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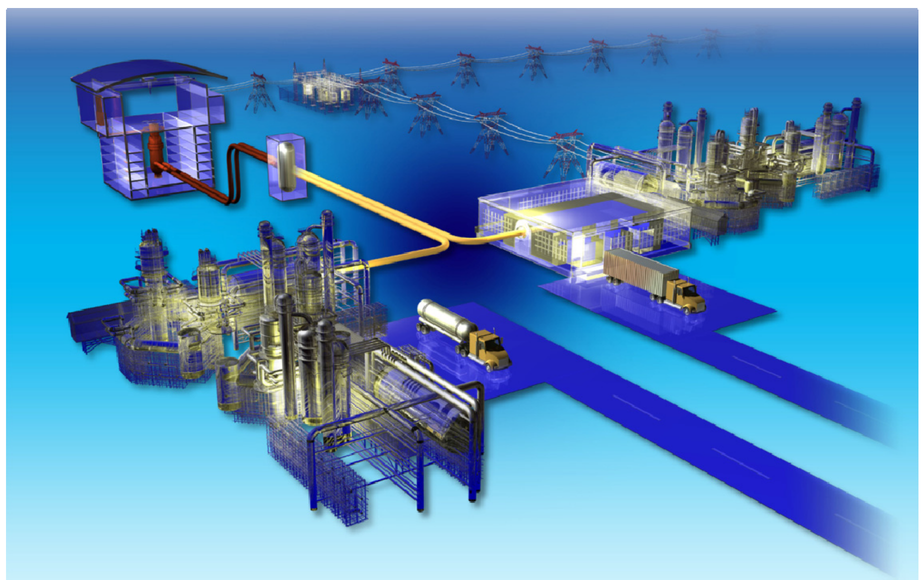
Technical Evaluation Study

Project No. 23843

Nuclear-Integrated Methanol-to Gasoline Production Analysis



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NUCLEAR-INTEGRATED METHANOL-TO GASOLINE PRODUCTION ANALYSIS	Identifier: TEV-667 Revision: ~~2~~ 1 Effective Date: 05/15/2010	Page: 1 of 68

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Signatures			
Signature and Typed or Printed Name	Signature Code	Date (mm/dd/yyyy)	Organization/Discipline
R. A. Wood	P	5/3/2010	NGNP Engineering Support
R. D. Boardman	A	5/3/2010	NGNP Engineering Support
M. W. Patterson	C	5/5/2010	NGNP Engineering Technical Manager

P For preparer of the document.

A For approval: This is for non-owner approvals that may be required as directed by a given program or project. This signature may not be applicable for all uses of this form.

C For documented review and concurrence.

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REVISION LOG

Rev.	Date	Affected Pages	Revision Description
0	11/05/09	All	Newly issued document.
1	05/15/10	All	Comment resolution plus inclusion of economic results. Model updates

EXECUTIVE SUMMARY

This technical evaluation (TEV) has been prepared as part of a study for the Next Generation Nuclear Plant (NGNP) Project to evaluate integration of high-temperature gas-cooled reactor (HTGR) technology with conventional chemical processes. This TEV addresses the integration of an HTGR with the methanol-to-gasoline (MTG) process. The main liquid product produced is gasoline.

The HTGR can produce steam, high-temperature helium that can be used for process heat, and/or electricity. 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 or electricity produced in an HTGR could be used to supply process heat or electricity to conventional chemical processes without generating any GHGs. This report describes how nuclear-generated heat or electricity could be integrated into conventional coal-to-MTG and gas-to-MTG processes, provides a preliminary economic analysis of the conventional and nuclear-integrated options, and assesses the well-to-wheel (WTW) GHG emissions of the conventional MTG processes versus the nuclear-integrated options.

The following conclusions were drawn when evaluating the nuclear-integrated coal-to-MTG process against the conventional process:

- Eleven and a half 600 MW_t HTGRs are required to support production of a 66,805 barrel per day coal-to-MTG facility. Nuclear integration decreases coal consumption by 54% using electrolysis and nuclear power as the hydrogen source. Nuclear integration decreases CO_2 emissions by 17% if sequestration is assumed and 98.5% without sequestration.

- The following table outlines the gasoline prices necessary for 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%. Average and historical high gasoline prices are also presented.

Table ES 1. Coal-to-MTG economic results summary for a 12% IRR.

Technology	**Gasoline Price ($/gal) No CO_2 Tax**	**Gasoline Price ($/gal) $50/ton CO_2 Tax**	**Gasoline Price ($/gal) $100/ton CO_2 Tax**
Conventional MTG	1.81	2.59	3.38
Conventional MTG, with Sequestration	2.00	2.01	2.02
Nuclear-Integrated MTG	3.50	3.51	3.53
Nuclear-Integrated MTG, -30% HTGR cost	2.95	2.96	2.97
Average US Gasoline Price	2.40		
High US Gasoline Price, June 2008	3.58		

- Integration of an HTGR can reduce WTW GHG emissions below baseline (U.S. crude mix) or imported crude-derived gasoline. WTW GHG emissions decrease 16% below baseline crude with nuclear-integrated coal-to-MTG. Even with CO_2 sequestration, conventional coal-to-MTG WTW GHG emissions are 9% higher than baseline crude emissions.

The following list identifies the major conclusions drawn evaluating the nuclear-integrated gas-to-MTG process against the conventional process:

- 722 MW_t would be required form the HTGRs to support production of a 38,748 barrel per day gas-to-MTG facility. Nuclear integration decreases natural gas consumption by 10.4% when nuclear heat is substituted for natural gas combustion in the primary reformer. As a result, CO_2 emissions are decreased by 68% from the conventional case.

- The following table outlines the gasoline prices necessary for a 12% 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%. Average and historical high gasoline prices are also presented.

Table ES 2. Gas-to-MTG economic results summary for a 12% IRR.

Technology	Gasoline Price ($/gal)			
	No CO_2 Tax			$50/ton CO_2 Tax
	Low Nat. Gas	Avg. Nat. Gas	High Nat. Gas	Avg. Nat. Gas
Conventional MTG	1.47	1.89	3.06	2.01
Nuclear-Integrated MTG	1.63	2.00	3.05	2.04
Nuclear-Integrated MTG, -30% HTGR Cost	1.53	1.90	2.95	1.94
Average US Gasoline Price	2.40			
High US Gasoline Price, July 2008	3.58			

- Integration of an HTGR can reduce WTW GHG emissions below baseline (U.S. crude mix) or imported crude-derived gasoline. WTW GHG emissions are 4% lower than baseline crude with nuclear-integrated gas-to-MTG. Conventional gas-to-MTG WTW GHG emissions are 16% higher than baseline crude emissions.

CONTENTS

ACRONYMS AND NOMENCLATURE

AACE	Association for the Advancement of Cost Engineering
ASU	air separation unit
ATCF	after tax cash flow
BTCF	before tax cash flow
CEPCI	Chemical Engineering Plant Cost Index
CMD	coal milling and drying
CTL	coal to liquids
DOE	Department of Energy
DME	dimethyl ether
EIA	Energy Information Administration
EOR	enhanced oil recovery
EPA	United States Environmental Protection Agency
GHG	greenhouse gas
GWP	global warming potential
GT-MHR	gas-turbine modular helium reactor
HP	high pressure
HRSG	heat recovery steam generator
HTSE	high-temperature steam electrolysis
HTGR	high-temperature gas reactor
IHX	intermediate heat exchanger
INL	Idaho National Laboratory
IPCC	Intergovernmental Panel on Climate Change
IRR	internal rate of return
LHV	lower heating value
LP	low pressure
LPG	liquefied petroleum gas
MACRS	modified accelerated cost recovery system
MARR	minimum annual rate of return
MMSCF	1,000,000 standard cubic feet
MSCF	1,000 standard cubic feet

MTG	methanol-to-gasoline
NETL	National Energy Technology Laboratory
NGNP	Next Generation Nuclear Plant
NIBT	net income before taxes
O&M	operations and maintenance
PSA	pressure swing absorption
PW	present worth
SCOT	Shell Claus offgas treatment
SMR	steam methane reformer
SUV	sport utility vehicle
TCI	total capital investment
TEV	technical evaluation
WTW	well to wheel

C_1	cost of equipment with capacity q1
C_2	cost of equipment with capacity q2
C_k	capital expenditures
d_k	depreciation
E_k	cash outflows
i'	IRR
k	year
n	exponential factor
q_1	equipment capacity
q_2	equipment capacity
R_k	revenues
t	tax rate
T_k	income taxes

1. INTRODUCTION

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

The HTGR produces steam, high-temperature helium that can be used for process heat, and/or electricity. 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 (GHGs) such as carbon dioxide. Heat or electricity produced in an HTGR could be used to supply process heat or electricity to conventional chemical processes while generating minimal greenhouse gases. The use of an HTGR to supply process heat or electricity to conventional processes is referred to as a nuclear-integrated process. This report describes how nuclear-generated heat or electricity could be integrated into conventional processes and provides a preliminary economic analysis to show which nuclear-integrated processes compare favorably with conventional processes.

Table 1. Projected outputs of the NGNP.

HTGR Product	Product Description
Steam	540°C and 17 MPa
High-Temperature Helium	Delivered at 700°C and 9.1 MPa
Electricity	Generated by Rankine cycle with 40% thermal efficiency

This TEV addresses potential integration opportunities for the methanol-to-gasoline (MTG) process. The HTGR would produce electricity, heat, and/or hydrogen and be located near the MTG production facility. Details of the specific cases considered are described in Section 2 of this report. A separate study should be conducted to assess the optimal siting of the HTGR with respect to the MTG facilities, 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 to evaluate the integration of HTGR technology with commercial MTG production methods. Process modeling results are subsequently used as inputs for economic analyses and life-cycle GHG emissions calculations (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 technical evaluation (TEV) study. Similarly, a familiarity with gasification, steam methane reforming (SMR), methanol synthesis, ExxonMobil's MTG process, and common gas purification technologies is assumed. Hence, a thorough explanation of these technologies is also considered to be beyond the scope of this TEV.

This TEV first presents an overview of the process modeling performed for each case. Afterwards, the results of the process modeling are discussed with emphasis placed on the impact of the HTGR integration. Next, an overview of the economic modeling is presented, followed by results of this modeling. Again, emphasis is placed on the impact of the HTGR integration. Following the economic modeling discussion, the method for calculating GHG emissions is discussed. Results are drawn from the GHG modeling, and conclusions are drawn comparing the conventional processes to the nuclear-integrated processes. Finally, overall conclusions for the coal-based and natural gas-based cases are discussed separately. These conclusions also focus on the impact of the HTGR integration.

2. PROCESS MODELING OVERVIEW

Plant models for the coal-to-MTG and natural gas-to-MTG process were developed using Aspen Plus (Aspen 2006). Because of the size and complexity of the process modeled, the simulation was constructed using "hierarchy" blocks. A hierarchy block is a method for nesting one simulation within another simulation. In this manner, submodels for each major plant section were constructed separately and then combined to represent the entire process.

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. Utility blocks tracked electricity, steam, and cooling water usage. Aspen

Plus Version 2006 (Build 20.0.3.4127), run under Windows XP SP3 on computer ID 410530 was used for all modeling calculations.

The original models for the fossil portion of the plant were developed using English units, which is common industrial practice in the United States. Nuclear plants typically use metric units; hence, this report contains both English and metric units depending on the context of the information presented.

Four cases were originally identified for modeling:

- Conventional coal-to-MTG process
- Conventional natural gas-to-MTG process
- Nuclear-integrated coal-to-MTG process
- Nuclear-integrated natural gas-to-MTG process.

For the natural gas-to-MTG cases, natural gas composition was taken from data published by Northwest Gas Association. Capacity for the plant was set at 11,023 ton/day of methanol, which corresponds to dual 5,512 ton/day methanol plants. Final product rate for these cases was 38,750 bbl/day of liquid products (gasoline plus liquefied petroleum gas [LPG]).

For the coal cases, a generic Illinois #6 coal was used as the feedstock due to its high availability and use within the United States. 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 conventional coal case was set based on a gasifier throughput of 3,600 tonne/day, representing a commercial Shell gasifier. This case considered six gasifiers operating in parallel, resulting in a liquid product rate (gasoline plus LPG) of 66,804 bbl/day. Throughput of the nuclear-integrated coal-to-MTG case was adjusted to achieve the same final product output as the conventional coal case.

For the Aspen models described in this analysis, rigorous submodels of the nuclear power cycle and high-temperature electrolysis have not yet been integrated. Results for the nuclear power cycle and high-temperature steam electrolysis (HTSE) were calculated separately using the UNISIM modeling package. Cooling water requirements for HTSE were then estimated and added to the overall Aspen model results. Water consumption for the HTGR and associated power cycle 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 methanol and gasoline are essentially unchanged between cases.

2.1 Conventional Coal-to-MTG Case

Figure 1 shows the block flow diagram for the conventional coal-to-MTG case. The proposed process includes unit operations for air separation, coal milling and drying, coal gasification, syngas cleaning and conditioning, sulfur recovery, CO_2 compression/liquefaction, methanol synthesis, methanol conversion to gasoline, power production, cooling towers, and water treatment. Each unit operation is briefly described below. For each description, the name capitalized and enclosed in parentheses corresponds to the name of the hierarchy block within the Aspen process model.

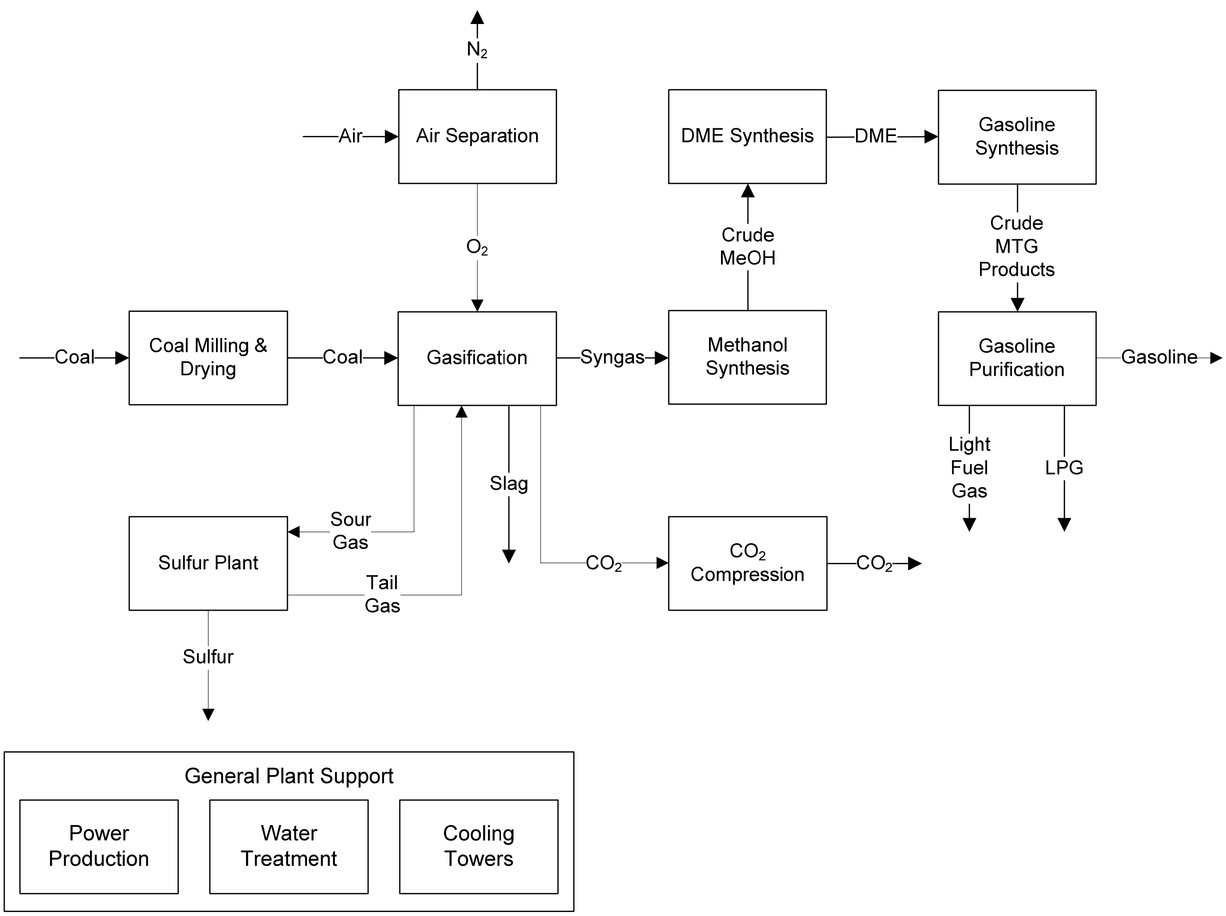

Figure 1. Block flow diagram for the conventional coal-to-MTG process.

- **Air Separation (ASU) –** Oxygen is produced via a standard cryogenic Linde-type ASU, which 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%, but the high-purity oxygen is desired to minimize diluent nitrogen in the fuel synthesis loops. The nitrogen co-product from the ASU can be used for coal drying and transport and as 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 (Worley Parsons 2002).

- **Coal Milling and Drying (CMD) –** Coal is pulverized to below 90 μm using a roller mill to ensure efficient gasification. Currently, coal milling power consumption is modeled based on the power calculated by Aspen assuming a Hardgrove grindability index of 60. Drying is accomplished simultaneously using a heated inert gas stream. The gas stream removes evaporated water as it sweeps the pulverized coal through an internal classifier for collection in a baghouse. The inert nitrogen, from the ASU, is heated by firing clean syngas in a burner. The nitrogen is mixed with this hot gas to create a hot inert gas stream that 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_2 vented during depressurization of the feed hopper is estimated using the ideal gas law.

- **Gasification (GASIFIER) –** The dry coal is gasified at 2,800°F using an entrained-flow, dry-fed, slagging, oxygen-blown gasifier. Oxygen is fed to the gasifier to achieve the outlet temperature of 2,800°F, while steam (700 psi) is fed such that the mass 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 high-pressure steam (Shell 2004). The syngas is further cooled by a water quench. A portion of the quenched syngas is returned to the gasifier effluent 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. Of the water from the slag quench loop, 2.5% is assumed to be sent to water treatment to avoid any buildup of contaminants.

- **Syngas Conditioning (GAS-CLN)**[a] – 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 methanol synthesis reactors. This ratio was specified as

$$\frac{H_2 - CO_2}{CO + CO_2} = 2.10 \quad (1)$$

This ratio is a commonly used metric to characterize the suitability of the syngas for methanol production. Steam (700 psi) 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. 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_2, H_2S, and COS (Rectisol process). It is assumed that 3% CO_2 and less than 1 ppm of H_2S are present in the clean syngas stream. Additional removal of CO_2 is possible, but not desirable, because some CO_2 in the syngas is beneficial in the downstream methanol synthesis reactor. The H_2S-rich stream is assumed to contain approximately 55% H_2S, with the remainder being CO_2 (Lurgi 2006).

H_2S containing gas from the sulfur reduction unit is also sent to the Rectisol process for sulfur removal. The nitrogen and argon contained in this stream are assumed to pass through to the CO_2-rich stream. It is also assumed that a steam reboiler rather than nitrogen flow is used for stripping to ensure a sufficiently pure CO_2 stream for sequestration. 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 because of 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 extreme sulfur and iron intolerance of the methanol synthesis 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.

a. This block was modeled separately but is included within the block labeled “Gasification” in Figure 1.

- **Sulfur Plant (CLAUS and S-REDUCT) –** Sulfur recovery is based on the Claus process. Illinois coal has a sufficiently high sulfur content, which can create an acid gas stream with up to 60% H_2S. 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_2 to H_2S (Kohl 1997). Tailgas 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.

- **CO_2 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_2 is produced. The resulting stream is then compressed, along with the CO_2 recycle from coal milling and drying, and liquefied prior to being pumped to the required pressure for use in enhanced oil recovery (EOR) or sequestration. CO_2 for filtration is split from the CO_2 pressurization scheme at 700 psi, while the CO_2 for coal transport is split from the CO_2 pressurization scheme at 1,160 psi. Eight stages are assumed for the CO_2 compression scheme, resulting in an overall efficiency of 84.4%. Carbon dioxide at 2,005 psi should be liquid, but Aspen's physical property methods do not predict the proper phase of the CO_2 stream because a small quantity of inert gas is present. The number of stages, stage efficiencies, and resulting power requirements were tuned to commercial CO_2 compression turbines; thus, the incorrect phase prediction will not impact the resulting power requirement.

- **Methanol Synthesis (MEOH-SYN) –** Syngas feeding the methanol synthesis unit has been previously adjusted to achieve a $(H_2 - CO_2)/(CO + CO_2)$ molar ratio 2.10. This results in a H_2/CO molar ratio for the feed gas of 2.45. Incoming feed gas is compressed to 1,090 psi, followed by heating via recuperation to 422°F prior to introduction into the methanol conversion reactor. Methanol is formed via the following reactions (English 2005):

$$CO + H_2O \rightarrow H_2 + CO_2 \tag{2}$$

$$CO_2 + 3H_2 \rightarrow CH_3OH + H_2O \tag{3}$$

- When these reactions are added, the net stoichiometric equation for reaction of CO to methanol becomes:

$$CO + 2H_2 \rightarrow CH_3OH \tag{4}$$

- Methanol and unreacted syngas exiting the reactor are cooled by recuperation with the incoming feed gas, followed by condensation and separation of the liquid methanol product. Unreacted gas is recompressed, mixed with fresh incoming syngas, and fed back to the methanol synthesis reactor. A purge on the unreacted gas stream is set to limit buildup of inert gas within the synthesis loop; the molar recycle ratio is currently set at 4.0:1. These conditions result in a reactor inlet CO_2 concentration of 1 mol% and a methanol concentration in the reactor exit stream of 7.6 mol%. Condensed methanol product is purified in a distillation column to remove light gases prior to storage in the methanol intermediate product tank. A portion of the methanol synthesis loop purge gas is routed through a pressure swing absorption (PSA) system to recover unreacted H_2 for use in the sulfur reduction and gasoline refining portions of the plant. The remainder of the purge gas and the PSA off-gas are used as fuel gas for coal drying and power production in the plant.

- **DME Synthesis, Gasoline Synthesis, Gasoline Purification (MTG) –** Methanol is converted to gasoline using ExxonMobil's patented process. Methanol is first pumped to 345 psi and heated using recuperation to 590°F prior to introduction to the dimethyl ether (DME) reactor. In this reactor, methanol is exothermically converted to an equilibrium concentration of DME, water, and methanol according to the following reaction (New Zealand Institute of Chemistry 1996):

$$2CH_3OH \rightarrow CH_3OCH_3 + H_2O \tag{5}$$

- The product of this reactor is mixed with recycle gas to cool the stream to 357°F before it is introduced to the ZSM-5 catalytic MTG reactor. In this reactor, methanol and DME are converted to hydrocarbons ranging from C_1 (methane) to C_{11} (1-naphtha) according to the following generic reaction:

$$nCH_3OCH_3 \rightarrow C_X H_Y + zH_2O \tag{6}$$

- The overall reaction from DME and methanol to gasoline is exothermic, resulting in an exit temperature of around 750°F. The crude gasoline product is cooled via recuperation. Additional heat is removed by raising steam, followed by condensation. Liquid product is separated for further refining, while light gas is recompressed and recycled to the ZSM-5 catalytic MTG reactor. A portion of the gas is purged to limit inert gas buildup within the gasoline synthesis loop. Crude liquid gasoline is purified using three distillation columns: de-ethanizer, de-propanizer, and de-waxing. Light gas exiting the de-ethanizer is used as fuel gas for coal drying and power production. Light gas exiting the de-propanizer is sold as LPG product. Gasoline product exits the top of the de-waxing column, while a durene-rich heavy stream is taken off as the bottoms product from this column. The durene-rich stream is treated in a hydrodealkylation unit to convert it to lighter hydrocarbons more suitable for gasoline. Light gases produced in the hydrodealkylation unit are removed as LPG product in a second de-propanizer, while the bottoms product from this column is mixed with the final gasoline product.

- **Power Production (HRSG-ST) –** The high- (700 psi), medium- (381 psi) and low-pressure (60 psi) steams 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 60 psi, efficiencies for the steam turbines remain constant at approximately 81% combined thermodynamic and mechanical efficiency. It is recognized that the piping size for the 60 psia steam may be impractical and other methods for recovering the heat contained in this stream may be required. The condensed steams 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. Low-pressure steam is added to the deaerator. Purge gas produced in the plant is fired in the heat recovery steam generator (HRSG) to raise additional steam to bolster power production and to preheat boiler feed water prior to deaeration. Aspen Utility blocks are used to track all steam generation and use in the plant. This information is used as input to the power production section of the model, allowing reconciliation of the entire plant steam balance.

- **Cooling Towers (COOL-TWR) –** Conventional cooling towers are modeled in Aspen Plus using literature data. Air cooling could potentially be used in certain areas of the plant to decrease water consumption; however, for simplicity, cooling water only was assumed. The evaporation rate, drift, and blowdown are based on a rule-of-thumb guide for the design and simulation of wet cooling towers (Leeper 1981). Aspen Utility blocks are used to track all cooling water use in the plant. This information is used as input to the cooling tower section of the model, allowing reconciliation of the entire plant cooling water balance.

- **Water Treatment (H2O-TRTM) –** Water treatment is simplistically modeled in Aspen Plus using a variety of separation blocks. INL is currently collaborating with a major water treatment vendor to develop the water treatment portion of the model. The existing water treatment scenario is a place holder and will be revised as information is received from the water treatment vendor. Hence, it is anticipated that energy consumption for the water treatment portion of the plant could change considerably based on water treatment vendor feedback. Aspen Transfer blocks are used to reconcile water in and out flows from various parts of the plant, allowing reconciliation of the entire plant water balance.

2.2 Conventional Natural Gas-to-MTG Case

Figure 2 shows the block flow diagram for the conventional natural gas-to-MTG case. The proposed process includes unit operations for air separation, natural gas purification and reforming, methanol synthesis, methanol conversion to gasoline, power production, cooling towers, and water treatment. Each unit operation is briefly described below. For each description, the name capitalized and enclosed in parentheses corresponds to the name of the hierarchy block within the Aspen process model. Because many of the unit operations remain unchanged from the conventional coal-to-MTG flow sheet, emphasis is placed on differences in configuration between the natural gas and coal cases.

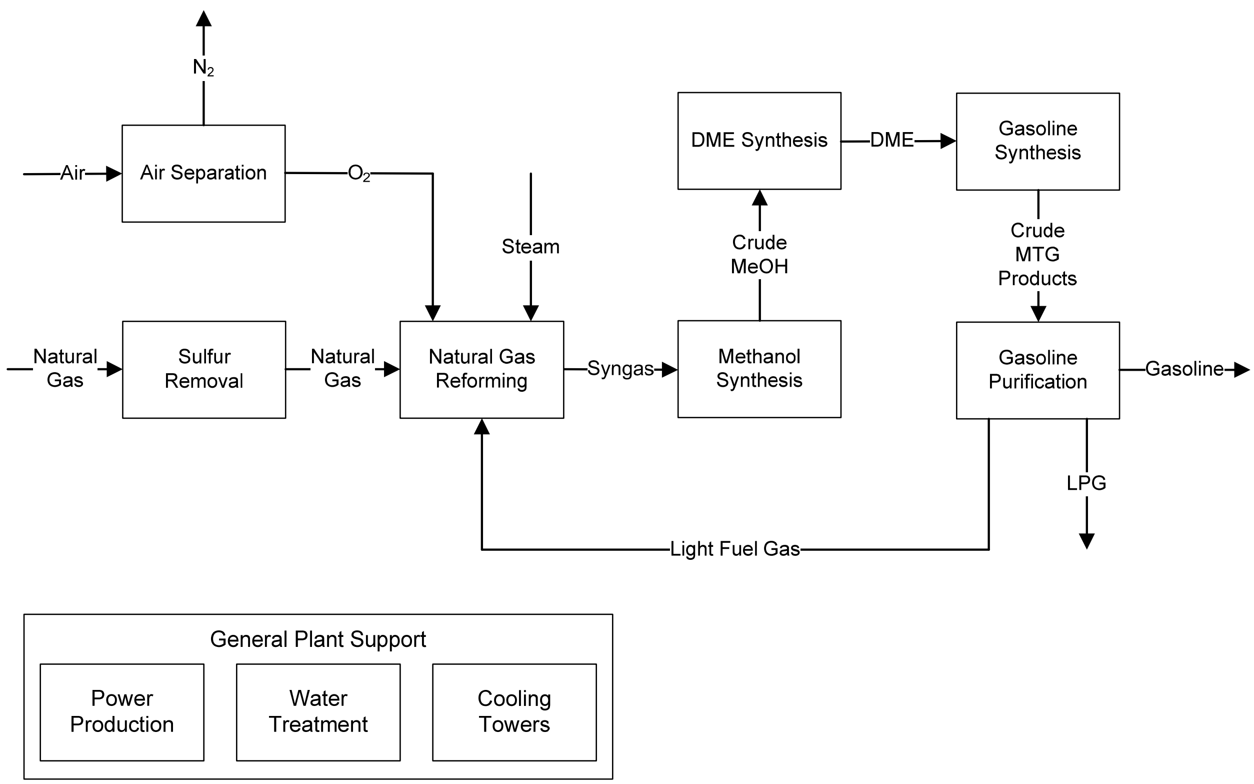

Figure 2. Block flow diagram for the conventional natural gas-to-MTG process.

- **Sulfur Removal, Natural Gas Reforming (NG-RFMR)** – Three reforming scenarios were considered: steam methane reforming, autothermal reforming, and two-step reforming consisting of primary steam reforming followed by secondary autothermal reforming. Although all three scenarios are commercially viable, two-step reforming appears to offer the best opportunity for nuclear heat integration while still allowing for optimization of the synthesis gas composition for methanol production. The desired syngas module (M) for methanol production is defined as (English 2005):

$$M = \frac{H_2 - CO_2}{CO + CO_2} = 2.0 \ \ to \ \ 2.1 \quad . \tag{7}$$

For this study, a value of M of 2.10 was selected as the target. This ratio was achieved by setting the steam-to-carbon inlet molar ratio to 1.80 (Haldor Topsoe 2009), by setting the exit temperature of the primary former to 1,362°F (739°C), and by setting the exit temperature of the secondary reformer to 1,900°F (1,038°C).

Natural gas is split into two streams. Of the total natural gas flow, 10.5% is burned to provide heat for the primary reformer. The remaining 89.5% of the natural gas flow is compressed to 615 psi and then preheated to 350°F and saturated with hot water. After saturation, the gas is further heated to 662°F and mixed with a small amount of hydrogen. Sulfur is removed from the gas and then mixed with steam to achieve the desired steam-to-carbon molar ratio of 1.8. Because the resulting natural gas/steam mixture is preheated to only 1000°F, a preformer is not included in this flowsheet.

The natural gas/steam mixture is fed to the primary reformer where methane is converted over a catalyst to CO, H_2, and CO_2. Methane conversion in this reactor is approximately 25%. A separate feed of the natural gas is mixed with fuel gas and burned to provide heat for the endothermic reforming reactions. The hot offgas from the reformer is exchanged with inlet syngas, water, and steam to provide preheat for these streams.

The effluent from the primary reformer and oxygen are fed to an autothermal reformer where conversion of the remaining methane to syngas is accomplished. The oxygen-to-carbon molar ratio is set at 0.41, which results in an exit temperature of 1,900°F. The hot syngas is cooled by exchange with boiler feed water to create steam, followed by condensation of the water from the syngas. The resulting syngas has a H_2/CO ratio of 3.1 and contains 7.2 mol% CO_2 and 0.9 mol% CH_4.

- **Air Separation (ASU) –** Air separation in the conventional natural gas-to-MTG case is identical to that of the conventional coal-to-MTG case. However, because the natural gas flow sheets do not require coal drying, N_2 product from the ASU can be available for sale as a byproduct.

- **Methanol Synthesis (MEOH-SYN) –** Methanol synthesis in the conventional natural gas-to-MTG case is identical to that of the conventional coal-to-MTG case. However, due to differences in syngas generation technique, the H_2/CO molar ratio for the feed gas is 3.1 compared to 2.45 for the coal-to-MTG case. This difference is primarily caused by increased CO_2 in the feed gas for the natural gas-fed case.

- **DME Synthesis, Gasoline Synthesis, Gasoline Purification (MTG) –** The gasoline synthesis and purification processes in the conventional natural gas-to-MTG case remain unchanged from the gasoline synthesis and purification processes in the conventional coal-to-MTG case.

- **Power Production (HRSG-ST) –** Power production in the conventional natural gas-to-MTG case is identical to that of the conventional coal-to-MTG case. However, power production is accomplished solely from steam generated throughout the plant. Purge gas generated during synthetic fuel production is burned in the primary reformer; hence, it is not available for firing a HRSG.

- **Cooling Towers (COOL-TWR) –** The cooling towers in the conventional natural gas-to-MTG case are identical to those in the conventional coal-to-MTG case.

- **Water Treatment (H2O-TRTM) –** Water treatment in the conventional natural gas-to-MTG case is identical to that of the conventional coal-to-MTG case.

2.3 Nuclear-Integrated Coal-to-MTG Case

Figure 3 shows the block flow diagram for the nuclear-integrated coal-to-MTG case. The proposed process includes the same unit operations as the conventional coal-to-MTG 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.

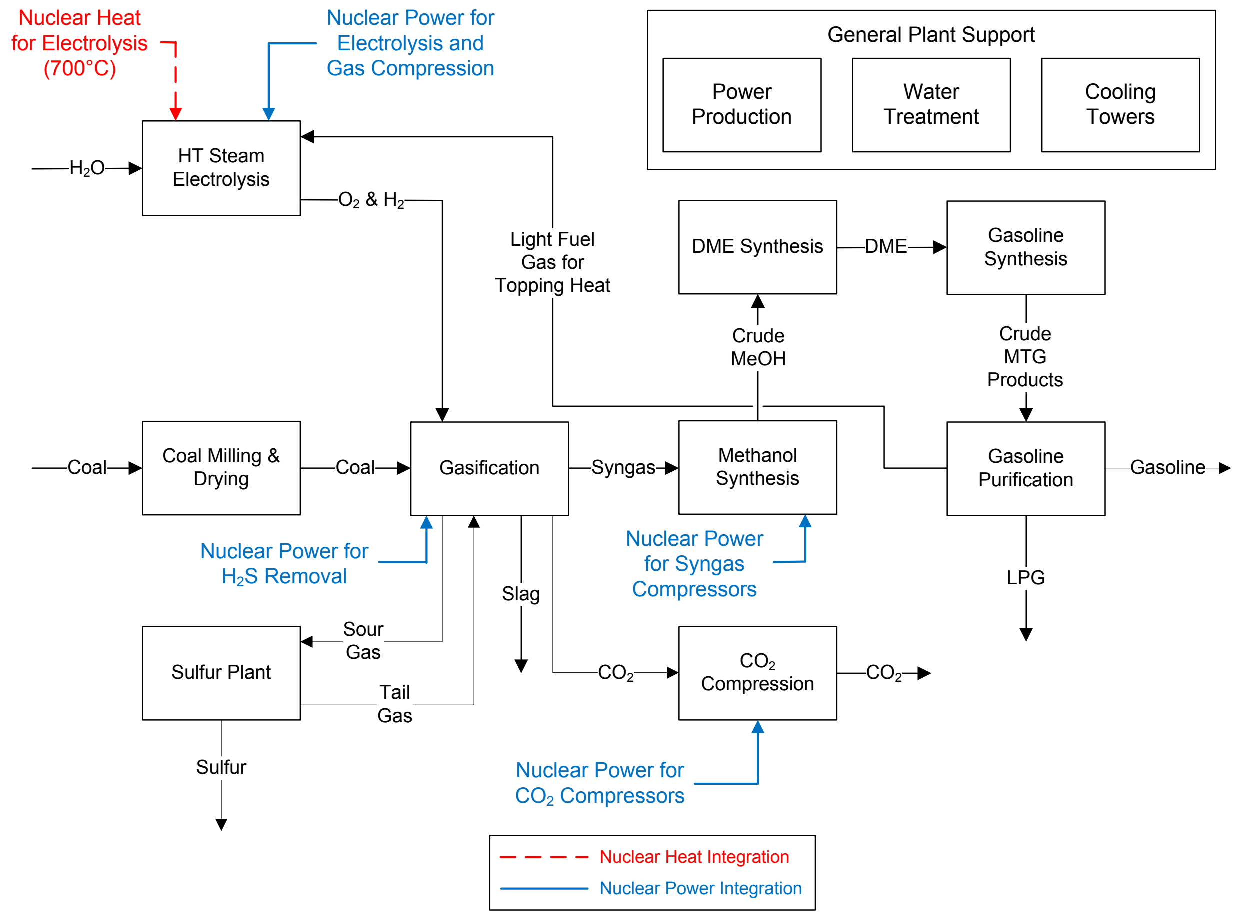

Figure 3. Block flow diagram for the nuclear-integrated coal-to-MTG process.

While developing the nuclear-integrated case, opportunities for heat integration between the nuclear 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 of heat that could provide for the required needs within this plant. In a few instances (notably gasoline refining and coal milling and drying), it was believed that nuclear heat could displace burning of light gas to reduce overall plant GHG emissions. However, the modeling analysis indicated that light gas recycle would lead to unacceptable buildup of inert gases in the process. Hence, it was deemed practical to use this gas as fuel rather than develop complex schemes to separate inerts from light gas.

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 for 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, fuelgas is fired to provide topping heat for the electrolyzers. 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 fuelgas 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 flow sheet, 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. In addition, the steam-to-coal ratio in the gasifier was increased from 1:7.0 to 1:9.5 in order to produce the additional CO_2 required for coal feeding. Operation of the Rectisol unit was also modified to capture more CO_2.

Each unit operation in the nuclear-integrated coal-to-MTG flow sheet is briefly described below. For each description, the name capitalized and enclosed in parentheses corresponds to the name of the hierarchy block within the Aspen process model. Because the majority of unit operations remain unchanged from the conventional coal-to-MTG flow sheet, emphasis is placed on differences in configuration between the two cases.

- **HT Steam 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 generated by burning fuel gas 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 the hydrogen is used to adjust to hydrogen-to-carbon monoxide ratio for methanol synthesis in place of sour shift reactors.

- **Coal Milling and Drying (CMD) –** Coal milling and drying for the nuclear-integrated case is similar to the conventional case. However, because fuel gas is required to produce topping heat for the electrolyzers, steam was selected as the heat source for coal drying. In addition, because nitrogen is not readily available in this scenario, coal drying is accomplished using air. 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_2 recovered from the Rectisol unit. Because CO_2 is not as abundant as in the baseline case, nitrogen concentration in the CO_2 will be elevated to 28 mol%.

- **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 46% of the baseline design to produce the same amount of liquid fuel product. As previously mentioned, the steam-to-coal ratio was increased from 1:7.0 to 1:9.5 in order to produce the additional CO_2 required for coal feeding.

- **Syngas Conditioning (GAS-CLN)[b]** – 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 methanol synthesis reactors. This ratio was specified as

$$\frac{H_2 - CO_2}{CO + CO_2} = 2.10\,. \tag{8}$$

  When the shift reactors are eliminated, CO_2 concentration entering the Rectisol unit is reduced from 30% in the baseline case to 6% in the nuclear-integrated case. Similarly, CO_2 concentration in the purified syngas is reduced from 3% in the baseline case to 1% in the nuclear-integrated case. Correspondingly, the H_2:CO ratio is decreased from 2.45 to 2.20. Rectisol capacity and utility usage are reduced by more than 50% in the nuclear-integrated case as compared to the baseline case.

- **Sulfur Plant (CLAUS and 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 half that of the baseline case configuration. In order to reduce inert content in the CO_2 gas used for coal transport into the gasifier, air in the Claus and sulfur reduction plants was enriched to 29 mol%.

- **CO_2 Compression (CO2-COMP) –** CO_2 compression for the nuclear-integrated case is similar to CO_2 compression in the conventional case. However, because of the elimination of the shift converters, required capacity and utility usage are reduced by a factor of ~9.

- **Methanol Synthesis (MEOH-SYN) –** The methanol synthesis plant remains unchanged between the conventional and nuclear-integrated cases. Inlet gas composition is slightly different between the cases because of decreased CO_2 in the nuclear-integrated case. Because of this

b. This block was modeled separately but is included within the block labeled “Gasification” in Figure 3.

difference, methanol produced from the nuclear-integrated case will contain ~3.5 wt% less water than in the conventional case.

- **DME Synthesis, Gasoline Synthesis, Gasoline Purification (MTG) –** The gasoline synthesis and purification processes in the nuclear-integrated case remain unchanged from the gasoline synthesis and purification processes in the conventional case.

- **Power Production (HRSG-ST) –** Power production in the nuclear-integrated case is similar to the conventional case, but because of size reductions in some portions of the plant, the capacity of the steam system in the nuclear-integrated case is approximately 2/3 of the conventional case. In addition, power production is accomplished solely from steam generated throughout the plant. Purge gas generated during synthetic fuel production is burned to provide topping heat for the electrolyzers; hence, it is not available for firing a HRSG.

- **Cooling Towers (COOL-TWR) –** The cooling water system is similar in the nuclear-integrated case to the conventional case.

- **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.

2.4 Nuclear-Integrated Natural Gas-to-MTG Cases

Figure 4 shows the block flow diagram for the nuclear-integrated natural gas-to-MTG case. The proposed process includes the same unit operations as the baseline process, except nuclear heat is used in the primary reformer rather than burning natural gas. Nuclear heat is also used to preheat all streams entering the primary reformer. Because higher temperature heat is desired for steam reforming of natural gas, this configuration assumes the use of an intermediate heat exchanger (IHX) to provide 700°C helium gas as the heat transfer fluid to the reformer.

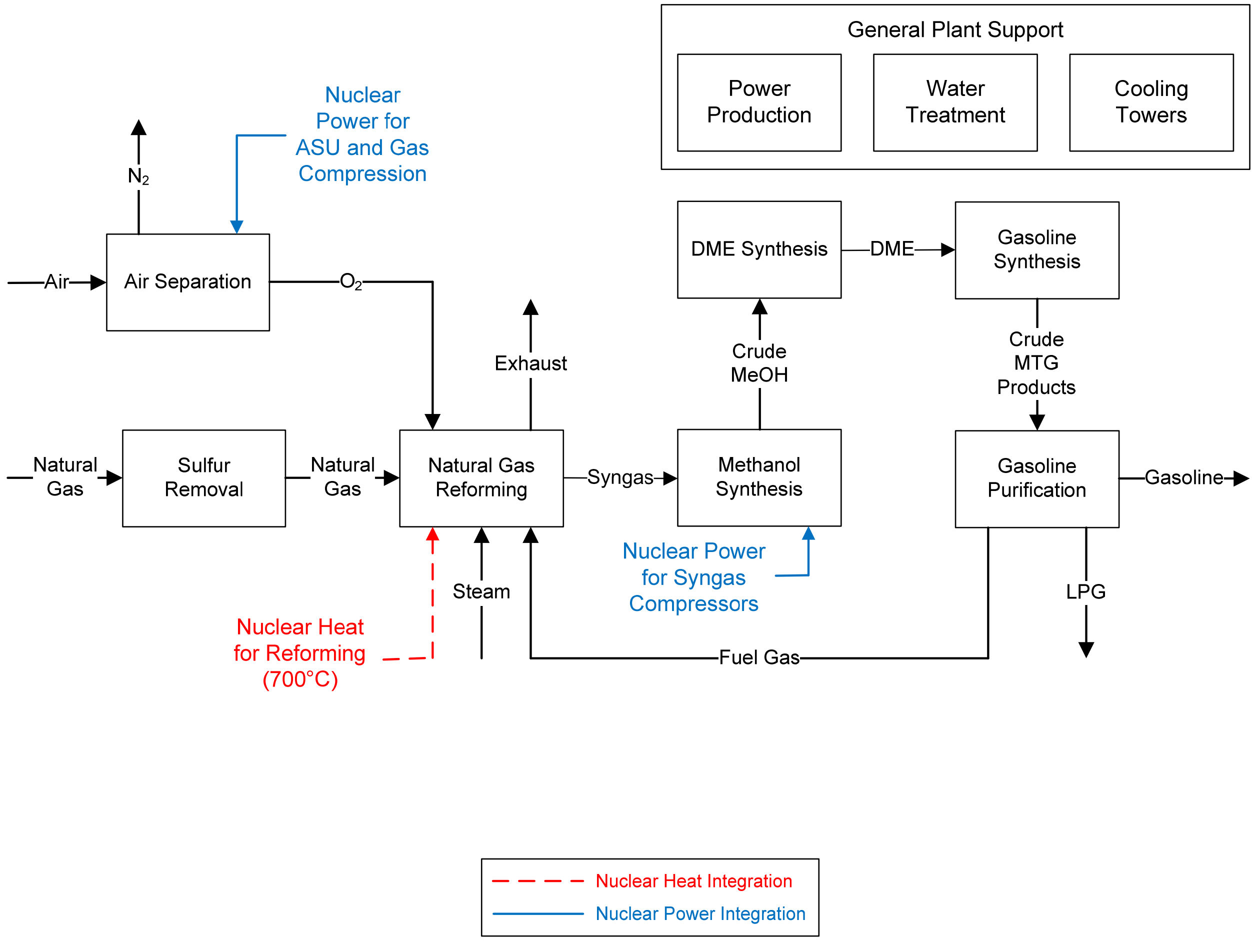

Figure 4. Block flow diagram for the nuclear-integrated natural gas-to-MTG process.

While developing the nuclear-integrated case, opportunities for heat integration between the nuclear and fossil plants were evaluated. The proposed process includes unit operations for air separation, natural gas purification and reforming, methanol synthesis, methanol conversion to gasoline, power production, cooling towers, and water treatment. Each unit operation is briefly described below. For each description, the name capitalized and enclosed in parentheses corresponds to the name of the hierarchy block within the Aspen process model. Because the majority of unit operations remain unchanged from the conventional natural gas-to-MTG flow sheet, emphasis is placed on differences in configuration between the conventional and nuclear-integrated cases.

- **Sulfur Removal, Natural Gas Reforming (NG-RFMR)** – Conditions in the reforming section of the plant had to be modified slightly because of the upper temperature limit of helium that can be delivered from the nuclear plant (700°C). Because of this constraint, primary reforming was split into two stages. In the first stage, nuclear heat is provided by hot helium exchange. The temperature of this reforming stage was set at 1,211°F (655°C). In the second stage of the primary reformer, purge gas is burned as the heat source. The temperature of this reforming stage was set at 1,362°F (739°C), which matches the primary reforming outlet temperature in the conventional natural gas-to-MTG case. The outlet temperature of the secondary (autothermal) reformer was maintained at 1,900°F (1,038°C), as in the conventional case.

- **Air Separation (ASU) –** Air separation in the nuclear-integrated case is identical to that of the conventional case.

- **Methanol Synthesis (MEOH-SYN) –** Methanol synthesis in the nuclear-integrated case is identical to that of the conventional case. The CO_2 concentration into the methanol synthesis reactor was slightly higher for the nuclear-integrated cases, resulting in slightly lower per-pass conversion.

- **DME Synthesis, Gasoline Synthesis, Gasoline Purification (MTG) –** The gasoline synthesis and purification processes in the nuclear-integrated case remain unchanged from the gasoline synthesis and purification processes in the conventional case.

- **Power Production (HRSG-ST) –** Steam generation and power production in the nuclear-integrated case is identical to that of the conventional case.

- **Cooling Towers (COOL-TWR) –** The cooling tower configuration in the nuclear-integrated case is identical to that of the conventional case.

- **Water Treatment (H2O-TRTM) –** The water treatment configuration in nuclear-integrated case is identical to that of the conventional case.

3. PROCESS MODELING RESULTS

Analysis of the conventional coal-to-MTG 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 GHG emissions from the process. It was also determined that the conventional coal-to-MTG case produced heat beyond what was needed to support demands of the plant. Based on these observations, a nuclear-integrated model was developed that focuses primarily on integrating nuclear hydrogen rather than nuclear heat.

Analysis of the conventional natural gas-to-MTG case indicates a strong potential heat integration opportunity for a HTGR. In the conventional case, 10.5% of the natural gas feed to the process is burned to provide heat to the primary reformer. The operating temperature in the primary reformer is 739°C, which is very close to the assumed 700°C temperature that can be supplied by an HTGR in this analysis.

A summary of the modeling results for all cases is presented in Table 2. The conventional coal and natural gas cases serve as a basis for comparison with the nuclear-integrated cases. A high-level material and energy balance summary for each case is graphically presented in Figure 5. For the complete Aspen stream results for all cases, see Appendixes C, D, E, and F.

Results from the nuclear-integrated coal-to-MTG case indicate that integration of nuclear hydrogen can drastically improve carbon utilization and reduce GHG emissions. Coal consumption is decreased by 54% 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 44.6% to 97.6%. Integrating nuclear power and HTSE also decreases CO_2 emissions from the plant. If carbon capture and sequestration are assumed for the conventional configuration, CO_2 emissions decrease by only 17% when electrolysis and nuclear power are utilized. However, if carbon capture and sequestration are not assumed for the conventional configuration, CO_2 emissions decrease by 98.5% when electrolysis and nuclear power are utilized. 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 413 MW_e to 2,481 MW_e, an increase of 500%. It is estimated that 11½ nuclear high-temperature reactors (600 MW_t each) would be required in this configuration to support production of 66,805 bbl/day of liquid fuel products.

Results for the nuclear-integrated natural gas-to-MTG case look promising. To support this configuration, 722 MW_t would be required from the HTGRs. By substituting nuclear heat for natural gas combustion in the primary reformer, natural gas consumption is decreased by 10.4% compared to the conventional gas-to-MTG case. Total power requirements for the plant decrease from 97.5 MW_e for the conventional case to 76.7 MW_e for the nuclear-integrated case. CO_2 emissions from the plant also decrease by integrating high-temperature nuclear reactors into the flow sheet. CO_2 emissions decrease by 68% for the nuclear-integrated case compared to the conventional case.

Table 2. MTG modeling case study results.

	Conventional Coal-to-MTG Process with CO_2 Capture	Nuclear-Integrated Coal-to-MTG Process w/ HTSE	Conventional Gas-to-MTG Process	Nuclear-Integrated Gas-to-MTG Process
Inputs				
Coal Feed Rate (ton/day)	25,934	11,845	N/A	N/A
Natural Gas Feed Rate (MMSCFD)[1]	n/a	N/A	288	258
# 600 MW_t HTGRs Required	n/a	11.45	N/A	1.20
Intermediate Products				
Methanol (ton/day)	20,055	19,342	11,023	11,023
Outputs				
Total Liquid Product	66,804	66,805	38,749	38,748
Gasoline (bbl/day)	57,703	57,704	33,471	33,470
Gasoline Produced / Coal Fed (lb/lb)	0.28	0.62	N/A	N/A
Gasoline Produced / Natural gas-fed (lb/lb)	N/A	N/A	0.65	0.73
Gasoline Produced / Methanol Fed (lb/lb)	0.37	0.38	0.39	0.39
LPG (bbl/day)	9,101	9,101	5,278	5,278
LPG Produced / Coal Fed (lb/lb)	0.03	0.07	N/A	N/A
LPG Produced / Natural gas-fed (lb/lb)	N/A	N/A	0.08	0.09
LPG Produced / Methanol Fed (lb/lb)	0.04	0.05	0.05	0.05
Nitrogen (ton/day)	N/A	N/A	16,638	16,623
Utility Summary				
Total Power (MW_e)	-413.4	-2480.6	-97.5	-76.7
Electrolyzers	N/A	-2488.7	N/A	N/A
Air Separation	-291.4	N/A	-75.1	-75.0
Coal Milling and Drying	-14.1	-10.7	N/A	N/A
Gasification Island	-13.9	-6.3	N/A	N/A
Natural Gas Reforming	N/A	N/A	-13.8	-9.3
Syngas Purification	-149.0	-56.1	N/A	N/A
Claus Plant	-0.7	-0.4	N/A	N/A
Sulfur Reduction (SCOT)	-10.2	-5.0	N/A	N/A
Non-Nuclear Power Island	340.7	225.4	59.8	76.5
CO_2 Compression	-135.8	-15.3	N/A	N/A
Methanol Plant	-103.1	-93.0	-49.1	-49.3
MTG Plant	-9.8	-9.8	-5.7	-5.7
Recycle Gas Compressor	N/A	-1.9	N/A	N/A
H_2 Recovery	-8.4	-5.9	-3.6	-3.7
Cooling Towers	-17.6	-12.8	-10.0	-10.1

Table 2. MTG modeling case study results.

	Conventional Coal-to-MTG Process with CO_2 Capture	Nuclear-Integrated Coal-to-MTG Process w/ HTSE	Conventional Gas-to-MTG Process	Nuclear-Integrated Gas-to-MTG Process
Water Treatment	N/A	-2488.7	N/A	N/A
Total Water Balance (gpm)*	-16,808	-12,716	-6,181	-6,370
Evaporation Rate (gpm)	-20,012	-13,869	-8,061	-8,279
Water Consumed / Liquid Produced (bbl/bbl)	8.63	6.53	5.47	5.64
Carbon Balance				
To Gasoline Product (% C Input)	40.10%	87.70%	75.8%	84.8%
To LPG Product (% C Input)	4.50%	9.90%	8.6%	9.6%
To Slag and Flyash (% C Input)	0.40%	0.40%	N/A	N/A
To Captured CO_2 (% C Input)	53.90%	N/A	N/A	N/A
To Emitted CO_2 (% C Input)	1.10%	1.80%	15.6%	5.6%
CO_2 Emissions				
Captured (ton/day CO_2)	30,856	N/A	N/A	N/A
Emitted (ton/day CO_2)	583	481	2,755	884
Nuclear Integration Summary				
Electricity (MW)	N/A	2480.6	N/A	115.3
HTE	N/A	2488.7	N/A	N/A
Balance of Plant	N/A	-8.1	N/A	76.7
Excess Power for Sale	N/A	N/A	N/A	38.6
Process Heat (MMBTU/hr)	N/A	N/A	N/A	1321.1
Helium Flow Rate (ton/hr)	N/A	N/A	N/A	1,290
Helium Supply Temperature (deg. F)	N/A	N/A	N/A	1,292
Helium Return Temperature (deg. F)	N/A	N/A	N/A	879
Electrolysis Heat (MMBTU/hr)	N/A	2,410	N/A	N/A
From Nuclear Plant	N/A	2,273	N/A	N/A
From Gasification Island	N/A	137	N/A	N/A
Electrolysis Products				
Total Hydrogen (ton/day)	N/A	1,939	N/A	N/A
Total Oxygen (ton/day)	N/A	15,281	N/A	N/A
Consumed in Plant	N/A	8,339	N/A	N/A
Available for Sale	N/A	6,941	N/A	N/A

[1]Standard temperature of 60°F.

*Detailed water balance can be found in Appendix A.

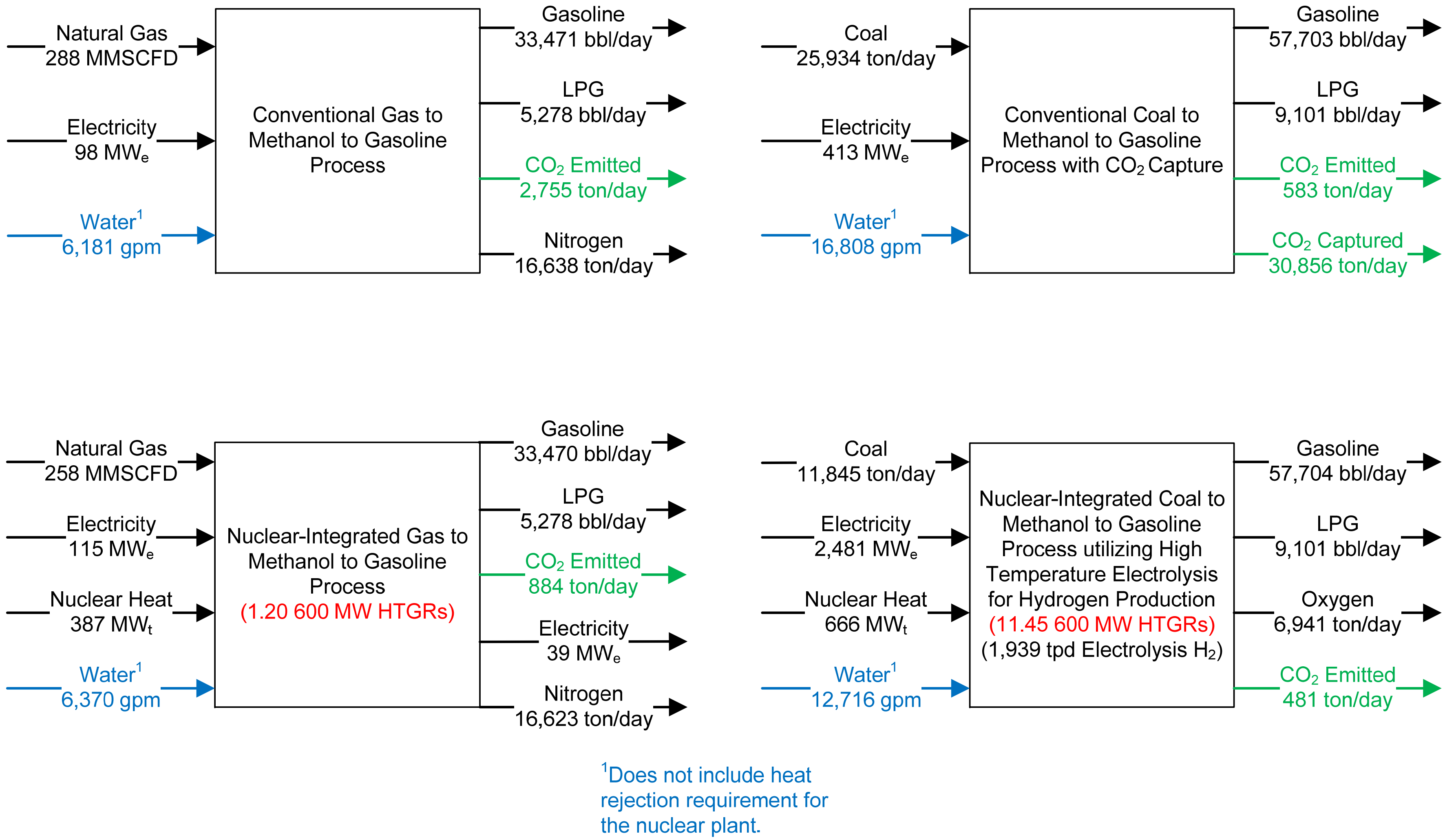

Figure 5. MTG modeling case material balance summary.

4. ECONOMIC MODELING OVERVIEW

The economic viability of the MTG 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) were then calculated for the TCI, as well as the TCI at +50% and –30% of the HTGR cost, with the debt to equity ratios equal to 80%/20% and 55%/45%. The following sections describe the methods used to calculate the capital costs, annual revenues, annual manufacturing costs, and the 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, methanol synthesis, DME and gasoline synthesis, steam turbines, the HRSG, cooling towers, HTSE electrolysis, and the HTGRs for the coal-to-MTG scenarios. Cost estimates were generated for SMR, the ASU, methanol synthesis, DME and gasoline synthesis, steam turbines, the HRSG, and the HTGR for the gas-to-MTG scenarios. In some instances, several costs were averaged. Gas cleanup includes costs for water-gas-shift reactors, the Rectisol process, sulfur recovery, pressure swing absorption, and CO_2 compression/liquefaction for coal-to-MTG. Significant gas cleanup beyond desulfurization and pressure swing absorption is not necessary in the gas-to-MTG flowsheets. Appendix B presents the detailed breakdown for the equipment item costs, including the original equipment cost bases. It is assumed that there is no impact on the capital cost of the MTG facility when sequestration is not assumed, as the Rectisol process is required for gas cleanup, and though the last stage of the CO_2 compressor would not be required, this cost is negligible when compared to the TCI required for the MTG 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:

$$C_2 = C_1\left(\frac{q_2}{q_1}\right)^n \qquad (9)$$

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). Costs for HTGRs, the associated power cycles, and HTSE were scaled directly based on capacity—the six-tenths factor rule was not used.

Table 3. CEPCI data.

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

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

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 (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:

Table 4. Capital cost adjustment factors.

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

Finally, an engineering fee of 10% and a project contingency of 18% were assumed to determine the TCI. The capital cost provided for the HTGR represents a complete and operable system; the total value represents all inside battery limits (ISBL) and outside battery limits (OSBL) 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 2 percent project definition, and based on preliminary design methodology (AACE 2005). Since the HTGR is a larger portion of the TCI, an overall Class 5 estimate was assumed.

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

Table 5 and Figure 6 presents the capital cost estimate breakdown for the conventional coal-to-MTG case, Table 6 and Figure 7 for the nuclear coal-to-MTG case, Table 7 and Figure 8 for the conventional gas-to-MTG case, and Table 8 and Figure 9 for the nuclear-integrated gas-to-MTG case. Varying only the cost of the nuclear facility was an adequate assumption, as the HTGR accounts for a large percentage of the overall cost for the nuclear-integrated cases. In addition, there is a greater level of uncertainty in the nuclear plant price given the nascency of HTGR development.

Table 5. Total capital investment, conventional coal-to-MTG case.

	Installed Cost	Engineering Fee	Contingency	Total Capital Cost
Coal Preparation	$267,870,314	$26,787,031	$53,038,322	$347,695,668
ASU	$374,500,115	$37,450,012	$74,151,023	$486,101,150
Gasification	$861,783,128	$86,178,313	$170,633,059	$1,118,594,500
Gas Cleaning	$885,934,670	$88,593,467	$175,415,065	$1,149,943,202
Methanol Synthesis	$410,224,373	$41,022,437	$81,224,426	$532,471,236
DME & MTG Synthesis	$519,834,625	$51,983,463	$102,927,256	$674,745,344
ST, HRSG & CT	$97,445,729	$9,744,573	$19,294,254	$126,484,557
Water Systems	$242,649,100	$24,264,910	$48,044,522	$314,958,532
Piping	$242,649,100	$24,264,910	$48,044,522	$314,958,532
I&C	$88,857,417	$8,885,742	$17,593,769	$115,336,927
Electrical Systems	$273,407,436	$27,340,744	$54,134,672	$354,882,852
Buildings and Structures	$314,418,552	$31,441,855	$62,254,873	$408,115,280
Total Capital Investment				**$5,944,287,779**

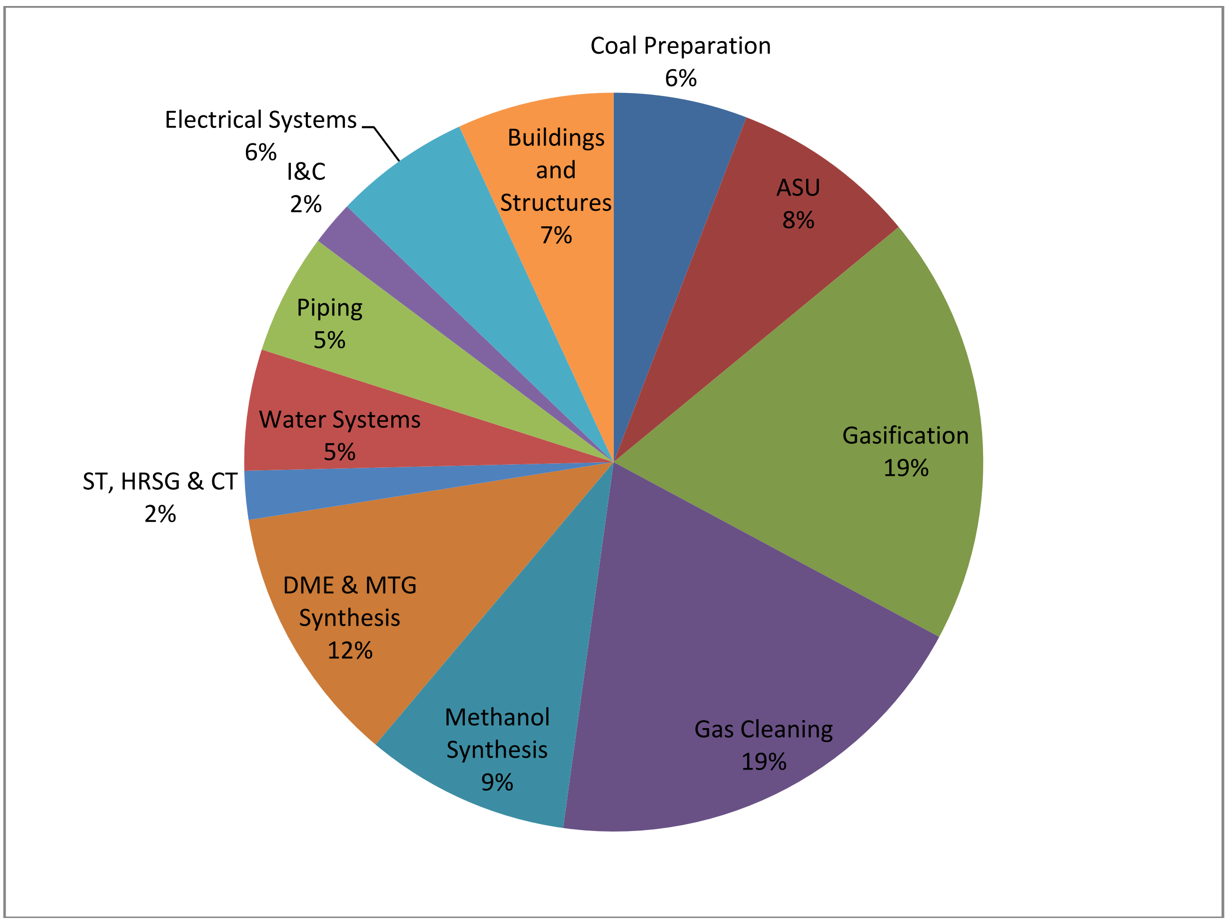

Figure 6. Total capital investment, conventional coal-to-MTG case.

Table 6. Total capital investment, HTGR-integrated coal-to-MTG case.

	Installed Cost	Engineering Fee	Contingency	Total Capital Cost
HTGRs	$11,732,236,071			$11,732,236,071
HTSE Electrolysis	$735,229,275	$73,522,928	$145,575,397	$954,327,599
Coal Preparation	$133,812,563	$13,381,256	$26,494,887	$173,688,707
Gasification	$430,326,800	$43,032,680	$85,204,706	$558,564,187
Gas Cleaning	$346,820,592	$34,682,059	$68,670,477	$450,173,128
Methanol Synthesis	$401,410,462	$40,141,046	$79,479,271	$521,030,780
DME & MTG Synthesis	$519,840,031	$51,984,003	$102,928,326	$674,752,360
ST, HRSG & CT	$54,266,651	$5,426,665	$10,744,797	$70,438,113
Nuclear Power Cycle	$1,680,769,139	$168,076,914	$332,792,289	$2,181,638,342
Water Systems	$186,141,153	$18,614,115	$36,855,948	$241,611,216
Piping	$186,141,153	$18,614,115	$36,855,948	$241,611,216
I&C	$68,164,366	$6,816,437	$13,496,544	$88,477,347
Electrical Systems	$209,736,510	$20,973,651	$41,527,829	$272,237,990
Buildings and Structures	$241,196,986	$24,119,699	$47,757,003	$313,073,688
Total Capital Investment				**$18,473,860,743**
Total Capital Investment (+50% HTGR)				**$24,339,978,779**
Total Capital Investment (-30% HTGR)				**$14,954,189,922**

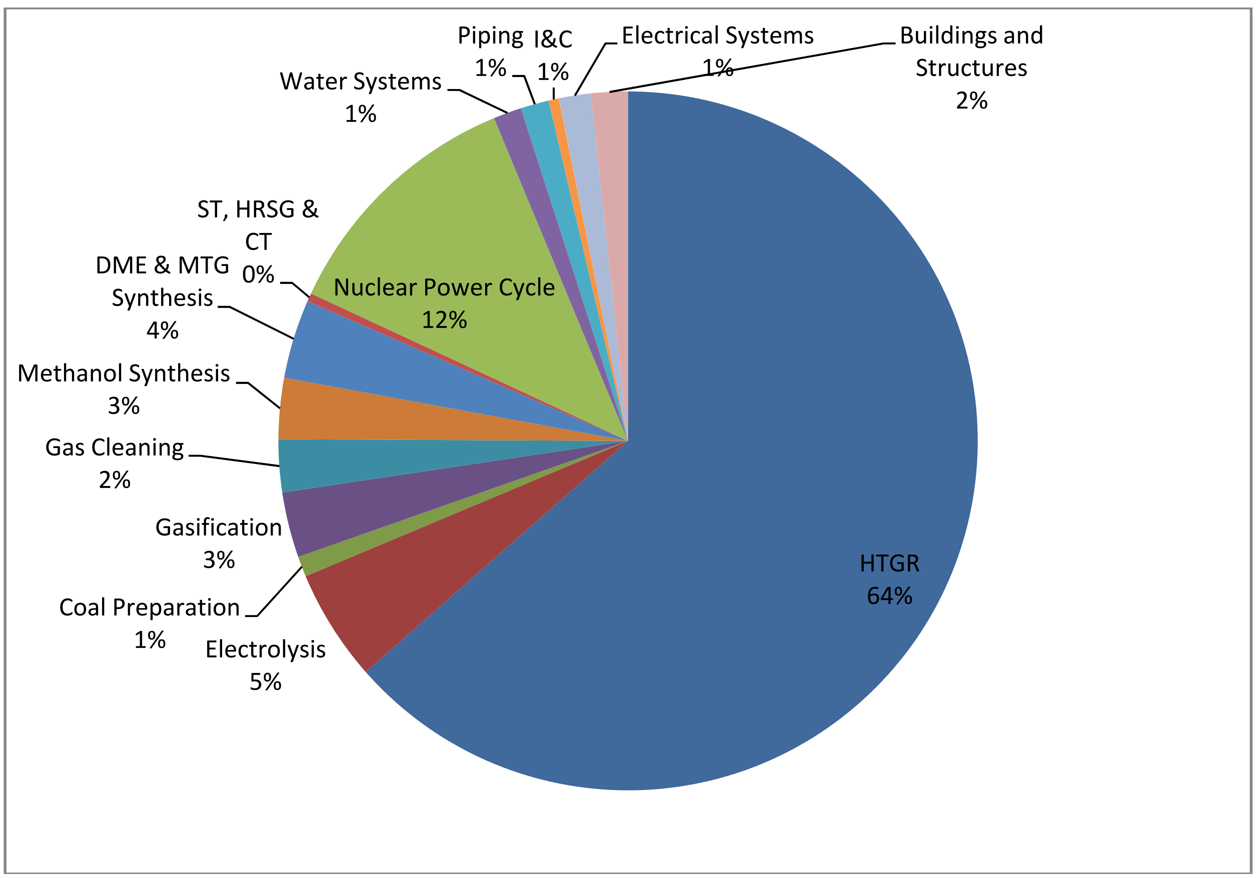

Figure 7. Total capital investment, HTGR-integrated coal-to-MTG case.

Table 7. Total capital investment, conventional gas-to-MTG case.

	Installed Cost	Engineering Fee	Contingency	Total Capital Cost
Natural Gas Reforming	$238,473,187	$23,847,319	$47,217,691	$309,538,197
ASU	$140,902,482	$14,090,248	$27,898,692	$182,891,422
PSA	$6,131,937	$613,194	$1,214,123	$7,959,254
Methanol Synthesis	$243,574,175	$24,357,418	$48,227,687	$316,159,280
DME & MTG Synthesis	$318,794,542	$31,879,454	$63,121,319	$413,795,315
ST, HRSG & CT	$26,202,116	$2,620,212	$5,188,019	$34,010,346
Water Systems	$69,159,569	$6,915,957	$13,693,595	$89,769,121
Piping	$69,159,569	$6,915,957	$13,693,595	$89,769,121
I&C	$25,326,039	$2,532,604	$5,014,556	$32,873,199
Electrical Systems	$77,926,275	$7,792,628	$15,429,402	$101,148,305
Buildings and Structures	$89,615,216	$8,961,522	$17,743,813	$116,320,551
Total Capital Investment				**$1,694,234,111**

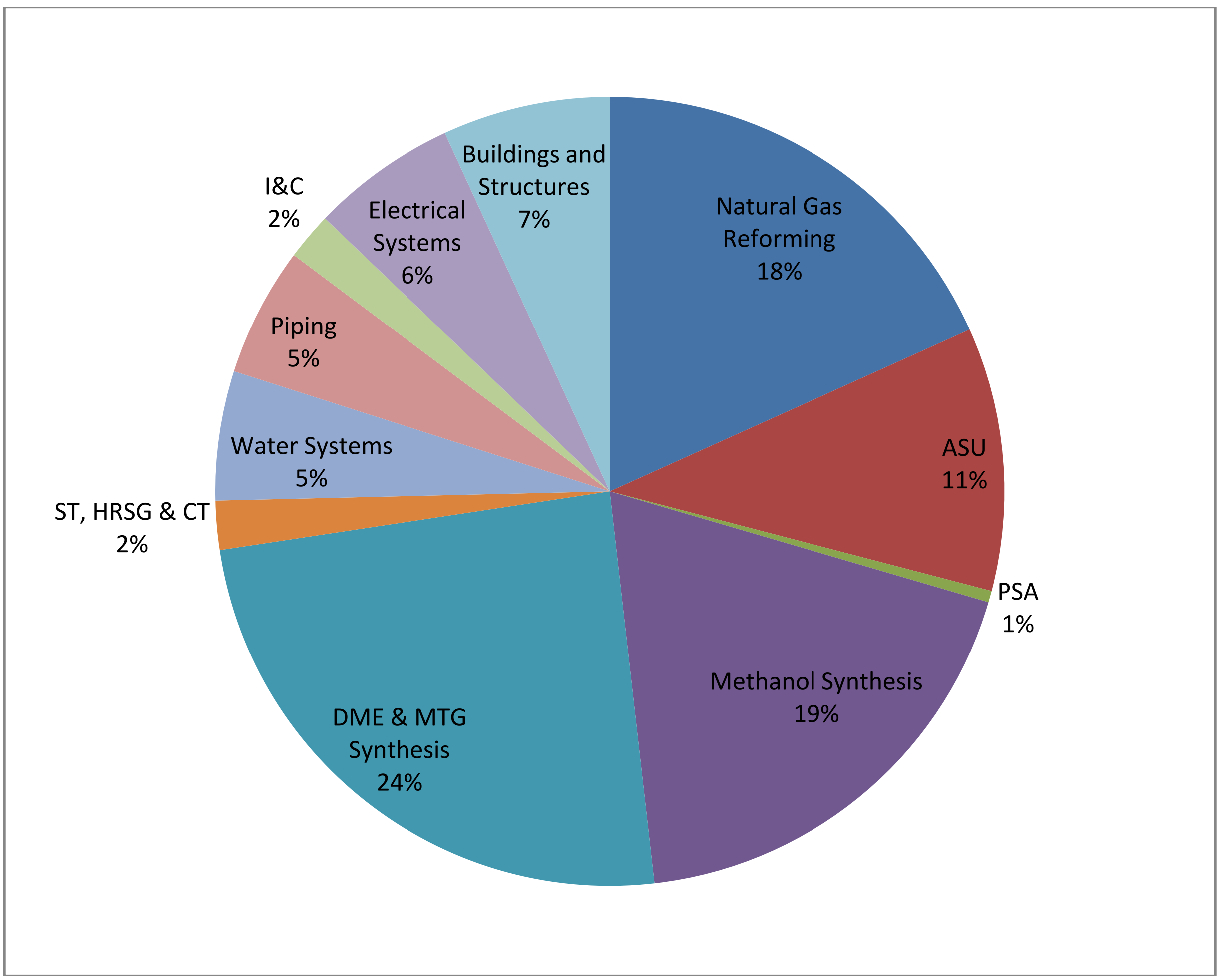

Figure 8. Total capital investment, conventional gas-to-MTG case.

Table 8. Total capital investment, nuclear-integrated gas-to-MTG case.

	Installed Cost	Engineering Fee	Contingency	Total Capital Cost
HTGR				$1,234,056,298
Natural Gas Reforming	$223,241,991	$22,324,199	$44,201,914	$289,768,104
ASU	$140,825,195	$14,082,520	$27,883,389	$182,791,103
PSA	$6,108,992	$610,899	$1,209,580	$7,929,471
Methanol Synthesis	$243,574,175	$24,357,418	$48,227,687	$316,159,280
DME & MTG Synthesis	$318,788,827	$31,878,883	$63,120,188	$413,787,898
ST and HRSG	$29,478,656	$2,947,866	$5,836,774	$38,263,295
Nuclear Power Cycle	$95,563,988	$9,556,399	$18,921,670	$124,042,056
Water Systems	$68,303,266	$6,830,327	$13,524,047	$88,657,640
Piping	$68,303,266	$6,830,327	$13,524,047	$88,657,640
I&C	$25,012,464	$2,501,246	$4,952,468	$32,466,178
Electrical Systems	$76,961,427	$7,696,143	$15,238,363	$99,895,932
Buildings and Structures	$88,505,641	$8,850,564	$17,524,117	$114,880,322
Total Capital Investment				**$3,031,355,217**
Total Capital Investment (+50% HTGR)				**$3,648,383,366**
Total Capital Investment (-30% HTGR)				**$2,661,138,327**

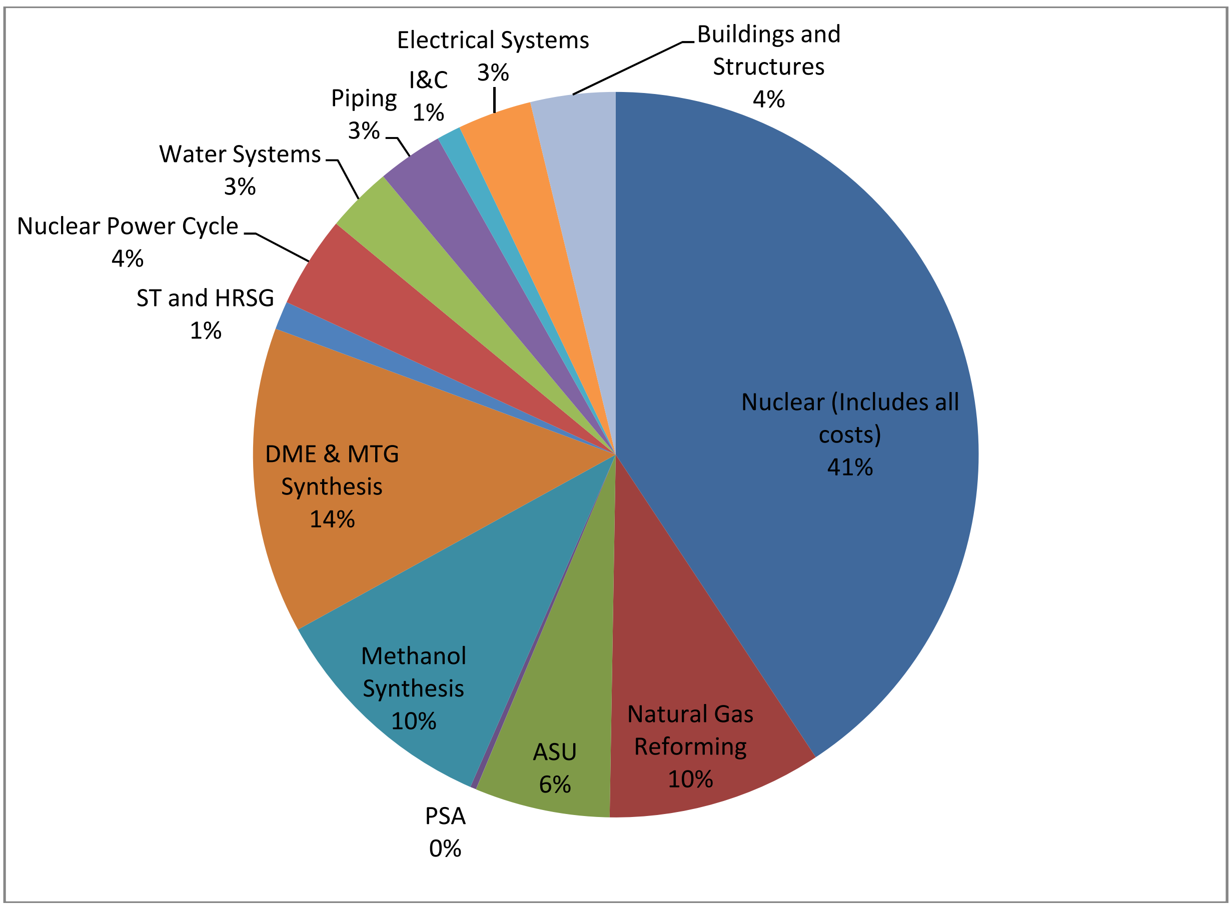

Figure 9. Total capital investment, nuclear-integrated gas-to-MTG case.

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 gasoline. High prices correspond to prices from June 2008, low prices are from December 2008, and average prices were the average of the high and low values. Gasoline prices were gathered from the Energy Information Administration (EIA); they represent wholesale prices and do not include taxes (EIA 2010a). Selling prices for LPG, electricity, oxygen, nitrogen, 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 liquid fuel products. A stream factor of 92% is assumed for both the fossil and nuclear plants.

In the calculation of revenue, credit was not taken for the sale of oxygen and nitrogen. This decision was made because the volume of these products exceeds 10% of the U. S. market for these gases; hence, it may not be realistic to assume that these products could be sold at market value without saturating the market.

Table 9 presents the revenues for the conventional coal-to-MTG case, Table 10 presents the revenues for the nuclear-integrated coal-to-MTG case, Table 11 presents the revenues for the conventional gas-to-MTG case, and Table 12 presents the revenues for the nuclear-integrated gas-to-MTG case.

Table 9. Annual revenues, conventional coal-to-MTG case.

	Price		Generated		Annual Revenue
LPG	2.36	$/gal	382,242	gal/day	$302,663,461
Slag	25.63	$/ton	1,852	ton/day	$15,937,949
Sulfur	38.13	$/ton	826	ton/day	$10,577,620
Gasoline - Low	1.22	$/gal	2,423,526	gal/day	$992,046,618
Gasoline – Avg.	2.40	$/gal	2,423,526	gal/day	$1,952,761,164
Gasoline - High	3.58	$/gal	2,423,526	gal/day	$2,913,475,710
Annual Revenue, low					**$1,321,225,648**
Annual Revenue, average					**$2,281,940,194**
Annual Revenue, high					**$3,242,654,741**

Table 10. Annual revenues, nuclear-integrated coal-to-MTG case.

	Price		Generated		Annual Revenue
LPG	2.36	$/gal	382,242	gal/day	$302,663,461
Slag	25.63	$/ton	846	ton/day	$7,279,208
Sulfur	38.13	$/ton	382	ton/day	$4,895,960
Gasoline - Low	1.22	$/gal	2,423,568	gal/day	$992,063,810
Gasoline – Avg.	2.40	$/gal	2,423,568	gal/day	$1,952,795,005
Gasoline - High	3.58	$/gal	2,423,568	gal/day	$2,913,526,201
Annual Revenue, low					**$1,306,902,438**
Annual Revenue, average					**$2,267,633,634**
Annual Revenue, high					**$3,228,364,829**

Table 11. Annual revenues, conventional gas-to-MTG case.

	Price		Generated		Annual Revenue
LPG	2.36	$/gal	221,676	gal/day	$175,525,519
Gasoline - Low	1.22	$/gal	1,405,782	gal/day	$575,443,085
Gasoline – Avg.	2.40	$/gal	1,405,782	gal/day	$1,132,711,799
Gasoline - High	3.58	$/gal	1,405,782	gal/day	$1,689,980,512
Annual Revenue, low					**$750,968,604**
Annual Revenue, average					**$1,308,237,317**
Annual Revenue, high					**$1,865,506,031**

Table 12. Annual revenues, nuclear-integrated gas-to-MTG case.

	Price		Generated		Annual Revenue
LPG	2.36	$/gal	221,676	gal/day	$175,525,519
Electricity	1.67	$/kW-day	39	MW_e	$21,651,524
Gasoline - Low	1.22	$/gal	1,405,740	gal/day	$575,425,893
Gasoline – Avg.	2.40	$/gal	1,405,740	gal/day	$1,132,677,957
Gasoline - High	3.58	$/gal	1,405,740	gal/day	$1,689,930,021
Annual Revenue, low					**$772,602,936**
Annual Revenue, average					**$1,329,855,000**
Annual Revenue, high					**$1,887,107,064**

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 the fossil portion of each case. This percentage is based on staffing requirements for a conventional 50,000 barrel per day coal-to-liquids (CTL) plant (see TEV-672); that percentage is assumed to adequately represent the labor for the fossil portion of the nuclear and non-nuclear coal-to-MTG and the gas-to-MTG plants. Maintenance costs were assumed to be 3% of the total capital investment 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 total capital investment, 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 or natural gas cost based on information presented in the *Handbook of Petroleum Processing* (Jones 2006). Table 13 and Table 14 provide the manufacturing costs for the conventional coal-to-MTG case and the nuclear-integrated coal-to-MTG case, respectively. Again, availability of both the fossil and nuclear plants was assumed to be 92%. Note that the conventional coal-to-MTG case annual manufacturing costs include costs for sequestration; in the model an analysis was performed for the conventional case to assess the impact on the economics of sequestering or not sequestering.

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

Operating and maintenance costs for the nuclear plant were based on data from General Atomics for the gas turbine-modular helium reactor (GT-MHR) HTGR published in 2002; these costs were inflated to 2009 dollars (GA 2002). 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 replacements costs (McKellar 2010).

Table 13. Annual manufacturing costs, conventional coal-to-MTG case.

	Price		Consumed		Annual Cost
Direct Costs					
Materials					
Coal	36.16	\$/ton	25,934	ton/day	\$314,929,845
Fly Ash Disposal	33.20	\$/ton	777	ton/day	\$8,663,234
Rectisol Solvent	1.10	\$/gal	4,431	gal/day	\$1,636,788
Makeup H_2O Treatment	0.02	\$/k-gal	24,203	k-gal/day	\$198,788
Wastewater Treatment	1.32	\$/k-gal	9,128	k-gal/day	\$4,030,488
Claus Catalyst	21.00	\$/ft^3	5.481	ton S/day	\$38,649
SCOT Catalyst	275.00	\$/ft^3	0.799	ton S/day	\$73,773
Carbon, Hg Guard Bed	5.56	\$/lb	33.715	lb/day	\$62,896
Zinc Oxide	300.00	\$/ft^3	1.042	ft^3/day	\$104,960
WGS Catalyst	825.00	\$/ft^3	2.139	lb/day	\$592,523
Iron Sorbent (Zeolite)	10.08	\$/lb	40	lb/day	\$136,854
Methanol Catalyst	750.00	\$/ft^3	0.397	ft^3/day	\$100,086
DME Catalyst	840.00	\$/ft^3	0.264	ft^3/day	\$74,417
MTG Catalyst	50.39	\$/lb	2,243	lb/day	\$37,949,927
HGT Catalyst	2,500	\$/ft^3	1.304	ft^3/day	\$1,094,605
CO_2 Sequestration	14.54	\$/ton	30,856	ton/day	\$150,634,927
Utilities					
Electricity	1.67	\$/kW-d	413,400	kW	\$231,884,460
Water	0.05	\$/k-gal	24,203	k-gal/day	\$373,862
Royalties					\$3,149,298
Labor and Maintenance					\$246,6876943
Indirect Costs					
Overhead					\$160,347,163
Insurance and Taxes					\$89,164,317
Manufacturing Costs					**\$1,251,929,806**

Table 14. Annual manufacturing costs, nuclear-integrated coal-to-MTG case.

	Price		Consumed		Annual Cost
Direct Costs					
Materials					
Coal	36.16	\$/ton	11,845	ton/day	\$143,833,380
Fly Ash Disposal	33.20	\$/ton	355	ton/day	\$3,956,624
Rectisol Solvent	1.10	\$/gal	1,624	gal/day	\$599,924
Makeup H_2O Treatment	0.02	\$/k-gal	18,312	k-gal/day	\$150,398
Wastewater Treatment	1.32	\$/k-gal	7,076	k-gal/day	\$3,124,566
Claus Catalyst	21.00	\$/ft^3	2.574	ton S/day	\$18,152
SCOT Catalyst	275.00	\$/ft^3	0.367	ton S/day	\$33,856
Carbon, Hg Guard Bed	5.56	\$/lb	15.398	lb/day	\$28,726
Zinc Oxide	300.00	\$/ft^3	1.007	ft^3/day	\$101,430
Iron Sorbent (Zeolite)	10.08	\$/lb	37	lb/day	\$123,992
Methanol Catalyst	750.00	\$/ft^3	0.390	ft^3/day	\$98,131
DME Catalyst	840.00	\$/ft^3	0.248	ft^3/day	\$69,896
MTG Catalyst	50.39	\$/lb	2,209	lb/day	\$37,380,905
HGT Catalyst	2,500	\$/ft^3	1.304	ft^3/day	\$1,094,613
HTSE Cell Replacement	0.02	\$/lb H_2	3,877,224	lb H_2/hr	\$31,572,008
Nuclear Fuel	8.80	\$/MW-h	2,747	MW$_e$	\$194,741,666
Utilities					
Electricity	1.67	\$/kW-d	0	kW	\$0
Water	0.05	\$/k-gal	18,312	k-gal/day	\$282,856
Royalties					\$1,438,334
O&M, Nuclear	3.57	\$/MW-h	2,747	MW$_e$	\$78,949,324
Labor and Maintenance, Fossil					\$172,347,834
Indirect Costs					
Overhead					\$112,026,092
Insurance and Taxes					\$101,124,370
Manufacturing Costs					**\$883,097,079**

Table 15. Annual manufacturing costs, conventional gas-to-MTG case.

	Price		Consumed		Annual Cost
Direct Costs					
Materials					
Average Natural Gas	6.50	$/MSCF	288	MSCFD	$628,617,600
Makeup H_2O Treatment	0.02	$/k-gal	8,900	k-gal/day	$73,102
Wastewater Treatment	1.32	$/k-gal	6,151	k-gal/day	$2,715,858
HDS Catalyst	700.00	$/ft^3	0.139	ft^3/day	$32,786
Zinc Oxide	300.00	$/ft^3	1.310	ft^3/day	$132,006
Preforming Catalyst	2,350	$/ft^3	0.000	ft^3/day	$0
Primary SMR Catalyst	750.00	$/ft^3	0.393	ft^3/day	$98,979
Secondary SMR Catalyst	650.00	$/ft^3	0.089	ft^3/day	$19,343
Methanol Catalyst	750.00	$/ft^3	0.244	ft^3/day	$61,538
DME Catalyst	840.00	$/ft^3	0.139	ft^3/day	$39,305
MTG Catalyst	50.39	$/lb	1,270	lb/day	$21,489,240
HGT Catalyst	2,500	$/ft^3	0.757	ft^3/day	$635,163
Utilities					
Electricity	1.67	$/kW-day	97,500	kW	$54,689,731
Water	0.05	$/k-gal	8,900	k-gal/day	$137,484
Royalties					$6,286,176
Labor and Maintenance					$70,310,716
Indirect Costs					
Overhead					$45,701,965
Insurance and Taxes					$25,413,512
Manufacturing Costs, Average Natural Gas					**$856,454,505**

Table 16. Annual manufacturing costs, nuclear-integrated gas-to-MTG case.

	Price		Consumed		Annual Cost
Direct Costs					
Materials					
Average Natural Gas	6.50	$/MSCF	258	MSCFD	$563,136,600
Makeup H_2O Treatment	0.02	$/k-gal	9,173	k-gal/day	$75,341
Wastewater Treatment	1.32	$/k-gal	6,213	k-gal/day	$2,743,199
HDS Catalyst	700.00	$/ft^3	0.139	ft^3/day	$32,771
Zinc Oxide	300.00	$/ft^3	1.310	ft^3/day	$131,946
Preforming Catalyst	2,350	$/ft^3	0.000	ft^3/day	$0
Primary SMR Catalyst	750.00	$/ft^3	0.921	ft^3/day	$232,056
Secondary SMR Catalyst	650.00	$/ft^3	0.089	ft^3/day	$19,471
Methanol Catalyst	750.00	$/ft^3	0.244	ft^3/day	$61,531
DME Catalyst	840.00	$/ft^3	0.139	ft^3/day	$39,304
MTG Catalyst	50.39	$/lb	1,270	lb/day	$21,488,286
HGT Catalyst	2,500	$/ft^3	0.757	ft^3/day	$635,133
Nuclear Fuel	8.80	$/MW-h	289	MW_e	$20,483,919
Utilities					
Electricity	1.67	$/kW-day	0	kW	$0
Water	0.05	$/k-gal	9,174	k-gal/day	$141,695
Royalties					$5,631,366
O&M, Nuclear	3.57	$/MW-h	289	MW_e	$8,304,292
Labor and Maintenance, Fossil					$69,440,160
Indirect Costs					
Overhead					$45,136,104
Insurance and Taxes					$26,959,484
Manufacturing Costs, Average Natural Gas					**$764,692,657**

4.4 Economic Comparison

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

- The plant startup year is 2014.
- We anticipate a construction period of three years for the fossil plant and five years for the nuclear plant. In order to easily perform the analysis in 2009 dollars, the following simplifying assumptions were made:
  - Fossil plant construction begins in 2011

- Nuclear plant construction begins in 2009

- It is assumed that all reactors come online at the same time. A study was conducted for CTL to determine the impact of six-month and three-month reactor staging versus all reactors coming online at one time. 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. These results were assumed to be equally valid for all nuclear MTG cases.
  - Percent capital invested for the fossil plant is 33% per year
  - Percent capital invested for the HTGR is 20% per year
- Plant startup time is one year.
  - Operating costs are 85% of the total value during startup
  - Revenues are 60% of the total value during startup
- The analysis period for the economic evaluation assumes an economic life of 30 years, excluding construction time (the model is built to accommodate up to 40 years).
- An availability of 92% was assumed for both the fossil and nuclear plants, the plants are assumed to operate 365 days a year, 24 hours per day.
- An inflation rate of 2.5% is assumed.
- Debt to equity ratios of 80%/20% and 55%/45% are calculated; however, results are only presented for 80%/20% as this would be most consistent for an n^{th}-of-a-kind plant.
  - The interest rate on debt is assumed to be 8%
  - The repayment term on the loan is assumed to be 15 years
- The effective income tax rate is 38.9%.
  - State tax is 6%
  - Federal tax is 35%
- Modified accelerated cost recovery system (MACRS) depreciation is assumed.
- A CO_2 tax of $0/ton to $200/ton is investigated for coal-to-MTG cases and a tax of $0/ton to $100/ton for gas-to-MTG 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):

$$T_k = t\left(R_k - E_k - d_k\right) \tag{10}$$

Depreciation for the economic calculations was calculated using a standard MACRS depreciation method with a property class of 15 years. Depreciation was assumed for the TCI over the 5-year construction schedule, including inflation. Table 17 presents the recovery rates for a 15-year property class (Perry 2008):

Table 17. MACRS depreciation.

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

The ATCF is then the sum of the before-tax cash flow (BTCF) minus the income taxes owed. Note that the expenditures for capital are not taxed but are included in the BTCF each year there is a capital expenditure (Ck)—this includes the equity capital and the debt principle. The BTCF is defined as follows (Sullivan 2003):

$$BTCF_k = R_k - E_k - C_k \tag{11}$$

The ATCF can then be defined as:

$$ATCF_k = BTCF_k - T_k \tag{12}$$

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

4.4.2 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).

$$PW(i'\%) = \sum_{k=0}^{N} ATCF_k (1+i')^{-k} = 0 \tag{13}$$

IRR calculations were performed for an 80%/20% debt to equity ratio for the calculated fossil TCI and at +50% TCI and -30% TCI for the HTGR for all cases at low, average, and high fuel prices for coal-to-MTG and gas-to-MTG as well as low, average, and high natural gas purchase prices for gas-to-MTG (only the average natural gas price data is presented). In addition, the price of gasoline 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 gasoline price required (for an IRR of 12%) was solved for using the Goal Seek function in Excel (Excel 2007).

Finally, a CO_2 tax was included into the calculations to determine the price of gasoline necessary in all cases for a 12% IRR and a CO_2 tax of \$0/ton to \$200/ton for coal-to-MTG and \$0/ton to \$100/ton for gas-to-MTG. These cases were calculated for 80%/20% and 55%/45% debt to equity ratios for the TCI and +50% TCI and -30% TCI of the HTGR. Additionally, the coal-to-MTG case was calculated for either sequestering or not sequestering the CO_2. The tax calculated was added to the existing tax liability for each year.

5. ECONOMIC MODELING RESULTS

5.1 Coal-to-MTG Economic Results

Table 18 presents the results for an 80%/20% debt to equity ratio for the conventional coal-to-MTG and nuclear-integrated coal-to-MTG case, listing the IRR for low, average, and high gasoline selling prices, and the gasoline selling price required for a 12% IRR. Figure 10 depicts the associated IRR results for the coal-to-MTG cases. From these results, it can be concluded that the significant capital investment increase for the nuclear-integrated case weighs heavily on the economic viability of this option. The conventional cases, both with and without sequestration, provide a significantly higher return than the nuclear-integrated case even when the cost for the HTGRs is decreased by 30%.

Table 18. Conventional and nuclear coal-to-MTG IRR results.

	TCI -30% HTGR		**TCI**		**TCI +50% HTGR**	
	IRR	$/gal	IRR	$/gal	IRR	$/gal
Conventional Coal-to-MTG			*$5,944,287,779*			
			0.18	$1.22		
			21.32	$2.40		
			37.18	$3.58		
			12.00	$1.81		
Conventional Coal-to-MTG with CO_2 sequestration			*$5,944,287,779*			
			-7.30	$1.22		
			18.42	$2.40		
			34.75	$3.58		
			12.00	$2.00		
HTGR-Integrated Coal-to-MTG	*$14,954,189,922*		*$18,473,860,743*		*$24,339,978,779*	
	-1.45	$1.22	-2.79	$1.22	-$4.42	$1.22
	8.60	$2.40	6.36	$2.40	3.83	$2.40
	15.52	$3.58	12.36	$3.58	8.93	$3.58
	12.00	$2.95	12.00	$3.50	12.00	$4.42

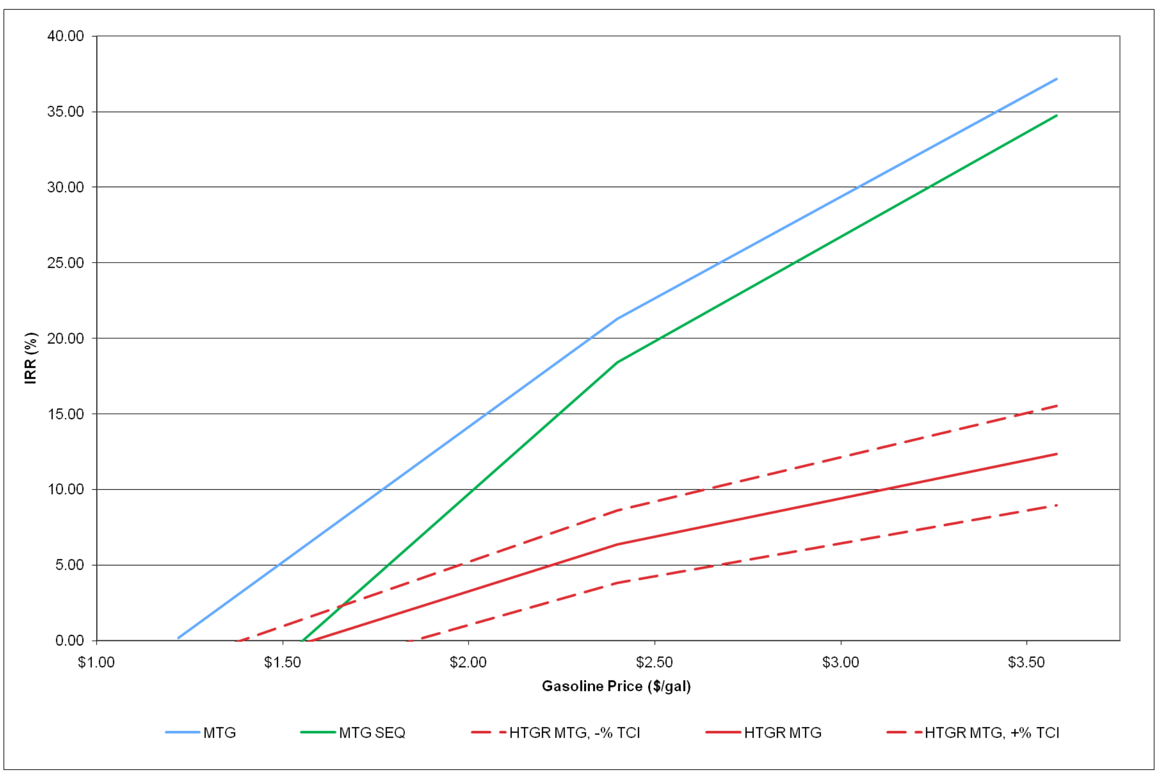

Figure 10. Conventional and nuclear coal-to-MTG IRR economic results.

The conclusions are somewhat different if a carbon tax is considered. Table 19 and Figure 11 present the economic implications of an imposed carbon tax on the conventional and nuclear-integrated coal-to-MTG cases. These results show the conventional coal-to-MTG flowsheet to have the most favorable economics for a CO_2 tax less than \$15/ton. For a CO_2 tax in excess of \$15/ton, the conventional coal-to-MTG with CO_2 sequestration case is the most economically favorable. However, if sequestration is not a viable option due to plant siting or other technical limitations, the nuclear-integrated coal-to-MTG process becomes more favorable than the conventional coal-to-MTG case at around \$110/ton CO_2 tax. Furthermore, if the cost of the HTGRs can be reduced by 30%, the tipping point favoring nuclear-integrated over conventional coal-to-MTG is reduced to around \$70/ton CO_2 tax.

Table 19. Conventional and nuclear coal-to-MTG carbon tax results (12% IRR).

Carbon Tax $/ton		TCI -30% HTGR	TCI	TCI +50% HTGR
		Gasoline Price ($/gal)		
Conventional Coal-to-MTG	0		1.81	
	50		2.59	
	100		3.38	
	150		4.17	
	200		4.96	
Conventional Coal-to-MTG with CO_2 sequestration	0		2.00	
	50		2.01	
	100		2.02	
	150		2.04	
	200		2.05	
HTGR-Integrated Coal-to-MTG	0	2.95	3.50	4.42
	50	2.96	3.51	4.44
	100	2.97	3.53	4.45
	150	2.99	3.54	4.46
	200	3.00	3.55	4.47

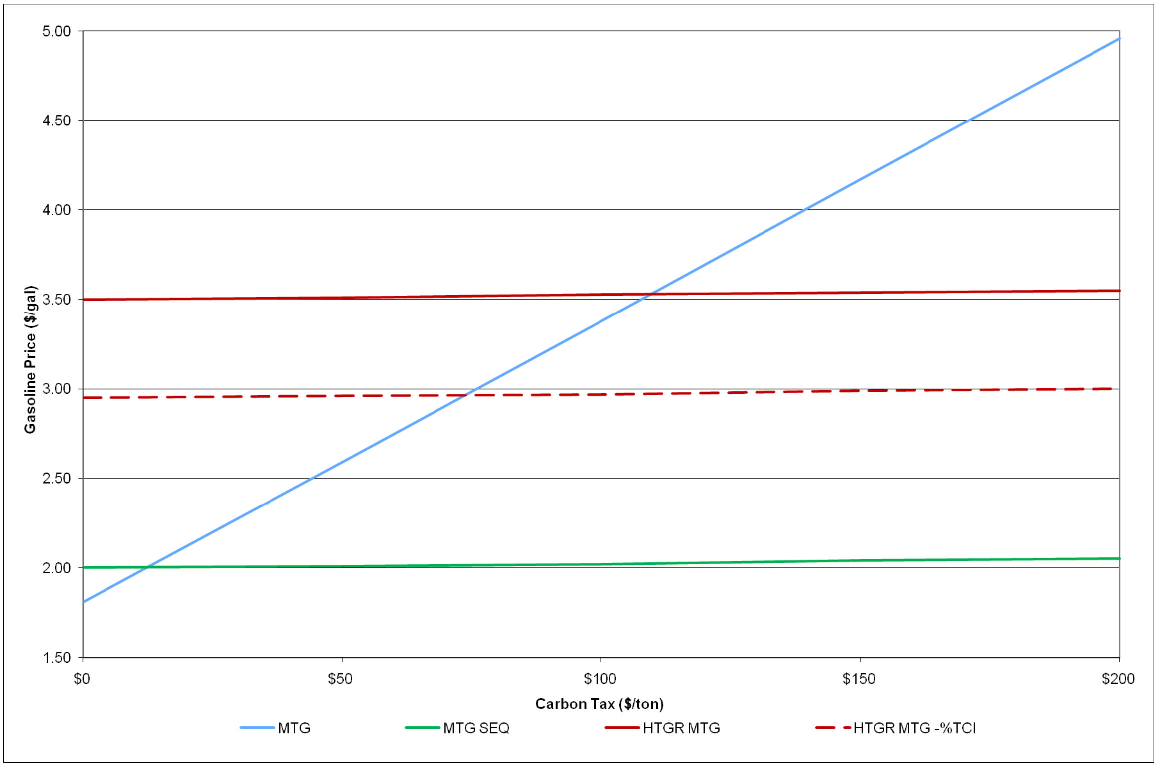

Figure 11. Conventional and nuclear coal-to-MTG carbon tax results (12% IRR).

5.2 Gas-to-MTG Economic Results

Table 20 presents the results for an 80%/20% debt to equity ratio for the conventional gas-to-MTG and nuclear-integrated gas-to-MTG cases, listing the IRR for low, average, and high gasoline selling prices, and the gasoline selling price required for a 12% IRR. Figure 12 depicts the associated IRR results for the gas-to-MTG cases at the average natural gas price of $6.50/MSCF. These results indicate that a favorable 12% IRR is achievable for the HTGR-integrated cases when gasoline prices rise above $2.00/gal; hence, such an option appears to be economically viable given current gasoline prices. Also from these results, it can be concluded that for gasoline prices above $2.00/gal, economics favor the conventional case over the nuclear-integrated cases. If the price for the HTGR can be reduced by 30%, the rate of return for the conventional case intersects that of the nuclear-integrated cases at around $1.90/gal. Above this price, economics again favor the conventional case over the nuclear-integrated case. In addition, the gap in IRR widens between the conventional and nuclear-integrated cases as gasoline price increases.

Table 20. Conventional and nuclear gas-to-MTG IRR results.

	TCI -30% HTGR		TCI		TCI +50% HTGR	
	IRR	$/gal	IRR	$/gal	IRR	$/gal
Conventional Gas-to-MTG Low NG: $4.50/MSCF			*$1,694,234,111*			
			2.82	$1.22		
			37.80	$2.40		
			61.62	$3.58		
			12.00	$1.47		
HTGR-Integrated Gas-to-MTG Low NG: $4.50/MSCF	*$2,661,138,327*		*$3,031,355,217*		*$3,648,383,366*	
	5.36	$1.22	4.17	$1.22	2.63	$1.22
	26.80	$2.40	23.56	$2.40	19.64	$2.40
	41.84	$3.58	37.22	$3.58	31.63	$3.58
	12.00	$1.53	12.00	$1.63	12.00	$1.79
Conventional Gas-to-MTG Average NG: $6.50/MSCF			*$1,694,234,111*			
			N/A	$1.22		
			26.73	$2.40		
			53.32	$3.58		
			12.00	$1.89		
HTGR-Integrated Gas-to-MTG Average NG: $6.50/MSCF	*$2,661,138,327*		*$3,031,355,217*		*$3,648,383,366*	
	-14.01	$1.22	-14.50	$1.22	-15.20	$1.22
	20.76	$2.40	18.16	$2.40	14.99	$2.40
	37.27	$3.58	33.08	$3.58	27.99	$3.58
	12.00	$1.90	12.00	$2.00	12.00	$2.17
Conventional Gas-to-MTG High NG: $12.00/MSCF			*$1,694,234,111*			
			N/A	$1.22		
			N/A	$2.40		
			26.31	$3.58		
			12.00	$3.06		
HTGR-Integrated Gas-to-MTG High NG: $12.00/MSCF	*$2,661,138,327*		*$3,031,355,217*		*$3,648,383,366*	
	N/A	$1.22	N/A	$1.22	N/A	$1.22
	-1.22	$2.40	-2.01	$2.40	-3.10	$2.40
	22.63	$3.58	19.91	$3.58	16.59	$3.58
	12.00	$2.95	12.00	$3.05	12.00	$3.22

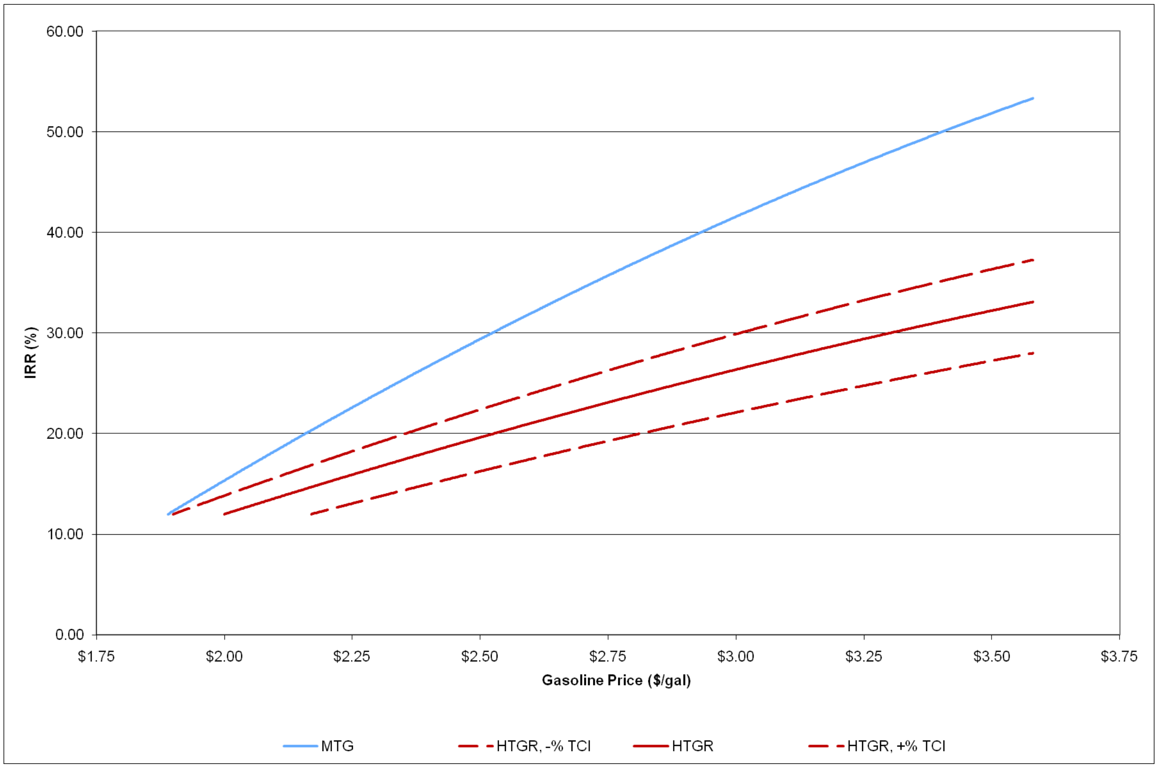

Figure 12. Conventional and nuclear gas-to-MTG IRR economic results (average natural gas price).

Figure 13 presents results from the sensitivity analysis which varies the natural gas price. For this analysis, the IRR is fixed at 12% by varying the selling price of gasoline. As the cost of natural gas increases, the HTGR-integrated case compares more favorably with the conventional gas-to MTG case. This is due to a sharper increase in manufacturing costs for the conventional case, which are due to higher natural gas usage than for the HTGR-integrated case. Above a natural gas price of $11.50/MSCF, economics for the HTGR-integrated case outperform the conventional case. If the cost of implementing HTGR technology can be reduced by 30%, the HTGR-integrated case outperforms the conventional gas-to-MTG when the price of natural gas rises above $7.00/MSCF.

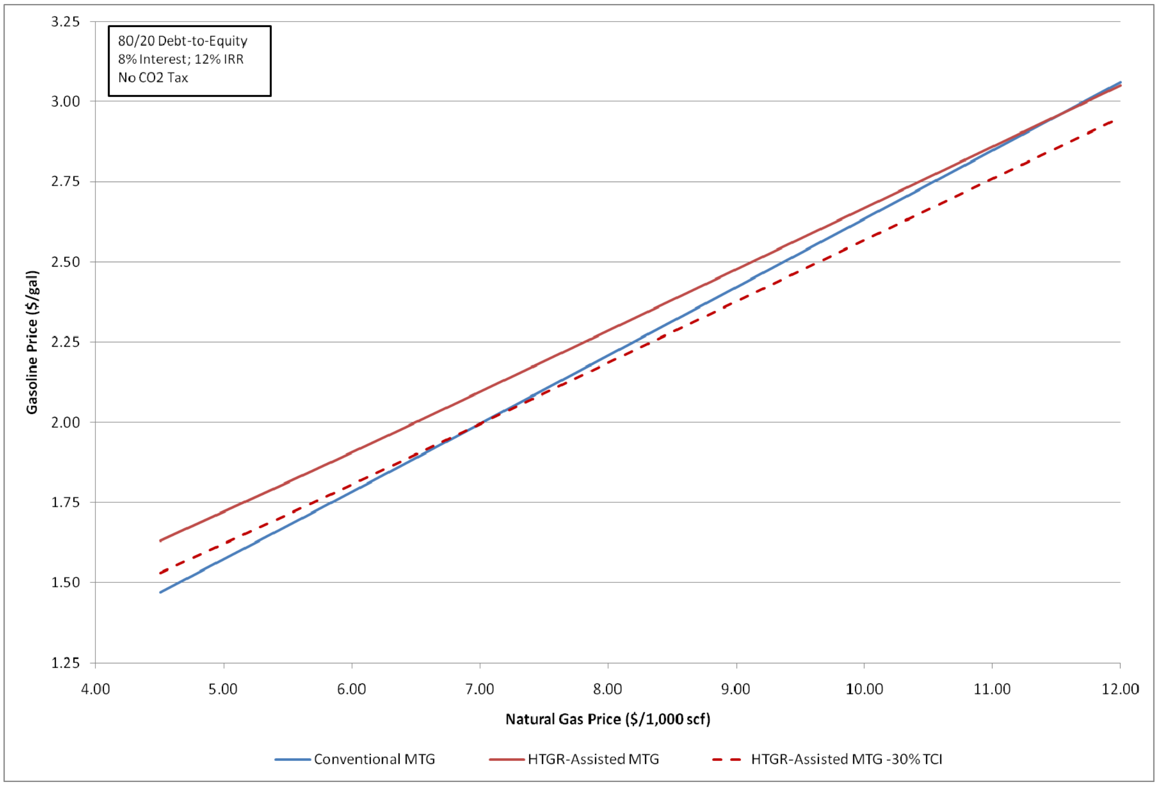

Figure 13. Conventional and nuclear gas-to-MTG, gasoline price as a function of natural gas price.

Table 21 presents the carbon tax results for the conventional and nuclear-integrated gas-to-MTG cases, and Figure 14 depicts the carbon tax results for the conventional and nuclear-integrated gas-to-MTG cases for an average natural gas price. Based on these results, a relatively high carbon tax of $70/ton CO_2 is required before the HTGR-integrated case outperforms the conventional case. As further shown in Figure 15, if a carbon tax of $75/ton CO_2 is imposed, the HTGR-integrated case will outperform the conventional case when natural gas prices rise above $6.00/MSCF. Hence, it is clear that the economic performance of the HTGR-integrated case can compete with the conventional gas-to-MTG case in a number of scenarios including: (1) natural gas prices rise above $11.50/MSCF, (2) a carbon tax in excess of $70/ton CO_2 is imposed, or (3) further development and commercialization of HTGR technology are able to reduce the price of implementation by 30%.

Table 21. Conventional and nuclear gas-to-MTG carbon tax results (average natural gas price).

Carbon Tax $/ton		TCI -30% HTGR	TCI	TCI +50% HTGR
			Gasoline Price ($/gal)	
Conventional Gas-to-MTG	0		1.89	
	25		1.95	
	50		2.01	
	75		2.07	
	100		2.13	
HTGR-Integrated Gas-to-MTG	0	1.90	2.00	2.17
	25	1.92	2.02	2.19
	50	1.94	2.04	2.21
	75	1.96	2.06	2.23
	100	1.98	2.08	2.25

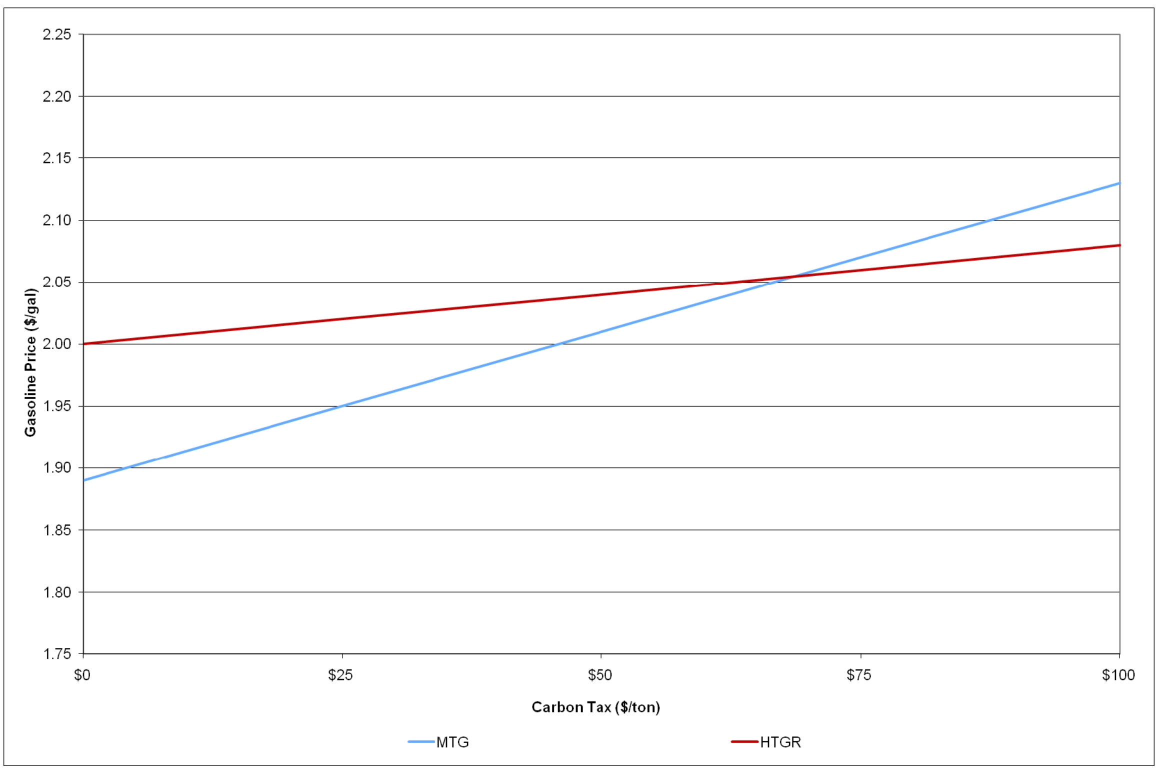

Figure 14. Conventional and nuclear gas-to-MTG carbon tax results (average natural gas price).

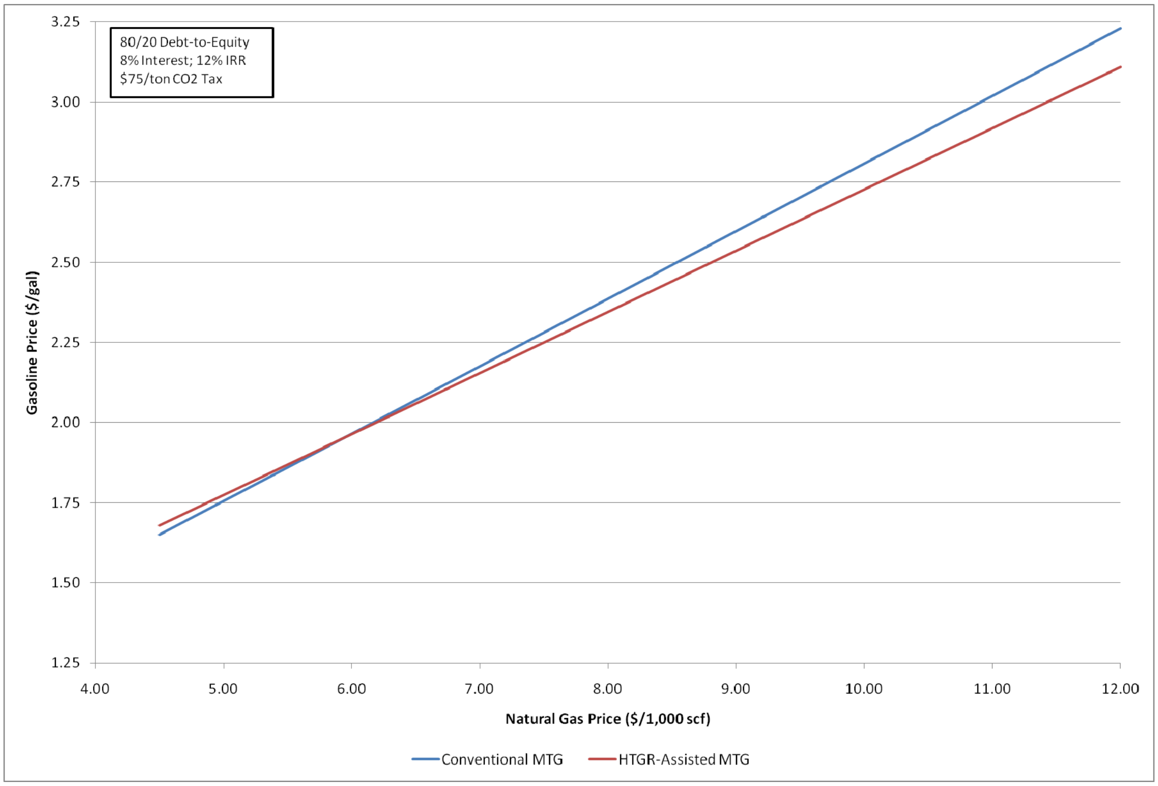

Figure 15. Conventional and nuclear gas-to-MTG, gasoline price as a function of natural gas price with $75/ton CO_2 tax.

6. GREENHOUSE GAS MODELING OVERVIEW

This section presents a full life-cycle inventory or well-to-wheel (WTW) analysis of GHG emissions for the production of synthetic gasoline using the conventional and HTGR-integrated coal-to-MTG and natural gas-to-MTG processes described in the preceding sections. The WTW analysis conducted for this study was based upon the formal methodology presented by NETL and categorizes GHG emissions according to the following sources (NETL 2001):

1. Resource extraction
2. Transportation of the resources to the plant
3. Conversion and refining of the product
4. Transportation and distribution of the product
5. End use combustion of the product.

Results from the WTW analysis for MTG gasoline were compared to WTW emissions for the U.S. baseline and average imported WTW emissions for conventional gasoline to determine the environmental impact of the synthetic fuels in comparison to standard petroleum fuels. The U.S. baseline and average imported WTW emissions for gasoline were derived from a 2009 NETL refinery report (NETL 2009).

6.1 GHG Methodology

The following sections outline the methodology used for calculating GHG emissions for the conventional and nuclear MTG cases analyzed. For this study, all results are scaled for the gasoline, liquefied petroleum gas (LPG), and/or electricity products. This is accomplished by ratioing the lower heating values of the products along with the electricity, if produced in the plant, to determine the emissions assignment, or the percentage of the total energy content for the gasoline, LPG, and/or electricity product. Note that gasoline and LPG have similar heating values on a mass basis; thus, including the LPG with the gasoline product has no appreciable impact on overall WTW emissions. The emissions for the gasoline product are converted to a gram-per-mile basis using a vehicle fuel economy of 21.3 miles per gallon. Note that the fuel economy was adjusted to account for the heating value of the synthetic fuel versus traditional petroleum-derived products (SAE 1999). The vehicle fuel economy represents the average mileage of a gasoline-powered SUV.

The GHG emissions considered in this report include carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). Emissions for CH_4 and N_2O are converted into CO_2 equivalents using their global warming potentials (GWP). CO_2 equivalents are the amount of carbon dioxide by weight emitted into the atmosphere that would produce the same radiative force as a given weight of another radiatively active gas. The GWPs used in this report are referenced from the Intergovernmental Panel on Climate Change's (IPCC) most recent climate study in 2006. The 100-year GWP for CH_4 and N_2O are 23 and 296, respectively (IPCC 2006).

6.2 Resource Extraction and Production

GHG emissions for resource extraction are calculated for the two feeds considered in this study: coal and natural gas. Coal extraction emissions include emissions from fuel usage associated with coal mining and coal-bed methane. Natural gas production emissions include emissions associated with natural gas extraction, natural gas processing, and natural gas transport from the wellhead to the processing facility. Natural gas production emissions include all vents and leaks from the wellhead through the processing phase.

6.2.1 Coal Extraction

The MTG plant is intended to operate using Illinois #6 bituminous coal. The majority of this coal will be mined in the state of Illinois. According to the Energy Information Administration, in 2007 approximately 82% of the coal mined in Illinois was mined using underground mining methods; the remainder was surface mined (EIA 2009). Fuel usage per ton of coal mined for both surface and underground mining were calculated based on the most recent U.S. Census data available— either 2002 or 1997, depending upon data released to the public. Based on this census data, power, coal, diesel, residual fuel oil, natural gas, and gasoline usage for mining activities were calculated. The associated CO_2 emissions were calculated based on the lower heating values (LHV) and carbon contents of the various fuel types; for power, the emissions for the average U.S. energy mixed were assumed. Emissions for CH_4 and N_2O were calculated assuming either mobile or stationary combustion emission factors from the 2006 IPCC report (IPCC 2006). Emissions for mining support activities were calculated in a similar fashion. Finally, coal-bed methane emissions are calculated for the methane released during Illinois mining operations based on the 2009 EPA report *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (U.S. EPA 2009).

6.2.2 Natural Gas Production

Methane and non-combustion CO_2 emissions from natural gas systems are generally process related, with normal operations, routine maintenance, and system upsets being the primary contributors. Emissions from normal operations include: natural gas engines and turbine uncombusted exhaust, bleed and discharge emissions from pneumatic devices, and fugitive emissions from system components. Routine maintenance emissions originate from pipelines, equipment, and wells during repair and maintenance activities. Pressure surge relief systems and accidents can lead to system upset emissions. The total CO_2 equivalent emissions were calculated for 2007 in the 2009 EPA report *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (U.S. EPA 2009). To determine the CO_2 equivalent emissions per MMSCF of natural gas utilized, the equivalent emissions were divided by the amount of natural gas processed in 2007, which is available from the EIA website (EIA 2010c).

6.3 Transportation and Distribution

All scenarios considered in this study include transportation of resources and products over long distances. The mode of transportation depends upon the location and destination of the products as well as the type of product being transported. For instance, dry materials being transported short distances would utilize trucks as the main mode of transportation, while dry materials being transported long distances near major rivers would take advantage of barge transportation. Table 22 lists the distances and modes of transportation assumed for the various resources and products. It was assumed that the plant would be located along a major river.

Table 22. Transportation information for resources and products.

Product Transported	Miles Transported	Mode of Transport
Petroleum Products to Mine	50	Rail
Natural Gas to Mine	50	Pipeline
Natural Gas-to-MTG Plant	50	Pipeline
Coal to MTG Plant	100	Rail
Petroleum Products to MTG Plant	50	Rail
CO_2 to Sequestration Area	50	Pipeline
Gasoline – Plant to Distribution Point	200	Pipeline
Gasoline – Distribution Point to Pump	200	Truck

The modes of transportation were assumed based on the amount of product being transported, the product state, the distance transported, and the available transportation methods. The emissions associated with the various transportation methods include the combustion of fuel necessary for the transportation (or electricity use) as well as the upstream emissions associated with producing the fuel or electricity. Fuel use per mode of transportation was developed based on information provided by the U.S. EPA's report *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (U.S. EPA 2009), the *Transportation Energy Databook* (Davis 2009), and the *Freight in America* report (U.S. DOT 2006).

6.4 Conversion and Refining

GHG emissions are generated from several sources within the conventional and nuclear coal-to-MTG and natural gas-to-MTG plants, including: emissions from importing power, emissions associated with nuclear power use, upstream emissions associated with methanol use, emissions from coal milling and drying, SMR emissions, Rectisol plant emissions, HRSG stack emissions, fired heater emissions, high-pressure (HP) and low-pressure (LP) flare systems, and fugitive emissions. Fugitive emissions are emissions from leaking equipment, e.g. valves, pumps, etc., storage tanks, and wastewater treatment facilities. Emissions for the HP and LP flare systems were assumed based on generalized plant startup parameters, and fugitive emissions were calculated based on recommendations from the 2006 IPCC guidelines (IPCC 2006). All other emissions were taken from the Aspen modeling results. Emissions were calculated for CH_4 and N_2O for all sources based on IPCC emission factors for CH_4 and N_2O.

6.5 End-Use Combustion

Emissions for the end-use combustion of the fuel were estimated from the carbon content of the synthetic gasoline. It was assumed that all carbon present in the fuel is completely combusted to form CO_2. Based on the fuel density, this would provide the emissions of CO_2 per barrel of fuel. Again, emissions for CH_4 and N_2O were added based on IPCC guidelines for mobile combustion sources.

7. GREENHOUSE GAS MODELING RESULTS

A summary of the GHG results for the cases analyzed is presented in Table 23 for conventional and nuclear coal-to-MTG and Table 24 for conventional and nuclear natural gas-to-MTG. GHG emissions results are presented on a gram CO_2 equivalent per barrel of gasoline (g CO_2-eq/bbl) basis, a gram CO_2 equivalent per LHV (g CO_2-eq/MMBTU), and a gram CO_2 equivalent per mile (g CO_2-eq/mile). Figures of the GHG emissions are presented in Figure 16 for the coal-to-MTG cases and Figure 17 for natural gas-to-MTG cases.

From the results presented in these tables and figures, it is apparent that to reduce WTW GHG emissions to levels below imported and/or baseline conventional gasoline, integration of the HTGR is necessary. Conventional coal-to-MTG WTW emissions are significantly higher than conventional gasoline; even with incorporation of sequestration, emissions are greater than conventional fuels. It may be possible to reduce GHG emissions below conventional gasoline with incorporation of biomass, but sequestration would still be necessary. Nuclear integration is the only option where WTW GHG emissions of coal-based synthetic fuels are lower than conventional fuels without CO_2 sequestration. The same can be said of natural gas-to-MTG—it may be possible to reduce emissions below conventional fuels with incorporation of a CO_2 capture scheme; however, removal of CO_2 from hot combustion exhaust is costly and currently not a common industrial practice because:

- The low pressure and dilute concentration dictate a high actual volume of gas to be treated.
- Trace impurities in the flue gas tend to reduce the effectiveness of the CO_2 adsorbing processes.
- Compressing captured CO_2 from atmospheric pressure to pipeline pressure represents a large parasitic load.

Table 23. Coal-to-MTG fuels—GHG case study results.

	Coal MTG	**Coal MTG w/ Seq**	**Coal MTG w/ HTGR**	**Baseline Gasoline**	**Imported Gasoline**
gCO_2-eq/bbl gasoline					
Extraction and Production	32,591	32,591	14,885	35,593	46,320
Transportation to Plant	1,165	1,165	532	6,826	9,264
Conversion and Refining	514,386	107,576	8,881	47,783	50,708
Transportation to Pump	4,357	5,621	4,357	5,363	4,876
End-Use Combustion	365,956	365,956	365,956	383,512	383,512
Total Fuel Chain	*918,454*	*512,908*	*394,610*	*479,078*	*494,680*
gCO_2-eq/MMBTU gasoline					
Extraction and Production	6,865	6,865	3,135	7,300	9,500
Transportation to Plant	245	245	112	1,400	1,900
Conversion and Refining	108,350	22,660	1,871	9,800	10,400
Transportation to Pump	918	1,184	918	1,100	1,000
End-Use Combustion	77,085	77,085	77,084	78,657	78,657
Total Fuel Chain	*193,463*	*108,039*	*83,120*	*98,257*	*101,457*
gCO_2-eq/mile					
Extraction and Production	37	37	17	40	52
Transportation to Plant	1	1	1	8	10
Conversion and Refining	588	123	10	53	57
Transportation to Pump	5	6	5	6	5
End-Use Combustion	418	418	418	429	429
Total Fuel Chain	*1,049*	*586*	*451*	*536*	*553*

Table 24. Natural gas-to-MTG fuels—GHG case study results.

	NG MTG	**NG MTG w/ HTGR**	**Baseline Gasoline**	**Imported Gasoline**
gCO_2-eq/bbl gasoline				
Extraction and Production	65,129	57,333	35,593	46,320
Transportation to Plant	22	20	6,826	9,264
Conversion and Refining	107,214	22,951	47,783	50,708
Transportation to Pump	4,357	4,357	5,363	4,876
End-Use Combustion	365,956	365,956	383,512	383,512
Total Fuel Chain	*542,678*	*450,616*	*479,078*	*494,680*
gCO_2-eq/MMBTU gasoline				
Extraction and Production	13,718	12,076	7,300	9,500
Transportation to Plant	5	4	1,400	1,900
Conversion and Refining	22,583	4,834	9,800	10,400
Transportation to Pump	918	918	1,100	1,000
End-Use Combustion	77,083	77,084	78,657	78,657
Total Fuel Chain	*114,306*	*94,917*	*98,257*	*101,457*
gCO_2-eq/mile				
Extraction and Production	74	66	40	52
Transportation to Plant	0	0	8	10
Conversion and Refining	122	26	53	57
Transportation to Pump	5	5	6	5
End-Use Combustion	418	418	429	429
Total Fuel Chain	*620*	*515*	*536*	*553*

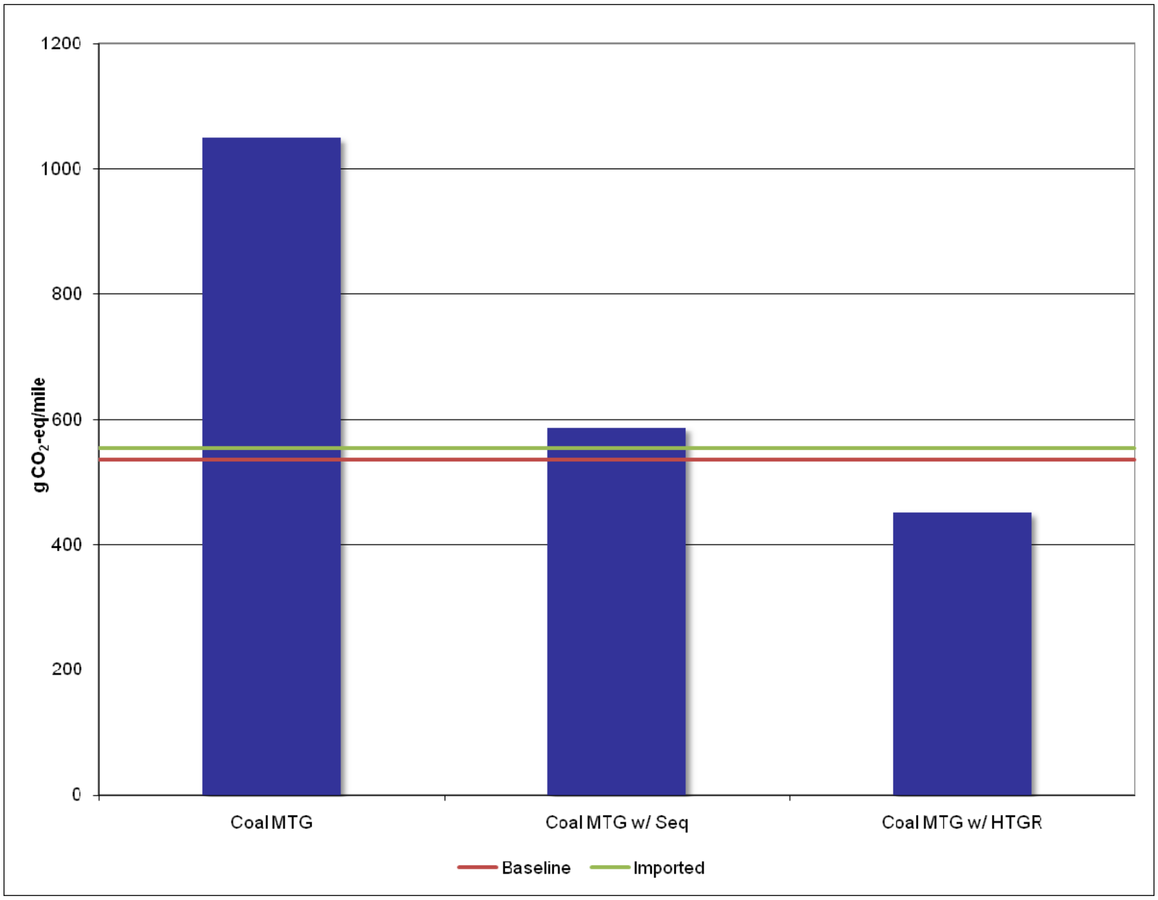

Figure 16. Coal-to-MTG fuels WTW GHG results.

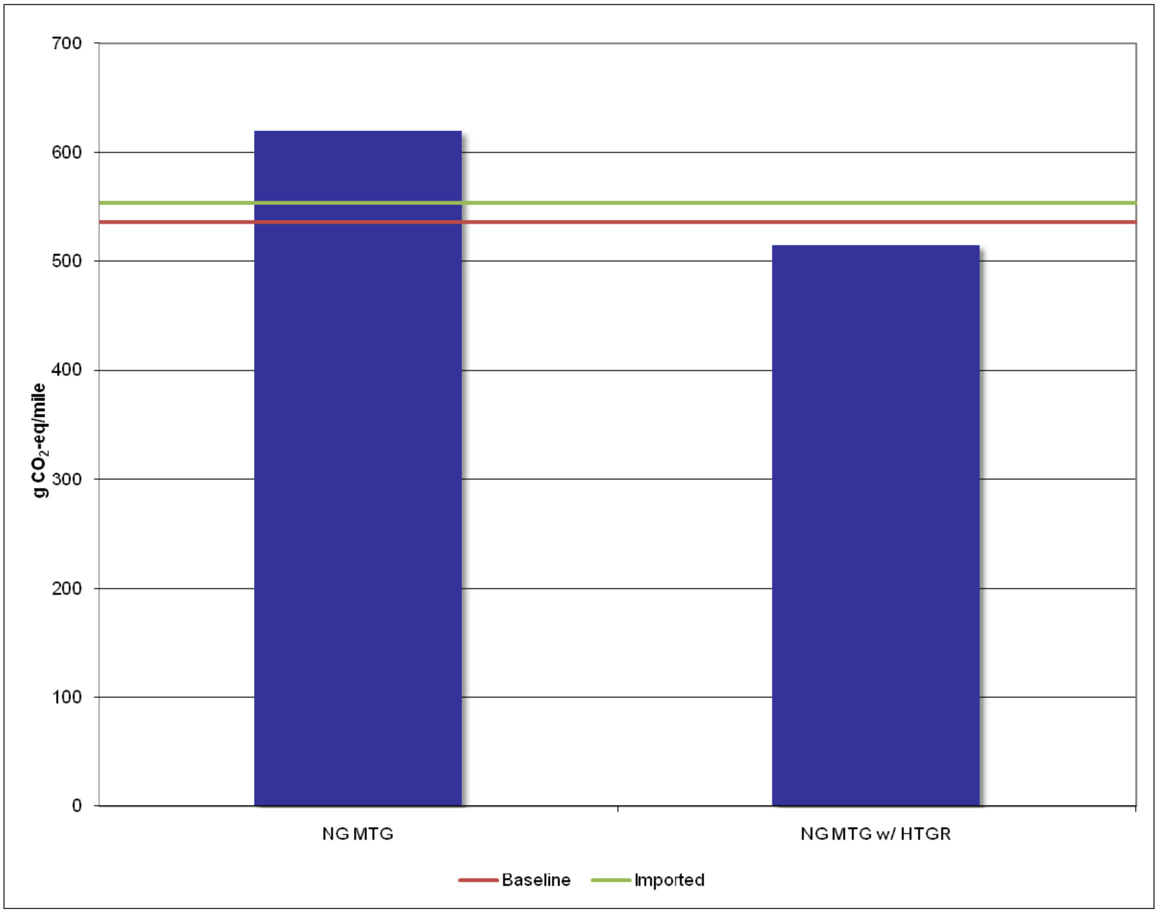

Figure 17. Natural gas-to-MTG fuels WTW GHG results.

8. COAL-TO-MTG CONCLUSIONS

Results from the nuclear-integrated coal-to-MTG case indicate that integration of nuclear hydrogen can drastically improve carbon utilization and reduce GHG emissions, even beyond what is achievable via sequestration alone. Coal consumption is decreased by 54% using electrolysis and nuclear power as the hydrogen source. Integrating nuclear power and high-temperature steam electrolysis also decreases CO_2 emissions from the plant. If carbon capture and sequestration are assumed for the conventional configuration, CO_2 emissions decrease by 17% when electrolysis and nuclear power are utilized. However, if carbon capture and sequestration are not assumed for the conventional configuration, CO_2 emissions decrease by 98.5% when electrolysis and nuclear power are utilized. Approximately 11½ nuclear high-temperature reactors (600 MW_t each) would be required in this configuration to support production of 66,805 bbl/day of liquid fuel products.

Economically, incorporation of 11 HTGRs and the associated HTSEs significantly impacts the expected return on investment when compared to conventional MTG with or without sequestration. The required selling price of gasoline to achieve a 12% IRR for the nuclear-integrated case is nearly two times the selling price required for the conventional MTG case, with or without sequestration, for an HTGR capital cost of \$2,000/kW$_t$. When the HTGR capital cost is decreased by 30%, the nuclear-integrated selling price of gasoline is still greater than the conventional case by about 63%. However, in a carbon-constrained scenario where CO_2 emissions are taxed and sequestration is not an option, a CO_2 tax of \$110/ton-CO_2 equates the economics of the nuclear-integrated MTG case with the conventional MTG case at a HTGR capital cost of \$2,000/kW$_t$. The necessary tax decreases to \$70/ton-CO_2 when the capital cost of the HTGR is decreased by 30%.

To reduce WTW GHG emissions to levels below imported and/or baseline conventional gasoline, integration of the HTGR is necessary. Conventional coal-to-MTG WTW emissions are significantly higher than conventional gasoline; even with incorporation of sequestration, emissions are greater than conventional fuels. It may be possible to reduce GHG emissions below conventional gasoline with incorporation of biomass, but sequestration would still be necessary. Nuclear integration is the only option where WTW GHG emissions of coal-based synthetic fuels are lower than conventional fuels without CO_2 sequestration. Therefore, if there is policy enacted that legislates that synthetically produced gasoline fuels must meet or beat current fuel WTW GHG emissions, HTGR incorporation provides a solution with less risk than options which employ CO_2 sequestration.

9. GAS-TO-MTG CONCLUSIONS

Results for the nuclear-integrated natural gas-to-MTG cases look promising. To support the evaluated configuration, 722 MW$_t$ would be required from the HTGRs. By substituting nuclear heat for natural gas combustion in the primary reformer, natural gas consumption is decreased by 10.4% compared to the conventional gas-to-MTG case. CO_2 emissions decrease by 68% for the nuclear-integrated case compared to the conventional gas-to-MTG case.

Economically, the nuclear-integrated gas-to-MTG option provides economic stability with respect to fluctuations in natural gas prices. Although the IRR is slightly lower than for conventional gas-to-MTG at higher gasoline selling prices, it is still significantly above 12%, indicating a sizable return on investment. Furthermore, as the cost of natural gas increases, the HTGR-integrated case compares more favorably with the conventional gas-to MTG case. Above a natural gas price of \$11.50/MSCF, economics for the HTGR-integrated case outperform the conventional case. In addition, if the cost of the HTGR can be reduced by 30%, the HTGR-integrated can compete with conventional gas-to-MTG for natural gas prices as low as \$7.00/MSCF. Results of the sensitivity analysis on carbon tax indicate that a relatively high carbon tax of \$70/ton CO_2 is required before the HTGR-integrated case outperforms the conventional case. If a carbon tax of \$75/ton CO_2 is imposed, the HTGR-integrated case will outperform the conventional case when natural gas prices rise above \$6.00/MSCFD. Hence, it is clear that the economic performance of the HTGR-integrated case can compete with the conventional gas-to-MTG case in a number of scenarios including: (1) natural gas prices rise above $11.50/MSCF, (2) a carbon tax in excess of $70/ton CO_2 is imposed, or (3) further development and commercialization of HTGR technology are able to reduce the price of implementation by 30%.

Integration of HTGR technology into the gas-to-MTG flowsheet results in lower lifecycle GHG emissions than for conventional gasoline. It may be possible to reduce emissions below conventional fuels with incorporation of a CO_2 capture scheme; however, removal of CO_2 from hot combustion exhaust is costly and currently not a common industrial practice. Therefore, if a policy is enacted that legislates that synthetically produced gasoline fuels must meet or beat current fuel WTW GHG emissions, HTGR incorporation provides a solution with less risk than options which employ CO_2 sequestration.

10. FUTURE WORK AND RECOMMENDATIONS

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

- Refined estimates of the HTGR capital cost, annual fuel costs, and annual O&M costs should be developed to refine the economic results.
- A separate study should be conducted to assess the optimal siting of the HTGR with respect to the MTG facilities, 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.
- It is likely that process and economic results for the nuclear-integrated cases could be improved if the HTGR temperature could be increased from 750 to 950°C. Hence, a study to quantify the performance improvement is recommended.
- Due to differences in how utility companies and fuel producers currently evaluate economics of proposed projects, and due to the high capital costs associated with integrating these technologies, additional work is recommended to identify and evaluate more realistic business models for this integration.

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12. APPENDIXES

Appendix A, Detailed Modeling Results and Flowsheets

Appendix B, MTG Capital Cost Estimates

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

Appendix D, [Electronic] Conventional Natural Gas to MTG Stream Results.xls

Appendix E, [Electronic] Coal to MTG Nuclear Integration Stream Results.xls

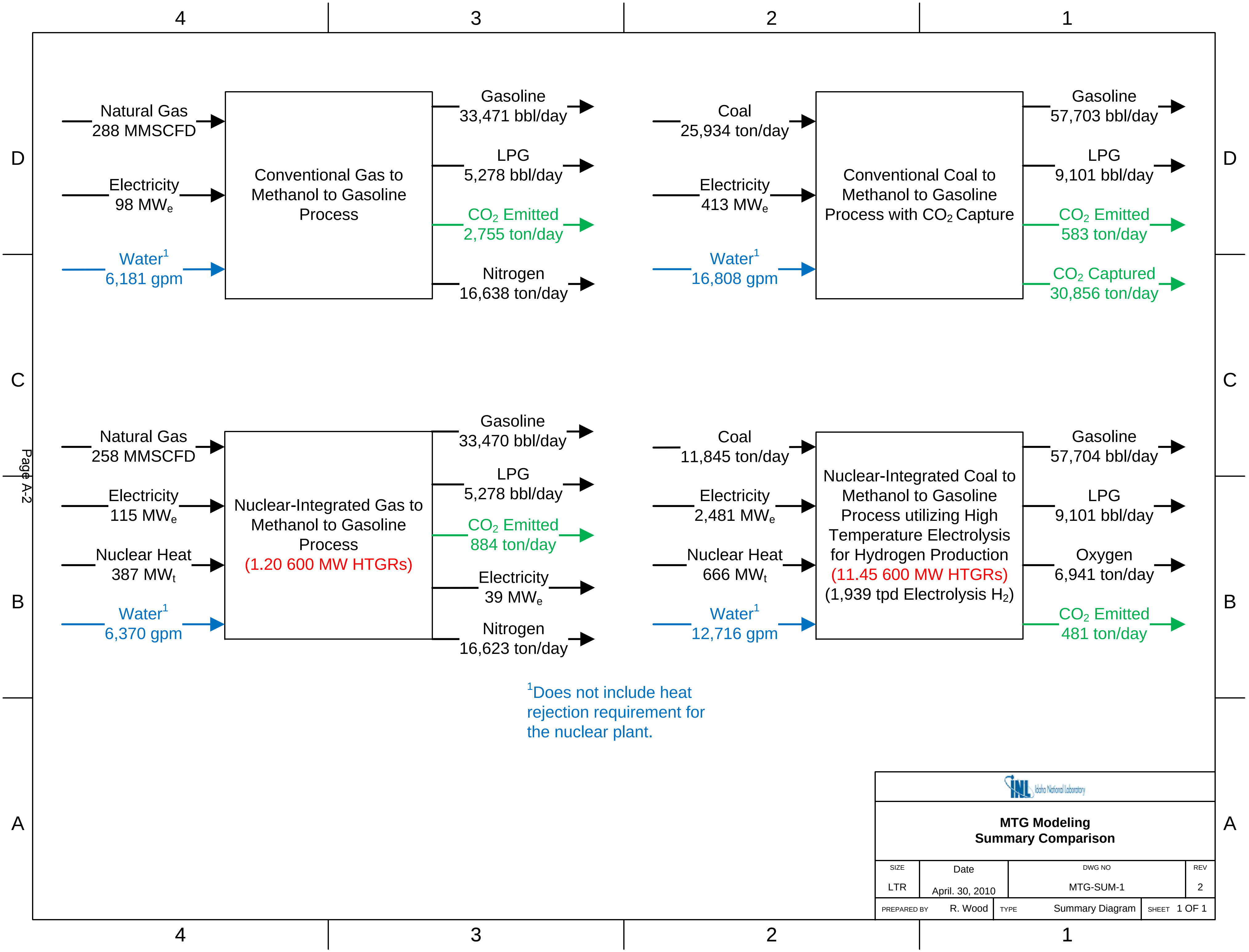
Appendix F, [Electronic] Natural Gas to MTG Nuclear Integration.xls

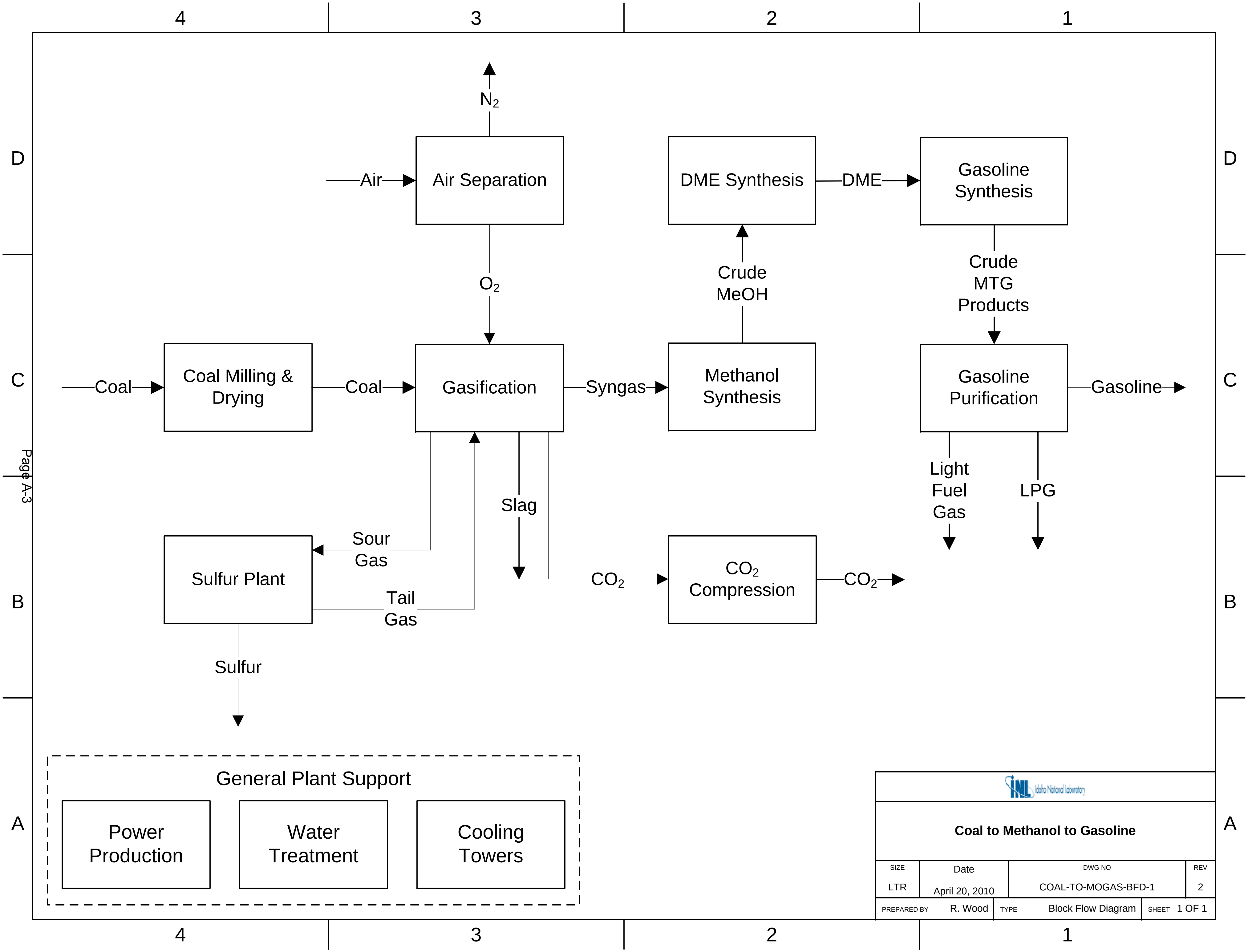
Appendix A
Detailed Modeling Results and Flowsheets

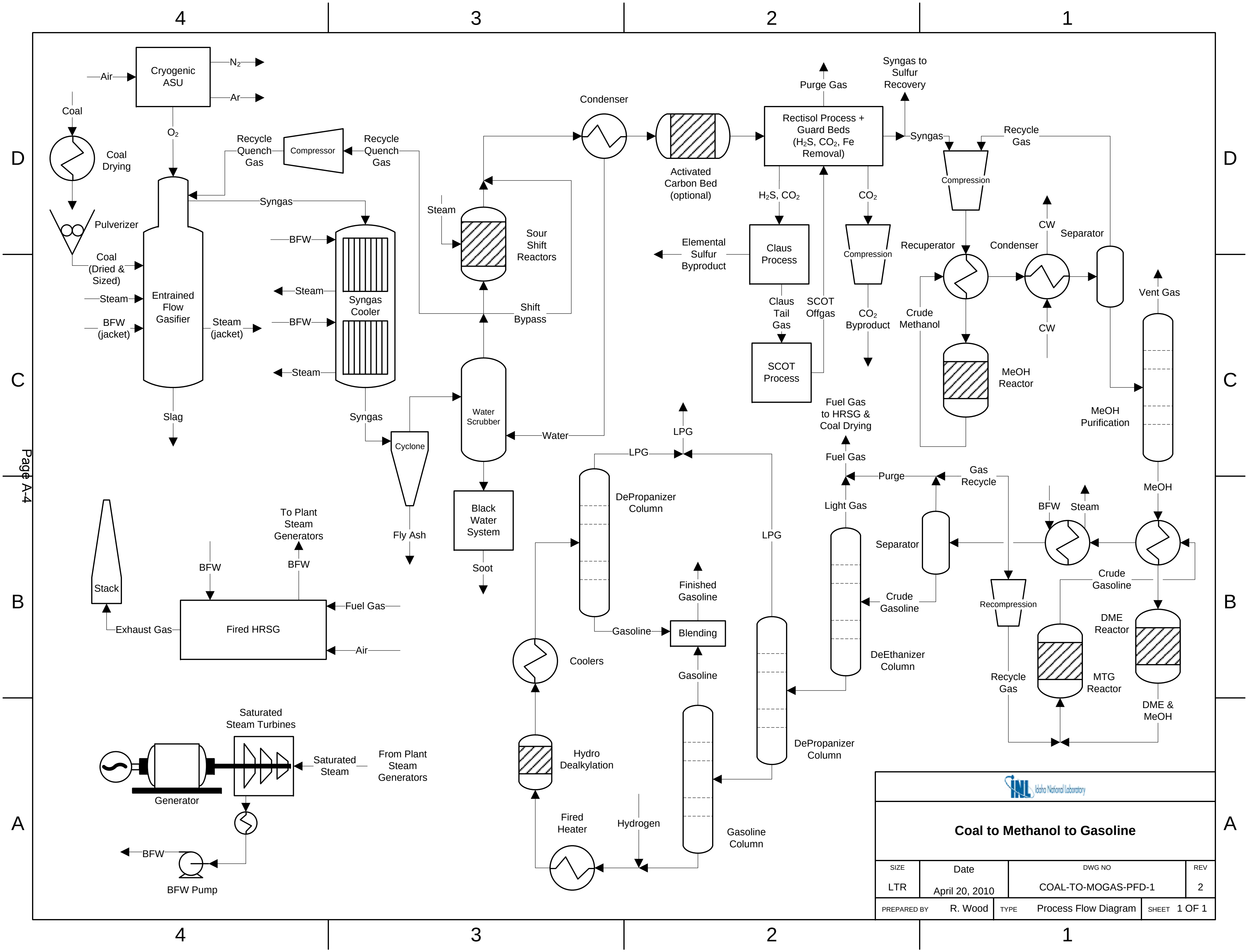
MTG Case Summary

	Coal Baseline	Coal Nuclear-Integrated	Natural Gas Baseline	Natural Gas Nuclear-Integrated
Inputs				
Coal Feed Rate (ton/day)	25,934	11,845	n/a	n/a
Natural Gas Feed Rate (MMSCFD)[1]	n/a	n/a	288	258
# 600 MWt HTGRs Required	n/a	11.45	n/a	1.20
Intermediate Products				
Methanol (ton/day)	20,055	19,342	11,023	11,023
Outputs				
Total Liquid Product	66,804	66,805	38,749	38,748
Gasoline (bbl/day)	57,703	57,704	33,471	33,470
Gasoline Produced / Coal Fed (lb/lb)	0.28	0.62	n/a	n/a
Gasoline Produced / Natural Gas Fed (lb/l	n/a	n/a	0.65	0.73
Gasoline Produced / Methanol Fed (lb/lb)	0.37	0.38	0.39	0.39
LPG (bbl/day)	9,101	9,101	5,278	5,278
LPG Produced / Coal Fed (lb/lb)	0.03	0.07	n/a	n/a
LPG Produced / Natural Gas Fed (lb/lb)	n/a	n/a	0.08	0.09
LPG Produced / Methanol Fed (lb/lb)	0.04	0.05	0.05	0.05
Nitrogen (ton/day)	n/a	n/a	16,638	16,623
Utility Summary				
Total Power (MW)	-413.4	-2480.6	-97.5	-76.7
Electrolyzers	n/a	-2488.7	n/a	n/a
Air Separation	-291.4	n/a	-75.1	-75.0
Coal Milling & Drying	-14.1	-10.7	n/a	n/a
Gasification Island	-13.9	-6.3	n/a	n/a
Natural Gas Reforming	n/a	n/a	-13.8	-9.3
Syngas Purification	-149.0	-56.1	n/a	n/a
Claus Plant	-0.7	-0.4	n/a	n/a
Sulfur Reduction (SCOT)	-10.2	-5.0	n/a	n/a
Non-Nuclear Power Island	340.7	225.4	59.8	76.5
CO_2 Compression	-135.8	-15.3	n/a	n/a
Methanol Plant	-103.1	-93.0	-49.1	-49.3
MTG Plant	-9.8	-9.8	-5.7	-5.7
H_2 Recovery	n/a	-1.9	n/a	n/a
Cooling Towers	-8.4	-5.9	-3.6	-3.7
Water Treatment	-17.6	-12.8	-10.0	-10.1
Total Water (gpm)	-16,808	-12,716	-6,181	-6,370
Evaporation Rate (gpm)	-20,012	-13,869	-8,061	-8,279
Water Consumed / Liquid Produced (bbl/bbl)	8.63	6.53	5.47	5.64
Carbon Balance				
To Gasoline Product (% C Input)	40.10%	87.70%	75.8%	84.8%
To LPG Product (% C Input)	4.50%	9.90%	8.6%	9.6%
To Slag & Flyash (% C Input)	0.40%	0.40%	n/a	n/a
To Captured CO_2 (% C Input)	53.90%	n/a	n/a	n/a
To Emitted CO_2 (% C Input)	1.10%	1.80%	15.6%	5.6%
CO_2 Emissions				
Captured (ton/day CO_2)	30,856	n/a	n/a	n/a
Emitted (ton/day CO_2)	583	481	2,755	884
Nuclear Integration Summary				
Electricity (MW)	n/a	2480.6	n/a	115.3
HTE	n/a	2488.7	n/a	n/a
Balance of Plant	n/a	-8.1	n/a	76.7
Excess Power for Sale	n/a	n/a	n/a	38.6
Process Heat (MMBTU/hr)	n/a	n/a	n/a	1321.1
Helium Flow Rate (ton/hr)	n/a	n/a	n/a	1,290
Helium Supply Temperature (deg. F)	n/a	n/a	n/a	1,292
Helium Return Temperature (deg. F)	n/a	n/a	n/a	879
Electrolysis Heat (MMBTU/hr)	n/a	2,410	n/a	n/a
From Nuclear Plant	n/a	2,273	n/a	n/a
From Gasification Island	n/a	137	n/a	n/a
Electrolysis Products				
Total Hydrogen (ton/day)	n/a	1,939	n/a	n/a
Total Oxygen (ton/day)	n/a	15,281	n/a	n/a
Consumed in Plant	n/a	8,339	n/a	n/a
Available for Sale	n/a	6,941	n/a	n/a

[1]Standard temperature of 60 degrees F.


Conventional Gas to Methanol to Gasoline Process
Natural Gas 288 MMSCFD
Electricity 98 MWe
Water[1] 6,181 gpm
Gasoline 33,471 bbl/day
LPG 5,278 bbl/day
CO2 Emitted 2,755 ton/day
Nitrogen 16,638 ton/day
Conventional Coal to Methanol to Gasoline Process with CO2 Capture
Coal 25,934 ton/day
Electricity 413 MWe
Water[1] 16,808 gpm
Gasoline 57,703 bbl/day
LPG 9,101 bbl/day
CO2 Emitted 583 ton/day
CO2 Captured 30,856 ton/day
Nuclear-Integrated Gas to Methanol to Gasoline Process
(1.20 600 MW HTGRs)
Natural Gas 258 MMSCFD
Electricity 115 MWe
Nuclear Heat 387 MWt
Water[1] 6,370 gpm
Gasoline 33,470 bbl/day
LPG 5,278 bbl/day
CO2 Emitted 884 ton/day
Electricity 39 MWe
Nitrogen 16,623 ton/day
Nuclear-Integrated Coal to Methanol to Gasoline Process utilizing High Temperature Electrolysis for Hydrogen Production
(11.45 600 MW HTGRs)
(1,939 tpd Electrolysis H2)
Coal 11,845 ton/day
Electricity 2,481 MWe
Nuclear Heat 666 MWt
Water[1] 12,716 gpm
Gasoline 57,704 bbl/day
LPG 9,101 bbl/day
Oxygen 6,941 ton/day
CO2 Emitted 481 ton/day
[1]Does not include heat rejection requirement for the nuclear plant.
INL Idaho National Laboratory
MTG Modeling
Summary Comparison
SIZE LTR
Date April. 30, 2010
DWG NO MTG-SUM-1
REV 2
PREPARED BY R. Wood
TYPE Summary Diagram
SHEET 1 OF 1


4
3
2
1
D
C
B
A
N_2
Air
Air Separation
DME Synthesis
DME
Gasoline Synthesis
O_2
Crude MeOH
Crude MTG Products
Coal
Coal Milling & Drying
Coal
Gasification
Syngas
Methanol Synthesis
Gasoline Purification
Gasoline
Slag
Light Fuel Gas
LPG
Sour Gas
Sulfur Plant
Tail Gas
CO_2
CO_2 Compression
CO_2
Sulfur
General Plant Support
Power Production
Water Treatment
Cooling Towers
Idaho National Laboratory
Coal to Methanol to Gasoline
SIZE
LTR
Date
April 20, 2010
DWG NO
COAL-TO-MOGAS-BFD-1
REV
2
PREPARED BY
R. Wood
TYPE
Block Flow Diagram
SHEET
1 OF 1


Air
Cryogenic ASU
N_2
Ar
O_2
Coal
Coal Drying
Pulverizer
Coal (Dried & Sized)
Steam
BFW (jacket)
Entrained Flow Gasifier
Steam (jacket)
Slag
Recycle Quench Gas
Compressor
Recycle Quench Gas
Syngas
BFW
Steam
Syngas Cooler
BFW
Steam
Syngas
Cyclone
Fly Ash
Water Scrubber
Black Water System
Soot
Steam
Sour Shift Reactors
Shift Bypass
Condenser
Water
Activated Carbon Bed (optional)
Purge Gas
Rectisol Process + Guard Beds (H_2S, CO_2, Fe Removal)
Syngas to Sulfur Recovery
Syngas
H_2S, CO_2
CO_2
Elemental Sulfur Byproduct
Claus Process
Compression
Claus Tail Gas
SCOT Offgas
CO_2 Byproduct
SCOT Process
Recycle Gas
Compression
Recuperator
Condenser
CW
CW
Separator
Crude Methanol
MeOH Reactor
Vent Gas
MeOH Purification
MeOH
Fuel Gas to HRSG & Coal Drying
Fuel Gas
Purge
Gas Recycle
Light Gas
Separator
BFW
Steam
Crude Gasoline
Crude Gasoline
DeEthanizer Column
Recompression
DME Reactor
MTG Reactor
Recycle Gas
DME & MeOH
LPG
LPG
LPG
DePropanizer Column
Gasoline
Blending
Finished Gasoline
Gasoline
Coolers
DePropanizer Column
Gasoline Column
Hydro Dealkylation
Fired Heater
Hydrogen
Stack
Exhaust Gas
Fired HRSG
BFW
To Plant Steam Generators
BFW
Fuel Gas
Air
Saturated Steam Turbines
Saturated Steam
From Plant Steam Generators
Generator
BFW
BFW Pump
Idaho National Laboratory
Coal to Methanol to Gasoline
SIZE
LTR
Date
April 20, 2010
DWG NO
COAL-TO-MOGAS-PFD-1
REV
2
PREPARED BY
R. Wood
TYPE
Process Flow Diagram
SHEET 1 OF 1

Conventional Coal to MTG Results

```
Calculator Block SUMMARY

   FEED & PRODUCT SUMMARY:

     FEEDS:

       RAW COAL FEED RATE =               25934.3 TON/DY
         COAL HHV AS FED =                10934. BTU/LB
         COAL MOISTURE AS FED =              13.70 %

       PROXIMATE ANALYSIS (DRY BASIS):
          MOISTURE                           13.70 %
          FIXED CARBON                       40.12 %
          VOLATILE MATTER                    49.28 %
          ASH                                10.60 %

       ULTIMATE ANALYSIS (DRY BASIS):
          ASH                                10.60 %
          CARBON                             70.27 %
          HYDROGEN                            4.84 %
          NITROGEN                            1.36 %
          CHLORINE                            0.11 %
          SULFUR                              3.72 %
          OXYGEN                              9.10 %

       SULFANAL ANALYSIS (DRY BASIS):
          PYRITIC                             1.94 %
          SULFATE                             0.08 %
          ORGANIC                             1.70 %

     INTERMEDIATES:

       COAL FEED RATE AFTER DRYING =      23809.9 TON/DY
         COAL HHV AFTER DRYING =          11910. BTU/LB
         COAL MOISTURE AFTER DRYNG =          6.00 %

       RAW SYNGAS MASS FLOW =           3890331. LB/HR
       RAW SYNGAS VOLUME FLOW =            1673. MMSCFD @ 60°F
       RAW SYNGAS COMPOSITION:
          H2                                 27.4 MOL.%
          CO                                 56.6 MOL.%
          CO2                                 5.8 MOL.%
          N2                                  0.6 MOL.%
          H2O                                 8.0 MOL.%
          H2S                             10663. PPMV
          CH4                                51. PPMV

       QUENCHED SYNGAS MASS FLOW =      4139100. LB/HR
       QUENCHED SYNGAS VOLUME FLOW =       1770. MMSCFD @ 60°F
       QUENCHED SYNGAS COMPOSITION:
          H2                                 25.9 MOL.%
          CO                                 53.5 MOL.%
          CO2                                 6.7 MOL.%
          N2                                  0.7 MOL.%
          H2O                                12.0 MOL.%
          H2S                             10082. PPMV
          CH4                                46. PPMV

       CLEANED SYNGAS MASS FLOW =       1736488. LB/HR
       CLEANED SYNGAS VOLUME FLOW =        1462. MMSCFD @ 60°F
       CLEANED SYNGAS COMPOSITION:
          H2                                 68.2 MOL.%
          CO                                 27.9 MOL.%
          CO2                                 3.2 MOL.%
```

```
      N2                                   0.6 MOL.%
      H2O                                  0.0 MOL.%
      H2S                                  0. PPMV
      CH4                                 53. PPMV

   METHANOL MASS FLOW =            1671215. LB/HR
   METHANOL MASS FLOW =              20055. TON/DY
      METHANOL PURITY =               94.61 WT.%
   METHANOL PRODUCED / COAL FED =      0.77 LB/LB

 FINAL PRODUCTS:

   GASOLINE PRODUCT:
      GASOLINE VOLUME FLOW =         57703. BBL/DY
      GASOLINE MASS FLOW =          613030. LB/HR
      GASOLINE MASS FLOW =            7356. TON/DY
      GASOLINE LHV FLOW =           273942. MMBTU/DY
      GASOLINE PRODUCED / METHANOL FED =  0.37 LB/LB
      GASOLINE PRODUCED / COAL FED =      0.28 LB/LB

   LPG PRODUCT:
      LPG VOLUME FLOW =               9101. BBL/DY
      LPG MASS FLOW =                73047. LB/HR
      LPG MASS FLOW =                  877. TON/DY
      LPG LHV FLOW =                 34291. MMBTU/DY
      LPG PRODUCED / METHANOL FED =       0.04 LB/LB
      LPG PRODUCED / COAL FED =           0.03 LB/LB

BYPRODUCTS SUMMARY:

 SLAG =                               1852. TON/DY
 FLYASH =                              777. TON/DY
 SULFUR =                              826. TON/DY


POWER SUMMARY:

 ELECTRICAL GENERATORS:
   STEAM TURBINE POWER GENERATION =     345.5 MW
 GENERATOR SUBTOTAL =                   345.5 MW

 ELECTRICAL CONSUMERS:
   COAL PREP POWER CONSUMPTION =         14.1 MW
   ASU POWER CONSUMPTION =              291.4 MW
   GASIFIER POWER CONSUMPTION =          13.9 MW
   GAS CLEANING POWER CONSUMPTION =     149.0 MW
   CLAUS POWER CONSUMPTION =              0.7 MW
   SCOT POWER CONSUMPTION =              10.2 MW
   POWER BLOCK POWER CONSUMPTION =        4.8 MW
   CO2 PROCESSING POWER CONSUMPTION =   135.8 MW
   MEOH SYNTHESIS POWER CONSUMPTION =   103.1 MW
   MTG POWER CONSUMPTION =                9.8 MW
   COOLING TOWER POWER CONSUMPTION =      8.4 MW
   WATER TREATMENT POWER CONSUMPTION =   17.6 MW
 CONSUMER SUBTOTAL =                    758.8 MW

 NET PLANT POWER CONSUMPTION =          413.4 MW


WATER BALANCE:

 EVAPORATIVE LOSSES:
   CMD WATER NOT RECOVERED =            486.0 GPM
   COOLING TOWER EVAPORATION =        18573.6 GPM
```

```
    ZLD SYSTEM EVAPORATION =                952.6 GPM
  TOTAL EVAPORATIVE LOSSES =              20012.2 GPM

  WATER CONSUMED:
    GASIFIER ISLAND MAKEUP =                416.7 GPM
    BOILER FEED WATER MAKEUP =             2268.8 GPM
    COOLING TOWER MAKEUP =                19520.0 GPM
  TOTAL WATER CONSUMED =                  22205.6 GPM

  WATER GENERATED:
    GASIFIER ISLAND BLOWDOWN =               92.2 GPM
    SYNGAS CONDENSER BLOWDOWN =              48.3 GPM
    RECTISOL BLOWDOWN =                     362.8 GPM
    SULFUR REDUCTION BLOWDOWN =              73.3 GPM
    MTG PROCESS WATER =                    1950.2 GPM
    COOLING TOWER BLOWDOWN =               3812.0 GPM
  TOTAL WATER GENERATED =                  6339.0 GPM

  PLANT WATER SUMMARY:
    NET MAKEUP WATER REQUIRED =           16807.8 GPM
    WATER CONSUMED / COAL FED =               3.89 LB/LB
    WATER CONSUMED / LIQUID PRODUCED =        8.63 BBL/BBL


CO2 BALANCE:

  CO2 CAPTURED (SEQUESTERED OR EOR) =  30856. TON/DY
  CO2 CAPTURED @ 60°F =                  532. MMSCFD @ 60°F
    CO2 PURITY =                          94.6 %

  CO2 EMITTED (TOTAL) =                  583. TON/DY
  CO2 EMITTED @ 60°F =                    10. MMSCFD @ 60°F
    FROM HRSG =                          170. TON/DY
      LHV TO HRSG =                     5382. MMBTU/DY
    FROM CMD =                           326. TON/DY
      LHV TO CMD =                     10381. MMBTU/DY
    FROM MTG FH =                         88. TON/DY
      LHV TO MTG FH =                   1522. MMBTU/DY
  CO2 EMITTED / COAL FED =                 0.02 LB/LB


CARBON BALANCE SUMMARY:

    % CARBON TO GASOLINE =                40.1 %
    % CARBON TO LPG =                      4.5 %
    % CARBON TO SLAG =                     0.0 %
    % CARBON TO FLY ASH =                  0.4 %
    % CARBON TO EOR =                     53.9 %
    % CARBON TO CMD EXHAUST =              0.6 %
    % CARBON TO HRSG EXHAUST =             0.3 %
    % CARBON TO FIRED HEATER EXHAUST =     0.2 %

STARTUP FLARE SUMMARY:

  CO2 FROM FLARE =                       314. TON/DY
  LHV TO FLARE =                        2290. MMBTU/DY


Calculator Block AIRPROPS

  HUMIDITY DATA FOR STREAM AIR-ASU:
    HUMIDITY RATIO =                      43.5 GRAINS/LB
    RELATIVE HUMIDITY =                   39.9 %
```

Conventional Coal to MTG Results

Calculator Block MEOH-SYN Hierarchy: MEOH-SYN

MEOH SYNTHESIS FEED GAS QUALITY:

$(H_2 - CO_2) / (CO + CO_2)$

TARGET =	2.10
ACTUAL =	2.095

$H_2 / (2\ CO + 3\ CO_2)$

TARGET =	1.05
ACTUAL =	1.045

H_2 / CO

ACTUAL =	2.447

MEOH SYNTHESIS OPERATING PARAMETERS:

MOLAR RECYCLE RATIO

TARGET =	3.0 - 4.0
ACTUAL =	4.00

REACTOR INLET CO_2 CONCENTRATION

TARGET =	< 4.0 MOL.%
ACTUAL =	1.05 MOL.%

REACTOR OUTLET MEOH CONCENTRATION

TARGET =	3.0 - 8.0 MOL.%
ACTUAL =	7.60 MOL.%

METHANOL PRODUCT CO_2 CONCENTRATION

TARGET =	500. PPBW
ACTUAL =	500. PPBW

Calculator Block MTG Hierarchy: MTG

YIELD SUMMARY (LB / 1,000 LB MEOH):

PRODUCT	EXXON LIT.	MODEL RESULT
GASOLINE	387.	386.
LPG	46.	46.
FUEL GAS	7.	8.
WATER	560.	560.

PRODUCT SUMMARY:

GASOLINE PRODUCT:

PRODUCTION RATE =	613030. LB/HR
PRODUCTION RATE =	57703. BBL/DAY
MOLECULAR WEIGHT =	94.5
CARBON PERCENT =	85.6
HIGHER HEAT CONTENT =	19941. BTU/LB
LOWER HEAT CONTENT =	18619. BTU/LB

PROPERTY COMPARISON:

PROPERTY	EXXON LIT.	MODEL RESULT
API GRAVITY, °	61.8	62.9
SPECIFIC GRAVITY	0.732	0.728
REED VAPOR PRES., PSI	9.0	8.7
AROMATIC CONTENT, %	26.5	24.3

Conventional Coal to MTG Results

	Conventional	Coal to MTG
OLEFIN CONTENT, %	12.6	16.4
BENZENE CONTENT, %	0.3	0.5
D86T 50%, °F	201.0	156.5
D86T 90%, °F	320.0	332.2

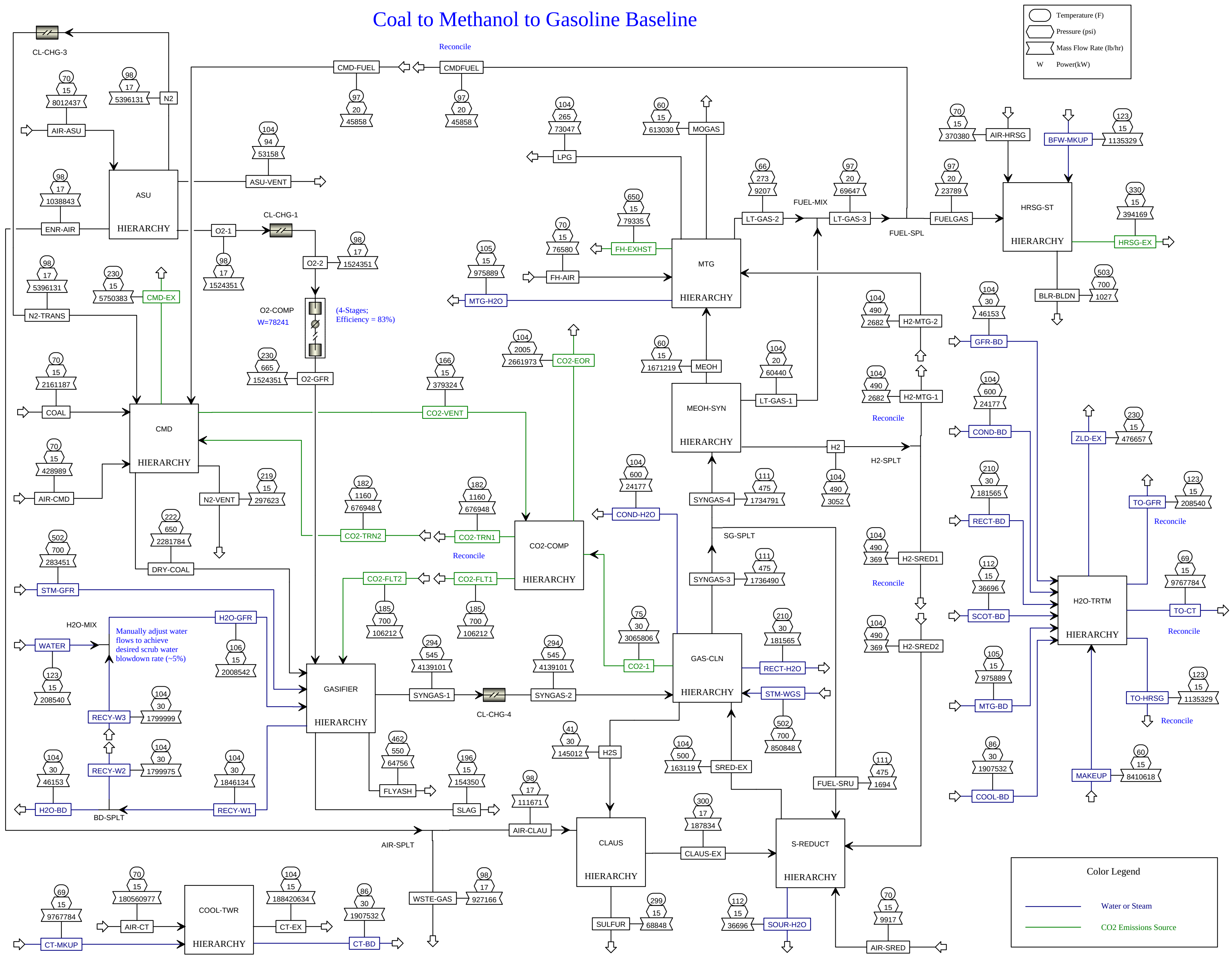
LPG PRODUCT:

PRODUCTION RATE =	73047. LB/HR
PRODUCTION RATE =	9101. BBL/DAY
SPECIFIC GRAVITY =	0.55
MOLECULAR WEIGHT =	50.1
CARBON PERCENT =	81.4
HIGHER HEAT CONTENT =	21218. BTU/LB
LOWER HEAT CONTENT =	19560. BTU/LB

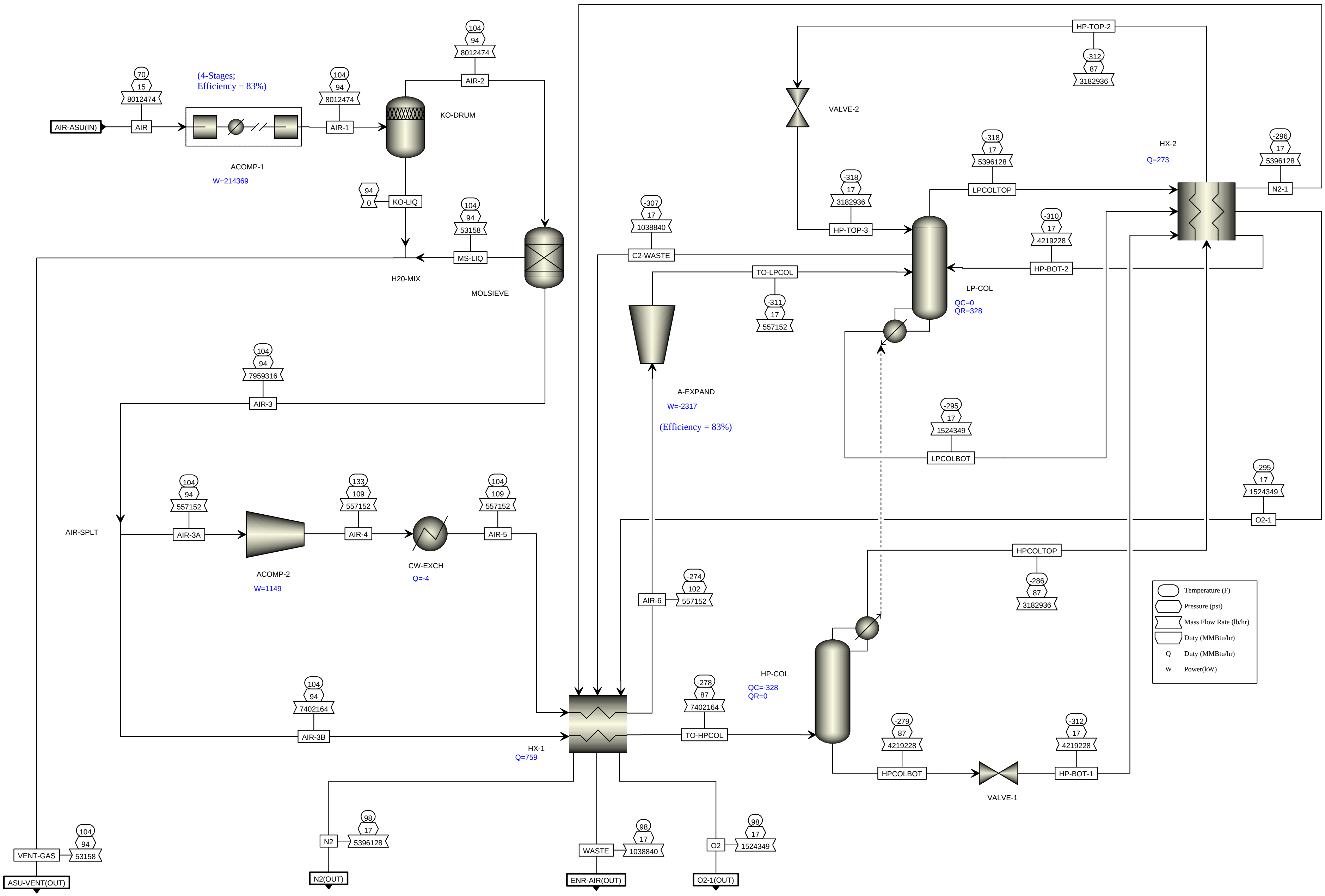
FUEL GAS PRODUCT:

NET PRODUCTION RATE =	9207. LB/HR
NET PRODUCTION RATE =	6.41 MMSCFD @ 60°F
MOLECULAR WEIGHT =	13.1
HIGHER HEAT CONTENT =	25597. BTU/LB

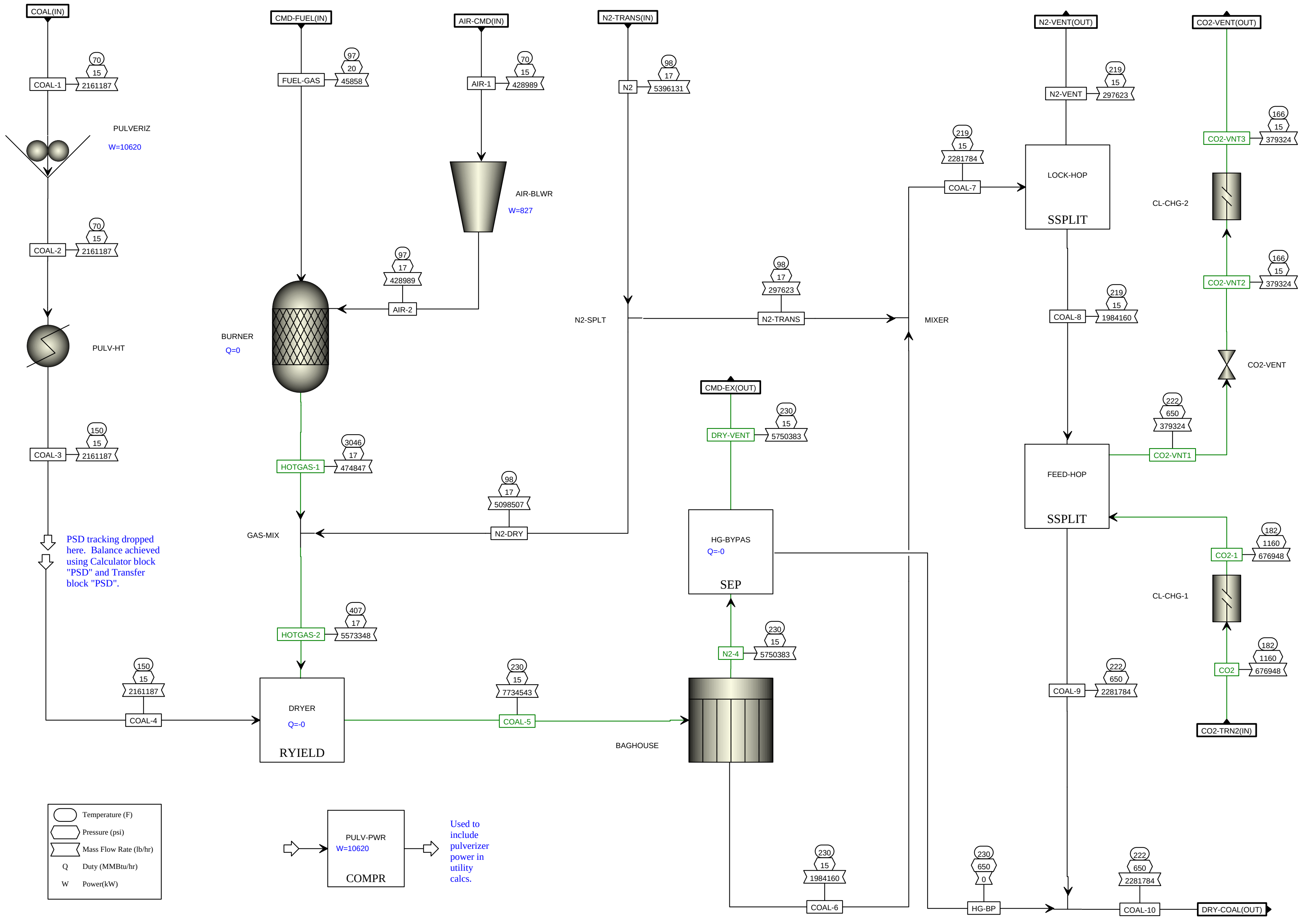
Coal to Methanol to Gasoline Baseline



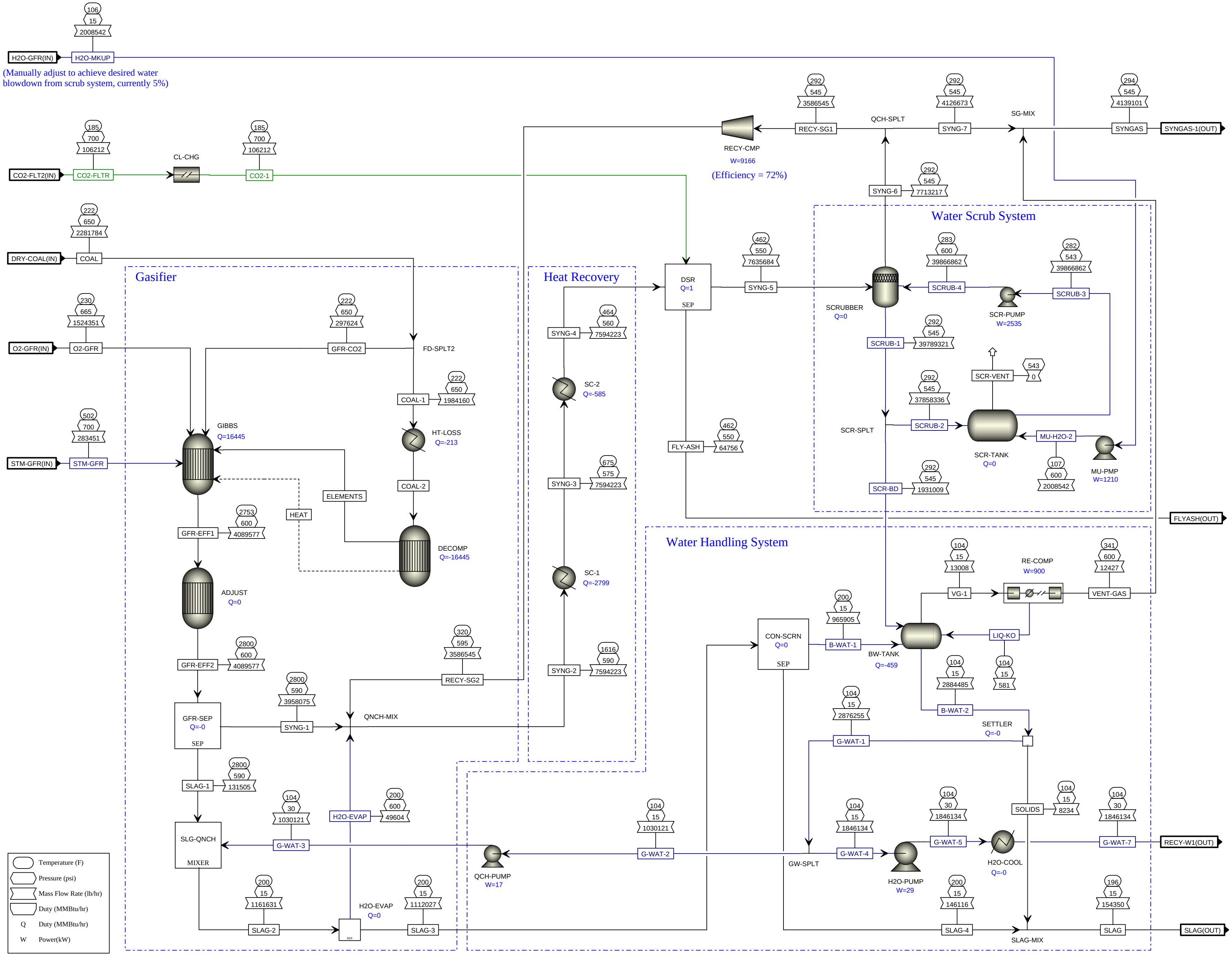
Air Separation Unit 99.5% O2 Purity



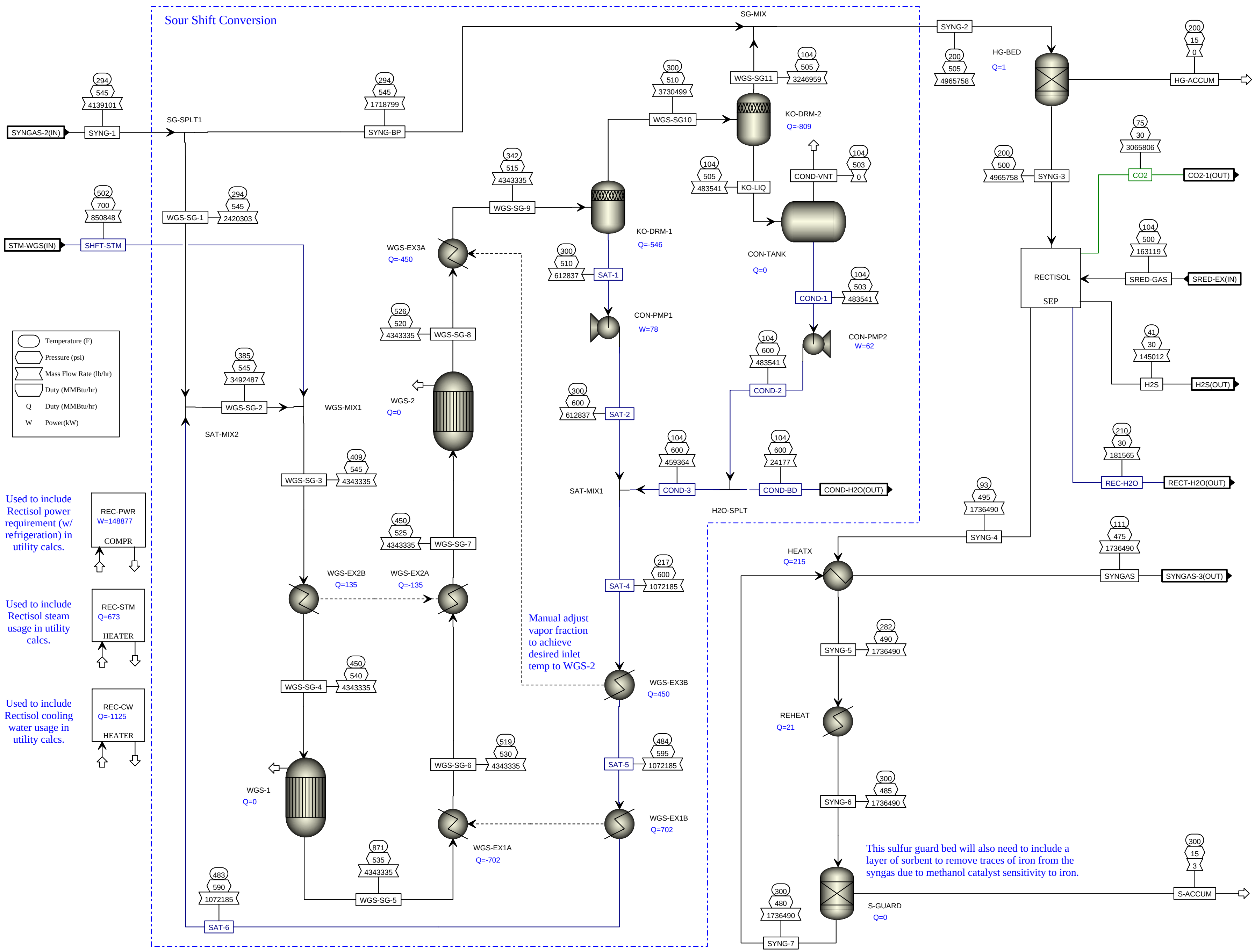
Coal Milling & Drying



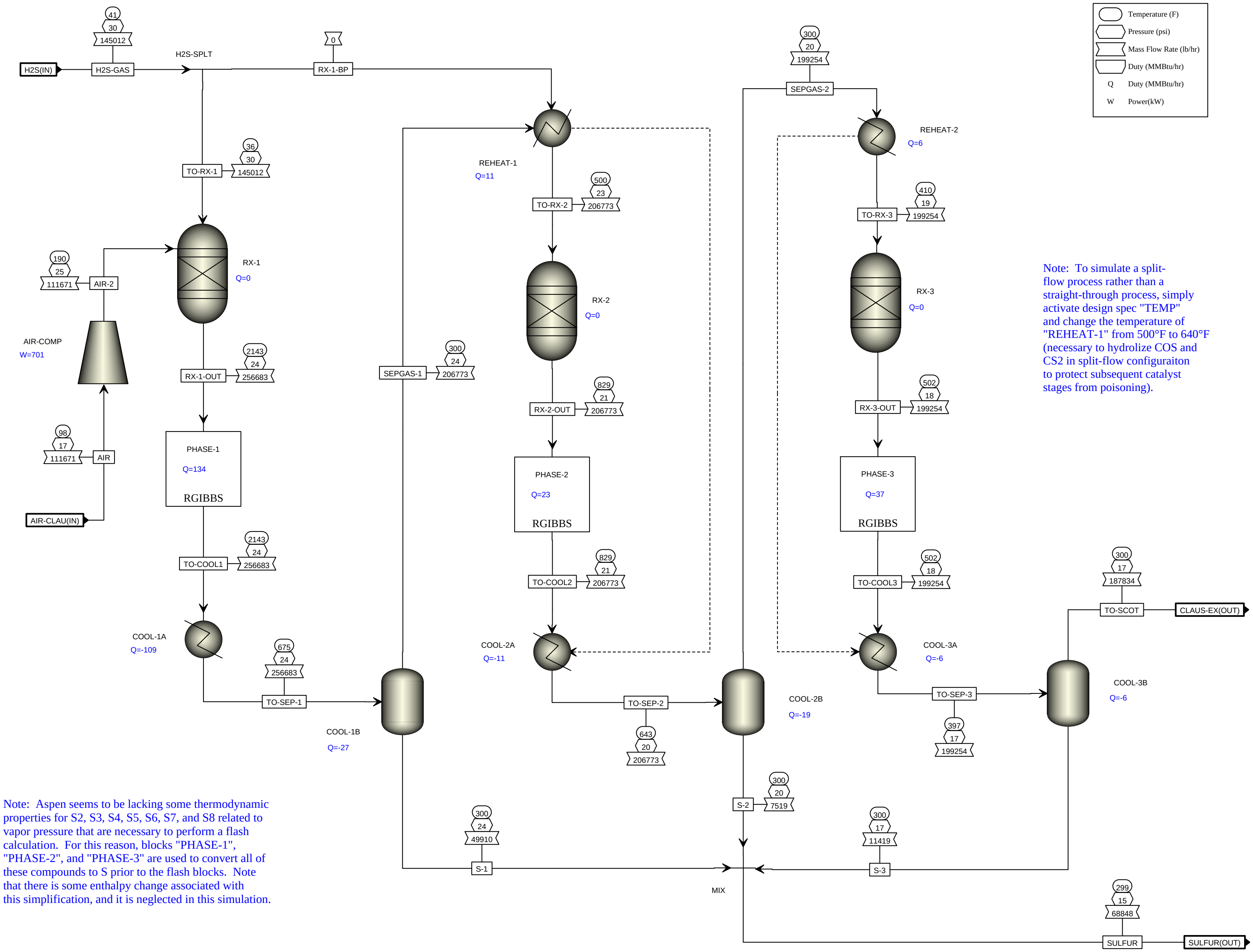
Dry-Fed Gasifier w/ Heat Recovery



Syngas Cleaning & Conditioning



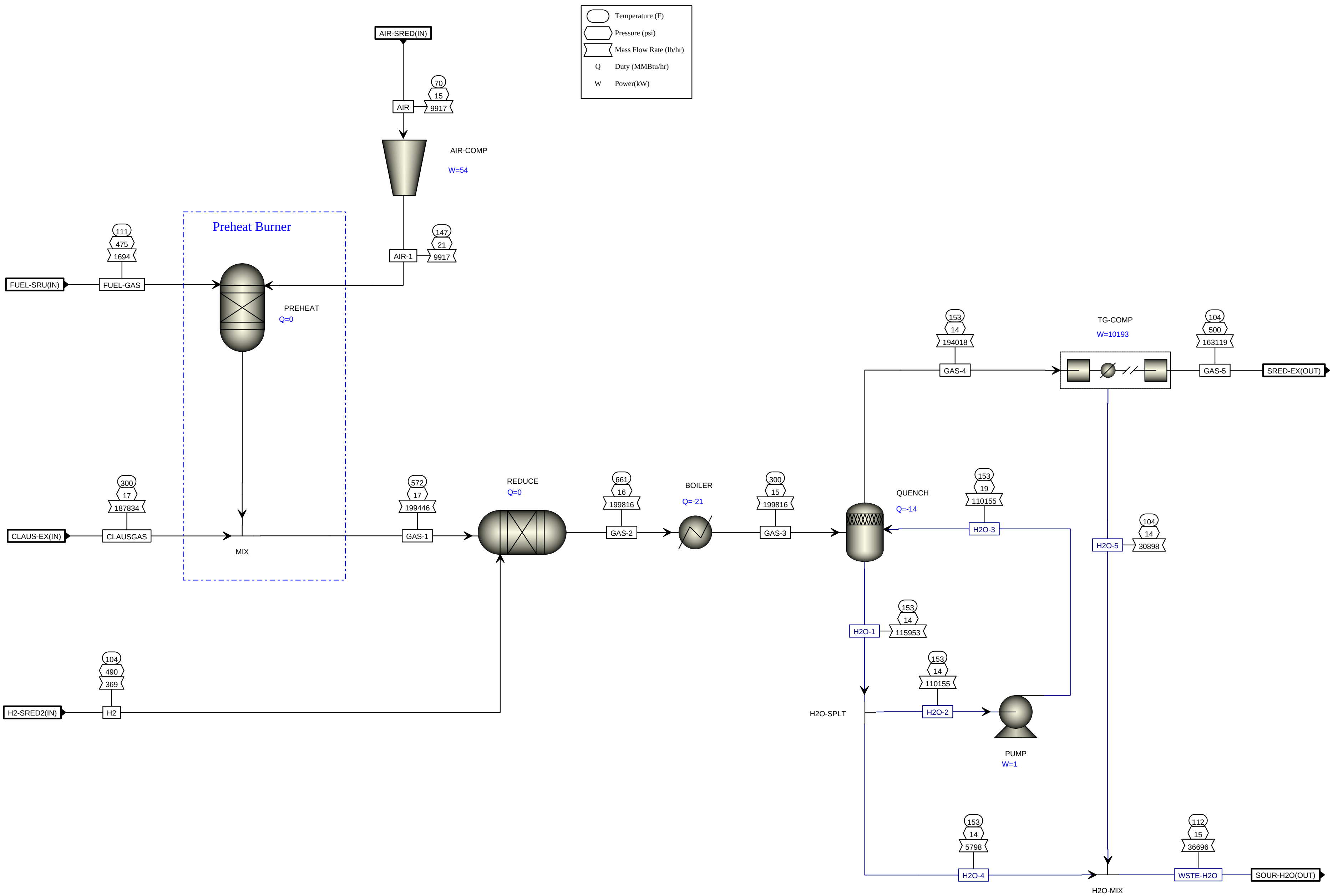
Claus Process



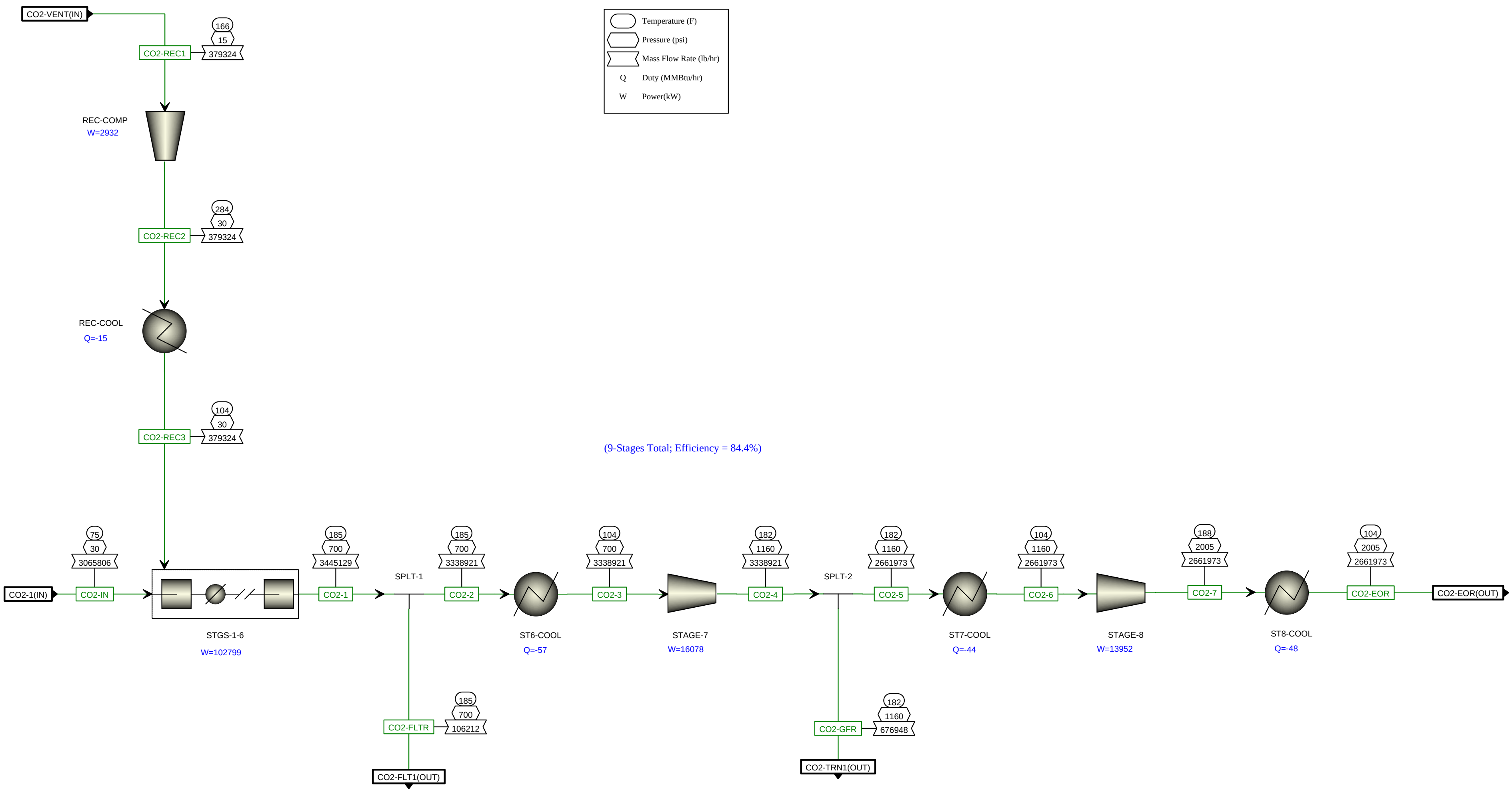
Note: To simulate a split-flow process rather than a straight-through process, simply activate design spec "TEMP" and change the temperature of "REHEAT-1" from 500°F to 640°F (necessary to hydrolize COS and CS2 in split-flow configuraiton to protect subsequent catalyst stages from poisoning).

Note: Aspen seems to be lacking some thermodynamic properties for S2, S3, S4, S5, S6, S7, and S8 related to vapor pressure that are necessary to perform a flash calculation. For this reason, blocks "PHASE-1", "PHASE-2", and "PHASE-3" are used to convert all of these compounds to S prior to the flash blocks. Note that there is some enthalpy change associated with this simplification, and it is neglected in this simulation.

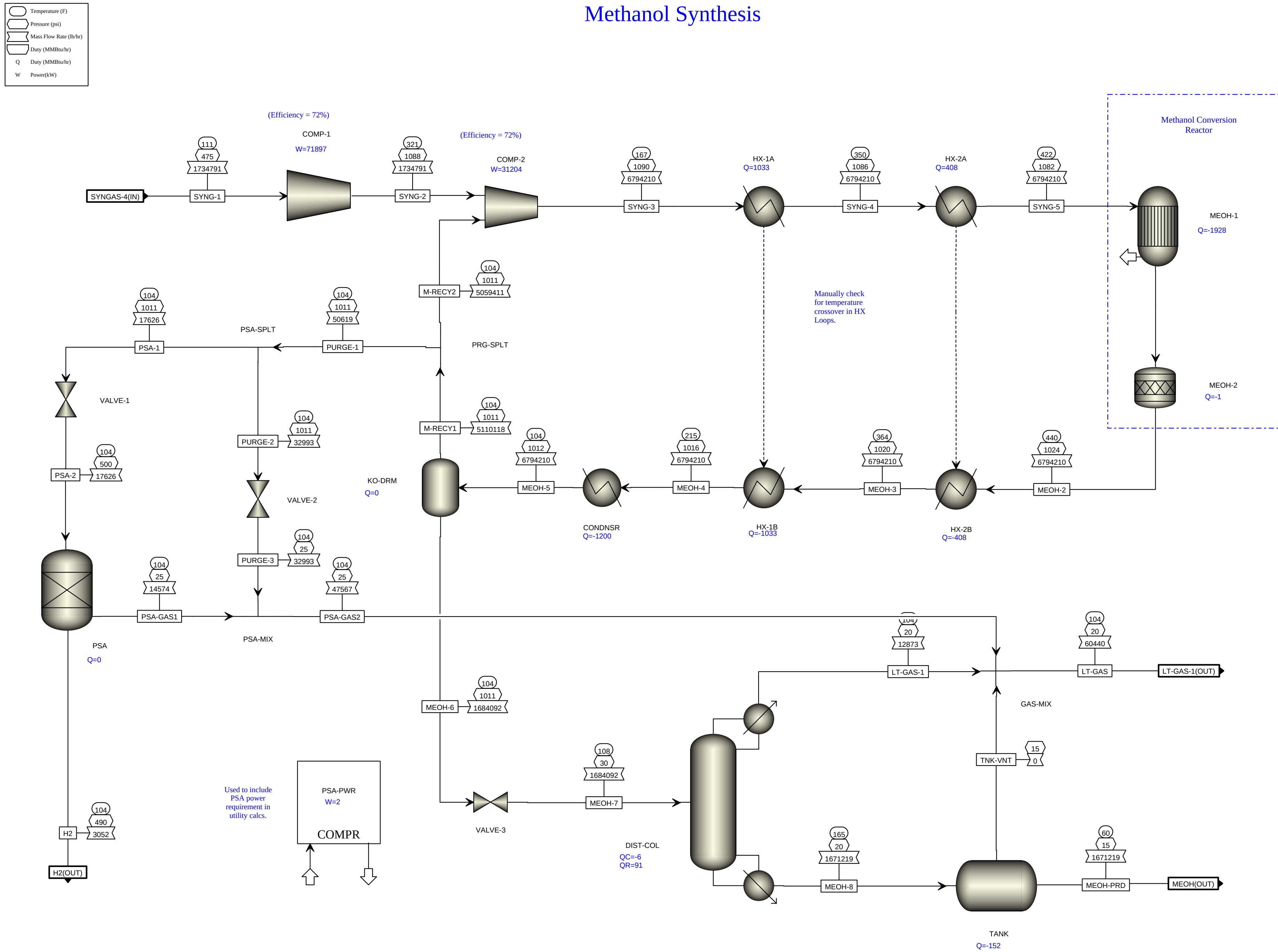
Catalytic Sulfur Reduction (SCOT or Beavon Process w/o H2S Absorber)



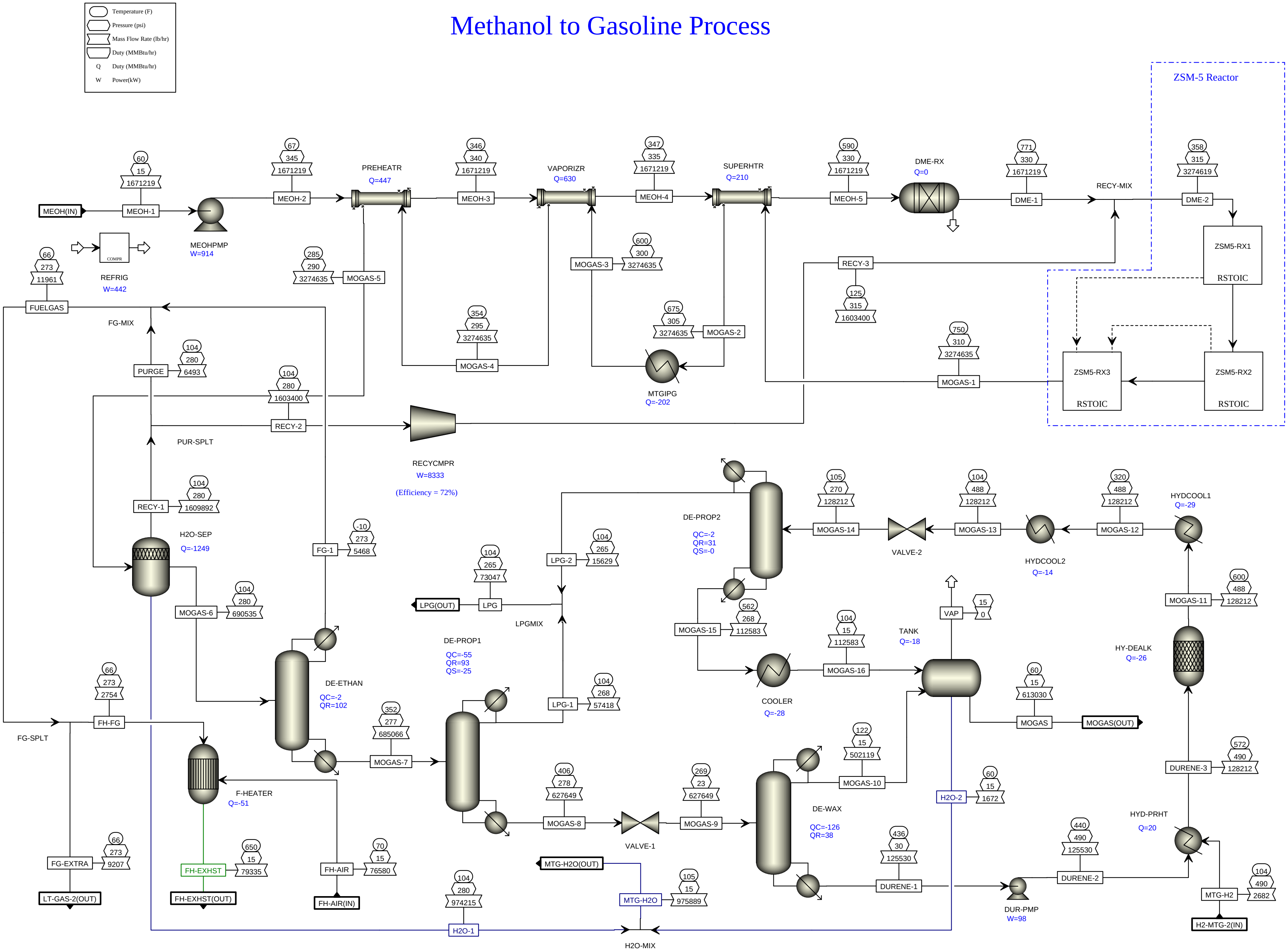
CO2 Compression



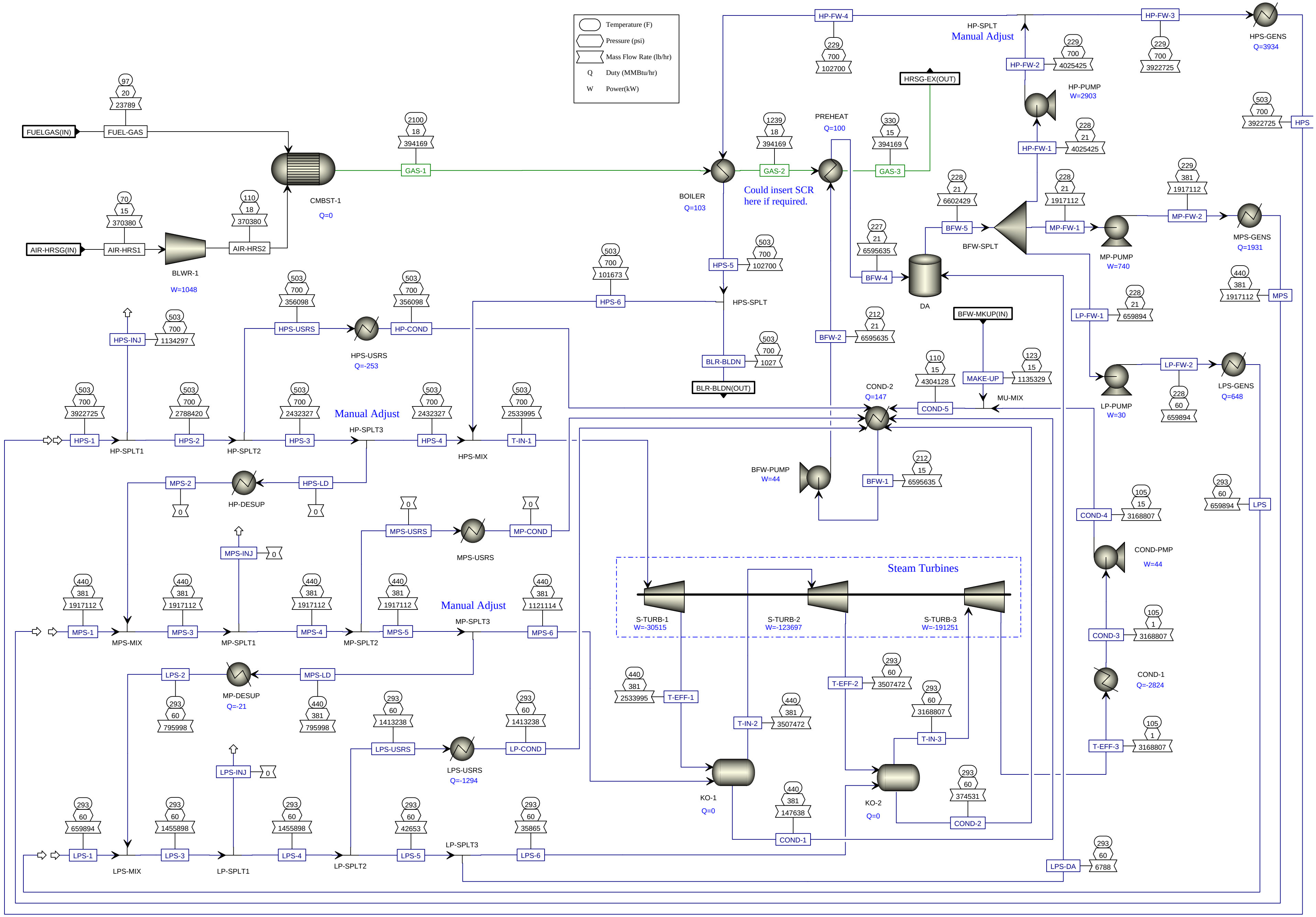
Methanol Synthesis



Methanol to Gasoline Process

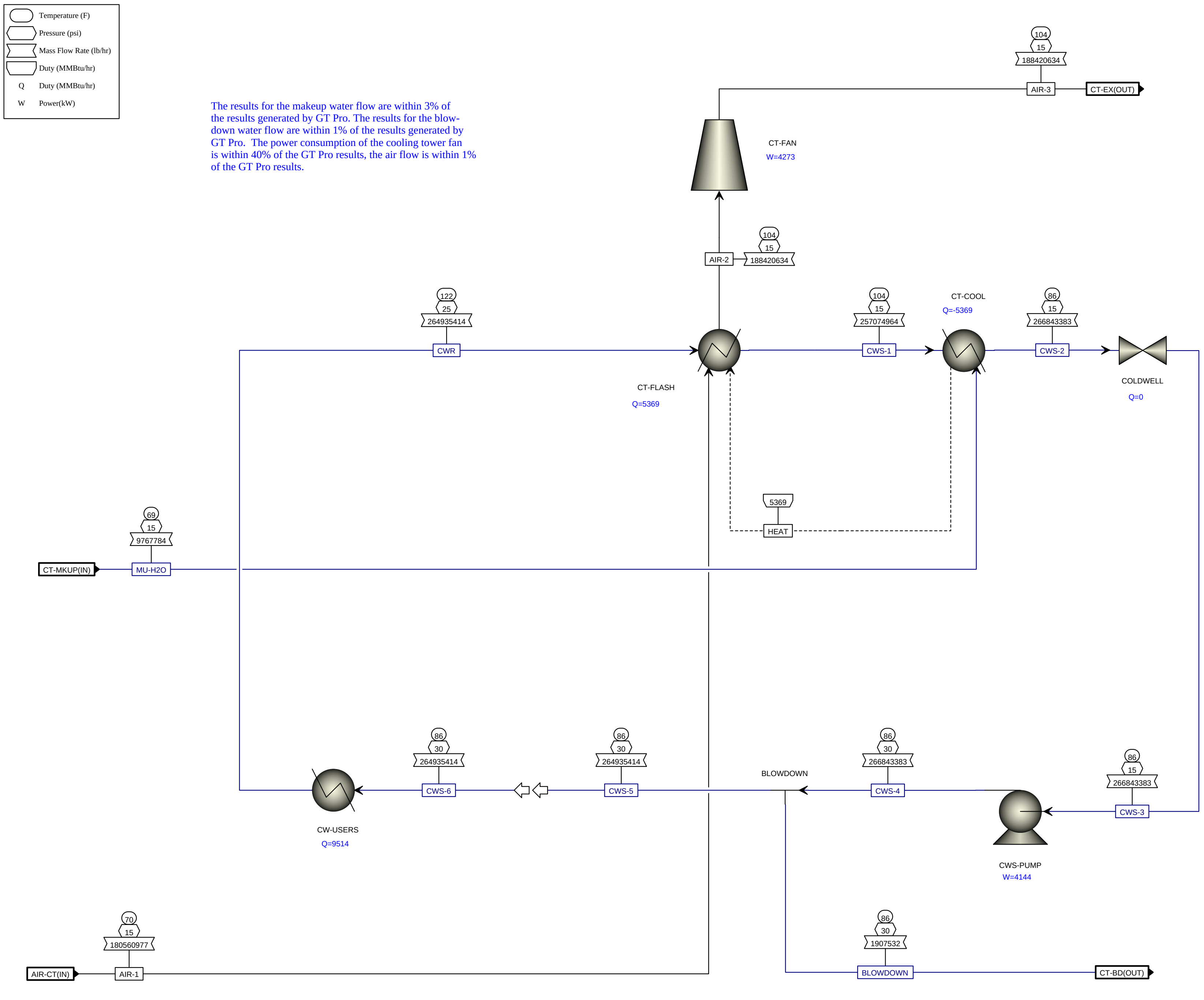


HRSG & Steam Turbines

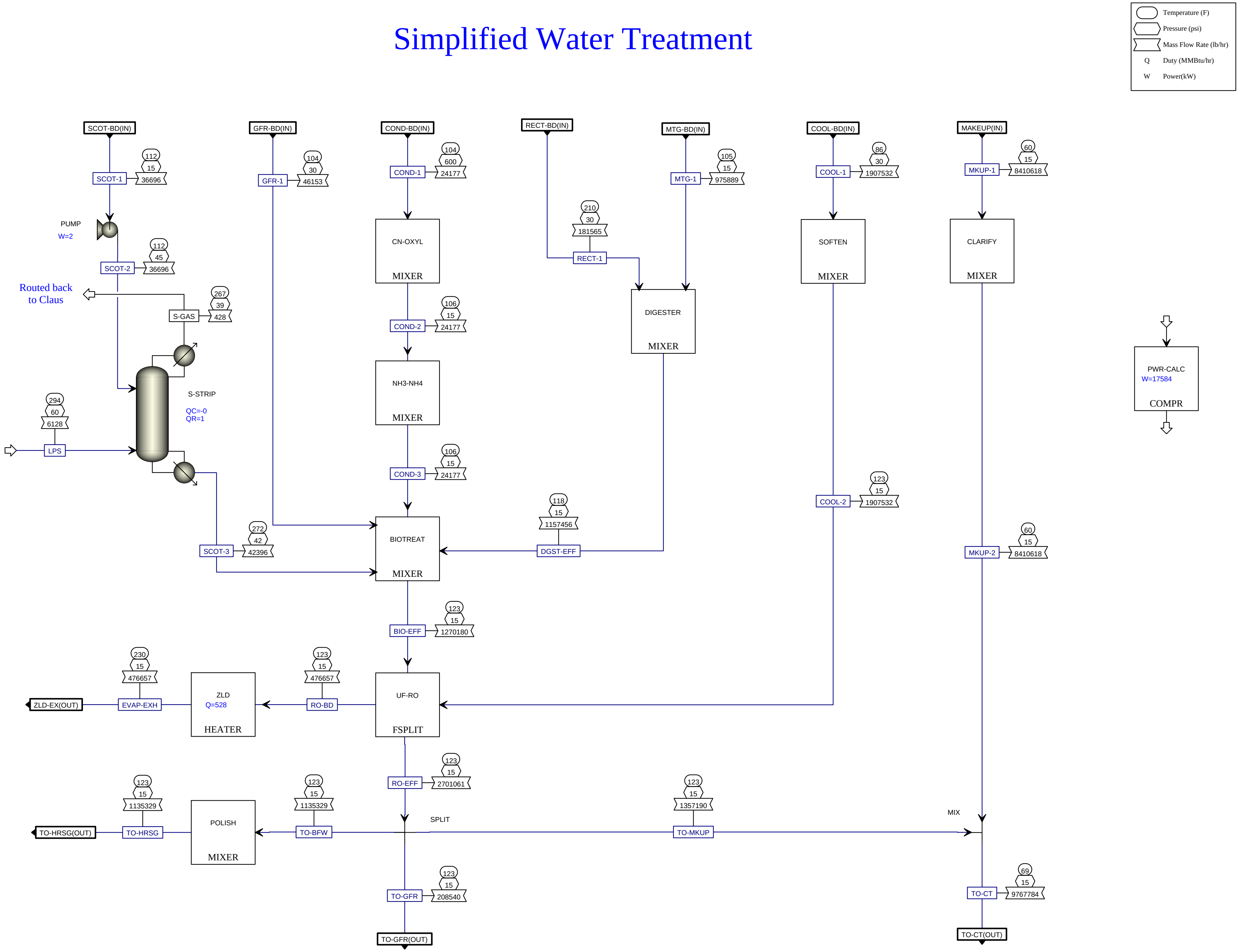


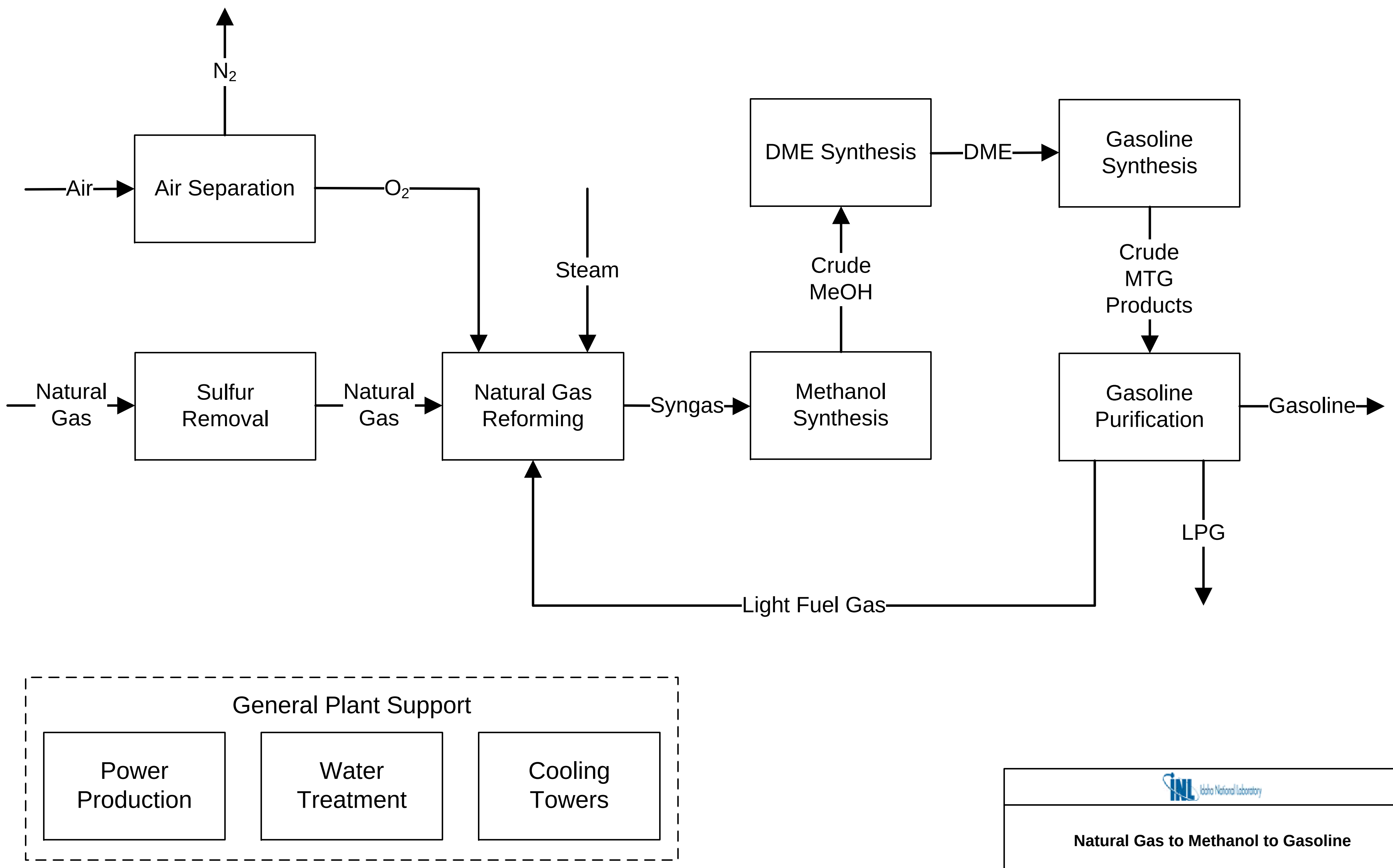
Cooling Tower

The results for the makeup water flow are within 3% of the results generated by GT Pro. The results for the blow-down water flow are within 1% of the results generated by GT Pro. The power consumption of the cooling tower fan is within 40% of the GT Pro results, the air flow is within 1% of the GT Pro results.



Simplified Water Treatment



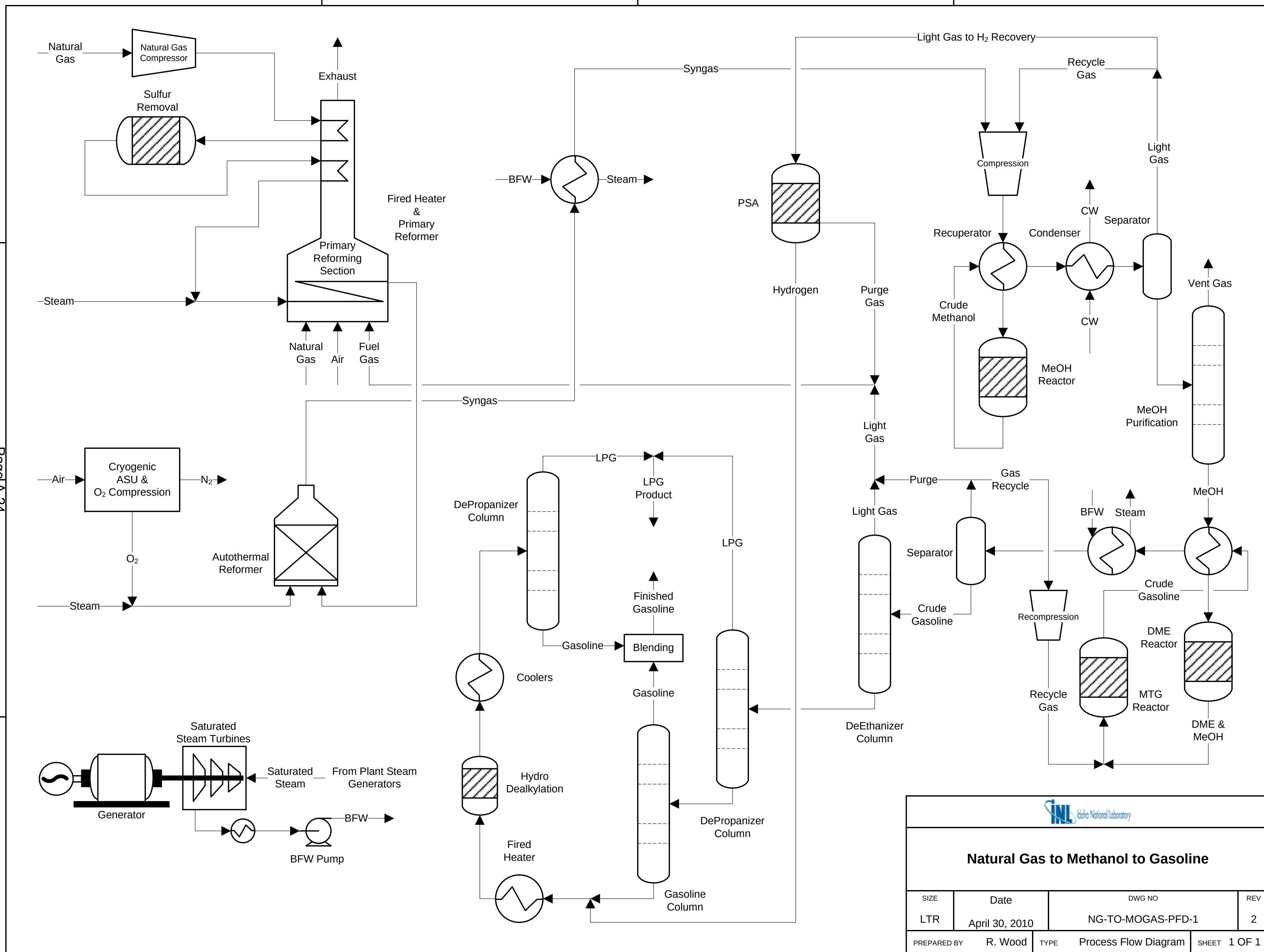


Idaho National Laboratory

Natural Gas to Methanol to Gasoline

SIZE	Date	DWG NO	REV
LTR	April 30, 2010	NG-TO-MOGAS-BFD-1	2

PREPARED BY	R. Wood	TYPE	Block Flow Diagram	SHEET	1 OF 1


Natural Gas
Natural Gas Compressor
Exhaust
Sulfur Removal
Fired Heater & Primary Reformer
Primary Reforming Section
Steam
Natural Gas
Air
Fuel Gas
Syngas
BFW
Steam
Light Gas to H_2 Recovery
Recycle Gas
PSA
Compression
Light Gas
Recuperator
Condenser
CW
Separator
Hydrogen
Purge Gas
Crude Methanol
MeOH Reactor
Vent Gas
MeOH Purification
Light Gas
Air
Cryogenic ASU & O_2 Compression
N_2
O_2
Autothermal Reformer
Steam
LPG
LPG Product
DePropanizer Column
Finished Gasoline
Gasoline
Blending
Coolers
Purge
Gas Recycle
Light Gas
BFW
Steam
MeOH
Separator
Crude Gasoline
Recompression
Crude Gasoline
DME Reactor
MTG Reactor
Recycle Gas
DeEthanizer Column
DME & MeOH
Saturated Steam Turbines
Saturated Steam
From Plant Steam Generators
Generator
BFW
BFW Pump
Hydro Dealkylation
Fired Heater
DePropanizer Column
Gasoline Column
Idaho National Laboratory
Natural Gas to Methanol to Gasoline
SIZE
LTR
Date
April 30, 2010
DWG NO
NG-TO-MOGAS-PFD-1
REV
2
PREPARED BY
R. Wood
TYPE
Process Flow Diagram
SHEET
1 OF 1

Conventional Natural Gas to MTG Results

Calculator Block SUMMARY

FEED SUMMARY:

NATURAL GAS PROPERTIES:

MASS FLOW =	6538. TON/DY
VOLUME FLOW =	288. MMSCFD @ 60°F
HHV =	23063. BTU/LB
HHV =	1047. BTU/SCF @ 60°F
ENERGY FLOW =	301569. MMBTU/DY

COMPOSITION:

METHANE =	93.571 MOL.%
ETHANE =	3.749 MOL.%
PROPANE =	0.920 MOL.%
BUTANE =	0.260 MOL.%
PENTANE =	0.040 MOL.%
HEXANE =	0.010 MOL.%
NITROGEN =	1.190 MOL.%
OXYGEN =	0.010 MOL.%
CO2 =	0.250 MOL.%
C4H10S =	1. PPMV
C2H6S =	0. PPMV
H2S =	0. PPMV

PRODUCT SUMMARY:

INTERMEDIATE PRODUCTS:

METHANOL MASS FLOW =	918624. LB/HR
METHANOL MASS FLOW =	11023. TON/DY
METHANOL PURITY =	99.85 WT.%
METHANOL PRODUCED / NAT. GAS FED =	1.69 LB/LB

FINAL PRODUCTS:

GASOLINE PRODUCT:

GASOLINE VOLUME FLOW =	33471. BBL/DY
GASOLINE MASS FLOW =	355601. LB/HR
GASOLINE MASS FLOW =	4267. TON/DY
GASOLINE LHV FLOW =	158906. MMBTU/DY
GASOLINE PRODUCED / METHANOL FED =	0.39 LB/LB
GASOLINE PRODUCED / NAT. GAS FED =	0.65 LB/LB

LPG PRODUCT:

LPG VOLUME FLOW =	5278. BBL/DY
LPG MASS FLOW =	42368. LB/HR
LPG MASS FLOW =	508. TON/DY
LPG LHV FLOW =	19891. MMBTU/DY
LPG PRODUCED / METHANOL FED =	0.05 LB/LB
LPG PRODUCED / NAT. GAS FED =	0.08 LB/LB

POWER SUMMARY:

ELECTRICAL GENERATORS:

STEAM TURBINE POWER GENERATION =	62.6 MW
GENERATOR SUBTOTAL =	62.6 MW

ELECTRICAL CONSUMERS:

NG REFORMER POWER CONSUMPTION =	13.8 MW
ASU POWER CONSUMPTION =	75.1 MW

Conventional Natural Gas to MTG Results

```
    POWER BLOCK POWER CONSUMPTION =        2.8 MW
    MEOH SYNTHESIS POWER CONSUMPTION =    49.1 MW
    MTG POWER CONSUMPTION =                5.7 MW
    COOLING TOWER POWER CONSUMPTION =      3.6 MW
    WATER TREATMENT POWER CONSUMPTION =   10.0 MW
  CONSUMER SUBTOTAL =                    160.1 MW

  NET PLANT POWER CONSUMPTION =           97.5 MW


WATER BALANCE:

  EVAPORATIVE LOSSES:
    COOLING TOWER EVAPORATION =         7419.8 GPM
    ZLD SYSTEM EVAPORATION =             640.7 GPM
  TOTAL EVAPORATIVE LOSSES =            8060.5 GPM

  WATER CONSUMED:
    BOILER FEED WATER MAKEUP =          1865.3 GPM
    COOLING TOWER MAKEUP =              7946.2 GPM
  TOTAL WATER CONSUMED =                9811.5 GPM

  WATER GENERATED:
    NG REFORMER PROCESS WATER =         1437.7 GPM
    MEOH PROCESS WATER =                 252.6 GPM
    MTG PROCESS WATER =                 1029.7 GPM
    COOLING TOWER BLOWDOWN =            1551.4 GPM
  TOTAL WATER GENERATED =               4271.4 GPM

  PLANT WATER SUMMARY:
    NET MAKEUP WATER REQUIRED =         6180.9 GPM
    WATER CONSUMED / LIQUID PRODUCED =     5.47 BBL/BBL


CARBON BALANCE:

  CARBON INPUTS:
    NATURAL GAS =                       4817. TPD CARBON
    COMBUSTION AIR =                       2. TPD CARBON
  TOTAL CARBON INPUT =                  4819. TPD CARBON

  CARBON OUTPUTS:
    MOGAS PRODUCT =                     3654. TPD CARBON
    LPG PRODUCT =                        414. TPD CARBON
    REFORMER EMISSIONS =                 752. TPD CARBON
  TOTAL CARBON OUTPUT =                 4819. TPD CARBON

  CARBON SUMMARY:
    CARBON TO FUEL =                      84.4 % OF TOTAL INPUT
    CARBON EMITTED =                      15.6 % OF TOTAL INPUT
    CO2 EMISSIONS =                     2755. TPD CO2
    CO2 TO SMR =                        2755. TPD CO2
      LHV TO SMR =                     46972. MMBTU/DY

STARTUP FLARE SUMMARY:

  CO2 FROM FLARE =                        91. TON/DY
  LHV TO FLARE =                        1399. MMBTU/DY
```

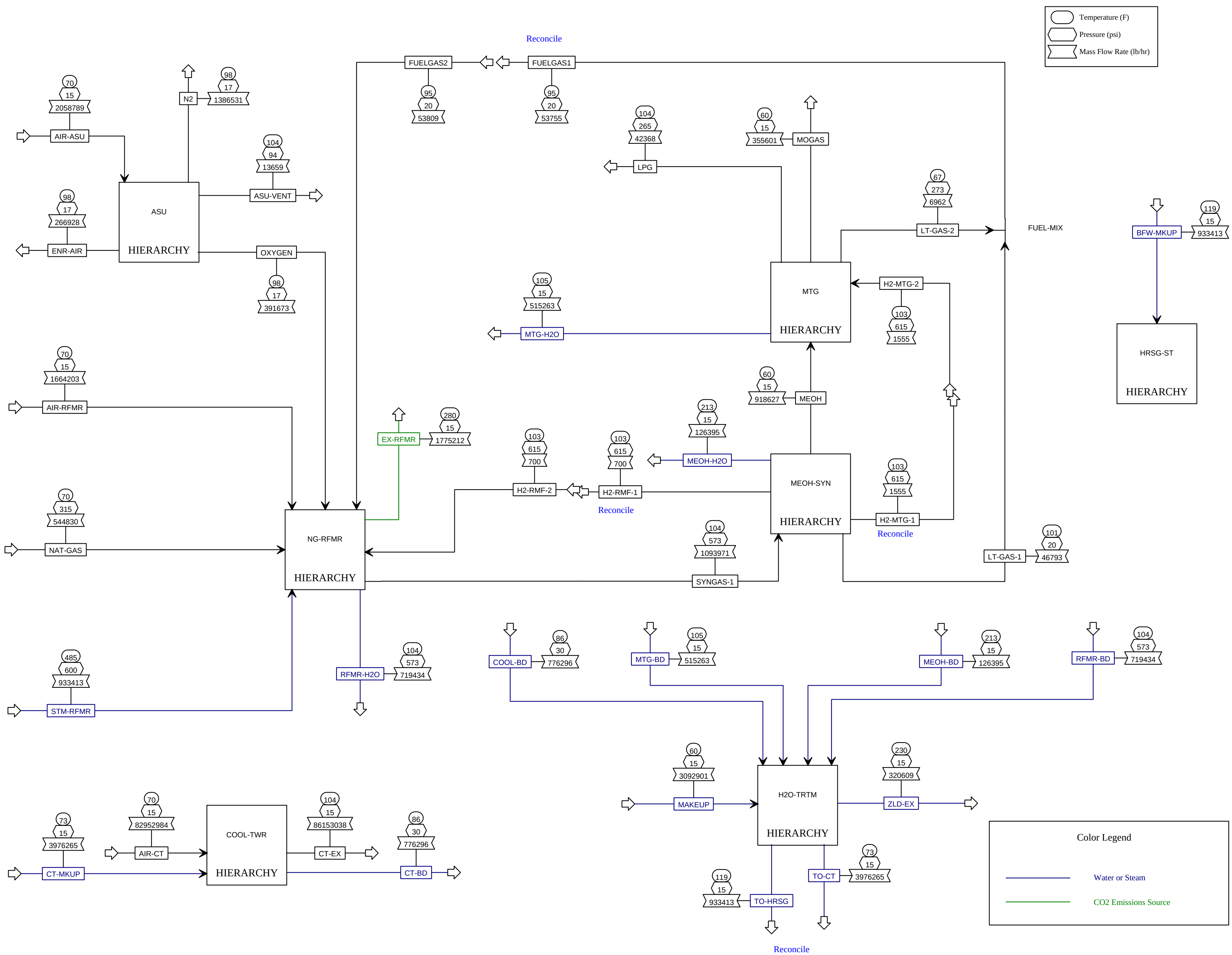
Calculator Block AIRPROPS

```
HUMIDITY DATA FOR STREAM AIR-ASU:
  HUMIDITY RATIO =                        43.5 GRAINS/LB
```

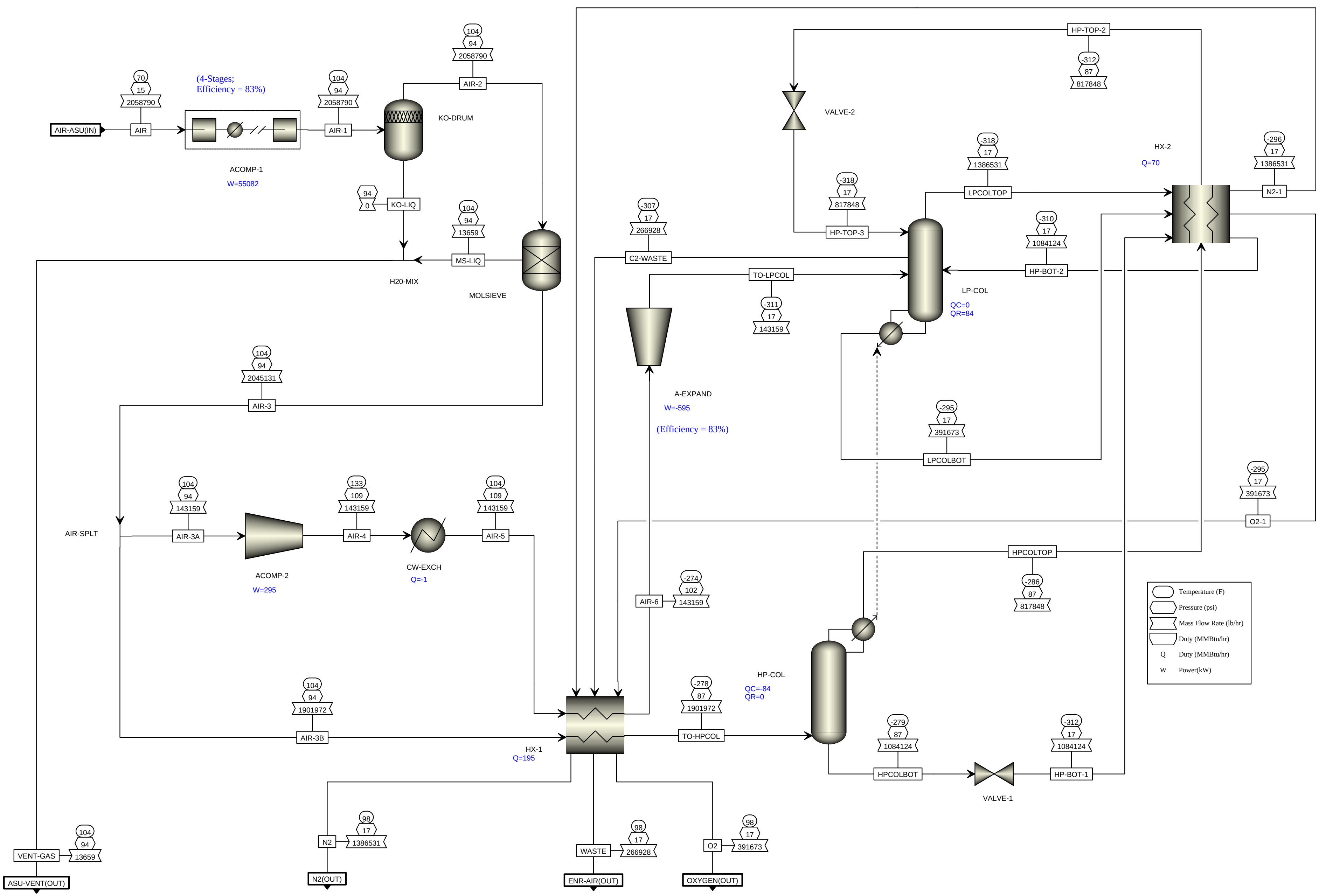
```
   RELATIVE HUMIDITY =                    39.0 %


Calculator Block MEOH-SYN Hierarchy: MEOH-SYN

   MEOH SYNTHESIS FEED GAS QUALITY:

     (H2 - CO2) / (CO + CO2)
       TARGET =                             2.10
       ACTUAL =                             2.101

     H2 / (2 CO + 3 CO2)
       TARGET =                             1.05
       ACTUAL =                             1.045

     H2 / CO
       ACTUAL =                             3.101

   MEOH SYNTHESIS OPERATING PARAMETERS:

     MOLAR RECYCLE RATIO
       TARGET =                       3.0 - 4.0
       ACTUAL =                             4.00

     REACTOR INLET CO2 CONCENTRATION
       TARGET =                           < 4.0 MOL.%
       ACTUAL =                             2.53 MOL.%

     REACTOR OUTLET MEOH CONCENTRATION
       TARGET =                       3.0 - 8.0 MOL.%
       ACTUAL =                             7.13 MOL.%

     METHANOL PRODUCT CO2 CONCENTRATION
       TARGET =                           500. PPBW
       ACTUAL =                           500. PPBW


Calculator Block MTG      Hierarchy: MTG

   YIELD SUMMARY (LB / 1,000 LB MEOH):

     PRODUCT                     EXXON LIT.   MODEL RESULT

     GASOLINE                     387.          386.
     LPG                           46.           46.
     FUEL GAS                       7.            8.
     WATER                        560.          560.

   PRODUCT SUMMARY:

     GASOLINE PRODUCT:
       PRODUCTION RATE =              355601. LB/HR
       PRODUCTION RATE =               33471. BBL/DAY
       MOLECULAR WEIGHT =                 94.5
       CARBON PERCENT =                   85.6
       HIGHER HEAT CONTENT =           19941. BTU/LB
       LOWER HEAT CONTENT =            18619. BTU/LB

       PROPERTY COMPARISON:
         PROPERTY                EXXON LIT.   MODEL RESULT

         API GRAVITY, °            61.8          62.9
         SPECIFIC GRAVITY           0.732         0.728
         REED VAPOR PRES., PSI      9.0           8.7
```

```
    AROMATIC CONTENT, %        26.5          24.3
    OLEFIN CONTENT, %          12.6          16.4
    BENZENE CONTENT, %          0.3           0.5

    D86T 50%, °F              201.0         156.5
    D86T 90%, °F              320.0         332.2

  LPG PRODUCT:
    PRODUCTION RATE =                 42368. LB/HR
    PRODUCTION RATE =                  5278. BBL/DAY
    SPECIFIC GRAVITY =                    0.55
    MOLECULAR WEIGHT =                   50.0
    CARBON PERCENT =                     81.4
    HIGHER HEAT CONTENT =             21221. BTU/LB
    LOWER HEAT CONTENT =              19562. BTU/LB

  FUEL GAS PRODUCT:
    NET PRODUCTION RATE =              6962. LB/HR
    NET PRODUCTION RATE =                 4.87 MMSCFD @ 60°F
    MOLECULAR WEIGHT =                   13.0
    HIGHER HEAT CONTENT =             25637. BTU/LB


Calculator Block NG-RFMR  Hierarchy: NG-RFMR

   SULFUR REMOVAL CONDITIONS:

     INLET BED TEMPERATURE =              662. °F

   PRIMARY REFORMER CONDITIONS:

     INLET TEMPERATURE =                 1000. °F
     STEAM TO CARBON MOLAR RATIO =          1.80
     NATURAL GAS BURNED FOR HEAT =         10.50 %
     OUTLET TEMPERATURE =                1362. °F
     METHANE CONVERSION =                  25.1 %

   SECONDARY REFORMER CONDITIONS:

     INLET TEMPERATURE =                 1362. °F
     STEAM TO CARBON MOLAR RATIO =          1.27
     OXYGEN TO CARBON MOLAR RATIO =         0.41
     OUTLET TEMPERATURE =                1900. °F
     H2/CO =                                3.10
     (H2 - CO2)/(CO + CO2) =                2.10

     OUTLET COMPOSITION (PRE-CONDENSER):
       H2                                  48.4614 MOL.%
       CO                                  15.6260 MOL.%
       CO2                                  5.0437 MOL.%
       H2O                                 29.9746 MOL.%
       CH4                                  0.6028 MOL.%

     OUTLET COMPOSITION (POST-CONDENSER):
       H2                                  69.0745 MOL.%
       CO                                  22.2727 MOL.%
       CO2                                  7.1873 MOL.%
       H2O                                  0.2007 MOL.%
       CH4                                  0.8592 MOL.%
```

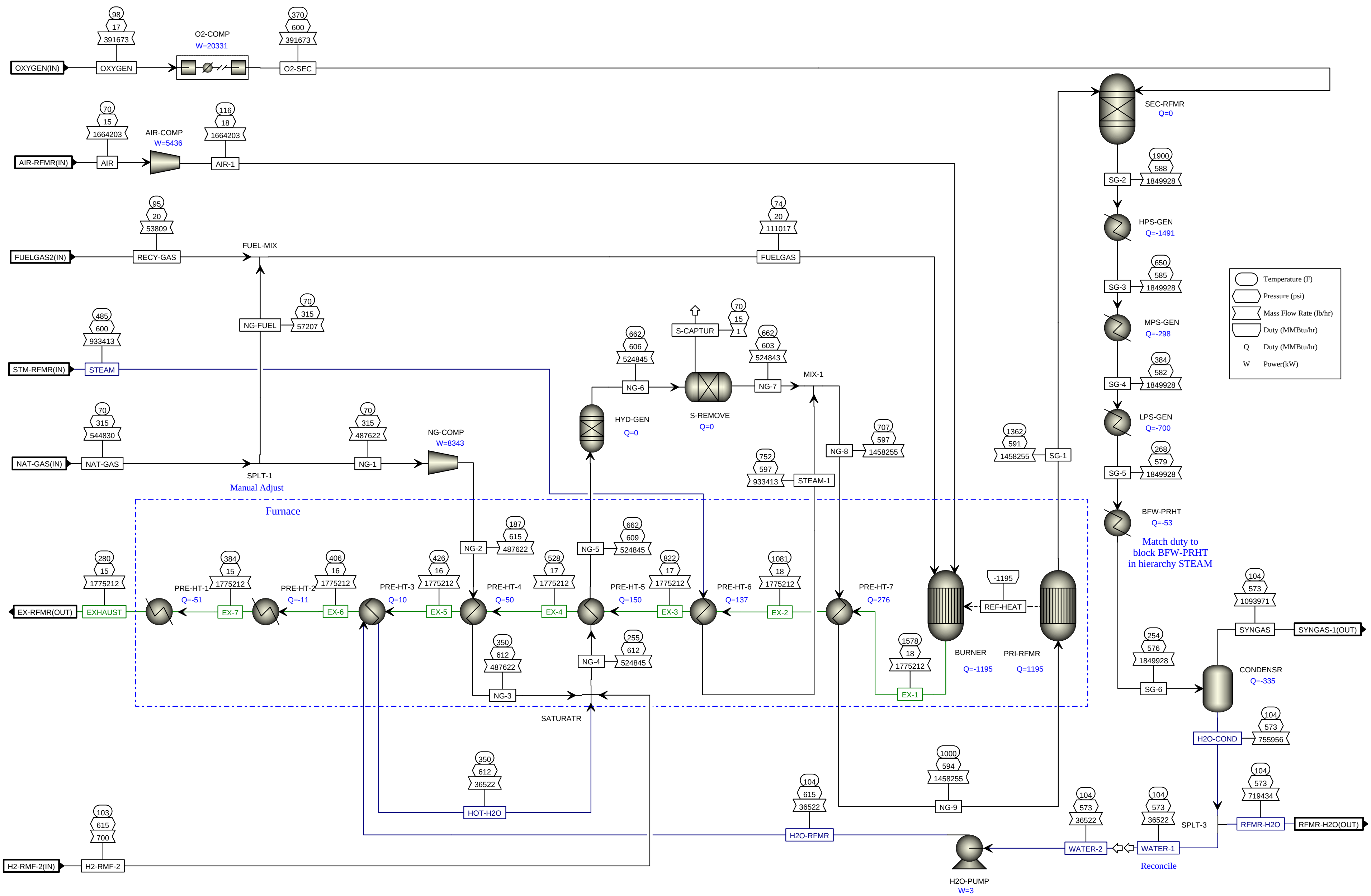
Natural Gas to Methanol to Gasoline Baseline



Air Separation Unit 99.5% O2 Purity

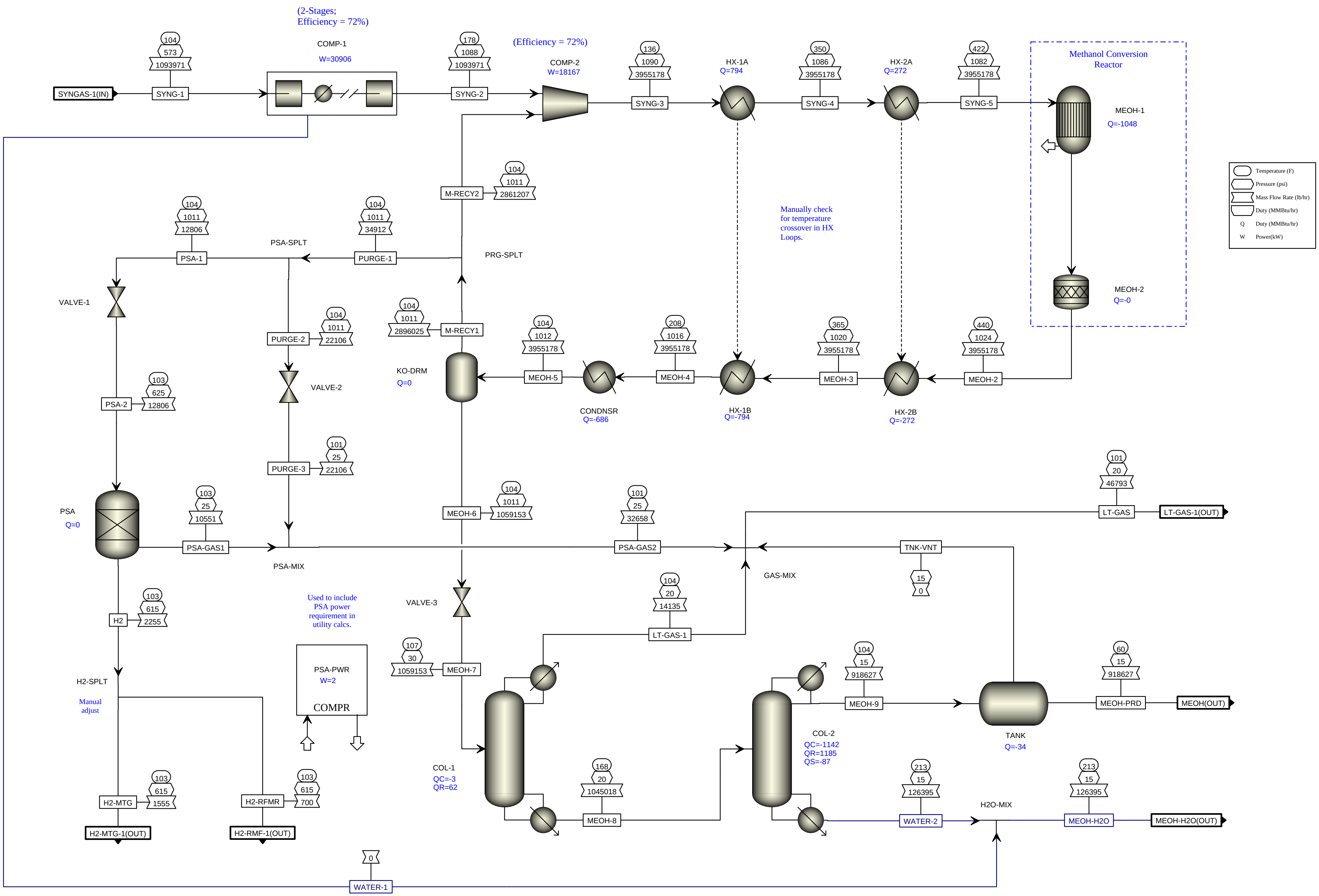


Natural Gas Two-Step Reforming

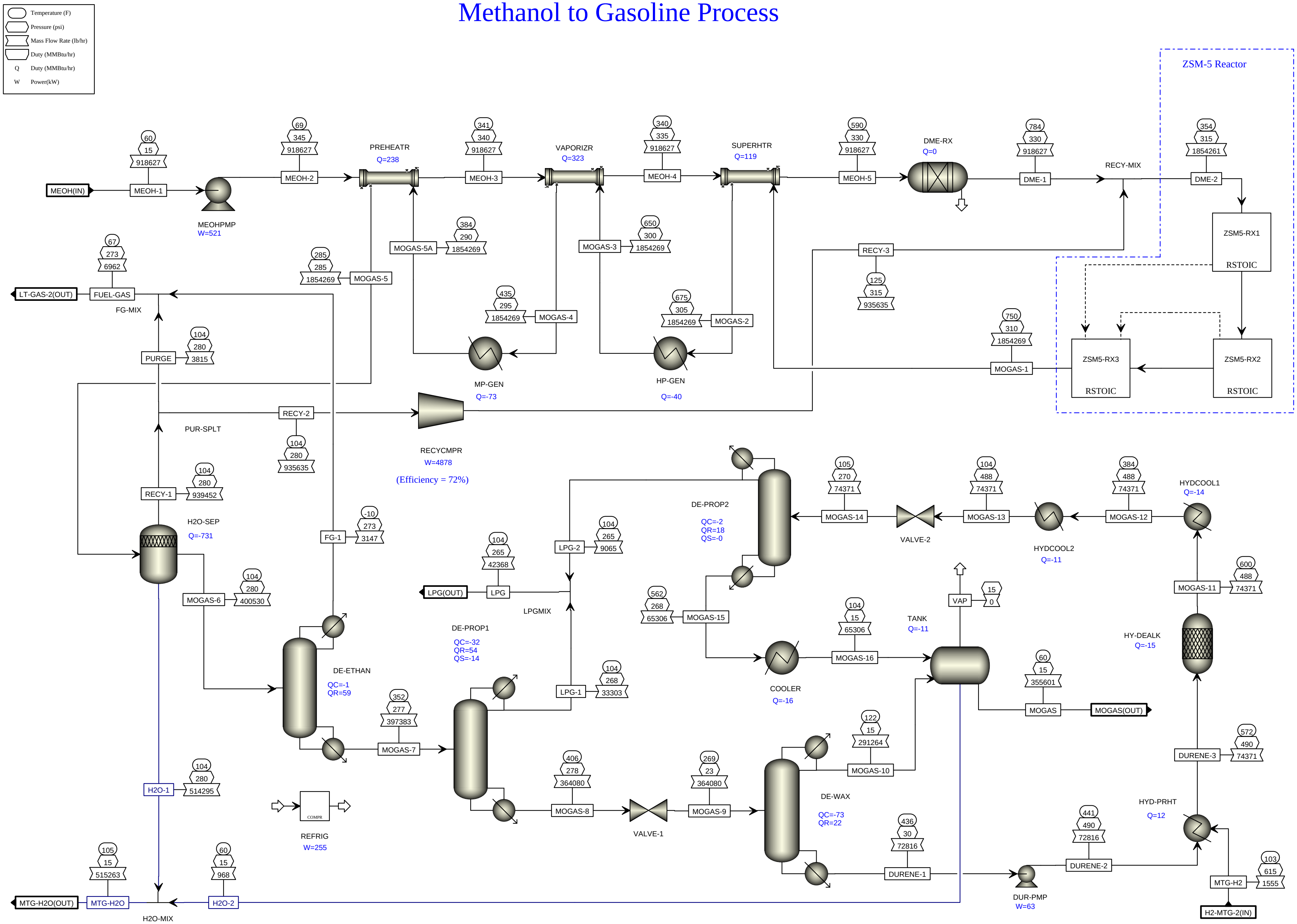


Page A-31

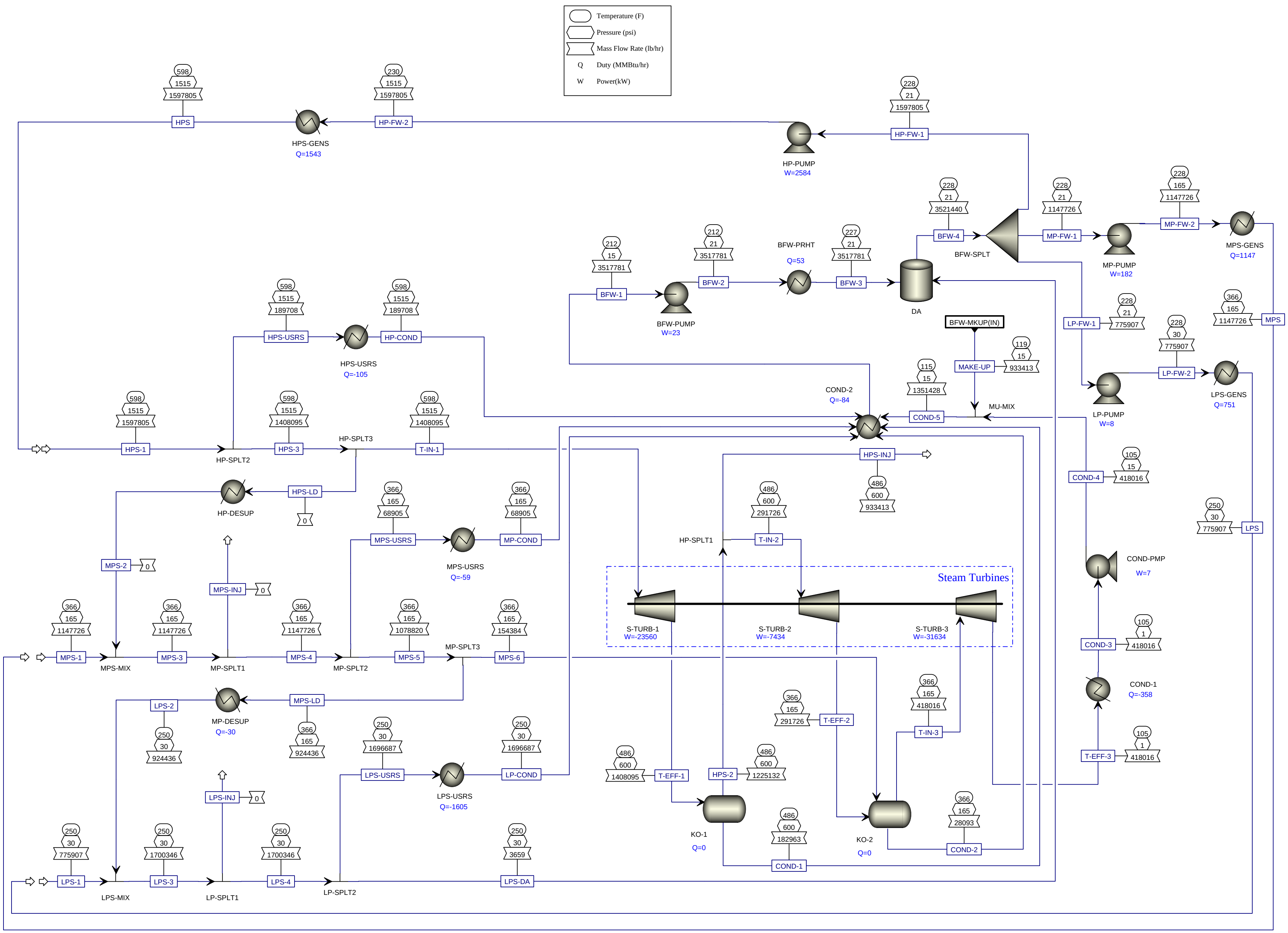
Methanol Synthesis



Methanol to Gasoline Process

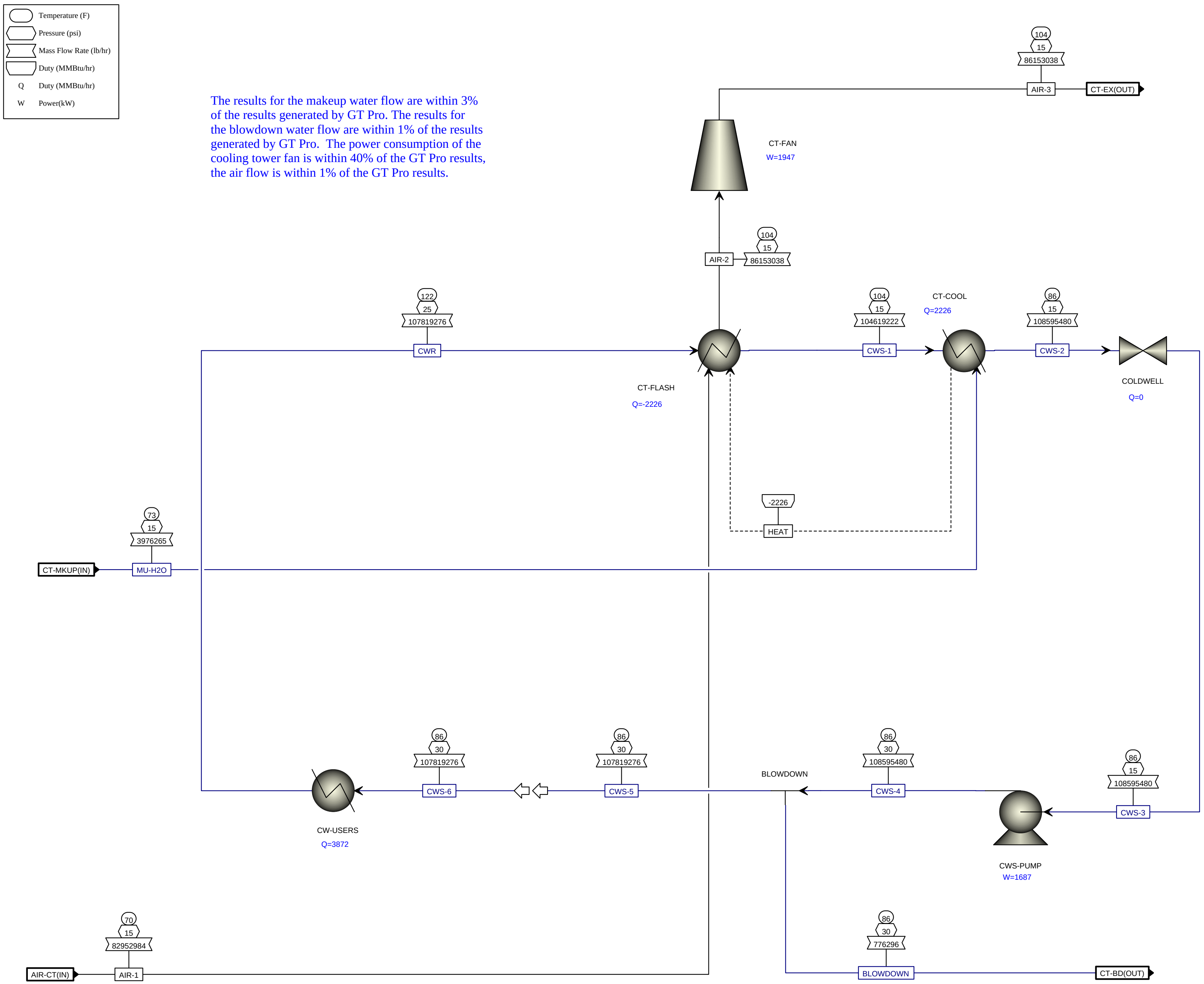


HRSG & Steam Turbines

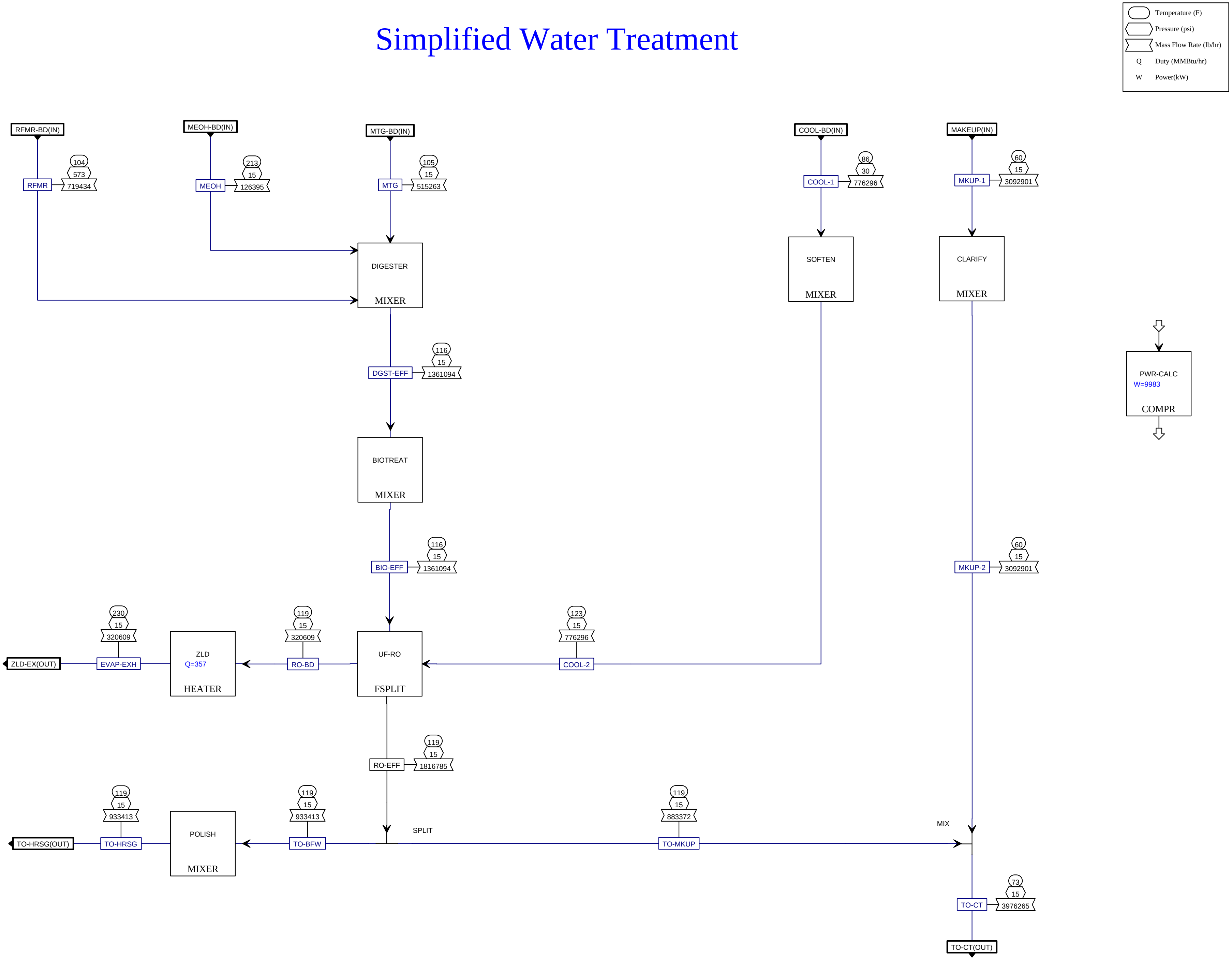


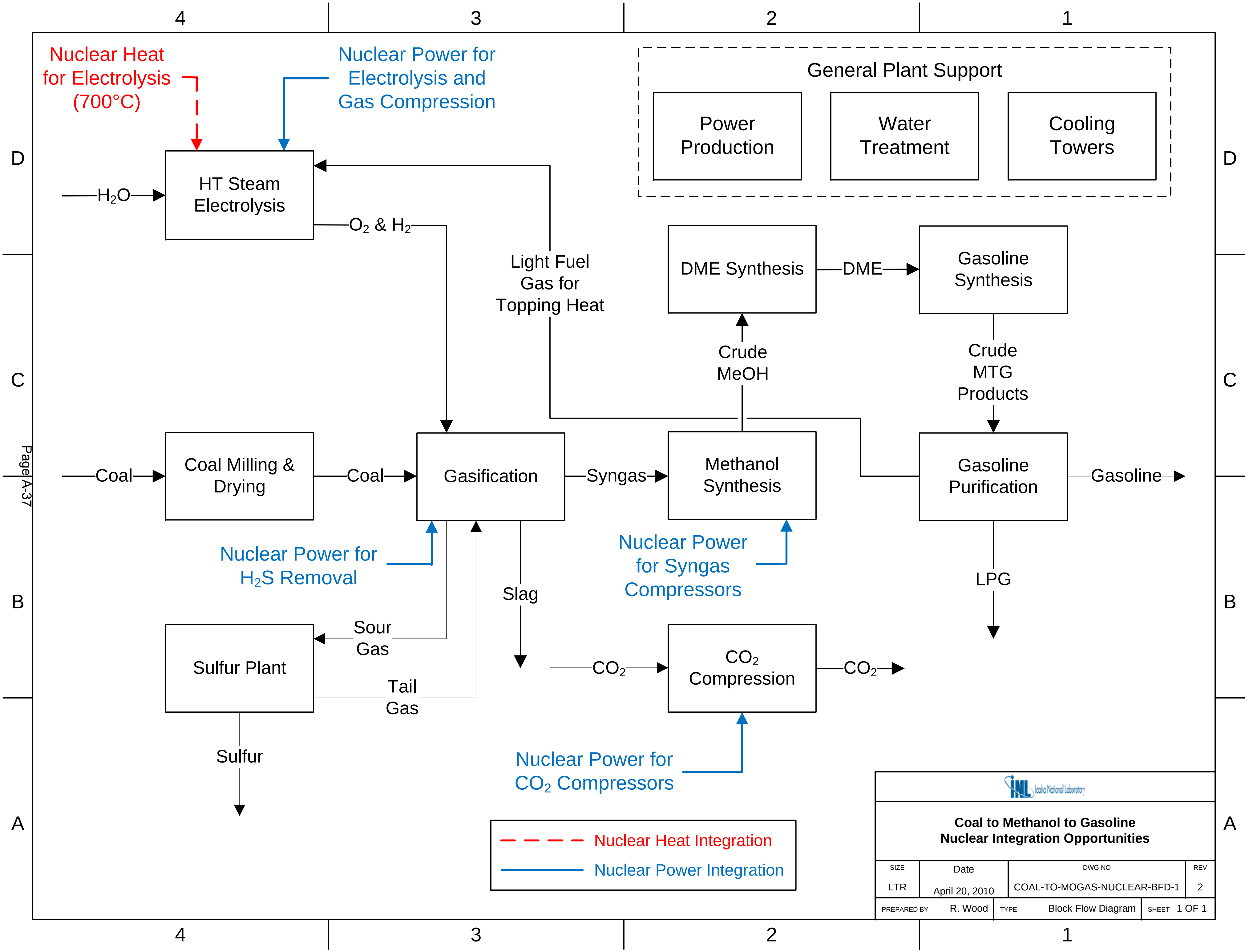
Cooling Tower

The results for the makeup water flow are within 3% of the results generated by GT Pro. The results for the blowdown water flow are within 1% of the results generated by GT Pro. The power consumption of the cooling tower fan is within 40% of the GT Pro results, the air flow is within 1% of the GT Pro results.

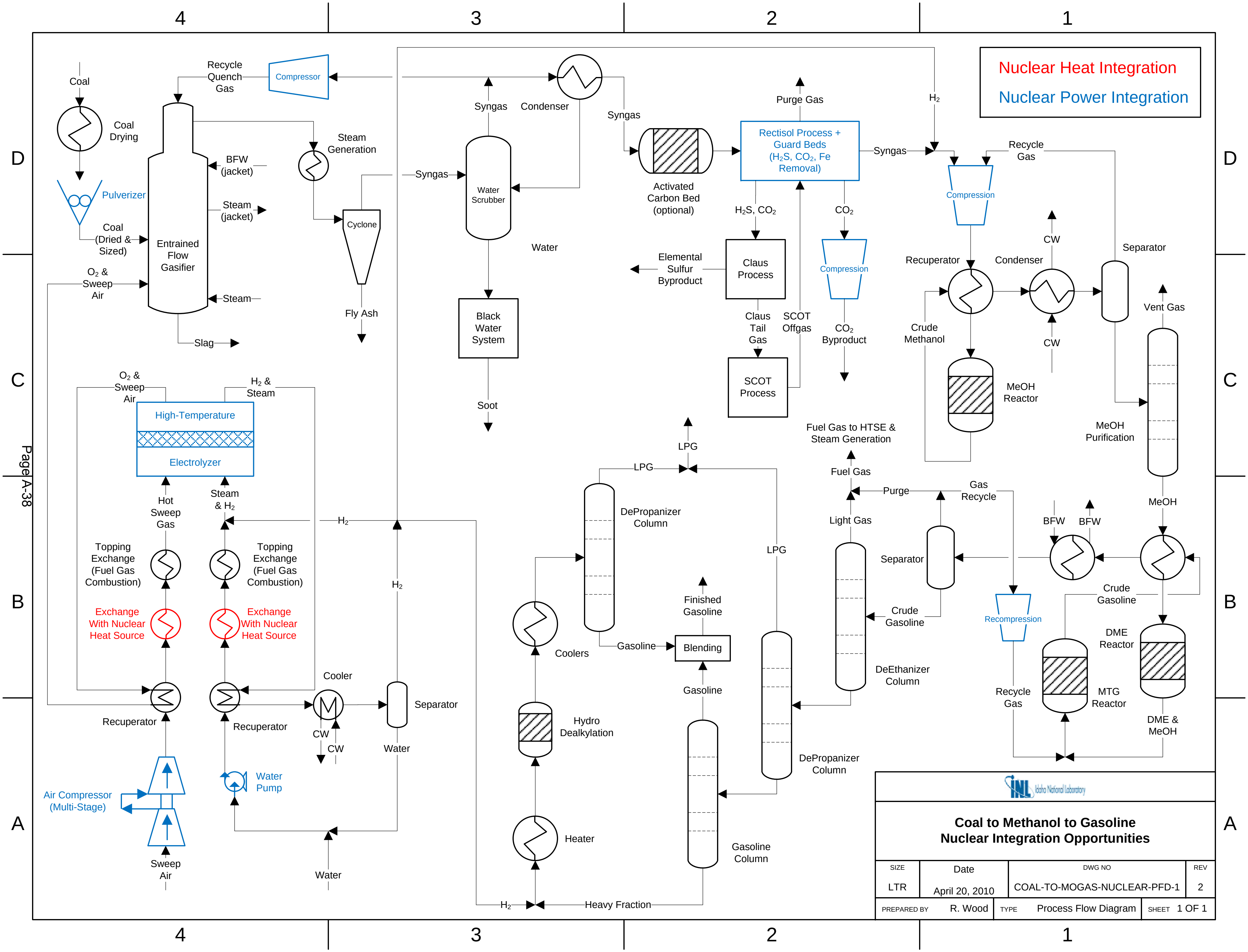


Simplified Water Treatment





Nuclear Heat for Electrolysis (700°C)
Nuclear Power for Electrolysis and Gas Compression
General Plant Support
Power Production
Water Treatment
Cooling Towers
H2O
HT Steam Electrolysis
O2 & H2
Light Fuel Gas for Topping Heat
DME Synthesis
DME
Gasoline Synthesis
Crude MeOH
Crude MTG Products
Coal
Coal Milling & Drying
Coal
Gasification
Syngas
Methanol Synthesis
Gasoline Purification
Gasoline
Nuclear Power for H2S Removal
Slag
Nuclear Power for Syngas Compressors
LPG
Sour Gas
Sulfur Plant
Tail Gas
CO2
CO2 Compression
CO2
Sulfur
Nuclear Power for CO2 Compressors
Nuclear Heat Integration
Nuclear Power Integration
Idaho National Laboratory
Coal to Methanol to Gasoline
Nuclear Integration Opportunities
SIZE LTR
Date April 20, 2010
DWG NO COAL-TO-MOGAS-NUCLEAR-BFD-1
REV 2
PREPARED BY R. Wood
TYPE Block Flow Diagram
SHEET 1 OF 1



Nuclear Heat Integration
Nuclear Power Integration
Coal
Coal Drying
Pulverizer
Coal (Dried & Sized)
O2 & Sweep Air
Recycle Quench Gas
Compressor
Entrained Flow Gasifier
BFW (jacket)
Steam (jacket)
Steam
Slag
Steam Generation
Cyclone
Fly Ash
Syngas
Condenser
Water Scrubber
Water
Black Water System
Soot
Activated Carbon Bed (optional)
Rectisol Process + Guard Beds (H2S, CO2, Fe Removal)
Purge Gas
H2S, CO2
CO2
Claus Process
Elemental Sulfur Byproduct
Claus Tail Gas
SCOT Offgas
SCOT Process
Compression
CO2 Byproduct
H2
Recycle Gas
Recuperator
CW
Separator
Crude Methanol
MeOH Reactor
Vent Gas
MeOH Purification
MeOH
High-Temperature Electrolyzer
H2 & Steam
Hot Sweep Gas
Steam & H2
Topping Exchange (Fuel Gas Combustion)
Exchange With Nuclear Heat Source
Air Compressor (Multi-Stage)
Sweep Air
Water Pump
Cooler
LPG
DePropanizer Column
Coolers
Gasoline
Blending
Finished Gasoline
Hydro Dealkylation
Heater
Heavy Fraction
Gasoline Column
Fuel Gas to HTSE & Steam Generation
Fuel Gas
Purge
Gas Recycle
Light Gas
Crude Gasoline
DeEthanizer Column
BFW
Recompression
DME Reactor
MTG Reactor
DME & MeOH
INL Idaho National Laboratory
Coal to Methanol to Gasoline
Nuclear Integration Opportunities
SIZE LTR
Date April 20, 2010
DWG NO COAL-TO-MOGAS-NUCLEAR-PFD-1
REV 2
PREPARED BY R. Wood
TYPE Process Flow Diagram
SHEET 1 OF 1

Calculator Block SUMMARY

FEED & PRODUCT SUMMARY:

FEEDS:

RAW COAL FEED RATE =	11844.6 TON/DY
COAL HHV AS FED =	10934. BTU/LB
COAL MOISTURE AS FED =	13.70 %
PROXIMATE ANALYSIS (DRY BASIS):	
MOISTURE	13.70 %
FIXED CARBON	40.12 %
VOLATILE MATTER	49.28 %
ASH	10.60 %
ULTIMATE ANALYSIS (DRY BASIS):	
ASH	10.60 %
CARBON	70.27 %
HYDROGEN	4.84 %
NITROGEN	1.36 %
CHLORINE	0.11 %
SULFUR	3.72 %
OXYGEN	9.10 %
SULFANAL ANALYSIS (DRY BASIS):	
PYRITIC	1.94 %
SULFATE	0.08 %
ORGANIC	1.70 %

INTERMEDIATES:

COAL FEED RATE AFTER DRYING =	10874.4 TON/DY
COAL HHV AFTER DRYING =	11910. BTU/LB
COAL MOISTURE AFTER DRYNG =	6.00 %
RAW SYNGAS MASS FLOW =	1735447. LB/HR
RAW SYNGAS VOLUME FLOW =	749. MMSCFD @ 60°F
RAW SYNGAS COMPOSITION:	
H2	27.7 MOL.%
CO	58.2 MOL.%
CO2	4.9 MOL.%
N2	1.7 MOL.%
H2O	6.1 MOL.%
H2S	10870. PPMV
CH4	69. PPMV
QUENCHED SYNGAS MASS FLOW =	1852905. LB/HR
QUENCHED SYNGAS VOLUME FLOW =	796. MMSCFD @ 60°F
QUENCHED SYNGAS COMPOSITION:	
H2	26.1 MOL.%
CO	54.8 MOL.%
CO2	5.6 MOL.%
N2	2.0 MOL.%
H2O	10.5 MOL.%
H2S	10228. PPMV
CH4	63. PPMV
CLEANED SYNGAS MASS FLOW =	1678074. LB/HR
CLEANED SYNGAS VOLUME FLOW =	1431. MMSCFD @ 60°F
CLEANED SYNGAS COMPOSITION:	
H2	67.3 MOL.%
CO	30.5 MOL.%
CO2	1.0 MOL.%

N2	1.1 MOL.%
H2O	0.0 MOL.%
H2S	0. PPMV
CH4	35. PPMV

METHANOL MASS FLOW =	1611796. LB/HR
METHANOL MASS FLOW =	19342. TON/DY
METHANOL PURITY =	98.10 WT.%
METHANOL PRODUCED / COAL FED =	1.63 LB/LB

FINAL PRODUCTS:

GASOLINE PRODUCT:

GASOLINE VOLUME FLOW =	57704. BBL/DY
GASOLINE MASS FLOW =	613043. LB/HR
GASOLINE MASS FLOW =	7357. TON/DY
GASOLINE LHV FLOW =	273948. MMBTU/DY
GASOLINE PRODUCED / METHANOL FED =	0.38 LB/LB
GASOLINE PRODUCED / COAL FED =	0.62 LB/LB

LPG PRODUCT:

LPG VOLUME FLOW =	9101. BBL/DY
LPG MASS FLOW =	73051. LB/HR
LPG MASS FLOW =	877. TON/DY
LPG LHV FLOW =	34289. MMBTU/DY
LPG PRODUCED / METHANOL FED =	0.05 LB/LB
LPG PRODUCED / COAL FED =	0.07 LB/LB

BYPRODUCTS SUMMARY:

SLAG =	846. TON/DY
FLYASH =	355. TON/DY
SULFUR =	382. TON/DY

POWER SUMMARY:

ELECTRICAL GENERATORS:

STEAM TURBINE POWER GENERATION =	227.7 MW
GENERATOR SUBTOTAL =	227.7 MW

ELECTRICAL CONSUMERS:

HTE POWER CONSUMPTION =	2488.7 MW
COAL PREP POWER CONSUMPTION =	10.7 MW
GASIFIER POWER CONSUMPTION =	6.3 MW
GAS CLEANING POWER CONSUMPTION =	56.1 MW
CLAUS POWER CONSUMPTION =	0.4 MW
SCOT POWER CONSUMPTION =	5.0 MW
POWER BLOCK POWER CONSUMPTION =	2.3 MW
CO2 PROCESSING POWER CONSUMPTION =	15.3 MW
MEOH SYNTHESIS POWER CONSUMPTION =	93.0 MW
MTG POWER CONSUMPTION =	9.8 MW
H2 RECOVERY POWER CONSUMPTION =	1.9 MW
COOLING TOWER POWER CONSUMPTION =	5.9 MW
WATER TREATMENT POWER CONSUMPTION =	12.8 MW
CONSUMER SUBTOTAL =	2708.3 MW

NET PLANT POWER CONSUMPTION = 2480.6 MW

WATER BALANCE:

EVAPORATIVE LOSSES:

CMD WATER NOT RECOVERED = 168.7 GPM

```
    COOLING TOWER EVAPORATION =        12962.6 GPM
    ZLD SYSTEM EVAPORATION =             737.9 GPM
  TOTAL EVAPORATIVE LOSSES =           13869.3 GPM

  WATER CONSUMED:
    GASIFIER ISLAND MAKEUP =             200.0 GPM
    BOILER FEED WATER MAKEUP =           191.2 GPM
    COOLING TOWER MAKEUP =             13639.2 GPM
  TOTAL WATER CONSUMED =               14030.4 GPM

  WATER GENERATED:
    GASIFIER ISLAND BLOWDOWN =            44.1 GPM
    RECTISOL BLOWDOWN =                  331.5 GPM
    SULFUR REDUCTION BLOWDOWN =           34.4 GPM
    MTG PROCESS WATER =                 1831.3 GPM
    COOLING TOWER BLOWDOWN =            2673.0 GPM
  TOTAL WATER GENERATED =               4914.2 GPM

  PLANT WATER SUMMARY:
    NET MAKEUP WATER REQUIRED =        12716.4 GPM
    WATER CONSUMED / COAL FED =            6.45 LB/LB
    WATER CONSUMED / LIQUID PRODUCED =     6.53 BBL/BBL


CO2 BALANCE:

  CO2 CAPTURED (SEQUESTERED OR EOR) =      1. TON/DY
  CO2 CAPTURED @ 60°F =                    0. MMSCFD @ 60°F
    CO2 PURITY =                         70.9 %

  CO2 EMITTED (TOTAL) =                  481. TON/DY
  CO2 EMITTED @ 60°F =                     8. MMSCFD @ 60°F
    FROM HTE =                           394. TON/DY
      LHV TO HTE =                      6934. MMBTU/DY
    FROM MTG FH =                         87. TON/DY
      LHV TO MTG FH =                   1509. MMBTU/DY
  CO2 EMITTED / COAL FED =                 0.04 LB/LB


CARBON BALANCE SUMMARY:

    % CARBON TO GASOLINE =               87.7 %
    % CARBON TO LPG =                     9.9 %
    % CARBON TO SLAG =                    0.0 %
    % CARBON TO FLY ASH =                 0.4 %
    % CARBON TO EOR =                     0.0 %
    % CARBON TO HTE EXHAUST =             1.5 %
    % CARBON TO FIRED HEATER EXHAUST =    0.3 %

STARTUP FLARE SUMMARY:

  CO2 FROM FLARE =                       142. TON/DY
  LHV TO FLARE =                        1049. MMBTU/DY


NUCLEAR INTEGRATION REQUIREMENTS:

  TOTAL ELECTRICITY DEMAND =            2480.6 MW
    FROM HTE =                          2488.7 MW
    FROM BALANCE OF PLANT =               -8.1 MW

  HYDROGEN DEMAND =                     1938.6 TON/DY
    PURITY =                              99.9159 MOL.%
```

Nuclear-Integrated Coal to MTG Results

```
  OXYGEN DEMAND =                            8339.2 TON/DY
    PURITY =                                   99.8910 MOL.%

  TOPPING HEAT SUPPLIED =                     136.7 MMBTU/HR
    SUPPLY TEMPERATURE =                     3092. °F
    RETURN TEMPERATURE =                     1756. °F


Calculator Block AIRPROPS

   HUMIDITY DATA FOR STREAM AIR-ASU:
     HUMIDITY RATIO =                          43.5 GRAINS/LB
     RELATIVE HUMIDITY =                       39.9 %


Calculator Block MEOH-SYN Hierarchy: MEOH-SYN

   MEOH SYNTHESIS FEED GAS QUALITY:

     (H2 - CO2) / (CO + CO2)
       TARGET =                                  2.10
       ACTUAL =                                  2.100

     H2 / (2 CO + 3 CO2)
       TARGET =                                  1.05
       ACTUAL =                                  1.049

     H2 / CO
       ACTUAL =                                  2.206

   MEOH SYNTHESIS OPERATING PARAMETERS:

     MOLAR RECYCLE RATIO
       TARGET =                            3.0 - 4.0
       ACTUAL =                                  4.00

     REACTOR INLET CO2 CONCENTRATION
       TARGET =                                < 4.0 MOL.%
       ACTUAL =                                  0.38 MOL.%

     REACTOR OUTLET MEOH CONCENTRATION
       TARGET =                            3.0 - 8.0 MOL.%
       ACTUAL =                                  7.79 MOL.%

     METHANOL PRODUCT CO2 CONCENTRATION
       TARGET =                                500. PPBW
       ACTUAL =                                500. PPBW


Calculator Block MTG      Hierarchy: MTG

   YIELD SUMMARY (LB / 1,000 LB MEOH):

     PRODUCT                         EXXON LIT.   MODEL RESULT

     GASOLINE                         387.           386.
     LPG                               46.            46.
     FUEL GAS                           7.             8.
     WATER                            560.           560.

   PRODUCT SUMMARY:

     GASOLINE PRODUCT:
       PRODUCTION RATE =                   613043. LB/HR
```

Nuclear-Integrated Coal to MTG Results

PRODUCTION RATE =	57704. BBL/DAY
MOLECULAR WEIGHT =	94.5
CARBON PERCENT =	85.6
HIGHER HEAT CONTENT =	19941. BTU/LB
LOWER HEAT CONTENT =	18619. BTU/LB

PROPERTY COMPARISON:

PROPERTY	EXXON LIT.	MODEL RESULT
API GRAVITY, °	61.8	62.9
SPECIFIC GRAVITY	0.732	0.728
REED VAPOR PRES., PSI	9.0	8.7
AROMATIC CONTENT, %	26.5	24.3
OLEFIN CONTENT, %	12.6	16.4
BENZENE CONTENT, %	0.3	0.5
D86T 50%, °F	201.0	156.5
D86T 90%, °F	320.0	332.2

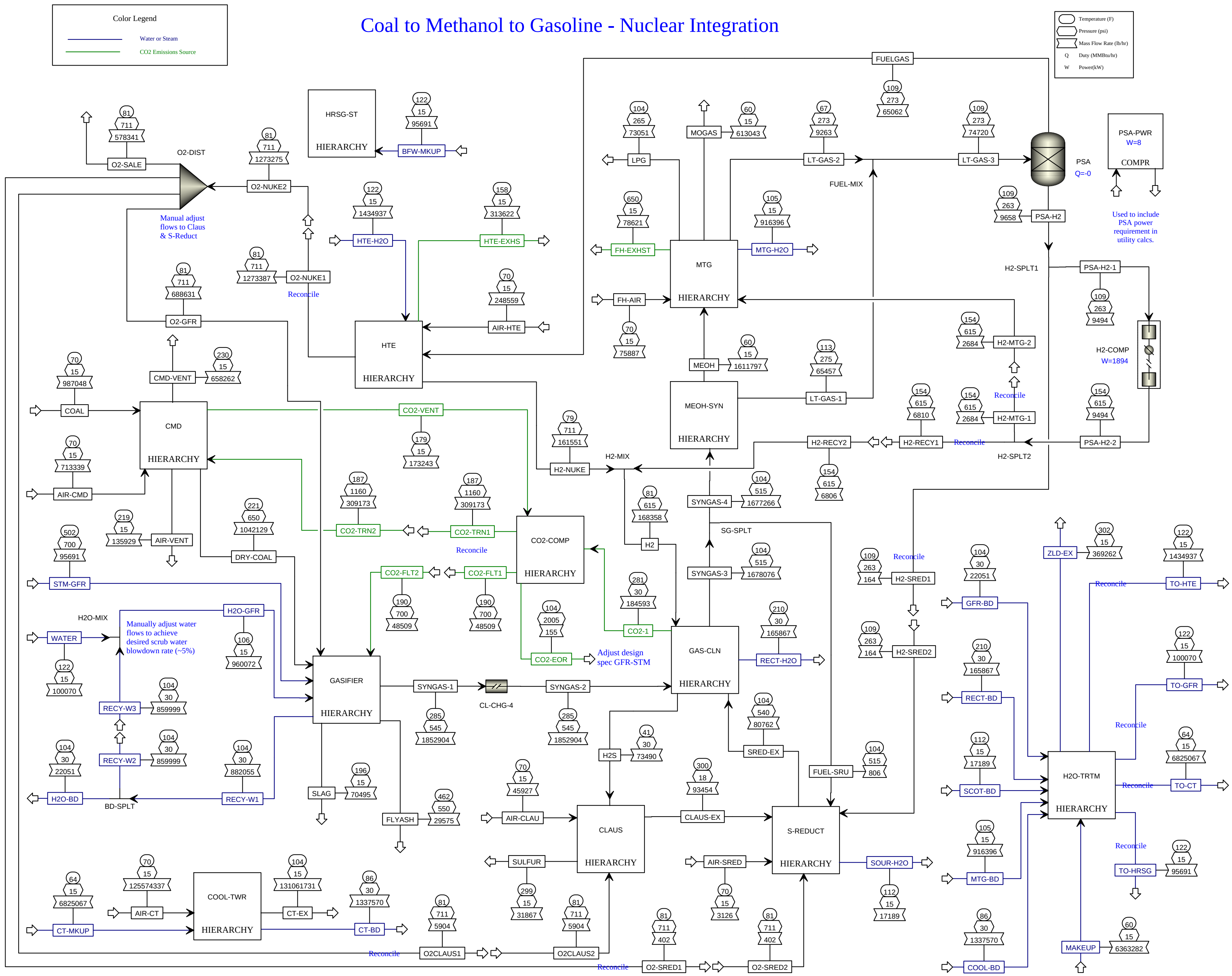
LPG PRODUCT:

PRODUCTION RATE =	73051. LB/HR
PRODUCTION RATE =	9101. BBL/DAY
SPECIFIC GRAVITY =	0.55
MOLECULAR WEIGHT =	50.1
CARBON PERCENT =	81.4
HIGHER HEAT CONTENT =	21215. BTU/LB
LOWER HEAT CONTENT =	19557. BTU/LB

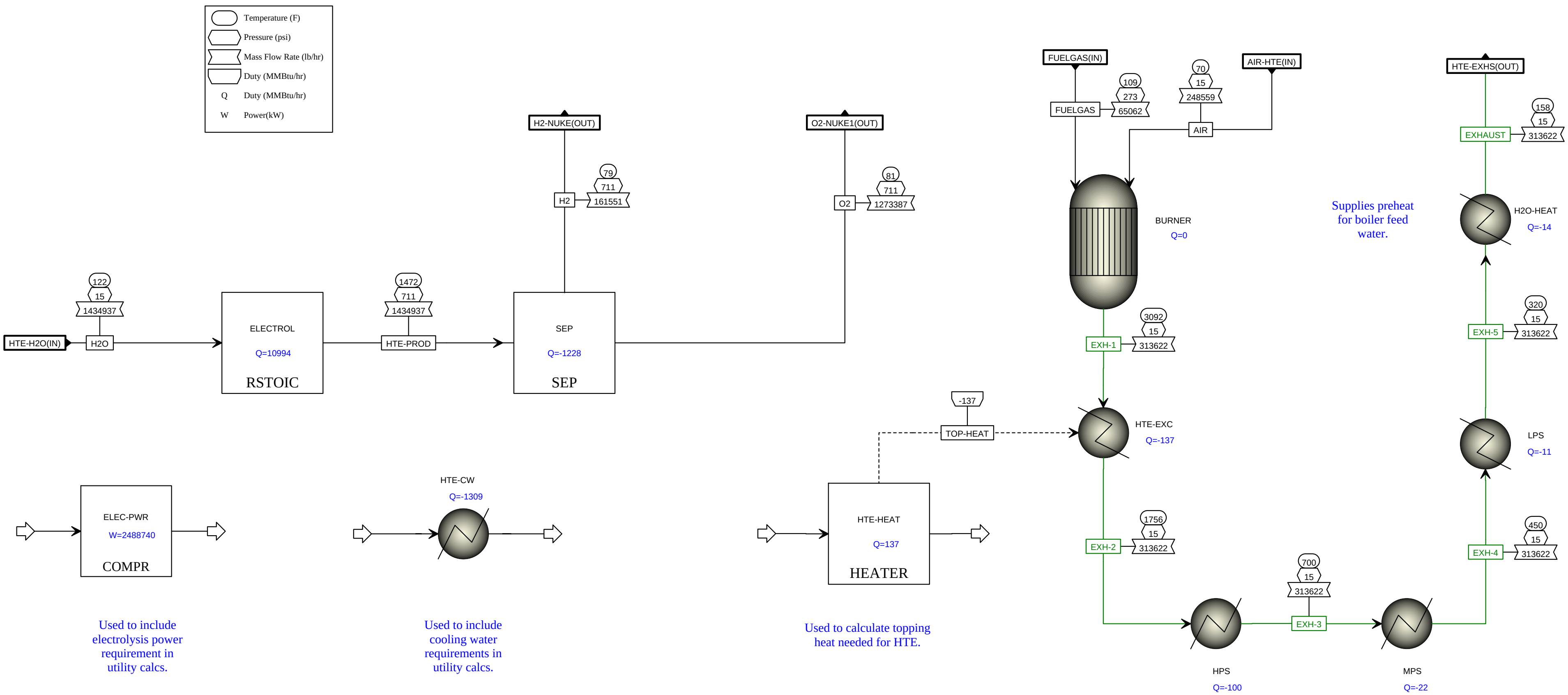
FUEL GAS PRODUCT:

NET PRODUCTION RATE =	9263. LB/HR
NET PRODUCTION RATE =	6.45 MMSCFD @ 60°F
MOLECULAR WEIGHT =	13.1
HIGHER HEAT CONTENT =	25569. BTU/LB

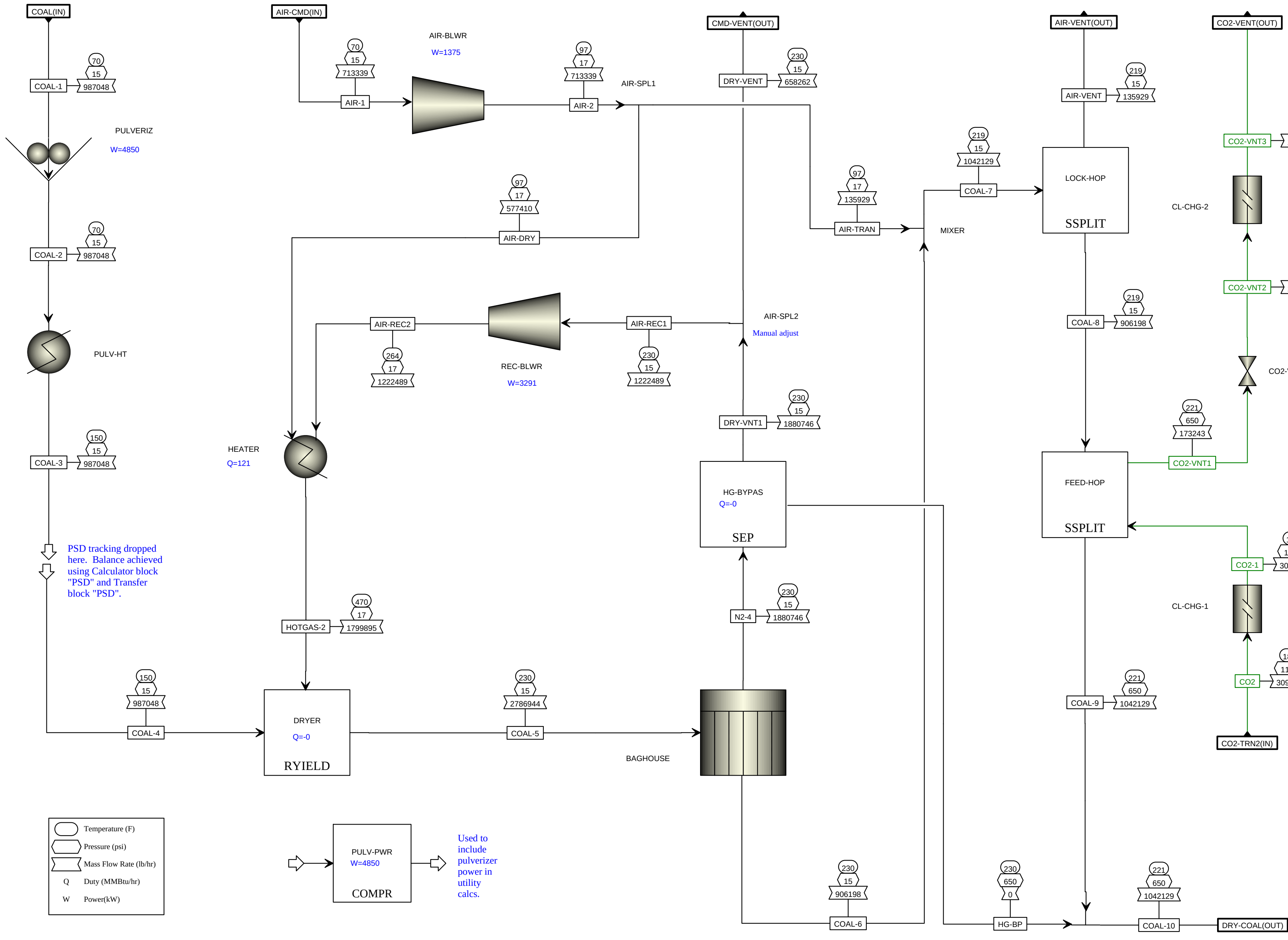
Coal to Methanol to Gasoline - Nuclear Integration



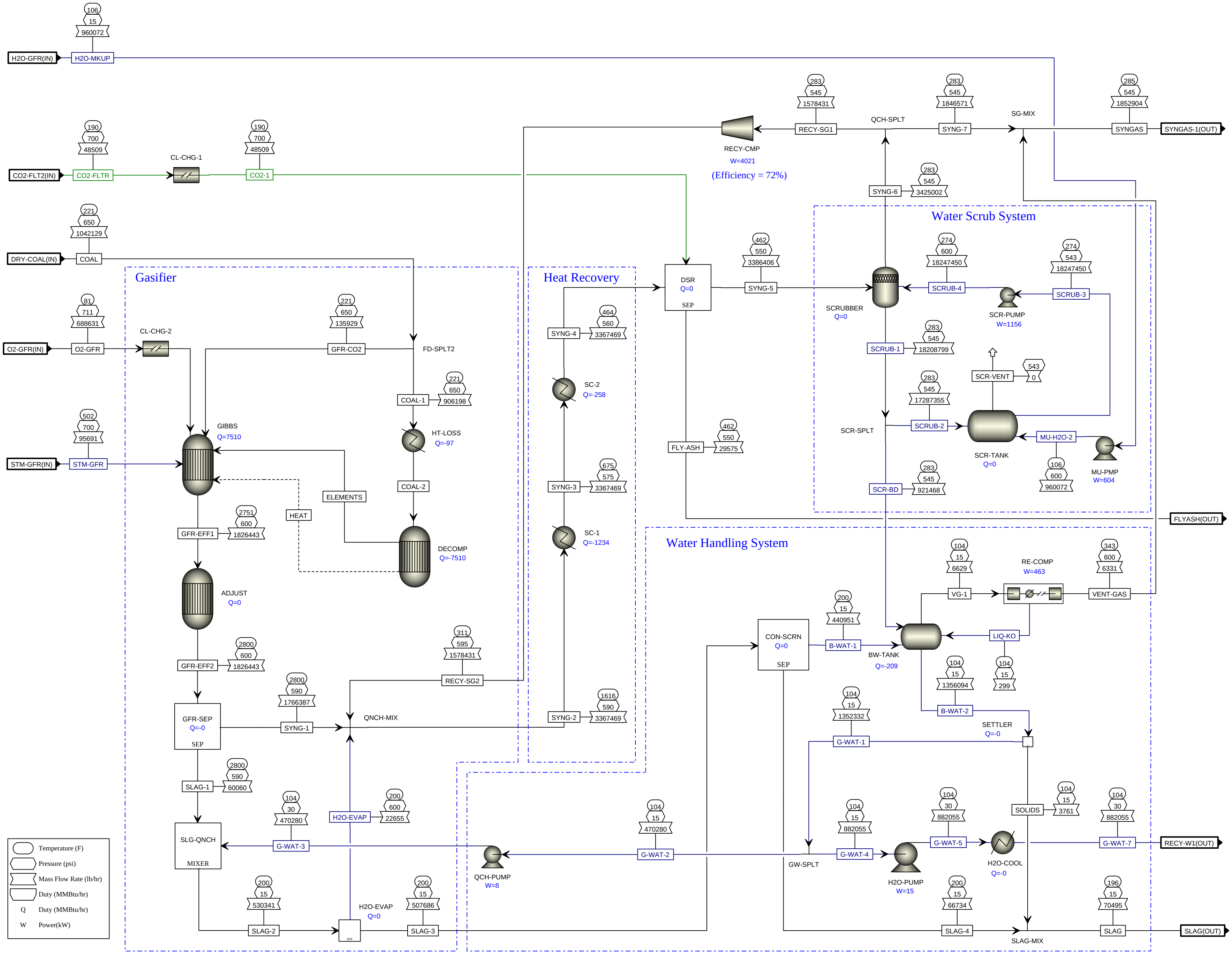
Simplified HTE Model



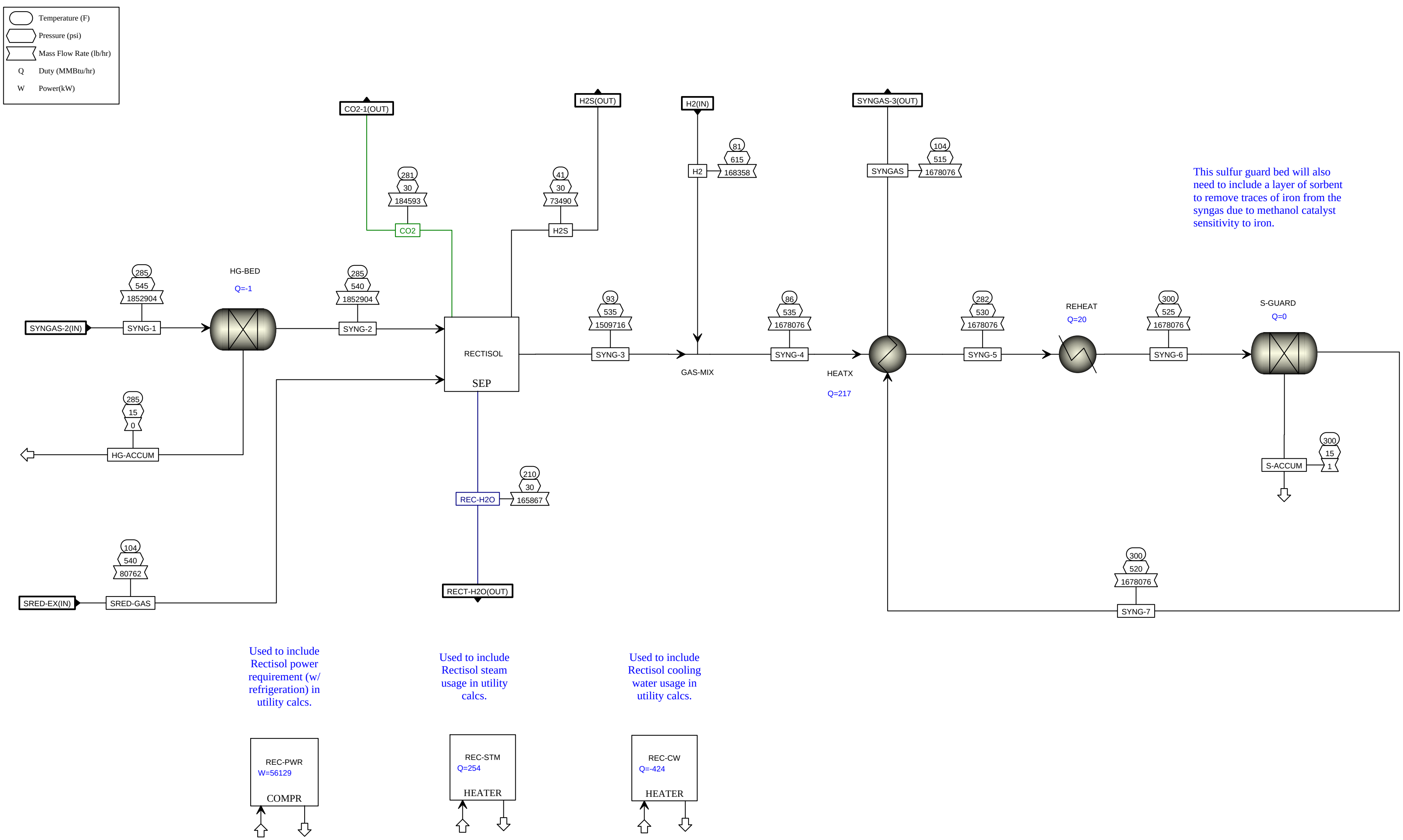
Coal Milling & Drying



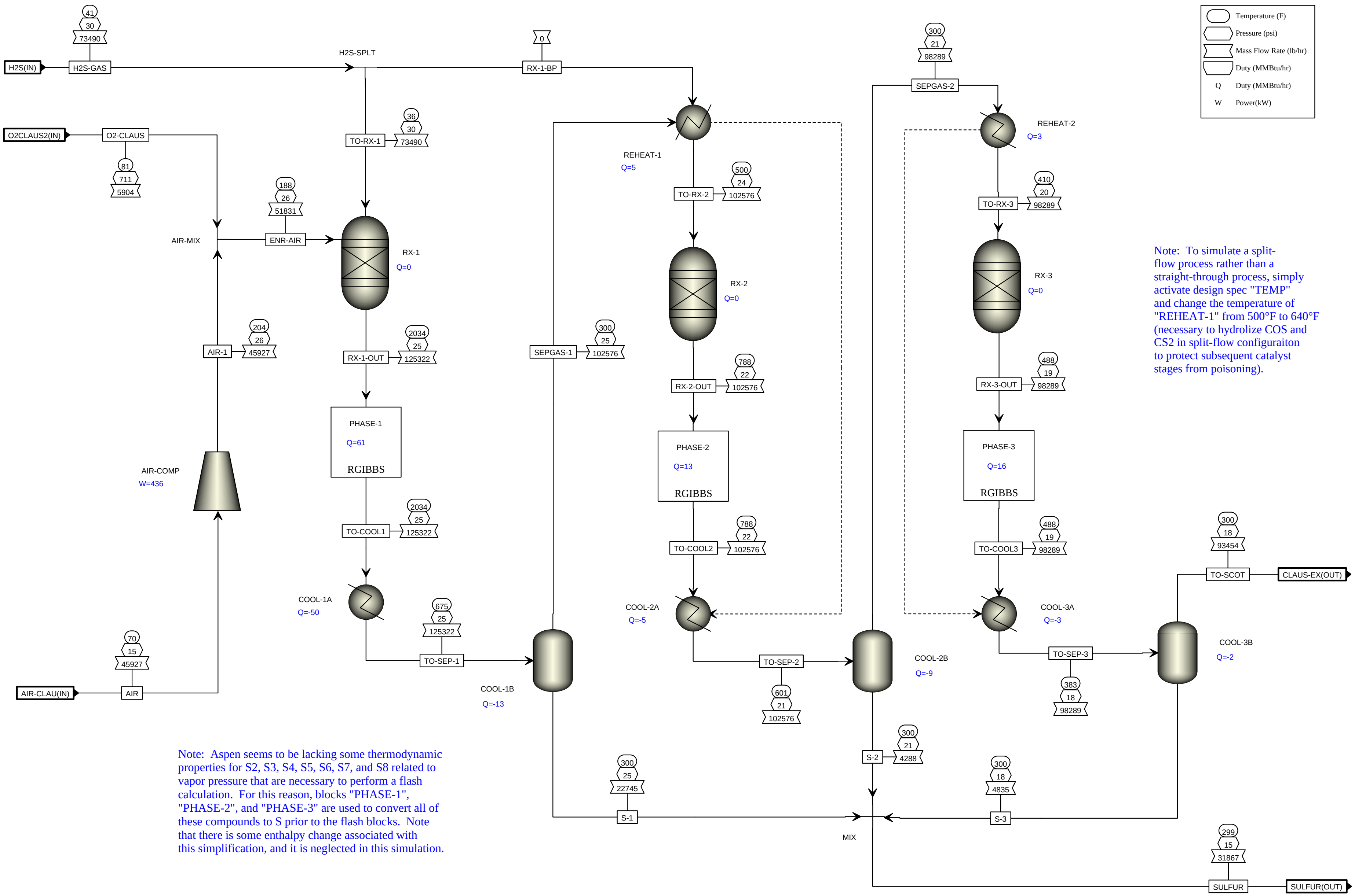
Dry-Fed Gasifier w/ Heat Recovery



Syngas Cleaning & Conditioning



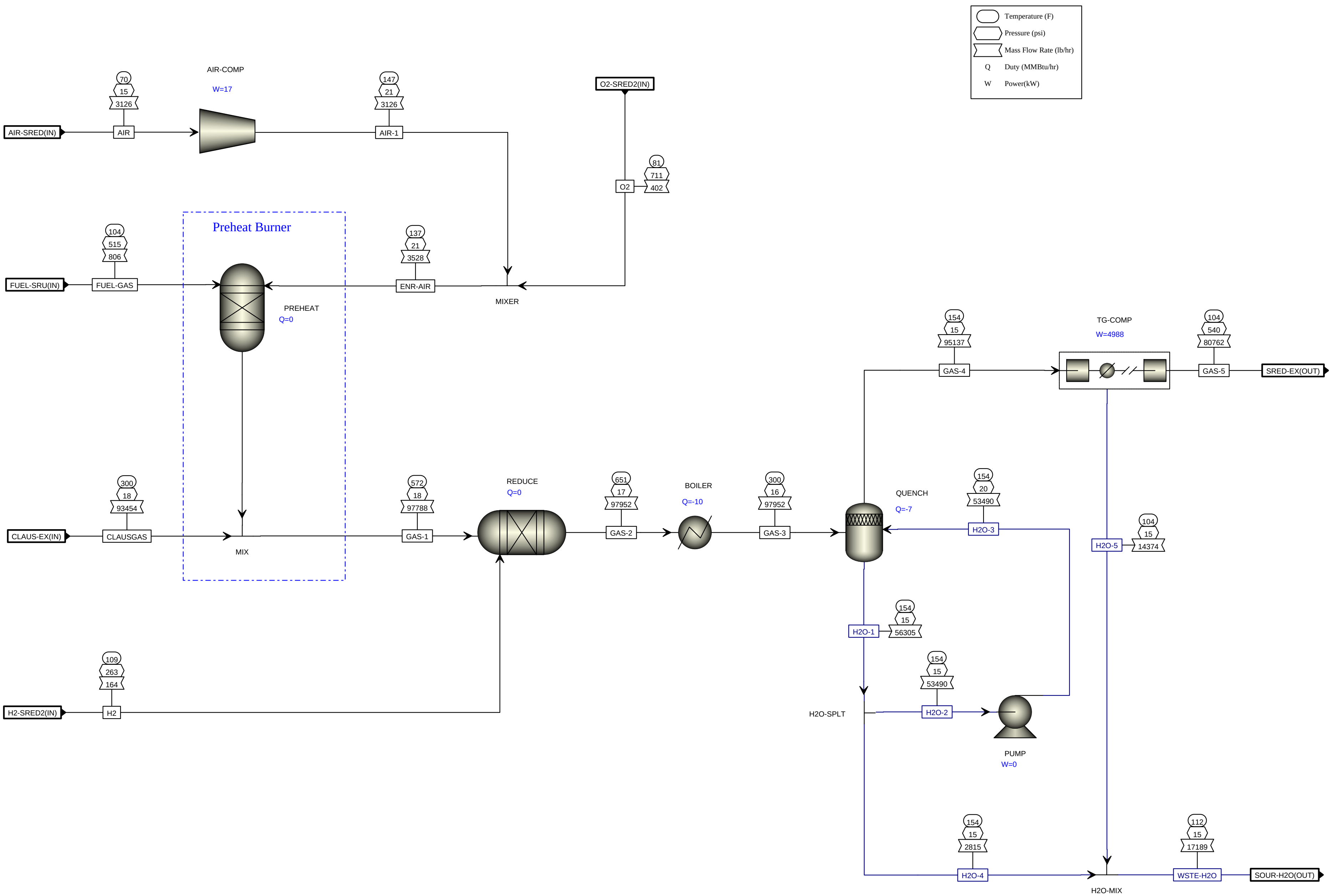
Claus Process



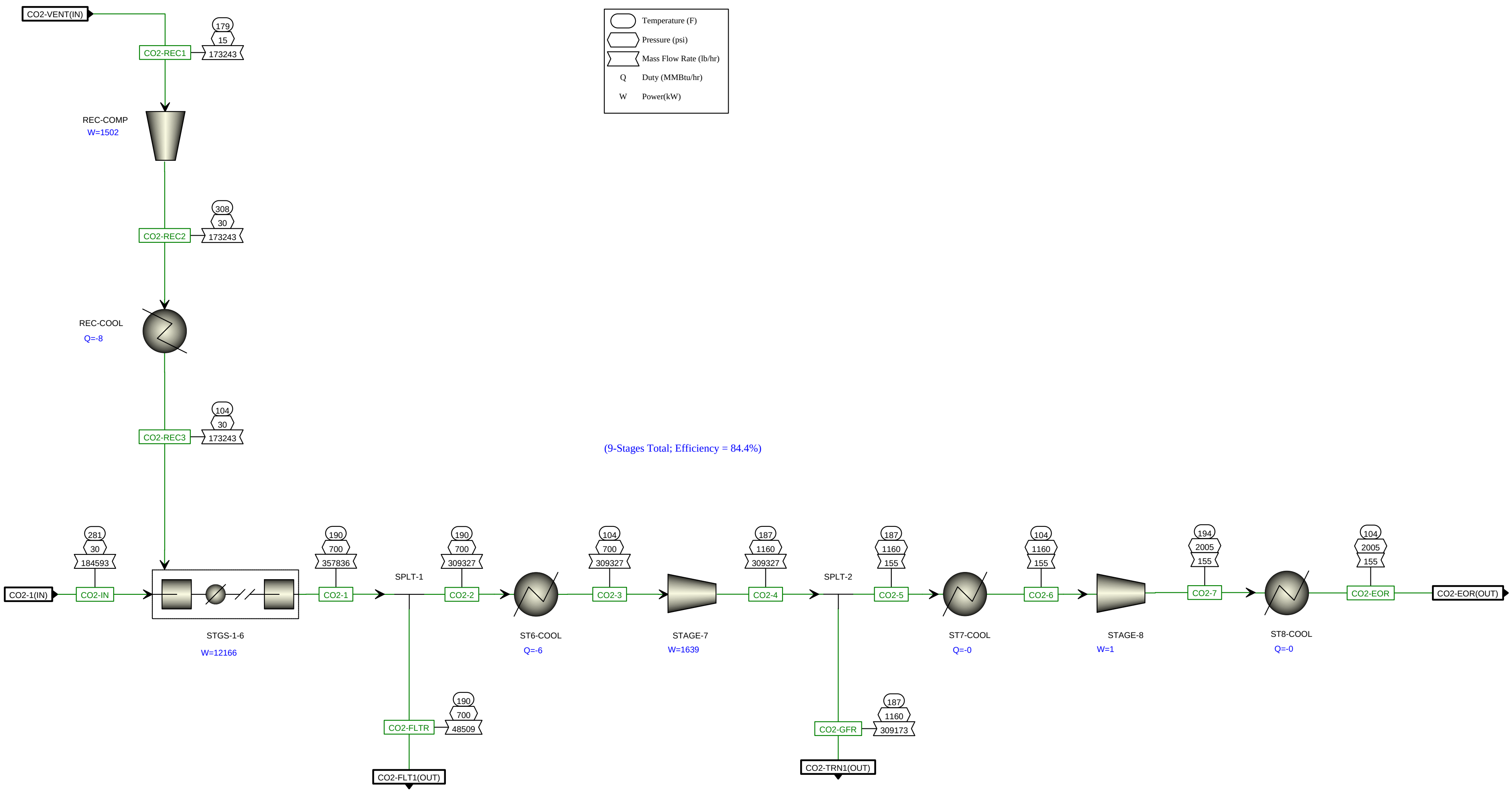
Note: To simulate a split-flow process rather than a straight-through process, simply activate design spec "TEMP" and change the temperature of "REHEAT-1" from 500°F to 640°F (necessary to hydrolize COS and CS2 in split-flow configuraiton to protect subsequent catalyst stages from poisoning).

Note: Aspen seems to be lacking some thermodynamic properties for S2, S3, S4, S5, S6, S7, and S8 related to vapor pressure that are necessary to perform a flash calculation. For this reason, blocks "PHASE-1", "PHASE-2", and "PHASE-3" are used to convert all of these compounds to S prior to the flash blocks. Note that there is some enthalpy change associated with this simplification, and it is neglected in this simulation.

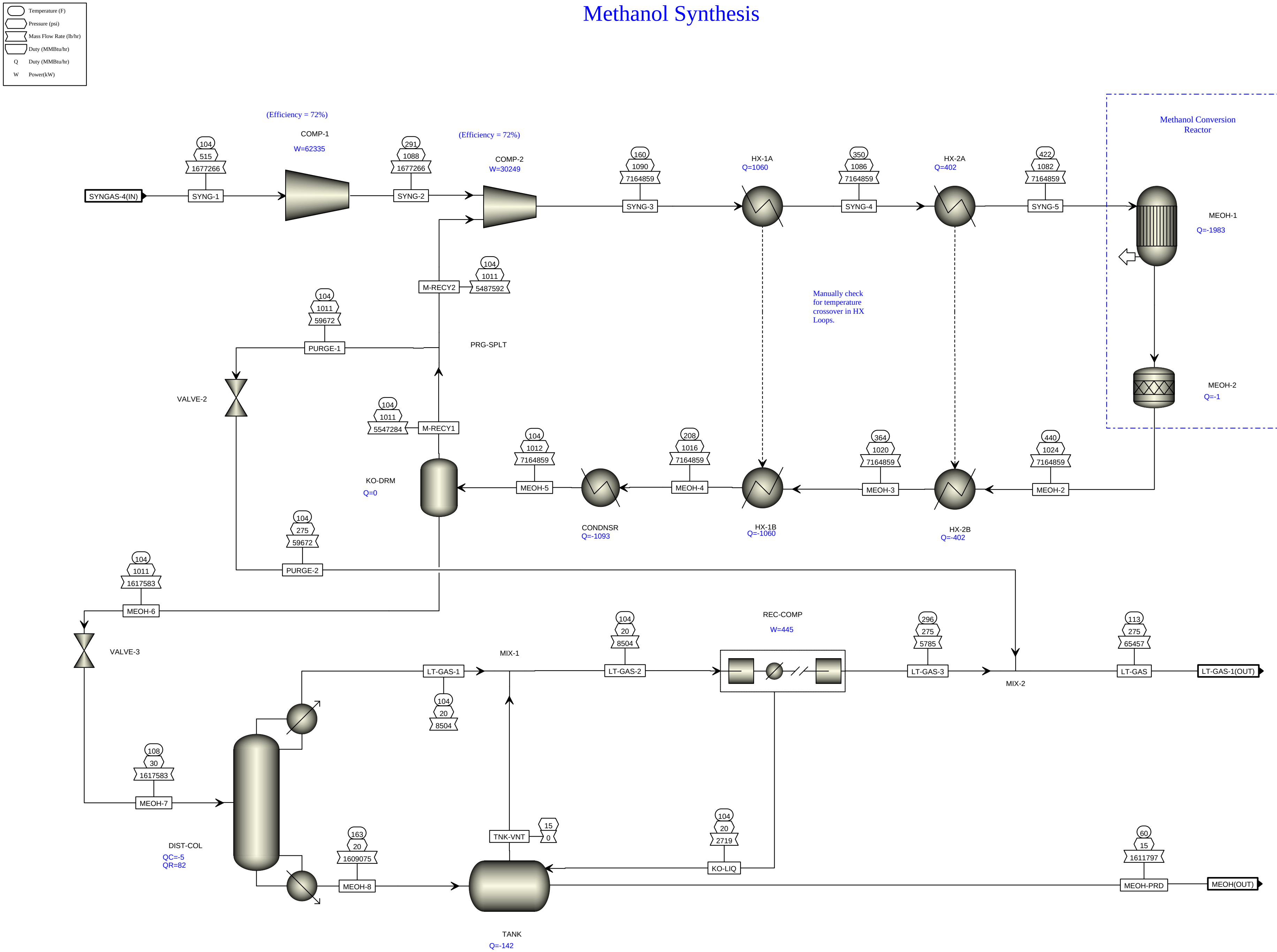
Catalytic Sulfur Reduction (SCOT or Beavon Process w/o H2S Absorber)



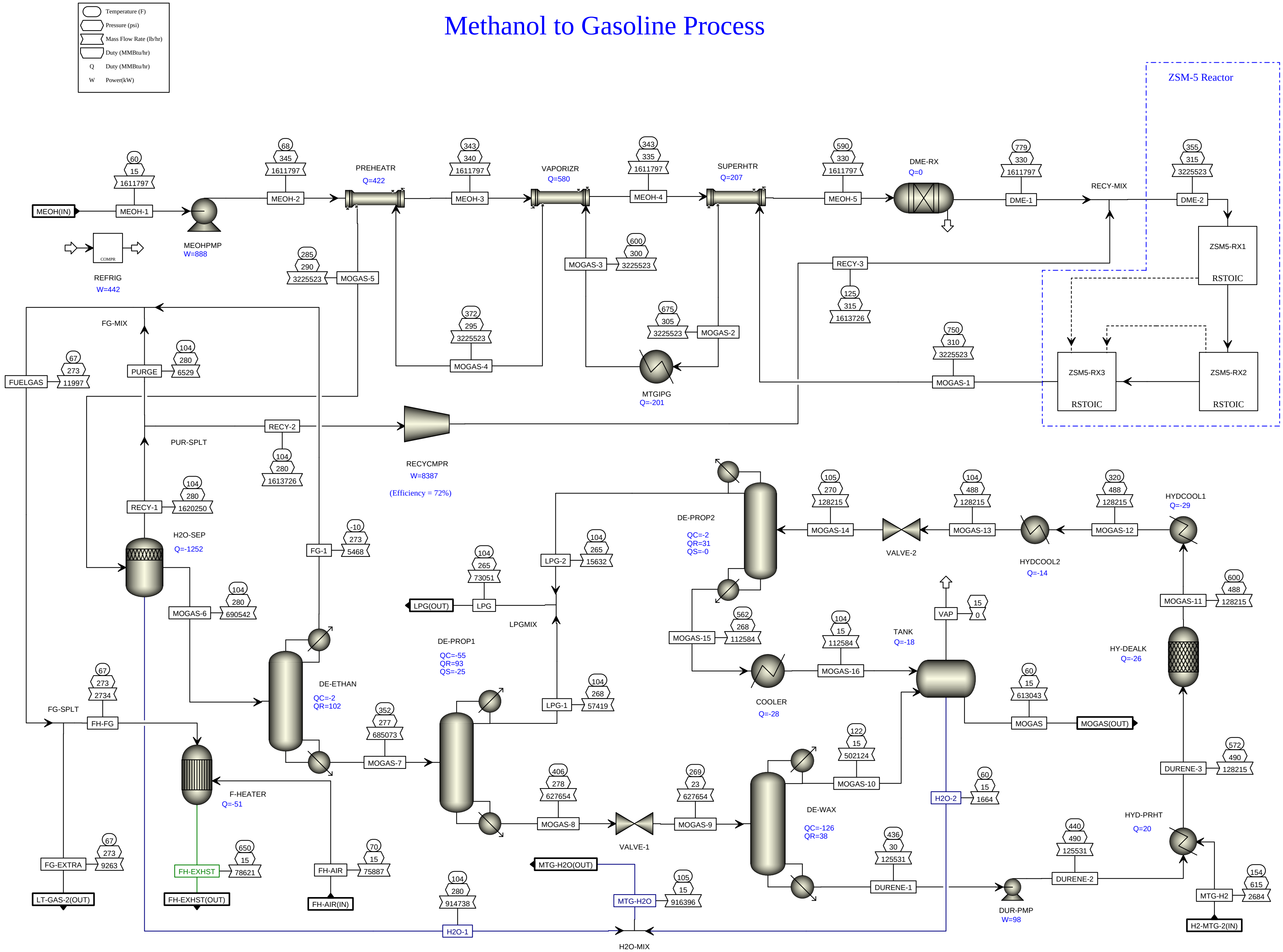
CO2 Compression



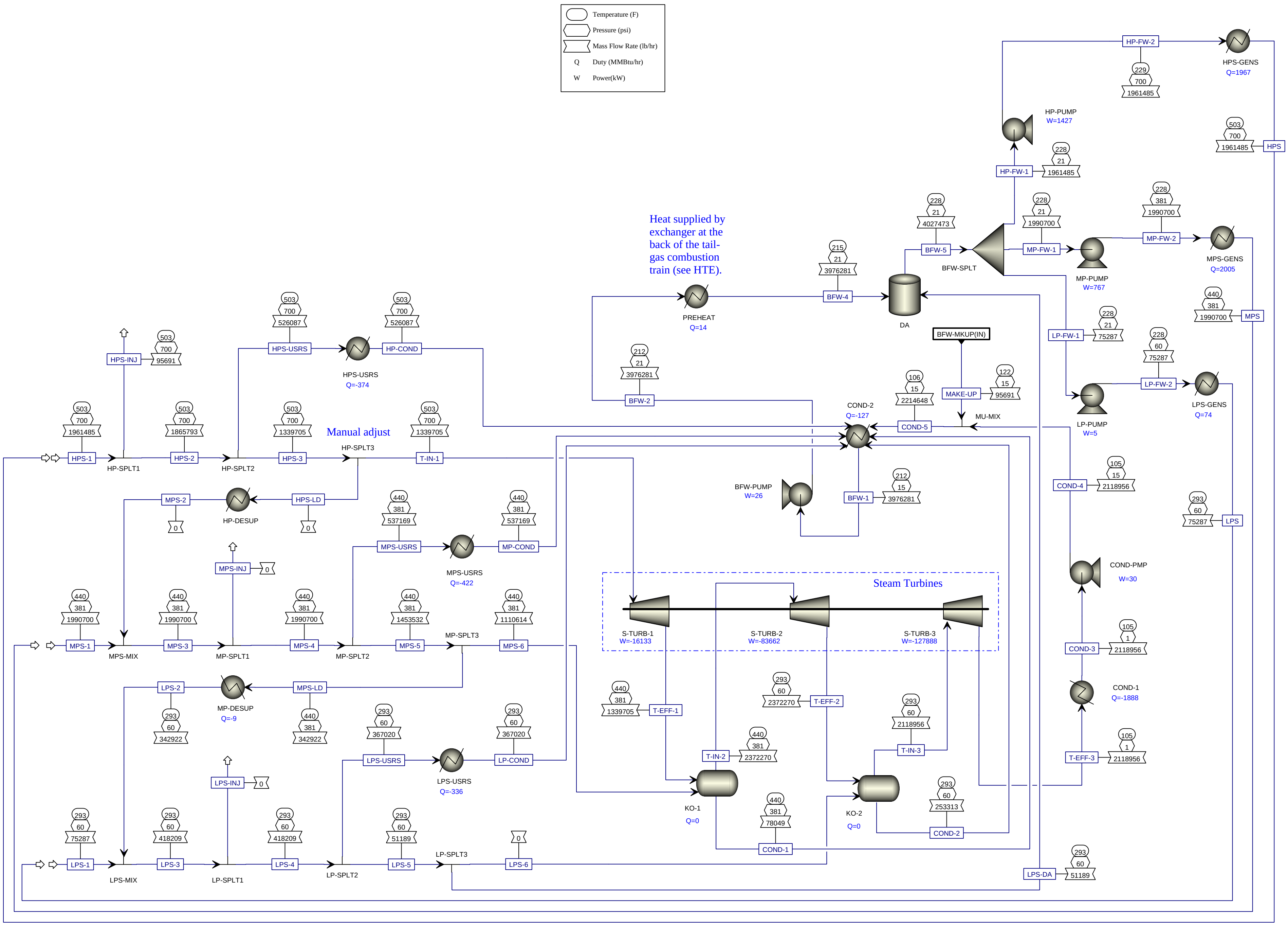
Methanol Synthesis



Methanol to Gasoline Process

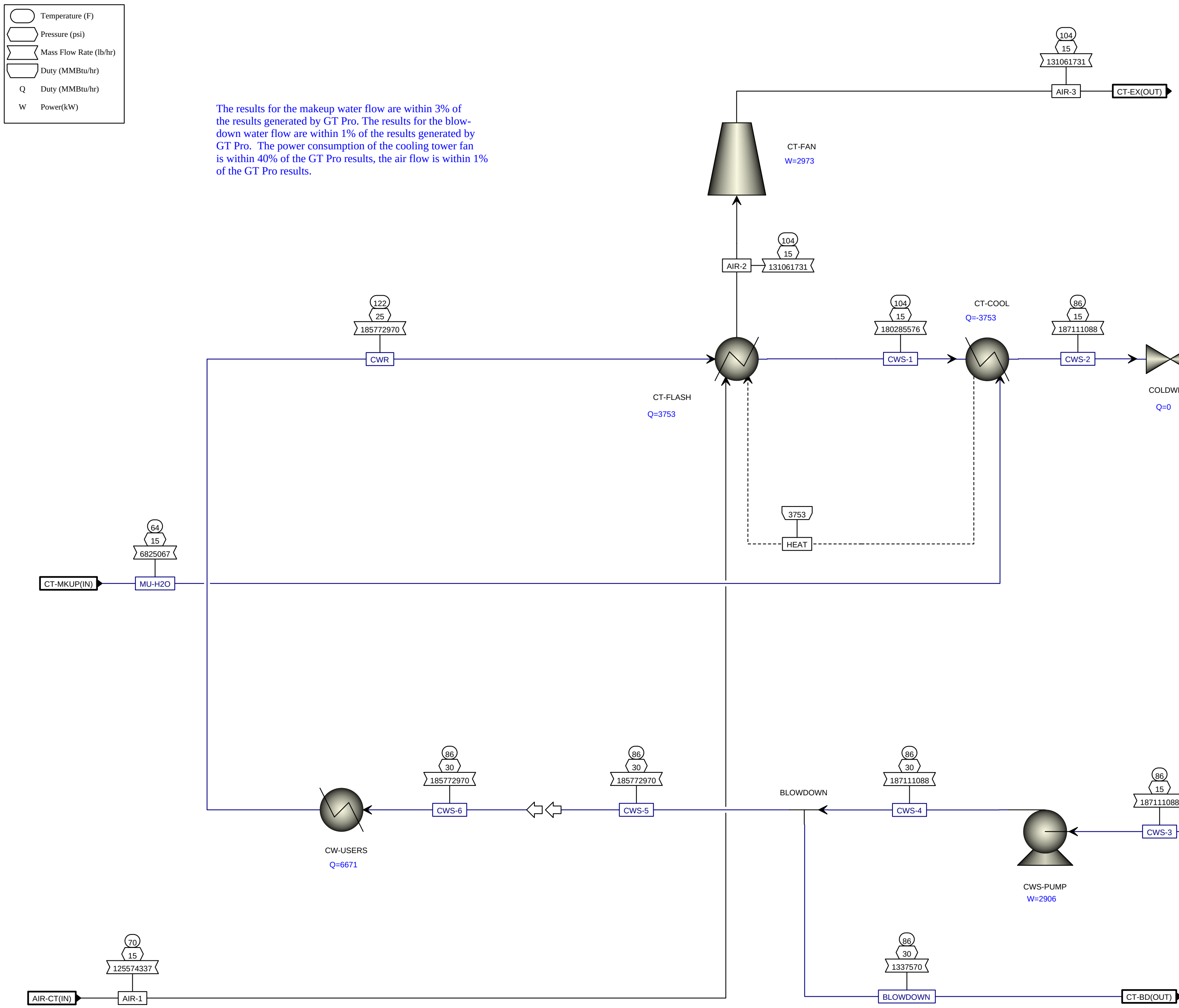


HRSG & Steam Turbines

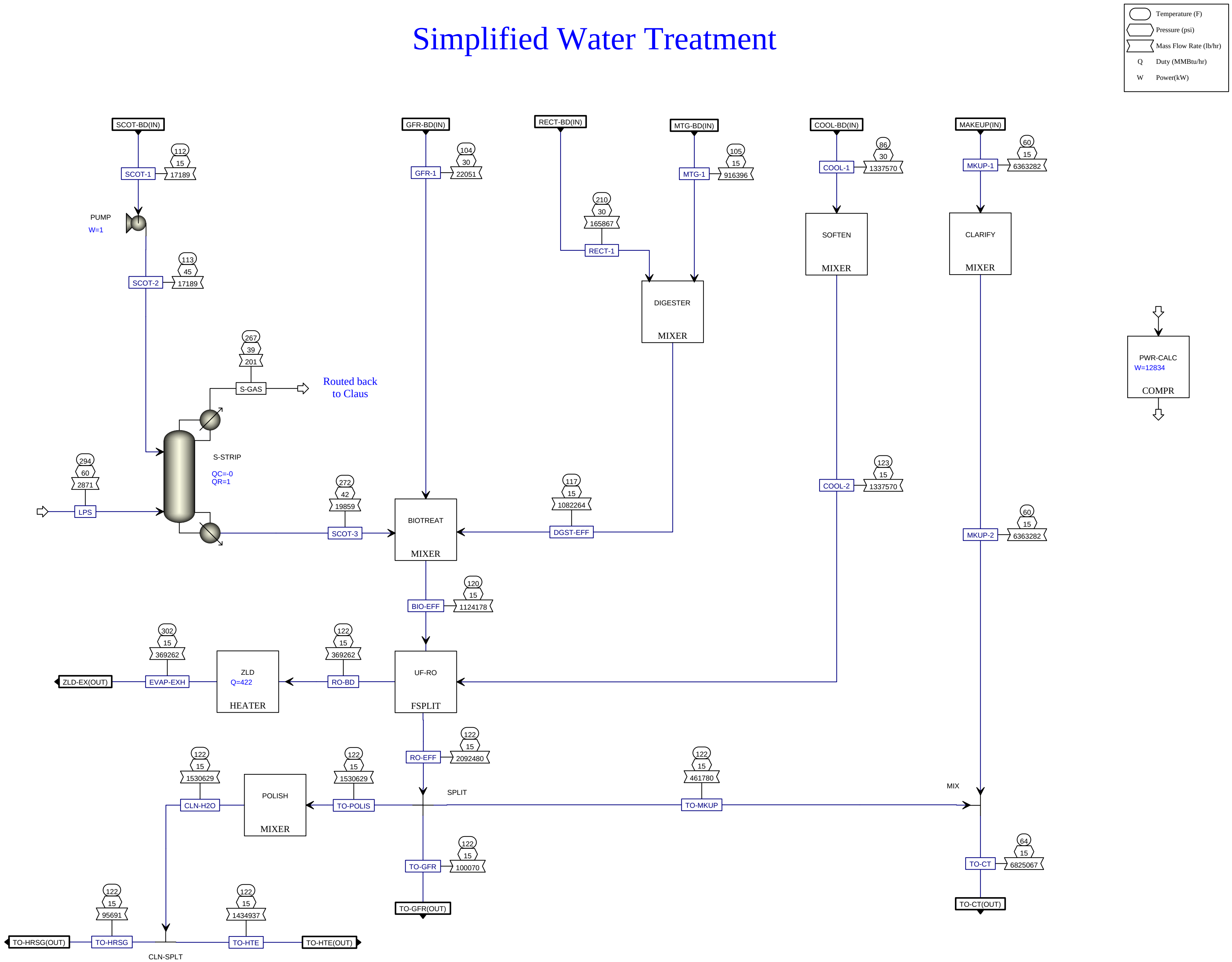


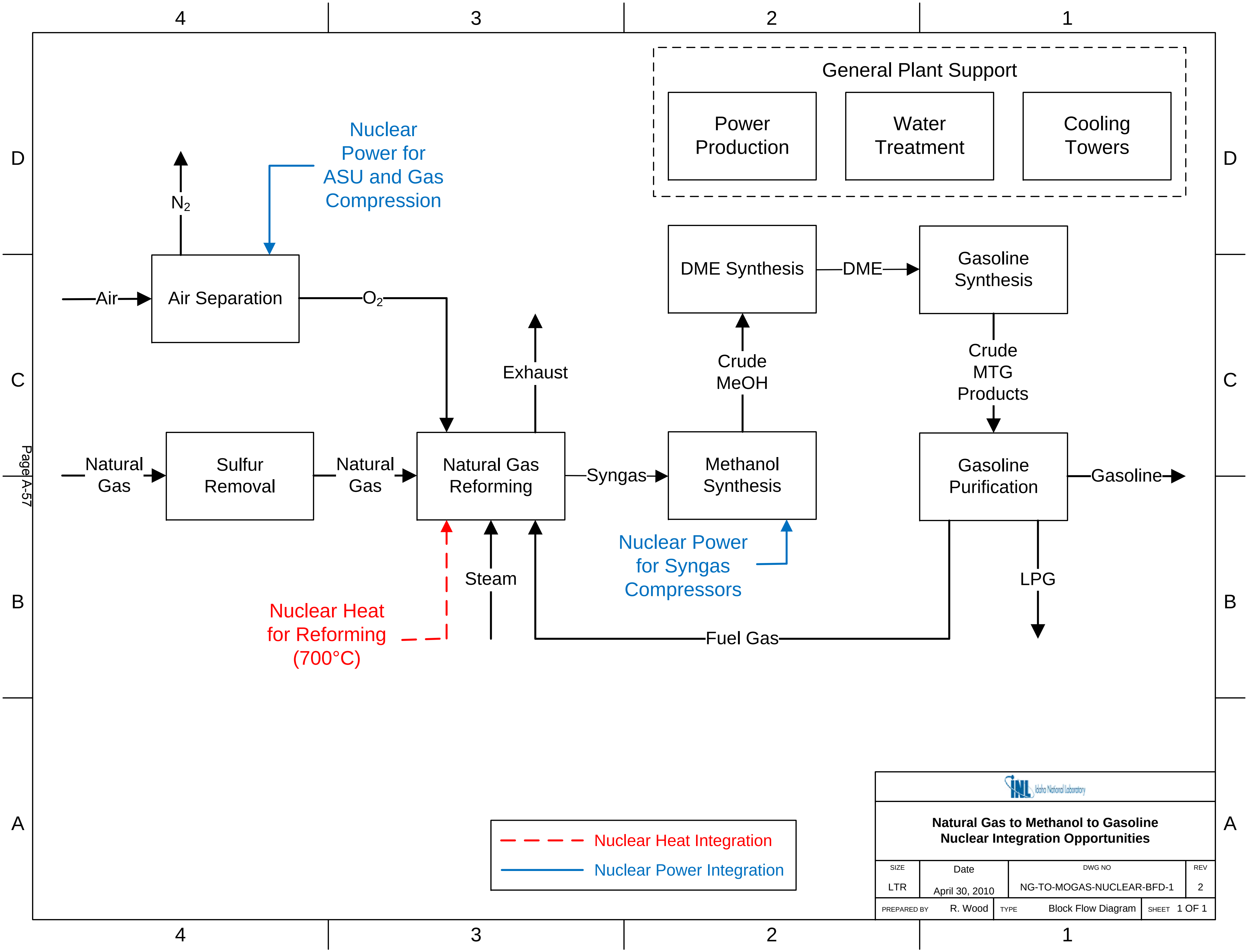
Cooling Tower

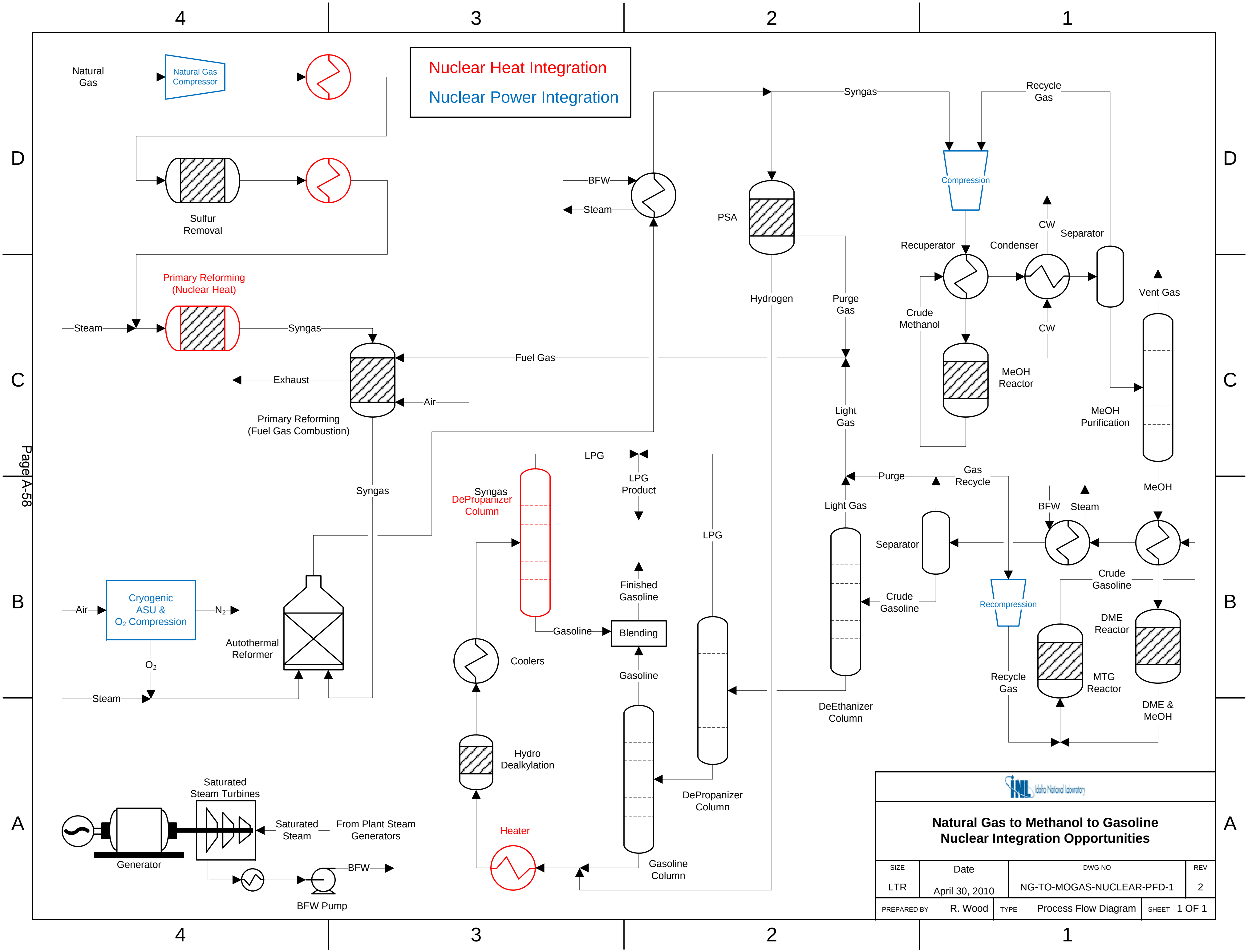
The results for the makeup water flow are within 3% of the results generated by GT Pro. The results for the blow-down water flow are within 1% of the results generated by GT Pro. The power consumption of the cooling tower fan is within 40% of the GT Pro results, the air flow is within 1% of the GT Pro results.



Simplified Water Treatment




General Plant Support
Power Production
Water Treatment
Cooling Towers
Nuclear Power for ASU and Gas Compression
N2
Air
Air Separation
O2
DME Synthesis
DME
Gasoline Synthesis
Exhaust
Crude MeOH
Crude MTG Products
Natural Gas
Sulfur Removal
Natural Gas
Natural Gas Reforming
Syngas
Methanol Synthesis
Gasoline Purification
Gasoline
Steam
Nuclear Power for Syngas Compressors
LPG
Nuclear Heat for Reforming (700°C)
Fuel Gas
Nuclear Heat Integration
Nuclear Power Integration
Idaho National Laboratory
Natural Gas to Methanol to Gasoline Nuclear Integration Opportunities
SIZE LTR
Date April 30, 2010
DWG NO NG-TO-MOGAS-NUCLEAR-BFD-1
REV 2
PREPARED BY R. Wood
TYPE Block Flow Diagram
SHEET 1 OF 1



Nuclear Heat Integration
Nuclear Power Integration
Natural Gas
Natural Gas Compressor
Sulfur Removal
Primary Reforming (Nuclear Heat)
Steam
Syngas
Fuel Gas
Exhaust
Air
Primary Reforming (Fuel Gas Combustion)
BFW
Steam
PSA
Hydrogen
Purge Gas
Light Gas
Recycle Gas
Compression
Recuperator
Condenser
CW
Separator
Crude Methanol
MeOH Reactor
Vent Gas
MeOH Purification
MeOH
Purge
Gas Recycle
Light Gas
Separator
Crude Gasoline
DeEthanizer Column
Recompression
DME Reactor
MTG Reactor
DME & MeOH
LPG
LPG Product
DePropanizer Column
Finished Gasoline
Blending
Gasoline
Coolers
Hydro Dealkylation
Heater
Gasoline Column
DePropanizer Column
Cryogenic ASU & O₂ Compression
N₂
O₂
Autothermal Reformer
Saturated Steam Turbines
Saturated Steam
From Plant Steam Generators
Generator
BFW Pump
Natural Gas to Methanol to Gasoline Nuclear Integration Opportunities
SIZE LTR
Date April 30, 2010
DWG NO NG-TO-MOGAS-NUCLEAR-PFD-1
REV 2
PREPARED BY R. Wood
TYPE Process Flow Diagram
SHEET 1 OF 1

Nuclear-Integrated Gas to MTG Results

Calculator Block SUMMARY

```
   FEED SUMMARY:

     NATURAL GAS PROPERTIES:

       MASS FLOW =                              5849. TON/DY
       VOLUME FLOW =                             258. MMSCFD @ 60°F
       HHV =                                   23063. BTU/LB
       HHV =                                    1047. BTU/SCF @ 60°F
       ENERGY FLOW =                          269781. MMBTU/DY

       COMPOSITION:
          METHANE =                               93.571 MOL.%
          ETHANE =                                 3.749 MOL.%
          PROPANE =                                0.920 MOL.%
          BUTANE =                                 0.260 MOL.%
          PENTANE =                                0.040 MOL.%
          HEXANE =                                 0.010 MOL.%
          NITROGEN =                               1.190 MOL.%
          OXYGEN =                                 0.010 MOL.%
          CO2 =                                    0.250 MOL.%
          C4H10S =                                 1. PPMV
          C2H6S =                                  0. PPMV
          H2S =                                    0. PPMV


   PRODUCT SUMMARY:

     INTERMEDIATE PRODUCTS:

       METHANOL MASS FLOW =                   918583. LB/HR
       METHANOL MASS FLOW =                    11023. TON/DY
          METHANOL PURITY =                       99.85 WT.%
       METHANOL PRODUCED / NAT. GAS FED =          1.88 LB/LB

     FINAL PRODUCTS:

       GASOLINE PRODUCT:
          GASOLINE VOLUME FLOW =               33470. BBL/DY
          GASOLINE MASS FLOW =                355585. LB/HR
          GASOLINE MASS FLOW =                  4267. TON/DY
          GASOLINE LHV FLOW =                 158898. MMBTU/DY
          GASOLINE PRODUCED / METHANOL FED =  0.39 LB/LB
          GASOLINE PRODUCED / NAT. GAS FED =  0.73 LB/LB

       LPG PRODUCT:
          LPG VOLUME FLOW =                     5278. BBL/DY
          LPG MASS FLOW =                      42366. LB/HR
          LPG MASS FLOW =                        508. TON/DY
          LPG LHV FLOW =                       19890. MMBTU/DY
          LPG PRODUCED / METHANOL FED =        0.05 LB/LB
          LPG PRODUCED / NAT. GAS FED =        0.09 LB/LB


   POWER SUMMARY:

     ELECTRICAL GENERATORS:
       STEAM TURBINE POWER GENERATION =       79.6 MW
     GENERATOR SUBTOTAL =                     79.6 MW

     ELECTRICAL CONSUMERS:
       NG REFORMER POWER CONSUMPTION =         9.3 MW
       ASU POWER CONSUMPTION =                75.0 MW
```

Nuclear-Integrated Gas to MTG Results

```
    POWER BLOCK POWER CONSUMPTION =        3.1 MW
    MEOH SYNTHESIS POWER CONSUMPTION =    49.3 MW
    MTG POWER CONSUMPTION =                5.7 MW
    COOLING TOWER POWER CONSUMPTION =      3.7 MW
    WATER TREATMENT POWER CONSUMPTION =   10.1 MW
  CONSUMER SUBTOTAL =                    156.3 MW

  NET PLANT POWER CONSUMPTION =           76.7 MW


WATER BALANCE:

  EVAPORATIVE LOSSES:
    COOLING TOWER EVAPORATION =         7631.9 GPM
    ZLD SYSTEM EVAPORATION =             647.2 GPM
  TOTAL EVAPORATIVE LOSSES =            8279.1 GPM

  WATER CONSUMED:
    BOILER FEED WATER MAKEUP =          1864.5 GPM
    COOLING TOWER MAKEUP =              8172.9 GPM
  TOTAL WATER CONSUMED =               10037.4 GPM

  WATER GENERATED:
    NG REFORMER PROCESS WATER =         1436.5 GPM
    MEOH PROCESS WATER =                 252.5 GPM
    MTG PROCESS WATER =                 1029.7 GPM
    COOLING TOWER BLOWDOWN =            1595.8 GPM
  TOTAL WATER GENERATED =               4314.4 GPM

  PLANT WATER SUMMARY:
    NET MAKEUP WATER REQUIRED =         6370.2 GPM
    WATER CONSUMED / LIQUID PRODUCED =     5.64 BBL/BBL


CARBON BALANCE:

  CARBON INPUTS:
    NATURAL GAS =                       4309. TPD CARBON
    COMBUSTION AIR =                       1. TPD CARBON
  TOTAL CARBON INPUT =                  4310. TPD CARBON

  CARBON OUTPUTS:
    MOGAS PRODUCT =                     3654. TPD CARBON
    LPG PRODUCT =                        414. TPD CARBON
    REFORMER EMISSIONS =                 241. TPD CARBON
  TOTAL CARBON OUTPUT =                 4309. TPD CARBON

  CARBON SUMMARY:
    CARBON TO FUEL =                      94.4 % OF TOTAL INPUT
    CARBON EMITTED =                       5.6 % OF TOTAL INPUT
    CO2 EMISSIONS =                      884. TPD CO2
    CO2 TO SMR =                         884. TPD CO2
      LHV TO SMR =                     18338. MMBTU/DY

STARTUP FLARE SUMMARY:

  CO2 FROM FLARE =                        81. TON/DY
  LHV TO FLARE =                        1251. MMBTU/DY


NUCLEAR INTEGRATION REQUIREMENTS:

  TOTAL ELECTRICITY DEMAND =              76.7 MW
```

```
                 Nuclear-Integrated Gas to MTG Results
     TOTAL HEAT DEMAND =                    387.2 MW
     TOTAL HEAT DEMAND =                   1321.1 MMBTU/HR

       HELIUM FLOWRATE REQUIRED =       2579410. LB/HR
       HELIUM FLOWRATE REQUIRED =           325.00 KG/S

       HELIUM SUPPLY TEMPERATURE =         1292. DEG. F.
       HELIUM SUPPLY TEMPERATURE =          700. DEG. C.

       HELIUM RETURN TEMPERATURE =          879. DEG. F.
       HELIUM RETURN TEMPERATURE =          471. DEG. C.


Calculator Block AIRPROPS

   HUMIDITY DATA FOR STREAM AIR-ASU:
     HUMIDITY RATIO =                        43.5 GRAINS/LB
     RELATIVE HUMIDITY =                     39.0 %


Calculator Block MEOH-SYN Hierarchy: MEOH-SYN

   MEOH SYNTHESIS FEED GAS QUALITY:

     (H2 - CO2) / (CO + CO2)
       TARGET =                               2.10
       ACTUAL =                               2.101

     H2 / (2 CO + 3 CO2)
       TARGET =                               1.05
       ACTUAL =                               1.045

     H2 / CO
       ACTUAL =                               3.101

   MEOH SYNTHESIS OPERATING PARAMETERS:

     MOLAR RECYCLE RATIO
       TARGET =                         3.0 - 4.0
       ACTUAL =                               4.00

     REACTOR INLET CO2 CONCENTRATION
       TARGET =                             < 4.0 MOL.%
       ACTUAL =                               2.51 MOL.%

     REACTOR OUTLET MEOH CONCENTRATION
       TARGET =                         3.0 - 8.0 MOL.%
       ACTUAL =                               7.13 MOL.%

     METHANOL PRODUCT CO2 CONCENTRATION
       TARGET =                             500. PPBW
       ACTUAL =                             500. PPBW


Calculator Block MTG      Hierarchy: MTG

   YIELD SUMMARY (LB / 1,000 LB MEOH):

     PRODUCT                      EXXON LIT.   MODEL RESULT

     GASOLINE                      387.          386.
     LPG                            46.           46.
     FUEL GAS                        7.            8.
     WATER                         560.          560.
```

Nuclear-Integrated Gas to MTG Results

PRODUCT SUMMARY:

GASOLINE PRODUCT:

PRODUCTION RATE =	355585. LB/HR
PRODUCTION RATE =	33470. BBL/DAY
MOLECULAR WEIGHT =	94.5
CARBON PERCENT =	85.6
HIGHER HEAT CONTENT =	19941. BTU/LB
LOWER HEAT CONTENT =	18619. BTU/LB

PROPERTY COMPARISON:

PROPERTY	EXXON LIT.	MODEL RESULT
API GRAVITY, °	61.8	62.9
SPECIFIC GRAVITY	0.732	0.728
REED VAPOR PRES., PSI	9.0	8.7
AROMATIC CONTENT, %	26.5	24.3
OLEFIN CONTENT, %	12.6	16.4
BENZENE CONTENT, %	0.3	0.5
D86T 50%, °F	201.0	156.5
D86T 90%, °F	320.0	332.2

LPG PRODUCT:

PRODUCTION RATE =	42366. LB/HR
PRODUCTION RATE =	5278. BBL/DAY
SPECIFIC GRAVITY =	0.55
MOLECULAR WEIGHT =	50.0
CARBON PERCENT =	81.4
HIGHER HEAT CONTENT =	21221. BTU/LB
LOWER HEAT CONTENT =	19562. BTU/LB

FUEL GAS PRODUCT:

NET PRODUCTION RATE =	6962. LB/HR
NET PRODUCTION RATE =	4.87 MMSCFD @ 60°F
MOLECULAR WEIGHT =	13.0
HIGHER HEAT CONTENT =	25637. BTU/LB

Calculator Block NG-RFMR Hierarchy: NG-RFMR

SULFUR REMOVAL CONDITIONS:

INLET BED TEMPERATURE =	662. °F

NUCLEAR REFORMER CONDITIONS:

INLET TEMPERATURE =	1000. °F
STEAM TO CARBON MOLAR RATIO =	1.80
OUTLET TEMPERATURE =	1211. °F
METHANE CONVERSION =	11.6 %

PRIMARY REFORMER CONDITIONS:

INLET TEMPERATURE =	1211. °F
STEAM TO CARBON MOLAR RATIO =	1.42
OUTLET TEMPERATURE =	1362. °F
METHANE CONVERSION =	15.3 %

SECONDARY REFORMER CONDITIONS:

INLET TEMPERATURE =	1362. °F

Nuclear-Integrated Gas to MTG Results

STEAM TO CARBON MOLAR RATIO =	1.27
OXYGEN TO CARBON MOLAR RATIO =	0.41
OUTLET TEMPERATURE =	1900. °F
H_2/CO =	3.10
$(H_2 - CO_2)/(CO + CO_2)$ =	2.10

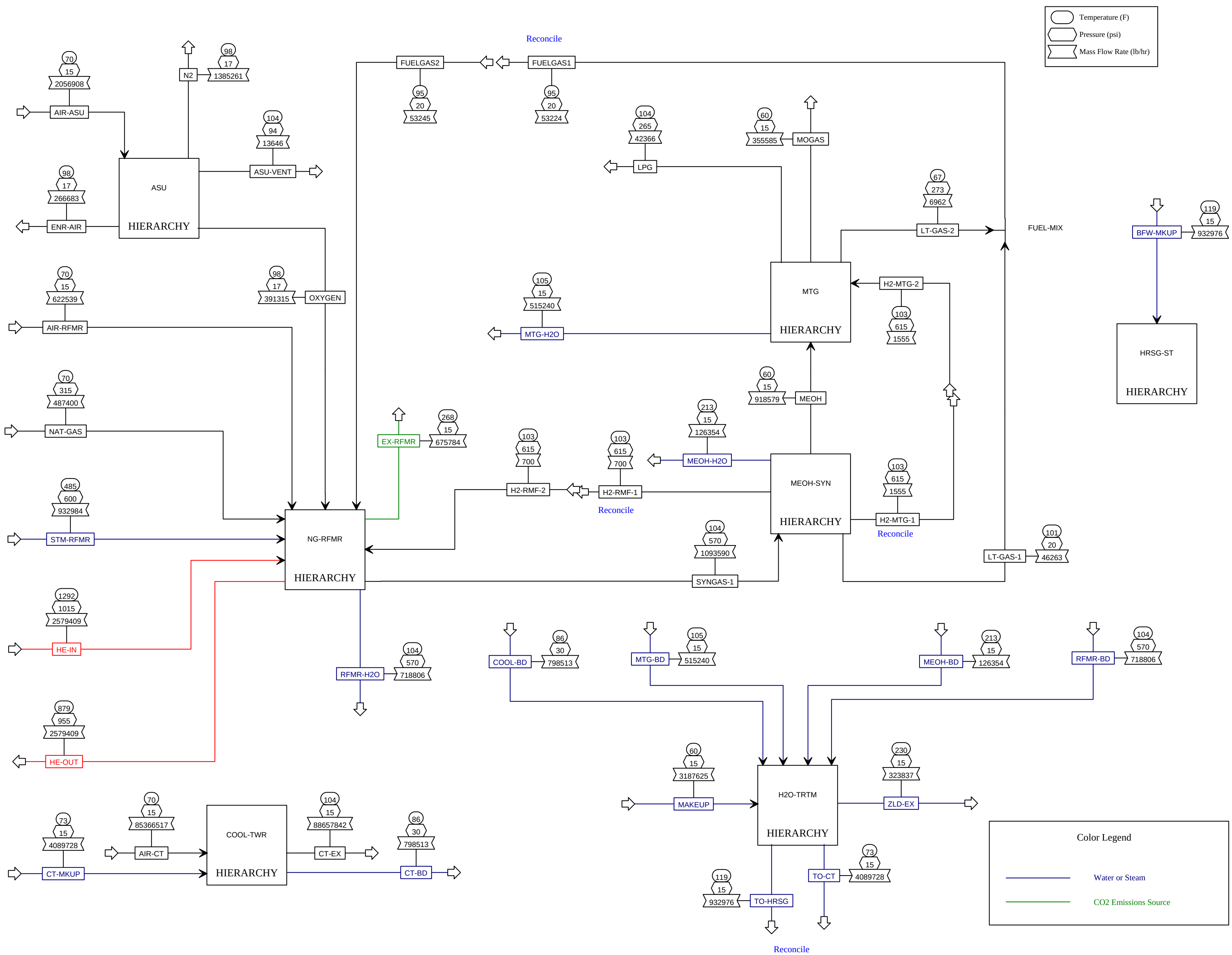
OUTLET COMPOSITION (PRE-CONDENSER):

H_2	48.4780 MOL.%
CO	15.6316 MOL.%
CO_2	5.0412 MOL.%
H_2O	29.9603 MOL.%
CH_4	0.5976 MOL.%

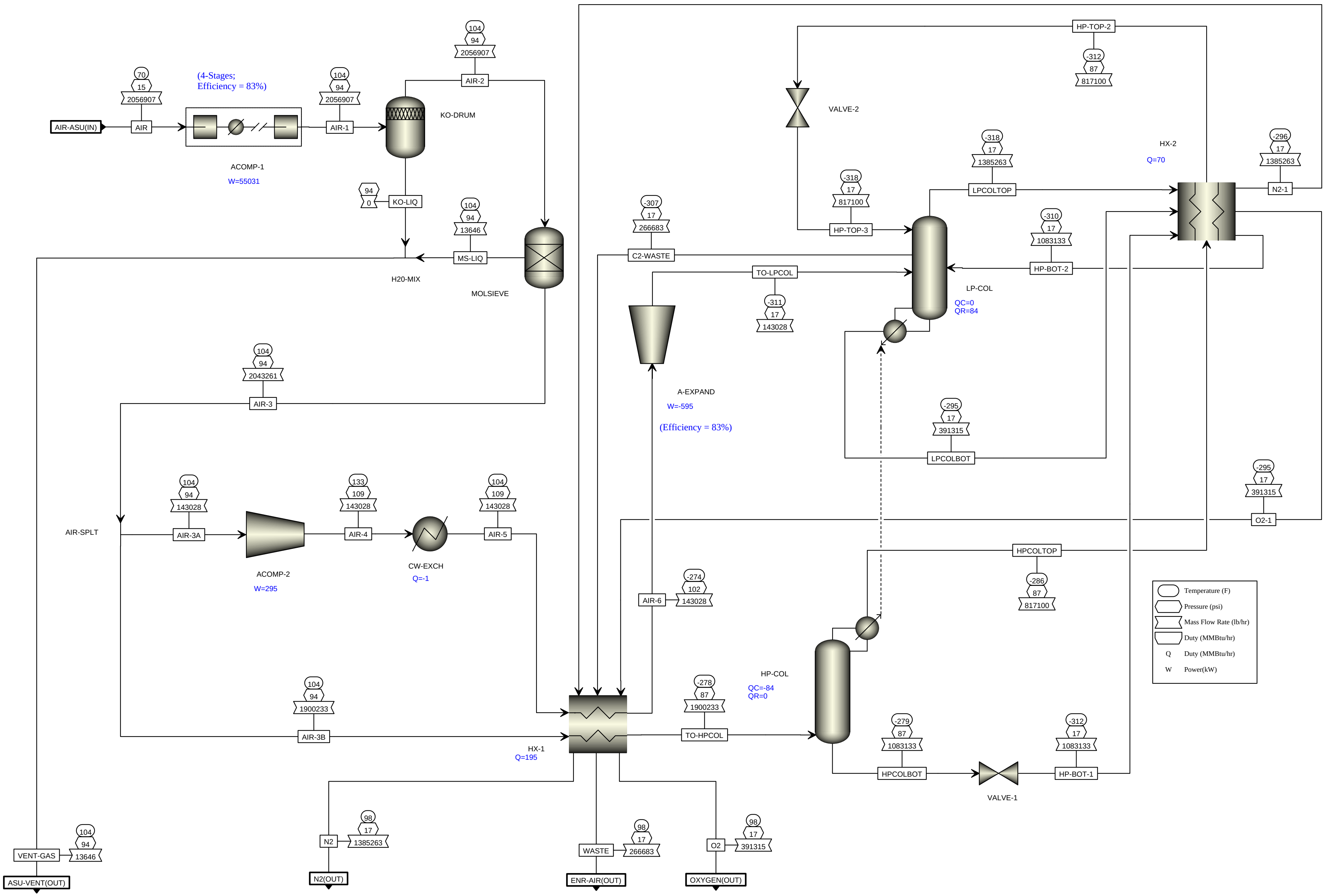
OUTLET COMPOSITION (POST-CONDENSER):

H_2	69.0834 MOL.%
CO	22.2758 MOL.%
CO_2	7.1822 MOL.%
H_2O	0.2015 MOL.%
CH_4	0.8515 MOL.%

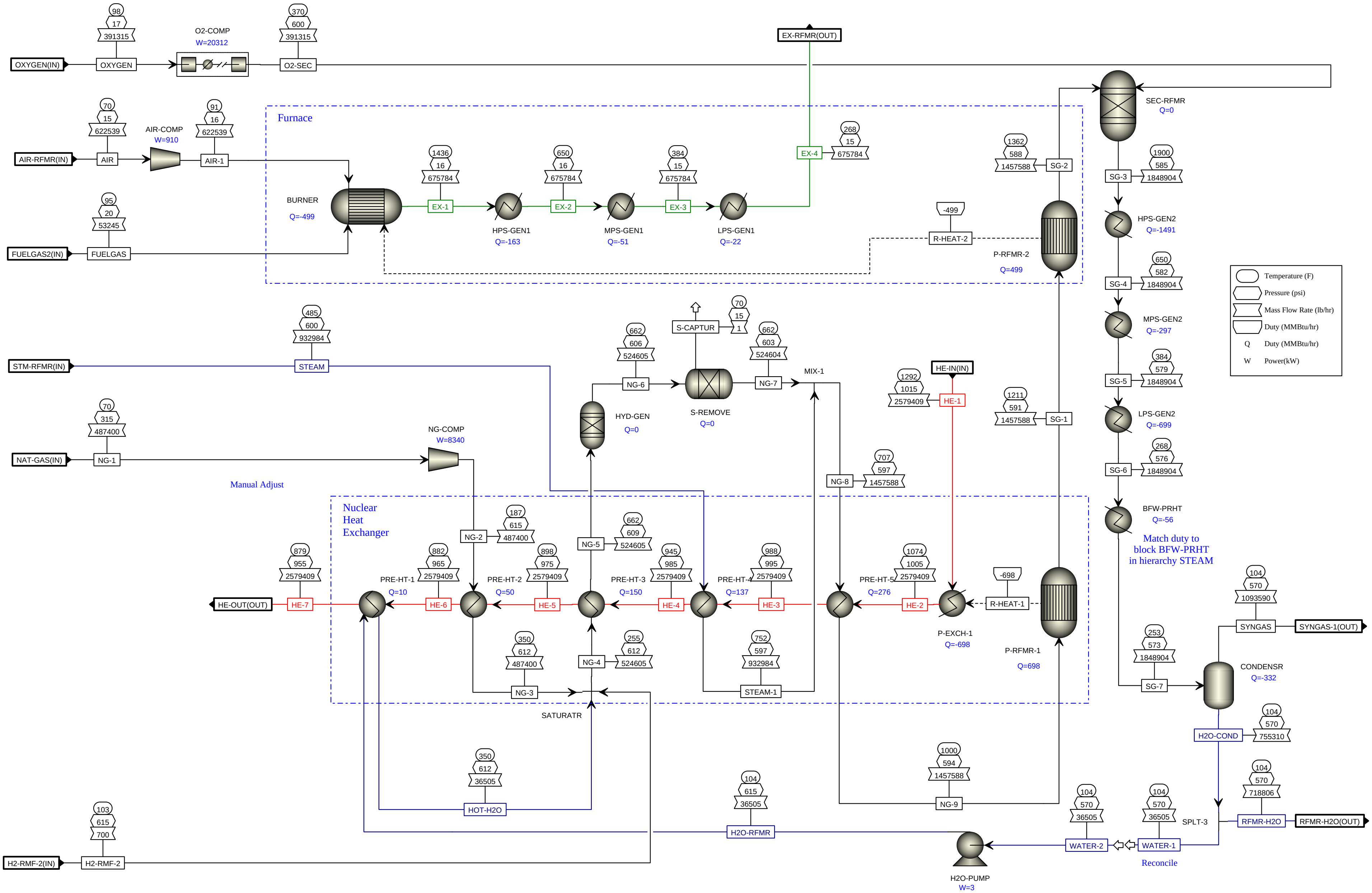
Natural Gas to Methanol to Gasoline - Nuclear Integration



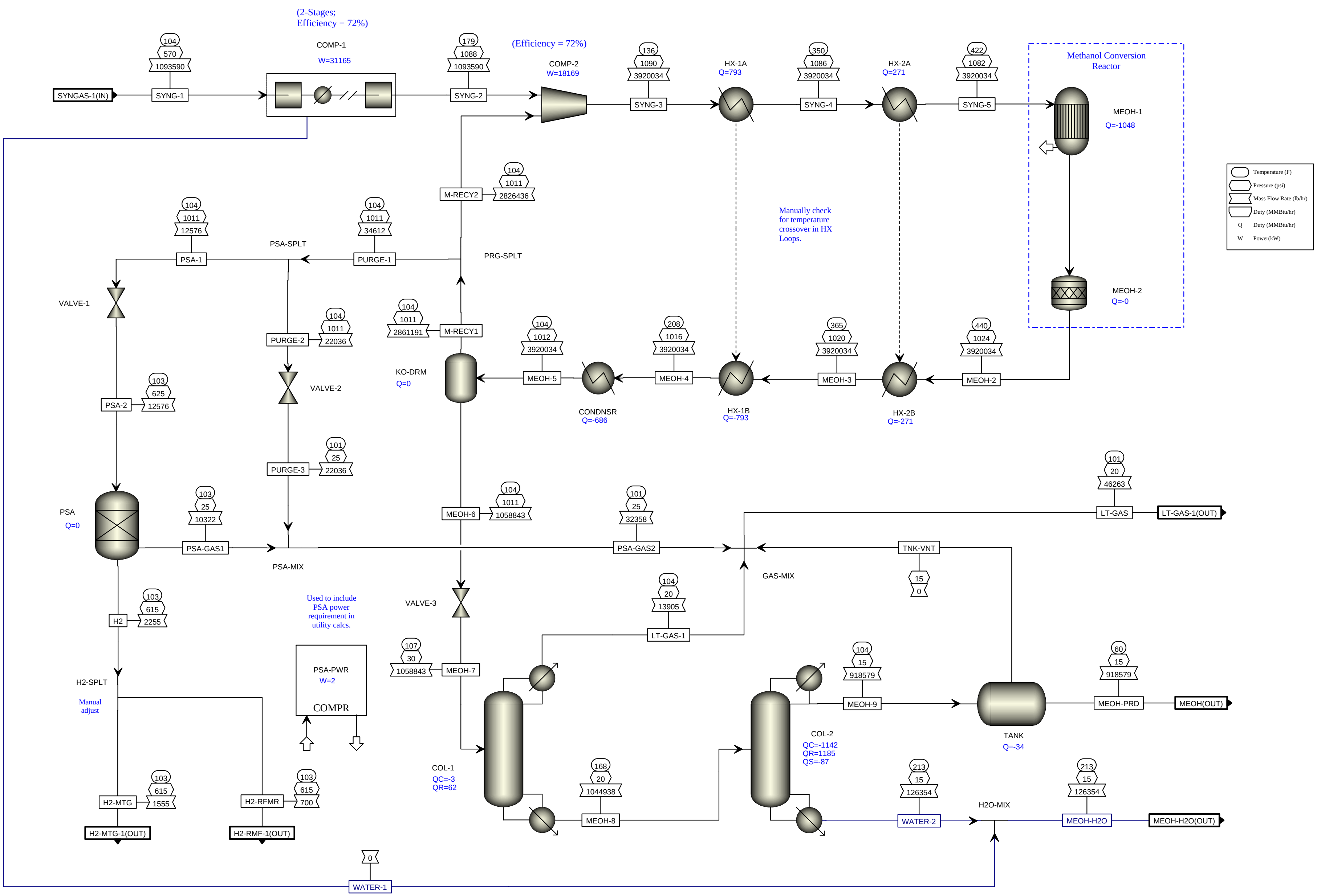
Air Separation Unit 99.5% O2 Purity



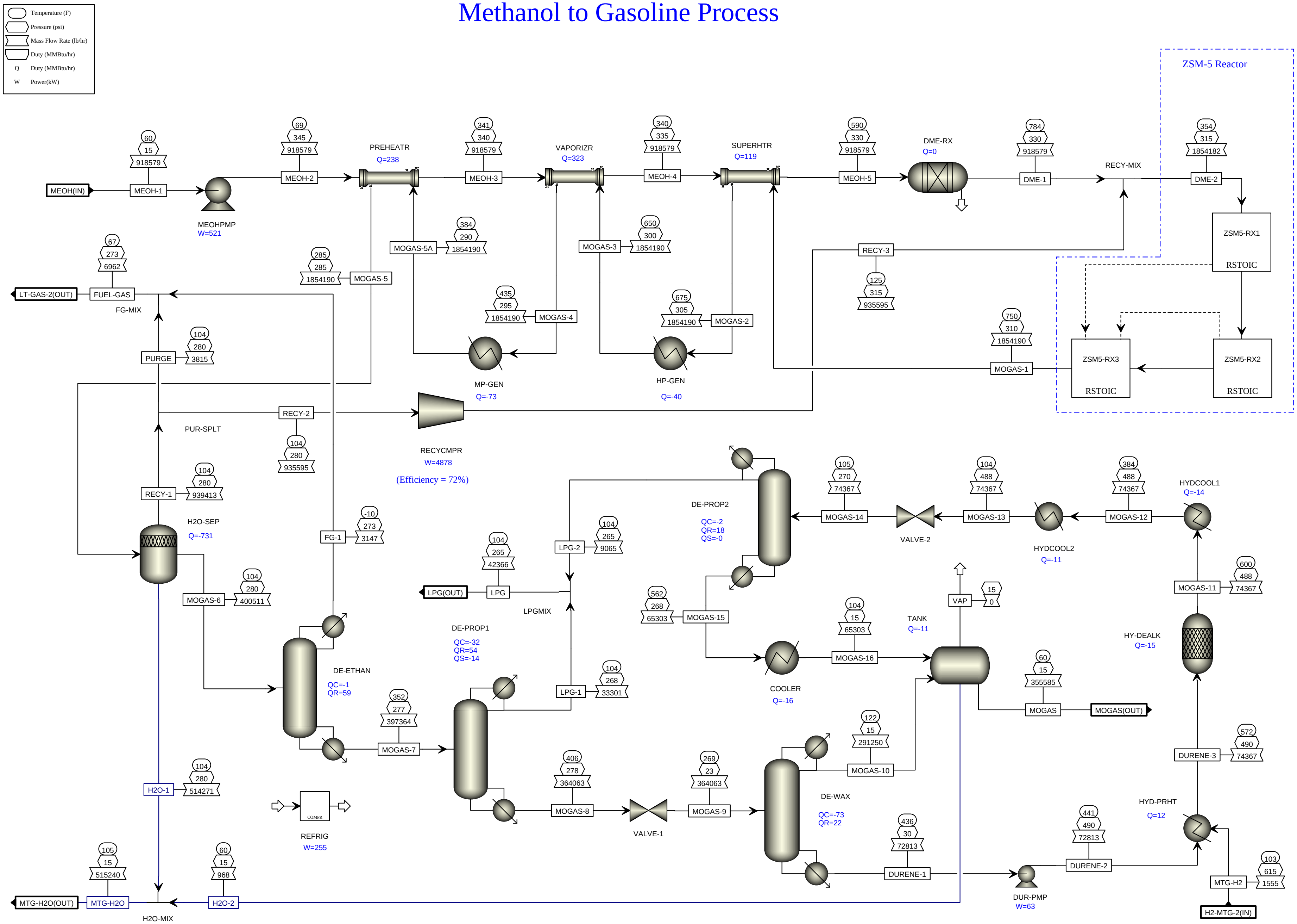
Natural Gas Two-Step Reforming



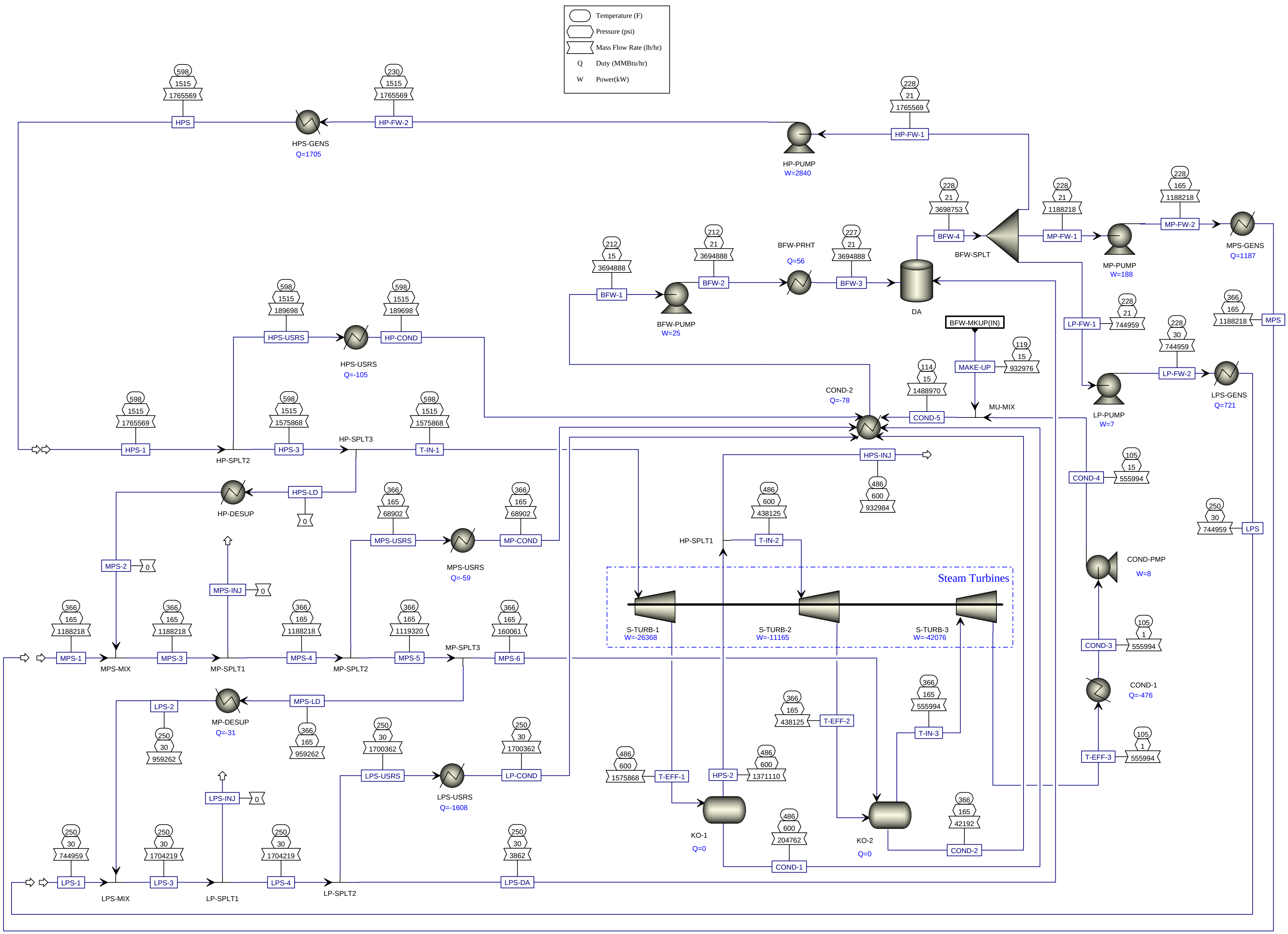
Methanol Synthesis



Methanol to Gasoline Process

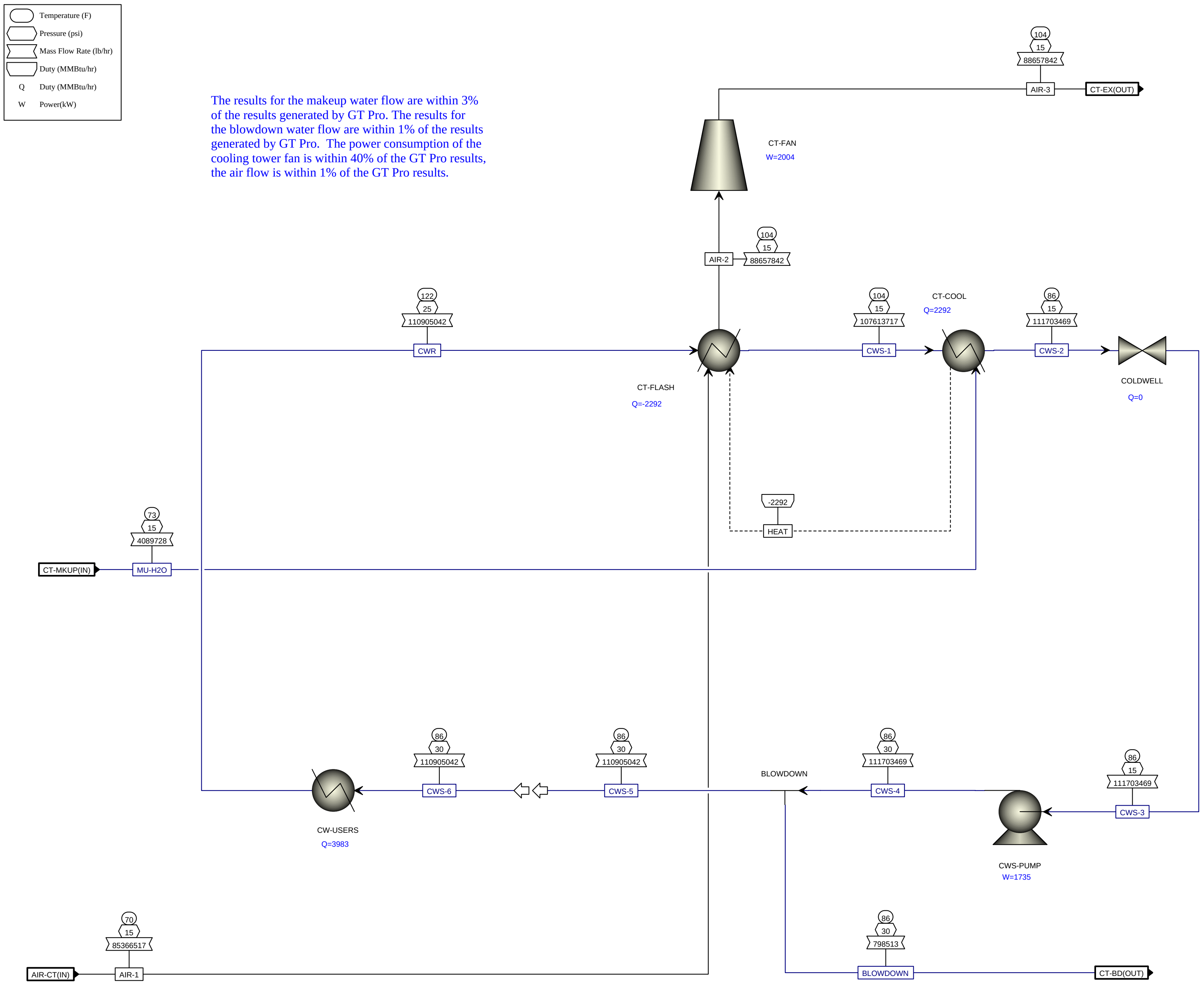


HRSG & Steam Turbines

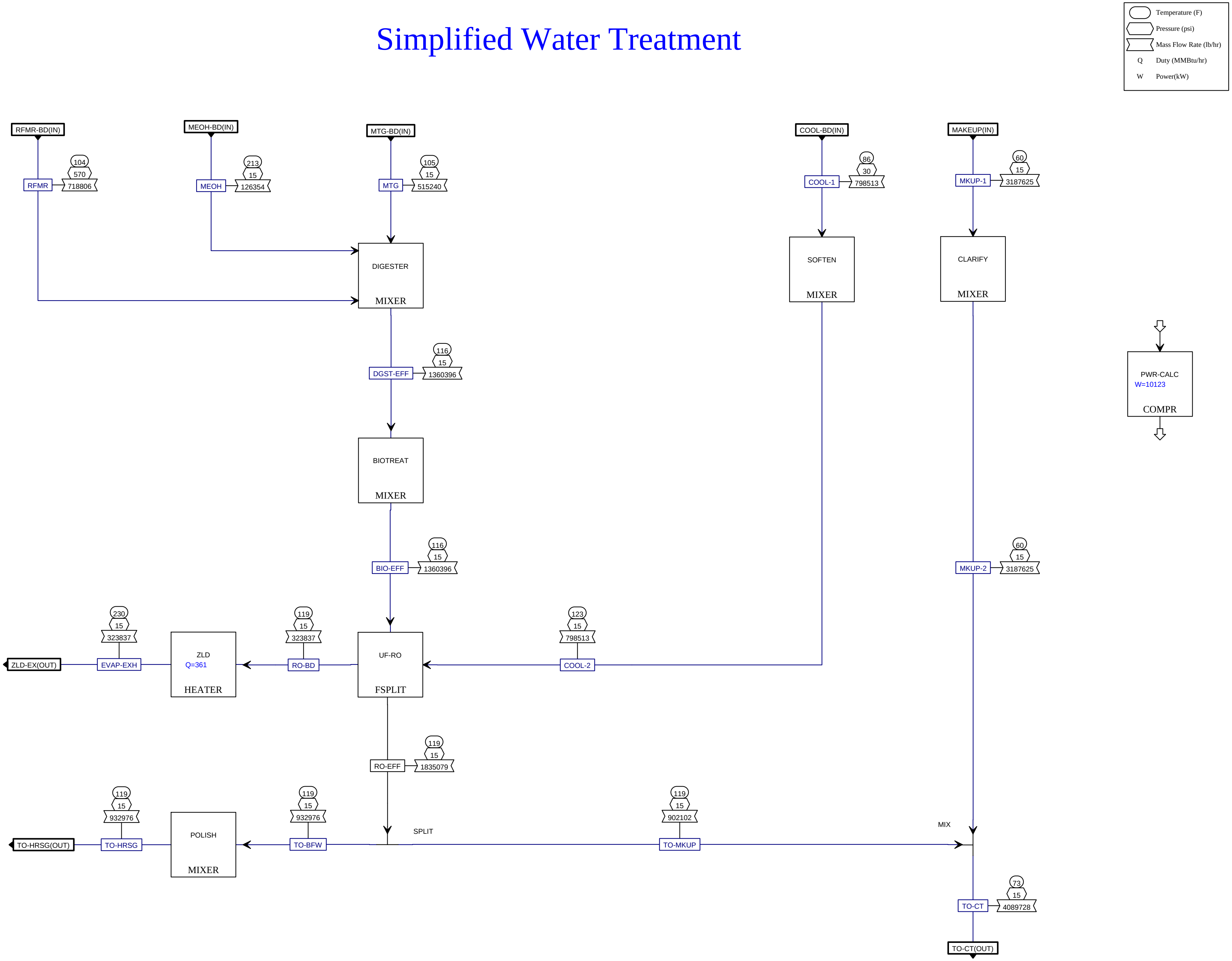


Cooling Tower

The results for the makeup water flow are within 3% of the results generated by GT Pro. The results for the blowdown water flow are within 1% of the results generated by GT Pro. The power consumption of the cooling tower fan is within 40% of the GT Pro results, the air flow is within 1% of the GT Pro results.



Simplified Water Treatment



Appendix B
MTG Capital Cost Estimates

INTEROFFICE MEMORANDUM

Idaho National Laboratory INL

Date: April 20, 2010

To: M. W. Patterson, Project Manager

From: B. W. Wallace, Cost Estimator BWW

Subject: NGNP Process Integration Estimates MA36-A through MA36-R

Per your request, Cost Estimating prepared cost estimates (Class 5) for the above-mentioned subject. The total estimated costs (TEC) rounded to the nearest $10 million, including contingency for these estimates are as follows:

MA36-A NGNP – Conventional Coal to Liquid $5,060,000,000
MA36-B NGNP – Nuclear Coal to Liquid $16,540,000,000
MA36-C NGNP – Conventional Gas to Liquid..............................$1,920,000,000
MA36-D NGNP – Nuclear Gas to Liquid $3,010,000,000
MA36-E NGNP – Conventional Coal to Synthetic Natural Gas......$1,920,000,000
MA36-F NGNP – Nuclear Coal to Synthetic Natural Gas..............$8,460,000,000
MA36-G NGNP – Conventional Coal to Methanol to Gas.............$5,940,000,000
MA36-H NGNP – Nuclear Coal to Methanol to Gas....................$18,470,000,000
MA36-I NGNP – Conventional Gas to Methanol to Gas................$1,690,000,000
MA36-J NGNP – Nuclear Gas to Methanol to Gas.........................$3,030,000,000
MA36-L NGNP – Conventional Coal to Ammonia $2,150,000,000
MA36-M NGNP – Conventional Gas to Ammonia $1,660,000,000
MA36-N NGNP – Nuclear Gas to Ammonia $2,530,000,000
MA36-O NGNP – HTSE Ammonia w/o ASU $6,940,000,000
MA36-P NGNP – HTSE Ammonia w/ ASU..................................$6,300,000,000
MA36-Q NGNP – Conventional Steam Assisted Gravity Drained..$1,060,000,000
MA36-R NGNP – Nuclear Steam Assisted Gravity Drained..........$2,720,000,000

Please note the following:

A. These estimates are intended for use as an input to economic analysis models that will be used in a feasibility study. An allowance for contingency instead of management reserve has been included in the estimates to align more closely with commercial practices and terminology.
B. These estimates reflect the nth of a kind (NOAK) projects. Use of NOAK in these estimates represented a condition where construction of both the integrated capability and the high temperature gas reactor (HTGR) is common place and represents routine construction.
C. All costs represent 2009 values, and construction costs are considered to be overnight costs. Forward looking factors for escalation are not included in the estimates.
D. These cost estimates have been evaluated in the AACEI classification matrix as Class 5 estimates (*ref. DOE G. 430.1-1X, Appendix J*). The primary characteristic used in this guideline to define the classification category is the degree of project definition at this time.

The intent of this classification is to assist in the interpretation of the quality and value of the information available to prepare these cost estimates and the expected accuracy levels that can be produced. Per AACEI, a Class 5 indicates the lowest amount of project information, quality, and value with a graded approach to a Class 1, which indicates the highest amount of project information, quality, and value.

E. In addition to multiple internal reviews performed with the appropriate project team technical lead, an external review of the cost estimates has been performed by Washington Division United Research Services (URS) Corporation. A meeting with URS and the Next-Generation Nuclear Plant (NGNP) Process Integration team on April 7, 2010, allowed the project team and this estimator to discuss, in detail, the perceived scope, basis of estimates, assumptions, project risks, and the resources that make up this cost estimate. Comments from this review have been incorporated into these estimates to reflect a project team consensus of the documents.
F. It is intended that these estimates reflect commercial construction of the facilities addressed. It is not intended, nor are there provisions included in the estimates that would make them appropriate for construction at Idaho National Laboratory.

Refer to the cost estimating summary, detail, markup, and labor sheets with the cost breakdowns. Also included for your use are the cost estimate recapitulation sheets describing the basis and assumptions used in development of this estimate.

These estimates, the work, and the work breakdown structure are based on the information perceived by this estimator as to the scope of work to be completed. Any changes to the methodology used to prepare these estimates could have a significant effect on the cost estimates and/or schedules and should be reviewed by me. If you have any questions or comments, do not hesitate to contact me at 526-5896 or e-mail Bruce.Wallace@inl.gov.

Attachments

cc: (electronic only)
A. M. Gandrik
R. R. Honsinger
V. C. Maio
J. B. Martin
M. G. McKellar
L. O. Nelson
M. M. Plum
R. A. Wood
Estimate Files MA36-A through MA36-J and MA36-L through MA36-R

Uniform File Code: 8309
Disposition Authority: A16-1.5-b
Retention Schedule: Cut off at the end of each fiscal year. Destroy 10 years after cutoff.

NOTE: Original disposition authority, retention schedule, and Uniform Filing Code applied by the sender may not be appropriate for all recipients. Make adjustments as needed.

NGNP Conventional Coal to MTG Summary

Project Name: NGNP Process Integration
Process: Conventional Coal to MTG
Estimate Number: MA36-G

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

Process Component	Subtotal From Detail Sheets	Engineering %	Engineering	Contingency %	Contingency	Total Cost
Air Separation Unit (ASU)	$ 501,830,154	10%	$ 50,183,015	18%	$ 99,362,371	$ 651,375,540
Coal Preparation	$ 358,946,221	10%	$ 35,894,622	18%	$ 71,071,352	$ 465,912,195
Gasification	$ 1,154,789,392	10%	$ 115,478,939	18%	$ 228,648,300	$ 1,498,916,630
Water Gas Shift Reactor	$ 137,235,666	10%	$ 13,723,567	18%	$ 27,172,662	$ 178,131,895
Rectisol	$ 729,204,550	10%	$ 72,920,455	18%	$ 144,382,501	$ 946,507,506
Pressure Swing Adsorption (PSA)	$ 9,461,456	10%	$ 946,146	18%	$ 1,873,368	$ 12,280,969
Claus & SCOT	$ 234,623,019	10%	$ 23,462,302	18%	$ 46,455,358	$ 304,540,678
CO2 Compression	$ 76,597,773	10%	$ 7,659,777	18%	$ 15,166,359	$ 99,423,910
Methanol Synthesis	$ 549,700,660	10%	$ 54,970,066	18%	$ 108,840,731	$ 713,511,456
Gasoline Synthesis	$ 696,578,398	10%	$ 69,657,840	18%	$ 137,922,523	$ 904,158,760
Steam Turbines	$ 102,986,940	10%	$ 10,298,694	18%	$ 20,391,414	$ 133,677,048
Heat Recovery Steam Generator (HRSG)	$ 9,895,339	10%	$ 989,534	18%	$ 1,959,277	$ 12,844,150
Cooling Towers	$ 17,694,999	10%	$ 1,769,500	18%	$ 3,503,610	$ 22,968,109
Total Cost - Conventional Coal to MTG						$ 5,944,248,847
Total Cost Rounded to the Nearest $10M						$ 5,940,000,000

	Remarks
Checked By:	
Approved By:	

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

COST ESTIMATE SUPPORT DATA RECAPITULATION

Project Title: NGNP Process Integration – Conventional Coal to MTG
Estimator: B. W. Wallace/CEP, R. R. Honsinger/CEP, J. B. Martin/CCT
Date: April 20, 2010
Estimate Type: Class 5
File: MA36-G
Approved By:

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

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-methanol-to-gasoline (MTG) process.

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

1. Engineering
2. Construction of a new coal-to-MTG refinery that consists of the following:
   a. Air separation unit
   b. Coal preparation
   c. Gasification process
   d. Water gas shift reactors
   e. Rectisol unit
   f. Pressure swing adsorption
   g. Claus and SCOT processes
   h. CO_2 compression
   i. Methanol synthesis
   j. Gasoline synthesis
   k. Steam turbines, internal to process
   l. Heat recovery steam generator, internal to process
   m. Cooling towers, internal to process
   n. Allowances for Balance of Plant (BOP)/offsite/outside of battery limits (OSBL), including the following:
      (1.) Site development/improvements
      (2.) Provisions for general and administrative buildings and structures
      (3.) Provisions for OSBL piping

(4.) Provisions for OSBL instrumentation and control
(5.) Provisions for OSBL electrical
(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.

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 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 MTG

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 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 affects the basic concepts of the supply and demand theories, thus increasing costs.
4. Impacts due to large quantities of materials, special alloy materials, fabrication capability, and labor availability could all represent conditions that may increase the total cost of the project.

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

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

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

VIII. OTHER COMMENTS/CONCERNS SPECIFIC TO THE ESTIMATE:

None.

Detail Item Report - Air Separation Unit (ASU)

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Shell IGCC Base Case (NETL 2000)	213,207	lb/hr	1	1999	$ 51,204,000	$ 51,204,000	$ 67,118,402	1,524,351	lb/hr	3	508,117	lb/hr	$ 113,015,750	$ 407,740,236
NETL Baseline Report (NETL 2007a)	1,728,789	lb/hr	2	2006	$ 287,187,000	$ 143,593,500	$ 147,157,470	1,524,351	lb/hr	3	508,117	lb/hr	$ 106,987,577	$ 385,991,686
Princeton Report (Kreutz 2008)	201,264	lb/hr	1	2007	$ 105,000,000	$ 105,000,000	$ 102,322,040	1,524,351	lb/hr	3	508,117	lb/hr	$ 178,356,018	$ 643,476,020
Hydrogen Report (Gray 2004)	296,583	lb/hr	1	2004	$ 76,000,000	$ 76,000,000	$ 87,600,180	1,524,351	lb/hr	3	508,117	lb/hr	$ 121,002,848	$ 363,008,544
Shell GTC Report (Shell 2004)	385,259	lb/hr	2	2004	$ 53,760,000	$ 26,880,000	$ 30,982,801	1,524,351	lb/hr	3	508,117	lb/hr	$ 55,445,363	$ 200,036,767
Shell IGCC Power Plant with CO2 Capture (NETL 2007b)	373,498	lb/hr	2	2006	$ 144,337,000	$ 72,168,500	$ 73,959,712	1,524,351	lb/hr	3	508,117	lb/hr	$ 134,839,916	$ 486,477,853

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Average of normalized and factored costs from NETL 2007a and Gray 2004													$ 113,995,212	$ 374,500,115

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 8,093,660	$ 26,589,508
Civil/Structural/Buildings	9.20%		$ 10,487,560	$ 34,454,011
Piping	7.10%		$ 8,093,660	$ 26,589,508
Control and Instrumentation	2.60%		$ 2,963,876	$ 9,737,003
Electrical Systems	8.00%		$ 9,119,617	$ 29,960,009
		Total Balance of Plant	$ 38,758,372	$ 127,330,039
		Total Balance of Plant Plus the Selected Source	$ 152,753,585	$ 501,830,154

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 under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

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

Detail Item Report - Coal Preparation

Project Name: NGNP Process Integration
Process: Conventional Coal to MTG
Estimate Number: MA36-G

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Shell IGCC Base Case (NETL 2000)	3,171	tpd	1	1999	$ 17,826,000	$ 17,826,000	$ 23,366,390	25,934	tpd	7	3,705	tpd	$ 25,653,095	$ 179,571,667
Hydrogen Report (Gray 2004)	7,787	tpd	1	2004	$ 47,000,000	$ 47,000,000	$ 54,173,796	25,934	tpd	7	3,705	tpd	$ 34,692,297	$ 242,846,078
Shell GTC Report (Shell 2004)	5,513	tpd	2	2004	$ 60,800,000	$ 30,400,000	$ 35,040,072	25,934	tpd	7	3,705	tpd	$ 41,842,079	$ 292,894,550
Shell IGCC Power Plant with CO2 Capture (NETL 2007b)	5,678	tpd	2	2006	$ 156,785,000	$ 78,392,500	$ 80,338,191	25,934	tpd	7	3,705	tpd	$ 94,251,594	$ 659,761,159

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Average of normalized and factored cost from Gray 2004 and Shell 2004 reports													$ 38,267,188	$ 267,870,314

Balance of Plant:

Description	% of Total Cost						Cost Per Train	Total Cost
Water Systems	7.10%						$ 2,716,970	$ 19,018,792
Civil/Structural/Buildings	9.20%						$ 3,520,581	$ 24,644,069
Piping	7.10%						$ 2,716,970	$ 19,018,792
Control and Instrumentation	2.60%						$ 994,947	$ 6,964,628
Electrical Systems	8.00%						$ 3,061,375	$ 21,429,625
						Total Balance of Plant	$ 13,010,844	$ 91,075,907
						Total Balance of Plant Plus the Selected Source	$ 51,278,032	$ 358,946,221

Rationale for Selection:

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

Detail Item Report - Gasification

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Gasifier														
Shell IGCC Base Case (NETL 2000)	2,977	tpd	1	1999	$ 87,802,000	$ 87,802,000	$ 115,091,203	23,810	tpd	7	3,401	tpd	$ 124,672,466	$ 872,707,260
Hydrogen Report (Gray 2004)	5,990	tpd	1	2004	$ 87,000,000	$ 87,000,000	$ 100,279,154	23,810	tpd	7	3,401	tpd	$ 71,408,562	$ 999,719,862
Shell IGCC Power Plant with CO2 Capture (NETL 2007b)	5,310	tpd	2	2006	$ 196,948,000	$ 98,474,000	$ 100,918,110	23,810	tpd	7	3,401	tpd	$ 117,092,653	$ 819,648,574
Shell GTC Report (Shell 2004)	5,201	tpd	2	2004	$ 202,240,000	$ 101,120,000	$ 116,554,345	23,810	tpd	7	3,401	tpd	$ 136,927,309	$ 958,491,160
Quench Compressor														
Shell IGCC Base Case (NETL 2000)	194,116	lb/hr	1	1999	$ 1,900,000	$ 1,900,000	$ 2,490,527	3,586,547	lb/hr	7	512,364	lb/hr	$ 4,458,632	$ 31,210,423

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Average of normalized and factored costs from NETL 2000 and NETL 2007b reports, including the NETL 2000 quench compressor cost with the NETL 2000 gasifier cost.													$ 123,111,875	$ 861,783,128

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 8,740,943	$ 61,186,602
Civil/Structural/Buildings	9.20%		$ 11,326,293	$ 79,284,048
Piping	7.10%		$ 8,740,943	$ 61,186,602
Control and Instrumentation	2.60%		$ 3,200,909	$ 22,406,361
Electrical Systems	8.00%		$ 9,848,950	$ 68,942,650
		Total Balance of Plant	$ 41,858,038	$ 293,006,264
		Total Balance of Plant Plus the Selected Source	$ 164,969,913	$ 1,154,789,392

Rationale for Selection:

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

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

Detail Item Report - Water Gas Shift Reactor

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Princeton Report (Kreutz 2008)	815	MW	1	2007	$ 11,760,000	$ 11,760,000	$ 11,460,069	6,616	MW	3	2,205	MW	$ 20,825,075	$ 62,475,225
Hydrogen Report (Gray 2004)	48,243	lbmol/hr	1	2004	$ 23,000,000	$ 23,000,000	$ 26,510,581	220,593	lbmol/hr	3	73,531	lbmol/hr	$ 34,138,225	$ 102,414,676
Shell IGCC Power Plant with CO2 Capture (NETL 2007b)	1,714,460	lbmol/hr	4	2006	$ 12,367,000	$ 3,091,750	$ 3,168,487	4,343,335	lbmol/hr	3	1,447,778	lbmol/hr	$ 6,577,074	$ 19,731,222

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Hydrogen Report (Gray 2004)	48,243	lbmol/hr	1	2004	$ 23,000,000	$ 23,000,000	$ 26,510,581	220,593	lbmol/hr	3	73,531	lbmol/hr	$ 34,138,225	$ 102,414,676

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 2,423,814	$ 7,271,442
Civil/Structural/Buildings	9.20%		$ 3,140,717	$ 9,422,150
Piping	7.10%		$ 2,423,814	$ 7,271,442
Control and Instrumentation	2.60%		$ 887,594	$ 2,662,782
Electrical Systems	8.00%		$ 2,731,058	$ 8,193,174
		Total Balance of Plant	$ 11,606,997	$ 34,820,990
		Total Balance of Plant Plus the Selected Source	$ 45,745,222	$ 137,235,666

Rationale for Selection:

Gray 2004 was selected based on input from the project team technical lead. The allowances listed under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

Detail Item Report - Rectisol

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Fluor/UOP Report (Fluor/UOP 2004)	28,735	lbmol/hr	1	2003	$ 91,640,000	$ 91,640,000	$ 116,715,622	245,378	lbmol/hr	3	81,793	lbmol/hr	$ 218,630,571	$ 655,891,712
Princeton Report (Kreutz 2008)	700,000	Nm3/hr	1	2007	$ 129,043,041	$ 129,043,041	$ 125,751,879	2,636,889	Nm3/hr	3	878,963	Nm3/hr	$ 144,157,763	$ 432,473,288

Source Selected:

Source	Reported Capacity	Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required	Trains Reqd.	Capacity per Train	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Average of normalized and factored costs from Fluor/UOP 2004 and Kreutz 2008										$ 181,394,167	$ 544,182,500

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 12,878,986	$ 38,636,957
Civil/Structural/Buildings	9.20%		$ 16,688,263	$ 50,064,790
Piping	7.10%		$ 12,878,986	$ 38,636,957
Control and Instrumentation	2.60%		$ 4,716,248	$ 14,148,745
Electrical Systems	8.00%		$ 14,511,533	$ 43,534,600
		Total Balance of Plant	$ 61,674,017	$ 185,022,050
		Total Balance of Plant Plus the Selected Source	$ 243,068,183	$ 729,204,550

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 - Pressure Swing Adsorption (PSA)

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Fluor/UOP Report (Fluor/UOP 2004)	27,498	lbmol/hr	1	2003	$ 25,000,000	$ 25,000,000	$ 31,840,796	2,234	lbmol/hr	1	2,234	lbmol/hr	$ 7,060,788	$ 7,060,788

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Fluor/UOP Report (Fluor/UOP 2004)	27,498	lbmol/hr	1	2003	$ 25,000,000	$ 25,000,000	$ 31,840,796	2,234	lbmol/hr	1	2,234	lbmol/hr	$ 7,060,788	$ 7,060,788

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 501,316	$ 501,316
Civil/Structural/Buildings	9.20%		$ 649,592	$ 649,592
Piping	7.10%		$ 501,316	$ 501,316
Control and Instrumentation	2.60%		$ 183,580	$ 183,580
Electrical Systems	8.00%		$ 564,863	$ 564,863
		Total Balance of Plant	$ 2,400,668	$ 2,400,668
		Total Balance of Plant Plus the Selected Source	$ 9,461,456	$ 9,461,456

Rationale for Selection:

Single source cost point. The allowances listed under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

Detail Item Report - Claus and SCOT

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Claus and SCOT														
Princeton Report (Kreutz 2008)	12,586	lb/hr	1	2007	$ 33,800,000	$ 33,800,000	$ 32,937,952	68,848	lb/hr	6	11,475	lb/hr	$ 31,160,757	$ 186,964,544
Shell IGCC Power Plant with CO2 Capture (NETL 2007b)	142	tpd	1	2006	$ 22,794,000	$ 22,794,000	$ 23,359,744	826	tpd	6	138	tpd	$ 22,939,076	$ 137,634,455
Claus														
Shell IGCC Base Cases (NETL 2000)	6,496	lb/hr	1	1999	$ 9,964,000	$ 9,964,000	$ 13,060,850	68,848	lb/hr	6	11,475	lb/hr	$ 18,375,532	$ 110,253,190
Cost Effective Options to Expand SRU Capacity Using Oxygen (WorleyParsons 2002)	79	tpd	1	1999	$ 11,970,000	$ 11,970,000	$ 15,690,323	826	tpd	6	138	tpd	$ 21,834,828	$ 131,008,966
SCOT														
Shell IGCC Base Cases (NETL 2000)	6,496	lb/hr	1	1999	$ 4,214,000	$ 4,214,000	$ 5,523,728	68,848	lb/hr	2	34,424	lb/hr	$ 15,023,582	$ 30,047,163
Cost Effective Options to Expand SRU Capacity Using Oxygen (WorleyParsons 2002)	143	tpd	1	1999	$ 8,910,000	$ 8,910,000	$ 11,679,263	826	tpd	2	413	tpd	$ 22,041,420	$ 44,082,839

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
WorleyParsons 2002: Combined Claus and SCOT costs													$ 43,876,247	$ 175,091,805

Detail Item Report - Claus and SCOT

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

Balance of Plant:

Description	% of Total Cost						Cost Per Train	Total Cost
Water Systems	7.10%						$ 3,115,214	$ 12,431,518
Civil/Structural/Buildings	9.20%						$ 4,036,615	$ 16,108,446
Piping	7.10%						$ 3,115,214	$ 12,431,518
Control and Instrumentation	2.60%						$ 1,140,782	$ 4,552,387
Electrical Systems	8.00%						$ 3,510,100	$ 14,007,344
						Total Balance of Plant	$ 14,917,924	$ 59,531,214
						Total Balance of Plant Plus the Selected Source	$ 58,794,171	$ 234,623,019

Rationale for Selection:

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

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

Detail Item Report - CO2 Compression

Project Name: NGNP Process Integration
Process: Conventional Coal to MTG
Estimate Number: MA36-G

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Subcritical														
Princeton Report (Kreutz 2008)	10	MW	1	2007	$ 6,310,000	$ 6,310,000	$ 6,149,067	119	MW	3	40	MW	$ 14,047,376	$ 42,142,127
Supercritical														
Princeton Report (Kreutz 2008)	13	MW	1	2007	$ 9,520,000	$ 9,520,000	$ 9,277,198	14	MW	3	5	MW	$ 5,006,797	$ 15,020,390

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Kreutz 2008: Combined Subcritical and Supercritical Processes													$ 19,054,172	$ 57,162,517

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 1,352,846	$ 4,058,539
Civil/Structural/Buildings	9.20%		$ 1,752,984	$ 5,258,952
Piping	7.10%		$ 1,352,846	$ 4,058,539
Control and Instrumentation	2.60%		$ 495,408	$ 1,486,225
Electrical Systems	8.00%		$ 1,524,334	$ 4,573,001
		Total Balance of Plant	$ 6,478,419	$ 19,435,256
		Total Balance of Plant Plus the Selected Source	$ 25,532,591	$ 76,597,773

Rationale for Selection:

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

Detail Item Report - Methanol Synthesis

Project Name: NGNP Process Integration
Process: Conventional Coal to MTG
Estimate Number: MA36-G

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Economics of Producing Methanol from Coal by Entrained and Fluidized-Bed Gasifiers (U.S. DOI Bureau of Mines, August 1977)	5000	tpd	1	1977	$ 63,096,600	$ 63,096,600	$ 158,282,505	20,055	tpd	3	6,685	tpd	$ 188,413,388	$ 565,240,163
Investigations on Catalyzed Steam Gasification of Biomass (PNL-3695 1981)	997	tpd	1	1980	$ 22,000,000	$ 22,000,000	$ 43,124,043	20,055	tpd	3	6,685	tpd	$ 135,071,344	$ 405,214,032
H-Coal and Coal-to-Methanol Liquefaction Processes: Process Engineering Evaluation (EPRI AP-3290, November 1983)	15919	tpd	6	1982	$ 183,327,000	$ 30,554,500	$ 49,821,350	20,055	tpd	3	6,685	tpd	$ 86,739,641	$ 260,218,924

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Average of the three available sources.													$ 136,741,458	$ 410,224,373

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 9,708,643	$ 29,125,930
Civil/Structural/Buildings	9.20%		$ 12,580,214	$ 37,740,642
Piping	7.10%		$ 9,708,643	$ 29,125,930
Control and Instrumentation	2.60%		$ 3,555,278	$ 10,665,834
Electrical Systems	8.00%		$ 10,939,317	$ 32,817,950
		Total Balance of Plant	$ 46,492,096	$ 139,476,287
		Total Balance of Plant Plus the Selected Source	$ 183,233,553	$ 549,700,660

Rationale for Selection:

Considering the date of the source and the available assumptions and methodologies used, an average cost for all sources was used to minimize reporting errors. 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.

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Detail Item Report - Gasoline Synthesis

Project Name: NGNP Process Integration
Process: Conventional Coal to MTG
Estimate Number: MA36-G

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Gas Usage & Value The Technology and Economics of Natural Gas Use in the Process Industries (PennWell Corporation, 2006)	14500	bpd	1	1985	$ 92,925,000	$ 92,925,000	$ 146,257,608	57,703	bpd	3	19,234	bpd	$ 173,278,208	$ 519,834,625

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Gas Usage & Value The Technology and Economics of Natural Gas Use in the Process Industries (PennWell Corporation, 2006)	14500	bpd	1	1985	$ 92,925,000	$ 92,925,000	$ 146,257,608	57,703	bpd	3	19,234	bpd	$ 173,278,208	$ 519,834,625

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 12,302,753	$ 36,908,258
Civil/Structural/Buildings	9.20%		$ 15,941,595	$ 47,824,786
Piping	7.10%		$ 12,302,753	$ 36,908,258
Control and Instrumentation	2.60%		$ 4,505,233	$ 13,515,700
Electrical Systems	8.00%		$ 13,862,257	$ 41,586,770
		Total Balance of Plant	$ 58,914,591	$ 176,743,773
		Total Balance of Plant Plus the Selected Source	$ 232,192,799	$ 696,578,398

Rationale for Selection:

Single source cost point. The allowances listed under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

Detail Item Report - Steam Turbines

Project Name: NGNP Process Integration
Process: Conventional Coal to MTG
Estimate Number: MA36-G

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Steam Turbine and HRSG														
Shell IGCC Base Cases (NETL 2000)	189	MW	1	1999	$ 50,671,000	$ 50,671,000	$ 66,419,744	346	MW	2	173	MW	$ 62,971,906	$ 125,943,812
Steam Turbine														
NETL Baseline Report (NETL 2007a)	401	MW	4	2006	$ 74,651,000	$ 18,662,750	$ 19,125,957	346	MW	2	173	MW	$ 26,510,833	$ 53,021,666
Princeton Report (Kreutz 2008)	275	MW	1	2007	$ 66,700,000	$ 66,700,000	$ 64,998,858	346	MW	2	173	MW	$ 49,176,424	$ 98,352,848
Shell IGCC Power Plant with CO2 Capture (NETL 2007b)	230	MW	1	2006	$ 44,515,000	$ 44,515,000	$ 45,619,856	346	MW	2	173	MW	$ 38,427,963	$ 76,855,925

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Shell IGCC Power Plant with CO2 Capture (NETL 2007b)	230	MW	1	2006	$ 44,515,000	$ 44,515,000	$ 45,619,856	346	MW	2	173	MW	$ 38,427,963	$ 76,855,925

Balance of Plant:

Description	% of Total Cost						Cost Per Train	Total Cost
Water Systems	7.10%						$ 2,728,385	$ 5,456,771
Civil/Structural/Buildings	9.20%						$ 3,535,373	$ 7,070,745
Piping	7.10%						$ 2,728,385	$ 5,456,771
Control and Instrumentation	2.60%						$ 999,127	$ 1,998,254
Electrical Systems	8.00%						$ 3,074,237	$ 6,148,474
						Total Balance of Plant	$ 13,065,507	$ 26,131,015
						Total Balance of Plant Plus the Selected Source	$ 51,493,470	$ 102,986,940

Rationale for Selection:

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

Detail Item Report - HRSG

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Steam Turbine and HRSG														
Shell IGCC Base Cases (NETL 2000)	189	MW	1	1999	$ 50,671,000	$ 50,671,000	$ 66,419,744	346	MW	2	173	MW	$ 62,971,906	$ 125,943,812
HRSG														
NETL Baseline Report (NETL 2007a)	5,155,983	lb/hr	3	2006	$ 27,581,000	$ 9,193,667	$ 9,421,852	394,170	lb/hr	2	197,085	lb/hr	$ 2,569,297	$ 5,138,594
Princeton Report (Kreutz 2008)	355	MW	1	2007	$ 52,000,000	$ 52,000,000	$ 50,673,772	59	MW	2	30	MW	$ 11,447,471	$ 22,894,942
Shell IGCC Power Plant with CO2 Capture (NETL 2007b)	8,438,000	lb/hr	2	2006	$ 45,291,000	$ 22,645,500	$ 23,207,558	394,170	lb/hr	2	197,085	lb/hr	$ 3,692,291	$ 7,384,581

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Shell IGCC Power Plant with CO2 Capture (NETL 2007b)	8,438,000	lb/hr	2	2006	$ 45,291,000	$ 22,645,500	$ 23,207,558	394,170	lb/hr	2	197,085	lb/hr	$ 3,692,291	$ 7,384,581

Balance of Plant:

Description	% of Total Cost						Cost Per Train	Total Cost
Water Systems	7.10%						$ 262,153	$ 524,305
Civil/Structural/Buildings	9.20%						$ 339,691	$ 679,381
Piping	7.10%						$ 262,153	$ 524,305
Control and Instrumentation	2.60%						$ 96,000	$ 191,999
Electrical Systems	8.00%						$ 295,383	$ 590,766
						Total Balance of Plant	$ 1,255,379	$ 2,510,758
						Total Balance of Plant Plus the Selected Source	$ 4,947,669	$ 9,895,339

Rationale for Selection:

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

Detail Item Report - Cooling Towers

Project Name: NGNP Process Integration
Process: Conventional Coal to MTG
Estimate Number: MA36-G

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Cooling Tower Depot	268,429	gpm	7	2009	$ 6,657,910	$ 951,130	$ 951,130	529,447	gpm	14	37,818	gpm	$ 943,230	$ 13,205,223

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Cooling Tower Depot	268,429	gpm	7	2009	$ 6,657,910	$ 951,130	$ 951,130	529,447	gpm	14	37,818	gpm	$ 943,230	$ 13,205,223

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 66,969	$ 937,571
Civil/Structural/Buildings	9.20%		$ 86,777	$ 1,214,881
Piping	7.10%		$ 66,969	$ 937,571
Control and Instrumentation	2.60%		$ 24,524	$ 343,336
Electrical Systems	8.00%		$ 75,458	$ 1,056,418
		Total Balance of Plant	$ 320,698	$ 4,489,776
		Total Balance of Plant Plus the Selected Source	$ 1,263,929	$ 17,694,999

Rationale for Selection:

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

NGNP Nuclear Coal to MTG Summary

Project Name: NGNP Process Integration
Process: Nuclear Coal to MTG
Estimate Number: MA36-H

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

Process Component	Subtotal From Detail Sheets	Engineering %	Engineering	Contingency %	Contingency	Total Cost
High Temperature Gas Reactor (HTGR)	$ 11,732,236,071	0%	$ -	0%	$ -	$ 11,732,236,071
Rankine Power Cycle	$ 1,680,769,141	10%	$ 168,076,914	18%	$ 332,792,290	$ 2,181,638,345
High Temperature Steam Electrolysis (HTSE)	$ 985,206,399	10%	$ 98,520,640	18%	$ 195,070,867	$ 1,278,797,906
Coal Preparation	$ 179,308,834	10%	$ 17,930,883	18%	$ 35,503,149	$ 232,742,867
Gasification	$ 576,637,913	10%	$ 57,663,791	18%	$ 114,174,307	$ 748,476,010
Rectisol	$ 339,529,433	10%	$ 33,952,943	18%	$ 67,226,828	$ 440,709,204
Claus & SCOT	$ 112,017,028	10%	$ 11,201,703	18%	$ 22,179,372	$ 145,398,103
CO2 Compression	$ 13,193,132	10%	$ 1,319,313	18%	$ 2,612,240	$ 17,124,685
Methanol Synthesis	$ 537,890,019	10%	$ 53,789,002	18%	$ 106,502,224	$ 698,181,245
Gasoline Synthesis	$ 696,585,641	10%	$ 69,658,564	18%	$ 137,923,957	$ 904,168,162
Steam Turbines	$ 60,774,185	10%	$ 6,077,418	18%	$ 12,033,289	$ 78,884,892
Heat Recovery Steam Generator (HRSG)	$ -	10%	$ -	18%	$ -	$ -
Cooling Towers	$ 11,943,128	10%	$ 1,194,313	18%	$ 2,364,739	$ 15,502,180
Total Cost - Nuclear Coal to MTG						$ 18,473,859,669
Total Cost Rounded to the Nearest $10M						$ 18,470,000,000

	Remarks
Checked By: _[signature]_	
Approved By: _[signature]_	

COST ESTIMATE SUPPORT DATA RECAPITULATION

Project Title:	NGNP Process Integration – Nuclear Coal to MTG
Estimator:	B. W. Wallace/CEP, R. R. Honsinger/CEP, J. B. Martin/CCT
Date:	April 20, 2010
Estimate Type:	Class 5
File:	MA36-H
Approved By:	

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

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 high-temperature gas reactors (HTGRs) integrated with a coal-to-methanol-to-gasoline (MTG) process.

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

1. Engineering
2. The allowance provided for the HTGR represents a complete and operable system. All elements required for construction of this nuclear reactor capability, including an initial steam generator, security systems, contingency, and owner's costs are included in the turn-key allowance. Owner's costs are included only in the case of the reactor capability. It is considered that the total value represents all inside of battery limits (ISBL) elements, outside of battery limits (OSBL) elements, site development, and all ancillary control and operational functions and capabilities.
3. Construction of a new integrated refinery capability to produce MTG from coal that consists of the following:
   a. Overnight island-type costs for HTGRs
   b. High-temperature steam electrolysis (HTSE) hydrogen production unit
   c. Coal preparation
   d. Gasification process
   e. Rectisol unit
   f. Claus and SCOT processes
   g. CO_2 compression
   h. Methanol synthesis

i. Gasoline synthesis
j. Steam turbines, internal to process
k. Heat recovery steam generator, internal to process
l. Cooling towers, internal to process
m. Allowances for Balance of Plant (BOP)/offsite/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
   (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, except those included for the HTGR
7. The allowance provided for the HTGR capability excludes all costs associated with materials development, or costs that would not be appropriately associated with an nth of a kind (NOAK) reactor/facility.

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

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

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.
4. The cost provided for the HTGR reflects internal BEA cost data that was developed for the HTGR and presented to the NGNP Process Integration team by L. Demmick. Considered in the cost is a pre-conceptual cost estimate prepared by three separate contractor teams. All contractor teams proposed 4-unit NOAK plants with thermal power levels between 2,000 MW_t and 2,400 MW_t at a cost of roughly \$4B, including owner's 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_t. 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.
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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 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.

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 MTG

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 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 affects the basic concepts of the supply and demand theories, thus increasing costs.
5. Impacts due to large quantities of materials, special alloy materials, fabrication capability, and labor availability could all represent conditions that may increase the total cost of the project.

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

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

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

VIII. OTHER COMMENTS/CONCERNS SPECIFIC TO THE ESTIMATE:

None.

Detail Item Report - High Temperature Gas Reactor (HTGR)

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
INL Internal Cost Data (INL 2009)	1	MWth		2009	$ 1,708,333	$ 1,708,333	$ 1,708,333	6,868	MWth				$11,732,236,071	$ 11,732,236,071

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
INL Internal Cost Data (INL 2009)	1	MWth		2009	$ 1,708,333	$ 1,708,333	$ 1,708,333	6,868	MWth				$11,732,236,071	$ 11,732,236,071

Balance of Plant:

Description	% of Total Cost						Cost Per Train	Total Cost
Water Systems	0.00%						$ -	$ -
Civil/Structural/Buildings	0.00%						$ -	$ -
Piping	0.00%						$ -	$ -
Control and Instrumentation	0.00%						$ -	$ -
Electrical Systems	0.00%						$ -	$ -
						Total Balance of Plant	$ -	$ -
						Total Balance of Plant Plus the Selected Source	$11,732,236,071	$ 11,732,236,071

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

Project Name: NGNP Process Integration
Process: Nuclear Coal to MTG
Estimate Number: MA36-H

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
INL Internal Cost Data (INL 2009)	240	MWe	1	2009	$ 148,362,255	$ 148,362,255	$ 148,362,255	2,481	MWe	13	191	MWe	$ 129,289,934	$ 1,680,769,141

Summary:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
INL Internal Cost Data (INL 2009)	240	MWe	1	2009	$ 148,362,255	$ 148,362,255	$ 148,362,255	2,481	MWe	13	191	MWe	$ 129,289,934	$ 1,680,769,141

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	0.00%		$ -	$ -
Civil/Structural/Buildings	0.00%		$ -	$ -
Piping	0.00%		$ -	$ -
Control and Instrumentation	0.00%		$ -	$ -
Electrical Systems	0.00%		$ -	$ -
		Total Balance of Plant	$ -	$ -
		Total Balance of Plant Plus the Selected Source	$ 129,289,934	$ 1,680,769,141

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 'Balance of Plant' allowances are considered to be included in the reported cost, based on direction from the Project Team Technical Lead.

Detail Item Report - High Temperature Steam Electrolysis (HTSE)

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
INL Internal Cost Data (INL 2009)	1.00	kg/s		2009	$ 36,120,156	$ 36,120,156	$ 36,120,156	20.36	kg/s				$ 735,228,656	$ 735,228,656

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
INL Internal Cost Data (INL 2009)	1.00	kg/s		2009	$ 36,120,156	$ 36,120,156	$ 36,120,156	20.36	kg/s				$ 735,228,656	$ 735,228,656

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 52,201,235	$ 52,201,235
Civil/Structural/Buildings	9.20%		$ 67,641,036	$ 67,641,036
Piping	7.10%		$ 52,201,235	$ 52,201,235
Control and Instrumentation	2.60%		$ 19,115,945	$ 19,115,945
Electrical Systems	8.00%		$ 58,818,292	$ 58,818,292
		Total Balance of Plant	$ 249,977,743	$ 249,977,743
		Total Balance of Plant Plus the Selected Source	$ 985,206,399	$ 985,206,399

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 Ceramatec and Proton Energy. The allowances listed under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

Detail Item Report - Coal Preparation

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Shell IGCC Base Case (NETL 2000)	3,171	tpd	1	1999	$ 17,826,000	$ 17,826,000	$ 23,366,390	11,845	tpd	4	2,961	tpd	$ 22,425,913	$ 89,703,650
Hydrogen Report (Gray 2004)	7,787	tpd	1	2004	$ 47,000,000	$ 47,000,000	$ 54,173,796	11,845	tpd	4	2,961	tpd	$ 30,327,974	$ 121,311,897
Shell GTC Report (Shell 2004)	5,513	tpd	2	2004	$ 60,800,000	$ 30,400,000	$ 35,040,072	11,845	tpd	4	2,961	tpd	$ 36,578,307	$ 146,313,228
Shell IGCC Power Plant with CO2 Capture (NETL 2007b)	5,678	tpd	2	2006	$ 156,785,000	$ 78,392,500	$ 80,338,191	11,845	tpd	4	2,961	tpd	$ 82,393,683	$ 329,574,731

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Average of normalized and factored cost from Gray 2004 and Shell 2004 reports													$ 33,453,141	$ 133,812,563

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 2,375,173	$ 9,500,692
Civil/Structural/Buildings	9.20%		$ 3,077,689	$ 12,310,756
Piping	7.10%		$ 2,375,173	$ 9,500,692
Control and Instrumentation	2.60%		$ 869,782	$ 3,479,127
Electrical Systems	8.00%		$ 2,676,251	$ 10,705,005
		Total Balance of Plant	$ 11,374,068	$ 45,496,271
		Total Balance of Plant Plus the Selected Source	$ 44,827,209	$ 179,308,834

Rationale for Selection:

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

Detail Item Report - Gasification

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Gasifier														
Shell IGCC Base Case (NETL 2000)	2,977	tpd	1	1999	$ 87,802,000	$ 87,802,000	$ 115,091,203	10,874	tpd	4	2,719	tpd	$ 108,988,837	$ 435,955,347
Hydrogen Report (Gray 2004)	5,990	tpd	1	2004	$ 87,000,000	$ 87,000,000	$ 100,279,154	10,874	tpd	4	2,719	tpd	$ 62,425,460	$ 499,403,683
Shell IGCC Power Plant with CO2 Capture (NETL 2007b)	5,310	tpd	2	2006	$ 196,948,000	$ 98,474,000	$ 100,918,110	10,874	tpd	4	2,719	tpd	$ 102,362,555	$ 409,450,219
Shell GTC Report (Shell 2004)	5,201	tpd	2	2004	$ 202,240,000	$ 101,120,000	$ 116,554,345	10,874	tpd	4	2,719	tpd	$ 119,702,037	$ 478,808,147
Quench Compressor														
Shell IGCC Base Case (NETL 2000)	194,116	lb/hr	1	1999	$ 1,900,000	$ 1,900,000	$ 2,490,527	1,578,431	lb/hr	4	394,608	lb/hr	$ 3,812,009	$ 15,248,035

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Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Average of normalized and factored costs from NETL 2000 and NETL 2007b reports, including the NETL 2000 quench compressor cost with the NETL 2000 gasifier cost.													$ 107,581,700	$ 430,326,800

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 7,638,301	$ 30,553,203
Civil/Structural/Buildings	9.20%		$ 9,897,516	$ 39,590,066
Piping	7.10%		$ 7,638,301	$ 30,553,203
Control and Instrumentation	2.60%		$ 2,797,124	$ 11,188,497
Electrical Systems	8.00%		$ 8,606,536	$ 34,426,144
		Total Balance of Plant	$ 36,577,778	$ 146,311,112
		Total Balance of Plant Plus the Selected Source	$ 144,159,478	$ 576,637,913

Rationale for Selection:

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

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

Detail Item Report - Rectisol

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Fluor/UOP Report (Fluor/UOP 2004)	28,735	lbmol/hr	1	2003	$ 91,640,000	$ 91,640,000	$ 116,715,622	89,938	lbmol/hr	2	44,969	lbmol/hr	$ 152,696,895	$ 305,393,790
Princeton Report (Kreutz 2008)	700,000	Nm3/hr	1	2007	$ 129,043,041	$ 129,043,041	$ 125,751,879	966,495	Nm3/hr	2	483,247	Nm3/hr	$ 100,683,279	$ 201,366,558

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Average of normalized and factored costs from Fluor/UOP 2004 and Kreutz 2008													$ 126,690,087	$ 253,380,174

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 8,994,996	$ 17,989,992
Civil/Structural/Buildings	9.20%		$ 11,655,488	$ 23,310,976
Piping	7.10%		$ 8,994,996	$ 17,989,992
Control and Instrumentation	2.60%		$ 3,293,942	$ 6,587,885
Electrical Systems	8.00%		$ 10,135,207	$ 20,270,414
		Total Balance of Plant	$ 43,074,630	$ 86,149,259
		Total Balance of Plant Plus the Selected Source	$ 169,764,717	$ 339,529,433

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 - Claus and SCOT

Project Name: NGNP Process Integration
Process: Nuclear Coal to MTG
Estimate Number: MA36-H

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Claus and SCOT														
Princeton Report (Kreutz 2008)	12,586	lb/hr	1	2007	$ 33,800,000	$ 33,800,000	$ 32,937,952	31,867	lb/hr	3	10,622	lb/hr	$ 29,750,613	$ 89,251,838
Shell IGCC Power Plant with CO2 Capture (NETL 2007b)	142	tpd	1	2006	$ 22,794,000	$ 22,794,000	$ 23,359,744	382	tpd	3	127	tpd	$ 21,903,794	$ 65,711,381
Claus														
Shell IGCC Base Cases (NETL 2000)	6,496	lb/hr	1	1999	$ 9,964,000	$ 9,964,000	$ 13,060,850	31,867	lb/hr	3	10,622	lb/hr	$ 17,543,968	$ 52,631,903
Cost Effective Options to Expand SRU Capacity Using Oxygen (WorleyParsons 2002)	79	tpd	1	1999	$ 11,970,000	$ 11,970,000	$ 15,690,323	382	tpd	3	127	tpd	$ 20,849,382	$ 62,548,147
SCOT														
Shell IGCC Base Cases (NETL 2000)	6,496	lb/hr	1	1999	$ 4,214,000	$ 4,214,000	$ 5,523,728	31,867	lb/hr	1	31,867	lb/hr	$ 14,343,706	$ 14,343,706
Cost Effective Options to Expand SRU Capacity Using Oxygen (WorleyParsons 2002)	143	tpd	1	1999	$ 8,910,000	$ 8,910,000	$ 11,679,263	382	tpd	1	382	tpd	$ 21,046,650	$ 21,046,650

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
WorleyParsons 2002: Combined Claus and SCOT costs													$ 41,896,033	$ 83,594,797

Detail Item Report - Claus and SCOT

Project Name: NGNP Process Integration
Process: Nuclear Coal to MTG
Estimate Number: MA36-H

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

Balance of Plant:

Description	% of Total Cost						Cost Per Train	Total Cost
Water Systems	7.10%						$ 2,974,618	$ 5,935,231
Civil/Structural/Buildings	9.20%						$ 3,854,435	$ 7,690,721
Piping	7.10%						$ 2,974,618	$ 5,935,231
Control and Instrumentation	2.60%						$ 1,089,297	$ 2,173,465
Electrical Systems	8.00%						$ 3,351,683	$ 6,687,584
						Total Balance of Plant	$ 14,244,651	$ 28,422,231
						Total Balance of Plant Plus the Selected Source	$ 56,140,684	$ 112,017,028

Rationale for Selection:

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

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

Detail Item Report - CO2 Compression

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Subcritical														
Princeton Report (Kreutz 2008)	10	MW	1	2007	$ 6,310,000	$ 6,310,000	$ 6,149,067	14	MW	2	7	MW	$ 4,922,810	$ 9,845,621
Supercritical														
Princeton Report (Kreutz 2008)	13	MW	1	2007	$ 9,520,000	$ 9,520,000	$ 9,277,198	-	MW	2	-	MW	$ -	$ -

Source Selected:

Source	Reported Capacity	Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required	Trains Reqd.	Capacity per Train	Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Kreutz 2008: Combined Subcritical and Supercritical Processes										$ 4,922,810	$ 9,845,621

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 349,520	$ 699,039
Civil/Structural/Buildings	9.20%		$ 452,899	$ 905,797
Piping	7.10%		$ 349,520	$ 699,039
Control and Instrumentation	2.60%		$ 127,993	$ 255,986
Electrical Systems	8.00%		$ 393,825	$ 787,650
		Total Balance of Plant	$ 1,673,756	$ 3,347,511
		Total Balance of Plant Plus the Selected Source	$ 6,596,566	$ 13,193,132

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 - Methanol Synthesis

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Economics of Producing Methanol from Coal by Entrained and Fluidized-Bed Gasifiers (U.S. DOI Bureau of Mines, August 1977)	5000	tpd	1	1977	$ 63,096,600	$ 63,096,600	$ 158,282,505	19,342	tpd	3	6,447	tpd	$ 184,365,216	$ 553,095,647
Investigations on Catalyzed Steam Gasification of Biomass (PNL-3695 1981)	997	tpd	1	1980	$ 22,000,000	$ 22,000,000	$ 43,124,043	19,342	tpd	3	6,447	tpd	$ 132,169,257	$ 396,507,771
H-Coal and Coal-to-Methanol Liquefaction Processes: Process Engineering Evaluation (EPRI AP-3290, November 1983)	15919	tpd	6	1982	$ 183,327,000	$ 30,554,500	$ 49,821,350	19,342	tpd	3	6,447	tpd	$ 84,875,989	$ 254,627,968

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Average of the three available sources.													$ 133,803,487	$ 401,410,462

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 9,500,048	$ 28,500,143
Civil/Structural/Buildings	9.20%		$ 12,309,921	$ 36,929,763
Piping	7.10%		$ 9,500,048	$ 28,500,143
Control and Instrumentation	2.60%		$ 3,478,891	$ 10,436,672
Electrical Systems	8.00%		$ 10,704,279	$ 32,112,837
		Total Balance of Plant	$ 45,493,186	$ 136,479,557
		Total Balance of Plant Plus the Selected Source	$ 179,296,673	$ 537,890,019

Rationale for Selection:

Considering the date of the source and the available assumptions and methodologies used, an average cost for all sources was used to minimize reporting errors. 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 - Gasoline Synthesis

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Gas Usage & Value The Technology and Economics of Natural Gas Use in the Process Industries (PennWell Corporation, 2006)	14500	bpd	1	1985	$ 92,925,000	$ 92,925,000	$ 146,257,608	57,704	bpd	3	19,235	bpd	$ 173,280,010	$ 519,840,031

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Gas Usage & Value The Technology and Economics of Natural Gas Use in the Process Industries (PennWell Corporation, 2006)	14500	bpd	1	1985	$ 92,925,000	$ 92,925,000	$ 146,257,608	57,704	bpd	3	19,235	bpd	$ 173,280,010	$ 519,840,031

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 12,302,881	$ 36,908,642
Civil/Structural/Buildings	9.20%		$ 15,941,761	$ 47,825,283
Piping	7.10%		$ 12,302,881	$ 36,908,642
Control and Instrumentation	2.60%		$ 4,505,280	$ 13,515,841
Electrical Systems	8.00%		$ 13,862,401	$ 41,587,202
		Total Balance of Plant	$ 58,915,203	$ 176,745,610
		Total Balance of Plant Plus the Selected Source	$ 232,195,214	$ 696,585,641

Rationale for Selection:

Single source cost point. The allowances listed under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

Detail Item Report - Steam Turbines

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Steam Turbine and HRSG														
Shell IGCC Base Cases (NETL 2000)	189	MW	1	1999	$ 50,671,000	$ 50,671,000	$ 66,419,744	228	MW	1	228	MW	$ 74,274,192	$ 74,274,192
Steam Turbine														
NETL Baseline Report (NETL 2007a)	401	MW	4	2006	$ 74,651,000	$ 18,662,750	$ 19,125,957	228	MW	1	228	MW	$ 31,288,905	$ 31,288,905
Princeton Report (Kreutz 2008)	275	MW	1	2007	$ 66,700,000	$ 66,700,000	$ 64,998,858	228	MW	1	228	MW	$ 58,039,536	$ 58,039,536
Shell IGCC Power Plant with CO2 Capture (NETL 2007b)	230	MW	1	2006	$ 44,515,000	$ 44,515,000	$ 45,619,856	228	MW	1	228	MW	$ 45,353,869	$ 45,353,869

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Shell IGCC Power Plant with CO2 Capture (NETL 2007b)	230	MW	1	2006	$ 44,515,000	$ 44,515,000	$ 45,619,856	228	MW	1	228	MW	$ 45,353,869	$ 45,353,869

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 3,220,125	$ 3,220,125
Civil/Structural/Buildings	9.20%		$ 4,172,556	$ 4,172,556
Piping	7.10%		$ 3,220,125	$ 3,220,125
Control and Instrumentation	2.60%		$ 1,179,201	$ 1,179,201
Electrical Systems	8.00%		$ 3,628,310	$ 3,628,310
		Total Balance of Plant	$ 15,420,316	$ 15,420,316
		Total Balance of Plant Plus the Selected Source	$ 60,774,185	$ 60,774,185

Rationale for Selection:

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

Detail Item Report - HRSG

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Steam Turbine and HRSG														
Shell IGCC Base Cases (NETL 2000)	189	MW	1	1999	$ 50,671,000	$ 50,671,000	$ 66,419,744	228	MW	1	228	MW	$ 74,274,192	$ 74,274,192
HRSG														
NETL Baseline Report (NETL 2007a)	5,155,983	lb/hr	3	2006	$ 27,581,000	$ 9,193,667	$ 9,421,852	-	lb/hr	1	-	lb/hr	$ -	$ -
Princeton Report (Kreutz 2008)	355	MW	1	2007	$ 52,000,000	$ 52,000,000	$ 50,673,772	-	MW	1	-	MW	$ -	$ -
Shell IGCC Power Plant with CO2 Capture (NETL 2007b)	8,438,000	lb/hr	2	2006	$ 45,291,000	$ 22,645,500	$ 23,207,558	-	lb/hr	1	-	lb/hr	$ -	$ -

Source Selected:

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

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ -	$ -
Civil/Structural/Buildings	9.20%		$ -	$ -
Piping	7.10%		$ -	$ -
Control and Instrumentation	2.60%		$ -	$ -
Electrical Systems	8.00%		$ -	$ -
		Total Balance of Plant	$ -	$ -
		Total Balance of Plant Plus the Selected Source	$ -	$ -

Rationale for Selection:

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

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Detail Item Report - Cooling Towers

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Cooling Tower Depot	155,090	gpm	5	2009	$ 3,719,460	$ 743,892	$ 743,892	371,249	gpm	12	30,937	gpm	$ 742,732	$ 8,912,782

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Cooling Tower Depot	155,090	gpm	5	2009	$ 3,719,460	$ 743,892	$ 743,892	371,249	gpm	12	30,937	gpm	$ 742,732	$ 8,912,782

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 52,734	$ 632,808
Civil/Structural/Buildings	9.20%		$ 68,331	$ 819,976
Piping	7.10%		$ 52,734	$ 632,808
Control and Instrumentation	2.60%		$ 19,311	$ 231,732
Electrical Systems	8.00%		$ 59,419	$ 713,023
		Total Balance of Plant	$ 252,529	$ 3,030,346
		Total Balance of Plant Plus the Selected Source	$ 995,261	$ 11,943,128

Rationale for Selection:

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

NGNP Conventional Gas to MTG

Project Name: NGNP Process Integration
Process: Conventional Gas the MTG
Estimate Number: MA36-I

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

Process Component	Subtotal From Detail Sheets	Engineering %	Engineering	Contingency %	Contingency	Total Cost
Air Separation Unit (ASU)	$ 188,809,327	10%	$ 18,880,933	18%	$ 37,384,247	$ 245,074,506
Steam Methane Reforming	$ 319,554,071	10%	$ 31,955,407	18%	$ 63,271,706	$ 414,781,184
Pressure Swing Adsorption (PSA)	$ 8,216,795	10%	$ 821,680	18%	$ 1,626,925	$ 10,665,400
Methanol Synthesis	$ 326,389,395	10%	$ 32,638,939	18%	$ 64,625,100	$ 423,653,435
Gasoline Synthesis	$ 427,184,686	10%	$ 42,718,469	18%	$ 84,582,568	$ 554,485,722
Steam Turbines	$ 28,005,667	10%	$ 2,800,567	18%	$ 5,545,122	$ 36,351,356
Heat Recovery Steam Generator (HRSG)	$ -	10%	$ -	18%	$ -	$ -
Cooling Towers	$ 7,105,167	10%	$ 710,517	18%	$ 1,406,823	$ 9,222,507
Total Cost - Conventional Gas to MTG						$ 1,694,234,110
Total Cost Rounded to the Nearest $10M						$ 1,690,000,000

	Remarks
Checked By: SHW	
Approved By: John Flynn	

4/20/2010

COST ESTIMATE SUPPORT DATA RECAPITULATION

Project Title:	NGNP Process Integration – Conventional Gas to MTG
Estimator:	B. W. Wallace/CEP, R. R. Honsinger/CEP, J. B. Martin/CCT
Date:	April 20, 2010
Estimate Type:	Class 5
File:	MA36-I
Approved By:	

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

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 gas-to-methanol to gasoline (MTG) process.

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

1. Engineering
2. Construction of a new gas-to-MTG refinery that consists of the following:
   a. Air separation unit
   b. Steam methane reformer
   c. Pressure swing adsorption
   d. Methanol synthesis
   e. Gasoline synthesis
   f. Steam turbines, internal to process
   g. Heat recovery steam generator, internal to process
   h. Cooling towers, internal to process
   i. Allowances for Balance of Plant (BOP)/offsite/outside of battery limits (OSBL), including the following:
      (1.) Site development/improvements
      (2.) Provisions for general and administrative buildings and structures
      (3.) Provisions for OSBL piping
      (4.) Provisions for OSBL instrumentation and control
      (5.) Provisions for OSBL electrical
      (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.

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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6. Brown, L. C., et al., "Alternative Flowsheets for the Sulfur-Iodine Thermochemical Hydrogen Cycle," *General Atomics*, February 2003.
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10. Douglas, Fred R., et al., *Conduction Technical and Economic Evaluations – as Applied for the Process and Utility Industries*, AACEi, April 1991.
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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 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.

Gas to MTG

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 NREL 2006 report presented the steam methane reformer cost with the cost of the water gas shift reactors. This cost was normalized to exclude the cost of the water gas shift reactors.

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 allowances, but source cost data from which the initial island costs were derived were not completely descriptive of the elements included, not included, or simply referred to with different nomenclature or combined with other elements. While every effort has been made to correctly normalize and factor the costs for use in this effort, the risk exists that not all of these were correctly captured due to the varied information available.
3. This project is heavily dependent on metals, concrete, petroleum, and petroleum products. Competition for these commodities in today's environment due to

global expansion, uncertainty, and product shortages affect the basic concepts of the supply and demand theories, thus increasing costs.

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

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

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

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

VIII. OTHER COMMENTS/CONCERNS SPECIFIC TO THE ESTIMATE:

None.

Detail Item Report - Air Separation Unit (ASU)

Project Name: NGNP Process Integration
Process: Conventional Gas to MTG
Estimate Number: MA36-I

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Shell IGCC Base Case (NETL 2000)	213,207	lb/hr	1	1999	$ 51,204,000	$ 51,204,000	$ 67,118,402	391,673	lb/hr	2	195,837	lb/hr	$ 63,781,822	$ 153,408,795
NETL Baseline Report (NETL 2007a)	1,728,789	lb/hr	2	2006	$ 287,187,000	$ 143,593,500	$ 147,157,470	391,673	lb/hr	2	195,837	lb/hr	$ 60,379,748	$ 145,226,088
Princeton Report (Kreutz 2008)	201,264	lb/hr	1	2007	$ 105,000,000	$ 105,000,000	$ 102,322,040	391,673	lb/hr	2	195,837	lb/hr	$ 100,657,402	$ 242,102,378
Hydrogen Report (Gray 2004)	296,583	lb/hr	1	2004	$ 76,000,000	$ 76,000,000	$ 87,600,180	391,673	lb/hr	2	195,837	lb/hr	$ 68,289,438	$ 136,578,877
Shell GTC Report (Shell 2004)	385,259	lb/hr	1	2004	$ 53,760,000	$ 53,760,000	$ 61,965,601	391,673	lb/hr	2	195,837	lb/hr	$ 41,289,077	$ 99,308,979
Shell IGCC Power Plant with CO2 Capture (NETL 2007b)	373,498	lb/hr	2	2006	$ 144,337,000	$ 72,168,500	$ 73,959,712	391,673	lb/hr	2	195,837	lb/hr	$ 76,098,557	$ 183,033,154

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Average of normalized and factored costs from NETL 2007a and Gray 2004													$ 64,334,593	$ 140,902,482

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 4,567,756	$ 10,004,076
Civil/Structural/Buildings	9.20%		$ 5,918,783	$ 12,963,028
Piping	7.10%		$ 4,567,756	$ 10,004,076
Control and Instrumentation	2.60%		$ 1,672,699	$ 3,663,465
Electrical Systems	8.00%		$ 5,146,767	$ 11,272,199
		Total Balance of Plant	$ 21,873,762	$ 47,906,844
		Total Balance of Plant Plus the Selected Source	$ 86,208,355	$ 188,809,327

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 under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

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

Detail Item Report - Methane Reforming

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Natural Gas to Liquids Conversion Project (Raytheon 2000)	150	MMS CFD	1	1999	$ 79,000,000	$ 79,000,000	$ 103,553,507	288	MMS CFD	2	144	MMS CFD	$ 101,047,961	$ 238,473,187
NETL Natural Gas Report (Choi 1996)	100	MMS CFD	1	1996	$ 22,800,000	$ 22,800,000	$ 30,583,181	288	MMS CFD	2	144	MMS CFD	$ 38,062,748	$ 76,125,497
Gas Usage & Value The Technology and Economics of Natural Gas Use in the Process Industries (PennWell Corporation 2006)	4,700	tpd	2	1985	$ 168,150,000	$ 84,075,000	$ 132,328,312	11,023	tpd	2	5,512	tpd	$ 220,679,736	$ 441,359,472
NREL Report (NREL 2006)	183	MMS CFD	1	2002	$ 175,391,586	$ 175,391,586	$ 226,998,210	288	MMS CFD	2	144	MMS CFD	$ 196,722,581	$ 393,445,162

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Natural Gas to Liquids Conversion Project (Raytheon 2000)	150	MMS CFD	1	1999	$ 79,000,000	$ 79,000,000	$ 103,553,507	288	MMS CFD	2	144	MMS CFD	$ 101,047,961	$ 238,473,187

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 7,174,405	$ 16,931,596
Civil/Structural/Buildings	9.20%		$ 9,296,412	$ 21,939,533
Piping	7.10%		$ 7,174,405	$ 16,931,596
Control and Instrumentation	2.60%		$ 2,627,247	$ 6,200,303
Electrical Systems	8.00%		$ 8,083,837	$ 19,077,855
		Total Balance of Plant	$ 34,356,307	$ 81,080,884
		Total Balance of Plant Plus the Selected Source	$ 135,404,267	$ 319,554,071

Rationale for Selection:

Raytheon 2000 was selected as the most recent cost point, with technology most similar to the intended process. The adjusted PennWell Corporation 2006 cost point concurs with the Raytheon 2000 value. Costs presented in the Raytheon report have been increased by 18% to account for the difference between an autothermal process and traditional steam methane reforming process. The allowances listed under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

Note: PennWell Corporation 2006 includes both the natural gas reformer and methanol synthesis units. The average cost for methanol synthesis, as calculated in this report, was subtracted from the total current cost for required trains cell so that this may be considered as a cost point for natural gas reforming. The NREL 2006 cost was scaled from the originally presented value to exclude the cost of the water gas shift reactors.

Detail Item Report - Pressure Swing Adsorption (PSA)

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Fluor/UOP Report (Fluor/UOP 2004)	27,498	lbmol/hr	1	2003	$ 25,000,000	$ 25,000,000	$ 31,840,796	1,766	lbmol/hr	1	1,766	lbmol/hr	$ 6,131,937	$ 6,131,937

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Fluor/UOP Report (Fluor/UOP 2004)	27,498	lbmol/hr	1	2003	$ 25,000,000	$ 25,000,000	$ 31,840,796	1,766	lbmol/hr	1	1,766	lbmol/hr	$ 6,131,937	$ 6,131,937

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 435,368	$ 435,368
Civil/Structural/Buildings	9.20%		$ 564,138	$ 564,138
Piping	7.10%		$ 435,368	$ 435,368
Control and Instrumentation	2.60%		$ 159,430	$ 159,430
Electrical Systems	8.00%		$ 490,555	$ 490,555
		Total Balance of Plant	$ 2,084,859	$ 2,084,859
		Total Balance of Plant Plus the Selected Source	$ 8,216,795	$ 8,216,795

Rationale for Selection:

Single source cost point. 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 - Methanol Synthesis

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Economics of Producing Methanol from Coal by Entrained and Fluidized-Bed Gasifiers (U.S. DOI Bureau of Mines, August 1977)	5000	tpd	1	1977	$ 63,096,600	$ 63,096,600	$ 158,282,505	11,023	tpd	2	5,512	tpd	$ 167,808,053	$ 335,616,106
Investigations on Catalyzed Steam Gasification of Biomass (PNL-3695 1981)	997	tpd	1	1980	$ 22,000,000	$ 22,000,000	$ 43,124,043	11,023	tpd	2	5,512	tpd	$ 120,299,622	$ 240,599,243
H-Coal and Coal-to-Methanol Liquefaction Processes: Process Engineering Evaluation (EPRI AP-3290, November 1983)	15919	tpd	6	1982	$ 183,327,000	$ 30,554,500	$ 49,821,350	11,023	tpd	2	5,512	tpd	$ 77,253,588	$ 154,507,177

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Average of the three available sources.													$ 121,787,088	$ 243,574,175

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 8,646,883	$ 17,293,766
Civil/Structural/Buildings	9.20%		$ 11,204,412	$ 22,408,824
Piping	7.10%		$ 8,646,883	$ 17,293,766
Control and Instrumentation	2.60%		$ 3,166,464	$ 6,332,929
Electrical Systems	8.00%		$ 9,742,967	$ 19,485,934
		Total Balance of Plant	$ 41,407,610	$ 82,815,220
		Total Balance of Plant Plus the Selected Source	$ 163,194,697	$ 326,389,395

Rationale for Selection:

Considering the date of the source and the available assumptions and methodologies used, an average cost for all sources was used to minimize reporting errors. 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 - Gasoline Synthesis

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Gas Usage & Value The Technology and Economics of Natural Gas Use in the Process Industries (PennWell Corporation, 2006)	14,500	bpd	1	1985	$ 92,925,000	$ 92,925,000	$ 146,257,608	33,471	bpd	2	16,736	bpd	$ 159,397,271	$ 318,794,542

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Gas Usage & Value The Technology and Economics of Natural Gas Use in the Process Industries (PennWell Corporation, 2006)	14,500	bpd	1	1985	$ 92,925,000	$ 92,925,000	$ 146,257,608	33,471	bpd	2	16,736	bpd	$ 159,397,271	$ 318,794,542

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 11,317,206	$ 22,634,412
Civil/Structural/Buildings	9.20%		$ 14,664,549	$ 29,329,098
Piping	7.10%		$ 11,317,206	$ 22,634,412
Control and Instrumentation	2.60%		$ 4,144,329	$ 8,288,658
Electrical Systems	8.00%		$ 12,751,782	$ 25,503,563
		Total Balance of Plant	$ 54,195,072	$ 108,390,144
		Total Balance of Plant Plus the Selected Source	$ 213,592,343	$ 427,184,686

Rationale for Selection:

Single source cost point. The allowances listed under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

Detail Item Report - Steam Turbines

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Steam Turbine and HRSG														
Shell IGCC Base Cases (NETL 2000)	189	MW	1	1999	$ 50,671,000	$ 50,671,000	$ 66,419,744	63	MW	1	63	MW	$ 34,248,425	$ 34,248,425
Steam Turbine														
NETL Baseline Report (NETL 2007a)	401	MW	4	2006	$ 74,651,000	$ 18,662,750	$ 19,125,957	63	MW	1	63	MW	$ 14,418,402	$ 14,418,402
Princeton Report (Kreutz 2008)	275	MW	1	2007	$ 66,700,000	$ 66,700,000	$ 64,998,858	63	MW	1	63	MW	$ 26,745,499	$ 26,745,499
Shell IGCC Power Plant with CO2 Capture (NETL 2007b)	230	MW	1	2006	$ 44,515,000	$ 44,515,000	$ 45,619,856	63	MW	1	63	MW	$ 20,899,752	$ 20,899,752

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Shell IGCC Power Plant with CO2 Capture (NETL 2007b)	230	MW	1	2006	$ 44,515,000	$ 44,515,000	$ 45,619,856	63	MW	1	63	MW	$ 20,899,752	$ 20,899,752

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 1,483,882	$ 1,483,882
Civil/Structural/Buildings	9.20%		$ 1,922,777	$ 1,922,777
Piping	7.10%		$ 1,483,882	$ 1,483,882
Control and Instrumentation	2.60%		$ 543,394	$ 543,394
Electrical Systems	8.00%		$ 1,671,980	$ 1,671,980
		Total Balance of Plant	$ 7,105,916	$ 7,105,916
		Total Balance of Plant Plus the Selected Source	$ 28,005,667	$ 28,005,667

Rationale for Selection:

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

Detail Item Report - HRSG

Project Name: NGNP Process Integration
Process: Conventional Gas to MTG
Estimate Number: MA36-I

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Steam Turbine and HRSG														
Shell IGCC Base Cases (NETL 2000)	189	MW	1	1999	$ 50,671,000	$ 50,671,000	$ 66,419,744	63	MW	1	63	MW	$ 34,226,675	$ 34,226,675
HRSG														
NETL Baseline Report (NETL 2007a)	5,155,983	lb/hr	3	2006	$ 27,581,000	$ 9,193,667	$ 9,421,852	-	lb/hr	1	-	lb/hr	$ -	$ -
Princeton Report (Kreutz 2008)	355	MW	1	2007	$ 52,000,000	$ 52,000,000	$ 50,673,772	-	MW	1	-	MW	$ -	$ -
Shell IGCC Power Plant with CO2 Capture (NETL 2007b)	8,438,000	lb/hr	2	2006	$ 45,291,000	$ 22,645,500	$ 23,207,558	-	lb/hr	1	-	lb/hr	$ -	$ -

Source Selected:

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

Balance of Plant:

Description	% of Total Cost						Cost Per Train	Total Cost
Water Systems	7.10%						$ -	$ -
Civil/Structural/Buildings	9.20%						$ -	$ -
Piping	7.10%						$ -	$ -
Control and Instrumentation	2.60%						$ -	$ -
Electrical Systems	8.00%						$ -	$ -
						Total Balance of Plant	$ -	$ -
						Total Balance of Plant Plus the Selected Source	$ -	$ -

Rationale for Selection:

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

Detail Item Report - Cooling Towers

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Cooling Tower Depot	258,006	gpm	7	2009	$ 6,283,460	$ 897,637	$ 897,637	215,466	gpm	6	35,911	gpm	$ 883,727	$ 5,302,364

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Cooling Tower Depot	258,006	gpm	7	2009	$ 6,283,460	$ 897,637	$ 897,637	215,466	gpm	6	35,911	gpm	$ 883,727	$ 5,302,364

Balance of Plant:

Description	% of Total Cost						Cost Per Train	Total Cost
Water Systems	7.10%						$ 62,745	$ 376,468
Civil/Structural/Buildings	9.20%						$ 81,303	$ 487,817
Piping	7.10%						$ 62,745	$ 376,468
Control and Instrumentation	2.60%						$ 22,977	$ 137,861
Electrical Systems	8.00%						$ 70,698	$ 424,189
						Total Balance of Plant	$ 300,467	$ 1,802,804
						Total Balance of Plant Plus the Selected Source	$ 1,184,195	$ 7,105,167

Rationale for Selection:

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

NGNP Nuclear Gas to MTG Summary

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

Process Component	Subtotal From Detail Sheets	Engineering %	Engineering	Contingency %	Contingency	Total Cost
High Temperature Gas Reactor (HTGR)	$ 1,234,056,299	0%	$ -	0%	$ -	$ 1,234,056,299
Rankine Power Cycle	$ 95,563,988	10%	$ 9,556,399	18%	$ 18,921,670	$ 124,042,057
Air Separation Unit (ASU)	$ 188,705,761	10%	$ 18,870,576	18%	$ 37,363,741	$ 244,940,078
Steam Methane Reforming	$ 299,144,268	10%	$ 29,914,427	18%	$ 59,230,565	$ 388,289,260
Pressure Swing Adsorption (PSA)	$ 8,186,049	10%	$ 818,605	18%	$ 1,620,838	$ 10,625,491
Methanol Synthesis	$ 326,389,395	10%	$ 32,638,939	18%	$ 64,625,100	$ 423,653,435
Gasoline Synthesis	$ 427,177,028	10%	$ 42,717,703	18%	$ 84,581,052	$ 554,475,783
Steam Turbines	$ 32,348,129	10%	$ 3,234,813	18%	$ 6,404,930	$ 41,987,871
Heat Recovery Steam Generator (HRSG)	$ -	10%	$ -	18%	$ -	$ -
Cooling Towers	$ 7,153,270	10%	$ 715,327	18%	$ 1,416,347	$ 9,284,944
Total Cost - Nuclear Gas to MTG						$ 3,031,355,217
Total Cost Rounded to the Nearest $10M						$ 3,030,000,000

Checked By: SNW	Remarks
Approved By: John Pz	

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COST ESTIMATE SUPPORT DATA RECAPITULATION

Project Title:	NGNP Process Integration – Nuclear Gas to MTG
Estimator:	B. W. Wallace/CEP, R. R. Honsinger/CEP, J. B. Martin/CCT
Date:	April 20, 2010
Estimate Type:	Class 5
File:	MA36-J
Approved By:	

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

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 high-temperature gas reactors (HTGRs) integrated with a gas-to-methanol to gasoline (MTG) process.

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

1. Engineering
2. The allowance provided for the HTGR represents a complete and operable system. All elements required for construction of this nuclear reactor capability, including an initial steam generator, security systems, contingency, and owner's costs are included in the turn-key allowance. Owner's costs are included only in the case of the reactor capability. It is considered that the total value represents all inside of battery limits (ISBL) elements, outside of battery limits (OSBL) elements, site development, and all ancillary control and operational functions and capabilities.
3. Construction of a new integrated refinery capability to produce MTG from natural gas that consists of the following:
   a. Overnight island-type costs for HTGRs
   b. Air separation unit
   c. Steam methane reformer
   d. Pressure swing adsorption
   e. Methanol synthesis
   f. Gasoline synthesis
   g. Steam turbines, internal to process
   h. Heat recovery steam generator, internal to process

i. Cooling towers, internal to process
j. Allowances for Balance of Plant (BOP)/offsite/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
   (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, except those included for the HTGR
7. The allowance provided for the HTGR capability excludes all costs associated with materials development, or costs that would not be appropriately associated with an nth of a kind (NOAK) reactor/facility.

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

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

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.
4. The cost provided for the HTGR reflects internal BEA cost data that was developed for the HTGR and presented to the NGNP Process Integration team by L. Demmick. Considered in the cost is a pre-conceptual cost estimate prepared by three separate contractor teams. All contractor teams proposed 4-unit NOAK plants with thermal power levels between 2,000 MW_t and 2,400 MW_t at a cost of roughly \$4B, including owner's 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_t. 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.
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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 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.

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.

Gas to MTG
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 NREL 2006 report presented the steam methane reformer cost with the cost of the water gas shift reactors. This cost was normalized to exclude the cost of the water gas shift reactors.

VII. **CONTINGENCY GUIDELINE IMPLEMENTATION:**

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

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

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

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

1. The singularly largest threat to this estimate surrounds the lump sum cost included for the HTGR reactor(s). While the overriding assumption is that the HTGR will be NOAK, currently, a complete HTGR has not been commissioned.
2. The level of project definition/development that was available at the time the estimate was prepared represents a substantial risk to the project 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 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.
5. Impacts due to large quantities of materials, special alloy materials, fabrication capability, and labor availability could all represent conditions that may increase the total cost of the project.

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

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

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

VIII. OTHER COMMENTS/CONCERNS SPECIFIC TO THE ESTIMATE:

None.

Detail Item Report - High Temperature Gas Reactor (HTGR)

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
INL Internal Cost Data (INL 2009)	1	MWth		2009	$ 1,708,333	$ 1,708,333	$ 1,708,333	722	MWth				$ 1,234,056,299	$ 1,234,056,299

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
INL Internal Cost Data (INL 2009)	1	MWth		2009	$ 1,708,333	$ 1,708,333	$ 1,708,333	722	MWth				$ 1,234,056,299	$ 1,234,056,299

Balance of Plant:

Description	% of Total Cost						Cost Per Train	Total Cost
Water Systems	0.00%						$ -	$ -
Civil/Structural/Buildings	0.00%						$ -	$ -
Piping	0.00%						$ -	$ -
Control and Instrumentation	0.00%						$ -	$ -
Electrical Systems	0.00%						$ -	$ -
						Total Balance of Plant	$ -	$ -
						Total Balance of Plant Plus the Selected Source	$ 1,234,056,299	$ 1,234,056,299

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

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
INL Internal Cost Data (INL 2009)	240	MWe	1	2009	$ 148,362,255	$ 148,362,255	$ 148,362,255	115	MWe	1	115	MWe	$ 95,563,988	$ 95,563,988

Summary:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
INL Internal Cost Data (INL 2009)	240	MWe	1	2009	$ 148,362,255	$ 148,362,255	$ 148,362,255	115	MWe	1	115	MWe	$ 95,563,988	$ 95,563,988

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	0.00%		$ -	$ -
Civil/Structural/Buildings	0.00%		$ -	$ -
Piping	0.00%		$ -	$ -
Control and Instrumentation	0.00%		$ -	$ -
Electrical Systems	0.00%		$ -	$ -
		Total Balance of Plant	$ -	$ -
		Total Balance of Plant Plus the Selected Source	$ 95,563,988	$ 95,563,988

Basis of Estimate Notes:

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

Detail Item Report - Air Separation Unit (ASU)

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Shell IGCC Base Case (NETL 2000)	213,207	lb/hr	1	1999	$ 51,204,000	$ 51,204,000	$ 67,118,402	391,315	lb/hr	2	195,658	lb/hr	$ 63,746,836	$ 153,324,648
NETL Baseline Report (NETL 2007a)	1,728,789	lb/hr	2	2006	$ 287,187,000	$ 143,593,500	$ 147,157,470	391,315	lb/hr	2	195,658	lb/hr	$ 60,346,629	$ 145,146,429
Princeton Report (Kreutz 2008)	201,264	lb/hr	1	2007	$ 105,000,000	$ 105,000,000	$ 102,322,040	391,315	lb/hr	2	195,658	lb/hr	$ 100,602,189	$ 241,969,581
Hydrogen Report (Gray 2004)	296,583	lb/hr	1	2004	$ 76,000,000	$ 76,000,000	$ 87,600,180	391,315	lb/hr	2	195,658	lb/hr	$ 68,251,980	$ 136,503,961
Shell GTC Report (Shell 2004)	385,259	lb/hr	1	2004	$ 53,760,000	$ 53,760,000	$ 61,965,601	391,315	lb/hr	2	195,658	lb/hr	$ 41,266,429	$ 99,254,506
Shell IGCC Power Plant with CO2 Capture (NETL 2007b)	373,498	lb/hr	2	2006	$ 144,337,000	$ 72,168,500	$ 73,959,712	391,315	lb/hr	2	195,658	lb/hr	$ 76,056,816	$ 182,932,757

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Average of normalized and factored costs from NETL 2007a and Gray 2004													$ 64,299,305	$ 140,825,195

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 4,565,251	$ 9,998,589
Civil/Structural/Buildings	9.20%		$ 5,915,536	$ 12,955,918
Piping	7.10%		$ 4,565,251	$ 9,998,589
Control and Instrumentation	2.60%		$ 1,671,782	$ 3,661,455
Electrical Systems	8.00%		$ 5,143,944	$ 11,266,016
		Total Balance of Plant	$ 21,861,764	$ 47,880,566
		Total Balance of Plant Plus the Selected Source	$ 86,161,068	$ 188,705,761

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 under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

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

Detail Item Report - Methane Reforming

Project Name: NGNP Process Integration
Process: Nuclear Gas to MTG
Estimate Number: MA36-J

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Natural Gas to Liquids Conversion Project (Raytheon 2000)	150	MMS CFD	1	1999	$ 79,000,000	$ 79,000,000	$ 103,553,507	258	MMS CFD	2	129	MMS CFD	$ 94,594,064	$ 223,241,991
NETL Natural Gas Report (Choi 1996)	100	MMS CFD	1	1996	$ 22,800,000	$ 22,800,000	$ 30,583,181	258	MMS CFD	2	129	MMS CFD	$ 35,631,694	$ 71,263,389
Gas Usage & Value The Technology and Economics of Natural Gas Use in the Process Industries (PennWell Corporation 2006)	4,700	tpd	2	1985	$ 168,150,000	$ 84,075,000	$ 132,328,312	11,023	tpd	2	5,512	tpd	$ 220,679,736	$ 441,359,472
NREL Report (NREL 2006)	183	MMS CFD	1	2002	$ 175,391,586	$ 175,391,586	$ 226,998,210	258	MMS CFD	2	129	MMS CFD	$ 184,157,981	$ 368,315,962

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Natural Gas to Liquids Conversion Project (Raytheon 2000)	150	MMS CFD	1	1999	$ 79,000,000	$ 79,000,000	$ 103,553,507	258	MMS CFD	2	129	MMS CFD	$ 94,594,064	$ 223,241,991

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 6,716,179	$ 15,850,181
Civil/Structural/Buildings	9.20%		$ 8,702,654	$ 20,538,263
Piping	7.10%		$ 6,716,179	$ 15,850,181
Control and Instrumentation	2.60%		$ 2,459,446	$ 5,804,292
Electrical Systems	8.00%		$ 7,567,525	$ 17,859,359
		Total Balance of Plant	$ 32,161,982	$ 75,902,277
		Total Balance of Plant Plus the Selected Source	$ 126,756,046	$ 299,144,268

Rationale for Selection:

Raytheon 2000 was selected as the most recent cost point, with technology most similar to the intended process. The adjusted PennWell Corporation 2006 cost point concurs with the Raytheon 2000 value. Costs presented in the Raytheon report have been increased by 18% to account for the difference between an autothermal process and traditional steam methane reforming process. The allowances listed under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

Note: PennWell Corporation 2006 includes both the natural gas reformer and methanol synthesis units. The average cost for methanol synthesis, as calculated in this report, was subtracted from the total current cost for required trains cell so that this may be considered as a cost point for natural gas reforming. The NREL 2006 cost was scaled from the originally presented value to exclude the cost of the water gas shift reactors.

Detail Item Report - Pressure Swing Adsorption (PSA)

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Fluor/UOP Report (Fluor/UOP 2004)	27,498	lbmol/hr	1	2003	$ 25,000,000	$ 25,000,000	$ 31,840,796	1,755	lbmol/hr	1	1,755	lbmol/hr	$ 6,108,992	$ 6,108,992

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Fluor/UOP Report (Fluor/UOP 2004)	27,498	lbmol/hr	1	2003	$ 25,000,000	$ 25,000,000	$ 31,840,796	1,755	lbmol/hr	1	1,755	lbmol/hr	$ 6,108,992	$ 6,108,992

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 433,738	$ 433,738
Civil/Structural/Buildings	9.20%		$ 562,027	$ 562,027
Piping	7.10%		$ 433,738	$ 433,738
Control and Instrumentation	2.60%		$ 158,834	$ 158,834
Electrical Systems	8.00%		$ 488,719	$ 488,719
		Total Balance of Plant	$ 2,077,057	$ 2,077,057
		Total Balance of Plant Plus the Selected Source	$ 8,186,049	$ 8,186,049

Rationale for Selection:

Single source cost point. 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 - Methanol Synthesis

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Economics of Producing Methanol from Coal by Entrained and Fluidized-Bed Gasifiers (U.S. DOI Bureau of Mines, August 1977)	5000	tpd	1	1977	$ 63,096,600	$ 63,096,600	$ 158,282,505	11,023	tpd	2	5,512	tpd	$ 167,808,053	$ 335,616,106
Investigations on Catalyzed Steam Gasification of Biomass (PNL-3695 1981)	997	tpd	1	1980	$ 22,000,000	$ 22,000,000	$ 43,124,043	11,023	tpd	2	5,512	tpd	$ 120,299,622	$ 240,599,243
H-Coal and Coal-to-Methanol Liquefaction Processes: Process Engineering Evaluation (EPRI AP-3290, November 1983)	15919	tpd	6	1982	$ 183,327,000	$ 30,554,500	$ 49,821,350	11,023	tpd	2	5,512	tpd	$ 77,253,588	$ 154,507,177

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Average of the three available sources.													$ 121,787,088	$ 243,574,175

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 8,646,883	$ 17,293,766
Civil/Structural/Buildings	9.20%		$ 11,204,412	$ 22,408,824
Piping	7.10%		$ 8,646,883	$ 17,293,766
Control and Instrumentation	2.60%		$ 3,166,464	$ 6,332,929
Electrical Systems	8.00%		$ 9,742,967	$ 19,485,934
		Total Balance of Plant	$ 41,407,610	$ 82,815,220
		Total Balance of Plant Plus the Selected Source	$ 163,194,697	$ 326,389,395

Rationale for Selection:

Considering the date of the source and the available assumptions and methodologies used, an average cost for all sources was used to minimize reporting errors. 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 - Gasoline Synthesis

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Gas Usage & Value The Technology and Economics of Natural Gas Use in the Process Industries (PennWell Corporation, 2006)	14500	bpd	1	1985	$ 92,925,000	$ 92,925,000	$ 146,257,608	33,470	bpd	2	16,735	bpd	$ 159,394,414	$ 318,788,827

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Gas Usage & Value The Technology and Economics of Natural Gas Use in the Process Industries (PennWell Corporation, 2006)	14500	bpd	1	1985	$ 92,925,000	$ 92,925,000	$ 146,257,608	33,470	bpd	2	16,735	bpd	$ 159,394,414	$ 318,788,827

Balance of Plant:

Description	% of Total Cost						Cost Per Train	Total Cost
Water Systems	7.10%						$ 11,317,003	$ 22,634,007
Civil/Structural/Buildings	9.20%						$ 14,664,286	$ 29,328,572
Piping	7.10%						$ 11,317,003	$ 22,634,007
Control and Instrumentation	2.60%						$ 4,144,255	$ 8,288,510
Electrical Systems	8.00%						$ 12,751,553	$ 25,503,106
						Total Balance of Plant	$ 54,194,101	$ 108,388,201
						Total Balance of Plant Plus the Selected Source	$ 213,588,514	$ 427,177,028

Rationale for Selection:

Single source cost point. The allowances listed under 'Balance of Plant' are based on NETL 2000. These allowance values are comparable to additional published estimating guides, such as Page 1996.

Detail Item Report - Steam Turbines

Project Name: NGNP Process Integration
Process: Nuclear Gas to MTG
Estimate Number: MA36-J

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Steam Turbine and HRSG														
Shell IGCC Base Cases (NETL 2000)	189	MW	1	1999	$ 50,671,000	$ 50,671,000	$ 66,419,744	80	MW	1	80	MW	$ 39,558,867	$ 39,558,867
Steam Turbine														
NETL Baseline Report (NETL 2007a)	401	MW	4	2006	$ 74,651,000	$ 18,662,750	$ 19,125,957	80	MW	1	80	MW	$ 16,654,070	$ 16,654,070
Princeton Report (Kreutz 2008)	275	MW	1	2007	$ 66,700,000	$ 66,700,000	$ 64,998,858	80	MW	1	80	MW	$ 30,892,564	$ 30,892,564
Shell IGCC Power Plant with CO2 Capture (NETL 2007b)	230	MW	1	2006	$ 44,515,000	$ 44,515,000	$ 45,619,856	80	MW	1	80	MW	$ 24,140,395	$ 24,140,395

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Shell IGCC Power Plant with CO2 Capture (NETL 2007b)	230	MW	1	2006	$ 44,515,000	$ 44,515,000	$ 45,619,856	80	MW	1	80	MW	$ 24,140,395	$ 24,140,395

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 1,713,968	$ 1,713,968
Civil/Structural/Buildings	9.20%		$ 2,220,916	$ 2,220,916
Piping	7.10%		$ 1,713,968	$ 1,713,968
Control and Instrumentation	2.60%		$ 627,650	$ 627,650
Electrical Systems	8.00%		$ 1,931,232	$ 1,931,232
		Total Balance of Plant	$ 8,207,734	$ 8,207,734
		Total Balance of Plant Plus the Selected Source	$ 32,348,129	$ 32,348,129

Rationale for Selection:

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

Detail Item Report - HRSG

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Steam Turbine and HRSG														
Shell IGCC Base Cases (NETL 2000)	189	MW	1	1999	$ 50,671,000	$ 50,671,000	$ 66,419,744	80	MW	1	80	MW	$ 39,558,867	$ 39,558,867
HRSG														
NETL Baseline Report (NETL 2007a)	5,155,983	lb/hr	3	2006	$ 27,581,000	$ 9,193,667	$ 9,421,852	-	lb/hr	1	-	lb/hr	$ -	$ -
Princeton Report (Kreutz 2008)	355	MW	1	2007	$ 52,000,000	$ 52,000,000	$ 50,673,772	-	MW	1	-	MW	$ -	$ -
Shell IGCC Power Plant with CO2 Capture (NETL 2007b)	8,438,000	lb/hr	2	2006	$ 45,291,000	$ 22,645,500	$ 23,207,558	-	lb/hr	1	-	lb/hr	$ -	$ -

Source Selected:

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

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ -	$ -
Civil/Structural/Buildings	9.20%		$ -	$ -
Piping	7.10%		$ -	$ -
Control and Instrumentation	2.60%		$ -	$ -
Electrical Systems	8.00%		$ -	$ -
		Total Balance of Plant	$ -	$ -
		Total Balance of Plant Plus the Selected Source	$ -	$ -

Rationale for Selection:

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

Detail Item Report - Cooling Towers

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

Sources Considered:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Cooling Tower Depot	257,440	gpm	7	2009	$ 6,211,600	$ 887,371	$ 887,371	221,633	gpm	6	36,939	gpm	$ 889,710	$ 5,338,261

Source Selected:

Source	Reported Capacity		Reported Trains	Report Cost Year	Reported Cost	Reporting Year Cost Per Train	Normalized Cost Per Train using CEPCI Index	Capacity Required		Trains Reqd.	Capacity per Train		Factored Cost per Train from Normalized Cost	Total Current Cost for Required Trains
Cooling Tower Depot	257,440	gpm	7	2009	$ 6,211,600	$ 887,371	$ 887,371	221,633	gpm	6	36,939	gpm	$ 889,710	$ 5,338,261

Balance of Plant:

Description	% of Total Cost		Cost Per Train	Total Cost
Water Systems	7.10%		$ 63,169	$ 379,017
Civil/Structural/Buildings	9.20%		$ 81,853	$ 491,120
Piping	7.10%		$ 63,169	$ 379,017
Control and Instrumentation	2.60%		$ 23,132	$ 138,795
Electrical Systems	8.00%		$ 71,177	$ 427,061
		Total Balance of Plant	$ 302,501	$ 1,815,009
		Total Balance of Plant Plus the Selected Source	$ 1,192,212	$ 7,153,270

Rationale for Selection:

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