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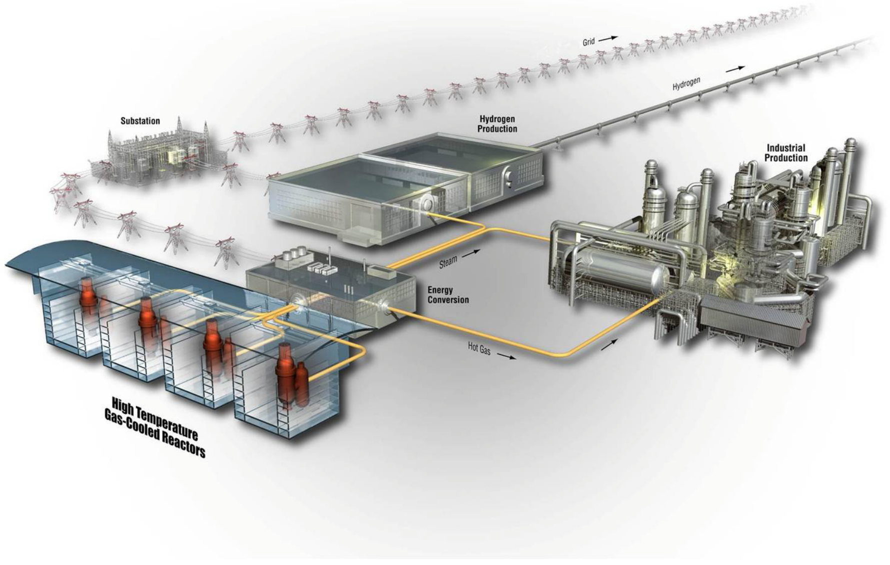
Technical Evaluation Study

Project No. 23843

Integration of HTGRs to an Ex Situ Oil Shale Retort Operation, Economic Analysis



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INTEGRATION OF HTGRS TO AN EX SITU OIL SHALE RETORT OPERATION, ECONOMIC ANALYSIS	Identifier: TEV-1321 Revision: 0 Effective Date: 08/02/2011 Page: 1 of 30

NGNP Project	Technical Evaluation Study (TEV)	eCR Number: 595012

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EXECUTIVE SUMMARY

This technical evaluation (TEV) has been prepared as part of a study for the Next Generation Nuclear Plant (NGNP) Project to evaluate the economics of integrating a high-temperature gas-cooled reactor (HTGR) with conventional chemical processes. This TEV addresses the economics of heat and power integration into ex situ oil shale operations, including mining, ex situ retorting, and shale oil upgrading. The economic results are preliminary and should be refined as the design of the HTGR progresses, if the design of the HTGR is changed significantly, or if additional refinements of the HTGR and/or ex situ oil shale retorting capital and/or operating costs become available. The HTGR capital, operating and maintenance (O&M) costs, fuel, and decommissioning costs are based on the correlations and costs presented for an n^{th} of a kind HTGR in TEV-1196 (Idaho National Laboratory [INL] 2011a).

The production of oil from oil shale using an ex situ retorting process has previously been addressed in detail in TEV-1091 (INL 2011b). In that report, process models for both conventional ex situ oil shale retorting and upgrading for oil production (henceforth referred to as ex situ oil shale retorting) and nuclear-integrated ex situ oil shale retorting were developed. This report is a follow-up to TEV-1091 and evaluates the economics of integration of HTGR heat and power production into ex situ oil shale retorting operations. The following conclusions were drawn when evaluating the economics of the conventional and nuclear-integrated cases:

- The nuclear-integrated ex situ oil shale retorting provides a consistently lower rate of return than the conventional process. This is mainly because the heat integrated from the HTGR is offsetting heat that is produced by burning char in the conventional process. This char is a byproduct of the retorting process and is essentially free. Figure ES 1 presents the internal rate of return (IRR) versus oil price for the convention and nuclear-integrated cases.

- Given the large CO_2 emissions in the conventional retorting case, a carbon tax of approximately \$65/ton-CO_2 is required for the nuclear-integrated case to economically outperform the conventional case, at a 12% IRR. Figure ES 2 presents the carbon tax results.

- An economic sensitivity analysis was performed, it was determined that the uncertainty in the assumed IRR can have the largest impact on the required oil selling price, followed by the total capital investment, and the debt to equity ratio. Figure ES 3 presents a tornado diagram for nuclear-integrated ex situ oil shale retorting, showing the resulting oil selling price when varying the baseline economic assumptions.

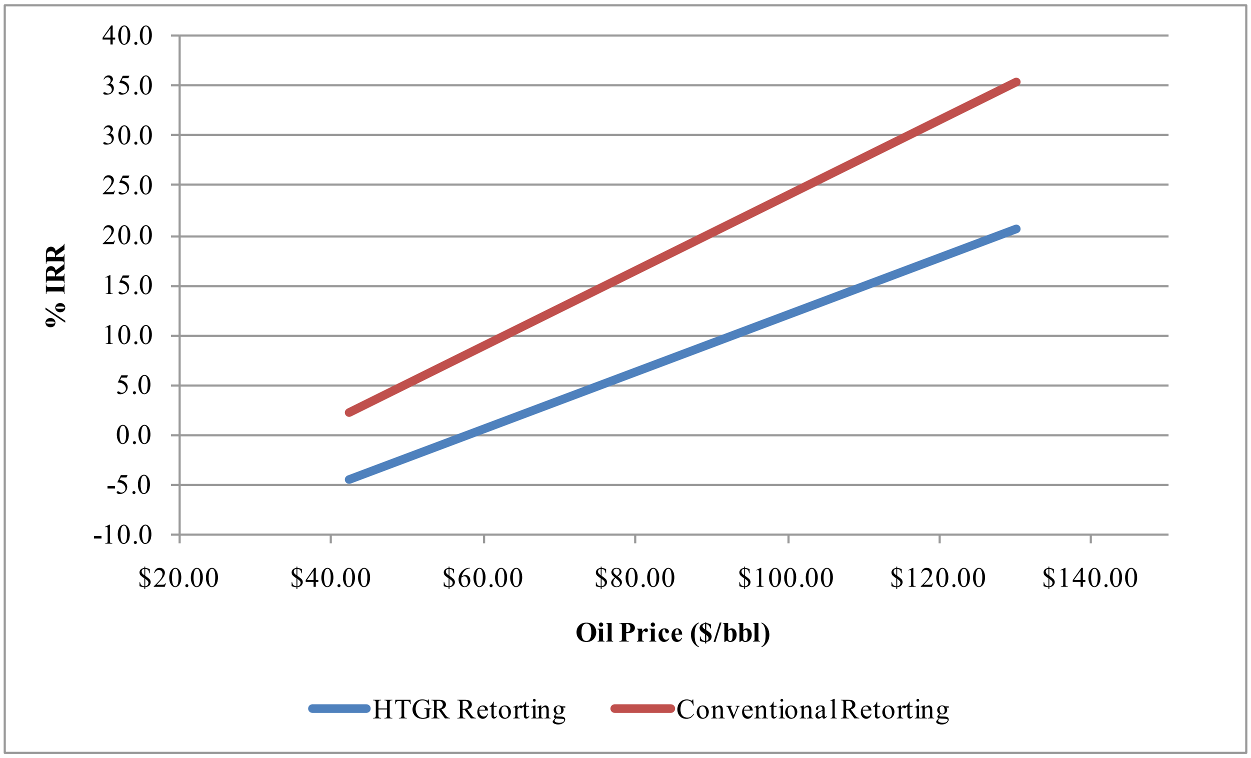

Figure ES 1. IRR as a function of oil price.

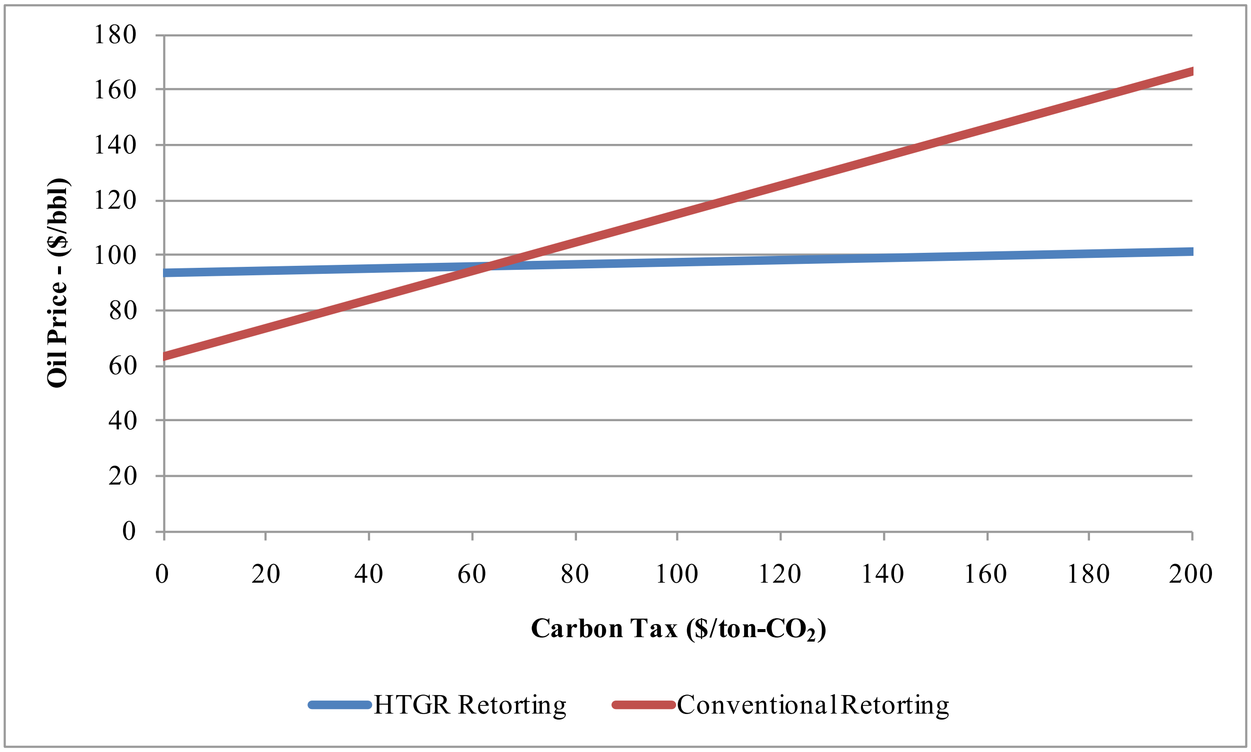

Figure ES 2. Oil price as a function of a carbon tax on CO_2 emissions, 12% IRR.

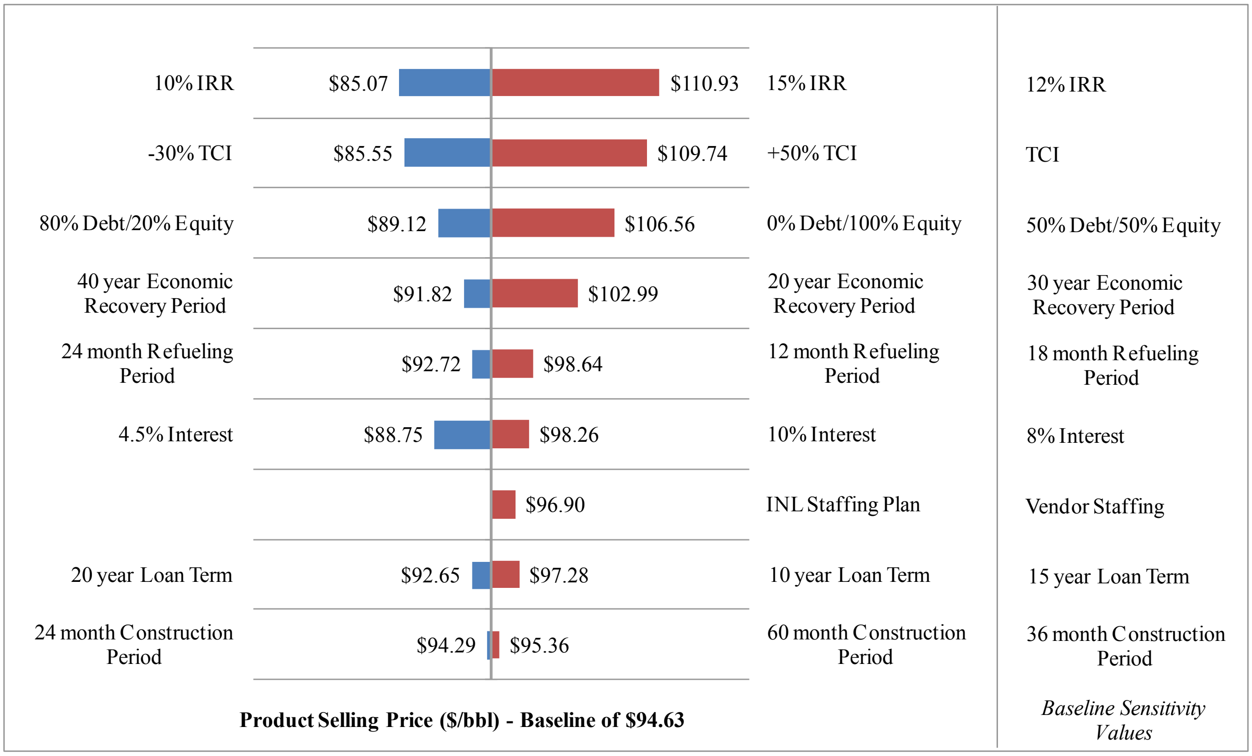

Figure ES 3. HTGR ex situ oil shale retorting tornado diagram.

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ACRONYMS AND NOMENCLATURE

AACE	Association for the Advancement of Cost Engineering
ATCF	after tax cash flow
BTCF	before tax cash flow
CEPCI	chemical engineering plant cost index
DOE	Department of Energy
EIA	Energy Information Administration
GAO	U.S. Government Accountability Office
GIF	GEN-IV International Forum
HTGR	high-temperature gas-cooled reactor
HTSE	high-temperature steam electrolysis
INL	Idaho National Laboratory
IRR	internal rate of return
MACRS	modified accelerated cost recovery system
MARR	minimum annual rate of return
NETL	National Energy Technology Laboratory
NIBT	net income before taxes
NGNP	Next Generation Nuclear Plant
O&M	operations and maintenance
PW	present worth
TCI	total capital investment
TEV	technical evaluation

C_k	capital expenditures
c_months	total number of months in the current modules construction period
CapF	capital breakdown per month
d_k	depreciation
E_k	cash outflows
i'	IRR
k	year
Mod	module/train being evaluated
ModF	capital fraction per module/train
month	current month in reactor/fossil construction period
Number	total number of reactor modules/fossil trains
R_k	revenues
t	tax rate
T_k	income taxes
y	exponent for current module/train

1. INTRODUCTION

This technical evaluation (TEV) has been prepared as part of a study for the Next Generation Nuclear Plant (NGNP) Project to evaluate the economics of integrating a high-temperature gas-cooled reactor (HTGR) with conventional chemical processes. The NGNP Project is being conducted under U.S. Department of Energy (DOE) direction to meet a national strategic need identified in the 2005 *Energy Policy Act* 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.

The HTGR produces high-temperature helium that can be used to produce electricity and/or process heat for export in the form of high-temperature helium or steam. A summary of these products and a brief description is shown in Table 1. For this study, an HTGR outlet temperature of 750°C is assumed; this reflects the initial HTGR design and assumes a more conservative outlet temperature. Eventually temperatures of 950°C are anticipated. Additionally, a 25°C temperature approach is assumed between the primary and secondary helium loops, if helium is the delivered working fluid. As a result, the helium stream available for heat exchange is assumed to be at 725°C. In conventional chemical processes heat and power 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. Heat or electricity produced in an HTGR could be used to supply process heat or electricity to conventional chemical processes while generating minimal greenhouse gases. The use of an HTGR to supply process heat or electricity to conventional processes is referred to as a nuclear-integrated process. This report provides an economic analysis of integrating nuclear-generated heat or electricity into conventional processes and compares the economic results with the conventional process.

Table 1. Projected outputs of the NGNP.

HTGR Product	Product Description
Steam	540°C and 17 MPa
High-Temperature Helium	Delivered at 725°C and 9.1 MPa
Electricity	Generated by a Rankine cycle, 43% efficiency

The production of oil from oil shale using an ex situ retorting process has previously been addressed in detail in TEV-1091 (Idaho National Laboratory [INL] 2011b). In that report, process models for both conventional ex situ oil shale retorting and upgrading for oil production (henceforth referred to as ex situ oil shale retorting) and nuclear-integrated ex situ oil shale retorting were developed. The models documented in TEV-1091 along with the detailed HTGR costs presented in TEV-1196 (INL 2011a) are used as the basis for the economic analysis conducted in this report. This TEV assumes familiarity with TEV-1091 and TEV-1196; hence, detailed descriptions of the process models documented in TEV-1091 and the costs documented in TEV-1196 are not presented here.

The economic models used for this analysis have been developed in Microsoft Excel (Excel 2007). This study makes extensive use of these models; this TEV assumes familiarity with Excel. A detailed explanation of the software capabilities is beyond the scope of this study.

This TEV first presents the general process configuration on which the economic models are based. Next, the details of the economic model are discussed. Finally, results of the economic analysis are presented and discussed. The economic results are preliminary and should be refined as the design of the HTGR progresses, if the design of the HTGR is changed significantly, or if additional refinements of the HTGR and/or ex situ oil shale retorting capital and/or operating costs become available.

2. CASES CONSIDERED

Two cases were identified for economic modeling based o the process models presented in TEV-1091:

- Conventional ex situ oil shale retorting
- Nuclear-integrated ex situ oil shale retorting

Figure 1 shows the block flow diagram for the conventional ex situ oil shale retorting case. The proposed process includes unit operations for surface mining operations, ex situ retorting, and product upgrading, of which the end product is suitable as feed to a conventional refining process.

Figure 2 shows the block flow diagram for the nuclear-integrated ex situ oil shale retorting case. The proposed process includes the same unit operations as the conventional case: surface mining operations, ex situ retorting, and product upgrading. In addition, this configuration adds the HTGR system for supplying heat and power to the conventional process.

In TEV-1091, the hydrogen used for upgrading in the nuclear-integrated case was assumed to be produced using high-temperature steam electrolysis (HTSE) coupled with an additional HTGR. However, to assess the impact of integrating HTGR heat and power solely for ex situ oil shale retorting, hydrogen for both cases was assumed to be purchased from an outside source at the market price.

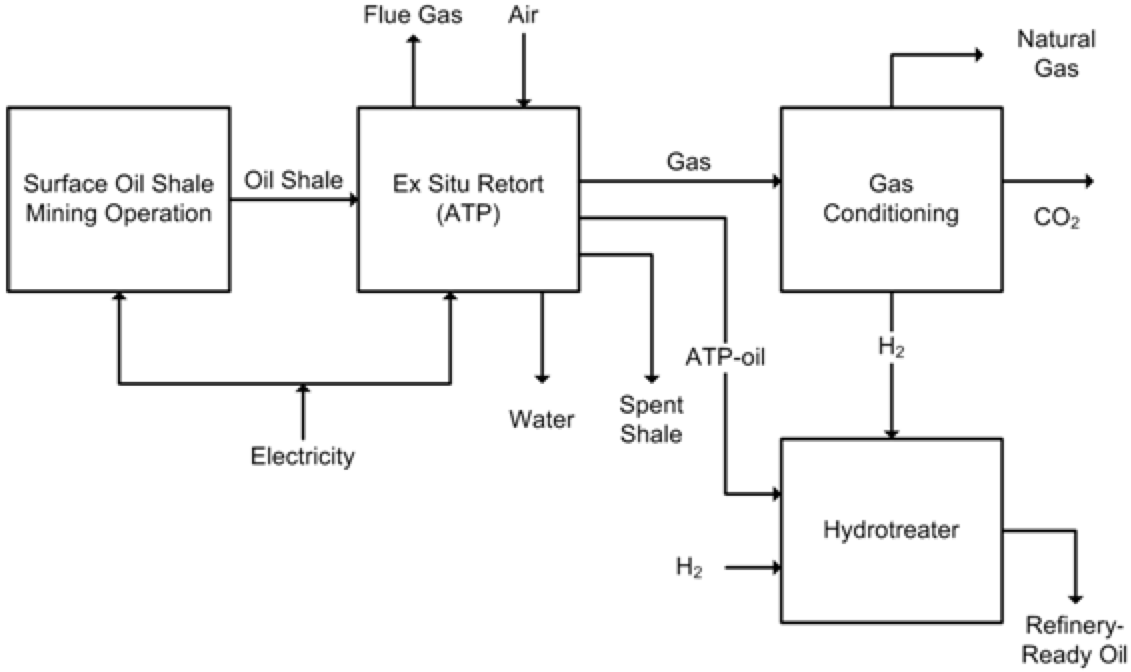

Figure 1. Block flow diagram for the conventional ex situ oil shale retorting case.

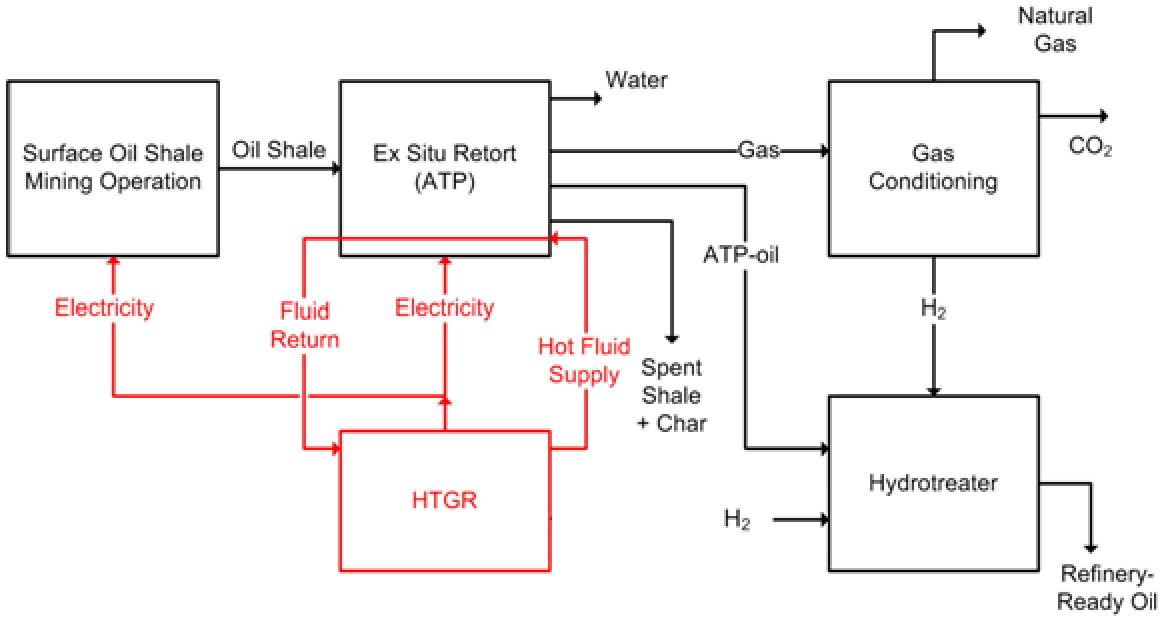

Figure 2. Block flow diagram for the nuclear-integrated ex situ oil shale retorting case.

Again, for detailed descriptions of the process models that provide the basis for the configurations considered for the economic analysis, see TEV-1091.

3. ECONOMIC MODELING OVERVIEW

The economic viability of the ex situ oil shale retorting processes was assessed using standard economic evaluation methods, specifically the internal rate of return (IRR). The economics were evaluated for the conventional and HTGR-integrated cases described in the previous section. The total capital investment (TCI), based on the total equipment costs; annual revenues; and annual manufacturing costs were first calculated for the cases. The present worth of the annual cash flows (after taxes) was then calculated for the TCI. The following sections describe the methods used to calculate the capital costs, annual revenues, annual manufacturing costs, and the resulting economic results. For the economics it is assumed that the products being sold are oil and natural gas, with oil being the primary product. The economics were analyzed for multiple owner operator scenarios, with the HTGR and retorting facilities operated by independent organizations or a single owner operator. The economic results are preliminary and should be refined as the design of the HTGR progresses, if the design of the HTGR is changed significantly, or if additional refinements of the HTGR and/or ex situ oil shale retorting capital and/or operating costs become available.

3.1 Capital Cost Estimation

The Association for the Advancement of Cost Engineering (AACE) International recognizes five classes of estimates. The level of project definition for this study was determined to be an AACE International Class 4 estimate, which has a probable error of -30% and +50% (INL 2011a). A Class 4 estimate is associated with a feasibility study or top-down cost estimate and has one to fifteen percent of full project definition (AACE 2005).

Equipment items for this study were not individually priced. Rather, cost estimates were based on scaled costs for major plant processes from published literature or vendor data. Cost estimates generated in this manner include costs for the oil shale mining equipment and the ex situ retorter (Sherrit 2007) and the heavy oil upgrading plant[1] (Candian Energy Research Institute [CERI] 2008).

After cost estimates were obtained for each of the process areas, the costs for water systems, piping, instrumentation and control, electrical systems, and buildings and structures were added based on scaling factors for the total installed equipment costs, based on information provided in studies performed by the National Energy Technology Laboratory (NETL) (2000). Table 2 presents the factors utilized in this study. These factors were not applied to the upgrading and HTGR costs as these costs are included in the capital cost basis.

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[1] The upgrading equipment used for bitumen upgrading is assumed to adequately represent the equipment used to upgrade the heavy oil produced from the shale oil. The cost was adjusted to reflect construction cost savings moving from the Alberta region to the U.S. (INL 2010a).

Table 2. Capital cost adjustment factors.

Year	Factor
Water Systems	7.1%
Piping	7.1%
Instrumentation and Control	2.6%
Electrical Systems	8.0%
Buildings and Structures	9.2%

Finally, an engineering fee of 10% and a project contingency of 18% were assumed to determine the TCI (NETL 2007). The capital cost provided for the HTGR and upgrading system represent complete and operable systems; therefore, engineering fees and contingencies were not applied to these costs.

The HTGR installed capital costs are based on the capital cost correlations presented in Section 2.6 of TEV-1196 for an n^{th} of a kind HTGR, a mature commercial installation, with a ROT of 750°C and a Rankine power cycle. Preconstruction costs, balance of equipment costs, indirect costs, and project contingencies were added in accordance with the costs outlined in Sections 2.1 through 2.5 of TEV-1196 (INL 2011a).

Cost indices were used to adjust equipment prices from previous years to 2010 values using the Chemical Engineering Plant Cost Index (CEPCI) as depicted in Table 3.

Table 3. CEPCI data.

Year	CEPCI
2001	394.3
2002	395.6
2003	402
2004	444.2
2005	468.2
2006	499.6
2007	525.4
2008	575.4
2009	521.9
2010	550.8

Table 4 presents the capital cost estimate breakdown for the conventional ex situ oil shale retorting case and Figure 3 presents the graphical breakdown of the costs. Table 5 presents the results for the nuclear-integrated ex situ oil shale retorting case and Figure 4 presents the graphical breakdown for the nuclear-integrated case.

Table 4. Total capital investment, conventional ex situ oil shale retorting.

	Installed Cost	**Engineering Fee**	**Contingency**	**Total Capital Cost**
Lease	$7,008,000	Inc.	Inc.	$7,008,000
Mining & Retorting	$973,294,192	$97,329,419	$192,712,250	$1,263,335,862
Upgrading	$1,353,575,116	Inc.	Inc.	$1,353,575,116
Water Systems	$69,103,888	$6,910,389	$13,682,570	$89,696,846
Piping	$69,103,888	$6,910,389	$13,682,570	$89,696,846
I&C	$25,305,649	$2,530,565	$5,010,519	$32,846,732
Electrical Systems	$77,863,535	$7,786,354	$15,416,980	$101,066,869
Buildings and Structures	$89,543,066	$8,954,307	$17,729,527	$116,226,899
Total Capital Investment				**$3,053,453,171**

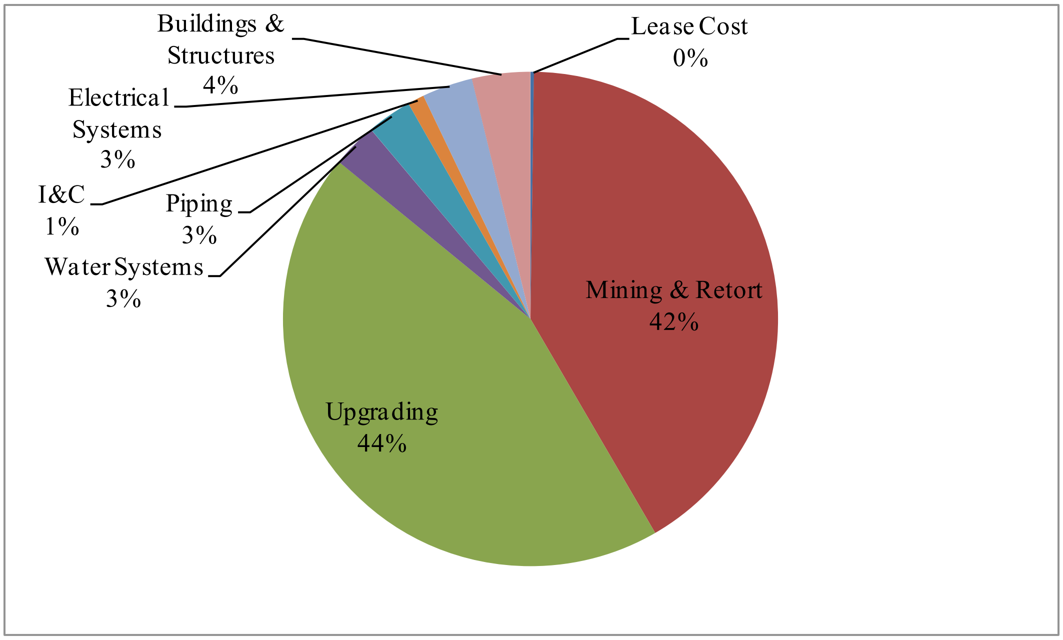

Figure 3. Total capital investment, conventional ex situ oil shale retorting.

Table 5. Total capital investment, nuclear-integrated ex situ oil shale retorting.

	Installed Cost	**Engineering Fee**	**Contingency**	**Total Capital Cost**
HTGR(s)	$2,829,910,834	Inc.	Inc.	$2,829,910,834
Rankine Power Cycle	$371,975,067	Inc.	Inc.	$371,975,067
Lease	$7,008,000	Inc.	Inc.	$7,008,000
Mining & Retorting[2]	$973,294,192	$97,329,419	$192,712,250	$1,263,335,862
Upgrading	$1,353,575,116	Inc.	Inc.	$1,353,575,116
Water Systems	$69,103,888	$6,910,389	$13,682,570	$89,696,846
Piping	$69,103,888	$6,910,389	$13,682,570	$89,696,846
I&C	$25,305,649	$2,530,565	$5,010,519	$32,846,732
Electrical Systems	$77,863,535	$7,786,354	$15,416,980	$101,066,869
Buildings and Structures	$89,543,066	$8,954,307	$17,729,527	$116,226,899
Total Capital Investment				**$6,255,339,072**
HTGR and Power Cycle				$3,201,885,901
Ex situ oil shale Process				$3,053,453,171

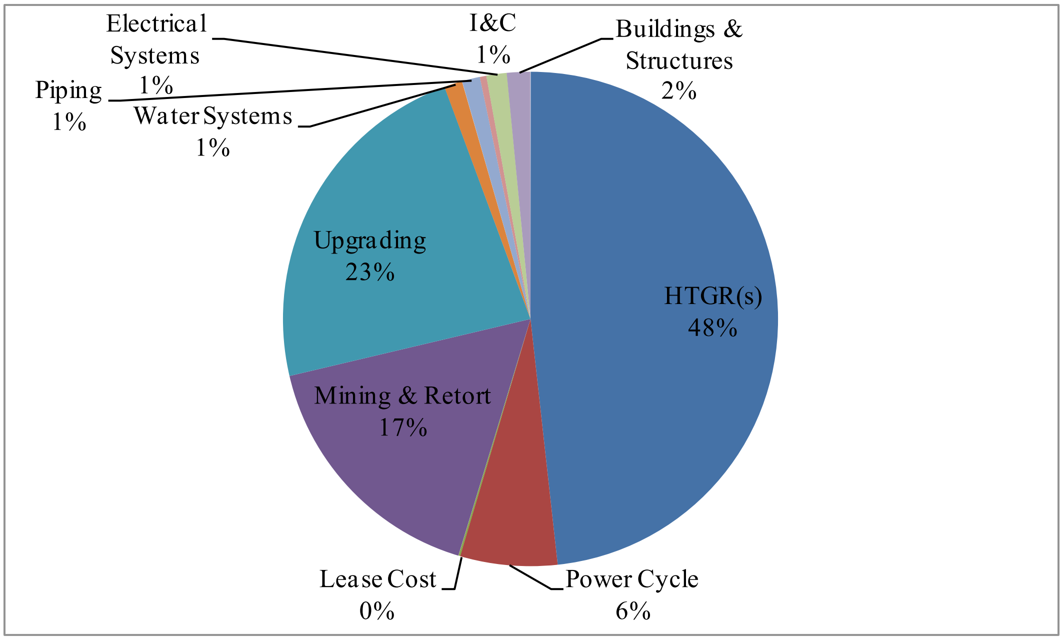

Figure 4. Total capital investment, nuclear-integrated ex situ oil shale retorting.

3.2 Estimation of Revenue

Yearly revenues were estimated for all cases based on recent price data for the oil, natural gas, heat, and electricity generated. When a separate owner operator

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[2] The capital costs for the retorting and upgrading facilities, for the nuclear-integrated case, are assumed to be equal to the costs for the conventional case. If ex situ oil shale retorting using nuclear-integrated heat is pursued in the future, the impact of heat integration on the capital costs of these items should be investigated further.

configuration is assumed, the HTGR collects revenues from the heat and electricity supplied to the retorting process. When heat is exported from the HTGR, the selling price is assumed to be related to electricity price based on the HTGR power generation efficiency based on the following equation:

$$Heat\ Price = Electricity\ Price * Power\ Generation\ Efficiency \tag{1}$$

This relationship provides that when either all heat or all electricity is generated in the HTGR the annual revenue remains the same for either product.

Revenues were estimated for low, average, and high selling prices for the oil produced. Oil prices were gathered from the Energy Information Administration (EIA) and represent wholesale prices. High prices correspond to values from July 2008, low prices are from March 2009, and average prices were the average of the high and low values (EIA 2011a). Natural gas revenues were estimated for all cases based on the current market price of natural gas, $5.50/MSCF (EIA 2011b). The selling price for natural gas was not varied in this study; this was a reasonable assumption as the natural gas product makes up less than five-percent of the total revenues. The electricity selling price is based on the current industrial market price of electricity, $67.90/MWe-hr (EIA 2011c). Revenues were also calculated to determine the necessary selling prices of oil and heat and electricity, for the separate owner operator scenario, to achieve a specific rate of return; however, these revenues are not presented in the following tables.

The revenues presented for the fossil portion are for selling oil at the low, average, and high product prices and natural gas at the market price. When intermediate revenues for the HTGR are presented for the independent owner operator scenarios the heat and electricity prices are presented at the market price. A stream factor of 90% is assumed for both the fossil and nuclear plants. Table 6 presents the revenues for conventional ex situ oil shale retorting case and Table 7 presents the revenues for the HTGR-integrated ex situ oil shale retorting case.

Table 6. Annual revenues, conventional ex situ oil shale retorting.

	Price		**Generated**		**Annual Revenue**
Oil, low	42.45	$/bbl	50,000	bbl/day	$697,241,250
Oil, average	85.27	$/bbl	50,000	bbl/day	$1,400,477,625
Oil, high	128.08	$/bbl	50,000	bbl/day	$2,103,714,000
Natural gas	5.50	$/MSCF	26,800	MSCFD	$48,420,900
Annual Revenue, low					**$745,662,150**
Annual Revenue, average					**$1,448,898,525**
Annual Revenue, high					**$2,152,134,900**

Table 7. Annual revenues, nuclear-integrated ex situ oil shale retorting.

	Price		Generated		Annual Revenue
Oil, low	42.45	$/bbl	50,000	bbl/day	$697,241,250
Oil, average	85.27	$/bbl	50,000	bbl/day	$1,400,477,625
Oil, high	128.08	$/bbl	50,000	bbl/day	$2,103,714,000
Natural gas	5.50	$/MSCF	26,800	MSCFD	$48,420,900
Annual Revenue - Fossil, low					**$745,662,150**
Annual Revenue - Fossil, average					**$1,448,898,525**
Annual Revenue - Fossil, high					**$2,152,134,900**
Heat	29.60	$/MWt-hr	915	MWt	$217,455,053
Electricity	69.70	$/MWe-hr	362	MWe	$193,787,143
Annual Revenue – HTGR (separate owner operator)					**$411,242,196**

3.3 Estimation of Manufacturing Costs

Manufacturing cost is the sum of direct and indirect manufacturing costs. Direct manufacturing costs for this project include the cost of raw materials, utilities, and operating labor and maintenance. Indirect manufacturing costs include estimates for the cost of overhead and insurance and taxes (Perry 2008).

Hydrogen purchase prices are based on hydrogen production via steam methane reforming and were assumed to be $0.68/lb-$H_2$ per TEV-954 (INL 2010b). The electricity purchase prices is based on the current industrial market price of electricity, $67.90/MWe-hr (EIA 2011c). Fixed operating costs, including operations and maintenance (O&M) costs for the mining and retorting process were lumped into a cost per barrel of oil produced (Sherrit 2007). O&M and chemical costs for the upgrading process were also lumped into a cost per barrel of oil produced (CERI 2007). Taxes and insurance was assumed to be 1.5% of the TCI, excluding the HTGR and an overhead of 65% of the labor and maintenance costs was assumed (Jones 2006). Table 8 provides the manufacturing costs for the conventional ex situ oil shale retorting case. Again, availability was assumed to be 90%.

Table 8. Annual manufacturing costs, conventional ex situ oil shale retorting.

	Price		Consumed		Annual Cost
Direct Costs					
Materials					
Hydrogen	0.68	$/lb	279,471	lb/hr	$62,409,819
Utilities					
Electricity	67.90	$/MWe-hr	289	MWe	$154,708,520
Operating Costs					
Oil Shale Processing	7.49	$/bbl	50,000	bbl	$70,039,485
Oil Shale Upgrading	6.58	$/bbl	50,000	bbl	$107,996,834
Indirect Costs					
Overhead					$115,723,608
Insurance and Taxes					$45,801,798
Manufacturing Costs					**$556,680,064**

Manufacturing costs for the nuclear plant were based on information presented in TEV-1196. HTGR manufacturing costs include O&M costs, fuel costs, and decommissioning costs. The O&M, fuel, and decommissioning costs are based on the total thermal rating of the plant (INL 2011a). O&M and decommissioning costs are presented on an annual basis, fuel costs are presented as the total refueling cost per core. The nuclear-integrated cases are presented for the single owner operator scenario only. Table 9 provides the manufacturing costs for the nuclear-integrated ex situ oil shale retorting. When the HTGR is operated independently, the retorting process would purchase heat and electricity as specified in the HTGR revenues table presented previously (Table 7) and the manufacturing costs would be comprised of the nuclear fuel, O&M, and decommissioning costs presented below (Table 9). Again, availability was assumed to be 90%.

The decommissioning fund payment is calculated using the decommissioning cost in dollars per MWt presented in TEV-1196, which is based on NUREG-1307 (NRC 2010). That cost is multiplied by the total reactor power level to determine the total decommissioning cost and then inflated to the year decommissioning will occur, which is based on the economic recovery period. The sinking fund payment is calculated based on the estimated decommissioning cost and a 5% discount rate (GIF 2007).

It is recognized that the HTGR may operate longer than the specified economic recovery period. However, assuming that the reactor is decommissioned at the end of the recovery period is an economically conservative assumption.

Table 9. Annual manufacturing costs, nuclear-integrated ex situ oil shale retorting.

	Price	Consumed	Annual Cost
Direct Costs			
Materials			
Hydrogen	0.68 $/lb	279,471 lb/hr	$62,409,819
Operating Costs			
Oil Shale Processing	7.49 $/bbl	50,000 bbl	$70,039,485
Oil Shale Upgrading	6.58 $/bbl	50,000 bbl	$107,996,834
Indirect Costs			
Overhead			$115,723,608
Insurance and Taxes			$45,801,798
Nuclear Costs			
O&M	5.32 $/MWt-hr	1,745 MWt	$73,224,884
Decommissioning Fund Payment			$16,058,590
Annual Manufacturing Costs			**$525,336,648**
			Cost Per Core
Refueling Cost			**$50,140,220**

3.4 Estimation of Royalties and Depletion

Royalties were estimated based on guidelines presented by the Government of Accountability Office (GAO) for oil and gas products. The GAO lists the royalty at 12.5-percent of the gross revenues for the oil and natural gas products (GAO 2007). The royalty is treated as a negative cash flow.

Depletion is calculated based on the cost method, such that the depletion unit is determined by dividing the adjusted cost basis of the property by the number of units to be mined over the property life. The deduction is calculated as the product of the number of units sold during the year times the depletion unit (Sullivan 2003). The depletion cost is used to reduce taxable income, similar to depreciation.

3.5 Economic Comparison

Several economic indicators were calculated for each case to assess the economic desirability of ex situ oil shale retorting. For all cases the IRR was calculated for the retorting cases at low, average, and high oil prices, as well as for multiple owner operator scenarios for the nuclear-integrated cases. In addition, the oil price necessary for a return of 12% was calculated for all cases, as well as the heat and electricity prices for a 12% rate of return for the separate owner operator nuclear configuration. Table 10 lists the economic assumptions used for the analyses.

Table 10. Economic assumptions.

	Assumption
Year Construction Begins	2012
Construction Information	
Preconstruction Period	6 months
Nuclear Construction Period – per Reactor	36 months
Reactor Startup Staggering	6 months
Fossil Construction Period – per Train	36 months
Train Startup Staggering	6 months
Percent Capital Invested Each Year	S-Curve Distribution
Plant Startup Information	
Startup Time	12 months
Operating Costs Multiplier	1.2
Revenue Multiplier	0.65
Economic Analysis Period	30 years
Availability	90%
Inflation Rate	3%
Debt to Equity Ratio	50%/50%
Loan Information	
Interest Rate on Debt	8%
Interest on Debt During Construction	8%
Loan Repayment Term	15 years
Tax Information	
Effective Tax Rate	38.9%
State Tax Rate	6%
Federal Tax Rate	35%
MACRS Depreciation Term	15 year life
IRR	12%

3.5.1 Cash Flow

To assess the IRR and present worth (PW) of each scenario, it is necessary to calculate the after tax cash flow (ATCF). To calculate the ATCF, it is necessary to first calculate the revenues (R_k); cash outflows (E_k); sum of all noncash, or book, costs such as depreciation (d_k); net income before taxes (NIBT); the effective income tax rate (t); and the income taxes (T_k), for each year (k). The taxable income is revenue minus the sum of all cash outflows and noncash costs. Therefore the income taxes per year are defined as follows (Sullivan 2003):

$$T_k = t(R_k - E_k - d_k) \qquad (2)$$

Depreciation for the economic calculations was calculated using a standard Modified Accelerated Cost Recovery System (MACRS) depreciation method with a property class of 15 years. Depreciation was assumed for the TCI for each reactor module and fossil process train with the first charge occurring the year the corresponding HTGR/process train comes online, i.e. when initial revenues are received. Table 11 presents the recovery rates for a 15-year property class (Perry 2008).

Table 11. MACRS depreciation.

Year	Recovery Rate	Year	Recovery Rate
1	0.05	9	0.0591
2	0.095	10	0.059
3	0.0855	11	0.0591
4	0.077	12	0.059
5	0.0693	13	0.0591
6	0.0623	14	0.059
7	0.059	15	0.0591
8	0.059	16	0.0295

The ATCF is then the sum of the before tax cash flow (BTCF) minus the income taxes owed. Note that the expenditures for capital are not taxed but are included in the BTCF each year there is a capital expenditure (C_k); this includes the equity capital and the debt principle. Figure 5 presents the yearly ATCFs for the nuclear-integrated retorting case at a 12% IRR.

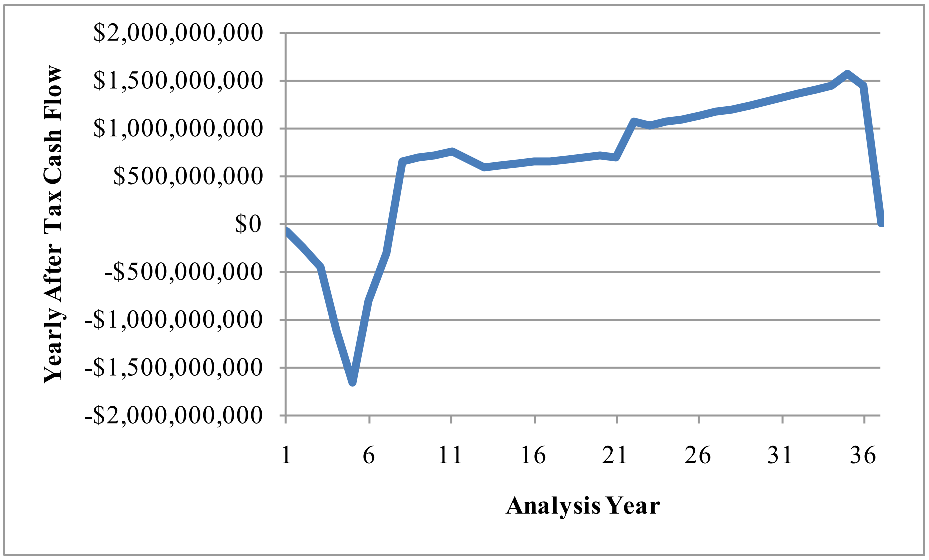

Figure 5. ATCFs, HTGR-integrated ex situ oil shale retorting, 12% IRR.

The BTCF is defined as follows (Sullivan 2003):

$$BTCF_k = R_k - E_k - C_k \tag{3}$$

The ATCF can then be defined as:

$$ATCF_k = BTCF_k - T_k \tag{4}$$

3.5.1.1 Capital Cash Flows during Construction

Capital cash flows for the HTGR and fossil processes during construction were calculated for each year of construction based on two separate correlations. First, the percentage of capital assigned to each module or train was calculated based on an exponential correlation (Demick 2011). The exponent for the correlation is calculated based on the current module/train number, such that:

$$y(Mod) = 0.102 \times \ln(Mod + 0.963) - 0.402 \tag{5}$$

where *y* is the exponent for the current module/train and *Mod* is the module/train being evaluated. The capital fraction is then determined for each module/train:

$$ModF(Mod) = \left(1 - \sum_{i=1}^{i=Mod} ModF(i-1)\right) \times (Number - (Mod - 1))^{y(Mod)} \tag{6}$$

where *Number* is the total number of reactor modules or process trains. The yearly fractional breakdown for each module's/train's capital is calculated by applying a generic standard cumulative distribution, the S-Curve, as recommended by the GEN-IV International Forum (GIF) (2007). The capital breakdown per month is calculated as follows:

$$CapF(month) = 0.5 \times \left(\sin\left(\frac{\pi}{2} + \frac{\pi \times month}{c\_months}\right) + 1\right) - CapF(month - 1) \tag{7}$$

where *month* is the current month in the reactor/fossil construction period and *c_months* is the total number of months in the current module's/train's construction period. The capital fraction for each year is calculated by summing the capital fraction for the corresponding months. The yearly capital fractions are then multiplied by the module/train fraction to determine to overall yearly capital fractional breakdown per module/train. Figure 6 presents the percentage of the TCI spent each year of construction for the HTGR-integrated ex situ oil shale retorting.

Figure 6. Percentage of TCI spent each year of construction, HTGR-integrated ex situ oil shale retorting.

3.5.1.2 Reactor Refueling Cash Flows

Reactor refueling charges occur in the year a refueling is scheduled. The occurrences are determined based on the total number of reactor modules, when the modules come online, and the specified refueling period.

3.5.2 Internal Rate of Return

The IRR method is the most widely used rate of return method for performing engineering economic analyses. This method solves for the interest rate that equates the equivalent worth of an alternative's cash inflows to the equivalent worth of cash outflows (after tax cash flow), i.e., the interest rate at which the PW is zero. The resulting interest is the IRR (i'). For the project to be economically viable, the calculated IRR must be greater than the desired minimum annual rate of return (MARR) (Sullivan 2003).

$$PW(i') = \sum_{k=0}^{N} ATCF_k(1+i')^{-k} = 0 \qquad (8)$$

IRR calculations were performed for the calculated TCI for all cases. In addition, the price of oil and heat and electricity, for the separate owner/operator scenario, necessary for an IRR of 12% and a PW of zero was calculated for each case. All calculations were performed using Excel (Excel 2007).

Finally, a CO_2 tax was included into the calculations to determine the price of oil necessary in all cases for a 12% IRR and a CO_2 tax of $0/ton to $200/ton. The tax calculated was added to the existing yearly tax liability.

4. ECONOMIC MODELING RESULTS

Table 12 presents the results for the conventional ex situ oil shale retorting case, presenting the IRR for selling oil at low, average, and high product prices, and the oil selling price required for a 12%

Table 12. Conventional ex situ oil shale retorting economic results[3].

	TCI	
	% IRR	Product Price
Conventional Ex situ oil shale Retorting	*$3,053,453,171*	
	0.0	$42.45/bbl
	20.3	$85.27/bbl
	33.3	$128.08/bbl
	12.0	$63.57/bbl

Table 13. Nuclear-integrated ex situ oil shale retorting economic results.

	TCI	
	% IRR	Product Price
HTGR Ex situ oil shale Retorting **Single Owner/Operator**	*$6,255,339,072*	
	-6.3	$42.45/bbl
	10.0	$85.27/bbl
	17.8	$128.08/bbl
	12.0	$94.63/bbl
HTGR Ex situ oil shale Retorting **Independent Owner/Operator** **Heat/Power at Market Price**	*$3,201,885,901*	
	6.1	$67.90/MWe-hr
	6.1	$30.14/MWt-hr
	$3,053,453,171	
	N/A	$42.45/bbl
	13.2	$85.27/bbl
	27.6	$128.08/bbl
	12.0	$82.49/bbl
HTGR Ex situ oil shale Retorting **Independent Owner/Operator** **Heat/Power at 12% IRR**	*$3,201,885,901*	
	12.0	$98.66/MWe-hr
	12.0	$43.80/MWt-hr
	$3,053,453,171	
	N/A	$42.45/bbl
	6.9	$85.27/bbl
	23.2	$128.08/bbl
	12.0	$96.24/bbl

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[3] When the IRR is listed as N/A it indicates that the manufacturing costs exceed the revenues.

From the nuclear-integrated results, it is apparent that selling heat and power at the market price provides for the largest return on investment for the retorting process. However, the HTGR only has a 6% IRR selling heat and power at the market price to the fossil process; therefore, this case will not be included in the results comparison. Considering the two remaining cases, it is economically beneficial to have a single owner operator for the retorting and HTGR facilities. As a result, the single owner operator scenario will be presented for the breakeven analyses. Figure 7 presents a graphical comparison of the IRR versus oil price for the convention and nuclear-integrated cases, the nuclear-integrated case presented is for the single owner/operator scenario.

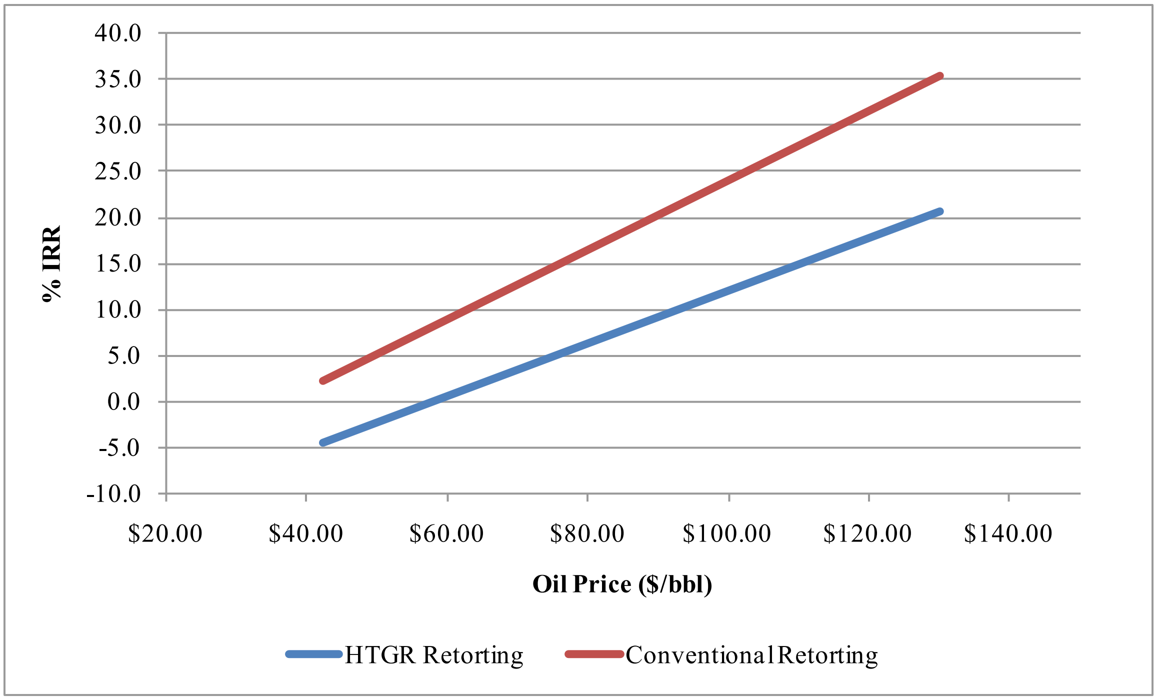

Figure 7. Conventional and nuclear-integrated ex situ oil shale retorting, % IRR as a function of oil price.

From these results, it is apparent that the nuclear-integrated ex situ oil shale retorting provides a consistently lower rate or return than the conventional process for all oil prices. This is mainly because the HTGR-integration for heat is offsetting heat that is produced by burning char in the conventional process. This char is a byproduct of the retorting process and is essentially free and is not being recovered or utilized in the HTGR-integrated case.

Table 14 presents the carbon tax results for the conventional and nuclear-integrated ex situ oil shale retorting cases, excluding the separate owner/operator scenario where heat and electricity are sold at the market price. Figure 8 depicts the carbon tax results for the conventional and nuclear-integrated ex situ oil shale retorting cases for the single owner/operator scenario and a 12% IRR.

Table 14. Conventional and nuclear ex situ oil shale retorting carbon tax results at 12% IRR.

	Carbon Tax $/ton	**Oil Price ($/bbl)**
Conventional Ex situ oil shale Retorting	0	63.57
	50	88.93
	100	114.79
	150	140.72
	200	166.68
HTGR Ex situ oil shale Retorting **Single Owner/Operator**	0	94.63
	50	96.48
	100	98.36
	150	100.24
	200	102.13
HTGR Ex situ oil shale Retorting **Independent Owner/Operator**	0	96.24
	50	98.07
	100	99.91
	150	101.79
	200	103.67

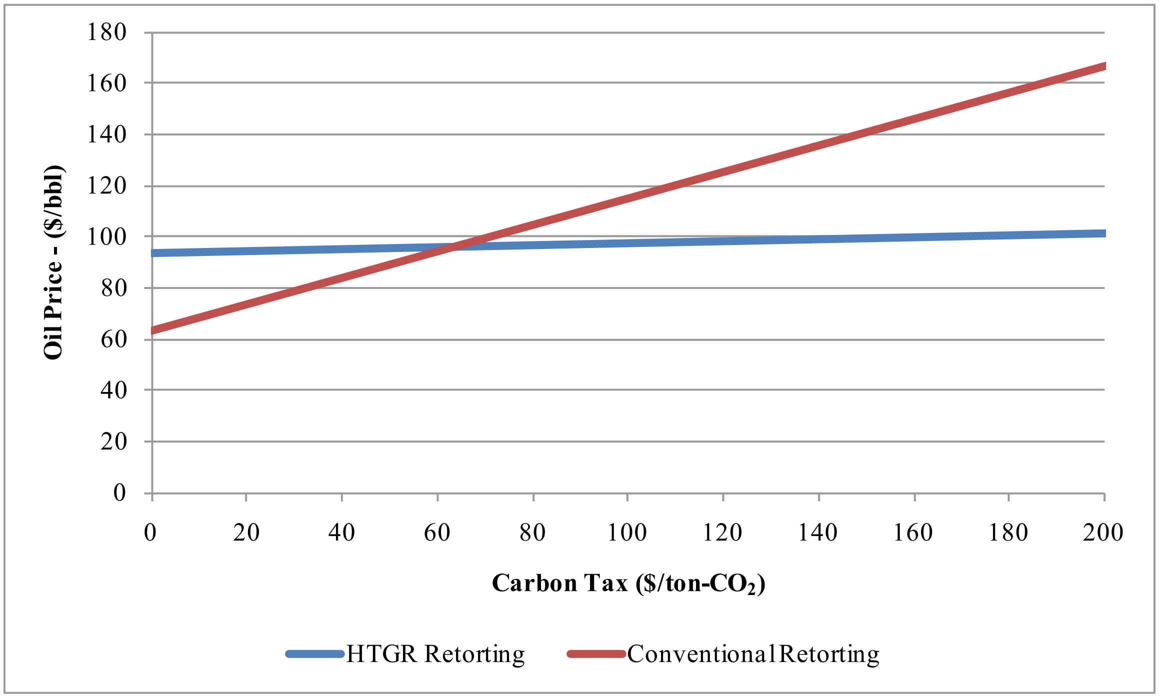

Figure 8. Conventional and nuclear ex situ oil shale retorting, oil price as a function of a carbon tax, 12% IRR, single owner/operator for the nuclear-integrated process.

The carbon tax results show that the nuclear-integrated retorting case outperforms the conventional case at a 12% IRR when the carbon tax is approximately \$65/ton-CO_2.

5. SENSITIVITY ANALYSIS

A sensitivity analysis was conducted for the nuclear-integrated retorting case, for the single owner operator scenario only. The sensitivity analysis assesses the impact on the required product selling price for various changes in the baseline economic assumptions; the result of this sensitivity analysis is a tornado diagram. A tornado diagram is useful in comparing the relative importance of variables, where the sensitive variable is varied while all other variables are held at baseline values.

For the economic assumptions sensitivity analysis, the baseline economic assumptions were varied to determine the effect on the product selling price for the HTGR-integrated case only. Table 15 lists the values used in the economic sensitivity analysis.

Table 15. Lower, baseline, and upper values used in the economic sensitivity analysis.

	Lower Value	**Baseline Value**	**Upper Value**
IRR (%)	10	12	15
Debt Ratio (%)	80	50	0
Debt Interest Rate (%)[4]	4.5	8	10
Loan Term (years)	20	15	10
Construction Period per HTGR (months)	24	36	60
HTGR Staffing Level		Design Supplier	INL Staffing[5]
Economic Recovery Period (years)	40	30	20
HTGR TCI	-30%	TCI	+50%
HTGR Refueling Period (months)	24	18	12

Again, the sensitivity analysis was only conducted for the single owner operator scenario. Table 16 summarizes the results of the sensitivity analysis listing the required product selling prices for the nuclear-integrated ex situ oil shale retorting case as well as the percent change in the product selling price versus the baseline case. The tornado plot is presented in Figure 9.

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[4] The debt interest rate selected in the sensitivity analysis is also used for the interest on debt during construction.

[5] The INL staffing level is outlined in TEV-1196. It assumes 595 employees for a four-pack facility versus the design supplier estimate of 418 employees (INL 2011a).

Table 16. Results from the economic sensitivity analysis, nuclear-integrated ex situ oil shale retorting, single owner/operator.

	Nuclear-Integrated Ex situ oil shale Retorting	
	$/bbl	% Change
Baseline Product Price	**94.63**	
IRR		
10%	$85.07	-10%
15%	$110.93	17%
Debt Ratio		
80%	$89.12	-6%
0%	$106.56	13%
Debt Interest Rate		
4.5%	$88.75	-6%
8%	$98.26	4%
Loan Term		
20 years	$92.65	-2%
10 years	$97.28	3%
Construction Period		
24 months per HTGR	$94.29	0%
60 months per HTGR	$95.36	1%
Staffing Level		
INL Staffing	$96.90	2%
Economic Recovery Period		
40 years	$91.82	-3%
20 years	$102.99	9%
HTGR TCI		
-30% TCI	$85.55	-10%
+50% TCI	$109.74	16%
Refueling Period		
24 months	$92.72	-2%
12 months	$98.64	4%

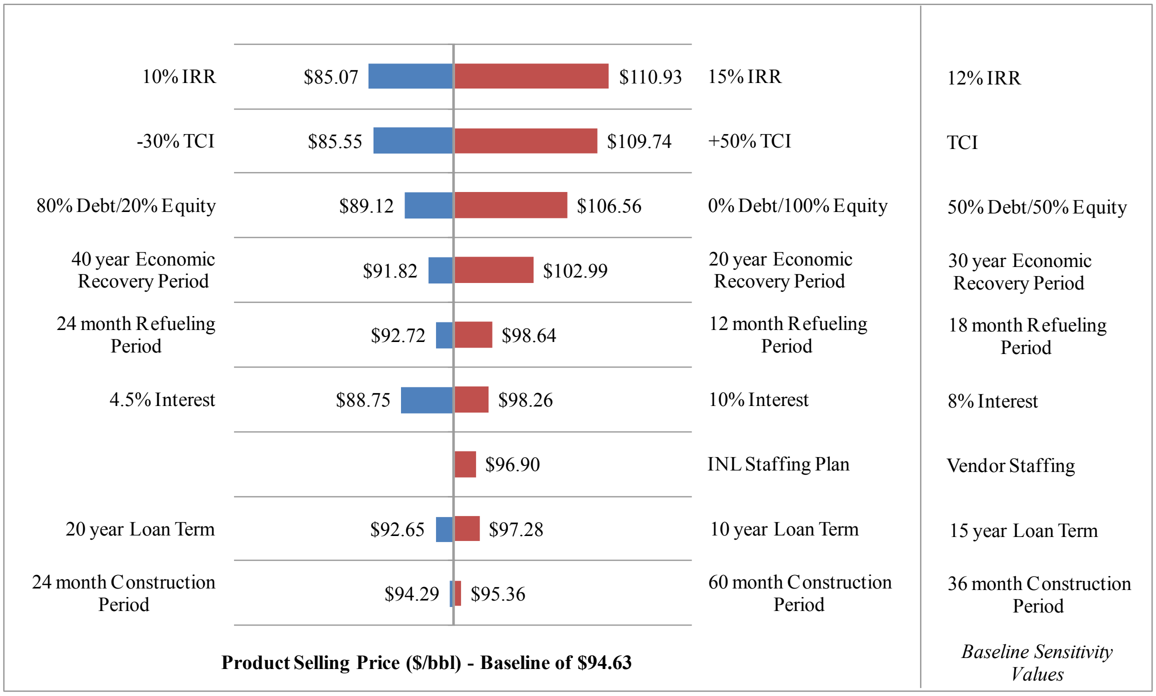

Figure 9. HTGR ex situ oil shale retorting sensitivity analysis.

From the economic sensitivity analysis, the assumed IRR can have the largest impact on the required product selling price, followed by the uncertainty in the HTGR TCI (AACE Class 4), and the debt to equity ratio.

6. FUTURE WORK AND RECOMMENDATIONS

As the design of the HTGR progresses towards finalization, this TEV will be updated if the design of the HTGR is changed significantly or if additional refinements of the capital, O&M, fuel, and decommissioning costs become available.

The costs utilized in this study were developed for the prismatic block reactor configuration. Costs for the pebble bed reactor configuration will be included in a future revision of the TEV, when TEV-1196 is updated; however, the capital costs are roughly equivalent and the difference does not affect the overall accuracy of the estimates for both prismatic and pebble bed configurations (INL 2011a).

The capital and operating costs for the ex situ oil shale retorting process are based on scaled estimates from single source references. If costs come down significantly in the near term or if refined costs become available, this TEV should be updated.

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