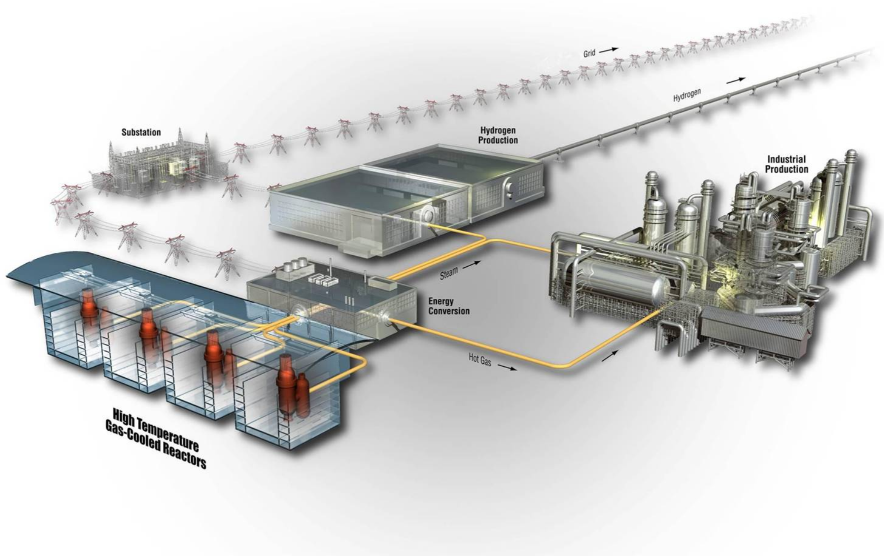
Document ID: TEV-704
Revision ID: 2
Effective Date: 09/30/2011

Technical Evaluation Study

Project No. 23843

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



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REVISION LOG

Rev.	Date	Affected Pages	Revision Description
0	11/06/2009	All	Newly issued document.
1	05/15/2010	All	Added economic sections and document reorganization.
2	09/30/2011	All	Document completely revised.

EXECUTIVE SUMMARY

This technical evaluation (TEV) has been prepared as part of a study for the Next Generation Nuclear Plant (NGNP) Project to evaluate the integration of high-temperature gas-cooled reactor (HTGR) technology with conventional chemical processes. This TEV addresses the integration of HTGR heat and power into oil sands recovery via steam assisted gravity drainage (SAGD); specifically, the technical and economic feasibility of the HTGR integration.

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

- Four 600 MWt HTGRs are required to support production of steam and power for a 190,000 barrel per day SAGD facility.

- Nuclear-integration decreases natural gas consumption by up to 100% using HTGR generated steam as the heat source, eliminating 192.5 MMSCFD of natural gas usage.

- Nuclear-integration also eliminates almost 12,000 tons per day of CO_2 production from the SAGD process, as natural gas combustion is eliminated.

The economic results presented in this TEV are preliminary and should be refined as the design of the HTGR progresses, if the design of the HTGR is changed significantly, or if additional refinements of the HTGR and/or SAGD capital and/or operating costs become available. The HTGR capital, operating and maintenance (O&M) costs, fuel, and decommissioning costs are based on the correlations and costs presented for an n^{th} of a kind HTGR in TEV-1196 (Idaho National Laboratory [INL] 2011a). The following conclusions were drawn when evaluating the economics of the conventional and nuclear-integrated SAGD cases:

- The nuclear-integrated SAGD case provides economic stability with respect to fluctuations in natural gas prices. Only at higher natural gas prices does the nuclear-integrated SAGD process economically outperform the conventional process. The natural gas price for the SAGD process must be at or above $14.00/MSCF in order for the nuclear-integrated case to economically outperform the conventional case for a 12% internal rate of return (IRR). Figure ES-1 presents bitumen price versus the natural gas purchase price for the convention and nuclear-integrated cases.

- The carbon tax results show that the nuclear-integrated SAGD case outperforms the conventional case at a 12% IRR when the carbon tax is approximately \$130/ton-CO_2 for the average natural gas price (\$5.50/MSCF) and \$35/ton-CO_2 for the high natural gas price (\$12.00/MSCF). Figure ES-2 presents the carbon tax results for low (\$4.40/MSCF), average, and high natural gas prices.

- An economic sensitivity analysis was performed, it was determined that the construction adder for the Alberta region can have the largest the largest impact on the required bitumen selling price, followed by the total capital investment, the assumed IRR, and the debt to equity ratio. Figure ES-3 presents a tornado diagram for nuclear-integrated SAGD process, showing the resulting bitumen price when varying the baseline economic assumptions.

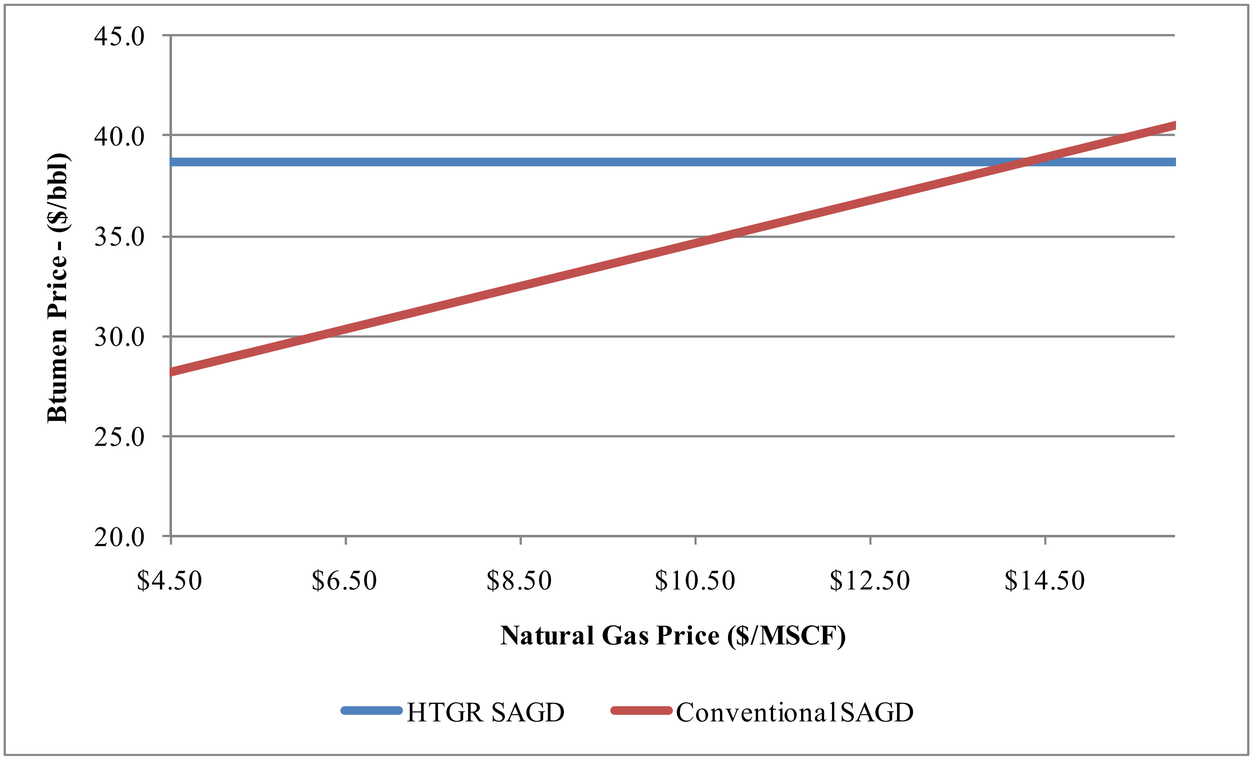

Figure ES-1. Bitumen price as a function of natural gas purchase price, 12% IRR.

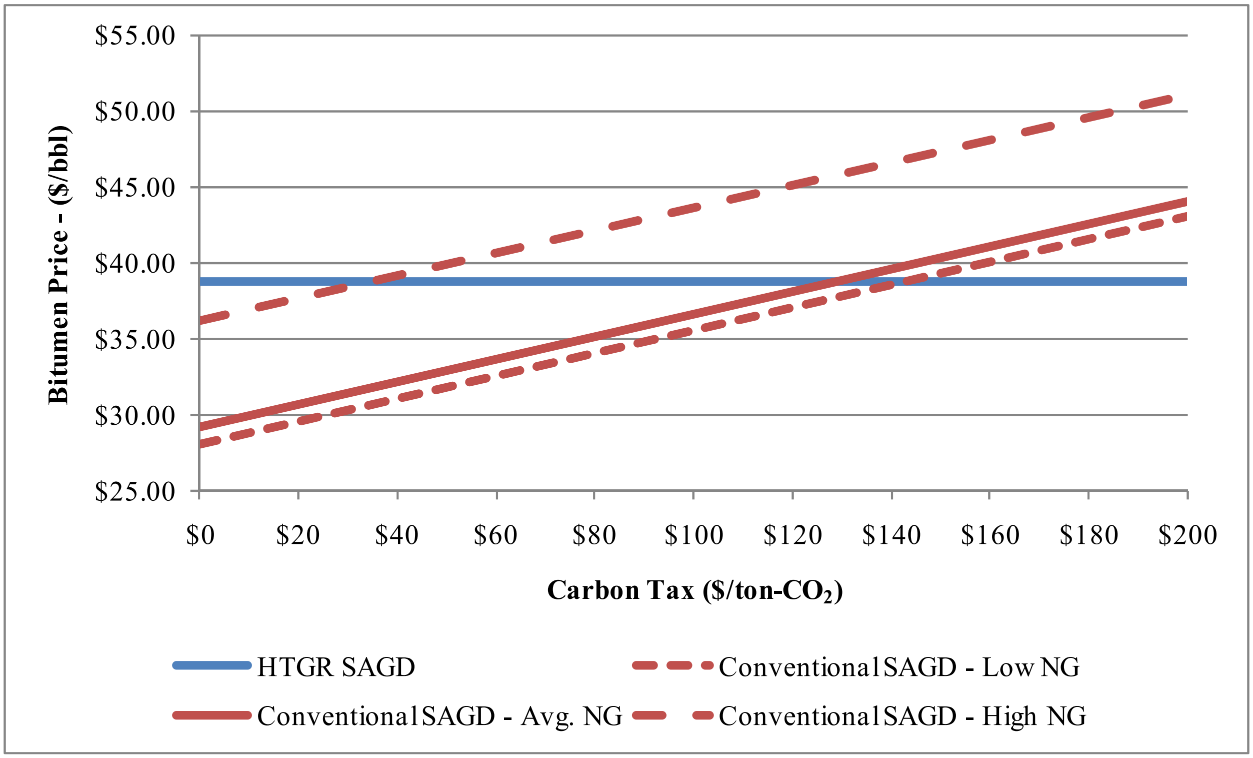

Figure ES-2. Bitumen price as a function of a carbon tax on CO_2 emissions, 12% IRR.

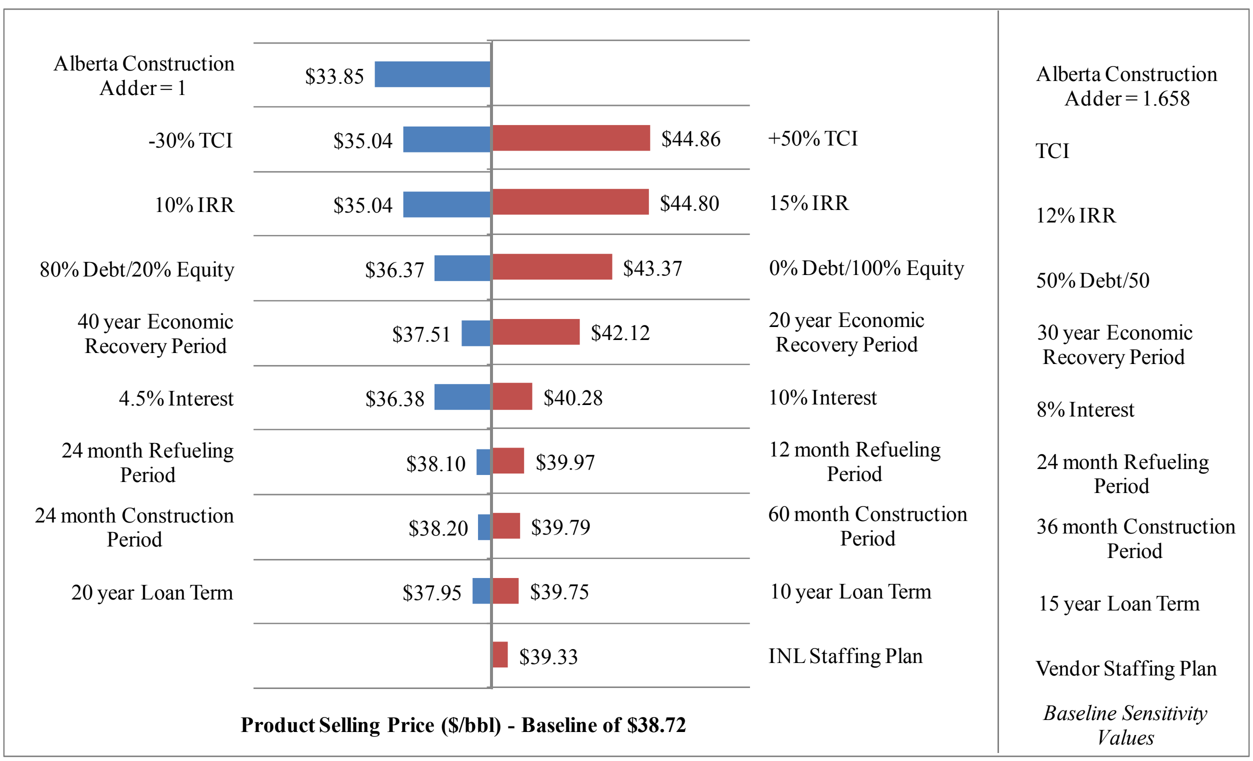

Figure ES-3. HTGR SAGD tornado diagram.

CONTENTS

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
CERI	Canadian Energy Research Institute
CESF	central energy supply facility
DOE	Department of Energy
EIA	Energy Information Administration
ERCB	Energy Resources Conservation Board
GIF	GEN-IV International Forum
HTGR	high-temperature gas-cooled reactor
INL	Idaho National Laboratory
IRR	internal rate of return
MACRS	modified accelerated cost recovery system
MARR	minimum annual rate of return
NIBT	net income before taxes
NGNP	Next Generation Nuclear Plant
O&M	operations and maintenance
OSP	oil sands producer
PTAC	Petroleum Technology Alliance Canada
PW	present worth
ROT	reactor outlet temperature
SAGD	steam assisted gravity drainage
SCO	synthetic crude oil
SMR	steam methane reforming
TCI	total capital investment
TEV	technical evaluation
C_k	capital expenditures
c_months	total number of months in the current modules construction period
CapF	capital breakdown per month
d_k	depreciation
E_k	cash outflows
i'	IRR
k	year
Mod	module/train being evaluated
ModF	capital fraction per module/train
month	current month in reactor/fossil construction period
Number	total number of reactor modules/fossil trains
R_k	revenues
t	tax rate
T_k	income taxes
y	exponent for current module/train

1. INTRODUCTION

This technical evaluation (TEV) has been prepared as part of a study for the Next Generation Nuclear Plant (NGNP) Project to evaluate the 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 2005 *Energy Policy Act* to promote reliance on safe, clean, economic nuclear energy and to establish a greenhouse-gas-free technology for the production of hydrogen. The NGNP represents an integration of high-temperature reactor technology with advanced hydrogen, electricity, and process heat production capabilities, thereby meeting the mission need identified by DOE. The strategic goal of the NGNP Project is to broaden the environmental and economic benefits of nuclear energy in the U.S. economy by demonstrating its applicability to market sectors not being served by light water reactors.

The HTGR produces high-temperature helium that can be used to produce electricity and/or process heat for export in the form of high-temperature helium or steam. A summary of these products and a brief description is shown in Table 1. For this study, an HTGR outlet temperature of 770°C is assumed; this reflects the optimal HTGR outlet temperature when steam is the delivered working fluid, as documented in TEV-981 (INL 2010a). In conventional chemical processes heat and power are generated by the combustion of fossil fuels such as coal and natural gas, resulting in significant emissions of greenhouse gases, including carbon dioxide. Heat or electricity produced in an HTGR could be used to supply process heat or electricity to conventional chemical processes while generating minimal greenhouse gases. The use of an HTGR to supply process heat or electricity to conventional processes is referred to as a nuclear-integrated process. This report provides technical and economic analyses of integrating nuclear-generated heat and electricity into conventional processes.

Table 1. Projected outputs of the HTGR.

HTGR Product	Product Description
Steam	540°C and 17 MPa
Electricity	Generated by a Rankine cycle, 43% efficiency

This TEV specifically addresses HTGR integration opportunities for oil sands recovery via steam-assisted gravity drainage (SAGD). The HTGR would produce steam, via high-temperature heat exchange, and electricity and be physically located near the SAGD production facility. A separate study has been conducted to assess heat losses associated with transporting high-temperature HTGR heat long distances, using a variety of transport fluids, in TEV-1351 (INL 2011b). HTGR capital and operating costs used in the economic analysis are based on the detailed cost estimate presented in TEV-1196 (INL 2011a). In addition, this TEV proposes a central energy supply facility concept, presented in Appendix A, where heat and power from the HTGR is distributed to both SAGD and bitumen upgrading processes. Heat and power requirements for the bitumen upgrading process are based on the results presented in TEV-1147 (INL 2011c). Detailed descriptions of the upgrading models documented in TEV-1147 and the costs documented in TEV-1196 are not presented in this report.

The SAGD simulations were developed using version 7.3 of Aspen Plus, a state-of-the-art steady-state chemical process simulator (Aspen 2011). The outputs from the material and energy balances generated in Aspen Plus were utilized as inputs into the Excel economic models (Excel 2007). This TEV assumes familiarity with both Aspen Plus and Excel. A detailed explanation of the software capabilities, of both Aspen Plus and Excel, is beyond the scope of this study.

The TEV first presents an overview of the process modeling performed for the conventional and nuclear-integrated SAGD cases. Next, the process modeling results are presented for each case, specifically the impact of the HTGR integration. Finally, the details of the economic model are discussed along with the analysis results.

2. PROCESS MODELING OVERVIEW

The plant models for the SAGD processes were developed using version 7.3 of Aspen Plus (Aspen 2011). Because of the size and complexity of the processes modeled, the simulations were constructed using "hierarchy" blocks, a method for nesting one simulation within another simulation. In this fashion, submodels for each major plant section were constructed separately and then combined to represent the entire process. For the purpose of modeling, English units were used.

Two cases were identified for modeling:

- Conventional SAGD process
- Nuclear-integrated SAGD process

The natural gas composition was taken from data published by the Northwest Gas Association. Capacity for the plant was set to produce 190,000 barrels per day of bitumen; bitumen production was set based on supplying heat and power from four 600 MWt HTGRs to the SAGD process.

For the Aspen models described in this analysis, detailed submodels of the HTGR heat supply have not yet been integrated. In addition, water consumption for the HTGR has not been included, as a detailed water balance for the HTGR has not been completed at this time. The general model descriptions for all cases are presented below.

2.1 Conventional SAGD Case

The block flow diagram for the conventional SAGD process is shown in Figure 1. The proposed process includes unit operations for steam generation, steam transport and injection into the SAGD wells, oil/water separation, and water treatment. Each unit operation is briefly described below.

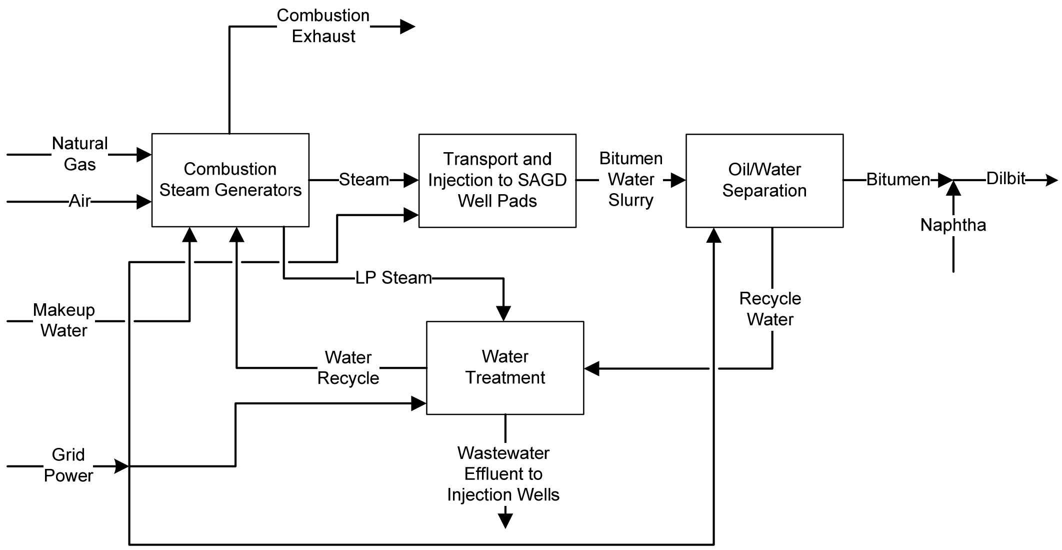

Figure 1. Block flow diagram for the conventional SAGD process.

- **Steam Generation –** Both high pressure and low pressure steam are required in the SAGD process. The high pressure steam is transported to the well pads, where it is injected into the SAGD well to recover the bitumen deposit. The low pressure steam is used for water treatment. The high pressure, saturated steam is generated at approximately 1,450 psia (592°F) by combusting natural gas in a once through steam generator (JACOS 2010, Devon 2010). 1,450 psia (10 MPa) was chosen as the steam pressure to ensure that it could be delivered a sufficient distance to the SAGD well pads, specifically for the HTGR integrated case, where the reactor life could be up to 60 years. Heat remaining in the hot combustion gas is then used to generate 45 psia (310 kPa) steam for use in water treatment, where 1 lb of low pressure steam is generated for every 23 lb of water sent to water treatment (JACOS 2010). The combustion exhaust stream is assumed to exit the low pressure steam generator with a temperature of 330°F; the combustion exhaust is emitted through a stack.

- **Steam Transport and Injection** – The high pressure steam is transported 25 kilometers though eight separate piping lines, each with a 24 inch nominal diameter. Each pipeline is assumed to have 16, 90 degree elbows and four branched tees. The heat transfer coefficient is assumed based on information presented in TEV-1351 (INL 2011b). The steam is then expanded to 725 psia (5 MPa) at the well pad for injection into the SAGD well; this is the assumed maximum injection pressure to the well (JACOS 2010). Prior to injection, any condensate formed during transport and after the pressure expansion is separated from the vapor. The condensate is then returned to the central SAGD facility, where heat is recovered for low pressure steam production. The dry steam is injected into the SAGD well, such that the dry steam injection ratio is 2.5 times the amount of bitumen produced. Thus for 190,000 barrels per day of bitumen extracted, 475,000 barrels per day of steam[1] are injected into the well. Ninety-five percent of the steam injected into the well is recovered with the bitumen product as water, in a bitumen water slurry, at a pressure of 145 psia (1 MPa) and 18°F (10°C) below the water saturation temperature, a temperature of 320°F (160°C) (JACOS 2010). The bitumen water slurry is transported back to the central facility.

- **Oil/Water Separation** – After the bitumen and water slurry is transported back the central facility, heat is recovered from the slurry cooling it to 235°F (112°C), using the heat recovered to preheat the boiler feedwater (JACOS 2010). In the Aspen Plus model, the bitumen is not included as a component in order to simplify the model, as bitumen would have to be modeled as a pseudocomponent which significantly increases the model complexity. Thus, heat recovery from the bitumen portion of the slurry was estimated using the heat capacity of bitumen. After heat recovery, the bitumen is separated from the bitumen water slurry at 65 psia (JACOS 2010). Naphtha, a diluent, is added to the bitumen product in order to make it flowable for pipeline transport; naphtha is blended in order to make up 30 vol-% of final dilbit product, a blend of bitumen and diluent.

- **Water Treatment** – Water treatment is not explicitly modeled. Rather, heat is recovered in accordance with the heat balance supplied in the JACOS Hangingstone project report. The water product after oil/water separation is assumed to be cooled further to 185°F (85°C) for makeup water heating/boiler feedwater preheat (JACOS 2010). After heat recovery, the water is treated to remove any remaining oil and solids. Oil is assumed to be removed using skim tanks, induced gas flotation, and walnut-shell filters. The de-oiled produced water is then fed to hot lime softeners, with heat supplied by the low pressure steam. The treated water is sent to a softener to reduce hardness to meet quality specifications for the steam generator feedwater. A fraction of the steam generator blowdown in sent to an evaporator, the resulting evaporator blowdown stream is highly concentrated in dissolved solids and organics, and is disposed of as wastewater. The wastewater stream is assumed to be approximately 1.5% of the treated water (JACOS 2010). Makeup water is added to replace the flow lost to the SAGD well and the wastewater stream.

1 The barrels per day of steam injected are expressed as the equivalent volume of water.

- **Grid Power** – Power for the conventional SAGD process is purchased from the grid. Power consumption is assumed to be 0.5 kWe per barrel of bitumen produced (JACOS 2010).

2.2 Nuclear-Integrated SAGD Case

The block flow diagram for the nuclear-integrated SAGD case is shown in Figure 2. The proposed process includes the same unit operations as the conventional process with the following exceptions: the once through steam generator fueled by natural gas combustion is replaced by a steam reboiler, i.e. a steam-to-steam heat exchanger, with the combustion heat replaced by heat supplied from the HTGR. In addition grid power is replaced with an HTGR Rankine cycle.

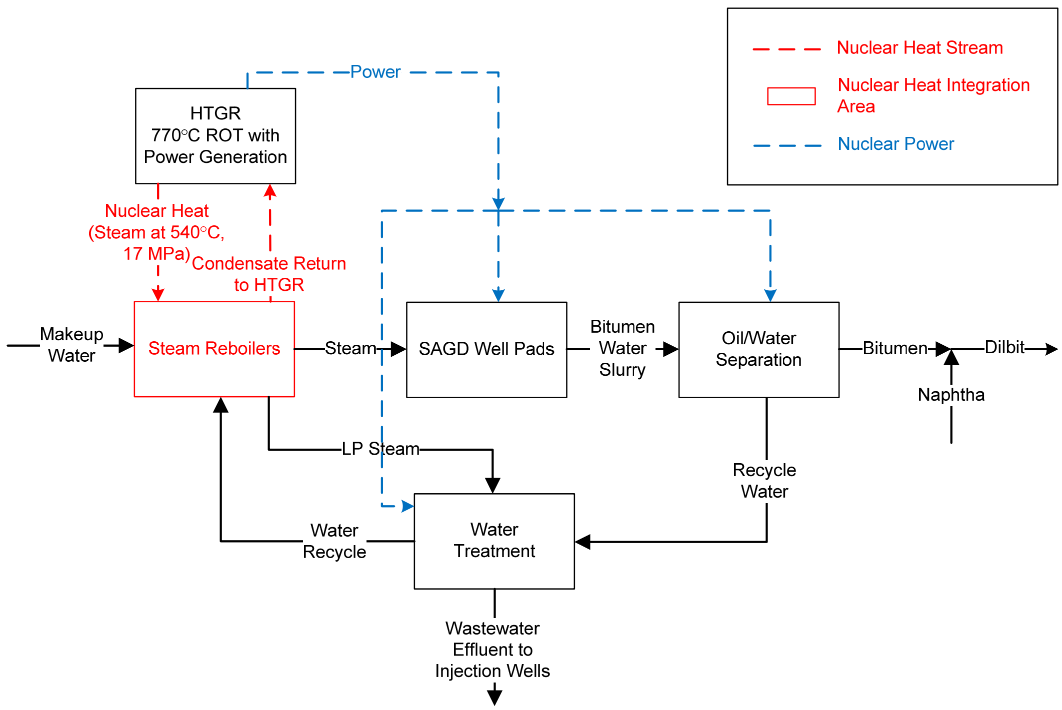

Figure 2. Block flow diagram for the nuclear-integrated SAGD process.

Each unit operation in the nuclear-integrated SAGD flowsheet is briefly described below. Because the majority of unit operations remain unchanged from the conventional flowsheet, emphasis is placed on differences between the two cases.

- **Steam Generation** – Steam generation for the nuclear-integrated case is similar to the conventional case, in that the conditions of the steam generated for the SAGD process remain unchanged. The high pressure, saturated steam is generated at approximately 1,450 psia (592°F) through heat exchange with the 540°C 17 MPa steam provided from the HTGR in a steam reboiler. Heat remaining in the HTGR steam is then used to generate 45 psia (310 kPa) steam for use in water treatment. Condensed steam is returned to the HTGR at 17.34 MPa.

- **Steam Transport and Injection** – Steam transport in the nuclear-integrated cases is identical to that of the conventional case.

- **Oil/Water Separation** – Oil/water separation in the nuclear-integrated cases is identical to that of the conventional case.

- **Water Treatment** – Water treatment in the nuclear-integrated cases is identical to that of the conventional case.

- **Power Generation** – Power is generated from the HTGR in a Rankine cycle, assuming 43% generation efficiency. It is assumed that power is generated to provide sufficient power for the SAGD process, 0.5 kW per barrel of bitumen produced.

3. PROCESS MODELING RESULTS

Analysis of the conventional SAGD case indicates a strong potential heat integration opportunity for an HTGR. In the conventional case, 100% of the natural gas fed to the process is combusted to provide heat for steam generation, which can alternatively be supplied by the steam from the HTGR via a steam reboiler. Additionally, the power requirements for the SAGD process can be supplied by power generated in an HTGR Rankine cycle.

The process modeling results for the nuclear-integrated SAGD case are technically promising. A four-pack of 600 MWt HTGRs would be required to produce 190,000 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. Power consumption for the plant does increase from 113 MWe for the conventional case to 200 MWe for the nuclear-integrated case; however, power is supplied by an HTGR Rankine cycle. The primary factor for increased power consumption is the increased power load required for the HTGR primary circulators. CO_2 emissions are also eliminated from the process. 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 2. A high-level material and energy balance summary for each case is graphically presented in Figure 3. The conventional SAGD case serves as a basis for comparison with the nuclear-integrated case. For the detailed Aspen Plus model summary results, see Appendix B. For the complete Aspen stream results for the SAGD and nuclear-integrated SAGD cases, see Appendixes C and D, respectively.

Table 2. SAGD modeling case study results.

	Conventional SAGD	Nuclear Integrated SAGD
Inputs		
Natural Gas Feed rate (MMSCFD)[2]	192.5	0
# HTGRs (600 MWt)	N/A	4
Naphtha as Diluent (bbl/day)	81,429	81,429
Outputs		
Dilbit Product (bbl/day)	271,429	271,429
Bitumen (bbl/day)	190,000	190,000
Naphtha (bbl/day)	81,429	81,429
Utility Summary		
Total Power (MWe)	-113.2	0
SAGD Process Consumption	-113.2	-108.9
HTGR Consumption	N/A	-83.7
HTGR Rankine Cycle Production	N/A	192.6
Water Requirements[3]		
Water Consumed (gpm)	884	884
CO_2 Summary		
Total CO_2 Emitted (ton/day)	11,831	0
Nuclear Integration Summary		
Nuclear Heat Supplied[4] (MWt)	N/A	2,486
HTGR Heat to SAGD Process	N/A	2,032
HTGR Heat to Power Generation	N/A	454
Nuclear Power Supplied (MWe)	N/A	108.9

[2] Standard temperature of 60°F.

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

[4] The HTGR heat supplied is greater than 2,400 MWt due to heat generated in the primary circulators.

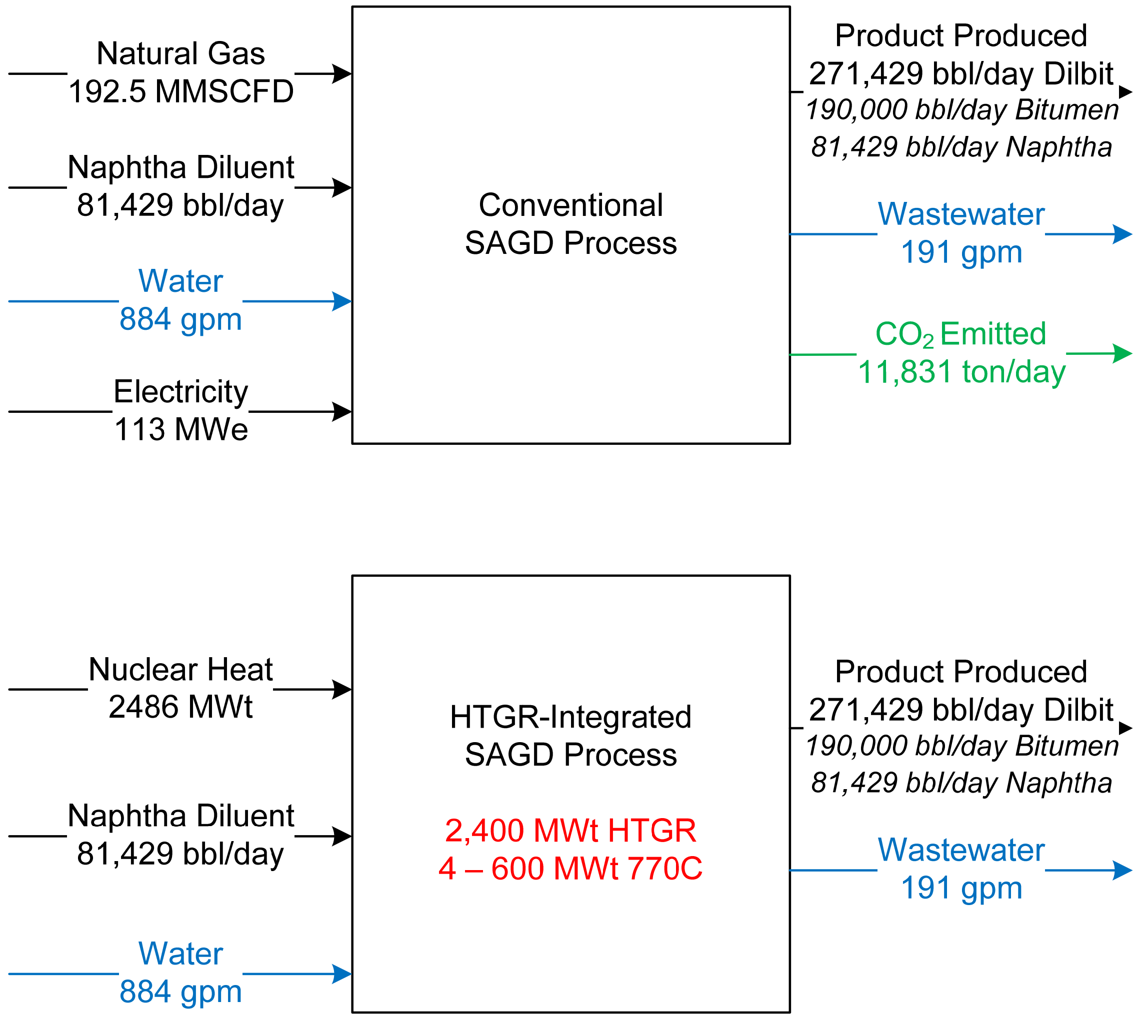

Figure 3. SAGD modeling case material balance summary.

4. ECONOMIC MODELING OVERVIEW

The economic viability of the SAGD processes was assessed using standard economic evaluation methods, specifically the internal rate of return (IRR). The economics were evaluated for the conventional and HTGR-integrated cases described in the previous section. The total capital investment (TCI), based on the total equipment costs; annual revenues; and annual manufacturing costs were first calculated for the cases. The present worth was then calculated based on the annual after tax cash flows. 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 primary selling product is bitumen; the naphtha added as diluents is assumed to be recycled back to the SAGD process, so it is not a factor in the economic analysis. The economics were analyzed for multiple owner operator scenarios, with the HTGR and

SAGD facilities operated by independent organizations or a single owner operator. The economic results are preliminary and should be refined as the design of the HTGR progresses, if the design of the HTGR is changed significantly, or if additional refinements of the HTGR and/or SAGD capital and/or operating costs become available.

4.1 Capital Cost Estimation

The Association for the Advancement of Cost Engineering (AACE) International recognizes five classes of estimates. The level of project definition for this study was determined to be an AACE International Class 4 estimate, which has a probable error of -30% and +50%, as described in TEV-1196 (INL 2011a). A Class 4 estimate is associated with a feasibility study or top-down cost estimate and has one to fifteen percent of full project definition (AACE 2005).

Equipment items for this study were not individually priced. Rather, cost estimates were based on scaled costs for major plant processes from published literature or vendor data. Cost estimates generated in this manner include the costs for the SAGD processing facility (Candian Energy Research Institute [CERI] 2008). All costs presented are assumed to represent a complete and operable system and include all engineering fees and contingencies. Fixed capital costs were estimated from literature data, scaled linearly with increasing capacity.

The HTGR installed capital costs are based on the capital cost correlations presented in Section 2.6 of TEV-1196 for an n^{th} of a kind HTGR, a mature commercial installation, with an ROT of 770°C and a Rankine power cycle (INL 2011a). Preconstruction costs, balance of equipment costs, indirect costs, and project contingencies were added in accordance with the costs outlined in Sections 2.1 through 2.5 of TEV-1196 (INL 2011a). A geographic location factor is assumed for HTGR construction in Alberta. It is set to be 1.658 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 (Hosinger 2010).

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

Table 3. CEPCI data.

Year	CEPCI
2007	525.4
2008	575.4
2009	521.9
2010	550.8

Table 4 presents the capital cost estimate breakdown for the conventional SAGD case. Table 5 presents the results for the nuclear-integrated SAGD case and Figure 4 presents the graphical breakdown for the nuclear-integrated case. It was assumed that the SAGD facility cost would be the same for both the conventional and nuclear-integrated processes, i.e. that the steam reboilers would be similar in cost to the once through steam generators.

Table 4. Total capital investment, conventional SAGD.

	Total Capital Cost
SAGD Facility	$4,800,108,074
Total Capital Investment	**$4,800,108,074**

Table 5. Total capital investment, nuclear-integrated SAGD.

	Total Capital Cost
HTGR(s)	$6,080,856,679
Rankine Power Cycle	$443,226,364
SAGD Process	$4,800,108,074
Total Capital Investment	**$11,324,191,117**
HTGR and Power Cycle	$4,800,108,074
SAGD Process	$6,524,083,043

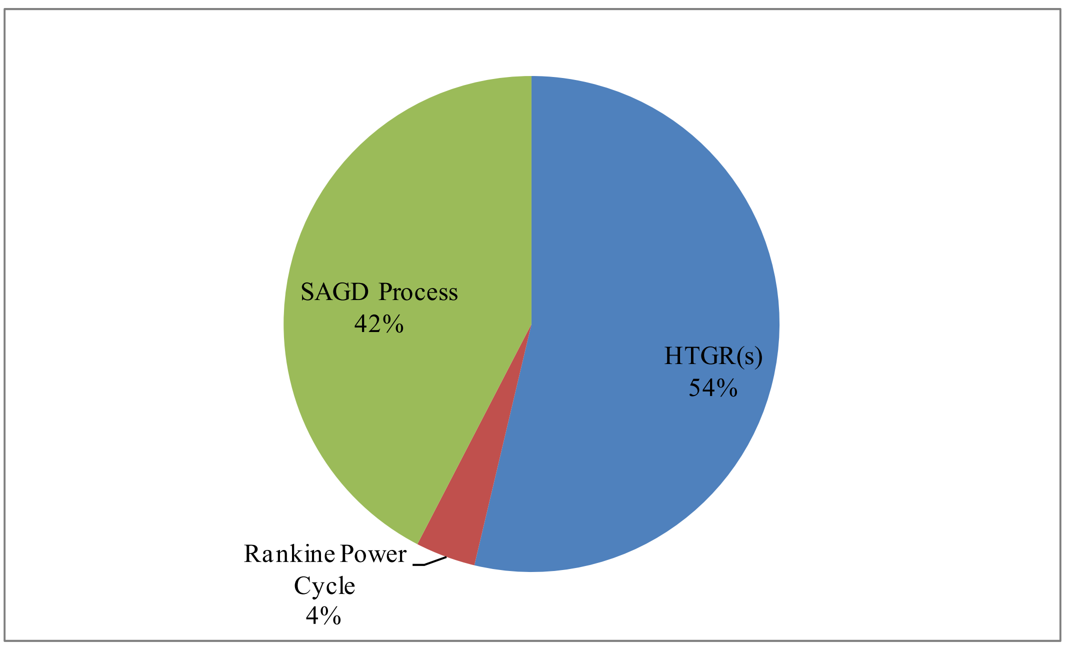

Figure 4. Total capital investment, nuclear-integrated SAGD process.

4.2 Estimation of Revenue

Yearly revenues were estimated for all cases based on recent price data for the bitumen product stream. When a separate owner operator configuration is assumed, the HTGR collects revenues from the heat and electricity supplied to the SAGD process. When heat is exported from the HTGR, the selling price is assumed to be related to electricity price based on the HTGR power generation efficiency as follows:

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

An HTGR power generation efficiency of 43% is assumed, regardless of the power cycle configuration. This allows for an equal comparison for cases where cycle efficiencies may be higher due to power cycle type and/or steam extraction.

Revenues were estimated for low, average, and high selling prices for the bitumen product. Bitumen prices were gathered from the Energy Information Administration (EIA) and represent wholesale prices and do not include taxes; it was assumed that the bitumen would sell for the same value as Canadian Heavy Hardisty. High prices correspond to values from July 2008, low prices are from March 2009, and average prices were the average of the high and low values (EIA 2011a). The electricity selling price is based on the current industrial market price of electricity, $67.90/MWe-hr (EIA 2011b). Revenues were also calculated to determine the necessary selling prices of bitumen and heat and electricity, for the separate owner operator scenario, to achieve a specific rate of return; however, these revenues are not presented in the following tables.

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

Table 6. Annual revenues, conventional SAGD.

	Price		Generated		Annual Revenue
Bitumen, low	41.38	$/bbl	190,000	bbl/day	$2,582,732,700
Bitumen, average	78.22	$/bbl	190,000	bbl/day	$4,882,101,300
Bitumen, high	115.06	$/bbl	190,000	bbl/day	$7,181,469,900
Annual Revenue, low					**$2,582,732,700**
Annual Revenue, average					**$4,882,101,300**
Annual Revenue, high					**$7,181,469,900**

Table 7. Annual revenues, nuclear-integrated SAGD.

	Price		Generated		Annual Revenue
Bitumen, low	41.38	$/bbl	190,000	bbl/day	$2,582,732,700
Bitumen, average	78.22	$/bbl	190,000	bbl/day	$4,882,101,300
Bitumen, high	115.06	$/bbl	190,000	bbl/day	$7,181,469,900
Annual Revenue - Fossil, low					**$2,582,732,700**
Annual Revenue - Fossil, average					**$4,882,101,300**
Annual Revenue - Fossil, high					**$7,181,469,900**
Heat	29.20	$/MWt-hr	2,032	MWt	$467,774,349
Electricity	69.70	$/MWe-hr	109	MWe	$58,296,740
Annual Revenue – HTGR (separate owner operator)					**$526,041,089**

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).

The natural gas purchase price for the conventional SAGD case was varied to account for the large fluctuations seen in the market. Costs were calculated for a low ($4.50/MSCF), average ($5.50/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 prices (EIA 2011c). Only average natural gas prices are presented in the tables that follow.

The electricity purchase price is based on the current industrial market price of electricity, $67.90/MWe-hr (EIA 2011b). Fixed operating costs, including operation and maintenance (O&M) costs for the SAGD process were lumped into a cost per barrel of bitumen produced (CERI 2008). Table 8 provides the manufacturing costs for the SAGD case. Again, availability was assumed to be 90%.

Table 8. Annual manufacturing costs, conventional SAGD.

	Price		Consumed		Annual Cost
Materials					
Natural Gas	5.50	$/MSCF	192.5	MSCFD	$347,799,375
Utilities					
Electricity	67.90	$/MWe-hr	113	MWe	$60,491,567
SAGD Costs					
Fixed O&M	5.47	$/bbl	190,000	bbl	$341,195,459
Variable O&M	5.09	$/bbl	190,000	bbl	$317,516,554
Manufacturing Costs					**$1,067,002,955**

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

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

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

Table 9. Annual manufacturing costs, nuclear-integrated SAGD.

	Price		Consumed		Annual Cost
SAGD Costs					
Fixed O&M	5.47	$/bbl	190,000	bbl	$341,195,459
Variable O&M	5.09	$/bbl	190,000	bbl	$317,516,554
Nuclear Costs					
O&M	4.88	$/MWt-hr	2,400	MWt	$92,427,123
Decommissioning Fund Payment					$20,130,091
Annual Manufacturing Costs					**$771,269,226**
					Cost Per Core
Refueling Cost					**$51,712,273**

4.4 Estimation of Royalties and Depletion

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 bitumen is priced at $110 or higher (Alberta 2009). Table 10 lists the royalties applied based on the selling price of bitumen. 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 10. Post payout royalty data.

Bitumen 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 bitumen production. For all cases the IRR was calculated for the SAGD processes at low, average, and high bitumen prices, as well as for multiple owner operator scenarios for the nuclear-integrated case. In addition, the bitumen price necessary for a return of 12% was calculated for all cases, as well as the heat and electricity prices for a 12% rate of return for the separate owner operator nuclear configuration. Table 11 lists the economic assumptions used for the analyses.

Table 11. Economic assumptions.

	Assumption
Year Construction Begins	2012
Construction Information	
Preconstruction Period	6 months
Nuclear Construction Period – per Reactor	36 months
Reactor Startup Staggering	6 months
Fossil Construction Period – per Train	36 months
Train Startup Staggering	6 months
Percent Capital Invested Each Year	S-Curve Distribution
Plant Startup Information	
Startup Time	12 months
Operating Costs Multiplier	1.2
Revenue Multiplier	0.65
Economic Analysis Period	30 years
Availability	90%
Inflation Rate	3%
Debt to Equity Ratio	50%/50%
Loan Information	
Interest Rate on Debt	8%
Interest on Debt During Construction	8%
Loan Repayment Term	15 years
Tax Information	
Effective Tax Rate	27.1%
Provincial Tax Rate	10%
Federal Tax Rate	19%
MACRS Depreciation Term	15 year life
IRR	12%

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

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

Depreciation for the economic calculations was calculated using a standard Modified Accelerated Cost Recovery System (MACRS) depreciation method with a property class of 15 years. Depreciation was assumed for the TCI for each reactor module and fossil process train with the first charge occurring the year the corresponding HTGR/process train comes online, i.e. when initial revenues are received. Table 12 presents the recovery rates for a 15-year property class (Perry 2008).

Table 12. MACRS depreciation.

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

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

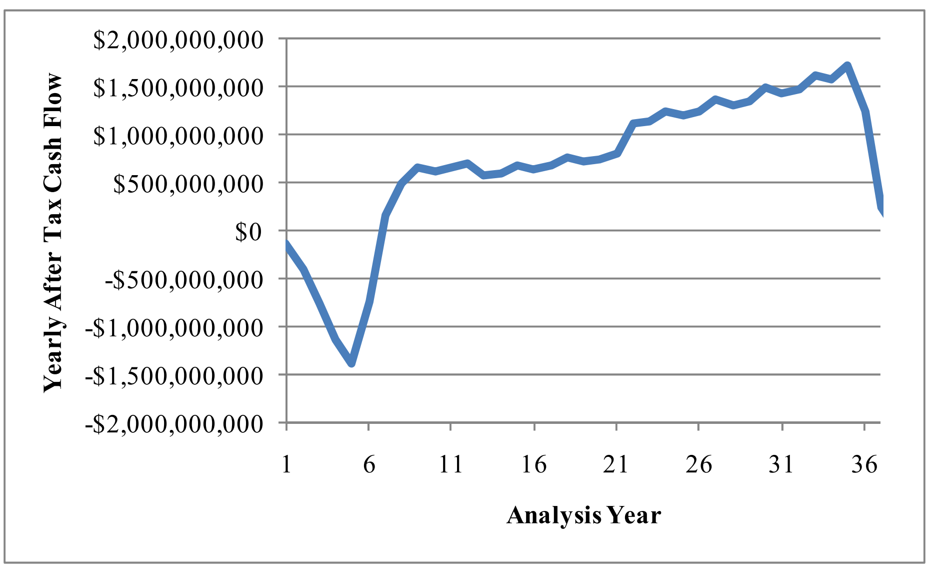

Figure 5. ATCFs, HTGR-integrated SAGD process, 12% IRR.

The BTCF is defined as follows (Sullivan 2003):

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

The ATCF can then be defined as:

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

4.5.1.1 Capital Cash Flows during Construction

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

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

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

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

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

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

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

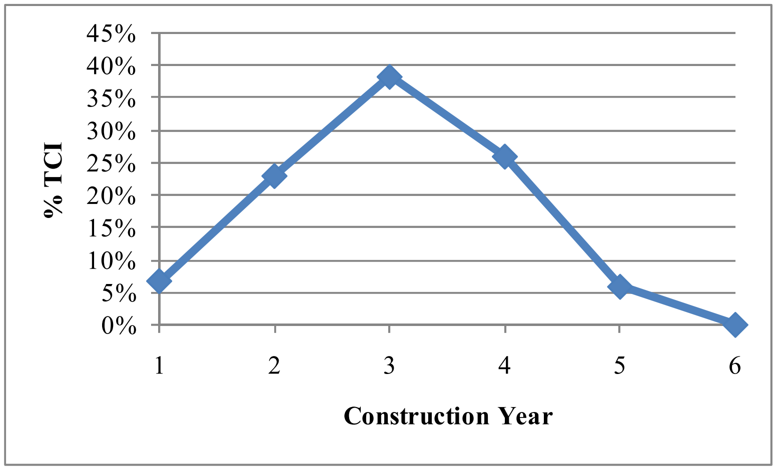

Figure 6. Percentage of TCI spent each year of construction, HTGR-integrated SAGD process.

4.5.1.2 Reactor Refueling Cash Flows

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

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 (after tax cash flow), i.e., the interest rate at which the PW is zero. The resulting interest is the IRR (i'). For the project to be economically viable, the calculated IRR must be greater than the desired minimum annual rate of return (MARR), which was assumed to be 12% (Sullivan 2003).

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

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

Finally, a CO_2 tax was included into the calculations to determine the price of bitumen necessary in all cases for a 12% IRR and a CO_2 tax of

$0/ton to $200/ton. The tax calculated was added to the existing yearly tax liability.

5. ECONOMIC MODELING RESULTS

Table 13 presents the results for the conventional SAGD case, presenting the IRR for selling bitumen at low, average, and high product prices, and the bitumen selling price required for a 12% IRR for low, average, and high natural gas purchase prices. The nuclear-integrated SAGD results are presented in Table 14, for both the single and independent owner/operator scenarios.

Table 13. Conventional SAGD economic results.

	TCI	
	% IRR	Product Price
Conventional SAGD Process	*$4,800,108,074*	
	24.2	$41.38/bbl
	45.5	$78.22/bbl
Low Natural Gas Price ($4.50/MSCF)	57.4	$115.06/bbl
	12.0	$28.16/bbl
Conventional SAGD Process	*$4,800,108,074*	
	23.3	$41.38/bbl
	44.9	$78.22/bbl
Average Natural Gas Price ($5.50/MSCF)	56.9	$115.06/bbl
	12.0	$29.24/bbl
Conventional SAGD Process	*$4,800,108,074*	
	17.0	$41.38/bbl
	40.7	$78.22/bbl
High Natural Gas Price ($12.00/MSCF)	53.8	$115.06/bbl
	12.0	$36.24/bbl

Table 14. Nuclear-integrated SAGD economic results.

	TCI	
	% IRR	Product Price
HTGR SAGD Process **Single Owner/Operator**	*$11,324,191,117*	
	11.9	$41.38/bbl
	24.4	$78.22/bbl
	31.6	$115.06/bbl
	12.0	$41.61/bbl
HTGR SAGD Process **Independent Owner/Operator** **Heat/Power at Market Price**	*$6,524,083,043*	
	2.6	$67.90/MWe-hr
	2.6	$29.20/MWt-hr
	$4,800,108,074	
	21.5	$41.38/bbl
	43.7	$78.22/bbl
	56.1	$115.06/bbl
	12.0	$31.24/bbl
HTGR SAGD Process **Independent Owner/Operator** **Heat/Power at 12% IRR**	*$6,524,083,043*	
	12.0	$124.44/MWe-hr
	12.0	$53.51/MWt-hr
	$4,800,108,074	
	14.7	$41.38/bbl
	39.2	$78.22/bbl
	52.7	$115.06/bbl
	12.0	$38.72/bbl

From the nuclear-integrated results, selling heat and power at the market price provides for the largest return on investment for the SAGD process. However, the HTGR only has a 3% IRR selling heat and power at the market price to the fossil process; therefore, this case will not be included in the results comparison. Considering the two remaining cases, it is economically beneficial to have an independent owner operator for the SAGD and HTGR facilities; due to cost savings associated with decreased royalty payments for the bitumen product. As a result, the independent owner operator scenario will be presented for the breakeven analyses. Figure 7 presents a graphical comparison of the bitumen selling price versus the natural gas purchase price for the convention and nuclear-integrated cases, the nuclear-integrated case presented is for the independent owner/operator scenario.

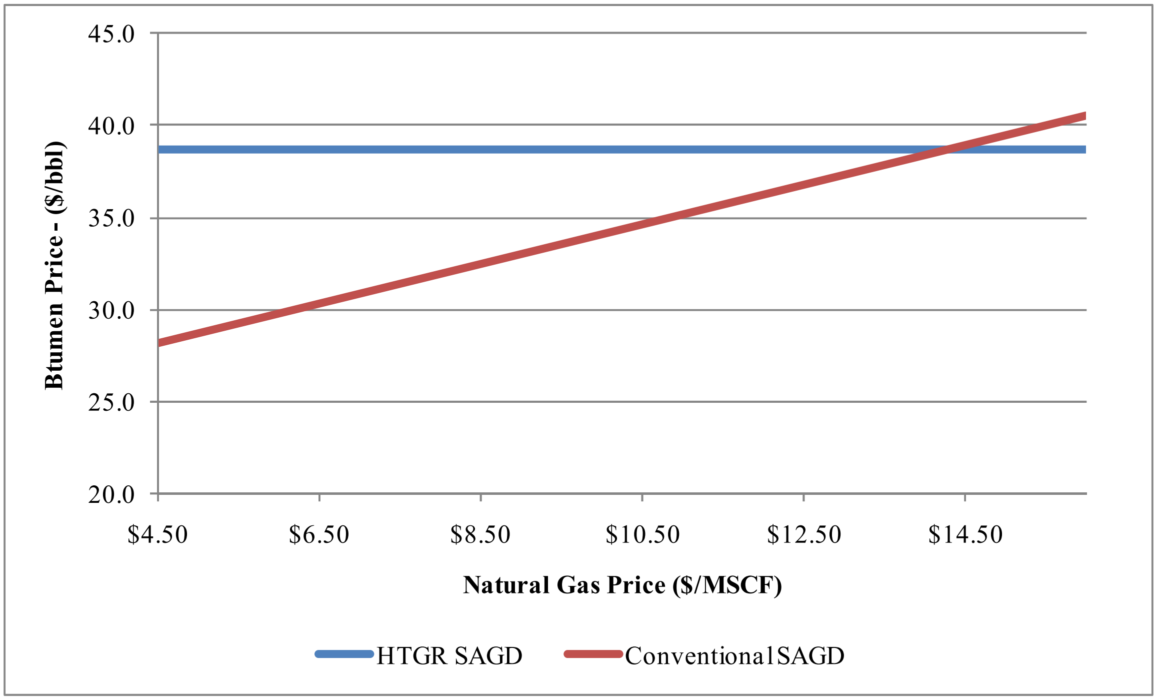

Figure 7. Conventional and nuclear-integrated SAGD, bitumen selling price as a function of natural gas purchase price.

From these results, it can be concluded that the nuclear-integrated SAGD case provides economic stability with respect to fluctuations in natural gas prices. Only at higher natural gas prices does the nuclear-integrated SAGD process economically outperform the conventional process. The natural gas price for the SAGD process must be at or above $14.00/MSCF in order for the nuclear-integrated case to economically outperform the conventional case.

Table 15 presents the carbon tax results for the conventional and nuclear-integrated SAGD cases, excluding the separate owner/operator scenario where heat and electricity are sold at the market price. Figure 8 depicts the carbon tax results for the conventional and nuclear-integrated SAGD cases for the independent owner/operator scenario and a 12% IRR.

Table 15. Conventional and nuclear SAGD carbon tax results at 12% IRR.

	Carbon Tax $/ton	Bitumen Price ($/bbl)
Conventional SAGD	0	28.16
	50	31.80
	100	35.52
Low Natural Gas	150	39.27
	200	43.03
Conventional SAGD	0	29.24
	50	32.87
	100	36.59
Average Natural Gas	150	40.34
	200	44.09
Conventional SAGD	0	36.24
	50	39.85
	100	43.53
High Natural Gas	150	47.26
	200	51.01
HTGR SAGD	0	41.61
	50	41.61
	100	41.61
Single Owner/Operator	150	41.61
	200	41.61
HTGR SAGD	0	38.72
	50	38.72
	100	38.72
Independent Owner/Operator	150	38.72
	200	38.72

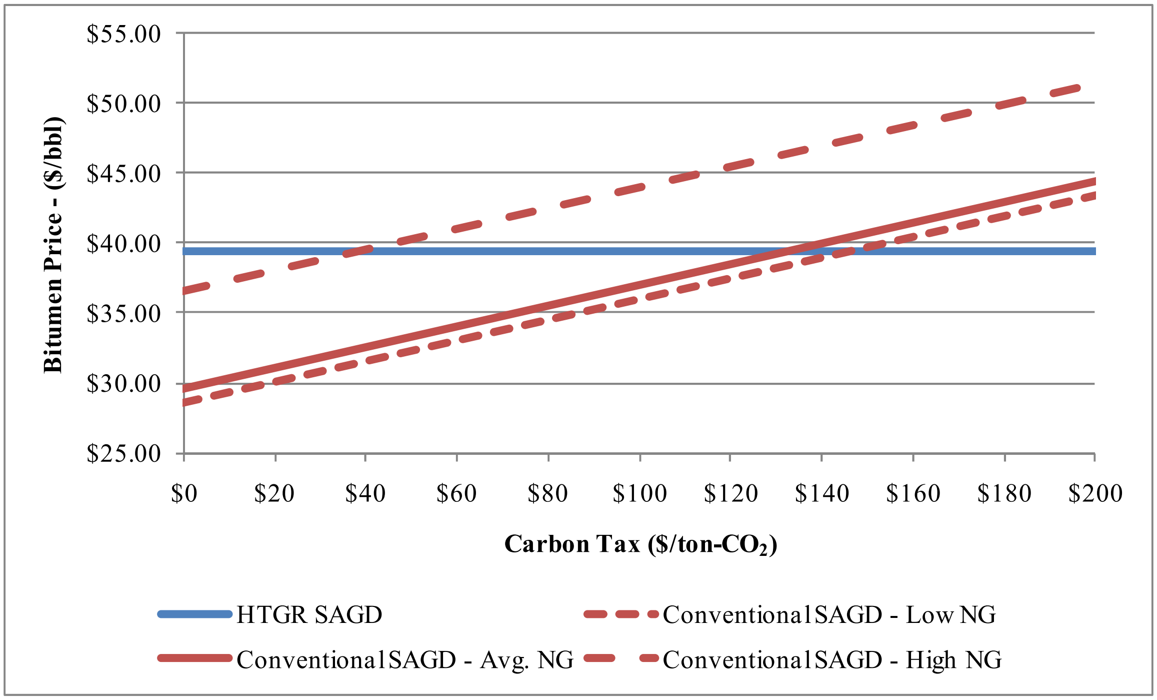

Figure 8. Conventional and nuclear-integrated SAGD as a function of a carbon tax, 12% IRR, independent owner/operator for the nuclear-integrated process.

The carbon tax results show that the nuclear-integrated SAGD case outperforms the conventional case at a 12% IRR when the carbon tax is approximately \$130/ton-CO_2 for the average natural gas price and \$35/ton-CO_2 for the high natural gas price.

6. SENSITIVITY ANALYSIS

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

For the economic assumptions sensitivity analysis, the baseline economic assumptions were varied to determine the effect on the product selling price for the HTGR-integrated case only. Table 16 lists the values used in the economic sensitivity analysis.

Table 16. Lower, baseline, and upper values used in the economic sensitivity analysis.

	Lower Value	Baseline Value	Upper Value
IRR (%)	10	12	15
Debt Ratio (%)	80	50	0
Debt Interest Rate (%)[5]	4.5	8	10
Loan Term (years)	20	15	10
Construction Period per HTGR (months)	24	36	60
HTGR Staffing Level		Design Supplier	INL Staffing[6]
Economic Recovery Period (years)	40	30	20
HTGR TCI	-30%	TCI	+50%
HTGR Refueling Period (months)	24	18	12
Alberta Construction Adder	1	1.658	

Again, the sensitivity analysis was only conducted for the independent owner operator scenario. Table 17 summarizes the results of the sensitivity analysis listing the required product selling prices for the nuclear-integrated SAGD case as well as the percent change in the product selling price versus the baseline case. The tornado plot is presented in Figure 9.

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

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

Table 17. Results from the economic sensitivity analysis, nuclear-integrated SAGD, independent owner/operator scenario.

	Nuclear-Integrated SAGD	
	$/bbl	% Change
Baseline Product Price	**38.72**	
IRR		
10%	35.04	-10
15%	44.80	16
Debt Ratio		
80%	36.37	-6
0%	43.37	12
Debt Interest Rate		
4.5%	36.38	-6
10%	40.28	4
Loan Term		
20 years	37.95	-2
10 years	39.75	3
Construction Period		
24 months per HTGR	38.20	-1
60 months per HTGR	39.79	3
Staffing Level		
INL Staffing	39.33	2
Economic Recovery Period		
40 years	37.51	-3
20 years	42.12	9
HTGR TCI		
-30% TCI	35.04	-10
+50% TCI	44.86	16
Refueling Period		
24 months	38.10	-2
12 months	39.97	3
Alberta Construction Adder		
Adder = 1	33.85	-13

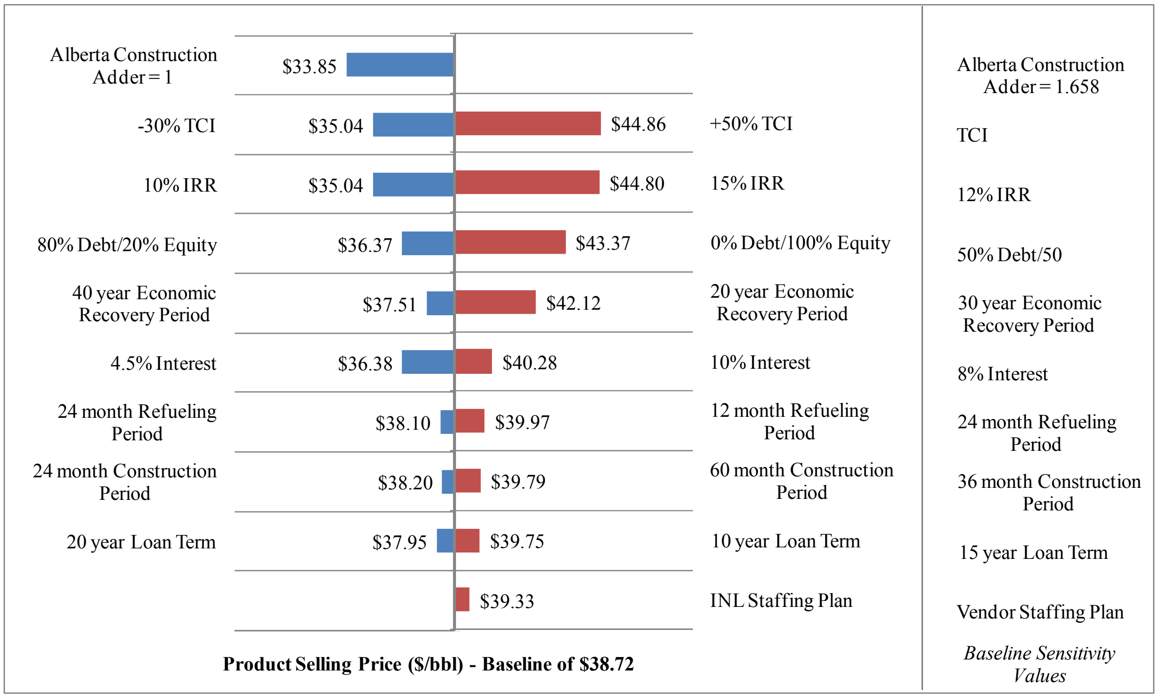

Figure 9. HTGR SAGD sensitivity analysis.

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

7. SAGD CONCLUSIONS

Results from the nuclear-integrated SAGD case indicate that integration of nuclear heat and power can reduce both natural gas consumption and associated CO_2 emissions:

- Four 600 MWt HTGRs are required to support production of steam and power for a 190,000 barrel per day SAGD facility.
- Nuclear-integration decreases natural gas consumption by up to 100% using HTGR generated steam as the heat source, eliminating 192.5 MMSCFD of natural gas usage.
- Nuclear-integration also eliminates almost 12,000 tons per day of CO_2 production from the SAGD process, as natural gas combustion is eliminated.

Economically, the incorporation of four HTGRs impacts the expected return on investment, when compared to the conventional SAGD process:

- The nuclear-integrated SAGD case provides economic stability with respect to fluctuations in natural gas prices. Only at higher natural gas prices does the nuclear-integrated SAGD process economically outperform the conventional process. The natural gas price for the SAGD process must be at or above \$14.00/MSCF in order for the nuclear-integrated case to economically outperform the conventional case for a 12% IRR.

- The nuclear-integrated SAGD case outperforms the conventional case at a 12% IRR when the carbon tax is approximately \$130/ton-CO_2 for the average natural gas price (\$5.50/MSCF) and \$35/ton-CO_2 for the high natural gas price (\$12.00/MSCF).

- From the economic sensitivity analysis, it was determined that the construction adder for the Alberta region can have the largest the largest impact on the required bitumen selling price, followed by the total capital investment, the assumed IRR, and the debt to equity ratio.

8. FUTURE WORK AND RECOMMENDATIONS

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

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

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

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10. APPENDIXES

Appendix A, PTAC Central Energy Facility Supply Concept

Appendix B, Detailed Modeling Results and Flowsheets

Appendix C, [Electronic] SAGD Baseline Stream Results.xlsx

Appendix D, [Electronic] SAGD HTGR Stream Results.xlsx

Appendix E, [Electronic] CESF Baseline Stream Results.xlsx

Appendix F, [Electronic] CESF HTGR Stream Results.xlsx

Appendix A
PTAC Central Energy Facility Supply Concept

A-1. INTRODUCTION

The INL performed an assessment to evaluate HTGR deployment for a central energy supply facility (CESF), providing heat and power to both SAGD and bitumen upgrading processes. This assessment was performed in support of interactions with the Petroleum Technology Alliance Canada (PTAC). The PTAC assessment included both technical and economic evaluations for the production of heat and power for a combined SAGD and bitumen upgrading production process. In this study, the economic assessment provides the supplied cost of heat and power to the oil sands producer (OSP) for a specific production of synthetic crude oil (SCO). Figure A-1 depicts the HTGR central energy supply facility.

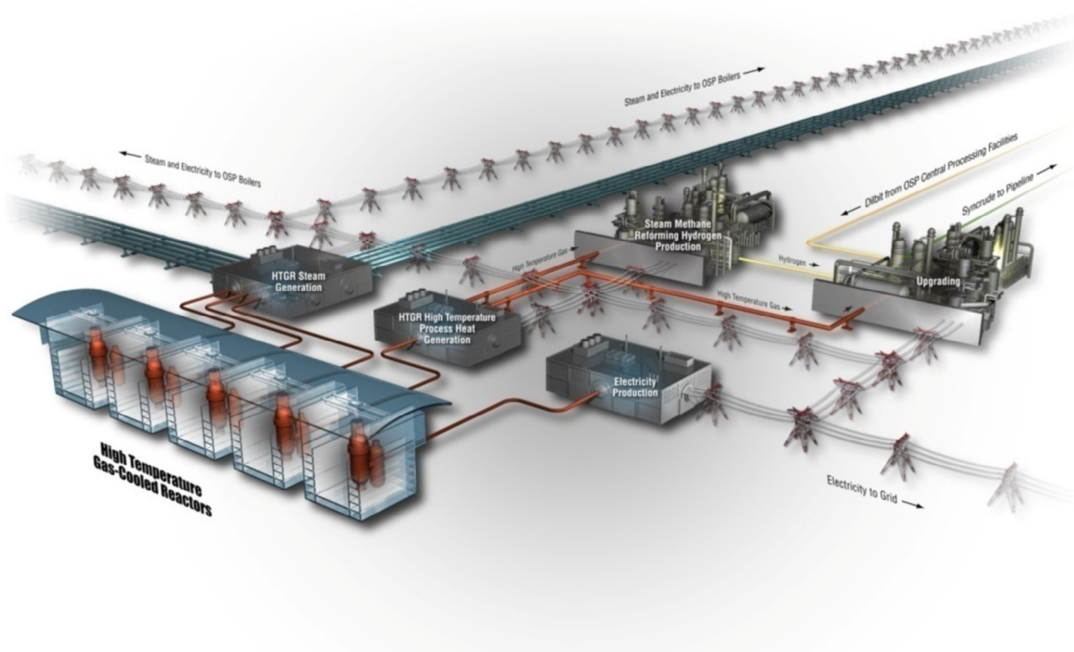


Figure A-1. HTGR central energy supply facility.

A-2. CENTRAL ENERGY SUPPLY CONCEPT SIZING

The HTGR central energy supply facility was sized as follows. First, a maximum upper HTGR reactor outlet temperature (ROT) of 850°C was assumed. This ROT represents the highest ROT attainable without extensive materials development for the HTGR. The bitumen upgrading process requires higher temperature heat for steam reforming, provided as hot helium, than the SAGD process, which only requires superheated steam to produce high pressure and low pressure steam. The plant was sized such that a single 565 MWt, 850°C ROT HTGR supplies heat to the bitumen upgrading process; the bitumen upgrading process is described in detail in TEV-1147 (INL 2011c). This limitation on heat supply to the upgrading process dictates how much bitumen is required for production of SCO. The bitumen feedstock flowrate is an input to the SAGD process model and determines the amount of HTGR heat required for steam production. Four 600 MWt 770°C ROT HTGRs were assumed for producing steam for the SAGD process as well as power production for both the SAGD and bitumen upgrading processes.. Any excess power would be exported to the grid. In addition to the nuclear-integrated process, a conventional process was also sized for equal bitumen and SCO production.

A-2.1 Bitumen Upgrading

The material and energy balance results in TEV-1147 were used to determine the heat, power, and hydrogen requirements for the nuclear-integrated bitumen upgrading process (INL 2011c). However, the nuclear-integrated upgrading case presented in the TEV specified an HTGR ROT of 875°C for hydrogen production. Consequently, results from TEV-961, which documents nuclear-integrated hydrogen production via steam methane reforming (SMR), were interpolated to determine the heat and power requirements for hydrogen production for an HTGR ROT of 850°C (INL 2010b). These results were combined with the heat, power, and hydrogen requirements for bitumen upgrading as specified in TEV-1147. Table A-1 presents the 875°C and 825°C material and energy balance summaries from TEV-961, along with the interpolated results for an HTGR ROT of 850°C.

Table A-1. Nuclear-integrated SMR material and energy balance results summary.

	TEV-961 875°C ROT	**TEV-961 825°C ROT**	**Interpolated 850°C ROT**
Inputs			
Natural Gas Feed Rate (MMSCFD[7])	34.5	37.7	36.1
Outputs			
Hydrogen (MMSCFD[7])	130	130	130
Steam for Export (MWt)	15.8	28.4	22.1
Utility Usage			
Power Requirements (MWe)	15.3	14.6	15.0
Nuclear Heat Requirements (MWt)	167	149	158
Total CO_2 Emitted (ton/day)	2,096	2,291	2,193
Capturable	1,970	2,024	1,997
Emitted	126	267	196

Hydrogen, heat, and power requirements for the bitumen upgrading process were taken from TEV-1147. The requirements are summarized in the following table for the conventional and nuclear-integrated bitumen upgrading cases.

7 Standard temperature of 60°F.

Table A-2. Bitumen upgrading material and energy balance results summary from TEV-1147.

	Conventional	Nuclear-Integrated[8]
Inputs		
Bitumen (bbl/day)	56,000	56,000
Natural Gas Feed Rate (MMSCFD[7])	47.3	N/A
SMR Hydrogen (MMSCFD[7])	N/A	97.3
Outputs		
Synthetic Crude Oil (bbl/day)	54,610	54,610
Butane (MMSCFD[7])	1.03	1.03
Coke (ton/day)	791	791
Sulfur (ton/day)	494	494
Utility Usage		
Power Requirements (MWe)	23.3	18.6
External Heat Requirements (MWt)	N/A	143.1
Total CO_2 Emitted (ton/day)	3,329	589

The heat requirements for the SMR and upgrading processes were summed and the steam available for export from the SMR process was deducted to determine the total heat requirements for the nuclear-integrated upgrading process, for an HTGR ROT of 850°C. The synthetic crude production was then adjusted, such that the total heat requirement for the upgrading process matches the available heat supply from a 565 MWt, 850°C ROT HTGR, 646.3 MWt[9], per the following equations:

$$\begin{aligned} Total\ \ Heat\ &= 143.1MWt + 97.3\ MMSCFD \times \frac{158MWt - 22.1MWt}{130MMSCFD} \\ &= 244.8MWt \end{aligned}$$

$$Syncrude = \frac{646.3MWt}{244.8MWt} \times 54{,}610bpd = 144{,}247bpd^{10}$$

The integrated SMR and bitumen upgrading process results for production of 144,247 barrels per day of SCO are presented in Table A-3. Results are presented graphically in Figure A-2.

8 The nuclear-integrated case presented does not include hydrogen manufacturing, as it was necessary to calculate the heat and power requirements for the nuclear-integrated SMR process for an 850°C ROT separately.

9 The total amount of heat available for heat transfer is greater than 565 MWt due to heat generated in the primary and secondary helium circulators, 20 MWt and 61.3 MWt, respectively.

10 Results may vary slightly due to rounding errors.

Table A-3. Bitumen upgrading material and energy balance results.

	Conventional	**Nuclear-Integrated**
Inputs		
Bitumen (bbl/day)	147,919	147,919
Natural Gas Feed Rate (MMSCFD[7])	124.9	71.4
Intermediates		
Hydrogen from SMR (MMSCFD[7])	N/A	257
Steam from SMR (MWt)	13.7	43.7
Heat Generated in Primary Circulator (MWt)	N/A	20.0
Heat Generated in Secondary Circulator (MWt)	N/A	61.3
Outputs		
Synthetic Crude Oil (bbl/day)	144,247	144,247
Butane (MMSCFD[7])	2.7	2.7
Coke (ton/day)	2,089	2,089
Sulfur (ton/day)	1,305	1,305
Power Requirements (MWe)	61.6	160.7
SMR	N/A	29.5
Upgrading	61.6	49.1
Primary Helium Circulator	N/A	20.8
Secondary Helium Circulator	N/A	61.3
External Heat Requirements (MWt)	N/A	690.0
SMR	N/A	312.3
Upgrading	N/A	377.7
Nuclear Heat Supplied (MWt)	N/A	565
Total CO_2 Emitted (ton/day)	8,793	5,890
From SMR	N/A	4,336
From Upgrading	8,793	1,555

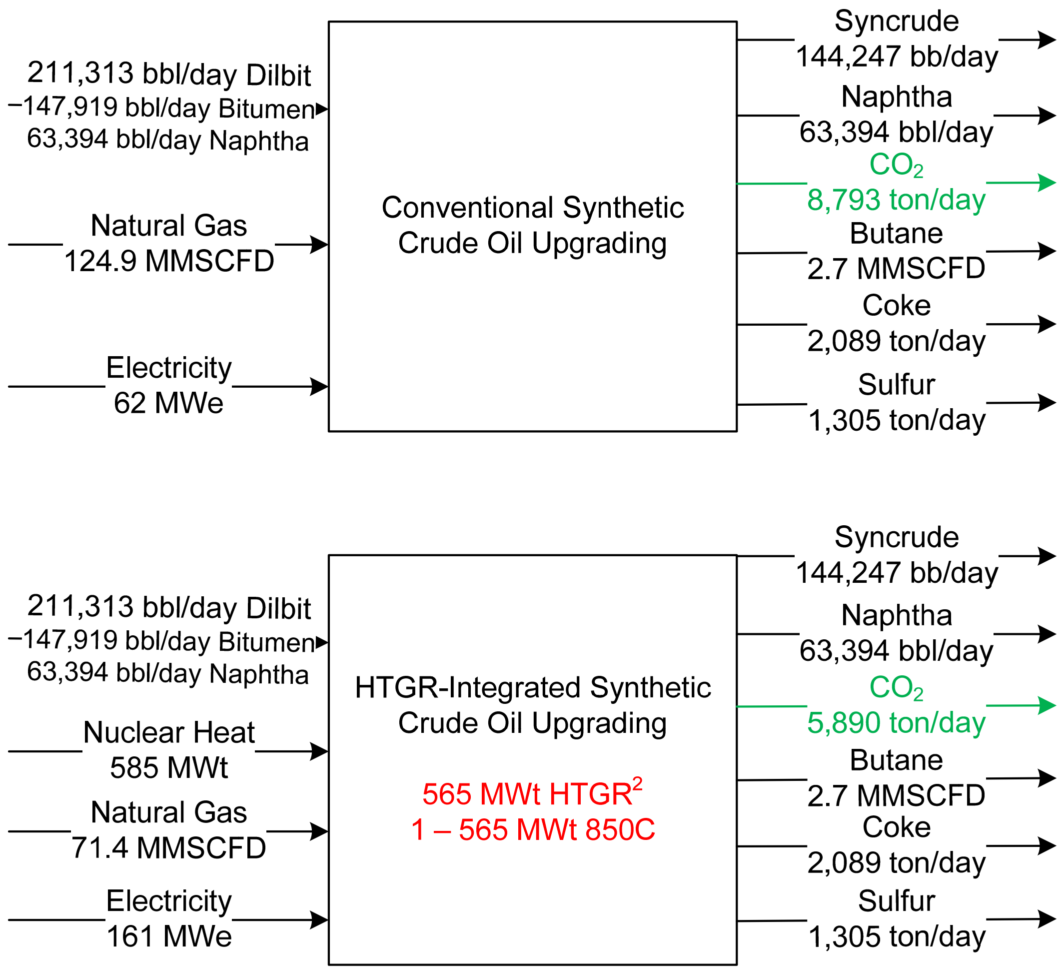


Figure A-2. Bitumen upgrading material balance summary.

A-2.2 SAGD Bitumen Production

The SAGD process modeling results presented in Section 3 of the main report were scaled to match the 147,919 barrel per day bitumen requirement identified in the above section for the bitumen upgrading process. Four 600 MWt HTGRs with an ROT of 770°C are used to generate the steam for the SAGD process and power requirements for both the SAGD and upgrading processes. A summary of the modeling results is presented in Table A-4. A high-level material and energy balance summary is graphically presented in Figure A-3.

Table A-4. SAGD results.

	Conventional SAGD	Nuclear-Integrated SAGD
Inputs		
Natural Gas Feed rate (MMSCFD)[11]	151.4	0
# HTGRs (600 MWt)	N/A	4
Naphtha as Diluent (bbl/day)	63,394	63,394
Outputs		
Dilbit Product (bbl/day)	211,313	211,313
Bitumen (bbl/day)	147,919	190,000
Naphtha (bbl/day)	63,394	81,429
Utility Summary		
Total Power (MWe)	-88.2	208.1
SAGD Process Consumption	-88.2	-84.8
HTGR Consumption	N/A	-83.7
HTGR Rankine Cycle Production	N/A	376.6
Water Requirements[12]		
Water Consumed (gpm)	688.3	688.3
CO_2 Summary		
Total CO_2 Emitted (ton/day)	9,304	0
Nuclear Integration Summary		
Nuclear Heat Supplied[13] (MWt)	N/A	2,486
HTGR Heat to SAGD Process	N/A	1,598
HTGR Heat to Power Generation	N/A	888
Nuclear Power Supplied (MWe)	N/A	84.8

[11] Standard temperature of 60°F.

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

[13] The HTGR heat supplied is greater than 2,400 MWt due to heat generated in the primary circulators.

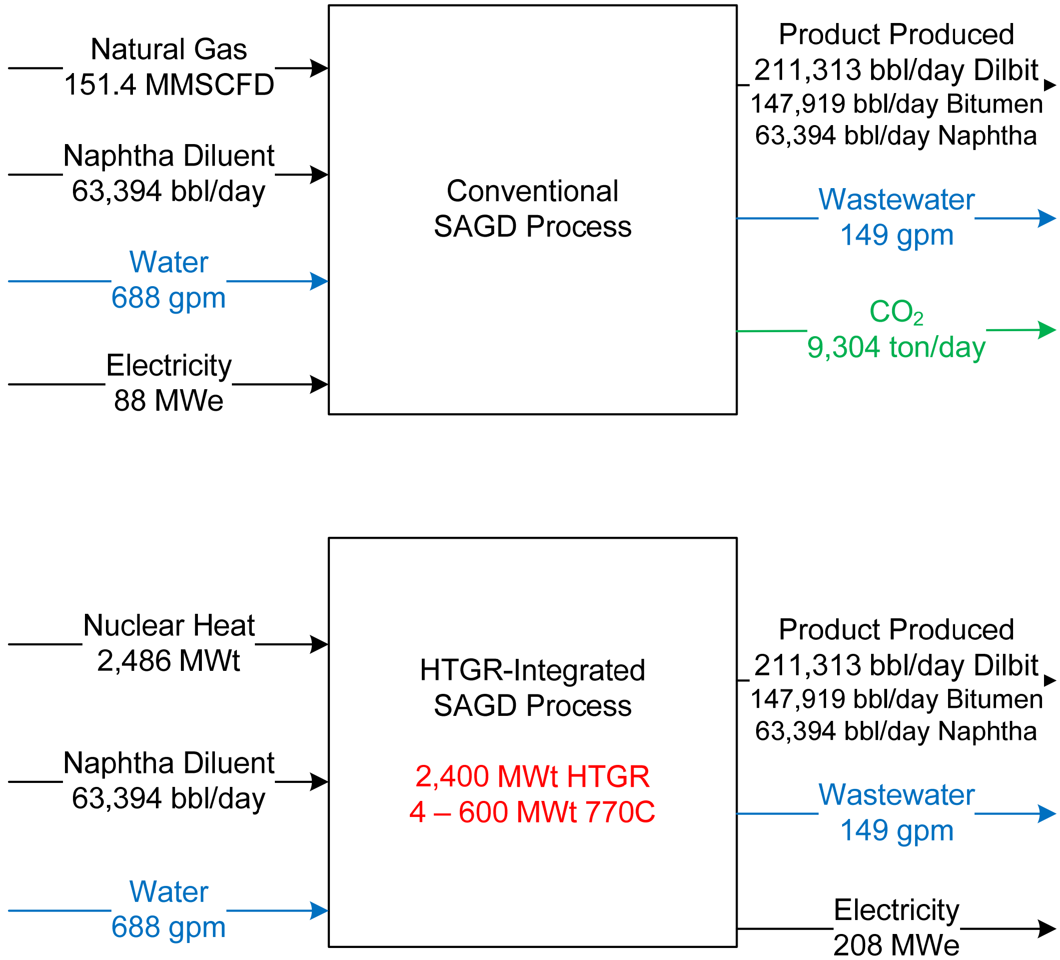


Figure A-3. SAGD material balance summary.

A-3. CENTRAL ENERGY SUPPLY MATERIAL AND ENERGY BALANCE RESULTS

The HTGR central energy supply facility supplies heat and power to the SAGD and bitumen upgrading processes. The areas of heat and power integration from the HTGR central energy supply facility with the SAGD and bitumen upgrading processes are illustrated in the block flow diagram presented in Figure A-4.

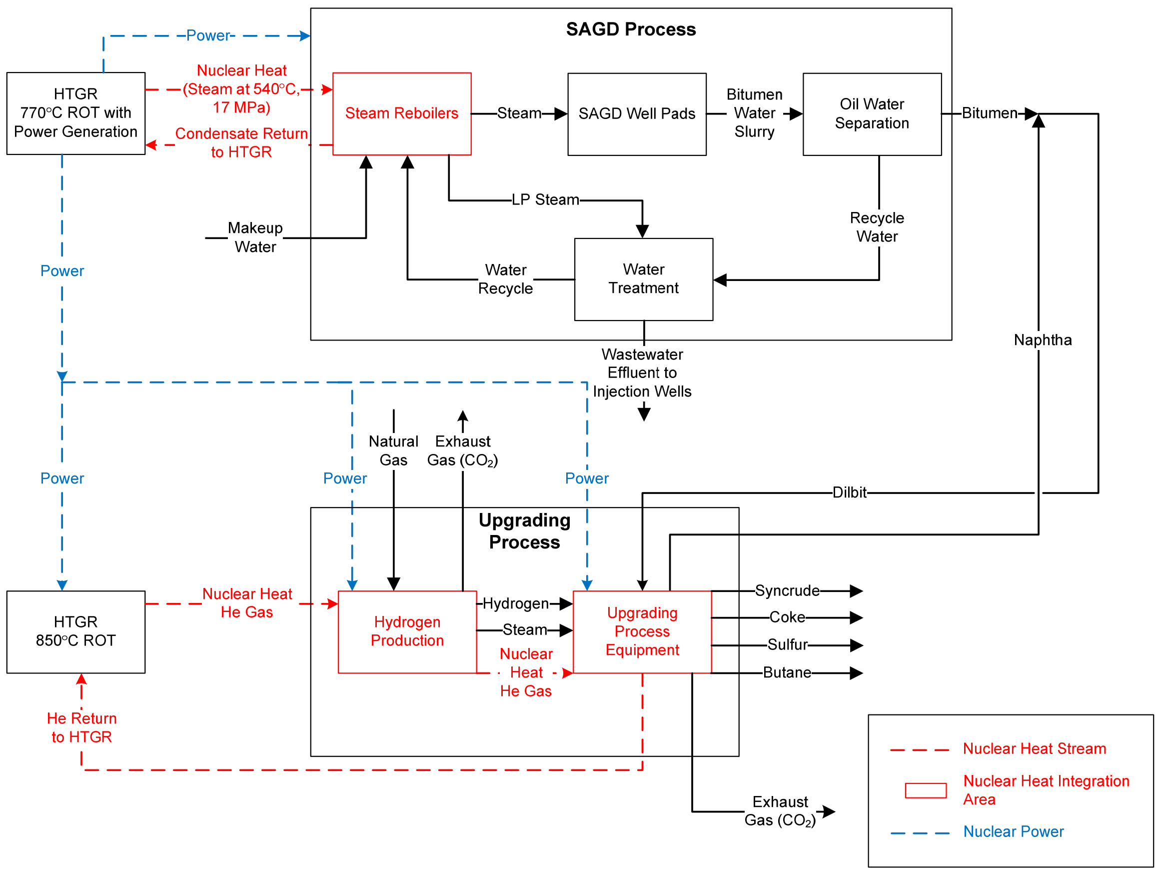


Figure A-4. HTGR central energy supply facility block flow diagram.

A summary of the modeling results for the conventional SAGD and upgrading processes and the nuclear-integrated central energy supply facility concept is presented in Table A-5. A high-level material and energy balance summary for each case is graphically presented in Figure A-5. The conventional case serves as a basis for comparison with the nuclear-integrated case. For the detailed Aspen Plus model summary results, see Appendix B. For the complete Aspen stream results for the SAGD and nuclear-integrated cases, see Appendixes E and F, respectively.

Table A-5. Central energy supply facility modeling case study results.

	Conventional	**Nuclear-Integrated**
Inputs		
Natural Gas Feed Rate (MMSCFD[14])	276.3	71.4
Intermediates		
Bitumen (bbl/day)	147,919	147,919
Outputs		
Synthetic Crude Oil (bbl/day)	144,247	144,247
Butane (MMSCFD[14])	2.7	2.7
Coke (ton/day)	2,089	2,089
Sulfur (ton/day)	1,305	1,305
Utility Summary		
Total Power (MWe)	-276.3	47.4
SAGD Process Consumption	-88.2	-84.8
Upgrading Process Consumption	-61.6	-140.0
HTGR Consumption	N/A	-104.4
HTGR Rankine Cycle Production	N/A	376.6
Water Requirements[15]		
Water Consumed (gpm)	688	688
Total CO_2 Emitted (ton/day)	18,097	5,890
SAGD	9,305	0
Upgrading	8,793	5,890
Nuclear Integration Summary		
Nuclear Heat Supplied[16] (MWt)	N/A	3,071
HTGR Heat to SAGD Process	N/A	1,598
	N/A	585
HTGR Heat to Power Generation	N/A	888
Nuclear Power Supplied (MWe)	N/A	272.2

14 Standard temperature of 60°F.

15 SAGD water requirements only, does not include water requirements for the HTGR or upgrading

16 The HTGR heat supplied is greater than 2,400 MWt due to heat generated in the primary circulators.

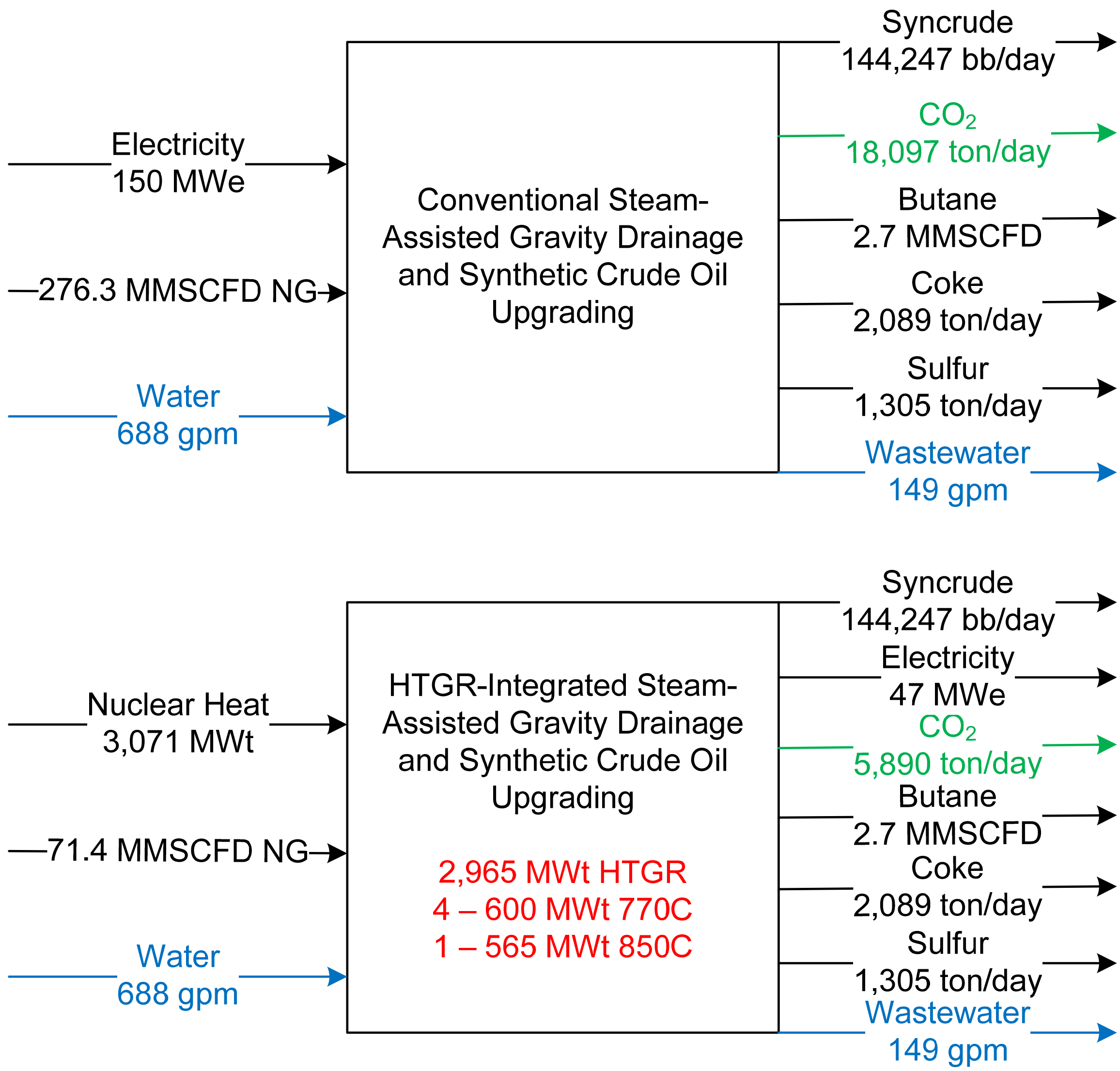


Figure A-5. Central energy supply facility material balance summary.

A-4. CENTRAL ENERGY SUPPLY ECONOMIC RESULTS

The heat and power selling prices for the central energy supply facility were calculated using the methodology described in Section 4 of the main report. Several economic indicators were calculated for each case to assess the economic desirability of heat and power production. For all cases the IRR was calculated for selling heat and power at the industrial market price. In addition, the heat and power prices necessary for a return of 10% were calculated. Table A-6 lists the economic assumptions used for the analysis. Figure A-6 provides a graphical summary of the heat and power supply for the HTGR central energy supply facility.

Table A-6. Economic assumptions.

	Assumption
Year Construction Begins	2012
Construction Information	
Preconstruction Period	6 months
Nuclear Construction Period – per Reactor	
Reactor 1	60 months
Reactor 2	48 months
Reactor 3 through n	36 months
Reactor Startup Staggering	6 months
Percent Capital Invested Each Year	S-Curve Distribution
Plant Startup Information	
Startup Time	12 months
Operating Costs Multiplier	1.2
Revenue Multiplier	0.65
Economic Analysis Period	40 years
Availability	90%
Inflation Rate	3%
Debt to Equity Ratio	80%/20%
Loan Information	
Interest Rate on Debt	8%
Interest on Debt During Construction	8%
Loan Repayment Term	20 years
Tax Information	
Effective Tax Rate	27.1%
Provincial Tax Rate	10%
Federal Tax Rate	19%
MACRS Depreciation Term	15 year life
IRR	10%

The TCI for the HTGR central energy supply facility is presented in Table A-7. Table A-8 presents the annual manufacturing costs for the HTGR central energy supply facility, with the annual revenues presented in Table A-9 and Table A-10for selling heat and power at the market price or to achieve a 10% IRR, respectively. A summary of the economic results is presented in Table A-11.

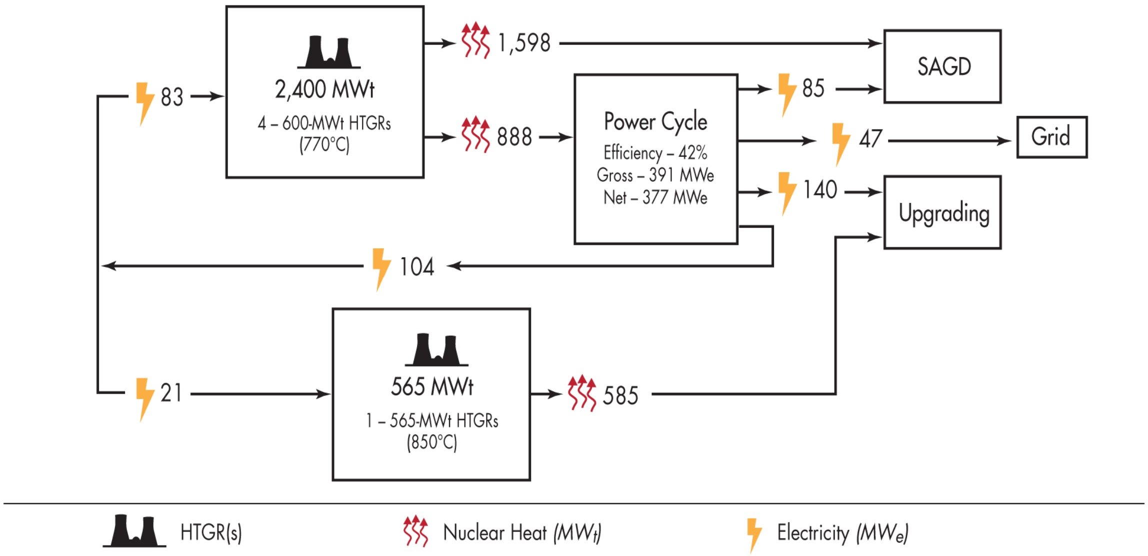


Figure A-6. HTGR heat and power supply summary.

Table A-7. HTGR central energy supply facility TCI.

	Total Capital Cost
600 MWt 770°C HTGRs	$5,818,770,244
565 MWt 850°C HTGR	$1,460,208,825
Rankine Power Cycle	$621,064,895
Total Capital Investment	**$7,900,043,965**

Table A-8. HTGR central energy supply facility manufacturing costs.

	Price		Consumed		Annual Cost
Nuclear Costs					
O&M	4.78	$/MWt-hr	2,965	MWt	$111,629,361
Decommissioning Fund Payment					$19,626,036
Annual Manufacturing Costs					**$131,255,398**
					Cost Per Core
Refueling Cost					**$51,108,963**

Table A-9. HTGR central energy supply facility revenues, heat/power at the market price.

	Price		Generated		Annual Revenue
Heat to SAGD/Upgrading	29.20	$/MWt-hr	2,183	MWt	$502,387,816
Electricity to SAGD/Upgrading	69.70	$/MWe-hr	225	MWe	$120,340,745
Electricity to Grid	59.28	$/MWe-hr	47	MWe	$22,134,173
Annual Revenue – Heat/Power at the Market Price					**$644,862,734**

Table A-10. HTGR central energy supply facility revenues, 10% IRR.

	Price		Generated		Annual Revenue
Heat to SAGD/Upgrading	43.03	$/MWt-hr	2,183	MWt	$740,409,323
Electricity to SAGD/Upgrading	100.07	$/MWe-hr	225	MWe	$177,355,833
Electricity to Grid	100.07	$/MWe-hr	47	MWe	$37,364,370
Annual Revenue – 10% IRR					**$955,129,526**

Table A-11. HTGR central energy supply facility economic results summary.

	Energy Product	% IRR	Product Price
Supplying Heat/Power at the Market Price	Power	3.2	$67.90/MWe-hr
	Heat	3.2	$29.20/MWt-hr
		3.2	$8.56/MMBTU
		3.2	$6.34/1000-lb
Supplying Heat/Power to Achieve the Specified IRR	Power	10.0	$100.07/MWe-hr
	Heat	10.0	$43.03/MWt-hr
		10.0	$12.61/MMBTU
		10.0	$9.34/1000-lb

From the results, the HTGR only has a 3.2% IRR selling heat and power at the market price to the OSP for use in the SAGD and bitumen upgrading process. In order to achieve and IRR of 10%, power must be sold at a premium compared to the current industrial market price. However, one of the main benefits of the HTGR integration is the large reduction in CO_2 emissions, which is not captured in the above results. In previous economic analyses performed for the NGNP project, it was possible to include a price on CO_2 emissions to determine the price necessary to equate the conventional and nuclear-integrated processes. However, in the central energy supply facility scenarios, the economics of the conventional cases were not assessed. As a result, rather than the conventional process paying a price for CO_2 emissions, the HTGR central energy supply facility will include an additional revenue stream for the CO_2 emission offset (12,207 tons per day of CO_2 avoided). This would be comparable to a cap and trade scenario, where the HTGR process could sell its CO_2 emission avoidance credits. Table A-12 presents the carbon credit summary results, for a CO_2 price of \$0 to \$200 per ton of CO_2 emissions avoided.

Table A-12. HTGR central energy supply facility carbon credit summary results, 10% IRR.

Carbon Credit	Electricity Price	Heat Price		
$/ton	$/MWe-hr	$/MWt-hr	$/MMBTU	$/1000-lb
0	100.07	43.03	12.61	9.34
50	79.06	34.00	9.96	7.38
100	58.06	24.96	7.32	5.42
150	37.05	15.93	4.67	3.46
200	16.04	6.90	2.02	1.50

The carbon credit results for the HTGR central energy supply facility were compared to the current industrial heat price, $6.33/MMBTU[17]. A graphical comparison of the carbon credit results is presented in Figure A-7. The results demonstrate that a carbon credit of $120 per ton of CO_2 offset would equate the HTGR heat selling price with the current industrial heat price.

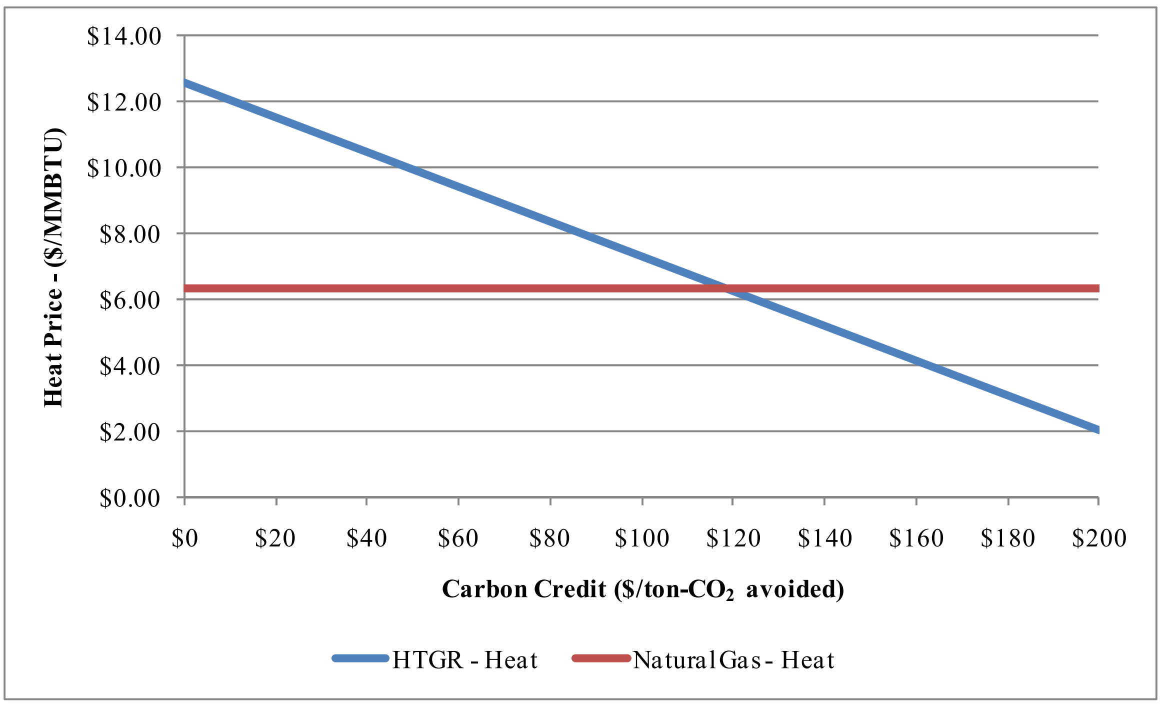


Figure A-7. HTGR central energy supply facility carbon credit results, 10% IRR.

[17] The industrial heat price was calculated assuming a natural gas price of $5.50/MSCF, a natural gas higher heating value of 1,047 MMBTU/1000 MSCF, a boiler efficiency of 83% (higher heating value) (EERE 2003). The following equation was used to calculate the associated price of heat:

$$Heat\ Cost = \frac{Fuel\ Cost}{Boiler\ Efficiency} \times \frac{1}{Heating\ Value}$$

A-5. CENTRAL ENERGY SUPPLY ECONOMIC SENSITIVITY RESULTS

A sensitivity analysis for the heat and power selling prices for the central energy supply facility was performed using the methodology described in Section 6 of the main report.

For the economic assumptions sensitivity analysis, the baseline economic assumptions were varied to determine the effect on the product selling prices. Table A-13 lists the values used in the economic sensitivity analysis.

Table A-13. Lower, baseline, and upper values used in the economic sensitivity analysis.

	Lower Value	Baseline Value	Upper Value
IRR (%)	8	10	15
Debt Ratio (%)	100	80	50
Debt Interest Rate (%)[18]	6	8	10
Loan Term (years)	25	20	10
Construction Period per HTGR (months)	24	36	60
HTGR TCI	-30%	TCI	+30%
Alberta Construction Adder	1	1.658	

Table A-14 summarizes the results of the sensitivity analysis listing the required product selling prices for the central energy supply facility as well as the percent change in the product selling price versus the baseline case. The corresponding tornado plots are presented in Figure A-8 through Figure A-10.

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

Table A-14. Results from the economic sensitivity analysis, central energy supply facility.

	Electricity Price $/MWe-hr	**Heat Price** $/MWt-hr	**Heat Price** $/MMBTU	**Heat Price** $/1000-lb	**% Change**
Baseline Product Price	**100.07**	**43.03**	**12.61**	**9.34**	
IRR					
8%	90.77	39.03	11.44	8.47	-9
15%	121.92	52.43	15.37	11.38	22
Debt Ratio					
100%	97.72	42.02	12.31	9.12	-2
50%	104.19	44.80	13.13	9.73	4
Debt Interest Rate					
6%	90.29	38.82	11.38	8.43	-10
10%	111.21	47.82	14.01	10.38	11
Loan Term					
25 years	98.23	42.24	12.38	9.17	-2
10 years	105.49	45.36	13.29	9.85	5
HTGR TCI					
-30% TCI	79.35	34.12	10.00	7.41	-21
+30% TCI	120.79	51.94	15.22	11.28	21
Alberta Construction Adder					
Adder = 1	72.66	31.24	12.61	9.34	-27

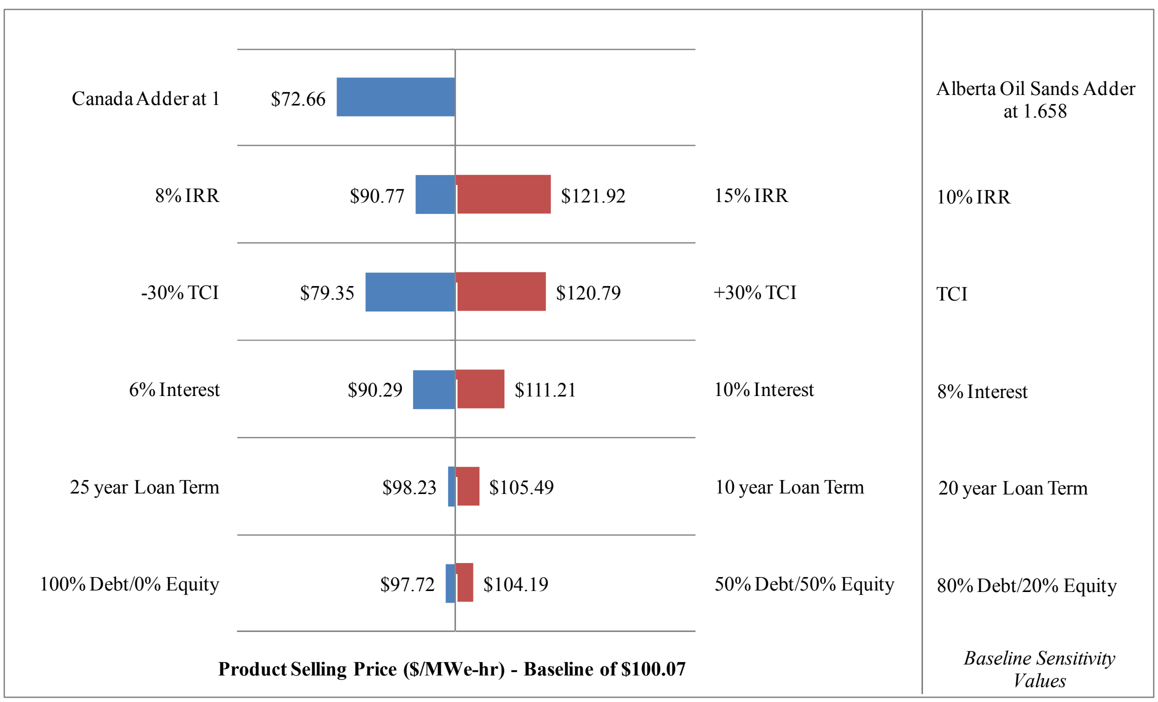


Figure A-8. Central energy supply facility sensitivity analysis, electricity price.

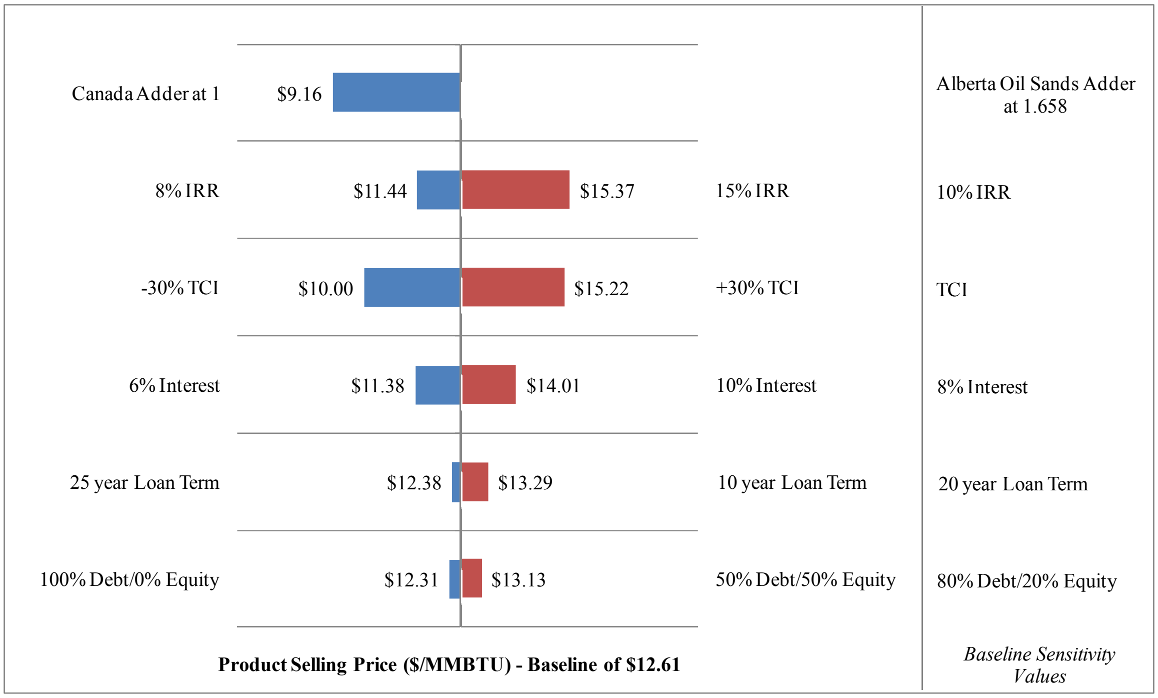


Figure A-9. Central energy supply facility sensitivity analysis, heat price.

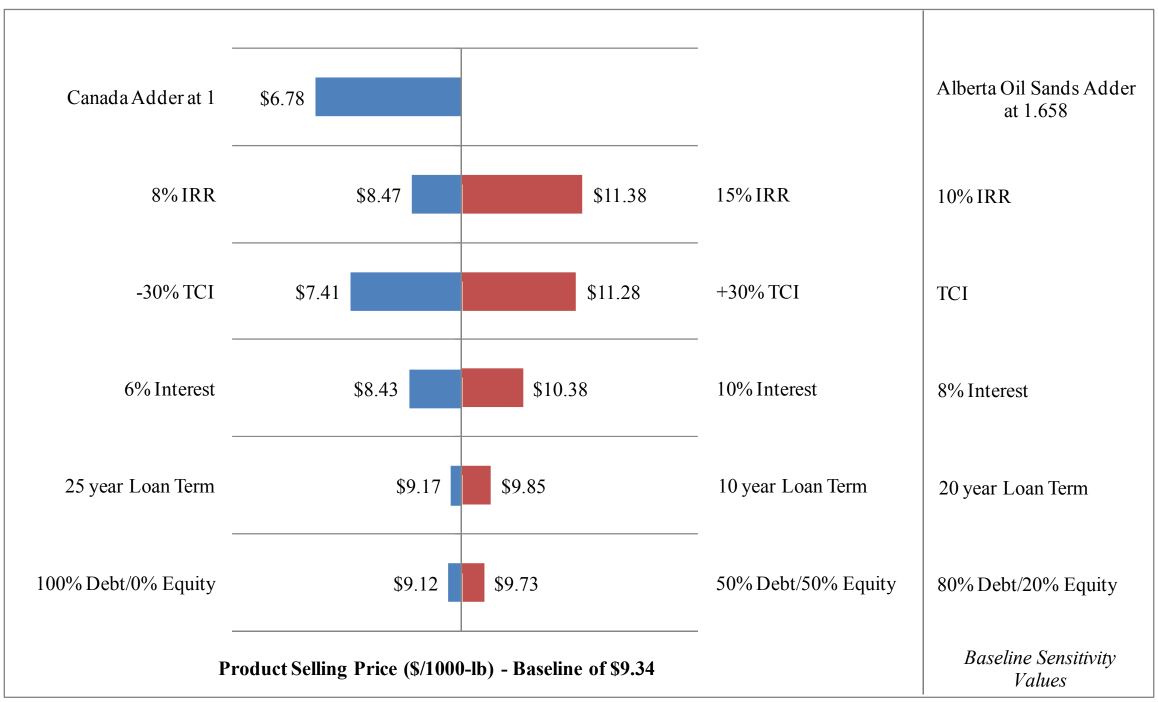


Figure A-10. Central energy supply facility sensitivity analysis, heat steam price.

From the economic sensitivity analysis, the Alberta construction adder can have the largest impact on the required product selling price, followed by assumed IRR, the uncertainty in the HTGR TCI (AACE Class 4), and the debt interest rate.

A-6. CENTRAL ENERGY SUPPLY FACILITY BITUMEN RECOVERY AREA

In order to determine the area the HTGR central energy supply facility could serve for bitumen extraction over the life of the reactors, it was necessary to determine the bitumen distribution in Alberta. The volume of bitumen and the associated area are updated annually by the Canadian Energy Resources Conservation Board (ERCB). The volume of bitumen available per square meter was calculated based on the following 2009 ERCB data, using the weighted average of the volume of bitumen available per area, presented in Table A-15. The SAGD process recovery factor is assumed to be 50% (ERCB 2009). Therefore, the calculated recoverable bitumen volume per area is7.5 barrels per square meter.

The volume per area recoverable for SAGD was used to calculate the project area served by the central energy supply facility described in the previous sections. For the recovery area a plant life for the HTGR facility was assumed to be 60 years, this is the actual anticipated operating lifetime, which is greater than the assumed economic recovery period. Based on a 60 year plant life, 147,919 barrels of bitumen extracted per day, and the 7.5 barrels of bitumen recoverable per square meter the HTGR central energy supply facility can support extraction for a project area of approximately 430 square kilometers.

Table A-15. Crude bitumen reserves and impact of central energy supply facility.

	Volume Bitumen (bbl)	**Area** (m^2)	**Volume/Area** (bbl/m^2)
Athabasca			
Grand Rapids	54,547,391,380	6,890,000,000	7.92
Wabiskaw-McMurray (mineable)	130,290,196,880	3,740,000,000	34.84
Wabiskaw-McMurray (in situ)	831,718,861,490	47,010,000,000	17.69
Nisku	64,931,384,300	4,990,000,000	13.01
Grosmont	317,428,355,000	41,670,000,000	7.62
Cold Lake			
Grand Rapids	108,767,925,840	17,090,000,000	6.36
Clearwater	59,223,959,620	4,330,000,000	13.68
Wabiskaw-McMurray	26,946,838,770	4,850,000,000	5.56
Peace River			
Bluesky-Gething	68,941,667,280	10,160,000,000	6.79
Belloy	1,772,570,220	260,000,000	6.82
Debolt	49,028,538,000	3,020,000,000	16.23
Shunda	15,777,132,100	1,430,000,000	11.03
Total	1,729,374,820,880	145,440,000,000	
Weighted Average			*15.06*
SAGD Bitumen (50% Recovery)			**7.53**

Central Energy Supply Facility Impact	
Bitumen Recovered (bbl/day)	147,919
Plant Life (years)	60
Bitumen Recovered over the Life of the Facility (million bbl)	3,239
Bitumen Recovery Area (km^2)	**430**

A-7. CENTRAL ENERGY SUPPLY FACILITY HYPOTHETICAL DEPLOYMENT

A hypothetical deployment scenario was developed for the HTGR central energy supply facility. The deployment scenario was developed to assess the progression of the HTGR heat supply to the individual OSPs and the associated heat supply to the SAGD well pads. Each well pad is assumed to extract approximately 7,500 barrels of bitumen per day. Well pads are assumed to have a life of ten years with ten paired wells per well pad (Devon 2010 and JACOS 2010). Thus, for the 147,919 barrels per day of bitumen extracted, the HTGR central energy supply facility would provide the OSPs with steam to supply 120 total wells pads and 1,200 paired wells, with 20 active well pads, serving an area of 430 square kilometers. The phased deployment is depicted in Figure A-11. The area is assumed to be served by two OSPs and a single refinery. The OSP identified in the upper half of the map serves 30% of the area identified, or 129 of the 430 square kilometers, the remaining OSP serves the remaining project area (301 square kilometers).

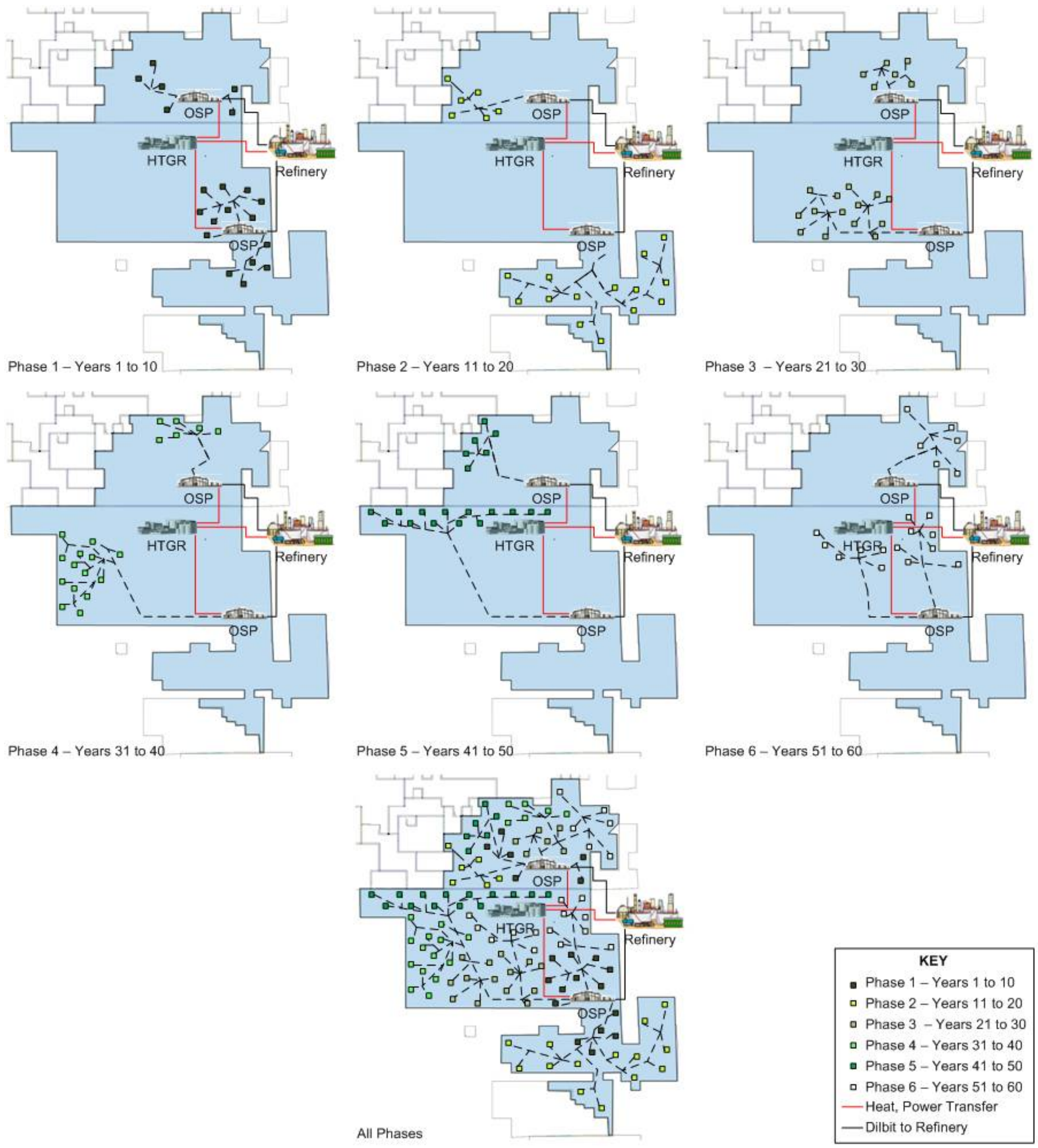


Figure A-11. Central energy supply facility, progressive energy supply to OSP facilities.

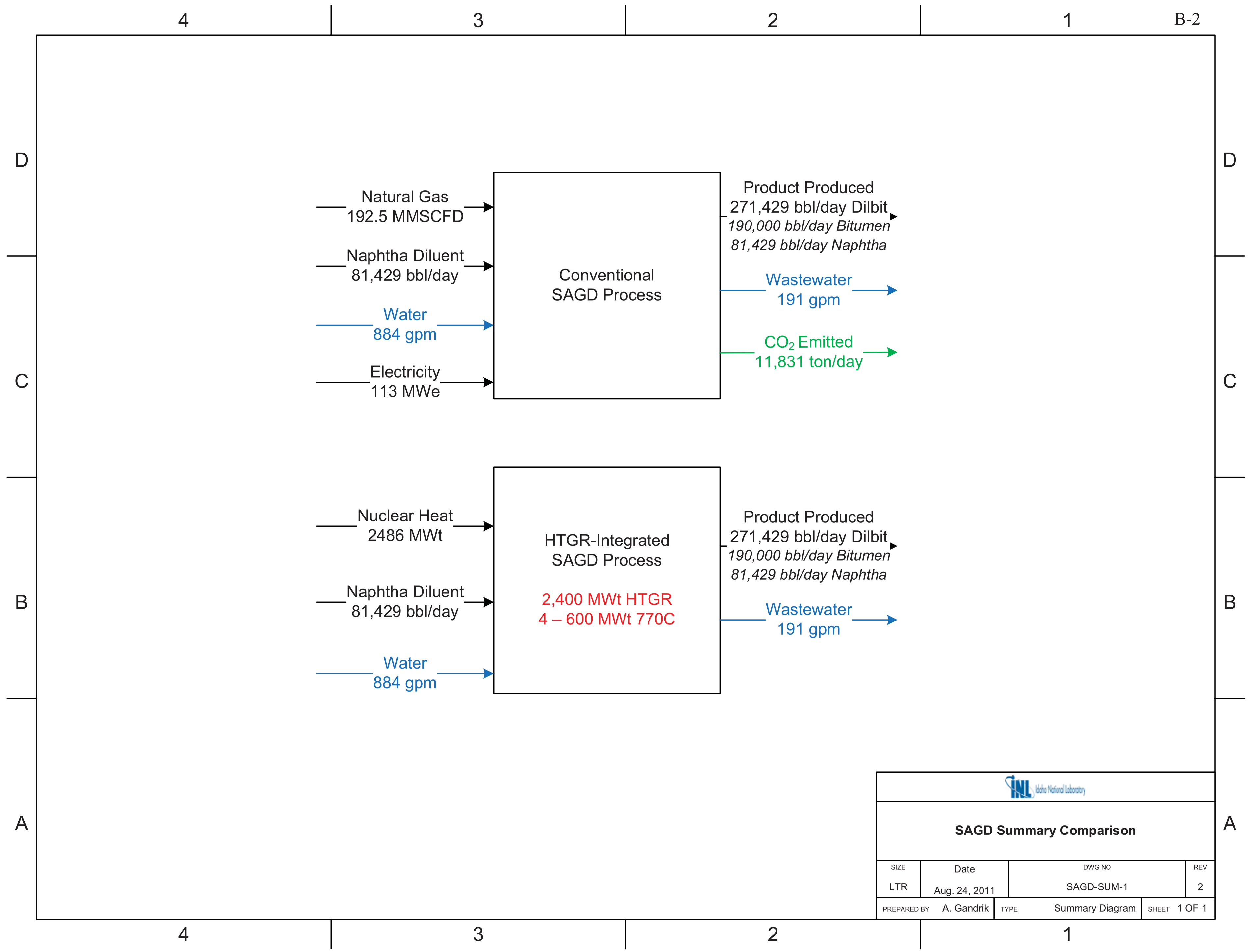
Appendix B
Detailed Modeling Results and Flowsheets

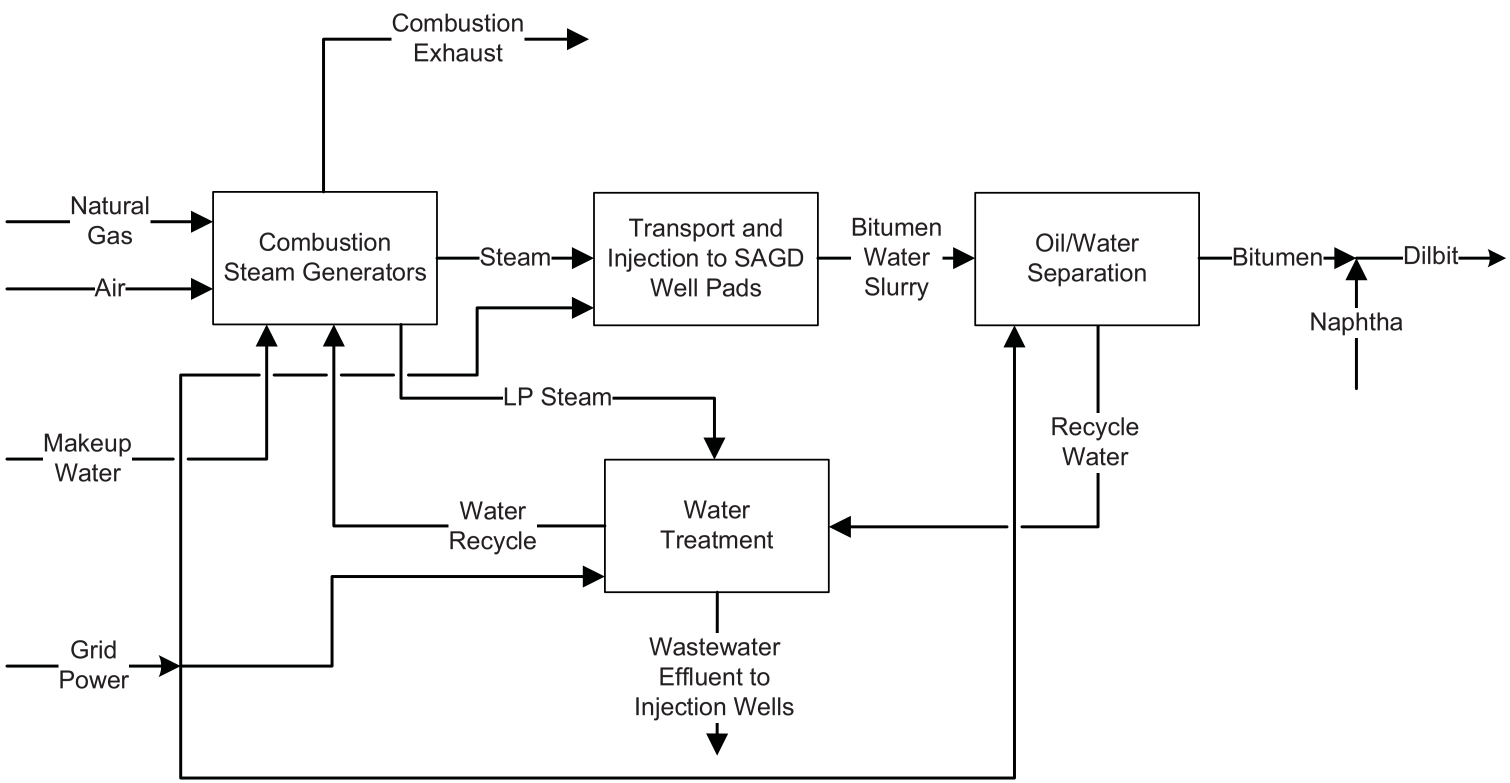
	Conventional SAGD	Nuclear Integrated SAGD
Inputs		
Natural Gas Feed rate (MMSCFD)[1]	192.5	0
# HTGRs (600 MWt)	N/A	4
Naphtha as Diluent (bbl/day)	81,429	81,429
Outputs		
Dilbit Product (bbl/day)	*271,429*	*271,429*
Bitumen (bbl/day)	190,000	190,000
Naphtha (bbl/day)	81,429	81,429
Utility Summary		
Total Power (MWe)	*-113.2*	*0*
SAGD Process Consumption	-113.2	-108.9
HTGR Consumption	N/A	-83.7
HTGR Rankine Cycle Production	N/A	192.6
Water Requirements[2]		
Water Consumed (gpm)	884	884
CO_2 Summary		
Total CO_2 Emitted (ton/day)	11,831	0
Nuclear Integration Summary		
Nuclear Heat Supplied[3] (MWt)	N/A	2,486
HTGR Heat to SAGD Process	N/A	2,032
HTGR Heat to Power Generation	N/A	454
Nuclear Power Supplied (MWe)	N/A	108.9

[1] Standard temperature of 60°F.

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

[3] The HTGR heat supplied is greater than 2,400 MWt due to heat generated in the primary circulators.


Natural Gas
192.5 MMSCFD
Naphtha Diluent
81,429 bbl/day
Water
884 gpm
Electricity
113 MWe
Conventional
SAGD Process
Product Produced
271,429 bbl/day Dilbit
190,000 bbl/day Bitumen
81,429 bbl/day Naphtha
Wastewater
191 gpm
CO_2 Emitted
11,831 ton/day
Nuclear Heat
2486 MWt
Naphtha Diluent
81,429 bbl/day
Water
884 gpm
HTGR-Integrated
SAGD Process
2,400 MWt HTGR
4 – 600 MWt 770C
Product Produced
271,429 bbl/day Dilbit
190,000 bbl/day Bitumen
81,429 bbl/day Naphtha
Wastewater
191 gpm
SAGD Summary Comparison
SIZE LTR
Date Aug. 24, 2011
DWG NO SAGD-SUM-1
REV 2
PREPARED BY A. Gandrik
TYPE Summary Diagram
SHEET 1 OF 1

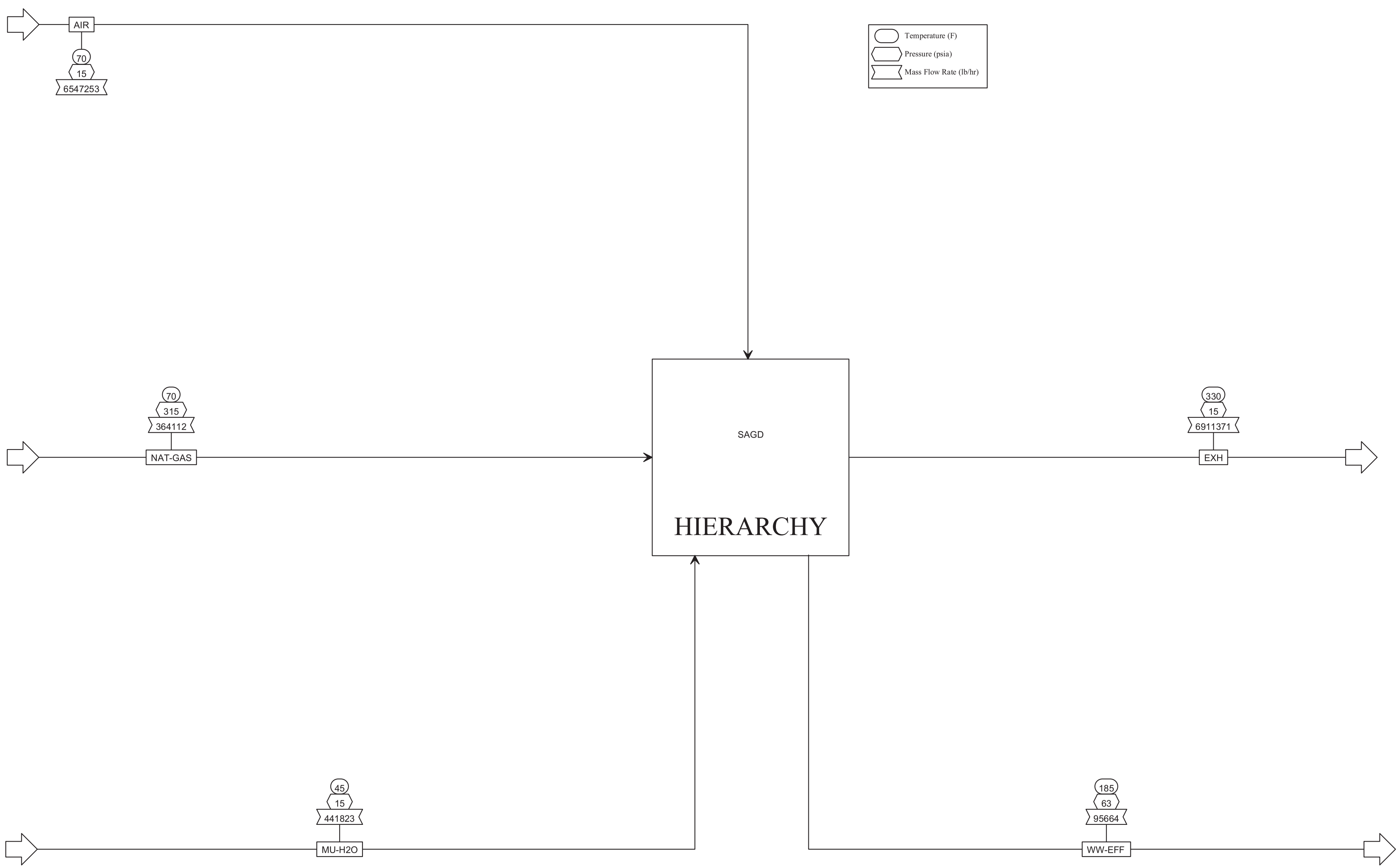


Idaho National Laboratory			
SAGD			
SIZE LTR	Date Aug. 24, 2011	DWG NO SAGD-BFD-1	REV 2
PREPARED BY A. Gandrik	TYPE Block Flow Diagram	SHEET 1 OF 1	

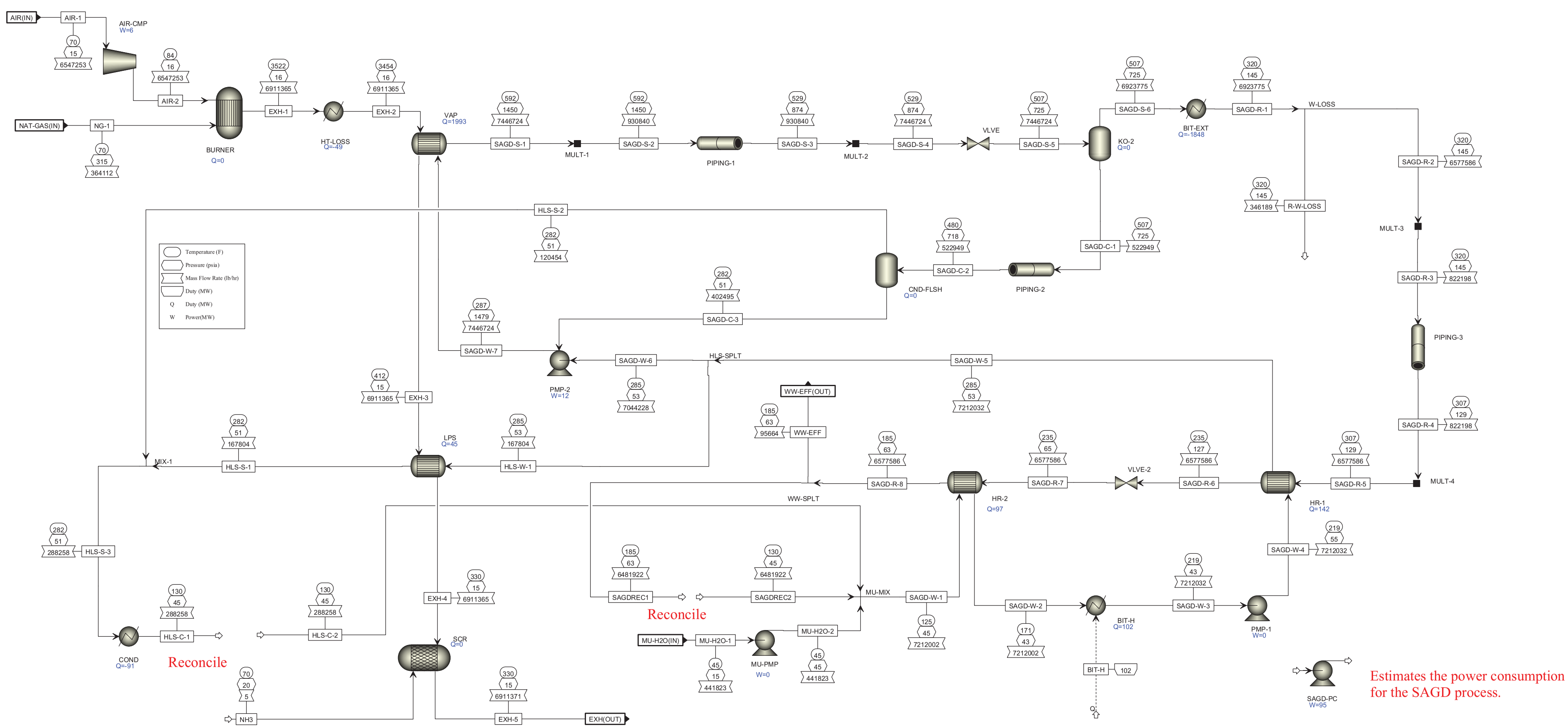
```
Calculator Block SUMMARY

   POWER CALCULATIONS:

     POWER GENERATORS:

     TOTAL POWER GENERATED =                   0.0 MW

     POWER CONSUMERS:
       SAGD POWER CONSUMPTION =              113.2 MW
     TOTAL POWER CONSUMED =                  113.2 MW

     NET PLANT POWER (+ GEN, - CONS)=       -113.2 MW


   SAGD WATER BALANCE:

     LOSSES:

       STEAM LOST TO INJECTION WELL:
         VOLUME:                           23750.0 BBL/DAY H2O EQ.
         VOLUME:                             692.7 GPM H2O EQ.
         MASS:                              4154.3 TON/DAY

       WASTEWATER EFFLUENT:
         VOLUME:                            6563.0 BBL/DAY
         VOLUME:                             191.4 GPM
         MASS:                              1148.0 TON/DAY

       TOTAL LOSSES:
         VOLUME:                           30313.0 BBL/DAY H2O EQ.
         VOLUME:                             884.1 GPM H2O EQ.
         MASS:                              5302.2 TON/DAY

     STEAM GENERATION:

       SAGD INJECTION STEAM:
         VOLUME:                          510876.5 BBL/DAY H2O EQ.
         VOLUME:                           14900.6 GPM H2O EQ.
         MASS:                             89360.7 TON/DAY
         TEMPERATURE:                        592. F
         PRESSURE:                          1450. PSI

       STEAM FOR WATER TREATMENT:
         VOLUME:                           19775.7 BBL/DAY H2O EQ.
         VOLUME:                             576.8 GPM H2O EQ.
         MASS:                             89360.7 TON/DAY
         TEMPERATURE:                        282. F
         PRESSURE:                            51. PSI

     STEAM INJECTED TO SAGD WELLS AFTER PIPING COND.:
       VOLUME:                            475000.0 BBL/DAY H2O EQ.
       VOLUME:                             13854.2 GPM H2O EQ.
       MASS:                               83085.3 TON/DAY

     TOTAL PROCESS WATER FOR STEAM GENERATION:
       VOLUME:                            494775.7 BBL/DAY
       VOLUME:                             14431.0 GPM
       MASS:                               86544.4 TON/DAY

     TOTAL MAKEUP WATER REQUIRED:
       VOLUME:                             30313.0 BBL/DAY.
       VOLUME:                               884.1 GPM.
       MASS:                                5302.2 TON/DAY
```

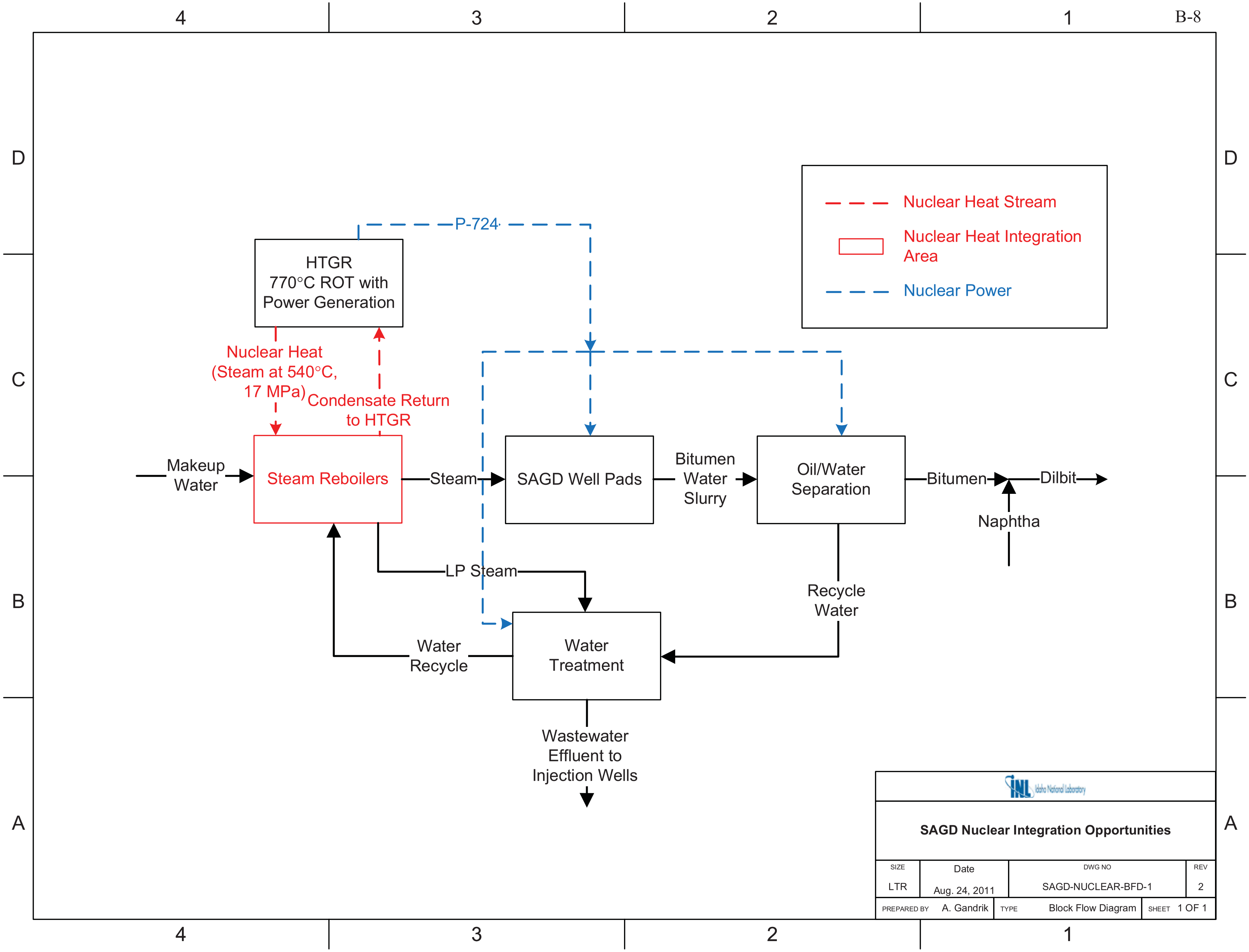
```
  PERCENTAGE WATER RECOVERY:              93.9%


LIQUID PRODUCTS SUMMARY:

  SAGD PRODUCT:
    BITUMEN PRODUCTION =             190000.0 BBL/DAY
    STEAM TO OIL RATIO =                  2.5

  SAGD PROCESS REQUIREMENTS:
    NATURAL GAS REQUIREMENT =           192.5 MMSCFD @ 60F
    POWER =                             113.2 MW

  SAGD PROCESS PRODUCTS:
    BITUMEN =                        190000.0 BBL/DAY
    CO2 EMITTED =                     11830.8 TON/DAY
```

Conventional SAGD Process



SAGD Process



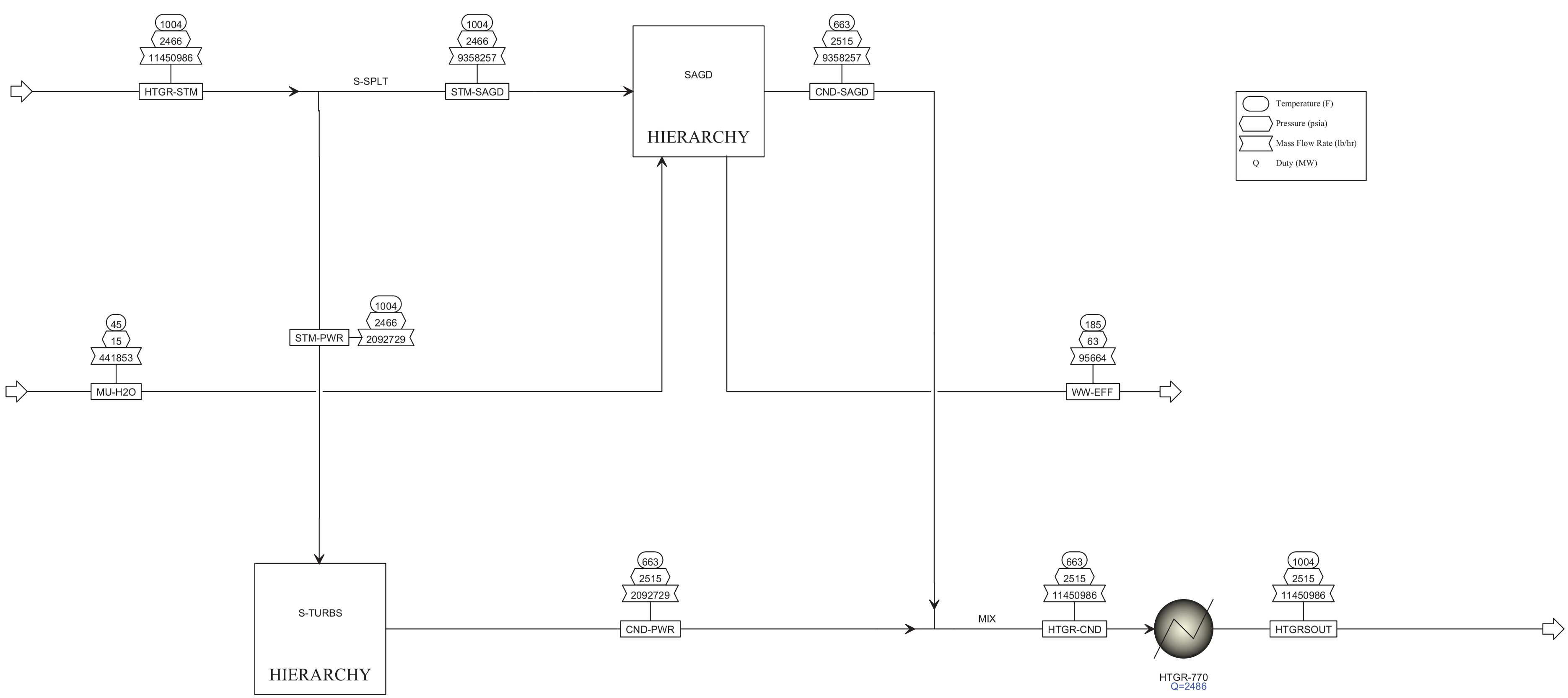


4
3
2
1
D
C
B
A
HTGR
770°C ROT with
Power Generation
P-724
Nuclear Heat Stream
Nuclear Heat Integration
Area
Nuclear Power
Nuclear Heat
(Steam at 540°C,
17 MPa)
Condensate Return
to HTGR
Makeup
Water
Steam Reboilers
Steam
SAGD Well Pads
Bitumen
Water
Slurry
Oil/Water
Separation
Bitumen
Dilbit
Naphtha
LP Steam
Recycle
Water
Water
Recycle
Water
Treatment
Wastewater
Effluent to
Injection Wells
Idaho National Laboratory
SAGD Nuclear Integration Opportunities
SIZE
LTR
Date
Aug. 24, 2011
DWG NO
SAGD-NUCLEAR-BFD-1
REV
2
PREPARED BY
A. Gandrik
TYPE
Block Flow Diagram
SHEET
1 OF 1

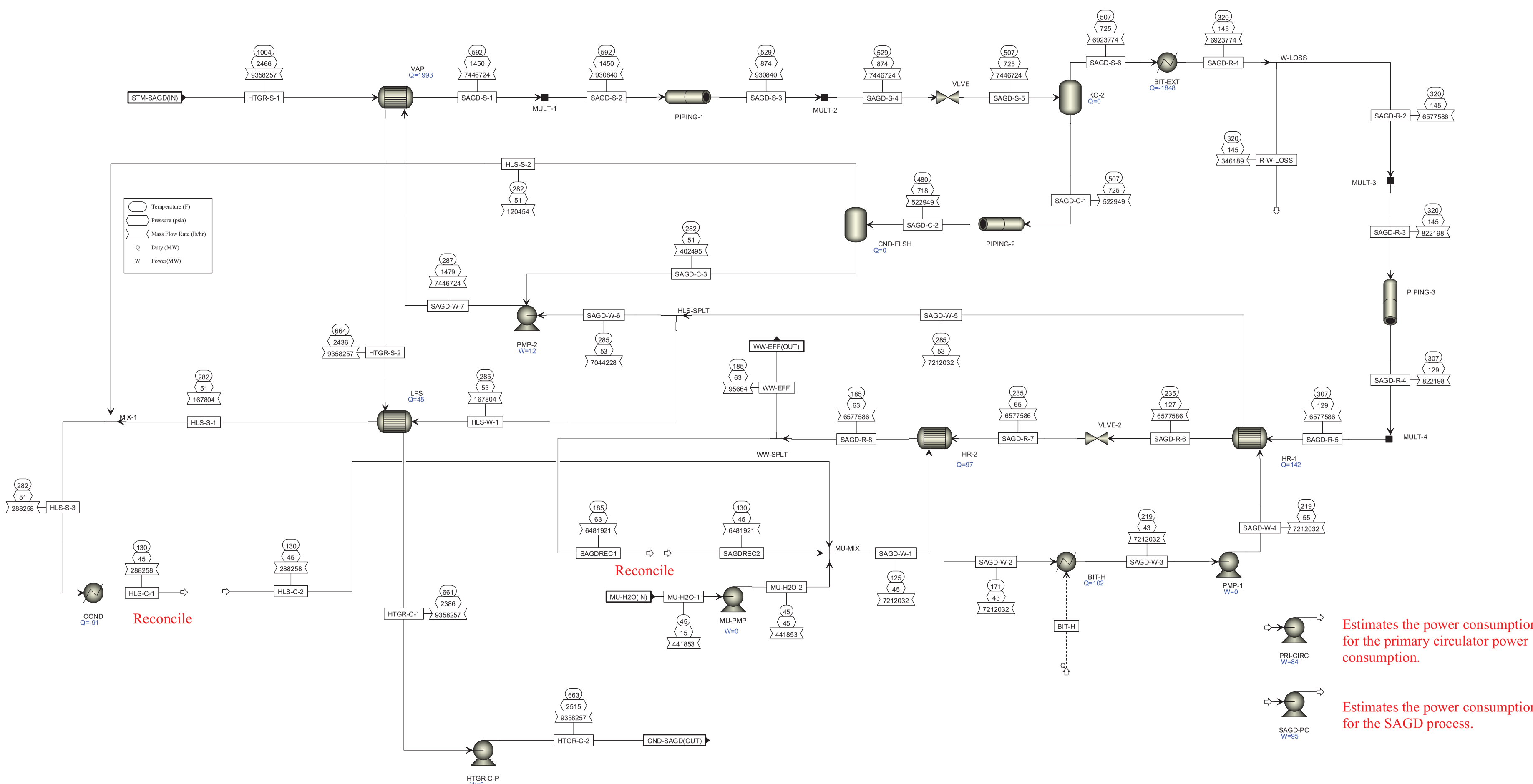
```
Calculator Block SUMMARY

   POWER CALCULATIONS:

     POWER GENERATORS:
       STEAM TURBINE POWER OUTPUT =          199.9 MW
     TOTAL POWER GENERATED =                 199.9 MW

     POWER CONSUMERS:
       HTGR POWER CONSUMPTION =               83.6 MW
       SAGD POWER CONSUMPTION =              108.9 MW
       UPGRADING POWER CONSUMPTION =           0.0 MW
       POWER BLOCK POWER CONSUMPTION =         7.3 MW
     TOTAL POWER CONSUMED =                  199.7 MW

     NET PLANT POWER (+ GEN, - CONS)=          0.2 MW


   SAGD WATER BALANCE:

     LOSSES:

       STEAM LOST TO INJECTION WELL:
         VOLUME:                           23750.0 BBL/DAY H2O EQ.
         VOLUME:                             692.7 GPM H2O EQ.
         MASS:                              4154.3 TON/DAY

       WASTEWATER EFFLUENT:
         VOLUME:                            6563.0 BBL/DAY
         VOLUME:                             191.4 GPM
         MASS:                              1148.0 TON/DAY

       TOTAL LOSSES:
         VOLUME:                           30313.0 BBL/DAY H2O EQ.
         VOLUME:                             884.1 GPM H2O EQ.
         MASS:                              5302.2 TON/DAY

     STEAM GENERATION:

       SAGD INJECTION STEAM:
         VOLUME:                          510876.5 BBL/DAY H2O EQ.
         VOLUME:                           14900.6 GPM H2O EQ.
         MASS:                             89360.7 TON/DAY
         TEMPERATURE:                        592. F
         PRESSURE:                          1450. PSI

       STEAM FOR WATER TREATMENT:
         VOLUME:                           19775.7 BBL/DAY H2O EQ.
         VOLUME:                             576.8 GPM H2O EQ.
         MASS:                             89360.7 TON/DAY
         TEMPERATURE:                        282. F
         PRESSURE:                            51. PSI

     STEAM INJECTED TO SAGD WELLS AFTER PIPING COND.:
       VOLUME:                            475000.0 BBL/DAY H2O EQ.
       VOLUME:                             13854.2 GPM H2O EQ.
       MASS:                               83085.3 TON/DAY

     TOTAL PROCESS WATER FOR STEAM GENERATION:
       VOLUME:                            494775.7 BBL/DAY
       VOLUME:                             14431.0 GPM
       MASS:                               86544.4 TON/DAY

     TOTAL MAKEUP WATER REQUIRED:
```

```
    VOLUME:                                30313.0 BBL/DAY.
    VOLUME:                                  884.1 GPM.
    MASS:                                   5302.2 TON/DAY

  PERCENTAGE WATER RECOVERY:                  93.9%


LIQUID PRODUCTS SUMMARY:

  SAGD PRODUCT:
    BITUMEN PRODUCTION =                 190000.0 BBL/DAY
    STEAM TO OIL RATIO =                      2.5


HTGR SUMMARY:

  770C HTGR - SADG & POWER:

    STEAM INLET FLOW =                      1442.8 KG/S
      TEMPERATURE =                          540.0 C
      PRESSURE =                              17.0 MPA
    STEAM FLOW TO SAGD =                    1179.1 KG/S
    STEAM FLOW TO POWER PROD. =              263.7 KG/S
    STEAM OUTLET FLOW =                     1442.8 KG/S
      TEMPERATURE =                          350.8 C
      PRESSURE =                              17.3 MPA
    HEAT AVAILABLE TO PROCESS =             2485.8 MW
      REACTOR HEAT TO SAGD =                2031.5 MW
      REACTOR HEAT TO POWER PROD. =          454.3 MW
```

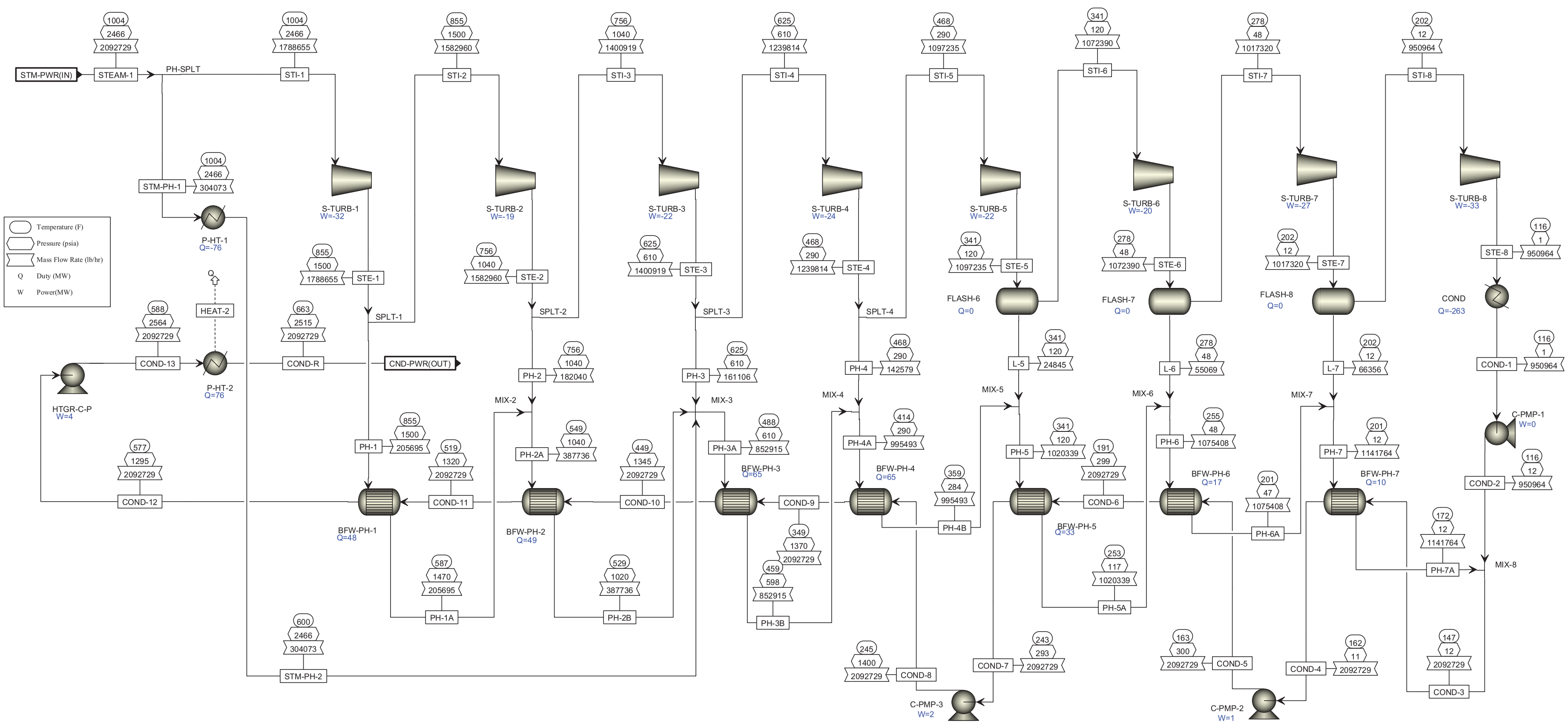
HTGR- Integrated SAGD Process



SAGD Process



Rankine Power Cycle

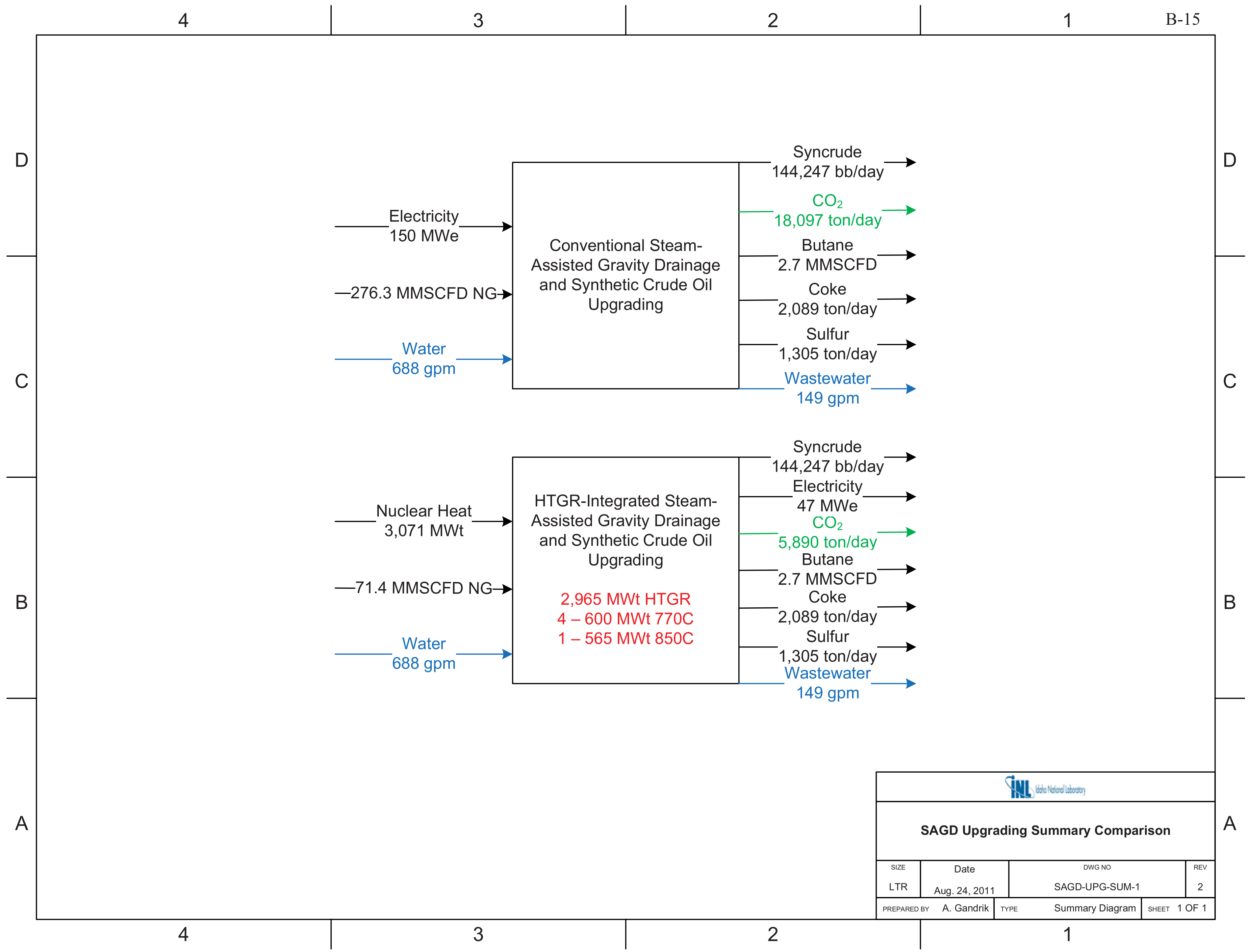


	Conventional	Nuclear-Integrated
Inputs		
Natural Gas Feed Rate (MMSCFD[1])	276.3	71.4
Intermediates		
Bitumen (bbl/day)	147,919	147,919
Outputs		
Synthetic Crude Oil (bbl/day)	144,247	144,247
Butane (MMSCFD[1])	2.7	2.7
Coke (ton/day)	2,089	2,089
Sulfur (ton/day)	1,305	1,305
Utility Summary		
Total Power (MWe)	-276.3	47.4
SAGD Process Consumption	-88.2	-84.8
Upgrading Process Consumption	-61.6	-140.0
HTGR Consumption	N/A	-104.4
HTGR Rankine Cycle Production	N/A	376.6
Water Requirements[2]		
Water Consumed (gpm)	688	688
Total CO_2 Emitted (ton/day)	18,097	5,890
SAGD	9,305	0
Upgrading	8,793	5,890
Nuclear Integration Summary		
Nuclear Heat Supplied[3] (MWt)	N/A	3,071
HTGR Heat to SAGD Process	N/A	1,598
	N/A	585
HTGR Heat to Power Generation	N/A	888
Nuclear Power Supplied (MWe)	N/A	272.2

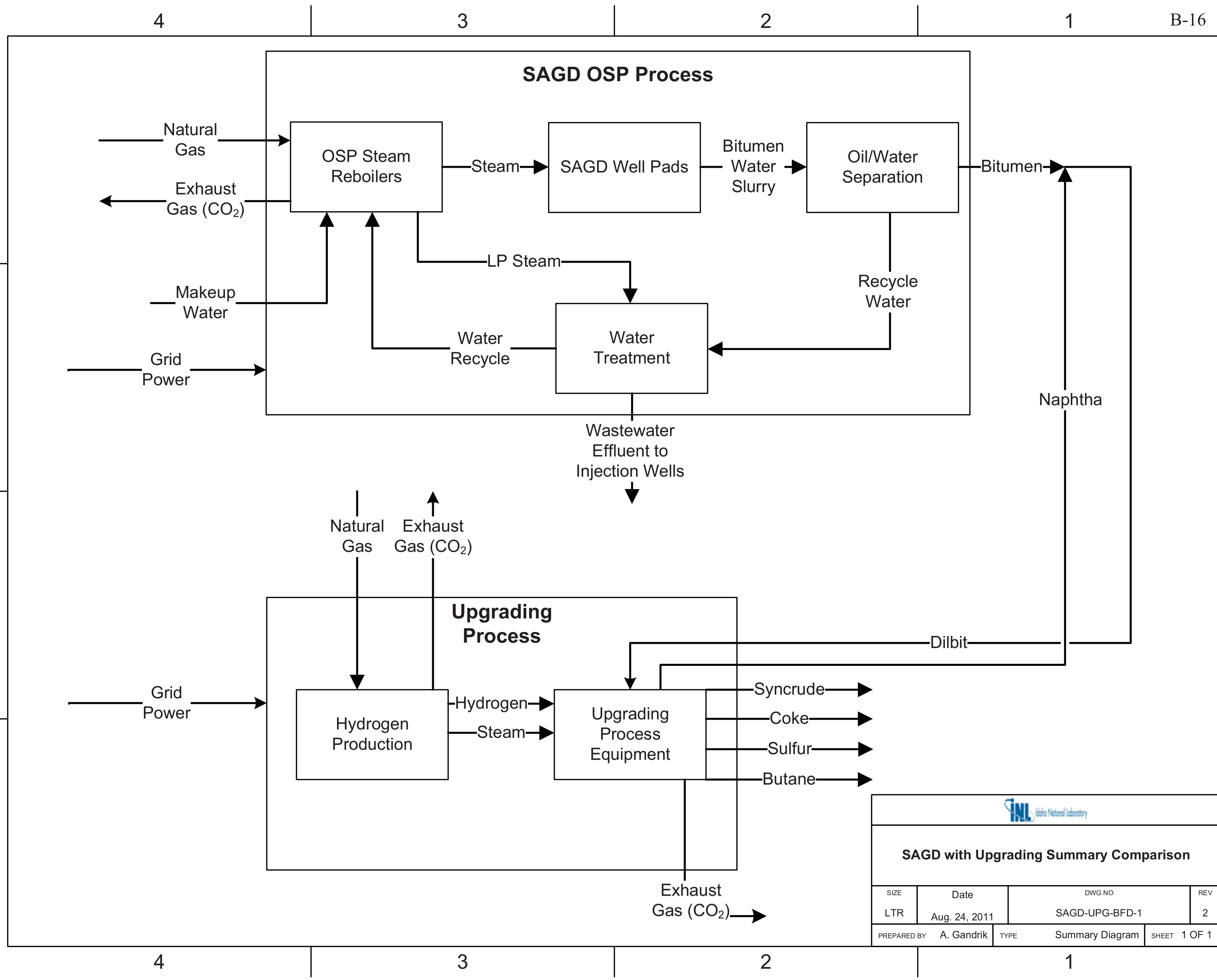
1 Standard temperature of 60°F.

2 SAGD water requirements only, does not include water requirements for the HTGR or upgrading

3 The HTGR heat supplied is greater than 2,400 MWt due to heat generated in the primary circulators.

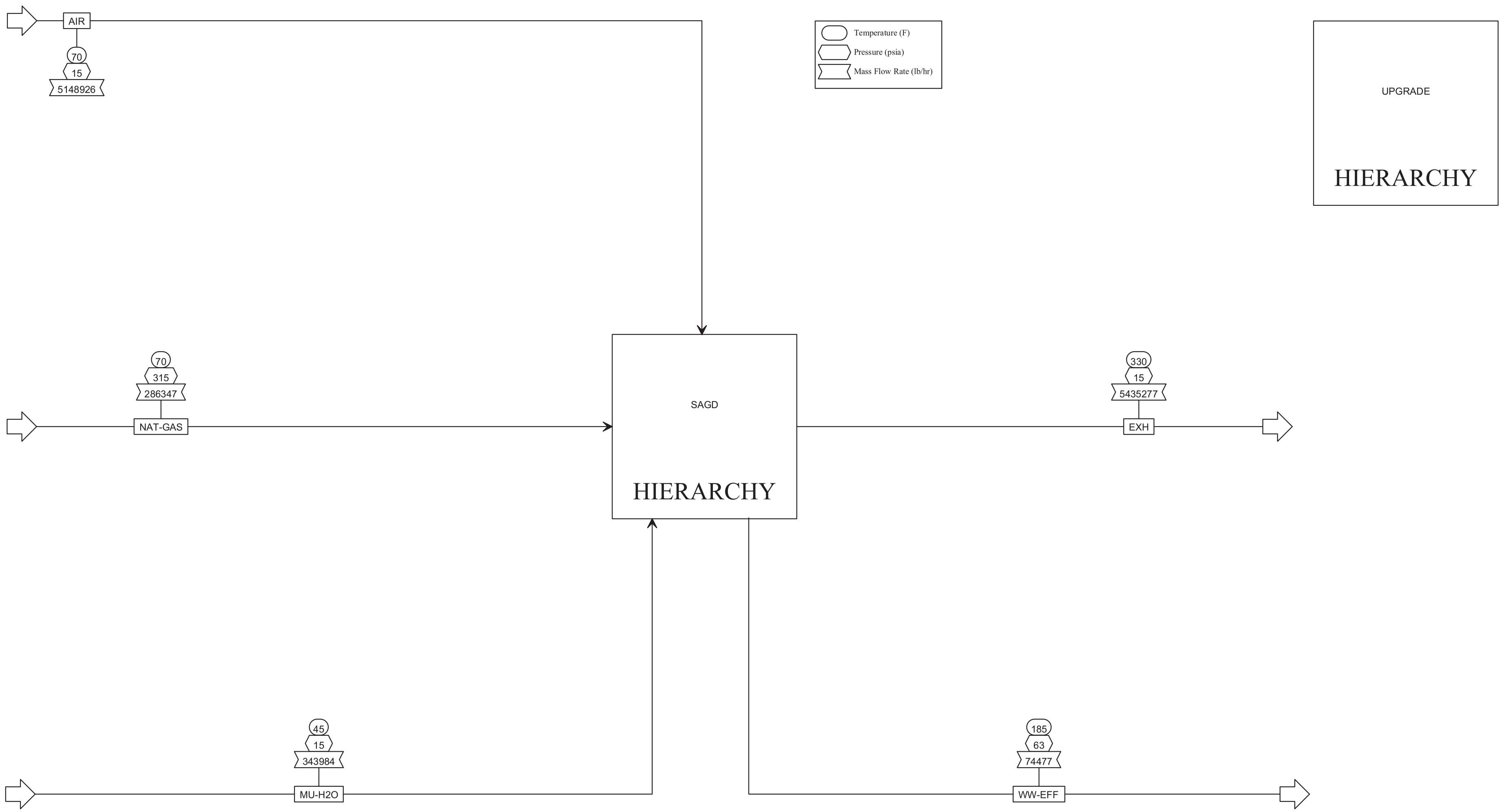


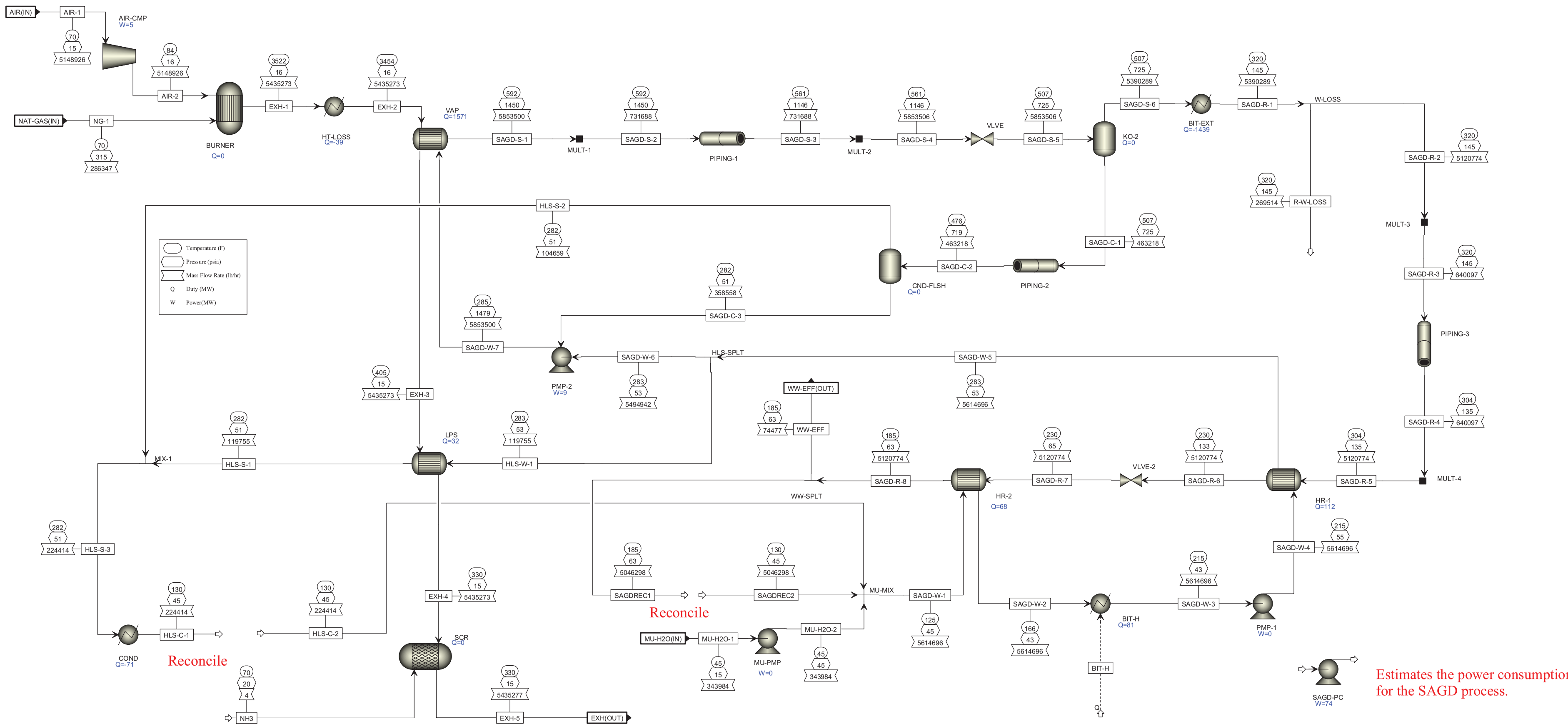
Electricity
150 MWe
276.3 MMSCFD NG
Water
688 gpm
Conventional Steam-Assisted Gravity Drainage and Synthetic Crude Oil Upgrading
Syncrude
144,247 bb/day
CO2
18,097 ton/day
Butane
2.7 MMSCFD
Coke
2,089 ton/day
Sulfur
1,305 ton/day
Wastewater
149 gpm
Nuclear Heat
3,071 MWt
71.4 MMSCFD NG
Water
688 gpm
HTGR-Integrated Steam-Assisted Gravity Drainage and Synthetic Crude Oil Upgrading
2,965 MWt HTGR
4 – 600 MWt 770C
1 – 565 MWt 850C
Syncrude
144,247 bb/day
Electricity
47 MWe
CO2
5,890 ton/day
Butane
2.7 MMSCFD
Coke
2,089 ton/day
Sulfur
1,305 ton/day
Wastewater
149 gpm
Idaho National Laboratory
SAGD Upgrading Summary Comparison
SIZE
LTR
Date
Aug. 24, 2011
DWG NO
SAGD-UPG-SUM-1
REV
2
PREPARED BY
A. Gandrik
TYPE
Summary Diagram
SHEET
1 OF 1


SAGD OSP Process
Natural Gas
Exhaust Gas (CO_2)
OSP Steam Reboilers
Steam
SAGD Well Pads
Bitumen Water Slurry
Oil/Water Separation
Bitumen
LP Steam
Makeup Water
Recycle Water
Water Recycle
Water Treatment
Grid Power
Naphtha
Wastewater Effluent to Injection Wells
Natural Gas
Exhaust Gas (CO_2)
Upgrading Process
Dilbit
Grid Power
Hydrogen Production
Hydrogen
Steam
Upgrading Process Equipment
Syncrude
Coke
Sulfur
Butane
Exhaust Gas (CO_2)
SAGD with Upgrading Summary Comparison
SIZE LTR
Date Aug. 24, 2011
DWG NO SAGD-UPG-BFD-1
REV 2
PREPARED BY A. Gandrik
TYPE Summary Diagram
SHEET 1 OF 1

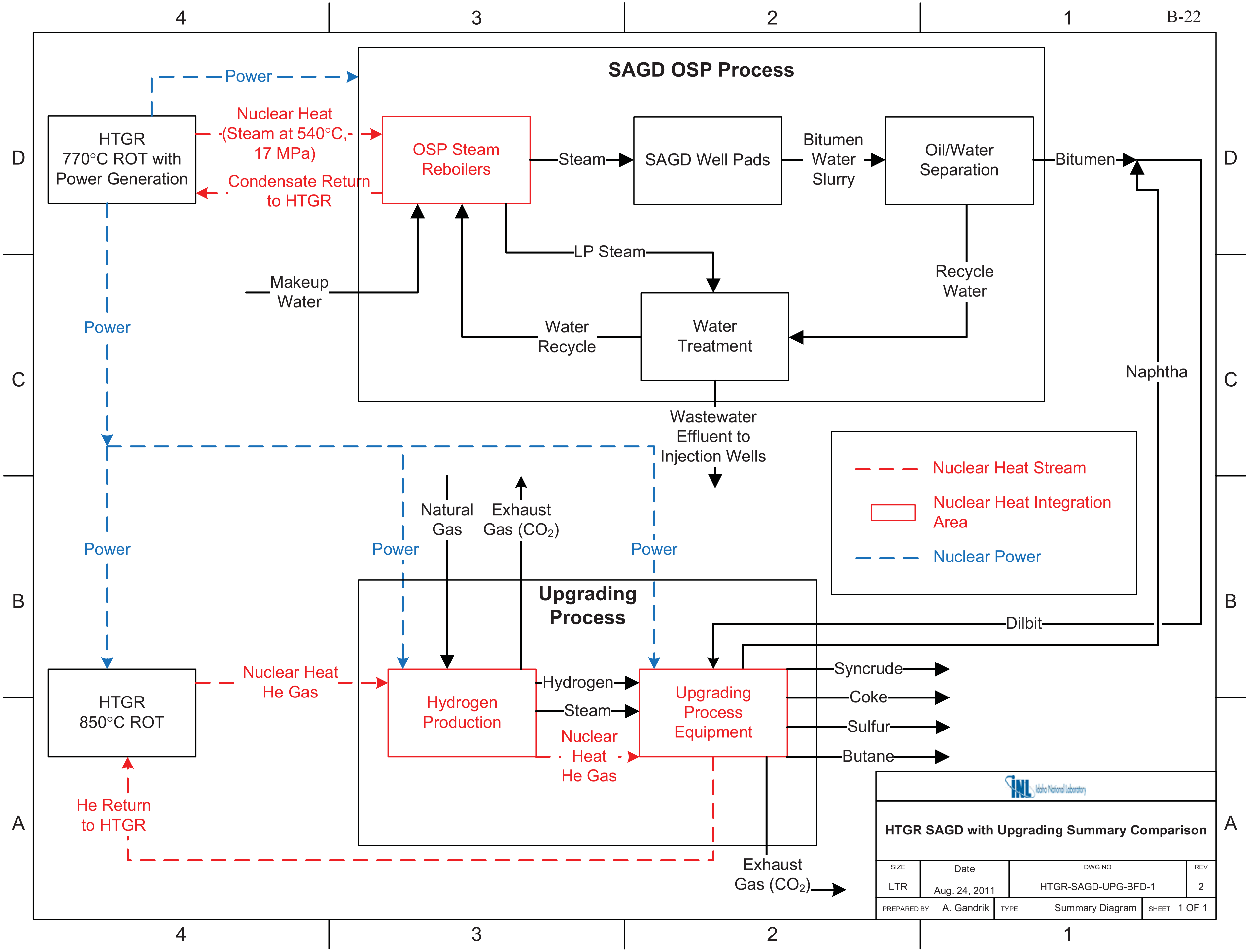
```
CALCULATOR BLOCK SUMMARY

   POWER CALCULATIONS:

     POWER GENERATORS:

     TOTAL POWER GENERATED =                     0.0 MW

     POWER CONSUMERS:
       SAGD POWER CONSUMPTION =                 88.2 MW
       UPGRADING POWER CONSUMPTION =            61.6 MW
     TOTAL POWER CONSUMED =                    149.8 MW

     NET PLANT POWER (+ GEN, - CONS)=         -149.8 MW


   SAGD WATER BALANCE:

     LOSSES:

       STEAM LOST TO INJECTION WELL:
         VOLUME:                             18489.8 BBL/DAY H2O EQ.
         VOLUME:                               539.3 GPM H2O EQ.
         MASS:                                3234.2 TON/DAY

       WASTEWATER EFFLUENT:
         VOLUME:                              5109.4 BBL/DAY
         VOLUME:                               149.0 GPM
         MASS:                                 893.7 TON/DAY

       TOTAL LOSSES:
         VOLUME:                             23599.2 BBL/DAY H2O EQ.
         VOLUME:                               688.3 GPM H2O EQ.
         MASS:                                4127.9 TON/DAY

     STEAM GENERATION:

       SAGD INJECTION STEAM:
         VOLUME:                            401574.7 BBL/DAY H2O EQ.
         VOLUME:                             11712.6 GPM H2O EQ.
         MASS:                               70242.0 TON/DAY
         TEMPERATURE:                          592. F
         PRESSURE:                            1450. PSI

       STEAM FOR WATER TREATMENT:
         VOLUME:                             15395.7 BBL/DAY H2O EQ.
         VOLUME:                               449.0 GPM H2O EQ.
         MASS:                               70242.0 TON/DAY
         TEMPERATURE:                          282. F
         PRESSURE:                              51. PSI

     STEAM INJECTED TO SAGD WELLS AFTER PIPING COND.:
       VOLUME:                              369796.4 BBL/DAY H2O EQ.
       VOLUME:                               10785.7 GPM H2O EQ.
       MASS:                                 64683.5 TON/DAY

     TOTAL PROCESS WATER FOR STEAM GENERATION:
       VOLUME:                              385191.7 BBL/DAY
       VOLUME:                               11234.8 GPM
       MASS:                                 67376.4 TON/DAY

     TOTAL MAKEUP WATER REQUIRED:
       VOLUME:                               23598.8 BBL/DAY.
       VOLUME:                                 688.3 GPM.
       MASS:                                  4127.8 TON/DAY
```

```
  PERCENTAGE WATER RECOVERY:              93.9%


LIQUID PRODUCTS SUMMARY:

  INTERMEDIATE PRODUCT:
    BITUMEN PRODUCTION =              147918.6 BBL/DAY
    STEAM TO OIL RATIO =                   2.5

  FINAL PRODUCT:
    SYNCRUDE PRODUCTION =             144247.0 BBL/DAY
    SYNCRUDE TO BITUMEN RATIO =            0.975


UPRGRADING/SMR PROCESS SUMMARY:

  UPGRADING PROCESS REQUIREMENTS:
    NATURAL GAS REQUIREMENT =            124.9 MMSCFD @ 60F
    POWER =                               61.6 MW

  UPGRADING PROCESS PRODUCTS:
    SYNCRUDE PRODUCT =                144247.0 BBL/DAY
    BUTANE =                               2.7 MMSCFD @ 60F
    COKE =                              2089.3 TON/DAY
    SULFUR =                            1304.9 TON/DAY
    CO2 EMITTED =                       8793.2 TON/DAY

  SAGD PROCESS REQUIREMENTS:
    NATURAL GAS REQUIREMENT =            151.4 MMSCFD @ 60F
    POWER =                               88.2 MW

  SAGD PROCESS PRODUCTS:
    BITUMEN =                         147918.6 BBL/DAY
    CO2 EMITTED =                       9304.1 TON/DAY

  OVERALL PROCESS RESULTS:
    NATURAL GAS REQUIREMENT =            276.3 MMSCFD @ 60F
    POWER =                              149.8 MW
    CO2 EMITTED =                      18097.3 TON/DAY
```


AIR
70
15
5148926
Temperature (F)
Pressure (psia)
Mass Flow Rate (lb/hr)
UPGRADE
HIERARCHY
70
315
286347
NAT-GAS
SAGD
HIERARCHY
330
15
5435277
EXH
45
15
343984
MU-H2O
185
63
74477
WW-EFF


AIR(IN)
AIR-1
AIR-CMP
W=5
AIR-2
NAT-GAS(IN)
NG-1
BURNER
Q=0
EXH-1
HT-LOSS
Q=-39
EXH-2
VAP
Q=1571
SAGD-S-1
MULT-1
SAGD-S-2
PIPING-1
SAGD-S-3
MULT-2
SAGD-S-4
VLVE
SAGD-S-5
KO-2
Q=0
SAGD-S-6
BIT-EXT
Q=-1439
SAGD-R-1
W-LOSS
R-W-LOSS
SAGD-R-2
MULT-3
SAGD-R-3
PIPING-3
SAGD-R-4
MULT-4
SAGD-C-1
PIPING-2
SAGD-C-2
CND-FLSH
Q=0
SAGD-C-3
HLS-S-2
Temperature (F)
Pressure (psia)
Mass Flow Rate (lb/hr)
Q Duty (MW)
W Power(MW)
SAGD-W-7
PMP-2
W=9
SAGD-W-6
HLS-SPLT
SAGD-W-5
EXH-3
WW-EFF(OUT)
WW-EFF
LPS
Q=32
HLS-S-1
HLS-W-1
MIX-1
SAGD-R-8
HR-2
Q=68
SAGD-R-7
VLVE-2
SAGD-R-6
HR-1
Q=112
SAGD-R-5
WW-SPLT
HLS-S-3
SAGDREC1
SAGDREC2
MU-MIX
SAGD-W-1
SAGD-W-4
SAGD-W-2
BIT-H
Q=81
SAGD-W-3
PMP-1
W=0
COND
Q=-71
HLS-C-1
Reconcile
HLS-C-2
EXH-4
SCR
Q=0
Reconcile
MU-H2O(IN)
MU-H2O-1
MU-PMP
W=0
MU-H2O-2
BIT-H
SAGD-PC
W=74
Estimates the power consumption for the SAGD process.
NH3
EXH-5
EXH(OUT)


Temperature (F)
Pressure (psia)
Mass Flow Rate (lb/hr)
W Power(MW)
UPG-PC
W=62
Estimates the power consumption for the reforming and upgrading processes based on information in TEV-1147.



4
3
2
1
D
C
B
A
SAGD OSP Process
HTGR 770°C ROT with Power Generation
Power
Nuclear Heat (Steam at 540°C, 17 MPa)
Condensate Return to HTGR
OSP Steam Reboilers
Steam
SAGD Well Pads
Bitumen Water Slurry
Oil/Water Separation
Bitumen
LP Steam
Makeup Water
Water Recycle
Water Treatment
Recycle Water
Naphtha
Wastewater Effluent to Injection Wells
Natural Gas
Exhaust Gas (CO_2)
Nuclear Heat Stream
Nuclear Heat Integration Area
Nuclear Power
Upgrading Process
Dilbit
HTGR 850°C ROT
Nuclear Heat He Gas
Hydrogen Production
Hydrogen
Steam
Nuclear Heat He Gas
Upgrading Process Equipment
Syncrude
Coke
Sulfur
Butane
He Return to HTGR
Exhaust Gas (CO_2)
Idaho National Laboratory
HTGR SAGD with Upgrading Summary Comparison
SIZE LTR
Date Aug. 24, 2011
DWG NO HTGR-SAGD-UPG-BFD-1
REV 2
PREPARED BY A. Gandrik
TYPE Summary Diagram
SHEET 1 OF 1

```
CALCULATOR BLOCK SUMMARY

   POWER CALCULATIONS:

     POWER GENERATORS:
       STEAM TURBINE POWER OUTPUT =          390.8 MW
     TOTAL POWER GENERATED =                 390.8 MW

     POWER CONSUMERS:
       HTGR POWER CONSUMPTION =              104.4 MW
       SAGD POWER CONSUMPTION =               84.8 MW
       UPGRADING POWER CONSUMPTION =         140.0 MW
       POWER BLOCK POWER CONSUMPTION =        14.2 MW
     TOTAL POWER CONSUMED =                  343.4 MW

     NET PLANT POWER (+ GEN, - CONS)=         47.4 MW


   SAGD WATER BALANCE:

     LOSSES:

       STEAM LOST TO INJECTION WELL:
         VOLUME:                           18489.8 BBL/DAY H2O EQ.
         VOLUME:                             539.3 GPM H2O EQ.
         MASS:                              3234.2 TON/DAY

       WASTEWATER EFFLUENT:
         VOLUME:                            5109.4 BBL/DAY
         VOLUME:                             149.0 GPM
         MASS:                               893.7 TON/DAY

       TOTAL LOSSES:
         VOLUME:                           23599.2 BBL/DAY H2O EQ.
         VOLUME:                             688.3 GPM H2O EQ.
         MASS:                              4127.9 TON/DAY

     STEAM GENERATION:

       SAGD INJECTION STEAM:
         VOLUME:                          401575.1 BBL/DAY H2O EQ.
         VOLUME:                           11712.6 GPM H2O EQ.
         MASS:                             70242.1 TON/DAY
         TEMPERATURE:                        592. F
         PRESSURE:                          1450. PSI

       STEAM FOR WATER TREATMENT:
         VOLUME:                           15395.7 BBL/DAY H2O EQ.
         VOLUME:                             449.0 GPM H2O EQ.
         MASS:                             70242.1 TON/DAY
         TEMPERATURE:                        282. F
         PRESSURE:                            51. PSI

     STEAM INJECTED TO SAGD WELLS AFTER PIPING COND.:
       VOLUME:                            369796.4 BBL/DAY H2O EQ.
       VOLUME:                             10785.7 GPM H2O EQ.
       MASS:                               64683.5 TON/DAY

     TOTAL PROCESS WATER FOR STEAM GENERATION:
       VOLUME:                            385192.2 BBL/DAY
       VOLUME:                             11234.8 GPM
       MASS:                               67376.4 TON/DAY

     TOTAL MAKEUP WATER REQUIRED:
```

VOLUME:	23599.2 BBL/DAY.
VOLUME:	688.3 GPM.
MASS:	4127.9 TON/DAY
PERCENTAGE WATER RECOVERY:	93.9%

LIQUID PRODUCTS SUMMARY:

INTERMEDIATE PRODUCT:	
BITUMEN PRODUCTION =	147918.6 BBL/DAY
STEAM TO OIL RATIO =	2.5
FINAL PRODUCT:	
SYNCRUDE PRODUCTION =	144247.0 BBL/DAY
SYNCRUDE TO BITUMEN RATIO =	0.975

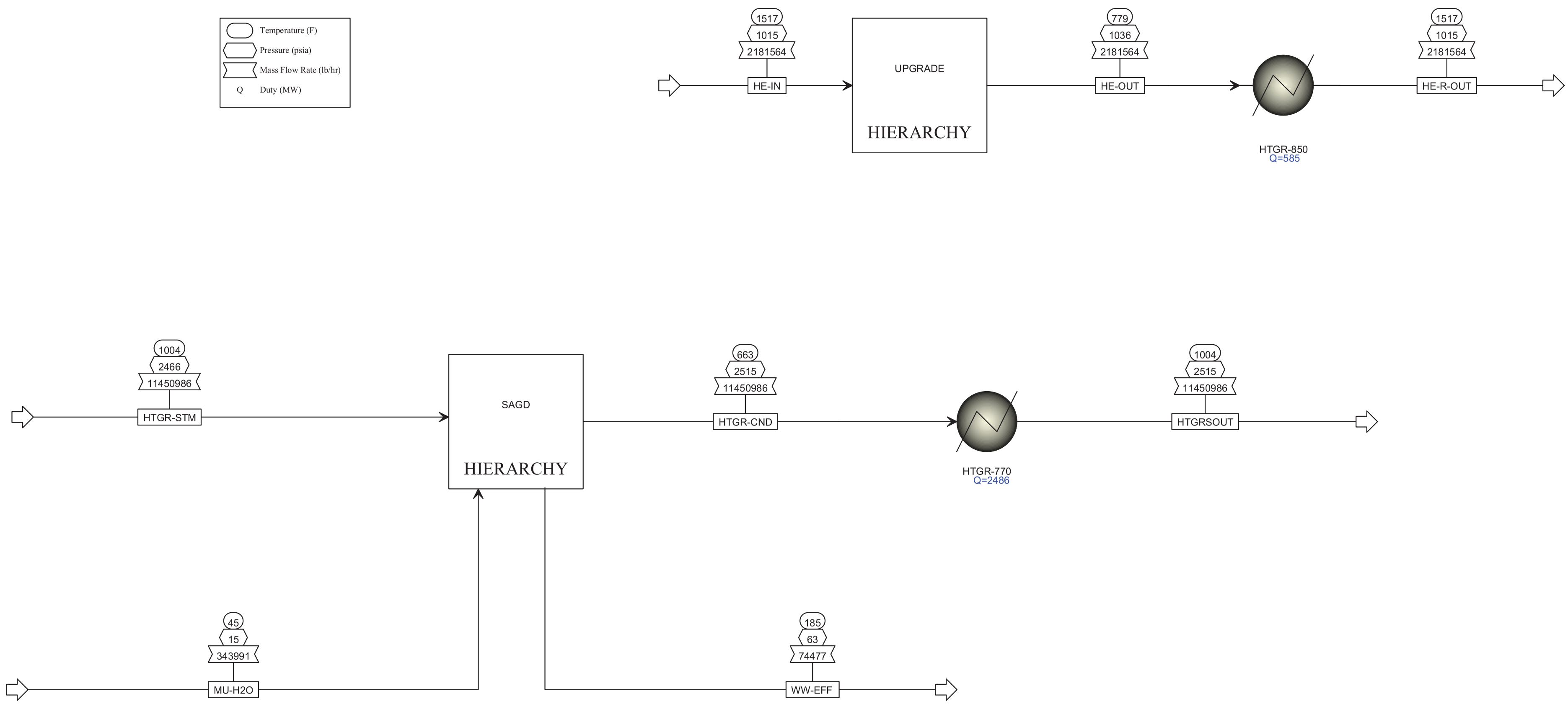
UPRGRADING/SMR PROCESS SUMMARY:

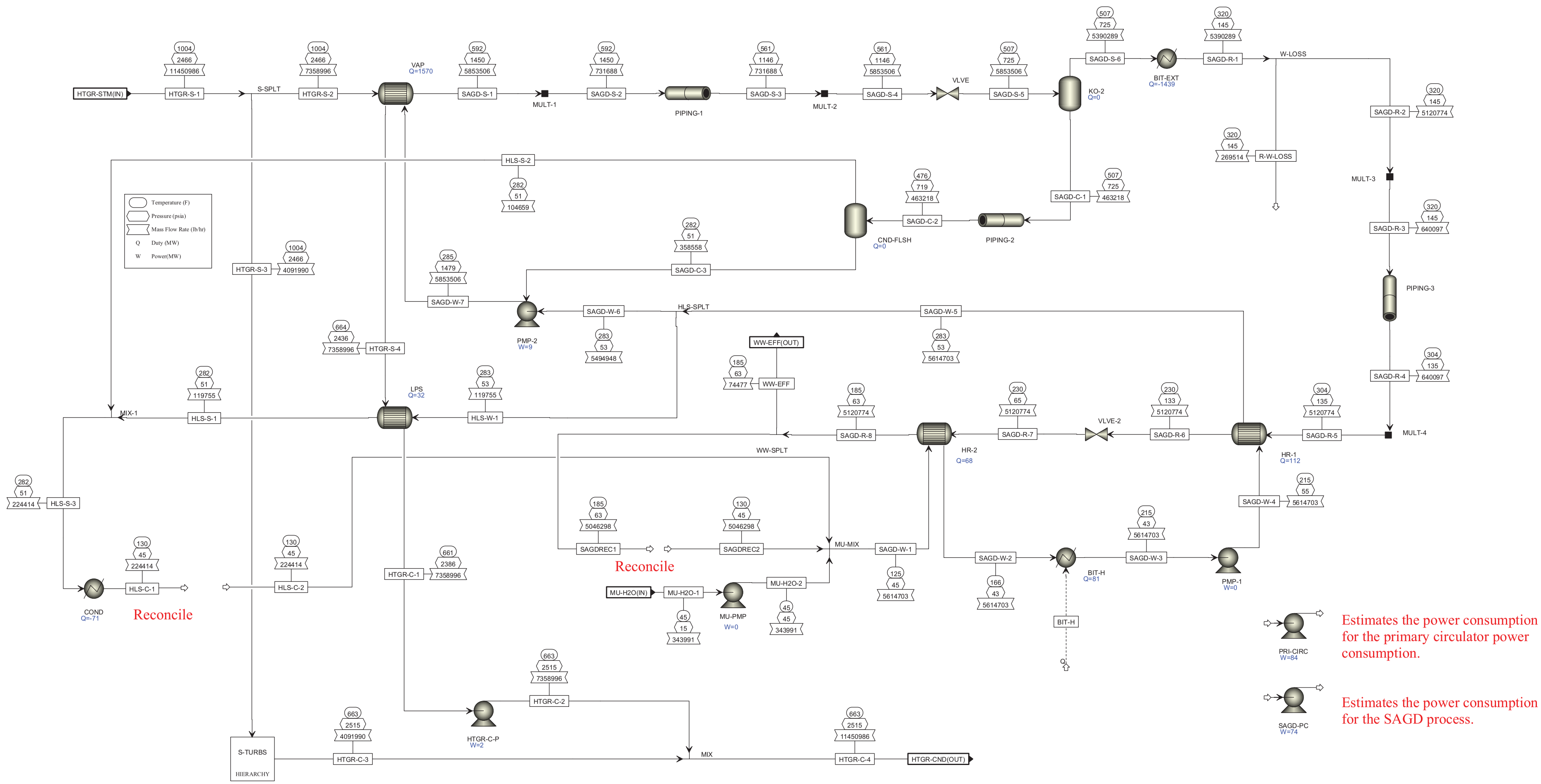
UPGRADING PROCESS REQUIREMENTS:	
HYDROGEN REQUIREMENT =	257.0 MMSCFD @ 60F
GENERAL PROCESS HEAT =	292.7 MW
PROCESS HEAT AS STEAM =	85.1 MW
POWER =	49.1 MW
UPGRADING PROCESS PRODUCTS:	
SYNCRUDE PRODUCT =	144247.0 BBL/DAY
BUTANE =	2.7 MMSCFD @ 60F
COKE =	2089.3 TON/DAY
SULFUR =	1304.9 TON/DAY
CO2 EMITTED =	1554.8 TON/DAY
SMR PROCESS REQUIREMENTS:	
NATURAL GAS REQUIREMENT =	71.4 MMSCFD @ 60F
PROCESS HEAT =	312.3 MW
POWER =	29.5 MW
SMR PROCESS PRODUCTS:	
HYDROGEN PRODUCT =	257.0 MMSCFD @ 60F
STEAM AS HEAT =	43.7 MW
CO2 EMITTED =	388.4 TON/DAY
CAPTURABLE CO2 =	3947.2 TON/DAY
OVERALL HEAT/POWER REQUIREMENTS:	
EXTERNAL PROCESS HEAT REQ. =	646.3 MW
TOTAL PROCESS HEAT REQ =	690.0 MW
STEAM AVAILABLE FROM SMR =	43.7 MW
EXTERNAL POWER REQ. =	78.7 MW
OVERALL CO2 BALANCE:	
TOTAL CO2 PRODUCED =	5890.4 TON/DAY
CO2 EMITTED =	1943.2 TON/DAY
CAPTURABLE CO2 =	3947.2 TON/DAY

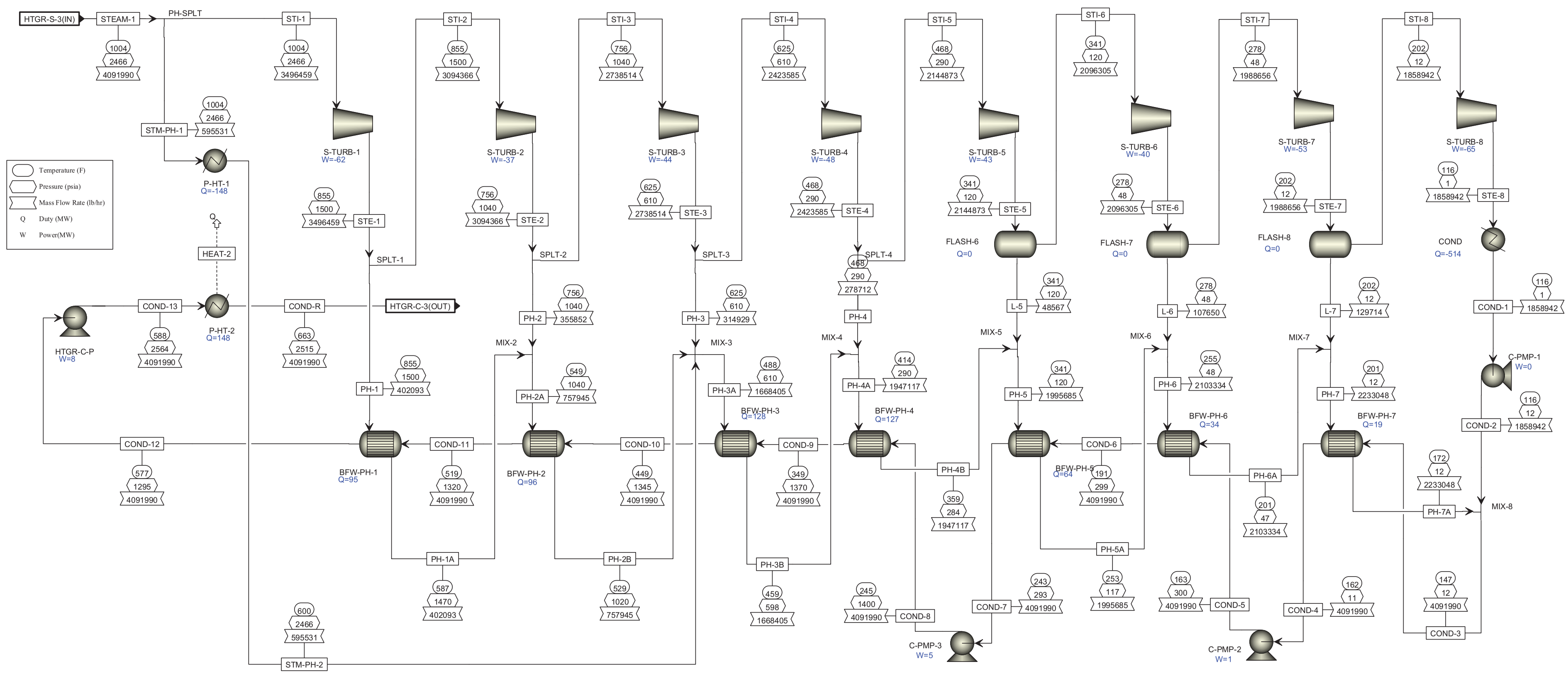
HTGR SUMMARY:

850C HTGR - UPGRADING:	
HELIUM INLET FLOW =	274.9 KG/S
TEMPERATURE =	825.0 C
PRESSURE =	7.0 MPA
HELIUM OUTLET FLOW =	274.9 KG/S
TEMPERATURE =	415.2 C

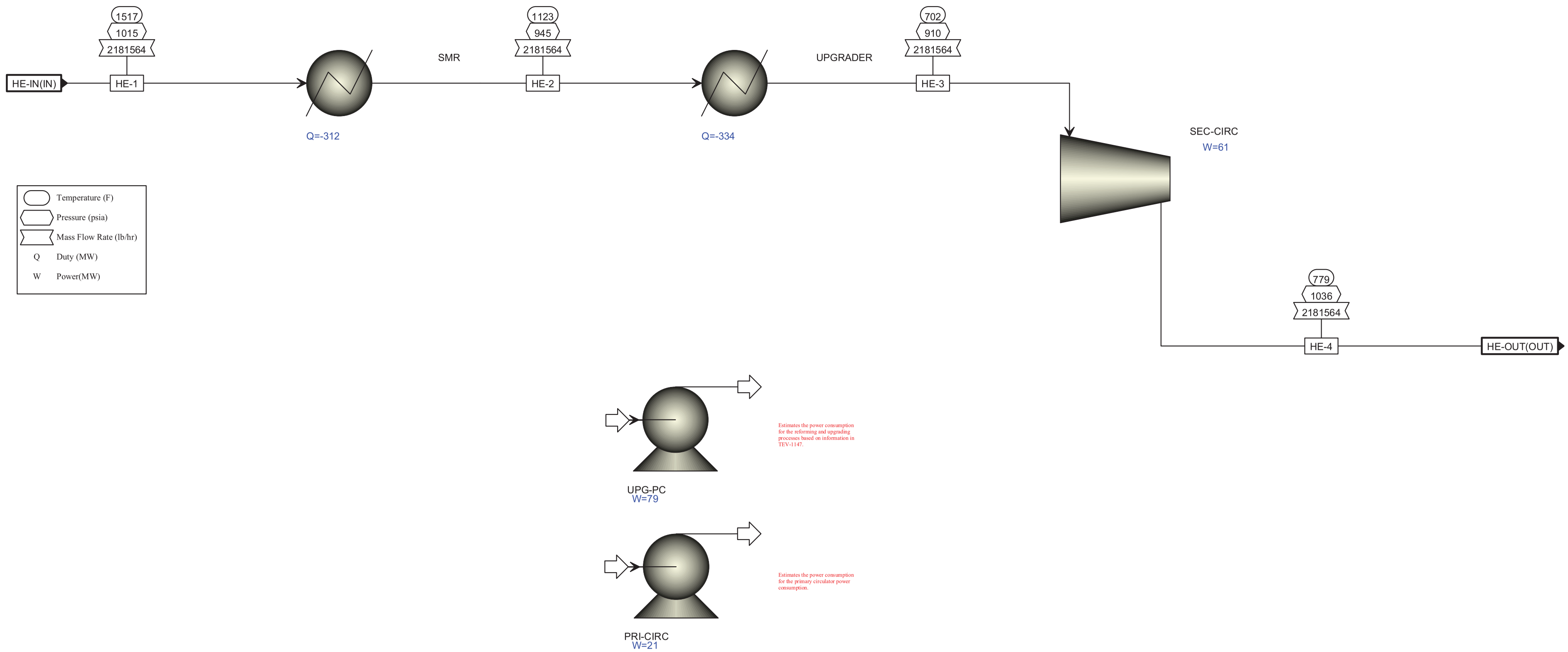
```
    PRESSURE =                            7.1 MPA
  HEAT AVAILABLE TO PROCESS =           646.3 MW
    REACTOR HEAT TO PROCESS =           585.0 MW
    HEAT GEN. IN SEC. CIRCULATOR =       61.3 MW

770C HTGR - SADG & POWER:

  STEAM INLET FLOW =                   1442.8 KG/S
    TEMPERATURE =                       540.0 C
    PRESSURE =                           17.0 MPA
  STEAM FLOW TO SAGD =                  927.2 KG/S
  STEAM FLOW TO POWER PROD. =           515.6 KG/S
  STEAM OUTLET FLOW =                  1442.8 KG/S
    TEMPERATURE =                       350.8 C
    PRESSURE =                           17.3 MPA
  HEAT AVAILABLE TO PROCESS =          2485.8 MW
    REACTOR HEAT TO SAGD =             1597.5 MW
    REACTOR HEAT TO POWER PROD. =       888.3 MW
```


Temperature (F)
Pressure (psia)
Mass Flow Rate (lb/hr)
Q Duty (MW)
1517
1015
2181564
HE-IN
UPGRADE
HIERARCHY
779
1036
2181564
HE-OUT
HTGR-850
Q=585
1517
1015
2181564
HE-R-OUT
1004
2466
11450986
HTGR-STM
SAGD
HIERARCHY
663
2515
11450986
HTGR-CND
HTGR-770
Q=2486
1004
2515
11450986
HTGRSOUT
45
15
343991
MU-H2O
185
63
74477
WW-EFF


HTGR-STM(IN)
HTGR-S-1
S-SPLT
HTGR-S-2
VAP
Q=1570
SAGD-S-1
MULT-1
SAGD-S-2
PIPING-1
SAGD-S-3
MULT-2
SAGD-S-4
VLVE
SAGD-S-5
KO-2
Q=0
SAGD-S-6
BIT-EXT
Q=-1439
SAGD-R-1
W-LOSS
R-W-LOSS
SAGD-R-2
MULT-3
SAGD-R-3
PIPING-3
SAGD-R-4
MULT-4
SAGD-R-5
HR-1
Q=112
SAGD-R-6
VLVE-2
SAGD-R-7
HR-2
Q=68
SAGD-R-8
WW-SPLT
WW-EFF
WW-EFF(OUT)
SAGD-C-1
PIPING-2
SAGD-C-2
CND-FLSH
Q=0
SAGD-C-3
HLS-S-2
HTGR-S-3
SAGD-W-7
PMP-2
W=9
SAGD-W-6
HLS-SPLT
SAGD-W-5
HTGR-S-4
LPS
Q=32
HLS-W-1
HLS-S-1
MIX-1
HLS-S-3
COND
Q=-71
HLS-C-1
HLS-C-2
Reconcile
HTGR-C-1
SAGDREC1
SAGDREC2
Reconcile
MU-H2O(IN)
MU-H2O-1
MU-PMP
W=0
MU-H2O-2
MU-MIX
SAGD-W-1
SAGD-W-2
BIT-H
Q=81
SAGD-W-3
PMP-1
W=0
SAGD-W-4
HTGR-C-P
W=2
HTGR-C-2
S-TURBS
HIERARCHY
HTGR-C-3
MIX
HTGR-C-4
HTGR-CND(OUT)
Temperature (F)
Pressure (psia)
Mass Flow Rate (lb/hr)
Q Duty (MW)
W Power(MW)
PRI-CIRC
W=84
SAGD-PC
W=74
Estimates the power consumption for the primary circulator power consumption.
Estimates the power consumption for the SAGD process.



Temperature (F)
Pressure (psia)
Mass Flow Rate (lb/hr)
Q Duty (MW)
W Power(MW)
HTGR-S-3(IN)
STEAM-1
PH-SPLT
STM-PH-1
P-HT-1
Q=-148
HEAT-2
P-HT-2
Q=148
HTGR-C-P
W=8
COND-13
COND-R
HTGR-C-3(OUT)
COND-12
STM-PH-2
STI-1
STI-2
STI-3
STI-4
STI-5
STI-6
STI-7
STI-8
S-TURB-1
W=-62
S-TURB-2
W=-37
S-TURB-3
W=-44
S-TURB-4
W=-48
S-TURB-5
W=-43
S-TURB-6
W=-40
S-TURB-7
W=-53
S-TURB-8
W=-65
STE-1
STE-2
STE-3
STE-4
STE-5
STE-6
STE-7
STE-8
SPLT-1
SPLT-2
SPLT-3
SPLT-4
FLASH-6
Q=0
FLASH-7
Q=0
FLASH-8
Q=0
COND
Q=-514
L-5
L-6
L-7
COND-1
C-PMP-1
W=0
COND-2
MIX-8
PH-1
PH-2
PH-3
PH-4
PH-5
PH-6
PH-7
PH-2A
PH-3A
PH-4A
PH-7A
MIX-2
MIX-3
MIX-4
MIX-5
MIX-6
MIX-7
BFW-PH-1
Q=95
BFW-PH-2
Q=96
BFW-PH-3
Q=128
BFW-PH-4
Q=127
BFW-PH-5
Q=64
BFW-PH-6
Q=34
BFW-PH-7
Q=19
COND-11
COND-10
COND-9
COND-6
COND-8
COND-7
COND-5
COND-4
COND-3
PH-1A
PH-2B
PH-3B
PH-4B
PH-5A
PH-6A
C-PMP-3
W=5
C-PMP-2
W=1



HE-IN(IN)
HE-1
1517
1015
2181564
Q=-312
SMR
HE-2
1123
945
2181564
Q=-334
UPGRADER
HE-3
702
910
2181564
SEC-CIRC
W=61
HE-4
779
1036
2181564
HE-OUT(OUT)
Temperature (F)
Pressure (psia)
Mass Flow Rate (lb/hr)
Q Duty (MW)
W Power(MW)
UPG-PC
W=79
Estimates the power consumption for the reforming and upgrading processes based on information in TEV-1147.
PRI-CIRC
W=21
Estimates the power consumption for the primary circulator power consumption.

Appendix C
SAGD Baseline Stream Results.xlsx

[Electronic]

Appendix D
SAGD HTGR Stream Results.xlsx

Appendix E
CESF Baseline Stream Results.xlsx

[Electronic]

Appendix F
CESF HTGR Stream Results.xlsx

[Electronic]