U.S. Department of Energy
National Energy Technology Laboratory

Early Entrance Co-Production Plant – Decentralized Gasification Cogeneration Transportation Fuels and Steam From Available Feedstocks

DOE Cooperative Agreement DE-FC26-00NT40693

Quarterly Technical Progress Report
January to March 2002

WMPI PTY., LLC

June 2002

DISCLAIMER

ABSTRACT

Waste Processors Management, Inc. (WMPI), along with its subcontractors Texaco Power & Gasification (now ChevronTexaco), SASOL Technology Ltd., and Nexant Inc. entered into a Cooperative Agreement DE-FC26-00NT40693 with the U. S. Department of Energy (DOE), National Energy Technology Laboratory (NETL) to assess the techno-economic viability of building an Early Entrance Co-Production Plant (EECP) in the United States to produce ultra clean Fischer-Tropsch (FT) transportation fuels with either power or steam as the major co-product. The EECP design includes recovery and gasification of low-cost coal waste (culm) from physical coal cleaning operations and will assess blends of the culm with coal or petroleum coke.

The project has three phases. Phase I is the concept definition and engineering feasibility study to identify areas of technical, environmental and financial risk. Phase II is an experimental testing program designed to validate the coal waste mixture gasification performance. Phase III updates the original EECP design based on results from Phase II, to prepare a preliminary engineering design package and financial plan for obtaining private funding to build a 5,000 barrel per day (BPD) coal gasification/liquefaction plant next to an existing co-generation plant in Gilberton, Schuylkill County, Pennsylvania.

The current report is WMPI's fourth quarterly technical progress report. It covers the period performance from January 1, 2002 through March 31, 2002.

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Section 1 Introduction and Summary

1.1 INTRODUCTION

WMPI, along with its subcontractors Texaco (now ChevronTexaco), Sasol, and Nexant entered into a Cooperative Agreement DE-FC26-00NT40693 with the U. S. Department of Energy (DOE), National Energy Technology Laboratory (NETL), to assess the technical and economic viability of building an Early Entrance Co-Production Plant (EECP) in the U. S. to produce ultra clean Fischer-Tropsch (FT) transportation fuels with either power or steam as the major co-product. The EECP design emphasizes on recovery and gasification of low-cost coal wastes (culm) from coal cleaning operations, and will assess blends of the culm with coal or petroleum coke as feedstocks. The project has three phases.

1.1.1 Phase I – Concept Definition and RD&T Planning

Phase I objectives include concept development, technology assessment, conceptual designs and economic evaluations of a greenfield commercial co-production plant and of a site specific demonstration EECP to be located adjacent to the existing Gilberton Power Station. There are very few expected design differences between the greenfield commercial co-production plant versus the EECP plant other than:

- The greenfield commercial plant will be a stand-alone FT/power co-production plant, potentially with larger capacity than the EECP to take full advantage of economies of scale.
- The EECP plant, on the other hand, will be a nominal 5,000 bpd plant, fully integrated into the Gilberton Power Company's Cogeneration Plant's existing infrastructure to reduce cost and minimize project risks. The Gilberton EECP plant will be designed to use eastern Pennsylvania anthracite coal waste and/or a mixture of culm and other fuels as feedstock.

Phase I includes 11 tasks and the following major deliverables.

- A project management plan.
- A process feasibility design package with sufficient details to determine order-of-magnitude cost estimates for preliminary economic and market analyses.
- A preliminary environmental and site analysis.
- A Research, Development and Testing (RD&T) plan for Phase II tasks.
- A preliminary project financing plan.

1.1.2 Phase II – R&D and Testing

The Phase II objective is to perform research, development and process performance verification testing of any design deficiencies identified in Phase I. Due to the relative maturity of the two key technologies (Texaco's coal gasification and SASOL's FT) proposed for the EECP designs, Phase II activities will focus on feedstock characterization and gasification process performance testing rather than research and development. Specific Phase II goals include:

- Characterization of anthracite culm and its mixture with other fuels as feedstocks for the Texaco gasifier.
- Gasification performance (pilot plant) testing of design anthracite culm feedstocks at an existing Texaco facility to verify its performance.

1.1.3 Phase III – Preliminary Engineering Design

The objective in Phase III is to upgrade the accuracy of the Phase I site-specific Gilberton EECP capital cost from plus or minus 35% to plus or minus 20%. The increased cost estimation accuracy is achieved by updating the Phase I inside battery limits (ISBL) processing plant design packages to incorporate Phase II findings, by refining the outside battery limits (OSBL) utility and offsite support facility design packages to include final and updated ISBL unit demands, by obtaining actual budgetary quotes for all major equipment, and by further engineering to define the actual bulk commodities requirements.

The upgraded Phase III capital cost estimate, together with the updated operating and maintenance cost estimate, are crucial elements to finalize the EECP Project Financing Plan needed to proceed with detailed engineering, procurement and construction of the EECP.

The Phase III goals and deliverables include the development of:

- Preliminary Engineering Design package of the EECP.
- A Project Financing Plan.
- An EECP Test Plan.

The project scope of work consists of sixteen tasks organized into the three phases as shown in Table 1.1. The table also shows the project team members responsible for the leading role for each task. The specific task description details were discussed in the Project Management Plan.

1.2 SUMMARY

The main technical activities performed during the current reporting period include work in the following tasks.

- Phase I Task 4 – Feasibility Design Package Development
    - Balance of Plant (BOP)
    - Offsites

Table 1-1

Scope of Work Task Summary

Phase/Task	Description	Task Leaders
Phase I	**Concept Definition and RD&T Planning**	
Task 1	Project Plan	Nexant
Task 2	Concept Definition, Design Basis & EECP Process Configuration Development	Nexant
Task 3	System Technical Assessment (Trade-off Analysis)	Nexant
Task 4	Feasibility Study Design Package Development	Nexant (w/individual Process Design package from Texaco and Sasol)
Task 5	Market Assessment	Texaco
Task 6	Preliminary Site Analysis	WMPI and Consultants
Task 7	Preliminary Environmental Assessment	WMPI and Consultants
Task 8	Economic Assessment	WMPI and Consultants
Task 9	Research Development and Test Plan	Texaco
Task 10	Preliminary Project Financing Plan	WMPI and Consultants
Task 11	Phase I - Concept Report	Nexant
Phase II	**R&D and Testing**	
Task 1	Feedstock Mix Characterization and Gasification Performance Verification	Texaco (w/ support from Nexant and WMPI)
Task 2	Update RD&T Plan	Texaco
Phase III	**EECP Engineering Design**	
Task 1	Preliminary Engineering Design Package Development	Nexant – with a) Texaco – Gasification Design Package b) Sasol – FT Design Package c) Nexant – BOP and cost estimate
Task 2	Project Financing Plan	WMPI and Consultants
Task 3	EECP Test Plan	Nexant

Section 2 Phase I Task 1 – Project Plan

TASK COMPLETED.

A Project Management Plan was prepared, issued and approved by DOE. A copy was submitted to the AAD Document Control Office of DOE/NETL on May 15, 2001.

This plan provides a road map for the overall project execution delineating the project:

- Objectives.
- Detailed work breakdown structure and obligated deliverables.
- Technical and management approach.
- Control plan – scheduling, budget and reporting.
- Administration details.

Section 3 Phase I Task 2 – Concept Definition, Design Basis & EECP Process Configuration

TASK COMPLETED.

3.1 EECP concept and process configuration defined, giving full considerations of:

- WMPI's feedstock availability and quality (e.g., ash content, composition and anticipated fusion temperature.)
- Desired mode of operation for Texaco's gasification process in handling the design project feed mix.
- Design consideration of Sasol's Low-Temperature FT (LTFT) process giving the estimated design syngas feed.
- System integration and site-related issues (e.g., syngas clean up, utility availability.)

3.2 Gilberton EECP Design Basis established, and a Basic Engineering Design Data (BEDD) package was developed to guide the overall process design development regarding:

- Plant capacity
- Site data
- Feedstock properties
- Product specifications
- Battery limits and offsite utility specifications

3.3 Project Instruction of Equipment Code of Accounts established.

Details of the above were reported in the April to June 2001 Quarterly Technical Progress Report.

EECP process configurations will be discussed in more details as part of the Phase 1 Task 4 activity.

Section 4 Phase I Task 3 – System Technical Assessment

Under this task 1) technical design issues/systems (e.g., ash fusion characteristics of EECP feed mix) identified in Phase 1 Task 2 were assessed in more detail, and 2) preliminary heat, material and utility balance sensitivity analyses were carried out, based on process performance estimates and utility demands from Texaco and Sasol for the gasification and FT synthesis section respectively, to continuously optimize the overall EECP process plant design and preliminary economics, and to provide preliminary emission and cost data needed for Phase I Tasks 7 and 8 planning.

Current sensitivity analysis activities included assessment of:

- The Base Case, stand-alone 5000 bpd Greenfield EECP plant with 2 separate gasification trains, in comparison with a reduced capacity design with only a single gasification train operating at a higher tail gas recycling ratio for FT synthesis.

- An integrated design with sending portion of the unconverted FT tail gas to the existing Gilberton cogen plant circulating fluidized bed boiler (CFB) as auxiliary feed.

Section 5 Phase I Task 4 – Feasibility Design Package development

Under this task, feasibility study process design packages are to be developed for the EECP gasification island, FT synthesis and offsite utility plants by Texaco, Sasol and Nexant respectively. With most of the major EECP processing plants already identified, Texaco has developed a gasification island Type C Feasibility Study package, and Sasol, the Slurry-Phase Distillate Process Feasibility Study package. Balance of Plant (BOP) and offsite facility designs are the major activities performed during this reporting period by Nexant.

Both the Texaco Type C Feasibility Study and Sasol Slurry-Phase Distillate Process Feasibility Study design packages have been discussed in the last quarterly report (4th quarter, 2001) and are considered CONFIDENTIAL. These two processes will be reviewed briefly in this quarterly report.

5.1 Overall EECP Configuration

Figure 5-1 shows the overall WMPI EECP block flow configuration.

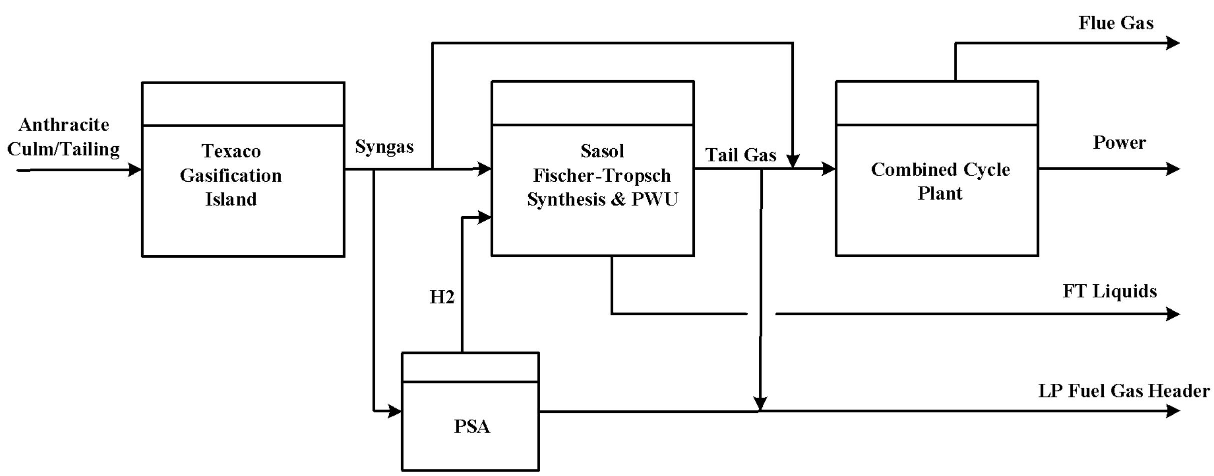


Figure 5-1 Overall EECP Process Configuration

The EECP plant consists of two main process sections: Texaco Gasification, and Sasol FT Synthesis and product work up (PWU). It is designed to use anthracite culm of 20% ash as the primary feed. The design has the operation flexibility of feeding in 25% petroleum coke as feed.

5.2 Texaco Gasification Feasibility Design

Texaco provided a Type C Feasibility Study Package as their input to Phase I EECP process design. The detailed feasibility study contains material confidential to Texaco, and if desired the DOE can inspect the report separately from the Quarterly Report.

The overall EECP gasification island block diagram is shown below, Figure 5-2.

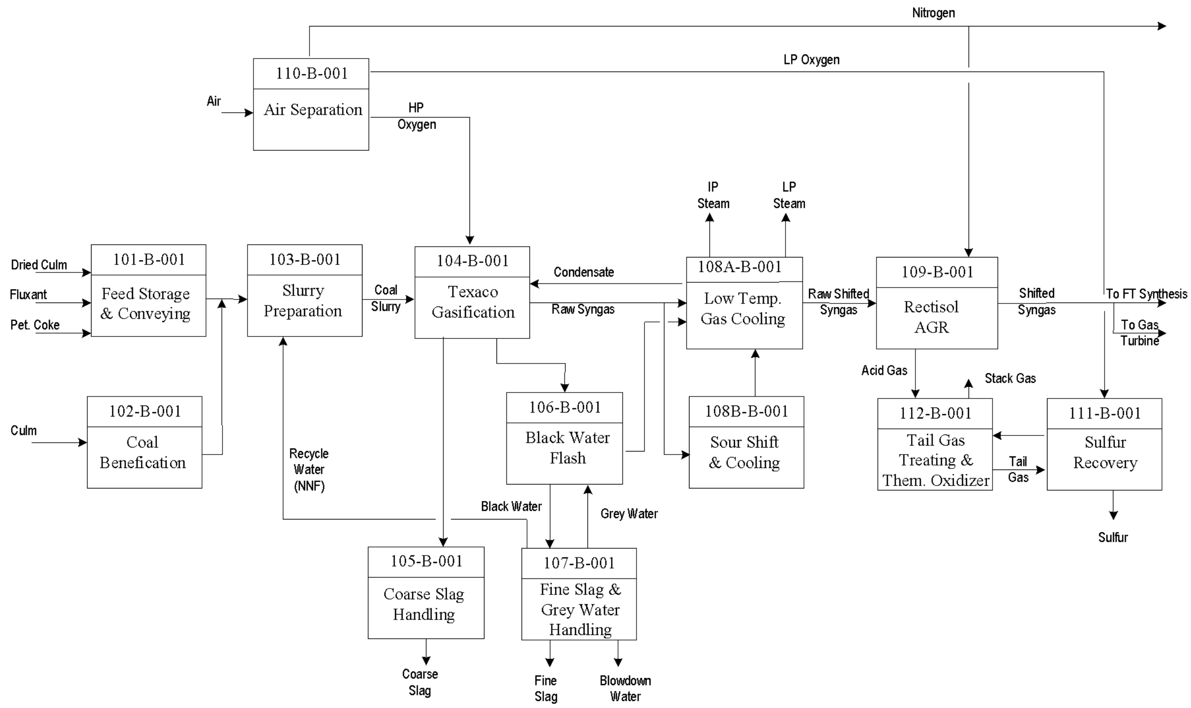


Figure 5-2 EECP Block Flow Diagram – Gasification Section

It consists a total of eleven major processing plants of which Coal Beneficiation (Plant 102B-001) design is the responsibility of WMPI. Other processing plants within the gasification island include:

- Feed Storage and Conveying
- Slurry Preparation, Gasification
- Slag Handling
- Black Water Flash
- Black Water Filtration
- Sour Shift and Low Temperature Gas Cooling
- Rectisol Acid Gas Removal
- Air Separation Unit
- Sulfur Recovery
- Tail Gas Treating

Individual process plant description, design criteria, stream flow characteristics and estimated plant emissions were presented in the last quarterly technical report

5.2 Sasol Slurry-Phase Distillate Process Feasibility Study

Sasol has prepared a Feasibility Design Package for the Fischer-Tropsch unit and the associated product work-up processing plant. The overall block flow diagram is shown below, Figure 5-3.

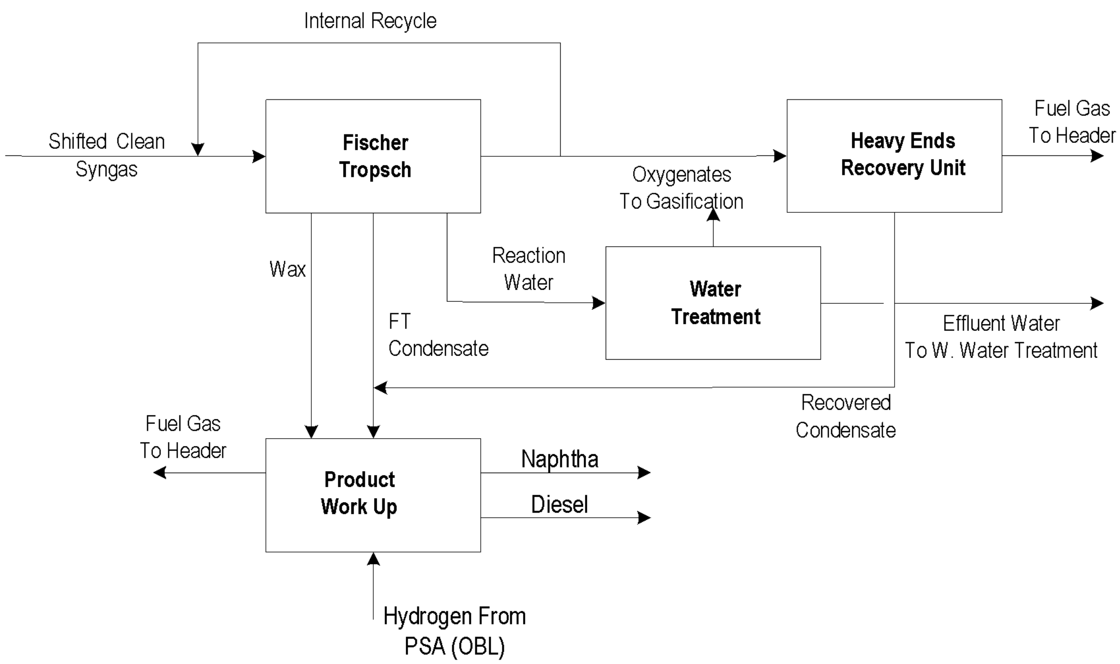


Figure 5-3 EECP Block Flow Diagram – FT and PWU Section

The Sasol EECP feasibility study scope includes the following process units:

- Plant 201 Fischer-Tropsch Synthesis Unit (including the Catalyst Reduction and Heavy Ends Recovery)
- Plant 202 Product Work-Up Unit
- Plant 203 Effluent Water Primary Treatment Unit

Individual process plant description, design criteria, stream flow characteristics and estimated plant emissions were presented in the last quarterly technical report

5.3 Balance of Plant / Offsites Feasibility Design

Nexant has prepared a Feasibility Design Package for the Balance of Plant and Offsite facilities. It consists of the following major offsite facilities:

Offsite Facilities:

- Plant 301 - Fuel Gas Collection and Distribution System
- Plant 302 - Relief and Blowdown
- Plant 303 - Steam and Condensate Collection and Distribution
- Plant 304 - Interconnecting Piping
- Plant 305 - Plant Air/Instrument Air System
- Plant 306 - Tankage
- Plant 307 - Tank Car/Truck Loading
- Plant 308 - Catalysts and Chemical Handling
- Plant 309 - Combined Cycle Plant
- Plant 310 - Electric Power Distribution
- Plant 311 - Raw/Potable/Process Water System
- Plant 312 - Cooling Water System

The following offsite plant designs are in progress:

- Plant 313 - Waste Water Treatment
- Plant 314 - Sewage/Effluent Treating
- Plant 315 - Solid Waste Storage and Handling
- Plant 316 - Fire Protection
- Plant 317 – Buildings

- Plant 318 - DCS, Communication, and General Services
- Plant 319 - Site Preparation

In addition, facilities that are outside the EECP plant boundary but are necessary for its operation are included in the scope of Area 400, the Outside-Fence-Facilities. These include:

- Facilities for coal/coke and solid wastes conveying from/to the rail cars
- Equipment for pumping mine pool water to EECP and treated mine pool water back to an outside-fence percolation pond
- Coal slurry lines to EECP
- Natural gas tie-ins to the gas main
- Electrical tie-ins to the main grid
- Well water pumps

5.3.1 Process Flow Diagrams

The BOP/Offsites Feasibility Study Design Package includes simplified process flow diagrams listed below. These drawings are available in the final design package.

<u>Drawing No.</u> <u>Description</u>

- 301-B-001 Fuel Gas Collection and Distribution System
- 303-B-001 Steam and Condensate Collection and Distribution System, Boiler Blowdown Collection and Flash
- 303-B-002 Steam and Condensate Collection and Distribution System, Condensate Collection
- 303-B-003 Steam and Condensate Collection and Distribution System, Condensate Collection
- 303-B-004 Steam and Condensate Collection and Distribution System, Gasification Steam and Condensate Collection
- 303-B-005 Steam and Condensate Collection and Distribution System, Fischer Tropsch Steam and Condensate Collection
- 305-B-001 Plant Air/Instrument Air System
- 309-B-001 Combined Cycle Plant
- 312-B-001 Cooling Tower Water System
- 313A-B-001 Sour Water Stripper
- 315-B-001 Solid Waste Storage & Handling

5.3.2 Process Description

The BOP/Offsites Facilities for the EECP completed for this quarterly report period are described in this section.

Plant 301 Fuel Gas Collection and Distribution System

PSA residual gas and low pressure FT vent gases are collected in the fuel gas receiver and is compressed by the fuel gas compressor to the LP fuel gas header pressure of 85 psig. A portion of the compressed fuel gas is mixed with the intermediate pressure (120 to 190 psia) offgases from the FT product workup area and is distributed to the users. The FT Hydrocracker Fired Heater and the FT Product Fractionator Fired Heater consume 19 and 17 MMBtu/hr of LP fuel gas respectively. Fuel gas is also required for the Fischer Tropsch startup heaters during startup.

Overpressure at the LP header is relieved to flare. Supplemental natural gas is available to make up for any fuel gas deficiency.

The HP fuel gas compressor further compresses excess low pressure fuel gas to the HP fuel gas header pressure of 325 psig. The compressor discharge is then mixed with high pressure offgases from the FT units for use as gas turbine fuel. The total fuel gas to the gas turbine is 770 MMbtu/hr with the majority (711 MMbtu/hr) coming from the FT tail gas. A condensate knockout drum is provided to remove any condensates.

Alcohol rich liquid stream from the FT water treating area is collected and stored in Plant 301. The alcohol rich stream is campaigned to the gasifier as gasifier feed.

The design fuel gas rates are shown in table 5-1:

Table 5-1
Fuel Gas Rates

Description	Source Pressure	MMbtu/hr
	Psia	
PSA Residual Gas	20	76.9
FT Diesel Strip Overhead Gas	36	8
FT Catalyst Reduction/Cond Vent	51	1.5
CO2 Rich Gas from FT	145	0.3
FT HC LP Sep Overhead Gas	189	4
FT Stabilizer Overhead Gas	126	19.7
FT WLP Sep Off Gas	131	1.5
Catalytic Reduction Off Gas	352	0.5
FT HC H2 Purge	972	3.3
FT Tail Gas	347	710.7
Total Fuel Gas		826.4

Plant 302 Relief and Blowdown System

The relief and blowdown system is based on relieving all the syngas from the gasification unit and is consisted of a hydrocarbon flare and a H_2S flare. Each elevated flare has its own liquid knockout drum and liquid drain pumps. Relief loads from process plants are routed to the emergency flare via the 36-inch main flare header and various relief laterals and sub-headers. Liquid collected in the surge drum is pumped out periodically.

The elevated hydrocarbon flare will handle reliefs from all process units except Rectisol, Sour Water and SRU/TGTU plants. Low pressure steam will be injected to produce a smokeless flame.

The elevated H_2S flare will handle reliefs containing H_2S from the Rectisol, Sour Water, and SRU/TGTU plants. Natural gas is injected to obtain a 1400°F flame temperature to ensure combustion of the H_2S relief streams.

When the H_2S flare is down, the load will be directed to the main flare.

Plant 303 Steam and Condensate Collection and Distribution System

<u>Condensate Distribution</u>

The Steam and Condensate Collection and Distribution System collects and distributes steam to users and recover steam condensate as the primary water makeup for the boiler feed water deaerators. Blowdowns from boilers are flashed and the low pressure flashed steam is recovered. The flashed liquid is collected and sent to waste water treatment.

The total condensate flow is approximately 2,196 gpm. The condensates are segregated into oily (process and IP/LP turbines) condensates and clean (1500 psig HP turbine). The oily condensates are collected and sent to a skimmer equipped condensate storage tank to remove oily contaminants. The clean HP turbine condensate is recycled directly to the BFW deaerators without oil skimming. Off-specification condensates are routed to the storage tank for further treating. The condensate rates are as follows:

- Process condensates (543 gpm)
- IP/LP process steam turbine condensate (978 gpm)
- HP turbine condensate (675 gpm)

The process condensates are discharged from the process units at various temperatures and must be air-cooled to 140 °F before they are transferred to the condensate storage tank. Approximately 3 hours of surge capacity is provided in the storage tank. The turbine condensates from combined cycle plant and process units are normally exhausted at 110 °F and no additional cooling is required.

Treated condensates from the storage tank and clean HP turbine condensate are then preheated and pumped to the deaerators to make BFW. Condensate preheat is provided by heat exchange with syngas in the gasification unit. Alternatively, the condensate can be preheated at the HRSG. Condensate losses are made up at the deaerators or the condensate storage tank from demineralized water supply. Maximum make up rate is 480 gpm.

Blowdowns from the boilers are flashed to recover 60 psig steam. The flashed blowdown liquid is sent to the water-treating unit (plant 313).

Steam Distribution

HHP (1500 psig) steam is generated at the HRSG boiler and except for 2,900 lbs/hr for the SRU/TGTU, is used mainly in the combined cycle plant steam turbo generator for generating electricity.

TGTU Oxidizer Boiler and the SRU Reactor Boiler are the primary sources of HP (700 psig) steam with a total HP steam generation rate of 139,200 lbs/hr. An additional 18,000 lbs/hr of HP steam is extracted from the turbo generator to meet the requirements of HP steam users. Approximately 2,000 lbs/hr of HP steam is consumed within the SRU/TGTU units with the balance going to the FT unit. The major users of HP steam in the FT plant are the FT Recycle Compressor (143,700 lbs/hr) and the FT Product Workup reboilers (11,600 lbs/hr).

The MP syngas exchanger/boiler in the gasification unit, HRSG MP boiler, and the FT Recycle Compressor steam turbine driver exhaust generate approximately 330,700 lbs/hr of MP (300 psig) steam. The primary MP steam users are the Air Separation Plant exchangers and the gas turbine combustor. The balance of the MP steam is sent to the turbo generator for generating power.

The IP syngas exchanger/boiler and the steam turbine drivers in the gasification unit generate 209,500 lbs/hr of superheated IP (150 psig) steam. Part of the IP steam is used in the Rectisol unit and the Sour Water Stripper unit. The balance is used in two 150 psig steam turbo generators for power generation.

The FT reactor generates 290,400 lbs/hr of saturated IP steam. Approximately half of the saturated IP steam is consumed in the FT Product Workup unit and 28,000 lbs/hr is sent to Plant 309 for deaerators stripping steam. The balance of the IP steam is sent to the 150 psig turbo generator for power generation.

The LTGC LP boiler in the gasification section is the major producer of 60 psig (LP) steam. It generates approximately 210,000 lbs/hr. Steam driver exhaust, IP steam letdown and BD flash make up the balance of the LP steam production.

The Rectisol unit, TGTU reboiler and the BFW deaerators are the major users of LP steam. A surplus of 133,400 lbs/hr of LP steam at the gasification unit is used locally to generate power from a LP turbo generator.

Plant 304 Interconnecting Piping

Unit 304 includes the off-plot pipeway piping, and off-sites and utility piping within the EECP Plant fence limits but outside of the process units. Excluded from Plant 304 are Outside-Plant-Fence pipelines such as product lines to railroad spur, mine pool water supply from valley pump-site, slurry feed line from Beneficiation (Plant 102), and treated effluent water line to the valley percolating pond for disposal. All piping connections inside process units are included in the associated process unit costs.

Process Piping

The following process lines are included:

- High pressure sour gas line to acid gas removal unit
- High pressure syngas line to Fischer-Tropsch Unit
- Low pressure purge gas line to tail gas treating
- Acid gas line to sulfur recovery unit
- High pressure oxygen line to Gasification Unit
- High pressure nitrogen line to Gasification Unit
- Low pressure nitrogen line to Fischer-Tropsch and Rectisol Units

Fuel Gas

A 10” high-pressure fuel gas main for supplying fuel gas to the combined cycle plant is included. Low-pressure fuel gas mains are inside process units and are included in the scope of associated process units.

Steam Systems

Four steam mains are provided in Plant 304 to the following four pressure levels:

- HP steam main, 700 psig steam
- MP steam main, 300 psig steam
- IP steam main, 150 psig steam
- LP steam main, 60 psig steam

The high-high-pressure steam main for 1500 psig superheated steam is inside the combined cycle plant.

Condensate Systems

Steam condensate from process blowdown drums, surface condensers and steam turbines is collected and returned to condensate storage tank through a condensate return main.

Steam condensate from the condensate storage tank is pumped through steam condensate transfer line to the deaerators in the combined cycle plant and gasification plant.

BFW Systems

A high-pressure BFW main designed for 2,000 psig distributes BFW from the combined cycle plant to process units for process injection. H.P. BFW main to boilers in sulfur recovery unit is included in the scope of Plant 309 and 111.

A medium pressure BFW main designed for 500 psig is provided to distribute BFW from two deaerators located in the Plant 309 and 309A to steam coils in Fischer Tropsch reactors, boilers in LTGC unit and process injection in gasification plant.

Plant Air & Instrument Air

A plant air main and an instrument air main are provided to distribute air from Plant 305 to other process units.

Product Lines

Product rundown lines are provided to deliver naphtha and diesel products from Fischer-Tropsch Unit to product storage tanks in the tankage area.

Off-spec recirculation lines are provided to transfer off-spec product back to Fischer-Tropsch Unit for re-processing.

Demineralized Water

A demineralized water supply line is provided to distribute demineralized water to the deaerators as makeup to boiler feed water system.

Water Supply Systems

A well water supply main collects fresh water from wells and transfer well water to well water treating facilities and then to demineralization facilities and potable water treating facilities, etc.

A mine pool water supply main transfers water from the EECP Plant fence limit to mine pool water treating facilities.

Cooling water system

The cooling water supply main is routed from cooling water pump house to the air separation Plant 110. The cooling water return main follows the same route with opposite flow direction from the Plant 110 back to cooling water towers.

Waste Water System

Oily water main is provided to collect hydrocarbon-contaminated water from Rectisol Unit, Fischer-Tropsch Unit, Gasification Unit and recovered condensate purge to waste water treatment facilities in Plant 313.

A sour water main is provided to transfer sour water from sour shift/LTGC Plant 108 to sour water stripper in Plant 313.

A separate waste water main collects all non-hydrocarbon contaminated water from water supply treating facilities and condensate treating facilities, etc. to the wastewater treatment Plant 313.

Storm Sewer Systems

Storm sewer systems are designed for 6" rainfall in 24 hours at plant location. Three independent containment systems are provided.

- Contaminated run-off from process units and tankage areas
- Coal pile run-off and uncontaminated run-off from air separation unit
- Combined Cycle Plant and building areas.

Plant 305 Plant Air/Instrument Air/Nitrogen System

Plant 305 supplies instrument air, plant air and nitrogen to the process plants and support facilities. Filtered atmospheric air (2,200 SCFM) is compressed to 140 psig and cooled to 100 °F before discharging to the plant air header. Approximately 1,800 SCFM of the compressed and cooled air stream is dried to –40 °F dew point to supply instrument air. A liquid nitrogen pump and vaporizer system is also included in this system to supply 800 psig nitrogen to the Fischer Tropsch unit and 60 psig N2 to various users. Nitrogen is also used as backup supply for the instrument air. N2 is either trucked in or supply from the Air Separation Plant.

Plant 306 Tankage

Plant 306 includes tanks and miscellaneous equipment required for hydrocarbon product storage and delivery. The hydrocarbon products are naphtha and diesel from the Fischer-Tropsch Product Work-up & Recovery Unit Plant 202.

Pumps for loading tank trucks, re-blending off-spec products and re-circulating the off-spec products back to the process units are included here. The product pumps that transfer the products from process units to the tankage are included in Plant 202.

Other non-product tanks are included in the associated process units. Sulfur storage tank in Sulfur Recovery Unit, fire water tank in Plant 316, well water tank and demineralized water tank in Plant 311 and condensate tank in Plant 303 are located in their respective process units.

All tanks are internal floating roof tanks with external cone roof to meet environmental emission requirement and to bearing snow load. The tanks are built per API 650. The production rates are 1,300 bbl per day for naphtha product and 3,800 bbl per day for diesel product. Each tank has two-day production holding capacity.

Truck Loading Pumps

Two identical truck loading pumps, one operating and one standby, are provided for each product. All pumps are per API 610. Truck loading rates are 350 gpm for naphtha product and 1,050 gpm for diesel product. In a normal eight hour shift, these loading rates will empty one and a half tank for each product.

Re-circulation Pumps

If the off-spec products could not be blended on site, two off-spec product re-circulating pumps per API 610, rated at 28 gpm at 100 psig, are provided to send the off-spec products back to Plant 202 for re-processing. One pump is used for off-spec naphtha and two pumps operated in parallel are used for re-circulating off-spec diesel.

Plant 307 Tank Car/Truck Loading

Plant 307 provides the product loading and weigh systems for delivery of the fuel oil products to customers. A separate loading system is provided for delivering naphtha and for delivering diesel.

The equipment for this unit includes the tank truck loading facilities for each product and tank truck weigh stations for tracking the amount of product transferred for accounting and billing purposes. A weigh station house is included in Plant 317 Buildings.

Loading and unloading facilities for sulfur, chemicals (methanol, acids and caustics) and catalysts, etc. are excluded from the unit scope.

Plant 308 Catalyst and Chemical Handling

Plant 308 provides storage and handling for the catalysts and chemicals used in all the plants. Additionally, it provides a consolidated location for tracking catalyst and chemical start-up and daily consumption requirements.

The equipment for this plant includes an enclosed warehouse for storing chemicals and catalysts and two 25-HP electric forklifts for transporting pallets of chemicals or catalysts into or out of the warehouse.

Plant 309 Combined Cycle Plant

Plant 309, the combined cycle plant, converts excess fuel gas from the process units to electrical power for internal consumption and export to the outside power grid. In addition, high and medium pressure steams are generated through waste heat recovery to produce additional power using steam turbo generators.

The power generated from the combined cycle plant is approximately 106 MW. An additional 29 MW is generated at the process units from intermediate and low pressure steam turbo-generators.

Process fuel gas from the high pressure fuel gas header is mixed with injection steam from the 300 psig steam header and is combusted in the gas turbine combustor. The process fuel gas to the GE gas turbine consists of high pressure Fischer Tropsch tail gas, low pressure PSA residual gas and low pressure/intermediate pressure (LP/MP) vent gas from various units. Steam is injected to the gas turbine combustor to control NOx emission.

Exhaust flue gas from the gas turbine at 1017 °F is sent to the HRSG for heat recovery by generating steam and preheating BFW. The cooled HRSG flue gas exits at 295 °F and is mixed with injected ammonia for the catalytic reduction of NOx and CO in the SCR unit. GE has indicated that a 2.5 ppm NOx and a 3 ppm CO levels in the stack flue gas can be achieved.

The HRSG boilers generate all of the superheated HHP (1500 psig) steam and part of the MP (300 psig) steam for the steam turbo generator.

The deaerators are vertical stripper/horizontal storage drum type vessel. Treated process condensate and clean high pressure turbine condensates are steam stripped in the vertical stripper to remove oxygen. Residual oxygen is removed by the addition of oxygen scavenger type chemicals. PH adjustment chemicals are also added at this time. The treated BFW is then pumped to the boilers.

Plant 310 Electric Power Distribution

The Electrical Distribution System (Plant 310) includes off-site power supply from the Gilberton Power and PPL power lines (from Eldred and Siegfried lines), as well as onsite power generation, on site substations and switchyards, high, medium and low voltage power distribution system throughout the facility.

The facility receives power from the 230kV high voltage switchyard. The switchyard will generally consist of a minimum four breaker arrangement with two off-site utility sources as well as direct line from the Gilberton Power station to insure high reliability and availability of the facility electrical distribution system. The Facility Electrical Single Line Diagram

assumes a four breaker ring bus arrangement. Alternate configurations will be examined during detailed design subject to Utility approval.
The plant electrical distribution system receives power from the 230kV high voltage switchyard. The switchyard will generally consist of a minimum four breaker arrangement with two off-site utility sources required to insure high availability of the facility electrical distribution system. The Facility Electrical Single Line Diagram assumes a four breaker ring bus arrangement. Alternate configurations will be examined during detailed design subject to Utility approval.

Two switchyard main transformers transform the 230kV source to 115 kV for distribution to the facility substations. The switchyard facility is assumed to be provided by local utility. The main facility 115kV double-bus switchgear (located adjacent to the 230kV switchyard) provides redundant feeders to Substation 1-4. The high voltage switchgear provides the normal running facility load from :

- In-house generation 112 + 22 MW (75MW from the Gas Turbine, ~37 MW Steam Turbine Generating Plant, and ~22MW from IP/LP steam turbines) source
- Off-site purchased power. During periods of start-up, all power may be derived from the off-site sources. During normal operation, the facility load will be split between the two 230 kV switchgear buses.

The high voltage 230 kV feeders are installed in underground duct banks. During detailed design, a cost saving overhead distribution system may be considered.

The Gas turbine generators and the steam turbine generators are connected to the main step-up transformer via a local synchronizing breaker (SF6 type). The generator power is delivered to the 230kV switchgear in an underground duct bank similar to the high voltage substation feeders.

The following table shows the plant load distribution from the four medium voltage substations:

Substation	Plant Loads
Substation 1	Plants 109 and 110, and Plants 101 thru 108
Substation 2	Plants 201 thru 206
Substation 3	Plants 301 thru 308, Tank Farm
Substation 4	OSBL & Power Generation Auxiliaries.

Substations

Each substation consists of two main transformers per swithgear lineup. One transformer is fed from main distribution switchgear (230 kV) Bus A and the other from Bus B. Each transformer is capable of the total secondary load with 15% spare section to maintain services, upon loss of either switchgear section of either transformer.

The distribution of loads on the individual plant switchgear buses will be such that equipment with redundancy will be on separate bus minimizing the impact to the facility processes upon failure of one electrical power source.

The substation electrical medium and low voltage service levels and associated motor assignment criteria are provided under design criteria.

Similar to the high voltage feeders, in outdoor areas the medium voltage (13kV and 4.16kV) substation feeders are expected to be installed in underground duct banks and/or direction buried cables. However, during detailed design, a cost saving overhead distribution may be considered.

Plant 311 Raw/Potable/Process Water System

Raw water is available from two water sources: onsite well water and off site mine pool water. The groundwater wells will supply process water for the plant for such uses as boiler water makeup and potable water. This well water is high quality water that has a salinity of about 70 ppm total dissolved solids. The second source is mine pool water which will be used for cooling tower makeup. This water has a nominal salinity of 1000 ppm.

The process water is obtained from onsite wells and provides water for the steam boilers, the gasifier, plant water consumption, and the potable water supply. Water for plant usages and for potable uses requires only filtration. The boiler feed water treatment consists of demineralization equipment. Additionally, the returned condensate will also require treatment. Equipment requirements for the steam and condensate collection are described in Plant 303.

The well water supply quality is shown in the table 5-2. This is very good quality water for feed to an ion exchange system because of its low total dissolved solids (TDS).

Table 5-2
Well Water Quality

CONSTITUENT	UNITS	WELL WATER (AVE)
CATIONS		AS ION
Mg	ppm	1.7
Mn	ppm	0.1
Na	ppm	1.3
Ca	ppm	14.0
K	ppm	0.0
Cu	ppm	0.2
Fe	ppm	0.4
SUM CATIONS	ppm	17.7
ANIONS		
Cl	ppm	2.2
F	ppm	0.0
NO3	ppm	0.0
SO4	ppm	14.3
HCO3	ppm	34.1
SUM ANIONS	ppm	50.6
Si02	ppm	5.7
TDS (CALC)	ppm	68
pH		6.5
TEMPERATURE	oF	60

The boiler feedwater treatment requirements are shown in the table 5-3 for 1500 psi steam generators. Because of the high operating pressure, very low levels on constituents must be achieved.

Table 5-3

BOILER FEEDWATER TREATMENT REQUIREMENTS

TREATMENT DESCRIPTION	PROCESS MAKE UP WATER
Source	Well Water
pH @ 25 oC	7
Total Hardness As CaCO3, ppm	0
Total Alkalinity AS CaCO3, ppm	0
Chloride As Cl, ppm	<0.01
Silicate as SiO2, ppm	<0.02
Total Dissolved Solids, ppm	<0.05
Sodium as Na2CO3, ppm	<0.01

Potable Water

The potable water system will provide treated water for all potable and sanitary use in the plant. It will also be used for the emergency shower/eyewash system. The potable water system will be fed to the water storage tank by a 100% potable water pump.

Design of the potable water system is based on the following criteria:

Plant total population: 100
Consumption rate: 50 gals per person per day
System pressure: 60 to 70 psig
Peak flow: 10 times daily average
Make up flow: 200% of the daily average
Daily Average: 4 gpm

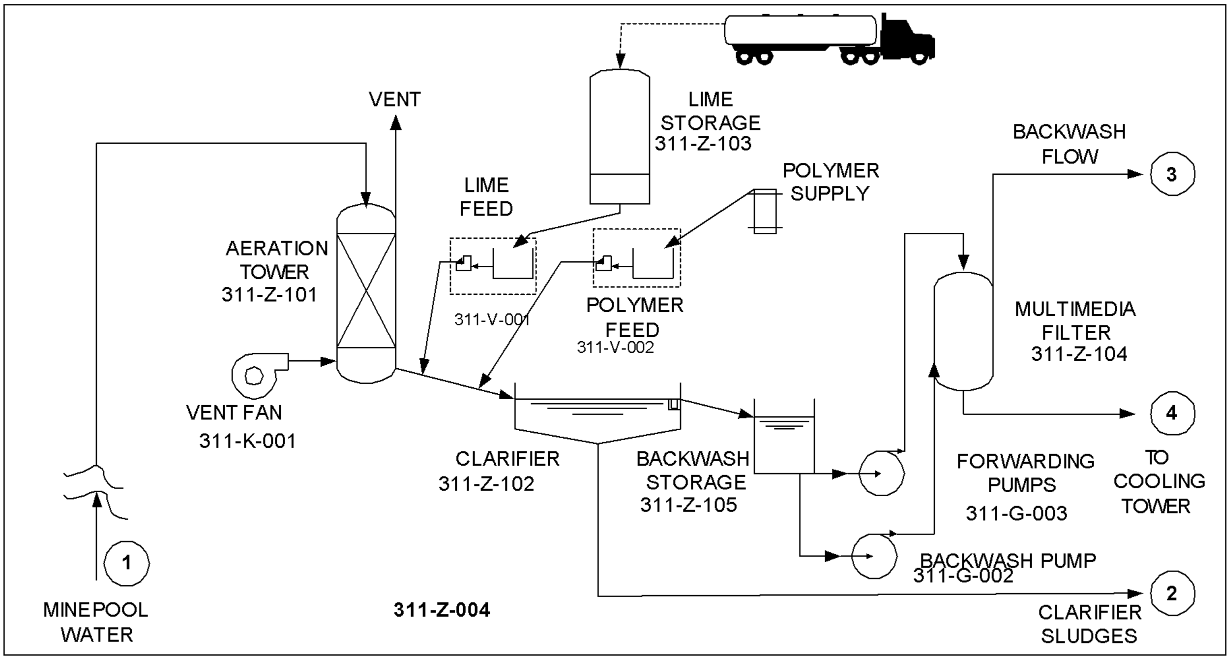
The water will meet drinking water standards and will have periodic disinfection with hypochlorite.

Cooling Tower Makeup

The selected treatment system is shown in Figure 5-4. Well water is aerated, treated with lime to increase pH, and then send to a clarifier. The treated water from the clarifier is then filtered in a mixed media pressure filter and sent to the storage tank. The storage tank supplies both cooling tower makeup and firewater.

FIGURE 5-4

COOLING TOWER MAKEUP TREATMENT SYSTEM



FLOWSTREAM		1	2	3	4
QUANTITY	UNITS	MINE POOL SUPPLY	FILTER BACKWASH	CLARIFIER SLUDGES	COOLING TOWER FEED
FLOW (DESIGN)	gpm	3600			
(EXPECTED	gpm	2744	110		2634
	lb/hr			33	
pH @ 25*C		6.3-6.5	8		8
FE	ppm	45	<0.1		<0.1
TDS	ppm	966	966		966

The aeration tower contains contactors trays with the water entering the top of the tower and air at the bottom. Because of the deposition of iron, periodically these trays are replaced while the used trays are cleaned. The pH is adjusted with lime to above 8. Additionally, a polymer feed is added to assist in the clarification.

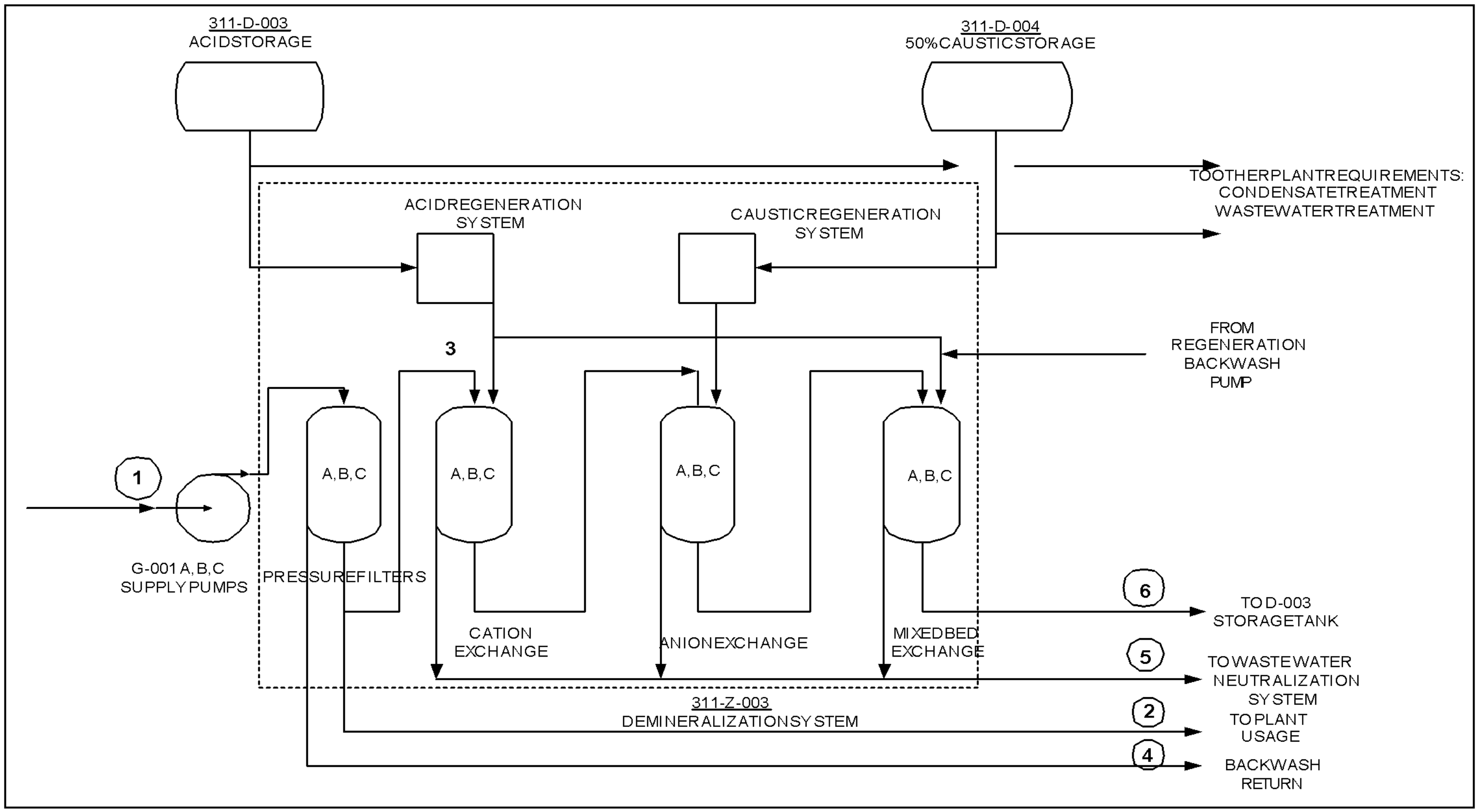
After clarification and sand filtration, the water may have additional pH adjustment to maintain the cooling tower basin at the proper pH to prevent scale. Proprietary chemicals along with the pH adjustment can also be used for scale control. They cooling tower will operate at a nominal 3 cycles of concentration

Process Water Treatment for Boiler Makeup

The well water will be filtered to remove particulates. A portion of the water will then be fed to the potable water treatment, to plant water, and the remained to the demineralization treatment system (see Figure 5-5). Additionally, another demineralization system will be provided for the recovered steam condensate treatment.

FIGURE 5-5

BOILER WATER MAKEUP SYSTEM



QUANTITY	UNITS	WELL SUPPLY	PLANT USAGE	DEMIN IN	FILTER BACKWASH	REGEN WASTE	DEMIN OUT
		1	2	3	4	5	6
FLOW (DESIGN)	GPM			680			
(EXPECTED)	GPM	669	42	607	20	9	597
	LBS/HR	334,500	21,000	303,500	10,000	4,500	298,500
TDS	PPM	68	68	68	68	4533	<0.5

The boiler makeup demineralizer system consists of three cation and anion exchanger trains. Each train is designed to produce 50% of the boiler feedwater makeup requirements. The standby train will be put into service when one train is in regeneration. Due to the characteristics of the well water, a two bed demineralization system is required which will be followed by a mixed bed ion exchange system to achieve the boiler water requirements.

Operation of the demineralizer system will be controlled by the level in the demineralized water storage tank. The tank will have 12 hours storage capacity based on the total boiler feed water normal operating requirements.

Regeneration of the demineralizer train will be done approximately every 22 hours based on the design flow rate. Demineralized water will be used for regeneration of the demineralizer system. Regeneration waste water will be treated in a neutralization system prior to discharging into the non-oily return stream.

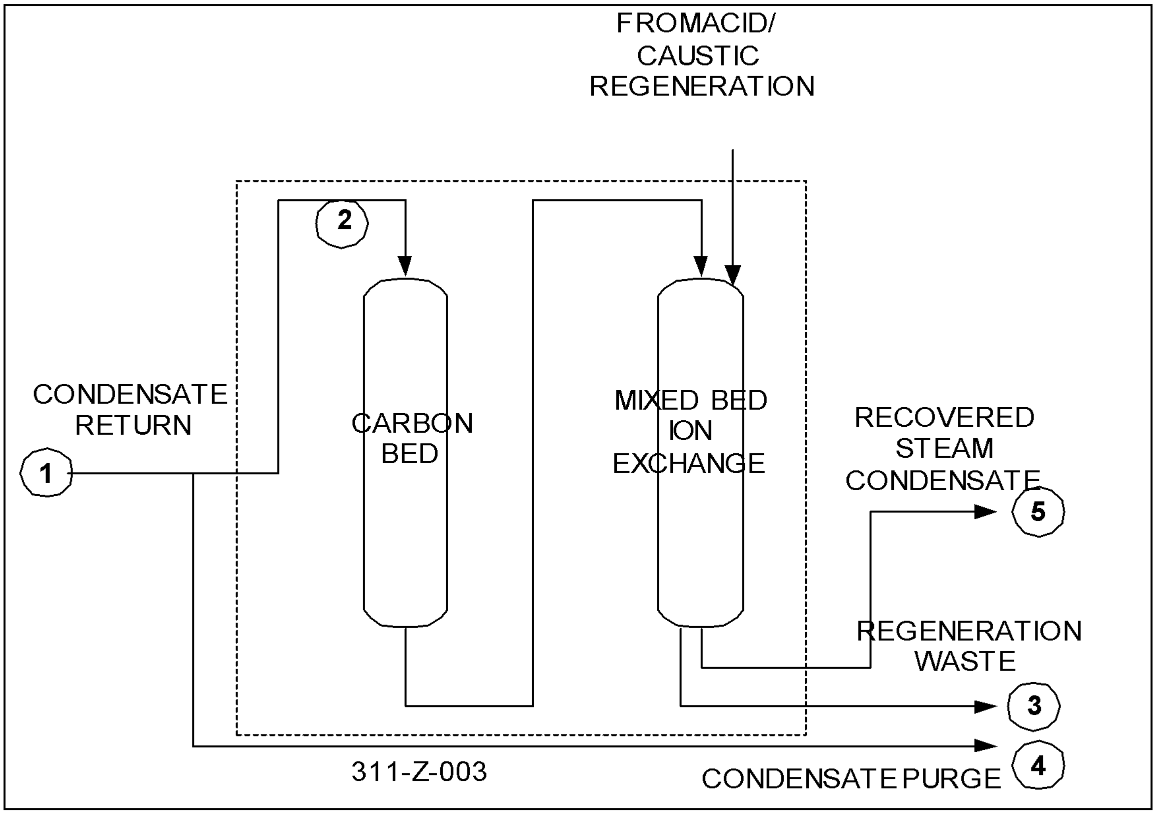
Returned Condensate Process Water

The recovered steam condensate will be treated by a carbon bed and mixed bed demineralizer. The demineralized water system is sized for a continuous boiler rate of 2,400 gpm for a design margin of 15%. There are 3 treatment trains; each train is designed to treat 50% of the returned condensate. The standby train will be put into service when one train is in regeneration or if return condensate is dumped. Due to the characteristics of the returned condensate, only a mixed bed demineralization system will be required. The carbon bed removes traces of oil before the ion exchange treatment. This too has 3 tretment trains, each train is designed to treat 50% of the returned condensate. The carbon will require periodic replacement.

The return condensate treatment system is shown in Figure 5-6.

FIGURE 5-6

RETURN CONDENSATE SYSTEM



QUANTITY	UNITS	CONDENSATE RETURN	CARBON BED FEED	REGEN WASTE	CONDENSATE PURGE	RECOVERED STEAM CONDENSATE
		1	2	3	4	5
FLOW (DESIGN)	GPM		2400			
(ACTUAL)	GPM	2196	2086	6	110	2080
	LBS/HR	1,098,000	1,043,000	3,000	55,000	1,040,000
TDS	PPM	1	1	333	1	<0.5

Regeneration

Both of the ion exchange treatment processes (makeup and return condensate) require regeneration. Acid and base chemicals are used in the regeneration process which prepares the ion exchange units to again treat the feedwater. The acid and base are stored in bulk storage tanks. Ninety-eight percent sulfuric acid and 50% caustic soda will be used for regeneration of the cation and anion resin respectively and in the mixed bed ion exchange units. The acid tank will be designed to have approximately 45 days of storage capacity based on normal regeneration frequency of the demineralizer system. The regeneration waste stream will be stored and neutralized before transfer to the waste treatment system.

Potable Water

The potable water system is shown in Figure 5-7. Air pressurizing system will be used for the potable water system. The potable water feed pump, controlled by the level in the pressurizing tank, will have a design capacity of 8 gpm to accommodate peak usage of the potable water.

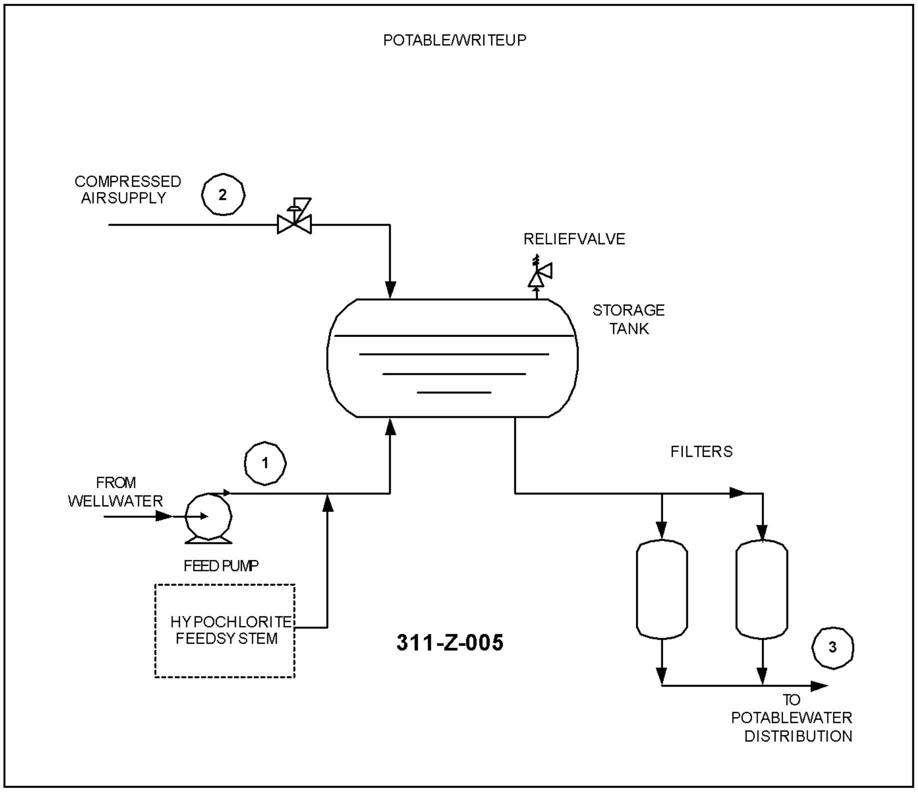
The pressurizing tank will have an effective storage capacity of 5,800 gals or about 24 hours storage at the daily average flow rate.

Intermittent injection of sodium hypochlorite will be used for disinfection of the potable water which is consistent with the current practices at the Gilberton Power Plant. A chlorine concentration of 0.5 to 1.0 mg/1 will be produced in the potable water distribution system. Plant service air will be used for pressurizing the potable water system.

Two 100% cartridge-type filters with 30µ filter elements will be provided for treatment of the potable water.

FIGURE 5-7

POTABLE WATER SYSTEM



QUANTITY		WELL SUPPLY	AIR	DISTRIBUTION
	UNITS	1	2	3
FLOW (DESIGN)	GPM	8	---	
(EXPECTED)	GPM	4	---	4
	SCFM	---		---
PRESSURE	PSIG	100	100	65
CL2	PPM	0	---	0.5
TDS	PPM	68	---	68

Plant 312 Cooling Water System

A closed-loop cooling water (CW) system (Plant 312) is provided to cool process streams to temperatures between 140°F and 90°F (i.e., lower than what can be attained with air cooling). The system is designed to meet the cooling needs of the gasification area (Area 100), the Fischer Tropic liquid production area (Area 200), the combined cycle plant and other utility and offsite area (Area 300).

The CW system consists of cooling towers with basin, CW circulation pumps, chemical injection facilities, and CW Distribution and Collection Headers

The required CW cooling loads for the various areas are summarized below:

Plant, Area	Plant Descriptions	Duty, MM	Flow, GPM
100	Gasification Facilities	176.2	17,727
109	Rectisol Plant	143.7	14,803
110	Air Separation Unit	87.1	25,094
111&112	Sulfur Block	21.9	2,201
200	FT Facilities	43.6	4,386
313A	Sour Water Stripping	0.3	30
309	Cogen STG Cond	337.0	22,600
309A	Gasification IP STG Cond	247.0	16,564
309A	Gasification LP STG Cond	76.0	5,090
309A	FT IP STG Condenser	147.0	9,858
	Allowance for Misc Users	24.6	1,647
	Total CW Load	1,304.4	120,000

The CW system, including a precasted concrete cross flow, mechanical induced-draft cooling tower with PVC fills, is designed to meet the process cooling needs of the EECP project. The CW will also be used for cooling rotating equipment bearings, jackets, lube, seal oil and intercoolers.

Circulation water will be cooled in a 12-cell cooling tower from a bulk return temperature of 102°F to 80°F with a 75°F wet bulb temperature. The cooling tower basin provides 15 minutes of storage at the normal total circulating rate of 120,000 gpm. Seven CW Circulation Pumps are provided with six normally running and the seventh being a standby spare. Six of the pumps will be motor driven and one will be turbine driven. Two of the six motor driven pumps will also be connected to an independent and redundant emergency power circuit. Therefore, at any given time at least one turbine driven pump or one motor driven pump connecting to the independent emergency power supply will be operating to allow safe and orderly plant shutdown in case of total power outage.

Cooling water makeup will be based on three cycles of concentration. Only treated Mine Pool water from Mine Pool Water Treatment (Plant 311) is used for cooling tower makeup for this evaluation. Treated process water effluents, such as Rectisol Wash Water and FT Produce Water, may be recycled as part of the cooling tower makeup to reduce Mine Pool Water demand. However, methanol and other volatile organics in the process effluent may pose potential emission problems. Feasibility of recycle process effluent water will need to be reviewed carefully during detailed engineering when emission permit limits are established.

Chemicals such as proprietary biocide, scale inhibitor, corrosion inhibitor, and chlorine will be injected into the makeup and the circulating stream to inhibit corrosion and fouling. Individual packaged injection system, including pre-filled tank and metering pumps, will be leased from each chemical provider.

A small blowdown stream from the Circulation Pump discharge is routed to the Waste Water Treatment (Plant 313) to control the total dissolved solids build-up in the CW circuit.

Section 6 Phase I Task 5 – Market Analysis

TASK COMPLETED.

Purvin & Gertz, Inc. completed this task under a subcontract to Texaco. Final report was delivered to WMPI. The report contains sensitivity business information that WMPI would prefer not to report it in writing. Under an agreement, DOE can review the report and its findings with WMPI.

Section 7 Phase I Task 6 – Preliminary Site Analysis

Under this task, WMPI will assess the site-specific project requirements to include:

- Raw material availability
- Site transportation accessibility
- Supporting utility services
- Land availability and cost
- Construction and skilled labor availability

As part of this Task 6, Nexant, with support from Bechtel personnel, helped with examining alternative modes of transporting large process vessels to the EECP site near the existing Gilberton cogen plant. Results were discussed in the July/September 2001 Quarterly Technical Progress Report. Sasol's slurry phase FT reactor is expected to be over 18 feet in diameter. Its dimensions and weight are important parameters governing how the vessel should be most cost effectively fabricated and transported to site.

A topical report, summarizing all Phase I, Task 6 activities is being drafted.

8.1 BIWEEKLY PROJECT STATUS REPORT

Informal Biweekly Project Status Reports are transmitted to keep the DOE Project Manager updated of all work in progress.

8.2 PROJECT MILESTONE PLAN AND LOG

Project Milestone Plan and Milestone Log are submitted on time as prescribed by the contract to keep DOE management informed of work-in-progress and accomplishments against major project milestones planned.

Section 9 Experimental

EXECUTIVE SUMMARY

9.1 EXPERIMENTAL

9.2 RESULTS AND DISCUSSION

9.3 CONCLUSION

9.4 REFERENCE

NOT APPLICABLE - The current project is a design feasibility and economics study, leading to detailed engineering, construction and operation of an EECP plant. It's not a typical research and development (R&D) project where a topical report format described in this section applied. There was no experimental work performed. This section is included only to fulfill DOE's prescribed reporting format.

List of Acronyms and Abbreviations

AGR .... Acid Gas Removal
API .... American Petroleum Institute
ASTM .... American Standard Testing Methods
BEDD .... Basic Engineering Design Data
BOC .... British Oxygen Company
BOP .... Balance Of Plant
BPD .... Barrel Per Day
BFW .... Boiler Feed Water
CFB .... Circulating Fluidized Bed
DCS .... Distributed Control System
DOE .... U.S. Department of Energy
EECP .... Early Entrance Co-Production Plant
FT .... Fischer-Tropsch
HER .... Heavy End Recovery
HHP .... High High Pressure
HP .... High Pressure, Horse Power
HRSG .... Heat Recovery Steam Generator
IP .... Intermediate Pressure
ISBL .... Inside Battery Limits
KV .... Kilo Volts
LHV .... Lower-Heating Value
LP .... Low Pressure
LTFT .... Low-Temperature Fischer-Tropsch
LTGC .... Low-Temperature Gas Cooling
MMSCFD .... Million Standard Cubic Feet Per Day
MW .... Mega Watt
NETL .... National Energy Technology Laboratory
OSBL .... Outside Battery Limits
PMCC .... Pensky-Martens Closed Cup
PPM .... Parts per Million
PSA .... Pressure Swing Absorption
PSIG .... Pounds per Squared Inch, gauge
PWU .... Product Work Up
RD&T .... Research, Development & Testing
RON .... Research Octane Number
RVP .... Reid Vapor Pressure
SCFM .... Standard Cubic Feet per Minute
SCR .... Selective Catalytic Reduction
SRU .... Sulfur Recovery Unit
TGTU .... Tail Gas Treating Unit
WMPI .... Waste Processors Management, Inc.