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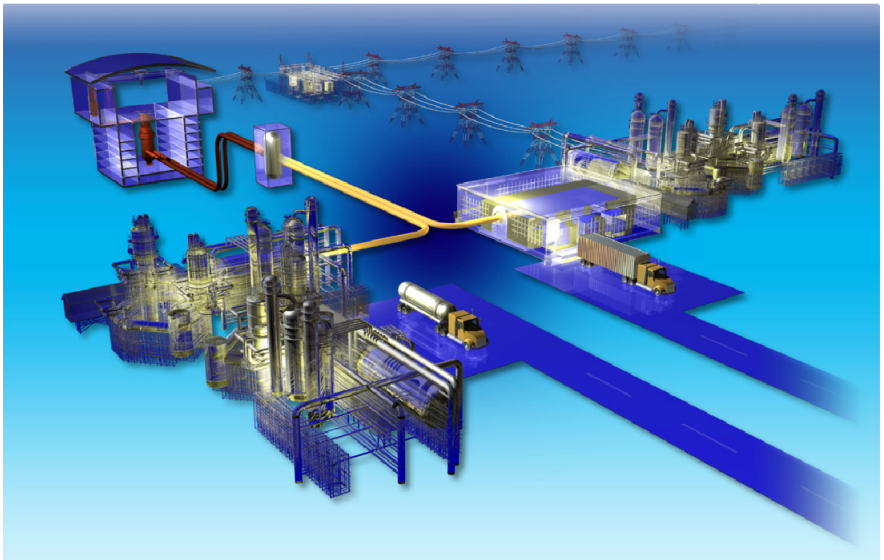
Technical Evaluation Study

Project No. 23843

Nuclear-Integrated Oil Sands Recovery via Steam-Assisted Gravity Drainage



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Idaho National Laboratory

NUCLEAR-INTEGRATED OIL SANDS RECOVERY VIA STEAM-ASSISTED GRAVITY DRAINAGE	Identifier: TEV-704 Revision: 1 Effective Date: 05/15/2010 Page: 1 of 32

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REVISION LOG

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0	11/06/2009	All	Newly issued document.
1	05/15/2010	All	Added economic sections and document reorganization.

EXECUTIVE SUMMARY

This technical evaluation (TEV) has been prepared as part of a study for the Next Generation Nuclear Plant Project to evaluate integration of high-temperature gas-cooled reactor (HTGR) technology with conventional chemical processes. This TEV addresses the integration of an HTGR with the steam-assisted gravity drainage (SAGD) process for the recovery of bitumen.

The HTGR can produce process heat (steam or high-temperature helium), electricity, and/or hydrogen. In conventional chemical processes these products 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, electricity, or hydrogen produced via an HTGR could be used to supply process heat, electricity, or hydrogen to conventional chemical processes without generating any greenhouse gases. This report describes how nuclear-generated heat, electricity, and/or hydrogen could be integrated into conventional SAGD processes and provides a preliminary economic analysis of the conventional and nuclear-integrated options.

The following conclusions were drawn when evaluating the nuclear-integrated SAGD process against the conventional process:

- One 600 MW_t HTGR is required to support recovery of 56,000 barrels per day of bitumen. Nuclear integration eliminates natural gas consumption, approximately 56 MMSCD, when nuclear heat is substituted for natural gas combustion for steam generation. As a result, CO_2 emissions are also eliminated from the process, although there are still CO_2 emissions from imported power.

- The following table outlines the crude prices (Canadian Heavy Hardisty) necessary for the SAGD applications to obtain a 12% internal rate of return (IRR) at low ($6.50/MSCF), average ($4.50/MSCF), and high natural gas prices ($12.00/MSCF); with and without a carbon tax; as well as assessing the impact of reducing the HTGR capital cost by 30%. Low, average, and historical high crude prices are also presented.

Table ES 1. SAGD economic results summary for a 12% IRR.

Technology	**Crude Price ($/bbl) no CO_2 Tax**			**Crude Price ($/bbl) $50/ton CO_2 Tax**		
	Low NG	Avg. NG	High NG	Low NG	Avg. NG	High NG
Conventional SAGD	26.52	29.50	37.69	32.88	35.85	44.05
Nuclear Integrated SAGD	42.72	42.72	42.72	42.72	42.72	42.72
Nuclear Integrated SAGD, -30% HTGR cost	36.34	36.34	36.34	36.34	36.34	36.34
Low Crude Price, March 2009	37.82					
Average US Crude Price	80.18					
High Crude Price, July 2008	122.53					

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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
dilbit	diluted bitumen (70% bitumen 30% naphtha, by volume)
DOE	Department of Energy
EIA	Energy Information Administration
GHG	greenhouse gas
GWP	global warming potential
HP	high pressure
HTGR	high-temperature gas reactor
INL	Idaho National Laboratory
IRR	internal rate of return
MARR	minimum annual rate of return
MSCF	thousand standard cubic feet
MMSCF	million standard cubic feed
NGNP	Next Generation Nuclear Plant
NIBT	net income before taxes
PW	present worth
SAGD	steam-assisted gravity drainage
TCI	total capital investment
TEV	technical evaluation

C_1	cost of equipment with capacity q_1
C_2	cost of equipment with capacity q_2
C_k	capital expenditures
d_k	depreciation
E_k	cash outflows
i'	IRR
k	year

n	exponential factor
q_1	equipment capacity
q_2	equipment capacity
R_k	revenues
t	tax rate
T_k	income taxes

1. INTRODUCTION

This technical evaluation (TEV) has been prepared as part of a study for the Next Generation Nuclear Plant (NGNP) Project to evaluate integration of high-temperature gas-cooled reactor (HTGR) technology 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 *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 process heat (steam or high-temperature helium), electricity, and/or hydrogen. A summary of these products and a brief description is shown in Table 1. For this study the HTGR outlet temperature is assumed to be 750°C; this reflects the initial HTGR design and assumes a more conservative outlet temperature, eventually temperatures of 950°C are anticipated. Additionally, a 50°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 700°C. In conventional chemical processes, these products 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, electricity, or hydrogen produced in an HTGR could be used to supply process heat, electricity, or hydrogen 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 a nuclear-integrated process. This report describes how nuclear-generated heat, electricity, or hydrogen could be integrated into conventional processes and provides a preliminary economic analysis to show which nuclear-integrated processes compare favorably with conventional processes.

Table 1. Assumed outputs of the HTGR

HTGR Product	Product Description
Process Heat	
Steam	540°C and 17 MPa
High-Temperature Helium	Delivered at 700°C and 9.1 MPa
Electricity	Generated by Rankine Cycle with thermal efficiency of 40%
Hydrogen	Generated via high-temperature steam electrolysis

This TEV addresses potential integration opportunities for in situ production of oil sands recovery via steam-assisted gravity drainage (SAGD). The HTGR would produce steam via high-temperature heat exchange and be physically located near the SAGD production facility. A separate study should be conducted to assess the optimal siting of the HTGR

with respect to the SAGD facility, balancing safety concerns associated with separation distance and heat losses associated with transporting high-temperature heat long distances.

Idaho National Laboratory (INL) has spent several years developing detailed process simulations of chemical processes, typically utilizing fossil fuels such as coal, biomass, or natural gas as the feedstock. This study makes extensive use of the modeling capability at INL in order to evaluate the integration of HTGR technology with commercial SAGD production. The outputs from the material and energy balances generated from a SAGD Excel model were utilized as inputs into the Excel economic model. This TEV assumes familiarity with the SAGD process; hence, a thorough explanation of this technology is considered to be beyond the scope of this TEV.

A literature review of previous assessments of nuclear-integrated SAGD processes was performed. The results of the modeling conducted in this study are in general agreement with the previous studies (SNC 2008, Andre 2009, Rolfe 2007, Oberth 2009, Finan 2007). This report is not intended to be a literature review; therefore, the results of the publications analyzed will not be included in this report; rather, a separate white paper will be prepared.

The TEV that follows first presents an overview of the spreadsheet-based modeling performed for conventional and nuclear-integrated SAGD recovery of oil sands. Afterwards, the results of the process modeling for each case are discussed; specifically, the impact of the HTGR integration. Next, an overview of the economic modeling is presented followed by results for both the conventional and the nuclear-integrated SAGD recovery processes. Finally, conclusions and recommendations for both the conventional and nuclear-integrated processes are discussed.

2. PROCESS MODELING OVERVIEW

The process models for the SAGD scenarios were developed utilizing Excel (Excel 2007). Significant emphasis in the models has been placed on the steam generation techniques, either using traditional natural gas fired steam generators or HTGR-based steam generation.

Two cases were originally identified for modeling:

- Conventional SAGD process
- Nuclear-integrated SAGD process.

A schematic diagram of a conventional SAGD operation is shown in Figure 1. The operation consists of a SAGD well pair; the top horizontal well is used to supply steam and the lower horizontal well is used to collect the heavy oil product. The wells run parallel to each other. The top and bottom wells are located 50 to 200 meters below the surface, are separated by approximately five meters, and are up to 1,000 meters in length.

The injected steam travels along the upper perforated-well bore and heats the oil sand deposits in the vicinity of the upper well. After the deposit is heated, the bitumen becomes fluid and drains to the lower perforated-well where it is pumped and collected along with water condensed from the injected steam. The bitumen/water mixture is then sent through a fairly complicated water/oil separation system consisting of standard API separators, hydro cyclone separators, and in some cases, air flotation devices. Up to 85% of the water can be recovered and recycled back to the steam generator after it is sufficiently treated. The recovered bitumen is then mixed with a diluent, assumed to be naphtha, to provide fluidity for conventional pipeline transport to an upgrading facility.

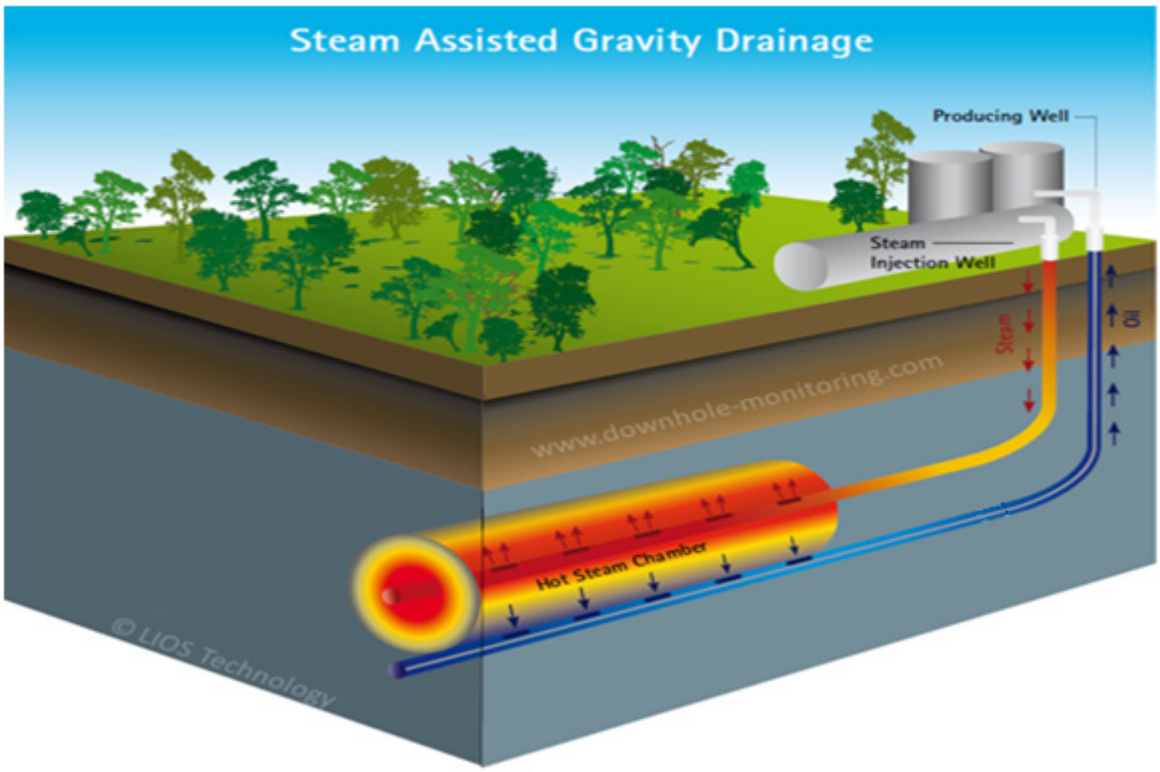

Figure 1. Typical schematic of a single SAGD well pair.

The models were sized to produce 56,000 barrels per day of pure bitumen product. Again, naphtha is blended with the pure bitumen to produce dilbit, i.e., diluted bitumen. The project was sized based on the amount of bitumen that could be recovered through the integration of a single HTGR unit for dedicated steam generation. The integration point of the HTGR is steam production only; the minimal amount of power required for the SAGD process is assumed to be purchased from the grid in order to minimize HTGR cost by eliminating equipment associated with power production from the HTGR. Thermal parasitic losses for the heat exchangers required for the nuclear-integrated option are accounted for in the model as well as heat losses from the long-distance, high-temperature steam piping.

The conventional SAGD block flow diagram is presented in Figure 2; Figure 3 presents the nuclear-integrated SAGD block flow diagram. The HTGR is assumed to be located within 2 kilometers of several SAGD well pairs in order to provide continuous production of bitumen over the life of the project; in this case assumed to be 30 years. A separate study was conducted to determine the impact of heat loss through the HTGR heat transport piping; it was concluded that 1% of the heat duty of the steam is lost per kilometer transported (AREVA 2008).

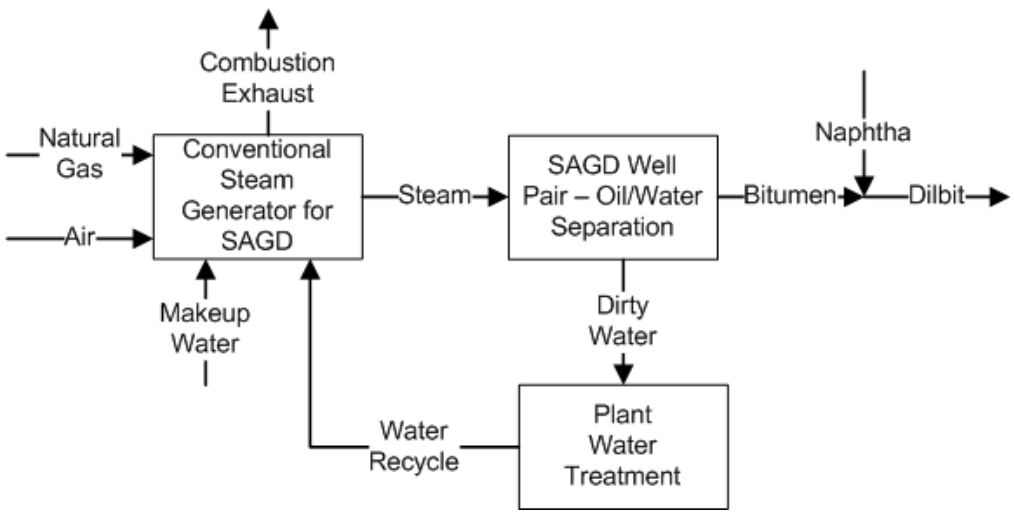

Figure 2. Conventional SAGD block flow diagram.

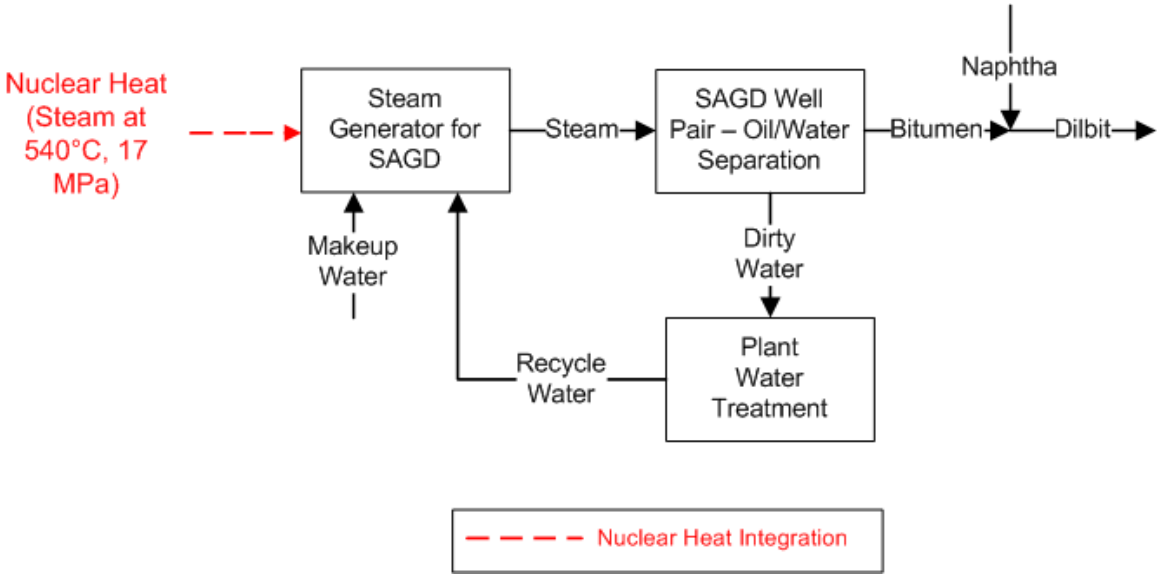

Figure 3. Nuclear-integrated SAGD block flow diagram.

Table 2 lists the major assumptions utilized to determine the overall material and energy balance for the conventional and nuclear-integrated SAGD processes.

Table 2. SAGD process modeling assumptions.

	Conventional SAGD	Nuclear integrated SAGD
Required Bitumen Output (bbl/day)	56,000	56,000
Steam to Oil Ratio (bbl/bbl)	2.5	2.5
Natural Gas Consumption (MSCF/bbl)	1.0	0
% Water Recovery	85%	85%

3. PROCESS MODELING RESULTS

Analysis of the conventional SAGD case indicates a strong potential heat integration opportunity for a HTGR. In the conventional case, 100% of the natural gas feed to the process is burned to provide heat for steam generation. The operating conditions for the steam are saturated steam at 310°C (Finan 2010), which can alternatively be supplied by the 540°C steam from the HTGR via an intermediate heat exchanger. Steam is supplied to the well pad via insulated piping to minimize heat loss between the HTGR and the well pad(s).

The process modeling results for the nuclear-integrated SAGD case look technically promising. A single 600 MW_t HTGR would be required to produce 56,000 barrels per day of bitumen. As mentioned previously, it was assumed that the reactor would supply only heat to the fossil process; the minimal amount of power required for the SAGD process is assumed to be purchased from the grid in order to minimize HTGR cost by eliminating equipment associated with power production from the HTGR. By substituting nuclear heat for natural gas combustion in the steam generator, natural gas consumption is eliminated from the process. Power consumption for the plant does increase from 6.9 MW for the conventional case to 16.9 MW for the nuclear-integrated case. The primary factor for increased power consumption is the increased power load required to operate miscellaneous equipment in the HTGR. CO_2 emissions are also eliminated from the process, although there are still CO_2 emissions from imported power. Water consumption for the HTGR has not been included, as a detailed water balance for the HTGR has not been completed.

A summary of the modeling results for all cases is presented in Table 3. A high-level material and energy balance summary for each case is graphically presented in Figure 4. The conventional SAGD case serves as a basis for comparison with the nuclear-integrated case.

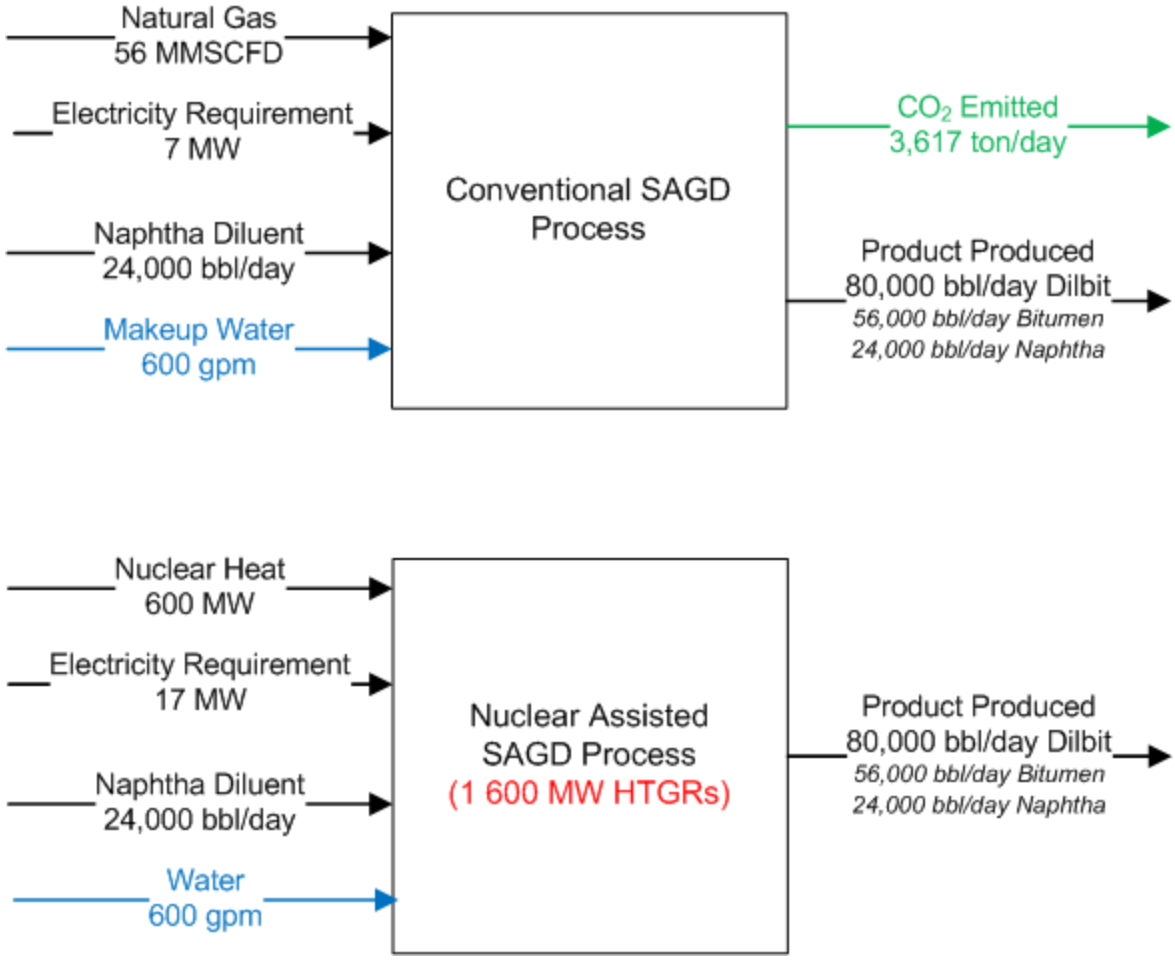

Figure 4. SAGD modeling case material balance summary.

Table 3. SAGD modeling case study results.

	Conventional SAGD	Nuclear Integration SAGD
Inputs		
Natural Gas Feed rate (MMSCFD)[1]	56	0
# HTGRs (600 MW_t)	N/A	1
Naphtha as Diluent (bbl/day)	24,000	24,000
Outputs		
Dilbit Product (bbl/day)	*80,000*	*80,000*
Bitumen (bbl/day)	56,000	56,000
Naphtha (bbl/day)	24,000	24,000
Utility Summary		
Total Power (MW)	*-6.8*	*-16.9*
SAGD Process	-6.8	-6.8
HTGR	N/A	-10.1
Water Requirements[1]		
Water Consumed (gpm)	600	600
CO_2 Summary		
Total CO_2 Emitted (ton/day)	3,617	0
Nuclear Integration Summary		
Nuclear Heat (MW)	N/A	600

[1]Standard temperature of 60 degrees F.

4. ECONOMIC MODELING OVERVIEW

The economic viability of the SAGD processes was assessed using standard economic evaluation methods. The economics were evaluated for the conventional and nuclear-integrated options described in the previous sections. 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, as well as the TCI at +50% and -30% of the HTGR cost, with the debt to equity ratio equal to 80%/20%. 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 product being sold is a diluted bitumen, or dilbit, which is a blend of 30% naphtha and 70% bitumen.

4.1 Capital Cost Estimation

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 were generated for the SAGD well pads and pairs, steam generators, oil/water separators, high-temperature steam piping, and the HTGRs for the SAGD scenarios. In some instances, several costs were

[1] SAGD water requirements only, does not include water requirements for the HTGR

averaged. Appendix A presents the detailed breakdown of the equipment item costs, including the original equipment cost bases for the SAGD cases. The estimate presented is a Class 5 estimate, which has a probable error up to +50% and -30% (AACE 2005).

The installed capital costs presented are for inside the battery limits and exclude costs for administrative offices, storage areas, utilities, and other essential and nonessential auxiliary facilities. Fixed capital costs were estimated from literature estimates and scaled estimates (capacity, year, and material) from previous quotes. Capacity adjustments were based on the six-tenths factor rule:

$$C_2 = C_1\left(\frac{q_2}{q_1}\right)^n \tag{1}$$

where C_1 is the cost of the equipment item at capacity q_1, C_2 is the cost of the equipment at capacity q_2, and n is the exponential factor, which typically has a value of 0.6 (Peters 2002). It was assumed that the number of trains did not have an impact on cost scaling. Cost indices were used to adjust equipment prices from previous years to values in July of 2009 using the Chemical Engineering Plant Cost Index (CEPCI) as depicted in Table 4. Costs for HTGRs were scaled directly based on capacity; the six-tenths factor rule was not used.

Table 4. CEPCI data.

Year	CEPCI	Year	CEPCI
1990	357.6	2000	394.1
1991	361.3	2001	394.3
1992	358.2	2002	395.6
1993	359.2	2003	402
1994	368.1	2004	444.2
1995	381.1	2005	468.2
1996	381.7	2006	499.6
1997	386.5	2007	525.4
1998	389.5	2008	575.4
1999	390.6	July 2009	512

For the nuclear-integrated cases, the estimates of capital costs and operating and maintenance costs assumed the nuclear plant was an “nth of a kind.” In other words, the estimates were based on the costs expected after the HTGR technology is integrated into an industrial application more than 10 times. The economic modeling calculations were based on two capital cost scenarios: a current best estimate of \$2,000/kWt (INL 2007) and a target of \$1,400/kW_t (Demick 2009) where kW_t is the thermal rating of the plant. In comparison, light water nuclear reactor costs are approximately \$1,333/kW_t (NEI 2008). Based on the two capital cost scenarios for HTGR technology, the nominal capital cost for a 600 MW_t HTGR would be \$1.2 billion; the target capital cost would be \$840 million.

After cost estimates were obtained for each of the process areas, the costs for 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) (NETL 2000). These factors were not added to the cost of the HTGR, as the cost basis for the HTGR was assumed to represent a complete and operable system. Costs for piping and water systems were calculated separately or included in the individual process costs. Table 5 presents the factors utilized in this study.

Table 5. Capital cost adjustment factors.

Year	Factor
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. The capital cost provided for the HTGR represents a complete and operable system; the total value represents all inside battery limits and outside battery limits elements as well as contingency and owner's costs. Therefore, engineering fees and contingencies were not applied to this cost.

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 5 estimate. However, the baseline case is actually more in line with the AACE International Class 4 estimate, which is associated with equipment factoring, parametric modeling, historical relationship factors, and broad unit cost data. The HTGR project definition falls under an AACE International Class 5 estimate, associated with less than 2 percent project definition and based on preliminary design methodology (AACE 2005). Since the HTGR is a larger portion of the total capital investment, an overall Class 5 estimate was assumed.

Based on the AACE International contingency guidelines as presented in DOE/FETC-99/1100, it would appear that the overall project contingency for the non-nuclear portion of the capital should be in the range of 30 to 50 percent, 30 to 40 percent for Class 4 and 50% for Class 5 (Parsons 1999). However, because the cost estimates were scaled based on estimated, quoted, and actual project costs, the overall non-nuclear project contingency should be more in the range of 15 to 20 percent. Eighteen percent was selected based on similar studies conducted by NETL (2007). Again, contingency was not applied to the HTGR, as project contingency was accounted for in the basis for the capital cost estimate.

Varying only the cost of the nuclear facility was an adequate assumption, as the cost of the non-nuclear portion of the plant remains relatively constant for both

cases; furthermore, the HTGR accounts for over 60% of the capital cost when nuclear heat is integrated. In addition, there is a greater level of uncertainty in the nuclear plant price given the nascency of HTGR development. A geographic location factor is assumed for HTGR construction in Alberta. It is set to be 1.65 for construction of the HTGR at an oil sands location in the Alberta Province due to the limited amounts of skilled labor in the northwest portion of the province (and the subsequent high costs of this labor), and as a result of unique transportation issues and lack of suitable and permanent transportation routes.

Table 6 and Figure 5 present the capital cost estimate breakdown for the conventional SAGD case and Table 7 and Figure 6 present the results for the nuclear-integrated SAGD case.

Table 6. Total capital investment, conventional SAGD case.

	Installed Cost	Engineering Fee	Contingency	Total Capital Cost
SAGD Well Pads & Pairs	$521,557,420	$52,155,742	$103,268,369	$676,981,532
Steam Generators	$80,610,524	$8,061,052	$15,960,884	$104,632,460
Oil Water Separators	$80,000,000	$8,000,000	$15,840,000	$103,840,000
I&C	$17,736,367	$1,773,637	$3,511,801	$23,021,804
Electrical Systems	$54,573,436	$5,457,344	$10,805,540	$70,836,319
Buildings and Structures	$62,759,451	$6,275,945	$12,426,371	$81,461,767
Total Capital Investment				**$1,060,773,882**

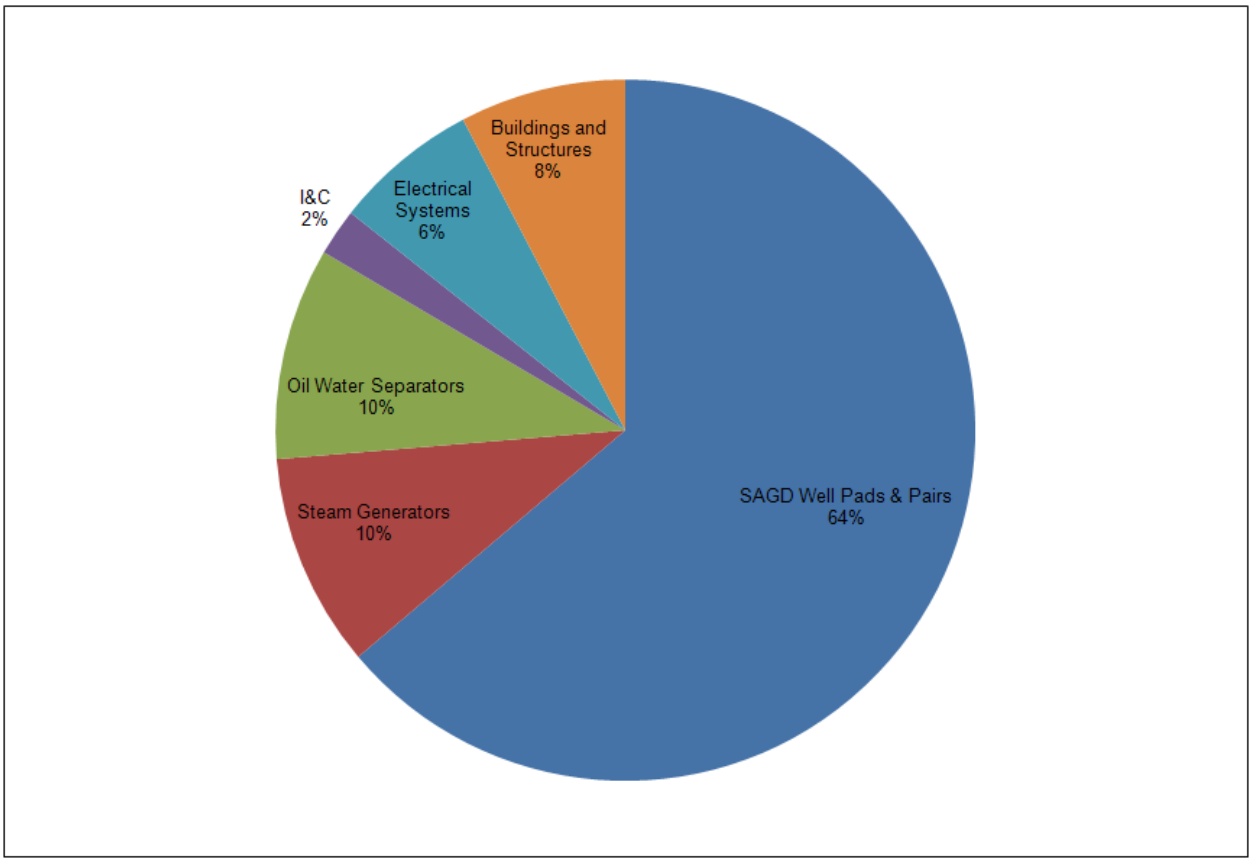

Figure 5. Total capital investment, conventional SAGD case.

Table 7. Total capital investment, nuclear integrated SAGD case.

	Installed Cost	Engineering Fee	Contingency	Total Capital Cost
HTGRs	$1,699,450,000			$1,699,450,000
SAGD Well Pads & Pairs	$521,557,420	$52,155,742	$103,268,369	$676,981,532
Steam Generators	$11,000,000	$1,100,000	$2,178,000	$14,278,000
Oil Water Separators	$80,000,000	$8,000,000	$15,840,000	$103,840,000
Piping	$51,051,010	$5,105,101	$10,108,100	$66,264,211
I&C	$17,253,819	$1,725,382	$3,416,256	$22,395,457
Electrical Systems	$49,004,594	$4,900,459	$9,702,910	$63,607,963
Buildings and Structures	$56,355,283	$5,635,528	$11,158,346	$73,149,157
Total Capital Investment				**$2,719,966,319**
Total Capital Investment (+50% HTGR)				**$3,569,691,319**
Total Capital Investment (-30% HTGR)				**$2,210,131,319**

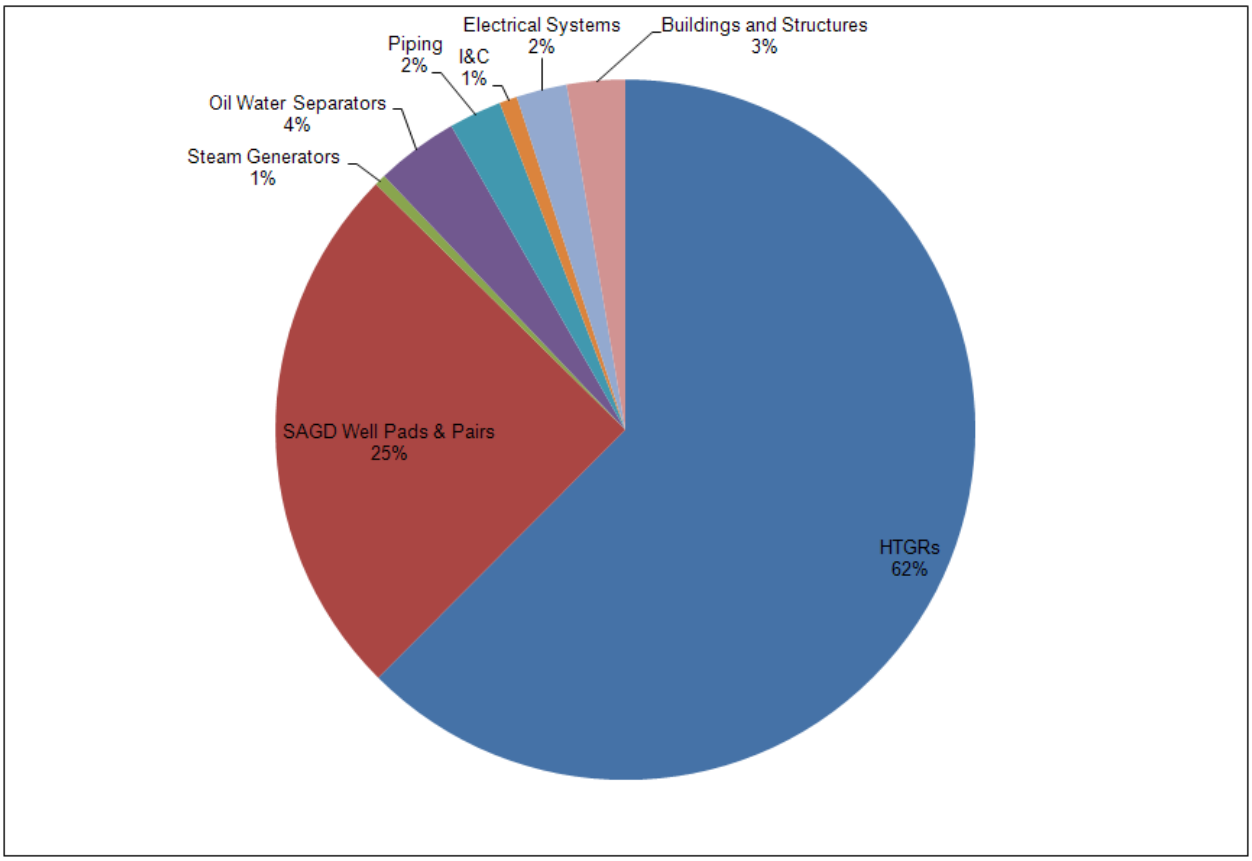

Figure 6. Total capital investment, nuclear integrated SAGD case.

4.2 Estimation of Revenue

Yearly revenues were estimated for all cases based on recent price data for the various products generated. Revenues were estimated for low, average, and high prices for the crude product less the naphtha diluent. High prices correspond to

prices from July 2008, low prices are from March 2009, and average prices were the average of the high and low values (EIA 2010a). Crude prices gathered from the Energy Information Administration (EIA) represent wholesale prices and do not include taxes; it was assumed that the dilbit would sell for the same value as Canadian Heavy Hardisty. Naphtha prices were scaled based on diesel prices, which naphtha tracks closely, and a 10% adder was applied to account for higher prices in Canada, per guidance by Canada's National Energy Board (NEB) (2006). Revenues were also calculated to determine the necessary selling price of crude (less the naphtha diluent) to achieve a specific rate of return; however, these revenues are not presented in the following tables. Though technically a manufacturing cost, the cost of the naphtha diluent is directly deducted from the crude revenue stream to simplify the economic calculations, since both prices are varied concurrently in the model. A stream factor of 92% is assumed for both the fossil and nuclear plants. Table 8 presents the revenues for the conventional SAGD case and Table 9 presents the revenues for the nuclear-integrated SAGD case.

Table 8. Annual revenues, conventional SAGD case.

	Price		Generated		Annual Revenue
Crude, low	37.82	$/bbl	80,000	bbl/day	$1,015,996,480
Crude, average	80.18	$/bbl	80,000	bbl/day	$2,153,854,780
Crude, high	122.53	$/bbl	80,000	bbl/day	$3,291,713,080
Naphtha, low	64.68	$/bbl	24,000	bbl/day	-$521,269,056
Naphtha, average	125.43	$/bbl	24,000	bbl/day	-$1,010,889,634
Naphtha, high	186.19	$/bbl	24,000	bbl/day	-$1,500,510,211
Annual Revenue, low					**$494,727,424**
Annual Revenue, average					**$1,142,965,146**
Annual Revenue, high					**$1,791,202,869**

Table 9. Annual revenues, nuclear-integrated SAGD case.

	Price		Generated		Annual Revenue
Crude, low	37.82	$/bbl	80,000	bbl/day	$1,015,996,480
Crude, average	80.18	$/bbl	80,000	bbl/day	$2,153,854,780
Crude, high	122.53	$/bbl	80,000	bbl/day	$3,291,713,080
Naphtha, low	64.68	$/bbl	24,000	bbl/day	-$521,269,056
Naphtha, average	125.43	$/bbl	24,000	bbl/day	-$1,010,889,634
Naphtha, high	186.19	$/bbl	24,000	bbl/day	-$1,500,510,211
Annual Revenue, low					**$494,727,424**
Annual Revenue, average					**$1,142,965,146**
Annual Revenue, high					**$1,791,202,869**

4.3 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). For the SAGD cases, natural gas prices were varied to account for the large fluctuations seen in the market. Costs were calculated for a low ($4.50/MSCF), average ($6.50/MSCF), and high ($12.00/MSCF) industrial natural gas price. High prices correspond to prices from June 2008, low prices are from September 2009, and the average price was chosen to reflect current natural gas price (EIA 2010b). Only average natural gas prices are presented in the SAGD tables below.

Labor costs are assumed to be 1.15% of the TCI for both cases. This percentage is based on staffing requirements for a conventional 50,000 bbl/day coal-to-liquids plant; that percentage is assumed to adequately represent the labor for the conventional SAGD facility and the fossil portion of the nuclear-integrated SAGD facility. Maintenance costs were assumed to be 3% of the TCI per the *Handbook of Petroleum Processing*. Taxes and insurance were assumed to be 1.5% of the TCI, excluding the HTGR, and an overhead of 65% of the labor and maintenance costs was assumed. These values were assumed based on information presented in the *Handbook of Petroleum Processing* (Jones 2006). Table 10 and Table 11 provide the manufacturing costs for the conventional SAGD case and the nuclear-integrated SAGD case, respectively. Again, availability of both the fossil and nuclear plants was assumed to be 92%.

Table 10. Annual manufacturing costs, conventional SAGD case.

	Price		Consumed		Annual Cost
Direct Costs					
Materials					
Natural Gas, average	6.50	$/MSCF	56,229	MSCFD	$122,730,103
Wastewater Treatment	1.31	$/k-gal	5,016	k-gal/day	$2,214,787
Makeup H_2O Treatment	0.02	$/k-gal	864	k-gal/day	$7,096
Diluent Transport	0.75	$/bbl	24,000	bbl/day	$6,049,177
Utilities					
Electricity	1.67	$/kW-day	6,760	kW	$3,791,821
Water	0.05	$/k-gal	864	k-gal/day	$14,507
Labor and Maintenance					$44,022,116
Indirect Costs					
Overhead					$28,614,375
Insurance and Taxes					$15,911,608
Manufacturing Costs					**$223,355,591**

Operating and maintenance costs for the nuclear plant were based on data from General Atomics for the gas-turbine modular high-temperature reactor published in 2002; these costs were inflated to 2009 dollars (GA 2002).

Table 11. Annual manufacturing costs, nuclear-integrated SAGD case.

	Price		Consumed		Annual Cost
Direct Costs					
Materials					
Natural Gas, average	6.50	$/MSCF	0	MSCFD	$0
Wastewater Treatment	1.31	$/k-gal	5,016	k-gal/day	$2,214,787
Makeup H_2O Treatment	0.02	$/k-gal	864	k-gal/day	$7,096
Diluent Transport	0.75	$/bbl	24,000	bbl/day	$6,049,177
Nuclear Fuel	8.80	$/MW-h	240	MW_e	$17,013,825
Utilities					
Electricity	1.67	$/kW-day	16,900	kW	$9,479,553
Water	0.05	$/k-gal	864	k-gal/day	$16,924
O&M, Nuclear	3.57	$/MW-h	240	MW_e	$14,507
Labor and Maintenance					$42,351,427
Indirect Costs					
Overhead					$27,528,428
Insurance and Taxes					$15,307,745
Manufacturing Costs					**$126,864,041**

4.4 Estimation of Royalties

Royalties were estimated based on guidelines presented by the Government of Alberta for oil sands. Technically, a sliding scale is used for oil sands royalty rates ranging from 1% to 9% pre-payout and 25% to 40% post-payout depending on the price of oil. Project "payout" refers to the point at which the oil sands developer has earned sufficient revenues to recover all of the allowed costs for the project plus a return allowance. To simplify the calculation, a conservative approach was taken to calculate the royalty, such that the post payout percentage was used for the entire project life. This assumption was made in order to simplify the economic calculations.

The net royalty starts at 25% and increases for every dollar oil is priced above $55 per barrel to 40% when oil is priced at $120 or higher (Alberta 2009). Table 12 lists the royalties applied based on the selling price of crude. Values were averaged from the data presented by Alberta in order to take advantage of Excel's built-in IF function which limits the number of nested statements available.

Table 12. Post payout royalty data.

Crude Price, $/bbl	Royalty %
<55	25
<62.5	26.705
<72.5	29.04
<82.5	31.345
<92.5	33.645
<102.5	35.96
<112.5	38.27
>112.5	40

4.5 Economic Comparison

Several economic indicators were calculated for each case to assess the economic desirability of the SAGD cases. For all cases, the internal rate of return (IRR) for low, average, and high crude selling prices was calculated for the SAGD cases, as well as low, average, and high natural gas prices. In addition, the crude price necessary for a return of 12% was calculated for low, average, and high natural gas prices. The following assumptions were made for the economic analyses:

- The plant startup year is 2014.
- A construction period of three years for the fossil plant and five years for the nuclear plant:
  - Fossil plant construction begins in 2011
  - Nuclear plant construction begins in 2009
- It is assumed that all reactors come online at the same time. A study was conducted to determine the impact of six-month and three-month reactor staging versus all reactors coming online at one time. It was determined that the simplification of assuming all reactors online at once does not impact the economic results significantly enough to warrant the complexity of creating multiple staging trains for each scenario. Differences in staging resulted in an average 1% difference in the economic results for three-month staging and 10% difference for six-month staging. Furthermore, when large quantities of reactors are required, it would be necessary for n^{th} of a kind plants to come online in at least 3-month intervals.
  - Percent capital invested for the fossil plant is 33% per year
  - Percent capital invested for the HTGR is 20% per year
- Plant startup time is one year

- Operating costs are 85% of the total value during startup
- Revenues are 60% of the total value during startup

- The analysis period for the economic evaluation assumes an economic life of 30 years, excluding construction time (the model is built to accommodate up to 40 years).
- An availability of 92% was assumed for both the fossil and nuclear plants; the plants are assumed to operate 365 days a year, 24 hours per day.
- An inflation rate of 2.5% is assumed.
- Debt to equity ratio of 80%/20%, the economic model can handle a variety of debt to equity ratios from 100% equity to 100% debt.
  - The interest rate on debt is assumed to be 8%.
  - The repayment term on the loan is assumed to be 15 years.
- The effective income tax rate is 27.1%:
  - Alberta province tax rate is 10%
  - Canadian corporate tax is 19%
- MARCS depreciation is assumed, with a 15-year plant life.
- A CO_2 tax of \$0/ton to \$100/ton.

4.5.1 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 outflow and noncash costs. Therefore, the income taxes per year are defined as follows (Sullivan 2003):

$$T_k = t(R_k - E_k - d_k) \tag{2}$$

Depreciation for the economic calculations was calculated using a standard MARCS depreciation method with a property class of 15 years. Depreciation was assumed for the TCI over the five-year construction

schedule, including inflation. Table 13 presents the recovery rates for a 15-year property class (Perry 2008):

Table 13. MARCS 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. 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:

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

When a CO_2 tax credit is included in the economic analysis, the tax would be treated essentially as a manufacturing cost, decreasing the yearly revenue.

4.5.2 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 (ATCF), 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).

$$PW(i'\%) = \sum_{k=0}^{N} ATCF_k (1+i')^{-k} = 0 \tag{5}$$

IRR calculations were performed for an 80%/20% debt to equity ratio at the calculated TCI, and at +50% to -30% TCI for the HTGR, at low, average, and high fuel crude prices as well as low, average, and high natural gas purchase prices. In addition, the price of crude necessary for an IRR of 12% and a PW of zero was calculated for each case. The IRR and crude price required (for an IRR of 12%) was solved for using the Goal Seek function in Excel.

Finally, a CO_2 tax was included into the calculations to determine the price of crude necessary in all cases for a 12% IRR and a CO_2 tax of \$0/ton to \$100/ton. These cases were calculated for an 80%/20% debt to equity ratios for the TCI and +50% and -30% TCI of the HTGR. The tax calculated was added to the existing yearly tax liability.

5. ECONOMIC MODELING RESULTS

Table 14 presents the results for an 80%/20% debt to equity ratio for the conventional SAGD and nuclear-integrated SAGD cases, for low, average, and high natural gas prices, presenting the IRR for low, average, and high crude selling prices, and the crude selling price required for a 12% IRR. Figure 7 depicts the associated IRR results for the SAGD cases for the baseline TCI of the HTGR and low, average, and high natural gas prices. Figure 8 presents the necessary selling price of crude for a 12% IRR as a function of natural gas price.

Table 14. Conventional and nuclear SAGD IRR results.

	TCI -30% HTGR		**TCI**		**TCI +50% HTGR**	
	IRR	\$/gal	IRR	\$/gal	IRR	\$/gal
SAGD Low NG: \$4.50/MSCF			*\$1,060,773,882*			
			24.57	\$37.82		
			59.39	\$80.18		
			75.71	\$122.53		
			12.00	\$26.52		
SAGD Average NG: \$6.50/MSCF			*\$1,060,773,882*			
			21.33	\$37.82		
			57.41	\$80.18		
			74.30	\$122.53		
			12.00	\$29.50		
SAGD High NG: \$12.00/MSCF			*\$1,060,773,882*			
			12.15	\$37.82		
			51.78	\$80.18		
			70.31	\$122.53		
			12.00	\$37.69		
HTGR SAGD	*\$2,210,131,319*		*\$2,719,966,319*		*\$3,569,691,319*	
	12.75	\$37.82	9.95	\$37.82	6.86	\$37.82
	30.26	\$80.18	25.10	\$80.18	19.48	\$80.18
	39.10	\$122.53	33.02	\$122.53	26.29	\$122.53
	12.00	\$36.34	12.00	\$42.72	12.00	\$53.36

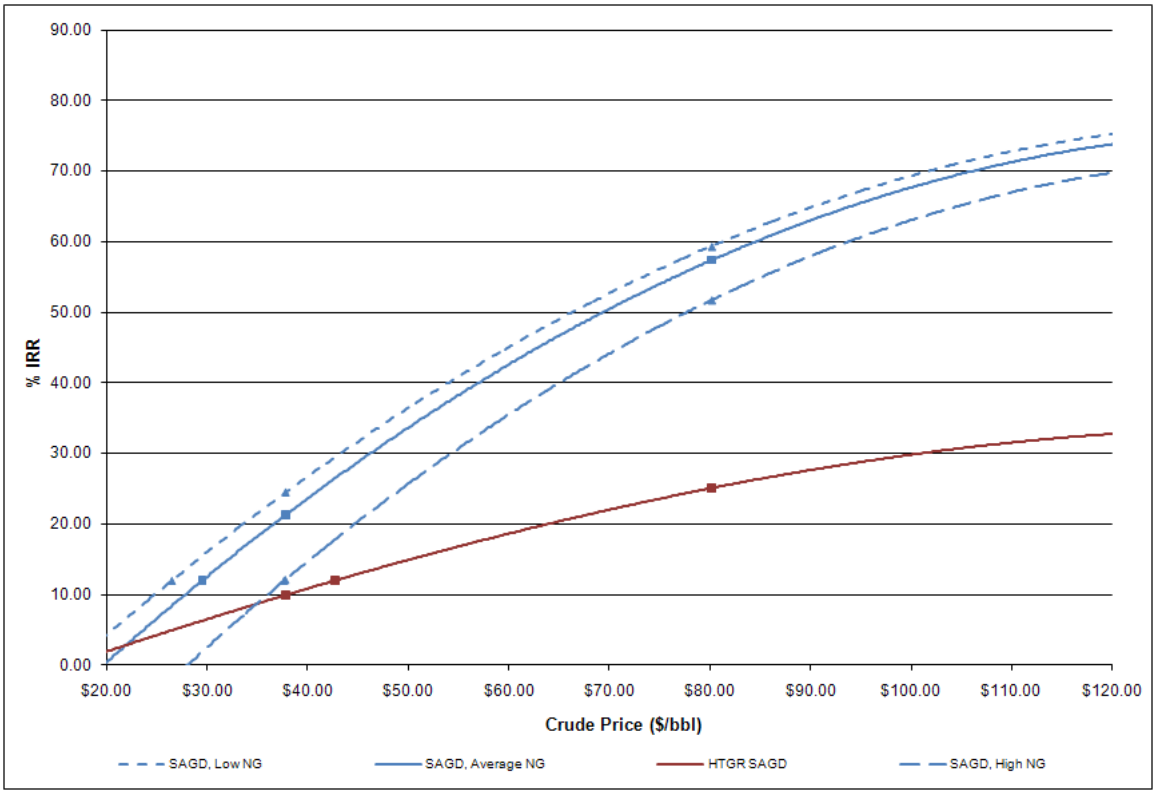

Figure 7. Conventional and nuclear SAGD IRR economic results.

From these figures, it is apparent that the nuclear-integrated SAGD option provides economic stability with respect to fluctuations in natural gas prices. Though the IRR is lower at all but the lowest crude selling price, it is still significantly above 12% for crude prices above $40/bbl, indicating a sizable return on investment (Figure 7). However, even with high natural gas prices, the traditional SAGD process economically outperforms the nuclear-integrated option. With a reduction in the HTGR cost by 30%, the nuclear-integrated option economically outperforms the traditional option when natural gas prices exceed $10.50/MSCF (Figure 8).

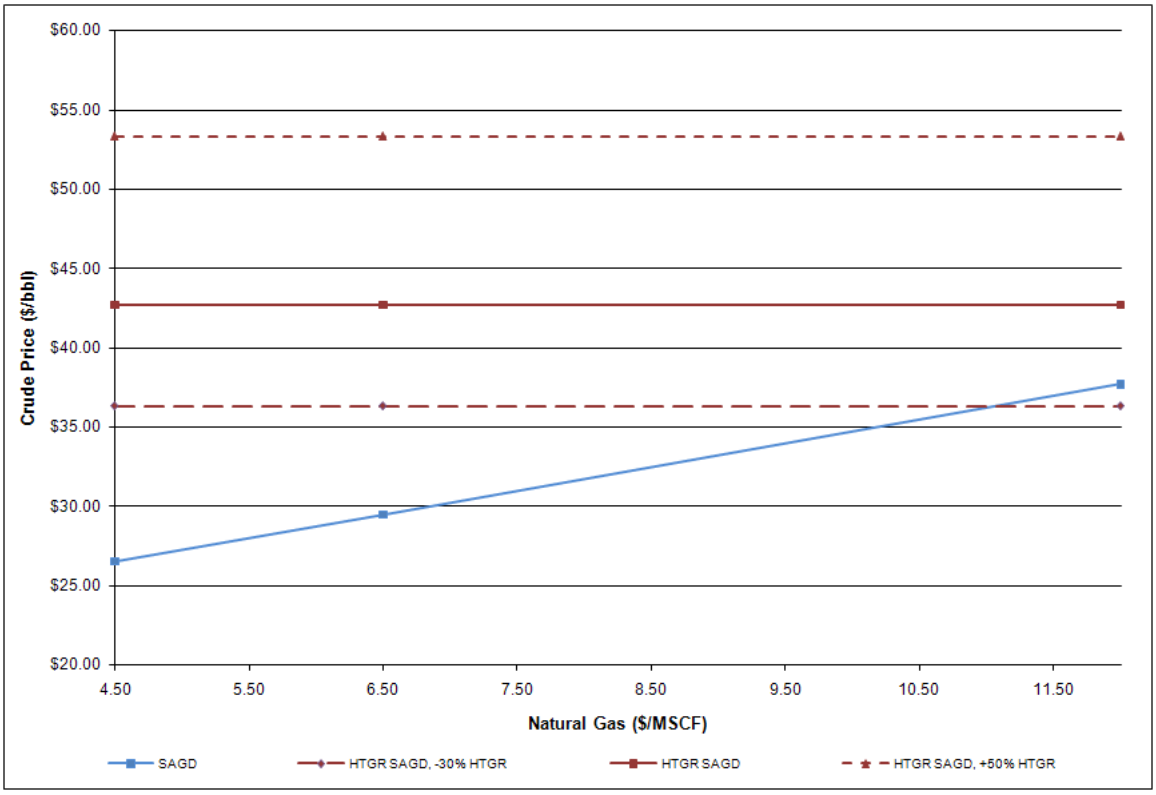

Figure 8. Conventional and nuclear SAGD, crude price as a function of natural gas price and a 12% IRR.

Table 15 presents the carbon tax results for the conventional and nuclear-integrated SAGD cases, and Figure 9 depicts the carbon tax results for the conventional and nuclear-integrated SAGD cases for an average natural gas price and a 12% IRR.

Table 15. Conventional and nuclear SAGD carbon tax results at 12% IRR and average natural gas price.

Carbon Tax $/ton		TCI -30% HTGR	TCI Crude Price ($/bbl)	TCI +50% HTGR
SAGD	0		29.50	
	25		32.68	
	50		35.85	
	75		39.03	
	100		42.21	
HTGR SAGD	0	36.34	42.72	53.36
	25	36.34	42.72	53.36
	50	36.34	42.72	53.36
	75	36.34	42.72	53.36
	100	36.34	42.72	53.36

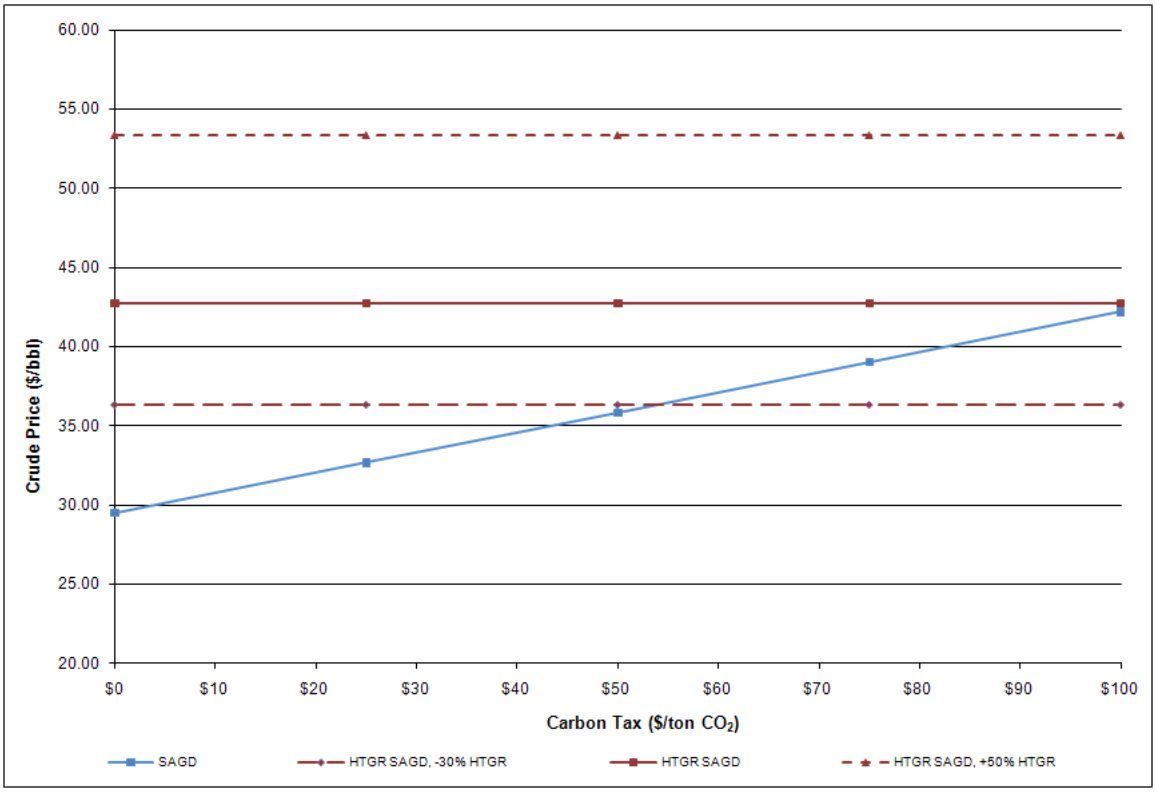

Figure 9. Conventional and nuclear SAGD carbon tax results at a 12% IRR and average natural gas price.

The carbon tax results show that the nuclear integrated SAGD case only outperforms the conventional SAGD case at a 12% IRR when the carbon tax is over \$100/ton CO_2 for the baseline HTGR cost, when HTGR cost is reduced by 30% a CO_2 tax of only \$50/ton is required. If a carbon tax of \$100/ton CO_2 is imposed, the nuclear-integrated case will outperform the conventional case when natural gas prices are over \$6.50/MSCF, as shown in Figure 10.

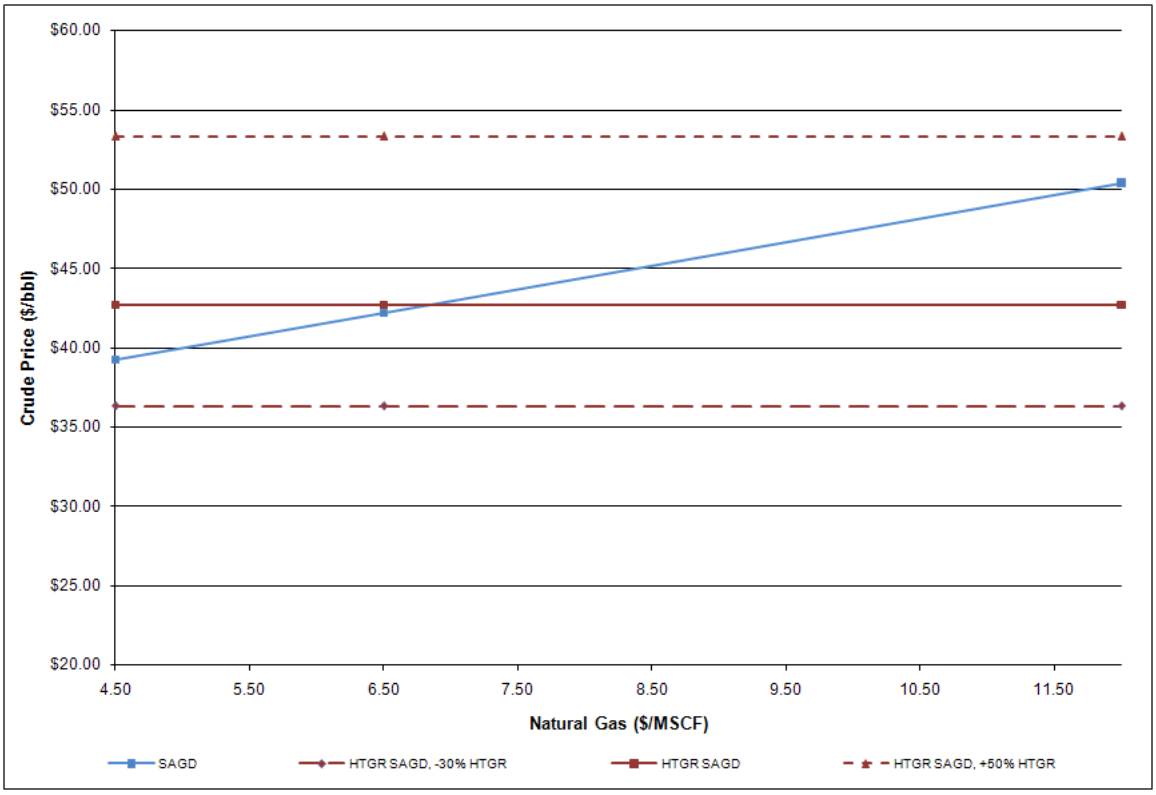

Figure 10. Conventional and nuclear SAGD, crude price as a function of natural gas price with a $100/ton CO_2 tax and a 12% IRR.

6. CONCLUSIONS

Technical results for the nuclear-integrated SAGD case look promising:

- A single 600 MW_t HTGR would be required to produce 56,000 barrels per day of bitumen
- By substituting nuclear heat for natural gas combustion in the steam generator, natural gas consumption is eliminated from the process
- CO_2 emissions from the plant are also eliminated completely by integrating a high-temperature nuclear reactor into the flowsheet, as natural gas is no longer combusted, although there would still be emissions associated with imported power.

Economically, the nuclear-integrated SAGD option provides economic stability with respect to fluctuations in natural gas prices:

- Though the IRR is lower for all crude prices considered, it is still above 12% when crude selling prices exceed $40/bbl, indicating a sizable return on investment

- The required selling price of crude to achieve a 12% IRR for the nuclear-integrated case is about one and a half times the selling price required for the conventional SAGD case for an HTGR capital cost of \$2,000/kW_t, \$43/bbl versus \$30/bbl for conventional SAGD at average natural gas prices

- When the HTGR capital cost is decreased by 30%, the nuclear-integrated selling price of crude is still greater than the price required in the conventional case, \$36/bbl versus \$30/bbl for conventional SAGD at average natural gas prices

- In a carbon-constrained scenario where CO_2 emissions are taxed, a CO_2 tax of greater than \$100/ton-CO_2 would be needed to equate the economics of the nuclear-integrated SAGD case with the conventional SAGD case, at a HTGR capital cost of \$2,000/kW_t and an average natural gas price

- The necessary CO_2 tax decreases to \$50/ton CO_2 when the capital cost of the HTGR is decreased by 30%

- If a carbon tax of \$100/ton CO_2 is imposed, the nuclear-integrated SAGD process economically outperforms the conventional SAGD process for natural gas prices above \$6.50/MSCF.

7. FUTURE WORK AND RECOMMENDATIONS

The following items should be performed in the future to further refine the process and economic modeling performed for the SAGD cases:

- A separate study should be conducted to assess the optimal siting of the HTGR with respect to the SAGD facility, balancing safety concerns associated with separation distance and heat losses associated with transporting high-temperature heat long distances.

- The economic viability of producing the power required for SAGD from the HTGR should be conducted to determine if it is indeed more economical to purchase power from the grid.

- Rigorous Aspen Plus submodels of the HTGR and SAGD units should be developed to fully couple heat and power integration from the HTGR, including a detailed water treatment model based on vendor input.

- As there is the potential of tritium migration to the environment, an assessment should be made to determine the potential concentration and quantify environmental impact.

- Refined estimates of the HTGR capital cost, annual fuel costs, and annual O&M costs should be developed to refine the economic results.

- A detailed cooling water balance should be completed for the HTGR to determine the amount of make-up water necessary for the system.

- An assessment should be performed to determine the exact configuration of the SAGD facility, specifically with regard to the configuration of the heat transfer system. There are multiple process configurations for transporting heat to the SAGD facility, all with separate benefits.

- A white paper will be prepared which compares the INL bottoms-up approach with previous SAGD studies.

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9. APPENDIXES

Appendix A, SAGD Capital Cost Estimates

Appendix A
SAGD Capital Cost Estimates

NGNP Conventional Steam Assisted Gravity Drainage Summary

Project Name: NGNP Process Integration
Process: Conventional Steam Assisted Gravity Drainage
Estimate Number: MA36-Q

Client: M. Patterson
Prepared By: B. Wallace, R. Honsinger, J. Martin
Estimate Type: Class 5

Process Component	Subtotal From Detail Sheets	Engineering %	Engineering	Contingency %	Contingency	Total Cost
SAGD Well Pads and Well Pairs	$ 624,825,790	10%	$ 62,482,579	18%	$ 123,715,506	$ 811,023,875
SAGD Boiler	$ 96,571,408	10%	$ 9,657,141	18%	$ 19,121,139	$ 125,349,687
SAGD Oil/Water Separation/Treatment	$ 95,840,000	10%	$ 9,584,000	18%	$ 18,976,320	$ 124,400,320
Total Cost - Conventional Steam Assisted Gravity Drainage						$ 1,060,773,882
Total Cost Rounded to the Nearest $10M						$ 1,060,000,000

	Remarks
Checked By:	
Approved By:	

Rev. 03-04-10
Battelle Energy Alliance, LLC

COST ESTIMATE SUPPORT DATA RECAPITULATION

Project Title:	NGNP Process Integration – Conventional Steam Assisted Gravity Drainage
Estimator:	B. W. Wallace/CEP, R. R. Honsinger/CEP, J. B. Martin/CCT
Date:	April 20, 2010
Estimate Type:	Class 5
File:	MA36-Q
Approved By:	

I. **PURPOSE:** *Brief description of the intent of how the estimate is to be used (i.e., for engineering study, comparative analysis, request for funding, proposal, etc.).*

The three distinct capital island costs indentified in this cost estimate will be used in a comparative economic analysis model. In turn, this overall model will evaluate the financial feasibility of a specific (non-nuclear integrated) process, the widely used and growing in situ oil sands recovery method known as Steam-Assisted Gravity Drainage or (SAGD). The economic comparison will involve at least this case and a nuclear-integrated case. The recapitulation data for the nuclear-integrated case of the same process is available as its separate report.

II. **SCOPE OF WORK:** *Brief statement of the project's objective. Thorough overview and description of the proposed project. Identify work to be accomplished, as well as any specific work to be excluded.*

A. **Objective:**
Develop a Class 5 capital cost estimate as defined by the Association for Advancement of Cost Engineering (AACEi). This estimate will identify only current capital costs, reported in 2009 U.S. dollars, associated with a typical Alberta in situ oil sands recovery operation using the popular SAGD technology. The portion of the title "Conventional SAGD" refers to this SAGD facility without the support of a high-temperature gas reactor.

B. **Included:**
The scope of work required to achieve this capital cost estimate objective includes the following:

1. Engineering as required for capital construction design
2. Construction (labor and capital equipment) of a centralized remote SAGD facility, surrounding well pads, and well pairs to recover 56,000 barrels per day (bpd) of oil sands bitumen. As listed below, costing for the capital construction has been divided into three separate islands with consideration of balance of plant (BOP) for each of the islands:
   a. SAGD well pads and well pairs
   b. SAGD methane boilers
   c. SAGD oil/water separation/treatment
   d. Allowances for BOP/offsite/outside of battery limits (OSBL), including the following:
      (1.) Provisions for general and administrative buildings and structures

(2.) Provisions for balance of plant instrumentation and control
(3.) Provisions for balance of plant electrical systems.

C. **Excluded:**
The scope of work for this capital cost estimate specifically excludes the following elements:

1. Licensing and permitting costs
2. Operational costs
3. Land costs and property taxes
4. Sales taxes
5. Construction financing costs
6. Startup costs
7. Decommissioning and demolition costs
8. Royalties
9. Owner's fees and owner's costs
10. Rail construction beyond the SAGD plant's perimeter
11. Capability that would allow power to be sold to the grid
12. Source methane production and pipeline distribution system outside of the specific SAGD facility's boundaries.

III. **ESTIMATE METHODOLOGY:** *Overall methodology and rationale of how the estimate was developed (i.e., parametric, forced detail, bottoms up, etc.). Total dollars/hours and rough order magnitude (ROM) allocations of the methodologies used to develop the cost estimate.*

This estimate is considered to be Class 5 based on the AACE International definition, as well as the level of project information and engineering development available at the time it was prepared, its intended use in a feasibility study, and the time and resources available for its completion. The island values in this estimate have been developed using standard parametric estimating techniques involving a bottom-up approach. The input costs are based on publicly available, published project costs that represent similar and or identical islands to those used in this project. Inflation adjustments have been made to these published costs using the Chemical Engineering Plant Cost Index. Where applicable, scaling of the published island costs has been accomplished using the six-tenths-factor capacity factoring method. Any normalization to provide for geographic cost differences was applied after considering the geographic factors available from RS Means Construction Cost Data 2009 references and other publically available resources. Cost-estimating relationships have been used to identify allowances to complete the costs.

BOP/OSBL costs were determined by the project team, considering data provided by Shell Gasifier IGCC Base Case report NETL 2000, *Conceptual Cost Estimating Manual* Second Edition by John S. Page, and additional adjusted sources. Because the allowances identified did not show significant variability, the allowances identified in the NETL 2000 report were chosen for this effort in order to minimize the mixing of data sources.

COST ESTIMATE SUPPORT DATA RECAPITULATION

– Continued –

Project Title: NGNP Process Integration – Conventional Steam Assisted Gravity Drainage
File: MA36-Q

IV. **BASIS OF THE ESTIMATE:** *Overall explanation of sources for resource pricing and schedules.*

A. **Quantification Basis:** *The source for the measurable quantities in the estimate that can be used in support of earned value management. Source documents may include drawings, design reports, engineers' notes, and other documentation upon which the estimate is originated.*

All island capacities for this particular case are based on mass and energy balance data from an Excel spreadsheet model, validated with actual SAGD/in situ oil sands performance and operating data.

B. **Planning Basis:** *The source for the execution and strategies of the work that can be used to support the project execution plan, acquisition strategy, schedules, and market conditions and other documentation upon which the estimate is originated.*

1. All islands represent nth of a kind projects, which is essentially the case for existing SAGD facilities in the Alberta oil sands regions.
2. Projects will be constructed and operated by commercial entities.
3. The SAGD project will be located in the northeast portion of the Canadian province of Alberta.
4. Costs are presented as overnight costs.
5. The cost estimate does not consider or address funding or labor resource restrictions outside of the norm for northwest Alberta, Canada. Sufficient funding and labor resources will be available in a manner that allows optimum usage of funding and resources as estimated and scheduled.

C. **Cost Basis:** *The source for the costing on the estimate that can be used in support of earned value management, funding profiles, and schedule of values. Sources may include published costing references, judgment, actual costs, preliminary quotes, or other documentation upon which the estimate is originated.*

1. All costs are represented as current value costs. Factors for forward-looking escalation and inflations factors are not included in this estimate.
2. Where required, published cost factors, as identified in the Chemical Engineering Plant Cost Index, will be applied to previous years' values to determine current year values.
3. Where required, published geographic factors as identified in RS Means Construction Cost Data references and other available published sources were applied to the island costs.
4. Costs for the multiple SAGD methane boilers is based on input from the project team's technical specialist and is based on an unofficial estimate from a supplier of once-through steam generators.

5. The well pad and well pair cost is a single source cost data point provided by the project team technical specialist and based on normal drilling costs as detailed in the draft cost data sheets .
6. The oil/water separation and treatment cost is used as a single source cost data point provided by the project team technical specialist and based on an averaging of limited published data from SAGD oil/water separation and SAGD boiler water treatment systems supplied by GE, Vieola, and Siemens.
7. AACEi, *Recommended Practices*, website, visited November 16, 2009, <http://www.aacei.org/technical/rp.shtml>.
8. *Chemical Engineering Magazine*, "Chemical Engineering Plant Cost Index," Nov. 2009: 64. Print.
9. Nickle's Energy and Information Technology, SAGD Report Card, 2008.
10. Page, John S., *Conceptual Cost Estimating Manual – 2nd ed.*, Houston: Gulf Publishing Company, 1996.
11. Ziff Energy Group: Scott Jones "SAGD Delivers Healthy Return on Investment."
12. A presentation of an actual cash flow analysis for a typical (non-nuclear) SAGD project, <www.strategywest.com/downloads/ceri20040310.pdf>.
13. Specific costs for Nexen's Long Lake SAGD project costs, <www.nexeninc.com/Operations/Athabasca_Oil.../SAGD.asp>.
14. Costs for Connachers recent SAGD upgrade, <http://news.moneycentral.msn.com/ticker/article.aspx?Feed=MCIntl&Date=20100105&ID=10960894&Symbol=CLL>.
15. A discussion of economic risk for a SAGD project, <www.strategywest.com/downloads/choa20030903.pdf>.
16. Table listing a variety of costs for all projected and ongoing oil sands projects inclusive of many recent initial SAGD projects and well pad expansions, <www.albertacanada.com/documents/Oilsands.pdf>.

V. **ESTIMATE QUALITY ASSURANCE:** *A listing of all estimate reviews that have taken place and the actions taken from those reviews.*

A review of the cost estimate was held on January 29, 2010, with the project team and the cost estimators. This review allowed for the project team to review and comment, in detail, on the perceived scope, basis of estimates, assumptions, project risks, and resources that make up this cost estimate. Comments from this review have been incorporated into this estimate to reflect a project team consensus of this document.

VI. **ASSUMPTIONS:** *Condition statements accepted or supposed true without proof of demonstration; statements adding clarification to scope. An assumption has a direct impact on total estimated cost.*

General Assumptions:

A. All costs are represented in 2009 values.
B. Costs that were included from sources representing years prior to 2009 have been normalized to 2009 values using the Chemical Engineering Plant Cost Index. This

index was selected due to its widespread recognition, acceptance, and specific orientation toward work associated with chemical and refinery plants.

C. Capital costs are based on process islands.
D. All construction values are considered to be overnight costs. Financing for the construction timeframe is not included in the estimate.
E. All costs associated with a plant initial startup are provided for in the follow-on later economic analysis.
F. Sufficient utilities will be available for use/tie-in at the plant location.
G. Sufficient labor, fabrication capability, material supply, and so forth will be available to facilitate the construction process.

SAGD Boilers

A. Seven conventional methane boilers are included in the conventional SAGD case to provide the system capacity to support a bitumen production rate of 56,000 bpd.
B. Standard once through steam generator boilers rated at 340 MMBTU/hr were priced at approximately $11,000,000 via an unofficial estimate from a Canadian steam generator manufacturer. Seven are required to meet the output production of a 600-MWt reactor, and therefore, recover 56,000 bpd bitumen via SAGD technology.
C. Balance of plant was customized to this specific process, omitting items that do not apply. Balance of plant items in the estimate includes civil/structural buildings, control and instrumentation, and electrical systems.
D. The methane once through steam generators/boilers will be located at the individual well pads.
E. Island cost for the methane boilers includes steam piping from the boiler to the connection at the well pad piping and methane supply piping and manifolds.

SAGD Well Pad and Well Pairs

A. Each well pad is assumed to contain nine well pairs on average.
B. One well pad is considered a single train for calculations performed in the estimate spreadsheet.
C. One well pair has the assumed capacity of approximately 1,000 bpd on average.
D. Drilling costs per SAGD well pair is based on drilling 50 m vertical and 1,000 m horizontal for both the recovery and the steam injection well. Drilling cost is assumed to be $9.00 (includes labor at about 42%) per meter for the combined well pair.
E. The centralized SAGD facility contains six well pads.
F. Balance of plant was customized to this specific process, omitting items that do not apply. Balance of plant items in the estimate include civil/structural buildings, control and instrumentation, and electrical systems.

SAGD Oil/Water Separation/Treatment

A. In order to allow for bitumen recovery expansion, an oil/water separator train allows capacity for up 100,000 bpd of bitumen and 300,000 bpd of water to be separated, even though the estimate is for 56,000 bpd.

B. Each SAGD facility will require at least eight steps of oil/water separation and water treatment, including AP separators, drum separators, pumps, settling tanks, clarifiers, nut shell filters, weak-acid cation exchanger, and hot/warm line softeners. Costs for advanced SAGD water treatment system using film evaporators, crystallizers, and zero liquid discharge systems were not estimated.

C. Balance of plant was customized to this specific process, omitting items that do not apply. Balance of plant items included in the estimate are civil/structural buildings, control and instrumentation, and electrical systems.

VII. CONTINGENCY GUIDELINE IMPLEMENTATION:

Contingency Methodologies: *Explanation of methodology used in determining overall contingency. Identify any specific drivers or items of concern.*

At a project risk review on December 9, 2009, the project team discussed risks to the project. An 18% allowance for capital construction contingency has been included at an island level based on the discussion and is included in the summary sheet. The contingency level that was included in the island cost source documents and additional threats and opportunities identified here were considered during this review. The contingency identified was considered by the project team and included in Cost and Performance Baseline for Fossil Energy Plants DOE/NETL-2007/1281 and similar reports. Typically contingency allowance provided in these reports ranged from 15% to 20%. Since much of the data contained in this estimate has been derived from these reports, the project team has also chosen a level of contingency consistent with them.

A. **Threats:** *Uncertain events that are potentially negative or reduce the probability that the desired outcome will happen.*

1. The level of project definition/development that was available at the time the estimate was prepared represents a substantial risk to the project.
2. These costs were determined through standard parametric estimating methods. This process used publicly available published costs that were related to the process required, costs were normalized using price indices, and the cost was scaled to provide the required capacity. The cost-estimating relationships that were used represent typical costs for balance of plant allowances. While every effort has been made to correctly normalize and factor the costs for use in this effort, a risk exists that not all of these were captured correctly due to the varied information available.
3. This project is heavily dependent on the availability of suitable materials and skilled labor available in the active oil sands region of northwest Alberta. Competition for these commodities in today's environment due to global expansion, uncertainty, and product shortages affect the basic concepts of the supply and demand theories, thus increasing costs.

COST ESTIMATE SUPPORT DATA RECAPITULATION		
– Continued –		
Project Title:	NGNP Process Integration – Conventional Steam Assisted Gravity Drainage	
File:	MA36-Q	Page 7 of 7

4. Impacts due to large quantities of materials, special alloy materials, fabrication capability, and labor availability could all represent conditions that may increase the total cost of the project.

B. **Opportunities:** *Uncertain events that could improve the results or improve the probability that the desired outcome will happen.*

1. Additional research and work performed with both vendors and potential owner/operators for a specific process may identify SAGD efficiencies and production means that have not been available for use in this analysis.
2. Recent historical data may identify and include technological advancements and efficiencies not included or reflected in the publicly available source data used in this effort.

Note: Contingency does not increase the overall accuracy of the estimate; it does, however, reduce the level of risk associated with the estimate. Contingency is intended to cover inadequacies in the complete project scope definition, estimating methods, and estimating data. Contingency specifically excludes changes in project scope, unexpected work stoppages (e.g., strikes, disasters, and earthquakes) and excessive or unexpected inflation or currency fluctuations.

VIII. **OTHER COMMENTS/CONCERNS SPECIFIC TO THE ESTIMATE:**

None.

Detail Item Report - SAGD Well Pads and Well Pairs

Project Name:	**NGNP Process Integration**	**Client:**	**M. Patterson**
Process:	**Conventional Steam Assisted Gravity Drainage**	**Prepared By:**	**B. Wallace, R. Honsinger, J. Martin**
Estimate Number:	**MA36-Q**	**Estimate Type:**	**Class 5**

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Ziff Energy	1,000	bpd	1	2009	$9,450,000	$ 9,450,000	$ 9,450,000	56,000	bpd	54	1,037	bpd	$ 9,658,471	$ 521,557,420

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Ziff Energy	1,000	bpd	1	2009	$9,450,000	$ 9,450,000	$ 9,450,000	56,000	bpd	54	1,037	bpd	$ 9,658,471	$ 521,557,420

Balance of Plant:

Description	Markup						Cost Per Train	Total Cost
Water Systems	0.00%						$ -	$ -
Civil/Structural/Buildings	9.20%						$ 888,579	$ 47,983,283
Piping	0.00%						$ -	$ -
Control and Instrumentation	2.60%						$ 251,120	$ 13,560,493
Electrical Systems	8.00%						$ 772,678	$ 41,724,594
						Total Balance of Plant	$ 1,912,377	$ 103,268,369
						Total Balance of Plant Plus the Selected Source	$ 11,570,848	$ 624,825,790

Rationale for Selection:

The well pad and well pair cost is a single source cost data point provided by the project team technical specialist. Balance of plant was customized to this specific process, omitting items that do not apply.

Detail Item Report - SAGD Boiler

Project Name:	**NGNP Process Integration**	**Client:**	**M. Patterson**
Process:	**Conventional Steam Assisted Gravity Drainage**	**Prepared By:**	**B. Wallace, R. Honsinger, J. Martin**
Estimate Number:	**MA36-Q**	**Estimate Type:**	**Class 5**

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Once Through Steam Generators (OTSG)	45,000,000	btuh	1	2009	$ 11,000,000	$ 11,000,000	$ 11,000,000	340,000,000	btuh	7	48,571,429	btuh	$ 11,515,789	$ 80,610,524

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Once Through Steam Generators (OTSG)	45,000,000	btuh	1	2009	$ 11,000,000	$ 11,000,000	$ 11,000,000	340,000,000	btuh	7	48,571,429	mm btuh	$ 11,515,789	$ 80,610,524

Balance of Plant:

Description	Markup						Cost Per Train	Total Cost
Water Systems	0.00%						$ -	$ -
Civil/Structural/Buildings	9.20%						$ 1,059,453	$ 7,416,168
Piping	0.00%						$ -	$ -
Control and Instrumentation	2.60%						$ 299,411	$ 2,095,874
Electrical Systems	8.00%						$ 921,263	$ 6,448,842
						Total Balance of Plant	$ 2,280,126	$ 15,960,884
						Total Balance of Plant Plus the Selected Source	$ 13,795,915	$ 96,571,408

Rationale for Selection:

The boiler cost is used as a single source cost data point provided by the project team technical specialist. Balance of plant was customized to this specific process, omitting items that do not apply.

Detail Item Report - Oil/Water Separation/Treatment

Project Name:	**NGNP Process Integration**	**Client:**	**M. Patterson**
Process:	**Conventional Steam Assisted Gravity Drainage**	**Prepared By:**	**B. Wallace, R. Honsinger, J. Martin**
Estimate Number:	**MA36-Q**	**Estimate Type:**	**Class 5**

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Veolia - Oil Water Separators	50000	bpd	1	2009	$10,000,000	$ 10,000,000	$ 10,000,000	400,000	bpd	8	50,000	bpd	$ 10,000,000	$ 80,000,000

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Veolia - Oil Water Separators	50000	bpd	1	2009	$10,000,000	$ 10,000,000	$ 10,000,000	400,000	bpd	8	50,000	bpd	$ 10,000,000	$ 80,000,000

Balance of Plant:

Description	Markup						Cost Per Train	Total Cost
Water Systems	0.00%						$ -	$ -
Civil/Structural/Buildings	9.20%						$ 920,000	$ 7,360,000
Piping	0.00%						$ -	$ -
Control and Instrumentation	2.60%						$ 260,000	$ 2,080,000
Electrical Systems	8.00%						$ 800,000	$ 6,400,000
						Total Balance of Plant	$ 1,980,000	$ 15,840,000
						Total Balance of Plant Plus the Selected Source	$ 11,980,000	$ 95,840,000

Rationale for Selection:

The oil/water separation and treatment cost is used as a single source cost data point provided by the project team technical specialist. Balance of plant was customized to this specific process, omitting items that do not apply.

NGNP Nuclear Steam Assisted Gravity Drainage Summary

Project Name: NGNP Process Integration
Process: Nuclear Steam Assisted Gravity Drainage
Estimate Number: MA36-R

Client: M. Patterson
Prepared By: B. Wallace, R. Honsinger, J. Martin
Estimate Type: Class 5

Process Component	Subtotal From Detail Sheets	Engineering %	Engineering	Contingency %	Contingency	Total Cost
High Temperature Gas Reactor (HTGR)	$ 1,699,450,000	0%	$ -	0%	$ -	$ 1,699,450,000
SAGD Well Pads and Well Pairs	$ 624,825,790	10%	$ 62,482,579	18%	$ 123,715,506	$ 811,023,875
SAGD Boiler	$ 13,178,000	10%	$ 1,317,800	18%	$ 2,609,244	$ 17,105,044
SAGD Oil/Water Separation/Treatment	$ 95,840,000	10%	$ 9,584,000	18%	$ 18,976,320	$ 124,400,320
Steam Transmission Piping	$ 52,378,336	10%	$ 5,237,834	18%	$ 10,370,910	$ 67,987,080
Total Cost - Nuclear Steam Assisted Gravity Drainage						$ 2,719,966,318
Total Cost Rounded to the Nearest $10M						$ 2,720,000,000

	Remarks
Checked By:	
Approved By:	

Rev. 03-04-10
Battelle Energy Alliance, LLC

COST ESTIMATE SUPPORT DATA RECAPITULATION

Project Title:	NGNP Process Integration – In situ Alberta Oil Sands Recovery via Nuclear Integrated SAGD
Estimator:	B. W. Wallace/CEP, R. R. Honsinger/CEP, J. B. Martin/CCT
Date:	April 19, 2010
Estimate Type:	Class 5
File:	MA36-R
Approved By:	

I. **PURPOSE:** *Brief description of the intent of how the estimate is to be used (i.e., for engineering study, comparative analysis, request for funding, proposal, etc.).*

The four distinct capital island costs indentified in this cost estimate will be used in a comparative economic analysis model. In turn, this overall model will evaluate the financial feasibility of a specific process, the widely used and growing in situ oil sands recovery method known as Steam-Assisted Gravity Drainage (SAGD), whereby the SAGD steam heat is provided by a nuclear high-temperature gas reactor (HTGR) instead of the current practice of using methane. The economic comparison will involve at least this case and an existing conventional SAGD case. The recapitulation data for the non-nuclear integrated, yet conventional, case of the same process is available as a separate report, Cost Estimating File MA36-Q.

II. **SCOPE OF WORK:** *Brief statement of the project's objective. Thorough overview and description of the proposed project. Identify work to be accomplished, as well as any specific work to be excluded.*

A. **Objective:**
Develop a Class 5 capital cost estimate, as defined by the Association for Advancement of Cost Engineering (AACEi). These estimates will identify only the current capital costs, reported in 2009 U.S. dollars, associated with a typical Alberta in situ oil sands recovery operation using the popular SAGD technology and integrated with an nth of a kind (NOAK) HTGR. The portion of the title "Nuclear Integrated SAGD" refers to this SAGD facility with the support of an HTGR.

B. **Included:**
The scope of work required to achieve this capital cost estimate objective includes the following:

1. Engineering as required for capital construction design.
2. Construction (labor and capital equipment) of a centralized remote SAGD facility, surrounding well pads, and well pairs to recover 56,000 barrels per day (bpd) of oil sands bitumen. As listed below, costing for the capital construction has been divided into four separate islands with consideration for balance of plant (BOP) for each of the islands:
   a. SAGD well pads and well pairs
   b. An HTGR without a power cycle and without a hydrogen production unit; included in the cost estimate is the long distance steam/heat pipeline from

the HTGR to each well pad. The allowance provided for the HTGR represents a complete and operable system. All elements required for construction of this nuclear reactor capability, including an initial steam generator, security systems, contingency, and owner's costs are included in the turn-key allowance. Owner's costs are included only in the case of the reactor capability. It is considered that the total value represents all inside of battery limits (ISBL) elements, outside of battery limits (OSBL) elements, site development, and all ancillary control and operational functions and capabilities.

c. One SAGD methane boiler
d. SAGD oil/water separation/treatment
e. Allowances for BOP/offsite/OSBL, including the following:
   (1.) Provisions for general and administrative buildings and structures
   (2.) Provisions for BOP instrumentation and control
   (3.) Provisions for BOP electrical systems.

C. **Excluded:**

This scope of work for this capital cost estimate specifically excludes the following elements:

1. Licensing and permitting costs
2. Operational costs
3. Land costs and property taxes
4. Sales taxes
5. Construction financing costs
6. Startup costs
7. Decommissioning and demolition costs
8. Royalties
9. Owner's fees and owner's costs, except those included for the HTGR
10. The allowance provided for the HTGR capability excludes all costs associated with materials development, or costs that would not be appropriately associated with an nth of a kind (NOAK) reactor/facility.
11. Rail construction beyond the SAGD plant's perimeter
12. Capability that would allow power to be sold to the grid
13. Source methane production and pipeline distribution system outside of the specific SAGD facility's boundaries.

III. **ESTIMATE METHODOLOGY:** *Overall methodology and rationale of how the estimate was developed (i.e., parametric, forced detail, bottoms up, etc.). Total dollars/hours and rough order magnitude (ROM) allocations of the methodologies used to develop the cost estimate.*

This estimate is considered to be Class 5 based on the AACE International definition, the level of project information and engineering development available at the time it was prepared, its intended use in a feasibility study, and the time and resources available for its completion. The island values in this estimate have been developed using standard parametric estimating techniques involving a bottom-up approach. The input costs are based on publicly available, published project costs that represent similar and or identical islands to those used in this project. Inflation adjustments have been made to these published costs using the Chemical Engineering Plant Cost Index. Where applicable, scaling of the published island costs has been accomplished using the six-tenths-factor capacity factoring method. Any normalization to provide for geographic cost differences was applied after considering the geographic factors available from RS Means Construction Cost Data 2009 references and other publically available resources. Cost-estimating relationships have been used to identify allowances to complete the costs.

It was identified to the Next Generation Nuclear Plant (NGNP) Process Integration team that the methodology employed by NGNP to develop the nuclear capability included constituents of parametric modeling, vendor quotes, actual costs, and proprietary costing databases. These preconceptual design estimates were reviewed by NGNP Project Engineering for credibility with regard to assumptions and bases of estimate and performed multiple studies to reconcile variations in the scope and assumptions within the three estimates.

BOP/OSBL costs were determined by the project team, considering data provided by Shell Gasifier IGCC Base Case report NETL 2000, *Conceptual Cost Estimating Manual* Second Edition by John S. Page, and additional adjusted sources. Because the allowances identified did not show significant variability, the allowances identified in the NETL 2000 report were chosen for this effort in order to minimize the mixing of data sources.

IV. **BASIS OF THE ESTIMATE:** *Overall explanation of sources for resource pricing and schedules.*

A. **Quantification Basis:** *The source for the measurable quantities in the estimate that can be used in support of earned value management. Source documents may include drawings, design reports, engineers' notes, and other documentation upon which the estimate is originated.*

All island capacities for this particular case are based on mass and energy balance data from an Excel spreadsheet model, validated with actual SAGD/in situ oil sands performance and operating data.

B. **Planning Basis:** *The source for the execution and strategies of the work that can be used to support the project execution plan, acquisition strategy, schedules, and market conditions and other documentation upon which the estimate is originated.*

1. All islands represent NOAK projects, which is essentially the case for existing SAGD facilities in the Alberta oil sands regions.
2. Projects will be constructed and operated by commercial entities.
3. The SAGD project will be located in the northeast portion of the Canadian province of Alberta.
4. Costs will be presented as overnight costs.
5. The cost estimate does not consider or address funding or labor resource restrictions outside of the norm for northwest Alberta, Canada. Sufficient funding and labor resources will be available in a manner that allows optimum usage of that funding and resources as estimated and scheduled.

C. **Cost Basis:** *The source for the costing on the estimate that can be used in support of earned value management, funding profiles, and schedule of values. Sources may include published costing references, judgment, actual costs, preliminary quotes, or other documentation upon which the estimate is originated.*

1. All costs are represented as current value costs. Factors for forward looking escalation and inflations factors are not included in this estimate.
2. Where required, published cost factors, as identified in the Chemical Engineering Plant Cost Index, will be applied to previous years' values to determine current year values.
3. Where required (which is the case for the HTGR in this application), published geographic factors as identified in RS Means Construction Cost Data references and other available published sources were applied to the island costs.
4. The cost provided for the HTGR reflects internal BEA cost data that was developed for the HTGR and presented to the NGNP Process Integration team by L. Demmick. Considered in the cost is a pre-conceptual cost estimate prepared by three separate contractor teams. All contractor teams proposed 4-unit NOAK plants with thermal power levels between 2,000 MW_t and 2,400 MW_t at a cost of roughly $4B, including owner's costs. This equates to $1,667 to $2,000 per kW_t. For the purposes of this report, the nominal cost of an HTGR will be set at the upper end of this range, $2,000 per kW_t. This is a complete turn-key cost and includes engineering and construction of a NOAK HTGR and contingency. The total HTGR cost is calculated linearly as $1,708,333 per MW_t of required capacity, excluding the cost of the power cycle.
5. Cost for the single (reserve) SAGD methane boilers is based on input from the project team technical specialist and is based on an unofficial estimate from a supplier of once through steam generators.
6. The well pad and well pair cost is a single source cost data point provided by the project team technical specialist and based on normal drilling costs as detailed in the draft cost data sheets.
7. The oil/water separation and treatment cost is used as a single source cost data point provided by the project team technical specialist and based on an

averaging of limited published data from SAGD oil/water separation and SAGD boiler water treatment systems supplied by GE, Vieola, and Siemens.

8. AACEi *Recommended Practices*, website, visited on November 16, 2009, <http://www.aacei.org/technical/rp.shtml>.
9. *Chemical Engineering Magazine*, "Chemical Engineering Plant Cost Index," November 2009: 64. Print.
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12. Ziff Energy Group: Scott Jones "SAGD Delivers Healthy Return on Investment."
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15. Costs for Connachers recent SAGD upgrade, <http://news.moneycentral.msn.com/ticker/article.aspx?Feed=MCIntl&Date=20100105&ID=10960894&Symbol=CLL>.
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17. Table listing a variety of costs for all projected and ongoing oil sands projects inclusive of many recent initial SAGD projects and well pad expansions, <www.albertacanada.com/documents/Oilsands.pdf>.

V. **ESTIMATE QUALITY ASSURANCE:** *A listing of all estimate reviews that have taken place and the actions taken from those reviews.*

A review of the cost estimate was held on January 29, 2010, with the project team and the cost estimators. This review allowed for the project team to review and comment, in detail, on the perceived scope, basis of estimates, assumptions, project risks, and resources that make up this cost estimate. Comments from this review have been incorporated into this estimate to reflect a project team consensus of this document.

VI. **ASSUMPTIONS:** *Condition statements accepted or supposed true without proof of demonstration; statements adding clarification to scope. An assumption has a direct impact on total estimated cost.*

General Assumptions:

A. All costs are represented in 2009 values.
B. Costs that were included from sources representing years prior to 2009 have been normalized to 2009 values using the Chemical Engineering Plant Cost Index. This index was selected due to its widespread recognition, acceptance, and its specific orientation toward work associated with chemical and refinery plants.
C. Capital costs are based on process islands.

D. All construction values are considered to be overnight costs. Financing for the construction timeframe is not included in the estimate.
E. All costs associated with a plant initial startup are provided for in the follow-on later economic analysis.
F. Sufficient utilities will be available for use/tie-in at the plant location.
G. Sufficient labor, fabrication capability, material supply, and so forth will be available to facilitate the construction process.
H. All costs that are considered to be BOP costs that can be specifically identified have been factored out of the reported source data and added into the estimate in a manner consistent with that identified in the NETL 2000 IGCC Base Cost report.

HTGR

A. The linearly scalable cost included for an HTGR reflects an NOAK reactor with a 750°C-operating temperature.
B. HTGR is considered to be linearly scalable, by required capacity, per the direction of the project team. This allows process integration feasibility studies to showcase the financial analysis of the process without the added burden of integer quantity 600-MWth HTGRs.
C. The allowance represents a turn-key condition for the reactor and its supporting infrastructure.
D. A high-temperature, high-pressure steam generator is included in the cost represented for HTGR.
E. A contingency allowance is included in the HTGR cost, but is not identified as a separate line item in this estimate. This allowance was identified and included by the NGNP HTGR project team.
F. The geographic location factor is assumed to be 1.65 for construction of the HTGR at an oil sands location in the Alberta Province due to the limited amounts of skilled labor in the northwest portion of the province (and the subsequent high costs of this labor), and as a result of unique transportation issues and lack of suitable and permanent transportation routes.

SAGD Boilers

A. One reserve/backup conventional methane boiler is included in the HTGR-integrated SAGD case to provide the system capacity to support a bitumen production rate of 56,000 bpd.
B. Standard once through steam generators boilers rated at 340 MMBTU/hr were priced at approximately $11,000,000 via an unofficial estimate from a Canadian steam generator manufacturer. Seven are required to meet the output production of a 600-MWt reactor, and therefore, recover 56,000 bpd bitumen via SAGD technology.
C. BOP was customized to this specific process, omitting items that do not apply. BOP items in the estimate include civil/structural buildings, control and instrumentation, and electrical systems.
D. The single methane once through steam generators/boilers will be located at the centralized SAGD facility.

E. Island cost for the methane boilers includes steam piping from the boiler to the connection at the well pad piping as well as methane supply piping and manifolds.

SAGD Well Pad and Well Pairs

A. Each well pad is assumed to contain nine well pairs, on average.
B. One well pad is considered a single train for calculations performed in the estimate spreadsheet.
C. One well pair has the assumed capacity of approximately 1,000 bpd, on average.
D. Drilling costs per a SAGD well pair is based on drilling 50 m vertical and 1,000 m horizontal for both the recovery and the steam injection well. Drilling cost is assumed to be $9.00 (includes labor at about 42%) per meter for the combined well pair.
E. The centralized SAGD facility connects to six well pads.
F. BOP was customized to this specific process, omitting items that do not apply. BOP items in the estimate include civil/structural buildings, control and instrumentation, and electrical systems.

SAGD Oil/Water Separation/Treatment

A. In order to allow for bitumen recovery expansion, an oil/water separator train allows capacity for up 100,000 bpd of bitumen and 300,000 bpd of water to be separated, even though the estimate is for 56,000 bpd.
B. Each SAGD facility will require at least eight steps of oil/water separation and water treatment, including AP separators, drum separators, pumps, settling tanks, clarifiers, nut shell filters, weak-acid cation exchanger, and hot/warm line softeners. Costs for advanced SAGD water treatment system using film evaporators, crystallizers, and zero liquid discharge systems were not estimated.
C. BOP was customized to this specific process, omitting items that do not apply. BOP items included in the estimate are civil/structural buildings, control and instrumentation, and electrical systems.

VII. CONTINGENCY GUIDELINE IMPLEMENTATION:

Contingency Methodologies: *Explanation of methodology used in determining overall contingency. Identify any specific drivers or items of concern.*

At a project risk review on December 9, 2009, the project team discussed risks to the project. An 18% allowance for capital construction contingency has been included at an island level based on the discussion and is included in the summary sheet. The contingency level that was included in the island cost source documents and additional threats and opportunities identified here were considered during this review. The contingency identified was considered by the project team and included in Cost and Performance Baseline for Fossil Energy Plants DOE/NETL-2007/1281 and similar reports. Typically contingency allowance provided in these reports ranged from 15% to 20%. Since much of

the data contained in this estimate has been derived from these reports, the project team has also chosen a level of contingency consistent with them.

While the level of contingency provided for the HTGR capability is not identified as a line item, the cost data provided to the NGNP Process Integration team was identified as including an appropriate allocation for contingency. No additional contingency has been added to this element.

A. **Threats**: *Uncertain events that are potentially negative or reduce the probability that the desired outcome will happen.*

1. The singularly largest threat to this estimate surrounds the lump sum cost included for the HTGR. While the overriding assumption is that the HTGR will be NOAK, currently, a complete HTGR has not been commissioned.
2. The level of project definition/development that was available at the time the estimate was prepared represents a substantial risk to the project.
3. These costs were determined through standard parametric estimating methods. This process used publicly available published costs that were related to the process required, costs were normalized using price indices, and the cost was scaled to provide the required capacity. The cost-estimating relationships that were used represent typical costs for BOP allowances. While every effort has been made to correctly normalize and factor costs for use in this effort, a risk exists that not all of these were captured correctly due to the varied information available.
4. This project is heavily dependent on the availability of suitable materials and skilled labor available in the active oil sands region of north west Alberta. Competition for these commodities in today's environment due to global expansion, uncertainty, and product shortages affects the basic concepts of the supply and demand theories, thus increasing costs.
5. Impacts due to large quantities of materials, special alloy materials, fabrication capability, and labor availability could all represent conditions that may increase the total cost of the project.

B. **Opportunities**: *Uncertain events that could improve the results or improve the probability that the desired outcome will happen.*

1. Additional research and work performed with both vendors and potential owner/operators for a specific process may identify SAGD and HTGR efficiencies and production means that have not been available for use in this analysis.
2. Recent historical data may identify and include technological advancements and efficiencies not included or reflected in the publicly available source data used in this effort.

COST ESTIMATE SUPPORT DATA RECAPITULATION		
	– Continued –	
Project Title:	NGNP Process Integration – In situ Alberta Oil Sands Recovery via Nuclear Integrated SAGD	
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Note: Contingency does not increase the overall accuracy of the estimate; it does, however, reduce the level of risk associated with the estimate. Contingency is intended to cover the inadequacies in the complete project scope definition, estimating methods, and estimating data. Contingency specifically excludes changes in project scope, unexpected work stoppages (e.g., strikes, disasters, and earthquakes) and excessive or unexpected inflation or currency fluctuations.

VIII. **OTHER COMMENTS/CONCERNS SPECIFIC TO THE ESTIMATE:**

None.

Detail Item Report - High Temperature Gas Reactor (HTGR)

Project Name:	**Nuclear Process Integration**	**Client:**	**M. Patterson**
Process:	**Nuclear Steam Assisted Gravity Drainage**	**Prepared By:**	**B. Wallace, R. Honsinger, J. Martin**
Estimate Number:	**MA36-R**	**Estimate Type:**	**Class 5**

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
INL Feasibility Study (INL 2009)	1	MWth	1	2009	$ 1,708,333	$ 1,708,333	$ 1,708,333	600	MWth	1	600	MWth	$ 1,025,000,000	$ 1,025,000,000

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
INL Feasibility Study (INL 2009)	1	MWth	1	2009	$ 1,708,333	$ 1,708,333	$ 1,708,333	600	MWth	1	600	MWth	$ 1,025,000,000	$ 1,025,000,000

Balance of Plant:

Description	Markup						Cost Per Train	Total Cost
Geographic Location Factor	65.80%						$ 674,450,000	$ 674,450,000
Water Systems	0.00%						$ -	$ -
Civil/Structural/Buildings	0.00%						$ -	$ -
Piping	0.00%						$ -	$ -
Control and Instrumentation	0.00%						$ -	$ -
Electrical Systems	0.00%						$ -	$ -
						Total Balance of Plant	$ 674,450,000	$ 674,450,000
						Total Balance of Plant Plus the Selected Source	$ 1,699,450,000	$ 1,699,450,000

Rationale for Selection:

Single source cost point. This cost has been provided by the subcontracted subject matter expert L. Demick to the INL NGNP Process Integration team. This cost represents a complete turnkey cost. The cost of an HTGR reactor, as provided by L. Demick, is $2,000,000 per MWth required. This cost used has been reduced to $1,708,333 per MWth to exclude the cost of power cycles. A geographic location factor of 65.8% was added to account fo the additional cost of performing the necessary work in northern Alberta. This location factor was developed by the Cost Estimating group, and is based on the RS Means 2010 City Cost Index for For McMurray, Alberta, Canada total weighted average of 109.6. This total weighted average was adjusted by the following cumulative multipliers: +10% for the increased labor cost for industrial/nuclear construction, +25% for the increased cost in transporting materials and equipment, +10% for the increased cost of special materials required for this project.

Detail Item Report - SAGD Well Pads and Well Pairs

Project Name:	**Nuclear Process Integration**	**Client:**	**M. Patterson**
Process:	**Nuclear Steam Assisted Gravity Drainage**	**Prepared By:**	**B. Wallace, R. Honsinger, J. Martin**
Estimate Number:	**MA36-R**	**Estimate Type:**	**Class 5**

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Ziff Energy	1,000	bpd	1	2009	$9,450,000	$ 9,450,000	$ 9,450,000	56,000	bpd	54	1,037	bpd	$ 9,658,471	$ 521,557,420

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Ziff Energy	1,000	bpd	1	2009	$9,450,000	$ 9,450,000	$ 9,450,000	56,000	bpd	54	1,037	bpd	$ 9,658,471	$ 521,557,420

Balance of Plant:

Description	Markup						Cost Per Train	Total Cost
Water Systems	0.00%						$ -	$ -
Civil/Structural/Buildings	9.20%						$ 888,579	$ 47,983,283
Piping	0.00%						$ -	$ -
Control and Instrumentation	2.60%						$ 251,120	$ 13,560,493
Electrical Systems	8.00%						$ 772,678	$ 41,724,594
						Total Balance of Plant	$ 1,912,377	$ 103,268,369
						Total Balance of Plant Plus the Selected Source	$ 11,570,848	$ 624,825,790

Rationale for Selection:

The well pad and well pair cost is a single source cost data point provided by the project team technical specialist. Balance of plant was customized to this specific process, omitting items that do not apply.

Detail Item Report - SAGD Boiler

Project Name:	**Nuclear Process Integration**	**Client:**	**M. Patterson**
Process:	**Nuclear Steam Assisted Gravity Drainage**	**Prepared By:**	**B. Wallace, R. Honsinger, J. Martin**
Estimate Number:	**MA36-R**	**Estimate Type:**	**Class 5**

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Once Through Steam Generators (OTSG)	45,000,000	btuh	1	2009	$11,000,000	$ 11,000,000	$ 11,000,000	45,000,000	btuh	1	45,000,000	btuh	$ 11,000,000	$ 11,000,000

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Once Through Steam Generators (OTSG)	45,000,000	btuh	1	2009	$11,000,000	$ 11,000,000	$ 11,000,000	45,000,000	btuh	1	45,000,000	btuh	$ 11,000,000	$ 11,000,000

Balance of Plant:

Description	Markup						Cost Per Train	Total Cost
Water Systems	0.00%						$ -	$ -
Civil/Structural/Buildings	9.20%						$ 1,012,000	$ 1,012,000
Piping	0.00%						$ -	$ -
Control and Instrumentation	2.60%						$ 286,000	$ 286,000
Electrical Systems	8.00%						$ 880,000	$ 880,000
						Total Balance of Plant	$ 2,178,000	$ 2,178,000
						Total Balance of Plant Plus the Selected Source	$ 13,178,000	$ 13,178,000

Rationale for Selection:

The boiler cost is used as a single source cost data point provided by the project team technical specialist. Balance of plant was customized to this specific process, omitting items that do not apply.

Note: One conventional methane boiler is included in the Nuclear SAGD case to provide partial system capacity in the case of HTGR outages. This is based on input from the project team technical specialist.

Detail Item Report - Oil/Water Separation/Treatment

Project Name:	**Nuclear Process Integration**	**Client:**	**M. Patterson**
Process:	**Nuclear Steam Assisted Gravity Drainage**	**Prepared By:**	**B. Wallace, R. Honsinger, J. Martin**
Estimate Number:	**MA36-R**	**Estimate Type:**	**Class 5**

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Veolia - Oil Water Separators	50000	bpd	1	2009	$10,000,000	$ 10,000,000	$ 10,000,000	400,000	bpd	8	50,000	bpd	$ 10,000,000	$ 80,000,000

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Oil Water Separators	50000	bpd	1	2009	$10,000,000	$ 10,000,000	$ 10,000,000	400,000	bpd	8	50,000	bpd	$ 10,000,000	$ 80,000,000

Balance of Plant:

Description	Markup						Cost Per Train	Total Cost
Water Systems	0.00%						$ -	$ -
Civil/Structural/Buildings	9.20%						$ 920,000	$ 7,360,000
Piping	0.00%						$ -	$ -
Control and Instrumentation	2.60%						$ 260,000	$ 2,080,000
Electrical Systems	8.00%						$ 800,000	$ 6,400,000
						Total Balance of Plant	$ 1,980,000	$ 15,840,000
						Total Balance of Plant Plus the Selected Source	$ 11,980,000	$ 95,840,000

Rationale for Selection:

The oil/water separation and treatment cost is used as a single source cost data point provided by the project team technical specialist. Balance of plant was customized to this specific process, omitting items that do not apply.

Detail Item Report - Steam Transmission Piping

Project Name:	**Nuclear Process Integration**	**Client:**	**M. Patterson**
Process:	**Nuclear Steam Assisted Gravity Drainage**	**Prepared By:**	**B. Wallace, R. Honsinger, J. Martin**
Estimate Number:	**MA36-R**	**Estimate Type:**	**Class 5**

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains Based on 12-km
Steam Transmission Piping														
United Engineers 1982 - Table 6-1, Case 2 - Based on 2-miles	1,000	MWt	1	1980	$ 7,400,000	$ 7,400,000	$ 14,505,360	540	MWt	1	540	MWt	$ 10,022,239	$ 37,366,142
United Engineers 1982 - Table 6-2, Case 2 Based on 2-miles	1,000	MWt	1	1995	$ 17,400,000	$ 17,400,000	$ 23,376,542	540	MWt	1	540	MWt	$ 16,151,636	$ 60,218,511
United Engineers 1982 - Table 6-1, Case 1 Based on 5-miles	1,000	MWt	1	1980	$ 23,400,000	$ 23,400,000	$ 45,868,300	540	MWt	1	540	MWt	$ 31,691,946	$ 47,263,120
United Engineers 1982 - Table 6-2, Case 1 Based on 5-miles	1,000	MWt	1	1995	$ 54,600,000	$ 54,600,000	$ 73,353,975	540	MWt	1	540	MWt	$ 50,682,720	$ 75,584,614
PCAT _Oil Sands Study - Based on 1-	1	km	1	2008	$ 3,800,000	$ 3,800,000	$ 3,569,908	12	km	12	1	km	$ 3,569,908	$ 42,838,899
Heat Exchanger	1	EA	1	2009	$ 1,000,000	$ 1,000,000	$ 1,000,000	6	EA	6	1	EA	$ 1,000,000	$ 6,000,000

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Steam Transmission Pipe - average cost														$ 45,051,010
Heat Exchanger	1	EA	1	2009	$ 1,000,000	$ 1,000,000	$ 1,000,000	1	EA	6	1	EA	$ 1,000,000	$ 6,000,000
Total														$ 51,051,010

Detail Item Report - Steam Transmission Piping

Project Name:	**Nuclear Process Integration**	**Client:**	**M. Patterson**
Process:	**Nuclear Steam Assisted Gravity Drainage**	**Prepared By:**	**B. Wallace, R. Honsinger, J. Martin**
Estimate Number:	**MA36-R**	**Estimate Type:**	**Class 5**

Balance of Plant:

Description	Markup						Cost Per Train	Total Cost
Water Systems	0.00%							$ -
Civil/Structural/Buildings	0.00%							$ -
Piping	0.00%							$ -
Control and Instrumentation	2.60%							$ 1,327,326
Electrical Systems	0.00%							$ -
						Total Balance of Plant		$ 1,327,326
						Total Balance of Plant Plus the Selected Source		$ 52,378,336

Rationale for Selection:

The Table 6-2 1995 cost data was not used, because the numbers were future projections from the Table 6-1 1980 cost data. The 2-mile cost data from Table 6-1 was not used because required distances are more accurately represented by the 5-mile cost data from Table 6-1. The 5-mile 1980 cost data from Table 6-1 and the PCAT Oil Sands study were selected as the most representative cost points and averaged. The heat exchanger is used as a single source cost data point provided by the project team technical specialist. Balance of plant was customized to this specific process, omitting items that do not apply.

Note: All 'Total Current Cost for Required Trains' steam transmission piping costs represent 12-km distances. The PCAT Oil Sands Study presented per kilometer costs for steam transmission piping; and was linearly adjusted to the required 12-km distance.