Evaluation of Energy Efficiency, Water Requirements and Availability, and CO_2 Emissions Associated With the Production of Oil & Gas From Oil Shale in the Piceance Basin of Western Colorado, Based on Shell's In-Situ Conversion Process (ICP)

F. Dexter Sutterfield, Ph.D., INTEK Inc.
Peter M. Crawford and Jeffrey Stone, INTEK Inc.
James C. Killen, United States Department of Energy

I. Summary

A detailed description of background information, the purpose of this paper, methodologies and major assumptions, and results are provided below, beginning with Section II. A summary of this information follows:

The United States has been endowed with vast oil shale resources in the Green River Formation in Colorado, Utah and Wyoming, about three-fourths of which are located on public lands. Green River resource estimates are approximately 4.3 trillion barrels of shale oil, about 800 billion barrels of which are potentially economic to recover -- or about 3 times Saudi Arabia's proved reserves. The economic potential of these resources is enormous; but environmental and social risks are substantial too. There has been an enormous research and development effort over the past several decades to commercialize oil shale production, but so far these efforts have not been successful. Appropriate public policies are still being debated, with the primary concerns being environmental impacts, social acceptability, and putting pubic policies in place that make it possible for investors to assess economic and compliance potential, as needed to ensure sound investment decisions. One of the obstacles of bringing the ongoing debate to a logical conclusion has been the lack of accurate and up to date scientific information, and especially information pertaining to energy efficiencies, water requirements and availability, and CO_2 emissions associated with a fully developed commercial oil shale industry.

Approximately 1.5 trillion barrels of the Green River Formation resources are located in the Piceance Basin in Colorado. The Piceance also has the highest concentrations of very high quality resources, and, as such, it represents "the prize" in terms of Green River economic potential. From the standpoint of environmental impact and social acceptability, the most challenging area of the Piceance Basin is an approximate 60 percent portion where very high quality oil shale resources and potentially useful ground water co-exist. In these zones, energy intensive technologies are needed to protect against groundwater intrusion and to protect water quality, thus decreasing energy efficiency, and increasing water requirements and CO_2 production.

The purpose of this paper is to provide the public and policy makers accurate estimates of energy efficiencies, water requirements, water availability, and CO_2 emissions associated with the development of the 60 percent portion of the Piceance Basin where economic potential is the greatest, and where environmental conditions and societal concerns and controversy are the most challenging: i.e., the portion of the Piceance where very high quality oil shale resources and useful ground water co-exist.

The evaluations presented are based on the following methodologies and major assumptions:

- Four cases were evaluated:
  -- Water cooled power plants (with and without CO_2 capture and beneficial CO_2 use or disposal: e.g., CO_2 enhanced oil recovery (CO_2 Capture/ CO_2 EOR); and
  -- Air cooled power plants (with and without CO2Capture/ CO2EOR).
- Shell's In-Situ Conversion Process (ICP) technology.
- Natural Gas Combined Cycle (NGCC power) plants fired with natural gas.
- Use of all produced natural gas for power generation, with the balance purchased from within the region (therefore, no electric power generation from outside the region).

- All of the water needed for shale oil processing is obtained from two rivers (the White River and the Colorado River) in the Colorado River Basin.
- Only minimal upgrading is required, to be accomplished with natural gas (and, therefore, no water required for upgrading).
- All produced water is separated, treated, and used for oil shale processing; thus reducing the net amount of water needed from the Colorado River Basin.
- In carbon capture cases, all captured CO_2 is beneficially utilized (e.g., for enhanced oil recovery), and thus is not emitted to the atmosphere.
- In non-carbon capture cases, all CO_2 production emitted to the atmosphere.

From the standpoint of adverse environmental impacts, the methodologies employed and the major assumptions used have led to results that the authors consider to be moderately conservative: i.e., it is more likely that adverse environmental impacts have been overstated than understated.

Results are summarized in Table 1 below. Note that no attempt has been made to determine shale oil production rates. Production rate scenarios from previous studies range from 250,000 to 1.5 million barrels of shale oil per day for the entire Piceance Basin. Water requirements and CO_2 emissions are in units per barrel of shale oil produced, and thus are proportional to production rate.

Table 1 -- Summary of Results

Case	EROI Energy Out – Energy In / Energy In	CO_2 Emissions (Metric Tonnes/Bbl of Shale Oil Produced)	Water Requirements (Bbls of Water/Bbl of Shale Oil Produced)	Water Requirements in Percent (%) of Average Daily Colorado River Basin Flows At Shale Oil Production Rates of:			
				250,000 Bbls/Day	500,000 Bbls/Day	1,000,000 Bbls/Day	1,500,000 Bbls/Day
1-Water Cooled w/o CO_2 Capture/ CO_2EOR	3.5	0.1635	2.6	1.0	2.0	4.0	5.9
2-Water Cooled w/ CO_2Capture/ CO_2EOR	2.5	0.0184	4.0	1.5	3.1	6.1	9.2
3-Air Cooled w/o CO_2Capture/ CO_2EOR	2.8	0.1762	1.2	0.5	0.9	1.8	2.7
4-Air Cooled w/ CO_2 Capture/ CO_2EOR	2.1	0.0198	2.5	1.0	1.9	3.8	5.7

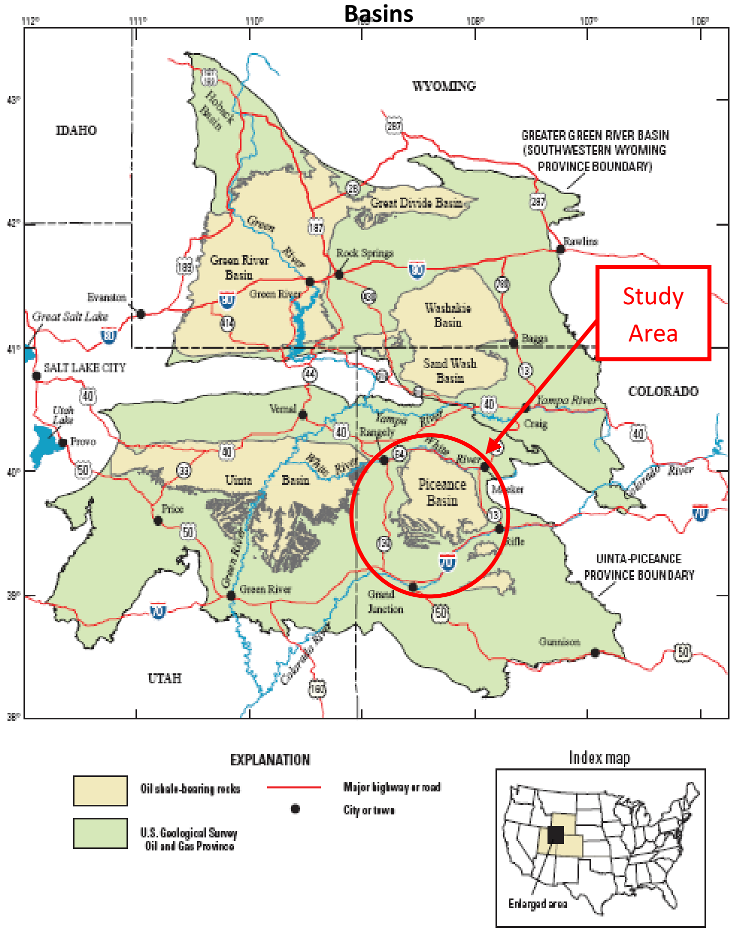
Note that first production in the Piceance Basin is likely to occur in lower geologic zones where technical, environmental and social concerns related to groundwater do not appear to be as challenging as in zones (containing ~60 percent of the Piceance Basin oil shale resources) where groundwater intrusion presents greater challenges. From this it follows that Piceance production from the unanalyzed 40 percent portion most likely would result in higher energy efficiencies, and lower water requirements, and slightly higher CO_2 emissions than reported in Table 1.

II. Background

The Green River Formation in Colorado, Utah, and Wyoming (see Figure 1), more than two thirds of which is located on Federal lands,[1] contains approximately 4.3 trillion barrels of shale oil resources[2], of which approximately 800 billion barrels may be recoverable[3], based on current economic conditions.

This is an enormous United States resource (approximately 3 times that of Saudi Arabia conventional crude oil reserves[4]) that has enormous economic potential in terms of contributions to gross national product; job creation/reducing unemployment; contributing to a more favorable trade balance; reducing the national debt; and reducing the United States' reliance on crude oil imports from foreign countries that are unfriendly or unstable. If fully developed, this resource could be a secure source of domestically produced fuels for over 100 years at the current crude oil consumption rate of 19.5 million barrels per day.[5] Notwithstanding these benefits, the risks are also substantial.

Figure 1: Extent of Uinta, Piceance and Greater Green River Basins



Production of oil from oil shale is more carbon intensive than from contemporary conventional crude oil, which could contribute to global climate change; oil shale processing would result in other emissions that could have an adverse impact on regional air and ground water quality; large quantities of water would be needed to process oil shale, in a region where water is at a premium; surface disturbances would be significant, thus posing biological risks. The oil shale industry would be subject to the same kinds of swings in the business cycle that apply to the petroleum industry as a whole, posing certain societal risks.

It does not appear that oil shale risks are any different than those posed by many other industries that are operating successfully, and safely, today. Given this, and given the economic potential, there has been an enormous effort over the past several decades to bring Green River shale oil to market. Thus far these efforts have not been successful. In the early years, the primary obstacle was one of economics. Crude oil prices were low, and the technologies being utilized were less efficient, expensive to build and operate, and highly water consumptive. With the drastic increases in oil prices over the past 5-10 years, as well as significant technological advances, the economic hurdle is now much lower. As of late, the primary concerns have been environmental impact and social acceptability; as well as the challenges of financing the research and development needed to overcome environmental and social obstacles, and to finance the processing, transportation, and other infrastructure that would be required for full scale commercial development.

Because most of the required capital for industry development would need to come from the private sector, two essential investment conditions must be met. First, investors would need to have confidence that oil shale technologies are technically viable, economic and environmentally compliant. Second, applicable laws and regulations would need to be in place so investors could make sound judgments on economic and compliance potentials, and especially those pertaining to environmental requirements and access to resources on public lands.

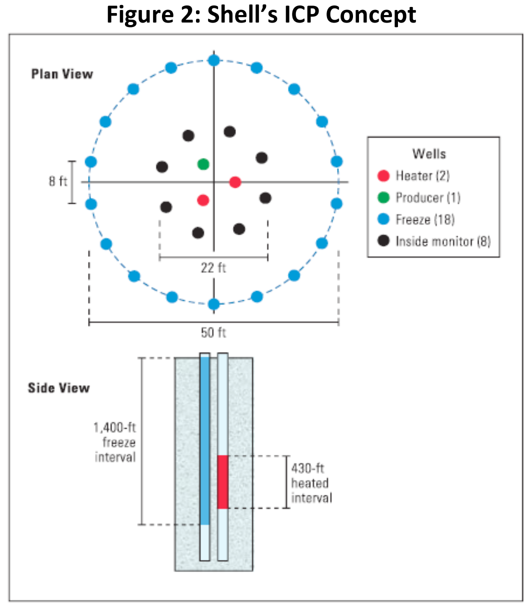
In recognition of this, in 2008 the Department of Interior (DOI) released regulations that were intended, at the time, to govern commercial oil shale development and operations. Since then, however, a public debate has ensued over the environmental and social acceptability of these regulations, and, as a result, DOI is re-engaging various processes in order to work through the issues at hand.

One of the biggest obstacles to bringing the public policy debate to a logical conclusion has been the lack of reliable scientific information with regard to energy efficiency, water requirements, and CO_2 emissions associated with a fully developed oil shale industry. During the past decade, a number of have attempted to address this short-coming, bust have been hampered by assumptions that were too wide ranging or insufficient information about current and emerging technologies and economics. In our view, this has contributed to bogging down and impeding the ongoing public policy debate.

Implementation of strategies and technologies such as air cooled power plants and carbon capture with beneficial re-use or storage can reduce water requirements and CO_2 emissions significantly, if the accompanying energy penalties could be tolerated from the standpoint of economics In the opinion of the authors, policy makers need more precise and up to date information on energy efficiencies, water requirements, and CO_2 emissions, including how these parameters would be affected using air cooling instead of water cooling, and with and without CO_2 capture/ CO_2 EOR.

The authors believe that there is sufficient basic oil shale information in the public domain that, together with the application of good engineering practices, makes it possible to determine with some precision what kind of energy efficiencies, water requirements and CO_2 emissions could be expected from a fully developed oil shale industry. With this information policy makers should be able to put policies in place that would make it possible for investors to make sound judgments on whether or not, and to what degree and pace, they should invest to further develop/perfect their respective technologies.

Figure 2: Shell's ICP Concept



^ Shell freeze wall isolation test. Using a technique dating to the 1880s, Shell constructed a circular freeze wall 1,400 ft [430 m] deep by circulating coolant in 18 freeze wells for 5 months. A 430-ft [130-m] interval of the enclosed formation was then heated to generate shale oil. The test verified that the freeze wall could confine produced fluids.

Because the Piceance Basin in Colorado contains approximately the richest and most concentrated oil shale resources in the Green River Formation, the basin shares both a large measure of the economic potential of oil shale, as well as the associated environmental and social risks and controversy associated with domestic oil shale industry development. Accordingly, the Piceance Basin has been chosen as the focal point to begin to address more precise and up to date analytics.

The vast majority of the oil shale resources in the Piceance Basin is best suited to the application of an in-situ technology. Very little of the resource is near surface or economically viable for mining and surface retort technologies. Because Shell's In-Situ Conversion Process (ICP) technology (see Figure 2) was the only in-situ process of its kind with sufficient technical information available in the public domain at the time this analysis was initiated it has been chosen by the authors as the analytical basis for this paper.

The most significant risks to the environment within the

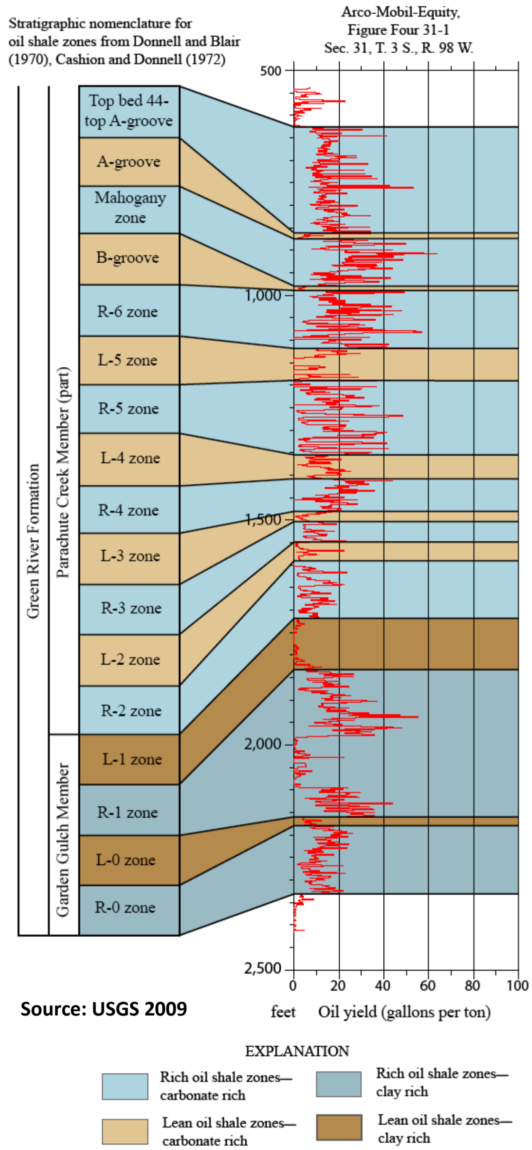
Piceance are in the areas where high quality oil shale resources are co-exists with ground water, which is undesirable for both process and environmental reasons. In these zones, Shell has proposed and demonstrated the use of impenetrable freeze walls (by freezing the ground water) that would surround and segregate production areas, preventing both groundwater intrusion and groundwater contamination during shale heating and production. These freeze walls require additional power to create and maintain which, in turn, reduces energy efficiency, increases CO_2 emissions and increases water requirements. Accordingly, areas within the Piceance with high quality groundwater, where the construction of freeze walls would be required, represent the greatest environmental and social challenge. It is these areas that have been chosen for evaluation in this paper. The units of the Piceance where high quality oil shale and ground water co-exist are the Mahogany, the R-6, the R-5, and the R-4 (Figure 3). Together these units contain approximately 457.5 billion barrels of shale oil resources, approximately 60 percent of the Piceance Basin resource as a whole.

III. Purpose

On the basis of the foregoing, the primary purpose of this paper is to provide the public and policy makers with accurate estimates of regional energy efficiencies, water requirements, and CO_2 emissions associated with the full development of approximately 60 percent of the Piceance Basin, where high quality oil shale and ground water resources co-exist, requiring something like Shell's proposed impenetrable freeze walls for ground water protection; and where oil shale benefits for the United States would be the most prolific, and where associated environmental and social risks have created the greatest concerns and the most controversy.

From this it follows that results reported in this paper may not apply to the approximate 40 percent of the basin where environmental issues appear to be less challenging. Oil shale development in these areas, (which is where Piceance production may begin) most likely would result in higher energy efficiencies and lower water requirements. The higher volumes of carbon dioxide that result from production in the nahcolite and illite oil shale zones must be separated in the gas treatment process to allow the produced hydrocarbon gases to be used in the power plant. A ready market for CO_2 near the Piceance Basin for CO_2 enhanced oil recovery provides an economic incentive to capture, rather than vent, this produced CO_2.

Figure 3: Green River Formation Oil



Source: USGS 2009

IV. Approach: Analytical Basis, Major Assumptions, and Discussion

Table 2 describes the analytical basis and major assumptions upon which the results presented in this paper are based, together with a discussion of each. From the standpoint of the environment, our approach can be considered to be moderately conservative. That is, because the reported results are based on conservative assumptions, they more likely overstate, rather than understate, potential adverse environmental impacts. It is unlikely, in our view, that in-situ oil shale development in the 60 percent portion of the Piceance Basin oil shale resource that was analyzed, would result in water requirements or CO_2 emissions to the atmosphere any greater than those presented herein; nor are energy efficiencies likely to be any less.

Table 2: Analytical Basis, Major Assumptions, and Discussion

	Basis/Major Assumptions	Discussion
1	**Location/Target Formation:** The Mahogany, R-4, R-5, and R-6 units (approximately 60%) of the Piceance Basin, where ground water control would be required, and thus where adverse environmental impacts would be the most severe.	The primary purpose of this paper is to provide the public and policy makers with more precise and up to date energy efficiencies, water requirements, and CO_2 emissions associated with the development of the most environmentally challenging zones of the Piceance Basin, where economic benefits to the United States would be the greatest, and where associated environmental and social risks have created the greatest concern and controversy.
2	**Technology:** • Shell's In-Situ Conversion Process (ICP) technology, or an equivalent technology, using electric heaters for all projects. • 1,270 KBTUs/Bbl of energy required for one barrel of shale oil produced.[6],[7] • Downhole electric heaters to heat the formation. • Freeze walls to control ground water.	ICP is the only in-situ technology with significant information in the public domain; therefore, ICP, or similar technologies are the only technologies upon which this paper could be based. Shell and others are intensely investigating more efficient methods of methods of heating. The authors of this paper believe that full industry development would ultimately employ a variety of technologies and heating methods that, taken together, would be more efficient than electric heaters alone. The heater assumption, therefore, likely understates EROI and overstates environmental impacts.
3	**Energy Return on Investment (EROI):** • Crude Oil Calorific value = 5.8 MM btu/bbl[8] • Produced shale oil calorific value = 5.7 MM btu/bbl .[9] • Produced gas calorific value = ~800 btu/scf after treatment.[10]	ICP using freeze walls for groundwater migration control requires more energy than ICP production in zones isolated from groundwater. Thus, the EROI presented for ICP with freeze wall should represent the lower end of the EROI, (e.g., a conservative estimate) in this basin. To the extent that calorific value or produced shale oil is less than 5.7 MM btu, EROI would be lower.
4	**Power Plant:** • NGCC power plants under four configurations (air cooled versus water cooled, and each with and without carbon capture/ CO_2 EOR). • All natural gas produced would be utilized to generate the necessary electric power. The balance of natural gas required would be purchased from within the region. • 56% power plant efficiency • 46% of power requirements provided by produced natural gas for water cooling options with no CO_2 Capture/ CO_2 EOR.[11] • For CO_2 capture/ CO_2 EOR, 15% increase in electrical load.[12] • Air cooling penalty of 9.48%.[13]	The authors expect that natural gas will be the fuel of choice for power generation. Natural gas is plentiful in the region, it would be produced in large quantities along with the production of shale oil, the cost is modest, and gas has significant well-known and widely-accepted environmental advantages. Absent a game-changing technology development (one that currently is not foreseeable), there is no need to consider any other primary energy source for power for oil shale production other than natural gas. The authors believe that, depending on industry size, some amount of power may need to be generated outside of the region; it is certainly possible that very little or no power would need to be imported at the lower range of industry sizes considered in this analysis. Accordingly, and in order to err on the side caution, it has been assumed that all power will be generated in the region. It is likely that regional water requirements and CO_2 emissions may be overstated.
	Carbon Capture & Sequestration: • In carbon capture cases, it is assumed that all captured CO_2 is utilized beneficially: such as for enhanced oil recovery (EOR), and not emitted. Uncaptured CO_2 is emitted to the	The authors believe that as time progresses, oil prices will continue to rise, making EOR more economic and desirable. If this occurs, the strong CO_2 EOR market that now exists in proximity to the region would expand, potentially allow large quantities of CO_2 to be disposed of without emission

5	atmosphere. • CO_2 sources: Power plant flue gas, and produced gas treatment plant. • Capture approach: Amine separation with 90% efficiency.[14] • Captured CO_2 is compressed from atmospheric to an assumed pipeline pressure of roughly 2000 psi.[15] • The analyses do not address the option of non-beneficial subsurface storage of CO_2. • In non-carbon capture cases, all of the CO_2 produced is emitted to the atmosphere.	to the atmosphere. Policy makers need to know what CO_2 emissions would look like under this potential scenario. For non-carbon capture cases, note that although life cycle CO_2 emissions from oil shale would be greater than that of today's contemporary conventional crude oil, CO_2 emissions associated with crude oils are rising as it becomes harder and harder to find, produce, and transport. Given that full scale oil shale development in the Piceance is at least 15-20 years away, it is not clear to what extent there will be any difference between conventional crude oil and oil shale by that time. It is also noteworthy that oil shale is not as carbon intensive as coal.
6	**Scientific Information:** Information is obtained from sources in the public domain, evaluated or augmented using customary and generally accepted engineering practices.	Oil shale research, development, and demonstration (RD&D) have been underway in the United States for decades. Some of Shell's most critical findings generously have been made available to the public at large. Extensive efforts to commercialize oil shale production outside of the United States have resulted in commercialization, albeit at small scales. The vast information in the public domain, along with customary and generally accepted engineering practices, are sufficient to address the viability of Piceance Basin oil shale resources, and support policy making.
7	**Water Recycling:** All water produced with shale oil and gas, and power plant cooling water is captured, treated, and recycled for re-use; thus reducing the volume of native water that would otherwise be required from the Colorado River Basin; and eliminating the need to otherwise dispose of waste water from these processes.	To the extent that other consumptive and sanitary water is also captured and treated, or water loss from various processes is reduced, our estimate of net water required may be conservative. There are both economic and environmental incentives to maximize water conservation in the Piceance Basin. Environmental regulations generally require water to be treated prior to disposal in any aquifer containing potable water. The industry has considerable experience in cleaning produced and process waters and typically cleans and recycles this water as much as possible.
8	**Water Use:** • Most water use is for the power plant • Other uses: are drilling and freezing, and recovery. • Flushing water is treated and recycled; the net amount of water consumed in flushing is ~1 bbl of water/bbl of shale oil produced.[16] • Water is used in small quantity for a water shift reaction with natural gas to produce hydrogen for upgrading.	The ICP process matures shale oil to a point that little if any upgrading is expected to be required. If upgrading is needed, natural gas would be used to produce hydrogen for hydrotreating due to plentiful gas availability, and the scarcity of water in the region. Natural gas and water requirements for upgrading are a very small portion of the lifecycle energy and water demand: -- Water: Water requirements for upgrading are negligible (~0.1 gal per barrel of shale oil.) -- Natural Gas: 33.54 scf of gas (or 34.2 kBtu) per barrel is needed for upgrading.
9	**Water Sources:** • Colorado River Basin (White River and Colorado River). • Produced water of 0.14 bbls of water/bbl of shale oil produced.[17]	Under the highest water-use scenario, less than 10% of the average combined river flow from the two rivers would be required. Under a more "likely" production rate of 250,000 barrels of shale oil per day[18], the water required would be less than 1.5% of the combined average flows. To the extent that water is sourced from the Yampa River or imported to the basin, the percent of daily flow required would be less.

Production Rates:

The authors do not attempt to project or predict the size of an oil shale industry that may be realized in the Piceance Basin. Estimates vary widely. A recent National Petroleum Council[19] report identified a “likely” case of 250,000 Bbls/day and a “maximum” case of 1,000,000 Bbl/d. In 2007, the Task Force on Strategic Unconventional Fuels[20] evaluated three cases: 0.5 MMBbl/d (Base Case), 1.5 MMBbl/d (Measured Case), and 2.4 MMBbl/d (Accelerated Case). The Task Force’s production estimates include all surface and subsurface technologies in 27 Green River Formation deposits in Colorado, Utah, and Wyoming. Actual production levels will ultimately depend on a range of economic, regulatory, technology, and market factors,. Production will begin at low levels and build to higher rates over a long period of time (probably between 20 to 40 years). Water use and carbon dioxide production will be roughly proportionate to production levels. Thus, the results of the analysis are presented on a “per barrel of shale oil produced” basis or as a percent of water availability.

Scenarios Analyzed

Base Case: Water-cooled Natural Gas Combined Cycle Power Plant without Carbon Capture: Due to the high availability of natural gas in the Piceance Basin area, power generation using natural gas combustion was selected for use in this analysis, relative to other alternatives, such as: coal, coal to gas, wind, etc. This analysis assumes that all production will come from oil shale zones that require isolation from groundwater intrusion and migration by use of a freezewall and remedial flushing (whereas deeper illitic and nahcolite-rich zones may not). The deeper formations can be produced without requiring use of a freeze wall, which would considerably reduce the water consumption. Produced gas from pyrolysis of kerogen in the heated formation fulfills nearly half (~46%) of the power requirement in the natural gas combined cycle (NGCC) fired power plant. Power plant requirements were calculated using a lower heating efficiency for the produced hydrogen rich natural gas.

Air-cooled versus water-cooled NGCC power plant: Air cooling decreases power plant water requirements by about 85% [21] but they employ cooling fans that produce an additional load within the power plant. This extra power load was assumed to be 9.48% based on the work of Zhai, et.al. [22] The difference in water- and air-cooled plants is shown by an increased consumption of energy in the plant itself and is therefore not included in the power going to the ICP process.

With and without carbon capture: Energy and water requirements were calculated with and without carbon capture. The carbon capture results reflect increased power plant external gas consumption and water use to account for the 15% energy penalty for carbon capture from gas-fired plants. Water is required for cooling the hot flue gases before capture of the carbon by an amine system. (Chapel, Zhai) The efficiency of the amine system is very dependent upon the temperature of the amine. Air-cooling of the gases is not practical.

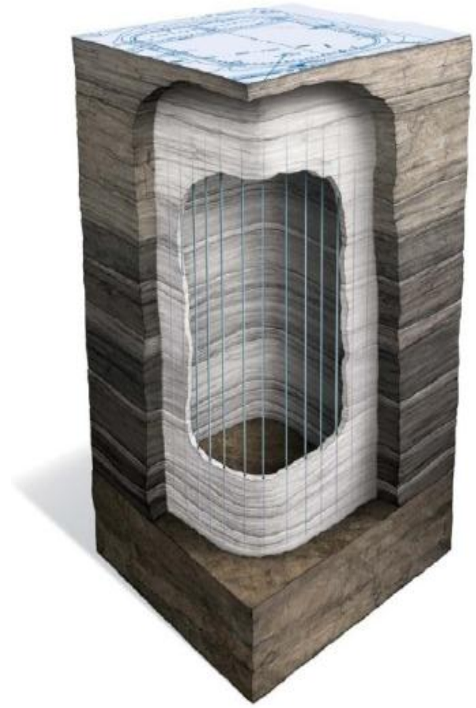
Data Sources

The analysis relies on data that was available in the public domain. Water requirements for the ICP process were based on data from Brandt, et. al.[23]. Energy requirements for the ICP process used Los Alamos National Laboratory (LANL data).[24] Brandt’s reclamation water use estimates were adjusted to reflect the requirement for one barrel of water to be left in the formation for every barrel of oil produced. Water requirements for electricity generation and power plant carbon capture were calculated using data from Zhai, et. al.[25]; Rubin, et. al.[26]; and Chapel, et. al.[27] using International Panel on Climate Change (IPCC)[28] information on energy requirements for carbon capture to adjust for gas-fired power plants. IPCC gives a range of energy penalty for carbon capture from gas-fired plants of 14-22%. The lower end (15%) of the energy penalty was used for these calculations since these newer plants are more efficient and can be configured for optimum CO_2 capture. Further, the produced gas to be used in the power plant contains significant hydrogen, reducing total carbon dioxide production. Data from Zhai, et al.[29] for air-cooled power plants were used to provide a basis for calculating the water requirements for carbon capture in an air-cooled gas-fired power plant. Air-cooled power plants are not as efficient as water-cooled power plants. A constant 9.48% efficiency penalty was used to account for the cooling fans power requirements.[30] Zhai’s [31] method was used for calculating water use for carbon capture from air-cooled power plants.

V. Results

The results presented below are based on Shell's ICP process and published designs. However, Shell has not released formal estimates of ICP EROI, water use, or carbon emissions. The reader should understand that the results contained in this paper are best estimates based on available information. The actual performance will ultimately be demonstrated in the course of Shell's ongoing research, development, and demonstration (RD&D) program, on its private lands and on RD&D leases issued by the United States Bureau of Land Management (BLM). However, in the absence of RD&D results, it is believed the results presented herein are sufficient for contemporaneous policy-making, and represent the best information currently available to the public at large showing how Shell's ICP technology integrates with natural gas power generation, air versus water use, and CO_2 capture technologies (if necessary) to reduce environmental impacts.

Figure 4: ICP Freezewall Concept



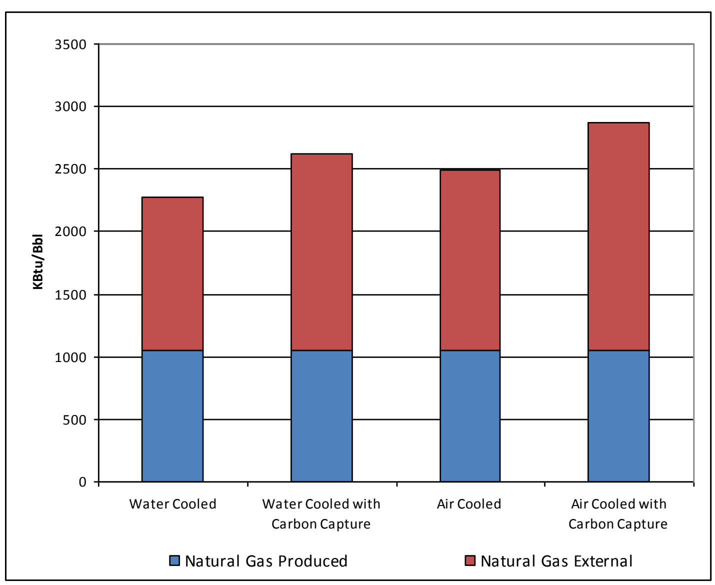
Energy Requirements and EROI: The ICP process uses electricity to power pumps that circulate refrigerant to create and maintain a freeze wall barrier in the formation to isolate the production area from groundwater intrusion (Figure 4). Electric power is also used to fuel down hole heaters that slowly heat the formation inside the freeze wall area to ~ 650° F (340° C). This heating gradually converts the kerogen to high-quality crude oil and hydrogen rich gas. The hydrogen-rich gas upgrades the oil in situ by hydrogenation. At maturity, the oil and gas is produced using conventional vertical wells, and the oil is processed and the produced gas is assumed to be treated and used in the NGCC power plant.

Natural gas produced in the area from other formations is assumed to supply the remainder of the power plant fuel requirements. For purposes of our calculations, the produced gas becomes part of the power plant requirements and is not included in the "Energy In" for energy return on invested energy (EROI) calculations. EROI is a method of directly comparing energy production from various sources. The higher the EROI, the better the overall energy balance. The EROI is a dimensionless number based on the following formula:

$$\frac{\text{Energy Out} - \text{Energy In}}{\text{Energy In}}$$

Note that changes in power plant cooling or carbon capture within the power plant do not change the energy required for the ICP. It does change the overall energy balance and the EROI. Energy requirements provided the basis for estimating carbon dioxide production.

Figure 5: Power Plant Energy Requirements



<u>Power plant energy requirements for the ICP process:</u> An ICP power requirement of 1,270 kBtu per barrel of produced oil to

heat the shale was used in all cases. The energy requirements were adjusted for the differences in power plant efficiency between water-cooled and air-cooled plants. After calculating power plant requirements on that basis, the additional energy requirement for carbon capture was determined and added to the external gas. These results are shown in Table 3 and Figure 5.

Table 3. Power Plant Energy Requirements for Water- and Air-Cooled Power Plants With and Without Carbon Capture K Btu Per Barrel of Shale Oil Produced.

Water-Cooled NGCC without Carbon Capture				
Power Source	Mix	Total Energy into power plant (kbtu/bbl)	Power Plant Efficiency	Energy out of Power Plant (kbtu/bbl)
NG Produced	46%	1049	56%	585
NG External	54%	1232	56%	687
Total	**100%**	**2281**		**1270**

Convert to kbtu/bbl to kwh/bbl	
Total Energy into Power Plant (kwh/bbl)	Energy out of Power Plant (kwh/bbl)
307	172
361	201
668	**373**

Water-Cooled NGCC with Carbon Capture				
NG Produced	40%	1049	56%	585
NG External	60%	1574	56%	878
Carbon Capture energy				-191
Total	**100%**	**2623**		**1270**

Convert to kbtu/bbl to kwh/bbl	
307	172
461	257
	-56
769	**373**

Air-Cooled NGCC without Carbon Capture				
NG Produced	42%	1049	56%	585
NG External	58%	1448	56%	808
Air-Cooled Efficiency Penalty				-121
Total	**100%**	**2497**		**1270**

Convert to kbtu/bbl to kwh/bbl	
307	172
424	237
	-35
732	**373**

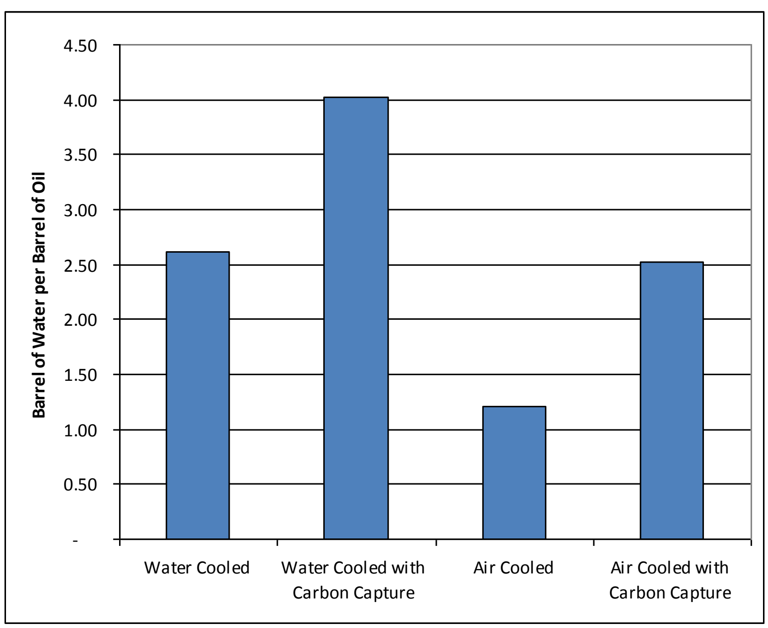
Air Cooled NGCC with Carbon Capture				
NG Produced	37%	1049	56%	585
NG External	63%	1822	56%	1017
Air-Cool & Carbon Capture Energy				-330
Total	**100%**	**2871**		**1270**

Convert to kbtu/bbl to kwh/bbl	
307	172
534	298
	-97
841	**373**

Using the energy requirements for a water-cooled power plant without carbon capture as a baseline, the energy requirements increase by 15% for carbon capture alone. The energy required for air-cooled NGCC plants is nearly 10% higher than the water-cooled NGCC plant and the air-cooled with carbon capture is 25% higher than the water-cooled plant without carbon capture.

Water Requirements (Gross and Net of Produced Water Use and Recycling): Water is required for power plant cooling, freeze wall formation, and carbon capture during the production of the shale oil. The very sallow overlying zones (i.e. well above the heated intervals) are migratory aquifers, meaning groundwater enters and exits the formation. The deeper water-bearing intervals have very low rates of water migration and lower water quality. After the shale oil is produced, the formation must be flushed with water to remove residual hydrocarbons and other contaminants to a level that makes the water potentially usable. Produced water is treated and

Figure 6: Net Water Requirements



recycled. For the purpose of this analysis, the baseline water requirement of Brandt was used. However, the estimated flushing water volume was adjusted to reflect the need to leave one barrel of water in the formation for each barrel of oil produced (balance).

Air-cooled vs. water-cooled results: A comparison of water requirements for air-cooled and water-cooled power plants is shown in Table 4 and Figure 6. Water is recycled where possible and some water is produced from the formation. Air cooling requires about 10% more power in the NGCC power plant to account for fan electrical loading. After adjusting plant size for greater power input requirements, the net power plant water requirement is reduced by about 80%. The production water requirement remains constant. When compared to net ICP power and production requirement of water, air cooling the NGCC power plant reduces water consumption by about 50%.

Effect of carbon capture on water requirements: Table 4 shows the effect of carbon capture on water use. Carbon capture requires additional power plant energy and the capture process requires significant water for cooling the hot gases prior to amine capture of the carbon dioxide. Additional power plant cooling and carbon capture cooling add more than one barrel of water per barrel of shale oil produced when using a water-cooled power plant. Water consumption rises from 2.6 barrels of water per barrel of shale oil produced without carbon capture to 4.0 barrels with carbon capture for ICP with water-cooled NGCC power plants.

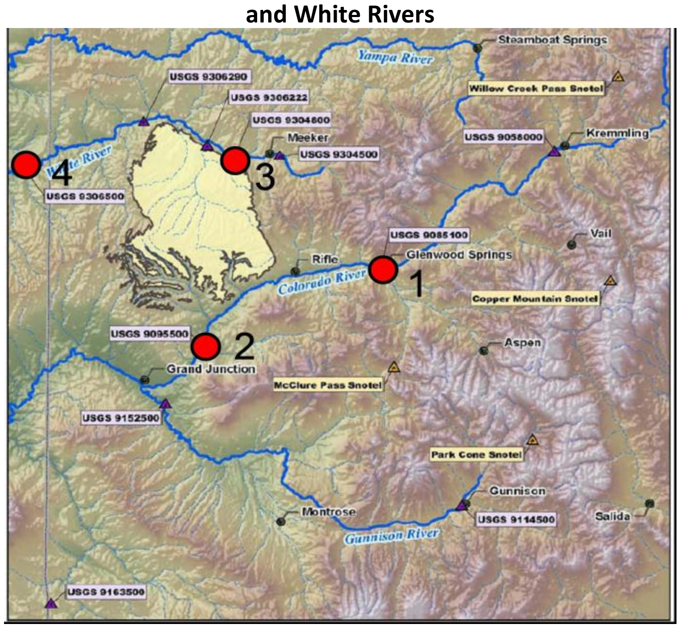
Table 4: Water Requirements for ICP Shale Oil Production in Barrels of Water Per Barrel of Oil Produced.

Water-Cooled NGCC without Carbon Capture (Water Use bbl/bbl of Oil Produced)					
Power Generation Requirement	**Production Requirement**	**Carbon Capture Requirement**	**Subtotal**	**Water Produced**	**Net Requirement**
1.7	1.1	-	2.8	0.14	**2.6**
Water-Cooled NGCC with Carbon Capture (Water Use bbl/bbl of Oil Produced)					
1.9	1.1	1.2	4.2	0.14	**4.0**
Air-Cooled NGCC without Carbon Capture (Water Use bbl/bbl of Oil Produced)					
0.3	1.1	-	1.3	0.14	**1.2**
Air Cooled NGCC with Carbon Capture (Water Use bbl/bbl of Oil Produced)					
0.3	1.1	1.3	2.7	0.14	**2.5**

The additional power load required for air cooling adds about ten percent to the carbon dioxide stream. Carbon capture adds an additional 15% to the total carbon stream to the additional power generation required for the capture process. This additional CO_2 and the capture process require 1.3 barrels of water per barrel of shale oil produced when the ICP process receives its power from an air-cooled NGCC power plant.

For ICP production with air-cooled power plants, 1.2 barrels of water per barrel of produced oil are required without carbon capture and 2.5 barrels per barrel of oil with carbon capture. Air cooling the power plant when CO_2 capture is required reduces overall ICP water consumption by about 40% versus a water-cooled plant. Air cooling the plant with carbon capture reduces water consumption

Figure 7: Water Flow Measurement Points on the Colorado and White Rivers



from the base water-cooled plant without carbon capture.

Water requirements relative to availability: Water requirements are calculated on a barrel of water required per barrel of shale oil produced basis. Based on these requirements, INTEK assessed the impact on surface water resources in two rivers in the Piceance Basin (the White River and the Colorado) assuming a maximum production of 1.5 million barrels of oil per day. For this analysis, water is assumed to be taken from the rivers at or between specific points upriver and downriver of the Piceance Basin. (Figure 7). This analysis also assumes that NGCC power plants will be located in the basin and draw water from the White or Colorado rivers or their tributaries. (This is less likely for very high production rates than for lower rates). Table 5 shows annual average flow rates of the Colorado and White Rivers.

Table 5: Average Combined Annual Flow Rates of Colorado and White Rivers

Average Annual River Flows in Piceance Basin			
River Point	River	Location	Average Annual Flow (af/y)
1	Colorado River	Below Glenwood Springs	2,438,357
2	Colorado River	Cameo	2,789,318
3	White River	Below Meeker	479,411
4	White River	Near Watson	487,649
1&2 Average	Colorado River Average		2,613,838
3&4 Average	White River Average		483,530
All Average	**Colorado + White River Averages**		**3,097,368**

Tables 6 and 7 show the average daily water use of an industry of various production rates between 250,000 bbl/d and 1.5 MM Bbl/d (in barrels and acre feet, respectively) for each of the four power plant configuration scenarios analyzed.

Table 6. Daily Water Use at Various Shale Oil Production Rates (Bbls)

Power Plant Scenario	Production Rate (Thousand Barrels Per Day)			
	250	500	1000	1500
Water Cooled	652,500	1,305,000	2,610,000	3,915,000
Water Cooled with CC	1,005,302	2,010,605	4,021,210	6,031,814
Air Cooled	301,469	602,938	1,205,876	1,808,813
Air Cooled with CC	629,071	1,258,142	2,516,285	3,774,427

Table 8 and Figure 8 show the industry requirement as a percentage of average flow at several shale oil production rates for each of the power plant scenarios analyzed.

Table 7: Daily Water Use at Various Shale Oil Production Rates (AcFt)

Power Plant Scenario	Production Rate (Thousand Barrels Per Day)			
	250	500	1000	1500
Water Cooled	84	168	336	505
Water Cooled with CC	130	259	518	777
Air Cooled	39	78	155	233
Air Cooled with CC	81	162	324	486

Without carbon capture, the impact of a shale oil production in the Piceance Basin on the combined average annual flows of both rivers (upstream of production to downstream of production) is between 1% for the NPC's "likely" case and 5.9% for the Task Force's "accelerated" development case,

Table 8. Percent of Flow Required to Support Shale Oil Production

Power Plant Scenario	Production Rate (Thousand Barrels Per Day)			
	NPC "Likely"	Mid-Range	NPC "High"	Task Force "Accelerated"
	250	500	1000	1500
Water Cooled	1.0%	2.0%	4.0%	5.9%
Water Cooled w CC	1.5%	3.1%	6.1%	9.2%
Air Cooled	0.5%	0.9%	1.8%	2.7%
Air Cooled with CC	1.0%	1.9%	3.8%	5.7%

depending on industry production rates.

Seasonal or annual variations of flows of these rivers make it likely that storage will be needed to ensure adequate supply and protect the health of the rivers during low flow periods

An ICP process with air-cooled power plants without carbon capture reduces the water demand on average flow from the White and Colorado rivers to between 0.5% and 2.7% - or less than half the impact with water-cooled power plants.

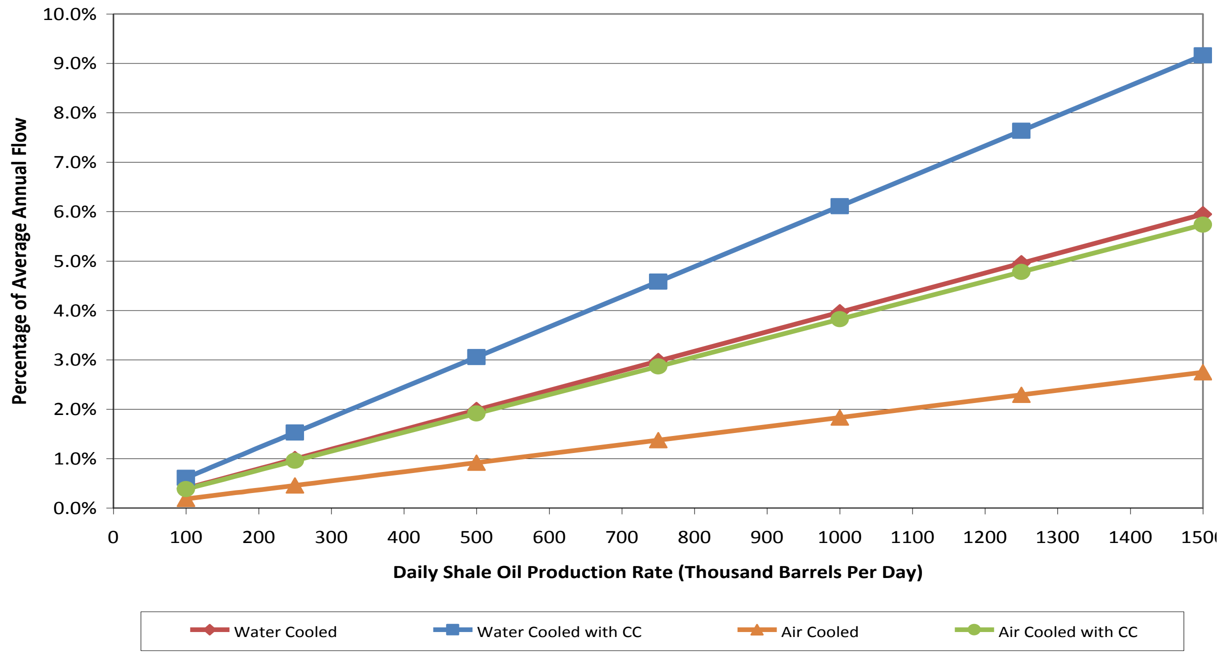
Carbon capture in either the water cooled or air cooled case requires additional power generation and water consumption in the capture process.

Between 1.5% and 9.29% of the average flow would be required for ICP production using water-cooled power plants with carbon capture from both the power plant flue gas and produced gas treatment.

An air-cooled plant with carbon capture would require between 1% and 5.7% of the flows. The water requirements are less for ICP production using air-cooled power plants with carbon capture than when using a water-cooled power plant without carbon capture.

The relationships and tradeoffs between the power plant cooling and carbon capture and sequestration scenarios analyzed, as they relate to industry requirements for water from the Colorado and White Rivers, at various shale oil production levels are in Figure 8, below.

Figure 8: Percent of Average Combined River Flow Required at Various Production Rates

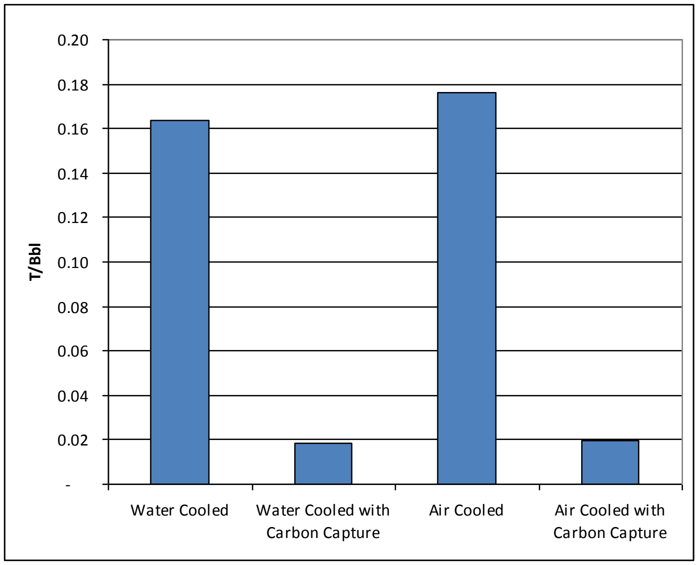


Carbon Dioxide Emissions: Natural gas when combusted forms carbon dioxide and water. The NGCC power plant accounts for most of the carbon dioxide produced for the ICP process. Treatment of the hydrocarbon gases produced from the ICP retorting process produces the remainder. Assuming production from dolomite formations, this would account for about 20% of the total CO_2 produced. This volume, by itself, may be too small to economically send to market. However, this is not the case if CO_2 from both the power plant flue gas and produced gas treatment is captured.

It should be noted that there may be a broad market for CO_2 for enhanced oil recovery (EOR). Shell intends to capture and market the CO_2 produced by gas treatment operations for this purpose.

Further, ICP production in the Nahcolite and deeper Illite zones would produce greater volumes of CO_2 that would be captured as part of the gas treatment process and could be marketed for EOR or other purposes. Table 9 and Figure 9 show the calculation of carbon dioxide emissions for the ICP process and results.

Figure 9: Carbon Dioxide Emissions



Carbon capture: Carbon capture reduces net carbon emissions versus water-cooled power plants without carbon capture by about 88%. Amine systems remove about 90% of produced carbon dioxide at the power plant. The process itself requires about 15% energy increase from the power plant. The net decrease of carbon dioxide emissions for the ICP process after adjusting for increased carbon dioxide production of a larger plant using either water- or air-cooled power plant is about 88%.

Table 9. Production and Emissions of Carbon Dioxide from NGCC Power Generation and Produced Gas Treatment Under Various Plant Cooling and Carbon Capture Scenarios (Tonnes/Barrel Produced Oil).

Water-Cooled NGCC without Carbon Capture					Additional Emissions	
Power Source	Mix	Energy out of Power Plant Including Penalties (kwh/bbl)	Emission (kg/kwh)	Total Power Gen Emissions (t/bbl)	Produced Gas Cleanup	Total Emissions (Power Gen & Gas Clean-up)
NG Produced	46%	172	0.358	0.06		
NG External	54%	201	0.358	0.07		
Total	**100%**	**373**		**0.13**	**0.03**	**0.16**
Water-Cooled NGCC with Carbon Capture					**Additional Emissions**	
NG Produced	40%	172	0.036	0.01		
NG External	60%	257	0.036	0.01		
Total	**100%**	**429**		**0.02**	**0.003**	**0.02**
Air-Cooled NGCC without Carbon Capture					**Additional Emissions**	
NG Produced	42%	172	0.358	0.06		
NG External	58%	237	0.358	0.08		
Total	**100%**	**408**		**0.15**	**0.03**	**0.18**
Air Cooled NGCC with Carbon Capture					**Additional Emissions**	
NG Produced	37%	172	0.036	0.01		
NG External	63%	298	0.036	0.01		
Total	**100%**	**470**		**0.02**	**0.003**	**0.02**

<u>Effect of carbon capture on EROI</u>: The EROI, as described in the approach, is a dimensionless number based on the following formula:

$$\frac{\text{Energy Out} - \text{Energy In}}{\text{Energy In}}$$

The EROI allows direct comparison with different energy sources. Higher EROI means less energy is required to produce a unit of usable energy. An EROI of one or below means that more energy is used than produced in the process. Produced gas from ICP pyrolysis of kerogen in the shale formation was used as part of the energy for the power plant but not used as "energy out" or "energy in" in the formula.

Carbon capture requires additional energy to capture the CO_2 and still provide the electricity needed for the ICP production process. This drives the EROI down.

Table 10 and Figure 10 show the effect of carbon capture on EROI using air-and water-cooled power plants. Carbon capture in a water-cooled power plant lowers the EROI for the ICP oil shale from 3.5 to 2.5. Similarly the EROI for ICP oil shale production using an air-cooled NGCC power plant decreases from 2.8 to 2.0 with carbon capture.

These EROI are slightly lower than those for conventional oil production but compare favorably with oil produced from tar sands. By comparison, EROI for ethanol from corn or cellulose and wind are one or lower. The favorable EROI numbers for shale oil production indicate that the constraints on shale oil production are more likely related to economic, technology or regulatory factors.

Figure 10: Estimated Energy Return on Investment (EROI)

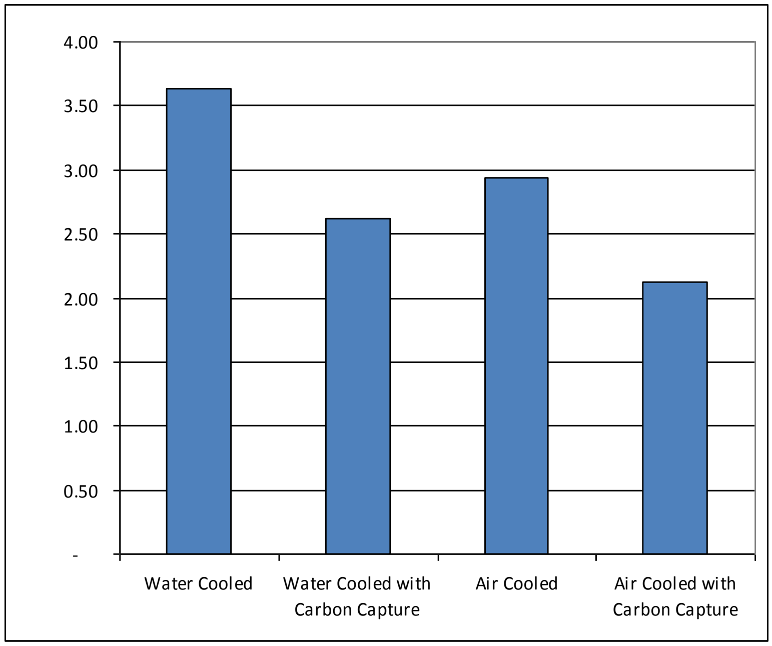


Table 10. Energy Return on Invested Energy (EROI) for ICP Shale Oil Production Using Water- or Air-Cooled NGCC Power Plants With or Without Carbon Capture.

Water-Cooled NGCC without Carbon Capture			
Total Energy In	Net Energy In (Less NGp)	Total Energy Out	EROI
2,281	1,266	1,273	**3.5**
Water-Cooled NGCC with Carbon Capture			
2,623	1,608	1,273	**2.5**
Air-Cooled NGCC without Carbon Capture			
2,497	1,482	1,273	**2.8**
Air Cooled NGCC with Carbon Capture			
2,871	1,856	1,273	**2.1**

VI. Discussion of Results

An oil shale industry operating at a capacity of 1.5 million barrels per day using an in-situ heating process such as Shell's ICP with a gas fired, water cooled power plant could yield an energy return on investment of 3.6:1 with minimal impact on available water flows. These impacts on water supply would decrease proportionately at lower production levels. Air cooling could cut water requirements by more than 50%, but with a modest impact on EROI and a slight increase in CO_2 production. Application of amine-based carbon capture technologies could reduce carbon emissions by nearly 90%, but would significantly impact EROI and more than double water requirements relative to the water or air cooled scenarios without carbon capture.

Net Water Consumption and Availability: Excluding the power plant water use, the water use for the freezewall, drilling and heating, and reclamation are fixed at just over one barrel of water consumed per barrel of oil produced and can only be reduced by small amounts. Since these water requirements for producing the shale oil from formations where groundwater is present cannot be reduced significantly, air cooling of the power plant is the only way to significantly reduce water consumption when producing from these formations.

In the highest water use case (water-cooled NGCC power plant with carbon capture), 9.1% of the combined White and Colorado Rivers' flow through the basin could be required at the peak production level of 1.5 million barrels per day cited by the Task Force on Strategic Unconventional Fuels. The least consumption of water would result from the use of an air-cooled NGCC power plant without carbon capture (2.7% of river flows). Water consumption for ICP shale oil production using a NGCC power plant can be reduced by about 40% by choosing an air-cooled power plant over a water-cooled plant when carbon capture is required.

More recent projections by the National Petroleum Council indicate that production levels at least through the year 2035 would likely be much lower than the 1.5 MM Bbl/d suggested by the Task Force's "accelerated" development case. At these lower production volumes, the water requirements would be proportionately less for all power plant and carbon capture configurations analyzed in this paper.

Further, the depositional setting of deep illite/nahcolite plays naturally precludes groundwater migration. The shale oil contained in these formations can be produced without freeze walls and without post-production flushing to prevent hydrocarbon contamination of adjacent formations that may contain transitional or migratory water. This alone could further reduce water consumption values presented above by over one barrel per barrel of produced oil for applications of the ICP process in these deep formations.

Based on these analyses it appears that water supply from these two rivers in the basin could support a commercial scale oil shale development in all cases, with the caveat that storage will be required to balance the seasonality of the flows and protect the health of the rivers.

Carbon Dioxide Emissions: CO_2 production ranges between .05 and .18 tonnes per barrel, depending on the scenario analyzed. However, carbon capture requires additional energy and water consumption and reduces the EROI. Environmental decisions must include the trade-offs between water use and carbon capture.

Energy Efficiency and Return on Investment: The energy return on investment (EROI) indicates that the shale oil resource is a net producer of energy. Ultimate development will depend upon other transportation fuel availability, technology, and economics.

These results highlight the tradeoffs among water use, carbon emissions, and energy efficiency, as well as project economics and societal benefits and impacts that must be considered in preparing for the development of an oil shale industry in the Piceance Basin.

In any event, the water, CO_2, EROI, and other impacts of oil shale industry development will be known early in the life of the Oil Shale Industry and will be subject to ongoing public and governmental scrutiny.

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[3] United States Geological Survey Fact Sheets: "Assessment of in-place oil shale resources of the Green River Formation, Greater Green River Basin in Wyoming, Colorado, and Utah (2011)," "In-place oil shale resources underlying Federal lands in the Piceance Basin, western Colorado (2010)," and "Assessment of in-place oil shale resources of the Green River Formation, Uinta Basin, Utah and Colorado (2010)."

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