected substances could come into contact with ground water. Complex factual issues must be resolved as part of the permitting process because, as the Utah Geological Survey notes, "[w]ith increased saline water disposal, the water quality in the Bird's-nest [sic] could degrade and create additional water disposals problems for oil shale development companies."[80]

Produced water disposal appears to be less of an issue for oil shale areas amenable to surface mining because ground water flows away from the Mahogany Outcrop in a generally northerly / northwesterly direction.[81] Produced water injection, if it occurred near the Mahogany Outcrop, could complicate in-situ oil shale or oil sands development, as ground water is believed to flow towards deeper resources developable with in-situ technologies. Actual impacts will depend on depth of the mineable oil shale bed, depth of injection, and ground water flow, all of which will require site-specific investigation.[82]

A better understanding of ground water quality, flow characteristics, and disposal capacity within the Birds Nest Aquifer is needed to evaluate potential produced water disposal options. Ongoing DOE-supported research by the Utah Geological Survey will help answer these questions.[83]

2.2.3. Reducing Byproduct Water Production

Lifting byproduct water to the surface, separating water from the hydrocarbons, treating the water to appropriate standards, transporting the water to an appropriate disposal site, and disposing of the unwanted byproduct water represent significant costs to operators. With these costs in mind, and with produced water disposal capacity representing a growing concern, produced water generators will likely seek to reduce the amount of water requiring disposal. In addition to EHR and application to a beneficial use, which avoid waste disposal issues and are discussed elsewhere in this report, operators may turn to downhole hydrocarbon separation. Since the majority of proposed development within the Uinta Basin involves natural gas, this section focuses on downhole gas/water separators, but the same conceptual considerations are applicable to downhole oil/water separators.

During the 1990s, oil and gas industry engineers developed various technologies to separate gas and oil from water inside the well; these devices are known as downhole gas/water separators (DGWS) and downhole oil/water separators (DOWS). DOWS reduce the quantity of produced water handled at the surface by actively separating water from the oil within the well bore and simultaneously injecting produced water underground. Since the difference in specific gravity between natural gas and water is larger than that between oil and water, gas and water separation occurs naturally in the well. DGWS therefore rely on natural separation to facilitate downhole water disposal while allowing gas production.[84] DGWS effectiveness is difficult to measure both because few papers on the topic have been published in the open literature, and because installation and production data are often proprietary. Argonne National Laboratory has further noted that many of the early trials were made in wells near the end of their useful life rather than in wells that had a good chance of success, and in some cases, equipment suppliers designed and installed systems based on inaccurate formation data. Furthermore, many of the failures were attributed to components other than the separators themselves, such as sheared cables, broken bolts, faulty pumps, and leaky seals.[85] Consequently, past performance may be a poor predictor of the technology's true potential.

Even after noting these shortcomings, Argonne National Laboratory found that based on summary data from fifty-three DGWS field tests, a fifty-seven percent increase in gas production rates occurred despite failure of roughly half the tests. About half of the failures were attributed to water cycling or poor injectivity issues. While concluding that the lack of published data made it impossible to predict performance solely based on geology of the production formation or the injection formation, Argonne points to industry consensus that site-specific properties of the disposal zone at individual wells are a useful predictor of DGWS success. "In general, disposal zones that are favorable for DGWS have high permeability, high porosity, and are underpressured."[86] However, despite these generally preferable conditions, DGWS have been deployed in tight shales and CBM wells, indicating that the general preference for certain disposal zone characteristics does not reflect a technical requirement.[87]

Given the large number of pending permits to drill natural gas wells, constraints posed by limited injection well capacity, and the lack of good alternative sources of disposal, natural gas operators are likely to pay more attention to DGWS technology. However, even with near complete adoption, DGWS technology can only reduce rather than eliminate byproduct water disposal requirements. Byproduct water management will therefore remain a disposal challenge and potential alternative source of water for oil shale and oil sands production. Whether downhole hydrocarbon separation technology could be incorporated into in-situ thermal processing of oil shale and oil sands is uncertain, but merits investigation.

3. Produced Water Regulation

Historically, comparatively little water was produced as a byproduct of fluid mineral extraction, and what water was produced tended to be of poor quality. Produced water was consequently treated as a waste product rather than a valuable resource, and addressed under waste management regulations as opposed to appropriative water law. Treating produced water associated with oil and gas production as a waste product was generally not problematic because produced water was of such poor quality that no market developed for its beneficial use. Likewise, the same geologic formations that trapped oil and gas resources isolated hydrocarbons and co-located water from usable water sources, such that produced water withdrawals did not risk drawing down higher quality aquifers.[88] CBM wells fundamentally changed this equation by producing greater quantities of higher quality water from sources that are often shallower and in continuity with usable aquifers.[89] During 2008, CBM operations in Colorado, Montana, New Mexico, Utah, and Wyoming generated approximately 128,893 AF (1 billion BBLs) of produced water.[90] Increased produced water generation has lead to litigation and regulation that could impact both produced water generators and those hoping to utilize produced water as a source of supply.

This section looks first to legal requirements applicable to the appropriation of produced water. Section four builds on section two and section three, discussing how produced water will likely be treated in light of evolving legal doctrines as well as the implications for commercial oil shale and oil sands production.

3.1. Overview of Appropriative Water Law

In Utah, as in most western states, water belongs to the public and is available for public appropriation and beneficial use.[91] Certain narrow exceptions aside, water rights today are obtained only through application to the State Engineer,[92] and water cannot be appropriated legally in the absence of a valid, state issued water right. "Beneficial use shall be the basis, the measure and the limit of all rights to the use of water in [Utah]."[93] Historically, beneficial use was equated with activities generating economic returns, but the concept has grown to include non-economic uses such as habitat protection.[94] The flip side of requiring beneficial use is a prohibition against waste. Waste, broadly defined, is use without benefit or a use that unreasonably deprives others of the opportunity to put water to a beneficial use. Utah courts readily acknowledge that Utah is an arid state "and the conservation of water is of the utmost importance to the public welfare. To waste water is to injure that welfare, and it is therefore the duty of the user of water to return surplus or waste water into the stream from which it was taken so that further use can be made by others."[95] In the words of one prominent water scholar, "[t]he state's interest is in the development and use of the water resources of the state, not in who the user is."[96] Therefore, the State Engineer cannot issue, and a prospective water user cannot obtain, a right to use water for anything other than a beneficial use.[97]

In essence, Utah allows water users to withdraw or divert no more than they can reasonably use, and to make available to others those waters not consumed, lost to evaporation, or lost to reasonable system inefficiencies such as leaky ditches. Where system inefficiencies or leaky ditches result in water that is left over after irrigation, such as runoff or canal leakage that flows onto the property of another, the "waste" water can constitute a source of supply for the down slope water user. Water users may appropriate such waste water and obtain protection against junior appropriators, but Utah encourages improvements in irrigation efficiency[98] and the appropriator of waste water cannot compel the continued wasteful use of water.[99]

These rules make sense in the context of agricultural uses where irrigators divert or withdraw only what is reasonably needed to irrigate crops and pressurize sprinkler systems. Even where water percolates past the root zone of the crops or is lost to leaky ditches, that water generally returns to streams or connected ground water sources as shallow ground water flow. Water that is wasted can be captured; and used by others and losses due to inefficiency are, at a larger temporal and geographic scale, not a complete loss to the larger hydrologic system.

If the withdrawal is not beneficial in nature, no water right is required. However, the party making a withdrawal that is not beneficial in nature may be enjoined from making water withdrawals that prove injurious to others.[100] Accordingly, landowners are allowed to drain unwanted water from their land as long as drainage does not impair others, either by reducing their supply of water or by damaging their land.[101] Drainage may involve either surface water runoff or ground water removal. For example, in *Sanford v. University of Utah*,[102] the University purchased property adjacent to the plaintiff's home, and constructed a building, parking lot, and roads that changed the way that surface water flowed. Drains installed to capture runoff proved inadequate and surface water runoff was inadvertently directed onto the plaintiff's property, where it caused extensive property damage. In holding the University liable for the damage, the Utah Supreme Court adopted the rule that "each possessor [of land] is legally privileged to make a reasonable use of his land, even though the flow of surface waters is altered thereby and causes some harm to others, but incurs liability when his harmful interference with the flow of surface waters is unreasonable."[103] Because the University's management of storm water was unreasonable, it was held liable for the damage.[104] In *N.M. Long & Co. v. Cannon-Papanikolas Const. Co.*,[105] residential developers were allowed to lower the ground water level beneath a ninety-two acre area in order to develop a residential subdivision even though draining and dewatering affected the source of supply for the plaintiffs' water rights. In allowing the draining and dewatering to proceed, the court adopted a tort standard that the party draining their land "would incur no liability unless they (1) willfully or intentionally interfered with the plaintiffs' water; or (2) were negligent or reckless with respect thereto in installation of their drains."[106]

Withdrawals for activities such as construction site or mine dewatering have normally been treated as outside the beneficial use requirement because the purpose of the withdrawal is to reduce the source of supply rather than to consume the water withdrawn. These exceptions to the rule have not been problematic because the withdrawals are normally temporary in duration and water withdrawn can be discharged to water bodies where other users can then obtain a benefit from what was a nuisance to the dewaterer. Dewatering is therefore not a complete loss to the system, any loss that occurs is short-term and of a limited volume, and those suffering injury from dewatering activities can seek redress under the tort standards discussed above. The problem with respect to produced water is that the withdrawal *is* the use of the water. The use is not consumptive, but unlike other non-consumptive uses, such as hydroelectric production, oil and gas formation dewatering cannot occur absent a loss to the source of supply. Because the source is often thousands of feet deep and was intentionally dewatered, produced water cannot be returned to the same source until hydrocarbon production ceases – potentially decades after the withdrawal occurred. Therefore operators must deal with a resource that they cannot consume or return to the source and which public policy dictates cannot be wasted, and they must do so for an extended period of time. The problem is similar to that experienced with respect to construction site dewatering but with several notable differences, formation dewatering associated with hydrocarbon production: (1) often involves much larger volumes of water, (2) involves moving water between often distinct systems and often over larger distances, and (3) often raises unique water quality concerns.

Western water law struggles to deal with these issues. To understand the problem and the various attempts to fit produced water into the existing framework of western water law, we begin by looking at whether the withdrawal of water as part of oil and gas production is an appropriation to a beneficial use, and whether any beneficial use that does occur is associated with produced water withdrawals or the subsequent application of water to another use. These two questions and their regulatory implications are the subject of the remainder of this section.

"An 'appropriation' is 'the application of a specified portion of the waters of the state to a beneficial use.'"[107] As a general rule, an appropriation of water requires an intentional, physical diversion of water from a natural watercourse to a beneficial use and must occur in accordance with permitting requirements. Beneficial use may include domestic, municipal, irrigation, stock watering, mining, waterpower, and recreation uses. Both direct flow appropriations and storage applications may be beneficial, and new uses such as instream flow protection, habitat maintenance, ground water recharge, and leaching minerals from the soil are often also considered beneficial uses.[108] Determining what constitutes a beneficial use is heavily dependent "on the facts and circumstances of each case, with the underlying facts varying significantly in each dispute."[109] "The concept of beneficial use is not static. Rather, it is susceptible to change over time in response to changes in science and values associated with water use."[110]

> What is a beneficial use, of course, depends upon the facts and circumstances of each case. What may be a reasonable beneficial use, where water is present in excess of all needs, would not be a reasonable beneficial use in an area of great scarcity and great need. What is a beneficial use at one time may, because of changed conditions, become a waste of water at a later time.[111]

Accordingly, beneficial use "must remain a flexible and workable doctrine."[112] Utah courts "are particularly skeptical of ends that appear to be merely incidental to water use and that are declared as beneficial only in hindsight."[113] "As developed in the courts, beneficial use has two different components: the type of use and the amount of use."[114]

Just as beneficial use is the measure and limit of any right to divert water issued by the State Engineer, beneficial use acts as a limit on any water right change, limiting the change to the amount of water that was historically put to a beneficial use. Therefore both the oil and gas operators generating the produced water and the oil shale and oil sands developers seeking to utilize produced water need to pay close attention to the purpose to which water is put and the amount actually utilized.

3.2. Developments in Western Water Law

Appropriations law has traditionally ignored water produced through mineral extraction.[115] Growth in CBM development and the attendant production of large quantities of what is some locations has been high-quality water has caused several states to revisit their treatment of produced water. There is no longer a clear consensus as to whether the withdrawal of byproduct water as a component of energy development required a state issued water right. Recent litigation exemplifies the potential pitfalls of contending that produced water withdrawals are not a beneficial use of water, and thus, are not subject to state administration under the water code. In 2005, a coalition of ranchers brought a declaratory judgment action[116] against the State of Colorado, seeking to ascertain whether the State Engineer was obligated to "require well permits and augmentation plans when ground water, which is hydraulically connected or tributary to the surface streams in which Plaintiffs hold water rights, is diverted in the course of [CBM] production."[117] The plaintiffs alleged that unregulated water withdrawals associated with CBM development impaired their water rights and that the state erred by failing to regulate produced water withdrawals under state appropriations law. The Colorado State Engineer responded that produced water was properly regulated under waste disposal regulations rather than as an appropriation. The Colorado Water Court[118] recognized that the Colorado Oil and Gas Conservation Commission regulated waste disposal but not water appropriation. The Water Court also noted that water is a public resource subject to the state permitting scheme and the doctrine of prior appropriation, and that non-exempted withdrawals of tributary ground water are subject to state water law.[119] However, the Water Court explicitly rejected arguments that no water right was required for water produced as a byproduct of energy development because intent to appropriate is required to obtain a water right and ground water removal is an unavoidable side effect of production.[120]

On appeal, the Colorado Supreme Court agreed, dismissing appellants' claim that produced water was a nuisance rather than a beneficial use, emphasizing that CBM producers "rely on the presence of the water to hold the gas in place until the water can be removed and the gas captured. Without the presence and subsequent extraction of water, CBM cannot be produced."[121] According to the Colorado court, the CBM development process "'uses' water –

by extracting it from the ground and storing it in tanks – to accomplish a particular 'purpose' – the release of methane gas. The extraction of water to facilitate CBM is therefore a 'beneficial use.'"[122] Consequently, CBM well operators in Colorado must now acquire water rights before proceeding, and such permits will be available only where withdrawals do not impair other appropriators or harm the public interest.

In response to the court's ruling, Colorado amended its water code, directing the Division of Water Resources to promulgate rules regarding the withdrawal of ground water to facilitate oil and gas development.[123] The rules simplify the permitting process by establishing "geographically delimited areas under which the ground water in only certain formations is nontributary for the limited purposes of these rules."[124] Water right permits are not required for nontributary ground water appropriation.[125] The new rules are quite controversial and being challenged as insufficient to protect other water users.[126] Notably, the rules are not limited to CBM wells but apply equally to produced water associated with conventional hydrocarbon production that involves tributary ground water.[127]

In Wyoming, the "intentional production, or appropriation, of ground water for [ ] CBM production led to the designation of CBM as a beneficial use of water and subsequently, to a requirement for a permit to appropriate the ground water."[128] As in Colorado, the incidental or unintended nature of these withdrawals is immaterial.[129] As a beneficial use, "whenever a bore hole constructed for mineral exploration, oil and gas exploration, stratigraphic information or any other purpose not related to groundwater development shall be found to be suitable for the withdrawal of underground water, application shall be filed with and approved by the state engineer before water from the bore hole is beneficially utilized."[130] "Unless specified in the well permit, there is no other beneficial use of this produced water authorized by the issuance of the well permit. . . . Unless specified in the ground water permit, water produced in the production of [CBM] gas has no other implied use and is considered to be un-appropriated waters of the state of Wyoming."[131]

Although Wyoming recognizes CBM dewatering as a beneficial use, CBM operators benefit from a streamlined well-permitting process. "The Wyoming [State Engineer's Office] considers most CBM water to be unappropriated, and permits are granted as a matter of course. 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."[132]

Declaring ground water withdrawals that occur as part of oil and natural gas production to be a beneficial use of water is problematic in that post-withdrawal management obligations are unclear. For conventional uses like irrigation, ground water appropriators have no incentive to withdraw more water than they can use. For surface water diverters, water that is not consumed is normally returned to the hydrologic system. Where the mere withdrawal of produced water is a beneficial use, operators are left with potentially large quantities of water after their beneficial use (formation dewatering) has been completed. Whether the beneficial use of produced water is a continuing obligation is unclear, but a compelling argument can be made that western water law's prohibition against waste of scarce water resources requires produced water generators to ensure that the water is not wasted.

Montana's approach differs from those of Colorado and Wyoming in that Montana concludes that "[a]lthough withdrawing groundwater is integral to the coal bed methane extraction method, water is not a desired product of the operation, and must be disposed. Since the withdrawal of the water is not a use of the water per se, a water use permit . . . is not required for withdrawing the water."[133] As a consequence, litigation in Montana has focused on the subsequent use of produced water. In *Diamond Cross Properties, LLC v. Montana*,[134] a coalition of environmentalists and local water users challenged a decision by the Montana Board of Oil and Gas Conservation (MBOGC) approving two CBM developments, alleging in pertinent part that approval violated the Montana Constitution and Water Use Act. The constitutional provision at issue states that "[a]ll surface, underground, flood, and atmospheric waters within the boundaries of the state are the property of the state for the use of its people and are subject to appropriation for beneficial use as provided by law."[135] As summarized by the court, the Montana Water Use Act requires that water must be: (1) put to optimum beneficial use, (2) not wasted, (3) protected and conserved for public uses and for wildlife and aquatic life, and (4) protected for existing uses and to ensure supplies for domestic, industrial, agricultural and other beneficial uses.[136] Based on the constitutional and statutory mandates, the court concluded, "that the production, use, or disposal of large quantities of CBM ground water must serve a statutorily defined beneficial use."[137] The court expressly rejected Montana's argument that "the extraction of water that is not needed or desired for a beneficial use, but is merely disposed of as a by-product of other activities, does not constitute a beneficial use of water requiring a beneficial water use permit."[138] The court did not dispute that, under Montana law, dewatering of a gravel pit or removal of contaminated water from a mining operation were examples of water withdrawals that did not require a water right, but noted that "the disposition of CBM produced ground water is distinguishable because the quantity of water that is produced in CBM extraction dwarfs the amounts of water disposed of in the examples cited by the [the state]."[139]

Tongue & Yellowstone Irrigation Dist. v. Montana Board of Oil and Gas Conservation[140] followed *Diamond Cross*, involved many of the same parties, and raised closely related issues. Plaintiffs again alleged that the MBOGC unlawfully approved CBM development and produced water disposal. Relying on the same constitutional and statutory provisions, the plaintiffs contended that the MBOGC could not authorize wasteful use of water without violating the Montana Water Use Act and the *Diamond Cross* ruling. As the court explained in ruling for the plaintiffs, the Water Use Act controls what constitutes acceptable use of produced water, and under the Act, ground water production associated with a CBM well must be managed in one of four ways: (1) used as irrigation or stock watering or for other beneficial uses, (2) re-injected into an acceptable aquifer, (3) discharged to the surface or subsurface, or (4) managed through other methods allowed by law.[141] Applying these rules to the defendant's water use practices, the court proceeded to uphold all of the operators' proposed disposal operations except for evaporation. The court concluded that evaporation was not an enumerated use and served no conceivable beneficial purpose otherwise authorized by point (1). Evaporation therefore amounted to a waste of natural resources.[142] As a consequence of the ruling, evaporation is no longer an acceptable means of produced water disposal within Montana.

New Mexico's approach to produced water is less well developed. In New Mexico, "prospecting, mining or . . . drilling operations designed to discover or develop the natural resources of the state" are subject to state water right permitting requirements.[143] However, "[m]ine dewatering is neither an appropriation of water nor waste, but is governed by the provisions of the Mine Dewatering Act [ ]. No water rights may be established solely by mine dewatering."[144] The New Mexico State Engineer is required to issue mine dewatering permits where dewatering will not impair existing water rights, but if dewatering will result in impairment, the applicant must submit and obtain State Engineer approval of a plan of replacement.[145]

New Mexico previously attempted to address produced water permitting issues by legislating that wells deeper than 2,500 feet and drawing water with total dissolved solid levels exceeding 1,000 parts per million (PPM) were considered hydrologically isolated.[146] As isolated wells, no impairment would occur and dewatering permits could be issued as a matter of course. However, the approach proved to be overly simplistic[147] and New Mexico repealed the exemption from its water code, reinstating the State Engineer's jurisdiction over such waters.[148] Today in New Mexico, "[n]o permit shall be required from the state engineer for the disposition of produced water in accordance with rules promulgated . . . by the oil conservation division of the energy, minerals and natural resources department."[149] As a consequence, the State Engineer has limited authority to prevent the appropriation or use of produced water.

There is nothing in the Utah Water Code that directly addresses de-watering, whether for CBM production or any other use. Whether produced water generation represents a beneficial use is therefore currently unresolved under Utah law. The Utah State Engineer's position is that absent a beneficial use derived from the withdrawal, the State Engineer is unable to approve a water right application.[150] Since the withdrawal, in and of itself, does not appear to constitute a beneficial use, and beneficial use is the limit and measure of all water rights,[151] the State Engineer would be unable to grant a water right solely for dewatering a mine or foundation, or for hydrocarbon production.[152] Accordingly, dewatering alone is unlikely to represent a beneficial use, and a water right is likely not required so long as the water is not subsequently put to a recognized beneficial use. However, this interpretation has not been subjected to judicial review.

An exception to the general rule that dewatering does not require a water right can occur when withdrawals are not returned to the system and production poses a risk of impairment to other water users. The basis for this exception is the State Engineer's broad obligation to manage waters of the state to maximize net benefit to the citizens of the state.[153] The Utah Supreme Court encapsulated the fundamental purpose underlying statutory and decisional law as "insuring the highest possible development and of the most continuous beneficial use of all available water with as little waste as possible."[154] By requiring a water right for withdrawals from the system, such as produced water disposed of in evaporative ponds, the Utah State Engineer can ensure that withdrawals will not impair other water users, satisfying the dual mandates of promoting development while simultaneously discouraging waste.

The best example of where the Utah State Engineer has required a water right for evaporation involves the Great Salt Lake. The Great Salt Lake is the lowest point in a terminal basin, and lake waters contain salts and other valuable minerals leached from the surrounding lands. As lake waters are lost to evaporation, minerals concentrations increase. Several companies divert water from the lake into shallow evaporation ponds; as the water in the ponds evaporates, minerals precipitate out and the increasingly saline water is moved to the next in a sequential series of ponds. The mineral precipitate is then mined, processed, and sold. For these industries, evaporation is an integral part of the production process rather than a waste disposal method, and the State Engineer requires that these operators possess valid water rights for their diversions from the Great Salt Lake. These operations can be quite sizeable, requiring extremely large water rights.[155] While the State Engineer has been diligent in requiring water rights for these kinds of evaporation ponds, water associated with evaporation from oil and gas operations has received less consistent attention, in part because DOGM regulates produced water management and disposal.[156] Attention, both from within the Office of the State Engineer and from external sources, is likely to increase as the volume of produced water increases. Underground injection or other disposal methods may sidestep issues associated with obligations to minimize waste by avoiding systemic water depletions because these activities are authorized and regulated under a complex regulatory regime.

Operators may also apply for and obtain water rights allowing them to put produced water to a beneficial use. Beneficial uses could include but are not limited to dust control, equipment and product cooling, environmental control systems, product upgrading and refining, site reclamation and revegetation, subsidence prevention, and various plant uses. For example, surface retorting of oil shale would produce a waste product that would be disposed of in landfills. Spent shale must be moistened prior to disposal in order to assure its physical stability. According to the National Oil Shale Association, spent shale moistening may require water volumes equivalent to as much as fifteen percent of the weight of the spent shale, depending upon the technologies deployed and the characteristics of the spent shale. Water applied to moisten spent shale reportedly does not leach from the spent shale under weather conditions common to the western United States.[157] Beneficial uses such as spent shale moistening could potentially be satisfied with comparatively low quality water, simultaneously reducing demand for water and minimizing disposal requirements.

Utah has not yet experienced the level of natural gas or CBM development that has driven water law changes in neighboring states, and CBM development and produced water have not featured prominently in Utah water law discussions. It may be that concerns about water right compliance and Utah's enforcement statute will prove sufficient to encourage permitting for consumptive and actual uses of water without additional statutory changes. Adjustments are already occurring within the mining industry and these evolutions are spreading to the oil and gas industry. It is also possible that greater development will drive evolutionary change to the Utah Water Code.

The legal theories that prevailed in Colorado and Montana may be adopted elsewhere and could have dramatic effects. In Colorado, recent changes "have the potential to affect up to 40,000 oil and gas wells. . . . So far, about 5,000 coal-bed methane wells have obtained permits, and some companies have begun filing for water rights in Water Court or substitute water supply plans from the Division of Water Resources."[158] The highly dynamic nature of this area of law cannot be overstated, given its potential to radically change energy production.

3.3. Implications for Utah

The arguments made before the Colorado courts could resonate with a Utah court. In Utah as in Colorado, all "waters in this state, whether above or under the ground, are hereby declared to be the property of the public."[159] In times of scarcity, the first in time is the first in right and senior water users are protected against injury by junior appropriators.[160] The Utah State Engineer administers water rights to "insur[e] the highest possible development and [ ] the most continuous beneficial use of all available water with as little waste as possible."[161] Additionally, in both Utah and Colorado, beneficial use is a fluid concept that requires fact-specific inquiry,[162] and interpreting beneficial use broadly to include beneficial withdrawals of water as well as subsequent application to traditional beneficial uses furthers broad state interests in avoiding waste and ensuring efficient use of scarce water resources.

While Colorado distinguishes between tributary and non-tributary ground water, Utah has not embraced that distinction.[163] Therefore, if Colorado's approach was adopted in Utah, oil and gas operators that produce byproduct water from deep, isolated sources would not be able to utilize statutory exemptions for non-tributary ground water basins similar to those available in

Colorado. This would at first appear to create a more restrictive rule in Utah and could impede energy production because, as noted earlier, ground water in Utah's energy-rich regions is essentially closed to new appropriations. However, this closure is a matter of policy rather than a statutory requirement and the Utah State Engineer can deviate from the policy as appropriate. A strong argument can be made that even if a water right is required for produced water, new appropriations may be made in "closed" areas provided that the operator can demonstrate that withdrawals are in the public interest and will not impact other water users.[164] Thus the policy does not act as a complete prohibition, but instead formalizes a presumption that new water rights cannot be issued without injuring others and shifts the burden to the applicant to demonstrate that unappropriated water is available. Operators could argue that the geologic formations that have trapped oil and gas for millennia have also trapped any co-located water resources. This argument would be strongest where resources are located at extreme depths or where water quality monitoring demonstrates a high likelihood of discontinuity. Such an interpretation is reasonable and appropriate as the twin objectives encapsulated by the Utah Water Code are to encourage development while discouraging waste or impairment to others. If waste and injury can be avoided, issuing new water rights would be consistent with state policy.

The larger challenge may be ensuring that produced water is not made unavailable to potential users or otherwise goes to waste. Just as Montana states that all waters within the state are public and subject to beneficial use,[165] the Utah Water Code holds that all waters of the state are public,[166] and "beneficial use shall be the basis, the measure and the limit of the right to use water in this state."[167] Similarly, both Montana and Utah prohibit the wasteful use of water,[168] and Utah imposes an affirmative duty upon appropriators to "return surplus or waste water into the stream from which it was taken so that further use can be made by others."[169] While it may not be feasible to return unconsumed produced water to the aquifer from which is was withdrawn,[170] "conservation of water is of the utmost importance to the public welfare."[171]

Therefore, management that fails to allow for beneficial use of produced water appears to be inconsistent with Utah law and the policies it intends to advance.

While Utah courts have not addressed waste in the produced water context, the 1980 opinion in *Gossner v. Utah Power & Light*[172] provides interesting parallels. The *Gossner* plaintiffs owned agricultural land along the Bear River and complained that Utah Power & Light, which owned several hydroelectric dams along the river, released too much water from its dams causing the plaintiffs' land to flood. Utah Power & Light defended that they possessed decreed water rights to divert and store up to 5,500 cubic feet per second (CFS) of water from the river and that these rights allowed them to release up to that amount of water from storage without liability for flooding or otherwise damaging downstream lands. However, Utah Power & Light's hydroelectric plants had maximum generating capacity of 3,000 CFS, and as the court pointed out, the purpose of the right was to divert from the river during peak flow periods for use during dryer periods of the year.[173] Utah Power & Light's right to discharge was not equivalent to its right to divert, and except for flood event discharges, the allowable rate of discharge was limited by the carrying capacity of the Bear River.

The court went on to state that "[s]ince beneficial use is the basis, the measure, and the limit of all rights to the use of water, and the power plants . . . can use beneficially no more than 3,000 CFS of water, it would be a great waste of valuable water to bypass the turbines at these plants with another 2,500 CFS."[174] State prohibitions against waste would appear to bar discharges, at least when available reservoir capacity would allow safe reductions in discharges. As already noted, within Utah, "the conservation of water is of the utmost importance to the public welfare. To waste water is to injure that welfare, and it is therefore the duty of the user of water to return surplus or waste water into the stream from which it was taken so that further use can be made by others."[175] In light of the policy against waste and desirability of making water available to potential water users, Utah law could be read to require that operators generating produced water make unappropriated and unused produced water available to other users in order to minimize waste, at east to the extent reasonable and consistent with operational requirements.

Without subverting this policy, a Utah court could reasonably conclude that qualitative concerns preclude produced water reuse and that no obligation to facilitate subsequent beneficial use exists. The quality of the water disposed of in the evaporation ponds at issue in *Diamond Cross and Tongue & Yellowstone Irrigation Dist.* is not addressed in either opinion. However, produced water associated with CBM development within the Powder River Basin is often low enough in TDS to support livestock, irrigation, or even potable uses.[176] In contrast, most produced water generated within the Uinta Basin is much more saline and unlikely to support beneficial uses absent treatment.[177] Arguments dependent on water quality would be fact-dependent and involve a balancing of interests.

A Utah court could also conclude that evaporation constitutes a beneficial use because evaporation concentrates pollutants contained in produced water, facilitating subsequent disposal. Such a conclusion would be more likely where water quality effectively precludes other beneficial uses and demand is insufficient to warrant more extensive water quality treatment. If alternatives to evaporation are available at reasonable cost, evaporation may be a harder sell as it could be seen as contrary to the state's goals of minimizing waste and maximizing development.

Whether dewatering is a beneficial use has important implications for the oil shale or oil sands developer who wants to utilize oil and gas byproduct water. If produced water generation is considered a beneficial use and a water right is required, the operator can convey that water right to a third party, such as an oil shale or oil sands developer, subject to State Engineer approval.[178] If produced water generation is not a beneficial use and the operator generating the water cannot obtain a water right, that operator has no water right to convey to the oil shale or oil sands developer. The oil shale or oil sands developer seeking to utilize produced water must file to appropriate the byproduct water generator's effluent stream. This may prove challenging if the produced water generator is required to dispose of byproduct water as a waste. While these problems are not insurmountable, they will require close cooperation between producers, developers, and regulators.

The Colorado and Montana approaches are not mutually exclusive and if the issue comes to a head in Utah, resolution should reflect unique local conditions. Which arguments will rule the day will depend on unique site-specific conditions and it is possible that the final rule may be best characterized as a rule of reasonableness – that the produced water generator is required to prevent waste to the maximum extent practicable.

4. Application to Oil Shale and Oil Sands Production Within Utah

At the outset, it should be noted that recent legal developments relating to produced water management have been driven largely by CBM production. Proposed development projects within the Uinta Basin target conventional oil and natural gas resources. Ground water quality varies throughout the western United States and between geologic formations. Therefore increased produced water generation in Utah may not raise the same questions faced elsewhere in the west. However, increasing competition for scarce water resources and produced water disposal challenges will force Utah to look more closely at produced water management. And as the cost of development and treatment fall in relation to the cost of acquiring alternate supplies, water sources once seen as unappealing will become increasingly attractive.

Produced water management poses a challenge to western appropriative water law because produced water's principal value, to the operator, is in its removal from the hydrocarbon bearing formation and the point of beneficial use can be described as the well itself. Produced water withdrawn from the hydrocarbon bearing formation is a depletion of (or consumptive loss to) the source aquifer, but unlike other ground water withdrawals, produced water generation does not consume the water withdrawn. Furthermore, unlike more conventional water uses such as agricultural irrigation where excess water can be returned to the source of supply, returning produced water to the source aquifer can impede hydrocarbon production and is therefore counterproductive unless carefully controlled and used for EHR. Policies discouraging deep injection of produced water will need to address whether producers or subsequent users of produced water should bear the cost of treatment. If the cost of treatment is imposed upon the producer without regard for the availability of subsequent uses, the producer may find treatment cost prohibitive and opt to reinject produced water under a UIC permit. Conversely, if prospective users bear the full burden of treating the producer's waste stream, the producer has very little incentive to control produced water quality.

Where produced water can be treated and put to other beneficial uses, management options that preclude beneficial use are arguably in conflict with statutory and decisional requirements to avoid waste and maximize beneficial use of the water withdrawn. The potential to put produced water to a beneficial use should be considered liberally, as the benefit may accrue to a broader constituency than the producer alone. For instance, utilizing treated or high quality produced water to recharge ground water aquifers may be outside the conventional understanding of beneficial use because the benefit does not accrue to the operator, but to broader social interests. Likewise, discharging treated or high quality produced water to surface streams may not represent a beneficial use to the operator, but may meet broader societal needs for habitat protection or recreation enhancement. While beneficial use is generally evaluated with respect to the party making the withdrawal, water rights can be issued for instream uses (though only statutorily designated entities can hold such rights).[179] Pending legislation also allows certain entities to file for and obtain rights to capture and inject flood flows in order to recharge aquifers within critical ground water management areas even though the water right holder does not intend to personally withdraw the water injected.[180] While these types of efforts to broaden the reach of beneficial use to encompass societal values may provide templates for produced water management, both examples required revisions to the Utah Water Code and similar clarifications may be required to address produced water management.

Litigation driven by the CBM development boom has addressed two significant, but different concerns: first, ensuring that produced water withdrawals do not impair the valid water rights of existing water users or harm ecological processes; and second, ensuring that produced water management and disposal does not result in waste of scarce public resources. The challenge for both produced water generators and those hoping to utilize produced water as a source of supply is to create certainty in rapidly changing legal climate.

Under these circumstances, oil and gas operators have a clear incentive to reduce the volume of produced water brought to the surface as part of their development operations. Every gallon of withdrawal avoided is also a permitting and disposal issue avoided, and lowering water production reduces the chance of causing impairment to other water right holders. Limiting withdrawals to no more than needed, and making unused produced water available to other water users, also recognizes the states interest in reducing waste and maximizing beneficial use. Furthermore, reducing water production decreases the size of the effluent stream subject to regulation under the CWA, the SDWA, and their state analogues. Independent of permitting concerns, reducing produced water volume means fewer disposal wells, infiltration galleries, evaporation ponds, and associated pumps and pipelines. It also means a smaller development footprint and foregone disposal costs.

Where produced water generation cannot be avoided, operators have a strong incentive to use the water they produce for their own operational requirements. Reuse similarly moderates the need to obtain additional scarce and expensive external water sources, moderates disposal costs, and reduces the amount of water subject to potential back-end beneficial use requirements. Produced water generators are likely to adopt and expand these two practices, if they have not done so already. Avoiding unnecessary production and minimizing their waste stream makes good business sense, and demonstrating the effectiveness of self-regulation may reduce the likelihood of external regulation.

Recognizing that complete elimination of byproduct water generation is unlikely, the most promising disposal options are those that are beneficial in nature, avoid waste, and make excess produced water available to other users. Where water quality allows, produced water can be used to irrigate crops and reclaim disturbed areas, to water livestock and wildlife, to augment stream flows, and to recharge ground water. To ignore these options, where they exist, may invite legal challenges based on waste. Avoiding potential challenges based on waste, however, does not address water right permitting or disposal requirements and operators should ensure that all required permits are obtained before beginning operations. While it may be impossible to avoid using evaporation ponds, such disposal methods should be deployed only where produced water cannot be utilized or made available to other users.

Efforts to reduce produced water generation and to increase produced water reuse are not good news for prospective oil shale and oil sands developers hoping to utilize produced water generated by oil and gas developers. However, even with the most aggressive reduction and reuse programs, some level of excess produced water generation is likely. Aside from non-legal concerns (e.g., produced water quality, treatment costs, transportation costs, and stability of supplies), prospective third-party produced water users will need to comply with state appropriations law. Provided that the produced water generator has complied with all applicable water law requirements, availability to third-party users will depend upon a water right change authorization (or a water right if one was not required for formation dewatering). If continued beneficial use is required in order to avoid waste, the oil shale and oil sands industry may benefit, as they would represent a market for a product that is of limited use to the operator and which would otherwise represent a disposal challenge.

As with any produced water generator, unconventional fuel developers seeking to utilize produced water should look first to reuse any water they may have generated. Recognizing that reuse is unlikely to be sufficient, the most desirable sources of supply will be producers that can deliver a stable quantity and quality of water over the lifetime of the project. Where interruptions are a concern, those hoping to rely on produced water will need to develop storage or backup sources of supply. The ability to integrate development plans will be key to the success or failure of the effort to reuse produced water.

In the end, produced water generators, prospective produced water users, and government regulators alike must be flexible in adapting to site-specific issues and constraints, a rapidly evolving legal framework, and a resource that may change over time. Predicting how Utah law may evolve is difficult, as legal evolutions will depend on a range of factors. Yet what can be said with reasonable confidence is that foreseeable increases in energy production will drive more stringent disposal and appropriations requirements. To a large extent, the ability to proactively avoid impairment to others as well as waste of potentially valuable resources will dictate the level of regulatory involvement that occurs.

5. Conclusion and Recommendations

Whether produced water represents a viable source of supply for prospective oil shale and oil sands developers depends on several factors. As a threshold matter, it is uncertain whether commercial scale oil shale and oil sands development is compatible with intensive oil and natural gas development. Intensive natural gas development is proposed within the Uinta Basin, but few approvals have been issued thus far, making it premature to conclude what level of development will occur or how development will proceed. Because of the uncertainties involved in the permitting process, it is not currently possible to determine whether well and surface facility density will preclude commercial oil shale or oil sands development. It is also possible that the environmental effects of intensive oil and natural gas development will degrade environmental conditions, such as air quality related values, to such an extent that additional energy development may be legally precluded. Oil and natural gas development therefore has the potential to displace as well as synergistically support, oil shale and oil sands production.

Provided that oil and natural gas development does not displace oil shale and oil sands development, byproduct water from oil and gas production represents a potentially important source of water to prospective oil shale and oil sands producers. While traditional water sources remain available, competition for these sources is sure to grow. In addition to representing an alternative source of supply, application of produced water to secondary beneficial uses may provide a direct benefit to oil and gas operators by reducing pressure on strained produced water disposal facilities. For their part, prospective oil shale and oil sands producers intending to use produced water will need to ascertain whether produced water generators will be able to provide a reliable quantity and predictable quality of water for the duration of the proposed oil shale or oil sands project.

Utah currently considers byproduct water from hydrocarbon production to be a waste product and regulates it as such. The Utah State Engineer generally does not consider the withdrawal of water, standing alone, to be a beneficial use. Absent a beneficial use, the Utah

State Engineer appears unable to grant a water right. However, state issued water rights are required for any person seeking to put water to a beneficial use, regardless of whether the water in question is obtained from a surface waterbody, ground water, or the effluent stream of another water user.

The significant increase in natural gas production proposed for the Uinta Basin will likely result in increased interest in produced water regulation. Rapid expansion of natural gas development led to water law revisions in both Colorado and Montana, and cases from those jurisdictions could be used as templates for litigation in Utah. While these potentialities do not preclude use of produced water, they may add a layer of regulatory complexity; and evolution of legal doctrines could delay water acquisition and management efforts. Although these challenges are not insurmountable, the presently unsettled nature of the regulatory landscape will continue to demand flexibility of both producers and potential end users of produced water.

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ENDNOTES

[1] *See e.g.*, U.S. Government Accountability Office, Energy-Water Nexus: A Better Coordinated Understanding of Water Resources Could Help Mitigate the Impacts of Potential Oil Shale Development (2010).

[2] A detailed discussion of the basis for these estimates is contained in section 2.1.1.

[3] *Id*. The water to oil ratios for surface mining and retorting is estimated at 2.43:1; 2.62:1 for situ combustion; 6.55:1 for in situ steam injection; and 7.0:1 for solvent extraction. Water use ratios are derived from the BUREAU OF LAND MGMT., U.S. DEP'T OF INTERIOR, PROPOSED OIL SHALE AND TAR SANDS RESOURCE MANAGEMENT PLAN AMENDMENTS TO ADDRESS LAND USE ALLOCATIONS IN COLORADO, UTAH, AND WYOMING AND FINAL PROGRAMMATIC ENVIRONMENTAL IMPACT STATEMENT, B-20 – B-39 (2008) [hereinafter FINAL PEIS].

[4] *See* JOHN RUPLE & ROBERT KEITER, UNIV. OF UTAH INST. FOR CLEAN AND SECURE ENERGY, POLICY ANALYSIS OF WATER AVAILABILITY AND USE ISSUES FOR DOMESTIC OIL SHALE AND OIL SANDS DEVELOPMENT, App. A (2010) [hereinafter WATER RESOURCES TOPICAL REPORT].

[5] *See* Utah Division of Water Resources, Southeast Uinta Basin Policy, http://www.waterrights.utah.gov/wrinfo/policy/wrareas/area49.html.

[6] *See* WATER RESOURCES TOPICAL REPORT, *supra* note 4, at 33-36.

[7] The term produced water describes "water produced from a wellbore that is not a treatment fluid. The characteristics of produced water vary and use of the term often implies an inexact or unknown composition." Water trapped in the pores of shale since formation is generally referred to as "connate water" or "fossil water," and the "chemistry of connate water can change in composition throughout the history of the rock." "Formation water, or interstitial water, in contrast, is simply water found in the pore spaces of a rock, and might not have been present when the rock was formed." All definitions are from the Schlumberger, Oilfield Glossary, http://www.glossary.oilfield.slb.com/default.cfm. As used in this report, produced water may include either connate water, formation water, or a combination of both that may or may not be contaminated by treatment fluids, drilling fluids, hydrocarbons, or naturally occurring elements.

[8] Production information was obtained from the Utah Dep't of Natural Res., Div. of Oil, Gas and Mining's online production database, which is available at http://oilgas.ogm.utah.gov/Data_Center/DataCenter.cfm.

[9] UTAH CODE ANN. § 73-1-1(1).

[10] UTAH CODE ANN. § 73-3-1.

[11] Memorandum from Ben Harding et al., AMEC Earth & Environmental, to Joint Energy Water Needs Subcommittee, re: Draft Oil Shale Direct Water Use Estimates 3 (April 13, 2010) (on file with authors). This is an estimated upper bounds of production. Surface retorting is anticipated to produce much less water, approximately 0.3 units of water per unit of oil produced or 706 acre feet annually for a 50,000 BPD facility. *Id*. at 5.

[12] *See* Onshore Oil and Gas Order No. 7, 58 FED. REG. 47354, 47362 (Sept. 8, 1993).

[13] Michael D. Vanden Berg et al., Utah Geological Survey, Abstract for the Am. Ass'n of Petroleum Geologists Rocky Mountain Section Meeting Durango, Colorado, *Stratigraphic Characterization of the Birds Nest Aquifer in the Uinta Basin, Utah: Implications for Saline Water Disposal from Natural Gas Production* (June 13-16, 2010), *available at* http://geology.utah.gov/emp/UBwater_study/pdf/abstracts/abstract-aapg0610.pdf.

[14] *See* NATIONAL OIL SHALE ASS'N, OIL SHALE: AMERICA'S UNTAPPED ENERGY SOURCE 6-7 (2010).

[15] *See* WATER RESOURCES TOPICAL REPORT, *supra* note 4, at 8-10 (discussing differences between oil sands in Canada and the United States).

[16] *See id*. at 3-8 (discussing the range of oil shale water use estimates). *See also* Memorandum from Ben Harding et al., AMEC Earth & Environmental, to Joint Energy Water Needs Subcommittee, re: Energy Water Use Scenarios 3-7 (June 29, 2010).

[17] Harding memo re: Draft Oil Shale Direct Water Use Estimates, *supra* note 11, at 3.

[18] The water to oil ratios for surface mining and retorting is estimated at 2.43:1; 2.62:1 for situ combustion; 6.55:1 for in situ steam injection; and 7.0:1 for solvent extraction. Water use ratios are derived from the FINAL PEIS, *supra* note 3, at B-20 – B-39.

[19] *See, e.g*., *id*. at 4-2 (stating assumption that surface and underground mining operations would produce 50,000 BPD and in situ facilities would produce 200,000 BPD).

[20] *See Hearing of the Utah Natural Res., Agriculture, and Environment Interim Committee*, Aug. 18,2010, (comments of Dr. Laura Nelson, Vice President, Energy and Envtl. Dev., Red Leaf Resources, Inc.), audio recordings available at http://www.le.utah.gov/asp/interim/Commit.asp?Year=2010&Com=INTNAE (describing 2,000 to 10,000 BPD production as feasible within the next 18-24 months). *See also* WATER RESOURCES TOPICAL REPORT *supra* note 4, at 19-20 (discussing the scale of foreseeable development).

[21] The environmental analysis preceding issuance of a commercial lease is specifically required to consider water demand. *See* 43 C.F.R. § 3922.20(c)(3).

[22] An acre-foot of water is 325,851 gallons – roughly enough water to support two four-person families for a year.

[23] Utah's population is projected to grow by 25 percent between 2010 and 2020, and 50 percent between 2010 and 2030. Population projections are available at http://www.governor.utah.gov/dea/projections.html. For an assessment of the impacts of a changing climate on the Colorado River *see* NATIONAL RESEARCH COUNCIL, COLORADO RIVER BASIN WATER MANAGEMENT: EVALUATING AND ADJUSTING TO HYDROCLIMATIC VARIABILITY (2007).

[24] UTAH CODE ANN. § 73-1-1(1).

[25] UTAH CODE ANN. § 73-3-1.

[26] UTAH CODE ANN. § 73-1-10.

[27] WATER RESOURCES TOPICAL REPORT, *supra* note 4, at 33-36, 40-41 and 43.

[28] *Id*. at 31-32.

[29] *Id*. at Appendix A.

[30] *Id*. at 33-36.

[31] *Id*.

[32] *Id*. at 61-68.

[33] Production summaries were obtained from the Utah Dep't of Natural Res., Div. of Oil, Gas and Mining's online production database, which is available at http://oilgas.ogm.utah.gov/Data_Center/DataCenter.cfm

[34] *Id*.

[35] UTAH DEP'T OF NATURAL RES., DIV. OF OIL GAS, AND MINING, STATE OF UTAH PRODUCED WATER DISPOSITION SUMMARY YEAR 2006 OPERATIONS (2007) (on file with authors).

[36] *Id*.

[37] E-mail from Chris Kierst, Senior Petroleum Specialist / Petroleum Geologist, Utah Div. of Oil, Gas, and Mining, to John Ruple, Stegner Center Fellow & ICSE Research Associate, Univ. of Utah (Aug. 23, 2010, 5:36:35 PM MDT) (on file with authors).

[38] *See* Michael D. Vanden Berg, Utah Geological Survey, SURVEY NOTES, *Saline Water Disposal in the Uinta Basin,* UTAH vol. 42, n. 2 (2010). On most federal and Indian land, injection is the generally preferred method of disposal. *See* Onshore Oil and Gas Order No. 7, *supra* note 12.

[39] UTAH DEP'T OF NATURAL RES., DIV. OF OIL, GAS AND MINING, GAS AND MINING BY COUNTY (July 2010), *available at*: https://fs.ogm.utah.gov/pub/Oil&Gas/Publications/Reports/Prod/County/Cty_Jul_2010.pdf.

[40] Salinity control issues are discussed in the WATER RESOURCES TOPICAL REPORT, *supra* note 4, at 116-18.

[41] BUREAU OF LAND MGMT., U.S. DEP'T OF THE INTERIOR, WEST TAVAPUTS PLATEAU PROJECT FINAL ENVIRONMENTAL IMPACT STATEMENT 2-23 (2010) and BUREAU OF LAND MGMT., U.S. DEP'T OF THE INTERIOR, RECORD OF DECISION 20, 22 (2010) [her3inafter WEST TAVAPUTS ROD].

[42] BUREAU OF LAND MGMT., U.S. DEP'T OF THE INTERIOR, UINTA BASIN NATURAL GAS DEVELOPMENT PROJECT DRAFT ENVIRONMENTAL IMPACT STATEMENT 2-22 – 2-23 (2010).

[43] BUREAU OF LAND MGMT., U.S. DEP'T OF THE INTERIOR, GREATER NATURAL BUTTES DRAFT ENVIRONMENTAL IMPACT STATEMENT 2-15 and 2-25 (2010).

[44] FOREST SERVICE, U.S. DEP'T OF AGRICULTURE, SOUTH UNIT OIL AND GAS DEVELOPMENT PROJECT DRAFT ENVIRONMENTAL IMPACT STATEMENT 19 (2010).

[45] *Id*. at 32-33.

[46] BUREAU OF LAND MGMT., U.S. DEP'T OF THE INTERIOR, XTO ENERGY'S RIVER BEND UNIT INFILL DEVELOPMENT ENVIRONMENTAL ASSESSMENT AND BIOLOGICAL ASSESSMENT 2-10 (2008).

[47] BUREAU OF LAND MGMT., U.S. DEP'T OF THE INTERIOR, ENDURING RESOURCES' BIG PACK ENVIRONMENTAL ASSESSMENT 2-4 – 2-11 (2008).

[48] BUREAU OF LAND MGMT., U.S. DEP'T OF THE INTERIOR, ENDURING RESOURCES' SOUTHAM CANYON ENVIRONMENTAL ASSESSMENT 2-3 – 2-4 (2008).

[49] WEST TAVAPUTS ROD, *supra* note 41, at 15-17.

[50] While some project descriptions are ambiguous, Utah's CBM resources are located southwest of the proposed projects, in the Drunkards Wash area. *See* MICHAEL D. VANDEN BERG, UTAH GEOLOGICAL SURVEY, UTAH'S ENERGY LANDSCAPE 19 (2009).

[51] NATIONAL RESEARCH COUNCIL, MANAGEMENT AND EFFECTS OF COALBED METHANE PRODUCED WATER IN THE UNITED STATES 23 (2010) (prepublication version).

[52] *See* WATER RESOURCES TOPICAL REPORT, *supra* note 4, at A-55 – A-60.

[53] Impacts to air quality related values are a significant concern within the Uinta Basin. Air quality monitoring at National Parks throughout the Rocky Mountain Region demonstrates an upward trend in ground level ozone, and monitors within areas undergoing intense energy development have registered ozone levels in exceedance of National Ambient Air Quality Standards (NAAQS). While more data is needed before the Uinta Basin can be classified as a non-attainment area for ozone under the Clean Air Act, the BLM is reluctant to authorize new developments that could result in Clean Air Act violations. The EPA is in the process of revising NAAQS for ozone and new standards are likely to be more restrictive than those currently in effect. More stringent regulation could make further development even more difficult. As such, impacts to air quality related values may reflect the single most significant obstacle to increased energy production within the Uinta Basin.

[54] 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 Production Water Quality Legal Issues in Utah, New Mexico, Colorado, Montana, and Wyoming*, 17 J. ENVTL. L. & LITIG. 281, 303 (2002).

[55] MANAGEMENT AND EFFECTS OF COALBED METHANE PRODUCED WATER IN THE UNITED STATES, *supra* note 51, at 43.

[56] *Id*.

[57] *Id*.

[58] Memorandum from Ben Harding et al., AMEC Earth & Environmental, to Joint Energy Water Needs Subcommittee, re: Energy Water Use Scenarios (June 29, 2010) 5 (on file with authors).

[59] Harding Mem. re: Draft Oil Shale Direct Water Use Estimates, *supra* note 11, at 3.

[60] *Id*.

[61] *Id*.

[62] *Id*.

[63] Jim Waldron, Chevron USA, Inc., *Produced Water Reuse at the Kern River Oil Field*, SOUTHWEST HYDROLOGY 26-27 (Nov./Dec. 2005).

[64] FINAL PEIS, *supra* note 3, at A-51.

[65] For a review of produced water treatment options, see MANAGEMENT AND EFFECTS OF COALBED METHANE PRODUCED WATER IN THE UNITED STATES, *supra* note 51, at 149-63.

[66] In 2008, 1,600 ducks died from exposure to toxic tailings ponds operated by Snycrude, Canada's largest oil sands processor. Syncrude was charged with violating the Migratory Birds Convention Act of 1917 (MBCA), S.C., ch. 22 (1970) (Can.), and Alberta's Environmental Protection and Enhancement Act. The Alberta Provincial Court held that Snycrude failed to take necessary steps to keep waterfowl away from the tailings ponds. Jeffrey Jones, *UPDATE 3-Syncrude Guilty in 1,600 Duck Deaths in Toxic Pond*, REUTERS, June 25, 2010, *available at* http://www.reuters.com/assets/print?aid=USN2525673320100625. The violation resulted in a $3.2 million fine, the largest penalty in Canadian history for a single environmental offense. Darcy Henton, *Syncrude Pays $3.2-Million Penalty Over Duck Deaths*, THE VANCOUVER SUN, Oct. 22, 2010, *available at* http://www.canada.com/business/Syncrude+pays+million+penalty+over+duck+deaths/3712532/story.html#ixzz155WkRkQO.

In 1916, the United States and Great Britain (on behalf of Canada) entered into a treaty for the protection of migratory birds in the United States and Canada. 39 Stat. 1702-05 (1916). The treaty adopts a uniform system of protection for certain species of birds that migrate between the two countries in order to assure the preservation of species either harmless or beneficial to man. Implementing legislation for the United States was accomplished by enactment of the Migratory Bird Treaty Act in 1918. 16 U.S.C. § 703-711. Under the Migratory Bird Treaty Act, "it shall be unlawful at any time, by any means or in any manner, to pursue, hunt, take, capture, [or] kill . . . any migratory bird." 16 U.S.C. § 703. If domestic oil shale and oil sands operators utilize ponds as part of their extraction or refining process, they should take great care to assure that ponds do not inadvertently threaten migratory birds. Operations anticipating the use of tailings or evaporative ponds should work closely with state and local agencies to design facilities that protect waterfowl and minimize operator liability.

[67] The Clean Water Act permitting process is discussed in the WATER RESOURCES TOPICAL REPORT, *supra* note 4, at 99-107.

[68] Utah does not require the holder of a water right to continue diversions, even when those diversions indirectly supply other water users. The water right holder can abandon or relinquish their right through

non-use. UTAH CODE ANN. § 73-1-4. Similarly, while a downstream beneficiary can use water that drains or runs from a neighbor's field as long as the upgradient irrigator makes the water available, the upgradient irrigator is under no obligation to make that water available to the downstream user. Lasson v. Seely, 238 P.2d 418, 422-23 (Utah 1951).

[69] The Safe Drinking Water Act permitting process is discussed in greater detail in the WATER RESOURCES TOPICAL REPORT, *supra* note 4, at 111-115.

[70] Onshore Oil and Gas Order No. 7, *supra* note 12, at 47362.

[71] *See* section 2.2.2, *infra*.

[72] As a specific example, surface retorting of oil shale produces spent shale that must be moisturized to assure stable landfill disposal. According to the National Oil Shale Ass'n, up to fifteen percent by weight of the amount of spent shale may be required depending upon the technology employed and characteristics of the spent shale. All of the water produced from the processing of oil shale in a surface retort could potentially be applied to this use, provided that water quality concerns can be addresses. Personal communication with Glen Vawter, Executive Director, National Oil Shale Ass'n (Dec. 20, 2010).

[73] MANAGEMENT AND EFFECTS OF COALBED METHANE PRODUCED WATER IN THE UNITED STATES, *supra* note 51, at 87.

[74] *See* WATER RESOURCES TOPICAL REPORT, *supra* note 4 at 116-18.

[75] Michael D. Vanden Berg, Utah Geological Survey, *Understanding the Birds Nest Aquifer in Uintah County, Utah: A Potential Source for Large-Scale Saline Water Disposal*, Presentation at Groundwater Protection Council Annual Forum (Sept. 13-17, 2009).

[76] *Id*.

[77] On most federal and Indian land, injection is the generally preferred method of disposal. *See* Onshore Oil and Gas Order No. 7, *supra* note 12, at 47362.

[78] Michael D. Vanden Berg, SURVEY NOTES, *Saline Water Disposal in the Uinta Basin, Utah*, *supra* note 38.

[79] Michael D. Vanden Berg, Utah Geological Survey, *Saline Water Disposal in the Uintah Basin, Utah: The Single Most Pressing Issue with Regard to Increasing Petroleum Production and Protecting Freshwater Aquifers*, Presentation at the Am. Ass'n of Petroleum Geologists Annual Convention (June 7-10, 2009).

[80] *Id*.

[81] Michael D. Vanden Berg, Utah Geological Survey, *Saline Water Disposal into the Birds Nest Aquifer in Uintah County, Utah: Implications for Potential Oil Shale Development*, Presentation at the Colorado School of Mines 29th Annual Oil Shale Symposium (Oct. 19, 2009), *available at* http://geology.utah.gov/emp/UBwater_study/pdf/presentation1009.pdf.

[82] *Id*.

[83] Ongoing research is described more fully at: http://www.netl.doe.gov/technologies/oil-gas/Petroleum/projects/Environmental/Produced_Water/05671_UintaWaterStudy.html.

[84] JOHN A. VEIL & JOHN J. QUINN, ARGONNE NATIONAL LABORATORY, DOWNHOLE SEPARATION TECHNOLOGY PERFORMANCE: RELATIONSHIP TO GEOLOGIC CONDITIONS 6, 9 (2004).

[85] *Id*. at 20.

[86] *Id*. at 3.

[87] *Id*. at Table 4.

[88] Darin, *supra* note 54, at 17.

[89] *Id*. Wyoming, which is one of the nation's leading natural gas producers, first encountered problems involving produced water from coalbed methane just 20 years ago. *Id*. As of 2007, Wyoming had 42,510 operating natural gas wells generating more than 300,000 AF of produced water. 2007 Wyoming Oil and Gas Statistics, http://wogcc.state.wy.us/cfdocs/2007_stats.htm.

[90] MANAGEMENT AND EFFECTS OF COALBED METHANE PRODUCED WATER IN THE UNITED STATES, *supra* note 51, at 11.

[91] *See, e.g*., UTAH CODE ANN. § 73-1-1; COLO. REV. STAT § 37-92-102(1)(a).

[92] UTAH CODE ANN. § 73-3-1. For exceptions, see Winters v. U.S., 207 U.S. 564 (1908) (reserved rights for Indian reservation), Cappaert v. U.S., 426 U.S. 128 (1976) (reserved rights for National Monument), and UTAH CODE ANN. § 73-5-13 (claims based on diversions to beneficial use that predate administrative requirements).

[93] UTAH CODE ANN. § 73-1-3.

[94] Steven E. Clyde, *Utah Waters and Water Rights* §§ II(A) and II(F) *in* WATER AND WATER RIGHTS (Robert E. Beck and Amy K. Kelly, eds., 2009).

[95] Brian v. Fremont Irr. Co., 186 P.2d 588, 590 (Utah 1947).

[96] Clyde, *supra* note 94, at § VII(A).

[97] UTAH CODE ANN. § 73-3-1(4); Deseret Livestock Co. v. Utah, 171 P.2d 401, 404 (Utah 1946) ("If [the water right permit applicant] cannot place the water to a beneficial use it cannot appropriate the water because beneficial use is the only basis upon which water can be appropriated in this state.").

[98] Estate of Steed v. New Escalante Irrigation Co., 846 P.2d 1223, 1229 (Utah 1992).

[99] Lasson v. Seely, 238 P.2d 418 at 422-23.

[100] "An invasion of one's interest in the use and enjoyment of land resulting from another's interference with the flow of surface water may constitute a nuisance." RESTATEMENT (SECOND) OF TORTS § 833 (1979). "The determination of the reasonableness of a use of water depends upon a consideration of the interests of the [ ] proprietor making the use, of any [ ] proprietor harmed by it and of society as a whole. Factors that affect the determination include the following: (a) The purpose of the use, (b) the suitability of the use to the watercourse or lake, (c) the economic value of the use, (d) the social value of the use, (e) the extent and amount of the harm it causes, (f) the practicality of avoiding the harm by adjusting the use or method of use of one proprietor or the other, (g) the practicality of adjusting the quantity of water used by each proprietor, (h) the protection of existing values of water uses, land, investments and enterprises and (i) the justice of requiring the user causing harm to bear the loss." *Id*. at § 850A. *See also* Bingham v. Roosevelt City, 235 P.3d 730 (Utah 2010) (applying the rule of reasonableness to water users' means of groundwater withdrawal).

[101] The Utah Div. of Water Quality issues Pollution Discharge Elimination System general permits for construction dewatering and hydrostatic testing.

[102] 488 P.2d 741 (Utah 1971).

[103] *Id*. at 743 (internal quotation and citations omitted).

[104] *Id*. at 745. *See also* Stubbs v. Ercanbrack, 368 P.2d 461 (Utah 1962) (holding that landowner had a right to establish a drainage system to turn swamp land into usable property, but that he did not have a right to interfere with previously established water rights).

[105] 343 P.2d 1100 (Utah 1959).

[106] *Id*. at 311.

[107] Vance v. Wolfe, 205 P.3d 1165, 1169 (Colo. 2009) (quoting COLO. REV. STAT. § 37-92-103(3)(a)).

[108] A. DAN TARLOCK, L. OF WATER RIGHTS AND RESOURCES § 5.66 (July 2010 Update).

[109] Butler Crockett and Walsh Dev. Co. v. Pinecrest Pipeline Operating Co., 98 P.3d 1, 11 (Utah 2004).

[110] *Id*. at 11.

[111] Janet C. Neuman, *Beneficial Use, Waste, and Forfeiture: The Inefficient Search for Efficiency in Western Water Use*, 28 ENVTL. L. 919, 942 (1998) (quoting Imperial Irrigation Dist. v. State Water Res. Control Bd., 225 Cal. App. 3d 548, 570 (Ct. App. 1990)).

[112] Butler Crockett and Walsh Dev. Co., 98 P.3d at 11 (quoting Jeffs v. Stubbs, 970 P.2d 1234, 1245 (Utah 1998)).

[113] *Id*. at 13.

[114] *Id*. at 13 (quoting Neuman, 28 ENVTL. L. at 926).

[115] Colby Barrett, *Fitting a Square Peg in a Round (Drill) Hole: The Evolving Legal Treatment of Coalbed Methane-Produced Water in the Intermountain West*, 38 ENVTL. L. REP. NEWS & ANALYSIS 10661 (2008).

[116] A declaratory judgment suit is an action to determine respective legal rights and positions regarding a controversy not yet ripe for adjudication, as when an insurance company seeks a determination of coverage before deciding whether to cover a claim. *See* BLACK'S L. DICTIONARY (9th ed. 2009).

[117] Vance v. Simpson, No. 2005CW063, slip op. at 2 (Colo. Dist. Ct., Water Div. 7, July 2, 2007), *aff'd*, Vance v. Wolfe, 205 P.3d 1165 (Colo. 2009).

[118] The State of Colorado has seven designated water divisions, each with a dedicated water court. Water courts have jurisdiction in the determination of water rights, the use and administration of water, and all other water matters within the jurisdiction of the water divisions. Water court decisions are appealable to the Colorado Supreme Court. The system is intended to ensure that courts dealing with water issues have the technical expertise and historical perspective to address these complex issues, and that legal issues are properly developed before being forwarded for appellate review. Utah does not have dedicated water courts, relying instead on state district courts.

[119] *Vance v. Simpson*, slip op. at 11.

[120] *Id.* at 16.

[121] 205 P.3d at 1170.

[122] *Id*. at 1167.

[123] H.R. 09-1303, 2009 Reg. Sess. (Colo. 2009). H.R. 09-1303 was signed into law by Governor Ritter on June 2, 2009.

[124] 2 COLO. CODE REGS. § 402-17.7.

[125] COLO. REV. STAT. § 37-90-103(6)(a).

[126] *See* Joe Hanel, *Water-Rights Owners Sue State – Again*, THE DURANGO HERALD, March 3, 2010.

[127] 2 COLO. CODE REGS. § 402-17.3.

[128] State Engineer's Office Guidance: CBM/Ground Water Permits (March 2004). *See also* WYO. CODE R. § 055-000-004(1)(c)(iii) ("The Office of the State Engineer regulates . . . the beneficial use of water produced in association with the recovery of hydrocarbons which includes water from coalbed methane wells.").

[129] "Inactive use of CBNG-produced water due to evaporation and/or infiltration" and "[a]ctive use of CBNG-produced water by discharging from the reservoir such as land application or in a leach field" are

considered beneficial uses. Memorandum from Patrick Tyrrell, Wyoming State Engineer, to State Engineer's Office (Apr. 26, 2004).

[130] WYO. STAT. § 41-3-930(a). *See also* Memorandum from Lisa Lindemann, Office of the Wyoming State Engineer, to Ground Water Division Employees (Oct. 25, 2007).

[131] Memorandum from Patrick Tyrrell, Wyoming State Engineer, to State Engineer's Office (Apr. 26, 2004).

[132] Barrett, *supra* note 115, at 10674.

[133] Montana Dep't of Natural Res. and Conservation, Final Order In the Matter of the Designation of the Powder River Basin Controlled Ground Water Area (1999).

[134] 2008 Mont. Dist. LEXIS 180.

[135] MONT. CONST. Art. IX, 3(3).

[136] 2008 Mont. Dist. LEXIS 180, *14 (citing MONT. CODE ANN. § 85-1-101).

[137] *Id*.

[138] *Id*. at *15.

[139] *Id*. at *16.

[140] 2010 Mont. Dist. LEXIS 116, *as amended* by 2010 Mont. Dist. LEXIS 126.

[141] 2010 Mont. Dist. LEXIS 116, *5, *as amended* by 2010 Mont. Dist. LEXIS 126 (citing MONT. CODE ANN. § 82-11-175(2)).

[142] 2010 Mont. Dist. LEXIS 116, *15, *as amended* by 2010 Mont. Dist. LEXIS 126.

[143] N.M. STAT. ANN. § 72-12-1.

[144] N.M. STAT. ANN. § 72-12A-5.

[145] N.M. STAT. ANN. § 72-12A-7(C)-(D).

[146] N.M. STAT. ANN. § 72-12-25 (2008).

[147] For example, in Sandoval County, New Mexico, two deep ground water wells (3,850 and 4,820 feet deep) produce up to 750 GPM, supplying water to 70,000 residences. Robert M. Sengebush, INTERA Inc., *Deep Brackish Water Considered for New Mexico Development*, SOUTHWEST HYDROLOGY 8 (Mar./Apr. 2008). Water from these two deep wells contains approximately 12,000 MG/L total dissolved solids, 3,100 MG/L chloride, and 4,400 MG/L sulfate. Id. While treatment costs are high at an estimated $1 to $3 per 1,000 gallons, *id*. pumping and treating deep, saline ground water represented the best remaining source of water given the region's rapid growth and few remaining undeveloped water resources.

[148] *See* H.R. 19, 49th Leg., 1st. Reg. Sess. (N.M. 2009) (amending N.M. STAT. ANN. § 72-12-25 (2008)).

[149] N.M. STAT. ANN. § 72-2-12.1.

[150] E-mail from Boyd Clayton, Deputy Utah State Engineer, to John Ruple, Stegner Center Fellow & ICSE Research Associate, Univ. of Utah (Nov. 4, 2010 2:27:17 PM MDT) (on file with authors). *See also* UTAH CODE ANN. §§ 73-5-9 (State Engineer's power to prevent waste, pollution, or contamination of water) and 73-2-25 (State Engineer's enforcement powers).

[151] UTAH CODE ANN. § 73-1-3.

[152] *See* Deseret Livestock Co. v Utah, 171 P.2d 401 at 404 (Utah 1946) ("If [the water right permit applicant] cannot place the water to a beneficial use it cannot appropriate the water because beneficial use is the only basis upon which water can be appropriated in this state.").

[153] E-mail from Boyd Clayton, Deputy Utah State Engineer, to John Ruple, Stegner Center Fellow & ICSE Research Associate, Univ. of Utah (Nov. 4, 2010, 2:27:17 PM MDT) (on file with authors).

[154] Wayman v. Murray City Corp., 458 P.2d 861, 863 (Utah 1969).

[155] For example, the Great Salt Lake Minerals Corp. holds, as part of its larger water right portfolio, an approved water right application for an 8,000 cfs diversion and year-around storage of up to 800,000 acre-feet in a 440,400 acre (688.125 square mile) impoundment area. *See* Water Right 13-3404. U.S. Magnesium LLC holds a certificated water right to 35,290 acre-feet for "[p]roduction of evaporite mineral and metals, development of aquaculture." *See* Water Right 16-727.

[156] UTAH ADMIN. CODE § R 649-9. Note, however, that DOGM regulations address only management and disposal of produced water, not the operator's antecedent right to withdraw the water.

[157] Personal communication with Glen Vawter, Executive Director, National Oil Shale Ass'n (Dec. 20, 2010).

[158] Chris Woodka, *Oil and Gas Wells Under New Colorado Water Policies*, THE PUEBLO CHIEFTAIN, Oct. 4, 2010.

[159] UTAH CODE ANN. § 73-1-1(1), *cf*. COLO. CONST. ART. XVI § 5 ("The water of every natural stream, not heretofore appropriated, within the state of Colorado, is hereby declared to be the property of the public, and the same is dedicated to the use of the people of the state, subject to appropriation as hereinafter provided.").

[160] UTAH CODE ANN. § 73-3-1(5)(a), *cf*. COLO. CONST. ART. XVI § 6 ("Priority of appropriations shall give the better right as between those using water for the same purpose.").

[161] Wayman v. Murray City Corp., 458 P.2d 861, 863 (Utah 1969). *Cf*. Wright v. Platte Valley Irrigation Co., 61 P. 603 (Colo. 1900).

[162] Clyde, *supra* note 94, at § II(b) and (F); *see also* Butler Crockett and Walsh Development Corp. v. Pinecrest Water Co., 98. P.3d 1, 10-15 (Utah 2004). *Cf*. Zigan Sand and Gravel, Inc. v. Cache La Poudre Water Users Ass'n, 788 P.2d 175, 182 (Colo. 1988) ("beneficial use is a broad concept and [ ] characterization of a use as beneficial requires case by case factual analysis").

[163] In Utah, a line of cases creates a strong presumption in favor of continuity and places the burden of proof on the party claiming isolation. *See* Mountain Lake Mining Co. v. Midway Irrigation Co., 154 P 584 (Utah 1916), and 149 P. 929 (Utah 1915) (party claiming developed water bears burden of proof to show he was not intercepting the supply to which his neighbor was entitled); Herriman Irrigation Co. v. Butterfield Mining Co., 57 P. 537 (Utah 1899) (party claiming developed water bears burden of proof to show it is not part of surface water); and Silver King Consol. Mining Co. v. Sutton, 39 P.2d 682 (Utah 1934) (same). Even if an applicant can demonstrate hydrologic isolation, such non-tributary ground water would still be subject to water right permitting requirements because the water remains public water. See Utah Code Ann. § 73-1-1 and Mosby Irrigation Co. v. Criddle, 354 P.2d 848, 852 (Utah 1960) ("right to the use of water is derived from the State").

[164] Statutory requirements for approval of applications to appropriate are set forth in UTAH CODE ANN. § 73-3-8.

[165] MONT. CONST. Art. IX § 3(3).

[166] UTAH CODE ANN. § 73-1-3.

[167] Wayman v. Murray City Corp., 458 P.2d 861 (Utah 1969).

[168] *See* MONT. CODE ANN. § 85-1-101(1). *Cf*. McNaughton v. Eaton, 242 P.2d 570, 572 (Utah 1952) (water may not be wasted, thereby depriving others of its beneficial use)

[169] Brian v. Freemont, 186 P.2d 588, 590 (Utah 1947).

[170] *See* MANAGEMENT AND EFFECTS OF COALBED METHANE PRODUCED WATER IN THE UNITED STATES, *supra* note 51, at 23 ("CBM produced water is not returned to the coal seams from which it was extracted because doing so would hinder additional methane recovery.").

[171] *Brian v. Freemont*, 186 P.2d at 590.

[172] Grossner v. Utah Power & Light, 612 P.2d 337 (Utah 1980).

[173] *Id*. at 340.

[174] *Id*. at 341.

[175] *Brian v. Fremont*, 186 P.2d at 590.

[176] *See* MANAGEMENT AND EFFECTS OF COALBED METHANE PRODUCED WATER IN THE UNITED STATES, *supra* note 51, at 43.

[177] *Id*.

[178] *See* UTAH ADMIN. CODE § R655-3

[179] UTAH CODE ANN. § 73-3-30.

[180] The Executive Water Task Force is investigating at least two possible means of addressing severe ground water mining by amending the Utah Water Code to state that beneficial use includes artificial recharge of ground water basins where ground water withdrawals consistently exceed the safe yield. Memorandum from Richard Bay, General Manager/CEO, Jordan Valley Water Conservancy Dist. to Senator Dennis Stowell, re: Artificial Groundwater Recharge in a Critical Management Area (Oct. 1, 2010) (on file with authors). This amendment would allow water users to dedicate a portion of their water right to aquifer recharge without risking forfeiture. Declaring artificial recharge of ground water basins a beneficial use would also allow local water districts to file for and obtain a right to seasonal flood flows, obtain a recharge permit under the Groundwater Recharge and Recovery Act, and divert flood flows into infiltration galleries. *Id*.

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