ENERGY DEVELOPMENT WATER NEEDS ASSESSMENT
PHASE II

FINAL REPORT

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Prepared by:

amec

For

Colorado River Basin Roundtable and Yampa/White River Basin Roundtable

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PREFACE

The Energy Subcommittee of the Colorado and Yampa/White Basin Roundtables has completed a study of energy development and water demands in Western Colorado that reaches important conclusions for policy-makers and citizens to consider. To help readers understand the study and employ it in planning, we offer this introduction to the work and its conclusions.

The study was commissioned jointly in 2007 by the Colorado and Yampa/White River Basin Roundtables, which were chartered by the General Assembly in 2005 under HB 05-1177 to complete water needs assessments in their respective basins, among other tasks. An Energy Subcommittee, whose members were appointed by both Roundtables, guided the work. The Subcommittee met numerous times over the course of the study and its meetings were open to any interested party.

In 2008, Phase I of the study was completed. Phase I's primary purpose was to estimate water demands in aggregate for each of the energy sectors – oil shale, natural gas, coal and uranium. Phase I also included estimates of water demands for the electrical generation needed to fuel energy production and the municipal water demands stemming from the increased population of workers. To our knowledge no such comprehensive study had ever been undertaken.

The Phase I study included water demands that were quite high – more than 400,000 acre-feet of water annually[1] – the vast majority for oil shale development and of that, more than 200,000 acre-feet was for electrical generation to serve in-situ (in place) oil shale production. At that time, energy interests criticized the estimates, saying they overstated oil shale's water demands.

In Phase II of the study, the Energy Subcommittee agreed to reexamine oil shale water demands and to work closely with energy interests in the formulation of those demands. The result is that overall demand estimates put forward in Phase I were cut to approximately 120,000 acre-feet, a dramatic reduction.

[1] An acre-foot is 325,851 gallons. For point of reference, roughly 500,000 acre-feet is diverted annually from the Colorado River for agricultural and municipal uses on the Front Range.

The other primary purpose for Phase II was to examine how energy demands for water could be met.

Important conclusions and caveats from the assessment:

- **The Study Is Not Predictive.** The study is intended to portray a range of scenarios – from high to low – of the water demands that could materialize in the future from energy development, including oil shale, natural gas, coal, and uranium mining. That range is large, from essentially zero to upwards of 120,000 acre-feet annually. What demands will actually occur depend on factors other than water availability. Those factors include technological and economic viability, future energy demands and availability and other limitations including environmental and local permitting.

- **The Relation to State-wide Water Planning.** This study is undertaken in the context of an ongoing effort at state-wide water supply planning. An emerging recognition is that a portion of additional water demands from the Front Range will need to be met from additional supplies from the West Slope. From the West Slope perspective, we believe it is important to assert that West Slope requirements for water should not take a back seat to East Slope needs. The identification of energy development water needs is critically important. If sufficient water is not available for energy development, we believe other existing uses of water – invariably from agriculture – will be converted for energy development. The East Slope does not want to see extensive "buy and dry" of its agricultural water, neither does the West Slope.

- **Oil shale versus Other Energy Water Demands**. The lion's share of water demands stem from oil shale development and the electrical generation and population increases needed to accommodate it. Water demands from the other energy sectors – natural gas, coal and uranium – are not insignificant but they do not pose the local, regional and state-wide issues that oil shale does.

- **White River Supplies Are Adequate.** The bulk of the water demands for energy development will occur in the White River Basin and White River supplies are adequate to accommodate an oil shale industry that produces up to 1.5 million barrels per day. Storage will be required to satisfy those demands and it appears that either an enlargement of Lake

Avery or development of a new reservoir at Wolf Creek – or both -- could be accomplished to meet that need. Other reservoir sites may also be adequate. For example, the Yellow Jacket Water Conservancy District is commissioning a more comprehensive study of reservoir sites in the Basin and one or more may emerge as preferable to Lake Avery or Wolf Creek. Again, we did not intend our study to be limiting or defining in terms of storage options. We simple intended to show two options that could work to meet demands.

- **Possible Multipurpose Water Project.** When we began this study several years ago we thought it might be possible to work with energy interests and look to develop storage supplies that could meet water needs of a number of energy companies, thereby avoiding what Meeker attorney Frank Cooley has termed a "spaghetti bowl" of water pipelines and projects needed to serve energy. Additionally, we thought that for a relatively low cost, storage facilities could be increased in size incrementally and thereby provide water supplies for not just energy but also other municipal, agricultural and environmental purposes. Since our study began, the climate for oil shale development has cooled considerably. We still believe, however, that should planning for an energy development water project proceed, cooperative opportunities should be explored to develop a multipurpose project.

Daniel R. Birch, Energy Subcommittee Co-Chair

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ACRONYM LIST

For the purpose of this report, the following terms are defined as:

Term	Definition
the Act	Colorado Water for the 21st Century Act
af	acre-feet
bbl/bbl	barrels of water required to produce one barrel of oil
bbl/day	barrels per day
CCGT	combined-cycle gas turbine
cfs	cubic feet per second
CWCB	Colorado Water Conservation Board
gpcd	gallons per capita per day
IBCC	Interbasin Compact Committee
kW·h	kilowatt·hours
MW·h	megawatt·hours
MW·h/yr	megawatt·hours per year
NOSA	National Oil Shale Association
StateMod	State of Colorado's Stream Simulation Model
SWSI	Statewide Water Supply Initiative

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EXECUTIVE SUMMARY

The Energy Development Water Needs Assessment, Phase II study provides information about the amount of water required to supply future oil shale development in northwestern Colorado, and evaluates water supply projects that could be developed to meet those water needs. The work described in this study refined information contained in the Energy Development Water Needs Assessment Phase I study, completed in September 2008, in which estimates were made regarding water demands associated with the development of energy in northwestern Colorado. In the Phase I study, four energy sectors were addressed: natural gas, coal, uranium and oil shale. The work described in this study, referred herein as the Phase II study, focused on refining only the water requirements of a future oil shale industry. Water demands developed in Phase I associated with the development of natural gas, coal and uranium were not changed in the Phase II study.

The Phase II study also used information regarding water rights that was developed as part of the Phase I study to evaluate water supply projects that could assist in meeting the projected water demands of an oil shale industry. These evaluations were carried out using the State of Colorado's Stream Simulation Model (StateMod) developed by the Colorado Water Conservation Board (CWCB).

<u>How Much Water is necessary for development</u>?

Water use rates and the technology of a future oil shale industry are uncertain. Past industry efforts and current experimental development by industry employ an array of above-ground and in situ (in place) technologies. Projected water use rates vary among the technologies employed and, until decisions are reached as to which technology might be eventually developed for commercial production of shale oil, uncertainty will remain. A range of water use estimates must be developed with the objective that the actual future level of water use will be contained between a low and high estimate to a reasonable degree of certainty. In developing a range of water use estimates a variety of assumptions can be made about the mix of production and upgrading technologies that will make up the future oil shale industry, and about the water use intensity of those individual technologies.

Tables ES-1, ES-2 and ES-3 summarize various above-ground (AG) and in situ (IS) development scenarios.

Table ES-1: In Situ Industry Configurations and Total Unit Water Use

In Situ Scenario	Scenario Description	Unit Use (bbl/bbl)	Comments
IS-1*	Solvent recovery or combustion heating; off-site upgrading. Low unit estimates.	-0.22	Without energy direct use or use by energy workforce; no upgrading use.
IS-2	Solvent recovery or combustion heating; off-site upgrading. High unit estimates.	0.01	Without energy direct use or use by energy workforce; no upgrading use.
IS-3	Electrical heating; off-site upgrading. Low unit estimates.	0.20	Includes energy direct use and use by energy workforce; no upgrading use.
IS-4*	Electrical heating; on-site upgrading. Low unit estimates.	0.77	Based on low estimates of electricity use and other process water uses. Oil produced by electrical heating reportedly may require less intensive upgrading.
IS-5	Electrical heating; off-site upgrading. High unit estimates.	1.02	Based on high estimates of electricity use and other process water uses. No upgrading use.
IS-6	Solvent recovery or combustion heating; on-site upgrading. High unit estimates.	1.61	Based on high estimates of process water uses. No electrical heating. Combustion-based processes are more likely to require more upgrading.
IS-7*	Electrical heating; on-site upgrading. High unit process, low unit upgrading estimates.	1.59	Uses low estimate of upgrading, as oil produced by electrical heating reportedly may require less upgrading. Otherwise uses high estimates.

* Selected scenario

Table ES-2: Above-Ground Industry Configurations and Total Unit Water Use

Above-Ground Scenario	Scenario Description	Unit Use (bbl/bbl)	Comments
AG-1*	Off-site electricity, off-site upgrading. Low unit estimates.	1.45	Judged a likely possibility if above-ground product is compatible with combustion-heated in situ product; small electricity demands can be met from grid. Pair with solvent recovery/combustion-heated in situ.
AG-2	Off-site electricity, on-site upgrading. Low unit estimates.	2.05	It is likely that above-ground retort product will require more intensive upgrading, so this estimate may be low. Pair with electrically heated in situ.
AG-3*	On-site electricity, on-site upgrading. Low unit estimates.	2.22	Use co-produced gas for on-site combined cycle gas turbine (CCGT). It is likely that above-ground retort product will require more intensive upgrading, so this estimate may be low. Pair with electrically heated in situ.
AG-4	Off-site electricity, off-site upgrading. High unit estimates.	2.47	Judged a likely possibility if above-ground product is compatible with down-hole in situ; small electricity demands can be from grid. Pair with solvent recovery/combustion-heated in situ.
AG-5	Off-site electricity, on-site upgrading. High unit estimates.	4.07	Judged a likely possibility combined with electrically-heated in situ recovery, since the small above-ground production might require on-site upgrading; small electricity demands can be from grid. Pair with electrically heated in situ.
AG-6*	On-site electricity, on-site upgrading. High unit estimates.	4.33	Use co-produced gas for on-site CCGT. Pair with electrically heated in situ.

* Selected scenario

Table ES-3: Total Water Use for Selected Scenarios

Scenario	Unit Use (bbl/bbl)	Industry Water Use, acre-feet/year		
		Low	Medium	High
IS-1	-0.22	-16,000		
IS-4	0.77		54,000	
IS-7	1.59			110,000
AG-1	1.45	3,400		
AG-3	2.22		5,200	
AG-6	4.33			10,000
Total		-13,000	59,000	120,000

The high water use scenario uses an electrical heating process, which is described as IS-7 in Table ES-1. This process uses electrical heating and therefore requires water to supply the direct and indirect water needs of generation. IS-7 assumes that the kerogen product would require upgrading in the study area, but assumes a lower unit water use for this process to reflect the reported ability of the electrical heating process to produce a more refined product. The build-out scenario for this conversion process would be 1.5 million barrels per day with a high industry water use of 110,000 acre-feet per year, supplied from the White River. There is also a high use, above-ground retorting scenario included at 50,000 bbl/day with an estimated water use of 10,000 acre-feet per year, supplied from the Colorado River. The total high use estimate is 120,000 acre-feet/year for total production.

There is uncertainty in these estimates for many reasons. However, this uncertainty is minimized by describing a long-term, high production, high use scenario that is plausible and defensible. The analysis in this study suggests that an oil shale industry, developed incrementally, using water and natural gas resources found on-site, with minimal in-basin coal-fired electrical production is not likely to exceed the high use water demands described above and in the study.

Besides industrial development and size, the source of electrical energy and by-product water usability for an in-situ process needs have the most influence on total water use. Coal-fired thermal power production instead of combined cycle gas turbines will increase water use for the high scenario by 170,000 acre-feet per year and would require twelve (12) power plants of 1,500 megawatts each within the basin. The writers judge that this is not a likely scenario. If by-product water from in-situ retort is not used to satisfy process needs, another 60,000 acre-feet per year will be added to the high scenario. Above-ground retorting has more influence on direct and indirect unit water use but is estimated on a smaller production scale; for every 50,000 bbl/day increase in production from above-ground retorting, the high scenario for water use increases by about 10,000 acre-feet per year.

<u>Where will the water for oil shale come from</u>?

StateMod is an allocation and accounting model that allows for a comparison between historic and future water management policies. StateMod allocates river water among ditches, reservoirs, and river confluences, (etc.). Allocations are based on priority, capacity, and physical supply and demand. It is estimated that 110,000 acre-feet is the total annual demand from the White River Basin calculated for the in-situ retorting, high production, long-term scenario. The study identified three water supply projects in the White River Basin to meet an annual demand of 110,000 acre-feet. These three projects are not the only combination of water supply available, but do prove that the water needs can be supplied from the White River, via development of junior decrees, with reasonable development costs.

The Lake Avery Enlargement is located off stream of the White River. Depending on the scenario, the Lake Avery Enlargement is supplied by Big Beaver Creek or the White River. It has a 48,274 acre-feet capacity. The Wolf Creek Reservoir is located on the White River or off-stream of the White River on Wolf Creek (depending on the scenario). It is supplied by the White River and has a capacity of 162,400 acre-feet. A new diversion at the Piceance Creek pump station (referred to in this report as "New Diversion") would be located at the confluence of Piceance Creek and the White River. It would be supplied by the White River and would flow at a rate of 165.05 cubic feet per second.

Several combinations were modeled and described in detail in the study. The Lake Avery Enlargement supplied by Big Beaver Creek could meet the 110,000 acre foot demand in all months, except in dry periods of 1977, 1978, 2003 and 2004. In this case, the 110,000 acre-foot demand was reduced to determine at what level demand could be met. This was 104,000 acre feet. Modeling of other scenarios determined that the 110,000 acre-foot demand could be met with or without the Wolf Creek Reservoir in operation. StateMod was also used to determine whether or not Exxon's water rights on the Colorado River could meet an additional demand of 10,000 acre-feet for above-ground retorting in the high production, long-term scenario. It was concluded that this demand could be met in every year.

This brings the total supply equal to the demand for water of 120,000 acre-feet/year required by in-situ and above-ground retorting in the high production, long-term scenarios.

Groundwater

The water quality of groundwater in the Piceance Basin is poor enough to be unusable for most industrial purposes without treatment. Some of the shallower formations may provide a feasible source of groundwater in the Basin for oil shale development. However, these aquifers are probably tributary in nature, so their use might require an augmentation plan and supply. The feasibility of groundwater sources will need to be determined by industry on a site-specific basis.

1.0 INTRODUCTION

This report provides information about the amount of water required to supply future energy development in northwestern Colorado, and evaluates water supply projects that could be developed to meet those water needs. The work described in this report refined information contained in the Energy Development Water Needs Assessment Phase I study completed in September 2008 in which estimates were made regarding water demands associated with the development of energy in northwestern Colorado. In the Phase I report, four energy sectors were addressed: natural gas, coal, uranium and oil shale. The work described in this report, referred herein as the Phase II study, focused on using information regarding water demands and water rights that were developed as part of the Phase I study to evaluate water supply projects that could assist in meeting the projected water demands of an oil shale industry. These evaluations were carried out using the State of Colorado's Stream Simulation Model (StateMod) developed by the Colorado Water Conservation Board. Similar evaluations were not done for the natural gas, coal and uranium sectors because water demands from those sectors were much smaller and more dispersed than is the case for the oil shale sector.

The Phase II study also refined the water requirements of a future oil shale industry. Water demands developed in Phase I associated with the development of natural gas, coal and uranium were not changed in the Phase II study.

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2.0 THE WATER SUPPLY PLANNING PROCESS

As Colorado's population grows, so does the need to utilize water for various purposes such as domestic, municipal/industrial and environmental/recreational uses. Consequently, water managers and decision makers are faced with increasingly complex issues as they work to create sustainable water management practices for their systems and for the State as a whole. While water management will always be contentious, stakeholders can discuss ways to mitigate impacts and work towards a common goal of practical and collaborative water supply solutions.

The Statewide Water Supply Initiative (SWSI) was the beginning of a variety of efforts led by the Colorado Water Conservation Board (CWCB) to address Statewide water demands and water supply needs as well as ways to address any gaps in water supply. Through the SWSI process, which began in 2003, eight Basin Roundtables were formed that were comprised of stakeholders from a particular river Basin representing various water use sectors such as agricultural and ranching community members, recreational/environmental interests, federal agencies, and municipal water providers. The SWSI Basin Roundtable meetings provided a forum for identification and discussion of current and future water supply conditions through the year 2030.

After completion of SWSI, HB05-1177, the Colorado Water for the 21st Century Act (the Act), was signed into law. The Act is the basis for a permanent forum for Statewide water discussions that are held under two new arrangements: nine Basin Roundtables (separate from the SWSI Basin Roundtables) and the Interbasin Compact Committee. These new arrangements are discussed below.

2.1 Basin Roundtables

Similar to SWSI, the Act created Basin Roundtables, one in each of the eight major river Basins, plus an additional Roundtable in the Denver metro area. However, Basin Roundtable membership under the Act is of a broader nature than that of SWSI, which reflects the objective of encouraging participation from a wider range of stakeholders. Designated Roundtable participants, which total over 300, include ten at-large members, non-voting members, agency liaisons, and the CWCB board member from that Basin. The Basin Roundtables are charged with facilitating discussions surrounding water management issues while promoting locally-driven decision-making processes to find water management solutions.

Using information developed in SWSI as a foundation, each Roundtable is responsible for the following:

- An assessment of basin-wide consumptive water needs (municipal, industrial, and agricultural);
- An assessment of basin-wide non-consumptive water needs (environmental and recreational);
- An assessment of available surface water and groundwater supplies and an analysis of available unappropriated water;
- Proposed projects or management options for meeting identified water needs and achieving water supply sustainability over time;
- Reviewing proposed projects; and
- Negotiating interbasin compacts.

Each Basin Roundtable is able to form Subcommittees to encourage discussion and address specific issues before the Roundtable. These Subcommittees can be formed any time a need arises, and they may be permanent or temporary. Examples of Basin Roundtable Subcommittees include, but are not limited to:

- Groundwater
- Needs Assessment
- Non-Consumptive Needs Assessment
- Water Transfers
- Project Screening
- Agriculture
- Energy

The role of the Basin Roundtable Subcommittees played a large part in the two studies discussed below.

2.2 Interbasin Compact Committee

The second arrangement created under the Act is the Interbasin Compact Committee, or IBCC. This group attempts to broaden the participation of those involved in the State's water decisions, and to facilitate inter basin negotiations. It is comprised of 27 members according to the following breakdown:

- Two members appointed by each of the nine Basin Roundtables;
- Six members appointed by the Governor, who come from "geographically diverse parts of the state" and have expertise in environmental, recreational, local governmental, industrial, and agricultural matters;
- One member appointed by the chairperson of the Senate Agriculture Committee;
- One member appointed by the chairperson of the House Agriculture Committee; and
- The Director of Compact Negotiations appointed by the Governor, who chairs the IBCC.

2.3 Energy Water Needs Assessments

While SWSI suggested future water needs related to energy development could be significant, it did not assess specific future water needs in the basins where energy development is expected. Due to the renewed interest in potential energy resources such as oil shale in the Colorado and White River Basins since the completion of SWSI, the roundtables representing these basins along with the Yampa River Basin recognized a need to develop more detailed estimates of water needs to support potential energy development. Therefore, an Energy Subcommittee was formed between the Colorado and the Yampa/White River Roundtables to assess the potential increased energy-related water demands that could occur in the Colorado, Yampa and White River Basins and to identify possible ways to meet those demands.

To evaluate the water needs necessary to support energy development in the Colorado and Yampa/White River Basins, a proposal was submitted by the Energy Subcommittee to the CWCB in January 2007 for a grant in the amount of $300,000. The grant was approved in March 2007. The evaluation was conducted in two phases; an overview of each Phase is provided below.

2.3.1 Overview of Phase I Study

Phase I of the Energy Water Needs study evaluated water demands necessary to support the extraction and production of energy in the Colorado, Yampa and White River Basins (Figure 2-1) for the following four sectors:

- Natural Gas
- Coal
- Uranium
- Oil Shale

Phase I sought to quantify associated water demands within each energy development sector. Additionally, a list of conditional water rights for this region was compiled to identify water that could be developed by energy companies for use in the various sectors. The Phase I report (URS, 2008) was finalized in September 2008.

Given the uncertain nature of the intensity and timing of energy development within the four sectors, different production scenarios and planning horizons were used in Phase I as a framework to provide a range of possible water demand estimates. The planning horizon timeframes, which were developed based upon existing water supply and energy-related studies, are as follows:

- Near-Term: 2007 – 2017
- Mid-Term: 2018 – 2035
- Long-Term: 2036 – 2050

The energy production scenarios were also defined using existing studies, with the addition of empirical data and information from industry. Production scenarios represent three general production output levels (low, medium and high) in units specific to each industry, e.g., average number of natural gas wells drilled per year or number of barrels oil from oil shale produced per day. The production scenarios developed in Phase I were also used in the Phase II study and are presented in Table 2-1.

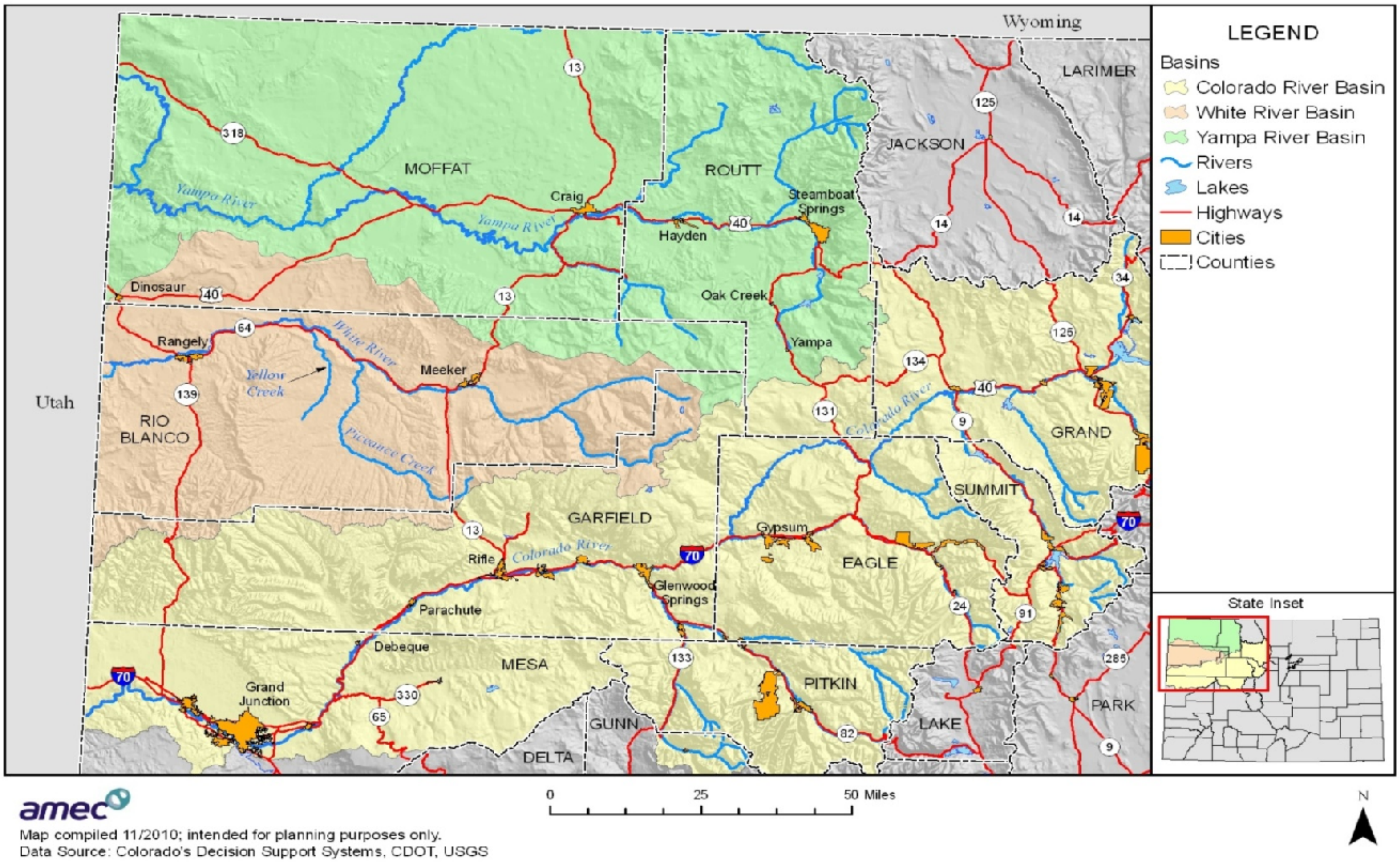

Figure 2-1: Phase I Study Area

Table 2-1: Phase I Assumptions Supporting Oil Shale Production Scenarios

Planning Horizon	Production Scenarios – Oil Shale		
	Low	Medium	High
Near-Term (2007–2017)	No Commercial Production RD&D Leases Only	No Commercial Production RD&D Leases Only	No Commercial Production RD&D Leases Only
Mid-Term (2018–2035)	No Commercial Production RD&D Leases Only	Underground mine/surface retort facility with 50,000 bbl/day production. Additional 25,000 bbl/day of in-situ production	Underground mine/surface retort facility with 50,000 bbl/day production. Additional 500,000 bbl/day of in-situ production
Long-Term (2036–2050)	No Commercial Production RD&D Leases Only	Underground mine/surface retort facility with 50,000 bbl/day production. Additional 150,000 bbl/day of in-situ production	Underground mine/surface retort facility with 50,000 bbl/day production. Additional 1.5 million bbl/day of in-situ production

bbl/day: barrels per day

To determine the total water demand for the four sectors over each planning horizon and production scenario, three types of water demands were evaluated in Phase I:

- Direct water demand: Water needed for extraction and development of the energy resource, e.g., construction, operation, production, processing and reclamation activities.
- Indirect water demand: Water required to support energy-related population growth due to the creation of new jobs. Includes both the direct workforce (those directly employed in the energy sectors) and the indirect workforce (direct workforce household members and increase in population due to the higher level of economic activity).
- Thermoelectric water demand: Water needs associated with power generation necessary to supply to the energy industry. Includes both extraction/production processes, and additional domestic energy needs due to increased energy-related population.

A summary of the total direct, indirect and thermoelectric water demands developed in Phase I are shown in Table 2-2.

Table 2-2: Phase I Study Annual Total Water Demands by Sector (acre-feet (af))

Planning Horizon	Production Scenario		
	Low	Medium	High
Near-Term (2007 – 2017)	Natural Gas: 18,050 Coal: 3,070 Uranium: 0 Oil Shale: 720 Total: 21,840 af	Natural Gas: 20,300 Coal: 3,380 Uranium: 3 Oil Shale: 720 Total: 24,403 af	Natural Gas: 21,460 Coal: 3,380 Uranium: 65 Oil Shale: 720 Total: 25,625 af
Mid-Term (2018 – 2035)	Natural Gas: 19,200 Coal: 3,070 Uranium: 0 Oil Shale: 720 Total: 22,990 af	Natural Gas: 23,980 Coal: 3,900 Uranium: 65 Oil Shale: 16,220 Total: 44,165 af	Natural Gas: 25,690 Coal: 3,900 Uranium: 65 Oil Shale: 134,711 Total: 164,366 af
Long-Term (2036 – 2050)	Natural Gas: 15,635 Coal: 3,070 Uranium: 0 Oil Shale: 720 Total: 19,425 af	Natural Gas: 21,085 Coal: 3,900 Uranium: 65 Oil Shale: 47,643 Total: 72,693 af	Natural Gas: 23,010 Coal: 8,590 Uranium: 130 Oil Shale: 378,310 Total: 410,040 af

As shown in Table 2-2, especially in the long-term planning horizon, Phase I estimated that large amounts of water may be required for oil shale development. To investigate the potential for water supplies needed to support energy development in the study area, Phase I reviewed existing conditional water rights on a water district basis. Through this evaluation, which included both storage and direct flow water rights, Phase I concluded that a majority of the water necessary to support energy development will be from conditional water rights in the Colorado and White River Basins.

2.4 Overview of the Phase II Study

The main purpose of the Phase II study was to identify and evaluate water supply scenarios utilizing water supply projects to illustrate plausible alternatives for meeting the projected water demands of an oil shale industry. Additionally, the Phase II study refined water demands estimated in Phase I for oil shale development given new information and understanding of the future of the industry. Water demands for the natural gas, coal and uranium energy industries developed in Phase I were not changed in the Phase II study

The study area defined for the Phase II study includes those portions of the Colorado River Basin and the White River Basin bounded on the south by the Colorado River and on the east by Colorado Highway 13. This is smaller than the study area for the Phase I study because the Phase II study focuses primarily on the water requirements of an oil shale industry.

Two main topics are addressed in the Phase II study: refining Phase I energy development water needs and assessing water supply alternatives to meet those needs. The following components are presented in this report:

- Section 3.0 – Background
- Section 4.0 – Oil Shale Process Water Demands
- Section 5.0 – Water Demand Scenarios for Oil Shale Development
- Section 6.0 – Groundwater
- Section 7.0 – Water Supply Project Alternatives
- Section 8.0 – References

3.0 BACKGROUND

The Phase II study refined the oil shale water use estimates reported in the Phase I report by breaking them down spatially as required by water resources modeling. During the early stages of the study, companies participating in oil shale development brought forward new information about the processes being evaluated for recovery of oil from oil shale, and about the time frame for development. According to the National Oil Shale Association (NOSA)(NOSA, 2009a), the time frames for development of the industry that were presented in Phase I were unrealistically short, the water-use intensity (the amount of water required to produce an equal volume of oil) was too high, and the estimates of population growth associated with development of oil shale were too high. As a result, the Energy Subcommittee directed AMEC to involve industry representatives in the process of refining the Phase I estimates of water use. Because of that involvement, the time frame for development of oil shale industry and its eventual scale were re-evaluated, and new estimates of energy- and water-use intensity were developed for use in this Phase II study, as described below.

3.1 Oil Shale Production Processes

Oil shale is a sedimentary rock that contains a solid hydrocarbon known as kerogen, which can be extracted from the rock as a liquid and subsequently processed to have properties similar to conventional petroleum. As described in the Phase I report, kerogen is extracted from oil shale using one of two process concepts: mining and surface retorting or in situ retorting. In situ retorting is a process in which the oil shale is recovered directly from the underground formation, using either solvents or heat to free liquid hydrocarbons which are then recovered through a system of wells. Surface retorting, which is specified as "above-ground" herein, requires mining of oil shale either via surface mining or underground mining. After the ore is mined, it is crushed and roasted in a retort (a type of kiln), which releases the hydrocarbon trapped in the rock. The raw liquid hydrocarbon produced by either in situ or surface retorting is referred to as shale oil. Before shale oil can be used as feedstock for conventional refining or chemical processes it must be upgraded, a chemical/physical process whereby the recovered shale oil is modified to be compatible with subsequent conventional transportation and refining processes. Both the above-ground and in situ processes produce some gaseous hydrocarbon and some water vapor as a byproduct of shale oil production

Several different varieties of in situ recovery processes are currently being considered or developed by industry. For the purpose of this study, in situ recovery processes were divided into two categories depending on whether the process uses combustion or electricity as a heat source. Electrical heating processes include the use of electric heaters placed in contact with the oil shale in wells or the use of radio-frequency or microwave radiation to heat large volumes of the oil shale formation. Combustion-based methods heat the oil shale using a variety of configurations to deliver hot gases or steam to the formation. With regard to water use, the principal difference between combustion-based and electrically heated methods is that the latter require additional water for generation of electricity. Combustion processes can also be expected to produce more water vapor than electrically heated processes. These two categories of in situ recovery processes provide reasonable upper and lower bounds for the water requirements for in situ recovery. For reasons that are explained later in this report, solvent-based in situ recovery processes will likely fall between these two processes in terms of water use intensity.

The mix of technologies used to recover shale oil will be determined by technical feasibility and economics, which will vary from locale to locale. Current expectations are that in situ recovery will probably prove superior in the basins of Yellow Creek and Piceance Creek, which are located west of Highway 13, running from Rifle through Meeker and Craig, and are bounded on the north by the White River and on the west, south and east by hydrologic divides. Above-ground recovery will probably prove superior along the outcrops of the Green River formation along the Colorado River, north of Parachute and Debeque. There is no evidence at this time to indicate that a different mix than projected in the Phase I report should be assumed for this analysis. The location of oil shale deposits and the general location of the expected in situ and above-ground developments are shown in Figure 3-1.

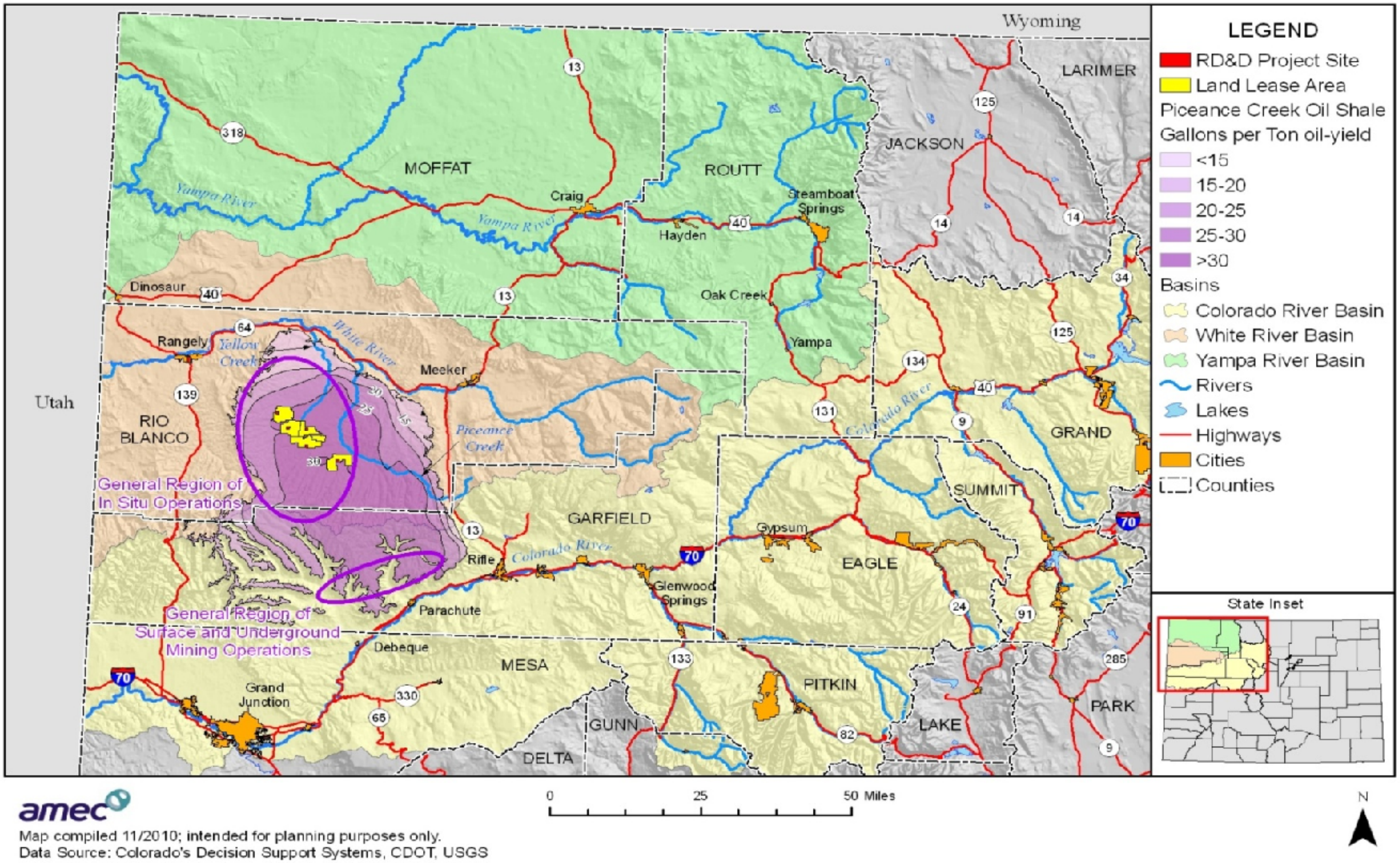

Figure 3-1: Phase II Study Regions of In Situ and Above-Ground Oil Shale Operations

3.2 Refinement of Oil Shale Planning Horizons

Whether or not an oil shale industry will exist will depend on the technical feasibility of recovery and processing, economics of recovery and processing, and market conditions. If recovery of shale oil proves technically or economically infeasible then no industry will develop, a case that is represented by the "Low" production scenario in Table 2-1. If recovery of shale oil proves technically feasible, and if economics and market conditions are favorable, then the industry will develop with its ultimate scale limited by resource constraints, market economics, non-market constraints such as government regulation and environmental constraints. It is also possible that the geography of the area might constrain the capacity of transportation infrastructure which in turn might place a constraint on the scale of the industry. This case is represented by the "Medium" and "High" scenarios in Table 2-1.

Industry did not question the Phase I estimate of the scale of a "mature" oil shale industry, as represented by the "Long-Term, High" scenario (1.55 million barrels per day (bbl/day)) but did question whether it was realistic to assume that an industry of that scale could develop as early as 2036 as concluded by the Phase I study. If recovery of shale oil proves to be technically feasible and economics of recovery are in a range that is favorable over a range of market conditions, then the timing of development of the industry will be driven primarily by market conditions and the ability to construct related infrastructure in a timely manner. Industry representatives suggested that development of the Athabasca oil sands in northeast Alberta, Canada could serve as a reasonable analog to development of an oil shale industry in the Piceance Basin.

The history of development of the Athabasca industry was used to evaluate the Phase I scenarios for development of the industry in the Piceance Basin. Table 3-1 places the significant Phase I scenarios in the context of the development of the Athabasca oil sands. In projecting development time frames, it was assumed that the initial field demonstration of technical feasibility for one or more in situ technologies could occur by 2015 and initial commercial production would occur 20 years later (compared to the 17-year period prior to development of first commercial production at the Athabasca oil sands). Subsequent projections of production employ growth rates of 10% and 14%, which bracket the 12% long-term growth rate for the Athabasca oil sands.

Table 3-1: Evaluation of Scenarios for Piceance Basin Oil Shale Industry

Milestone/Production Level	Time Frame for Development	
	Phase I	Phase II Projected Scenario
Field demonstration of technical feasibility		2015
Initial commercial production, 50,000 barrels/day		2035
550,000 barrels/day	2018 – 2035	2053 – 2060
1,550,000 barrels/day	2036 – 2050	2061 – 2071

This analysis indicates that the Phase I estimates do not overstate the size of a mature, unconstrained oil shale industry in the Piceance Basin. However, comparison with the development of the Athabasca oil sands indicates that production at the levels identified in the Phase I report might occur anywhere from 10 to 35 years later than the dates projected in the Phase I report. Further information about this analysis can be found in Appendix A.

These development periods are important when estimating future water use as there are two conceptual time frames that can be used for water resources planning: (1) estimates at a specific point in time or range of times in the future, or (2) estimates at "build-out" that represent the level of water use by a mature, fully–developed industry.

Water use estimates that are used for planning the timing of development of specific elements of infrastructure are usually made for specific time frames. In such cases the time frames conventionally range from 20 to about 50 years into the future. Water use estimates that are used for an assessment of the adequacy of physical or legal water supply, without consideration of the capability or cost of infrastructure, are often based on the build-out scenario. The time frame used in developing a build-out estimate is an indefinite time in the future when water use has matured, and this is usually intended to represent a realistic maximum level of development.

Selection of the conceptual scenario for estimating future water use, and selecting the specific future time frame or time frames at which estimates of water use might be developed is a policy decision that depends on how the water use estimates will be employed. The Energy Subcommittee directed that a build-out scenario be used as the basis for the Phase II study water use estimates and model studies, and also directed that the "Long-term/High" estimate of industry scale developed by the Phase I study be used to quantify build-out conditions in the Phase II study. The build-out scenario projects an oil shale industry with 1.5 million bbl/day production from in situ processes (located in the Piceance Basin) and 50,000 bbl/day production from above-ground retorting (located at massive outcrops of the Green River Formation south of the Piceance Creek Basin and north of the Colorado River).

As such, no time frame was associated with the industry scale estimates used in The Phase II study, although the analysis provided above regarding development of the Athabasca oil sands indicates that, should an oil shale industry develop at all, it is plausible that the "Long-term/High" scale developed in the Phase I study would be reached within this century.

4.0 OIL SHALE PROCESS WATER DEMANDS

The original objective of the Phase II study was to disaggregate oil shale development water demands presented in Phase I with sufficient spatial resolution to allow a particular water use to be assigned to a specific water storage project in a water supply scenario. As discussed above, additional information was obtained from industry, which suggested that there was an opportunity to refine the magnitude of the Phase I demands.

To arrive at the total water use by an oil shale industry in the study area, assumptions about the size of industry, the mix of production technologies in industry, the direct water use intensity of production technologies, the energy use intensity of production technologies, and the population intensity of production technologies is required. The measure of water use "intensity" is expressed as the amount of water required to produce a unit of production, which is a barrel of oil in the case of shale oil. The analogous concept in municipal water use is per-capita use. In the case of energy and population, intensity is expressed in terms of the amount of energy and the amount of population growth required to produce a barrel of shale oil. Energy and population, in turn, have a water use intensity and it is the combination of the amount of energy and population, combined with their respective water use intensities, that determines the amount of water use attributed to oil shale development for that particular component of the water budget.

This section presents the water use for each category that constitute the direct and indirect components for oil shale development. The values are provided in terms of barrels of water required to produce one barrel of oil from oil shale (bbl/bbl). Total water use can be determined by incorporating the scale of the industry, as presented in Section 5.0.

4.1 Oil Shale Direct Water Use

Estimates of direct water use were obtained from the Phase I report (URS, 2008), from information obtained from industry, and from a review of readily available literature. Following an initial review of water use estimates provided in the Phase I report, meetings and consultation were held with industry representatives, wherein AMEC explained the objectives of the Phase II study and explored how industry representatives could provide information to the study. In order to address concerns on the part of industry about disclosure of proprietary information, a process was agreed to wherein a questionnaire developed by AMEC in collaboration with Shell and NOSA would be circulated to industry representatives by NOSA, industry would provide NOSA with water use estimates in response to the questionnaire, and NOSA would compile a single statement of water use that expressed water use as a range or an average. Separate questionnaires were used to address water use for the two identified major technology categories (1) in situ retorting and recovery (in situ retorting) and (2) underground mining and above-ground retorting (above-ground retorting).

The questionnaires were provided to NOSA who, in turn, distributed them to the industry representatives they had identified. The identity of the industry respondents were not disclosed to AMEC. AMEC received responses to the questionnaire in September 2009. Those responses are provided in Appendix B.

Additional estimates of direct water use were compiled from literature. These estimates are provided in Table 1 of Appendix B. Estimates of overall levels of water use have been made by a number of sources and are available in a recent compilation by Western Resource Advocates (2009). The bases for the water use estimates reported in the literature and provided in Appendix B are not well defined and most of these estimates are not broken down categorically in a way that would allow for a direct comparison to the categorical estimates provided by the industry and in the Phase I report. Therefore, the numbers provided by industry in the questionnaires along with estimates from the Phase I report were used in the Phase II analysis. A comparison between industry-wide estimates of direct water use from literature and those obtained from industry and from the Phase I report is shown in Table 2 of Appendix B.

4.1.1 Phases and Timeframes

Three phases in the development of an oil shale retorting operation were identified by NOSA: construction/pre-production, production, and reclamation. These phase names are used in the discussion below to label water use that takes place during a phase. Within a phase there may be a number of processes that have water demands, such as electrical energy generation, upgrading and spent shale disposal. The timing of the phases are shown in Table 4-1 for the two production methodologies (NOSA, 2009b). For in situ technology, the phases represent the development of one module or "panel." For above-ground retorting, the phases represent the development of one mine (or a complex of mines) and its associated retort. For additional information on each of the phases and the associated water requirements related to in situ and above-ground retorting processes, see Appendix B.

Table 4-1: Duration of Phases (Years)

Phase	In Situ Retorting	Above-Ground Retorting
Construction/Pre-production	2.5	4
Production	6.5	25
Reclamation	5.5	4
Total	14.5	33

Water is required for the following activities or processes:

Construction/Pre-production

This category includes water required for preparation and construction of the site, including activities such as surface preparation, trenching, dust control, road construction, buildings and facilities construction, mine construction, and drilling of production wells, freeze wall wells (required by some in situ recovery methods to isolate the recovery zone), and formation heating wells.

Production

This category includes water required for recovery and initial processing of shale oil for both in situ retorting and above-ground retorting. Water requirements for generating electrical energy, which is required by some in situ recovery methods, and upgrading are categorized separately.

Upgrading

This category includes water required for upgrading of shale oil, a physical/chemical process that is required to convert shale oil to a product that is similar to conventional oil and can be transported by pipeline and used as a refinery feed stock. Upgrading occurs throughout the production phase and might occur at a central location with proximity to a petroleum pipeline in order to achieve economies of scale. Based on the feedback from NOSA, Grand Junction would be an appropriate location within the study area for upgrading of shale oil. It is also arguable that upgrading would not be required in the study area: The scale of production from a mature oil shale industry in the Piceance Basin is similar to the scale of the North Slope oil fields in Alaska, which is of a scale to support a dedicated pipeline to a regional processing/refining center. Should this come to pass, upgrading could be done at the same location as refining, in which case the water use from upgrading would occur outside the study area.

Some companies expect that shale oil produced by their in situ retorting technology will not require upgrading prior to transportation and refining. On the other hand, some retorting technologies (both in situ and above-ground) produce a product that is *paraffinic* in nature. Products of this type must be heated before they can be transported in a pipeline, and will congeal into a semi-solid mass should the flow through the pipeline be interrupted for a sufficient time. Because such an event would cause a catastrophic interruption in oil production, it is unlikely that paraffinic products would be transported through a pipeline without at least partial upgrading very near the production site (Boak, 2010).

Given these considerations, the actual water requirement for upgrading is highly uncertain and will depend substantially on the mix of retorting technologies that eventually develops in the Piceance Basin. If the emerging dominant in situ technology does not require upgrading prior to transportation, then the only requirement for water for upgrading in the study area will be for the relatively small production from above-ground retorting.

Reclamation

For in situ retorting this category includes water required for cooling and rinsing of the production zone and for re-watering of the formation after recovering oil and gas. For both in situ and above-ground retorting, this category includes the water required for revegetation of the disturbed site after completing production activities. Water requirements for stabilizing and re-vegetating spent shale from above-ground retorting are categorized separately.

Spent Shale Disposal

This category includes the water required to stabilize and compact spent shale residue produced by above-ground retorting, and to re-vegetate the surface of the spent shale piles. This activity occurs throughout the production phase.

Electrical Energy

This category includes the water needed to generate the electrical energy required for formation heating required by some in situ retorting technologies, and for non-heating uses at in situ and above-ground retorting operations. Non-heating energy would include energy for lifts, compressors, pumps, lighting, heating and ventilation, and other needs. Both NOSA and the Phase I report provided combined estimates for heating and mechanical energy requirements for in situ retorting operations. Some in situ retorting methodologies use chemical or solvent-based methods and do not require formation heating, and some of the methods that require formation heating propose to generate heat by combustion and therefore will not require electrical energy for heat production.

In Situ Retorting

Not all in situ recovery processes use electricity to heat the oil shale formations, but for those that do Table 4-2 shows the two estimates of energy and water use for in situ retorting operations for a 50,000 bbl/day module. The Phase I study used an estimate of 300 kilowatt·hours (kW·h) per barrel, which equates to 5,500,000 megawatt·hours (MW·h) per year (MW·h/yr) for a 50,000 bbl/day facility. NOSA provided a lower estimate of 2,200,000 MW·h/yr for a 50,000 bbl/day module. This estimate is an average of an undisclosed number of responses from industry participants and presumably represents an industry with a mix of production technologies that reflects the technologies being developed by the respondents to the NOSA questionnaire.

Table 4-2: Water Use for Electrical Power Generation to Support In Situ Retorting

Data Source	Heating Energy Intensity		Water Use bbl/bbl	Water Use af/year
	MW h/50,000 bbl/day	kW h/bbl		
Phase I	5,550,000	300	1.0	2,400
NOSA	2,200,000	120	0.41	970

The water use estimates in Table 4-2 are based on the use of combined cycle gas turbines (CCGT) for generation of electrical energy for those in situ processes that use electricity for formation heating. These estimates differ from those produced by the Phase I study, which assumed that electrical energy for formation heating for electrically-heated in situ processes would be generated using coal-fired thermal generating plants located within the study area. Water use intensity for CCGT generation is estimated to be 30% of the water used by a coal-fired thermal power plant (Phase I study).

The Phase II study estimates that the energy requirements for an in situ oil shale industry of 1.5 million bbl/day (assuming that all oil recovery utilized electrical heating) would be more than ten times the energy generation of the Craig Generating Station in the Yampa River Basin. Limitations arising from coal supplies, coal transportation and air quality, timeframe for building energy plants, as well as possible regulatory requirements to limit carbon emissions, would tend to restrict the ability to develop coal-fired generation resources of this scale in the study area. In addition, industry representatives indicate that a substantial part, and perhaps all, of the energy required for formation heating can be obtained through the use of byproduct gas from the in situ retorting process, and that the in situ processes can be adjusted to produce a larger fraction of energy in the form of gas should this be desirable (Vawter, 2010). Were this byproduct gas not used at or near in situ retorting operations it would have to be transported to market areas or wasted. In addition to byproduct gas, the Piceance Basin provides a significant amount of natural gas. The use of byproduct gas or natural gas for local generation using CCGT generation is not without its own complications, but the considerations set out here led to the judgment that such local generation is the most likely source of electrical energy needed for formation heating for a large-scale in situ industry as it develops incrementally.

Above-Ground Retorting

NOSA provided an estimate of 900,000 megawatt-hours per year for a 50,000 bbl/day above-ground retorting module. The Phase I study used an estimate of 75 kW·h per barrel, which equates to 1,369,000 MW·h/year for a 50,000 bbl/day facility. Projections of the scale of the above-ground component of a future oil shale industry are on the order of a single 50,000 bbl/day module, which is relatively much smaller than projections for the scale of an in situ industry, so the energy requirements for the expected above-ground retorting operations could be supplied from the grid if they are not supplied by near-site generation using byproduct gas or natural gas.

Produced Water

Water is produced during the production of shale oil by both in situ and above-ground recovery processes. Some water is recovered during de-watering of the in situ formation or dewatering mines. This water arguably is appropriable under Colorado water law and thus subject to administration, including requirements for augmentation. In addition to this appropriable water, there are three sources of byproduct water that arguably are not appropriable: 1) vaporization of unrecoverable pore water and connate water, 2) dehydration of minerals and hydrocarbons and 3) water of combustion. The term "byproduct water" as used herein refers to water from these latter three sources, which are assumed to be un-appropriable and therefore may be fully consumed. NOSA estimates that byproduct water will be produced at a rate of 0.8 bbl water/bbl oil for in situ retorting and 0.3 bbl water/bbl oil for above-ground retorting, which equate to 1,900 af/year and 700 af/year, respectively, for a 50,000 bbl/day module. In the following analyses, byproduct water was included as a source to satisfy process needs, based on an assumption that discharge and disposal requirements will be sufficiently stringent that the required level of treatment will make treated byproduct water suitable for process needs. The Phase I study did not consider produced water in its water needs assessment.

Consumptive Use Associated with Direct Water Uses

All direct water use was considered to be 100% consumptive for the Phase II study analyses, based on an assumption that discharge and disposal requirements will be sufficiently stringent that the required level of treatment will make treated process water suitable for process needs and that any concentrated residuals will not be suitable for reuse or release into a surface or groundwater water resource that could be put to beneficial use. Relatively small volumes of water will be lost in transporting or disposing of concentrated process wastes, but this study assumes that these waters will not be discharged to the environment.

4.2 Oil Shale Indirect Water Use

Indirect uses include water required to support population growth and economic activity resulting from production of shale oil. The Phase I study provided estimates of indirect water use attributable to development of natural gas, uranium, coal and oil shale. The Phase II study adopted the Phase I estimates of indirect water use for natural gas, uranium and coal. The Phase I study estimates of indirect water use for oil shale have been refined as discussed below. Additional detail can be found in Appendix C.

<u>Estimates of Employment and Population</u>

The Phase II study differs from the Phase I study in that the water use scenarios developed in The Phase II study will be incorporated in the statewide water supply planning activities that are part of the Colorado Water for the 21st Century Act (the Act) water supply planning process. Water supply planning under the Act is taking place within the IBCC, which has developed a set of water supply and water demand scenarios based on input from the nine Basin Roundtables. The Phase II study results will serve as the basis for input from the Colorado, Yampa/White River Roundtables to the IBCC process and therefore should be as consistent as possible with the assumptions and methods used by the IBCC. Among the methods used by the IBCC are models of economic activity on which are based estimates of future employment and population.

The Phase I study used a different basis for its estimates of population due to development of an oil shale industry (BBC Research & Consulting, 2008). Further, the Phase I study based its estimates of direct and indirect water use on the conclusion that the electrical energy required to heat oil shale formations in an in situ production process would be generated using coal-fired thermal generation. As described above, this study has concluded that it is much more likely that any required electrical energy will be generated using CCGT generation, fueled by byproduct gas or local natural gas. CCGT requires less labor for construction and operation than does coal-fired thermal generation. In order to use methodologies and assumptions that are consistent with the IBCC process, the Phase II study adopted estimates of employment and population that were developed for the IBCC by Harvey Economics for an oil shale industry consisting of 1,500,000 bbl/day of in situ production and 50,000 bbl/day of above-ground production (build-out scenario) and assuming that CCGT is used to generate electricity. These estimates are shown in Appendix C. Table 4-3 summarizes the estimates of employment provided by Harvey Economics (Harvey Economics, 2010).

Table 4-3: Regional Employment Attributable to Production of Oil from Oil Shale

Process	Employment	Percent of Employment
In situ	14,375	84%
Above-Ground	1,920	11%
Energy generation	800	5%
Total Oil Shale	17,095	100%

Estimates in Table 4-3 are taken from year 32 of Harvey Economics estimates of employment (Appendix C, Exhibit 1) as these represent approximately stable employment at the build-out scale of the industry. Some additional employment would be required approximately every 25 years when a new mine must be opened to support above-ground retorting. Harvey estimates that total population in the study area (Garfield County, Mesa County and Rio Blanco County) will increase to 51,090 as a result of the increased employment (Appendix C, Exhibit 2).

Estimates of Indirect Water Use

Water use from increased population was estimated by multiplying population estimates by an estimate of per-capita daily water use. Water use due to population growth not directly employed in the oil shale industry was estimated using a per-capita daily rate of 200 gallons per capita per day (gpcd), which is the value adopted by the Phase I study. To estimate water use due to employment, a smaller per-capita daily water use rate of 100 gpcd was used to reflect the fact that oil shale workers will spend considerable time at production locations or traveling and therefore will not have any associated outdoor water use.

Estimates of indirect water use in the Phase II study do not include the water required for generation of electricity to support population growth, under the assumption that this electricity will come from the grid and will not be attributable to a single generating station in the study area.

4.3 Estimates of Unit Water Use by Category

Table 4-4 shows estimates of indirect unit water use and Table 4-5 shows the direct unit water uses for the build-out scenario for an oil shale industry. Water use estimates in these tables are provided in terms bbl/bbl for the entire industry in the study area.

In calculating water use per barrel of produced oil, the following approach was used: For each category of use, the total amount of water required for that category over the life of the oil shale production facility was calculated and that amount was divided by the total amount of oil that would be produced by the facility over its lifetime. In making these calculations no adjustment was made for changes in volume that might occur during upgrading.

Table 4-4: Estimates of Indirect Water Use for Production of Oil from Oil Shale (bbl/bbl)

Water Use Category	In situ Retorting	Above-Ground Retorting
Electrical Energy Workforce	0.008	0.002
Construction and Production Workforce	0.11	0.46

Table 4-5: Estimates of Direct Water Required for Production of Oil from Oil Shale (bbl/bbl)

	In situ Retorting		Above-Ground Retorting	
Water Use Category	Low	High	Low	High
Construction/Pre-production	0.02	0.16	0.01	0.07
Electrical Energy	0.41	1.00	0.17	0.26
Production			0.47	0.47
Reclamation	0.45	0.54	0.02	0.17
Spent Shale Disposal			0.80	1.60
Upgrading	0.57	1.60	0.60	1.60

Table 4-6 shows the unit amount of water produced as a byproduct of shale oil production. Only one estimate of the rate of water production was obtained for each of in situ and above-ground retorting; therefore no quantitative information can be provided regarding the uncertainty of this estimate. Because of the nature of the processes, methods using combustion heating can be expected to produce more byproduct water than methods using electrical heating or solvents.

Table 4-6: Estimates of Water Co-Produced When Retorting Oil Shale (bbl/bbl)

In situ Retorting	Above-Ground Retorting
0.80	0.30

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5.0 WATER DEMAND SCENARIOS FOR ENERGY DEVELOPMENT

Based on foundational information provided herein, water demands for oil shale development can be summarized. Water use scenarios depend on the scale of the projected future oil shale industry and the water use intensity of the industry. Using the separate components of unit water use presented in Section 4.0 and multiplying by the scale of the industry, comprehensive estimates of total water use by an oil shale industry can be determined as provided below. Additional information can be found in Appendix D.

Water use for oil shale depends on the production methodology, and there is considerable uncertainty regarding which methodologies ultimately will be used for production, as discussed in Section 3.0. To reflect this uncertainty, water use estimates for oil shale are provided for low, medium and high water use scenarios and are generally provided with a precision of two significant figures.

5.1 Oil Shale Industry Unit Water Use Estimates

Because both unit water use rates and the configuration of a future oil shale industry are uncertain, a range of water use estimates must be developed with the objective that the actual future level of water use will be contained between a low and high estimate to a reasonable degree of certainty. Table 5-1 and Table 5-2 present total (direct and indirect) unit water use estimates for plausible industry configurations.

Table 5-1: In Situ Industry Configurations and Total Unit Water Use

In Situ Scenario	Scenario Description	Unit Use (bbl/bbl)	Comments
IS-1*	Solvent recovery or combustion heating; off-site upgrading. Low unit estimates.	-0.22	Without energy direct use or use by energy workforce; no upgrading use.
IS-2	Solvent recovery or combustion heating; off-site upgrading. High unit estimates.	0.01	Without energy direct use or use by energy workforce; no upgrading use.
IS-3	Electrical heating; off-site upgrading. Low unit estimates.	0.20	Includes energy direct use and use by energy workforce; no upgrading use.
IS-4*	Electrical heating; on-site upgrading. Low unit estimates.	0.77	Based on low estimates of electricity use and other process water uses. Oil produced by electrical heating reportedly may require less intensive upgrading.
IS-5	Electrical heating; off-site upgrading. High unit estimates.	1.02	Based on high estimates of electricity use and other process water uses. No upgrading use.
IS-6	Solvent recovery or combustion heating; on-site upgrading. High unit estimates.	1.61	Based on high estimates of process water uses. No electrical heating. Combustion-based processes are more likely to require more upgrading.
IS-7*	Electrical heating; on-site upgrading. High unit process, low unit upgrading estimates.	1.59	Uses low estimate of upgrading, as oil produced by electrical heating reportedly may require less upgrading. Otherwise uses high estimates.

* Selected scenario

In situ (IS) scenarios 1, 4 and 7 were selected to represent the low, medium and high levels of water use. IS-1 assumes an industry that uses solvent recovery or combustion heating to heat formations to recover oil, and upgrades shale oil outside the study area. The use of solvent recovery or combustion heating eliminates the direct and indirect water use required for electrical generation for electric heating. Combustion heating is likely to produce more byproduct water than electrical heating or solvent recovery but no change was made to the value provided by NOSA. Solvent-recovery processes would not require water to support electrical generation, but it would also not produce as much byproduct water. Accordingly, a solvent recovery process would represent a low water use scenario, but would not be expected to have lower water use than IS-1. IS-7 assumes an industry that uses an electrically-heated recovery process, which requires water to supply the direct and indirect water needs of generation. IS-7 assumes that the shale oil would require upgrading in the study area, but assumes a lower unit water use for this process to reflect the reported ability of electrically heated processes to produce a more refined product. IS-6 and IS-7 are essentially equivalent in terms of water use estimates based on the information available to the study. However, because the electrically-heated process is likely to produce less byproduct water, the actual water use of IS-7 may be greater than shown in Table 5-1. However, at this time sufficient information is not available to refine the estimate of water use further. IS-4 is similar to IS-7 except that low estimates for water use intensity are used.

Table 5-2: Above-Ground Industry Configurations and Total Unit Water Use

Above-Ground Scenario	Scenario Description	Unit Use (bbl/bbl)	Comments
AG-1*	Off-site electricity, off-site upgrading. Low unit estimates.	1.45	Judged a likely possibility if above-ground product is compatible with combustion-heated in situ product; small electricity demands can be met from grid. Pair with solvent recovery/combustion-heated in situ.
AG-2	Off-site electricity, on-site upgrading. Low unit estimates.	2.05	It is likely that above-ground retort product will require more intensive upgrading, so this estimate may be low. Pair with electrically heated in situ.
AG-3*	On-site electricity, on-site upgrading. Low unit estimates.	2.22	Use co-produced gas for on-site CCGT. It is likely that above-ground retort product will require more intensive upgrading, so this estimate may be low. Pair with electrically heated in situ.
AG-4	Off-site electricity, off-site upgrading. High unit estimates.	2.47	Judged a likely possibility if above-ground product is compatible with down-hole in situ; small electricity demands can be from grid. Pair with solvent recovery/combustion-heated in situ.
AG-5	Off-site electricity, on-site upgrading. High unit estimates.	4.07	Judged a likely possibility combined with electrically-heated in situ recovery, since the small above-ground production might require on-site upgrading; small electricity demands can be from grid. Pair with electrically heated in situ.
AG-6*	On-site electricity, on-site upgrading. High unit estimates.	4.33	Use co-produced gas for on-site CCGT. Pair with electrically heated in situ.

* Selected scenario

Above-ground (AG) scenarios 1, 3 and 6 were selected to represent the low, medium and high levels of water use. AG-1 assumes that electricity is taken from the grid, that upgrading is done outside the study area, and that lower levels of water use intensity will occur. AG-6 assumes that electricity is generated on site, that upgrading takes place in the study area, and that higher levels of water use intensity occur. AG-3 assumes that electricity is generated on site, that upgrading takes place in the study area, but that lower levels of water use intensity occur.

5.2 Oil Shale Industry Total Water Use Estimates

Table 5-3 provides estimates of the total, industry-wide water use for the build-out industry scenario (1.5 million bbl/day in situ production and 50,000 bbl/day above-ground production) for low, medium and high water use scenarios. Industry-wide water use estimates are presented to a precision of no more than two significant figures to reflect the uncertainty in those estimates.

Table 5-3: Total Water Use for Selected Scenarios

Scenario	Unit Use (bbl/bbl)	Industry Water Use, acre-feet/year		
		Low	Medium	High
IS-1	-0.22	-16,000		
IS-4	0.77		54,000	
IS-7	1.59			110,000
AG-1	1.45	3,400		
AG-3	2.22		5,200	
AG-6	4.33			10,000
Total		-13,000	59,000	120,000

Uncertainties in the estimates provided in Table 5-3 arise from estimates and judgments about the following factors: the size of the future oil shale industry, the split between in situ and above-ground retorting, the water intensity of individual industrial processes, the mix of in situ retorting processes, the source of electrical energy for formation heating, the rate at which byproduct water is produced and the degree to which byproduct water will be re-used for process purposes. These factors, in turn, will be influenced by the economic, political, regulatory and social conditions that exist at the time an oil shale industry develops decades in the future.

Aside from whether an industry develops at all and the size of the industry, the two factors with the most influence over the estimate of total industry water use are the source of electrical energy for formation heating and the amount of byproduct water and its usability for in situ process needs. If electricity is generated by coal-fired thermal generation within the study area, rather than combined cycle gas turbines, water use for the *high* scenario will increase by 170,000 af/year. However, because coal-fired thermal generation would be assumed to be located in the Yampa River Basin, this projection of additional water use represents, for the high scenario, an increase in projected water use in the Yampa River Basin of about 240,000 acre-feet/year and a reduction in projected water use in the White River Basin from about 110,000 acre-feet/year to about 40,000 acre-feet/year. If byproduct water from in situ production is not used to satisfy process needs, water use for the *high* scenario will increase by an additional 60,000 af/year. The estimate of 50,000 bbl/day production from above-ground retorting used in this analysis may understate the future value. For every 50,000 bbl/day increase in production from above-ground retorting, water use for the *high* scenario will increase by about 10,000 af/year. Increases in production from above-ground retorting will have a relatively larger proportional influence on direct and indirect water use in the Colorado River Basin.

5.3 Natural Gas, Coal and Uranium Industry Total Water Use Estimates

The water demands developed in the Phase I study for the natural gas, coal and uranium industry in the study area were not changed in the Phase II study. Table 5-4 below shows the total direct, indirect and thermoelectric water demands for these energy sectors.

Table 5-4: Total Water Demands for Natural Gas, Coal & Uranium Production (af/year)

Planning Horizon	Production Scenarios		
	Low	Medium	High
Near-Term (2007–2017)	Natural Gas: 18,050 Coal: 3,070 Uranium: 0	Natural Gas: 20,300 Coal: 3,380 Uranium: 3	Natural Gas: 21,460 Coal: 3,380 Uranium: 65
Mid-Term (2018–2035)	Natural Gas: 19,200 Coal: 3,070 Uranium: 0	Natural Gas: 23,980 Coal: 3,900 Uranium: 65	Natural Gas: 25,690 Coal: 3,900 Uranium: 65
Long-Term (2036–2050)	Natural Gas: 15,635 Coal: 3,070 Uranium: 0	Natural Gas: 21,085 Coal: 3,900 Uranium: 65	Natural Gas: 23,010 Coal: 8,590 Uranium: 130

5.4 Energy Development Total Water Use Estimates

Table 5-5 shows the total water requirements for energy development, combining the estimates from Phase I for the development of coal, natural gas and uranium with the refined estimates of water requirements for oil shale development developed by this Phase II study.

Table 5-5: Total Long-Term Energy Development Water Demands (af/year)

Production Scenarios		
Low	**Medium**	**High**
Natural Gas: 15,635 Coal: 3,070 Uranium: 0 Oil Shale: -13,000	Natural Gas: 21,085 Coal: 3,900 Uranium: 65 Oil Shale: 59,000	Natural Gas: 23,010 Coal: 8,590 Uranium: 130 Oil Shale: 120,000
Total: 5,705	**Total: 84,050**	**Total: 151,730**

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6.0 GROUNDWATER

This section provides background and suggestions about using Piceance Basin groundwater to meet water demands for energy development estimated in the Phase I study. This evaluation builds upon previous hydrologic research performed in the Piceance Basin over the past 30 years. The following tasks were accomplished to support this investigation, all of which are described in more detail in Appendix E:

- Compilation of a bibliography of previous hydrogeologic research in the Piceance Basin.
- Creation of a comprehensive spreadsheet of the published hydrogeologic properties of water-bearing geologic units (aquifers) in the Piceance Basin.
- Description of the general conceptual models for groundwater flow, surface water interaction, and the hydrogeology of the Piceance Basin.
- Evaluation of the groundwater development potential in the project areas, including estimation of well head costs for development of Piceance Basin groundwater in the project areas.
- Evaluation of existing groundwater quality.

The results of this study indicate that the potential for developing significant water supplies from groundwater in the project areas is low, because the study indicates that productivity from wells is expected to be minimal and that water quality is expected to be poor. Groundwater may prove to be a feasible water supply in a limited number of locations, depending on site-specific conditions.

Figure 3-1 depicts the areas of interest for exploring the feasibility of using groundwater resources to meet part of the water demand for the oil shale industry.

The geology of the Piceance Basin and a brief evaluation of groundwater development potential in the study area are described below. Additional detail about the groundwater evaluation can be found in Appendix E.

6.1 Piceance Basin Geologic Setting

The Piceance Basin is a geologic structure in northwestern Colorado extending more than 100 miles in length and encompassing approximately 7,110 square miles in various portions of Moffat, Rio Blanco, Garfield, Mesa, Pitkin, Delta, Gunnison, and Montrose counties (Figure 6-1). This geologic structure is named after and encompasses the Piceance Creek Basin. The structure of the Piceance Basin is complex, having numerous folds, faults, and variable formation thicknesses and composition (USGS, 1987). The Piceance Basin geology covered in this section is confined to the project areas shown in Figure 3-1 and the formations (aquifers) that are at a reasonable depth for groundwater development. Herein, the proposed in situ operation area is called the Northern Area, and the proposed above-ground retorting operation area is called the Southern Area.

Across the project areas, one discontinuous aquifer is recognized in the unconsolidated alluvium and Uinta Formation, two aquifers in the Green River Formation, a potential Piceance Basin-spanning aquifer in the Wasatch Formation (Molina Sand), and aquifers in the Rollins Sandstone and Ohio Creek Members of the Mesa Verde Formation. These aquifer designations are presented in Figure 6-2.

Figure 6-3 presents cross-sections running east to west across the Piceance Basin (the cross section lines are identified on Figure 6-1). The sections clearly depict the thickening and deepening of the basinal sediments in the northern part of the Piceance Basin (Colorado Geological Survey (CGS), 2003). Hydrogeologic data for formations of interest are available from shallow wells in the Piceance Basin margins.

The rocks of the Piceance Basin have been subject to several episodes of deformation that have systematically fractured the beds (USGS, 1987). There are at least eight sets of joints (fractures with a common orientation) for which orientation and spacing have been determined for the Piceance Basin. Joint orientation and spacing often strongly influences groundwater flow. Locating wells on areas of high joint density, or laterally continuous fractures, offers advantages in well yield, and certainty of supply. However, this type of site-specific analysis was not done as part of this study.

Source: CGS, 2003

Figure 6-1: Location and Extent of the Piceance Basin, and Figure 6-3 Lines of Cross Section

Period		Formation	Members	Aquifer
Quaternary		Alluvium	Steven Gulch alluvium	x
			Unconsolidated Quaternary deposit	x
			Gunnison River alluvium	x
			White River alluvium	x
Tertiary	Tv	Basalt flows		
		West Elk volcanic field		
	Ti	Uinta Formation		x
		Green River Formation	Main body	
			Evacuation Creek Member	
			Upper Parachute Creek Member	x
			Mahogany Zone	
			Lower Parachute Creek Member	x
			Garden Gulch Member	
			Douglas Creek Member	
			Lower Sandy Member (Anvil Points Member)	
	Tl	Wasatch Formation	Total body	
			Shire Member	
			Molina Member	x
			Atwell Gulch Member	
		Ft. Union Formation		
Cretaceous	K	Mesa Verde Group Iles Form. Williams Fork Form.	Total body	
			Ohio Creek Member	x
			Barren Member (undifferentiated Member)	
			Upper Coal Member (Paonia Shale)	
			Lower Coal Member (Bowie Shale)	
			Rollins Sandstone	x
			Cozzette Member	
			Corcoran Member	
			Upper Sego Sandstone	
		Mancos Shale	Anchor Mine Tongue	
		Mesa Verde Group	Lower Sego Sandstone	
			Castlegate Sandstone	
		Mancos Shale	Main body	
		Dakota Group	Total body	
			Dakota Sandstone	

Figure 6-2: Stratigraphy of the Study Area

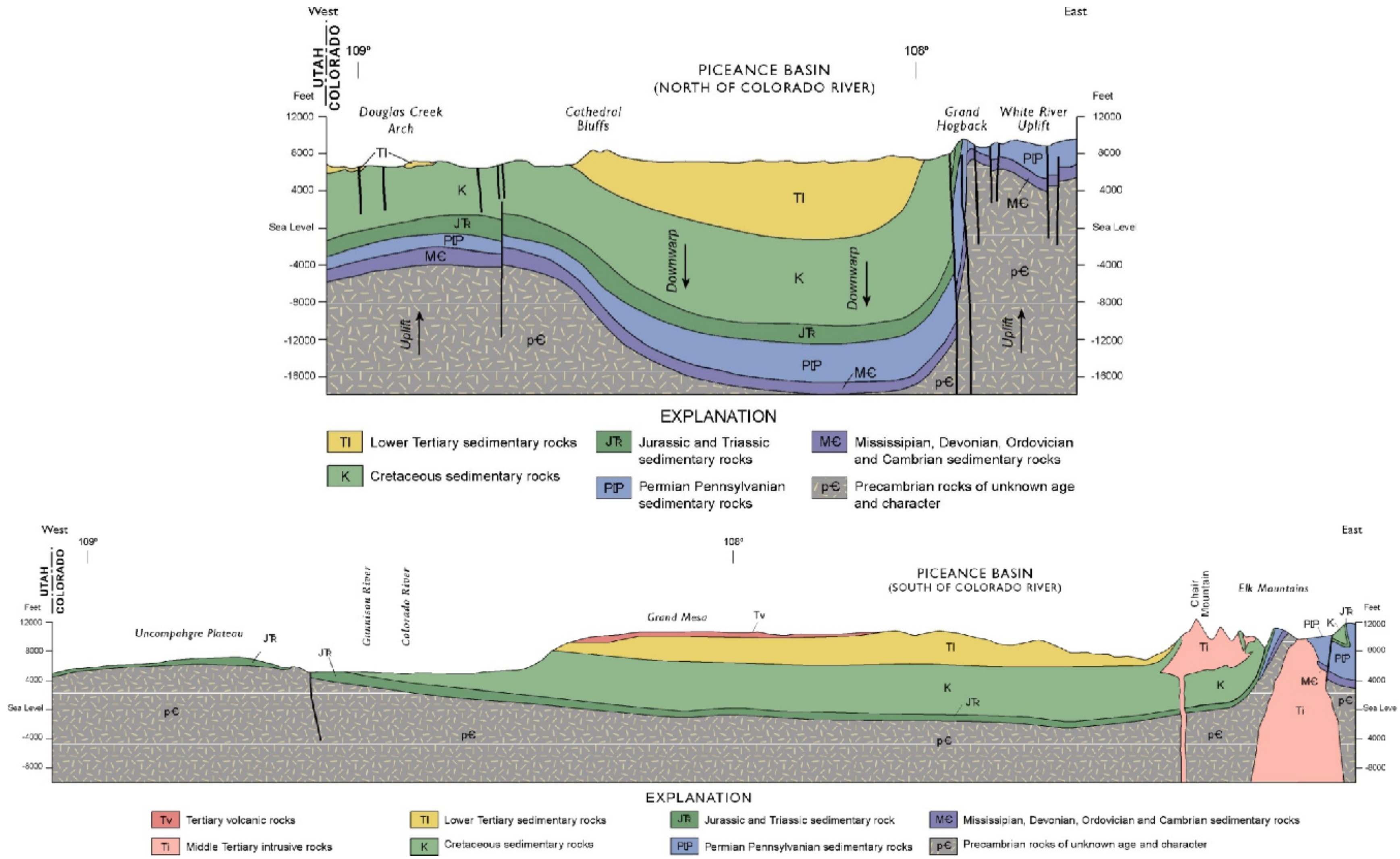

Figure 6-3: Cross-Sections across the Piceance Basin (east to west) Source: CGS, 2003

6.2 Feasibility of Using Groundwater for Oil Shale

There are three major criteria for determining the feasibility of groundwater use for oil shale development: the water quality, the quantity of water that can be produced, and the cost to do so. While water quality targets were not available for use as a quantitative criterion for comparison, in general the water quality of groundwater in the Piceance Basin is poor enough to be unusable for most industrial purposes without treatment. With respect to the quantity of water to be produced, the Wasatch and Mesa Verde Formations (Figure 6-2) are likely unsuitable because of the numbers of wells required and due to the well spacing (¼ to 1 mile between wells) needed to prevent interference (where pumping from one well lowers the water level in one or more neighboring wells). There is a broad range in potential costs for groundwater development in the project areas as indicated in Table 3 in Appendix E. The alluvial and Green River Formation aquifers have the lowest cost per well, the closest feasible well spacing, and the highest water quality. These shallower formations may provide the only feasible source of groundwater in the Piceance Basin for oil shale development. However, these aquifers are probably tributary in nature, so their use might require an augmentation plan and supply.

In conclusion, while the use of groundwater for energy development in the study area may play a minor role as compared to surface water supplies, there may be localized groundwater sources available. The feasibility of such sources will need to be determined by industry on a site-specific basis.

7.0 WATER SUPPLY PROJECT ALTERNATIVES

7.1 Introduction to StateMod

The analysis of water supply project alternatives used the State of Colorado's Stream Simulation Model (StateMod) developed by the CWCB. StateMod is an allocation and accounting model that allows for comparisons between various historic and future water management policies, e.g., administration of water rights, to be made in a river basin. StateMod can be run using a monthly or daily time step. StateMod allocates the river water among model nodes (representing ditches, reservoirs, river confluences, etc.) based upon priority, capacity, physical supply, and demand. StateMod uses the Modified Direct Solution algorithm to allocate river water among model nodes. StateMod can simulate direct flow rights, instream flow rights, reservoir storage rights, well rights, and operational rights. In StateMod each water right is assigned an administration number that identifies the seniority of a water right compared to other water rights in a river basin (i.e., the administration number tells the model which water right should be satisfied first). The river basin is represented in StateMod by a network of nodes (representing water rights) and lines (representing river channels and tributaries). Operational agreements and exchanges between one or more structures can be simulated in StateMod as operating rules.

The modeling studies considered an historical period of record from 1909 through 2006 for the White River model and an historical period of record from 1909 through 2005 for the Colorado River model, both of which contain substantial hydrologic variability. These periods represent the longest periods for which StateMod models have data. Both models were run using a monthly time step. The impact of climate change has not been considered in any of the modeling scenarios described herein.

7.2 White River Water Supply Projects

Working with the Energy Subcommittee, AMEC identified four water supply projects in the White River Basin (shown in Table 7-1). These four projects were evaluated to see if they would be sufficient to meet an annual demand of 110,000 acre-feet. The 110,000 acre-feet is the total annual demand in the White River Basin calculated for in-situ retorting, high production, long-term scenario as presented in Table 5-3. In the StateMod, the 110,000 acre-feet was assumed to occur in every year from 1909 through 2006. This 110,000 acre-feet was disaggregated in the model equally among the 12 calendar months in every year, i.e. 9,167 acre-feet in each month from 1909 through 2006.

Table 7-1: Selected White River Water Supply Projects

Water Supply Project	Description
Lake Avery Enlargement Filled From Big Beaver Creek.	Location: Off stream of White River on Big Beaver Creek Water Supply: Big Beaver Creek Capacity: 48,274 acre-feet Modeled Priority: 2010 Operation Assumptions: water released from Lake Avery would run downstream using the White River channel to the confluence of Piceance Creek and White River and then pumped up to the Piceance Creek Basin to meet in-situ retort demand.
Lake Avery Enlargement Filled From White River.	Location: Off stream of White River on Big Beaver Creek Water Supply: White River Capacity: 48,274 acre-feet Modeled Priority: 2010 Operation Assumptions: water released from Lake Avery would run downstream using the White River channel to the confluence of Piceance Creek and White River and then pumped up to the Piceance Creek Basin to meet in-situ retort demand.
Wolf Creek Reservoir	Location: On the White River or off-stream of White River on Wolf Creek Water Supply: White River Capacity: 162,400 acre-feet (total decreed capacity for three conditional storage rights owned by the Colorado River Water Conservation District) Modeled Priority: 2010 Operation Assumptions: water released from Wolf Creek Reservoir would be either (1) exchanged up to the confluence of Piceance Creek and White River and then pumped up to the Piceance Creek Basin to meet in-situ retort demand, or (2) pumped directly from Wolf Creek Reservoir to Piceance Creek Basin to meet in-situ retort demand.
New Diversion	Location: Confluence of Piceance Creek and White River Water Supply: White River Capacity: 165.05 cubic feet per second (cfs) Modeled Priority: 2010 Operation Assumptions: water diverted by this diversion would be pumped up to Piceance Creek Basin to meet in-situ retort demand.

7.3 White River Water Supply Modeling Scenarios

The following water supply scenarios have been evaluated. All these scenarios were simulated over a 98 year period from 1909 through 2006 using a monthly time step. In all the scenarios presented in this section, it was tested to see if Wolf Creek Reservoir would be needed to fully meet the 110,000 acre-feet demand after the supplies from the New Diversion and Lake Avery Enlargement have been exhausted. Based on the modeling analysis, Wolf Creek Reservoir was not used to meet the demand under any of the tested scenarios described herein. However, Wolf Creek Reservoir could be used instead of Lake Avery Enlargement to meet the 110,000 acre-feet demand in the White River Basin.

<u>Scenario 1:</u> Low water use/Initial water supply Scenario. This scenario uses the following supplies: (1) Lake Avery Enlargement filled in priority from Big Beaver Creek , and 2) a New Diversion from the White River located at the confluence of Piceance Creek and White River. For this scenario, it was assumed that Lake Avery enlargement would be filled using a 2010 priority with a storage capacity of 48,274 acre-feet and that the New Diversion would be filled using a 2010 priority and 165.05 cfs diversion rate. The 165.05 cfs diversion rate was used to ensure that this New Diversion <u>alone</u> can divert sufficient water to meet the 9,167 acre-feet monthly demand in any month. The 48,274 acre-feet storage capacity is the storage capacity for Lake Avery Enlargement as proposed in a study conducted by the International Engineering Company (1983). This study proposed feasible water supply alternatives for energy development in the White River Basin by evaluating information such as cost, engineering design, water supply, water rights and water demands.

This modeling scenario was designed so that for each month the demand would be first met by the New Diversion. Then, if the 9,167 acre-feet monthly demand is not fully satisfied, the deficit would be met by release from Lake Avery enlargement filled from Big Beaver Creek.

<u>Scenario 1 Modeling Results</u>: the results for this modeling scenario show that the 110,000 acre-feet annual demand couldn't be fully met in every year from 1909 through 2006, specifically in dry periods such as in 1977, 1978, 2003 and 2004. Therefore, the annual demand was gradually reduced to determine the maximum annual demand that can be fully met under this scenario in

every month from 1909 through 2006. It was found that the available supply under this scenario can only meet 104,000 of the 110,000 acre-feet per year (an annual shortage of 6000 acre-feet). Figure 7-1 shows the simulated end-of-month content for Lake Avery Enlargement, simulated monthly diversions by the New Diversion and the maximum available supply (8,667 acre-feet) from both the New Diversion and release from Lake Avery Enlargement from 1909 through 2006.

The following are the supplies used to meet the 104,000 acre-feet maximum annual demand (8,667 acre-feet/month) in a descending order as simulated in the StateMod model: (1) a New Diversion from the White River located at the confluence of Piceance Creek and White River, (2) Lake Avery Enlargement filled in priority from Big Beaver Creek.

Scenario 2: Multiple Supplies, Junior rights, unlimited diversion from White River to Lake Avery. Three water supply projects were simulated at the same time: (1) a New Diversion from the White River located at the confluence of Piceance Creek and White River, and (2) Lake Avery Enlargement supplied directly from Big Beaver Creek, and (3) Lake Avery Enlargement supplied from White River via a very large pipeline (1677 cfs [1]). In this scenario, the flow from the White River to Lake Avery Enlargement is only limited by the storage capacity and the 2010 priority of Lake Avery Enlargement. The purpose of this modeling scenario is to determine if the 110,000 acre-feet per year annual demand (9,167 acre-feet per month) can be fully met by the above supplies in every month from 1909 through 2006. The model for this scenario was designed so that the demand in each month is first met by the New Diversion. Then, if the demand in any month is still not fully met, the deficit would be met by release from Lake Avery Enlargement.

The following are the supplies tested to meet the 110,000 acre-feet annual demand (9,167 acre-feet/month) in a descending order as simulated in the StateMod model: (1) a New Diversion from the White River located at the confluence of Piceance Creek and White River, (2) Lake Avery Enlargement filled in priority from Big Beaver Creek and via a pipe from White River with a diversion capacity of 1,677 cfs.

[1] Maximum historical flow rate recorded at an upstream gauge.

<u>Scenario 3:</u> Multiple Supplies, Junior rights, 100 cfs diversion from White River to Lake Avery Enlargement. This scenario is identical to Scenario 2 with the exception of restricting the flow rate from the White River to Lake Avery Enlargement to 100 cfs. The 100 cfs flow rate represents a feasible flow rate for a pipe and a pumping station and at the same time large enough to ensure that meeting the 110,000 acre-feet annual demand is not physically restricted. The following are the supplies used to meet the 110,000 acre-feet annual demand (9,167 acre-feet/month) in a descending order as simulated in the StateMod model: (1) a New Diversion from the White River located at the confluence of Piceance Creek and White River, (2) Lake Avery Enlargement filled in priority from Big Beaver Creek and via a pipe from White River with a diversion capacity of 100 cfs.

<u>Scenarios 2 and 3 Modeling Results:</u> The modeling results for Scenarios 2 and 3 show that the New Diversion and Lake Avery Enlargement (supplied from Big Beaver Creek and White River) are sufficient to fully meet the 110,000 acre-feet and that Wolf Creek Reservoir is not needed in any month from 1909 through 2006 even if the flow from the White River to Lake Avery Enlargement is restricted to 100 cfs. Figures 7-2 and 7-3 show the modeling results for Scenarios 2 and 3, respectively. Each figure shows end-of-month simulated content for Lake Avery Enlargement, end-of-month simulated content for Wolf Creek Reservoir, in priority diversions by the New Diversion, and the monthly demand (9,167 acre-feet) met from 1909 through 2006.

7.4 Conclusions for White River Water Supply

Given the modeling results described above, it appears that in-situ water demand for the high production, long-term scenario in the White River Basin can be fully met in every month during average and wet periods but not during dry periods using the following example supplies (1) a junior diversion from the White River located at the confluence of Piceance Creek and White River, and (2) a junior storage right in Lake Avery Enlargement from Big Beaver Creek. In some months during dry periods, the above supplies alone would not be sufficient and therefore would have to be supplemented by a junior storage right in Lake Avery Enlargement from the White River in order to fully meet the water demand for in-situ retorting.

This study did not look at all possible water supply projects and water management scenarios that can be used to meet the 110,000 acre-feet demand in the White River Basin. This study only looked at some example projects to see if the 110,000 acre-feet can be met and concluded that there is a sufficient water supply in the White River Basin to meet the 110,000 acre-feet annual demand. The 110,000 acre-feet can be met by many combinations of other water supply projects that were not tested in this study.

In conducting this assessment, the water rights database developed in Phase I of the study (URS, 2008) and Colorado's Decision Support System supplemented by the information available in Water Rights Tabulation (2010) was relied upon.

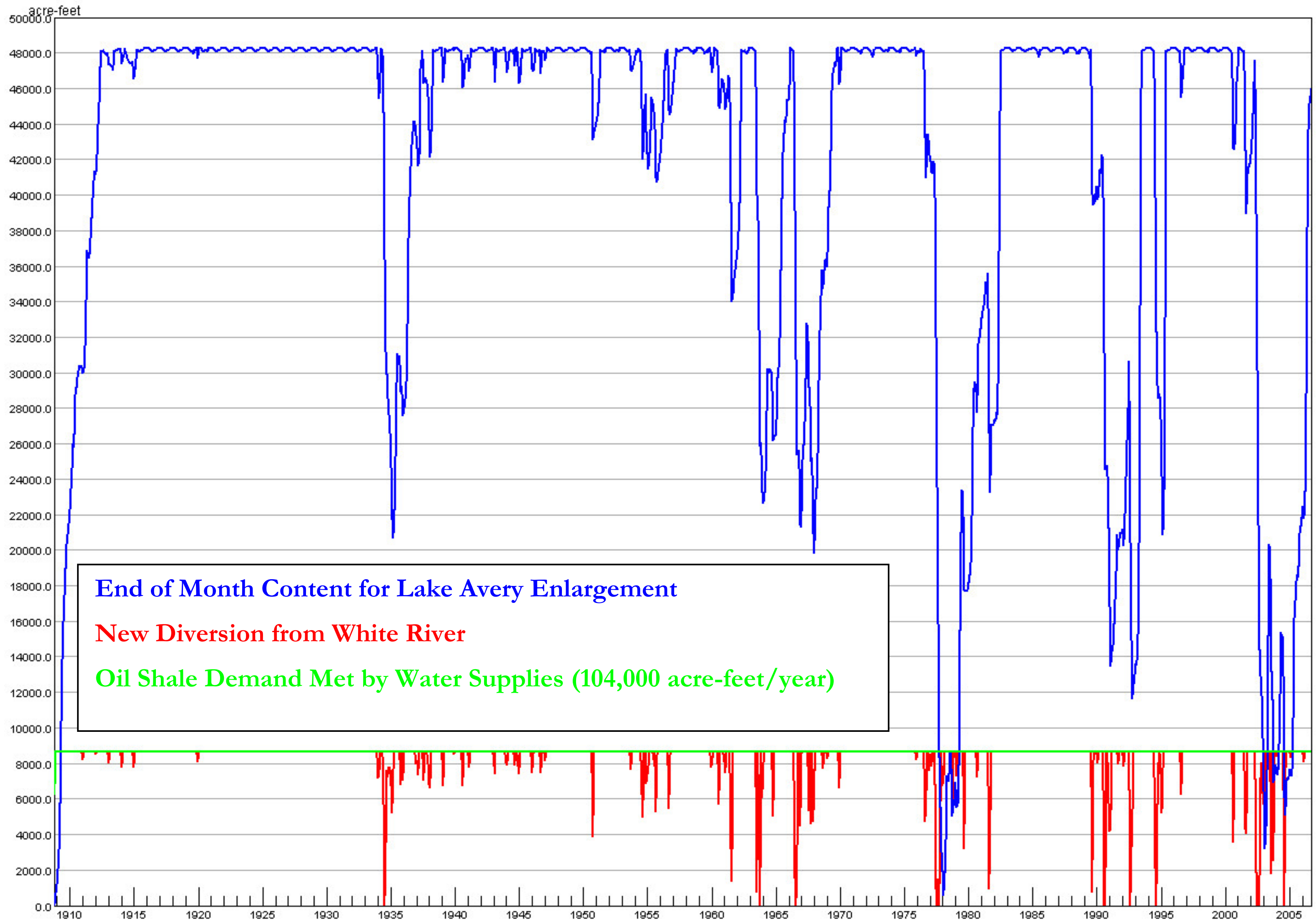

Figure 7-1: Results for White River Scenario 1

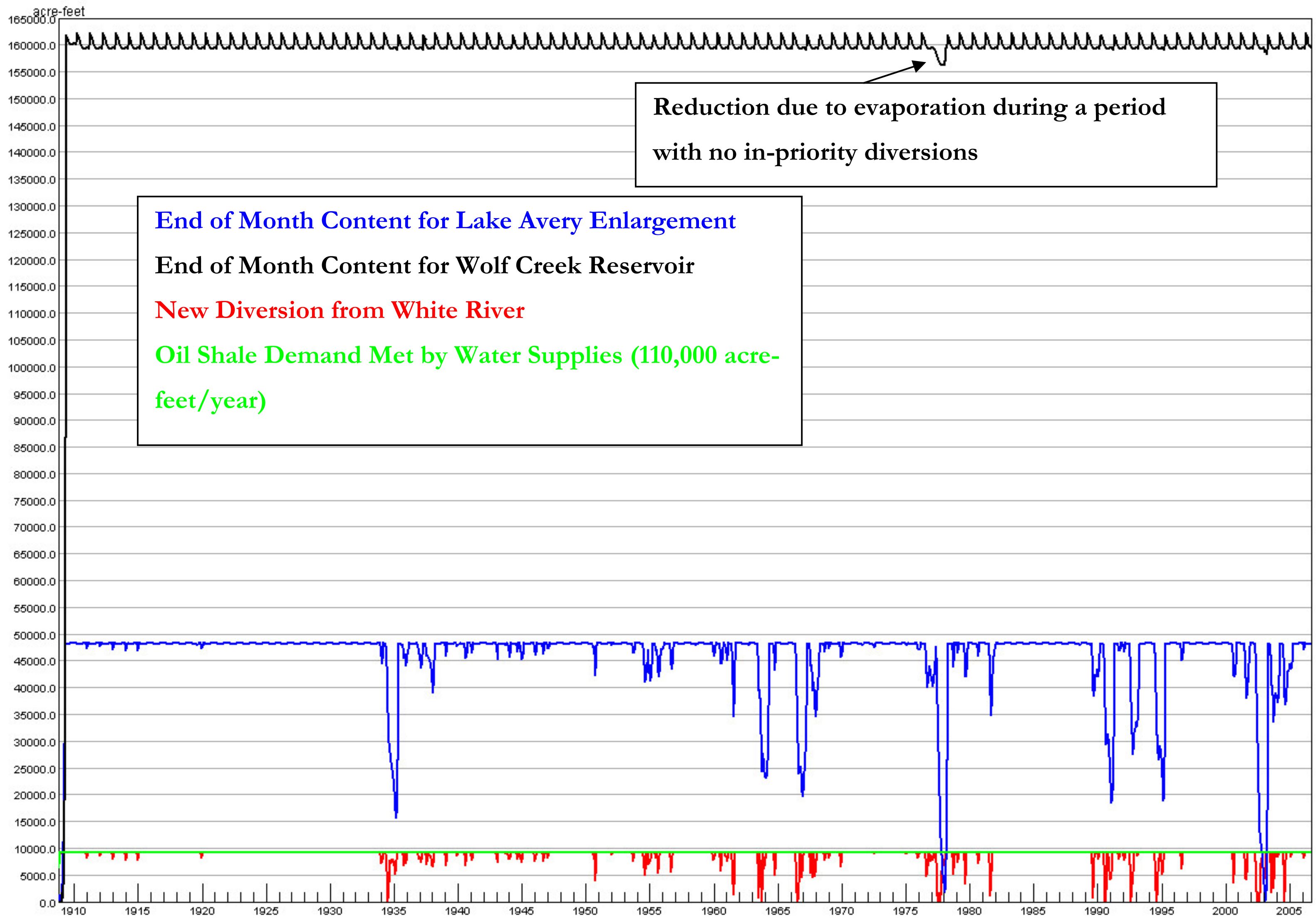

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Figure 7-2: Results for White River Scenario 2

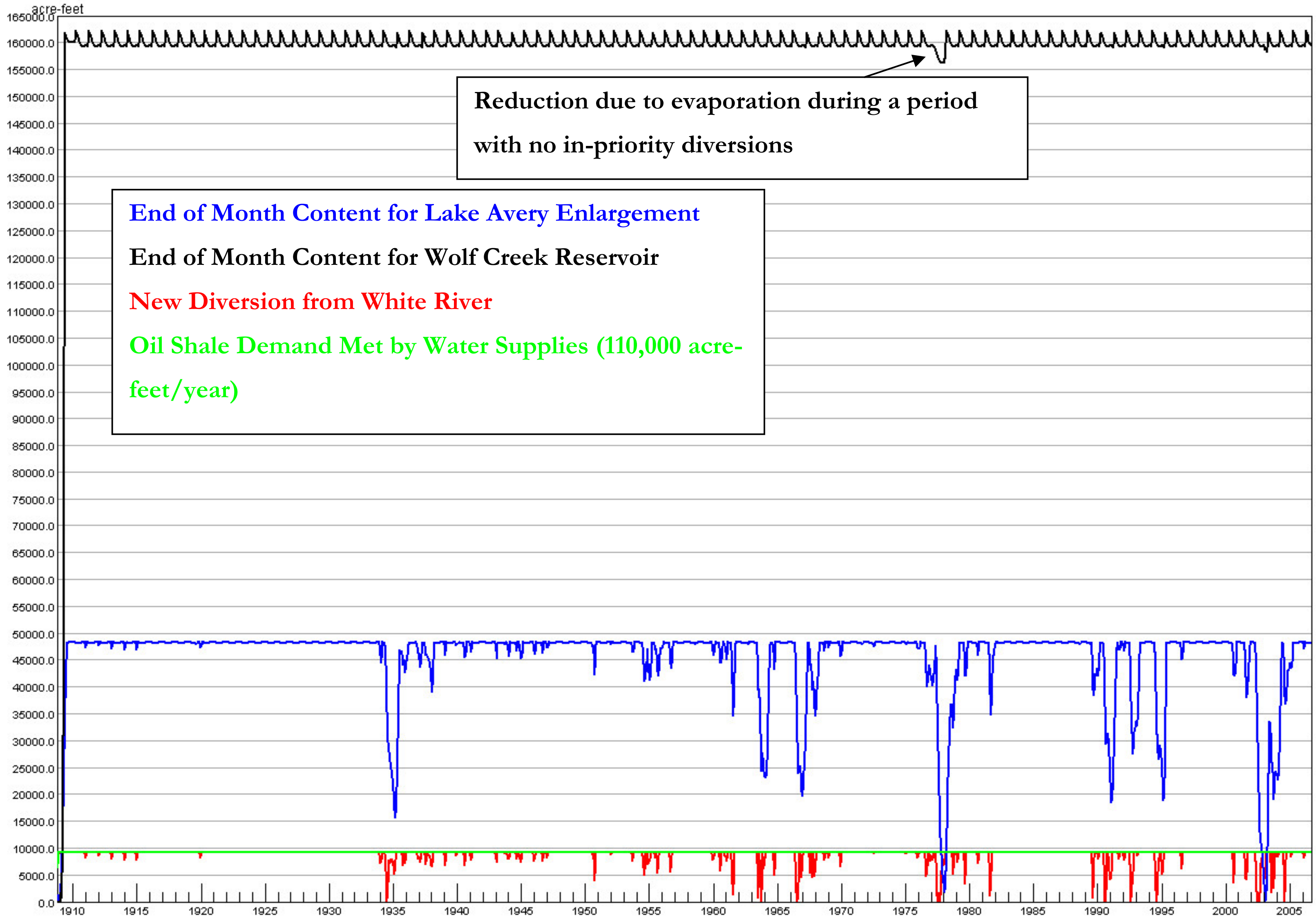

Figure 7-3: Results for White River Scenario 3

7.5 Colorado River Water Supply Projects

Working with the Energy Subcommittee, AMEC identified seven water supply projects in the Colorado River Basin (shown in Table 7-2). These seven projects are described in Exxon Mobil's water rights application in Case No. 08CW199. In this water right application, Exxon Mobil seeks to change the place of use of the water rights in Table 7-2 which would divert from the Colorado River and Parachute Creek. The waters diverted under these rights would be used in the Piceance Creek and Yellow Creek Basins. These water rights were modeled using their conditional water rights limits, priorities and decreed locations as described in the Exxon Mobil's water rights application and the Colorado StateMod Model. The decreed locations of these water rights are shown in Figure 7-4.

Table 7-2: Selected Colorado River Water Supply Projects

Water Supply Project	Description
Dow Pumping Station	Location: On stream of Colorado River, Section 6, Township 7S, Range 95 West, 6th P.M. Water Supply: Colorado River Capacity: 94.8 cfs Modeled Priority: January 24, 1955
Dow Middle Fork Pipeline	Location: Middle Fork of Parachute Creek, Section 31, Township 4S, Range 95 West, 6th P.M. Water Supply: Parachute Creek Capacity: 1.088 cfs Modeled Priority: October 20, 1954
Dow East Middle Fork Pipeline	Location: East Middle Fork of Parachute Creek, Section 10, Township 5S, Range 95 West, 6th P.M. Water Supply: Parachute Creek Capacity: 13.54 cfs Modeled Priority: October 19, 1954
Middle Fork Reservoir	Location: Middle Fork of Parachute Creek, Section 6, Township 9S, Range 95 West, 6th P.M. Water Supply: Parachute Creek Capacity: 171.622 acre-feet, 1438.378 acre-feet (enlargement) Modeled Priorities: September 17, 1959, September 30, 1974 (enlargement)
Davis Gulch Reservoir	Location: Davis Gulch of Parachute Creek, Section 12, Township 5S, Range 96 West, 6th P.M. Water Supply: Parachute Creek Capacity: 204 acre-feet, 996 acre-feet (enlargement) Modeled Priorities: September 15, 1959, September 30, 1974 (enlargement)
East Middle Fork Reservoir	Location: East Middle Fork of Parachute Creek, Section 15, Township 5S, Range 95 West, 6th P.M. Water Supply: Parachute Creek Capacity: 130.558 acre-feet Modeled Priority: September 17, 1959
Lower East Middle Fork Reservoir	Location: East Middle Fork of Parachute Creek, Section 18, Township 5S, Range 95 West, 6th P.M. Water Supply: Parachute Creek and Colorado River Capacity: 6200 acre-feet Modeled Priority: February 2, 1982

7.6 Colorado River Water Supply Scenario

A firm yield analysis scenario was simulated using the Colorado StateMod Model and a monthly time step to see if Exxon Mobil's water rights (Table 7-2) would be sufficient to meet an annual demand of 10,000 acre-feet. The 10,000 acre-feet is the total annual demand calculated for above ground retorting, high production, long-term scenario in the Colorado River Basin as presented in Table 5-3. For this modeling scenario, the 10,000 acre-feet was assumed to occur in every year from 1909 through 2005. The 10,000 acre-feet was disaggregated in the model equally among the 12 calendar months in each year from 1909 through 2005, i.e. 833 acre-feet per month.

Lower East Middle Fork Reservoir is the largest reservoir in Exxon Mobil's water rights application. Given also that Lower Middle Fork Reservoir is located relatively downstream of the other Exxon Mobil's diversion and storage structures in Parachute Creek, Lower East Middle Fork Reservoir was modeled as a forebay, i.e. water diverted by Dow Middle Fork Pipeline, Dow East Middle Fork Pipeline, Middle Fork Reservoir, Davis Gulch Reservoir and East Middle Fork Reservoir was assumed to be released and stored in Lower East Middle Fork Reservoir before it is delivered to supply oil shale development.

This modeling scenario was designed so that in any month demand would be first met by Dow Pumping Station diversion. If Dow Pumping Station diversion is not fully sufficient, the remaining deficit would be met by release from Lower East Middle Fork Reservoir.

7.7 Conclusions for Colorado River Water Supply

The results for the Colorado River firm yield analysis scenario are shown in Figure 7-5. Based on these modeling results, it appears that the 10,000 acre-feet annual demand for above ground retort in the Colorado River Basin could be fully met in every month from 1909 through 2005 using in priority diversions by Exxon Mobil's water rights shown in Table 7-2 including in dry periods.

Another modeling scenario was simulated in which Dow Pumping Station diversions would also be stored in Lower Middle Fork Reservoir. The water available under this modeling scenario (results are not shown in this memorandum) would also be sufficient to fully meet the 10,000 acre-feet annual demand in every month from 1909 through 2005, including dry periods.

This study didn't look at all possible water supply projects and water management scenarios that can be used to meet the 10,000 acre-feet demand for above ground retorting in the Colorado River Basin. The 10,000 acre-feet can be met by many combinations of other water supply projects that were not tested in this study.

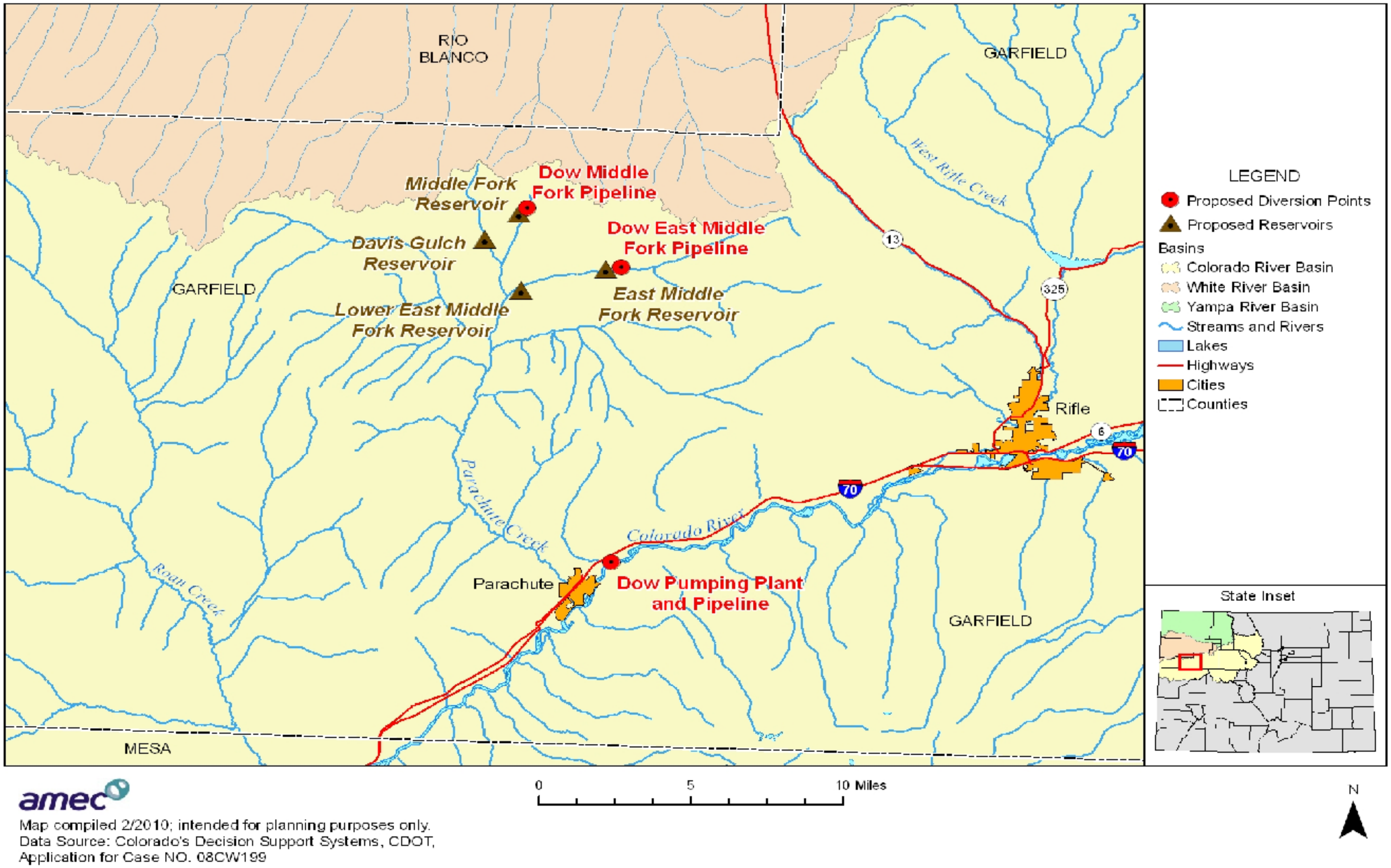

Figure 7-4: Proposed Diversion Points and Reservoirs by Exxon Mobil (Case No. 08CW199)

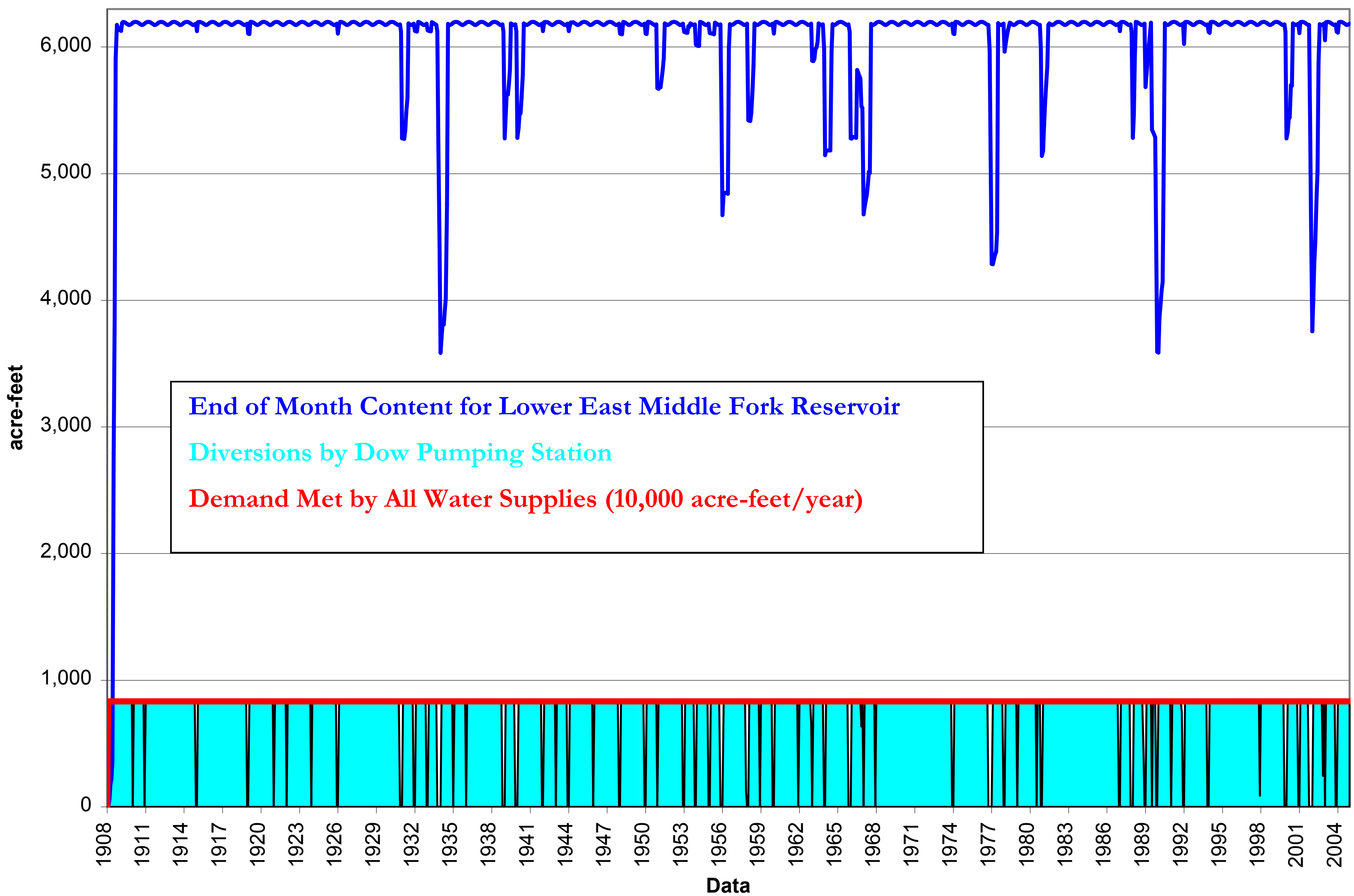

Figure 7-5: Results for Colorado River Scenario

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Appendix A

Oil Shale Production Scenarios

Memorandum

To: Joint Energy Water Needs Subcommittee
cc:
From: Ben Harding, Shaden Musleh, Hanna Sloan
Subject: Oil Shale Production Scenarios
Date: June 16, 2010

This Technical Memorandum provides background and information about development of scenarios for the scale of a future oil shale industry as part of Task 2 of the Energy Water Needs Assessment Phase II Study (Phase II Study).[1] The Energy Development Water Needs Assessment is being conducted by the Energy Subcommittee (Subcommittee) of the Colorado, Yampa and White River Basin Roundtables as part of the Colorado Water for the 21st Century (HB-1177) water supply planning process.

The objective of Task 2, *Refine Water Demand Estimates*, is to develop estimates of water demand caused by future energy development and to break those demands down by location to allow a particular water use to be assigned to a particular water supply facility in a water supply scenario. The Study area for the Phase II Study includes all of the Yampa River and White River basins and that portion of the Colorado River basin west of a line running north and south approximately through Edwards.

The scope of Task 2 involves refinement of the water use estimates reported in the Phase I report (URS, 2008). This memo provides information about Sub-task 2.3 *Develop Basin Water Use Scenarios.* The objective of Sub-task 2.3 is to develop a water use scenario for each basin. Subsequent sections of this technical memorandum discuss: an introduction, the time frame for scenarios, evaluation of estimates of the scale of an oil shale industry, and references.

Introduction

Phase I developed estimates of future water required for development of oil shale, coal, natural gas and uranium energy resources. Only estimates of water use attributable to oil shale development will be refined in the Phase II Study. The work in Task 2 will result in revised estimates of water use attributable to oil shale that reflect new information about and improved understanding of the future possibilities for an oil shale industry. Task 2 will also break down estimates of water use for all industry sectors as required by water resources modeling; the result of that work is not reported in this technical memorandum.

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[1] This memorandum supersedes information about industry scale in the technical memorandum dated August 18, 2010, entitled "Energy Water Use Scenarios".

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Water use scenarios depend on the scale of the projected future oil shale industry and the water use intensity of the industry. Water use intensity is expressed as the amount of water required to produce a unit of production, which is a barrel of oil in the case of oil shale. This memorandum addresses the assumption to be used by the study for the scale of the oil shale industry.

The scope of Task 2 involves refinement of the water use estimates reported in the Phase I report (URS Corporation, 2008). That refinement was to involve breaking down the Phase I water use estimates into components that would allow water use to be assigned to particular locations or regions as required by water resources modeling. The Phase I water use estimates have been criticized by the National Oil Shale Association (NOSA, 2009), with the principal criticisms being that the time frames for development of the industry were unrealistically short, the water-use intensity was too high, and the estimates of population growth associated with development of oil shale were too high. Although the Subcommittee did not agree with the oil shale industry in all instances, AMEC was directed to involve industry representatives in the process of refining the Phase I estimates of water use. In this technical memorandum we address comments from industry by comparing the Phase I estimates of the scale and timeframe of development of a future oil shale industry against the history of development of the Athabasca oil sands industry in northeastern Alberta, Canada.

Time frame for scenarios

There are two conceptual approaches that can be used for estimating future water use: (1) estimates at a specific point in time or at a range of times in the future, or (2) estimates at “build-out” that are not based on a specific point in time but that are intended to represent the level of water use by a mature, fully–developed industry.

Water use estimates that are used for planning the timing of development of specific elements of infrastructure are usually made for specific time frames. In such cases the time frames conventionally range from 20 to about 50 years into the future. Water use estimates that are used for an assessment of the adequacy of physical or legal water supply, without consideration of the capability or cost of infrastructure, are often based on the build-out scenario. The time frame used in developing a build-out estimate is an indefinite time in the future when water use has matured, and this is usually intended to represent a realistic maximum level of development.

Selection of the conceptual scenario for estimating future water use, and selecting the specific future time frame at which estimates of water use might be developed, is a policy decision that depends on how the water use estimates will be employed. The Subcommittee has directed that a build-out scenario be used as the basis for the Phase II water use estimates and model studies, and has directed that the “high, long-term” estimate of industry scale developed by the Phase I study be used to quantify build-out conditions in Phase II. As such, no time frame will be associated with the industry scale estimates used in Phase II, although the analysis we provide below indicates that, should an oil shale industry develop at all, it is plausible that the “high, long-term” scale developed in the Phase I study would be reached within this century.

Evaluation of Estimates of Oil Shale Industry Scale

The Phase I report included estimates of the scale and timeframe for development of a future oil shale industry (URS, 2008, Table 3-13, p 3-34). Those estimates are shown in Table 1.

Table 1. Phase I Assumptions Supporting Oil Shale Production Scenarios

Planning Horizon	Production Scenarios – Oil Shale		
	Low	Medium	High
Near-Term (2007–2017)	No Commercial Production RD&D Leases Only	No Commercial Production RD&D Leases Only	No Commercial Production RD&D Leases Only
Mid-Term (2018–2035)	No Commercial Production RD&D Leases Only	Underground mine/surface retort facility with 50,000 bpd production. Additional 25,000 bpd of in-situ production	Underground mine/surface retort facility with 50,000 bpd production. Additional 500,000 bpd of in-situ production
Long-Term (2036–2050)	No Commercial Production RD&D Leases Only	Underground mine/surface retort facility with 50,000 bpd production. Additional 150,000 bpd of in-situ production	Underground mine/surface retort facility with 50,000 bpd production. Additional 1.5 million bpd of in-situ production

The Phase I water use estimates were criticized by industry (NOSA, 2009), with one of the principal criticisms being that the time frames for development of the industry were unrealistically short.

Whether or not an oil shale industry will exist will depend on the technical feasibility of recovery and processing, economics of recovery and processing, and market conditions. If recovery of shale oil proves technically or economically infeasible then no industry will develop, a case that is represented by the “Low” production scenario in Table 1. If recovery of shale oil proves technically feasible, and if economics and market conditions are favorable, then the industry will develop, with its ultimate scale limited by resource constraints and possibly by non-market constraints such as government regulation. The case of a feasible industry is represented by the “Medium” and “High” scenarios in Table 1. Industry did not question the Phase I estimate of the scale of a “mature” oil shale industry, as represented by the “Long-Term, High” scenario (1.55 million bbl/day) but did question whether it was realistic to assume that an industry of that scale could develop as early as 2036 as suggested in the Phase I Study. If recovery of shale oil proves to be technically feasible and economics of recovery are in a range that is favorable over a range of market conditions, then the timing of development of the industry will be driven by market conditions. Industry representatives suggested that development of the Athabasca oil sands in northeast Alberta, Canada could serve as a reasonable analog to development of an oil shale industry in the Piceance basin.

Oil Sands are deposits of sand in which the individual sand particles are coated with bitumen, which is very heavy (viscous) oil. Because of the high viscosity of the oil in oil sands, the oil is recovered by strip mining and above-ground recovery of oil, or by in situ recovery methods that involve lowering the viscosity of the oil with heat or solvents. All three of these production methods have been tried or proposed for production of shale oil, although within the Phase II study area mining and surface retorting of oil shale is likely feasible only at outcrops along the southern extent of the Piceance Basin. The energy density of oil sands is similar to the energy density of oil shale (approximately 20 gallons per ton). Like kerogen produced from oil shale, the bitumen produced from oil sands must be diluted or upgraded into a synthetic crude oil before it can be transported or used as a refinery feedstock. Oil sand deposits differ from oil shale deposits in that oil sands are generally found at shallower depths than are oil shale deposits in the study area, and the oil sand deposits and their overburden are generally unconsolidated, while the opposite is true for oil shale deposits in the study area. These factors will tend to require higher capital investment and operating expense for production from oil shale compared to production from oil sands. However, if the uncertainties arising from the differences between the two industries are kept in mind, , the development of the oil sands industry can be used as a reasonable analog for development of an oil shale industry.

A history of production from the Athabasca oil sands is shown in Table 2.

Table 2. Production History of Athabasca Oil Sands (after Humphries, 2008, Foucher, 2006)

Year	Production (bbl/day)	Long-term annual growth rate
1967	12,000	
1978	130,000	27%
2002	550,000	12%
2003	750,000	12%
2005	880,000	12%
2007	1,200,000	12%

Research and development of methods for recovering oil from oil sands began early in the 20th century. A hot water extraction method was developed by 1923 and technical feasibility was demonstrated in a pilot scale plant by 1950 (Humphries, 2008). However, initial commercial production of oil from oil sands from the Athabasca deposits did not occur until 1967 with a 12,000 bbl/day facility. Although commercial feasibility was established by this facility, oil prices declined through 1973 and a second facility was not constructed until 1978 (129,000 bbl/day). In recent years, development accelerated with rising oil prices. In 2002 production was about 550,000 bbl/day; by the first quarter of 2006 production was about 900,000 bbl/day and by the end of 2007 it was 1.2 million bbl/day (Humphries, 2008). From inception through 2007 the industry grew at a long-term rate of approximately 12% per year, and though growth proceeded in steps, the long-term growth rate at any time after 1978 was consistently around 12% per year. Production is projected to reach 2,800,000 bbl/day by 2015, which would represent a continuation of the 12% growth rate. Other sources say that the initial production capacity of the first commercial production unit was 30,000 bbl/day. Using this capacity as a starting point yields a long-term growth rate of 10% per year.

Assuming that the Athabasca oil sands industry presents a reasonable analog to an oil shale industry in the Piceance Basin, the history of development of the Athabasca industry can be used to evaluate the Phase I scenarios for development of the industry in the Piceance Basin. Table 3 places the significant Phase I scenarios in the context of the development of the Athabasca Oil Sands. In projecting development time frames, we have assumed that the initial field demonstration of technical feasibility for one or more in situ technologies would occur by 2015 (initial technical feasibility of above-ground retorting has likely already been established) and initial commercial production would occur 20 years later (compared to the 17-year period prior to development of first commercial production at the Athabasca oil sands). Subsequent projections of production employ growth rates of 10% and 14%, which bracket the 12% long-term growth rate for the Athabasca oil sands.

Table 3. Evaluation of Scenarios for Piceance Basin Oil Shale Industry

	Time Frame for Development	
Milestone/Production Level	**Phase I**	**Projected Scenario**
Field demonstration of technical feasibility		2015
Initial commercial production, 50,000 barrels/day		2035
550,000 barrels/day	2018 – 2035	2053 – 2060
1,550,000 barrels/day	2036 – 2050	2061 – 2071

This analysis indicates that the Phase I estimates do not overstate the size of a mature, unconstrained oil shale industry in the Piceance Basin. However, comparison with the development of the Athabasca Oil Sands indicates that production at the levels identified in the Phase I report might occur anywhere from ten to twenty-five years later than the later dates projected in the Phase I report.

The size, measured by rate of production, of a mature oil shale industry that would represent a build-out scenario is not bounded by the oil shale resource in the study area, which contains an estimated 1.2 trillion barrels of recoverable shale oil (BLM, 2006), and could support production of many millions of barrels of oil per day for hundreds of years. However, it is reasonable to think that the scale of the industry, the methodology used for production, the type and location of electrical generating facilities, or the location of other required infrastructure, might be constrained or influenced by public opinion reflected in regulations or legislation. What those effects might be are uncertain but it is reasonable to conclude that the scale of the industry could be at least as large as was estimated by the Phase I report.

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Appendix B

Oil Shale Direct Water Use Estimates

Memorandum

To:	**Joint Energy Water Needs Subcommittee**
cc:	
From:	**Ben Harding, Shaden Musleh, Hanna Sloan** **AMEC Earth & Environmental**
Subject:	**Oil Shale Direct Water Use Estimates**
Date:	**April 13, 2010**

Introduction

This Technical Memorandum summarizes information developed as part of Task 2 of the Energy Water Needs Phase II Study (Study).

The objective of Task 2, *Refine Water Demand Estimates*, is to develop water demands with sufficient spatial resolution to allow a particular water use to be assigned to a particular water storage project in a water supply scenario.

This memo provides information about Sub-tasks 2.1, *Review Phase I Report and Demands,* and 2.2, *Estimate Consumptive Use and Return Flow Patterns.* Subsequent sections of this technical memorandum discuss: an introduction, the approach used in refining water demand estimates, estimates of direct unit water use by category, and references.

Introduction

This memorandum provides estimates of the amounts of water required to support the operations of an oil shale industry within the study area. Water use associated with oil shale production can be broken into two principal classes, direct uses and indirect uses. Direct uses include those uses associated with construction, operation, production, processing and reclamation processes that are directly required for oil shale development and commercial production of a petroleum product suitable for a refinery feedstock. Water use associated with electrical energy needed to support the above processes is considered as a direct use. Indirect uses include water required to support population growth and economic activity resulting from production of shale oil. Only direct uses of water are reported herein; estimates of indirect water use will be based on estimates of population growth provided by the Colorado Water Conservation Board as part of the Inter-Basin Compact Committee process and will be reported in a separate technical memorandum.

Water use estimates presented herein are provided in terms of barrels of water required to produce one barrel of oil from oil shale (bbl/bbl). The liquid produced by retorting oil shale, whether by in situ or above-ground technologies, is described as kerogen pyrolysis products, and is referred to herein as “shale oil”. Once shale can be converted

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to a product that is commercially and industrially similar to conventional petroleum products, which is referred to herein as “oil”.

Approach

Estimates of direct water use were obtained from the Phase I report (URS, 2008), from information obtained from industry and from a review of readily available literature.

Following an initial review of water use estimates provided in the Phase I report, meetings and consultation were held with industry representatives. A meeting was held with Tracy Boyd from Shell Exploration and Production Company (Shell) and Glenn Vawter from the National Oil Shale Association (NOSA) on June 29, 2009. At that meeting AMEC explained the objectives of the Phase II study and explored how industry representatives could provide information to the Study. In order to address concerns on the part of industry about disclosure of proprietary information, a process was agreed to wherein a questionnaire developed by AMEC in collaboration with Shell and NOSA would be circulated to industry representatives by NOSA, industry would provide NOSA with water use estimates in response to the questionnaire, and NOSA would compile a single statement of water use that expressed water use as a range or an average. Separate questionnaires were used to address water use for the two identified major technologies (1) in situ retorting and recovery (in situ retorting) and (2) underground mining and above-ground retorting (above-ground retorting). Based on conventional industry practice during previous oil-shale development efforts, and based on advice from industry, AMEC elected to use an operational module of 50,000 barrels per day (bbl/day) production as a basis for requesting water use estimates from industry. The questionnaires are provided in Appendix A.

Shortly after the June meeting, the questionnaires were provided to Mr. Vawter who, in turn, distributed them to the industry representatives he had identified. The identity of the industry respondents were not disclosed to AMEC. AMEC received responses to the questionnaire in September 2009. Those responses are provided in Appendix B.

Additional estimates of direct water use were compiled from literature. These estimates are provided in Table 1 of Appendix C. Estimates of overall levels of water use have been made by a number of sources and are available in a recent compilation by Western Resource Advocates (2009). The bases for the water use estimates reported in the literature and provided in Appendix C are not well defined and most of these estimates are not broken down categorically in a way that would allow for a direct comparison to the categorical estimates provided by the industry and in the Phase I report. A comparison between industry-wide estimates of direct water use from literature and those obtained from industry and from Phase I report is shown in Table 2 of Appendix C.

Estimates of Direct Water Use by Category

A summary of estimates of the amount of water used directly in the production of oil from oil shale are shown in Table 1. Estimates of the amount of water co-produced during the retorting of oil shale are shown in Table 2.

Table 1.
Estimates of Water Required for Production of Oil from Oil Shale (bbl/bbl)

	In situ Retorting		Above-Ground Retorting	
Water Use Category	**Low**	**High**	**Low**	**High**
Construction/Pre-production	0.02	0.16	0.01	0.07
Electrical Energy	0.41	1.00	0.17	0.26
Production			0.47	0.47
Reclamation	0.45	0.54	0.02	0.17
Spent Shale Disposal			0.80	1.60
Upgrading	0.57	1.60	0.60	1.60

In calculating water use per barrel of produced oil, the following approach was used: For each category of use the total amount of water required for that category over the life of the oil shale production facility was calculated and that amount was divided by the total amount of oil that would be produced by the facility over its lifetime. In making these calculations no adjustment was made for changes in volume that might occur during upgrading.

Table 2.
Estimates of Water Co-Produced When Retorting Oil Shale (bbl/bbl)

In situ Retorting	Above-Ground Retorting
0.80	0.30

The basis for these estimates are described in the following sections.

Phases and Timeframes

Three phases in the development of an oil shale retorting operation were identified by NOSA: Construction/Pre-production, Production, and Reclamation. These phase names are also used in Table 1 and in the discussion below to label water use that takes place during a phase. The timing of the phases are shown in Table 3 for the two production methodologies (NOSA, 2009).

Table 3.
Duration of Phases (Years)

Phase	In Situ Retorting	Above-ground Retorting
Construction/Pre-production	2.5	4
Production	6.5	25
Reclamation	5.5	4
Total	14.5	33

Construction/Pre-production

This category includes water required for preparation and construction of the site, including activities such as surface preparation, trenching, dust control, road construction, buildings and facilities construction, mine construction, and drilling of production, freeze wall, and formation heating wells).

In Situ Retorting

NOSA estimated the total amount of water required for construction/pre-production phase to be 300 acre-feet (af) for a 50,000 bbl/day module. Estimates of water use in the Phase I report related to the construction/pre-production phase were 417 acre-feet/year for site preparation and 583 acre-feet/year for subsurface preparation, for a total of 1,000 acre-feet/year for a 50,000 bbl/day module. It appears that the Phase I report applied these annual water uses throughout the production phase, even though the construction/pre-production phase is completed before production begins. We have chosen to apply the annual rates from Phase I for the duration of construction/pre-production phase (2.5 years).

Above-Ground Retorting

NOSA estimated the total amount of water required for construction/pre-production phase to be 300 acre-feet (af) for a 50,000 bbl/day module. The Phase I report did not provide a separate estimate of the water requirement for the construction/pre-production phase for an above-ground retorting operation. We adopted the same annual rate as was provided in the Phase I report for an in situ retorting operation and applied that annual rate for the duration of the construction/pre-production phase (4 years).

Electrical Energy

This category includes the water needed to generate the electrical energy required for formation heating required by some in situ retorting technologies, and for non-heating uses at in situ and above-ground retorting operations. Non-heating energy would include energy for lifts, compressors, pumps, lighting, heating and ventilation, and other needs. Both NOSA and and the Phase I report provided combined estimates for heating and mechanical energy requirements for in situ retorting operations. Some in situ retorting methodologies use chemical or solvent-based methods and do not require formation heating, and some of the methods that require formation heating propose to generate heat by combustion and therefore will not require electrical energy for heat production.

In Situ Retorting

Table 4 shows the two estimates of energy and water use for in situ retorting operations for a 50,000 bbl/day module. NOSA provided an estimate of 2,200,000 megawatt-hours per year for a 50,000 bbl/day module. This estimate is an average of an undisclosed number of responses from industry participants and presumably represents an industry with a mix of production technologies that reflects the technologies being developed by the respondents to the NOSA questionnaire. The Phase I study used an estimate of 300 kilowatt-hours (kWh) per barrel, which equates to 5,475,000 megawatt-hours (MWh) per year (MWh/yr) for a 50,000 bbl/day facility. This estimate represents an in situ industry that is entirely heated electrically.

Table 4.
Water Use for Electrical Power Generation to Support In Situ Retorting

Data Source	Heating Energy Intensity		Water Use bbl/bbl	Water Use acre-feet/year
	MWh/50,000 bbl/day	kWh/bbl		
Phase I	5,475,000	300	1.0	2,400
NOSA	2,200,000	120	0.41	970

The water use estimates in Table 4 are based on the use of combined cycle gas turbines (CCGT) for generation. Water use intensity for CCGT generation is estimated to be 144 gallons/MWh based on a water use intensity for coal-fired thermal generation of 480 gallons/MWh and an estimate that CCGT uses 30% of the water used by a coal-fired thermal power plant (Phase I study).

The Phase I study assumed that electrical energy for formation heating for in situ retorting would be generated using coal-fired thermal generating plants located within the study area. We estimate that the energy requirements for an in situ oil shale industry of 1.5 million bbl/day would be approximately ten to twelve times the energy generation of the Craig Generating Station in the Yampa River Basin. We judge that limitations arising from coal supplies, coal transportation and air quality, as well possible regulatory requirements to limit carbon emissions, would tend to restrict the ability to develop coal-fired generation resources of this scale in the study area. In addition, industry representatives indicate that a substantial part, and perhaps all, of the energy required for formation heating can be obtained through the use of byproduct gas from the in situ retorting process, and that the in situ processes can be adjusted to produce a larger fraction of energy in the form of gas should this be desirable (Vawter, 2010). Were this byproduct gas not used at or near in situ retorting operations it would have to be transported to market areas or wasted. The use of byproduct gas for local generation using CCGT generation is not without its own complications, but the considerations set out here led us to the judgment that such local generation is the most likely source of electrical energy needed for formation heating for a large-scale in situ industry.

Above-Ground Retorting

NOSA provided an estimate of 900,000 megawatt-hours per year for a 50,000 bbl/day above-ground retorting module. The Phase I Study used an estimate of 75 kilowatt-hours (kWh) per barrel, which equates to 1,369,000 MWh/year for a 50,000 bbl/day facility. Projections of the scale of the above-ground component of a future oil shale industry are on the order of a single 50,000 bbl/day module, which is relatively much smaller than projections for the scale of an in situ industry, so the energy requirements for the expected above-ground retorting operations could be supplied from the grid if they are not supplied by near-site generation using byproduct gas.

Production

This category includes water required for recovery and initial processing of shale oil for both in situ retorting and above-ground retorting. This is a physical process occurring at the production site and is separate from upgrading.

In Situ Retorting

Neither NOSA nor the Phase I report provided an estimate of water use for production activities aside from upgrading, which is categorized separately. Water will certainly be required to support on-site operations (e.g. for dust control and domestic needs) but these amounts are likely to be relatively minor compared to water use in other categories.

Above-Ground Retorting

NOSA did not provide an estimate of water use for production activities aside from upgrading, which is reported separately. The Phase I report estimated that water use for mining and crushing would be 440 acre-feet/year and for retorting would be 655 acre-feet/year, both for a 50,000 bbl/day module.

Reclamation

For in situ retorting this category includes water required for cooling and rinsing of the zone inside the freeze wall and for re-watering of the heated site after recovering oil and gas. For both in situ and above-ground retorting, this category includes the water required for revegetation of the disturbed site after completing production activities. (Water requirements for stabilizing and re-vegetating spent shale from above-ground retorting are categorized separately.)

In Situ Retorting

NOSA estimates water use for reclamation of an in situ retorting site to be 1,500 acre-feet/year for a 50,000 bbl/day module. The water use estimates from NOSA are averages of an undisclosed number of responses from industry. The Phase I report provided an estimate of water use for reclamation and rinsing of 1,243 acre-feet per year. It appears that the Phase I study applied these annual water uses throughout the production phase, even though the reclamation phase would begin after the production phase is completed. We have chosen to apply the annual rates from the Phase I report over the duration of the reclamation phase (5.5 years for in situ retorting).

Some producers believe that no rinsing will be required in their location or with their technology and estimates of the quantity of rinse water are highly uncertain for those technologies where rinsing will be required. However, our judgment is that all rinse water will be treated and re-used, subject to inevitable losses in the treatment process due to disposal of concentrated residuals and incidental evaporation. A more precise estimate of the requirements for rinse water will require specific information about the in situ retorting technology and the water treatment technology to be employed.

Above-Ground Retorting

NOSA estimates water required for reclamation to be 1,000 acre feet for a 50,000 bbl/day above-ground retorting module. NOSA characterizes this as a “rough estimate”. The Phase I report provides an estimate of the water requirements for revegetation of 350 acre-feet per year. We have chosen to apply this annual water use rate over both the production and reclamation phases (a duration of 29 years, total, for above-ground retorting).

Spent Shale Disposal

This category includes the water required to stabilize and compact spent shale residue produced by above-ground retorting, and to re-vegetate the surface of the spent shale piles. NOSA reported an estimate of 0.8 barrel of water per barrel of oil (bbl/bbl), which equates to about 1,800 acre-feet per year for a 50,000 bbl/day model. That estimate represents an average across several responses; according to NOSA some technologies expect to use nearly no water for spent shale disposal while some expect to use over 1 bbl/bbl for that purpose. The Phase I report provided an estimate of 3,650 af/year for a 50,000 bbl/day module for spent shale disposal. We have applied the water use for spent shale disposal over the production period (a duration of 25 years).

Upgrading

This category includes water required for upgrading of shale oil, a physical/chemical process that is required to convert shale oil to a product that is similar to conventional oil and can be transported by pipeline and used as a refinery feed stock. Upgrading might occur at a central location with proximity to a petroleum pipeline in order to achieve economies of scale. Based on the feedback from NOSA, Grand Junction would be an appropriate location within the study area for upgrading of shale oil. It is also arguable that upgrading would not be required in the study area: The scale of production from a mature oil shale industry in the Piceance Basin is similar to the scale of the North Slope oil fields in Alaska, which is of a scale to support a dedicated pipeline to a regional processing/refining center (e.g. Salt Lake City). Should this come to pass upgrading could be done at the same location as refining, in which case the water use from upgrading would occur outside the study area.

Some companies expect that shale oil produced by their in situ retorting technology will not require upgrading prior to transportation and refining. On the other hand, some retorting technologies (both in situ and above-ground) produce a product that is *paraffinic* in nature. Products of this type must be heated before they can be transported in a pipeline, and will congeal into a semi-solid mass should the flow through the pipeline be interrupted for a sufficient time. Because such an event would cause a catastrophic, interruption in oil production, it is unlikely that paraffinic products would be transported through a pipeline without at least partial upgrading very near the production site (Boak, 2010).

Given these considerations, the actual water requirement for upgrading is highly uncertain and will depend substantially on the mix of retorting technologies that eventually develops in the Piceance Basin. If the emerging dominant in situ technology does not require upgrading prior to transportation, then the only requirement for water for upgrading in the study area will be for the relatively small production from above-ground retorting.

In Situ Retorting

NOSA reported a range of water requirements for upgrading from 0.6 bbl/bbl to 1.6 bbl/bbl, which equates to a range of 1,400 af/year to 3,800 af/year for a 50,000 bbl/day module. The Phase I report provided an estimate of 1,333 af/year for production and upgrading for a 50,000 bbl/day module.

Above-Ground Retorting

NOSA reported a range of water requirements for upgrading from 0.6 bbl/bbl to 1.6 bbl/bbl, which equates to a range of 1,400 af/year to 3,800 af/year for a 50,000 bbl/day module. The Phase I report provided an estimate of 1,825 af/year for upgrading for a 50,000 bbl/day module.

Produced water

NOSA estimates that water will be produced as a byproduct of oil production at a rate of 0.8 bbl water/bbl oil for in situ retorting and 0.3 bbl water/bbl oil for above-ground retorting, which equate to 1,900 af/year and 700 af/year for a 50,000 bbl/day module. In subsequent analyses we will assume that this water will be used to satisfy process needs, based on an assumption that discharge and disposal requirements will be sufficiently stringent that the required level of treatment will make water suitable for process needs.

Consumptive Use Associated with Direct Water Uses

All direct water use will be assumed to be 100% consumptive for Phase II analyses, based on an assumption that discharge and disposal requirements will be sufficiently stringent that the required level of treatment will make water suitable for process needs and that any concentrated residuals will not be suitable for reuse or release into a surface or groundwater water resource that could be put to beneficial use.

References

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URS Corporation, Energy Development Water Needs Assessment (Phase I Report), prepared for Colorado, Yampa, and White River Basin Roundtabes Energy Subcommittee. September, 2008

Western Resource Advocates. Water on the Rocks, Oil Shale Water Rights in Colorado, 2009.

Vawter, Glenn, personal communications, 2010.

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Appendix A

Questionnaire Developed By AMEC

	Questionnaire Regarding Energy Water Requirements in Northwestern Colorado				
Information Provided Below Reflect a Production Module of 50,000 bbl/day					
		Check Applic able	**Amount for 50,000 bbl/day Production**		**Comments**
1)Type of Process					
	In-Situ				
	Surface Retort/Ground Mining				
2) Expected Production Period				Years	
3) Construction Period				Years	
4) Reclamation Period				Years	
5)Power					
	a) Total Energy Requirement			MWH/Year	
	b) Percent Required from Grid			%	
6)Construction/Pre-production					
	a)Total Water Requirement			acre-feet	
	b)Total Module Life			bbl/bbl	
	c)Percent Water Consumed			%	
7)Production/Initial Separation (oil/gas/water)					
	a)Rate of Production of Byproduct Water			bbl/bbl	
	b)Percent Water Consumed			%	
8)Upgrading&Refining					
	Will you do this on/near site?, If yes, total water requirement			bbl/bbl	
9)Reclamation					
	a)Total Water Requirement			acre-feet	
	b)Percent Water Consumed			%	
10)Spent Shale Disposal					
	a)Total Water Requirement			bbl/bbl	
	b)Percent Water Consumed			%	
11)Rinsing/GroundwaterReclamation					
	a)Total Water Requirement			acre-feet	
	b)Percent Water Consumed			%	

Appendix B

Responses to Questionnaire

Questionnaire Regarding Energy Water Requirements in Northwestern Colorado

Information Provided Below Reflect a Production Module of 50,000 bbl/day

	Check Applicable	Amount for 50,000 bbl/day Production		Comments
1)Type of Process				
In-Situ				
Surface Retort/Ground Mining	X			
2) Expected Production Period		25	Years	The life is estimated as a normal life expectancy of a surface retorting facility, but could run longer.
3) Construction Period		4	Years	
4) Reclamation Period		4	Years	
5)Power				
a) Total Energy Requirement		900,000	MWH/Year	Estimate based upon studies conducted in the 1970's, but expected to be in the correct range. Some power could be produced from produced shale gas, but assumption here is it will all be imported.
b) Percent Required from Grid		100	%	
6)Construction/Pre-production				
a)Total Water Requirement		300	acre-feet	Rough Estimate
b)Total Module Life			bbl/bbl	
c)Percent Water Consumed		100	%	
7)Production/Initial Separation (oil/gas/water)				
a)Rate of Production of Byproduct Water		0.3	bbl/bbl	
b)Percent Water Consumed		100	%	
8)Upgrading&Refining				
Will you do this on/near site?, If yes, total water requirement		0	bbl/bbl	If upgrading were performed on site a range of 0.6 to 1.6 Bbl/Bbl providing an average of 1.1 Bbl/Bbl.

9)Reclamation

a)Total Water Requirement	1000	acre-feet	Rough estimate – you may have better figures
b)Percent Water Consumed	100	%	

10)Spent Shale Disposal

a)Total Water Requirement	0 .8	bbl/bbl	Estimates range from near zero for some technologies to over 1.0 Bbl/Bbl, but this is used as a planning average.
b)Percent Water Consumed	100	%	

11) Total Water Required for the facility as a whole – no rinse water

a)Total Water Requirement	2.0	acre-feet	Range of values between 1.4 and 2.6 with a net of 4,500 AFA
b)Percent Water Consumed	100	%	Based upon water used for process cooling. If all air cooling used deduct 1000 AFA

Questionnaire Regarding Energy Water Requirements in Northwestern Colorado

Information Provided Below Reflect a Production Module of 50,000 bbl/day

	Check Applicable	Amount for 50,000 bbl/day Production		Comments
1)Type of Process				
In-Situ	X			
Surface Retort/Ground Mining				
2) Expected Production Period		6.5	Years	
3) Construction Period		2.5	Years	
4) Reclamation Period		5.5	Years	
5)Power				
a) Total Energy Requirement		2,200,000	MWH/Year	Some power could be produced from produced shale gas, but assumption here is it will all be imported. Estimates range widely (by an order of magnitude) based on whether electric heating is used for retorting. This estimate assumes an average acknowledging that there is expected to be a mix of technologies for a commercial industry.
b) Percent Required from Grid		100	%	
6)Construction/Pre-production				
a)Total Water Requirement		300	acre-feet	Rough estimate
b)Total Module Life			bbl/bbl	
c)Percent Water Consumed		100	%	
7)Production/Initial Separation (oil/gas/water)				
a)Rate of Production of Byproduct Water		0.8	bbl/bbl	This average assumes a mix of technologies and differing oil shale resource assumptions (what portion of the of the oil shale resource will be developed, and now its hydrologic and geologic properties vary.
b)Percent Water Consumed		100	%	

8)Upgrading&Refining

Will you do this on/near site?, If yes, total water requirement	0	bbl/bbl

If upgrading were performed on site a range of 0.6 to 1.6 Bbl/Bbl providing an average of 1.1 Bbl/Bbl. The range results from the range of alternative upgrading schemes, whether air or water cooling is use, and the degree of upgrading required before refining the shale oil. Most Colorado developers indicated they do not expect on site upgrading for initial plants.

9)Reclamation

a)Total Water Requirement	1,500	AFA
b)Percent Water Consumed	100	%

Rinse water used by some technologies is not actually consumed but removed from the system for a very long period of time and counted as consumed. However other insitu technologies do not anticipate the use of rinse water so an average is shown here to account for the variation in technologies that will likely emerge.

10)Spent Shale Disposal

a)Total Water Requirement	0	bbl/bbl
b)Percent Water Consumed	0	%

11) Total Water Required for the facility as a whole –rinse water in 9) above

a)Total Water Requirement	3800	AFA
b)Percent Water Consumed	100	%

Appendix C

Water Use Data Reported in Literature

Table 1: Water Use Data for a 50,000 BBL/Day Production Module Reported in Selected Publications

Source	Referenced Publication in Source	Water Demand (acre-feet/yr)	Water Demand in Bbl/Bbl	Water Demand (MGD)	Consumptive Use (acre-feet/yr)	Technology Type	Notes
Western Advocates, 2009	BLM (2008)	4,650-8,650		4.2-7.7		in situ retorting	
Western Advocates, 2009	BLM (2008)	4,900-7,400		4.4-6.6		above-ground retorting	
Western Advocates, 2009	RAND (2005)	7,063	3.0	6.3			
Western Advocates, 2009	Prien (1954)	11,350	4.8	10.1	4125		
Western Advocates, 2009	Cameron and Jones (1959)	10,000	4.3	8.9	4125		
Western Advocates, 2009	US DOI (1968)	7,250	3.1	6.5	3050-4800		
Western Advocates, 2009	US DOI (1973a)	8,700	3.7	7.8		underground mining	
Western Advocates, 2009	US DOI (1973a)	8,400	3.6	7.5		surface retorting	
Western Advocates, 2009	US DOI (1973a)	4,400	1.9	3.9		in situ retorting	
Western Advocates, 2009	US DOI (1973a)	8,150	3.5	7.3		mix of technologies	
Western Advocates, 2009	US DOI (1973a)	7,750	3.3	6.9		mix of technologies	
Western Advocates, 2009	McDonald (1980)	6,650	2.8	5.9			
Western Advocates, 2009			1-3			in situ retorting	water water use for upgrading is not included in estimate
Western Advocates, 2009			5			above-ground retorting	water use for electricity is incl in estimate. water use for upgarding is not incl in estimate
BLM, 2008			2.0-3.7			in situ retorting	
BLM, 2008			2.1-3.2			above-ground retorting	
Alley, USGS			3				

Table 2: A Comparison of Water Use (BBL/BBL) Reported by NOSA & Phase I to Those Reported in Literature

Technology Type	NOSA	Phase I	Others
in situ retorting	3.99 [c]	5.01	1.9, 1-3 [a], 2.0-3.7
above-ground retorting	3.23 [c]	3.81	2.1-3.2,5[a,b]

Appendix C

Oil Shale Indirect Water Use Estimates

Memorandum

To: Joint Energy Water Needs Subcommittee

cc:

From: Ben Harding, Shaden Musleh, Hanna Sloan
AMEC Earth & Environmental

Subject: Oil Shale Indirect Water Use Estimates

Date: August 18, 2010

This Technical Memorandum documents the development of estimates of indirect water use for oil shale development as part of Task 2 of the Energy Development Water Needs Assessment Phase II Study (Study). The Energy Development Water Needs Assessment is being conducted by the Energy Subcommittee (Subcommittee) of the Colorado, Yampa and White River Basin Roundtables as part of the Colorado Water for the 21st Century (HB-1177) water supply planning process.

The objective of Task 2, *Refine Water Demand Estimates*, is to develop estimates of water demand caused by future energy development and to break those demands down by location to allow a particular water use to be assigned to a particular water supply facility in a water supply scenario. The Study area for the Phase II Study includes all of the Yampa River and White River basins and that portion of the Colorado River basin west of a line running north and south approximately through Edwards.

The scope of Task 2 involves refinement of the water use estimates reported in the Phase I report (URS, 2008). This memo provides information about Sub-task 2.3 *Develop Basin Water Use Scenarios.* The objective of Sub-task 2.3 is to develop a water use scenario for each basin. Subsequent sections of this technical memorandum discuss: an introduction, estimates of employment and population, estimates of indirect water use, and references.

Introduction

Water use associated with oil shale production can be broken into two principal classes, direct uses and indirect uses. Direct uses include those uses associated with construction, operation, production, processing and reclamation processes that are directly required for oil shale development and commercial production of a petroleum product suitable for a refinery feedstock. Water use associated with electrical energy needed to support the above processes is considered as a direct use. Indirect uses include water required to support population growth and economic activity resulting from production of shale oil. This memorandum provides estimates of indirect uses of water based on estimates of population growth provided by the Colorado Water Conservation Board as part of the Interbasin Compact Committee (IBCC) process.

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Estimates of Employment and Population

The Phase I Study provided estimates of indirect water use attributable to development of natural gas, uranium, coal and oil shale. The Phase II Study will adopt the Phase I estimates of indirect water use for natural gas, uranium and coal. The Phase I Study estimates of indirect water use for Oil Shale have been refined as discussed below.

The Phase II Study differs from the Phase I Study in that the water use scenarios developed in Phase II will be incorporated in the statewide water supply planning activities that are part of the Colorado Water for the 21st Century (HB-1177) water supply planning process. Water supply planning under the HB-1177 process is taking place within the IBCC. The IBCC has developed a set of water supply and water demand scenarios based on input from the nine basin roundtables. The Phase II Study results will serve as the basis for input from the Colorado, Yampa and White River Roundtables to the IBCC process and therefore should be as consistent as possible with the assumptions and methods used by the IBCC. Among the methods used by the IBCC are models of economic activity on which are based estimates of future employment and population.

The Phase I Study used a different basis for its estimates of population due to development of an oil shale industry (BBC, 2008). Further, the Phase I Study based its estimates of direct and indirect water use on the conclusion that the electrical energy required to heat oil shale formations in an in situ production process would be generated using coal-fired thermal generation. Based on information from industry, the Phase II Study has concluded that it is much more likely that any required electrical energy will be generated using combined cycle gas turbine (CCGT) generation, fueled by byproduct gas or local natural gas. CCGT requires less labor for construction and operation than does coal-fired thermal generation. In order to use methodologies and assumptions that are consistent with the IBCC process, the Phase II Study adopted estimates of employment and population that were developed for the IBCC by Harvey Economics for an oil shale industry consisting of 1,500,000 bbl/day of in situ production and 50,000 bbl/day of above-ground production (build-out scenario). These estimates are shown in Appendix A.

Table 1 summarizes the estimates of employment provided by Harvey Economics (Harvey Economics, 2010).

Table 1.
Regional Employment Attributable to Production of Oil from Oil Shale

Process	Employment	Percent of Employment
In situ	14,375	84%
Above-Ground	1,920	11%
Energy generation	800	5%
Total Oil Shale	17,095	100%

Estimates in Table 1 are taken from year 32 of Harvey Economics estimates of employment (Appendix A, Exhibit 1) as these represent approximately stable employment at the build-out scale of the industry. Some additional employment would be required approximately every 25 years when a new mine must be opened to support above-ground retorting. Harvey estimates that population in the study area will increase to 48,208 as a result of the increased employment (Appendix A, Exhibit 2).

Estimates of Indirect Water

Water use from increased population was estimated by multiplying population estimates by an estimate of per-capita daily water use. Water use due to population growth not directly employed in the oil shale industry was estimated using a per-capita daily rate of 200 gallons per-capita per day (gpcd), which is the value adopted by the Phase I Study. To estimate water use due to employment, a smaller per-capita daily water use rate of 100 gpcd was used to reflect the fact that oil shale workers will spend considerable time at production locations or traveling and therefore will not have any associated outdoor water use.

Estimates of indirect water use in the Phase II Study do not include the water required for generation of electricity to support population growth, under the assumption that this electricity will come from the grid and will not be attributable to a single generating station in the study area.

Table 2 shows estimates of indirect water use for the build-out scenario for an oil shale industry. Water use estimates in Table 2 are provided in terms of barrels of water required to produce one barrel of oil from oil shale (bbl/bbl) and in terms of acre-feet per year for the entire industry in the study area. All estimates of water use have been rounded to no more than two significant figures.

Table 2.
Estimates of Indirect Water Use for Production of Oil from Oil Shale

	In situ Retorting		Above-Ground Retorting	
Water Use Category	**bbl/bbl**	**acre-feet per year**	**bbl/bbl**	**acre-feet per year**
Construction and Production	0.11	7,800	0.46	1,100
Electrical Energy	0.008	560	0.002	5.6

Table 3 shows estimates of indirect water use for the four sectors of energy development in the study area.

Table3.
Estimates of Indirect Water Use for Energy Development

Sector	Indirect Water Use (acre-feet/year)
Oil Shale	
Construction and Production	8,900
Electrical Energy	570
Natural Gas	8,900 to 11,100
Uranium	Not significant
Coal	2,400

References

BBC Research & Consulting (BBC). Northwest Colorado Socioeconomic Analysis and Forecasts. Prepared for the Associated Governments of Northwest Colorado. April, 2008.

Harvey Economics, 2010. Employment and Population data developed for the IBCC. August.

URS Corporation. Energy Development Water Needs Assessment (Phase I Report), prepared for Colorado, Yampa, and White River Basin Roundtables Energy Subcommittee. September, 2008

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Appendix A

Employment and Population Estimates

Exhibit 1. Oil Shale Employment Projections

		In Situ Mining		Underground Mine, Surface Retort		Generation		Total	Total	Total
Year	**Bbl/Per Day**	**Construction**	**Operations**	**Construction**	**Operations**	**Construction**	**Operations**	**Construction**	**Operations**	**Employment**
-5	0	375	0	0	0	0	0	375	0	375
-4	0	750	0	0	0	20	0	770	0	770
-3	0	1,125	0	0	0	1,500	0	2,625	0	2,625
-2	0	1,250	0	0	0	2,000	0	3,250	0	3,250
-1	0	1,375	0	0	0	1,520	0	2,895	0	2,895
1	50,000	1,375	125	1,470	0	1,500	100	4,345	225	4,570
2	100,000	1,375	250	1,470	0	2,000	100	4,845	350	5,195
3	150,000	1,375	375	1,470	0	1,520	100	4,365	475	4,840
4	200,000	1,375	500	1,470	0	1,500	200	4,345	700	5,045
5	300,000	1,375	625	0	1,920	2,000	200	3,375	2,745	6,120
6	350,000	1,375	750	0	1,920	1,520	200	2,895	2,870	5,765
7	350,000	1,375	875	0	1,920	1,500	300	2,875	3,095	5,970
8	350,000	1,375	1,000	0	1,920	2,000	300	3,375	3,220	6,595
9	350,000	1,375	1,125	0	1,920	1,500	300	2,875	3,345	6,220
10	350,000	1,375	1,250	0	1,920	20	400	1,395	3,570	4,965
11	350,000	1,750	1,375	0	1,920	1,500	400	3,250	3,695	6,945
12	350,000	2,500	1,500	0	1,920	2,000	400	4,500	3,820	8,320
13	350,000	3,250	1,500	0	1,920	1,500	400	4,750	3,820	8,570
14	350,000	4,125	1,500	0	1,920	20	500	4,145	3,920	8,065
15	350,000	4,750	1,500	0	1,920	1,500	500	6,250	3,920	10,170
16	400,000	5,625	1,625	0	1,920	2,000	500	7,625	4,045	11,670
17	500,000	6,125	1,875	0	1,920	1,500	500	7,625	4,295	11,920
18	600,000	6,625	2,125	0	1,920	20	600	6,645	4,645	11,290
19	750,000	6,750	2,500	0	1,920	1,500	600	8,250	5,020	13,270
20	900,000	6,875	2,953	0	1,920	2,000	600	8,875	5,473	14,348
21	1,100,000	6,875	3,375	0	1,920	1,520	600	8,395	5,895	14,290
22	1,250,000	6,875	3,875	0	1,920	1,500	700	8,375	6,495	14,870
23	1,350,000	6,875	4,375	0	1,920	2,000	700	8,875	6,995	15,870
24	1,450,000	6,875	4,875	0	1,920	1,500	700	8,375	7,495	15,870
25	1,500,000	6,875	5,375	0	1,920	0	800	6,875	8,095	14,970
26	1,550,000	6,875	5,875	0	1,920	0	800	6,875	8,595	15,470
27	1,550,000	6,875	6,375	0	1,920	0	800	6,875	9,095	15,970
28	1,550,000	6,875	6,750	0	1,920	0	800	6,875	9,470	16,345
29	1,550,000	6,875	7,000	0	1,920	0	800	6,875	9,720	16,595
30	1,550,000	6,875	7,250	0	1,920	0	800	6,875	9,970	16,845
31	1,550,000	6,875	7,375	0	1,920	0	800	6,875	10,095	16,970
32	1,550,000	6,875	7,500	0	1,920	0	800	6,875	10,220	17,095

Source: Harvey Economics, 2010.

Exhibit 2.
Summary of Population and Employment Projections for Areas Affected by a 1.55 Million Barrel per Day Colorado Oil Shale Industry

	No Oil Development Scenario	Sustained Kerogen Production @ 1.55 million bls/ day	Difference
State of Colorado			
Oil Shale Related Employment*	0	17,095	17,095
Total Employment	6,390,733	6,414,513	23,779
Total Population	12,987,917	13,025,496	37,578
Population Effects by: *River Basin*			
Arkansas Basin	2,361,082	2,358,725	-2,356
Colorado	988,220	1,026,103	37,883
Gunnison	289,324	290,241	918
South Platte Basin	8,768,425	8,754,240	-14,184
Yampa	174,991	190,309	15,318
Population Effects by: *County*			
Adams County	1,192,186	1,189,900	-2,286
Arapahoe County	1,404,002	1,401,310	-2,692
Boulder County	670,801	669,515	-1,286
Broomfield County	148,261	147,977	-284
Denver County	1,327,888	1,325,342	-2,546
Douglas County	849,571	847,942	-1,629
Eagle County	175,669	177,070	1,401
El Paso County	1,567,951	1,565,595	-2,356
Garfield County	228,388	256,611	28,223
Jefferson County	1,186,135	1,183,861	-2,274
Mesa County	416,947	426,123	9,176
Moffat County	36,531	38,159	1,628
Rio Blanco County	64,796	78,486	13,690
Weld County	827,051	825,864	-1,187

Note: These data assume high scenario economic and demographic assumptions.

*Includes construction and operational personnel working on-site in oil shale and CCG electric facilities plus administrative personnel in the Denver Metro Area.

Source: Harvey Economics, August 2010.

Appendix D

Energy Water Use Scenarios

Memorandum

To: Joint Energy Water Needs Subcommittee
cc:
From: Ben Harding, Shaden Musleh, Hanna Sloan
Subject: Energy Water Use Scenarios
Date: August 18, 2010

This Technical Memorandum documents the development of scenarios of water use as part of Task 2 of the Energy Water Needs Assessment Phase II Study (Study). The Energy Development Water Needs Assessment is being conducted by the Energy Subcommittee of the Colorado, Yampa and White River Basin Roundtables (Subcommittee) as part of the Colorado Water for the 21st Century (HB-1177) water supply planning process.

The objective of Task 2, *Refine Water Demand Estimates*, is to develop estimates of water demand attributable to future energy development and to break those demands down by location to allow a particular water use to be assigned to a particular water supply facility in a water supply scenario. The Study area for the Phase II Study includes all of the Yampa River and White River basins and that portion of the Colorado River basin west of a line running north and south approximately through Edwards.

The scope of Task 2 involves refinement of the water use estimates reported in the Phase I report (URS, 2008). This memo provides information about Sub-task 2.3 *Develop Basin Water Use Scenarios.* The objective of Sub-task 2.3 is to develop a water use scenario for each basin. Subsequent sections of this technical memorandum discuss: an introduction, time frame for scenarios, water use scenarios, and references.

Introduction

Phase I developed estimates of future water required for development of oil shale, coal, natural gas and uranium energy resources. Only estimates of water use attributable to oil shale development have been refined in the Phase II Study; the work in Task 2 has resulted in revised estimates of water use attributable to oil shale that reflect new information about and improved understanding of the future possibilities for an oil shale industry. Water use scenarios depend on the scale of the projected future oil shale industry and on the water use intensity of the industry. Water use intensity is expressed as the amount of water required to produce a unit of production, which is a barrel of oil in the case of oil shale. Revised estimates of the unit water use (in terms of barrels of water per barrel of oil, bbl/bbl) for oil shale development and production activities were reported in project task memorandum *Oil Shale Direct Water Use Estimates*, April 13, 2010. Estimates of unit water use for the population changes caused by oil shale development and production were reported in project task memorandum, *Oil Shale Indirect Water Use Estimates*, August 18, 2010. Validation of Phase I estimates of the projected scale of an oil shale industry were reported in project technical memorandum *Oil Shale Production Scenarios*, June 16, 2010. This technical memorandum provides

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comprehensive estimates of water use by all four energy sectors. Water use for oil shale depends on the production methodology, and there is considerable uncertainty regarding which methodologies ultimately will be used for production. To reflect this uncertainty, water use estimates for oil shale are provided for low, medium and high water use scenarios.

Time frame for scenarios

There are two conceptual time frames that can be used for estimating future water use: estimates at a specific point in time or range of times in the future or estimates at "build-out" that represent the level of water use by a mature, fully–developed industry.

Selection of the conceptual scenario for estimating future water use, and selecting the specific future time frame or time frames at which estimates of water use might be developed is a policy decision that depends on how the water use estimates will be employed. The Subcommittee has determined that a build-out time frame will be used. Accordingly, water use estimates presented in this memo are based on estimates of build-out conditions.

Water Use Scenarios

Coal

Table 1 shows the development scenarios for the coal industry in the study area adopted by the Phase 1 Study.

Table 1. Phase I Assumptions Supporting Coal Production Scenarios

Planning Horizon	Production Scenarios – Coal		
	Low	**Medium**	**High**
Near-Term (2007–2017)	Red Cliff mine begins producing 2.5 million tpy by 2011. Total production holds steady at 20.5 million tpy.	No change from low/near-term production scenario.	No change from low/near-term production scenario.
Mid-Term (2018–2035)	Production rate holds steady at 20.5 million tpy.	Red Cliff mine begins producing 8 million tpy by 2018. Total production holds steady at 26 million tpy.	No Change from Medium/Mid-Term production scenario.
Long-Term (2036–2050)	Production rate holds steady at 20.5 million tpy.	No change from medium/mid-term production scenario.	Add 1 coal gasification or liquefaction plant in northwest Colorado processing approximately 4 million tons of coal per year. Total coal production of 30 million tpy.

Table 2. Phase I Total Direct Water Demands for Coal Production (af/year)

Planning Horizon	Production Scenarios – Coal		
	Low	Medium	High
Near-Term (2007–2017)	1,213	1,213	1,213
Mid-Term (2018–2035)	1,213	1,538	1,538
Long-Term (2036–2050)	1,213	1,538	5,063

Natural Gas

Table 3 shows the development scenarios for the natural gas industry in the study area adopted by the Phase 1 Study.

Table 3. Phase I Assumptions Supporting Natural Gas Production Scenarios

Planning Horizon	Production Scenarios – Coal		
	Low	Medium	High
Near-Term (2007–2017)	Average drilling rate ≈ 1,800 wells/year.	Average drilling rate ≈ 1,900 wells/year.	Average drilling rate ≈ 2,000 wells/year.
Mid-Term (2018–2035)	Average drilling rate ≈ 1,700 wells/year. Drilling rate slowly declines in Garfield County and shifts to Rio Blanco County..	Average drilling rate ≈ 2,125 wells/year to account for additional activity in the northern Piceance Basin. Approx. 65,000 operational wells by 2035.	Average drilling rate ≈ 2,300 wells/year to provide thermoelectric power to the oil shale industry for start-up
Long-Term (2036–2050)	Drilling activity slowly declines to ~1,100 well/year by 2050.	Drilling activity slowly declines to ~1,500 well/year by 2050.	Drilling activity slowly declines to ~1,700 well/year by 2050.

Table 4. Phase I Total Direct Water Demands for Natural Gas Production (af/year)

Planning Horizon	Production Scenarios – Coal		
	Low	Medium	High
Near-Term (2007–2017)	2007: 2,965 2017: 4,292	2007: 3,133 2017: 4,880	2007: 3,165 2017: 5,230
Mid-Term (2018–2035)	2018: 4,168 2035: 3,975	2018: 5,044 2035: 4,874	2018: 5,437 2035: 5,276
Long-Term (2036–2050)	2036: 3,869 2050: 2,834	2036: 4,769 2050: 3,285	2036: 5,171 2050: 3,686

Uranium

Table 5 shows the development scenarios for the uranium industry in the study area adopted by the Phase 1 Study.

Table 5. Phase I Assumptions Supporting Uranium Production Scenarios

Planning Horizon	Production Scenarios – Coal		
	Low	Medium	High
Near-Term (2007–2017)	No uranium mining within project area.	No uranium mining within project area.	1 underground uranium mine.
Mid-Term (2018–2035)	No uranium mining within project area.	1 underground uranium mine.	1 underground uranium mine.
Long-Term (2036–2050)	No uranium mining within project area.	1 underground uranium mine.	2 underground uranium mines: 1 in Mesa County and one in Moffat County.

Table 6. Phase I Total Direct Water Demands for Uranium Production (af/year)

Planning Horizon	Production Scenarios – Coal		
	Low	Medium	High
Near-Term (2007–2017)	No uranium mining within project area.	No uranium mining within project area.	62
Mid-Term (2018–2035)	No uranium mining within project area.	62	62
Long-Term (2036–2050)	No uranium mining within project area.	62	124

Oil Shale

Development scenarios for oil shale are discussed in project technical memo *Oil Shale Production Scenarios*, June 16, 2010. Table 7 shows the development scenarios for the oil shale industry in the study area adopted by the Phase 1 Study.

Table 7. Phase I Assumptions Supporting Oil Shale Production Scenarios

Planning Horizon	Production Scenarios – Oil Shale		
	Low	Medium	High
Near-Term (2007–2017)	No Commercial Production RD&D Leases Only	No Commercial Production RD&D Leases Only	No Commercial Production RD&D Leases Only
Mid-Term (2018–2035)	No Commercial Production RD&D Leases Only	Underground mine/surface retort facility with 50,000 bpd production. Additional 25,000 bpd of in-situ production	Underground mine/surface retort facility with 50,000 bpd production. Additional 500,000 bpd of in-situ production
Long-Term (2036–2050)	No Commercial Production RD&D Leases Only	Underground mine/surface retort facility with 50,000 bpd production. Additional 150,000 bpd of in-situ production	Underground mine/surface retort facility with 50,000 bpd production. Additional 1.5 million bpd of in-situ production

The Subcommittee adopted the Phase 1 "Long-term/High" scenario to represent the level of development expected at the build-out time frame. That scenario projects an oil shale industry with 1.5 million bbl/day production from in situ processes (located in the Piceance Basin) and 50,000 bbl/day production from above-ground retorting (located at outcrops along the southern extent of the Piceance Basin, in the Colorado River Basin). Estimates of unit water use for direct use and indirect use for oil shale are provided in project technical memoranda *Oil Shale Direct Water Use Estimates*, April 13, 2010 and, *Oil Shale Indirect Water Use Estimates*, June 16, 2010. Table 8 shows the indirect unit water use and Table 9 shows the direct unit water uses for oil shale production processes.

Table 8. Estimates of Indirect Water Use for Oil Shale (bbl/bbl)

Water Use Category	In situ Retorting	Above-Ground Retorting
Electrical Energy Workforce	0.008	0.002
Production Workforce	0.11	0.46

Table 9. Estimates of Direct Water Use for Oil Shale (bbl/bbl)

	In situ Retorting		Above-Ground Retorting	
Water Use Category	**Low**	**High**	**Low**	**High**
Construction/Pre-production	0.02	0.16	0.01	0.07
Electrical Energy	0.41	1.00	0.17	0.26
Production			0.47	0.47
Reclamation	0.45	0.54	0.02	0.17
Spent Shale Disposal			0.80	1.60
Upgrading	0.57	1.60	0.60	1.60

Table 10 shows the unit amount of water produced as a byproduct of shale oil production. Only one estimate of the rate of water production was obtained for each of in situ and above-ground retorting; therefore no quantitative information can be provided regarding the uncertainty of this estimate. Because of the nature of the processes, methods using combustion heating can be expected to produce more byproduct water than methods using electrical heating or solvents.

Table 10. Estimates of Water Co-Produced When Retorting Oil Shale (bbl/bbl)

In situ Retorting	Above-Ground Retorting
0.80	0.30

Because both unit water use rates and the configuration of a future oil shale industry are uncertain, a range of water use estimates must be developed with the view that the actual future level of water use will be contained between a low and high estimate to a reasonable degree of certainty. In developing a range of water use estimates a variety of assumptions can be made about the mix of production and upgrading technologies that will make up the future oil shale industry, and about the water use intensity of those individual technologies. Tables 11 and 12 present total (direct and indirect) unit water use estimates for plausible industry configurations.

Table 11. In Situ Industry Configurations and Total Unit Water Use

In Situ Scenario	Scenario Description	Unit Use (bbl/bbl)	Comments
IS-1	Down-hole combustion heating off-site upgrading. Low estimates.	-0.22	Without energy direct use or use by energy workforce; no upgrading use.
IS-2	Down-hole combustion heating, off-site upgrading. High estimates.	0.01	Without energy direct use or use by energy workforce.
IS-3	Shell in situ conversion process (ICP), off-site upgrading. Low estimates.	0.20	Without energy direct use or use by energy workforce; no upgrading use.
IS-4	Shell ICP, on-site upgrading. Low estimates.	0.77	Based on low estimates of electricity use and other process water uses. ICP will likely require less intensive upgrading.
IS-5	Shell ICP, off-site upgrading. High estimates.	1.02	Based on high estimates of electricity use and other process water uses.
IS-6	Down-hole combustion heating on-site upgrading. High estimates.	1.61	Based on high estimates of process water uses. No electrical heating. Combustion-based processes are more likely to require more upgrading. Highest combustion value.
IS-7	Shell ICP, on-site upgrading. High process, low upgrading.	1.59	Uses low estimate of upgrading, as ICP process is more likely to require less upgrading. Otherwise uses high estimates. Highest ICP value.

In situ scenarios 1,4 and 7 were selected to represent the low, medium and high levels of water use. Scenario 1 assumes an industry that uses combustion heating to heat formations to recover oil, and that upgrades kerogen products outside the study area. The use of combustion heating eliminates the direct and indirect water use required for electrical generation for electric heating. Combustion heating is likely to produce more byproduct water than electrical heating or solvent recovery. A solvent-recovery scenario has not been included. Like Scenario 1 it would not require water to support electrical generation, but it would also not produce much, if any, byproduct water. Accordingly, it would be a low water use scenario, but would not be expected to have lower water use than Scenario 1. Scenario 7 assumes an industry that uses the Shell in situ conversion process. This process uses electrical heating and therefore requires water to supply the direct and indirect water needs of generation. Scenario 7 assumes that the kerogen product would require upgrading in the study area, but assumes a lower unit water use for this process to reflect the reported ability of the Shell process to produce a more refined product. Scenarios 6 and 7 are equivalent in terms of water use estimates based on the information available to the Study. However, because the Shell process is likely to produce less byproduct water, the actual water use of Scenario 7 may be greater than shown in Table 11. However, at this time sufficient information is not available to refine the estimate of water use further. Scenario 4 is similar to Scenario 7 except that low estimates for water use intensity are used.

Table 12. Above-Ground Industry Configurations and Total Unit Water Use

Above-Ground Scenario	Scenario Description	Unit Use (bbl/bbl)	Comments
AG-1	Off-site electricity, off-site upgrading. Low estimates	1.45	Seems a likely possibility, if above-ground product is compatible with down-hole in situ product; small electricity demands can be met from grid. Use with down-hole in-situ.
AG-2	Off-site electricity, on-site upgrading. Low estimates	2.05	Likely that above-ground retort product will require more intensive upgrading, so this estimate may be low. Use with ICP.
AG-3	On-site electricity, on-site upgrading. Low estimates	2.22	Use co-produced gas for on-site combined cycle gas turbine (CCGT). Likely that above-ground retort product will require more intensive upgrading, so this estimate may be low. Use with ICP.
AG-4	Off-site electricity, off-site upgrading. High estimates	2.47	Seems a likely possibility, if Above-Ground product is compatible with down-hole in situ; small electricity demands can be from grid. Use with down-hole in situ method.
AG-5	Off-site electricity, on-site upgrading. High estimates	4.07	Seems a likely possibility with ICP in situ, since the small above-ground production might require on-site upgrading; small electricity demands can be from grid. Use with ICP.
AG-6	On-site electricity, on-site upgrading High estimates,	4.33	Use co-produced gas for on-site CCGT. Use with ICP.

Above-ground Scenarios 1, 3 and 6 were selected to represent the low, medium and high levels of water use. Scenario 1 assumes that electricity is taken from the grid, that upgrading is done outside the study area, and that lower levels of water use intensity will occur. Scenario 6 assumes that electricity is generated on site, that upgrading takes place in the study area, and that higher levels of water use intensity occur. Scenario 3 assumes that electricity is generated on site, that upgrading takes place in the study area, but that lower levels of water us intensity occur.

Table 13 provides estimates of the total, industry-wide water use for the build-out industry scenario (1.5 million bbl/day in situ production and 50,000 bbl/day above-ground production) for low, medium and high water use scenarios. Industry-wide water use estimates are presented to a precision of no more than two significant figures to reflect the uncertainty in those estimates.

Table 13. Total Water Use for Selected Scenarios

Scenario	Unit Use (bbl/bbl)	Industry Water Use, acre-feet/year		
		Low	Medium	High
IS-1	-0.22	-16,000		
IS-4	0.77		54,000	
IS-7	1.59			110,000
AG-1	1.45	3,400		
AG-3	2.22		5,200	
AG-6	4.33			10,000
Total		-13,000	59,000	120,000

Uncertainties in the estimates provided in Table 13 arise from, among other things, estimates and judgments about the following factors: the size of the future oil shale industry, the split between in situ and above-ground retorting, the water intensity of individual industrial processes, the mix of in situ retorting processes, the source of electrical energy for formation heating, the rate at which byproduct water is produced and the degree to which byproduct water will be re-used for process purposes. These factors, in turn, will be influenced by the economic, political, regulatory and social conditions that exist at the time a commercial oil shale industry develops decades in the future.

The factor that has the most significant effect on water use is the size of the industry, including the possibility that no oil shale industry will develop at all. Aside from the scale of the industry, the two factors with the most influence over the estimate of total industry water use are the source of electrical energy for formation heating and the amount of byproduct water and its usability for in situ process needs. If electricity is generated by coal-fired thermal generation within the study area, rather than combined cycle gas turbines, total water use for the *high* scenario would increase by approximately 170,000 af/year. Population will also increase, because coal-fired thermal generation is more labor-intensive than the combined cycle gas turbines. If byproduct water from in situ production is not used to satisfy process needs, total water use for the *high* scenario will increase by an additional 60,000 af/year.

In addition, the estimate of 50,000 bbl/day production from above-ground retorting used in this analysis may understate the future value. For every 50,000 bbl/day increase in production from above-ground retorting total, industry-wide water use for the *high* scenario will increase by about 10,000 af/year. This increase in water use will occur predominantly in the Colorado River basin, along with a related increase in population.

References

URS Corporation, Energy Development Water Needs Assessment (Phase I Report), prepared for Colorado, Yampa, and White River Basin Roundtabes Energy Subcommittee. September, 2008.

Appendix E

Use of Groundwater to Meet Energy Water Use Demands

Memorandum

To:	**Joint Energy Water Needs Subcommittee**
cc:	
From:	**Greg Miller, Ph.D., P.G., Jim McCord, Ph.D.**
Subject:	**Use of Groundwater to Meet Energy Water Use Demands**
Date:	**September 2, 2010**

Introduction

This Technical Memorandum provides background and suggestions about the use of groundwater as part of Task 4 of the Energy Water Needs Phase II Study (Study).

The objective of Task 4, *Potential Use of Piceance Basin Groundwater to Meet Demands*, is to address the topic of using Piceance Basin (Basin) groundwater to meet water demands for energy development estimated in Phase I of the Study. This was done by building upon previous hydrologic research performed in the Piceance Basin over the past 30 years. The following tasks were accomplished to support our investigation:

- Compilation of a bibliography of previous hydrogeologic research in the Piceance Basin.
- Creation of a comprehensive spreadsheet of the published hydrogeologic properties of water-bearing geologic units (aquifers) in the Piceance Basin.
- Description of the general conceptual models for groundwater flow, surface water interaction, and the hydrogeology of the Basin.
- Evaluation of the groundwater development potential in the project areas, including estimation of well head costs for development of Piceance Basin groundwater in the project areas.
- Evaluation of existing groundwater quality.

The above tasks are covered in detail in this memo, along with a summary of the feasibility of using groundwater to meet water demands associated with the oil shale industry when considering water quality, quantity, and costs.

Energy Water Needs Assessment

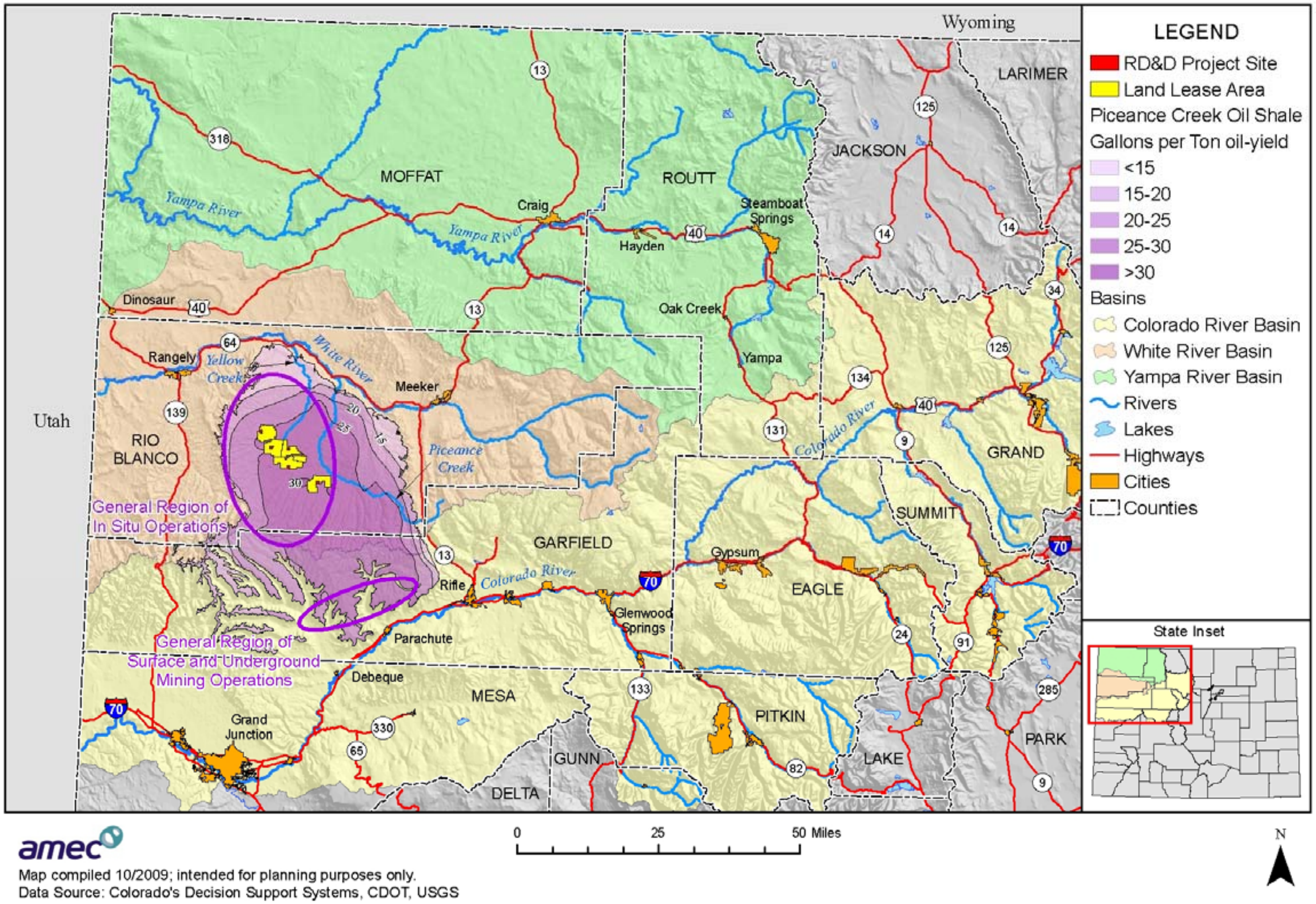

Figure 1: In Situ and Above-Ground Retorting Project Area

The results of this study indicate that the potential for developing significant water supplies from groundwater in the project areas is low, because the study indicates that productivity from wells is expected to be low and that water quality is expected to be poor. Groundwater may prove to be a feasible water supply in a limited number of locations, depending on site-specific conditions.

Figure 1 depicts the areas of interest for exploring the feasibility of using groundwater resources to meet part of the water demand for the oil shale industry.

Piceance Basin Hydrogeologic Bibliography

The Piceance Basin (Basin) hydrogeologic publication bibliography is contained in Appendix A. The bibliography was created by searching common geoscience reference databases, State and Federal agency collections, and references contained in selected documents. While there is a wide variety of literature available on the geology of the Basin, hydrogeologic information on the Basin is limited when compared to the spatial variability in groundwater resources and aquifer properties. As a result, a determination of the feasibility of groundwater development at a particular location will require new site-specific field investigations.

Piceance Basin Hydrogeologic Properties Spreadsheets

The purpose of our document review was to collect and collate hydrogeologic information on aquifers in the project areas and to review conceptual models for groundwater flow in the Basin. Increased development of groundwater resources in the Basin, along with oil and gas exploration over the past 10 to 20 years, has greatly added to the available hydrogeologic data for the Basin. However, the utility of this information is limited because the available data are often not collocated with the proposed projects. As part of oil shale and coal bed methane investigations (S.S. Papadopulos, 2007), detailed information on aquifer hydrogeologic properties and water quality for a few aquifers collocated with the project area have been published.

The majority of references in the bibliography were not fully reviewed during development of the hydrogeologic properties spreadsheets. For our investigation, we used the most recent compilations of hydrogeologic data or reviews of previously available hydrogeologic data in the Piceance Basin (URS 2006 and 2008; S.S. Papadopulos, 2007; BLM, 2006). Other references were reviewed if the abstracts showed potential that the reference contained quantitative hydrogeologic data.

Using data from these reports, Excel spreadsheets were created tabulating hydrogeologic properties in the Piceance Basin. The units used in the spreadsheets for physical properties are as published (i.e., conversions to common units were not made). Condensed versions of the spreadsheets are presented in Appendix B.

Groundwater Flow Conceptual Models

The focus here is to evaluate the *current* competing theories of the hydrogeology of the Basin that are well supported by observation, and to identify the potential constraints that those theories imply to resource development in the project areas.

The structure of the Piceance Basin is complex, having numerous folds, faults, and variable formation thicknesses and composition (USGS, 1987). The Basin geology covered in this memo is confined to the project areas shown in Figure 1 and the formations (aquifers) that are at a reasonable depth for groundwater development. Herein, the proposed in situ operation area is called the Northern Area, and the proposed above-ground retorting operation area is called the Southern Area. Table 1 presents the stratigraphy of the project areas. Across the project areas, one discontinuous aquifer is recognized in the unconsolidated alluvium and Uinta Formation, two aquifers in the Green River Formation, a potential Basin-spanning aquifer in the Wasatch Formation (Molina Sand), and aquifers in the Rollins Sandstone and Ohio Creek Members of the Mesa Verde Formation. The Northern Area was split into two sub-areas to more clearly present spatial trends in hydrogeology. Table 2 presents the *approximate* formation elevation, thickness, and potentiometric surface elevation for the two project areas.

Figure 2 presents cross-sections running east to west across the Basin. The sections clearly depict the thickening and deepening of the basinal sediments in the northern part of the Basin (S.S. Papadopulos, 2007). Hydrogeologic data for formations of interest are available from shallow wells in the Basin margins.

Table 1: Stratigraphy of the Project Areas

Period	Epoch	Formation	Members
Quaternary		Alluvium	Steven Gulch alluvium
			Unconsolidated Quaternary deposit
			Gunnison River alluvium
			White River alluvium
Tertiary	Miocene	Basalt flows	
	Oligocene	West Elk volcanic field	
	Eocene	Uinta Formation	
		Green River Formation	Main body
			Evacuation Creek Member
			Parachute Creek Member
			Mahogany Zone
			Garden Gulch Member
			Douglas Creek Member
			Lower Sandy Member (Anvil Points Member)
	Paleocene	Wasatch Formation	Total body
			Shire Member
			Molina Member
			Atwell Gulch Member
		Ft. Union Formation	
Cretaceous	Upper	Mesa Verde Group Iles Form. Williams Fork Form.	Total body
			Ohio Creek Member
			Barren Member (undifferentiated Member)
			Upper Coal Member (Paonia Shale)
			Lower Coal Member (Bowie Shale)
			Rollins Sandstone
			Cozzette Member
			Corcoran Member
			Upper Sego Sandstone
	Lower	Mancos Shale	Anchor Mine Tongue
	Upper	Mesa Verde Group	Lower Sego Sandstone
			Castlegate Sandstone
	Lower	Mancos Shale	Main body
	Lower	Dakota Group	Total body
			Dakota Sandstone

Table 2: Approximate Formation Elevation, Aquifer Thickness, and Potentiometric Surface Elevation for the Project Areas

Green River Formation Upper Aquifer	Northern Project Area		Southern Project Area
	Northern Half	Southern Half	
Aquifer Thickness	250 – 750 ft	500 – 1,000 ft	0 – 400 ft
Formation Thickness	1,000 – 2,000 ft	1,000 – 2,000 ft	0 – 1,000 ft
Potentiometric Surface	6,200 – 6,800 ft	6,200 – 7,200 ft	7,800 – 8,400 ft
Top of Formation	6,500 – 6,000 ft	6,500 – 6,000 ft	8,000 – 9,300 ft
Ground Surface	6,500 – 9,300 ft	6,500 – 9,300 ft	6,500 – 9,300 ft

Green River Formation Lower Aquifer	Northern Project Area		Southern Project Area
	Northern Half	Southern Half	
Aquifer Thickness	500 – 750 ft	650 – 1,000 ft	0 – 500 ft
Formation Thickness	1,000 – 2,000 ft	1,000 – 2,000 ft	0 – 1,000 ft
Potentiometric Surface	6,200 – 6,900 ft	6,200 – 6,900 ft	7,800 – 8,200 ft
Top of Formation	5,500 – 6,500 ft	5,500 – 6,500 ft	7,500 ft
Ground Surface	6,500 – 9,300 ft	6,500 – 9,300 ft	6,500 – 9,300 ft

Wasatch - Molina Aquifer	Northern Project Area	Southern Project Area
Aquifer Thickness	110 – 400 ft	110 – 400 ft
Formation Thickness	3,500 – 5,000 ft	2,500 – 3,500 ft
Potentiometric Surface	6,500 ft	7,500 ft
Top of Formation	3,500 – 4,500 ft	6,000 – 7,300 ft
Ground Surface	6,500 – 9,300 ft	6,500 – 9,300 ft

Table 2 Continued: Approximate Formation Elevation, Aquifer Thickness, and Potentiometric Surface Elevation for the Project Areas

Mesa Verde Aquifer	Northern Project Area	Southern Project Area
Aquifer Thickness	1,000 – 1,560 ft	500 – 1,560 ft
Formation Thickness	3,000 – 7,000 ft	4,500 – 6,500 ft
Potentiometric Surface	6,000 – 7,500 ft	5,500 – 7,500 ft
Top of Formation	-500 to -3,000 ft	0 to -1,000
Ground Surface	6,500 – 9,300 ft	6,500 – 9,300 ft

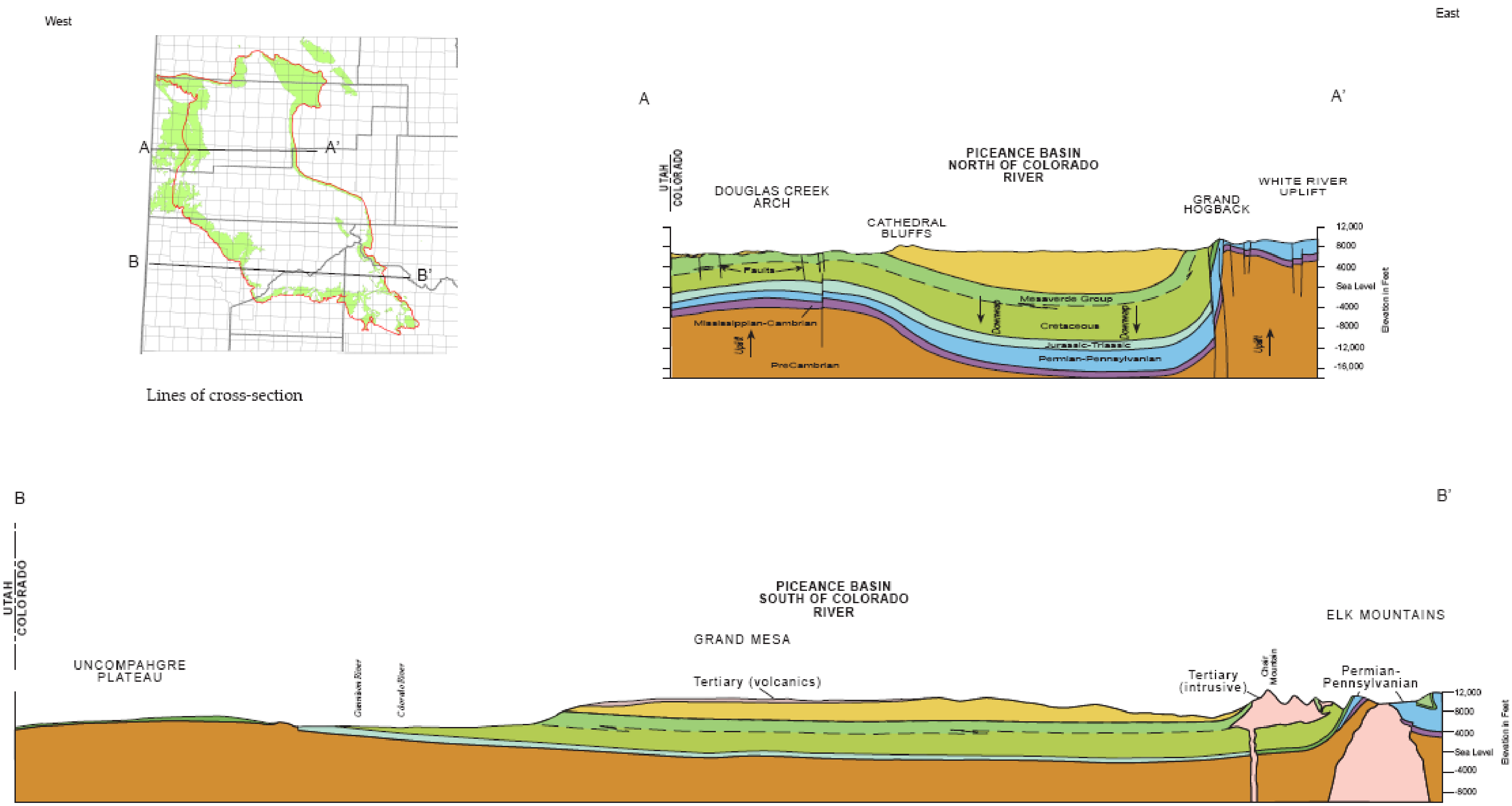

Figure 2: Cross-Sections across the Basin (east to west)

Source: S.S. Papadopulos, 2007

At the Basin scale, conceptual models for groundwater flow are fairly well resolved; over the approximately 1,200 square mile Basin area there is only limited scientific disagreement found in recent publications. However, the literature expresses a high degree of uncertainty (Cordilleran, 2002; USGS, 1998; BLM, 2006). These publications indicate that further investigation is needed in:

- The degree of horizontal and vertical hydraulic connection between deep water bearing units (thousands of feet below ground surface) that are coal bed methane targets, and the stratigraphically equivalent, distally located, zones that are shallow targets (hundreds of feet) for water supply wells.

- The degree of vertical connection between water bearing units in and below the Green River Formation.

Qualitatively, all authors recognize that there is some vertical hydraulic connection between aquifers, and some strata-bound horizontal flow connection; however, there is a question of degree. Now that groundwater hydrologic processes are being investigated with rigor as part of coal bed methane and oil shale permitting, new knowledge is being obtained. That new knowledge will require revisions to the existing model(s). These are not revisions in general theory, but revisions in quantitative assumptions regarding vertical and horizontal values for hydraulic conductivity. For example, it has been long held by many authors that the R7 Unit and the Mahogany Bed formed an aquitard between the two Green River Formation aquifers (USGS, 1982 and 1998; Colorado Geological Survey, 2003). Extensive testing at Shell Site 1 in the Northern Area has revealed that at this location, the R7 unit is permeable, and that the aquitard lies about 500 feet deeper in the section (BLM, 2006). Similarly, a recent investigation identified numerous cross-cutting vertical beds (dikes) of permeable silts and sands present in the upper sections of the Green River Formation (Gulliver, 2007). Recent detailed investigations are tending to favor groundwater flow in a Basin with leakier aquitards compared to previous investigations. Conceptual models will need to be refined to incorporate explicit recognition of leakage should this continue to be proven at the regional scale by future investigations.

The rocks of the Piceance Basin have been subject to several episodes of deformation that have systematically fractured the beds (USGS, 1987). There are at least eight sets of joints (fractures with a common orientation) that have had their orientation and spacing determined for the Piceance Basin. Joint orientation and spacing often strongly influences groundwater flow. The treatment of joints and their effect on flow is an important part of a conceptual model. Most of the governing principles in groundwater hydrology rely on the assumption of porous granular geomedia (e.g., clay, silt, sand, gravel) forming aquifers and aquitards. If the joint spacing is small compared to the area under consideration, a conceptual model can be framed using the concept of a Representative Porous Media (RPM). We assume that a RPM approach is valid for our evaluation of available water resources. However, while the RPM approach may be adequate for qualitative or quantitative estimation of regional groundwater flow in the Basin, selection of well locations is best served when fractures are accounted for explicitly. Locating wells on areas of high joint density, or laterally continuous fractures, offers advantages in well yield, and certainty of supply. This type of site-specific analysis was not done as part of this study.

Modeling of the Water Supply Potential of Hypothetical Wells

To estimate well and well field performance, a RPM approach was taken when modeling the hypothetical wells. The software package AQTESOLV was used to model well yield, drawdown, and radius of influence using the data contained in Table 3. Trial and error methods were used to select pumping rates, evaluating the drawdown that occurs when Table 3 parameters are varied over the range of properties particular to the aquifer being evaluated.

Feasibility and Cost of Well Development

Groundwater wells deeper than 3,000 feet below ground surface are rare because of cost and construction limitations. Using 3,000 feet as a cutoff when referencing Table 3, it can be determined that development of the Mesa Verde Formation for water resources is not practical in the Northern or Southern Area and that development of the Wasatch Formation may only be practical in the Southern Area. An additional restriction on use of the Mesa Verde Formation for water supply is that the Mesa Verde is believed to be over-pressured and gas-saturated over all of the Northern Area (S.S. Papadopulos, 2007).

Table 3 presents the configuration of hypothetical water supply wells for the Northern and Southern Areas. The hypothetical well depths and screen lengths are based on the information in Table 2. Table 3 dimensions and hydrologic values are used to estimate well drilling and completion costs and to support forward modeling of well drawdown, yield, and operating costs. All portions of wells that are open to the aquifer are set at a 6-inch diameter. Based on recent bids received on deep well projects in similar formations, we have used a price of $200.00 per linear foot to estimate well construction costs. To provide a basis for comparison between the aquifers, the number of wells required to produce 1,000,000 gallons per day (1 million gallons per day (MGD) ~ 3.07 acre-foot/day) was determined. The costs in Table 3 reflect only those costs to complete the well to the well head. The costs for pumping water are based on maximum drawdown and the power costs and pump efficiencies contained in Table 3. High and low pumping costs are determined from maximum and minimum modeled 100 day drawdown, and maximum and minimum pumping rates, calculated per million gallons based on the following equation:

$$\text{Total Pumping Cost (per well)} = \frac{D \times H \times h \times Q \times 0.746 \times k}{3960 \times eP \times eM}$$

D = days operated
H = Hours per day pumping
h = pumping head (ft)
Q = discharge rate (GPM)
0.746 = conversion from HP to kWh
k = cost per kWh
3960 = conversion from mass × time × elevation to HP
eP = Pump efficiency
eM = Motor efficiency

Table 3: Configuration of Hypothetical Water Supply Wells for the Project Areas

Northern Area - Northern Half

	Well Total Depth (ft BGS)	Well Screen Length (ft)	Static Water Level (ft BGS)	Transmissivity (ft^2/min)	Dimensionless Storage Coefficient	Sustainable Pumping Rate (GPM)	Drawdown (ft)	100 day Radius of Influence (ft)	Drilling Cost (per well)	High Number of Wells to produce 1 MGD	Low Number of Wells to produce 1 MGD	High Well Field Cost	Low Well Field Cost	High Pumping Cost per MG	Low Pumping Cost per MG
Uinta - Alluvium	250	100	-100	0.07 to 0.7	NA	40 to 300	250 to 200	100 to 1,000	$ 50,000	17.4	2.3	$ 900,000	$ 150,000	$1,200	$26
Upper Green River	1,500	250	-400	0.01 to 0.1	0.0001	15 to 100	800 to 550	100 to >1,000	$ 300,000	46.3	6.9	$ 14,100,000	$ 2,100,000	$3,500	$62
Lower Green River	3,000	250	-500	0.01 to 0.1	0.0001	15 to 100	800 to 550	100 to >1,000	$ 600,000	46.3	6.9	$ 28,200,000	$ 4,200,000	$3,500	$62
Wasatch	4,000	100	-600	0.007 to 0.07	0.0001	25 to 150	700 to 525	>3,000 to >5,000	$ 800,000	27.8	4.6	$ 22,400,000	$ 4,000,000	$3,700	$88

Northern Area - Southern Half

	Well Total Depth (ft BGS)	Well Screen Length (ft)	Static Water Level (ft BGS)	Transmissivity (ft^2/min)	Dimensionless Storage Coefficient	Sustainable Pumping Rate (GPM)	Drawdown (ft)	100 day Radius of Influence (ft)	Drilling Cost (per well)	High Number of Wells to produce 1 MGD	Low Number of Wells to produce 1 MGD	High Well Field Cost	Low Well Field Cost	High Pumping Cost per MG	Low Pumping Cost per MG
Uinta - Alluvium	250	100	-100	0.07 to 0.7	NA	40 to 300	250 to 200	100 to 1,000	$ 50,000	17.4	2.3	$ 900,000	$ 150,000	$1,200	$26
Upper Green River	1,500	250	-300	0.01 to 0.1	0.0001	15 to 100	800 to 550	100 to >1,000	$ 300,000	46.3	6.9	$ 14,100,000	$ 2,100,000	$3,200	$56
Lower Green River	3,000	250	-400	0.01 to 0.1	0.0001	15 to 100	800 to 550	100 to >1,000	$ 600,000	46.3	6.9	$ 28,200,000	$ 4,200,000	$3,200	$56
Wasatch	4,000	100	-500	0.007 to 0.07	0.0001	25 to 150	700 to 525	>3,000 to >5,000	$ 800,000	27.8	4.6	$ 22,400,000	$ 4,000,000	$3,400	$80

Table 3 Continued: Configuration of Hypothetical Water Supply Wells for the Project Areas

Southern Area	Well Total Depth (ft BGS)	Well Screen Length (ft)	Static Water Level (ft BGS)	Transmissivity (ft^2/min)	Dimensionless Storage Coefficient	Sustainable Pumping Rate (GPM)	Drawdown (ft)	100 day Radius of Influence (ft)	Drilling Cost (per well)	High Number of Wells to produce 1 MGD	Low Number of Wells to produce 1 MGD	High Well Field Cost	Low Well Field Cost	High Pumping Cost per MG	Low Pumping Cost per MG
Uinta - Alluvium	250	100	-100	0.07 to 0.7	NA	40 to 300	250 to 200	100 to 1,000	$ 50,000	17.4	2.3	$ 900,000	$ 150,000	$1,200	$26
Upper Green River	750	250	-200	0.01 to 0.1	0.0001	15 to 100	800 to 550	100 to >1,000	$ 150,000	46.3	6.9	$ 7,050,000	$ 1,050,000	$3,200	$56
Lower Green River	1,750	250	-300	0.01 to 0.1	0.0001	15 to 100	800 to 550	100 to >1,000	$ 350,000	46.3	6.9	$ 16,450,000	$ 2,450,000	$2,700	$56
Wasatch	2,500	100	-400	0.007 to 0.07	0.0001	25 to 150	700 to 525	>3,000 to >5,000	$ 500,000	27.8	4.6	$ 14,000,000	$ 2,500,000	$2,900	$80
Mesa Verde	6,000	200	-500	0.001 to 0.01	0.0001	5 to 30	1,000 to 625	>1,000 to >5,000	$1,200,000	138.9	23.1	$ 166,800,000	$27,600,000	$2,000	$117
Electrical Cost $/KWH	$0.10														
Pump Efficiency	80%														
Motor Efficiency	90%														

Groundwater Quality

Moderately poor quality waters (500 to 1,000 milligrams per Liter (mg/L) dissolved solids) are found in the Uinta/alluvial and Upper Green River Formation aquifers. All other groundwater in the Basin is poor quality (1,000 to 10,000 mg/L) or very poor in quality (>10,000 mg/L). While the dominant water type is sodium bicarbonate, dissolved calcium and magnesium have sufficient concentrations to make almost all groundwater very hard (scale forming). Additionally, many wells exhibit concentrations of boron, fluoride, iron, sodium and sulfate that raise concerns with respect to discharge to the near-surface environment.

Tributary Nature of Aquifers

Tributary Aquifers

In the Northern Area the existing conceptual, numerical, and water budget models support a tributary water designation for all alluvial aquifers, the Upper Green River Formation Aquifer, and the Lower Green River Formation Aquifer. In the Northern Area the existing conceptual models support a non-tributary nature for the Wasatch and Mesa Verde aquifers.

Care should be used in the assumption that Wasatch and Mesa Verde aquifers are always non-tributary. The deeper aquifers rise closer to the surface at the edges of the basin, cropping out at the ground surface. In the Piceance Basin, shallow aquifers (0 to ~ 500' bgs) will generally be tributary in nature.

In the Southern Area, the units of the Wasatch Formation lie near the surface, an indication of the possibility that this aquifer is tributary. In the Southern area all alluvial aquifers, the Upper Green River Formation Aquifer (often missing), the Lower Green River Formation Aquifer, and near-surface portions of the Wasatch Formation have a tributary nature.

Glover Analysis

To evaluate whether or not the Glover analysis as presented in SSPA's 2007 report provides an over- or under- conservative estimate of the impact of groundwater withdrawals on in-stream flows in basin surface water it is helpful to review the assumptions of the Glover analysis. As part of past work looking at stream depletions due to well pumping in the South Platte and Rio Grande basins, we have had opportunities to closely evaluate the Glover model, its underlying assumptions, and impacts of deviations from those assumptions on estimated stream depletions due to well pumping. The assumptions as listed by SSPA are presented below with an assessment of the degree that the assumptions are met, and the implications for tributary designation using the Glover analysis when they are not met:

1. <u>The aquifer is homogeneous</u>
   The aquifers under consideration are not homogeneous. The method used by S.S. Papadopulos to average the hydraulic conductivity over the full thickness of the saturated section can result in over estimates of impact (when high conductivity layers are discontinuous) or underestimates of impact (when high conductivity units are laterally extensive). It is not possible to quantify the magnitude and direction of errors in impact determination.

2. The aquifer is semi-infinite in extent
The aquifers are not semi-infinite in extent. It is known that structural features of the basin (faults, folds, gas pressures, etc.) limit the extent of the aquifers in the study area, at the scale of the projects proposed. Violation of this assumption typically results in the Glover model under predicting the impacts to streams.

3. The boundary at which depletions are calculated is a linear stream that fully penetrates the aquifer, where the streambed is in hydraulic connection with the aquifer
The streambeds do not fully penetrate the aquifers. This assumption also ignores the potential for a streambed clogging layer. In the immediate vicinity of the stream (say distances closer than 10-times the aquifer thickness), violations to this assumption lead to a understatement of the head loss associated with a streambed clogging layer as well as losses associated with vertical flow through the aquifer. At greater distances between the stream and the pumping well, however, the total head loss due to these two features become negligibly small compared to the head loss associated with horizontal flow between the stream and the well, and stream depletion errors associated with this assumption are quite small.

4. Flow within the aquifer is horizontal
For wells located at distances from the stream that are greater than 10-times the aquifer thickness, any violations to this assumption are small and would have negligible impact on calculated depletions..

5. Flow is dominated by one phase
By definition, coal bed methane targets are dominated by multi-phase flow. Glover analysis does not consider this. As gas is liberated from coal cleats due to water production and drawdown, the flow system becomes two phase, and the hydraulic conductivity (permeability to water) in regions with two-phase flow is reduced by a relative conductivity factor. More than one flow phase will be involved in the basin, and the Glover analysis is not designed to evaluate any aspect of multiphase flow. Violation of this assumption leads to overprediction of stream impacts and cannot be adjusted for empirically using Glover analysis.

These five assumptions must hold for the Glover analysis to be valid, and they are all violated to varying degrees in the Piceance Basin.. Because of the potential for over and under prediction of the effects of groundwater withdrawals using the method, and the inability to assess accurately the direction or degree of those inaccuracies, the use of the Glover method in the Piceance Basin is unsupported and unreliable. Numerical and analytical methods that quantitatively account for the assumption violations listed above should be employed.

Feasibility of Using Groundwater for Oil Shale

There are three major areas to evaluate the feasibility of groundwater use for oil shale development: the water quality, the quantity of water that can be produced, and the cost to do so. While water quality targets were not identified as a criterion for comparison, in general the water quality of groundwater in the Basin is poor enough to be unusable for most industrial purposes without treatment. With respect to the quantity of water to be produced, the Wasatch and Mesa Verde Formations are likely unsuitable because of the numbers of wells required and due to the well spacing needed to prevent interference (¼ to 1 mile between wells). From Table 3 it is clear that there is a broad range in potential costs for groundwater development in the project areas. The alluvial and Green River Formation aquifers have the lowest cost per well, the closest feasible well spacing, and the highest water quality. These shallower formations may provide the only feasible source of groundwater in the Basin for oil shale development. However, these aquifers are probably tributary in nature, so their use might require an augmentation plan and supply.

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Appendix B - Porosity (%)

Period	Epoch	Formation	Members	Cordilleran Compliance Services, 2002 Cedaredge and Paonia, Delta Co, CO	Freethey and Cordy, 1991 Vicinity of Cedaredge and Paonia, Delta County, CO	Spencer, 2001 Uinta-Piceance Basin Province	Coffin, Welder and Glanzman, 1971 Piceance Creek structural basin between the White and Colorado Rivers	Topper, R.; Spray, K.L.; Bellis, W.H.; Hamilton, J.L.; Barkmann, P.E. Piceance Basin	Geldon, 1989 Glenwood Springs, northwestern Colorado
Tertiary	Miocene	Basalt flows							
	Oligocene	West Elk volcanic field							
	Eocene	Uinta Formation							
		Green River Formation	Main body						
			Evacuation Creek Member						
			Parachute Creek Member						
			Garden Gulch Member						
			Douglas Creek Member			11 - 15			
			Lower Sandy Member (Anvil Points Member)						
	Paleocene	Wasatch Formation	Total body						
			Shire Member						
			Molina Member						
			Atwell Gulch Member						
		Ft. Union Formation							
Cretaceous	Upper	Mesaverde Group – Williams Fork Form.	Total body		<10			<10	
			Ohio Creek Member	0.7 - 9.7					
			Barren Member (undifferentiated Member)	<1.0 - 11.1					
			Upper Coal Member (Paonia Shale)	4 - 12		5 - 8			
			Lower Coal Member (Bowie Shale)						
		Mesaverde Group – Iles Form.	Rollins Sandstone	0 - 16					
			Cozzette Member						
			Corcoran Member						
			Upper Sego Sandstone						
	Lower	Mancos Shale	Anchor Mine Tongue						
	Upper	Mesaverde Group	Lower Sego Sandstone						
			Castlegate Sandstone						
	Lower	Mancos Shale	Main body						
	Lower	Dakota Group	Total body						
			Dakota Sandstone		2 - 22				
Mississippian			Leadville Limestone						2 - 3
Devonian			Dyer Dolomite						
			Parting Formation						

Appendix B - Permeability

Period	Epoch	Formation	Members	Cordilleran Compliance Services, 2002 Cedaredge and Paonia, Delta Co, CO	Freethey and Cordy, 1991 Vicinity of Cedaredge and Paonia, Delta County, CO	**Weigel, 1987 Upper Colorado River Basin	**West Elk permit. 1995 and 1999 West Elk Mine	**Olson, 2003 White River Dome Field	**Law (Pangea), 2003 for WWE Grand Mesa	**Nance and Kaiser, 1995 Grand Valley/Ruison, Garfield County
Quaternary		Alluvium								
			Steven Gulch alluvium							
			Unconsolidated Quaternary deposit							
			Gunnison River alluvium							
			White River alluvium							
Tertiary	Miocene	Basalt flows								
	Oligocene	West Elk volcanic field								
	Eocene	Uinta Formation								
		Green River Formation	Main body							
			Evacuation Creek Member							
			Parachute Creek Member							
			Garden Gulch Member							
			Douglas Creek Member							
			Lower Sandy Member (Anvil Points Member)							
	Paleocene	Wasatch Formation	Total body							
			Shire Member							
			Molina Member							
			Atwell Gulch Member							
		Ft. Union Formation								
Cretaceous	Upper	Mesaverde Group Williams Fork Formation	Total body		5-23 millidarcies: mean 15 millidarcies [a]	0.02 - 28 millidarcies Rio Blanco, Garfield, Mesa Counties [a]			<0.1 millidarcy [a]	very low [a]
			Ohio Creek Member	<0.0001 - 0.01 darcies						
			Barren Member (undifferentiated Member)	<0.001 - 0.01 darcies			range: 52 - 200 millidarcies at 1.0 - 4.1 gpd/ft² in F seam; range 2 - 4 millidarcies at 0.042 -0.083 gpd/ft² in B seam [a]	productive sandstone 0.01 - 0.1; insitu permeability of 0.02 millidarcies [a]		
			Upper Coal Member (Paonia Shale)	<0.001 - 0.022 darcies [a]				0.2 millidarcies [a]		
			Lower Coal Member (Bowie Shale)							
		Iles Formation	Rollins Sandstone	$<10^{-3}$ darcies			<0.1 - 11 millidarcies [a]			
			Cozzette Member							
			Corcoran Member							
			Upper Sego Sandstone							
	Lower	Mancos Shale	Anchor Mine Tongue							
	Upper	Mesaverde Group	Lower Sego Sandstone							
			Castlegate Sandstone							
	Lower	Mancos Shale	Main body		6 millidarcies					
	Lower	Dakota Group	Total body		45 millidarcies					
			Dakota Sandstone							
Jurassic	Upper		Morrison Formation							
			Redwater Member							
	Middle		Curtis Member							
			Entrada Sandstone							
			Carmel Formation							
Triassic	Upper		Glen Canyon Formation							
			Chinle Formation							
		State Bridge Formation	Moenkopi Formation							
Permian			Park Bridge Formation							
			Weber Sandstone							
			Maroon Formation							
Pennsylvanian			Minturn Formation							
			Eagle Valley Formation							
			Belden Formation							
			Molas Formation							
Mississippian			Leadville Limestone							
Devonian			Dyer Dolomite							
			Parting Formation							
Ordovician			Manitou Dolomite							
Cambrian			Dotsero Formation							
			Sawatch Quartzite							
Precambrian		Unita Mountain Group								
		Granitic Rocks								
		Metasedimentary								

Appendix B - Yield

Period	Epoch	Formation	Members	Brooks and Ackerman, 1985 Lower Gunnison River basin	Brooks, 1983 Cedaredge and Paonia, Delta County, CO	Cordilleran Compliance Services, 2002 Cedaredge and Paonia, Delta Co, CO	Van Liew and Genick, 1985 White River Valley, Rio Blanco Co, CO	Coffin, Welder and Glanzman, 1971 Piceance Creek structural basin between the White and Colorado Rivers	Topper, R.; Spray, K.L.; Bellis, W.H.; Hamilton, J.L.; Barkmann, P.E. Piceance Basin	Glover, Naftz, Martin, 1998 Upper Colorado River basin
Quaternary		Alluvium			25 gal/min	2 - 40 gpm		up to 1500 gpm		
			Steven Gulch alluvium							
			Unconsolidated Quaternary deposit							
			Gunnison River alluvium	1 - 750 gal/min						
			White River alluvium				<25 gpm			
Tertiary	Miocene	Basalt flows								
	Oligocene	West Elk volcanic field								
	Eocene	Uinta Formation								
		Green River Formation	Main body							
			Evacuation Creek Member					100 gpm	1- 900 gpm	upper aquifer: 1 - 900 gpm confining: <25 gpm lower aquifer: 1 - 1000 gpm
			Parachute Creek Member					1000 gom		
			Garden Gulch Member							
			Douglas Creek Member					unknown but probably <50 gpm		
			Lower Sandy Member (Anvil Points Member)					wells- 10 gpm, springs - 100 gpm	1-1000 gpm	
	Paleocene	Wasatch Formation	Total body							
			Shire Member							
			Molina Member			25 gpm				
			Atwell Gulch Member							
		Ft. Union Formation								
Cretaceous	Upper	Mesaverde Group Williams Fork Form.	Total body							
			Ohio Creek Member							
			Barren Member (undifferentiated Member)							
			Upper Coal Member (Paonia Shale)	0.7 - 24 gal/min						
			Lower Coal Member (Bowie Shale)							
		Iles Form.	Rollins Sandstone							
			Cozzette Member							
			Corcoran Member							
			Upper Sego Sandstone							
	Lower	Mancos Shale	Anchor Mine Tongue							
	Upper	Mesaverde Group	Lower Sego Sandstone							
			Castlegate Sandstone							
	Lower	Mancos Shale	Main body	1 - 20 gal/min						
	Lower	Dakota Group	Total body							
			Dakota Sandstone	5 - 14 gal/min						
Jurassic	Upper		Morrison Formation							
			Redwater Member							
	Middle		Curtis Member							
			Entrada Sandstone	11 - 15 gal/min						
			Carmel Formation							

Appendix B - Storage Coefficient

<table>
<tr><th>Period</th><th>Epoch</th><th>Formation</th><th>Members</th><th>Brooks, 1983

Cedaredge and Paonia, Delta County, CO</th><th>Freethey and Cordy, 1991

Vicinity of Cedaredge and Paonia, Delta County, CO</th><th>Coffin, Welder and Glanzman, 1971

Piceance Creek structural basin between the White and Colorado Rivers</th><th>Geldon, 1989

Glenwood Springs, northwestern Colorado</th></tr>
<tr><td rowspan="5">Quaternary</td><td rowspan="5"></td><td rowspan="5">Alluvium</td><td></td><td></td><td></td><td>0.2</td><td></td></tr>
<tr><td>Steven Gulch alluvium</td><td>0.0002</td><td></td><td></td><td></td></tr>
<tr><td>Unconsolidated Quaternary deposit</td><td>0.2</td><td></td><td></td><td></td></tr>
<tr><td>Gunnison River alluvium</td><td></td><td></td><td></td><td></td></tr>
<tr><td>White River alluvium</td><td></td><td></td><td></td><td></td></tr>
<tr><td rowspan="15">Cretaceous</td><td rowspan="9">Upper</td><td rowspan="9">Mesaverde Group
Williams Fork Form.
Iles Form.</td><td>Total body</td><td></td><td>0.000002 - 0.007</td><td></td><td></td></tr>
<tr><td>Ohio Creek Member</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Barren Member (undifferentiated Member)</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Upper Coal Member (Paonia Shale)</td><td rowspan="2">0.00004 - 0.097</td><td></td><td></td><td></td></tr>
<tr><td>Lower Coal Member (Bowie Shale)</td><td></td><td></td><td></td></tr>
<tr><td>Rollins Sandstone</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Cozzette Member</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Corcoran Member</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Upper Sego Sandstone</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Lower</td><td>Mancos Shale</td><td>Anchor Mine Tongue</td><td></td><td></td><td></td><td></td></tr>
<tr><td rowspan="2">Upper</td><td rowspan="2">Mesaverde Group</td><td>Lower Sego Sandstone</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Castlegate Sandstone</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Lower</td><td>Mancos Shale</td><td>Main body</td><td></td><td></td><td></td><td></td></tr>
<tr><td rowspan="2">Lower</td><td rowspan="2">Dakota Group</td><td>Total body</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Dakota Sandstone</td><td></td><td>0.001</td><td></td><td></td></tr>
<tr><td>Mississippian</td><td></td><td></td><td>Leadville Limestone</td><td></td><td></td><td></td><td rowspan="2">$0.2x10^{-4}$ - $7x10^{-4}$</td></tr>
<tr><td rowspan="2">Devonian</td><td rowspan="2"></td><td rowspan="2"></td><td>Dyer Dolomite</td><td></td><td></td><td></td></tr>
<tr><td>Parting Formation</td><td></td><td></td><td></td><td></td></tr>
</table>

Appendix B - Hydraulic Conductivity

Period	Epoch	Formation	Members	Brooks, 1983 Cedaredge and Paonia, Delta County, CO	Cordilleran Compliance Services, 2002 Cedaredge and Paonia, Delta Co, CO	Freethey and Cordy, 1991 Vicinity of Cedaredge and Paonia, Delta County, CO	Environmental Assessment on Oil Shale Research, Development and Demonstration bt Shell Frontier Oil and Gas Rio Blanco Co, CO	Topper, R.; Spray, K.L.; Bellis, W.H.; Hamilton, J.L.; Barkmann, P.E. Piceance Basin	Geldon, 1989 Glenwood Springs, northwestern Colorado	Glover, Naftz, Martin, 1998 Upper Colorado River basin	Taylor, 1982 Piceance Basin (vertical conductivity)	**Teller and Chafin, 1986	**Weigel, 1987 Upper Colorado River Basin	**West Elk permit. 1995 and 1999 West Elk Mine	**Olson, 2003 White River Dome Field	Papadopulos, 2007
Quaternary		Alluvium														
			Steven Gulch alluvium													
			Unconsolidated Quaternary deposit													
			Gunnison River alluvium													
			White River alluvium													
Tertiary	Miocene	Basalt flows														
	Oligocene	West Elk volcanic field														
		Uinta Formation									1.3×10^{-3} - 5.6×10^{-1}					
	Eocene	Green River Formation	Main body					<0.2 - >1.6 ft/d		upper aquifer: 0.003 - 1.6 ft/d confining: 0.0003 - 0.1 ft/d lower aquifer: 0.001 - 1.2 ft/d	1.7×10^{-3} - 8.06×10^{-1} above Mahogany					
			Evacuation Creek Member													
			Parachute Creek Member				Upper aquifer is 3 - 0.75 ft/d, lower aquifer is 37 - 0.08 ft/d									
			Mahogany Zone								1×10^{-4} - 3×10^{-2}					
			Garden Gulch Member													
			Douglas Creek Member													
			Lower Sandy Member (Anvil Points Member)					<0.1 - >1.2 ft/d								
	Paleocene	Wasatch Formation	Total body													
			Shire Member													
			Molina Member													
			Atwell Gulch Member													
		Ft. Union Formation														
Cretaceous	Upper	Mesaverde Group Williams Fork Form.	Total body			0.00001 - 0.001 in SE; 0.01 - 0.1 in W [a]; lab tests 1x10-5 to 13.7 (median: 0.45 ft/day) in aquifers; 1x10-5 to 10.9 (median: 0.06 ft/day) in confining units; deeply buried <0.001 ft/day; near surface 0.04 to 1.0 ft/day drill tests: median: 0.021 ft/day in aquifers; median: 0.0.17ft/day in confining units				<0.01 where deeply buried higher in outcrops [a]		0.0002 - 0.27 ft/day [a]	0.00019 - 0.5 ft/day in Rio Blanco, Mesa, Routt, and Moffat Counties; 0.07 - 30 ft/day in Delta County and 0.00005 - 0.068 ft/day in Rio Blanco, Garfield and Mesa Counties [a]			
			Ohio Creek Member	minimal [a]												
			Barren Member (undifferentiated Member)													
			Upper Coal Member (Paonia Shale)		0.0027-0.06 ft/day [a]									0.14 - 0.54 ft/day in F seam; 0.006 - 0.011 ft/day in B seam [a]	0.0005 ft/day in coals	1.6×10^{-4} to 0.6 ft/day at outcrops; generally < 2.7×10^{-4} to 2.7×10^{-3} ft/day
			Lower Coal Member (Bowie Shale)													
		Iles Form.	Rollins Sandstone													
			Cozzette Member													
			Corcoran Member													
			Upper Sego Sandstone													
	Lower	Mancos Shale	Anchor Mine Tongue													
	Upper	Mesaverde Group	Lower Sego Sandstone													
			Castlegate Sandstone													
	Lower	Mancos Shale	Main body													
	Lower	Dakota Group	Total body													
			Dakota Sandstone			<0.1 ft/d										
Jurassic	Upper		Morrison Formation													
			Redwater Member													
	Middle		Curtis Member													
			Entrada Sandstone													
			Carmel Formation													
Triassic	Upper		Glen Canyon Formation													
			Chinle Formation													
			Moenkopi Formation													
Permian			Park Bridge Formation													
			Weber Sandstone													
			Maroon Formation													
Pennsylvanian			Minturn Formation													
			Eagle Valley Formation													
			Belden Formation													
			Molas Formation													
Mississippian			Leadville Limestone						0.00057 - 0.0097 ft/d							
Devonian			Dyer Dolomite													
			Parting Formation													
Ordovician			Manitou Dolomite													
Cambrian			Dotsero Formation													
			Sawatch Quartzite													
Precambrian		Unita Mountain Group														
		Granitic Rocks														
		Metasedimentary														

** Hard copy of report currently not in hand

[a] Values sited in Table 6.1 in Papadopulos and Associates Draft Report titled Coalbed Methane Stream Depletion Assessment Study-Piceance Basin C

Appendix B - Transmissivity

Period	Epoch	Formation	Members	Brooks and Ackerman, 1985 Lower Gunnison River basin	Brooks, 1983 Cedaredge and Paonia, Delta County, CO	Van Liew and Genick, 1985 White River Valley, Rio Blanco Co, CO	Freethey and Cordy, 1991 Vicinity of Cedaredge and Paonia, Delta County, CO	Coffin, Welder and Glanzman, 1971 Piceance Creek structural basin between the White and Colorado Rivers	Topper, R.; Spray, K.L.; Bellis, W.H.; Hamilton, J.L.; Barkmann, P.E. Piceance Basin	Geldon, 1989 Glenwood Springs, northwestern Colorado	Taylor, 1982 Piceance Basin	**Weigel, 1987 Upper Colorado River Basin	**West Elk permit. 1995 and 1999 West Elk Mine
Quaternary		Alluvium			108 - 230 ft^2/day			20000 - 150000 gpd/ft					
			Steven Gulch alluvium		187 - 230 ft²/d								
			Unconsolidated Quaternary deposit		1900 ft²/dt								
			Gunnison River alluvium										
			White River alluvium			860 - 93000 ft^2/day							
Tertiary	Miocene	Basalt flows											
	Oligocene	West Elk volcanic field											
	Eocene	Uinta Formation							610 - 770 ft2/d		1 - 450 ft2/d		
		Green River Formation	Main body								1 - 480 ft2/d above Mahogany		
			Evacuation Creek Member										
			Parachute Creek Member					3000 gpd (margins) - 20000 (center) gpd/ft					
			Mahogany Zone								$5.3x10^{-2}$ - $1.6x10^{1}$ ft2/d		
			Garden Gulch Member										
			Douglas Creek Member										
			Lower Sandy Member (Anvil Points Member)						260 - 380 ft2/d				
	Paleocene	Wasatch Formation	Total body										
			Shire Member										
			Molina Member										
			Atwell Gulch Member										
		Ft. Union Formation											
Cretaceous	Upper	Mesaverde Group: Iles Formation, Williams fork Formation	Total body	0.3 - 16.7 ft²/d [a] for sandstones	0.33 - 400 ft2/d		<50 - 500 ft²/day [a]						
			Ohio Creek Member									0.0015 - 6.1 ft²/day in Rio Blanco, Mesa, Routt, and Moffat Counties and 11 - 450 ft²/day in Delta County [a]	
			Barren Member (undifferentiated Member)		0.33 ft²/d								
			Upper Coal Member (Paonia Shale)		1.5 - 16.7 ft²/d [a]								0.028 - 61 gpd/ft in F seam; 3.3 gpd/ft in B seam [a]
			Lower Coal Member (Bowie Shale)										
			Rollins Sandstone										0.18 m/s [a]
			Cozzette Member										
			Corcoran Member										
			Upper Sego Sandstone										
Mississippian			Leadville Limestone							0.1 - 1000 ft^2/d			
Devonian			Dyer Dolomite										
			Parting Formation										

** Hard copy of report currently not in hand

[a] Values sited in Table 6.1 in Papadopulos and Associates Draft Report titled
Coalbed Methane Stream Depletion Assessment Study-Piceance Basin CO, 2007

Appendix B - Thickness

Period	Epoch	Formation	Members	Brooks and Ackerman, 1985 Lower Gunnison River basin	Brooks, 1983 Cedaredge and Paonia, Delta Co, CO	Hettinger and Kirschbaum, 2002 Southern part of Piceance Basin	Cordilleran Compliance Services, 2002 Cedaredge and Paonia, Delta Co, CO	URS, 2006 Mamm Creek, Garfield Co, CO, near Rifle	Freethey and Cordy, 1991 Vicinity of Cedaredge and Paonia, Delta County, CO	Donnell, 1957 Piceance Creek Basin	Duncan and Besler, 1950 Piceance Creek Basin	Environmental Assessment on Oil Shale Research, Development and Demonstration bt Shell Frontier Oil and Gas Rio Blanco Co, CO	Coffin, Welder and Glanzman, 1971 Piceance Creek structural basin between the White and Colorado Rivers	Donnell, 1969 Southern part of Piceance Creek Basin	Topper, R.; Spray, K.L.; Bellis, W.H.; Hamilton, J.L.; Barkmann, P.E. Piceance Basin	Geldon, 1989 Glenwood Springs, northwestern Colorado	Glover, Naftz, Martin, 1998 Upper Colorado River basin	MacLachlan and Welder, 1987, in Taylor Near Yampa River
Quaternary		Alluvium											0 - 140					
			Steven Gulch alluvium															
			Unconsolidated Quaternary deposit	100	200			12-100										
			Gunnison River alluvium	<100 - 200														
			White River alluvium															
Tertiary	Miocene	Basalt flows		200														
	Oligocene	West Elk volcanic field																
	Eocene	Uinta Formation										120			0 - 1400		Upper Piceance aquifer (until Mahogany Zone) Lower Piceance Aquifer until Garden Gulch	
		Green River Formation	Main body	1000						3500	3500							
			Evacuation Creek Member								1000		0 - 1250					
			Parachute Creek Member								400 - 1680	Upper aquifer is 500ft, lower is 600	500 - 1800		500 - 1800			
			Garden Gulch Member								400 - 1020	700	0 - 900		0 - 900			
			Douglas Creek Member								70 - 760	800	0 - 800		0 - 900			
			Lower Sandy Member (Anvil Points Member)								1875		0 - 1870		0 - 1870			
	Paleocene	Wasatch Formation	Total body					1800 - 5500				5500						
			Shire Member	1000	1000			up to 5000		5500	3400 - 5200		300 - 5000	600 - 1800	5000			
			Molina Member					300 - 1200						0 - 500				
			Atwell Gulch Member											700 - 1850				
		Ft. Union Formation		NA											Very thin			
Cretaceous	Upper	Mesaverde Group Williams Fork Formation	Total body	3000					7000						Averages 3000, may be >7000			
			Ohio Creek Member			50 - 400	500 - 900											
			Barren Member (undifferentiated Member)		500	2000 - 4000	750 - 1000											
			Upper Coal Member (Paonia Shale)		600	560	180 - 270											
			Lower Coal Member (Bowie Shale)			680 - 1000	260 - 330											
		Iles Formation	Rollins Sandstone		150 - 200	0 - 200	80 - 200											
			Cozzette Member		NA	<230												
			Corcoran Member		NA	100												
			Upper Sego Sandstone		NA	100												
	Lower	Mancos Shale	Anchor Mine Tongue			430												
	Upper	Mesaverde Group	Lower Sego Sandstone			100												
			Castlegate Sandstone			0 - 90												
	Lower	Mancos Shale	Main body	4500	3500+	3450 - 4150			7000						>7000			5700
	Lower	Dakota Group	Total body						200									
			Dakota Sandstone	350					0 - 200									100
			Cedar Mountain Formation						130									up to 200
Jurassic	Upper		Morrison Formation	600														Up to 650
			Redwater Member															70 - 300
	Middle		Curtis Member															Up to 25
			Entrada Sandstone	150														up to 150
			Carmel Formation															60
Triassic	Upper		Glen Canyon Formation															625+
			Chinle Formation	100														290+
		State Bridge Formation	Moenkopi Formation															Up to 560
Permian			Park City Formation													103		110 - 150
			Weber Sandstone													79		900+
			Maroon Formation													2376		
Pennsylvanian			Minturn Formation													1239		
			Eagle Valley Formation													80 - 3100		
			Belden Formation													604		
			Molas Formation													0 - 50		
Mississippian			Leadville Limestone													187		
Devonian			Dyer Dolomite													90		
			Parting Formation													66		
Ordovician			Manitou Dolomite													154		
Cambrian			Dotsero Formation													91		
			Sawatch Quartzite													268		
Precambrian		Unita Mountain Group																
		Granitic Rocks														24000		
		Metasedimentary Rocks																

Appendix F

White and Colorado Rivers Water Supply Alternatives

Memorandum

To: Joint Energy Water Needs Subcommittee
cc:
From: Shaden Musleh and Ben Harding
Subject: White and Colorado Rivers Water Supply Alternatives
Date: December 27, 2010

This Technical Memorandum documents the water supply alternatives that have been evaluated as part of Task 5 of the Energy Water Needs Assessment Phase II Study (Study). The Energy Development Water Needs Assessment is being conducted by the Energy Subcommittee of the Colorado, Yampa and White River Basin Roundtables (Subcommittee) as part of the Colorado Water for the 21st Century (HB-1177) water supply planning process.

White River Water Supply Projects

Working with the Energy Subcommittee, AMEC identified four water supply projects in the White River basin (shown in Table 1). These four projects were evaluated to see if they would be sufficient to meet an annual demand of 110,000 acre-feet. The 110,000 acre-feet is the total annual demand calculated in Task 2 for in-situ retorting, high production, long-term scenario in the White River Basin. We used the State of Colorado's Stream Simulation Model (StateMod) developed by the Colorado Water Conservation Board to model the impact of the annual demand of 110,000 acre-feet on water supply. StateMod is an allocation and accounting model that allows for comparisons between various historic and future water management policies, e.g., administration of water rights, to be made in a river basin.

StateMod can be run using a monthly or daily time step. StateMod allocates the river water among model nodes (representing ditches, reservoirs, river confluences, etc.) based upon priority, capacity, physical supply, and demand. In the StateMod model, the 110,000 acre-feet was assumed to occur in every year from 1909 through 2006. This 110,000 acre-feet was disaggregated in the model equally among the 12 calendar months in every year, i.e. 9,167 acre-feet in each month from 1909 through 2006.

Table 1. Selected White River Water Supply Projects

Water Supply Project	Description
Lake Avery Enlargement Filled From Big Beaver Creek.	Location: Off stream of White River on Big Beaver Creek Water Supply: Big Beaver Creek. Capacity: 48,274 acre-feet Modeled Priority: 2010 Operation Assumptions: water released from Lake Avery would run downstream using the White River channel to the confluence of Piceance Creek and White River and then pumped up to the Piceance Creek Basin to meet in-situ retort demand.
Lake Avery Enlargement Filled From White River.	Location: Off stream of White River on Big Beaver Creek Water Supply: White River. Capacity: 48,274 acre-feet Modeled Priority: 2010 Operation Assumptions: water released from Lake Avery would run downstream using the White River channel to the confluence of Piceance Creek and White River and then pumped up to the Piceance Creek Basin to meet in-situ retort demand.
Wolf Creek Reservoir	Location: On the White River or off-stream of White River on Wolf Creek Water Supply: White River Capacity: 162,400 acre-feet (total decreed capacity for three conditional storage rights owned by the Colorado River Water Conservation District) Modeled Priority: 2010 Operation Assumptions: water released from Wolf Creek Reservoir would be either (1) exchanged up to the confluence of Piceance Creek and White River and then pumped up to the Piceance Creek Basin to meet in-situ retort demand, or (2) pumped directly from Wolf Creek Reservoir to Piceance Creek Basin to meet in-situ retort demand.
New Diversion	Location: Confluence of Piceance Creek and White River Water Supply: White River Capacity: 165.05 cfs Modeled Priority: 2010 Operation Assumptions: water diverted by this diversion would be pumped up to Piceance Creek Basin to meet in-situ retort demand.

White River Water Supply Modeling Scenarios

The following water supply scenarios have been evaluated. All these scenarios were simulated over a 98 year period from 1909 through 2006 using a monthly time step. We note that in all the scenarios presented in this section, we tested to see if Wolf Creek Reservoir would be need to fully meet the 110,000 acre-feet demand after the supplies from the New Diversion and Lake Avery Enlargement have been exhausted. Based on our modeling analysis, Wolf Creek Reservoir was not used to meet the demand under any of the tested scenarios described herein. However, Wolf Creek Reservoir could be used instead of Lake Avery Enlargement to meet the 110,000 acre-feet demand in the White River Basin.

Scenario 1 - Low water use/Initial water supply Scenario. This scenario uses the following supplies: (1) Lake Avery Enlargement filled in priority from Big Beaver Creek , and 2) a New Diversion from the White River located at the confluence of Piceance Creek and White River. For this scenario, it was assumed that Lake Avery enlargement would be filled using a 2010 priority with a storage capacity of 48,274 acre-feet and that the New Diversion would be filled using a 2010 priority and 165.05 cfs diversion rate. The 165.05 cfs diversion rate was used to ensure that this New Diversion <u>alone</u> can divert sufficient water to meet the 9,167 acre-feet monthly demand in any month. The 48,274 acre-feet storage capacity is the storage capacity for Lake Avery Enlargement as proposed in a study conducted by the International Engineering Company (1983). This study proposed feasible water supply alternatives for energy development in the White River Basin by evaluating information such as cost, engineering design, water supply, water rights and water demands.

This modeling scenario was designed so that for each month the demand would be first met by the New Diversion. Then, if the 9,167 acre-feet monthly demand is not fully satisfied, the deficit would be met by release from Lake Avery enlargement filled from Big Beaver Creek.

Scenario 1 Modeling Results: the results for this modeling scenario show that the 110,000 acre-feet annual demand couldn’t be fully met in every year from 1909 through 2006, specifically in dry periods such as in 1977, 1978, 2003 and 2004. Therefore, the annual demand was gradually reduced to determine the maximum annual demand that can be fully met under this scenario in every month from 1909 through 2006. We found that the available supply under this scenario can only meet 104,000 of the 110,000 acre-feet per year (an annual shortage of 6000 acre-feet). Figure 1 shows the simulated end-of-month content for Lake Avery Enlargement, simulated monthly diversions by the New Diversion and the maximum available supply (8,667 acre-feet) from both the New Diversion and release from Lake Avery Enlargement from 1909 through 2006.

The following are the supplies used to meet the 104,000 acre-feet maximum annual demand (8,667 acre-feet/month) in a descending order as simulated in the StateMod model: (1) a New Diversion from the White River located at the confluence of Piceance Creek and White River, (2) Lake Avery Enlargement filled in priority from Big Beaver Creek.

Scenario 2 - Multiple Supplies, Junior rights, unlimited diversion from White River to Lake Avery. Three water supply projects were simulated at the same time: (1) a New

Diversion from the White River located at the confluence of Piceance Creek and White River, and (2) Lake Avery Enlargement supplied directly from Big Beaver Creek, and (3) Lake Avery Enlargement supplied from White River via a very large pipeline (1677 cfs[1]). In this scenario, the flow from the White River to Lake Avery Enlargement is only limited by the storage capacity and the 2010 priority of Lake Avery Enlargement. The purpose of this modeling scenario is to determine if the 110,000 acre-feet per year annual demand (9,167 acre-feet per month) can be fully met by the above supplies in every month from 1909 through 2006. The model for this scenario was designed so that the demand in each month is first met by the New Diversion. Then, if the demand in any month is still not fully met, the deficit would be met by release from Lake Avery Enlargement.

The following are the supplies tested to meet the 110,000 acre-feet annual demand (9,167 acre-feet/month) in a descending order as simulated in the StateMod model: (1) a New Diversion from the White River located at the confluence of Piceance Creek and White River, (2) Lake Avery Enlargement filled in priority from Big Beaver Creek and via a pipe from White River with a diversion capacity of 1,677 cfs.

Scenario 3 - Multiple Supplies, Junior rights, 100 cfs diversion from White River to Lake Avery Enlargement. This scenario is identical to Scenario 2 with the exception of restricting the flow rate from the White River to Lake Avery Enlargement to 100 cfs. The 100 cfs flow rate represents a feasible flow rate for a pipe and a pumping station and at the same time large enough to ensure that meeting the 110,000 acre-feet annual demand is not physically restricted.

The following are the supplies used to meet the 110,000 acre-feet annual demand (9,167 acre-feet/month) in a descending order as simulated in the StateMod model: (1) a New Diversion from the White River located at the confluence of Piceance Creek and White River, (2) Lake Avery Enlargement filled in priority from Big Beaver Creek and via a pipe from White River with a diversion capacity of 100 cfs.

Scenarios 2 and 3 Modeling Results: the modeling results for Scenarios 2 and 3 show that the New Diversion and Lake Avery Enlargement (supplied from Big Beaver Creek and White River) are sufficient to fully meet the 110,000 acre-feet and that Wolf Creek Reservoir is not needed in any month from 1909 through 2006 even if the flow from the White River to Lake Avery Enlargement is restricted to 100 cfs. Figures 2 and 3 show the modeling results for Scenarios 2 and 3, respectively. Each figure shows end-of-month simulated content for Lake Avery Enlargement, end-of-month simulated content for Wolf Creek Reservoir, in priority diversions by the New Diversion, and the monthly demand (9,167 acre-feet) met from 1909 through 2006.

Conclusions

Given the modeling results described above, it appears that in-situ water demand for the high production, long-term scenario in the White River Basin can be fully met in every month during average and wet periods but not during dry periods using the following

[1] Maximum historical flow rate recorded at an upstream gauge.

example supplies (1) a junior diversion from the White River located at the confluence of Piceance Creek and White River, and (2) a junior storage right in Lake Avery Enlargement from Big Beaver Creek. In some months during dry periods, the above supplies alone would not be sufficient and therefore would have to be supplemented by a junior storage right in Lake Avery Enlargement from the White River in order to fully meet the water demand for in-situ retorting.

This study didn't look at all possible water supply projects and water management scenarios that can be used to meet the 110,000 acre-feet demand in the White River Basin. This study only looked at some example projects to see if the 110,000 acre-feet can be met and concluded that there is a sufficient water supply in the White River Basin to meet the 110,000 acre-feet annual demand. The 110,000 acre-feet can be met by many combinations of other water supply projects that were not tested in this study.

In conducting this assessment, we relied on the water rights database developed in Phase I of the study (URS, 2008) and CDSS supplemented by the information available in WRT (2010).

Colorado River Water Supply Projects

Working with the Subcommittee, AMEC identified seven water supply projects in the Colorado River basin (shown in Table 2). These seven projects are described in Exxon Mobil's water rights application in Case No. 08CW199. In this water right application, Exxon Mobil seeks to change the place of use of the water rights in Table 2 which would divert from the Colorado River and Parachute Creek. The waters diverted under these rights would be used in the Piceance Creek and Yellow Creek basins. These water rights were modeled using their conditional water rights limits, priorities and decreed locations as described in the Exxon Mobil's water rights application and the Colorado StateMod Model. The decreed locations of these water rights are shown in Figure 5.

Table 2. Selected Colorado River Water Supply Projects

Water Supply Project	Description
Dow Pumping Station	Location: On stream of Colorado River, Section 6, Township 7S, Range 95 West, 6th P.M. Water Supply: Colorado River. Capacity: 94.8 cfs Modeled Priority: January 24, 1955
Dow Middle Fork Pipeline	Location: Middle Fork of Parachute Creek, Section 31, Township 4S, Range 95 West, 6th P.M. Water Supply: Parachute Creek Capacity: 1.088 cfs Modeled Priority: October 20, 1954
Dow East Middle Fork Pipeline	Location: East Middle Fork of Parachute Creek, Section 10, Township 5S, Range 95 West, 6th P.M. Water Supply: Parachute Creek Capacity: 13.54 cfs Modeled Priority: October 19, 1954
Middle Fork Reservoir	Location: Middle Fork of Parachute Creek, Section 6, Township 9S, Range 95 West, 6th P.M. Water Supply: Parachute Creek Capacity: 171.622 acre-feet, 1438.378 acre-feet (enlargement) Modeled Priorities: September 17, 1959, September 30, 1974 (enlargement)
Davis Gulch Reservoir	Location: Davis Gulch of Parachute Creek, Section 12, Township 5S, Range 96 West, 6th P.M. Water Supply: Parachute Creek Capacity: 204 acre-feet, 996 acre-feet (enlargement) Modeled Priorities: September 15, 1959, September 30, 1974 (enlargement)
East Middle Fork Reservoir	Location: East Middle Fork of Parachute Creek, Section 15, Township 5S, Range 95 West, 6th P.M. Water Supply: Parachute Creek Capacity: 130.558 acre-feet Modeled Priority: September 17, 1959
Lower East Middle Fork Reservoir	Location: East Middle Fork of Parachute Creek, Section 18, Township 5S, Range 95 West, 6th P.M. Water Supply: Parachute Creek and Colorado River Capacity: 6200 acre-feet Modeled Priority: February 2, 1982

Colorado River Water Supply Scenario

A firm yield analysis scenario was simulated using the Colorado StateMod Model and a monthly time step to see if Exxon Mobil's water rights (Table 2) would be sufficient to meet an annual demand of 10,000 acre-feet. The 10,000 acre-feet is the total annual demand calculated in Task 2 for above ground retorting, high production, long-term scenario in the Colorado River Basin. For this modeling scenario, the 10,000 acre-feet was assumed to occur in every year from 1909 through 2005. The 10,000 acre-feet was disaggregated in the model equally among the 12 calendar months in each year from 1909 through 2005, i.e. 833 acre-feet per month.

Lower East Middle Fork Reservoir is the largest reservoir in Exxon Mobil's water rights application. Given also that Lower Middle Fork Reservoir is located relatively downstream of the other Exxon Mobil's diversion and storage structures in Parachute Creek, Lower East Middle Fork Reservoir was modeled as a forebay, i.e. water diverted by Dow Middle Fork Pipeline, Dow East Middle Fork Pipeline, Middle Fork Reservoir, Davis Gulch Reservoir and East Middle Fork Reservoir was assumed to be released and stored in Lower East Middle Fork Reservoir before it is delivered to supply oil shale development.

This modeling scenario was designed so that in any month demand would be first met by Dow Pumping Station diversion. If Dow Pumping Station diversion is not fully sufficient, the remaining deficit would be met by release from Lower East Middle Fork Reservoir.

Conclusions

The results for the Colorado River firm yield analysis scenario are shown in Figure 6. Based on these modeling results, it appears that the10,000 acre-feet annual demand for above ground retort in the Colorado River Basin could be fully met in every month from 1909 through 2005 using in priority diversions by Exxon Mobil's water rights shown in Table 2 including in dry periods.

Another modeling scenario was simulated in which Dow Pumping Station diversions would also be stored in Lower Middle Fork Reservoir. The water available under this modeling scenario (results are not shown in this memorandum) would also be sufficient to fully meet the 10,000 acre-feet annual demand in every month from 1909 through 2005, including dry periods.

This study didn't look at all possible water supply projects and water management scenarios that can be used to meet the 10,000 acre-feet demand for above ground retorting in the Colorado River Basin. The 10,000 acre-feet can be met by many combinations of other water supply projects that were not tested in this study.

General Note

The impact of climate change has not been considered in any of the modeling scenarios described in this memorandum.

References

Exxon Mobil Corporation (2008). An Application for change of Water Rights and Approval of Plan for Augmentation. Case No. 08CW199.

Wright Water Engineers (WWE). (2010). An Engineering Report to Support the Application by Exxon Mobile Corporation in Case No. 08CW199, July, 2010.Th

International Engineering Company (IEC). (1983). White River Study, December, 1983.

Colorado's Decision Support Systems (CDSS), Water Rights Transactions, http://cdss.state.co.us/DNN/WaterRights/tabid/76/Default.aspx.

URS Corporation (URS). (2008). Appendix A-1 of the Phase I Report Received From Jared Walter.

Water Rights Tabulation (WRT). (2010). Colorado Division of Water Resources, July 1, 2010.

White River StateMod Model, version 12.201, http://cdss.state.co.us/DNN/Products/SurfaceWaterModel/tabid/69/Default.aspx.

Colorado River StateMod Model, version 11.50, http://cdss.state.co.us/DNN/Products/SurfaceWaterModel/tabid/69/Default.aspx.

Figure 1: Results for White River Scenario 1

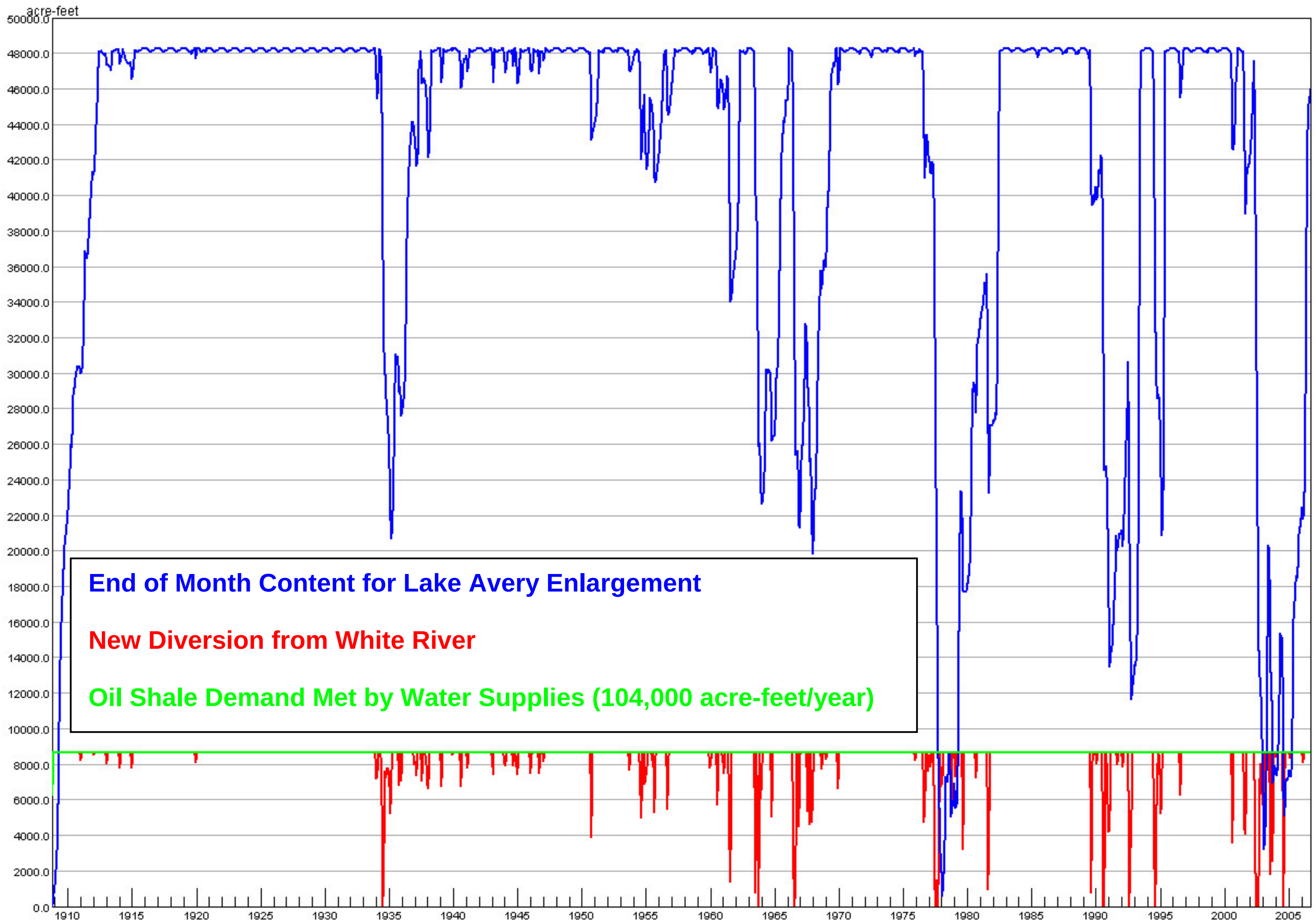


Figure 2: Results for White River Scenario 2

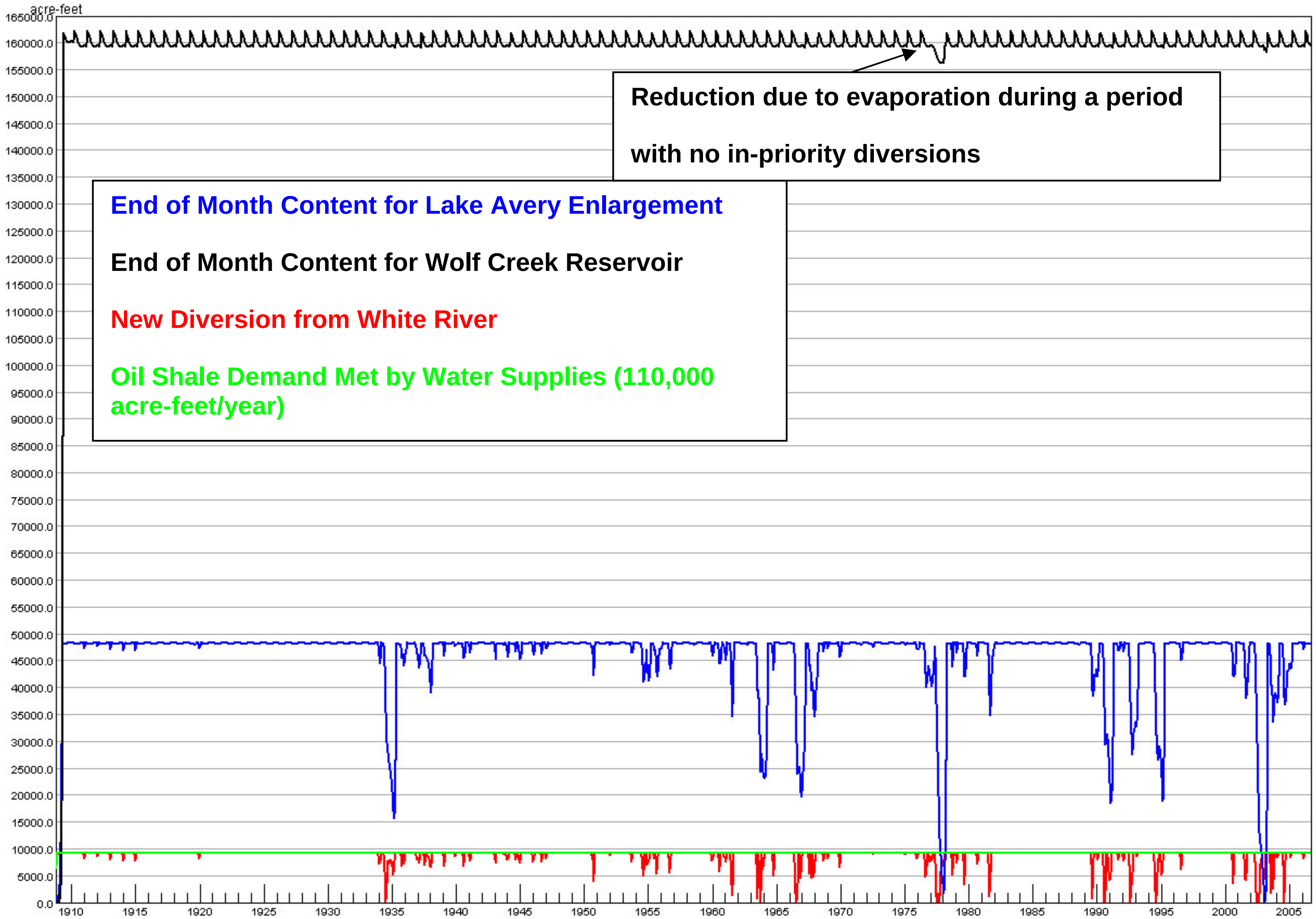


Figure 3: Results for White River Scenario 3

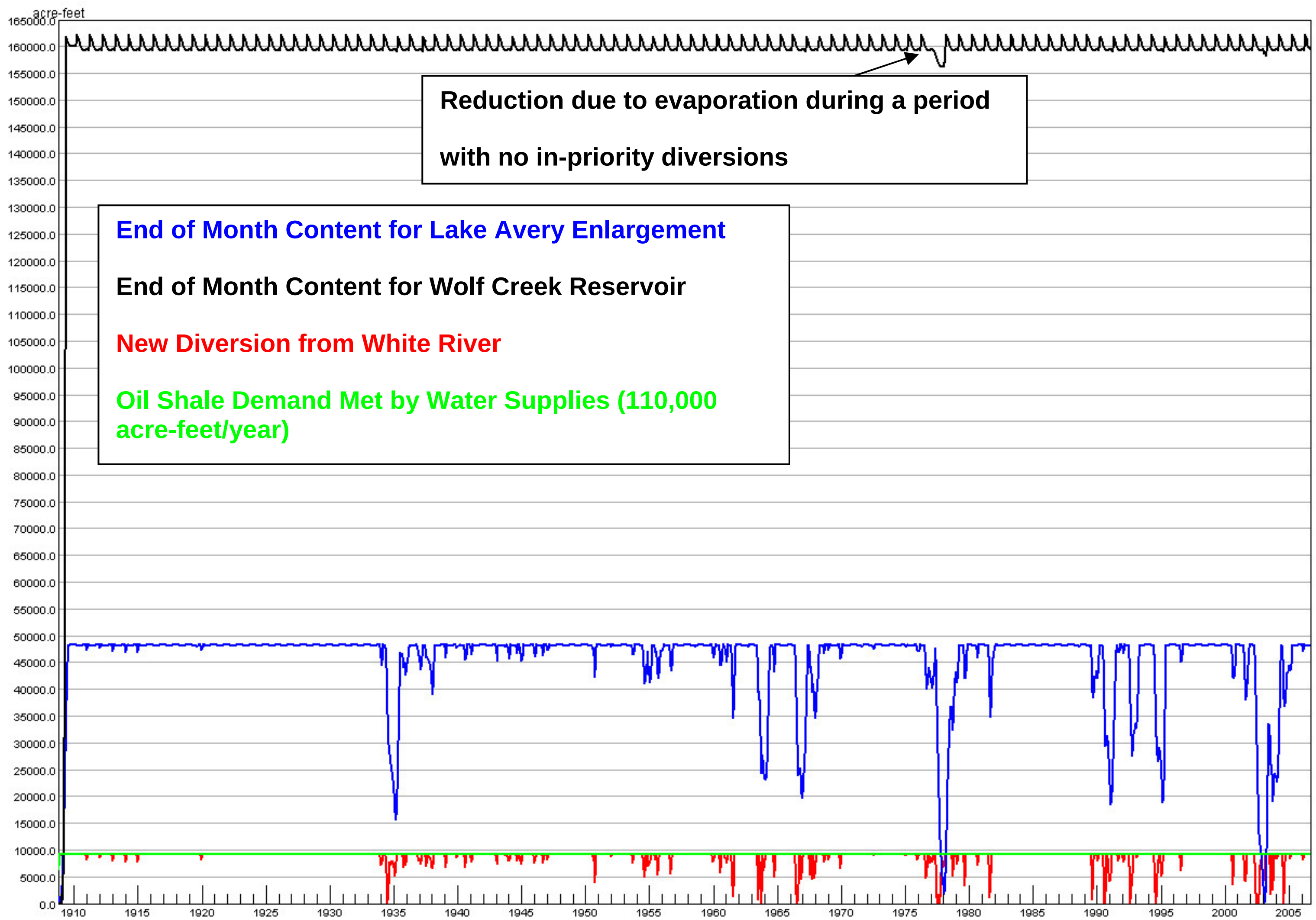
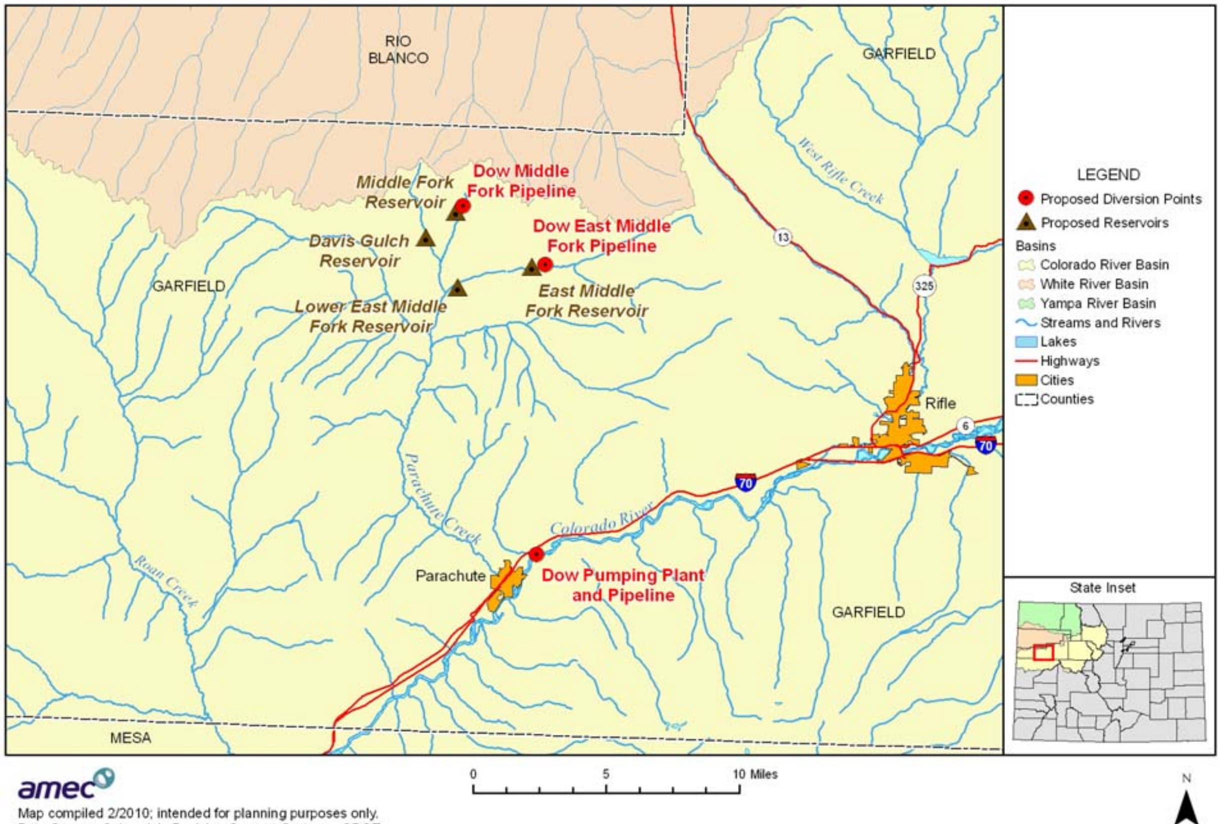


Figure 4

Proposed Diversion Points & Reservoirs by Exxon Mobil (Case NO. 08CW199)



Map compiled 2/2010; intended for planning purposes only.
Data Source: Colorado's Decision Support Systems, CDOT, Application for Case NO. 08CW199

Figure 5: Results for Colorado River Scenario