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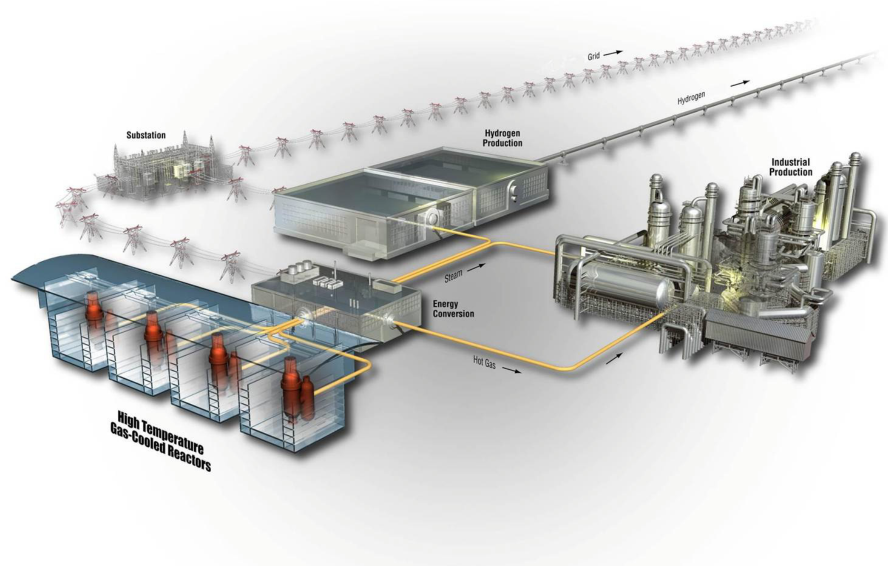
Technical Evaluation Study

Project No. 23843

Integration of HTGRs with an In Situ Oil Shale Operation



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REVISION LOG

Rev.	Date	Affected Pages	Revision Description
0	11/18/2010	All	Newly issued document
1	05/16/2011	All	Refined approach and calculations

CONTENTS

ACRONYMS AND NOMENCLATURE

API	American Petroleum Institute
bbl	barrel (42 gallons)
Btu	British thermal unit
DOE	Department of Energy
EROI	energy return on investment
FA	Fischer Assay
gal	gallon
HTGR	high-temperature, gas-cooled reactor
INL	Idaho National Laboratory
lbm	pound (mass)
MPa	mega pascal
MW	mega watt
NGNP	next generation nuclear plant
RD&D	research, development, and demonstration
SAGD	steam-assisted gravity drainage
scf	standard cubic feet
TEV	technical evaluation

1. INTRODUCTION

This technical evaluation (TEV) addresses potential integration opportunities for single or multiple High Temperature Gas-cooled Reactor (HTGR) modules with production of oil from oil shale using an in situ retort process. It has been prepared as part of a study for the Next Generation Nuclear Plant (NGNP) Project to evaluate the integration of HTGR technology with conventional chemical processes. The NGNP Project functions under U.S. Department of Energy (DOE) direction to meet a national strategic need identified in the *Energy Policy Act* of 2005 to promote reliance on safe, clean, economic nuclear energy and to establish a greenhouse-gas-free technology for the production of hydrogen. The NGNP represents an integration of high-temperature reactor technology with advanced hydrogen, electricity, and process heat production capabilities, thereby meeting the mission need identified by DOE. The strategic goal of the NGNP Project is to broaden the environmental and economic benefits of nuclear energy in the U.S. economy by demonstrating its applicability to market sectors not being served by light water reactors.

1.1 High Temperature Gas-Cooled Nuclear Reactor Background

An HTGR module produces process heat (steam or high-temperature helium), electricity, and/or hydrogen. An HTGR outlet temperature of 750°C for the primary fluid loop is assumed for this study, which reflects the initial HTGR design and assumes a conservative outlet temperature; temperatures of 950°C are anticipated for advanced HTGR designs. The output from a single HTGR module is assumed to be 600 MWth. A 25°C temperature approach is also assumed for the heat exchanger between the primary and secondary fluid loops.

In conventional chemical processes, process heat, electricity, and hydrogen are generated by the combustion of fossil fuels such as coal and natural gas, resulting in significant emissions of greenhouse gases such as carbon dioxide (CO_2). An HTGR could produce and supply these products to conventional chemical processes without generating any greenhouse gases. The use of an HTGR to supply process heat, electricity, or hydrogen to conventional processes is referred to as an HTGR-integrated process.

1.2 Oil Shale Background

The oil resource within the Green River Formation oil shale deposits in Colorado, Utah, and Wyoming is over 3 trillion barrels (Johnson et al. 2010a; Johnson et al. 2010b; Bartis et al. 2005). The total recoverable oil from this resource is estimated to be about 1.4 trillion barrels (Bartis et al. 2005), which is greater than the 1.1 trillion barrels of total historical world oil production (BP, 2010). Comparing these historical and potential oil recoveries shows that the oil shale recoverable resource is very, very large and that commercial oil production from oil shale will likely continue for many decades and perhaps centuries due to the huge quantity of the resource.

There are no commercial scale in situ oil shale operations anywhere in the world at this time. However, field-scale research, development, and demonstration (RD&D) projects are currently operating in western Colorado and eastern Utah. A large-scale, commercial in situ oil shale industry in the U.S. may emerge within the next 10 to 15 years. Even though there are no commercial in situ oil shale operations, numerous reports and analyses have been written and performed from which to draw the parameters necessary to perform an analysis of a hypothetical in situ oil shale production operation and its integration with an HTGR. Development and deployment of a commercial HTGR may also require 10 to 15 years. Thus, this conceptual study of integrating an HTGR with an in situ oil operation is timely.

The process of heating oil shale in an anoxic environment to pyrolyze the kerogen embedded within the oil shale and produce oil and gas is commonly called retorting. Kerogen is the organic portion of oil shale and is largely insoluble in organic solvents because of its very large molecular structure. If buried at sufficient depth, time, and concentration, kerogen will release oil and gas; however, kerogen-rich oil shale deposits have not been buried at sufficient depths for oil and gas to form naturally. Retorting the oil shale is a method to convert the kerogen to oil and gas.

Shallow oil shale deposits may be mined and processed in a surface, or ex situ, retort. Deeper oil shale deposits may be retorted in situ by conveying heat into the subsurface and producing the resulting oil and gas in a manner similar to conventional oil and gas production.

The basis for this evaluation is an in situ oil shale production project producing 50,000 bbl/day of shale oil, the product being ready for transport via pipeline to a local refinery. This analysis assumes that refining capacity exists in the region to accept the shale oil produced from the operation.

Production from an in situ oil shale operation is assumed to be located in the Piceance Basin in northwestern Colorado from the R1 through R2 zones, oil shale zones below the nahcolite sealing zone, which separates the fresh water aquifer above and the highly saline water zone below (Burnham 2008a; Day 2009). Contamination of fresh ground water during and after an in situ oil shale retort is not expected to occur because of the thickness of the low permeability nahcolite layer separating the fresh water aquifer and the deeper oil shale retort zone. No additional efforts to limit contamination of the shallower fresh water zones (e.g., development and maintenance of a freeze wall) are assumed to be required.

A schematic diagram of an in situ oil shale retort operation developed by American Shale Oil LLC is shown in Figure 1. Heat is supplied to the desired subsurface interval or zone to be retorted through a closed loop injection and return piping system. The circulating fluid does not directly contact the oil shale, but transfers its heat by conduction through the pipe wall.

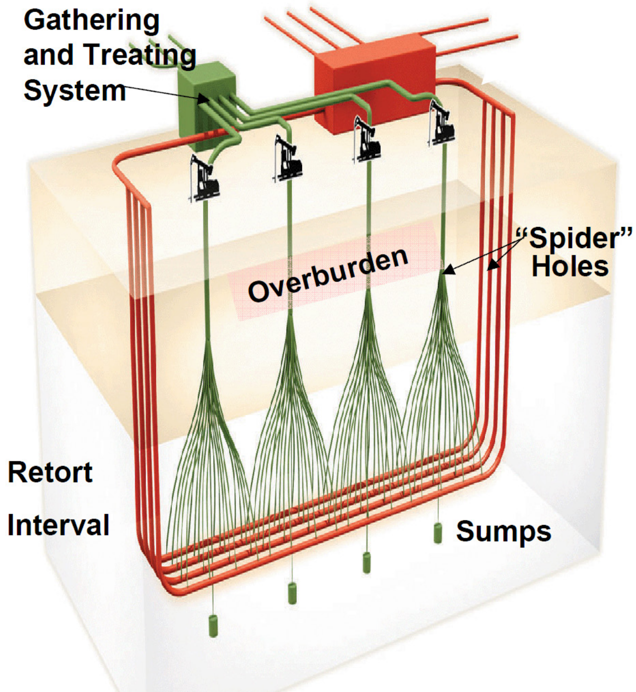

Figure 1. A schematic diagram of a possible configuration for the production of oil from an in situ oil shale retort operation. The closed loop piping system for the circulation of hot fluids is shown in red and the hydrocarbon fluids-gathering system is shown in green.

Other alternative configurations for supplying heat to the formation are being actively considered by industry such as vertical electric heater wells (Vinegar 2006) and using electrically conductive fractures to supply heat (Symington 2006). However, the design shown in Figure 1 where heat is transferred to the oil shale by conduction through the walls of a closed-loop piping system takes advantage of the heat supplied by an HTGR without the inherent energy losses associated with energy conversion.

1.3 Integrating HTGRs with In Situ Oil Shale Retort Operation

This report describes how an HTGR could be integrated into an in situ oil shale production operation. A future report will provide a preliminary economic analysis comparing the HTGR-integrated process with the base concept of an in situ oil shale production process.

Two fluids, high temperature helium and steam, were initially considered as working fluids in the secondary flow loop that supplies heat to the in situ retort. However, the steam option required significantly less power to circulate the fluid through the closed loop piping system and the helium option was dropped from further consideration. Other heat transfer fluids are possible, but because this report relies on completed assessments by the NGNP working group, considering new heat transfer fluids is beyond the scope of this report. For this TEV, an

HTGR module(s) is assumed to be physically located near the oil shale operation such that the heat lost during surface transport of the heating fluid is negligible. This TEV does not offer an assessment of the optimal siting of an HTGR with respect to an in situ oil shale retort operation facility. If an optimal siting assessment is desired, a separate study will be conducted that balances the distance between the two facilities to consider safety, heat loss, and licensing concerns.

The option shown in Figure 1 is an early design of a commercial scale in situ oil shale operation developed by American Shale Oil LLC, which is actively advancing its technology on its in situ RD&D oil shale lease in the United States. American Shale Oil LLC has modified their design for its small-scale demonstration, but may revert to the Figure 1 design for commercial operation.[a] Using electricity (as opposed to utilizing the HTGR heat directly) from an HTGR for heat generation via electric heaters is possible, but converting heat to electricity and then back to heat is an inefficient process and has high energy losses. The closed-loop production design in Figure 1 was selected as the base case for HTGR integration because it has the capacity to directly utilize and recycle the heat output from an HTGR.

2. MASS BALANCE – PRODUCTION FROM IN SITU RETORT

Shale oil is produced from oil shale by pyrolyzing the kerogen molecules within the oil shale to generate oil, gas, and char. The mass balance for oil and gas generation for an in situ oil shale retort was done by balancing the carbon and hydrogen atoms in the parent molecule (kerogen) with the carbon and hydrogen atoms in the product molecules (char, oil, and gas). The mass balance of the generated products per mass of kerogen is listed in Table 1. For details on the mass balance calculations, refer to Appendix A.

Table 1. Kerogen pyrolysis mass balance for in situ retort.

Product	Calculated Value	Units
Char	0.286	g char/g kerogen
Gas	0.196	g gas/g kerogen
Shale oil	0.518	g oil/g kerogen
Total of products	1.000	g total product/g kerogen

The produced char is a solid that is left in place within the oil shale retort zone, while the oil and gas are mobile and able to flow through the subsurface to production wells. The shale oil is high quality oil with a gravity of 40°API. The produced gas has a high BTU content of about 1770 Btu/scf compared to common natural gas, which has a Btu content of about 1000 Btu/scf.

[a] Personal communication with Alan Burnham, of American Shale Oil LLC (August 2010).

Based on the mass balance values shown in Table 1, the amounts of the pyrolysis products were calculated per ton of in-place, raw oil shale ore. (The volume of one ton of raw oil shale is about 14.6 ft^3 or a cube with sides 2.44 feet in length). Table 2 shows the pyrolysis products in various units per ton of oil shale.

Table 2. Amounts of each in situ pyrolysis product in various forms. Amount of Fischer Assay oil is shown for comparison.

		Product generated per ton of oil shale			
Pyrolysis product		**Gal**	**scf**	**million Btu**	**lbm**
In situ pyrolysis products	Shale oil	20.0	—	2.68	138
	Gas	—	652	1.15	52
	Char	—	—	1.03	76
Fischer Assay oil		25.2	—	3.68	197

The oil shale grade is commonly measured using a standardized test called a Fischer Assay (FA). It is a measure of the richness of the oil shale and provides a measurement of the oil generated from a laboratory sample following a proscribed methodology, which generates a standardized measurement that can be used to compare oil shale zones. The gas and char produced by the FA are not typically reported.

3. MODELING THE INTEGRATION OF HTGR HEAT TO IN SITU OIL SHALE PRODUCTION

Two oil shale production cases were identified for modeling:

1. A base case concept of in situ oil shale retort in which a subsurface retort interval is heated by circulating steam through a closed-loop piping system drilled horizontally through the retort interval. The high-pressure steam is heated in a gas-fired burner.

2. An HTGR-integrated case, which is the same as the base case except the gas-fired burner is replaced by a heat exchanger taking heat from an HTGR.

A schematic block flow diagram of the base case concept of an in situ oil shale retort is shown in Figure 2. Products include light oil, similar in gravity to a high-quality conventional crude oil; a high-Btu content gas; electricity, and carbon dioxide. A portion of the produced gas is burned to provide heat to the heating fluid loop and the rest is sold. A power cycle is added to the heating fluid loop between the in situ retort and the combustor in order to reduce the temperature of the returning heat transfer fluid to the maximum pumping temperature.

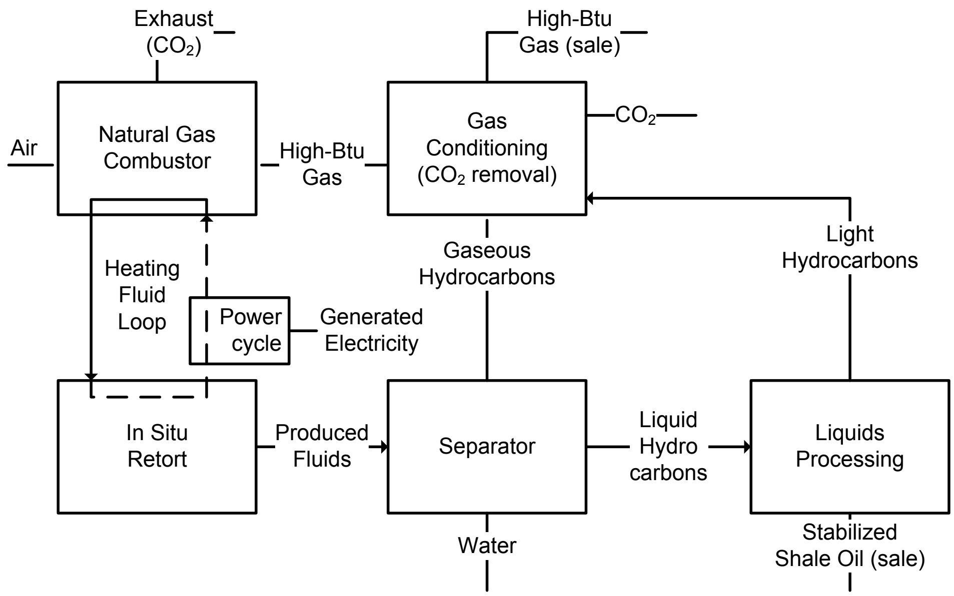

Figure 2. Simplified block flow diagram for the base case concept of an in situ oil shale retort operation.

The simplified block flow diagram for the HTGR-integrated case is shown in Figure 3. The natural gas combustor used in the base case is replaced by an HTGR/heat-exchanger located nearby that supplies heat to the oil shale operation. In the HTGR-integrated case, the entire high-Btu gas stream is sold instead of burning a portion of it to heat the steam; thus, CO_2 emissions from flue gas are eliminated.

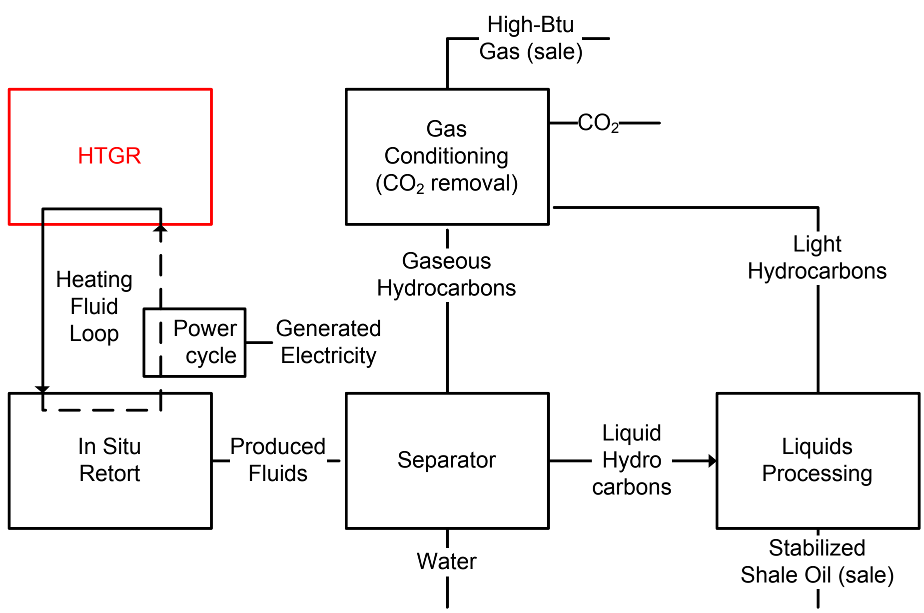

Figure 3. Simplified block flow diagram for an HTGR-integrated in situ oil shale retort operation. Objects in red represent changes to the base case.

A simplified schematic of the flow loops employed to deliver heat to an in situ retort zone is shown in Figure 4 with the HTGR-integrated case shown as part (A) and the base case shown as part (B). The flow loop of the base case is the same as the HTGR-integrated case except that a gas fired burner and heat exchanger replace the HTGR and helium heat transfer loop shown in part (A).

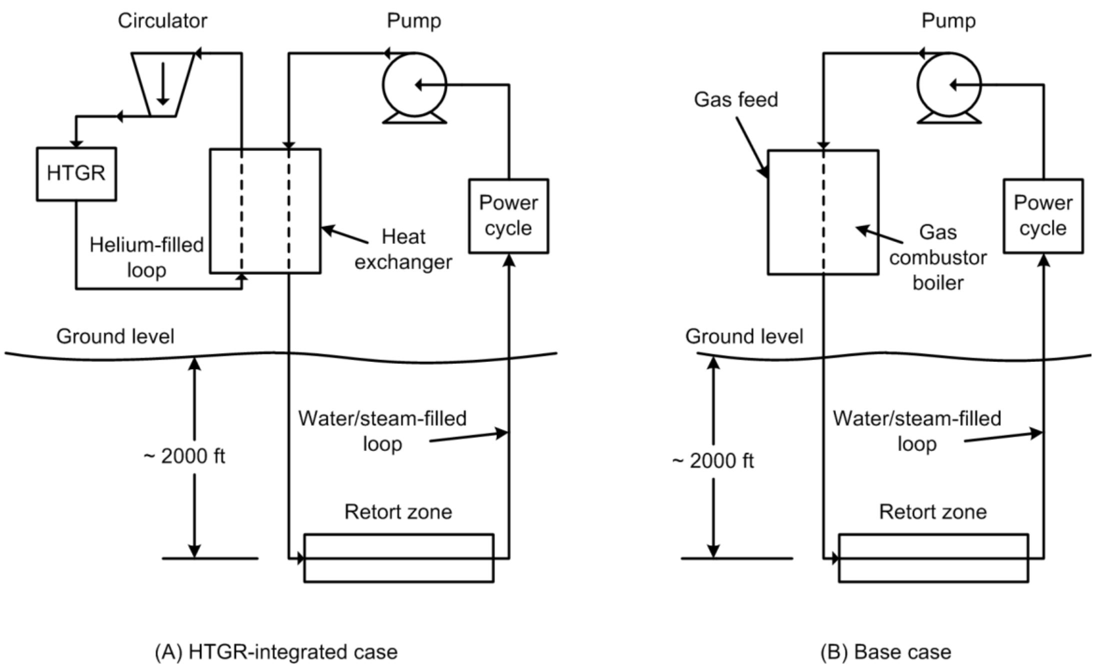

Figure 4. Simplified schematic of the integration of the closed-loop heat transfer lines integrating the HTGR to the in situ oil shale retort zone.

Heat and fluid movement through the heat transfer loops for both cases were modeled using Hyprotech's HYSYS.Plant™ process modeling software.[b] A single, closed 8-inch heat transfer loop (Burnham et al. 2008b) was modeled and then scaled up to match the required heat transfer rate to produce 50,000 bbl/day of shale oil. The following assumptions were used to model the flow loops:

- Pressure drops in heat exchangers are 2% of the nominal pressure
- The helium circulators have adiabatic efficiencies of 80%
- Water pumps have an adiabatic efficiency of 75%
- Power cycle efficiency was assumed to 35% (TEV-981 2010)
- Four inches of insulation on the surface pipe
- Vacuum insulated pipe for the two 2000-ft vertical sections of the piping system

[b] v2.2.2 (Build 3806).

- Uninsulated pipes for the underground horizontal leg running through the retort zone.

Figure 5 is a schematic of the HTGR-integrated case showing values for key fluid parameters of a full-scale operation. All values shown in this figure and elsewhere in this evaluation were calculated using the default or most likely input parameters unless otherwise noted. The values associated with the right flow loop apply to the base case as well as the HTGR-integrated case.

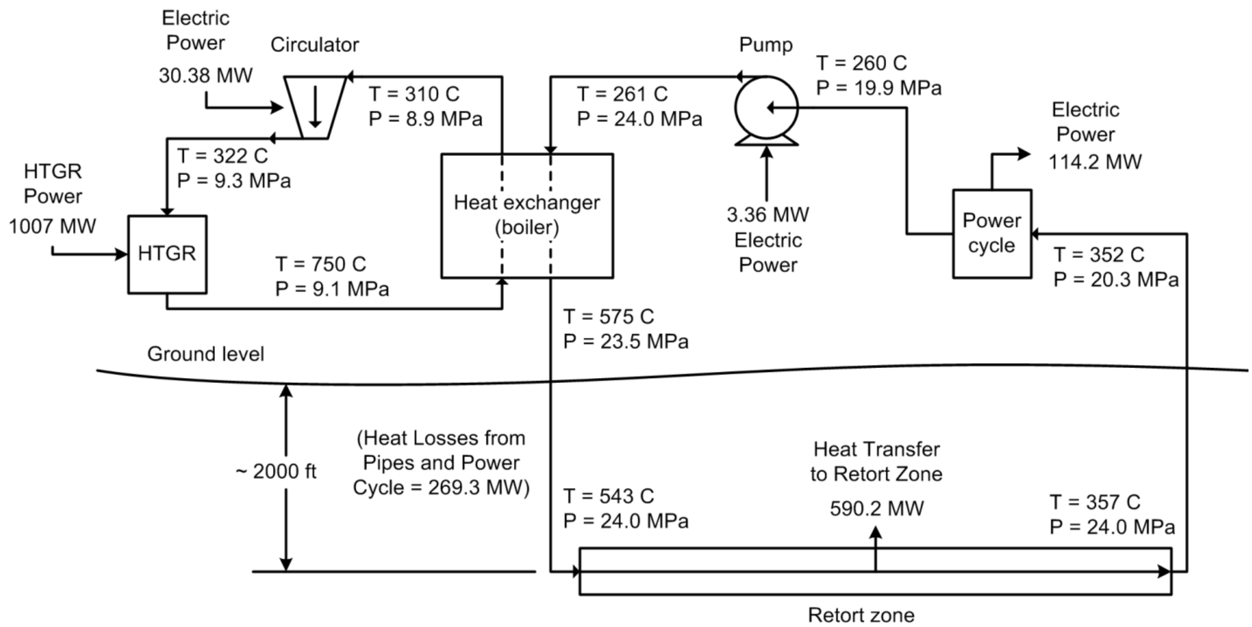

Figure 5. Process flow diagram for an HTGR-integrated oil shale process. For the base case, the figure and values are identical except a gas burner replaces the primary heat transfer loop containing the HTGR.

All values shown in Figure 5 were calculated by the modeling software except the temperatures and pressures at the following locations, which were set and fixed:

- helium exiting the HTGR, temperature and pressure (based on the prismatic HTGR operating at 750°C)
- steam exiting the heat exchanger, temperature and pressure (575°C is maximum temperature for subsurface injection to avoid decomposition of the oil shale carbonate host rock)
- steam in retort zone, average temperature (set above the minimum retort temperature) and heat transfer rate (set to that required to achieve production of 50,000 bbl/day of shale oil)
- steam entering pump, temperature (set below maximum pump temperature design specification).

For the HTGR-integrated case, the energy content of the helium entering the heat exchanger is 1007 MW and was calculated by the following equation:

$$\begin{aligned}\text{HTGR power} = {} & \text{Heat transfer rate to retort zone} \\ & + \text{Heat loss rate from pipes and power cycle} \\ & + \text{Power generated by power cycle} \\ & - \text{Power used in water pump} \\ & - \text{Power used in helium circulator}\,.\end{aligned} \tag{1}$$

For the base case, the heat content of the gas being combusted in the gas burner is the sum of the power used and the power generated divided by the thermal efficiency of the gas burner. A thermal efficiency for the gas burner of 86.5% was calculated by ASPEN Plus using ethane and assuming a stack exhaust temperature of 275°F (135°C). The heat content of the gas feed into the gas burner was calculated to be 1122 MW.

4. ENERGY BALANCE

Assumptions, calculations, and details pertaining to the energy balance are located in Appendix A. To produce 50,000 bbl/day of shale oil, the required heat transfer rate to the subsurface retort zone was calculated to be 590 MW_{th}. This is the total heat transfer rate that needs to occur through the horizontal heater wells drilled through the retort zone. A number of heater wells must be employed simultaneously to achieve the necessary heat transfer rate to the retort zone.

The energy output from the HTGR or the gas burner/steam boiler is equal to the required energy to retort oil shale and produce 50,000 bbl/day of shale oil plus any other losses or uses.

4.1 Energy Input

The energy input into each case includes all heat and electricity necessary to operate the systems. For the base case, this includes the heat content of the gas being burned in the gas boiler and the electricity necessary to run the circulation pump and surface facilities. The energy input for the base case is 1131 MW.

For the HTGR-integrated case, the energy input includes the heat content of the helium exiting the HTGR, the electricity necessary to circulate the helium heat transfer loop, electricity necessary to circulate the steam heat transfer loop, and the electricity necessary to operate the other surface facilities. The energy input for the HTGR-integrated case is 1047 MW.

4.2 Energy Output

Total energy output is the energy content of the produced oil, gas, and electricity. Both cases produce the same amount of oil, gas, and electricity. After converting the heat content flow of these streams to similar units, they sum to 5027 MW.

4.3 Energy Balance Summary

The energy balance for two cases was determined and the energy return on investment (EROI) was calculated. The EROI is the ratio of the total energy outputs to the total energy inputs described in the previous paragraphs. The EROIs for the base case and the HTGR-integrated case are 4.44 and 4.80 respectively. The energy inputs, outputs, and EROIs for each case are summarized in Table 3. As a comparison, Lerwick (2006) estimated an EROI of 10.5 for conventional petroleum recovery and 5.0 for steam-assisted gravity drainage (SAGD) recovery of Canadian oil sands.

Table 3. Energy input and output values used to calculate the (EROI) for the base case and the HTGR-integrated case using default valued for the input parameters.[c]

	Base case	**HTGR case**
Energy Output		
Shale oil sold, MW	3431	3431
Gas total, MW	1482	1482
Electricity total, MW	114	114
Total output, MW	5027	5027
Energy Input		
Boiler output, MW	1122	—
HTGR, MW	—	1007
Steam pump, MW	3	3
Helium circulator, MW	—	30
Processing facilities, MW	6	6
Total input, MW	1131	1047
EROI, MW_{out}/MW_{in}	4.44	4.80

5. CARBON DIOXIDE EMISSIONS

CO_2 emissions can result from decomposition of the oil shale mineral and from combustion of fossil fuels to generate heat or electricity.

c. The EROI calculations do not include energy used to capture, compress, and sequester any produced carbon dioxide for either case.

5.1 CO_2 from Mineral Decomposition

The CO_2 production rate resulting from the decomposition of the oil shale minerals (kerogen and nahcolite), CO_{2m}, is calculated from the following equation:

$$CO_{2m} = 720.2\frac{CO_{2k}q_o}{G_{FA}} \; ; \qquad (2)$$

where CO_{2k} is the CO_2 produced per gram of oil shale (6.4 mg/g of oil shale from Boak [2007] and Burnham and Carrol [2008]) and the 720.2 coefficient is a conversion factor with units of (1,000 gal-scf/ton-bbl) and results in 9,142,000 scf/day of CO_2 from mineral decomposition for a 50,000 bbl/day shale oil operation. This portion of the total CO_2 emissions applies to both the base case and the HTGR case. The FA grade of the oil shale is represented by G_{FA} and the shale oil production rate represented by q_o.

5.2 CO_2 from Flue Gas

Carbon dioxide emitted from combustion of the produced gas to produce the heat necessary for retorting the oil shale is the major contributor to CO_2 emissions for the base case, but has no bearing on the HTGR case because in this case, no fossil fuels are combusted.

Flue gas CO_2 is a function of the number of carbon atoms in the combustion gas molecule and the flow rate of the combustion gas into the steam boiler. All the carbon in the combustion gas is assumed to be converted to CO_2. Assuming a gas composition equivalent to ethane (see Table 4), the CO_2 emission rate is 103.9 million scf/day

5.3 Total CO_2 Emissions

The total amount of CO_2 emitted is the sum of the CO_2 emitted in the flue gas stream and the CO_2 emitted as a result of the decomposition of kerogen and minerals. Table 4 shows the total CO_2 emitted for the base case and the two HTGR integrated cases.

Table 4. Total CO_2 emitted from a 50,000 bbl/day in situ oil shale operation for the cases described in this document.

	Total CO_2 Emitted	
Case	**scf/day**	**ton/day**
Base Case	113,100,000	6,595
HTGR-Integrated Case	9,140,000	533

6. DISCUSSION

6.1 Physical Phase of the Heat Transfer Fluid

The water is in a supercritical state (critical point for water is 374.08°C and 22.11 MPa) a significant portion of the time as it moves through the heat transfer loop (refer to Figure 5).

It is supercritical as it exits the heat exchanger and remains supercritical until halfway through the retort zone.

As the fluid exits the retort zone, it is in the compressible liquid state, with a temperature slightly lower than the critical temperature, but the pressure remains above the critical pressure. It is a true liquid as it enters the power cycle and remains in the true liquid state until it exits the pump and is pressurized to a point above the critical pressure, but below the critical temperature (compressible liquid state). Upon exiting the heat exchanger, both the temperature and the pressure are above the critical point and it is again a supercritical fluid.

6.2 Velocity of Heat Transfer Fluid and Frictional Pressure Drop

The mass flow rate for the steam/water in the secondary heat transfer loop (see Figure 5) was calculated by the HYSIS modeling software to deliver the specific heat to the retort zone. Knowing the internal diameter of the pipe through which it travels and the density of the fluid, its velocity can be calculated.

For a single heat transfer loop, the mass flow rate was calculated to be 0.82 kg/s through an eight-inch pipe. The average velocity of the fluid entering the retort zone is 1.1 ft/s. The average velocity exiting the retort zone is 0.14 ft/s. Further downstream, the density decreases, further reducing the velocity.

With such low flow velocities, the pressure drop due to pipe friction through the eight-inch diameter, 10,000-ft heat transfer loop is quite small. A smaller diameter piping system could be possible. Preliminary modeling of smaller pipes indicated that pipe diameters less than four inches resulted in significant frictional pressure drops.

6.3 Affect of Heater Pipe Temperature on HTGR Size and Gas Burner Input

The size (power output) of the HTGR for the HTGR-integrated case and the power input to the gas burner for the base case are both strongly dependent on the average temperature of the heater pipe. The lowest average temperature of the heater pipe within the retort zone is 450°C constrained by the maximum temperature entering the ground and the minimum temperature exiting the retort zone. Higher average temperatures can be obtained by increasing the mass flow rate such that the outlet temperature is raised to nearly the inlet temperature.

Recall that the maximum temperature of the water entering the pump is 260°C per pump specifications. Although raising the average heater pipe temperature decreases the time required for the formation to reach the retort temperature, it also requires that more heat be taken out of the system before entering the circulation pump. Heat is removed from the secondary loop by employing a power cycle to generate electricity. The more heat must be removed, the more electricity will be produced, and the more heat must be added upstream to compensate. As the average temperature of the pipe in the retort zone approaches 550°C, the amount of electricity produced in the power cycle begins to dwarf the amount of heat delivered to the retort zone, and both cases, in effect, become electricity generating plants.

This is demonstrated for the HTGR-integrated case by the data plotted in Figure 6, which plots the HTGR power, heat loss, and electric power generated as functions of the average temperature of the heater pipe through the retort zone. Results would be similar for the base case. For the base case, as the average temperature increases to above 465°C, insufficient gas is produced to supply the necessary heat to power the system and the case becomes a net importer of gas.

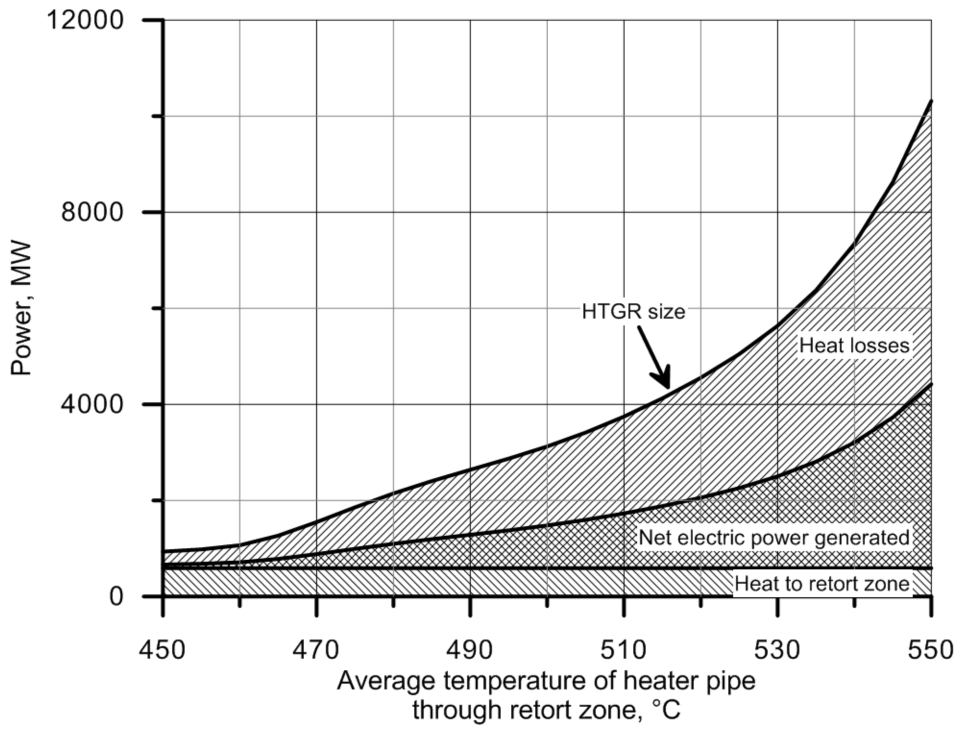

Figure 6. Relationship showing HTGR reactor size necessary to deliver the required heat transfer rate to the retort zone for various heater pipe temperatures.

6.4 Subsurface Development Rate

A 50,000 bbl/day in situ oil shale operation can be expected to expand in the subsurface at a rate of 68.6 acres per year based on an oil shale grade of 25.2 gal/ton, the oil shale retort zone thickness of 235 ft, and a recovery efficiency of 80%. If the life of such a project is assumed to be 30 years of production, the area of the subsurface retorted zone would be just over 2000 acres or 3.2 mi^2. A thicker retort zone would reduce the expansion rate and the ultimate retort area would be smaller. Doubling the 30-year life to 60 years would also double the subsurface retort area.

6.5 Monte Carlo Analysis

By applying a distribution to the values of the input parameters, a probabilistic outcome can be obtained, which yields greater information than a single deterministic result. The preceding mass and energy balance and carbon dioxide emission calculations are included in an Excel™ spreadsheet, which is included in the project files. All input values were selected from best available sources, but may vary from these sources depending on site ultimately selected for field implementation. This section describes how the results can vary because of changes to the input variables and discusses which inputs are the most critical with respect to key output parameters.

A Monte Carlo analysis was done in the spreadsheet using Oracle Crystal Ball software.[d] The distributions of all input variables were assumed to be triangular with minimum, maximum, and most likely values as listed in Table 5.

6.5.1 Base case Monte Carlo analysis

The probability distribution for the base case EROI is shown in Figure 7. The EROI calculated using the most likely input values was 4.44, the mean value was 4.58, and the standard deviation of the distribution was 0.57. Other distribution parameters are listed in the figure.

[d] Excel-based add-in software from Oracle Corporation

Table 5. Input parameters and their respective default (most likely) values and triangular distribution parameters.

Input parameter	Units	Minimum	Most Likely	Maximum
API gravity of shale oil	°API	36.0	40.0	44.0
API gravity of FA oil, °API	°API	18.0	20.0	22.0
H/C ratio of kerogen	dimensionless	1.44	1.60	1.76
H/C ratio of char	dimensionless	0.40	0.44	0.48
H/C ratio of gas	dimensionless	2.75	3.00	3.75
FA/kerogen ratio	g/g	0.67	0.74	0.81
Shale oil/FA oil ratio	g/g	0.63	0.70	0.77
Boiler thermal efficiency	dimensionless	0.85	0.865	0.88
Recovery of oil and gas	dimensionless	0.72	0.80	0.88
FA grade	gal/ton	22.69	25.21	27.73
Average final temperature in retort zone	°C	360	370	380
CO_2 from mineral and kerogen	mg/g	5.8	6.4	7.0
Surface facilities electricity needs	W/(bbl/day)	111	123	135
Heater well average temperature	ft	450	450	550
Spacing of heater wells	ft	35	55	75
Heat transfer ratio	dimensionless	1.0	2.0	4.0

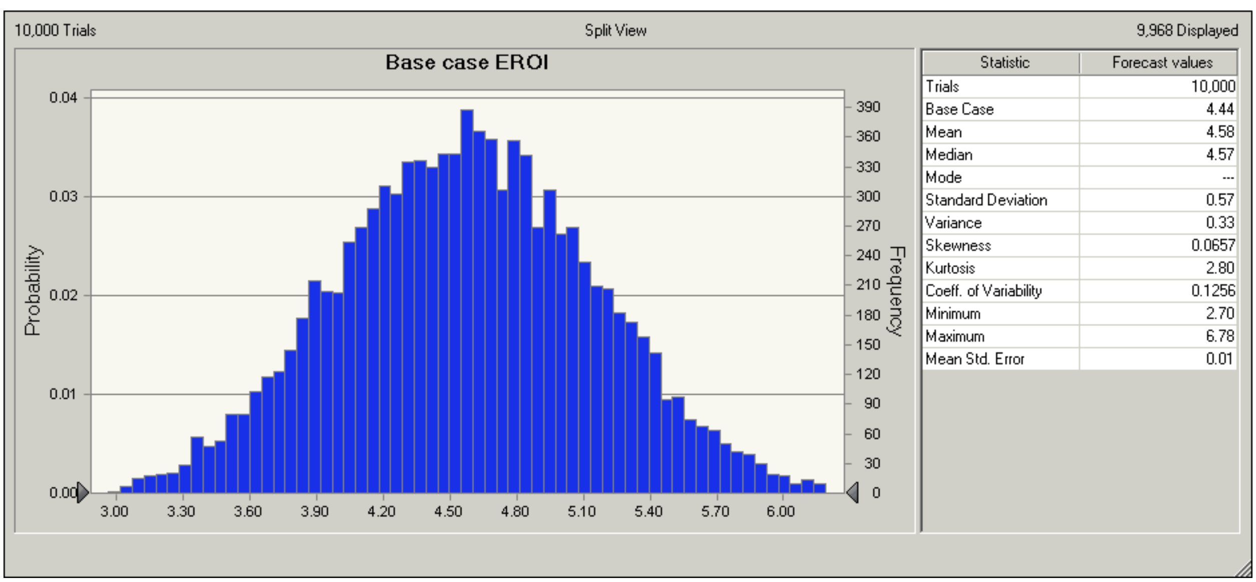

Figure 7. Probabilistic distribution of the energy return on investment (EROI) for the base case.

A sensitivity analysis of the input variables was done to determine changes in which parameters cause the most variance in the EROI. Results of this sensitivity analysis are shown in Figure 8. The sensitivity chart shows the influence of each input parameter on the calculated EROI ranked according to their importance to the outcome of the EROI. The most critical input parameters for the base case identified by the sensitivity analysis were:

- the heat transfer ratio
- the recovery of the converted kerogen
- the composition of the kerogen
- the mass of FA oil to kerogen ratio, and
- the FA grade of the oil shale.

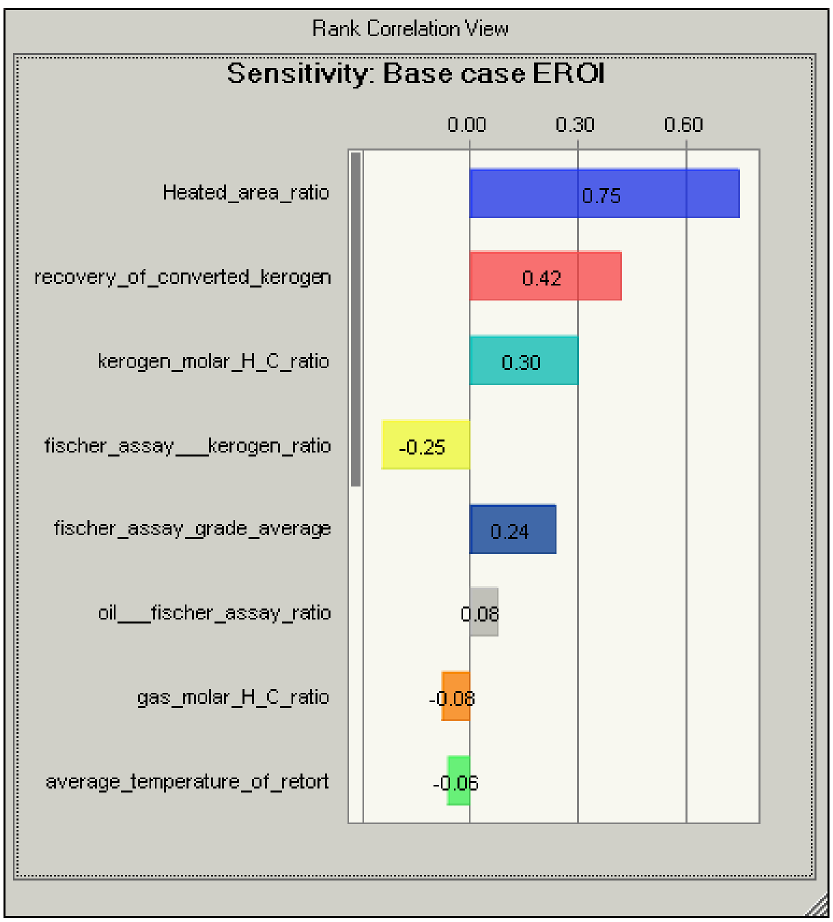

Figure 8. Sensitivity analysis of input variables on the EROI of the base case.

6.5.2 HTGR-integrated case Monte Carlo analysis

The probability distribution for the HTGR-integrated case EROI was very similar to the base case. The EROI using the most likely values for the input parameters is 4.80 (slightly higher than the base case), the mean value is 4.97, and the standard deviation of the distribution is 0.67.

The most critical input parameters for the HTGR-integrated case identified by the sensitivity analysis were the same and in the same order as the base case.

7. SUMMARY, CONCLUSIONS, AND RECOMMENDATIONS

An in situ oil shale retort operation with output of 50,000 bbl/day of refinery-ready shale oil was modeled for two different cases. Each case used a closed-loop piping system through which steam, used as a heat transfer fluid, delivered heat to the in situ retort operation. The two cases are described below.

Case Name	Heat Source	Heat Transfer Fluid
Base	Natural gas burner	Steam
HTGR-Integrated	HTGR	Steam

Results for each of the cases using the most likely input parameters are summarized in Figure 9 showing mass and energy inputs and outputs for each case.

7.1 Conclusions

The following conclusions were drawn from this evaluation:

- High-Btu hydrocarbon gas is produced in each case during the pyrolysis of the kerogen in the oil shale. Over 75% of the produced gas in the base case is used to generate the heat needed for the retort process (see dashed line in Figure 9); while in the HTGR-integrated case, the full gas stream is available for sale.

- CO_2 is produced from both cases as well, but the base case produces more than 12 times more CO_2 than the HTGR-integrated cases, which may become an important economic and environmental issue if future CO_2 emissions are restricted either by governmental controls or through penalties.

- In both cases, excess electricity is generated and can be sold as revenue. The base case produces 42% more electricity than the HTGR-integrated case.

- The heat put into the system for the HTGR-integrated case (1007 MW) is less than the heat input for the base case (1122 MW).

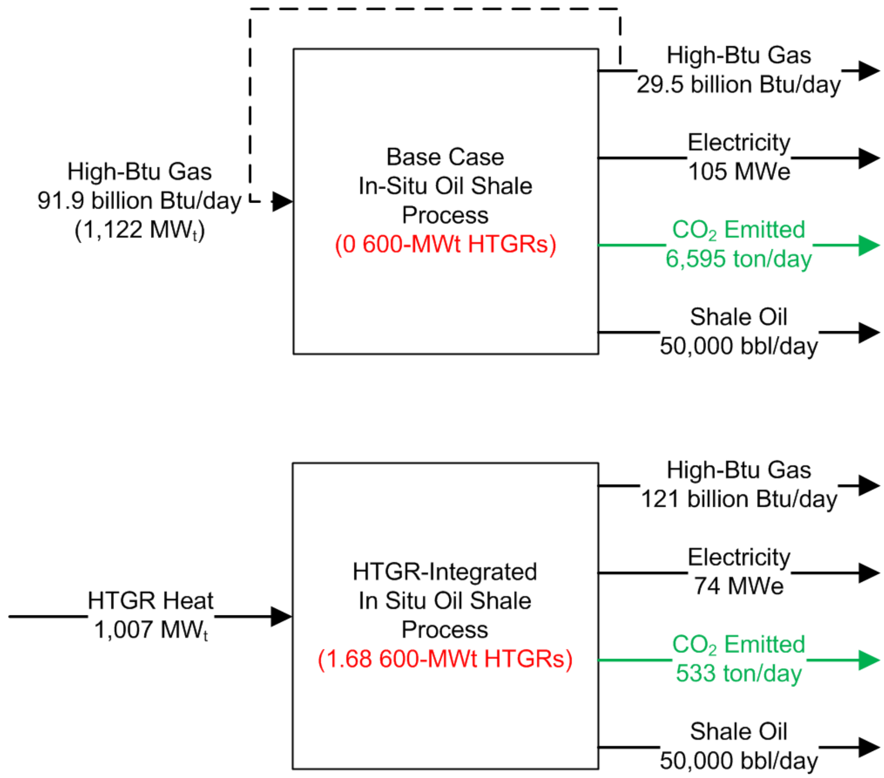

Figure 9. Summary results showing net mass and energy inputs and outputs of the two cases analyzed for oil production from an in situ oil shale retort operation using the most likely values for the input parameters.

- The energy return on investment (EROI) for the base case is 4.44, while the EROI for the HTGR-integrated case is 4.80. These EROI values do not include the energy required to capture, compress, and sequester any generated CO_2.

- High average temperatures of the heater pipe through the retort zone result in excessive energy losses due to temperature and pressure constraints on the pump circulating the steam and water through the retort zone.

- After 60 years of oil production from an in situ retort operation, the retorted zone would expand to just over 4000 subsurface acres or 6.4 square miles. If an HTGR were to be located in the center of the 6.4 mi^2, the distance from the HTGR to the furthest point of the retort zone would be 1.8 miles. Transporting heat this distance is not expected to be of concern. If the retort zone thickness were greater than the assumed 235 ft, the horizontal area of the zone could potentially be much smaller.

- For both cases, the analysis identified the heat transfer ratio as the most critical input parameter for this case, followed by the recoverable fraction of the generated oil and gas, the composition of the kerogen in the oil shale, the mass of FA oil to kerogen ratio, and the FA grade of the oil shale. Refining the estimates and narrowing the potential distribution of these critical variables through further research would reduce the variability and uncertainty associated with the outcome of these cases.

7.2 Future Work and Recommendations

The following work is recommended to more fully understand the challenges and advantages of integrating an HTGR to a commercial-scale in situ oil shale retort project:

- Incorporate an economic analysis of the cases evaluated in this paper.

- Understand in greater detail the heat transfer rate from a heated pipe to an oil shale retort zone and incorporate findings to reduce the uncertainty of model results. This work should be done at in situ retorting conditions and should include the potential for thermal fragmentation and heat transfer by fluid convection, as well as heat transfer by simple conduction.

- Examine the energy requirements for CO_2 capture, compression, and storage; and incorporate them in the energy balance to provide a clearer picture of the comparison between the HTGR-integrated oil shale case and the base case that utilizes fossil fuels to generate the required retorting heat.

- Compare HTGR-integrated oil shale recovery and recovery using vertical electric heater wells and electrically conductive fractures, including economics, when there is sufficient data to support a meaningful comparison.

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9. APPENDIXES

Appendix A, Mass and Energy Balance Calculations and Incorporation of External Review Comments

Appendix B, External Review of Preliminary INL work by Ray Zahradnik

APPENDIX A—Mass and Energy Balance Calculations and Incorporation of External Review Comments

Dr. Ray Zahradnik of Mountain Bay Associates, Steamboat Springs, Colorado, provided an external review of the initial version of this report. This external technical review document (Zahradnik, 2011) is included in full in Appendix B. The external review highlighted five things that could improve the initial version of this report. These points are listed below.

1. The mass of oil generated from an in situ retort relative to the mass of oil produced from the FA should be around 70%. The initial INL report did not calculate this ratio.

2. The produced oil from an in situ retort should have an API gravity of 40°API instead of 45°API, which was assumed by the initial INL report.

3. On a volume basis, the oil produced from an in situ retort should be about 75% of the volume of FA oil. The initial INL report did not calculate this ratio.

4. The gas generation from an in situ retort should be about 17% of the FA oil on a mass basis. The initial INL report did not calculate this ratio.

5. The oil produced from an in situ retort would contain nitrogen that would need to be removed via hydrotreating before shipping to a refinery. The initial INL report did not consider this need. However, Nair et al. (2008) analyzed the oil produced from an in situ retorting process and concluded that the nitrogen of the produced shale oil is less than 1% by mass. They further concluded that because hydrotreating plants to remove nitrogen were common to most oil refineries, removing nitrogen at the wellhead before shipping via pipeline to a refinery was not necessary.

The external review document approached the mass balance by balancing the carbons present in the kerogen and those present in the produced char, oil, and gas. The updated (current) version of this report incorporates this approach to the mass balance and attempts to resolve his comments. The external review was timely and contributed towards additional refinements to the mass and energy balances. Table A-1 lists the inputs necessary to calculate the mass balance on an elemental level of converting kerogen into char, oil, and gas.

Table A-1. Values of inputs necessary to calculate the mass balance of converting kerogen to char, gas, and shale oil.

Mass balance input	Symbol	value	units	Notes and source of data
H/C ratio in kerogen	R_k	1.60	—	Average of 1.65 reported by Laity et al. (1988) and 1.54 reported by Sherritt and Jia (2008). Zahradnik (2011) assumes 1.52, but provides no reference.
H/C ratio in char	R_c	0.44	—	Laity et al. (1988). Also used by Zahradnik (2011)
H/C ratio in gas	R_g	3.00	—	Engineering judgment (Zahradnik 2011). Value can range between 2.5 for butane and 4.0 for methane. 3.0 is equivalent to ethane.
H/C ratio in shale oil	R_o	1.82	—	Based on correlation from Schmidt (1985) relating API gravity to H/C ratio. API gravity of produced shale oil is 40°API (Burnham and McConaghy 2006; Zahradnik 2011). Zahradnik (2011) uses a value of 1.90 for the H/C ratio, but provides no reference.
Shale oil/kerogen ratio	R_{ok}	0.518	g/g	Calculated from FA oil/kerogen ratio of 0.74 g/g (Laity et al. 1988) and shale oil/FA ratio of 0.70 g/g (Burnham and McConaghy 2006; Zahradnik 2011). Zahradnik (2011) also uses a value of 0.518 g/g in his analysis

A-1. Mass Balance Calculations

The mass balance is based on a gram of kerogen, which is converted to grams of char (solid and is unrecoverable from the subsurface for an in situ retort), gas (or light hydrocarbons lighter than pentane, recoverable), and shale oil (liquid and recoverable).

The amounts of non-hydrocarbon elements in kerogen and product molecules are small and are neglected in the mass balance. Molecular mass fractions for kerogen, char, gas, and shale oil were calculated based on the elemental masses of carbon and hydrogen. The fraction of the molecular mass of kerogen that is carbon (f_{Ck}) is calculated by:

$$f_{Ck} = \frac{M_C}{M_C + R_k M_H}, \quad \text{(A-1)}$$

where M_C is the mass of carbon per mole of carbon, R_k is the moles of hydrogen per moles of carbon in kerogen, M_H is the mass of hydrogen per mole of hydrogen. The mass fraction of kerogen that is hydrogen is calculated by:

$$f_{Hk} = 1 - f_{Ck}\,. \quad \text{(A-2)}$$

Similarly, the equations for the mass fractions of char, gas, and oil that are carbon are respectively:

$$f_{Cc} = \frac{M_C}{M_C + R_c M_H}, \tag{A-3}$$

$$f_{Cg} = \frac{M_C}{M_C + R_g M_H}, \tag{A-4}$$

$$f_{Co} = \frac{M_C}{M_C + R_o * M_H}, \tag{A-5}$$

and the mass fractions of char, gas, and oil that are hydrogen are respectively:

$$f_{Hc} = 1 - f_{Cc}, \tag{A-6}$$

$$f_{Hg} = 1 - f_{Cg}, \tag{A-7}$$

$$f_{Ho} = 1 - f_{Co}. \tag{A-8}$$

Using the input values in table A-1 and the above equations, the mass fractions of carbon and hydrogen can be calculated. They are listed in Table A-2.

Table A-2. Mass fractions of carbon and hydrogen in oil shale retort parent and product molecules.

Molecule		Mass fraction	
Parent	**Product**	**Carbon**	**Hydrogen**
Kerogen		0.882	0.118
	Char	0.964	0.036
	Gas	0.867	0.133
	Shale oil	0.799	0.201

Knowing the grams of shale oil generated per gram of kerogen (0.518 g/g from Table A-1) and the carbon and hydrogen mass fractions (see Table A-2), the amount of char (R_{ck}) and gas (R_{gk}) generated per gram of kerogen can also be calculated.

$$R_{ck} = \frac{f_{Co} f_{Hk} + f_{Ho} f_{Cg} R_{ok} - f_{Co} f_{Hg} R_{ok} - f_{Ho} f_{Ck}}{f_{Co} f_{Hc} - f_{Ho} f_{Cc}}, \tag{A-9}$$

and

$$R_{gk} = 1 - R_{ok} - R_{ck}. \tag{A-10}$$

The mass balance of generated product per mass of kerogen is listed in Table A-3. The values obtained by Zahradnik in the external review can be obtained by neglecting the mass of hydrogen in the molecules (assuming the mass of hydrogen is zero), and assuming a shale oil H/C ratio of 1.90 (instead of 1.82) and a kerogen H/C ratio of 1.52 (instead of 1.60) (see Table A-1). Note that significantly more gas and less char are produced using the values in Table A-2 and including the mass of hydrogen than the values for gas and char calculated by Zahradnik (2011).

Table A-3. Kerogen pyrolysis mass balance for in situ retort.

Product Mass Ratio	Symbol	Calculated Value	Values from Zahradnik (2011)	Units
Char/kerogen	R_{ck}	0.286	0.356	g char/g kerogen
Gas/kerogen	R_{gk}	0.196	0.126	g gas/g kerogen
Shale oil/kerogen	R_{ok}	0.518	0.518	g oil/g kerogen
Total/kerogen	—	1.000	1.000	g total product/g kerogen

A-1.1 Mass balance on Fischer Assay basis

The oil shale grade is commonly measured using a standardized test called a Fischer Assay (FA). It is a measure of the richness of the oil shale and provides a measurement of the oil generated from a laboratory sample following a proscribed methodology. Results are commonly given in gallons of oil per ton of oil shale rock. In the Fischer Assay, oil, gas, and char are produced, but only the produced oil production is reported. The oil that is produced is referred to as FA oil. The FA test does not provide a measurement of optimal production from the oil shale, but generates a standardized measurement that can be used to compare other oil shale zones. There are many retort processes, some of which generate products in greater quantities than the FA value.

Because the FA grade is a commonly measured value for most oil shale deposits, the ratio of pyrolysis products to the FA grade is useful. These ratios, shown in Table A-4, are obtained by dividing the values in Table A-3 by the FA to kerogen ratio (0.74) as reported by Laity et al. (1988).

Table A-4. Ratio of mass of pyrolysis products to mass of oil produced from Fischer Assay analysis.

Product Mass Ratio	Calculated Value	Values from Zahradnik (2011)	Units
Char/FA oil	0.386	0.480	g char/g FA oil
Gas/FA oil	0.265	0.170	g gas/g FA oil
Shale oil/FA oil	0.700	0.700	g oil/g FA oil
Recoverable products (oil + gas)/FA oil	0.965	0.870	g (oil+gas)/g FA oil

Again, the calculated values for char and gas are significantly different from the values calculated by Zahradnik because of the hydrogen mass addition and the values used for the shale oil and kerogen H/C ratios. On a volume basis, the ratio of shale oil produced to FA oil produced is 0.792 bbl/bbl based on the API gravity of the shale oil and FA oil – 40°API and 20°API respectively.

A-1.2 Mass balance summary

The mass balance of the in situ retort process is based on the mass of kerogen as it is pyrolyzed into char, shale oil, and high-Btu gas. The mass balance approach suggested in the external review (Zahradnik 2011) was incorporated into this document. Three changes were made to the input values used in the external review that resulted in significant differences in results.

1) The external review assumed that the mass of hydrogen had a negligible effect on the mass balance results; however, this analysis found that it had a significant effect on the results. Hydrogen mass was included in the calculations.

2) The hydrogen to carbon ratio (H/C) for the shale oil was 1.82 in this report and was calculated based on the assumption of 40°API shale oil (also assumed in the external review); whereas the external review assumed an H/C ratio of 1.9 and provided no reference.

3) The H/C ratio of the kerogen molecule was assumed to be 1.60 in this report and was the average of reported values for Colorado oil shale from the Green River formation; whereas this value in the external review was 1.52, which was modified based on a single reported value.

A-1.2.1 Suggested changes from external review and current results

The external review suggested that the mass of oil generated from an in situ retort relative to the mass of oil produced from the FA should be around 70%. This report used the same value based on published data.

The external review suggested that the produced oil from an in situ retort should have an API gravity of 40°API instead of 45°API. This report used the same value based on published data.

The external review suggested that on a volume basis, the oil produced from an in situ retort should be about 75% of the volume of FA oil. This report calculated this ratio to be 0.792 bbl shale oil/bbl FA oil.

The external review suggested that the gas generation fraction from an in situ retort should be about 0.17 of the FA oil on a mass basis. This report calculated this fraction to be 0.265 g gas/g FA oil.

A-2. Energy Contained in Pyrolysis Products

The heat content of the produced oil and gas as a ratio of the FA oil is also an important measurement parameter. The heat content of the produced gas is a function of the composition of the gas. The gas composition is known based on the value of the H/C ratio assumed in Table A-1 and assuming that the gas is fully saturated with hydrogen. The number or carbons (C) in a saturated hydrocarbon molecule is calculated by:

$$C = \frac{2}{\left(1 - \frac{2}{H/C\ ratio}\right) H/C\ ratio}. \tag{A-11}$$

Smith (1983) provides data from which heat content (in Btu/scf) can be calculated as a function of carbons atoms (C) in the gas molecule. The following correlation was derived to fit gas heat content data for C ranging from 1 (methane) to 4 (butane):

$$Gas\ heat\ content = 245.05 + 768.58C - 3.6C^2\,. \tag{A-12}$$

The produced gas heat content assuming an H/C ratio of three (see Table A-1) is calculated to be 1767.8 Btu/scf. The density of the produced gas at standard conditions is 0.00128 g/mL NIST (2011).

The heat content of the FA oil is calculated from a correlation relating API gravity to heat content (Schmidt 1985). Assuming an API gravity of 20°API (Beer et al. 2008), the heat content of FA oil is 6.127 million Btu/bbl. The density of a 20°API FA oil is 0.934 g/mL.

Knowing the ratio of the gas mass to the FA oil mass (see Table A-4), the heat content of the gas, the gas density, the heat content of the FA oil, and the FA oil density; the ratio of the gas heat content to the FA oil heat content can be calculated. Similarly, the ratio of the shale oil heat content to the FA oil heat content can be calculated. The heat content of the generated oil and gas sums to 1.041 Btu/(Btu FA oil).

These values are compared to those calculated by Zahradnik (2011) in Table A-5. Once again, the calculated value for gas is significantly higher than the value calculated by Zahradnik because of the addition of hydrogen mass and the values used for the shale oil and kerogen H/C ratios.

Table A-5. Energy ratios the in situ retort products with respect to Fischer Assay produced oil.

Product Energy Ratio	Calculated Value	Values from Zahradnik (2011)	Units
Gas/FA oil	0.314	0.19	Btu gas/Btu FA oil
Shale oil/FA oil	0.727	0.73	Btu oil/Btu FA oil
Recoverable products (oil + gas)/FA oil	1.041	0.92	Btu (oil+gas)/Btu FA oil

A-3. Assumptions for Energy Balance

Energy balance default input assumptions are listed in Table A-6. These default values are used throughout this technical evaluation to calculate a most likely result. However, these values are subject to change depending on actual field location, process efficiencies, etc.

Table A-6. Default values of input necessary for energy balance calculations along with references to data source and explanatory notes.

Energy balance input	Value	Units	Notes and source of data
Boiler thermal efficiency	0.85	—	Engineering judgment
Overall thermal efficiency	0.80	—	EGL (2006), p 18
Recovery of converted kerogen	0.80	—	EGL (2006), p 18
FA grade average of retort zone	25.21	gal/ton	Burnham et al. (2008a); Johnson et al. (2010)
Average temperature of retort zone after heating	370	°C	BLM (2008), p A-62
Power requirements for surface facilities	123	W/bbl/day	TEV-704 (2010)
Heater well average temperature in retort zone	450	°C	Average temperature through retort zone can range between 450°C and 550°C
Thickness of retort zone	235	ft	Burnham et al. (2008b); Johnson et al. (2010)
Spacing between horizontal heater wells	55.0	ft	Engineering judgment

A-4. Gas Production Calculation

Gas production rate (q_g) is a function of shale oil production rate (q_o), gas and oil density, and the mass ratios of gas and oil generated to kerogen:

$$q_g = q_o \frac{\rho_o R_{gk}}{\rho_g R_{ok}}. \quad \text{(A-13)}$$

Total light hydrocarbon gas production is 68,645,963 scf/day.

A-5 Retorting Heat Requirements

The heat required to retort the oil shale on a mass of shale basis was obtained from data presented by Sohns et al. (1951) and shown graphically in Figure A-1. The heat requirement is given as a function of average retort temperature and FA grade of the oil shale. The characteristics of the oil shale assumed for this analysis are the same as zones R-1 through R-2 that lie below the American Shale Oil, LLC (AMSO) lease tract in the Piceance Basin, Colorado (Burnham et al. 2008a). The average FA grade of the oil shale is 25.21 gal/ton (Burnham et al. 2008a; Johnson et al. 2010b), and an average retort temperature is 370°C (698°F) (BLM 2008). The heat requirement for retorting this grade of oil shale at this temperature is 183.9 Btu/lbm as shown in Figure A-1.

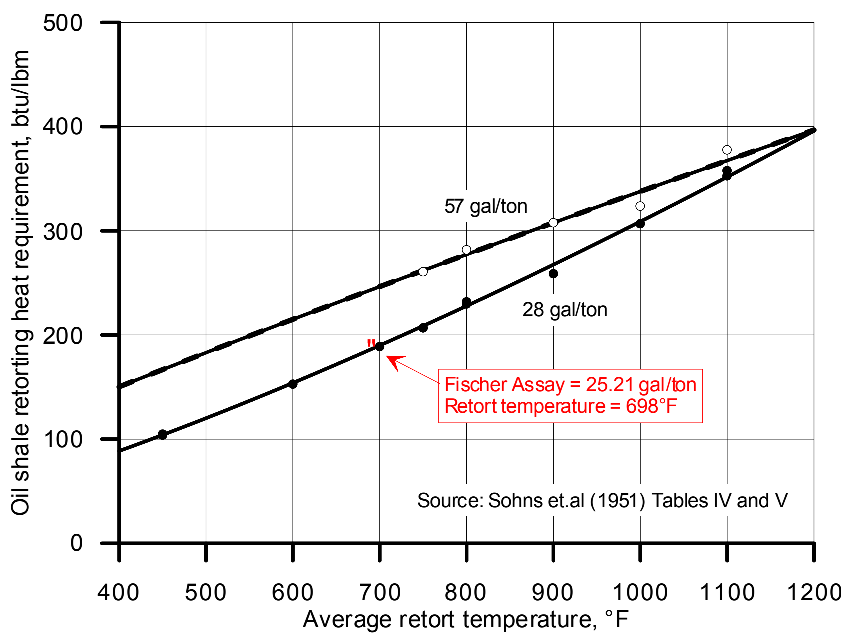


Figure A-1. Retort heat requirements for different grades of oil shale as a function of retort temperature. Data taken from Tables IV and V of Sohns et al. (1951).

The total heat delivery rate or thermal power requirement (P_{th}) to retort enough oil shale to produce 50,000 bbl/day of shale oil is a function of the heat of retorting

(H_r, see Figure A-1), the FA grade of the oil shale (G_{FA}), shale oil output (q_o), the ratio of the mass of the oil generated per mass of FA oil (R_{oFA}) , the densities of the produced shale oil (ρ_o) and the FA oil (ρ_{FA}) , and the efficiency of the product extraction or recovery process (η_r):

$$P_{th} = \frac{H_r q_o \rho_o}{G_{FA} \rho_{FA} R_{oFA} \eta_r}. \quad \text{(A-14)}$$

Using the above equation, the thermal power requirement to produce 50,000 bbl/day of shale oil is 590.22 MW_{th}.

A-6 Single loop heat transfer rate

Determining the heat injection rate per loop is necessary in order to calculate the power required to circulate the heating fluid through the closed-loop heating system. In this section, the heat transfer rate, in MW, per heat transfer loop is calculated.

A-6.1 Shale oil recovered per acre

Knowing the FA grade of the oil shale leads to a value of 2.19 g/mL for the bulk density of the raw oil shale (Vanden Berg and Tabet 2007); and assuming that 80% of the generated shale oil is ultimately produced (EGL 2006), the volume of oil produced per volume of oil shale is 1,132 bbl/ac-ft. Further, if the average thickness of the oil shale retort zone is 235 ft (Burnham et al. 2008b; Johnson et al. 2010b), the oil recovered per acre is 266,000 bbl/ac.

A-6.2 Heater wells per acre

The number of heating loops per acre is a function of the length of the horizontal heating section of the well, the thickness of the retort zone, and the space between the heater wells. The length of the horizontal heating section has estimated to be 3000 ft (EGL 2006).

The heated volume of one heater well can be thought of as the volume of a rectangular cube with sides equal to the well spacing (S_w = 55 ft) and length equal to the length of the horizontal section of the well through the retort zone (L_w = 3000 ft). The heated volume (V_h) for one well is the calculated volume of the rectangular cube:

$$V_h = L_w S_w^2 \quad \text{(A-15)}$$

Dividing the retort zone thickness (235 ft) by the heated volume of one well results in a value of 1.13 heater wells per acre.

A-6.3 Heater wells drilled per year

The number of acres developed per year is a function of the oil recovered per acre (266,000 bbl/ac) and the oil production rate (50,000 bbl/day), which gives 68.63 acres developed every year. Combining the acres developed per year and the 1.13 heater wells per acre results in 77 heater wells drilled per year.

A-6.4 Heat transfer and time to reach retort temperature between heater wells

The rate that heat is transferred from the heater well to the oil shale formation is a very important part of the in situ retort process as it has a large impact on the performance of the project. Faster heat transport results in a shorter heat soak time and quicker conversion of kerogen to valuable oil and gas. Two heat transfer scenarios were evaluated, but more work should in this area to better understand and quantify this variable.

A-6.4.1 Heat transfer by conduction alone

Shell (2006) published data for heat transfer rates from a 550°C well in oil shale for conduction alone. Sondrup[e] corroborated the work done by Shell and expanded the heat conduction work to include larger distances between heater wells and at higher temperatures. Based on these two pieces of work and assuming heat transfer by conduction alone, an empirical correlation was developed to calculate the heat up time (the time required for the temperature at the midpoint between heater wells to reach the pyrolysis temperature of 370°C) based on the distance between heater wells and the average temperature of the heater well.

A-6.4.2 Heat transfer by conduction, convection, and thermal fragmentation

Burnham et al. (2008b) argued that faster heat transfer rates were possible if thermal fragmentation and fluid convection were included in the heat transfer analysis. To account for a higher heat transfer rate, a heat transfer variable was introduced that includes the effect of thermal fracturing and fluid convection. This variable is based on the assumption

e Unpublished INL record: A.J. Sondrup, 2008, “Long Distance HTGR Heat Transport for In-Situ Oil Shale Extraction: An Analysis of Heat Transfer Media.”

that there is a direct relationship between increasing the heat transfer rate and the resulting increase in the cross-sectional area of the heated zone surrounding a horizontal heater well.

For example, doubling the heat transfer rate from a horizontal heater pipe also doubles the area around the heater well that has reached the pyrolysis temperature at a given time. In other words, doubling the heat transfer rate halves the time to reach the pyrolysis temperature between heater wells.

This dimensionless heat transfer variable is the ratio of the heat transfer rate that includes conduction, convection, and thermal fracturing to the heat transfer rate for conduction alone. The base or default value used in this evaluation for the heat transfer ratio (R_h) is 2.0 and was based on engineering judgment.

The heating time equation that includes conduction, convection, and fracturing (t_{ccf}) is obtained by dividing the conduction-alone heating time (t_c) by the heat transfer ratio (R_h):

$$t_{ccf} = \frac{{D_w}^{1.938}}{29.07 R_h (T_w - 370)^{0.453}} . \qquad \text{(A-16)}$$

A-6.4.3 Between-well heat up time

The amount of kerogen in the oil shale (shale richness or FA grade) does influence the heat transfer rate, but insufficient data was available to develop a relationship between heating time (t_{ccf}) and FA grade. The heat transfer ratio (R_h) assumed a constant FA grade for shale richness of 25.21 gal/ton. Using the above correlation and assuming a distance of 55 ft between wells, a heat transfer ratio of 2.0, and an average heater pipe temperature of 450°C, the time required to heat the area between heater wells is 6.29 years.

A-6.5 Heat injection rate per heater well

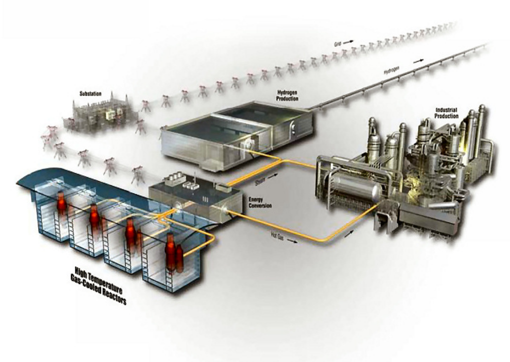
The heat injection rate can be calculated based on the total heat required to produce 50,000 bbl/day (590 MW), the number of heater wells drilled every year (77 wells/yr), the between-well heat up time (6.29 yr), and the percent recovery of the generated shale oil (0.80). Based on these values, the heat injection rate across the 3000 feet contacting the oil shale retort zone is calculated to be 0.97 MW/well.

APPENDIX B—External Review by Ray Zahradnik of Preliminary INL Work

Technical Evaluation Study

Project No. 23843

Integration of HTGRs to an In Situ Oil Shale Operation



TECHNICAL REVIEW

of

TECHNICAL EVALUATION STUDY

INTEGRATION of HTGRs to an IN SITU OIL SHALE OPERATION

Prepared for

Dr. Eric P. Robertson

Idaho National Laboratory

By

Ray Zahradnik

Mountain Bay Associates

January 17, 2011

Statement of the assignment

TEV-1029, "Integration of HTGRs and an In situ Oil Shale Retort," November. 2010.

Review the existing mass and energy balances and provide comments on the approach taken. This includes a thorough review of the assumptions, results, and conclusions and recommendations. Comments are also requested for additional nuclear integration opportunities associated with the flow sheets presented. Input for additional integration opportunities are also requested in association with this review.

Executive Summary

The mass and energy balances provided in the study are consistent with the thermodynamic data for oil shale. However, the approach taken in the study fails to provide confirmation that the designed heater can deliver to the oil shale formation the heat calculated by the energy balances.

I also question the uncritical acceptance of oil yield from data reported in the literature. My own examination of the data in question and of other information in the literature suggests a different interpretation of oil yield from the one selected in this study, and I have provided my own recommendation for an alternate approach.

I have suggested that a different surface processing configuration be considered that is more specific to the in situ process considered in this study and which may offer additional opportunity for the use of HTGR heat.

I have recommended that a careful analysis of retort heating be carried out to determine what effect the unsteady state nature of this heating has on the assumptions used in making the energy balances for the system. I further recommend that this detailed study consider other features of the heater system such as diameter, number and location of the heater pipes, as well as the field restrictions that could limit alternate heater configurations.

Introduction

The in situ process selected for the study was the oil shale retort developed by American Shale Oil LLC (AMSO) and known as the the CCR™ (Condensation, Convection, and Reflux) Process. To illustrate the process, Figure 1 is a schematic of an element of the process or panel that is replicated many times to provide the desired production of oil (Figure 2 from The AMSO RD&D Program). The height of the panel is 200ft; the length is 2000 ft. The study does not indicate a width per se, but identifies flow loops, which, as I understand it, consist of the amount of shale being heated by one heater pipe. In the case of helium as the heating fluid, about 67 flow loops are operating at any one time to produce 50,000 bbl/day of oil. Given the other parameters of the study, it appears that the "width" of a flow loop panel is about 60 ft. These dimensions would imply an oil production from each panel of about 850,000 barrels, consistent with the AMSO projection of between 0.6 and 1.2 million barrels per heating well over a period of 2 to 4 years (Burnham 2008a).

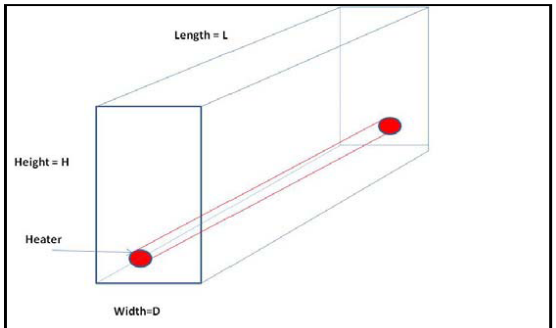


Figure 1 Panel for CCRTM (Condensation, Convection, and Reflux) Process

To better illustrate what takes place in the process, Figure 3 provides a side view of an individual panel. Hot fluid is introduced from the surface in a heater pipe imbedded longitudinally along the bottom in the oil shale panel. Initially, the heater provides heat to the shale which is conducted into the body of the shale according to heat conduction laws.

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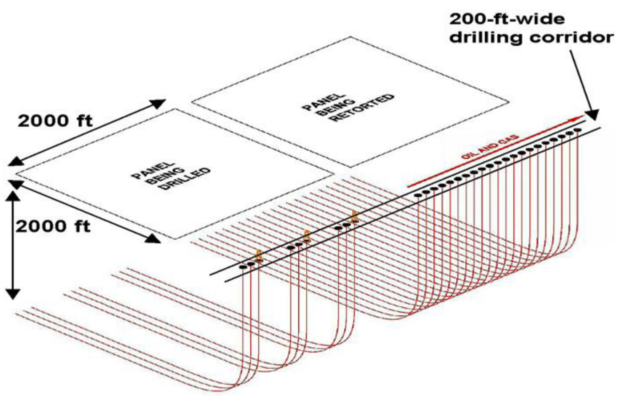

Figure 2. Panels are replicated to achieve desired production rate

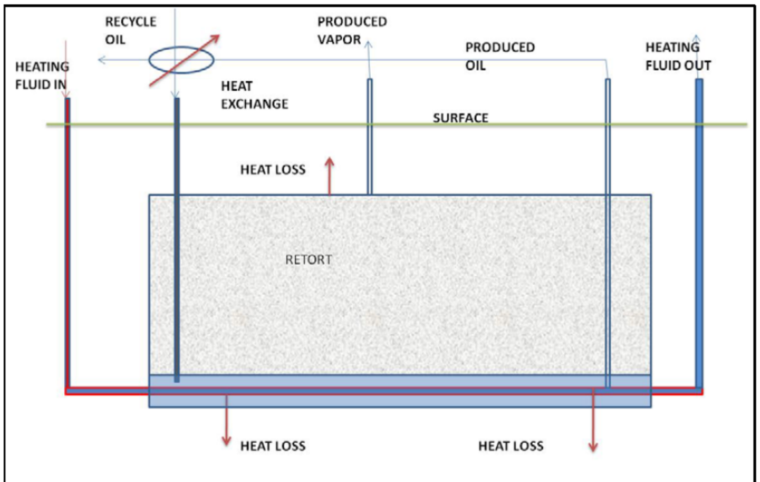

Figure 3 Side view of CCR™ Showing various process Elements

According to the process developers, when the shale is heated to a sufficient degree in this manner, fracture of the rock around and above the heater occurs with subsequent oil production. In some manner, the oil that is produced collects around the heater, forming a pool of oil, some of which is vaporized by the heat transferred from the heater. This vaporized oil propagates through the retort, releasing its heat by condensation, as illustrated in Figure 4.

Oil is pumped to the surface via a production well and the vapors may proceed to the surface through a separate well. It may be necessary during the boiling heat transfer phase to add additional oil to the retort from the surface. This is shown on the schematic in Figure 3. It is important from an overall heat economy point of view that this recycle oil is at or near the retort temperature and I have shown a surface heat exchanger to accomplish this. Heat may be lost from the retort panel by conduction from the top and sides or from the oil pool to the rock below.

A question for this study is to determine at what point in the process of heating the shale does fracture occur and oil production begin. The patent suggests that, "One of the key issues affecting the economic success of oil shale processes is the rate at which heat can be extracted from the horizontal heating pipe …and transferred to the region above to be retorted. The region around the horizontal pipe is surrounded by boiling oil. … The heat diffuses laterally away from the well by thermal conduction, thereby heating the region between the wells."

There are three features that distinguish in situ processes such as the CCR^{TM}:

The first is that in situ oil shale retorting involves unsteady state processing –both in heating and pyrolyzing the shale and in producing the shale oil.

The second is that there is a loss of heat input to the underground surroundings that needs to be accounted for.

The third is that by its nature, the in situ heating process occurs at slow heating rates which alter the oil yield and distribution.

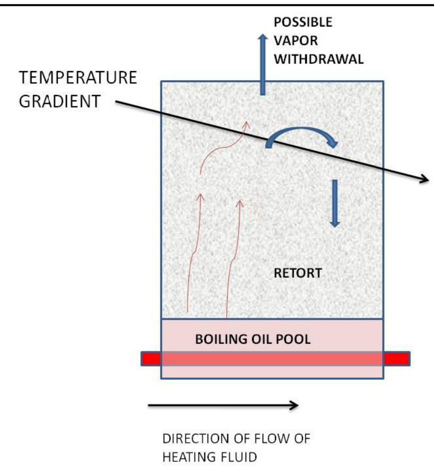

Figure 4 Illustration of Condensation, Convection, and Reflux

Heat input to the retort region may be supplemented by recycling hot oil into the retort. This requires the temperature of the injected oil to exceed the temperature of oil vapors being produced. Also, it requires managing heat loss from the well through which the recycling occurs for both formation damage and thermal efficiency reasons. I have little to say about such thermal management, although it is considered in the study.

Unsteady Conditions

In the process of interest, heating of the oil shale takes place in several steps: conduction heating which brings about shale fracture, non condensable gas, water, and subsequently oil vaporization which involves condensation, convection, and reflux. Heat for these steps is provided by the fluid flowing in the heat pipe. The inlet and outlet conditions for the heater fluid are specified by an overall steady state balance with the heat demands of the oil shale heating, and are shown in Figure 5 (Figure 5 in the study).

The fluid flow in the heater is calculated to supply the amount of heat required by equation 3.

$$P_{th} = 84{,}000 \frac{q_o H_r}{G_{FA} f_l \eta_{conv} \eta_{rec} \eta_{th}} ; \qquad (3)$$

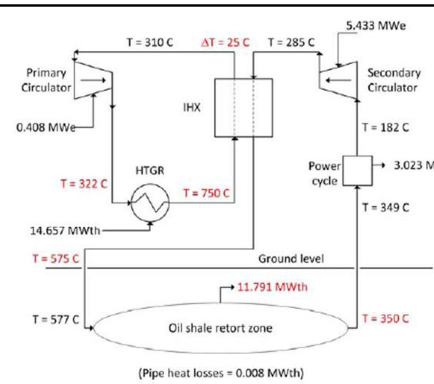

Figure 5 (Figure 5 in Study Document) Showing design Conditions for Helium heating

However, it is important to ensure that the "other side" of the heat exchanger can accept this heat. As observed above, the other side is quite complex.

As the heating process begins, the heater transfers heat radially into the formation (see Figure 6), until it reaches the well spacing distance, D, at which point the heat would be conducted in the vertical (up into the retort and down) direction.

The AMSO patent provides results of a simulation of this heat conduction phenomenon in the up and down plane: " FIG. 5 (as identified in the patent application) graphically represents kerogen conversion profiles between two wells ... at two selected times, *assuming no bore-hole fragmentation.* The fully retorted regions ... join midway between the two wells at about 390

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days and then continue upward in a U-shaped retorting front. At 833 days, ˜85% of the kerogen is converted when depletion of the refluxing oil pool occurs."

The patent simulation provides a well spacing and height of shale above the heaters but does not provide a heater well diameter. Heater well bore diameter is a critical parameter in determining the rate of this heat transfer. The use of 8 inch pipes in the present study will limit the ability of the heaters to transfer heat very far or very rapidly into the formation, but it is probably impractical to use larger diameter pipes.

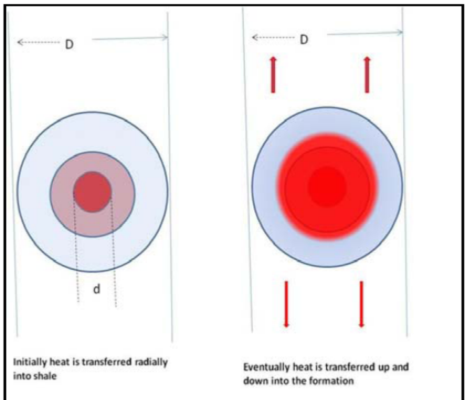

Figure 6 Progression of heat transfer in formation from heater pipe

The situations represented in Figures 6 and 7 illustrate what is taking place at a given axial position in a panel. The heating fluid in the pipe provides the heat for the process as it passes longitudinally through the retort, so its temperature declines in transit and has to be linked to the amount of heat transferred to the formation at each axial position. I have tried to simulate these phenomena with very approximate models. *I find that a single 8 inch od pipe embedded in a 60 ft.wide panel is probably unable to heat the shale surrounding it to a sufficient temperature to promote the phenomena that AMSO seems to require for the CCR*^{TM} *process.* I have found that increasing the number of such tubes may provide a basis for the requisite heat transfer.

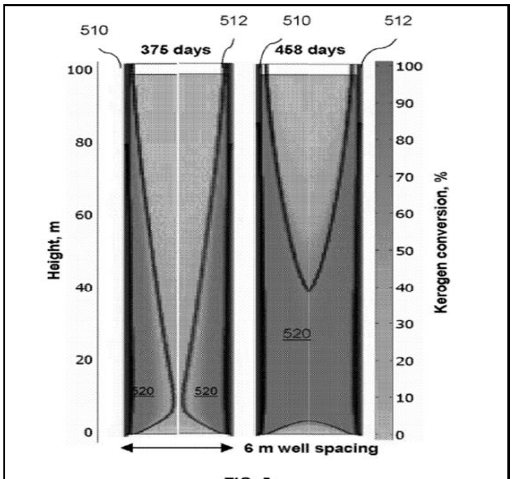

Figure 7 Vertical (Temperature Dependent) profiles projected by AOS (2010)

I have illustrated the results of my analysis in Figure 8, which is a plot of the temperature of the heating fluid as it exits the oil shale formation vs. time since beginning of operations, employing three 8 inch heater tubes per panel, but maintaining the total flow rate of heating fluid per panel from the study, divided equally among the heater tubes. The topmost curve in Figure 8 is a projection of what the exit fluid temperature would be if conduction were the only heat transfer mechanism that occurred. The lower curve is a projection of the exit fluid temperature if vaporization from the oil pool occurs. Vaporization is triggered in the model when a portion of the shale around the heater has reached a specified temperature. This is an arbitrary and instantaneous trigger and a more refined analysis would be beneficial.

A steady state is reached in the latter case, so that the retort heating process will continue until the design amount of heat has been added. This cycle time depends upon the amount of heat lost during the conduction period and the overall heat transfer coefficient from the heater pipe to the boiling oil. Based on the values I calculated for these variables, I estimate the total operating cycle to be between five and six years. There is a possible complication here for the HTGR integration. The average heating fluid exit temperature that I estimate for the He heating cycle is higher than the one used in the study, which was already too high for return to the HTGR. I'm not sure that there is anything that can be done about this from the heater point of view.

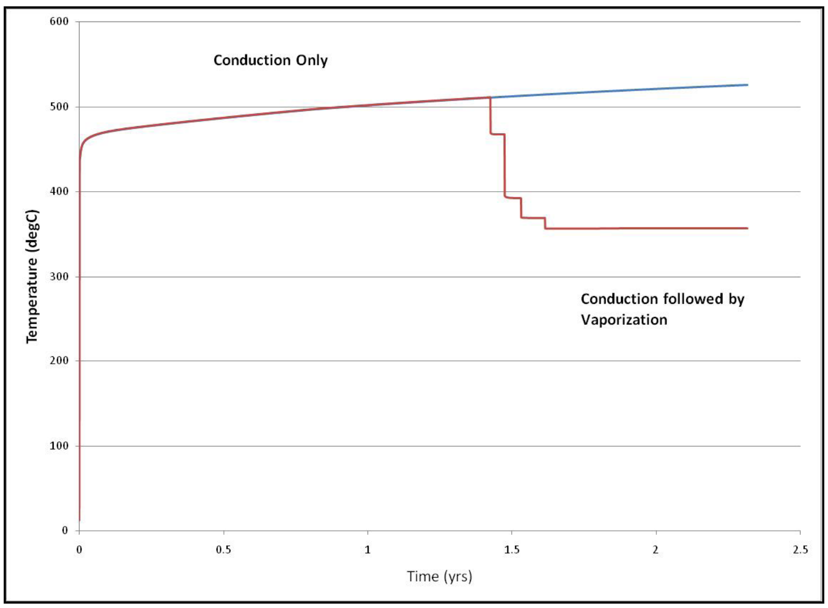

Figure 8 Heating Fluid Exit Temperatures vs. Time for the CCR™ Retort

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It is possible to choose other values for the heater pipe diameter, the number of heater pipes per panel and their location or make other adjustments in such a way that heat output from the heater matches the heat receptivity by the shale. My preliminary analysis indicates that multiple heating pipes, carefully located in the formation, can bring the heat balance to closure. I have no specific set of values to suggest at this time because of uncertainty as to what requirements thermo mechanical fracturing places on temperature distribution and other configuration issues related to gas and vapor release from the shale. But I do suggest a more thorough analysis of the situation be carried out, or at least discussed in the report. If strategically located multiple heater pipes are needed to carry out the HTGR integration, the costs associated with the integration will have to reflect this necessity. Also, if the cycle time is longer than that used as a basis in the study, the rate of heat input per panel will be less and more panels will need to be operating at any given time. This will not have an effect on the overall heat rate supplied by the HTGR.

I have also accepted the AMSO claim that after oil vaporization from the oil pool, condensation, convection, and reflux of the vapors will distribute the heat delivered by the heater pipe instantaneously and discriminately in the formation above – assumptions which probably need some sort of verification.

Heat loss

It seems to me that during the conduction period heat would be transferred equally in both the up and down direction from the heater center axis, as I suggested in Figure 6. The heat transferred downward represents a heat loss. So an unsteady state heat analysis can be used to estimate a heat loss. My analysis suggests that such heat loss is in the 10 to 20% range, close to what was assumed in the study.

Reductions in Oil Yield

The study calculates the heat load for the retort by equation 3 as noted above.

I have already commented on the heat loss efficiency. I have no comments on the recovery efficiency, except to note that shale oil can be adsorbed or even absorbed by oil shale. If such a phenomenon does occur, the recovery efficiency may be lower than the value used in the study. But the value used is fine for the moment. There will also be some oil in the “oil pool” that will not be (easily) recoverable, but that amount should be small – tens of thousands of barrels per panel.

As for conversion, I believe citing Shell’s reference to 110% conversion efficiency (Vinegar2006) deserves further examination.

To shed some independent light on this subject, I examined the data provided by Vinegar (2006) on Shell’s most recent results. A material balance for this case is provided in Table 1, using the C/H ratios and product distribution presented by Laity (1988). Others provide different distributions for the FA products (e.g. Wu, 1988); use of such alternate distributions would change the specific numbers in the FA row of Table 1, but would not alter the discussion to follow.

Table 1 reflects a material balance on carbon and hydrogen as they distribute from the shale into char, oil and gas fractions. There are thus two equations to solve for three variables. Usually the oil fraction as a % of Fischer Assay is specified, permitting calculation of the product distribution. In the case of the Shell results, the % of Fischer Assay of the oil plus gas as well as the ratio of oil to gas are specified, over constraining the balance. If the reported Shell values are used, the hydrogen balance is not satisfied.

The analysis, with the above caveat, suggests that in situ oil recovery is about 52% by weight – which is considerably lower than what would normally be expected, even for the reduced heating rate encountered in in-situ processing.

Burnham (1983), Campbell (1978) and Shell (US Patent 6991032) have all collected data on oil recovery vs. heating rate. I have put these data onto a graph (Figure 9) along with recovery calculated from the material balance calculation above placed at a heating rate of 0.5 deg C/d, which is based on heating shale to 350 deg C in 2 years.

Table 1. Material Balances for Reported Shell Results (from Vinegar 2006) and Projected CCR™ Product Distributions

	Shale	Char	Fischer AssayOil	AMSO in Situ Oil	Shell In Situ Oil	Light Oil C5+	LHC Gas C4-
C	1.00	1.00	1.00			1.00	1.00
H	1.52	0.44	1.69	1.90	2.03	2.40	3.00
Distribution Fraction FA		0.20	0.73			0.02	0.06
Distribution Fraction Shell		0.43			0.39		0.18
Shell recovery as Wt % FA					0.52		0.24
Distribution Fraction CCR™ in situ		0.35		0.52			0.12
CCR™ recovery as WT %of FA				0.70			0.13

One can draw one's own conclusions from Figure 12, but I suggest that the field data represented by the material balance calculation are inconsistent with the laboratory data from the other investigators, and an explanation is in order.

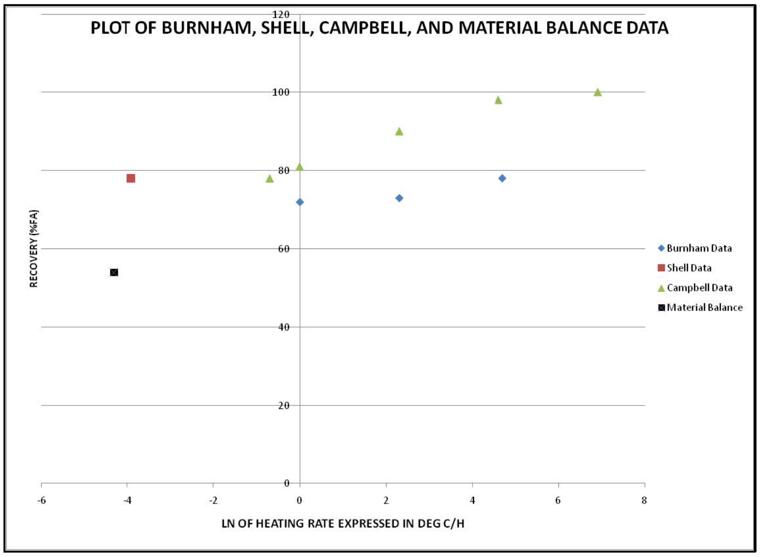

Figure 9 Composite of Recovery vs. Heating Rate Data

I propose that the Shell field data represent shale oil product derived from a de facto retort but reported on the basis of an assigned retort volume, a de jure retort. To see why this is not unreasonable, consider Figure 10 below, which provides the results of a simulation of the temperature distribution in the vicinity of an ICP heating well bore. More elaborate three dimensional simulations for an ICP field available in the Shell patent (US Patent 6991032) do not change this observation. The difficulty of assigning an area as the de jure Retort is apparent. Moreover, the input of hydrocarbons from outside the de jure Retort boundaries is likely to have a greater hydrogen content than the overall average because it is at a lower temperature and therefore in an earlier stage of retorting. A ratio of de facto Retort volume to de jure Retort volume of about 1.3 preserves the hydrogen balance from Table 1, while providing 110% FA recovery on a BTU basis for the sum of the oil and the light hydrocarbons based on the de jure retort volume.

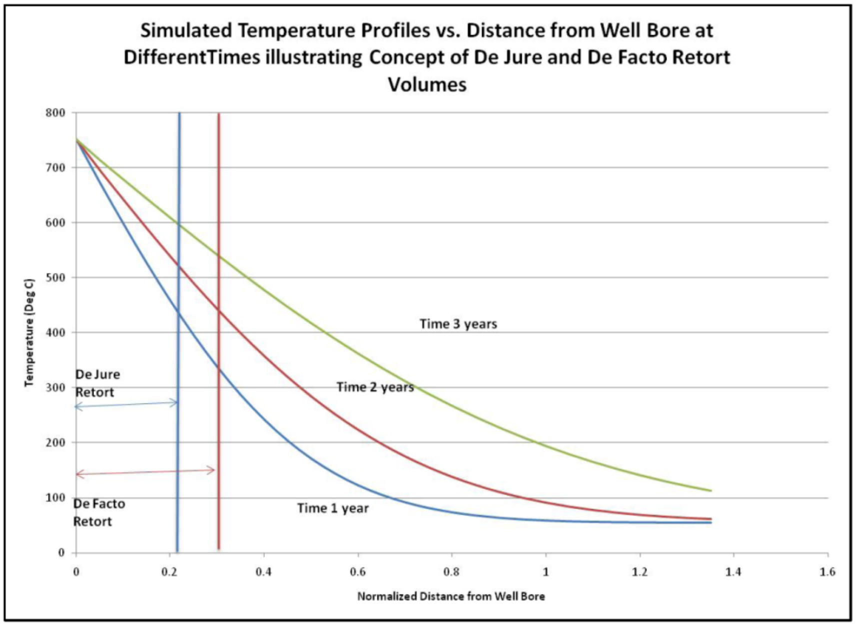

Figure 10 Illustration of De Facto vs. De Jure Retort Assignment

The CCR^{TM} retort will not experience such an input of hydrocarbons from outside the retort boundary. Each panel in a field consists of a thin, long section with other such sections on each side. (If anything, the de facto retort will be smaller than the de jure one.) To estimate the fraction of FA oil that is captured, another approach is required from that of using the Shell field data. For this purpose, I have reproduced Burnham's (2006) presentation on oil recovery vs. heating rate. These data suggest that at low heating rates, an oil recovery of 70% FA by weight can be expected, which provides a 40 API gravity in situ oil, similar to, but not identical to, the Shell ICP oil which has a reported API gravity of 45.

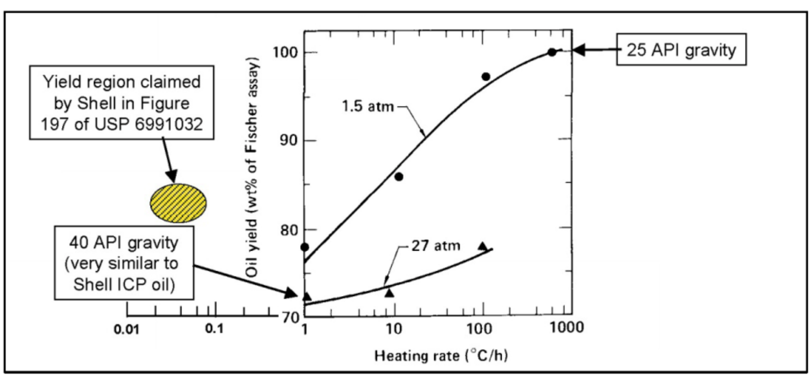

Figure 11 Burnham's Summary of LLNL and Shell Data

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As far as the present study is concerned, a CCR™ in situ oil recovery of 70 wt % of FA is reasonable. This equates to a 73 % FA oil recovery on a BTU basis and a 77% FA recovery on a volume basis The73% in situ oil recovery on a BTU basis thereby suggested corresponds to the $f_1\eta_{conv}$ product in the study, which was about 75%. The similarity is coincidental because the designation of the de jure retort volume is arbitrary.

This long winded discussion does not change the mechanics of the study, but it puts the recovery issue on firmer grounds. As a matter of reference, Burnham (2008) proposes for the CCR™ process a recovery efficiency of 75% by volume, which may be the proper citation for the study.

However, a CCR™ oil yield of 70% of FA has a significant implication for LHC recovery, as shown in Table 1. LHC recovery expected for the CCR™ process is about 13 wt. % FA (19% of FA on a BTU basis), compared to the reported Shell field data value of 35% of FA on a BTU basis, which was adopted for the present study. In other words, one would expect the CCR™ retort to produce fewer light hydrocarbons than were reported in the Shell field tests.

Integrated Plant

The proposed integrated block flow diagram from the study is shown below. In order to be more specific to the process, I propose a modification to that shown in Figure 13. This modification displays the recycle feature of the process and points out an opportunity that the HTGR integration provides. There are times in the process when large quantities of recycle oil is projected to be required. In order to avoid attendant heat losses to the process, it is important that this oil be introduced into the retort at temperatures as close to the retorting temperature as possible. This should be able to be provided by heat exchange with the shale oil being produced. If this step creates processing problems, and it could, then the heat for the recycle oil could be provided by the HTGR in a straightforward manner.

The AMSO patent goes on to state that apart from preventing heat loss by heating the recycle oil to retort temperature before reinjection, a way of supplying additional heat to the retort would be to heat the recycle oil to a temperature greater than that of the retort. This heating could be accomplished with HTGR heat.

Similarly, there will be a need for hydrogen to treat the product oil, which will be about 40 deg API. In many proposals for shale oil facilities, this hydrogen is produced from the LHC's derived from the retorting. But if this is not possible nor economically advisable, it would be another opportunity to use the HTGR, as has been suggested in the companion ex situ study (INL 2010). There will be less LHC than originally projected, and this must be factored in.

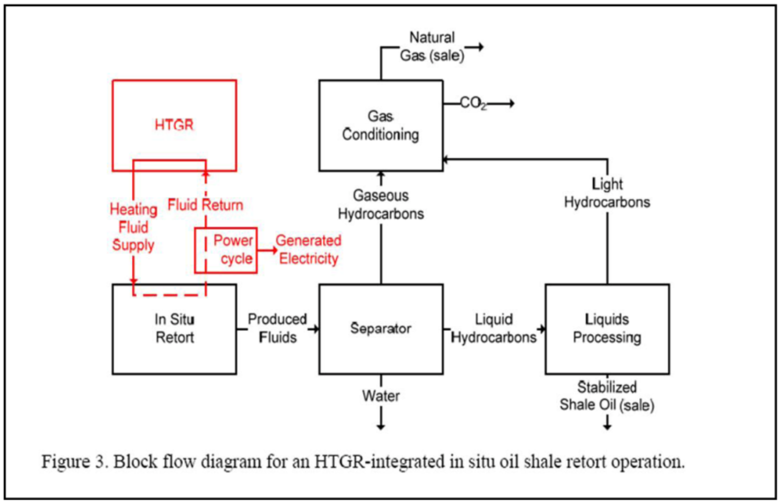

Figure 3. Block flow diagram for an HTGR-integrated in situ oil shale retort operation.

Figure 12 Block Flow Diagram from Study

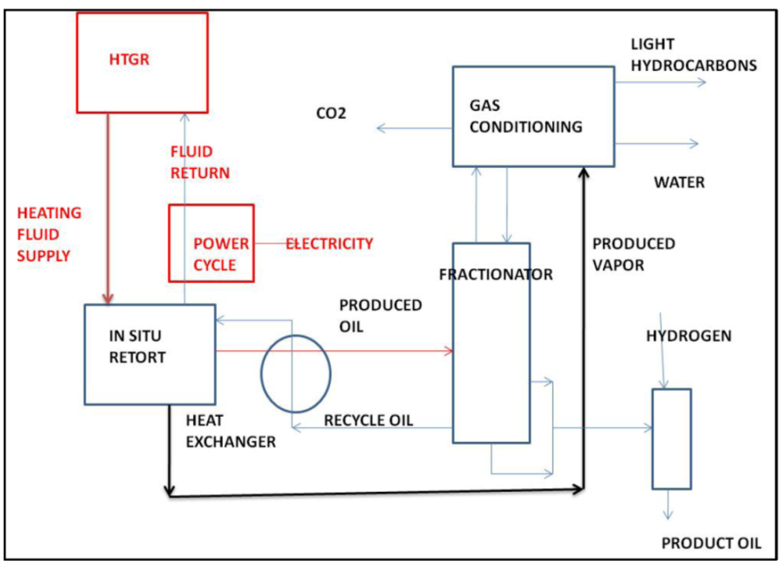

Figure 13 Alternative Block Flow Diagram of Surface Facilities

CO2 emissions

I have no problem with your calculations here; Boak (2007) and Burnham and Carroll (2008) are excellent references

Future Work and Recommendations

In addition to the future work and recommendations cited in the report, I would suggest that a more detailed analysis be carried out concerning the unsteady state heat transfer into the CCR™ oil shale retort and what restrictions this provides for a heating fluid based heater. Although the AMSO literature (Burnham 2008a) suggests that a single heater well per "panel" is sufficient, my analysis does not confirm this. As I noted earlier, my simulations are intended to provide illustration, and more sophisticated modeling may provide resolution of the concerns that I have raised. In particular, exploring the size, number and location of the heating wells may disclose appropriate conditions for the requisite heat transfer.

I would also recommend basing the in situ oil recovery on the relationships I provided in my discussion on oil yield.

The need to heat the recycle oil to near retort temperatures could provide additional prospects for use of HTGR heat. Also, fewer light hydrocarbons will be available than suggested by the Shell study (Vinegar 2006) and the CCR™ oil will be of lesser quality than the 45 API gravity oil reported by Shell, so there will be a need for hydrotreating as well as denitrification of the product. If there are not enough light hydrocarbons to produce the hydrogen to carry out this step, or if there is another use deemed for them, hydrogen production from the HTGR could be considered.

General observations

In the practical situation of implementing the CCR™ process, there will be additional limitations on the heater pipe imposed by drilling, installation, and other field activities. Acknowledgement of these restrictions and a discussion of what they imply for the proposed integration should be considered.

As a bottom line for the study, I think it is technically defensible to state that an HTGR can provide the heat necessary to carry out a CCR™ operation, provided that the design and operation of the heater units is based on consideration of the heating processes taking place in the shale formation.

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Appendix B