Oil & Natural Gas Technology

DOE Award No.: DE-FE0001243

Topical Report

POLICY ANALYSIS OF WATER AVAILABILITY AND USE ISSUES FOR DOMESTIC OIL SHALE AND OIL SANDS DEVELOPMENT

Submitted by:
University of Utah
Institute for Clean and Secure Energy
155 South 1452 East, Room 380
Salt Lake City, Utah 84112

Prepared for:
United States Department of Energy
National Energy Technology Laboratory

March, 2010

Office of Fossil Energy

Policy Analysis of Water Availability and Use Issues For Domestic Oil Shale and Oil Sands Development

Topical Report

Reporting Period: October 1, 2009 through March 31, 2010

Principal Authors: John Ruple and Robert Keiter

Report Issued: March 2010

DOE Award No.: DE-FE0001243

University of Utah
Institute for Clean and Secure Energy
155 South 1452 East, Room 380
Salt Lake City, Utah 84112

ABSTRACT

Oil shale and oil sands resources located within the intermountain west represent a vast, and as of yet, commercially untapped source of energy. Development will require water, and demand for scarce water resources stands at the front of a long list of barriers to commercialization. Water requirements and the consequences of commercial development will depend on the number, size, and location of facilities, as well as the technologies employed to develop these unconventional fuels. While the details remain unclear, the implication is not – unconventional fuel development will increase demand for water in an arid region where demand for water often exceeds supply.

Water demands in excess of supplies have long been the norm in the west, and for more than a century water has been apportioned on a first-come, first-served basis. Unconventional fuel developers who have not already secured water rights stand at the back of a long line and will need to obtain water from willing water purveyors. However, uncertainty regarding the nature and extent of some senior water claims combine with indeterminate interstate river management to cast a cloud over water resource allocation and management. Quantitative and qualitative water requirements associated with Endangered Species protection also stand as barriers to significant water development, and complex water quality regulations will apply to unconventional fuel development.

Legal and political decisions can give shape to an indeterminate landscape. Settlement of Northern Ute reserved rights claims would help clarify the worth of existing water rights and viability of alternative sources of supply. Interstate apportionment of the White River would go a long way towards resolving water availability in downstream Utah. And energy policy clarification will help determine the role oil shale and oil sands will play in our nation's future.

EXECUTIVE SUMMARY

Oil shale and oil sands resources located within the intermountain west represent a vast, and as of yet, commercially untapped source of energy. Mid-range estimates of potentially recoverable oil shale resources within Colorado, Utah, and Wyoming are more than three times Saudi Arabia's proven conventional oil reserves. If tapped, oil shale could reshape our national energy future.

Oil shale and oil sands development will require water – water that is already scarce in much of the prospective development area. Water's scarcity and importance to local residents is reflected in the time-worn adage, "whiskey is for drinking; water is for fighting over." This adage holds true throughout the intermountain west and much of the discourse over water for oil shale and oil sands development does more to fuel the fight than illuminate the choices ahead. These choices and the tradeoffs they reflect are made more difficult because water needs are not well understood at either the facility or industry level. Water requirements and the consequences of commercial development will depend on the number, size, and location of facilities, as well as the technologies employed to develop unconventional fuels. As commercialization has yet to occur, each of these factors represents an assumption rather than a known value. Assumptions regarding each of these factors carry a high degree of uncertainty, which compound as we attempt to look farther into the future and project to higher production levels.

While the details remain unclear, the implication is unmistakable – unconventional fuel development will increase demand for water in an arid region where demand for water often exceeds supply. Not all who seek water will be able to satisfy their thirst at a palatable cost, and non-consumptive uses will be pitted against powerful economic interests.

These problems, while profound, are far from new. Western water law grew out of conflicting claims; for more than a century, western water has been apportioned on a first-come, first-served basis and elaborate systems are in place to ensure that senior rights are protected from harm caused by subsequent water appropriators. These systems allow for the transfer of water rights to more economically profitable uses, provided that transfers do not result in injury to other water users, and it is these types of transfers that lead to the second tired adage – "in the west, water flows uphill towards money."

Prior appropriation, while simple in theory, becomes complicated in application because undeveloped rights may be senior to rights that have been in beneficial use for years. In Colorado, many energy companies hold long dormant conditional water rights that, if developed, would be senior to subsequently filed but already perfected water rights. In Utah, the most promising sources of supply represent underdeveloped rights that are senior to many existing uses. Development of these latent rights could displace existing, junior water users and change the face of western communities. Unconventional fuel developers who have not already secured water rights stand at the back of a long line and will need to obtain water from willing water purveyors. However, uncertainty regarding the nature and extent of some senior water claims combine with indeterminate interstate river management to cast a cloud over water resource allocation and management.

The Northern Ute Tribe of Indians can lay claim to vast quantities of water from both the White and Green river systems. These claims are senior to almost all other claims within eastern Utah's Uinta Basin and can either support or compete with commercial oil shale and oil sands development. regardless of how these rights are developed, they threaten to displace what were previously considered secure water rights.

Furthermore, the White River flows from Colorado into Utah, along the northern edge of the Piceance Basin and through the heart of the Uinta Basin – the two richest oil shale basins in the world. While a complex body of law has developed to allocate water between the states within the Colorado River Basin, this body of law remains virtually silent with respect to apportionment of Colorado River tributaries such as the White River. This silence creates uncertainty for prospective water users in Utah because there are no clear limits on development of upstream water rights, and their development could reduce downstream supplies.

These pending but unperfected uses stand against the backdrop of quantitative and qualitative water requirements dictated by the Endangered Species Act. The major river systems within the prospective development area are home to four federally protected fish that indirectly lay claim to water for habitat protection. Furthermore, complex water quality regulations will apply to unconventional fuel development. While water quality regulations are dealt with as a routine part of oil and natural gas development, unique requirements will likely apply to underground injections for certain in situ processes. The combined effect of these factors is to call into question the size of the proverbial pie, as well as the number of slices that have already been spoken for.

Moving forward, policy makers must recognize the limits inherent in current information about the nascent oil shale and oil sands industries, the resources they require, and the effluent streams they will produce. A commercial oil shale or oil sands industry will take decades to develop, if it develops at all; decisions made today should focus on resolving uncertainty and maintaining flexibility to adapt to the changes that lay ahead. Policies should drive development of an industry consistent with carefully articulated national energy and environmental objectives, emphasizing transparency and innovation while avoiding irretrievable commitments to an unproven industry. Together, clarifying water availability, determining the weight given to competing resource values, and articulating a clear national energy strategy will provide the sideboards needed to refine assessments of water for unconventional fuel development.

Legal and political decisions can give shape to an indeterminate landscape. Ongoing efforts to evaluate the effect of hydraulic fracturing will illuminate an increasingly important area of legal and policy disagreement. Interstate apportionment of the White River would go a long way towards resolving water availability in downstream Utah. Interstate compacts provide a valuable tool to resolving allocation dilemmas and represent an attractive alternative to costly and protracted litigation. Settlement of the Northern Utes' reserved rights claims would help clarify the relative value of competing water rights. Clarity regarding the number and extent of competing water rights will facilitate the reallocation of water rights that will accompany commercial oil shale or oil sands development. While prior efforts to resolve both issues have been unsuccessful, energy production may provide the spark needed to move forward. Importantly, resolving each of these challenges provides utility that extends well beyond the oil shale or oil sands industry.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

ACRONYMS

AC	Acres
AF	Acre-Foot
AF/Y	Acre-Foot per Year
BADT	Best Available Demonstrated Control Technology
BAT	Best Available Technology
BBL	Barrel
BCT	Best Conventional Pollution Control Technology
BLM	Bureau or Land Management
BMP	Best Management Practice
BPD	Barrel per Day
BPT	Best Practicable Control Technology Currently Available
CBM	Coalbed Methane
CFS	Cubic Foot Per Second
CO_2	Carbon Dioxide
CWA	Clean Water Act
DOE	Department of Energy
EIS	Environmental Impact Statement
ELG	Effluent Limitation Guidelines
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
ESA	Endangered Species Act
FEIS	Final Environmental Impact Statement
GPD	Gallons per Day
GPT	Gallons per Ton
FLPMA	Federal Land Policy and Management Act
HCP	Habitat Conservation Plan
KM	Kilometer
MCF	Thousand Cubic Feet
NEPA	National Environmental Policy Act
NPDES	National Pollution Discharge Elimination System
NOSR	Naval Oil Shale Reserve
OSEC	Oil Shale Exploration Company
PAC	Polycyclic Aromatic Compounds
PEIS	Programmatic Environmental Impact Statement
PIA	Practicable Irrigable Acreage
RD&D	Research, Development, and Demonstration
RMP	Resource Management Plan
ROD	Record of Decision
SDWA	Safe Drinking Water Act
SITLA	Utah School and Institutional Trust Lands Administration
STSA	Special Tar Sands Area
TDS	Total Dissolved Solids
TMDL	Total Maximum Daily Load
TSS	Total Suspended Solids
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
WMU	Watershed Management Unit

This report is divided into two sections. Section I addresses water availability and allocation of water resources for oil shale and/or oil sands development. Section II addresses water quality issues likely to arise with commercial oil shale or oil sands development. Uncertainty regarding the number of facilities, the size of facilities, the location of facilities, each facility's resource requirements, each facility's emissions, federal leasing requirements, federal energy policy, and important regulatory sideboard such as endangered species protection and greenhouse gas regulation necessitate a conceptual framework. Rather than focus on what are currently unanswered and unanswerable questions, this report attempts to illuminate policy options by focusing on the choices ahead and measures that can be taken to improve decision-making capacity. Because policy choices are most notable with respect to water resource allocation, the discussion of water resources is more detailed than the discussion of water quality issues and constraints.[1]

I. WATER AVAILABILITY

Water is the figurative lifeblood of the Colorado River Basin (shown in Figure 7), and like most critically important resources, it is heavily regulated by an interrelated web of laws and policies. Decisions allocating water to one set of uses imply that less water will be available for other uses and such decisions can literally ripple throughout the Basin. This section addresses how to allocate scarce water resources in light of growing demand, increasing recognition of non-consumptive uses, and an emerging consensus that water resources are neither as plentiful nor as reliable as previously thought.

A. Introduction

While much has been written about the vast quantities of water that will be needed for oil shale and/or oil sands development, most estimates are based on more than three-decade-old

[1] This topical report builds on previously published research and analysis, *see John C. Ruple and Robert Keiter, Water for Commercial Oil Shale Development in Utah: Allocating Scarce Resources and the Search for New Sources of Supply*, 30 J. LAND RESOURCES & ENVTL. L. 1 (2010) and *John Ruple and Robert Keiter*, *Water for Commercial Oil Shale Development in Utah: Clarifying How Much Water is Needed and Available*, 28 J. ENERGY & NAT. RESOURCES L. 49 (2010).

information and technologies. Emerging technologies are universally described as less water intensive, but emerging technologies' actual requirements are often proprietary and untested at commercial scales. The numbers that are available, therefore, do more to polarize than to illuminate decisions.

Even if water demand for commercial oil shale and oil sands development can be quantified, a growing population, water demand associated with competing energy technologies, and increasing awareness of the need to maintain natural processes will influence water availability. For example, water associated with carbon capture and sequestration could increase significantly the demand for water across all carbon-based energy resources.[2] Efforts to advance plug-in hybrid or electric vehicles would reduce demand for oil and gas but increase demand for electricity, and with it the need for water-hungry power plants.[3] Even concentrated solar power generation will require large quantities of water, as would nuclear power plants.[4] While putting reliable numbers to water demand is problematic, competition between municipal, agricultural, energy, industrial, and instream water uses will clearly increase – and some seeking to use water will be left, quite literally, high and dry. Likewise, development policies for onshore and offshore oil and gas resources in sensitive areas will influence demand for oil shale and oil sands. Federal incentives designed to increase domestic energy production will cause certain technologies to rise and others to fall. All of these decisions – and many more – impact demand for water.

The establishment of clear, national policies that drive visionary and environmentally responsible technologies are needed if development of oil shale and/or oil sands is to occur.

---

[2] Carbon capture and sequestration associated with electric power generation is projected to increase water consumption by 25%, or an additional 1 to 2 billion gallons per day by 2030. Mike Hightower, *At the Crossroads: Energy Demands for Water Versus Water Availability*, SOUTHWEST HYDROLOGY 24-25 (May/June 2007).

[3] Thermoelectric power represents the largest single use of water in the United States, with use estimated at 201 billion GPD (225,000,000 AF/Y). Most of this water is used for plant cooling. JOAN F. KENNEY ET AL., U.S. GEOLOGICAL SURVEY, ESTIMATED USE OF WATER IN THE UNITED STATES IN 2005 38 (2009).

[4] Gary Woodward, *Alt-Fuel Development May Impact Natural Resources*, SOUTHWEST HYDROLOGY 8 (March/April 2009).

The Research, Development and Demonstration (RD&D) leasing model that is currently used for oil shale is well suited to answering the important questions surrounding oil shale and oil sands, and if utilized appropriately, can do so while policy makers formulate the complex, interconnected national policies that will provide the sideboards to commercially successful development. Research should focus on narrowing informational gaps and reducing uncertainty. The discussion that follows flows from this premise, identifying gaps in water resource policies and, where appropriate, recommending alternative means of moving forward.

B. The Demand for Water

1. Water Demand for Oil Shale Development

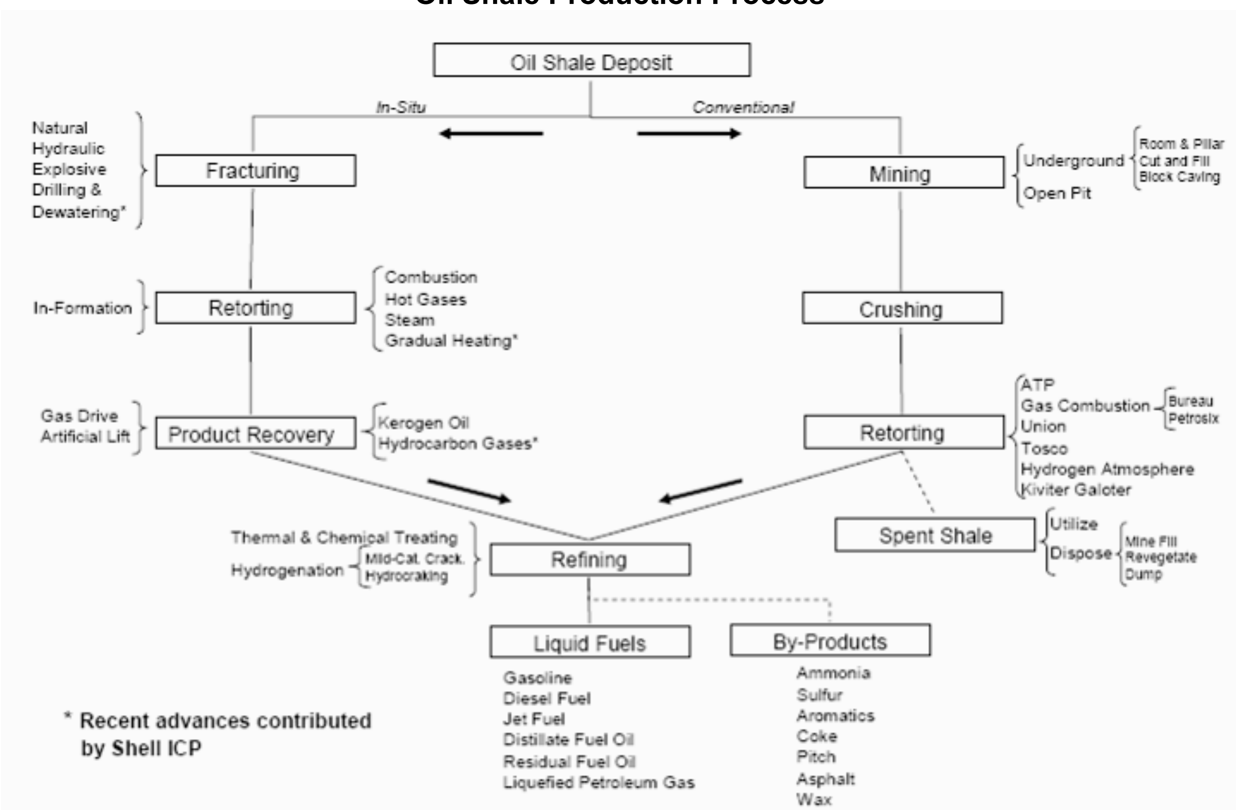
Quantifying water needs associated with commercial oil shale production is difficult at best. Estimates are based on dated technologies and assumptions that become questionable with the passage of time.[5] As estimates grow stale, little new information has emerged to aid policy makers. The lack of credible estimates does not, however, indicate a lack of interest or research in the area, but rather, that details about the most promising processes remain proprietary.

Gross water needs depend on consumption at each phase of the production processes, a summary of which is shown in Figure 1. For mining and surface retorting, water is needed for dust control during materials extraction, crushing, transport, storage and disposal; for cooling,

[5] For example, the most recent and comprehensive evaluation of oil shale development impacts estimates conventional mining with surface retorting will require from 2.6 to 4.0 barrels of water for each barrel of shale oil produced. *See* BUREAU OF LAND MANAGEMENT, U.S. DEPARTMENT 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, 4-4 and 4-8 (Sept. 2008) (hereinafter "FINAL PEIS"). These figures are derived from the Department of Interior's 1973 ENVIRONMENTAL IMPACT STATEMENT FOR THE OIL SHALE PROTOTYPE LEASING PROGRAM. *See* U.S. DEPARTMENT OF INTERIOR, FINAL ENVIRONMENTAL IMPACT STATEMENT FOR THE PROTOTYPE OIL SHALE LEASING PROGRAM, Vol. 1, III-34 (1973) (hereinafter "1973 PROTOTYPE LEASING FEIS"). Estimating water needs for in situ retorting is equally difficult. The FINAL PEIS cites a 2005 Rand Corp. study for the proposition that in situ development would require 1 to 3 barrels of water for each barrel of oil produced, *see* FINAL PEIS at 4-11. The Rand report, BARTIS ET AL., RAND CORPORATION, OIL SHALE DEVELOPMENT IN THE UNITED STATES: PROSPECTS AND POLICY ISSUES 50 (2005), relies on information from a 17 year-old report by the U.S. Water Resources Council. *See* U.S. WATER RESOURCES COUNCIL, SECTION 13(A) WATER ASSESSMENT REPORT, SYNTHETIC FUEL DEVELOPMENT IN THE UPPER COLORADO REGION (1981).

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. In situ retorting eliminates or reduces a number of these water requirements, but considerable volumes of water may be required for oil and synthesis gas extraction, post extraction cooling, product upgrading and refining, environmental control systems, power production, and post-production site reclamation and revegetation. Use and consumption at each phase depend on the technologies utilized.

Figure 1
Oil Shale Production Process[6]



Prospective oil shale developers are well aware that water is a constraining resource and have gone to great lengths to reduce water use. Chevron Shale Oil Company, which holds an RD&D lease in Colorado's Piceance Basin, contends its in situ method "will consume less water than the quantity of groundwater pumped out of the target zone," making it "a net

[6] Adapted from J.A. VEIL AND M.G. PUDER, ARGONNE NATIONAL LABORATORY, POTENTIAL GROUND WATER AND SURFACE WATER IMPACTS FROM OIL SHALE AND TAR SANDS ENERGY-PRODUCTION OPERATIONS 6 (2006).

producer of water."[7] Red Leaf Resources, Inc., which has almost 17,000 AC of state land under lease in Utah,[8] contends its modified in situ retorting process requires no outside water and total water use will be less than half a gallon of water for each gallon of shale oil produced, almost all of which is dedicated to postproduction site reclamation.[9] EnShale, Inc., which also holds leases to state lands in Utah, claims "water consumption of less than one gallon per barrel of liquid fuels produced."[10]

It is often unclear what considerations are reflected in various water use estimates, making evaluation and comparison across estimates problematic. The Department of Energy's 1973 PROTOTYPE LEASING FINAL ENVIRONMENTAL IMPACT STATEMENT (FEIS) provides a model for quality disclosure, evaluating direct water needs for each of six separate phases of production[11] for several different technologies as well as indirect impacts to water needs from urban domestic growth and power generation under multiple development scenarios.[12] While more recent estimates generally anticipate lower water use, they often fail to state what phases of production are considered. Therefore, the transparency in the DOE estimate makes its estimate of approximately three gallons of water for each gallon of shale oil produced a reasonable, conservative estimate. A range of water use estimates is provided in Table 1.

---

[7] JASON HANSON AND PATTY LIMERICK, UNIVERSITY OF COLORADO, WHAT EVERY WESTERNER SHOULD KNOW ABOUT OIL SHALE: A GUIDE TO SHALE COUNTRY 20 (2009). The ability to capture and use water "produced" as a byproduct of energy extraction raises complicates legal issues which are addressed in more detail later in this report.

[8] Figures are as of October 31, 2008. Statistics were compiled from data provided by the Utah School and Institutional Trust Lands Administration (SITLA) and *available at* http://168.178.199.154/publms/contents.htm.

[9] *See* Testimony before the Utah Legislature's Interim Committee on Natural Resources, Agriculture, and the Environment (June 17, 2009) *available at* http://le.utah.gov/asp/interim/Commit.asp?Year=2009&Com=INTNAE. Dr. Nelson, Chair of the Utah Mining Association's Oil Shale and Oil Sands Committee, also testified that estimated water use is falling rapidly as industry continues to innovate and currently sits at an average of 1.5 barrels of water for each barrel of shale oil produced, less than water demands associated with conventional oil and gas production.

[10] OFFICE OF NAVAL PETROLEUM AND OIL SHALE RESERVES, U.S. DEPARTMENT OF ENERGY, SECURE FUELS FROM DOMESTIC RESOURCES: THE CONTINUED EVOLUTION OF AMERICA'S OIL SHALE AND TAR SANDS INDUSTRIES 33 (Revised Aug. 2008).

[11] Mining and crushing, retorting, oil shale upgrading, processed shale disposal, power generation, revegetation, and sanitary uses.

[12] 1973 PROTOTYPE LEASING FEIS, *supra* note 5.

Table 1
Water Use Estimates for 100,000 BPD Oil Shale Production Facilities

Source	Scenario	AF/Y	Gallons of Water per Gallon of Oil Produced
Prien (1954)*		8,250	1.75
Cameron & Jones (1959)*		13,000	2.76
Ely (1968)*		25,000	5.31
DOI (1968)*		6,100	1.30
DOI (1968)*		9,600	2.04
DOI (1973)**	underground	15,660	3.33
DOI (1973)**	surface	15,285	3.25
DOI (1973)**	in situ	6,990	1.49
McDonald (1980)*		13,300	2.83
U.S. Water Resources Council (1981)	mixed technology	11,400	2.42
RAND (2005)*		14,125	3.00
DOI (2008)**	surface/surface	15,500	3.29
DOI (2008)**	underground/surface	15,500	3.29
DOI (2008)**	in situ	9,400	2.00
URS (2008)	surface	13,840	2.94
URS (2008)	in situ	7,152	1.52
Burian (2009)	base (mean)	9,409	2.00
Burian (2009)	realistic	3,584	0.76
MEAN			2.52

* As reported in Argonne National Laboratory, *Potential Ground Water and Surface Water Impacts from Oil Shale and Tar Sands Energy-Production Operations* (2006).
** Mean estimate of scenarios contained in original document.

While in situ technologies generally appear to require less water for extraction and retorting than ex situ technologies, in situ technologies require significant amounts of energy to heat shale or sands and may require significant energy to stabilize groundwater. If energy generation requires its own source of water, generation-related water demand could offset purported savings.

As noted in the Rand Report, that "Reliable estimates of water requirements will not be available until the technology reaches the scale-up and confirmation stage."[13] Developing a better understanding of the size and shape of the oil shale industry will also provide the basis for extrapolating water demand estimates to include the population growth sure to accompany commercial oil shale development.

Colorado recognizes that oil shale development may increase strains on scarce water

[13] BARTIS ET AL., *supra* note 5 at 50.

resources, treating water demands as unknown but potentially significant.[14] A pending study of water needs associated with future energy development will explore "various alternatives to identify and quantify reliable water supplies to meet the energy sector's increasing water demands."[15] While Utah is less specific in its discussions of water for oil shale, past efforts to develop water resources demonstrate that it too recognizes potentially significant demand requirements.[16]

What is certain is that commercial oil shale ease applications must include a "description of the source and quantities of water to be used,"[17] and plans of development must include a narrative description of the mine or in situ operation that includes an "estimate of the quantity of water to be used and pollutants that may enter any receiving water."[18] Similar disclosures are required under the latest round of RD&D leases.[19] These disclosures will help resolve questions that are today unanswerable.

As Jennifer Gimbel, Executive Director of the Colorado Water Conservation Board, encapsulates, "[w]hen you are dealing with water, you are dealing with our future. It's going to take choices, and it's going to take trade-offs."[20] The tradeoffs and the uncertainties involved in commercial oil shale development suggest that planners and policymakers will obtain immediate benefits from inventorying available water resources and addressing the vagaries of water law.

---

[14] COLORADO WATER CONSERVATION BOARD, STATEWIDE WATER SUPPLY INITIATIVE, 6-82 (Nov. 2004).
[15] *See* URS CORP., DRAFT ENERGY DEVELOPMENT WATER NEEDS ASSESSMENT (PHASE I REPORT) ES-13 (2008) (referring to pending Phase II analysis). Note, the Phase I report contains assumptions such as the exclusive use of "electric heating for the in-situ process," *id*. at ES-9, n. 5, that coal fired power plants utilizing wet cooling technology would provide all needed power, *id*. at ES-7 – ES-9, and that mid-term (2018 to 2035) in-situ development will reach 500,000 BPD capacity, *id* at 3-34. While these assumptions provide a margin of safety for water purveyors, they combine to create net water use estimates that appear unlikely, especially within the next 2 decades.
[16] *See e.g.,* BUREAU OF LAND MANAGEMENT, U.S. DEPARTMENT OF INTERIOR, FINAL WHITE RIVER DAM PROJECT ENVIRONMENTAL IMPACT STATEMENT (1982) (proposing to dam the White River to support oil shale development).
[17] 43 C.F.R. § 3922.20(c)(3).
[18] 43 C.F.R. § 3931.11(h).
[19] Notice of Potential Oil Shale Development: Call for Nominations—Oil Shale Research, Development and Demonstration Program, 74 FED. REG. 56867-69 (Nov. 3, 2009).
[20] Chris Woodka, *Water Debate Takes on a New Ripple: Energy*, THE PUEBLO CHIEFTAIN (March 31, 2009).

2. Water Demand for Oil Sands Development

Evaluating water demand for oil sands development is subject to the same challenges discussed with respect to oil shale. The nature and extent of a potential industry is speculative at best. Shortcomings aside, a review of recent assumptions provides a frame of reference through which to consider water availability. The discussion of water for oil sands is based on development envisioned in the Bureau of Land Management's (BLM's) programmatic RMP amendments allocating public lands for oil shale and oil sands development.[21] Under the BLM's approved plan amendments, commercial oil sands development could occur on some or all of ten Special Tar Sands Areas (STSAs) scattered throughout eastern Utah.[22] Together, these areas include 431,224 AC,[23] roughly 84% of which are administered by the BLM.[24] While there are significant, though unquantified, additional developable oil sands on state, private, and tribal lands, the discussion of water needs associated with federal public lands is sufficient to illuminate issues that are likely to arise independent of jurisdictional claims.

While much can be learned from commercial oil sands operations in Canada, physical and chemical differences between the resources in Canada and the United States may necessitate different mining and processing technologies,[25] making direct comparison difficult. Even if the raw materials were comparable, the process utilized in water-rich parts of Canada would likely be infeasible in water-scarce eastern Utah. As Argonne National Laboratory explains:

---

[21] *See* BUREAU OF LAND MANAGEMENT, U.S. DEPARTMENT OF INTERIOR, APPROVED RESOURCE MANAGEMENT PLAN AMENDMENTS/RECORD OF DECISION (ROD) FOR OIL SHALE AND TAR SANDS RESOURCES TO ADDRESS LAND USE ALLOCATIONS IN COLORADO, UTAH, AND WYOMING AND FINAL PROGRAMMATIC ENVIRONMENTAL IMPACT STATEMENT (2008) (hereinafter "OIL SHALE ROD").

[22] The Circle Cliffs Special Tar Sands Area was identified but not considered in the BLM analysis because the area is entirely within the Grand Staircase National Monument and Glen Canyon National Recreation Area, which are managed by the National Park Service and where mineral leasing and development are prohibited. *See* FINAL PEIS, *supra* note 5 at 2050, n. b.

[23] OIL SHALE ROD, *supra* note 21 at 29.

[24] *Id*. at 31. The remaining lands involve split estates, where surface or mineral rights are owned or managed by entities other than the BLM. *Id*.

[25] VEIL AND PUDER, *supra* note 6 at 9.

> The properties and composition of the tar sands and the bitumen significantly influence the selection of recovery and treatment processes and vary among deposits. In the so-called "wet sands" or "water-wet sands" of the Canadian Athabasca deposit, a layer of water surrounds the sand grain, with the bitumen partially filling the voids between the wet grains. The bitumen can be separated from the sand by using water. Utah tar sands lack the water layer; the bitumen is directly in contact with the sand grains without any intervening water and is sometimes referred to as "oil-wet sands." Processing beyond water washing is needed to recover the bitumen.[26]

Because Utah's oil sands lack the layer of water that surrounds the sand found in Alberta, oil sands development in Utah could require more water.[27] Utilizing chemical solvents to extract the bitumen could reduce water demand, though the potential extent of reductions is unknown.[28]

Detailed estimates of water requirements associated with oil sands development in Utah, while relying on somewhat dated analysis, are contained in the 2008 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 (FINAL PEIS).[29] Argonne National Laboratory also provides detailed water use estimates based on Canadian oil sands developments.[30] Both assessments consider surface and in situ retorting under multiple technological scenarios. Under a conventional (surface or underground) mining scenario, operators would first excavate the oil sands and then use either thermal processing or solvents to extract the bitumen. According to the FINAL PEIS, conventional mining with solvent extraction would require 8.7 gallons of water per gallon of oil produced;[31] if conventional mining and retorting are used, water use falls to between 2.6 and 4.0 gallons of water per gallon of oil produced.[32] A 2009 publication by Argonne National Laboratory reviewed water use at oil sands

---

[26] *Id*.
[27] FINAL PEIS, *supra* note 5 at 5-35.
[28] *Id*. at 5-35.
[29] *See id.* at 5-1 – 5-9, and B-18 – B-41. BLM draws much of its information from a 1981 Doctoral Dissertation by JEFFREY IRVIN DANIELS, LAWRENCE LIVERMORE NATIONAL LABORATORY, ENVIRONMENTAL, HEALTH, SAFETY, AND SOCIOECONOMIC IMPACTS ASSOCIATED WITH OIL RECOVERY FROM TAR-SAND DEPOSITS IN THE UNITED STATES (1981).
[30] MAY WU ET AL., ARGONNE NATIONAL LABORATORY, CONSUMPTIVE WATER USE IN THE PRODUCTION OF ETHANOL AND PETROLEUM GASOLINE (2009).
[31] Based on figures contained in FINAL PEIS, *supra* note 5 at 5-4.
[32] FINAL PEIS, *supra* note 5 at 4-4 and 4-8.

facilities in Canada, reporting a water to oil ratio of 3.0 to 1 for conventional mining and surface retorting, 0.3 to 1 for in situ processing utilizing steam assisted gravity drainage, and 1.2 to 1 for in situ processing utilizing cyclical steam stimulation.[33] Bitumen must be upgraded prior to refining and water requirements for upgrading are highly variable. The BLM estimates a 25.3 to 1 ratio, though this figure appears questionable in comparison to other estimates;[34] the U.S. Water Resources Council estimated 2.4 to 1,[35] and Argonne National Laboratory estimates 1.0 to 1.[36]

These water use estimates do not address indirect water needs associated with the sanitary facilities needed to operate an industrial facility, water for dust suppression, water for reclamation and revegetation, or changes in municipal and domestic uses that will occur as local communities grow with an influx of new workers. In 1973, the Department of Energy estimated that revegetation for a 50,000 BPD facility would require up to 700 AF of water per year.[37] Sanitary use for such a facility would require an additional 20 to 50 AF per year.[38] Associated urban uses (domestic use and domestic energy production) would require 740 to 1,000 AF per year.[39]

3. <u>Water Demand Unrelated to Oil Shale and Sands Development</u>

Water resource planners must consider not just demand directly and indirectly attributable to oil shale development, but the demand that is likely to occur independent of oil shale development.

In Colorado, the population of Moffat, Rio Blanco, and Routt counties, which make up the majority of the most prospective development area, are anticipated to grow by 56% between

[33] WU ET AL., *supra* note 30 at 52.
[34] Based on figures contained in FINAL PEIS, *supra* note 5 at 5-4.
[35] U.S. WATER RESOURCES COUNCIL , *supra* note 5 at 5-5.
[36] WU ET AL., *supra* note 30 at 52.
[37] 1973 PROTOTYPE LEASING FEIS, *supra* note 5 at III-34.
[38] *Id.* at III-34.
[39] *Id.* at III-34.

2000 and 2030.[40] Gross water demand is anticipated to increase by 79% over the same period, from 29,400 to 52,600 AF.[41] While Colorado believes 900 AF of water can be saved through conservation, that leaves 22,300 AF of new depletions anticipated within Colorado's portion of the most geologically prospective oil shale area. This increase in demand does not include direct and indirect demand associated with oil shale development, which Colorado deems too speculative to quantify.

The region is also targeted for withdrawals by water developers intent on providing water to Colorado's rapidly growing and increasingly thirsty Front Range population. The U.S. Army Corps of Engineers is evaluating a proposal to divert 250,000 AF of water annually from the Green River (a potential source of supply for oil shale and oil sands development), at or immediately upstream of Wyoming's Flaming Gorge Reservoir. Ten-percent of the water diverted would go to users in southeast Wyoming, with the remaining 225,000 AF being piped 560 miles to Colorado's Front Range.[42] While only preliminary in nature, the proposal is generating significant public interest and opposition from residents of southwest Wyoming.[43] Other, less developed efforts to divert water from the Green River to Colorado's western slope also appear to be in the works.[44]

In Utah, the richest oil shale resources are located in eastern Uintah County, near the Colorado border; Uintah County is part of the larger Uinta Basin.[45] Utah's portion of the Uinta

---

[40] COLORADO WATER CONSERVATION BOARD, STATEWIDE WATER SUPPLY INITIATIVE FACT SHEET (2006).
[41] *Id*.
[42] Notice of Intent to Prepare Environmental Impact Statement for the Proposed Regional Watershed Supply Project in Wyoming and Colorado, 74 FED. REG. 11920 (March 20, 2009).
[43] *See e.g.,* NEW YORK TIMES, *De-watering Wyoming* (April 20, 2009), Joan Barron, CASPER STAR-TRIBUNE, *Gov: Water Diversion Potential Endangered Species Concern* (April 16, 2009), Jeff Gearino, CASPER STAR-TRIBUNE, *Water Project Draws Ire* (April 15, 2009), Jack H. Smith, GREEN RIVER STAR, *Hundreds Gather at GRHS to Protest Proposed Transbasin Pipeline* (April 15, 2009), DENVER POST, *Corps' Look at Water Project Questioned* (April 13, 2009), DENVER POST, *Concerns Raised about Wyo-Col Water Pipeline* (April 15, 2009).
[44] *See* Jack H. Smith, THE GREEN RIVER STAR, *Another Transbasin Diversion Project Proposed* (May 6, 2009).
[45] Uinta is sometimes spelled Uintah, as in the case of Uintah County. This report adopts the spelling Uinta unless spelled otherwise in specific reports or place names.

Basin is approximately 10,890 square miles, extending from the Wyoming and Colorado borders to the north and east, to the Wasatch Mountains and Roan Cliffs to the west and south.[46]

In the Uinta Basin, average per capita daily water use is estimated at 351 gallons, or roughly 135% of the state average of 260 gallons per capita per day.[47] Per capita water use within Uintah County is slightly less, averaging 326 gallons per capita per day, of which 266 gallons reflect potable water use and the remaining 60 gallons per capita per day reflect nonpotable uses.[48] Municipal and industrial water supplies within Uintah County are supplied by seven public community systems, one Indian system, eight public non-community systems, and eight self-supplied industries.[49] Residential outdoor water use represents the greatest use of water from these sources at 36.6%, residential indoor use is 27.8%, industrial use is 17.9%, commercial use is 13.7%, and industrial/stockwatering represents just four-percent.[50] As of 2005, reliable potable water supplies for public community systems within Uintah County were estimated at 36,127 AF/Y.[51] Potable water use for public community systems within the same area was estimated at 7,719 AF/Y, or 22% of the reliable supply.[52]

Irrigation represents the largest use of water in the Uinta Basin, with approximately 220,000 AC of privately owned crop and pasturelands.[53] Irrigated cropland depletes, on average, 411,320 AF annually and is anticipated to remain relatively stable.[54] At 38,384 AC or 48.9% of Uintah County's irrigated land, alfalfa is the most widely irrigated crop.[55] Pasturelands are the second most widely irrigated category of lands at 31,873 AC, or 40.6% of the county's

---

[46] DIVISION OF WATER RESOURCES, UTAH DEPARTMENT OF NATURAL RESOURCES, MUNICIPAL AND INDUSTRIAL WATER SUPPLY AND USES IN THE UINTAH BASIN 3 (2007).
[47] *Id*. at xi. The State of Utah and U.S. Geological Survey utilize slightly different methodologies to quantify water use; because of these differences water use statistics are not comparable across reports.
[48] *Id.* at 40.
[49] *Id.* at 37.
[50] *Id.* at xi.
[51] MUNICIPAL AND INDUSTRIAL WATER SUPPLY AND USES IN THE UINTAH BASIN*, supra* note 46 at 37.
[52] *Id.* at 39.
[53] WATER RESOURCES DIVISION, UTAH DEPARTMENT OF NATURAL RESOURCES, WATER-RELATED LAND USE INVENTORIES: UINTAH BASIN 2006 INVENTORY 5 (Dec. 2007).
[54] DIVISION OF WATER RESOURCES, UTAH DEPARTMENT OF NATURAL RESOURCES, UTAH STATE WATER PLAN: UINTA BASIN, 10-2 and 10-5 (Dec. 1999).
[55] UINTAH BASIN 2006 INVENTORY, *supra* note 53 at 7.

irrigated lands.[56] No other category of irrigated land exceeds 3,500 AC.[57] Sprinkler irrigation accounts for approximately 60% of irrigation within Uintah County, while the remaining 40% is flood irrigated.[58] Sub-irrigated lands account for an additional 2,411 AC.[59]

The State Water Plan for the Uinta Basin estimates the basin's population at 39,596 in 1998, projecting an increase of 15,855 people or 40% by 2020.[60] Basin employment is projected to increase from 17,823 jobs in 1995 to 28,025 in 2020.[61] Municipal and industrial diversions from public suppliers within the basin are anticipated to increase from 13,140 AF in 2000 to 16,900 AF in 2020;[62] industrial depletions from privately held water rights, which are generally around half the volume diverted, are projected to increase from 11,830 AF in 1996 to 23,700 AF in 2050.[63] Like Colorado, Utah's projections do not include water to support commercial oil shale development.

Estimating population growth attributable to commercial oil shale and/or oil sands development is, at best, challenging. Aggregate population change will depend upon the number and size of facilities, the number of workers required to support various technologies, the ratio of permanent to temporary workers, and the indirect employment created by workers flowing into the development area. Population increases will affect most profoundly those communities proximate to development. Population change associated with development of Alberta's oil sands industry is informative and, "[b]ased on the data from Fort McMurray, considerations of the likely demographics . . . [Institute researchers] estimated the population

---

[56] *Id.* at 5.
[57] *Id.* at 5.
[58] *Id.* at 5.
[59] *Id.* at 5.
[60] UTAH STATE WATER PLAN: UINTA BASIN, *supra* note 54 at 4-1.
[61] *Id.* at 2-2.
[62] *Id.* at 9-14.
[63] *Id.* at 18-2.

growth rate in the Uinta and Piceance Basin to be 80,000 per 1,000,000 bbl/day production rate."[64]

Direct and indirect population growth associated with oil shale development is estimated at 400 to 3,000 persons for development of existing RD&D leases.[65] Development of a 50,000 BPD mining and surface retort facility together with a 25,000 BPD in situ production facility would result in direct and indirect employment of an estimated 6,900 persons.[66] These levels of production and employment equate to an estimated 700 and 1,545 AF/Y of indirect water demand.[67] These estimates include construction and operation employment for new thermoelectric power generation facilities that may be required to support oil shale development and therefore may overstate both employment and water use if production relies on less water intensive sources of power.

Like Colorado, Utah appropriators are proposing large withdrawals from the Green River. Nuclear power proponents recently filed applications to consume 53,600 AF of water from the Green River to satisfy cooling water requirements for a proposed nuclear power plant near the town of Green River, Utah.[68] Under the proposed transfers, water rights secured from the San Juan River and Wahweap Creek, near Lake Powell for a planned coal fired steam generation power plant in southern Utah[69] would be transferred upstream. The Kane County Water Conservancy District would lease 29,600 AF of water to the plant's developers,[70] while the San Juan County Water Conservancy District would lease the remaining 24,000 AF.[71] This project has engendered significant opposition, including at least 239 formal protests. Major

---

[64] STEVE BURIAN, UNIVERSITY OF UTAH DEPARTMENT OF CIVIL AND ENVIRONMENTAL ENGINEERING, FINAL REPORT ON PROJECT: MEETING DATA NEEDS TO PERFORM A WATER IMPACT ASSESSMENT FOR OIL SHALE DEVELOPMENT IN THE UINTA AND PICEANCE BASINS 12 (2009).
[65] URS CORP., *supra* note 15 at 4-7.
[66] *Id.* at 4-7.
[67] *Id.* at 4-7. Assumes 200 gallons per capita per day.
[68] Patty Henetz, *Utah Nuclear Power Proposal Has a Powerful Thirst*, SALT LAKE TRIBUNE (April 6, 2009).
[69] The power plant was planned for a site now within the Grand Staircase Escalante National Monument and cannot be constructed consistent with Monument management direction.
[70] Water Right Change Application No. a35402, *available at* http://www.waterrights.utah.gov/cgi-bin/wrprint.exe?Startup.
[71] Water Right Change Application No. a35874, *available at id*.

concerns include impacts to instream flows and endangered fish.[72] As Colorado and Utah continue to grow, scarce water supplies will become subject to only more intense competition.

4. Climate and Water Availability

The Upper Colorado Basin is subject to significant fluctuations in precipitation and prolonged periods of drought that must be considered in planning for future water use. Drought affects water resource management, exacerbating tensions between the beneficiaries of competing uses. Extended drought periods can last for a decade or more, as suggested by long-term flow reconstructions. For instance, the mid-1100s were characterized by thirteen consecutive years of below average stream, resulting in a cumulative 36,500,000 AF flow deficit.[73] This thirteen-year period flow was part of a sustained 62-year period characterized by recurrent low flows and only isolated flows exceeding long-term means.[74] Based on reconstructed Colorado River flow records, the National Academy of Sciences concludes "extended drought episodes are a recurrent and integral feature of the basin's climate," and more pronounced than those observed over the past century. Reconstruction, "along with the temperature trends and projections for the region, suggest that future droughts will recur and that they may exceed the severity of droughts of historical experience, such as the drought of the late 1990s and early 2000s."[75] Climate change, the effects of which are difficult to project, may further undermine water availability within the Upper Colorado River Basin.

> The 20th century saw a trend of increasing mean temperatures across the Colorado River basin that has continued into the early 21st century. There is no evidence that this warming trend will dissipate in the coming decades; many different climate model projections point to a warmer future for the Colorado River region.
>
> Modeling results show less consensus regarding future trends in precipitation. Several hydroclimatic studies project that significant decreases in

[72] *See* Amy Joi O'Donoghue, *Critics Say N-Plant Would Harm Ecosystem*, DESERET NEWS (May 27, 2009).
[73] David M. Meko et al., *Medieval Drought in the Upper Colorado River Basin*, GEOPHYSICAL RESEARCH LETTERS 4 (2007).
[74] *Id*. at 4.
[75] COMMITTEE ON THE SCIENTIFIC BASES OF COLORADO RIVER BASIN WATER MANAGEMENT, NATIONAL RESEARCH COUNCIL, COLORADO RIVER BASIN WATER MANAGEMENT: EVALUATING AND ADJUSTING TO HYDROCLIMATIC VARIABILITY 110 (2007).

> runoff and streamflow will accompany increasing temperatures. Other studies, however, suggest increasing future flows, highlighting the uncertainty attached to future runoff and streamflow projections. Based on analysis of many recent climate model simulations, *the preponderance of scientific evidence suggests that warmer future temperatures will reduce future Colorado River streamflow and water supplies*. Reduced streamflow would also contribute to increasing severity, frequency, and duration of future droughts.[76]

Prolonged drought periods are not limited to individual subbasins, but appear to extend across multiple tributary basins "more often than not."[77]

The prospect of a changing climate, extended drought, and increasing demand necessitate careful planning and management to ensure that during times of scarcity, existing water resources are allocated equitably and impacts are minimized to the maximum extent possible. This is no simple task. As the Congressional Research Service observed,

> Adjusting the demand for water as supplies shrink during droughts is difficult. Federal, state, and local authorities make water resource decisions within the context of multiple and often conflicting laws and objectives, competing legal decisions, and entrenched institutional mechanisms, including century-old water rights and long-standing contractual obligations (i.e., long-term water delivery and power contracts).[78]

While future precipitation is uncertain, the possibility of prolonged periods of below average stream flow extending across a large geographic area is of great concern to water planners and water managers.[79] A large, commercial oil shale and/or oil sands industry would increase pressure during periods of prolonged drought.

5. Oil Shale and Sands Water Needs in Context

The desirability of oil shale and oil sands as sources of fuel is not a question that can be answered in isolation, but one that must be answered in relation to the alternatives. Most researchers agree that oil, natural gas, and coal will remain important fuels for decades to come

[76] *Id.* at 108-09 (emphasis added).
[77] *Id.* at 108.
[78] PETER FOLGER ET AL., CONGRESSIONAL RESEARCH SERVICE, DROUGHT IN THE UNITED STATES: CAUSES AND ISSUES FOR CONGRESS 12 (2009).
[79] *See e.g.*, SOUTHWEST HYDROLOGY (March/April 2005) (devoting entire issue to drought on the Colorado River).

– even in a carbon-constrained world transitioning aggressively to other fuels.[80] All liquid transportation fuels are produced, upgraded, and/or refined using water,[81] and a decision to forego oil shale and oil sands development will not eliminate energy-related demands for water from this region.

Comparing water demand across energy alternatives is important because Colorado's Piceance Basin contains oil shale, conventional oil, natural gas, coal, and coalbed methane.[82] Utah's Uintah Basin contains oil shale, oil sands, conventional oil, and natural gas.[83] Conventional oil and gas resources near oil shale are undergoing rapid development – development that not only uses water but that will require even more water as it intensifies.

At a conservative estimate of three gallons of water per barrel of oil produced, oil shale and oil sands may or may not prove less water intensive than many alternatives. By comparison, conventional oil production can be broken into three phases, each of which has different water requirements. During the initial phase of production, primary production, natural pressure brings oil, gas, and water to the surface and just 0.2 gallons of water are required for each gallon of oil produced.[84] As reservoir pressure falls, secondary production is required and water is injected into oil fields to increase production. Secondary production requires, on average, 8.6 gallons of water per gallon of oil produced.[85] Even with secondary production, surface tension eventually traps oil droplets and production falls again, requiring enhanced oil recovery (EOR) or tertiary production. Under EOR, steam, CO_2, or other solvents are injected

---

[80] *See e.g.*, ENERGY INFORMATION ADMINISTRATION, U.S. DEPARTMENT OF ENERGY, ANNUAL ENERGY OUTLOOK (2009) (including oil and gas in energy assessments through planning horizon, 2030); COMMITTEE FOR THE NATIONAL ACADEMIES, SUMMIT ON AMERICA'S ENERGY FUTURE 92 (2008) (projecting continued use of coal and gas through the planning horizon, 2050); MASSACHUSETTS INSTITUTE OF TECHNOLOGY, THE FUTURE OF COAL 5 (2007).
[81] *See* WU ET AL., *supra* note 30 (comparing water consumption across various fuels).
[82] FINAL PEIS, *supra* note 5.
[83] *Id*.
[84] *Id.*
[85] *Id.*

into the field to again increase production. EOR requires, on average, 8.7 gallons of water per gallon of oil produced.[86]

Direct water demand associated with natural gas production is estimated at 2.1 AF per well drilled, plus 0.14 AF per billion cubic feet of gas produced.[87] Under a "medium" production scenario, analysts predict drilling of, on average, 2,125 new natural gas wells per year in the northern Piceance Basin, resulting in approximately 65,000 operating wells by 2035.[88] This equates to natural gas related water demand within the Piceance Basin of 4,874 AF/Y in 2035 (up from 2,965 AF/Y in 2007, but down from a projected high of 5,044 AF/Y in 2018).[89] Likewise, coal mining within the Piceance Basin requires, on average, slightly more than 59 AF per million tons of coal produced.[90] A "medium" production scenario of 26 million tons per year within the Piceance Basin from 2018 through 2035 will require 1,538 AF/Y.[91]

Within Utah, the EIS for the BLM's Vernal Field Office anticipates 4,345 new natural gas wells, most of which will occur in the Monument Butte-Red Wash area along the White River.[92] The EIS also anticipates 130 new coalbed methane wells and 2,055 new oil wells.[93] New wells will be in addition to the 5,785 existing active wells within the Uinta Basin.[94] Water consumption will depend on production levels, which were not estimated in the FEIS. However, as the total number of wells is anticipated to more than double, water demand is likely to increase in rough proportion to new development.

---

[86] *Id.*
[87] URS CORP., *supra* note 15 at 3-11.
[88] *Id.* at 3-8.
[89] *Id.* at 3-12.
[90] *Id.* at 3-19. This does not include water used during subsequent coal combustion and thermoelectric production. Unconventional technologies such as coal gasification use 10-14 times the amount of water required by conventional coal mining operations. *Id.*
[91] *Id.* at 3-18 – 3-19.
[92] BUREAU OF LAND MANAGEMENT, VERNAL FIELD OFFICE PROPOSED RESOURCE MANAGEMENT PLAN AND FINAL ENVIRONMENTAL IMPACT STATEMENT 3-36 (2008) (hereinafter VERNAL RMP FEIS).
[93] *Id.*
[94] DIVISION OF OIL, GAS, AND MINING, UTAH DEPARTMENT OF NATURAL RESOURCES, SUMMARY PRODUCTION REPORT BY COUNTY (2009) *available at* https://fs.ogm.utah.gov/pub/Oil&Gas/Publications/Reports/Prod/County/Cty_Oct_2009.pdf.

The questions faced today with respect to water for oil shale and oil sands consumption depend in large part on the scale of development, and whether oil shale and/or oil sands development is in addition to, or as a replacement for, more traditional fuel sources. A 50,000 BPD oil shale retort exists nowhere in the world today,[95] and by all accounts, a million BPD commercial oil shale industry is still several decades away.[96] By way of comparison, the Canadian oil sands industry began production in 1967 and did not exceed 100,000 BPD production until 1979.[97] Production in excess of 1,000,000 BPD first occurred in 2006, almost 40-years after commencement of commercial production.[98] While increases in production were not linear in nature, annual production increases averaged less than 30,000 BPD. Considering the high costs of development, limited capital availability, stringent environmental regulations, and the prospect of climate change legislation that could transform the entire energy industry, it seems doubtful that commercial oil shale or oil sands development in Utah or Colorado will outpace Canadian oil sands development.

Water for foreseeable oil shale and/or oil sands development is but one of a growing list of energy-related demands on water resources. The challenge is to drive sufficient oil shale and oil sands related research and development to fill our informational voids, facilitating informed decision-making without prematurely committing to or foregoing technologies that are, as of today, only promises on an uncertain horizon. The tradeoffs and uncertainties involved in commercial oil shale and oil sands development suggest that planners and policymakers will obtain immediate benefits from inventorying available water resources and addressing the

---

[95] *See* BARTIS, *supra* note 5 at 13-14 (estimating total worldwide oil shale production at 10,000 to 15,000 BPD).

[96] *See e.g.,* ANNUAL ENERGY OUTLOOK 2009, *supra* note 80 at 80 (projecting that oil shale production will not exceed 200,000 BPD in 2030) *see also*, *id*. at 38 ("EIA estimates that the earliest date for initiating construction of a commercial project is 2017. Thus, with the leasing, planning, permitting, and construction of an in situ oil shale facility likely to require some 5 years, 2023 probably is the earliest initial date for first commercial production.").

[97] CANADIAN ASS'N OF PETROLEUM PRODUCERS, TECHNICAL REPORT, STATISTICAL HANDBOOK FOR CANADA'S UPSTREAM PETROLEUM INDUSTRY Table 3.2a (2009) *available at* http://www.capp.ca/GetDoc.aspx?DocID=146286.

[98] *Id*.

vagaries of water law. Such steps form the basis for careful water resource planning that will provide value regardless of whether a commercial oil shale or oil sands industry develops.

C. The Law of Water Allocation

Water rights administration is, apart from certain narrow but important exceptions, a matter of state law,[99] and while the details of western water law vary from state to state, the common concepts provide a sufficient framework for this analysis.[100] State efforts dominate because localized dispute resolution lead to territorial and state statutes defining appropriative law, and the federal government largely deferred to states on matters of water allocation. Stated simply, "[w]hile Congress debated, settlers went west. As a result, some of the earliest and most significant federal 'land [and water] laws' were in part legitimization of uses that were already taking place on western lands."[101]

Recognizing the importance of custom and the body of common law that developed, the federal government opted to defer to state allocative systems, at least so long as they did not adversely impact federal interests.[102] The resulting system is one of state primacy, which despite expansive federal deference, remains subject to federal Supremacy Clause,[103]

---

[99] *See* 43 U.S.C. § 661 ("Whenever, by priority of possession, rights to the use of water [on public lands] for mining, agricultural, manufacturing, or other purposes, have vested and accrued, and the same are recognized and acknowledged by the local customs, laws, and decisions of courts, the possessors and owners of such vested rights shall be maintained and protected in the same; and the right of way for the construction of ditches and canals for the purposes herein specified is acknowledged and confirmed."); *see also* 43 U.S.C. § 666 (submitting the federal government to state jurisdiction for water right adjudications) and *California v. United States*, 438 U.S. 645, 653 (1978) (describing "the consistent thread of purposeful and continued deference to state water law by Congress."). Congress, in the Energy Policy Act of 2005, reinforced the primacy of state law by stating, "Nothing in this section preempts or affects any State water law or interstate compact relating to water." Pub. L. 109-58 § 369 (2005).

[100] Bureau of Reclamation water contracts are also generally subject to state law, *see* 43 U.S.C. § 383. Likewise, transfers involving Bureau of Reclamation water rights contracts are also subject to state law. *United States v. Alpine Land and Resources Co*., 503 F. Supp. 877 (D. Nev. 1983), *aff'd as modified* at 697 F.2d 851, 858 (9th Cir. 1983).

[101] PAMELA BALDWIN, LEGAL ISSUES RELATED TO LIVESTOCK WATERING IN FEDERAL GRAZING DISTRICTS, CONGRESSIONAL RESEARCH SERVICE REPORT TO CONGRESS 94-688 A, (1994), *available at* http://www.ncseonline.org/nle/crsreports/water/h2o-14.cfm?&CFID=12940973&CFTOKEN=87120625.

[102] *See California v. United States*, 438 U.S. 645, 674 (1978) (holding state law governs but only if not inconsistent with "congressional directives" or "with congressional provisions authorizing the project in question"). *See also*, Clean Water Act, 33 U.S.C. § 1251(g) (deferring to states on water allocation).

[103] U.S. CONST. art VI, § 2.

Commerce Clause,[104] and Property Clause jurisdiction.[105] Thus statutes such as the Clean Water Act (CWA) and Endangered Species Act (ESA) mark important federal sideboards on state appropriative law.

Common to western water law, water belongs to the public and is available for public appropriation and beneficial use.[106] The process for obtaining a water right in Utah is shown in Figure 2 and summarized here. In Utah and throughout the arid west, water is considered a public resource.[107] Except for federal reserved rights and a small number of water rights obtained prior to codification of Utah's water code, water rights must be obtained through application to the Office of the State Engineer.[108] There are five basic steps in the application process: First, the applicant files an application to appropriate water with the Division of Water Resources (the State Engineer's Office).[109] Second, the application is advertised, those fearing adverse impacts have an opportunity to protest the application, and a hearing may be held.[110] Third, the State Engineer renders a decision on the application.[111] Fourth, if the application is approved, the applicant is allowed time to develop the proposed diversion and use water.[112] When the diversion and use are fully developed, the applicant files proof of development and beneficial use with the Division.[113] Finally, upon verification of proof of development and beneficial use, the State Engineer issues a Certificate of Appropriation, thus "perfecting" the water right.[114]

In applying for a groundwater right, the applicant must indicate the source of supply.[115]

---

[104] *Id.* at art I, § 8, cl. 3
[105] *Id.* at art. IV, § 3, cl. 2.
[106] *See e.g.*, UTAH CODE ANN. § 73-1-1; COLO. REV. STAT § 37-92-102(1)(a).
[107] E.g., UTAH CODE ANN. § 73-1-1 (2009) ("All waters in this state, whether above or under the ground are hereby declared to be the property of the public.").
[108] *Id*. at § 73-3-1.
[109] *Id*. at § 73-3-2.
[110] *Id*. at § 73-3-6 and -7.
[111] *Id*. at § 73-3-8.
[112] *Id*. at § 73-3-10(3).
[113] *Id*. at § 73-3-16(3).
[114] *Id*. at § 73-3-17.
[115] UTAH CODE ANN. § 73-3-2(1)(b)(v).

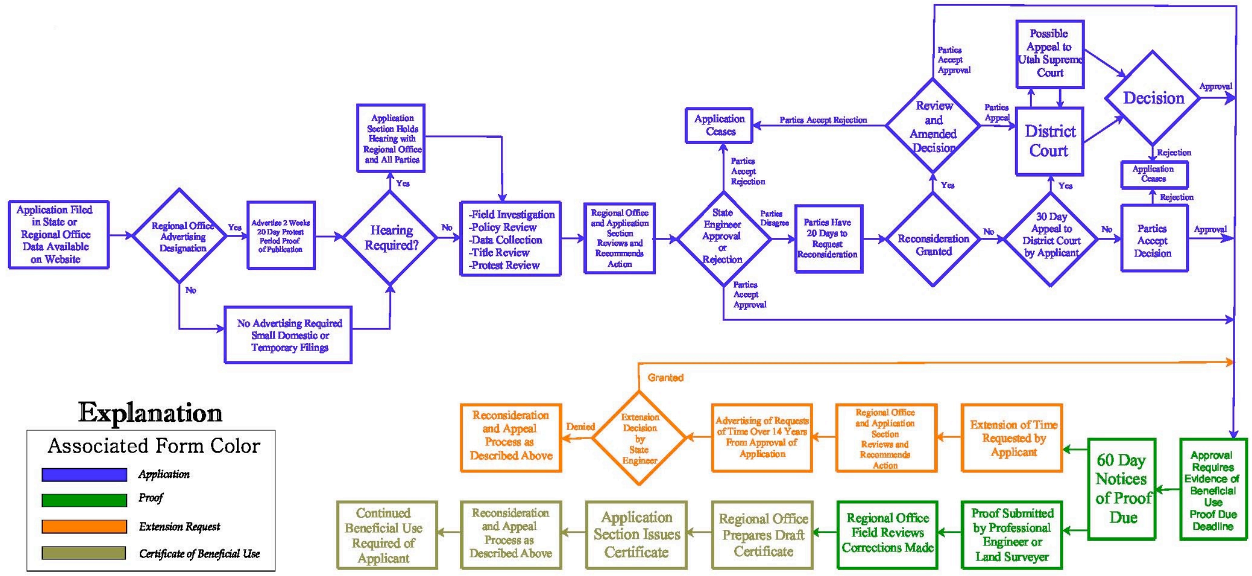
The State Engineer must then approve the application if, based on information contained in the application and in accordance with the criteria noted above, "there is unappropriated water in the proposed source."[116] No unappropriated water is available "where perfected appropriations and prior pending applications of record in the state engineer's office[ ] established the appropriation of all available water of the source."[117] Doubts regarding water availability are resolved in favor of the applicant,[118] and dispute resolution is left to the courts.[119]

Each water right contains provisions governing the source of supply, the point of diversion, the nature of use, the quantity of water appropriated and/or the rate of diversion/withdrawal, and the season of use.[120] Procedural requirements vary from state to state, but because western states' statutory water laws emerged from a common body of judicial dispute resolution, state courts routinely look to the decisions of their neighbor states.[121]

---

[116] *Id.* at § 73-3-8(1)(a)(i).
[117] *Little Cottonwood Water Co.v. Kimbal*, 289 P. 116, 118 (Utah 1930).
[118] *Lehi Irr. Co. v. Jones*, 202 P.2d 892, 895 (Utah 1949) ("If then it is not clear that there is no unappropriated water in the proposed source, and the applicant satisfies the other requirements, the State Engineer should not withhold his approval.").
[119] *Little Cottonwood Water Co.v. Kimbal*, 289 P. at 118 ("[If] there is reasonable probability that a portion of the waters are not necessary to supply existing rights the engineer should have the power to approve the application and afford the applicant the opportunity for an orderly recourse to the courts, who have the facilities and powers to dispose of the matter definitely and satisfactorily.").
[120] *Id*. at § 73-3-2.
[121] *See e.g.*, *R.D. Merrill Co. v. State, Pollution Control Hearings Bd.*, 969 P.2d 458, 463 (Wash. 1999) ("This court gives weight to well-established principles of western water law.").

Figure 2
Water Right Application Process in Utah[122]



The maxim of "first in time, first in right" is the foundation upon which western water law is built.[123] Each water right has a priority date that coincides with the date upon which the application was filed; when demand for water exceeds available supply, those with senior rights can require full or partial curtailment of junior water users' diversions, leaving junior priority users with less than their allotted amount of water, or none at all.[124] Thus, the more senior the water right, the more valuable it is during times of drought.

Wasteful use of water is not protected and appropriators are generally unable to hold water rights for future, speculative needs.[125] Thus, if a water right is not put to a beneficial use

122 Figure courtesy of the Utah Division of Water Rights.
123 UTAH CODE ANN. § 73-3-1; *see also United States v. County of Denver*, 656 P.2d 1, 12 (Colo. 1982) (noting that the doctrine of prior appropriation generally governs, in one form or another, the acquisition of water rights in the 19 western states).
124 Under Utah law, a senior appropriator is guaranteed the full measure of his or her appropriation before any junior claim may be satisfied. *Sanpete Water Conservancy Dist. v. Carbon Water Conservancy Dist.*, 226 F.3d 1170, 1173 (10th Cir. 2000).
125 Important exemptions exist under most state permitting systems, allowing municipalities to secure senior domestic water sources sufficient to meet projected demand. While these rights must eventually be perfected through beneficial use, the timeline for right perfection is much longer. *See e.g.*, UTAH CODE ANN. § 73-3-12(2)(c). Similarly, many states grant conditional water rights for infrastructure-intensive water developments that may require years of planning and construction. *See e.g.*, COLO. REV. STAT. § 32-92-103(6). Conditional rights allow permittees to secure water right priority in advance of development and beneficial use. In the absence of such rights, capitol acquisition costs would likely be much higher given the uncertainty associated with the underlying water right.

within the statutory period for perfection, the water right reverts to the state and is available for appropriation.[126] Perfection timelines may be extended where the applicant exercises due diligence in developing water rights.[127] In 2008, the Utah legislature revised the water code to exempt public water supplies from forfeiture if water is required for the reasonable needs of the public and the supplier can demonstrate a need for the water within the next 40 years based on projected population growth or other water use demand.[128] Where water right applications have been approved and perfection deadlines extended repeatedly, perfection of these dormant rights can displace rights with junior priority dates but which were developed more promptly.

The concepts of relinquishment and dormant senior rights are important because many prospective oil shale developers obtained water rights in anticipation of the development that appeared certain in the 1970s. These companies and their successors in interest hold significant water rights, the continued validity of which is subject to state law. So far, Colorado's Water Court has generally accepted existing efforts as sufficient to demonstrate diligent development,[129] but the longer such rights remain contingent, the more difficult it may become to demonstrate diligent development.

Given the long history of water development and the evolving nature of concepts such as waste and diligent development, it should come as no surprise that water sources are often subject to multiple competing water rights claims, and resolving competing claims often

---

126 *See e.g.*, UTAH CODE ANN. § 73-1-4(2)(a).
127 *See e.g.*, *Id.* at § 73-3-12.
128 *Id.* at § 73-1-4(2)(f)(i).
129 *See e.g.*, *Municipal Subdistrict, Northern Colorado Water Conservancy Dist. v. Getty Oil Exploration Co*., 997 P.2d 557 (Colo. 2000) (holding that under the "can and will" test, Getty "can" develop oil shale given existing technology and "will" upon changed economic considerations), *Municipal Subdistrict, Northern Colorado Water Conservancy Dist. v. OXY USA, Inc.,* 990 P.2d 701 (Colo. 1999) (holding conditional water right application not filed for purposes of speculation and OXY "can" develop oil shale given existing technology and "will" upon changed economic considerations), *Municipal Subdistrict, Northern Colorado Water Conservancy Dist. v. Chevron Shale Oil Co*., 986 P.2d 918 (Colo. 1999) (holding economic conditions properly considered in evaluating adequacy of efforts to perfect water rights for oil shale), *but see Bar 70 Enterprises, Inc. v. Highland Ditch Ass'n*, 694 P.2d 1253 (Colo. 1985) (holding the association failed to obtain required finding of reasonable diligence in developing its conditional water right), and *Bar 70 Enterprises, Inc. v. Tosco Corp*, 703 P.2d 1297 (Colo. 1985) (denying claimed appropriation date for conditional water right because Tosco failed to demonstrate diligent development).

necessitates an adjudication of water rights. A general adjudication is a legal process to determine the extent and validity of water rights within a specific geographic area (usually a watershed or river basin). Adjudications are conducted in state courts and, because of the numerous competing claims and complicated factual questions, can take years to conclude. At the outset, the State Engineer investigates all water rights claims and prepares a proposed determination of water rights, which serves as the basis for the court's decree.[130] In Utah, all but two of the drainages within the state are currently involved in a court ordered adjudication of water rights. Utah's ongoing general adjudications began in the 1950s through the early 1970s.[131] Within Area 49, the basin containing most of Utah's oil shale resources, an adjudication is underway, but no proposed determination of water rights has been published.[132]

Prospective oil shale developers have long recognized the value of senior rights to large quantities of water, obtaining extensive and senior rights in portions of the Piceance Basin. These rights fall into two general classifications: (1) conditional water rights, often with priority dates in the 1950s and 1960s that are tied to storage, and (2) very senior agricultural water rights, often with priorities dating to the 1880s or earlier, that have been leased back to agricultural users. These two classes of water rights present differing problems for water managers.

Conditional water rights, while undeveloped, may be senior to certain existing rights. Therefore development of conditional rights would make less water available to existing but junior water rights holders. Potentially effected interests include communities along Colorado's Front Range holding relatively junior rights to augment existing supplies as well as resort

---

[130] *See* http://www.waterrights.utah.gov/adjdinfo/default.asp.
[131] *See id*.
[132] *See* Utah Division of Water Resources, http://www.waterrights.utah.gov/wrinfo/policy/wrareas/area49.html.

communities and western slopes towns that grew up relatively recently.[133] These communities could be hit hard if oil shale development undermines the security of their planned water supplies. An almost certain consequence of increased interest in oil shale development is increasing scrutiny of conditional water rights. As other water users increasingly see conditional right development as a threat to their water supplies they will invariably grow more aggressive in challenging industry's diligence in pursuing development.

As the prior discussion implies, water rights may be conveyed separately from the land upon which they are used.[134] Changes in the use of a water right are also allowed subject to the general rule that they do not result in an injury to other water users.[135] It follows that when inadequate water is available to satisfy the needs of all prospective users, markets develop and water rights are conveyed to economically higher uses. Historically, conversion of agricultural water rights to municipal and industrial rights has facilitated significant western expansion.

D. Sources of Water for Oil Shale Development[136]

The White River flows west from its headwaters in Colorado's Flat Tops Wilderness, across the border with Utah and then joins the Green River. As the major surface water source closest to Utah's oil shale resources, the White River is of particular importance. The vast majority of Colorado's most geologically prospective area for oil shale also drains to the White River, making it a logical source of supply for Colorado as well.

Other important river systems that may be potential sources of supply for commercial oil

[133] *See* WESTERN RESOURCE ADVOCATES, WATER ON THE ROCKS: OIL SHALE WATER RIGHTS IN COLORADO 33-35 (2009) (discussing communities whose domestic water rights that may be impacted by development of conditional water rights for oil shale).
[134] Water rights evidenced by shares of stock in a corporation are transferred as personal property in accordance with provisions of the Uniform Commercial Code. UTAH CODE ANN. § 73-1-10(2). Water rights evidenced by certificate, decree, or diligence claim are conveyed as real property. UTAH CODE ANN. § 73-1-10(1)(a).
[135] See e.g., UTAH CODE ANN. § 73-3-3(2)(b).
[136] This section focuses on oil shale resources in Colorado and Utah because of their interdependent water resources, because of the greater amount of interest in developing resources within these states, and because "[i]n general, the rich Wyoming deposits are situated in thinner, less continuous layers and represent a less favorable development target, compared with the Colorado and Utah deposits." BARTIS ET AL., *supra* note 5 at 8. Accordingly, as the RAND report concluded, "[w]hen commercial oil shale operations begin, operations are likely in both Utah and Colorado." *Id*. at 7.

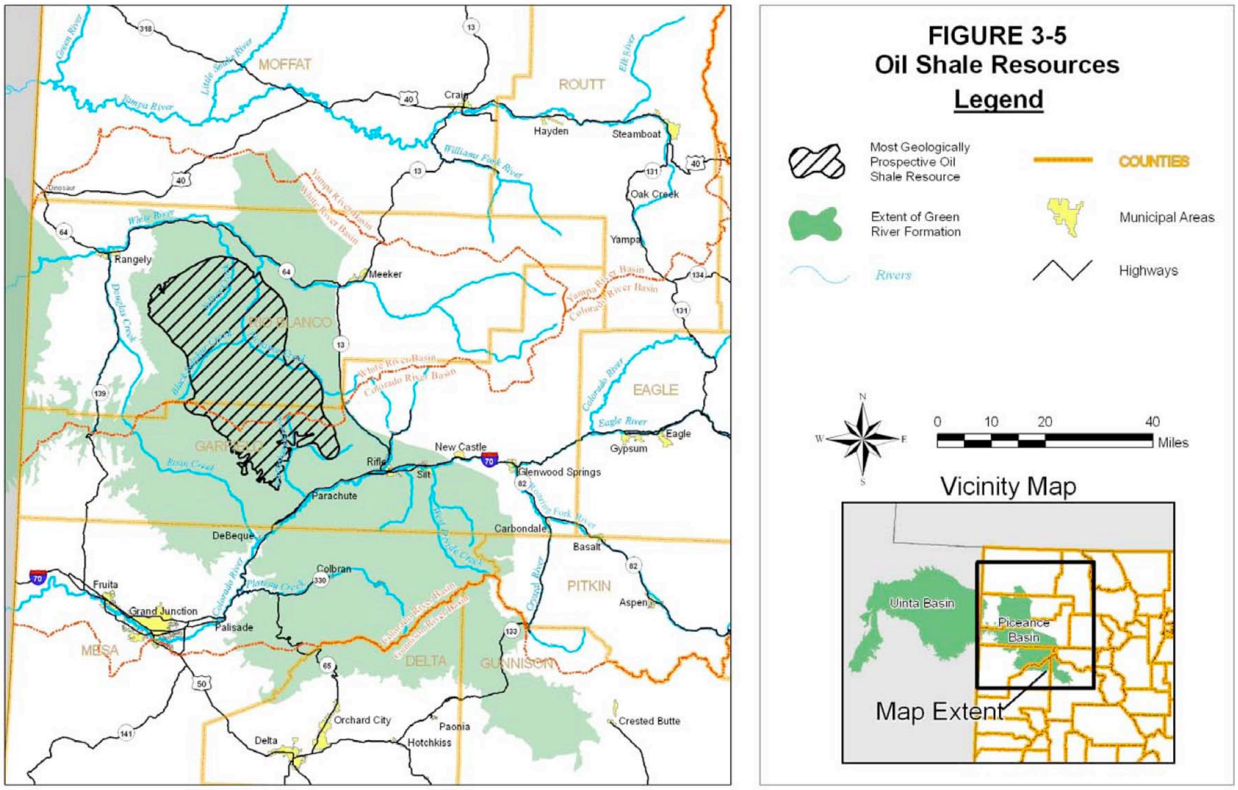
shale development include the Yampa River as well as the Duchesne River and its tributaries (including the Uinta and Lake Fork rivers), which all drain to the Green and Colorado rivers. The Yampa is a potential source of supply for developments in Colorado, and the Green River is a potential source of supply in Utah and Colorado, though diversions from the Green River would involve a system of pipelines and pumping that could increase costs compared to those associated with withdrawals from the White River.[137] The extent of these costs is unknown and depends on facility location, pipeline length and location, pipeline and pump station size, and the ability to utilize infrastructure already in place. The Colorado River, while south of most major oil shale resources, is still important because water could be conveyed from the Colorado River to the Piceance Basin and because changes to its tributaries will impact this highly regulated river system. As part of the Colorado River Basin, water rights associated with these river systems are governed by the Colorado River Compact.

1. Water Resources Within Colorado's Prospective Development Area

Water is scarce within the most prospective area, necessitating consideration of both physical resources and their legal availability. The four primary surface water sources within Colorado are the Colorado, Green, White and Yampa rivers, as shown in Figure 3.

[137] *Id*. at 27.

Figure 3
Yampa, White, Green & Colorado Rivers Within Colorado[138]



Although it is the smallest of the four major rivers at roughly 500,000 AF per year near the Utah-Colorado border,[139] the White River is the closest major surface water source to both states' oil shale resources, requiring less pipeline construction or pumping. Accordingly, earlier oil shale development proposals relied heavily on the White River, declaring it the "first-choice source of water."[140] Already, there are 34 conditionally decreed rights for reservoirs within Colorado's portion of the White River Basin,[141] not all of which can or will be built, but they are an indication of both the level of preparation that has occurred and the potential for diversions upstream of Utah.

The Yampa merges with the Green River within Dinosaur National Monument, roughly

---

[138] URS Corp., *supra* note 15 at 3-27 (2008).
[139] Stream flows are based on gauge data available from the United States Geological Survey and reflect data available as of November 2009. Data reflect measured flows and therefore reflect existing diversions and depletions. Data is *available at* http://waterdata.usgs.gov/nwis/rt.
[140] UTAH ENERGY OFFICE, UTAH DEPARTMENT OF NATURAL RESOURCES AND ENERGY, AN ASSESSMENT OF OIL SHALE AND TAR SANDS DEVELOPMENT IN THE STATE OF UTAH, PHASE II: POLICY ANALYSIS 27 (1982).
[141] WESTERN RESOURCE ADVOCATES, *supra* note 133 at 8.

five miles east of the Colorado-Utah border. The Yampa is a significant source of water, discharging on average 1,485,000 AF/Y at Deerlodge Park, just inside the Monument.[142] Roughly 27% of flows at Deerlodge Park are attributable to the Little Snake River, which joins the Yampa just upstream of the Monument's eastern boundary. Yampa River flows are apportioned between Colorado and Utah in the Upper Colorado River Compact, requiring Colorado to deliver 500,000 AF/Y, based on a ten year running average, at Maybell, Colorado, upstream of the confluence of the Green and Little Snake.[143] The average annual delivery requirement is approximately 45% of average flows at the Maybell gauge.[144] Power plants near Craig and Hayden, Colorado, as well as irrigated agriculture represent the major consumptive uses along the Yampa. Some water may be legally and physically available from the Yampa, subject to the ESA and the Law of the River,[145] but development will require reservoir construction.[146]

The Green River flows east from Utah into Colorado before turning south, joining the Yampa, and turning back west into Utah. The Green River discharges on average 1,443,000 AF/Y upstream of the Colorado border, then roughly doubles its size below its confluence with

---

142 Stream flows are based on gauge data available from the United States Geological Survey and reflect data available as of November 2009. Data reflect measured flows and therefore reflect existing diversions and depletions. Data is available at http://waterdata.usgs.gov/nwis/rt.

143 Upper Colorado River Compact at Art. XIII.

144 Stream flows are based on gauge data available from the United States Geological Survey and reflect data available as of November 2009. Data reflect measured flows and therefore reflect existing diversions and depletions. Data is *available at* http://waterdata.usgs.gov/nwis/rt.

145 The term "Law of the River" refers to the numerous compacts, federal laws, court decisions and decrees, contracts, and regulatory guidelines that apportion water and regulate the use and management of the Colorado River among the seven basin states and Mexico. Copies of key documents are *available at* http://www.usbr.gov/lc/region/g1000/lawofrvr.html.

146 *Statewide Water Supply Initiative, supra* note 14 at 7-82. In December 2008, Shell Exploration and Production filed for the right to divert up to 375 CFS from the Yampa during high flow periods in order to fill a 45,000 AF reservoir off of the main stem of the Yampa between Maybell, Colorado and Dinosaur National Monument. Tom Ross, *Shell Oil's Pursuit of Local Waters Could Have Big Impacts*, THE STEAMBOAT PILOT AND TODAY, (Jan. 11, 2009). In light of the global economic downturn, Shell is no longer pursuing this application. However, Shell has "purchased or appropriated a diversity of water rights" to support its next phases of development. E-mail from Tracy C. Boyd, Venture Support Integration Lead, Shell Exploration and Production Co., to John Ruple, Institute for Clean and Secure Energy (March 3, 2010) (on file with authors); *see also* Mark Jaffe, *Shell Drops Bid for Yampa River Water*, THE DENVER POST (Feb. 24, 2010).

the Yampa.[147] Colorado can – subject to legal availability, the Law of the River, and constraints imposed by the ESA – withdraw significant amounts of water from the Yampa River above the Maybell gauge, potentially causing a significant reduction in Green River flows entering Utah.

The Colorado River is the largest river in the region, discharging on average 4,437,000 AF/Y at the Utah – Colorado border.[148] However, the Colorado River is lower in elevation than oil shale resources within the Piceance Basin and diversions from the Colorado River would need to be pumped significant distances up and over the Roan Plateau, a several thousand foot elevation gain that would increase delivery costs.

2. <u>Water Resources Within Utah's Prospective Development Area</u>

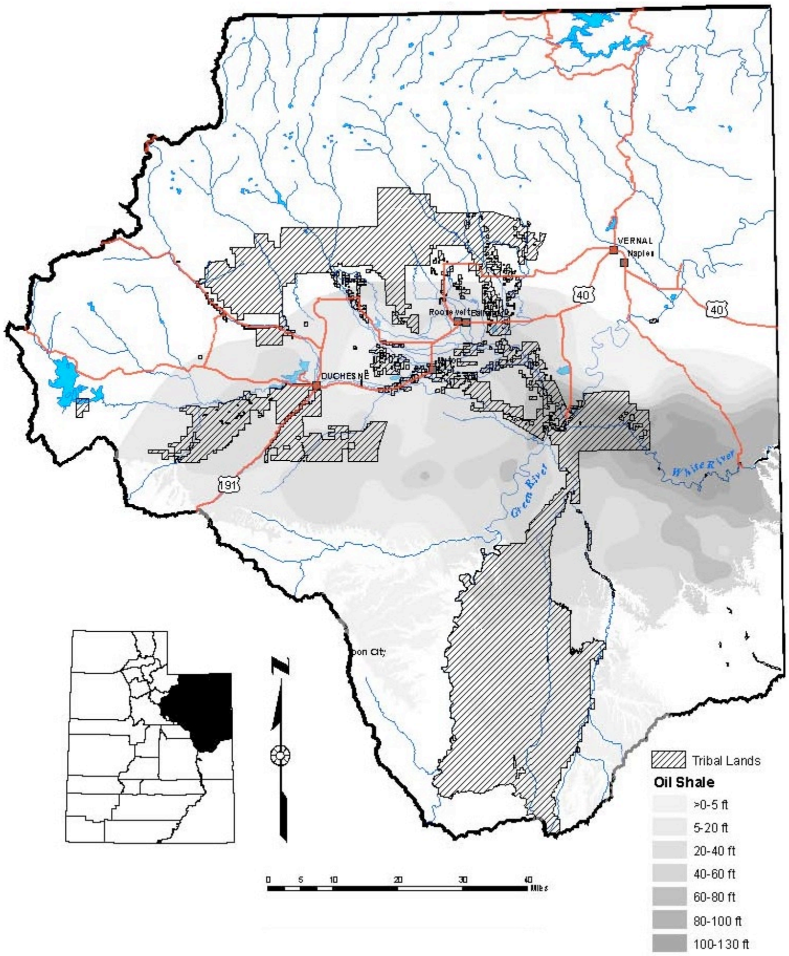
Utah's richest oil shale resources are located within the Uinta Basin. Figure 4 shows water and oil shale resources within Utah's portion of the Uinta Basin, bounded to the north by the State of Wyoming and to the east by the State of Colorado. The White River flows through Utah's richest oil shale resources.

---

147 *Id.*

148 Stream flows are based on gauge data available from the United States Geological Survey and reflect data available as of November 2009. Data reflect measured flows and therefore reflect existing diversions and depletions. Data is *available at* http://waterdata.usgs.gov/nwis/rt.

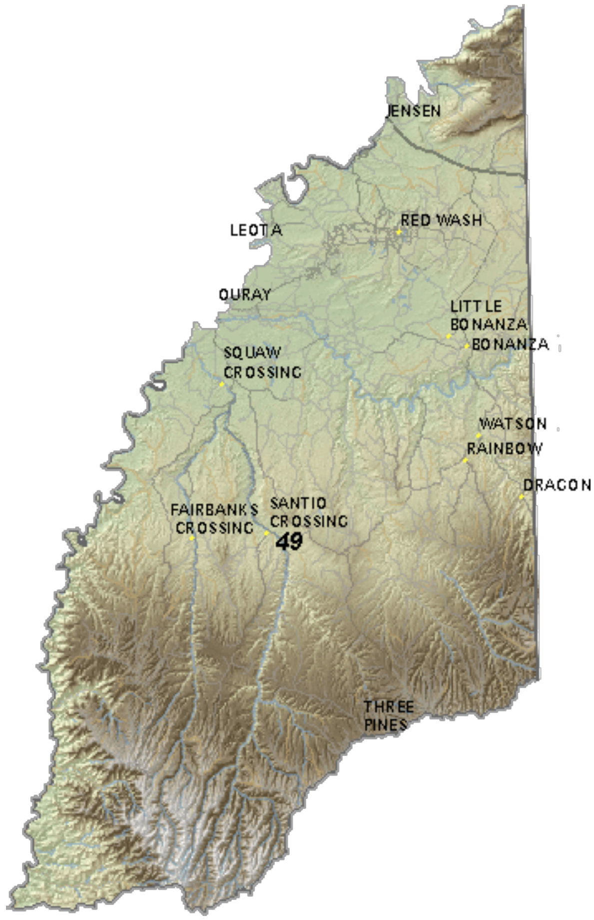
Figure 4
Water & Oil Shale Resources Within the Uinta Basin[149]



Within Utah, water resources are managed in resource areas defined by major hydrologic basins. Utah's richest oil shale resources are located in Area 49, which is shown in Figure 5. The Green River forms the northwest border of Area 49, and Utah's richest oil shale resources are southwest of Bonanza, Utah.

[149] Map prepared by the Utah Automated Geographic Reference Center based on data provided by the Utah Geological Survey. Oil shale is shown based on the 25 GPT isopach.

Figure 5
Water Resource Area 49[150]



Surface waters are fully appropriated throughout the most prospective oil shale area.[151] Groundwater resources are also in scarce supply, generally limited to domestic or temporary supplies, when they are available at all.[152] New consumptive uses must therefore be accomplished via transfer of existing rights. The discussion that follows addresses first water for the Oil Shale Exploration Company's (OSEC's) existing RD&D leases, then turns to the physical resources that could supply oil shale development if existing water uses were reallocated, and concludes with a discussion of water uses that will compete with oil shale and oil sands for scarce water resources.

---

150 *Source*: Division of Water Rights, Utah Department of Natural Resources.
151 *See* Appendix A.
152 *Id*.

a. Water for OSEC's RD&D Lease

OSEC holds the only RD&D lease within Utah. "OSEC's goal is to be producing 50,000 barrels per day of shale oil within the next ten years."[153] Applying a conservative assumption that OSEC's operations, which rely on an underground mine and surface retort, will require four gallons of water per gallon of oil produced, OSEC will require approximately 9,410 AF/Y (approximately 3.07 billion gallons) of water.[154] OSEC has applied to consume up to 10,739.75 AF/Y for mining and industrial purposes from the White River, approximately six miles south of Bonanza, Utah.[155]

OSEC's application has a priority date of February 15, 1965. To perfect the right, OSEC must demonstrate that it has put the water to a beneficial use.[156] On August 28, 2008, the Utah State Engineer approved the third extension of the time within which to submit proof of beneficial use,[157] and OSEC must now file proof of beneficial use, or an application for an additional extension, no later than July 31, 2013.[158] Provided OSEC's proposed diversions are not subject to interruption by more senior right holders and that flow requirements for endangered species do not require curtailment of diversions, it appears OSEC has sufficient water rights to proceed to commercial development of at least the projected 50,000 BPD rate. If water use can be reduced to levels that appear feasible,[159] OSEC has sufficient water to support expansion well beyond its immediate 50,000 BPD target.

b. Water for Non-RD&D Oil Shale Developments

In 1965, the Utah Division of Water Resources filed to appropriate 250,000 AF annually from the White River and its tributaries, identifying mining, drilling, and oil shale retorting as

[153] Letter from Edwin R. Mighell, Stantec Consulting, Inc., to Utah Division of Water Rights re: Request for Extension of Time on Water Right Number 49-258 (A36730) (May 22, 2008) (on file with authors).
[154] An acre foot is approximately 325,851 gallons.
[155] Water right 49-258 (A36730) *available at* http://www.waterrights.utah.gov/cgi-bin/wrprint.exe?Startup.
[156] UTAH CODE ANN. §§ 73-3-16 and -17.
[157] Water right 49-258 (A36730), *supra* note 155.
[158] *Id*.
[159] *See* section I.B.1. *supra*.

intended uses.[160] This reflects 100% of the river's flow during low-flow periods.[161] The full application remains pending but unapproved. In 1976, the State Board of Water Resources[162] sought to "segregate" the application, applying for 105,000 AF from the original application to supply the proposed White River Dam and Reservoir.[163] This smaller application also remains pending and unapproved.[164] In 1983 the Board tried once again to segregate applications, applying to use 3,000 AF from the 1976 application to support "[m]ining, drilling, retorting, steam generation, cooling, and related uses" by the White River Oil Shale Corp.[165] This segregation was approved and proof of beneficial use is due by June 30, 2018.[166] While the water rights and associated infrastructure addressed in the parent applications were not developed, the two parent applications remain pending and represent water that may be available.[167] However, given the number and extent of approved water right applications, certificated water rights, and reserved rights claims to the White River and its tributaries, it may be difficult to obtain approval for the unapproved parent applications.

The White River, while the most convenient source of supply, is not the only option. In 1958, the Bureau of Reclamation filed to appropriate water for the Flaming Gorge Dam;[168] this application has been segregated into four separate water rights, the most significant of which involves 447,500 AF and is held by the State Board of Water Resources[169] Although the state has conveyed much of this water to other users, water may be available from remaining state

---

160 UTAH STATE DIVISION OF WATER RESOURCES, WHITE RIVER DAM PROJECT: PROPOSED ACTION PLAN (REVISED) 3 (1980).
161 FINAL WHITE RIVER DAM PROJECT ENVIRONMENTAL IMPACT STATEMENT, *supra* note 16 at 59.
162 The Board of Water Resources is the policy making body that directs the Division of Water Resources. *See* UTAH CODE ANN. § 73-10-1.5
163 *See* water right 49-304 *available at* http://www.waterrights.utah.gov/cgi-bin/wrprint.exe?Startup.
164 *Id*.
165 *See* water right 49-1239 and associated file documents, *available at id*.
166 *Id*.
167 *See* water rights 49-113 (250,000 AF), 49-309 (105,000 AF), and 49-1234 (3,000 AF) *available at id*.
168 *See* water right 41-2963 *available at id*.
169 *See* water right 41-3479 *available at id*.

water rights or from the subsequently segregated rights.[170] However, under rules promulgated by the Utah Division of Water Resources, which holds the state's water rights in Flaming Gorge Reservoir, water from the reservoir is unavailable for "mining."[171] The term mining is undefined in the rule and, if interpreted to include commercial oil shale development, could limit availability from this source.

Even if commercial oil shale development is outside the scope of the term "mining," water rights supporting such uses would still be the lowest priority for approval under an administrative rule giving priority first to uses involving public health, safety, and welfare; next to political subdivisions requesting water rights for existing or anticipated municipal and industrial water uses; third to agricultural water projects providing a significant economic benefit to a local community; and only then to applications submitted for a private development located outside of a political subdivision that provides municipal and industrial water service.[172] Even if unavailable for oil shale development, water from Flaming Gorge could supply other users, freeing up other water for oil shale development.

The Duchesne River and its tributaries, which are north of the most prospective area, are heavily impacted by development as part of the Central Utah Project. Currently, daily average streamflow near the confluence with the Green River is 634 CFS.[173] As discussed in Section I.I.1, the Northern Ute Tribe of Indians has vast claims to waters from the Duchesne River system. The Tribe could, once its claims are resolved, lease water from this system or apply to change points of diversion and use to groundwater or the White River, providing additional potential sources of water. If approved, changing the point of withdrawal to a location

[170] Under water right number 41-3479, the State of Utah Board of Water Resources holds the right to divert up to 447,500 AF from the Green River at Flaming Gorge Dam. 25 separate water rights, representing rights to divert 147,815.398 AF, have been segregated from this right, leaving the Board with a paper right to divert 299,684.602 AF of water. If this water can be diverted in light of other considerations, some water from this source may be available to support commercial oil shale development. Water may also be available from rights segregated from 41-3479.

[171] UTAH ADMIN. CODE § R653-8-3(2)(a).

[172] *Id.* at § R653-8-3(1).

[173] FINAL PEIS, *supra* note 5 at 3-87.

closer to Utah's oil shale resources would reduce delivery costs.

The last oil shale boom also prompted construction of Red Fleet Reservoir approximately ten miles north of Vernal. The burst of the oil shale bubble left about 70% of Red Fleet water unsubscribed as of a decade ago.[174] It is unclear whether this water source remains undersubscribed; what water may currently be available, if any, will likely go fast as planners anticipate growing water demands.

c. Competing Water Uses Within Area 49

A comprehensive evaluation of water rights potentially impacted by commercial oil shale development is not currently feasible given the uncertain number, size, location, and water use requirements associated with the nascent oil shale industry. Likewise, an accurate assessment of the extent to which prospective oil shale developers have already secured water rights and identification of those users most likely to be impacted by oil shale development would require an assessment of all valid and pending water rights claims. While such an investigation is beyond the scope of this study, a review of summary information regarding valid and pending claims provides some illumination.

Within Area 49, the State Engineer's Office maintains records of 1,661 water right claims, each of which can be described in terms of (among other things) permissible uses and the status of the claim. Within Area 49, claims fall into one of twelve potential classes;[175] these classes can be combined into three general categories: valid,[176] invalid,[177] and those missing information regarding their status. Government agencies submitted almost all claims with an undefined status. These claims generally involve watering livestock and were submitted in

[174] UTAH STATE WATER PLAN: UINTA BASIN, *supra* note 54 at 9-4.
[175] These classes are: approved, certificated, disallowed, expired, lapsed, no proof required, rejected, terminated, unapproved, withdrawn, water use claims, and those missing information.
[176] For purposes of this report, valid claims include approved, certificated, no proof required, water use claims, and unapproved claims. Unapproved claims are treated as valid because no final decision has been rendered; their inclusion produces the most conservative estimate of water availability.
[177] For purposes of this report, invalid claims include disallowed, expired, lapsed, rejected, terminated, and withdrawn claims.

order to avoid waiving claims during general adjudications.[178] For purposes of this analysis, we treat these claims as likely valid and lump all valid and missing claims together as "not invalid" claims. Of the 1,661 total claims, 1,091 claims are treated as not invalid.

Of the not invalid claims, stockwatering (891) and "other" (715) are the most numerous uses claimed. However, in terms of the amount of water subject to not invalid claims, power production and mining represent the two largest uses, involving 24.7% and 21.8% of the water claimed, respectively. Of the not invalid claims, "other," stockwatering, and irrigation represent the most senior uses; claims associated with mining and energy production are the most junior.[179] While domestic and municipal claims generally predate the large claims associated with mining and power production, they can be junior to both unperfected rights and reserved rights claims.

The often-junior nature of domestic and municipal claims has important implications. If commercial oil shale development comes to pass, Colorado's and Utah's respective rights to water from the White River will need to be settled, as this will largely define the amount of water physically available within Utah. Instream flow requirements for ESA protection will also need clarification, as they will largely determine how much water is actually available for diversion. Additionally, the extent of the Northern Ute Tribe of Indian's reserved rights claims must be resolved as they predate almost all other claims within the basin and, if developed, could displace significant existing water uses. Any of these issues, plus perfecting pending water right applications or leasing of water rights held by the Utah Department of Water Resources, could displace rights that were previously considered stable. Western Resource Advocates noted a similar concern affecting many communities along Colorado's western slope, stating:

---

[178] *See generally*, 43 U.S.C. § 666, (waiving the federal government's claims of sovereign immunity in state court actions adjudicating administration of river systems where it appears the federal government holds water rights). Since failure to state a claim during an adjudication can result in waiver of that claim, state and federal agencies frequently file claims to avoid waiver.

[179] For this general discussion, assessments of seniority are based on mean age of claims.

> West Slope communities have grown considerably since the 1950s. The headwaters towns in the Colorado River Basin now support substantial year-round populations as well as large numbers of second homes . . . . Much of the water supply that has been developed to serve this population depends on water rights with relatively recent appropriation dates.[180]

Until recently, Utah's Water Code recognized the unique risk of displacing domestic water users. As recently as 2008, the Water Code stated that "in times of scarcity, while priority of appropriation shall give the better right as between those using water for the same purpose, the use for domestic purposes, without unnecessary waste, shall have preference over use for all other purposes."[181] This provision proved to be controversial, and was rescinded in 2009. Pending legislation (as introduced) would replace the stricken provision with a narrow, temporary exemption to normal priority rules in favor of "water for drinking, sanitation, and fire suppression" during "temporary water shortage emergencies."[182] Such emergencies would require a gubernatorial declaration and could not exceed two years.[183] Unlike the prior statutory scheme, preferential water users under the pending bill would be required to pay reasonable compensation to appropriators whose water use is interrupted.[184]

Drinking water supplies cannot be interrupted without causing significant harm and social dislocation. If domestic supplies are subject to interruption because of junior priority dates, domestic water users and purveyors will need to obtain more senior sources of supply. Since irrigation rights are often senior to domestic rights,[185] and most irrigation is used to grow alfalfa and provide pasture for livestock,[186] irrigation rights appear to be a likely target for acquisition. While displacement of low economic value agricultural water uses may make sense

[180] WESTERN RESOURCE ADVOCATES, *supra* note 133 at 34.
[181] UTAH CODE ANN. § 73-3-21 (2008). This provision was revoked in 2009.
[182] H.B. 231, 2010 General Session (Utah 2010).
[183] *Id*.
[184] *Id*.
[185] Because almost all water rights claims with an undefined status are associated with government agency stock and wildlife watering claims, we can assume that these rights are not available for purchase and conversion to other purposes. We therefore need concern ourselves only with valid claims. Of the 428 valid claims, claims including irrigation as a use are, on average, the most senior (mean priority date of 1941) and 28 years senior to mean priority date for both valid and not invalid claims to domestic use.
[186] WATER RESOURCES DIVISION, UTAH DEPARTMENT OF NATURAL RESOURCES, WATER-RELATED LAND USE INVENTORIES: UINTAH BASIN 2006 INVENTORY 7 (Dec. 2007).

from an economic perspective and would be consistent with experiences throughout the west, it would have a transformative effect on local communities.

Just as the last oil shale boom saw planning for significant water development, the boom also spurred planning for increased power production. During the late 1970s, Deseret Generation and Transmission Cooperative (Deseret) anticipated that the 9.9% annual growth in power demand it experienced over the prior decade would continue and increase to almost fifteen-percent annually as oil shale developments came on line.[187] To accommodate this growth, Deseret proposed to construct and operate a two-unit coal fired thermoelectric generation facility near Bonanza, Utah.[188] Unit One came on line in 1986 and is commonly referred to as the Bonanza Power Plant. Unit Two was not constructed because interest in oil shale declined and power demand did not increase as anticipated.

Deseret secured water rights for both units. Water for the Bonanza Power Plant is drawn from the Green River, approximately three miles south of Jensen, Utah,[189] and pumped south to the power plant. Unit 2 would have drawn water from nine groundwater wells along the Green River, also near Jensen, Utah.[190] While this use never occurred and Deseret was unable to certificate its right, the application to appropriate was approved and contemplates diversion of up to 15 CFS or 12,500 AF/Y.[191] On September 29, 2008, the State Engineer approved an application for extension of time within which to submit proof of beneficial use until December 31, 2018.[192]

If power demand continues to increase, Deseret may seek to increase production by constructing Unit 2. While no such proposal currently exists, development of the water right

---

[187] DEPARTMENT OF AGRICULTURE AND DEPARTMENT OF THE INTERIOR, MOON LAKE POWER PLANT PROJECT UNITS 1 AND 2 FINAL ENVIRONMENTAL IMPACT STATEMENT 20-27 (1981) (hereinafter MOON LAKE EIS).
[188] *Id*. at 36-37.
[189] Water right 49-225. Water rights can be viewed at http://www.waterrights.utah.gov/cgi-bin/wrprint.exe?Startup.
[190] Water right 49-1610. Water rights can be viewed at http://www.waterrights.utah.gov/cgi-bin/wrprint.exe?Startup.
[191] *Id*.
[192] *Id*.

secured to provide cooling and process water for Unit Two would reduce flows in the Green River, complicating efforts to develop other water-dependent projects.

3. Existing Water Rights for Oil Shale Development

Energy companies recognize the importance of water and the need to secure adequate water rights. Not surprisingly, prospective oil shale developers already control significant water rights, many of which are senior to authorized irrigation projects and domestic supplies.[193] A recent study commissioned by Western Resource Advocates details water rights for oil shale development within western Colorado:

> Companies interested in oil shale development have established conditional water rights associated with more than 200 proposed structures, such as a diversion or storage dam in the Colorado River and White River Basins, dating back more than 50 years. . . . There are approximately 105 separate proposed structures with associated conditional water rights that could be used for oil shale development in the Colorado River Basin. These rights are for a mixture of both direct diversion and storage rights. In addition, there are 114 proposed structures with conditional rights in the White River Basin. These conditional structures include proposed reservoirs, pipelines (most with pumps), ditches, wells, and springs. These rights would enable a total direct diversion of approximately 5,000 cfs in the Colorado River Basin and nearly 5,700 cfs in the White River Basin. They would provide for total storage of approximately 735,000 af of water in the Colorado River Basin and over 1 million af in the White River Basin . . . .
>
> In addition to establishing conditional water rights, energy companies have been actively purchasing existing agricultural ditch rights in both basins. . . . Acquisition of ditches provides control of water with senior priorities, especially important on the flow-limited tributaries in which they are located . . . . 57 irrigation ditches in the Colorado River Basin are now owned in whole or in part by energy companies, with decreed absolute rights to divert approximately 470 cfs of water. According to state records, average diversions under these rights are approximately 50,000 af of water per year. Another 57 ditches in the White River Basin are now owned by energy companies. In many cases, companies have acquired only partial ownership of a ditch (less than 100% of total ditch shares). Sometimes several energy companies share in the ownership of the same ditch. The decreed absolute diversion rates associated with these ditches total approximately 200 cfs. The total annual volume of water diverted under these rights, on average, is approximately 19,000 af.[194]

Many, and perhaps even most, of these water rights will never be developed. They do,

---

[193] CHARLES ANDREWS, ET AL., UNIV. OF WISCONSIN-MADISON, INST. FOR ENVTL. STUDIES, OIL SHALE DEVELOPMENT IN NORTHERN COLORADO: WATER AND RELATED LAND IMPACTS 40, 53, 66, 87, 94, and 99 (1975). *See also*, WESTERN RESOURCE ADVOCATES, *supra* note 133.

[194] WESTERN RESOURCE ADVOCATES, *supra* note 133 at 7-9.

however, reflect effort that has gone into planning for oil shale development and potential diversions that would impact downstream water users.

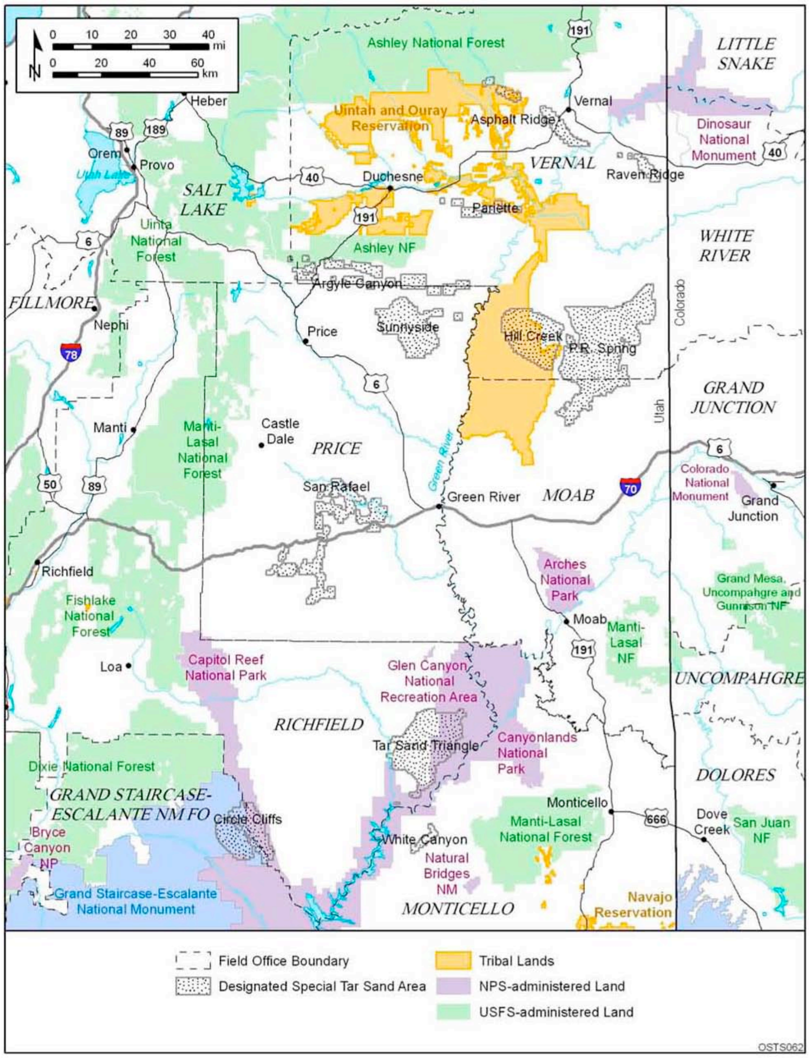
While Western Resource Advocates is preparing an assessment of existing water rights for oil shale development within Utah, no such comprehensive evaluation is yet available. There are almost 1,700 water rights claims on file within Area 49. Determining which of these claims anticipates oil shale development is extremely difficult as oil shale mining and retorting is not coded as a distinct use category, necessitating a claim-by-claim review of the almost 1,200 claims listing either mining or "other" as a proposed use. Such a comprehensive review is beyond the scope of this analysis, but 28 claims involving oil shale development were identified based on the applicant's name. In addition to OSEC's application discussed above, the Paraho Development Corp. has six pending but unapproved applications, totaling over 900 AF.[195] These applications, while not disapproved, have been pending since 1982 and are unlikely to proceed to approval given that approved and certificated rights within the area already exceed available supplies. The other 21 claims were all rejected, lapsed, or are temporary claims that have expired. While this review does not constitute a comprehensive assessment of potential claims and should not be treated as such, it highlights the importance of state-held water rights in the White River and Flaming Gorge Reservoir.

E. Sources of Water for Oil Sands Development

Water for oil sands development is in short supply. The ten STSAs stretch from near Vernal in the north to near Monument Valley and the Navajo Indian Reservation in the south, as illustrated in Figure 6. The STSAs extend into portions of ten different water rights areas. A description of water availability in each of the ten water resource areas is contained in Appendix A and summarized here.

[195] Water rights 49-1232 through 49-1237. Water rights can be viewed at http://www.waterrights.utah.gov/cgi-bin/wrprint.exe?Startup.

Figure 6
Special Tar Sands Areas Within Utah[196]



Surface waters within nine of the ten water rights areas are fully appropriated, and new diversions or consumptive uses of surface water must be accompanied by change applications filed on valid existing water rights. Some new surface water is available in Water Rights Area 99, near the White Canyon STSA in San Juan County, but new surface water diversions in this area are limited to domestic and associated small-scale irrigation and stock watering, precluding new surface water diversions as a source of supply for commercial oil sands development.[197] Limited groundwater resources are available for new appropriations in all ten water rights areas,

[196] Source: Oil Shale & Tar Sands Programmatic EIS Information Center, http://ostseis.anl.gov/guide/maps/index.cfm.
[197] http://nrwrt1.nr.state.ut.us/wrinfo/policy/wrareas/area99.html.

but new groundwater rights are limited to domestic use and associated small-scale irrigation and stock watering, again precluding groundwater as a new source of supply for commercial oil sands development. A description of water resources proximate to each STSA is contained in the FINAL PEIS and is not repeated here.[198]

As noted with respect to oil shale, it is difficult to identify existing water rights dedicated to oil sands development because oil sands mining and retorting is not a searchable use within the State Engineer's on-line database. A search for known oil sands development companies identified one valid water right application. Earth Energy Resources, Inc., which holds active leases to Utah School and Institutional Trust Lands Administration (SITLA) land in Uintah and Grand Counties, has an approved application to use 360 AF/Y from the Green River to mine oil sands. Earth Energy Resources' facilities are located approximately 65 miles southeast of Vernal, Utah. Proof of beneficial use is due by May, 31, 2012.[199]

Prospective oil sands developers are in essentially the same situation as prospective oil shale developers with respect to the acquisition of water rights – both must obtain valid, existing water rights and comply with administrative requirements to change the use and point of diversion as appropriate. Water from Flaming Gorge Reservoir represents the most promising untapped resource.

F. Surface Water Storage and Reservoir Construction

Seasonal flows pose significant problems for year-round water use unless storage facilities are constructed. Average annual undepleted flows of the White River near the Colorado-Utah border are estimated at 590,100 AF,[200] with mean flow of 604 CFS.[201] Flows vary year-to-year and season-to-season, with spring runoff swelling the river to an average discharge of 1,765 CFS during June, almost five times the average discharge experienced in

[198] FINAL PEIS, *supra* note 5.
[199] *See* water right application 49-2274 *available at* http://www.waterrights.utah.gov/cgi-bin/wrprint.exe?Startup.
[200] FINAL PEIS at 3-81.
[201] FINAL WHITE RIVER DAM PROJECT ENVIRONMENTAL IMPACT STATEMENT, *supra* note 16 at 59.

December and January.[202] Such seasonal fluctuations are common to snowmelt-fed rivers within the region and the seasonal nature of surface flows means that while ample water may be readily available during spring runoff, much less water is generally available during winter months. Securing reliable, year-round supplies from variable streamflows will require a significant increase in water storage capacity. Impoundment construction requires both federal and state permits. The following discussion focuses on requirements applicable to water storage projects proposed within Utah.

In Utah, "[n]o person may construct, enlarge, repair, alter, remove, or abandon a dam or reservoir without obtaining written permission from the state engineer."[203] Impoundments exceeding 20 AF in capacity or posing a threat to human life should they fail are subject to a formal application and approval process; smaller, safer impoundments require only submission of formal plans.[204]

Impoundment construction alters streambeds and stream banks, and in Utah such alterations require State Engineer approval.[205] Impoundment construction also involves placement of fill material in waters of the United States, which is regulated under Section 404 of the CWA[206] and Section ten of the Rivers and Harbors Act.[207] The State of Utah and U.S. Army Corps of Engineers combine the state stream alteration permit review process with the Corp's Section ten and Section 404 permitting processes, utilizing a common permit application.[208] Completed applications are circulated by the State Engineer to the Corps, U.S. Fish and Wildlife Service, the Environmental Protection Agency (EPA), the Utah Division of Wildlife Resources, the Utah Division of Water Quality, the Utah State Historic Preservation Office, local agencies,

[202] *Id*. Between 1923 and 1978, average monthly flows just west of the state line peaked at 2,934 CFS; monthly low flows over the same period were just 140 CFS. *Id*.
[203] UTAH CODE ANN. § 73-5a-201.
[204] *Id.* at § 73-5a-202.
[205] *Id.* at § 73-3-29.
[206] 33 U.S.C. § 1344, *see also* discussion in section II.D.3., *infra*.
[207] *Id.* at § 403.
[208] Permit applications are *available at* http://www.waterrights.utah.gov/strmalt/forms.asp.

adjacent property owners and the general public.[209] The joint permitting process allows the Corps to authorize actions under Regional General Permit 40, but only absent concerns such as adverse affects on a species listed as threatened or endangered under the ESA.[210] Where a general permit is precluded, applicants must proceed with the more complicated individual permitting process. It is important to note that the Corps reviews each application for compliance with Section 404(b)(1) Guidelines, allowing only the alternative that will achieve the basic project purpose while resulting in the least adverse impact to the aquatic environment conditions.[211] The Corps will deny applications for projects that significantly degrade the nation's waters.[212]

In addition to construction related requirements, prospective developers will need to obtain rights to access and use reservoir sites. Where reservoirs and related facilities such as roads or pipelines are located on public land, operators will need to obtain rights of way pursuant to Subchapter V of the Federal Land Policy and Management Act (FLPMA).[213] Prospective developers may also encourage the state to acquire needed federal lands through sale or exchange, again pursuant to FLPMA.[214] If a reservoir or associated infrastructure will encroach on state or private lands, additional land use permissions will be required. Construction of a reservoir or associated infrastructure on federal lands is a major federal action subject to review and approval under the National Environmental Policy Act (NEPA).[215]

In addition to conventional reservoir storage, water may be injected and stored in underground aquifers for subsequent use. In Utah, such projects are governed by the

[209] Army Corps of Engineers Regional General Permit No. 40, for Discharges of Dredged and Fill Material or Excavations in Streams in the State of Utah Where a Stream Alteration Permit has Been Issued by the State Engineer *available at* http://www.spk.usace.army.mil/organizations/cespk-co/regulatory/regional.html.
[210] *Id*.
[211] *See* 40 C.F.R. §§ 230.1 – 230.98, *see also*, section II.D.3., *infra*.
[212] *Id*.
[213] 43 U.S.C. §§ 1761-70.
[214] *See id.* at § 1721.
[215] 42 U.S.C. § 4332(2)(C).

Groundwater Recharge and Recovery Act,[216] which prohibits groundwater recharge and recovery absent State Engineer authorization.[217] To obtain authorization, the applicant must possess a water right for the water proposed for storage.[218] The applicant also must demonstrate that the project is hydrologically feasible, will not cause unreasonable harm to land, will not impair any existing water right, will not adversely affect the water quality of the aquifer, and the technical and financial capability to conduct and operate the project.[219]

In 1965, the State of Utah filed to appropriate 250,000 AF from the White River and its tributaries,[220] identifying the intended uses as mining, drilling, and retorting oil shale.[221] The Utah Division of Water Resources filed connected applications with the BLM, seeking authorization to construct an 11.7-mile long reservoir just west of the Colorado border. As proposed, the reservoir would have impounded 109,250 AF of water and had an active storage capacity of 70,700 AF.[222] The Final EIS for the White River Dam was issued in May of 1982, addressing availability of land for the reservoir site. Interest in the project waned when the price of oil fell sharply and the dam was not built. As noted earlier, the original 250,000 AF application remains pending but unapproved, and only 3,000 AF that were segregated from the application reflect an approved water rights application.[223] How much of the 1965 or 1976 segregation applications could be approved given current levels of development and constraints is uncertain. Therefore, whether the White River Dam proposal could move forward is uncertain.

---

216 UTAH CODE ANN. §§ 73-3b-101 through 402.
217 *Id.* at § 73-3b-103.
218 *Id.* at § 73-3b-106.
219 *Id.* at § 73-3b-202.
220 WHITE RIVER DAM PROJECT: PROPOSED ACTION PLAN (REVISED), *supra* note 160 at 3.
221 *Id.* at 3.
222 FINAL WHITE RIVER DAM PROJECT ENVIRONMENTAL IMPACT STATEMENT, *supra* note 16 at 1. The difference between capacity and active storage is attributable primarily to capacity dedicated to sediment storage. The project went through several modifications and evolving water requirements are reflected in water right 49-304 and associated file documents, which are *available at* http://www.waterrights.utah.gov/cgi-bin/wrprint.exe?Startup.
223 *See* water rights 49-304 and 49-1239 *available at* http://www.waterrights.utah.gov/cgi-bin/wrprint.exe?Startup.

Dams are only the most obvious and visible component of a water resource development project. Additional components of water resource development may include pipelines, pumping stations, and various other facilities needed to get water from the source to the place of use. Infrastructure requirements and their associated cost of development are difficult to estimate as the specific location of development facilities and their operational requirements remain uncertain.

G. Groundwater Resources and Regulation

Groundwater provides an additional potential source of water that could supplement surface water development. While a detailed analysis of groundwater resources is beyond the scope of this analysis, ample information is available to obtain a fair picture of available resources. We begin with a discussion of groundwater resources, then turn to groundwater regulation.

1. Groundwater Resources

Groundwater resources with the Piceance Basin are dominated by two shallow aquifer systems. The White River alluvial aquifer extends along the White River, covering approximately 3,770 square miles.[224] Water levels within the alluvial aquifer are quite shallow, ranging from 3 to 90 feet.[225] Ninety percent of wells within the alluvial aquifer are completed to less than 120 feet, and the mean depth of completed wells is just 58 feet.[226]

Sedimentary rock aquifers within the northern part of the Piceance Basin underlie portions of the alluvial aquifer, extending further to the south and well past the most prospective area.[227] "The principal bedrock aquifers in the northern portion of the Piceance Basin are the saturated, porous members of the Uinta Formation and Parachute Creek Member of the Green

---

224 RALF TOPPER ET AL., COLORADO GEOLOGICAL SURVEY, GROUND WATER ATLAS OF COLORADO 5.5-1 (2003) (hereinafter GROUNDWATER ATLAS OF COLORADO) *available at* http://geosurvey.state.co.us/wateratlas/.
225 *Id.* at 5.5-1.
226 *Id.* at 5.5-1.
227 *Id.* at 6.2-1.

River Formation . . . . The thickness of Tertiary-age rocks in the Piceance Basin varies from 2,000 to approximately 12,000 feet."[228] "Aquifers in the Piceance Basin are typically under confined conditions, except along outcrops at the basin edge. The potentiometric surface indicates that the pressure head is at or very near the surface within the drainage valleys."[229] "Well permit records indicate that 90 percent of these wells are completed at depths of 300 feet or less. The minimum well depth reported is two feet and the maximum well depth is 2,395 feet, with a mean depth of 162 feet."[230]

Within the most geologically prospective portion of Utah, groundwater occurs in alluvial deposits along major stream courses and within portions of the Uinta, Green River, Wasatch, and Mesa Verde Formations.[231] Alluvial groundwater occurs along the White River and Evacuation Creek at depths of 0 to 30 feet below the ground surface.[232] The Douglas Creek Aquifer is south of the White River Mine and has an upper elevation of approximately 165 feet below ground level.[233] The most extensive aquifer in the area is the Bird's Nest Aquifer; the "depth to water within the Bird's Nest Aquifer increases to the northwest, in the direction of the dip of the aquifer, and ranges from zero at the outcrop areas along Evacuation Creek to about . . . 500 feet."[234] A smaller "upper aquifer" is found approximately 75 feet above portions of the Bird's Nest Aquifer.[235]

Development of the White River Mine "started in 1982 with the sinking of a vertical 1,058-foot deep, 30 foot diameter concrete-lined main shaft and the driving of a 4,574 foot long, three-segment decline to the Mahogany Zone mining horizon. The overlying Birds Nest Aquifer

---

[228] *Id.* at 6.2-1.
[229] *Id.* at 6.2-3.
[230] *Id.* at 6.2-3.
[231] BECHTEL PETROLEUM, INC., WHITE RIVER SHALE PROJECT DETAILED DEVELOPMENT PLAN OIL SHALE TRACTS UA AND UB 2-63 (1981).
[232] *Id.* at 2-78.
[233] *Id.* at 2-64.
[234] *Id.* at 2-78.
[235] *Id.* at 2-73.

was grouted off in the shaft and the decline to minimize water inflow into the mine."[236] Mine dewatering efforts ceased with abandonment, and the mine is currently partially flooded.[237] "The amount of water in the mine is not known at this time; but it is known to be below the 1,000 foot level in the 30 foot diameter shaft."[238] Efforts to reopen the White River mine, to operate similar underground facilities, and to utilize in situ technologies are all likely to require groundwater management. In contrast, technologies utilizing shallower shales, such as Red Leaf Resources' Ecoshale technology,[239] will necessitate less groundwater management.

2. Groundwater Administration

The Utah Water Code does not distinguish between surface and groundwater rights, and acquisition of a right to utilize groundwater is subject to the same five-step process discussed earlier. The central question with respect to new groundwater development is whether development would interfere with other water rights, including rights to utilize surface water.[240] Unfortunately, continuity between surface and groundwater is not always easily ascertained. Given this difficulty, it is not surprising that Utah, like most western states, applies the "rule of reasonableness" in addressing groundwater withdrawals.

> [The rule of reasonableness] involves an analysis of the total situation: the quantity of water available, the average annual recharge in the basin, the existing rights and their priorities. All users are required where necessary to employ reasonable and efficient means in taking their own waters in relation to others to the end that wastage of water is avoided and that the greatest amount of available water is put to beneficial use.[241]

Thus, some level of reservoir drawdown is permissible provided it does not interfere with other users' reasonable use of the water source.

---

[236] *Id.* at C-1.
[237] *Id.* at C-6—7.
[238] *Id.* at C-6.
[239] SECURE FUELS FROM DOMESTIC RESOURCES, *supra* note 10 at 28-29
[240] *Little Cottonwood Water Co. v. Sandy City*, 258 P.2d 440, 443 (Utah 1953) ("no one can interfere with the source of supply of [a] stream, regardless of how far it may be from the place of use, and whether it flows on the surface or underground, in such a manner as will diminish the quantity or injuriously affect the quality of the water of these established rights.").
[241] *Wayman v. Murray City Corp.*, 458 P.2d 861, 865 (Utah 1969).

Like Utah, Colorado presumes groundwater is tributary to surface water,[242] and groundwater ultimately bound for a natural stream is "recognized as a part of the waters of the stream to the same extent as though flowing upon the surface."[243] Outside of the Denver Basin, which is subject to unique regulations, Colorado recognizes three types of groundwater basins that are subject to unique requirements depending on whether groundwater is in continuity with surface water.[244]Accordingly, any attempt to develop groundwater within Colorado must begin with the factual question of whether the water is tributary to waters already subject to beneficial use.

As noted earlier, the State Engineer treats the Southeast Uinta Basin as closed to most new water rights acquisition and has done so for several years.[245] Existing certificated water rights together with approved applications and federal reserved rights claims are sufficient to demonstrate appropriation of essentially all available water. Acquisition of new groundwater rights therefore turns on the applicant's ability to convince the State Engineer that the new appropriations would not impair existing rights in the over-appropriated basin. One such approach is to discover "new," untapped aquifers – a goal often pursued but seldom achieved.[246]

While undiscovered groundwater is generally a mirage, deep groundwater confined by impermeable geologic strata may represent an important exception to the rule. Two examples

---

[242] *McClennan v. Hurdle*, 33 P. 280, 282 (Colo 1893).
[243] *Medano Ditch Co. v. Adams*, 68 P.431, 434 (Colo. 1902).
[244] "Designated groundwater basins" contain groundwater, "which in its natural course would not be available to and required for the fulfillment of decreed surface rights." COLO. REV. STAT. § 37-90-103(6)(a). "Nontributary groundwater" is "ground water, located outside the boundaries of any designated ground water basins . . . the withdrawal of which will not, within one hundred years, deplete the flow of a natural stream . . . at an annual rate greater than one-tenth of one percent of the annual rate of withdrawal." *Id*. § 37-90-103(10.5). Prior appropriation does not apply to nontributary ground water, which is allocated based on ownership of the overlying land. *Id*. § 37-90-102(2). Finally, "not nontributary ground water" reflects the broadest classification and groundwater outside of designated basins where withdrawal will "within one hundred years, deplete the flow of a natural stream." *Id*. § 37-90-103(10.7).
[245] *See* Appendix A.
[246] *See, e.g.,* Mark Havens, *Geologist: Southern Utah Aquifer Could be Developed*, SALT LAKE TRIBUNE, (June 14, 2009) (describing claimed discovery of a "deep aquifer, filled with prehistoric water that has filtered through a porous formation of Navajo sandstone, [and which] slumbers deep underground in southern Utah, waiting to be tapped.")

are worth considering. First, with groundwater produced in association with natural gas extraction, the geologic strata preventing natural gas from escaping also prevent co-located water resources from interacting with other water resources. Such deep groundwater is, at least theoretically, isolated so new diversions would not impair existing rights. Deep groundwater encountered during natural gas production is, however, often high in dissolved solids and requires costly treatment prior to use or disposal; it is also subject to complicated legal issues addressed in the produced water section.

Deep groundwater may be located apart from oil or natural gas resources. For example, in Sandoval County, New Mexico, two deep groundwater wells (3,850 and 4,820 feet deep) produce up to 750 GPM, supplying water to 70,000 residences.[247] While these deep wells are isolated from other water resources, they were expensive to tap and treat, with treatment costs estimated at $1 to $3 per 1,000 gallons.[248] As the cost of development and treatment fall in relation to the cost of acquiring alternate supplies, deep groundwater will become increasingly attractive.

H. The Colorado River Compact and the "Law of the River"[249]

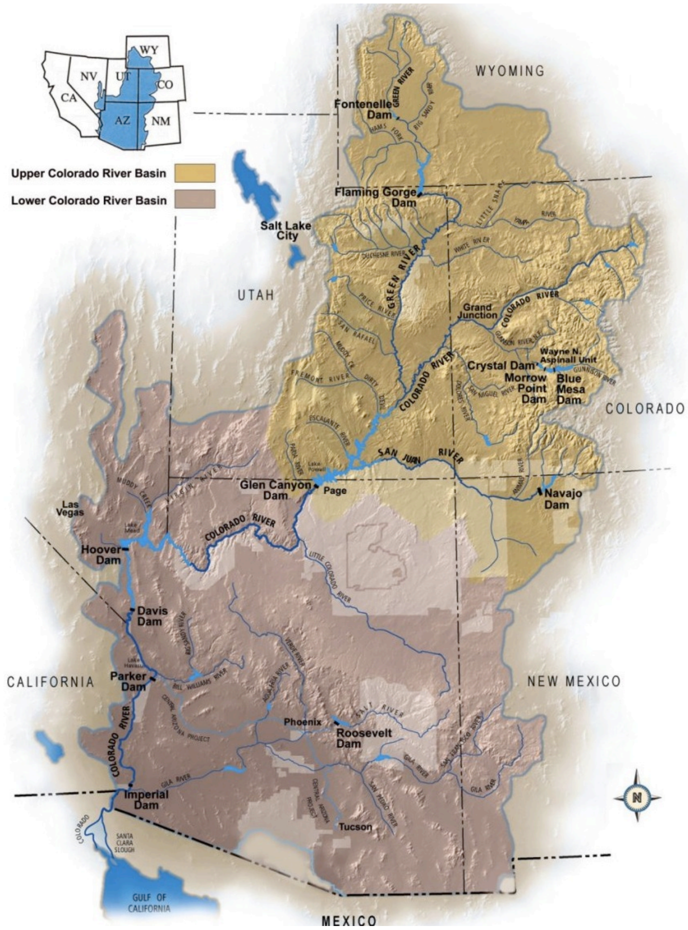
The Colorado River Compact[250] apportions surface water among the seven states that drain to the Colorado River. These states are Arizona, California, Colorado, Nevada, New Mexico, Utah, and Wyoming.[251] The Compact divides the watershed into upper and lower basins based on whether lands drain to the Colorado River at points above or below Lee Ferry,

---

[247] Robert M. Sengebush, INTERA Inc., *Deep Brackish Water Considered for New Mexico Development*, SOUTHWEST HYDROLOGY 8 (Mar./Apr. 2008).
[248] *Id*. (noting the deep aquifer contains approximately 12,000 mg/l total dissolved solids, 3,100 mg/l chloride, and 4,400 mg/l sulfate).
[249] The term "Law of the River" refers to the body of law that has developed around Colorado River management, including interstate compacts, Supreme Court decrees, an international treaty, and a large body of administrative law.
[250] 70 CONG. REC. 324 (1928) [hereinafter Colorado River Compact]. The Colorado River Compact is also codified by most of the compacting states. *See* ARIZ. REV. STAT. ANN. § 45-1311; COLO. REV. STAT. ANN. § 37-61-101; N.M. STAT. ANN. § 72-15-5; UTAH CODE ANN. § 73-12a-1; and WYO. STAT. ANN. § 41-12-301. Congress officially approved the Colorado River Compact in the Boulder Canyon Project Act, 43 U.S.C. § 617l.
[251] Colorado River Compact at Preamble.

Arizona.[252] Except for the southwest corner of Utah, Colorado, Utah, and Wyoming are located entirely within the upper basin; portions of Arizona and New Mexico are also located in the upper basin. The Upper and Lower Basins are illustrated in Figure 7.

Figure 7
Colorado River Basin [253]



Under the Compact, both the upper and lower basins are entitled to annual consumptive use of up to 7,500,000 AF of water.[254] The lower basin is also "given the right to increase its

[252] *Id.* at Art. II §§ (f) and (g). "Lee Ferry" and "Lee's Ferry" are distinct locations on the river. Lee Ferry is the hydrologic divide between the upper and lower basins and is used as the measurement point for the allocation between the 2 basins. Lee's Ferry, about a mile upstream of Lee Ferry, is the location of the U.S. Geological Survey's stream gauge. The Paria River enters the Colorado River between Lee's Ferry and Lee Ferry, so its gauged flow is added to the Lee's Ferry gauged flow to measure the upper basin's total delivery to the lower basin.
[253] Figure courtesy of the U.S. Bureau of Reclamation.
[254] Colorado River Compact at Art. III § (a).

beneficial consumptive use of such waters by one million acre-feet per annum."[255] Mexico is entitled to 1,500,000 AF pursuant to the Treaty with Mexico,[256] which is provided out of flows surplus to the upper and lower basins' entitlements. When surplus flows are unavailable the obligation to Mexico is born by an equal reduction in each basins' apportionment.[257]

The upper basin's 7,500,000 AF entitlement is misleading as the risk of shortages is not borne equally by all parties. In all but the most severe and prolonged droughts the upper basin is obligated to deliver an average of 7,500,000 AF of water at Lee Ferry.[258] Acceptance of this obligation was based on an overly optimistic assessment of water availability, and "surplus" flows are uncommon. Therefore, in most years the upper basin's apportionment can be reduced first to satisfy obligations to the lower basin and again to satisfy the upper basin's share of obligations to Mexico.[259] This has not been a major problem because upper basin use has averaged approximately 4,200,000 AF per year.[260] However, increasing water use and the prospect of reduced precipitation and prolonged drought periods will likely create tension in coming years. Upper Colorado River Basin water use is shown in Table 2.

---

[255] *Id.* at Art. III § (b). This right is satisfied after all other obligations have been met.
[256] Treaty Between the United States of America and Mexico Respecting Utilization of Waters of the Colorado and Tijuana Rivers and of the Rio Grande, Act of Feb. 3, 1944, U.S.-Mex. 59 Stat. 1219 at Art. 10.
[257] Colorado River Compact at Art. II § (c).
[258] *Id.* at Art. III §§ (a) and (d).
[259] Under very limited circumstances, the upper basin states' delivery obligations can be reduced to 7,480,000 AF if Lake Powell's storage capacity falls below 9,500,000 AF (39% of capacity) and Lake Mead is above the 1,025-foot elevation level. Delivery obligations can be reduced further to 7,0000,000 AF annually if Lake Powell's storage capacity falls below 5,900,000 AF (24% of capacity). U.S. DEPARTMENT OF INTERIOR, RECORD OF DECISION, COLORADO RIVER INTERIM GUIDELINES FOR LOWER BASIN SHORTAGES AND THE COORDINATED OPERATIONS FOR LAKE POWELL AND LAKE MEAD 50 (DEC. 2007). Such shortages have not occurred during the period of operation for these 2 facilities but appear possible based on longer term instream flow estimates and in light of modeled instream flow reductions attributable to climate change.
[260] *Bureau of Reclamation,* U.*S. Department of the Interior, Provisional Upper Colorado River Basin Consumptive Uses and Losses Report 2001-2005* (2007) and *2006-2010* (2009) *available at* http://www.usbr.gov/uc/library/envdocs/reports/crs/crsul.html.

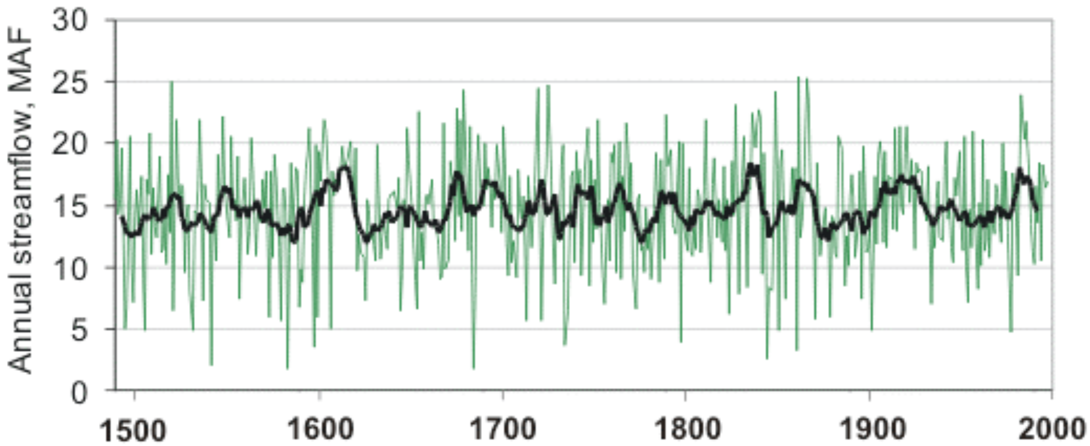
Table 2
Upper Colorado River Basin Water Use (1,000 AF)[261]

	2001	2002	2003	2004	2005	2006	2007	2001-2007 Average
Arizona	38	37	36	38	37	38	37	37
Colorado	2,330	2,123	2,079	1,893	1,856	2,028	1,961	2,039
New Mexico	403	334	383	408	466	393	415	400
Utah	967	811	878	830	853	825	678	835
Wyoming	430	438	437	369	405	460	516	436
Colorado River Storage Project Reservoir Evaporation	616	514	428	355	394	444	453	458
TOTAL	4,783	4,256	4,241	3,893	4,012	4,187	4,059	4,204

During Compact negotiations, it was widely assumed the Colorado River flows averaged at least 17,400,000 AF at Lee Ferry.[262] Flow from 1906 through 2005 averaged 15,072,000 AF, ranging between 5,399,000 and 25,432,000 AF.[263] Recognizing the significant variability in Colorado River flows and that gauged data may not provide an accurate assessment of either variability or average flows, several studies utilized tree-ring data to establish historic flow levels. These studies place average annual flow near Lee Ferry at between 13,000,000 and 14,700,000 AF.[264] In light of these river flow estimates, evaporation estimates, the upper basin states' obligation to the lower basin, and obligation to Mexico, the upper basin states are left with an average annual allocation of at most 6,000,000 AF – possibly much less.[265] Figure 8 shows reconstruction of annual streamflow for the Colorado River at Lee's Ferry, 1490-1997, with annual values in green and the ten-year running mean in black.

[261] Based on *id*.
[262] NORRIS HUNDLEY, JR., WATER AND THE WEST: THE COLORADO RIVER COMPACT AND THE POLITICS OF WATER IN THE AMERICAN WEST, 184 (1975). Compact negotiators are reported as claiming that the Colorado River had a total supply of as much as 21,600,000 AF. ERIC KUHN, THE COLORADO RIVER: THE STORY OF A QUEST FOR CERTAINTY ON A DIMINISHING RIVER 22 n. 63 (Roundtable Ed. May 8, 2007) (on file with authors).
[263] COLORADO RIVER INTERIM GUIDELINES FOR LOWER BASIN SHORTAGES AND COORDINATED OPERATIONS FOR LAKE POWELL AND LAKE MEAD, *supra* note 259 at 3-15.
[264] NATIONAL RESEARCH COUNCIL, *supra* note 75 at 104.
[265] The amount of water available to the upper basin states is a mater of considerable controversy. Eric Kuhn, General Manager of the Colorado River Water Conservancy District, evaluated several scenarios for determining water available to the upper basin after satisfying delivery obligations, concluding that upper basin states should plan on a reasonable yield of 5,250,000 AF. Notably, this estimate does not account for inflow reduction attributable to climate change and assumes shortages will occur in 6% of all years. *See* KUHN, *supra* note 262 at 104-05.

Figure 8
Reconstructed Streamflows at Lee's Ferry[266]



While the amount of water that will be available in the future is unknown, we do know how available resources are divided. The upper basin states' share of the Colorado River is apportioned according to the Upper Colorado River Compact.[267] Arizona receives 50,000 AF annually; Colorado, New Mexico, Utah, and Wyoming receive 51.75, 11.25, 23, and 14% of the remainder, respectively.[268] Applying these percentages to the 6,000,000 AF presumably available to the upper basin, Colorado's and Utah's average annual consumptive rights from the Colorado River and its tributaries are 3,079,000 and 1,369,000 AF, respectively. Despite disagreement about how best to quantify water use within each state, reasonable estimates are that, during an average year, Colorado has roughly 1,000,000 AF of unused appropriations under the Compact.[269] Utah has, during an average year, as much as 520,000 AF of unused

[266] Based on Woodhouse et al., *Updated Streamflow Reconstructions for the Upper Colorado River Basin*, WATER RESOURCES RESEARCH 42 (2006), as reported at: http://wwa.colorado.edu/treeflow/lees/woodhouse.html.

[267] Pub. L. No. 81-37, 63 Stat. 31 (1949) [hereinafter Upper Colorado River Compact]. With respect to state law, the Upper Colorado River Compact is codified at ARIZ. REV. STAT. ANN. § 45-1321; COLO. REV. STAT. ANN. § 37-62-101; N.M. STAT. ANN. § 72-15-26; UTAH CODE ANN. § 73-13-9; and WYO. STAT. ANN. § 41-12-401.

[268] Upper Colorado River Compact at Art. III § (a).

[269] Between 1998 and 2006, Colorado consumed an average of 2,060,000 AF of Colorado River Basin water annually. *See Provisional Upper Colorado River Basin Consumptive Use and Losses Reports supra* note 260. Given a right to consume up to 3,079,00 AF annually, Colorado has roughly 1,000,000 AF remaining.

Colorado River apportionments.[270] Though both Colorado and Utah appear to have sufficient water to proceed with significant oil shale and/or oil sands developments (setting aside non-Compact related constraints that will be discussed later), water is not always available when or where it would be needed.

1. The White River – a River Without a Compact

When water demand exceeds supply, junior right holders must either go without or secure more senior supplies. Both scenarios require knowledge of who owns competing water rights, the terms and conditions associated with those rights, and the competing rights' relative priorities. In the absence of information, the security of supplies is called into question, the value of competing water rights cannot be judged, and markets struggle to reallocate resources.

With respect to the White River, it is not know how much water Colorado must allow to pass downstream. Western Resource Advocates recently identified 114 proposed structures with conditional rights in Colorado's portion of the White River Basin that, if built, would enable total direct diversion of almost 5,700 CFS. Energy companies also control total decreed absolute diversion rights to approximately 200 CFS.[271] Exactly how much of this can be developed is unclear.

The Colorado River Compact and Upper Colorado River Compact apportion rights between respective states, but they do little to address management of interstate rivers.[272]

---

[270] Between 1998 and 2006, Utah consumed an average of 848,000 AF of Colorado River Basin water annually. *Id.* Given a right to consume up to 1,369,000 AF annually, Utah has roughly 520,000 AF remaining. This may, however, overstate Utah's remaining apportionment because the Division of Water Rights believes "Utah is currently depleting about 1,007,500 AF if its entitlement and all of the remaining water is covered by approves applications." Division of Water Rights, Utah Dept. of Natural Resources, 2009 Proposed Water Rights Policy Regarding Applications to Appropriate Water and Change Applications Which Divert Water From the Green River Between Flaming Gorge Dam and the Duchesne River 2 (hereinafter Proposed Green River Policy) *available at* http://www.waterrights.utah.gov/meetinfo/m20090820/policy-upcorviMC09L.pdf.

[271] MACDONNELL, *supra* note 260 at 7-9.

[272] The Upper Colorado River Compact contains an important exception to this general rule, requiring Colorado to deliver an average of 500,000 AF per year at a point on the Yampa River upstream of Dinosaur National Monument. The Yampa feeds into the Green River, which is a potential source of supply. Upper Colorado River Compact at Article XIII § (a). A Memorandum of Understanding (MOU) between Colorado and Utah for Pot Creek (in the Green River drainage) establishes a schedule of

While the White River is the logical source of supply for oil shale development, neither compact states how much water Colorado must leave in the river for Utah's downstream users, and no other interstate agreement governs the river's apportionment.[273] The lack of formal agreement has not been problematic because of limited development of water from the White River or its tributaries,[274] but is certain to change if demand increases. Colorado and Utah have three options for allocating interstate waters. They can proceed with litigation before the U.S. Supreme Court, they can enter into a negotiated agreement, or they can turn to Congress for resolution. These three options are addressed in turn.

In the absence of an agreement regarding their respective rights to the White River, Colorado and Utah could pursue litigation. The U.S. Supreme Court would hear a suit between the two states.[275] The Supreme Court applies rules of equity to apportion interstate rivers.[276] "The doctrine of equitable apportionment is a flexible rule that allows the Supreme Court to consider a variety of factors in determining what is a fair state share,"[277] and as such any equitable apportionment decision is highly fact specific.

In determining whether one state is "using, or threatening to use, more than its equitable

---

priorities for use in both states and defines a period before which direct flow diversions cannot be exercised, namely May 1 of each year. STATEWIDE WATER SUPPLY INITIATIVE*, supra* note 14 at 4-5.

[273] Colorado administers water rights within the White River Basin based solely on conditions within Colorado. Telephone interview with Erin C. H. Light, Division Engineer, Colo. Div. of Water Res. (Jan. 4, 2010).

[274] *Id*.

[275] *See* U.S. CONST. Art. III § 2. Under Utah law, the State Engineer is specifically authorized to file suit to resolve interstate allocation issues. UTAH CODE ANN. § 73-4-2. ("For the purpose of co-operating with the state engineers of adjoining states in the determination and administration of rights to interstate waters and for such other purposes as he may deem expedient, the state engineer, with the approval of the executive director and the governor, is authorized to initiate and to join in suits for the adjudication of such rights in the federal courts and in the courts of other states without requiring a petition of water users as provided by Section 73-4-1. The state engineer, with the approval of the executive director and the governor, may also commence, prosecute and defend suits to adjudicate interstate waters on behalf of this state or its citizens in the courts of other states, in federal courts, and in the Supreme Court of the United States.").

[276] *See e.g. Kansas v. Colorado*, 206 U.S. 46 (1907) (balancing equities by comparing the value of water use by competing states); *see also Hinderlider v. LaPlata River & Cherry Creek Ditch Co.*, 304 U.S. 92, 106 (1938) (holding that where the apportionment of the water of an interstate stream is made by compact, the apportionment is binding upon the citizens of each state and all water claimants, even where the state had granted the water rights before it entered into the compact).

[277] A. DAN TARLOCK, LAW OF WATER RIGHTS AND RESOURCES § 10.16 (2008).

share of the benefits of a stream, all of the factors which create equities in favor of one state or the other must be weighed as of the date when the controversy is mooted."[278] While "the effort always is to secure an equitable apportionment without quibbling over formulas,"[279] the key question is often the extent to which water has been put to a beneficial use "and among states with the same water law, the Court has applied the common law of the party states. Thus, prior appropriation applies among appropriation states."[280] But prior appropriations alone are not dispositive:

> [I]f an allocation between appropriation States is to be just and equitable, strict adherence to the priority rule may not be possible. For example, the economy of a region may have been established on the basis of junior appropriations. So far as possible those established uses should be protected though strict application of the priority rule might jeopardize them. Apportionment calls for the exercise of an informed judgment on a consideration of many factors. Priority of appropriation is the guiding principle. But physical and climatic conditions, the consumptive use of water in the several sections of the river, the character and rate of return flows, the extent of established uses, the availability of storage water, the practical effect of wasteful uses on downstream areas, the damage to upstream areas as compared to the benefits to downstream areas if a limitation is imposed on the former – these are all relevant factors.[281]

Factors other than priority have increased in importance over time. The Court, in allocating a small stream between Colorado and New Mexico, faced questions about both the efficiency of competing water uses and the proper weight afforded to competing harms and benefits.[282] In an opinion marking an increased emphasis on efficiency and relative harm, Justice Marshall wrote:

> We recognize that the equities supporting the protection of existing economics will usually be compelling. The harm that may result from disrupting established uses is typically certain and immediate, whereas the potential benefits from a proposed diversion may be speculative and remote. Under some circumstances, however, the countervailing equities supporting a diversion for future use in one state may justify the detriment to existing users in another state. This may be the case, for example, where the state seeking a diversion demonstrates by clear

[278] *Colorado v. Kansas*, 320 U.S. 383, 394 (1943).
[279] *New Jersey v. New York*, 283 U.S. 336, 343 (1931), *accord Colorado v. New Mexico*, 459 U.S. 176, 183 (1982).
[280] LAW OF WATER RIGHTS AND RESOURCES, *supra* note 277 at § 10.15
[281] *Nebraska v. Wyoming*, 325 U.S. 589, 618 (1945).
[282] *Colorado v. New Mexico*, 459 U.S. 176 (1982).

> and convincing evidence that the benefits of the diversion substantially outweigh the harm that might result. In the determination of whether the state proposing the diversion has carried this burden, an important consideration is whether the existing users could offset the diversion by reasonable conservation measures to prevent waste. This approach comports with our emphasis on flexibility in equitable apportionment and also accords sufficient protection to existing uses.[283]

As interstate allocation decisions are highly fact dependent and the weight the Court gives to various considerations is an evolving matter of law, neither Colorado nor Utah can be confident in the outcome of suit to apportion their respective rights in the White River. Moreover, resolving interstate allocation disputes can take many years that may not be practicable in the face of a pressing dispute.[284] Even if resolution is obtained, the relief proscribed by the Court will not include the kinds of detailed administrative procedures that are needed and possible under an interstate compact, effectively forcing the states to negotiate day-to-day management.

Rather than allow uncertainty to fester or rely on what would almost certainly be long and complex litigation that cannot address the full range of issues, the states could negotiate a compact for the White River.[285] Such compact negotiations were proposed at least once before.[286] Under Article I § 10 of the U.S. Constitution, "No State shall, without the Consent of Congress . . . enter into any Agreement or Compact with another State." Congressional ratification is therefore required for all interstate compacts, whether granted implicitly or explicitly, and whether granted before or after negotiations are complete.[287] Upon ratification, an

[283] *Colorado v. New Mexico*, 459 U.S. at 187-88.
[284] For example, litigation between the states of Kansas and Colorado, regarding diversions from the Arkansas River system, were only recently resolved after 24 years of litigation. *See* SOUTHWEST HYDROLOGY, *KS, CO Reach Arkansas River Agreement* 14 (Jan./Feb. 2010).
[285] The Supreme Court disfavors equitable apportionment cases, preferring states to resolve matters on their own. *Texas v. New Mexico*, 462. U.S. 544, 567 n.13 (1983). Negotiated settlements also avoid a potential thicket of procedural problems such as ripeness. *See e.g.* ROBERT E. BECK AND AMY L. KELLEY, EDS., WATER AND WATER RIGHTS §§ 45.02 – 45.04 (3d ed. 2009).
[286] Letter from Utah Governor Calvin L. Rampton to Colorado Governor John D. Vanderhoof, (Dec. 11, 1973) (on file with authors).
[287] LAW OF WATER RIGHTS AND RESOURCES, *supra* note 277 at § 10.25.

interstate compact operates both as federal law and as a contract between the states.[288] Even though interstate compacts are generally preferable to litigation, they to can leave issues unresolved and lead to protracted legal battles.[289]

A third alternative means of allocating White River flows is for Congress to apportion the states' respective rights. The Commerce Clause of the U.S. Constitution provides Congress with authority to allocate interstate rivers to further federal interests.[290] Removing barriers to interstate commerce, increasing domestic energy production, and reducing reliance on imported oil would further a federal interest. However, congressional action may not result in a resolution amenable to the parties involved, and Congress has been reluctant to apportion interstate rivers through legislation, acting only when negotiations break down and litigation proves impractical.[291]

Clarification of Colorado's and Utah's respective rights to the White River would greatly aid efficient resource allocation. Absent resolution, rights to a prime water source are uncertain. An interstate compact apportioning the White River is preferable to the alternatives as a compact affords the states an opportunity to consider a broad range of competing water uses,

---

[288] *Id.* at § 10.25. Less formal agreements that do not increase the political power of the states at the expense of the federal government and do not rise to the level of a compact can also encapsulate a binding agreement between the party states while avoiding the congressional ratification requirement. *See Northeast Bankcorp, Inc. v. Board of Governors*, 472 U.S. 159 (1985), and *United States Steel Corp. v. Multistate Tax Comm'n*, 434 U.S. 452 (1978). However, such procedural expediencies may be outweighed by the prospect that such an agreement would be challenged as a compact masquerading as a contract and failing to satisfy constitutional requirements. The Draft Agreement for Management of the Snake Valley Groundwater System between the states of Utah and Nevada is an example of a non-compact interstate agreement. The Draft Agreement expressly states that it "is not intended to be an interstate compact," and is being entered into "with the intention of avoiding an equitable apportionment action regarding the Snake Valley Groundwater Basin in the United States Supreme Court." *Agreement for Management of the Snake Valley Groundwater System* 1 (draft submitted for public comment and *available at* http://waterrights.utah.gov/snakeValleyAgreement/snakeValley.asp). *See also*, Pot Creek MOU, *supra* note 272.

[289] *See e.g.* SOUTHWEST HYDROLOGY, *KS, CO Reach Arkansas River Agreement* 14 (Jan./Feb. 2010) (discussing pending settlement of interstate allocation dispute); *see also* SOUTHWEST HYDROLOGY, *Pecos River Settlement Implemented* 16, (Jan./Feb. 2010) (discussing efforts to implement six-year-old Pecos River Compact).

[290] *See e.g.*, *Arizona v. California*, 373 U.S. 546 (1963).

[291] *See e.g.*, the Boulder Canyon Project Act, 43 U.S.C. § 617 – 617f (apportioning flows of the lower Colorado River) and the Truckee-Carson-Pyramid Lake Water Rights Settlement Act, Pub. L. 101-618 (1990) (apportioning the Truckee River basin between California and Nevada). Both Acts were passed only after years of conflict and failed attempts to resolve disputes through other means.

crafting more flexible allocation formulas and enforcement mechanisms than those likely to result form litigation of congressional apportionment. Increasing interest in commercial oil shale and oil sands development may provide the impetus to resurrect compact negotiations, and improving certainty regarding water availability would benefit all water planers in this arid region.

I. Reserved Rights

When the federal government reserves land for a specific purpose, it impliedly reserves the right to sufficient water to serve the primary purpose of the reservation. These "reserved rights" carry a priority date reflecting the date upon which the reservation was created or its associated use began. Where reservations were created long ago, the resulting reserved rights can be some of the most senior water rights within a basin. Two classes of reserved rights are important for oil shale and oil sands development: Tribal reserved water rights, and reserved rights for Naval Oil Shale Reserves. These are addressed in turn.

1. Indian Reserved Rights

Indian reserved rights are often created when Indian reservations are established. With regard to potential oil shale and oil sands development, the Uintah and Ouray Reservation, which is home to the Northern Ute Tribe of Indians, is by far the most important because of its proximity to oil shale and oil sands resources, extensive claims, and progress in settling reserved rights claims. While less effort has gone into settling the Navajo Nation's reserved rights claims and the Navajo Nation is well removed from oil shale resources, they remain a potential source of water for oil sands development in southern Utah – assuming a long list of intermediate steps fall into place.

The Uintah and Ouray Indian Reservation, located in Utah's Uinta Basin, was established by Executive Order in 1861.[292] According to the Northern Utes, the Uintah and

[292] For a detailed discussion of reservation establishment and subsequent modifications, *see Ute Indian Tribe v. State of Utah*, 521 F.Supp. 1072, 1092-1150 (D. Utah 1981) (involving reservation disestablishment and jurisdictional implications). While Ute Indian Tribe was reversed in part, it contains a wealth of valuable, historic information.

Ouray Reservation is the second largest Indian Reservation in the United States, covering over 4,500,000 AC and containing approximately 1,300,000 AC of trust land.[293]

The landmark case, *Winters v. United States*[294] held that the creation of federally recognized Indian reservations impliedly reserved to the Indians the water needed to meet the needs of the reservation, even if water rights are not expressly discussed or quantified in the treaty or executive order creating the reservation.[295] The priority date associated with Indian reserved rights is generally the date upon which the reservation was created.[296] Unlike water rights granted under state law, *Winters'* rights are not subject to forfeiture or abandonment for nonuse.[297] Reserved rights claims must be satisfied by the states in which the reservation lies and will be debited against the state's Colorado River apportionment.[298]

Quantification of Indian reserved rights is no simple task. "How many Indians there will be and what their future needs will be can only be guessed . . . . [T]he only feasible and fair way by which reserved water for the reservations can be measured is irrigable acreage."[299] In the leading case quantifying irrigable acreage, *In re General Adjudication of All Rights to Use Water in the Big Horn River System* (*Big Horn I*),[300] the Wyoming Supreme Court determined the primary purpose of the Wind River Indian Reservation was to promote agriculture among the resident tribes and that the proper measure of the tribes' reserved rights was "those acres

---

[293] *See* The Ute Indian Tribe, http://www.utetribe.com/. The Uintah Valley Indian Reservation was created by Executive Order in 1861. The Spanish Fork Reservation was created by treaty on June 6, 1865. The 2 were subsequently combined into the Uinta and Ouray Indian Reservation.
[294] 207 U.S. 564, 577 (1908).
[295] The reserved rights doctrine was extended to reservations created by Executive Order in *United States v. Walker River Irrigation Dist*., 104 F.2d 334,336 (9th Cir 1939).
[296] *Arizona v. California*, 373 U.S. 546, 600 (1963) (holding the United States reserved water rights for the Indians effective as of the time reservations were created). *But see U.S. v. Adair*, 723 F.2d 1394, 1414, (9th Cir. 1983) (when "a tribe shows its aboriginal use of water to support a hunting and fishing lifestyle, and then enters into a treaty with the United States that reserves this aboriginal use, the water right thereby established retains a priority date of the first or immemorial use.").
[297] *See e.g*., *In re General Adjudication of All Rights to Use of Water in Gila River System and Source*, 35 P.3d 68, 72 (Ariz. 2001).
[298] *Arizona v. California*, 376, U.S. 340, 346 (1964) (holding water delivered to the tribes is to be applied against the total allocation for each state within which the reservation is located).
[299] *Arizona v. California*, 373 U.S. 546, 601 (1963).
[300] 753 P.2d 76 (Wyo. 1988), *aff'd by equally divided Court*, 492 U.S. 406 (1989).

susceptible to sustained irrigation at reasonable costs."[301] This is known as the practicable irrigable acreage (PIA) standard. PIA has been criticized for including projects that are unlikely to be developed.[302] Conversely, where reservations were established in particularly harsh and arid areas, little if any of the reservation may meet minimum economic feasibility standards, and tribes could be left with very little water.[303] In light of these concerns, the Arizona Supreme Court rejected PIA, choosing instead to balance a "myriad of factors" in quantifying reserved rights.[304] The Arizona Court noted "the essential purpose of Indian reservations is to provide Native American people with a 'permanent home and abiding place,' that is, a 'livable' environment."[305] It went on to explain that:

> Other right holders are not constrained in this, the twenty-first century, to use water in the same manner as their ancestors in the 1800s. . . . [A]griculture has steadily decreased as a percentage of our gross domestic product. Just as the nation's economy has evolved, nothing should prevent tribes from diversifying their economies if they so choose and are reasonably able to do so. The permanent homeland concept allows for this flexibility and practicality. We therefore hold that the purpose of a federal Indian reservation is to serve as a 'permanent home and abiding place' to the Native American people living there.[306]

Great effort has gone into quantifying the Northern Utes' reserved rights, resulting in two draft settlements.[307] Negotiations during the 1980s and 1990s resulted in the Ute Indian Rights Settlement, which was contained in the federal government's Reclamation Projects Authorization and Adjustment Act of 1992.[308] Believing that an agreement was at hand, the

---

[301] 753 P.2d at 101.

[302] *See* Brief of Amici Curiae Sates of California et al. in Support of the Petitioner at 10, *Wyoming v. United States*, 492 U.S. 406 (1989) (No. 88-390).

[303] *See e.g.,* State *ex rel.* Martinez v. Lewis, 861 P.2d 235, 250 (N.M. Ct. App. 1993).

[304] *In re* General Adjudication of All Rights to Use Water in Gila River System and Source (Gila V), 35 P.3d 68, 79-80 (Ariz. 2001) (identifying 5 non-exclusive considerations for quantifying reserved rights: (1) the tribe's history and culture, (2) "the tribal land's geography, topography, and natural resources, including groundwater availability," (3) the reservations "[p]hysical infrastructure, human resources, including present and potential employment base, technology, raw materials, financial resources, and capital," (4) past water use, and (5) "a tribe's present and projected future population.").

[305] 35 P.3d at 74 (quoting *Winters*, 207 U.S. at 565 and *Arizona I*, 373 U.S. at 599).

[306] 35 P.3d at 76 (internal quotations and citations omitted).

[307] *See e.g.*, Utah Laws of 1980, c. 74 §§ 1 and 2.; UTAH CODE ANN. §§ 73-21-1 and -2; and Pub. L. 102-575 at §§ 501-07.

[308] Pub. Law 102-575 at §§ 501 – 507 (1992).

State of Utah codified the Ute Indian Water Compact into state law, subject to ratification by the parties.[309] Under the settlement, the state would be responsible for diverting water into the reservation water system, and the Northern Utes and federal government would be responsible for subsequent administration within the reservation.[310] The Northern Utes, however, did not ratify the Compact.[311] It appears that the primary obstacle to ratification was not the volume of water available to the Northern Utes, but the allocation of administrative responsibility.

Since the stumbling blocks to ratification have thus far involved administration rather than the quantity, seniority, or potential use of the Northern Utes' water, the Ute Indian Water Compact is a reasonable starting point for discussing the Tribe's rights. Under the Compact, the Northern Utes would obtain the right to divert a total of up to 471,035 AF of water annually, with the right to deplete up to 248,943 AF.[312] The Tribe would have the right to divert 66,502 AF from the White River and its tributaries, consuming up to 32,880 AF. The Northern Utes could divert up to 271,733 AF from the Duchesne River and its tributaries, consuming up to 148,752 AF. The Tribe could also divert up to 132,359 AF from the Green River, consuming up to 67,311 AF.[313] The priority date for these rights would be 1861 or 1882, except when water is supplied from storage in the Central Utah Project.[314] The Tribe would receive an additional 10,000 AF of depletions from the Green River subject to an October 3, 1861 priority date.[315] The volume of water was based on a report, commissioned by the Northern Utes, identifying

[309] UTAH CODE ANN. §§ 73-21-1 and -2.
[310] *Id.* at § 73-21-2.
[311] *See* DANIEL MCCOOL, NATIVE WATERS: CONTEMPORARY INDIAN WATER SETTLEMENTS AND THE SECOND TREATY ERA 177-82 (2002) (discussing the history of settlement negotiations); *see also* DANIEL MCCOOL, *The Northern Utes' Long Water Ordeal*, HIGH COUNTRY NEWS 8-9 (July 15, 1991) (same). For a detailed discussion of prior efforts to resolve the Northern Ute's water rights, including an extensive discussion of concerns over state administration, *see* JOHN SHURTS, INDIAN RESERVED WATER RIGHTS: THE WINTERS DOCTRINE IN ITS SOCIAL AND LEGAL CONTEXT, 1880S-1930S (2000). Another area of concern involved restrictions on transfers of water to users in the lower basin. *See* Pub. Law 102-575 at § 503(c) (1992) and NATIVE WATERS AT 174 (discussing concerns over potential transfer to Las Vegas and southern Nevada).
[312] UTAH CODE ANN. §§ 73-21-1 and -2.
[313] Ute Indian Tribe of the Uintah and Ouray Reservation, Utah, Tabulation of Ute Indian Water Rights 8-9 (Oct. 1990) (on file with authors).
[314] UTAH CODE ANN. § 73-21-2.
[315] *Id.* at § 73-21-2.

existing and potentially irrigable acreage as well as the water duty associated with various areas.[316] To put this into perspective, at a water to oil ratio of 3:1, consumptive rights on the White River alone could support over 230,000 BPD production. If the Tribe leased half its water rights for the Green and White River systems and retained all of its rights to the Duchesne River system, leased rights could support almost 400,000 BPD production.[317] This is not meant to imply that the Tribe would support oil shale or oil sands development, only highlight the transformative effect such a decision could have.

Moreover, under the Ute Indian Water Compact, the Northern Utes' water "shall not be restricted to any particular use, but may be used for any purpose selected by the Tribe," including "sale, lease, or any other use whatsoever."[318] Accordingly, the Northern Utes could change the point of diversion, place of use, or nature of use, but such changes would be subject to state law, thus protecting other water users from injury.[319] The Compact anticipates that water could be transferred from tribal lands, subject to the requirements of state law and approval of the Secretary of Interior.[320] The ability to change the point of diversion as well as the nature and place of use provide important flexibility for adapting to the needs of a fledgling oil shale and/or oil sands industry – assuming the Northern Utes choose to support development. If allowed, changes in the place of use could make water available at much lower cost by eliminating the need to construct pipelines and associated infrastructure.

As extensive and well positioned as their water rights may be, they were quantified based on agricultural use and PIA acreage,[321] and therefore include seasonal limits coinciding with the irrigation season. Diversionary rights are available April 10th through October 10th and

---

[316] Tabulation of Ute Indian Water Rights, *supra* note 313 at 1.
[317] For Alberta's oil sands industry to develop comparable levels of production took roughly 20 and 30 years, respectively. *See* CANADIAN ASS'N OF PETROLEUM PRODUCERS, *supra* note 97.
[318] *Id.* at § 73-21-2.
[319] *Id.* at § 73-21-2, Art. III.
[320] *Id.* at § 73-21-2. Note, however, that because water rights are property rights, they are subject to the Indian Non-Intercourse Act's prohibition against conveyances of Indian property without federal consent. 25 U.S.C. § 177.
[321] Tabulation of Ute Indian Water Rights, *supra* note 313 at 10-13.

the rate of diversion varies throughout that period.[322] Since the right to use water under the settlement is seasonal in nature while the energy industry's needs are year-round, industrial use of tribal water rights would require either a change to allow year-round use or water storage. It is also important to note that the exercise of Indian reserved water rights is likely subject to restrictions imposed by the ESA.[323]

Even with settlement of the Northern Utes' reserved rights claims, full utilization would require a significant investment in infrastructure. Construction, while normally slow and difficult, could be expedited by financial settlements contained in the Ute Indian Rights Settlement[324] or by significant investments from oil shale, oil sands, or power development interests.

The breadth of the proposed settlement, if finalized in similar form, has the potential to shape commercial oil shale and oil sands development. The Northern Ute's water rights would be senior to all but a handful of water rights within the basin and therefore not subject to call during times of shortage. If reserved rights can be conveyed to other users and utilized off the reservation without interfering with other water rights, reserved rights could support significant development. Changes in the place or manner of use, if approved, could reduce conveyance costs significantly. The Tribe would be in a powerful position to provide water for commercial oil

---

[322] *Id.* at at 10-13.

[323] *See e.g.,* Adrian N. Hansen, *Note, The Endangered Species Act and Extinction of Reserved Rights on the San Juan River*, 37 ARIZ. L. REV. 1305 (1995) (concluding enforcement of the ESA precluded new Indian water projects along the San Juan River, interfering with the tribes' ability to use their senior water rights).

[324] Pub. L. 102-575 § 502. (1992). Recognizing that development of water rights in the arid Uinta Basin would require significant infrastructure and that the federal government had not lived up to its obligations to the Tribe, (as part of the Central Utah Project, the Tribe was promised federal Reclamation facilities which were never built). WATERS OF ZION, THE POLITICS OF WATER IN UTAH (Daniel McCool, ed. 1995), the federal Ute Indian Rights Settlement included significant financial payments in lieu of completion of certain federal reclamation projects. Section 502(a) specifically provided that for 50 years, the federal government would make annual payments equivalent to 26% of the cost associated with 35,500 AF of municipal and industrial water delivered to the Bonneville Basin. The annual value of these payments was estimated at $2,000,000 in 1993. Memorandum from George Waters Consulting Services to the Ute Business Committee, Re: Appropriations for the Ute Indian Rights Settlement Act (June 28, 1993) (on file with authors). After expiration of the 50-year period, the Tribe would receive, in perpetuity, annual payments equivalent to 7 % of the cost associated with 35,500 AF of municipal and industrial water delivered to the Bonneville Basin. Pub. L. 102-575 § 502(a)(2)(B) (1992). Additional funds were authorized for tribal economic development, upgrade agricultural opportunities, and improve facilities and resource conditions. *See id*. at §§ 504 - 506 (1992). Altogether, the total financial settlement was valued at over $295,000,000 in 1993 dollars.

shale and/or oil sands development, should they so choose. Conversely, a decision to utilize water rights for other purposes would make water for oil shale and oil sands development harder to obtain. Regardless of how the Northern Ute's water rights are put to use, these water rights are likely to displace many junior right holders and upset what has long been a fairly stable allocation of resources. Accordingly, resolution of tribal reserved rights and clarification of water development plans should be a high priority.

Navajo reserved rights claims are subject to the same legal considerations and quantification dilemmas. While the Navajo Nation is far from Utah's oil shale resources, it is much closer to oil sands, and the White Canyon STSA in particular. However, comparatively little effort has gone into settling the Navajo Nation's reserved rights claims within Utah. Given the time and effort required to settle such claims, Navajo water rights are unlikely to represent a viable near-term source of supply for oil shale or oil sands development.

2. Reserved Rights for Naval Oil Shale Reserves

Reserved water rights can be created any time the federal government reserves land.[325] The priority date is generally the date upon which the reservation was created and the quantity of water reserved is that required to fulfill the primary purpose of the reservation.[326] In the early 20th century, with the U.S. Navy transitioning from coal to liquid fuels and concerned over fuel availability, the President issued a series of executive orders setting aside three federal oil shale reserves. Naval Oil Shale Reserves (NOSRs) Nos. 1 (36,406 AC) and 3 (20,171 AC) are located eight miles west of Rifle, Colorado. Reserve No. 2 (88,890 AC) is located in Utah's Carbon and Uintah counties.[327]

[325] *Cappaert v. United States*, 426 U.S. 128, 138 (1976). However, a federal reservation can expressly disclaim reserved water rights, as was the case with creation of the Grand Staircase-Escalante National Monument. *See* Sept. 9, 1996 Presidential Proclamation establishing the Grand Staircase-Escalante National Monument, *available at* 32 WEEKLY COMPILATION OF PRESIDENTIAL DOCUMENTS 38 at 1788-91 (Sept. 23, 1996).
[326] *United States v. New Mexico*, 438 U.S. 696, 718 (1978).
[327] ANDREWS, *supra* note 193 at 2.

In 1971, the United States filed a statement of claim with the Colorado Water Court, seeking confirmation of its reserved water rights for NOSR Nos. 1 and 3.[328] In amended filings, the United States asserted the right to divert 100 CFS from the mainstem of the Colorado River at the Anvil Points Diversion, near NOSR Nos. 1 or 3.[329] The Colorado Supreme Court assumed without deciding that the NOSRs created a federal reserved right. The court's decision, however, subordinated the federal right to other state rights because the federal government failed to comply with procedural requirements.[330] It appears that the federal government retains reserved rights to NOSR Nos. 1 and 3. However, the value of these rights is presumably low, at least absent associated storage, because of their late priority date.[331] Nonetheless, the potential existence of reserved rights associated with the 145,467 AC contained in the original Naval Oil Shale Reserves deserves further investigation and could affect water availability for contemporary oil shale development.

The National Defense Authorization Act of 2000[332] transferred NOSR No. 2 to the Northern Ute Indian Tribe,[333] which received the land, including mineral rights, in fee simple and not subject to federal trust management.[334] The transfer of NOSR no. 2 may have terminated reserved right claims because the Act specifically states, "[e]ach withdrawal that applies to NOSR No. 2 and that is in effect on the date of the enactment . . . is revoked to the extent that the withdrawal applies to NOSR No. 2."[335] However, the Tribe can claim reserved rights independent of NOSR status as the lands were part of the Tribe's reservation before creation of NOSR-2.[336] Alternatively, the Northern Utes can claim that "withdrawal," as used in the act,

---

328 *See United States v. Bell*, 724 P.2d 631, 634 (Colo. 1986).
329 *See id.* at 635.
330 *Id.*
331 *See United States v. Bell*, 724 P.2d 631,635 (Colo. 1986).
332 Pub. L. 106-398.
333 ANDREWS, *supra* note 193 at 28.
334 Pub. L. 106-398 § 3405(b) and (c).
335 *Id.* at § 3405(c)(5).
336 Courts have generally found that reacquired lands retain reserved water rights; most disagreements involve the priority associated with reserved rights for reacquired lands. *See* BECK AND KELLEY, *supra* note 285 at § 37.02(f)(3) for a discussion of the issues associated with reacquired lands.

means mineral withdrawal and does not affect reserved rights. The basis of the reserved right is important because it affects both the priority date and the purposes to which the water may be put to use. Under *U.S. v. New Mexico*, reserved rights for federal lands are limited to the primary purpose of the reservation,[337] thus limiting a reserved right to waters needed to produce oil shale from the reservation. Indian reserved rights are normally available for more expansive purposes.[338] The basis for the claim therefore determines how much water is available and where it can be used as well as the priority date. If these issues are not resolved through negotiated settlement of all tribal reserved rights claims,[339] additional investigations will be needed.

J. Making More Water Available

While reallocation reflects the simplest path forward, increasing competition for water resources will drive interest in developing "new" sources of water. Four potential new sources are: water produced through precipitation augmentation (cloud seeding), water imported from other basins, reuse of water produced through natural gas production, and conservation. These are addressed in turn.

1. Precipitation Augmentation

Precipitation augmentation, or cloud seeding, is not new to the Colorado River Basin. Local water users in central Utah began seeding clouds as early as the 1950's. The State of Utah began funding projects in 1973 and large-scale seeding projects have been ongoing ever since. During 2007, there were six active cloud seeding projects in Utah, utilizing 148 generators and reportedly increasing seasonal precipitation by between 2 and 20%.[340] Four of these projects target areas within the Colorado River Basin, and four potential new target zones

---

[337] *United States v. New Mexico*, 438 U.S. 696, 718 (1978).
[338] *See generally*, section I.I.1., *supra*.
[339] *Id*.
[340] http://www.water.utah.gov/cloudseeding/CurrentProjects/Default.asp.

have been identified within the basin.[341] Utah's cloud seeding projects generally operate December through March and are intended to increase snowfall. Snowmelt is captured as spring runoff and used to fill reservoirs through the state, providing water throughout the year.[342]

Colorado's cloud seeding operations and research has been underway since the 1950s and, like Utah, focuses on increasing snowfall. In Colorado, there are ten operational cloud seeding target areas that overlay at least a portion of the Colorado River Basin and five additional areas within the basin identified as potential target areas.[343]

Precipitation resulting from cloud seeding is indistinguishable from natural precipitation and available for appropriation through existing state regulatory programs.[344] Accordingly, few cloud seeding operations are privately funded because of difficulties capturing the direct benefits.[345] While difficult to test empirically, cloud seeding may increase precipitation by between 5 and 20%.[346] Streamflow model simulations conducted by the National Weather Service predicted that new cloud seeding programs together with augmentation of existing programs could produce an average increase of 1,227,000 AF of runoff into Lake Powell, and that new seeding programs in Arizona could gain an additional 154,000 AF of runoff.[347] Preliminary cost estimates indicate that full development of these programs would cost around

---

[341] Don A. Griffith and Mark E. Solak, *Cloud Seeding in the Upper Colorado Basin: Technical Feasibility*, SOUTHWEST HYDROLOGY 19 (March/April 2007).

[342] Wyoming recently initiated 5-year pilot projects using weather modification to increase snowpack over the Medicine Bow/Sierra Madre Mountains and the Wind River Range. http://www.rap.ucar.edu/projects/wyoming/. The Wind River Range is in the Green River Basin and precipitation would eventually flow into Utah and the Colorado River. Two potential future target areas within the Colorado River Basin have also been identified. Griffith and Solak, *supra* note 341 at 19.

[343] *Id*. at 19. The Southern Nevada Water Authority apparently believes precipitation augmentation can improve water availability in portions of the Colorado River basin. According to Southwest Hydrology and the Las-Vegas Review Journal, "SNWA has already been funding cloud seeding in Colorado areas that provide snowmelt to the Colorado River, Las Vegas's [sic] primary water source." SOUTHWEST HYDROLOGY, *SNWA Supports Cloud Seeding* 17 (Jan./Feb. 2010).

[344] UTAH CODE ANN. § 73-15-4.

[345] *But see*, Samantha Young, *Governments Turn to Cloud Seeding to Fight Drought*, U.S. NEWS & WORLD REPORT (Dec. 11, 2009) (discussing public-private cloud seeding partnerships).

[346] AMERICAN SOCIETY OF CIVIL ENGINEERS, GUIDELINES FOR CLOUD SEEDING TO AUGMENT PRECIPITATION 1 (2d. ed. 2006).

[347] Griffith and Solak, *supra* note 341 at 19.

$7,000,000 annually, or approximately $5 per AF.[348] If accurate, the amount of potential increases and their relatively low cost make cloud seeding an attractive technology.

Recent studies suggest that precipitation gains from cloud seeding may be offset by precipitation reduction due to air pollution. While cloud seeding injects silver iodide or similar cloud condensation nuclei to enhance downwind precipitation, air pollution introduces much smaller particles into the atmosphere. These smaller, more numerous particles create clouds with higher droplet concentrations but smaller droplet diameter. These smaller droplets often fail to reach the critical mass required to fall as rain or snow,[349] and reductions in precipitation can offset gains resulting from cloud seeding.[350] Reductions in precipitation of between 15 and 25% were tied to air pollution in California and Israel.[351] Subsequent research attributed 30% or greater reduction in snowfall in Colorado's Rocky Mountains to pollution occurring in the Denver and Colorado Springs areas.[352] Not only can pollution reduce precipitation, it can accelerate snowmelt. Forthcoming research from the Department of Energy reportedly shows that "pollution from automobile and coal-fired power plants is contributing to the melting of mountain snowpacks as much as a month early, thereby exacerbating water shortages and other problems across the parched western United States."[353]

These changes in precipitation are distinct from the impacts of climate change, but could increase its effect. Such changes would make water-intensive development even more difficult

---

348 *Id.* at 19.

349 Randolph D. Borys et. all, *Mountaintop and Radar Measurements of Anthropogenic Aerosol Effects on Snow Growth and Snowfall Rate*, 30 GEOPHYSICAL RESEARCH LETTERS No, 10, 1538 at 45-1 (May 2003); *see also* Amir Givati and Daniel Rosenfeld, *Separation Between Cloud-Seeding and Air-Pollution Effects*, 44 JOURNAL OF APPLIED METEOROLOGY 1298-1314 (2005); *see also* Daniel Rosenfeld and William L. Woodley, *The Double-Sided Sensitivity of Clouds to Air Pollution & Intentional Seeding* 21 SOUTHWEST HYDROLOGY (March/April 2007).

350 Givati and Rosenfeld, *supra* note 349 at 1298.

351 Amir Givati and Daniel Rosenfeld, *Quantifying Precipitation Suppression Due to Air Pollution*, 43 JOURNAL OF APPLIED METEOROLOGY 1038 (2004).

352 Borys et. all, *supra* note 349 at 45-1; Israel L. Jirak and William R. Cotton, *Notes and Correspondence: Effects of Air Pollution on Precipitation Along the Front Range of the Rocky Mountains*, 45 JOURNAL OF APPLIED METEOROLOGY AND CLIMATOLOGY 236 (2005).

353 Scott Streater, *Water: New Study Details Effects of Soot Pollution in Snowpack, Water Supply in West*, PUBLIC LANDS LETTER (Jan. 22, 2009).

and renew calls for additional water storage. How these factors will interact to affect precipitation is unclear, but they portend greater precipitation variability. Any decrease in precipitation would exacerbate competition for scarce water resources and reductions in precipitation would likely raise concern not just in Colorado (which obtains most of its water from snowfall in areas downwind of the Uinta and Piceance basins), but also in the other basin states that depend on snowfall for Colorado River flows.

2. Water Importation

A second option to increase water within the Colorado River Basin is to import water. As the Office of Technology Assessment noted in anticipation of the last predicted oil shale boom:

> Water could be transferred directly to the oil shale region, either exclusively for oil shale development or for all users. Alternatively, the water needs of Colorado's eastern slope cities, presently being supplied in part from the Upper Colorado River Basin, could be met from other hydrologic basins. The water presently being exported from the Upper Basin then could be used for oil shale development. In a third application of interbasin transfers, all or a portion of the 750,000 acre-ft/yr presently being supplied to Mexico by the Upper Basin States under the Mexican Water Treaty of 1944-45, could be taken from another hydrological basin (perhaps the Mississippi basin). The water thus freed in the Upper Basin could be assigned in part to oil shale development (750,000 acre-ft/yr would be sufficient for a 3-million- to 7.5-million-bbl/d shale oil industry).[354]

Exxon proposed water importation during the oil shale boom of the 1970s and 1980s.[355] As proposed, a 680-mile long, nine-foot-diameter pipeline would have originated at the Oahe Reservoir on the Missouri River in South Dakota, bringing 1,100,000 AF of water yearly to the Piceance Basin.[356] As of 1980, the cost of water delivered via this project was estimated at between $950 and $1,150 per AF.[357] The Office of Technology Assessment mentioned the possibility of importing water from the Yellowstone or Columbia rivers, estimating the economic cost of importation at $750 and $1,520 per AF, respectively.[358]

---

[354] OFFICE OF TECHNOLOGY ASSESSMENT, AN ASSESSMENT OF OIL SHALE TECHNOLOGIES 77-78 (1980).
[355] DAVID F. PRINDLE, CENTER FOR ENERGY STUDIES AT THE UNIVERSITY OF TEXAS AT AUSTIN SHALE OIL, WATER AND THE POLITICS OF AMBIGUITY, 22 (Oct. 1982)
[356] *Id.*, *see also* ANDREW GULLIFORD, BOOMTOWN BLUES 127 (2003).
[357] OFFICE OF TECHNOLOGY ASSESSMENT, *supra* note 354 at 393.
[358] *Id.* at 388.

While importation has some appeal, it suffers from two major problems. First, the Colorado River Basin Project Act guarantees the state of origin "adequate and equitable protection" sufficient to ensure continued availability of reasonably priced water.[359] Moreover, the state of origin retains "priority of right in perpetuity to the use of the waters of that [exporting] river basin" unless otherwise stated in an interstate compact.[360] In effect, the basin of origin must have so much excess water that it will not now, or in the foreseeable future, need its own water. As competition for water resources increases, the likelihood of such excess supplies becomes increasingly suspect.

Environmental impacts represent the second major implementation hurdle. Large water importation projects would be subject to review under NEPA and would need to comply with a host of federal and state environmental laws, including the ESA and CWA. The approval process alone would take years and millions of dollars, not counting financial and temporal delays resulting from near-certain litigation.

3. Produced Water[361]

When oil and gas are developed, operators often encounter groundwater that must be removed and disposed of to facilitate mineral extraction. Water produced through mineral extraction is normally treated as a waste product rather than a valuable resource and regulated as waste rather than under appropriations law.[362] Qualitative concerns aside, produced water, if available for appropriation, represents a potential source of water for oil shale and oil sands

[359] 43 U.S.C. § 1513(a).
[360] *Id*. at § 1513(b).
[361] The terms "produced water" and "process water" are used interchangeably in this report.
[362] This is a rapidly evolving area of law and regulatory changes should be anticipated. *See e.g., Vance v. Wolfe*, 205 P.3d 1165 (Colo. 2009) (holding the extraction of water to facilitate coalbed methane production constitutes a beneficial use and therefore necessitates acquisition of a water right). For surveys of various states' approaches to regulating produced water *see* 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); Rebecca W. Watson *et al*., *Produced Water: Water Rights and Water Quality: "A 'Meeting' of the Waters"?,* PROCEEDINGS OF THE ROCKY MOUNTAIN MINERAL LAW FIFTY-SECOND ANNUAL INSTITUTE 12-1 (2006); and Thomas F. Darin, *Waste or Wasted?—Rethinking the Regulation of Coalbed Methane Byproduct Water in the Rocky Mountains: A Comparative Analysis of Approaches to Coalbed Methane Produced Water Quantity Legal Issues in Utah, New Mexico, Colorado, Montana, and Wyoming*, 17 J. ENVTL. L. & LITIG. 281 (2002).

development. According to the Utah Mining Association:

> 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.[363]

The potential to use produced water in support of oil shale and oil sands development raises questions about produced water's place in the established water resources permitting scheme. A brief discussion of the produced water resource gives shape to the issues.

Treating produced water as a waste product made sense in the context of early oil well development as the amount of water produced was minimal and generally of low quality, and at the time the doctrine was developed, other water sources were often readily available.[364] Similarly, treating produced water associated with natural gas production as waste was generally not problematic because water was of poor quality and wells were so deep that produced water was isolated from usable water sources. Coalbed methane (CBM) wells fundamentally changed this equation by producing greater quantities of higher quality water from sources that are often in continuity with usable aquifers.[365]

Colorado is the epicenter of legal battles over produced water management. In 2007, the Colorado Water Court explicitly rejected arguments that groundwater removal is an unavoidable side effect of production and that since intent to appropriate is required to obtain a water right, no water right was required for water produced as a byproduct of energy

---

[363] LAURA S. NELSON AND TIM J. WALL, UTAH MINING ASSOCIATION, DEVELOPMENT OF UTAH OIL SHALE AND TAR SANDS RESOURCES, 9 (2008).
[364] Darin, *supra* note 362 at 17.
[365] *Id.* at 17. 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, *available at* http://wogcc.state.wy.us/cfdocs/2007_stats.htm

development.[366] The Colorado Supreme Court agreed, dismissing appellants' claim that produced water was a nuisance rather than a beneficial use by noting 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."[367] According to the Colorado court, groundwater interception and use is therefore an "inevitable result" of development and the CBM 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.'"[368] Under *Vance*, CBM well operators in Colorado must now acquire water rights before proceeding, and such permits will be available only where the no injury rule is satisfied.

In response to the *Vance* decision, Colorado amended its water code, directing the Division of Water Resources to promulgate rules regarding the withdrawal of groundwater to facilitate oil and gas development.[369] Under the new regulations, oil and gas well operators have until March 31, 2010 to come into compliance with water right requirements.[370] Notably, the rules are not limited to the CBM wells discussed in *Vance*.[371] The rules simplify the permitting process by establishing "geographically delimited areas under which the groundwater in only certain formations is nontributary for the limited purposes of these rules."[372] Water right permits are not required for nontributary groundwater appropriation.[373] The new rules are being

---

[366] *Vance v. Simpson*, No. 2005CW063, slip op. at 16 (Colo. Dist. Ct., Water Div. 7, July 2, 2007) (*aff'd Vance v. Wolfe*, 205 P.3d 1165 (Colo. 2009).
[367] 205 P.3d at 1170.
[368] 205 P.3d at 1167.
[369] H.R. 09-1303, 2009 Reg. Sess. (Colo. 2009). H.R. 09-1303 was signed into law by Governor Ritter on June 2, 2009.
[370] Pending legislation would extent the deadline to August 31, 2010. Joe Hanel, *Water-Rights Owners Sue State – Again*, THE DURANGO HERALD (March 3, 2010).
[371] *Id*.
[372] 2 COLO. CODE REGS. § 402-17.7.
[373] COLO. REV. STAT. § 37-90-103(6)(a).

challenged as insufficient to protect other water users.[374] Colorado's approach comports with Wyoming law, under which appropriation of CBM production water also requires a water right.[375]

The trend towards requiring water rights for produced water use holds important implications for energy development: First, requiring a water right creates a strong incentive for water producers to dispose of produced water in ways that minimize consumptive loss to the source aquifer, thereby minimizing the size of the required water right and the likelihood of interference with other water uses. Efforts to minimize consumptive use will limit produced water as a source of supply for oil shale and oil sands development.

Second, *Vance* and its progeny could be a harbinger of legal arguments applicable to oil shale and oil sands developers who need to dewater formations prior to extracting shale oil. In situ oil shale development wells are likely to be 1,000 to 2,000 feet in depth,[376] and therefore much more likely to intercept usable water than deep, conventional natural gas wells.[377] Should de-watering for oil shale or oil sands development interfere with existing beneficial uses of water, in situ oil shale and oil sands developers may face challenges similar to those raised in *Vance*.

4. <u>Water Conservation</u>

Water lost to inefficient use represents a potentially untapped resource that, if used more efficiently, could help support commercial oil shale and oil sands development. Subtly changing the appropriation doctrine could incentivize water conservation. The policy aim would be to make western water law more amenable to conservation, thereby allowing water users to

---

[374] *See* Hanel, *supra* note 370.
[375] *See* WYO. STAT ANN. § 41-3-904(a) (requiring any person intending to appropriate "by-product water" to file an application to appropriate groundwater with the State Engineer). *See also*, *William F. West Ranch v. Tyrell*, 206 P.3d 722, 725 n.1 (Wyo. 2009) (dictum) (recognizing that the Wyoming State Engineer "has determined that produced water for CBM extraction is a beneficial use.").
[376] Shell Exploration and Production's in-situ technology targets zones from 1,000 to 2,000 feet deep. SECURE FUELS FROM DOMESTIC RESOURCES, *supra* note 10 at 68.
[377] Most recently drilled oil and gas wells within Uintah County are drilled into geologic formations 5,000 to 10,000 feet below the surface – much deeper than most potable water supplies and presumably isolated from usable water sources. *See* Utah Department of Natural Resources, Division of Oil Gas, and Mining, Data Research Center, http://oilgas.ogm.utah.gov/Data_Center/DataCenter.cfm.

accomplish more with less. Oil shale and oil sands development, and their associated demands for water resources, may provide an impetus to do just this.

The prior appropriations doctrine is often criticized because it, "does not permit a party who conserves water to benefit from the effort, and because implementing conservation is expensive, few venture down that road because the return is simply not worth the investment."[378] Two competing legal doctrines help explain this criticism: First, an appropriator may change the place of use, nature of use, or point of diversion without losing their original priority date – but they may do so only where the change impairs no other water right, whether junior or senior in priority.[379] So a change to a more efficient use of water is generally not allowed where it impairs an existing use, even if the net effect is increased efficiency.

Second, a water right change cannot result in an increase in the annually consumed quantity of water.[380] The quantity of water consumed is the amount of water diverted, less return flow. Return flow is seepage water that if not intercepted, would return to the source from which it was diverted and is therefore a part of the same source available to downstream rights holders.[381] If a change holds diversions constant but lessens the amount of return flow, it enlarges the right and risks impairing the rights of other water users.[382] Therefore, if an irrigator applies water more efficiently, thus reducing groundwater recharge relied upon by downstream appropriators,[383] the downstream water user who receives less water can claim interference with

[378] Steven E. Clyde, *Marketplace Reallocation in the Colorado River Basin: Better Utilization of the West's Scarce Water Resources*, 28 J. LAND RESOURCES & ENVTL. L. 49, 54 (2008).
[379] UTAH CODE ANN. § 73-3-3; *see also East Bench Irrigation Co. v. Deseret Irrigation Co*., 271 P.2d 449 (Utah 1954).
[380] UTAH CODE ANN. § 73-3-3(2)(b).
[381] *Bower v. Big Horn Canal Ass'n*, 307 P.2d 593, 602 (Wy. 1957).
[382] *See Salt Lake City v. Telluride Power Co*., 17 P.2d 281, 284 (Utah 1932) (holding that after water has been used on the appropriators' lands, they have no further right to water that leaves their lands and finds its way back to the main channel as either runoff or seepage).
[383] *See Howcroft v. Union & Jordan Irrigation Co*., 71 P. 487 (Utah 1903) (establishing a presumption that water lost to seepage in the bed of a stream rejoins the stream),

their vested rights and seek either injunctive relief or monetary damages – provided that the well is fed by water classified as "return flow" rather than waste or imported water.[384]

Incentivizing conservation effectively creates more water and can come "by plowing around the doctrine rather than plowing it under."[385] Washington State has done just that, funding water conservation in return for the water conserved, which is deposited into the state trust water rights program.[386] Acquired water rights retain their priority date[387] and are held or authorized for "instream flows, irrigation, municipal, or other beneficial uses consistent with applicable regional plans for pilot planning areas, or to resolve critical water supply problems,"[388] provided that use does not impair existing users or the public interest.[389] A similar result could occur, without the need for state funding, if state law were to reward those who conserve water by giving them title to a portion of the water they conserve under their existing priority date while dedicating the remainder to instream flows. If senior water right holders were able to obtain marketable title to a portion of the water saved through conservation, they may have sufficient incentive to invest in more efficient infrastructure. The remainder, if dedicated to instream flow related purposes, could provide public benefits during periods of low flow when instream values are most at risk. In developing such an approach, legislators would need to avoid interfering with return flows and the takings claims such perceived interferences would almost certainly provoke. Where one sits will affect where they choose to draw the line between using the public

---

[384] Waste is not return flow, but water "abandoned" by the appropriator that does not return to the source of supply. *Estate of Steed v. New Escalante Irrigation Co*., 846 P.2d 1223, 1226 (Utah 1992). A downstream appropriator may make use of imported water or irrigation waste as long as the upstream irrigator makes it available, but the downstream user has no right to compel the continued wasteful use of water upon which his diversion depends. *Id.*, *see also Stookey v. Green*, 178 P. 586 (Utah 1919) (holding that if waste or seepage water forms an "artificial" rather than a natural source of supply, no relief will be available if interference occurs.). The key to this distinction is that return flows returns to the stream or natural groundwater system from which they were diverted. "Waste" does not return to the same source of supply. Imported water originates in another basin and therefore does not return to the same source of supply.

[385] A. Dan Tarlock, *The Future of Prior Appropriations in the New West*, 41 NATURAL RESOURCES JOURNAL 769, 776 (2001).

[386] WASH. REV. CODE § 90-42-030(2).

[387] *Id.* at § 90-42-040(3).

[388] *Id.* at § 90-42-040(1).

[389] *Id.* at § 90-42-030(4).

interest to promote efficiency and interfering with vested water rights. This is not an easy fix and will require considerable policy debate.

In Utah, there is common law precedence for allowing prospective appropriators to upgrade existing diversion works that are owned by others in return for the water saved. In *Big Cottonwood Tanner Ditch Co. v. Shurtliff*,[390] senior appropriators obtained water by way of an 807 foot long "open ditch over porous and gravelly soil."[391] In order to obtain the required 20,000 GPD, the senior appropriators diverted over 323,000 GPD.[392] The ditch company, which held junior appropriative rights to the same source of supply, was unable to consistently obtain their full water right. The ditch company therefore proposed to construct, at its sole expense, a pipeline to supply the senior water user's needs, thus saving over 300,000 GPD and improving the ditch company's ability to obtain water. The Utah Supreme Court concluded that

> if another water user who is entitled to the water can save the water and can put it to a beneficial use by changing the manner of diversion of the prior water user, he may do so if it be done at his own cost and expense, and if he preserves and maintains all the rights of the prior user whose means or methods of diversion is thus changed or affected.[393]

While incentivizing conservation represents a formidable challenge and is not an expeditious path forward, it reflects a long-term strategy for increasing water availability.

Prior appropriations law also provides an underdeveloped opportunity to critically evaluate whether a change is in the public interest. A water right change application provides the state an opportunity to review the entire permit under the public interest analysis.[394] In Utah, public interest considerations require denial of a change application where the change "will prove detrimental to the public welfare."[395] The elements considered and their relative weight

---

[390] 189 P. 587 (Utah 1919).
[391] *Id*. at 589.
[392] *Id*.
[393] *Id*. at 590. In reaching its conclusion, the Utah Court relied on *Salt Lake City v. Gardner*, 114 P. 147, 153 (Utah 1911), in which the court approved new diversions from Utah Lake provided that the junior appropriator upgrade the senior appropriator's point of diversion to ensure no change to the senior appropriator's right to apply water to a beneficial use.
[394] *Hardy v. Higginson*, 849 P.2d 946 (1993).
[395] UTAH CODE ANN. § 73-3-8(1)(b)(i), made applicable to change applications by § 73-3-3(5)(a).

depend on local considerations,[396] giving the State Engineer considerable discretion in determining whether to grant a change application.[397] The State Engineer can deny a change application because the proposed use is so inefficient that a change would authorize waste,[398] an unreasonably inefficient means of diversion would interfere with other beneficial uses,[399] the change would harm water quality,[400] or the change would interfere with other values such as public recreation or wildlife habitat.

Conservation offers utility independent of oil shale or oil sands development, and its benefit will increase in importance with population growth, growing recognition of the importance of non-consumptive uses, and increasing precipitation variability. The prospect of oil shale and oil sands development may present the impetus needed to revise the prior appropriations doctrine.

K. Conclusion and Recommendations

Oil shale and oil sands developments direct and indirect water-related requirements are not well defined. Changing technologies bring with them the promise of greatly reduced water usage. However, even if direct demand is less than projected 30 years ago, indirect demand for power generation, dust suppression, revegetation, and municipal supplies will be important, especially as competition for scarce resources increases.

Water rights within the prospective development area are in short supply and most sources are over appropriated. The existing water rights administrative system is flexible enough to accommodate creative reallocations of scarce water resources. But reallocation of

[396] *Shokal v. Dunn*, 70 P.2d 441 (Idaho 1985).
[397] *Tanner v. Bacon*, 136 P.2d 957 (Utah 1943) (holding the State Engineer has a duty to control the appropriation of water in a manner that is in the best interests of the public and must act reasonably, without arbitrariness or caprice, in fulfilling this duty.).
[398] *Dep't of Ecology v. Grimes*, 852 P.2d 1044 (Wash. 1993) (holding the quantum of water available for appropriation is limited to the amount needed to irrigate applying reasonable technology.).
[399] *Colorado Springs v. Bender*, 366 P.2d 552, 555 (Colo. 1961) (holding "priority of appropriation does not give a right to an inefficient means of diversion, such as a well which reaches to such a shallow depth into the available water supply that a shortage would occur . . . even though diversion by others did not deplete the stream below where there would be an adequate supply for the senior's lawful demand.").
[400] UTAH CODE ANN. § 73-3-20(1).

existing water rights and development of approved but unperfected (conditional) water rights could reshape the western landscape. The question is therefore what competing uses and values are we, as a society, willing to forego to enable development. If a commercial oil shale or oil sands industry develops at a pace comparable to the Canadian oil sands industry, sufficient time appears available to plan for and address the changes that are likely to occur. RD&D leases afford the opportunity to test new technologies and verify both their consumptive needs and environmental impacts. NEPA analysis required of projects proposed on federal lands creates a transparent public process for analyzing impacts and weighing tradeoffs. By law, these kinds of assessments must precede any large-scale resource commitments.

Independent of the policy choices involving commercial oil shale and oil sands development, several concrete steps could clarify the nature and comparative value of existing water rights. First, the White River flows through Colorado's and Utah's richest oil shale resources, yet the states' respective rights to the river remain uncertain. Certainty regarding the extent of available supplies and relative priorities is critical to resolving competing claims to scarce water resources – the kinds of claims that will increase in intensity with commercial oil shale or oil sands development. The risk is that "[u]ntil state claims have been reduced to definite rights in specific quantities of water, private capital cannot afford the investment risk, states will have difficulty selling bonds, and even the federal government will not authorize projects."[401] The governors of Colorado and Utah could add certainty by negotiating a compact clarifying each states' respective water rights.

Second, the Northern Ute Indian Tribe's reserved rights claims are massive and senior to those of almost every other water right within the Uinta Basin. The potential that water rights are subordinated to the Tribe's water rights is a cloud over all water users within the basin, not just the energy industry. Finalizing the Ute Indian water settlement should be a high priority, and any settlement should clearly articulate the extent to which water resources may be

[401] TARLOCK ET AL., WATER RESOURCE MANAGEMENT 913-14 (5th ed. 2002).

transferred to non-Indians, used for commercial and industrial purposes, and used off the reservation.

Broad water and energy policy initiatives will indirectly influence water availability, and efforts to craft a national water policy must address critical infrastructure issues. Energy and environmental policy decisions will indirectly drive technologies that have comparatively more or less demand for water, impacting the economic value of water resources within the basin and consequently the economics of oil shale and oil sands development. The efforts most likely to create certainty regarding water resources are not, *per se*, water resource decisions, but closely intertwined water and energy policy initiatives.

II. ENVIRONMENTAL FACTORS COMPETING FOR WATER

A. Introduction

Commercial oil shale and oil sands development raise complicated questions regarding water quality. With the size, shape, location, technology, resource inputs, and environmental impacts associated with an oil shale or oil sands industry all very much in question, it is not possible to address the environmental factors competing for water at the level of detail or certainty that many would like.

Even if water is physically available to appropriate, effects to instream flows, protected species, and water quality may limit or preclude water withdrawals. Development that does occur will generate effluent that, if improperly managed, may impact water quality related values. The discussion that follows addresses the regulatory issues presented by the ESA and related instream flow requirements. The remainder of this section is devoted to more conventional water quality issues, such as the potential to impact water quality related values, the laws and regulations in place to protect those values, and specific permitting programs that are likely to affect the development of a commercial oil shale or oil sands industry.

B. Endangered Species and Instream Flows

Prime oil shale and oil sands lands include critical habitat for at least four species of fish protected under the ESA.[402] The ESA requires protection of these species, imposing obligations on federal agencies, their agency licensees and permittees, state and local governments, and private individuals. These obligations may supersede state water rights. Where water use limitations are necessary to protect ESA listed species, water resources may be available physically but not legally.

The ESA recognizes that various species have gone extinct because of human action, and that other species are in danger of extinction because of growth and development

[402] 16 U.S.C. §§ 1531-44.

"untempered by adequate concern and conservation."[403] In light of this recognition and the desirability of conserving imperiled species, the ESA "provide[s] a means whereby the ecosystems upon which endangered species and threatened species depend may be conserved, . . . provide[s] a program for the conservation of such endangered species and threatened species, and[requires] such steps as may be appropriate to achieve [these goals]."[404]

The ESA's goals are accomplished by prohibiting the "take" of listed[405] animals, except under federal permit.[406] The take prohibition's reach is broad, applying to any "person," regardless of land ownership.[407] "Take," under the ESA, means "to harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, or collect or attempt to engage in any such conduct."[408] Through regulation, "harm" is defined as "an act which actually kills or injures wildlife. Such an act may include significant habitat modification or degradation where it actually kills or injures wildlife by significantly impairing essential behavioral patterns, including breeding, feeding, or sheltering."[409] The U.S. Fish and Wildlife Service (Service) has primary jurisdiction over listed terrestrial and freshwater organisms.

Section seven of the ESA requires federal agencies to promote the ESA's conservation purposes and to consult with the Service to ensure actions they authorize, fund, or carry out will

---

403 *Id.* at § 1531(a).
404 *Id.* at § 1531(b).
405 Under the ESA, species may be listed as either endangered or threatened: "Endangered" species are in danger of extinction throughout all or a significant portion of their range, *id.* at § 1532(6) "threatened" species are likely to become endangered within the foreseeable future. *Id.* at § 1532(20). Section 4 of the ESA requires species to be listed based solely on their biological status and threats to their existence; economic impacts of a listing decision are not considered. *Id.* at § 1533. The U.S. Fish and Wildlife Service also maintains a list of "candidate" species which warrant listing, but whose listing is precluded by higher listing priorities.
406 *Id.* at § 1538(a)(1)(B). ESA listed plants are not protected from take, although it is illegal to collect or "maliciously damage or destroy" them on Federal land. *Id.* at §1538(a)(2). Protection from commercial trade and the effects of Federal actions do apply for plants.
407 *Id.* at §1538(a)(1), *see also, Babbitt v. Sweet Home Chapter of Communities for a Great Oregon*, 515 U.S. 687, 703 (1995).
408 16 U.S.C. § 1532(19).
409 50 C.F.R. § 222.102.

not jeopardize the continued existence of listed species.[410] At the outset, the agency proposing or overseeing the proposal and the Service consult to determine whether threatened or endangered species may be present within the project area.[411] If so, the lead agency prepares a "biological assessment" determining whether the proposed action is likely to affect listed species. If the assessment determines that the proposed action is likely to affect a listed species, the agency must formally consult with the Service, and the Service must issue a "biological opinion" stating whether the proposed action would jeopardize the species or destroy or adversely modify critical habitat. If the Service issues a "jeopardy opinion," the Service must suggest reasonable and prudent alternatives that will not result in violation of the take prohibition.[412] If the applicant minimizes impacts to the maximum extent practicable and the proposed action will not appreciably reduce the likelihood of survival or recovery of a listed species, the Secretary issues a permit authorizing the take of a listed species incidental to otherwise lawful activities.[413]

The ESA also requires the designation of "critical habitat" for listed species when "prudent and determinable."[414] Critical habitat includes geographic areas containing physical or biological features essential to species conservation and that may need special management or protection.[415] Critical habitat may include areas that are not occupied by the species at the time of listing but are essential to its conservation.[416] Unlike the initial listing decision, an area can be excluded from critical habitat designation if the economic benefits of excluding it outweigh the benefits of designation, unless failure to designate the area as critical habitat may lead to extinction of the listed species.[417] Federal agencies are required to avoid "destruction" or

[410] 16 U.S.C. § 1536(a).
[411] *Id.* at § 1536(c)(1); *see also*, *Thomas v. Peterson*, 753 F.2d 754, 763 (9th Cir. 1985) (holding Forest Service's failure to consult for timber sale violated the Endangered Species Act).
[412] 16 U.S.C. § 1536(b)(3)(A).
[413] *Id*. at § 1539(a).
[414] *Id*. at § 1533(a)(3)(A).
[415] *Id.* at § 1532(5)(A)(i).
[416] *Id.* at § 1532(5)(A)(ii).
[417] *Id.* at § 1532(b)(2).

"adverse modification" of designated critical habitat, and cannot authorize actions that would affect such a result.[418]

Section ten of the ESA provides relief to non-federal landowners who want to develop property inhabited by listed species.[419] Non-federal landowners can obtain a permit to take listed species incidental to otherwise legal activities, provided they have an approved habitat conservation plan (HCP).[420] HCPs include an assessment of the likely impacts on the species from the proposed action, the steps that the permit holder will take to minimize and mitigate the impacts, and the funding available to carry out the steps.[421]

Water right utilization is subject to the ESA's prohibition against the "take" of a listed species under Section nine.[422] Therefore, the ESA may require water projects to maximize species protection, thus subordinating state water rights and federal water delivery contracts.[423] Under such circumstances, instream flow requirements for listed species can trump water rights, including water rights apportioned by interstate compact.[424] Therefore, while water for listed species does not have a fixed priority date, it effectively supersedes competing uses.

The White, Yampa, and Green rivers are the rivers most likely to experience development pressure. The White River from Rio Blanco Dam to its confluence with the Green River is critical habitat for several ESA listed fish.[425] Adult Colorado pikeminnow (*Putchocheilus lucius*) are the primary protected fish found in the White River, and are found at higher densities

---

418 *Id.* at § 1536(a)(2).
419 *Id.* at § 1539.
420 *Id.* at § 1539(a).
421 *Id.* at § 1539(a)(2).
422 *See United States v. Glenn-Colusa Irrigation Dist*., 788 F.Supp 1126, 1134 (E.D. Cal. 1992) (enjoining pumping in accordance with state granted water rights where pumping was a substantial proximate cause of injury to listed salmon species) *see also Klamath Water User Protection Ass'n v. Patterson*, 204 F.3d 1206,1213 (9th Cir. 1999) as amended at 203 F.3d 1175 (9th Cir. 2000) (holding that where Reclamation retains ownership and management authority over a water project, its obligations under the ESA override irrigators' water rights.), *Bartelos & Wolfsen, Inc. v. Westlands Water Dist*., 849 F.Supp. 717, 732 (E.D. Cali. 1993) (same).
423 *See Carson-Truckee Water Conservancy Dist. v. Clark*, 549 F.Supp 704 (D.Nev. 1982) *aff'd in part, reversed in part* 741 F.2d 257 (9th Cir. 1984).
424 LAW OF WATER RIGHTS AND RESOURCES, *supra* note 277 at § 9.31.
425 U.S. Fish & Wildlife Service, Upper Colorado River Endangered Fish Recovery Program, http://www.fws.gov/ColoradoRiverrecovery/Crrpch.htm.

in the White than in other rivers.[426] "Colorado pikeminnow that utilize the White River may represent one of the few remaining local populations that stabilize a larger regional population, and therefore the White River system contributions may be critical to Colorado pikeminnow recovery."[427] The White River is uniquely important to the Colorado pikeminnow because of quality in-channel habitat, linkage between other important habitats, and "as one of the least altered major tributaries to the Green River, it makes biological, physical, and chemical contributions to the Green that are similar to its historic contributions."[428] Current flow regimes are similar to pre-development flows, with depletions representing only five percent of base flows, and upstream reservoirs (Taylor Draw Dam and Kenney Reservoir) operating in a run of the river mode.[429] Flows above 300 CFS are apparently needed to provide passage over riffles.[430] Maintenance of riffle productivity during base flow periods appears to require 400 to 500 CFS.[431] The Service is in the process of finalizing interim flow recommendations for the White River and will likely issue a Biological Opinion incorporating flow requirements and depletion limits.[432]

"The Yampa River is the largest remaining essentially unregulated river in the Upper Colorado River Basin, and its inflow into the Green River, 65 miles downstream of Flaming Gorge Dam, ameliorates some effects of dam operation on river flow, sediment load, and temperature."[433] All four species of endangered fish occupy portions of the Yampa River

---

[426] U.S. FISH & WILDLIFE SERVICE, WHITE RIVER BASE FLOW STUDY FOR ENDANGERED FISHES, COLORADO AND UTAH, 1995-1996 2 (Feb. 2004).
[427] DIVISION OF WILDLIFE RESOURCES, UTAH DEPARTMENT OF NATURAL RESOURCES, THE WHITE RIVER AND ENDANGERED FISH RECOVERY: A HYDROLOGICAL, PHYSICAL AND BIOLOGICAL SYNOPSIS 34 (2000).
[428] *Id*.
[429] WHITE RIVER BASE FLOW STUDY FOR ENDANGERED FISHES, *supra* note 426 at 1, and THE WHITE RIVER AND ENDANGERED FISH RECOVERY*, supra* note 427 at 34.
[430] *WHITE RIVER BASE FLOW STUDY FOR ENDANGERED FISHES, supra* note 426 at 18-19.
[431] *Id*.
[432] *See Section 7 Consultation, Sufficient Progress, and Historic Projects Agreement and Recovery Implementation Program Recovery Action Plan* (RIPRAP) 18 (as amended April 2, 2009) *available at* http://www.fws.gov/mountain-prairie/crrip/rea.htm.
[433] *Id.* at 15.

between Craig, Colorado and its confluence with the Green River.[434] According to the Service, spring peak flows on the Yampa are "crucial" to maintenance of the Green River's "large-river" characteristics and, therefore, "very important to maintaining suitable conditions in the Green River downstream of the confluence."[435] Under Service recommendations,[436] Yampa River base flows should not be allowed to fall below 93 CFS from July through October, or 124 CFS from November through March at a frequency, magnitude, or duration exceeding historical records.[437]

Endangered fish also occupy the Green River from Dinosaur National Monument to its confluence with the Colorado River; the Colorado River from Rifle, Colorado to Lake Powell; and the Gunnison River from Delta, Colorado to Grand Junction, Colorado. All of these stream reaches are protected as critical habitat.[438] Minimum flows for species protection are imposed under the Colorado River Endangered Fish Recovery Program[439] and the Programmatic Biological Opinion for operation and depletions to the Colorado River above the Gunnison River,[440] which call for additional deliveries for fish while restricting future depletions. As discussed below, the State of Utah imposes base flow requirements on certain water rights along the Green River. These requirements tier to the Biological Opinion for operation of the Flaming Gorge Dam.

Accordingly, activities within the Uinta and Piceance basins will require consultation under Section seven of the ESA and water use must not affect a "take" of a listed species or

---

434 *Id.* at 15.
435 *Id.* at 15.
436 TIMOTHY MODDE ET AL., U.S. FISH & WILDLIFE SERVICE, DETERMINATION OF HABITAT AVAILABILITY, HABITAT USE, AND FLOW NEEDS OF ENDANGERED FISHES IN THE YAMPA RIVER BETWEEN AUGUST AND OCTOBER, RECOVERY IMPLEMENTATION PROGRAM PROJECT 13 (1999).
437 GERALD W. ROEHM, U.S. FISH & WILDLIFE SERVICE, MANAGEMENT PLAN FOR ENDANGERED FISHES IN THE YAMPA RIVER BASIN AND ENVIRONMENTAL ASSESSMENT 32 (2004)
438 U.S. Fish & Wildlife Service, Upper Colorado River Endangered Fish Recovery Program http://www.fws.gov/ColoradoRiverrecovery/Crrpch.htm.
439 *See RIPRAP, supra* note 432.
440 U.S. FISH AND WILDLIFE SERVICE, FINAL PROGRAMMATIC BIOLOGICAL OPINION FOR BUREAU OF RECLAMATION'S OPERATIONS AND DEPLETIONS, OTHER DEPLETIONS, AND FUNDING AND IMPLEMENTATION OF RECOVERY PROGRAM ACTIONS IN THE UPPER COLORADO RIVER ABOVE THE CONFLUENCE WITH THE GUNNISON RIVER (Dec. 1999).

destruction of its habitat.[441] There are five main classes of activities that will be of concern with respect to water resource development: (1) reduced quantity and quality of seasonal back-water habitat used during spawning and migration; (2) reduced availability of nursery and rearing habitat; (3) reduced sediment transport capacity and associated changes in river habitat and productivity; (4) created habitats favoring non-native fishes that compete with endangered native species; and (5) reduced future flexibility in stream flow management resulting from increased consumptive use.[442]

Within Utah, appropriations from the Green River below Flaming Gorge Dam are subject to base flow requirements[443] intended to protect flow characteristics resembling pre-dam conditions. Water rights applications and change applications approved between November 30, 1994 and September 21, 2009 are subject to summer and fall bypass flow requirements.[444] Under a pending policy amendment, water rights applications and change applications approved after September 21, 2009 would be subject to year around bypass flow requirements, including spring peak flow requirements intended to mimic spring runoff.[445]

The State of Colorado also independently imposes instream flow requirements throughout much of the Yampa/White/Green river system.[446] The lower 60 miles of the White River are subject a 250 CFS instream flow requirement while the 43-mile segment upstream to the confluence with Piceance Creek is subject to a 200 CFS instream flow.[447] Many tributaries

---

441 "Take" is defined broadly as "harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, or collect, or attempt to collect, or attempt to engage in any such conduct." 16 U.S.C. § 1532(19). The prohibition against a "take" includes harming its habitat. *See Babbitt v. Sweet Home Chapter*, 515 U.S. 687 (1995).
442 BECK, ROBERT E. AND AMY L. KELLEY, EDS., 6 WATER AND WATER RIGHTS 43-44 (2004 ed.) (citations omitted).
443 Proposed Green River Policy, *supra* note 270.
444 *Id*.
445 *Id*.
446 Colorado maintains a database of instream flow requirements, which can be found at: http://cwcb.state.co.us/StreamAndLake/RelatedInformation/ToolsResources/InstreamFlowNaturalLakeLevelWaterRightsDB/.
447 *See* Colorado Water Conservation Board case numbers 5-77W3652C and 5-77W3652D, *available at* http://cwcb.state.co.us/StreamAndLake/RelatedInformation/ToolsResources/InstreamFlowNaturalLakeLevelWaterRightsDB/.

and upstream segments are also subject to instream flow requirements.[448] Increases in diversions must therefore contend not only with potential interference with senior appropriative rights, but potential interference with instream flow requirements.

The development of senior conditional water rights may affect the success of recovery efforts by increasing depletions or changing flow conditions. Even appropriation of peak flows experienced during spring runoff may be difficult if diversions impede the ability of natural flows to create or maintain habitat. Additionally, junior rights may be difficult if not impossible to utilize as the needs of both fish and senior water rights have superior priority. Development of on-channel storage may be difficult, if not impossible, in light of its potential to affect flow conditions such as the timing and quantity of water delivered, water temperature, and sediment content.

C. Water Quality

1. <u>Potential for Water Quality Contamination</u>

Oil shale and oil sands production and development have the potential to impact water quality at several points in the process. Surface mining removes vegetation, topsoil, and overburden, exposing stockpiled resources and oil shale and oil sands to wind, precipitation, and oxygen. Chemical changes may occur, and leachate can impact surface and groundwater quality. Leachate characteristics are shown in Tables 3 and 4. Leachate constituents vary depending on the source material, retorting temperature, and retorting time, so the values listed in Tables 3 and 4 may not reflect leachate under all development scenarios. The University of Utah is currently conducting research on leachate characteristics.

[448] *See* Colorado Instream Flow and Natural Lake Level Water Rights Database, *see* note 447. Under the ESA, the Service may not rely on incomplete or advisory state programs that attempt protect species and their habitat or prevent listing of imperiled species. “The [Service] may only consider conservation efforts that are currently operational, not those promised to be implemented in the future.” *Oregon Natural Resources Defense Council v. Daley*, 6 F.Supp. 2d 1139, 1154 (D. Or. 1998).

Table 3
Summary of Leachate Characteristics of Simulated Spent Oil Shale from In Situ and Above Ground Retorts (mg/L)[449]

Constituent	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

Table 4
Expected Characteristics of Leachates from Raw Oil Shale and Spent Oil Shale Piles (mg/L)[450]

Water Quality Parameter	Raw Shale	Spent Shale from Paraho Retort	Spent Shale from TOSCO II Retort
TDS	18,000	28,000	55,000
Molybdenum	9	3	9
Boron	32	3	18
Fluoride	16	10	19

For surface retorted shale, most spent shale will be stockpiled on the surface, where it can come in contact with precipitation. Spent shale will have more pore space than the original

[449] From FINAL PEIS, *supra* note 5 at A-51.
[450] *Id*. at A-52.

shale, allowing greater precipitation infiltration. The leachate from spent shale can contaminate surface or groundwater. Some spent shale may be disposed of in underground mines or backfilled into exhausted surface mines where groundwater infiltration through high porosity spent shale can affect groundwater quality. Spent oil sands will require disposal following processing, and like spent shale, may result in leaching to surface or groundwater.

In situ retorting requires fracturing the shale to facilitate heating. These fractures increase groundwater permeability, increasing the risk that kerogen, trace minerals, post-retorting hydrocarbons, and solvents will come into contact with groundwater resources. Upgrading takes place in an industrial facility similar to a refinery and raises effluent management problems comparable to those associated with other, large industrial facilities. Lastly, all production and upgrading technologies utilize chemicals that are potentially harmful to human health and the environment if spilled or otherwise subject to inadvertent release.

Recent studies indicate that oil sands development in Alberta results in higher levels of water contamination than previously realized.[451] The study found "[s]ubstantial deposition of airborne particulates" within 50 KM of the Suncor and Syncrude upgrading facilities.[452] These particulates, which are high in polycyclic aromatic compounds (PACs), accumulate over winter and are released with spring snowmelt, potentially resulting in a "pulse" in PAC concentrations.[453] While the age of Canadian facilities, smaller size of a reasonably foreseeable oil shale or oil sands industry in the United States, different resource composition, and differences in regulatory requirements all suggest caution in extrapolating Canadian experiences to potential development in the United States, the findings identify contaminants and contaminant pathways that should be managed if domestic oil shale and/or oil sands development is to proceed.

[451] Erin N. Kelly et al., *Oil Sands Development Contributes Polycyclic Aromatic Compounds to the Athabasca River and its Tributaries*, PROCEEDINGS OF THE NATIONAL ACADEMIES OF SCIENCE 22346-22351 (Dec. 29, 2009) *available at* www.pnas.org/content/106/52/22346.full.pdf.
[452] *Id.* at 22347.
[453] *Id.* at 22350.

Although the general nature of water quality issues is clear, more detailed analysis and efforts to address water quality impacts suffer from the same uncertainties plaguing water availability discussions. Subsequent rounds of NEPA must evaluate the impacts development will have on the quality of the human environment.[454] These potential impacts fall into five general categories: the quantity of waste produced (solid, liquid, and gaseous), hazardous substance content and concentrations contained in the waste produced, ecological mobility of elements contained in the waste stream, efficacy of available waste management methods, and natural resource (e.g., air and water) consumption.[455] By federal regulation, applications to lease federal lands must describe "the water treatment and disposal methods necessary to meet applicable water quality standards."[456] "If the proposed lease development would include disposal of wastes on the lease site, [the lease application must] include a description of measures used to prevent the contamination of soils and of surface ad groundwater."[457] If a lease proceeds to development, plans of development must include descriptions of the methods utilized to monitor and protect all aquifers,[458] as well as a narrative description of the mine or in situ operation that includes an estimate of the "pollutants that may enter any receiving water."[459] The plan of development must also include a narrative description of the "necessary impoundment, treatment, control, or injection of all produced water, runoff water, and drainage from workings."[460] And of course, all activities must comply with applicable laws and regulations. Since the specifics of water quality impacts will be addressed when more information becomes available, the discussion that follows summarizes major areas of water quality regulation that will be relevant to oil shale and oil sands development.

---

[454] *See* 42 U.S.C. § 4331(2)(C), 43 C.F.R. § 3900.50(b) and (c).
[455] Y. Zhirjakov, *Ecological Aspects of Oil Shale Processing* 4 PROCEEDINGS OF THE 26TH OIL SHALE SYMPOSIUM, COLORADO SCHOOL OF MINES (2006).
[456] 43 C.F.R. § 3922.20(c)(3).
[457] 43 U.S.C. § 3922.20(c)(6).
[458] *Id.* at § 3931.11(d)(8).
[459] 43 C.F.R. § 3931.11(h)(1).
[460] *Id.* at § 3931.11(h)(2).

2. Water Quality Standards

The CWA[461] establishes the basic structure for regulating surface water quality.[462] In the CWA, Congress set twin goals of "restor[ing] and maintain[ing] the chemical, physical, and biological integrity of the Nation's waters."[463] As set forth in the CWA, states have primary responsibility to "prevent, reduce, and eliminate pollution."[464] State water quality standards are subject to review and approval by the EPA and must assure attainment of the designated use.[465]

States must also develop an antidegradation policy satisfying three criteria.[466] First, all existing instream water uses must be maintained and protected, and water quality degradation interfering with existing uses is prohibited.[467] Second, existing high quality waters[468] must be maintained except where lower water quality standards are "necessary to accommodate important economic or social development in the area in which the waters are located."[469] Third, where impairment is associated with thermal discharge, the policy must conform to Section 316 of the CWA.[470]

Under Section 303(d) of the CWA, each state must identify water bodies where existing pollution controls are insufficient to attain water quality standards.[471] Water bodies may be impaired because of point source discharges, non-point pollutant discharges, or both.

---

[461] 33 U.S.C. §§ 1251-1387.

[462] The Federal Water Pollution Control Act of 1948 was amended and expanded in 1972 and again in 1977. As amended in 1977, the Act became the "Clean Water Act."

[463] 33 U.S.C. § 1251(2).

[464] *Id.* at § 1251(b).

[465] 40 C.F.R. § 131.21 (containing the process for obtaining EPA approval). Disapproved state standards, however, remain in effect until either the state revises the standard or EPA promulgates a superseding standard. *Id.* at § 131.21(c).

[466] *Id.* at § 131.12(a).

[467] *Id.* at § 131.12(a)(1).

[468] "High quality waters" are those where water quality exceeds levels needed to support interim fishable/swimmable goals. *Id.* at § 131.12(a)(2).

[469] *Id.* at § 131.12(a)(2). Lower water quality standards require a showing that existing uses will be fully protected, no "outstanding National resources" (such as parks or wildlife refuges) will be degraded, and achievement of the most protective requirements for all point sources and all reasonable use and cost-effective BMPs for non-point sources. 40 C.F.R. § 131.12(a)(2) and (3).

[470] *Id.* at § 131.12(a)(4). Section 316 directs EPA to establish cooling water discharge standards to minimize environmental impact and create permit variance provisions where dischargers can show their discharges will not adversely affect indigenous aquatic species. Variance requirements are set forth in *id.* at § 122.21.

[471] 33 U.S.C. § 1313(d)(1)(A).

Examples of common measures of impairment include: pH, temperature, total dissolved solids (TDS), salinity, phosphorous, and heavy metal content. States must prioritize their impaired waters (also known as water quality limited segments), and these priority rankings are commonly referred to as 303(d) lists.[472]

States must prepare a Total Maximum Daily Load (TMDL) for each pollutant-impaired water quality limited segment.[473] The TMDL is the maximum amount of a pollutant that can be added to a waterbody without exceeding applicable water quality criteria, and reflects natural background sources as well as anthropogenic inputs.[474] The TMDL includes a wasteload allocation reflecting existing and future point sources,[475] and a load allocation reflecting existing and future nonpoint sources, including natural background sources.[476] Based on the TMDL analysis, states allocate load reductions as required to attain water quality standards.[477]

The Utah Division of Water Quality divides the state into ten water quality management units, assessing streams and lakes within each unit for attainment of water quality standards. Utah's oil shale resources are located within the Uinta Watershed Management Unit; oil sands resources are found in the Uinta, Colorado River West, and Colorado River Southeast units.

Within the Uinta Watershed Management Unit, there are approximately 3,445 miles of perennial streams, of which 2,719 miles have been assessed for support of beneficial uses.[478] Of the assessed segments, 77.8% fully support beneficial uses, 8.4% partially support beneficial uses, and 13.8% do not support at least one designated beneficial use.[479] Assessments of beneficial use support are summarized in Table 5. Causes of stream quality impairment and the sources of impairment are shown in Figures 9 and 10. "The White River was assessed as fully

---

[472] *See* THE CLEAN WATER ACT HANDBOOK 207 (Mark A. Ryan ed., 2d ed. 2003).
[473] 33 U.S.C. § 1313(d)(1)(C).
[474] 40 C.F.R. § 130.2(e).
[475] *Id*. at. § 130.2(h).
[476] *Id*. at § 130.2(g).
[477] CLEAN WATER ACT HANDBOOK, *supra* note 472 at 209.
[478] Utah Department of Environmental Quality, *Uinta Watershed Management Unit Water Quality Assessment – 2004 305(b)*, *available at* http://www.waterquality.utah.gov/documents/uintafactsheet2004305b01-03-05.pdf
[479] *Id.*

supporting all of the beneficial uses it was assessed for."[480]

Table 5
Beneficial Uses Within the Uinta Watershed Management Unit[481]

Goals	Use	Miles Assessed	Miles Fully Supporting	Miles Partially Supporting	Miles Not Supporting
Protect & Enhance Ecosystems	Aquatic Life	2,718.7	2,418.5	99.0	201.3
Protect & Enhance Public Health	Fish Consumption	16.0	0	0	16.0
	Swimming	0	0	0	0
	Secondary Contact	0	0	0	0
	Drinking Water	1,534.9	1,534.9	0	0
Social & Economic	Agriculture	2,711.5	2,322.1	152.8	236.6
	Total	2,718.7	2,144.4	229.0	375.3

Within the Colorado River Southeast Management Unit, 566 stream miles were assessed for support of beneficial uses.[482] Of the segments assessed, 76.2% fully support all the beneficial uses assessed, 18.2% partially support beneficial uses, and 5.6% do not support one or more designated beneficial use.[483] Assessments of beneficial use support are summarized in Table 6. Causes of stream quality impairment and sources of impairment are shown in Figures 11 and 12. The Colorado River fully supports beneficial uses except for the 37.6-mile segment downstream from the Utah/Colorado border. According to the Utah Department of Environmental Quality, "[t]his portion of the river exceeded the chronic levels for selenium and the source is outside the borders of the state."[484]

---

[480] *Id.*
[481] *Id.*
[482] Utah Department of Environmental Quality, *Colorado River Southeast Watershed Management Unit Water Quality Assessment – 2004 305(b)*, *available at* http://www.waterquality.utah.gov/documents/coloradoriversoutheast2004fact12-22-04.pdf. The streams in this unit were not assessed for contact recreation.
[483] *Id.*
[484] *Id.*

Figure 9
Causes of Impairment to the Uinta WMU

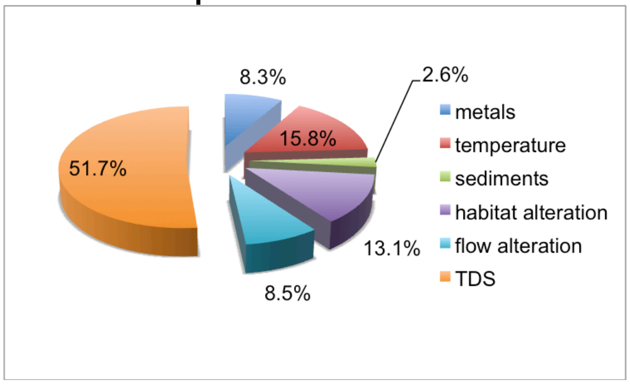


Figure 10
Sources of Impairment to the Uinta WMU

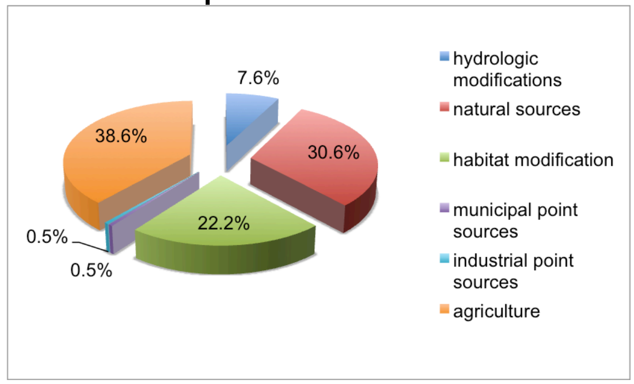


Table 6
Beneficial Uses Within the Colorado River Southeast Watershed Management Unit[485]

Goals	Use	Miles Assessed	Miles Fully Supporting	Miles Partially Supporting	Miles Not Supporting
Protect & Enhance Ecosystems	Aquatic Life	566.0	481.4	84.6	0
Protect & Enhance Public Health	Fish Consumption	0	0	0	0
	Swimming	0	0	0	0
	Secondary Contact	0	0	0	0
	Drinking Water	451.2	429.4	0	21.8
Social & Economic	Agriculture	566.0	518.6	37.3	10.2
	Total	566	431.7	102.8	31.9

485 *Uinta Watershed Management Unit Water Quality Assessment, supra* note 478.

Figure 11
Causes of Impairment to the Colorado River Southeast WMU

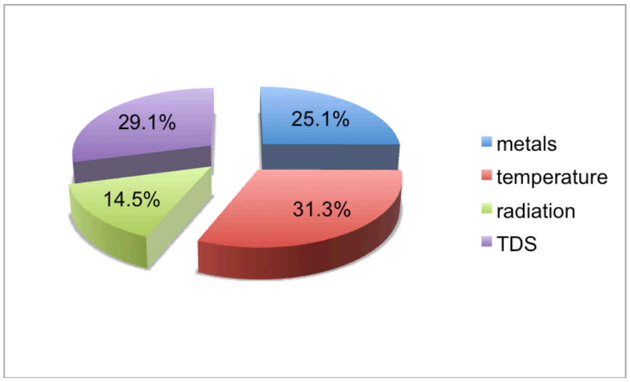
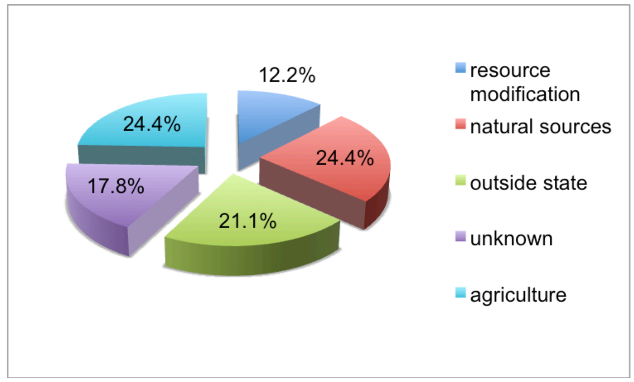


Figure 12
Sources of Impairment to the Colorado River Southeast WMU



Within the Colorado River West Watershed Management Unit, approximately 1,919 of 2,551 perennial stream miles have been subject to beneficial use assessments.[486] Of these, 69.8% fully support assessed beneficial uses, 7.0% partially support beneficial uses, and 23.2% do not support one or more designated beneficial use.[487] High TDS levels impair the San Rafael River, which flows through the San Rafael STSA.[488] Assessments of beneficial use support are summarized in Table 7. Causes of stream quality impairment and the sources of impairment are shown in Figures 13 and 14.

Table 7
Beneficial Uses Within the Colorado River West Watershed Management Unit[489]

Goals	Use	Miles Assessed	Miles Fully Supporting	Miles Partially Supporting	Miles Not Supporting
Protect & Enhance Ecosystems	Aquatic Life	1,918.6	1,830.9	26.7	24.5
Protect & Enhance Public Health	Fish Consumption	0	0	0	16.0
	Swimming	0	0	0	0
	Secondary Contact	0	0	0	0
	Drinking Water	708.2	708.2	0	0
Social & Economic	Agriculture	1,693.8	1,202.2	75.7	415.9
	Total	1,918.6	1,339.3	133.7	445.6

486 Utah Department of Environmental Quality, *Colorado River West Watershed Management Unit Water Quality Assessment – 2004 305(b), available at* http://www.waterquality.utah.gov/documents/coloradoriverwest2004bfact-01-10-05.pdf.
487 *Id.*
488 *Id.*
489 *Id.*

Figure 13
Causes of Impairment to the Colorado River West WMU

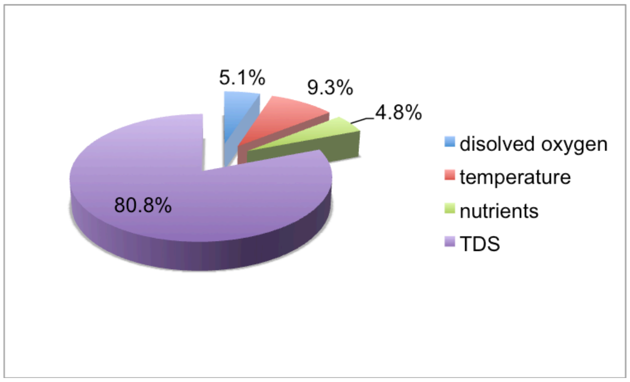
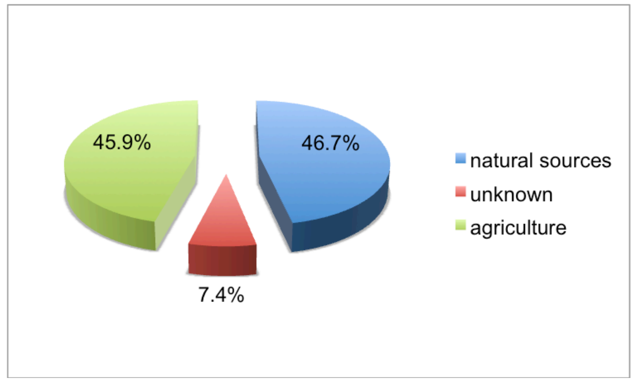


Figure 14
Causes of Impairment to the Colorado River West WMU



Water quality impairment will complicate industrial development and prospective developers should anticipate that more rigorous permit requirements would be incorporated into permits involving discharges to impaired waters. Permit requirements will vary depending on the facility and the receiving water, but in light of identified causes of impairment, particular attention should be paid to erosion control and to controlling process water discharges that increase water temperature. How formidable the challenge posed by water quality protection turns out to be will depend on the number, size, and design specifics of individual facilities.

D. Permitting Considerations

1. Discharge Permitting

Under the CWA, any discharge of a pollutant from a point source to navigable water requires a permit,[490] whether or not it results in pollution to the receiving waters or has an adverse effect on the environment. Facilities discharging into surface waters are governed by the National Pollution Discharge Elimination System (NPDES),[491] which regulates the quantity and quality of allowable discharges. NPDES permits contain effluent limitations based on (1) applicable technology based and (2) water quality based standards that are deemed sufficient to protect receiving water quality. The permit also contains monitoring and reporting requirements

[490] *Id.* at § 1311(a).
[491] *Id.* at § 1342. Utah has obtained primacy in administering certain aspects of the NPDES program and issues Utah Pollution Discharge Elimination System (UPDES) permits.

to evaluate treatment efficiency and compliance with permit conditions. In contrast to the Clean Air Act, the CWA (with exception of toxic pollutants) starts with an identification of industries to be regulated while the Clean Air Act begins with identification of pollutants to be regulated.[492]

Congress intended that the states would be primarily responsible for abating pollution, and that states wishing to do so could assume applicable CWA jurisdiction, provided they meet certain conditions.[493] Colorado and Utah have assumed regulatory jurisdiction for certain sections of the CWA, which are discussed below. While the states have primary responsibility, "delegation of the permit authority does not strip the EPA of its enforcement power with regard to discharges."[494]

Whether issued by the state or the EPA, NPDES permits will contain technology requirements reflecting the facility and effluent stream, variance provisions needed to accommodate factors unique to the discharger, notice and reporting requirements, and a reopener clause allowing imposition of new limits on toxic effluent discharges consistent with evolution of the best available control technology economically available (BAT).[495] More stringent effluent limitations may also be contained in the permit if necessary to achieve compliance with water quality standards.[496] The permit will also contain requirements for controlling toxic and hazardous pollutants.[497]

It is possible that neighboring states may have different water quality standards for the same river. It is also possible that a federally recognized Indian tribe may petition for treatment as a state[498] and adopt its own water quality standards. If the downstream state or tribe adopts

[492] BECK AND KELLEY, *supra* note 284 at § 53.02(a)(1).
[493] *See e.g.*, 33 U.S.C. §§ 1342 and 1344 for point sources and § 1288 for non-point sources.
[494] BECK AND KELLEY, *supra* note 284 at § 52.03(a); *see also* 33 U.S.C. § 1342(d)(2).
[495] 40 C.F.R. § 122.44(c).
[496] 40 C.F.R. § 122.44. at § 12.44(d).
[497] 33 U.S.C. § 1314(e); 40 C.F.R. § 122.44(k).
[498] 33 U.S.C. § 1377(e).

more stringent water quality standards, dischargers may need to meet the downstream state or tribe's water quality standards as well as those of the source state.[499]

Under the CWA, specific effluent limits apply to "facilities engaged in the production, field exploration, drilling, well completion and well treatment in the oil and gas extraction industry."[500] These standards reflect application of the "best practicable control technology currently available" (BPT).[501] The "oil and gas extraction industry" includes "the production of oil through the mining and extraction of oil from oil shale and oil sands and the production of gas and hydrocarbon liquids through gasification, liquid faction [sic], and pyrolysis of coal at the mine site."[502] Thus, oil shale and oil sands exploration and development is subject to the same effluent limitations as traditional oil and gas development.

Stormwater runoff triggers an additional layer of NPDES permitting requirements. Stormwater runoff is generated when rain or snowmelt flows over land, facilities, equipment, or impervious surfaces. As runoff flows over these surfaces, it accumulates contaminants that can adversely affect water quality if the runoff is discharged untreated. Most stormwater is managed in a way that results in point source discharges,[503] and operators of these sources are normally required to obtain an NPDES permit before they can discharge. Stormwater originates not only from existing facilities, but also from sites undergoing construction and development. Accordingly, the NPDES stormwater program requires construction site operators engaged in

---

[499] *See Oklahoma v. EPA*, 908 F.2d 595, 607 (10th Cir. 1990) (requiring permit for municipal wastewater treatment plant in Arkansas to include conditions sufficient to satisfy more stringent water quality standards applicable in downstream Oklahoma).
[500] 40 C.F.R. § 435.30.
[501] *Id.* at § 435.32.
[502] EPA utilizes the U.S. Department of Labor, Occupational Safety and Health Administration's Standard Industry Classifications (SIC codes) to categorize industries. *See* U.S. EPA, NPDES PERMIT WRITER'S MANUAL 59 (Dec. 1996). SIC code 1311 applies to "Crude Petroleum and Natural Gas," which is described at: http://www.osha.gov/pls/imis/sic_manual.display?id=387&tab=description.
[503] "Put simply, a point source is an identifiable conveyance of pollutants," BECK AND KELLEY, *supra* note 284 at § 53.01(b)(3) and expansively interpreted. "[E]ven diffuse random discharges can be regulated as point source discharges if, prior to release, they are confined or collected in an 'identifiable' source." *Id*.

clearing, grading, and excavating activities above certain size criteria to obtain a construction stormwater permit.[504]

Section 402(l)(2) of the CWA exempts from permitting requirements uncontaminated stormwater discharges from "oil and gas exploration, production, processing or treatment operations, or transmission facilities."[505] Section 323 of the Energy Policy Act of 2005 amended the CWA, broadening the reach of Section 402(l)(2) by defining "oil and gas exploration, production, processing, or treatment operations or transmission facilities" to include associated construction activities.[506] On June 12, 2006, the EPA published a final rule addressing this provision, exempting from NPDES permit requirements stormwater discharges from construction activities unless stormwater discharges contained reportable quantity of oil or hazardous substances.[507]

On May 23, 2008, the 9th Circuit Court of Appeals invalidated the EPA's 2006 oil and gas construction stormwater regulation. The court reasoned that the EPA impermissibly changed its interpretation of what constitutes a "contaminant" based on statutory amendments speaking not to the meaning of contaminant but to classes of facilities, and in so doing the EPA's revised interpretation was inconsistent with Section 402(l)(2) of the CWA.[508] The oil and gas extraction industry, including oil shale and oil sands development and extraction, therefore remains subject to construction stormwater permitting unless it demonstrates that its discharges are uncontaminated by pollutants, including sediment. Because soils within much of the most geologically prospective area are highly erosive, the prospects of permit avoidance appear slim.

Until recently, construction and development stormwater regulations required operators to implement control measures, but contained neither performance standards nor monitoring

[504] 40 C.F.R. § 122.26.
[505] 33 U.S.C. § 1342(d)(2).
[506] *See id*. at § 1362(24).
[507] *See* 40 CFR § 122.26(a)(2)(ii).
[508] *Natural Resources Defense Council v. United States Environmental Protection Agency*, 526 F.3d 591, 606-08 (9th Cir. 2008).

requirements.[509] The EPA's Effluent Limitations Guidelines and Standards for the Construction and Development Point Source Category (ELGs), which went into effect on February 1, 2010, are intended to fill this gap.[510] Under the new ELGs, existing facilities must implement, at a minimum, "best practicable control technologies currently available" or BPT requirements to control conventional,[511] nonconventional,[512] and toxic (priority) pollutants.[513] BPT requirements address erosion and sediment control,[514] soil stabilization,[515] dewatering,[516] pollution prevention,[517] and outlets from surface impoundments.[518] Certain discharge types posing a higher risk of resource damage are prohibited.[519] "Best conventional pollution control technology" or BCT, is also required to control conventional pollutants,[520] but the EPA concluded that BPT and BCT are synonymous with respect to construction and development stormwater control, and applied the same requirements.[521] "Best available technology" or BAT is required to address toxic pollutants and applies numeric standards for discharge turbidity.[522] New construction and development "have the opportunity to install the best and most efficient production processes and treatments,"[523] and "new source performance standards" or NPS require application of the "best available demonstrated control technology" (BADT), which is equivalent to BPT.[524]

[509] 74 Fed. Reg. 62998 (Dec. 1, 2009).
[510] *Id.* at 62996-63058 (Dec. 1, 2009).
[511] Biochemical oxygen demand (BOD), nonfilterable total suspended solids (TSS), pH, fecal coliform, and oil and grease, *see* 40 C.F.R. § 401.16.
[512] All pollutants not classified as either conventional or toxic.
[513] 74 Fed. Reg. at 63002. Toxic pollutants are listed at 40 C.F.R. § 401.15.
[514] 40 C.F.R. § 450.21(a).
[515] *Id.* at 450.21(b).
[516] *Id.* at § 450.21(c).
[517] *Id.* at § 450.21(d).
[518] *Id.* at § 450.21(f).
[519] *Id.* at § 450.21(e).
[520] 74 Fed. Reg. 63002 (Dec. 1, 2009).
[521] *See* 40 C.F.R. § 450.23 (incorporating BCT requirements for BCT), *see also* 74 Fed. Reg. at 63002.
[522] 40 C.F.R. § 450.22(a).
[523] 74 Fed. Reg. at 63003.
[524] *See* 40 C.F.R. subpart B.

The new ELGs are "nationally applicable" and "intended to work in concert with . . . existing state and local [stormwater] programs."[525] The EPA's new ELGs are, however, not intended to "interfere with existing state and local requirements that are more stringent than [the ELGs]."[526] How the ELGs compare to current requirements imposed by states with delegated NPDES authority (including Colorado and Utah) is uncertain, but the new ELGs establish a nationwide floor below which state regulations cannot fall. Where state regulations are less protective, operators will be required to undertake additional measures to comply with the new requirements. Oil shale and oil sands developers may face a minor increase in construction and development costs as they improve stormwater management, but since the ELGs are based on existing technologies, operators may benefit from consistent national standards and regulatory certainty. The nascent oil shale and oil sands industries should also recognize that the EPA intends to update the construction general permit[527] that incorporates these ELGs, so regulatory requirements will continue to evolve.[528]

Whether water transfers require discharge permits is an additional consideration. The CWA generally prohibits the "discharge of any pollutant" except as otherwise authorized by the Act.[529] Under the Act, "discharge of pollutants" means "any addition of any pollutant to navigable waters from any point source."[530] A "pollutant" is broadly defined to encompass a large number of substances, including industrial, municipal, and agricultural wastes.[531] "Navigable waters" are "the waters of the United States, including the territorial seas."[532] A "point source" is "any discernible, confined and discrete conveyance, including but not limited to any pipe, ditch, channel, tunnel, conduit, well, discrete fissure, container, rolling stock,

---

[525] 74 Fed. Reg. 62998 (Dec. 1, 2009).
[526] 74 Fed. Reg. 62998 (Dec. 1, 2009).
[527] Discharges can be authorized under either individual or general permits. The difference between these two types of permits is not addressed because individual permits represent less than 0.5% of stormwater permits. 74 Fed. Reg. 63001 (Dec. 1, 2009).
[528] http://cfpub.epa.npdes/stormwater/cgp.cfm.
[529] *See* 33 U.S.C. § 1311(a).
[530] 33 U.S.C. § 1362(12).
[531] *See* 33 U.S.C. § 1362(6).
[532] 33 U.S.C. § 1362(7).

concentrated animal feeding operation, or vessel or other floating craft, from which pollutants are or may be discharged. This term does not include agricultural stormwater discharges and return flows from irrigated agriculture."[533]

Historically, the EPA did not require NPDES permits for water transfers.[534] On June 13, 2008, the EPA published its Final Water Transfers Rule, stating that discharges from a water transfer do not require NPDES permits.[535] The rule defines "water transfer" as "an activity that conveys or connects waters of the United States without subjecting the transferred water to intervening industrial, municipal, or commercial use. This exclusion does not apply to pollutants introduced by the water transfer activity itself to the water being transferred."[536] Therefore, a transfer conveying lower quality water to a comparatively pristine water source would not require a NPDES permit, even if such a transfer would result in a water quality degradation.

On June 4, 2009, the 11th Circuit Court of Appeals issued a highly-anticipated opinion[537] in *Friends of the Everglades v. South Florida Water Management District* addressing a challenge to the EPA's 2008 water transfer rule.[538] *Friends* involved a challenge to an ongoing flood control project utilizing pumps to convey 400,000 GPM or more of agricultural, industrial, and residential runoff from the Everglades Agricultural Area to Lake Okeechobee.[539] The runoff was described by the court as "a loathsome concoction of chemical contaminants including nitrogen, phosphorous, and un-ionized ammonia . . . full of suspended and dissolved solids and

[533] 33 U.S.C. § 1362(14).
[534] *See* NPDES Water Transfers Proposed Rule, 71 Fed. Reg. 32,887, 32,891 (June 7, 2006) (explaining that EPA historically concluded that "Congress did not generally intend to subject water transfers to the NPDES program"); *see also South Florida Water Mgmt. Dist. v. Miccosukee Tribe of Indians*, 541 U.S. 95, 107 (2004) (noting the "longstanding EPA view that the process of transporting, impounding, and releasing navigable waters cannot constitute an addition of pollutants to the waters of the United States" (internal quotations omitted)).
[535] *See* NPDES Water Transfers Rule, 73 Fed. Reg. 33,697 (June 13, 2008) (codified at 40 C.F.R. § 122.3(i)).
[536] 40 C.F.R. § 122.3(i).
[537] On April 29, 2009, the Federal District Court for the Southern District of New York stayed its ruling on the Water Transfer Rule's validity, noting that a challenge to the rule's validity was currently pending before the 11th Circuit. *Catskill Mountain Chapter of Trout Unlimited v. EPA*, Nos. 08-CV-5606 (KMK), 08-CV-8430 (KMK), 2009 WL 1174802, *48 (S.D.N.Y. 2009).
[538] 570 F.3d 1210 (11th Cir. 2009).
[539] 570 F.3d at 1214.

[possessing] a low oxygen content."[540] Plaintiffs sought to enjoin discharges until a permit was obtained from the EPA; Defendants contended no such permit was required.

The court characterized the issue as whether to afford deference to the EPA's choice between the "unitary waters theory,"[541] which treats all waters as connected, and *Friends*' theory that the source and receiving bodies should be treated as separate and distinct. After noting, "all of the existing precedent and the statements in our own vacated decision are against the unitary waters theory,"[542] the court concluded that such unanimous judicial conclusions were not dispositive. The issue was not whether the courts embraced the unitary waters theory, but whether the statute was ambiguous, and if so, whether the EPA's regulation was a reasonable construction of an ambiguous statute.

After carefully considering the statutory language, the context in which it is used, and the broader context of the statute as a whole, the court concluded the statute was ambiguous. With ambiguity established, the court concluded the EPA's interpretation of its mandate, and therefore its transfer rule, was reasonable. Ironically, the court recognizes that under their ruling, pumping "dirty canal water into a reservoir of drinking water" is entirely permissible provided pumping added no new contaminant and only moved polluted water through the pipes.[543] The court also recognizes that such an event would "not comport with the broad, general goals of the Clean Water Act."[544] The court noted, however, that the CWA is far from pure in its application, and that the NPDES program ignores serious water quality problems associated with non-point pollution.[545] Therefore, in the court's estimation, it "is not difficult to

---

540 570 F.3d at 1214.
541 Under the unitary waters theory "it is not an 'addition . . . to navigable waters' to move existing pollutants from one navigable water to another. An addition occurs . . . only when pollutants first enter navigable waters from a point source, not when they are moved between navigable waters." 2009 WL 1545551 at *4.
542 570 F.3d at 1218.
543 570 F.3d at 1226.
544 570 F.3d at 1226.
545 570 F.3d at 1226-27.

believe that the legislative process resulted in a Clean Water Act that leaves more than 1 gap in the permitting requirements it enacts."[546]

If the EPA's rule confounds more than the Act's "lofty goals," the foundation upon which *Friends* rests may erode quickly and other courts may reach different conclusions.[547] The rule articulated in *Friends* applies only where waters are moved without the addition of new pollutants; the rule is inapplicable where contaminants are introduced as part of the transfer. Accordingly, prospective water users in oil shale and oil sands country should not assume broad application of *Friends*.

2. Hydraulic Fracturing & Underground Injection Well Permitting

"Oil shale has little native permeability, so combustion retorting can only be achieved by adding porosity by mining or explosive uplift."[548] In situ processes also require porosity enhancement for circulation of steam or other solvents and for extraction of freed kerogen or bitumen. In situ processing therefore necessitates fracturing of the target formation. Hydraulic fracturing is a well-established practice in the oil and gas industry, and 2005 amendments to the Safe Drinking Water Act (SDWA)[549] exempt it from regulation.[550] These regulatory exemptions do not, however, apply to in situ oil shale or oil sands development, thus prospective in situ oil shale and oil sands developers face challenges not currently faced by their counterparts in the oil and gas industry. Furthermore, recent congressional comments may signal a more stringent regulatory environment for all energy companies contemplating hydraulic fracturing.[551] We begin with a review of oil shale development technologies and the practice of hydraulic

---

[546] 570 F.3d at 1227.
[547] The richest domestic oil shale resources are beyond the 11th Circuits jurisdiction and the 10th Circuit Court of Appeals, which presides over Colorado, Utah, and Wyoming, is not bound to follow the 11th Circuit's conclusions.
[548] Alan K. Burnham and James R. McConaghy, *Comparison of the Acceptability of Various Oil Shale Processes* 3 PROCEEDINGS OF THE 26TH OIL SHALE SYMPOSIUM, COLORADO SCHOOL OF MINES (2006).
[549] 42 U.S.C. §§ 300f – 300j-26.
[550] Pub. L. No. 109-58 (2005).
[551] Memorandum from Chairman Henry A. Waxman and Subcommittee Chairman Edward J. Markey, to Members of the Subcommittee on Energy and the Environment, regarding examining the potential impact of hydraulic fracturing (Feb. 18, 2010) *available at* http://energycommerce.house.gov/Press_111/20100218/hydraulic_fracturing_memo.pdf.

fracturing, turn to the problems encountered, and conclude with a discussion of related regulatory concerns.

Various technologies can produce a range of fracturing and rubblization. In modified in situ processing, between 10 to 30% of the formation is mined by conventional mining methods,[552] and combustion or explosions are used to enhance permeability of surrounding shale. True in situ processing utilizes technologies already in use by the oil and gas industry to create numerous, smaller fractures without the need for commercial mining operations.[553] In its analysis of the impacts of oil shale and oil sands development, the Department of the Interior identified six categories of "true" in situ production technologies.[554]

Hydraulic fracturing is a common practice in conventional oil and gas production and involves pumping fluids into the target formation at pressures sufficient to cause the formation to fracture.[555] As fractures propagate, propping agents such as sand are added to the fluid; when fluid injection ceases and fracturing fluids are pumped back out of the well, propping agents prevent the newly formed fractures from closing and increase movement of fluids and gasses through the target formation.[556] Hydraulic fracturing can be used to increase both the injection capacity and production capacity of a well.[557]

Oil field service companies that conduct hydraulic fracturing attempt to recover hydraulic fracturing fluids, but some of the fracturing fluid inevitably leaks from the target formation or is otherwise unrecoverable.[558] Fracturing fluids contain primarily "water, inert or nontoxic gasses,

---

552 *Id*. at A-25.
553 FINAL PEIS, *supra* note 5 at A-25.
554 *Id.* at A-26.
555 AMERICAN PETROLEUM INSTITUTE, HYDRAULIC FRACTURING OPERATIONS—WELL CONSTRUCTION AND INTEGRITY GUIDELINES 15 (2009).
556 *Id*.
557 U.S. DEPARTMENT OF ENERGY – HYDRAULIC FRACTURING WHITE PAPER A1-2 (2004) *available at* http://www.epa.gov.safewater/uic/wells_coalbedmethanestudy.html.
558 AMERICAN PETROLEUM INSTITUTE, *supra* note 555 at 16.

and/or nitrogen foam and guar (a naturally occurring substance derived from plants);"[559] chemical additives and petroleum distillates represent a small fraction of their contents. Injection, recovery, and management of fracturing fluids are highly controversial because chemical additives and petroleum distillates can pose environmental and human health risks.[560] The fracturing process can involve large quantities of fracturing fluid and can therefore result in injections of significant quantities of potentially harmful chemicals.[561]

According to a 2004 the EPA study, there is no "confirmed evidence" that drinking water wells have been contaminated by hydraulic fracturing fluids injected into coalbed methane wells.[562] The EPA did, however, recognize that "poorly constructed, sealed, or cemented wells used for various purposes may provide a conduit for methane to move into shallow geologic strata and water wells, or even to surface water."[563] Surface or groundwater contamination can also occur if well surface impoundments leak, spills occur, or fracturing fluids leak from the target formation via "natural fractures" and migrate to potable water sources.[564]

Significant controversy surrounds hydraulic fracturing due to of dramatic events such as the December 15, 2007 explosion of a home in Bainbridge Township, Ohio. The explosion was attributed to elevated natural gas levels; the natural gas was, in turn, attributed to activity at a recently competed natural gas well.[565] Well completion involved hydraulic fracturing.[566] While

---

[559] EPA, EVALUATION OF IMPACTS TO UNDERGROUND SOURCES OF DRINKING WATER BY HYDRAULIC FRACTURING OF COALBED METHANE RESERVOIRS 7-3 (2004) (hereinafter EPA FRAC STUDY) *available at* http://www.epa.gov.safewater/uic/wells_coalbedmethanestudy.html.

[560] *See e.g.*, HYDRAULIC FRACTURING WHITE PAPER, *supra* note 557 At A-11 – A-13; *see also* ENVIRONMENTAL WORKING GROUP, DRILLING AROUND THE LAW (2009) (critiquing regulatory controls applicable to fracturing fluids) *available at* http://www.ewg.org/drillingaroundthelaw.

[561] EPA FRAC STUDY, *supra* note 559 at ES-11.

[562] *Id*. at 7-6.

[563] *Id.* at 7-2 (citations omitted).

[564] EPA FRAC STUDY, *supra* note 559 at 7-2; *see also Abrahm Lustgarten*, PROPUBLICA, *Frack Fluid Spill in Dimock Contaminates Stream, Killing Fish* (Sept. 21, 2009) (describing 8,000 gallon fracking fluid spill) *available at* http://www.propublica.org/feature/frack-fluid-spill-in-dimock-contaminates-stream-killing-fish-921.

[565] OHIO DEPT. OF NATURAL RES., DIV. OF MINERAL RES. MGMT., REPORT ON THE INVESTIGATION OF THE NATURAL GAS INVASION OF AQUIFERS IN BAINBRIDGE TOWNSHIP, OHIO (2008) *available at* http://s3.amazonaws.com/propublica/assets/natural_gas/ohio_methane_report_080901.pdf.

[566] *Id*. at 44.

no one was injured, the explosion severely damaged one home and forced evacuation of nineteen homes.[567] The Ohio Division of Mineral Resources Management conducted an investigation, concluding over pressurization of the well casing resulted in the "invasion, or migration, of natural gas from the annulus[568] of the well into the natural fractures in the bedrock below the base of the cemented surface casing. This gas migrated vertically through fractures into the overlying aquifers and discharged, or exited, the aquifers through local water wells."[569] Investigators identified three factors in drilling and the completion of the problem well that contributed to the "gas invasion": (1) inadequate cementing of the production casing, (2) proceeding with hydraulic fracturing without adequate cementing of the production casing, and (3) confinement of the high-pressure natural gas within the annular space.[570]

The Bainbridge Township explosion and other dramatic examples of water contamination attributable to natural gas development[571] are not technically at odds with the EPA report. These natural gas "invasions" appear to result not from injection of hydraulic fracturing fluids per se, but from failures attributable to well casings, grouting, or surface management of fluids. Growing concern regarding the efficacy of hydraulic fracturing raises important questions for the nascent oil shale and oil sands industry because regulatory exemptions applicable to the oil and gas industry likely do not apply to the oil shale and oil sands industry, and because increasing calls for regulation of this controversial practice may impact in situ processes.

---

[567] *Id*. at 8.
[568] Annulus is "[t]he space between two concentric objects, such as between the well bore and casing or between casing and tubing, where fluid can flow." *Schlumberger Oil Field Glossary*, http://www.glossary.oilfield.slb.com/default.cfm.
[569] OHIO DEPT. OF NATURAL RES, *supra* note 565 at 4-5.
[570] *Id*. at 5.
[571] ProPublica has published 22 articles (as of Feb. 22, 2010) on hydraulic fracturing and threats to water quality, many of which have been picked up by the Associated Press and other media outlets. These articles are *available at* propublica.org/series/buried-secrets-gas-drilling-environmental-threat. *See also*, Nancy Loftholm, DENVER POST, *Fears of Tainted Water Well Up in Western Colorado* (Oct. 10, 2009).

Under the SDWA, an injection well is a device that places fluid deep underground into porous rock formations, or into or below the shallow soil layer.[572] Injected fluids may include water, wastewater, brine, or water mixed with chemicals.[573] Injection well owners and operators may not site, construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity that endangers underground sources of drinking water (USDWs),[574] and all injections must be authorized by rule or permit.

Under the SDWA, states and tribes may apply for primacy to implement the Underground Injection Control (UIC) Program within their borders.[575] In Utah, the state has primacy in regulating injection wells; in Colorado, UIC wells are administered under a joint state and the EPA program. No tribes within the geologically most prospective area have petitioned to assume UIC permitting or administration.[576]

There are five classes of UIC wells,[577] two of which merit discussion. Class II wells inject fluids that "are brought to the surface in connection with conventional oil or natural gas production and may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection."[578] Wells used for disposal of "produced" or "product" water are examples of Class II wells. Class II wells also include injection wells used for "enhanced recovery of oil or natural gas" – the kinds of enhanced recovery discussed above.[579] Class V wells include all

[572] 42 U.S.C. § 300h(b)(1)(A).
[573] *See* 40 C.F.R. § 144.3
[574] 42 U.S.C. § 300h(b)(1). An underground source of drinking water (USDW) is an aquifer or a part of an aquifer that is currently used as a drinking water source or may be needed as a drinking water source in the future. Specifically, a USDW supplies any public water system, or contains a sufficient quantity of ground water to supply a public water system, and currently supplies drinking water for human consumption, or contains fewer than 10,000 mg/l total dissolved solids (TDS), and is not an exempted aquifer. 40 C.F.R. § 144.3. Exempted aquifers satisfy the requirement for USDWs, but do not currently serve as a source of drinking water and will not serve as future sources of drinking water. 40 C.F.R. § 146.4.
[575] 42 U.S.C. § 300h-1.
[576] http://www.epa.gov/safewater/uic/primacy.html.
[577] 40 C.F.R. § 144.6.
[578] 40 C.F.R. § 146.5(b)(1).
[579] 40 C.F.R. § 146.5(b)(2).

injection wells not included in Classes I-IV and specifically include "[i]njection wells used for in situ recovery of lignite, coal, tar sands, and oil shale."[580]

Wells used for installation of fully contained heating or cooling systems (e.g. resistance heaters or sealed refrigeration systems) would not be regulated as UIC wells because they do not involve an "underground injection" of a "fluid."[581] Likewise, a well that only captures kerogen or bitumen produced through in situ processing would not be regulated under the UIC program. However, if steam or other solvents are injected to liquefy or gasify oil shale, in situ development would require UIC compliance. Where the use of the well changes with time, the regulatory requirements must adjust to that reality.[582] Thus, a well that initially injects steam or other solvents to enhance production, but which is subsequently used to withdraw kerogen or bitumen, would cease to be regulated as a UIC well following the injection.[583]

A well that injects fluids in order to hydraulically fracture subsurface oil shale or oil sands would also appear to fall within the UIC program. In *Legal Environmental Assistance Foundation v. EPA* (*LEAF v. EPA*), the 11th Circuit addressed a challenge to the EPA's approval of Alabama's UIC program, including its decision not to regulate hydraulic fracturing for coalbed methane extraction. In refuting the EPA's contention that hydraulic fracturing for coalbed methane production was only a "Class-II *like* underground injection activity,"[584] falling outside the SDWA's mandate, the court clearly stated, "wells used for the injection of hydraulic fracturing fluids fit squarely within the definition of Class II wells. Accordingly, they must be regulated as such."[585] Furthermore, all underground injections are subject to regulation under

[580] 40 C.F.R. § 146.5(e)(16).
[581] *See* 42 U.S.C. § 300h(d)(1)(A), but note, "fluid" is defined broadly to mean a "material or substance which flows or moves whether in a semisolid, liquid, sludge, gas, or any other form or state." 40 C.F.R. § 146.3.
[582] *Legal Environmental Assistance Foundation v. EPA*, 118 F.3d 1467, 1475 n.11 (11th Cir. 1997) (hereinafter *LEAF I*).
[583] *LEAF I* at 1475 n.11.
[584] *Legal Environmental Assistance Foundation v. EPA*, 276 F.3d 1253, 1261 (11th Cir. 2001) (emphasis added) (hereinafter *LEAF II*).
[585] *Id.* at 1263.

the UIC program,[586] regardless of whether the injection is secondary to the wells primary purpose.[587] The question is therefore not whether an injection is regulated, but which regulations apply.[588] Whether the well is used to extract shale oil or to facilitate fracturing of oil shale in preparation for in situ processing appears to make no difference; injection wells "used for in situ recovery of . . . tar sands, and oil shale" are regulated as Class V wells.[589] Accordingly, within Colorado, UIC wells used for in situ oil shale or oil sands development would be regulated by the EPA, while in Utah, such wells would be regulated by the state.[590]

However, in the wake of the *LEAF* decision, Congress amended the SDWA to exclude certain activities from the definition of underground injection. The amendment excludes "the underground injection of fluids or propping agents (other than diesel fuels) pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities."[591] The phrase "related to oil, gas, or geothermal production activities" remained undefined, but given the SDWA's specific reference to in situ recovery of oil shale and oil sands, it appears likely that these unconventional resources fall outside the scope of oil and gas, at least with respect to the exemption. Thus, operators considering in situ processing for oil shale or oil sands should expect to face regulatory requirements unique to their industry.

Even if the hydraulic fracturing exception is found applicable to in situ processing of oil shale and oil sands, proposed amendments to the SDWA may eliminate the exception before significant production can occur. On June 9, 2009, Representative Diana DeGette of Colorado and Senator Bob Casey of Pennsylvania introduced legislation to repeal the exemption for

---

[586] *Id.* at 1263 ("Where the classification system sets forth 5 classes, one of which serves as a catch-all for any well not covered by the first 4, EPA must classify hydraulic fracturing into one of those categories.").
[587] *LEAF I*, 118 F.3d at 1475.
[588] *LEAF II,* 276 F.3d at 1263.
[589] 40 C.F.R. § 146.5(e)(16).
[590] U.S. EPA. Class V Permitting Authorities, http://www.epa.gov/safewater/uic/class5/permittingauthorities.html.
[591] Pub. L. 109-58 § 322 (Aug. 8, 2005).

hydraulic fracturing in the SDWA.[592] The call for regulation is intensifying as the House Committee on Energy and Commerce and Subcommittee on Energy and the Environment conduct investigations. A recent memorandum to subcommittee members noted concern over apparent violations of a 2003 memorandum of agreement regarding the use of certain fracturing fluids, the use of toxic and carcinogenic chemicals, and the lack of regulation regarding this growing practice. To investigate these concerns, the committees requested information regarding the types and quantities of chemicals used by hydraulic fracturing companies.[593]

Legal considerations aside, those seeking to dispose of produced water must rely on evaporation ponds or find a receiving aquifer with sufficient capacity that is not an underground source of drinking water.[594] The latter consideration could pose a major problem in the Uinta Basin as the ameliorative capacity of the primary deep aquifer is at or near capacity.[595] According to the Utah Geological Survey, operators are increasingly interested in injecting produced water or other fluids into the Birds Nest Aquifer, which is shallower in depth and in continuity with potable supplies.[596] Studies to ascertain the flow characteristics of this aquifer are underway and should provide some insight into the feasibility of increased deep injection.[597]

Other potential impacts to surface and groundwater quality will depend on site-specific conditions and the technologies used to develop oil shale or oil sands resources. Groundwater management systems must account for changes in resource permeability and composition during in situ treatment and during post-development facility closure and reclamation. In

---

592 *See* H.R. 2766, 111th Cong. (2009); S. 1215, 111th Cong. (June 9, 2009).

593 Waxman – Markey Memorandum, *supra* note 551.

594 An underground source of drinking water is any portion of an aquifer supplying a public water system, containing a sufficient quantity of groundwater to supply a public water system, supplying drinking water for human consumption, or containing fewer than 10,000 mg/l FDS, and not otherwise exempted from regulation. 40 C.F.R. § 144.3

595 *Water-Related Issues Affecting Conventional Oil and Gas Recovery and Potential Oil Shale Development in the Uinta Basin,* (no date) *Utah available at* www.geology.utah.gov/emp/UBwater_study/pdf/projectsum.pdf.

596 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 (2009) *available at* www.geology.utah.gov/emp/UBwater_study/pdf/presentation1009.pdf.

597 *Id*.

groundwater-rich areas, efforts to physically isolate and remove groundwater during in situ processing will likely cease as processing is completed and economically recoverable resources are removed. As groundwater returns to these areas it will come into contact with residual hydrocarbons and other potential water quality contaminants. If residual hydrocarbons remain soluble and, if inadequately managed, groundwater intrusion could negatively impact water quality. These challenges will need to be addressed on a case-by-case basis.

3. Dredge and Fill Permitting

Regulations on the placement of fill within waters of the United States may complicate site development and spent shale disposal. The EPA contends that spent shale from above ground retorting operations are not hazardous under Subtitle C of the Resource Conservation and Recovery Act.[598] While this simplifies disposal, under Section 404 of the CWA, dredged or fill material may not be discharged into "navigable waters" absent permit authorization.[599] Navigable waters need not be navigable in fact, but are defined as "waters of the United States, including the territorial seas."[600] Regulations broadly define waters of the United States to include, among other things, "all waters which are currently used, or were used in the past, or may be susceptible to use in interstate or foreign commerce."[601] This definition includes certain wetlands and intermittent streams.[602] Regulations also apply to "[t]ributaries"[603] of waters of the U.S., and wetlands "adjacent"[604] to such water and tributaries.

Dredge and fill permits are administered by the U.S. Army Corps of Engineers and the EPA, which evaluate applications under a public interest standard, as well as the environmental

598 42 U.S.C. §§ 6901 – 6992k. *See* U.S. Environmental Protection Agency, Notice of Data Availability on Spent oil Shale from Above Ground Retorting Operations, 73 Fed. Reg. 79089-96 (Dec. 24, 2008).
599 33 U.S.C. §§ 1311(a) and 1342(a).
600 33 U.S.C. § 1362(7).
601 33 C.F.R. § 328.3(a)(1).
602 *Id*. at § 328.3(a)(3).
603 *Id*. at § 328.3(a)(5).
604 *Id*. at § 328.3(a)(7). The scope of jurisdiction over wetlands, and tributary and adjacent wetlands in particular, is one of the most hotly contested areas of environmental law. While a precise delineation of regulatory jurisdiction is not necessary for this analysis, prospective oil shale/sands developers should recognize that jurisdictional limits remain unsettled.

criteria set forth in the CWA Section 404(b)(1) Guidelines.[605] No discharge of dredged or fill material may be permitted if either a practicable alternative exists that is less damaging to the aquatic environment, or the nation's waters would be significantly degraded.[606]

Even though the most geologically prospective oil shale development area is generally arid in nature, it does contain wetlands or other "waters of the United States." This is especially important for operations that involve surface retorting, as they will require disposal of enormous quantities of spent shale. For example, a surface retort producing 50,000 BPD from shale yielding 30 GPT would need to dispose of approximately 450 million cubic feet of spent shale annually.[607] The BLM assumes that spent shale disposal would occupy 75 AC/Y based on 250-foot-high piles.[608] Over the assumed 20-year lifetime of a mine, this would result in 1,500 AC (approximately 2.34 square miles) of surface disposal.[609]

During the oil shale boom of the 1970s and early 1980s, spent shale disposal proposals called for filling of large canyons.[610] If similar geographic features are a central part of future disposal proposals, Section 404 permitting will add another level of complication to the approval process.

E. Salinity Control

Although the Colorado River system is naturally saline, human alterations have roughly doubled natural salinity concentrations, with large increases in salinity as the river flows south towards the Mexican border.[611] The largest anthropogenic salinity sources are inefficient irrigation practices.[612] Other significant salinity sources include soil erosion, oil and gas product water discharges, mine tailings, and wastewater treatment plants. Prior to recent interventions

---

605 40 C.F.R. §§ 230.1 – 230.98.
606 *Id*. at § 230.10(a).
607 FINAL PEIS, A-49 (Sept. 2008). To put this into perspective, if placed in a column the size of a football field, that amount of spent shale would reach roughly 1.5 miles high.
608 *Id*. at 4-9.
609 *Id*. at 4-9.
610 PRINDLE, *supra* note 355 at 6.
611 BUREAU OF RECLAMATION, U.S. DEPARTMENT OF INTERIOR, QUALITY OF WATER, COLORADO RIVER BASIN PROGRESS REPORT NO. 23. 9 (2009).
612 *Id*.

intended to reduce salinity contributions, the Uinta Basin contributed 450,000 tons of salt per year to the Colorado River.[613] Efforts have reduced salinity delivery within the Uinta Basin by approximately 135,000 tons of salt per year.[614]

Within the Upper Colorado River Basin, programs focus on meeting interstate and international water quality standards. In 1973, the Internal Boundary and Water Commission ratified Minute No. 242, requiring the United States to adopt salinity control measures ensuring that water delivered to Mexico met salinity requirements.[615] In 1974, Congress enacted the Colorado River Basin Salinity Control Act,[616] which, in its amended form, controls construction, operation and maintenance of salinity control works within the Colorado River Basin. Title I of the Act addresses the United States' commitments to Mexico.[617] Title II created the Colorado River Basin Salinity Control Program, directing federal agencies to manage the river's salinity, including salinity contributed from public lands.[618] The Act directs that preference be given to those projects that are the most cost-effective in obtaining the greatest reduction in salinity concentration per dollar spent.[619]

Oil shale and oil sands development utilizing surface mining techniques have the potential to detach significant quantities of sediment that could be delivered to the Colorado River or its tributaries, which would increase salinity. Mining will fracture rock, increasing permeability and groundwater infiltration. Dewatering may be required, necessitating careful consideration of disposal technologies. Surface retorting of shale would likewise involve

---

[613] NATURAL RESOURCES CONSERVATION SERVICE, COLORADO RIVER SALINITY CONTROL PROGRAM UINTA BASIN UNIT MONITORING AND EVALUATION REPORT, FY2007 8 (April 17, 2008).
[614] *Id.* at 14.
[615] International Boundary and Water Commission, United States and Mexico, Minute No. 242 Permanent and Definitive Settlement of the International Problem of the Salinity of the Colorado River (Aug. 30, 1973).
[616] Pub. L. 93-320, codified as amended at 43 U.S.C. § 1571.
[617] 43 U.S.C. § 1571 – 80.
[618] *Id*. at §§ 1591 – 99.
[619] *Id*. at § 1578.

crushing and retorting, which increases permeability, and with it, the likelihood that minerals will leach from tailing piles. Process water is also high in sodium and other trace minerals.[620]

Both natural precipitation and water applied to cool spent shale will cause mineral leaching. The extent to which existing technologies can provide long-term water quality protection should be evaluated carefully. While in situ technologies will greatly reduce surface disturbance, fracturing and retorting will increase permeability, and with it, the potential to mobilize salts or other minerals. In general, these concerns will be addressed through stormwater management and discharge permitting.

F. Conclusion and Recommendations

There is insufficient information regarding the number, size, and location of oil shale and oil sands facilities or the associated extraction and retorting processes to discuss specific impacts on water quality and competing water uses. It is undisputed that development could severely impact water dependent values. Those interested in developing oil shale or oil sands resources on public land are required to provide important information as part of the leasing process, and this information will provide the basis for more detailed water quality assessments. The most significant and unique constraints appear to involve endangered species.

Most of the major streams within the Piceance and Uinta basins are critical habitat for one or more fish species. The effect that diversions, storage, and effluent discharges will have on flow and habitat quality stand as the most formidable challenges to water development. The ESA represents a unique barrier to water development and development's proximity to that barrier must be clearly understood by all parties at the outset.

Water quality concerns associated with oil shale and oil sands development are a product of uncertainty regarding the technologies that will be utilized to produce and upgrade kerogen and bitumen, uncertainty regarding their effluent stream, and uncertainty regarding the ability to manage the effluent stream to prevent environmental harm and endangerment of

---

620 UNIVERSITY OF WISCONSIN-MADISON, *supra* note 193 at 138-40.

human life. While the quantity and quality of effluent streams remain uncertain, the environmental protections that will apply generally fit within a well-defined regulatory structure. Potential concerns fit within two broad categories – effluent discharges and stormwater runoff. In both cases, the size of the industry is at present the best indicator of the level of impacts that are likely to occur. Prospective in situ developers should, however, pay close attention to evolutions in hydraulic fracturing regulations and its implications for oil shale and oil sands development.

APPENDIX A
WATER FOR TAR SANDS ON FEDERAL LANDS
SPECIAL TAR SANDS AREAS OPEN UNDER PEIS ALT. B

STSA Name	BLM Acres	Split Estate Acres	Total Acres	Water Right Area #	Status
Argyle Canyon (Vernal, Price & Salt Lake (?) Field Offices; Wasatch, Utah, Duchesne & Carbon counties)	1,022	10,204	11,226	43 (very small portion) / 90 / 91	43 - Surface waters are fully appropriated, except for isolated springs. New diversions and consumptive uses must be accomplished by change applications filed on owned or acquired rights. Non-consumptive use applications will be considered on their individual merits. 43 – Limited groundwater is available. Appropriations from isolated springs and groundwater are generally limited to sufficient amounts to serve the domestic needs of one family, irrigate 0.25 acres, and support ten head of livestock. In the Strawberry River drainage above Soldier Creek dam and the Red Creek drainage above Red Creek dam, applications are limited to in-house domestic use only. Water is available for larger projects on a temporary or fixed-time basis in the lower reaches of the drainage. 90 - Surface waters are fully appropriated. New diversions and consumptive uses of surface waters must be accomplished by change applications filed on valid existing water rights owned or acquired by the applicant. Some water is available for larger appropriations on a temporary (one-year) or fixed time period basis. Non-consumptive uses would be considered on the merits of each application. 90 - Limited groundwater resources are available. Isolated springs in the Argyle Canyon area must meet the criteria outlined in the 2007 policy declaration. Permanent applications for isolated springs and groundwater are generally limited to sufficient amounts to serve the domestic purposes of one family, irrigate one acre, and support ten head of livestock. 91 - Surface waters are fully appropriated. New diversions and consumptive uses of surface sources must be accomplished by change applications filed on valid existing water rights owned or acquired by the applicant. Some water is available for larger appropriations on a temporary (one-year) or fixed time period basis. Non-consumptive uses would be considered on the merits of each application. 91 - Limited groundwater is available. Permanent applications for isolated springs and underground water are generally limited to sufficient amounts to serve the domestic purposes of one family, irrigate one acre, and support ten head of livestock.
Asphalt Ridge (Vernal FO; Uintah County)	5,310	125	5,435	45	Surface waters are fully appropriated, except for isolated springs. New diversions and consumptive uses must be accomplished by change applications filed on owned or acquired rights. A large block of water under the Flaming Gorge Project has been transferred to the State of Utah and is available for some of these changes. Filings made after November 30, 1994, which divert from the Green River between Flaming Gorge Dam and the confluence with the Duchesne River are subject to bypass flow requirements, during the period of June 22 to November 1, as required by a state-federal cooperative agreement regarding endangered fish in the Colorado River basin. Non-consumptive use applications will be considered on their individual merits. Limited groundwater is available. Appropriations from isolated springs and groundwater are generally limited to sufficient amounts to serve the domestic needs of one family, irrigate one acre, and support a reasonable amount of livestock. Water is available for larger projects on a temporary or fixed-time basis, (generally limited to five years). Changes from surface to underground sources, and vice versa, are also considered on their individual merits, with emphasis on the existence of a hydrologic tie between the two sources, the potential for interference with existing rights, and to ensure that there is no enlargement of the underlying rights.

Hill Creek (Vernal FO; Uintah County)	19,923	36,583	56,506	49	Surface waters are fully appropriated, except for isolated springs. New diversions and consumptive uses must be accomplished by change applications filed on owned or acquired rights. A large block of water under the Flaming Gorge Project has been transferred to the State of Utah and is available for some of these changes. Non-consumptive use applications will be considered on their individual merits. Limited groundwater is available. Appropriations from isolated springs and groundwater are generally limited to sufficient amounts to serve the domestic needs of one family, irrigate one acre, and support a reasonable amount of livestock. Water is available for larger projects on a temporary or fixed-time basis, (generally limited to five years). Changes from surface to underground sources, and vice versa, are also considered on their individual merits, with emphasis on the existence of a hydrologic tie between the two sources, the potential for interference with existing rights, and to ensure that there is no enlargement of the underlying rights.
Pariette (Vernal FO; Uintah & Duchesne counties)	10,083	78	10,161	43 / 47	43 - Surface waters are fully appropriated, except for isolated springs. New diversions and consumptive uses in these sources must be accomplished by change applications filed on owned or acquired rights. Non-consumptive use applications will be considered on their individual merits. 43 - Limited groundwater is available. Appropriations from isolated springs and groundwater are generally limited to sufficient amounts to serve the domestic needs of one family, irrigate 0.25 acres, and support ten head of livestock. In the Strawberry River drainage above Soldier Creek dam and the Red Creek drainage above Red Creek dam applications are limited to in-house domestic use only. Water is available for larger projects on a temporary or fixed-time basis in the lower reaches of the drainage. 47 - Surface waters are fully appropriated, except for isolated springs. New diversions and consumptive uses must be accomplished by change applications filed on owned or acquired rights. A large block of water under the Flaming Gorge Project has been transferred to the State of Utah and is available for some of these changes. Non-consumptive use applications will be considered on their individual merits. 47 - Limited groundwater is available. Appropriations from isolated springs and groundwater are generally limited to sufficient amounts to serve the domestic needs of one family, irrigate one acre, and support a reasonable amount of livestock. Water is available for larger projects on a temporary or fixed-time basis, (generally limited to five years). Changes from surface to underground sources, and vice versa, are also considered on their individual merits, with emphasis on the existence of a hydrologic tie between the two sources, the potential for interference with existing rights, and to ensure that there is no enlargement of the underlying rights.
P.R. Springs (Vernal & Moab FOs; Uintah & Grand counties)	145,922	7,081	153,003	49	Surface waters are fully appropriated, except for isolated springs. New diversions and consumptive uses must be accomplished by change applications filed on owned or acquired rights. A large block of water under the Flaming Gorge Project has been transferred to the State of Utah and is available for some of these changes. Non-consumptive use applications will be considered on their individual merits. Limited groundwater is available. Appropriations from isolated springs and underground water are generally limited to sufficient amounts to serve the domestic needs of one family, irrigate one acre, and support a reasonable amount of livestock. Water is available for larger projects on a temporary or fixed-time basis (generally limited to five years). Changes from surface to underground sources, and vice versa, are also considered on their individual merits, with emphasis on the existence of a hydrologic tie between the two sources, the potential for interference with existing rights, and to ensure that there is no enlargement of the underlying rights.

Raven Ridge (Vernal FO; Uintah County)	14,348	16	14,364	49	Surface waters are fully appropriated, except for isolated springs. New diversions and consumptive uses must be accomplished by change applications filed on owned or acquired rights. A large block of water under the Flaming Gorge Project has been transferred to the State of Utah and is available for some of these changes. Non-consumptive use applications, such as hydroelectric power generation, will be considered on their individual merits. There is a limited ground-water resource available. Appropriations from isolated springs and underground water are generally limited to sufficient acre-foot amounts to serve the domestic needs of one family, irrigate one acre, and support a reasonable amount of livestock. Water is available for larger projects on a temporary or fixed-time basis (generally limited to five years). Changes from surface to underground sources, and vice versa, are also considered on their individual merits, with emphasis on the existence of a hydrologic tie between the two sources, the potential for interference with existing rights, and to ensure that there is no enlargement of the underlying rights.
San Rafael Swell (Price FO; Emery County)	70,475	0	70,475	93 / 94 (same requirements for both areas)	Surface waters of the area are fully appropriated. New diversions and consumptive uses from surface sources must be accomplished by change applications filed on valid existing water rights owned or acquired by the applicant. Some water is available for larger appropriations on a temporary (one-year) or fixed-time period basis. Non-consumptive uses would be considered on the merits of each application. Limited groundwater is available. Permanent applications in valley locations are generally limited to sufficient amounts to serve the domestic purposes of one family, irrigate one acre, and support ten head of livestock.
Sunnyside (Price FO; Carbon County)	61,093	17,023	78,116	90	Surface waters of the area are fully appropriated. New diversions and consumptive uses from surface sources must be accomplished by change applications filed on valid existing water rights owned or acquired by the applicant. Some water is available for larger appropriations on a temporary (one-year) or fixed-time period basis. Non-consumptive uses would be considered on the merits of each application. Limited groundwater is available. Isolated springs in the Argyle Canyon area must meet the criteria outlined in the 2007 policy declaration. Permanent applications for isolated springs and underground water are generally limited to sufficient amounts to serve the domestic purposes of one family, irrigate one acre, and support ten head of livestock.
Tar Sands Triangle (Richfield FO; Wayne & Garfield counties)	24,938	0	24,938	95	New surface diversions and uses must be accomplished by change applications filed on owned or acquired existing rights. The State Engineer believes that there is limited unappropriated groundwater available. Generally this supply is to be allocated only for domestic purposes of one family (0.45 AF), irrigation of 0.25 acre (0.75 AF), and a nominal amount of stockwatering to individual applicants.
White Canyon (Monticello FO; San Juan County)	7,001	0	7,001	99	New appropriations are limited to small amounts of beneficial use sufficient to serve the domestic requirements of one family, irrigate one acre, and support ten head of livestock. New diversions and consumptive uses that require more water must be accomplished by filing a change application on valid existing water rights owned or acquired by the applicant. Some water is available for larger appropriations on a temporary (one-year) or fixed time period basis. Non-consumptive uses would be considered on the individual merits of each application.

In general, the State Engineer is placing all applicants on notice that that development should be pursued as soon as possible and extension of time requests will be critically reviewed.

BIBLIOGRAPHY & LIST OF AUTHORITIES

BIBLIOGRAPHY

AM. PETROLEUM INST., HYDRAULIC FRACTURING OPERATIONS—WELL CONSTRUCTION AND INTEGRITY GUIDELINES (2009).

AM. SOC'Y OF CIVIL ENG'RS, GUIDELINES FOR CLOUD SEEDING TO AUGMENT PRECIPITATION (2d. ed. 2006).

ANDREWS, ANTHONY, CONG. RESEARCH SERV., OIL SHALE: HISTORY, INCENTIVES, AND POLICY (2006).

BALDWIN, PAMELA, CONG. RESEARCH SERV., LEGAL ISSUES RELATED TO LIVESTOCK WATERING IN FEDERAL GRAZING DISTRICTS (1994).

Barrett, Colby, *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).

Barron, Joan, CASPER STAR-TRIBUNE, *Gov: Water Diversion Potential Endangered Species Concern* (April 16, 2009).

BARTIS ET ALL., RAND CORP., OIL SHALE DEVELOPMENT IN THE UNITED STATES: PROSPECTS AND POLICY ISSUES (2005).

BECHTEL PETROLEUM INC., WHITE RIVER SHALE PROJECT, DETAILED DEVELOPMENT PLAN, OIL SHALE TRACTS UA AND UB (1981).

BECK, ROBERT E. AND AMY L. KELLEY, EDS., WATER AND WATER RIGHTS (3d ed. 2009).

Borys, Randolph D., et. all, *Mountaintop and Radar Measurements of Anthropogenic Aerosol Effects on Snow Growth and Snowfall Rate*, 30 GEOPHYSICAL RESEARCH LETTERS No, 10 (2003).

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 ENVTL. IMPACT STATEMENT (2008).

BUREAU OF LAND MGMT., U.S. DEP'T OF INTERIOR, FINAL WHITE RIVER DAM PROJECT ENVTL. IMPACT STATEMENT (1982).

BUREAU OF LAND MGMT., U.S. DEP'T OF INTERIOR, FINAL ENVTL IMPACT STATEMENT FOR THE PROTOTYPE OIL SHALE LEASING PROGRAM (1973).

BUREAU OF LAND MGMT., U. S. DEP'T OF INTERIOR, VERNAL FIELD OFFICE PROPOSED RESOURCE MANAGEMENT PLAN AND FINAL ENVTL. IMPACT STATEMENT (2008).

BUREAU OF RECLAMATION, U.S. DEP'T OF THE INTERIOR, PROVISIONAL UPPER COLORADO RIVER BASIN CONSUMPTIVE USES AND LOSSES REPORT 2006-2010 (2009).

BUREAU OF RECLAMATION, U.S. DEP'T OF THE INTERIOR, PROVISIONAL UPPER COLORADO RIVER BASIN CONSUMPTIVE USES AND LOSSES REPORT 2001-2005 (2007).

BURIAN, STEVE, UNIV OF UTAH DEP'T OF CIVIL & ENVTL. ENG'G, FINAL REPORT ON PROJECT: MEETING DATA NEEDS TO PERFORM A WATER IMPACT ASSESSMENT FOR OIL SHALE DEVELOPMENT IN THE UINTA AND PICEANCE BASINS (2009).

Burnham, Alan K. and James R. McConaghy, *Comparison of the Acceptability of Various Oil Shale Processes*, PROCEEDINGS OF THE 26TH OIL SHALE SYMPOSIUM, COLORADO SCH. OF MINES (2006).

CANADIAN ASS'N OF PETROLEUM PRODUCERS, TECHNICAL REPORT, STATISTICAL HANDBOOK FOR CANADA'S UPSTREAM PETROLEUM INDUSTRY (2009).

Clyde, Steven E., *Marketplace Reallocation in the Colorado River Basin: Better Utilization of the West's Scarce Water Resources*, 28 J. LAND RESOURCES & ENVTL. L. 49 (2008).

COLORADO WATER CONSERVATION BD., STATEWIDE WATER SUPPLY INITIATIVE (2004).

COLORADO WATER CONSERVATION BD., STATEWIDE WATER SUPPLY INITIATIVE FACT SHEET (2006).

COMM. FOR THE NAT. ACADEMIES, SUMMIT ON AMERICA'S ENERGY FUTURE (2008).

DANIELS, JEFFREY IRVIN, LAWRENCE LIVERMORE NAT'L LAB., ENVIRONMENTAL, HEALTH, SAFETY, AND SOCIOECONOMIC IMPACTS ASSOCIATED WITH OIL RECOVERY FROM TAR-SAND DEPOSITS IN THE UNITED STATES (1981).

Darin, Thomas F., *Waste or Wasted?—Rethinking the Regulation of Coalbed Methane Byproduct Water in the Rocky Mountains: A Comparative Analysis of Approaches to Coalbed Methane Produced Water Quantity Legal Issues in Utah, New Mexico, Colorado, Montana, and Wyoming*, 17 J. ENVTL. L. & LITIG. 281 (2002).

DENVER POST, *Concerns Raised about Wyo-Col Water Pipeline* (April 15, 2009).

DENVER POST, *Corps' Look at Water Project Questioned* (April 13, 2009).

DIV. OF OIL, GAS, AND MINING, UTAH DEP'T OF NATURAL RES., SUMMARY PRODUCTION REPORT BY COUNTY (2009).

DIV. OF WATER RES., UTAH DEP'T OF NATURAL RES., MUNICIPAL AND INDUSTRIAL WATER SUPPLY AND USES IN THE UINTAH BASIN (2007).

DIV. OF WATER RES., UTAH DEP'T OF NATURAL RES., UTAH STATE WATER PLAN: UINTA BASIN (1999).

DIV. OF WATER RES., UTAH DEP'T OF NATURAL RES., WHITE RIVER DAM PROJECT: PROPOSED ACTION PLAN (REVISED) (1980).

DIV. OF WATER RES., UTAH DEP'T OF NATURAL RES., WATER-RELATED LAND USE INVENTORIES: UINTAH BASIN 2006 INVENTORY (2007).

DIV. OF WILDLIFE RES., UTAH DEP'T OF NATURAL RES., THE WHITE RIVER AND ENDANGERED FISH RECOVERY: A HYDROLOGICAL, PHYSICAL AND BIOLOGICAL SYNOPSIS (2000).

Dudley, Melinda, *Water District Opposes Shell Oil Request*, THE STEAMBOAT PILOT AND TODAY (Feb. 28, 2009).

ENVT'L WORKING GROUP, DRILLING AROUND THE LAW (2009).

FISH & WILDLIFE SERV., U.S. DEP'T OF THE INTERIOR, WHITE RIVER BASE FLOW STUDY FOR ENDANGERED FISHES, COLORADO AND UTAH, 1995-1996 (2004).

FISH AND WILDLIFE SERV., U.S. DEP'T OF THE INTERIOR, FINAL PROGRAMMATIC BIOLOGICAL OPINION FOR BUREAU OF RECLAMATION'S OPERATIONS AND DEPLETIONS, OTHER DEPLETIONS, AND FUNDING AND IMPLEMENTATION OF RECOVERY PROGRAM ACTIONS IN THE UPPER COLORADO RIVER ABOVE THE CONFLUENCE WITH THE GUNNISON RIVER (1999).

FOLGER, PETER, ET AL., CONG. RESEARCH SERV., DROUGHT IN THE UNITED STATES: CAUSES AND ISSUES FOR CONGRESS (2009).

Gearino, Jeff, CASPER STAR-TRIBUNE, *Water Project Draws Ire* (April 15, 2009).

Givati, Amir and Daniel Rosenfeld, *Separation Between Cloud-Seeding and Air-Pollution Effects*, 44 J. OF APPLIED METEOROLOGY 1298-1314 (2005).

Givati, Amir and Daniel Rosenfeld, *Quantifying Precipitation Suppression Due to Air Pollution*, 43 J OF APPLIED METEOROLOGY 1038 (2004).

Griffith, Don A. and Mark E. Solak, *Cloud Seeding in the Upper Colorado Basin: Technical Feasibility*, SOUTHWEST HYDROLOGY (March/April 2007).

Havens, Mark, *Geologist: Southern Utah Aquifer Could be Developed*, SALT LAKE TRIBUNE (June 14, 2009).

Hansen, Adrian N., Note, The Endangered Species Act and Extinction of Reserved Rights on the San Juan River, 37 ARIZ. L. REV. 1305 (1995).

HANSON, JASON & PATTY LIMERICK, UNIV. OF COLO, WHAT EVERY WESTERNER SHOULD KNOW ABOUT OIL SHALE: A GUIDE TO SHALE COUNTRY (2009).

Henetz, Patty, *Utah Nuclear Power Proposal Has a Powerful Thirst*, SALT LAKE TRIBUNE (April 6, 2009).

Hightower, Mike, *At the Crossroads: Energy Demands for Water Versus Water Availability*, SOUTHWEST HYDROLOGY (May/June 2007).

HUNDLEY, NORRIS JR., WATER AND THE WEST: THE COLORADO RIVER COMPACT AND THE POLITICS OF WATER IN THE AMERICAN WEST (1975).

Int'l Boundary and Water Comm'n, United States and Mexico, Minute No. 242 Permanent and Definitive Settlement of the International Problem of the Salinity of the Colorado River (Aug. 30, 1973).

INTERNATIONAL ENGINEERING CO., WHITE RIVER STUDY (1983).

Jaffe, Mark, *Yampa River Water Plan Hits Wall of Foes*, THE DENVER POST (March 12, 2009).

Jirak, Israel L. and William R. Cotton, *Notes and Correspondence: Effects of Air Pollution on Precipitation Along the Front Range of the Rocky Mountains*, 45 J. OF APPLIED METEOROLOGY AND CLIMATOLOGY 236 (2005).

Kelly, Erin N. et al., *Oil Sands Development Contributes Polycyclic Aromatic Compounds to the Athabasca River and its Tributaries*, PROCEEDINGS OF THE NAT'L ACADEMIES OF SCIENCE 22346-22351 (2009).

KENNEY, JOAN F. ET AL., U.S. GEOLOGICAL SURVEY, ESTIMATED USE OF WATER IN THE UNITED STATES IN 2005 (2009).

KUHN, Eric, THE COLORADO RIVER: THE STORY OF A QUEST FOR CERTAINTY ON A DIMINISHING RIVER (Roundtable Ed. May 8, 2007).

Light, Erin C. H., Division Engineer, Colo. Div. of Water Res., telephone interview (Jan. 4, 2010).

Loftholm, Nancy, DENVER POST, *Fears of Tainted Water Well Up in Western Colorado* (Oct. 10, 2009).

Lustgarten, *Abrahm, Frack Fluid Spill in Dimock Contaminates Stream, Killing Fish*, PROPUBLICA (Sept. 21, 2009).

MCCOOL, DANIEL, NATIVE WATERS: CONTEMPORARY INDIAN WATER SETTLEMENTS AND THE SECOND TREATY ERA (2002).

MCCOOL, DANIEL, ED., WATERS OF ZION, THE POLITICS OF WATER IN UTAH (1995).

MCCOOL, DANIEL, *The Northern Utes' Long Water Ordeal*, HIGH COUNTRY NEWS (July 15, 1991).

Meko, David M. et al., *MEDIEVAL DROUGHT IN THE UPPER COLORADO RIVER BASIN*, GEOPHYSICAL RESEARCH LETTERS (2007).

Mighell, Edwin R., Stantec Consulting, Inc., Letter to Utah Division of Water Rights re: Request for Extension of Time on Water Right Number 49-258 (A36730) (May 22, 2008).

MASSACHUSETTS INSTITUTE OF TECHNOLOGY, THE FUTURE OF COAL (2007).

Mittal, Anu, Gov't Accountability Office, Testimony Before the Subcomm. on Energy and Envt., Comm. on Science and Technology, House of Representatives, Preliminary *Observations on the Links Between Water and Biofuels and Electricity Production* (July 9, 2009).

MODDE, TIMOTHY, ET AL., U.S. FISH & WILDLIFE SERV., DETERMINATION OF HABITAT AVAILABILITY, HABITAT USE, AND FLOW NEEDS OF ENDANGERED FISHES IN THE YAMPA RIVER BETWEEN AUGUST AND OCTOBER, RECOVERY IMPLEMENTATION PROGRAM PROJECT (1999).

NATURAL RES. CONSERVATION SERV., U.S. DEP'T OF AGRIC., COLORADO RIVER SALINITY CONTROL PROGRAM UINTA BASIN UNIT MONITORING AND EVALUATION REPORT, FY2007 (2008).

NATIONAL RESEARCH COUNCIL, COMMITTEE ON THE SCIENTIFIC BASES OF COLORADO RIVER BASIN WATER MANAGEMENT, COLORADO RIVER BASIN WATER MANAGEMENT: EVALUATING AND ADJUSTING TO HYDROCLIMATIC VARIABILITY (2007).

Nelson, Laura, Chair of the Utah Mining Assns' Oil Shale and Oil Sands Comm., testimony before the Utah Legislature's Interim Comm. on Natural Res., Agric., and the Env't (June 17, 2009).

NELSON, LAURA S. AND TIM J. WALL, UTAH MINING ASS'N, DEVELOPMENT OF UTAH OIL SHALE AND TAR SANDS RESOURCES (2008).

NEW YORK TIMES, *De-watering Wyoming* (April 20, 2009).

O'Donoghue, Amy Joi, *Critics Say N-Plant Would Harm Ecosystem*, DESERET NEWS (May 27, 2009).

OFFICE OF NAVAL PETROLEUM AND OIL SHALE RESERVES, U.S. DEP'T OF ENERGY, SECURE FUELS FROM DOMESTIC RESOURCES: THE CONTINUED EVOLUTION OF AMERICA'S OIL SHALE AND TAR SANDS INDUSTRIES (2008).

OHIO DEPT. OF NATURAL RES., DIV. OF MINERAL RES. MGMT., REPORT ON THE INVESTIGATION OF THE NATURAL GAS INVASION OF AQUIFERS IN BAINBRIDGE TOWNSHIP, OHIO (2008).

PRINDLE, DAVID F., CENTER FOR ENERGY STUDIES AT THE UNIV. OF TEXAS AT AUSTIN, SHALE OIL, WATER AND THE POLITICS OF AMBIGUITY (1982)

Rampton, Calvin L., Governor of Utah, letter to Colorado Governor John D. Vanderhoof, (Dec. 11, 1973).

ROEHM, GERALD W., U.S. FISH & WILDLIFE SERV., MANAGEMENT PLAN FOR ENDANGERED FISHES IN THE YAMPA RIVER BASIN AND ENVIRONMENTAL ASSESSMENT (2004)

Rosenfeld, Daniel and William L. Woodley, *The Double-Sided Sensitivity of Clouds to Air Pollution & Intentional Seeding* SOUTHWEST HYDROLOGY (March/April 2007).

Ross, Tom, *Shell Oil's Pursuit of Local Waters Could Have Big Impacts*, THE STEAMBOAT PILOT AND TODAY, (Jan. 11, 2009).

Ruple, John C. and Robert Keiter, Water for Commercial Oil Shale Development in Utah: Allocating Scarce Resources and the Search for New Sources of Supply, 30 J. LAND RESOURCES & ENVTL. L. 1 (2010)

Ruple, John C. and Robert Keiter, *Water for Commercial Oil Shale Development in Utah: Clarifying How Much Water is Needed and Available*, 28 J. ENERGY & NAT. RESOURCES L. 49 (2010).

RYAN, MARK A. ED., THE CLEAN WATER ACT HANDBOOK (2d ed. 2003).

Schlumberger Oil Field Glossary, http://www.glossary.oilfield.slb.com/default.cfm.

Sengebush, Robert M., *Deep Brackish Water Considered for New Mexico Development*, SOUTHWEST HYDROLOGY, (Mar./Apr. 2008).

Sept. 9, 1996 Presidential Proclamation establishing the Grand Staircase-Escalante National Monument, *available at* 32 WEEKLY COMPILATION OF PRESIDENTIAL DOCUMENTS 38 at pp. 1788-91 (Sept. 23, 1996).

SHURTS, JOHN, INDIAN RESERVED WATER RIGHTS: THE WINTERS DOCTRINE IN ITS SOCIAL AND LEGAL CONTEXT, 1880S-1930S (2000).

Smith, Collin, *Moffat County Commission Acts on Shell Water Filing*, THE STEAMBOAT PILOT AND TODAY (Feb. 20, 2009).

Smith, Jack H., *Another Transbasin Diversion Project Proposed,* THE GREEN RIVER STAR, (May 6, 2009).

Smith, Jack H., *Hundreds Gather at GRHS to Protest Proposed Transbasin Pipeline,* The GREEN RIVER STAR, (April 15, 2009).

SOUTHWEST HYDROLOGY, *KS, CO Reach Arkansas River Agreement* (Jan./Feb. 2010).

SOUTHWEST HYDROLOGY, *Pecos River Settlement Implemented* (Jan./Feb. 2010).

SOUTHWEST HYDROLOGY, *SNWA Supports Cloud Seeding* (Jan./Feb. 2010).

Streater, Scott ,*Water: New Study Details Effects of Soot Pollution in Snowpack, Water Supply in West*, PUBLIC LANDS LETTER (Jan. 22, 2009).

TARLOCK, A. DAN, LAW OF WATER RIGHTS AND RESOURCES (2008).

TARLOCK, A. DAN ET AL., WATER RESOURCE MANAGEMENT (5th ed. 2002).

Tarlock, A. Dan, *The Future of Prior Appropriations in the New West*, 41 NAT. RESOURCES J. 769 (2001).

TOPPER, RALF ET AL., COLORADO GEOLOGICAL SURVEY, GROUND WATER ATLAS OF COLORADO (2003).

UNIV. OF WISCONSIN-MADISON, OIL SHALE DEVELOPMENT IN NORTHWESTERN COLORADO: WATER AND RELATED LAND IMPACTS (1975).

URS CORP., DRAFT ENERGY DEVELOPMENT WATER NEEDS ASSESSMENT (PHASE I REPORT) (2008).

U.S. DEP'T OF AGRIC. AND DEP'T OF THE INTERIOR, MOON LAKE POWER PLANT PROJECT UNITS 1 AND 2 FINAL ENVTL. IMPACT STATEMENT (1981).

U.S. DEP'T OF ENERGY – HYDRAULIC FRACTURING WHITE PAPER (2004).

U.S. DEP'T OF ENERGY, ENERGY INFO. ADMIN., ANNUAL ENERGY OUTLOOK (2009).

U.S. DEP'T OF INTERIOR, RECORD OF DECISION, COLORADO RIVER INTERIM GUIDELINES FOR LOWER BASIN SHORTAGES AND THE COORDINATED OPERATIONS FOR LAKE POWELL AND LAKE MEAD (2007).

U.S. ENVTL. PROT. AGENCY, EVALUATION OF IMPACTS TO UNDERGROUND SOURCES OF DRINKING WATER BY HYDRAULIC FRACTURING OF COALBED METHANE RESERVOIRS (2004).

U.S. ENVTL. PROT. AGENCY, NPDES PERMIT WRITER'S MANUAL (1996).

U.S. OFFICE OF TECHNOLOGY ASSESSMENT, AN ASSESSMENT OF OIL SHALE TECHNOLOGIES (1980).

U.S. WATER RES. COUNCIL, SECTION 13(A) WATER ASSESSMENT REPORT, SYNTHETIC FUEL DEVELOPMENT IN THE UPPER COLORADO REGION (1981).

UTAH DEP'T OF ENVTL. QUALITY, UINTA WATERSHED MANAGEMENT UNIT WATER QUALITY ASSESSMENT – 2004 305(B).

UTAH DEP'T OF ENVTL. QUALITY, COLORADO RIVER SOUTHEAST WATERSHED MANAGEMENT UNIT WATER QUALITY ASSESSMENT – 2004 305(B).

UTAH DEP'T OF ENVTL. QUALITY, COLORADO RIVER WEST WATERSHED MANAGEMENT UNIT WATER QUALITY ASSESSMENT – 2004 305(B).

UTAH ENERGY OFFICE, UTAH DEP'T OF NATURAL RES. AND ENERGY, AN ASSESSMENT OF OIL SHALE AND TAR SANDS DEVELOPMENT IN THE STATE OF UTAH, PHASE II: POLICY ANALYSIS (1982).

UTE INDIAN TRIBE OF THE UINTAH AND OURAY RESERVATION, UTAH, TABULATION OF UTE INDIAN WATER RIGHTS (1990).

VANDEN BERG, MICHAEL D., UTAH GEOLOGICAL SURVEY, SALINE WATER DISPOSAL INTO THE BIRDS NEST AQUIFER IN UINTAH COUNTY, UTAH: IMPLICATIONS FOR POTENTIAL OIL SHALE DEVELOPMENT (2009).

VEIL, J.A. AND M.G. PUDER, ARGONNE NAT'L LAB., POTENTIAL GROUND WATER AND SURFACE WATER IMPACTS FROM OIL SHALE AND TAR SANDS ENERGY-PRODUCTION OPERATIONS (2006).

Watson, Rebecca W. *et al*., *Produced Water: Water Rights and Water Quality: "A 'Meeting' of the Waters"?,* PROCEEDINGS OF THE ROCKY MOUNTAIN MINERAL LAW FIFTY-SECOND ANNUAL INSTITUTE 12-1 (2006).

Waxman, Henry A., Chairman and Subcomm. Chairman Edward J. Markey, Mem. to Members of the Subcomm. on Energy and the Envt., regarding examining the potential impact of hydraulic fracturing (Feb. 18, 2010).

WESTERN RES. ADVOCATES, WATER ON THE ROCKS: OIL SHALE WATER RIGHTS IN COLORADO (2009).

Woodhouse et al., *Updated Streamflow Reconstructions for the Upper Colorado River Basin*, WATER RESOURCES RESEARCH (2006).

Woodward, Gary, *Alt-Fuel Development May Impact Natural Resources*, SOUTHWEST HYDROLOGY (March/April 2009).

Woodka, Chris, *Water Debate Takes on a New Ripple: Energy*, THE PUEBLO CHIEFTAIN (March 31, 2009).

WU ET AL., ARGONNE NAT'L LABORATORY, CONSUMPTIVE WATER USE IN THE PRODUCTION OF ETHANOL AND PETROLEUM GASOLINE (2009).

Zhirjakov, Y., *Ecological Aspects of Oil Shale Processing PROCEEDINGS OF THE 26TH OIL SHALE SYMPOSIUM, COLORADO SCHOOL OF MINES* (2006).

LIST OF AUTHORITIES

<u>US Supreme Court Opinions</u>

Arizona v. California, 376, U.S. 340 (1964).

Arizona v. California, 373 U.S. 546 (1963).

Babbitt v. Sweet Home Chapter of Communities for a Great Oregon, 515 U.S. 687 (1995).

California v. United States, 438 U.S. 645 (1978).

Cappaert v. United States, 426 U.S. 128 (1976).

Colorado v. Kansas, 320 U.S. 383 (1943).

Colorado v. New Mexico, 459 U.S. 176 (1982).

Hinderlider v. LaPlata River & Cherry Creek Ditch Co., 304 U.S. 92 (1938).

Kansas v. Colorado, 206 U.S. 46 (1907).

Nebraska v. Wyoming, 325 U.S. 589 (1945).

New Jersey v. New York, 283 U.S. 336 (1931).

Northeast Bankcorp, Inc. v. Board of Governors, 472 U.S. 159 (1985).

South Florida Water 1Mgmt. Dist. v. Miccosukee Tribe of Indians, 541 U.S. 95 (2004).

Sporhase v. Nebraska, 458 U.S. 941 (1982).

Texas v. New Mexico, 462. U.S. 544 (1983).

United States Steel Corp. v. Multistate Tax Comm'n, 434 U.S. 452 (1978).

United States v. New Mexico, 438 U.S. 696 (1978).

Winters v. United States, 207 U.S. 564 (1908).

Wyoming v. United States, 492 U.S. 406 (1989).

<u>Federal Appellate Opinions</u>

Legal Environmental Assistance Foundation v. EPA, 276 F.3d 1253 (11th Cir. 2001).

Legal Environmental Assistance Foundation v. EPA, 118 F.3d 1467 (11th Cir. 1997).

Natural Resources Defense Council v. EPA, 526 F.3d 591, (9th Cir. 2008).

Oklahoma v. EPA, 908 F.2d 595 (10th Cir. 1990).

Sanpete Water Conservancy Dist. v. Carbon Water Conservancy Dist., 226 F.3d 1170 (10th Cir. 2000).

Thomas v. Peterson, 753 F.2d 754 (9th Cir. 1985).

United States v. Adair, 723 F.2d 1394 (9th Cir. 1983).

United States v. Walker River Irrigation Dist., 104 F.2d 334 (9th Cir 1939).

<u>Federal Trial Court Opinions</u>

Bartelos & Wolfsen, Inc. v. Westlands Water Dist., 849 F.Supp. 717 (E.D. Cali. 1993).

Carson-Truckee Water Conservancy Dist. v. Clark, 549 F.Supp 704 (D.Nev. 1982) *affirmed in part, reversed in part* 741 F.2d 257 (9th Cir. 1984).

Catskill Mountain Chapter of Trout Unlimited v. EPA, 2009 WL 1174802, (S.D.N.Y. 2009).

Klamath Water User Protection Ass'n v. Patterson, 204 F.3d 1206 (9th Cir. 1999) *as amended* at 203 F.3d 1175 (9th Cir. 2000).

Oregon Natural Resources Defense Council v. Daley, 6 F.Supp. 2d 1139 (D. Or. 1998).

United States v. Alpine Land and Resources Co., 503 F. Supp. 877 (D. Nev. 1983), *affirmed as modified* at 697 F.2d 851, 858 (9th Cir. 1983).

United States v. Glenn-Colusa Irrigation Dist., 788 F.Supp 1126 (E.D. Cal. 1992).

Ute Indian Tribe v. State of Utah, 521 F.Supp. 1072, 1092-1150 (D. Utah 1981).

Arizona State Court Opinions

In re General Adjudication of All Rights to Use of Water in Gila River System and Source, 35 P.3d 68 (Ariz. 2001).

Colorado State Court Opinions

Bar 70 Enterprises, Inc. v. Highland Ditch Ass'n, 694 P.2d 1253 (Colo. 1985).

Bar 70 Enterprises, Inc. v. Tosco Corp, 703 P.2d 1297 (Colo. 1985).

Colorado Springs v. Bender, 366 P.2d 552, 555 (Colo. 1961).

McClennan v. Hurdle, 33 P. 280 (Colo 1893).

Medano Ditch Co. v. Adams, 68 P.431 (Colo. 1902).

Municipal Subdistrict, Northern Colorado Water Conservancy Dist. v. Chevron Shale Oil Co., 986 P.2d 918 (Colo. 1999).

Municipal Subdistrict, Northern Colorado Water Conservancy Dist. v. Getty Oil Exploration Co., 997 P.2d 557 (Colo. 2000).

Municipal Subdistrict, Northern Colorado Water Conservancy Dist. v. OXY USA, Inc., 990 P.2d 701 (Colo. 1999).

United States v. Bell, 724 P.2d 631 (Colo. 1986).

United States v. County of Denver, 656 P.2d 1, 12 (Colo. 1982).

Vance v. Simpson, No. 2005CW063, slip op. (Colo. Dist. Ct., Water Div. 7, July 2, 2007).

Vance v. Wolfe, 205 P.3d 1165 (Colo. 2009).

Idaho State Court Opinions

Shokal v. Dunn, 70 P.2d 441 (Idaho 1985).

Utah State Court Opinions

East Bench Irrigation Co. v. Deseret Irrigation Co., 271 P.2d 449 (Utah 1954).

Estate of Steed v. New Escalante Irrigation Co., 846 P.2d 1223 (Utah 1992).
Hardy v. Higginson, 849 P.2d 946 (1993).
Howcroft v. Union & Jordan Irrigation Co., 71 P. 487 (Utah 1903).
Lehi Irrigation Co. v. Jones, 202 P.2d 892 (Utah 1949).
Little Cottonwood Water Co.v. Kimbal, 289 P. 116 (Utah 1930).
Little Cottonwood Water Co. v. Sandy City, 258 P.2d 440 (Utah 1953).
Salt Lake City v. Gardner, 114 P. 147 (Utah 1911).
Salt Lake City v. Telluride Power Co., 17 P.2d 281 (Utah 1932).
Silver King Mining Co. v. Sutton, 39 P.2d 682 (Utah 1934).
Stookey v. Green, 178 P. 586 (Utah 1919).
Tanner v. Bacon, 136 P.2d 957 (Utah 1943).
Wayman v. Murray City Corp., 458 P.2d 861 (Utah 1969).

<u>New Mexico State Court Opinions</u>
State ex rel. Martinez *v. Lewis*, 861 P.2d 235 (N.M. Ct. App. 1993).

<u>Washington State Court Opinions</u>
Dep't of Ecology v. Grimes, 852 P.2d 1044 (Wash. 1993).
R.D. Merrill Co. v. State, Pollution Control Hearings Bd., 969 P.2d 458 (Wash. 1999).

<u>Wyoming State Court Opinions</u>
Bower v. Big Horn Canal Ass'n., 307 P.2d 593 (Wy. 1957).
William F. West Ranch v. Tyrell, 206 P.3d 722, (Wyo. 2009).

<u>Federal Constitutional Provisions</u>
U.S. Const. art I, § 8, cl. 3.
U.S. Const. art. III § 2.
U.S. Const. art VI, § 2.
U.S. Const. art IV, § 3, cl. 2.

<u>Federal Statutory Provisions</u>
16 U.S.C. §§ 1531 *et seq.*
16 U.S.C. § 1532.
16 U.S.C. § 1533.
16 U.S.C. § 1536.
16 U.S.C. § 1539.
25 U.S.C. § 177.
33 U.S.C. § 131.12.
33 U.S.C. § 131.21.
33 U.S.C. § 403.
33 U.S.C. § 1251.
33 U.S.C. §§ 1251 *et seq*.
33 U.S.C. § 1311.

33 U.S.C. § 1313.
33 U.S.C. § 1314.
33 U.S.C. § 1342.
33 U.S.C. § 1344.
33 U.S.C. § 1362.
42 U.S.C. § 300h.
42 U.S.C. § 4331.
42 U.S.C. § 4332.
43 U.S.C. § 383.
43 U.S.C. § 485h.
43 U.S.C. § 523-24.
43 U.S.C. § 617.
43 U.S.C. § 661.
43 U.S.C. § 666.
43 U.S.C. § 1513.
43 U.S.C. § 1571.
43 U.S.C. § 1571 *et seq*.
43 U.S.C. § 1578.
43 U.S.C. §§ 1591 *et seq*.
43 U.S.C. § 1721.
43 U.S.C. §§ 1761 *et seq*.
43 U.S.C. § 3922.
43 U.S.C. § 3931.
Pub. L. 81-37, 63 Stat. 31 (1949).
Pub. L. 93-320, 88 Stat 266. (1974)
Pub. L. 101-618, 104 Stat 3289 (1990).
Pub. L. 102-575, 106 Stat 4600 (1992).
Pub. L. 106-398, 114 Stat 1654 (2000).
Pub. L. 109-58, 119 Stat 594 (2005).
59 Stat. 1219 (1944).

<u>Federal Regulatory Provisions</u>

33 C.F.R. § 328.3.
40 C.F.R. § 122.3.
40 C.F.R. § 122.44.
40 C.F.R. § 122.26.
40 C.F.R. § 130.2.
40 C.F.R. § 131.21.
40 C.F.R. § 144.3
40 C.F.R. § 146.5.
40 C.F.R. § 144.6.
40 C.F.R. §§ 230.1 *et seq.*
40 C.F.R. § 230.10.
40 C.F.R. § 401.15.
40 C.F.R. § 401.16.
40 C.F.R. § 435.30.
40 C.F.R. § 435.32.
40 C.F.R. § 450.21.
40 C.F.R. § 450.22.
40 C.F.R. § 450.23.
43 C.F.R. § 3900.50.
43 C.F.R. § 3922.20.
43 C.F.R. § 3931.11.
50 C.F.R. § 222.102.

<u>Federal Regulatory Documents</u>

71 Fed. Reg. 32887 *et seq.* (June 7, 2006).
73 Fed. Reg. 33697 (June 13, 2008).
73 Fed. Reg. 43491 *et seq.* (July 25, 2008).
73 Fed. Reg. 79089 *et seq.* (Dec. 24, 2008).
74 Fed. Reg. 62998 (Dec. 1, 2009).
74 Fed. Reg. 63001 *et seq*. (Dec. 1, 2009).
74 FED. REG. 56867 *et seq.* (Nov. 3, 2009).
74 FED. REG. 11920 (March 20, 2009).

Arizona Statutory Provisions

ARIZ. REV. STAT. ANN. § 45-1302.

ARIZ. REV. STAT. ANN. § 45-1312.

Colorado Statutory Provisions

COLO. REV. STAT. § 37-61-101.

COLO. REV. STAT. § 37-62-101.

COLO. REV. STAT. § 37-92-102.

COLO. REV. STAT. § 37-90-103.

New Mexico Statutory Provisions

N.M. STAT. ANN. § 72-15-5.

N.M. STAT. ANN. § 72-15-26.

Utah Statutory and Regulatory Provisions

UTAH CODE ANN. § 40-6-5.

UTAH CODE ANN. § 73-1-1.

UTAH CODE ANN. § 73-1-4.

UTAH CODE ANN. § 73-1-10.

UTAH CODE ANN. § 73-3-1.

UTAH CODE ANN. § 73-3-2.

UTAH CODE ANN. § 73-3-3.

UTAH CODE ANN. § 73-3-6

UTAH CODE ANN. § 73-3-7.

UTAH CODE ANN. § 73-3-8.

UTAH CODE ANN. § 73-3-10.

UTAH CODE ANN. § 73-3-12.

UTAH CODE ANN. § 73-3-16.

UTAH CODE ANN. § 73-3-17.

UTAH CODE ANN. § 73-3-20.

UTAH CODE ANN. § 73-3-21 (2008).

UTAH CODE ANN. § 73-3-29.

UTAH CODE ANN. §§ 73-3b-101 *et seq*.

UTAH CODE ANN. § 73-3b-103.

UTAH CODE ANN. § 73-3b-106.

UTAH CODE ANN. § 73-3b-202.

Utah Code Ann. § 73-4-2.

UTAH CODE ANN. § 73-5a-201.

UTAH CODE ANN. § 73-5a-202.

UTAH CODE ANN. § 73-12a-1.

UTAH CODE ANN. § 73-13-9.

UTAH CODE ANN. § 73-15-4.

UTAH CODE ANN. § 73-19-7.

UTAH CODE ANN. § 73-21-1.

UTAH CODE ANN. § 73-21-2.

UTAH ADMIN. CODE § R653-8-3.

Washington Statutory Provisions

WASH. REV. CODE § 90-42-030.

WASH. REV. CODE § 90-42-040.

WYOMING STATUTORY PROVISIONS

WYO. STAT ANN. § 41-3-930.

WYO. STAT. ANN. § 41-12-301.

WYO. STAT. ANN. § 41-12-401.

National Energy Technology Laboratory

626 Cochrans Mill Road
P.O. Box 10940
Pittsburgh, PA 15236-0940

3610 Collins Ferry Road
P.O. Box 880
Morgantown, WV 26507-0880

13131 Dairy Ashford, Suite 225
Sugarland, TX 77478

1450 Queen Avenue SW
Albany, OR 97321-2198

2175 University Ave. South
Suite 201
Fairbanks, AK 99709

Visit the NETL website at:
www.netl.doe.gov

Customer Service:
1-800-553-7681