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## **Technical Evaluation Study**

**Project No. 23843**

# **Nuclear-Integrated Substitute Natural Gas Production Analysis**



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 **Idaho National Laboratory** 

#### **NUCLEAR-INTEGRATED SUBSTITUTE NATURAL GAS PRODUCTION ANALYSIS**

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#### **REVISION LOG**





#### **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:

- $\bullet$  Six 600 MWt 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  $CO<sub>2</sub>$ emissions 97.4% if sequestration is not assumed. If sequestration is assumed,  $CO<sub>2</sub>$ emissions increase by over 350 tons per day.
- $\bullet$  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.

<b>Technology</b>	no CO <sub>2</sub> Tax	SNG Price (\$/MSCF) SNG Price (\$/MSCF) SNG Price (\$/MSCF) \$100/ton CO <sub>2</sub> Tax	\$150/ton CO <sub>2</sub> 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.



#### **CONTENTS**



#### **ACRONYMS AND NOMENCLATURE**









#### **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.

<b>HTGR Product</b>	<b>Product Description</b>			
Process Heat				
Steam	$540^{\circ}$ 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,



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.



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,  $CO<sub>2</sub>$ 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  $O_2$  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  $CH_4$  purity. The nitrogen coproduct 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  $O_2$ -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  $\mu$ m 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



and carbon dioxide transport gases. The amount of  $CO<sub>2</sub>$  vented during depressurization of the feed hopper is estimated using the ideal gas law.

- $\bullet$  **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.
- $\bullet$  **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  $H_2$ :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  $CO<sub>2</sub>$ , H<sub>2</sub>S, and COS (Rectisol process). It is assumed that  $1.5\%$  CO<sub>2</sub> 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  $55\%$  H<sub>2</sub>S, with the remainder being  $CO_2$  (Lurgi 2006). Gas containing H<sub>2</sub>S 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  $CO<sub>2</sub>$  rich stream.



It is also assumed that a steam reboiler, rather than nitrogen flow, is used for stripping in order to ensure a sufficiently pure  $CO<sub>2</sub>$  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  $H_2S$ .

- $\bullet$  **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  $60\%$  H<sub>2</sub>S. 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  $0.55:1 O<sub>2</sub>$  to H<sub>2</sub>S (Kohl 1997). Tail gas from the Claus unit is hydrogenated over a catalyst to convert the remaining sulfur species to  $H_2S$ , 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.
- $\bullet$  **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  $CO<sub>2</sub>$  is produced. The resulting stream is then compressed, along with the  $CO<sub>2</sub>$  recycle from coal milling and drying, and liquefied prior to being pumped to the required pressure for use in enhanced oil recovery or sequestration.  $CO<sub>2</sub>$  for filtration is split from the  $CO<sub>2</sub>$  pressurization scheme at 700 psia, while the  $CO<sub>2</sub>$  for coal slurrying is split from the  $CO<sub>2</sub>$  pressurization scheme at 1,160 psia. Eight stages are assumed for the  $CO<sub>2</sub>$  compression scheme resulting in an overall efficiency of 84.4%. The  $CO<sub>2</sub>$  at 2,005 psia should be liquid; however, Aspen's physical property methods do not predict the proper phase of the supercritical  $CO<sub>2</sub>$ 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  $CO<sub>2</sub>$  compression turbines; thus, the incorrect phase prediction will not impact the resulting power requirement.
- $\bullet$  **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  $H_2$  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



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.

- $\bullet$ **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.
- $\bullet$  **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.
- $\bullet$ **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.



#### **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  $CO<sub>2</sub>$  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.

- $\bullet$  **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.
- $\bullet$  **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.



Transport of coal into the gasifier is accomplished using  $CO<sub>2</sub>$  recovered from the Rectisol unit.

- $\bullet$  **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.
- $\bullet$  **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  $H_2$ : 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  $CO<sub>2</sub>$  concentration entering the Rectisol unit is reduced from 34% in the conventional case to 13% in the nuclear-integrated case. Similarly,  $CO<sub>2</sub>$  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.

- $\bullet$  **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.
- **CO<sub>2</sub> Compression (CO2-COMP)** CO<sub>2</sub> compression for the nuclearintegrated case is similar to  $CO<sub>2</sub>$  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  $CO<sub>2</sub>$  is recycled to the gasifier to increase carbon conversion to the SNG product.
- $\bullet$  **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  $N_2$  in the nuclearintegrated case from the recycle of  $CO<sub>2</sub>$  back to the gasifier. Due to this difference, SNG produced from the nuclear-integrated case will contain  $\sim$ 1% more  $N_2$  than in the conventional case.



- $\bullet$ **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 nuclearintegrated case is approximately 85% of the conventional case.
- $\bullet$  **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  $CO<sub>2</sub>$  emissions from the plant. If carbon capture and sequestration are not assumed for the conventional configuration,  $CO<sub>2</sub>$ emissions decrease by 97.4% when electrolysis and nuclear power are utilized. However, if carbon capture and sequestration are assumed for the conventional configuration,  $CO<sub>2</sub>$ emissions increase by over 350 tons per day of  $CO<sub>2</sub>$  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  $(600 \text{ MW}_t \text{ each})$  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



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.



<sup>2</sup>Does 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-



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  $CO<sub>2</sub>$  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  $CO<sub>2</sub>$  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.



For the nuclear-integrated cases, the estimates of capital costs and operating and maintenance costs assumed the nuclear plant was an "n<sup>th</sup> 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<sub>t</sub>$  (NEI 2008). Based on the two capital cost scenarios for HTGR technology, the nominal capital cost for a  $600 \text{ MW}_t$ HTGR would be \$1.2 billion; the target capital cost would be \$840 million.

After cost estimates were obtained for each of the process areas, the costs for 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
<b>Water Systems</b>	$7.1\%$
Piping	$7.1\%$
Instrumentation and Control	2.6%
<b>Electrical Systems</b>	$8.0\%$
<b>Buildings and Structures</b>	$9.2\%$

Table 4. Capital cost adjustment factors.

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



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

The Association for the Advancement of Cost Engineering (AACE) International recognizes five classes of estimates. The level of project definition for this study was determined to be an AACE International Class 5 estimate. 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.



	<b>Installed Cost</b>	<b>Engineering Fee</b>	Contingency	<b>Total Capital Cost</b>
Coal Preparation	\$111,581,623	\$11,158,162	\$22,093,161	\$144,832,946
<b>ASU</b>	\$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
<b>Methanation Reactors</b>	\$104,887,394	\$10,488,739	\$20,767,704	\$136,143,838
<b>Steam Turbines</b>	\$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
1&C	\$28,650,309	\$2,865,031	\$5,672,761	\$37,188,101
<b>Electrical Systems</b>	\$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
<b>Total Capital Investment</b>				\$1,916,617,513

Table 5. Total capital investment, conventional SNG case.



Figure 4. Total capital investment, conventional SNG case.

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



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



#### **4.2 Estimation of Revenue**

Yearly revenues were estimated for all cases based on recent price data for the various products generated. Revenues were estimated for low, average, and high prices for the 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.

	Price		<b>Generated</b>		<b>Annual Revenue</b>	
Slag	25.63	$\frac{\text{S}}{\text{ton}}$	757	ton/day	\$6,510,242	
Sulfur	38.13	$\frac{\text{S}}{\text{ton}}$	333	$\text{ton}/\text{day}$	\$4,265,586	
SNG, low	5,350	\$/MMSCF	151	<b>MMSCFD</b>	\$271,276,030	
SNG, average	8,600	\$/MMSCF	151	<b>MMSCFD</b>	\$436,069,880	
SNG, high	11,850	\$/MMSCF	151	<b>MMSCFD</b>	\$600,863,730	
<b>Annual Revenue, low</b>					\$282,051,858	
<b>Annual Revenue, average</b>					\$446,845,708	
<b>Annual Revenue, high</b>					\$611,639,558	

Table 7. Annual revenues, conventional SNG case.



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		<b>Price</b>		<b>Generated</b>	<b>Annual Revenue</b>	
Slag	25.63	$\frac{\text{S}}{\text{ton}}$	273	ton/day	\$2,374,326	
Sulfur	38.13	$\frac{\text{S}}{\text{ton}}$	123	ton/day	\$1,576,780	
SNG, low	5,350	\$/MMSCF	148	<b>MMSCFD</b>	\$265,886,440	
SNG, average	8,600	\$/MMSCF	148	<b>MMSCFD</b>	\$427,406,240	
SNG, high	11,850	\$/MMSCF	148	<b>MMSCFD</b>	\$588,926,040	
<b>Annual Revenue, low</b>				\$269,837,545		
<b>Annual Revenue, average</b>				\$431,357,345		
<b>Annual Revenue, high</b>				\$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  $CO<sub>2</sub>$  on the economics.





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).





#### **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:

- $\bullet$ The plant startup year is 2014.
- $\bullet$  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



- $\bullet$  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  $n<sup>th</sup>$  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
- $\bullet$  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
- $\bullet$  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).
- $\bullet$  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.
- $\bullet$  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%.
	- $\bullet$ 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  $CO<sub>2</sub>$  tax of \$0/ton to \$200/ton is investigated for the SNG cases.



#### **4.4.1 Cash Flow**

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):

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

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):

Year	<b>Recovery Rate</b>	Year	<b>Recovery Rate</b>
	0.05		0.0591
$\mathfrak{D}$	0.095	10	0.059
	0.0855	11	0.0591
	0.077	12	0.059
	0.0693	13	0.0591
	0.0623	14	0.059
	0.059	15	0.0591
	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  $CO<sub>2</sub>$  tax credit is included in the economic analysis, the tax would be treated essentially as a manufacturing cost, decreasing the yearly revenue.

#### **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).

$$
PW(i^{10}\%) = \sum_{k=0}^{N} ATCF_k(1+i^{\prime})^{-k} = 0
$$
\n(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  $CO<sub>2</sub>$  tax was included into the calculations to determine the price of SNG necessary in all cases for a  $12\%$  IRR and a  $CO<sub>2</sub>$  tax of \$0/ton to \$200/ton. These cases were calculated for an 80%/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  $CO<sub>2</sub>$ . 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, 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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Table 12. Conventional and nuclear-integrated SNG IRR results.							
	TCI-30% HTGR		<b>TCI</b>		<b>TCI +50% HTGR</b>		
	<b>IRR</b>	\$/MSCF	<b>IRR</b>	\$/MSCF	<b>IRR</b>	\$/MSCF	
				\$1,916,617,513			
			N/A	\$5.35			
<b>SNG</b>			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	
<b>HTGR SNG</b>	$-6.04$	\$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	

15.00  $10.00$  $5.00$  $0.00$  $%$  IRR  $-5.00$  $-10.00$  $-15.00$  $-20.00$  $-25.00$ \$2.00 \$7.00 \$12.00 \$17.00 \$27.00 \$32.00 \$37.00 \$22.00 **SNG Price (\$/MSCF)**  $+$   $+$  HTGR SNG, +50% HTGR SNG SEQ  $-$  HTGR SNG, -30% HTGR - HTGR SNG · SNG

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,



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.







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

HTGR SNG, -30% HTGR

Carbon Tax (\$/ton CO2)

- HTGR SNG

- HTGR SNG +50% HTGR

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  $$2,000/kW<sub>t</sub>$ , a carbon tax of approximately  $$140/ton CO<sub>2</sub>$  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/t$ on  $CO<sub>2</sub>$  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  $CO<sub>2</sub>$  is emitted in the conventional case. However, given the high natural gas required for the 12% IRR return, over \$25/MSCF, even with a  $CO<sub>2</sub>$  tax, the HTGR SNG case is economically undesirable.

#### **6. SNG CONCLUSIONS**

- SNG

SNG SEQ

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

- $\bullet$  Coal consumption is decreased by 64% using electrolysis and nuclear power as the hydrogen source.
- $\bullet$ Integrating nuclear power and high temperature steam electrolysis also decreases  $CO<sub>2</sub>$ emissions from the plant:



- If carbon capture and sequestration are not assumed for the conventional configuration,  $CO<sub>2</sub>$  emissions decrease by 97.4% when electrolysis and nuclear power are utilized.
- If carbon capture and sequestration are assumed for the conventional configuration,  $CO_2$  emissions increase by over 350 tons per day of  $CO_2$  in order to provide topping heat to the electrolyzers.
- It is estimated that a little less than six nuclear high temperature reactors  $(600 \text{ MW}_t)$ 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.
- $\bullet$  In a carbon constrained scenario where  $CO<sub>2</sub>$  emissions are taxed and sequestration is not an option, a  $CO<sub>2</sub>$  tax of \$140/ton-CO<sub>2</sub> equates the economics of the nuclearintegrated SNG case with the conventional SNG case.
- The necessary tax decreases to  $$100/ton-CO<sub>2</sub>$  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.


- 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



#### **Appendix A Detailed Modeling Results and Flowsheets**









Calculator Block SUMMARY





WATER GENERATED:



#### 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



Cooling Tower



# Simplified Water Treatment







 Calculator Block ELECSUM ELECTROLYSIS SUMMARY: FEED SUMMARY: H2O FEED:  $MASS FLOW = 732901. LB/HR$  $TEMPERATURE =$  72. DEG. F PRESSURE = 14.7 PSI PRODUCT SUMMARY: H2 PRODUCT:  $MASS$  FLOW = 82534. LB/HR  $H2$  PURITY =  $99.91$  MOL-%<br>EMPERATURE =  $79.$  DEG. F  $TEMPERATURE =$ PRESSURE = 650.0 PSI O2 PRODUCT:  $MASS FLOW =$  650367. LB/HR  $O2$  PURITY = 99.89 MOL-% TEMPERATURE = 81. DEG. F PRESSURE = 650.0 PSI HEAT AND POWER SUMMARY: ELECTROLYSIS POWER REQUIREMENT = 1272.3 MW HEAT SUMMARY: REACTOR HEAT: DUTY REQUIRED = 1231.6 MMBTU/HR HELIUM MASS FLOW = 1344129. LB/HR INLET TEMPERATURE = 1292. DEG. F OUTLET TEMPERATURE = 554. DEG F. PRESSURE DROP = 5.0 PSI TOPPING HEAT: DUTY REQUIRED = 79.9 MMBTU/HR SYNGAS MASS FLOW = 21718. LB/HR Calculator Block SUMMARY FEED & PRODUCT SUMMARY: FEEDS: RAW COAL FEED RATE =  $3864.2$  TON/DY COAL HHV AS FED =  $10934.$  BTU/LB<br>COAL MOISTURE AS FED =  $13.70 \%$  COAL MOISTURE AS FED = 13.70 % PROXIMATE ANALYSIS: MOISTURE 13.70 % FIXED CARBON 40.12 % VOLATILE MATTER 49.28 % ASH 10.60 % ULTIMATE ANALYSIS: ASH 10.60 % CARBON 70.27 % HYDROGEN 4.84 % NITROGEN 1.36 % CHLORINE 0.11 % SULFUR 3.72 %









#### **Electrolysis**









## Claus Process



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








Cooling Tower



# Simplified Water Treatment





**Appendix B SNG Capital Cost Estimates** 

## **NGNP Conventional Coal to SNG Summary**

**NGNP Process Integration<br>Conventioonal Coal to SNG Project Name:** Process: Estimate Number: MA36-E

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





4/20/2010

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

## COST ESTIMATE SUPPORT DATA RECAPITULATION



PURPOSE: Brief description of the intent of how the estimate is to be used (i.e., for I. 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. **SCOPE OF WORK:** Brief statement of the project's objective. Thorough overview and description of the proposed project. Identify work to be accomplished, as well as any specific work to be excluded.

#### A. Objective:

Develop 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.

#### Included: Β.

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

#### $1.$ Engineering

- Construction of a new coal-to-SNG refinery that consists of the following:  $2.$ 
	- 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. CO<sub>2</sub> compression
	- i. Steam turbines, internal to process
	- j. Heat recovery steam generator, internal to process
	- k. Cooling towers, internal to process
	- Allowances for Balance of Plant (BOP)/offsite/outside of battery limits 1. (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 SNG File: MA36-E Page 2 of 7

- (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 Page 3 of 7

- 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. **Planning Basis:** *The source for the execution and strategies of the work that can be used to support the project execution plan, acquisition strategy, schedules, and market conditions and other documentation upon which the estimate is originated.* 
	- 1. All islands represent nth of a kind projects.
	- 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. **Cost Basis:** *The source for the costing on the estimate that can be used in support of earned value management, funding profiles, and schedule of values. Sources may include published costing references, judgment, actual costs, preliminary quotes or other documentation upon which the estimate is originated.* 
	- 1. All costs are represented as current value costs. Factors for forward-looking escalation and 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. **ASSUMPTIONS:** *Condition statements accepted or supposed true without proof of demonstration; statements adding clarification to scope. An assumption has a direct impact on total estimated cost.*

## **General Assumptions:**

- A. All costs are represented in 2009 values.
- B. Costs that were included from sources representing years prior to 2009 have been normalized to 2009 values using the Chemical Engineering Plant Cost Index. This index was selected due to its widespread recognition 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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Project Title: NGNP Process Integration – Conventional Coal to SNG File: MA36-E Page 6 of 7

> 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 1.36^0.6 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. **CONTINGENCY GUIDELINE IMPLEMENTATION:**

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

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

- A. **Threats:** *Uncertain events that are potentially negative or reduce the probability that the desired outcome will happen.* 
	- 1. The level of project definition/development that was available at the time the estimate was prepared represents a substantial risk to the project 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)**



### **Sources Considered:**



## **Source Selected:**



### **Balance of Plant:**



#### **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 listed i 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 need 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**



### **Sources Considered:**



#### **Source Selected:**



### **Balance of Plant:**



### **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**



### **Sources Considered:**



## **Source Selected:**



## **Balance of Plant:**



### **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 allowa 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 add 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**



### **Sources Considered:**



## **Source Selected:**



### **Balance of Plant:**



### **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 va are comparable to additional published estimating guides, such as Page 1996.

## **Detail Item Report - Rectisol**



### **Sources Considered:**



#### **Source Selected:**



### **Balance of Plant:**



### **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**



### **Sources Considered:**



#### **Source Selected:**



### **Balance of Plant:**



#### **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**



### **Sources Considered:**



### **Source Selected:**



## **Detail Item Report - Claus and SCOT**



### **Balance of Plant:**



## **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 liste '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**



### **Sources Considered:**



#### **Source Selected:**



### **Balance of Plant:**



### **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**



### **Sources Considered:**



## **Source Selected:**



### **Balance of Plant:**



#### **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 NET 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**



### **Sources Considered:**



#### **Source Selected:**



#### **Balance of Plant:**



#### **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 comparab additional published estimating guides, such as Page 1996.

**NGNP Nuclear Coal to SNG Summary** 

**NGNP Process Integration<br>Nuclear Coal to SNG** Project Name:<br>Process: Estimate Number: MA36-F

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





4/20/2010

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

## **COST ESTIMATE SUPPORT DATA RECAPITULATION**



PURPOSE: Brief description of the intent of how the estimate is to be used (i.e., for Ι. 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. SCOPE OF WORK: Brief statement of the project's objective. Thorough overview and description of the proposed project. Identify work to be accomplished, as well as any specific work to be excluded.

#### Objective:  $A<sub>1</sub>$

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
- The allowance provided for the HTGR represents a complete and operable 2. 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.
- Construction of a new integrated refinery capability to produce SNG from coal 3. 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.  $CO<sub>2</sub>$  compression



- 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

 $\overline{-}$  Continued – Project Title: NGNP Process Integration – Nuclear Coal to SNG

File: MA36-F Page 3 of 9

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. **Planning Basis:** *The source for the execution and strategies of the work that can be used to support the project execution plan, acquisition strategy, schedules, and market conditions and other documentation upon which the estimate is originated.* 
	- 1. All islands 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 SNG File: MA36-F Page 4 of 9

- C. **Cost Basis:** *The source for the costing on the estimate that can be used in support of earned value management, funding profiles, and schedule of values. Sources may include published costing references, judgment, actual costs, preliminary quotes or other documentation upon which the estimate is originated.* 
	- 1. All costs are represented as current value costs. Factors for forward-looking escalation and 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  $2,000$  MW<sub>t</sub> and  $2,400$  $MW<sub>t</sub>$  at a cost of roughly \$4B, including owner's cost. This equates to \$1,667 to \$2,000 per  $kW_t$ . For the purposes of this report, the nominal cost of an HTGR will be set at the upper end of this range,  $$2,000$  per kW<sub>t</sub>. 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**

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- 32. Ramsden, Todd, et al., *Current (2005) Hydrogen Production from Central Grid Electrolysis*, NREL, May 2008.
- 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. **ASSUMPTIONS:** *Condition statements accepted or supposed true without proof of demonstration; statements adding clarification to scope. An assumption has a direct impact on total estimated cost.*

## **General Assumptions:**

- A. All costs are represented in 2009 values.
- B. Costs that were included from sources representing years prior to 2009 have been normalized to 2009 values using the Chemical Engineering Plant Cost Index. This index was selected due to its widespread recognition 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. **CONTINGENCY GUIDELINE IMPLEMENTATION:**

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

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

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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. **Threats:** *Uncertain events that are potentially negative or reduce the probability that the desired outcome will happen.* 
	- 1. The singularly largest threat to this estimate surrounds the lump sum cost included for the HTGR 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)**



### **Sources Considered:**



#### **Source Selected:**



#### **Balance of Plant:**



#### **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**



## **Sources Considered:**



# **Summary:**



# **Balance of Plant:**



#### **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 incl in the Rankine power cycle cost. Water and electrical systems BOP allowances are included in the reported cost for the Rankine power cycle.

# **Detail Item Report - High Temperature Steam Electrolysis (HTSE)**



## **Sources Considered:**



#### **Source Selected:**



#### **Balance of Plant:**



#### **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**



## **Sources Considered:**



#### **Source Selected:**



#### **Balance of Plant:**



## **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**



## **Sources Considered:**



# **Source Selected:**



# **Balance of Plant:**



## **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 allowa 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 add 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**



## **Sources Considered:**



#### **Source Selected:**



## **Balance of Plant:**



## **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**



## **Sources Considered:**



# **Source Selected:**



### **Balance of Plant:**



#### **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 o NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

# **Detail Item Report - Claus and SCOT**



## **Sources Considered:**



## **Source Selected:**



# **Detail Item Report - Claus and SCOT**



## **Balance of Plant:**



# **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 liste '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**



## **Sources Considered:**



#### **Source Selected:**



### **Balance of Plant:**



#### **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**



## **Sources Considered:**



# **Source Selected:**



#### **Balance of Plant:**



#### **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 NET 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**



## **Sources Considered:**



## **Source Selected:**



## **Balance of Plant:**



## **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 NET 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**



## **Sources Considered:**



#### **Source Selected:**



#### **Balance of Plant:**



#### **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 'Balanc are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.



# **Appendix C Conventional Coal to SNG Steam Results.xls**

[Electronic]



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

[Electronic]