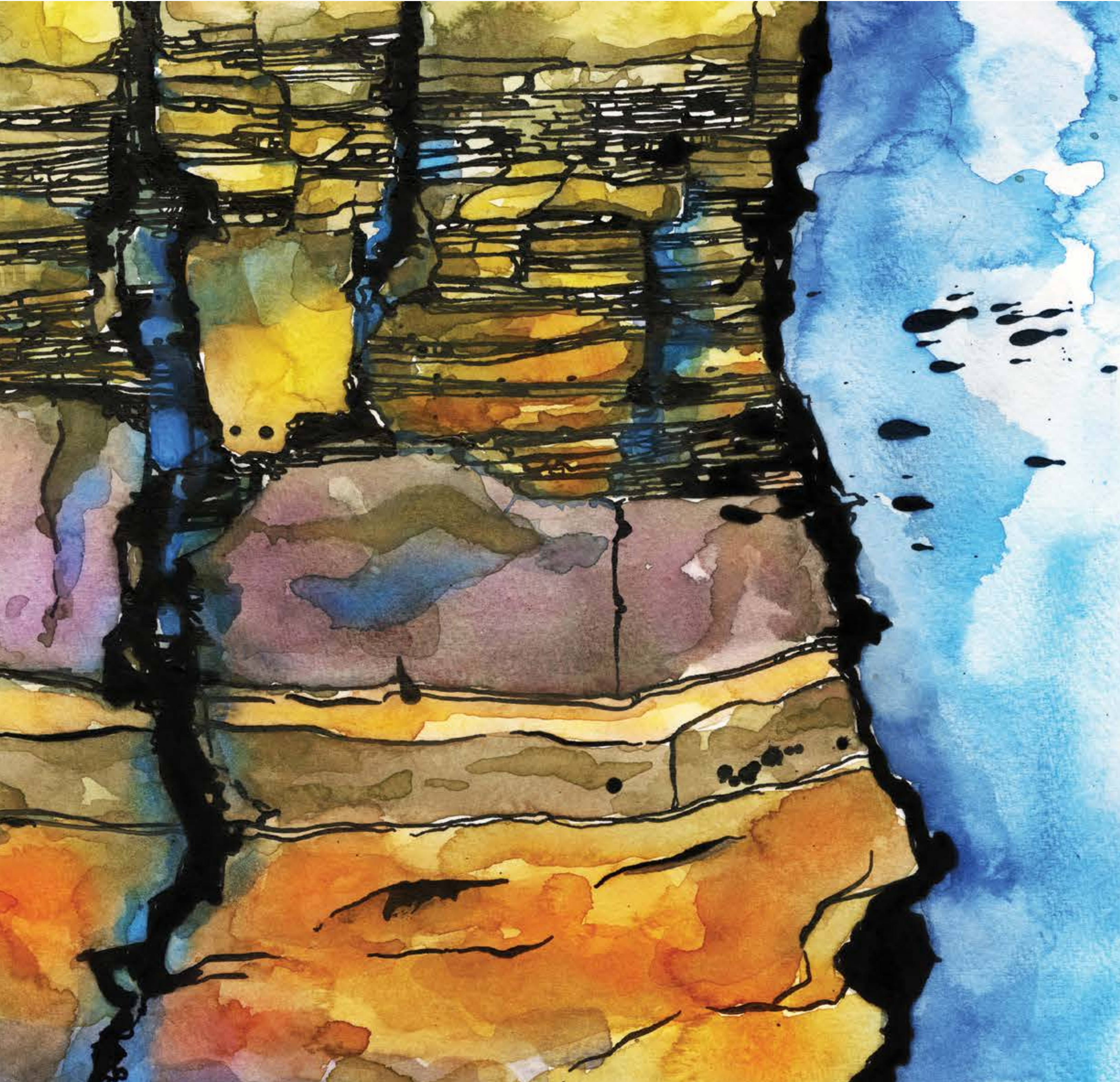

A Market Assessment of Oil Shale and Oil Sands Development Scenarios in Utah's Uinta Basin

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Executive Summary

The enormous size of U.S. oil shale and oil sands resources, and Utah resources in particular, is well-known. Recent analyses by the United States Geological Survey of oil shale resources in western Colorado and eastern Utah have estimated the total in-place oil in the Piceance Basin of Colorado at 1.53 trillion barrels [1] and in the Uinta Basin of Utah at 1.32 trillion barrels [2]. A 2008 Utah Geological Survey study estimates the economically-recoverable resource in the Uinta Basin to be 77 billion barrels [3]. The total U.S. oil sands resource is estimated at 76 billion barrels of in-place oil. The largest U.S. oil sands deposits are found in the State of Utah, which has an estimated resource size of 32 billion barrels of in-place oil [4]. A 2013 study of a large Utah deposit known as Tar Sand Triangle estimates a commercially viable resource size of 1.30–2.46 billion barrels in that deposit [5]. Despite the size of the resource and the fact that U.S. production of liquid transportation fuels from oil sands and oil shale has been shown to be technically feasible [1–3], there is currently no commercial scale production of either resource.

Purpose of Assessment

Given today's economic and political climate, this report seeks to assess significant impediments to and impacts of development of U.S. oil shale and oil sands resources. It focuses on three specific questions: (1) what positive and negative externalities and non-market costs are associated with development of these resources and how does the perception of these costs impact development; (2) what is the per barrel cost of oil produced from four oil shale and oil sands development scenarios; and (3) what are the broad regional impacts that may result as side effects if the scenarios are realized.

Assessment Approach

This assessment is divided into ten sections.

Sections 1–3. The first three sections provide background material to better understand the economic analysis that follows. Section 1 focuses on the impact of U.S. energy policy and rising public concern about anthropogenic climate change on oil shale and oil sands development. Section 1 also reviews past evaluations of commercial unconventional fuels development and outlines the scope of the study. Section 2 reviews what is known about oil shale and oil sands resources in the Uinta Basin of Utah. Section 3 examines the set of rules concerning how local, state, and federal government revenue would be derived from the production of oil from oil sands and oil shale. Collectively, this set of rules is known as "fiscal policy."

Section 4. This section reviews the concept of externalities and explores four commonly cited externalities related to oil shale and oil sands development: water resources and availability, land use impacts, air quality, and carbon management.

Sections 5–9. Section 5 outlines the cost estimating methodologies used to determine the economic viability of four unconventional fuel development scenarios in Utah's Uinta Basin. These scenarios (Sections 6–9) are:

- Ex situ extraction (underground mining, surface retorting) of oil shale
- In situ extraction (underground heating) of oil shale
- Ex situ extraction (surface mining, surface processing) of oil sands
- In situ extraction (Steam-Assisted Gravity Drainage) of oil sands.

The production capacity of the two oil shale scenarios is set at 50,000 barrels per day (BPD) while the production capacity of the two oil sands scenarios is 10,000 BPD. All scenarios are assumed to start in 2012 and end in 2035, with four years for design and construction and 20 years for production. The scenarios encompass extraction with the subsequent upgrading of the extracted product (raw shale oil and bitumen) to make a light, low-sulfur synthetic crude oil that is pipelined from the point of upgrading to North Salt Lake City, Utah, refineries. Each scenario includes a detailed description of the process components, an estimate of process inputs and outputs such as water requirements and CO_2 emissions, a capital cost estimate, a supply price analysis for a "base case" set of assumptions (including a detailed price breakdown), a supply price evaluation of raw product (i.e. no upgrading), a net present value analysis using oil price projections from the U.S. Energy Information Administration (EIA) [6], and a sensitivity analysis that examines the effect of various parameter values on the computed supply price of oil. In addition, a carbon management scheme that involves using oxygen rather than air for all combustion processes is analyzed.

Section 10. This section reports results from an input-output analysis of the potential economic impacts arising from successful ex situ oil shale or oil sands projects in the Uinta Basin.

Key Results

All of the projects will require extensive capital investment with "base case" capital costs ranging from $800 million for a 10,000 BPD oil sands production facility to $6 billion for a 50,000 BPD in situ oil shale production facility.

Assuming that investors require a minimum rate of return of 10% and that prices for a West Texas Intermediate (WTI)-quality crude oil follow the EIA reference forecast to 2035 [6], both the 50,000 BPD ex situ oil shale and the 10,000 BPD ex situ oil sands scenarios ("base cases") are profitable. If investors are willing to accept a slightly lower rate of return (9%), then the "base case" 10,000 BPD in situ oil sands scenario is profitable as well. The "base case" 50,000 BPD in situ oil shale scenario is not profitable given the crude oil reference forecast price.

The economic impacts to the State of Utah associated with 20-year operations phase of a 50,000 BPD ex situ oil shale facility are based on the assumption that 50% of total expenditures are spent somewhere in the state. Depending on the technology used, the $5.87–$6.27 billion assumed spent on Utah-based suppliers generates an additional $10.4–$11.0 billion in business sales, $2.25–$2.50 billion of additional wage earnings associated with 50,500–59,000 person-years of employment, and $5.85–$6.20 billion of gross state product (GSP) in Utah. The $1.53 billion assumed spent on Utah-based suppliers during the 20-year operations phase of a 10,000 BPD ex situ oil sands facility generates an additional $2.75 billion in business sales, $622 million of wage earnings associated with approximately 15,000 person-years of employment, and $1.50 billion of GSP.

Externalities

Diverse public costs, or externalities, are associated with development of oil shale and oil sands. One positive externality that is used as an argument for development is the increase in energy security resulting from increased domestic production. However, the impact on energy security of the scenarios analyzed in this study would be limited because: (1) a 50,000 BPD production level represents about one-quarter of 1% of U.S. petroleum consumption and (2) if such production did have an impact on oil prices, which are determined in an integrated global market, it is also likely to increase oil consumption. Another oft-cited positive externality, that such activity will benefit the U.S. in terms of job opportunities and private and public revenue, depends on the particular state of the economy during the time of production. To the extent that capital and other resources are fully employed in other activities during the course of development, they are shifted from one activity to another. When unemployment rates are high, the value of forgone opportunities is low and much of the gross gain in employing labor, capital, and resources in the new industry is net gain.

Given the arid environment of the Uinta Basin, water resources and availability are frequently mentioned as negative externalities associated with development. While the financial cost of water is readily addressed in economic models, water acquisition represents an externality because water supplies are finite and water rights reallocations can impact the quality of life in rural communities and environmental values. Opposition to reallocation has the potential to increase transaction and permitting costs. The specifics of the water challenges associated with obtaining water for oil shale or oil sands development will depend upon how industries develop and whether such development supplants or supplements other water uses.

Land use also represents an externality as development of oil shale and oil sands may render land incompatible for previous or planned uses during the time period of production and reclamation. Opposition to shifts in land use for large tracts of land can impact permitting costs. The Endangered Species Act presents additional land use challenges for development given that Uintah County, situated in the Uinta Basin, is home to nine federally-listed or candidate animal species and other species with special designations [7]. Additionally, the most prospective oil shale area is home to several federally protected or candidate plant species.

Reduced air quality from industrial development represents a negative externality for those living in the Uinta Basin airshed. Degraded ambient conditions in the Uinta Basin pose a serious challenge to any development proposal that further reduces air quality. A related concern is whether the U.S. Environmental Protection Agency, which has primary regulatory jurisdiction over Indian Country (where 72% of oil and gas production in the Uinta Basin occurs [8]), has the local knowledge and flexibility needed to craft innovative response strategies that protect local economic interests.

The externalities associated with carbon management hinder both energy policy and energy resource development. For oil shale and oil sands, the raw material extraction, processing, and upgrading life-cycle stages can be important contributors to the carbon footprint. Given the uncertainty of the regulatory climate with respect to carbon, two different combustion systems are considered to supply heat for the various scenarios. In the conventional system, natural gas is combusted with air and the resulting combustion gases are sent to a stack. For the profitability analysis, two cases are considered: (1) no tax on CO_2 and (2) a $25 per ton tax on CO_2. In the oxy-combustion system, natural gas is combusted with a mixture of oxygen and recycled flue gas (mainly CO_2 and water). After processing, a nearly pure CO_2 stream remains that can be sold for enhanced oil recovery or sequestered.

Ex Situ Oil Shale Scenario

This scenario is located in the northeast section of the Uinta Basin, the most promising area for development as it corresponds to the basin depocenter. The oil shale is mined underground and processed in a surface retort to extract the raw shale oil. Two retorting technologies were selected for this report, Tosco II and Paraho Direct. The raw shale oil undergoes an upgrading step (hydrotreating) such that the finished product is a WTI-quality synthetic crude oil. The finished product is then pipelined to North Salt Lake City, Utah, refineries. Two methods of assessing profitability are employed. The Supply Price Method finds the minimum price of oil that ensures profitability of the project if that price, adjusted for inflation, were received on each barrel of oil sold from the project. The Net Present Value Method evaluates the profitability of the project when the oil prices received are those of the most recent EIA oil price forecasts.

Table 1 lists the major outputs from and inputs to ex situ production of synthetic crude oil from oil shale on a per barrel basis. The production of CO_2 is greater for the Paraho Direct process than for the Tosco II process because the high temperature in the Paraho Direct retort leads to formation of CO_2 from carbonate decomposition; CO_2 emissions from carbonate decomposition in the the Tosco II retort are assumed to be negligible. The CO_2 from the oxy-fired scenario is captured and of pipeline-quality that can be sold; CO_2 from the air-fired scenario is dilute and is emitted into the atmosphere from a smokestack.

Table 1. Major process outputs and inputs on a per barrel basis for ex situ oil shale scenario.

Category	Item	Tosco II Air-Fired	Tosco II Oxy-Fired	Paraho Air-Fired	(Units) / bbl of oil
Outputs	Ammonium Sulfate	20.94	20.94	20.94	lb
	CO_2 [a]				
	Emitted to Atmosphere	544	191	833	lb
	Sold to Pipeline	-	421	-	lb
	Spent Shale	41.69	41.69	42.02	ft^3
	Steam (600 psig, 700°F)	396	396	396	lb
	Sulfur	1.96	1.96	1.96	lb
Inputs	Catalyst	0.02	0.02	0.02	lb
	Electricity	14.31	35.96	88.77	kWh
	Fuel [b]				
	Purchased	1.19	1.16	1.93	MMBtu
	Total	3.84	3.80	3.01	MMBtu
	Makeup Water	6.28	6.32	3.00	bbl
	O_2	-	396	-	lb
	Refrigerant	2.72	2.72	2.72	MJ
	Steam				
	50 psig	433	433	250	lb
	450 psig	77	77	184	lb

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[a] The per barrel CO_2 output is CO_2 equivalent (CO_2e). These emissions do not include those associated with facilities construction, refrigeration, and water treatment.
[b] The fuel input refers to natural gas only.

The total capital investment for the complete Tosco II air-fired plant is $5.941 billion; that of the Tosco II oxy-fired plant is $6.192 billion. The total capital investment for the Paraho Direct air-fired plant is almost 20% lower at $4.789 billion. A capital cost breakdown is available in the report.

Base case supply prices as a function of hurdle rate are given in Table 2 for Tosco II air-fired combustion and in Table 3 for Paraho Direct air-fired combustion. The hurdle rate is the minimum rate of return that an investor requires before investing his/her funds in the project; it is the opportunity cost of capital [9]. All supply costs listed in the tables are positive contributors to the supply price while all non-oil revenue streams are negative contributors.

Table 2. Supply price for Tosco II air-fired ex situ oil shale production scenario as a function of hurdle rate. Footnotes also apply to Table 3.

Hurdle Rate	0%	2%	4%	6%	8%	10%	12%
Mine [a]	$ 9.79	$ 9.79	$ 9.79	$ 9.79	$ 9.79	$ 9.79	$ 9.79
Retort	$ 8.36	$ 8.36	$ 8.36	$ 8.36	$ 8.36	$ 8.36	$ 8.36
Upgrading [b]	$ 13.14	$ 13.14	$ 13.14	$ 13.14	$ 13.14	$ 13.14	$ 13.14
Taxes	$ 10.73	$ 13.33	$ 16.61	$ 20.37	$ 24.62	$ 29.79	$ 35.77
Oil Royalties	$ 8.30	$ 9.19	$ 10.25	$ 11.47	$ 12.84	$ 14.45	$ 16.28
Net Earnings	$ -	$ 4.69	$ 10.16	$ 16.43	$ 23.51	$ 31.61	$ 40.75
Maintenance	$ 13.65	$ 13.65	$ 13.65	$ 13.65	$ 13.65	$ 13.65	$ 13.65
Other [c]	$ 14.81	$ 14.86	$ 14.93	$ 15.01	$ 15.10	$ 15.20	$ 15.31
Supply Cost	**$ 78.79**	**$ 87.02**	**$ 96.90**	**$ 108.23**	**$ 121.02**	**$ 135.99**	**$ 153.06**
Other Revenue	$ 1.47	$ 1.47	$ 1.47	$ 1.47	$ 1.47	$ 1.47	$ 1.47
Oil Supply Price	**$ 77.32**	**$ 85.56**	**$ 95.43**	**$ 106.76**	**$ 119.55**	**$ 134.52**	**$ 151.60**

[a] "Mine" includes costs for mining and size reduction/solids handling (e.g. crushing).
[b] "Upgrading" includes all costs associated with the fractionator, hydrotreater, hydrogen plant, sour water stripper, amine treatment unit, and sulfur recovery unit.
[c] "Other" includes all costs associated with the oil pipeline, water pipeline, allocated costs for utility plants, water reservoir, site preparation, service facilities, contingency, permitting, research, administration, incentive compensation, insurance, intellectual property royalties, overhead, land, startup, and CO_2 compressor (oxy-firing only).

Table 3. Supply price for Paraho Direct air-fired ex situ oil shale production scenario as a function of hurdle rate.

Hurdle Rate	0%	2%	4%	6%	8%	10%	12%
Mine	$ 11.32	$ 11.32	$ 11.32	$ 11.32	$ 11.32	$ 11.32	$ 11.32
Retort	$ 9.12	$ 9.12	$ 9.12	$ 9.12	$ 9.12	$ 9.12	$ 9.12
Upgrading	$ 18.41	$ 18.41	$ 18.41	$ 18.41	$ 18.41	$ 18.41	$ 18.41
Taxes	$ 8.84	$ 10.97	$ 13.61	$ 16.64	$ 20.07	$ 24.24	$ 29.05
Oil Royalties	$ 8.42	$ 9.14	$ 9.99	$ 10.97	$ 12.08	$ 13.37	$ 14.84
Net Earnings	$ -	$ 3.79	$ 8.19	$ 13.24	$ 18.94	$ 25.44	$ 32.78
Maintenance	$ 10.87	$ 10.87	$ 10.87	$ 10.87	$ 10.87	$ 10.87	$ 10.87
Other	$ 12.87	$ 12.92	$ 12.98	$ 13.04	$ 13.11	$ 13.19	$ 13.28
Supply Cost	**$ 79.85**	**$ 86.53**	**$ 94.49**	**$ 103.60**	**$ 113.91**	**$ 125.95**	**$ 139.67**
Other Revenue	$ 1.47	$ 1.47	$ 1.47	$ 1.47	$ 1.47	$ 1.47	$ 1.47
Oil Supply Price	**$ 78.38**	**$ 85.06**	**$ 93.02**	**$ 102.13**	**$ 112.44**	**$ 124.48**	**$ 138.20**

Detailed supply price breakdowns and an analysis of the sensitivity of the supply price to a range of parameters are included in the report.

In Situ Oil Shale Scenario

The scenario is located near Bonanza, Utah, across the White River from the ex situ oil shale scenario. In situ production occurs by underground heating to extract oil from the oil shale followed by pumping of the produced oil to the surface and upgrading. The upgraded product is then pipelined to North Salt Lake City, Utah, and sold to a refinery. The design production capacity is 50,000 BPD, but this production volume is only achieved in the final years of the 24-year project due to the long time delay between the initiation of underground heating and the maximum production rate. This scenario is developed using commercially-available reservoir simulation tools and equipment that can be purchased "off-the-shelf" and does not necessarily represent what might be achievable using technologies currently under development.

Table 4 lists the major outputs from and inputs to this in situ oil shale production scenario on a per barrel basis. The CO_2 emissions are nearly double those of ex situ production (Tosco II, air-fired) due to the energy requirements of heating the resource underground and the long time lag from the initiation of heating to the start of significant production.

Table 4. Major process outputs and inputs on a per barrel basis for in situ oil shale scenario.

Category	Item	Air-Fired	Oxy-Fired	(Units) / bbl of oil
Outputs	Ammonium Sulfate	9.64	9.64	lb
	CO_2 [a]			
	Emitted to Atmosphere	1,060	1,016	lb
	Sold to Pipeline	-	59	lb
	Steam (600 psig, 700°F)	25	25	lb
	Sulfur	2.09	2.09	lb
Inputs	Catalyst	0.02	0.02	lb
	Electricity	10.68	14.78	kWh
	Fuel [b]			
	Purchased	6.44	6.44	MMBtu
	Total	7.01	7.00	MMBtu
	Makeup Water [c]	0.74	0.74	bbl
	O_2	-	72	lb
	Refrigerant	2.72	2.72	MJ
	Steam			
	50 psig	266	266	lb
	450 psig	77	77	lb

[a] *The per barrel CO_2 output is CO_2e. These emissions do not include those associated with facilities construction, refrigeration, water treatment or in situ decomposition of carbonate minerals in the oil shale.*
[b] *Same as Table 1, footnote "b."*
[c] *The makeup water includes the water required for drilling. If the water for drilling is excluded, makeup water is 0.09 bbl/bbl of oil.*

The total capital investment for the complete air-fired production facility is \$6.02 billion and for the oxy-fired facility is \$6.08 billion. A breakdown of all capital costs is available in the report; the largest capital cost (48% of the total) is for drilling.

Base case supply prices for air-fired in situ oil shale production for hurdle rates up to 6% are given in Table 5. Due to the high supply prices associated with this scenario, additional hurdle rates were not investigated.

Table 5. Supply price for air-fired in situ oil shale production scenario as a function of hurdle rate.

Hurdle Rate	0%	2%	4%	6%
Drilling	$ 23.00	$ 23.00	$ 23.00	$ 23.00
In Situ Retort [a]	$ 44.13	$ 44.13	$ 44.13	$ 44.13
Upgrading [b]	$ 12.42	$ 12.42	$ 12.42	$ 12.42
Taxes	$ 47.66	$ 61.05	$ 78.63	$ 101.92
Oil Royalties	$ 22.05	$ 27.03	$ 33.42	$ 41.66
Net Earnings	$ -	$ 22.73	$ 51.47	$ 87.93
Maintenance	$ 14.72	$ 14.72	$ 14.72	$ 14.72
Other [c]	$ 19.41	$ 19.68	$ 20.04	$ 20.50
Supply Cost	**$ 183.39**	**$ 224.76**	**$ 277.82**	**$ 346.27**
Other Revenue	$ 0.18	$ 0.18	$ 0.18	$ 0.18
Oil Supply Price	**$ 183.21**	**$ 224.58**	**$ 277.64**	**$ 346.08**

[a] *"In Situ Retort" includes all costs associated with the natural-gas fired generators and the electrical heaters.*
[b] *Same as Table 2, footnote "b."*
[c] *Same as Table 2, footnote "c."*

The report also includes detailed supply price breakdowns and an analysis of the sensitivity of the supply price to a range of parameters.

Ex Situ Oil Sands Scenario

The location for this scenario is the Asphalt Ridge-Whiterocks Special Tar Sands Area (STSA) southwest of Vernal, Utah. The oil sands are mined from an outcrop on the Asphalt Ridge and then mining is assumed to proceed down-dip, following the deposit to the southwest. The mined material undergoes grinding, sand/oil separation in hydrocyclones using a hot water/solvent extraction process to extract bitumen, and primary and secondary upgrading of the bitumen. The synthetic crude oil that results is then pipelined to refineries in North Salt Lake City, Utah.

Table 6 lists the major outputs from and inputs to this ex situ oil sands production scenario on a per barrel basis. Water usage is similar to that for the Paraho Direct ex situ oil shale scenario and half that of the Tosco II ex situ oil shale scenario.

Table 6. Major process outputs and inputs on a per barrel basis for ex situ oil sands scenario.

Category	Item	Air-Fired	Oxy-Fired	(Units) / bbl of oil
Outputs	Ammonium Sulfate	5.76	5.76	lb
	CO_2[a]			
	Emitted to Atmosphere	253	150	lb
	Sold to Pipeline	-	152	lb
	Steam (600 psig, 700°F)	78	78	lb
	Petroleum Coke	46	46	lb
	Sulfur	0.85	0.85	lb
	Tailings [b]	9,274	9,274	lb
Inputs	Catalyst	0.02	0.02	lb
	Electricity	17.89	25.42	kWh
	Fuel [c]			
	Purchased	0.91	0.89	MMBtu
	Total	1.39	1.38	MMBtu
	Makeup Water	2.80	2.81	bbl
	O_2	-	179	lb
	Refrigerant	13.58	13.58	MJ
	Solvent	0.16	0.16	gal
	Steam			
	50 psig	332	332	lb
	450 psig	383	383	lb

[a] *Same as Table 1, footnote "a."*
[b] *Tailings includes both overburden and wet sand. Quantity reported here is for the average stripping ratio of two.*
[c] *Same as Table 1, footnote "b."*

The total capital investment for the complete air-fired plant is $818 million; that of the oxy-fired plant is $848 million. The largest capital costs (air-fired) are for the hydrotreater (16% of total) and bitumen separation system (13% of total). The report contains a detailed breakdown of capital costs.

Table 7 lists base case supply prices as a function of hurdle rate for the air-fired ex situ oil sands scenario. The supply cost at a hurdle rate of 0% is the cost of the project without any investor profit.

Table 7. Supply price for air-fired ex situ oil sands production scenario as a function of hurdle rate.

Hurdle Rate	0%	2%	4%	6%	8%	10%	12%
Mine [a]	$ 17.31	$ 17.31	$ 17.31	$ 17.31	$ 17.31	$ 17.31	$ 17.31
Bitumen Recovery	$ 7.62	$ 7.62	$ 7.62	$ 7.62	$ 7.62	$ 7.62	$ 7.62
Upgrading [b]	$ 15.38	$ 15.38	$ 15.38	$ 15.38	$ 15.38	$ 15.38	$ 15.38
Taxes	$ 6.58	$ 8.20	$ 10.14	$ 12.42	$ 15.24	$ 18.51	$ 22.42
Oil Royalties	$ 8.02	$ 8.55	$ 9.18	$ 9.92	$ 10.80	$ 11.81	$ 13.01
Net Earnings	$ -	$ 2.77	$ 6.08	$ 9.97	$ 14.52	$ 19.74	$ 25.77
Maintenance	$ 8.17	$ 8.17	$ 8.17	$ 8.17	$ 8.17	$ 8.17	$ 8.17
Other [c]	$ 13.81	$ 13.85	$ 13.89	$ 13.94	$ 13.99	$ 14.06	$ 14.13
Supply Cost	**$ 76.90**	**$ 81.85**	**$ 87.78**	**$ 94.74**	**$ 103.05**	**$ 112.61**	**$ 123.82**
Other Revenue	$ 1.41	$ 1.41	$ 1.41	$ 1.41	$ 1.41	$ 1.41	$ 1.41
Oil Supply Price	**$ 75.50**	**$ 80.44**	**$ 86.37**	**$ 93.33**	**$ 101.65**	**$ 111.21**	**$ 122.42**

[a] *"Mine" includes costs for mining and size reduction/solids handling (e.g. crushing).*
[b] *Upgrading" includes all costs associated with the delayed coker, hydrotreater, hydrogen plant, sour water stripper, amine treatment unit, and sulfur recovery unit.*
[c] *Same as Table 2, footnote "c."*

Included in the report are detailed supply price breakdowns and an analysis of the sensitivity of the supply price to a range of parameters.

In Situ Oil Sands Scenario

In this scenario, synthetic crude oil is produced from a Uinta Basin oil sand deposit using an in situ extraction process commonly employed in Alberta, Canada, Steam-Assisted Gravity Drainage (SAGD). The scenario is situated within the P.R. Spring STSA, 50 miles south of Vernal, Utah. Due to the lithological variability of the oil sand resource in the Uinta Basin in general and P.R. Spring in particular, it is not possible to model the SAGD process in the geologic setting of the P.R. Spring deposit. Instead, SAGD production costs for this scenario are based on information from a recent SAGD project in Alberta [10] and represents a best case "what-if" scenario were a producer to locate an oil sand deposit amenable to in situ development.

Table 8 lists the major outputs from and inputs to the in situ production of synthetic crude oil from oil sands on a per barrel basis. The CO_2 output (air-fired) is 60% higher than that from the ex situ oil sands scenario (air-fired) due to the CO_2 penalty of heating the ground with steam. The tradeoff is that because the bitumen is produced in situ, there is not a large waste stream of oil sand tailings as with the ex situ oil sands scenario.

Table 8. Major process outputs and inputs on a per barrel basis for in situ oil sands scenario.

Category	Item	Air-Fired	Oxy-Fired	(Units) / bbl of oil
Outputs	Ammonium Sulfate	5.63	5.63	lb
	CO_2 [a]			
	Emitted to Atmosphere	409	324	lb
	Sold to Pipeline	-	107	lb
	Steam (600 psig, 700°F)	83	83	lb
	Petroleum Coke	68	68	lb
	Sulfur	0.77	0.77	lb
	Waste Disposal [b]	5.42	5.42	lb
Inputs	Catalyst	0.02	0.02	lb
	Electricity	18.65	25.14	kWh
	Fuel [c]			
	Purchased	2.18	2.17	MMBtu
	Total	3.06	3.05	MMBtu
	Makeup Water	0.53	0.54	bbl
	O_2	-	109	lb
	Refrigerant	13.58	13.58	MJ
	Steam			
	50 psig	232	232	lb
	450 psig	383	383	lb
	SAGD	1,569	1,569	lb

[a] *Same as Table 1, footnote "a."*
[b] *Mass of solids in brine from one of process units.*
[c] *Same as Table 1, footnote "b."*

The total capital investment for the complete SAGD facility and an air-fired upgrading plant is $1.300 billion; with an oxy-fired upgrading plant, the cost rises to $1.328 billion. The largest capital cost for the air-fired heating system is for SAGD (25% of the total). A breakdown of all capital costs is available in the report.

The base case supply prices for this scenario (air-fired) as a function of hurdle rate are given in Table 9. Taxing CO_2 at the rate of $25 per ton increases the base case supply price by $4.68 to $88.62/bbl at a 0% hurdle rate.

Table 9. Supply price for air-fired in situ oil sands production scenario as a function of hurdle rate.

Hurdle Rate	0%	2%	4%	6%	8%	10%	12%
Drilling	$ 1.29	$ 1.29	$ 1.29	$ 1.29	$ 1.29	$ 1.29	$ 1.29
SAGD	$ 16.83	$ 16.83	$ 16.83	$ 16.83	$ 16.83	$ 16.83	$ 16.83
Upgrading [a]	$ 15.31	$ 15.31	$ 15.31	$ 15.31	$ 15.31	$ 15.31	$ 15.31
Taxes	$ 11.10	$ 13.77	$ 17.10	$ 20.90	$ 25.19	$ 30.38	$ 36.31
Oil Royalties	$ 8.92	$ 9.83	$ 10.92	$ 12.16	$ 13.57	$ 15.20	$ 17.05
Net Earnings	$ -	$ 4.94	$ 10.70	$ 17.29	$ 24.72	$ 33.19	$ 42.71
Maintenance	$ 13.87	$ 13.87	$ 13.87	$ 13.87	$ 13.87	$ 13.87	$ 13.87
Other [b]	$ 18.27	$ 18.33	$ 18.40	$ 18.48	$ 18.57	$ 18.68	$ 18.79
Supply Cost	**$ 85.59**	**$ 94.18**	**$ 104.41**	**$ 116.13**	**$ 129.35**	**$ 144.75**	**$ 162.17**
Other Revenue	$ 1.66	$ 1.66	$ 1.66	$ 1.66	$ 1.66	$ 1.66	$ 1.66
Oil Supply Price	**$ 83.93**	**$ 92.52**	**$ 102.76**	**$ 114.47**	**$ 127.70**	**$ 143.10**	**$ 160.52**

[a] *Same as Table 7, footnote "b."*
[b] *Same as Table 2, footnote "c."*

Detailed supply price breakdowns and an analysis of the sensitivity of the supply price to a range of parameters are available in the report.

Economic Impact Analysis

An input-output analysis evaluates potential economic impacts arising from a 50,000 BPD ex situ oil shale project and a 10,000 BPD ex situ oil sands project from the point of view of two regions: the State of Utah as a whole and the Uinta Basin. The impacts associated with the projects' four-year construction phase are estimated separately from those of the 20-year operations phase. Because the reported estimates are for a successful industry, impact estimates for projects unlikely to realize commercial success are as speculative as the project itself.

Table 10 reports the economic impacts by region associated with the operations phase. In this analysis, one-third of total expenditures are expected to be spent in the Uinta Basin, while one-half are expected to be spent in the State of Utah. As there is no historical data on purchases, these fractions are simply assumed. If the actual amount is higher or lower by some factor, the estimated impacts are increased or reduced by the same factor because of the linearity of the input-output model.

Table 10. Economic impacts attributed to the operations phase of the ex situ development scenarios during the 20 years of production. With the exception of "Job-Years," all units are in millions of 2012 US$.

Industry	Regional Share	Sales	Wage Earnings	Job-Years	Value-Added
Tosco II oil shale—State of Utah	6,274.6	10,996.2	2,495.6	58,954	6,203.9
Tosco II oil shale—Uinta Basin	4,141.3	5,220.5	1,250.7	26,304	—
Paraho Direct oil shale—State of Utah	5,871.6	10,353.6	2,245.6	50,468	5,853.7
Paraho Direct oil shale—Uinta Basin	3,875.2	5,047.8	1,130.1	21,879	—
Ex situ oil sands—State of Utah	1,525.5	2,746.1	622.2	15,013	1,493.7
Ex situ oil sands—Uinta Basin	1,006.8	1,320.3	344.8	7,388	—

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