NOVEL GAS CLEANING/ CONDITIONING FOR INTEGRATED GASIFICATION COMBINED CYCLE

VOLUME I – CONCEPTUAL COMMERCIAL EVALUATION

OPTIONAL PROGRAM FINAL REPORT

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ABSTRACT

Development efforts have been underway for decades to replace dry-gas cleaning technology with humid-gas cleaning technology that would maintain the water vapor content in the raw gas by conducting cleaning at sufficiently high temperature to avoid water vapor condensation and would thus significantly simplify the plant and improve its thermal efficiency. Siemens Power Generation, Inc. conducted a program with the Gas Technology Institute (GTI) to develop a Novel Gas Cleaning process that uses a new type of gas-sorbent contactor, the “filter-reactor”. The Filter-Reactor Novel Gas Cleaning process described and evaluated here is in its early stages of development and this evaluation is classified as conceptual. The commercial evaluations have been coupled with integrated Process Development Unit testing performed at a GTI coal gasifier test facility to demonstrate, at sub-scale the process performance capabilities. The commercial evaluations and Process Development Unit test results are presented in Volumes 1 and 2 of this report, respectively.

Two gas cleaning applications with significantly differing gas cleaning requirements were considered in the evaluation: IGCC power generation, and Methanol Synthesis with electric power co-production. For the IGCC power generation application, two sets of gas cleaning requirements were applied, one representing the most stringent “current” gas cleaning requirements, and a second set representing possible, very stringent “future” gas cleaning requirements. Current gas cleaning requirements were used for Methanol Synthesis in the evaluation because these cleaning requirements represent the most stringent of cleaning requirements and the most challenging for the Filter-Reactor Novel Gas Cleaning process.

The scope of the evaluation for each application was:

- Select the configuration for the Filter-Reactor Novel Gas Cleaning Process, the arrangement of the individual gas cleaning stages, and the probable operating conditions of the gas cleaning stages to conceptually satisfy the gas cleaning requirements;
- Estimate process material & energy balances for the major plant sections and for each gas cleaning stage;
- Conceptually size and specify the major gas cleaning process equipment;
- Determine the resulting overall performance of the application;
- Estimate the investment cost and operating cost for each application.

Analogous evaluation steps were applied for each application using conventional gas cleaning technology, and comparison was made to extract the potential benefits, issues, and development needs of the Filter-Reactor Novel Gas Cleaning technology. The gas cleaning process and related gas conditioning steps were also required to meet specifications that address plant environmental emissions, the protection of the gas turbine and other Power Island components, and the protection of the methanol synthesis reactor. Detailed material & energy balances for the gas cleaning applications, coupled with preliminary thermodynamic modeling and laboratory testing of candidate sorbents, identified the probable sorbent types that should be used, their needed operating conditions in each stage, and their required levels of performance.

The study showed that Filter-Reactor Novel Gas Cleaning technology can be configured to address and conceptually meet all of the gas cleaning requirements for IGCC, and that it can potentially overcome several of the conventional IGCC power plant availability issues, resulting in improved power plant thermal efficiency and cost. For IGCC application, Filter-Reactor Novel Gas Cleaning yields 6% greater generating capacity and 2.3 percentage-points greater

efficiency under the Current Standards case, and more than 9% generating capacity increase and 3.6 percentage-points higher efficiency in the Future Standards case. While the conceptual equipment costs are estimated to be only slightly lower for the Filter-Reactor Novel Gas Cleaning processes than for the conventional processes, the improved power plant capacity results in the potential for significant reductions in the plant cost-of-electricity, about 4.5% for the Current Standards case, and more than 7 % for the Future Standards case.

For Methanol Synthesis, the Novel Gas Cleaning process scheme again shows the potential for significant advantages over the conventional gas cleaning schemes. The plant generating capacity is increased more than 7% and there is a 2.3 %-point gain in plant thermal efficiency. The Total Capital Requirement is reduced by about 13% and the cost-of-electricity is reduced by almost 9%. For both IGCC Methanol Synthesis cases, there are opportunities to combine some of the filter-reactor polishing stages to simplify the process further to reduce its cost.

This evaluation has devised plausible humid-gas cleaning schemes for the Filter-Reactor Novel Gas Cleaning process that might be applied in IGCC and Methanol Synthesis applications. These schemes are simpler than those used in conventional dry-gas cleaning for these applications and show the conceptual-potential to provide plant availability, plant thermal efficiency and cost improvements over the conventional plants. Since methanol synthesis gas cleaning requirements are more stringent than any other syngas application, the Filter-Reactor Novel Gas Cleaning process is expected to achieve similar advantages for other applications, such as for coal-fueled, Solid Oxide Fuel Cell applications.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

ACRONYMS AND ABBREVIATIONS

AGR	Acid Gas Removal
ASU	Air Separation Unit
COE	Cost of Electricity
EPRI	Electric Power Research Institute
GTI	Gas Technology Institute
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
IGCC	Integrated Gasification Combined Cycle
ISO	International Organization for Standards
KRW	Kellogg Rust Westinghouse
LHV	Lower Heating Value
MDEA	Methyldiethanolamine
PC	Pulverized Coal
PDU	Process Development Unit
PFBC	Pressurized Fluidized bed Combustion, -Combustor
ppbv	Parts per billion (10^9) by volume

ppmv	Parts per million by volume
ppmw	Parts per million by weight
TCR	Total Capital Requirement
VOC	Volatile Organic Compound

1. EXECUTIVE SUMMARY

The gasification of coal generates a raw gas that requires considerable cleaning, removing particulate and several vapor-phase contaminants to very low levels before the gas can be used in applications such as IGCC power generation or fuel/chemical synthesis. Conventional gas cleaning processes cool the raw gas to a low temperature that results in nearly complete removal of condensable species (primarily water vapor and volatile metal contaminants) from the gas. This produces a condensate stream that is used in a gas-condensate contactor to absorb highly water-soluble contaminants from the gas (halides and ammonia), generating a nearly dry gas and a highly contaminated condensate stream that requires extensive processing. It is followed by "dry-gas" treatment in a low-temperature, gas-solvent absorption contactor to remove sulfur species. In IGCC applications, the clean, dry gas must be re-humidified and diluted with nitrogen to generate a fuel gas that can be fired in turbine combustors with acceptable NOx emission. This "dry-gas" cleaning technology, while being highly effective for gas cleaning, results in a complex process that has high overall power and thermal energy consumption.

Development efforts have been underway for decades to replace this dry-gas cleaning technology with "humid-gas" cleaning technology that would maintain the water vapor content in the raw gas by conducting cleaning at sufficiently high temperature to avoid water vapor condensation and would thus significantly simplify the plant and improve its thermal efficiency. These humid-gas cleaning techniques have been previously designated "hot-gas" or "warm-gas" cleaning. Such methods have the potential for improved thermal efficiency and reduced process complexity, but they have not yet been fully defined for integrated plant operation, nor demonstrated at any significant scale.

The most promising and most developed approach proposed for gas cleaning under humid-gas conditions is to configure a series of stages of gas-sorbent particle contactors that will either adsorb or chemically react with specific contaminants (halide species, sulfur species, mercury species, etc.). For example, sodium-based sorbents have been tested at high temperatures in gas-sorbent contactors to remove halides (primarily HCl), and zinc-, iron-, and a number of other metal oxide-based sorbents have been tested in various types of contactors to remove sulfur species. The types of gas-sorbent contactors considered in the past have been fixed beds, moving beds, fluidized beds, and transport beds, all using appropriate sorbent materials reactive to the specific contaminant of interest and with particle sizes appropriate to the type of contactor. All of these contactors, though, are prone to performance issues related to plugging, transient pressure drop increases, sorbent particle attrition and elutriation, and the need to operate with high-cost, highly durable, specially fabricated sorbent particles. Also, none of these gas-sorbent contactors can achieve the very low gas contaminant levels that will be required in future IGCC plants or the extremely low contaminant levels required in many fuel/chemical synthesis applications, and are only suitable for "bulk" contaminant removal.

Filter-Reactor Novel Gas Cleaning Concept

Siemens Power Generation, Inc. (Siemens) is conducting a program with the Gas Technology Institute (GTI) to develop a Novel Gas Cleaning process that uses a new type of gas-sorbent contactor, the "filter-reactor". The filter-reactor is both a barrier filter that achieves very efficient removal of particulate from the gas, and a gas-sorbent reactor used for once-through sorbent, gas-contaminant polishing. The filter-reactor behaves, in principle, as a fixed bed reactor, but having several potential advantages over conventional gas-sorbent contactors. It is continuously replenished with fresh sorbent particles by injecting fine sorbent particles into its inlet gas. These sorbent particles distribute uniformly on the filter elements, providing very efficient gas-sorbent contacting conditions, and several contaminant polishing functions, including particulate removal and various gas-phase contaminant removals using once-through sorbents can be simultaneously performed in a single vessel. Two key features of the filter-reactor that contrast it with the conventional gas-sorbent contactors are that its outlet particle loading is extremely low, and it might operate efficiently using cheap, fine, unsupported sorbent particles.

The filter-reactor gas-sorbent contactors proposed for use in this highly efficient, humid-gas cleaning process, called the Filter-Reactor Novel Gas Cleaning process, have the potential to provide improved plant operating behavior and improved thermal efficiency while being able to achieve the very low gas contaminant levels that will be required in future IGCC plants or the extremely low contaminant levels required in many fuel/chemical synthesis applications.   This process builds upon prior humid-gas cleaning technologies for bulk halide and sulfur removal developed under DOE sponsorship and is integrated with these bulk removal technologies to improve their performance.

Evaluation Objectives and Scope

The Siemens Novel Gas Cleaning Base Program generated an initial process evaluation supported by laboratory test data that identified the potential merits of advanced technology (Siemens Power Generation, "Novel Gas Cleaning/Conditioning for Integrated Gasification Combined Cycle, Siemens, Base Program Final Report", August, 2001, AC26-99FT40674-02).   The overall objective of the Siemens Novel Gas Cleaning Optional Program, described in Volume I of the report, is to produce sub-scale, Process Development Unit (PDU) test data that demonstrates the performance potential of the filter-reactor for key humid-gas cleaning and polishing functions. This PDU test data is described and analyzed in Volume II of this Final Optional Program Report. The evaluation described in this report has been conducted to support this program's experimental filter-reactor sub-scale development by:

- devising commercial, integrated, humid-gas cleaning process configurations that apply the filter-reactor contacting stages,
- identifying the filter-reactor contacting stages performance requirements,
- identifying their likely ranges of operating conditions,
- generating process material & energy balances and conceptual equipment designs for commercial applications,
- quantifying the overall, conceptually-based, gas cleaning performance and cost potential,
- providing a framework for quantitatively assessing the Process Development Unit (PDU) filter-reactor test results generated in this program (reported in Volume II).

The Filter-Reactor Novel Gas Cleaning process described and evaluated here is in its early stages of development and this evaluation is classified as "conceptual." This evaluation is not intended to represent absolute estimates of performance and cost for the plant applications considered, but is only applied to estimate the conceptual performance and cost potential of the Filter-Reactor Novel Gas Cleaning process relative to conventional gas cleaning technologies. A set of process assumptions has been developed for the evaluation that address the features and performance of the Filter-Reactor Novel Gas Cleaning process components based on the current state-of-understanding of those components. Process performance and conceptual-cost comparisons with conventional gas cleaning technology have been used to draw quantitative, but conceptually-based conclusions for the Filter-Reactor Novel Gas Cleaning potential performance, cost benefits, and technology issues.

Two gas cleaning applications have been considered in the evaluation, the two having significantly differing gas cleaning requirements:

- IGCC power generation,
- Methanol Synthesis with electric power co-production.

For the IGCC power generation application, two sets of gas cleaning requirements have been selected and applied, one representing the most stringent of "current" gas cleaning requirements for IGCC, and a second set representing possible, very stringent "future" gas cleaning requirements for IGCC. The gas cleaning requirements for Methanol Synthesis have been considered in the evaluation because these cleaning requirements represent the most stringent of cleaning requirements and the most challenging for the Filter-Reactor Novel Gas Cleaning process.

The scope of the evaluation for each application was:

- Select the configuration for the Filter-Reactor Novel Gas Cleaning Process, the arrangement of the individual gas cleaning stages, and the probable operating conditions of the gas cleaning stages to conceptually satisfy the gas cleaning requirements;
- Estimate process material & energy balances for the major plant sections and for each gas cleaning stage;
- Conceptually size and specify the major gas cleaning process equipment;
- Determine the resulting overall performance of the application:
    - generating capacity and heat rate,
    - product and by-product production rates,
    - chemical and catalyst feed rates and auxiliary consumptions,
    - plant emissions performance,
    - gas turbine protection performance,
    - synthesis catalyst protection performance,
    - quantities of, and final fate of gas contaminants and waste solids.
- Estimate the investment cost and operating cost for each application:
    - gas cleaning process major equipment purchased and installed cost,
    - plant Total Capital Requirement,
    - plant annual operating cost,
    - plant Cost-of-Electricity.

Analogous evaluation steps were applied for each application using conventional gas cleaning technology, and comparison was made to extract the potential benefits, issues, and development needs of the Filter-Reactor Novel Gas Cleaning technology.

Evaluation Basis

Two types of applications for Filter-Reactor Novel Gas Cleaning have been considered: 1) IGCC power generation with two levels of gas cleaning requirements, Current Standards and Future Standards; and 2) Methanol Synthesis with co-production of power, subjecting the Filter-Reactor Novel Gas Cleaning process to very stringent requirements. A set of commercial plant specifications are presented in Section 3 of this report that identify the evaluation bases for these two applications in sufficient detail to conduct the conceptual evaluation.

The major factors selected for the plant basis as being representative of likely future plants are:

- gasifier type: representative of a single-stage, oxygen-blown, entrained, slagging gasifier,
- coal feeding and pressurization method: coal-water slurry system,
- air-side integration level: 100% integration (even though 50% may be nearer the optimum condition),
- coal type: Illinois Number 6, high-sulfur bituminous,
- raw-gas heat recovery method: radiant and convective heat recovery to generate HP-steam,
- gas turbine type: representative of "F" turbine technology (SGT6-5000F), modified for air-side integration and syngas operating duty,
- methanol production rate: 218 tonne/day (240 tons/day),
- methanol grade: fuel-grade.

The gas cleaning process and related gas conditioning steps must meet specifications that address:

- the plant environmental emissions,
- the protection of the gas turbine and other Power Island components,
- the protection of the methanol synthesis reactor.

The following gas cleaning specifications are of critical importance to the design of the gas cleaning process, and achieving these specifications, while maintaining the overall plant performance and economics at acceptable levels, is a key measure of the success of the gas cleaning technology.

The IGCC power plant evaluation considered two sets of gas cleaning standards, “Current Standards” and “Future Standards” with respect to environmental emissions and Power Island protection standards. Current Standards are based on the "best-of-current-practice" reported for existing IGCC power plants. The IGCC power plant Future Standards approach the emissions performance of natural gas-fired power plants, and reflect standards that may be imposed on the future generation of IGCC plants. The gas cleaning requirements considered for the Methanol Synthesis plant evaluation include standards for the protection of the methanol synthesis reactor as well as emissions and Power Island standards. The environmental standards applied for Methanol Synthesis are identical to the Future Standards case used for IGCC. The Power Island standards are the same as those used for the IGCC application. The Methanol Synthesis standards for gas cleaning are extremely stringent. These gas cleaning standards are listed and compared in Table 1.1.

Table 1.1 – Gas Cleaning Requirements Basis for Evaluation Cases

Evaluation Case	**IGCC**		**Methanol**
Standards	Current	Future	Future
Environmental			
SOx, % coal sulfur removed	99	99.98	99.98
NOx, ppmv at stack, corrected to 15% oxygen, dry	15	5	5
Particulate, mg/MJ (lb/10^6 Btu)	2.15 (0.005)	2.15 (0.005)	2.15 (0.005)
Mercury, % coal Hg removed	90	95	95
Power Island fuel gas			
Halides, ppmv	5	5	5
volatile metals, ppbv	40	40	40
Particulate, ppmw	0.1	0.1	0.1
Methanol Synthesis syngas			
total sulfur species, ppbv	---	---	60
total halide species, ppbv	---	---	10
Ammonia, ppmv	---	---	10
hydrogen cyanide, ppbv	---	---	10
Metal carbonyls, ppbv	---	---	100
Particulate, ppmw	---	---	0.1
Mercury, % removal	---	---	95

IGCC Evaluation Results

The Filter-Reactor Novel Gas Cleaning technology can be configured to address and conceptually meet all of the gas cleaning requirements for IGCC. It can also potentially overcome several of the conventional IGCC power plant availability issues, and can result in improved power plant thermal efficiency and cost.

Overall, generic gas cleaning process schemes for IGCC using conventional dry-gas cleaning and Filter-Reactor Novel Gas Cleaning are illustrated and compared in Figure 1.1. The AGR Absorber in the figure is a generic process block representing any one of a number of technologies, such as MDEA absorption or Rectisol absorption. The conventional dry-gas cleaning process for IGCC contains a series of highly-integrated process steps with several recycle streams and applies numerous heat interchangers that provide temperature control and water vapor condensation and gas re-humidification to generate a clean fuel gas. Raw gas cooling is followed by particle removal and COS hydrolysis in both process schemes. Conventional dry-gas cleaning applied low-temperature cooling to condense out halide and

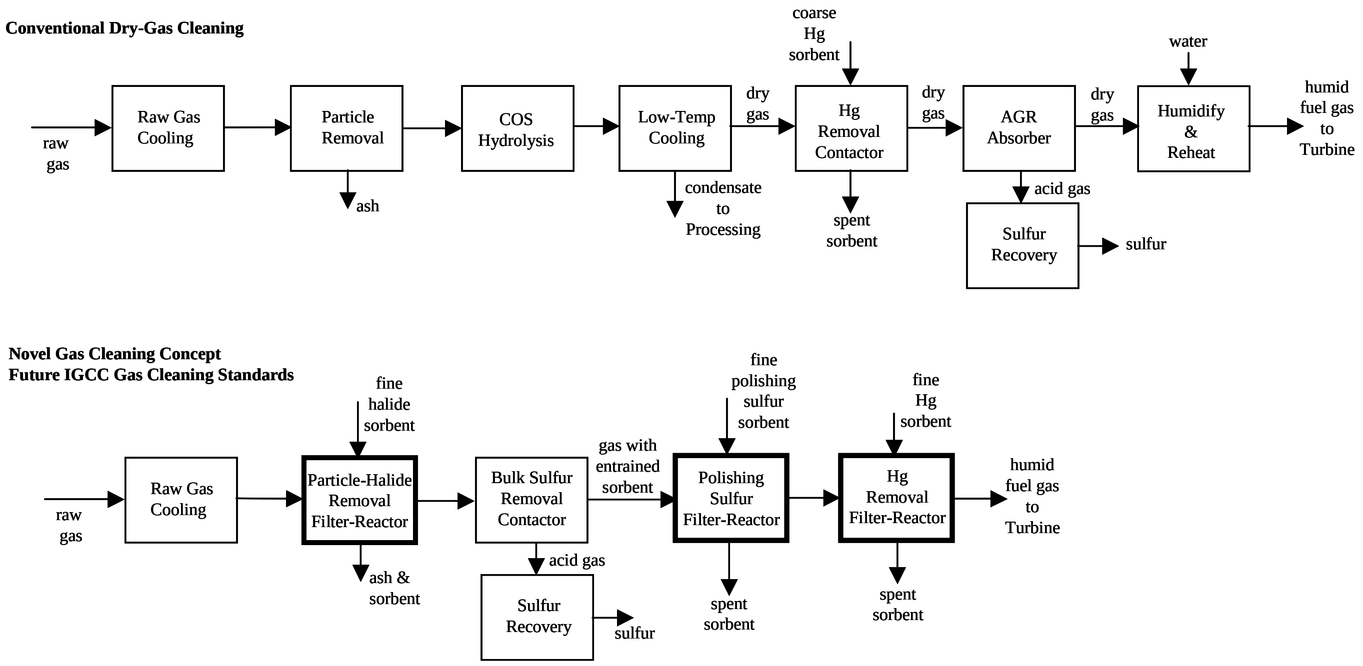


Figure 1.1 – Conventional and Novel Gas Cleaning Process Schemes for IGCC

ammonia. Mercury removal is performed in a low-temperature, packed bed adsorber process. An absorber process is used for acid gas removal (AGR) and its selection depends on the degree of sulfur removal required. The cleaned syngas is humidified and reheated before passing to the gas turbine.

The Filter-Reactor Novel Gas Cleaning scheme is relatively simple compared to the conventional dry-gas cleaning process. In the Filter-Reactor Novel Gas Cleaning process, halides are controlled by once-through nahcolite, or trona sorbent injection into a filter-reactor located before the bulk sulfur removal process. Bulk sulfur removal is conducted in a transport desulfurizer using zinc-based sorbent. A filter-reactor following the transport reactor captures entrained sulfur sorbent from the transport reactor and provides conditions for additional reaction between the entrained sorbent and gas, with the temperature of the filter-reactor controlled to provide best reaction conditions. Additional sorbent is injected into this filter-reactor to achieve the IGCC Future Standards for sulfur removal. Mercury is captured in a final filter-reactor using a humid-gas mercury sorbent, although these two cleaning functions could potentially be performed in the same filter-reactor vessel if an appropriate mercury sorbent could be identified. NOx emission control is by means of advanced, low-NOx staged, turbine-combustors that incorporate ammonia decomposition.

While the Filter-Reactor Novel Gas Cleaning process should be able to meet all of the gas cleaning requirements, the conventional dry-gas cleaning technology, using MDEA Acid Gas Removal for Current Standards, and Rectisol Acid Gas Removal for Future Standards, will result in lower halide content and lower fuel-bound nitrogen (ammonia and HCN) in the clean fuel gas.

The IGCC overall conceptual performance results are tabulated in Table 1.2. The results indicate that the Filter-Reactor Novel Gas Cleaning scheme has the potential for significant improvements in IGCC power plant generating capacity and heat rate. Filter-Reactor Novel Gas Cleaning yields 6% greater generating capacity and 2.3 percentage-points greater efficiency under the Current Standards case, and more than 9% generating capacity increase and 3.6 percentage-points higher efficiency in the Future Standards case. Note that Novel Gas Cleaning performance is almost entirely insensitive to the gas cleaning standards, with little difference between the Current and Future Standards cases. Solid waste from IGCC with Filter-Reactor Novel Gas Cleaning is about 8% greater than IGCC with conventional dry-gas cleaning. While the conceptual equipment costs are estimated to be only slightly lower for the Filter-Reactor Novel Gas Cleaning processes than for the conventional processes, the improved power plant capacity results in the potential for significant reductions in the plant cost-of-electricity, about 4.5% for the Current Standards case, and more than 7 % for the Future Standards case.

Table 1.2 – Conventional and Novel Gas Cleaning Performance and Cost for IGCC

Gas Cleaning Technology	**Conventional Cleaning**	**Novel Cleaning**	**Conventional Cleaning**	**Novel Cleaning**
Gas Cleaning Standards	Current	Current	Future	Future
Generation capacity, MWe	285	303	276	303
Plant thermal efficiency (%, HHV)	37.6	39.9	36.3	39.9
Plant Heat Rate (HHV), kJ/kWh (Btu/kWh)	9,574 (9,074)	9,022 (8,551)	9,916 (9,399)	9,022 (8,551)
Total Capital Requirement, $/kW	1,500	1,415	1,614	1,435
Total COE, cents/kWh	6.6	6.3	6.9	6.4

Methanol Synthesis Evaluation Results

The chemical synthesis application evaluated is a combined electric power and Methanol Synthesis plant, so there are two major gas streams be cleaned: a fuel gas stream for power generation, and a syngas stream for Methanol Synthesis. The Filter-Reactor Novel Gas Cleaning technology can be configured to meet all of the gas cleaning requirements for gas cleaning presented by Methanol Synthesis.

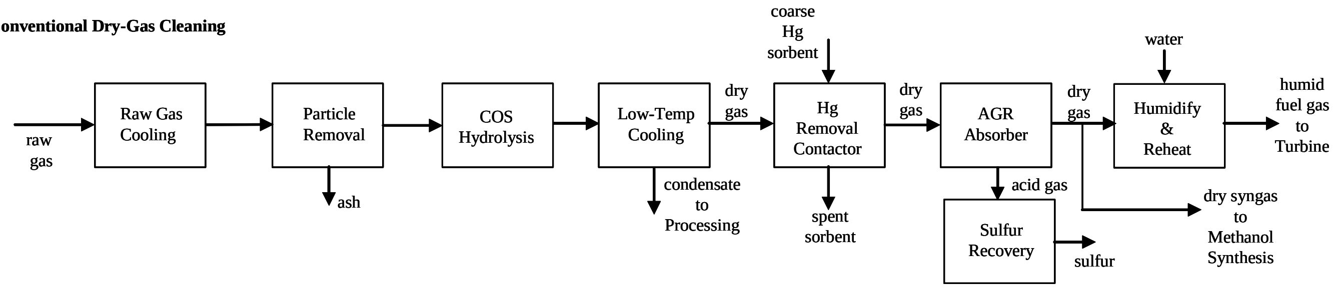
The primary gas cleaning process features applied for conventional dry-gas cleaning and for Filter-Reactor Novel Gas Cleaning are:

- conventional dry-gas cleaning for Methanol Synthesis is similar to the IGCC gas cleaning process for Future Standards, but uses Rectisol Acid Gas Removal technology, as well as fixed, guard-bed sulfur sorbent stages to meet the very stringent gas cleaning requirement for sulfur control;
- Filter-Reactor Novel Gas Cleaning is similar to the IGCC gas cleaning process for Future Standards, but incorporates an additional filter-reactor sulfur polishing stage and applies a water scrubbing step for methanol synthesis syngas halide and ammonia polishing.

The two process schemes are illustrated and compared in Figure 1.2. The conventional dry-gas cleaning process uses low-temperature wet scrubbing for halide and ammonia removal, Rectisol Acid Gas Removal process for sulfur species control, and low-temperature packed bed adsorption of mercury. It then separates the gas into a methanol syngas stream and a fuel gas stream, and it places guard beds within the Methanol Synthesis process for final-stage syngas sulfur removal and metal carbonyls removal.

The Filter-Reactor Novel Gas Cleaning process uses halide sorbent injection into a Filter-Reactor for particulate and bulk halide removal, a zinc oxide-based sorbent for bulk sulfur removal, and a Filter-Reactor sulfur polishing stage to meet the IGCC fuel gas cleaning requirements. A stage of mercury adsorbent injection into a mercury Filter-Reactor is operated at a temperature of 260°C (500°F) to achieve the mercury requirement. The separated methanol syngas stream is then treated in an additional sulfur polishing Filter-Reactor, followed by a water scrubbing stage for syngas polishing of halides and ammonia. The sour water from the scrubber is recycled to the gasifier where the captured ammonia is thermally decomposed, and the captured halide is released and eventually captured in the bulk halide removal Filter-Reactor, making this water scrubber process much less complex and less costly than that used in the conventional dry-gas cleaning process.

Conventional Dry-Gas Cleaning



Novel Gas Cleaning Concept

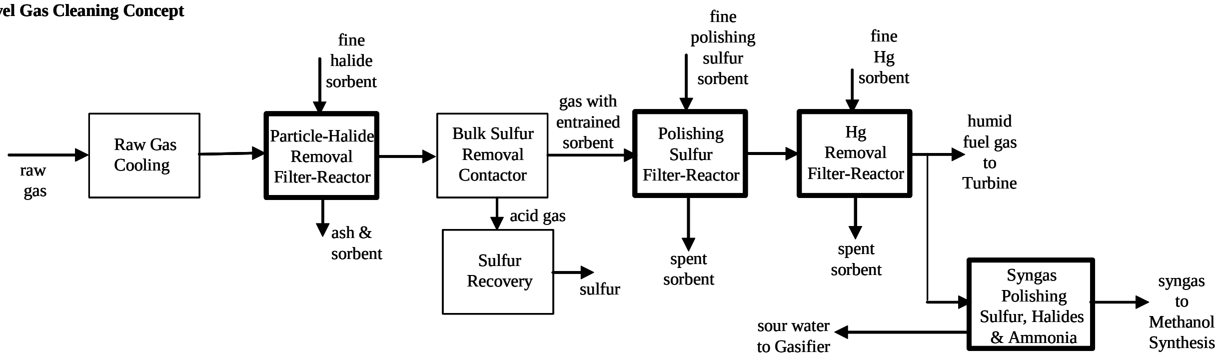


Figure 1.2 – Conventional and Novel Gas Cleaning Process Schemes for Methanol Synthesis

The Novel Gas Cleaning process scheme again shows the potential for significant advantages over the conventional gas cleaning schemes (Table 1.3). The plant generating capacity is increased more than 7% and there is a 2.3 %-point gain in plant thermal efficiency. The Total Capital Requirement is reduced by about 13% and the cost-of-electricity is reduced by almost 9%. Again, there are opportunities to combine some of the filter-reactor polishing stages to simplify the process further to reduce its cost.

Table 1.3 – Conventional and Novel Gas Cleaning Performance and Cost for Methanol Synthesis

Gas Cleaning Technology	**Conventional Cleaning**	**Novel Cleaning**
Generation capacity, MWe	288	309
Plant thermal efficiency (%, HHV)	32.7	35.0
Plant Heat Rate (HHV), kJ/kWh (Btu/kWh)	11,008 (10,434)	10,286 (9,749)
Total Capital Requirement, $/kW	1,791	1,565
Total COE, cents/kWh (constant $)	5.6	5.1

Evaluation Conclusions

This evaluation has devised plausible humid-gas cleaning schemes for the Filter-Reactor Novel Gas Cleaning process that might be applied in IGCC and Methanol Synthesis applications. These schemes are simpler than those used in conventional dry-gas cleaning for these applications and show the conceptual-potential to provide plant availability, plant thermal efficiency and cost improvements over the conventional plants. Since methanol synthesis gas cleaning requirements are more stringent than any other syngas application, the Filter-Reactor Novel Gas Cleaning process is expected to achieve similar advantages for other applications, such as for coal-fueled, Solid Oxide Fuel Cell applications.

The Filter-Reactor should have a basic design similar to near-commercial barrier filters, with a large number of independently pulse-cleaned filter plenums that will allow the Filter-Reactor to maintain high levels of emission control. Sorbent particle sizes injected into the Filter-Reactors are expected to operate best at -325 mesh, with a mass-mean size of about 20 μm. The major uncertainties are 1) the contaminant removal performance that can actually be achieved in these Filter-Reactors, with their relatively thin, 5-13 mm (0.2 to 0.5 inch) sorbent filter cakes and low gas velocities through the filter cakes, and 2) the possible reaction-sintering behavior of the filter cakes that might occur at the stage conditions. These uncertainties were resolved in PDU testing conducted under representative conditions in this program.

Detailed material & energy balances for the gas cleaning applications, coupled with preliminary thermodynamic modeling and laboratory testing of candidate sorbents have identified the probable sorbent types that should be used, their needed operating conditions in each stage, and their required levels of performance. These performance goals and the results from the PDU testing are summarized in Table 1.4. In general, the performance goals have been demonstrated in the PDU testing, with the exceptions noted in the table. A water scrubbing stage is used for syngas polishing of halides and ammonia in the Methanol Synthesis application, and this stage should be able to be applied commercial using available technology experience. The conditions and performance levels that have not been demonstrated in the PDU testing in this program have been extrapolated from the PDU test results to apply to the commercial design and evaluations. Particle removal efficiency was not measured in this test program because of the previously established success of barrier filter technology

The evaluation utilized a regenerative, zinc-based sulfur sorbent in a transport reactor configuration for bulk sulfur removal, but the Filter-Reactor Novel Gas Cleaning process can be coupled with any developing bulk desulfurization technology (alternative sorbents and alternative gas-sorbent bulk desulfurization contactors) operating under humid gas cleaning conditions. The use of alternative bulk desulfurization technology will alter some of the Filter-Reactor stage conditions and polishing sorbent requirements.

Table 1.4 – Filter-Reactor Novel Gas Cleaning Stage Performance Goals and Test Results

Cleaning Stage	**Sorbent type (-325 mesh)**	**Process Temperature °C (°F)**	**Process Performance Goals**	**PDU Test Results (Final Report Volume II)**
IGCC Applications				
Bulk halide removal	Sodium mineral (Trona or Nahcolite)	593 (1100)	99% halide removal, 5 ppmv HCl outlet, Na/Cl mole feed ratio 4, 75% ammonia decomposition.	Met the performance goals at 427°C (800°F), Ammonia decomposition not measured (not in program scope)
Sulfur polishing	Zinc-titanate	482 (900)	96% removal, 40 ppmv inlet to 2 ppmv outlet, Zn/S mole feed ratio 3.	Not considered in PDU tests (focus placed on more challenging Methanol sulfur polishing)
Mercury removal	TDA sorbent	204-316 (400-600)	90-95% Hg removal, Sorbent/Hg mass feed ratio 1000, Possibly simultaneous with sulfur polishing.	90% Hg removal achieved at 260°C (500°F), Simultaneous sulfur removal not attempted (insufficient test time).
Methanol Synthesis Application				
Halide & ammonia polishing	Water absorbent	93-149 inlet (200-300)	97% ammonia removal to 10 ppmv, 99.8% HCl removal to 10 ppbv.	Halide and ammonia scrubbing not addressed in PDU tests (design from scrubbing experience).
Sulfur polishing	Zinc-titanate	260-316 (500-600)	98% sulfur removal, 60 ppbv sulfur outlet, Zn/S mole ratio 5.	Sulfur polishing met the performance goals in PDU tests.
Mercury removal	TDA sorbent	204-316 (400-600)	95% Hg removal, Sorbent/Hg mass feed ratio 1000.	90% Hg removal achieved at 260°C (500°F) (data extrapolated for commercial evaluation).

2. INTRODUCTION

IGCC is a relatively recently-commercialized power generation technology. It competes with conventional pulverized coal (PC) steam plant power generation, as well as with natural gas combined-cycle power generation. IGCC power generation applies conventional, low-temperature gas cleaning technology and has demonstrated its environmental emission control capabilities, being far superior to other coal-fueled power generation technologies. IGCC is designated by many as the coal-based power generation technology of the future because of its excellent environmental performance, its ability to utilize a range of solid and liquid fossil fuels, and its ability to be easily adapted for CO_2 sequestration with relatively low cost impact.

IGCC power generation marketability, though, is currently hampered by its process complexity, high capital and maintenance costs, and low power plant availability, in large-part due to the characteristics of conventional, low-temperature gas cleaning technology. Many aspects of IGCC with conventional, low-temperature fuel gas cleaning technologies are still being refined and upgraded to provide more acceptable power plant availability and cost. Five factors inherent in conventional, low-temperature, dry-gas cleaning technologies reduce IGCC power plant efficiencies and increase equipment costs:

1) Nearly all of the water vapor in the raw gas is condensed and removed, resulting in a significant plant energy loss;
2) The low-temperature gas cooling calls for the use of several stages of complex and expensive process stream heat interchangers, and with some acid gas removal technologies, solvent chilling or even refrigeration is needed that consumes significant energy;
3) The process condensate streams generated by raw gas condensation require processing to effectively remove their contained contaminant salts and dissolved gases and prepare them for final disposition, increasing plant complexity and cost;
4) The cleaned and reheated fuel gas has a high peak flame temperature with large NOx generation-potential in the gas turbine combustors, and it must be diluted by water vapor, using a fuel gas humidification process or steam injection, resulting in additional plant complexity;
5) The low-temperature sulfur absorption processes used remove a significant portion of the fuel gas CO_2 content along with the sulfur species, reducing the fuel gas mass flow and making sulfur recovery more energy intensive and expensive.

Conventional, low-temperature dry-gas cleaning technology can generally meet all of the host of gas cleaning requirements that are imposed for gas turbine protection and plant emissions control. Several of the IGCC plant availability issues, though, that have been reported in the literature relate directly to the nature of the conventional, low-temperature, dry-gas cleaning technology:

- Volatile metal species in the cleaned fuel gas, in the form of iron and nickel carbonyls, are reported in some IGCC power plants, resulting in deposition and corrosion in the gas turbine combustors, and disruption of plant operation (Collodi and Brkic, 2003; Bonzani and Pollarolo, 2004; Bruijn et al, 2003). The conventional gas cleaning process operating conditions may promote the formation of these metal carbonyls and protection from these metal carbonyls is not generally included in IGCC – these carbonyls are commonly guarded against in Methanol Synthesis plants by installing low-temperature, packed bed carbonyl adsorbers before the methanol synthesis reactor.
- Particulate, generated by fuel gas piping corrosion and by heat exchanger leaks, or entering the gas through ineffective particulate control devices, is reported in some IGCC power plants to reduce availability, resulting in gas cleaning process equipment fouling, and gas turbine erosion and deposition. This has been dealt with in some IGCC power plants by adding intermediate fuel gas particulate control to protect equipment from such particulate (McDaniel and Hornick, 2003).
- The process condensate streams generated in the conventional, low-temperature gas cleaning processes are highly corrosive to process equipment and result in reduced power plant availability.

Coal-gasification-based Methanol Synthesis has been operating commercially for many years at the Eastman Chemical Company using conventional, low-temperature dry syngas cleaning to meet the stringent syngas cleaning requirements for Methanol Synthesis (Air Products, 2003; Wang, 1997). Here, the gas cleaning process is designed to meet all of the cleaning requirements of the gas turbine, the plant environmental emissions, and the Methanol Synthesis process. This requires significantly different, more effective syngas desulfurization technologies to be applied than are used in IGCC, and the Rectisol Acid Gas Removal process has been applied because of its ability to achieve very low sulfur content in the synthesis gas (Smith, 2000). To ensure acceptable plant availability, the Methanol Synthesis catalyst is protected by guard beds for additional sulfur and metal carbonyl removal.

Filter-Reactor Novel Gas Cleaning Concept

The basic principles of the Filter-Reactor Novel Gas Cleaning technology for IGCC and Methanol Synthesis, as well as for other fuel or chemical synthesis applications are described below. The gas contaminants of major interest to IGCC and Methanol Synthesis are coal ash particles (in slag and char forms), sulfur species, halides, fuel-bound nitrogen (such as ammonia and HCN), volatile metals, and mercury. Each of these contaminants exist at differing levels in the raw gas and need to be reduced by a differing process technique to meet clean gas requirements. For example, sulfur species generally exist in relatively large quantities in the raw gas (typically, total sulfur is as high as 10,000 ppmv) and must be reduced by a large factor of about 99% or greater. At the other extreme, mercury exists in very small quantity (typically, about 3 ppbv mercury in the raw gas) and needs to be reduced by a relatively small factor of 90-95%.

Filter-Reactor Novel Gas Cleaning Process Concept

The conceptual configuration of the conventional, dry-gas cleaning process; the traditional, advanced humid-gas cleaning process; and the Filter-Reactor Novel Gas Cleaning, humid-gas cleaning process are illustrated in Figure 2.1. In each of the three process configurations, the raw, high-temperature gas issued from the gasifier is first cooled in a raw gas cooler. The gas is then cleaned of particulate using cyclones and a particle barrier filter. In the conventional, dry-gas cleaning configuration, the gas is then cooled to a low-temperature, condensing out most of the water vapor in the gas and removing most of the halides and ammonia contained in the gas in condensate-gas contacting columns. Mercury is then removed from the dry-gas in a adsorbent-gas contactor, such as a fixed bed reactor. The gas then passes through an appropriate, conventional acid gas removal process (e.g., MDEA), a solvent-gas column absorber and solvent stripper column, to reduce the sulfur species content to a sufficient level. In some cases, the gas COS content must first be hydrolyzed to H_2S so that sufficiently low sulfur levels can be achieved. The sulfur species removed from the gas is converted to elemental sulfur in a conventional Claus plant. The cold, dry-gas is then reheated and humidified before being fired in the gas turbine.

The traditional, advanced humid-gas cleaning processes operate at temperatures warm enough that no sour condensate is generated (>260°C). Following particle removal, the gas is contacted with halide sorbent in a conventional contactor, such as a fixed bed, moving bed, or a fluidized bed reactor, capturing the halides as solid reaction products for disposal. The humid gas is then desulfurized in a gas-sulfur coarse-sorbent contactor, such as a moving bed, fluidized bed, or transport bed. The sulfur sorbent is regenerative, and regenerated sulfur is converted to elemental sulfur using modified-Claus plant operation. A number of sulfur sorbents have been under development to achieve very efficient sulfur removal at temperatures between 260 and 538°C (500 and 1000°F), with ZnO-based sorbents having the highest potential. Mercury removal in a gas-sorbent contactor is then performed, using an advanced, coarse mercury sorbent that operates at a temperature of at least 245°C (400°F), in a gas-sorbent contactor such as a fixed bed or fluidized bed. The clean, humid gas is then reheated and fired in the gas turbine. The cleanup process, operating under humid-gas conditions, allows the IGCC power plant to operate at higher thermal efficiency, but issues with the durability of the sulfur sorbent, the mercury sorbent, process availability, and the cleanliness of the fuel gas (particulate content, fuel-nitrogen content) and its ability to achieve the very stringent cleaning standards for Methanol Synthesis exist.

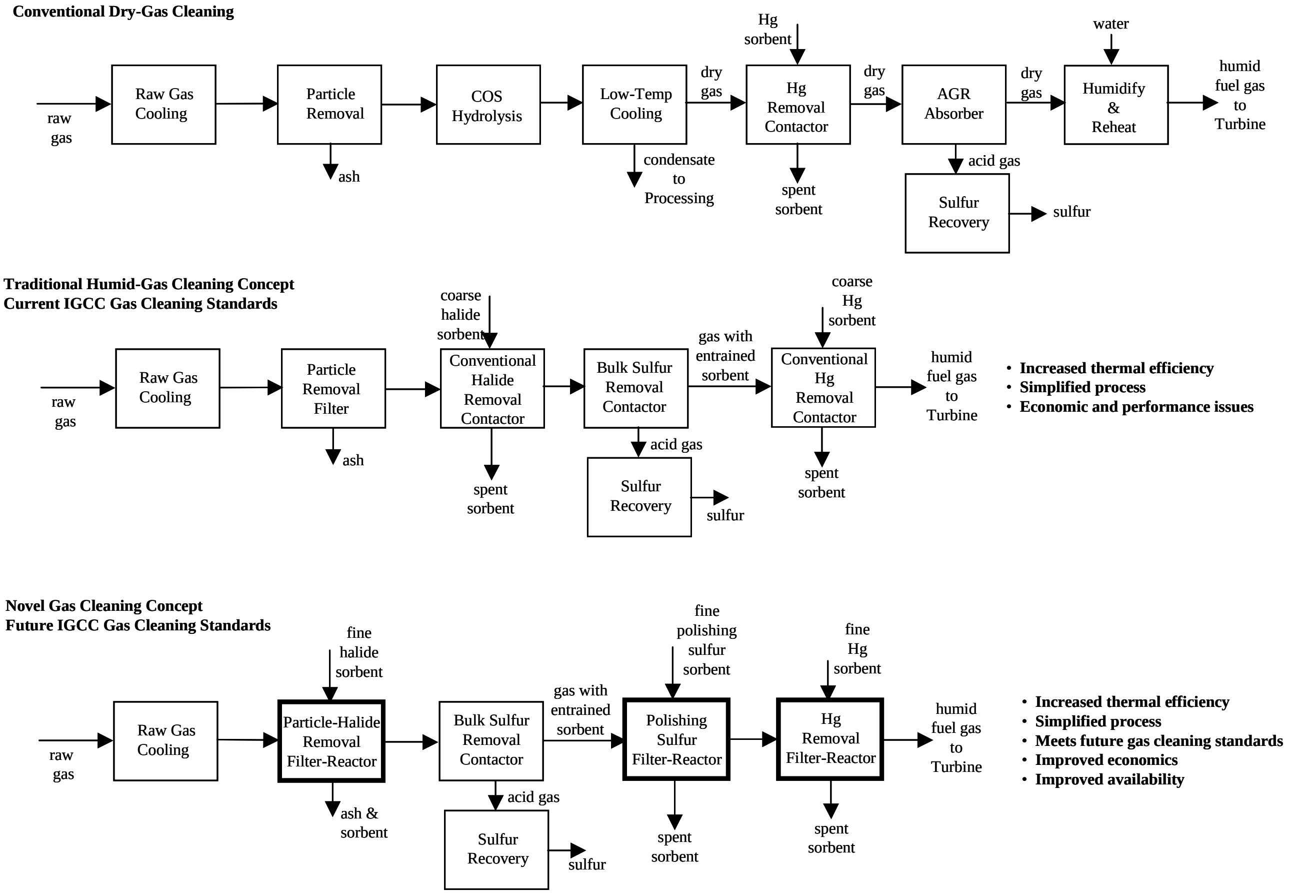


Figure 2.1 – Comparison of Filter-Reactor Novel Gas Cleaning Process with Traditional Humid-Gas Cleaning and Conventional Dry-Gas Cleaning Processes

The conceptual features of the Filter-Reactor Novel Gas Cleaning Process for IGCC fuel gas and Methanol Synthesis and other Chemical Synthesis syngas cleaning applications are:

- As in the traditional humid-gas cleaning process, gas condensation is avoided, or minimized, reducing the gas temperature only as low as is needed for the dry sorbent particle-contaminant removal reactions to effectively proceed.
- The process uses a series of gas, contaminant-removal stages to achieve the levels of contaminants in the gas required by the application. For contaminants that exist in a relatively large quantity in the raw gas (i.e., sulfur and halides), the initial stage removes the "bulk" of the contaminant. Subsequent polishing in “filter-reactor” steps are used to achieve levels meeting the gas cleaning requirements. Each subsequent stage removes a much smaller amount and operates at a temperature lower than the previous stage. This staged arrangement is used because higher operating temperature induces a higher sorbent-contaminant reaction rate, but the higher-temperature sorbent-contaminant reaction thermodynamics limit the outlet concentration of the contaminant that can be achieved. Lower operating temperature, in contrast, reduces the sorbent-contaminant reaction rate, but the lower-temperature sorbent thermodynamics provides the potential for lower outlet contaminant

concentration. The temperature of each removal stage is selected based on the contaminant removal nature of the sorbent particles to be used in each stage and the contaminant outlet concentration that is desired. This staged arrangement is inherently superior to single-stage, single-temperature processes that attempt to achieve contaminant control of such contaminant species.

- The bulk sulfur removal stage can be one of many bulk desulfurization processes currently under development that use fixed beds, fluidized beds or transport reactors with appropriate sorbent or catalyst particles, having forms such as regenerative zinc-, iron-, copper-, manganese-based sorbents. The Filter-Reactor Novel Gas Cleaning Process integrates well with these bulk sulfur removal processes and enhances their performance by capturing and utilizing sorbent particles that are inevitably lost from these bulk desulfurizers, being carried out with the exiting fuel gas.
- For contaminants existing in very small quantity in the raw gas and requiring relatively small removal factors (i.e., mercury), a single stage of removal is ample, but this stage must operate at low enough temperature so that thermodynamics are favorable to the desired outlet contaminant concentration.
- The process uses small-diameter sorbent particles (nominal feed size is <325 mesh, with mean size about 20 microns, but feed sizes up to 100 microns are potentially effective) to remove the contaminants by chemical and/or physical adsorption reactions.
- Multiple contaminant removal can be performed in a single stage if desired. For example, sulfur and halides can be removed simultaneously by injecting appropriate sorbents into the same filter-reactor vessel with appropriate selection of the operating temperature.
- In principle, the only difference between IGCC fuel gas cleaning, and the more stringently controlled Chemical Synthesis applications will be the number of gas cleaning stages and the conditions of those stages.

Filter-Reactor Gas-Sorbent Contactor Concept

The filter-reactor, gas-sorbent contactor is a substitute for more conventional gas-sorbent contactors (fixed beds, moving beds, fluidized beds, transport beds) used for contaminant polishing, and these are illustrated in Figure 2.2, with the reactors shown at their relative size scales. In these contaminant polishers the gas-phase contaminants are removed by particulate-sorbent reactions with the contaminants, forming stable, solid-phase reaction products. In most cases, the sorbents are used on a once-through basis with no regeneration and the contaminants are relatively small in their content with little reaction heat effects, and these are designated “polishing” rather than “bulk” contaminant removal.

The Filter-Reactor features are:

- Since the clean gas must be essentially particulate-free, barrier filters are used as the sorbent reactors in the gas cleaning process -- all other forms of sorbent-contaminant reactors (fixed beds, moving beds, fluidized beds, transport beds) result in particulate contamination of the exiting gas.
- On each stage of the process, sorbent particles are injected into the inlet piping of a barrier filter vessel. The barrier filter unit effectively separates all of the injected sorbent particles from the gas, as well as removing any other contaminant particles existing in the gas. This "filter-reactor" is the only type of reactor that can provide near-zero outlet particulate content while operating in a near-steady, continuous fashion. The filter-reactor provides an ideal reaction environment for the injected sorbent particles. The sorbent particles mix vigorously with the gas and reside as a dilute mixture of sorbent particles and gas for 1 to 10 seconds before the sorbent particles deposit on the filter elements in the vessel to form a filter cake. This filter cake acts as a fixed bed reactor as the gas passes through it, and the contact time between the sorbent filter cake and the gas is 0.1 to 1 second. The filter cake continually grows in thickness as more sorbent is deposited, and periodically (ever 15 minutes to every 100 hours depending on the contaminant content in the gas) the cake is removed by a reverse gas pulse, and the buildup of a new filter cake begins.
- Barrier filters can be utilized as semi-continuous, fixed bed reactors, designated "filter-reactors", having extremely effective particle sorbent-contaminant removal performance and having no need for

parallel reactor vessels with complex switching valves and piping mechanisms that are used with fixed bed reactors.

- Multiple contaminants can be simultaneous removed in a single filter-reactor if appropriate sorbents effective for the contaminant species removal at the same temperature can be identified.
- Powdered sorbent particles suitable for injection into filter-reactors have very high specific surface area on the filter cakes, and have no need for highly reactive support structure, or special particle attrition resistance features, so they are expected to be relatively cheap and highly available.

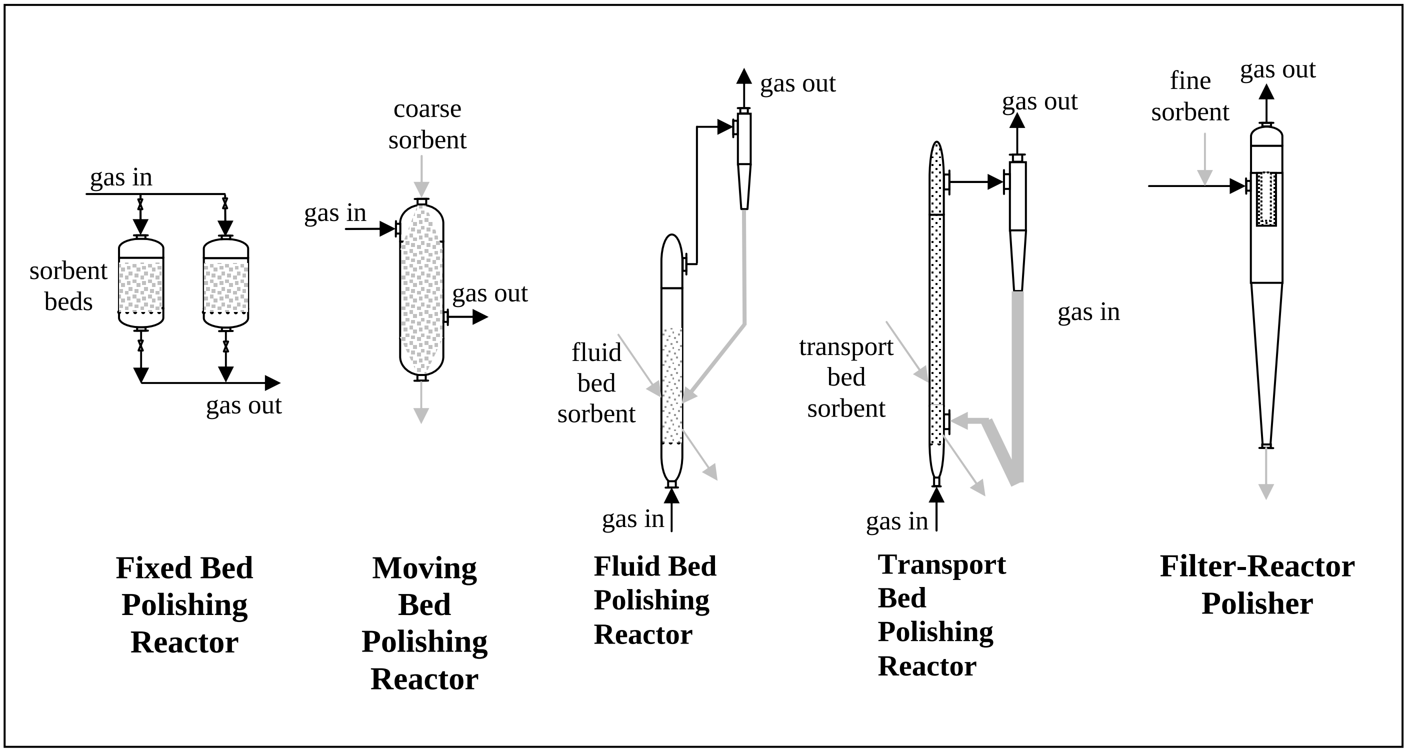


Figure 2.2 – Filter-Reactor Comparison with Conventional Contaminant Polishing Reactors

The characteristics of the various types of gas-sorbent contactors for gas polishing are listed in Table 2.1. The filter-reactor has several advantages over the more conventional fixed bed reactor configuration commonly used for gas-contaminant polishing. The conventional fixed bed reactor, if applied for halide, sulfur, and mercury removal applications might work well as a contaminant removal reactor, but is prone to the following practical issues:

- The fixed bed reactor is a batch reactor that requires periodic isolation from the process, depressurization and cooling, sorbent removal, sorbent refill, repressurization, re-integration with the process gas and reheat. This can be done with one, or more, parallel reactor vessels that are periodically switched in operation from adsorption to regeneration and/or recharge using switching valves and bypass piping.

Table 2.1 – Characteristics of Gas-Sorbent Polishing Contactors

Contactor type	Merits	Issues
Fixed bed	• No solids transport required • Unattended, simple operation • Little bed bypassing • Best traditional contactor for gas polishing under low heat-generation conditions	• Multiple, parallel vessels needed with switching valves • Bed pressure drop increases and plugging – need particle-free inlet gas • Need excess capacity design • Large pressure drop vs. vessel size trade-off • Some particle attrition and elutriation • Need bed support, inlet gas distribution, bed loading and unloading features and facilities • No on-line control and difficult for multiple contaminant removal • Large particles needed with large mass transfer resistance • Large inventory of sorbent exposed to gas
Moving bed	• Yields steady-state operation with some control capability • More tolerant of heat generation than the fixed bed	• Complex bed flow and handling equipment • Non-uniform gas flow • Large particles needed with large mass transfer resistance • Large inventory of sorbent exposed to gas • Bed pressure drop increases and plugging – need particle-free inlet gas • Large pressure drop vs. vessel size trade-off • Some particle attrition and elutriation
Fluid bed	• Easy sorbent feeding and withdrawal • Can control performance by sorbent feed rate • Uniform temperatures • Small vessel diameters than fixed beds	• Bed mixing reduces breakthrough time for bed • Increase gas bypassing • Need bed support, inlet gas distribution, bed loading and unloading features and facilities • Extensive particle attrition and elutriation
Transport bed	• Easy sorbent feeding and withdrawal • Can control performance • Uses smaller, more reactive sorbent particles • Results in smaller vessel diameters than fluidized beds	• Bed mixing reduces breakthrough time for bed • Increase gas bypassing • Need bed support, inlet gas distribution, bed loading and unloading features and facilities • Extensive particle attrition and elutriation • Smaller vessel diameter than fluid bed, but much taller
Filter-Reactor	• Uses very small sorbent particles, highly reactive, and potentially cheaper • Ease of sorbent feeding and performance control • Can feed multiple sorbents • Inherent uniform coating of filter elements for uniform removal performance • Inlet gas can contain significant particulate content • Outlet gas will be particle-free • Protects downstream equipment and can utilize or recover upstream particulate • Can control pressure drop to maintain flow capacity	• Relatively complex manifolding to hold filter elements • Possible damage to filter elements, causing sorbent leaks • Uncertain filter cake contaminant removal performance – reaction kinetics vs. mass transfer resistances for fine, packed particles • Uncertain filter cake sintering • Pulse cleaning may allow gas breakthrough momentarily

- The fixed bed reactor for large-scale gas flows is not a simple design, but requires means to uniformly distribute the inlet gas across the inlet side of the packed bed, and means to uniformly withdraw the gas from the fixed bed to ensure uniformity of flow. This is usually done with large distribution plates and layers of large pellet beds that also support the adsorbent bed, and result in increased pressure drop across the reactor vessel.
- The fixed bed reactor must be designed to maximize the sorbent bed capacity, so that the number of vessels and the frequency of switching is minimized, and to maintain acceptable vessel pressure drop. This is most economically accomplished in shop-fabricated vessels, limiting the maximum vessel outer diameter to about 4.0 m (13-ft).
- The fixed bed reactor is prone to plugging if the inlet gas contains any amount of entrained particulate, and even with almost particulate-free fuel gas will result in gradual increasing pressure drop due to corrosion products, chemical deposition, and settling of the fixed bed.
- The fixed bed reactor is a source of particle emission into the gas. Even with low gas velocities through the fixed bed, the bed particles are subject to high levels of crushing forces and locally high gas velocities near the gas distribution plates, as well as particle chemical decrepitation within the bed, and such particle emissions cannot be tolerated in the industrial application.

Most of the fixed bed issues are shared by the moving bed contactors, but some additional issues also arise, as are listed in Table 2.1. Moving beds are only selected for contaminant polishing where heat effects are small and the inlet gas is free of particulate. Fluid beds and transport beds result in high rates of gas and sorbent bed mixing that reduces reaction driving forces, but are advantageous if high heat generation rates exist to provide more uniform temperature conditions. They can also tolerate moderate particulate content in the inlet gas, although such particulate can plug or erode the inlet gas distribution equipment. The fluid bed and transport bed contactors are also subject to very high sorbent particle attrition and elutriation that require these contactors to be operated with specially-fabricated sorbent particles that are durable but also reactive in the contactor environment.

The proposed filter-reactor acts like a semi-continuous fixed bed reactor, with each filter cake section acting as a continuously-fed, fixed bed reactor that is periodically removed from service for an instant during pulse gas cleaning. The filter-reactor has no tendency for plugging at the temperature of operation selected and maintains particle-free outlet gas conditions. This evaluation projects the filter-reactor has a high potential to provide high levels of contaminant removal performance, potentially using cheap, fine, unsupported sorbent particles.

Filter-Reactor Novel Gas Cleaning Development Status

The gasification technology, the raw gas heat recovery technology, the air separation technology, the conventional gas cleaning technologies, the Methanol Synthesis technology, and the Power Island technology applied in this evaluation represent commercial technologies. The Filter-Reactor Novel Gas Cleaning processes described here are the only non-commercial technologies addressed. The individual components of the Filter-Reactor Novel Gas Cleaning processes are primarily commercial, or near-commercial components, or are currently being developed in various prototype development activities.

The most significant development aspect of the Filter-Reactor Novel Gas Cleaning process is the adaptation of barrier filter technology to combined use as a chemical reactor utilizing injected sorbent particles to remove gas-phase contaminants. The major equipment components of this polishing process, the barrier filter and sorbent handling and feeding equipment, have reached a mature status and have been demonstrated at large scales, but the use of barrier filters as gas-particle reactors has seen only limited testing (Newby et al., 1995). Field Testing of a barrier filter at the Tidd PFBC demonstration project has provided evidence of the effectiveness of the barrier filter as a filter-reactor, showing considerable removal of SO_2 from the process flue gas by reaction with entrained dolomite particles. Modeling of the filter-reactor suggests that effective contaminant control will result by 1) effective dilute-phase sorbent-gas contacting with high internal recirculation at contact times of 1 to 10 seconds, and 2) dense-phase contacting through uniform, dense sorbent filter cakes, with gas residence times of 0.1 to 1 second.

The Filter-Reactor Novel Gas Cleaning process is in its early stages of development in regard to the selection of sorbents, the identification of acceptable operating conditions, and the establishment of the performance of barrier-filters for gas-phase contaminant removal. Previously reported laboratory testing has been used to select appropriate sorbents and to identify their probable operating temperatures in the Novel Gas Cleaning process as the starting point for this evaluation (Newby et al., 2001).

Barrier Filter Technology Status

Barrier filters are in use commercially in three operating IGCC power plants, the Buggenum IGCC plant (Eurlings and Ploeg, 1999), the Wabash River IGCC plant (Wabash River Energy Ltd., 2000), and the Puertollano IGCC plant (Mendez-Vigo et al., 1997) for high-temperature gas particulate removal prior to low-temperature, dry-gas cleaning, although the barrier filter operating temperatures do not exceed 371°C (700°F) in any of these applications. This efficient particle removal provides benefits to the downstream gas cleanup processing by eliminating particulate contamination of the condensate and solvent streams generated in the low-temperature cooling process and desulfurization process. The particle removal performance and operating reliability of these barrier-filters have been acceptable once their design features and operating procedures were optimized. While the commercial IGCC barrier filter experience has been limited to temperatures up to about 371°C (700°F), considerable test experience in coal fuel-gases and combustion-gases up to 927°C (1700°F) has been accumulated (Newby et al., 2001, Lippert et al., 2001). Ceramic filter elements and metal filter elements, in the form of "candles", typically 60 mm (2.4 inches) in diameter and with lengths of 1.5 m (59 inches), are the principle type of barrier filter elements of interest today.

Siemens barrier filter testing experience has shown that ceramic filter elements can be successfully operated at very high temperatures if the filter system design and operation protects the ceramic candles from thermal shock and mechanical vibration damage. Metal filter elements have lower temperature operating limits than ceramic filter elements and are subject to corrosion damage and pore plugging. Metal filter candles are also considerably more expensive than ceramic filter candles. Some filter ashes, if exposed to temperatures above a critical level can result in severe filter cake sintering, and "bridges" can result that upset the barrier-filter performance and operability. Highly reliable operation of barrier filters can be achieved with well-behaved filter ashes in fuel gases at temperatures up to about 650°C (1200°F).

Humid-Gas Cleaning Technology Status

Humid-gas cleaning processes (so-called "hot", or "warm" gas cleaning) are primarily founded on the principle of contacting the process gas with solid sorbent particles that react heterogeneously with the desired contaminant species for contaminant removal. The descriptor "hot" or "warm" is arbitrary and indicates that the temperature of the sorbent-gas contactor is far above the dew point of the gas being cleaned. In principle, the contactor temperature is selected to match the desired temperature of the gas in its process application, or is selected to yield a sufficiently high rate of reaction for the gas cleaning process to be economically acceptable. Again in principle, operation of the gas cleaning system at this higher temperature, which eliminates condensation from the gas and delivers cleaned gas at an elevated temperature, has the potential to result in higher power plant thermal efficiencies than using conventional, low-temperature, dry-gas cleaning. The promise of improved IGCC power plant thermal performance and cost by using humid-gas cleaning provides great incentive for developing such technology.

Humid-gas cleaning for IGCC application has been the subject of research and development for several decades, and numerous sorbent types, contactor types, and process configurations have been proposed, tested, and characterized, but without reaching commercialization (Parsons Power Group, 1997; Sierra Pacific Power Co., 1994; O'Hara et al, 1987; Cicero et al, 2003). The only example of a "near commercial" humid-gas cleaning system for IGCC is the use of limestone within a fluidized bed gasifier, operating at about 871°C (1600°F) to remove as much as 95% of the coal sulfur content, and operating as a once-through sorbent process (KRW and GTI fluid bed gasifier). Such in-gasifier desulfurization only deals with sulfur removal and the IGCC gas still requires significant cleaning of several other contaminants before it can satisfy gas cleaning requirements.

The types of humid-gas cleaning processes that have been previously considered for IGCC are designated as "bulk" gas cleaning systems in this evaluation, in that they have the capability to remove a very large portion of the fuel gas contaminant (maybe 90-99%), but cannot achieve low enough contaminant concentration to satisfy the stringent gas cleaning requirement of many applications. Bulk gas cleaning systems have been proposed for sulfur species and halides to achieve moderately low contaminant levels, operating at temperatures up to about 650°C (1200°F). The bulk sulfur removal processes proposed are regenerative, generating an acid gas stream suitable for sulfur recovery, and recycling sorbent particles to the desulfurizer. The acid gas stream generated is usually in the form of a gas consisting primarily of SO_2 and N_2, and such a gas requires reduction by a reducing agent if elemental sulfur is the desired sulfur recovery product. Alternatively, sulfuric acid, or a sulfur product such as gypsum could be made directly from the acid gas by contact with limestone, but would result in a large sulfur release in the tail gas (Wasaka and Suzuki, 2003).

Many bulk gas desulfurization sorbent types (for example, iron-, nickel-, manganese-, copper-, and zinc-based sorbent particles on various support structures) have been tested at laboratory scale. Zinc-based sorbents, operated at temperatures up to about 593°C (1100°F), have the highest thermodynamic potential for efficient sulfur removal and have reached the highest level of commercial-readiness. These sulfur sorbents have been considered for use in a variety of gas-particle contactor types: fixed beds, moving beds, fluidized beds and transport beds. Of these, the most developed and promising may be the transport bed. Various test and development efforts are currently underway using zinc-based sulfur sorbents in transport beds (Yi, et al, 2003; Everitt and Bissett, 2003; Silverman et al, 2003; Gangwal et al, 2003) and these provide the basis for the bulk desulfurization process step used in the Filter-Reactor Novel Gas Cleaning process in this evaluation.

Bulk halide removal has generally been based on the use of cheap, once-through sodium-based sorbents that are contacted with process gas in fixed beds or fluidized beds at temperatures as high as 816°C (1500°F). These have high performance capability and form the basis of the bulk halide removal process used in the Filter-Reactor Novel Gas Cleaning process in this evaluation.

Currently, proposed humid-gas cleaning processes do not address all of the gas contaminants that must be controlled in IGCC. There are no hot fuel gas sorbents for fuel-bound nitrogen species (e.g., ammonia and hydrogen cyanide) and most testing has been focused on catalysts capable of promoting the thermal decomposition of ammonia. Humid-gas cleaning processes depend on the condensation of many contaminant species to form liquid and solid phases at relatively high temperatures that can then be physically removed from the gas (e.g., alkali metal vapors and various other metal vapors). Other important contaminants, such as mercury and metal carbonyls, have seen little development effort for their removal under humid-gas cleaning conditions. Overall, there is currently no humid-gas cleaning process available that can, even in principle, meet all of the gas cleaning requirements dictated for IGCC power generating plants. The status of humid syngas cleaning for Chemical Synthesis applications, where syngas cleaning requirements are much more stringent, is even further from realization.

3. EVALUATION BASIS

A plant design basis has been established that allows direct comparison of the performance and cost of the conventional, dry-gas cleaning technology with the Filter-Reactor Novel Gas Cleaning process applied for meeting the gas cleaning requirements of IGCC power generation and IGCC-Methanol Synthesis. The level of detail defined for this conceptual evaluation by this basis is sufficient to clearly identify the potential, relative merits of the Filter-Reactor Novel Gas Cleaning technology.

3.1 PLANT DESIGN BASIS

The major aspects of the design basis selected for the IGCC and Methanol Synthesis plants for this evaluation are listed below. In both applications, the plant is designed with sufficient fuel gas and syngas flow rates to match the requirements of the gas turbine combined-cycle, and the desired methanol production rate.

Power Island

A gas turbine having characteristics representative of "F" gas turbine technology (for example, the Siemens SGT6-5000F gas turbine) is used in a single-train, combined-cycle Power Island configuration. The gas turbine air compressor and combustors are modified to handle the required air extraction, to accommodate IGCC low heating-value fuel gas operation, and to meet low-NOx emission requirements. It is assumed that a Selective Catalytic Reactor is not needed for the plant to achieve the required NOx emission limit. The turbine combustor air-side pressure drop is fixed at 60 kPa (8.7 psi) for all the evaluation cases. The gas turbine air compressor inlet loss is fixed at 1 kPa (0.14 psi), and the turbine exhaust pressure is set at 108 kPa (15.7 psia) in all cases. The turbine firing conditions are fixed at those used with natural gas operation, and the gas turbine cooling air rate and distribution to the turbine stages are comply with their normal, natural gas-fired turbine values for all of the evaluation cases.

Steam Bottoming-cycle Conditions

The steam bottoming cycle uses a single-pressure, heat recovery steam generator (HRSG) system with reheat,

- superheat steam temperature 538°C (1000ºF),
- reheat steam temperature 538°C (1000ºF),
- steam throttle pressure 10.1 MPa (1465 psig),
- condenser pressure 7 kPa (0.98 psia).

Plant Nominal Capacity

The IGCC power plant has a nominal, net generating capacity of about 300 MWe, resulting from the generating capacity of the Power Island gas turbine and steam-bottoming plant, and the net power losses associated with the gasification and gas cleaning processes. The Methanol Synthesis plant has a nominal, net generating capacity of about 300 MWe, with a selected production rate of methanol of about 218 tonne/day (240 tons/day). In both cases, the 300 MWe size represents the expected nominal capacity of "F" engine, combined-cycle technology.

Coal Characteristics

A bituminous, high-sulfur coal, Illinois Number 6, is the plant fuel. Table 3.1 lists its moisture-free composition, heating value, and as-fed moisture content. Chlorine and mercury contents of the coal are included.

Coal Feed Rates

The IGCC power plant, as-fed coal rate is 98,847 kg/hr (217,921 lb/hr) with energy input of 759 MW(t) (2,589 x 10^6 Btu/hr). The Methanol Synthesis coal feed rate is 115,058 kg/hr (253,661 lb/h) with energy input of 883 MW(t) (3,013 x 10^6 Btu/hr).

Table 3.1 - Illinois Number 6 Coal Analysis (ultimate)

Constituent	Wt%
H	5.32
O	10.0
C	69.4
N	1.25
S	3.85
Ash	10.0
Cl	0.18
Hg	6.3 X 10^{-8}
SUM	100
heating value (HHV, dry) MJ/kg (Btu/lb)	32.05 (13,781)
moisture, as fed (wt%)	4.2

Plant Design Layout

For this conceptual design evaluation, a single gasifier unit and a single gas cleaning train are used with no equipment spares, and are integrated with a single gas turbine combined-cycle Power Island, and a single Methanol Synthesis process. The air separation unit (ASU) and gas turbine air compressor are 100%-integrated, meaning that all of the air needed for the ASU is extracted from the turbine's air compressor. Actual commercial designs may call for 50%, or less air-side integration.

Coal Gasifier Type

Gasifier technology representative of an oxygen-blown, entrained, single-stage, slagging gasifier is used. Coal is fed to this gasifier as a water slurry containing 69 wt% solids.

Gasifier Operating Pressure

The IGCC gasifier operating pressure is selected to be sufficiently high, 2578 kPa (400 psia outlet), to deliver clean fuel gas to the gas turbine combustors with at least a 345 kPa (50 psi) pressure drop available for flow control, using moderate component design pressure drops in the process equipment. The Methanol Synthesis plant gasifier operating pressure is selected to be sufficient, 8791 kPa (1275 psia) outlet to deliver clean syngas to the Methanol Synthesis process at its inlet pressure of about 7033 kPa (1020 psia) – the high-pressure fuel gas stream is expanded and delivered to the gas turbine combustors with at least a 345 kPa (50 psi) pressure drop available for flow control.

Raw Gas Cooling Type

Non-quench heat recovery is used to cool the raw gas, producing high-pressure, saturated steam.

Ambient Conditions

The plant site is assumed to be fixed at ISO-conditions, with ambient air at 15ºC (59ºF), 60% relative humidity, and a pressure of 101 kPa (14.7 psia). This evaluation is limited to a point-design, and the influences of off-design ambient conditions on the equipment designs and process performance are not considered.

Cooling Water Conditions

Cooling water is available at 21ºC (70ºF) with a supply pressure of 345 kPa (50 psia).

Ambient Air Composition

The air composition (volume percent) used is

O_2: 20.73
N_2: 77.22
Ar: 1.01
CO_2: 0.03
H_2O: 1.01.

Air Separation Unit Oxidant Composition

95% oxygen purity is specified with a composition (volume percent) of

O_2 : 95.0
N_2 : 4.5
Ar : 0.5.

Air Separation Unit Nitrogen Composition

Two types of nitrogen are produced by the ASU and used in the plant, a low-purity nitrogen, and a high-purity nitrogen:

low-purity nitrogen (volume percent):

O_2 : 0.5
N_2 : 98.5
Ar : 1.0.

high-purity nitrogen (volume percent):

O_2 : 0.03
N_2 : 99.92
Ar : 0.05.

Significantly different quantitative results from those produced in this evaluation would be expected if some of the major power plant design basis criteria were changed, using instead:

- alternative coals that are in wide use in the United States, such as Power River Basin sub-bituminous,
- alternative, commercial coal gasifier technologies, such as two-stage, oxygen-blown, entrained, slagging gasifiers, or fixed or fluidized bed gasifiers, or transport gasifiers,
- alternative raw gas cooling schemes, such as water quench, or recycle gas quench.

Nonetheless, it is expected that the same qualitative conclusions with respect to the potential benefits and issues for the Filter-Reactor Novel Gas Cleaning technologies would result.

3.2 GAS CLEANING AND CONDITIONING REQUIREMENTS

The gas cleaning process and related gas conditioning steps must meet certain specifications that address:

- the plant environmental emissions,
- the protection of the gas turbine and other Power Island components,
- the protection of the Methanol Synthesis reactor.

These specifications are of critical importance to the design of the gas cleaning processes, and achieving these specifications, while maintaining the overall plant performance and economics at acceptable levels, is a key measure of the success of the gas cleaning technology.

IGCC Gas Cleaning Specifications

The IGCC power plant gas cleaning technology evaluation considers two sets of fuel gas cleaning requirements, designated “Current Standards” and “Future Standards”, representing a major parameter in the assessment of the Filter-Reactor Novel Gas Cleaning technology. The fuel gas cleaning requirements for the Current Standards, and for the hypothesized Future Standards are listed in Table 3.2. These fuel gas cleaning requirements are developed from three sets of criteria:

1) representative, new coal-fired power plant environmental emission standards, that translate stack gas emission requirements into fuel gas cleaning requirements,
2) hypothetical, future environmental emission standards that will ensure that IGCC is environmentally competitive with natural gas-fired power plants,
3) representative gas turbine specifications for fuel gas contaminants.

Nine categories of fuel gas contaminants are listed in Table 3.2, and for each the maximum allowable content of the contaminant in the fuel gas is shown, along with an indication of the basis for the contaminant specification. Comments are also provided on each to provide additional perspective. The fuel gas cleaning requirements listed apply the following specific assumptions:

- the fuel gas location where the fuel gas cleaning criteria in Table 3.2 apply is in the moisture-free, clean fuel gas being fed to the turbine combustors, prior to nitrogen dilution,
- the clean, moisture-free fuel gas is assumed to have a heating value of about 200 Btu/sft^3,
- the fuel gas cleaning criteria assume that <u>no</u> contaminants exist in the air, steam, or nitrogen streams that are fed to the turbine.

The IGCC power plant Current Standards are based on the "best-of-current-practice" reported for existing IGCC power plants. The following set of contaminant control targets result:

- SOx: minimum of 99% coal sulfur removal "net" for the entire power plant,
- NOx: 15 ppmv (corrected to 15% oxygen, dry) at the plant stack,
- particulate: 0.1 ppmw in the clean fuel gas,
- mercury: 90% coal mercury removal,
- Power Island contaminants in the fuel gas to meet gas turbine standards:
    - halides: 5 ppmv before turbine to protect low-temperature heat recovery in the power island,
    - metals (Ni, Fe carbonyls): no specific controls for metal carbonyls are included,
    - particulate: 0.1 ppmw in the fuel gas.

The IGCC power plant Future Standards, approaching the emissions performance of natural gas-fired power plants, have the following set of targets:

- SOx: 99.98% coal sulfur removal "net" for entire power plant,
- NOx: 5 ppmv (corrected to 15% oxygen, dry) at the plant stack,
- particulate: 0.1 ppmw in the fuel gas,
- mercury: 95% coal mercury removal,
- Power Island contaminants:
    - halides: 5 ppmv before turbine to protect low-temperature heat recovery in the Power Island,
    - metals (Ni, Fe carbonyls): no specific controls for metal carbonyls are included,
    - particulate: 0.1 ppmw in the fuel gas.

The SOx, NOx, particulate, and mercury requirements represent the emissions from the entire power plant, the stack and all other exhaust vents in the plant. The Power Island contaminant control targets are the same for the Current Standards and the Future Standards. The Power Island contaminants need only be controlled to protect the gas turbine and the downstream power island equipment. Alkali metals, and several other potential contaminants listed in Table 3.2 are expected to be inherently removed by condensation mechanisms in both the conventional gas cleaning and the Novel gas Cleaning processes.

Table 3.2 - IGCC Gas Cleaning Current and Future Standards

Contaminant	Evaluation Environmental Emission Requirements	Power Island Fuel Gas Requirements (moisture-free fuel gas prior to nitrogen dilution)	Basis	Comments
Total sulfur (H_2S, COS, etc.)	Current: 99% total removal	750 ppmv	Current: best reported IGCC performance.	Emission requirement more stringent than turbine requirements.
	Future: 99.98% total removal	750 ppmv	Future: competitive with emission from natural gas-fired plant	
Total halide (Cl, F, Br)	Current: none	Current: 5 ppmv	Protect gas cleaning sorbents/ minimize power island low-temperature corrosion.	Lower halide may be desirable to heat recovery protection during transient operations
	Future: none	Future: 5 ppmv		
Particulate (char, sorbents, metal corrosion products)	Current: PM-10 standards	Current: 0.1 ppmw	Reflects best performance reported for barrier filters.	More stringent than PM-10 and PM-2.5, or turbine fuel gas standards of 0.7 ppmw
	Future: PM-2.5 standards	Future: 0.1 ppmw		
Total fuel-nitrogen (NH_3, HCN)	Current: NOx emission of 15 ppmv (15% O2, dry)	Current: fuel bound nitrogen 225 ppmv for NOx control	Acceptable NOx generation in turbine combustors; 75% NH_3 catalytic decomposition in cleanup process	Assumed staged, or catalytic diffusion burners will limit fuel-nitrogen to 5% (current)/ 3% (future) conversion to NOx.
	Future: NOx emission of 5 ppmv (15% O2, dry)	Future: FBN 375 ppmv for NOx control		
Total mercury	Current: 90% removal	Current: no specific limit	Expected mercury environmental standards for coal-fueled power plants	No impact on gas turbine protection.
	Future: 95% removal	Future: no specific limit		
Trace elements (As, Se, etc)	No current standards	No standards apply		Mercury removal provides removal potential for these trace elements.
Total alkali metals (Na, K, Li vapor and solid phases)	None	Current: 100 ppbv	Gas turbine corrosion and deposition standards	Removed efficiently by condensation in fuel gas cleaning system at 1000°F or less.
		Future: 100 ppbv		
Volatile metals (V, Ni, Fe, Pb, Ca, Ba, Mn, P)	None	Current: 10 -1000 ppbv	Gas turbine corrosion and deposition	Metal carbonyls (40 ppbv required) are only issue in IGCC .
		Future: 10-1000 ppbv		

Additional protection against metal carbonyls and corrosion-derived particulate is not included in this evaluation. Low-temperature adsorption processes and a final filter stage can be added with dry gas cleaning to remove metal carbonyls (Collodi and Brkic, 2003), but metal carbonyl minimization and particulate protection are inherent aspects of the Filter-Reactor Novel Gas Cleaning technology.

Fuel-bound nitrogen species, such as ammonia and HCN, are not themselves contaminants in IGCC, but they are precursors to NOx generated in the gas turbine combustors. While the conventional, low-temperature gas cleaning technology provides effective removal of fuel-bound nitrogen species from the fuel gas, the Filter-Reactor Novel Gas Cleaning technology relies primarily on the use of advanced low-NOx combustors using staged combustion and possible catalytic combustion mechanisms for fuel-bound nitrogen NOx control.

The conventional gas cleaning technology and the Novel Gas Cleaning technology both generate solid wastes and process-condensate streams that need to be processed and controlled to minimize emissions and other environmental impacts. It is important to minimize the effects of both solid waste and liquid waste streams.

Representative fuel gas contaminant specifications for the gas turbine are listed in Table 3.3 for both natural gas and coal-gas-fired SGT6-5000F turbines. Conventional dry-gas cleaning technologies are expected to be able to satisfy these specifications, with the possible exception of iron and nickel, where volatile forms (carbonyls forms $Ni(CO)_4$ and $Fe(CO)_5$) may be present in the fuel gas in some cases (Bonzani and Pollarolo, 2004).

Table 3.3 – Gas Turbine Fuel Gas Contaminant Specifications

Fuel Gas Constituent	Natural gas SGT6-5000F Specification	IGCC fuel gas SGT6-5000F Specification*	Comments
Total Sulfur (H_2S, COS, etc.)	0.5 wt%	750 ppmv	Relates to Power Island heat recovery protection -- this specification far exceeds emission limits, so is not an issue.
Fuel-Nitrogen (NH_3, HCN, etc.)	0.015 wt%	40 ppmv	Relates to stack NOx emissions. Specification depends on type of combustor.
Particulate	0.00015 lb/ x 10^6 Btu	0.7 ppmw	Relates to turbine erosion/deposition protection. Specification is more stringent than plant emission requirement for particulate.
Mercury	None	None	No impact on Power Island.
Trace Toxics (As, Se, etc.)	None	None	No impact on Power Island.
Total alkali metals (Na, K, Li)	0.5 ppmw	0.1 ppmv	Relates to turbine corrosion protection. Gas cleaning at temperatures < 1000°F should achieve this by condensation.
Total Halogens (Cl, Br, F, I)	6.0 ppmw	5 ppmv	Relates to power island heat recovery protection during transient periods.
Volatile Metals			All relate to turbine deposition/corrosion protection
V	0.5 ppmw	0.05 ppmv	Should not be an issue with small V-content of most coals
Ca	10.0 ppmw	1.2 ppmv	Should be removed cleanup system by condensation
Ba	2.0 ppmw	0.1 ppmv	Should be removed cleanup system by condensation
Pb	0.5 ppmw	0.01 ppmv	Should be removed cleanup system by condensation
Mn	2.0 ppmw	0.2 ppmv	Should be removed cleanup system by condensation
P	2.0 ppmw	0.3 ppmv	Should be removed cleanup system by condensation
Fe	0.5 ppmw	0.04 ppmv	Possible issue -- Fe-carbonyls form at temperatures < 400°F
Ni	0.5 ppmw	0.04 ppmv	Possible issue – Ni-carbonyls form at temperatures < 900°F

* contaminant content in moisture-free syngas prior to humidification or nitrogen dilution for typical oxygen-blown gasification syngas

Metal carbonyls may be a greater problem with refinery residue gasification than with coal due to the high iron and nickel content of residues. Metal carbonyls, forming at temperatures less than 482ºC (900°F) for Ni and 204ºC (400°F) for Fe, decompose when raised above these temperatures, depositing nickel and iron metals on available surfaces. These deposits can disrupt the operation of some gas cleaning stages in dry-gas cleaning (e.g., COS hydrolysis reactor, or water gas shift reactor), as well as degrade the performance of gas turbine combustors and other turbine hot parts (Bruijn et al, 2003). Metal carbonyls can also form through fuel gas contacting piping and equipment metal surfaces at appropriate temperatures. Metal carbonyls are expected to be less likely to form in a humid-gas cleaning process where Fe- and Ni-particulate is removed from the fuel gas before the temperature is lowered to the metal carbonyl formation temperature, and where contact with metal surfaces at temperatures lower than the formation temperature is minimized.

The IGCC power plant fuel gas cleaning process must also simultaneously meet other performance criteria:

- should not result in a decrease in coal-carbon utilization in the plant,
- have acceptable impact on plant solid waste (i.e., solid waste volume, cost of hazardous waste disposal),
- have acceptable water consumption and water discharge, removing absorbed halides and ammonia from condensate streams and disposing of these halide and ammonia streams with minimal environmental impact,
- provide fuel gas conditioning for acceptable NOx combustor emission (e.g., water vapor content and nitrogen dilution for acceptable peak flame combustion temperature),
- integrate with the power island for acceptable power plant thermal efficiency,
- the conditioned fuel gas reheat maximum allowable temperature is 371ºC (700°F) based on current control valve materials, but temperatures up to 538ºC (1000°F) are acceptable, although more expensive valve materials are needed.
- have acceptable gas cleaning train pressure drop,
- have acceptable gas cleaning train operability, reliability, and availability,
- have acceptable gas cleaning train capital investment, and operating & maintenance cost.

The last three items – pressure drop, operating reliability, and cost -- are design-performance tradeoff parameters that interact with each other but do not have specific numerical targets.

Methanol Synthesis Gas Cleaning Requirements

The gas cleaning requirements considered for Methanol Synthesis are broken into three classes:

Environmental Air Emissions

- SOx: 99.98% sulfur removal "net"
- NOx: 5 ppmv (corrected to 15% oxygen, dry)
- mercury: 95% removal

Power Island Fuel Gas Contaminant Standards

- halides: 5 ppmv in the fuel gas (dry)
- fuel-nitrogen (NH_3 + HCN): 225 ppmv (dry)
- metal carbonyls: 40 ppbv in fuel gas (dry)
- particulate: 0.1 ppmw

Methanol Syngas Requirements

- total sulfur: 60 ppbv (dry)
- total halides: 10 ppbv (dry)
- NH_3: 10 ppmv (dry)
- HCN: 10 ppbv (dry)
- metal carbonyls: 100 ppbv (dry)
- mercury: 95% removal
- particulate: 0.1 ppmw

The environmental standards applied are identical to the Future Standards case used for IGCC. The Power Island standards are the same as those used for IGCC. The Methanol Synthesis standards for syngas are extremely stringent and are based on protecting the Methanol Synthesis catalyst.

3.3 MATERIAL & ENERGY BALANCE ESTIMATION AND EQUIPMENT SIZING

Process flow sheet development and materials & energy balance computations were performed using the ChemCad process simulator software (by Chemstations, Inc., Houston, Texas) for both the conventional, low-temperature gas cleaning processes and for the Filter-Reactor Novel Gas Cleaning processes. Considerable effort was applied to properly converge the process material balances due to the low concentrations of several of the chemical contaminants of interest in the evaluations. Material & energy balances are highly dependent on process reactor conversion efficiency assumptions and separation equipment contacting efficiency assumptions, and these assumptions are listed with the process and equipment descriptions provided in the following sections of the report. For the Filter-Reactor Novel Gas Cleaning processes, several assumptions of sorbent compositions, feed rates, and reaction conversions were made based on available literature information and laboratory test results. These assumptions are listed in the descriptions of the processes and equipment in the report sections that follow.

Equipment and process sub-systems have been conceptually designed and specified using standard industrial sizing criteria and design factor estimates. For example, available industrial experience information and design criteria were input for:

- heat transfer coefficients, with fouling,
- heat exchanger pressure drops,
- heat exchanger minimum temperature approaches,
- reactor operating temperatures and pressure drops,
- reactor equilibrium temperature approaches,
- reactor residence times,
- compressor-type selection and efficiencies,
- pump-type selection and efficiencies,
- absorber and stripper column contacting efficiencies and pressure drops.

The representative SGT6-5000F gas turbine expander was scaled in each of the IGCC and Methanol Synthesis cases to yield the required compressor air delivery pressure and fuel gas delivery pressure, and to determine the air compressor pressure ratio and adiabatic efficiency. It is assumed that an adapted gas turbine air compressor would be utilized in each case, modifying the standard air compressor, with the compressor air flow rate adjusted to allow the same rotor inlet temperature as the standard, natural gas-fired turbine. It is assumed that the cooling air rate and its distribution to the vanes and rotors of the four stages of the turbine expander are the same in all of the cases and identical to that for the standard natural gas-fired turbine.

The ChemCad process simulator used in the process evaluation includes facilities for the design and specification of many of the equipment components and does rigorous design of heat exchangers, and absorption and stripping columns. Barrier filters and filter-reactors have been sized and designed using Siemens proprietary design codes. Heat exchanger designs have accounted for appropriate materials of construction and maintenance considerations.

Solids handling equipment are particularly important for the Filter-Reactor Novel Gas Cleaning technology. Equipment for on-site storage, transport, pressurization, and feeding of sorbents have been sized using typical specifications for vessel storage and holding times, transport gas requirements, and vent gas handling. Likewise, equipment for waste solids cooling, depressurization, transport and storage have been designed by similar criteria. All solids handling equipment has been designed using a 50% excess capacity factor.

3.4 ECONOMIC CRITERIA AND COST ESTIMATION APPROACH

This is a conceptual design evaluation and the equipment costs and operating costs generated are approximations based on the use of purchased-equipment general cost correlations and operating cost factors extracted from prior IGCC plant cost studies. The objective of the cost estimates generated is to compare the relative cost potential and cost sensitivities of the conventional dry-gas cleaning technologies and the Filter-Reactor Novel Gas Cleaning technologies.

A “factored” cost evaluation, estimating the purchased and installed costs of the major equipment in the Gas Cleaning Sections of each plant has been performed. These cost estimates were generated by sizing all of the major gas cleaning equipment, using generalized equipment cost correlations and other available cost data to estimate the purchase price of each major equipment component, and applying "installation factors" to each item to estimate the installed equipment cost, or Base Erected Cost for the gas cleaning process. In some cases, for very expensive process components, vendor budgetary cost inputs have been obtained. The equipment costs of barrier filters have been developed using Siemens internal cost data and correlations.

The "balance-of-total plant", that is, the remaining plant apart from the Gas Cleaning Sections, has been assumed to have a cost nearly identical for all of the IGCC cases, being essentially unchanged in the cases. This "balance of total plant cost" has been estimated from previous conventional IGCC power plant cost studies that provide Base Plant Total Capital Requirement (TCR) values.

No process contingencies or project contingencies have been assigned for the Conventional or Filter-Reactor Novel Gas Cleaning processes. The Total Capital Requirement (TCR) is estimated from the values of the installed major equipment costs, using assumptions and procedures representative of the EPRI Technical Assessment Guide (EPRI, 1986). This results in the use of a constant ratio of Total Capital Requirement (TCR)-to-Bare Erected Cost equal to 1.5 applied in the estimates. The major cost assumptions applied, based on the general findings of numerous previous IGCC evaluations, were:

- Cost-basis year: end-2002
- Plant capacity factor: 65% for IGCC and 80% for Methanol Synthesis co-production plant
- TCR/Bare Erected Cost ratio: 1.50
- Base Conventional IGCC plant TCR: 1500 $/kW
- Base Conventional Methanol Synthesis plant TCR: 1790 $/kW

The balance-of-total plant cost was assumed the same for all of the plants, except for that of the steam-bottoming plant cost which was scaled, since its capacity changed significantly between the various plant cases.

The cost-of-electricity (COE) was estimated on a “first-year of operation” basis. It was estimated using a Capital Charge of 15% per year, and Operating and Maintenance (O&M) costs estimated, based on general results from numerous prior IGCC evaluations, as:

- Operating labor: 0.87% of TCR/yr
- Maintenance labor: 0.67% of TCR/yr
- Maintenance materials: 1.01% of TCR/yr
- Administrative and support labor: 0.39% of TCR/yr

The Fixed O&M cost is the sum of the operating labor, the maintenance labor and the administrative & support labor. The Variable O&M is equal to the maintenance materials. The Total O&M is the sum of the fixed and variable O&M values.

Process consumable costs, by-product values, and solid waste disposal costs have been assigned to the various import stream catalysts, chemicals and sorbents, and fuels consumed, and export streams produced by the process. The following cost assumptions were made:

fuels: coal: 2.00 $\$/10^6$ Btu (HHV),
chemicals, catalysts, and conventional sorbents:
- raw water: 0.04 $/kW-hr.
- Claus catalyst, hydrolysis catalysts, methanol synthesis catalyst makeup costs were neglected,
- methanol solvent for Rectisol process: 0.40 $/lb,
- MDEA solvent: 1.00 $/lb,
- Sulfur sorbent pellets for conventional Methanol Synthesis guard bed: 4.0 $/lb
- mercury sorbent (sulfur-impregnated activated carbon) for conventional cleaning: 6.5 $/lb,

Novel Gas Cleaning sorbents:
- bulk halide sorbent: 0.03 $/lb,
- bulk desulfurization sorbent: 3.0 $/lb,
- polishing sulfur sorbent: 1.0 $/lb,
- mercury sorbent: 3.0 $/lb.

by-products:
- slag by-product value: 0 $/ton,
- sulfur by-product value: 50 $/ton,
- methanol product value: 0.15 $/lb

disposal:
- ash and inert sorbent waste non-hazardous disposal: 20 $/ton,
- mercury, once-through sorbent, hazardous disposal: 200 $/ton.

The sorbent costs listed above are representative of expected, delivered prices for these sorbent materials as mature, commercial commodities. The mercury sorbent cost for the Filter-Reactor Novel Gas Cleaning technology is a hypothetical value since the actual sorbent has not yet been commercialized. The two sulfur sorbents for the Filter-Reactor Novel Gas Cleaning technology also have uncertain costs, and it is likely that even lower costs may result for these. Some of the chemicals and by-products listed above, such as methanol and sulfur, have unstable costs. All of the items listed can have significant variations in cost subject to the power plant location and market factors.

4. IGCC WITH CONVENTIONAL GAS CLEANING

An overall process flow diagram for IGCC with conventional dry-gas cleaning is shown in Figure 4.1. It portrays the relations between the major process systems in the plant and shows only the major process streams.

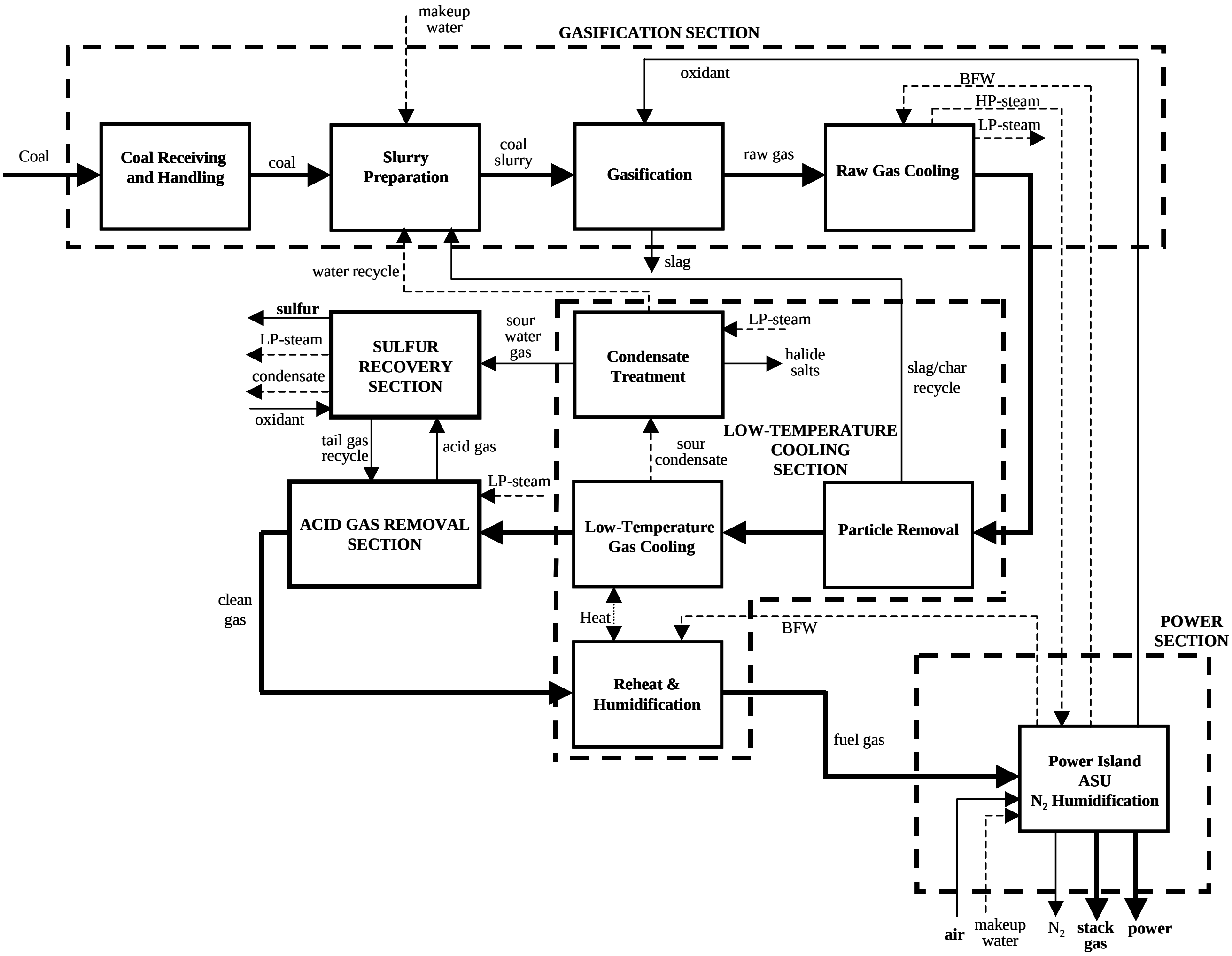


Figure 4.1 - Overall IGCC Plant with Conventional Dry-gas Cleaning

The overall process schematic is broken into five major plant sections: the Gasification Section, consisting of coal receiving and handling, slurry preparation, gasification, slag handling, and raw gas cooling sub-sections; the Low-temperature Cooling Section, the Acid Gas Removal (AGR) Section, the Sulfur Recovery Section, and the Power Section, consisting of the power island and air separation sub-sections. The diagram is highly simplified, not indicating all of the numerous sub-functions of each section and the numerous streams that pass between the various sections. The Low-temperature Cooling Section produces a large recycle water stream sent to the slurry preparation section, a sour-water gas stream sent to Sulfur Recovery, and a halide salts disposal product.

The major functions of these plant sections are:

Gasification Section (Figure 4.2)
- prepare coal slurry
- accept recycled slag
- accept recycled water
- accept recycled sulfur recovery tail gas
- gasify coal slurry
- cool raw fuel gas, generating saturated, HP-steam
- cool and separate slag from water for disposal

Low-Temperature Cooling Section (Figure 4.3)
- remove raw gas particulate (slag) and recycle to Gasification Section
- cool gas and remove condensate
- remove halide and ammonia by scrubbing with condensate
- perform COS and HCN hydrolysis
- extract soot blower gas for compression to Gasification Section
- remove mercury
- humidify and reheat clean fuel gas (from AGR Section)
- remove halide salts for condensate (Condensate Treatment), and water recycle to Gasification Section
- strip ammonia from condensate, generating sour-water gas sent to the Sulfur Recovery Section, and water recycle to Gasification Section

AGR Section (Figure 4.4 and Figure 4.7)
- desulfurize fuel gas
- produce acid gas suitable for sulfur recovery

Sulfur Recovery Section (Figure 4.5)
- accept recycled sour-water gas
- oxidize acid gas with oxygen to generate desired H_2S-SO_2 gas mixture
- decompose sour-water gas ammonia
- produce elemental sulfur product
- recycle tail gas to Gasification Section
- condensate recycle to Gasification Section
- produce IP-steam and LP-steam

Power Section (Figure 4.6)
- compress air for air separation and fuel gas combustion
- separate air to generate gasifier oxidant, sulfur recovery oxidant, and nitrogen streams
- humidify low-purity nitrogen stream and mix with clean fuel gas
- combust fuel gas for low-NOx production and gas turbine expansion for power generation
- recover heat from gas turbine exhaust gas for steam cycle power generation
- circulate BFW to Gasification Section and Low-Temperature Cooling Section

Material & energy balances have been developed for the five sections in sufficient detail to relate the dry-gas cleaning technology to its impacts on the power plant performance, and to provide a basis for sizing the associated major process equipment for cost estimation purposes. Only those aspects of the plant have been incorporated into the evaluation material & energy balances that are direct influenced by the gas cleaning functions.

4.1 IGCC WITH CONVENTIONAL GAS CLEANING TO MEET CURRENT STANDARDS

The case of conventional, low-temperature, dry-gas cleaning to meet Current Standards is considered in this section. Descriptions of the process sections of the IGCC power plant that are impacted by the gas cleaning functions are provided, along with the characterization of major process streams and equipment.

Gasification Section

Figure 4.2 shows the process flow diagram constructed for the Gasification Section, and includes the Coal Receiving and Handling System and the Slurry Preparation System. Table 4.1 lists the characteristics of the major streams in this section. An entrained, oxygen-blown, single-stage, slagging gasifier, with coal-slurry feeding is used (Item 3). The coal is pumped (Item 1) as a slurry containing about 31wt% water, and this slurry is preheated to 149ºC (300°F)(Item 2). Most of the slurry water is recycled water (treated condensate) from the Low-Temperature Cooling Section of the plant. Oxidant from the Power Section's Air Separation Unit combines with the coal slurry to generate high-temperature, raw gas and slag streams. An additional 1,346 kg/hr (2,968 lb/hr) of oxidant is generated for use in the Sulfur Recovery Section. The raw gas is cooled in a radiant cooler (Item 4), raising saturated, high-pressure (HP) steam, and cooling the raw gas to about 824ºC (1516ºF) to solidify slag particles before cooling the gas further in a convective cooler (Item 7) to generate additional saturated HP-steam. The raw gas stream has heat content of 1,958 x 10^6 kJ/hr (1,856 x 10^6 Btu/hr) (LHV) and heating value of about 7.6 MJ/Nm^3 (194 Btu/scf), and includes about 9,979 kg/hr (22,000 lb/hr) of recycled, clean fuel gas used as soot blower gas in the heat exchangers. These values differ slightly in the two conventional fuel gas cleaning cases (Current Standards and Future Standards) due to the recycle of tail gas from the Sulfur Recovery Section to the gasifier in these cases. Net carbon loss from the gasification process is assumed to be 1 percent of the coal carbon content and is contained in the plant's slag waste stream.

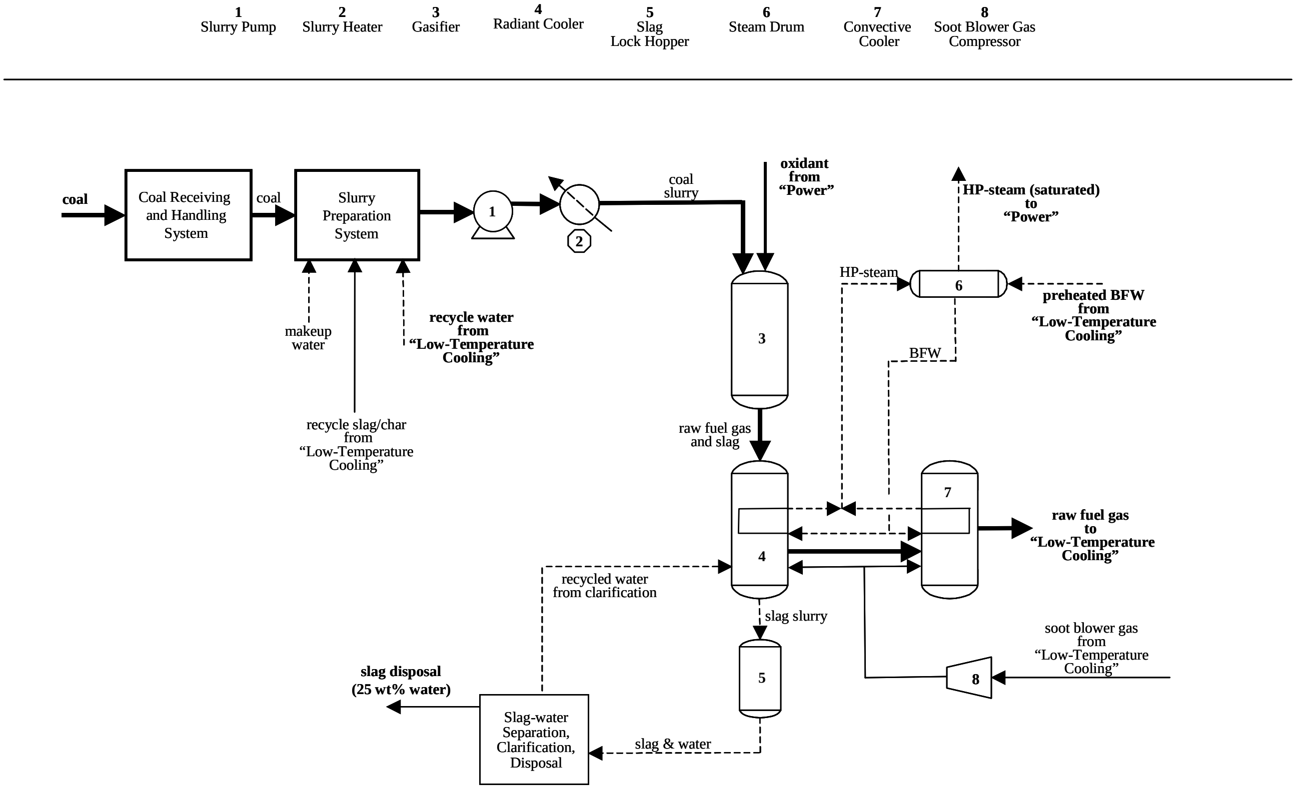


Figure 4.2 - Gasification Section for Conventional Dry-gas Cleaning

The fuel gas exits the Gasifier at about 1410ºC (2570ºF) and 2758 kPa (400 psia), and is 371ºC (700ºF) at the exit of the Convective Cooler, with the estimated composition listed in Table 4.2, not including entrained slag.

Table 4.1 – Stream Characteristics for Gasification Section - Current Standards

Stream name	Coal feed	Total slurry water feed	Gasifier oxidant	Raw fuel gas	Slag	HP-steam
Molar flow, kmole/hr	8,810	2,429	2,899	11,448	224	14,767
Mass flow, kg/hr	98,847	43,767	92,357	248,353	10,511	266,032
Volumetric flow, m^3/hr	122	45	2,377	23,324	13	4,900
Temperature, °C	26	56	81	371	667	318
Pressure, kPa	101	110	3585	2634	2468.	10,583
Enthalpy MJ/hr	-1.25E+05	-6.89E+05	4,283	-1.49E+06	-41,751	-3.52E+06
Molecular wt	11.2	18.0	31.9	21.7	46.9	18.0

Table 4.2 - Raw Gas Composition – Conventional Gas Cleaning with Current Standards

	Major constituents (vol%)
H_2	23.63
CH_4	0.30
CO	40.95
CO_2	10.93
H_2O	21.30
N_2	1.57
Ar	0.14
Total	98.86
	Major contaminants (ppmv)
H_2S	9,524
COS	721
CS_2	0.7
S_X	9
SO_2	4
NH_3	675
HCN	19
HCl	425
Hg (ppbv)	3

Gasification reaction conversions are estimated from thermodynamic equilibrium calculation, with suitable adjustments to methane, ammonia, and hydrogen cyanide to be representative of reported gasifier performance. The estimated distribution of contaminants in the raw gas issued from the gasifier is based on the empirical assumptions listed in Table 4.3. Significant sulfur content is assumed to remain in the gasifier slag, and the hot gas from the gasifier is assumed to be at equilibrium with respect to sulfur species. All of the coal's chlorine content is assumed converted to HCl in the raw gas, and other halides have been neglected in the evaluation. All of the coal's mercury is assumed to be issued in the raw gas as elemental mercury. Empirical conversions are assumed for ammonia and hydrogen cyanide. Metal carbonyls may be formed in the raw gas only at temperatures less than about 480°C (900°F) though gas-solid reactions with the ash metal constituents, or with the materials of construction, and the level of formation is highly uncertain. There are a multitude of other trace species contained within the raw gas that are not listed and these are not expected to be of concern to either gas turbine protection or environmental emissions due to their expected condensed-form fate in the cleanup processes, or due to their low level of content in the fuel gas. The hot gas composition is assumed to be frozen at this level once it has passed through the raw gas cooler heat exchangers.

Table 4.3 – Distribution of Contaminants in Gasification Section Raw Gas

Contaminant	Generation (% of coal constituent)	Contaminant forms
Sulfur species	90% (10% retained with slag)	H_2S, COS, CS_2, SO_2 based on equilibrium at exit temperature
Halides	100% of coal Cl content	HCl (other halides neglected)
Ammonia	25 % of coal nitrogen	NH_3
Hydrogen cyanide	0.5 % of coal nitrogen	HCN
Mercury	100% of coal mercury content	Hg^o only
Metal carbonyls	0 (generated <900°F only)	$Fe(CO)_5$, $Ni(CO)_4$

Low-Temperature Cooling Section

Figure 4.3 represents the process flow diagram for the Low-Temperature Cooling Section used with conventional dry-gas cleaning. It includes all of the equipment treating the gas before it goes to the

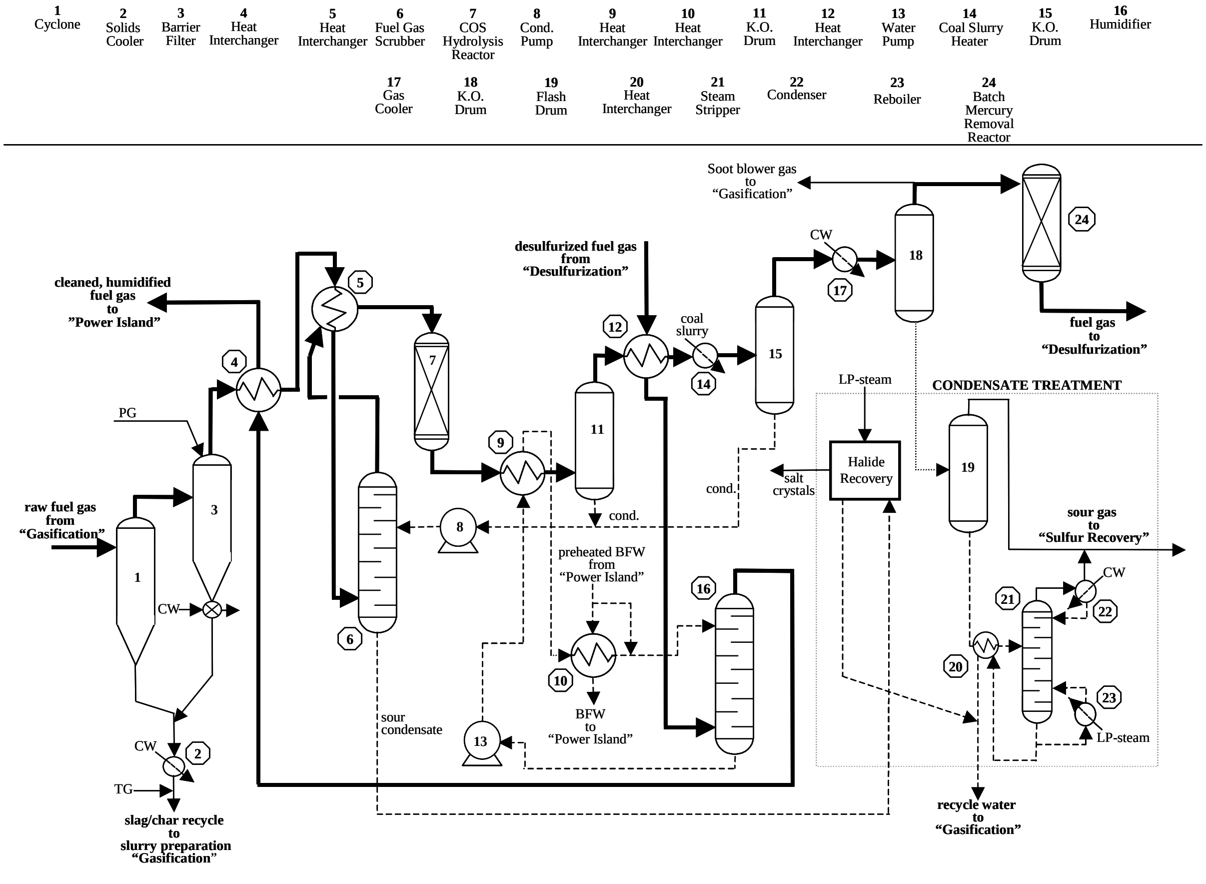


Figure 4.3 - Low-Temperature Cooling Section

AGR Section, as well as equipment for humidifying and reheating the cleaned fuel gas before it goes to the Power Section. Table 4.4 lists characteristics of major streams in the Low-Temperature Cooling Section. The raw gas from the Gasification Section is first pre-cleaned of entrained slag particulate using a conventional cyclone (Item 1). The subsequent sequence of processing steps is described below.

Table 4.4 – Stream Characteristics for Low-Temperature Cooling Section

Stream name	Cooled raw gas	Slag/char recycle	Fuel gas to Desulfurization	Desulfurized fuel gas	Reheated fuel gas to Power Island
Molar flow, kmole/hr	11,448	43	8,549	8,190	10,166
Mass flow, kg/hr	248,353	2,562	192,203	177,397	213,005
Volumetric flow, m^3/hr	23,324	2.0	9,933	9,802	22,934
Temperature, °C	371	371	38	44	310
Pressure, kPa	26,342	2,468	2,220	2,206	2,158
Enthalpy, MJ/hr	-1.49E+06	-12,177	-9.69E+05	-8.67E+05	-1.26E+06
Molecular wt	21.7	46.9	22.5	21.7	21.0

Barrier filter: A ceramic, or metal, candle-type barrier filter (Item 3) operates at about 370°C (700°F) to removal particulate (solidified slag particles and char) from the raw gas to a level of < 0.1 ppmv as the first step in the cleaning process. The filter is pulse cleaned using compressed, high-purity nitrogen from the air separation unit. The collected particulate is combined with the cyclone catch and is pneumatically conveyed back to the gasifier for additional carbon conversion and slag collection, using recycled, clean fuel gas as the transport gas.

Fuel gas coolers: A process heat interchanger (Item 4), a shell-and-tube unit, is now used to cool the gas to about 228°C (443°F), while reheating the clean, humidified fuel gas to about 310°C (590°F) before it goes to the gas turbine combustors. This cooled gas then passes through a second heat interchanger (Item 5) that cools it to about 199°C (390°F).

Fuel gas condensate scrubber: The gas is next scrubbed in a bubble-cap, tray column (Item 6) with collected process condensate, about 22.435 kg/hr (49,460 lb/hr), to remove halides to a very low level, and results in the further cooling of the gas to about 158°C (316°F). The scrubber condensate is collected and treated in a crystallization process (Condensate Treatment) to remove the collected halides, primarily HCl, as ammonium chloride salts for disposal. The treated water is recycled to the Gasification Section's slurry preparation system.

Gas reheater: The gas is now reheated in a gas heat interchanger (Item 5) to about 186°C (366°F) in preparation for COS hydrolysis. This preheating step is required to elevate the temperature of the water-saturated gas at least 28°C (50°F) to protect the hydrolysis catalyst bed from possible condensate contact.

COS hydrolysis: The reheated gas is treated in a catalytic reactor (Item 7) to hydrolyze its COS content to H_2S, allowing more efficient sulfur removal to be performed downstream. This unit also effectively hydrolyzes HCN to ammonia.

Fuel gas cooling and ammonia removal: A series of process heat interchangers and water-cooled heat exchangers (Items 9, 12, 14, and 17) are used to cool the gas to about 38°C (100°F), simultaneously removing most of its water content and collecting process condensate that contains most of the gas ammonia as well as a portion of the sulfur species. The cooling water use represents the greatest thermal energy loss in the IGCC process. The condensate is collected and treated in a steam stripping process (Items 18, 19, 20, 21, and 22) to remove ammonia and sulfur gases. The treated condensate is recycled to the Gasifier Section to be used for coal slurry feeding. The stream of released sour-water gases from condensate processing is sent to the Sulfur Recovery Section. Its composition is listed in Table 4.5.

Table 4.5 - Sour-water Gas Composition - Current Standards

	Constituents (vol%)
H_2	1.16
CH_4	0.03
CO	2.18
CO_2	17.79
H_2O	47.90
N_2	0.06
H_2S	8.03
COS	0.04
NH_3	22.80
HCN	0.00
Total	99.99

Soot-blower gas: A portion of the partially cleaned gas is withdrawn at this point in the process to be compressed and used as soot-blower gas in the raw gas heat recovery units, and as transport gas to carry the cyclone and filtered slag back to the gasifier.

Condensate Treatment: The halides are converted to ammonia salts for disposal, and ammonia is sent to the Sulfur Recovery Section to be decomposed in the high temperature Claus furnace. Considerable LP-steam is utilized in the condensate treatment process.

Mercury removal: The gas is now treated in a fixed bed reactor (Item 24) containing sulfur-impregnated, activated carbon to remove 90% of the gas mercury. This activated carbon bed is periodically drained and refilled with fresh adsorbent, and the used adsorbent is disposed as a hazardous material. This is assumed to be a single, fixed bed adsorption reactor operated in batch-mode. It is operated with no parallel-reactor switching, and is drained and refilled during annual power plant outage periods. This single vessel system is subject to the possibilities of bed flow bypassing, packed bed pressure drop increases, and elutriation of fine particulate. The criteria in the Eastman Chemical Synthesis plant for change out of their mercury sorbent bed is its increase in pressure drop beyond an established limit (Trapp et al., 2004). The composition of the gas sent to the AGR Section of the plant is listed in Table 4.6.

Table 4.6 - Gas Composition to AGR Section - Current Standards

	Major constituents (vol%)
H_2	29.96
CH_4	0.39
CO	51.93
CO_2	13.97
H_2O	0.28
N_2	2.00
Ar	0.17
Total	98.70
	Major contaminants (ppmv)
H_2S	12,955
COS	2.5
NH_3	0.5
HCN	0.004
Hg (ppbv)	0.25

The fates of the gas contaminants in the raw gas entering this section as estimated in the process simulation are listed in Table 4.7. The halides, ammonia, and hydrogen cyanide contaminants are very effectively removed from the raw gas, and are recovered from the condensate streams for final processing.

Table 4.7 – Fate of Contaminants in Low-temperature Cooling Section – Current Standards

Contaminant	Removal (% of inlet to Section)	Contaminant conversions
Sulfur species	5.3	Hydrolysis Partial condensate absorption
Halides	100	Condensate absorption Salt crystallization
Ammonia	99.95	Hydrolysis Condensate absorption Salt crystallization
Hydrogen cyanide	100	Hydrolysis
Mercury	90	Sorbent fixation

Humidification: The clean and dry fuel gas from the AGR Section is reheated to about 141°C (286°F), interchanging heat (Item 12) with the previous gas cooling-condensation process streams. This fuel gas is passed through a packed column (Item 16) where it is contacted with circulating boiler feed water to humidify the dry fuel gas to a water content of about 20 vol%. Heat for this humidification process is provided by some of the low-grade sources in the previous gas cooling steps. The humidification step is needed to produce a fuel gas that will have an acceptably low, peak flame temperature in the turbine combustors to minimize NOx formation.

Fuel gas reheat: The cleaned and humidified fuel gas is now reheated to about 310°C (590°F) in a heat interchanger (Item 4). There is no positive protection provided against metal carbonyls or corrosion particulate possibly generated in the low-temperature equipment. This reheated fuel gas is mixed with a humidified nitrogen stream from the air separation unit before being distributed to the turbine combustors. These combustors are diffusion flame burners, specifically designed for low heating-value fuel gas, and the fuel gas has been conditioned by humidification and nitrogen dilution so that the NOx generated will be less than 15 ppmv (corrected to 15 vol% O_2, dry).

AGR Section

Figure 4.4 represents the process flow diagram for the AGR Section to achieve the Current Standards requirements. Table 4.8 lists characteristics of major streams in the AGR Section. The cooled gas from the Low-Temperature Cooling Section is desulfurized in a conventional, amine-based absorption-stripping process. The gas passes through an amine absorption, bubble-cap tray column (Item 1), and the desulfurized fuel gas meets the requirement for an overall 99% sulfur removal performance in the power plant, since the plant is designed with no other sulfur release points in the power plant. Makeup water, at 274 kg/hr (603 lb/hr) and makeup MDEA solvent, at 34 kg/hr (75 lb/hr) are fed to the process. The lean solvent from the absorber is flashed (Item 5) to low pressure (about 30 psia), and flows through a stripping column (Item 9). Significant LP-steam, at 12 MW(t) (42 x 10^6 Btu/hr), is used to operate the solvent stripper reboiler (Item 10), generating a low-pressure, acid gas that is sent to a Sulfur Recovery Section. The flash gas is compressed (Item 3), cooled (Item 2) and circulated back to the inlet of the absorber column. A solvent reclaimer system is also needed to renew the MDEA solvent because of contaminant interactions.

Table 4.9 lists the composition of the desulfurized fuel gas. Table 4.10 lists the composition of the acid gas sent to the Sulfur Recovery Section.

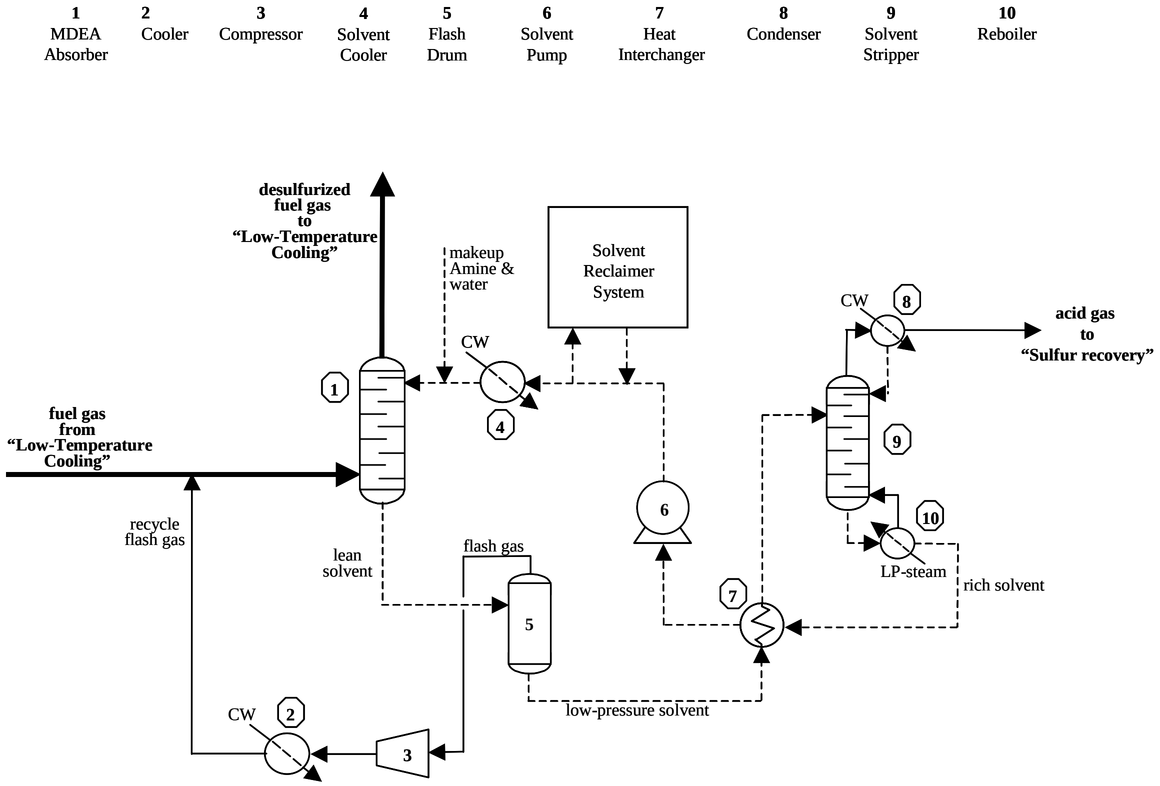


Figure 4.4 - AGR Section - MDEA for Current Standards

Table 4.8 – Stream Characteristics for AGR Section – Current Standards

Stream name	Fuel gas from LT-Cooling	Desulfurized fuel gas	Acid Gas to Sulfur Recovery
Molar flow, kmole/hr	8,549	8,190	375
Mass flow, kg/hr	192,203	177,397	15,076
Volumetric flow, m^3/hr	9,933	9,802	5,156
Temperature, °C	38	44	38
Pressure, kPa	2,220	2,206	186
Enthalpy, MJ/hr	-9.69E+05	-8.67E+05	-1.04E+05
Molecular wt	22.5	21.7	40.2

Table 4.9 - Desulfurized Fuel Gas Composition - Current Standards

	Major constituents (vol%)
H_2	31.28
CH_4	0.40
CO	54.21
CO_2	11.50
H_2O	0.33
N_2	2.08
Ar	0.18
Total	99.98
	Major contaminants (ppmv)
H_2S	126.1
COS	1.2
NH_3	0.5
HCN	0.0
Hg	0.0002

Table 4.10 - Acid Gas Composition - Current Standards

	Major constituents (vol%)
H_2	0.00
CO	0.01
CO_2	67.35
H_2O	3.35
H_2S	29.28
HCN	0.00
Total	99.99

Table 4.11 summarizes the fates of the contaminants within the desulfurization process.

Table 4.11 – Fate of Contaminants in the MDEA AGR Section

Contaminant	Removal (% of inlet to Section)	Contaminant conversions
sulfur species	99.06	Solvent absorption
halides	NA	---
ammonia	9.8	Solvent absorption
hydrogen cyanide	96.6	Solvent absorption
mercury	0	---

The clean and humidified fuel gas composition after passing through the Low-Temperature Cooling Section is listed in Table 4.12.

Table 4.12 - Cleaned and Humidified Fuel Gas Composition - Current Standards

	Major constituents (vol%)
H_2	25.20
CH_4	0.33
CO	43.67
CO_2	9.27
H_2O	19.70
N_2	1.68
Ar	0.14
Total	99.99
	Major contaminants (ppmv)
H_2S	101.6
COS	0.1
NH_3	0.4
HCN	0.0
Hg (ppbv)	0.29

Sulfur Recovery Section

Figure 4.5 shows the process flow diagram for the Sulfur Recovery Section of the IGCC power plant. Table 4.13 lists characteristics of major streams in the Sulfur Recovery Section. The low-pressure, acid gas combined with waste gas from the sour-water condensate treatment process are treated in a Claus-type sulfur recovery process. The sour-water gas, containing significant ammonia and H_2S, and an appropriate portion of the acid gas are combined and are burned in the Claus furnace (Item 1) with a stream of oxygen from the air separation unit. The use of oxygen, rather than air, makes the Claus reactors smaller and lower in cost. This burner is operated at sufficiently high temperature, >1427°C (>2600°F) to promote decomposition of ammonia, and also converts most of the contained H_2S to SO_2. The burner off-gas is mixed with the untreated acid gas, the proportions of H_2S and SO_2 being optimized for Claus reactor conversion. The gas is then cooled in a boiler (Item 3) to generate IP-steam, followed by a boiler-sulfur condenser (Item 4) generating LP-steam. Any elemental sulfur contained in the product acid gas is separated before the gas enters the first Claus reactor (Item 5). Three stages of acid gas reheat, with IP-steam heat source, Claus catalytic reactor, gas cooling to generate LP-steam, and sulfur separation are used in the process. The sulfur recovery process recovers about 91.60% of the sulfur content of the acid gas. The collected sulfur streams are combined and the sulfur is stored for treatment and marketing as a by-product.

The tail gas has a high content, and variety of sulfur species (H_2S, SO_2, S_x), and the most effective way the power plant can achieve its overall 99% sulfur removal goal is for this tail gas to be recompressed and recycled to the gasifier. After cooling and compression and condensate removal, the tail gas recycled to the Gasifier has the composition reported in Table 4.14. The fates of the contaminants in the Sulfur Recovery Section are listed in Table 4.15.

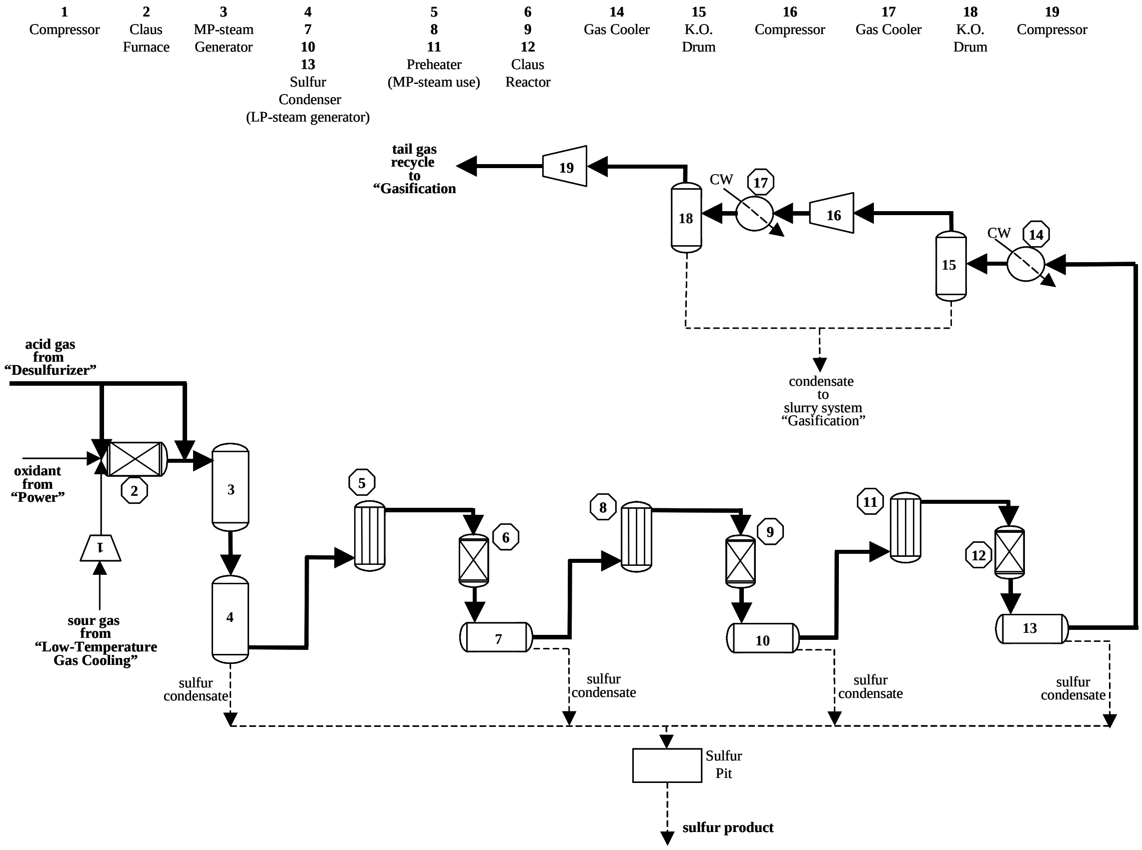


Figure 4.5 - Sulfur Recovery Section with Conventional Technology

Table 4.13 – Stream Characteristics for Sulfur Recovery Section

Stream name	Acid Gas to Sulfur Recovery	Oxidant from Power Island	Sour gas	Sulfur product	Tail gas recycle
Molar flow, kmole/hr	375	42	11	132	278
Mass flow, kg/hr	15,076	1,346	259	3805	11,354
Volumetric flow, m^3/hr	5,156	133	193	2.4	312
Temperature, °C	38	27	62	124	221
Pressure, kPa	186	793	103	153	3620
Enthalpy, MJ/hr	-1.04E+05	0.44	-2327	-18157	-92511
Molecular wt	40.2	31.9	23.8	28.8	40.9

Table 4.14 - Recycle Tail Gas Composition – Conventional Technology with Current Standards

	Major constituents (vol%)
H_2	2.91
CO	9.02
CO_2	82.38
H_2O	1.12
N_2	1.11
Ar	0.08
H_2S	2.09
SO_2	0.98
COS	0.28
NH_3	0.00
HCN	0.02
Total	99.99

Table 4.15 – Fate of Contaminants in Conventional Sulfur Recovery - Current Standards

Contaminant	Removal (% of inlet to Section)	Contaminant conversions
Sulfur species	91.60	Claus conversion to elemental sulfur Hydrolysis to reduced forms
Halides	NA	----
Ammonia	99.0	Furnace decomposition to N_2
Hydrogen cyanide	NA	----
Mercury	NA	----

Power Section

The Power Section process flow diagram is shown in Figure 4.6. Characteristics of major streams in the Power Section are listed in Table 4.16. An oxygen stream with 95% purity, is generated by conventional, pressurized, cryogenic air separation (ASU). The air separation unit's input air is totally supplied as pressurized air extracted from the turbine air compressor. A relatively low-purity nitrogen stream is also produced that is compressed (Item 19) and humidified to be used for clean fuel gas dilution. A smaller stream of high-purity nitrogen (99.9%) is also produced that is compressed (Item 20, Item 22) to be used for various small process needs including filter pulse cleaning. The oxygen feed rate differs slightly between the two evaluation cases due to the consumption of oxygen needed to operate the gasifier with recycled streams, and oxygen consumed by the sulfur recovery process, with the conventional, low-temperature gas cleaning technology. Low-purity nitrogen is humidified (Item 24) to about 15 vol% water vapor using low-grade heat sources (Item 16, Item 21), and the nitrogen stream is mixed with the clean fuel gas before the mixture is distributed to the gas turbine combustors.

The turbine combustors operate with an outlet temperature of about 2770°F, and, with the peak flame temperature being about 3000°F, the NOx emission is expected to be less than 15 ppmv (dry, corrected to 15% oxygen). The turbine exhaust gas has a temperature of 1152°F. The exhaust gas passes through the heat recovery steam generator (HRSG – Item 5), generating a superheated, high-pressure steam flow of 337,698 kg/hr (744,500 lb/hr). The stack gas from the power plant has a temperature of about 121°C (250°F) and a composition listed in Table 4.17. The fates of the contaminants in the Power Section are listed in Table 4.18.

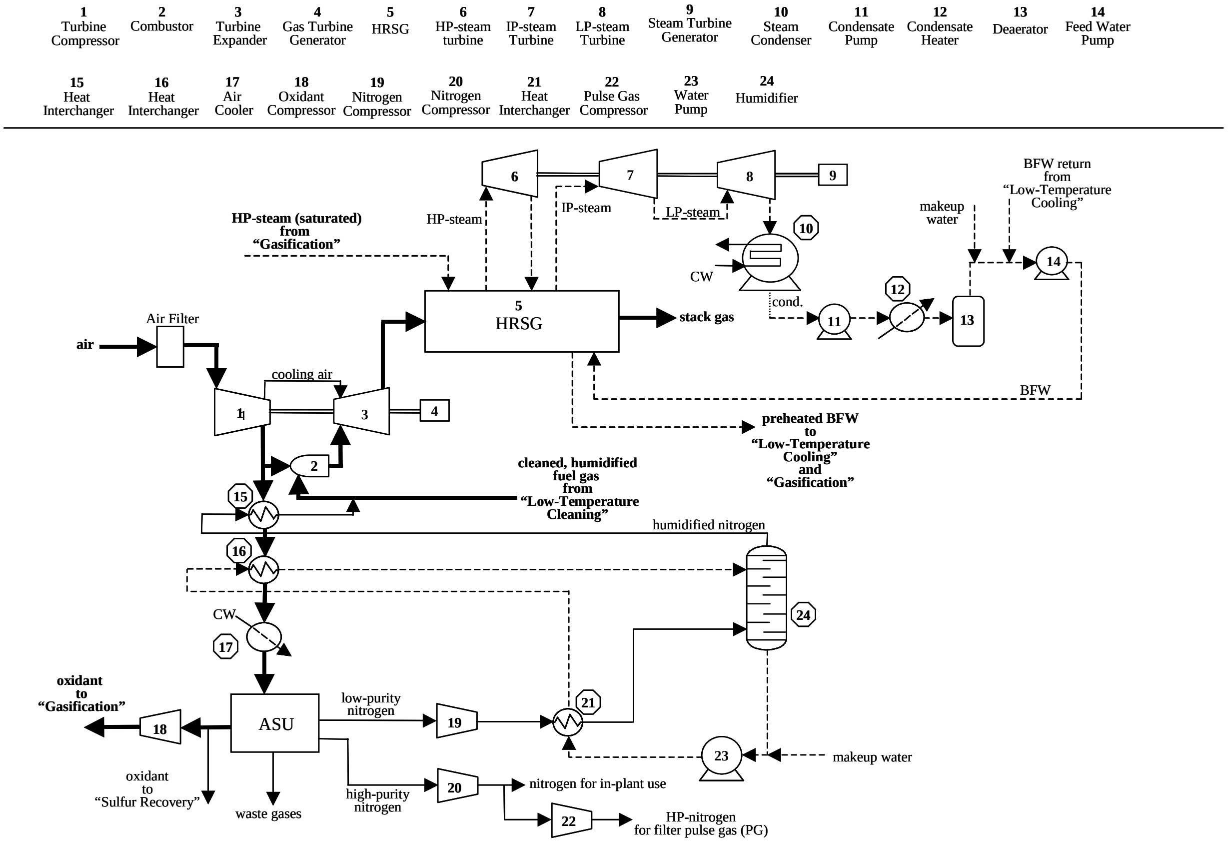


Figure 4.6 - Power Section – Conventional Technology

Table 4.16 – Stream Characteristics for Power Section

Stream name	Air to gas turbine	Gasifier oxidant	Low-purity nitrogen	Makeup water	Fuel gas to gas turbine	Stack gas
Molar flow, kmole/hr	53,609	2,899	10,650	1,863	10,166	59,035
Mass flow, kg/hr	1,546,965	92,357	299,941	33,566	213,005	1,696,586
Volumetric flow, m^3/hr	1,278,821	2,377	33,514	34	22,934	1,911,005
Temperature, °C	15	81	27	15	310	122
Pressure, kPa	100	3585	793	2068	2,158	101
Enthalpy MJ/hr	-1.52E+05	4,283	108	-5.34E+05	-1.26E+06	-3.63E+06
Molecular wt	28.9	31.9	28.2	18.0	21.0	28.7

Table 4.17 - Stack Gas Composition - Current Standards

	Major constituents (vol%)
O_2	8.06
CO_2	9.19
H_2O	11.68
N_2	70.22
Ar	0.84
Total	99.99
	Major contaminants
SO_2 (ppmv)	17.7
NOx (ppmv)	15
Mercury (ppbv)	0.05

Table 4.18 – Fate of Contaminants in Conventional Power Section – Current Standards

Contaminant	Removal (% of inlet to Section)	Contaminant form conversion
Sulfur species	0	Oxidation to SOx
Halides	NA	----
Ammonia	0	Partial oxidation conversion to NOx
Hydrogen cyanide	NA	----
Mercury	0	Partial conversion to oxidized forms

4.2 IGCC WITH CONVENTIONAL GAS CLEANING TO MEET FUTURE STANDARDS

IGCC using conventional, low-temperature gas cleaning technology to meet Future Standards has a very similar process flow configuration to the power plant meeting Current Standards, with only the process flow diagram for the AGR Section being different. The process stream flow rates and compositions are slightly different from the Current Standards case in most of the process sections, especially in the AGR Section. Where the process section descriptions are identical to those provided for the Current Standards case, only the modified flows and compositions are indicated.

Gasification Section

Figure 4.2 shows the process flow diagram for the Gasification Section. The flows for the Future Standards case differ only slightly from those estimated for the Current Standards case. Table 4.19 lists characteristics of major streams in the Gasification Section. The raw gas flow rate at the exit of the Convective Cooler (Item 7) is about 245,350 kg/hr (540,907 lb/hr), with heat content of 540 MW(t) (1,843 x 10^6 Btu/hr) (LHV) and heating value of about 7.51 MJ/Nm^3 (191 Btu/scf), and includes 9,979 kg/hr (22,000 lb/hr) of recycled, clean fuel gas used as soot blower gas in the raw gas heat exchangers. The raw gas has the estimated composition in Table 4.20.

Table 4.19 – Stream Characteristics for Gasification Section - Future Standards

Stream name	Coal feed	Total slurry water feed	Gasifier oxidant	Raw fuel gas	Slag	HP-steam
Molar flow, kmole/hr	8,810	2,429	2,902	11,437	224	15,447
Mass flow, kg/hr	98,847	43,767	92,490	247,913	10,511	278,279
Volumetric flow, m^3/hr	122	45	2,352	22,709	13	5,123
Temperature, °C	26	56	84	371	670	318
Pressure, kPa	101	110	3654	2703	2537	10,583
Enthalpy MJ/hr	-1.25E+05	-6.89E+05	4,495	-1.49E+06	-41,7031	-3.69E+06
Molecular wt	11.2	18.0	31.9	21.7	46.9	18.0

Table 4.20 - Raw Gas Composition - Future Standards

	Major constituents (vol%)
H_2	23.65
CH_4	0.31
CO	40.97
CO_2	10.90
H_2O	21.38
N_2	1.58
Ar	0.14
Total	98.88
	Major contaminants (ppmv)
H_2S	9,578
COS	726
CS_2	0.7
S_X	8
SO_2	4
NH_3	676
HCN	20
HCl	425
Hg (ppbv)	3

Low-Temperature Cooling Section

Figure 4.3 represents the process flow diagram for the Low-Temperature Cooling Section and flows differ slightly from the Current Standards case. Table 4.21 lists characteristics of major streams in this section.

Table 4.21 – Stream Characteristics for Low-Temperature Cooling Section – Future Standards

Stream name	Cooled raw gas	Slag/char recycle	Fuel gas to Desulfurization	Desulfurized fuel gas	Reheated fuel gas to Power Island
Molar flow, kmole/hr	11,437	43	8,536	8,162	10,159
Mass flow, kg/hr	247,913	2,562	191,746	176,981	212,968
Volumetric flow, m^3/hr	22,709	2.0	9,032	9,092	23,289
Temperature, °C	371	371	38	18	310
Pressure, kPa	2,703	2,537	2,441	2,165	2,124
Enthalpy, MJ/hr	-1.49E+06	-12,177	-9.66E+05	-8.68E+05	-1.26E+06
Molecular wt	21.7	46.9	22.5	21.7	21.0

Barrier filter: A ceramic, or metal, candle barrier filter (Item 3) operates at about 370°C (700°F) to removal particulate (solidified slag particles and char) from the raw gas to a level of < 0.1 ppmv as the first step in the cleaning process.

Fuel gas coolers: A process heat interchanger (Item 4) is now used to cool the gas to about 228°C (442°F), while reheating the clean fuel gas to about 310°C (590°F) before it goes to the gas turbine combustors. This cooled gas then passes through a second heat interchanger (Item 5) that cools it to about 198°C (389°F).

Gas condensate scrubber: The gas is next scrubbed in a column (Item 6) with collected process condensate to remove halides to a very low level, and results in the further cooling of the gas to about 158°C (317°F).

Gas reheater: The gas is now reheated in a fuel gas heat interchanger (Item 5) to about 186°C (367°F) in preparation for COS hydrolysis.

COS hydrolysis: The reheated gas is treated in a catalytic reactor (Item 7) to hydrolyze its COS content to H_2S, allowing more efficient sulfur removal to be performed downstream, and to prevent HCN accumulation in the AGR solvent.

Gas cooling and ammonia removal: Next, a series of process heat interchangers and water-cooled heat exchangers (Items 9, 12, 14, and 17) are used to cool the gas to about 38°C (100°F), simultaneously removing most of the gas water content and collecting process condensate that contains most of the fuel gas ammonia. The stream of released gases from condensate processing is sent to the Sulfur Recovery Section of the plant. Its composition is listed in Table 4.22.

Table 4.22 - Sour-water Gas Composition - Future Standards

	Constituents (vol%)
H_2	1.12
CH_4	0.03
CO	2.11
CO_2	17.12
H_2O	47.50
N_2	0.06
H_2S	7.90
COS	0.04
NH_3	24.11
HCN	0.00
Total	99.99

Mercury removal: The gas is treated in a fixed bed reactor (Item 24) containing sulfur-impregnated, activated carbon to remove 95% of the mercury. The composition of the gas sent to the AGR Section is listed in Table 4.23.

Table 4.23 - Gas Composition to AGR Section - Future Standards

	Major constituents (vol%)
H_2	29.99
CH_4	0.39
CO	51.97
CO_2	13.90
H_2O	0.27
N_2	2.00
Ar	0.17
Total	98.69
	Major contaminants (ppmv)
H_2S	13,081
COS	0.0
NH_3	0.5
HCN	0.0
Hg (ppbv)	0.14

Humidification & Fuel gas reheat: The clean and dry-gas from the desulfurizer is reheated to about 141°C (286°F), interchanging heat (Item 12) with the previous gas cooling-condensation process streams. The cleaned and humidified fuel gas is now reheated to about 310°C (590°F) in a heat interchanger (Item 4).

Acid Gas Recovery (AGR) Section

Figure 4.7 shows the process flow diagram for the AGR Section with the Future Standards. Table 4.24 lists characteristics of major streams in the AGR Section. The Rectisol desulfurization technology is selected for the desulfurization step, with other commercial low-temperature desulfurization technologies, such as Selexol, unable to meet the stringent requirements (Sharp et al., 2003). Rectisol claims that this process will also effectively remove HCN, NH_3, CS_2, iron and nickel carbonyls, VOCs, and mercury effectively (Koss and Meyer, 2003). On the other hand, users of Rectisol perform mercury removal in a separate unit placed before the Rectisol process, and place adsorbers to capture metal carbonyls after the Rectisol process to ensure performance and because if these contaminants are absorber in the Rectisol solvent, will either accumulate within the solvent or be released from the stripper and need separate processing to engage their final disposition. Maintenance of the Rectisol columns is a critical path item in an IGCC power plant using this technology due to the severe conditions in the columns (Trapp et al., 2004).

The cooled gas, following mercury removal, is desulfurized in a conventional, Rectisol-based absorption-stripping process. The Rectisol process contacts gas recuperatively-cooled to about -27°C (-17°F) (Item 1) with refrigerated methanol at about -63°C (-82°F) (Item 8) in a multi-staged, bubble-cap tray, counter-current absorption column (Item 3). A small portion of methanol is injected directly into the gas stream before the heat interchanger Item 1 to remove water from the gas (Item 2) to eliminate the possibility of ice formation. The desulfurized gas meets the requirement for an overall 99.98% sulfur removal performance in the power plant, if there are no other sulfur release points in the power plant. The desulfurized, reheated gas exits the process (Item 1) at about 18°C (64°F). Makeup methanol solvent (141 lb/hr) is fed to the process to account for process losses, and a methanol decontamination step is included in the process. The process uses significant energy for refrigeration associated with heat interchanger Item 8 and condenser Item 12 to meet this level of sulfur removal. The lean solvent is flashed in a series of flash tanks (Item 6 and 7) to low pressure (15 psia) and is circulated to a solvent stripper column (Item 11). The stripper generates a low-pressure, acid gas that is sent to a sulfur recovery process. Table 4.25 lists the composition of the desulfurized fuel gas.

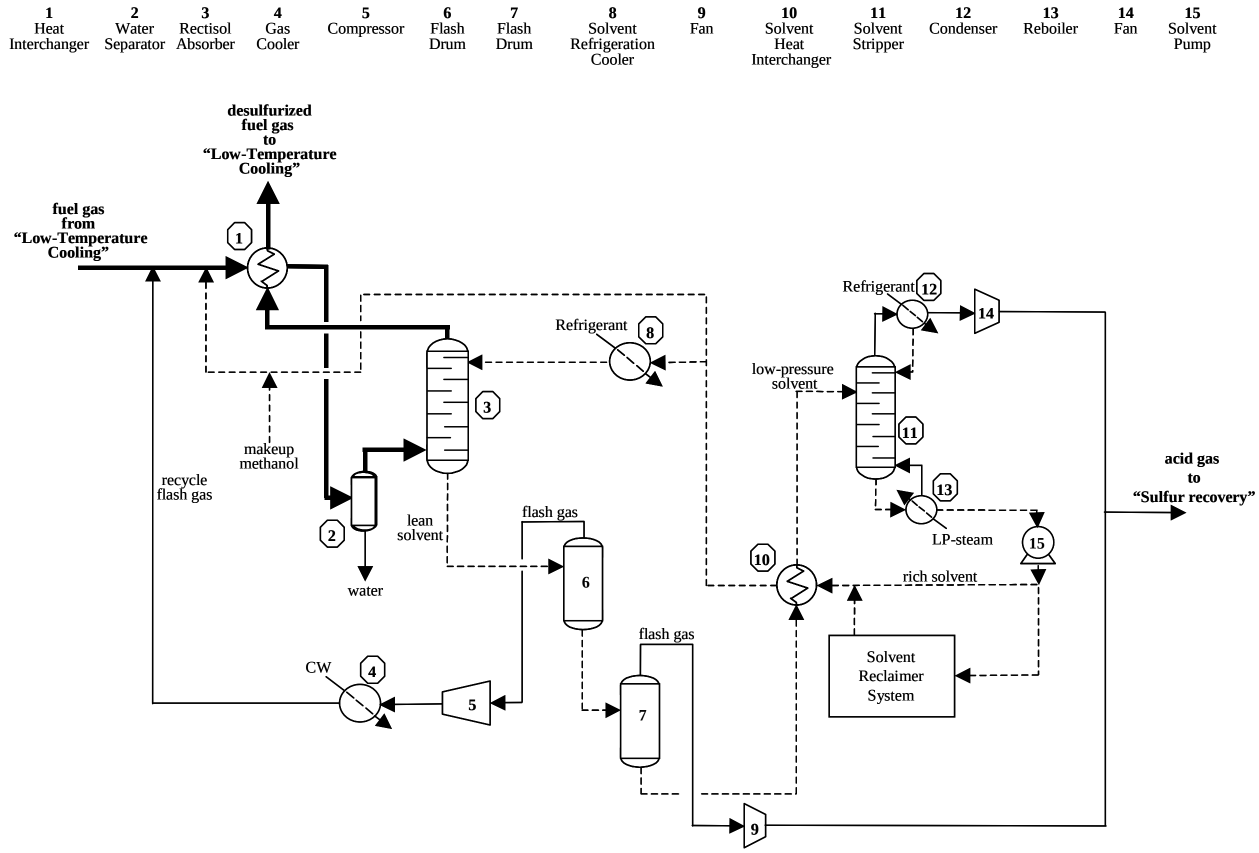


Figure 4.7 – AGR Section – Rectisol for Future Standards

Table 4.24 – Stream Characteristics for AGR Section – Future Standards

Stream name	Fuel gas from LT-Cooling	Desulfurized fuel gas	Acid Gas to Sulfur Recovery
Molar flow, kmole/hr	8,536	8,162	353
Mass flow, kg/hr	191,746	176,986	14,406
Volumetric flow, m^3/hr	9,032	9,093	4,902
Temperature, °C	38	18	41
Pressure, kPa	2,441	2,165	186
Enthalpy, MJ/hr	-9.66E+05	-8.75E+05	-0.97E+05
Molecular wt	22.5	21.7	40.8

Table 4.25 - Desulfurized Fuel Gas Composition - Future Standards

	Major constituents (vol%)
H_2	31.37
CH_4	0.41
CO	54.35
CO_2	11.60
H_2O	0.00
N_2	2.09
Ar	0.18
Total	100.00
	Major contaminants (ppmv)
H_2S	2.1
COS	0.5
NH_3	0.0
HCN	0.0
Hg (ppbv)	0.12

Table 4.26 lists the composition of the acid gas sent to the Sulfur Recovery Section. Note that some methanol solvent is estimated to be lost to the acid gas stream.

Table 4.26 - Acid Gas Composition - Future Standards

	Major constituents (vol%)
H_2	0.00
CO	0.02
CO_2	67.93
H_2O	0.00
H_2S	31.51
COS	0.00
NH_3	0.00
HCN	0.00
methanol	0.53
Total	99.99

Table 4.27 summarizes the fates of the contaminants within the AGR process for the Future Standards case. The fuel gas composition after humidification is listed in Table 4.28.

Table 4.27 – Fate of Contaminants in the Conventional AGR Section – Future Standards

Contaminant	Removal (% of inlet to Section)	Contaminant conversions
Sulfur species	99.981	Methanol absorption
Halides	NA	---
Ammonia	99.99	None
Hydrogen cyanide	NA	---
Mercury	100	Accumulates in methanol

Table 4.28 - Cleaned and Humidified Fuel Gas Composition - Future Standards

	Major constituents (vol%)
H_2	25.20
CH_4	0.33
CO	43.66
CO_2	9.32
H_2O	19.66
N_2	1.68
Ar	0.14
Total	99.99
	Major contaminants (ppmv)
H_2S	1.7
COS	0.4
NH_3	0.0
HCN	0.0
Hg (ppbv)	0.146

Sulfur Recovery Section

Figure 4.5 shows the process flow diagram for the Sulfur Recovery Section of the IGCC power plant. The stream flows and conditions are very similar to those for the Current Standards case. The sour-water gas, containing significant ammonia and H_2S, and an appropriate portion of the acid gas are combined and are burned in the Claus furnace (Item 1) with a stream of oxygen at 1,352 kg/hr (2,980 lb/hr) from the air separation unit. The sulfur recovery process recovers about 92.6% of the sulfur content of the acid gas. The collected sulfur streams are combined and the sulfur is stored for treatment and marketing as a by-product.

The tail gas, at 10,800 kg/hr (23,811 lb/hr), contains a considerable content, and variety of sulfur species (H_2S, SO_2, S_x), and the only way the power plant can achieve its overall 99.85% sulfur removal goal is for this tail gas to be recompressed and recycled to the gasifier. After cooling and compression and condensate removal, the tail gas recycled to the Gasifier has the composition reported in Table 4.29.

Table 4.29 - Recycle Tail Gas Composition - Future Standards

	Major constituents (vol%)
H_2	3.15
CO	10.36
CO_2	80.37
H_2O	1.00
N_2	1.16
Ar	0.08
H_2S	2.21
SO_2	1.04
COS	0.39
NH_3	0.00
HCN	0.03
methanol	0.20
Total	99.99

Power Section

The Power Section process flow diagram is shown in Figure 4.6. The characteristics of major streams are listed in Table 4.30. An oxygen stream with 95% purity, is generated by conventional, pressurized, cryogenic air separation (ASU). Low-purity nitrogen is humidified to about 15 vol% water vapor using low-grade heat sources, and the nitrogen stream is mixed with the clean fuel gas before the mixture is distributed to the gas turbine combustors.

Table 4.30 – Stream Characteristics for Power Section – Future Standards

Stream name	Air to gas turbine	Gasifier oxidant	Low-purity nitrogen	Makeup water	Fuel gas to gas turbine	Stack gas
Molar flow, kmole/hr	53,550	2,903	10,666	1,863	10,159	58,967
Mass flow, kg/hr	1,545,243	92,490	300,385	33,566	212,968	1,694,683
Volumetric flow, m^3/hr	1,277,397	2,352	33,563	34	23,289	1,905,963
Temperature, °C	15	84	27	15	310	121
Pressure, kPa	100	3654	793	2068	2,124	101
Enthalpy MJ/hr	-1.52E+05	4,495	108	-5.34E+05	-1.26E+06	-3.63E+06
Molecular wt	28.9	31.9	28.2	18.0	21.0	28.7

The turbine combustors, advanced, low-NOx burners specifically designed for low heating-value fuel gas, operate with an outlet temperature of about 1529°C (2784°F), and with the peak flame temperature being less than 1649°C (3000°F), the NOx emission is expected to be less than 5 ppmv (dry, corrected to 15% oxygen). The turbine exhaust gas has a temperature of 622°C (1152°F). The exhaust gas passes through the heat recovery steam generator (HRSG), generating a superheated, high-pressure steam flow of 346,996 kg/hr (765,000 lb/hr). The stack gas from the power plant has a temperature of 121°C (250°F) and a composition listed in Table 4.31. While the major constituents in the stack gas are very similar to those in the Current Standards case (Table 4.17), the major contaminants are significantly lower in the Future Standards case.

Table 4.31 - Stack Gas Composition - Future Standards

	Major constituents (vol%)
O_2	8.04
CO_2	9.20
H_2O	11.68
N_2	70.23
Ar	0.84
Total	99.99
	Major contaminants
SO_2 (ppmv)	0.4
NOx (ppmv)	5
Mercury (ppbv)	0.026

4.3 CONVENTIONAL IGCC POWER PLANT PERFORMANCE ESTIMATES

The breakdown of power generation and power use in the IGCC power plant with conventional, low-temperature, dry-gas cleaning technology is shown in Table 4.32. For the two gas cleaning cases, all of the sections of the power plant have similar total power use, except for the AGR Section where the refrigeration power needed in the Future Standards case is significantly greater than the power use for the AGR Section in the Current Standards case. Overall, the lower sulfur emission of the Future Standards case results in an increase in plant heat rate of about 3.5%, a reduction in the power plant thermal efficiency of about 1.3 percentage-points, and a reduction in net plant generating capacity of about 9.7 MWe.

Table 4.32 - IGCC Power Plant Thermal Performance with Conventional Gas Cleaning

Section	Current Standards Power (MWe)	Future Standards Power (MWe)
Power Island Generation		
Turbine air compressor	-169.8	-169.5
Gas turbine	365.8	365.2
Steam turbine	137.9	139.6
Generator	-6.7	-6.7
BOP	-4.8	-4.9
Total power	322.4	323.7
Air Separation Consumption		
ASU Air compressor	0	0
Oxygen compressor	4.19	4.26
Nitrogen compressor	9.04	9.05
ASU	20.60	20.64
Total power use	33.83	33.95
Gasification Consumption		
Fans & blowers	0.6	0.5
Pumps	0.10	0.10
Coal handling and preparation	1.5	1.5
Ash handling	1.3	1.3
Total power use	3.5	3.4
Desulfurization Consumption		
Refrigeration	0.0	10.77
Compressors	0.004	0.25
Pumps	0.19	0.12
Total power use	0.2	11.14
Sulfur Recovery Consumption		
Compressors	0.97	0.95
Pumps	0.00	0.00
Total power use	0.97	0.95
Total Plant		
Net plant power generated, MW	285.2	275.5
Plant net heat rate (HHV), kJ/kWh (Btu/kWh)	9579 (9079)	9915 (9397)
Plant net efficiency, (%, LHV)	40.56	39.19
Plant net efficiency, (%, HHV)	37.58	36.31

Table 4.33 lists several quantities related to the use of resources and emissions in the IGCC power plant with conventional, low-temperature, dry-gas cleaning technology. The power plants in both cases use large quantities of LP-steam in the gas cleaning process steps. Cooling water use in the processing steps is also very large. Large quantities of process condensate are generated in both cases,

primarily in the Low-Temperature Cooling Section. A moderate level of fresh process water is required in the gas cleaning processes, and both cases result in a significant discharge of excess process water. Both cases require large quantities of boiler-quality makeup water for fuel gas humidification.

Table 4.33 - IGCC Power Plant Resource Use and Emissions with Conventional Gas Cleaning

	Current Standards	Future Standards
Auxiliaries		
Net IP steam use, MJ/hr (10^6 Btu/hr)	33,025 (31.3)	32,603 (30.9)
Net LP steam use, MJ/hr (10^6 Btu/hr)	64,783 (61.4)	51,383 (48.7)
Total cooling water use, MJ/hr (10^6 Btu/hr)	251,641 (238.5)	199,625 (189.2)
Net condensate generated, kg/hr (lb/hr)	1,523 (3,357)	1849 (4,077)
Total process water used, kg/hr (lb/hr)	988 (2,178)	680 (1,499)
Net process water discharge, kg/hr (lb/hr)	274 (603)	0
Total boiler-water makeup, kg/hr (lb/hr)	69,263 (152,696)	69,646 (153,540)
Emissions		
Sulfur total removal efficiency (%)	99.08	99.98
Sulfur total emission, mg/MJ (lb $SO_2/10^6$ Btu)	24.4 (0.0568)	0.52 (0.0012)
Sulfur total emission, kg/MW (lb SO_2/MW)	0.23 (0.516)	0.005 (0.011)
NOx total emission, mg/MJ (lb $NO_2/10^6$ Btu)	14.9 (0.0347)	4.7 (0.0110)
Particulate emission, mg/MJ (lb/10^6 Btu)	0.0073 (1.708E-05)	0.0073 (1.701E-05)
Hg emission, mg/MJ (lb/TBtu)	0.22 (0.51)	0.11 (0.26)
Consumibles, kg/hr (lb/hr)		
Chemicals	34 (75)	64 (142)
Sorbents	1.4 (3)	1.4 (3)
Catalysts	0.9 (2)	0.9 (2)
Solid waste, kg/hr (lb/hr)		
Slag product (25 wt% water)	14,015 (30,897)	14,015 (30,897)
Waste salts (25 wt% water)	285 (628)	285 (628)
Sorbent wastes (hazardous)	1.4 (3)	1.4 (3)
Total solid waste	14,301 (31,528)	14,301 (31,528)

The total sulfur emissions are expressed under three different bases: percent removal, mg/MJ (lb per10^6 Btu) of fuel input, and kg/MWe (lb per MWe) of net power generated. The sulfur emissions are significantly lower for the Future Standard case, and are comparable to the sulfur emissions from a natural gas-fired, combined-cycle power plant. Solid waste rates from the IGCC power plants are identical in both cases.

4.4 CONVENTIONAL IGCC PLANT COST ESTIMATES

The major equipment purchase costs and installed costs associated and sensitive to the gas cleaning process are listed in Table 4.34 for each of the sections of the power plant evaluated. The cost of the Convective Cooler from the Gasification Section, and the Mercury Removal cost has been taken out and reported as separate items. The Low-temperature Cooling Section is the most expensive of the gas cleaning sections. Its cost is approached by the cost of the AGR Section for the Future Standards case. The total gas cleaning costs are also reported on the basis of dollars per kilowatt of net power generated. The equipment costs are about 50% greater for the Future Standards case than for the Current Standards case, reflecting primarily the great cost increase associated with increased sulfur removal performance of the gas cleaning system. The technical difficulty of achieving the sulfur removal standards are reflected in the percent of the feed sulfur emitted to the stack in each plant: 1% of the raw gas sulfur is emitted in the Current Standards case versus a 0.02% sulfur emission in the Future Standards case.

Table 4.34 - Conventional Gas Cleaning Technology Equipment Cost Breakdown

Plant Section	Current Standards Cost, k$	Future Standards Cost, k$
Raw Gas Convective Cooling		
purchased equipment	902	960
installed equipment	1,802	1,919
Low-temperature Gas Cooling		
purchased equipment	6,550	6,421
installed equipment	11,679	11,623
AGR		
purchased equipment	1,143	7,663
installed equipment	2,459	12,860
Sulfur Recovery		
purchased equipment	2,531	2,839
installed equipment	4,711	5,228
Mercury Removal		
purchased equipment	1,018	1,036
installed equipment	1,482	1,540
Total Gas Cleaning		
purchased equipment	12,143	18,919
installed equipment	22,132	33,169
purchased equipment, $/kW	43	69
installed equipment, $/kW	78	120
Total Plant		
TCR, k$	427,748	444,703
TCR, $/kW	1,500	1,614

The Total Capital Requirements for the IGCC power plants using conventional, low-temperature, dry-gas cleaning technology are also computed in Table 4.34. The costs are, in part, based on the assumption that an IGCC power plant of this capacity and scope, using conventional gas cleaning technology to meet current standards, has a representative Total Capital Requirement of 1,500 $/kW (Holt, 2003). For the Standard gas cleaning requirements, the conventional gas cleaning process TCR is about 7.8% of the total plant TCR. For Future gas cleaning standards, the conventional gas cleaning process TCR is about 11.2% of the total plant TCR. On a total power plant basis, the Total Capital Requirement ($/kW) for the Future Standards case is about 8.0% greater than for the Current Standards case.

The cost-of-electricity (COE) for the IGCC power plant for the Current Standards and Future Standards cases are also computed in Table 4.35. The COE of the power plant under the Future Standards case is 5.6% greater than that for the Current Standards case. The capital charges are the dominant cost factor, with the fuel cost and O&M cost being comparable.

Table 4.35 – Cost-of-Electricity – Conventional Gas Cleaning

	Current Standards	Future Standards
Fixed O&M	0.51	0.53
Variable O&M	0.27	0.27
Consumables	0.21	0.21
water	0.04	0.04
chemicals, sorbents, catalysts	0.032	0.027
waste Disposal	0.108	0.112
chemicals for BFW, CW and waste treatment	0.03	0.03
Sulfur by-product credit	0.063	0.066
Fuel	1.68	1.74
Capital charges	3.95	4.25
Total	6.56	6.93

5. IGCC WITH FILTER-REACTOR NOVEL GAS CLEANING

The IGCC power plant process configuration using the Filter-Reactor Novel Gas Cleaning Process differs considerably from the conventional IGCC power plant, and these differences result in significantly improved power plant performance and cost. A simplified process flow diagram for IGCC with Novel Gas Cleaning is shown in Figure 5.1. It portrays the relations between the major process systems in the plant and shows only the major process streams.

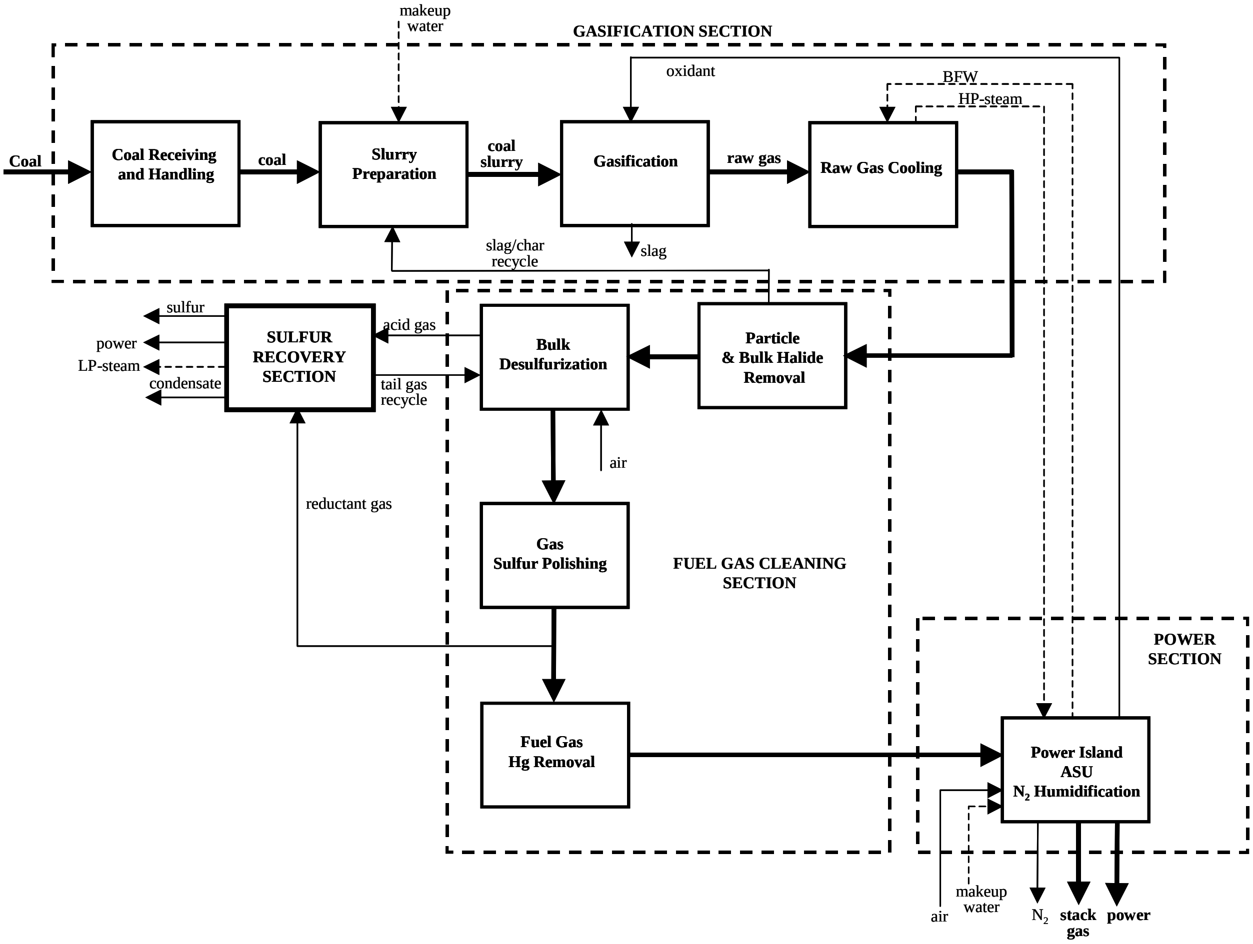


Figure 5.1 – Overall IGCC Power Plant Scheme with Filter-Reactor Novel Gas Cleaning

The overall process schematic is broken into major plant sections: the Gasification Section, consisting of coal receiving and handling, slurry preparation, gasification, slag handling, and raw gas cooling sub-sections; the Desulfurization Section, which includes mercury removal, the Sulfur Recovery Section, and the Power Section, consisting of the Power Island and air separation sub-sections. The diagram is highly simplified, not showing all of the numerous sub-functions of each section and the numerous streams that pass between the various sections.

Unlike the conventional, low-temperature, dry-gas cleaning diagram, in Figure 4.1, Figure 5.1 has no Low-temperature Cooling Section and the gas is maintained above its dew-point temperature – this is designated "humid-gas" cleaning. Thus, there is no large recycle water stream sent to the slurry preparation section, no sour-water gas stream sent to Sulfur Recovery, and no halide-salt disposal product appears. Also, fuel gas humidification is not needed. Sulfur Recovery tail gas is recycled to the

Desulfurization Section rather than to the Gasification Section as it is with conventional gas cleaning, and a small stream of clean gas is sent to the Sulfur Recovery Section. Mercury Removal follows directly after desulfurization, and sorbents are fed to the Desulfurization and Mercury Removal sections, with associated sorbent wastes withdrawn from each of these sections.

Detailed material & energy balances have been developed for the several sections that relate directly to gas cleaning and its impacts on the power plant performance: Gasification , Desulfurization, Sulfur Recovery, and the Power Section.

The major functions of each gas cleaning-related sections are:

Novel Gas Cleaning Gasification Section (Figure 5.2):

- prepare coal slurry
- accept recycled slag
- gasify coal slurry
- cool raw gas, generating saturated, HP-steam
- cool and separate slag from water for disposal

Fuel Gas Cleaning Section (Figure 5.3):

- remove raw gas particulate (slag) and recycle to Gasification Section
- remove raw gas halide
- accept tail gas recycle from Sulfur Recovery Section
- desulfurize gas
- produce suitable acid gas
- reheat cleaned fuel gas
- remove mercury (once-through or regenerative sorbent systems)
- split off clean gas stream for compression as soot blower gas
- split off clean gas stream for Sulfur Recovery Section reductant

Sulfur Recovery Section (Figure 5.4):

- acid gas expansion and power recovery
- acid gas partial reduction to desired H_2S-SO_2 gas mixture
- elemental sulfur production
- tail gas recycle to Desulfurization Section
- condensate recycle to Gasification Section
- IP-steam and LP-steam production

Power Section (Figure 5.5):

- air compression for air separation and fuel gas combustion
- air separation to generate gasifier oxidant, and nitrogen streams
- low-purity nitrogen stream humidification and mixing with clean fuel gas
- fuel gas combustion for low-NOx production and expansion for power generation
- gas turbine exhaust gas heat recovery steam generation
- steam expansion for power generation
- circulate BFW to Gasification Section and Desulfurization Section

5.1 FATE OF CONTAMINANTS WITH NOVEL GAS CLEANING TECHNOLOGY

Coal contains significant content of a large number of trace elements, including all of those listing in Tables 3.2 and 3.3, with their associated fuel gas cleaning requirements. To estimate what content these trace elements might have in the gas, and in what forms and phases (vapor, liquid, or solid), the NASA-Lewis Chemical Equilibrium Program was utilized (McBride and Gordon, 1996). Average values of Eastern-US coal trace element content were input, along with the relative input of water and oxidant, and equilibrium gas compositions were generated over the range of gas cleaning temperatures representative of the conditions seen in both conventional gas cleaning and Novel Gas Cleaning technologies. With the conventional, low-temperature, dry-gas cleaning technology, it is well known that many of the gas-phase contaminants are condensed out of the raw gas and either accumulate on process equipment, such as heat exchangers, or are trapped in process condensate streams, resulting in condensate treatment requirements and water discharge issues. In this assessment, the key trace element contents in the gas were followed from the raw gas hot outlet of the gasifier, through the various cleaning stage temperatures, all the way to the turbine combustor inlet.

Table 5.1 lists the results, showing what compound-forms of each elements might be present, where condensed forms of these elements might be removed in the process, what forms might reach the gas turbine in the clean fuel gas, and what content they might have at the conditions of the lowest-temperature section, the Mercury Removal Section, and on to the turbine combustors. Only Hg, and Ni and Fe in carbonyl forms are of concern. It is expected that 90-95% mercury removal, in the form of elemental mercury, will be required by the mercury removal section. It is possible that some nickel removal, in the form of nickel carbonyl, might also result in the mercury removal stage.

It is estimated that Ni-carbonyls will not form above about 480°C (900°F), and Fe-carbonyls above about 220°C (400°F), and conversely, once formed they will decompose when raised above these temperatures. Potential Ni and Fe sources are the coal ash constituents and the process equipment and piping. In the Novel Gas Cleaning process, in contract to conventional gas cleaning technology, the coal ash constituents are removed from the gas at temperatures above those where metal carbonyls can form, so this source is eliminated. Also in the Novel Gas Cleaning process, some Ni-carbonyls could form in the lowest temperature cleaning stages on contact with Ni-containing equipment and piping, but these Ni-carbonyls will decompose in subsequent reheat steps, protecting the turbine from damage. The amount of nickel carbonyl that will form in the actual process is uncertain, but it is likely that much less will form at the Novel Gas Cleaning conditions than will form at the conventional gas cleaning conditions. It is also very likely that no iron carbonyls will form when using the Novel Gas Cleaning process.

The other trace element forms listed in Tables 3.2 and 3.3 are condensed out in the gasifier slag, in the halide filter-reactor, in the bulk sulfur removal system, in the polishing sulfur removal filter-rector or in the mercury removal system. As and Se are the only other forms prevalent in the clean fuel gas and are not currently regulated. Further, specific removal steps are not needed.

As part of the process requirements for the evaluation, the final disposition of the contaminants captured and the sorbents fed in the Novel Gas Cleaning Process are also specified. The captured contaminant's final dispositions are:

- sulfur: converted to elemental sulfur by-product,
- halides: tied up as dry solid salts with halide sorbent as non-hazardous disposal product,
- fine char/slag particulate: recycled to gasifier and incorporated into gasifier slag,
- ammonia: primarily destroyed in the staged, turbine combustors, with some conversion to NOx,
- mercury: contained in once-through sorbent,
- nickel carbonyl: if formed, is likely to plate out on clean fuel gas reheat exchangers.

The gas cleaning sorbents are fed as relatively small streams to the system and their final dispositions are:

- halide removal sorbent: once-through sorbent disposal as non-hazardous waste,
- bulk sulfur removal sorbent: regenerative sorbent, with waste fed to gasifier for slagging, or disposed as non-hazardous waste,
- polishing sulfur removal sorbent: once-through or regenerative sorbent, with waste fed to gasifier for slagging, or disposed as non-hazardous waste,
- mercury removal adsorbent: once-through sorbent disposed as hazardous waste.

Table 5.1 - Trace Component Fates in IGCC with Novel Gas Cleaning

	Major forms existing at 220-260°C (400-500°F)	Removal of condensed forms	Forms in clean fuel gas to turbine	Equilibrium in gas at 220-260°C (400-500°F (ppbw)
As	As_4, AsCl, AsN, AsH_3	None	As_4, AsCl, AsN, AsH_3	20
Hg	Hg	None	Hg	5
Se	Se_2, SeO, SeH, SeH_2, PbSe	None (possible $NiSe_{1.05}$ (S) in bulk sulfur removal system)	Se_2, SeO, SeH, SeH_2	900
Ba	$BaCl_2$, BaF_2, $Ba(OH)_2$, BaS(CR)	$BaCl_2$, BaF_2, BaO, BaS in gasifier slag, char/halide filter, and bulk sulfur removal	Many possible	$< 10^{-12}$
Ca	$CaCl_2$, CaF_2	$CaCl_2$ in char/halide filter, bulk sulfur removal, polishing sulfur removal	$CaCl_2$, CaF_2	$< 10^{-12}$
Fe	FeS, Fe, $FeCl_2$, $Fe(OH)_2$, $Fe(CO)_5$, FeS(L)	With gasifier slag and slag/halide filter	$Fe(CO)_5$	10
K	KBr, K_2Br_2, K_2CO_3, KS, K_2S, K, KCN, KCl, KF, K_2Cl_2, K_2F_2, KH, KOH, NaK	KCl and KBr liquids and solids in bulk sulfur removal and polishing sulfur removal	Many possible	$< 10^{-12}$
Li	LiCl, LiF, LiBr, Li, LiH, LiOH	LiCl, LiF in char/halide filter, bulk sulfur removal, polishing sulfur removal	Many possible	$< 10^{-12}$
Mn	MnBr, MnCl, MnS, Mn	MnS, MnC_2 in gasifier slag and char/halide removal filter	Many possible	$< 10^{-12}$
Na	Na_2Br_2, NaBr, NaK, NaS, NaCN, NaCL, NaF, Na_2, Na_2Cl_2, Na_2F_2, NaS, NaSH, NaH, NaOH	NaOH, NaCl, NaF, Na_2CO_3, NaCN in char/halide filter, bulk sulfur removal, polishing sulfur removal	Many possible	$< 10^{-12}$
Ni	$Ni(CO)_4$, Ni, NiS, Ni_3S_2(L), NiH, $Ni(OH)_2$, NiCl,	Ni_3S_2 in gasifier slag, char/halide filter, bulk sulfur removal	$Ni(CO)_4$	1000
P	HPO, P_2, PH_3, PO, PS, P_2O_3, $Ca_2P_2O_7$(L), $PSCl_3$, PCl_3, $PFCl_2$, PF_3	H_3PO_4, $Ca_2P_2O_7$ in gasifier slag, char/halide filter, bulk sulfur removal	Many possible	$<10^{-12}$
Pb	PbSe, Pb, PbCl, PbS, PbH, PbBr, PbO	PbS in char/halide filter, bulk sulfur removal	PbS, PbCl, PbBr	$<10^{-12}$
V	VCl_2, $VOCl_3$, VCl_4, VO_2	V_2O_3 in slag removal, char/halide filter, bulk sulfur removal	Many possible	$<10^{-12}$
Zn	ZnO, ZnS, Zn, ZnCl, $ZnCl_2$, ZnH	ZnS in char/halide filter, bulk sulfur removal	Zn, $ZnCl_2$	$<10^{-12}$

5.2 IGCC WITH NOVEL GAS CLEANING TO MEET CURRENT STANDARDS

The IGCC power plant with the Filter-Reactor Novel Gas Cleaning technology must meet:

- SOx: 99% coal sulfur removal "net" for entire power plant,
- NOx: 15 ppmv (corrected to 15% oxygen, dry) at the plant stack,
- Particulate: 0.1 ppmw in the fuel gas,
- Mercury: 90% coal mercury removal,
- Power island contaminants:
    - halides: 5 ppmv in the fuel gas (after humidification, before nitrogen dilution)

- volatile metals (Ni, Fe,): formation of metal carbonyls are unlikely in the process
- particulate: 0.1 ppmw in the fuel gas.

This control is projected to be achieved in the Novel Gas Cleaning process steps described.

Gasification Section

Figure 5.2 shows the process flow diagram constructed for the Gasification Section using the Novel Gas Cleaning Process, and includes designation of the Coal Receiving and Handling System and the Slurry Preparation System. Table 5.2 lists characteristics of major streams in this section. The process diagram is very similar to the Gasification Section process flow diagram for the conventional, low-temperature gas cleaning situation, differing primarily in the fact that no tail gas is recycled to the gasifier, and little process condensate is available (only a small amount is generated during the soot blower gas cooling and within the Sulfur Recovery Section). Thus, the slurry preparation system uses mostly fresh makeup water. Oxidant from the Power Section's Air Separation Unit combines with the coal slurry to generate high-temperature, raw gas and slag streams. The raw gas flow at the exit of the Convective Cooler (Item 7) has a heat content of 539 MW(t) (1,839 x 10^6 Btu/hr) (LHV) and heating value of about 7.82 MJ/Nm^3 (199 Btu/scf), and includes about 9,979 kg/hr (22,000 lb/hr) of recycled, clean gas used as soot blower gas for the raw gas heat exchangers.

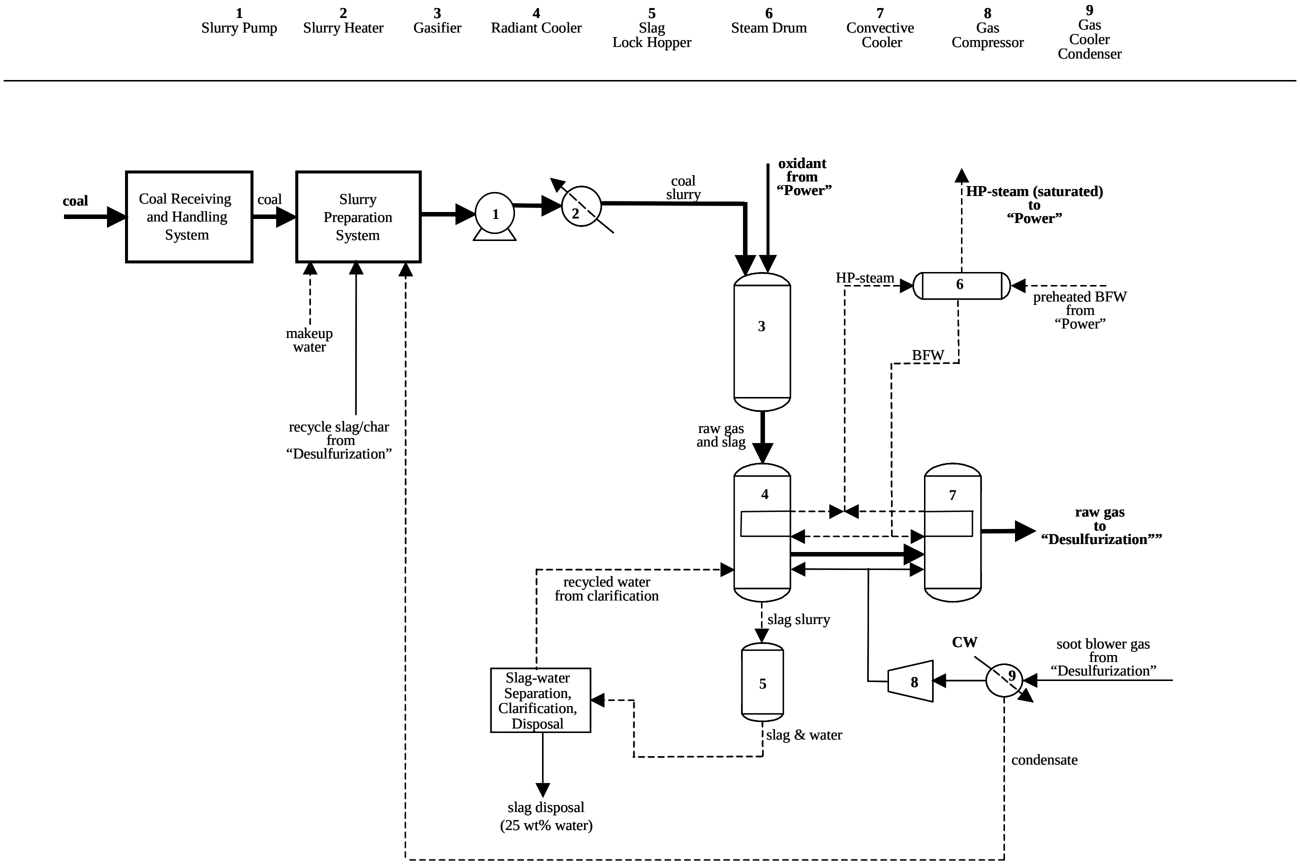


Figure 5.2 - Novel Gas Cleaning Gasification Section

The raw gas is cooled in a radiant cooler, raising saturated, high-pressure (HP) steam, and cooling the gas to about 1500ºF to solidify slag particles before cooling the gas further in a convective cooler to generate additional saturated HP-steam.

Table 5.2 – Stream Characteristics for Gasification Section - Current Standards

Stream name	Coal feed	Total slurry water feed	Gasifier oxidant	Raw fuel gas	Slag	HP-steam
Molar flow, kmole/hr	8,810	2,429	2,857	11,068	181	14,050
Mass flow, kg/hr	98,847	43,760	91,026	231,900	7,949	253,105
Volumetric flow, m^3/hr	122	45	2,343	31,459	10	4,652
Temperature, °C	26	29	81	593	49	318
Pressure, kPa	101	110	3585	2551	110.	10,583
Enthalpy MJ/hr	-1.25E+05	-6.94E+05	4,221	-1.27E+06	-36,210	-3.35E+06
Molecular wt	11.2	18.0	31.9	21.0	43.8	18.0

The raw gas exits the gasifier at about 1407ºC (2565ºF) and 2758 kPa (400 psia), and at 593ºC (1100ºF) from the Convective Cooler, with the estimated composition listed in Table 5.3, not including entrained slag.

Table 5.3 - Raw Gas Composition – Novel Gas Cleaning with Current Standards

	Major constituents (vol%)
H_2	25.46
CH_4	0.30
CO	40.77
CO_2	9.73
H_2O	20.59
N_2	1.93
Ar	0.14
Total	98.92
	Major contaminants (ppmv)
H_2S	8,611
COS	634
CS_2	0.6
S_X	7
SO_2	3
NH_3	695
HCN	20
HCl	434
Hg (ppbv)	3

Fuel Gas Cleaning Section

Figure 5.3 shows the process flow diagram for the Fuel Gas Cleaning Section. Table 5.4 lists characteristics of major streams in the Fuel Gas Cleaning Section. The raw gas from the Gasification Section is first pre-cleaned of entrained slag particulate using a conventional cyclone (Item 1). The sequence of processing steps is described below.

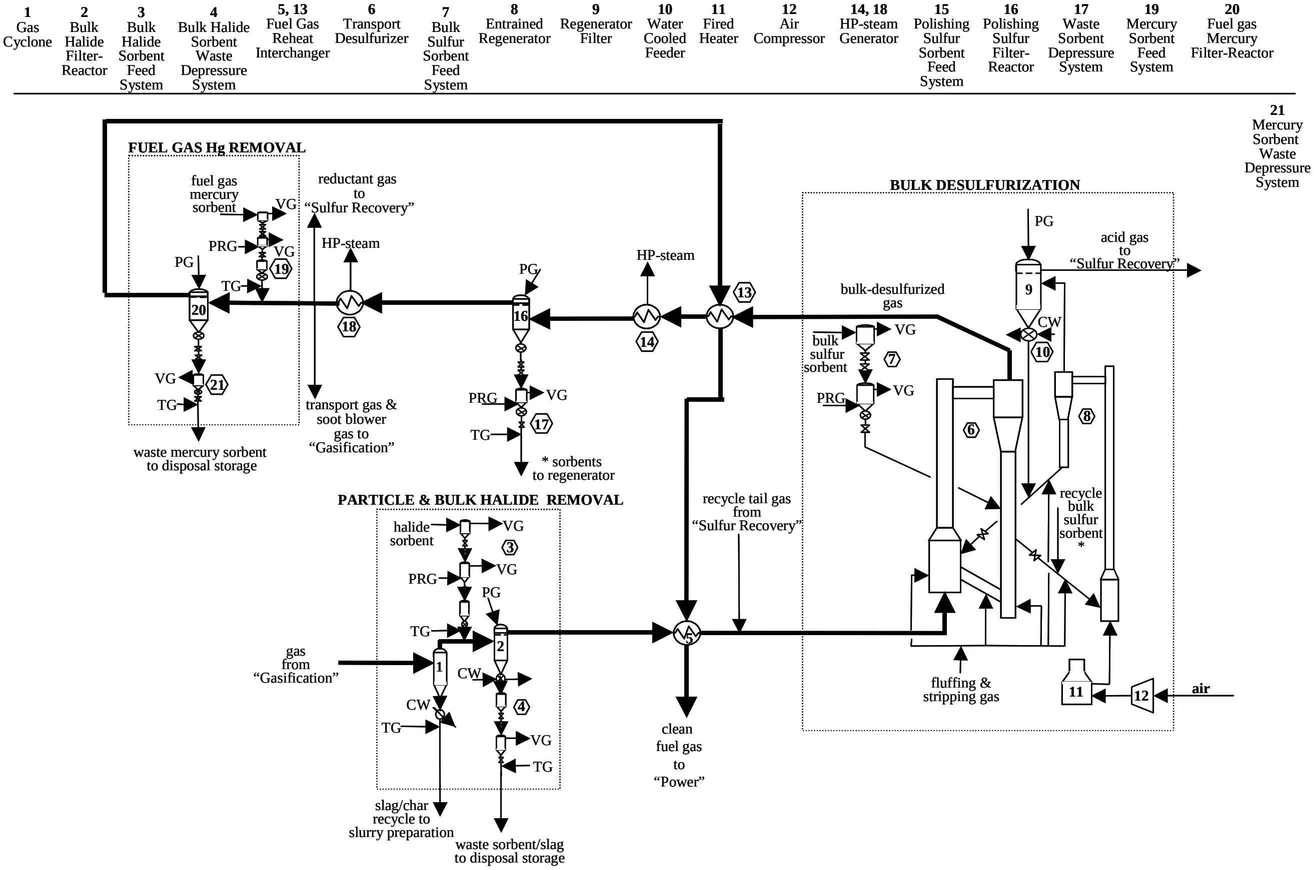


Figure 5.3 – Fuel Gas Cleaning Section - Current Standards

Table 5.4 – Stream Characteristics for Fuel Gas Cleaning Section – Current Standards

Stream name	Gas to cleanup	HCl sorbent feed	HCl sorbent waste	Desulfurized gas	Regenerator acid gas	Air to regenerator	Hg sorbent feed	Reheated fuel gas
Molar flow, kmole/hr	11,069	26	24	12,311	749	770	0.1	11,490
Mass flow, kg/hr	231,900	2,019	1,730	267,483	24,840	22,210	6.8	249,664
Volumetric flow, m^3/hr	31,460	0.9	1.8	28,972	2,752	18,360	0	34,189
Temperature, °C	593	27	79	372	742	15	27	507
Pressure, kPa	2551	2758	2424	2290	2317	100	2482	2193
Enthalpy, MJ/hr	-1.27E+06	-20326	-13404	-1.44E+06	-15610	-2184.1	-34.627	-1.30E+06
Molecular wt	21	77.8	72.5	21.7	33.1	28.9	60.1	21.7

Halide filter-reactor (Item 2):

A ceramic barrier filter is operated at about 593°C (1100°F) to remove the remaining solidified slag and char from the raw gas. Halide sorbent, -325 mesh particles of a cheap, once-through, sodium-based mineral, is fed volumetrically from a lock-hopper system (Item 3) and is mixed into the raw gas and collected in the filter-reactor. The sodium mineral reacts with the raw gas halide species, primarily HCl, while the particles are in-flight and while they reside within the filter cake. It is estimated that more than 99% of the halides will be removed, resulting in a halide (mostly HCl) content in the fuel gas less than 5 ppmv. The halide sorbent used in the evaluation is nacholite (80 wt% sodium bicarbonate, 20 wt% inert solids), and the molar feed ratio of sodium/HCl is assumed to be 4.0 times stoichiometric. The captured slag-char, and sorbent product is drained from the halide filter-reactor, is cooled to 79°C (175°F) in a water-cooled screw conveyor (Item 4), and is depressurized and stored for disposal as a non-hazardous material. This filter-reactor provides one additional function, with the alloy-metal internals, and possibly, additional alloy surfaces installed in the vessel head, being catalytically-active for ammonia decomposition.

It is estimated that at the selected operating temperature, about 75% of the ammonia will be decomposed to nitrogen and hydrogen. A Pulse Gas Control System accepts HP-nitrogen from the Power Section ASU and distributes cleaning pulses to the filter-reactor, as well as the other barrier filters (Items 9, 16, and 20) in this section.

Gas heat interchanger (Item 5):

The gas is cooled in a heat interchanger to 482°C (900°F). This gas is then mixed with recycled tail gas from the downstream, sulfur recovery process, a flow of about 10% of the gas stream.

Bulk desulfurization:

The gas now enters the “humid-gas” bulk-desulfurization process where its total sulfur content is reduced to less than 50 ppmv, about a 99.5% reduction of H_2S, COS, CS_2, Sx, and SO_2 contained in the gas, with significant hydrolysis of CS_2, Sx and SO_2 to H_2S also expected. This meets the entire desulfurization needs for the Current Standards case, so long as no other sulfur release points exist in the power plant.

Any, of a number of bulk-desulfurization processes that are under development using a regenerative desulfurization sorbent, effective above the gas dew point, could be applied. In this evaluation, the well-developed, zinc titanate-based, transport reactor desulfurization process is applied. This selection results in the need for about a 482°C (900°F) inlet temperature. The zinc titanate sorbent is assumed to have a Zn/Ti mole ratio of 1.0, and to operate with a net, sorbent makeup stoichiometric molar feed ratio of 0.004 Zn/S, 45 kg/hr (98 lb/hr) provided by the sorbent feed system, Item 7.

The gas passes through a transport reactor (Item 6) of circulating zinc titanate sorbent, producing a bulk-desulfurized gas having total sulfur content of about 40 ppmv and containing some entrained sorbent particles that escape the transport reactor disengaging section. The partially-sulfided sorbent particles circulating to the desulfurizer leg have a molar ratio for ZnO/S of about 174. The sulfided sorbent particles circulate to the parallel, entrained regenerator vessel (Item 8) where air contacting generates an SO_2 acid gas and regenerated zinc titanate sorbent. Compressed air is provided by compressor Item 12, and a fired heater (Item 11) is also provided for preheating the regenerator air. Nitrogen fluffing gas and nitrogen purging of the transport legs between the gasifier and regenerator are used, this compressed nitrogen coming from the Power Section. The regenerator acid gas, at about 1350°F, passes through a relatively small barrier filter (Item 9) to separate its entrained sorbent particles. The entrained sorbent particles captured in this filter are cooled and drained back to the standleg of sorbent flowing back to the desulfurizer vessel, or may be drained into the bulk desulfurized fuel gas exiting the vessel.

The bulk-desulfurized gas leaves the process at about 549°C (1020°F) carrying all of the sorbent lost by attrition and elutriation from the bulk-desulfurization process. The bulk desulfurized gas is at 552°C (1026°F) and 2365 kPa (343 psia), and its composition is listing in Table 5.5. Note that it contains significant particulate in the form of zinc-titanate sorbent particles. The relatively high nitrogen content in the gas results largely from the recycled sulfur recovery tail gas. The acid gas generated has the composition listed in Table 5.6.

Table 5.5 - Bulk Desulfurized Gas Composition - Current Standards

	Major constituents (vol%)
H_2	22.94
CH_4	0.28
CO	36.68
CO_2	10.27
H_2O	19.52
N_2	10.10
Ar	0.19
Total	99.98
	Major contaminants (ppmv)
H_2S	39.98
COS	2.85
HCl	3.5
NH_3	158
HCN	19
Hg (ppbv)	2.5
particulate (ppmw)	265

Table 5.6 - Acid Gas Composition – Novel Gas Cleaning with Current Standards

	Major constituents (vol%)
N_2	83.77
Ar	0.96
CO_2	0.03
H_2O	1.03
SO_2	14.20
Total	99.99

Gas cooling and barrier filter:

The bulk desulfurized gas is cooled in two process heat exchangers (13 and 18) to a temperature of no lower than 204°C (400°F), suitable for mercury removal in the Mercury Removal Section. The first is a recuperative heat interchanger (Item 13) used to reheat the clean fuel gas from 204°C (400°F) to 404°C (760°F) and passes the gas and entrained sorbent particles into a barrier filter-reactor (Item 16). The entrained sorbent is collected on the filter elements, allowing additional sulfur removal. The sorbent particles may be recycled to the Bulk Desulfurizer regenerator, disposed of, or sent to the gasifier to be incorporated into the slag. The second is a BFW-cooled heat exchanger that completes the fuel gas cooling and preheats BFW. The clean fuel gas then passes to recuperative heat interchanger (Item 5) where it is reheated to 507°C (945°F).

Soot-blower gas and Sulfur Recovery fuel gas:

A small portion of the bulk-desulfurized gas is separated, cooled and compressed at this point for use as soot-blower gas in the slagging heat exchangers. About 2.9% of this gas stream is separated at this point to be used in the Sulfur Recovery process.

Mercury sorbent feed system:

Two mercury removal process schemes are considered, since this aspect of the plant is uncertain at this time: 1) once-through operation with powdered mercury sorbent injection into a filter-reactor, and

2) regenerative operation with powdered mercury sorbent injection into a filter-reactor. Only the once-through process is shown in Figure 5.3.

A TDA sorbent for mercury removal, and identification of its associated best operating conditions, have been established in the PDU test program, but it is assumed for the process evaluation that potential adsorbents (e.g., a zeolite) or sorbents operable at greater than 204°C (400°F) exist. Specific operating conditions are based on the mercury sorbent work by TDA Research, Inc. (Alptekin et al., 2003) and the PDU testing in this program. Based on this background, a mercury sorbent might effectively adsorb elemental mercury in syngas at temperatures as high as 260°C (500°F), with a gas residence time of about 0.1 second, and achieve a sorbent uptake of about 0.04 wt% (grams mercury per gram sorbent). The hypothetical sorbent could be regenerated by heating it to 288-299°C (550-570°F) in an inert gas if regenerative operation is desired.

The mercury sorbent is injected into the gas by feed system (Item 19). The assumed feed rate is 6.8 kg/hr (15 lb/hr), which represents a mass ratio of adsorbent to mercury vapor of greater than 1000.

Mercury removal filter-reactor:

The cooled gas passes into a ceramic, or metal candle barrier filter (Item 20) to conduct mercury removal. Optionally, if the barrier filter (Item 16) was eliminated, the mercury filter-reactor would also collect the bulk desulfurization sorbent contained in the gas, and any equipment corrosion particulate that might be present in the gas from upstream sources. The mercury sorbent and other particulate is drained from the filter and is depressurized (Item 21) to be stored for disposal, probably as a hazardous solid waste, or regenerated if only mercury sorbent is present.

Regenerative Operation of Mercury Sorbent:

If regenerative sorbent operation where used, the mercury sorbent drained from the filter would be contacted with steam or warmed nitrogen in an entrained reactor segment, heating the sorbent to about 288°C (550°F) and driving off the captured mercury. This product stream would be separated in a small barrier filter, and the separated sorbent particles would be pneumatically conveyed back to the mercury removal filter-reactor. The water vapor and mercury vapor stream from the filter would be cooled and condensed, and the very small amount of mercury separated from the liquid water would be stored as a by-product. Waste sorbent produced in the process would be low in mercury content and may be disposed directly as a non-hazardous solid waste, or may be fed to the gasifier to be incorporated into the plant's slag by-product.

The fates of contaminants in the Gas Cleaning Section are summarized in Table 5.7.

Table 5.7 – Fate of Contaminants in Fuel Gas Cleaning Section – Novel Gas Cleaning with Current Standards

Contaminant	Removal (% of inlet to Section)	Contaminant conversions
sulfur species	99.54	Partial hydrolysis Combustion to SOx Sorbent fixation
halides	99	Sorbent fixation
ammonia	75	Catalytic partial decomposition to nitrogen
hydrogen cyanide	0	----
mercury	90	Sorbent fixation

Sulfur Recovery Section

Figure 5.4 shows the process flow diagram for the Sulfur Recovery Section of the IGCC power plant. Table 5.8 lists characteristics of major process streams. The acid gas from the bulk desulfurizer regenerator contains about 14 vol% SO_2, with negligible oxygen content, and the remaining components being largely nitrogen with a little CO_2. This acid gas is first expanded (Item 1) to about 193 kPa (28 psia), cooling the gas to about 353°C (668°F) and generating a small amount of electrical power. Modern Claus technology allows relatively low H_2S content, in the range of 5 – 10 vol%, to be efficiently and economically processed to recover sulfur (Bruijn et al., 2003).

The acid gas is then mixed with a portion of bulk desulfurized gas and is catalytically reacted to hydrogenate (Item 2) an appropriate portion of the acid gas SO_2 to H_2S for the Claus reaction. This conversion requires a substantial fraction (about 2.9%) of the desulfurized gas and results in some degradation in the overall performance of the power plant. The gas is then cooled in a boiler (Item 3) to generate IP-steam, followed by a boiler-sulfur condenser (Item 4) generating LP-steam. Any elemental sulfur contained in the product acid gas is separated before the gas enters the first Claus reactor (Item 5). The remaining steps of the process are very similar to those described for the conventional gas cleaning sulfur recovery process: three stages of gas preheat, Claus reactors and sulfur condensers. If a sulfur product other than elemental sulfur were selected as the final disposition for the captured sulfur, such as $CaSO_4$ or sulfuric acid, the Novel Gas Clean process would show performance advantages over the conventional gas cleaning technology even greater than shown in this evaluation (Wasaka, 2003).

The sulfur recovery process recovers about 95.7% of the sulfur content of the acid gas. The collected sulfur streams are combined, and stored for treatment and marketing as a by-product. The tail gas contains a considerable content of sulfur species (H_2S and SO_2), and the only way the power plant can achieve its overall 99.5% sulfur removal goal is for this tail gas to be recompressed and recycled to the bulk desulfurizer. After cooling, compression and condensate removal, the tail gas recycled to the bulk desulfurizer has the composition reported in Table 5.9.

Table 5.8 – Stream Characteristics for Sulfur Recovery Section – Current Standards

Stream name	Acid Gas to Sulfur Recovery	Clean fuel gas	Sulfur product	Tail gas recycle
Molar flow, kmole/hr	749	361	113	858
Mass flow, kg/hr	24,840	7,847	3,466	26,758
Volumetric flow, m^3/hr	2.752	650	2.0	1420
Temperature, °C	742	204	137	217
Pressure, kPa	2317	2207	163	2482
Enthalpy, MJ/hr	-15,610	-44,358	-12,557	-64,081
Molecular wt	33.1	21.7	30.7	31.2

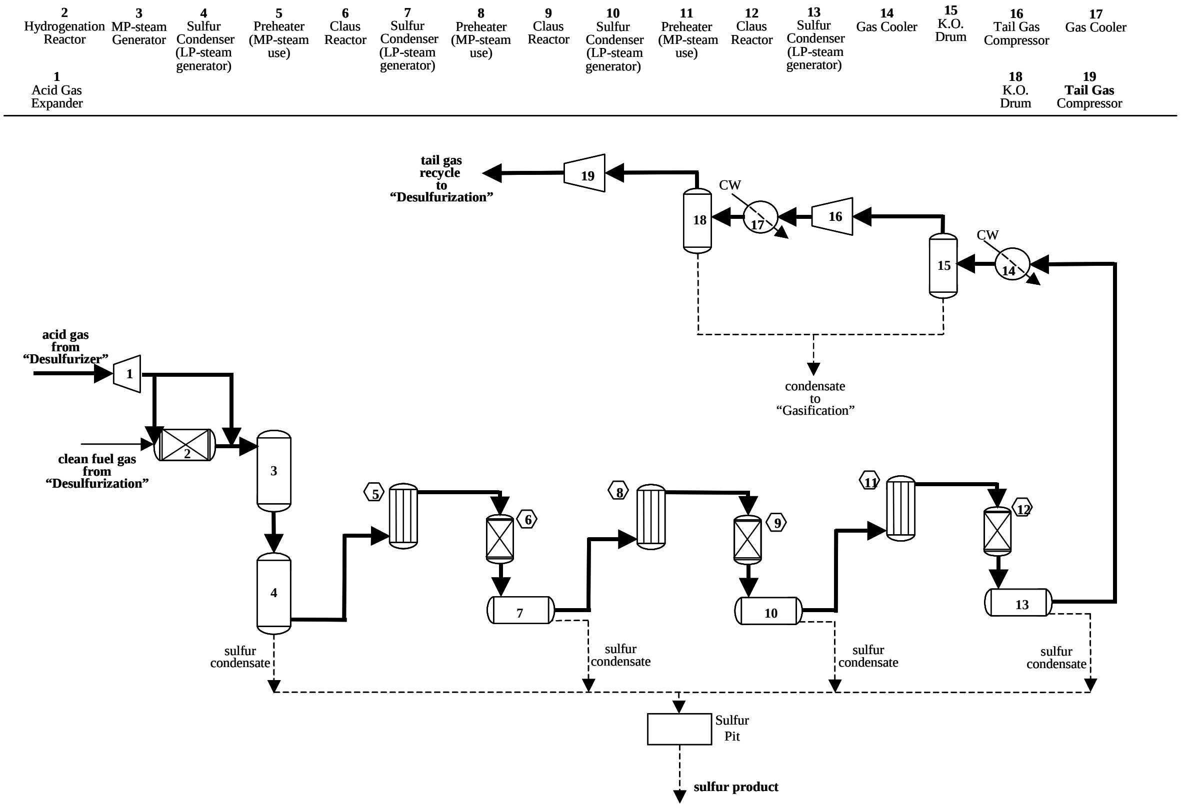


Figure 5.4 - Sulfur Recovery Section – Novel Gas Cleaning

Table 5.9 - Recycle Tail Gas Composition – Novel Gas Cleaning with Current Standards

	Major constituents (vol%)
H_2	0.12
CH_4	0.12
CO	0.17
CO_2	19.63
H_2O	1.09
N_2	77.43
Ar	0.91
Total	99.47
	Major contaminants (ppmv)
H_2S	3665
SO_2	1648
COS	1
CS_2	0
NH_3	46
HCN	8

The fate of the contaminants within the Sulfur Recovery section are listed in Table 5.10.

Table 5.10 – Fate of Contaminants in Sulfur Recovery Section – Novel Gas Cleaning with Current Standards

Contaminant	Removal (% of inlet to Section)	Contaminant conversions
sulfur species	95.72	Claus conversion to elemental sulfur Hydrolysis to reduced forms
halides	NA	----
ammonia	30.0	Furnace decomposition
hydrogen cyanide	NA	----
mercury	NA	----

Power Section

The Power Section process flow diagram is shown in Figure 5.5. Table 5.11 lists characteristics of major streams. An oxygen stream with 95% purity, is generated by conventional, pressurized, cryogenic air separation (ASU). A relatively low-purity N_2 stream is also produced and compressed (Item 21) that is used for clean fuel gas dilution. A smaller stream of high-purity N_2 (99.9%) is also produced and compressed (Item 22) that is used in the gas cleaning process for solids pressurization, stripping, purging, pneumatic transport, and filter pulse cleaning. Low-purity nitrogen is humidified (Item 25) to about 15 vol% water vapor using low-grade heat sources (3, 23), and the nitrogen stream is mixed with the clean fuel gas before the mixture is distributed to the gas turbine combustors (Item 6).

The turbine combustors operate with an outlet temperature of about 1521°C (2770°F), and with the peak flame temperature of less than 1649°C (3000°F), the NOx emission is expected to be less than 15 ppmv (dry, corrected to 15% oxygen). These are special burners designed for the efficient combustion of low heating-value fuel gases with low NOx production. They are expected to use a staged combustion design that promotes the decomposition of ammonia with less than 5% ammonia conversion to NOx. The turbine expansion gas has a temperature of 619°C (1147°F). The expansion gas passes through the heat recovery steam generator (HRSG), generating a superheated, high-pressure steam flow of 370,810 kg/hr (817,500 lb/hr). The stack gas from the power plant has a temperature of 121°C (250°F) and a composition listed in Table 5.12.

Table 5.11 – Stream Characteristics for Power Section – Current Standards

Stream name	Air to gas turbine	Gasifier oxidant	Low-purity nitrogen	Makeup water	Fuel gas to gas turbine	Stack gas
Molar flow, kmole/hr	53,621	2,857	9,946	1,863	11,491	60,137
Mass flow, kg/hr	1,547,310	91,026	280,171	33,566	249,665	1,725,182
Volumetric flow, m^3/hr	1,279,105	2,343	31,298	34	34,189	1,944,040
Temperature, °C	15	81	27	15	507	121
Pressure, kPa	100	3585	793	2068	2,193	101
Enthalpy MJ/hr	-1.52E+05	4,221	101	-5.34E+05	-1.30E+06	-3.71E+06
Molecular wt	28.9	31.9	28.2	18.0	21.7	28.7

Table 5.12 - Stack Gas Composition – Novel Gas Cleaning with Current Standards

	Major constituents (vol%)
O_2	8.17
CO_2	9.04
H_2O	11.99
N_2	69.95
Ar	0.84
Total	99.99
	Major contaminants
SO_2 (ppmv)	8.2
NOx (ppmv)	15
Mercury (ppbv)	0.05
Halides (ppmv)	0.67

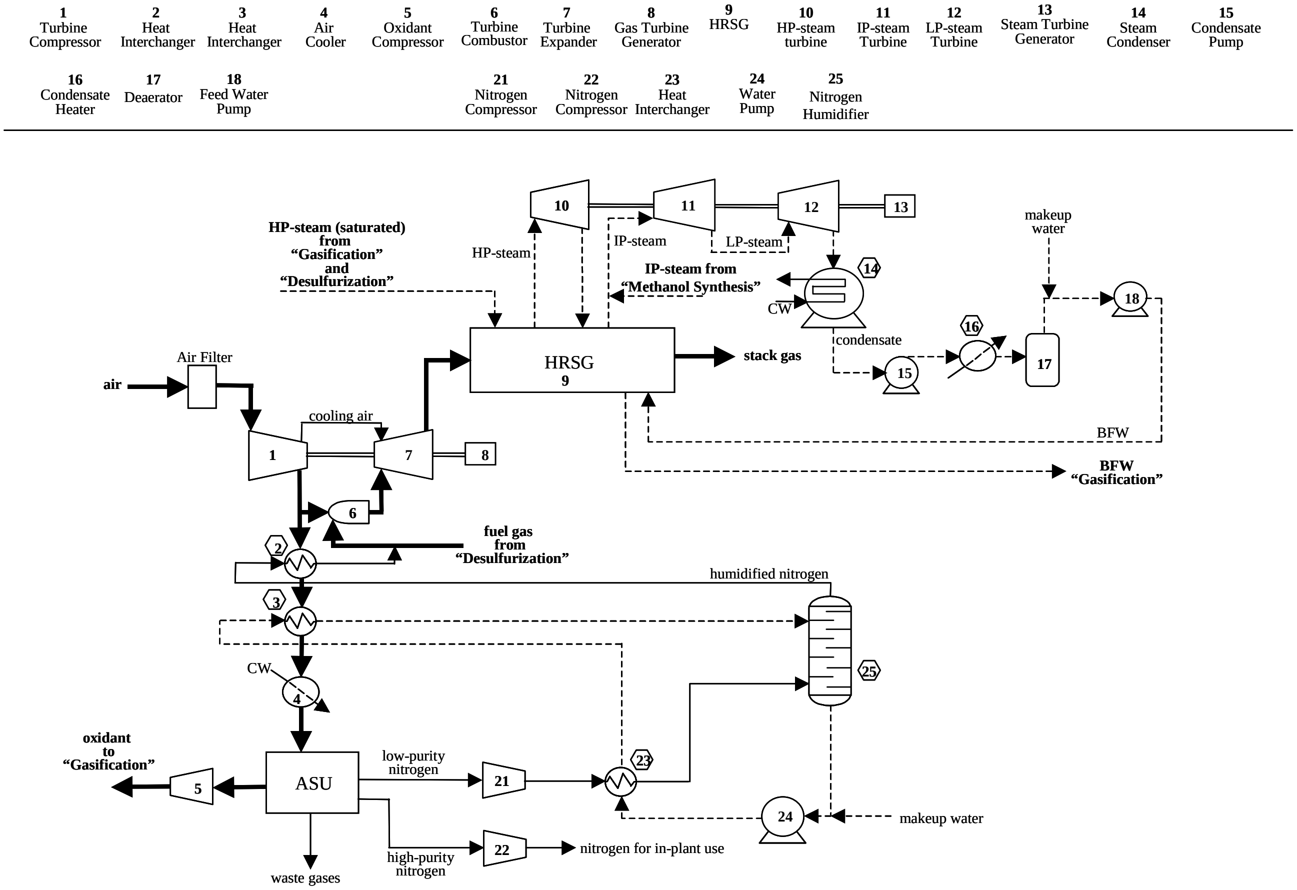


Figure 5.5 - Power Section

The fate of the contaminants within the Power section are listed in Table 5.13 .

Table 5.13 – Fate of Contaminants in Power Section – Novel Gas Cleaning - Current Standards

Contaminant	Removal (% of inlet to Section)	Contaminant form conversion
sulfur species	0	Oxidation to SOx
halides	NA	----
ammonia	0	Partial oxidation conversion to NOx
hydrogen cyanide	NA	----
mercury	0	Partial conversion to oxidized forms

5.3 IGCC WITH NOVEL GAS CLEANING TO MEET FUTURE STANDARDS

The IGCC power plants using the Novel Gas Cleaning technology to achieve Future Standards that approach the emissions performance of natural gas-fired power plants has the following targets:

- SOx: 99.98% coal sulfur removal "net" for entire power plant,
- NOx: 5 ppmv (corrected to 15% oxygen, dry) at the plant stack,
- particulate: 0.1 ppmw in the fuel gas,
- mercury: 95% coal mercury removal,

- Power Island contaminants:
    - halides: 5 ppmv in the fuel gas (after humidification, before nitrogen dilution)
    - metals (Ni, Fe): formation of metal carbonyls unlikely in the process
    - particulate: 0.1 ppmw in the fuel gas.

The gas cleaning system description for this IGCC application is almost the same as that just described for Novel Gas Cleaning for Current Standards, except for the additional of a Sulfur Polishing Filter-Reactor to the Desulfurization Section, and resulting changes to the clean fuel gas reheat temperatures.

Gasification Section

Figure 5.2 shows the process flow diagram constructed for the Gasification Section using the Novel Gas Cleaning process. The process diagram and the stream flows and conditions are identical to the Gasification Section process flow diagram for the Current Standards case.

Fuel Gas Cleaning Section

Figure 5.6 shows the process flow diagram for the Fuel Gas Cleaning Section. It is identical to Figure 5.3, for the Current Standards case, except that a Sulfur Polishing Filter-Reactor (Item 16) and Polishing Sorbent Feed System (Item 15), and Sorbent Waste Removal System (Item 17) have been inserted after the bulk desulfurizer for additional sulfur removal.

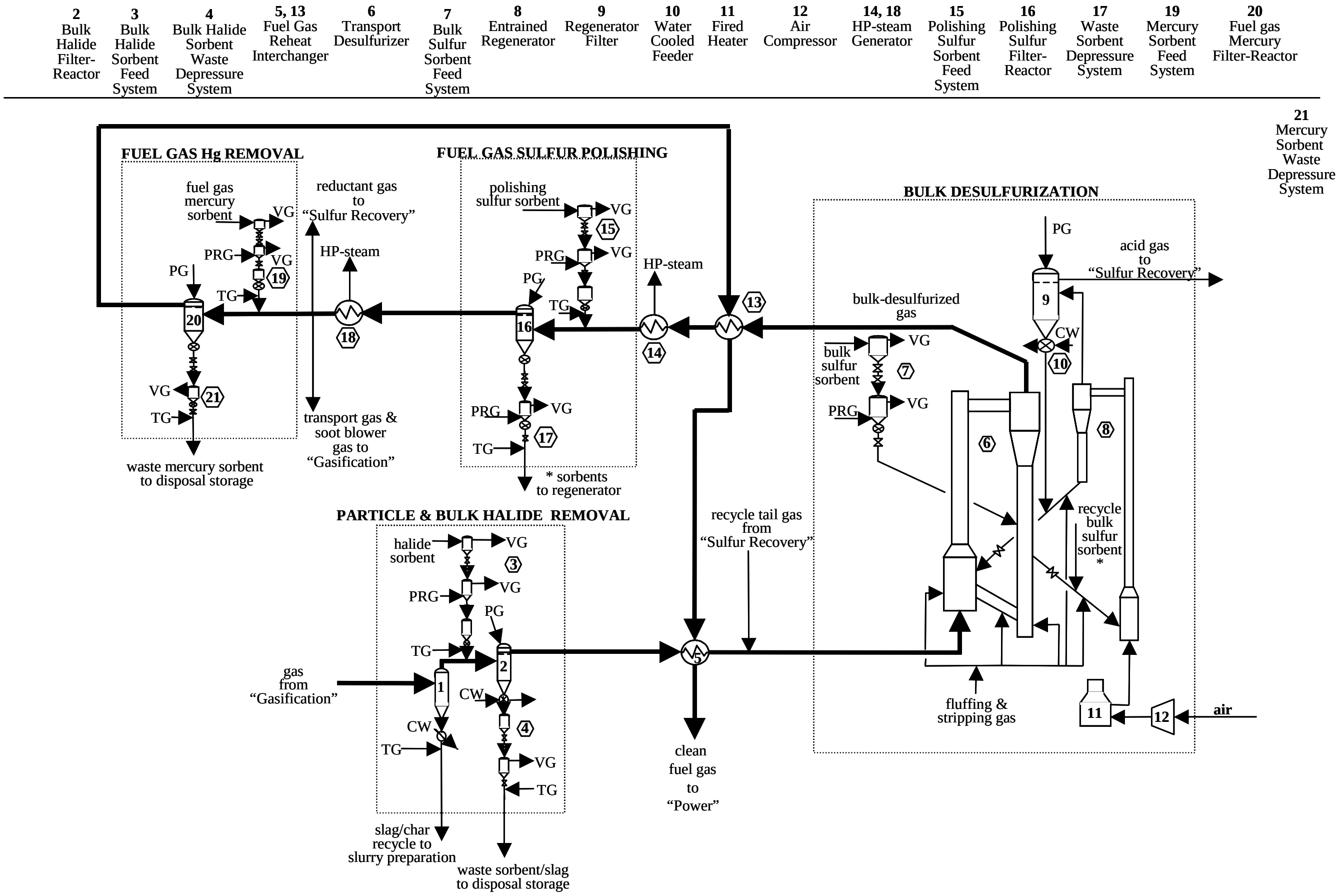


Figure 5.6 – Fuel Gas Cleaning Section for Novel Gas Cleaning – Future Standards

Gas heat interchanger (Item 5):

The gas is cooled in a recuperative heat interchanger to 482°C (900°F). This gas is then mixed with recycled tail gas from the downstream, sulfur recovery process, a flow of about 11% of the main gas stream.

Bulk desulfurization:

The gas now enters humid-gas, bulk-desulfurization process where its total sulfur content is reduced to less than 50 ppmv, about a 99.5% reduction of H_2S, COS, CS_2, Sx, and SO_2 contained in the gas, with significant hydrolysis of CS_2, Sx and SO_2 to H_2S also expected. The zinc titanate sorbent is assumed to have a Zn/Ti mole ratio of 1.0, and to operate with a net, sorbent makeup stoichiometric molar feed ratio of 0.0027 Zn/S provided by the sorbent feed system. The gas passes through a transport reactor (Item 6) of circulating zinc titanate sorbent, producing a bulk-desulfurized gas having total sulfur content of about 40 ppmv and containing some entrained sorbent particles that escape the transport reactor disengaging section. The partially-sulfided sorbent particles circulating in to the desulfurizer leg have a molar ratio for ZnO/S of about 219. The sulfided sorbent particles circulate to the parallel, entrained regenerator vessel (Item 8) where air contacting generates an SO_2 acid gas and regenerated zinc titanate sorbent. Compressed air is provided by compressor, and a fired heater (Item 11) is also provided for preheating the regenerator air. Nitrogen fluffing gas and nitrogen purging of the transport legs between the gasifier and regenerator are used, this compressed nitrogen coming from the Power Section. The regenerator acid gas, at about 741°C (1365°F), passes through a relatively small barrier filter (Item 9) to separate its entrained sorbent particles. The entrained sorbent particles captured in this filter are cooled and sent back to the standleg of sorbent flowing back to the desulfurizer vessel, or may be drained into the bulk desulfurized fuel gas exiting the vessel. The bulk-desulfurized gas leaves the process at about 1025°F carrying all of the sorbent lost by attrition and elutriation from the bulk-desulfurization process. The bulk desulfurized gas has a flow of 267,826 kg/hr (590,459 lb/hr), at 553°C (1027°F) and 2365 kPa (343 psia), and its composition is listing in Table 5.14. Note that it contains significant particulate in the form of zinc-titanate sorbent particles. The relatively high nitrogen content in the gas results largely from the sulfur recovery tail gas. The acid gas generated has the composition listed in Table 5.15. Its flow is 24,860 kg/hr (54,808 lb/hr) at 741°C (1365°F) and 2327 kPa (336 psia).

Sulfur Polishing filter-reactor:

Polishing sulfur sorbent particles, also zinc titanate-type, are injected (item 15) into the gas and, combined with the entrained sorbent particles from the bulk-desulfurization process, the mixture enters a filter-reactor (Item 16) and results in additional 96% sulfur removal down to a level of total sulfur less than 2 ppmv. The sorbent makeup rate uses a stoichiometric ratio of 0.2 Zn/S in the regenerative operation. The partially-sulfided sorbent particles carried with the gas have a molar ratio for ZnO/S of about 3.3. The filter separates the entrained bulk-sorbent particles and the polishing sorbent particles from the gas. The collected sorbent particulate is drained from the filter (Item 17) and is pneumatically fed back to the bulk desulfurization process regenerator. The small amount of waste sorbent ultimately drained from this system is either disposed directly or is fed to the gasifier to be incorporated into the plant slag by-product.

Gas cooling:

The bulk desulfurized gas is cooled in process heat exchangers (Item 13) to 900°F and in cooler Item 18 to a minimum temperature of about 400°F, suitable for mercury removal in the Mercury Removal Section. The Hg-cleaned fuel gas passes through heat interchangers (Item 13) and to reheat the clean fuel gas from 400°F to 761°F. Item 18 is a BFW-cooled heat exchanger that completes the gas cooling and preheats BFW. The clean fuel gas then passes to heat interchanger (Item 5) where it is reheated to 946°F.

Soot-blower gas is separated, cooled and compressed at this point for use as soot-blower gas in the slagging heat exchangers. About 2.9% of this gas stream is separated at this point to be used in the sulfur recovery process.

Mercury Removal:

The mercury removal process is similar to the previous description, but is designed and operated for 95% mercury removal. Two mercury removal process schemes almost identical to those with the Current Standards case are considered: 1) once-through operation with powdered mercury sorbent injection into a filter-reactor, and 2) regenerative operation with powdered mercury sorbent injection into a filter-reactor.

The mercury sorbent is injected into the gas by feed system 19. The assumed feed rate is 15 lb/hr, the same as was assumed in the Current Standards case for 90% mercury removal. The cooled gas passes into a ceramic, or metal candle filter-reactor (Item 20) to conduct mercury removal. This barrier filter is injected with a small flow of a high-temperature, mercury sorbent to remove 95% of the elemental mercury in the gas. The filter also collects any equipment-corrosion particulate that might be present in the gas from upstream sources, and the sorbent may also capture metal carbonyls, should they be generated. The mercury sorbent is drained from the filter and is depressurized (Item 17) to be disposal as a hazardous solid waste.

Table 5.14 - Bulk Desulfurized Gas Composition - Future Standards

	Major constituents (vol%)
H_2	22.93
CH_4	0.28
CO	36.67
CO_2	10.27
H_2O	19.51
N_2	10.10
Ar	0.19
Total	99.95
	Major contaminants (ppmv)
H_2S	39.96
COS	2.85
HCl	3.5
NH_3	158
HCN	19
Hg (ppbv)	2.5
particulate (ppmw)	1284

Table 5.15 - Acid Gas Composition – Novel Gas Cleaning for Future Standards

	Major constituents (vol%)
N_2	83.77
Ar	0.96
CO_2	0.03
H_2O	1.03
SO_2	14.20
Total	99.99

The polished fuel gas composition following mercury removal is listed in Table 5.16.

Table 5.16 - Polished Fuel Gas Composition – Novel Gas Cleaning for Future Standards

	Major constituents (vol%)
H_2	22.94
CH_4	0.28
CO	36.68
CO_2	10.27
H_2O	19.52
N_2	10.11
Ar	0.19
Total	99.99
	Major contaminants (ppmv)
H_2S	1.6
COS	0.1
HCl	3.5
NH_3	158
HCN	19
Hg (ppbv)	2.5
particulate (ppmw)	0.1

The fates of the contaminants estimated for the Fuel Gas leaning Section are listed in Table 5.17.

Table 5.17 – Fate of Contaminants in Fuel Gas Cleaning Section – Novel Gas Cleaning for Future Standards

Contaminant	Removal (% of inlet to Section)	Contaminant conversions
sulfur species	99.98	Partial hydrolysis Combustion to SOx Sorbent fixation
halides	99	Sorbent fixation
ammonia	75	Catalytic partial decomposition to nitrogen
hydrogen cyanide	0	----
mercury	95	Sorbent fixation

Comments on the Mercury Removal process:

The performance of the filter-reactors with injected sorbents have not yet been experimentally established, so the process evaluation is speculative. In particular, the type of mercury sorbent, the characteristics of the mercury removal process, and the performance of the mercury removal process are all highly speculative at this time. The evaluation identifies the process' acceptable range of operating conditions, required range of performance, and potentially acceptable operational modes:

- mercury removal should operate as hot as about 204-316°C (400-600°F), removing 90-95% of the mercury,

- the type of mercury sorbent has not been established, and a TDA sorbent has been used in this evaluation, and it could be either a once-through or a regenerative sorbent -- it is expected that it may be advantageous for it to be a regenerative adsorbent, but this is not a necessity for process feasibility,
- the mercury removal process should be a continuous process -- it is expected that a continuous process will have advantages over a batch process with respect to power plant availability and performance,
- the selected mercury sorbent must not result in the release of any contaminants, such as sulfur, to the cleaned fuel gas that will exceed the emission requirements,
- the mercury adsorbent, if regenerative, might be regenerated by heating it in an available, clean gas or vapor stream, such as nitrogen or steam, to a temperature of no greater than 343°C (650°F), with liquid mercury being subsequently condensed and separated,
- the mercury removal step provides the final, clean fuel gas that goes to the gas turbine combustors, and it should have the capability of also handling upstream equipment corrosion particulate removal,
- the minimum operating temperature for the mercury removal stage is about 204°C (400°F), based on vapor condensation -- if lower operating temperatures are desired, water vapor will be condensed from the fuel gas.

Sulfur Recovery Section

Figure 5.6, the process flow diagram for the Sulfur Recovery Section of the IGCC power plant, is almost identical for both the Current Standards and Future Standards cases. The acid gas from the bulk desulfurizer regenerator contains about 14 vol% SO_2, with very low oxygen content, and the remaining components being largely nitrogen with a little CO_2.

The sulfur recovery process recovers about 95.7% of the sulfur content of the acid gas. The collected sulfur streams are combined and the sulfur is stored for treatment and marketing as a by-product. The tail gas, at 29,247 kg/hr (64,478 lb/hr), contains a considerable content of sulfur species (H_2S and SO_2), and the only way the power plant can achieve its overall 99.85% sulfur removal goal is for this tail gas to be recompressed and recycled to the bulk desulfurizer. After cooling and compression and condensate removal, the tail gas recycled to the bulk desulfurizer has the composition reported in Table 5.18.

Table 5.18 - Recycle Tail Gas Composition – Novel Gas Cleaning for Future Standards

	Major constituents (vol%)
H_2	0.12
CH_4	0.12
CO	0.17
CO_2	19.63
H_2O	1.09
N_2	77.43
Ar	0.91
Total	99.47
	Major contaminants (ppmv)
H_2S	3675
SO_2	1648
COS	0
CS_2	0
NH_3	6
HCN	8

Power Section

The Power Section process flow diagram is the same as that shown for the Current Standards case in Figure 5.7. An oxygen stream at 91,026 kg/hr (200,679 lb/h)r, with 95% purity, is generated by conventional, pressurized, cryogenic air separation (ASU). A relatively low-purity N_2 stream is also produced that is used for clean fuel gas dilution. A smaller stream of high-purity N_2 (99.9%) is also produced that is used in the gas cleaning process for solids pressurization, stripping, purging, pneumatic transport, and filter pulse cleaning. Low-purity nitrogen is humidified to about 15 vol% water vapor using low-grade heat sources, and the nitrogen stream at 313,736 kg/hr (691,672 lb/hr) is mixed with the clean fuel gas before the mixture is distributed to the gas turbine combustors. The turbine combustors, advanced, catalytic, and/or diffusion flame burners that promote the decomposition of the remaining ammonia in the fuel gas with less than 5% conversion to NOx, operate with an outlet temperature of about 1521°C (2770°F), and with the peak flame temperature of less than 1649°C (3000°F), the NOx emission is expected to be less than 5 ppmv (dry, corrected to 15% oxygen).

The turbine expansion gas has a mass flow of 1,724,957 kg/hr (3,802,899 lb/hr) and a temperature of 619°C (1147°F). The expansion gas passes through the heat recovery steam generator (HRSG), generating a superheated, high-pressure steam flow of 370,810 kg/hr (817,500 lb/hr). The stack gas from the power plant has a temperature of 121°C (250°F) and a composition listed in Table 5.19.

Table 5.19 - Stack Gas Composition – Novel Gas Cleaning for Future Standards

	Major constituents (vol%)
O_2	8.17
CO_2	9.04
H_2O	11.99
N_2	69.95
Ar	0.84
Total	100.00
	Major contaminants
SO_2 (ppmv)	0.3
NOx (ppmv)	5
halides	0.68
mercury (ppbv)	0.025

5.4 DESCRIPTION AND PERFORMANCE OF FILTER-REACTORS

Designs and estimates of performance of the three filter-reactors used in the IGCC Novel Gas Cleaning Process have been developed. The three filter-reactors are 1) the Halide Filter-Reactor, 2) the Sulfur Polishing Filter-Reactor, and 3) the Mercury Removal Filter-Reactor. The designs were developed based on the requirements for the filter-reactor to perform as an effective particle filter and as an effective chemical reactor for contaminant removal. The barrier filter design aspects were based on commercial barrier filter design methods and supply experience for units in the required capacity range. The chemical reactor performance estimates were based on numerical modeling of transient filter cake contaminant removal using available reaction kinetics information for the proposed types of sorbents. The reaction kinetic behavior information is significantly uncertain at this time and these predicted results are considered preliminary. They are applied for the assessment of equipment performance feasibility and for program planning purposes. These results will be refined when PDU testing of sub-scale filter-reactors has been completed and the test data has been analyzed to extract contaminant removal performance parameters.

The results reported below provide the basic filter-reactor design dimensions, weights, filter performance, and contaminant removal performance estimates. Preliminary conclusion are also extracted and reported.

Halide Filter-Reactor

The Halide Filter-Reactor has several performance objectives: 1) efficiently removal char/slag particulate contained in the raw fuel gas, 2) remove sufficient HCl from the fuel gas to meet the assumed plant requirement of 5 ppmv HCl in the fuel gas to the gas turbine, and 3) induce some catalytic decomposition of ammonia contained in the raw fuel gas to assist in the final control of NOx emitted from the plant. The raw fuel gas is cooled sufficiently so that the gasifier particulate will be in the form of solidified slag and char, and is also pre-cleaned by particle removal through an efficient cyclone to limit the slag/char loading. HCl is removed by injecting a particulate sorbent into the filter that will react with HCl in the entrained zone of the filter as well as in the filter cake accumulated on the filter elements. Decomposition of ammonia is inherently induced within the filter-reactor by the catalytic activity of the high-alloy materials used in parts of the filter internals. It is also possible to pack regions of the filter-reactor vessel with similar catalytic alloy-materials in forms such as wire mesh to contact the fuel gas for additional ammonia decomposition.

Table 5.20 lists the sorbent assumptions and expected performance for the filter-reactor. Nacholite, pneumatically fed as -325 mesh particles, is used as the HCl sorbent, and several other cheap mineral forms high in sodium content, such as Trona, could also be used. It is used in a once-through operation, with the reacted Nacholite sorbent to be disposed as a non-hazardous solid waste. The total particulate loading of char and sorbent in the gas to the filter-reactor is about 9,800 ppmw, a typical-to-low level of loading in prior barrier filter test experience. HCl removal of about 99% is needed to meet the IGCC plant requirement, and it is assumed that ammonia decomposition of about 75% is possible based on literature reports on this subject (see, for example, work reported by: S. A. Qader, et al., Energy and Environmental Technology Corporation, "Decomposition of Ammonia. in IGCC Fuel Gas Streams," Proceedings of Advanced Coal-fired Power Systems Review Meeting, Morgantown, WV, July 1996, CONF-960757--24 ; and W. Wang et al., Lund University, "Reduction of Ammonia and Tar in Pressurized Biomass Gasification," International Symposium on Gas Cleaning at High Temperatures, 2002). The barrier filter has been shown to reliably achieve outlet particle loadings less than 0.1 ppmw in prior gasifier testing (Southern Company Services, PSDF Test Reports).

Table 5.20 - Halide Filter-Reactor Sorbent Assumptions

Sorbent type	Nacholite powder
Sorbent feed size	-325 mesh
Sorbent feed rate, kg/hr (lb/hr)	2,019 (4,451)
Type of sorbent operation	Once-through
Na/Cl molar feed ratio	4.0
Inlet gas total particle loading, ppmw	9.817
HCl removal, %	99.1
NH_3 decomposition, %	75
Outlet particulate loading, ppmw	0.1

Based on the values in Table 5.20, the filter-reactor inlet and outlet fuel gas stream characteristics in Table 5.21 have been computed. The change in fuel gas mass and molar flow rates across this filter-reactor are due to feed sorbent transport gas, pulse cleaning gas, and sorbent decomposition gas (water vapor).

Table 5.21 - Halide Filter-Reactor Inlet and Outlet Streams

	Inlet Stream	Outlet Stream
Fuel gas flow, kg/hr (lb/hr)	231,899 (511,253)	232,363 (512,276)
Fuel gas flow, kg-mole/hr (lb-mole/hr)	11,069 (24,403)	11,095 (24,460)
Fuel gas flow, m^3/hr (ft^3/min)	524 (18,516)	534 (18,845)
Temperature, °C (°F)	593 (1100)	586 (1087)
Pressure, kPa (psia)	2,551 (370)	2,496 (362)
Coal slag/char, ppmw	1,106	0
Total sulfur, ppmv	9253.9	9230.9
H_2S	8609	8588
CS_2	0.6	0.6
COS	634	632
S	7.4	7.4
SO_2	2.9	2.9
HCl, ppmv	434	3.9
NH_3, ppmv	687	171
HCN, ppmv	20	20
Hg, ppbv	2.7	2.8

To estimate the HCl removal performance of this filter-reactor, the reaction behavior of the entrained zone of the vessel and of the transient filter cakes were estimated by numerical modeling. The differential material conservation equations for the entrained zone were developed using the following assumptions:

- the entrained reaction zone acts as a steady-state, dilute reaction stage,
- fuel gas and entrained sorbent particles flow co-currently with limited slip velocity and little back-mixing,
- the fuel gas and entrained sorbent particle contact time is assumed to be the average gas residence time of fuel gas in the vessel,
- the contaminant levels in the fuel gas are small enough that the total fuel gas molar flow, volumetric flow, and temperature do not change due to the removal reactions,
- gas-particle mass transfer rate and chemical reaction rate are both considered,
- the gas-particle mass transfer coefficient was estimated from available experimental correlations reported in the literature for entrained particle mass transfer based on calculated values of the particle-Reynolds Number and the particle-Schmidt Number.

Similarly, for the transient filter cake, the assumptions applied were:

- the fuel gas and sorbent particles arrive at the outer filter cake surface having their average entrained zone outlet compositions,
- the filter cake builds in depth as a function of time, assuming a constant mass flow rate of fuel gas and sorbent particles, until it is periodically pulse cleaned,
- the time-dependent and radial distance-dependent behavior of the fuel gas phase and the sorbent filter cake phase are described by a pair of differently material balance equations that are coupled through mass transfer and chemical reaction between the two phases,
- the contaminant levels in the fuel gas are small enough that the total fuel gas molar flow, volumetric flow, and temperature do not change across the filter cake due to the removal reactions,

- the gas-particle mass transfer coefficient was estimated from available experimental correlations reported in the literature for packed bed mass transfer based on calculated values for packed bed particle-Reynolds and Schmidt numbers.
- an empirical form of the gas contaminant-sorbent particle reaction rate was assumed:

$$\text{Rate (moles/volume-second)} = k\ A_s C_g\ (y - y_e)(1 - X)^m$$

where k is the experimental rate constant, A_s is the sorbent particle external surface area per unit bed volume, C_g is the gas total molar density, y is the gas contaminant mole fraction in the bulk of the gas, y_e is the equilibrium content of contaminant that would exist in the gas, X is the mole fraction of the sorbent reactive species that has been converted, and m is an empirical rate factor.

Table 5.22 lists the key reaction parameters applied in the performance estimates for the Halide Filter-Reactor reaction performance. The HCl reaction rate parameters were taken from Siemens in-house TGA test results for Trona and HCl reaction at conditions representative of the Halide Filter-Reactor. The same reaction rate parameters were applied in both the filter cake and the entrained zones.

Table 5.22 - Halide Filter-Reactor HCl Removal Factors Estimated

Mean sorbent particle diameter, µm	20
Particle sphericity factor	0.7
Cake voidage, %	75
Dilute zone gas-particle mass transfer coefficient, m/s (ft/s)	3 (10)
Cake gas-particle mass transfer coefficient, m/s (ft/s)	0.6 (2)
HCl equilibrium content, ppmv	1
Reaction rate constant k, m/s (ft/s)	0.005 (0.015)
Empirical rate factor “m”	1.6

The estimated filter-reactor design and performance characteristics are listed in Table 5.23. The vessel design characteristics are typical of prior filter design, testing, and commercial supply experience. Twenty plenums are arranged in the filter vessel and are individually pulse cleaned at uniform intervals to maintain HCl removal control. The maximum vessel pressure drop occurs at the time of each plenum pulse cleaning event, and this pressure drop is reduced to the baseline pressure drop immediately following the pulse cleaning event. This is a shop fabricated pressure vessel that is transported by truck to the IGCC site.

About 30% of the HCl feed to the filter-reactor is expected to be removed in the dilute zone, with the remaining removed across the filter cake. Figure 5.7 illustrates the transient behavior of the filter-reactor performance over a single pulse cleaning cycle of one plenum, showing the HCl emitted from the plenum being pulse cleaned, and the total Filter-Reactor HCl emission. The item in Table 5.23 listed as "average HCl from working plenums" is the level of HCl emitted from the 19 plenums that are not pulse cleaned at a given pulse cleaning event, and this level is estimated to be very near the equilibrium HCl content for the given reaction rate factors applied, but a conservatively-higher value has been assumed. The term "highest HCl from filter at pulse event" is the HCl content in the fuel gas passing through the filter-reactor immediately following a pulse cleaning event, and it is seen that this worst level is about 14 ppmv, slightly above the required HCl control level of 5 ppmv. The term "time to recover plenum to HCl control" is the time that it takes a plenum, once pulsed, to regain sufficient HCl removal to again control the HCl content of the gas to the average level of the filter plenums. Finally, the term " highest 1-hour average HCl from filter" is the one-hour averaged HCl content in the fuel gas emitted from the filter-reactor and is representative of an actual performance criteria that might be used for judging the filter-reactor HCl control performance. It is seen that this one-hour average is expected to be below the HCl requirement of 5 ppmv.

Thus, it is expected that the Halide Filter-Reactor will satisfy the control level required for HCl in IGCC. Other major considerations that must be characterized in the test program for this filter-reactor are the impact of the gasifier slag/char on the filtration and reaction performance and the flow behavior of the particulate waste materials from the filter-reactor vessel drain nozzle.

Table 5.23 - Halide Filter-Reactor Characteristics

Design	
face velocity, m/min (ft/min)	2.1 (6.9)
number parallel clusters	5
number plenums	20
total number candles	930
vessel outer diameter, m (ft)	3.5 (11.4)
vessel total height, m (ft)	17.7 (58)
vessel wall thickness, mm (inch)	44.5 (1.75)
vessel refractory thickness, mm (inch)	88.9 (3.5)
vessel weight with internals, tonne (ton)	142 (156)
Performance	
maximum vessel pressure drop, kPa (psi)	0.06 (8.4)
pulse cleaning frequency, 1/hr	1
solids storage capacity in vessel, hr	4
gas residence time in dilute zone, sec	5
HCl removal in the dilute zone, %	32
maximum cake thickness, mm (inch)	10.2 (0.4)
time between plenum pulses, min	3
average filter cake age, hr	0.5
average HCl from working plenums, ppmv	2
highest HCl from filter at pulse event, ppmv	14
time to recover plenum to HCl control, min	1
highest 1-hour average HCl from filter, ppmv	2.1

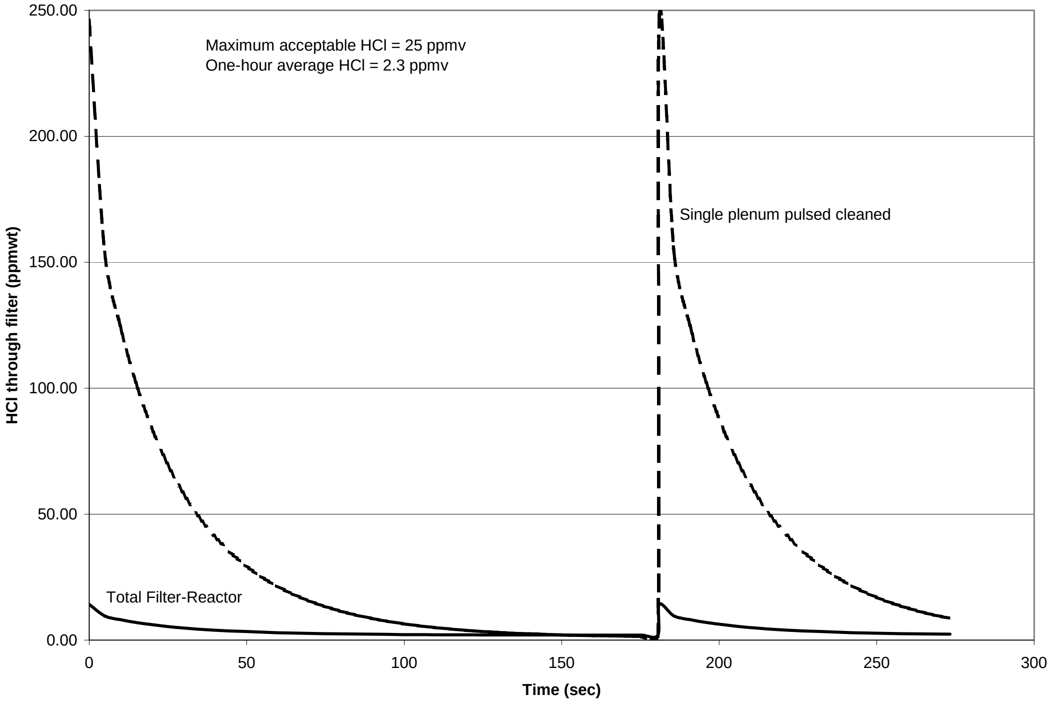


Figure 5.7 - Halide Filter-Reactor HCl Removal Performance

Bulk Desulfurizer

The Bulk Desulfurizer follows the Halide Filter-Reactor stage, reducing the total sulfur content of the fuel gas to less than 50 ppmv using a regenerative zinc titanate sorbent in a transport bed desulfurizer. Its discussion is included here to present the major assumptions applied and to display the changes in fuel gas composition that occur across this desulfurizer. The fuel gas from the Halide Filter-Reactor is cooled by indirect heat exchange to about 482°C (900°F), and a stream of recycled tail gas from the sulfur recovery process is mixed with the main fuel gas stream. The mixed gas stream then passes into the transport desulfurizer. The assumptions listed in Table 5.24 have been applied for material & energy balance development. Some sorbent is lost from the transport desulfurizer, and from the parallel entrained bed regenerator, primarily by sorbent physical attrition and elutriation from the disengaging section of these vessels. This lost sorbent is carried to the next process stage, the Sulfur Polishing Filter-Reactor, with the bulk desulfurized fuel gas. A high level of sulfur removal for H_2S and COS is expected in the bulk desulfurizer. Effective hydrolysis of minor sulfur species (CS_2, S_x, SO_2) is also expected. The catalysis of the water-gas-shift reaction is likely in the transport desulfurizer, but in this evaluation, zero water-gas-shift has been assumed.

Table 5.24 - Bulk Desulfurizer Sorbent Assumptions

Sorbent type	Zinc titanate
Sorbent feed size (mean)	100 micron
Feed rate, kg/hr (lb/hr)	45 (98)
Type of sorbent operation	regenerative
Zn/S makeup mole feed ratio	0.0027
ZnO/S molar circulation ratio	232
Source of sorbent losses	attrition and elutriation
Sulfur removal, %	99.5
Hydrolysis of CS_2, S_x, SO_2, %	100
Extent of water gas shift, %	0

Table 5.25 lists the bulk desulfurizer inlet and outlet fuel gas stream characteristics. A relatively large increase in flow occurs due to the recycled tail gas stream as well as fluffing gas and solids streams stripping gases. The relatively large particulate content in the outlet fuel gas stream is primarily attrited zinc titanate sorbent particulate. Uncertainty exists in the nature of this attrited sorbent (average level of sulfidation and its reactivity), but it was assumed to possess the average outlet sorbent sulfidation level in this evaluation.

Table 5.25 - Bulk Desulfurizer Inlet and Outlet Streams

	Inlet Stream	Outlet Stream
Fuel gas flow, kg/hr (lb/hr)	259,121 (571,267)	267,800 (590,401)
Fuel gas flor, kg-mole/hr (lb-mole/hr)	11,953 (26,351)	12,314 (27,148)
Fuel gas flow, m^3/hr (ft^3/min)	498 (17,594)	600 (21,198)
Temperature, °C (°F)	463 (866)	552 (1026)
Pressure, kPa (psia)	2,468 (358)	2,365 (343)
Particulate, ppmw	0	1277
Total sulfur, ppmv	8950	42.3
H_2S	8235	40.0
CS_2	0.5	0
COS	587	2.9
S	6.9	0
SO_2	121	0
HCl, ppmv	3.6	3.5
NH_3, ppmv	162	158
HCN, ppmv	19	19
Hg, ppbv	2.5	2.4

Sulfur Polishing Filter-Reactor

The Sulfur Polishing Filter-Reactor has three functions: 1) capture sorbent-based particulate emitted from the bulk desulfurizer, 2) utilize this captured sorbent, plus fresh polishing sorbent to desulfurize the fuel gas, and 3) recycle the captured sorbent back to the bulk desulfurizer's regenerator vessel where this sorbent will be reactivated and used for further cycles of desulfurization.

Table 5.26 lists the sorbent assumptions applied for M&E balances and the estimated performance for the Sulfur Polishing Filter-Reactor. The same sorbent type as that used in the bulk desulfurizer would probably be fed to the Sulfur Polishing Filter-Reactor, except with a smaller mean particle size. The level of sulfur removal needed is about 96%, and the quantity of sulfur removed is about a factor of 20 smaller than the sulfur quantity removed in the bulk desulfurizer.

Table 5.26 - Sulfur Polishing Filter-Reactor Sorbent Assumptions

Sorbent type	Zinc-titanate powder
Sorbent feed size	-325 mesh
Sorbent feed rate, kg/hr (lb/hr)	16 (36)
Type of sorbent operation	regenerative
Zn/S makeup mole feed ratio	0.2
ZnO/S circulation ratio	3.7
Inlet gas total particle loading, ppmw	1,343
Sulfur removal, %	96
Outlet particulate loading, ppmw	0.1

Table 5.27 shows that little change occurs to the characteristics of the fuel gas stream, other than to the sulfur species content, as it passed through the Sulfur Polishing Filter-Reactor.

Table 5.27 - Sulfur Polishing Filter-Reactor Inlet and Outlet Streams

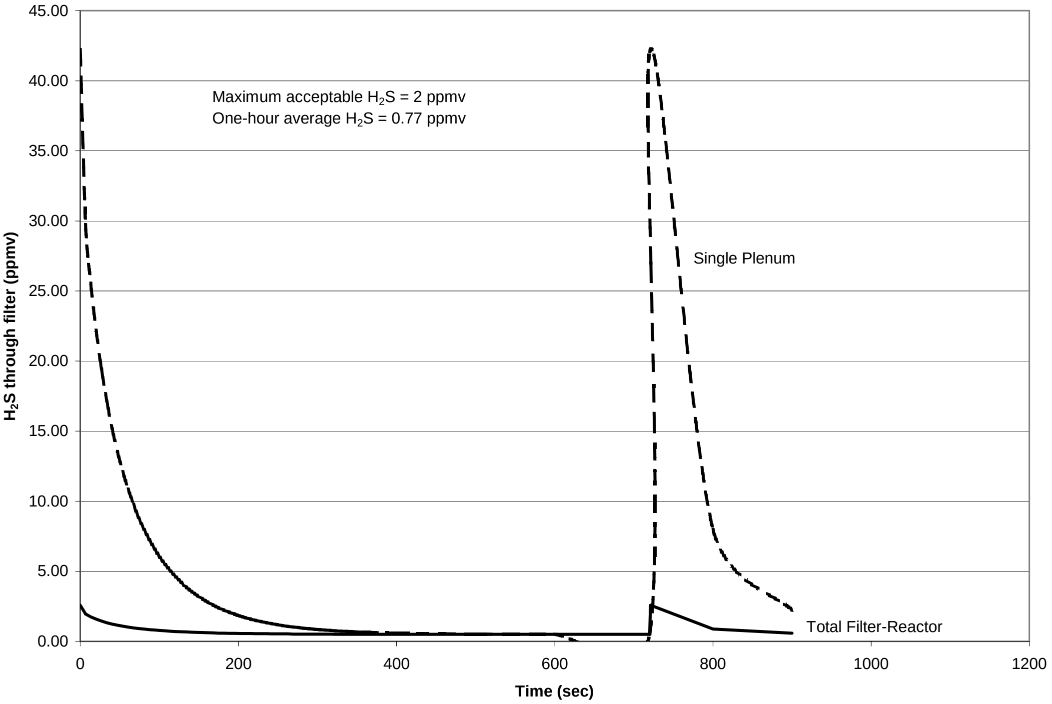
	Inlet Stream	Outlet Stream
Fuel gas flow, kg/hr (lb/hr)	267,823 (590,459)	267,045 (588,736)
Fuel gas flor, kg-mole/hr (lb-mole/hr)	12,315 (27,149)	12,311 (27,142)
Fuel gas flow, m^3/min (ft^3/min)	554 (19,565)	566 (19,994)
Temperature, °C (°F)	482 (900)	482 (900)
Pressure, kPa (psia)	2344 (340)	2289 (332)
Particulate, ppmw	1277	0.1
Total sulfur, ppmv	42.8	1.71
H_2S	40.0	1.6
CS_2	0	0
COS	2.8	0.11
S	0	0
SO_2	0	0
HCl, ppmv	3.5	3.5
NH_3, ppmv	158	158
HCN, ppmv	19	19
Hg, ppbv	2.5	2.5

For estimating the sulfur removal performance of the Sulfur Polishing Filter-Reactor, the factors listed in Table 5.28 were estimated, being similar to those listed in Table 5.22 for the Halide Filter-Reactor, but are specific to H_2S removal. The reaction factors reported in the table have been estimated from available packed bed test results for zinc-based sorbents found in the literature (for example, K. C. Kwon, Tuskegee University, "Kinetics of Hot Gas Desulfurization Sorbents for Transport Reactors," Annual Technical Process Report for FY1999 under contract DE-FG26-98FT40145--01, January 2000) as well as from Siemens in-house, pressurized TGA test results.

Table 5.28 - Sulfur Polishing Filter-Reactor H_2S Removal Factors Estimated

Mean sorbent particle diameter, μm	20
Particle sphericity factor	0.7
Cake voidage, %	75
Dilute zone gas-particle mass transfer coefficient, m/s (ft/s)	3 (10)
Cake gas-particle mass transfer coefficient, m/s (ft/s)	0.6 (2)
H_2S equilibrium content, ppmv	0.5
Reaction rate constant k, m/s (ft/s)	0.024 (0.08)
Empirical rate factor “m”	2

The Sulfur Polishing Filter-Reactor design described in Table 5.29 is very similar to the Halide Filter-Reactor design, and the analogous factors to those in Table 5.22 are reported. Only about 10% of the sulfur is expected to be removed in the entrained zone. Like the Halide Filter-Reactor, it has the potential to maintain the fuel gas sulfur content lower than is required by the IGCC application (less than 2 ppmv) on a one-hour time average basis, as is illustrated in Figure 5.8. In addition to characterizing the



reaction performance of the filter-reactor, the PDU testing will consider the filter cake behavior, pulse cleaning performance, and vessel hopper drainage performance.

Figure 5.8 - Sulfur Polishing Filter-Reactor H_2S Removal Performance

Mercury Removal Filter-Reactor

The Mercury Removal Filter-Reactor also has multiple functions: 1) remove mercury from the fuel gas stream to a level of 95% removal (to about 0.125 ppbv Hg), 2) capture the injected mercury sorbent and transport it to a regenerator that will separate elemental mercury from the regenerated sorbent and will recycle the sorbent to the filter-reactor, and 3) remove any corrosion-based particulate from the fuel gas, as well as potentially remove other trace species from the fuel gas. The sorbent assumptions and performance estimates applied for M&E balances are listed in Table 5.30. The amount of circulating sorbent in the filter-reactor relative to the mercury flow is very high to maintain reliably-high mercury removal.

Table 5.29 - Sulfur Polishing Filter-Reactor Characteristics

Design	
face velocity, m/min (ft/min)	2.2 (7.2)
number parallel clusters	5
number plenums	20
total number candles	930
vessel outer diameter, m (ft)	3.4 (11.3)
vessel total height, m (ft)	18 (59)
vessel wall thickness, mm (inch)	38 (1.5)
vessel refractory thickness, mm (inch)	70 (2.75)
vessel weight with internals, tonne (tons)	127 (140)
Performance	
maximum vessel pressure drop, kPa (psi)	0.05 (7.3)
pulse cleaning frequency, 1/hr	0.25
solids storage capacity in vessel, hr	17
gas residence time in dilute zone, sec	5
H_2S removal in the dilute zone, %	12
maximum cake thickness, mm (inch)	6.4 (0.25)
time between plenum pulse, min	12
average filter cake age, hr	2
average H_2S from working plenums, ppmv	1
highest H_2S from filter at pulse event, ppmv	3
time to recover plenum to H_2S control, min	4
highest 1-hour average H_2S from filter, ppmv	1.1

Table 5.30 - Mercury Removal Filter-Reactor Sorbent Assumptions

Sorbent type	Zeolite powder
Sorbent feed size	-325 mesh
Sorbent makeup feed rate, kg/hr (lb/hr)	7 (15)
Type of sorbent operation	Regenerative
Recycled sorbent rate, kg/hr (lb/hr)	82 (180)
Sorbent feed/Hg removed (mass ratio)	1,242
Sorbent circulation/Hg removed (mass ratio)	14,920
Inlet gas total particle loading, ppmw	273
Hg removal, %	95
Outlet particulate loading, ppmw	0

The inlet and outlet streams estimated for plant materials & energy balances for the Mercury Removal Filter-Reactor are listed in Table 5.31. Before the fuel gas reaches the Mercury Removal Filter-Reactor a portion of the fuel gas is extracted for soot-blower gas in the gasifier's radiant heat exchanger and for reducing gas in the sulfur recovery process, resulting in a reduced fuel gas flow compared to the other filter-reactors.

Table 5.31 - Mercury Removal Filter-Reactor Inlet and Outlet Streams

	Inlet Stream	Outlet Stream
Fuel gas flow, kg/hr (lb/hr)	249,665 (550,419)	249,672 (550,435)
Fuel gas flow, kg-mole/hr (lb-mole/hr)	11,491 (25,333)	11,491 (25,333)
Fuel gas flow, m^3/min (ft^3/min)	335 (11,827)	344 (12,164)
Temperature, °C (°F)	204 (400)	204 (400)
Pressure, kPa (psia)	2268 (329)	2206 (320)
Particulate, ppmw	0	0
Total sulfur, ppmv	1.71	1.71
H_2S	1.6	1.6
CS_2	0	0
COS	0.11	0.11
S	0	0
SO_2	0	0
HCl, ppmv	3.5	3.5
NH_3, ppmv	158	158
HCN, ppmv	19	19
Hg, ppbv	2.5	0.13

The specific type of mercury removal sorbent that will be used has not been determined at this point in the program, but will be the subject of selection in upcoming laboratory testing. Estimates of generic adsorbent parameters listing in Table 5.32 are provided only for initial feasibility estimates and have been based on available literature information.

Table 5.32 - Mercury Removal Filter-Reactor Hg Removal Factors Estimated

Mean sorbent particle diameter, μm	20
Particle sphericity factor	0.7
Cake voidage, %	75
Dilute zone gas-particle mass transfer coefficient, m/s (ft/s)	3 (10)
Cake gas-particle mass transfer coefficient, m/s (ft/s)	0.6 (2)
Hg equilibrium content, ppbv	0.001
Reaction rate constant k, m/s (ft/s)	0.003 (0.01)
Empirical rate factor “m”	1.5

The physical characteristic of the Mercury Removal Filter-Reactor listed in Table 5.33 are well-founded, although the mercury removal performance is uncertain at this time. The filter-reactor vessel and internals are considerably cheaper than those of the Halide Filter-Reactor and the Sulfur Polishing Filter-Reactor because of its smaller volumetric flow and lower temperature. No independent pulse cleaning skid is required for this filter-reactor because of its infrequent pulsing, and it utilizes the equipment in the Sulfur Polishing Filter-Reactor pulse control skid. It is estimated that very little entrained zone mercury removal will occur due to the low mercury content in the fuel gas. The cleaning pulses are very infrequent in this filter-reactor and the removal performance is expected to be adequate to meet the requirement for 0.13 ppbv.

Table 5.33 - Mercury Removal Filter-Reactor Characteristics

Design	
face velocity, m/min (ft/min)	1.7 (5.5)
number parallel clusters	4
number plenums	16
total number candles	748
vessel outer diameter, m (ft)	3.0 (9.7)
vessel total height, m (ft)	16.8 (55)
vessel wall thickness, mm (inch)	35.1 (1.38)
vessel refractory thickness, mm (inch)	25.4 (1.0)
vessel weight with internals, tonne (tons)	92 (101)
Performance	
maximum vessel pressure drop, kPa (psi)	0.06 (9.1)
pulse cleaning frequency, 1/hr	0.03
solids storage capacity in vessel, hr	68
gas residence time in dilute zone, sec	6.5
Hg removal in the dilute zone, %	0
maximum cake thickness, mm (inch)	0.7
time between plenum pulses, min	120
average filter cake age, hr	17
average Hg from working plenums, ppbv	0.1
highest Hg from filter at pulse event, ppbv	0.17
time to recover plenum to Hg control, min	30
highest 1-hour average Hg from filter, ppbv	0.1

Filter-Reactor Conclusions

The evaluation has shown that the filter-reactor concept has the capability to be applied for the fuel gas cleaning functions required in an IGCC power plant with Future Standards. The three filter-reactors have equipment designs well within the prior experience of design, testing, and commercial supply, and their equipment costs are well-founded. The contaminant removal performances of the three filter-reactors are supported by the results of the PDU testing of prototype equipment, where process performance goals have been achieved under representative application conditions.

The evaluation also shows that the filter-reactor has several advantages over the more conventional packed bed reactor configuration for use in IGCC applications. The conventional packed bed reactor, if applied for similar halide, sulfur, and mercury removal applications might work well as a contaminant removal reactor, but is prone to the following practical issues:

- The packed bed reactor is a batch reactor that requires periodic isolation from the process, depressurization and cooling, sorbent removal, sorbent refill, repressurization, re-integration with the process gas and reheat. This may be done with one, or more, parallel reactor vessels that are periodically switched in operation from adsorption to regeneration and/or recharge using switching valves and bypass piping.

- The packed bed reactor for large-scale fuel gas flows is not a simple design, but requires means to uniformly distribute the inlet gas across the inlet side of the packed bed, and means to uniformly withdrawal the fuel gas from the packed bed to ensure uniformity of flow. This is usually done with large distribution plates and layers of large pellet beds that also support the adsorbent bed, and result in increased pressure drop across the reactor vessel.
- The packed bed reactor must be designed to maximize the sorbent bed capacity, so that the number of vessels and the frequency of switching is minimized, and to maintain acceptable vessel pressure drop. This is most economically accomplished in shop-fabricated vessels, limiting the maximum vessel outer diameter to about 4.9 m (16-ft).
- The packed bed reactor is prone to plugging if the inlet fuel gas contains any amount of entrained particulate, and even with almost particulate-free fuel gas will result in gradual increasing pressure drop due to corrosion products, chemical deposition, and settling of the packed bed.
- The packed bed reactor is a source of particle emission into the fuel gas. Even with low fuel gas velocities through the packed bed, the bed particles are subject to high levels of crushing forces and locally high gas velocities near the gas distribution plates, as well as particle chemical decrepitation within the bed, and such particle emissions cannot be tolerated in the IGCC application.

The proposed filter-reactor acts like a semi-continuous packed bed reactor, with each filter cake section being a continuously fed packed bed reactor that is periodically removed from service for an instant. The filter-reactor has no tendency for plugging and maintains particle-free fuel gas conditions. This evaluation indicates the filter-reactor has a high potential to provide high levels of contaminant removal performance.

Specifically, the filter-reactor evaluation has indicated the following:

- Significant HCl removal is expected in the entrained zone of the Halide Filter-Reactor, and the outlet fuel gas HCl content should be easily maintained below the required 5 ppmv level.
- The face velocity of the filter-reactor does not significantly influence the performance of contaminant removal in the filter-reactor, the recovery time for a plenum increasing only little as the face velocity is increased. Increased face velocity does increase the pulse cleaning frequency significantly, though.
- Only little sulfur removal is expected in the entrained zone of the Sulfur Polishing Filter-Reactor. The one-hour time averaged sulfur content of the outlet fuel gas is expected to be much below the required level of 2 ppmv, but the H_2S level may jump above the required sulfur content momentarily during pulse cleaning events.
- No mercury removal is expected in the entrained zone of the Mercury Removal Filter-Reactor. Because the sorbent-to-mercury ratio can be maintained very high by recirculation, the level of mercury should always be maintained below the required level of control.
- The filter-reactor can perform multiple processing tasks that can improve IGCC performance and economics.
- The filter-reactor contaminant removal behavior, and the influence of the sorbent reaction products on the barrier filter performance need to be determined in PDU testing of prototype equipment.

5.5 PERFORMANCE ESTIMATES FOR IGCC WITH NOVEL GAS CLEANING

The breakdown of power generation and power use in the IGCC power plant with Filter-Reactor Novel Gas Cleaning technology is shown in Table 5.34. Compared are Novel Gas Cleaning meeting Current Standards and Future Standards. Overall, the lower sulfur emissions of the Future Standards case result in almost no change in plant heat rate, power plant thermal efficiency, or net plant power. The impact of the Future Standards is small because the only major change in the process is the insertion of the stage for sulfur polishing. Note that the Sulfur Recovery Section net power use is nearly zero, with the acid gas expander's generation balancing the power losses in the system.

Table 5.34 - IGCC Power Plant Thermal Performance with Novel Gas Cleaning Technology

Section	Current Standards Power (MWe)	Future Standards Power (MWe)
Power Island Generation		
Turbine Air Compressor	-171.60	-171.57
Gas turbine	374.89	374.83
Steam turbine	149.22	149.22
Generator	-7.1	-7.0
BOP	-5.2	-5.2
Total power	340.2	340.2
Air Separation Consumption		
ASU Air compressor	0	0
Oxygen compressor	4.129	4.129
Nitrogen compressor	8.98	8.98
ASU	20.0	20.0
Total power use	33.1	33.1
Gasification Consumption		
Fans & blowers	0.52	0.51
Pumps	0.094	0.094
Coal handling and preparation	1.5	1.5
Ash handling	1.3	1.3
Total power use	3.4	3.4
Desulfurization Consumption		
Refrigeration	0.0	0.0
Compressors	2.6	2.6
Pumps	0	0
Total power use	2.6	2.6
Sulfur Recovery Consumption		
Expander	-2.81	-2.81
Compressors	2.64	2.64
Pumps	0.00	0.00
Total power use	-0.17	-0.17
Total Plant		
Net plant power generation, MW	302.5	302.5
Plant net heat rate (HHV), kJ/kWh (Btu/kWh)	9029 (8558)	9029 (8558)
Plant net efficiency, % (LHV)	43.03	43.03
Plant net efficiency, % (HHV)	39.87	39.87

Table 5.35 lists several quantities related to the use of resources and emissions in the IGCC power plant with Novel Gas Cleaning technology. The power plants in both cases use lower quantities of LP-steam in the gas cleaning process steps than does conventional gas cleaning technology. Cooling water use in the processing steps is also lower. Only small quantities of process condensate are generated in both cases, primarily in the Sulfur Recovery Section, and this is recycled without treatment. A moderate level of fresh process water is required in the gas cleaning processes, and both cases result in no discharge of process water. Both cases require small quantities of boiler-quality makeup water for nitrogen humidification.

The total sulfur emissions are expressed in three different bases (percent removal, mass per unit coal fuel input, and mass per MWe net power generated), and are significantly lower for the Future Standard case -- comparable to the sulfur emissions from a natural gas-fired combined-cycle power plant. Solid waste rates from the IGCC power plants are identical for both cases.

Table 5.35 - IGCC Power Plant Resource Use and Emissions with Novel Gas Cleaning

	Current Standards	Future Standards
Auxiliaries		
Net IP steam use, MJ/hr (10^6 Btu/hr)	40,305 (38.2)	40,305 (38.1)
Net LP steam use, MJ/hr (10^6 Btu/hr)	-25,744(-24.4)	-25,744 (-24.4)
Total cooling water use, MJ/hr (10^6 Btu/hr)	10,899 (103.3)	10,899 (103.2)
Total condensate generated, kg/hr (lb/hr)	2,463 (5,430)	2,465 (5,435)
Total process water used, kg/hr (lb/hr)	42,305 (93,266)	42,306 (93,268)
Net process water makeup, kg/hr (lb/hr)	39,842 (87,836)	39,841 (87,833)
Total boiler water makeup, kg/hr (lb/hr)	33,566 (74,000)	33,566 (74,000)
Emissions		
Sulfur total removal efficiency, %	99.57	99.983
Sulfur total emission (HHV), mg/MJ (lb SO_2/ 10^6 Btu)	11.38 (0.02648)	0.464 (0.00108)
Sulfur total emission, kg/MW (lb SO_2/ MW)	0.0239 (0.2295)	0.00418 (0.00921)
NOx total emission (HHV), mg/MJ (lb NO_2/ 10^6 Btu)	15.22 (0.0354)	5.073 (0.0118)
Particulate emission (HHV), mg/MJ (lb/ 10^6 Btu)	0.0086 (2E-05)	0.0086 (2E-05)
Hg emission, mg/MJ (lb/TBtu) (HHV)	0.218 (0.507)	0.1088 (0.253)
Consumables, kg/hr (lb/hr)		
Chemicals	0	0
Sorbents	2,070 (4,564)	2,087 (4,600)
Catalyst	0.9 (2)	0.9 (2)
Solid waste, kg/hr (lb/hr)		
Slag product (25 wt% water)	13,673 (30,144)	13,673 (30,144)
Slag & HCl sorbent waste	1,706 (3,760)	1,706 (3,760)
Waste salts (25 wt% water)	0	0
Sorbent wastes	53 (117)	71 (156)
Total	15,432 (34,021)	15,450 (34,060)

5.6 COST ESTIMATES FOR IGCC WITH NOVEL GAS CLEANING

The costs for the Novel Gas Cleaning process and for the entire IGCC power plant using the Novel Gas Cleaning technology are displayed in Tables 5.36 through 5.38. Table 5.36 lists the purchased equipment and installed equipment costs, broken down to each section of the Novel Gas Cleaning process, for the Current and Future Standards cases. The total installed cost of the Future Standards case is about 19% greater than that of the Current Standards case. The Mercury Removal Section used in the cost results presented is the "once-through, powdered mercury sorbent" system.

Table 5.36 - Novel Gas Cleaning Technology Equipment Cost Breakdown

Plant Section	Current Standards Cost, k$	Future Standards Cost, k$
Raw Gas Convective Cooling		
purchased equipment	239	239
installed equipment	478	478
Desulfurization		
purchased equipment	5,959	8,737
installed equipment	9,676	13,734
Sulfur Recovery		
purchased equipment	4,705	4,548
installed equipment	8,747	8,590
Mercury Removal		
purchased equipment	1,430	1,442
installed equipment	2,013	2,038
Total Gas Cleaning		
purchased equipment	12,333	14,966
installed equipment	20,914	24,840
purchased equipment, $/kW	41	49
installed equipment, $/kW	69	82
Total Plant		
TCR, k$	428,179	434,087
TCR, $/kW	1415	1435

Cost estimates have been made for the Mercury Removal Section once-through and regenerative sorbent processes described, and are listed in Table 5.37 for the Future Standards case. Also shown are the equipment costs for comparable processes using pelletized mercury removal sorbents in packed bed reactors. The packed bed processes are significantly more expensive than the use of powdered sorbents in a filter-reactor process configuration.

Table 5.37 - Mercury Removal Section Installed Equipment Costs

	Future Standards Cost, k$
Once-through, Powdered Sorbent (filter-reactor)	2,038
Regenerative, Powdered Sorbent (filter-reactor)	2,671
Once-through, Pelletized Sorbent (packed bed reactor)	3,473
Regenerative, Pelletized Sorbent (packed bed reactor)	7,105

The IGCC power plant Total Capital Requirement is computed in Table 5.36 for the Current and Future Standards cases. The Total Capital Requirement is about 1.5% greater in the Future Standards case than in the Current Standards case. The cost-of- electricity (COE) is estimated in Table 5.38 for the two cases, using a "first year of operation" basis. The COE is about 1.0% higher in the Future Standards case than in the Current Standards case.

Table 5.38 – Cost-of-Electricity for IGCC with Novel Gas Cleaning

	Current Standards	Future Standards
	(Cents/kWh)	(Cents/kWh)
Fixed O&M	0.48	0.48
Variable O&M	0.27	0.27
Consumables	0.34	0.38
water	0.04	0.04
chemicals, sorbents, catalysts	0.16	0.20
waste Disposal	0.11	0.11
chemicals for BFW, CW and waste treatment	0.03	0.03
Sulfur by-product credit	0.06	0.06
Fuel	1.59	1.59
Capital charges	3.73	3.78
Total	6.34	6.40

5.7 ASSESSMENT OF IGCC WITH NOVEL GAS CLEANING

All four of the IGCC case simulations have been with respect to the quality of the simulations:

- validity of process flow diagrams,
- major component pressure drop estimates,
- pulse gas and transport gas rate estimates,
- once-though and regenerative mercury removal scheme assumptions,
- overall material & energy balance convergences,
- gas turbine scaling,
- plant steam balances and steam turbine cycle conditions,
- plant performance calculations.

The results are valid as a means for "relative" comparison to indicate potential merits and issues. A consistent design basis and emissions control approach has been applied so that overall power plant performance and cost comparisons are meaningful and representative of actual expectations on a relative basis. The evaluation shows that the Filter-Reactor Novel Gas Cleaning technology provides reduction in IGCC power plant complexity, increase in power plant generating capacity and thermal efficiency, and reduced investment and cost-of-electricity over IGCC power generation using conventional dry-gas cleaning technology. Expected are power plant availability advantages for the IGCC power plant using Filter-Reactor Novel Gas Cleaning technology, with the technology providing greater gas turbine protection than the conventional gas cleaning technology.

5.7.1 Performance Potential

The IGCC overall performance results are tabulated in Table 5.39. The results indicate that the Novel Gas Cleaning schemes have the potential for significant improvements in IGCC power plant generating capacity and heat rate. Novel Gas Cleaning yields 6% greater generating capacity and 2.3 percentage-points greater efficiency under the Current Standard case, and more than 9% generating capacity and 3.6 percentage-points higher efficiency in the Future Standards case. Note that Novel Gas Cleaning performance is almost entirely insensitive to the gas cleaning standards, with little difference between the Current and Future Standards cases. Solid waste from IGCC with Novel Gas Cleaning is about 8% greater than from IGCC with conventional gas cleaning.

Table 5.39 - Overall IGCC Performance Comparison

	Conventional Cold Gas Cleaning	Conventional Cold gas Cleaning	NGC	NGC
Standards	Current	Future	Current	Future
Net Power, MW	285	276	303	303
Net Eff, % (HHV)	37.6	36.3	39.9	39.9
Solid Waste, kg/hr	14,288	14,288	15,432	15,450

The comparison of power plant performance between a conventional, natural gas combined-cycle and the four IGCC power plants are shown in Tables 5.40 and 5.41. Table 5.40 focuses on water resource use, power generating capacity, and thermal efficiency factors for each power plant. Table 5.41 focuses on power plant environmental factors.

Table 5.40 shows that the Novel Gas Cleaning technology provides the potential for improvement in IGCC power plant water resource use and thermal performance over IGCC using conventional gas cleaning technology. The Novel Gas Cleaning technology uses less than half the cooling water rate used by the conventional gas cleaning technology. Total water consumption is about the same for both technologies. Novel Gas Cleaning technology consumes more process makeup water than the conventional gas cleaning technology, primarily for coal slurry preparation, but it uses much less boiler-quality makeup water, a more expensive water source.

The detailed power consumption breakdowns listed in this report indicate that every section of the fuel gas cleaning process, except for the sulfur recovery process, shows significant advantage for the Novel Gas Cleaning technology. Conventional fuel gas cleaning technology applies a large number of fuel gas cooling and reheating operations, conducting total condensation of the fuel gas water vapor, followed by re-humidification, and this results in significant losses in overall power plant thermal efficiency that do not occur when using the Novel Gas Cleaning technology. When meeting the fuel gas cleaning requirements of the Current Standards case, the IGCC power plant with Novel Gas Cleaning technology produces 17.3 MWe greater power output than the plant using conventional gas cleaning, a 6.1% increase in power. Similarly, the Novel Gas Cleaning technology results in a 2.3 percentage-point increase in power plant efficiency (HHV) over the IGCC power plant using conventional gas cleaning technology.

Table 5.40 - Natural Gas Combined-Cycle and IGCC Fuel Gas Cleaning Plant Comparisons

	Natural Gas Combined-Cycle	Conventional Cleaning Current Standards	Novel Gas Cleaning Current Standards	Conventional Cleaning Future Standards	Novel Gas Cleaning Future Standards
Cooling water use , MJ/hr	0	252,169	108,675	199,414	108,675
Process water Makeup, kg/hr	0	-274	42,305	0	42,306
Boiler feed water Makeup, kg/hr	0	69,263	33,566	69,646	33,566
Total water consumption, kg/hr	0	68,989	75,872	69,646	75,873
Net power generated, MW	272.3	285.2	302.5	275.5	302.5
Plant net heat rate, kJ/kWh (LHV)	6581	8876	8367	9187	8366
Plant net efficiency, % (LHV)	54.7	40.6	43.0	39.2	43.0
Plant net efficiency, % (HHV)	---	37.6	39.9	36.3	39.9

Even greater advantages result when meeting the gas cleaning requirements of the Future Standards case. Here, the IGCC power plant with Novel Gas Cleaning technology produces 27.0 MWe greater power output than the plant using conventional gas cleaning, a 9.8% increase in power. Similarly, the Novel Gas Cleaning technology results in a 3.6 %-point increase in power plant efficiency (HHV) over the IGCC power plant using conventional gas cleaning.

The evaluation basis calling for the Novel Gas Cleaning Process to produce the final sulfur product in the form of elemental sulfur makes the sulfur recovery process the largest contributor to thermal performance reduction in the Novel Gas Cleaning Process. If other products were acceptable sulfur forms, such as sulfuric acid, the process would show even greater thermal performance advantages over the conventional gas cleaning technology.

The IGCC power plants (all four cases) generate 3 to 30 MWe more electric power than the natural gas combined-cycle power plant using the same gas turbine and steam turbine conditions, but at 12 to 15 percentage-points lower thermal efficiency. The natural gas-fired power plant requires no gas cleaning and thus there are no cooling water, process water, of boiler feed water makeup flow associated the gas cleaning for the natural gas combined-cycle power plant.

Table 5.41 lists the clean fuel gas and stack gas compositions estimated for the IGCC power plant cases, and compares them to the conventional, natural gas combined-cycle. With a typical natural gas sulfur content of 7 ppmv, the IGCC stack emissions of sulfur oxides for the Future Standards case approach the emissions of sulfur oxides from the natural gas combined-cycle power plant. It should be noted that natural gas is processed before use in the combined-cycle power plant to remove sulfur species, water vapor, carbon dioxide, and mercury, and this processing results in various emissions of carbon dioxide, sulfur species, and mercury species that are not reflected in this comparison.

The conventional gas cleaning technology has established capability to achieve the levels of sulfur control required in the evaluation. The Filter-Reactor Novel Gas Cleaning technology is estimated as having this capability based on the development work completed. Where these gas cleaning technologies differ is that the conventional gas cleaning technology will reduce the fuel gas halide, ammonia, and HCN contents to much lower levels in the fuel gas than will the Novel Gas Cleaning technology. The Novel Gas Cleaning technology can, though, reduce the fuel gas halide, ammonia and HCN contents sufficiently to satisfy the requirements for IGCC applications. The Novel Gas Cleaning technology uses partial-decomposition of ammonia in the process, and low-NOx, diffusion flame, fuel gas combustors (staged, rich-quench-lean; or catalytic) to achieve low NOx emissions from the IGCC power plant. The higher-temperature operations of the Novel Gas Cleaning technology may provide advantages, with less potential for the formation of metal carbonyls, and its final stage Mercury Removal Filter-Reactor may provide additional protection against corrosion-based particulate damage to the gas turbine not provided by conventional gas cleaning technology. The conventional gas cleaning technology, with operation at conditions of high corrosion potential, is inherently more prone to availability losses than the Novel Gas Cleaning technology.

All of the IGCC power plants produce comparable solid waste streams, with the total mass of waste for the Novel Gas Cleaning technology being about 8% greater than with the conventional gas cleaning. The nature of the waste differs slightly for the two technologies. The slag waste streams are very similar in flow rate and composition for the four IGCC power plants. The conventional gas cleaning technology produces a wet stream of halide salts that contain numerous traces of contaminants, as well as a small, hazardous mercury sorbent waste. The Novel Gas Cleaning technology produces dry, non-hazardous sorbent waste, some of which can be incorporated into the plant slag waste. The hazardous nature of the mercury sorbent waste from the Novel Gas Cleaning Process is uncertain at this time.

5.7.2 Cost Potential

While the equipment costs are estimated to be only slightly lower for the Novel Gas Cleaning processes than for the conventional processes, the improved power plant capacity results in the potential for significant reductions in the plant cost-of-electricity.

The IGCC power plant investment and cost-of-electricity (COE) is compared for the four plants in Table 5.42. The plant meeting Current Standards has 6% lower investment when using the Novel Gas Cleaning technology. For the Future Standards case, the capital investment is almost 13% lower for the Novel Gas Cleaning technology.

The COE is reduced by about 3% in the Current Standards case by using the Novel Gas Cleaning technology. Almost 8% reduction is found for the Future Standards case. It is also seen that IGCC using

Table 5.41 - Natural Gas Combined-Cycle and IGCC Fuel Gas Cleaning Emission Comparisons

	Natural Gas Combined-Cycle	Current Standards		Future Standards	
		Conventional Cleaning	Novel Cleaning	Conventional Cleaning	Novel Cleaning
Clean Fuel Gas (before N_2 dilution)					
H_2 (vol%)	0	25.2	22.9	25.2	22.9
CO (vol%)	0	43.7	36.7	43.7	36.7
CH_4 (vol%)	98	0.3	0.3	0.3	0.3
CO_2 (vol%)	0	9.3	10.3	9.3	10.3
H_2O (vol%)	0	19.7	19.5	19.7	19.5
N_2 (vol%)	2	1.7	10.1	1.7	10.1
Ar (vol%)	0	0.14	0.19	0.14	0.2
Total sulfur (ppmv)	7	102.6	42.9	2.1	1.7
Halides (ppmv)	0	0.1	3.5	0.1	3.5
Ammonia (ppmv)	0	0.4	158	0	158
HCN (ppmv)	0	0	19	0	19
Hg (ppbv)	0	0.29	0.26	0.146	0.129
Stack Gas					
CO_2 (vol%)	3.8	9.2	9.0	9.5	9.0
H_2O (vol%)	8.4	11.7	12.0	11.7	12.0
N_2 (vol%)	74.1	70.2	70.0	70.2	70.0
O_2 (vol%)	12.2	8.1	8.2	8.0	8.2
HCl (ppmv)	0	0	0.7	0	0.7
SO_2 (ppmv)	0.26	17.7	8.2	0.36	0.33
NO (ppmv)	<15	<15	<15	<5	<5
Hg (ppbv)	0	0.05	0.05	0.026	0.025
Sulfur Removal					
Total removal efficiency (%)	0	99.08	99.57	99.981	99.983
Total emission (mg SO_2/ MJ)	0.494	24.506	11.522	0.503	0.464
Solid Waste					
Slag and flyash (wet, kg/hr)	0	14,015	13,673	14,015	13,673
Waste salts (wet, kg/hr)	0	285	0	285	0
Sorbent wastes (kg/hr)	0	1.4	1,713	1.4	1,708
Total (kg/hr)	0	14,301	15,386	14,301	15,381

the Novel Gas Cleaning technology could achieve the Future Standards at about the same investment and COE as the conventional IGCC power plant that achieves only Current Standards.

Table 5.42 - Total IGCC Power Plant Investment and COE

Gas Cleaning Technology	**Conventional Cleaning**	**Novel Cleaning**	**Conventional Cleaning**	**Novel Cleaning**
Gas Cleaning Standards	Current	Current	Future	Future
Generation capacity, MWe	285.2	302.5	275.5	302.5
Plant Heat Rate, kJ/kWh (HHV)	9574	9022	9917	9022
Total Capital Requirement, $/kW	1500	1415	1614	1435
Total COE, cents/kWh (constant $)	6.56	6.34	6.93	6.40

6. METHANOL SYNTHESIS WITH CONVENTIONAL GAS CLEANING

The focus of the evaluation now turns to Novel Gas Cleaning for coal-based chemical synthesis in Sections 6 and 7. The chemical synthesis application evaluated is a methanol synthesis plant combined with electric power production. The Liquid Phase Methanol synthesis process is the methanol synthesis technology applied in the evaluation. The plant is generally similar to the IGCC power plant evaluated in Sections 4 and 5, except that 1) it operates at a higher pressure to generate a clean fuel gas stream and a clean synthesis gas stream that can be utilized for methanol synthesis without syngas compression, 2) it achieves more stringent gas cleaning standards, and 3) the power island utilizes the fuel energy in the clean fuel gas steam and in the purge gas from the methanol synthesis portion of the plant. The nominal capacity of the plant is 300 MWe electric power, and 318 tonnes (350 tons) of methanol (fuel grade) per day. The plant chemical synthesis process requires stringent cleaning of sulfur species, halide species, particulate, ammonia, hydrogen cyanide, mercury, and metal carbonyls.

The questions addressed by the evaluation are:

- How is the Novel Gas Cleaning technology best configured to meet the chemical synthesis gas cleaning requirements?
- How does the resulting Novel Gas Cleaning process compare to conventional synthesis gas cleaning technology with respect to performance and cost potential?
- What are the major development issues for the Novel Gas Cleaning technology for chemical synthesis applications?

Two plant configurations have been evaluated in addressing these issues:

- a plant using conventional, low-temperature gas cleaning technology, in Section 6,
- a plant using the Siemens Novel Gas Cleaning technology to meet the methanol synthesis requirements, in Section 7 of the report.

6.1 METHANOL SYNTHESIS PLANT WITH CONVENTIONAL GAS CLEANING

The overall methanol synthesis process flow diagram with conventional gas cleaning is illustrated in Figure 6.1. The plant consists of six major sections: Gasification, Low-Temperature Cooling, Acid Gas Removal (AGR), Sulfur Recovery, Methanol Synthesis, and Power. It is similar to the conventional IGCC power plant overall process diagram, except that

- a greater coal feed rate is consumed to accommodate the fuel needs for both power generation and methanol synthesis,
- cleaned gas is split into a “syngas” stream for methanol synthesis and a “fuel gas” for power generation, and
- the gasifier is operated at a much higher pressure to generate syngas that can meet the high-pressure needs of the methanol synthesis reactor without syngas compression.

The methanol synthesis gas cleaning requirements are those outlined in Section 3.2 of the report. The raw gas is desulfurized using Rectisol desulfurization technology to a lower sulfur content than in the IGCC Future Standards case (Report Section 4). The stream of syngas split from the cleaned gas is further cleaned of sulfur and metal carbonyls in fixed beds of sorbents before the syngas is conditioned and reacted for methanol synthesis. The methanol synthesis purge gas and the cleaned fuel gas streams are both expanded and combined in the Power Section before being fed to the Power Island gas turbine combustors. The recycling of process streams and the interchanging of heat between the major process sections are numerous and require complex integration.

GASIFICATION SECTION

The Gasification Section primary function is to convert coal into a raw gas cooled to a suitable temperature for treatment in the subsequent Low-Temperature Cooling Section. Figure 6.2 shows the process flow diagram for the Gasification Section. Table 6.1 lists characteristics of the major stream in the Gasification Section. The process diagram is identical to the configuration used in the conventional IGCC power plant evaluation.

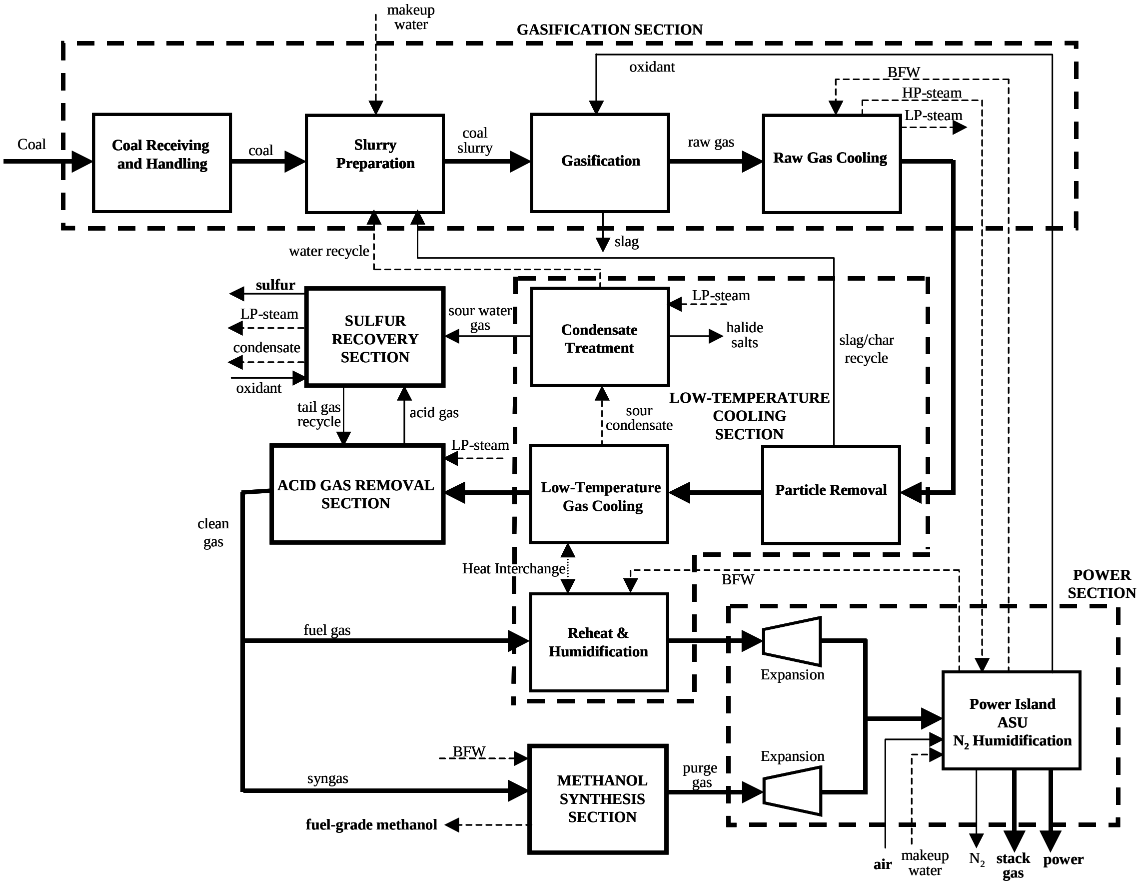


Figure 6.1 – Conventional Methanol Synthesis Overall Process Scheme

Oxidant from the Power Section's air separation unit has a flow of about 108,567 kg/hr (239,345 lb/hr). The raw gas flow rate at the exit of the Convective Cooler (Item 7) has a heat content of 634 MW(t) (2,165 x 10^6 Btu/hr) (LHV) and a heating value of about 7.82 MJ/Nm^3 (199 Btu/scf), and includes 11,612 kg/hr (25,600 lb/hr) of recycled, clean fuel gas used as soot blower gas in the raw gas heat exchangers. The raw gas exits the Gasifier (Item 3) at a temperature of about 1467ºC (2582ºF) and a pressure of 8791 kPa (1275 psia), and is cooled to about 282ºC (540ºF) at the exit of the Convective Cooler (Item 7), with the estimated composition in Table 6.2.

The estimated distribution of contaminants in the raw gas issued from the gasifier is based on the empirical assumptions listed in Table 6.3. Significant sulfur content is assumed to remain in the gasifier slag, and the hot gas from the gasifier is assumed to be at equilibrium with respect to sulfur species. All of the coal's chlorine content is assumed converted to HCl in the raw gas, and other halides have been neglected in the evaluation. All of the coal's mercury is assumed to be issued in the raw gas as elemental mercury. Empirical conversions are assumed for ammonia and hydrogen cyanide. Metal carbonyls may be formed in the raw gas only at temperatures less than 900°F though gas-solid reactions with the ash metal constituents, or with the materials of construction, and the level of formation is highly uncertain. The hot gas composition is assumed to be frozen at this level once it has passed through the raw gas cooler heat exchangers.

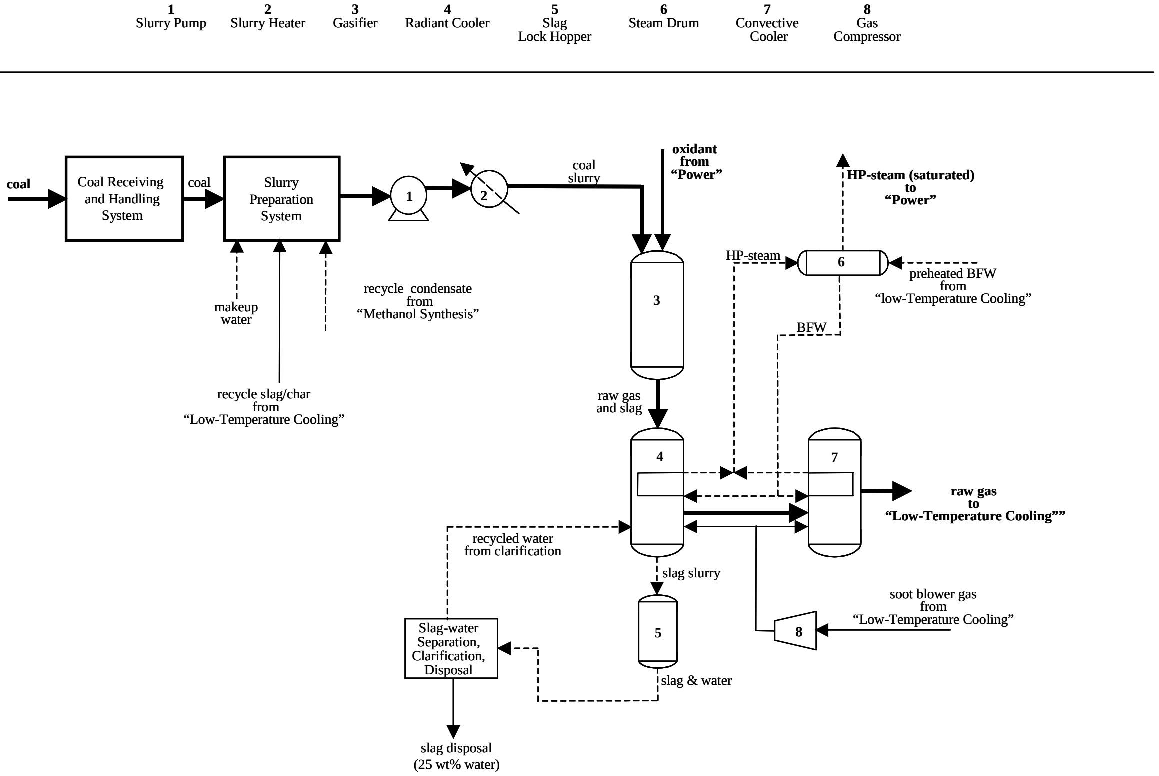


Figure 6.2 – Gasification Section - Conventional Methanol Synthesis

Table 6.1 – Stream Characteristics for Gasification Section for Current Standards

Stream name	Coal feed	Total slurry water feed	Gasifier oxidant	Raw fuel gas	Slag	HP-steam
Molar flow, kmole/hr	10,255	2,826	3,352	12,975	261	20,898
Mass flow, kg/hr	115,058	50,940	106,814	272,191	12,235	376,482
Volumetric flow, m^3/hr	174	77	1,142	7,654	20	6,941
Temperature, °C	26	47	115	282	642	318
Pressure, kPa	101	110	9534	7922	7922	10,583
Enthalpy MJ/hr	-1.46E+05	-8.03E+05	7,714	-1.64E+06	-49,025	-4.99E+06
Molecular wt	11.2	18.0	31.9	21.0	46.9	18.0

Table 6.2 - Raw Fuel Gas Composition – Conventional Methanol Synthesis

	Major constituents (vol%)
H_2	25.39
CH_4	0.30
CO	41.03
CO_2	9.86
H_2O	20.63
N_2	1.58
Ar	0.14
Total	98.93
	Major contaminants (ppmv)
H_2S	9,020
COS	641
CS_2	0.6
S_X	2
SO_2	1
NH_3	670
HCN	19
HCl	435
Hg (ppbv)	3

Table 6.3 – Distribution of Contaminants in Gasification Section Raw Gas

Contaminant	Generation (% of coal constituent)	Contaminant forms
Sulfur species	90% (10% retained with slag)	H_2S, COS, CS_2, SO_2 based on equilibrium at exit temperature
Halides	100% of coal Cl content	HCl (other halides neglected)
Ammonia	25 % of coal nitrogen	NH_3
Hydrogen cyanide	0.5 % of coal nitrogen	HCN
Mercury	100% of coal mercury content	Hg^o only
Metal carbonyls	0 (generated <900°F only)	$Fe(CO)_5$, $Ni(CO)_4$

Low-Temperature Cooling Section

Figure 6.3 represents the process flow diagram for the Low-Temperature Cooling Section. Table 6.4 list characteristics of the major process streams in this section. This complex section cools the raw gas to the temperature required by the Desulfurization Section, and it functions to remove significant halides, ammonia, hydrogen cyanide, and mercury. The major equipment components are described below.

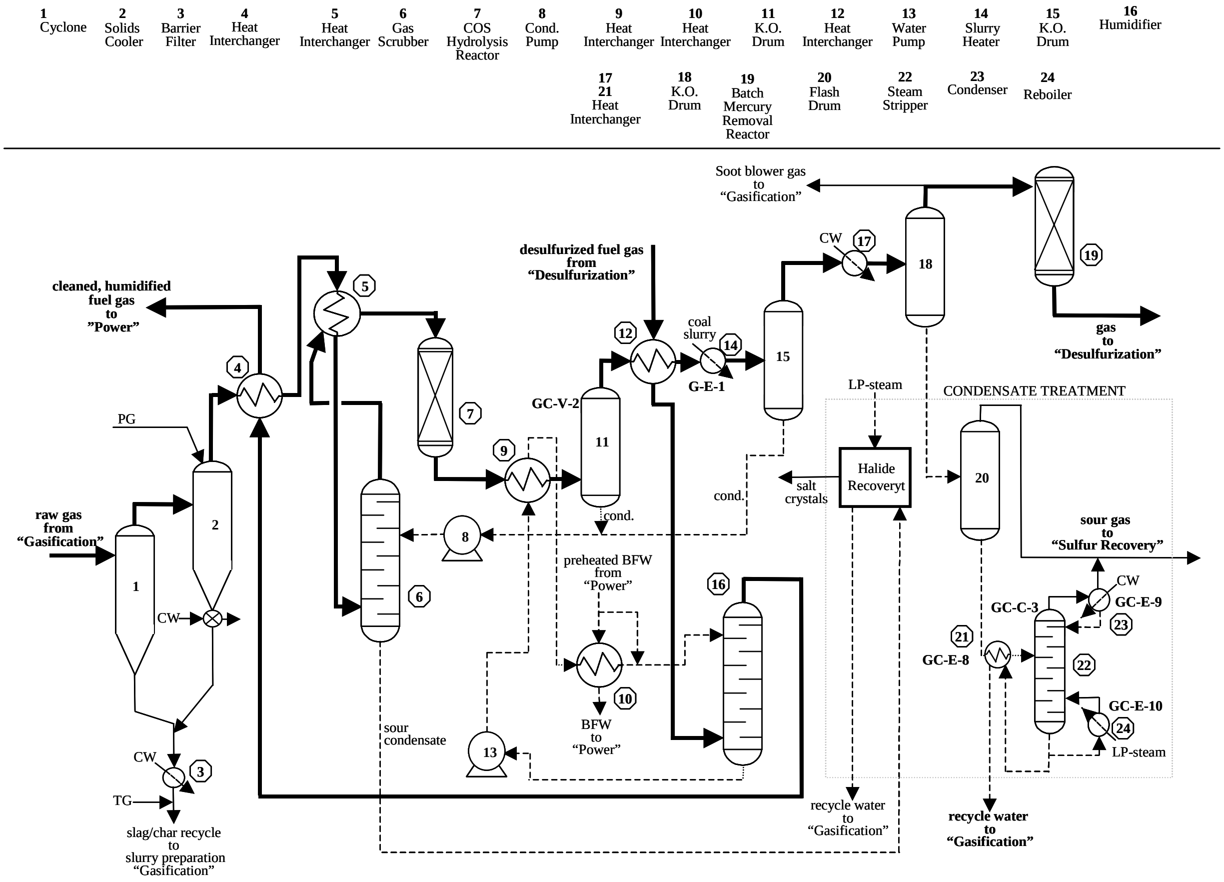


Figure 6.3 – Low Temperature Cooling Section - Conventional Methanol Synthesis

Table 6.4 – Stream Characteristics for Low-Temperature Cooling Section

Stream name	Cooled raw gas	Slag/char recycle	Fuel gas to Desulfurization	Desulfurized fuel gas	Reheated fuel gas to Power Island
Molar flow, kmole/hr	13,025	50	8,536	9,759	11,397
Mass flow, kg/hr	275,173	2,982	191,746	212,044	241,942
Volumetric flow, m^3/hr	7,211	2.0	9,032	3,525	8.965
Temperature, °C	282	282	38	38	360
Pressure, kPa	8,419	7,922	2,441	7,191	6,847
Enthalpy, MJ/hr	-1.66E+06	-14,446	-9.66E+05	-1.044E+06	-1.26E+06
Molecular wt	21.1	60.0	22.5	21.7	21.2

Barrier filter: A ceramic, or metal, candle barrier filter (Item 2) is placed to follow a conventional cyclone (Item 1) and operates at about 282°C (540°F) to removal particulate (solidified slag particles and char) from the raw gas to a level of < 0.1 ppmv as the first step in the cleaning process.

Fuel gas coolers: A process heat interchanger (Item 4) is now used to cool the gas to about 241°C (467°F), while reheating the clean fuel gas stream to about 271°C (520°F) before it goes to the Power

Section. This cooled gas then passes through a second heat interchanger (Item 5) that cools it to about 219°C (426°F).

Gas condensate scrubber: The gas is next scrubbed in a column (Item 6) with collected process condensate to remove halides to a very low level, and results in the further cooling of the gas to about 203°C (397°F).

Gas reheater: The gas is now reheated in a gas heat interchanger (Item 5) to about 225°C (437°F) in preparation for COS hydrolysis. This reheat is dictated by a need to heat the saturated gas to minimize the possibility of condensate formation in the hydrolysis reactor.

COS hydrolysis: The reheated gas is treated in a catalytic reactor (Item 7) to hydrolyze its COS content to H_2S, allowing more efficient sulfur removal to be performed downstream. This also results in substantial HCN hydrolysis to NH_3.

Gas cooling and ammonia removal: Next, a series of process heat interchangers and water-cooled heat exchangers (Items 9, 12, 14, and 17 and their associated knock-out drums) are used to cool the gas to about 38°C (100°F), simultaneously removing most of the gas water content and collecting process condensate that contains most of the gas ammonia. A Stream of released gases from condensate processing (sour-gas water), at 388 kg/hr (856 lb/h)r, is sent to the Sulfur Recovery Section of the plant. The composition of this sour-water gas is listed in Table 6.5.

Table 6.5 - Sour-water Gas Composition – Conventional Methanol Synthesis

	Constituents (vol%)
H_2	1.62
CH_4	0.03
CO	2.85
CO_2	20.87
H_2O	50.30
N_2	0.08
H_2S	9.12
COS	0.10
NH_3	15.02
HCN	0.00
Total	99.99

Mercury removal: The gas is now treated in a fixed bed reactor (Item 19) containing sulfur-impregnated, activated carbon, and sized to remove 95% of the gas mercury (Smith, 2000).

The fates of the gas contaminants in the raw gas entering this section as estimated in the process simulation are listed in Table 6.6. The halides, ammonia, and hydrogen cyanide contaminants are very effectively removed from the raw gas, and are recovered from the condensate streams for final processing. The halides are converted to ammonia salts for disposal, and ammonia is sent to the Sulfur Recovery Section to be decomposed in the high temperature Claus furnace. Considerable LP-steam is utilized in the condensate treatment process. The composition of the gas sent to the Desulfurization Section of the plant is listed in Table 6.7.

Table 6.6 – Fate of Contaminants in Low-temperature Cooling Section

Contaminant	Removal (% of inlet to Section)	Contaminant conversions
sulfur species	6.1	Hydrolysis Partial condensate absorption
halides	100	Condensate absorption Salt crystallization
ammonia	99.05	Hydrolysis Condensate absorption Salt crystallization
Hydrogen cyanide	100	Hydrolysis
mercury	98	Sorbent fixation

Table 6.7 - Gas Composition to Desulfurization – Conventional Methanol Synthesis

	Major constituents (vol%)
H_2	31.99
CH_4	0.38
CO	51.70
CO_2	12.47
H_2O	0.09
N_2	1.99
Ar	0.17
Total	98.79
	Major contaminants (ppmv)
H_2S	12,065
COS	0.0
NH_3	8.5
HCN	0.0
Hg (ppbv)	0.1

Humidification: The clean and dry gas from the desulfurizer is split into two streams, one being "fuel gas", the other "syngas". The clean and dry fuel gas from the desulfurizer is reheated to about 142°C (288°F), interchanging heat (Item 12) with the previous gas cooling-condensation process streams. This stream is humidified in a column (Item 16) of countercurrent warm water, the exit gas being at 185°C (365°F).

Fuel gas reheat: The cleaned and humidified fuel gas is now reheated to about 271°C (520°F) in a heat interchanger (Item 4). The clean fuel gas composition is listed in Table 6.8.

Acid Gas Removal (AGR) Section

Figure 6.4 shows the process flow diagram for the AGR Section when meeting the methanol synthesis cleaning standards. Table 6.9 list characteristics of the major stream in this section. The Rectisol desulfurization technology is selected for the desulfurization step, with other commercial low-temperature desulfurization technologies unable to meet the stringent requirements of this evaluation. Rectisol claims that this desulfurization process will also remove HCN, NH_3, CS_2, iron and nickel carbonyls, VOCs, and mercury very effectively (Koss and Meyer, 2003). On the other hand, users of

Rectisol continue to perform mercury removal in a separate unit placed before the Rectisol process, and place adsorbers to capture metal carbonyls after the Rectisol process to ensure performance. If these contaminants are absorber in the Rectisol solvent, they will either accumulate within the solvent leading to operating problems, and/or be released from the stripper and need separate processing to engage their final disposition. Maintenance of the Rectisol columns is a critical path item in a conventional methanol synthesis plant due to the severe conditions in the columns (Trapp et al., 2004).

Table 6.8 - Cleaned and Humidified Fuel Gas Composition – Conventional Methanol Synthesis

	Major constituents (vol%)
H_2	27.18
CH_4	0.32
CO	43.82
CO_2	10.63
H_2O	16.18
N_2	1.72
Ar	0.15
Total	100.00
	Major contaminants (ppmv)
H_2S	0.22
COS	0.02
NH_3	0.4
HCN	0.0
Hg (ppbv)	0.1

The Rectisol process contacts fuel gas recuperatively-cooled to about -32°C (-26°F) (Item 1) with refrigerated methanol at about -71°C (-95°F) (Item 8) in a multi-staged, bubble-cap tray, counter-current absorption column (Item 3). A small portion of methanol is injected directly into the fuel gas stream before heat interchanger Item 1 to remove water from the fuel gas (Item 2) to eliminate the possibility of ice formation. The desulfurized fuel gas achieves a level of about 0.3 ppmv total sulfur content. The desulfurized, reheated fuel gas exits the process (Item 1) at about 13°C (56°F). Makeup methanol solvent at 133 kg/hr (293 lb/hr) is fed to the process to account for process losses, and a methanol decontamination step is included in the process. The process uses significant energy for refrigeration associated with heat interchanger Item 8 and condenser Item 12 to meet this level of sulfur removal. The lean solvent is flashed in a series of three flash to low pressure, 103 kPa (15 psia) and is circulated to a solvent stripper column (Item 11). The stripper generates a low-pressure, acid gas that is sent to a sulfur recovery process. Table 6.10 summarizes the fates of the contaminants within the desulfurization process.

Table 6.9 – Stream Characteristics for AGR Section

Stream name	Fuel gas from LT-Cooling	Desulfurized fuel gas	Acid Gas to Sulfur Recovery
Molar flow, kmole/hr	9,759	9,654	625
Mass flow, kg/hr	212,045	208,384	26,216
Volumetric flow, m^3/hr	3,530	3,287	8,143
Temperature, °C	38	14	22
Pressure, kPa	7,191	6,978	186
Enthalpy, MJ/hr	-1.044E+06	-1.050E+06	-1.99E+05
Molecular wt	21.7	21.6	41.9

Table 6.10 – Fate of Contaminants in the Conventional Desulfurization Section

Contaminant	Removal (% of inlet to Section)	Contaminant conversions
Sulfur species	99.9978	Methanol stripper
Halides	NA	
Ammonia	99.1	None
Hydrogen cyanide	NA	
Mercury	100	Accumulates in methanol

Table 6.11 lists the composition of the desulfurized fuel gas. Table 6.12 lists the composition of the acid gas sent to the Sulfur Recovery Section.

Table 6.11 - Desulfurized Fuel Gas Composition – Conventional Methanol Synthesis

	Major constituents (vol%)
H_2	32.43
CH_4	0.39
CO	52.27
CO_2	12.68
H_2O	0.00
N_2	2.05
Ar	0.18
Total	100.00
	Major contaminants (ppmv)
H_2S	0.26
COS	0.03
NH_3	0.4
HCN	0.0
Hg (ppbv)	0.1

Table 6.12 - Acid Gas Composition - Conventional Methanol Synthesis

	Major constituents (vol%)
H_2	0.00
CO	0.05
CO_2	79.34
H_2O	0.00
H_2S	19.89
COS	0.02
NH_3	0.07
HCN	0.00
Methanol	0.63
Total	100.00

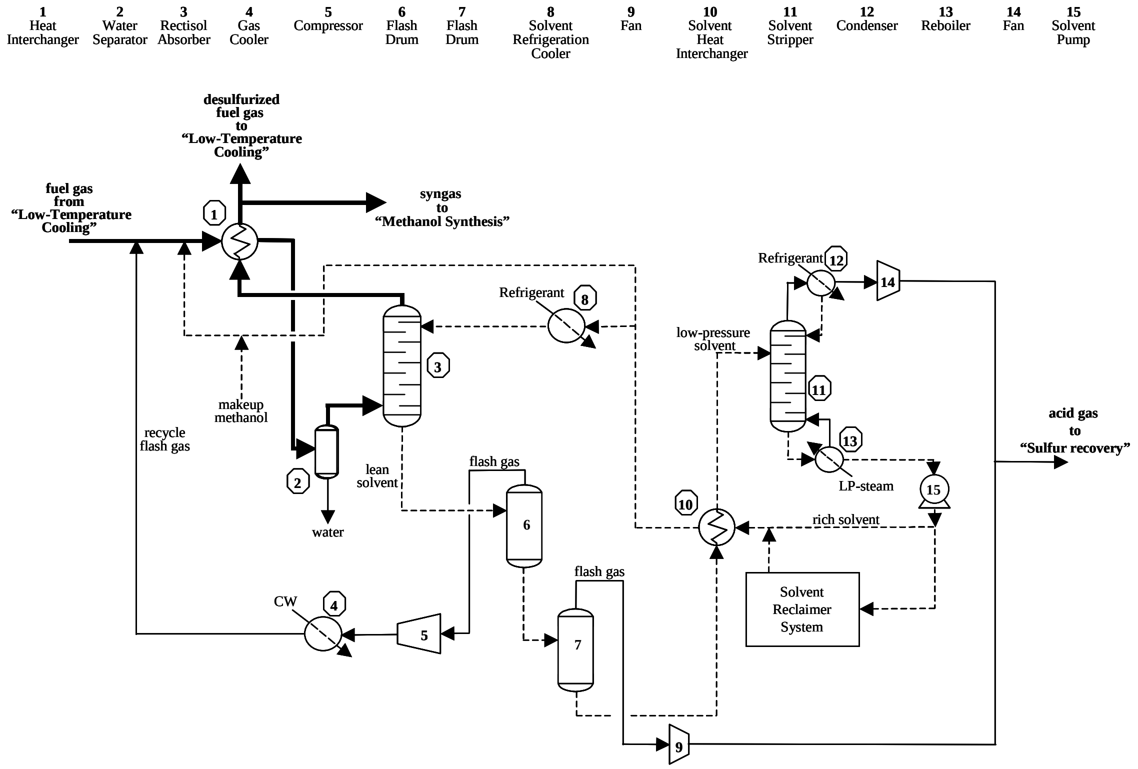


Figure 6.4 – AGR Section - Conventional Methanol Synthesis

Methanol Synthesis Section

Figure 6.5 illustrates the Methanol Synthesis Section of the plant. Table 6.13 lists characteristics of the major streams in this section. Liquid Phase Methanol synthesis technology is applied. Syngas, at 13°C (56°F), is split from the AGR Section product stream, is passed through a metal carbonyl adsorption bed (Item 1), followed by a process stream heat interchanger (Item 2) that warms the syngas to 204°C (400°F), and a sulfur adsorption bed (Item 3) that polishes the syngas to meet methanol synthesis sulfur requirements. This syngas is then humidified to greater than 9 vol% water vapor in a column of circulating boiler feed water (Item 4). This circulating water is heated by internal heat transfer surface placed in the Liquid Methanol synthesis reactor (Item 7). The humidified syngas passes through the methanol synthesis reactor where about 41% of the syngas hydrogen is converted to methanol. In addition to heating circulating boiler feed water, LP-steam is generated in the methanol reactor fluid bed, controlling the exit gas temperature to about 249°C (480°F). A cyclone captures and recycles elutriated catalyst particles and oil to the bed. The methanol reactor product gas is then cooled to about 99°C (210°F) and oil is separated from the product gas in a separation vessel (Item 9). The product gas is further cooled to about 38°C (100°F) before passing through a knock-out vessel (Item 12) to separate the synthesis liquid and purge gas products. The purge gas from the knock-out vessel is reheated to about 87°C (189°F) before passing to the Power Section.

The fate of the contaminants within the Methanol Synthesis Section are listed in Table 6.14. The purge gas composition is presented in Table 6.15, and has a heating value of about 8.73 MJ/Nm^3 (222 Btu/scf). The synthesis product is flashes to about 117 kPa (17 psia) (Item 13) to separate some dissolved gases, at about 109 kg/hr (240 lb/hr) from the crude methanol product. The crude methanol is distilled (Item 14) to generate the fuel-grade methanol product. In total, 93.0 % of the methanol generated in the synthesis reactor is recovered in the final product.

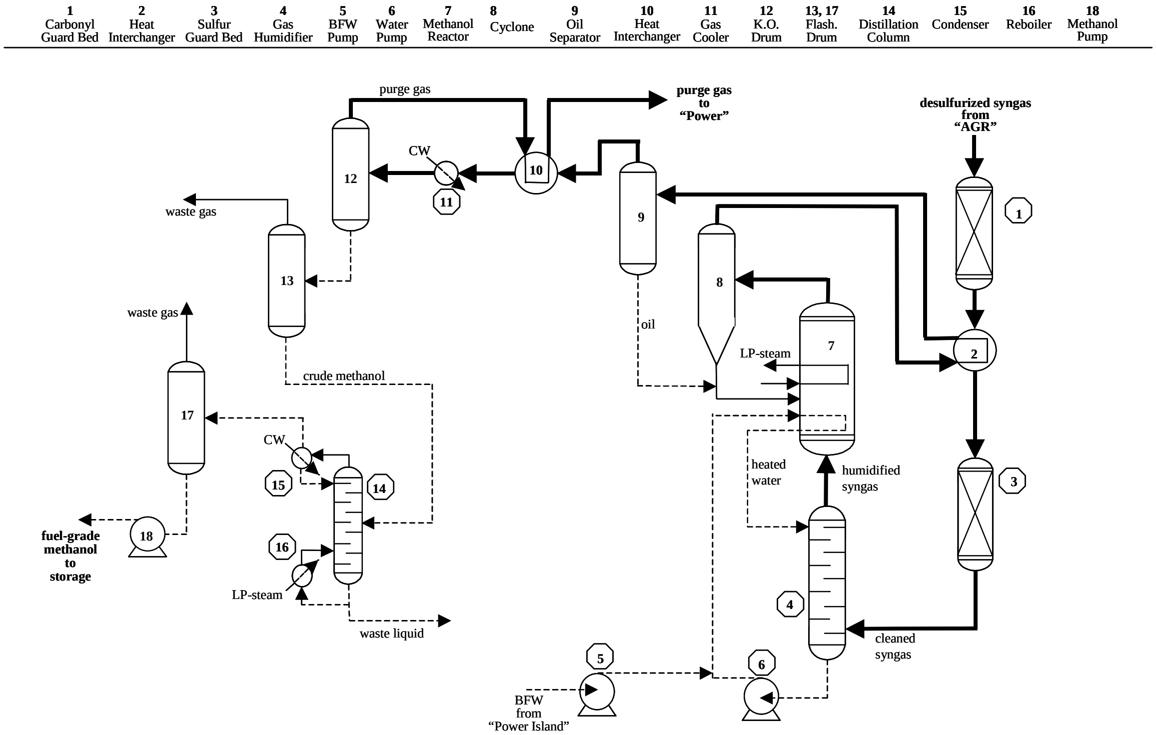


Figure 6.5 – Methanol Synthesis Section - Conventional Methanol Synthesis

Table 6.13 – Stream Characteristics for AGR Section

Stream name	Desulfurized fuel gas feed	Methanol product	Purge gas to Power Section
Molar flow, kmole/hr	4.427	280	3,973
Mass flow, kg/hr	95,566	8970	94,220
Volumetric flow, m^3/hr	1,504	12	1,855
Temperature, °C	13	38	87
Pressure, kPa	6,978	345	6,440
Enthalpy, MJ/hr	-4.82E+05	-67,731	-5.64E+05
Molecular wt	21.6	32.1	23.7

Table 6.14 – Fate of Contaminants in Methanol Synthesis Section

Contaminant	Removal (% of inlet to Section)	Contaminant conversions
Metal carbonyls	90	Sorbent fixation
Sulfur species	90	Sorbent fixation
Halides	NA	----
Ammonia	NA	----
Hydrogen cyanide	NA	----
Mercury	NA	----

Table 6.15 – Purge Gas Composition - Conventional Methanol Synthesis

	Major constituents (vol%)
H_2	31.87
CH_4	0.43
CO	39.76
CO_2	24.98
H_2O	0.01
N_2	2.29
Ar	0.20
methanol	0.45
Total	99.99

The composition of the fuel-grade methanol is listed in Table 6.16. The composition is reported on a weight-percent basis and meets all specifications for fuel-grade methanol.

Table 6.16 – Methanol Composition with Conventional Cleaning

	Major constituents (wt%)
H_2O	0.55
CO_2	0.04
Methanol	98.00
Methyl formate	0.18
Ethanol	1.23
Total	100.00

Sulfur Recovery Section

Figure 6.6 shows the process flow diagram for the Sulfur Recovery Section of the plant. It is almost identical in configuration to the Sulfur Recovery Section described for IGCC application with conventional gas cleaning, only with increased flow capacity of about 16%. The sour-water gas, containing significant ammonia and H_2S, and an appropriate portion of the acid gas are combined and are burned in the Claus furnace (Item 2) with a stream of oxygen, at 1,750 kg/hr (3,857 lb/hr) from the air separation unit. The sulfur recovery process recovers about 94.6% of the sulfur content of the acid gas. The collected sulfur streams are combined and the sulfur, at 4,096 kg/hr (9,031 lb/hr) is stored for treatment and marketing as a by-product.

The untreated tail gas, at 24,253 kg/hr (53,467 lb/hr), contains a considerable content and variety of sulfur species (H_2S, SO_2, S_x), and the only way the power plant can achieve its overall 99.85% sulfur removal goal is for this tail gas to be recompressed and recycled to the desulfurizer. A catalytic hydrolyzer bed (Item 20), operating at about 316°C (600°F) is used to eliminate the oxidized sulfur species, and requires an additional oxygen feed stream of 363 kg/hr (800 lb/hr) to conduct partial oxidation to bring the gas to sufficient temperature.

The fates of the contaminants in the Sulfur Recovery Section are listed in Table 6.17. After cooling and compression and condensate removal, the tail gas recycled to the Gasifier has the composition reported in Table 6.18.

Table 6.17 – Fate of Contaminants in Conventional Sulfur Recovery Section

Contaminant	Removal (% of inlet to Section)	Contaminant conversions
Sulfur species	94.66	Claus conversion to elemental sulfur Hydrolysis to reduced forms
Halides	NA	----
Ammonia	86.5	Furnace decomposition to N_2
Hydrogen cyanide	NA	----
Mercury	NA	----

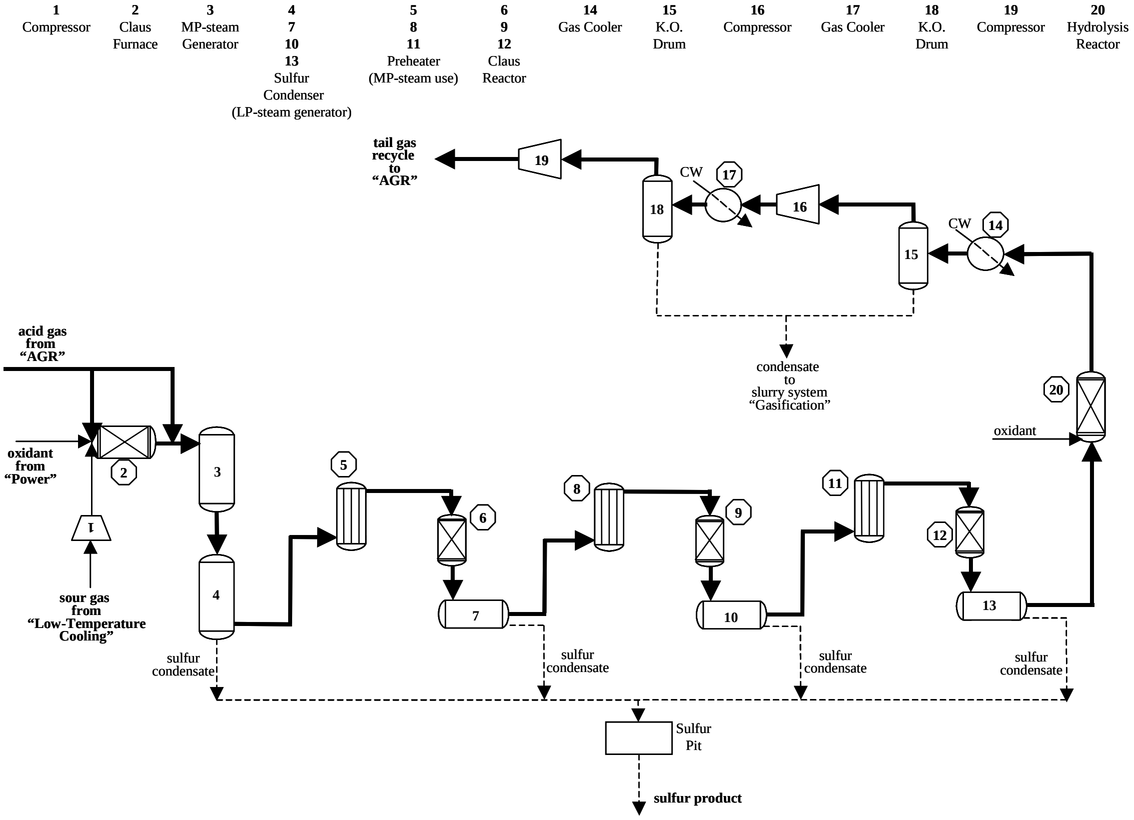


Figure 6.6 – Sulfur Recovery Section - Conventional Methanol Synthesis

Table 6.18 - Recycle Tail Gas Composition - Conventional Methanol Synthesis

	Major constituents (vol%)
H_2	1.56
CO	0.26
CO_2	95.53
H_2O	0.44
N_2	0.79
Ar	0.06
H_2S	1.26
SO_2	0.00
COS	0.00
NH_3	0.07
HCN	0.00
Methanol	0.00
Total	99.97

Power Section

The Power Section process flow diagram is shown in Figure 6.7. This is identical to the process flow diagram for the conventional IGCC Power Section, except that a purge gas stream from the Methanol Synthesis Section and the clean fuel gas stream are both expanded and mixed before being fired in the gas turbine combustors. An oxygen stream, at 108,567 kg/hr (239,345 lb/hr), with 95% purity, is generated by conventional, pressurized, cryogenic air separation (ASU). High-pressure fuel gas from the fuel gas cleaning process, at 130,988 kg/hr (288,774 lb/hr), 271°C (520°F) and 6,846 kPa (993 psia) is expanded (Item 14) to the pressure needed by the turbine combustors, and electric power is generated. Purge gas from the methanol synthesis plant, at 94,222 kg/hr (207,720 lb/hr), 32°C (89°F) and 6,440 kPa (934 psia) is expanded (Item 20) and is combined with the clean fuel gas. Low-purity nitrogen from the ASU is humidified (Item 25) to about 15 vol% water vapor using low-grade heat sources, and the nitrogen stream, at 333,848 kg/hr (735,997 lb/hr) is mixed with the clean fuel gas before the mixture is distributed to the gas turbine combustors (Item 6).

The turbine combustors, advanced, low-NOx burners specifically designed for low heating-value fuel gas, operate with an outlet temperature of about 1524°C (2775°F), and with the peak flame temperature of less than 1649°C (3000°F). The NOx emission is expected to be less than 5 ppmv (dry, corrected to 15% oxygen). The turbine exhaust gas has a mass flow of 1,727,969 kg/hr (3,809,456 lb/hr) and a temperature of 621°C (1150°F). The exhaust gas passes through the heat recovery steam generator (Item 9), generating a superheated, high-pressure steam flow of 401,890 kg/hr (886,000 lb/hr). The fates of the contaminants in the Power Section are listed in Table 6.19. The stack gas from the power plant has a temperature of 104°C (220°F) and a composition listed in Table 6.20.

1 Turbine Compressor
2 Heat Interchanger
3 Heat Interchanger
4 Air Cooler
5 Oxidant Compressor
6 Turbine Combustor
7 Turbine Expander
8 Gas Turbine Generator
9 HRSG
10 HP-steam turbine
11 IP-steam Turbine
12 LP-steam Turbine
13 Steam Turbine Generator
14 Steam Condenser
15 Condensate Pump
16 Condensate Heater
17 Deaerator
18 Feed Water Pump
19 Fuel Gas Expander
20 Purge Gas Expander
21 Nitrogen Compressor
22 Nitrogen Compressor
23 Heat Interchanger
24 Water Pump
25 Nitrogen Humidifier
26 Pulse Gas Compressor

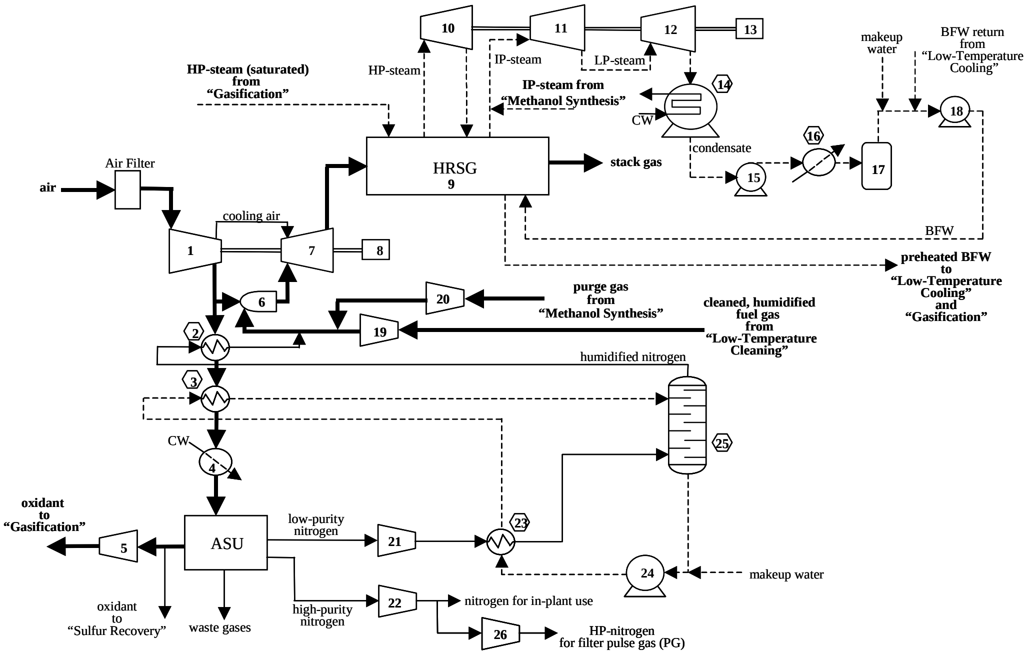


Figure 6.7 – Power Section - Conventional Methanol Synthesis

Table 6.19 – Fate of Contaminants in Conventional Power Section

Contaminant	Removal (% of inlet to Section)	Contaminant form conversion
Sulfur species	0	Oxidation to SOx
Halides	NA	----
Ammonia	0	partial oxidation conversion to NOx
Hydrogen cyanide	NA	----
Mercury	0	partial conversion to oxidized forms

Table 6.20 - Stack Gas Composition - Conventional Methanol Synthesis

	Major constituents (vol%)
O_2	7.92
CO_2	10.12
H_2O	10.65
N_2	70.46
Ar	0.85
Total	100.00
	Minor contaminants
SO_2 (ppmv)	0.033
NOx (ppmv)	5
Mercury (ppbv)	0.012
Particulate (ppmw)	0.1

6.2 CONVENTIONAL METHANOL SYNTHESIS PLANT PERFORMANCE ESTIMATES

The breakdown of power generation and power use in the Methanol Synthesis plant with conventional, low-temperature gas cleaning technology is shown in Table 6.21. The Power Island of the plant generates a net 348.5 MWe which includes 8.6 MWe from the fuel gas and purge gas expanders. The ASU consumes a total of 41.2 MWe of power. The next dominant power consumer in the plant is the AGR Section, 12.8 MWe consumed primarily for gas refrigeration. The net plant efficiency of 32.7% (HHV) does not include any credit for the methanol product heating value.

Table 6.22 lists several quantities related to the use of resources and emissions in the plant with conventional, low-temperature gas cleaning technology. The plant uses a large quantity of LP-steam in the gas cleaning process steps. Cooling water use in the processing steps is also very large. Large quantities of process condensate are generated, primarily in the Low-Temperature Cooling Section. A moderate level of fresh process water is required in the gas cleaning processes. A large quantity of boiler-quality makeup water for fuel gas humidification is used.

The total sulfur emissions are expressed under three different bases: percent removal, lb per unit fuel energy input, and mass per MWe net power generated. The sulfur emissions are extremely low, and are comparable to the sulfur emissions from a natural gas-fired, combined-cycle power plant. Estimated solid waste rates from the plant are large, resulting mainly from the wet slag product and the waste salts generated. The rate of solid waste is not sensitive to the gas cleaning process performance.

Table 6.21 –Methanol Synthesis Plant Thermal Performance with Conventional Gas Cleaning

Section	Power (MW)
Power Island Generation	
Turbine air compressor	-180.3
Gas turbine expander	371.4
Steam turbine cycle	161.7
Fuel gas expander	6.2
Purge gas expander	2.4
Generator	-7.2
BOP	-5.7
Total power generation	348.5
Air Separation Consumption	
ASU Air compressor	0
Oxygen compressor	8.2
Nitrogen compressor	9.1
ASU	23.9
Total power use	41.2
Gasification Consumption	
Compressors	0.3
Pumps	0.2
Coal handling and preparation	1.8
Ash handling	1.5
Total power use	3.8
Low-Temperature Cooling Consumption	
Pumps	0.0
AGR Consumption	
Refrigeration	10.9
Compressors	1.3
Pumps	0.6
Total power use	12.8
Sulfur Recovery Consumption	
Compressors	2.3
Pumps	0.0
Total power use	2.3
Methanol Synthesis Consumption	
Pumps	0.0
Total Plant	
Net plant power generated, MW	288.3
Plant net heat rate, kJ/kWh (Btu/kWh) (HHV)	11,008 (10,434)
Plant net efficiency, %, (LHV)	35.2
Plant net efficiency, %, (HHV)	32.7

Table 6.22 – Methanol Plant Conventional Gas Cleaning Resource Use and Emissions

Process Steam & Water	
Net IP steam process use, MJ/hr (10^6 Btu/hr)	-264 (-2.5)
Net LP steam process use, MJ/hr (10^6 Btu/hr)	77,233 (73.2)
Total process cooling water use, MJ/hr (10^6 Btu/hr)	308,089 (292)
Net process condensate generated, kg/hr (lb/hr)	2,641 (5,823)
Total process water used, kg/hr (lb/hr)	3,139 (6,920)
Net process water makeup, kg/hr (lb/hr)	498 (1,097)
Total boiler-feed-water makeup, kg/hr (lb/hr)	59,972 (132,213)
Emissions	
Sulfur total removal efficiency, %	99.9985
Sulfur total emission (HHV), mg/MJ (lb SO_2/ 10^6 Btu)	0.0426 (9.916x$10^{-5)}$
Sulfur total emission, kg/MW (lb SO_2/MW)	0.00044 (0.00096)
NOx total emission (HHV), mg/MJ (lb NO_2/ 10^6 Btu)	4.30 (0.0100)
Particulate emission, mg/MJ (lb/ 10^6 Btu) (HHV)	0.0071 (1.65E-05)
Hg emission, mg/MJ (lb/TBtu) (HHV)	0.043 (0.101)
Chemicals, Sorbents, and Catalysts, kg/hr (lb/hr)	
Methanol	136 (300)
Mercury sorbent	2.3 (5)
Guard bed sulfur sorbent	0.9 (2)
Guard bed metal carbonyl sorbent	0.9 (2)
COS hydrolysis catalyst	0.5 (1)
Claus reactor catalyst	2.3 (5)
Solid waste, kg/hr (lb/hr)	
Slag product (25 wt% water)	16,313 (35,964)
Waste salts (25 wt% water)	338 (745)
Sorbent & catalyst wastes (hazardous)	7 (15)
Total solid waste	16,658 (36,724)

6.3 CONVENTIONAL METHANOL SYNTHESIS PLANT COST ESTIMATES

No financial analysis for this co-production plant has been performed in this evaluation. The evaluation utilizes direct comparison of gas cleaning equipment investment, annual operating cost of the gas cleaning equipment, total plant electricity production and methanol production as the basis for comparison.

The major equipment purchase costs and installed costs are listed in Table 6.23 for each of the cleaning sections of the plant evaluated. The Gasification Section's cost for the convective cooler has been included in the cost breakdown since this will differ from the convective cooler cost in the Novel Gas Cleaning process. Also, the Mercury Removal cost has been taken out of the Low-Temperature Cooling Section cost and reported as a separate item. Only the gas cleaning costs associated with the Methanol Synthesis Section are included. The Low-temperature Cooling Section is the second most expensive of the gas cleaning sections, and its cost approaches the cost of the Desulfurization Section. The total gas cleaning costs are also reported on the basis of dollars per kilowatt of net power generated. While the total gas cleaning equipment cost approaches 200 \$/kW, this is clearly only a small portion of the total plant equipment cost. The impact of gas cleaning on the overall plant performance and its operating cost are much more important factors.

Table 6.23 - Conventional Gas Cleaning Technology Equipment Cost Breakdown

Plant Section	Cost, k$
Raw gas convective cooling	
purchased equipment	1,481
installed equipment	2,962
Low-temperature Cooling	
purchased equipment	6,824
installed equipment	13,294
Mercury removal	
purchased equipment	481
installed equipment	704
AGR	
purchased equipment	11,177
installed equipment	19,385
Sulfur Recovery	
purchased equipment	6,345
installed equipment	10,781
Methanol Synthesis (gas cleaning only)	
purchased equipment	1,766
installed equipment	3,443
Fuel gas and Purge gas expanders	
purchased equipment	870
installed equipment	1,305
Total	
purchased equipment	28,944
installed equipment	51,873
purchased equipment, $/kW	96
installed equipment, $/kW	172
Total Plant	
TCR, k$	516,316
TCR,$/kW	1791

The Total Capital Requirement for the Methanol Synthesis plant using conventional, low-temperature gas cleaning technology was estimated by scaling the non-gas cleaning equipment costs from IGCC power plant cost data. A confirmed basis does not exist for making this estimate, so the total plant costs are uncertain, but represent a good basis for technology comparisons. Table 6.24 shows the estimate for the Total Capital Requirement for the plant, and lists the breakdown for the Cost-of-Electricity (COE) for the plant using representative by-product values for the methanol and elemental sulfur products. Coal slag is assumed to be a disposal product having no value. The objective here is not to assess the financial implications for such a plant, but it to provide a basis for comparison with the COE for a comparable plant using Novel Gas Cleaning technology.

Table 6.24 – Methanol Plant with Conventional Gas Cleaning -Cost-of-Electricity

	COE (Cents/kWh)
Fixed O&M	0.40
Variable O&M	0.26
Consumables	0.22
water	0.040
chemicals, sorbents, catalysts	0.051
waste Disposal	0.130
By-product credit	1.10
sulfur	0.073
methanol	1.03
Fuel	1.94
Capital charges	3.83
Total	5.55

Table 6.24 shows clearly that the gas cleaning process equipment cost has little impact on the COE of the plant, but the gas cleaning process influence on the plant efficiency is very important. Consumables in the conventional technology plant have a very small impact on the COE. This sensitivity perspective indicates that the gas cleaning process focus should be on minimizing performance losses rather than on minimizing equipment costs.

7. METHANOL SYNTHESIS WITH NOVEL GAS CLEANING

The Novel Gas Cleaning technology for methanol synthesis is similar to the Novel Gas Cleaning technology applied for IGCC with Future Standards (Section 5), but an additional syngas polishing section is used to meet the methanol synthesis requirements. This section of the report describes the Novel Gas Cleaning technology applied to methanol synthesis. The performance and cost-potential of methanol synthesis using Novel Gas Cleaning technology is compared to that of methanol synthesis using conventional gas cleaning technology, as described in Section 6.

7.1 DESCRIPTION OF METHANOL SYNTHESIS WITH NOVEL GAS CLEANING

The overall Methanol Synthesis process is illustrated in Figure 7.1. It is similar to the IGCC power plant using Novel Gas Cleaning technology with Future Standards, except that

- a greater coal feed rate, about 16% greater, is used to accommodate the fuel needs for both power generation and methanol synthesis,
- the gasifier is operated at a much higher pressure to generate syngas that can meet the high-pressure needs of the methanol synthesis reactor,
- the partially cleaned gas is split into a fuel gas stream for power generation and a syngas stream for methanol synthesis, and this syngas stream is polished using a water scrubbing process to meet its stringent cleaning standards.

The plant consists of six sections: Gasification, Fuel Gas Cleaning, Sulfur Recovery, Syngas Cleaning, Methanol Synthesis & Distillation, and Power. As with the conventional methanol synthesis plant described in Section 6, a stream of “syngas” is split from the cleaned fuel gas stream, and this is further cleaned of sulfur, halides and fuel-bound nitrogen using a wet scrubbing process before the syngas is conditioned and reacted for methanol synthesis. The methanol synthesis purge gas is expanded and combined with the fuel gas fed to the Power Section of the plant.

The very stringent gas cleaning standards for methanol synthesis are met by using a zinc oxide sorbent in a regenerative, transport reactor system for bulk sulfur control, followed by two stages of once-through, zinc-based sorbent polishing. Halides are controlled by once-through nahcolite sorbent injection into a primary filter vessel located before the bulk sulfur removal process, followed by an additional polishing stage of halide wet scrubbing at a lower temperature condition. For methanol synthesis, specifications for ammonia and HCN are also very stringent. Because no ammonia sorbent is current available, and because there is little advantage in retaining water in the synthesis gas stream, HCN hydrolysis to ammonia is followed by warm-water scrubbing of ammonia. Using this scrubbing scheme, the ammonia is easily reduced to less than the specified level for methanol synthesis, and the halides are simultaneously reduced to acceptable levels. Condensate containing ammonia and HCl is recycled to the gasifier where ammonia is decomposed. Recycled HCl is eventually captured in the Bulk Halide Removal system. Metal carbonyls are less likely to form in the Novel Gas Cleaning process than in the conventional gas cleaning process, but because of uncertainty, a carbonyl guard bed is included in the Novel Gas Cleaning process.

Gasification Section

Figure 7.2 shows the process flow diagram constructed for the Gasification Section using the Novel Gas Cleaning technology, and includes designation of the Coal Receiving and Handling System and the Slurry Preparation System. The process diagram is nearly identical to the Gasification Section process flow diagram for IGCC with Future Standards in Section 5. Oxidant from the Power Section's Air Separation Unit, at about 106,476 kg/hr (234,735 lb/hr) combines with the coal slurry, at 166,004 kg/hr (365,969 lb/hr) to generate high-temperature, raw gas and slag streams. The raw gas flow rate at the exit of the Convective Cooler (Item 7) is about 273,006 kg/hr (601,864 lb/hr), with heat content of 2,254,745 MJ (2,137 x 10^6 Btu/hr) (LHV) and heating value of about 7.78 MJ/Nm^3 (198 Btu/scf), and includes about 11,794 kg/hr (26,000 lb/hr) of recycled, clean fuel gas used as soot blower gas for the raw gas heat exchangers.

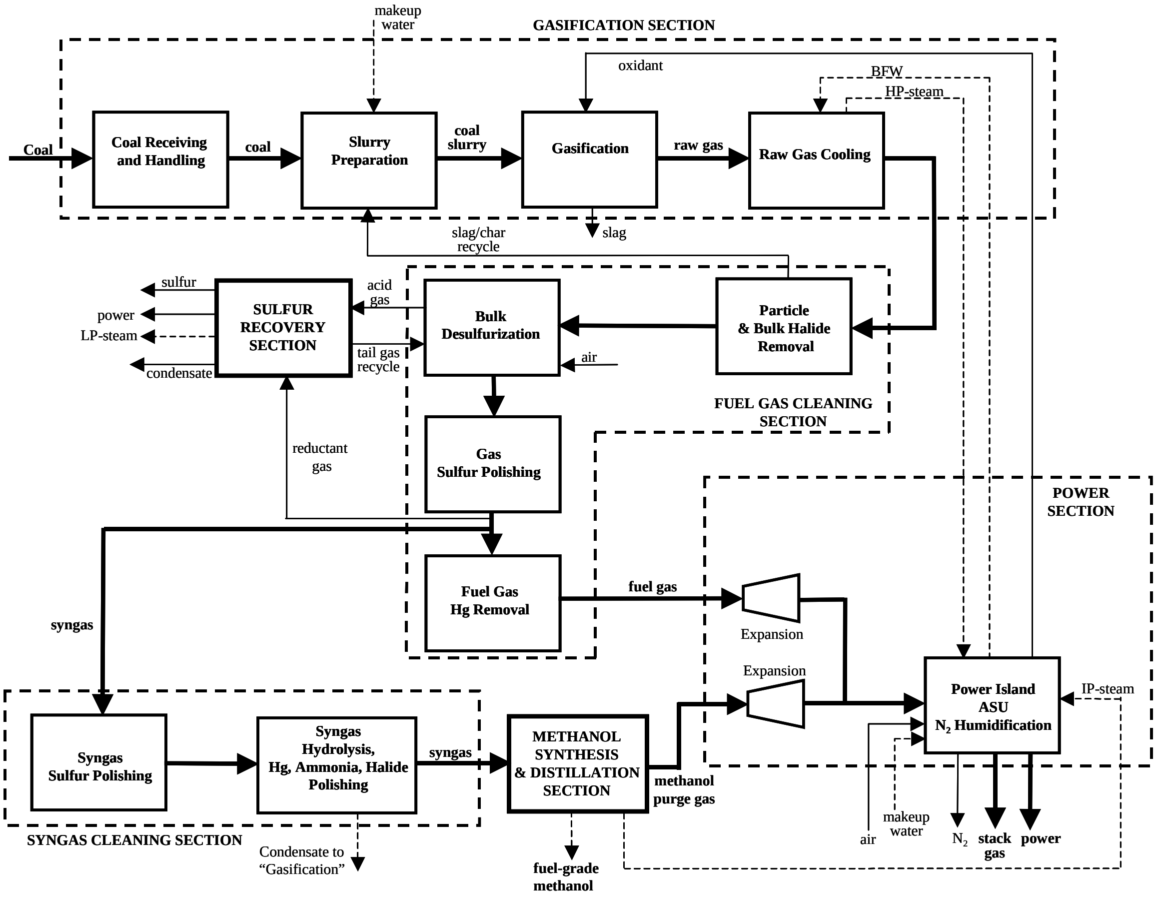


Figure 7.1 - Overall Plant Scheme for Methanol Synthesis with Novel Gas Cleaning

The raw gas exits the gasifier at about 1407ºC (2565ºF) and 8,791 kPa (1275 psia), and 593ºC (1100ºF) from the Convective Cooler, with the estimated composition listed in Table 7.1, not including entrained slag. The raw gas is cooled in a radiant cooler, raising saturated, high-pressure (HP) steam, and cooling the fuel gas to about 816ºC (1500ºF) to solidify slag particles before cooling the fuel gas further in a convective cooler to generate additional saturated HP-steam.

Fuel Gas Cleaning Section

Figure 7.3 shows the process flow diagram for the Fuel Gas Cleaning Section. It is identical to Figure 5.3, for the Current Standards case, except that a Fuel Gas Polishing Filter-Reactor (Item 16) and Polishing Sulfur Sorbent Feed System (Item 15), and Sorbent Waste Removal System (Item 17) have been inserted after the bulk desulfurizer for additional sulfur removal. The flows and compositions are also similar except as noted below.

Table 7.1 - Raw Gas Composition – Novel Gas Cleaning

	Major constituents (vol%)
H_2	25.39
CH_4	0.30
CO	40.77
CO_2	9.86
H_2O	20.68
N_2	1.80
Ar	0.14
Total	98.94
	Major contaminants (ppmv)
H_2S	8,515
COS	636
CS_2	0.6
S_X	2
SO_2	1
NH_3	687
HCN	20
HCl	436
Hg (ppbv)	3

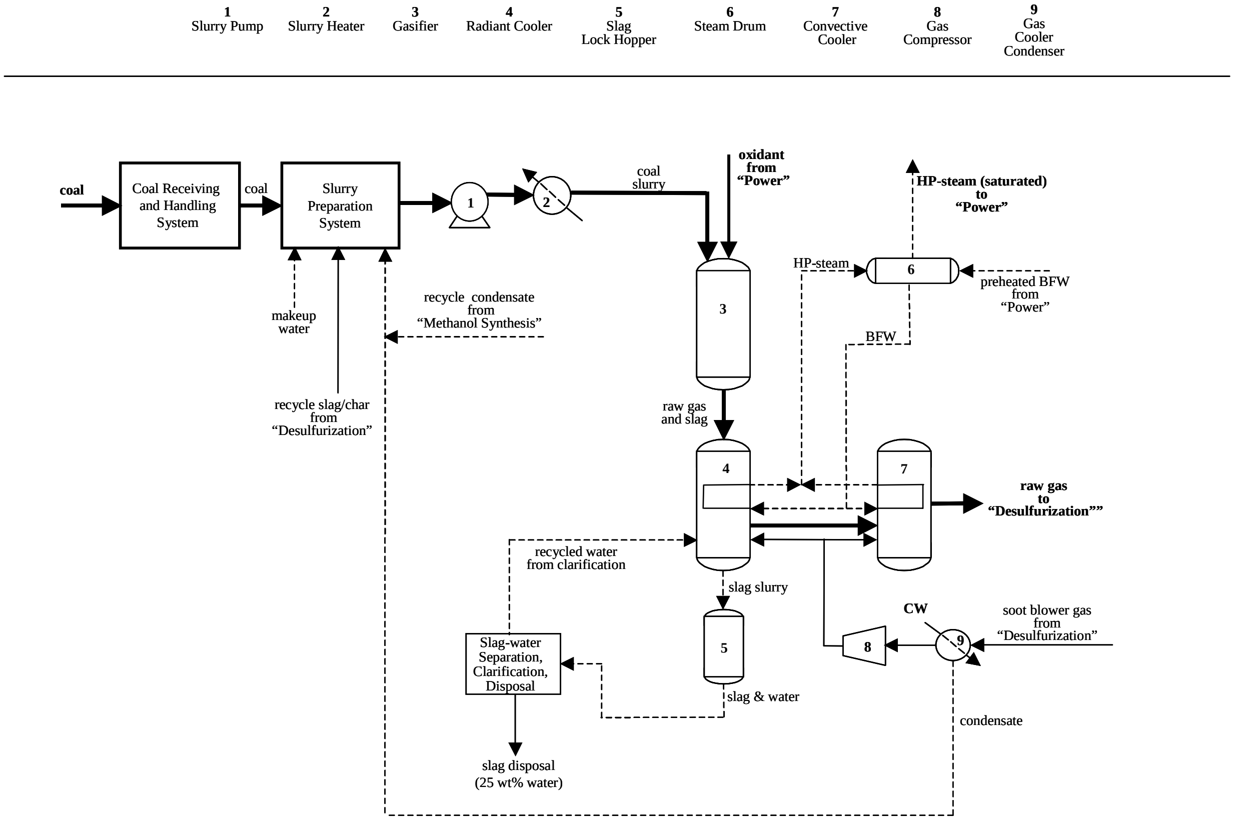


Figure 7.2 - Gasification Section with Novel Gas Cleaning

Particle & Bulk Halide Removal: This section is identical its functions and performance as the Particle & Bulk Halide Removal system described in Section 5 for IGCC. It operates at 593ºC (1100°F) and removes raw gas particulate using a conventional cyclone followed by a ceramic barrier filter-reactor, as was used for IGCC in Section 5. 2,424 kg/hr (5,343 lb/hr) of a halide sorbent, nahcolite, is injected into the gas entering the filter-reactor to capture halides. This feed rate is equivalent to a sodium-to-halide molar feed ratio of greater than 4. 99.1% of the halides (HCl-basis) are removed, to a content of about 4 ppmv. Because the gas volumetric flow at this high pressure is relatively small, the filter-reactor is relatively small, less than 9 feet in diameters and 50 feet tall, containing two standard filter clusters, holding a total of 374 standard, low-cost, commercial ceramic filter candles.

Gas heat interchanger (Item 5): The gas is cooled in a heat interchanger to 482ºC (900°F) preheating the methanol purge gas stream that passes to the Power Section of the plant. This gas is then mixed with recycled tail gas from the downstream, sulfur recovery process, a flow of about 11% of the gas stream.

Bulk desulfurization: The gas now enters the bulk-desulfurization process where its total sulfur content is reduced to less than 50 ppmv, about a 99.5% reduction of H_2S, COS, CS_2, Sx, and SO_2 contained in the gas, with significant hydrolysis of CS_2, Sx and SO_2 to H_2S also expected. The zinc titanate sorbent is assumed to have a Zn/Ti mole ratio of 1.0, and to operate with a net, sorbent makeup stoichiometric molar feed ratio of 0.0027 Zn/S provided by the sorbent feed system D-P-3. The gas passes through a transport reactor (Item 6) of circulating zinc titanate sorbent, producing a bulk-desulfurized gas having total sulfur content of about 43 ppmv and containing some entrained sorbent particles that escape the transport reactor disengaging section. The partially-sulfided sorbent particles circulating in to the desulfurizer leg have a molar ratio for ZnO/S of about 221. The sulfided sorbent particles circulate to the parallel, entrained regenerator vessel (Item 8) where air contacting generates an SO_2 acid gas and regenerated zinc titanate sorbent. Compressed air is provided by compressor Item 12, and a fired heater (Item 11) is also provided for preheating the regenerator air. Nitrogen fluffing gas and nitrogen purging of the transport legs between the gasifier and regenerator are used, this compressed nitrogen coming from the Power Island. The regenerator acid gas, at about 733ºC (1352°F), passes through a relatively small barrier filter (Item 9) to separate its entrained sorbent particles. The entrained sorbent particles captured in this filter are cooled and back to the standleg of sorbent flowing back to the desulfurizer vessel, or may be drained into the bulk desulfurized fuel gas exiting the vessel. The bulk-desulfurized gas leaves the process at about 550ºC (1022°F) carrying all of the sorbent lost by attrition and elutriation from the bulk-desulfurization process. The bulk desulfurized fuel gas has a flow of 311,534 kg/hr (686,803 lb/hr), at 550ºC (1022°F) and 7770 kPa (1127 psia), and its composition is listing in Table 7.2. Note that it contains significant particulate in the form of zinc-titanate sorbent particles. The relatively high nitrogen content in the fuel gas results largely from the sulfur recovery tail gas. The acid gas generated has the composition listed in Table 7.3. Its flow is 28,970 kg/hr (63,867 lb/hr) at 733ºC (1352°F) and 7688 kPa (1115 psia). Note that in contrast to the IGCC application in Section 5, for methanol synthesis it is desirable to minimize the nitrogen content of the methanol synthesis gas, and recycled fuel gas us used for pulse gas cleaning, sorbent feeding, fluffing and stripping rather than using nitrogen. Waste sorbent handling continues to use nitrogen since this does not dilute the synthesis gas stream.

Fuel Gas Sulfur Polishing Filter-Reactor: The bulk desulfurized gas is cooled in process heat exchangers 13 and 14 to 482C (900°F). 20 kg/hr (43 lb/hr) of polishing sulfur sorbent particles, also zinc titanate-type, are injected into the gas and, combined with the entrained sorbent particles from the bulk-desulfurization process, the mixture enters a barrier filter and results in additional 96% sulfur removal down to a level of total sulfur less than 2 ppmv. The polished fuel gas composition is listed in Table 7.4. The sorbent makeup rate uses a stoichiometric ratio of 0.2 Zn/S in the regenerative operation. The partially-sulfided sorbent particles carried with the fuel gas have a molar ratio for ZnO/S of about 3.3. The filter separates the entrained bulk-sorbent particles and the polishing sorbent particles from the fuel gas. The collected sorbent particulate is drained from the filter and is pneumatically fed back to the bulk desulfurization process regenerator. This filter-reactor is slightly smaller in dimension than the bulk halide filter-reactor and contains the same number of filter candles. The small amount of waste sorbent ultimately drained from this system is either disposed directly or is fed to the gasifier to be incorporated into the plant slag by-product. At this point the gas stream is split into the “fuel gas” stream, at 162,454 kg/hr (358,144 lb/hr) and the “syngas” stream at 148,688 kg/hr (327,796 lb/hr).

Gas cooling: The fuel gas stream is cooled in Item 18 to a temperature of about 204ºC (400°F), suitable for mercury removal in the Fuel Gas Mercury filter-reactor (Item 20). The Hg-cleaned fuel gas passes through a heat interchanger (Item 22) to reheat the clean fuel gas from 204ºC (400°F) to 433ºC (811°F) and to cool the syngas stream passing to the Methanol Synthesis Section. The clean fuel gas then passes to heat interchanger 13 where it is reheated to 522ºC (972°F), before passing to the Power Section.

Table 7.2 - Bulk Desulfurized Gas Composition – Novel Methanol Synthesis

	Major constituents (vol%)
H_2	23.80
CH_4	0.29
CO	38.20
CO_2	10.82
H_2O	19.43
N_2	7.21
Ar	0.19
Total	99.94
	Major contaminants (ppmv)
H_2S	39.78
COS	2.84
HCl	3.65
NH_3	160
HCN	19
Hg (ppbv)	2.5
Particulate (ppmw)	1411

Table 7.3 - Acid Gas Composition – Novel Methanol Synthesis

	Major constituents (vol%)
N_2	83.80
Ar	0.95
CO_2	0.03
H_2O	1.03
SO_2	14.18
Total	99.99

Soot-blower gas, at 11,616 kg/hr (25,608 lb/hr), transport and pulse gas, at 15,513 kg/hr (34,200 lb/hr) and Sulfur Recovery reductant gas, at 8,763 kg/hr (19,319 lb/hr) are extracted from the fuel gas stream at this point. This gas is particulate-free, and is compressed at this point. About 5.4% of this fuel gas stream is separated to be used as a reductant in the sulfur recovery process. These are all recycles streams and result in little fuel gas loss.

Table 7.4 - Polished Fuel Gas Composition – Novel Methanol Synthesis

	Major constituents (vol%)
H_2	23.81
CH_4	0.29
CO	38.21
CO_2	10.82
H_2O	19.44
N_2	7.21
Ar	0.20
Total	99.98
	Major contaminants (ppmv)
H_2S	1.8
COS	0.1
HCl	3.6
NH_3	160
HCN	19
Hg (ppbv)	2.5
Particulate (ppmw)	0.1

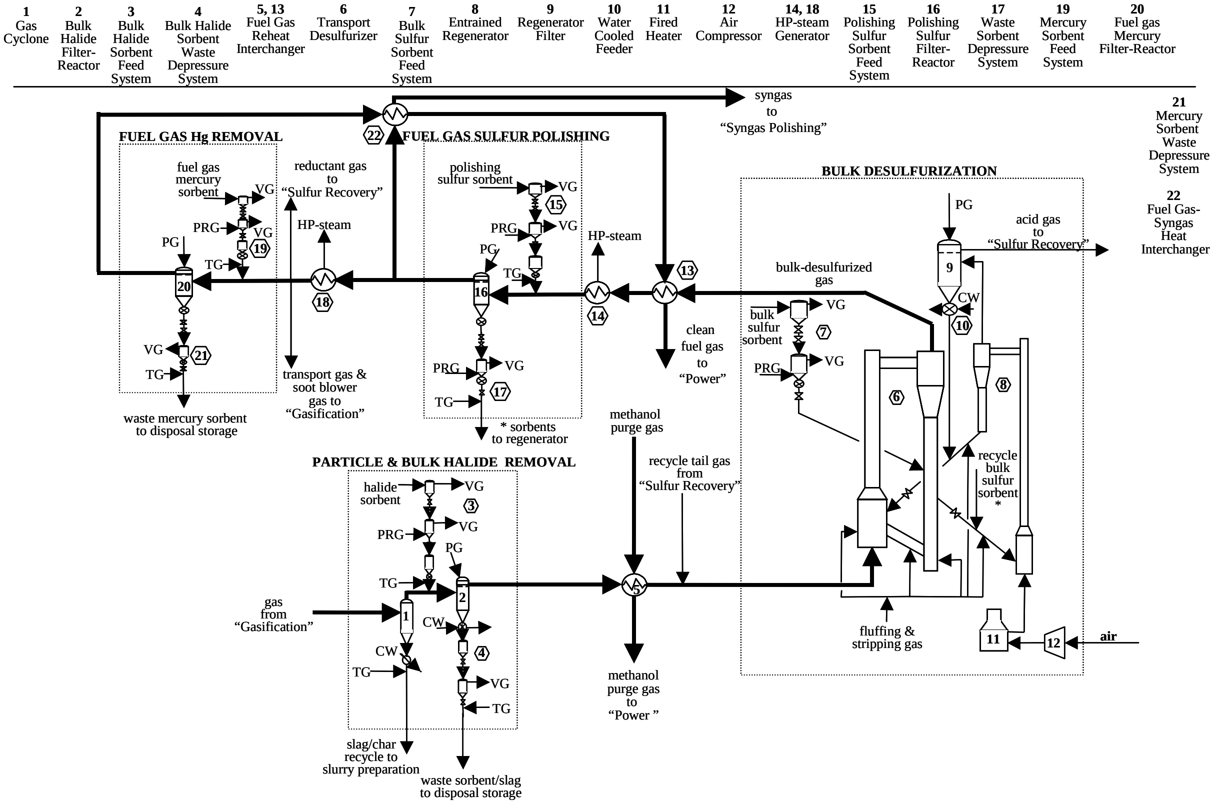


Figure 7.3 - Fuel Gas Cleaning Section - Novel Methanol Synthesis

<u>Fuel Gas Mercury Removal System: </u>The mercury removal process is similar to the previous descriptions for IGCC application, and is designed and operated for 95% mercury removal. The mercury removal process scheme is a once-through operation using powdered mercury sorbent injection into a filter-reactor (Item 20). The mercury sorbent is injected into the fuel gas by feed system (Item 19). The assumed feed rate is 7 kg/hr (15 lb/hr), equivalent to a sorbent-to-mercury mass ratio greater than 2000. The cooled fuel gas passes into a ceramic candle barrier filter (Item 20) to conduct mercury removal. This small filter-reactor vessel is slightly greater than 1.5 m (5 ft) in diameter, with a total height of 13.1 m (43 ft), and holds 187 filter elements. The filter also collects any equipment-corrosion particulate that might be present in the fuel gas from upstream sources. The mercury sorbent is drained from the filter and is depressurized (Item 21) to be disposal as a hazardous solid.

An alternative Fuel Gas Cleaning process with a simpler configuration having lower equipment cost is shown in Figure 7.4. Here the sulfur polishing filter-reactor and the fuel gas mercury removal filter-reactor are combined (Item 17) and are placed to follow the fuel gas coolers. This single filter-reactor, operating at a temperature of 204 to 288ºC (400 to 550°F) would accomplish both gas cleaning functions with a mixture of two injected sorbents. The once-through sorbents would be depressurized and stored for disposal, and there would be no recycle of sulfur sorbent to the bulk sulfur removal system. While this alternative configuration must be considered for future development, defining an additional set of operating conditions for the candidate mercury and polishing sulfur sorbents, its specific performance and cost have not been estimated in this evaluation.

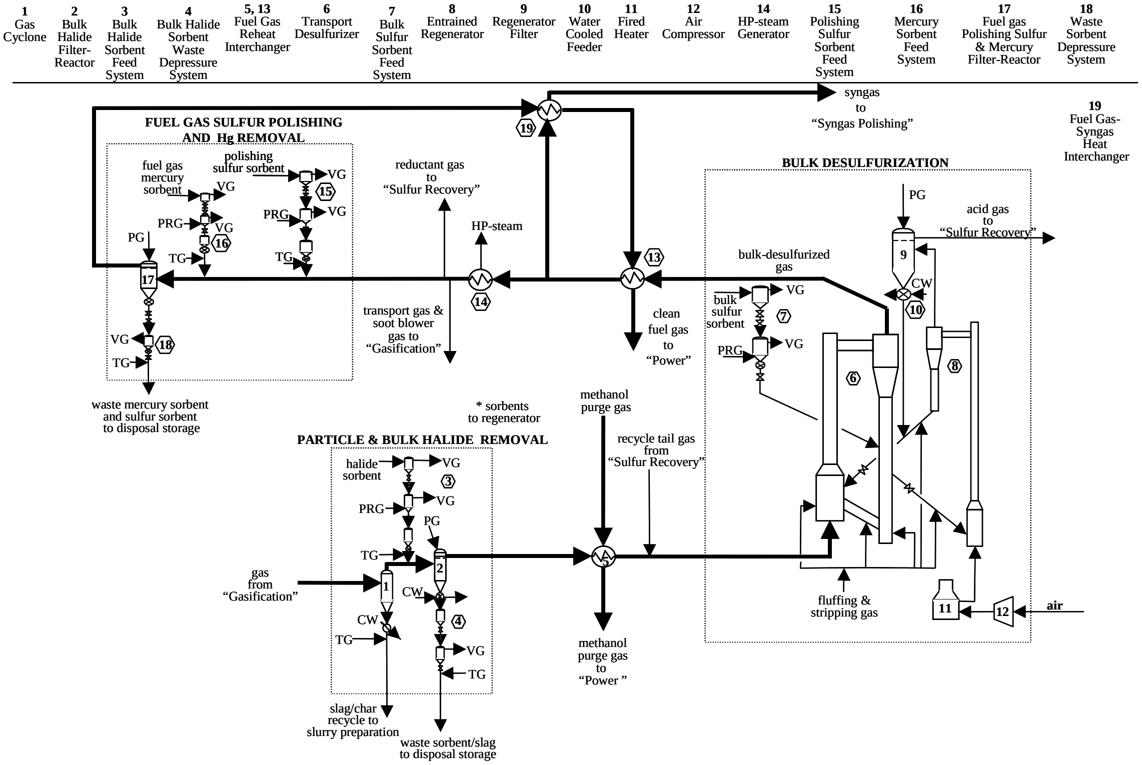


Figure 7.4 – Alternative Fuel Gas Cleaning Section - Novel Methanol Synthesis

Table 7.5 – Fate of Contaminants in Fuel Gas Cleaning Section - Novel Methanol Synthesis

Contaminant	Removal (% of inlet to Section)	Contaminant conversions
Sulfur species	99.98	Partial hydrolysis Combustion to SOx Sorbent fixation
Halides	99	Sorbent fixation
Ammonia	75	Catalytic partial decomposition to nitrogen
Hydrogen cyanide	0	----
Mercury	95	Sorbent fixation

<u>Comments on the Mercury Removal process</u>: The performance of the filter-reactors with injected sorbents have not yet been experimentally established, so the process evaluation is speculative. In particular, the type of mercury sorbent, the characteristics of the mercury removal process, and the performance of the mercury removal process are all highly speculative at this time. The evaluation identifies the process' acceptable range of operating conditions, required range of performance, and potentially acceptable operational modes:

- mercury removal should operate as hot as about 204-288ºC (400-550°F), removing 90-98% of the mercury,
- the type of mercury sorbent has not been established, and it could be either a once-through or a regenerative sorbent -- it is expected that it will be advantageous for it to be a regenerative adsorbent (e.g., a zeolite),
- the mercury removal process should be a continuous process -- it is expected that a continuous process will have advantages over a batch process with respect to power plant availability and performance,
- the selected mercury sorbent must not result in the release of any contaminants, such as sulfur, to the cleaned fuel gas that will exceed the emission requirements,
- the mercury adsorbent, if regenerative, might be regenerated by heating it in an available, clean gas or vapor stream, such as nitrogen or steam, to a temperature of no greater than 343ºC (650°F), with liquid mercury being subsequently condensed and separated,
- the mercury removal step provides the final, clean fuel gas that goes to the gas turbine combustors, and it should have the capability of also handling upstream equipment corrosion particulate removal,
- the minimum operating temperature for the mercury removal stage is about 204ºC (400°F), based on vapor condensation -- if lower operating temperatures are desired, water vapor will be condensed from the fuel gas,
- if water vapor in the fuel gas hinders the mercury removal step, the fuel gas can be reduced significantly in water vapor content by adding a water gas shift reaction stage,

Syngas Polishing Section

The scheme for syngas halide and ammonia polishing control considered is based on warm-water scrubbing of the syngas. The process flow diagram for the Syngas Polishing Section using water scrubbing is shown in Figure 7.5. This process removes halides and ammonia to very low levels and generates a water stream used in the coal slurry stream that is fed to the gasifier. The contained ammonia in the scrub water is decomposed in the gasifier and the contained halides are ultimately recycled and captured by the bulk halide removal process. The warm-water scrubbing process can reduce ammonia levels in the fuel gas to less than 10 ppmv, and halides to negligible levels.

1	2	3	4, 7	5	6	8	9	10	11	12	13	14	15	16
Syngas Sulfur Filter-Reactor	Sulfur Sorbent Feed System	Sulfur Sorbent Waste Depressure System	Syngas Heat Interchanger	Syngas Cooler	Hydrolysis Reactor	Syngas Condenser	Condensate Separator	Condensate Cooler	Condensate Pump	Flash Vessel	Compressor	Syngas Mercury Filter-Reactor	Mercury Sorbent Feed System	Mercury Sorbent Waste Depressure System

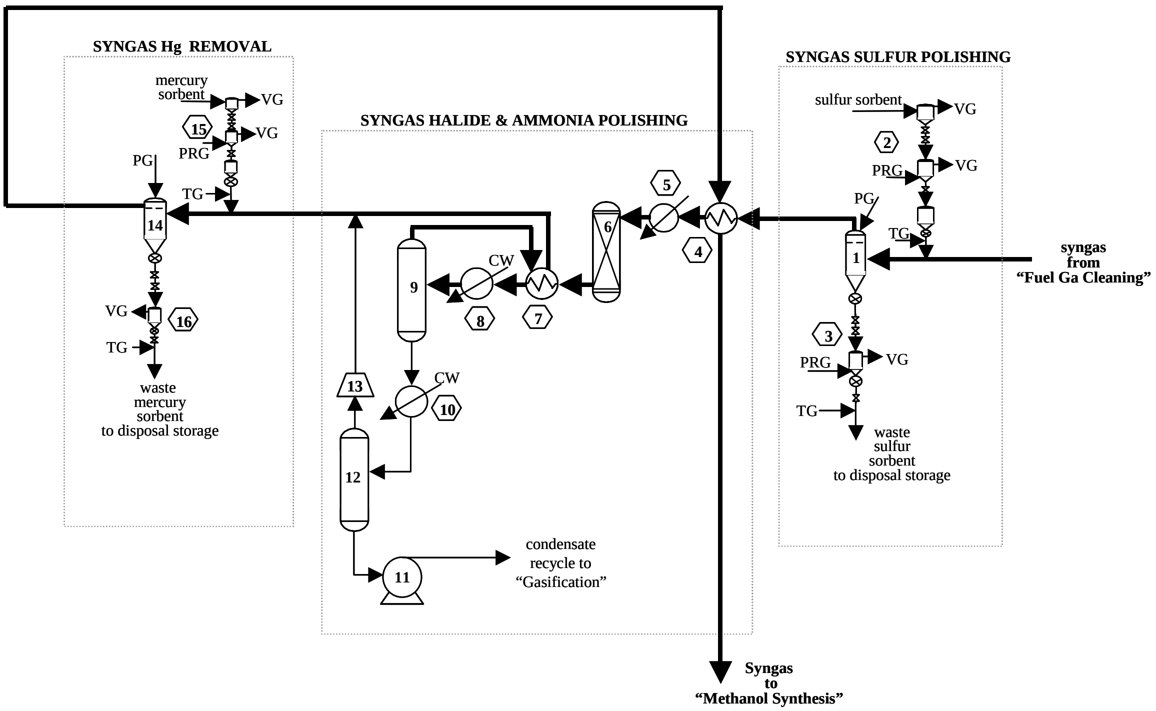


Figure 7.5 – Syngas Polishing Section - Novel Methanol Synthesis

Sulfur Polishing: A barrier-filter reactor (Item 1) operated at 288ºC (550°F) is used to reduce the syngas sulfur content to the required level, injecting 6 kg/hr (13 lb/hr) of a Zn-based sulfur sorbent into the gas using injection system (Item 2). The Zn/S molar feed ratio in this system is about 4.7. The same Zn-based sorbent used in the Bulk Sulfur Removal system, crushed to a finer size distribution, is used here. The filter-reactor used here has about 1.8 m (5.5 ft) diameter and is 13.1 m (43 ft) tall, similar in design to the fuel gas polishing filter-reactor.

Wet Scrubbing: The sulfur-polished syngas HCN content is hydrolyzed at 204ºC (400°F) to ammonia in a catalytic reactor (Item 6) after gas cooling by a heat interchanger (Item 4) and cooler (Item 5). . The hydrolyzed gas is then recuperatively cooled (Item 7), and then cooled and condensed further in Item 8 to 101ºC (213°F). The condensate-gas mixture passes through a gas-condensate separator (Item 9), simultaneously absorbing halides and ammonia into the condensate to very low levels. The separated syngas is reheated to 188ºC (370°F) across Item 7. The collected condensate is cooled further to 38ºC (100°F) across cooler 10, and is then flashed to 117 kPa (17 psia), separating out a condensate stream that is recirculated to the gasification slurry preparation system. The offgas is compressed (Item 13) and placed back into the syngas.

Mercury Removal: Mercury sorbent is injected at 4.5 kg/hr (10 lb/hr) into the syngas (Item 15), and the gas-sorbent mixture passes through the mercury filter-reactor (Item 14), removing 95% of the syngas mercury. This filter-reactor is about 5 feet in diameter and 43 feet tall, operating with a face velocity of about 1.2 m/min (3.9 ft/min). The mercury sorbent is depressurize (Item 16) for storage and disposal. A carbonyl guard bed (Item 17) could also be inserted into the process, but should not be needed with proper selection of materials of construction. The cleaned syngas is reheated across a heat interchanger (Item 4). The cleaned syngas composition is estimated in Table 7.6.

Table 7.6 – Syngas Composition – Novel Methanol Synthesis

	Major constituents (vol%)
H_2	29.13
CH_4	0.36
CO	46.75
CO_2	13.22
H_2O	1.45
N_2	8.86
Ar	0.24
Total	100.00
	Major contaminants (ppmv)
H_2S	0.47
COS	0.00
HCl	0.00
NH_3	5.5
HCN	0.03
Hg (ppbv)	0.061

An alternative Syngas Polishing Section process configuration with low-cost potential is illustrated in Figure 7.6. The syngas sulfur polishing and mercury removal functions are combined into a single filter-reactor in this configuration, simplifying the configuration greatly. The combined filter reactor could be placed before the wet scrubber, operating at about 204ºC (400°F), and could be placed to follow the wet scrubber, operating at a temperature as low as 104ºC (220°F). This then defines the range of operating temperatures needed for the combined polishing sulfur sorbent and the syngas mercury sorbent if this alternative configuration is to be used: 104-204ºC (220 – 400°F). An additional simplification is to eliminate HCN hydrolysis, with the expectation from the literature than HCN is not really a significant contaminant to the methanol catalyst in the Liquid Phase Methanol process.

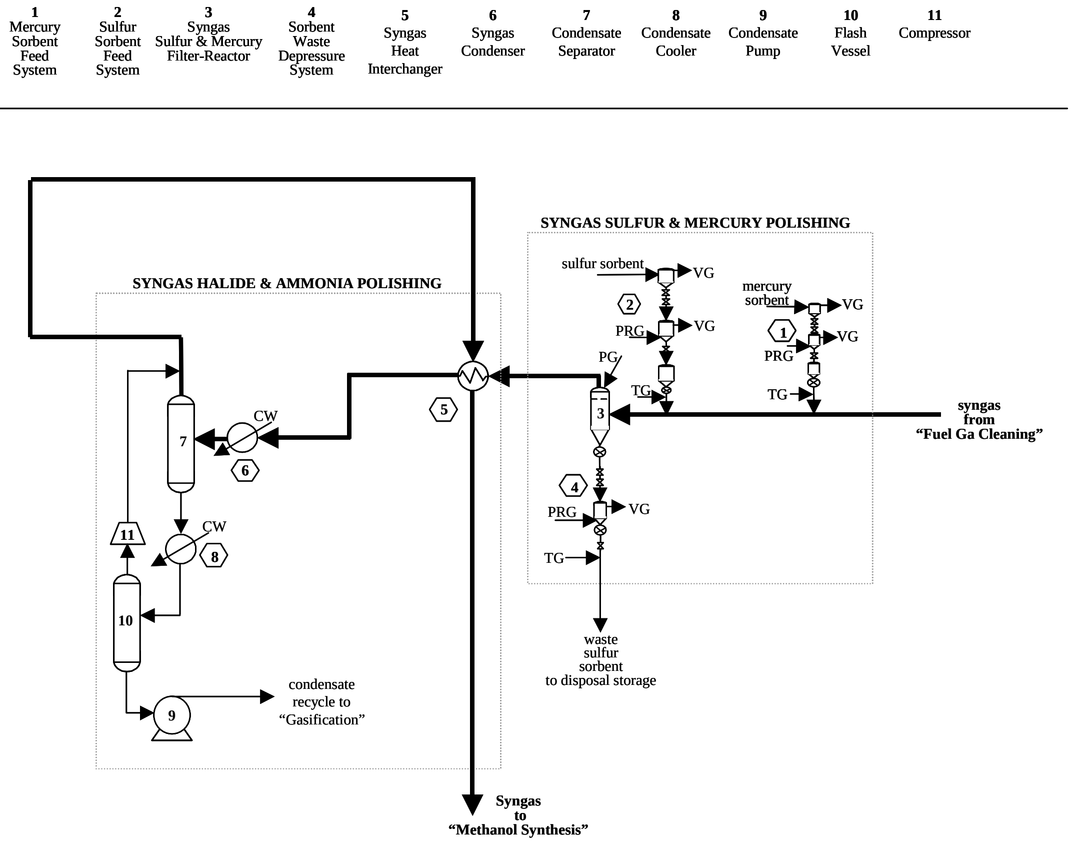


Figure 7.6 – Alternative Syngas Polishing Section - Novel Methanol Synthesis

The fate of the contaminants within the Syngas Polishing section are listed in Table 7.7. The performance hypothesized to be achieved here satisfies all of the methanol synthesis gas cleaning requirements without additional guard beds inserted before the synthesis reactor.

Table 7.7 – Fate of Contaminants in Syngas Polishing Section - Novel Methanol Synthesis

Contaminant	Removal (% of inlet to Section)	Contaminant conversions
Sulfur species	98	Sorbent fixation
Halides	100	Water scrubbing Recycle to Bulk Halide Removal
Ammonia	97	Hydrolysis Water scrub Decomposition in gasifier
Hydrogen cyanide	100	Hydrolysis
Mercury	98	Sorbent fixation

Methanol Synthesis Section

The Methanol Synthesis Section flow diagram is shown in Figure 7.7. The first processing step is to humidify the syngas to about 8.5 vol% in Item. The humid syngas passes through the methanol synthesis reactor where about 41% of the syngas hydrogen is converted to methanol. LP-steam and IP-steam are generated in the methanol reactor fluid bed, controlling the exit gas temperature to about 249ºC (480°F). A cyclone captures and recycles elutriated catalyst particles and oil to the bed. The methanol reactor product gas is then cooled to about 99ºC (210°F) and oil is separated from the product gas in a separation vessel. The product gas is further cooled to about 38ºC (100°F) before passing through a knock-out vessel to separate the synthesis liquid and purge gas products. The purge gas, at 124,280 kg/hr (273,985 lb/hr) and 6,433 kPa (933 psia), from the knock-out vessel is reheated to about 482ºC (900°F) before passing to the Power Section.

The purge gas composition is presented in Table 7.8, and has a heating value of about 8.73 MJ/Nm^3 (222 Btu/scf). The synthesis product, at 11,816 kg/hr (26,050 lb/hr), is flashed to about 117 kPa (17 psia) to separate some dissolved gases, about 107 kg/hr (235 lb/hr) from the crude methanol product. The crude methanol is distilled to generate the fuel-grade methanol product, at 8998 kg/hr (19,837 lb/hr). In total, 91.3 % of the methanol generated in the synthesis reactor is recovered in the final product. The product methanol composition is presented in Table 7.9

Table 7.8 – Purge Gas Composition - Novel Methanol Synthesis

	Major constituents (vol%)
H_2	29.58
CH_4	0.39
CO	35.55
CO_2	24.05
H_2O	0.01
N_2	9.69
Ar	0.26
Methanol	0.45
Total	99.98

Table 7.9 – Fuel-Grade Methanol Composition - Novel Methanol Synthesis

	Major constituents (wt%)
H_2O	0.41
CO_2	0.05
Methanol	98.20
Methyl formate	0.15
Ethanol	1.18
Total	99.99

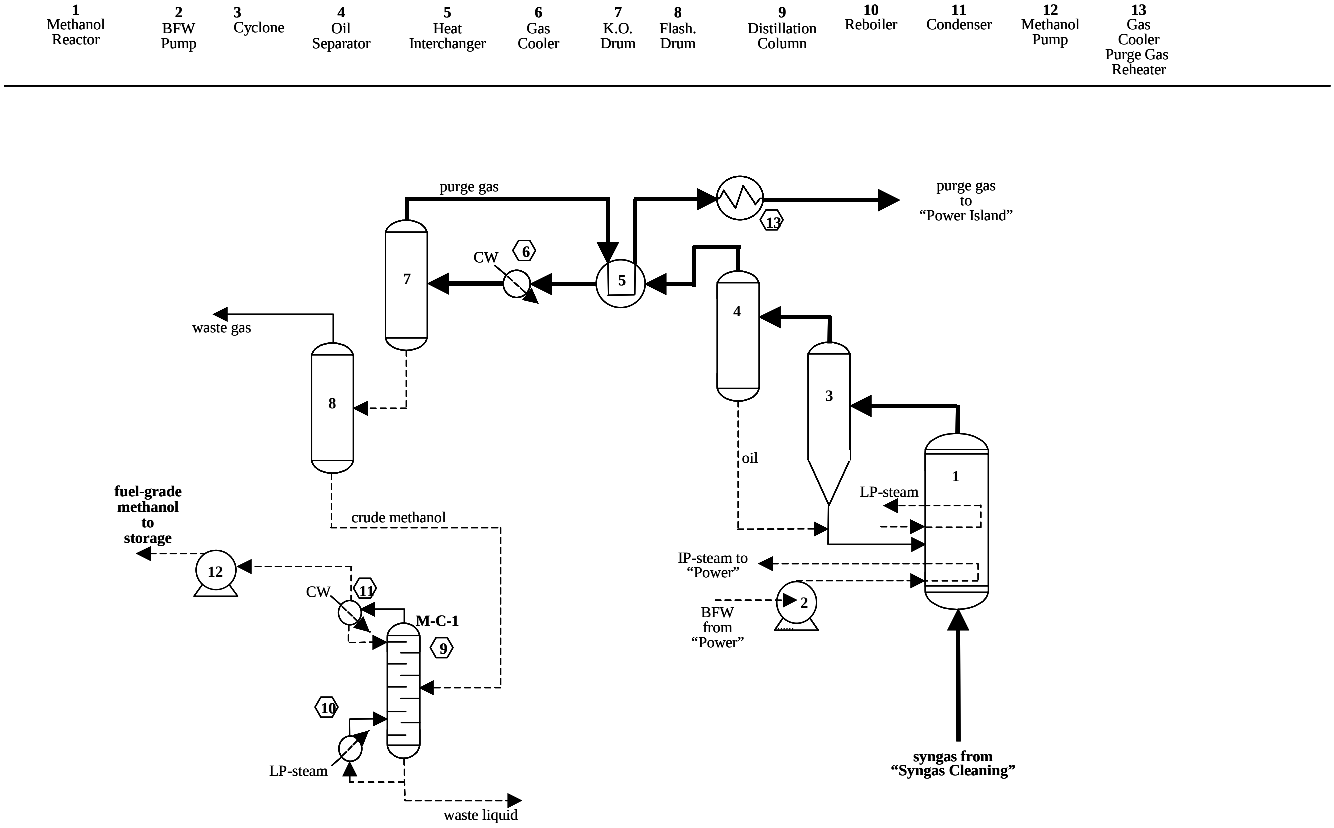


Figure 7.7 – Methanol Synthesis Section - Novel Methanol Synthesis

Sulfur Recovery Section

Figure 7.8, the process flow diagram for the Sulfur Recovery Section, is identical to Sulfur Recovery in the IGCC power plant. The acid gas from the bulk desulfurizer regenerator contains about 14 vol% SO_2, with very low oxygen content, and the remaining components being largely nitrogen with a little CO_2. This acid gas is first expanded (Item 1) to about 193 kPa (28 psia), cooling the gas to about 224ºC (435°F) and generating a small amount of electrical power. The acid gas is then mixed with a portion of bulk desulfurized fuel gas and is catalytically reacted to hydrogenate an appropriate portion of the acid gas SO_2 to H_2S for the Claus reaction in reactor Item 2. The gas is then cooled in a boiler (Item 3) to generate IP-steam, followed by a boiler-sulfur condenser (Item 4) generating LP-steam. Any elemental sulfur contained in the product acid gas is separated before the gas enters the first Claus reactor (Item 5). The remaining steps of the process are very similar to those described for the conventional fuel gas cleaning sulfur recovery process: three stages of gas preheat, Claus reactors and sulfur condensers.

The sulfur recovery process recovers about 95.7% of the sulfur content of the acid gas. The collected sulfur streams are combined and the sulfur, at 4,030 kg/hr (8,885 lb/hr) is stored for treatment and marketing as a by-product. The tail gas, at 30,759 kg/hr (67,811 lb/hr), contains a considerable content of sulfur species (H_2S and SO_2), and the only way the power plant can achieve its overall 99.85% sulfur removal goal is for this tail gas to be recompressed and recycled to the bulk desulfurizer. After cooling and compression and condensate removal, the tail gas recycled to the bulk desulfurizer has the composition reported in Table 7.10.

Table 7.10 - Recycle Tail Gas Composition - - Novel Methanol Synthesis

	Major constituents (vol%)
H_2	0.13
CH_4	0.12
CO	0.21
CO_2	20.08
H_2O	0.35
N_2	77.62
Ar	0.93
Total	99.47
	Major contaminants (ppmv)
H_2S	3772
SO_2	1677
COS	0
CS_2	0
NH_3	46
HCN	8

The fate of the contaminants within the Sulfur Recovery section are listed in Table 7.11.

Table 7.11 – Fate of Contaminants in Sulfur Recovery Section - Novel Methanol Synthesis

Contaminant	Removal (% of inlet to Section)	Contaminant conversions
Sulfur species	95.66	Claus conversion to elemental sulfur Hydrolysis to reduced forms
Halides	NA	----
Ammonia	30.0	Furnace decomposition
Hydrogen cyanide	NA	----
Mercury	NA	----

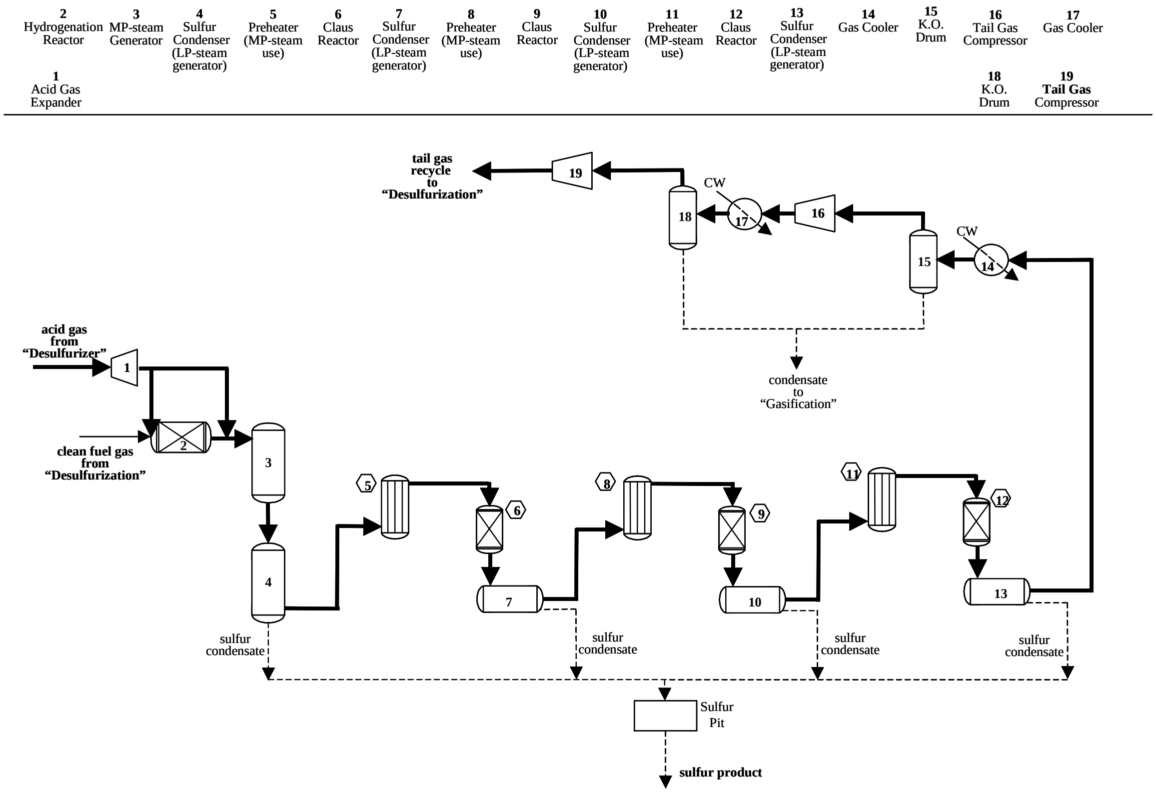


Figure 7.8 – Sulfur Recovery Section - Novel Methanol Synthesis

Power Section

The Power Island process flow diagram is identical to those described for the IGCC cases, except that the clean fuel gas is expanded to the required turbine combustor pressure, and is mixed with expanded methanol purge gas. The process diagram is shown in Figure 7.9. An oxygen stream at 106,476 kg/hr (234,735 lb/hr), with 95% purity, is generated by conventional, pressurized, cryogenic air separation unit (ASU). A relatively low-purity N_2 stream is also produced that is used for clean fuel gas dilution. A smaller stream of high-purity N_2 (99.9%) is also produced that is used in the gas cleaning process for solids pressurization, stripping, purging, pneumatic transport, and filter pulse cleaning. The purge gas stream from Methanol Synthesis, and the clean fuel gas stream are both expanded, recovering electrical power, and are mixed together as a single turbine fuel gas stream. Low-purity nitrogen is humidified to about 16 vol% water vapor using low-grade heat sources, and the nitrogen stream, at 305,726 kg/hr (674,000 lb/hr) is mixed with the clean fuel gas before the mixture is distributed to the gas turbine combustors. The turbine combustors, advanced, catalytic, and/or diffusion flame burners that promote the decomposition of the remaining ammonia in the fuel gas with less than 5% conversion to NOx, operate with an outlet temperature of about 1521ºC (2770°F), and with the peak flame temperature of less than 1649ºC (3000°F), the NOx emission is expected to be less than 5 ppmv (dry, corrected to 15% oxygen).

The turbine expansion gas has a mass flow of 1,742,665 kg/hr (3,841,854 lb/hr) and a temperature of 619ºC (1147°F). The expansion gas passes through the heat recovery steam generator (HRSG), generating a superheated, high-pressure steam flow of 400,529 kg/hr (883,000 lb/h). The stack gas from the power plant has a temperature of 104ºC (220°F) and a composition listed in Table 7.12. The fate of the contaminants within the Power section are listed in Table 7.13 .

Table 7.12 - Stack Gas Composition – Novel Methanol Synthesis

	Major constituents (vol%)
O_2	8.27
CO_2	9.99
H_2O	10.73
N_2	70.16
Ar	0.85
Total	100.00
	Major contaminants
SO_2 (ppmv)	0.2
NOx (ppmv)	5
Mercury (ppbv)	0.0125
Particulate (ppmw)	0.1

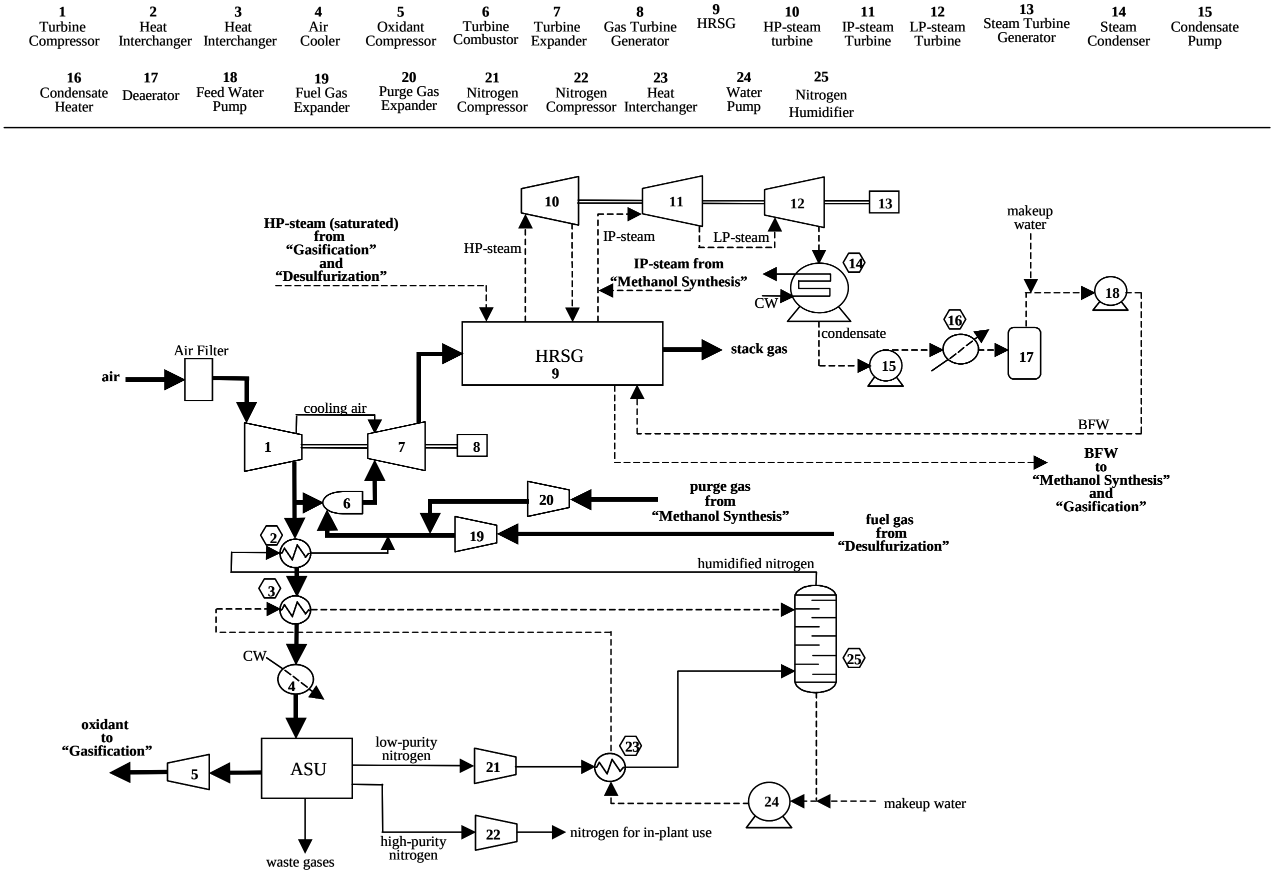


Figure 7.9 – Power Section - Novel Methanol Synthesis

Table 7.13 – Fate of Contaminants in Power Section - Novel Methanol Synthesis

Contaminant	Removal (% of inlet to Section)	Contaminant form conversion
sulfur species	0	Oxidation to SOx
Ammonia	0	partial oxidation conversion to NOx
Mercury	0	Partial conversion to oxidized forms

7.2 PERFORMANCE OF METHANOL SYNTHESIS WITH NOVEL GAS CLEANING

The breakdown of power generation and power use in the Methanol Synthesis plant with Novel Gas Cleaning technology is shown in Table 7.14. Note that the Sulfur Recovery Section net power use is nearly zero, with the acid gas expander's generation balancing the power losses in the system.

Table 7.14 –Methanol Synthesis Plant Thermal Performance with Novel Gas Cleaning

Section	**Power (MW)**
Power Island	
Turbine Air Compressor	-182.14
Gas turbine	375.82
Steam turbine	161.17
Fuel gas expander	8.95
Syngas expander	6.60
Generator	-7.4
BOP	-5.6
Gross power	357.4
Air Separation	
ASU Air compressor	0
Oxygen compressor	-8.19
Nitrogen compressor	-8.21
ASU power	-23.40
Total ASU system	-39.80
Gasification	
Fans & blower	-0.28
Pumps	-0.21
Coal handling and preparation	-1.8
Ash handling	-1.5
Total	-3.8
Fuel Gas Cleaning	
Refrigeration	0.0
Compressor	-4.58
Pump	0
Net	-4.58
Syngas Cleaning	
	-0.014
Methanol Synthesis	
	0
Sulfur Recovery	
Expander	4.24
Compressor	-4.27
Pump	0.00
Net	-0.03
Total Plant	
Net plant power generation, MW	309.1
Plant net heat rate, kJ/kWh (Btu/kWh) (HHV)	10,286 (9749)
Plant net efficiency, %, (LHV)	37.77
Plant net efficiency, %, (HHV)	35.00

Table 7.15 lists several quantities related to the use of resources and emissions in the Methanol Synthesis plant with Novel Gas Cleaning technology. Only small quantities of process condensate are generated in both cases, primarily in the Sulfur Recovery Section, and this is recycled without treatment. A moderate level of fresh process water is required in the gas cleaning processes, and both cases result in no discharge of process water. Both cases require small quantities of boiler-quality makeup water for fuel gas humidification. The total sulfur emissions are expressed in three different bases (percent removal, mass per unit fuel energy input, and mass per MWe net power generated).

Table 7.15 –Methanol Synthesis Plant Resource Use and Emissions with Novel Gas Cleaning

Auxiliaries	
Net IP steam use, MJ/hr (10^6 Btu/hr)	37,140 (35.2)
Net LP steam use, MJ/hr (10^6 Btu/hr)	-18,675 (-17.7)
Total cooling water use, MJ/hr (10^6 Btu/hr)	258,183 (244.7)
Total condensate generated, kg/hr (lb/hr)	5,979 (13,181)
Total process water used, kg/hr (lb/hr)	26,464 (58,343)
Net process water makeup, kg/hr (lb/hr)	20,485 (45,162)
Total boiler water makeup, kg/hr (lb/hr)	41,469 (91,421)
Emissions	
Sulfur total removal efficiency (%)	99.991
Sulfur total emission, mg/MJ (lb SO_2/ 10^6 Btu) (HHV)	0.238 (0.000554)
Sulfur total emission, kg/MW (lb SO_2/ MWe)	0.00245 (0.0054)
NOx total emission, mg/MJ (lb NO_2/ 10^6 Btu) (HHV)	4.34 (0.0101)
Particulate emission, mg/MJ (lb/ 10^6 Btu) (HHV)	0.0079 (1.835E-05)
Hg emission, mg/MJ (lb/TBtu) (HHV)	0.0763 (0.1774)
Feed Streams, kg/hr (lb/hr)	
Chemicals	0
Sorbents	2,070 (4,564)
Catalysts	0.9 (2)
Solid waste, kg/hr (lb/hr)	
Slag product (25 wt% water)	15,915 (35,087)
Slag & HCl sorbent waste	1,384 (3,052)
Waste salts (25 wt% water)	0
Sorbent wastes	94 (208)
Total	17,394 (38,347)

7.3 COST ESTIMATES FOR METHANOL SYNTHESIS WITH NOVEL GAS CLEANING

No financial analysis of such a co-production plant has been performed in this evaluation. The evaluation utilizes direct comparison of gas cleaning equipment investment, annual operating cost of the gas cleaning equipment, total plant electricity production and methanol production as the basis for comparison.

The major equipment purchase costs and installed costs are listed in Table 7.16 for each of the cleaning sections of the plant evaluated. The Gasification Section's cost for the convective cooler has been included in the cost breakdown since this will differ from the convective cooler cost in the Novel Gas Cleaning process. Also, the Mercury Removal cost has been taken out of the Low-Temperature Cooling Section cost and reported as a separate item. The Low-temperature Cooling Section is the second most expensive of the gas cleaning sections, and its cost approaches the cost of the

Desulfurization Section. The total gas cleaning costs are also reported on the basis of $ per kW of net power generated. While the total gas cleaning equipment cost approaches 100 $/kW, this is clearly only a small portion of the total plant equipment cost. The impact of gas cleaning on the overall plant performance and its operating cost are much more important factors.

Table 7.16 – Equipment Cost Breakdown - Novel Methanol Synthesis

Plant Section	Cost, k$
Raw gas convective cooling	
purchased equipment	324
installed equipment	648
Gas Cleaning (fuel and syngas)	
purchased equipment	8,014
installed equipment	13,500
Mercury removal	
purchased equipment	1,435
installed equipment	2,339
Sulfur Recovery	
purchased equipment	6,192
installed equipment	10,157
Methanol Synthesis	
purchased equipment	1,517
installed equipment	2,882
Fuel gas and Purge gas expanders	
purchased equipment	1,536
installed equipment	2,304
Total	
purchased equipment	19,017
installed equipment	30,144
purchased equipment, $/kW	57
installed equipment, $/kW	91
Total Plant	
TCR, k$	483,723
TCR, $/kW	1565

The Total Capital Requirement for the Methanol co-production plant using conventional, low-temperature gas cleaning technology was estimated by scaling the non-gas cleaning equipment costs from IGCC power plant cost data. A confirmed basis does not exist for making this estimate, so the total plant costs are uncertain, but represent a good basis for technology comparisons. Table 7.17 shows the estimate for the Total Capital Requirement for the plant, and lists the breakdown for the Cost-of-Electricity (COE) for the plant using by-product values for the methanol and elemental sulfur products. Coal slag is assumed to be a disposal product having no value. The objective here is not to assess the financial implications for such a plant, but it to provide a basis for comparison with the COE for a comparable plant using Novel Gas Cleaning technology.

Table 7.17 – Cost-of-Electricity - Novel Methanol Synthesis

	COE (Cents/kWh)
Fixed O&M	0.35
Variable O&M	0.23
Consumables	0.35
water	0.040
chemicals, sorbents, catalysts	0.189
waste Disposal	0.125
By-product credit	1.03
sulfur	0.0678
methanol	0.963
Fuel	1.81
Capital charges	3.35
Total	5.06

Table 7.17 shows clearly that the gas cleaning process equipment cost has little impact on the COE of the plant, but the gas cleaning process influence on the plant efficiency is very important. Consumables in the conventional technology plant have a very small impact on the COE. This sensitivity perspective indicates that the gas cleaning process focus should be on minimizing performance losses rather than on minimizing equipment costs.

7.4 Assessment of Methanol Synthesis with Novel Gas Cleaning

7.4.1 Performance Potential

Table 7.18 shows that the Novel Gas Cleaning technology provides the potential for improvement in Methanol Synthesis plant water resource use and thermal performance over using conventional gas cleaning technology. The Novel Gas Cleaning technology uses less than half the cooling water rate used by the conventional gas cleaning technology. Total water consumption is about the same for both technologies. Novel Gas Cleaning technology consumes more process makeup water than the conventional gas cleaning technology, primarily for coal slurry preparation, but it uses much less boiler-quality makeup water, a more expensive water source. The conventional gas cleaning technology results in a water discharge stream from the power plant, a plant export that is restricted in some locations.

The detailed power consumption breakdowns listed in this report indicate that every section of the fuel gas cleaning process, except for the sulfur recovery process, shows significant advantage for the Novel Gas Cleaning technology. Conventional fuel gas cleaning technology applies a large number of fuel gas cooling and reheating operations, conducting total condensation of the fuel gas water vapor, followed by re-humidification, and this results in significant losses in overall power plant thermal efficiency that do not occur when using the Novel Gas Cleaning technology.

Table 7.18 - Methanol Synthesis Gas Cleaning Resource Comparison

	Conventional Gas Cleaning	Novel Gas Cleaning
Cooling water use, MJ/hr (10^6 Btu/hr)	252,169 (239)	108,675 (103)
Process water makeup, kg/hr (lb/hr)	498 (1097)	42,305 (93,266)
Boiler feed water makeup, kg/hr (lb/hr)	59,972 (132,213)	33,566 (74,000)
Total water consumption, kg/hr (lb/hr)	60,469 (133,310)	75,872 (167,266)
Net power generated (MW)	288	309
Plant net heat rate, kJ/kWh (Btu/kWh) (HHV)	11,009 (10,434)	10,286 (9749)
Plant net efficiency, % (LHV)	35.2	37.8
Plant net efficiency, % (HHV)	32.7	35.0

Table 7.19 lists the clean fuel gas and stack gas compositions estimated for the Methanol Synthesis. The conventional gas cleaning technology has established capability to achieve the levels of sulfur control required in the evaluation. The Novel Gas Cleaning technology is estimated as having this capability based on the development work completed. Where these gas cleaning technologies differ is that the conventional gas cleaning technology will reduce the fuel gas halide, ammonia, and HCN contents to much lower levels in the fuel gas than will the Novel Gas Cleaning technology. The Novel Gas Cleaning technology can, though, reduce the fuel gas halide, ammonia and HCN contents sufficiently to satisfy the requirements for application. The Novel Gas Cleaning technology uses partial-decomposition of ammonia in the process, and low-NOx, diffusion flame, fuel gas combustors (staged, rich-quench-lean; or catalytic) to achieve low NOx emissions from the IGCC power plant. The higher-temperature operations of the Novel Gas Cleaning technology may provide advantages, with less potential for the formation of metal carbonyls, and its final stage Mercury Removal Filter-Reactor may provide additional protection against corrosion-based particulate damage to the gas turbine not provided by conventional gas cleaning technology. The conventional gas cleaning technology, with operation at conditions of high corrosion potential, is inherently more prone to availability losses than the Novel Gas Cleaning technology.

The plants produce comparable solid waste streams, with the total mass of waste for the Novel Gas Cleaning technology being about 5% greater than with the conventional gas cleaning. The nature of the waste differs slightly for the two technologies. The slag waste streams are very similar in flow rate and composition for the plants. The conventional gas cleaning technology produces a wet stream of halide salts that contain numerous traces of contaminants, as well as a small, hazardous mercury sorbent waste. The Novel Gas Cleaning technology produces dry, non-hazardous sorbent waste, some of which can be incorporated into the plant slag waste. The hazardous nature of the mercury sorbent waste from the Novel Gas Cleaning Process is uncertain at this time.

7.4.2 Cost Potential

The Methanol Synthesis co-production plant investment and cost-of-electricity (COE) is compared for the two plants in Table 7.20. While the equipment costs are estimated to be only slightly lower for the Novel Gas Cleaning process than for the conventional gas cleaning process, the improved power plant capacity and heat rates result in the potential for significant reductions in plant capital investment (greater than 14%) and cost of electricity (greater than 9%).

Table 7.19 – Methanol Synthesis Gas Cleaning Emission Comparisons

	Conventional Cleaning	Novel Gas Cleaning
Clean Fuel Gas (before N_2 dilution)		
H_2 (vol%)	27.2	23.8
CO (vol%)	43.8	46.6
CH_4 (vol%)	0.3	0.3
CO_2 (vol%)	10.6	10.8
H_2O (vol%)	16.2	19.4
N_2 (vol%)	1.7	7.2
Ar (vol%)	0.15	0.2
Total sulfur (ppmv)	0.24	1.9
Halides (ppbv)	0.1	3600
Ammonia (ppmv)	0.4	160
HCN (ppmv)	0	19
Hg (ppbv)	0.07	0.125
Clean Syngas		
H_2 (vol%)	32.4	29.1
CO (vol%)	52.3	46.8
CH_4 (vol%)	0.4	0.4
CO_2 (vol%)	12.7	13.2
H_2O (vol%)	0.0	1.5
N_2 (vol%)	2.1	8.9
Ar (vol%)	0.18	0.24
Total sulfur (ppmv)	0.03	0.47
Halides (ppbv)	0.1	0.15
Ammonia (ppmv)	0.44	5.5
HCN (ppmv)	0.0	0.03
Hg (ppbv)	0.07	0.05
Stack Gas		
CO_2 (vol%)	10.1	10.0
H_2O (vol%)	10.7	10.7
N_2 (vol%)	70.5	70.2
O_2 (vol%)	7.9	8.3
HCl (ppmv)	0.0	0.35
SO_2 (ppmv)	0.033	0.2
NO (ppmv)	<5	<5
Hg (ppbv)	0.01	0.02
Sulfur Removal		
Sulfur total removal efficiency, %	99.9985	99.9911
Sulfur total emission, mg/MJ (lb SO_2/ 10^6 Btu)	0.413 (0.00096)	2.32 (0.0054)
Solid Waste		
Slag and flyash (wet), kg/hr (lb/hr)	16,313 (35,964)	15,915 (35,087)
Waste salts (wet), kg/hr (lb/hr)	338 (745)	0
Sorbent wastes, kg/hr (lb/hr)	1.8 (4)	1,479 (3,260)
Total, kg/hr (lb/hr)	16,653 (36,713)	17,394 (38,347)

Table 7.20 - Methanol Synthesis Plant Investment and COE Comparison

Gas Cleaning Technology	**Conventional Gas Cleaning**	**Novel Gas Cleaning**
Generation capacity, MWe	288	309
Plant Heat Rate, kJ/kWh (Btu/kWh) (HHV)	11,009 (10,434)	10,286 (9749)
Total Capital Requirement, $/kW	1791	1565
Total COE, cents/kWh (constant $)	5.6	5.1

8. CONCLUSIONS AND RECOMMENDATIONS

This evaluation has devised plausible humid-gas cleaning schemes for the Filter-Reactor Novel Gas Cleaning process that might be applied in IGCC and Methanol Synthesis applications. These schemes are simpler than those used in conventional dry-gas cleaning for these applications and show the conceptual-potential to provide plant availability, plant thermal efficiency and cost improvements over the conventional plants.

The Filter-Reactor should have a basic design similar to the design of near-commercial barrier filters, with a large number of independently pulse-cleaned filter plenums that allow the Filter-Reactor to maintain high levels of emission control. Sorbent particle sizes injected into the Filter-Reactors are expected to operate best at –325 mesh, with a mass-mean size of about 20 μm. The major uncertainties have been 1) the contaminant removal performance that can actually be achieved in these Filter-Reactors, with their relatively thin 5 to 13 mm (0.2 to 0.5 inch) sorbent filter cakes and low gas velocities through the filter cakes, and 2) the possible reaction-sintering behavior of the filter cakes that might occur at the stage conditions. These uncertainties have been resolved in the program's PDU tests under representative conditions.

Detailed material & energy balances for the gas cleaning applications, coupled with preliminary thermodynamic modeling and laboratory testing of candidate sorbents, have identified the probable sorbent types that should be used, their needed operating conditions in each stage, and their required levels of performance. These performance goals and the results from the PDU testing are summarized in Table 1.4. In general, the performance goals have been demonstrated in the PDU testing, with the exceptions noted in the table. A water scrubbing stage is used for syngas polishing of halides and ammonia in the Methanol Synthesis application, and this stage should be able to be applied commercial using available technology experience. The conditions and performance levels that have not been demonstrated in the PDU testing in this program have been extrapolated from the PDU test results to apply to the commercial design and evaluations.

The evaluation utilized a regenerative, zinc-based sulfur sorbent in a transport reactor configuration for bulk sulfur removal, but the Filter-Reactor Novel Gas Cleaning process can be coupled with any developing bulk desulfurization technology (such as alternative sorbents and alternative gas-sorbent bulk desulfurization contactors) operating under humid-gas conditions. The use of alternative bulk desulfurization technology will alter some of the Filter-Reactor stage conditions and sorbents.

The success of PDU tests completed in the program, and the conceptual advantages of the Filter-Reactor technology indicated by the evaluation results lead to conclusion that continued scale-up development of the technology is merited. This development should focus on the optimization of the Filter-Reactor performance (operating face velocity, sorbent feed rate, sorbent properties and size distribution, operating temperature, simultaneous removal of multiple contaminants), Filter-Reactor scale-up through larger-scale test units, and continued commercial process evaluation.

Table 8.1 – Filter-Reactor Novel Gas Cleaning Stage Performance Goals and Test Status

Cleaning Stage	**Sorbent type (-325 mesh)**	**Process Temperature °C (°F)**	**Process Performance Goals**	**PDU Test Status (Final Report Volume II)**
IGCC Applications				
Bulk halide removal	Sodium mineral (Trona or Nahcolite)	593 (1100)	99% halide removal, 5 ppmv HCl outlet, Na/Cl mole feed ratio 4, 75% ammonia decomposition.	Demonstrated at 427°C (800°F), Ammonia decomposition not measured (not in program scope)
Sulfur polishing	Zinc-titanate	482 (900)	96% removal, 40 ppmv inlet to 2 ppmv outlet, Zn/S mole feed ratio 3.	Not considered in PDU tests (focus placed on more challenging Methanol sulfur polishing)
Mercury removal	TDA sorbent	204-316 (400-600)	90-95% Hg removal, Sorbent/Hg mass feed ratio 1000, Possibly simultaneous with sulfur polishing.	90% Hg removal demonstrated at 260°**C** (500°F), Simultaneous sulfur removal not attempted (insufficient test time).
Methanol Synthesis Application				
Halide & ammonia polishing	Water absorbent	93-149 inlet (200-300)	97% ammonia removal to 10 ppmv, 99.8% HCl removal to 10 ppbv.	Halide and ammonia scrubbing not addressed in PDU tests (design from scrubbing experience).
Sulfur polishing	Zinc-titanate	260-316 (500-600)	98% sulfur removal, 60 ppbv sulfur outlet, Zn/S mole ratio 5.	Sulfur polishing demonstrated in PDU tests.
Mercury removal	TDA sorbent	204-316 (400-600)	95% Hg removal, Sorbent/Hg mass feed ratio 1000.	90% Hg removal demonstrated at 260°C (500°F) (data extrapolated for design).

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