Document ID: TEV-671 Revision ID: 1 Effective Date: 05/15/2010

Technical Evaluation Study

Project No. 23843

Nuclear-Integrated Substitute Natural Gas Production Analysis



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Note: Applicable QLD: REC-000101

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REVISION LOG

Rev.	Date	Affected Pages	Revision Description
0	11/05/2009	All	Initial document release
1	05/15/2010	All	Added economics section

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EXECUTIVE SUMMARY

This technical evaluation (TEV) has been prepared as part of a study for the Next Generation Nuclear Plant Project to evaluate integration of high temperature gas-cooled reactor (HTGR) technology with conventional chemical processes. This TEV addresses the integration of an HTGR with substitute natural gas production (SNG).

The HTGR can produce process heat (steam or high-temperature helium), electricity, and/or hydrogen. In conventional chemical processes these products are generated by the combustion of fossil fuels such as coal and natural gas, resulting in significant emissions of greenhouse gases (GHGs) such as carbon dioxide. Heat, electricity, or hydrogen produced via an HTGR could be used to supply process heat, electricity, or hydrogen to conventional chemical processes without generating any GHGs. This report describes how nuclear-generated heat, electricity, and/or hydrogen could be integrated into conventional SNG process and provides a preliminary economic analysis of the conventional and nuclear-integrated options.

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

- Six 600 MW_t HTGRs are required to support production of a 150 MMSCFD SNG facility. Nuclear integration decreases coal consumption by 64% using electrolysis and nuclear power as the hydrogen source. Nuclear integration decreases CO₂ emissions 97.4% if sequestration is not assumed. If sequestration is assumed, CO₂ emissions increase by over 350 tons per day.
- The following table outlines the SNG prices necessary for the SNG process to obtain a 12% internal rate of return (IRR) for the cases analyzed with and without a carbon tax as well as assessing the impact of reducing the HTGR capital cost by 30%. Low, average, and historical high city gate natural gas prices are also presented.

Technology	SNG Price (\$/MSCF) no CO ₂ Tax	SNG Price (\$/MSCF) \$100/ton CO ₂ Tax	SNG Price (\$/MSCF) \$150/ton CO ₂ Tax		
Conventional SNG	11.06	23.15	29.20		
Conventional SNG, with Sequestration	13.06	13.06	13.06		
Nuclear-Integrated SNG	27.90	28.81	28.37		
Nuclear-Integrated SNG, -30% HTGR cost	23.46	23.77	23.93		
Low U.S. City Gate Natural Gas Price, September 2009	\$5.35/MSCF				
Average U.S. City Gate Natural Gas Price	\$8.60/MSCF				
High U.S. City Gate Natural Gas Price, June 2008	\$11.85/MSCF				

Table ES 1. SNG economic results Summary for a 12% IRR.

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ACRONYMS AND NOMENCLATURE

AACE	Association for the Advancement of Cost Engineering
ASU	air separation unit
ATCF	after tax cash flow
BTCF	before tax cash flow
CEPCI	chemical engineering plant cost index
CMD	coal milling and drying
DOE	Department of Energy
EIA	Energy Information Administration
GHG	greenhouse gas
HRSG	heat recovery steam generator
HT	high temperature
HTSE	high temperature steam electrolysis
HTGR	high temperature gas reactor
INL	Idaho National Laboratory
IRR	internal rate of return
LT	low temperature
MARR	minimum annual rate of return
MSCF	thousand standard cubic feet
MMSCF	million standard cubic feet
NETL	National Energy Technology Laboratory
NGNP	Next Generation Nuclear Plant
NIBT	net income before taxes
PSA	pressure swing absorption
PW	present worth
SGCP	Shell coal gasification process
SNG	substitute natural gas
SMR	steam methane reformer
TCI	total capital investment
TEV	technical evaluation

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C_1	cost of equipment with capacity of	[1		
C_2	cost of equipment with capacity of	2		
C_k	capital expenditures			
d_k	depreciation			
E_k	cash outflows			
i'	IRR			
k	year			
п	exponential factor			
q_1	equipment capacity			
q_2	equipment capacity			
R_k	revenues			
t	tax rate			
T_k	income taxes			

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1. INTRODUCTION

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

The HTGR produces process heat (steam or high-temperature helium), electricity, and/or hydrogen. A summary of these products and a brief description is shown in Table 1. For this study the HTGR outlet temperature is assumed to be 750°C, this reflects the initial HTGR design and assumes a more conservative outlet temperature, eventually temperatures of 950°C are anticipated. Additionally, a 50°C temperature approach is assumed between the primary and secondary helium loops, if helium is the delivered working fluid. As a result, the helium stream available for heat exchange is assumed to be at 700°C. In conventional chemical processes these products are generated by the combustion of fossil fuels such as coal and natural gas, resulting in significant emissions of greenhouse gases such as carbon dioxide. Heat, electricity, or hydrogen produced in an HTGR could be used to supply process heat, electricity, or hydrogen to conventional chemical processes without generating any greenhouse gases. The use of an HTGR to supply process heat, electricity, or hydrogen to conventional processes is referred to as a nuclear-integrated process. This report describes how nuclear-generated heat, electricity, or hydrogen could be integrated into conventional processes and provides a preliminary economic analysis to show which nuclear-integrated processes compare favorably with conventional processes.

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

Table 1. Assumed outputs of the HTGR

This TEV addresses potential integration opportunities for substitute natural gas (SNG) production. The HTGR would produce electricity, heat, and/or hydrogen and be physically located near the SNG production facility. A separate study should be conducted to assess the optimal siting of the HTGR with respect to the SNG facility,

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balancing safety concerns associated with separation distance and heat losses associated with transporting high temperature heat long distances.

The Advanced Process and Decision Systems Department at Idaho National Laboratory (INL) has spent several years developing detailed process simulations of chemical processes, typically utilizing fossil fuels such as coal, biomass, or natural gas as the feedstock. These simulations have been developed using Aspen Plus, a state-of-the-art steady-state chemical process simulator (Aspen 2006). This study makes extensive use of these models and the modeling capability at INL in order to evaluate the integration of HTGR technology with commercial SNG production methods. The outputs from the material and energy balances generated in Aspen Plus were utilized as inputs into the Excel economic model (Excel 2007).

This TEV assumes familiarity with Aspen Plus; hence, a detailed explanation of the software capabilities, thermodynamic packages, unit operation models, and solver routines is beyond the scope of this document. Similarly, it assumes a familiarity with gasification, methane synthesis, and common gas purification technologies. Hence, a thorough explanation of these technologies is considered to be beyond the scope of this TEV.

The following TEV first presents an overview of the process modeling performed for the SNG and nuclear-integrated SNG cases. Afterwards, the results of the process modeling for each case are discussed, specifically the impact of the HTGR integration. Next, an overview of the economic modeling is presented, followed by results for SNG and nuclear-integrated SNG. Again, focus is placed on the impact of HTGR integration. Finally, conclusions for the SNG cases are presented. These conclusions focus on the impact of the HTGR integration on the process modeling as it pertains to the overall material and energy balance and economic results.

2. PROCESS MODELING OVERVIEW

The plant models for the coal SNG process were developed using Aspen Plus (Aspen 2006). 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.

Significant emphasis in the models has been placed on heat integration between different parts of the plant. To facilitate energy tracking, Aspen's "utility" blocks were used extensively. Utilities tracked in this manner were electricity generated, electricity consumed, steam generated (medium pressure 700 psia, intermediate pressure 300 psia, and low pressure 150 psia), steam consumed (medium pressure 700 psia, intermediate pressure 150 psia, and low pressure 150 psia), and cooling water usage.

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Two separate models were constructed for the coal to SNG cases, one for a conventional SNG facility, not unlike the Dakota SNG facility, as well as a SNG facility coupled with a HTGR and high temperature steam electrolysis (HTSE) units, both utilizing a generic Illinois #6 coal and producing 150 MMSCFD of SNG. Illinois #6 was chosen as the coal type because it is a very commonly used and abundant coal. A dry-fed, entrained-flow, slagging gasifier (similar to a Shell, Uhde, or Siemens design) was selected as the gasification technology for this evaluation. Capacity for the nuclear-integrated case was adjusted to produce the same SNG output as in the conventional case. The general model descriptions for both cases are presented below.

For the Aspen models described in this analysis, rigorous submodels of the nuclear power cycle and high temperature electrolysis have not yet been integrated; this integration is planned for the near future. Hence, in order to account for water usage, heat rejection for the HTSE was calculated separately using the UNISIM modeling package. Cooling water requirements for this operation were then estimated and added to the overall Aspen model results. 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. Although the method of producing syngas varies from case to case, production of methane is essentially unchanged between cases.

2.1 Conventional Coal to SNG Case

The block flow diagram for the conventional SNG case is shown in Figure 1. The proposed process includes unit operations for air separation, coal milling and drying, coal gasification, syngas cleaning and conditioning, sulfur recovery, CO_2 compression/liquefaction, methanation, power production, cooling towers, and water treatment. Each unit operation is briefly described below.



Figure 1. Block flow diagram for the coal to SNG process.

- Air Separation (ASU) Oxygen is produced via a standard cryogenic Linde type air separation unit (ASU) that utilizes two distillation columns and extensive heat exchange in a cold box (Linde 2008). The oxygen product is used for gasification. In order to reduce the inert content in the synthesis gas, an O₂ purity of 99.5% is specified. It should be noted that lower oxygen purity could be specified, such as 95%; however, the high purity oxygen is desired to minimize diluent nitrogen in the SNG product stream so that cryogenic separation is not required to enhance CH₄ purity. The nitrogen co-product from the ASU can be used for coal drying and transport, and as an inert gas to be used throughout the plant. The waste stream from the ASU is an O₂-enriched air stream. A portion of the enriched air stream is used as feed to the Claus unit in place of air (WorleyParsons 2002).
- Coal Milling & Drying (CMD) Coal is pulverized to below 90 µm using a roller mill to ensure efficient gasification. Currently, coal milling power consumption is modeled based on the power calculated by Aspen assuming a Hardgrove grindability index of 60. Drying is accomplished simultaneously using a heated inert gas stream. The gas stream removes evaporated water as it sweeps the pulverized coal through an internal classifier for collection in a baghouse. Inert nitrogen from the ASU, is heated using heat recovered throughout the process. The nitrogen is mixed with this hot gas to create a hot inert gas stream which dries the Illinois coal down to 6% moisture (Shell 2005). Nitrogen is also used as transport gas for the coal from the baghouse to the lock hoppers. Pressurized carbon dioxide, from the Rectisol unit, is then used to transport the dry, sized coal into the gasifier. The transport gas is assumed to be 0.15 pounds of gas per pound of solids, for both the nitrogen

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and carbon dioxide transport gases. The amount of CO_2 vented during depressurization of the feed hopper is estimated using the ideal gas law.

- **Gasification (GASIFIER)** The dry coal is gasified at 2,800°F using Shell's • SCGP technology (entrained-flow, dry-fed, slagging, oxygen-blown, upflow gasifier). Oxygen is fed to the gasifier to achieve the outlet temperature of 2,800°F, while steam (700 psia) is fed such that the molar ratio of dry coal to steam is 7:1. This ratio was selected in order to inhibit methane formation in the gasifier. Although some heat is recovered in the membrane wall of the gasifier, the majority of the heat recovery is accomplished downstream of the gasifier in the syngas coolers, which cool the gas down to 464°F, generating medium and intermediate pressure steam (Shell 2004). The syngas is further cooled by a water quench. A portion of the quenched syngas is returned to the top of the gasifier to cool the particle-laden gas to below the ash softening point. Makeup water is provided to the quench loop to achieve a blowdown rate of approximately 5% around the quench loop. This blowdown is then used in the slag quench loop. 2.5% of the water from the slag quench loop is assumed to be sent to water treatment to avoid any buildup of contaminants.
- Syngas Cleaning & Conditioning (GAS-CLN) After gasification, a fraction of the syngas is passed through sour shift reactors and then remixed with unshifted syngas to provide the optimal H₂:CO ratio to the methanation reactors. This ratio was specified as follows based on the Haldor Topsoe TREMP process:

$$\frac{H_2 - CO_2}{CO + CO_2} = 2.99\tag{1}$$

Steam (700 psia) is added to the syngas stream to maintain the water concentration necessary for the water gas shift reaction (steam to dry gas molar ratio of 1.2 is currently specified). To minimize the steam requirement, heat recuperation around the shift converters is employed in conjunction with a saturation/desaturation water recycle loop. Five percent of the water recycled around the water gas shift loop is sent to water treatment to avoid high concentrations of ammonia and chloride compounds in the shift loop. Heat is further recovered from the syngas after shifting and used for nitrogen heating in CMD and Rectisol heat requirements. Elemental mercury is then captured in a mercury guard bed. The syngas is further treated in an absorber with refrigerated methanol, which acts as a physical solvent for the removal of CO₂, H₂S, and COS (Rectisol process). It is assumed that 1.5% CO₂ and less than 1 ppm of H_2S are present in the clean syngas stream. The H_2S rich stream is assumed to contain approximately 55% H₂S, with the remainder being CO₂ (Lurgi 2006). Gas containing H₂S from the sulfur reduction unit is also sent to the Rectisol process for sulfur removal. The nitrogen and argon contained in this stream are assumed to pass through to the CO_2 rich stream.

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It is also assumed that a steam reboiler, rather than nitrogen flow, is used for stripping in order to ensure a sufficiently pure CO_2 stream for sequestration or enhanced oil recovery. Utility usage is calculated based on values presented in literature for the Rectisol process (Cover 1986). However, confidence in the predicted utility usage is low due to the substitution of steam for nitrogen stripping. It is believed that this substitution may significantly increase the power requirement for refrigeration and steam usage. Because of the extreme sulfur intolerance of the methanation catalyst, guard beds are included as an added measure of protection against poisoning. A small portion of the cleaned syngas is sent to the sulfur reduction unit to provide both heat and hydrogen required to reduce sulfur compounds to H₂S.

- Sulfur Plant (CLAUS & S-REDUCT) Sulfur recovery is based on the Claus process. The Illinois coal has a sufficiently high sulfur content, which can create a sour gas stream with up to 60% H₂S. As a result, a straight through Claus process can be used. In order to achieve optimal sulfur recovery, air flow to the Claus furnace is adjusted to achieve a molar ratio of 0.55:1 O₂ to H₂S (Kohl 1997). Tail gas from the Claus unit is hydrogenated over a catalyst to convert the remaining sulfur species to H₂S, and this stream is recycled to the Rectisol unit to maximize sulfur recovery. A small stream of clean syngas is used to fire and preheat the feed gas to the sulfur reduction unit.
- **CO₂ Compression (CO2-COMP)** Carbon dioxide is removed from the syngas in the Rectisol process. By properly designing the solvent regeneration scheme, a pure stream of CO₂ is produced. The resulting stream is then compressed, along with the CO₂ recycle from coal milling and drying, and liquefied prior to being pumped to the required pressure for use in enhanced oil recovery or sequestration. CO₂ for filtration is split from the CO₂ pressurization scheme at 700 psia, while the CO₂ for coal slurrying is split from the CO₂ pressurization scheme at 1,160 psia. Eight stages are assumed for the CO₂ at 2,005 psia should be liquid; however, Aspen's physical property methods do not predict the proper phase of the supercritical CO₂ stream because of the presence of a small quantity of inert gas. The number of stages, stage efficiencies, and resulting power requirement were tuned to commercial CO₂ compression turbines; thus, the incorrect phase prediction will not impact the resulting power requirement.
- Methanation (METH) Three methanation reactors in series are modeled in Aspen to simulate the Haldor Topsoe TREMP process. All reactors are assumed to be adiabatic. Eighty-three percent of the product from the first reactor is recycled to achieve a sufficiently high conversion of H₂ and CO to CH₄. Conversely, the recycle could be decreased and a fourth reactor could be added to increase conversion. The first two reactors are assumed to operate

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with a high temperature (HT) methanation catalyst, and have inlet temperatures of 480°F. The third reactor utilizes a low temperature (LT) methanation catalyst, and has an inlet temperature of 374°F (Udengaard 2008). Medium, intermediate, and low pressure steam are generated from cooling the product gas after each reactor.

- **Power Production (ST)** The medium (700 psia), intermediate (300 psia), and low pressure (150 psia) steam generated throughout the plant are sent to the power production block where they are passed through three steam turbines to generate power. The efficiencies of the turbines for the various steam pressures were calculated using Steam Pro, steam turbine modeling software from Thermoflow (Thermoflow 2009). It was found that even given low quality steam at 150 psia, efficiencies for the steam turbines remain constant at approximately 81%. The condensed steam from the turbine outlets are mixed with condensate return from the plant and makeup water is added to provide the necessary flow to the boiler feedwater pumps. Medium pressure steam is added to the deaerator to achieve the appropriate dew point temperature. Aspen Utility blocks are used to track all steam generation and use in the plant. This information is used as input to the power production section of the model, allowing reconciliation of the entire plant steam balance.
- **Cooling Towers (COOL-TWR)** Conventional cooling towers are modeled in Aspen Plus using literature data. Air cooling could potentially be used in certain areas of the plant to decrease water consumption; however, for simplicity cooling water only was assumed. The evaporation rate, drift, and blowdown are based on a rule of thumb guide for the design and simulation of wet cooling towers (Leeper 1981). Aspen utility blocks are used to track all cooling water use in the plant. This information is used as input to the cooling tower section of the model, allowing reconciliation of the entire plant cooling water balance.
- Water Treatment (H2O-TRTM) Water treatment is simplistically modeled in Aspen Plus using a variety of separation blocks. INL is currently collaborating with a major water treatment vendor to develop the water treatment portion of the model. The existing water treatment scenario is a place holder, and will be revised as information is received from the water treatment vendor. Hence, it is anticipated that energy consumption for the water treatment portion of the plant could change considerably based on water treatment vendor feedback. Aspen transfer blocks are used to reconcile water in and out flows from various parts of the plant, allowing reconciliation of the entire plant water balance.

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2.2 Nuclear-Integrated Coal to SNG Case

The block flow diagram for the nuclear-integrated SNG case is shown in Figure 2. The proposed process includes the same unit operations as the conventional process with the following exceptions: the cryogenic air separation unit and water gas shift reactors are replaced by HTSE to provide oxygen and hydrogen for the process.

While developing the nuclear-integrated case, opportunities for heat integration between the nuclear, electrolysis, and fossil plants were also evaluated; however, very few opportunities were identified. The primary reason for this conclusion was that the fossil plant produced an excess amount of heat that could provide for the heat requirements within the fossil portion of the plant.

An opportunity to use heat from the gasifier as topping heat for the electrolysis unit was identified. However, use of this heat would require that the exchanger required for the electrolysis topping heat would be constructed utilizing exotic materials to guard against metal dusting by carbon formed from the Boudouard reaction. To avoid this complication, syngas is fired to provide topping heat; however, this does increase CO_2 emissions to the atmosphere. As HTGR technology matures and reactor outlet temperatures increase, the nuclear reactors may be able to supply electrolysis topping heat. However, because of the upper limit of 700°C deliverable heat assumed in this study, supplying topping heat from syngas firing to the electrolyzers is an attractive means of increasing electrolyzer efficiency.

With the air separation unit and water gas shift reactors removed from the flowsheet, an unexpected result was observed. A shortage of inert gas for use in coal drying, transport, and feeding was created. To overcome this issue, air was selected for use in coal drying and transport, rather than nitrogen.

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



Figure 2. Block flow diagram for the nuclear-integrated coal to SNG process.

- Electrolysis (ELEC) Water is converted to hydrogen and oxygen utilizing high temperature electrolysis units. Helium at 1,292°F, provided by the HTGR, is used to convert the water to steam and raise the temperature to 1,274°F, while heat recuperated from the firing syngas is used to provide topping heat to raise the steam temperature to 1,472°F for electrolysis. Conversion and power consumption are based on data provided by the INL high temperature electrolysis team. The oxygen generated is used for gasification and air enrichment for the Claus and sulfur reduction units, the hydrogen is used to adjust the hydrogen to carbon monoxide ratio for methanation, in place of sour shift reactors. A portion of syngas is fired in this hierarchy to provide topping heat to the electrolyzers, the exhaust gas is further cooled, generating medium, intermediate, and low pressure steam.
- **Coal Milling & Drying (CMD)** Coal milling and drying for the nuclearintegrated case is similar to the conventional case. However, because nitrogen is not readily available in this scenario, coal drying is accomplished using air; the airflow for drying is specified to be 2.5 times the coal flowrate (Mullinger 2008). Air is also used as transport gas for the pulverized coal. Although air is used industrially for coal drying and transport, it introduces additional flammability issues as compared to using an inert gas for this purpose.

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Transport of coal into the gasifier is accomplished using CO₂ recovered from the Rectisol unit.

- **Gasification (GASIFIER)** Gasification for the nuclear-integrated case is similar to the conventional case. However, because hydrogen is supplied externally from the electrolyzers rather than shifting the syngas, the gasification island throughput is reduced to 36% of the conventional design to produce the same amount of SNG product.
- Syngas Cleaning & Conditioning (GAS-CLN) Syngas cleaning is greatly simplified for the nuclear-integrated case, as the water gas shift reactors are eliminated. Hydrogen from the electrolyzers is added to the syngas to achieve the optimal H₂:CO ratio to the methanation synthesis reactors. This ratio was specified as follows based on the Haldor Topsoe TREMP process:

$$\frac{H_2 - CO_2}{CO + CO_2} = 2.99\tag{2}$$

When the shift reactors are eliminated, the CO_2 concentration entering the Rectisol unit is reduced from 34% in the conventional case to 13% in the nuclear-integrated case. Similarly, CO_2 concentration in the purified syngas is reduced from 1.5% in the conventional case to 0.5% in the nuclear-integrated case. Rectisol capacity and utility usage are reduced by more than half in the nuclear-integrated case as compared to the conventional case.

- Sulfur Plant (CLAUS & S-REDUCT) The Claus and sulfur reduction plants for the nuclear-integrated case are similar to those in the conventional case. However, as with the gasification island, the required capacity of these units is approximately less than half that of the conventional case configuration.
- CO₂ Compression (CO2-COMP) CO₂ compression for the nuclearintegrated case is similar to CO₂ compression in the conventional case. However, because the shift converters are eliminated, required capacity and utility usage are reduced by a factor of approximately eight. Additionally, the last stage of compression is removed, as all CO₂ is recycled to the gasifier to increase carbon conversion to the SNG product.
- Methanation (METH) The methanation synthesis plant remains unchanged between the conventional and nuclear-integrated cases. Inlet gas composition is slightly different between the cases because of increased N₂ in the nuclear-integrated case from the recycle of CO₂ back to the gasifier. Due to this difference, SNG produced from the nuclear-integrated case will contain ~1% more N₂ than in the conventional case.

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- **Power Production (ST)** Power production in the nuclear-integrated case is similar to the conventional case. However, because of size reductions in some portions of the plant, the capacity of the steam system in the nuclear-integrated case is approximately 85% of the conventional case.
- **Cooling Towers (COOL-TWR)** The cooling water system requirements are similar for both cases. Again, cooling water requirements for the HTGR are not included in this analysis.
- Water Treatment (H2O-TRTM) The water treatment system in the nuclear-integrated case is similar to the conventional case. No further comparison will be made on water treatment between the two cases until feedback from the water treatment vendor has been received, and the water treatment scenarios have been tuned up.

3. PROCESS MODELING RESULTS

Analysis of the conventional coal to SNG case indicated a potential need for hydrogen supplementation from HTSE. By supplementing the process with an external hydrogen source, the need to "shift" the syngas using conventional water-gas shift reactors was eliminated. The primary benefit of this change is a reduction in greenhouse gas (GHG) emissions from the process. It was also determined that the conventional coal to SNG case produced heat beyond what was needed to support demands of the plant. Based on these observations, a nuclear-integrated model was developed which focuses primarily on integrating nuclear hydrogen rather than nuclear heat.

Results from the nuclear-integrated coal to SNG case indicate that integration of nuclear hydrogen can drastically improve carbon utilization and reduce GHG emissions. Coal consumption is decreased by 64% using electrolysis and nuclear power as the hydrogen source. Similarly, with nuclear integration the fraction of carbon in the coal partitioned to the liquid fuel products increases from 35.3% to 95.1%. Integrating nuclear power and high temperature steam electrolysis can also decrease CO₂ emissions from the plant. If carbon capture and sequestration are not assumed for the conventional configuration, CO₂ emissions decrease by 97.4% when electrolysis and nuclear power are utilized. However, if carbon capture and sequestration are assumed for the conventional configuration, CO₂ emissions increase by over 350 tons per day of CO₂ in order to provide topping heat to the electrolyzers. In the nuclear-integrated case, nuclear energy is used to offset a portion of the energy requirement derived from coal. This is evident, as power consumption is increased from 133 MW to 1,203 MW, an increase of 905%. It is estimated that a little less than six nuclear high temperature reactors (600 MWt each) would be required in this configuration to support production of 150 MMSCFD of SNG.

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 coal case serves as a basis for comparison with the nuclear-integrated

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case. For the complete Aspen stream results for the SNG and nuclear-integrated SNG cases, see Appendixes C and D.



Figure 3. SNG modeling case material balance summary.

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Table 2. SNG modeling case study results.

	Conventional SNG	Nuclear Integration SNG
Inputs		
Coal Feed rate (ton/day)	10,600	3,864.2
% Carbon to SNG Product	35.3%	95.1%
# HTGRs (600 MW _t)	N/A	5.61
Outputs		
Total Product		
SNG Product (MMSCFD) ¹	151	148
SNG Purity (mol-%)	94.3%	94.2%
Utility Summary		
Total Power (MW)	-132.7	-1,202.9
Electrolyzers	N/A	-1,272.3
ASU	-118.3	N/A
Coal Milling and Drying	-5.6	-4.1
Gasification and Gas Cleanup	-73.3	-26.8
CO ₂ Compression/Liquefaction	-64.3	-8
Methanation	-27	-26
Cooling Tower	-4.6	-2.3
Water Treatment	-6.4	-4.7
Steam Turbines	168.6	142.4
Water Requirements ²		
Water Consumed (gpm)	6,531.3	5,486.4
Water Consumed/Coal Feed (lb/lb)	3.70	8.53
CO ₂ Summary		
Total CO ₂ Produced (ton/day)	15,025	383
Emitted	0	383
Captured	15,025	0
Nuclear Integration Summary		
Electricity (MW)	N/A	-1,202.9
HTSE	N/A	-1,272.3
Balance of Plant	N/A	69.4
Electrolysis Heat (MMBTU/hr)	N/A	1,311.4
From Nuclear Plant	N/A	1,231.5
From Gasification Island	N/A	79.9
Electrolysis Products		
Total Hydrogen (ton/day)	N/A	990
Total Oxygen (ton/day)	N/A	7,593
Used in Plant (ton/day)	N/A	2,906
Available for Sale (ton/day)	N/A	4,898
¹ Standard temperature of 60 degrees F.		

²Does not include water usage for HTGR.

4. ECONOMIC MODELING OVERVIEW

The economic viability of the SNG processes was assessed using standard economic evaluation methods. The economics were evaluated for the conventional and nuclear-

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integrated options described in the previous sections. The total capital investment (TCI), based on the total equipment costs annual revenues, and annual manufacturing costs were first calculated for the cases. The present worth (PW) of the annual cash flows (after taxes) was then calculated for the TCI, as well as the TCI at +50% and -30% of the HTGR cost, with the debt to equity ratio equal to 80%/20%. The following sections describe the methods used to calculate the capital costs, annual revenues, annual manufacturing costs, and the resulting economic results.

4.1 Capital Cost Estimation

Equipment items for this study were not individually priced. Rather, cost estimates were based on scaled costs for major plant processes from published literature. Cost estimates were generated for coal preparation, the ASU, gasification, gas cleanup, SNG production, steam turbines, cooling towers, HTSE electrolysis, and the HTGRs for the SNG scenarios. In some instances, several costs were averaged. Gas cleanup includes costs for water-gas-shift reactors, the Rectisol process, sulfur recovery, and CO₂ compression/liquefaction for SNG. Appendix B presents the detailed breakdown for the equipment item costs, including the original equipment cost bases for SNG. It is assumed that there is no impact on the capital cost of the SNG facility when sequestration is not assumed, as the Rectisol process is required for gas cleanup and though the last stage of the CO₂ compressor would not be required, this cost is negligible when compared to the TCI required for the SNG process. The estimate presented is a Class 5 estimate and has a probable error of +50% and -30% (AACE 2005).

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

$$C_2 = C_1 \left(\frac{q_2}{q_1}\right)^n \tag{3}$$

where C_1 is the cost of the equipment item at capacity q_1 , C_2 is the cost of the equipment at capacity q_2 , and n is the exponential factor, which typically has a value of 0.6 (Peters 2002). It was assumed that the number of trains did not have an impact on cost scaling. Cost indices were used to adjust equipment prices from previous years to values in July of 2009 using the Chemical Engineering Plant Cost Index (CEPCI) as depicted in Table 3. Costs for HTGRs, and HTSE were scaled directly based on capacity, the six-tenths factor rule was not used.

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Table 3. CEP	CI data.					
Year	CEPCI]	Year	СЕР	CI	
1990	357.6	2	2000	394	.1	
1991	361.3	2	2001	394	.3	
1992	358.2	2	2002	395	.6	
1993	359.2	2	2003	40	2	
1994	368.1	2	2004	444	.2	
1995	381.1	2	2005	468	.2	
1996	381.7	2	2006	499	.6	
1997	386.5	2	2007	525	.4	
1998	389.5	2	2008	575	.4	

July 2009

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

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After cost estimates were obtained for each of the process areas, the costs for water systems, piping, instrumentation and control, electrical systems, and buildings and structures were added based on scaling factors for the total installed equipment costs based on information provided in studies performed by the National Energy Technology Laboratory (NETL) (2000). These factors were not added to the cost of the HTGR, as the cost basis for the HTGR was assumed to represent a complete and operable system. Table 4 presents the factors utilized in this study:

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

1999

Table 4. Capital cost adjustment factors.

390.6

Finally, an engineering fee of 10% and a project contingency of 18% were assumed to determine the TCI. The capital cost provided for the HTGR represents a complete and operable system; the total value represents all inside battery limits and outside battery limits elements as well as contingency and

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owner's costs; therefore, engineering fees and contingencies were not applied to this cost.

The Association for the Advancement of Cost Engineering (AACE) International recognizes five classes of estimates. The level of project definition for this study was determined to be an AACE International Class 5 estimate. Though, the baseline case is actually more in line with the AACE International Class 4 Estimate, which is associated with equipment factoring, parametric modeling, historical relationship factors, and broad unit cost data, the HTGR project definition falls under an AACE International Class 5 estimate, associated with less than two percent project definition, and based on preliminary design methodology (AACE 2005). Since the HTGR is a larger portion of the total capital investment, an overall Class 5 estimate was assumed.

Based on the AACE International contingency guidelines as presented in DOE/FETC-99/1100 it would appear that the overall project contingency for the non-nuclear portion of the capital should be in the range of 30% to 50%, 30% to 40% for Class 4 and 50% for Class 5 (Parsons 1999). However, because the cost estimates were scaled based on estimated, quoted, and actual project costs, the overall non-nuclear project contingency should be more in the range of 15% to 20%. 18% was selected based on similar studies conducted by NETL (2007). Again, contingency was not applied to the HTGR as project contingency was accounted for in the basis for the capital cost estimate.

Table 5 and Figure 4 present the capital cost estimate breakdown for the conventional SNG case and Table 6 and Figure 5 for the nuclear SNG case. Varying only the cost of the nuclear facility was an adequate assumption, as the cost of the HTGR accounts for over 60% of the capital for the nuclear integrated case. In addition, there is a greater level of uncertainty in the nuclear plant price given the nascency of HTGR development.

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	Installed Cost	Engineering Fee	Contingency	Total Capital Cost
Coal Preparation	\$111,581,623	\$11,158,162	\$22,093,161	\$144,832,946
ASU	\$141,104,835	\$14,110,483	\$27,938,757	\$183,154,075
Gasification	\$358,818,685	\$35,881,868	\$71,046,100	\$465,746,653
Gas Cleaning	\$321,921,945	\$32,192,194	\$63,740,545	\$417,854,684
Methanation Reactors	\$104,887,394	\$10,488,739	\$20,767,704	\$136,143,838
Steam Turbines	\$58,770,525	\$5,877,052	\$11,636,564	\$76,284,141
Cooling Towers	\$4,849,953	\$484,995	\$960,291	\$6,295,239
Water Systems	\$78,237,382	\$7,823,738	\$15,491,002	\$101,552,122
Piping	\$78,237,382	\$7,823,738	\$15,491,002	\$101,552,122
I&C	\$28,650,309	\$2,865,031	\$5,672,761	\$37,188,101
Electrical Systems	\$88,154,797	\$8,815,480	\$17,454,650	\$114,424,926
Buildings and Structures	\$101,378,016	\$10,137,802	\$20,072,847	\$131,588,665
Total Capital Investment				\$1,916,617,513

Table 5. Total capital investment, conventional SNG case.



Figure 4. Total capital investment, conventional SNG case.

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	Installed Cost	Engineering Fee	Contingency	Total Capital Cost
HTGRs	\$5,753,550,508			\$5,753,550,508
HTSE	\$375,595,878	\$37,559,588	\$74,367,984	\$487,523,450
Power Cycles	\$799,048,670	\$79,904,867	\$158,211,637	\$1,037,165,174
Coal Preparation	\$51,783,920	\$5,178,392	\$10,253,216	\$67,215,528
Gasification	\$166,930,172	\$16,693,017	\$33,052,174	\$216,675,364
Gas Cleaning	\$166,225,747	\$16,622,575	\$32,912,698	\$215,761,020
Methanation Reactors	\$136,683,372	\$13,668,337	\$27,063,308	\$177,415,017
Steam Turbines	\$2,364,167	\$236,417	\$468,105	\$3,068,689
HRSG	\$53,106,909	\$5,310,691	\$10,515,168	\$68,932,767
Cooling Towers	\$4,175,358	\$417,536	\$826,721	\$5,419,615
Water Systems	\$67,937,452	\$6,793,745	\$13,451,616	\$88,182,813
Piping	\$67,937,452	\$6,793,745	\$13,451,616	\$88,182,813
I&C	\$24,878,504	\$2,487,850	\$4,925,944	\$32,292,298
Electrical Systems	\$76,549,242	\$7,654,924	\$15,156,750	\$99,360,916
Buildings and Structures	\$88,031,628	\$8,803,163	\$17,430,262	\$114,265,053
Total Capital Investment	\$8,455,011,024			
Total Capital Investment	(+50% HTGR)			\$11,331,786,278
Total Capital Investment	\$6,728,945,872			

Table 6. Total capital investment, nuclear-integrated SNG case.



Figure 5. Total capital investment, nuclear-integrated SNG case.

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4.2 Estimation of Revenue

Yearly revenues were estimated for all cases based on recent price data for the various products generated. Revenues were estimated for low, average, and high prices for the SNG product, which is assumed to be the price of natural gas at the city gate, which is the distributed price of natural gas and is the wellhead price plus pipeline transport cost. High prices correspond to values from June 2008, low prices are from September 2009, and average prices were the average of the high and low values (EIA 2010). SNG (city gate natural gas) prices were gathered from the Energy Information Administration (EIA) and represent wholesale prices and do not include taxes. Selling prices for slag and sulfur were not varied in the study; this was a reasonable assumption since these prices historically follow the standard rate of inflation and do not vary widely during the year, unlike natural gas prices. Revenues were also calculated to determine the necessary selling prices of SNG to achieve a specific rate of return; however, these revenues are not presented in the following tables. A stream factor of 92% is assumed for both the fossil and nuclear plants. Table 7 presents the revenues for the conventional SNG case and Table 8 presents the revenues for the nuclearintegrated SNG case.

Oxygen is generated in the nuclear-integrated SNG case. However, it was determined that the volume produced would saturate the U.S. oxygen market if several plants were constructed. Therefore, revenues for this stream are not included in the analysis.

	F	Price		erated	Annual Revenue
Slag	25.63	\$/ton	757	ton/day	\$6,510,242
Sulfur	38.13	\$/ton	333	ton/day	\$4,265,586
SNG, low	5,350	\$/MMSCF	151	MMSCFD	\$271,276,030
SNG, average	8,600	\$/MMSCF	151	MMSCFD	\$436,069,880
SNG, high	11,850	\$/MMSCF	151	MMSCFD	\$600,863,730
Annual Revenue, l	0W				\$282,051,858
Annual Revenue, a	verage				\$446,845,708
Annual Revenue, h	igh				\$611,639,558

Table 7. Annual revenues, conventional SNG case.

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	P	Price		erated	Annual Revenue
Slag	25.63	\$/ton	273	ton/day	\$2,374,326
Sulfur	38.13	\$/ton	123	ton/day	\$1,576,780
SNG, low	5,350	\$/MMSCF	148	MMSCFD	\$265,886,440
SNG, average	8,600	\$/MMSCF	148	MMSCFD	\$427,406,240
SNG, high	11,850	\$/MMSCF	148	MMSCFD	\$588,926,040
Annual Revenue,	low				\$269,837,545
Annual Revenue, average				\$431,357,345	
Annual Revenue, high					\$592,877,145

Table 8. Annual revenues, nuclear-integrated SNG case.

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).

Labor costs are assumed to be 1.15% of the TCI for both cases. This percentage is based on staffing requirements for a conventional 50,000 bbl/day coal to liquids plant, that percentage is assumed to adequately represent the labor for the conventional SNG plant and the fossil portion of the nuclear-integrated SNG plant. Maintenance costs were assumed to be 3% of the TCI per the Handbook of Petroleum Processing. The power cycles and HTSE were not included in the TCI for operation and maintenance costs, as they were calculated separately. Taxes and insurance were assumed to be 1.5% of the TCI, excluding the HTGR, an overhead of 65% of the labor and maintenance costs was assumed, and royalties were assumed to be 1% of the coal cost, this value was assumed based on information presented in the Handbook of Petroleum Processing (Jones 2006). Table 9 and Table 10 provide the manufacturing costs for the conventional SNG case and the nuclear-integrated SNG case, respectively. Again, availability of both the fossil and nuclear plants was assumed to be 92%. The conventional SNG annual manufacturing costs includes sequestration, in the model an analysis was performed for the conventional case to assess the impact of sequestering or not sequestering CO_2 on the economics.

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Table 9. Annual manufactur	ing cos	sts, convent	ional Siv	G case.	
		Price	Con	sumed	Annual Cost
Direct Costs					
Materials					
Coal	36.1	6 \$/ton	10,600	ton/day	\$128,719,740
Fly Ash Disposal	33.2	0 \$/ton	318	ton/day	\$3,540,961
Rectisol Solvent	1.1	0 \$/gal	3,360	gal/day	\$1,241,095
Wastewater Treatment	1.3	l \$/k-gal	3,276	k-gal/day	\$1,446,436
Makeup H ₂ O Clarifying	0.0	2 \$/k-gal	9,405	k-gal/day	\$77,246
Carbon, Hg Guard Bed	7.64	4 \$/lb	14	lb/day	\$25,745
Zinc Oxide	30	$0 \ \text{/ft}^3$	3.44	ft ³ /day	\$346,088
Sour Shift Catalyst	82	5 $$/ft^3$	2.15	ft ³ /day	\$595,612
Claus Catalyst	2	$1 \ \text{$/ft}^3$	2.60	ft ³ /day	\$18,364
Sulfur Reduction Catalyst	27	$5 \ \text{/ft}^3$	0.54	ft ³ /day	\$49,597
HT Methanation Catalyst	3,60	$0 \ \text{$/\text{ft}^3}$	0.39	ft^3	\$471,620
LT Methanation Catalyst	70	$0 \ \text{$/ft}^3$	0.06	ft^3	\$15,096
CO ₂ Sequestration	14.54	4 \$/ton	15,025	ton/day	\$73,350,071
Utilities					
Electricity	1.67	/ \$/kW-day	132,700	kW	\$74,434,126
Water	0.05	5 \$/k-gal	9,405	k-gal/day	\$145,278
Royalties					\$1,287,197
Labor and Maintenance					\$79,539,627
Indirect Costs					·
Overhead					\$51,700,757
Insurance and Taxes					\$28,749,263
Manufacturing Costs					\$445,753,919

Operating and maintenance costs for the nuclear plant were based on data from General Atomics for the gas-turbine modular high-temperature reactor published in 2002; these costs were inflated to 2009 dollars (GA 2002). These costs include all costs for the HTGR including cooling water costs and water treatment costs. HTSE cell replacement costs were calculated assuming cell replacement every eight years based on vendor input; see TEV-693, *Nuclear-Integrated Hydrogen Production Analysis*, for detailed information regarding calculation of cell replacement costs (McKellar 2010).

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Table 10 Annual manufactu	ring co	oste	s nuclear	-integrat	ed SNG ca	se
	11115 0	Pri	ce	Cor	sumed	Annual Cost
Direct Costs				001		
Materials						
Coal	36.1	6	\$/ton	3,864	ton/day	\$46,921,988
Fly Ash Disposal	33.2	0	\$/ton	116	ton/day	\$1,290,869
Rectisol Solvent	1.1	0	\$/gal	902	gal/day	\$333,195
Wastewater Treatment	1.3	1	\$/k-gal	2,532	k-gal/day	\$1,117,969
Makeup H ₂ O Clarifying	0.0	2	\$/k-gal	7,901	k-gal/day	\$64,890
Carbon, Hg Guard Bed	7.6	4	\$/lb	5	lb/day	\$8,955
Zinc Oxide	30	0	ft^3	2.91	ft ³ /day	\$293,254
Sour Shift Catalyst	82	5	ft^3	0.90	ft ³ /day	\$6,315
Claus Catalyst	2	1	ft^3	0.21	ft ³ /day	\$19,124
HT Methanation Catalyst	3,60	0	ft^3	0.38	ft^3	\$454,746
LT Methanation Catalyst	70	0	ft^3	0.06	ft^3	\$14,497
HTSE Cell Replacement	0.02	4	\$/lb H ₂	1,981	k-lb/hr H ₂	\$16,128,887
Nuclear Fuel	8.8	0	\$/MW-h	1,347	MW _e	\$95,502,341
Utilities						
Electricity	1.67	7	\$/kW-day	0	kW	\$0
Water	0.05	5	\$/k-gal	7,901	k-gal/day	\$122,038
Royalties						\$469,220
O&M, Nuclear	3.5	7	\$/MW-h	1,347	MW _e	\$38,717,165
Labor and Maintenance						\$60,439,092
Indirect Costs					I	
Overhead						\$39,285,410
Insurance and Taxes						\$40,521,908
Manufacturing Costs						\$341,711,862

4.4 Economic Comparison

To assess the economic desirability of the SNG cases several economic indicators were calculated for each case. For all cases the internal rate of return (IRR) for low, average, and high SNG selling prices was calculated. In addition, the SNG price necessary for a return of 12% was calculated for all cases. The following assumptions were made for the economic analyses:

- The plant startup year is 2014.
- A construction period of three years for the fossil plant and five years for the nuclear plant:
 - Fossil plant construction begins in 2011
 - Nuclear plant construction begins in 2009

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- It is assumed that all reactors come online at the same time. A study was conducted to determine the impact of six month and three month reactor staging versus all reactors coming online at one time. It was determined that the simplification of assuming all reactors online at once does not impact the economic results significantly enough to warrant the complexity of creating multiple staging trains for each scenario. Differences in staging resulted in on average a 1% difference in the economic results for three month staging and 10% difference for six month staging. Furthermore, when large quantities of reactors are required, it would be necessary for nth of a kind plants to come online in at least 3 month intervals.
 - Percent capital invested for the fossil plant is 33% per year
 - Percent capital invested for the HTGR is 20% per year
- Plant startup time is one year
 - Operating costs are 85% of the total value during startup
 - Revenues are 60% of the total value during startup
- The analysis period for the economic evaluation assumes an economic life of 30 years, excluding construction time (the model is built to accommodate up to 40 years).
- An availability of 92% was assumed for both the fossil and nuclear plants, the plants are assumed to operate 365 days a year, 24 hours per day.
- An inflation rate of 2.5% is assumed.
- Debt to equity ratio of 80%/20%, the economic model can handle a variety of debt to equity ratios from 100% equity to 100% debt.
 - The interest rate on debt is assumed to be 8%.
 - The repayment term on the loan is assumed to be 15 years.
- The effective income tax rate is 38.9%:
 - State tax is 6%
 - Federal tax is 35%
- MARCS depreciation is assumed, with a 15 year plant life.
- A CO₂ tax of 0/ton to 200/ton is investigated for the SNG cases.

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4.4.1 Cash Flow

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

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$$T_k = t \left(R_k - E_k - d_k \right) \tag{4}$$

Depreciation for the economic calculations was calculated using a standard MARCS depreciation method with a property class of 15 years. Depreciation was assumed for the total capital investment over the five year construction schedule, including inflation. Table 11 presents the recovery rates for a 15 year property class (Perry 2008):

	1		
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

Table 11. MARCS depreciation.

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 flow each year there is a capital expenditure (C_k), this includes the equity capital and the debt principle. The BTCF is defined as follows (Sullivan 2003):

$$BTCF_k = R_k - E_k - C_k \tag{5}$$

The ATCF can then be defined as:

$$ATCF_k = BTCF_k - T_k \tag{6}$$

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

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4.4.2 Internal Rate of Return

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

$$PW(i^{\prime}\%) = \sum_{k=0}^{N} ATCF_{k} (1+i^{\prime})^{-k} = 0$$
(7)

IRR calculations were performed for an 80%/20% debt to equity ratio for the calculated TCI and at +50% and -30% TCI for the HTGR at low, average, and high SNG prices. In addition, the price of SNG necessary for an IRR of 12% and a PW of zero was calculated for each case at each debt to equity ratio. The IRR and SNG price required (for an IRR of 12%) was solved for using the Goal Seek function in Excel (Excel 2007).

Finally, a CO₂ tax was included into the calculations to determine the price of SNG necessary in all cases for a 12% IRR and a CO₂ tax of 0/100 to 200/100. These cases were calculated for an 0/20 debt to equity ratio for the TCI and +50% and -30% TCI of the HTGR. Additionally, the SNG case was calculated for either sequestering or not sequestering the CO₂. The tax calculated was added to the existing yearly tax liability.

5. ECONOMIC MODELING RESULTS

Table 12 presents the results for an 80%/20% debt to equity ratio for the conventional SNG and nuclear-integrated SNG cases, listing the IRR for low, average, and high SNG selling prices, and the SNG selling price required for a 12% IRR. Figure 6 depicts the associated IRR results for the SNG cases. Table 13 presents the carbon tax results for the conventional and nuclear-integrated SNG cases for a 12% IRR and Figure 7 depicts the carbon tax results for the conventional and nuclear-integrated SNG cases for a 12% IRR and Figure 7 depicts the carbon tax results for the conventional and nuclear-integrated SNG cases, at a 12% IRR. All results are presented for the HTGR at TCI and at +50% and -30% of the HTGR TCI. A value of "N/A" indicates that the manufacturing costs exceeded the revenues.

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	TCI -30	TCI -30% HTGR		CI	TCI +50	% HTGR
	IRR	\$/MSCF	IRR	\$/MSCF	IRR	\$/MSCF
			\$1,916	,617,513		
			N/A	\$5.35		
SNG			2.98	\$8.60		
			14.50	\$11.85		
			12.00	\$11.06		
			\$1,916	,617,513		
			N/A	\$5.35		
SNG with Seq.			-21.65	\$8.60		
			7.96	\$11.85		
			12.00	\$13.06		
	\$6,728,	945,872	\$8,455	,011,024	\$11,331	,786,278
	N/A	\$5.35	N/A	\$5.35	N/A	\$5.35
HTGR SNG	-6.04	\$8.60	-7.23	\$8.60	-8.70	\$8.60
	0.50	\$11.85	-1.08	\$11.85	-2.94	\$11.85
	12.00	\$23.46	12.00	\$27.90	12.00	\$35.29

Table 12. Conventional and nuclear-integrated SNG IRR results.



Figure 6. Conventional and nuclear-integrated SNG IRR economic results.

From these results it is apparent that the conventional SNG process, with or without sequestration, provides a higher rate of return than the nuclear-integrated SNG option,

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unless natural gas prices are extremely low; however, this results in negative returns for both cases. As the SNG selling price increases, the disparity between the IRR increases between the two options. However, at very high SNG prices the nuclear-integrated option just becomes economically feasible; however, the natural gas selling price required is probably unrealistically high, over \$25/MSCF. Furthermore, as HTGR price decreases, the associated IRR increases. Given the low rate of return for this option, it is unlikely that the nuclear-integrated SNG process is economically feasible or the conventional case for that matter.

Carbon Tax		TCI -30% HTGR	TCI	TCI +50% HTGR
\$/	ton		SNG Price (\$/MSCF)	
	0		11.06	
	50		17.11	
SNG	100		23.15	
	150		29.20	
	200		35.24	
	0		13.06	
SNC	50		13.06	
SING	100		13.06	
Seq	150		13.06	
	200		13.06	
	0	23.46	27.90	35.29
UTCD	50	23.62	28.05	35.45
HTGR	100	23.77	28.21	35.61
SING	150	23.93	28.37	35.76
	200	24.09	28.52	35.92

Table 13. Conventional and nuclear-integrated SNG carbon tax results at 12% IF	RR.
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Figure 7. Conventional and nuclear-integrated SNG carbon tax results at 12% IRR.

The carbon tax results for the SNG cases show that as the carbon tax increases, the nuclear-integrated SNG economics begin to come in line with the conventional SNG case economics. For the assumed HTGR price of $2,000/kW_t$, a carbon tax of approximately $140/ton CO_2$ equates the economics of the conventional and nuclear-integrated SNG cases. When the HTGR price is decreased by 30%, the necessary carbon tax is approximately $100/ton CO_2$ to equate the economics of the two cases. If sequestration is assumed, no value for the carbon tax would be able to equate the cases, as no CO_2 is emitted in the conventional case. However, given the high natural gas required for the 12% IRR return, over 25/MSCF, even with a CO_2 tax, the HTGR SNG case is economically undesirable.

6. SNG CONCLUSIONS

Results from the nuclear-integrated coal to SNG case indicate that integration of nuclear hydrogen can drastically improve carbon utilization and reduce GHG emissions:

- Coal consumption is decreased by 64% using electrolysis and nuclear power as the hydrogen source.
- Integrating nuclear power and high temperature steam electrolysis also decreases CO₂ emissions from the plant:

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- If carbon capture and sequestration are not assumed for the conventional configuration, CO₂ emissions decrease by 97.4% when electrolysis and nuclear power are utilized.
- If carbon capture and sequestration are assumed for the conventional configuration, CO₂ emissions increase by over 350 tons per day of CO₂ in order to provide topping heat to the electrolyzers.
- It is estimated that a little less than six nuclear high temperature reactors (600 MW_t each) would be required in this configuration to support production of 150 MMSCFD of SNG.

Economically, incorporation of six HTGRs and the associated HTSEs significantly impacts the expected return on investment, when compared to conventional SNG with or without sequestration:

- The required selling price of SNG to achieve a 12% IRR for the nuclear-integrated case is more than two times the selling price required for the conventional SNG case, with or without sequestration.
- When the HTGR capital cost is decreased by 30%, the nuclear-integrated selling price of SNG is still more than one and a half times greater than the conventional case.
- In a carbon constrained scenario where CO₂ emissions are taxed and sequestration is not an option, a CO₂ tax of \$140/ton-CO₂ equates the economics of the nuclear-integrated SNG case with the conventional SNG case.
- The necessary tax decreases to $100/ton-CO_2$ when the capital cost of the HTGR is decreased by 30%.
- The SNG cases have undesirable economics; the necessary selling price for the Nuclear-integrated option to provide a return of at least 12% is roughly four times the current city gate natural gas price (\$27.90/MSCF versus approximately \$7.00/MSCF), the conventional case is roughly one and a half times greater (\$11.06/MSCF).

7. FUTURE WORK AND RECOMMENDATIONS

The following items should be performed in the future, in the event natural gas prices increase to make production of SNG economically feasible, to further refine the process and economic modeling performed for the SNG cases:

• A separate study should be conducted which assesses the optimal siting of the HTGR with respect to the SNG facility, balancing safety concerns associated with separation distance and heat losses associated with transporting high temperature heat long distances.
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- Rigorous Aspen Plus submodels of the HTGR and HTSE units should be developed to fully couple heat and power integration from the HTGR.
- The simplified water treatment hierarchy should be replaced with more rigorous water treatment models based on vendor input.
- Refined estimates of the HTGR capital cost, annual fuel costs, and annual O&M costs should be developed to refine the economic results.
- A water balance around the HTGR should be performed, to determine water requirements.

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9. APPENDIXES

Appendix A, Detailed Modeling Results and Flowsheets

Appendix B, SNG Capital Cost Estimates

Appendix C, [Electronic] Conventional Coal to SNG Stream Results.xls

Appendix D, [Electronic] Nuclear-Integration Coal to SNG Stream Results.xls

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Appendix A Detailed Modeling Results and Flowsheets

	P	rice	Con	sumed	Annual Cost
Direct Costs					
Materials					
Coal	36.16	\$/ton	3,864	ton/day	\$46,921,988
Fly Ash Disposal	33.20	\$/ton	116	ton/day	\$1,290,869
Rectisol Solvent	1.10	\$/gal	902	gal/day	\$333,195
Wastewater Treatment	1.31	\$/k-gal	2,532	k-gal/day	\$1,117,969
Makeup H ₂ O Clarifying	0.02	\$/k-gal	7,901	k-gal/day	\$64,890
Carbon, Hg Guard Bed	7.64	\$/lb	5	lb/day	\$8,955
Zinc Oxide	300	\$/ft ³	2.91	ft ³ /day	\$293,254
Sour Shift Catalyst	825	ft^3	0.90	ft ³ /day	\$6,315
Claus Catalyst	21	ft^3	0.21	ft ³ /day	\$19,124
HT Methanation Catalyst	3,600	\$/ft ³	0.38	\$/ft ³	\$454,746
LT Methanation Catalyst	700	ft^3	0.06	\$/ft ³	\$14,497
HTSE Cell Replacement	0.024	\$/lb H ₂	1,981	k-lb/hr H ₂	\$16,128,887
Nuclear Fuel	8.80	\$/MW-h	1,347	MW _e	\$95,502,341
Utilities					
Electricity	1.67	\$/kW-day	0	kW	\$0
Water	0.05	\$/k-gal	7,901	k-gal/day	\$122,038
Royalties					\$469,220
O&M, Nuclear	3.57	\$/MW-h	1,347	MWe	\$38,717,165
Labor and Maintenance					\$60,439,092
Indirect Costs					
Overhead					\$39,285,410
Insurance and Taxes					\$40,521,908
Manufacturing Costs					\$341,711,862







Calculator Block SUMMARY

FEED & PRODUCT SUMMARY:	
FEEDS:	
RAW COAL FEED RATE = COAL HHV AS FED = COAL MOISTURE AS FED =	10600.3 TON/DY 10934. BTU/LB 13.70 %
PROXIMATE ANALYSIS: MOISTURE FIXED CARBON VOLATILE MATTER ASH	13.70 % 40.12 % 49.28 % 10.60 %
ULTIMATE ANALYSIS: ASH CARBON HYDROGEN NITROGEN CHLORINE SULFUR OXYGEN	10.60 % 70.27 % 4.84 % 1.36 % 0.11 % 3.72 % 9.10 %
SULFANAL ANALYSIS: PYRITIC SULFATE ORGANIC	1.94 % 0.08 % 1.70 %
INTERMEDIATES:	
COAL FEED RATE AFTER DRYING = COAL HHV AFTER DRYING = COAL MOISTURE AFTER DRYNG =	9732.0 TON/DY 11910. BTU/LB 6.00 %
RAW SYNGAS MASS FLOW = RAW SYNGAS VOLUME FLOW = RAW SYNGAS HHV (WET) = RAW SYNGAS HHV (DRY) =	1590292. LB/HR 684. MMSCFD 284.8 BTU/SCF 309.6 BTU/SCF
H2 CO CO2 N2 H2O CH4 H2S	27.3 MOL.% 56.6 MOL.% 5.8 MOL.% 0.6 MOL.% 8.0 MOL.% 51. PPMV 10662. PPMV
QUENCHED SYNGAS MASS FLOW = QUENCHED SYNGAS VOLUME FLOW = QUENCHED SYNGAS HHV (WET) = QUENCHED SYNGAS HHV (DRY) = QUENCHED SYNGAS COMPOSITION:	1555342. LB/HR 655. MMSCFD 293.4 BTU/SCF 301.0 BTU/SCF
H2 CO CO2 N2 H2O CH4 H2S	28.6 MOL.% 59.3 MOL.% 7.4 MOL.% 0.7 MOL.% 2.5 MOL.% 53. PPMV 11171. PPMV
CLEANED SYNGAS MASS FLOW = CLEANED SYNGAS VOLUME FLOW = CLEANED SYNGAS HHV (WET) =	572570. LB/HR 587. MMSCFD 315.1 BTU/SCF

CLEANED SYNGAS HHV (DRY) =	315.1 BTU/SCF
H2 CO CO2 N2 H2O CH4 H2S	74.6 MOL.% 22.9 MOL.% 1.5 MOL.% 0.8 MOL.% 0.0 MOL.% 56. PPMV 0. PPMV
PRODUCT: SNG MASS FLOW = SNG MASS FLOW = SNG VOLUME FLOW = SNG PRODUCED / COAL FED = SNG PRODUCED / COAL FED = SNG HHV (WET) = SNG HHV (DRY) = SNG COMPOSITION:	275062. LB/HR 3301. TON/DY 151. MMSCFD 0.31 LB/LB 14.24 MSCF/TON 958.0 BTU/SCF 961.0 BTU/SCF
CH4 H2 CO CO2 N2 AR H2O H2S	94.3 MOL.% 1.2 MOL.% 0.0 MOL.% 0.5 MOL.% 0.7 MOL.% 0.3 MOL.% 0. PPMV
POWER CALCULATIONS:	
POWER GENERATORS: SATURATED TURBINE POWER OUTPUT = TOTAL POWER GENERATED =	168.6 MW 168.6 MW
POWER CONSUMERS: COAL PROCESSING POWER CONSUMPTION ASU POWER CONSUMPTION = GASIFIER POWER CONSUMPTION = GAS CLEANING POWER CONSUMPTION = SCOT PROCESS POWER CONSUMPTION = CLAUS POWER CONSUMPTION = CO2 LIQUEF. POWER CONSUMPTION = POWER BLOCK POWER CONSUMPTION = METHANATION POWER CONSUMPTION = COOLING TOWER POWER CONSUMPTION = WATER TREATMENT POWER CONSUMPTION = WATER TREATMENT POWER CONSUMPTION TOTAL POWER CONSUMED =	= 5.6 MW 118.3 MW 8.2 MW 60.7 MW 3.9 MW 0.5 MW 64.3 MW 1.9 MW 27.0 MW 4.6 MW 301.3 MW
NET PLANT POWER (+ GEN, - CONS)=	-132.7 MW
WATER BALANCE:	
EVAPORATIVE LOSSES: CMD WATER NOT RECOVERED = COOLING TOWER EVAPORATION = ZLD SYSTEM EVAPORATION = TOTAL EVAPORATIVE LOSSES =	144.6 GPM 6877.6 GPM 341.9 GPM 7364.1 GPM
WATER CONSUMED: GASIFIER ISLAND MAKEUP = BOILER FEED WATER MAKEUP = COOLING TOWER MAKEUP = TOTAL WATER CONSUMED =	24.3 GPM 1211.0 GPM 7233.6 GPM 8468.9 GPM

WATER GENERATED:

GASIFIER ISLAND BLOWDOWN = SYNGAS CONDENSER BLOWDOWN = RECTISOL BLOWDOWN = SULFUR REDUCTION BLOWDOWN = SNG PROCESS WATER = COOLING TOWER BLOWDOWN = TOTAL WATER GENERATED =	186.1 GPM 41.0 GPM 9.1 GPM 30.0 GPM 594.5 GPM 1414.2 GPM 2274.9 GPM
PLANT WATER SUMMARY: NET MAKEUP WATER REQUIRED = WATER CONSUMED / COAL FED = WATER CONSUMED / SNG PRODUCED =	6531.3 GPM 3.70 LB/LB 11.88 LB/LB
CARBON BALANCE SUMMARY:	
% CARBON TO SNG = % CARBON TO SLAG = % CARBON TO FLY ASH = % CARBON TO EOR = % CARBON TO VENT = % UNACCOUNTED CARBON =	35.3 % 0.0 % 0.4 % 64.3 % 0.0 % 0.0 %
CO2 CAPTURED (SEQ OR EOR) = CO2 CAPTURED (SEQ OR EOR) = CO2 PURITY = CO2 CAPTURED / SNG PROD = CO2 CAPTURED / SNG PROD = CO2 CAPTURED / COAL FED =	15025. TON/DY 263. MMSCFD 95.4 % 4.55 LB/LB 1.74 SCF/SCF 1.42 LB/LB
CO2 EMITTED = CO2 EMITTED = FROM CMD = CO2 EMMITED / SNG PROD = CO2 EMMITED / COAL FED =	0. TON/DY 0. MMSCFD 0. TON/DY 0.00 TON/MMSCFD 0.00 LB/LB
EFFICIENCY CALCULATIONS:	
HEAT IN (HHV BASED): COAL HEAT CONTENT =	9658.8 MMBTU/HR
HEAT OUT (HHV BASED): NET POWER = SNG HEAT CONTENT = NET HEAT OUT =	-452.8 MMBTU/HR 6023.3 MMBTU/HR 5570.6 MMBTU/HR
PLANT EFFICIENCY (HHV BASED): EFFICIENCY =	57.7 %

Conventional Coal to SNG





Coal Milling & Drying





Shell Gasifier w/ Heat Recovery



Claus Process



Catalytic Sulfur Reduction (SCOT or Beavon Process w/o H2S Absorber)







Steam Turbines





Simplified Water Treatment







Calculator Block ELECSUM **ELECTROLYSIS SUMMARY:** FEED SUMMARY: H20 FEED: 732901. LB/HR MASS FLOW = 72. DEG. F TEMPERATURE = PRESSURE = 14.7 PSI **PRODUCT SUMMARY:** H2 PRODUCT: 82534. LB/HR MASS FLOW = H2 PURITY = 99.91 MOL-% TEMPERATURE = 79. DEG. F PRESSURE = 650.0 PSI O2 PRODUCT: MASS FLOW = 650367. LB/HR 99.89 MOL-% O2 PURITY = TEMPERATURE = 81. DEG. F PRESSURE = 650.0 PSI HEAT AND POWER SUMMARY: ELECTROLYSIS POWER REQUIREMENT = 1272.3 MW HEAT SUMMARY: **REACTOR HEAT:** 1231.6 MMBTU/HR DUTY REQUIRED = 1231.6 MMBTU 1344129. LB/HR HELIUM MASS FLOW = INLET TEMPERATURE = OUTLET TEMPERATURE = 1292. DEG. F 554. DEG F. 5.0 PSI PRESSURE DROP = TOPPING HEAT: SYNGAS MASS FLOW = 79.9 MMBTU/HR 21718. LB/HR Calculator Block SUMMARY FEED & PRODUCT SUMMARY: FEEDS: RAW COAL FEED RATE = 3864.2 TON/DY 10934. BTU/LB 13.70 % COAL HHV AS FED = COAL MOISTURE AS FED = PROXIMATE ANALYSIS: MOISTURE 13.70 % FIXED CARBON 40.12 % 49.28 % VOLATILE MATTER 10.60 % ASH ULTIMATE ANALYSIS: 10.60 % ASH 70.27 % CARBON 4.84 % HYDROGEN 1.36 % NITROGEN CHLORINE 0.11 % 3.72 % SULFUR

OXYGEN	9.10 %
SULFANAL ANALYSIS: PYRITIC SULFATE ORGANIC	1.94 % 0.08 % 1.70 %
INTERMEDIATES:	
COAL FEED RATE AFTER DRYING =	3547.6 TON/DY
COAL HHV AFTER DRYING =	11910. BTU/LB
COAL MOISTURE AFTER DRYNG =	6.00 %
RAW SYNGAS MASS FLOW = RAW SYNGAS VOLUME FLOW = RAW SYNGAS HHV (WET) = RAW SYNGAS HHV (DRY) = RAW SYNGAS COMPOSITION:	697991. LB/HR 272. MMSCFD 253.6 BTU/SCF 289.4 BTU/SCF
H2	20.1 MOL.%
C0	53.8 MOL.%
C02	10.5 MOL.%
N2	2.0 MOL.%
H20	12.4 MOL.%
CH4	12. PPMV
H2S	9694. PPMV
QUENCHED SYNGAS MASS FLOW =	653636. LB/HR
QUENCHED SYNGAS VOLUME FLOW =	246. MMSCFD
QUENCHED SYNGAS HHV (WET) =	273.4 BTU/SCF
QUENCHED SYNGAS HHV (DRY) =	277.9 BTU/SCF
H2	22.3 MOL.%
C0	59.7 MOL.%
C02	12.8 MOL.%
N2	2.4 MOL.%
H20	1.6 MOL.%
CH4	13. PPMV
H2S	10778. PPMV
CLEANED SYNGAS MASS FLOW = CLEANED SYNGAS VOLUME FLOW = CLEANED SYNGAS HHV (WET) = CLEANED SYNGAS HHV (DRY) = CLEANED SYNGAS COMPOSITION:	485173. LB/HR 208. MMSCFD 311.2 BTU/SCF 311.2 BTU/SCF
H2	26.2 MOL.%
C0	70.5 MOL.%
C02	0.5 MOL.%
N2	2.8 MOL.%
H20	0.0 MOL.%
CH4	15. PPMV
H2S	0. PPMV
PRODUCT: SNG MASS FLOW = SNG MASS FLOW = SNG VOLUME FLOW = SNG PRODUCED / COAL FED = SNG PRODUCED / COAL FED = SNG HHV (WET) = SNG HHV (DRY) = SNG COMPOSITION:	268977. LB/HR 3228. TON/DY 148. MMSCFD 0.84 LB/LB 38.37 MSCF/TON 957.3 BTU/SCF 960.3 BTU/SCF
CH4	94.2 MOL.%
H2	1.2 MOL.%
C0	0.0 MOL.%
C02	0.5 MOL.%

N2 AR H2O H2S	3.7 MOL.% 0.0 MOL.% 0.3 MOL.% 0. PPMV
POWER CALCULATIONS:	
POWER GENERATORS: SATURATED TURBINE POWER OUTPUT = TOTAL POWER GENERATED =	142.4 MW 142.4 MW
POWER CONSUMERS: COAL PROCESSING POWER CONSUMPTION = ELECTROLYSIS POWER CONSUMPTION = GASIFIER POWER CONSUMPTION = GAS CLEANING POWER CONSUMPTION = SCOT PROCESS POWER CONSUMPTION = CLAUS POWER CONSUMPTION = CO2 LIQUEF. POWER CONSUMPTION = POWER BLOCK POWER CONSUMPTION = METHANATION POWER CONSUMPTION = COOLING TOWER POWER CONSUMPTION = WATER TREATMENT POWER CONSUMPTION = TOTAL POWER CONSUMED =	4.1 MW 1272.3 MW 5.6 MW 19.6 MW 1.4 MW 0.2 MW 8.0 MW 1.3 MW 26.0 MW 2.3 MW 4.7 MW 1345.3 MW
NET PLANT POWER (+ GEN, - CONS)=	-1202.9 MW
WATER BALANCE:	
EVAPORATIVE LOSSES: CMD WATER NOT RECOVERED = COOLING TOWER EVAPORATION = ZLD SYSTEM EVAPORATION = TOTAL EVAPORATIVE LOSSES =	62.7 GPM 5172.6 GPM 264.0 GPM 5499.3 GPM
WATER CONSUMED: ELECTROLYSIS FEED = GASIFIER ISLAND MAKEUP = BOILER FEED WATER MAKEUP = COOLING TOWER MAKEUP = TOTAL WATER CONSUMED =	1464.6 GPM 0.0 GPM 84.4 GPM 5433.7 GPM 6982.7 GPM
WATER GENERATED: GASIFIER ISLAND BLOWDOWN = RECTISOL BLOWDOWN = SULFUR REDUCTION BLOWDOWN = SNG PROCESS WATER = COOLING TOWER BLOWDOWN = TOTAL WATER GENERATED =	121.4 GPM 15.8 GPM 10.8 GPM 553.6 GPM 1057.1 GPM 1758.6 GPM
PLANT WATER SUMMARY: NET MAKEUP WATER REQUIRED = WATER CONSUMED / COAL FED = WATER CONSUMED / SNG PRODUCED =	5486.4 GPM 8.53 LB/LB 10.21 LB/LB
CARBON BALANCE SUMMARY:	
% CARBON TO SNG = % CARBON TO SLAG = % CARBON TO FLY ASH = % CARBON TO EOR = % CARBON TO VENT = % UNACCOUNTED CARBON =	95.1 % 0.0 % 0.4 % 0.0 % 4.5 % 0.0 %
CO2 CAPTURED (SEQ OR EOR) =	0. TON/DY

CO2 CAPTURED (SEQ OR EOR) = CO2 PURITY = CO2 CAPTURED / SNG PROD = CO2 CAPTURED / SNG PROD = CO2 CAPTURED / COAL FED =	0. MMSCFD 0.0 % 0.00 LB/LB 0.00 SCF/SCF 0.00 LB/LB
CO2 EMITTED = CO2 EMITTED = FROM TOPPING HEAT = CO2 EMMITED / SNG PROD = CO2 EMMITED / COAL FED =	383. TON/DY 7. MMSCFD 383. TON/DY 2.58 TON/MMSCFD 0.10 LB/LB
EFFICIENCY CALCULATIONS:	
HEAT IN (HHV BASED): COAL HEAT CONTENT =	3521.0 MMBTU/HR
HEAT OUT (HHV BASED): NET POWER = SNG HEAT CONTENT = NET HEAT OUT =	-4104.5 MMBTU/HR 5913.4 MMBTU/HR 1808.9 MMBTU/HR
PLANT EFFICIENCY (HHV BASED): EFFICIENCY =	51.4 %



Electrolysis







.....



Claus Process



Catalytic Sulfur Reduction (SCOT or Beavon Process w/o H2S Absorber)






Methanation





Simplified Water Treatment



Idaho National Laboratory

NUCLEAR-INTEGRATED SUBSTITUTEIdentifier:TEV-671NATURAL GAS PRODUCTIONRevision:1ANALYSISEffective Date:05/15/2010

Appendix B SNG Capital Cost Estimates

NGNP Conventional Coal to SNG Summary

Project Name: NGNP Process Integration Process: Conventioonal Coal to SNG Estimate Number: MA36-E Client:M. PattersonPrepared By:B. Wallace, R. Honsinger, J. MartinEstimate Type:Class 5

Process Component	Subtotal From Detail Sheets	Engineering %	Engineering	Contingency %	Contingency	Total Cost
Air Separation Unit (ASU)	\$ 189,080,478	10%	\$ 18,908,048	18%	\$ 37,437,935	\$ 245,426,461
Coal Preparation	\$ 149,519,375	10%	\$ 14,951,937	18%	\$ 29,604,836	\$ 194,076,148
Gasification	\$ 480,817,037	10%	\$ 48,081,704	18%	\$ 95,201,773	\$ 624,100,514
Water Gas Shift Reactor (WGS)	\$ 32,413,311	10%	\$ 3,241,331	18%	\$ 6,417,836	\$ 42,072,477
Rectisol	\$ 275,493,867	10%	\$ 27,549,387	18%	\$ 54,547,786	\$ 357,591,039
Methanation	\$ 140,549,108	10%	\$ 14,054,911	18%	\$ 27,828,723	\$ 182,432,742
Claus & SCOT	\$ 91,556,456	10%	\$ 9,155,646	18%	\$ 18,128,178	\$ 118,840,280
CO2 Compression	\$ 31,911,773	10%	\$ 3,191,177	18%	\$ 6,318,531	\$ 41,421,481
Steam Turbines	\$ 78,752,503	10%	\$ 7,875,250	18%	\$ 15,592,996	\$ 102,220,749
Cooling Towers	\$ 6,498,937	10%	\$ 649,894	18%	\$ 1,286,790	\$ 8,435,620
Total Cost - Conventional Coal to SNG						\$ 1,916,617,513
Total Cost Rounded to the Nearest \$10M				_		\$ 1,920,000,000

	Remarks
Checked By: Sole	

4/20/2010

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

COST ESTIMATE SUPPORT DATA RECAPITULATION

Project Title:	NGNP Process Integration – Conventional Coal to SNG	
Estimator:	B. W. Wallace/CEP, R. R. Honsinger/CEP, J. B. Martin/CCT	
Date:	April 20, 2010	
Estimate Type:	Class 5	
File:	MA36-E	
Approved By: 🤇	durta	• Page 1 of 7
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I. **<u>PURPOSE</u>**: Brief description of the intent of how the estimate is to be used (i.e., for engineering study, comparative analysis, request for funding, proposal, etc.).

It is expected that the capital costs identified in these estimates will be used in a model producing an economic analysis for each specific integrated application and subsequently will be considered in a related feasibility study.

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

A. **Objective**:

Develop Class 5 estimates as defined by the Association for Advancement of Cost Engineering (AACEi) that will identify the current capital cost associated with a coal-to-synthetic natural gas (SNG) process.

B. Included:

The scope of work required to achieve this objective includes the following:

1. Engineering

- 2. Construction of a new coal-to-SNG refinery that consists of the following:
 - a. Air separation unit
 - b. Coal preparation
 - c. Gasification process
 - d. Water gas shift reactors
 - e. Rectisol unit
 - f. Methanation
 - g. Claus and SCOT processes
 - h. CO₂ compression
 - i. Steam turbines, internal to process
 - j. Heat recovery steam generator, internal to process
 - k. Cooling towers, internal to process
 - 1. Allowances for Balance of Plant (BOP)/offsite/outside of battery limits (OSBL), including the following:
 - (1.) Site development/improvements
 - (2.) Provisions for general and administrative buildings and structures
 - (3.) Provisions for OSBL piping
 - (4.) Provisions for OSBL instrumentation and control
 - (5.) Provisions for OSBL electrical

- Continued -

Project Title:NGNP Process Integration – Conventional Coal to SNGFile:MA36-E

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- (6.) Provisions for facility supply and OSBL water systems
- (7.) Provisions for site development/improvements
- (8.) Project/construction management.

C. Excluded:

This scope of work specifically excludes the following elements:

- 1. Licensing and permitting costs
- 2. Operational costs
- 3. Land costs
- 4. Sales taxes
- 5. Royalties
- 6. Owner's fees and owner's costs.
- III. **ESTIMATE METHODOLOGY:** Overall methodology and rationale of how the estimate was developed (i.e., parametric, forced detail, bottoms up, etc.). Total dollars/hours and rough order magnitude (ROM) allocations of the methodologies used to develop the cost estimate.

Consistent with the AACEi Class 5 estimates, the level of definition and engineering development available at the time they were prepared, their intended use in a feasibility study, and the time and resources available for their completion, the costs included in this estimate have been developed using parametric evaluations. These evaluations have used publicly available and published project costs to represent similar islands utilized in this project. Analysis and selection of the published costs used have been performed by the project technical lead and Cost Estimating. Suitability for use in this effort was determined considering the correctness and completeness of the data available, the manner in which total capital costs were represented, the age of the previously performed work, and the similarity to the capacity/trains required by this project. The specific sources, selected and used in this cost estimate, are identified in the capital cost estimate detail sheets. Adjustments have been made to these published costs using escalation factors identified in the Chemical Engineering Price Cost Index. Scaling of the published island costs has been accomplished using the six-tenths capacity factoring method. Any normalization to provide for geographic factors was considered using geographic factors available from RS Means Construction Cost Data references. Cost-estimating relationships have been used to identify allowances to complete the costs.

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

- Continued -

Project Title: NGNP Process Integration – Conventional Coal to SNG File: MA36-E

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

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

All islands and capacities have been provided to Cost Estimating by the respective project expert.

- B. <u>Planning Basis</u>: The source for the execution and strategies of the work that can be used to support the project execution plan, acquisition strategy, schedules, and market conditions and other documentation upon which the estimate is originated.
 - 1. All islands represent nth of a kind projects.
 - 2. Projects will be constructed and operated by commercial entities.
 - 3. All projects will be located in the U.S. Gulf Coast refinery region.
 - 4. Costs are presented as overnight costs.
 - 5. The cost estimate does not consider or address funding or labor resource restrictions. Sufficient funding and labor resources will be available in a manner that allows optimum usage of the funding and resources as estimated and scheduled.
- C. <u>Cost Basis</u>: The source for the costing on the estimate that can be used in support of earned value management, funding profiles, and schedule of values. Sources may include published costing references, judgment, actual costs, preliminary quotes or other documentation upon which the estimate is originated.
 - 1. All costs are represented as current value costs. Factors for forward-looking escalation and inflation factors are not included in this estimate.
 - 2. Where required, published cost factors, as identified in the Chemical Engineering Plant Cost Index, will be applied to previous years' values to determine current year values.
 - 3. Geographic location factors, as identified in RS Means Construction Cost Data reference manual, were considered for each source cost.
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V. **ESTIMATE QUALITY ASSURANCE:** A listing of all estimate reviews that have taken place and the actions taken from those reviews.

A review of the cost estimate was held on January 14, 2010, with the project team and the cost estimators. This review allowed for the project team to review and comment, in detail, on the perceived scope, basis of estimates, assumptions, project risks, and resources that make up this cost estimate. Comments from this review have been incorporated into this estimate to reflect a project team consensus of this document.

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

General Assumptions:

- A. All costs are represented in 2009 values.
- B. Costs that were included from sources representing years prior to 2009 have been normalized to 2009 values using the Chemical Engineering Plant Cost Index. This index was selected due to its widespread recognition and acceptance and its specific orientation toward work associated with chemical and refinery plants.
- C. Capital costs are based on process islands. The majority of these islands are interchangeable, after factoring for the differing capacities, flowsheet-to-flowsheet.
- D. All chemical processing and refinery processes will be located in the U.S. Gulf Coast region.
- E. All costs considered to be balance of plant costs that can be specifically identified have been factored out of the reported source data and added into the estimate in a

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manner consistent with that identified in the NETL 2000 IGCC Base Cost report. Inclusion of the source costs in this manner normalizes all reported cost information to the bare-erected costs.

Coal to SNG

- A. The air separation unit for this process requires an increase in oxygen output purity from 95 to 99.5%. A factor, based on INL simulations, of 1.36⁰.6 was applied to the sources, which assumed 95% oxygen purity.
- B. The NETL 2000 report lists the quench compressor separately from the gasification unit. The NETL 2007b report includes the cost of the quench compressor with the cost of the gasification unit. The costs were normalized to include both the quench compressor and gasification unit.
- C. The WorleyParsons 2002 report includes engineering costs in the costs presented. Information from this report was factored by 0.9 to normalize the data by excluding the engineering allowance.

VII. <u>CONTINGENCY GUIDELINE IMPLEMENTATION</u>:

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

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

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

- 1. The level of project definition/development that was available at the time the estimate was prepared represents a substantial risk to the project and is likely to occur. The high level at which elements were considered and included has the potential to include additional elements that are within the work scope but not sufficiently provided for or addressed at this level.
- 2. The estimate methodology employed is one of a stochastic parametrically evaluated process. This process used publicly available published costs that were related to the process required, costs were normalized using price indices, and the cost was scaled to provide the required capacity. The cost-estimating relationships that were used represent typical costs for balance of plant

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allowances, but source cost data from which the initial island costs were derived were not completely descriptive of the elements included, not included, or simply referred to with different nomenclature or combined with other elements. While every effort has been made to correctly normalize and factor the costs for use in this effort, the risk exists that not all of these were correctly captured due to the varied information available.

- 3. This project is heavily dependent on metals, concrete, petroleum, and petroleum products. Competition for these commodities in today's environment due to global expansion, uncertainty, and product shortages affect the basic concepts of the supply and demand theories, thus increasing costs.
- 4. Impacts due to large quantities of materials, special alloy materials, fabrication capability, and labor availability could all represent conditions that may increase the total cost of the project.

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

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

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

VIII. OTHER COMMENTS/CONCERNS SPECIFIC TO THE ESTIMATE:

None.

Detail Item Report - Air Separation Unit (ASU)

Project Name:	NGNP Process Integration	Client:	M. Patterson
Process:	Conventional Coal to SNG	Prepared By:	B. Wallace, R. Honsinger, J. Martin
Estimate Number:	MA36-E	Estimate Type:	Class 5

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	R	Reported Cost	Reporting Year Cost Per Train		No P	ormalized Cost er Train using CEPCI Index	Capaci Require	Capacity Required		Capacity per Train		Capacity per Train		Capacity per Train		Fa pe No	actored Cost er Train from ormalized Cost	Tot	al Current Cost for Required Trains
Shell IGCC Base Case (NETL 2000)	213,207	lb/hr	1	1999	\$	51,204,000	\$	51,204,000	\$	67,118,402	623,231	lb/hr	1	623,231	lb/hr	\$	127,746,839	\$	153,629,108				
NETL Baseline Report (NETL 2007a)	1,728,789	lb/hr	2	2006	\$	287,187,000	\$	143,593,500	\$	147,157,470	623,231	lb/hr	1	623,231	lb/hr	\$	120,932,921	\$	145,434,650				
Princeton Report (Kreutz 2008)	201,264	lb/hr	1	2007	\$	105,000,000	\$	105,000,000	\$	102,322,040	623,231	lb/hr	1	623,231	lb/hr	\$	201,603,914	\$	242,450,065				
Hydrogen Report (Gray 2004)	296,583	lb/hr	1	2004	\$	76,000,000	\$	76,000,000	\$	87,600,180	623,231	lb/hr	1	623,231	lb/hr	\$	136,775,020	\$	136,775,020				
Shell GTC Report (Shell 2004)	385,259	lb/hr	1	2004	\$	53,760,000	\$	53,760,000	\$	61,965,601	623,231	lb/hr	1	623,231	lb/hr	\$	82,696,746	\$	99,451,598				
Shell IGCC Power Plant with CO2	1							· · · · · · · · · · · · · · · · · · ·											-				
Capture (NETL 2007b)	373,498	lb/hr	2	2006	\$	144,337,000	\$	72,168,500	\$	73,959,712	623,231	lb/hr	1	623,231	lb/hr	\$	152,415,687	\$	183,296,010				
			1													1							

Source Selected:

Source	Report Capac	ed ity	Reported Trains	Report Cost Year	Reported Cost	Normalized Cost Reporting Year Per Train using Capacity Reported Cost Cost Per Train CEPCI Index Required		Trains Reqd.	Trains Capacity per Regd. Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains	
Average of normalized and factored costs from NETL 2007a and Gray 2004										\$ 128,853,970	\$ 141,104,835		

Balance of Plant:

Description	% of Total Cost				Cost Per	Train	Total Cost
Water Systems	7.10%				\$ 9,1	48,632	\$ 10,018,443
Civil/Structural/Buildings	9.20%				\$ 11,8	54,565	\$ 12,981,645
Piping	7.10%				\$ 9,1	48,632	\$ 10,018,443
Control and Instrumentation	2.60%				\$ 3,3	50,203	\$ 3,668,726
Electrical Systems	8.00%				\$ 10,3	08,318	\$ 11,288,387
				Total Balance of Plant	\$ 43,8	10,350	\$ 47,975,644
				Total Balance of Plant Plus the Selected Source	\$ 172,6	64,320	\$ 189,080,478

Rationale for Selection:

NETL Baseline Report (NETL 2007a) and Hydrogen Report (Gray 2004) have been selected. An average cost of the two has been selected in order to not represent an overly agressive or conservative cost. The allowances lister under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

Note: The base ASU cost was multiplied by "1.36^0.6" to account for the increase in oxygen output purity from 95% to 99.5%. The adjustment is based on INL simulations calculating the increase in capacity that would be needed have the required purity output. The Gray 2004 report uses an oxygen purity of 99% and was not adjusted by the "1.36^0.6."

Detail Item Report - Coal Preparation

Project Name:	NGNP Process Integration	Client:	M. Patterson
Process:	Conventional Coal to SNG	Prepared By:	B. Wallace, R. Honsinger, J. Martin
Estimate Number:	MA36-E	Estimate Type:	Class 5

Sources Considered:

Source	Report Capaci	ed ity	Reported Trains	Report Cost Year	R	eported Cost	Re	eporting Year ost Per Train	Noi Pe C	rmalized Cost r Train using CEPCI Index	Capa Requi	ity red	Trains Reqd.	Capacity Train	Capacity per Train		Capacity per Train		Capacity per Train		Capacity per Train		actored Cost er Train from rmalized Cost	Total Current for Require Trains	Cost ed
Shell IGCC Base Case (NETL 2000)	3,171	tpd	1	1999	\$	17,826,000	\$	17,826,000	\$	23,366,390	10,600) tpd	3	3,533	tpd	\$	24,933,580	\$ 74,800),741						
Hydrogen Report (Gray 2004)	7,787	tpd	1	2004	\$	47,000,000	\$	47,000,000	\$	54,173,796	10,600) tpd	3	3,533	tpd	\$	33,719,252	\$ 101,157	7,755						
Shell GTC Report (Shell 2004)	5,513	tpd	2	2004	\$	60,800,000	\$	30,400,000	\$	35,040,072	10,600) tpd	3	3,533	tpd	\$	40,668,497	\$ 122,005	5,491						
Shell IGCC Power Plant with CO2 Capture (NETL 2007b)	5,678	tpd	2	2006	\$	156,785,000	\$	78,392,500	\$	80,338,191	10,60) tpd	3	3,533	tpd	\$	91,608,037	\$ 274,824	1,111						

Source Selected:

Source	Report Capaci	ed ity	Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required	Trains Reqd.	Capacity Trair	per	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Average of normalized and factored co	verage of normalized and factored cost from Gray 2004 and Shell 2004 repo		04 reports								\$ 37,193,874	\$ 111,581,623	

Balance of Plant:

Description	% of Total Cost				Cost	Per Train	Total Cost
Water Systems	7.10%				\$	2,640,765	\$ 7,922,295
Civil/Structural/Buildings	9.20%				\$	3,421,836	\$ 10,265,509
Piping	7.10%				\$	2,640,765	\$ 7,922,295
Control and Instrumentation	2.60%				\$	967,041	\$ 2,901,122
Electrical Systems	8.00%				\$	2,975,510	\$ 8,926,530
				Total Balance of Plant	\$	12,645,917	\$ 37,937,752
				Total Balance of Plant Plus the Selected Source	\$	49,839,792	\$ 149,519,375

Rationale for Selection:

The Gray 2004 and the Shell 2004 reports identified recent actual costs that appear to be consistent with this project's needs. An average cost of the two has been selected in order to not represent an overly agressive or conservative cost. Cost factoring reflects the 6/10 rule. The allowances listed under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

Detail Item Report - Gasification

Project Name:	NGNP Process Integration	Client:	M. Patterson
Process:	Conventional Coal to SNG	Prepared By:	B. Wallace, R. Honsinger, J. Martin
Estimate Number:	MA36-E	Estimate Type:	Class 5

Sources Considered:

Source	Report Capaci	ed ity	Reported Trains	Report Cost Year	Re	eported Cost	Re	eporting Year ost Per Train	No Pe C	rmalized Cost er Train using CEPCI Index	Capacit Require	y d	Trains Reqd.	Capacity per Train		F p No	actored Cost er Train from ormalized Cost	Total Current C for Required Trains	Cost d
Gasifier																			
Shell IGCC Base Case (NETL 2000)	2,977	tpd	1	1999	\$	87,802,000	\$	87,802,000	\$	115,091,203	9,732	tpd	3	3,244	tpd	\$	121,177,876	\$ 363,533,	,629
Hydrogen Report (Gray 2004)	5,990	tpd	1	2004	\$	87,000,000	\$	87,000,000	\$	100,279,154	9,732	tpd	3	3,244	tpd	\$	69,406,968	\$ 416,441,	,808,
Shell IGCC Power Plant with CO2																			
Capture (NETL 2007b)	5,310	tpd	2	2006	\$	196,948,000	\$	98,474,000	\$	100,918,110	9,732	tpd	3	3,244	tpd	\$	113,810,527	\$ 341,431,	,582
Shell GTC Report (Shell 2004)	5,201	tpd	2	2004	\$	202,240,000	\$	101,120,000	\$	116,554,345	9,732	tpd	3	3,244	tpd	\$	133,089,214	\$ 399,267,	,642
Quench Compressor																			
Shell IGCC Base Case (NETL 2000)	194,116	lb/hr	1	1999	\$	1,900,000	\$	1,900,000	\$	2,490,527	1,404,686	lb/hr	3	468,229	lb/hr	\$	4,224,053	\$ 12,672,	,158

Source Selected:

Source	Report Capac	ed	Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required	Trains Reqd.	Capacity Train	per	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Average of normalized and factored or	sets from NE	TI 200	and NETI	2007h rer	orts including the M	JETL 2000 quench	compressor cost wit	h the NETL 20))) agoifior c	net		\$ 119,606,228	\$ 358,818,685

Balance of Plant:

Description	% of Total Cost				Cost P	Per Train	Tota	al Cost
Water Systems	7.10%				\$ 8	8,492,042	\$ 2	25,476,127
Civil/Structural/Buildings	9.20%				\$ 1 ⁻	1,003,773	\$ 3	33,011,319
Piping	7.10%				\$ 8	8,492,042	\$ 2	25,476,127
Control and Instrumentation	2.60%				\$ 3	3,109,762	\$	9,329,286
Electrical Systems	8.00%				\$ 9	9,568,498	\$ 2	28,705,495
				Total Balance of Plant	\$ 40	0,666,118	\$ 12	21,998,353
				Total Balance of Plant Plus the Selected Source	\$ 160	0,272,346	\$ 48	30,817,037

Rationale for Selection:

Shell IGCC Base Case (NETL 2000) and Shell IGCC Power Plant with CO2 Capture (NETL 2007b) are consistent in factored normalized cost per train, and in the size of trains required. An average cost of the two has been selected in order to not represent an overly agressive or conservative cost. Hydrogen Report (Gray 2004) was excluded as an unexplained and inconsistent outlier cost point. Cost factoring reflects the 6/10 rule. The allowances listed under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

Note: The reported cost of Gray 2004 is \$87,000,000 for the gasification unit, and does not include a heat recovery unit. This cost has been doubled, based on information from an active vendor, UDHE, to account for the addition cost of the heat recovery unit. The quench compressor is listed as an independent line item in the NETL 2000 report. It is factored separately here to better fit the new process model. NETL 2007b includes quench compressor.

Detail Item Report - Water Gas Shift Reactor

Project Name:	NGNP Process Integration	Client:	M. Patterson
Process:	Conventional Coal to SNG	Prepared By:	B. Wallace, R. Honsinger, J. Martin
Estimate Number:	MA36-E	Estimate Type:	Class 5

Sources Considered:

Source	Report Capaci	ed ity	Reported Trains	Report Cost Year	Re	eported Cost	Repo Cost	orting Year t Per Train	Nor Pei C	malized Cost r Train using EPCI Index	Capaci Require	ty ed	Trains Reqd.	ains Capacity eqd. Train		Factored Cost per Train from Normalized Cost	Total Current Co for Required Trains
		MMB										MMB			MMB		
		TU/da										TU/d			TU/da		
Princeton Report (Kreutz 2008)	66,742	У	1	2007	\$	11,760,000	\$	11,760,000	\$	11,460,069	231,801	ay	1	231,801	У	\$ 24,189,038	\$ 24,189,03
		lbmol/										Ibmol			lbmol/		
Hydrogen Report (Gray 2004)	48,243	hr	1	2004	\$	23,000,000	\$	23,000,000	\$	26,510,581	102,999	/hr	1	102,999	hr	\$ 41,788,662	\$ 41,788,66
Shell IGCC Power Plant with CO2		lbmol/										Ibmol			lbmol/		
Capture (NETL 2007b)	63,376	hr	4	2006	\$	12,367,000	\$	3,091,750	\$	3,168,487	102,999	/hr	1	102,999	hr	\$ 9,741,656	\$ 9,741,65

Source Selected:

Source	Report Capac	ed ity	Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacit Require	ty ed	Trains Reqd.	Capacity Trair	/ per	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
		MMB							MMB			MMB		
		TU/da							TU/d			TU/da		
Princeton Report (Kreutz 2008)	66,742	у	1	2007	\$ 11,760,000	\$ 11,760,000	\$ 11,460,069	231,801	ay	1	231,801	у	\$ 24,189,038	\$ 24,189,038

Balance of Plant:

Description	% of Total Cost				Cost Per Tra		Total Cost
Water Systems	7.10%				\$	1,717,422	\$ 1,717,422
Civil/Structural/Buildings	9.20%				\$	2,225,391	\$ 2,225,391
Piping	7.10%				\$	1,717,422	\$ 1,717,422
Control and Instrumentation	2.60%				\$	628,915	\$ 628,915
Electrical Systems	8.00%				\$	1,935,123	\$ 1,935,123
				Total Balance of Plant	\$	8,224,273	\$ 8,224,273
				Total Balance of Plant Plus the Selected Source	\$ 3	32,413,311	\$ 32,413,311

Rationale for Selection:

Princeton Report (Kreutz 2008) is the most recent cost available, the capacity per train most closely reflects this project's needs. The allowances listed under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

Detail Item Report - Rectisol

Project Name:	NGNP Process Integration	Client:	M. Patterson
Process:	Conventional Coal to SNG	Prepared By:	B. Wallace, R. Honsinger, J. Martin
Estimate Number:	MA36-E	Estimate Type:	Class 5

Sources Considered:

Source	Report Capaci	ed ity	Reported Trains	Report Cost Year	R	eported Cost	Re C	eporting Year ost Per Train	No Pe	rmalized Cost er Train using CEPCI Index	Capaci Require	ty ed	Trains Reqd.	Capacity Train	per	Factor per Tra Normali	ed Cost ain from zed Cost	Total Current Cost for Required Trains
		lbmol/										Ibmo			lbmol/			
Fluor/UOP Report (Fluor/UOP 2004)	28,735	hr	1	2003	\$	91,640,000	\$	91,640,000	\$	116,715,622	102,999	l/hr	1	102,999	hr	\$ 251	,062,629	\$ 251,062,629
		Nm3/										Nm3			Nm3/			
Princeton Report (Kreutz 2008)	700,000	hr	1	2007	\$	129,043,041	\$	129,043,041	\$	125,751,879	1,047,113	/hr	1	1,047,113	hr	\$ 160	,122,247	\$ 160,122,247

Source Selected:

Source	Reported Reporte Capacity Trains		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacit Require	y d	Trains Reqd.	Capacity Train	per	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Average of normalized and factored co								\$ 205,592,438	\$ 205,592,438					

Balance of Plant:

Description	% of Total Cost				Cost Per Train		Total Cost
Water Systems	7.10%				\$	14,597,063	\$ 14,597,063
Civil/Structural/Buildings	9.20%				\$	18,914,504	\$ 18,914,504
Piping	7.10%				\$	14,597,063	\$ 14,597,063
Control and Instrumentation	2.60%				\$	5,345,403	\$ 5,345,403
Electrical Systems	8.00%				\$	16,447,395	\$ 16,447,395
				Total Balance of Plant	\$	69,901,429	\$ 69,901,429
				Total Balance of Plant Plus the Selected Source	\$	275,493,867	\$ 275,493,867

Rationale for Selection:

Fluor/UOP Report (Fluor/UOP 2004) and Princeton Report (Kreutz 2008) have been selected. An average cost of the two has been selected in order to not represent an overly agressive or conservative cost. The allowances listed under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

Detail Item Report - Methanation

Project Name:	NGNP Process Integration	Client:	M. Patterson
Process:	Conventional Coal to SNG	Prepared By:	B. Wallace, R. Honsinger, J. Martin
Estimate Number:	MA36-E	Estimate Type:	Class 5

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	R	eported Cost	Re	eporting Year ost Per Train	Noi Pe C	rmalized Cost r Train using CEPCI Index	Capaci Require	ty ed	Trains Reqd.	Capacity Train	per	Fac per Nori	ctored Cost r Train from malized Cost	Total Current for Requir Trains	t Cost red
Hydrogen Report (Gray 2004)	34	MMS CFD	1	2004	\$	33,000,000	\$	33,000,000	\$	38,036,920	151	MMS CFD	1	151	MMS CFD	\$	93,047,383	\$ 93,04	7,383
Haldor Topsoe Report (Udengaard 2008)	150,000	MMB TU/da y	1	2007	\$	110,000,000	\$	110,000,000	\$	107,194,518	144,658	MMB TU/d ay	1	144,658	MMB TU/da y	\$	104,887,394	\$ 104,88	7,394
			1													1			

Source Selected:

Source	Report Capaci	ed ity	Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacit Require	y d	Trains Reqd.	Capacity Train	per	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
		MMB							MMB			MMB		
Haldor Topsoe Report (Udengaard		TU/da							TU/d			TU/da		
2008)	150,000	у	1	2007	\$ 110,000,000	\$ 110,000,000	\$ 107,194,518	144,658	ay	1	144,658	у	\$ 104,887,394	\$ 104,887,394

Balance of Plant:

Description	% of Total Cost				Cost Per Tra		1	Total Cost
Water Systems	7.10%				\$	7,447,005	\$	7,447,005
Civil/Structural/Buildings	9.20%				\$	9,649,640	\$	9,649,640
Piping	7.10%				\$	7,447,005	\$	7,447,005
Control and Instrumentation	2.60%				\$	2,727,072	\$	2,727,072
Electrical Systems	8.00%				\$	8,390,992	\$	8,390,992
				Total Balance of Plant	\$	35,661,714	\$	35,661,714
				Total Balance of Plant Plus the Selected Source	\$	140,549,108	\$	140,549,108

Rationale for Selection:

The Haldor Topsoe Report (Udengaard 2008) was selected as the most recent cost point, and because the reported capacity is similar the required capacity per train.

Detail Item Report - Claus and SCOT

Project Name:	NGNP Process Integration	Client:	M. Patterson
Process:	Conventional Coal to SNG	Prepared By:	B. Wallace, R. Honsinger, J. Martin
Estimate Number:	MA36-E	Estimate Type:	Class 5

Sources Considered:

	Report	eported	Reported	Report Cost			Re	porting Year	No Pe	rmalized Cost er Train using	Capaci	ty	Trains	Capacity	per	Fact per	tored Cost Train from	Total C for F	urrent Cost Required
Source	Capac	ity	Trains	Year	Re	ported Cost	Co	ost Per Train	C	CEPCI Index	Require	ed	Reqd.	Train		Norm	alized Cost	Т	Trains
Claus and SCOT																			
Princeton Report (Kreutz 2008)	151	tpd	1	2007	\$	33,800,000	\$	33,800,000	\$	32,937,952	333	tpd	2	167	tpd	\$	34,937,385	\$	69,874,770
Shell IGCC Power Plant with CO2																			
Capture (NETL 2007b)	142	tpd	1	2006	\$	22,794,000	\$	22,794,000	\$	24,926,373	333	tpd	2	167	tpd	\$	27,432,542	\$	54,865,085
Claus																			
Shell IGCC Base Cases (NETL 2000)	78	tpd	1	1999	\$	9,964,000	\$	9,964,000	\$	13,060,850	333	tpd	2	167	tpd	\$	20,591,816	\$	41,183,632
Cost Effective Options to Expand																			
SRU Capacity Using Oxygen																			
(WorleyParsons 2002)	79	tpd	1	1999	\$	11,970,000	\$	11,970,000	\$	15,690,323	333	tpd	2	167	tpd	\$	24,474,822	\$	48,949,644
SCOT																			
Shell IGCC Base Cases (NETL 2000)	78	tpd	1	1999	\$	4,214,000	\$	4,214,000	\$	5,523,728	333	tpd	1	333	tpd	\$	13,199,986	\$	13,199,986
Cost Effective Options to Expand																			
SRU Capacity Using Oxygen																			
(WorleyParsons 2002)	143	tpd	1	1999	\$	8,910,000	\$	8,910,000	\$	11,679,263	333	tpd	1	333	tpd	\$	19,376,069	\$	19,376,069

Source Selected:

Source	Report Capaci	ed itv	Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required	Trains Read.	Capacity Trair	per	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
		Ĩ											
VorleyParsons 2002: Combined Claus and SCOT costs												\$ 43,850,891	\$ 68,325,713

Detail Item Report - Claus and SCOT

Project Name:	NGNP Process Integration	Client:	M. Patterson
Process:	Conventional Coal to SNG	Prepared By:	B. Wallace, R. Honsinger, J. Martin
Estimate Number:	MA36-E	Estimate Type:	Class 5

Balance of Plant:

Description	% of Total Cost				Cost Per	Train	Total Cost
Water Systems	7.10%				\$ 3,1	13,413	\$ 4,851,126
Civil/Structural/Buildings	9.20%				\$ 4,0	34,282	\$ 6,285,966
Piping	7.10%				\$ 3,1	13,413	\$ 4,851,126
Control and Instrumentation	2.60%				\$ 1,1	40,123	\$ 1,776,469
Electrical Systems	8.00%				\$ 3,5	08,071	\$ 5,466,057
				Total Balance of Plant	\$ 14,9	09,303	\$ 23,230,743
				Total Balance of Plant Plus the Selected Source	\$ 58,7	60,195	\$ 91,556,456

Rationale for Selection:

The WorleyParsons 2002 cost point was selected because of WorleyParsons' status as a working vendor in this industry. It is expected that this is the highest quality information available at this time. The allowances listed under Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

Note: Costs from WorleyParsons 2002 have been multiplied by 0.9 to adjust for the included engineering costs. This factor was consistent with general process industry standards, and was selected with project team consensus.

Detail Item Report - CO2 Compression

Project Name:	NGNP Process Integration	Client:	M. Patterson
Process:	Conventional Coal to SNG	Prepared By:	B. Wallace, R. Honsinger, J. Martin
Estimate Number:	MA36-E	Estimate Type:	Class 5

Sources Considered:

Source	Report Capaci	ed ity	Reported Trains	Report Cost Year	Re	eported Cost	Rej Co	porting Year ost Per Train	No Pe	rmalized Cost er Train using CEPCI Index	Capaci Require	ty ed	Trains Reqd.	Capacity Train	per	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Subcritical									-								
Princeton Report (Kreutz 2008)	10	MW	1	2007	\$	6,310,000	\$	6,310,000	\$	6,149,067	58	MW	1	58	MW	\$ 17,581,776	\$ 17,581,776
Supercritical																	
Princeton Report (Kreutz 2008)	13	MW	1	2007	\$	9,520,000	\$	9,520,000	\$	9,277,198	7	MW	1	7	MW	\$ 6,232,980	\$ 6,232,980

Source Selected:

Source	Report Capac	ed ity	Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required	Trains Reqd.	Capacity Train	per	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Kreutz 2008: Combined Subcritical and Supercritical Processes										\$ 23,814,756	\$ 23,814,756		

Balance of Plant:

Description	% of Total Cost				Cost P	er Train	Tota	al Cost
Water Systems	7.10%				\$ ´	1,690,848	\$	1,690,848
Civil/Structural/Buildings	9.20%				\$ 2	2,190,958	\$	2,190,958
Piping	7.10%				\$ ´	1,690,848	\$	1,690,848
Control and Instrumentation	2.60%				\$	619,184	\$	619,184
Electrical Systems	8.00%				\$ ´	1,905,180	\$	1,905,180
				Total Balance of Plant	\$ 8	3,097,017	\$	8,097,017
				Total Balance of Plant Plus the Selected Source	\$ 3'	1,911,773	\$	31,911,773

Rationale for Selection:

Single source cost point. Both subcritical and supercritical process costs were included under the CO2 Compression heading. The allowances listed under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

Detail Item Report - Steam Turbines

Project Name:	NGNP Process Integration	Client:	M. Patterson
Process:	Conventional Coal to SNG	Prepared By:	B. Wallace, R. Honsinger, J. Martin
Estimate Number:	MA36-E	Estimate Type:	Class 5

Sources Considered:

Source	Report Capaci	ed ity	Reported Trains	Report Cost Year	Re	eported Cost	Re	eporting Year ost Per Train	Noi Pe C	rmalized Cost r Train using CEPCI Index	Capaci Require	ty ed	Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Steam Turbine and HRSG																	
Shell IGCC Base Cases (NETL 2000)	189	MW	1	1999	\$	50,671,000	\$	50,671,000	\$	66,419,744	169	MW	3	56	MW	\$ 32,082,035	\$ 96,246,104
Steam Turbine																	
NETL Baseline Report (NETL 2007a)	401	MW	4	2006	\$	74,651,000	\$	18,662,750	\$	19,125,957	169	MW	3	56	MW	\$ 13,514,946	\$ 40,544,839
Princeton Report (Kreutz 2008)	275	MW	1	2007	\$	66,700,000	\$	66,700,000	\$	64,998,858	169	MW	3	56	MW	\$ 25,069,629	\$ 75,208,886
Shell IGCC Power Plant with CO2																	
Capture (NETL 2007b)	230	MW	1	2006	\$	44,515,000	\$	44,515,000	\$	45,619,856	169	MW	3	56	MW	\$ 19,590,175	\$ 58,770,525

Source Selected:

Source	Reported Reporte Capacity Trains		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacit Require	ty ed	Trains Reqd.	Capacity Train	per	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Shell IGCC Power Plant with CO2 Capture (NETL 2007b)	230	MW	1	2006	\$ 44,515,000	\$ 44,515,000	\$ 45,619,856	169	MW	3	56	MW	\$ 19,590,175	\$ 58,770,525

Balance of Plant:

Description	% of Total Cost				Cost	Per Train	Total Cost
Water Systems	7.10%				\$	1,390,902	\$ 4,172,707
Civil/Structural/Buildings	9.20%				\$	1,802,296	\$ 5,406,888
Piping	7.10%				\$	1,390,902	\$ 4,172,707
Control and Instrumentation	2.60%				\$	509,345	\$ 1,528,034
Electrical Systems	8.00%				\$	1,567,214	\$ 4,701,642
				Total Balance of Plant	\$	6,660,659	\$ 19,981,978
				Total Balance of Plant Plus the Selected Source	\$ 2	26,250,834	\$ 78,752,503

Rationale for Selection:

Shell IGCC PowerPlant with CO2 Capture (NETL 2007b) is a recently reported cost point that closely reflects this project's requirements. The Princeton Report (Kreutz 2008) source for the steam turbine cost point is the NETL 2007b report. The allowances listed under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

Detail Item Report - Cooling Towers

Project Name:	NGNP Process Integration	Client:	M. Patterson
Process:	Conventional Coal to SNG	Prepared By:	B. Wallace, R. Honsinger, J. Martin
Estimate Number:	MA36-E	Estimate Type:	Class 5

Sources Considered:

Source	Report Capac	ed ity	Reported Trains	Report Cost Year	Rep	ported Cost	Repor Cost I	ting Year Per Train	Norr Per CE	nalized Cost Train using EPCI Index	Capaci Require	ty ed	Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Cooling Tower Depot	200,000	gpm	5	2009	\$	4,892,420	\$	978,484	\$	978,484	197,115	gpm	5	39,423	gpm	\$ 969,991	\$ 4,849,953

Source Selected:

				Report			Normalized Cost					Factored Cost	Total Current Cost
	Report	ed	Reported	Cost		Reporting Year	Per Train using	Capacity	Trains	Capacity	per	per Train from	for Required
Source	Capac	ity	Trains	Year	Reported Cost	Cost Per Train	CEPCI Index	Required	Reqd.	Train		Normalized Cost	Trains

Balance of Plant:

Description	% of Total Cost				Cost Per Train	Total Cost
Water Systems	7.10%				\$ 68,869	\$ 344,347
Civil/Structural/Buildings	9.20%				\$ 89,239	\$ 446,196
Piping	7.10%				\$ 68,869	\$ 344,347
Control and Instrumentation	2.60%				\$ 25,220	\$ 126,099
Electrical Systems	8.00%				\$ 77,599	\$ 387,996
				Total Balance of Plant	\$ 329,797	\$ 1,648,984
				Total Balance of Plant Plus the Selected Source	\$ 1,299,787	\$ 6,498,937

Rationale for Selection:

Single source cost. Publically available current data. Calculated capital costs based on publically available cost data from a vendor regularly engaged in the building of cooling towers. These allowance values are comparable to additional published estimating guides, such as Page 1996.

NGNP Nuclear Coal to SNG Summary

Project Name: NGNP Process Integration Process: Nuclear Coal to SNG Estimate Number: MA36-F Client:M. PattersonPrepared By:B. Wallace, R. Honsinger, J. MartinEstimate Type:Class 5

	Subtotal From Detail					[
Process Component	Sheets	Engineering %	Engineering	Contingency %	Contingency	1	otal Cost
High Temperature Gas Reactor (HTGR)	\$ 5,753,550,508	0%	\$ -	0%	\$ -	\$	5,753,550,508
Rankine Power Cycle	\$ 799,048,670	10%	\$ 79,904,867	18%	\$ 158,211,637	\$	1,037,165,174
High Temperature Steam Electrolysis (HTSE)	\$ 503,303,210	10%	\$ 50,330,321	18%	\$ 99,654,036	\$	653,287,567
Coal Preparation	\$ 69,390,453	10%	\$ 6,939,045	18%	\$ 13,739,310	\$	90,068,807
Gasification	\$ 223,686,431	10%	\$ 22,368,643	18%	\$ 44,289,913	\$	290,344,987
Rectisol	\$ 165,142,957	10%	\$ 16,514,296	18%	\$ 32,698,306	\$	214,355,558
Methanation	\$ 183,155,719	10%	\$ 18,315,572	18%	\$ 36,264,832	\$	237,736,123
Claus & SCOT	\$ 50,392,320	10%	\$ 5,039,232	18%	\$ 9,977,679	\$	65,409,231
CO2 Compression	\$ 7,207,224	10%	\$ 720,722	18%	\$ 1,427,030	\$	9,354,977
Steam Turbines	\$ 71,163,257	10%	\$ 7,116,326	18%	\$ 14,090,325	\$	92,369,908
Heat Recovery Steam Generator	\$ 3,167,984	10%	\$ 316,798	18%	\$ 627,261	\$	4,112,043
Cooling Towers	\$ 5,594,980	10%	\$ 559,498	18%	\$ 1,107,806	\$	7,262,284
Tatal Cost Nuclear Cost to SNC						c	8 455 017 168
Total Cost - Nuclear Coal to SNG						\$	0,400,017,100
Total Cost Rounded to the Nearest \$10M						S	8,460,000,000

	Remarks
Checked By: SAW	

4/20/2010

Page 1 of 1

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

COST ESTIMATE SUPPORT DATA RECAPITULATION

Project Title:	NGNP Process Integration – Nuclear Coal to SNG	
Estimator:	B. W. Wallace/CEP, R. R. Honsinger/CEP, J. B. Martin/CCT	
Date:	April 20, 2010	
Estimate Type:	Class 5	
File:	MA36-F	
Approved By: 🤇	soluto	Page 1 of 9

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

It is expected that the capital costs identified in these estimates will be used in a model producing an economic analysis for each specific integrated application and subsequently will be considered in a related feasibility study.

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

A. **Objective:**

Develop Class 5 estimates as defined by the Association for Advancement of Cost Engineering (AACEi) that will identify the current capital cost associated with high-temperature gas reactors (HTGRs) integrated with a coal-to-synthetic natural gas (SNG) process.

B. Included:

The scope of work required to achieve this objective includes the following:

- 1. Engineering
- 2. The allowance provided for the HTGR represents a complete and operable system. All elements required for construction of this nuclear reactor capability, including an initial steam generator, security systems, contingency, and owner's costs are included in the turn-key allowance. Owner's costs are included only in the case of the reactor capability. It is considered that the total value represents all inside of battery limits (ISBL) elements, outside of battery limits (OSBL) elements, site development, and all ancillary control and operational functions and capabilities.
- 3. Construction of a new integrated refinery capability to produce SNG from coal that consists of the following:
 - a. Overnight island-type costs for HTGRs
 - b. High-temperature steam electrolysis (HTSE) hydrogen production unit
 - c. Coal preparation
 - d. Gasification process
 - e. Rectisol unit.
 - f. Methanation
 - g. Claus and SCOT processes
 - h. CO₂ compression

C	OST ESTIMATE SUPPORT DATA RECAPITULATION
	– Continued –
Project Title:	NGNP Process Integration – Nuclear Coal to SNG
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	 i. Steam turbines, internal to process j. Cooling towers, internal to process k. Allowances for Balance of plant (BOP)/offsite/OSBL, including the following: Site development/improvements Provisions for general and administrative buildings and structures Provisions for OSBL piping Provisions for OSBL instrumentation and control Provisions for OSBL electrical Provisions for facility supply and OSBL water systems
C. <u>Er</u> Tl 1. 2. 3. 4. 5.	 (8.) Project/construction management. xcluded: his scope of work specifically excludes the following elements: Licensing and permitting costs Operational costs Land costs Sales taxes Royalties

- 6. Owner's fees and owner's costs, except those included for the HTGR
- 7. The allowance provided for the HTGR capability excludes all costs associated with materials development, or costs that would not be appropriately associated with an nth of a kind (NOAK) reactor/facility.
- III. **ESTIMATE METHODOLOGY:** Overall methodology and rationale of how the estimate was developed (i.e., parametric, forced detail, bottoms up, etc.). Total dollars/hours and rough order magnitude (ROM) allocations of the methodologies used to develop the cost estimate.

Consistent with the AACEi Class 5 estimates, the level of definition and engineering development available at the time they were prepared, their intended use in a feasibility study, and the time and resources available for their completion, the costs included in this estimate have been developed using parametric evaluations. These evaluations have used publicly available and published project costs to represent similar islands utilized in this project. Analysis and selection of the published costs used have been performed by the project technical lead and Cost Estimating. Suitability for use in this effort was determined considering the correctness and completeness of the data available, the manner in which total capital costs were represented, the age of the previously performed work, and the similarity to the capacity/trains required by this project. The specific sources, selected and used in this cost estimate, are identified in the capital cost estimate detail sheets. Adjustments have been made to these published costs using escalation factors identified in the Chemical Engineering Price Cost Index. Scaling of the published island costs has been accomplished using the six-tenths capacity factoring method. Costs included for the HTGR, power cycles, and HTSE, have been identified and provided by the respective BEA

- Continued -

Project Title:NGNP Process Integration – Nuclear Coal to SNGFile:MA36-F

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subject matter experts. The total cost for each of these items has been linearly calculated from the respective base unit costs. Any normalization to provide for geographic factors was considered using geographic factors available from RS Means Construction Cost Data references. Cost-estimating relationships have been used to identify allowances to complete the costs.

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

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

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

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

All islands and capacities have been provided to Cost Estimating by the respective project expert.

- B. <u>**Planning Basis:**</u> The source for the execution and strategies of the work that can be used to support the project execution plan, acquisition strategy, schedules, and market conditions and other documentation upon which the estimate is originated.
 - 1. All islands and HTGRs represent NOAK projects.
 - 2. Projects will be constructed and operated by commercial entities.
 - 3. All projects, with the exception of the Steam-Assisted Gravity Drainage Project, will be located in the U.S. Gulf Coast refinery region.
 - 4. Costs are presented as overnight costs.
 - 5. The cost estimate does not consider or address funding or labor resource restrictions. Sufficient funding and labor resources will be available in a manner that allows optimum usage of the funding and resources as estimated and scheduled.

– Continued –

Project Title:NGNP Process Integration – Nuclear Coal to SNGFile:MA36-F

- C. <u>Cost Basis</u>: The source for the costing on the estimate that can be used in support of earned value management, funding profiles, and schedule of values. Sources may include published costing references, judgment, actual costs, preliminary quotes or other documentation upon which the estimate is originated.
 - 1. All costs are represented as current value costs. Factors for forward-looking escalation and inflation factors are not included in this estimate.
 - 2. Where required, published cost factors, as identified in the Chemical Engineering Plant Cost Index, will be applied to previous years' values to determine current year values.
 - 3. Geographic location factors, as identified in RS Means Construction Cost Data reference manual, were considered for each source.
 - 4. The cost provided for the HTGR reflects internal BEA cost data that was developed for the HTGR and presented to the NGNP Process Integration team by L. Demmick. Considered in the cost is a pre-conceptual cost estimate prepared by three separate contractor teams. All contractor teams proposed 4-unit NOAK plants with thermal power levels between 2,000 MWt and 2,400 MWt at a cost of roughly \$4B, including owner's cost. This equates to \$1,667 to \$2,000 per kWt. For the purposes of this report, the nominal cost of an HTGR will be set at the upper end of this range, \$2,000 per kWt. This is a complete turnkey cost and includes engineering and construction of a NOAK HTGR, the power cycle, and contingency. The total HTGR cost for each process is calculated linearly as \$1,708,333 per MWth of required capacity, excluding the cost of the power cycles.
 - 5. The cost included for the power cycle was provided by the INL project team expert. The power cycle cost is based on the definition of a 240-MWe capacity and \$618,176 per MWe. The total power cycle cost for each process is calculated linearly as \$618,176 per MWe of required capacity. BOP, engineering, and contingency costs are added to the base cost.
 - 6. The cost included for HTSE was provided by the INL project team expert. The total HTSE cost for each process is calculated linearly as \$36,120,156 per kg/s of required capacity. BOP, engineering, and contingency costs are added to the base cost.
 - 7. Apt, Jay, et al., *An Engineering-Economic Analysis of Syngas Storage*, NETL, July 2008.
 - 8. AACEi, *Recommended Practices*, website, visited November 16, 2009, http://www.aacei.org/technical/rp.shtml.
 - 9. Brown, L. C., et al., "Alternative Flowsheets for the Sulfur-Iodine Thermochemical Hydrogen Cycle," *General Atomics*, February 2003.
 - 10. CEPCI, *Chemical Engineering Magazine*, "Chemical Engineering Plant Cost Index," November 2009: 64.
 - 11. Choi, 1996, Choi, Gerald N., et al, *Design/Economics of a Once-Through Natural Gas Fischer-Tropsch Plant with Power Co-Production*, Bechtel, 1996.
 - 12. Dooley, J., et al, *Carbon Dioxide Capture and Geologic Storage*, Battelle, April 2006.

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COST ESTIMATE SUPPORT DATA RECAPITULATION										
	– Continued –									
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13.	Douglas, Fred R., et al., Conduction Technical and Economic Evaluations – as									
14.	FLUOR/UOP, 2004, Mak, John Y., et al., Synthesis Gas Purification in									
15.	Friedland, Robert J., et al., <i>Hydrogen Production Through Electrolysis</i> , NREL, huma 2002									
16.	Gray, 2004, Gray, David, et al, <i>Polygeneration of SNG, Hydrogen, Power, and</i> <i>Carbon Dioxida from Taxas Lignita</i> , MTP 04, 2004, 18, NETL, December 2004									
17.	Harvego, E. A., et al., <i>Economic Analysis of a Nuclear Reactor Powered</i> High Temperature Electrolysis Hydrogen Production Plant, INL August 2008									
18.	High-Temperature Electrolysis Hydrogen Froduction Flam, INL, August 2008. Harvego, E. A., et al., Economic Analysis of the Reference Design for a Nuclear-Driven High-Temperature-Electrolysis Hydrogen Production Plant, INL, January 2008.									
19.	Ivy, Johanna, <i>Summary of Electrolytic Hydrogen Production</i> , NREL September 2004.									
20.	Ibsen, Kelly, et al., <i>Equipment Design and Cost Estimation for Small Modular</i> <i>Biomass Systems, Synthesis Gas Cleanup, and Oxygen Separation Equipment,</i> NREL, May 2006.									
21.	Klett, Michael G., et al., <i>The Cost of Mercury Removal in an IGCC Plant</i> , NETL, September 2002.									
22.	Kreutz, 2008, Kreutz, Thomas G., et al, "Fischer-Tropsch Fuels from Coal and Biomass," 25 th Annual International Pittsburgh Coal Conference, Pittsburgh, Princeton University, October 2008.									
23.	Loh, H. P., et al., <i>Process Equipment Cost Estimation</i> , DOE/NETL-2002/1169, NETL, 2002.									
24.	NETL, 2000, Shelton, W., et al., <i>Shell Gasifier IGCC Base Cases</i> , PED-IGCC-98-002, NETL, June 2000.									
25.	NETL, 2007a, Van Bibber, Lawrence, <i>Baseline Technical and Economic</i> Assessment of a Commercial Scale Fischer-Tropsch Liquids Facility, DOE/NETL-207/1260, NETL, April 2007.									
26.	NETL, 2007b, Woods, Mark C., et al., <i>Cost and Performance Baseline for Fossil Energy Plants</i> , NETL, August 2007.									
27.	NREL, 2005, Saur, Genevieve, <i>Wind-To-Hydrogen Project: Electrolyzer</i> Capital Cost Study, NREL, December 2008.									
28.	O'Brien, J. E., et al., <i>High-Temperature Electrolysis for Large-Scale Hydrogen</i> and Syngas Production from Nuclear Energy – System Simulation and Economics, INL, May 2009.									
29.	O'Brien, J. E., et al., <i>Parametric Study of Large-Scale Production of Syngas via High-Temperature Co-Electrolysis</i> , INL, January 2009.									
30.	Page, John S., <i>Conceptual Cost Estimating Manual</i> – 2 nd ed., Houston: Gulf Publishing Company, 1996.									
31.	Pietlock, Bernard A., et al., <i>Developing Location Factors by Factoring- as</i> <i>Applied in Architecture, Engineering, Procurement, and Construction</i> , AACEi, October 2006.									

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COST ESTIMATE SUPPORT DATA RECAPITULATION

– Continued –

Project Title:	NGNP Process Integration – Nuclear Coal to SNG	
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- 33. Ramsden, Todd, et al., *Longer-Term (2025) Hydrogen Production from Central Grid Electrolysis*, NREL, May 2008.
- 34. Richardson Construction Estimating Standards, *Process Plant Cooling Towers*, Cost Data Online, September 16, 2009, website, visited December 15, 2009, http://www.costdataonline.com/.
- 35. Sohal, M. S., et al., *Challenges in Generating Hydrogen by High Temperature Electrolysis Using Solid Oxide Cells*, INL, March 2008.
- 36. Steinberg, Meyer, *Conversion of Coal to Substitute Natural Gas (SNG)*, HCE, 2005.
- 37. Udengaard, 2008, Udengaard, Niels R., et al., *Convert Coal, petcoke into valuable SNG*, Haldor Topsoe, April 2008.
- 38. van der Ploeg, H. J., et al., *The Shell Coal Gasification Process for the US Industry*, Shell, October 2004.
- 39. WorleyParsons, 2002, Rameshni, Mahin, *Cost Effective Options to Expand SRU Capacity Using Oxygen*, WorleyParsons, May 2002.
- V. **ESTIMATE QUALITY ASSURANCE:** A listing of all estimate reviews that have taken place and the actions taken from those reviews.

A review of the cost estimate was held on January 14, 2010, with the project team and the cost estimators. This review allowed for the project team to review and comment, in detail, on the perceived scope, basis of estimates, assumptions, project risks, and resources that make up this cost estimate. Comments from this review have been incorporated into this estimate to reflect a project team consensus of this document.

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

General Assumptions:

- A. All costs are represented in 2009 values.
- B. Costs that were included from sources representing years prior to 2009 have been normalized to 2009 values using the Chemical Engineering Plant Cost Index. This index was selected due to its widespread recognition and acceptance and its specific orientation toward work associated with chemical and refinery plants.
- C. Capital costs are based on process islands. The majority of these islands are interchangeable, after factoring for the differing capacities, flowsheet-to-flowsheet.
- D. All chemical processing and refinery processes will be located in the U.S. Gulf Coast region.
- E. All costs considered to be BOP costs that can be specifically identified have been factored out of the reported source data and added into the estimate in a manner consistent with that identified in the NETL 2000 IGCC Base Cost report. Inclusion of the source costs in this manner normalizes all reported cost information to the bare-erected costs.

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HTGR:

- A. The linearly scalable cost included for an HTGR reflects an NOAK reactor with a 750°C-operating temperature.
- B. HTGR is considered to be linearly scalable, by required capacity, per the direction of the project team. This allows the process integration feasibility studies to showcase the financial analysis of the process without the added burden of integer quantity 600-MWth HTGRs.
- C. The allowance represents a turnkey condition for the reactor and its supporting infrastructure.
- D. A high-temperature, high-pressure steam generator is included in the cost represented for HTGR.
- E. A contingency allowance is included in the HTGR cost, but is not identified as a separate line item in this estimate. This allowance was identified and included by the NGNP HTGR project team.
- F. Total cost range, including contingency, for HTGR is -50%, +100%.
- G. Cost included for the power cycle reflects NOAK research and manufacturing developments to allow for assumed high pressures and temperatures.
- H. The power cycle is considered to be linearly scalable, by required capacity, per the direction of the project team. This allows the process integration feasibility studies to showcase the financial analysis of the process.
- I. The cost included for HTSE reflects NOAK research and manufacturing developments, which will increase the expected lifespan of the electrolysis cells.
- J. The HTSE is considered to be linearly scalable, by required capacity, per the direction of the project team. This allows the process integration feasibility studies to showcase the financial analysis of the process.

Coal to SNG

- A. The NETL 2000 report lists the quench compressor separately from the gasification unit. The NETL 2007b report includes the cost of the quench compressor with the cost of the gasification unit. The costs were normalized to include both the quench compressor and gasification unit.
- B. The WorleyParsons 2002 report includes engineering costs in the costs presented. Information from this report was factored by 0.9 to normalize the data by excluding the engineering allowance.

VII. <u>CONTINGENCY GUIDELINE IMPLEMENTATION</u>:

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

At a project risk review on December 9, 2009, the project team discussed risks to the project. An 18% allowance for capital construction contingency has been included at an island level based on the discussion and is included in the summary sheet. The contingency level that was included in the island cost source documents and additional threats and opportunities identified here were considered during this review. The contingency

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identified was considered by the project team and included in Cost and Performance Baseline for Fossil Energy Plants DOE/NETL-2007/1281 and similar reports. Typically, contingency allowance provided in these reports ranged from 15% to 20%. Since much of the data contained in this estimate has been derived from these reports, the project team has also chosen a level of contingency consistent with them.

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

- A. <u>**Threats:**</u> Uncertain events that are potentially negative or reduce the probability that the desired outcome will happen.
 - 1. The singularly largest threat to this estimate surrounds the lump sum cost included for the HTGR reactor(s). This is followed by the HTSE process, where applicable. While the overriding assumption is that these elements will be NOAK, currently, a complete HTGR has not been commissioned and the HTSE has been successfully developed in an integrated laboratory-scale model, but has not been completed in either pilot plant or production scales.
 - 2. The level of project definition/development that was available at the time the estimate was prepared represents a substantial risk to the project and is likely to occur. The high level at which elements were considered and included has the potential to include additional elements that are within the work scope but not sufficiently provided for or addressed at this level.
 - 3. The estimate methodology employed is one of a stochastic parametrically evaluated process. This process used publicly available published costs that were related to the process required, costs were normalized using price indices, and the cost was scaled to provide the required capacity. The cost-estimating relationships that were used represent typical costs for BOP allowances, but source cost data from which the initial island costs were derived were not completely descriptive of the elements included, not included, or simply referred to with different nomenclature or combined with other elements. While every effort has been made to correctly normalize and factor the costs for use in this effort, the risk exists that not all of these were correctly captured due to the varied information available.
 - 4. This project is heavily dependent on copper, petroleum, and petroleum products. Competition for these commodities in today's environment due to global expansion, uncertainty, and product shortages affect the basic concepts of the supply and demand theories, thus increasing costs.
 - 5. Impacts due to large quantities of materials, special alloy materials, fabrication capability, and labor availability could all represent conditions that may increase the total cost of the project.

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- B. **Opportunities:** Uncertain events that could improve the results or improve the probability that the desired outcome will happen.
 - 1. Additional research and work performed with both vendors and potential owner/operators for a specific process or refinery may identify efficiencies and production means that have not been available for use in this analysis.
 - 2. Recent historical data may identify and include technological advancements and efficiencies not included or reflected in the publicly available source data used in this effort.

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

VIII. OTHER COMMENTS/CONCERNS SPECIFIC TO THE ESTIMATE:

None.

Detail Item Report - High Temperature Gas Reactor (HTGR)

Project Name:	NGNP Process Integration	Client:	M. Patterson
Process:	Nuclear Coal to SNG	Prepared By:	B. Wallace, R. Honsinger, J. Martin
Estimate Number:	MA36-F	Estimate Type:	Class 5

Sources Considered:

Source	Report Capaci	ed ity	Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capaci Require	ty ed	Trains Reqd.	Capacity Trair	y per	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
INL Internal Cost Data (INL 2009)	1	MWth		2009	\$ 1,708,333	\$ 1,708,333	\$ 1,708,333	3,368	MWt h				\$ 5,753,550,508	\$ 5,753,550,508
	İ						1	İ					İ	

Source Selected:

Source	Report Capac	ed ity	Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacit Require	y d	Trains Reqd.	Capacity Train	per	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
									MWt					
INL Internal Cost Data (INL 2009)	1	MWth		2009	\$ 1,708,333	\$ 1,708,333	\$ 1,708,333	3,368	h				\$ 5,753,550,508	\$ 5,753,550,508

Balance of Plant:

Description	% of Total Cost				Cost Per Train	Total Cost
Water Systems	0.00%				\$-	\$-
Civil/Structural/Buildings	0.00%				\$-	\$-
Piping	0.00%				\$-	\$-
Control and Instrumentation	0.00%				\$-	\$-
Electrical Systems	0.00%				\$-	\$-
				Total Balance of Plant	\$-	\$-
				Total Balance of Plant Plus the Selected Source	\$ 5,753,550,508	\$ 5,753,550,508

Basis of Estimate Notes:

Single source cost point. This cost has been provided by the subcontracted subject matter expert L. Demick to the INL NGNP Process Integration team. This cost represents a complete turnkey cost. The cost of an HTGR reactor, as provided by L. Demick, is \$2,000,000 per MWth required. This cost used has been reduced to \$1,708,333 per MWth to exclude the cost of power cycles.
Detail Item Report - Rankine Cycle - Case 11, Supercritical PC Case

NGNP Process Integration	Client:	M. Patterson
Nuclear Coal to SNG	Prepared By:	B. Wallace, R. Honsinger, J. Martin
MA36-F	Estimate Type:	Class 5
	NGNP Process Integration Nuclear Coal to SNG MA36-F	NGNP Process IntegrationClient:Nuclear Coal to SNGPrepared By:MA36-FEstimate Type:

Sources Considered:

Source	Report Capaci	ed ity	Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capaci Require	ity ed	Trains Reqd.	Capacity Trair	y per	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
INL Internal Cost Data (INL 2009)	240	MWe	1	2009	\$ 148,362,255	\$ 148,362,255	\$ 148,362,255	1,203	MWe	6	200	MWe	\$ 133,174,778	\$ 799,048,670
	1													
	1						İ		İ					

Summary:

Source	Report Capaci	ed ity	Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capaci Require	ity ed	Trains Reqd.	Capacity Train	per	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
INL Internal Cost Data (INL 2009)	240	MWe	1	2009	\$ 148,362,255	\$ 148,362,255	\$ 148,362,255	1,203	MWe	6	200	MWe	\$ 133,174,778	\$ 799,048,670

Balance of Plant:

Description	% of Total Cost				Cost Per Train	۱	Total Cost
Water Systems	0.00%				\$	- 9	- ÷
Civil/Structural/Buildings	0.00%				\$	- 9	
Piping	0.00%				\$	- 9	- ÷
Control and Instrumentation	0.00%				\$	- 9	- 6
Electrical Systems	0.00%				\$	- 9	-
				Total Balance of Plant	\$	- 9	- 6
	1			Total Balance of Plant Plus the Selected Source	\$ 133,174,77	8	5 799,048,670

Basis of Estimate Notes:

Single source cost. The reported costs are from the INL project team expert. The reported cost represents a Rankine power cycle, excluding the steam generator. The cost is based on information found in NETL 2007b, which has been adjusted and customized for this project by the INL project team expert. The allowances listed under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996. The allowances have been adjusted and customized for this project based on estimator judgment. The reduced civil/structural/buildings allowance accounts for the buildings that are included in the reported cost for the Rankine power cycle.

Detail Item Report - High Temperature Steam Electrolysis (HTSE)

Project Name:	NGNP Process Integration	Client:	M. Patterson
Process:	Nuclear Coal to SNG	Prepared By:	B. Wallace, R. Honsinger, J. Martin
Estimate Number:	MA36-F	Estimate Type:	Class 5

Sources Considered:

Source	Report Capaci	ed ity	Reported Trains	Report Cost Year	Re	eported Cost	Re Co	porting Year ost Per Train	Nor Pe C	malized Cost r Train using EPCI Index	Capaci Requir	ity ed	Trains Reqd.	Capacity Train	per	Fa pe Noi	actored Cost er Train from rmalized Cost	Total Current Cost for Required Trains
INL Feasibility Study (INL 2009)	1.00	kg/s		2009	\$	36,120,156	\$	36,120,156	\$	36,120,156	10.40	kg/s				\$	375,599,411	\$ 375,599,411

Source Selected:

Source	Report Capaci	ed ity	Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required	, 1	Trains Reqd.	Capacity Train	per	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
INL Feasibility Study (INL 2009)	1.00	kg/s		2009	\$ 36,120,156	\$ 36,120,156	\$ 36,120,156	10.40	kg/s				\$ 375,599,411	\$ 375,599,411

Balance of Plant:

Description	% of Total Cost				Cost P	Per Train	Total Cost
Water Systems	7.10%				\$ 26	6,667,558	\$ 26,667,558
Civil/Structural/Buildings	9.20%				\$ 34	4,555,146	\$ 34,555,146
Piping	7.10%				\$ 26	6,667,558	\$ 26,667,558
Control and Instrumentation	2.60%				\$ 9	9,765,585	\$ 9,765,585
Electrical Systems	8.00%				\$ 30	0,047,953	\$ 30,047,953
				Total Balance of Plant	\$ 127	7,703,800	\$ 127,703,800
				Total Balance of Plant Plus the Selected Source	\$ 503	3,303,210	\$ 503,303,210

Basis of Estimate Notes:

Single source cost. The reported costs are from the INL project team expert. The cost is based on information from Harvego 2008, Solid State Energy Conversion Alliance, and discussions between INL engineers and Ceramate and Proton Energy. The allowances listed under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

Detail Item Report - Coal Preparation

Project Name:	NGNP Process Integration	Client:	M. Patterson
Process:	Nuclear Coal to SNG	Prepared By:	B. Wallace, R. Honsinger, J. Martin
Estimate Number:	MA36-F	Estimate Type:	Class 5

Sources Considered:

Source	Report Capaci	ed ity	Reported Trains	Report Cost Year	Re	eported Cost	Re	porting Year ost Per Train	Noi Pe C	rmalized Cost r Train using CEPCI Index	Capaci Requir	ty ed	Trains Reqd.	Capacity Train	per	Fa pe Noi	actored Cost er Train from rmalized Cost	Total Current Cost for Required Trains
Shell IGCC Base Case (NETL 2000)	3,171	tpd	1	1999	\$	17,826,000	\$	17,826,000	\$	23,366,390	3,864	tpd	2	1,932	tpd	\$	17,357,139	\$ 34,714,279
Hydrogen Report (Gray 2004)	7,787	tpd	1	2004	\$	47,000,000	\$	47,000,000	\$	54,173,796	3,864	tpd	2	1,932	tpd	\$	23,473,153	\$ 46,946,306
Shell GTC Report (Shell 2004)	5,513	tpd	2	2004	\$	60,800,000	\$	30,400,000	\$	35,040,072	3,864	tpd	2	1,932	tpd	\$	28,310,767	\$ 56,621,533
Shell IGCC Power Plant with CO2 Capture (NETL 2007b)	5,678	tpd	2	2006	\$	156,785,000	\$	78,392,500	\$	80,338,191	3,864	tpd	2	1,932	tpd	\$	63,771,566	\$ 127,543,133
																1		
																1		

Source Selected:

Source	Report Capaci	ed ty	Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required	Trains Reqd.	Capacity Trair	/ per	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Average of normalized and factored co	ost from Gray	2004 ;	and Shell 20	04 reports								\$ 25,891,960	\$ 51,783,920

Balance of Plant:

Description	% of Total Cost				Cost F	Per Train	Total Cost
Water Systems	7.10%				\$	1,838,329	\$ 3,676,658
Civil/Structural/Buildings	9.20%				\$	2,382,060	\$ 4,764,121
Piping	7.10%				\$	1,838,329	\$ 3,676,658
Control and Instrumentation	2.60%				\$	673,191	\$ 1,346,382
Electrical Systems	8.00%				\$	2,071,357	\$ 4,142,714
				Total Balance of Plant	\$	8,803,266	\$ 17,606,533
				Total Balance of Plant Plus the Selected Source	\$ 3	4,695,226	\$ 69,390,453

Rationale for Selection:

The Gray 2004 and the Shell 2004 reports identified recent actual costs that appear to be consistent with this project's needs. An average cost of the two has been selected in order to not represent an overly agressive or conservative cost. Cost factoring reflects the 6/10 rule. The allowances listed under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

Detail Item Report - Gasification

Project Name:	NGNP Process Integration	Client:	M. Patterson
Process:	Nuclear Coal to SNG	Prepared By:	B. Wallace, R. Honsinger, J. Martin
Estimate Number:	MA36-F	Estimate Type:	Class 5

Sources Considered:

Source	Report Capaci	ed ity	Reported Trains	Report Cost Year	Re	eported Cost	Re C	eporting Year ost Per Train	No Pe	rmalized Cost er Train using CEPCI Index	Capaci Require	ty ed	Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Cur for Re Tra	rrent Cost quired iins
Gasifier																		
Shell IGCC Base Case (NETL 2000)	2,977	tpd	1	1999	\$	87,802,000	\$	87,802,000	\$	115,091,203	3,548	tpd	2	1,774	tpd	\$ 84,362,026	\$ 168	8,724,051
Hydrogen Report (Gray 2004)	5,990	tpd	1	2004	\$	87,000,000	\$	87,000,000	\$	100,279,154	3,548	tpd	2	1,774	tpd	\$ 48,319,979	\$ 193	3,279,915
Shell IGCC Power Plant with CO2																		
Capture (NETL 2007b)	5,310	tpd	2	2006	\$	196,948,000	\$	98,474,000	\$	100,918,110	3,548	tpd	2	1,774	tpd	\$ 79,233,000	\$ 158	8,465,999
Shell GTC Report (Shell 2004)	5,201	tpd	2	2004	\$	202,240,000	\$	101,120,000	\$	116,554,345	3,548	tpd	2	1,774	tpd	\$ 92,654,501	\$ 185	5,309,002
Quench Compressor																		
Shell IGCC Base Case (NETL 2000)	194,116	lb/hr	1	1999	\$	1,900,000	\$	1,900,000	\$	2,490,527	631,632	lb/hr	2	315,816	lb/hr	\$ 3,335,147	\$ 6	6,670,294

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required	Trains Reqd.	Capacity Train	per	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Average of normalized and factored costs from NETL 2000 and NETL 2007b reports, including the NETL 2000 quench compressor cost with the NETL 2000 gasifier cost. \$ 83,										\$ 83,465,086	\$ 166,930,172		

Balance of Plant:

Description	% of Total Cost				Cos	t Per Train	Тс	otal Cost
Water Systems	7.10%				\$	5,926,021	\$	11,852,042
Civil/Structural/Buildings	9.20%				\$	7,678,788	\$	15,357,576
Piping	7.10%				\$	5,926,021	\$	11,852,042
Control and Instrumentation	2.60%				\$	2,170,092	\$	4,340,184
Electrical Systems	8.00%				\$	6,677,207	\$	13,354,414
				Total Balance of Plant	\$	28,378,129	\$	56,756,259
				Total Balance of Plant Plus the Selected Source	\$ 1	111,843,216	\$	223,686,431

Rationale for Selection:

Shell IGCC Base Case (NETL 2000) and Shell IGCC Power Plant with CO2 Capture (NETL 2007b) are consistent in factored normalized cost per train, and in the size of trains required. An average cost of the two has been selected in order to not represent an overly agressive or conservative cost. Hydrogen Report (Gray 2004) was excluded as an unexplained and inconsistent outlier cost point. Cost factoring reflects the 6/10 rule. The allowances listed under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

Note: The reported cost of Gray 2004 is \$87,000,000 for the gasification unit, and does not include a heat recovery unit. This cost has been doubled, based on information from an active vendor, UDHE, to account for the addition cost of the heat recovery unit. The quench compressor is listed as an independent line item in the NETL 2000 report. It is factored separately here to better fit the new process model. NETL 2007b includes quench compressor.

Detail Item Report - Rectisol

Project Name:	NGNP Process Integration	Client:	M. Patterson
Process:	Nuclear Coal to SNG	Prepared By:	B. Wallace, R. Honsinger, J. Martin
Estimate Number:	MA36-F	Estimate Type:	Class 5

Sources Considered:

Source	Report Capac	ed ity	Reported Trains	Report Cost Year	R	eported Cost	Re C	eporting Year ost Per Train	No Pe	rmalized Cost er Train using CEPCI Index	Capaci Require	ty ed	Trains Reqd.	ains Capacity r aqd. Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
		lbmol/										Ibmo			lbmol/		
Fluor/UOP Report (Fluor/UOP 2004)	28,735	hr	1	2003	\$	91,640,000	\$	91,640,000	\$	116,715,622	27,652	l/hr	2	13,826	hr	\$ 75,248,908	\$ 150,497,815
		Nm3/										Nm3			Nm3/		
Princeton Report (Kreutz 2008)	700,000	hr	1	2007	\$	129,043,041	\$	129,043,041	\$	125,751,879	281,117	/hr	2	140,558	hr	\$ 47,992,105	\$ 95,984,210

Source Selected:

Source	Report Capaci	ed ity	Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacit Require	y d	Trains Reqd.	Capacity Train	per	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Average of normalized and factored costs from Fluor/UOP 2004 and Kreutz 2008													\$ 61,620,506	\$ 123,241,013

Balance of Plant:

Description	% of Total Cost				Cos	Cost Per Train		Total Cost
Water Systems	7.10%				\$	4,375,056	\$	8,750,112
Civil/Structural/Buildings	9.20%				\$	5,669,087	\$	11,338,173
Piping	7.10%				\$	4,375,056	\$	8,750,112
Control and Instrumentation	2.60%				\$	1,602,133	\$	3,204,266
Electrical Systems	8.00%				\$	4,929,641	\$	9,859,281
				Total Balance of Plant	\$	20,950,972	\$	41,901,944
				Total Balance of Plant Plus the Selected Source	\$	82,571,479	\$	165,142,957

Rationale for Selection:

Fluor/UOP Report (Fluor/UOP 2004) and Princeton Report (Kreutz 2008) have been selected. An average cost of the two has been selected in order to not represent an overly agressive or conservative cost. The allowances listed under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

Detail Item Report - Methanation

Project Name:	NGNP Process Integration	Client:	M. Patterson
Process:	Nuclear Coal to SNG	Prepared By:	B. Wallace, R. Honsinger, J. Martin
Estimate Number:	MA36-F	Estimate Type:	Class 5

Sources Considered:

Source	Report Capac	ed ity	Reported Trains	Report Cost Year	R	Reported Cost	Re C	eporting Year ost Per Train	No Pe	rmalized Cost er Train using CEPCI Index	Capaci Require	ty ed	Trains Reqd.	Capacity per Train		Fact per 1 Norm	ored Cost Frain from alized Cost	Total Current Cost for Required Trains
Hydrogen Report (Gray 2004)	34	MMS CFD	1	2004	\$	33,000,000	\$	33,000,000	\$	38,036,920	148	MMS CFD	1	148	MMS CFD	\$	91,933,761	\$ 91,933,761
		MMB										MMB			MMB			
Haldor Topsoe Report (Udengaard		TU/da										TU/d			TU/da	I		
2008)	150,000	У	1	2007	\$	110,000,000	\$	110,000,000	\$	107,194,518	141,680	ay	2	70,840	у	\$	68,341,686	\$ 136,683,372
DOE FE Report (DOE 1978)	1,000	tpd	1	1978	\$	1,467,000	\$	1,467,000	\$	3,432,834	3,332	tpd	2	1,666	tpd	\$	4,662,918	\$ 9,325,836

Source Selected:

Source	Reported Capacity		Report Reported Cost Trains Year Reported Cost		Reporting Year Cost Per Train	Reporting Year Per Train using Cost Per Train CEPCI Index		ty ed	Trains Reqd.	Capacity Trair	y per	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains	
		MMB							MMB			MMB		
Haldor Topsoe Report (Udengaard		TU/da							TU/d			TU/da		
2008)	150,000	у	1	2007	\$ 110,000,000	\$ 110,000,000	\$ 107,194,518	141,680	ay	2	70,840	у	\$ 68,341,686	\$ 136,683,372

Balance of Plant:

Description	% of Total Cost				Cost Per Train		Total Cost
Water Systems	7.10%				\$	4,852,260	\$ 9,704,519
Civil/Structural/Buildings	9.20%				\$	6,287,435	\$ 12,574,870
Piping	7.10%				\$	4,852,260	\$ 9,704,519
Control and Instrumentation	2.60%				\$	1,776,884	\$ 3,553,768
Electrical Systems	8.00%				\$	5,467,335	\$ 10,934,670
				Total Balance of Plant	\$	23,236,173	\$ 46,472,347
				Total Balance of Plant Plus the Selected Source	\$	91,577,859	\$ 183,155,719

Rationale for Selection:

The Haldor Topsoe Report (Udengaard 2008) was selected as the most recent cost point, and because the reported capacity is similar the required capacity per train. The allowances listed under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

Detail Item Report - Claus and SCOT

Project Name:	NGNP Process Integration	Client:	M. Patterson
Process:	Nuclear Coal to SNG	Prepared By:	B. Wallace, R. Honsinger, J. Martin
Estimate Number:	MA36-F	Estimate Type:	Class 5

Sources Considered:

	Report	ed	Reported	Report Cost			Re	porting Year	Noi Pe	rmalized Cost er Train using	Capaci	ty	Trains	Capacity	per	Fac per	tored Cost Train from	Total Current for Require	: Cost red
Source	Capac	ity	Trains	Year	Re	ported Cost	Co	ost Per Train	C	EPCI Index	Require	ed	Reqd.	Train		Norn	nalized Cost	Trains	
Claus and SCOT																			
Princeton Report (Kreutz 2008)	151	tpd	1	2007	\$	33,800,000	\$	33,800,000	\$	32,937,952	123	tpd	2	62	tpd	\$	19,229,402	\$ 38,458	8,803
Shell IGCC Power Plant with CO2																			
Capture (NETL 2007b)	142	tpd	1	2006	\$	22,794,000	\$	22,794,000	\$	24,926,373	123	tpd	2	62	tpd	\$	15,098,765	\$ 30,197	7,531
Claus																			
Shell IGCC Base Cases (NETL 2000)	78	tpd	1	1999	\$	9,964,000	\$	9,964,000	\$	13,060,850	123	tpd	2	62	tpd	\$	11,333,656	\$ 22,667	7,312
Cost Effective Options to Expand																			
SRU Capacity Using Oxygen																			
(WorleyParsons 2002)	79	tpd	1	1999	\$	11,970,000	\$	11,970,000	\$	15,690,323	123	tpd	2	62	tpd	\$	13,470,847	\$ 26,941	1,695
SCOT																			
Shell IGCC Base Cases (NETL 2000)	78	tpd	1	1999	\$	4,214,000	\$	4,214,000	\$	5,523,728	123	tpd	1	123	tpd	\$	7,265,221	\$ 7,265	5,221
Cost Effective Options to Expand																			
SRU Capacity Using Oxygen																			
(WorleyParsons 2002)	143	tpd	1	1999	\$	8,910,000	\$	8,910,000	\$	11,679,263	123	tpd	1	123	tpd	\$	10,664,514	\$ 10,664	4,514

Source Selected:

Source	Report Capaci	ed ity	Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required	Trains Reqd.	Capacity Trair	per	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
WorleyParsons 2002: Combined Claus	s and SCOT	costs										\$ 24,135,361	\$ 37,606,209

Detail Item Report - Claus and SCOT

Project Name:	NGNP Process Integration	Client:	M. Patterson
Process:	Nuclear Coal to SNG	Prepared By:	B. Wallace, R. Honsinger, J. Martin
Estimate Number:	MA36-F	Estimate Type:	Class 5

Balance of Plant:

Description	% of Total Cost				Cost	Per Train	Total Cost
Water Systems	7.10%				\$	1,713,611	\$ 2,670,041
Civil/Structural/Buildings	9.20%				\$	2,220,453	\$ 3,459,771
Piping	7.10%				\$	1,713,611	\$ 2,670,041
Control and Instrumentation	2.60%				\$	627,519	\$ 977,761
Electrical Systems	8.00%				\$	1,930,829	\$ 3,008,497
				Total Balance of Plant	\$	8,206,023	\$ 12,786,111
	1			Total Balance of Plant Plus the Selected Source	\$ 3	32,341,384	\$ 50,392,320

Rationale for Selection:

The WorleyParsons 2002 cost point was selected because of WorleyParsons' status as a working vendor in this industry. It is expected that this is the highest quality information available at this time. The allowances listed under Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

Note: Costs from WorleyParsons 2002 have been multiplied by 0.9 to adjust for the included engineering costs. This factor was consistent with general process industry standards, and was selected with project team consensus.

Detail Item Report - CO2 Compression

Project Name:	NGNP Process Integration	Client:	M. Patterson
Process:	Nuclear Coal to SNG	Prepared By:	B. Wallace, R. Honsinger, J. Martin
Estimate Number:	MA36-F	Estimate Type:	Class 5

Sources Considered:

Source	Report Capaci	ed ity	Reported Trains	Report Cost Year	Re	eported Cost	Re Co	porting Year ost Per Train	No Pe	ormalized Cost er Train using CEPCI Index	Capaci Require	ty ed	Trains Reqd.	Capacity Train	per	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Subcritical																	
Princeton Report (Kreutz 2008)	10	MW	1	2007	\$	6,310,000	\$	6,310,000	\$	6,149,067	8	MW	1	8	MW	\$ 5,378,526	\$ 5,378,526
Supercritical																	
Princeton Report (Kreutz 2008)	13	MW	1	2007	\$	9,520,000	\$	9,520,000	\$	9,277,198	-	MW	1	-	MW	\$-	\$-

Source Selected:

Source	Report Capac	ed ity	Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required	r Trai I Req	ns d.	Capacity Train	per	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Kreutz 2008: Combined Subcritical and	d Supercritic	al Proc	esses										\$ 5,378,526	\$ 5,378,526

Balance of Plant:

Description	% of Total Cost				Cost Per Train	Total Cost
Water Systems	7.10%				\$ 381,875	\$ 381,875
Civil/Structural/Buildings	9.20%				\$ 494,824	\$ 494,824
Piping	7.10%				\$ 381,875	\$ 381,875
Control and Instrumentation	2.60%				\$ 139,842	\$ 139,842
Electrical Systems	8.00%				\$ 430,282	\$ 430,282
				Total Balance of Plant	\$ 1,828,699	\$ 1,828,699
				Total Balance of Plant Plus the Selected Source	\$ 7,207,224	\$ 7,207,224

Rationale for Selection:

Single source cost point. Both subcritical and supercritical process costs were included under the CO2 Compression heading. The allowances listed under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

Detail Item Report - Steam Turbines

Project Name:	NGNP Process Integration	Client:	M. Patterson
Process:	Nuclear Coal to SNG	Prepared By:	B. Wallace, R. Honsinger, J. Martin
Estimate Number:	MA36-F	Estimate Type:	Class 5

Sources Considered:

Source	Report Capaci	ed ity	Reported Trains	Report Cost Year	Re	eported Cost	Re	eporting Year ost Per Train	Nor Pe C	rmalized Cost er Train using CEPCI Index	Capaci Require	ty ed	Trains Reqd.	Capacity Train	per	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Steam Turbine and HRSG																	
Shell IGCC Base Cases (NETL 2000)	189	MW	1	1999	\$	50,671,000	\$	50,671,000	\$	66,419,744	142	MW	3	47	MW	\$ 28,990,343	\$ 86,971,029
Steam Turbine																	
NETL Baseline Report (NETL 2007a)	401	MW	4	2006	\$	74,651,000	\$	18,662,750	\$	19,125,957	142	MW	3	47	MW	\$ 12,212,534	\$ 36,637,602
Princeton Report (Kreutz 2008)	275	MW	1	2007	\$	66,700,000	\$	66,700,000	\$	64,998,858	142	MW	3	47	MW	\$ 22,653,711	\$ 67,961,132
Shell IGCC Power Plant with CO2		1															
Capture (NETL 2007b)	230	MW	1	2006	\$	44,515,000	\$	44,515,000	\$	45,619,856	142	MW	3	47	MW	\$ 17,702,303	\$ 53,106,909

Source Selected:

Source	Report Capac	ed ity	Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacit Require	ty ed	Trains Reqd.	Capacity Train	per	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Shell IGCC Power Plant with CO2 Capture (NETL 2007b)	230	MW	1	2006	\$ 44,515,000	\$ 44,515,000	\$ 45,619,856	142	MW	3	47	MW	\$ 17,702,303	\$ 53,106,909

Balance of Plant:

Description	% of Total Cost				Cost	Per Train	Total Cos	it
Water Systems	7.10%				\$	1,256,864	\$ 3,770),591
Civil/Structural/Buildings	9.20%				\$	1,628,612	\$ 4,885	5,836
Piping	7.10%				\$	1,256,864	\$ 3,770),591
Control and Instrumentation	2.60%				\$	460,260	\$ 1,380),780
Electrical Systems	8.00%				\$	1,416,184	\$ 4,248	3,553
				Total Balance of Plant	\$	6,018,783	\$ 18,056	3,349
				Total Balance of Plant Plus the Selected Source	\$ 2	3,721,086	\$ 71,163	3,257

Rationale for Selection:

Shell IGCC PowerPlant with CO2 Capture (NETL 2007b) is a recently reported cost point that closely reflects this project's requirements. The Princeton Report (Kreutz 2008) source for the steam turbine cost point is the NETL 2007b report. The allowances listed under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

Detail Item Report - HRSG

Project Name:	NGNP Process Integration	Client:	M. Patterson
Process:	Nuclear Coal to SNG	Prepared By:	B. Wallace, R. Honsinger, J. Martin
Estimate Number:	MA36-F	Estimate Type:	Class 5

Sources Considered:

Source	Reporte Capaci	ed ty	Reported Trains	Report Cost Year	Repor	rted Cost	Rep Cos	oorting Year st Per Train	Nor Per C	malized Cost r Train using EPCI Index	Capaci Require	ty ed	Trains Reqd.	Capacity Train	per	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
NETL Baseline Report (NETL 2007a)	5,155,983	lb/hr	3	2006	\$ 2	7,581,000	\$	9,193,667	\$	9,421,852	93,747	lb/hr	1	93,747	lb/hr	\$ 1,645,116	\$ 1,645,116
Princeton Report (Kreutz 2008)	355	MW	1	2007	\$ 52	2,000,000	\$	52,000,000	\$	50,673,772	9	MW	1	9	MW	\$ 5,587,168	\$ 5,587,168
Shell IGCC Power Plant with CO2																	
Capture (NETL 2007b)	8,438,000	lb/hr	2	2006	\$ 4	5,291,000	\$	22,645,500	\$	23,207,558	93,747	lb/hr	1	93,747	lb/hr	\$ 2,364,167	\$ 2,364,167

Source Selected:

Source	Report Capaci	ed ty	Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required	y d	Trains Reqd.	Capacity Train	per	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Shell IGCC Power Plant with CO2														
Capture (NETL 2007b)	8,438,000	lb/hr	2	2006	\$ 45,291,000	\$ 22,645,500	\$ 23,207,558	93,747	lb/hr	1	93,747	lb/hr	\$ 2,364,167	\$ 2,364,167

Balance of Plant:

Description	% of Total Cost				Cost Per Train	Total Cost
Water Systems	7.10%				\$ 167,856	\$ 167,856
Civil/Structural/Buildings	9.20%				\$ 217,503	\$ 217,503
Piping	7.10%				\$ 167,856	\$ 167,856
Control and Instrumentation	2.60%				\$ 61,468	\$ 61,468
Electrical Systems	8.00%				\$ 189,133	\$ 189,133
				Total Balance of Plant	\$ 803,817	\$ 803,817
				Total Balance of Plant Plus the Selected Source	\$ 3,167,984	\$ 3,167,984

Rationale for Selection:

Shell IGCC PowerPlant with CO2 Capture (NETL 2007b) is a recently reported cost point that closely reflects this project's requirements. The Princeton Report (Kreutz 2008) source for the steam turbine cost point is the NETL 2007b report. The allowances listed under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

Detail Item Report - Cooling Towers

Project Name:	NGNP Process Integration	Client:	M. Patterson
Process:	Nuclear Coal to SNG	Prepared By:	B. Wallace, R. Honsinger, J. Martin
Estimate Number:	MA36-F	Estimate Type:	Class 5

Sources Considered:

Source	Report Capac	ed ity	Reported Trains	Report Cost Year	Rep	ported Cost	Rep Co:	oorting Year st Per Train	Nor Pei C	rmalized Cost r Train using CEPCI Index	Capacit Require	ty ed	Trains Reqd.	Capacity Train	per	Factored Cost per Train from Normalized Cost	Total Current for Requir Trains	: Cost red
Cooling Tower Depot	78,205	gpm	2	2009	\$	2,153,820	\$	1,076,910	\$	1,076,910	148,487	gpm	4	37,122	gpm	\$ 1,043,840	\$ 4,175	5,358

Source Selected:

Source	Report Capac	ed	Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required	Trains Reqd.	Capacity Train	per	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Cooling Tower Depot	78,205	gpm	2	2009	\$ 2,153,820	\$ 1,076,910	\$ 1,076,910	148,487 gpr	n 4	37,122	gpm	\$ 1,043,840	\$ 4,175,358

Balance of Plant:

Description	% of Total Cost				Cost Per Train	Total Cost
Water Systems	7.10%				\$ 74,113	\$ 296,450
Civil/Structural/Buildings	9.20%				\$ 96,033	\$ 384,133
Piping	7.10%				\$ 74,113	\$ 296,450
Control and Instrumentation	2.60%				\$ 27,140	\$ 108,559
Electrical Systems	8.00%				\$ 83,507	\$ 334,029
				Total Balance of Plant	\$ 354,905	\$ 1,419,622
				Total Balance of Plant Plus the Selected Source	\$ 1,398,745	\$ 5,594,980

Rationale for Selection:

Single source cost. Publically available current data. Calculated capital costs based on publically available cost data from a vendor regularly engaged in the building of cooling towers. The allowances listed under 'Balance of Pla are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

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Identifier: NUCLEAR-INTEGRATED SUBSTITUTE NATURAL GAS PRODUCTION Revision: ANALYSIS Effective Date: 05/15/2010

Appendix C Conventional Coal to SNG Steam Results.xls

TEV-671

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NUCLEAR-INTEGRATED SUBSTITUTEIdentifier:TEV-671NATURAL GAS PRODUCTIONRevision:1ANALYSISEffective Date:05/15/2010

Appendix D Nuclear-Integrated Coal to SNG Steam Results.xls

[Electronic]