Kemper County IGCC

Commissioning and Startup Report

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ABSTRACT

The Kemper County IGCC plant was a lignite-fueled 2 x 1 Integrated Gasification Combined-Cycle (IGCC) facility that demonstrated the air-blown Transport Integrated Gasification (TRIG™) technology jointly developed by Southern Company, KBR, Inc. (KBR), and the U.S. Department of Energy (DOE) at the Power Systems Development Facility (PSDF) in Wilsonville, Ala. The plant is owned by Mississippi Power Company (MPC) and has a calculated nameplate capacity of 830 MW with a peak net output of 582 MW. As a result of advanced emissions control equipment, the facility is designed to produce marketable products of ammonia (NH_3), sulfuric acid (H_2SO_4), and carbon dioxide (CO_2). The plant is designed to capture 65 percent of the carbon producing a CO_2 stream for use in enhanced oil recovery (EOR), making the plant carbon emissions comparable to those of a natural gas-fired combined cycle power plant. This report describes the unit commissioning activities from the end of construction through first coal operations to the gasifier. These activities include precommissioning planning, commissioning of major equipment, and operation of processes leading up to first coal feed.

CONTENTS

Executive Summary 10
1.0 INTRODUCTION 11
2.0 PLANT DESCRIPTION 11
2.1 Project Description 11
2.2 Process Overview 11
2.2.1 Gasification Island 12
2.2.2 Combined Cycle 13
3.0 COMMISSIONING OVERVIEW 14
3.1 Introduction 14
3.2 Startup Team Structure 14
3.3 Turnover Package Development 15
3.3.1 TOP Overview 15
3.3.2 List of Turnover Packages 18
3.4 Test Package Development 18
3.4.1 Test Package Overview 18
3.4.2 Integrated Test Package Overview 18
3.4.3 List of Equipment/System Level Test Packages 18
3.4.4 TOPs to Milestone Assignments 19
3.5 General Commissioning Timeline 19
4.0 COMMISSIONING OF SUPPORT SYSTEMS 22
4.1 Engineering Simulator 22
4.1.1 Scope Overview 22
4.1.2 Significant Events 24
4.1.3 Final Summary 25
4.2 Operator Training Simulator (OTS) 27
4.2.1 System Overview 27
4.2.2 Initial Commissioning Plan 28
4.2.3 Significant Events 30
4.2.4 Final Summary 36
4.3 Distributed Control System 37
4.3.1 System Overview 37
4.3.2 Initial Commissioning Plan 42
4.3.3 Operator Training Simulator (OTS) Impact on DCS Commissioning 45

4.3.4 Significant Events....47
4.3.5 Final Summary....48
4.4 Safety Instrumented System....48
4.4.1 System Overview....48
4.4.2 Initial Commissioning Plan....50
4.4.3 Significant Events....50
4.4.4 Final Summary....58
4.5 Continuous Emissions Monitoring Systems (CEMS)....58
4.5.1 System Overview....58
4.5.2 CEMS Design Requirements....64
4.5.3 Initial Commissioning Plan....71
4.5.4 Significant Events....71
4.5.5 Final Summary....72
4.6 System Cleaning....74
4.6.1 Cleaning Overview....74
4.6.2 Significant Events....75
4.6.3 Final Results....77
4.7 Utilities....78
4.7.1 Instrument Air System....78
4.7.2 Nitrogen....78
4.7.3 General Water Systems....80
4.7.4 Tempered Water System....84
4.7.5 Steam System....92
4.8 Combined Cycle Power Block....94
4.8.1 System Overview....94
4.8.2 Initial Commissioning Plan....103
4.8.3 Significant Events....105
4.8.4 Final Summary....107
5.0 UNIT COMMISSIONING EXECUTION AND TESTING....107
5.1 Coal Storage and Preparation....107
5.1.1 Lignite storage and preparation....108
5.1.2 Dryer Fan System....121
5.1.3 Venturi Condenser System....139
5.1.4 Pulverizer and Storage System....160
5.1.5 Recovered Water....171

5.1.6 Dryer Feed System 178
5.1.7 Dryer system 185
5.2 Process Air System 230
5.2.1 System Overview 230
5.2.2 Initial Commissioning Plan 234
5.2.3 Significant Events 235
5.2.4 Final Summary 250
5.3 PDAC Coal Feed System 251
5.3.1 System Overview 251
5.3.2 Initial Commissioning Plan 252
5.3.3 Significant Events 252
5.3.4 Final Summary 259
5.4 Gasifier 259
5.4.1 System Overview 259
5.4.2 Initial Commissioning Plan 267
5.4.3 Significant Events 269
5.4.4 Cold Solids Circulation Tests in Train A 290
5.4.5 Refractory Cure-out 303
5.4.6 Final Summary 311
5.5 Syngas Cooling 313
5.5.1 System Overview 313
5.5.2 Initial Commissioning Plan 315
5.5.3 Significant Events 315
5.5.4 Final Summary 319
5.6 Particulate Control Device 322
5.6.1 System Overview 322
5.6.2 Initial Commissioning Plan 324
5.6.3 Significant Events 325
5.6.4 Final Summary 326
5.7 Ash Cooling and Depressurization 331
5.7.1 Coarse Ash Cooling and Depressurization (CCAD System) 331
5.7.2 CFAD 337
5.8 Ash Storage and Removal 339
5.8.1 Ash Storage Systems 339
5.8.2 Ash Conveying 347

5.8.3 Ash Mixers 350
5.8.4 Coarse Ash Feeder 357
5.8.5 Gasifier Bottoms Drain Pot Feeders 362
5.9 LP Vent Gas System 366
5.9.1 System Overview 366
5.9.2 Initial Commissioning Plan 367
5.9.3 Significant Events 367
5.9.4 Final Summary 371
5.10 Syngas Scrubbers 371
5.10.1 System Description 371
5.10.2 Syngas Scrubber Initial Commissioning Plans – Train A and B 374
5.10.3 Syngas Scrubber Train A and B Commissioning Milestones 375
5.10.4 Syngas Scrubber Train A and B Significant Events During Unit Commissioning 375
5.11 Syngas Cleanup Train A and B 377
5.11.1 System Overview 377
5.11.2 Initial Commissioning Plan 385
5.11.3 Significant Events 391
5.11.4 Final Summary 395
5.12 Recycle Gas Compressors 396
5.12.1 System Overview 396
5.12.2 Initial Commissioning Plan 398
5.12.3 Significant Events 399
5.12.4 Final Summary 402
5.13 Acid Gas Removal 403
5.13.1 System Overview 403
5.13.2 Initial Commissioning Plan 406
5.13.3 Significant Events 408
5.13.4 Final Summary 413
5.14 AGR Refrigeration 413
5.14.1 System Overview 413
5.14.2 Initial Commissioning Plan 416
5.14.3 Significant Events 417
5.14.4 Final Summary 420
5.15 AGR Compressors 420
5.15.1 System Overview 420

5.15.2 Initial Commissioning Plan 423
5.15.3 Significant Events 423
5.15.4 Final Summary 431
5.16 CO_2 Preparation and Offtake 431
5.16.1 System Overview 431
5.16.2 Initial Commissioning Plan 433
5.16.3 Significant Events 436
5.16.4 Final Summary 447
5.17 Sour Water and Ammonia Purification 447
5.17.1 System Overview 447
5.17.2 Initial Commissioning Plan 451
5.17.3 Significant Events 451
5.17.4 Final Summary 456
5.18 Wet Gas Sulfuric Acid 456
5.18.1 System Overview 456
5.18.2 Initial Commissioning Plan 460
5.18.3 Significant Events 461
5.18.4 Final Summary 467
5.19 Flare Systems 467
5.19.1 System Overview 467
5.19.2 Initial Commissioning Plan 472
5.19.3 Significant Events and Final Summary 473
6.0 SPECIAL ACTIVITIES 477
6.1 Syngas Cooler Mechanical Integrity 477
6.1.1 Significant Events 477
6.1.2 Final Summary 488
6.2 Gasifier Structure Vibration During Sand Circulation 491
6.2.1 Significant Events 491
6.2.2 Final Summary 494
6.3 Gasifier Refractory and Nozzle Modifications 508
6.3.1 Introduction 508
6.3.2 Initial Design 508
6.3.3 Initial Commissioning Plan 514
6.3.4 Refractory Failure in Train A 515
6.3.5 Refractory Failure in Train B 518

6.3.6 Development of Modified Refractory System 518
6.3.7 Implementation of Modified Refractory System 520
6.3.8 Final Summary 530
6.4 Gasifier Remote Piloted PRV Design Modification 530
6.4.1 Overview 530
6.4.2 Long-Term Resolution 533
6.4.3 Final Summary 534
7.0 SIGNIFICANT FINDINGS AND CONCLUSIONS (LESSONS LEARNED) 534
8.0 ACRONYMS AND ABBREVIATIONS 535
ATTACHMENTS 539
Section 3.3.2 – Turnover Package List 539
Section 3.4.3 – Test Packages Summary 565
Section 3.4.4 – TOP to Milestone Assignments 569

EXECUTIVE SUMMARY

The Kemper County Project demonstrated Transport Integrated Gasification (TRIG™) technology at a 2 x 1 Integrated Gasification Combined Cycle (IGCC) facility in Kemper County, Mississippi. Capable of generating up to 582 MW during syngas operations, the facility represents the largest IGCC project ever undertaken, the first to use lignite as fuel, the first to capture and sell CO_2, and the first to produce multiple byproducts from initial startup.

Southern Company entered into a cooperative agreement with the U.S. Department of Energy (DOE) to demonstrate TRIG™ technology with CO_2 capture on a commercial scale. The demonstration was undertaken at the Kemper County IGCC project, a nominal 582 MW net plant that transformed locally mined lignite into a syngas, fueling a combined cycle power plant and simultaneously capturing CO_2 for enhanced oil recovery. This commissioning report was developed as a deliverable under the DOE cooperative agreement.

The Kemper County IGCC project featured a 2 x 1 configuration with two gasification trains, two combustion turbines, two heat recovery steam generators (HRSG), and a common steam turbine. The process began with the delivery of lignite to each gasification train from the adjacent mine. Lignite was dried, milled, and subsequently fed to the gasifier, producing a syngas. The syngas passed through several cleanup steps to remove particulate matter, ammonia, sulfur species, and CO_2, before fueling the combustion turbine to generate electricity. Steam produced in the process generated additional electricity in a steam turbine generator.

The plant was designed to produce several marketable byproducts, including commercial grade anhydrous ammonia and sulfuric acid. The plant was designed to capture up to 65 percent of the carbon entering the facility, with the resultant carbon dioxide stream sold for use in enhanced oil recovery (EOR), reducing carbon emissions to a level comparable to that of a natural gas-fired combined cycle power plant. Further details regarding plant design are available in the Final Public Design Report.

This report summarizes the commissioning and early integration activities starting with the completion of construction up to first coal feed to the gasifier. The commissioning phase of the project included the checkout, testing, and tuning of all auxiliaries, process equipment, and gas processing systems needed to safely operate the facility during the production of syngas. A separate Final Report discusses plant operations from first coal feed through the remainder of the project. A corresponding Reference Plant report provides general design and cost information on a future n^{th}-generation plant. Developed in conjunction with the unit report, a comprehensive lessons-learned document provides a consolidated grouping of the challenges overcome at the Kemper County project. It includes a summary of common conclusions and a detailed breakdown of observations and findings by process area. The context and observations from each lesson are included in the Final Report and can serve as reference for future projects.

The report was developed to reflect the cumulative nature of startup and commissioning. A base methodology is established, equipment and auxiliaries are commissioned into systems, and systems are integrated into a plant. The outline reflects this approach through the following themes:

- Project and site overview.
- Startup structure and planned methodology.
- Commissioning of auxiliary and utility systems.
- Commissioning of gasification systems.
- Summary of modifications.

A detailed description at the beginning of the section for each system offers a general understanding of the equipment scope in that section. Each section follows a planned (initial commissioning plan) versus actual (narrative of significant events) format. The planned-versus-actual approach highlights the challenges that occurred during initial checkout and commissioning.

Despite the challenges, nearly all the initial technical objectives for startup and commissioning leading up to first coal feed (syngas production) were achieved.

1.0 INTRODUCTION

This report provides an overview of the startup and commissioning activities for the Kemper County IGCC project, which used the Transport Integrated Gasification (TRIG™) technology. It details the preparations made during precommissioning and highlights the challenges encountered during execution and early testing of the project. The structure of this report reflects the cumulative nature of startup and commissioning. From initial planning through testing and through lessons learned, the report follows these themes, providing a basis for future projects to build on:

- Project and site overview.
- Startup structure and planned methodology.
- Commissioning of auxiliary and utility systems.
- Commissioning of gasification systems.
- Summary of modifications.

The scope includes precommissioning planning, the commissioning of major equipment, and individual plant processes leading up to first coal feed to the gasifier. A separate Final Report will discuss overall integration testing and operations beginning with first coal feed to the gasifier.

2.0 PLANT DESCRIPTION

2.1 Project Description

The Kemper County IGCC plant is an advanced coal generation technology project developed by Mississippi Power Company (MPC) with a goal of developing a viable resource alternative to support future load growth, provide a reliable and diverse fuel supply, and replace aging generation plants. The project is a lignite-fueled 2 x 1 IGCC facility incorporating the air-blown TRIG™ technology jointly developed by Southern Company, KBR, and the United States DOE at the PSDF in Wilsonville, Alabama.

Lignite reserves near the plant site, developed and mined by Liberty Fuels, a subsidiary of North American Coal Corporation (NACC), were the feedstock for the Kemper County IGCC plant. As designed, the estimated nameplate capacity of the plant would be 830 MW with a peak net output capability of 582 MW. The peak capacity would occur while firing syngas in the combustion turbine coupled with natural gas firing in the duct burners. During syngas-only operations, the plant anticipated a net generating capacity of 524 MW and a heat rate of 12,150 Btu/kWh. With its advanced emissions control equipment, the facility could produce marketable byproducts of NH_3, H_2SO_4, and CO_2. Up to 65% of the carbon entering the facility would be captured and used for enhanced oil recovery (EOR), making the Kemper County facility's carbon emissions comparable to those of a natural-gas-fired combined cycle power plant.

The 2,968-acre plant site is located near the unincorporated community of Liberty in Kemper County, Mississippi. The plant footprint occupied 80 acres, including the gasifier and combined-cycle power block and the lignite-handling facilities. It was a greenfield site without any pre-existing power generation facilities. The 31,000-acre coal mine is adjacent to the plant site.

2.2 Process Overview

The Kemper County plant consisted of a combined-cycle power island that when constructed, was fueled with syngas produced from air-blown, lignite-fueled transport gasifiers.

The general characteristics of the plant included:

- Two separate gasification trains; each gasification train supplied syngas to a single combustion turbine and heat recovery steam generator (HRSG).
- Two gasification/combustion turbine trains supplied steam to a single, common steam turbine.
- Three parallel coal drying and milling (coal preparation) trains per gasification train, with each feeding two high-pressure coal feed systems, for a total of six coal feeders per gasifier.
- Two process air compressors per gasification train.

- As it exited each gasifier, the syngas split into two parallel streams through the high-temperature syngas coolers and the particulate control devices (PCD). The streams recombined after the PCDs and flowed as a single stream through the gas cleanup systems to a combustion turbine.
- Systems are common to both gasification trains: the steam turbine, the gasifier sour water system, NH_3 recovery, and the wet gas sulfuric acid (WSA) process.
- Balance of plant (BOP) systems common to both gasification trains: water treatment, cooling tower/closed loop cooling water, instrument air, natural gas, diesel, and so forth. There were two separate cooling towers, one for the gasification island heat load and one for the combined cycle.

2.2.1 Gasification Island

Each of the two gasifiers was designed to be fueled with lignite for a total raw feed rate of 600 ton/hour and a total air-feed rate of 840 ton/hour, based on the expected average lignite composition. Carbon conversion was projected to be more than 97%. Sulfur and other contaminants in the lignite are removed from the syngas upstream of the combustion turbine.

The particulate-laden syngas leaves the gasifier at approximately 650 psia and is indirectly cooled from 1,740 to 600 °F, producing high-pressure superheated steam. Subsequent dry gas filtration in the PCD removes essentially all the particulate matter present in the cooled syngas stream. A proprietary continuous fine ash depressurization (CFAD) unit removes the ash from the filter vessel, while cooling and depressurizing it. CFAD has no moving parts and exhibited high reliability in more than 16,000 hours of operation at the PSDF.

Following filtration, the syngas enters a syngas scrubber column where water-soluble compounds such as chlorides and fluorides are removed, and the syngas is nearly saturated with water before entering the water gas shift (WGS) reactors. In the WGS reactors, CO reacts with water to produce CO_2 and H_2. This step facilitates the removal of CO_2 in the acid gas removal (AGR) unit.

Exiting the WGS reactors, the syngas is cooled using high-temperature recuperators before entering the carbonyl sulfide (COS) hydrolysis reactor, which converts most of the COS (a trace sulfur compound) to H_2S to facilitate removal in the AGR. Low-temperature recuperators and water-cooled heat exchangers further cool the syngas, while condensing moisture from it. The resulting process condensate is recycled back to the syngas scrubber. After the process condensate is removed, the syngas is cooled further before passing through a final water-spray column, the ammonia scrubber, to remove the remaining solubles. The resulting sour water is combined with sour water from the syngas scrubber and sent to the plant sour water system. The sour water system prepares the water for reuse while producing anhydrous ammonia for sale as a byproduct.

The scrubbed syngas then enters absorbers that remove more than 99% of the H_2S using a SELEXOL™ solvent. The captured H_2S is stripped from the solvent, which is then recycled back to the absorbers, and the concentrated H_2S stream is routed to a sulfuric acid plant where the sulfur is converted into commercial grade H_2SO_4. Following sulfur removal, a portion of the CO_2 in the syngas is removed using an additional set of absorbers. The removed CO_2 stream is dehydrated and compressed, then sold as a byproduct for EOR, which results in its geologic storage.

After the CO_2 removal system, the syngas passes through a fixed-bed adsorption vessel that removes nearly all the mercury remaining in the gas. A portion of the sweet syngas is separated and passed to the syngas recycle system where it is used to back-pulse clean the filter elements in the dust filtration system, for aeration in the gasifiers, and for concentrating the acid gas stream in AGR area. The remainder of the sweet syngas stream is heated by passing it back through the low- and high-temperature recuperators before flowing to the combustion turbines. Approximately 440 ton/hour of syngas is sent to each combustion turbine with a lower heating value of approximately 120 Btu/scf. The combustion turbine compressors provide the combustion air for the syngas and about 60% of the air required by the gasification island at full load. The remaining required air is supplied by motor-driven process air compressors.

Ash removed from the gasifier and the dry gas filtration system is sent to storage silos. Each silo, complete with dust-suppression equipment, is discharged into trucks that transport the ash to an appropriate ash disposal site.

The plant is composed primarily of commercially available equipment with the exception of the transport gasifiers, fine- and coarse-ash cooling and depressurization systems, and coal feed devices. These proprietary systems are based on established design principles, incorporate commercially available equipment items, and have been successfully demonstrated at the PSDF.

2.2.2 Combined Cycle

The two combustion turbines for the Kemper County project are modified to operate on syngas. Flame-diffusion combustors, rather than low-NOX designs, are used to prevent flashback caused by the hydrogen content of the syngas. Ports have been added to the compressor casing, allowing air to be extracted and supplied to the gasification island.

When firing syngas, each combustion turbine generates approximately 232 MWgross. This power output is maintained across the expected ambient temperature range by adjusting the air extraction rate so the mass of gas passing through the turbine is constant. For example, at low ambient temperatures, more air is induced into the compressor section because of the increased air density, and this allows more to be extracted. The total air entering the gasifier is relatively constant for a given load, so the mass flow rate of air from the process air compressor is reduced because of the availability of the increased extraction air, which decreases the power consumption of the process air compressor. To maximize the air induced into the compressor and maintain combustion turbine output during periods of high ambient temperature, an inlet air evaporative cooling system is placed in service when the ambient temperature is at or above 65 °F.

Although the plant is designed and intended to operate on syngas, it has the capability to fire the combustion turbines on natural gas. During natural gas operations, steam must be injected into the combustion cans to limit thermal NOX formation to 25 ppmv. The reduction in fuel mass flow rate during natural gas firing decreases power output as low as 200 MW at high ambient temperatures.

Each combustion turbine exhausts into a conventionally designed, triple-pressure level HRSG. When operating on syngas, the normal HRSG stack temperature is 274 °F. This temperature is above the acid dewpoint temperature so there are no problems with wet corrosion. Any ammonium bisulfate that may deposit on the economizer tubes downstream of the selective catalytic reduction (SCR) unit will be removed by offline washing.

High-pressure superheated steam from both HRSGs is combined with superheated steam from the gasifier islands and passed to the steam turbine. Under normal conditions, the high pressure (HP) superheated steam enters the steam turbine at approximately 1,816 psia and 1,000 °F. Steam exhausted from the high-pressure turbine is reheated in the HRSGs to 1,000 °F at 327 psia, combined with superheated intermediate-pressure (IP) steam generated in the HRSGs, and expanded through the IP turbine. Exhaust from the IP turbine is combined with superheated low-pressure steam generated in the HRSGs and passed to the low-pressure turbine before being condensed at 1.8 in. of mercury. Varying amounts of each steam level are extracted from the HRSGs and steam turbine for use in the gasifier island processes. At normal operating conditions, the steam turbine generates 310 MWgross. For peaking duty, steam turbine output can be increased to around 365 MWgross by firing natural gas in the HRSGs.

Condensate from the steam turbine condenser is used for cooling in the gasification process before returning to the HRSG for further heating and deaeration. High-pressure feedwater flows from the HRSG to the gasifier island where it is used in the syngas cooler to generate the superheated HP steam.

Within the HRSG, an SCR for NOX reduction during natural gas operation is installed at a location where the flue gas temperature is in the optimal temperature range of 600 to 700 °F. Liquid anhydrous ammonia produced by the gasification island is used for the SCR reagent.

3.0 COMMISSIONING OVERVIEW

3.1 Introduction

> *Commissioning is the use of a disciplined, systematic and professional methodology, to convert newly a constructed process plant into a fully integrated and operational unit in the most safe, efficient, cost-effective and timely of manners, to achieve start-up and production targets whilst, where at all possible, conforming to the ideal of getting it "right the first time".*
>
> *Chemical and Process Plant Commissioning Handbook; Killcross, Martin*
> *© 2012 Butterworth-Heinemann (Elsevier) Books; page xii*

The referenced handbook defines the mission of a project commissioning team, and the three categories of commissioning: precommissioning, commissioning, and startup (production operations commence). For the Kemper project, with blended Commissioning and Operations staffs and the corporate history of previous projects, the categories were commissioning (or startup), integrated operational testing, and turnover to commercial operations.

3.2 Startup Team Structure

The Startup team structure was based on a common commissioning organization for large industrial projects. Startup began as Construction completed equipment installation within predefined package boundaries and transferred responsibility of the package to the Startup and Commissioning (SU&C) team. The SU&C team would then validate equipment readiness to operate and proceed with testing. As equipment became operational, it would be merged into systems for functional testing. As systems completed their functional testing, the final cleaning and installation of process materials (column packing, catalyst, desiccants, solvents, and reactants) and the integrated operational testing of systems and partial plant trains began.

When system packages demonstrated functionality and control, full train operation began, producing syngas, co-product, and electricity. While the plant produced sellable products (electricity, carbon dioxide, sulfuric acid, and ammonia), it had not met all the objectives necessary to declare commercial operation before state regulators intervened, causing Mississippi Power to suspend plant operations.

The project commissioning team is the bridge between the construction team and the permanent plant operations crew and was staffed and managed by a project executive. The commissioning team consisted of experienced startup mechanical, Instrumentation and Controls (I&C), and operations personnel; subject matter experts (SME); vendor technical field assistants (TFA); and incoming permanent plant personnel. The commissioning team acts as the final construction quality check, confirming the operation of the installed equipment is compliant with the design and procurement specifications.

The project benefited from using personnel with previous commissioning experience, with higher productivity in developing checkout and testing procedures, executing procedures, and quickly identifying solutions to shortfalls and failures. Most of the commissioning personnel started their careers as system operators who were pulled into supporting the commissioning of earlier projects in the process and power industries. The commissioning managers had participated in more than 25 major projects before Kemper; and the team members had supported nearly 100 previous and unique projects before Kemper.

Early in project planning, contracts were finalized with vendors to provide SMEs and TFAs when needed to support procedure writing, review, training, and execution. Based on previous new plant commissioning efforts within the company, it was expected that operations labor would be provided by permanent plant personnel who would be incorporated into the SU&C teams early in the process to participate in inspections, walk-downs, test planning, procedure editing, and test execution. However, permanent plant personnel were not fully available to SU&C teams during 2013. Temporary operators were brought onto the project from different sources for testing and early operations. The plant's permanent subject matter experts were not fully available for commissioning support in 2014 and 2015 due to other required project tasks. This delay resulted in a greater reliance on vendor technical field assistants and

contractors for process background and troubleshooting, which was then vetted and reviewed by plant personnel before proceeding with testing as written. Because the operator and technician workload during commissioning is higher than in long-term production operations, the effective commissioning headcount (by work-hours and personnel) is greater than would be expected for long-term production. The additional coordinators, technicians, and craft labor leave after production operations commence.

Specialists supported the SU&C teams in instrumentation and controls, electrical switchgear, programming of the programable logic controllers, and distributed control system including the operator human-machine-interface screens in the control room. These specialists were available to backfill vacancies or meet additional needs for complicated test procedures. A specialized contractor for lube oil system flushes and another for cleaning process piping were brought in to cover the whole project, moving from system to system as priority and availability dictated. These specialists were associated with the project to the completion of their assignments, many of which ended before final operational demonstrations started.

A resource pool management process was implemented during construction and maintained throughout startup. This process enabled the project to facilitate project communications while maintaining control of the scope, schedule, and budget.

To monitor remaining and emergent activities between Construction-to-Startup and Operations-to-Startup, a project master punch list was initiated. This master punch list ensured adequate communication across project segments while maintaining control of priority resources.

System walkdowns were conducted to populate the master punch list as installation and commissioning activities were completed. As care and custody of equipment and systems were transferred from Construction to Startup and finally to Operations, items that required additional consideration were tracked as punch list items. Each punch list item was prioritized as A, B, or C based on following criteria:

- Priority A was either safety-related or significant enough to prevent further operation of the equipment. Transfer of care and custody was not completed until all priority A activities were completed.
- Priority B was assigned to items that were significant but did not prevent testing or further operation, for example noncritical instrumentation.
- Priority C items did not impede full operation or testing of equipment or systems.

3.3 Turnover Package Development

3.3.1 TOP Overview

Following Southern Company corporate policies, the plant was divided into approximately 1,000 turnover packages (TOP) that defined the equipment and boundaries for each package. See section 3.6.1, Turnover Package List. Each package was sized to allow effective isolation and initial checkout of the equipment, including loop checks of the instrumentation and controls, rotating equipment coupling alignment checks, cleaning and inspections, and uncoupled motor runs.

The packages were sorted into three major divisions (balance of plant, combined cycle, and gasification island) and assigned to separate Startup managers to plan and execute commissioning and functional testing within each division.

The balance of plant (BOP) TOPs consisted of the plant utility packages and systems: buildings, controls, switchgear, water supplies, instrument air, building sumps, and waste water marshalling and treatment. The combined cycle (CC) TOPs consisted of all the power block equipment; turbine generators, heat recovery steam generators, condenser, deaerators, feedwater pumps, various steam headers, and related environmental compliance equipment. The gasification island (GI) TOPs consisted of all the dedicated equipment from coal receiving to gas turbine fuel skids: lignite prep, gasifiers, syngas cooling and cleanup, co-product purification or conversion, and related support packages.

While both the CC and GI divisions rely on BOP systems to operate, the CC and GI trains were isolated and independent of each other to allow substantial integrated operation within the division. For example, the CC was

operated on natural gas at design production rates for several thousand hours before the gasification island integrated operational testing progressed to clean, reliable syngas available to support the final train-level integration testing of syngas fueled gas turbine operations. Figure 3.3-1 illustrates system dependencies and predecessor relationships, ending with satisfied operational objectives for both the gasification island and combined cycle before moving into the final train and plant level integration demonstration tests necessary before the plant would be turned over for continuing production (commercial) operations. As the testing and demonstration of integrated operation of equipment and systems was completed, the TOPs were turned over from the Startup and Commissioning team to Mississippi Power Operations, signifying the transfer of care, custody, and control to final ownership and readiness for subsequent commercial operations.

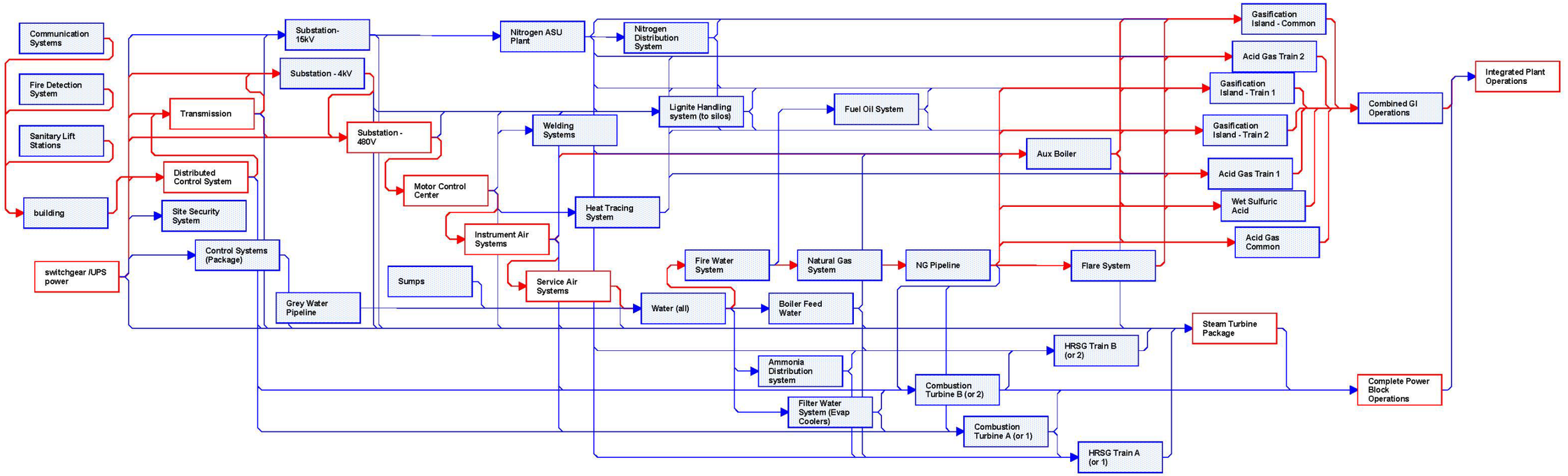


Figure 3.3-1 – Graphic representation of system dependencies for commissioning planning

3.3.2 List of Turnover Packages

See Attachments, 3.3.2, Turnover Package List.

3.4 Test Package Development

3.4.1 Test Package Overview

The gasification island commissioning effort was divided into independent systems for checkout and initial testing:

- Lignite prep and ash storage (solids handling).
- Gasifiers from utility headers to PCD outlets.
- Water-gas-shift catalysis units from syngas scrubber to AGR inlet.
- Acid gas recovery (SELEXOL™) units.
- WSA plant.
- Sour water treatment and ammonia purification.
- GI process compressors.

After each system or subsystem TOP was accepted and processed to certify the equipment and controls within were ready to progress to operational testing, the initial test packages were defined, testing procedures written, and test team personnel trained before test execution started.

The first operational testing in most test packages used inert, low energy materials (air for combustible or toxic gases, water for solvents, sand or ash for lignite or char) to allow ready access for inspection and repair posttest. The procedures were to step through each process variable (flow, pressure, temperature) to the extent possible and to demonstrate the operational progression of returning the subject system to production operations when commissioning was completed. When the controls were tuned to maintain system stability for each process variable on the inert materials, test packages would progress to actual materials where possible, or merge with adjacent process packages to tune controls and demonstrate interdependent system stability of the merged packages. This step was meant to allow for parallel processing of the TOPs, build operational background for the plant's subject matter experts (system owners), and better match personnel experiences with the upcoming tasks.

3.4.2 Integrated Test Package Overview

After the basic test packages were completed and the associated systems declared functional and ready for subsequent operational testing, a second tier of test packages were executed from procedures previously developed and vetted. In addition to the 86 basic test packages developed for the gasification island, 34 second- and third-tier test packages were identified and developed to merge the subsystems and demonstrate operational coordination and functional integration. The third-tier testing (TP1026, TP1027, TP2026, TP2027) culminated with the production of clean, reliable syngas on each gasifier train and available at the gas turbine skids to support the initial operations of the turbines on syngas. These test packages are referenced in section 3.4.3. Several of the tier 2 and 3 test packages were recognized as significant events or project milestones; these are referenced in section 3.4.4, along with the TOPs incorporated into the integrated test package for the first time.

This step-wise approach was developed from commissioning previous first-of-a-kind development and demonstration projects and was intended to limit the overall process risk by building each plant system up in a methodical and safe manner.

3.4.3 List of Equipment/System Level Test Packages

See Attachments, 3.4.3 Test Package Summary.

3.4.4 TOPs to Milestone Assignments

See Attachments, 3.4.4 TOP to Milestone Assignments.

3.5 General Commissioning Timeline

The commissioning director was named in the summer of 2010, approximately 4 years before the expected turnover to production operations. In the following 6 months, the initial commissioning team management and staff were named, and planning began in detail. Planning included definition of the TOPs; initial conceptualization of the test packages; and developing and finalizing contracts and material procurement agreements for personnel, TFAs, specialized flush and cleaning contractors, additional services, and operating consumables.

The SU&C teams were staffed starting in 2012. They finished compiling the turnover package binders (with basic acceptance test forms to be completed) and TOP commissioning procedures that had been started with the management and staff in 2011. For every TOP identified for the project, the time between turnover from construction and integration testing was taken by traditional initial commissioning work of loop-checks, component-level tightness and functional tests, and control interface validation. The last of the TOP binders and commissioning procedures were finished in 2013. As the teams finished, they started the work of scoping the installation and writing the system-level test package procedures for Process Engineering review and approval.

Some TOP installation inspections and procedure reviews revealed issues to be corrected before equipment commissioning could begin. When commissioning teams accepted turnovers from construction and proceeded with the acceptance and commissioning testing, additional issues (vibration, lack of adequate process control, seal leaks, motor and equipment failure) were identified and usually immediately addressed before processing by the procedures.

The first TOPs received from Construction were the administration building (June 2012) and the station service transformers (August 2012). Next were the switchgear and digital control system (DCS) packages in preparation for the first integration test package, initial energization of the plant station service (power supply). Initial energization of the plant station service was done Nov. 8, 2012, 18 months before the planned turnover to production operations. The treated effluent pumping stations started commissioning in June 2012, began filling the make-up pond in October 2012, and reached the pond's normal level in January 2013.

Afterward, the filtered water system was commissioned to support the upcoming cooling tower operations. As combined cycle cooling tower and directly connected packages were turned over and prepared for wet operations, the fan and pump electric motors were checked, instrumentation validated, and the piping cleaned and leak checked. The combined cycle (CC) closed loop cooling water was released for operation in the spring of 2013, to support upcoming oil flushes, additional equipment checkout testing, and the chemical cleaning of the gas turbine HRSGs and associated steam piping during the summer. BOP and combined cycle TOPs were commissioned in the summer of 2013 in preparation for the CC-related integrated operational tests of gas turbine first fires (Aug. 28, 2013 for A and Sept. 4, 2013 for B), HRSG steam blows, steam turbine synchronization (Oct. 5, 2013), and 2 x 1 CC operation on natural gas (completed 8 months before the planned turnover to production operations). In the 11 months between station service energization to 2 x 1 combined cycle operations, the BOP and CC TOPs not required for station service were turned over, checked, tested, operationally commissioned, and demonstrated as part of at least one integrated test; which is consistent with other natural gas-fired combined cycle plant commissioning efforts.

The construction process on the gasification island was delayed for reasons beyond the scope of this report, with turnovers to the startup team starting early 2013 with dedicated GI electrical and DCS equipment. Many systems were independently checked out, tested, and operated before being integrated with the other systems into train level test package demonstrations (figure 3.3-1). Compressor lube oil systems turnovers began in July 2013 to allow checkout and oil flushes to begin according to plan. Lignite prep rotary valves were turned over in the same timeframe. Due to high equipment count and six parallel systems, the lignite dryer packages were planned for early turnover, checkout, and testing. Constructability challenges led to substantial delays into 2014 before complete dryer systems were ready for live testing.

Most of the outstanding GI packages were turned over in 2014, except heat tracing and the ash transport and storage systems. These would be needed for integration late in operational testing. The gasification island parallel commissioning efforts were intended to reduce the total time to prepare systems for integrated operations. Operations were successfully demonstrated in 2014 and 2015, when most of the equipment was loop checked, pressure tested, alignments confirmed, piping cleaned, processes charged, and initially operated.

Process air compressor and gasifier A pneumatic testing began in April 2014 and was successfully completed in May. Work began in June 2014 on gasifier B pneumatic testing, cleaning the process air piping from the gas turbine to the gasifier, flushing the tempered water piping, interlock testing, and delivery of the AGR solvent into the make-up storage tank. Most of this work continued into September. In the fall of 2014, work included cleaning steam and process piping, validating controls and interlocks for upcoming testing, and preparing the two gasifier and syngas cleanup trains for the air flow and startup burner first fire tests. Coordinating between steam and syngas side process piping, which had to be independent activities sharing equipment, caused by delays in completing the steam side piping and interconnecting headers, presented challenges

By the end of 2014, Construction had turned over all but ten of the TOPs for commissioning and startup. The SU&C teams were well into the TOP procedure execution and preparations for additional testing going forward. System-level cleaning activities had begun, but the initial cleanliness of the piping did not meet expectations, resulting in more time and work than originally expected. Challenges were discovered due to installation quality, requiring rework or replacement of piping and components before operational testing could proceed. As operational test packages were attempted, additional issues were identified, particularly with control valve sizing under initial operating conditions necessary to slowly pressurize and warm the gasifiers and downstream equipment. As these issues were evaluated, changes in procedure or valve specification were made before the test package was restarted, such as for the gasifier air flow tests, which were completed in March 2015. The WSA air flow testing was also completed in March 2015.

Throughout the first quarter of 2015, AGR pumps were initially checked out and readied for upcoming water circulation testing before installing the column packing and degreasing the entire system on both trains. Equipment checkout proceeded in ash handling, sour water, and lignite dryers, moving toward test package execution starting in the second and third quarters of the year. Functional testing of lignite dryers began with tightness testing, resulting in substantial rework of many assembled components and ductwork before meeting the maximum acceptable leak rates. Issues with the pressure relief valves were identified and required corrections before proceeding with functional testing. After the relief valve issue was addressed, the lignite dryer fan testing was affected by a motor issue that had to be corrected in order to proceed with the testing in the dryer areas in the second and third quarters of 2015.

At the completion of the gasifier air-blows, both train absorber/scrubber columns were packed, and all filter elements installed in preparation for the upcoming gasifier fluidization testing. After the test, the various absorption columns were flushed and degreased as deemed necessary. The syngas coolers were readied for upcoming syngas operations, including the steam side hydrostatic testing, as required by the State permits, in the second quarter of 2015. As the equipment checkout proceeded, several instances arose where proper care of the solids handling and fluidization components was not maintained, requiring substantial extra effort in restoring or repairing the issues during the second quarter of 2015. These instances are discussed in more detail in section 5.1 of this report.

Summer 2015 was spent checking out subsystems, and modifications and retrofits in preparation for upcoming gasifier fluidization testing before moving into the final refractory cure-out and syngas production. Most of the gasification island equipment was operated and rough tuned for initial operations. All the plant systems were to be tested individually before they were integrated into complete trains. As the gasifier experienced delays, other systems were delayed due to issues found.

The AGR refrigeration unit was tested for vacuum tightness in July. The A AGR system was degreased in late September 2015, and the B AGR in February to March 2016. Following the tie-in of the plate and frame recuperators, the systems were flushed and air-freed, waiting under a nitrogen blanket for the gasifiers to be ready for syngas operations. The B AGR was charged with SELEXOL in July 2016 and the A AGR charged in August. The refrigeration unit was initially vacuum-leak tested July 2015, then retested and prepared for ammonia charge in April 2016 before the system loading in June.

Lignite was introduced to the first dryer in October 2015 to support test and demonstration work, which continued to summer 2016; with many modifications and repairs required. Testing of all six dryers continued through the following 12 months to establish reliability and capacity, after significant and substantial redesigns and modifications that continued to suspension of operations.

The wet sulfuric acid (WSA) system was initially fired in November 2015 for boilout of the steam generator and superheaters in December 2015 and January 2016. Subsequently, the WSA was fired to support steam blows to the process header connections at the steam turbine valve station. Repairs and modifications were required to assure reliability before the oxidization catalyst was loaded and inerted in June 2016.

The sour water and ammonia purification unit columns were packed at the same time as the scrubbers and AGR columns, and flushed, but not degreased, to prepare for upcoming service. The system was then air-freed on nitrogen and the pumps tested moving water between storage tank, drums, and columns. The system was charged with aqueous ammonia in June 2016 to complete the testing of the purification unit, identifying additional pump related issues to be resolved later.

The gasifier A initial fluidization testing occurred in October 2015 and prompted modifications to address vibration and rumble from the gasifier. When heating the A gasifier started in November, refractory failure in the mixing zone was found. Modifications were made to gasifier B before starting B fluidization testing. Gasifier B fluidization testing began in late February and progressed to the refractory cure before shutting down for inspection and subsequent repairs. The gasifier B repairs were completed by the end of June and the gasifier released for its first integrated operational test and syngas production. The gasifier A repairs were completed by the end of August and the gasifier released for its first integrated operational test and syngas production.

Starting with the test package executions in late 2014, operational testing of systems like the gasifiers, gas cleanup, WSA, AGRs, and dryers was regularly suspended due to issues identified during setup and initial execution of the test packages. Breaks in the operational testing were planned from the outset to reconfigure systems to allow testing to progress. Those suspensions were recognized as outages in the planning and scheduling of the project. Some outages were limited to particular systems or gasifier trains, and others included much of the plant from generators to utilities. The first such outage was the tie-ins of high energy steam for cleaning blows of the gasification island steam headers in the fall of 2014, followed by a restoration outage at the end of the year. The chemical cleaning of the syngas coolers also required preparation and restoration outages of the gasifier trains. Similar restoration outages of both gasifier trains were in winter 2015, followed by outages to pack the syngas and ammonia scrubbers in spring 2016. In spring and summer 2015, at the completion of the gasifier air-blows, both trains went into the final preparation outages to prepare for upcoming syngas operations and to correct deficiencies identified in previous test evolutions. The gas turbines were offline in fall 2015 for scheduled inspections. After the AGR packing was loaded, the systems were flushed and degreased before another outage to normalize the recuperating solvent heat exchanger. The sour water system was taken down several times to address issues including the partial collapse of the sour water tank due to overnight cooling. Gasifier-related outages were related to repairs following the initial fluidization testing with sand. Each of the dryer trains experienced repeated outages to address operational issues experienced during testing. As the systems went into outages, plans were adjusted to best fill the time until the system was ready for service again.

By the time the gasification island equipment and systems were commissioned and ready for integrated testing, many of the operational challenges were addressed, corrected, or compensated for. July and September 2016 marked the first syngas production for each gasifier train and the beginning of the integrated operational testing phase of the project.

4.0 COMMISSIONING OF SUPPORT SYSTEMS

4.1 Engineering Simulator

4.1.1 Scope Overview

The engineering simulator for Kemper is a dynamic simulator that allows evaluation of process and equipment design changes. Early in front-end engineering design (FEED), steady state process models were created. However, these models did not allow evaluation of the design during transient conditions such as startup, load changes, and shutdown. Because Kemper combined systems in a new configuration, a dynamic model was needed to evaluate processes, operating modes, and other situations such as equipment failure.

A specification was prepared for the engineering simulator and sent out for bids. The bids were evaluated, the lowest bid selected, and a kickoff meeting held with the selected vendor. The vendor was responsible for providing the simulation software for Southern Company use and providing the engineering to simulate eight process phases. The phases of the dynamic simulation were:

- Gas flow model.
- PCD heating model.
- Gasifier heating model.
- Steam system model.
- Coal feed system model.
- Water gas shift, acid gas removal, and WSA model.
- Transition from startup to normal mode model.
- Integrated plant model.

These specific phases were selected based on Southern Company engineers' understanding of equipment integration requirements, control system integration requirements, and the effect they would have on plant operations at that point in the design process. The phases are summarized below.

- Phase 1: Gas flow model

  The top priority for this model and study was to establish that the air compressors could provide the needed flow and turndown for startup, normal operation, and shutdown using the existing equipment design and control scheme. This model included the gas flow from the compressor inlet; through the distribution piping, gasifier, and gas cleanup equipment; then, depending on the mode of operation selected, out the startup stack or flare or into gas turbine fuel skid inlet. The model included any known piping details and vessel volumes and estimates and assumptions for items that were still being designed. The studies from this model showed the compressors, downstream equipment, and control scheme were adequate to take the plant from a cold, warm, or hot start through normal operation and back to a shutdown condition.

- Phase 2: PCD heating model

  The PCDs are sensitive to moisture condensation during startup. To minimize the amount of condensation during startup, air from the process air compressors is blown through the tubes of the low temperature economizer while boiler feedwater heated with intermediate pressure steam is circulated through the shell of the low temperature economizer to provide a heat source. This study showed the heat transfer through the systems and the amount of energy required to generate and sustain the required temperatures.

- Phase 3: Gasifier heating model

  The gasifier is a large heavy steel walled vessel with two layers of refractory inside. Heating the gasifier is a multistep process that must be done in a controlled manner to meet the heating requirements of each of the components. The gasifier is first heated with air, then by exhaust from natural gas fired burners, followed by two

types of diesel burners. The heat-up process takes place with and without the circulation of solids inside the gasifier. This study looked at each of these heat-up steps to confirm the amount of time needed to heat the gasifier to operating temperature. This duration was a critical parameter in startup planning for the evaluation of available resources.

- Phase 4: Steam system model

  Steam is generated and used in several processes in an IGCC plant. This study focused only on the generation and use of high pressure (HP) steam. HP steam is generated by both heat recovery steam generators (HRSG) downstream of the two gas turbines and by the syngas coolers for each gasifier. This HP steam is used to power the steam turbine and generate electricity. HP and turbine extraction steam are used as needed for process heating. This study looked at the generation of steam at partial load cases and at full load with duct firing in the HRSGs.

- Phase 5: Coal feed system model

  Lignite coal is dried in a closed loop system. The coal is then milled, pressurized, and conveyed into the gasifier. The coal is dried in a fluid bed dryer (FBD) by gas heated with tempered water. This dried coal is conveyed to the pulverizer mills where it is reduced in size. The coal is then conveyed to a series of lock hoppers where the pressure is increased before the coal is fed into the gasifier. The system is arranged so that for each gasifier train, three fluid bed dryers feed three mills. These mills then feed two high pressure coal feeders each for a total of six coal feeders per gasifier. During startup, before tempered water is available, steam is used to raise the temperature of the drying gas in the FBD. This study looked at the amount of steam required to raise the temperature of the drying gas sufficiently before tempered water was available, and at the minimum and maximum coal feed rates for individual feeders or combinations of feeders. The minimum and maximum cycle time for a lock vessel cycle was confirmed along with how much time was required to purge the coal feeder loop of oxygen.

- Phase 6: Water gas shift, acid gas removal, and WSA model

  This phase included the water gas shift system, the acid gas removal (SELEXOL™) system, and the WSA system. The constituent content of the coal the plant received varied widely. This model looked at the effect of variable coal quality and varying gas turbine loads on these systems. This phase also looked at the production of medium pressure steam in the WSA system.

- Phase 7: Transition from startup to normal mode model

  This model focused on syngas production and process flow. It looked at both a cold start and a hot start of the equipment, the heating of equipment, and the different fuels burned in the gas turbine during different stages of startup.

- Phase 8: Integrated plant model

  This model included the 2 x 1 combined cycle portion of the plant along with the gasifier island equipment. This study looked at the effects on the plant and the power grid if various pieces of equipment tripped offline during normal operation of the plant. The results were an input into the plant load-shedding criteria development.

The specification defined each of the phases in detail, the transient studies for the phase, and the due date for the phase. The model was to be built in a modular fashion that would allow the deletion or addition of entire processing units. It was to include a basic control system configuration to allow the process and control engineers to observe how the equipment and processes responded during transient operation and the interaction of the equipment and controls during these transients. The completed model would identify equipment sizing issues, process related issues, and control system problems.

The specification for the engineering simulator included training for process engineers and control engineers to review and run the models the contractor provided. The training would allow the process and control engineers to make changes to the simulation to evaluate different scenarios than those included in the contracted cases.

The target completion dates for each phase of the model and report were:

- Phase 1 – 7/2/2009.
- Phase 2 – 8/7/2009.
- Phase 3 – 9/4/2009.
- Phase 4 – 11/5/2009.
- Phase 5 – 12/11/2009.
- Phase 6 – 2/26/2010.
- Phase 7 – 4/30/2010.
- Phase 8 – 6/30/2010.

Before each phase began, a meeting was held with the vendor to review the requirements for that phase and to clarify any questions the vendor had about the modeling requirements. The vendor would request any specific information needed to complete the modeling for that phase and provide the date the information should be received.

4.1.2 Significant Events

The engineering simulator was specified and purchased during the early stages of FEED. At this phase of the project, a combustion turbine manufacturer had been selected, but equipment was not purchased so equipment sizing and configuration could not be determined. The engineering simulator specification was based on the equipment from the selected combustion turbine manufacturer. During modeling of phase 1 of the simulator, a different combustion turbine manufacturer was selected as the supplier. Because of this change, many process parameters and some equipment configuration had to be changed. The changes were significant enough that a change request was initiated with the simulator supplier to make the required changes to the model. The changes did not result in a change to price, so no change order was issued to the supplier. Even though early purchase of the simulator led to this change request, the project still gained a significant time advantage by having the model already prepared and then making model adjustments for the new combustion turbine.

In the fall of 2009, after the phase 1, 2, and 3 reports had been received, a new heat and material balance (HMB) was generated based on the new combustion turbine vendor's process data. This new HMB had significant process and system configuration modifications. To provide the accuracy needed for the engineering simulator, the simulator supplier was requested to rerun phases 1, 2, and 3 using the new HMB. This change required work for phases that had previously been completed, and a change order was entered to provide funds to the simulator supplier for the work. This change delayed phase 4 by nearly 6 weeks, because the data needed to complete phase 4 was based on the model developed for the previous three phases.

As detailed design work progressed, additional changes were made to the plant. For example, the water gas shift area of the plant was expanded from one reaction stage per train to two reaction stages per train. Changes were made to the acid gas removal (AGR) system, the WSA system, and the steam system. Additional model runs for phase 8 were requested. These changes resulted in Change Order #2 with an additional 2-month delay to the phase 6 model and an additional 5 weeks required to complete the phase 8 model.

Because the steam system is common to the entire plant, including the two HRSGs and both gasifier trains, Southern Company decided to change the scope of phase 7 from modeling just one gasifier train to modeling both gasifier trains. This expansion was to provide a more realistic view of the interactions and process parameters during startup and shutdown of both gasifier trains. Southern Company also requested two additional case runs be completed with the phase 8 model. These requests resulted in Change Order #3 and delayed the delivery of phases 7 and 8.

The multiple delays resulted in these milestone dates for each phase of the engineering simulator:

Task	Date
Kickoff meeting	5/28/2009
Process modeling began	6/1/2009
Phase 2 process modeling began	6/19/2009
Modeling software training (1 week)	6/22/2009
Phase 3 process modeling began	6/29/2009
Phase 1 process model and report received	7/24/2009
Phase 4 process modeling began	8/13/2009
Phase 2 process model and report received	8/21/2009
Phase 5 process modeling began	9/4/2009
Phase 3 process model and report received	9/10/2009
Phase 6 process modeling began	2/19/2010
Phase 5 process model and report received	5/4/2010
Phase 4 process model and report received	5/24/2010
Phase 8 process modeling began	5/28/2010
Phase 7 process modeling began	6/9/2010
Phase 6 process model and report received	10/25/2010
Phase 8 process model and report received	12/17/2010
Phase 7 process model and report received	3/10/2011

4.1.3 Final Summary

The vendor completed all eight phases and training as requested. The vendor met with the responsible process engineer and control engineer at the conclusion of each phase to establish the work had been completed correctly. This meeting was to verify the process could be controlled as designed, and that, provided with the inputs from the HMB, the model provided steady-state outputs that matched the corresponding outputs from the HMB. The vendor pointed out any issues identified during modeling or when transitioning the model from one state to another. Process engineers made several discoveries during the modeling, studies, and operation of the model. These discoveries led to changes in process design or startup plans that helped prevent lost time or equipment damage.

One of the benefits of the engineering simulator was identifying or more clearly defining certain operating scenarios to avoid. For example, after the gasifier has been in operation, ash particles will accumulate in the particulate control devices (PCD). These ash particles will contain a significant quantity of carbon. Because the ash containing carbon will be in the PCD when the PCD passes through the heating stage during subsequent startups, the model was used to confirm the combination of carbon and oxygen in the flue gas at the expected temperature would burn and damage the PCD. Startup plans were modified to minimize excess oxygen at higher temperatures.

When heating of the gasifier and PCD was modeled, it was determined that additional equipment would be required in preheating the PCD to prevent condensation during startup. As described in phase 2 of the model, hot air from the process air compressors is initially used to heat the PCD. The engineering simulator demonstrated the heat losses through the equipment during this stage of startup were too great to maintain the PCD above the condensation temperature. Steam heating coils were added to the cone of the PCD vessel to maintain the vessel temperature during this stage of startup.

The engineering simulator identified problems with venting high-pressure lock vessels into the baghouse based on the rate of release. Because the high-pressure lock vessels contain coal, they must be vented down to a device that will control the coal dust present in the vent gases. The baghouse operates at a much lower pressure than the lock vessels. Due to the volume of the lock vessels and the baghouse, if multiple lock vessels are allowed to vent at the same time, the design pressure of the baghouse would be exceeded. To avoid exceeding the design pressure of the baghouse, logic was created to limit the number of lock vessels that could vent simultaneously.

The relief valve for the baghouse had been sized for normal operating conditions. The engineering simulator demonstrated that during lock vessel cycling, the original design for the pressure relief system was not adequate. The pressure relief system for the baghouse was reevaluated and redesigned.

The engineering simulator assisted in sizing the surge drums for the coal handling system. The plant is equipped with a high-pressure nitrogen generation unit designed for a continuous flow of nitrogen. Because lock vessels operate in cycles, a storage volume is needed to supply the nitrogen during charging of the lock vessel. The engineering simulator provided the charging time needed to refill the vessel to maintain the cycle time of the lock vessels at full load on the plant.

Not only was the engineering simulator used to assist in sizing the nitrogen surge drums, it also was used to verify the high-pressure nitrogen header design pressure was adequate to recharge the drums during lock vessel cycling. The time required for this action is dependent on the volume of the tanks, the number of tanks being filled, the supply piping design, and the header pressure that supplies these tanks. The simulator allowed the process engineers to vary these parameters to verify the selected equipment was adequate for the task.

In modeling the operation of the columns in the sour water area of the plant, it was determined the desired operating pressure for the ammonia stripper column could not be maintained for all operating conditions. The process models developed for specific cases were all steady state models. The engineering simulator allowed the process engineers to vary process conditions and observe operation of the equipment as the load changed or as other operating conditions varied. The modeling showed that the pressure control scheme for this column would not perform as desired during all scenarios. The control scheme for the column was changed, which helped avoid field modifications during commissioning.

For normal operation of the plant, two process air compressors (PAC) per gasifier provide most of the air used in the gasification process. This air is provided in high volumes and at high pressures. The PAC air for each gasifier is supplemented with air extracted from the associated gas turbine compressor. These combined sources provide the total amount of air needed for each gasifier. This extraction air is available only when the gas turbine is fired with syngas, so additional air sources are needed during startup and at low loads, or while the gas turbines are firing on natural gas. During startup, air is needed at high volume and low pressure. To remedy the startup case, a startup air compressor was added to the design to provide air during startup conditions. One of the first stages of startup requires air from the startup air compressor to be provided to the gasifier and downstream equipment for warming and initial operation of the equipment. Later in startup, the PACs are used to provide the air needed to initiate gasification. After the gasifier is providing sufficient syngas to fire the gas turbine, air is extracted from the gas turbine compressor, and the pressure is boosted to the process air requirements by the extraction air compressors (EAC).

In phase 1 of the engineering simulator model, the process engineers reviewed the air needs during startup and for the transition from the startup air compressor to the PACs. This model provided verification that the startup air compressor had been sized adequately for the system.

Because of the multiple sources of air at varying pressures and flow rates during various stages of startup, the air control scheme for the plant was complicated. The engineering simulator model allowed the process and controls engineers to review system parameters as these transitions were made and to confirm the control scheme could adequately control the header pressure and provide sufficient air for each stage of operations from startup to full load operation.

Phase 6 of the engineering simulator included modeling and preparing studies of the WSA system. Using the simulator, process engineers observed how the WSA unit would operate during transients and at specific load points for the gas

turbine. Model review showed the potential for the medium pressure steam drum for the WSA to run dry if a specific operating condition were maintained for an extended period. The process engineers could mitigate this possibility during the design phase instead of during actual plant operation, avoiding expensive repair and rework of the WSA unit.

The engineering simulator was a valuable tool in evaluating process and equipment early in the design process, resulting in significant cost and time savings during construction and commissioning of the plant. As process engineers became more involved in equipment procurement, the evolving detailed design and resource limitations prevented more in-depth analysis and model utilization beyond the original eight phases the vendor provided. Continued focus on transients and on startup and shutdown planning would have paid even greater dividends.

4.2 Operator Training Simulator (OTS)

4.2.1 System Overview

The operator training simulator (OTS) at Kemper is a robust, comprehensive model of the IGCC plant linked to a copy of the plant control systems. The DCS graphical interface and real-time running capability provide a complete virtual plant environment. The OTS offers control room operators a realistic simulator for training, while also serving as a tool for evaluating plant controls, interlocks, graphical interfaces, and operational procedures.

Southern Company awarded the OTS contract to a vendor used on other Southern Company projects. As part of the contract, the vendor then provided:

- Process models simulating all relevant plant operations.
- A server and model computer to execute the simulation.
- Integration with replicated DCS operator workstations.
- An instructor workstation.
- Emulations of non-DCS controls, including compressor PLCs, the plant SIS, and the steam turbine controls.
- An integrated virtual turbine control system model developed by the gas turbine vendor.

The process model covered all major areas of the IGCC plant, including:

- Coal handling and drying.
- Coal feed.
- Gasifier.
- Coarse and fine ash removal.
- Syngas coolers and steam generation.
- Syngas processing, WGS, and COS hydrolysis.
- AGR.
- Recycle gas.
- Air compression.
- CO_2 compression.
- WSA.
- Sour water system.
- Gas turbine.
- Steam turbine.
- All plant steam and water systems.
- Plant electrical system.

The Kemper OTS was the first time many of these systems were modeled in a real-time operator training simulator. The OTS vendor worked closely with subject matter experts at Southern Company to ensure the models provided accurate results. To enable the most accurate simulation possible, the vendor modeled both gasification trains (six

dryers, two gasifiers, two clean-up trains, and two gas turbines). The vendor modeled all systems using the vendor's own real-time simulation tool, developing first-of-a-kind systems (the bulk of the gasification island) from scratch.

Southern Company provided Emerson Ovation DCS workstations to replicate the plant control room workstations, complete with control graphics, alarms, and trends. The replicas allow the operator to gain experience using controls with no discernible difference from those used in the control room. Programmers emulated controls outside the DCS, including the compressor PLC logic, the plant safety instrumented system (SIS), and the specific steam turbine controls. The combustion turbine manufacturer provided the turbine control system and model to the OTS vendor separately, also using copies of the control room interface.

An instructor station runs the simulation, using controls such as run, freeze, snapshot, reset, and backtrack. The workstations communicate to each other and the simulation server through a dedicated simulator LAN. Using the simulator controls, the instructor can load scenarios, run, and freeze the simulation, and backtrack to highlight issues. Training scenarios used in the OTS include:

- Complete cold and hot startups of the entire plant.
- Shutdowns.
- Load and process changes.
- Normal operating conditions.
- Abnormal operating conditions.
- Emergency operating conditions.

Because the model is a single simulator covering the entire facility, training requires a full team of operators and at least one instructor for a training session. While labor-intensive, modelling the entire plant is beneficial for evaluating control logic, system interfaces, capacity requirements, and procedural coordination between operators of different process units. The simulator also is useful for process and controls engineers can use it to check logic, run procedures, improve graphical interfaces, and evaluate control room protocol.

4.2.2 Initial Commissioning Plan

The primary objective of the OTS was to provide an engineering-grade simulator for training operators. A secondary objective was to provide a platform for engineering and control system analyses to support design activities, verify conceptual operation, and pre-tune control systems. To meet these goals, the OTS had to provide accurate results at near real-time speed. Lower speeds would mean erroneous response times, interfering with control system tuning and operator response training. The project had already developed standard process simulators for generating highly accurate results, but the OTS required development of a new model capable of quickly providing reasonably accurate data.

OTS development was in four main phases:

- Process model development.
- Process configuration (for example, hydraulics).
- Integration between the model and the DCS/turbine controls.
- Acceptance testing.

The goal of the Process Model Development Phase was to create new process models capable of realistically generating results from processes not already part of the proprietary simulation software. The vendor previously had limited or no model experience with many of the unit operations at Kemper. The schedule set 33 weeks from the kickoff meeting to develop models for these systems. Systems to be modeled included:

- Transport gasifiers.
- Fluidized bed dryers.
- SELEXOL absorption, stripping, and distillation columns.

- Water-gas-shift reactors.
- COS hydrolysis reactors.
- Sour water columns.
- WSA SO_2 converter.
- Syngas and ammonia scrubbers.

In the Process Configuration Phase, models would use existing simulation tools (including the newly developed unit operations) to model the system hydraulically. Configuration of systems with existing unit operations models, such as the combined cycle, could overlap with the Process Model Development Phase, while systems such as the gasifier required the new models to be completed. Developers anticipated some systems, such as PDAC, CFAD, CCAD, the gasifier, and all distillation, stripping, and absorption columns, would require unique configuration using the tools to create accurate models. Most of this effort was to occur in parallel with the Process Model Development Phase, concluding 33 weeks after the project kickoff.

The goal of the Integration Phase was to connect the completed model of the entire plant to the plant control system. To support the OTS, Southern Company supplied a computer network with an exact copy of the plant DCS configuration. The OTS vendor would then take the completed Kemper process simulation and connect it to the plant DCS, allowing the model to receive control commands from the equipment in the model and send the process results back to the instrument inputs in the DCS.

Most of the controls at Kemper were in the DCS, but a significant minority were in other control systems, including compressor PLCs, hardwired panels, steam and combustion turbine controls, and the SIS. Plans were to emulate controls for the PLCs, hardwired panels, steam turbine logic, and SIS within the model. The combustion turbine manufacturer provided a separate control scheme and model for the two combustion turbines that the OTS vendor planned to tie to the model separately. All of the emulation and turbine control work was to occur during the Integration Phase of OTS development.

The Integration Phase was scheduled for 22 weeks, due to the complex nature of the Kemper project, the large number of inputs and output, and the amount of emulation needed, particularly for the SIS. The Integration Phase consisted of four subphases:

- Initial DCS setup.
- Combined cycle integration.
- Gasifier island integration.
- Integrated operation.

Each phase was to have a short, 1- to 2-week test afterward to confirm results. After the final phase of integration, the plant simulation was to run at normal operating conditions and fully connected to plant controls, allowing the OTS factory acceptance test (FAT) to start.

Acceptance testing provided the opportunity for Southern Company to review the OTS and ensure the accuracy of the process models, the stability of the system, and the ease of use. Running a complete shutdown and restart of the simulated plant was the best way to ensure the OTS performed well over the entire spectrum of plant operations. Plans included a time at the end of the FAT to review special instructor-created malfunctions needed to train operators on upset recovery. There was a 6-week time to complete the FAT, including a 2-week period to address any discrepancies. The plans were to include sufficient staffing of operators, trainers, and engineers to shut down and restart the plant.

When the FAT was successful, the OTS vendors planned to immediately ship the simulator to Kemper for the site acceptance test (SAT). The SAT would ensure proper installation and that the OTS was not damaged during shipping. The original schedule discussed at the OTS kickoff meeting set the project completion date at March 15, 2013 (table 4.2-1).

Table 4.2-1 – Original OTS Schedule

Task	Date*
Initial contract award	12/22/11
Kickoff meeting	2/23/12
Final contract approval	5/4/12
Design scope finalized	5/25/12
Plant process modeling complete	10/12/12
Integration complete	1/1/13
FAT complete	2/15/13
SAT complete	3/15/13

**Dates in bold were actual, others were as planned as of the kickoff meeting.*

4.2.3 Significant Events

4.2.3.1 *Accomplishments*

Task	Date
Kickoff meeting	2/23/12
Process modeling began	3/15/12
First process models received	5/16/12
Initial process model review	9/19/12
Revised process models complete	3/21/13
SIS integration complete	6/24/13
First successful initiation	7/30/13
Normal operation checkouts complete	11/21/13
Beginning of first process checkout	1/8/14
Completion of first process checkout	5/15/14
Beginning of second process checkout	6/9/14
Completion of second process checkout	12/12/14
Gas turbine integrated	1/11/15
Beginning of third process checkout	1/12/15
Completion of third process checkout	7/2/15
Beginning of fourth process checkout	7/6/15
Completion of fourth process checkout	10/23/15
Beginning of factory acceptance test	11/2/15
Factory acceptance test complete	12/11/15
Arrived at site	12/17/15
Site acceptance test complete	1/28/16

4.2.3.2 *Project Kickoff*

On Dec. 22, 2011, Southern Company awarded the OTS contract to a vendor used for other training simulators in the Southern Company system. Since many of the processes at Kemper were first-of-a-kind technology, and the vendor was more familiar with conventional power plant simulators, Southern Company hosted an extended kickoff meeting with the vendor in February 2012. From the kickoff meeting, the vendor developed the schedule shown in table 4.2-1, delivering the simulator in time for operator training to support the plant's original COD of May 2014.

In the kickoff meeting, the vendor acknowledged the uniqueness of the Kemper facility and requested additional information, including empirical data from the pilot plant. In March, the vendor arranged to have their principal R&D engineer meet with subject matter experts at Southern Company to develop models for systems they were not familiar with, such as gasifier, distillation, absorption, and water-gas-shift reactors. Since the vendor did not have experience with many of the Kemper processes, the R&D lead relied heavily on publicly available literature, empirical data, and recommendations from Southern Company engineers to develop information such as vapor-liquid and reaction equilibrium data for several of the new systems.

4.2.3.3 *Process Model Development*

The OTS developers began to generate the new process blocks in April, starting with distillation and adsorption models, then the WGS reactors and gasifier. Each time they created a new model, the developers sent it to Southern Company for review. After Southern Company completed the final contract approval in May and the vendor signed the relevant NDAs, the programmers used heat and material balance input data to generate results for the newly modeled process blocks, generating results from the gasifier and WGS models that matched those of the heat and material balance.

As scheduled, Southern Company and the OTS vendor met to finalize the design scope on May 25, 2012. In the design scope meeting, both sides agreed on which systems to include in the OTS and which to model as boundary conditions. All major equipment controlled by the DCS operators in the plant control room would be modeled. The model contained most automatic valves and controllers, but only the significant manual valve operation needed for training. For training, the model would have nine initial conditions (IC) (scenarios the instructor could load to begin a training session) and a number of malfunctions to test operator response.

After the design scope meeting, work slowed dramatically on the simulator. The combustion turbine manufacturer informed Southern Company they would not be able to provide the virtual turbine model and controls until after March 2013, when the completed OTS was originally scheduled to ship. To maintain schedule, Southern Company proposed the OTS vendor deliver a modified OTS without the combustion turbine model. Around the same time, procurement delay on the DCS hardware shifted its arrival to late September. Without the equipment, Southern Company could not complete DCS configuration, and would not be able to deliver configuration files to the OTS programmers for the DCS work scheduled to begin Oct. 12, 2012.

The OTS vendor did not deliver any new process models until Aug. 31, 2012, when they provided results for the ammonia scrubber and the H_2S stripper. The syngas scrubber and remaining sour water models were available a few days later. Although the initial gasifier and WGS results had closely matched HMB data and required only small adjustments, all the new models deviated significantly from expected results and required more extensive modifications. The deviation appeared to be the result of the model neglecting electrolytic effects in the absorption and distillation systems.

4.2.3.4 *Process Model Configuration*

In summer 2012, while the model development group continued work on improving the absorption and distillation process models, their configuration team began work on the other systems. They started with combined cycle and then began working on the gasifier island systems as the process models became available. By the end of the year, they had created the basic hydraulic model for the entire plant, although the AGR, sour water, and WSA portions of the plant did not yet have process models connected to them.

Some of the equipment unique to Kemper required novel techniques for the existing simulation software. One example is the absorption and distillation columns, where the modelers treated them as multi-vessel systems, with each virtual vessel serving as a process stage or column sump. The techniques were effective and eventually produced accurate hydraulic results after detailed process review.

4.2.3.5 *Integration*

The OTS DCS equipment arrived at the OTS development facility on Sept. 28, 2012. While model development and configuration continued on the gasifier island systems, the combined cycle work was complete and ready for integration with the plant DCS. Southern Company I&C loaded the combined cycle DCS configuration onto the OTS computers, and the OTS vendor staff began integrating the combined cycle, connecting the inputs and output from the model to the DCS. During integration, the developers noted multiple DCS configuration and screen errors that both parties worked together remotely to address.

The control emulation for the steam turbine went smoothly; the other emulated controls such as SIS and compressor logic were not available at this time. The combustion turbine manufacturer was not able to improve on delivery of the Kemper-specific turbine logic and controls and sent a generic model instead. Southern had requested the generic model to allow the modeling vendor to attempt to meet a spring 2013 delivery date for training needs. Southern Company purchased hardware for a second, duplicate simulator to allow training on the combined cycle simulator at the plant site, while the OTS vendor continued work on the full IGCC simulator at their testing facility.

4.2.3.6 *Combined Cycle Acceptance Testing*

By the end of Dec. 2012, the combined cycle integration was complete. There was another month of DCS verification testing in Jan. 2013 before beginning the combined cycle factory acceptance test. During the combined cycle acceptance testing, Southern Company worked with the vendor to check out the combined cycle in normal operating mode to ensure it matched expected behavior, then performed a shutdown and restart on the simulator to validate the system responses. Finally, the testing reviewed a number of instructor-initiated malfunctions to determine if they were suitable for training purposes.

The combined cycle FAT concluded on Mar. 8, 2013 and shipped the following week to the plant site. Although the system did not have the specific combustion turbine model and controls, it did have the remaining combined cycle systems and DCS. It was useful to train the operators well in advance of the combined cycle startup in August 2014. Meanwhile, the OTS vendor and Southern Company loaded the model and DCS controls onto the duplicate simulator to further develop the gasifier island systems.

4.2.3.7 *Gasifier Island Integration*

Work on gasifier island integration began in March 2013, as soon as the duplicate simulator was operational, with the revised goal of supplying the completed OTS to the plant site by June 2013. The complexity of the gasifier island systems greatly slowed progress, and it was quickly determined that the existing DCS configuration was inadequate both for controlling the plant and for displaying the model results. Early attempts at running the model integrated with the DCS resulted in numerous errors that caused the model to crash within seconds. The preliminary DCS checkouts, originally scheduled to last only a couple of weeks at the end of the integration period, stretched to more than 2 months. The DCS errors included missing logic (items in the model or plant but not in the DCS), improper interfaces with the plant SIS, undefined instrumentation ranges, missing graphics, and inverted points (signals programmed as true, when they should have been false). In addition to DCS challenges, the delivery dates of the combustion turbine model and final plant SIS continued to slip, making the project impossible to compete by June 2013. The number of points in the DCS overwhelmed the DCS hardware, leading to further delay as the DCS programmers moved large amounts of logic from one DCS network to a second one to contain the points. These issues delayed the OTS delivery but finding them early with the OTS allowed the overall project to develop solutions in advance of actual field activities, providing significant savings to the project schedule.

Another challenge that lengthened the OTS schedule was the operator interface design. Southern Company had an initiative to replace all piping and instrumentation diagram (P&ID)-style graphics with bench-board-style graphics for simplicity. While the bench-board graphics were good for simpler, established systems, they did not adequately illustrate the complex processes at Kemper without the use of process flow drawings. There was a concern that reaction time to transient or emergency situations would suffer due to a lack of process flow graphics. Graphics modifications were needed at both the plant site and the OTS, which impeded progress.

4.2.3.8 *Pre-FAT Testing*

By May 2013, the significant challenges encountered during OTS development and testing resulted in a revised schedule with a delivery in December 2013. The revised schedule included a pre-FAT activity. The pre-FAT is a series of tests performed with increasingly more features and systems incorporated into the OTS, to limit the extensive number of issues to a manageable amount. The pre-FAT phases were:

- Completing preliminary DCS checkouts. The OTS vendor and Southern Company I&C would try to correct enough of the DCS errors to keep the model running and provide enough information for the DCS screens to operate.
- Performing initial rough shutdown and restart on the simulated plant. The vendor would tie the model to the simulator running at full gasifier load. Then, the vendor and Southern Company process engineers would go through a plant shutdown and restart with Southern I&C support. The main goal was to keep the model running and be sure things were moving in the correct direction without regard to accuracy.
- Performing a second shutdown and restart on the plant with interlocks. In this phase, I&C could examine the interaction between the DCS and SIS systems, and process engineers could more carefully evaluate the accuracy of the model results, especially important due to the now-active plant trip system.
- Performing a third shutdown and restart on the plant with the combustion turbine model. The process engineers and I&C staff could evaluate the integrated operation with the true turbine model and controls and any further fine-tuning necessary to the model.

Progress slowed further during the next few months as Southern Company and the vendor worked to identify and correct issues in both the model and the DCS. By late June 2013, the vendor had received a copy of the plant SIS and emulated it in the model. After installing the SIS, the programmers left the SIS offline to ensure it would not trip the plant during the initial integration. Finally, on July 30, 2013, after 4 months of resolving discrepancies between the model and the DCS, the integrated DCS/OTS was initialized.

The availability of the integrated OTS would allow testing of various plant systems, but many of the systems in the combined DCS/OTS model were not properly set up in normal operating mode, resulting in DCS/OTS conflicts. Individual systems were not stable enough to begin the shutdown. Additional time was required to allow SMEs on each system to review the operation and ensure adjustments produced results that were generally in the right direction and rough order of magnitude.

These issues continued with both the DCS and the model, severely impacting the OTS schedule. The model continued to crash due to conflicts with the DCS, often erasing work and creating further delays. The effort did discover and address errors and inadequacies in the DCS configuration and operator interface. The interactions with the OTS convinced project management to allow some P&ID-style graphics where such graphics were needed. The I&C group was able to improve both the operability and layout of the DCS logic. By the time plant commissioning began, only minor DCS logic changes were necessary. Logic improvements based on this experience include the PDAC lock-vessel filling cycles, CFAD/CCAD startup sequences, AGR solvent master controllers, fluidized bed dryer controls, and preliminary gasifier feed and pressure controls.

4.2.3.9 *First Process Checkout*

Individual system testing lasted through Nov. 21, 2013, followed by a short period of model and DCS adjustments. After struggling with initial testing, the OTS vendor decided to revise the shutdown-first, restart-second, test plan to a startup-first, shutdown-second plan. The primary reason for the change was that the model was inherently stable at shutdown conditions and loading new DCS or model configurations did not result in instability. Bringing the plant up one unit at a time was easier than checking the entire plant to ensure each unit was running as specified in the full-load HMB.

Startup testing began Jan. 8, 2014, with train 1 at full load by late March and train 2 at full load in early May. The shutdown went smoothly, finishing a few days later on May 15, 2014. During the test, the focus was on achieving operational responses in the correct direction and order of magnitude, not on accuracy. The test proved to be vital in evaluating plant controls during startup and shutdown, and identified several areas needing revision.

Some issues discovered during the first test were simple typographical errors, common in systems with tens of thousands of points. Others involved conflicts between systems. For example, the fluidized bed coal dryer needed to increase bed height to process additional coal. When the gasifier logic requested additional coal, the PDAC coal feeders increased coal feed rate, but the upstream dryers reduced throughput temporarily to build level. These diverging responses resulted in the coal storage silos running out of coal. By identifying this issue early on, process and controls engineers were able to develop an algorithm to meet the needs of both systems, maintaining the desired coal feed rate to the gasifier before the feeders ran out of coal.

The testing identified the need for a startup sour water pump. During normal operations, the pressure of the syngas and ammonia scrubber in the syngas cleanup section of the facility was well above the plant sour water system. The pressure differential was sufficiently high during startup of the first train. However, if the first train is operating and the second train is starting up, the pressure of the second train syngas cleanup scrubbers is too low to enter the sour water system, resulting in level buildup in the scrubber. By discovering this issue with the OTS, the project saved time by having the required pumps delivered well in advance of the actual plant operation.

The issues were not just design-related. Few detailed gasifier island procedures were available before the second process checkout, and engineers operated from loosely defined startup narratives. By going through the startup on the simulator, process engineers discovered the unforeseen challenges of bringing the plant online. They could improve the plant startup sequencing, create detailed procedures, and develop protocol for control room communication, since operators from different parts of the plant had to work together to bring their respective systems online.

4.2.3.10 *Second Process Checkout*

After the first checkout proved the OTS could operate in a stable manner with approximate results, the project progressed to the second process checkout, repeating a plant startup and shutdown. The second checkout began June 9, 2014. The primary goal was to ensure the OTS could achieve accurate, realistic results while maintaining stability and real-time operation. Secondary goals were to evaluate the plant SIS system (the majority of plant interlocks) and to evaluate plant procedures. By the time the second checkout began, detailed, accurate procedures were available, and the OTS helped validate them.

The second process checkout was much slower than the first. The newly activated SIS made operating more of a challenge. Maintaining plant operations with a small number of people proved difficult, since any unaddressed process upset could eventually lead to a trip. Model inaccuracies, still present at the time, also contributed to plant trips.

The lack of emulated PLCs created additional challenges. Although the plant DCS contained most of the controls logic at Kemper, the plant compressors and burners often required PLC control. Little information was available on the PLCs earlier in the project, and the programmers had not included them in the model. The vendors were able to develop emulated controls for these systems, but there were additional delays to the schedule. The new emulations allowed the OTS to identify errors in both the tie-ins and the configuration itself, saving countless hours of work during commissioning.

As the model accuracy improved, the checkout revealed an issue inherent to simulators linked to copies of the plant control system: pressure and temperature overcompensation. In general, instruments measure a volumetric flow and assume a temperature and pressure to convert the volume flow into a mass flow using an equation of state (usually the ideal gas law). Then, the DCS logic takes the estimated mass flow and adjusts it using the equation of state with the actual temperature and pressure measured nearby. On an operating plant, these calculations result in precise flow measurements. The OTS model, unlike the plant, provided exact calculated mass flow rates that needed no compensation.

When the DCS used the flow rates from the model and compensated them for temperature and pressure conditions, mass flow errors resulted in both the wrong mass flow being displayed and the DCS controlling the wrong value. The only way to correct the issue was for the model to use the correct mass flows for process calculations, and to uncompensate the value using the correct temperature and pressure before sending it to the DCS. When the DCS compensates the value, it then would determine the correct mass flow for control and display. This work required reverse compensating all of the controls, another time-consuming effort.

Southern Company's control engineers resolved the issues with the DCS and SIS and addressed problems in the operator interfaces. The OTS vendor dealt with issues relating to the model accuracy and stability. The vendor was able to greatly improve the first-of-a-kind gasifier model and the performance of the hydraulic models of complex systems such as the CFAD, CCAD, and the plant absorption and distillation columns. Although the test was necessarily lengthy, by the end of the second process checkout on Dec. 12, 2014, the OTS was providing reasonable results throughout the entire plant and operated within the bounds of the SIS. In addition, the plant procedures were improved and ready for operator evaluation.

4.2.3.11 *Third Process Checkout*

The combustion turbine emulation arrived at the OTS testing facility on June 11, 2014. The second checkout was already underway, so it was not connected until December. At that time, the OTS vendor integrated the turbine model into the OTS, and the third process checkout began Jan. 12, 2015. The primary goal of the third checkout (an additional startup and shutdown) was to evaluate the integrated turbine model. This test was critical, given that Kemper was the first use of syngas controls on this particular turbine model. Secondary goals included evaluating the improvements made on the procedures, interlocks, and PLC emulations during the second checkout, and reviewing the malfunction scenarios created for operator training.

The third checkout marked the first-time operators from the plant site came to the OTS facility to operate the simulation. Operator participation proved valuable in evaluating the procedures and graphics while providing the participants with hands-on training. The operators provided additional oversight on the increasingly complex simulator and provided practical feedback on plant operations, but they also experienced a learning curve that lengthened the checkout. The benefits of including the operators in the OTS checkout, however, were a net positive, and helped improve subsequent commissioning operations.

The turbine integration proved to be more involved than anticipated. The combustion turbine logic, while generally appropriate for natural gas, was missing some of the conditional controls needed for operating on syngas. For example, when transitioning to syngas from natural gas, a loss of steam flow to the turbine tripped the system. The turbine does not require steam to control emissions during syngas operation due to the lower BTU content of the gas, and steam flow is not even possible during syngas operations because the steam nozzles are used for syngas. Other issues related to turbine controls included inadequate controls for extraction air and smooth syngas-to-natural gas transitions.

The third process checkout concluded July 6, 2015. Most of the delay was from the turbine integration, but model instability and fine tuning also lengthened the schedule. By the end of the test run, nearly all remaining issues were resolved, with the model running smoothly and producing excellent results. The testing resolved several turbine controls issues that otherwise could have resulted in equipment damage and excessive delays during commissioning.

4.2.3.12 *Fourth Process Checkout*

Based on the results of the third process checkout, Kemper project management decided to pursue a fourth checkout to ensure changes made during the third checkout did not create instability or erroneous results. The fourth test run began July 6, 2015 and consisted of two major sections: the standard plant startup and shutdown, and detailed malfunction testing. The plant startup and shutdown portion finished in a fraction of the time of earlier checkouts, without major incident and yielding excellent results.

Testing then focused on malfunction scenarios supplied to operators training on recovery from anticipated process upsets. One scenario was testing on new logic for a fast fuel transfer, where natural gas could rapidly replace syngas after a gasifier trip and allow the plant to continue to produce power. The OTS proved invaluable in developing complex logic that would have been impractical to test at the plant site. The logic later deployed at the plant performed as predicted in the OTS, safely swapping the turbine from syngas to natural gas. The fourth checkout finished Oct. 23, 2015, with the OTS ready for the final acceptance test before shipping.

4.2.4 Final Summary

4.2.4.1 *Final Testing and Unit Performance*

The FAT began Nov. 11, 2015, with one final test run for the entire plant from cold start to full load operations, then to shutdown. Testing went well, and the OTS was ready to ship Dec. 11, 2015. The simulator shipped early the following week and arrived on site Dec. 17, 2015, where crews from the OTS vendor worked with MPC staff to assemble it. To ensure proper setup, a site acceptance test (SAT) took place in early January. The SAT format was similar to the FAT, with operations staff assisting to operate the plant from startup to shutdown.

The SAT successfully concluded Jan. 28, 2016. The training department began to use the OTS for operator training and for evaluating new process and controls enhancements. The operators responded well to the training, noting that it gave them confidence for the first gasification operations in July 2016 and the first syngas-to-turbine operations in October 2016. Plant engineering used the simulator to evaluate proposed changes in controls and procedures before implementing on the actual plant to minimize risk.

4.2.4.2 *Conclusion and Summary*

Developing a real-time process simulator for training and engineering evaluation was a huge undertaking for the Kemper project. Due to the complexity of the process and the lack of early DCS configuration, the simulator schedule slipped significantly from the original delivery date of Mar. 15, 2013 to Jan. 28, 2016. The OTS checkouts proved critical in evaluating the plant logic and procedures, and they played an important role in the ability of the plant to reach full integrated operations.

It was a challenge to schedule training, due to the large scope of having the complete plant simulated and because the system required an entire team of operators to run. The inconvenience was outweighed by the benefits of testing the combined facility, including most process and controls interfaces, and teaching the staff to function as a team. The plant intended to develop individual stand-alone models to provide single student instruction to mitigate temporary scheduling constraints, but the plans were never implemented due to the project suspension.

The results at Kemper indicate the net benefit of having a robust real-time simulator to test controls justifies the costs associated with simulator development for a unique facility. The OTS identified more than 3,000 items for correction in the DCS configuration, procedures, and graphical interfaces. By resolving errors early with the OTS, the commissioning schedule was reduced by several months, costs were lowered by millions of dollars, and field commissioning proceeded more smoothly. In addition, the simulator is now available to train new operators and test proposed plant modifications, should the need arise.

4.3 Distributed Control System

4.3.1 System Overview

The control system philosophy for Kemper County was to provide the unit operator with the control tools and documentation needed to operate the plant, improve performance, and avoid problems. A distributed control system (DCS) achieves this goal. The DCS also helps protect plant assets and alerts the operator when trouble arises.

The DCS is a distributed microprocessor-based control system that implements process controls strategies. The DCS integrates coordinated equipment control, process data acquisition, and plant annunciation functions.

The primary interfaces to the DCS are a series of workstations in the plant control room. The control room is designed with appropriate ergonomics to enhance the operator's ability to fulfill the operating philosophy, with particular attention to providing information effectively. The DCS design supported operators in meeting the key performance parameters of safety, reliability, efficiency, and compliance.

These elements were considered when designing and configuring the Kemper DCS:

- Redundant high-speed networks that use fast ethernet standards to transmit data between the stations and controllers connected to the networks.
- Workstations (Windows-based computers) that interact with operators and engineers to send and receive data needed to operate and control all plant processes. These workstations are connected to the control networks.
- Controllers that execute control strategies and interface with input and output modules. Each controller is a network drop containing input/output (I/O) modules connected to devices on actual plant equipment.
- Hardware such as cabinets, cables, and grounding equipment.
- I/O modules that interface to field devices such as temperature sensors and pressure transmitters to send data between the actual plant processes and the associated controllers.
- Software that runs on DCS workstations and performs tasks needed to configure, manage, and operate the control system.

4.3.1.1 *DCS Design Details*

The DCS is a fully integrated, flexible, and expandable microprocessor-based system that can perform plant control functions, plant monitoring, alarming, logging, and sequence of events monitoring. It includes redundant ethernet communications with the combustion turbines control systems, steam turbine control system, process air compressors PLCs, extraction air compressors PLCs, and other plant control systems. It displays graphical information and can trend all plant data in the system.

The DCS functions include:

- Gasifier control.
- Heat recovery steam generator (HRSG) control.
- Duct burner management system (BMS) control.
- Selective catalytic reduction (SCR) control.
- Cooling tower control.
- Electrical breaker and switching control.
- Balance of plant (BOP) control.
- Syngas cleanup equipment control.

The BOP includes condensate control, circulating water control, service water control, wastewater control, and fuel delivery control. Examples of control functions include starting and stopping motors, opening, and closing valves, controlling modulating valves and drive units, and monitoring pressures, temperatures, flows, and vibration.

The DCS is designed to operate in a plant environment. All operator workstations, engineering workstations, and printers are in the climate-controlled control room. The control processors are in the control equipment room or remote I/O buildings. The I/O racks for the process areas are mounted in remote locations.

This section summarizes DCS design details, including general requirements, controllers, I/O details, and performance requirements.

4.3.1.2 *General Requirements*

- Kemper County standardized on common control platforms for the DCS, turbine control system, boiler controls, balance of plant, BMS, safety instrumented system (SIS), and PLCs.
- The plant design minimizes the use of local controls to reduce maintenance and system complexity.
- The plant uses Southern Company master purchase agreements and volume procurement to minimize cost.
- The design, hardware selection, and implementation of controls and instrumentation follow published Southern Company Engineering and Construction Services (E&CS) standards and guidelines.
- All DCS-connected systems are specified to include GPS timestamp, and all times are synchronized.
- Human ergonomics are the prime consideration in the design of the control room and control consoles.
- The DCS is composed of functionally and physically separate processing units, a plant-wide database, and redundant high-speed data highways.

4.3.1.3 *DCS Controllers*

Each DCS controller is contained in one or more cabinets along with associated I/O modules connected to field devices. These modules monitor devices for changes in equipment conditions. The DCS controller communicates with both DCS I/O and third-party control systems I/O. When a change (input) is detected, the controller reads the change and tells a device (output) to perform an appropriate action as determined by the control logic.

This required control logic is programmed into the controller by using control sheets (signal diagrams). These diagrams consist of building blocks (algorithms) that define what action to take when certain events occur. These algorithms, linked by signals, can represent a simple two-step process or complex control logic comprised of many other algorithms contained on many sheets.

The controller executes the control strategies and supports the following additional functions:

- Originates and receives process point data in real time.
- Adds, deletes, and modifies points online.
- Provides alarming for DCS points originating in the specific controller.
- Reads I/O modules and converts data to process point parameters.
- Reads process points and writes data to I/O modules.
- Adds, deletes, and modifies control algorithms online.
- Detects, reports, or bypasses system faults.
- Provides redundancy for all critical functions.

The controllers are provided with redundant processors, memory, data highway communication, and power supplies. This redundancy ensures no single failure in any function will change the operation of the control system. Failure of any processing unit, communication device, or operator workstation does not prevent safe and continuous operation of the DCS functions. Failure of one processing unit does not cause the failure of another processing unit.

Processing units can be configured over the data highway from an engineer's workstation. Security provisions for preventing unauthorized personnel from changing tuning or configuration parameters are included and password protected.

4.3.1.4 *Process I/O Equipment*

The process I/O equipment consists of the hardware needed to interface analog input, analog output, digital input, and digital output signals from the field to the control system. The I/O equipment communications are dedicated to its parent redundant processing units and are not part of a shared communication network with other processing units. Each processing unit is capable of sharing process information with other processing units over the DCS data highway.

I/O cards are grouped considering the effects of component failures. Redundant process equipment I/O signals are wired to separate cards and in separate card racks, where practical.

All system I/O cards with field power originating at the card are provided with fast-blow current limiting fuses to protect the cards from field wiring faults. Each card is provided with the means to prevent propagation of a fault to another I/O card. All I/O points have individual fusing or individual current limiting capability.

DCS I/O modules consist of plug-in components that offer built-in fault tolerance and system diagnostics. DCS I/O modules receive input signals and transmit output signals. Design considerations for the most common of these are outlined in the following sections.

4.3.1.5 *Analog Inputs*

The analog inputs receive 4-20ma (24-Vdc) electrical signals from transmitters, representing process values for temperature, pressure, flow, and other physical parameters. The 24-Vdc power normally used to power each transmitter is provided by the DCS and individually fused to prevent a short on one transmitter circuit from disabling the operation of any other transmitter. All analog input channels have highway addressable remote transducer (HART) communication capability. Each channel is individually configurable for field power or local power. Each analog input card is capable of a combination of HART-enabled channels and channels without HART functionality.

4.3.1.6 *Analog Outputs*

The analog outputs provide 4-20ma (24-Vdc) electrical signals from the DCS to devices such as modulating valves and variable frequency drives, to control a variety of process conditions. The DCS is designed so that disconnecting, shorting, or grounding an analog output does not cause an upset in any other control system output or function. Final drive elements are configured to fail in place, fail high, or fail low on a loss of the control system analog output. Power for the analog outputs is provided by the DCS. All analog output channels have HART communication capability. Each card is capable of a combination of HART-enabled channels and channels without HART functionality.

4.3.1.7 *Digital Inputs*

The digital inputs receive discrete electrical signals from various process devices such as valves and motors, representing the state of the equipment (ON/OFF, OPEN/CLOSE, and so forth). The digital input cards provide 24-Vdc power to sense the state of the digital input field contact (system wetted). Each channel on a digital input card can limit current in the event of a field wiring fault. The occurrence of such a fault is alarmed by the control system.

4.3.1.8 *Digital Outputs*

The digital outputs provide electrical signals from the DCS to devices such as motors and ON/OFF-type valves. Each output is capable of driving 2 amps continuously at 24 Vdc. Each channel is fused or otherwise current limited. When interposing relays are provided to meet these requirements, each relay is protected with indicating fuses.

4.3.1.9 *DCS Configuration Effort*

DCS configuration was a monumental effort requiring thousands of man-hours to complete. The most significant of many contributing factors was the first-of-a-kind nature of the plant. Configuration consisted of:

- Development of the initial process control narratives by process engineers and control system engineers. These narratives described the functional requirements for the DCS and other plant control systems

- Preparation of the initial DCS configuration and graphics by contractors and design engineers. At this point, issues began to arise with the schedule, budget, and scope of configuration.
- OTS development work. The initial DCS configuration and graphics were used as the basis for designing the OTS. During OTS development, gaps were found in the DCS graphics and configuration. These problems were addressed as the OTS was developed.
- Tiger Team review. To address DCS configuration issues, a management decision was made to form a Tiger Team of Southern Company Ovation experts. This group was to review and modify the DCS configuration to ensure it would meet process and plant control system requirements. This team was initially operating in Birmingham but moved to Kemper County during DCS commissioning. Many team members remained there throughout the Kemper startup.

4.3.1.10 *DCS Network Layout*

The DCS networks connect the components of the DCS so all can communicate with each other in real time. They are based on the standard fast ethernet protocol, implemented in a robust, fail-safe, open design. This design provides for easy, direct connection of third-party devices such as printers, WANs, LANs, PLCs, combustion turbine controls, and other similar equipment that use ethernet communications.

The networks are media independent, allowing both fiber-optic and copper (UTP) to be used. See figure 4.3-1 for the network architecture diagram of the Kemper County DCS.

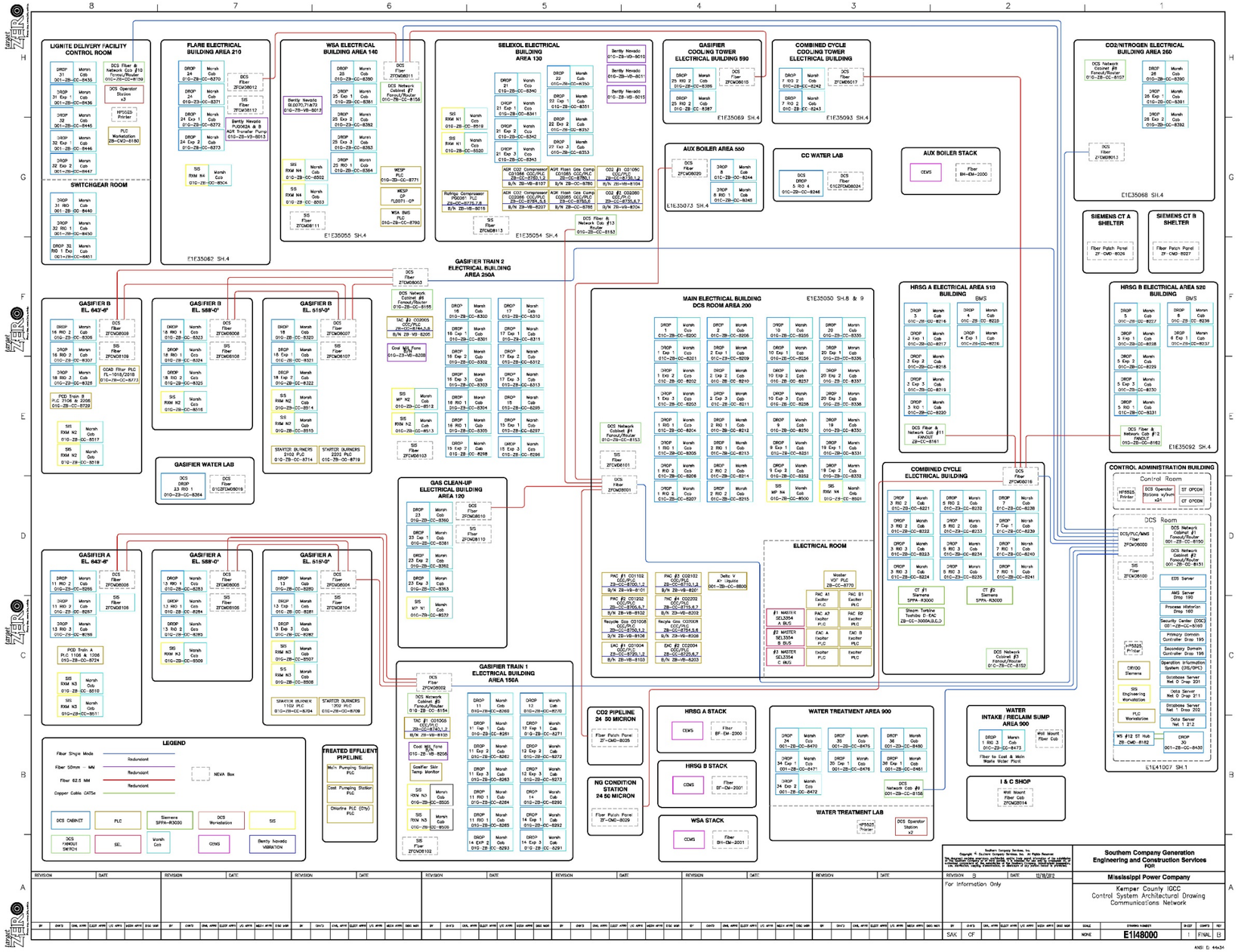


Figure 4.3-1 – Kemper County DCS network

4.3.1.11 *DCS Network Drops*

The DCS configuration is divided among many redundant processor pairs. Each processor pair is called a drop. This segmentation distributes the processing load and controls functionality among the distinct operating areas of the plant. Some of those areas are:

- Combustion turbine control system (TCS) and interface.
- Steam turbine control system.
- Gasifier controls.
- Air compressors control systems.
- Lignite delivery facility (LDF) control system.
- Acid gas removal (AGR)/SELEXOL) controls.
- Syngas cleanup controls.
- Burner management systems (BMS).
- Pressure decoupled advanced coal (PDAC) feeder controls.
- Particulate control device (PCD) controls.
- Continuous fine ash depressurization (CFAD) controls.
- Continuous course ash depressurization (CCAD) controls.
- Ash handling controls.
- CO_2 controls.
- Sulfuric acid system controls.
- Sour water controls.
- Wastewater controls.
- Ammonia storage, loading, and unloading controls.
- Generator hydrogen, lube oil, seal oil, and stator cooling system controls.
- Vibration monitoring systems.
- Balance of plant (BOP) controls.

4.3.1.12 *Performance Requirements*

The DCS is designed with extensive redundancy to assure high system availability. Each controller is provided with redundant internal power supplies and redundant functional processors. The system includes redundant data highway communication modules and redundant highways. The I/O cards are not redundant, but the communications links from the I/O cards to the redundant processors are.

The system is internally protected against system errors and hardware damage caused by connecting and disconnecting devices or removing and inserting cards while the system is powered.

The DCS is designed and configured for high availability and reliability. All modules and highway communication devices are designed with independent hardware and software. This functionally maintains integrity by extensive self-checking and failure detection, fault containment, and inherent safety designed into the system.

The redundant processing unit can automatically assume all control functions of the primary processing unit. All loop modes, setpoints, and control outputs remain the same during the transfer, and no upsets to the process, operator displays, calculations, or other functions occur due to the transfer. After the transfer, the failed processor can be replaced or repaired without disturbing the operating processor. Failure of a processor is alarmed by the control system to the operator's workstation describing the hardware fault.

4.3.2 Initial Commissioning Plan

The DCS did not have a separate commissioning plan like the other systems comprising the Kemper Plant. It was commissioned in phases as part of the 103 different test plans used to commission the other systems. Southern Company Startup was responsible for commissioning the DCS. The required tasks included a series of control logic

tests, instrument loop tests, and activities to confirm the plant control system was ready for startup and operations at rated conditions (see Control Logic and Instrument Loop Tests in section 4.3.2.4.). Successful commissioning of the DCS was one of the most important factors in establishing reliable operation of the entire plant.

The DCS commissioning was broken down into several different phases for this project. See table 4.3-1 for milestones.

Table 4.3-1 – DCS commissioning phases and associated I/O counts

Milestone	DCS I/O Count	I/O Checkout Completion Date	Number of Turnover Packages
First fire in combustion turbine A	3265	12/03/14	81
First fire in combustion turbine B	1923	12/13/14	29
Gasifier A first warmup	3722	6/23/15	90
Gasifier B first warmup	3361	6/29/15	71
Lignite prep ready for first coal feed	2610	4/21/15	52
Clean, reliable syngas available from gasifier A	8326	9/15/15	257
Clean, reliable syngas available from gasifier B	4320	6/15/15	110
Sync to grid	645	11/26/14	23
Miscellaneous I/O necessary for COD	1272	4/17/15	30
Modifications after syngas to turbine	929	4/21/15	26

4.3.2.1 *Commissioning Goals and Objectives*

DCS commissioning is the process of ensuring control systems perform according to design intent and process operational requirements. Before commissioning, all equipment and systems must be installed according to manufacturer's recommendations and the best practices and standards of the industry.

The commissioning task includes documenting the performance of the plant control systems to the design intent. The primary goals of the commissioning process were:

- Facilitate the final acceptance of the project.
- Facilitate the transfer of the project to Mississippi Power's O&M staff.
- Ensure the systems meet the process requirements.

DCS commissioning is intended to achieve these specific objectives:

- Document that equipment can be controlled per manufacturer's recommendations.
- Document that equipment and systems receive complete operational checkout.
- Document system performance with thorough functional performance testing and monitoring.
- Verify the completeness of operations procedures and maintenance materials.
- Ensure Mississippi Power personnel are adequately trained on the operation of all process equipment using the DCS and other control systems.

4.3.2.2 *DCS Commissioning Team*

The DCS commissioning team worked closely for a successful and seamless startup of the plant. Groups serving on the team included:

- Southern Company Startup personnel (startup engineers and process SMEs).
- Construction contractors and vendor commissioning teams (equipment installation contractors, instrumentation and controls specialists, and vendor equipment experts).
- Mississippi Power process engineering, operations, and maintenance (O&M) staffs.

The responsible engineer from Southern Company Startup was the manager of the team assigned to each test plan executed as part of the plant commissioning activity.

The construction group and vendors were responsible for all installation activities and many initial commissioning tasks before completion of the turnover packages (TOP) associated with each test plan. The final stages of commissioning activities and startup were performed by the process engineering, operations, and startup teams, with support from contractor staff and vendor technical personnel. The scope of vendor support varied from system to system. It was important to thoroughly identify what each commissioning subteam would deliver, so all parties were fully aware of their scope and boundaries of responsibility.

The presence of the O&M staff helped smooth the handover of the systems being commissioned and helped ensure all lessons learned during the commissioning process were retained. It allowed the O&M staff to become more aware of the performance details of the equipment packages and control systems.

4.3.2.3 *General Testing Guidelines*

- Prefunctional inspections and startup procedures

A prefunctional inspection was completed for all commissioned equipment to confirm the as-built status of the equipment or systems. The inspection ensured the systems were complete and operational, and it documented the installation of components and commissioning of the systems.

- Functional tests and verification procedures

Functional performance testing verified the intended operation of individual components and system interactions under various conditions and modes of operation. The systems were run through all the sequences of operation, and the response of components was verified. Testing started with I/O checkout and graphics verification for all systems, included verifying interlocks and connections between systems.

The test plans were prepared by the responsible engineers using manufacturer's data, drawings, and specifications to include the required installation, checkout, and startup procedures. They included the complete sequence of operations and all documentation, such as updated I/O lists and control loop setpoints. The vendors, contractors, and design team were usually involved in the commissioning activities. Before the plan was executed, the responsible startup engineer provided a copy to all team members to review the tests for feasibility, safety, and equipment protection.

- Execution of test plans and verification of procedures

The responsible startup engineers typically scheduled functional tests through Operations and included construction personnel and subcontractors. Under the supervision of the startup engineer, the installing subcontractor performed any additional hardware manipulations required for testing. The DCS and PLC configuration engineers performed any software manipulations needed during commissioning, including forcing I/O signals to various states as appropriate. The Mississippi Power and Southern Company process engineers witnessed the execution of the test plan and monitored performance of associated equipment. Mississippi Power maintenance staff were usually present to assist in system observation and provide support, where possible.

Any deficiencies found during execution of the test plan were documented on a punch list. This list provided details of adjustments or changes required to correct system operation and identified the responsible party. The startup engineer scheduled any required retesting through plant operations. Decisions regarding deficiencies and corrections were made at as low a level as possible, but those regarding cost, schedule, and safety were escalated to project management.

- Management of change (MOC)

Management of change (MOC) was a challenge in the DCS commissioning process. Due to the first-of-a-kind (FOAK) nature of the plant and the number of changes made, a systematic procedure was required. If not managed properly through an MOC process, changes could present safety and reliability issues with equipment, control systems, and the rest of the plant.

- Control logic and instrument loop tests

Two important steps related to DCS commissioning were confirmation of the control logic operation and performance of instrument loop tests. The startup group was responsible for completing these tasks, but it was important for the entire commissioning team to be familiar with the logic and loops to minimize issues or malfunctions during commissioning.

The commissioning team needed to be familiar with all individual equipment control subsystems that interfaced with the DCS. Commissioning task activities included tuning of control loops, checking control parameters, checking alarms, and verifying trip settings.

For instrument loop tests, there were four tasks for each I/O point:

- Wiring verification.
- Instrument configuration (with Emerson's asset management system, if applicable).
- Functional testing of device.
- Final verification of instrument operation using the DCS screen.

The entire loop from the transmitter to the DCS screen had to be tested, so the range of the process variable could be validated as accurate on the process control graphics and faceplates. This test was normally done with two people, one in the field and the other at the DCS console. For inputs, the field technician would simulate an analog value at the transmitter and the console technician would check the corresponding value at the DCS. For outputs, the console technician would initiate a change at the workstation, and the field technician would observe the response at the device.

4.3.2.4 *Control Loop Tuning*

One of the most important commissioning tasks was tuning the proportional-integral-derivative (PID) control loops. The level of effort ranged from selecting fixed values for PID controller gain parameters, to modifying the function of the PID controller block to use adaptive gain techniques. (In the latter case, the gain values were set as functions of process parameters, resulting in numbers that changed with process conditions.) There were more than 1,000 control loops that required tuning. The task was complicated by fact that many loops could not be tuned until the actual process fluid was available to accurately reflect the correct operating conditions.

4.3.3 Operator Training Simulator (OTS) Impact on DCS Commissioning

The operator training simulator (OTS) included a computer network with an exact copy of the plant DCS configuration and was connected to a high-fidelity simulation of the Kemper process. The model received control commands from the DCS and returned simulated process results back as instrument inputs in the DCS, allowing engineers to monitor the reaction of the control system to the plant simulation. The OTS not only provided an environment for training, but also was useful for checking the DCS configuration.

Much of the logical commissioning of the DCS was performed using the OTS, which helped resolve unknowns in the process operations associated with the FOAK nature of the plant. The size, complexity, and FOAK nature of the plant systems made it apparent that the original DCS control configuration provided for the OTS was inadequate for operating the integrated plant. Numerous additions and corrections were required during OTS commissioning. This development was not unexpected; a complex IGCC plant would naturally require more DCS configuration than a typical combined-cycle power plant.

OTS commissioning helped resolve many DCS errors, including missing and incorrect logic, interface issues with other plant control systems, instrument range errors, and graphics problems. While resolution of these errors lengthened the OTS development schedule, the OTS found errors early, and many were corrected before full plant commissioning began.

- Operator workstation graphics

Like the DCS configuration, the OTS featured copies of all the graphics included on the DCS operator workstations (more than 8,900 individual graphics files). Operators and process engineers could review the new designs as they went through the OTS checkout, resulting in more functional operator displays connected to the correct points in the DCS. Performing this task on the OTS minimized the effect of graphics problems during full plant commissioning.

- Operating procedures

To adequately test the DCS and ensure it provided proper plant control, it was necessary to operate the plant from startup through normal operations to shutdown. Working with the OTS allowed engineers to create more detailed procedures and provided a way to evaluate them prior to testing them on the DCS during full plant commissioning.

- Logic and configuration evaluation

The OTS proved to be most valuable in evaluating and improving the FOAK control logic developed for Kemper. Improvements included logic corrections for operating sequences; dryer bed level controls; and gasifier coal, air, and pressure controls. These controls are straightforward in principle but require a considerable amount of time to develop the DCS configuration. Testing the configuration logic was vital in evaluating plant controls during startup and shutdown, times when traditional online logic testing is difficult due to schedule pressure and unexpected problems.

Using the OTS before actual plant commissioning allowed many logic corrections and improvements to be made. Some of the problems found and resolved with the OTS prior to full plant commissioning are:

- Tested the combustion turbine controls when operating on syngas. Multiple logic issues were found and resolved. As a result, the initial transitions to syngas on site went more smoothly.
- Discovered issues in the control logic for extraction air and the syngas-to-natural gas transition. These were corrected prior to commissioning.
- Discovered the Ovation-specific implementation of controller tracking did not work well for the cascaded controllers used to control the gasifier pressure. The resulting operational problems would have caused undesirable gasifier pressure changes. Discovering this issue during OTS commissioning allowed DCS configuration engineers to develop alternate control strategies before online testing at the site.
- Improved PDAC feed control logic and operating sequences, which allowed the feeders to start more uniformly and transition correctly as they were cycled on and off. This logic was more complex than expected and would have been impossible to evaluate in advance of plant commissioning without the use of the OTS.
- Many interlock settings in the DCS and SIS were found to be too restrictive, particularly after considering some of the process equipment and instrumentation limitations. This discovery allowed alternatives to be developed before plant commissioning.

- Interface evaluation

With such a large DCS and SIS, proper operations of the various control interfaces to other systems were critical to the success of the project. The OTS provided a platform to check the data requirements of these interfaces and helped find deficiencies before they occurred during DCS commissioning. There was a concerted effort to find and correct errors and make modifications, particularly in the data requirements between the DCS and SIS, and the DCS and local PLCs. Changes were made in the interfaces between the DCS and the combustion turbine controllers, particularly during syngas operations, when the turbine controls interact with gasifier pressure and extraction air controls in the DCS.

- Operator training

During the later phases of the OTS checkout, plant operators participated in the testing. Their contributions proved invaluable in evaluating the procedures and graphics. While operator testing of the OTS lengthened the OTS commissioning schedule, including them in the review dramatically improved the operating procedures and consistency of control logic. This improvement reduced the level of on-the-job training for operators during the actual plant commissioning effort.

4.3.4 Significant Events

4.3.4.1 *DCS Procurement*

The purchase order was issued to Emerson on Feb. 4, 2011, for the Ovation-type DCS installed at the Kemper County IGCC plant. Significant changes and events associated with the procurement process include:

- In February 2012, the DCS I/O configuration was expanded to support general changes in design details. This expansion required additional thermocouple inputs modules, digital relay output modules, analog output modules and digital input modules.
- In April 2012, additional DCS hardware was purchased as more gasifier and water lab design details became available. This change included cabinets, thermocouple inputs modules, digital relay output modules, analog output modules, and digital input modules.
- In August 2012, additional DCS hardware was purchased as more design details were made available for the lignite delivery facility. This hardware included cabinets, controllers, power supplies, digital relay output modules, analog output modules, digital input modules, interface module, and licensing. Additional DCS licenses were purchased for hardware interface modules that connected the Ovation system to other plant controllers, and more software licenses were purchased to increase the number of seats available for development of the DCS configuration.
- In February 2013, new computer servers were added for interfaces between DCS and data collection equipment outside the control network firewall. The new servers provided all data to the external data archiving systems. Interface licenses were added for the steam turbine interfaces.
- In the summer of 2013, as work continued on commissioning at the OTS, it became apparent that the number of points used in the DCS were going to exceed operating system limits before the tasks were complete. As a result, the control network was divided into two separate but interconnected networks. This new network required additional equipment from Emerson and configuration changes that were completed over the next year. See section 4.3.4.2 for details.
- In November 2013, two dedicated redundant controllers were added for the SIS to DCS interfaces.
- In February 2014, four new routers were added to the DCS to support interface requirements resulting from the 2013 DCS network realignment. Five more DCS workstations were added to support DCS I/O and logic testing in the gasifier island areas.
- In August 2014, more I/O hardware was added to support the DCS network split started in 2013. I/O hardware was added to support the instrumentation for coal dryer fan bearing temperature measurements and HRSG reheater metal temperature measurements (needed during gasifier steam blows).

- In September 2014, a second server was purchased to allow all points from both DCS networks to be used in the EDS application.
- The original purchase order from Emerson for the Ovation DCS hardware and software was closed in December 2015.

4.3.4.2 *DCS Network Realignment*

The DCS was initially designed with two networks to keep the water plant and lignite delivery facility separate from the systems operated by Mississippi Power. During OTS commissioning (summer 2013), issues began to develop with limits to the number of data blocks allowed to communicate across the DCS network. These issues were related to the versions of Ovation software in use and the modifications being made to the DCS configuration during OTS commissioning. The result was network capacity utilization factors over 89% for NET1, well above the vendor's recommended levels. Engineers decided to move all the DCS configuration and controllers for the combined cycle and gas cleanup systems from NET1 to NET0, which allowed more space for expansion and modifications of the DCS configuration supporting the processes for Train A and B gasifiers.

4.3.4.3 *DCS Alarm Management Strategy*

The Kemper project hazard reviews clearly showed there would be a large number of process alarms to consider. Kemper engineers undertook a comprehensive alarm rationalization effort to determine which alarms should be used and at what time they should be active. The goals were to minimize the number of nuisance-type alarms from the DCS and to ensure the operator had sufficient information available to accurately perform any necessary mitigation tasks.

Before commissioning of each process, a process engineer was assigned as the subject matter expert to be responsible for resolving what alarms should be displayed on the operator's workstation and when they were to be active.

When a significant turnover of the plant is completed, plant Operations will set up its own alarm analysis team and processes in keeping with Southern Company Generation alarm management methodology. The PSS software package would be used in the dynamic alarm rationalization process going forward for the plant.

4.3.5 Final Summary

Commissioning all the control systems for the Kemper project was a large-scale process, with these contributing factors:

- First of a kind nature of the IGCC plant.
- Size of the DCS configuration (more than 9,000 Ovation signal diagrams and 280,000 DCS tags).
- The number of DCS screens created to allow operator control of the processes (more than 8,900 graphic screens and popups).
- Large number of control subsystems that interfaced with the DCS.
- Large number of I/O points (more 28,000 points to be loop checked).

These factors made it necessary to break the DCS commissioning plan into smaller tasks that were grouped with various equipment test plans. Much of the work had to be performed offsite using the OTS before commissioning the actual plant. Having smaller tasks allowed parallel activities to be undertaken and completed before the actual startup of the Kemper plant. Otherwise, the task of commissioning the DCS would have been unwieldy and required an unacceptably long test period before actual plant commissioning.

4.4 Safety Instrumented System

4.4.1 System Overview

The safety instrumented system (SIS) is an independent control system that provides an additional layer of protection for process systems and equipment when needed. The design approach for safety is to first design out any potentially

dangerous situation. If that is not possible, then the design of a passive device or system is investigated. The next step is to have the plant control system take mitigating actions. If this is not possible, or the severity of the threat is great enough, the SIS is designed to mitigate the hazard. The SIS is designed as a fail-safe system with extremely high reliability.

In the SIS implementation of the fail-safe system, each individual circuit is designed so power must be present for the circuit to operate as commanded by the plant control system. If the SIS detects an unsafe operation, it will remove power from the circuit, and the devices controlled by the circuit will go to the unpowered position selected to ensure the circuit, system, or plant is in the safe position until power is returned. For example, if the operator attempts to open a fail closed valve monitored by the SIS using the plant DCS, the SIS will evaluate all associated programmed SIS logic and allow the operator to open the valve only if all safety and environmental concerns are satisfied. If the SIS determines it is not safe to open the valve, it will not allow power in the circuit, which blocks the opening action of the valve. Monitoring points shown on the operator screens will inform the operator if the SIS permissives have been met. The DCS screens have controls to allow the operator to perform functions from the plant DCS for those devices monitored by the SIS.

The SIS is composed of logic processors, power supplies, communications cards, and input and output (I/O) cards. The processors and communications cards are triple redundant: if any one device fails, there are two additional devices that can take over operation. For example, there are three logic processors (controllers) in a drop. One controller is actively monitoring the process and will take action if needed. Two additional controllers, with identical programs loaded, run in parallel, monitoring the process and processing the logic. If the first controller fails, the second controller will take over control of the process without any interruption to the process. In the extremely rare event that both the first and second controller fail, the third controller will take over process control and ensure safe operation of the plant. This arrangement prevents unsafe operation in the event of failure of a single component of the safety system.

The Kemper County IGCC is a large and complex facility. Equipment integration makes communication between different areas critical. Because of Kemper's size, the SIS has four separate process areas: gasifier A (Gas_1), gasifier B (Gas_2), main electrical (Main_Elec), and SELEXOL. The controls are divided among these four controllers based on the speed at which the controllers can process the information received and the physical location of the connected instruments. Each of the four process areas has a main process cabinet, which contains the three controllers for that area and the communications cards for the local cabinet and local I/O cards. The cabinets hold redundant I/O communication modules for the associated I/O cards in remote cabinets. All communications between remote cabinets and the main cabinet, and between processors, is over triple redundant fiber-optic cable routed along different paths. This redundancy ensures a single failure such as a cable tray fire will not be able to disrupt all communications between devices. Each processor rack and each I/O location has redundant power supplies. The logic processing and control is triple redundant to the hardwired I/O point. Each I/O point is independent and does not have redundancy built in. A failure at this point should affect only the individual I/O point, and each circuit associated with the I/O point is designed to be fail-safe. No redundancy is required from the I/O point to the associated field device.

To increase reliability for the individual I/O points that could cause shutdown of a significant portion of the plant, the circuit and logic were assessed, and typically three transmitters monitoring the same process parameter were installed. The transmitters were powered by different power supplies and landed on separate I/O cards. The three signals were then brought into the SIS, where the system did a two out of three (2oo3) vote to determine if a shutdown was required. In the event one of the inputs failed, degradation voting was put in place so the processor would make the appropriate decision if one, two, or all three inputs failed.

Since the SIS is a safety system, a great deal of documentation is required. A safety requirement specification (SRS), a design verification report (DVR), and other documents were produced to support and document the design of the system. Other required documents included the safety integrity level (SIL) selection, the safety instrumented function (SIF) calculations, and the cause and effects diagrams. The development of these documents was a joint effort by Southern Company Services (SCS), KBR, and MPC plant staff. KBR began the original development of the documents. As their participation on the project was scaled back, SCS took over responsibility for the documents and worked with Startup and MPC to complete them.

The design of the plant SIS allowed every identified safety concern that required a SIF to be reduced to an acceptable risk level. The SIS is the last line of defense by the control system to prevent an unsafe operation of plant equipment. The SIS stops the operation of equipment and systems when the process parameters exceed the identified hazardous operation limits.

Numerous personnel changes on the SIS design team during the project, including the person with primary responsibility for procurement and design, hampered progress during the project, but these challenges were overcome.

The SIS faced several significant events that affected the procurement cycle, causing schedule delays. The team still was able to deliver a safety system that met all requirements by the date it was needed by the plant.

4.4.2 Initial Commissioning Plan

The initial commissioning plan for the Kemper SIS was for KBR to complete all design and documentation required for the system. They would then provide this documentation to the selected SIS vendor for system design and programming. Following programming by the vendor, KBR would checkout the system at the vendor's facility and, when it was completed to their satisfaction, the system would be shipped to the SCS I&C lab for checkout with the plant DCS. When this process was complete, the SIS would be shipped to the plant site where it would be installed by Construction.

After Construction had completed installation of the cabinets, Startup would, with the vendor's assistance, power up the cabinets, verify communications among the local SIS cabinets, the remote SIS cabinets, and between the four SIS processor cabinets, then load the programs in each of the four controllers. Startup would verify communications between the SIS and the DCS and check the SIS field terminations loop by loop until each loop had been checked. As they progressed this loop by loop check, they would document their checks and verify the instrument calibrations. This action was to be followed by a check of each interlock during execution of the test packages for each process system. On completion of the test packages, each safety function would have been tested and verified to work properly.

4.4.3 Significant Events

4.4.3.1 *HAZOPS*

One of the main drivers for interlocks included in the SIS is concerns discussed during process hazard analysis (PHA) review meetings, including hazard and operability studies (HAZOP). Following the PHA, a layer of protection analysis (LOPA) or safety integrity level (SIL) meeting is held to determine what safeguards for each safety concern are in place and to determine if additional safety features are warranted. This process can lead to the addition of an interlock in the SIS.

Multiple PHAs were held to ensure that each system for the plant could be operated safely. Before the formal PHA, there was a safety review of the process flow diagrams (PFD) from Aug. 28, 2007 through Aug. 30, 2007. This meeting was intended to ensure the inherent dangers in the processes would be addressed during the design phase.

The PHAs began with a HAZOP review of the KBR/SCS scope IPL release of the P&IDs for the gasifier island in Houston, Texas on Nov 2, 2009, and was completed in Birmingham, Ala. on Dec. 11, 2009. Process engineers, control system engineers, corporate specialists, and safety specialists took part in these meetings. During the meetings, each system in the plant was reviewed, P&ID by P&ID, to make sure that each system could be operated safety and that connections between systems did not raise any additional safety concerns. Following the HAZOP, the KBR safety staff developed a spreadsheet listing each concern and what safeguards for each was in place. This spreadsheet listed items to be addressed by the SIS team, such as providing three transmitters for some critical signals so that the SIS could perform a 2-out-of-3 vote before taking action. Each action item was addressed, and a response for each was documented.

The system vendor provided the design for several systems. Each of these systems, and the system interface to the rest of the gasifier island, was covered by separate HAZOPs. The first was a PHA for the WSA system from Jan. 25,

2010 through Jan. 29, 2010. It was followed by a PHA for the AGR system from March 1, 2010 through March 4, 2010. Each of these PHAs resulted in action items that eventually shaped the design of the SIS.

By May 2011, the vendors for several of the material handling systems had been determined and had provided P&IDs for their systems. These P&IDs were reviewed in a PHA at KBR in Houston from May 23, 2011 through May 27, 2011.

Following the completion of these PHAs, a SIL review meeting was held from June 13, 2011 through June 24, 2011 to determine the risk associated with each PHA finding so that the SIS design could progress. Only findings that required additional protection and could adequately be addressed by a highly redundant and secure independent control system were added to the SIS.

During the spring, summer, and fall of 2011, the equipment for much of the plant was purchased and the design for many systems were modified, leading to updates of the P&IDs and releases of new vendor P&IDs. When the existing KBR/SCS P&IDs had been marked for these changes, another safety review was held to evaluate safety aspects of the updates. This HAZOP/SIL review started on Nov. 8, 2011 and continued until Dec. 9, 2011. This review was followed the next week by the completion of the HAZOP for the nitrogen system on Dec. 12 and 13, 2011, which had begun on Nov. 29, 2011 and been put on hold for the KBR HAZOP/SIL review. New action items were generated that had to be addressed by the design team. A PHA action item resolution meeting was held on Jan. 19, 2012, which resulted in additional changes to the SIS.

In addition to the markups that resulted from the evolving design, new and existing vendors submitted new P&IDs for their systems. To ensure the effect of these systems on the safe operation of the plant had been considered, another vendor P&ID HAZOP was held from March 12, 2012 through March 14, 2012, resulting in additional action items and more modifications to the SIS.

The action items generated from the PHAs that affected the SIS varied from simple changes, such as adding an alarm, to changing the design of the system. For complex changes, the SIS team held specific meetings with the responsible process engineer to determine how the action item could be resolved. For example, a recycle gas compressor PHA resolution meeting was held on Dec. 5, 2012 to review issues including that the original design did not consider operating at multiple pressures such as during startup, shutdown, and low load operation.

Even simple changes to the SIS, such as adding an alarm, required updating the cause-and-effect diagrams (C&E), the SIS database, and the affected P&ID(s). Complex changes, such as the ones for the recycle gas compressor, affected the design for the whole system and required a great deal of rework for both the SIS and DCS.

In spring 2013, Startup hired a consultant to review the previous HAZOPS. The consultant presented findings in a report on March 26, 2013. The consultant determined there were some gaps in the documentation provided for these HAZOPS, resulting in another round of HAZOPS starting Aug. 12, 2013 that was completed Sept. 13, 2013. On Oct. 29 and Oct. 30, 2013, the SIS team met with plant representatives to finalize their request for modifications to the SIS because of the preceding HAZOPS. These HAZOPS required additional modification to the SIS by the team.

Before operation, plant management decided to do one additional round of HAZOPS. This round began on Jan. 5, 2015 and continued until Apr. 2, 2015. Meetings were then held with the design team and plant personnel to determine how each action item would be resolved, which led to additional changes to the SIS.

Following this HAZOP, all design changes were covered by the management of change (MOC) process. Each design change request was assigned to an MOC. This MOC was evaluated by plant staff to determine if the change was required. If the MOC was approved for implementation, it was reviewed by the plant safety staff. If they determined there was a potential safety or environmental concern, a HAZOP was held when the design was near completion. There were numerous MOCs approved for implementation, and the HAZOP for these led to a large number of changes to the SIS.

4.4.3.2 *Procurement and Design*

A specification for the SIS was prepared by KBR, reviewed and modified by SCS, then issued to three companies on Oct. 29, 2010 for competitive bidding. The vendors were given the month of November to respond to the inquiry.

During December, SCS Gasification Technology (GT or Gas Tech) I&C and KBR worked with Southern Company Supply Chain Management (SCM) to clarify questions about the proposals from the vendors. After the bids were received and the proposal questions answered, they were evaluated against the specification and a low bidder was selected. The final bid clarification meetings were held with the winning vendor on Jan. 25 and Jan. 26, 2011 to verify all intents of the specification would be met. The terms and conditions were reviewed by SCM and the vendor during this meeting and most items were agreed to. Open questions were answered after the meeting by the vendor and agreed on.

A kickoff meeting was held with the SIS vendor on Apr. 12, 2011. The vendor's proposal was reviewed against the specification and most questions were clarified in the meeting. The vendor and SCS provided answers for remaining questions by email within a few days following the meeting. After agreement on details of the specification and proposal, a conformed specification and proposal was prepared and a purchase order for the SIS was issued on May 31, 2011.

During the kickoff meeting, it was established that there would be biweekly conference calls between SCS and the vendor to track progress and cover any changes or items critical to the design of the system. It was also determined that the vendor would maintain an action item list, with due dates for each, to make sure the design, manufacturing, and programming of the system was completed to meet the required delivery date.

Over the next several months, SCS and KBR worked to finalize the hardwired I/O list, soft I/O list, instrument range list, SIS control narrative, P&IDs, cause and effect diagrams, and alarm and trip setpoint summary documents. All these documents were provided to the vendor to be used for system assembly and programming.

Because Construction required an earlier than normal control system equipment delivery date for their floor-by-floor completion plan, the factory acceptance test (FAT) was divided into three parts. The first was a hardware only checkout, the second was a software checkout, and the third was a checkout at the plant site.

The vendor completed assembly of the SIS, and a team from SCS and KBR traveled to a vendor facility for the hardware checkout of the system. The SIS hardware checkout occurred from Mar. 19, 2012 through Mar. 23, 2012. Following the hardware checkout and resolution of checkout punch list items, the SIS cabinets were shipped to the plant on April 30, 2012 and arrived on site between May 9, 2012 and May 23, 2012, and Construction placed the cabinets in the structure and begin wiring the I/O points.

A commissioning system for the SIS was included with the order. The commissioning enclosure was shipped on June 15, 2012 and arrived on site on June 22, 2012. This equipment was for plant personnel to use for training and logic development when changes were required.

As the plant design evolved, the SIS documents such as the C&Es and the I/O lists were updated to reflect the current design. The first set of C&Es for the AGR and WSA was provided to the vendor on Aug. 22, 2011. The vendor began programming of the system with this package. Additional C&E packages for other systems were completed and sent to the vendor for programming. By Feb. 5, 2013, the complete set of C&Es had been provided to the vendor for programming.

The vendor completed programming of the system and loaded the software on test systems. From Apr. 22, 2013 through May 24, 2013, SCS and MPC personnel conducted a checkout of the logic on these systems. Checkout of these systems consisted of four different activities for each of the four nodes. For each node, the transmitter and hardwired I/O programming was verified, then the cause and effect logic was verified, followed by the open/close valve (XV) logic verification, and finally the peer to peer (P2P) communications was verified. As the checkout progressed, a punch list was maintained for any items that could not be immediately corrected for the vendor to complete after the checkout teams had left the facility.

The program files from the SIS were a critical input to the operator training simulator (OTS). As each node was completed, the program file was provided to the OTS team. Node 4 checkout was completed first and was provided to the OTS team on May 23, 2013. The files for the three other nodes were provided at the completion of checkout on May 24, 2013.

The Startup group at the plant site began installed cabinet checkout of the 23 SIS cabinets on May 28, 2013 in preparation to power up the cabinets. After checkout of the cabinets, the program files were downloaded to the controllers. This task was completed by Aug. 26, 2013. By Nov. 4, 2013, Startup had completed the checkout of all SIS field I/O and was prepared to support turnover package tasks.

In November 2013, the Gas Tech SIS group completed an update of the SIS programs and provided them to the plant to be uploaded. The task of uploading the programs was completed by the Startup group to support completion of turnover packages. From this point forward, all SIS program changes were completed by either the Startup group or MPC operations personnel with support from the Gas Tech SIS group.

4.4.3.3 *Preparation of the Requisition*

One of the first significant events specifically for the SIS was the preparation of the requisition. KBR was asked to take the lead on preparing the specification for the SIS, since SCS had never designed or purchased an SIS. KBR prepared the original specification. SCS reviewed and modified the specification where appropriate to meet standard plant and SCS engineering, construction, and operation practices. KBR then updated and placed the specification in a requisition package. SCS reviewed the documents in the package, made modifications where needed, added the SCS-specific requirements, and sent the package out for bids.

4.4.3.4 *Vendor Kickoff Meeting*

SCS and KBR held a kickoff meeting with the selected vendor to review the details of the job requirements and to set contacts and protocols for communications and issues resolution. A single point of contact was determined for both SCS and the vendor, and contact information provided to the group. Each person on the team was introduced and their roles explained. The commercial portion of the contract was discussed to make sure there were no issues with the terms and conditions, to agree on the payment schedule, and to establish a change order procedure. Project management issues were discussed, such as the location and frequency of project meetings, progress reports, and document transfer protocol. The preliminary schedule was reviewed to ensure the vendor could deliver according to critical project milestones. The detailed design of the system was discussed, including physical details, functional details, and testing and acceptance criteria.

4.4.3.5 *Received First Set of Cause and Effects Diagrams*

In May 2011 SCS received the first set of cause and effects diagrams (C&E) from KBR. There were only a few drawings, but the transmittal allowed SCS to work with KBR on the drawing format and to communicate details of the system design. This was the first of several transmittals from KBR before SCS ultimately took responsibility for the C&Es.

4.4.3.6 *SIS Programming Specification*

In May 2011, the SIS vendor provided an SIS programming specification, which SCS and KBR reviewed and provided comments to the vendor for incorporation. The program structure section of the specification covered how the inputs would be processed, how alarms and trips would be processed, how control logic programming would be done, how first out alarms would be handled, and how system alarms would be done. The naming convention section described how tag names used in the program were assigned. The logic conventions section described how each type of logic would be programmed.

4.4.3.7 *SIS Logic Narrative*

In July 2011, KBR issued the SIS logic narrative. This document described what C&Es would be used. It included:

- Legend for the C&Es.
- How SIS logic would be reset for all the different types of interlocks.
- How triplicated analog signals would be handled by the SIS and displayed in the DCS.
- How digital inputs would be used and monitored.

- Scenarios for how valve operation would be monitored and reported.
- How flow measurements would be pressure and temperature compensated.
- What types of overrides would be programmed in the SIS.
- What information would be displayed on the DCS screens.

The issued for design (IFD) version of the document was transmitted in March 2012.

4.4.3.8 *SIS Programming Starts*

In August 2011, the SIS vendor was issued a preliminary copy of the logic narrative and a partial set of C&Es that included the AGR and WSA areas of the plant. The vendor used this information to begin programming the system. Providing the C&Es in small batches allowed SCS and KBR to continue development of the C&Es while the SIS vendor finalized their work process for programming the logic.

4.4.3.9 *Hardware Checkout*

In March 2012, the SIS vendor completed assembly of the cabinets. SCS and KBR sent representatives to their factory to perform a hardware checkout of the equipment. The equipment was checked to verify it had been designed and assembled to meet the specification. A punch list listed any discrepancies. The vendor was able to correct most of these before the system was shipped to the plant site and committed to providing a resolution for the remainder after the cabinets had been installed.

4.4.3.10 *Safety Requirement Specification*

During March 2012, KBR issued the safety requirement specification delineating the design requirement for the SIS. It included the codes and standards used in the design, a list of documents used to design the system, and project-specific information on how the SIS was designed.

4.4.3.11 *Cabinets Shipped to Site*

In May 2012, the SIS cabinets were received on site. This arrangement, where the cabinets were shipped before programming was complete, allowed Construction to begin placing the cabinets in their designated areas earlier than would have been possible otherwise.

4.4.3.12 *Change Order #1 Issued*

Process design changes affected the SIS I/O list, the interlock index, and the C&Es while hardware checkout and shipping were occurring. The changes were significant and required SCS to issue a change order to the SIS vendor in June 2012. The change order included new hardware to meet the revised I/O requirements.

4.4.3.13 *SIS Startup Engineer Named*

Startup dedicated an engineer to the SIS full time, which allowed faster resolution of issues. The Startup SIS engineer began working with SCS to plan commissioning of the system.

4.4.3.14 *OTS Configuration*

The plant purchased an operator training simulator (OTS) for use in training their operators. The SIS has a significant impact on how the plant operates. The OTS configuration initially focused on the DCS. In January 2013, the SIS team began supplying information to the OTS team to be used in their configuration efforts.

4.4.3.15 *Software FAT*

A team from SCS and the plant arrived at the SIS vendor office to begin the software FAT on Apr. 22, 2013. The test was completed on May 24, 2013. At the conclusion of the test, all the SIS configuration files were supplied to the OTS team so they could complete their programming.

4.4.3.16 *SIS Graphics*

Some limited function SIS graphics were developed by the OTS team. Beginning in July 2013, the SIS team started working directly with the DCS graphics team to build all the SIS graphics that would be needed by the plant operators and engineers.

4.4.3.17 *First Node Put into Service*

In July 2013, the first SIS node (main electrical) was put into service at the plant.

4.4.3.18 *Field Checkout of SIS Loops*

In August 2013, the Startup team at the plant began checking the loops wired to the SIS. Because this is a safety system monitored by process safety management (PSM), each loop check had to be carefully performed and well documented. With 2,768 loops connected to the SIS at that time, this was a significant task that required several months to complete. Along with the loop checks, the calibration for each transmitter was checked to verify it was calibrated to the correct range with the proper measurement units.

4.4.3.19 *Change Order #2 Issued*

Process design changes continued as the SIS checkout was occurring. The changes necessitated updating the SIS hardware. A change order was issued to the vendor in August 2013 to add an additional SIS cabinet and add I/O modules in each of the SIS cabinets as needed to reflect the current design requirements.

4.4.3.20 *Last SIS Controller Put into Operation*

The design for the Kemper SIS contained four separate controllers. These were put into operation one-by-one so a thorough checkout could occur. In August 2013, the fourth and final SIS controller was placed on-line and in operation.

4.4.3.21 *SIFs Separated*

The design for the SIS included several equipment interlocks that were not environmental- or safety-related. These equipment interlocks did not require the same level of documentation as the safety instrumented functions (SIF). In September 2013, the SIS team reviewed all the interlocks and documented each that was a SIF.

4.4.3.22 *Biweekly Calls with Startup*

By October 2013, the Startup team and the plant were requiring a great deal of support from the SIS design team. A biweekly conference call between the groups was established to expedite issue resolution and to keep each team aware of current work that could affect the other teams.

4.4.3.23 *Updated Narrative and SRS*

Although KBR was no longer supporting SIS design changes, they had committed to providing one last update of both the SIS logic narrative and the safety requirement specification (SRS). Both documents were received from KBR in October 2013.

4.4.3.24 *DCS/SIS Communications*

This test was an integrated test with the DCS to verify communications between the DCS and SIS and rectify any problems before they became a critical path for startup. The communication between the two systems was

accomplished by the MODBUS communication protocol over ethernet. In November 2013, the two systems had been sufficiently commissioned so the communications could be tested. The connections, both wired and fiber optic, were tested and found to be acceptable. Following the connection tests, messages were successfully sent and received from both systems, verifying the MODBUS was working properly.

4.4.3.25 *Change Order #3 Issued*

Both the plant and Startup had a small staff to support the SIS. The magnitude of the changes required by the design changes and PHA updates exceeded the capability of the existing team. A third change order was issued in October 2013 to the vendor so that personnel familiar with the SIS equipment and programming could be supplied to the site to make the required changes. The change involved updating the application programming to reflect the most recent C&Es, updating the P2P communications and the associated databases, and testing all logic changes. These changes were initially made in the vendor's offices, and in November 2013, they were brought to the plant and uploaded into the active SIS controllers.

4.4.3.26 *SIS Program Control Transferred*

Following the completion of work on change order #3 at the end of November, control of the SIS programming was transferred to the Startup group at the plant site. This program control transfer was necessary to allow scheduling of logic changes around startup activities. This change allowed the Startup team to make logic changes on a one-by-one basis, so only one controller or cabinet was affected instead of the entire system having to be removed from service for a complete software upload. This process allowed checkout of the other equipment in the system to continue while changes were made to individual controllers.

4.4.3.27 *Site Acceptance Test*

In February 2014, the SIS had been commissioned to the point that a site acceptance test (SAT) could be performed. This test confirmed the SIS performed according to the specification, the vendor's commitments from the proposal were complete, all punch list items had been resolved, and all approved change order work had been accomplished satisfactorily. The successful completion of this test was the final requirement of the purchase order, allowing the vendor to receive final compensation for the system.

4.4.3.28 *Change Order #4 Issued*

The plant and Startup had a limited staff to maintain the SIS. Their primary duties were to maintain the equipment, assist with checkout of systems, and provide around-the-clock test package support. They also tracked and scheduled required program updates and informed the SIS design team of any issues discovered. They did not have sufficient personnel to make large quantities of program changes. By March 2014, a number of program changes had accumulated that had not been programmed. Change order #4 was issued to the vendor to provide personnel onsite to make the required programming changes. These I/O changes and C&E diagram changes resulted from design changes, development of startup procedures, development of operating procedures, development of shutdown procedures, training development, PHA reviews, SIL reviews, and error corrections. This scope was outside the original project scope and schedule when the purchase order was issued.

4.4.3.29 *SIS/DCS Screen Checkout*

The SIS does not have a dedicated operator interface. All operator actions for the SIS are accomplished by the operators using the DCS screens. This process allows the operators to use one set of DCS screens as their view into how the process is operating, minimizing distractions by avoiding switching between multiple systems, to monitor the overall health of the process. By May 2014, the SIS logic programming, DCS interface programming, and DCS screen programming had progressed to the point that the SIS/DCS screen interfaces could be checked. The SIS/DCS graphics that had been developed to date were checked and programming of additional graphics for the recently processed SIS programming changes began.

4.4.3.30 *Valve Actuation Time Reviews*

In June 2014, the GT SIS design team began working with the process engineers to determine the required valve actuation time for valves that were part of safety interlocks. It is important for a valve to take the appropriate action when a safety concern is detected, and to respond in a timeframe that will prevent the concern. The SIS team made a list of valves that were part of a SIF and asked the process engineers to provide the stroke time for the valve to prevent an event of concern from occurring. By this time in the project, the process engineers' time was almost completely taken up with startup activities. The SCS design group was enlisted to assist with completing the tables, which were sent to the process engineers for review and verification. The valve stroke times were compared with the vendor-supplied information, and when placed into operation, the valve stroke time was measured in the field to verify that they met the requirement. The information from the process engineers and the actual measured valve stoke times took several weeks to be completed. The field-measured valve stroke times and the process engineer-required valve stroke times are required for the SIL calculations that are part of the documentation package required for the SIS. These calculations are kept up to date and on file at the plant so they will be available for review. Meeting the required actuation time required the rework or replacement of some valves.

4.4.3.31 *SIS Checkout at the OTS*

By July 2014, the OTS had been completed to the point that the SIS team and the process engineers could begin checking the SIS interlocks at the OTS vendor's facility. This was a significant milestone, because previous checks had been either with an isolated piece of equipment or on a system that was not in operation. The OTS allowed the team to simulate operation of a system and check to see that the system could be operated in the bounds of the SIS interlocks. It allowed the team to run a process parameter past the interlock setpoint to verify the system took the appropriate action.

4.4.3.32 *SIS Update to the OTS*

Design changes affecting the SIS continued to be implemented. In December 2014, an updated copy of the SIS programs was provided to the OTS vendor, allowing the OTS checkout to proceed with the then-current SIS design.

4.4.3.33 *SIS Documentation Updated*

Design changes affecting the SIS had occurred after KBR released the SIS documentation. Neither the GT SIS team nor the plant had sufficient personnel to complete updates of these documents. The GT SIS team worked with Startup personnel to develop a work plan to update the documents, and Startup supplied the personnel for much of the work. In May 2015, the updated C&Es and the updated design verification report (DVR) were transmitted. The following month, the safety requirement specification (SRS) was completed and transmitted.

4.4.3.34 *Another SIS Update to the OTS*

The design changes that affected the SIS continued. In June 2015, an updated copy of the SIS programs was provided to the OTS vendor, allowing the final OTS checkout to proceed with the then current SIS design.

4.4.3.35 *Plant Adds Full-time SIS Staff*

In July 2015, the plant added a full-time engineer to their staff for the SIS. This addition allowed the team to begin planning for the transition from design and startup to operations. The plant engineer was integrated into the existing SIS teams so that he could become aware of all ongoing SIS activities.

4.4.3.36 *SIS Documentation Updated*

In November 2015, the process safety times (PSTs) were completed by Startup personnel and Plant personnel. Inputs to these calculations were the valve stroke information obtained earlier in the project and other design information. Following the completion of the PSTs, the DVR and SIS were updated and transmitted. By this time, the I/O count for the SIS had grown to almost 3,000 points.

4.4.3.37 *Formal SIS Force Log*

Until this time, plant and Startup personnel could force the SIS points as desired to allow checkout of the systems, because plant systems were not yet in operation. With plant commissioning progressing to the point that entire systems were operating, it was recognized that a formal process must be put in place to communicate which SIS forces were not operational. Because of the integrated nature of the plant, one team might need to force an SIS point so it would not trip their process during checkout, but at the same time, another team might be depending on the trip to shut down their system at the appropriate time or under the trip condition. In February 2016, a formal log of SIS forces was developed to require signoff by various groups at the plant and ensure the forces were effectively communicated.

4.4.3.38 *Formal SIS Programming Change Log by Plant*

For the SIS program changes to this point, only a small group of people directly involved in a specific process change needed to know about the changes. Now, with multiple integrated systems operating simultaneously, any change had to be communicated to the entire commissioning team. The GT SIS team had maintained a meticulous log of all changes up to this point, but development of a plant change log allowed the plant to take control of the SIS changes.

4.4.3.39 *SIS Documentation Updated Again*

In spring 2016, the DVR and SRS were again updated and the changes were transmitted in May. These updates covered all changes since the last revision of the documents.

4.4.4 Final Summary

As the installation of each SIS instrument was completed, the field I/O was checked back to the SIS. The continuity and signal level were checked. This action verified that the point was operable and correctly connected. The first true test of the SIS trips occurred during the completion of system test packages. The SIS team worked with the process engineers to determine which trips had to be bypassed to allow the test package to be completed. As the test package checkout progressed, the SIS trips for that system that had not been bypassed were tested to ensure trips occurred as planned. Because of the close integration of systems, many of the trips in the systems and between systems had to be bypassed during the test package checkout.

The design approach used for the SIS was a conservative design that included trips of entire systems when only a small portion of the system might be a cause for concern. Many of these system trips cascaded to plant trips, and in some cases led to unnecessary trips of the plant or of systems. As these were discovered, a team of system experts with the personnel required by a PHA was pulled together to review the trip and determine if it could be eliminated or changed without affecting such a large portion of the plant. Making these changes did not diminish the safety of the system or plant and allowed the plant reliability and operability to be improved.

Despite the challenges encountered during the procurement and initial setup of the system, the SIS provided safe plant operations within the required environmental limits. The SIS prevented equipment from starting that could have caused a safety or environmental concern, and tripped equipment when programmed limits were exceeded to prevent operating in an unsafe condition or causing an environmental concern. The system performed as intended and was functional in time to support commissioning and plant integration activities.

4.5 Continuous Emissions Monitoring Systems (CEMS)

4.5.1 System Overview

Continuous emissions monitoring systems (CEMS) monitor flue gas for NO_x, SO_x, oxygen, carbon monoxide, and carbon dioxide to provide information for combustion control in industrial plants. CEMS are a means to comply with monitoring requirements for air emission standards set by federal and state regulations. These requirements are based on the US EPA 1990 Clean Air Act and detailed in 40 CFR 60 and 40 CFR 75. Plants use CEMS units to continuously collect, record, and report emissions data required by these laws.

The emissions information in each report that relies on CEMS data must be certified as reasonably complete, accurate, and true. Understanding this CEMS generated data and using it for reporting and recordkeeping purposes is an important plant operational requirement.

Plant personnel rely on the accuracy of the facility's CEMS equipment for the data they will submit to demonstrate compliance with the plant permits maximum allowable emission rates. The validity of CEMS data is critical.

Completing the commissioning of the Kemper County CEMS units was a significant project milestone. The success of this task provided the plant with proven technology to meet all the requirements for CEMS under the Clean Air Act and subsequent rules and regulations.

Due to these federal permit requirements, a CEMS is an industrial necessity. As an additional benefit, data generated by CEMS units can help evaluate the condition of the plant and provide details on operational performance.

Each Kemper County CEMS includes the hardware, software, shelter, and other equipment to provide for the emission monitoring and reporting for one exhaust stack. A total of four CEMS shelters are required for this plant: one for each HRSG stack, one for the auxiliary boiler, and one for the WSA process stack. The shelter associated with the WSA process stack includes additional signal input racks and cards to allow monitoring of the gasifier startup stacks and the flare derrick. Process information associated with the HRSG stacks is shown in table 4.5-1, and process information associated with the WSA process stack is shown in table 4.5-2.

Table 4.5-1 –HRSG stack emissions and flows specification

HRSG stack Emissions (per stack)

		Syngas		Natural gas	
Constituent	Engr Units	minimum	maximum	minimum	maximum
NOx	ppmvd @ 15% O2	16.4	18.3	3.8	3.9
CO	ppmvd @ 15% O2	10.0	14.6	10.0	30.0
SO2	ppmvd @ 15% O2	0.8	0.9	0.0	0.0
SO3	ppmvd @ 15% O2	0.1	0.1	0.0	0.0
VOC	ppmvd @ 15% O2	2.4	3.6	2.4	6.0
Ammonia Slip	ppmvd @ 15% O2	0.0	0.0	5.0	5.0

HRSG stack Flows (per stack)

Case	HRSG Exhaust flow to stack (lb/hr)	HRSG Exhaust temp (degF)	CO2 Injection flow (lb/hr)	CO2 Injection temp (degF)	Stack flow (lb/hr)	Stack temp at CEMS probe (degF)
Natural Gas 20% load	2,522,286	258	0	n/a	2,522,286	258
Syngas S26095	3,283,713	260	0	n/a	3,283,713	260
Syngas S26095 with CO2	3,283,713	260	180,000	45	3,463,713	250
Syngas S2EC65	4,159,356	265	0	n/a	4,159,356	265
Syngas S2XX10	4,276,192	269	0	n/a	4,276,192	269
Syngas S2EC65 with CO2	4,159,356	265	467,925	45	4,627,281	246
Syngas S2XX10 with CO2	4,276,192	269	483,230	45	4,759,422	250

Table 4.5-1 notes:

1. Each HRSG stack internal diameter is approximately 24 ft.
2. The stack temperature at the CEMS probe can increase rapidly on a winter startup from a low ambient temperature to the temperature in the table.

Table 4.5-2 – WSA stack process specification

CASE/DESCRIPTION	Units	High Sulfur	Average	Low Sulfur
Flow Rate	lb/hr	397,570	262,198	127,297
Temperature	°F	176	176	176
Stack Inlet Pressure (Note 1)	inch WG	V	V	V
Design Temperature (min/max)	°F	10/250	10/250	10/250
Design Pressure (min/max)	psig	-1.5/3	-1.5/3	-1.5/3
COMPOSITION				
Argon	mole%	0.91	0.89	0.82
Carbon Dioxide	mole%	7.09	9.38	7.79
Hydrogen Cyanide	ppm	0	0	0
Hydrogen Sulfide	ppmv	0	0	0
Nitric Oxide	ppm	9	9	6
Nitrogen	mole%	75.61	73.46	68.73
Nitrogen Dioxide	ppm	11	12	11
Oxygen	mole%	8.56	8.13	9.94
Sulfur Dioxide	ppm	41	58	7
Sulfuric Acid	ppm	3	5	8
Water	mole%	7.82	8.14	12.71
Total		100.00	100.01	99.99
Molecular Weight	lb/lb mol	28.82	29.13	28.48
Acid Gas Dewpoint	°F	253	259	275

Table 4.5-2 notes:

1. The WSA stack inlet pressure is a function of the stack design.
2. The WSA stack CEMS is mounted in the horizontal duct leading to the WSA stack.
3. The internal diameter of the WSA stack inlet duct is approximately 6 ft.

The CEMS associated with the auxiliary boiler stack includes a dilution extractive system. It is designed so the stack mounted equipment will require minimum maintenance. The extraction technologies for the CEMS associated with the WSA process stack and the HRSG stacks are based on the requirements and process conditions for each area.

Each CEMS is programmed to generate all necessary reports and electronic files to meet regulatory requirements. The CEMS installations communicate with the plant information network. The status of each is monitored remotely from the plant control room and any of the CEMS shelters.

Each unit is a Spectrum Systems Model 300, which meets all requirements for CEMS under the Clean Air Act Amendments of 1990 and subsequent rules and regulations. Each phase of the sampling process is performed with reference and accountability towards maintaining source compliance while maximizing sensor reliability and equipment accuracy.

Each CEMS is made up of these subsystems:

- Sample acquisition.
- Sample analysis.
- Sample control.
- Data reporting.

See sections 4.5.1.1 through 4.5.1.4 for overviews of each subsystem.

4.5.1.1 *Sample acquisition subsystem*

The sample acquisition subsystem delivers clean and representative samples of the extracted flue gases to the analyzer subsystems. Dilution, extraction, transport, and sample integrity is accomplished with these components:

- Dilution probe.
- Sample transport system.
- Probe controller.
- Dilution air cleanup system.

- Dilution probe

The dilution probe removes a sample of flue gas at the point of acquisition. It is an M&C model SP2006-H/DIL/BR/BB/2x/FRP, manufactured by Spectrum Systems, Inc. Constructed of stainless steel, the probe is mounted outside of the stack to a 4-in. ANSI Class 150 mounting flange. This configuration is designed to withstand high operating temperatures. A filter for coarse particulate is mounted in the heated, out-of-stack unit.

- Sample transport system

The sample transport system conveys the sample gas from the probe location to the analysis enclosure. It includes a heated, multiple-tube umbilical with these design features:

- The sample gas umbilical contains the necessary gas lines plus two spare sample lines. All sample and calibration gas lines are Teflon FEP tubing.
- All compression fittings and interconnects are Swagelok. Other devices in contact with the sample are constructed of materials proven resistant to the corrosive effects of the gas.
- The umbilicals are ATP outer jacketed. The probe and the umbilical for the auxiliary boiler and HRSG stack CEMS are designed for installation on an uninsulated steel stack with a maximum stack skin temperature of 325 °F.
- A chemical ammonia scrubber is included in each HRSG stack sample line to prevent any ammonia from being seen as NO_x by the NO_x monitor.
- The sampling system for the WSA process stack is designed to automatically go into blowback mode upon failure of the probe heater or umbilical line heater.

- Probe controller

The probe controller controls and monitors the operation and sample acquisition capability of the dilution probe. A control panel allows the operator to manually tune all air pressures and flow rates required to transport the sample to the analyzer rack. It includes all the necessary gauges, regulators, flow control devices, and tubing to support the dilution probe's sampling process. All automatic and manually initiated functions are performed by this device.

The controller places the dilution probe into one of four possible modes of operation. They include:

- Sampling.
- Back-purging.
- Fast calibration.
- Normal calibration.

The *sampling* mode involves admission of dilution air to the probe and transport of the diluted sample through the sample line to the analyzers. The probe extracts the sample from the stack by creating an area of lower pressure, or vacuum, with respect to the flue gas environment. This vacuum is created by the bypass eductor pump, which pulls the gas from the stack, through the probe filters, into the probe, and past an inline critical orifice. The bypass eductor then discharges excess gas back into the stack. A second probe eductor pump draws the sample through the critical orifice and sends it to the analyzers through the diluted sample line. The size of the orifice is chosen to achieve the correct dilution ratio for the specific CEMS instruments.

In *back-purging* mode, high-pressure air is admitted to the probe from the blow-back valve and the calibration/purge line. The blow-back air exhausts into the sample inlet, creating positive pressure and dislodging large particles. Dilution air to the probe is maintained as in the sampling mode of operation. Analyzer readings will momentarily dip due to the probe sampling air at this time; the controller sends a signal to the data acquisition and control system (DACS) to reject the readings.

In *fast calibration* mode, the selected gas is admitted to the probe through the calibration and back-purge flowmeters using the calibration/purge line. This process saves time by providing an extra volume of gas to clear stack gases from the probe and to purge previous gases from the line. During fast calibration, the diluted sample containing the correct ratio of calibration gas is returned through the sample line.

During *normal calibration* mode, calibration gas passes through the calibration flowmeter to the probe through the calibration/purge line. This mode maintains a curtain of calibration gas at the end of the probe, ensuring the probe acquires calibration gas of known concentration for transport to the analyzers during calibration periods. In addition, the bypass eductor pump flow is reduced to lower the bypass sample flow through the sample probe. This reduces the amount of gas required to supply the sample probe, using the calibration gas more efficiently and providing a longer life to the calibration gas cylinder.

- Dilution air cleanup subsystem

The dilution air cleanup subsystem provides the dilution probe with a continuous source of scrubbed and moisture-free air for all modes of operation. All interferents with the monitored pollutants are eliminated or reduced below instrument detection levels by this part of the sample acquisition subsystem.

4.5.1.2 *Sample Analyzer Subsystem*

The types of analyzers in the CEMS and the plumbing configuration required to support sample integrity during analysis are application dependent. Each of the four CEMS units is specifically engineered to site specifications with respect to both monitored emissions and instrument range requirements. Analyzers are included, as required, for detection and measurement of the identified emissions or parameters. The analyzers provided in each Kemper CEMS unit are:

- HRSG A and B CEMS include CO_2, NO_x, SO_2, O_2, and CO.
- WSA CEMS includes CO_2 and SO_2.
- Aux. Boiler CEMS includes CO_2 and NO_x.

4.5.1.3 *Sample Control Subsystem*

Sample control is performed by the Data Acquisition and Control System (DACS), a programmable control system that performs all control functions to operate and calibrate the CEMS. The device integrates, controls, and monitors all system functions including calibrating, purging, fault/status monitoring, and cycle sequencing. The SpectraView® configuration software allows the setup of the sequence tables from an external personal computer. The control system can handle a power failure and restart without damaging the CEMS. An alarm for loss of power to equipment is provided within the DACS. The DACS is a SpectraPak E manufactured by Spectrum Systems.

The DACS performs these automatic functions:

- System startup and shutdown under cold start or hot start conditions.
- Remote initiation of daily span and zero calibration checks.
- Control of probe filter blowback when necessary.
- Control of sample system purge.
- Linearity checking initiated by operator.

The SpectraView® software is stored in nonvolatile memory but can be modified by a plant engineer/operator with proper training using Windows-based software. The control software can be configured to freeze analog output signals when the related analyzer is in a calibration or blowback cycle.

The plant DCS is interfaced with the DACS to share information, as required.

The DACS can be configured to automatically monitor analog and digital inputs from external field devices. It can collect the raw data in 10-second averaged digital data packets that are each date and time stamped. It can store up to 264 hours of the raw 10-second averaged data packets between data transfers to both a local or remote DACS. Additionally, the controller can be preprogrammed to operate field equipment with contact closures.

4.5.1.4 *Data Reporting Subsystem*

Data reporting is provided by the DACS and additional computer hardware located in the HRSG A CEMS shelter. It includes hardware and software designed specifically for CEMS data acquisition, handling, and reporting in compliance with US EPA, state, and local regulations.

The subsystem consists of a primary computer running the data acquisition application program, communicating over fiber optic cables and Ethernet with remote computers. It automatically provides audit logs, alarm logs, calibration check results, compliance reports, trending displays, and other on-line functions to assist the CEMS operator and administrator.

The computer server hardware and operating system software associated with the DACS are installed in the HRSG A CEMS shelter. A remote computer terminal with hardware and software for the DACS is installed in the plant control room.

All necessary software is included to allow CEMS operation and emission values to be monitored by plant operators through the DACS computer. This monitoring capability includes:

- Continuous display of instantaneous values for all measured and calculated emissions.
- Alarms for high emission levels, analyzer failures, system alarms, HVAC failure alarms, calibration gas alarms, and zero and calibration drift alarms.
- Accumulated unit time online.
- Status of sequential valving for the CEMS and calibration cycle progress.
- Manual compensation of all analyzer outputs based on daily zero and span calibrations.
- Display of daily zero and span calibration response.

Custom software is provided to monitor, produce calculations, and generate regulatory compliant reports that can be modified by plant support personnel. This software can:

- Form averages, calculate pollutant emission value, and flag exceedances.
- Automatically print daily, weekly, monthly, quarterly, and annual data logs.
- Provide on-demand display and printing of historical logs.
- Display screen printing on demand.
- Create periodic logs in EPA format.
- Edit reason and action codes.
- Enter exceedance and monitor failure codes.
- Perform system file maintenance and data backup.
- Form averages (1-hr block, 3-hr block, 3-hr rolling, 24-hr block, 30-day rolling, 12-month rolling) for all measured and calculated emissions.
- Accumulate year-to-date total NO_x (tons), SO_2 (tons), CO (tons), and CO_2 (tons).
- Automatically replace missing data according to the EPA regulations and guidance documents.

4.5.2 CEMS Design Requirements

4.5.2.1 *General Requirements*

The CEMS is designed and constructed to meet these general requirements:

- Have a high reliability (98% or better availability).
- Require low maintenance.
- Have a relative accuracy of 7.5% or better or meet the alternative performance specification for low emitters, where applicable, which allows annual testing as defined by 40 CFR 75 and 40 CFR 60.
- Easily interfaced to the existing Mississippi Power Company CEMS corporate data systems, which were furnished by Spectrum Systems of Pensacola, Fla.

The CEMS was designed to work with the existing Mississippi Power installed base of CEMS equipment, to maximize the use of existing spare parts and training investment.

Each CEMS is designed to provide 98% or greater availability. Availability is based on hourly averages and is calculated only during emission source operating periods, based on the time the entire CEMS is operational versus the time any CEMS component necessary for data reporting or accuracy, as defined by federal regulations, is inoperative. The averaging period for determining compliance with this provision is 30 combustion source operating days.

The sampling and analyzer systems associated with the HRSG stacks are designed to minimize any ammonia interference with the NO_x measurement. The use of material that could act as a NO_x /ammonia catalyst is minimized to the greatest extent practical to ensure an accurate reading at the NO_x analyzer.

CEMS instrumentation is connected to the DACS from a remote location with an Ethernet TCP/IP connection to allow monitoring of system calibration and operation, both in real time and historically. Daily calibration gases are provided with pressure transmitters to monitor quantity of gas remaining, and an alarm is provided when a gas quantity drops below a predetermined level.

The system is designed to operate continuously for a minimum of 45 days without any routine maintenance.

The system includes devices to measure barometric pressure, ambient temperature, sample gas moisture content, and relative humidity.

The sampling and analyzer system associated with the WSA process stack is designed to minimize any corrosion or degradation associated with the sulfuric acid mist.

4.5.2.2 *CEMS Network Layout*

An overview of the CEMS network layout is shown in figure 4.5-1. This drawing identifies the emission point labels for the Kemper CEMS units and includes the computer network interconnections.

Figure 4.5-2 provides details on the equipment connected to the CEMS Ethernet switches, the network IP addresses for these devices, and a list of the analyzers.

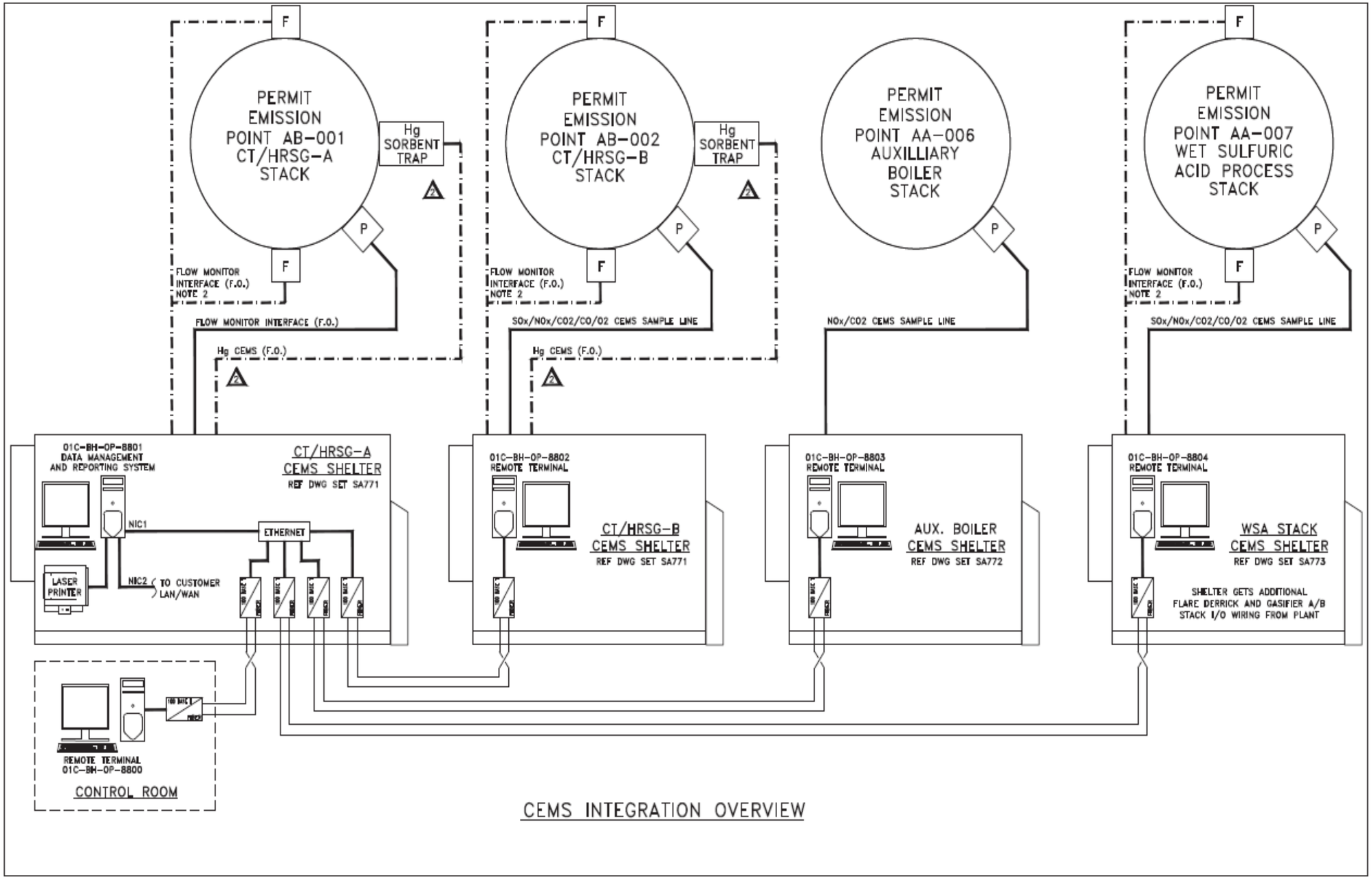
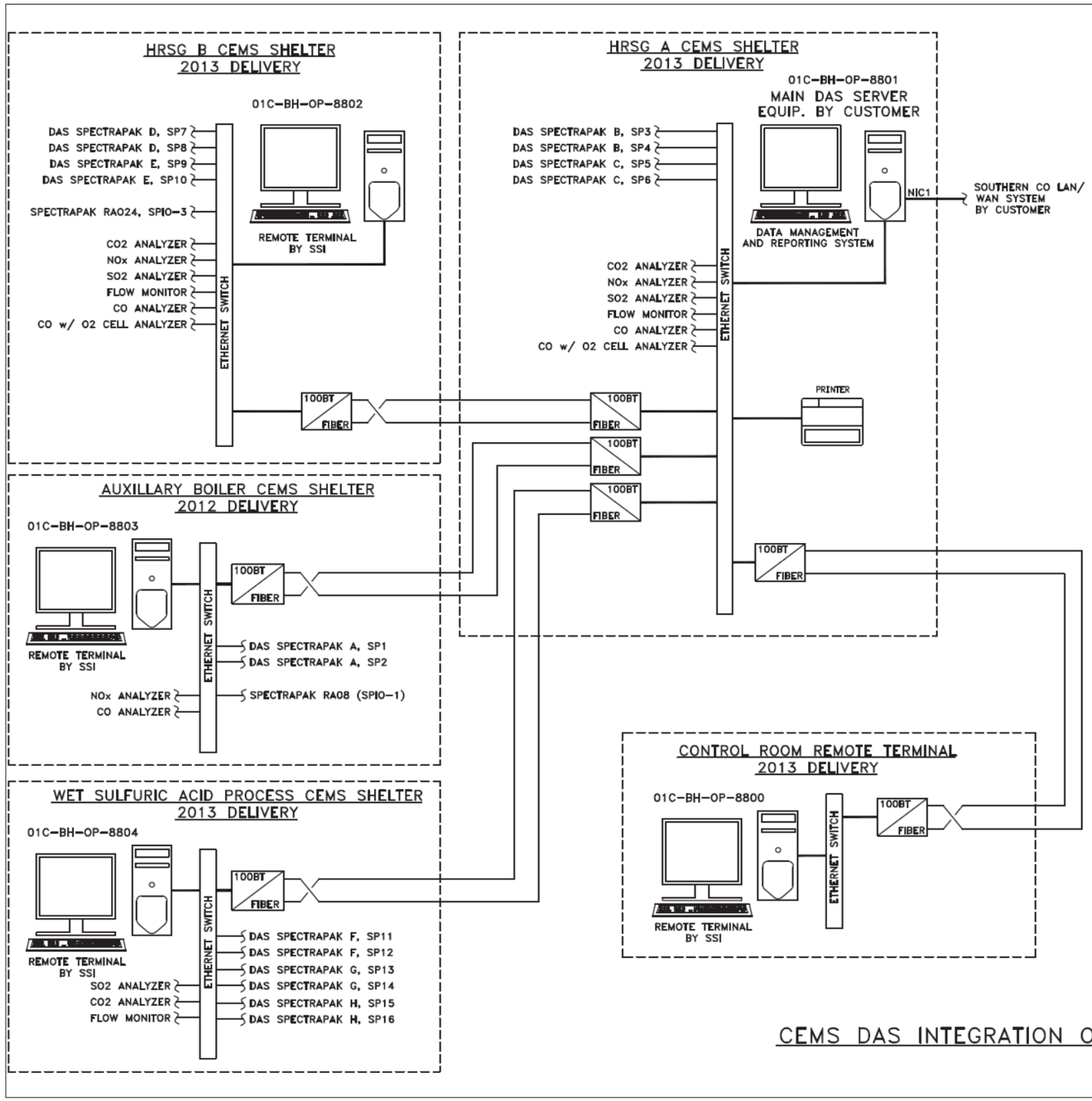


Figure 4.5-1 – Kemper County CEMS Network



CEMS DATA ACQUISITION COMPONENT ADDRESS CONFIGURATION

CEMS NETWORK ADDRESS	CONTROLLER	LOCATION	DESCRIPTION OF DEVICE - FUNCTION
192.168.1.1	N/A	HRSG-A STACK CEMS SHELTER	DAHS SERVER IN AUX BOILER CEMS IN 2012 (HARDWARE BY CUSTOMER)
192.168.1.2	N/A	CONTROL ROOM	DAS REMOTE TERMINAL PROVIDED IN 2012
192.168.1.3	N/A	AUX BOILER CEMS SHELTER	DAS REMOTE TERMINAL PROVIDED IN 2012
192.168.1.4	N/A	HRSG-B STACK CEMS SHELTER	DAS REMOTE TERMINAL PROVIDED IN 2013
192.168.1.5	N/A	WSAP CEMS SHELTER	DAS REMOTE TERMINAL PROVIDED IN 2013
192.168.1.6	N/A	HRSG-A CEMS SHELTER	PRINTER
192.168.1.201	SP1 (A/SP1)	AUX BOILER CEMS SHELTER	CEMS/DAS CONTROLLER PROVIDED IN 2012
192.168.1.202	SP2 (A/SP2)	AUX BOILER CEMS SHELTER	CEMS/DAS CONTROLLER PROVIDED IN 2012
192.168.1.203	SP3 (B/SP1)	HRSG-A STACK CEMS SHELTER	CEMS/DAS CONTROLLER PROVIDED IN 2013
192.168.1.204	SP4 (B/SP2)	HRSG-A STACK CEMS SHELTER	CEMS/DAS CONTROLLER PROVIDED IN 2013
192.168.1.205	SP5 (C/SP1)	HRSG-A STACK CEMS SHELTER	CEMS/DAS CONTROLLER PROVIDED IN 2013
192.168.1.206	SP6 (C/SP2)	HRSG-A STACK CEMS SHELTER	CEMS/DAS CONTROLLER PROVIDED IN 2013
192.168.1.207	SP7 (D/SP1)	HRSG-B STACK CEMS SHELTER	CEMS/DAS CONTROLLER PROVIDED IN 2013
192.168.1.208	SP8 (D/SP2)	HRSG-B STACK CEMS SHELTER	CEMS/DAS CONTROLLER PROVIDED IN 2013
192.168.1.209	SP9 (E/SP1)	HRSG-B STACK CEMS SHELTER	CEMS/DAS CONTROLLER PROVIDED IN 2013
192.168.1.210	SP10 (E/SP2)	HRSG-B STACK CEMS SHELTER	CEMS/DAS CONTROLLER PROVIDED IN 2013
192.168.1.211	SP11 (F/SP1)	WSAP CEMS SHELTER	CEMS/DAS CONTROLLER PROVIDED IN 2013
192.168.1.212	SP12 (F/SP2)	WSAP CEMS SHELTER	CEMS/DAS CONTROLLER PROVIDED IN 2013
192.168.1.213	SP13 (G/SP1)	WSAP CEMS SHELTER	CEMS/DAS CONTROLLER PROVIDED IN 2013
192.168.1.214	SP14 (G/SP2)	WSAP CEMS SHELTER	CEMS/DAS CONTROLLER PROVIDED IN 2013
192.168.1.215	SP15 (H/SP1)	WSAP CEMS SHELTER	CEMS/DAS CONTROLLER PROVIDED IN 2013
192.168.1.216	SP16 (H/SP2)	WSAP CEMS SHELTER	CEMS/DAS CONTROLLER PROVIDED IN 2013
192.168.1.101	RA08-1	AUX BOILER CEMS SHELTER	SPAK RAD 1
192.168.1.102	RA024-2	HRSG-A STACK CEMS SHELTER	SPAK RAD 2
192.168.1.103	RA024-3	HRSG-B STACK CEMS SHELTER	SPAK RAD 3
192.168.1.104	RA08-4	WSAP CEMS SHELTER	SPAK RAD 4
192.168.1.105	N/A	HRSG-A STACK CEMS SHELTER	PS-12B/30B Hg SORBENT TRAP SYSTEM
192.168.1.106	N/A	HRSG-B STACK CEMS SHELTER	PS-12B/30B Hg SORBENT TRAP SYSTEM
	N/A	AUX BOILER CEMS SHELTER	NOx ANALYZER
	N/A	AUX BOILER CEMS SHELTER	CO2 ANALYZER
	N/A	HRSG-A STACK CEMS SHELTER	NOx ANALYZER
	N/A	HRSG-A STACK CEMS SHELTER	CO2 ANALYZER
	N/A	HRSG-A STACK CEMS SHELTER	SO2 ANALYZER
	N/A	HRSG-A STACK CEMS SHELTER	CO ANALYZER
	N/A	HRSG-A STACK CEMS SHELTER	CO W/ O2 CELL ANALYZER
	N/A	HRSG-A STACK CEMS SHELTER	FLOW MONITOR
	N/A	HRSG-B STACK CEMS SHELTER	NOx ANALYZER
	N/A	HRSG-B STACK CEMS SHELTER	CO2 ANALYZER
	N/A	HRSG-B STACK CEMS SHELTER	SO2 ANALYZER
	N/A	HRSG-B STACK CEMS SHELTER	CO ANALYZER
	N/A	HRSG-B STACK CEMS SHELTER	CO W/ O2 CELL ANALYZER
	N/A	HRSG-B STACK CEMS SHELTER	FLOW MONITOR
	N/A	WSAP CEMS SHELTER	SO2 ANALYZER
	N/A	WSAP CEMS SHELTER	CO2 ANALYZER
	N/A	WSAP CEMS SHELTER	FLOW MONITOR

Figure 4.5-2 – Kemper County CEMS Network

4.5.2.3 *Input/output Signals*

The following signals are available to the CEMS from the plant DCS for each of the two heat-recovery steam generator (HRSG) stacks (permit emission points AB-001 and AB-002 in figure 4.5-1):

- Natural gas flow to the combustion turbine.
- Natural gas flow to the HRSG duct burners.
- Syngas flow to the combustion turbine.
- Heating value of the syngas in Btu/lb.
- HRSG A total steam flow.
- HRSG B total steam flow.
- HRSG ammonia flow to the SCR.
- CO_2 mass flow to the HRSG stack.
- CO_2 mass flow to the pipeline.
- Combustion turbine gross megawatt output.
- Steam turbine gross megawatt output.
- Spare for CO_2 injection stream H_2S content in ppmvd.
- Spare for CO_2 injection stream COS content in ppmvd.
- Spare for CO_2 injection stream CS_2 content in ppmvd.
- Combustion turbine firing with natural gas.
- Combustion turbine firing with syngas.
- HRSG duct burner firing.
- CT steam injection active.
- CO_2 being injected into the HRSG stack.

The following emission and status values are measured or calculated by the CEMS installed for each HRSG stack and are available from the system as electronic data:

- Stack NO_x (measured in ppm and calculated in ppmvd, lb/hr, and lb/MMBtu on a 15% oxygen dry volume basis).
- Stack SO_2 (measured in ppm and calculated in ppmvd and lb/hr on a 15% oxygen dry volume basis).
- Stack CO (measured in ppm and calculated in ppmvd, lb/hr, and lb/MMBtu on a 15% oxygen dry volume basis).
- Stack CO_2 (measured in percent).
- Stack O_2 (measured in percent).
- Stack flow (measured in SCFM and indicated in ACFM).
- Reduced sulfur compounds (RSCs) in CO_2 injection stream (calculated in terms of H_2S equivalent ppmvd based on the CO_2 mass flow to the HRSG stack).
- Heat input (calculated from natural gas flow, manually entered heating value of natural gas, syngas flow, and heating value of syngas).
- Heat input at duct burner (included in the heat input calculated for the previous item).
- Syngas providing 25% or more of the heat input to the CT (determined from natural gas flow, manually entered heating value of natural gas, syngas flow, and heating value of syngas).
- Combustion turbine in startup/shutdown mode (determined from less than 60% load on natural gas OR less than 75% load on syngas),
- Duct burner fired hours (cumulative for each day),
- 24-hr NO_x operating rolling average in lb/hr when syngas is providing 25% or more of the heat input to the CT.
- 24-hr NO_x operating rolling average in lb/hr when syngas is not providing 25% or more of the heat input to the CT.
- 24-hr NO_x operating rolling average in lb/MMBtu when syngas is not providing 25% or more of the heat input to the CT.
- Total NO_x emissions in ton/yr.
- 24-hr SO_2 operating rolling average in lb/hr when syngas is providing 25% or more of the heat input to the CT.

- 3-hr block average SO_2 in lb/hr when syngas is not providing 25% or more of the heat input to the CT.
- Total SO_2 emissions in ton/yr.
- 24-hr CO operating rolling average in lb/hr when syngas is providing 25% or more of the heat input to the CT and the captured CO_2 is not being bypassed to the HRSG stack.
- 24-hr CO operating rolling average in lb/hr when syngas is providing 25% or more of the heat input to the CT and the captured CO_2 is being bypassed to the HRSG stack.
- 24-hr CO operating rolling average in lb/hr when syngas is not providing 25% or more of the heat input to the CT.
- 24-hr CO operating rolling average in lb/MMBtu when syngas is not providing 25% or more of the heat input to the CT.
- Total CO emissions in ton/yr.
- Total CO_2 emissions in ton/yr.
- Total CO_2 flow to the pipeline in ton/yr.

The following 4-20mADC signals are provided to the DCS from the CEMS installed for each HRSG stack:

- Stack NO_x (ppm, lb/MMBtu, and lb/hr).
- Stack SO_2 (ppm and lb/hr).
- Stack CO (ppm, lb/MMBtu, and lb/hr).
- Stack CO_2 (percent and lb/hr).
- Stack O_2 (percent).
- Stack flow (SCFM).
- H_2S equivalent reduced sulfur compounds (RSC) from CO_2 injection (ppm and lb/hr).
- Total heat input (MMBtu/hr).

The following signals are sent to the CEMS from the plant DCS for the auxiliary boiler stack (permit emission point AA-006 in figure 4.5-1):

- Natural gas flow to the auxiliary boiler.
- Auxiliary boiler in service firing with natural gas.

The following emission and status values are measured or calculated by the CEMS installed for the auxiliary boiler stack and are available as electronic data:

- Stack NO_x (measured in ppm and calculated in ppmvd, lb/hr, and lb/MMBtu on a 15% oxygen dry volume basis).
- Stack CO_2 (measured in percent).
- Heat input (calculated from natural gas flow and the manually entered heating value of natural gas).
- 30-day NO_x rolling average in lb/hr.
- 30-day NO_x rolling average in lb/MMBtu.
- Total NO_x emissions in ton/yr.
- Total operating hours for last 12 months.

The following 4-20mADC signals are provided to the DCS from the CEMS installed for the auxiliary boiler stack:

- Stack NO_x (ppm, lb/MMBtu, and lb/hr).
- Stack CO_2 (percent).
- Total heat input (MMBtu/hr).

The following signals are sent to the CEMS shelter from the plant DCS for the WSA stack (permit emission points AA-007 in figure 4.5-1):

- Flow of sulfuric acid being produced.
- WSA stack in service
- The following emission and status values are measured or calculated by the CEMS installed for the WSA stack and are available from the system as electronic data:

- Stack SO_2 (measured in ppm and calculated in ppmvd and lb/hr on a 0% excess air basis).
- Stack CO_2 (measured in percent).
- Stack flow (measured in SCFM and indicated in ACFM).
- 24-hr SO_2 operating rolling average in lb/hr.
- 12-month rolling total SO_2 emissions in ton/yr.
- Total CO_2 emissions in ton/yr.
- Total reduced sulfur compound (RSC) emissions for the plant site in ton/yr.
- A report is provided for Generation on user demand, based on a user-specified period, of the estimated sulfuric acid mist emissions, in pounds of emission per ton of acid produced. These emissions are calculated based on a manually entered WSA stack flow-based emission factor.

The following 4-20mADC signals are provided to the DCS from the CEMS installed for the WSA stack:

- Stack SO_2 (ppm and lb/hr).
- Stack CO_2 (percent).
- Stack flow (SCFM).

The following signals are sent to the CEMS shelter from the plant DCS for each gasifier startup stack (permit emission points AA-001 and AA-002; equipment shared with WSA Stack AA-007):

- Natural gas flow to gasifier startup burners.
- Diesel oil flow to gasifier startup burners.
- Gasifier startup burners in service burning natural gas.
- Gasifier startup burners in service burning diesel oil.
- Gasifier startup stack in service.

The following emission and status values are measured or calculated by the CEMS installed for each gasifier startup stack and are available from the system as electronic data:

- Heat input when firing natural gas (calculated from the natural gas flow and the manually entered heating value of natural gas).
- Heat input when firing diesel oil (calculated from the diesel oil flow and the manually entered heating value of the diesel fuel).
- 12-month rolling total natural gas usage by the startup burners in lb/yr.
- 12-month rolling total diesel oil usage by the startup burners in lb/yr.
- 12-month rolling total number of startup events.
- Date, time, duration, fuel type and fuel quantity for each startup event.

The following signals are sent to the CEMS shelter from the plant DCS for the flare derrick (permit emission point AA-003; equipment shared with WSA Stack AA-007):

- Natural gas flow to LP acid gas flare.
- Process gas flow to LP acid gas flare.
- Heating value of LP acid gas in Btu/lb.
- LP Acid gas hydrogen sulfide quantity in ppm.
- Natural gas flow to ammonia flare.
- Process gas flow to ammonia flare.
- Heating value of ammonia gas in Btu/lb.
- Ammonia gas hydrogen sulfide quantity in ppm.
- Natural gas flow to high pressure (HP) flare A.
- Process gas flow to HP flare A.
- Heating value of HP flare A gas in Btu/lb.
- HP flare A gas hydrogen sulfide quantity in ppm.

- Natural gas flow to HP flare B.
- Process gas flow to HP flare B.
- Heating value of HP flare B gas in Btu/lb.
- HP flare B gas hydrogen sulfide quantity in ppm.
- LP acid gas flare pilot in service.
- LP acid gas flare process gas flow in service.
- Ammonia flare pilot in service.
- Ammonia flare process gas flow in service.
- HP flare A pilot in service.
- HP flare A process gas flow in service.
- HP flare B pilot in service.
- HP flare B process gas flow in service.

The following emission and status values are measured or calculated by the CEMS installed for the flare derrick and are available from the system as electronic data:

- Flare derrick in startup/shutdown mode (determined to be true any time process gas flow to HP flare A or HP flare B is in service).
- Total heat input to the flare derrick from firing natural gas (calculated from the individual natural gas flows and the manually entered heating value of natural gas).
- Total heat input to the flare derrick from firing process gases (calculated from the individual process gas flows and the individual process gas heating values).
- 12-month rolling total number of startup events.
- 12-month rolling total heat input from natural gas for the flare derrick in MBtu/yr.
- 12-month rolling total heat input from process gas for the flare derrick in MBtu/yr.
- 12-month rolling total CO flow for the flare derrick in ton/yr.
- 12-month rolling total NO_x flow for the flare derrick in ton/yr.
- 12-month rolling total SO_2 flow for the flare derrick in ton/yr.
- 24-hour CO operating rolling average in lb/hr.
- 24-hour NO_x operating rolling average in lb/hr.
- 24-hour SO_2 operating rolling average in lb/hr.
- 12-month rolling total CO emissions in ton/yr.
- 12-month rolling total NO_x emissions in ton/yr.
- 12-month rolling total SO_2 emissions in ton/yr.

The following 0.5 amp, 125 VDC, Form C, dry contact signals are provided to the DCS from each of the CEMS shelters:

- Stack NO_x lb/MMBtu output signal valid (for AA-006, AB-001 and AB-002 shelters only).
- NO_x or NO_x related analyzer in calibration cycle (for AA-006, AB-001 and AB-002 shelters only).
- General CEMS fault.
- DACS fault.
- Shelter HVAC fault.
- Shelter power failure.
- Shelter smoke alarm.
- Shelter oxygen depletion alarm.

4.5.3 Initial Commissioning Plan

The CEMS commissioning was broken down into the four areas associated with the CEMS shelters (table 4.5-3).

Table 4.5-3 – CEMS commissioning milestones and associated I/O counts

Milestone	CEMS Hardwired I/O Count	I/O Checkout Completion Date
Aux Boiler	7	08/03/13
HRSG A	53	11/13/13
HRSG B	53	11/13/13
WSA	30	03/04/14

4.5.3.1 *Commissioning Goals and Objectives*

The CEMS commissioning was a process to ensure the four CEMS units performed according to the design intent and the process operational requirements. All equipment and systems were installed according to manufacturer's recommendations and the best practices and standards of the industry before CEMS commissioning.

The commissioning task documented the performance of the CEMS in relation to the design intent. The goals of the commissioning process were:

- Facilitate the final acceptance of the four CEMS units.
- Facilitate the transfer of the Kemper CEMS units to Mississippi Power's O&M staff.
- Ensure the systems meet the plant regulatory requirements.

CEMS commissioning was intended to achieve these specific objectives:

- Document that the equipment and systems receive complete operational checkout.
- Document system performance with functional performance testing and monitoring.
- Verify the completeness of operating procedures and maintenance materials.
- Ensure Mississippi Power personnel are adequately trained on the operation of all CEMS equipment

4.5.3.2 *Functional Tests*

These tests were performed to demonstrate the functional operation of all CEMS equipment:

- Point-to-point checks with wiring diagrams to ensure accurate system assembly. This work included continuity testing of all wires, confirmation of correct marking of terminal block and wire terminations, and checking of contact configuration on all switches and relays.
- System functional tests, designed to demonstrate the full functionality of the CEMS and all auxiliary equipment. These tests included complete operation of all equipment to emulate actual in-service field devices. This generated data at various instrument ranges and included the generation of regulatory report type records and reports at the different ranges.

4.5.4 Significant Events

The purchase order was issued to Spectrum Systems on February 4, 2011, for the four CEMS and associated shelters, with the following test and delivery schedule:

CEMS Unit	Factory Test Date	Required Delivery Date	Data Logging Start
Auxiliary Boiler	9/18/2012	9/28/2012	9/20/2015
HRSG A Stack	2/19/2013	3/1/2013	9/4/2015
HRSG B Stack	2/19/2013	3/1/2013	9/4/2015
WSA Stack	5/21/2013	5/31/2013	9/25/2016

4.5.5 Final Summary

The Kemper County CEMS units are designed to monitor the actual emissions from the facility's defined emission points. These systems include analyzers that test for specific pollutants and determine their concentrations in terms of parts per million (ppm), or percentage (%) on a volume basis. The components analyzed by the CEMS include SO_2, NO_x, CO, O_2, and CO_2.

Figures 4.5-3 through 4.5-5 illustrate the data generated by the CEMS for HRSG A during the three plant commissioning phases. Figure 4.5-3 shows the CEMS data while running on natural gas (no syngas). In review of this trend the NO_x value averages slightly less than the minimum specified in the design requirements for the CEMS units. The SO_2 value is virtually zero, as is expected for natural gas combustion. The CO value determined by the CEMS varies the most, ranging from essentially zero much of the time up to a maximum of 34.8 ppmvd. The conclusion for this regime is that the CEMS units perform within a reasonable range.

Figure 4.5-4 shows trends with the CEMS data while running in co-firing mode (averaging 40% natural gas and 60% syngas) with the combustion turbine at about 50% of load. In review of this trend, the average NO_x value is stable but somewhat low at 2.5 ppm. This value is less than the minimum expected in the design requirements for the CEMS units. The SO_2 value is virtually zero, demonstrating a high level of sulfur removal in the AGR. This value could point to a need to examine the analyzer for operational issues. The CO value determined by the CEMS is stable at around 17 ppmvd, which is within the expected range for co-firing. The conclusion for this regime is that the CEMS units perform as expected.

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Figure 4.5-3 – HRSG A CEMS data during natural gas-only operation

Figure 4.5-4 – HRSG A CEMS data during co-firing operation

Figure 4.5-5 shows trends of the CEMS data while running in 100% syngas mode with the combustion turbine varying between 99 and 179 Megawatts output. In review of this trend, the average NO_x value varies between 0.1 and 7.7

ppm and tracks the combustion turbine power output. This value is less than the minimum expected in the design requirements for the CEMS units. The SO_2 value is still virtually zero, which is consistent with the expected SO_2 content of less than 1 ppm. The CO value determined by the CEMS averages around 11 ppmvd, which is within the expected range for syngas operations. The conclusion for this regime is that the CEMS units, except for the SO_2 analysis, perform as expected.

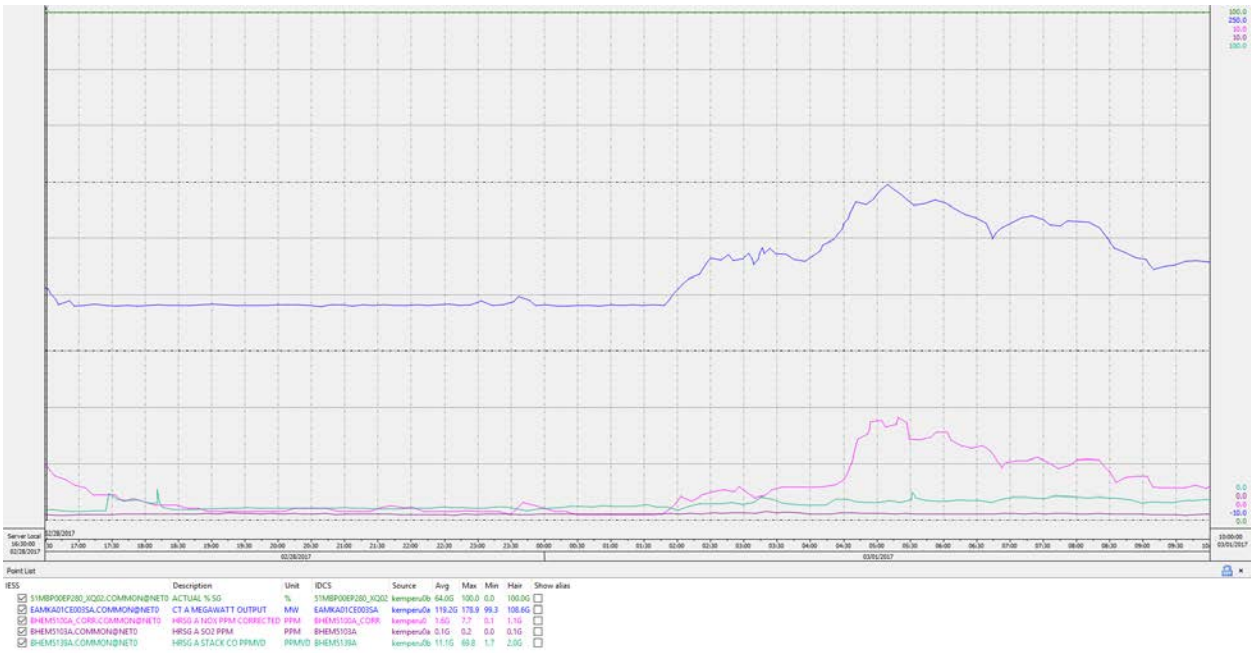


Figure 4.5-5 – HRSG A CEMS data during syngas-only operation

4.6 System Cleaning

4.6.1 Cleaning Overview

Cleanliness of plant piping and equipment is critical to proper operation of various processes. Trash and particulate in the piping can cause fouled filters, strainers, tubesheets, nozzles and valve trims; damage to compressors, pumps, and turbines; and impaired heat or mass transfer and reaction rates. One step in precommissioning new equipment and systems is to ensure everything is cleaned before energizing. For many systems, the standard is to ensure piping and equipment has been cleaned sufficiently to prevent future issues or failures.

The cleanliness standard is met for air, steam, and liquid piping when flow conditions exceed those that would ever be seen in the normal course of operations and operational upsets.

To clean liquid piping, higher-velocity flows are established for flushes by using external, temporary pumps and heat exchangers. Strainers or filters are installed to capture any contaminant dislodged from the walls. The piping system is flooded with a flushing liquid (water or appropriate oil), the pumps started, and flows established. The temperature builds until it stabilizes for several hours (typically 8 to 24) before shutting down the pumps and inspecting the strainer or filter for accumulated debris. The flushes are declared complete when the strainers or filters have no debris captured after the flush cycle.

For closed loop oil systems, the flushing oil is sampled and analyzed for remaining micron-sized particles. When flushing lube oil systems is complete, they are drained and the reservoirs hand-cleaned before refilling with the equipment normal lube oil and placed into service for preservation. For other liquid piping systems such as cooling

water, condensate or waste water, simple flushing at valves wide open and full pressure is sufficient to ensure cleanliness.

For most gas phase piping, line blows are equivalent to flushing. These blows are designed to achieve flow conditions that should not be matched in subsequent operations, usually evaluated by Reynolds Number calculation and comparisons. For utility gas and air lines (including natural gas), the blows are simply opening the valves wide open for a predetermined length of time. In some cases, the discharge must be directed to a safe location, or the control valves replaced with spools, if required for safety, equipment protection, or to meet the required volumetric flow rates.

Some blows are carefully planned and dynamically modeled to ensure successful results. For steam line blows, valves are spooled through, the discharge of the lines is carefully located, the piping is specially braced for the reaction forces, the steam supply conditions are prescribed by special procedure, and the entire effort is carefully scheduled as a major milestone of the commissioning effort. New power plant steam blows are usually witnessed and carefully documented by the insurance underwriters to minimize future claims of turbine damage from foreign particles in the lines during operation. A similar effort was made to ensure cleanliness in the syngas supply piping for the gas turbines.

Some piping systems require additional cleaning (usually before the final blows) to improve heat or mass transfer, minimize corrosion, or to reduce the time and energy required to achieve the cleanliness standard from the flushes or blows.

The traditional method of precleaning boilers and steam generators after construction or substantial heating surface replacement is to chemically clean the piping and heat exchanger tubes. A series of flushes and soaks of dilute acids, caustics, surfactants, and passivating chemicals removes machining oils, corrosion products, and welding aids. This process is carefully planned and coordinated to account for the piping modifications, specialized chemicals (with special hazard identification), complex disposal requirements, and the continuing chemical analysis required to ascertain the completion of each procedure step.

Lower pressure steam systems are usually treated with a simpler degreasing or boilouts to remove oils and trash remaining from fabrication or maintenance work. Acid gas recovery units are typically degreased to prevent contamination of the circulating solvent, which could affect absorption of acid gases or degrade the solvent.

A newer method of precleaning piping systems is to use an automated, high-pressure water jet that blasts the material to low points in the piping. Called hydroblasting, this process uses a rotating jet of 1,500+ psi water that rotates as it moves through the pipe, creating an overlapping cleaning pattern. Cleaning depth is controlled by the speed of the supporting cart moving in the pipe. When cleaning is complete, the water is treated with a passivating agent to prevent additional corrosion in the pipe until the system goes into service.

4.6.2 Significant Events

Hydroblasting was used to prepare for upcoming flushes and commissioning, due to the extended piping lengths and construction time when the piping was open to humidity. Process gas systems were hydroblasted, including AGR overheads, product CO_2 compressor discharges to the pipeline gate at the fence line, syngas lines downstream of the syngas scrubber to gas turbines, sour water lines to the ammonia condenser, and the ammonia refrigeration lines. The contractor started in late 2014 and finished in 2Q 2016. This timeframe was due to scope increases as delays and retrofits left the piping exposed much longer than initially anticipated. Extensive passivation efforts were employed, but they were not always suitable for the duration between process cleaning and operation.

The power block (gas and steam turbine generators, HRSGs, and associated piping) was ready for initial commissioning in 2013. Flushing the piping systems was included in the commissioning scope of work, starting in early 2013 with cleaning the make-up water lines to the reclaim sump, then to the water treatment plant. Circulating water and closed loop cooling water systems were flushed before final fills and going into service. The condensate system from the storage tank to condenser hotwell, HRSG deaerators, and boiler feed pump suction strainers was flushed before tying in temporary pumps for the HRSG chemical cleaning. The HRSGs were flushed as the first step in their chemical cleaning, which proceeded with acid and caustic washes before the final passivation for lay-up. As the gas turbines were initially tested, the HRSG steam piping was modified for the steam blow that would occur

immediately after generator synchronization and tuning at mid-loads. The steam blow paths included the steam turbine inlet piping and bypasses, with a short outage mid-way to tie the main steam bypass to the cold reheat steam headers, then completing the steam path through the reheaters and raising mass flow to maximum to finish the blows before restoration and steam turbine trials began early in 2014.

The power block gas and instrument air lines were blown before going into service. The instrument air system was blown in stages, starting at the compressor station dryers and receivers, before blowing different branches of the header system individually. In these blows, the discharge plume started dark and dirty before clearing up and meeting completion standards of blowing a clear discharge for greater than 15 min. Based on practices in the power industry, where natural gas lines were blown clean using the gas pressure in the supply line, rental compressors were used to blow clean the Kemper natural gas headers similar to the use of instrument air. The plant auxiliary boiler was brought on line late summer of 2013, and boiled out before the LP steam headers were blown clean and steam fed to the waste water plant.

The gasification island closed loop cooling water and circulating water streams, and their filtered and demineralized (demin) water supplies, were flushed and the low points vacuumed several times starting in the summer of 2013, before the systems were complete and ready for service. The cleaning standards were based on the fouling experienced by the strainers with which each of these systems was equipped. After the circulating water streams were put into service, they were continually treated with biocides and passivating compounds. The closed loop cooling water could not be treated as aggressively, due to the requirements of the direct contact heat exchanger in the air separation unit, which led to later problems of anaerobic bacteria in the system. The diesel fuel piping was flushed in a similar fashion to the lube oil system, by circulating for several weeks with the bypass valve trims replaced and with temporary strainers on the return line at the tank that were regularly cleaned.

The GI natural gas lines were blown clear using temporary air compressors, immediately following the power block gas line blows. The GI instrument air headers were blown clean as they were finished and released by the project construction team and put into service. The nitrogen headers were blown clean with the ASU product nitrogen, with discharges routed to high, open spaces to prevent low oxygen levels in potentially occupied areas. The process ductwork for the WSA, lignite dryers, and syngas paths were blown using air driven by the permanent blowers and compressors before column packing, filters, or catalyst was installed. The syngas path blows included the flare headers, after the pressure control valve trims were replaced with bypass flushing trims or replaced with pipe spools. After the blows in the WSA, dryers and gasifiers, the vessels were inspected and cleaned to remove material that might have fallen out of the air flow from the pipes.

Most of the gasification island piping was not easily modified for effective flushes or blows. In some cases, the piping was too complex to ensure the material would not drop out of the high velocity fluid stream. In others, the piping had been exposed to ambient air for more than a year or had not been properly dried after hydrostatic testing. In those conditions, piping required substantially more cleaning than a simple flush or blow. Due in part to the extended lay-up of the piping before it would be purged for normal services, the effort ended with the passivation pass to extend the possible lay-up duration over that of raw carbon steel pipe. When the liquid lines were charged for final commissioning, they would be flushed and filtered before normal operations. Vapor lines would be blown to the extent possible as those systems would be commissioned.

Tanks and drums were pressure washed, vacuumed, and hand-cleaned before final commissioning, including the demin water, SELEXOL storage, all three acid tanks, and the sour water tank. The sour water drum, all four ammonia product drums, refrigeration receiver and subcooler, the product CO_2, extraction, and transport air knockout drums were vacuumed clean because personnel access was difficult.

Some piping systems required additional cleaning to ensure proper process function, either heat or mass transfer, including the steam generator syngas coolers, WSA heat recovery, and CCAD primary coolers. The CCAD heat exchangers were degreased before assembly, which was acceptable due to the stainless alloys used throughout. The WSA was degreased by boilout similar to the auxiliary boiler 2 years earlier. This process involved dosing the boiler condensate with tri-sodium-phosphate (TSP) as a surfactant, removing the machine oils from the inside of the tubes and maximizing nucleate boiling and heat transfer. This is typically done in two stages, an ambient low pressure and

a fired high pressure, followed by rinses of treated condensate to protect the tubing in the heat exchangers before the steam blows begin after the piping is reconfigured. The syngas cooler economizer and steam generator sections were chemically cleaned to remove both the oils and any corrosion products on the low chromium steels. The system is also thermally cycled. Steam generators being chemically cleaned are usually heated using the furnace's burners in a low fire condition, but the Kemper syngas coolers were fired by temporary burners inserted in the syngas piping to establish a reverse to normal gas flow, primarily heating the economizers. Initially, there was a misalignment in the burner arrangement that resulted in an overtemperature excursion in the piping, which delayed the cleaning for 3 months for inspection and repairs.

After the degreasing and chemical cleaning was completed, steam piping was configured for steam blows at temperature. The WSA steam blows used the heat from the permanent combustor, using natural gas to raise and superheat the steam used in blowing the piping to the distribution manifold in the power block. The syngas cooler piping was steam-blown using main steam from the power block HRSGs, as part of the process steam header blows early in 2016. At Kemper, the steam blows were a modification of the Sigma-Blow™ extended blow sequence, where steam is discharged into special units (crab-pots) to mostly condense and be recycled to the HRSGs. With typical pop blows or extended blows, the steam is wasted to the atmosphere, increasing the related demin water usage costs. By filtering and reusing the condensed blow steam, the water costs are reduced, similar to the HRSG main steam and hot reheat bypasses to the condenser in startup and trip operations.

The wetted surfaces of the AGRs were degreased after hydroblasting and column packing installation, to prevent contamination of the SELEXOL solvent after the units were put into operation. As with the boilouts, TSP was used as the surfactant. The AGR degreasing used the heat from pumping to raise temperatures to roughly 180 ˚F, circulating the surfactant through various flow paths at increasing levels and flow rates for maximum coverage and cleaning. As expected, the cleaning mixture created foam in the columns that contributed to the cleaning coverage, but the foaming required several rinses at high circulation rates to completely remove the cleaner from the columns. The plate and frame SELEXOL recuperators were bypassed for the degreasing and restored following the final rinse. Afterward, the recuperators were flushed in final water flushes before both trains were charged with the SELEXOL solvent.

In association with cleaning activities, the filter vessels, columns, drums, and reactors were loaded after the first gasifier air blows were completed in early 2015. The filters and the column packing began before flushing the packing. For the AGRs, the packing was included in the degreasing scope. The water gas shift catalyst was installed after the scrubber columns were flushed and the inerting and warmup loops were verified. The WSA catalyst was installed after the initial boilouts were completed. The carbon filter media was installed after the sour water system flushes were completed. In all cases, outside specialty contractors were brought in to install the materials. These contractors were reviewed and approved by the process vendors and the company early in the bid evaluation process, and all were experienced in the work they were contracted for.

4.6.3 Final Results

After the systems were cleaned and readied for syngas operations, they were laid up under nitrogen blankets until needed for service. There were several occasions during the integrated operational trials when piping systems were contaminated by upsets and failures. They were subsequently cleaned by flushing and filtering, to remain in the best condition possible to support operational goals of throughput, high efficiency, and reliability.

4.7 Utilities

4.7.1 Instrument Air System

4.7.1.1 *System Overview*

The instrument air system is a vital utility in any industrial facility. Instrument air is required to operate and control plant components including control valves, isolation valves, and positioners such as dampeners and inlet guide vanes.

At Kemper, the instrument air system is an extensive network of headers that supplies 100 psig air to the plant. The instrument air must be dry to prevent corrosion of equipment internals and to ensure process equipment performs as required in critical applications. The Kemper instrument air system is operated with a dewpoint of -20 °F or less.

The air headers are supplied by six compressors and three air dryer units. Five of the six compressors are water cooled, while the sixth is air-cooled. The air-cooled compressor provides an initial charging capability before the cooling water system is operational during outage periods and initial commissioning. The compressors discharge into a common header that connects to the three parallel desiccant air dryers. The compressors and dryer each cycle into service as demand dictates.

Each process area header is supplied with a dedicated surge reservoir and supply side isolation valve. Individual air trees branch off each area header to feed the equipment in the area. Larger valves are supplied with additional surge tanks to mitigate transient demand during operation.

4.7.1.2 *Initial Commissioning Plan*

Commissioning of the instrument air system involves walking the system down to ensure all the valves, branches, and tubing are installed correctly. After the system is mechanically complete, the commissioning of the compressors and dryers is completed, and the system is charged area by area. The area header and branches are leak checked before systematically moving to additional areas. After charging, the instrument air headers are blown down during commissioning and leak tested before opening the supply valves to individual valve operators and equipment.

4.7.1.3 *Final Summary*

The Kemper instrument air system was commissioned early in the startup phase to support broader commissioning. The headers were charged, and the system commissioned with no significant issues. After commissioning was complete and air demand increased, the compressors required additional tuning to improve operating efficiency. This work was anticipated and did not affect the progress of plant commissioning activities.

When taking a clearance on a piece of equipment such as on an isolation valve, the instrument air to the valve actuator was isolated and vented. There were instances after clearance was removed that the clearance was released but instrument air was not restored. This delay allowed moisture infiltration into the air header, requiring extra diligence when removing clearances and recharging the supplies and headers. Despite instances of moisture ingress, the system reliably supported startup and commissioning activities at Kemper.

4.7.2 Nitrogen

4.7.2.1 *System Overview*

The availability of nitrogen was critical to startup and operations at Kemper. The plant was supplied with high pressure (HP) (800 psi) and low pressure (LP) (100 psi) from an air separation unit (ASU). The high purity requirements of the AGR system set the specification for nitrogen at >99.95% purity and <1,000 ppm oxygen. The AGR requires much higher purity to avoid oxygen-related breakdown of the SELEXOL solvent. This restriction required the use of liquid distillation towers for the ASU technology. A liquid nitrogen (LiN) storage and vaporizer package was included, to back up the ASU and minimize plant upsets caused by ASU equipment shutdowns or outages that would otherwise initiate

plant-side emergency shutdown. The ASU was capable of providing the two pressure levels (HP and LP) from online production and from the LiN backup for distribution to the rest of the plant.

The HP and LP nitrogen has many uses throughout the plant. It is used as an inert purge for the gasifier pressure impulse taps and other intermittent injection nozzles, as inert fluidizing and pressurizing media for coal and ash handling systems, as intermittent transport fluid for solids, as inerting cap on tanks and vessels; and for intermittent sweep of headers during operational changes.

Despite the extensive number of uses, it is the most expensive utility used during startup and operations, with nearly double the costs for all other plant utilities.

The ASU consists of two main air compressors (MAC), a series of filters and heat exchangers, an expansion turbine, a distillation tower (cold box), a single product compressor, and the valves to control the system operation and performance. The two MACs are 100% capacity each, also in order to supply lower-pressure air to the gasifiers' startup burners when warming the gasifiers for service. All other ASU equipment has no installed spare.

The liquid nitrogen storage tanks and vaporizers primarily serve as emergency backup to the ASU. Liquid nitrogen can be pumped from the three storage tanks to a single water-heated vaporizer. The LiN storage backup is capable of maintaining flow to the plant distribution network for approximately 8 hours before the tanks reach a low limit setpoint. The pumps remain cryogenically chilled while in standby, ready for operation. The LiN can be used to augment the ASU capacity during high-demand periods such as gasifier heat-up to establish sweet syngas recycle.

4.7.2.2 *Initial Commissioning Plan*

The air separation unit was built under a turnkey agreement. Commissioning and operations were completed by third-party personnel. Commissioning of the nitrogen headers and supply lines was to include a series of air blowdowns, followed by a targeted blow of each segment. After the lines had been blown down to each component, the system would be leak tested and finally pressurized for service.

4.7.2.3 *Significant Events*

As the nitrogen headers were completed and leak tested, they were then blown-down for cleanliness, finishing with targeted blows on the main headers. Managing clearances during this period required extra diligence. There are two isolation points for the nitrogen headers, the fence boundary of the ASU and a common station at grade by the gasification structure. From the isolation station, piping is routed throughout the plant to systems that will require nitrogen at various stages of plant operation. The initial concept was for a single isolation point to expedite outage clearances. However, some packages like the AGRs and the WGS catalyst beds require nitrogen only during outages, preventing the effective use of single-point nitrogen isolation. In some cases, the nitrogen from the isolation station is routed beside the nitrogen supply header to the isolation station including the B side WGS and AGR packages, and to the LP nitrogen pads on the SELEXOL solvent and demin water storage tanks, crushed coal silos, and utility stations. The result was that the blowdowns and preparation of the distribution system for service took a considerable amount of time to complete.

Nitrogen headers should be run throughout the plant directly from the ASU fence boundary, area isolation stations feeding operation-only users, and separate isolations for continuous or offline-only users. This routing should reduce the amounts of recursive piping and simplify the clearances to offline equipment, while maintaining supply to those vessels requiring nitrogen pads while the unit is offline or needed continuously.

Initially, the HP portion of the nitrogen system supplying both trains was intended to be controlled by a single 8-in. NPS butterfly-style control valve. The control valve did not perform well in low turndown scenarios during commissioning and startup activities. The single control valve was replaced by a split range globe valve set, with a 6-in. NPS and a 3-in. NPS. This control scenario was far more effective in controlling a wide range of flows in the nitrogen system.

The ASU was sized to support both trains at base-load conditions with recycle syngas in service, and to support the dryers in steady state operations at minimum bleed and feed of the vitiated drying air for oxygen control. However, the nitrogen demand varies greatly throughout the plant's operating envelope. During early operations in support of the

gasifier train commissioning work, demand was below the ASU minimum turndown, and the excess nitrogen vented to the atmosphere. Under certain atmospheric conditions, the vented nitrogen could be downwashed into nearby areas of the plant, setting off area gas monitors. The vent stack was relocated and extended to reduce such occurrences during low-demand periods such as plant outages.

Under normal operations, the initial purge and pressurization of the gasifier train uses a substantial amount of nitrogen, requiring special operator diligence to return the second gasification train to service while maintaining operation on the first train. During commissioning, the plant relied on liquid nitrogen trucked in from other ASU facilities to meet the demand, at great cost and occasional delays to the project. Future applications should consider the cost of nitrogen during startup and investigate ways to recycle the vented nitrogen. Dryer, lockhopper, and surge-bin fluidization consumes most of the plant's high-pressure nitrogen after the trains have the AGR in service, and this nitrogen is vented from a series of baghouses. This stream could be filtered and routed to the recycle compressor for reuse in the solids handling system. If much of the nitrogen was recycled and could be used under relaxed purity standards for operation, the options for nitrogen production would increase, further lowering lifecycle costs. In such a scenario, the critical quality nitrogen would be supplied by liquid storage and vaporizers, at much smaller rates.

Due to the cryogenic nature of LiN, the storage vessels are much colder than ambient, and are negatively impacted by local air temperatures and solar energy impacting the vessel walls, even when insulated. The LiN storage tanks are filled with thermodynamically saturated nitrogen, which reacts to changing energy (heat) flows. As heat is added to the tank, more vapor is released, raising the tank's pressure. To prevent an overpressure event, some of the vapor must be vented off. In many LiN applications, the vented pure nitrogen from this thermo-build action is directly vented to atmosphere rather than being recaptured for use to supply the plant's needs. With two different pressure nitrogen supply systems, 100 psi and 850 psi, the current LiN storage tanks are controlled to maintain ~100 psi. The vented thermobuild nitrogen could be directly injected into the lower pressure header. Otherwise, the vented nitrogen could be routed to the suction of the HP nitrogen compressor alongside other nitrogen separated by the nitrogen plant. A provision to route the vented nitrogen used in cooling LiN trailer pumps before refilling the storage tanks would save more cost, improving the plant's bottom line. Considerable effort was expended to limit the impact of availability of nitrogen to plant commissioning and startup operations. Future facilities should consider startup and the cost-benefit of design options regarding nitrogen users earlier in design.

4.7.2.4 *Final Summary*

The nitrogen system and the ASU were commissioned, with some system modifications needed, in a relatively orderly manner. The system capacity was stretched thin during initial startup of each gasifier and during integration of the remaining stages of each train, until recycle sweet syngas was made available during normal steady state operation. LiN had to be used to supplement system demand of the ASU during these times. This major need, and the need for additional valves in the system to facilitate a smoother clearance process, should be considered for a future design.

4.7.3 General Water Systems

Water as a utility is essential in specifying project requirements. The IGCC plant requires potable, process, and cooling water as well as treatment, make-up supply, storage, final disposition of waste streams. These are discussed in detail in this section. The general block flow diagram of the Kemper water systems (figure 4.7-1) shows the interconnected nature of the multiple systems.

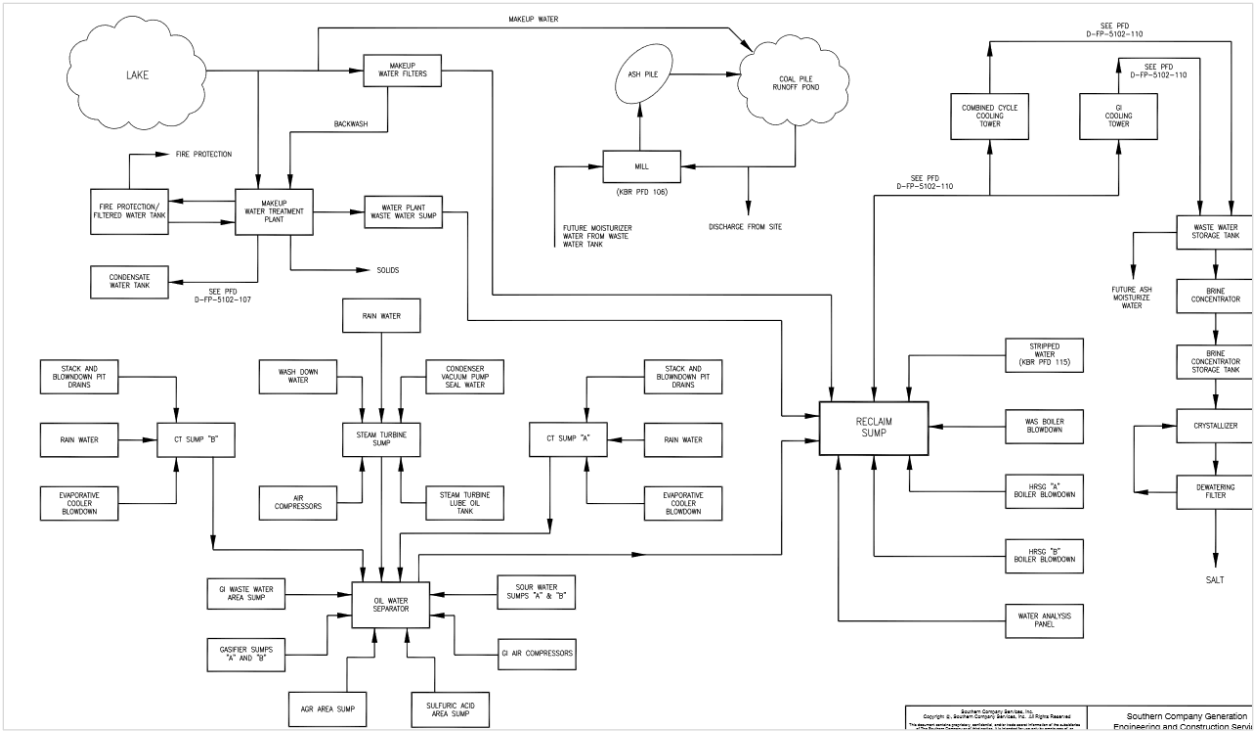


Figure 4.7-1 – Block flow diagram, Kemper water systems

4.7.3.1 *Make-up Pond and Meridian Gray Water*

Most power plants are located close to a water source to minimize installation and operation costs. Kemper is one of a growing number of plants designed to use gray water from a local sewage treatment system (Meridian, Miss. in this case). This design avoids the plant taking water from local rivers and streams, and the municipality does not discharge treated water back into local waterways. Grey-water systems require onsite storage to accommodate disparate supply and demand rates, and pipelines from the water sources to the onsite storage.

The 130-acre treated effluent pond at Kemper was completed in the fall 2012, as well as the pipeline from the two Meridian treatment plants and associated pumping stations provided by the project. The pumping stations had several electrical issues to address before being completely reliable, but filling of the pond began on Oct. 15, 2012. Three months of pumping was required to fill the pond to sufficient level for the intake water pumps to reliably operate for final checkout and commissioning in January 2013.

4.7.3.2 *Filtered and Fire Water*

The first stage in treating the water from the holding pond is filtration. The pond intake water pumps discharge directly to the onsite water treatment facility for filtering. The plant's washdown and fire water are drawn from the filtered water tank. The piping connections for normal filtered water are halfway up the tank walls, leaving the bottom half of the tank as a dedicated fire water reserve supply. The filtered water tank does not normally receive treatment for biological growth and has on occasion experienced infestations that impacted downstream treatment operations and other processes. These infestations usually grew in the still areas at the bottom of the tank and were disturbed when water was recirculated in testing the fire pumps. The material would be pulled into the normal downstream treatment processes, causing fouling and reducing throughput. The infestations were treated with a biocide shock, and the pump inlet strainer was cleaned.

The fire water system consists of one electric and two diesel driven pumps, each with enough discharge head to supply fire suppression to the cyclonic baghouses nearly 300 ft above the pump discharges. Booster pumps for the gasification tower were not required. Several excursions with the fire water system can be attributed to the higher than

typical fire water header pressure, especially when subject to sudden pressure upsets as when branches were cut in. Fire water is also used as deluge water to minimize potential anhydrous ammonia releases in the storage areas for shipping and the HRSG SCR.

4.7.3.3 *Water Treatment Plant*

In an effort to maximize efficiency and minimize per unit water costs, the plant subcontracted most water treatment functions to AquaTech International. Their scope was to provide high purity demin water for high-pressure steam production, and to manage the wastewater unit to meet the zero liquid discharge permitting requirement. Demin water is prepared with a series of ultrafilters and reverse osmosis units before the final ion exchange beds that discharge to the condensate make-up tank or directly to the condenser hotwell. AquaTech personnel commissioned this unit as utilities became available.

The plant uses demin water to charge and make-up several closed loop heat management systems as well as process water make-up streams. The AquaTech unit was sized for long-term syngas operations, which is substantially less than required for demin water and condensate in initial commissioning and natural gas operation by the gas turbine. Additional connections for demin water trailers were added early in commissioning. These trailers arrive loaded with filters and ion exchange beds and can process ~200 kgal of demin water before being pulled at 400 gpm. Three trailers were available to support plant operations during commissioning.

At times during commissioning, operations were constrained due to high demand and conflicts with regeneration schedules. Because the trailers were more self-sufficient, they provided the initial demin water to the closed loop cooling water systems. Utilities were dependent on each other, which at times could cause a conflict. The water treatment plant needed instrument air to operate, but most of the instrument air compressors require closed loop cooling water charged with demin water from the water treatment plant. In this case, water treatment trailers and one air-cooled air compressor were employed.

4.7.3.4 *Condensate Storage and Make-up*

Steam-electric units condense steam at the turbine exhaust and recirculate the condensate back to the steam generators. The total amount of water in circulation in steam cycle equipment varies at different points in the load range. This process requires an additional storage tank to hold unneeded water at low loads and supply condensate as load increases. When steam is lost from the system to gas turbine operations or other process consumers, the condensate is replaced from the storage tank and the demin water tank at the water treatment plant.

Cleanliness of the condensate system, starting at the demin water tank, is critical for reliable and efficient steam cycle operations. During early commissioning, the tanks were washed and rinsed several times to achieve the required purity in the water leaving the tanks for downstream consumers. The condensate being returned from the gasification island flash tanks was cleaned to the same standard.

4.7.3.5 *Wastewater and Zero Liquid Discharge*

When a site starts as greenfield, it almost always will be permitted as a zero-liquid-discharge (ZLD) facility. This restriction will require considerations to manage all waste streams generated by the facility, including storm runoff from the process areas. For a ZLD site, wastewater must be treated and recirculated in the processes until it is evaporated.

For Kemper, the treatment of the plant's wastewater was subcontracted to AquaTech, which also managed most water treatment functions. AquaTech provided and operates a filtering and concentrating unit (brine plant) that discharges a solid waste stream of salts and solids removed from the wastewater. The ZLD unit draws water for processing from the wastewater tank, which is filled from cooling tower blowdown streams. The water is filtered, with the remaining dirty water continuing to the evaporator. The filtered water is recycled in the reclaim sump. This system was commissioned by the AquaTech staff separately from rest of the facility. They required adequate electricity, instrument air, 50 psig steam supply, and plant wastewater to begin operational testing.

A set of temporary wastewater vaporizers were used to concentrate the chemical cleaning wastewater produced during commissioning. A similar system could be modified to manage bottoms from the sour water and ammonia purifier units, with the vent stream suitably routed to prevent release of trace contaminants.

4.7.3.6 *Cooling Towers and Circulating Water*

Cooling towers remove heat from the circulating water stream by evaporation. The warm circulating water is sent to the spray header at the top of the cooling tower. It is finely atomized into the air stream created by the tower fans drawing through the tower's packing to maximize air-water contact. The Kemper facility has two towers, one dedicated to the combined cycle power block and the other for the gasification island equipment. Both are equipped with circulating water and auxiliary circulating water pumps. The circulating water pumps supply water to the condensers and other coolers that need the coolest possible water for efficient operations. The auxiliary circulating water pumps provide the cooling water to the closed loop cooling water systems. The combined cycle circulating water pumps are the larger pumps on the CC cooling tower, while the GI auxiliary circulating water pumps are the larger on the GI cooling tower. As the cooling towers use evaporation to remove heat from the returning hot circulating water streams, the resulting cold basin temperature is a function of the ambient dewpoint.

The circulating water is constantly being evaporated, and large quantities of make-up water are required. This water is provided from the reclaim sump that collects water from building sumps, water treatment plant, sewage treatment plant, filter press filtrate, and blowdown tanks. Most reclaimed water has been processed through an oil-water separator before reaching the sump itself. As the circulating water evaporates in the cooling towers, most of the contaminants in the water basin remain, increasing the concentration and affecting the pH and corrosiveness of the water. One method used to control the contaminants in the water is a blow-down of the towers, discharging a stream to the wastewater tank that feeds the AquaTech ZLD plant. Other treatment measures also are in use to allow higher levels of contaminants than cooling tower vendors typically recommend.

Cooling water systems are needed early in the commissioning process to initially bring up plant utilities. To support the early operation of the cooling towers, a second stream from the intake water pumps was routed to the reclaim sump and used to commission the reclaim sump, cooling towers, circulating water pumps, and heat exchangers for operational support of the other plant utilities.

4.7.3.7 *Closed Loop Cooling Water*

The plant's closed loop cooling water (CLCW) system is divided into two packages: the combined cycle and the gasification island related equipment. Both systems are charged with buffered, treated demin water. The closed loop cooling reduces the fouling related heat and corrosion issues seen in service water systems using cooling tower (circulating) water directly in lube oil and generator air or hydrogen coolers. The use of the closed loop cooling water greatly improved plant reliability and reduced year-over-year maintenance costs for cooler cleaning. It allows for more consistent water temperatures from summer to winter, minimizing thermally influenced operational events.

Each system consists of plate and frame heat exchangers to transfer heat to the circulating water. Cooling water pumps circulate the cooling water. A head tank maintains positive pressure on the pumps to prevent cavitation as the system load changes, and a make-up chemical injection line maintains level and quality. There are bypass valves at the opposite end of the loop to ensure minimum flow through the loop. Each cooler is fitted with temperature control valves on the discharge to maintain full pressure on the cooler itself.

- Combined cycle closed loop cooling water

The combined cycle closed loop cooling water system is typical for a single 2 x 1 combined cycle application, providing utility cooling water to turbine-generator gas coolers, boiler water sample chillers, and lube oil coolers for turbines, pumps, and instrument air compressors.

After hand cleaning and initial flushing, the CC closed loop cooling water system was charged with demin water and air-freed by venting before being placed into service. Because this system is similar in size and scope to other

combined cycle units, only initial checkout and standard acceptance testing was needed to release the system for service.

- Gasification island closed loop cooling water

The gasification island closed loop cooling water (GI CLCW) system is subject to an unusually high demand. In addition to supplying lube oil coolers and electric motor coolers for more than 225MW of operating machinery (300k hp), the GI CLCW provides process cooling in the lignite prep, process air, syngas, sour water/ammonia purification, acid gas removal packages, and air separation unit. There are three 1,950hp pumps and six plate and frame circulating/cooling water heat exchangers in the system, with no effective spare for either pump or heat exchanger. There are provisions for back-flushing the circulating water side of the heat exchangers, and coarse mesh strainer baskets are installed, but the strainers will not stop the fine (<250µm) particles in the circulating water.

After hand cleaning and initial flushing, the GI CLCW system was charged with demin water and air-freed by venting. The air-freeing was complicated by several loops not being completed to a point they could support cooling water, and by the wide coverage (approximately 3/4 sq mi) of the GI CLCW headers. Some coolers were elevated up to 70 ft above grade, requiring additional time for venting to ensure no pockets remained in the coolers or connected piping. After the system was completely vented, each pump was carefully worked into service, avoiding overload conditions from too much flow or discharge pressure. The pump isolation valves had to be regulated during this period, due in part to the sensitivity of the 20-in. kick-back valve. After flow was established in most of the separate branch loops of the GI CLCW system, all three pumps were in service and the system performed as designed.

- CLCW issues

The most frequent trips on the CLCW system were attributed to the air separation unit (ASU). The ASU has two CLCW applications that are not typical for that type of system. The first is a direct contact absorber (DCA) heat exchanger, which has dual functions. It has better cooling efficiency than many indirect cooling options and washes out impurities in the ASU process air stream before they can impact the metallurgies of the cryogenic cooling system. The CLCW is constantly being re-oxygenated and contaminated by the DCA. The DCA function also was impacted by CLCW treatment chemicals and biological contamination resulting from lack of treatment.

The other atypical CLCW application is the liquid nitrogen (LiN) vaporizer heated by the CLCW stream. This application requires precise temperature control of the CLCW, which was not identified during initial design. Isolating the DCA from the CLCW addressed the cause of several plant-wide trips and reduced Operations staff workload in monitoring, sampling, and controlling what is otherwise a twice-per-shift requirement. The LiN vaporizer design is not a passive design, which was assumed by Haz-Op or SiL studies and would require additional layers of protection to be implemented at the desired risk level. Removing these two atypical components from the CLCW would improve overall CLCW reliability and reduce demand for operator supervision and intervention.

4.7.4 Tempered Water System

4.7.4.1 *System Overview*

The tempered water system is a waste heat integration system that collects waste heat from various process heat exchangers and provides heat for coal drying. It touches a large part of the plant in order to collect all useful residual heat. Due to its size and highly integrated nature, the control strategy of the tempered water system is complex. The system must balance all available heat sources and heat sinks in the gasification island during all normal operating and transient conditions.

The tempered water system itself consists of a network of heat exchangers, pumps, and control valves connected in a closed loop network of piping. Two 100% pumps circulate treated water through the closed system. The water picks up waste heat from process heat exchangers or by being heated indirectly with steam from the tempered water heater (HX0095), then is used to provide heat to the fluid bed dryers for coal drying.

The tempered water system provides cooling water to several process exchangers that are indirectly heated with sour syngas, air, and an ammonia water mixture. Because the system has the potential to develop simultaneous tube leaks in both an air and syngas exchanger, steps were taken in the design to segregate air and syngas from each other in order to prevent combustible mixtures. Gas disengaging sections were added downstream of all the process heat exchangers to either vent air to the atmosphere in the case of an air exchanger tube leak, or vent syngas gas to the flare header in the case of a syngas tube leak.

Additional complexity was introduced to the tempered water system by an error with the rated pressure of some of the tempered water heat exchangers used in the coal drying area. During procurement, it was realized that the PC drying heaters were only rated for 175 psig, which was below the design operating pressure of the tempered water system at the time. In an effort to limit schedule slip and reduce cost, the tempered water system was fundamentally changed to accommodate operations at lower pressures. The tempered water expansion tank was moved to the discharge side of the pump and controls were added to ensure the discharge pressure leaving the pump could be controlled using the head tank pressure controller. The suction side pressure would vary depending on where the pump was operating on the pump curve. Controlling the head tank pressure and flow through the pump are critical parameters for ensuring the system operates smoothly.

There is a gas disengaging section just upstream of the tempered water pump suction return, which makes flow control and discharge pressure control even more important. If the flow through the pump is decreased while the discharge pressure is fixed by the head tank pressure control loop, the system runs the risk of lowering the liquid level in the suction standpipe to the point that gas from the flare is entrained. This could potentially damage the pump (figures 4.7-2 and 4.7-3). As the flow through the pump is restricted the system moves further back on the pump curve. With the discharge head fixed by the head tank, the only variable to manipulate and develop more discharge head is the suction pressure at the pump which, if lowered, in turn lowers the liquid level in the suction standpipe. This design feature could result in pulling gas into the suction of the pump if the head tank pressure were not controlled correctly. If the pump were to trip or move too far out on the pump curve, the level in the gas disengaging section upstream of the suction of the pump could overfill and send water into the flare header. Due to the lower design pressure of the coal drying heat exchangers, there is little margin between the desired operating pressure of the system and the point at which the PRVs in the system will began to lift. The discharge pressure at the tempered water pumps is 165 psig, or 10 psig away from the PRV lift pressure.

The control scheme for the tempered water system is relatively complex for a heat recovery system. As heat input from the process heat exchangers increases or decreases, the tempered water system must respond to meet both the energy demanded of the fluid bed dryers for coal drying and the cooling demand of the process heat exchangers. The tempered water system must bridge the gap between heat recovered from the process heat exchangers and heat demand from the fluid bed dryers. One of the more critical control loops of the tempered water system is the split range differential pressure control loop that controls the pressure drop across the fluid bed dryers. As the demand for tempered water goes up at the fluid bed dryers, the flow control valves open, which lowers the pressure drop across the fluid bed dryers. To increase flow to the fluid bed dryers, the tempered water system first diverts any flow going toward HX0091 (a waste heat recovery heat exchanger) and sends it to the fluid bed dryers by closing the valve downstream of HX0091. After this valve is completely closed, the split range controller begins to open a valve that diverts flow around the process heat exchangers, increasing flow to the fluid bed dryers and bringing the differential pressure back to set point across the dryers (figure 4.7.2). When the demand for tempered water goes down, the fluid bed dryer control valves will begin to close and increase the pressure drop across the fluid bed dryers. As the pressure increases, the bypass valve around the process heat exchanger will begin to close. After this valve is completely closed, the bypass valve around the fluid bed dryers will open and allow flow to be diverted to HX0091. The differential pressure controller is the key control loop to balancing the heat generated from the process heat exchangers and the heat needed for coal drying at the fluid bed dryers.

The tempered water heater (HX0095) is critical to providing heat to the fluid bed dryers. This exchanger uses LP steam to heat the tempered water upstream of the fluid bed dryers. During a startup scenario or when there is not enough hot water generated by the process heat exchangers, HX0095 will provide the heat needed for coal drying. The LP steam used to heat the tempered water passes through the shell side of the heat exchanger and tempered water flows

through the tube side. The tempered water temperature is controlled using the discharge temperature leaving HX0095 as the process variable to adjust the condensate level on the shell side of the heat exchanger. As the liquid level increases in the shell of the exchanger, the available heat transfer area decreases and limits the amount of heat input from condensing steam on the shell side. After the shell is completely full of condensate, there is no more area for heat transfer and heating of the tempered water is stopped.

If the fluid bed dryers no longer require tempered water for coal drying and the process heat exchangers still require cooling, the tempered water trim cooler (HX0094) provides the necessary cooling for the process heat exchangers. This heat exchanger was sized to handle the full load from all process exchangers in the system. This scenario can occur when shutting down the dryers, while maintaining coal feed to the gasifier to deplete the levels in the coal silos. HX0094 uses tower water to cool the tempered water that passes through the tubes of the exchanger. The temperature of the tempered water is controlled using a split range control loop that will either bypass the tempered water flow around HX0094 or divert more flow through the heat exchanger in the event that more cooling is needed.

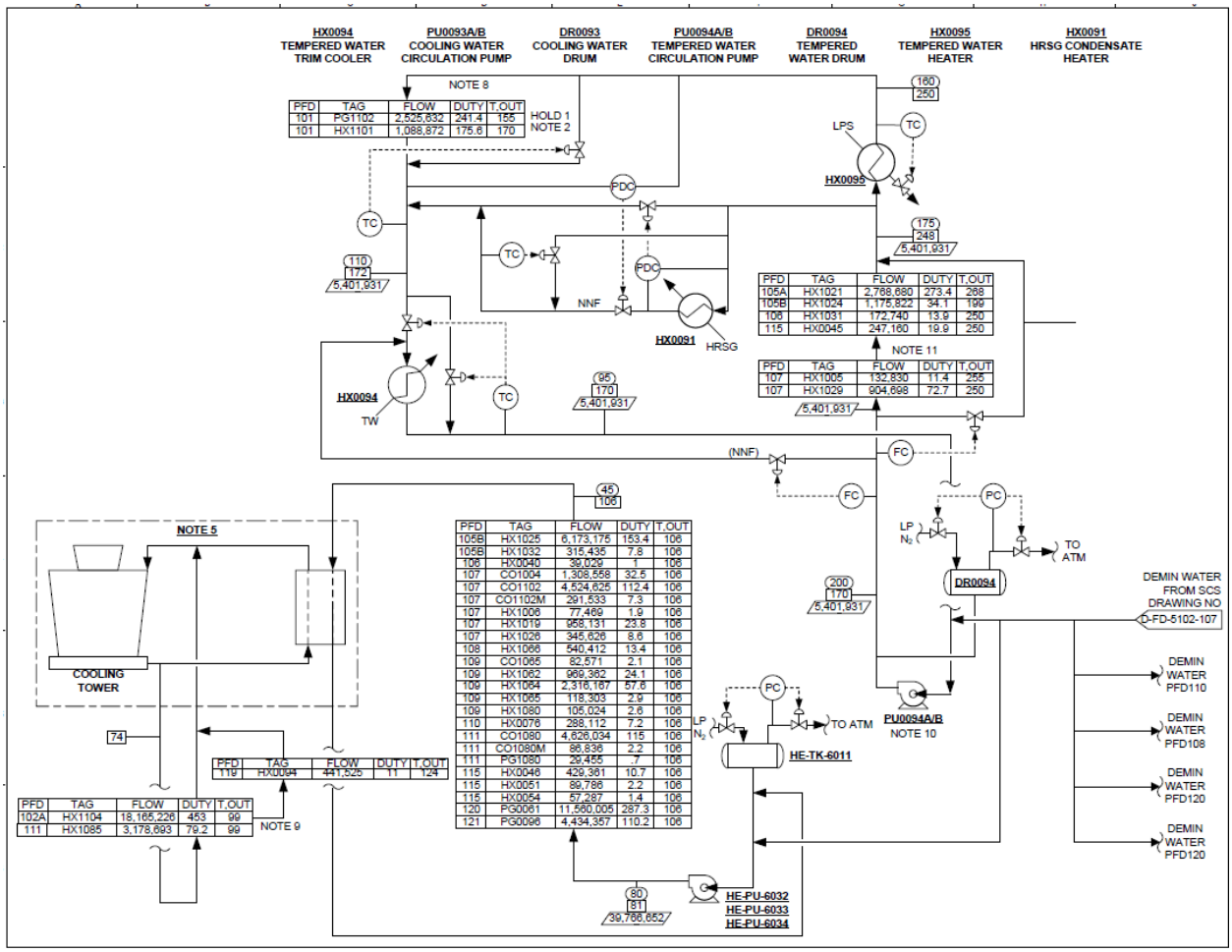


Figure 4.7-2 – Process flow diagram of tempered water system

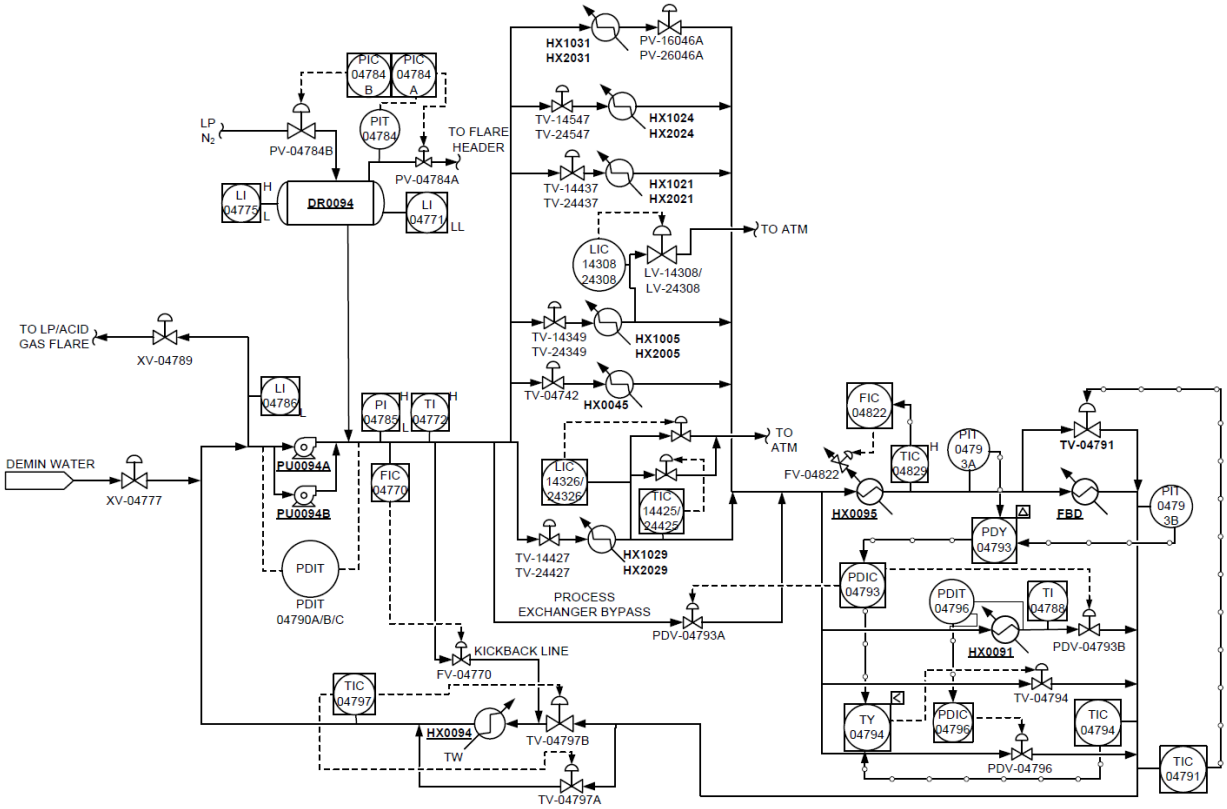


Figure 4.7-3 – Detailed process flow diagram with control loops

4.7.4.2 *Initial Commissioning Plan*

The initial commissioning plan for the tempered water system called for first filling the system with demin water and venting all the trapped gas out of the system. The concern with leaving gas trapped inside the tempered water system was that it could induce water hammer and damage the piping if a section of water hit an elbow or other turn in the piping network after the air was pushed through the system.

After filling the tempered water system with demin water, the next step was to run the pump and tune the kickback valve. It is critical to control the pump location on the pump curve, which controls the liquid level in the suction standpipe and prevents pump damage. The starting conditions in the head tank and suction standpipe must be correct. The suction standpipe and head tank at the discharge of the pump act like a large U-tube monometer. After the pump starts pumping water, the head developed by the pump will pull the liquid level down in the suction standpipe and push liquid into the head tank. If the starting pressure is too high in the head tank, the pump could easily lift the PRV or overpressure the tank. If the suction standpipe has too low a liquid level, gas could be pulled into the pump and cause damage. The system settle-out conditions were calculated and were built into the logic to prevent a pump start if the settle-out conditions were not met. The pump was started in total kickback, with the kickback valve in manual at a calculated position while the pressure control loops on the head tank were tuned. After the head tank pressure control loop was tuned, the kickback valve was tuned. The kickback valve was used to control the pump at a fixed point on the pump curve.

After the kickback valve and pressure control on HX0095 level pot DR0094 were tuned, the next critical control loop to be tuned was the split range differential pressure control loop PDIC04793. This loop modulates the flow of tempered water to the fluid bed dryers based on the pressure drop across the fluid bed dryers. It is the critical control loop that balances flows of the tempered water system to ensure there is enough heat provided to the fluid bed dryers or to divert excess heat away from the fluid bed dryers if more heat is generated than required. The differential pressure

control loop was initially tuned by modulating the bypass valve around the fluid bed dryers TV04791 to replicate the changes in differential flow through the fluid bed dryers without sending water through the fluid bed dryers.

The next critical control loops to be tuned were the two temperature control loops TIC04829 and TIC04797. Heat was added to the tempered water system using HX0095 to make up the heat demand when the process heat exchangers were not providing an adequate amount of heat. The heat input to HX0095 is controlled by modulating the condensate level on the shell side of the heat exchanger, using temperature control loop TIC04829, which controls the valve position of FV04822. Control valve FV04822 allows liquid condensate to drain from the shell side of HX0095 and flow into the LP condensate header, which uncovers the tubes of the heat exchanger and allows more heat to be transferred into the tempered water. While the temperature control loop on HX0095 was being tuned, the temperature control loop TIC04797 around HX0094 was tuned simultaneously. HX0094 cools excess tempered water from the process heat exchangers, with the amount of cooling controlled by a split range control loop that modulates the flow through and around the heat exchanger. If the temperature leaving HX0094 is below a set point, the bypass valve will begin to open and the valve that allows flow through the exchanger will start closing. The two control loops had to be tuned simultaneously to prevent overheating the tempered water system.

The final control loops to be tuned were TIC04794 and PDIC04796. Temperature control loop TIC04794 controls the temperature of the tempered water leaving the fluid bed dryers or HX0091. Heat exchanger HX0091 heats HRSG condensate water when excessive tempered water is generated from the process heat exchanger and flow needs to be bypassed around the fluid bed dryers. The HRSG condensate heater HX0091 has the potential to lower the temperature leaving the exchanger below 170 °F. TIC04794 is used to bypass flow around HX0091 if the mixed flow coming from the fluid bed dryers and HX0091 is below 170 °F. By bypassing the flow around HX0091, hot tempered water will mix with the cooler tempered water and increase the temperature back up to 170 °F before it goes back to the suction of the tempered water pump. The tempered water temperature is maintained at 170 °F to ensure the temperature leaving the process heat exchangers is at a suitable temperature for coal drying. PDIC04796 diverts excess flow around HX0091 through a bypass to prevent excessive pressure drop across the HRSG condensate heater HX0091. There is an operating scenario where the process heat exchangers are providing significantly more hot water than the fluid bed dryers need and HX0091 cannot take the entire flow from the process heat exchangers. The bypass around HX0091 must be opened to avoid taking tempered water from the process heat exchangers.

The final step in the tuning of the tempered water system was to tune all the process heat exchangers serviced by the tempered water during their own unit operations testing and commissioning. For example, the intermediate temperature syngas cooler HX1021/HX2021 was tuned during the nitrogen heat-up test package of the WGS system. Retuning the various control loops was undertaken while operating under normal operating conditions with design process fluids and conditions. This process was required to ensure the system had been properly tuned.

When all the control loops had been tuned, interlock testing was performed to ensure the various interlocks in the tempered water system worked correctly. To simulate a pump failure, one of the tempered water pumps was stopped to ensure the spare pump started. The interlock on the extraction air compressor recuperators was tested. If the tempered water pumps stopped for a specified duration, the system would trip a dump valve to keep tempered water flowing through the extraction air recuperator to prevent damage to the exchanger from overheating. It was verified that the SIS interlock that trips the whole plant was functioning correctly by simulating a pump failure and ensuring that the SIS system responded correctly.

4.7.4.3 *Significant Events*

Tempered Water System	Start Date	End Date
Turnover packages (TOP) from Construction complete	10/10/2013	8/4/2014
Perform clearance activities	1/15/2014	3/13/2015
Resolve kickback valve design including procure and install new valve	1/12/2015	4/15/2015
Execute test package (TP1001)	6/15/2015	9/15/2016
Identify and repair pump vibration issue	8/5/2015	1/7/2016

- Kickback valve sizing

During development of the control loop tuning plan, which was part of the test package development, the kickback valve on the tempered water pump was found to be undersized. The original kickback valve was not sized to maintain minimum flow through the tempered water pump when the downstream process heat exchangers were not in service. The valve was replaced with a spare valve of the correct size that was available onsite.

- High point bleeds

While executing the valve lineup for the test package procedure, it was found that high point bleeds needed to be installed to prevent pockets of gas from being trapped in some areas. Test package execution proceeded after the vents were added and some piping was reconfigured.

- Pump vibration

During the tempered water test package execution, the tempered water pumps began to experience high vibration at the motor inboard bearing. It was quickly determined that there was a strong correlation in the temperature of the tempered water being pumped through the system and the vibration at the pump (figure 4.7-4).

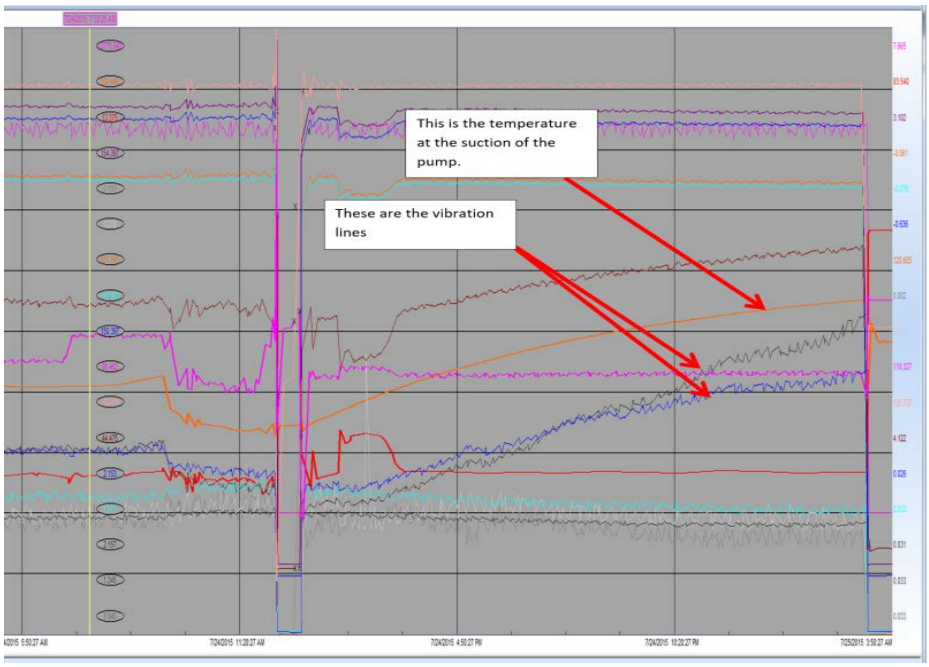


Figure 4.7-4 – Correlation of temperature and vibration

As temperature increased, the pump vibration increased correspondingly. It was determined that as the pipe was heating up in the tempered water system, the pipe growth and stress was moving the pump out of alignment with the motor. This issue was found to be caused by a mismatch in the piping and pump design standards between SCS and KBR design teams. Such design interface issues were considered on a broad basis, but did not catch this item

Expansion joints were added to the suction and discharge of the pump to alleviate the stress on the pump nozzles. Pipe growth stops were added to the system to limit pipe stress on the pump. The pump coupling was replaced with a disc-type coupling to prevent high vibration at the motor inboard bearing.

- Control logic change for thermal expansion

The control logic associated with the fluid bed dryer and the check valve configuration in the tempered water system resulted in blocking in tempered water while the water was being heated by the coal drying fan. This situation resulted in thermal expansion of the water trapped in the tubes of the heat exchanger, which eventually resulted in high pressure buildup in the tubes of the exchanger and the failure of all the gaskets. The trapping of liquid in the tubes of the heat exchanger and increased pressure was discovered during test package execution and resulted in failure of multiple gaskets in the fluid bed dryer. The in-bed heat exchanger was not damaged. The control logic was changed to open the tempered water flow control valves when the fluid bed dryer fan was started, to prevent a reoccurrence.

- HX0095 temperature control

The control strategy for HX0095 is to modulate the condensate liquid level in HX0095 as a means to control the heat transfer surface area of the heat exchanger. As the liquid level on the shell side of the heat exchanger decreases, more tubes are exposed to heat transfer and more steam is drawn from the steam header to heat the tempered water.

The initial design did not have any liquid level indication on HX0095, which meant there was no effective way to know how the heat transfer area was changing in the exchanger.

A level transmitter was relocated to measure the liquid level across HX0095, and the controls were modified to not let the level drop significantly below the level of the heat exchanger. This arrangement improved the ability to control the heat transfer and to analyze when non-condensable gas had built up in the heat exchanger and needed to be vented.

- Venting non-condensable gas from HX0095

There was not an effective way to vent non-condensable gas from HX0095. During operations of the tempered water system, it was discovered that the temperature of the tempered water leaving HX0095 could not be maintained, despite having a vapor liquid interface in DR0048. Very little steam was being pulled from the LP steam header, but the liquid interface in DR0048 meant all the tubes in HX0095 are uncovered and exposed for heat transfer with steam, which should pull a large amount of steam. It was concluded that non-condensable gas had built up in the exchanger and needed to be vented out. A method was developed to vent non-condensable gas from HX0095 while running the tempered water system, but because the liquid level in HX0095 could not be controlled during venting, there were process upsets and a limited amount of heat that could be delivered for coal drying in the fluid bed dryer. A design modification was being developed to vent non-condensable gas from HX0095 without having all the tubes uncovered. The modifications planned for venting non-condensable gas would have eliminated process upsets by maintaining liquid level in the heat exchanger.

- Temperature control loop HX0094

The temperature transmitter downstream of HX0094 was not far enough downstream to allow for adequate mixing, and the temperature measurement was not accurate. The temperature measurement using TIT04797, directly downstream of HX0094, was significantly different from TIT04772 at the discharge of the tempered water pumps. This difference was discovered when heating of the tempered water system was started as part of the test package. The logic was changed to use the temperature transmitter downstream of the tempered water pumps, which added a delay in the control loop and contributed to instability in the temperature of the tempered water leaving HX0094. After the control loop was modified to use the temperature measurement at the discharge of the tempered water pump, the long lag in measurement introduced temperature swings of roughly +5 °F to -5 °F in the tempered water system. The poor system response could not be tuned out of the system. Moving the temperature transmitter closer to HX0094 would have resolved this issue. This modification had not yet been made when operation was suspended.

4.7.4.4 *Final Summary*

The biggest issue with the tempered water system was the vibration at the motor inboard bearing. The motor vibration limited the ability of the tempered water system to be heated to normal operating conditions in order to support the testing of the fluid bed dryer. After the issue was resolved, the tempered water system performed as expected and fully supported the fluid bed dryers. The tempered water heater (HX0095) pulled the estimated steam from the LP steam header per design.

Almost all the control loops worked as expected. One that did not operate properly, control loop TIC04791, was removed from the control logic due to flashing across the control valve. There was concern that the control loop could introduce instability in the system due to interactions with the other control loops. There were some tuning issues with TIC04797, which controlled the temperature of the tempered water leaving HX0094. The thermocouple for this control loop was too close to the mixing point where hot water was bypassed around the HX0094 and where cold water come from the outlet of HX0094. The thermocouple did not provide an accurate measurement of the water, and the process indication for the control loop had to be moved to TI04772 at the outlet of the pump. Changing the process indication increased the delay in the control loop and introduced instability in the system temperature.

The tempered water system was able to meet all the demands and requirements of the gasifier island during the commissioning phase of the project. Having to lower the operating pressure of the tempered water system did complicate the system and made it more susceptible to upsets. It would be advantageous to design for higher operating pressures and not have the thermal expansion tank located at the discharge side of the pump.

Despite the issues with the pump motor vibration and other minor issues, the tempered water system ultimately performed well, and the control system worked per design. There were lengthy delays in commissioning the system that led to delays in startup. For example, if startup and abnormal operating conditions been considered in the design phase of the project, the kickback valve might not have needed to be replaced with a larger valve to meet the startup requirements. Construction documentation and QA work led to delays in when commissioning work began. The

lengthiest delays associated with the execution of the tempered water system were related to the motor vibration problem.

4.7.5 Steam System

4.7.5.1 *System Overview*

- Steam

Steam is produced as a medium to transfer energy between various plant systems and to cool the higher-temperature process streams for downstream process and equipment requirements. Steam is used as a reactant for the gasifier and downstream catalytic water gas shift reactors.

Because of the steam pressure and temperature, and to protect downstream equipment, steam quality is critical. The absence of contaminants protects piping and turbines from corrosion or erosion. Sufficient superheat in the steam prevents condensation and erosion in piping, valves, and heat exchangers.

- Steam system overview

Process steam headers and condensate recovery

The gasification island uses steam to provide heat to several systems at three different pressure levels. The highest-pressure system, known as the medium pressure (MP) steam system, operates at about 820 psia. The MP steam system provides steam into the gasification process and purge process sampling systems, heats the sweet syngas being sent to the gas turbine, and provides emergency hydration vapor for the WGS reaction. The next system, the intermediate pressure (IP) steam system, operates at about 325 psia and is used to regenerate SELEXOL, strip hydrogen sulfide and ammonia out of the sour water streams, and further purify ammonia to commercial specifications. It provides steam to preheat the WGS reactors, the PCDs, and the WSA during return-to-service evolutions. The IP process steam is used to atomize diesel fuel in the startup burners and direct diesel injectors during gasifier heat-ups. The lowest pressure steam header, the low pressure (LP) steam header, operates at about 50 psia. The LP steam header provides trim heat to the lignite dryers, startup and supplemental heat to the tempered water system, and service steam to the plant's utility stations.

The three steam headers can be supplied from several sources: the syngas cooler superheater outlet or gasifier main steam, the WSA steam superheater outlet, the auxiliary boiler, and several sources within the gas turbine heat recovery steam generators (HRSG). The MP header is designed to normally be fed from the WSA process but can be fed from the auxiliary boiler, the gasifier island main steam lines, and the HRSG main steam line. The IP header is designed to normally be fed from the cold reheat or extraction steam from the HRSG and steam turbine but can be fed from a letdown station from the MP header, the auxiliary boiler, or a main HRSG steam let down valve. The LP header is designed to normally be supplied by cold reheat or extraction steam but can be fed from a letdown station from the IP header or the auxiliary boiler. The condensate from the IP steam users is routed to a designated flash tank where flashed steam is sent overhead into the LP steam header near the gasifier island. The condensate from the bottom of the IP flash tank is then routed to an LP flash tank where an overhead vent condenser captures energy from the flashed steam using HRSG condensate as the cooling medium. The condensate from the LP steam users is routed to the LP flash tank. The condensate held in the LP flash tank can then be sent back to the HRSG condensate loop or sent to the WSA as boiler feedwater for the steam system there. There is a dedicated pair of pumps for each user of LP condensate.

Auxiliary boiler

The auxiliary boiler provides steam to preheat the gasification island systems before establishing normal operations. The boiler provides steam to the HRSG deaerators, steam turbine seals, and the ZLD unit before normal steam supplies are available. It is a natural gas fired unit with water walls, economizer, superheater, and separate deaerator, rated for 325 psig. During plant commissioning, the auxiliary boiler provided steam for extended periods before the gasifiers were maintaining ~30% fuel throughput. This steam supported the lignite dryers, AGR regenerators, sour water

system, and PCD steam jackets during initial operations because the GT HRSG steam pressures and flows were not compatible with supplying sufficient amounts of steam to the gasification island without potentially overheating the HRSG reheater headers.

4.7.5.2 *Significant Events*

All three process steam header systems were blown clean using steam provided by the GT HRSG packages. There was a detailed, intricate plan to warm, dry, and blow down each leg from the HRSGs to several specially-located condensing steam vent/drain units (nicknamed "crabpots" for the steam blowing off the tops). Before the operation began, check valves were removed, valves pulled and replaced with spools, and pipe hangers set up for heat-up and blowdown. The steam backblow required 4 days to complete. Afterwards, the headers were restored and prepared for service. The final charging of the steam header using steam supplied by the auxiliary boiler occurred mid-2015, in time to support subsequent commissioning activities in the lignite dryer, AGR, sour water, and gasifier areas.

As the steam headers went into service, condensed steam from more than 100 process steam traps was routed to atmospheric blowdown tanks that drain into nearby building sumps, then on to the plant's ZLD waste water system. This condensate is near saturation temperature (>200 °F), which would overheat the sump pumps, so additional cool filtered water was required to manage the sump water temperatures. This condensate was constantly flowing at off-design and startup conditions, due in large part to the minimal amount of superheat in the steam per operating procedures (~50 °F at the source), the extended pipeline distances, and the relatively low velocities seen in standby and turndown operations. These flows were not properly planned for in evaluating the expected make-up flow to the cooling towers from the reclaim sump, leading to fewer cycles of concentration (and contaminant loading) in the cooling tower blowdown to the waste water tanks. While cleaner water in the cooling towers is good for cooling performance, the ZLD must filter and evaporate more water to generate filter cake and manage the tank level. This lost condensed steam represents higher costs in replacement demin water, required quench water for the sumps, increased filter and ZLD plant demands, and lost energy in the process steam system.

Steam generators need to manage contaminant concentration by bleeding (blowing down) a small percentage of recirculating condensate from the drums or steam/condensate separators. Otherwise, condensate blowdown flow is a function of heat loss in the piping systems. As steam piping is warmed for service, drains and vents are opened to establish steam flow in the piping, which will then condense while transferring heat to the piping and insulation cover. Depending on how the piping was laid up and protected during shutdown, the warming condensate may be initially dirty. As the pipe temperature rises, the condensate flow is reduced and the quality improves. The condensate drain needs to accommodate warmup conditions with sampling and safe bypasses to a sump, but much of the condensate should be recycled back to lower pressure steam headers or returned to condensate storage tank. During the initial warmup phase of plant operation, using steam from flashed condensate reduces the fuel required before meaningful production begins. This technique would also reduce the required size of an auxiliary steam source (boiler) to supply steam heat to various plant processes warming to return to service. As the piping comes to temperature, some heat is lost to the environment through the pipe insulation and other design features. Depending on the steam flow in the piping, the heat loss results in lowered steam temperatures, eventually reaching saturation and partial condensation to be drained by the steam traps.

Steam headers in a Rankine or a combined cycle power plant have adequate superheat and velocity to prevent condensation in the piping after the line has been put into service, but process steam applications do not have the same amount of superheat. They have longer piping and more variable mass flow and velocities than the power steam applications. The design of process steam headers should be different from power steam headers. Additional superheat exiting process steam generators would reduce this load, but steam traps are needed to remove the condensate resulting from long piping. These traps should drain into collection heaters maintained at a pressure higher than the next lower process steam header, to allow flashing of the high-pressure condensate into the lower pressure process steam header. The condensate would then cascade in pressure down to the lowest pressure condensate piping to be collected and returned to condensate storage for recycling. This process will save demin water and reduce the steam demand on lower pressure process headers. Using a concept from the Rankine steam power plant, the lowest pressure process condensate could be flashed at subambient pressure in a feedwater heater, which would

transfer the last of the thermal energy possible to condensate headed to the steam generator's deaerator and cool the returning condensate to hotwell compatible temperatures.

As the process steam lines were being prepared for service, the warming drains were too small to establish adequate steam flow to properly warm the piping. There were not enough thermocouples and pressure transmitters to convey the steam conditions at the isolation valve before it was opened. When the line has not been properly and completely warmed before the isolation valve is opened, there is a high possibility the initial burst of steam will condense before it reaches the process zone. To properly warm the line, flow is established through the line to drains and vents located close to the isolation valve itself. As the temperature in the pipe rises, so should the pressure, until the pressure in the pipe is greater than the process, while steam is blowing out the drain line. Another way to improve temperature control near the isolation valve is to steam-jacket the pipe with steam vented from the inside, to better manage internal steam temperatures and minimize condensate reaching the process. Using a steam jacket on the offline purge stream downstream of the steam isolation valve would help prevent condensation in the injection nozzle and reduce the thermal shock the nozzle experiences when steam is first introduced.

Due to the condensate return from the process heaters and reboilers, the system was contaminated when the H_2S stripper reboiler failed and started leaking sour water into the condensate return when the header pressure was reduced below the pressure in the stripper column. This leak was quickly identified and the reboiler condensate isolated from the return header. The rest of the system was blown-down to the building sumps to clean it to acceptable levels before returning the condensate to the hotwell.

The auxiliary boiler was commissioned, including phosphate boilouts, in fall 2013. Steam blows followed during the next year. During the long-duration operating runs, the boiler experienced numerous steam leaks and tubing failures. Repairs were made and the control system tuning refined to better support the operations personnel.

Due to the reliability issues with the auxiliary boiler and the operational constraints in pulling much steam from the GT HRSGs, two rental boilers were installed and tied into the IP steam header. Together, they were equivalent to the auxiliary boiler capacity (pressure, temperature, flow) and tied into the IP process steam header between the WSA and the sour water unit. Due to the local nature of the rental boiler controls, they required close onsite monitoring by operations. There were several failures on these boilers, but they were quickly resolved and did not impact commissioning and testing within the gasification island.

4.7.5.3 *Final Summary*

Steam is a critical resource needed for the startup and operation of the plant. After the cleaning blows were complete, several challenges were encountered during the tuning of the steam control systems. Despite the issues with the auxiliary boiler, all testing objectives for the steam system were accomplished. The MP, IP, and LP systems all were available and operated reliably in time for integrated gasifier testing and first coal feed.

4.8 Combined Cycle Power Block

4.8.1 System Overview

4.8.1.1 *Combined Cycle Overview*

The power block at Kemper consists of a traditional 2 x 1 combined cycle unit. It includes two combustion turbines (CT-A and CT-B) and a single steam turbine (ST). The exhaust from each combustion turbine is fed to a heat recovery steam generator (HRSG). Each HRSG produces a significant portion of the total steam required to operate the steam turbine, with the balance provided by the steam drums from the gasifier island.

The two combustion turbines for Kemper are modified to operate on syngas. Flame-diffusion combustors, rather than low-NO_X designs, prevent flashback caused by the hydrogen content of the syngas. Ports added to the compressor casing allow air to be extracted and supplied to the gasification island.

When firing syngas, each combustion turbine generates approximately 232 MW_{gross}. This power output is maintained across the expected ambient temperature range by adjusting the air extraction rate so the mass of the gas passing through the turbine is constant. For example, at low ambient temperatures, more air is induced into the compressor section because of the increased air density, allowing more air to be extracted. The total air entering the gasifier is relatively constant for a given load, so the mass flow rate of air from the process air compressor is reduced because increased extraction air is available, which decreases the power consumption of the process air compressor. To maximize the air induced into the compressor and maintain combustion turbine output during periods of high-ambient temperature, an inlet air evaporative cooling system is placed in service when the ambient temperature is at or above 65 °F.

Although the plant is designed and intended to operate on syngas, the capability exists to fire the combustion turbines on natural gas. During natural gas operations, steam must be injected into the combustion cans to limit thermal NO_X formation to 25 ppmv. The reduction in fuel mass flow rate during natural gas firing decreases power output as low as 200 MW at high ambient temperatures. Each engine can be fired solely on natural gas, syngas, or by co-firing a mixture of natural gas and syngas.

Each combustion turbine exhausts into a conventionally designed, triple-pressure level HRSG. When operating on syngas, the normal HRSG stack temperature is 274 °F, which is above the acid dewpoint temperature to avoid problems associated with wet corrosion. Any ammonium bisulfate deposits on the economizer tubes downstream of the SCR unit during operations with syngas will be removed by offline washing. Because emissions will be within permissible limits, there is not a need to inject anhydrous ammonia to the SCR unit with 100% syngas operation. In an extended co-firing operation, ammonia will be injected at a reduced rate, which could lead to salt deposits on economizer tubes.

High pressure (HP) superheated steam from both HRSGs is combined with superheated steam from the gasifier islands and passed to the steam turbine. Under normal conditions, the HP superheated steam enters the steam turbine at approximately 1,830 psia and 1,000 °F. Steam exhausted from the HP turbine is reheated in the HRSGs to 1,000 °F at 327 psia, combined with superheated intermediate-pressure (IP) steam generated in the HRSGs, and expanded through the IP turbine. Exhaust from the IP turbine is combined with superheated low-pressure steam generated in the HRSGs and passed to the low-pressure turbine before being condensed at 1.8 in. of mercury. Varying amounts of each steam level are extracted from the steam system for use in the gasifier island processes. At normal operating conditions, the steam turbine generates 310 MW_{gross}. For peaking duty, steam turbine output can be increased to around 365 MW_{gross} by firing natural gas in the HRSG duct burners.

A portion of the condensate from the steam turbine condenser is used for cooling in the gasification process before returning to the HRSG for further heating and deaeration. HP feedwater flows from the HRSG to the gasifier island, where it is used in the syngas cooler to generate the superheated HP steam.

Within the HRSG, an SCR is installed for NO_X reduction during natural gas operation at a location where the flue gas temperature is in the optimal temperature range of 600 to 700 °F. Liquid anhydrous ammonia is used for the SCR reagent.

The components shown in figures 4.8-1 and 4.8-2 are discussed in more detail in this section.

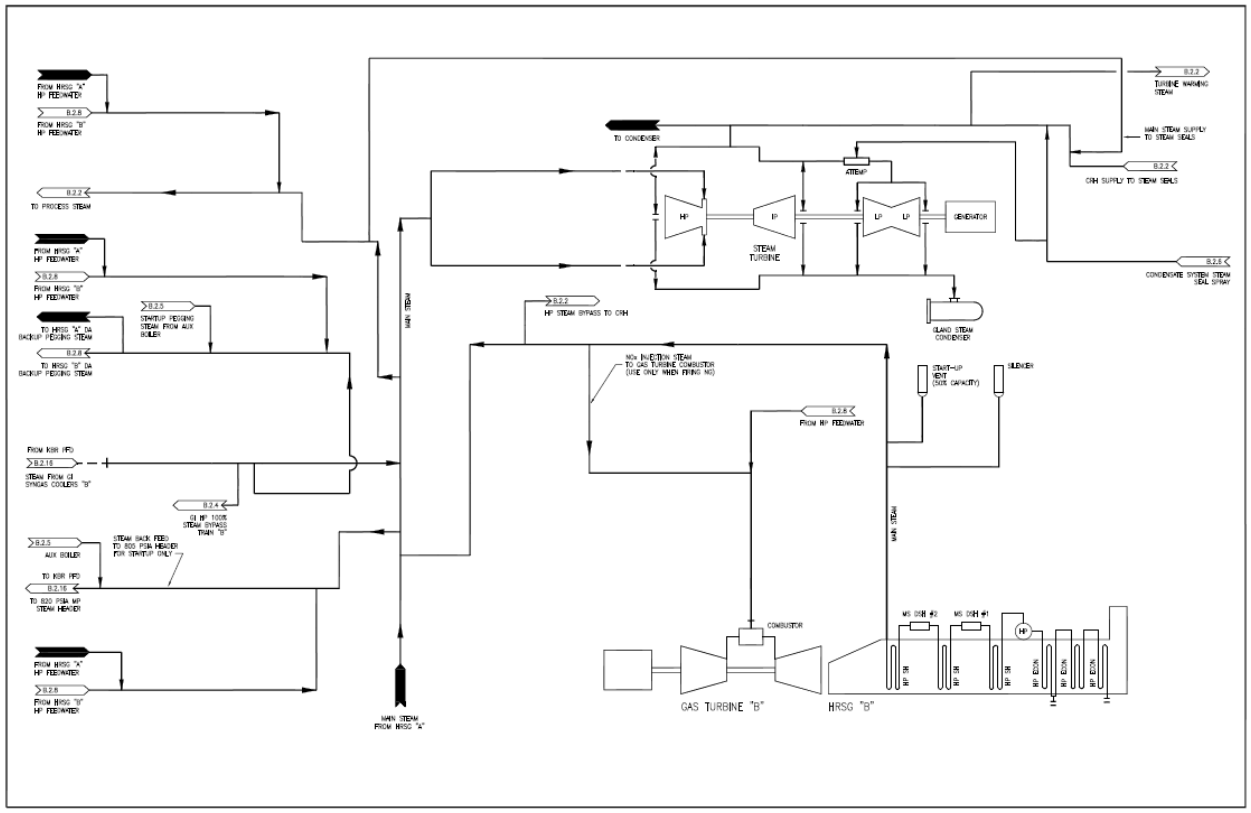


Figure 4.8-1 – Combustion turbine, steam turbine, and HRSG

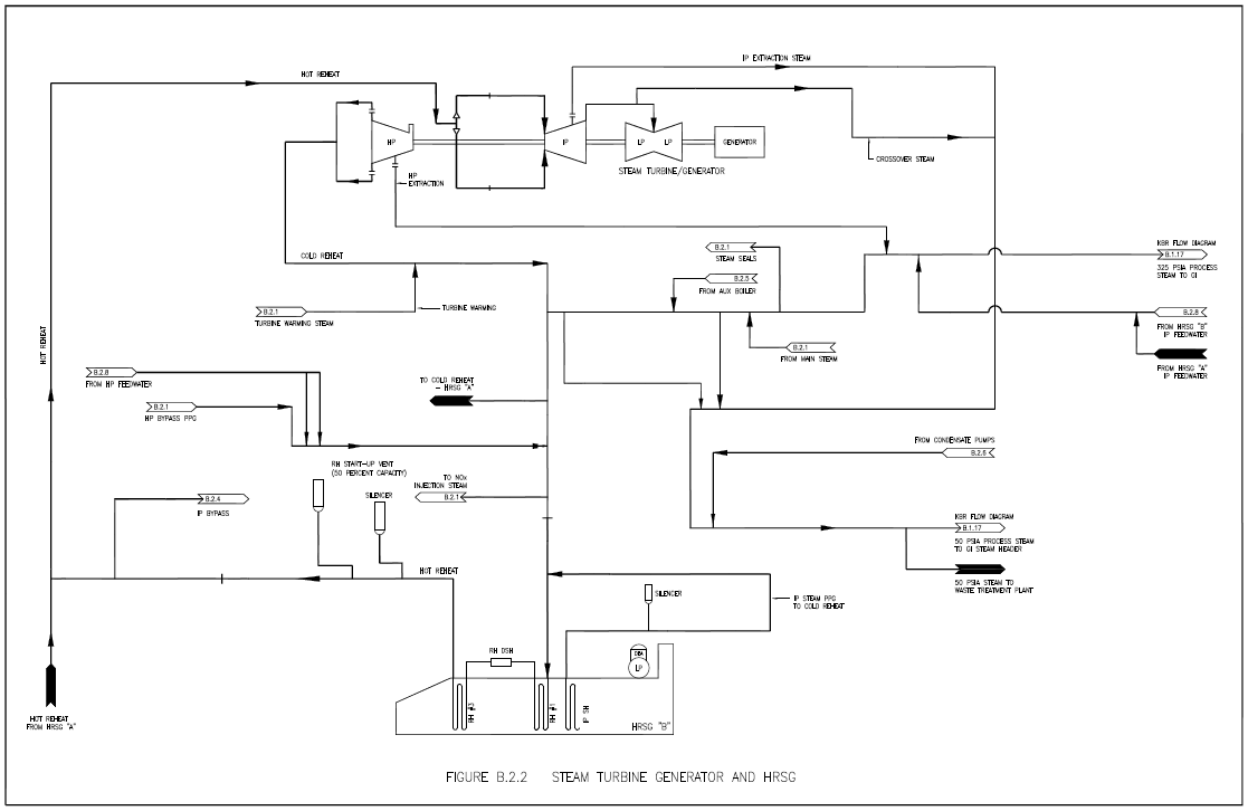


FIGURE B.2.2 STEAM TURBINE GENERATOR AND HRSG

Figure 4.8-2 – Steam turbine and HRSG

4.8.1.2 *Combustion Turbine*

The combustion turbine for the Kemper project is modified from a typical natural-gas-fired engine that uses a dry low NO_X (DLN) system. Equipment changes to the combustion turbine for IGCC application chiefly focus on the combustion system and fuel delivery systems. Figure 4.8-3 is a cutaway diagram showing the rotor and shell.

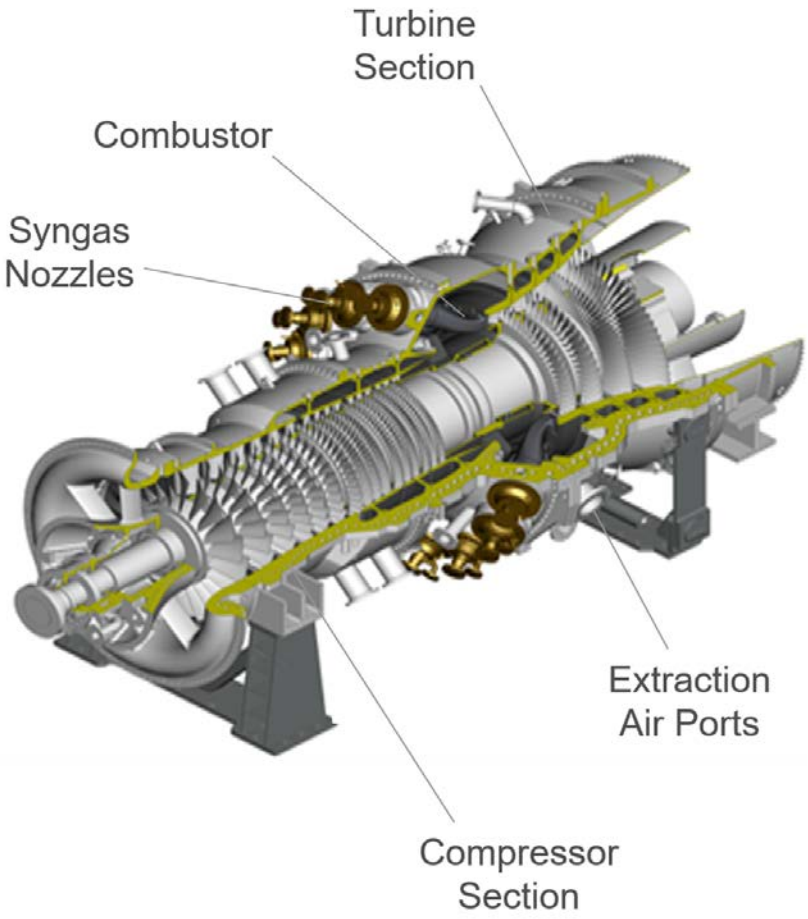


Figure 4.8-3 – Combustion turbine rotor/shell cross-section

The combustion system uses diffusion flame combustors arranged around the periphery of a combustor shell and introduces fuel into a single stage. Diffusion flame combustion is like a candle flame, where fuel mixes with air after ignition, a reliable and simple technology. It was the primary means of combustion turbine combustion before attention to NO_X reduction led to the introduction of premix systems, in which air is mixed with fuel before combustion and fuel is introduced in multiple stages.

Combustion system components are designed to operate on syngas and natural gas. Syngas is supplied through larger stage A nozzles in the combustor during syngas operation. Natural gas is supplied by stage B nozzles when the unit operates on natural gas or while co-firing. Steam is injected to limit thermal NOx during natural gas operations, using the stage A nozzles. Figure 4.8-4 provides an overview of the burner nozzle configuration and stage location for each combustor can.

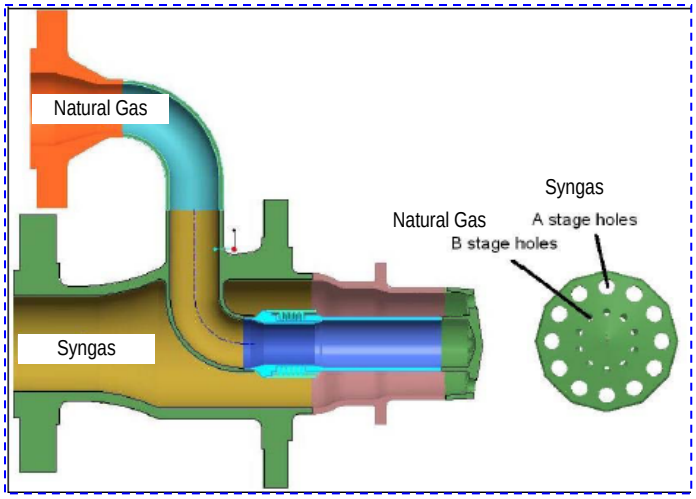


Figure 4.8-4 – Combustor can nozzle profile

The fuel nozzle is designed to accommodate multi-fuel operation, diluents injection, fuel transfers, and co-firing. It can introduce syngas, natural gas, steam, air, and nitrogen into the combustion system. Figure 4.8-5 shows the integrated layout of each fuel source.

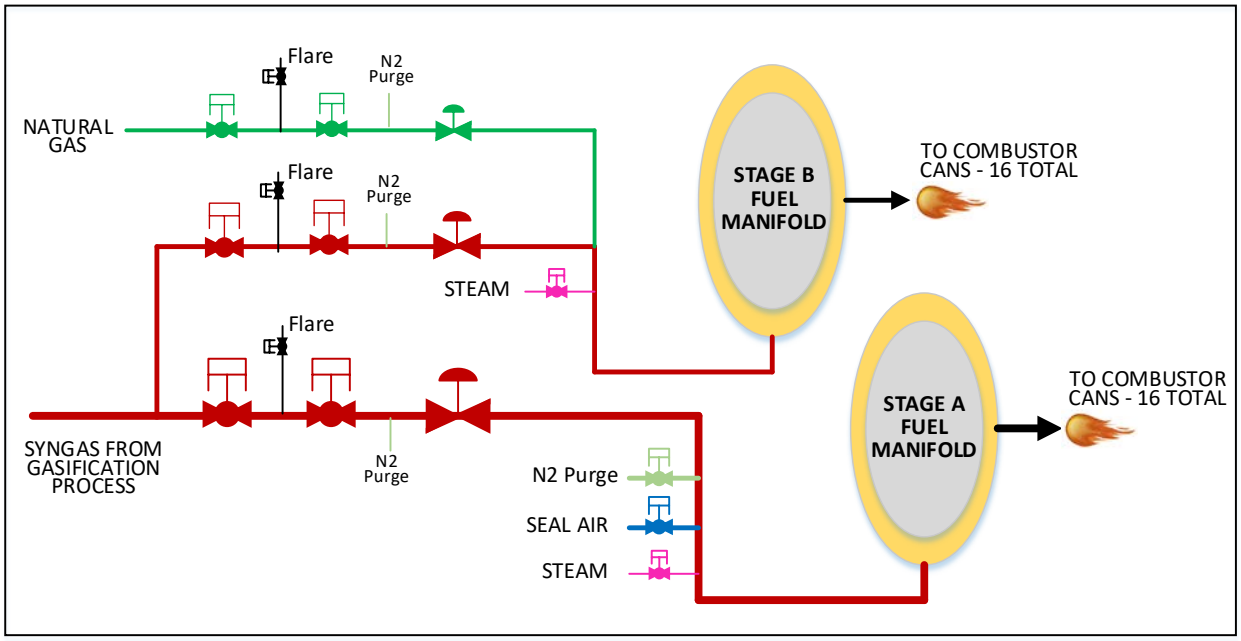


Figure 4.8-5 – Fuel supply to burner stage

Combustor baskets attach to a transition piece that fits into the row one vane inlet. Each basket contains a single retractable high energy igniter that is used for igniting gas in the combustor. Cross flame tubes are not used in this design.

Syngas is the primary fuel and is designed to operate the unit between 30% load and a maximum rated power of 232 MW. This fuel system is not intended to be operated below 30% load, so the system always is brought into service with natural gas. Because syngas is approximately 30% hydrogen, it is highly flammable and lightweight. The design must include precautions to prevent syngas escape to either the atmosphere or through backflow into the fuel manifolds. The system is designed per Hazardous Class 1 Division 2 Group D requirements.

Fuel is switched on a principle of maintaining constant energy. Energy supplied by the syngas is approximately nine times less than natural gas on a mass basis. By measuring energy input, two fuels can be mixed in various proportions to provide a constant energy content in the mixed gas.

The natural gas system is designed as an alternate fuel system capable of continuous full-load operation and must be used for ignition and startup of the combustion turbine until reaching 30% combustion turbine load. Above 30% load, natural gas may be co-fired with syngas as long as both fuels are at a ratio to meet a constant energy input. When operating with natural gas solely, or when co-firing, steam injection is required to meet NOx emission compliance when loads are 60% to 100%.

The combustion turbine includes an air extraction system that provides some of the air required by the gasification process. Without this air extraction, the process air compressors would have to be sized to meet the air requirements for the gasifier. This air extraction allows the combustion turbine to operate at maximum output, irrespective of ambient air temperature, after base-load conditions are established. The extraction air system functions closely with the gasification island and with the fuel the gasification island provides to the turbine. With this interdependence of systems, both extraction air and fuel supply controls are closely integrated into operation of the plant.

4.8.1.3 *Heat Recovery Steam Generator (HRSG)*

The HRSG is located at the exhaust of the combustion turbine. The function of the HRSG is to recover exhaust energy from the combustion turbine and use it to generate steam. Combustion turbine exhaust gas enters the HRSG through an inlet transition duct and expands to the full height of the HRSG. This expansion duct is designed to provide uniform distribution of the exhaust gas both vertically and horizontally across the entrance to the heat transfer surface. This inlet duct contains a stainless-steel distribution grid to assist in proper flow division. The hot combustion turbine exhaust gas flows horizontally through the HRSG, across tubes containing water and steam. These tubes are positioned vertically with flow going both up and down in alternating sections. A selective catalytic reduction (SCR) system is located within the tube modules to control NO_X emissions.

The HRSG contains a duct burner within the tube modules to provide additional heat energy when steam demand is high. An augmenting air system is provided with the duct burner system. Two 100% fans provide air to the firing elements to supplement the low oxygen concentration in the turbine exhaust gas stream. The use of syngas in the combustion turbine requires additional oxygen to be added to the gas stream.

The heat transfer sections are divided into LP, intermediate pressure (IP), and HP systems. A diagram of each section is provided in figure 4.8-6.

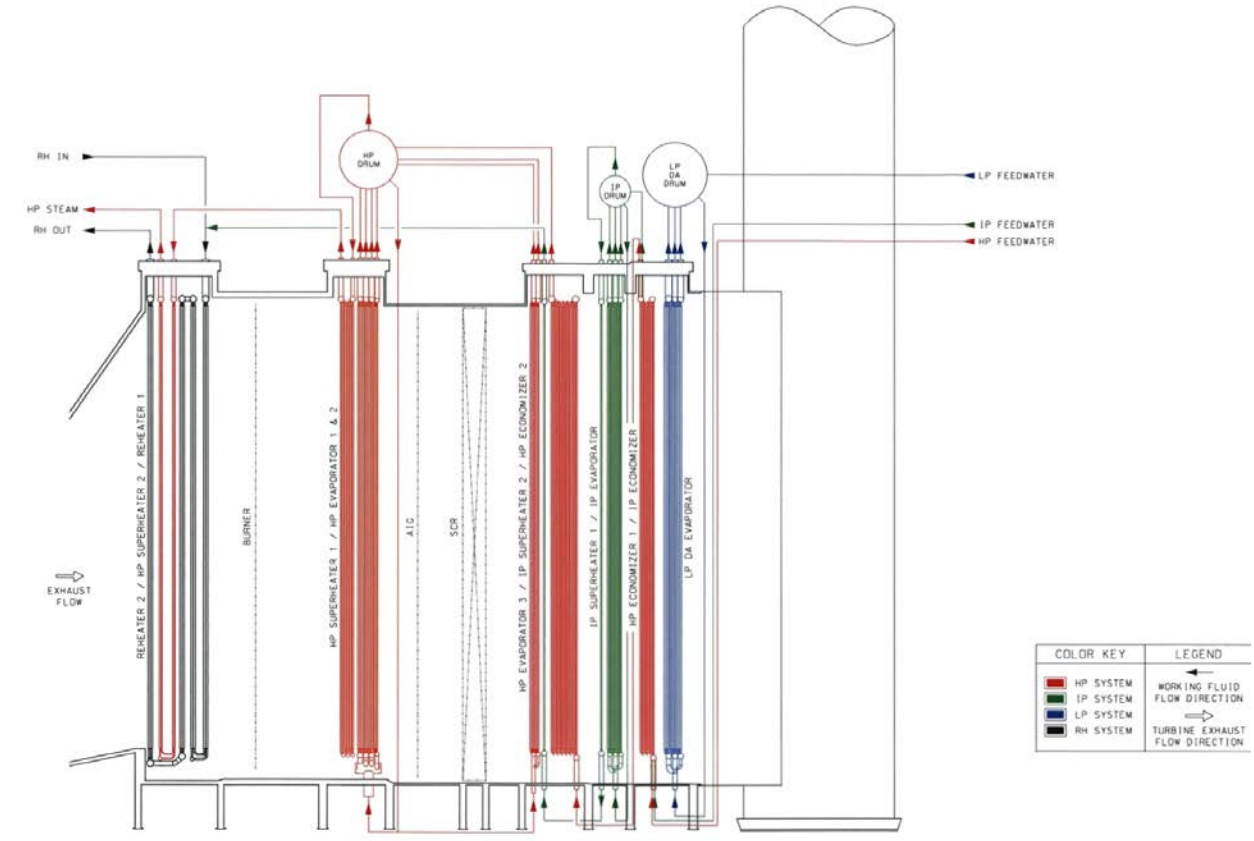


Figure 4.8-6 – HRSG cross section/exchanger configuration

A unique challenge in the Kemper design was how to safely vent CO_2 from the plant-side offtake systems and the AGR in the event of a pipeline or plant-side trip. Carbon dioxide will autorefrigerate when vented as the pressure decreases. It was determined during design that the volume of CO_2 vented from 2000+ psi offtake stream would require a significant heat input to prevent the gas from collecting at grade onsite and posing a health hazard.

It was determined that the quantity of residual heat available in the HRSG exhaust was sufficient to prevent the CO_2 from descending back to grade following release. This finding resulted in the CO_2 vent lines being routed to the HRSG stack. The stack height was raised to ensure the exhaust was released with sufficient heat at altitude to allow the prevailing winds to disperse the CO_2, an added margin of safety.

4.8.1.4 *Low Pressure Steam System*

Condensate enters the LP evaporator through the deaerator at the cold end of the HRSG. Steam that forms in the evaporator section circulates back to the deaerator. This LP steam scrubs the incoming condensate to remove noncondensable gases that vent out of the system. Deaerated condensate is then stored in the LP drum.

4.8.1.5 *Intermediate Pressure Steam System*

Condensate from the LP drum feeds the IP boiler feed pump (BFP), which provides water to the IP economizer. In the economizer, the water is heated close to the saturation temperature of the IP drum pressure. Water from the economizer enters the IP drum where it flows down into the IP evaporator and back up to the IP drum. Steam is separated from the entrained liquid in the IP drum separators. Condensate re-enters the evaporator while the IP steam flows out of the drum into the IP superheater. Two IP superheater modules superheat the steam above the saturation temperature. Superheated IP steam mixes with cold reheat steam from the steam turbine. The cold reheat steam is

then superheated in two reheater modules before going back to the steam turbine IP section. Reheat steam is attemperated to 1,005 °F by mixing a stream of cooler cold reheat steam with the hot reheat outlet steam.

4.8.1.6 *High Pressure Steam System*

Condensate from the LP drum feeds the HP BFP, which provides water to the HP economizer. In the economizer, the water is heated close to the saturation temperature of the HP drum pressure. Water from the economizer enters the HP drum where it flows down into the HP evaporator and back up to the HP drum. Steam is separated from the entrained liquid in the HP drum separators. Condensate re-enters the evaporator while the HP steam flows out of the drum into the HP superheater. Two HP superheater modules superheat the steam above the saturation temperature. Superheated HP steam is attemperated to 1,005 °F by spraying BFP water into the header between the two HP superheaters.

4.8.1.7 *Steam Turbine Generator*

The single steam turbine converts the energy from the steam generated in the HRSG and syngas cooler into electricity.

The Kemper steam turbine is a two casing, tandem compound, double-flow exhaust, condensing steam turbine consisting of a single-flow HP turbine, single-flow IP turbine and a two-flow low-pressure turbine. The HP turbine and the IP turbine are in one casing. The two-flow LP turbine is in another casing and has 40 in. last stage blades.

During normal operating conditions, steam is admitted into the HP turbine at approximately 1,720 psia and 1,000 °F. It flows through the HP turbine and provides a portion of the power to turn the generator. Steam exhausted from the HP turbine is reheated in the HRSG and returned to the turbine at 1,000 °F. This hot reheat steam expands through the IP and LP sections of the steam turbine, providing the remainder of the power to turn the generator. Steam is exhausted from the LP turbine to the condenser.

At normal operating conditions, the steam turbine generates approximately 310 MW_{gross}. For peaking duty, steam turbine output can be increased to approximately 365 MW_{gross} by firing natural gas in the HRSG duct burner.

Varying amounts of each steam level are extracted from the HRSG and steam turbine for processes in the gasification island.

4.8.1.8 *Electrical System*

The plant is designed to provide electric power into the MPC transmission system at 230 kV through an MPC transmission switchyard located adjacent to the unit. Each of the generators has a dedicated GSU transformer to transform the nominal generator voltage up to the transmission voltage level. Each GSU transformer is sized for its turbine generator output rating.

The high voltage (HV) side of each GSU transformer is connected to a transmission collector bus with a HV circuit breaker. This HV circuit breaker is used to synchronize the generator to the transmission grid. The collector bus also supplies two station auxiliary transformers (SATs). The three collector buses connect to an MPC transmission switchyard in separate bays of a breaker and a half bus substation arrangement. Multiple transmission connections are used because of the number of SATs and GSU transformers required. The generator and SATs are separated per gasifier and common BOP on the collector buses to balance power flows on the three transmission connections. Most major loads are centrally located in the compressor alley, so one plant switchyard was designed. For clear separation of generation owner and transmission owner, a separate transmission switchyard is provided.

There are six SATs to provide electrical power for station service. The SATs supply plant station service for both unit startup and normal running conditions. The SATs have two low-side windings, 4,160 V and 13,800 V, which were selected to best serve the specific loads. Station service at rated output is expected to be in the range of 225 to 250 MW. The total nameplate connected load is larger. The approximate station service split is one-third on the 4,160 V system and two-thirds on the 13,800 V system at the SAT level.

There are two process air compressors per gasifier. For gasifier operation, the preference is to lose both process air compressors on one gasifier rather than one on each gasifier. The power is distributed by gasifier 1, gasifier 2, and BOP common. Each system has two main 13,800 V systems and two main 4,160 V systems. When multiple load equipment (for example, two 100% pumps/trains) is used, the electric supply is from separate buses within that system.

The plant is not designed for operation without connection to the transmission system (that is, islanding). The plant is not designed with black-start capability on syngas or natural gas. The total loss of offsite AC power is an unlikely event, but it has been evaluated and is considered acceptable for personnel safety and investment protection (based on HAZOP evaluations). No onsite AC source, such as a diesel generator, is provided. Limited use of permanent construction power (maintenance power) as backup power is included for certain key facilities. No cross connections between the major buses are provided because of the equipment redundancy and large loads involved.

4.8.1.9 *Combustion Turbine Generator*

The combustion turbine generators (CTG) are rated 18.0 kV, 60 Hz, 277 MVA, 0.85 power factor at a 95 °F cooling water temperature. The generators are totally enclosed water-to-air cooled (TEWAC) design. Generator capability (MVA) is a function of cooling water temperature, and so is directly related to ambient temperature and increases with colder cooling water to coordinate with the increase in combustion turbine power output at lower ambient conditions.

4.8.1.10 *Steam Turbine Generator*

The steam turbine generator is rated 18 kV, 60 Hz, 410 MVA, 0.9 power factor at 60 psig hydrogen and 95 °F cooling water. Generator capability (MVA) is a function of cooling water temperature, and so is related to ambient temperature, and decreases with cooling water above rated temperature.

4.8.1.11 *Isolated Phase Bus*

The isolated phase bus provides the electrical interconnection between the generators' terminals and the GSUs. The isolated phase bus voltage capability is at least 1.05 times the generator voltage rating.

4.8.1.12 *Combustion Turbine Starting System*

Each CTG is started using a static starting system consisting of a static frequency converter. The static frequency converter is powered by a dedicated static frequency converter isolation transformer, which is supplied from the plant 4,160 V station service bus. The static start system interfaces with the turbine control system using a communication bus. One static starting system is shared by two CTGs. The static frequency converter and excitation system are supplied by the vendor in a control house. The station service design allows for starting of only one CTG at a time. The plant is not designed to be able to start without power supplied from the transmission system.

4.8.2 Initial Commissioning Plan

The commissioning of the power block involved many items typically required for commissioning a 2 x 1 gas plant. Testing of individual equipment included loop/logic checks, stroking and adjusting control valves, flush and cleaning oil skids and process piping, and final leak checks before commencement of the equipment startup and integration.

At Kemper, vendor personnel were expected to directly engage with Startup personnel to ensure planning and testing were completed in accordance with contractual requirements and industry best practices. The following activities were to be completed for each of the major process components.

Unless specified, commissioning activities are identical between Train A and Train B. Only the activities for one train are discussed.

4.8.2.1 *HRSG*

Precommissioning of the HRSG was to include a thorough checkout of the following items:

- Completed general walkdown.
- Confirmation of valve orientation and stroke times.
- Verification of critical gaskets.
- Verification of level control devices.
- Instrumentation loop checks and alarm verification.

When completed, cleaning of the process piping and tubeside passageways was to begin. A chemical cleaning of the tubeside piping was to be conducted by a third-party cleaning contractor. This process would remove any construction debris, oils, and scale that had accumulated in the tubing. Per the vendor, it was critical to ensure a clean process so piping would develop a magnetite layer necessary for boiler performance.

Following the chemical cleaning, the piping vessels were to be further cleaned with steam blows. These could use either the auxiliary boiler or the low-load exhaust from a combustion turbine. Steam blows were to continue until a clean target was achieved per vendor criteria.

Cold startup of a HRSG was to include filling the drums to a minimum water level. After level was established in each drum, the following steps were to be completed to bring the HRSG online.

- Start the feedwater pumps.
- Complete startup valve alignment to the HP, IP, and LP sections.
- After flow is established, open the startup vents.
- Start the CT and begin warming the HRSG to normal operating conditions.

After the HRSG reaches temperature and steam is available from each section, the CT can then be loaded as necessary to support further testing and operations. The startup of the HRSG is then complete.

4.8.2.2 *Steam Turbine*

The steam turbine was to be commissioned in accordance with vendor testing protocol. To complete this process, the precommissioning and startup functional verification was to include:

- Auxiliary utilities (power, water, and fire water).
- Lube oil system flushing and start.
- Instrumentation and controls verification.

When the turbine precommissioning was complete, the following steps were to be performed to bring the turbine online:

- Complete CO_2 and H_2 purge of the generator.
- Roll the turbine on turning gear.
- Establish gland seal steam and raise condenser vacuum.
- Start the turbine-generator set.
- Monitor baseline performance.
- Synchronize to grid and begin loading.
- Begin integration of second HRSG.

When turbine baseline performance testing was complete, the turbine would be available to support commissioning of the combustion turbines and combined cycle integration.

4.8.2.3 *Combustion Turbine*

Commissioning of the combustion turbine was to strictly follow vendor testing protocol. The vendor provided a detailed procedure for checkout including a generic startup schedule, which was incorporated the project startup schedule and

was to be the basis for this initial checkout of the combustion turbines. This schedule was to include the functional checkout and flushing of the following systems:

- Electrical cabling and auxiliary power system.
- Instrumentation and controls.
- Lube oil and seal oil systems.
- Generator/high voltage system.

The commissioning steps were to also include the checkout of the fuel, water, and steam systems. The steam turbine and these systems were to be fully operational before beginning the initial startup and commissioning of each combustion turbine.

After precommissioning activities were complete, turbine testing was to proceed based on this testing:

- Test 1: Initial roll.
- Test 2: Overspeed trip test.
- Test 3: Full speed no load (FSNL).
- Test 4: Initial synchronization (baseload).
- Test 5: Syngas testing, set ignition flow.
- Test 6: Syngas testing, baseload.
- Test 7: Performance test.

Detailed procedures for each test were to be provided by the vendor. After each combustion turbine had been brought online, integration testing of all the components of the combined system would be performed as shown in table 4.8-1.

Table 4.8-1 – Power block integration overview

CCPB Operating Mode	Steam Turbine	Gas Turbine	HRSG
Initial Start	Online	Online	Online
2-on-1 Operation	20 % steam turbine tests, valve tests, high speed stop, overspeed	GT A/B online	Online
GT B online, 1-on-1 operation	Online, No Testing	Fine tune GT B	1-on-1 operation
GT A online, 1-on-1 operation	Online, No Testing	Fine tune GT A	1-on-1 operation
GT A online, 1-on-1 operation	Online, No Testing	PSS Test GT A - complete	SCR commissioning
GT B online, 1-on-1 operation	Online, No Testing	PSS test GT B - complete	SCR commissioning
2-on-1 operation	50% Load tests; HP IP efficiency test	GT A/B online	HRSG, SCR, Duct Burners in service
2-on-1 operation	Online	GT A/B online	HRSG, SCR, Duct Burners in service
2-on-1 operation	Online	GT A/B online	HRSG, SCRs in service, DBs in service
1-on-1 operation	Online	Water wash / startup GT B	Online
2-on-1 operation	Online -	Water wash / startup GT A	A/B online
2-on-1 operation	Online - Performance testing	GT A/B online	HRSG, SCR, Duct Burners in service

4.8.3 Significant Events

4.8.3.1 *Accomplishments*

	CT-A	CT-B	ST	HRSG
Oil flush complete	4/15/2013	4/2/2013	4/8/2013	
Chemical cleaning complete				9/27/2013
CT first fire	8/28/2013	9/4/2013		
Steam blows				10/5/2013
Synchronization	10/26/2013	10/23/2013	10/5/2013	
2 x 1 integrated operations	10-31-2013			
Commercial operations date	8/14/2014			

- Activities

The commissioning of the combined cycle power block was critical to the progression of startup activities. This process required many of the items outlined sequentially in the initial commissioning plans to be done in parallel. Initial efforts were applied to utilities and common systems first, including electrical testing of cabling and step up transformers (GSUs):

- Megger testing of cables and windings.
- Grounding studies.
- Energization and soak.
- Testing of support systems (for example, cooling fans).

Initial items included the commissioning of the lube oil, control oil, seal oil, and turning gear systems for the CT-A, CT-B, and steam turbines. These systems form the basis of the auxiliary support systems for each unit and needed to be operational early in the startup cycle. The instrumentation for each system was loop checked. Valve stroke times and control logic were validated. Each system was blown clean and flushed to ensure any construction debris or contaminants were removed before establishing circulation through each turbine. Initial electrical testing was completed in April 2013. The completion of auxiliary control and oil systems was in May 2013.

When the initial checkout of the auxiliary systems was complete, precommissioning activities expanded to include the HRSGs. Commissioning of each HRSG included preparing the extensive network of supply and return piping for pressurization and operation. Following the initial walkdown and verification of installed components such as instrumentation and gaskets, the instrumentation was loop-checked. Valve stroke times were tested and adjusted as necessary to ensure a timely response during operations. Safety interlocks were confirmed before testing of the feedwater pumps. The systems commissioned included:

- Boiler feedwater system.
- Condensate system.
- Phosphate system.
- Anhydrous ammonia system.
- Nitrogen system.
- Steam piping (HP, IP, and reheat).
- Natural gas piping.

- Blowdown piping.

Cleaning of the water systems included flushing the lines. The gas and steam lines were initially air blown and then steam blown until clean. Internal HRSG piping and tubing were chemically cleaned. The cleaning of HRSG-A was completed in August 2013. The HRSG-B cleaning activities were completed in September 2013. Precommissioning activities for both units were completed in September 2013.

The commissioning of the auxiliary boiler was critical to the timely steam-out of power block piping. Kemper used a packaged auxiliary boiler that required significant checkout to ensure reliable operation. Commissioning of the auxiliary boiler began in March 2013. Activities included verification of the speed detector and flame detector, and the general verification of functional logic and instrumentation. Final verification and initial startup were completed in May 2013. The unit was completed in time to support the initial steam blow schedule.

Following the completion of the HRSG checkout, verification, flushing, and commissioning of the combined cycle closed-loop cooling water and combined cycle auxiliary water systems were completed. The systems were flushed, filled, and available to support testing in August 2013.

As the supporting systems for CT and ST operation neared completion, the checkout and final preparations were completed for both combustion turbines and the steam turbine. The checkout of each of these systems included extensive testing of control logic, start-and-stop sequences, and verification of critical operational logic such as for fuel swapping and extraction air. The work had sufficiently progressed by August 2013 that the CT-A and CT-B were placed

on turning gear. Southern and the vendor conducted a final readiness review for each unit in mid-August. After both parties were satisfied, each CT was started. First fire on CT-A was completed in late August 2013. The CT-B first fire was completed in early September 2013. Both units fired successfully.

Following first fire, the testing of each CT proceeded per the vendor test plan. Each unit achieved full speed/no load and initial synchronization while operating on natural gas in October 2013.

Testing of the steam turbine began in October 2013. Per the vendor testing criteria, the steam turbine was placed on turning gear. Initial roll began in early October. Testing continued into November 2013 and included the initial soak, overspeed test, and load testing.

Integration testing of the combined cycle began when each of the components was commissioned. Integrated testing included fine-tuning each CT-ST in 1 x 1 operation. While the unit operated briefly in a 2 x 1 configuration in October 2013, integrated 2 x 1 testing did not begin until January 2014. In 2 x 1 operations, the following testing was completed:

- HRSG tuning.
- Commissioning of each SCR.
- Tuning of duct burners.
- CEMS testing/certification.

Final station performance testing was completed in February 2014.

4.8.4 Final Summary

Startup of the power block was a major milestone for the Kemper project. It was important to bring the unit online early as a revenue stream for Mississippi Power. It was equally necessary as a source of station service and steam to support the increasing demand of commissioning activities within the gasifier island and throughout the plant.

All commissioning objectives for natural gas testing and operation were successfully completed for each of the major components within the power block. The integration of the systems into a fully operational 2 x 1 combined cycle was equally successful. The performance testing of the combustion turbines on natural gas was completed with each engine performing within contractual expectations. The unit operated within environmental limits indicating that the modified combustor design was adequate. Testing of the engines on syngas was not completed during the initial commissioning phase. Syngas and co-fire operations will be discussed in more detail in the final report.

5.0 UNIT COMMISSIONING EXECUTION AND TESTING

5.1 Coal Storage and Preparation

The construction equipment turnover packages in the lignite preparation area provided the first opportunity to check out the equipment. During the turnover phase:

- Motors were bumped.
- Rotations were checked.
- Valves were stroked, and stroke times were checked for adequacy.
- Systems were pressure checked.
- Water was circulated through the pumps.
- Instruments were calibrated and tested when possible.

The initial equipment turnover was planned so equipment would be checked by priority for the upcoming test package. The turnover packages were arranged systematically so equipment checkout would match the turnover priorities and ultimately the test package priorities. For lignite preparation, there were 74 turnover packages providing the prechecks for the 44 lignite prep test packages (7 test packages per train and 2 common systems).

The equipment turnover plans started with mechanical and electrical testing of the following equipment and subsystems:

- Lignite dryer fans (part A and B).
- Lignite dryer systems.
- Venturi condenser systems (part A and B).
- Pulverizers, pulverizer fans, and baghouses (part A and B).
- Multiclone systems.

When this testing was completed, the dryer and pulverizer systems were tested for pressure tightness.

Other standalone systems, including the filter press system, the recovered water system, and the pyrite system, were planned to be functionally checked out before the dryer test package. After the basic equipment was functionally checked, the larger integrated systems could be tested.

When these functional or turnover tests were complete, the new focus was on the integrated system or test packages. Three lignite preparation trains supported each gasifier. Each lignite train had five main test packages. The test package followed the same order as the turnover packages. For each train, the test packages were the dryer fans (packages A and B), the venturi-condensers, the pulverizer fans and baghouse, and the dryers. The stand-alone systems tested were the pyrite system, the recovered water system, and the filter press system. The test packages were sequenced in this order as a progression of system complexity and priority.

This section of the report is organized in the order that commissioning of the systems occurred. Each of the six lignite preparation trains consists of multiple functional systems. As challenges occurred in individual trains, work would shift to other trains to maintain progress. As individual issues were resolved, the results were implemented in the other trains. This process was intended to maintain progress commensurate with the schedule for commissioning of the gasifiers and syngas processing systems. As equipment became available for testing from each of the six trains, the installation and operation were improved based on experience and better data. The general strategy for commissioning the dryer trains focused on two dryers per gasifier. Based on their closeness in the schedule, trains 1 and 2 for gasifier A and trains 5 and 6 for gasifier B were chosen to commission first. This strategy streamlined the manpower support for the turnover packages and dryer train test packages in an effort to enhance progress and prevent negative impacts to the gasifier startup schedule. Section 5.1.1.2, Initial Commissioning Plan, includes tables of test packages, significant events from different packages, and a general summary of findings from commissioning equipment when changes were made.

5.1.1 Lignite storage and preparation

5.1.1.1 *System Overview*

The Kemper County IGCC facility is located at the lignite mine managed by North American Coal Company (NAC). Since the plant is located next to the mine, long-distance transportation is not necessary, resulting in cost savings and carbon emission reduction. The mine portion of the plant included the mining dragline, the dump trucks, and the storage piles.

The lignite delivery facility (LDF), which also is managed by NAC, provides the interface between the mine and the plant with the purpose of processing run-of-mine lignite to a minus two-inch product (figure 5.1-1).

Figure 5.1-1 – Lignite delivery facility

The LDF provides storage and delivery of the lignite to the plant. NAC was responsible for operating and maintaining the mine. The lignite delivery contract made NAC responsible for delivering the lignite to the Kemper County IGCC facility and maintaining the crushed lignite silo levels. NAC operated their equipment from an independent control system at the mine. The lignite quality delivered to the facility was broad and based on specifications given in table 5.1-1:

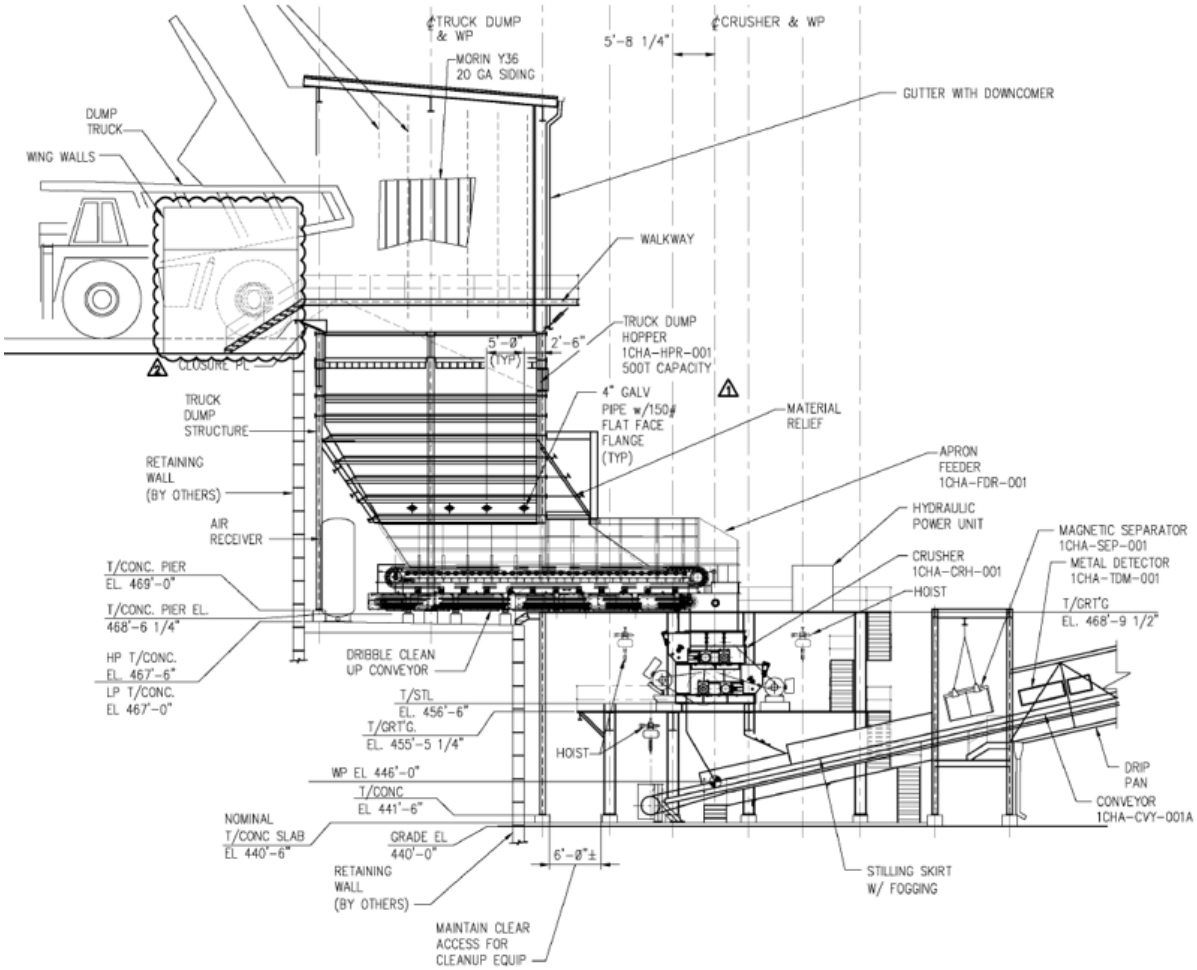
Table 5.1-1 – Contract specifications for lignite composition

Kemper Lignite Composition				
		Average	Min	Max
Heat Content	Btu/lb	5290	4765	5872
Moisture	%	45.5	42.2	50
Ash	%	11.95	8.61	17
Sulfur	%	0.99	0.35	1.7

To maintain lignite quality, there was a plan to blend the lignite from multiple mining pits, or from the storage pile when the lignite was outside the contract ranges. Instruments to measure moisture, ash, and BTU/lb value were mounted above the lignite conveyor belts to provide inline measurement for use in the blending process. In addition to chemical composition quality, the lignite was specified in the contract to be below 2-in. particle size delivered to the crushed lignite silos. An automatic grab sampler was installed on the belt to the crushed lignite silos to take samples twice per day to evaluate the analyzers' performance. In order to keep the lignite quality within the contract range (table 5.1-1), the steam and combustion turbines had to be operated at the desired conditions and the chemical byproducts kept

within the design ranges for production. The grab samples were riffled and sent to the Alabama Power lab for a certified analysis. The plan to maintain lignite quality by blending lignite from different piles or seams was never implemented, because the instruments on the belt were never calibrated. Calibration had been planned to take place when the gasifier load was at the highest capacity and commissioned.

At the mine, the non-lignite overburden is removed by a drag line. Large track loaders remove the lignite from the seam and place it into oversized, off-road mining trucks. The trucks deliver the lignite directly from the area where the lignite was mined to a storage pile and then to a covered truck dump hopper (figure 5.1-2), located near the mining site. A heavy grid of steel beams reinforces the inlet to the hopper. The 6-ft x 12-ft openings provide resistance to the flow to the hopper. The 8-ft wide apron feeder located under the truck dump hopper receives the initial impact of the lignite. The apron feeder helps distribute the lignite so it is fed at a controlled rate instead of a huge surge to the primary crusher. The primary crusher is a two-stage unit. Each stage has two electrically-driven crushing rolls. Variable roll spacing allows some adjustment of lignite size. The unit is designed to reduce the run-of-mine lignite that passes through the dump hopper to 95% minus 1.75 in. in size. After the product has been crushed, it drops onto the first transfer conveyor. Three suspended magnetic separators remove tramp ferrous metal. One magnetic separator was placed above the belt after the crusher, and other magnets were located above the belts feeding the crushed lignite silos. A metal detector senses nonferrous metal for removal. A belt scale records the weight of lignite processed.



Truck Dump Hopper, Roll Crusher, and Transfer Conveyor 1A

Figure 5.1-2 - Mine truck dump

The lignite is conveyed to the barn transfer station, a tower where diverter gates direct the lignite to one of three possible points:

- A concrete storage dome equipped with a circular stacker/reclaimer.
- Fed directly to the IGCC plant.
- Directed to an outdoor stockpile.

The lignite is normally stored in the storage dome, where excess moisture can drain. The dome has a capacity of 3 days at maximum gasifier load. The dome is a hollow, concrete hemisphere, free-span with no internal supports. There are portals to allow access for mobile equipment to move the material in the dome if necessary. A large opening in the top of the dome provides ventilation. The ventilation opening did not shed the water effectively and allowed rain to run into the dome. There was a plan to repair the roof over the opening but was not implemented at the project suspension.

Inside the storage dome is a centrally supported radial stacker/reclaimer. The feed belt conveyor from the barn transfer station enters the dome in the upper side wall and discharges into the load hopper at the top of the stacker/reclaimer.

A radial stacking belt forms a pile that can be up to 85 ft tall. The belt can form a 360˚ pile for maximum storage capacity or can create two or more independent piles. See the inset on figure 5.1-3 for illustration of stacking configurations. At the time plant operation was suspended, one dryer was being fed fine lignite, another dryer was being fed screened lignite, and yet another dryer was being fed unscreened lignite. The screened lignite was screened at 2 to 12 in. and then crushed to below 2 in. top size. Unscreened came directly from the storage pile. Fine lignite is material that went through the 2-in. screen. The fine lignite was also sent through the crusher. This process required three separate piles in the dome, which reduced the working storage volume. Storage management is discussed in detail in 5.1.1.3, Significant Events.

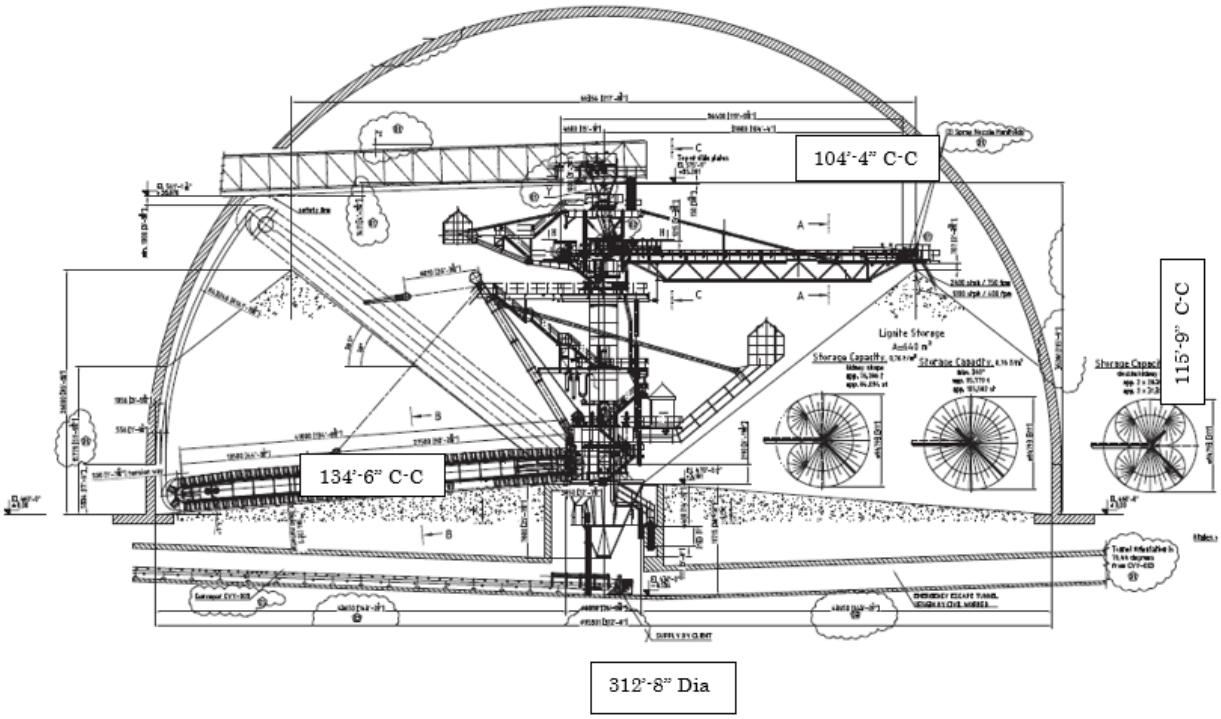


Figure 5.1-3 – Lignite delivery facility lignite dome

The stored lignite is reclaimed by an over-pile drag conveyor. The conveyor travels radially around the pile and scrapes the lignite into the feed hopper of the under-pile reclaim belt conveyor. Lignite is normally withdrawn from the storage pile at 1,200 ton/hr but can be withdrawn at 2,400 ton/hr if necessary. The feed stacker and reclaim conveyor operate independently, allowing both operations to occur simultaneously.

The reclaimed lignite is discharged through an adjustable flow splitter onto two parallel conveyor systems. Normally, only one system is operated. The conveyor systems elevate the lignite and discharge onto parallel tripper conveyors that discharge into the crushed lignite silos. Each of the parallel tripper conveyors is sized to operate at 1,200 ton/hr. With both conveyors in operation, 2,400 ton/hr can be delivered, approximately twice the demand of the IGCC plant at full production. Both lines can operate simultaneously, allowing for rapid recovery of the level of crushed lignite in the silos when needed.

Lignite is normally supplied to one crushed lignite silo at a time. The tripper conveyors are in an enclosure located above the row of silos. Each belt conveyor has a rail-mounted, travelling tripper that can travel the length of the enclosure to allow filling any silo. The trippers operate independently for maximum flexibility.

The top of each silo has two parallel openings that span the diameter on either side of center. Mounted above these openings are chutes connected lengthwise to provide a continuous opening into which each tripper can discharge. This configuration prevents spillage onto the silo tops and the concrete deck.

To prevent the escape of fugitive dust when the silos are being filled, the head pulley of each tripper is enclosed in a discharge chute that is supported from and travels with the tripper car.

A dust collection system extracts air from all the silos and filters it. The gas displaced by the lignite being fed into the silo is vented through a 12-in. collection header to a baghouse located on a platform adjacent to the silos on the west side of the lignite prep structure. The filtered exhaust gas is vented to the atmosphere. The bags are cleaned with a reverse gas flow. Captured dust is discharged from the filter hopper back into one of the two center silos by a pair of screw conveyors.

The openings in the silo inlet hoppers use a dust seal belt resting on a grid in the top of the chute. The support grid for the dust seals was modified to support the belt without plugging from lignite. This support grid had to be modified during the LDF commissioning before lignite operation. The belt is lifted as the tripper moves so a minimal sized opening is formed at the tripper discharge. This small opening, combined with the gas extracted by the dust collection system, was designed to eliminate fugitive dust.

The tripper floor is across the top of all six crushed lignite silos. Each silo feeds a lignite preparation system. There are six lignite preparation systems (three per gasifier) with sufficient design capacity that if one system trips offline, the throughput of the others will increase to meet the design preparation rate by maintaining the level in the gasifier lignite feed storage bins.

Each of the six lignite silos has a diameter of 31ft 0 in., a straight wall height of 42 ft 0 in., and a 70˚ cone. The overall height is approximately 95 ft. Each silo holds approximately 9,500 tons.

The silos are supported by the lignite preparation building structure on skirts, which are an extension of the cylindrical walls. The cone extends through the structure and terminates in a stainless-steel transition cone (figure 5.1-4).

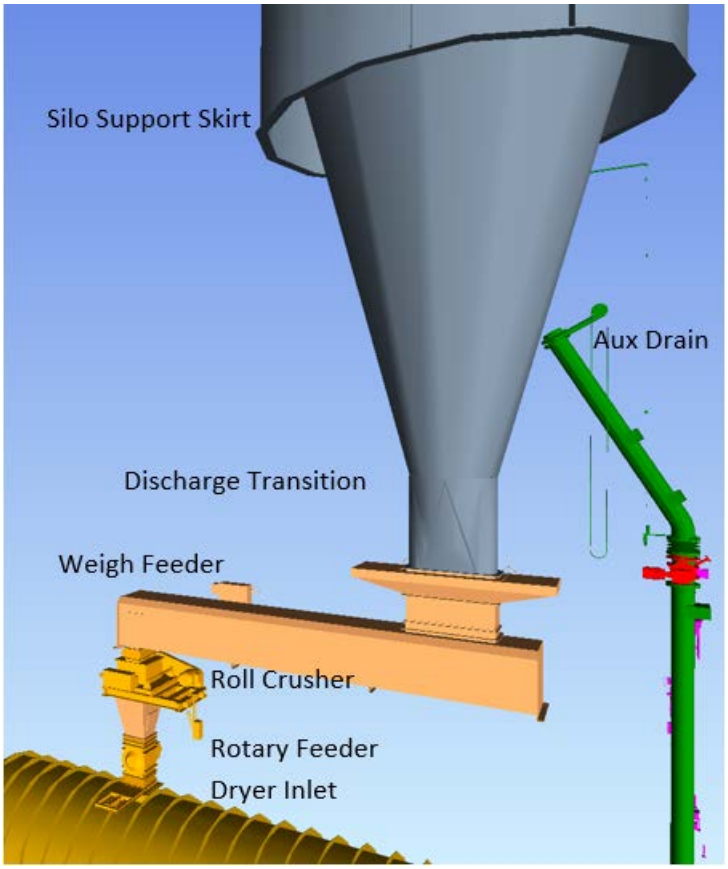


Figure 5.1-4 - Wet lignite feed system to dryer

The silos are designed for mass flow so the lignite flows in a first-in/first-out pattern. To facilitate this process, the silo cones have ultra-high molecular weight (UHMW) plastic liners, which provide an ultra-slick, low friction, highly wear-resistant surface. The liners extend to the discharge transition cone.

The discharge transition cone has an elongated opening with tapered sides to promote mass flow and provide for even flow across the outlet. The inlet of the transition cone is 80 in. diameter. The outlet opening of the silo exit hopper is 30 in. wide by 80 in. long. The transition was fabricated from 304 stainless steel with a smooth mill finish to promote flow. Extensive lignite laboratory testing was done on contract design basis lignite to size the opening, hopper wall angle, and transition to ensure consistent flow to the weigh belt feeder.

An auxiliary outlet located in the sidewall of the cone was provided to allow emptying most of the silo contents if necessary. A slide gate was located near the attachment point of the drain chute at the silo wall. A rotary feeder was located on a platform to control the flow of lignite. The chute emptied into the pyrite drag conveyor system to allow discharging to a truck.

Temperature and carbon monoxide sensors were provided for fire detection. Multiple hose cabinets were in the area. Several firefighting ports are located on the silos.

5.1.1.2 *Initial Commissioning Plan*

- Lab analysis plans

Before the test packages implementation began, analysis related shortcomings were identified for Startup and Operations in the sample analysis methods, lab equipment, lignite trained technician manpower, and lab buildings. Temporary lab equipment was installed in the LDF lab so particle size and lignite moisture could be tested. All lab

tests related to the lignite preparation test packages were done at the LDF lab. In June 2016, two Conex containers were set up with lab equipment in preparation for the gasification run. Operators and technicians were trained, performed needed daily tests, and functioned in a manner more like normal plant operations.

- Lignite storage and preparation test package objective

The lignite storage and preparation test package was designed to test and tune the truck dump, conveyors, crusher, and stacker reclaimer at the LDF. After the system was electrically and mechanically checked out, the priorities were to test the equipment at various operating conditions and ensure the LDF was ready to provide lignite to fluid bed dryers when they were ready for commissioning.

The truck dump test plan was to verify ability of the apron feeder to move lignite from low rates all the way up to 2,400 ton/hr. The belt conveyor test plans started with belt alignment checks, feeding lignite at increasing rates to verify belt alignment and test motor current draws, and finally to feed lignite at 2,400 ton/hr. The crusher test objectives were to test initial mechanical integrity, basic operation, and crushing capability up to 2,400 ton/hr. The stacker reclaimer test objective was to operate all machinery and verify automated controls up to 2,400 ton/hr.

- Lignite storage and preparation test package overview

The LDF was an expansive area to commission (figure 5.1-5). The conveyor runs, equipment size, and high feed rates required extensive planning and scheduling of equipment vendors and technical field assistants to witness and provide technical support. The large quantities of lignite used to test the equipment required that the lignite be recirculated, since the MPC plant was not yet operational. While the commissioning was extensive, the equipment checkout was nearly trouble-free after the lignite dome repairs were completed.

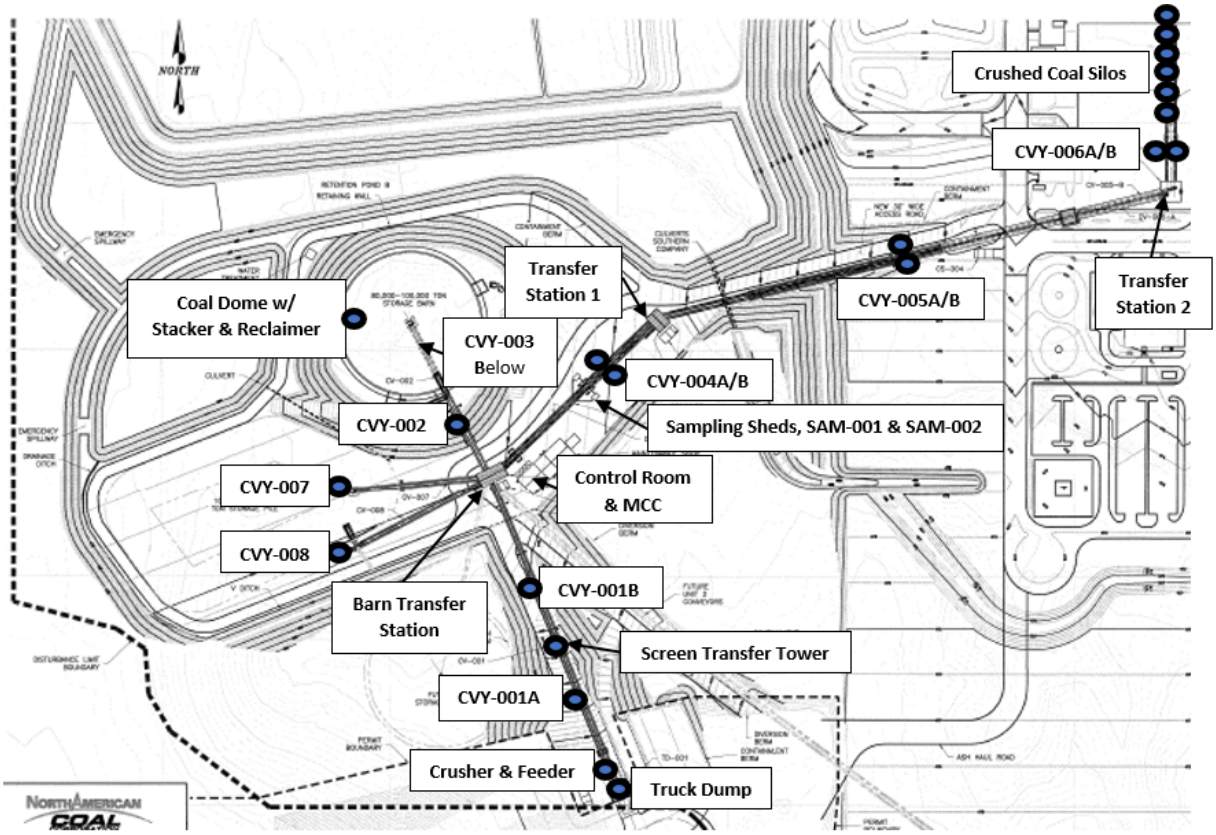


Figure 5.1-5 - LDF equipment layout

- Lignite delivery facility initial commissioning

Commissioning of the lignite delivery system began in April 2013, as construction of the individual components neared completion. The major components of the system were both conveying equipment and process equipment, including:

- Truck dump hopper and stilling shed HPR-001.
- Apron feeder FDR-001, 40 ft, 6.75 in. long x 48 in. wide, hydraulic drive, 1,200-2,400 ton/hr.
- 12 belt conveyors (for details, see table 5.1-2)

Table 5.1-2 – LDF Conveyors

Equipment Number	Function	Size x Nominal Length, Capacity
CVY-001A	Conveys crushed lignite from truck dump to screen tower, includes belt scale	60 in. wide x 365 ft long, 1,200-2,400 ton/ hr
CVY-001B	Conveys crushed lignite from truck dump to screen tower, includes belt scale	60 in. wide x 365 ft long, 1,200-2,400 ton/ hr
CVY-002	Conveys crushed lignite from diverter gate to stacker in lignite dome, includes belt scale	60 in. wide x 387 ft long, 1,200-2,400 ton/hr
CVY-003	Conveys crushed lignite from reclaim feeder in lignite dome to feed CVY-004A and CVY-004B, includes belt scale and lignite analyzer 002	60 in. wide x 386 ft long, 1,200-2,400 ton/hr
CVY-004A	Conveys crushed lignite from CVY-003 discharge splitter to CVY-004A	48 in. wide x 520 ft long, 1,200 ton/hr
CVY-004B	Conveys crushed lignite from CVY-003 discharge splitter to CVY-004B	48 in. wide x 520 ft long, 1,200 ton/hr
CVY-005A	Conveys from CVY-004A to CVY-006A on top of crushed lignite silos	48 in. wide x 1,160 ft long, 1,200 ton/hr
CVY-005A	Conveys from CVY-004 to CVY-006B on top of crushed lignite silos	48 in. wide x 1,180 ft long, 1,200 ton/hr
CVY-006A	Conveys from CVY-005A to crushed lignite silos, includes tripper TPR-001	48 in. wide x 367 ft long, 1,200 ton/hr
CVY-006B	Conveys from CVY-005B to crushed lignite silos, includes tripper TPR-002	48 in. wide x 367 ft long, 1,200 ton/hr
CVY-007	Stack-out conveyor, conveys crushed lignite from barn transfer station to long-term outdoor stockpile	60 in. wide x 295 ft long, 1,200-2,400 ton/hr
CVY-008	Reclaim conveyor, conveys crushed lignite from reclaim feeder (FDR-004) at long-term stockpile to barn transfer station	60 in. wide x 295 ft long, 1,200-2,400 ton/hr

- Reclaim feeders:

FDR-002	Receives crushed lignite from HPR-002 in the barn transfer station and feeds CVY-004A and CVY-004B	50 in. wide, 40.75 ft long feed inlet, x 52.4 ft O.A. length, 1,200-2,400 ton/hr
FDR-003	Receives crushed lignite reclaimer in lignite dome and feeds CVY-008, the reclaim conveyor, at a controlled rate	50 in. wide, 40.75 ft long feed inlet, x 52.4 ft O.A. length, 1,200-2,400 ton/hr

FDR-004	Reclaims crushed lignite from long-term stockpile to CVY-008	50 in. wide, 17 ft long feed inlet, x 38 ft O.A. length, 1,200-2,400 ton/hr

- Two lignite sampling systems (SAM-001 and SAM-002) including two sampler sheds, automatic rifflers, and controls.
- Magnetic separators.
- Metal detectors.
- Miscellaneous hoppers, diverter gate, and chutes.
- Lignite analyzer.
- Dust collector system, including baghouse, and conveyors to return dust to center silo.
- LDF control room and DCS.
- Motor control center

The commissioning started with walkdowns and inspections of the conveyors and equipment as it was being installed. Turnover packages were prepared and released. Interlock tests and loop checks were conducted for each system. Functional tests were conducted. Motors were decoupled from gear reducers and motor current was checked. Motors were checked for proper rotation. Motors were recoupled, and the couplings were checked for proper alignment.

During the assembly of the conveyors on the structural steel, they are checked for alignment using laser levels and checked for cross-belt levelness. The spacing between idlers is confirmed to be per the tolerances specified in the erection drawings. When the initial operation is conducted, the tracking of the belt is confirmed. If a belt tracks to one side, the angle of the idler in the affected area is adjusted by loosening the bolts and rotating it slightly until the belt tracks correctly. Before operating any belt, a walkdown and visual inspection was performed. These visual inspections could be conducted on an empty belt before operating. New belt material is usually stiff after being installed but not operated for an extended period, so the belt conveyor is started and let run for several hours to monitor it for correct tracking in an unloaded condition. This testing is repeated under varying load conditions as the system is being brought on line. Other field checks included:

- Inspecting safety guards to verify they provided adequate protection from rotating equipment and shafts.
- Inspecting tail pulley guards to ensure proper installation.
- Inspecting and testing safety pull cords.
- Checking belt run-off switches.
- Checking belt scrapers to ensure proper contact and pressure against the belt.
- Inspecting gravity take-ups on belts to ensure proper alignment.
- Checking that safety cages were installed around gravity take-ups.
- Inspecting skirtboards for proper alignment and pressure against the belt.
- Operating the lignite delivery tripper cars.
- Verifying tripper controls to position the cars on the silo top.
- Calibration of weigh scales.

The spacing of magnets above conveyor belts was set and tested for field strength. The tracking of the belt on each magnet was set and run for 8 hours to verify tracking. Metal detectors and control circuits were set for sensitivity and tested by feeding tramp metal.

Diverter gates were tested for freedom of movement. Position switches were tested for correct indication.

Vendor technical field assistance (TFA) for purchased equipment was scheduled and brought on site as needed, including:

- Stacker reclaimer system in lignite dome: Several trips by the equipment manufacturer providing technical equipment, controls, and operation.
- Primary crusher: Inspection and initiation by vendor.
- Primary crusher discharge feeder: Inspection and initial operation.
- Lignite analyzers: Initial technical startup assistance. There was insufficient feed rate to perform a final calibration.

Before feeding lignite to the crushed lignite silos, the dust collection system was tested. The exhaust fan rotation and rotation of the screw conveyors were verified to be correct. The rotary feeder was checked for rotation and freedom of movement. The bag cleaning system was checked for proper operation.

The initial operation of the system started at the truck dump and went to the storage pile as additional conveyors were commissioned and lignite was conveyed around the system. Test runs were initially conducted at reduced throughput rates as the equipment was inspected and verified to operate in an acceptable manner.

The final commissioning runs were conducted delivering lignite to the crushed lignite silos. There was a limitation in removing the lignite from the silos. The initial design included a side drain on each silo with a discharge valve and rotary feeder. The lignite was damp and prone to form clumps that would not flow reliably from the chute, limiting the ability to run lignite into the silos until the dryers could accept it.

5.1.1.3 *Significant events*

- Dome failure

In March 2014, the lignite storage dome developed multiple serious cracks, and pieces of the inside of the dome fell out of the ceiling. To repair it, the dome was taken down and rebuilt by the vendor.

- Crusher study of rock

In February 2014, after all the mine equipment was commissioned, the mine crusher was evaluated for crushing effectiveness. Small rip-rap sized, 2-in. x 3-in., chunks of rock and lignite were dumped into the crusher to test the crusher's particle size reduction (table 5.1-3). The roll crusher crushed 99.5% of the newly mined lignite 2-in. topside and also about 85% of the rock. Another trial was run with larger chunks of 2 in. x 8 in. and up to 2 in. x 14 in. of petrified wood that had been mined from the Kemper and Red Hills mine (figure 5.1-6). This trial showed that about 57% was crushed below 2 in. (table 5.1-4). The crusher performed sufficiently on the smaller feed but did not maintain 2-in. top-size material with the larger petrified wood. Larger chunks of lignite were also dropped into the crusher and the lignite was crushed 98% below 2 in. This test was important to determine that the size reduction would be sufficient to allow processing through the dryer.

Table 5.1-3 – LDF crusher study on small rock

Uncrushable Project Size Distribution

	Sandstone	Shale	Pet Wood	Lignite
	340 psi	340 psi	350 psi	350 psi
Screen Size - Standard	%	%	%	%
+2"	15.3%	10.2%	16.3%	0.7%
1-1/4"	19.0%	14.8%	20.7%	4.7%
1 "	8.3%	6.6%	7.9%	4.2%
3/4"	7.1%	7.7%	6.9%	15.5%
1/2"	8.4%	12.1%	13.7%	32.8%
1/4"	9.7%	16.9%	21.3%	21.1%
Pan	32.2%	31.8%	13.2%	20.9%
total	100.0%	100.0%	100.0%	100.0%

Table 5.1-4 – Lignite delivery facility crusher study on large rock

	Cumulative	
Retained	% Thru	% Ret
3 1/2" Sq	95.52	4.48
3" Sq	89.95	10.05
2" Sq	71.20	28.80
1" Sq	5.07	94.93
1/2" Sq	1.10	98.90
3/8" Sq	0.97	99.03
1/4" Sq	0.83	99.17
1/8" Sq	0.74	99.26
Pan	0.00	100.00

Figure 5.1-6 – Petrified wood for crushing study

- Coal pile weathering

In preparation for the gasifier startup, the LDF began building a large lignite stockpile beginning in May 2013 to support the expected schedule. The mined lignite was stored in piles for almost 2 years before commissioning of the fluid bed dryers. During that time, the lignite significantly degraded from weathering. After the first year of storage, the lignite storage pile particle size was tested, and it was determined that 60-70% of the pile was less than 1 in. top-size due to degradation. Further testing of the lignite showed that 13-30% of the storage pile was less than 1,000 microns in size. In April 2015, rented mobile lignite screens were brought to the mine storage piles to separate oversized rock and lignite, coarse lignite, and fine lignite. The screens were capable of processing enough lignite for 2/3 of the one gasifier's capacity. The screens removed large lignite or rock (greater than 12 in. square) and separated it from the pile. This material was run over with a track hoe to break it up to be sent to the LDF crusher. The coarse lignite (less than 12 in. but greater than 2 in.) was stored in an area of the mine to be sent to the LDF crusher. The fine material was sent to the LDF crusher and then stored in the emergency pile area near the dome. At first, the coarse lignite was the only material used to commission the fluid bed dryers, because the fines caused filtration problems in the plant. After the filters were upgraded, all three types of lignite were processed in the dryers.

- Use of lignite fines

Because the screened lignite had been used to commission the fluid bed dryers, and 60% of the pile was fine material, the screening process was limited in what it could supply to the dryers and ultimately the gasifier. The dome helped dry and drain water from the lignite, but sometimes during this transfer and storage process, the lignite fines would trap pockets of air. With the internal heat from storage, the fine lignite could smolder inside the dome (figure 5.1-7). Normal dome management could prevent this smoldering, but the storage of three types of lignite made prevention more difficult. The fine lignite was typically reclaimed directly from the fines pile to avoid smoldering in the dome.

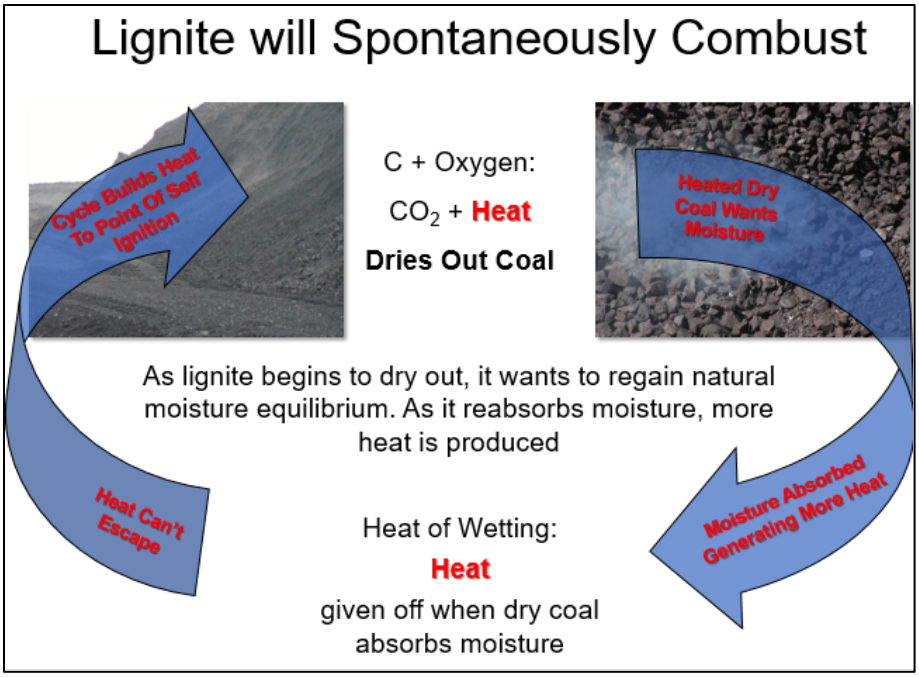


Figure 5.1-7 - Lignite dome and pile management difficulties

5.1.1.4 *Final Summary*

The mine and LDF equipment checkout during commissioning and startup went well. The quick planning by NAC allowed for lignite screens to be delivered and tested at the LDF before the fluid bed dryers were tested at Kemper. Figure 5.1-8 shows the lignite demand met by NAC for the commissioning of the fluid bed dryers before the gasifier startup. While the tons delivered to MPC are low, this amount was only the demand required by the Kemper fluid bed dryers and PDAC for commissioning. Most of the tons supplied was screened lignite. Due to the dryer feed system modifications, there were extended periods when lignite delivery was not required.

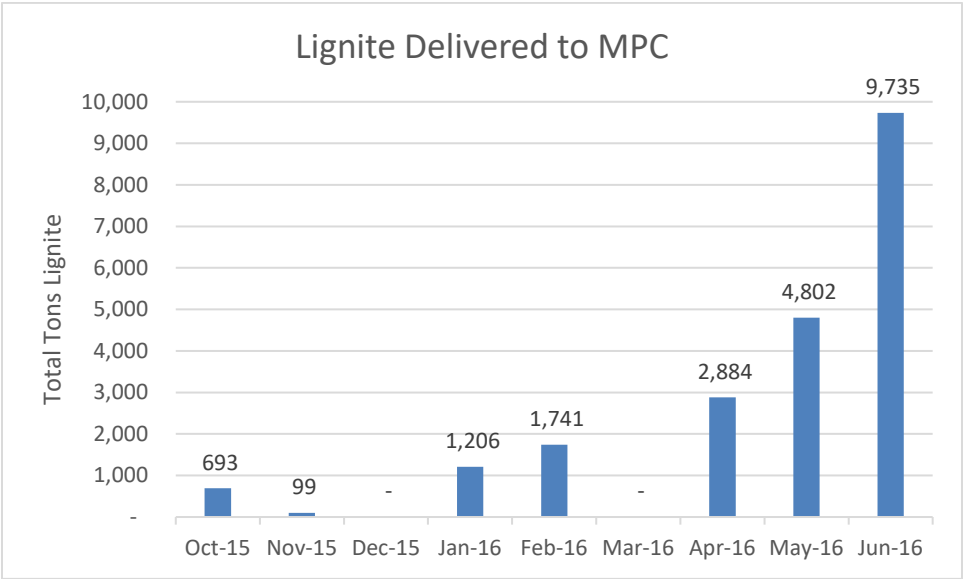


Figure 5.1-8 – Lignite delivered to MPC

5.1.2 Dryer Fan System

5.1.2.1 *System Overview*

The dryer gas fan supplies drying gas at a sufficient flow based on bed level in the dryer. It uses a suction flow control damper to provide enough pressure or force to fluidize the lignite bed and carry the moisture away from the dryer. The gas is compressed by the fan, heating the gas slightly and helping evaporation in the dryer. The dryer fan takes suction from the venturi condenser, increases gas pressure and velocity, then discharges through dryer tempered water heater HX2201 and dryer steam heater HX2202 in series (figure 5.1-10; the tags are for #5 dryer system).

The drying gas consists primarily of nitrogen (N_2), and leakage is compensated for by injecting additional nitrogen. During normal operation, the N_2 injection rate is determined by a comparison between the fan's suction pressure, indicated by PIC22062B, and the oxygen content of the drying gas. AIT22607 senses the oxygen content, which is on the suction side of the dryer fan. The signals representing these parameters are compared, and the one with the greatest magnitude is selected as the controlling signal. If suction pressure is too high, N_2 injection will be reduced, and vice versa. If the oxygen level becomes too high, the N_2 injection rate will be increased. If this increase is insufficient, the nitrogen deluge system will be activated. When the deluge is activated, the normal operating control scheme is adjusted to allow the PIC22062A to control the pressure while the oxygen content AIT22607 is brought back to setpoint. If the control scheme causes a high-pressure situation downstream of FN2202 dryer gas feed fan, another pressure controller reduces it. PIC22062A will open and vent some of the gases to FL2204 PC cyclonic baghouse. The gas flow to the dryer is controlled by the fan damper, which throttles in accordance with the fan flow meter. This controller receives an input from either its local setpoint or a remote setpoint from the dryer bed level, which correlates flow from the fan in ACFM to the target bed depth in PG2202.

The gas circulation fan (figure 5.1-9) moves the drying gas around the dryer loop. The fan discharge pressure is nominally between 85 and 100 in. W.C. with a gas flow rate of 285 kacfm, to provide the necessary fluidization of the lignite bed in the dryer and to prevent the influx of air. The fan operates on average at 90 in. W.C., but can supply up to 115 in. W.C. pressure for upset conditions such as the collapse of the lignite bed in the dryer. The fan supplies 285,000-300,000 acfm during normal operation.

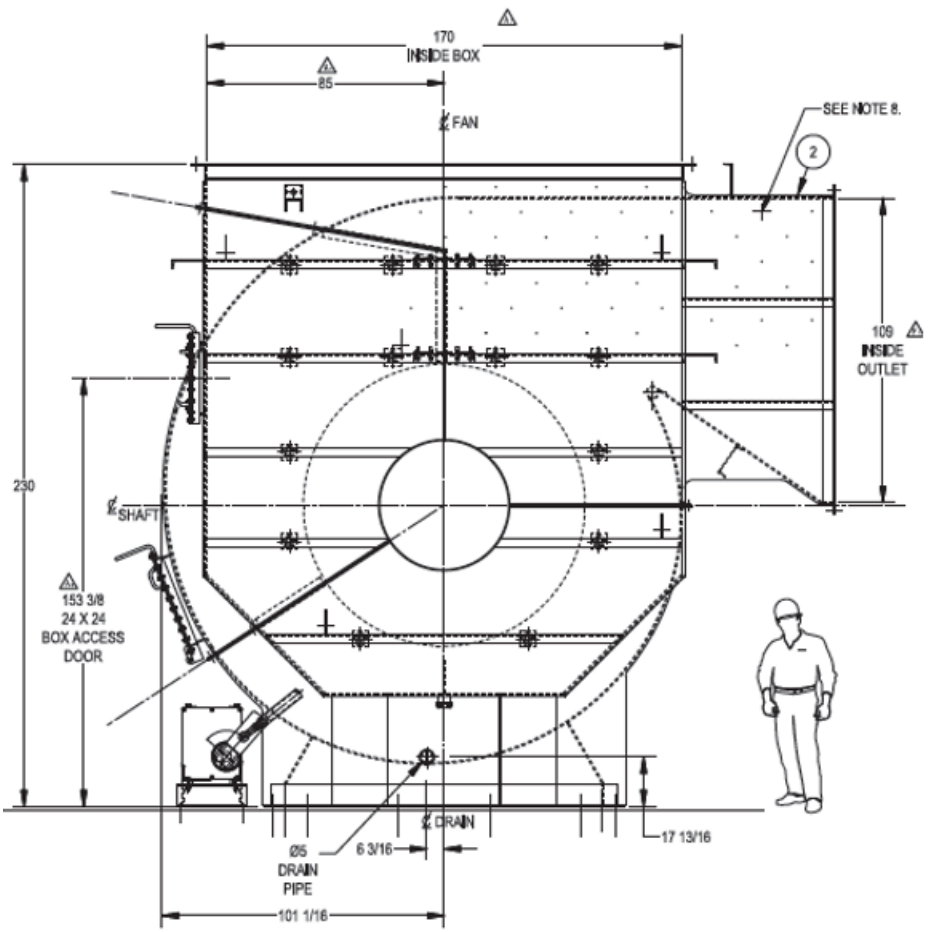


Figure 5.1-9 - Lignite dryer fan, side view

The test block rating is 336,287 acfm at a static pressure of 118.5 in. W.C. with the inlet damper fully open. The fan has an 8,100-hp drive to be able to operate at maximum conditions. Normal operation is well below this point. The fan operates at a motor speed of 1,180 rpm with flow control from an inlet vane damper. The available space for the fans was limited by the need for maintenance access on the west side. To accommodate this access, the fan discharges directly into the heat exchanger with a short transition zone. A perforated grid plate in the heat exchanger inlet distributes the sweep gas flow across the heat exchanger width and height for improved efficiency. Before the sweep gas enters the dryer, it is preheated in a large heat exchanger. This primary gas heater provides 30% to 50% of the heat necessary to evaporate the lignite moisture.

5.1.2.2 *Initial Commissioning Plan*

- Pre-test package work

Precommissioning activities for the dryer fan system were to include alignment verification, instrument loop-checks, and commissioning of the lube oil skid. This work was to be completed at the turnover package level before the fan and system level testing began. After satisfactory completion of all general precommissioning activities, the plans detailed in this section commenced. The testing of the fan and dryer loop were grouped into two separate test packages. The first was to establish a flow path for testing and tuning of the gas feed fan. The second was to introduce heat into the gas path and to tune the fluid bed dryer heat-up controls and startup sequence.

- Ductwork leak rate checks

Before the test began, two 1,500 cfm air compressors pressurized the system to 20 in. W.C. to determine where leaks were in the system. A soap bubble test identified the leaks so repairs could be made to major leaks before the fan was started. Many leaks were found, and repairs were planned so the system would hold pressure during normal operation. One compressor was located on the nitrogen surge line upstream of valve HY-22105, and the second compressor was located on the LP nitrogen line upstream of valve AV-22101 (figure 5.1-10). Before the test began, the two 1,500 cfm compressors pressurized the system to 15 in. W.C.

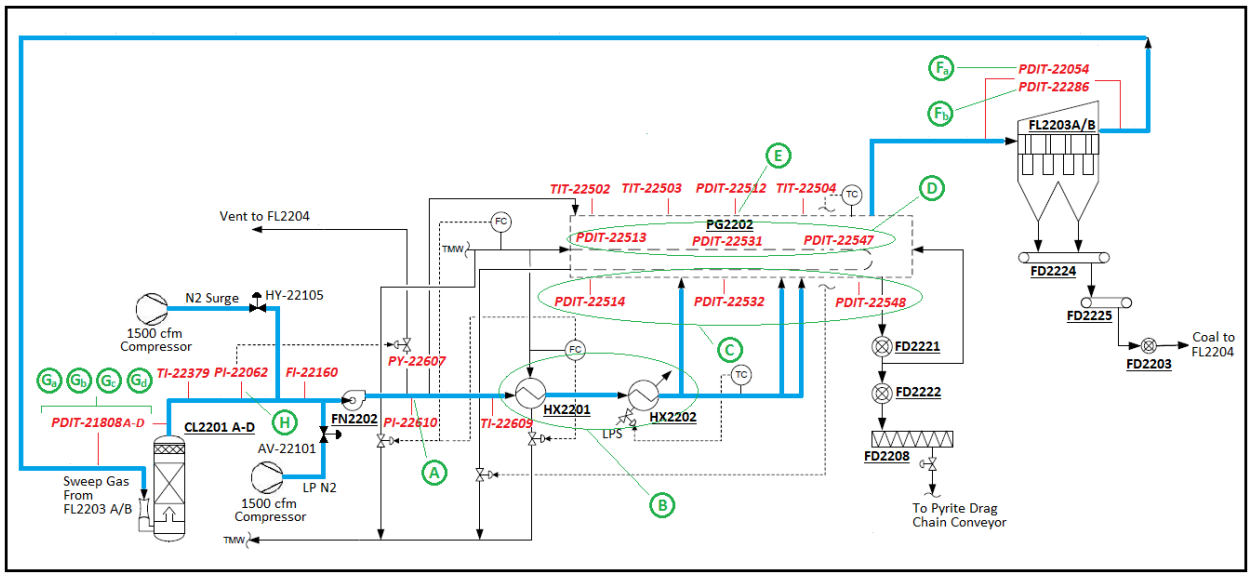


Figure 5.1-10 – #5 Dryer process flow diagram

- System pressure protection

To prevent damage to the system's duct work and fan housing, the system's inlet pressure PIT-22062 and outlet pressure PIT-22610 are monitored and controlled using vent control valves and nitrogen supply valves. In the case of over pressurization, pressure controller PIC-22062 will open the vent valve PV-22607 and send excess gas to the PC cyclonic baghouse FL2204. Additional pressure protection is provided by pressure relief valves PRV-22603A/B, set at 4.4 psig, located at the discharge of the dryer gas feed fan FN2202. If under pressured, PIC-22062 will open nitrogen supply valve AV-22101 to supply make-up nitrogen from the LP nitrogen header. The pressure limits for the system are 15 in. W.C. for the inlet pressure and 120 in. W.C. for the outlet pressure.

- Dryer fan test package overview

The functional objectives of part A and part B of the test package are described in this section.

Part A

The first fan test package, TP1005A, checked the functionality of the fan and was the final duct pressure check for the system. This test was to verify that the system was pressure tight and to further tune the fan controls. The procedure was performed with the ductwork access doors, manways, and inspection ports closed. The fan was planned to circulate only air, and a supplemental air supply was provided using a temporary oil-free air compressor and air dryer. The closed loop flow path for the dryer fan sweep gas proceeds through the dryer to the multiclone, followed by the venturi condenser and then back to the fan. Table 5.1-5 shows the part A test package implementation dates.

Table 5.1-5 – Dryer fan test package dates, part A

Part A

Test Package	Begin	End
Dryer 1 Fan A	4/27/2015	5/3/2015
Dryer 2 Fan A	5/24/2015	5/29/2015
Dryer 3 Fan A	5/31/2015	6/3/2015
Dryer 4 Fan A	5/31/2015	5/31/2015
Dryer 5 Fan A	5/26/2015	5/29/2015
Dryer 6 Fan A	6/24/2015	6/29/2015

Part B

The second part of the fan test package was to prepare for feeding lignite to the fluid bed dryer. Nitrogen was added to tune the loop and reduce the oxygen concentration to less than 8%. Since the condenser now had internal packing material installed, the plan was to run the venturi and/or the condenser to control the temperature to avoid damage to the condenser packing. Both the venturi and condenser had been fully checked out and were both ready for testing the integrated system (figure 5.1-11). To dry the lignite, the fluid bed dryer is heated to approximately 150 ˚F using tempered water in a series of tubes running horizontally across the dryer. Circulating nitrogen gas conveys the lignite. The tempered water valve (FV-22651) controlled the flow to the fluid bed dryer preheater HX2202 to control the circulating gas heat ramp-up rate to less than 75 °F/hr to prevent damage to the fiberglass ductwork. To prevent overheating and damage to the packing within the scrubber, which should not exceed 160 °F, circulated water was sprayed over the packing. The water was used to cool the circulated gas as well as condense moisture from the vapor phase. The temperature controller (TIC-22379), located on the fiberglass duct at the top of the venturi scrubber, was used to control the temperature of the circulating gas. The controller maintains the temperature of the gas by regulating the flow of the circulating water using a valve on the bypass line of the condenser heat exchanger HX2204. These dryer requirements needed to be tuned before lignite feed could begin. Table 5.1-6 shows the part B test package dates.

Table 5.1-6 – Pulverizer test package dates, part B

Part B

Test Package	Begin	End
Dryer 1 Fan B	11/3/2015	11/6/2015
Dryer 2 Fan B	11/23/2015	11/28/2015
Dryer 3 Fan B	9/4/2015	9/4/2015
Dryer 4 Fan B	8/12/2015	8/17/2015
Dryer 5 Fan B	4/11/2016	4/12/2015
Dryer 6 Fan B	2/22/2015	2/25/2015

- Dryer fan test package objective

Execution of the two-part test packages would ensure the dryer gas loop and venturi condenser gas loops were sufficient to support further testing of the system, including the addition of lignite.

Part A

The first dryer fan test package, TP1005A, was to have a short, basic dryer fan startup and tune various instruments without the venturi condensers in operation. The system's performance was monitored. Since the venturi condenser was not going to be run, it was important to run the test quickly enough that the duct temperature did not reach 200 °F, which would damage the fiberglass ductwork. The primary parts of the test package were:

- Monitor and record fan performance data until system flows and temperatures stabilized, then through fan shutdown. The process conditions measured were:
  - Inlet and outlet duct pressures.
  - Vibrations.
  - Current draw.
  - Variable speed control.
  - Bearing temperatures.
  - Fan performance data.
- Balance the fan and adjust the fan inlet damper as required.
- Validate mechanical integrity.
- Validate associated alarms, controller set points, controller-valve responses, interlocks, and related solenoid process control valve operations.
- Address any discrepancies and note any vibration problems or air leaks.

Part B

The objective of the second part of the dryer fan test package, TP1005B, was to execute the dryer fan startup and add heat to the system. The system's performance was monitored. The primary parts of the test package were:

- Monitor and record fan performance data until system flows and temperatures stabilized, then through fan shutdown. The process conditions measured were:
  - Inlet and outlet duct pressures.
  - Vibrations.
  - Current draw.
  - Variable speed control.
  - Bearing temperatures.
  - Fan performance data.
- Test and tune the nitrogen inerting system and verify the automatic startup logic.
- Test and tune the gas heater with tempered water and verify the automatic startup logic.
- Run the venturi and condenser systems to control the system temperature, and test and tune the controller in the condenser loops needed for gas cooling.
- Validate associated alarms, controller set points, controller-valve responses, interlocks, and related solenoid process control valve operations.

- Dryer fan commissioning plan

Part A

The initial checkout of the dryer fan and gas loop are shown in figure 5.1-11. The pink lines represent the gas path. The fan was started, and the fan vibration and motor parameters were measured and evaluated first due to the problems experienced with the motor two months earlier. The fan and motor manufacturer were onsite and conducted their field checks during the operation. This test package was aided by the air compressors. Since the ductwork was leaking substantially, at 2,000 cfm, the compressors added 3,000 cfm to help maintain pressure for the system. Due to the absence of process medium and equipment internals, the fan damper was clamped at 15% open travel.

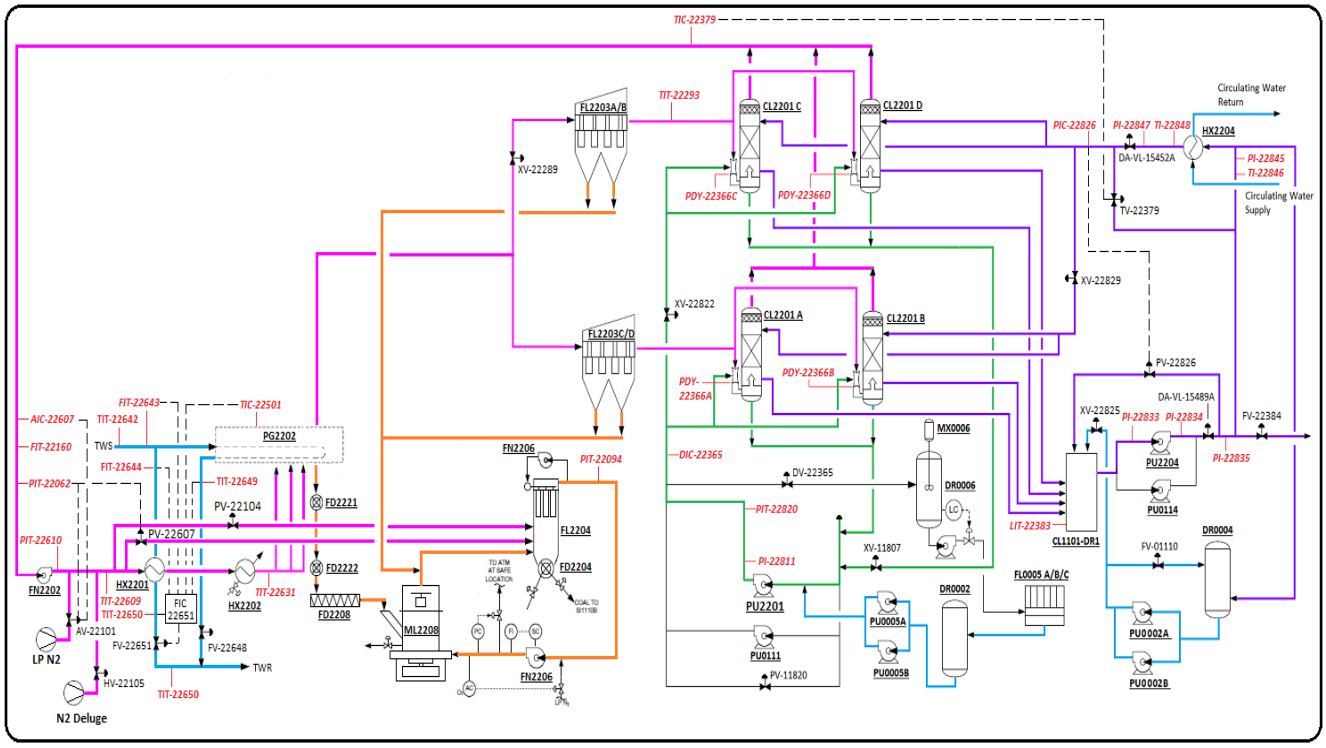


Figure 5.1-11 - Lignite preparation overview

Part B

The second part of the test package was intended to extend the dryer gas loop operation beyond the equipment level. It included more advanced testing, such as verification of the fluid bed dryer heat-up sequence and operation of the venturi condenser. The testing was initiated on air from temporary compressors and moved to the normal process medium of nitrogen. Before tuning the instrumentation, LP nitrogen was used to inert the system, then circulated through the fluid bed dryer loop to ensure the loop was gas tight and would remain inerted to levels below 8% oxygen.

Tempered water was used to heat the dryer to operating temperature. The temperature of the dryer and the vibration of the dryer fan FN2202 were closely monitored for stability. Before starting dryer fan FN2202, oxygen levels were at 19.2%.

After the instruments were checked and the system was mechanically functionally verified, the loop tuning could begin. The first controller to be tuned was the pressure control loop. The fan, nitrogen addition, and vent system were run

through a series of tests to develop a robust pressure control tuning for the fan operation. This step was critical for overall operation and process stability.

The dryer fan suction pressure controller PIC-22062 controlled the vent valve PV-22607 to the PC cyclonic baghouse and the nitrogen supply valve AV-22101. To properly tune the pressure controller, either the vent valve or the supply valve position must be fixed while the other is adjusted.

The venturi was started to maintain temperature in the loop during the test package execution.

5.1.2.3 *Significant Events*

- Fan motor failure

In February 2015, during the first functional test and before the dryer fan test package, the dryer fan stopped abruptly while coupled to its motor after only a few minutes of operation, damaging the fan motor. The 8,100-hp motors were a custom application for the Kemper project. The motor manufacturer was contacted, came onsite and inspected the motor. It was initially thought there was a fabrication quality problem with the motor on FN2202, not a design problem. A second fan was started, and its motor also failed but there was less damage because it was shut down immediately when problems were detected. A cross-functional team that included the motor manufacture was developed after the first failure. The team recommended conducting a complete root cause analysis (RCA). The RCA started onsite with fact finding on the motor and failure, and then was completed at the factory. Inspections and tests of the failed motors and another motor that had not been run or damaged were also part of the RCA investigation.

The dryer fan motor RCA was jointly conducted with the supplier. The RCA determined that a cooling fan attached to the motor shaft had come loose and then hit and damaged the winding of the motor. The cooling fan was designed to blow air across the motor to keep the windings cool during normal operation. During the shop inspection, an infrared thermal camera was used during a locked rotor test to inspect the heat-up conditions at blower startup. It was determined that the six connection points where the cooling fan was connected to the motor shaft heated up faster than the shaft, and the circulating currents being induced from the motor during load starts heated the blower hub to a higher temperature relative to the motor shaft. The fan connections were designed to be heat shrink-fitted to the motor shaft, but when thermal expansion of the connections was greater than the shaft, the fan slid off the shaft. During startup, as the motor began to heat up to normal operating temperature, the motor windings heated the six fan connections to the shaft by 40 °C greater than the shaft, 22 °C higher than the fan designers had anticipated. This excessive temperature difference caused a loss of the interference fit. When the RCA determined the cause of the failure, a repair plan was implemented. The motors were repaired at the factory and then were reinstalled at Kemper within about 2 weeks. The project delay was approximately 8 weeks for the first fan and 3.5 months to complete repair of all six fans.

Dryer gas preheater leak

After the fan was shut down, it was observed that the fluid bed dryer gas preheater began to leak tempered water. It was determined that when the dryer was not in operation, the tempered water would not be sent through the gas heater. The logic design and check valve configuration blocked the tempered water in the heat exchanger, which resulted in the stagnant tempered water being further heated by the heat of compression when the fan was running. This water expanded from being heated and put pressure on the gaskets at the top of the heat exchanger. To prevent this from reoccurring, the logic was changed to open the tempered water flow control valves by 5% during the fan operation. This scenario was missed during the HAZOP of this system with the vendor, but the solution was recommended by the vendor after the events were explained.

5.1.2.4 *Final Summary*

The fan was checked out during the first part of the test package and a baseline was developed. Some leaks were found during the test package, but this work would continue off and on for the next 2.5 months. The fan checkout and the damper tuning were completed during the first test. The pressure controller PIC-22062 was tuned to the extent

possible using the air compressors. This part of the test package did not work as well as anticipated as the pressure controller could be set, but the range was limited. It was able to maintain the pressure of the loop. The fan was successfully started without vibrational issues or excessive overheating of the ductwork.

The second fan test successfully pressurized and inerted with nitrogen without any leaks. The pressure controller PIC-22062 performed as it should and maintained the pressure of the loop. The fan was successfully started and operated without vibrational issues. The system avoided excessive overheating of the ductwork or venturi packing. The ramp-up rate for the circulating gas never exceeded 75 °F/hr. The total gas flow was plotted versus the power output from motor FN2202M (figure 5.1-12).

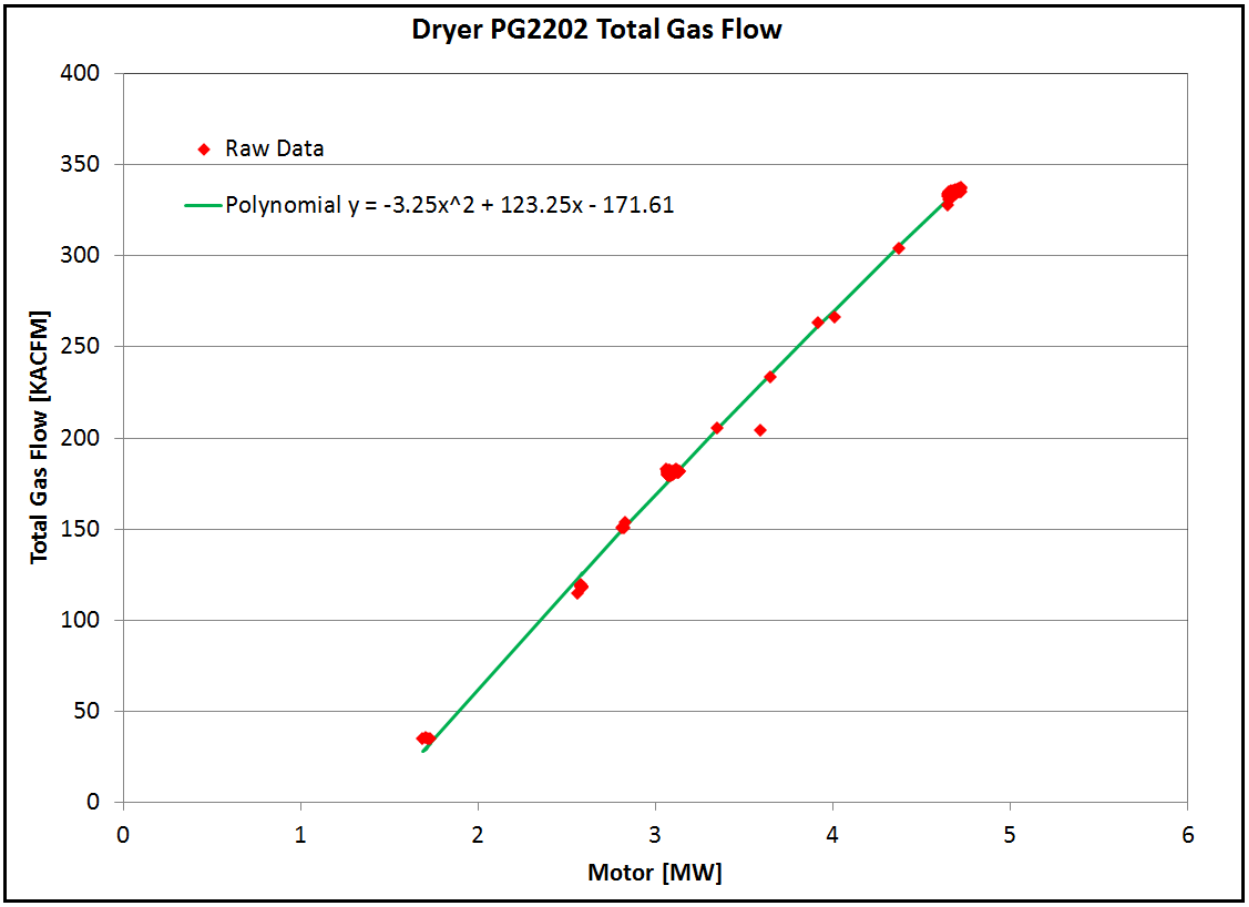


Figure 5.1-12 – Dryer PG2202 total gas flow versus motor power

The fan motor correlation helped check that the fan flow meter was working properly. The flow was verified with the damper curve provided by the manufacturer for the fan flow correlation (figure 5.1-13).

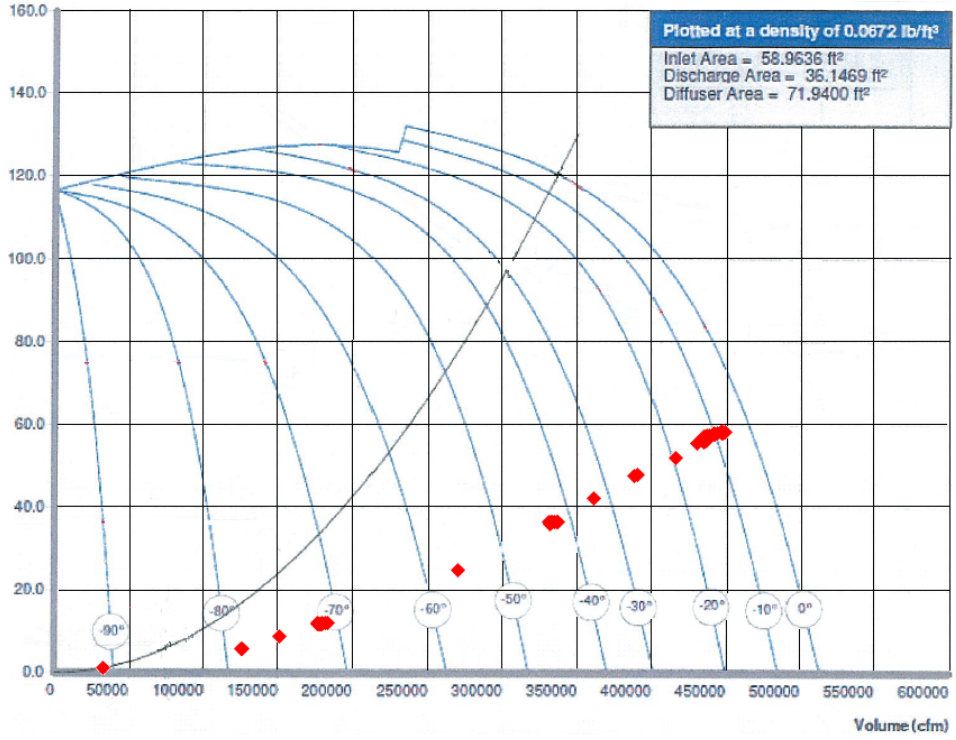


Figure 5.1-13 – Fan FN2202 – performance curve

The differential pressure versus the calculated total gas flow was plotted and overlaid onto the fan performance curve for the dryer fan (FN2202). The system's head was obtained using the differential pressure calculated by subtracting the suction pressure of fan FN2202 (01G-PIT22062) from the discharge pressure of fan FN2202 (01G-PIT22610). See table 5.1-7.

Table 5.1-7 - Dryer fan operating data

DATE	TIME	MOTOR [MW] FN2202M-JI	(H) Circ Fan FN2202 Suction Press [inH2O] PIT22062	(A) FN2202 Disch Press XMTR [inH2O] PIT22610	(A-H) Fan FN2102 DP [inH2O]
5/23/2015	10:40:20 AM	1.73	26.79	28.10	1.31
	10:44:20 AM	2.58	25.77	31.62	5.85
	10:48:20 AM	3.14	23.57	35.49	11.92
	10:52:20 AM	3.10	21.02	32.93	11.91
	10:56:20 AM	3.07	18.45	30.28	11.84
	11:00:20 AM	3.10	19.89	31.67	11.78
	11:04:20 AM	3.07	23.99	35.97	11.98
	11:08:20 AM	4.72	12.11	48.53	36.42
	11:12:20 AM	4.69	11.87	48.17	36.30
	11:16:20 AM	4.67	11.64	48.10	36.46
	11:20:20 AM	4.66	12.68	49.00	36.32
	11:24:20 AM	5.31	8.76	56.48	47.72
	11:28:20 AM	5.60	11.63	63.54	51.91
	11:32:20 AM	5.82	10.91	66.46	55.55
	11:36:20 AM	5.99	7.28	65.48	58.20
	11:40:20 AM	5.97	7.35	65.20	57.85
	11:44:20 AM	5.93	8.10	66.06	57.96
	11:48:20 AM	5.91	8.88	66.44	57.56
	11:52:20 AM	5.86	9.40	66.76	57.36
	11:56:20 AM	5.84	9.88	66.95	57.07
	11:59:40 AM	5.82	10.02	67.04	57.02

The dryer is divided into three zones, each with a grid plate at its base used to evenly distribute the gas that dries the lignite. The grid plate slots in zone 1 and 2 have an opening of 7 mm, and the slots for the grid plates in zone 3 have an opening of 5 mm. Pressure indicators PDIT-22514, PDIT-22532, and PDIT-22548 measure the differential pressure across the grid plates. See figure 5.1-14 for a plot of the grid plate differential pressure versus the calculated total gas flow, which shows all three zones have comparable trends. A smaller opening should produce a greater pressure drop.

Each zone of the dryer contains a pressure indicator that measures the differential pressure from the top of the grid plate or base of the heating coils to the top of the dryer. PDIT-22513, PDIT-22531, and PDIT-22547 measure the differential pressure. The pressure drop across the heat exchangers HX2201/HX2202 was obtained by first subtracting the fan FN2202 discharge pressure (PIT22610) from the dryer's hood pressure (PDIT22512). From this value, the average dP across the grid plate and the average dP across the bed of the dryer was subtracted (figure 5.1-14). Figure

5.1-14 shows the relationship between the average grid plate dP, dryer dP, and dP due to heating coils with respect to the calculated total gas flow.

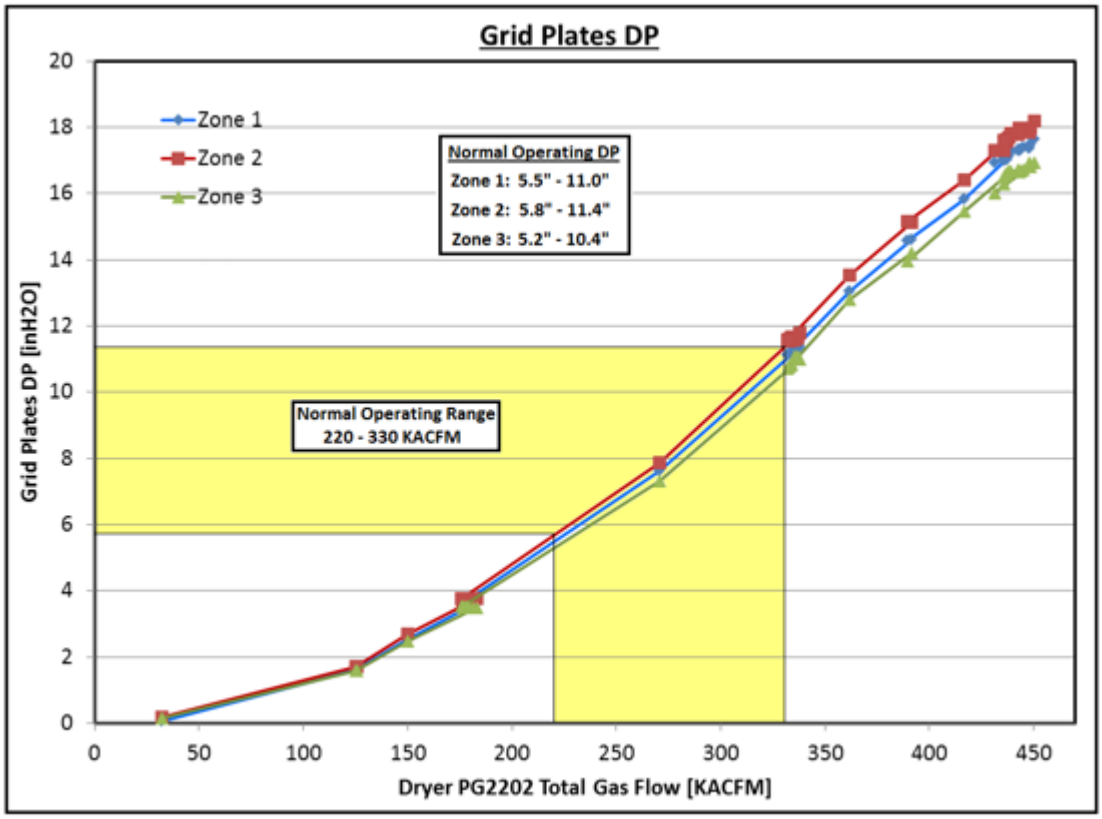


Figure 5.1-14 – Dryer PG2202 grid plate dP

The system loop consists of the following equipment:

- Heat exchanger HX2201 and HX2202.
- Dryer PG2202.
- Two multiclones run in parallel FL2203A/B.
- Four venturi scrubbers CL2201A/B/C/D.

The differential pressure across the individual venturi scrubbers, measured by PDIT-22808A-D, are shown in figure 5.1-14. The reading for venturi CL2201D is significantly higher than the other three due to inaccurate measurement. Pressure indicator PDIT-22808D shows high dP in figure 5.1-16. This discrepancy was a common sensing line problem at any given time during operation. A preventive maintenance program was set up to blow out the condensate in the pressure sensing line and remove the condensate that was building up and causing false readings. This problem was

not fixed until May 2017. The pressure drop across the venturi scrubbers is plotted versus flow rate in figure 5.1-15. An increase in dP results in an increase in flow rate for all four venturi scrubbers.

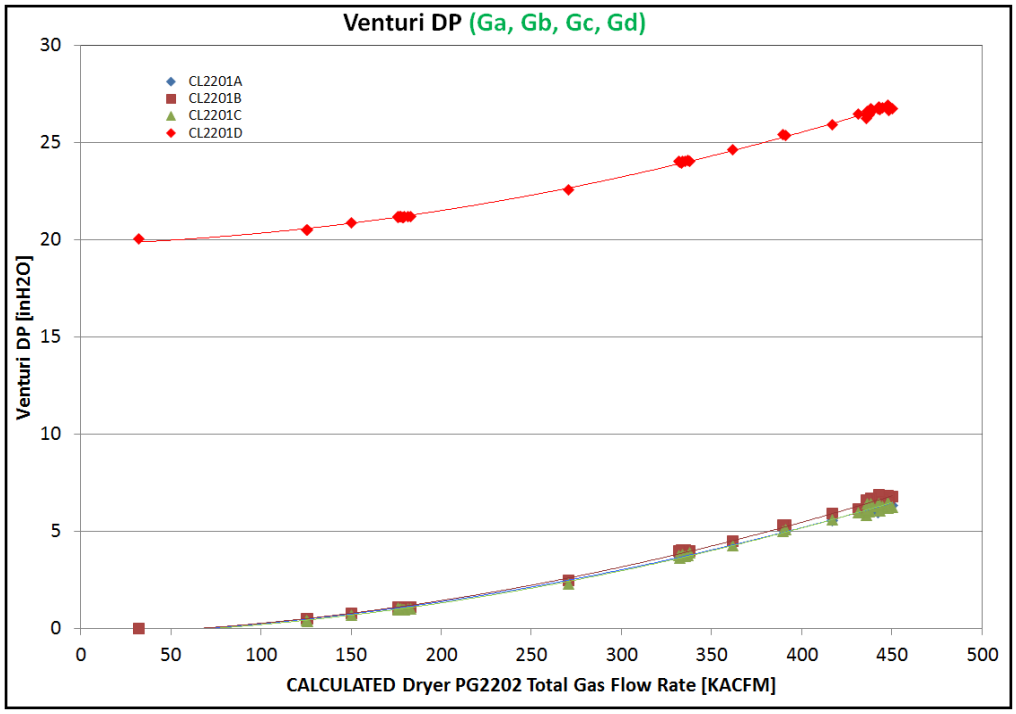


Figure 5.1-15 – Venturi scrubber CL2201A-D dP vs. calculated total gas flow

The pressure drop across the multiclones is plotted versus flow rate in figure 5.1-16. An increase in dP is followed by an increase in flow rate for both FL2203A and FL2203B.

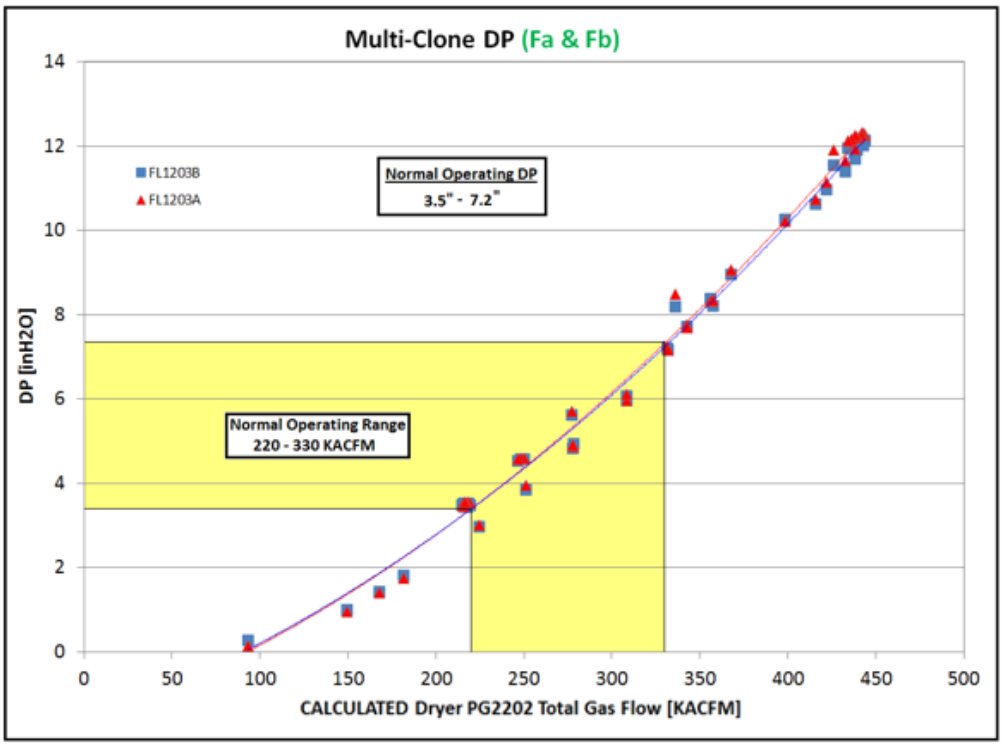


Figure 5.1-16 – Multiclone FL2203A-B dP vs. calculated total gas flow

Three temperature indicators TIT-22502, TIT-22503, and TIT-22504 are located on dryer PG2201, one in each of the three zones. The temperature for the three indicators are comparable, indicating a uniform temperature profile within the dryer. Over the duration of the test, the temperature in the dryer increases. As the speed of the fan increases, additional work is added to the system, heating the gas circulating through the system. The three zone temperatures in the dryer are plotted versus time in figure 5.1-17.

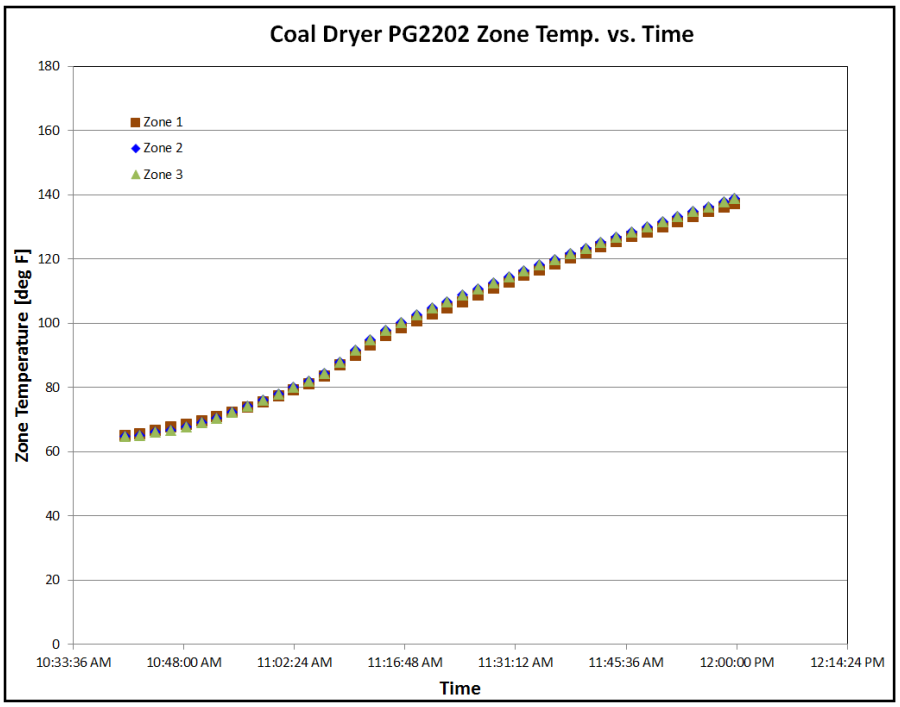


Figure 5.1-17 – Dryer PG2202 zone temperatures. vs. time

The fan generates heat within the dryer loop from compression of the circulating gas. The heat transferred to the loop from fan FN2202 was determined using the following equation:

$$\dot{q} = \dot{m} c_p \Delta T$$ **(Heat Transfer Rate)**

Where:

$\dot{q}$ = heat transfer rate [kJ/min]

$\dot{m}$ = mass flow rate in [kg/min]

c_p = specific heat of air [kJ/kg*K]

ΔT = change in gas temperature [K]

For c_p a value of 1 kJ/kg•K) was used. To determine the mass flow rate, the volumetric flow rate of the gas was multiplied by the density of the air. The ideal gas law was used to determine the density of the air at the various temperatures and pressures within the loop during the test.

$$\rho = \frac{MW \cdot P}{R \cdot T}$$ **(Density as a Function of Pressure & Temperature)**

Where:

ρ = density of air [kg/m^3]

MW = molecular weight of air

P = pressure [atm]

R = universal gas constant [(L*atm)/(mol*k)]

T = temperature [K]

The immediate rise in air temperature within the dryer loop on the start of the fan is shown in figure 5.1-18.

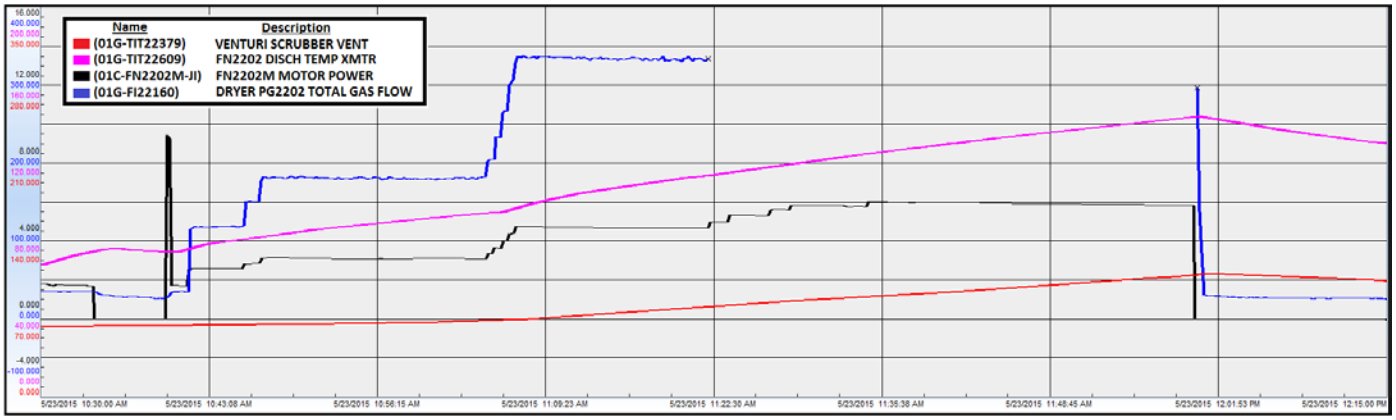


Figure 5.1-18 – Temperature rise in dryer loop

The test ran for 1.33 hours. Near the end of the test, the gas flow rate through the dryer was about 330 kacfm and the fan discharge and venturi scrubber vent temperatures were about 144 ˚F and 109 ˚F. The cumulative heat generated by the fan during the test period was about 11.7 million BTUs (table 5.1-8).

Table 5.1-8 – Dryer fan heat of compression calculation

DATE	TIME	Venturi Scrubber Vent [deg K] TIT22379	FN2202 Disch Temp [deg K] TIT22609	FN2202 Disch Press [atm] PIT22610	$\rho = \frac{MW * P}{RT}$ Density of Air [kg/m^3]	CALCULATED Dryer PG2202 Total Gas Flow [m^3/min]	$\dot{m}\left[\frac{kg}{min}\right] = flowrate\left[\frac{m^3}{min}\right] * \rho\left[\frac{kg}{m^3}\right]$ Mass Flow Rate [kg/min]	$\dot{q} = \dot{m} c_p \Delta T$, $c_p = 1.0\ kJ/(kg \cdot K)$ Q Dot [KJ/min]	Q [KJ]	Q [BTU]
5/23/2015	10:40:20 AM	290.79	296.45	1.073	1.278	917.83	1172.76	6637.63	2213	2097
	10:44:20 AM	290.97	299.45	1.078	1.270	3547.82	4506.11	38203.34	12734	12070
	10:48:20 AM	291.23	301.33	1.087	1.273	5186.88	6605.25	66731.97	22244	21083
	10:52:20 AM	291.61	303.32	1.080	1.257	5082.81	6387.91	74791.71	24931	23630
	10:56:20 AM	292.00	304.78	1.074	1.243	4989.73	6203.76	79280.56	26427	25048
	11:00:20 AM	292.40	306.18	1.079	1.244	5068.39	6304.09	86885.34	28962	27450
	11:04:20 AM	293.08	307.42	1.088	1.249	4985.71	6228.78	89323.66	29775	28221
	11:08:20 AM	293.97	310.33	1.120	1.273	9570.76	12185.97	199467.45	66489	63020
	11:12:20 AM	295.72	313.45	1.119	1.260	9499.35	11968.76	212185.51	70729	67038
	11:16:20 AM	297.47	315.62	1.119	1.251	9434.03	11797.76	214184.60	71395	67669
	11:20:20 AM	299.22	317.60	1.121	1.245	9403.01	11707.66	215166.09	71722	67979
	11:24:20 AM	300.97	319.49	1.140	1.259	11081.39	13949.45	258329.82	86110	81616
	11:28:20 AM	302.73	321.51	1.163	1.276	11808.96	15067.27	282961.39	94320	89399
	11:32:20 AM	304.20	323.51	1.163	1.269	12342.05	15656.14	302264.77	100755	95497
	11:36:20 AM	305.66	325.35	1.160	1.259	12756.09	16055.02	316021.34	105340	99843
	11:40:20 AM	307.13	327.10	1.160	1.252	12700.32	15896.49	317470.12	105823	100301
	11:44:20 AM	308.79	328.85	1.162	1.247	12602.24	15719.28	315249.71	105083	99600
	11:48:20 AM	310.61	330.47	1.164	1.243	12560.04	15606.86	309895.40	103298	97908
	11:52:20 AM	312.43	332.08	1.164	1.237	12442.11	15393.28	302589.98	100863	95600
	11:56:20 AM	314.25	333.70	1.165	1.232	12387.88	15258.38	296818.56	98940	93777
	11:59:40 AM	315.78	335.05	1.162	1.224	12342.61	15110.17	291136.88	97046	91982
								TOTAL:	12,338,810	11,694,935
								Per Hour:	9,292,827	8,807,901

Pressure controller PIC-22062 was functioning appropriately (figure 5.1-19). The suction pressure (red line) is in accord with the suction pressure setpoint (dotted black line). The controller makes slight periodic modification to the vent valve PV-22607, shown in blue, to maintain the pressure at the designated setpoint.

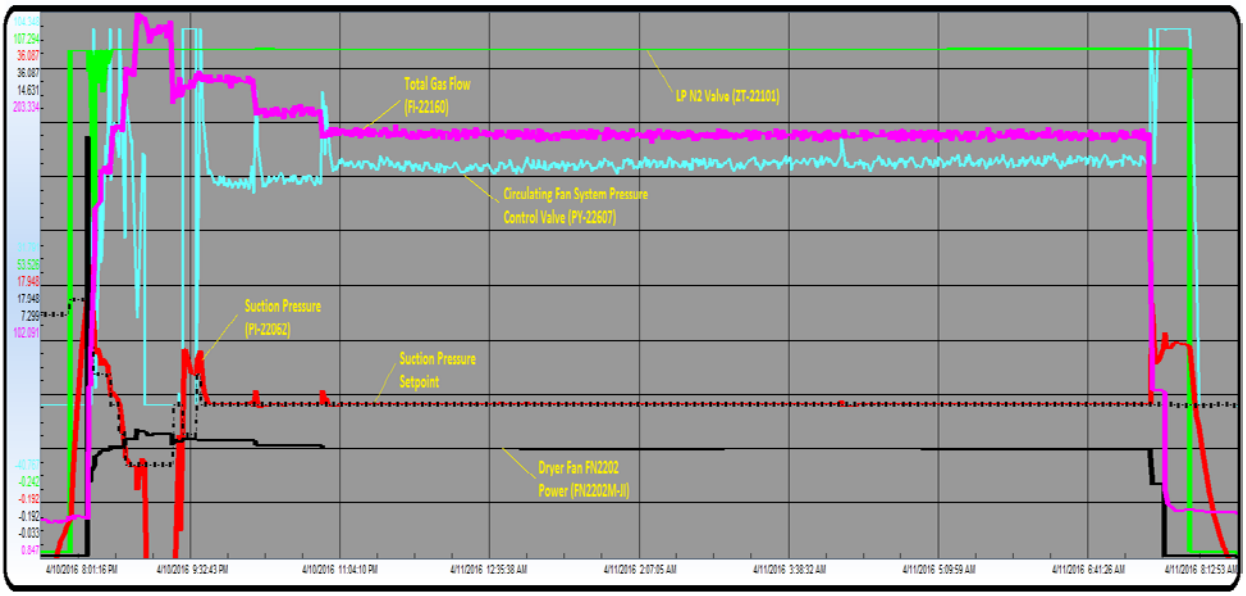


Figure 5.1-19 – Suction pressure controller data during tuning PIC-22062

During the tuning of temperature controller TIC-22379, it was discovered that controlling the temperature of the circulating gas with heat exchanger HX2204 bypass valve TV-22370 was not a viable option with the current

configuration. The temperature probe was located too close to the unmixed laminar layer in the duct. The probe was moved about 3 months later after this initial test was performed.

The circulating gas is heated by tempered water heater HX2201, with additional heating from compression from fan FN2202. The rate of temperature rise must be closely monitored and controlled to prevent damage to the fiberglass ductwork. If the temperature rise exceeds 75 °F/hr, the fiberglass composite will expand too quickly and be damaged. The ramp-up rate is controlled by flow controller FIC-22651, which regulates the temperature by adjusting tempered water valve FN-22651 on the tempered water line to HX2201.

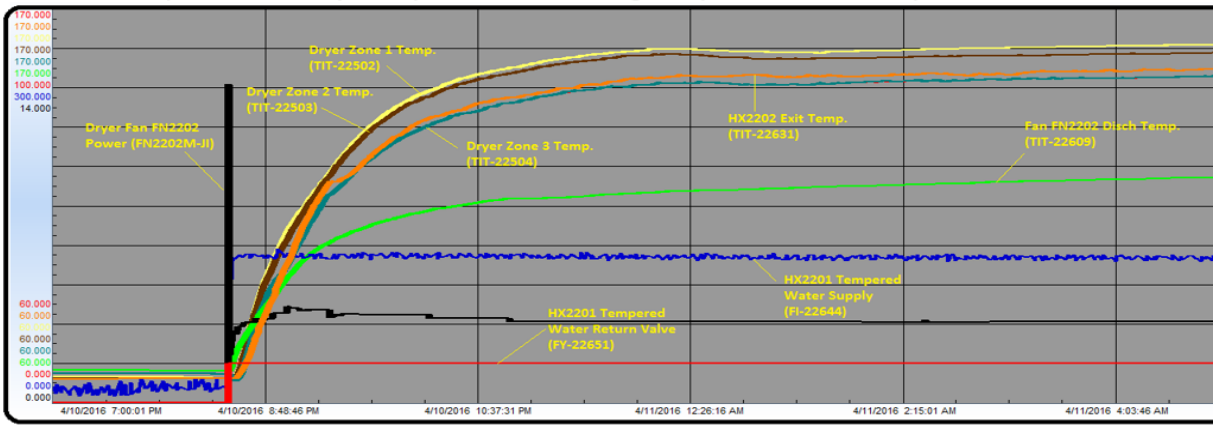


Figure 5.1-20 – Exit process gas temperature rise for dryer fan, gas heater, and fluid bed dryer

The green curve in figure 5.1-20 indicates the rise in temperature due to the compression of the fan. The tempered water flow to HX2201 was 112 GPM with the tempered water valve FV-22651 10% open. Figure 5.1-20 shows a gradual increase in temperature of the circulating air before stabilizing at roughly 150 °F at the discharge of heat exchanger HX2202 and in the dryer. The temperature ramp-up rate did not exceed the limit of 75 °F/hr (table 5.1-9).

Table 5.1-9 – Dryer air test temperature rise during startup

Time	Fan FN2202 Discharge Temp [Deg F] TIT-22609	HX2202 Exit Gas Temp [Deg F] TIT-22631	Dryer Temp. Zone 1 [Deg F] TIT-22502	Dryer Temp. Zone 2 [Deg F] TIT-22503	Dryer Temp. Zone 3 [Deg F] TIT-22504
8:30 PM	68.88	66.76	66.81	66.85	67.84
9:30 PM	107.08	122.96	130.48	129.65	122.49
10:30 PM	115.31	142.01	150.68	149.29	140.79
11:30 PM	117.60	148.63	156.89	155.33	147.10
12:30 PM	119.24	151.13	158.62	157.10	149.51

Fan vibration must be monitored to ensure it stays within acceptable limits to prevent damage. The axial vibration (VE-52921C) for dryer fan FN2202 during operation is shown in figure 5.1-21. The maximum vibration occurred during the initial starting of the fan, which is as expected. During the run, vibrational measurements were within acceptable limits.

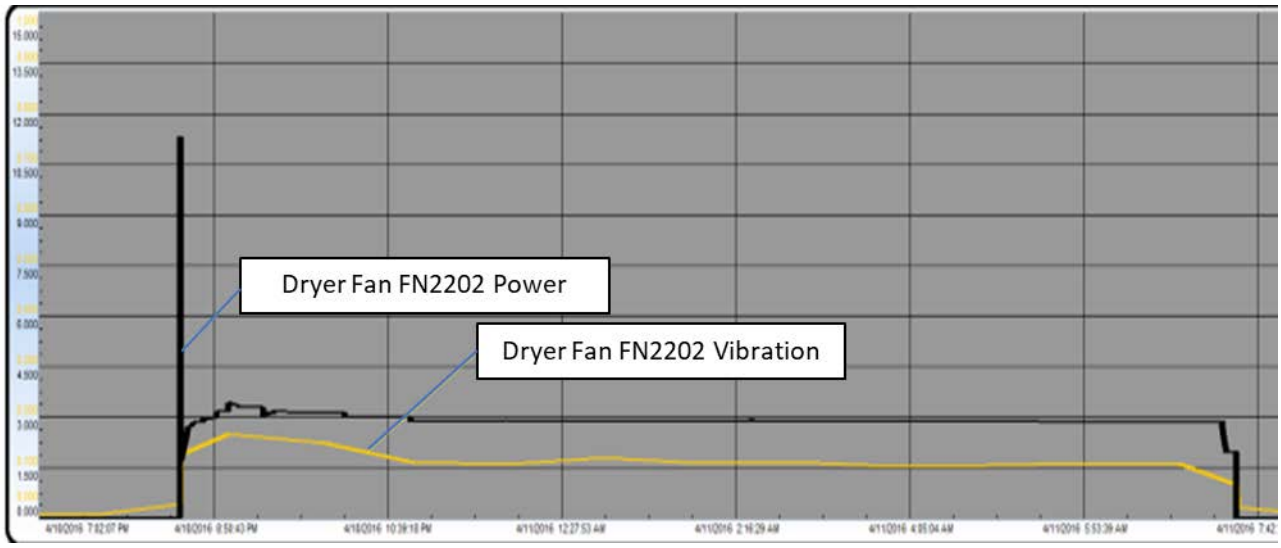


Figure 5.1-21 – Fluid bed dryer fan axial vibration

The LP nitrogen valve AV-22101 was 100% open inerting the loop to 1.8% percent oxygen before starting the fan (figure 5.1-22).

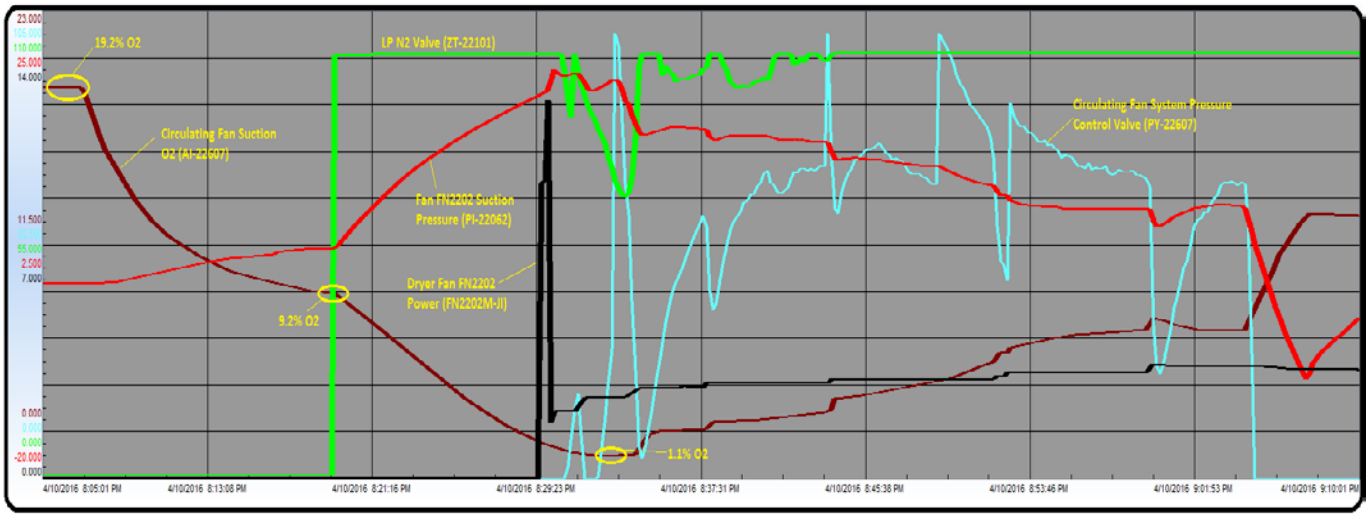


Figure 5.1-22 – Inerting of fluid bed dryer loop

The controller was tuned by incrementally decreasing the suction pressure setpoint while maintaining the LP nitrogen valve position at 100% open. Immediately following the drop in the setpoint, the vent valve opening abruptly increases followed by a gradual decrease until the suction pressure reaches the designated setpoint. The pressure controller was tuned at various gas flow rates due to the pressure's dependence upon gas flow (figure 5.1-23).

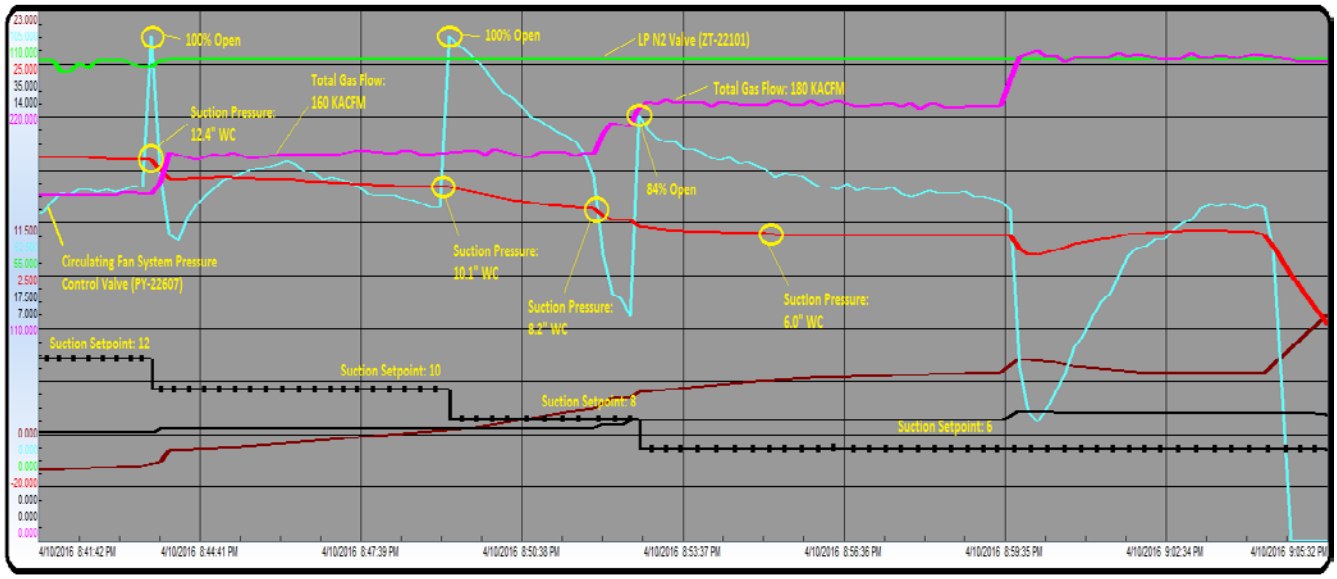


Figure 5.1-23 – Tuning of suction pressure controller PIC-22062

5.1.3 Venturi Condenser System

5.1.3.1 *System Overview*

After exiting the multiclones, the drying gas passes through a group of four vessels. Each vessel has two distinct parts with different functions: the venturi scrubber and the condenser. This system has the following equipment (figure 5.1-25):

- CL1101A/B/C/D venturi condenser.
- PU1101 venturi pump.
- PU1104 condenser pump.
- HX1104 condenser cooler.

The gas first enters a venturi scrubber where a fine water spray captures fine particulate. The venturi condenser processes the drying gases vented from PG1102 fluid bed dryer through multiclone FL1103A/B to capture entrained fines, recovers excess moisture for reuse elsewhere, and recycles the gases back to the fluid bed dryer. Water used at the venturi condenser is filtered to remove entrained particulate and allow the water to be reused.

The drying gas velocity increases in the venturi throat, causing a decrease in pressure that allows water to be drawn through. The water that enters is sprayed into the venturi to entrain particulates. After exiting the venturi throat, the gases are directed towards the venturi wetted elbow, which collects most of the water from the venturi spray. The gas enters the bottom of the condenser through a chimney tray that helps to remove the remaining water droplets. These water droplets fall into the venturi sump where they are collected and reused as venturi spray. The water is drawn from the bottom of CL1101A/B/C/D venturi sump by PU1101 venturi pump. The venturi sump level is controlled by LIC11373, which adjusts the filtrate flow from DR0002 filtrate drum and PU0005A/B filtrate pump. The venturi pump pumps most of the water through the venturi throat to perform the particulate removal. The rest of the discharge flow is directed to DR0006 filter press feed tank for solids removal. DIC11365 senses the density of the PU1101 venturi pump discharge water and adjusts a bypass stream around CL1101 venturi directly to DR0006 filter press feed tank. Level control LIC11373 located at the venturi sump will cause filtered water from the filter press to replace what was recycled.

The gas then enters the condenser, which is a packed tower. The gas flows countercurrent to the water sprayed down on the condenser packing. The contact of the gas with the water as it passes through the packing cools the gas and helps condense the water from the gas. The water falls through the packing and onto a chimney tray, which drains to

condensate level tank CL1101DR1, where it is withdrawn into the recovered water system. Each set of condensers is designed to remove 130-200 gpm (figure 5.1-24). See section 5.1.5, Recovered Water, for details of the recovered water system.

After the packed bed, the gases continue upward through a demister that removes additional moisture. Sweep gas is then sent back to the fluid bed dryer through FN1102. The condenser pump PU1104 takes suction from the CL1101DR1 condensate level tank and sends the water through HX1104 condenser cooler for cooling or to the water recovery system, based on the signal from LIC11383. The portion of the flow sent through HX1104 condenser cooler enters the condenser section of CL1101A/B/C/D venturi condenser above the packed bed. The remaining flow is directed downstream to recover the water.

A kickback line on condensate level tank CL1101DR1 connects to the discharge of PU1104 condenser pump. This line contains PV11826, which receives an open command based on the pressure in the pump discharge line. The pressure setpoint is set by the operator and is based on all four condensers operating. The kickback valve PV11826 is opened during turndown conditions, when only two condensers are operating.

The condenser cooler HX1104 uses circulating water from the gasifier island cooling tower to cool the discharge water from PU1104 condenser pump. HX1104 removes the heat that the water absorbed during its previous cycle through CL1101A/B/C/D condenser. Temperature controller TIC11379 allows a portion of the flow to bypass HX1104 condenser cooler to maintain the target overhead condenser temperature. From HX1104 condenser cooler, the water is directed back to the packed bed inside the CL1101 A/B/C/D condenser.

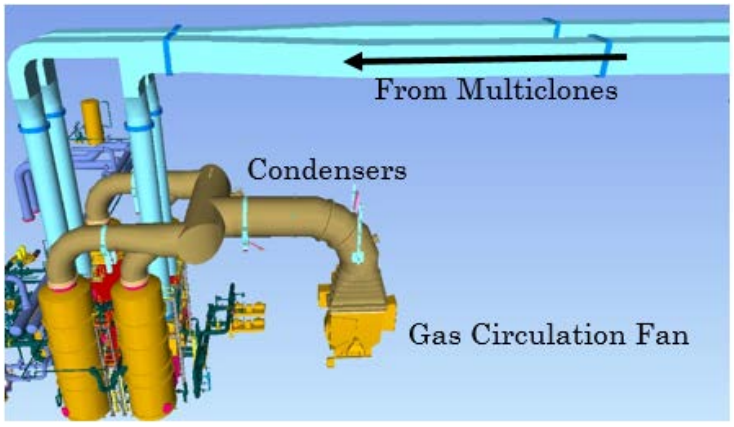


Figure 5.1-24 – Venturi condenser system

5.1.3.2 *Initial Commissioning Plan*

- Venturi test package overview

The plan for the venturi condenser was to initially flush the system to remove construction debris. After the flush was complete, the plan was to install the instruments, nozzles, and the packing in the condenser, and then perform systems tests to ensure the venturi condenser would support the fluid bed dryer operation. The test plan was to test the pump circulation, condenser spray patterns, and system pressure drops, and perform loop tuning. See figure 5.1-25 for overview diagram.

The test package started with the venturi scrubber pump PU1101 circulating continuous clean water stream to the venturi scrubbers CL1101 A-D.

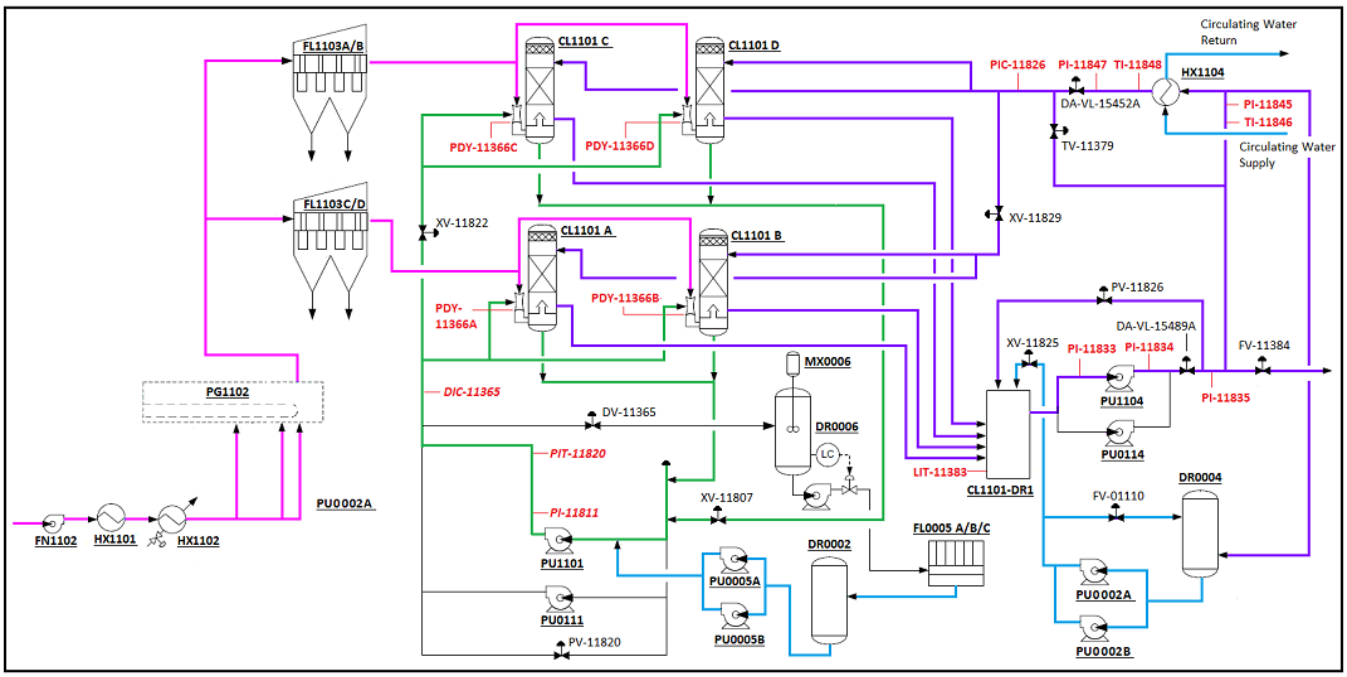


Figure 5.1-25 – Venturi condenser system

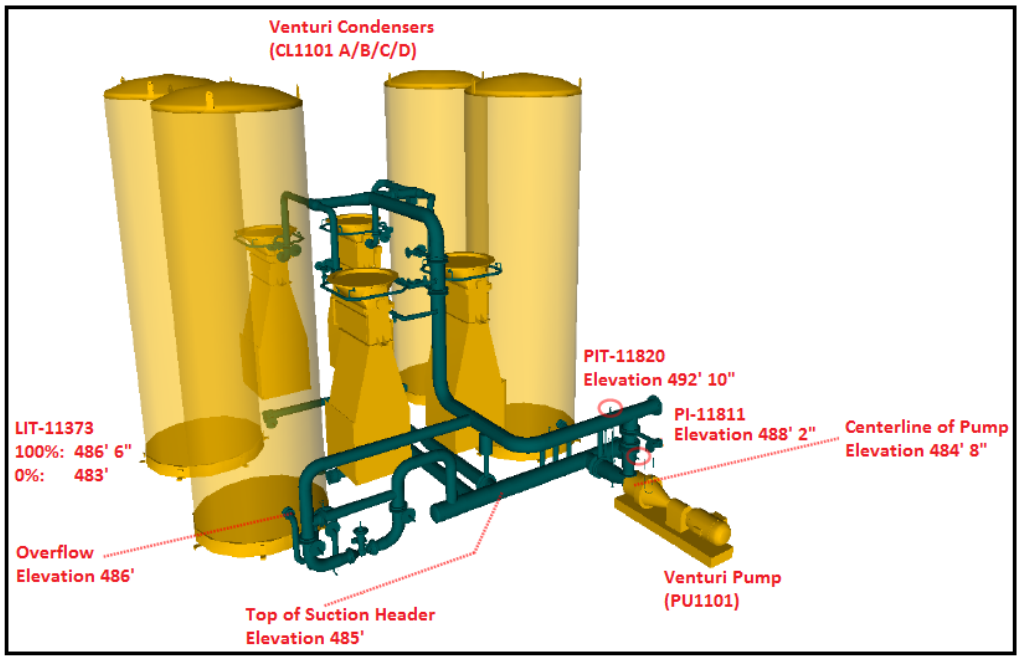


Figure 5.1-26 – Venturi scrubber pump

The venturi scrubber pump (figure 5.1-26) needed to deliver 70 ft of head to support a 10% lignite solution with a specific gravity of approximately 1.16 at a flow rate of 4,800 GPM. The specific gravity of the lignite solution was determined by taking the true density of lignite (164.2 lb/ft^3) and that of water at 4 °C.

$$\rho_{lignite} = 164.2\ \frac{lb}{ft^3}$$

$$\rho_{water} = 64.3\ \frac{lb}{ft^3}$$

$$\rho_{10\%\ lignite\ Sol} = \left(64.3\ \frac{lb}{ft^3}\right) * + \left(164.2\ \frac{lb}{ft^3}\right) * 0.1 = 74.3\ \frac{lb}{ft^3}$$

$$\rho_{10\%\ lignite\ Sol} = \frac{74.3\ \frac{lb}{ft^3}}{64.3\ \frac{lb}{ft^3}} = 1.16$$

The pump to be commissioned was a 21-in. impeller diameter to deliver the required head for the venturi system. The pump curve (figure 5.1-27) was developed using a solution with a specific gravity of 1.05. At a flow rate of 4,800 GPM, the pump produces 90 feet of head. A solution with a higher specific gravity will lower the pump curve, reducing the available head. Since head is inversely proportional to the specific gravity, a 10% lignite solution with a specific gravity of 1.16 should reduce the available head to 70 feet at a flow rate of 4,800 GPM.

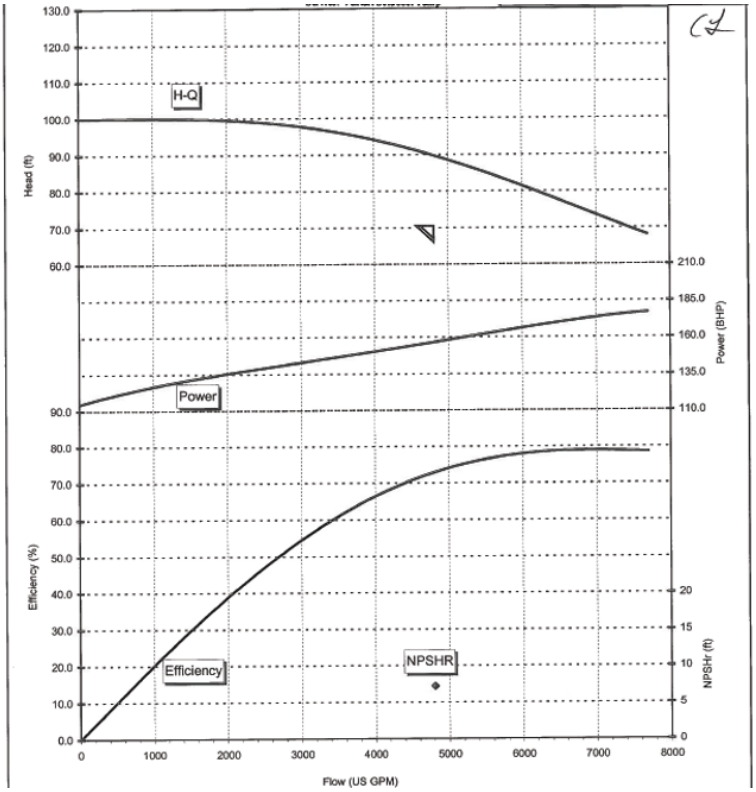


Figure 5.1-27 – Venturi pump curve

- Condenser test package overview

The condenser pump PU1104 (figure 5.1-28) circulates a continuous stream of water (cooled with circulating cooling tower water) to the condenser portion of condenser CL1101A/B/C/D, to condense the moisture in the sweep gas picked up in the dryer.

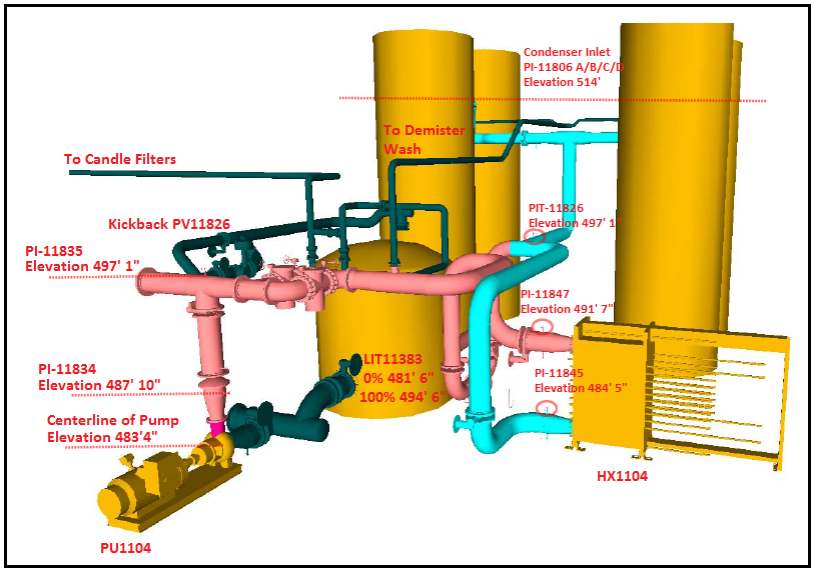


Figure 5.1-28 – Condenser pump

The condenser pump needs to deliver 126 feet of head at a flow rate of 6,600 gpm. The pump was designed with a 20.875-in. impeller diameter to deliver the required head for the system. The pump curve (figure 5.1-29) was performed using a solution with a specific gravity of 1.00. At a flow rate of 6,600 gpm, the pump produced approximately 150 feet of head.

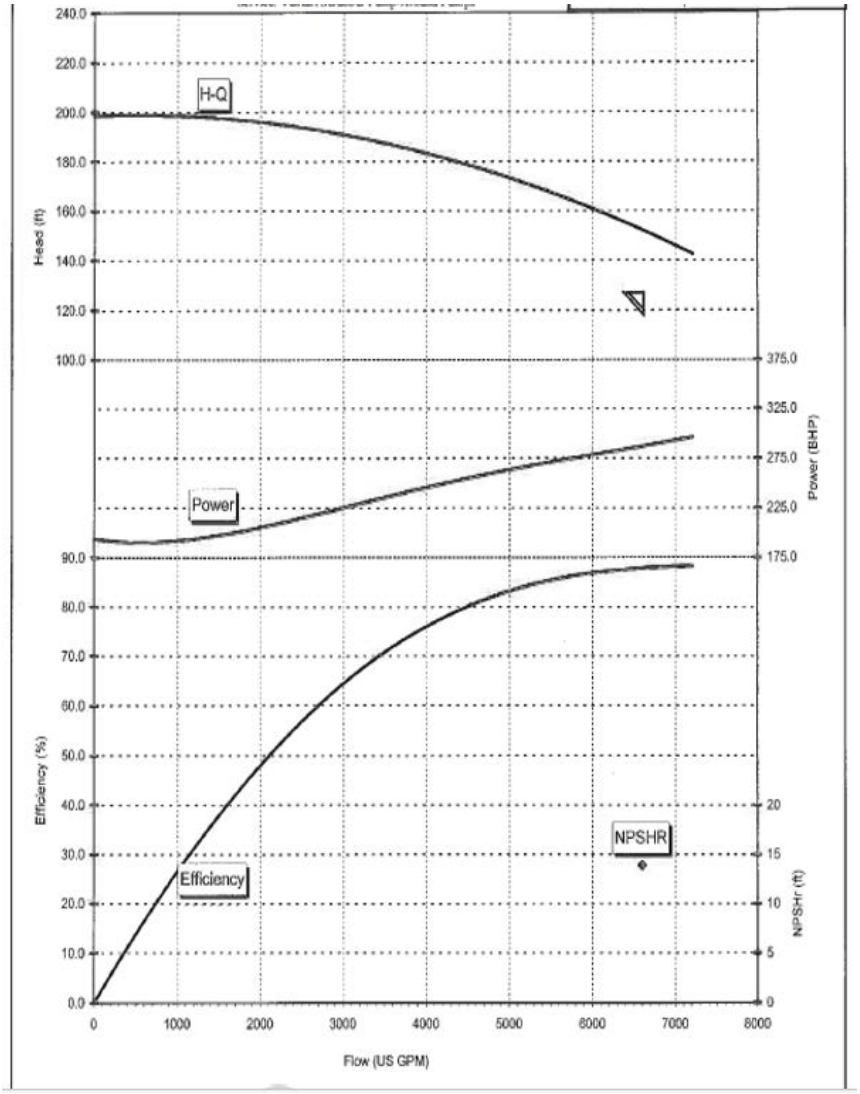


Figure 5.1-29 – Condenser pump curve

- Venturi condenser test package objective

Part A

The first part of the test package was to flush the system of construction debris. Some of the equipment was removed for the flush, including system instruments, control valves, venturi nozzles, condenser packing, strainer elements, and heat exchanger. The system was flushed by extracting the water, slurry, and debris from the venturi circuit and condenser pipe and pumping circuits to the frac tank and filter system. When the flush was performed, the make-up

from PU0005A/B to the venturi sumps and from PU0002A/B to the condensate level tank was connected and flushed as well. See table 5.1-10 for test package dates.

Table 5.1-10 – Venturi condenser test package dates-part A

Part A

Test Package	Begin	End
Venturi 1 A	7/2/2015	7/23/2015
Venturi 2 A	7/23/2015	8/8/2015
Venturi 3 A	8/9/2015	9/3/2015
Venturi 4 A	5/11/2015	5/28/2015
Venturi 5 A	6/2/2015	6/23/2015
Venturi 6 A	6/23/2015	7/14/2015

Part B

The second part of the test package was to test and tune the venturi scrubber pump PU1101 and the condenser pump PU1104. The plan was to test pump capacity, check system pressure drops, tune the controllers, check system heat rejection, and vendor checks for initial startup. See table 5.1-11 for test package dates. See figure 5.1-25 where the green lines represent the venturi pump circulation and the blue line represents the condenser pump.

Table 5.1-11 – Venturi Condenser Test Package Dates-Part B

Part B

Test Package	Begin	End
Venturi 1 B	7/23/2015	8/8/2015
Venturi 2 B	7/23/2015	8/8/2015
Venturi 3 B	9/3/2016	9/3/2016
Venturi 4 B	1/7/2016	1/8/2016
Venturi 5 B	1/3/2016	1/8/2016
Venturi 6 B	1/4/2016	1/8/2016

- Venturi test package initial commissioning plan

A series of tests was conducted to ensure the venturi circulation pump would perform as expected during dryer operation. The pump and system were run through various flow rates and the resultant pumping head was measured. The first set of tests was performed on Aug. 7, 2015 to validate the pump curve. The test was initially performed with the inlet valve to the venturi PDY-11366A/B/C/D opened 100%. The test data showed that when the pump is operating with water only, 70 ft of head will produce a flow rate of approximately 7,000 GPM. The kickback control valve PY-11820 (figure 5.1-25) was incrementally closed to create back pressure in the system decreasing the flow rate (table 5.1-12).

Table 5.1-12 – Venturi pump data

Friday 8/7/15								
Tank Level [%] LIT-11373	Tank Level [ft]	Discharge Pressure [psig] (PIT11811)	Discharge Pressure [psig] PIT11820	Suction Pressure [in Hg] (PIT11810)	Suction Pressure [psig]	Head [ft]	Kickback [%] PV11820	Notes
100%	3'	26.0	24	-3.5	-1.7	68	0	A/B/C/D Valved IN
100%	3'	31.5	30.5	-4.0	-2.0	81	53%	A/B Valved In, C/D valved out
100%	3'	32.0	30.7	-4.0	-2.0	82	50%	A/B Valved In, C/D valved out
100%	3'	33.0	32.2	-4.0	-2.0	85	40%	A/B Valved In, C/D valved out
100%	3'	34.5	33.5	-4.0	-2.0	88	30%	A/B Valved In, C/D valved out
100%	3'	35.3	34.4	-4.0	-2.0	90	20%	A/B Valved In, C/D valved out
100%	3'	35.8	34.6	-4.0	-2.0	91	10%	A/B Valved In, C/D valved out

The kickback control valve PY-11820 is controlled by the discharge pressure (PIT-11820) of the venturi scrubber pump. The normal value for PIT-11820 is approximately 24 psig when all 4 venturis are valved-in. The initial setpoint for PIT-11820 was set at 30 psig. To ensure the flow to venturi A and B is the same whether 2 venturis are valved-in or all 4 are valved-in, the setpoint needs to be lowered to 25 psig. On Aug. 11, 2015, a strap-on flow meter was attached to the discharge of the pump to record the flow rate. Since the necessary upstream/downstream diameter to the flow meters was not available, the flow rate measurements were often sporadic table 5.1-13).

Table 5.1-13 – Venturi pump data

Tuesday, 8-11-15									
Tank Level [%] LIT-11373	Tank Level [ft]	Discharge Pressure [psig] (PIT11811)	Discharge Pressure [psig] PIT11820	Suction Pressure [in Hg] (PIT11810)	Suction Pressure [psig]	Head [ft]	Kickback [%] PV11820	Notes	Strap Flow Meter [gpm]
88	2.6	27	22.6	-3.5	-1.7	70	0	A/B/C/D valved in	7500
86	2.6	27	22.9	-3.5	-1.7	70	0	A/B/C/D valved in	7600
86	2.6	27.5	23.1	-3.5	-1.7	71	0	A/B/C/D valved in	8000
86	2.6	34	30	-4	-2.0	87	47	C/D valved out	7300
85	2.6	34	31.1	-4	-2.0	87	40	C/D valved out	5800
85	2.6	35	32.1	-4	-2.0	89	30	C/D valved out	6800
85	2.6	35.5	33.1	-4	-2.0	91	20	C/D valved out	6100
85	2.6	36	33.4	-4	-2.0	92	10	C/D valved out	5300
85	2.6	36	33.4	-4	-2.0	92	0	C/D valved out	5400
85	2.6	35.5	33.2	-4	-2.0	91	20	C/D valved out	6200
85	2.6	35	32.3	-4	-2.0	89	30	C/D valved out	5300
85	2.6	34	30.8	-4	-2.0	87	40	C/D valved out	5800
85	2.6	33.5	29.8	-4	-2.0	86	48	C/D valved out	6800
85	2.6	27	22.9	-3.5	-1.7	70	0	A/B/C/D valved in	8400
85	2.6	27	22.8	-3.5	-1.7	70	0	A/B/C/D valved in	7400
85	2.6	27	22.8	-3.5	-1.7	70	0	A/B/C/D valved in	7600
85	2.6	27.5	23	-3.5	-1.7	71	0	A/B/C/D valved in	7600

During the pump circulation test (figure 5.1-30), all four inlet venturi dampers PDY-11366A/B/C/D were open 100%. The head of the pump was 70 ft at approximately 7,500 gpm, which closely matched the manufacturer's data. A second set of tests was performed where the venturi dampers were closed and the pump kickback control valve PY-11820 was incrementally closed to see the effect on the pump head as back pressure is introduced. The expectation was that when solids were introduced into the loop, it would raise the position of the operation point on the pump curve (4,800 gpm) to 70 ft of head instead of the 90 ft generated when water without solids is used. The assumption was that when solids were introduced to the system, increasing the solution's specific gravity, the curve would lower and would match closer to the design pump curve. The measured flow rate from the strap-on flow meter deviated slightly from the manufacturer's pump curve when PDY-11366C/D were closed. The measured values were slightly higher, possibly because of inaccuracies in the assumption of simulating solids in the circulation loop.

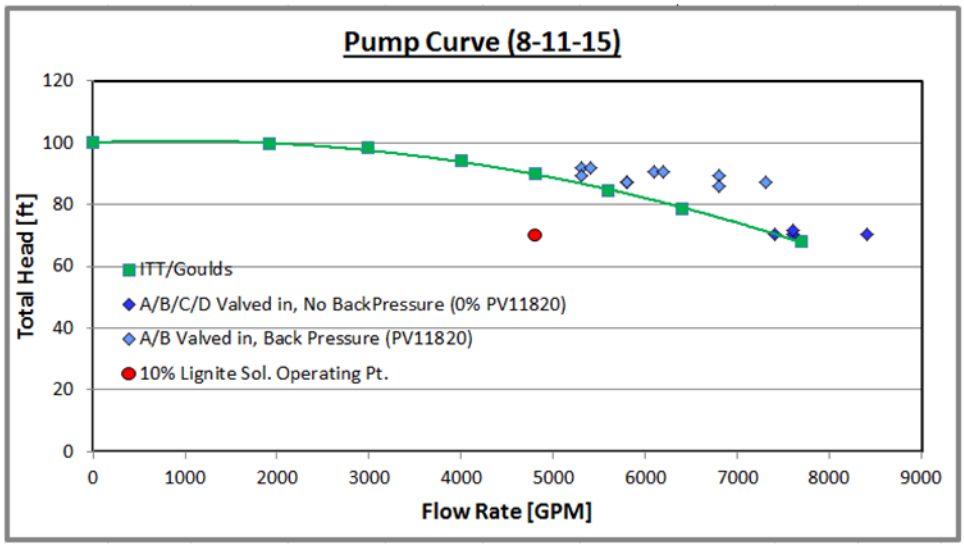


Figure 5.1-30 – Venturi pump curve

The predicted flow rate of 4,800 gpm could not be obtained by simply closing the kickback control valve, so the manual discharge valve DA-VL-15079A was throttled incrementally closed (table 5.1-14). By closing the kickback valve in conjunction with the manual discharge valve, 89 ft of head was achieved, which corresponds to the desired flow rate of 4,800 gpm.

Table 5.1-14 – Venturi pump data

Wednesday 8-12-15									
Tank Level [%] LIT-11373	Tank Level [ft]	Discharge Pressure [psig] (PIT11811)	Discharge Pressure [psig] PIT11820	Suction Pressure [in Hg] (PIT11810)	Suction Pressure [psig]	Head [ft]	Kickback [%] PV11820	Notes	Manual Discharge Throttle Valve [%] DA-VL-15079A
75	2.3	26.5	24.4	-3.5	-1.7	69	0	A/B/C/D valved in	100
75	2.3	28	22.4	-2.5	-1.2	72	0	A/B/C/D valved in	50
75	2.3	31.5	19.7	-2	-1.0	79	0	A/B/C/D valved in	25
75	2.3	32	29.6	-4	-2.0	82	56	C/D valved out	100
75	2.3	33.5	29.1	-3.5	-1.7	85	50	C/D valved out	50
75	2.3	34	31	-4	-2.0	87	40	C/D valved out	50
75	2.3	35	32	-3.5	-1.7	89	30	C/D valved out	50

Entrained air in a fluid affects the performance of a pump by lowering the pump curve. A series of tests was performed on Aug. 13, 2015 to determine if running the dryer gas feed fan FN1102 would affect the content of entrained air in the stream and ultimately reduce the pump's performance.

As experienced on Aug. 12, 2015, throttling only the discharge valve DA-VL-15079A was insufficient to obtain the desire flow rate of 4,800 gpm and made the strap-on flow meter readings more sporadic. The pump discharge valve remained 100% open. The venturi dampers PDY-11366A/B/C/D and the density meter v-port valve DV-11365 were incrementally closed until the desired flow rate was achieved (table 5.1-15).

Table 5.1-15 – Venturi operation during dryer run

Thursday 8-13-15																	
Tank Level [ft]	Discharge Pressure [psig] PIT11820	Suction Pressure [psig]	Head [ft]	Kickback [%] PV11820	Manual Discharge Throttle Valve [%] DA-VL-15079A	Venturi Inlet % Open [%] PDY11366A-D	Density Meter V-Port % Open [%] DV-11365	Strap Flow Meter [gpm]	Notes	IGV on Fan [%]	IGV ACFM [ACFM]	PU1101M [Amps]	Pump Curve Calc	PU1101M [HP]	Power Factor	Eff	Voltage
2.6	23.6	-1.7	70	0	50	50	100	-	0% cav	0	0	214	7541	173	0.8	0.95	460
2.6	26.6	-2.0	66	0	100	50	100	6000	0% cav	0	0	219	7959	178	0.8	0.95	460
2.6	33.6	-1.6	72	0	100	50	50	6779	0% cav	0	0	216	7321	175	0.8	0.95	460
2.6	33.8	-1.0	85	0	100	50	40	5100	0% cav	0	0	206	5650	167	0.8	0.95	460
2.6	33.9	-1.1	85	0	100	45	40	5152	0% cav	0	0	207	5650	168	0.8	0.95	460
2.6	34.6	-1.0	87	0	100	40	40	5170	0% cav	0	0	204	5337	165	0.8	0.95	460
2.6	36	-1.0	87	0	100	35	40	5212	0% cav	0	0	203	5337	165	0.8	0.95	460
2.6	36	-0.9	91	0	100	35	37	4496	0% cav	0	0	200	4633	162	0.8	0.95	460
2.6	36.1	-0.9	91	0	100	35	38	4302	0% cav	0	0	-	4633	-	0.8	0.95	460
2.6	36.1	-0.9	91	0	100	35	38	4800	0% cav	0	0	199	4633	161	0.8	0.95	460
2.6	36.1	-0.3	90	0	100	35	38	4435	1% cav	0	0	198	4821	161	0.8	0.95	460
2.7	37	0.0	89.8	0	100	35	38	4517	5% cav	20	115	196	4857	159	0.8	0.95	460
2.7	36.2	-0.2	91.0	0	100	35	38	4573	4% cav	30	147	196	4633	159	0.8	0.95	460
2.7	36.4	-0.1	89.9	0	100	35	38	4433	0.5% cav	40	205	197	4839	160	0.8	0.95	460
2.7	36.3	0.0	90.3	0	100	35	38	4708	0% cav	50	261	196	4765	159	0.8	0.95	460
2.7	36.3	-0.2	90.7	0	100	35	38	4382	0% cav	58	316	195	4690	158	0.8	0.95	460
2.4	36	-0.1	90.2	0	100	35	38	4401	0% cav	55	282	195	4784	158	0.8	0.95	460

After the desired flow rate was obtained by closing the venturi inlet and the density meter v-port valves, the dryer fan was started. The horsepower produced by the venturi scrubber pump was calculated and monitored at various damper positions. The venturi scrubber pump is a three-phase alternating current pump. Its horsepower was calculated using the equation:

$$P_{HP} = \frac{1.73\ PF\ \eta\ V_V\ I_{amp}}{746}$$

(Pump Horsepower)

Where:

$PF = Power\ \ factor$

$V_V = Voltage\,[Volts]$

$\eta = Efficiency$

$I_{amp} = Current\,[amps]$

The tests were run at 10-min increments at various damper positions. There was an initial slight decrease in the pump's horsepower when the fan started, but it remained relatively constant thereafter. If air entrainment had occurred, there

would have been a noticeable decrease in the pump's horsepower during fan operation. The conclusion is that little or no air was being entrained.

The measured head versus flow rate (figure 5.1-31, blue and orange diamonds) was plotted against the pump curve (figure 5.1-31, green). Except for two points, the data aligns itself with the pump curve, indicating that the head provided by the pump corresponds with the correct flow rate for a fluid with a specific gravity of 1.05.

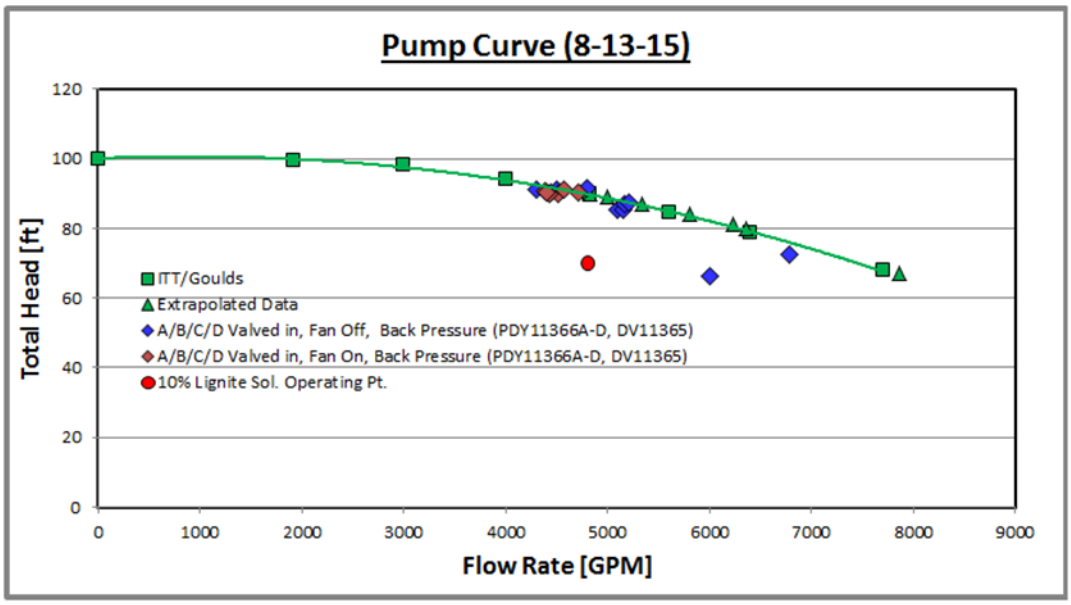


Figure 5.1-31 – Condenser pump curve

- Condenser initial commissioning plan

The pump was run through a series of tests similar to the venturi scrubber pump PU1101 tests, in which valves were closed to create back pressure to decrease the flow to the desired rate. It was assumed during the pump design that air would be entrained in the circulating fluid and would affect the performance of the pump by lowering the pump curve. To validate this design assumption, air was introduced to the system, to determine if the curve would lower to the desired 126 feet of head at 6,600 gpm.

Initial tests were performed with all four inlet valves to the venturi dampers (PDY-11366A/B/C/D) lined up, while varying the position of the condenser heat exchanger bypass valve TV-11379 from 100% to 0% open. The greatest amount of head developed in the system during the tests was 101.3 ft. This amount of head was achieved with the bypass valved 0% opened (table 5.1-16). With the bypass valved 0% open, the flow passes through the condenser heat

exchanger HX1102 where it experiences considerable resistance and subsequent reduction in velocity and increase in head.

Table 5.1-16 – Condenser pump data

20.875" Impeller (original run)																	
										Pump Calc (from Pipe Flow program)							
Tank Level [ft]	Suction Pressure [psig]	Discharge Pressure [psig] PI-11834	Head [ft]	Bypass [%] TV-11379	Kickback Valve [%] PV-11826	Condenser Inlet [psig] PIT-11826	Condense Inlet Pressure [psig]	HX Inlet Pressure [psig] PI-11845	NOTES	Tank Level [ft]	Calculated Pump Discharge [psig]	Calculated Pump Flow [gpm]	Bypass Flow [gpm]	HX Flow [gpm]	Total To Condenser [gpm]	Recirc Flow [gpm]	To Each Cond [gpm]
0 ft @ 481.5	484.00	488.00	-	-	-	497	<10 psig desired	-	8/6/2015	-	-	-	-	-	-	-	-
5.3	-1	24.6	63.1	100	34.0%	16.0	8.6	3.5	A/B/C/D valved in	4.5	34.16	11210	6822	3771	10593	617	2648
5.2	-1.1	23.1	59.9	90	34.0%	16.0	8.6	5	A/B/C/D valved in	4.5	34.38	11177	6689	3869	10558	619	2640
4.6	-1.2	24.8	64.1	80	30.0%	16.0	8.6	6	A/B/C/D valved in	4.5	35.13	11065	6418	4152	10570	495	2643
4.4	-1.4	25.8	66.8	70	27.0%	16.0	8.6	8	A/B/C/D valved in	4.5	36.1	10918	5948	4552	10500	418	2625
4.4	-1.8	26.2	68.7	60	23.0%	16.0	8.6	9	A/B/C/D valved in	4.5	37.49	10707	5358	5038	10396	311	2599
4.4	-1.4	28.5	73.1	50	15.0%	16.0	8.6	9.5	A/B/C/D valved in	4.5	39.46	10410	4613	5661	10274	136	2569
4.4	-1.2	31.1	78.6	40	0.0%	15.5	8.1	11	A/B/C/D valved in	4.5	41.67	10076	3674	6402	10076	0	2519
4.4	-1.2	33.5	84.2	30	0.0%	15.2	7.8	12.5	A/B/C/D valved in	4.5	44.1	9707	2573	7134	9707	0	2427
3.8	-1.2	36	89.9	20	0.0%	14.7	7.3	17	A/B/C/D valved in	4.5	46.47	9347	1553	7794	9347	0	2337
3.8	-1.1	40	98.9	10	0.0%	14.0	6.6	19.5	A/B/C/D valved in	4.5	48.76	8999	560	8439	8999	0	2250
4.7	-1.1	41	101.3	0	0.0%	13.8	6.4	21	A/B/C/D valved in	4.5	50.24	8773	0	8773	8773	0	2193
4.8	0.8	28	66.8	0	100%	16.1	8.7	10.5	C/D valved out	4.5	37.85	10653	0	5718	5718	4935	2859
5.1	1.1	27.1	64.1	10	100%	16.5	9.1	9.5	C/D valved out	4.5	37.44	10715	363	5451	5814	4901	2907
5.1	1.1	25.9	61.3	20	100%	17.1	9.7	9	C/D valved out	4.5	36.69	10829	997	4994	5991	4838	2996
4.6	1.2	25.1	59.2	30	100%	17.5	10.1	8.3	C/D valved out	4.5	35.9	10948	1640	4538	6178	4770	3089
4.6	1	23	54.8	40	100%	18.0	10.6	8	C/D valved out	4.5	35.22	11051	2318	4021	6339	4712	3170

Figure 5.1-32 shows the pump is too far out on the pump curve, resulting in high flow rates of 10,500 gpm. The pump is overdesigned, developing more flow at lower head. The vendor's pump design was 126 ft of head at 6,600 gpm.

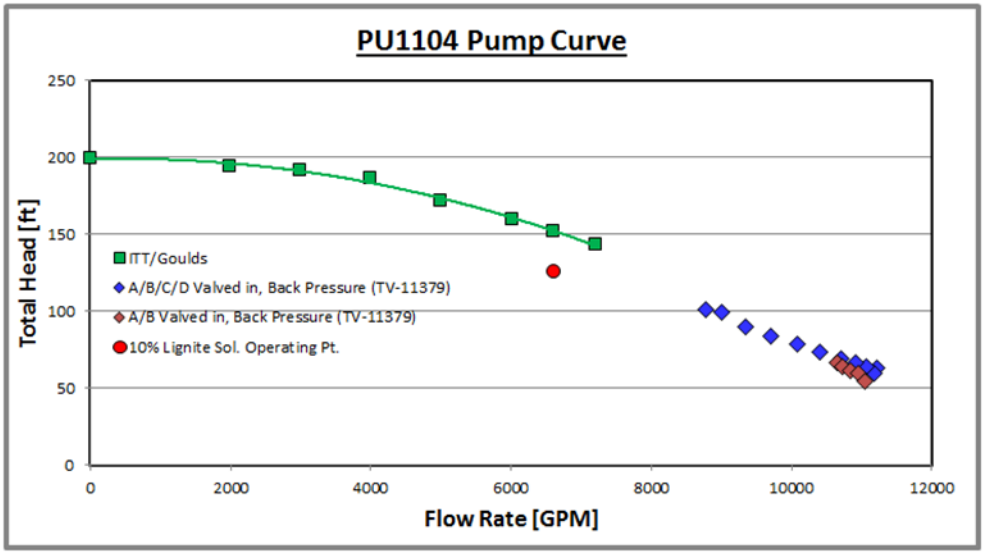


Figure 5.1-32 – Condenser pump curve

The desired pressure at the inlet to the condensers is 5-10 psig. Any pressure above 10 psig can damage the spray headers. Sending flow through bypass valve TV-11379 results in an increased flow rate to the condenser, causing an increase in pressure at the inlet to the spray headers due to less flow going to heat exchanger HX1104. In the initial set of tests with all four inlet valves to the venturi damper open, the pressure at the inlet to the condensers remained below 10 psig. However, when venturi inlet valves C and D were valved out, the pressure at the inlet to the condensers exceeded 10 psig when the bypass valve was 30% opened.

In addition to the issue with the operating point being too far to the right of the pump curve, the higher-than-design flow rates due to the oversized pump impeller was circulating more water than design which added to the flooding in the venturi sumps.

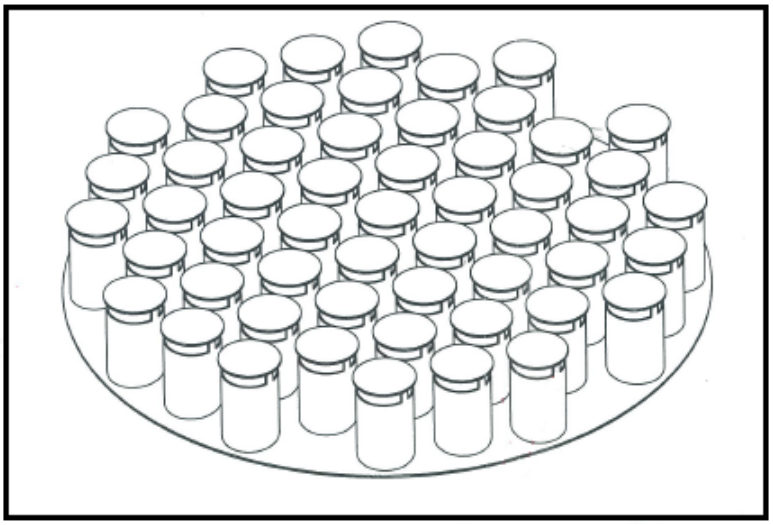


Figure 5.1-33 – Condenser chimney trays

To decrease the flow rate and condenser inlet pressure, outlet manual valve DA-VL-15489A was closed to 50% open and tests from the previous run repeated (table 5.1-17 and figure 5.1-33). There was a slight increase in backpressure and a reduction in flow, but nowhere near the 6,600 gpm needed. The maximum head obtained was 104 ft while all four venturi dampers PDY-11366A/B/C/D where valved in, significantly less than the required 126 ft of head for the system. With venturi inlet valves C and D valved out, the condenser pump heat exchanger bypass valve TV-11379 could open 50% before the pressure at the condenser inlet exceeded the maximum allowable pressure of 10 psig. The outlet manual valve DA-VL-15489A was trimmed back further from 50% to 25%, but at this position the dP was too high and cavitation across the valve started to occur.

Table 5.1-17 – Condenser pump data

20.875'' impeller (outlet valve trimmed to 50% open)																		
Outlet manual valve trimmed to 50% open										Pump Calc (from Pipe Flow program)								
Tank Level [ft]	Suction Pressure [psig]	Discharge Pressure [psig] PI-11834	Head [ft]	Bypass [%] TV-11379	Kickback Valve [%] PV-11826	Condenser Inlet [psig] PIT-11826	Condense Inlet Pressure [psig]	HX Inlet Pressure [psig] PI-11845	NOTES	Tank Level [ft]	Pump Discharge Pressure [psig]	Pump Flow [gpm]	Bypass Flow [gpm]	HX Flow [gpm]	Total To Condenser [gpm]	Recirc Flow [gpm]	B'fly Loss [ft]	To Each Cond [gpm]
0 ft @ 481.5	484.00	488.00	-	-	-	497	<10 psig desired	491	8/6/2015	-	-	-	-	-	-	-	-	-
9.0	0.8	34.4	77.6	100	0.0%	15.5	8.1	3.5	A/B/C/D valved in	9	40.62	10528	6778	3750	10528	0	20.88	2632
9.0	0.8	34	76.7	90	0.0%	16.0	8.6	4.5	A/B/C/D valved in	9	41.13	10451	6621	3830	10451	0	20.58	2613
9.0	0.8	32	72.1	80	0.0%	16.0	8.6	6.5	A/B/C/D valved in	9	41.6	10379	6303	4076	10379	0	20.3	2595
9.0	0.8	32.5	73.2	70	0.0%	15.8	8.4	7.5	A/B/C/D valved in	9	42.2	10289	5833	4457	10290	-1	19.95	2573
9.0	0.8	34	76.7	60	0.0%	15.6	8.2	8.5	A/B/C/D valved in	9	43.08	10156	5231	4924	10155	1	19.43	2539
9.0	0.8	35.5	80.2	50	0.0%	15.4	8.0	9.5	A/B/C/D valved in	9	44.34	9964	4477	5486	9963	1	18.71	2491
9.0	0.8	37	83.6	40	0.0%	15.0	7.6	10.5	A/B/C/D valved in	9	45.97	9718	3541	6177	9718	0	17.8	2430
9.0	0.8	39	88.2	30	0.0%	14.7	7.3	12.5	A/B/C/D valved in	9	48.04	9403	2495	6908	9403	0	16.66	2351
9.0	0.8	41	92.9	20	0.0%	14.2	6.8	14.5	A/B/C/D valved in	9	50.07	9095	1511	7583	9094	1	15.59	2274
9.1	0.9	44.5	100.7	10	0.0%	13.6	6.2	17.5	A/B/C/D valved in	9	52.07	8789	546	8243	8789	0	14.56	2197
9.1	1	46	104.0	0	0.0%	13.3	5.9	18.5	A/B/C/D valved in	9	53.36	8593	0	8593	8593	0	13.91	2148
9.8	1.1	36.3	81.3	0	96.4%	16.0	8.6	9.5	C/D valved out	10	43.66	10132	0	5569	5569	4563		2785
10.3	1	33.5	75.1	10	98.6%	16.0	8.6	8.5	C/D valved out	10	42.71	10277	348	5227	5575	4702		2788
10.1	0.9	32.5	73.0	20	100%	16.3	8.9	7	C/D valved out	10	41.83	10410	950	4776	5726	4684	20.42	2863
10.0	0.9	31.5	70.7	30	100%	16.6	9.2	6.5	C/D valved out	10	41.19	10506	1567	4322	5889	4617	20.8	2945
9.8	0.9	30.5	68.4	40	100%	17.0	9.6	6	C/D valved out	10	40.6	10596	2208	3835	6043	4553	21.16	3022
9.8	1.1	30.5	67.9	50	100%	17.5	10.1	5.5	C/D valved out	10	40.21	10655	2762	3382	6144	4511	21.39	3072
9.8	0.8	29.5	66.3	60	100%	17.6	10.2	5	C/D valved out	10	39.81	10715	3239	3008	6247	4468	21.63	3124
9.9	1	30	67.0	70	100%	17.7	10.3	4.5	C/D valved out	10	39.52	10759	3605	2719	6324	4435	21.81	3162
				80	100%				C/D valved out	10	39.32	10789	3874	2502	6376	4413	21.93	3188
				90	100%				C/D valved out	10	39.22	10805	4043	2361	6404	4401	22	3202
				100	100%				C/D valved out	10	39.22	10805	4123	2281	6404	4401	22	3202

The same type of pump testing was planned for the condenser pump used for the venturi scrubber pump PU1101. A series of tests was performed with the dryer gas feed fan FN1102 running. The fan tests were to determine if running the fan would affect the content of entrained air in the pumping circuit, which would alter the pump's performance by lowering the pump curve. The original pump design called for 1% entrained air due to the condenser packing design. The tests also were to confirm how the condenser would operate with the fan running. It had already been observed that the condenser flooded the venturi sump without the fan running. The condenser manufacturer expected that with at least 50% fan flow, the condenser circulation would prevent water from leaking into the venturi sump through the chimney tray (figure 5.1-34). The vendor was concerned that if the pump was over-designed, more circulation would cause more leak-by which is typically a percentage of the total flow.

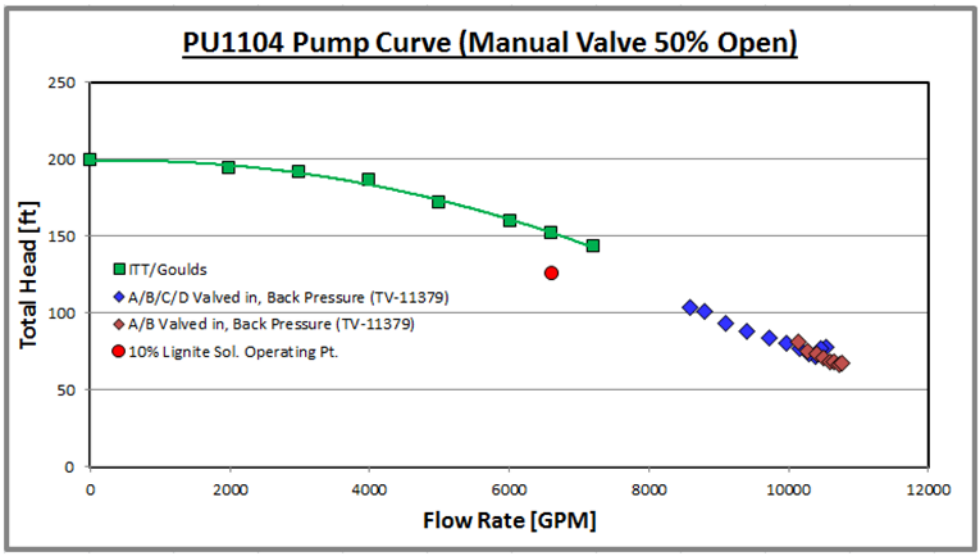


Figure 5.1-34 – Condenser pump curve

To determine if the cause of the flooding was the high flow rate delivered by the condenser pump to the pump's manual discharge valve DA-VL-15489A, the condenser heat exchanger manual discharge valve DA-VL-15452A and the inlet valve to the venturi dampers PDY-11366A/B/C/D were trimmed back to get the flow rate as close as possible to the design flow rate of 6,600 gpm. A strap-on flow meter was attached to the discharge of the pump, but the readings were sporadic since the necessary upstream/downstream diameters to the flow meters were not available.

Trimming back on the manual valve decreased the flow rate to a mid-to-high 7,000 gpm, still significantly higher than the desired design rate of 6,600 gpm (table 5.1-18). After the lowest attainable flow rate was achieved, the dryer fan was turned on and the horsepower produced by condenser pump PU1104 was calculated and monitored at various damper positions. The horsepower was not affected with gas flow and it was concluded there was no entrained air in

the system. The pressure at the inlet to the condenser was significantly above the 10 psig limit, with values in the high 20s and 30s psig.

Table 5.1-18 – Condenser pump data

20.875" impeller 8/14/2015 (with and without fan run)																			
Tank Level [ft]	Suction Pressure [psig]	Discharge Pressure [psig] PI-11834	Platform Pressure [psig] PI-11835	Head [ft]	Bypass [%] TV-11379	Kickback Valve [%] PV-11826	Condenser Inlet [psig] PIT-11826	Condenser Inlet Pressure [psig]	PU1104M [amps]	IGV on Fan [%]	IGV ACFM [ACFM]	PU1104 Discharge Valve [%] DA-VL-15489A	HX Isolation Valve [%] DA-VL-15452A	Condenser Inlet Isolation [%] PDY11366A-D	Strap Flow Meter [gpm]	Pump Curve	PU1104M [HP]	Power Factor	Eff	Voltage
0 ft @ 481.5	484.00	488.00	-	-	-	-	497	<10 psig desired	-	-	-	-	-	-	-	-	-	-	-	-
8.71	1.5	53	48	123.0	0	0	27.9	20.0	37.0	0	0	50	100	25	-	9186	261	0.8	0.95	4000
7.93	1.3	60		139.6	0	0	39.3		35.9	0	0	50		20	5755	8165	253	0.8	0.95	4000
7.8	1.3	62		144.2	0	0	37.1	30	35.7	0	0	50	45	20	5471	7856	252	0.8	0.95	4000
7.8	1.4	63	58	146.3	0	0	34	26	35.5	0	0	50	25	20	4758	7711	250	0.8	0.95	4000
6.76	0.8	64.5		151.1	0	0	31.2	24	34.9	0	0	20	25	20	4240	7368	246	0.8	0.95	4000
6.37	0.4	63		148.6	0	0	35.1	27	35.5	0	0	20	50	20	5293	7549	250	0.8	0.95	4000
6.11	0.3	61		144.2	0	0	36.7	29.5	35.7	0	0	30	50	20	5114	7856	252	0.8	0.95	4000
8.97	2.1	64		147.0	0		39.2	39.5	35.9	30	150	30	50	20	4950	7662	253	0.8	0.95	4000
9.62	2.4	58		132.4	0	0	27.2	31	36.9	30	150	30	50	25	5669	8624	260	0.8	0.95	4000
8.84	1.4	56.5		131.3	0	0	27.3	30	37	40	208	30	50	25	5526	8691	261	0.8	0.95	4000
5.85	0.8	56.5		132.7	0	0	26.9	29.5	37.1	50	274	30	50	25	5433	8605	262	0.8	0.95	4000
3.77	-0.2	57		136.2	0	0	25.7		36.9	55	300	30	48	25	-	8385	260	0.8	0.95	4000
2.73	-0.2	58.5		139.7	0	0	25.21	35.5	35.9	47	250	30	25	25	5266	8158	253	0.8	0.95	4000

The feed fan operation did not prevent the venturi sump from flooding. The pump circulation rate was 10,000 gpm instead of 6,600 gpm. The typical design chimney leak-by rate was expected to be 0.75-1%, which should have given a leak-by rate of 50-65 gpm. With the pump impeller oversized, the expected leak-by rate would have been 75-100 gpm. However, the total leak-by was measured at more than 400 gpm. It was determined that the water loss to the venturi sump was due more to the chimney tray design than flow issues. The velocity profile within the scrubber was not homogenous, which led to areas where the outward force of the gas leaving the chimney tray was not sufficient to prevent the water from entering. A design change to circumvent flooding was to strategically add permanent caps to the chimney trays to seal them (figure 5.1-35). There were 55 total chimneys per vessel and 18 were sealed. With four vessels per condenser, this meant that 72 chimneys were sealed per train or 432 chimneys for all the condensers. With higher velocity coming out of the chimneys, the water had less likelihood to drain into the chimney. Another design change was to the width of the chimney hat. By making the hats wider the hats shed the water away from the chimney opening. The total system design change is discussed in section 5.1.3.3, Significant Events. After the two design changes were made to the chimney trays, the new leak-by rate was 25-40 gpm. This successful change was made within a month of the discovery of the problem and allowed the implementation of the test package to continue.

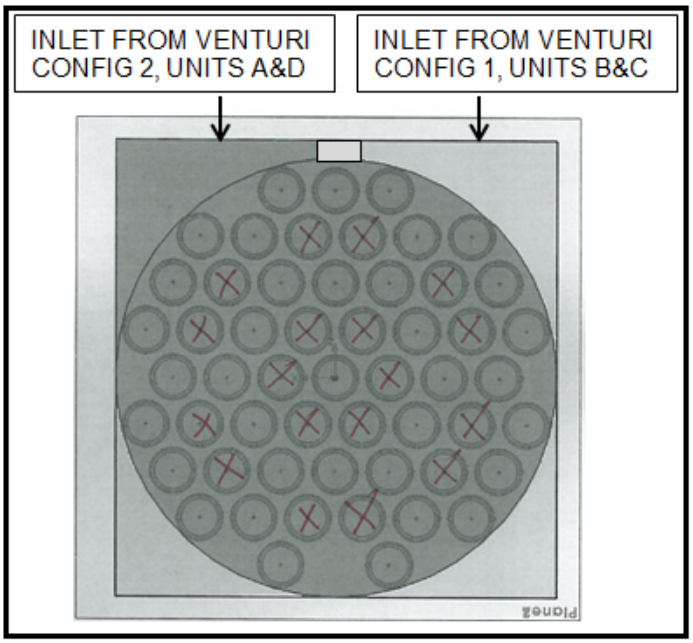


Figure 5.1-35 – Diagram indicating sealed chimneys in the trays

5.1.3.3 *Significant Events*

- Venturi condenser flush

In April 2015, the first venturi condenser test package implementation began with part A of the test package, preparation for operation. This phase included flushing all the piping and internals from construction debris. It took about 2 weeks to mobilize the cleaning unit, take the clearances, flush the systems twice, and reinstall all the instruments and valves. For all six trains, it took about 3 months to complete the flush test packages. After the flush was completed, the packing was installed in each condenser train. Each train took 8 days to fill all four vessels with packing. It took 7 weeks to add all the packing to the condensers.

- Pump pipe stress

After the dryer fan was back onsite, part B of the venturi condenser test package began. For this test package, the dryer fan would be run in conjunction with the venturi and condenser pumps to verify the performance of the system. Water was circulated through the condenser pumps for several hours. During this time, functional and instrumentation checks were made by the Kemper vibration analysis team. It was determined that both the venturi and condenser pumps had excessively high vibration. The test package was stopped until a root cause investigation could determine the reason for the vibration. The preliminary investigation indicated that the suction and discharge nozzles had excessive stress caused by the pipe connections. The stress from the pipe connection caused the pump bearing to vibrate excessively and would eventually cause bearing failure. The suction and discharge nozzles of each pump were disconnected. All the pumps were confirmed to have excessive stress caused from the pipe connections. Each pump was uncoupled, and a preliminary alignment was performed. All the pumps were confirmed to be out of alignment. Many of the pumps and motors were at or near the extent of travel, which limited the ability of the repair team to properly align the equipment. To further complicate the repair, some of the pump bases did not comply with the flatness requirement, adding difficulty to the piping repair. The venturi pumps were supported on only two feet, so added support was placed around the piping at the suction and discharge nozzles to reduce the pipe stress on the pumps and coupling. This work was difficult to set correctly, requiring the pump and piping to have virtually no stress at each nozzle to operate properly.

It is not common practice to connect the process piping before ensuring the equipment is set correctly. An anchoring procedure had to be developed by onsite personnel to ensure each pump remained immobile during the alignment. After each pump was set correctly, the piping had to be adjusted to address the pipe stress on each nozzle. Each pump was connected to a supply and return header with a very short transition from the nozzle through an elbow and into the header. This arrangement limited how much stress could be removed solely by adjusting the piping at each flange. The best repair option for the observed stress was to cut the piping near each nozzle, but the length of piping from the elbow to the nozzle was too short to prevent movement of the connection flange when the piping was being rewelded. During the reweld process, it was common for the flange face to move between 80 mil and 200 mil. The allowable deflection was +/- 10mil to be within tolerance. The piping crew then sweated the pipe to draw the flange back to the correct position. This repair was difficult and took a considerable amount of time for each of the 18 pumps. All the pump repairs were made before any of the venturi condenser test packages implementation was started. This work created a test package delay of 1.5 weeks per pump.

- Condenser chimney hat leak-by

The first part of the venturi test packages was to operate the gas recirculation through the venturi condenser while operating the pumping systems through the condenser. Within a few hours of operation, it was determined that too much water was channeling through the condenser chimney hats (figure 5-1.36). It was calculated that 100 gpm per condenser leaked by the chimneys, or 400 gpm per condenser unit. This amount of leak-by represented about 4% per minute of the condenser pump circulation.

Figure 5.1-36 – Chimney trays during original fabrication

The vendor determined the chimney hats were too short for the splashing action of the water as it came down on the internal chimney trays inside the condenser. A waterproof camera mounted inside the vessel during operation further confirmed that the hats were too short. The video showed water leaking by the hats into the chimney opening. Fan

and water circulation tests were conducted, and both tests showed similar results. The water was short-circuiting around the hat and down into the venturi sump.

A two-part solution was developed by the vendor and implemented by the startup team. The number of chimneys was reduced by blanking several of the chimney openings (figure 5.1-35), and the diameter of the remaining chimney hats was increased (figure 5.1-38). Reducing the number of chimneys increased the velocity of the gas (figure 5.1-39) through the chimneys, which pushed the water back as it tried to fall into the opening. The wider hat shed the water away from the chimney opening. After the repairs were made, the total loss dropped from 400 to 25 gpm loss to the venturi sump (figure 5.1-37).

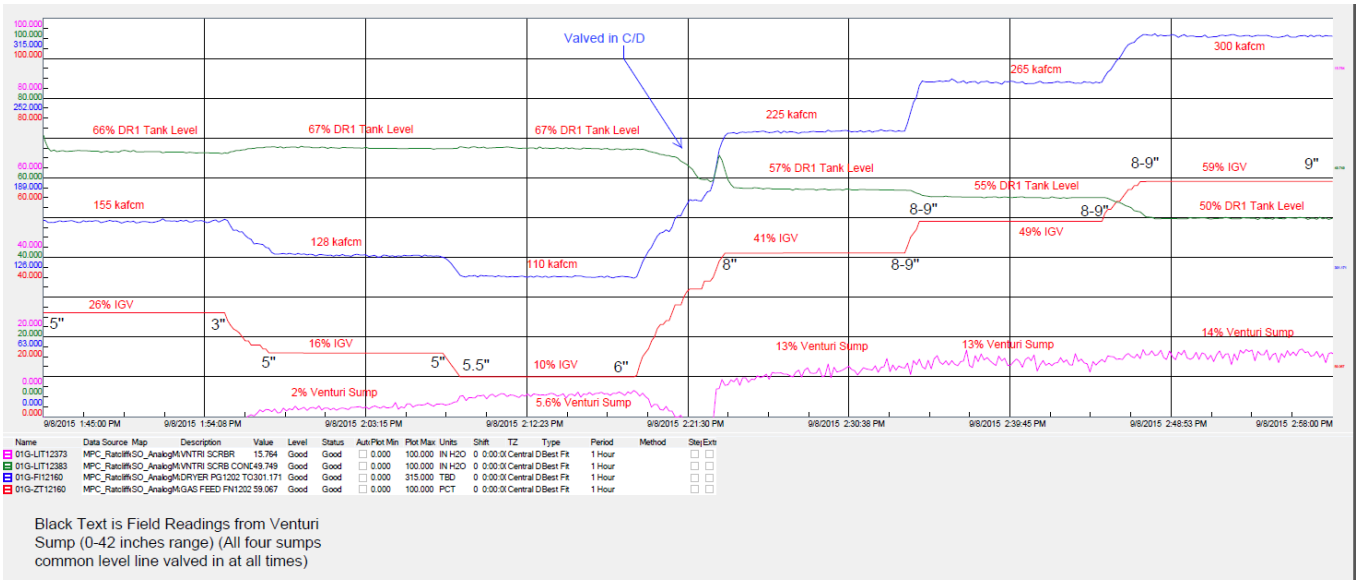


Figure 5.1-37 – Condenser leak-by analysis after repair

Figure 5.1-38 – Chimney hat redesign

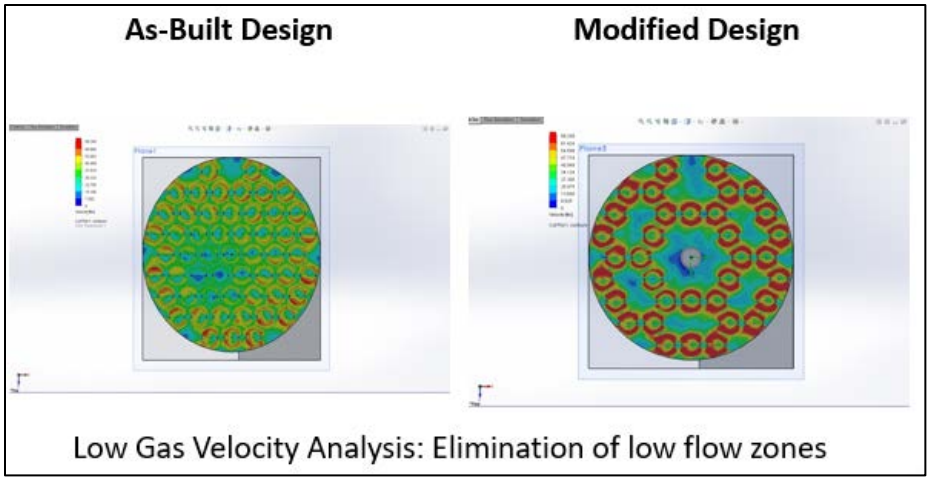


Figure 5.1-39 – Chimney tray gas velocity profile

The fan had been run above the 30% process design flow limits without water flowing through the condenser, causing the condenser packing to be fluidized out of the vessels during the chimney testing. Since packing holddowns were not part of the original design, new packing holddowns were developed onsite and placed in most of the condensers. While working on the holddowns, the demister pad tiedowns were installed.

- Dryer fan vibration problems

In August 2015, the venturi and condenser water circulation tests were performed with the dryer fan to simulate normal operation. During this test, the #1 dryer fan discharge duct expansion joint cracked (figure 5.1-40), and the metal bellows was damaged from stress. SCS civil engineers determined through field analysis that the duct was damaged due to high vibration, which was probably coming from the fan pulsing. This stress failure was determined to be due to high cycle fatigue. The #2 dryer fan was run, and the vibration levels were measured at 60 in/sec peak (ips pk). The expected levels for this joint were planned to be less than 5 ips pk. Field testing determined that dynamic pressure pulsations at 85 Hz (figure 5.1-41) excited the natural frequency of the fan impeller and fan foundation. The fan and foundation vibrated together in such a way that it caused high vibration on the fan axial outboard bearing. The vibration in the fan shook the ductwork and caused the expansion joint to fail.

Figure 5.1-40 – Cracked metal expansion joint

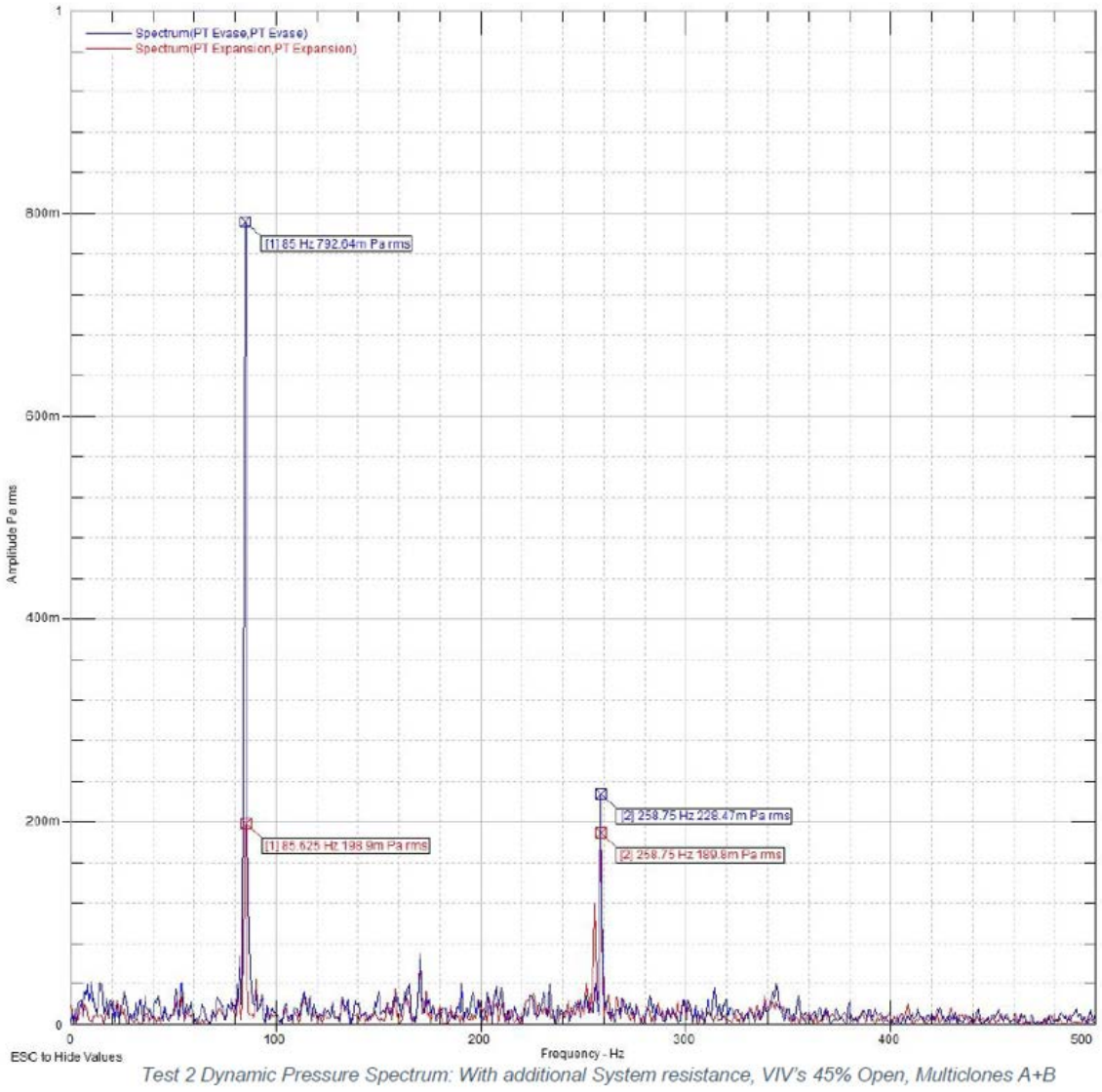


Figure 5.1-41 – High vibration at 85 Hz and 259 Hz

In figure 5.1-41, the vibration shows up as a sharp spike on the graph. At 85 Hz, the effect of the natural frequency is evident. A second frequency is excited at 285.75 Hz, but this is beyond the operating range of the system and is not important. An additional significant result of the excessively high dynamic pressure generated during the low flow condition was that the fan generated a load roar that could be heard across the plant site. The high sound pressure dissipated only slightly as gas flow was increased.

Vibration analysis was done on the fan discharge ductwork, which showed extensive vibration that would eventually fatigue the metal. A finite elemental analysis (FEA) was done using the field vibration readings. It determined that if this duct vibration continued long enough it would cause a crack that could propagate up to 30-40 ft. After the metal expansion joint was replaced with a fabric joint, more vibration analysis was done. The fabric joint reduced the downstream duct vibration to acceptable levels of <1 ips pk. The fan shroud and upstream duct before the expansion joint continued to vibrate at high levels; the fan shroud was vibrating at 7.2 ips root mean square.

It was noticed during the vibration testing that the vibration was not high at certain fan flow operating ranges. At lower fan flow rates, a higher vibration response was seen at the blade passing frequency (259 Hz) (figure 5.1-41) than at higher fan flow rates. It was observed that there was a low frequency pulsation with the variable inlet vanes (VIVs) 35% open but not at 45%. The onsite fan manufacturer personnel surmised that unstable inlet conditions could lead to choppy air entering the fan, which can amplify blade passing frequency. This condition would explain why the level of dynamic pressure at blade passing frequency appears to dissipate as the flow rate is increased. It should be noted that the level of response at blade passing frequency increases again after the VIVs are opened to 50%. It was observed that during a 40 kacfm range the vibration was extremely high.

With all the data and with the new fabric joint in place, an RCA was begun to determine the cause of the failure and to help develop a repair plan for the fan. When the RCA analysis was complete, fan manufacturer field personnel were brought onsite to analyze the system and help develop a permanent solution to the fan vibration. Based on recommendations of the RCA, a plan was developed to proceed with the dryer test package and avoid the flow range that caused the high vibration. The team agreed that the broad-band subsynchronous vibration did not have to be eliminated to run the test package. Until a final fix was determined by the fan manufacturer, the operations staff would minimize dwell time in the high vibration ranges.

Later onsite testing by the manufacturer showed that the vibrations were at a blade passing frequency of 259 Hz, and there was a discrete pulsation between 68-89 Hz. The pulsations were highest around the fan inlet, casing, and discharge, which suggested that the source of the pulsation was within the fan system. After visual inspections inside the fan, it was concluded that the fan was inducing vortex shedding. The amplitude of these peaks is affected by plant operating conditions and variable inlet vane position. The discrete pulsation between 68-89 Hz drives the response of the vibration, with the localized magnitude being influenced by structural natural frequency. It was determined that the duct pulsations were caused by inlet cone vortices, which could easily be broken up by increasing the height of the dorsal fins on the fan impeller. The longer fins would break up these vortices at the VIVs and adjust the frequency of the pressure pulses. If the natural vibration frequency of the fan or foundation was changed, the violent shaking would cease altogether. Other changes were made to reposition the inlet cone stiffeners and dorsal fins so they were not in line with the VIVs, which would help reduce vortex shedding and fan pulsing. The fan inlet windbox and casing were stiffened to reduce vibration levels and further change the vibration frequency. The total delay for the first dryer train, waiting on modifications to feed lignite to the dryer, was 2 months.

- Dryer duct spring can problems

An evaluation of the proper placement and cold settings of spring supports beneath the ductwork of the dryer gas feed fan was conducted based on the RCA of excessive vibration of train 1 fan and ductwork. It was suspected that the ductwork might not have been properly set or that the spring cans had not been set correctly. If correct, this construction error would potentially add stress to the flanged connections near the fan and might contribute to the system vibration.

Since the system had been heated during the fan runs, it was suspected that the ductwork might have shifted and could be inducing further stress at the fan discharge expansion joints. The train 1 joint cracked and failed during a fan run. A survey of the ductwork confirmed that some of the elevation measurements were off. None of the deviations were significant enough to require resetting of the ductwork.

The appropriate course was to ensure each spring support was installed correctly, ungagged, and adjusted to within tolerance of the cold setting. After the system was reheated, the supports would then be reevaluated to ensure the travel was within the correct tolerance of the hot setting.

Based on the condition of the train 1 supports, the project decided to evaluate, repair, and set as appropriate all the supports for the all six dryer trains. To minimize the impact to the commissioning schedule, three crews were assigned to complete the work. The first crew was to perform the evaluation while the remaining two were tasked with repairing and setting the supports correctly.

A representative from the spring support supplier was retained onsite to support the crews and to provide quicker guidance as needed. The initial challenge was to provide the crews with clear guidance on acceptability as they evaluated and adjusted each support. Startup personnel wanted to convey clearly defined guidelines based on industry

best practices, to prevent having to revisit the supports more than required. The representative stated the cans were to be set to either +/- 1/8 in. or +/- 1/16 in. of the cold setting. This setting was application-specific and corresponded to +/- 10% of the design loading. This setting offered a clear standard to field personnel and complied with industry and supplier criteria.

Work began in early September 2015. Repairs to all six trains took approximately 1 month to complete. A repair report was developed for each support and included the as-found and as-adjusted condition for each spring support.

5.1.3.4 *Final Summary*

The venturi test package proved that the scrubber pump PU1101 and the venturi system operated as designed. The pump tests evaluated the flow and pressure limits of the pump during operation, and both checked out for the design limits. When solids are introduced to the system, it will generate 70 ft of head at 4,800 gpm. The condenser pump PU1104 was oversized, which did not affect the operation of the condenser, but at the highest flow conditions, it would stress the spray nozzles and header system. The major finding for the test package was that the chimney hats caused flooding in the venturi sump, determined to be due to a nonhomogeneous velocity profile within the scrubber. The problem was solved by sealing the chimney trays that had insufficient gas flow through them and widening the chimney hat to deflect the water from getting into the chimney.

5.1.4 Pulverizer and Storage System

5.1.4.1 *System Overview*

After passing through the fluid bed dryer, the lignite is pulverized in a nitrogen-swept lignite pulverizer ML1108. The pulverizer is a vertical roller mill that can produce coarse or fine lignite depending on the operating settings (figure 5.1-42). The pulverizer has a capacity of processing 160,000 lb/hr of lignite with a 20% moisture content and producing a lignite feed product with a d50 of 500 microns. The pulverizer uses a high-volume fan to move the pulverized lignite out the top of the pulverizer to PC cyclonic baghouse FL1104. As planned, operation of the pulverizer is completely automatic. The lignite feed rate to the pulverizer is controlled by the level in fluid bed dryer PG1102 as indicated by the dryer bed level LIC11511. In the pulverizer, plows located ahead of each roller direct the lignite upward, between the grinding rollers and the heavy alloy steel bull ring where it is ground to size. The grinding rollers are free to swing out centrifugally, forcing them to bear down and grind the lignite. Because they pivot freely, the rollers automatically assume the proper position for grinding and need no adjustment to compensate for wear. After the lignite is ground to size, it is swept out of the pulverizer by the controlled flow rate created by pulverizer fan FN1106. This fan takes suction from the clean side of PC cyclonic baghouse FL1104. Nitrogen is injected into the fan's suction path to maintain the target oxygen content of the gas.

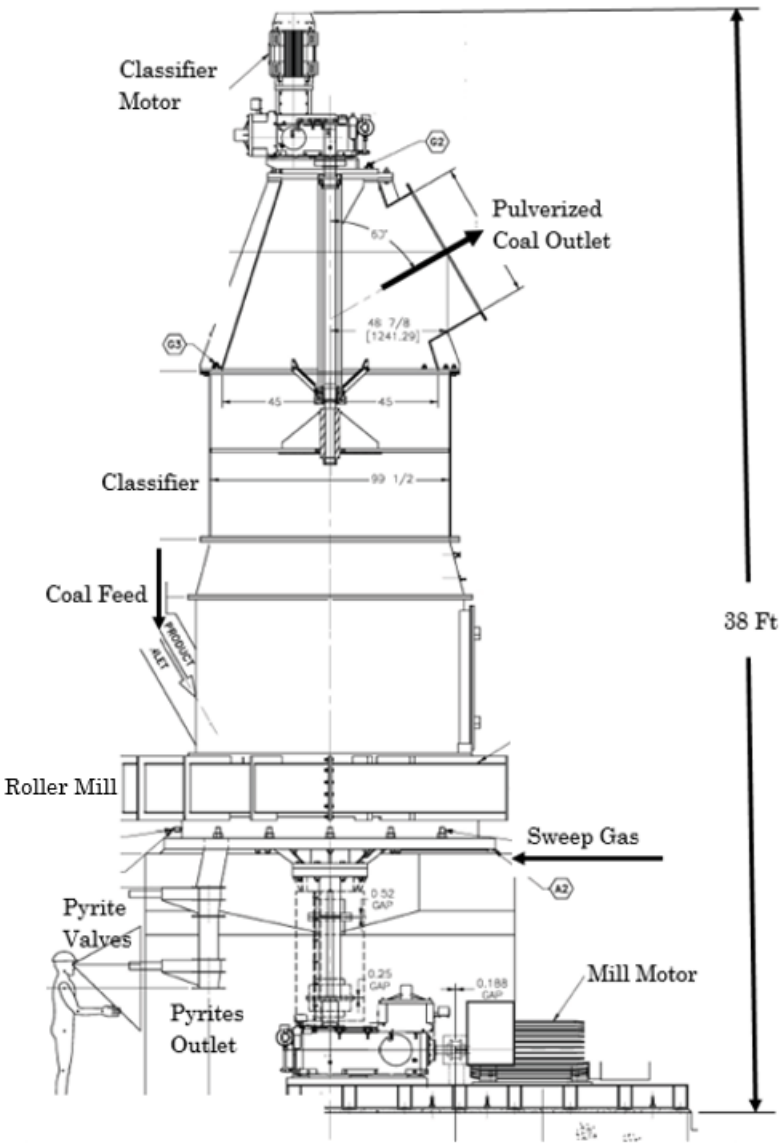


Figure 5.1-42 – Pulverizer elevation view

Lignite is fed to the pulverizer by the fluid bed dryer discharge screw feeder. The screw has a diameter of 24 in. and operates at a constant speed of 25 rpm. The feed rate is controlled by the high-pressure dryer discharge rotary feeder. The operator varies the feed rate based on gasifier demand and the level of lignite in the lignite feed bins. The lignite enters the pulverizer through an inclined chute. A flexible coupling isolates vibration from the screw feeder. The feed chute enters the pulverizer at the top of the pulverizer stationary grinding ring.

The pulverizer gas flow picks up a large concentration of pulverized lignite as it flows through the pulverizer. In the upper portion of the pulverizer, the flow is passed through an adjustable spinner separator, which is a fine control for particle size. At the top of pulverizer is the separator, a spinning multiblade device where an accurate size classification is made. Lignite of the proper size is conveyed out of pulverizer while oversize pieces are returned for additional grinding. The final size of the lignite fuel is determined by the air classifier, the variable speed of the rotating grinding

rolls, and the circulating gas flow rate. This feature is important because the gasifier operates better with a coarser particle size fuel than a conventional pulverized coal boiler.

The grinding rolls are mounted on pivoting arms. The pulverizer roller speed and spinner separator speed are controlled by the DCS speed controllers SIC11035 and SIC11038 respectively, which receive a setpoint based on the lignite mass flow from the fluid bed dryer. The controller setpoints are biased based on the lignite particle size leaving the PC cyclonic baghouse as measured by particle analyzer AIC11044. Lignite is pulverized between the revolving rolls and the stationary grinding ring, which is bowl-shaped. The inside diameter of the ring is 100 in. and the bottom of the ring sits a small distance above the pulverizer table. Centrifugal force pushes the pulverizer rolls against the grinding ring. The faster the pulverizer shaft turns, the higher the force of the roll against the grinding ring. This higher pressure produces a finer lignite product. Multiple plows attached to the shaft that holds the rollers sweep the pulverizer table and lift the unground lignite into the grinding zone. The rolls are manufactured from a highly wear-resistant alloy. The tips of the plows are fabricated from ni-hard, another highly wear-resistant material. Both are replaceable. See figure 5.1-43 for pulverizer layout.

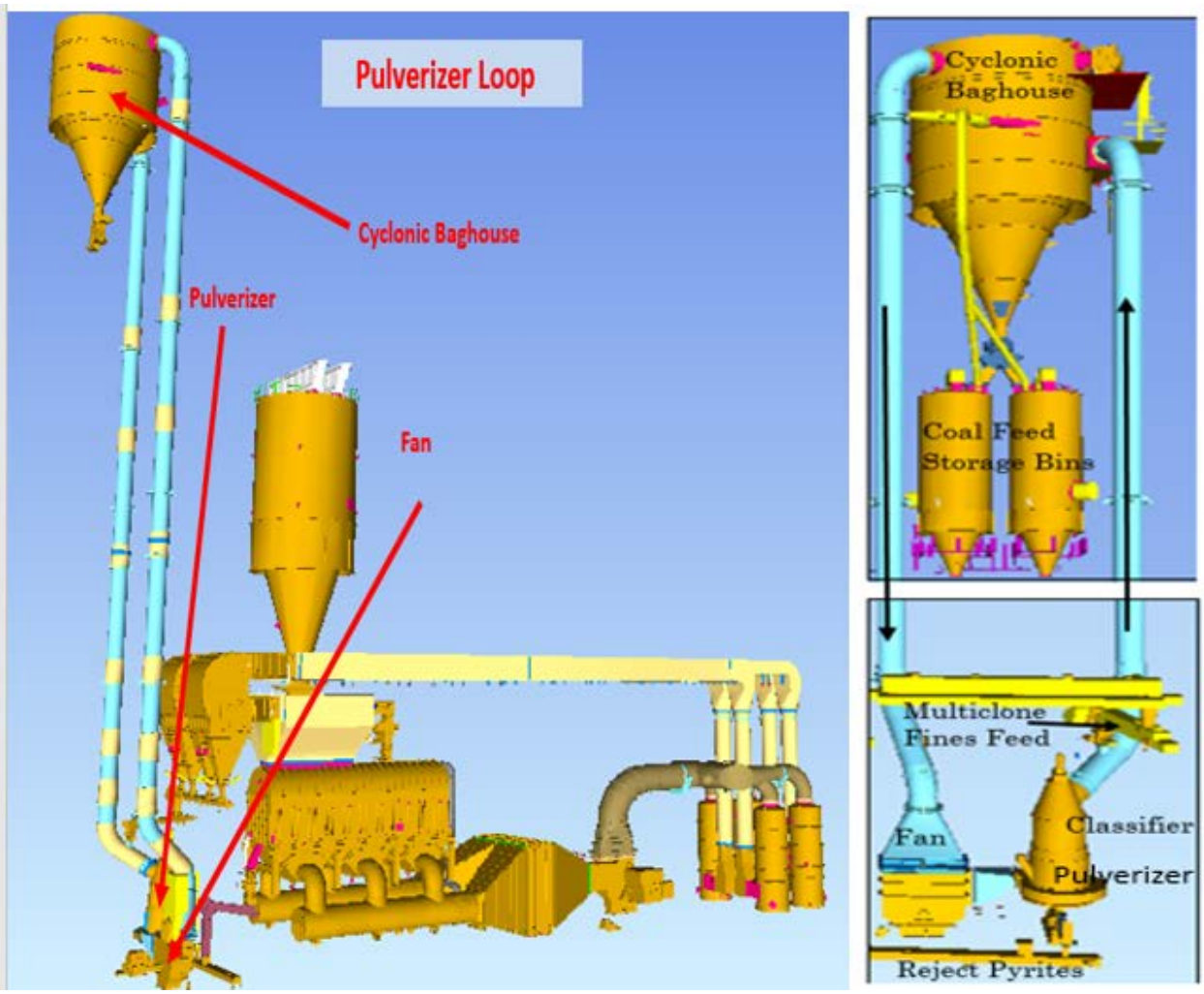


Figure 5.1-43 – Pulverizer and dryer gas loop

The pulverized lignite flows out the top of the pulverizer, is combined with lignite particulate from multiclone FL1103A/B, and the flow is then directed to PC cyclonic baghouse FL1104. Pyrites fall out of the process, collect in the bottom of the pulverizer, and are removed with the pyrite drag chain.

The inerted circulating gas operates in a semi-closed loop (figure 5.1-43). The sweep gas is filtered and recirculated back to the pulverizer feed fan, which discharges into the pulverizer' s windbox. Excess filtered gas is vented through the baghouse. Gas enters the pulverizer through the windbox, which has openings along its base below the grinding ring. The windbox has a decreasing diameter around its base to distribute the gas around the periphery of the grinding ring. The upward current of the gas lifts the fine material and entrains it in the gas stream as it exits the pulverizer. Both the oxygen content in the loop and the temperature of the circulating gas are monitored. The control system adds nitrogen to the loop when necessary. Make-up gas is provided by the periodic venting of the lignite feed system lock vessel during the normal feed cycle.

The pulverizer fan operates at a constant 1,180 rpm. Gas flow is controlled by an actuated inlet damper. The fan has an operating range of 90-110 kacfm. The fan has a 900 hp motor.

The pulverized lignite from the pulverizer is combined with the fines captured by the multiclones. The fine solids captured by the multiclone do not require further milling. To reduce wear on the pulverizers, the fine solids are discharged through a drag conveyor system into the pulverizer exhaust duct downstream of the classifier. A rotary airlock limits gas flow between the dryer and pulverizer systems. The combined solids flow enters the PC cyclonic baghouse, where the lignite is separated from the conveying gas.

The baghouse has a tangential inlet that acts as a cyclone separator to remove most of the solids from the incoming stream ahead of the filters (figure 5.1-44). Abrasion-resistant plates line the inlet. The gas containing the remaining fines flows through the filter cartridges where the fines are separated from the gas and discharged into the cyclone hopper.

The pulverizer fan FN1106 suction comes from the clean side of the PC cyclonic baghouse. It discharges the gases into the pulverizer to provide the upward driving force for the pulverized lignite. The fan circulates nitrogen to maintain a low oxygen environment and mitigate the risk of a dust explosion from the pulverized lignite. The pulverizer fan should provide enough pressure or force to convey the pulverized lignite out of the pulverizer to the PC cyclonic baghouse. The gas is compressed and heats up slightly due to the heat of compression. Flow through the fan is controlled by a suction damper. This damper gets its control signal from FIC11082, which calculates a setpoint based on mass flow rate through the dryer HP rotary discharge feeder FD1121 and the baghouse discharge particle size analyzer AIC11044, which senses the size of the lignite particles exiting the bottom of PC cyclonic baghouse. The controller compares the fan flow with this flow setpoint and generates a control signal to adjust the damper accordingly. The oxygen content, indicated by AIC11086, and the pressure, indicated by PIC11085, of the gases entering the pulverizer are controlled by injecting a regulated amount of LP nitrogen at the feed fan suction. This regulator receives a command signal based on either the gas inlet oxygen content or its pressure, whichever is highest.

Higher gas velocities carry finer pulverized lignite particles out of the pulverizer, while larger particles remain in the pulverizer bowl for further grinding. The higher gas velocities through the pulverizer are achieved with the pulverizer fan. The PC cyclonic baghouse separates the lignite particles from the gas and sends them to the PC cyclonic baghouse airlock FD1104 for further distribution to the PC cyclonic lignite storage bins SI1110A/B. The PC cyclonic baghouse cyclone uses centrifugal force to separate the heavier lignite particles from the gases. The gases are filtered through the baghouse and sent to the suction of the dryer fan FN1106, and the lignite flows by gravity to the storage bin.

The baghouse pressure controller PIC11094 on the cyclonic baghouse controls the emission point for the pulverizing and drying equipment as well as the high-pressure lignite feed. This pressure controller prevents air ingress to the system. PC cyclonic baghouse flush fan FN1105 is used to flush any retained solids out of the cyclonic baghouse filter elements and into the bottom of the cyclone, where it joins the rest of the pulverized lignite. The backflush fan recycles clean gas from the baghouse clean side plenum back through the bags in the baghouse. The PC cyclonic baghouse airlock is a rotary feeder that moves lignite from the bottom of PC cyclonic baghouse and sends it through a flop gate to the PC cyclonic lignite storage bins while maintaining the pulverizer loop pressure boundary.

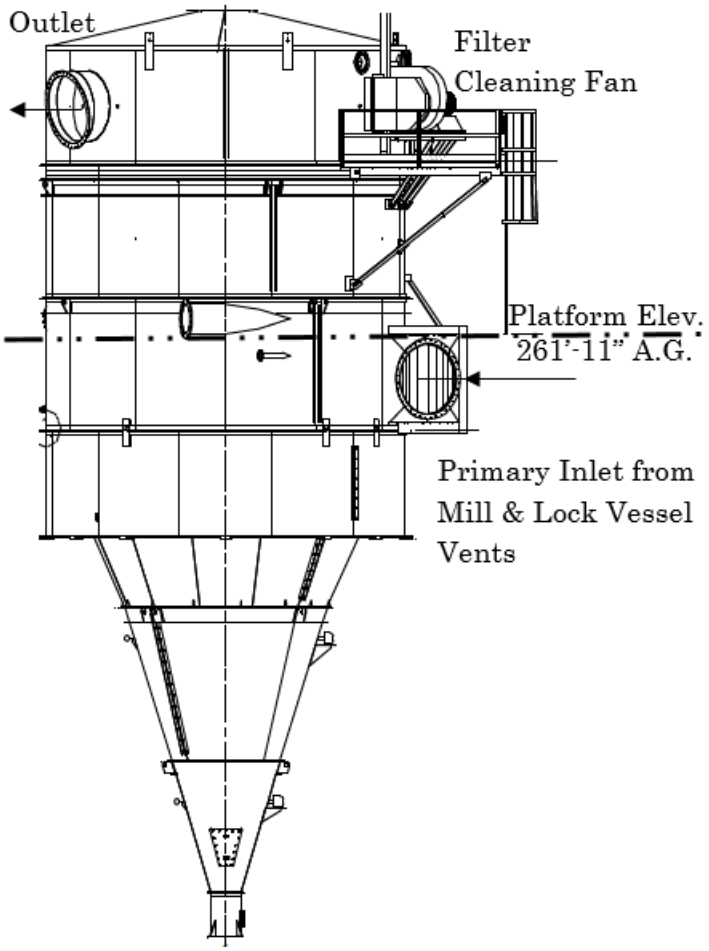


Figure 5.1-44 - Pulverizer baghouse

The cyclonic baghouse is 30 ft in diameter and 62 ft 10 in. tall. It has 1,200 pleated filter cartridges that are 84 in. long. Each cartridge has an effective area of 56.3 sq ft, with a total filter area of 67,560 sq ft. The top of the baghouse is one of the highest points onsite at nearly 300 ft above grade (A.G.) level (figure 5.1-45).

The walk-in plenum at the top of the baghouse houses the filter cleaning system. The system uses a revolving sweep arm to blow filtered gas through a row of bags at a time. A blower mounted on a platform near the top of the baghouse takes gas from the clean gas plenum and blows it through the arm to gently blow through the cartridges and remove adherent lignite dust. The fan runs at low speed until the differential pressure across the filter elements exceeds setpoint. After the setpoint is reached, the fan speed is increased for more reverse gas flow.

A spray header in the plenum serves as a fire extinguishing system. A magnetically latched door in the baghouse discharge cone is designed to open if the extinguishing system is triggered, and the water level in the cone reaches a level a few feet above the door. This arrangement is to protect the unit from structural overload in the event of a fire.

The solids that exit the baghouse cone are gravity-fed through a rotary feeder into a duplex flow controlling valve. A tap between the rotary feeder and valve extracts a lignite sample. A venturi eductor pulls the sample from the chute

and sends it through a particle size analyzer. The sample is discharged into the lignite feed bins and used in the gasifier.

Each leg of the bifurcated flow-controlling valve discharges into a gasifier lignite feed storage bin. The duplex valve controls the rate of feed to each of the lignite feed bins. Normally, the flow is split evenly between the bins, but all the flow can be directed to either lignite feed storage bin when required.

The lignite feed storage bins are 12 ft in diameter and have an overall height of 40 ft. Each silo has a capacity of 135,000 lb. An 18-in. rotating disk valve is located at the outlet of the bin. The displacement gas from filling the bins is vented to the cyclonic baghouse.

Each lignite feed storage bin discharges into a lock vessel associated with one of the gasifier lignite feed systems.

The storage bins discharge into the lock vessels, which are part of each of the lignite feed systems. (See section 5.3, Coal Feed System). The gas from the baghouse is recycled back to the pulverizer using the pulverizer feed fan.

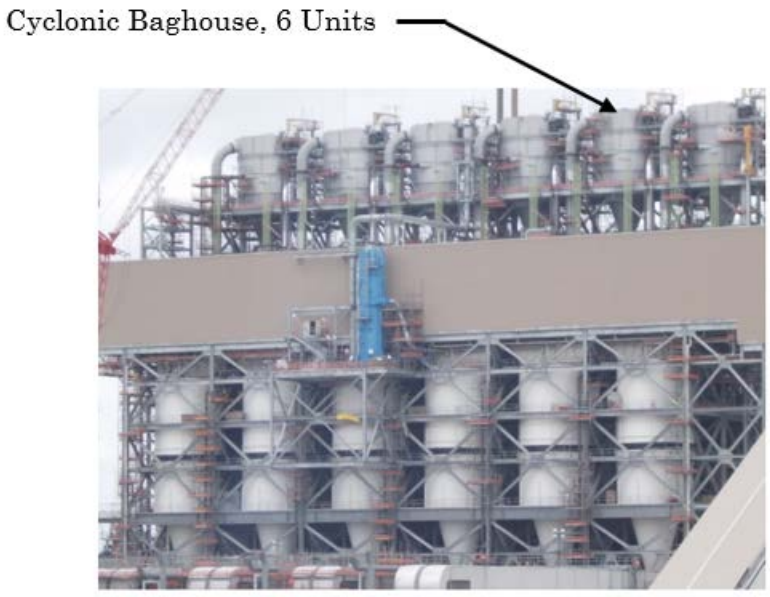


Figure 5.1-45 - Pulverizer baghouse in the superstructure

Non-crushable material, such as petrified wood and pyrites, settles to the floor of the pulverizer chamber because it is too heavy for the rotating plows and sweep gas to lift and transport it to the cyclonic baghouse. These materials can cause accelerated wear to the pulverizer components if they are not removed periodically.

There is an opening in the floor of the grinding table in the pulverizer, with an upper and lower slide gate operated in sequence to purge this material periodically while limiting the amount of gas leaving the system. The system can be operated either on a time basis or on detecting a rise in motor current. The purged material is discharged into the pyrites system. The pyrite removal system uses drag conveyors to transport the reject material from the pulverizers to the structure on the north end of the facility that also houses the secondary filters from the ash conveying system.

The drag conveyors run at grade level between the dryers and the pulverizers. At the north end of the drying area, a bucket elevator lifts the material and discharges it into a surge bin/load hopper.

The pyrite conveyors can also be used to empty the dryers when necessary. An intermediate outlet in the bottom of the dryer discharge screw conveyor can be used to empty the material from the dryer into the pyrite drag conveyors. The pyrite conveyors have nozzles for the injection of nitrogen when emptying a dryer. The pyrite conveyor drives are two-speed to allow operating at a higher speed when emptying a dryer, to reduce unloading time.

A loading bay at the north end of the dryer structure can be used to dump pulverizer rejects into a truck, or they can be discharged onto the ground and loaded into a truck or container at another time.

A dust collection system and an extendable loading spout are provided to aid in loading trucks.

5.1.4.2 *Initial Commissioning Plan*

Before the test began, a 1,000-cfm compressor pressurized the system to 35 in. W.C. to identify leaks in the system. A soap bubble test identified the leaks so repairs could be made to major leaks before the fan was started. Many leaks were found in the system and repairs were planned so the system would hold pressure during normal operation. The next test package TP1075B would be the final test for the fan. This test verifies that the system is pressure-tight and is used to further tune the fan controls.

- Pulverizer fan test package overview

This test package performs the necessary testing of the pulverizer fan FN1106 and ancillary equipment. The test package verifies that:

- The system is gas tight.
- The PC cyclonic baghouse equipment operates normally.
- The pulverizer fan startup sequence works as expected.
- The pulverizer gas loop inerts properly.
- The acceptable leakage rate does not exceed the capacity of the AV11086 valve to maintain an 8% oxygen content during the test.
- The controls are tuned as required.

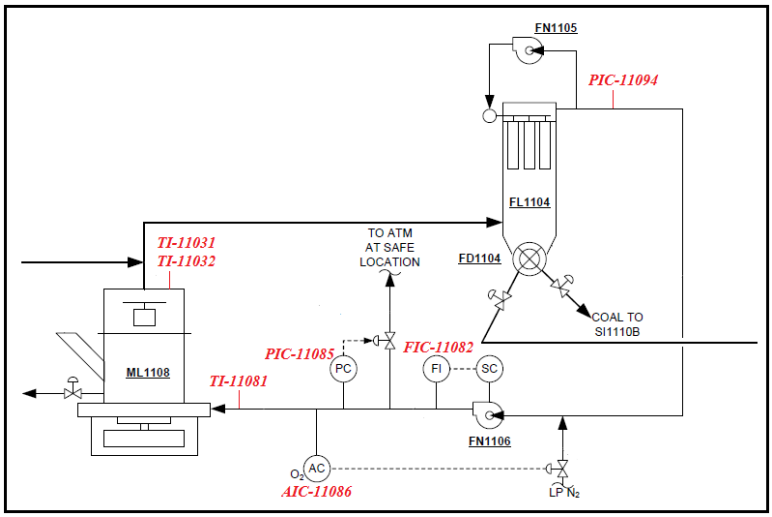


Figure 5.1-46 – Pulverizer process flow diagram

- Pulverizer fan test package objective

The commissioning of the pulverizer feed fan and subsequent gas loop was planned to be completed in two separate test packages. All turnover level activities were to be completed prior to the commencement of each test package. This included installation validation, loop-checks, and commissioning of the fan lube oil skid.

The primary objective of the first test package was to complete the functional checkout of the pulverizer feed fan. The test medium was air, which was supplied by temporary air compressors. See table 5.1-19 for test package dates. Expected activities included:

Part A

Part A of the test package was run on Dec. 8, 2014 and included the following.

- Run the pulverizer fan with damper at 15% open.
- Monitor and record fan performance data until system flows and temperatures stabilize, as well as through the fan shutdown. The process conditions measured are:
  - Inlet and outlet duct pressures.
  - Vibrations.
  - Current draw.
  - Variable speed control.
  - Bearing temperatures.
  - Fan performance data.
- Adjust FV-11082 inlet damper.
- Tune the pressure controller PV-1094.
- Validate mechanical integrity.
- Validate associated alarms, controller set points, controller-valve responses, interlocks, and related solenoid process control valve operations.
- Address any discrepancies and note any vibration damage or air leaks.

Table 5.1-19 – Pulverizer test package dates-part A

Test Package	Begin	End
Pulverizer 1 A	12/1/2014	12/10/2015
Pulverizer 2 A	12/8/2014	12/17/2014
Pulverizer 3 A	5/4/2015	5/7/2015
Pulverizer 4 A	5/11/2015	5/15/2015
Pulverizer 5 A	1/19/2015	1/19/2015
Pulverizer 6 A	11/21/2015	1/21/2015

Part B

The second part of the test package would extend the pulverizer fan gas loop to include the pulverizer baghouse equipment and validate that the fan loop can maintain a nitrogen blanket. See table 5.1-20 for test package dates. The functional steps included:

- Start the fan with the automatic start sequence.

- Conduct a leak check of the gas loop and associated equipment.
- Validate the PC cyclonic baghouse automatic start sequence.
- Validate the inerting procedure of the pulverizer gas loop.
- Tune the nitrogen supply and vent valves.
- Validate the maximum acceptable leakage rate does not exceed the capacity of the nitrogen supply to maintain an 8% oxygen content throughout the test.

Table 5.1-20 - Pulverizer test package dates-part B

Test Package	Begin	End
Pulverizer 1 B	10/7/2015	10/7/2015
Pulverizer 2 B	11/6/2015	11/7/2015
Pulverizer 3 B	2/18/2015	2/20/2015
Pulverizer 4 B	8/8/2016	8/10/2016
Pulverizer 5 B	2/4/2016	2/12/2016
Pulverizer 6 B	11/25/2015	11/28/2015

- Pulverizer fan test package commissioning plan

To start the test package, the pulverizer fan loop was again pressurized to 35 in. H_20. The baghouse pressure controller PIC-11094 (figure 5.1-46), was tuned and adjusted the pressure to 20 in. W.C. After the system was at 20 in. W.C., the pulverizer feed fan FN1106 was turned on and the pulverizer damper FY-11082 was incrementally opened to increase the gas flow through the pulverizer fan and then incrementally stepped back down (figure 5.1-47).

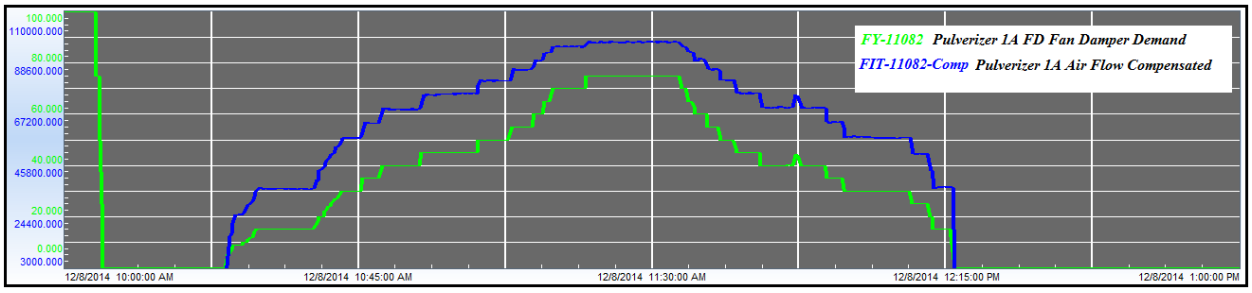


Figure 5.1-47 – Pulverizer fan damper and compensated gas flowrate

5.1.4.3 *Significant Events*

- Pulverizer installation problems

In December 2014, during the construction turnover for the pulverizer, it was recognized that the pulverizer had improperly installed components requiring repair. The vendor's technical field service was initiated, and a punch list was developed. Some of the repairs were supervised by the vendor per the technical field assistance (TFA) contract to prevent further mistakes. Repairs and actions included:

- Replacing rigid lubrication system piping with flexible connections to prevent transmission of vibration from the pulverizer to the piping.
- Replacing rigid electrical conduit mounted to the pulverizer foundation with flexible conduit to prevent transmission of vibration from the pulverizer.
- Installing gaskets on the pulverizer joints to prevent gas leakage from the closed-loop system.
- Eliminating interferences between access platforms and lubrication ports on the structure grating.
- Correcting the routing of horizontal tubing runs that could fill with condensate and affect control transmitter operation.

- Dryer and pulverizer ductwork leaks

While modifications to the venturi condenser pump piping were being done in June 2015, dryer ductwork pressure checks were being made on trains that did not have ongoing pump repairs. Those ductwork pressure checks revealed faulty supplier parts and faulty fabricated components that leaked gas, initially at a rate of 4,000 acfm. The ductwork was inspected with soap bubble and acoustic tests, and progressively large leaks (1,000-2,000 acfm) were found. The leakage rate was reduced to 500 cfm for the dryer system and 250 cfm for the pulverizer system. After the leaks were repaired, the main test package for the dryer system was ready.

A key finding during the leak check led to the redesign of the pulverizer baghouse magnetic door. This door in the baghouse cone was intended to open when the fire protection system is activated, to release water and prevent structural failure of the baghouse. A complete redesign and testing at the vendor's manufacturing facility was required.

5.1.4.4 *Final Summary*

As the gas flow rate (FIC-11082) increases, the fan pressure (PI-11085) increases as more gas passes through the fan (figure 5.1-48).

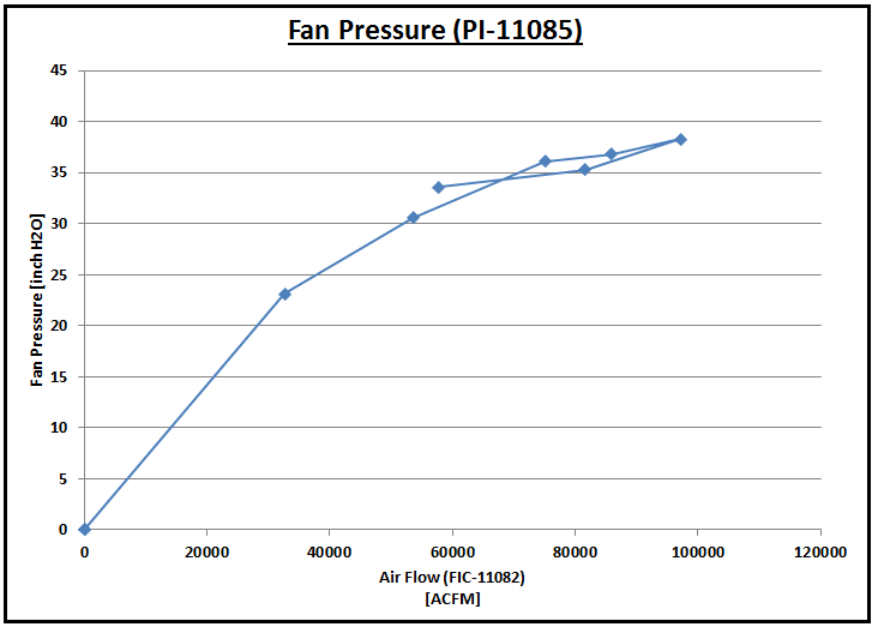


Figure 5.1-48 – Pulverizer Fan pressure versus gas flow

Because there is no pressure indicator in the immediate vicinity on the suction side of the pulverizer feed fan, the system head was obtained by the differential pressure calculated by subtracting the baghouse pressure (PIC-11094) from the fan pressure (PI-11085) (table 5.1-21).

Table 5.1-21 - Pulverizer fan flow data

DATE	TIME	DELTA TIME [mins]	AIR FLOW (FIC-11082) [ACFM]	FAN PRESSURE (PI-11085) [inH2O]	BAGHOUSE PRESS (PIC-11094) [inH2O]	DP (PI11085-PIC11094) [inH2O]
12/8/2014	10:24	0	0	0	20	
12/8/2014	10:29	5	32604	23.1	19	4.1
12/8/2014	10:42	18	53563	30.6	20	10.6
12/8/2014	10:55	31	75094	36.1	15.8	20.3
12/8/2014	11:10	46	85884	36.8	12	24.8
12/8/2014	11:25	61	97109	38.3	7.5	30.8
12/8/2014	11:42	78	81550	35.3	13.6	21.7
12/8/2014	12:00	96	57792	33.6	22.6	11
12/8/2014	12:16	112				
12/8/2014	12:19	115	2	0	-0.6	

The differential pressure was plotted versus the gas flow (FIC-11082) and overlaid onto the fan manufacturer performance curve for the pulverizer feed fan. Figure 5.1-49 shows that the differential pressure, shown by the red markers, corresponds with the system curve provided by the fan manufacturer.

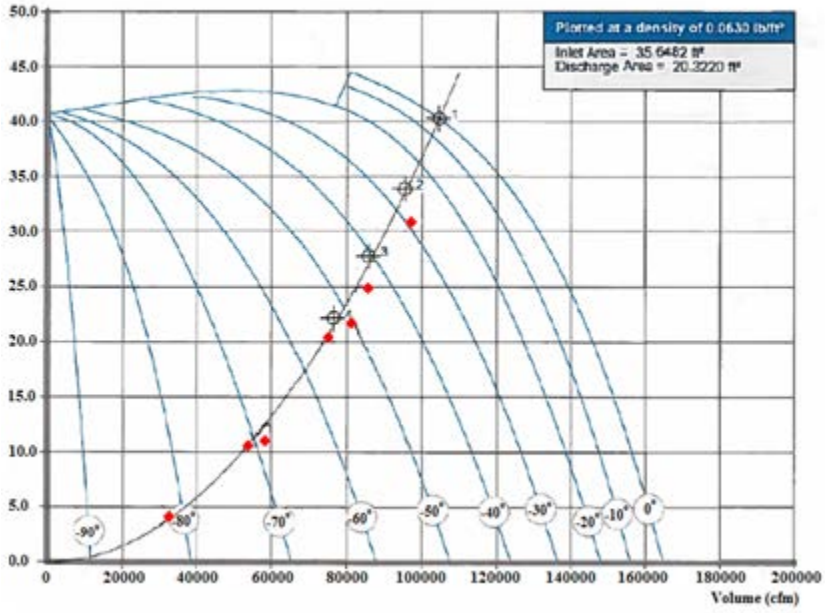


Figure 5.1-49 - Pulverizer fan – manufacturer performance curve

Two temperature indicators, TI-11032 and TI-11031, are located on the outlet of the pulverizer ML1108. The values of temperature indicator TI-11032 are comparable to those of the fan temperature indicator TI-11081, but a significant difference is observed for TI-11031 (table 5.1-22). TI11031 was not working during the test package but was repaired by I&C after it was discovered. As the speed of the fan increases, additional work is added to the system, indicated by the current consumption. This additional work normally causes an increase in the fan discharge temperature.

Table 5.1-22 - Pulverizer and fan temperatures

DATE	TIME	DELTA TIME [mins]	MILL FAN TOTAL CURRENT [amps]	FAN TEMP (TI-11081) [F]	MILL TEMP #1 (TI-11032) [F]	MILL TEMP #2 (TI-11031) [F]
12/8/2014	10:24	0	fan start-up			
12/8/2014	10:29	5	226.3	73	81	73
12/8/2014	10:42	18	248.7	86	95	82
12/8/2014	10:55	31	283	92	106	89
12/8/2014	11:10	46	301.3	101	120	89
12/8/2014	11:25	61	332.6	112	135	109
12/8/2014	11:42	78	no data	121	148	118
12/8/2014	12:00	96	241.8	125	156	123
12/8/2014	12:16	112	fan shutdown			
12/8/2014	12:19	115	system shutdown (1.1)	125	150	118

5.1.5 Recovered Water

5.1.5.1 *System Overview*

The recovered water system (figure 5.1-50) filters the water that was evaporated in the dryer. This system provides a needed source of process water for the Kemper facility and offsets some of the need for water pumped from the Meridian, Miss. waste water treatment plant approximately 30 miles away.

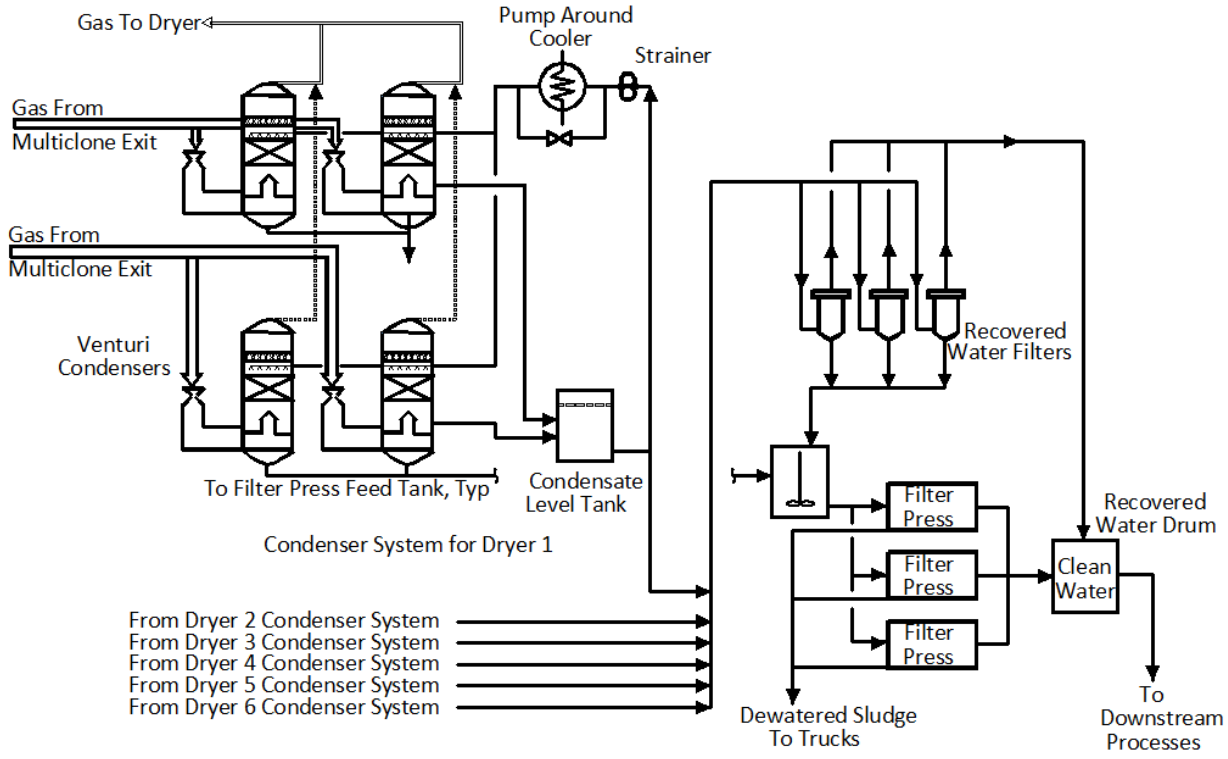


Figure 5.1-50 – Recovered water system layout

Recovered particulate-laden venturi water from CL1101A/B/C/D venturi sump was treated to remove the particulate from the water and then was recycled back to CL1101A/B/C/D venturi sump. Figure 5.1-51 shows the system controls. The venturi condenser water recovery was associated with the following equipment:

- PU0013A/B recovered water booster pump.
- FL0001A/B/C recovered water filter.
- DR0004 recovered water drum.
- PU0002A/B excess water pump.
- PU0008A/B HP make-up water pump.
- DR0006 filter press feed tank.
- FL0005A/B/C-PU1/2 filter press feed pump.
- FL0005A/B/C filter press.
- DR0002 filtrate drum.
- PU0005A/B filtrate pump.

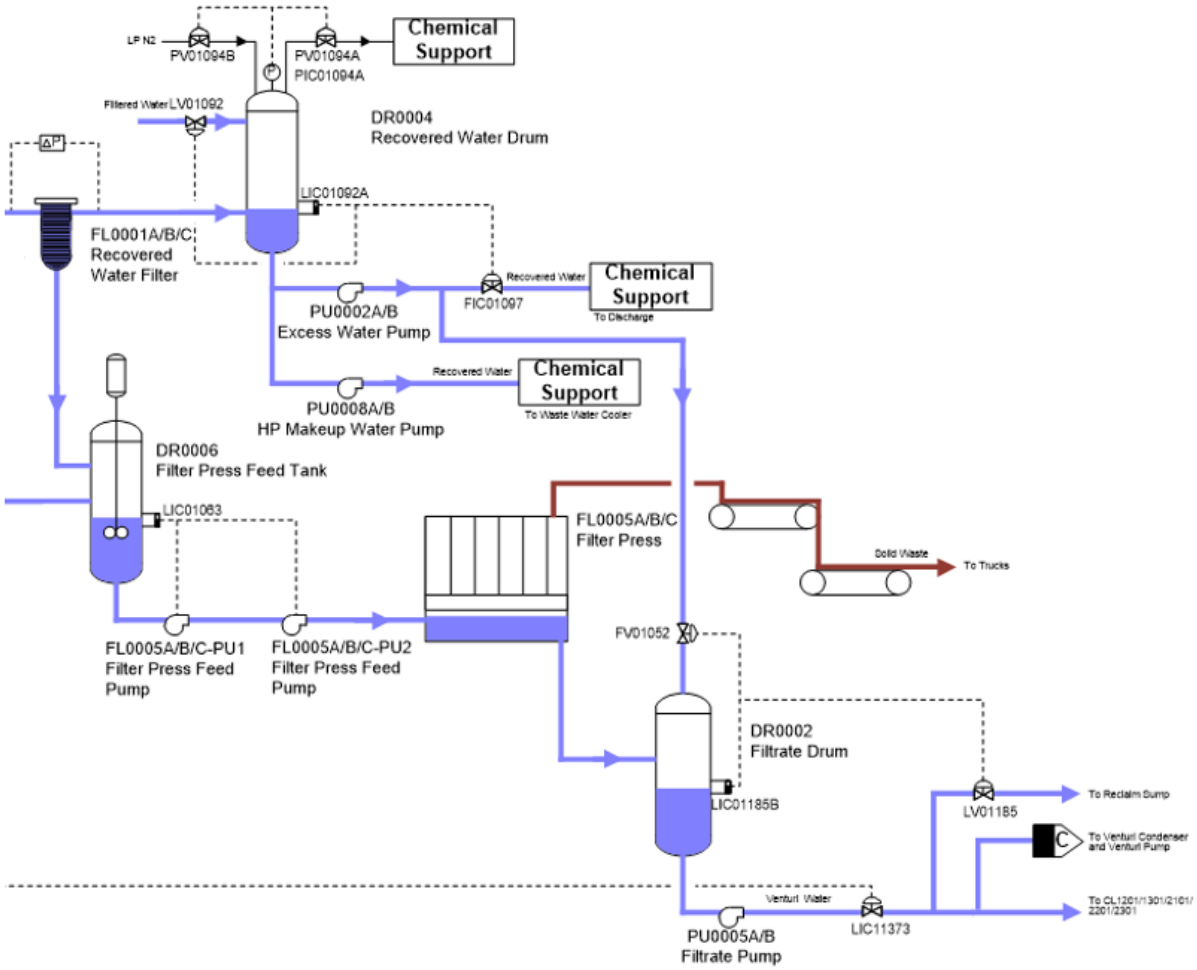


Figure 5.1-51 – Recovered water system controls

The recovered water booster pump PU0013A/B receives water from condenser pump PU1104 and discharges it through recovered water filter FL0001A/B/C (figure 5.1-51). Just upstream of the pump, all six condenser trains

combine to provide suction to recovered water booster pumps. The booster pumps are put in service only when the flow rate to the recovered water filter is high enough to require additional head. Otherwise, the flow is directed around the pumps in a bypass line using XV01049. The recovered water filter FL0001A/B/C receives water from the recovered water booster pump and filters out the remaining lignite particles. The filtered-out fines are sent to filter press feed tank DR0006, and the remaining water flows into recovered water drum DR0004. The recovered water drum receives the water exiting the recovered water filter. It provides the NPSH (net positive suction head) for the excess water pump PU0002A/B and HP make-up water pump PU0008A/B. A slight pressure was maintained in DR0004 using PIC01094A. This pressure controller controls the inlet nitrogen flow by PV01094B and the vent to the LP/Acid gas flare by PV01094A. The pressure was maintained so the LP flare gas does not back up through the venturi condensers CL1101A/B/C/D. The recovered water drum level was controlled by rejecting a portion of the recovered water from the condenser system or by supplying make-up demin water directly to the drum with level controller LIC01092A.

The filter press feed tank DR0006 receives the backwash from the recovered water filter, mixes it with water from venturi sump CL1101A/B/C/D, and supplies it to the suctions of filter press feed pumps FL0005A/B/C PU1/2. The filter press feed tank has an electric motor-driven agitator extending into its contents. Water diverted from the discharge of venturi pump PU1101 goes into the tank, where the agitator mixes the water and lignite fines to ensure that the fines do not settle out of the suspension. The agitator prevents stratification of the suspension, which ensures the fines continue to be pumped through the system to be processed in filter press FL0005A/B/C. The tank level was controlled by LIC01063. The filter press feed pumps FL0005A/B/C-PU1/2 receive the slurry from filter press feed tank DR0006 and discharge to filter feed press FL0005A/B/C for processing and further reuse in the venturi.

The filter press FL0005A/B/C collects the water and lignite fines from filter press feed tank. The filter press feed pumps push the water and fines through filter elements designed to separate the water and fines and recover both for further processing. The water is sent to filtrate drum and the lignite fines are sent to conveyors and then to a truck. If a filter cloth fails, a turbidity meter at the outlet of the filter press will indicate the failure and will lead to a shutdown of that filter press. In the filter press, a hydraulic power unit (HPU) pushes the water through the filter element, and the element allows the water to pass through and traps the lignite particulate on the outside of the filter plates. The cake formed in the process is removed to a truck loading bay. The filtrate drum collects water from filter press FL0005A/B/C. Level in this drum is maintained by recovered water pumps PU0002A/B, which receive water from the recovered water drum. It provides NPSH to filtrate pumps PU0005A/B that send water to venturi sump. The filtrate drum level is controlled by LIC01185B, which senses its level and throttles the purge flow using LV01185 to the reclaim sump. The level transmitter LIT01185 is compared to the setpoint with a bias to determine if make-up water from DR0004 is necessary using FV01052. The bias was necessary to prevent the two controllers from fighting one another. The filtrate pump takes suction from DR0002 filtrate drum and discharges back to CL1101A/B/C/D venturi sump. Its discharge flow can also be directed to the venturi in the other trains. The tank level controller LIC11373 throttles its discharge in accordance with level in this train's venturi sump.

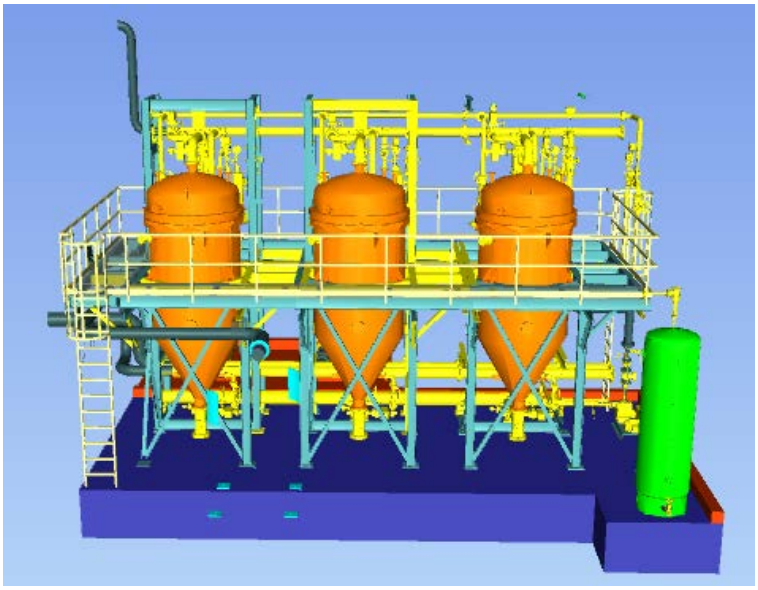


Figure 5.1-52 - Recovered water filter skid

The filtered water flows to the recovered water drum. It can be pumped from the recovered water drum to the reclaim sump or be recirculated to the condensers as make-up water if needed.

Each of the candle filters has 179 elements (figure 5.1-52). The initial designed requirement was for each filter to process 400 gpm for a total filtration capacity of 1,200 gpm.

The sludge from the recovered water filters was typically around 10% solids. High solids compatible sludge pumps were required to pump the sludge to the filter press feed tank.

The filter press feed tank has a 14-ft diameter and is 38 ft tall. It is a flat bottom tank with capacity of 42,600 gallons. In the filter press feed tank, the candle filter sludge and the purge streams from all the venturi scrubber sumps is mixed. An agitator/mixer in the tank keeps the solids dispersed in the blowdown water streams. There are three filter presses. Sludge is fed to each press by a high-pressure pump. The feed to the filter presses was typically 10% solids, with a normal range of 7.5 to 15%.

The filter presses use multiple vertical polypropylene filter assemblies (figure 5.1-53). At the start of each cycle, the press closes by sliding the filter plates together, then a high-pressure pump starts the fill cycle. The cake begins to form between the filter plates while the water drains from the press to its filtrate drum. This process continues until the pump reaches its high pressure set point. Typically, the press achieves 50-60% solids cake.

At the end of the cycle, the stack of filter elements is extended, and the filter cake is discharged from the bottom of the press. The filter cake that exits the press is cohesive and compacted and typically falls in large clumps. Cake breaker wires are strung across the press outlet to assist with breaking up the clumps. The filter cake drops from the bottom of each filter press onto a belt conveyor. A collecting belt conveyor transfers the cake from the three presses to a declining discharge chute. A truck loading area was provided at the north end of the facility. The filter cake can either be loaded directly into a truck or discharged into the three-sided, open top structure for loading with a front-end loader. The cake was transported back to the mine, where it was being stored for evaluation for future use or as landfill. The filtered water drains to each press, core separation tank. The three tanks drain to a common filtrate tank. Two filtrate pumps send the recovered water to the reclaim sump for use as process water or to the condenser sumps to maintain or refill the level. The water also was used in the waste water cooler and the ammonia scrubber.

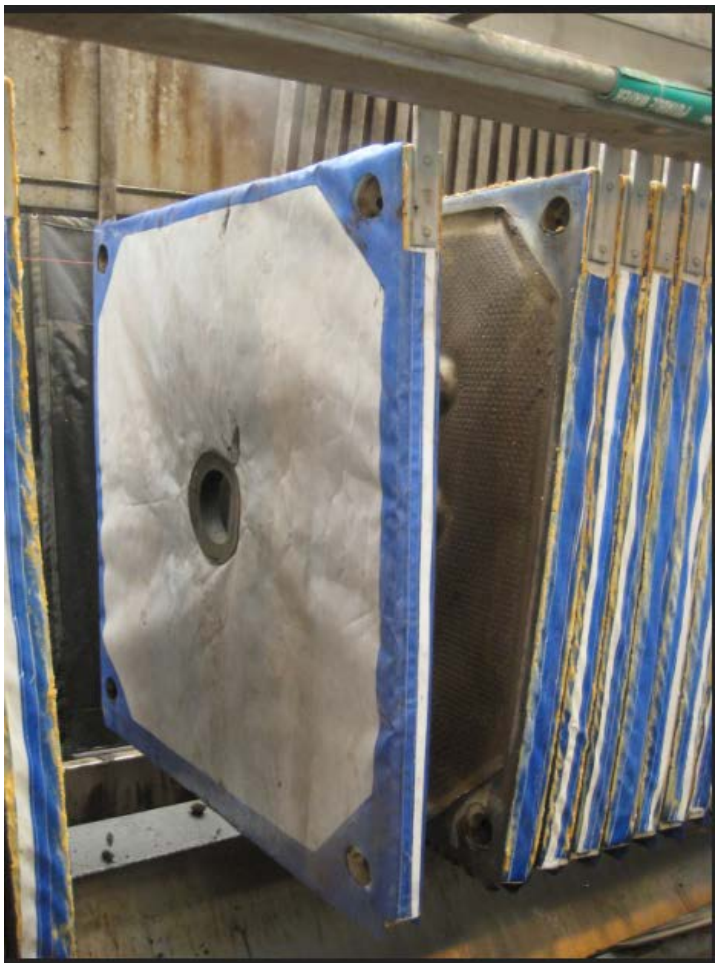


Figure 5.1-53 – Filter press plates

5.1.5.2 *Initial Commissioning Plan*

- Recovered water test package objective

The objective of the recovered water test package was to flow water through the recovered water filters and filter presses, and to operate the related tanks and pumps necessary for this operation. The recovered water filters and filter presses were to be commissioned along with the tuning of the controls. The logic of the filter controls was also validated. The equipment associated with this procedure was:

- CL 1101 A/B/C/D venturi scrubber.
- CL 1101 DR-1 condensate level tank.
- PU 1101 venturi scrubber pump.
- PU 1104 condensate level tank pump.
- DR0002 filtrate drum.
- FL0005-PU1 filter press wash pumps.
- FL0005-PU2 filter press seal water pumps.
- DR0004 recovered water drum.

- PU0002A/B excess water pump.
- DR0006 filter press feed tank.
- Recovered water filter air accumulator tanks FL0001-TK1.
- Recovered water filter sludge booster pump FL0001-PU1.
- Recovered water filters FL0001 A/B/C.
- Filter presses FL0005 A/B/C.
- Filter press conveyors FD0027 A/B/C.
- Filter press transfer conveyor FD0028.
- Filter press feed pumps FL0005A/B/C, PU ½.
- Filtrate pumps PU0005A/B.
- DR0002 filtrate drum is at or above a 50% setpoint.
- DR0004 recovered water drum is at or above a 60% setpoint.
- DR0006 filter press feed tank is at or above a 50% setpoint.
- TP1000A recovered water flush procedure has been completed.

Initial commissioning of the recovered water system started in November 2015. Before starting any commissioning activities of the recovered water filters, it was ensured that the filtration unit was leak tested and the water circuit was flushed from the condensate tanks CL1101/1201/1301 to charge the headers going to the candle filter filtration unit. Flush water ran through the circuit for 10 to 15 minutes using the excess water pumps, ensuring the pumps associated with the recovered water system were operational and had no issues. The pressure and level controllers associated with the equipment were tuned (PIC xx826 and LIC xx383). The tanks and the pumps were set to operate at normal operating level (~50-70%). The recovered water test package included standard operating procedures for commissioning in three modes: single, duplex, and triplex. In the single operating mode, only one recovered water filter was operated at a time. For example, filter A was set into sequence mode with a timer set point of 30 min and its operation was monitored. During the sequence, any issues associated with the logic were corrected to ensure the filter operated continuously and progressed adequately through several cycles, including the backflush cycle as required by the logic algorithm. Once, filter A was in backflush cycle, the sequence on filter B and filter C was started respectively and the same steps as repeated.

In the duplex mode, two filters are run in parallel mode operation with different timer set points. For example, A and B filters are operated simultaneously in sequence, with a timer setpoint of 0.5 and 1 hr respectively. Operation of both filters was monitored; any logic changes were made as needed. The operation was validated when the filters progressed through an entire cycle including backwash.

In the triplex mode, all three filters were operated and monitored simultaneously. It was important to ensure there was adequate header pressure and flow to fill the filter vessel.

Commissioning the recovered water filters was not straightforward. The original filter units were designed to handle only a certain particle size (>10 μm) and a slurry containing up to 5,000 mg/l of suspended solids. The filter media was designed to operate under a differential pressure of 0-30 psid. During commissioning, it was observed that the ultrafine particle carryover from the dryer was excessive, which caused a ripple effect on downstream equipment such as multiclones, venturis, and condensers. Eventually, the recovered water filters were overloaded with particles under 3 μm and the solids present in the slurry were in the range of 2-5% (20-50K mg/l).

- Commissioning of filter presses

The first step for commissioning the filter presses was to verify the availability of adequate operational process water level in the recovered water and filtrate drum (DR0004 and DR0002 respectively) and to ensure there was an available make-up source. Filter press feed tank DR0006 was verified to have at least 50% water level along with the availability of a make-up water source for commissioning.

During continuous operation of the recovered water filters, it is ensured that enough sludge is generated, which is then pumped to the filter press feed tank DR0006. Sludge from the venturi scrubbers is periodically diverted to DR0006 so the level in the feed tank is generally greater than 50%.

After verification of enough water level (> 50%) in DR0002, DR0004 and DR0006, the filter press agitator MX0006 was started. Immediately following this verification, the filter press conveyor FD-00027A was started to verify belt alignment. The filter press transfer conveyor emergency shutdown procedure was also verified by tripping the conveyor with the emergency shutdown cord. After verification, the conveyor was restarted. The procedure was repeated for verifying the belt alignment and transfer conveyor for FD00027B, FD00027C and FD00028 respectively. The process was now ready for commissioning the filter presses.

For commissioning the filter presses, venturi scrubber pump PU1101 was first placed in manual and started. Next, filtrate pumps PU0005 A or B were manually started. The filter press was then started manually in the field. The safety lanyard associated with the filter press was pulled, and it was verified that the filter press tripped. After manual verification in the field, the filter press was started remotely from the DCS for a single cycle. It was ensured that there was enough water flow to DR0006 and the filter press was commissioned in the presence of the vendor. All associated controllers were tuned during this phase. After finishing one cycle on each of the filter presses, all associated pumps and conveyors were stopped, which concluded the filter press commissioning.

5.1.5.3 *Significant Events*

There were multiple issues identified problems with the filter press during the circulating water filter test. The pump seal packing had to be repaired due to excessive leaking during operation. The doors would not align to seal off material from falling on the belt after the door close cycle was complete. The fix for two doors was to adjust the alignment on the closer, but the third door had to be trimmed. Each press had a continued problem with the hydraulic system, which would overpressure and trip the system. The flood wash valve failed due to the fast-acting valve and ripped the seat out in the sudden thrust of initial operation. The valve liner tore out causing continuous leak through.

During the water circulation tests, the filter press had hydraulic sensor problems. There was missing logic that was not provided by the vendor from the bid package. The gaps in logic were caught by the field representative and changes were made onsite with the representative present. Limit switch settings were a common problem among all the filter presses and extra time was needed to set these correctly.

The candle filter had similar logic and sequence checkout problems common to starting up new equipment. The initial pump sequence for filling the candle filter body was not correct. The level probes were not inserted into the flow fully, which caused the vessel to overflow during initial startup. The dome depressurizing and the venting logic and timers had to be adjusted to get the water out of the header at the correct rate. Another logic step had to be added by the vendor to drain the vessel.

5.1.5.4 *Final Summary*

After the initial checkout of the filter press and the candle filter, both filters were ready to receive lignite for filtration. The various mechanical improvements and adjustments to instrumentation allowed the system to be available for filtration. The initial problems with the fast-acting valve, filter press bomb bay doors and hydraulic systems added a 2-week delay to completing the dryer test package. With the vendors onsite and the quick responses by the startup team, the repairs and logic changes were made and allowed the test package to conclude with a complete success.

5.1.6 Dryer Feed System

5.1.6.1 *System Overview*

The dryer feed equipment consists of the crushed lignite silo, weigh belt feeder, roll crusher, and dryer isolation valve (figure 5.1-54). The crushed lignite, which is supposed to be less than 2 in., exits the bottom of the crushed lignite silo onto a weigh belt feeder. The weigh belt feeder (figure 5.1-55) controls the rate at which lignite is fed to the dryer. A twin gate valve located between the silo outlet and the weigh belt can be used to stop the flow from the silo for maintenance. The gate valve is normally open during operation. The chute between the silo and the weigh feeder housing has a slip joint that allows for a 2-in. vertical movement of the silo to compensate for silo growth due to variations in material loading as the silo is loaded and unloaded.

Lignite exits the bottom of crushed lignite silo SI1102 by gravity and flows through a vertical chute containing a manual knife gate. This flow is regulated by the speed of weigh belt feeder FD1102.

A side path (normally closed) containing crushed lignite silo deinventory airlock FD1119 allows some or all the silo contents to be sent through an outlet in the bottom of fluid bed dryer discharge feeder FD1108 to be de-inventoried to the pyrite removal system.

Fire suppression is supplied to the crushed lignite silo by a four-head manifold that allows fire water to be manually admitted if necessary.

Fire monitoring is provided by CO analyzer AI11005 located on top of the crushed lignite silo and by temperature sensor TI11012A located in the silo vent line to the crushed lignite silo baghouse FL0002.

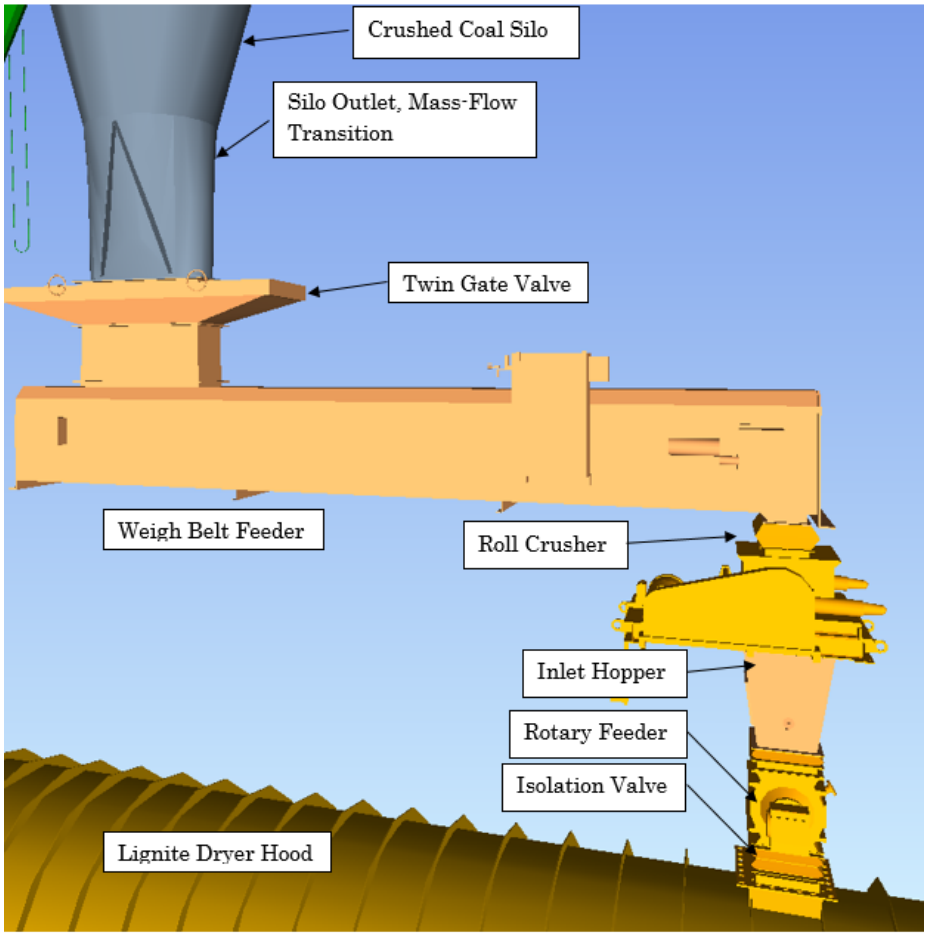


Figure 5.1-54 – Dryer feed system

The feeder inlet hopper uses sidewalls that promote constant drawdown across the length of the feeder inlet. When combined with the silo cone configuration, this design promotes mass flow. The result is a first-in/first-out flow configuration, which is important with a fuel such as lignite, which tends to autocombust when left in a silo for too long.

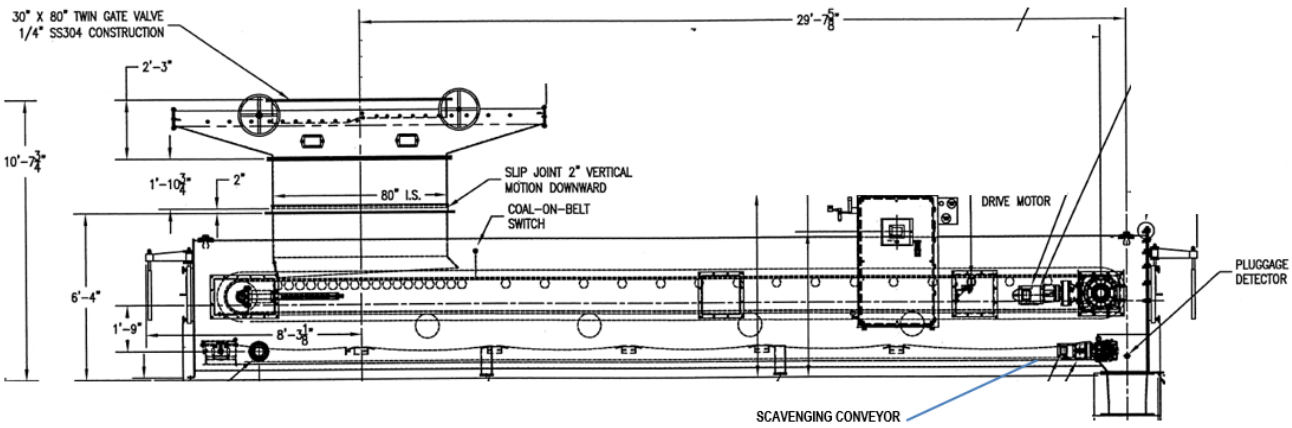


Figure 5.1-55 – Weigh belt feeder

The weigh belt feeder has a 48-in. wide belt and is approximately 30 ft long. It is totally enclosed in a housing to provide a dust-tight enclosure. The belt initially provided was flat with flexible sidewalls to contain the lignite. The feeder capacity is 150 ton/hr.

The feeder uses a variable speed belt traveling over a weigh bridge to control the feed rate to the dryer. The control system adjusts the speed of the belt to meet the dryer's demand for lignite. Variations in material bulk density due to changing moisture content and density are automatically compensated for in the control system.

A separately driven conveyor chain runs along the bottom of the housing to scavenge material that falls from the belt after being weighed. The conveyor belt and the scavenging chain discharge into a common outlet. A level control in the discharge chute notifies the operator if material flow stops or the chute plugs.

The lignite is fed into a roll crusher, where it is crushed to -0.5 in. before being fed into the fluid bed dryer. The roll crusher has two opposing toothed rolls driven by a single motor. The drive roll is fixed. The driven roll can move horizontally to relieve oversize material. A set of pivoting arms with spur gears keeps the rolls synchronized to maintain the geometry of the intermeshing roll teeth. The gap in the crusher can be adjusted.

An automatic system uses a cylinder on each end of the movable roll. The cylinders are fed with bottled nitrogen to act as a spring to load the roll. The nitrogen pressure is pre-set using the bottle's pressure regulator based on the material being crushed. Oversize material that enters the crusher moves the second roll, compressing the gas in the cylinders to allow crushing oversized material. Non-crushable material spreads the rolls and passes through.

The design of the system was constrained by limited vertical space for adequate lignite storage capacity. To provide space for roll crusher maintenance such as roll replacement, a platform was provided in the bay west of the roll crusher. When major maintenance is required, the crusher is moved onto the platform, where better access is available.

Crushed material is discharged into the dryer feed hopper, which acts as a transition from the roll crusher outlet to the dryer inlet rotary feeder. The rotary feeder and hopper are supported on a separate structure above the dryer inlet. A maintenance slide gate and an expansion joint are located below the rotary feeder to facilitate installation and to provide isolation from movement of the dryer hood due to thermal expansion.

A moisture sample extraction device is provided in the dryer feed hopper. A sample extraction screw feeder extracts a lignite sample from across the width of the flow stream as it flows through the hopper. The sample flows through an analytical instrument then is reinjected into the hopper.

The dryer feed rotary feeders were fixed-speed and operated at 20 rpm. Their rated capacity was 300,000 lb/hr with the throughput regulated by the weigh belt feeder. Originally, the feeders had eight vane rotors.

Since the dryer operates at a positive pressure of approximately 50 in. W.C., the rotary feeder was equipped with body vents to minimize the amount of humid nitrogen vented up to the weigh feeder and crushed lignite silo. A nitrogen

motivated eductor was mounted to the rotary feeder body vent. The vent gas containing some residual fines was vented into the multiclone exhaust duct between the multiclone and the venturi scrubber/condensers.

5.1.6.2 *Initial Commissioning Plan*

- Dryer feed test package objective

The dryer feed system was part of the fluid bed dryer test package. The equipment had functionally been checked out by the equipment manufacturer field technicians before lignite was fed to the system but had never been tested with lignite before the dryer test package.

The first objective was to test the emergency deinventory system on the side of the crushed lignite silo. After the deinventory system was proven, the weigh belt and crusher functionality checks were the next tests. After the weigh belt feeder (WBF) was operational, the vendor would calibrate the feeder, then the roll crusher gap would be set for dryer operation. The last step in the dryer feed system checks was to calibrate and test the rotary feeder eductor.

- Dryer feed test package overview

The initial plan was to put a minimal amount of lignite in the silo and test the functionality of the deinventory system from the silo to the dryer inlet. This system had a silo discharge slide gate valve and weigh belt feeder. The main method to deinventory the silo was through the fluid bed dryer. The dryer could be deinventoried to the pyrite system or through the pulverizer to the ash mixer. After the initial problems with the silo deinventory were solved, this system was proved to be slow but workable in case of an emergency.

After the silo deinventory was completed, the next step was to feed lignite to the weigh belt feeder and then to the crusher. The weigh belt feeder was the first piece of equipment on which lignite would be tested. After the WBF was tested and calibrated, the roll crusher spacing would be set. The rotary feeders would then be tested.

Before the first feed test, a field technician from the weigh feeder manufacturer performed pre-operational checks. The initial precommissioning visit was in July 2015. These checks included:

- Checking motor rotation and no-load amperage.
- Checking belt tracking.
- Operating the scavenging conveyor in the feeder housing.
- Checking the operation of limit switches.
- Performing the initial calibration of the weigh scale bridge with certified weights.
- Training the plant operators in scale operation.
- Training plant technicians in weigh bridge calibration.

Normally, lignite is extracted from the silo using the weigh belt feeder. The silos have an additional outlet to allow emptying the silo in the event of the failure of downstream equipment. The deinventory chute has a rotary feeder located on a platform below the silo. To maintain a 60° downward angle on the discharge chute, the inlet was located high in the silo cone. The chute discharged into the pyrite drag conveyor system for lignite disposal.

The chute and rotary feeder did not perform reliably due to the wet, sticky nature of the lignite as received from the mine. The flow of the lignite through the opening in the 16-in. diameter chute was unreliable. The material tended to stick in the pockets of the rotary feeder, impeding the flow. When the chute plugged, it was difficult to re-establish flow. The chutes were difficult to operate, but they could be used in an emergency to empty the silo if needed. They performed better when the lignite was less moist.

The roll crushers are located directly below the weigh belt feeders. They were pre-commissioned in the fall of 2015. Motor rotation and amperage, lubricant level in the gear reducer, and the Nitrol system that controlled the spacing between the crushing rolls all were checked. The spacing of the rolls was set to produce -0.5 in. material.

The dryer inlet rotary feeders were operated, and the correct direction of rotation and gear reducer lubricant level were checked. Since the rotary feeders were initially provided with adjustable tips, the tip clearance was checked. A maintenance slide gate, provided between the rotary feeder and the dryer inlet to allow isolating the feeder from the dryer, was opened.

A vent in the rotary feeder vented dryer gas as the feeder turned, then a venturi eductor captured the vent gas and returned it to the dryer vent duct. Low pressure nitrogen provided motive force for the eductor. The flow regulator for the nitrogen was set and the function of the nitrogen control valve was confirmed.

For the initial commissioning of the dryer feed equipment, 100 tons of lignite was loaded into one of the crushed lignite silos. The first dry runs occurred in November 2015. After the initial run, a technical field assistant from the roll crusher manufacturer inspected the roll crusher and made final adjustments before commissioning the dryer.

The dryer manufacturer provided a moisture analyzer, which was mounted in the dryer feed hopper between the roller crusher and the dryer inlet rotary feeder. After the basic feed equipment had been operated, the technical advisor from the manufacturer commissioned the instrument in January 2016. The instrument delivered acceptable results, but the sample extraction screw conveyor and the sample return conveyor remained problematic.

5.1.6.3 *Significant Events*

- Dryer rotary feeder changeout

In early November 2015 during the first dryer test, there were many operational challenges. After overcoming a series of small mechanical problems that prevented any lignite feed to the dryer, it was determined that the inlet and outlet rotary feeders were impeding lignite flow. In January 2016, the rotary feeder vendor and the dryer supplier met at Kemper and observed the operation. The vendors recommended the inlet feeders be changed from 12 vanes to 8 vanes and that the outlet feeders be changed from 8 vanes to 6 vanes. The inlet feeder could easily be changed by moving the 8-vane outlet feeders to the inlet feeder. For the outlet feeders, it would take 2 months to get the new part onsite, and 1 month to test before fabrication of the other five could begin, for a total of 4 months for all outlet feeders to be replaced. There were more operational difficulties with the inlet 8-vane feeder, and the rotary feeder vendor recommended replacing the 8-vane feeder with a 6-vane. After the 6-vane feeder was onsite in April 2016, it was determined to be ineffective and the 8-vane was swapped back. The 6-vane feeder allowed too much gas leakage from the dryer to the crusher, which would not allow the dryer to build pressure. Extensive design work was done on the feeder and the final recommended design changed the feeder to a scalloped 7-vane rotor in late June 2016. This feeder was not delivered to the plant until October 2016.

- Dryer rotary feeder pocket cleanout problems

During the dryer operation, both the inlet and outlet rotary feeder pockets plugged with lignite (figure 5.1-56) and tripped on high amps. Modifications were made to the feeders as quickly as possible, then changes were made in stages and improvements were evaluated. The rotary feeder manufacturer met onsite and recommended an immediate plan to add pocket purges to improve the rotary feeder pocket cleanout. The pocket purges were added to the inlet and outlet rotary feeders (figure 5.1-57). In March 2016, when the new dryer outlet 6-vane rotary feeder was delivered, it was quickly installed, and the dryer outlet feeder was swapped to the inlet feeder. Each feeder worked better than the original vendor design. In addition to the outlet feeder modifications, intermittent nitrogen cannons were added to both rotary feeders to replace the pocket purges. The rotor end plates were removed, and the rotor blades lengthened to allow purge gas to be better directed to where packing occurs. Additional work was done to locate the nitrogen cannon nozzle closer to the pocket apex to improve pocket cleaning. Figure 5.1-58 shows the cannon design, and figure 5.1-59 shows the installation.

Figure 5.1-56 – Plugged rotary feeder

Figure 5.1-57 – Rotary feeder pocket purge

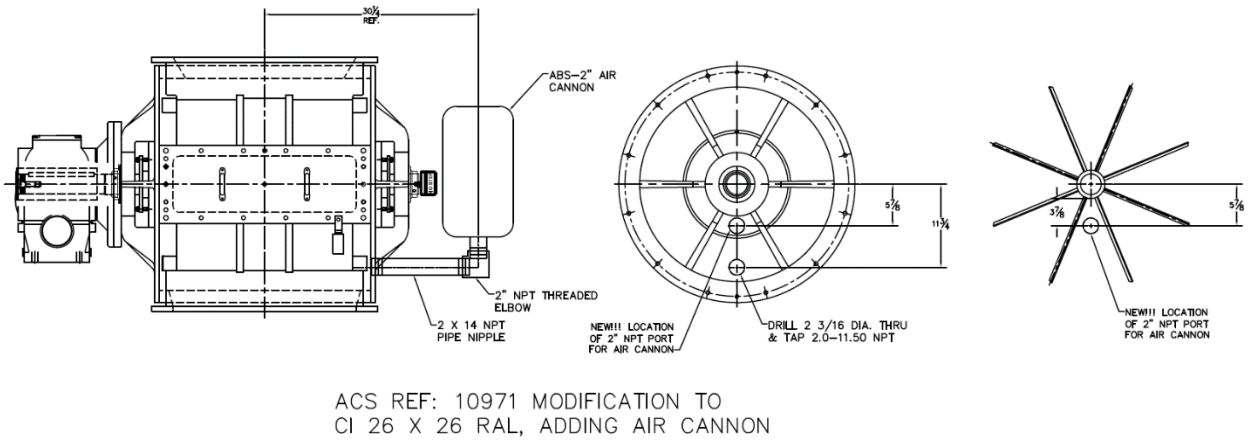


Figure 5.1-58 – Nitrogen cannon design

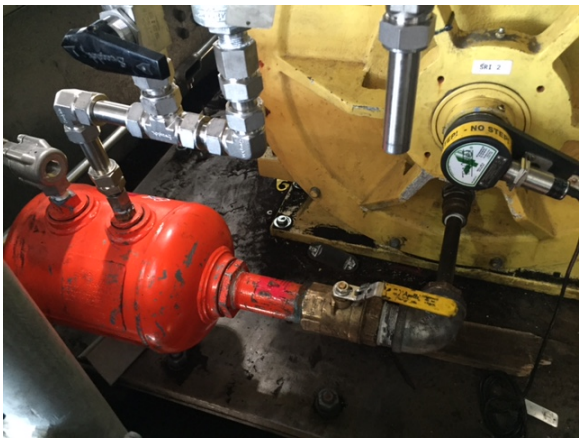


Figure 5.1-59 – Nitrogen cannon on rotary feeder

- Roll crusher gearbox bearing seals

The weigh belt feeder discharges through a chute into the lignite crusher (figure 5.1-60), which performs the final sizing of lignite before it is fed to the dryer. The desired size exiting the crusher is -0.5 in.

Figure 5.1-60 – Dryer crusher

The crusher uses a single motor/reducer gearbox with one stationary shaft and one shaft that can move horizontally to allow the rolls to spread and relieve. The shafts are connected by two pivoting arms. Spur gears on the arms keep the shafts synchronized to keep the toothed rolls correctly intermeshing to produce the correct lignite size. The moving shaft is loaded using nitrogen bottle pressurized cylinders

The crushers were commissioned initially in October 2015. Lignite feed started with the initial testing of the dryers in November 2015.

The bearings on the crusher are manually lubricated on a regular basis with grease (figure 5.1-60). There was a significant amount of fines in the lignite, and the system was subject to pressurization as rotary feeder and eductor issues were being resolved. As a result, the lignite fines worked their way into the grease and the bearings failed. During the operating period, the bearings needed replacement several times as possible solutions were developed.

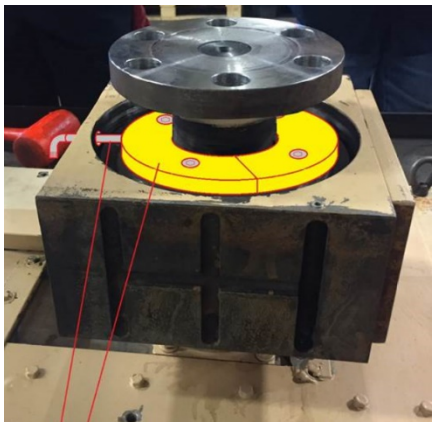


Figure 5.1-61 – Dryer feed roll crusher bearing seal

After the rotary feeder eductor was functioning, the amount of fines entering the bearing was reduced. The design team developed a nitrogen purged seal (figure 5.1-61) that would hold the grease in the bearing, with the nitrogen preventing lignite fines from entering. This repair had not been implemented when operations were suspended.

5.1.6.4 *Final Summary*

The lignite feed system was the most difficult part of the dryer test package. Each piece of equipment had significant problems and required redesign to accommodate the condition of the lignite delivered by the LDF. Design, operations, and maintenance personnel had visited a nearby lignite-fired power plant and reviewed its problems and solutions. They believed Kemper would be in good shape to manage startup. While some problems with the system were unique to Kemper, other problems with silos, belts breaking, and petrified wood had been experienced at the other plant. In contrast to Kemper, the PSDF had run completely trouble-free during the 5,000 test hours with the feed system. The biggest problem at the PSDF was huge clay chunks that were delivered wet and would not crush when fed into the crusher. This problem was resolved at Kemper with the screens at the storage piles at the mine and with the extended time the lignite and clay had degraded in size.

The inlet dryer rotary air lock was crucial to maintain the pressure barrier for the dryer operation and feeding lignite to the dryer. The rotary feeder iterative change-outs improved dryer operation, but either when wet fines were in the unscreened feed or when the fines were fed directly to the dryer, the rotary feeder pockets had to be cleaned two or three times per week to remove buildup inside the pockets. The combination of moisture and particle size plugged the rotary feeder pockets and was detrimental to sustaining the design dryer operational rates.

The modifications to the crusher and gearbox that were made during final operation were successful but had not been realized fully during commissioning.

5.1.7 Dryer system

5.1.7.1 *System Overview*

- Dryer fluidization operation

Closed-loop, waste heat, fluidized bed dryer systems provide the most thermally efficient means of drying lignite. The lignite processing system used a fluid bed dryer (FBD) system to dry lignite, resulting in a large amount of water evaporated (360-420 kpph). For environmental purposes and efficiency, the system was designed to reuse the evaporated water in plant processes. The evaporated water from the lignite was condensed and used in the water gas shift, syngas cooling, ammonia removal, and sour water systems. The closed loop system minimizes make-up requirements and keeps operating costs low for the lignite area. Process improvements made during commissioning

created a more reliable dryer operation than was purchased from the suppliers. The improvements overcame lignite quality issues that affected equipment operation. The two most significant improvements were in dryer operation and the recovered water filters. The dryer feed system and fluidization changes allowed for more reliable lignite feed rates to the dryer. The flocculation, sedimentation, and filtration improvements resulted in higher reliability water feed rates to the downstream process.

The fluid bed dryer loop consists of the dryer fan FN1102, gas heater HX1101/2, fluid bed dryer PG1102, multiclone FL1103A/B, and venturi condenser CL1101A/B/C/D (figure 5.1-62). The dryer was designed to operate efficiently from 30% to full load. Adjusting the bed height adds retention time and drying surface area to accommodate increased lignite flow and higher evaporation rates. The lignite fed into the dryer had a moisture content that often exceeded 50%. In the dryer, the lignite was dried to approximately 22% moisture or less. The in-bed heat exchangers heated the lignite by conduction, while the external gas exchangers heated the lignite by convection. The lignite entered the dryer and was moved along its length by jets of hot drying gas supplied by dryer fan FN1102. This gas flowed up through the bed of lignite, fluidizing and drying it by evaporating some of the moisture. A specially designed gas distribution plate (PRISMAJET) was used along the bottom of the dryer to evenly distribute the gas while moving lignite debris of up to 2 in. towards the dryer's product discharge chute. Along the grid plate, high velocity jets helped propel the lignite along the length of the dryer. Adding lignite into the top of the dryer pushes the lignite toward the discharge. The high-velocity jets also fluidize the lignite particles in the dryer to increase the overall heat transfer area. Heat was transferred to the crushed lignite bed in the dryer by fluidization from hot gas and internal heat exchangers in the dryer.

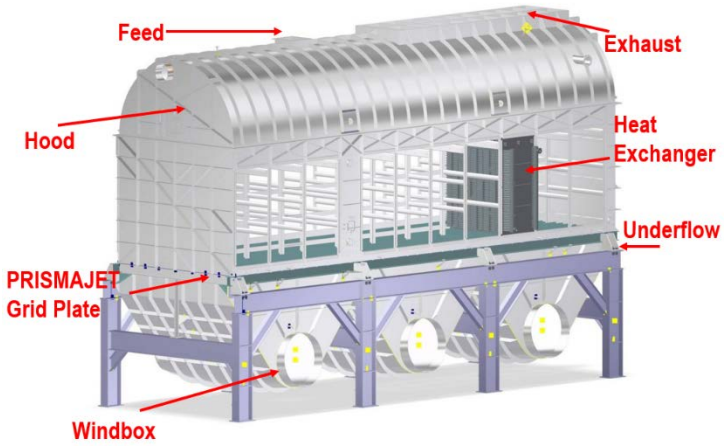


Figure 5.1-62 – Fluid bed dryer components

- Dryer fluidization theory

Since the primary motive force in the dryer is fluidization, NAC and the MPC operators had critical roles in operating the dryer. Lignite quality, specifically particle size and on-spec moisture, was a major factor for operations. MPC operations' role was to ensure the crusher was operating properly and to set the dryer gas flow to provide sufficient fluidization for the lignite fed (figure 5.1-63).

The desired type of fluidization is between U_L and U_1, where the bed was stable but was not over-fluidized and could be described as smooth bubbling with some channeling occurring. When the dryer gets to level U_3, this is a turbulent fast-moving gas that causes larger bubbles to propel particles into the gas stream, which causes high particle carryover to the downstream equipment. More particles carried over due to over fluidization means more particles carried over to the multiclone, venturi, and condenser. When there are large size differences in the particles coming into a dryer, it is difficult to get the right amount of gas to keep the particles in suspension. The amount of gas supplied to the bed was typically based on what was needed to prevent loss of fluidization. Loss of fluidization, or bed collapse, occurs when too little gas is added to the dryer (U_0 and U_L in figure 5.1-63). The amount of gas required to keep the lignite particles in suspension is called the minimum velocity. If lignite that was too heavy or too wet came into the dryer, the amount of gas would be lower than minimum fluidization, causing localized bed collapse. When the bed collapses, the

area around the collapse grows, which causes significant differences in bed levels going down the dryer length. When bed collapse occurs, the dryer is shut down to refluidize the bed.

When fine lignite is fed to the dryer, the material fluidizes too easily, causing high carryover. When both heavy or wet lignite and fines are fed to the dryer, the fine particles are carried with the gas as it travels through the dryer bed and the large particles ride along the bottom of the dryer. When the particles are more uniform, it is easier for fluidization to match U_L or U_1 (figure 5.1-63). At Kemper, the lignite fines and screened lignite fluidized well because they had the most uniform particle size. The unscreened lignite, which was made up of lignite with fines, heavy rock, and design sized lignite, used 15% more gas for fluidization, resulting in the highest carryover of the three types of lignite. The fine lignite used 30% less gas than the unscreened lignite (40% less under minimum fluidization conditions). The less gas used to dry and transport the lignite, the less carryover there is and the easier operation is for the filter systems.

It was easier to meet the lignite demand by over-fluidizing the lignite in the dryer and then dealing with the fluidization problems in the filtration process. The best solution for fluidization would have been to control all the lignite fed to the dryer for uniform particle size by screening and crushing and controlling the excess moisture with lignite storage dome management practices. The excess water added for dust suppression at the belt transfer points could be eliminated by adding dust collection equipment.

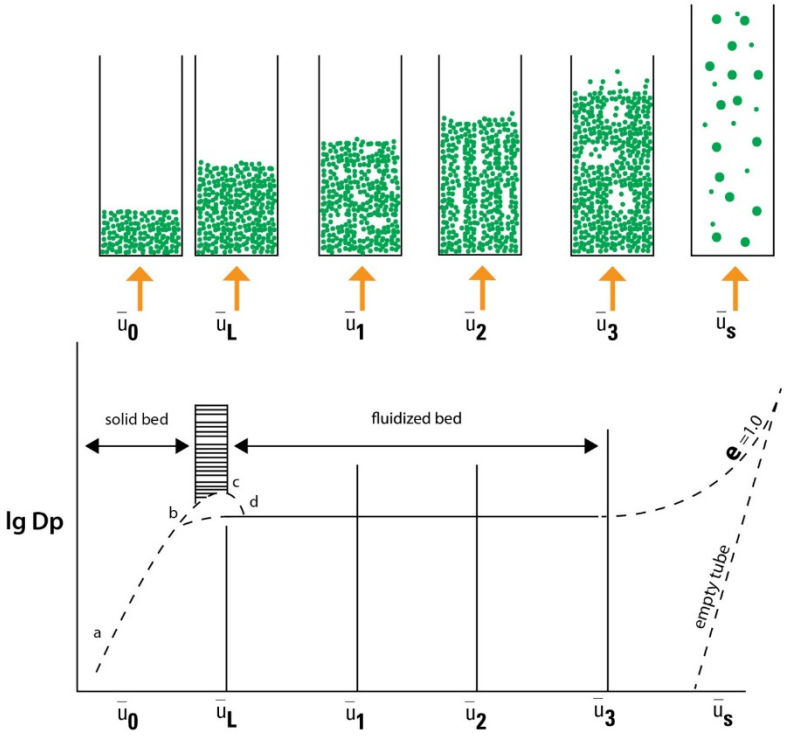


Figure 5.1-63 – Dryer feed fluidization regimes

- Dryer control

Hot water was pumped through heat exchangers in the dryer for heating as shown in figures 5.1-10 and 5.1-11. The bank of internal heaters uses tempered water (TW) as the heating medium. The flow of TW was controlled by FIC11648, which receives its setpoint from the heat input control system. The heat input control system generates the setpoint signal based on the mass and moisture content of the lignite entering the dryer and the moisture target of the lignite leaving it. TW requirements are determined by mass and energy balances. To maximize efficiency, the level of

the bed, indicated by LIC11511, was used as a guide to split the hot water between the in-bed exchanger and the gas preheater. FIC11648 controls tempered water to the in-bed exchanger. FIC11651 controls tempered water to dryer tempered water heater HX1101. Each of their setpoints was supplied by mass and energy balance calculations in the heat input control system that determine the amount of heat required to drive off the desired amount of water. The lignite was discharged from the dryer through dryer outlet HP rotary valve FD1121 and dryer outlet LP rotary valve FD1122, which are arranged in series to isolate downstream equipment from dryer pressure. The speed and discharge rates of these valves are controlled by the lignite bed level controller LIC11511.

- Dryer gas loop

The fluid bed dryer dries lignite from about 50% to 20% moisture in an inert environment created by circulating the process gas in a closed loop (figure 5.1-64). Since lignite fines are combustible, mitigation measures were put in place to reduce the chance of combustion and fire. The risk of smoldering and fire is drastically reduced in a low oxygen environment. The oxygen content of the drying gas was monitored, and nitrogen added as necessary to maintain the safe level for operation.

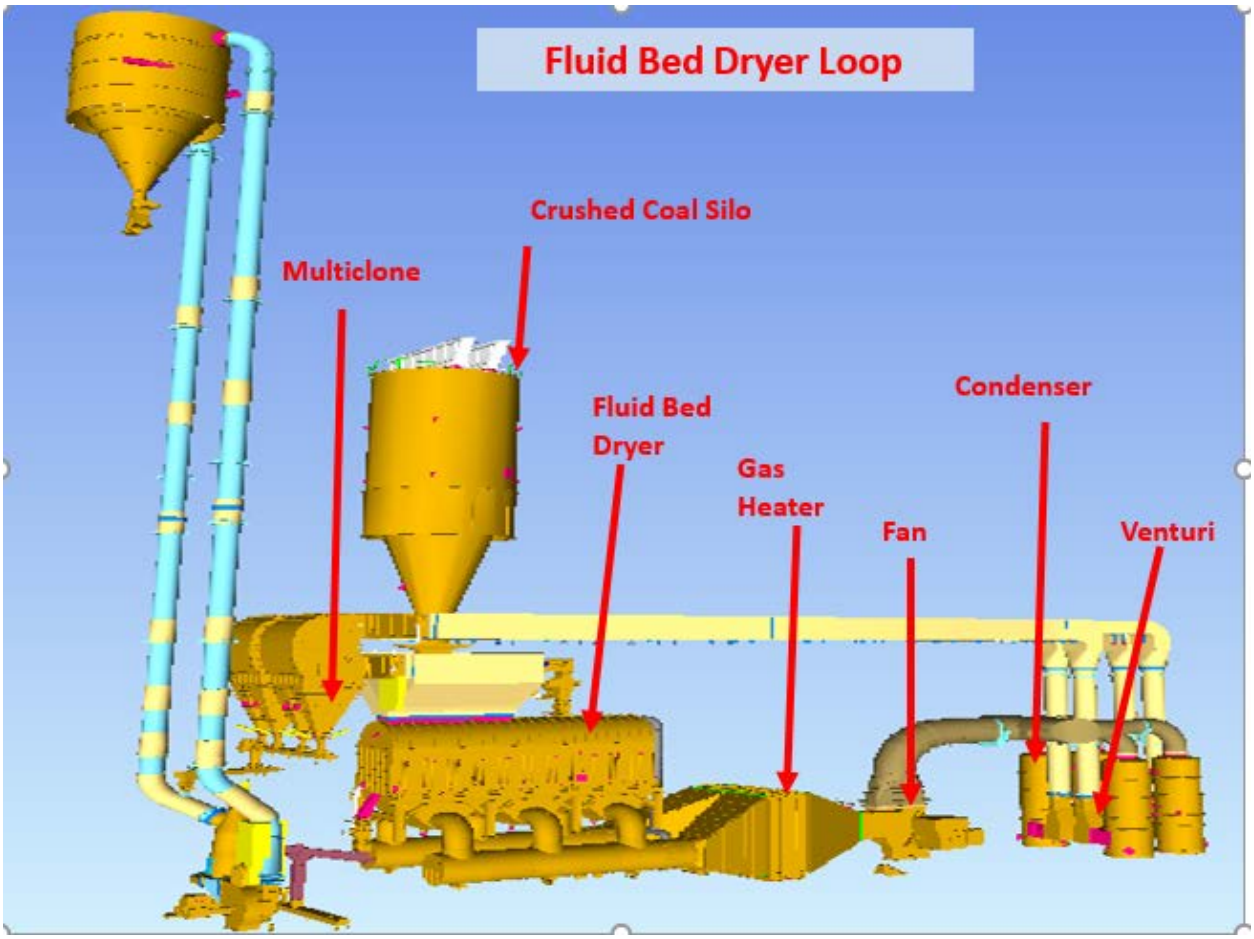


Figure 5.1-64 – Fluid bed dryer loop

Drying used a mixture of air and nitrogen containing less than 8% oxygen by volume. For lignite, National Fire Protection Association Code 69 defines gas with such low oxygen concentrations as being inert and unable to sustain a fire. When the dryer was in operation, the gas loop humidity between the dryer hood and the inlet to the venturi was maintained between 50% and 85% humidity. This level of humidity further mitigated the fire risk during operation. Since the drying process produced high humidity conditions, it was important to not let the gas loop temperature drop below dewpoint. A saturation temperature (with a bias) was constantly calculated from the hood humidity analyzer,

and the gas temperature was controlled using the dryer hood temperature controller TC11601. Hot bypass gas was sent to the dryer hood to control the temperature from going below the dewpoint. If the gas temperature to the inlet of the multiclone dropped below the dewpoint, the risk for plugging the multiclone cyclone was high, which would cause significant upset conditions in the capture and subsequent lignite carryover from the multiclone to the venturi. In addition to the hood temperature bypass controller, there were hopper heaters installed on the multiclone hopper walls. These hoppers were temperature controlled since there was not sufficient hot gas circulation. The temperature was controlled so the gases would not condense in the hopper and plug the rotary feeders or chutes.

After leaving the multiclone, the gas goes to the venturi scrubber where, through a change in pressure, the water spray is atomized and collects the fine lignite carried over from the multiclone. The gas continues to the condenser where the evaporated water from the dryer is condensed and freed from the gas so a drier gas can be recirculated back to the dryer and complete the gas circuit. After leaving the condenser, the gas goes through the fan where the pressure is raised from atmospheric up to 118 in. W.C. After leaving the fan, the gas goes through a perforated plate to evenly disperse it across the gas heater. Without the perforated plate, the heat exchanger would have channeling and poor heat transfer performance. The fan circulates the gas through the tempered water and steam heat exchangers. The gas leaves the heat exchanger and flows through a pair of manifolds that delivers it to six gas inlets, three on either side of the dryer. There are three gas plenums that feed the gas up through the gas distribution plate. A small amount of fine lignite, called siftings, typically falls through the small opening in the dryer floor. To prevent the hoppers from filling with this material, a pneumatic conveying system sweeps the hoppers periodically and conveys the siftings into the dryer hood where it mixes with the dry lignite.

- Dryer heating

One advantage of fluid bed dryer systems compared to other forms of drying was that they operate very efficiently using low temperature heat. Energy sources that are normally considered waste heat can be used effectively and efficiently for drying the lignite. There was a deep layer of heating coils throughout the length of the dryer, except in the feed zone. Inside the suspended lignite layer, the coils are in direct contact with the lignite. From 50% to 70% of the total heat needed to evaporate lignite moisture was transferred by the heating coils in the bed of the dryer. The lack of heating coils in the feedzone promoted distribution and improved mixing of the incoming lignite.

The dryer used tempered water as the primary heat source. The tempered water system is a hot water loop that transfers heat from one area of the gasification process to another, using demin water as the heat transfer fluid. It removes waste heat from process heat exchangers and rejects heat to dry the lignite in the fluid bed dryers. The system conserves energy by using heat for drying rather than rejecting heat to the cooling towers.

The heat was rejected through the dryer heat exchangers and the water was recirculated to be reused as a cooling fluid in various units downstream of the gasifier. The tempered water system collected low grade heat from these plant sources: CCAD cooler, 3%; waste water ammonia stripper condenser, 5%; intermediate syngas cooler, 64%; low temperature syngas cooler, 8%; transport air cooler, 3%; and extraction air cooler, 17% (figure 5.1-65). The tempered water supplies heat to the fluidized bed dryers in bed heat exchangers and external gas heat exchangers, allowing them to dry the lignite to the desired moisture content. Since none of the TWS was in operation at the initial startup, the TWS system was supplied heat from an indirect contact steam heater. Under normal operating conditions, the dryer does not require any steam to dry the lignite and uses all available tempered water for drying. By integrating the dryer design into the plant heat balance, the dryers efficiently use almost 13 billion Btu/day of heat energy that would otherwise be rejected as heat to the cooling towers. On average, the dryers process about 14,000 tons of lignite per day and evaporate about 5,000 tons of water per day. (See section 4.7.4, Tempered Water System.) The tempered water loop is pressurized to keep the water above the boiling point for improved heat transfer. The water was normally around 260 ˚F and heated the lignite directly with in-bed heating coils and by heating the recirculating drying gas. In addition to the tempered water heat exchangers, there was a set of heat exchangers near the end of the dryer bed that used 50 psia steam. These heat exchangers can provide an additional 20% of the heat load, if necessary.

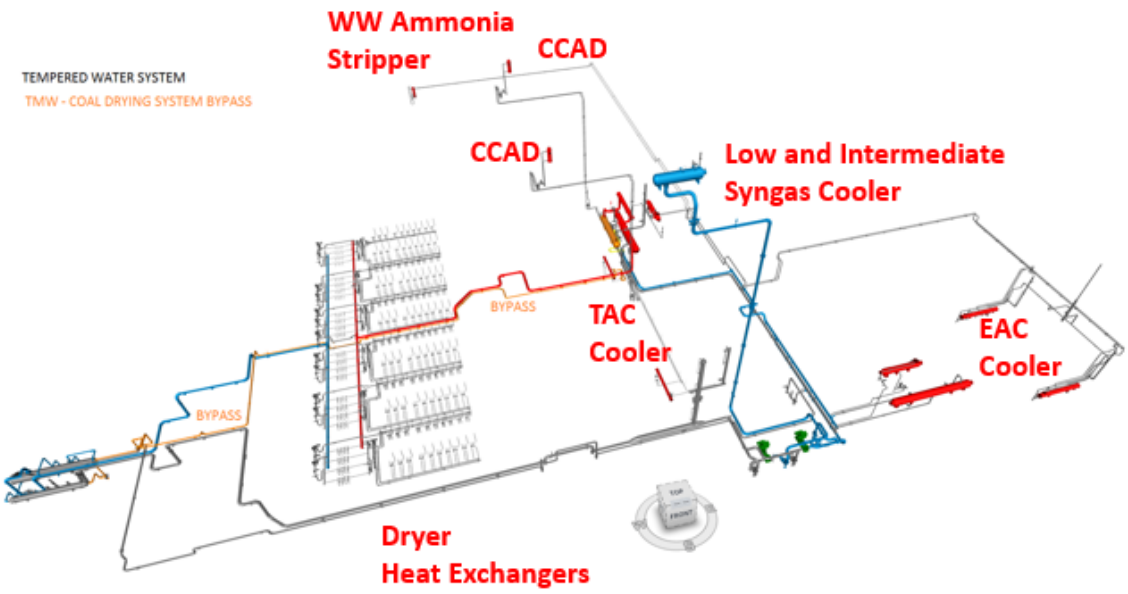


Figure 5.1-65 – TWS piping network for dryer heating

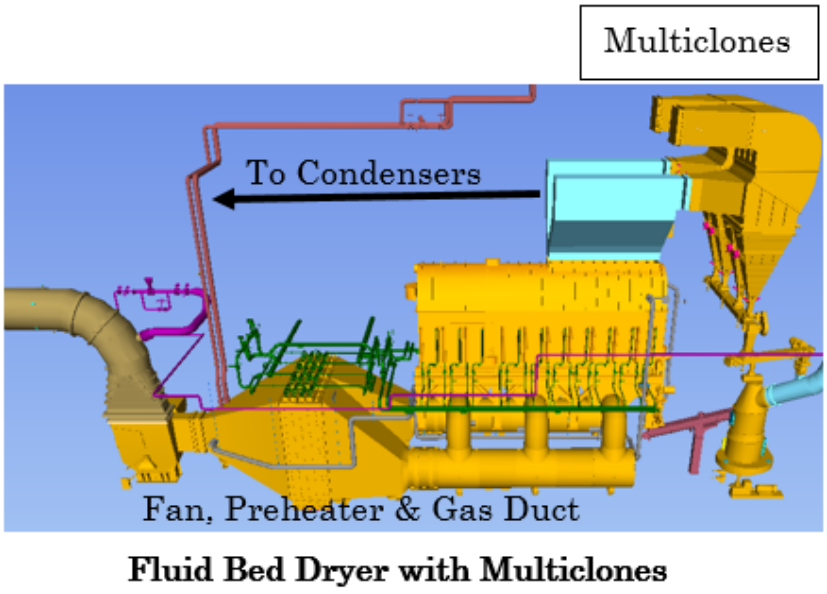


Figure 5.1-66 – Multiclone system

- Multiclone

A multiclone removed particulate from the drying gases received from the fluid bed dryer PG1102. It vents the drying gases to the venturi condenser CL1101A/B/C/D) and sends the captured particulate to the pulverizer discharge duct. Particulate removal was associated with the following equipment:

- FL1103A/B multiclone.
- FD1124 multiclone collection conveyor.

- FD1125 multiclone transfer conveyor.
- FD1103 multiclone air lock.

The circulating (sweep) gas leaves the FBD carrying elutriated lignite fines from the lignite bed in the dryer. The multiclone removed 90% of this lignite carryover from the dryer. The gas leaves the multiclone and continues to the venturi condensers CL1101A/B/C/D. Most of the fines carried over were large enough to be settled out by the centrifugal spinning action in the cyclones. The separated lignite fines are then collected in the bottom of multiclones and conveyed to the pulverizer discharge duct as useful lignite. The multiclone consists of banks of vertically mounted collecting tubes that employ cyclonic action to remove dried lignite particles from the gas flow. There are two multiclone separators for each of the dryer trains. Centrifugal force is used to disengage the larger particles from the gas exiting the dryer. Gas enters the collecting tubes tangentially and the gas spins toward the bottom of the multiclone tubes, depositing the lignite fines. Gas then returns particle free, upward through the center of the tube. The spinning action of the gas inside creates the centrifugal force that separates the solids from the gas. The collecting tubes capture entrained lignite particles, allowing them to fall through two separate outlets, out the bottom of multiclones and onto the multiclone collection conveyor. The multiclone collection conveyor collects the lignite from multiclones and transports it to the multiclone transfer conveyor. The multiclone transfer conveyor receives lignite fines from the multiclone collection conveyor and transports them to the multiclone airlock FD1103. The multiclone airlock receives the discharged lignite from multiclone transfer conveyor, discharges it into the pulverizer exhaust 57-in. diameter duct, and sends it to the PC cyclonic baghouse along with the lignite flowing from pulverizer. A rotary feeder limits gas flow between system components. These fines mix with the pulverized lignite and become part of the gasifier feed lignite.

After leaving the dryer, the drying gas passes through parallel ductwork to the two multiclone units. Each multiclone (figure 5.1-66) has 126 8-in. collecting tubes and vanes that act as small, high-efficiency cyclones. The combined units have a peak flow capacity of 350,000 acfm. The multiclones remove most of the fine lignite particles entrained in the drying gas. To maintain efficiency over this wide operating range, the multiclones were designed in pairs. When the gas flow was less than 165 kacfm operation, one of the multiclones was taken offline by closing a damper in the ductwork. This action kept the tube velocity higher in the operating unit for improved particle capture efficiency at reduced operating loads.

The moist, particle-laden gas exiting the dryer proceeds to two parallel multiclones where entrained particles (30 microns or larger) are captured. For the relatively finer particle size fed to the multiclone, the collection efficiency was around 85%. When coarser material was fed to the dryer, the multiclones operated at up to 90% efficiency.

From the multiclones, the gas stream continues to the venturi scrubber-condensers, where the remaining lignite fines are removed, and the evaporated water is condensed for recovery and reuse. Each dryer system has four scrubber condensers. The venturi scrubber collects the larger particles with an average size of 12 microns, while the water being condensed collects the ultrafine particles with an average size of 3 microns.

The scrubber-condensers are arranged in pairs so the exhaust from one multiclone feeds two of the scrubber-condensers. This design keeps system efficiency higher when operating at reduced throughput with the gas flowing through one multiclone and two scrubber-condensers.

The venturi section was located at the inlet to the condenser (figure 5.1-68). In the venturi, the gas velocity was increased, and water was sprayed into the throat. This spray creates small water droplets that intermingle with the lignite particles and become entrained with them. An adjustable throat with a pneumatically actuated damper allows adjusting the pressure drop across the venturi for optimal droplet size and maximum separation efficiency.

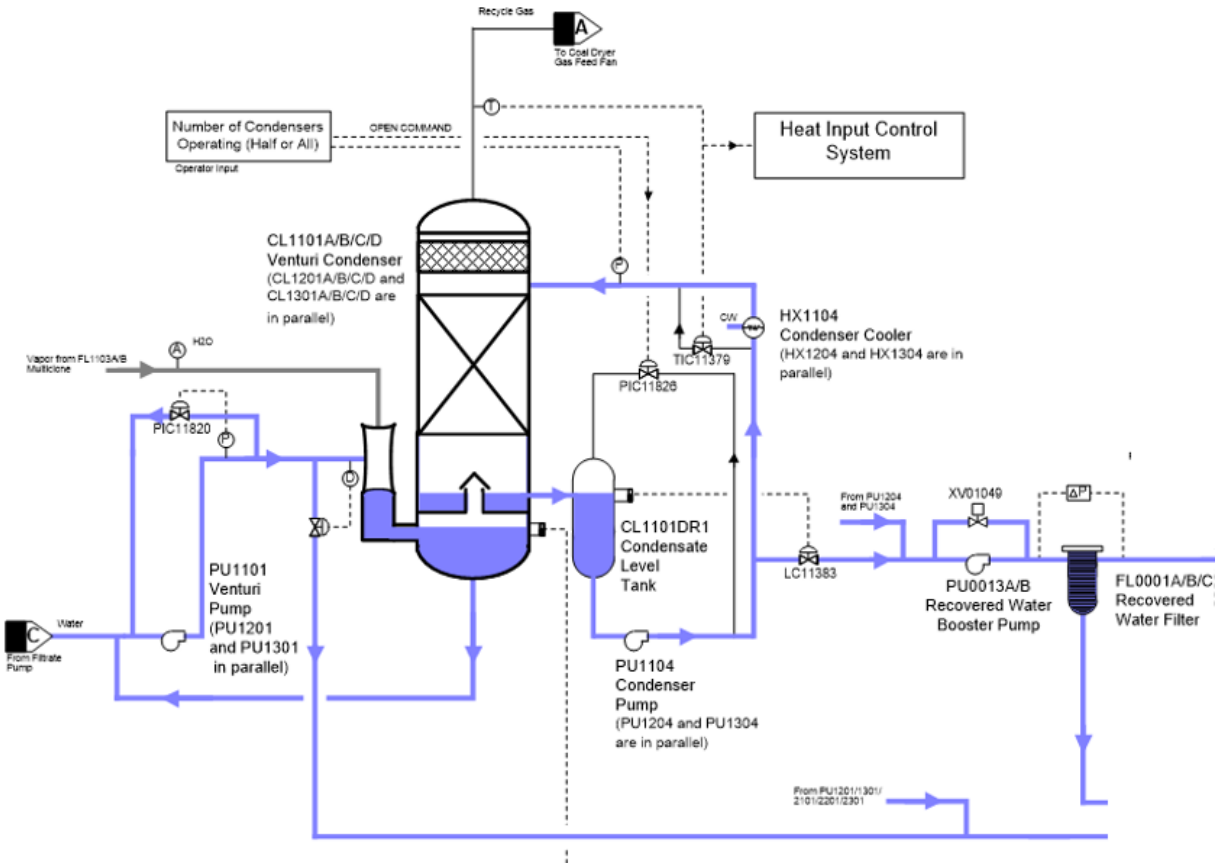


Figure 5.1-67 – Venturi condenser

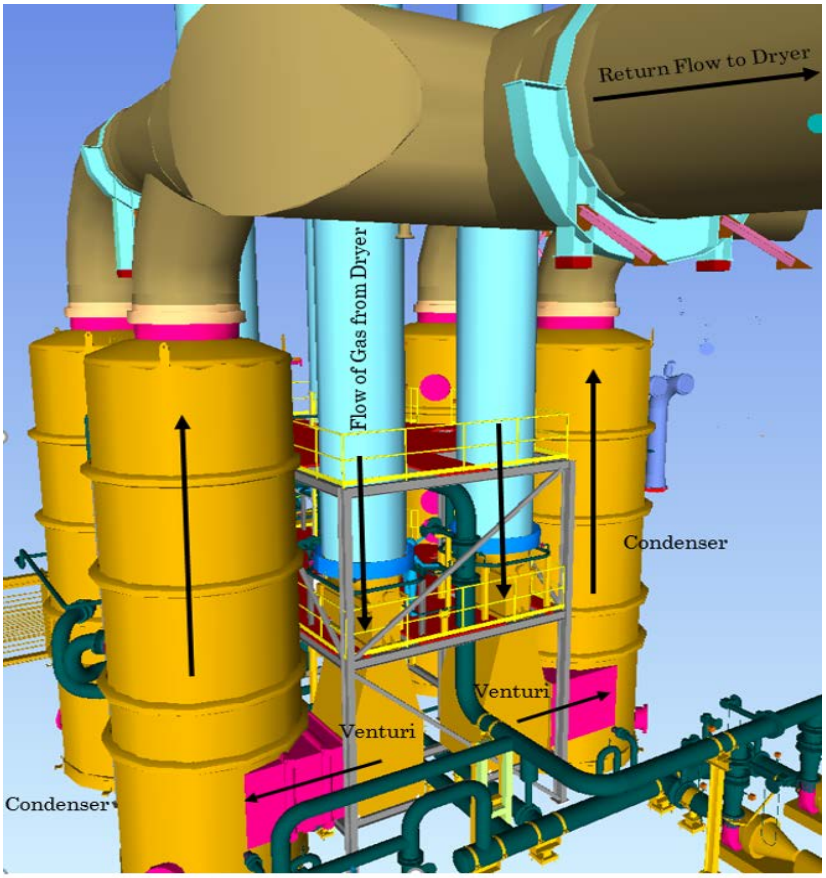


Figure 5.1-68 - Venturi scrubber-condensers

From the venturi scrubber, the gas passes into the lower section of the condenser. The inlet to the condenser is tangential and acts like a cyclone separator to drop out the particulate laden liquid. The liquid collects in the sump in the lower section of the condenser. See figure 5.1-69.

The saturated gas continues upward through a chimney tray, which allows the gas to move upward while the water from sprays in the condenser flows down to the sump. The chimney tray helps distribute the gas across the cross section of the condenser.

There is a packed bed several feet above the chimney tray to condense water. Recirculated water cooled in a plate and frame heat exchanger is sprayed onto the packed bed counter current to the gas flow, which lowers the temperature of the gas below the saturation point. Above the packed bed, a mist eliminator traps entrained water droplets and allows the gas to exit free of entrained water droplets.

The scrubbed gas from the condensers is combined in a common duct that terminates at the inlet to the dryer fan and the gas preheater before returning to the dryer.

The water level in the four condenser sumps is maintained at the desired level using level controls. Excess water flows by gravity to a common condensate level tank. There was one condensate level tank for each set of four condensers.

A recirculating pump takes water from the condenser sump and supplies it to the venturi sprays. A portion of the water is diverted to the filter press mix tank to control the solids content of the water in the sump and condensate level tank.

The condensed water can either be recycled to the condenser sprays or filtered for use as plant process water. A plate and frame heat exchanger in the recirculating loop cools the condensate with cooling tower water. The heat exchanger cools the flow, which can range from 1,700 gpm to 7,200 gpm, from approximately 124 ˚F to about 90 ˚F. A bypass

loop allows the water to bypass the heat exchanger during low flow conditions, when the low ambient temperature makes the heat exchanger provide too much cooling, or for maintenance and cleaning. A minimum flow must be maintained through the heat exchanger to prevent plugging from solids in the water. The minimum flow and solids content varied due to changing concentration of fines going to the condenser. When the dryers were started on pit lignite, the TSS for the condenser was at or near the design of 1,000-2,000 ppm, but when running finer lignite from the lignite storage pile, the TSS was 10,000-20,000 ppm. A duplex strainer was placed in the loop ahead of the heat exchanger to remove material greater than 2 mm to prevent it from plugging. This strainer required replacement with a more robust system to prevent plugging the heat exchanger plates with solids. See section 5.1.6.3, Significant Events.

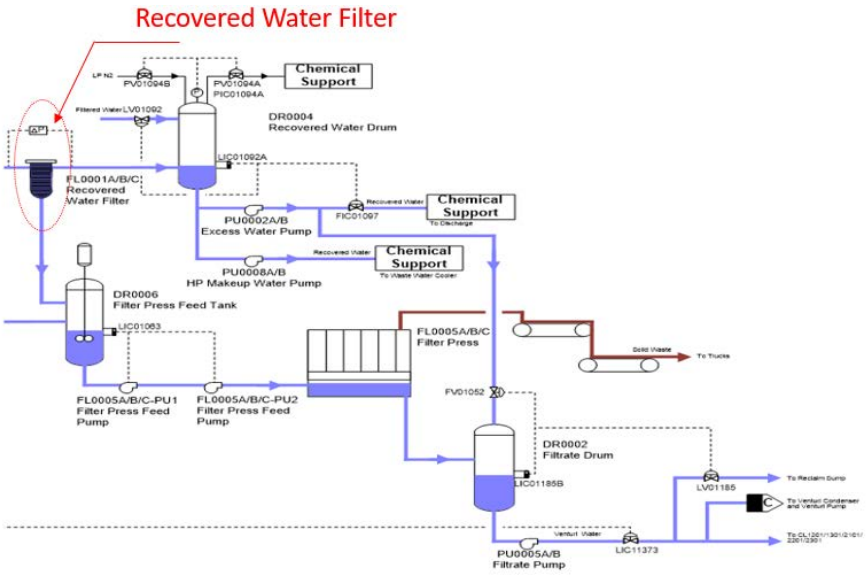


Figure 5.1-69 - Integrated flow diagram recovered water system

Excess water that was not recirculated to the condensers was diverted to the recovered water booster pumps for feeding to the three recovered water filters (figure 5.1-67). The recovered water filters operate in parallel, generally with two units online and one being cleaned. The filters use candle-style elements to remove solids from the recovered water. The water enters the units through radial inlets located below the filter elements, flows upward through the filter elements, and exits through a tube sheet at the top of the unit. This water is suitable for use in the downstream processes.

The dried solids travel through the dryer, exiting at the discharge end through a collection hopper to a set of vertically stacked rotary feeders. A manual slide gate is located above the upper slide gate to allow maintenance on the rotary feeder. The upper high-pressure rotary feeder sets the rate of withdrawal of solids and maintains the level in the dryer. The lower rotary feeder operates at 10% above the speed of the upper rotary feeder to prevent choking the upper feeder with solids. It also assists in minimizing gas flow between the dryer and the pulverizer.

- Lignite to the pulverizer

Crushed lignite silos can be deinventoried through the pyrite system. The pyrite system will operate in high capacity mode during this operation. A maximum of one silo can be deinventoried at a time, due to the rate capacity of 60,000 lb/hr for the deinventory rotary feeder from the silo. The dryers can be deinventoried during a train or plant shutdown through the pyrite removal system. Only one dryer can be deinventoried at a time due to the high throughput of lignite in this mode.

The rotary feeders discharge to the dryer discharge screw feeder (section 5.1.4), which transports the dry lignite to the pulverizer. The feed screw has two outlets. The main outlet is at the end of the screw and feeds the pulverizer. An intermediate outlet allows bypassing the pulverizer to enable emptying the dryer. An actuated slide gate in the screw conveyor trough is connected to the pyrite drag conveyor system. To deinventory the dryer without using the pulverizer the gate is opened, and the lignite inventory of the dryer conveyed to the pyrite discharge station, where the material can be emptied into trucks.

A second outlet in the dryer discharge chute, located next to the main chute, feeds a chute that connects to the outlet moisture analyzer. When the analyzer is operating, a rotary feeder meters a slipstream of lignite to the analyzer. The lignite is re-injected into the main chute and conveyed to the pulverizer.

5.1.7.2 *Initial Commissioning Plan*

- Dryer feed test package overview

Before the test package, all checks had been completed including valves, instruments, pumps, motors, fans, heat exchangers, pressure checks and pressure control tuning, and system integration checks. The venturi condenser, filter press, and candle filter had been operated with water. The next step in the lignite preparation process was to integrate the equipment by running lignite through the system. The dryer test package objectives were to test the equipment on feeding, drying, pulverizing, and filtering lignite, which included running lignite on some equipment for the first time.

Each vendor developed an hourly plan to schedule assistance and checks by the I&C, inside operator, lignite prep outside operator, and the vendor technician. The hold points for the test packages were developed for small logical steps to ensure reliability before the next operational step was taken. The following major steps were planned as hold points for the integrated dryer and pulverizer systems with lignite.

- Lignite commissioning steps

As part of startup plant the following equipment will be operated at increasing rates and observations will be made on operational characteristics for any deviation from original intent. Also, evaluations will be made for the planned commissioning objectives for this equipment described below.

1. Lignite silo - fill 150 tons

   Major equipment in the system

   - Crushed lignite silo SI2202.
   - FD1119 crushed lignite silo deinventory airlock.
   - Lignite silo dust collection.
   - Lignite silo baghouse exhaust blower.

   Objectives for equipment checkout

   Fill silo and test NAC feed system.
   Test tripper car controls.
   Test crushed lignite silo level instruments.
   Test deinventory system.

2. Lignite feed at 10 kpph

   Major equipment in the system

   - FD1102 weigh belt feeder.

- FD1112 roll crusher airlock.
- Roll crusher ML2207.

Objectives for equipment checkout

Set and calibrate weigh belt feeder.
Set and calibrate dryer crusher.
Validate associated alarms, controller set points, controller-valve responses, interlocks, and related solenoid-process control valve operations.
Address any discrepancies and note any vibration problems or air leaks.

- Check Merrick feeder and set roll crusher.
- Check coal conveying equipment: FD1112/FD1121/1122/1108/1124/1125/1103.
- Test and tune pyrite drag chain system with truck loading.
- Test and tune ash conditioner MX0002A.
- Check PC baghouse operation.
- Check A multiclone.
- Check dryer fluidization and grid plate dP checks.
- Test and d siftings system air flow.

3. Lignite dryer and pyrite at 10 kpph and 50 kpph

Major equipment in the system

- Inlet lignite dryer extraction screw PG2202-FD1.
- Inlet lignite dryer return screw PG2202-FD2.
- Fluid bed dryer PG2202 FD1121.
- Dryer outlet HP rotary valve.
- FD1122 dryer outlet LP rotary valve.
- FD1108 fluid bed dryer discharge feeder.
- Fluid bed dryer discharge feeder FD2208.
- Multiclone FL2203A/B.
- Pulverized lignite cyclonic baghouse FL2204.
- SI0035 pyrite holding bin and extendable load chute.
- FL0035 Pyrite baghouse.
- FN0035 Pyrite baghouse fan.
- FD0035 Pyrite baghouse airlock.
- Venturi condenser CL2201A/B/C/D.
- Recovered water drum DR0004.
- Recovered water filters FL0001A/B/C.
- HP Make-up water pump PU0008A/B.
- Excess water pump PU0002A/B.
- Filter press feed tank DR0006
- Filter press feed pump FL0005A-PU1/2, BPU1/2, CPU1/2.
- Filtrate drum DR0002.

Objectives for equipment checkout

Validate operation of pyrite system.
Verify multiclone discharge drag chain amps.

Calibrate dryer sifting valves.
Set and verify crusher calibration.
Verify dryer fluidization.
Verify dryer bed dP and temp readings.
Analyze evaporative loads.
Verify multiclone performance.
Validate baghouse operation and pressure drop.
Verify pulverizer baghouse cleaning efficiency performance.
Verify venturi scrubber performance.
Check operation of condenser pump strainers.
Calibrate venturi density meter.
Check filter press solids content.
Tune TWS heat exchanger and bypass controller.
Shallow fluid bed dryer operation.
Fan performance data.
Validate of associated alarms, controller set points, controller-valve responses, interlocks, and related solenoid-process control valve operations.
Address any discrepancies and note any vibration problems or air leaks.
Test and tune gas preheater and inbed heat exchangers.
Test and tune humidity controller.
Test and tune condenser heat exchanger
Test and tune ash conditioner MX0002A.
Test and tune candle filters.

4. Lignite dryer and pyrite test at 50 kpph + 50 kpph until 200 kpph

Major equipment in the system

- Pulverized lignite cyclonic baghouse FL2204.
- Pulverizer ML2208.
- ML1108 coal pulverizer.
- FN1106 coal pulverizer feed fan.
- FL1104 PC cyclonic baghouse.
- FN1105 PC cyclonic baghouse flush fan.
- FD1104 PC cyclonic baghouse airlock.
- MX0002A/B/C/D ash conditioner.
- CL0009A/B ash conditioner vent scrubber.
- PU0011A/B ash conditioner vent scrubber pump.
- BL0009A/B ash conditioner vent scrubber blower.
- FL0012A/B/C/D ash silo secondary baghouse.
- HX0083 ash storage secondary baghouse air cooler.

Objectives for equipment checkout

Baghouse clean efficiency performance.
Pulverizer checkout and tuning.
Take particle samples and test pulverizer performance while varying operating parameters.

The commissioning of the fluid bed dryer system was conducted during the dryer test package in November 2015. The main components of the dryer loop were tested first: initial lignite feed to the wet lignite feed system, fluid bed dryer, multiclone, venturi condenser, and FBD fan. The pulverizer gas loop components were also tested. The equipment

had to have lignite to test its functionality and the components relied on instruments for control, making this a challenging task to complete all at once. The commissioning plans for the dryer feed system are listed in the previous section as steps 1 through 4. Steps 1 and 2 are detailed in section 5.1.6, Dryer Feed. After the feed system was functional, lignite could be sent to the dryer. In step 3, when lignite started coming out of the dryer at a 10 kpph rate, the pyrite system would be tested and tuned. The dryer fan was in operation and the multiclone and PC baghouse would be receiving gas and fines carryover, so these systems could be tested and tuned. Lignite would be carried to the venturi and condenser, which would test the carryover from the multiclone to the venturi. The plan was to calibrate the inlet and outlet dryer lignite moisture meters and the venturi density meters within the first few days. During this step 3, the filter press and candle filter could be tested to filter the lignite from the multiclone carryover. After the mechanical functionality was tested, the plan was to increase lignite feed from 10 to 50 kpph during step 3. After the pyrite was tested at 50 kpph, the lignite would be diverted to the pulverizer to begin step 4.

Testing the pulverizer also tested the ash mixer. When all the mechanical systems were tested and tuned, the dryer gas preheaters, dryer hood humidity probes, and condenser heat exchanger could be tested. When the dryer moisture control tuning was complete, the pulverizer tuning for particle size control would begin. The lignite feed was increased up from 100 kpph to 200 kpph and the pulverizer was tuned during this part of the test package. After the pulverizer was tuned, the lignite feed type was switched from screened pit lignite to screened pile lignite and the pulverizer tuning was checked for variation in parameter with a different type of particle size. See table 5.1-23 for test package dates.

Table 5.1-23 – Dryer test package dates

Test Package	Begin	End
Dryer 1	11/6/2015	1/15/2017
Dryer 2	11/29/2015	1/15/2017
Dryer 3	10/10/2016	1/15/2017
Dryer 4	8/8/2016	1/11/2017
Dryer 5	5/4/2016	1/12/2017
Dryer 6	2/26/2016	1/12/2017

5.1.7.3 *Significant Events*

- Oxygen meter repair

From the August 2015 dryer condenser run, it was also determined that the oxygen analyzer for the dryer and pulverizer baghouse were not functioning properly. Oxygen and carbon dioxide content are measured for safety and risk mitigation to maintain a low oxygen content and reduce the risk of fire or dust explosion in the dryer or the pulverizer baghouse. Figure 5.1-70 shows particle size distribution in relation to the NFPA definition of combustible dust. In the graph, everything to the left of the red line is considered combustible dust because it is less than 420 microns. During dryer design, it was identified that during idle periods with heat in the dryer, devolatilization of the lignite can occur. When this happens, the lignite releases its own oxygen, and begins the smoldering process. To mitigate this process, the oxygen content of the gas in the dryer needs to be maintained below 8%. In the presence of high CO, more nitrogen needs to be added to the dryer loop to stop the smoldering. After a few weeks of working with the vendor and field troubleshooting, new motherboards were ordered for the analyzers. All analyzers had the same problem and the new components were ordered and changed out. The first two boards came in within 6 weeks for one dryer train. To repair

all the instruments, it took 3 months. The analyzers were unreliable at times and would read out of range even with nitrogen in the system. A team was developed in March and worked with the manufacturer to improve the reliability. The manufacturer determined that the cabinets and component filter, chillers, pumps, and sensors needed to be serviced and by April 2016 everything was working properly.

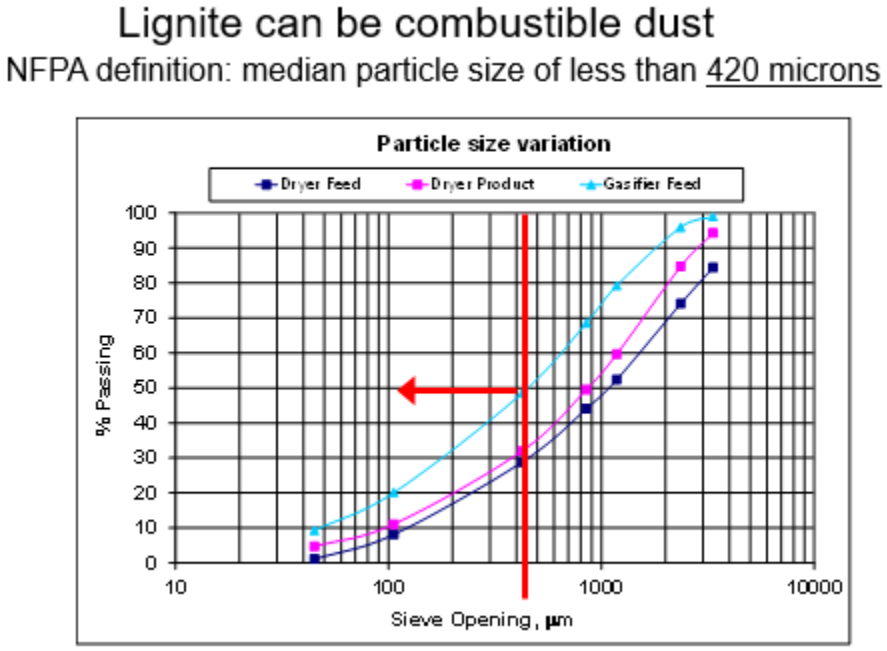


Figure 5.1-70 – Lignite particle size distribution

- Dryer HP nitrogen deluge valve changeout

In late October 2015, before the first dryer test package, the high pressure (HP) nitrogen deluge valve developed a slight leak that caused the dryer to remain under higher pressure when the system was not running. This nitrogen leak-by was continually vented to the baghouse to maintain dryer pressure. Before the dryer test package was started, the valve had to be changed. This problem would reoccur later in the year during the operations phase. A permanent solution was developed to eliminate the valve seat from being cut by the HP nitrogen.

- Steam condensate return

In November 2015, the first day of operation was on tempered water system. The steam condensate system had a delay because the condensate would not properly drain back to the header. In evaluating the piping network, it was determined that a booster pump could be used to transfer the condensate back to the condensate return header. However, the most cost-effective solution was to increase the condensate piping diameter from 1in. to 3 in., which would reduce friction loss and allow steam pressure to push the condensate back to the header. This change was being made when the project was suspended in 2017.

- Baghouse vacuum condition

During the first week of dryer operation, the plan was to deinventory the dryers through the pyrite system to test the equipment and tune the controls, the first time lignite had ever been fed to the equipment. The dried lignite that exits the dryer can be fed to either the pyrite system or the pulverizer. Both systems were fed by an inclined screw conveyor with an intermediate outlet with slide gate to empty the dryer into the pyrite drag conveyor system for disposal. The pulverizer loop normally operates at about 50 in. W.C. to prevent the influx of air. During the initial operation of the

deinventory system, the circulating gas from the pulverizer loop vented through the screw conveyor outlet as the slide gate was opened. This sudden outflow of gas caused the cyclonic baghouse, which is normally pressurized, to be subjected to vacuum. The valve was quickly closed to prevent damage to the baghouse. To temporarily manage this condition during pyrite deinventory, the nitrogen deluge valve was used to add nitrogen to the dryer, which could vent gas to the pulverizer baghouse and maintain pressure. As a more permanent equipment solution to this problem, a rotary feeder was installed in the screw conveyor intermediate outlet to limit the amount of gas that could exit the system. A nitrogen fed pressure control valve set at -1 in. W.C. was installed in the baghouse to prevent vacuum excursions.

- Condenser pump strainer pluggage

The condenser heat exchanger HX2204 (figure 5.1-25) was a plate and frame heat exchanger with small gap openings between its plates. When the dryer was operating in a turned down condition, this reduced flow rates through the heat exchanger and resulted in solid particles settling and plugging the gaps between the plates. Diverting the flow from the heat exchanger with bypass valve TV-22370 diminished the flow and the minimum required flow rate of 2,000 GPM could not be achieved to prevent plugging. With this process flow rate limitation on the heat exchanger, focus was placed on the strainer of the heat exchanger to limit the size and quantity of particles entering. The initial strainer for HX2204 had a mesh size of 2 mm. When the strainer plugged, it caused high dP and stopped the heat exchanger working.

In January 2016, the condenser pump strainer baskets were on the repair plan. During the November 2015 dryer run, the basket strainers were damaged when they plugged (figures 5.1-71A and 5.1-71B). An insert was added to the strainer to decrease the mesh size to 2.5 mm. The insert, a fine perforated plate, required frequent backwashing. It proved to have inadequate structural integrity and was in use for only a short time before the pressure collapsed it. The next short-term fix was to use different mesh with stronger reinforcing so the baskets could capture material and not be damaged. The metal mesh would be replaced to limit the size of particles that could pass through the screen. There were trials of multiple mesh sizes, but none proved effective. Since the fines were so small, they would form a bridge over the very fine mesh. When the size was increased and bridging was not a problem, the particle was the size of the heat exchanger gap.

The condenser strainer plugged with material that was not anticipated in the design. The purpose of the strainer was to collect large material like condenser packing or tramp material larger than 2 mm. It was not expected that a 0.0025 mm particle would bridge the opening, or that it would build up with fines. The condenser fines d50 was 2.5 microns. The strainer was not designed to be cleaned online. When the fines bridged together or agglomerated, they plugged the 2 mm slots. During operation, the basket strainers plugged within 1 to 3 days. After the baskets bridged, the dryer and condenser had to be taken offline and the baskets cleaned or swapped out. After 1 month of off and on dryer operation, the baskets were taken out of the strainers and no baskets were used by March 2016.

A more permanent solution using a self-cleaning strainer with a fully automatic backwash system was designed, but not implemented. The automatic strainers used 1.5 mm wedge wire screens to prevent oversized particles from entering the heat exchangers (figure 5.1-71C). The original baskets were taken out of service while the new strainers were being fabricated. A new strainer was ordered with a wedge wire designed screen that would be able to withstand the pressure requirements of the system. The slot opening size of the screen was 1.5 mm and it was equipped with an automatic cleaning and backflushing system. The new strainers were onsite in May 2016 but were not installed for another year as commissioning operations could be sustained with the existing setup. The new strainers were in service the last month before operation was suspended.

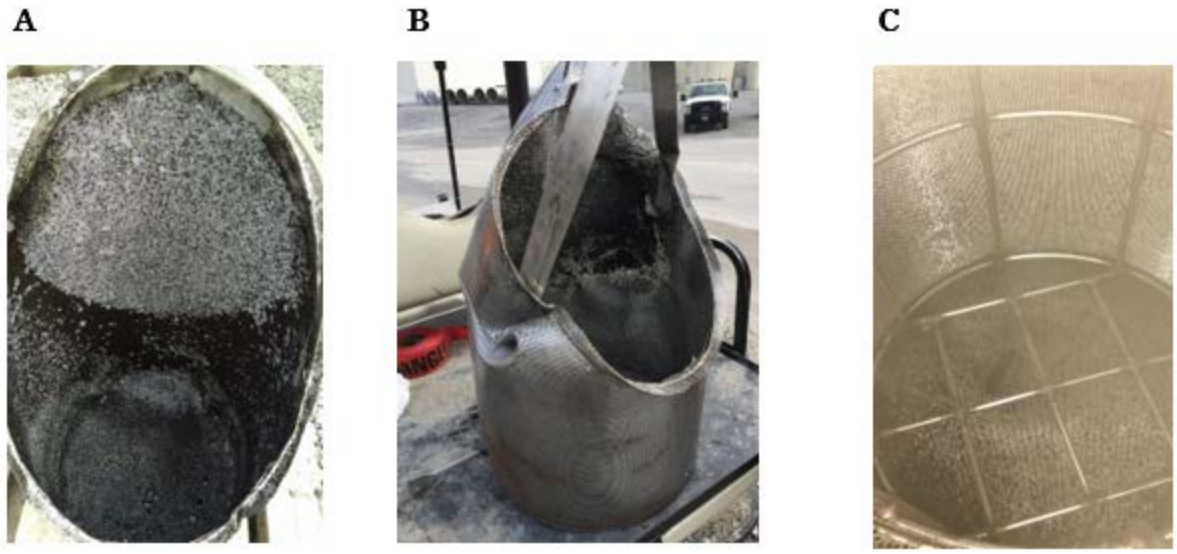


Figure 5.1-71 – Condenser heat exchanger basket strainer

- Condenser heat exchanger pluggage

Another equipment change was recommended in January 2016 was a backwash system for the venturi condenser heat exchanger. The venturi condenser heat exchanger was designed for high velocity flow and low solids concentration. When the velocity dropped due to operational needs or the solids concentration increased in the condenser water, solids would settle between the heat exchanger plates, causing pluggage and short-circuiting, resulting in less overall heat transfer for the process. There was no provision in the piping design to backflush this system. The heat exchanger had the backflush ports built on the housing, which made it easy to add a flex hose backflush system. The backflush addition began in February 2016 and took 2 weeks per condenser.

The condenser heat exchanger had a manual twin-basket strainer ahead of the heat exchanger to prevent tramp material from plugging the heat exchanger (figure 5.1-72A). The original baskets were designed so they could only be manually swapped from A to B, with no plans for cleaning while the condenser was in operation. The lignite fines plugged the original mesh strainer baskets, requiring a new design. A new style online 1.5 mm wire strainer (figure 5.1-72B; also see condenser pump strainer pluggage section) was designed and purchased in March 2016. When this exchanger plugged with fines or tramp material like bits of condenser packing, the material would be backwashed to the sump and sent to the LDF.

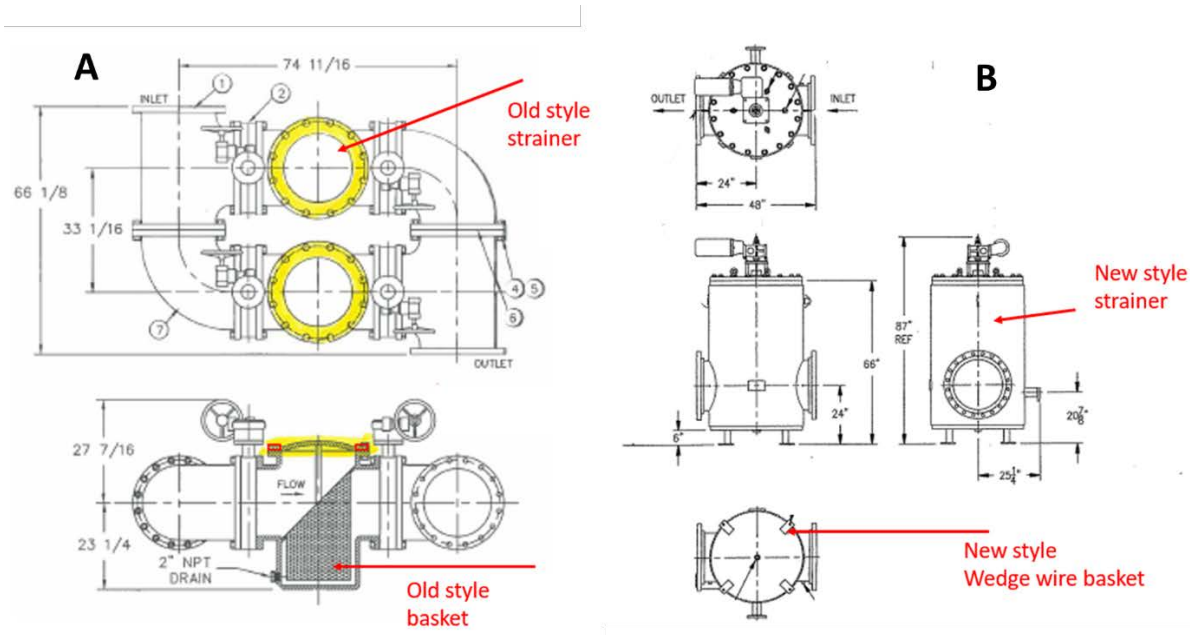


Figure 5.1-72 – Condenser heat exchanger strainer change

- Multiclone hopper leak

While the rotary feeder problem was being evaluated during this dryer run, other significant problems were found with the system. The recovered water system filtration capacity began to slowly decrease due to filter plugging, and after 3 weeks of operation the throughput was about 25% of what it should have been. After about 3 weeks of sporadic operation, these fines built up behind the insulation of the multiclone hopper and began to come out of holes found in the hopper. After the problem was found, operations were ceased until hopper repairs could be made and the holes sealed. A reinforcing pad for the hopper heaters was collecting the fines from gas leaks on the hopper wall. A small weep hole is normally left in the weld, or a small hole drilled in a reinforcing plate, to prevent corrosion or some other hidden flaw that could lead to future failure. The weep hole vents trapped gas and prevents molten metal from blowing out when the final weld seam is closed. This hole was leaking the lignite fines behind the hopper insulation. The insulation had to be stripped off the hopper, each hopper wall heater removed, the weep spots around the leaking welds found, the leaks closed, and everything reinstalled for operations. The multiclone repairs took 1.5 weeks per multiclone hopper.

- Manual dryer slide gate changeout

During the November dryer run, it was determined that the outlet manual slide gate (figure 5.1-73A) was not effective for isolating the rotary feeder during a slumped dryer bed. When the bed slumped, a large pile of lignite packed directly on top of the rotary feeder and bound it in place. If the manual valve was closed above the feeder, the rotary feeder would start up freely. The manual valve above the feeder was not designed to close through material, and the valve shaft bent and rendered it useless. Every time the dryer was shut down or the bed was allowed to slump, the outlet feeder had to be cleaned out or no lignite could leave the dryer because the feeder was bound in place. A new automatic knife gate slide valve was ordered and replaced the manual valve. The valve ordered was a custom solids handling slide gate valve (figure 5.1-73B) for each dryer. It took 10 weeks to be delivered to the plant. The total time required to replace these valves from the time of failure to delivery and installation was 5 months.

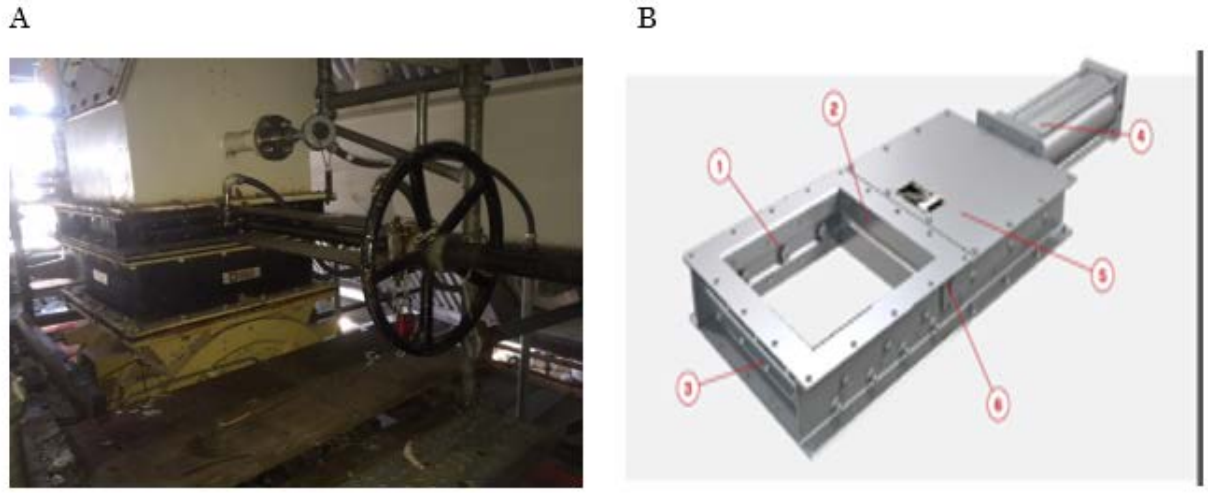


Figure 5.1-73 – Condenser heat exchanger strainer change

- Dryer feedzone buildup

During the November 2016 dryer operational run, the dryer feedzone intermittently would build up with petrified wood and other rocks (figure 5.1-74). Not all of the lignite feed to the dryer could be screened, and 3- to 4-in. material would enter the dryer and plug up the feed zone. As long as the material was this size, it did not appear to harm operation. There were several times when loud crushing noises were heard by the outside operator and much bigger pieces were taken from the dryer.

Figure 5.1-74 – Heavy oversized rock in dryer feedzone

- Recovered water filter trial

The candle filter operation was a single point of failure for the gasifier operation. Without the integrated evaporated water, the downstream gasifier processes would not be able to operate. The dryers were expected to produce water at about 800 gpm or 1.15 MMGal/d. Since the original candle filter media was not working, this failure was recognized as a major problem for the gasifier startup. An aggressive strategy was developed, and outside coal filtration experts were contacted for advice and expertise. Other filter media vendors and some original bidders for the candle filter unit were sent condenser water samples for testing. A filtration company with research capability was brought to Kemper to study the candle filter problem as well as the LDF sump settling and filtration problem.

On February 8, 2016, there was an onsite pilot test of new media to solve the recovered water filtration problem. The trial was coupled with the dissolved air flotation (DAF) pilot system trial towards the end of the month. Since the DAF trial was being done in conjunction with the filter media trials, the DAF was considered for a stand-alone solution and a polishing step for filtration. At times, the filter media pilot unit was used in series with the DAF system. The trail was planned as an experiment with different media brands, types, and pore size to determine a direct replacement for the elements in the candle filters. (See figure 5.1-75 for failed filter design.) While the trials were being run onsite, an outside solids lab was hired to test powdered metal filters and a disc-and-drum filter with diatomaceous earth precoat. Other testing was evaluated by the outside lab, which said centrifuge, ceramic, and electrocoagulation would not be cost effective with the particle size application or slurry concentration. After filter media trials at Kemper, there also was a trial running a diatomaceous earth precoat to evaluate the filter performance and capacity. The lab work and onsite pilot work produced a recommendation to switch the original media from a woven fabric with Teflon liner to an expanded polytetrafluoroethylene (e-PTFE) membrane filter that provided good filtration results in the lab and pilot work (figure 5.1-76). The Startup team bought and installed a set of elements for a single candle filter body in April 2016 for the upcoming gasifier run in July 2016. From the pilot work, it appeared a single set of filters could support all the flow for one gasifier. The other two sets of filters would not arrive until June 2016 because they were not a stock item for order. The intense trial work took 6 weeks to complete, and it took only 3 months for this solution to be put in place.

Figure 5.1-75 – Failed candle filters

Figure 5.1-76 – Successful candle filter pilot

- DAF trial to support candle filter operation

On Feb. 25, 2016, the dissolved air flotation (DAF) system trial was operated using aluminum sulfate (alum) as a coagulant and Megafloc 3890 cationic polymer as a flocculant. The objective was to repeat the results of a previous test performed Feb. 19, 2016, in which greater than 99% removal efficiency of solids was achieved. The solids leaving the condenser had a particle size distribution heavily skewed toward an ultrafine particle size. Particle size analysis performed Feb. 19, 2016 showed a D50 value of 1.2 micron (figure 5.1-77). These ultrafine particles caused the candle filters FL0001 downstream of the process to blind before a cake could develop. Typically, with wider particle size distributions, larger particles that cannot pass through the filter media will start to form a cake without blinding the media. This cake will filter the finer particles. Over time, as the cake develops, the pressure drop across the filter will

increase and the flowrate will gradually decrease, at which point the system must be backwashed to remove the cake. The lack of coarser particles exiting the condenser was causing the filter media to blind before a cake could develop. Multiple attempts had been made to backwash the filter media.

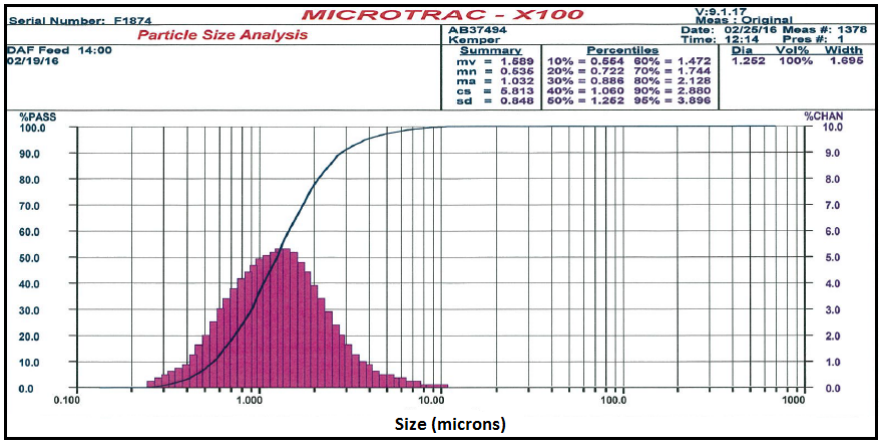


Figure 5.1-77 - Particle size analysis

On Feb. 25, 2016, influent water from the frac tank was sent to the DAF pilot unit (figure 5.1-78) to validate the success of the test performed the previous week on Feb. 19, 2016. The influent water was fed at a flow rate of 4 gpm to the first stage of the DAF system, the flash tank. In the flash tank, the feed was blended with aluminum sulfate (alum) coagulant at a dose rate of 750 ppm and with as hydroxide to maintain the pH at 6.7 to 7.0. The fine lignite particles in the influent feed stream are negatively charged and hydrophilic. The coagulant converts the particles from hydrophilic to hydrophobic. The stream then proceeded to the flocculant tank, where it was blended with polymer 1128BD, a cationic polymer, at a dose rate of 15 ppm. Jar tests performed by a local polymer vendor the same day (Feb. 25, 2016) indicated that polymer 1128BD cationic polymer would service as a replacement for Megafloc 3890. In the flocculant tank, the lignite particles combine with the polymer to form flocculants (flocs). From the flocculant tank, the feed enters the DAF vessel, where the flocs attach themselves to air bubbles bubbled in at the base of the DAF vessel. The air increases the floc buoyancy and causes them to float to the surface where they are skimmed off the top.

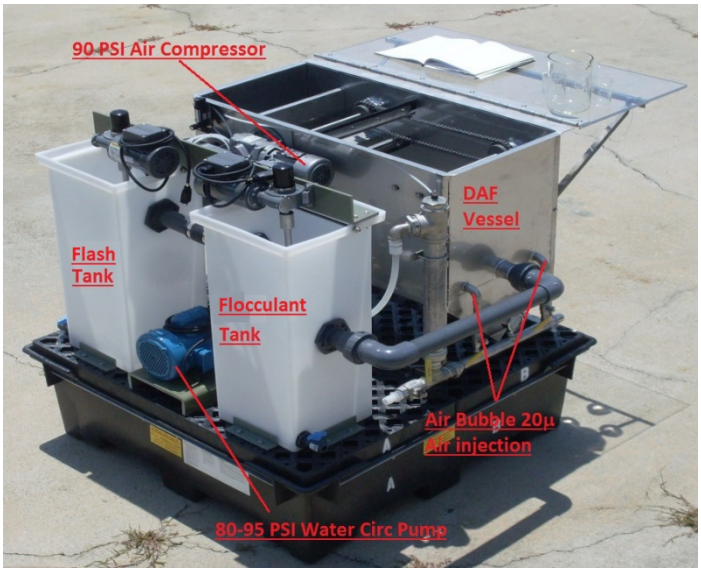


Figure 5.1-78 – DAF pilot unit

Although the same criteria were implemented as the trials performed the previous week on Feb. 19, 2016, successful separation of lignite fines could not be achieved. Physical inspection of the flash tank showed the formation of lignite agglomerates was insufficient to form flocs of adequate size. The coagulant was gradually increased from 750 ppm to 1,500 ppm to improve agglomeration, but this had no effect. Jar tests were run on the condenser feed and found that 1128CT (sodium aluminate) might work better as a coagulant. The following day, Feb. 26, 2016, testing resumed using sodium aluminate as a coagulant. Sodium aluminate was added directly to the flash tank, since it cannot be diluted because the aluminum would precipitate out. No sodium hydroxide was needed because the sodium aluminate raised the pH, but aluminum sulfate (alum) was added to lower the pH to the desire pH range of 6.7 to 7.0.

The sodium aluminate with the cationic polymer 1128CT coagulated and flocculated the solids, but flotation in the DAF vessel was not occurring. The anionic flocculent polymer 414 was added in conjunction with the cationic polymer to encourage flotation of the solids in the DAF vessel. The sodium aluminate was dosed at a rate of 280 ppm, a 0.20% cationic polymer 1128CT solution at 175 ml/min and a 0.05% anionic polymer 414 at 75 ml/min. The addition of the anionic polymer significantly improved flotation of the solids, but optimal separation of solids from the effluent could not be achieved.

The study was ongoing and the chemistry was still being evaluated to determine which chemistry would properly coagulate and flocculate solids for removal in the DAF system. The concentration of solid in the influent was significantly higher on Feb. 25 and Feb. 26, 2016 than in the initial tests on Feb. 19, 2016. While doing jar testing of the influent stream, the solids were allowed to settle to the bottom of the beaker. On Feb. 19 the solids settled to approximately the 100-ml mark, while on Feb. 25 and Feb. 26, the solids settled at approximately the 350-ml mark, a factor of 3.5 more solids. Over the course of the 6 to 7 days that separated the run of the tests, the solids in the frac tank had time to settle to the bottom, significantly increasing the concentration of solids in the influent stream.

Despite the less than optimal effluent being discharged, two 300-gallon totes were filled with effluent from the DAF unit so it could be run through the pilot candle filter the following day, Feb. 27, 2016. Two sets of tests were performed on the pilot candle filter, a 14-micron sock and a 3-micron sock.

The first test showed the 14-micron sock could not filter out most of the solid particles. The smaller 3-micron sock blinded quickly from the excess polymer in the solution. Over time, the samples got progressively worse (figure 5.2-79) because the totes were filled the night before and the solid particles had time to settle to the bottom of the tote. Comparing sample 7 with the effluent from the previous day, it was apparent that sample 7 had considerable more suspended solid particles. It appeared the 14-micron sock was breaking the flocs into smaller particles as it passed through.

The second test had less excess free polymer in solution, and the 3-micron sock performed considerably better than the 14-micron sock at filtering out solid particles. However, over time the flow rate decreased and the pressure drop across the filter increased considerably. After backwashing four times with water and once with plant air, the flow rate never fully recovered (table 5.1-24). Although the 3-micron sock performed better (table 5.1-24), the solid particles blinded the media. During the runs in table 5.1-24, the flow rate dropped off from about 17 gpm to 3 gpm, did not recover after the backwash, and then quickly began to drop off in flowrate back to about 4 gpm.

Table 5.1-24 –Flow rate and pressure for 3-5 micron sock

3-5 micron Sock			
Sample	Flow Rate [gpm]	Pressure [psi]	
1	17.65		
2	15.79	22	
3	12.5	40	
4	5.36	60	
5	3.85	60	← Backwashed
6	7.89	58	
7	4.41	60	

- DAF trial summary

The DAF pilot proved that air flotation works for separating ultrafine particles, but it is not effective when the process varies with both pH and charge. During the DAF trial, the pH varied enough that an acid and base had to be added to keep the polymer working effectively. When enough clay was present, the polymer became completely ineffective and a new polymer needed to be added to combat the positively charged clay. It was determined that DAF was not robust or cost-effective enough for lignite slurry separation.

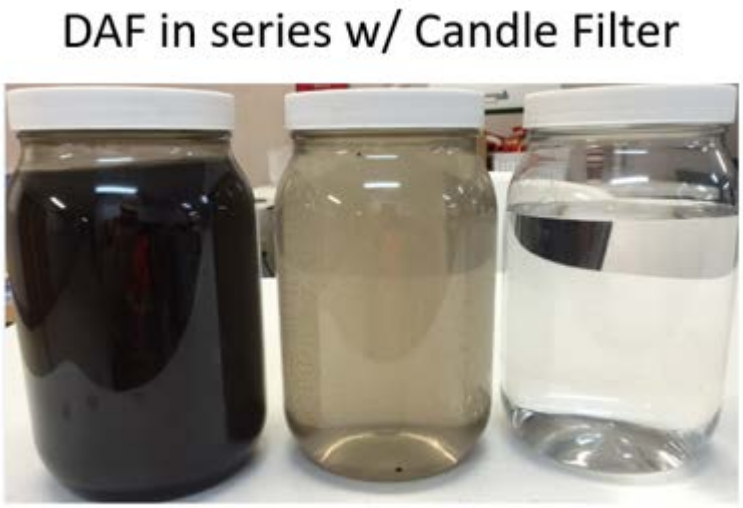


Figure 5.1-79 – Trial for DAF candle filter results

- Dryer fan flow meter erratic

In March 2016 during the commissioning of the fluid bed dryer system, it was determined that with the varying conditions of the venturi condenser, the fan flow meter was providing erratic readings. The 3-pitot tube array was installed across the 10-ft ductwork downstream of the venturi condensers and just upstream of the dryer fan. The selected vendor used the pitot array to get a more representative average of the overall duct since it was a large diameter. The flow meter was a gas monitor system and initially used a multivariable dP transmitter, with the fan flow being calculated in the DCS based on the dP measurement. The initial design of the instrumentation setup did not consider the level of lignite dust and water that would be present and plug the pitot array. During original gas flow, it appeared the fan flow meter was functioning. As lignite dust and water were introduced into the gas stream, it became evident there was an issue and the reading were inaccurate. Maintenance was called in to blow out the lines, and the reading would improve for a short time and then return to erroneous readings. It was determined to install a purge. Dryer 2 was outfitted with the purge controller in August 2016, and the frequency was set to an hourly pulse for ~3 to 5 seconds. Testing was conducted under true operating conditions, and it was determined that the flow was calculating accurately. Testing continued for a 2-week period with no significant deterioration of signal accuracy. It was then determined to implement on the remaining five dryers, but this work was not done before operation was suspended.

The pulverizer fan used the same flow meter setup as the dryer fan flowmeter, but that service was assumed to be dirty and came installed with the automatic blowback purge. From initial startup, there was not a problem with the quality of that flow signal.

- Pulverizer analyzer problems

In March 2016, the pulverizer particle analyzer vendor was brought onsite to troubleshoot the automatic sampling and operation of the analyzer. The analyzer allows the operator to make real-time adjustments to the pulverizer speed and pulverizer classifier speed based on changes in lignite feed rate, temperature, and moisture. There is a required size

distribution for the lignite particle size leaving the pulverizer. It was important to control the top size of the lignite as well as the fines produced from the pulverizer to the high-pressure lignite feed system and the gasifier. With the changes the vendor made to the analyzer, the meter could be used for testing and tuning the pulverizer control parameters. See section 5.1.7.4, Summary, for results.

- Rotary feeder motors undersized

With the new rotary feeder in place, it became obvious the rotary feeder was working better but the feeder was still tripping excessively. It was determined the motor was undersized, causing the feeder system to trip on high current. Both the inlet and outlet rotary feeders tripped frequently and would not restart under load because of undersized motors. New motors were ordered, and both were changed from 10 hp to 20 hp. The total time required for part changes and testing was about 12 weeks to receive the motors and complete repair of all six trains. Other motors on the ash mixer rotary feeder were determined to be undersized and were replaced, yielding positive results. While the larger motors reduced tripping of the rotary feeder, it did not entirely solve the problem. To reduce the rotary feeder pocket from plugging with wet lignite, 30 psig nitrogen cannons were added to the feeder on the empty side of each dump cycle to blast nitrogen into the pocket and help purge any remaining lignite. The nitrogen cannons and motors were easy to obtain and install. Four of the rotary feeders were fitted with a nitrogen cannon within 1.5 months. The other two trains were not fitted due to the cannons' lack of success.

- PRV reseating difficulties

A pressure relief valve protected the dryer hood from over-pressure from the two high pressure sources, the dryer fan and the nitrogen deluge system. In April 2016, four of the pressure relief valves on the dryer began to lift due to operation close to the PRV setpoint. The relief valves were pilot-operated tank vents set initially to relieve at 55 in. W.C. The valves began relieving at 50 in. W.C., so that the maximum pressure when wide open would not exceed the dryer design pressure rating. When the pressure in the dryer loop approached the relief valve setting, it caused the seal to flutter on the seat. This flutter allowed fine particles to become trapped between the seal and the seat. Although the relief valves were supposed to reseal, they did not. The result was excessive leakage of gas from the dryer loop. This prevented operating the dryer at the desired pressure. The manufacturer proposed an engineering fix to the valves. It included a tapered seat instead of the flat seat and added a nitrogen purge to the valve seat to blow dust away from the seat and allow the valve to reclose after it was lifted during a high-pressure event (figure 5.1-80). Two valves were rebuilt with these modifications and two more valves were sent to the factory to be reset. Half of the dryers had this repair in place by the time the first gasifier was online in July 2016. Working with the vendor, it took 1 month to come onsite and find a solution. It took another week to make the valve repairs per valve.

Operating parameters were adjusted to help avoid the PRV relieving, but these changes limited dryer throughput. Some of the time the PRV lifting was due to incorrect fan flow meter reading, which caused the dryer operator to set the fan flow too high. When the high flow occurred, it over-pressured the dryer and caused the PRV to lift. Sometimes the PRV would easily reseat and not get stuck, but most often when it lifted it would be stuck open, which fully depressurized the dryer and forced operations to take an outage to reset the PRV.

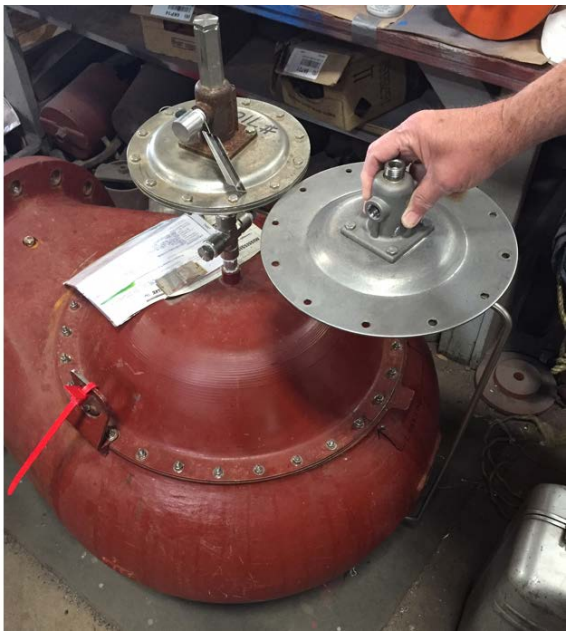


Figure 5.1-80 – Dryer PRV valve

- Wet lignite related complications

In March 2016, it was observed that the NAC operation was adding excessive water fogging on the transfer points of the belt conveyor system delivering lignite to the crushed lignite silos. The fogging was designed for a lignite feed of 2.4 million lb/hr, but the startup operation was only running about 100,000 lb/hr. The spray system used 180 nozzles to distribute 74 gpm on to the lignite to prevent the lignite from dusting as it dropped from one transfer belt to the next. This spray increased the water content of the lignite between 3% and 8%, which made the lignite more difficult to feed. Additional logic was added to the NAC belt logic to turn off the water fogging when the lignite was not on the belt. This improvement helped prevent water from being added needlessly to the crushed lignite silos.

The mined lignite varied between 42-46%. The lignite delivered to the plant had higher moisture than this level. Lignite above 50% water was determined to be caused by the LDF belt conveyor dust control water spray. The performance of the spray system was evaluated, and manual controls were put in place to adjust the water flow based on the rate the dryers were running. The manual setup was unreliable since the rate to the dryer would vary based on startup operation. An automated system was needed as a long-term solution.

- Sludge pump and header pluggage

Candle filter sludge header tie-ins were made June 29, 2016.

The discharge of each of the three recovered water filters was connected into a common 10-in. horizontal header that reduced down in steps to a sludge pump with a 2-in. inlet and outlet. The sludge was pumped to DR0006, the filter press feed tank.

The header and the pump were prone to plugging by the sludge, which thickened quickly in the filter hoppers. Initially, the outlet from each filter used a pipe cross with the discharge on one of the horizontal legs. The thickened solids stream settled in the horizontal pipe, causing the flow to stop.

The pipe cross was replaced with a vertical pipe section. The outlet valve was relocated into the vertical pipe run, which helped alleviate the plugging in the discharge fitting. There were still issues due to the high solids content sludge settling in the discharge piping. The centrifugal sludge pump (figure 5.1-81) was replaced with a pneumatically driven reciprocating piston pump. This substitution helped to improve flow, but the sludge left in the pipe at the end of each cycle continued to settle in the pipe and cause the pipe to plug.

To provide a flushing system, the common 10-in. header into which the three filters discharge was extended by lengthening the pipe upstream of the first filter feed point. This extension created a reservoir to provide water to help flush the solids from the pipe during and after each cycle. An automatic valve allowed refilling the flush pipe with process water. Since more solids were being processed by the filter due to the finer lignite feed, the size of the sludge header holes had to be increased for the candle filter sludge inlet header (figure 5.1-82). The original pump supplied with the recovered water system had to be replaced with an easy-to-obtain pneumatic sludge pump with a mine duty centrifugal pump and wear-resistant impeller and housing. The long-term plan was to replace this pump with another a centrifugal pump after startup was complete.

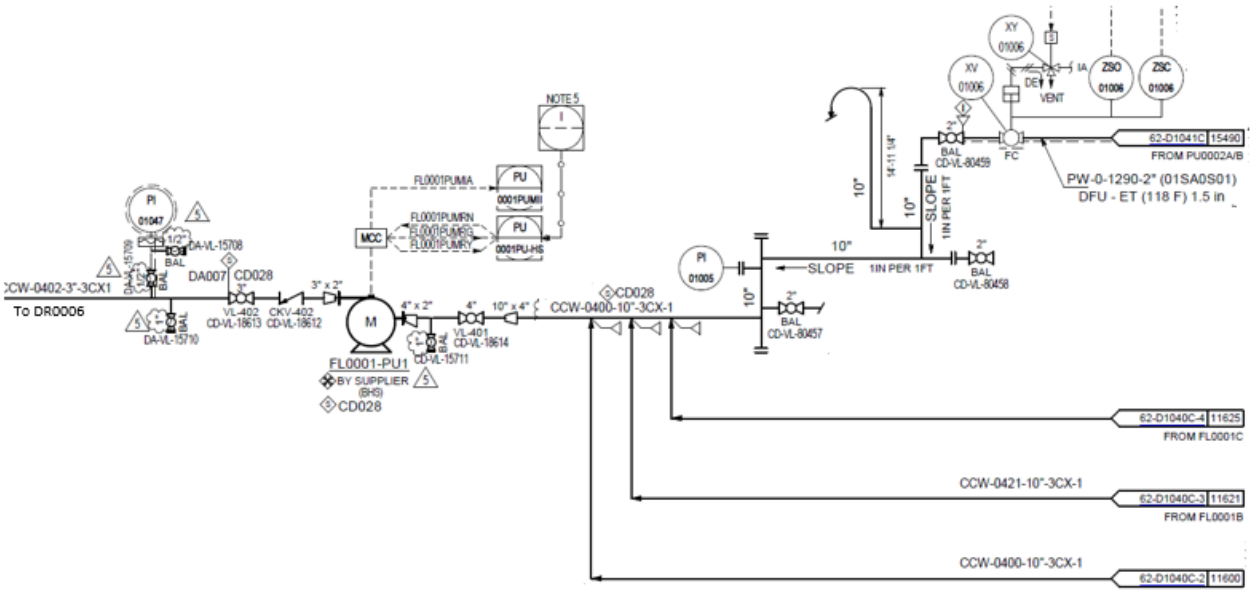


Figure 5.1-81 – Recovered water sludge pump

Figure 5.1-82 – Recovered water sludge header

- Dryer inlet expansion joint replacement

The dryer inlet expansion joint broke due to the nitrogen cannon. The large quick nitrogen release into the rotary feeder pockets helped break up the sticky fine lignite stuck inside the rotary feeder vane. However, it caused an expansion

of the flex joint, which rubbed a hole in the joint over a few months. The repair (figure 5.1-83) was performed in May 2016. It added a backing bar to stiffen the joint and prevent it from rubbing on the housing.

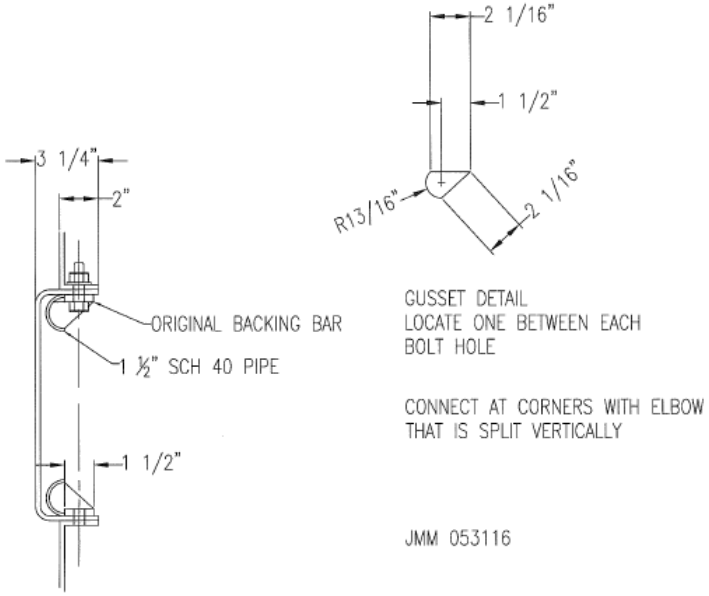


Figure 5.1-83 – Expansion joint repair

- Dryer inlet rotary feeder eductor difficulties

The dryer inlet rotary feeder limits the amount of gas vented up through the inlet. The dryer operates at a normal pressure of about 45 in. W.C. The crushed lignite silos are at atmospheric pressure. The dryer inlet rotary feeder acts as an airlock to limit the amount of gas that flows out of the dryer, through the feed system, and into the crushed lignite silos. The rotary feeder operates at constant speed. The lignite feed rate was regulated by the weigh belt feeder.

A venturi eductor operating on low pressure nitrogen was connected to the rotary feeder gas vent. A motive gas flow of approximately 100 acfm induces a flow of about 200 acfm, which was the gas flow up through the rotary feeder. This motive gas flow prevents the upward flow of moisture-laden gas into the weigh belt feeder. The combined gas was discharged into the gas duct that connects the outlet of the multiclones to the venturi-condensers.

The rotary feeder vane configuration combined with overly moist lignite created feed problems. During development of configurations to improve rotary feeder performance, a six-vane configuration was tried. With the six-vane configuration, the feeder inlet and vent are within the same pocket for a short period of time. The amount of material vented exceeded the eductor capacity to convey. The final configuration for the rotary feeder used a seven-vane configuration that corrected this condition. In the final configuration the eductor functioned properly.

- Dryer fan modifications

During an outage in March 2016, the dryer fans were fitted with new dorsal fins and repairs were made to the wind box. These changes improved the dryer fan ductwork vibration and allowed for successful and unhindered operation for the fluid bed dryer in all fan flow operational zones with and without lignite in the dryer.

- Dryer inlet expansion joint

The dryer inlet expansion joint failed a month after the nitrogen cannon was installed on the inlet rotary feeder. The nitrogen injected into the feeder helped clean out the pocket but the eductor (vent) on the rotary feeder was not designed for the amount of nitrogen flow from the cannon. The high-pressure pulse of nitrogen expanded the expansion joint each time the nitrogen cannon operated. The repair plan included stiffening the joint and moving the stiffener that supported the fabric joint to the side.

5.1.7.4 *Final Summary*

- Dryer operation

In November 2015, when lignite was first fed to the fluid bed dryer, the solids handling problems indicated the equipment design limitations. The dryer feed systems' highest feed rate was 50 kpph (figure 5.1-84). This feed rate only supported low dryer bed levels, due to the significant number of equipment trips on the weigh belt feeder and rotary feeder. (See section 5.1.7.3, Significant Events, for details, including repairs.) In January 2016, after the weigh belt feeder problems were corrected, there was a maximum of 200 kpph fed to the dryer, a substantial improvement from November 2015 (figure 5.1-85). After several iterations of rotary feeder changes, stable lignite feed to the dryer improved again to 175 kpph (figures 5.1-86 and 5.1-87). In June 2016, before gasifier operation, the dryers were more stable than they had been all year. All six dryers operated only 57 days from January through June 2016 (figures 5.1-88 through 5.1-93). The amount of lignite fed was limited by dryer feed problems and evaporated water filtration problems. From the early dryer operation, no real feed zone or fluidization problems were evident.

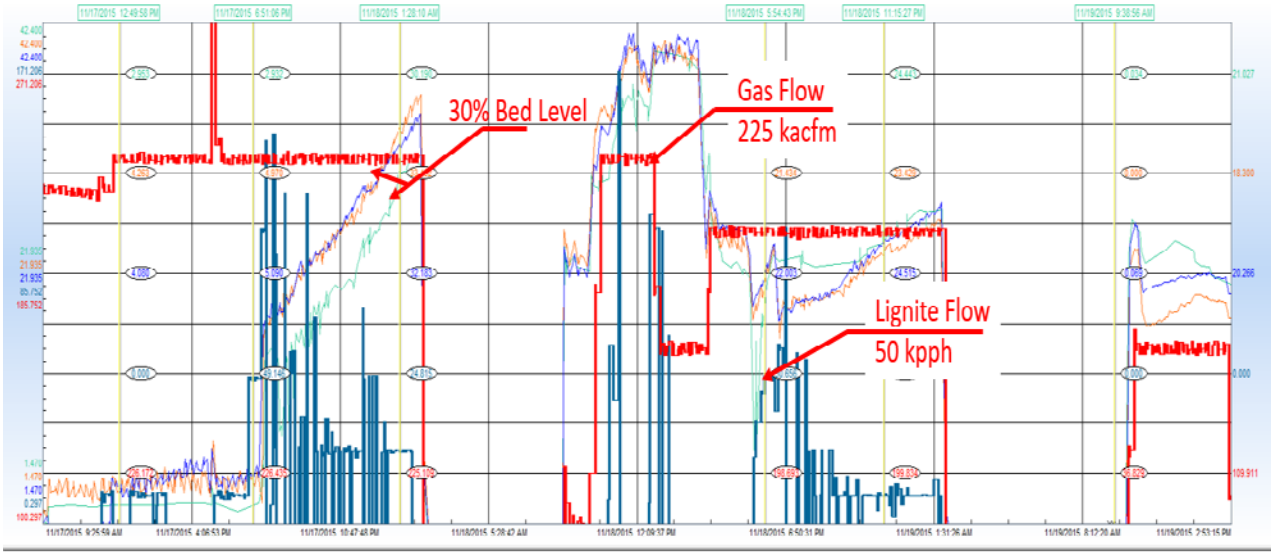


Figure 5.1-84 – #1 Dryer Operation-November 2015

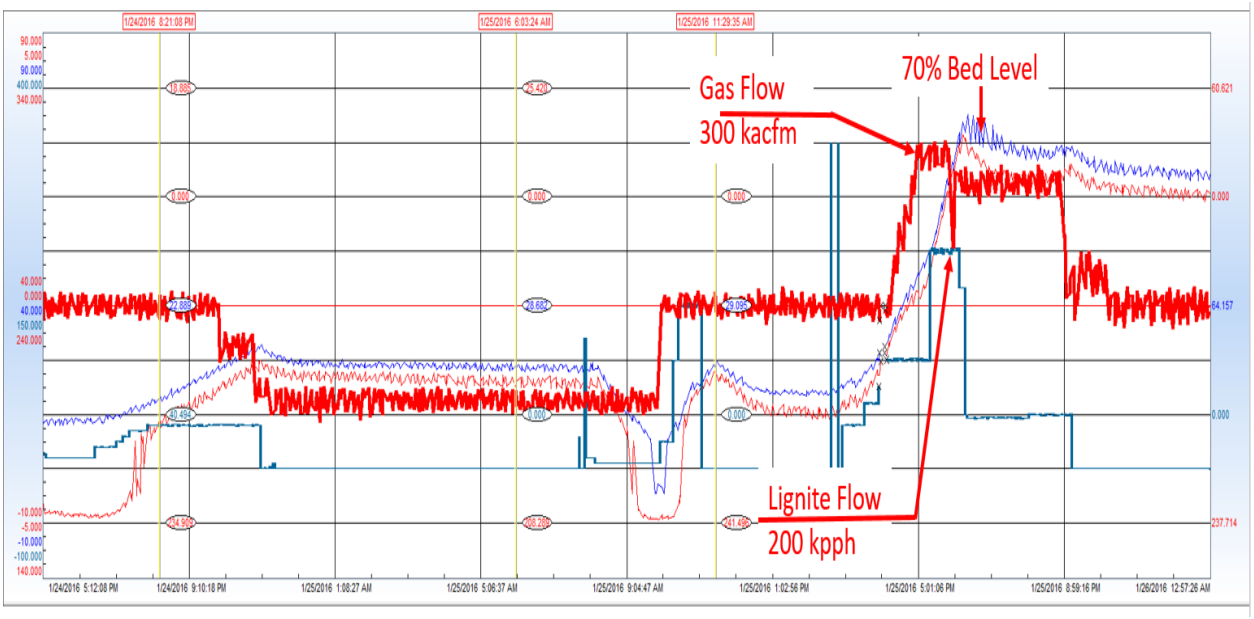


Figure 5.1-85 – #2 Dryer Operation-January 2016

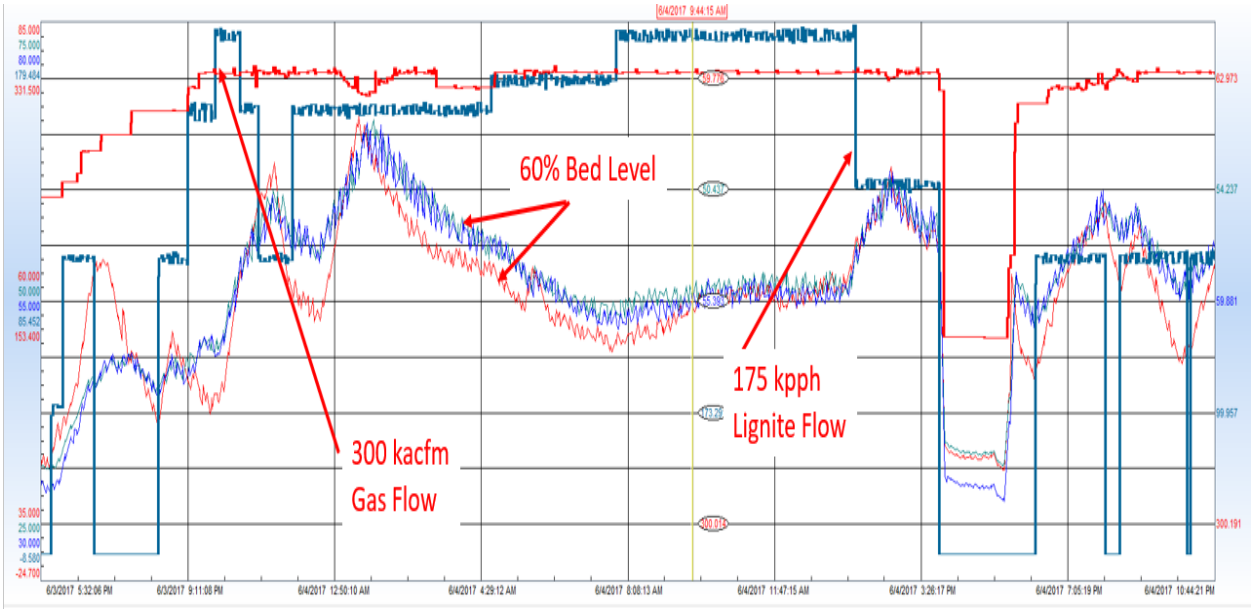


Figure 5.1-86 – #5 Dryer Operation-June 2017

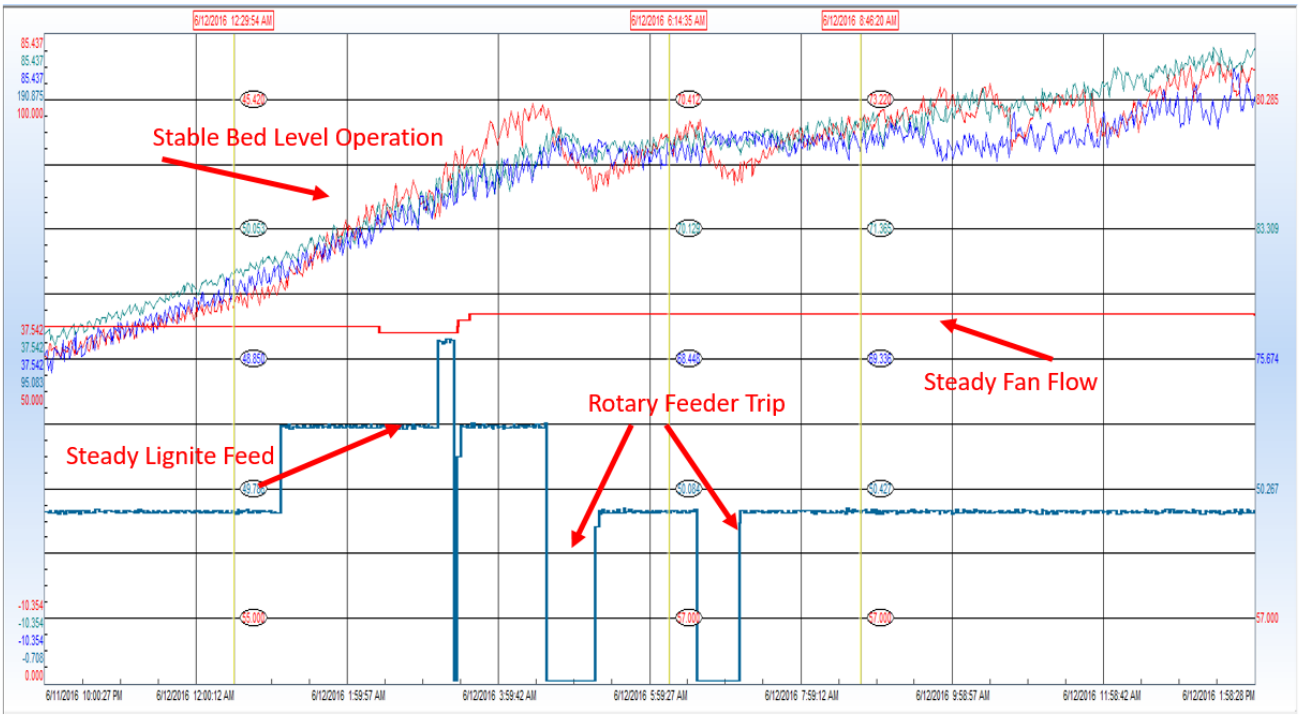


Figure 5.1-87 – #5 Dryer Operation-June 2017

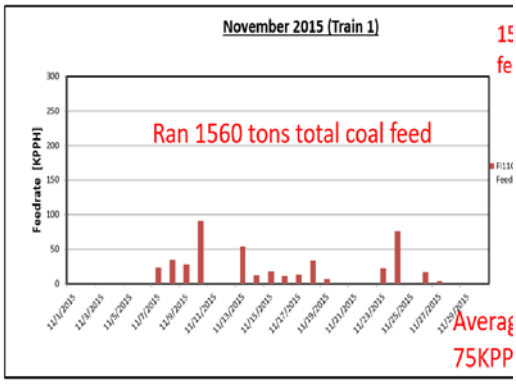


Figure 5.1-88 – FBD Production Data

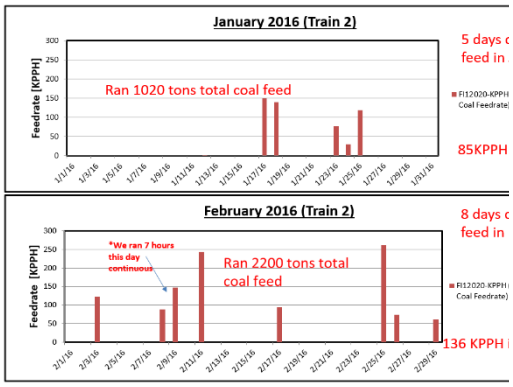


Figure 5.1-89 – FBD Production Data

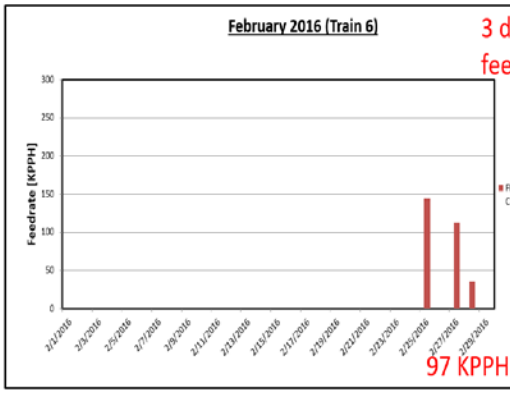


Figure 5.1-90 – FBD Production Data

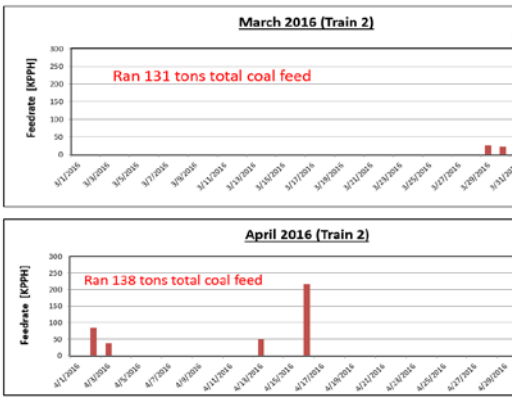


Figure 5.1-91 – FBD Production Data

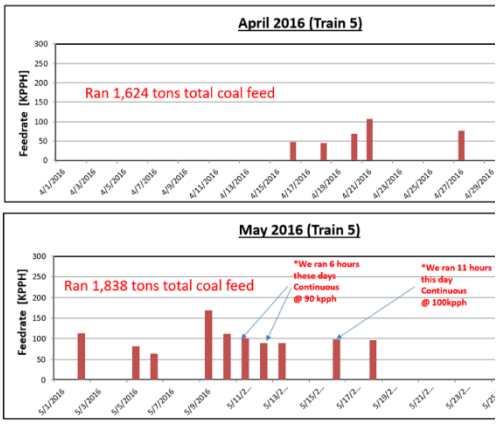


Figure 5.1-92 – FBD Production Data

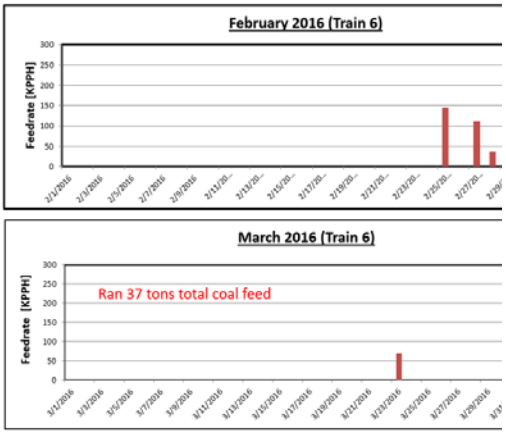


Figure 5.1-93 – FBD Production Data

The initial dryer run in November 2015 uncovered the lignite operational difficulties, which would have to be overcome for a successful dryer test package. The multiclone hopper fire due to pinhole weld leaks caused a delay. (See section

5.1.7.3, Significant Events.) After the pinhole leaks in the multiclone hopper were sealed, the dryer train was available for operation.

The inlet and outlet dryer rotary feeder operational issues required major design changes, which had to be completed before any dryer could have a successful dryer test package operation. The inlet rotary valve was switched from a 12-vane valve to an 8-vane valve. The dryer outlet feeder was already an 8-vane feeder, so after a new dryer outlet valve was delivered to the plant they were switched to the inlet valve. Wet lignite would not feed into sharp 12-vane angled pockets.

At PSDF, a simple rotary feeder was used. The pilot dryer had higher fines than planned for Kemper, but it did not have the high moisture fines in the feed material like the lignite dryers did at Kemper. The prebid package for dryer pilot testing sent to the supplier did not contain fine or wet lignite. The rotary feeder corrections were iterative due to the vendor's inexperience with wet lignite operation. The main approach to the feeder problem was to decrease the number of pockets and to add nitrogen cannons to clean the pockets. Solving rotary feeder operation problems was complicated, because the planned or design lignite was not expected to be as fine and wet except when emptying the pile of mined lignite. The solutions were temporary fixes to a problem that was not expected to be a long-term issue.

Other complications such as overloading the recovered water filters caused significant operational delays. The filters were scrapped 2 months into startup. In January 2016, 528 filters were removed from the filter housing. Without a means to filter the slurry, the water was processed to the LDF sumps. This change caused water management problems. The LDF could not filter or settle 100,000 gallons a day of slurry. The immediate plan was to evaluate other filters or technologies to support the slurry filtration. Section 5.1.7.3, Significant Events, covers these problems in detail and explains the repairs made to the equipment.

The condenser strainers and condenser plugged with fines and shut down the dryer operation. Approximately 20% of the dryer feed was fine material with a particle size lower than 1,000 microns (blue line in figure 5.1-94). The excessive fine material drastically increased the solids loading to the downstream venturi and condenser. The condenser solids content was 4 to 5 times greater than design. In figure 5.1-95, the black line represents a mined lignite crushed to 2-in. top size. This data was developed from crusher pilot studies using Mississippi lignite. The red line represents a 2-in. top size lignite and crushed to 0.5 in. top size.) The two changes for the condenser heat exchanger were the basket

strainer redesign and the backflush system addition. These field design changes took time to evaluate and implement, which further delayed the dryer operation.

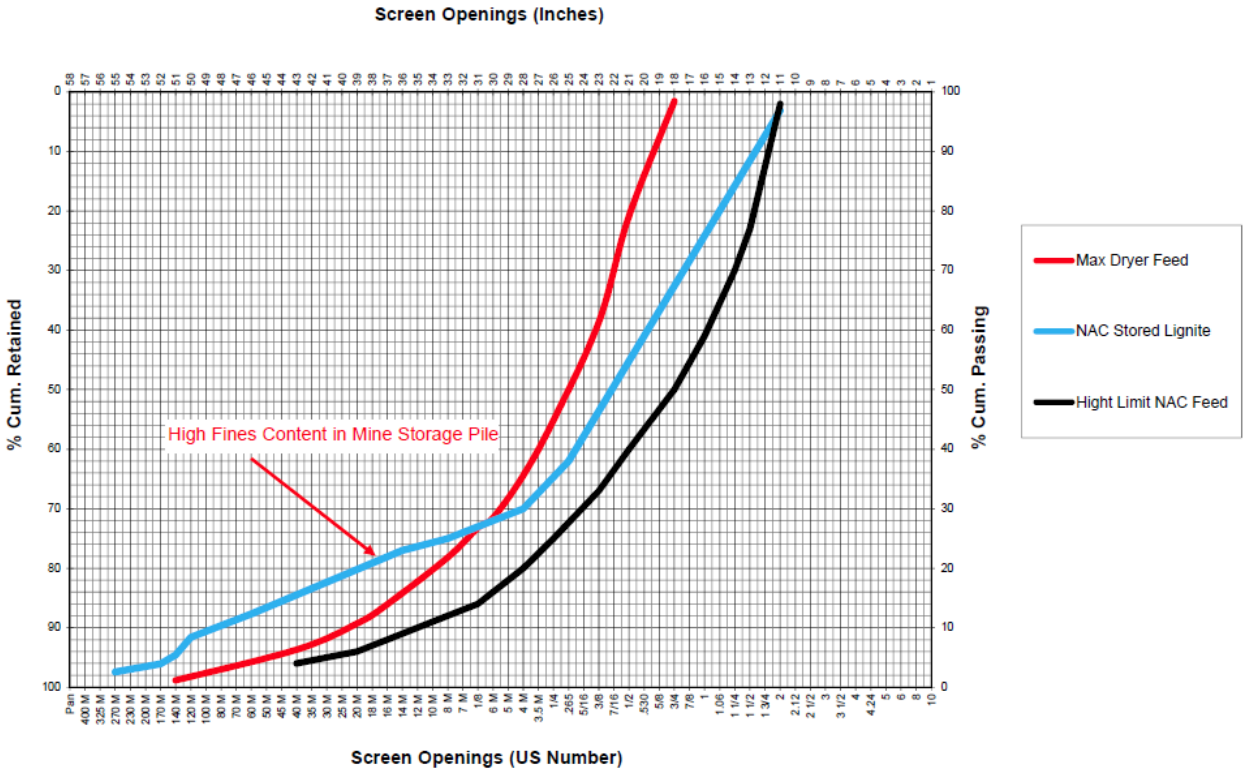


Figure 5.1-94 – LDF and dryer lignite particle size distribution

The easiest fix, which significantly changed dryer operation, was changing the manual slide gate valve above the dryer outlet rotary feeder. The new automatic valve was a solids-handling valve designed to break the flow of solids and not bind as it closed. Without this automatic slide gate, the feeder would plug when the bed slumped or collapsed, and the dryer would have to be shut down to clean out the feeder.

The dryer feed zone buildup was an intermittent problem had not yet been solved when operation was suspended. A successful prescreening system with secondary crushing for top size control would have been an important step to improve lignite feed quality.

Dryer operation was improved by correcting the fan flow meter, which appeared to be varying under the same dryer operational conditions. Investigation found the meter had drifted, which varied the fan flow reading by 40-60 kacfm. Water carryover from the condenser would build up in the flowmeter and cause the incorrect reading. The dryer operator would set the fan at the wrong operational setting for the fan flow, not knowing that the meter had drifted. The dryer fan flowmeter drift was suspected in February 2016, and afterward dryer feed zone fluidization was used as a parametric indicator to set the fan flow. This method of setting the fan flow caused overfluidization in the feed zone. This problem was temporarily fixed in June 2016 by adding DCS logic that followed the fan manufacturer's curve for flow, pressure, and damper position (figure 5.1-95). It was difficult to control the dryer fluidization without knowing the fan flow. If the fan flow was reading low, it caused operational problems like dryer bed level collapse. If the reading showed high flow, overfluidization occurred, which caused high carryover. With very high fan flow rates, the PRV would

be lifted, which would take the dryer offline until it was reset. In mid-June, a vendor curve was generated and integrated into the DCS logic to prevent under- or over-fluidization.

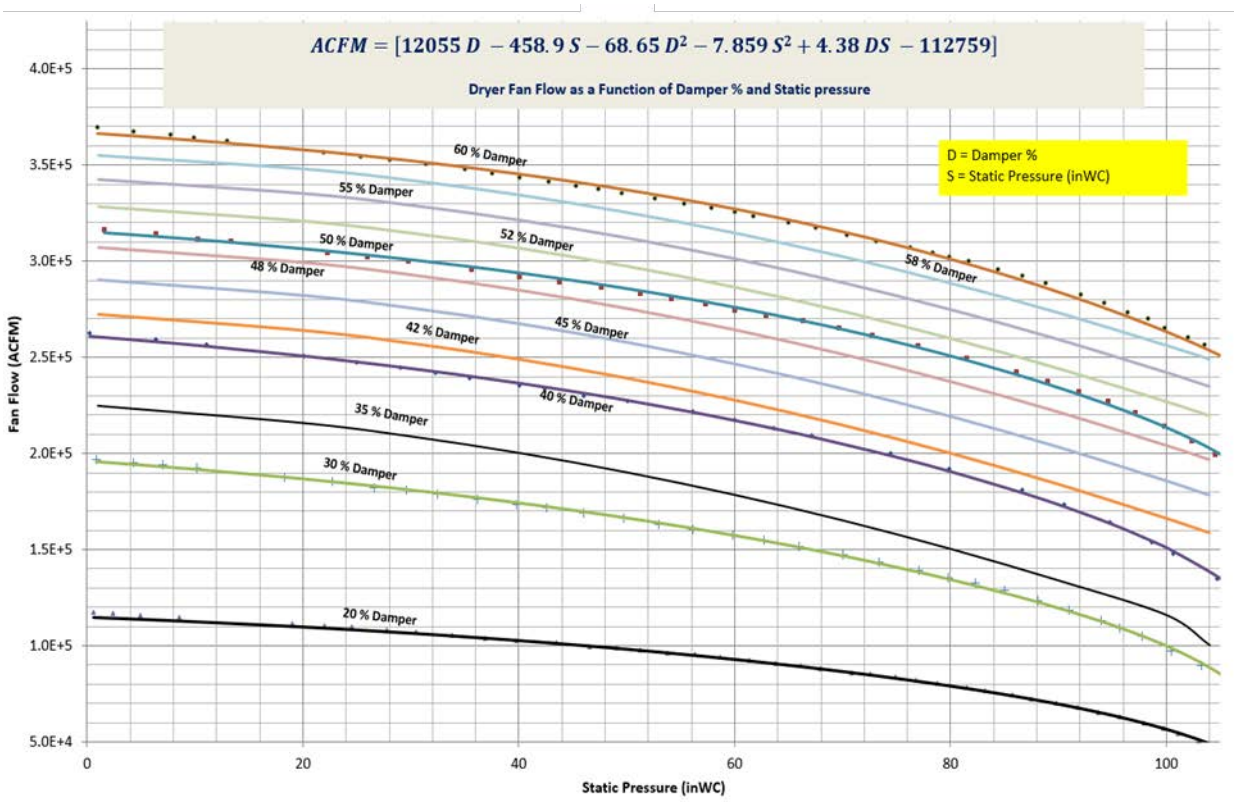


Figure 5.1-95 – Dryer fan flow versus damper position

- Multiclone operation

During the dryer run in November 2015, the plant used pit-run lignite that had been mined immediately before the dryer test package started. The main reason to run the pit mined lignite for the initial startup was that the dryer equipment was not designed for fine lignite and the equipment needed to be checked out under design conditions before the complicated task of running the fine lignite. The dryer, multiclone, venturi, condenser, filter press, and candle filter were not designed for the high fines content of the LDF lignite storage piles. The plan was to evaluate the initial carryover and filtration performance on this lignite. The mine had stored over a year's worth of lignite for both gasifiers at 100% gasifier feed rate. It was clear the plant would eventually be running the lignite that had already been mined. This initial checkout plan was to validate the equipment operation with design specification lignite. The dryer carryover to the multiclone averaged 11%. The low carryover was due to the coarser lignite feed (figure 5.1-96). If the amount of fine lignite in the feed to the dryer is lowered, the fines carried over to the multiclone, venturi, and condenser are lower. The carryover to the venturi and condenser was below the design targets for operation. About 550 tons was

sent to the dryer with 3 days of consistent low lignite feed rates for 15,16, and 29 hours. The multiclone efficiency was above 90%, which was the design operational target.

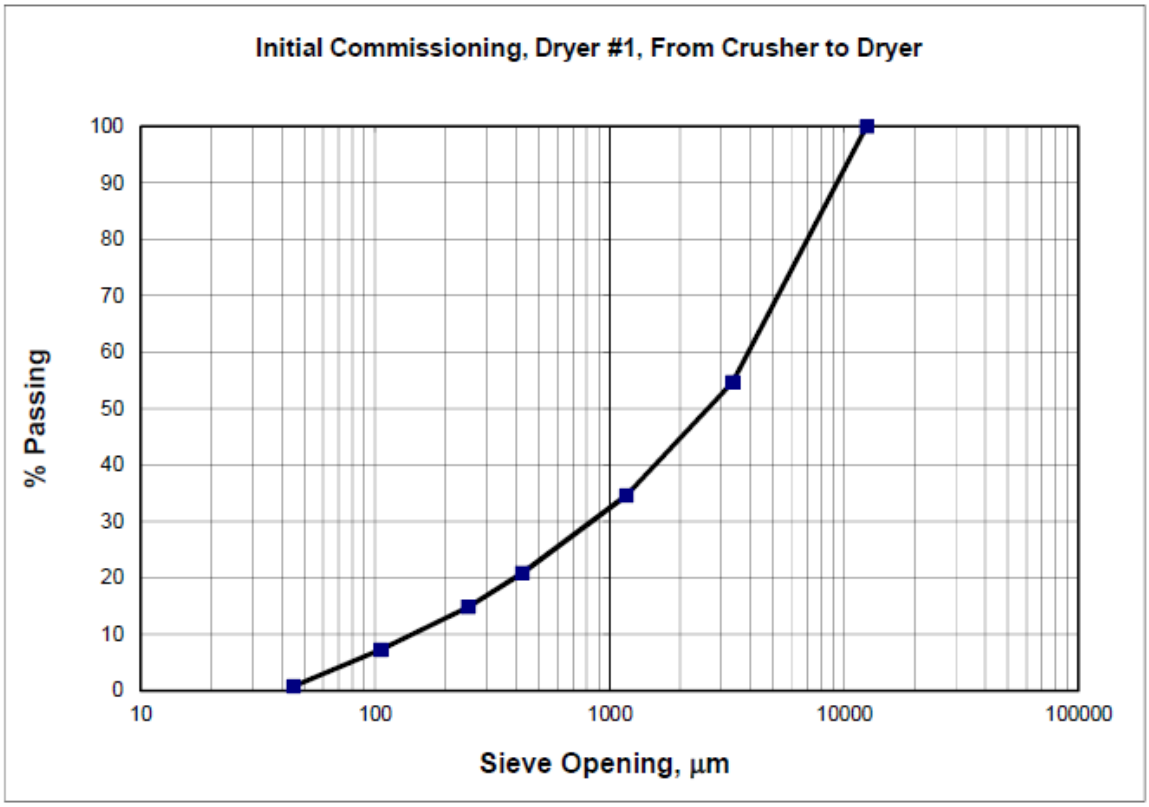


Figure 5.1-96 – November 2015 dryer lignite particle size

After November, the multiclone received much higher carryover (20-30%) through the next 6 months. The capture efficiency dropped to 85-88% due to the lower particle size the cyclones received (table 5.1-25). The amount of carryover and capture efficiency was still within the operational design performance for all the downstream equipment of the dryer. During March 2016, the lignite particle size carryover had a typical particle size of d50 = 50 microns (figure 5.1-97).

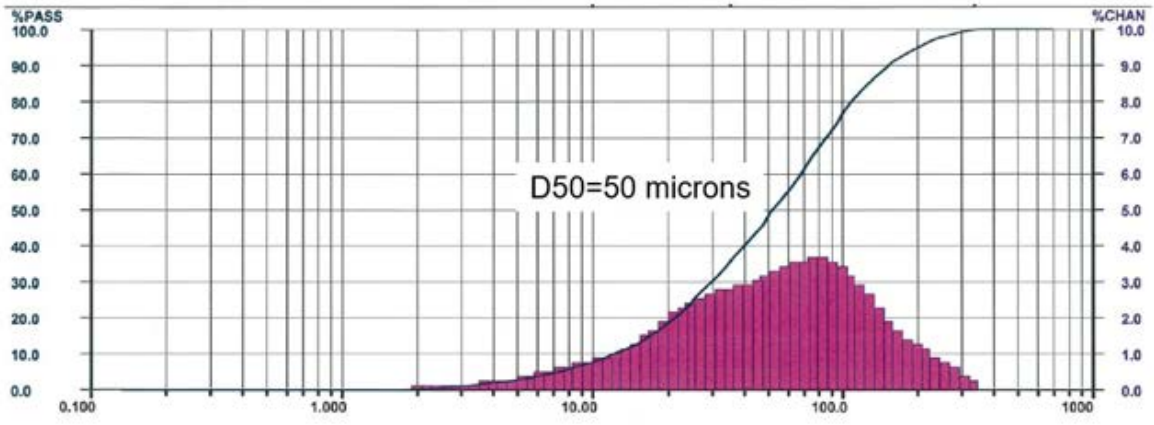


Figure 5.1-97 – March 2016 multiclone lignite particle size

Table 5.1-25 – Multiclone performance data March 2017

Sample	Time	Feedrate	Feedrate Dry Basis	Fan Flow Rate	Multiclone Efficiency	Dryer Carryover to MC	Dryer Carryover to Venturi
		KPPH	PPH	KACFM	%	%	%
1	3/16/2017 23:00	150	65000	240	85	14%	2%
2	3/17/2017 4:00	150	45500	240	85	22%	3%
3	3/17/2017 13:00	200	104000	250	85	18%	3%
4	3/17/2017 16:00	175	91000	250	85	21%	3%
5	3/17/2017 17:00	150	78000	250	85	23%	3%
6	4/3/2017 20:00	180	93600	250	85	24%	4%

- Venturi operation

The venturi scrubber collected 99% of the fines greater than 3 microns particle size. The planned venturi capture efficiency is shown table 5.1-26. The venturi scrubber typically operated with 12-14 in. W.C. dP. During March 2016, the lignite particle size carryover had a typical particle size of d50 = 14 microns (figure 5.1-98). The condenser was the final lignite particle collection point, and the typical particle size was d50 =2 microns (figure 5.1-99). With higher lignite particle breakdown, both the venturi and condenser were running higher TSS than designed. The filter presses during commissioning were not loaded because only a few dryers were running at one time. With the new candle filters finally operational, the main challenges were with the sludge header and pump being undersized for the increase lignite fines load.

Table 5.1-26 – Venturi percentage capture based on pressure drop

dP (in H2O) Particle Size, Micron	10	12	14	16	18	20
0.2	0.8%	1.1%	1.4%	1.7%	2.1%	2.4%
0.3	3.5%	4.7%	5.9%	7.2%	8.5%	9.8%
0.4	9.3%	12.0%	14.7%	17.4%	20.1%	22.7%
0.5	18.2%	22.7%	27.0%	31.0%	34.8%	38.4%
0.6	29.2%	35.1%	40.5%	45.3%	49.6%	53.5%
0.7	40.8%	47.5%	53.3%	58.2%	62.4%	66.1%
0.8	51.9%	58.6%	64.2%	68.7%	72.4%	75.6%
0.9	61.5%	67.9%	72.8%	76.7%	79.9%	82.4%
1	69.6%	75.2%	79.5%	82.7%	85.2%	87.3%
1.5	90.4%	92.7%	94.3%	95.4%	96.2%	96.8%
2	96.3%	97.3%	97.9%	98.3%	98.6%	98.8%
3	99.0%	99.3%	99.4%	99.5%	99.6%	99.7%
4	99.6%	99.7%	99.7%	99.8%	99.8%	99.8%
5	99.8%	99.8%	99.8%	99.9%	99.9%	99.9%

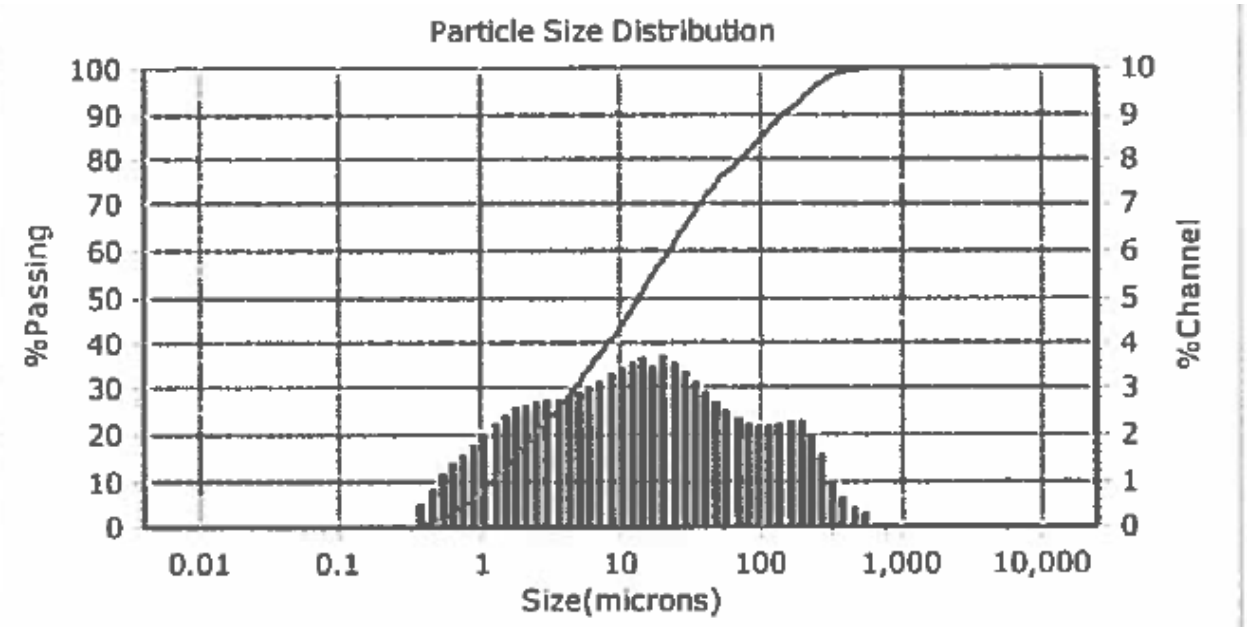


Figure 5.1-98 – Venturi fines particle size

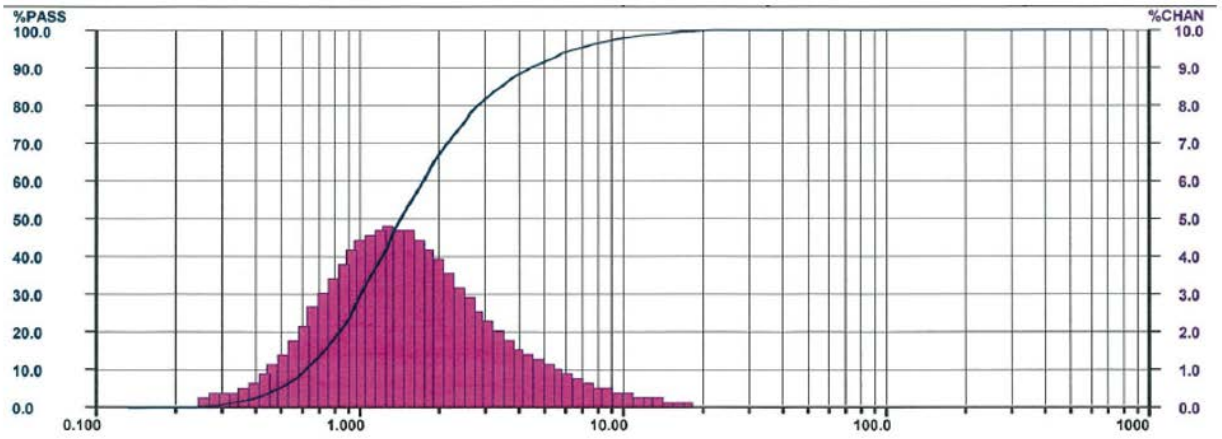


Figure 5.1-99 – Condenser fines particle size

- Candle filter operation

The candle filters were operated between 3-5 psi during the early November dryer commissioning run. The candle filter operational priority was to maintain the condenser tank inventory. The priority at this time was to improve the dryer feed system. The candle filter fill rate tuning, filtration and backflush timer adjustments were made by the vendor during the first weeks of operation. A plan was developed to push the candle filters to the design limits of operation. Since the dryer operation had decreased substantially till the multiclone leak issues were resolved, water for the filtration test was limited.

The first test to push the upper limit of filtration was done on Dec. 10, 2015. The first filtration test shows a design flow limit for the filter of 173 gpm at a max pressure of 9 psid (figure 5.1-100). The filter was designed to operate at a maximum throughput of 400 gpm at 30 psid. Another test was done on Dec. 11, 2015, but this time the filter had less flow through the filter with 138 gpm at 22 psid (figure 5.1-101). The last filtration test that was done just after significantly backflushing the filter, and the flow went back up to 173 gpm at 22 psid (figure 5.1-102). At this point there was concern that the filter was not meeting the design flowrate of 400 gpm. A maximum throughput of only 235 gpm was achieved based on these performance tests. These tests were the best performance for the filter operation. The next tests were performed with more fines in the dryer system and the filters plugged more readily, which caused the dryer to cease operation until a water management strategy could be developed.

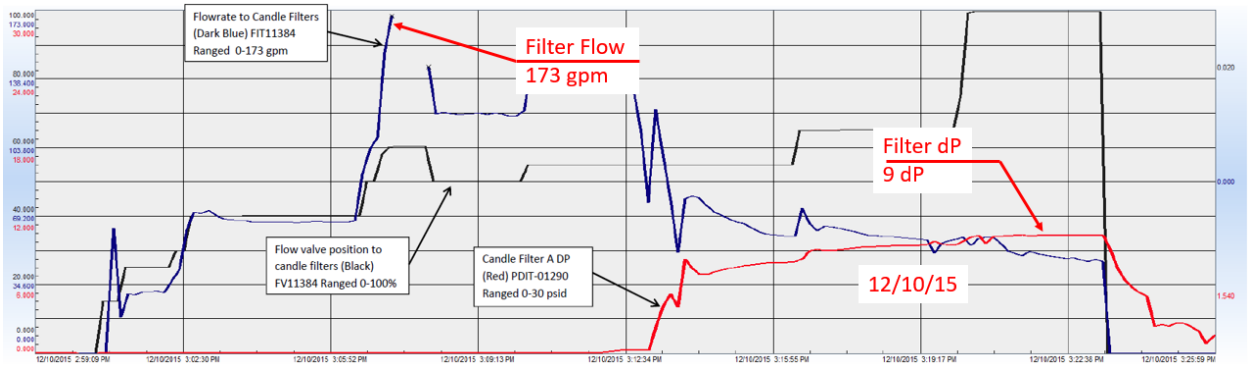


Figure 5.1-100 – Candle filter test 1

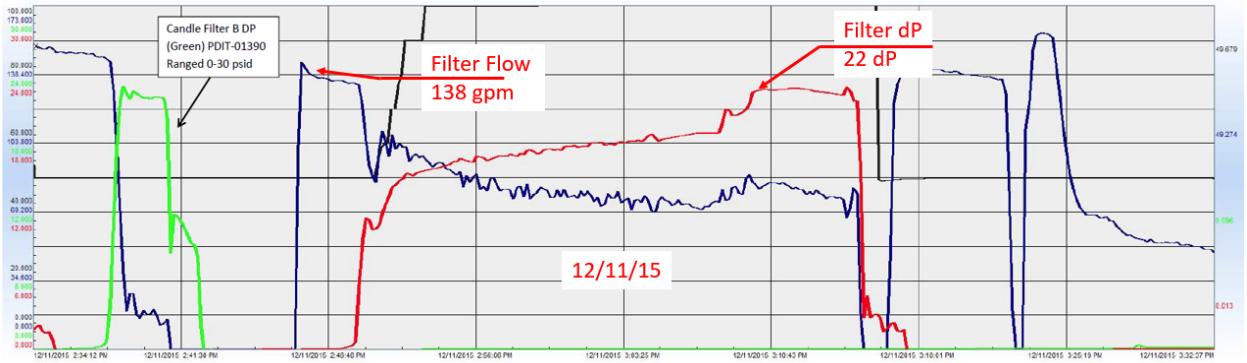


Figure 5.1-101 – Candle filter test 2

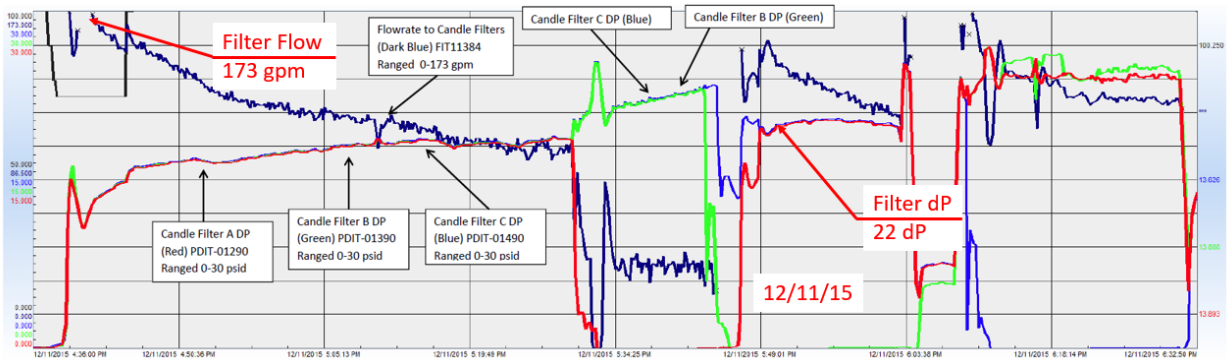


Figure 5.1-102 – Candle filter test 3

By Jan. 22, 2016, filtration had virtually stopped. During the last candle filter run, the flowrate was 25 gpm instead of 400 gpm. During the high sustained flowrates in the December and January candle filter operation, the fine particles plugged the membrane between the cloth and the Teflon liner. It was evident that other filters or processes would be required to make the system functional again. A pretreatment system was a potential next step. Primary pretreatment processes such as dissolved air flotation were tested on a pilot scale with process slurry from the units.

The dissolved air flotation (DAF) system was used for a pilot study to determine the treatability of ultrafine coal particles entrained in the process water stream (figure 5.1-103). The system included the following:

- Stainless steel DAF vessel Model RT-3, 5 -10 gpm capacity, with variable speed top skimmer drive system.
- Recycle pressurization system for production of dissolved air stream.
- Flash/equalization tank with mixer.
- Flocculant tank with mixer.

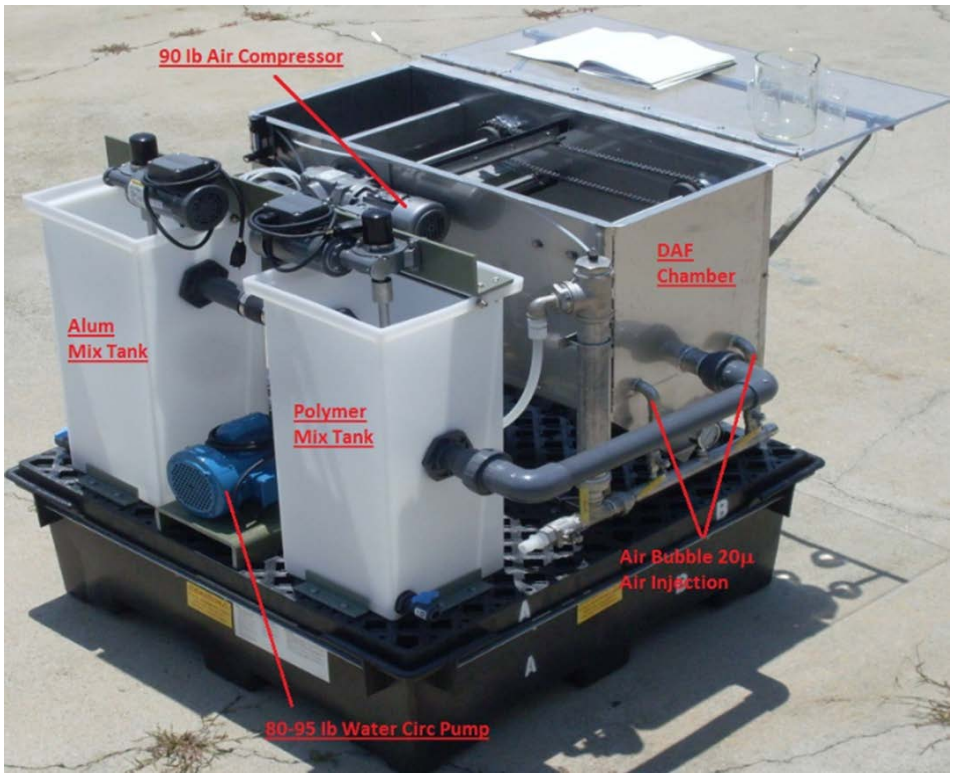


Figure 5.1-103 – Pilot scale dissolved air flotation system

Influent feed process water from the venturi condensers to the DAF system was maintained at 4.5 gpm. Air pressure for creating the dissolved air stream was maintained between 90-100 psig. Polyacrylamide-based polymers (Megafloc 3890) and PolyDADMAC were used as the flocculants for the tests. All the polymers tested were 0.2% solutions. Tests were also performed using aluminum chlorohydrate (ACH) and aluminum sulfate (20% W/W solutions) as coagulants. ACH did not provide the desired solids removal even at high concentrations and was discarded. The pH of the feed water with coal fines was around 5.8, which required the periodic addition of sodium hydroxide to maintain the pH at around 6.5-7.0. It was important to maintain close to neutral pH for the aluminum sulfate (coagulant) to be effective.

The system was started with clean feed water while maintaining the air pressure at 90-100 psig to make the dissolved air stream (whitewater). After the system produces a steady whitewater stream, the condenser water containing coal fines is introduced into the system at a constant rate of 4.5 gpm. The water first enters the flash tank followed by the flocculant tank and the DAF cell. Both the flash tank and the flocculant tank are equipped with agitators for constantly mixing the feed water and ensuring proper mixing of the solids present in the feed. The residence time for the process to come to steady state was approximately 15 minutes: ~ 4 minutes in flash tank, 4 minutes in flocculant tank, and 7 minutes in the DAF cell. However, testing established that the process had too many variables. The DAF system was difficult to operate due to constantly changing feed conditions. Another major issue with the process was the carryover of excess polymer to the filtration unit. The presence of excess polymer immediately clogged the pores of the original filter media, causing failure of the overall process.

Eventually, a decision was made to completely replace the original filter media with a new e-PTFE membrane candle filter with a pore size of 0.5 µm. The new filter media was a like-for-like replacement. Initial pilot testing of the new filter media in March 2016 showed these filters would be able to capture ultrafine particles and would be able to treat slurry containing 2% solids. The filter media remained stable and worked much better than the original filter media after 1 week of pilot testing (~ 200 operating cycles) (figure 5.1-104). The maximum achievable flowrate through these filters was ~600 gpm, which was lower than the downstream requirement (figure 5.1-105). In March 2016, with first coal feed to the gasifier fast approaching, it was decided to go with the filters and increase capacity at a later time.

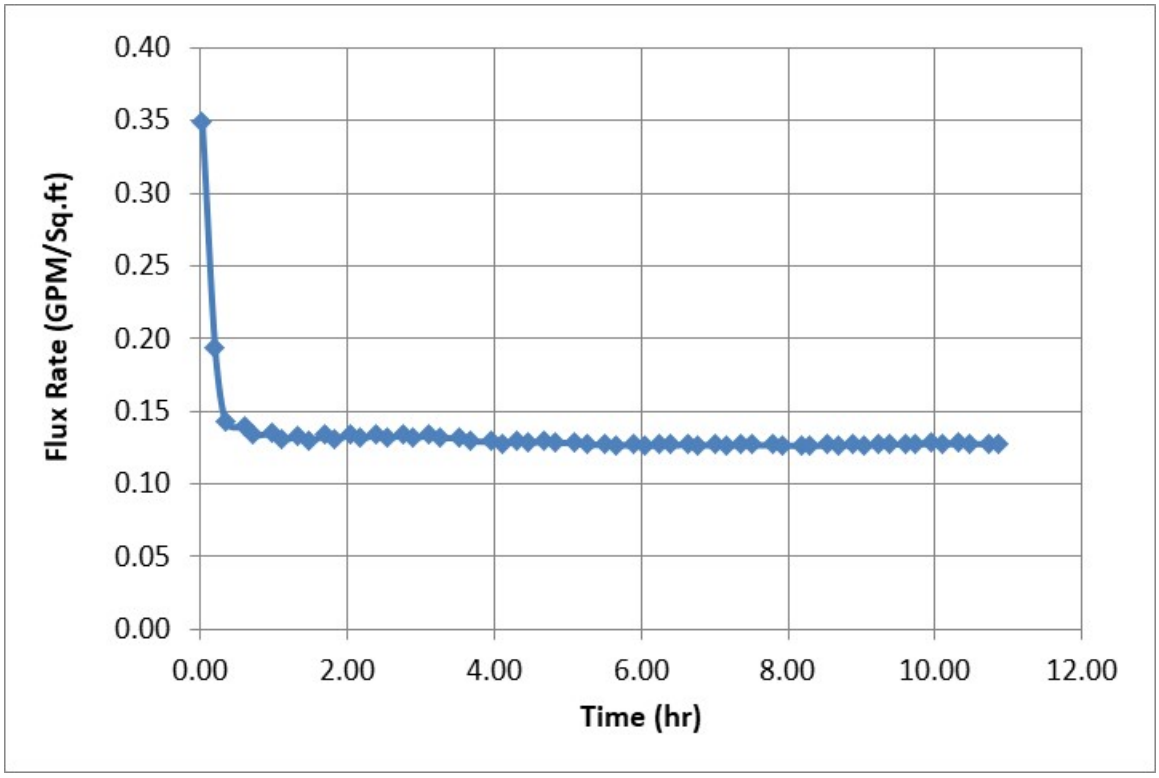


Figure 5.1-104 – Flux rates achieved using e-PTFE membrane

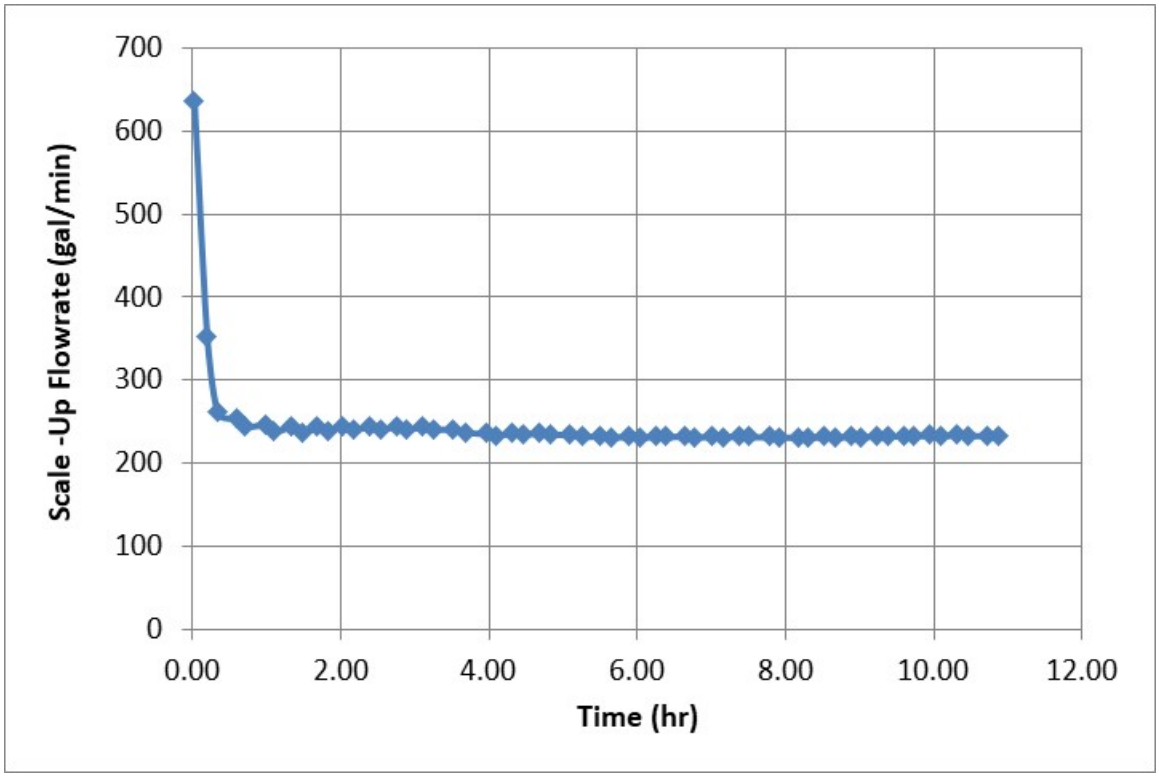


Figure 5.1-105 – Achievable flowrates on the commercial scale candle filter unit

Commissioning of the recovered water system was laden with issues described in previous sections. The original candle filter media was incapable of treating slurry loaded with high solids concentration and containing ultrafine particles lower than 3 µm. New e-PTFE membrane filters were chosen as a like-for-like replacement for the nonperforming original woven filter cloth media. Systematic testing on a pilot scale unit was conducted using a slipstream of the process slurry to evaluate the effectiveness of the new filter media. On a commercial scale, the filter media was capable of treating ~ 600 gpm of slurry containing about 2% ultrafine solids.

The new filters were a like-for-like replacement of the original filter media and readily available off the shelf. The filters were replaced in May-June 2016. The commissioning of the new filters was done in June 2016 using a test package like the one used for the original filters. The only difference in commissioning was that the new filters used a water backflush while the old unit operated on an air backflush mode.

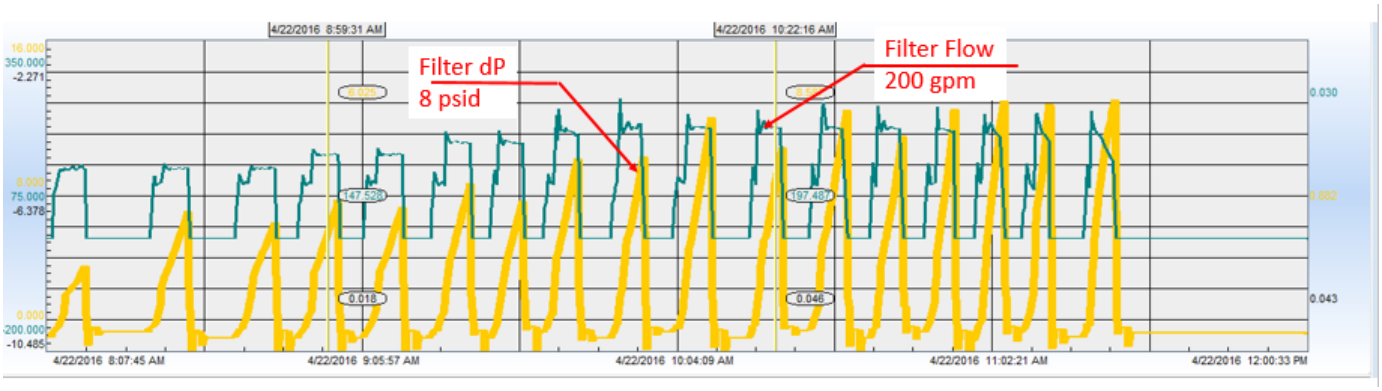


Figure 5.1-106 – New e-PTFE membrane filters in operation

The maximum flowrate achieved with the new filters was 210 gpm, with cycle times around 10 to 12 minutes of filtration (figure 5.1-106). This level of performance was encouraging because the filtration was sustained and repeatable. This capacity ensured a simple in-kind candle filter media replacement could be made quickly and would support a gasifier at full load and two gasifiers at 60% load. The plan in April was to buy filters for all three filter bodies and evaluate the performance to determine whether other comparable rental filters should be brought in to support 100% gasifier load for two gasifiers, or if other technology should be pursued for high filtration performance.

- Pulverizer operation

In March 2016, the pulverizer particle analyzer vendor was brought onsite to troubleshoot the automatic sampling and operation of the analyzer. The analyzer allows the operator to make real-time adjustments to the pulverizer speed and pulverizer classifier speed based on changes in lignite feed rate, temperature, and moisture variations. There is a required size distribution for the lignite particle size leaving the pulverizer. It was important to control the top size of the lignite as well as the fines produced from the pulverizer to the high-pressure lignite feed system and the gasifier. Since the continuous monitoring using the particle size analyzer was unavailable at this time, pulverizer particle size control was optimized using response surface regression analysis.

The particle size of coal leaving the pulverizer was obtained using an optimized equation that took into consideration all five process parameters governing the operation of the pulverizer: moisture of coal, pulverizer fan speed, feedrate to the pulverizer, roller speed, and spinner speed. The equation is:

$$D_P = [30.50\,R - 24.19\,S - 4.84\,M + 0.007\,AF + 0.024\,F - 0.331\,R^2 + 0.422\,RS - 0.0005\,RF - 609\ ]$$

Where, D_P = particle size (µm), R = roller speed %, S = spinner speed %, M = moisture %, AF = air flow (ACFM), F = pulverizer feedrate (PPH).

Table 5.1-27 shows the design parameters used for the response surface methodology and for determining the particle size.

Table 5.1-27 – Pulverizer operational data for control

	Process Variable	Low	High
Design Parameters	Moisture %	4.6	50
	Spinner speed %	14.3	64
	Roller speed %	9.6	60.2
	Fan flowrate (ACFM)	59621	71191
	Feedrate (PPH)	29894	83005

The range of values for the process parameters were obtained during actual operation of the pulverizer. For comparing the actual particle size and the predicted particle size using the optimized equation, several samples were collected from the baghouse and analyzed for particle size. The actual particle size obtained was compared with the predicted particle size in the chart (figure 5.1-107) indicating a good fit to the data. The predicted particle size was close to 99% of the actual particle size (figure 5.1-107).

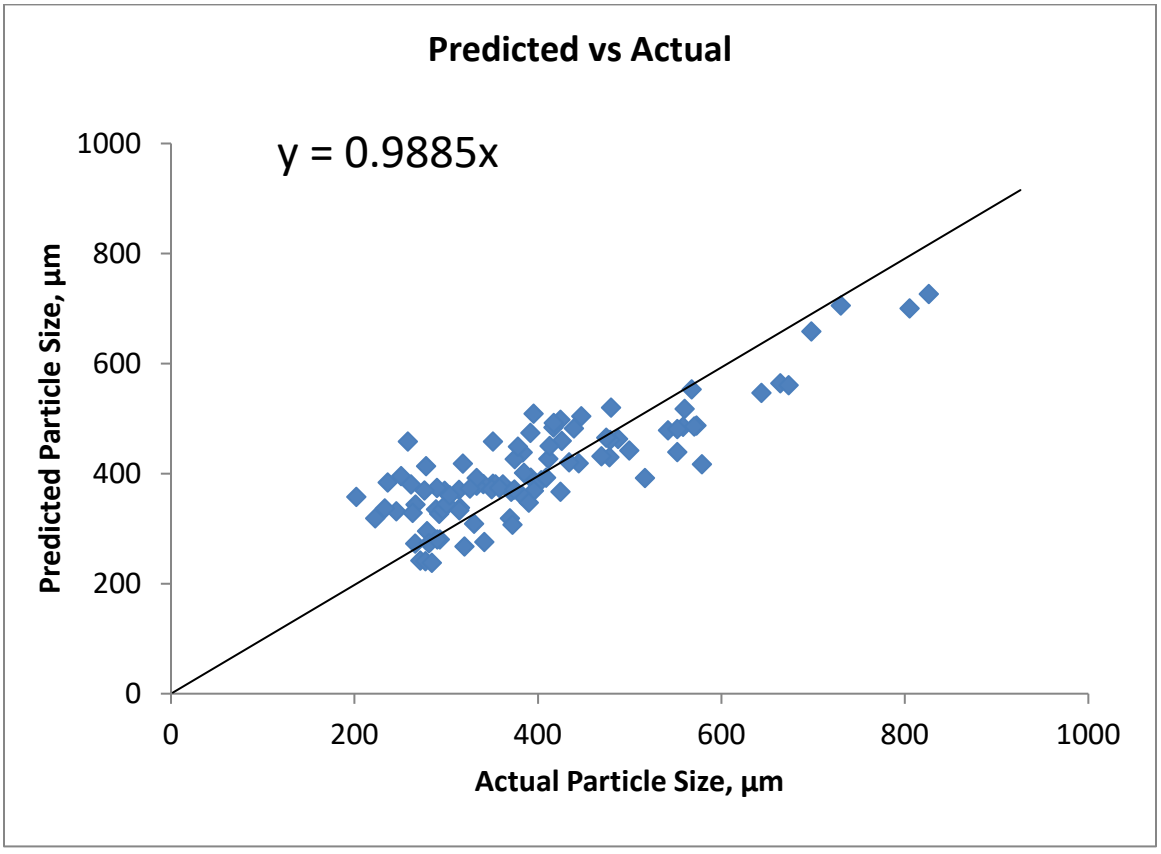


Figure 5.1-107 – Actual vs predicted particle size for pulverizer

An optimized control curve for particle size analysis of coal from pulverizer is shown in figure 5.1-108. The target gasifier coal particle size and moisture of 400 microns and 18% respectively was used for obtaining the control curve for pulverizer operation (figure 5.1-109).

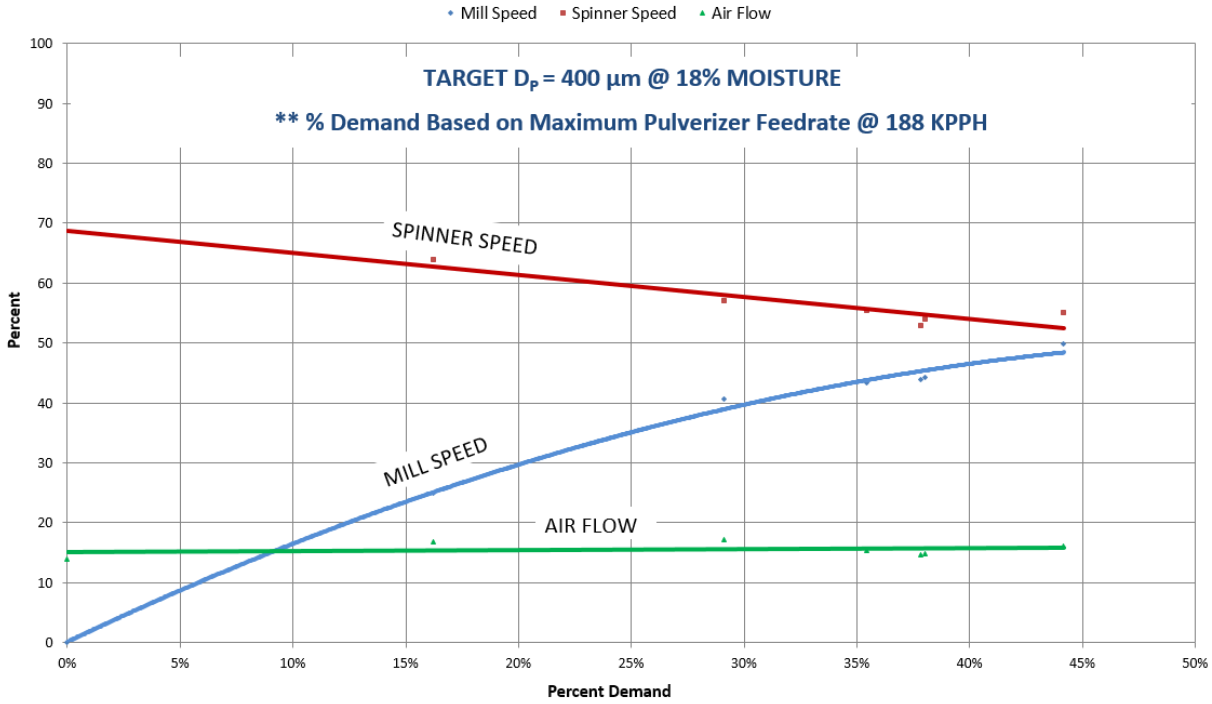


Figure 5.1-108 – Fluid bed dryer production data

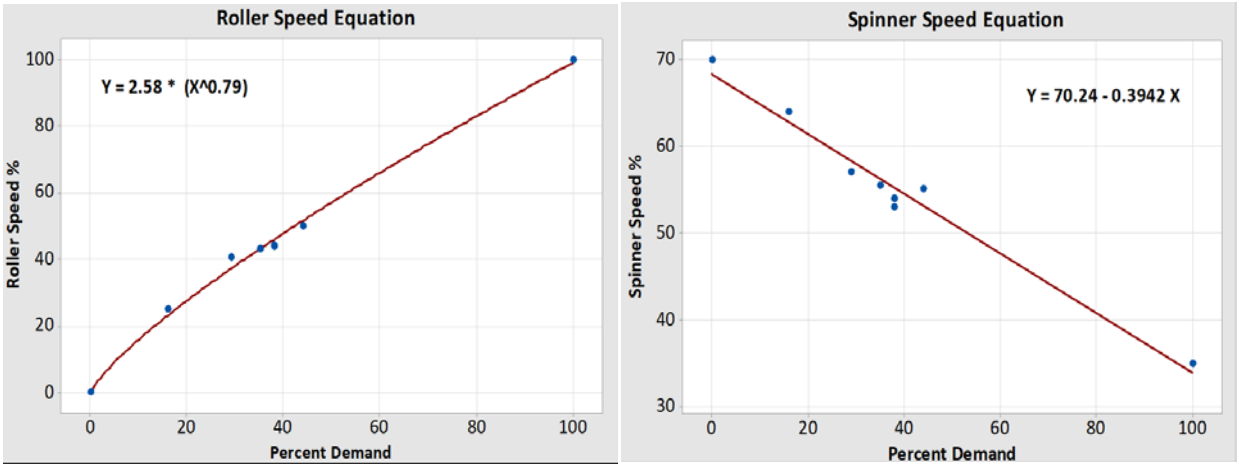


Figure 5.1-109 – Pulverizer tuning control curves

The pulverizer tuning control curves show the particle size is most dependent on roller speed for coarse control and spinner speed for fine control. Increasing the roller speed drastically reduces the particle size. It is important to find the correct range of process parameters for obtaining the right particle size for gasifier operation. For obtaining a particle size range of 400-500 microns at a pulverizer federate of 125,000 PPH and 18% moisture, it was determined

that the roller speed should be ~ 50-52%, spinner speed ~ 55-65%, and fan flow rate of ~ 70-72 KACFM (figure 5.1-110).

Particle Size	Spinner Speed	Roller Speed	Fan Flow	Moisture	Feedrate
µm	%	%	ACFM	%	PPH
588	35	51	85000	20	125000
532	40	45	55000	18	100000
493	35	49	70000	20	80000
562	38	45	68000	25	90000
502	35	50	71191	15	80000
386	57	41	71190	18	54673
458	40	52	70000	10	80000
479	50	40	70000	10	57000
494	60	38	70000	8	70000
538	50	35	70000	15	68000
506	50	50	72000	18	125000

Figure 5.1-110 – Pulverizer actual operational parameters for obtaining particle size

5.2 Process Air System

5.2.1 System Overview

The TRIG™ gasifier at Kemper is an air-blown gasifier, requiring a sizeable air supply system. During normal operations, the air is provided from two sources: combustion turbine extraction and ambient atmospheric air.

Each gasifier train consists of a process air system. Each system consists of two process air compressors (PAC) CO1102 and CO1202, one extraction air compressor (EAC) CO1004, one transport air compressor (TAC) CO1005, and a transport air dryer unit (TAD) PG1007 (figure 5.2-1).

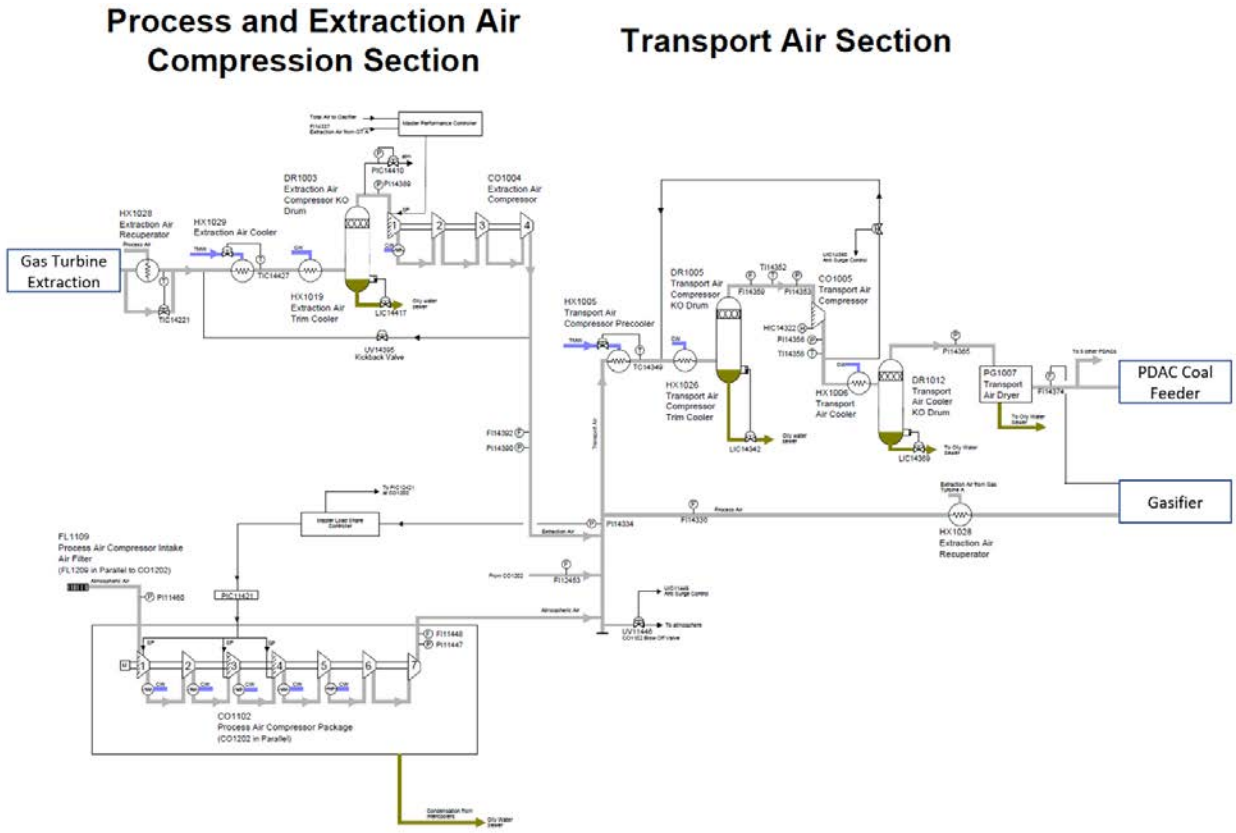


Figure 5.2-1 – Process air system overview

The process air compressors consist of a seven-stage, synchronous motor driven, integral gear machine. Atmospheric air is filtered and compressed from ambient conditions to 735 psia and 285 °F. The gas is intercooled with demin water to minimize the cost of subsequent compressor stages. There are intercoolers located before stages two through six. This design improves application efficiency and allows for more cost-effective materials of construction. Because the gas temperature to the gasifier should be elevated, there is no intercooler before the seventh stage.

The compressor is controlled by a set of adjustable inlet guide vanes on the suction of stages 1, 3, and 4. The machine is protected from surge by a single stage blowoff valve (with silencer) to the atmosphere, located near the compressor discharge (figure 5.2-2).

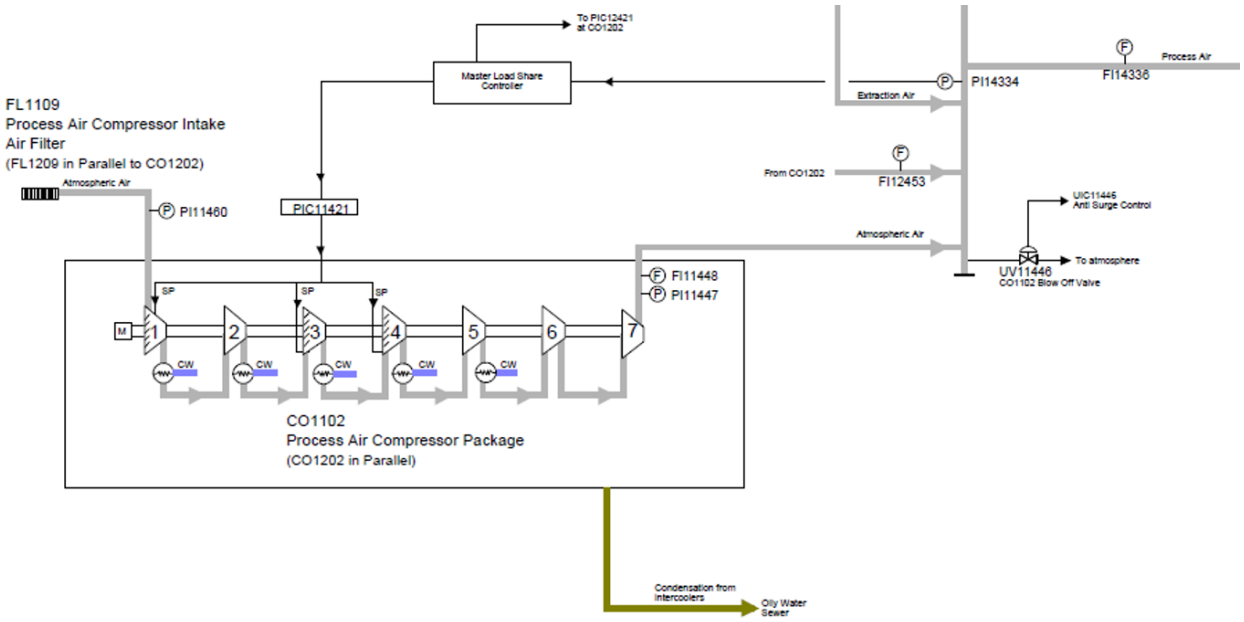


Figure 5.2-2 – Process air compressor diagram

The extraction air compressor is a four-stage, synchronous motor driven, integral gear machine. The compressor raises the gas pressure from 135 psia to a final pressure of 745 psia. Air extracted from the discharge of the combustion turbine compressor is recuperated in the extraction air recuperator with the process air (for additional heating of the process air to the gasifier) and then cooled in a series of heat exchangers. The extraction air cooler provides heat to the tempered water system while the extraction air trim cooler reduces the air to a design operating temperature of 110 °F. The cooled extraction air then passes through a knockout drum before entering the extraction air compressor. Consistent with the design of the process air compressors, the extraction air compressor does not have interstage cooling between the final two stages. This design improves plant performance by providing air to the gasifier at higher temperatures.

Air leaving the extraction air compressor combines with the discharge of the two process air compressors in the process air header. The compressor is controlled by a single set of adjustable inlet guide vanes on the suction of the first stage. For surge protection, air is diverted back to the suction of the compressor through an antisurge kickback loop. A closer view of the extraction air process configuration is shown in figure 5.2-3.

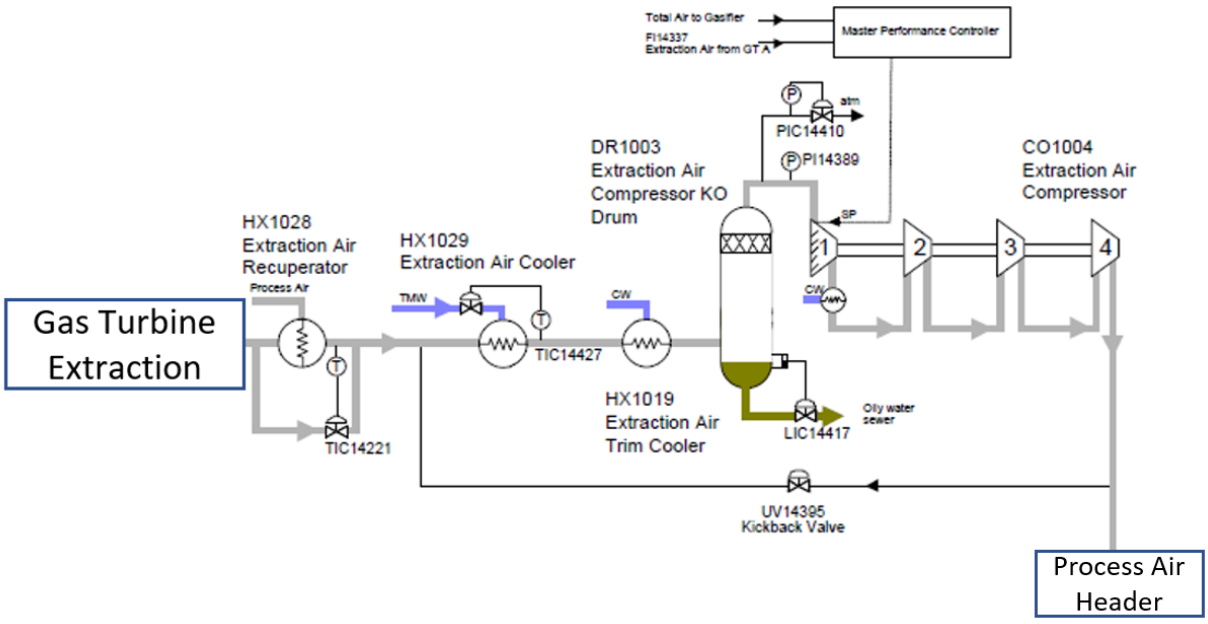


Figure 5.2-3 – Extraction air compressor process configuration

A performance controller maintains overall control of the process air system by monitoring and adjusting the PAC output to maintain a set pressure on the process air header. The controller handles load-sharing between the two process air compressors and balances the process air compressors with the available air from the extraction air compressor. As the flow of the extraction air compressor changes, the PAC performance controller will adjust the PACs to maintain a setpoint pressure on the process air header.

A small slipstream of air is removed from the process air header for further compression. This air is used as transport air for conveying coal into the gasifier. Usable heat within the gas is first transferred into the tempered water system by the transport air compressor precooler. The stream is further cooled in the transport air compressor trim cooler, and any free moisture is removed in the transport air compressor knockout drum just before entering the transport air compressor.

The transport air compressor is a single-stage, vertically split barrel-type, motor-driven compressor. The air is compressed from 630 psia to about 720 psia. Surge control is provided by a recirculation kickback to the suction of the compressor. Process control uses a set of guide vanes on the suction of the compressor. An overview of the transport air system is shown in figure 5.2-4.

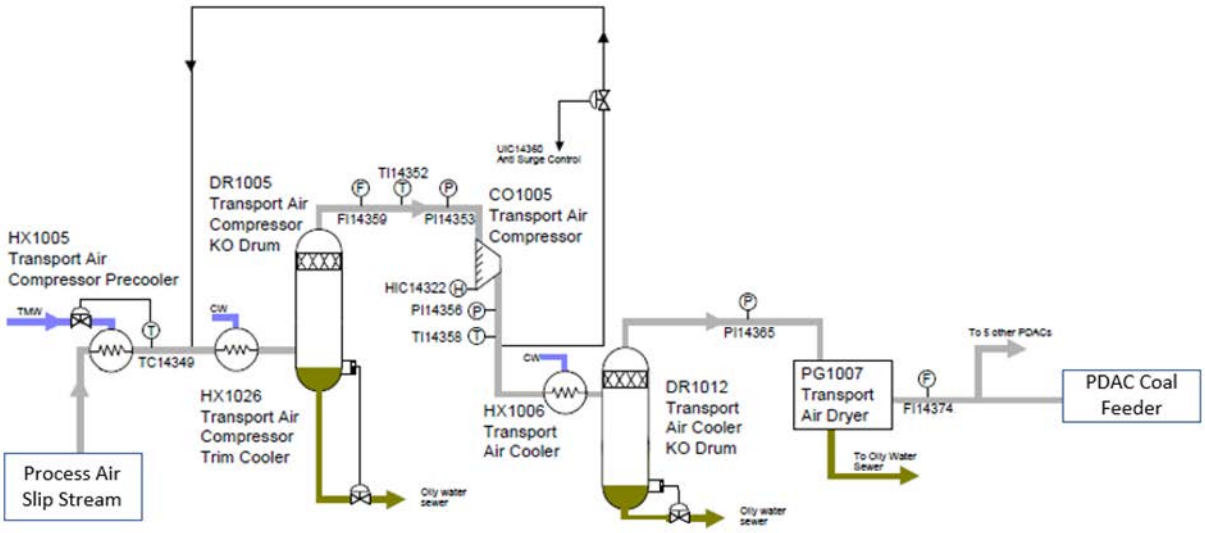


Figure 5.2-4 – Transport air system overview

Air discharged from the transport air compressor is cooled in the transport air cooler. Any free moisture is removed in the transport air cooler knockout drum. The air contacting the coal feedstock must be very dry to prevent the feed lines from becoming clogged and it is dehydrated to a dew point of -40 °F in the transport air dryer. The transport air dryer is a dual chamber, solid desiccant dehydration unit. One chamber is always in operation. The operational chamber ensures a dry supply of air to the coal feed system while the nonoperational chamber is regenerated by blowing warm air counter-current to the normal process flow direction. The transport air dryer is the final processing step of the transport air stream. An outline of the dryer components is shown in figure 5.2-5.

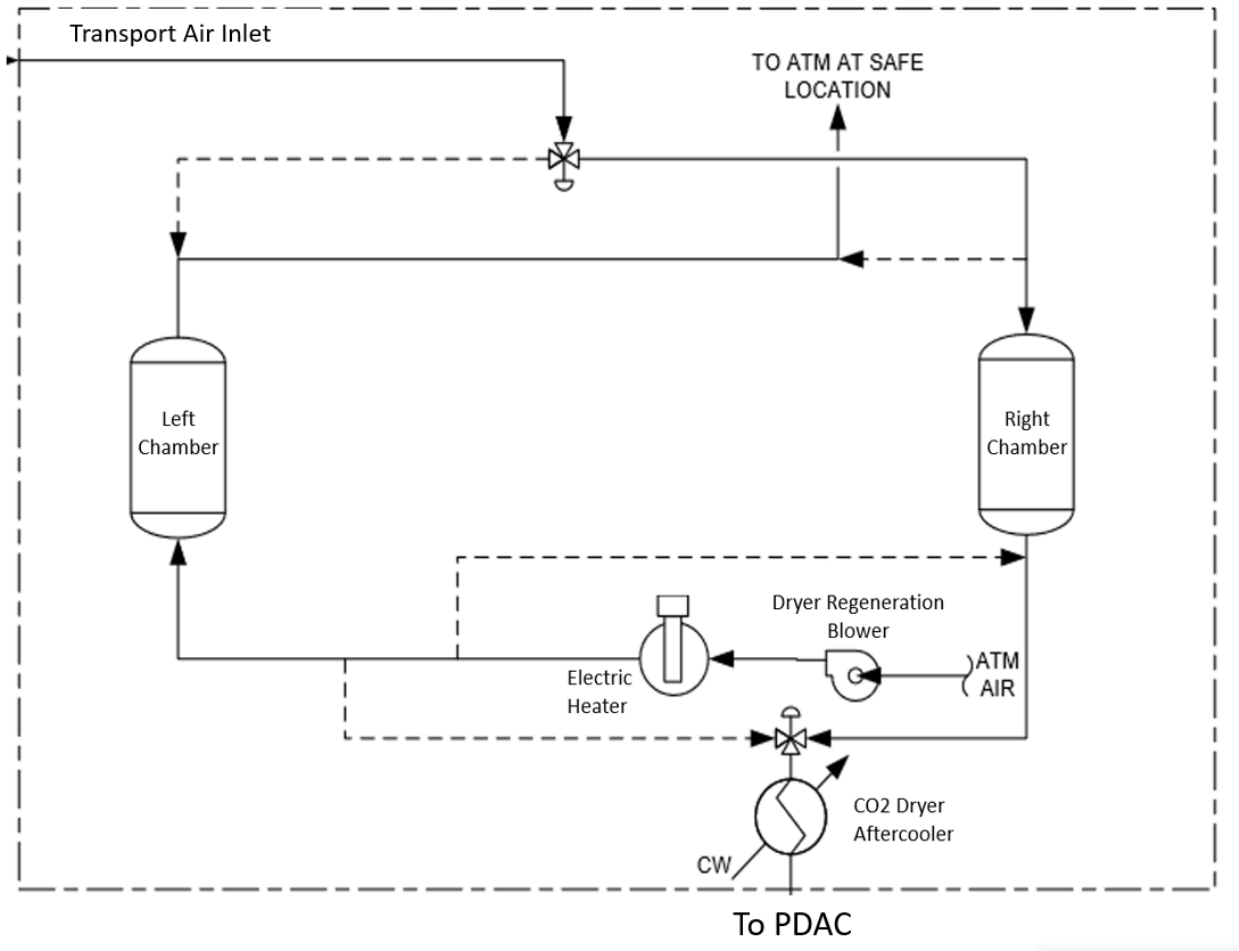


Figure 5.2-5 – Transport air dryer system

The air requirements during startup of the gasifier vary significantly from conditions observed during normal operations. A large volume of air is required at pressures substantially lower than the process air system can provide for long durations. For this reason, air is supplied to the process air header from the ASU/startup air compressor. This application is maintained and operated by an onsite, third party vendor.

5.2.2 Initial Commissioning Plan

The initial commissioning plans for the process air system consisted of commissioning the individual compressor applications. After complete, each application would be integrated with the process air compressor and, by extension, the gasifier. The plans presented in this section will address the compressors collectively, since the testing requirements for each of these applications is similar. The transport air dryer will also be briefly discussed. Each of the compressor applications in the process air system were similar.

The commissioning of each of the compressors and dryers was to occur in 10 distinct test packages. The scope of each test package commenced at the completion of precommissioning activities. Precommissioning included preparation of the auxiliary systems, instrumentation loop and logic checks, electrical checkout, uncoupled runs of the main motors and lube oil pumps, and flushing and commissioning of each lube oil skid.

On completion of precommissioning, the compressors were to be prepared for testing and a controlled test environment established. For the process air compressors, the discharge isolation valve was closed. During commissioning, air would be compressed and blown off to atmosphere through the antisurge blowoff valve. The extraction air and

transport air compressors were to be isolated on the discharge side, with the suction side allowed to float on header pressure. The test volume was controlled, and air was recirculated back to the suction of the compressor through the antisurge kickback valves.

Each compressor was commissioned based on these functional activities:

- Start the compressor.
- Conduct low-pressure leak testing.
- Record baseline data (for example, bearing temperatures, vibration levels, and initial process conditions).
- Conduct medium-pressure leak testing.
- Verify mechanical integrity (including mapping the bottom of the compressor map).
- Test and tune antisurge valve.
- Verify surge points and surge limit line.
- Complete interlock trip testing.

After compressor testing was complete, the system was to be prepared for integration with the process air header. This process would include equalizing pressures to within 15 psi across the compressor discharge isolation valve and then opening the valve.

The transport air dryer unit is similar to an instrument air dryer set used for plant air systems. The commissioning plans followed the methodology commonly used to commission air dryers and were to be completed before loading of the desiccant. The procedure included:

- Complete a system leak check.
- Complete loop/logic checkout.
- Conduct an uncoupled blower motor run.
- Walk the dryer through start/stop/swap logic.

After the dryer was commissioned, loading of the desiccant was to be completed. It was anticipated the loading would be handled by a third-party vendor, which recommended a loading method.

5.2.3 Significant Events

5.2.3.1 *Process Air*

- Accomplishments

Train A:

PAC-1		PAC-2	
Lube oil system commissioned	2-28-2014	Lube oil system commissioned	2-28-2014
PAC-1 commissioned	5-9-2014	PAC-2 commissioned	6-20-2014
Process header cleaning complete	8-6-2014		
Process header commissioned	8-29-2014		

Train B:

PAC-3		PAC-4	
Lube oil system commissioned	4-4-2014	Main motor corrosion repair complete	8-24-2014
Process header crossover piping installed	10-24-2014	Foundation/soleplate repair complete	3-11-2015
Process header cleaning complete	12-19-2014	Lube oil system commissioned	3-18-2015
Precommissioning complete	2-20-2015	Precommissioning complete	4-9-2015
PAC-3 commissioned	2-21-2015	PAC-4 commissioned	5-15-2015

Commissioning of the process air system was a significant undertaking. An effort was made to commission the units sequentially while Construction was installing the next unit, to maintain the tight commissioning schedule. The turnover packages were structured to allow for commissioning of the auxiliary systems as they were constructed. This approach worked well for PACs 1 and 2. Resource constraints affected the availability of auxiliary systems, and adjustments to the project plan were made to achieve all testing goals.

Per the turnover structure, the lube oil skids were the first packages received from Construction. The PAC-1 and PAC-2 skids were received in late 2013. Precommissioning activities immediately began on each skid, including instrumentation and logic checkout, electrical and pump testing, and oil flushing. Several of the vendor-installed piping runs were found to have pipe stress near the oil pumps and required repair. Oil flushing was started after the repairs were complete. An oil flushing contractor was used to complete the flushing activities. Per procedure, all oil piping was flushed using an off-skid pump and sock filter. Flushing continued until no visible particles were observed on the sock. Final flushing was completed using on-skid equipment. Commissioning of the oil skids was completed in February 2014 for Train A units, April 2014 for PAC-3, and March 2015 for PAC-4.

Cleaning of the Train A PAC piping began immediately after commissioning of the oil skids. This process was completed with minimal effort since it involved only the discharge line from each compressor to the outlet isolation valve and up to the compressor blow off valve, roughly 100 ft of piping for each compressor. As part of the cleaning, an internal inspection of the inlet filter housing was conducted. PAC-2 inlet duct was clean. The PAC-1 duct contained a small pile of rock immediately upstream of the stage-1 inlet guide vanes (IGV). It was difficult to find and appeared to be intentionally placed, because the rest of the inlet housing was clean. After removal of the debris, final preparations were made to commission PAC-1 and PAC-2.

Due to delays in completing the cooling water system, the compressor was available for commissioning before cooling water was available. Water is required in each of the compressor intercoolers, the main motor, and the VFD/soft-start drives. To avoid delaying the schedule, a temporary cooling water system was set up along compressor row (the area of the plant that contained the PACs, EAC, and RGCs). This temporary system included a small cooling tower, piping, and connections to each compressor. Erection of this temporary source allowed for testing to continue on PAC-1 and PAC-2.

PAC-1 testing began in May 2014. PAC-2 testing commenced in June 2014. There were no significant challenges to the commissioning of either application. This section will describe the activities as one test plan.

The compressor was started, and all connections were leak tested. Several leaks were identified and repaired near the final two stages of the compressor. When complete, the blowoff valve and inlet guide vanes were tuned in preparation for surge testing. The verification of the guide vane positioner calibration is shown in figure 5.2-6.

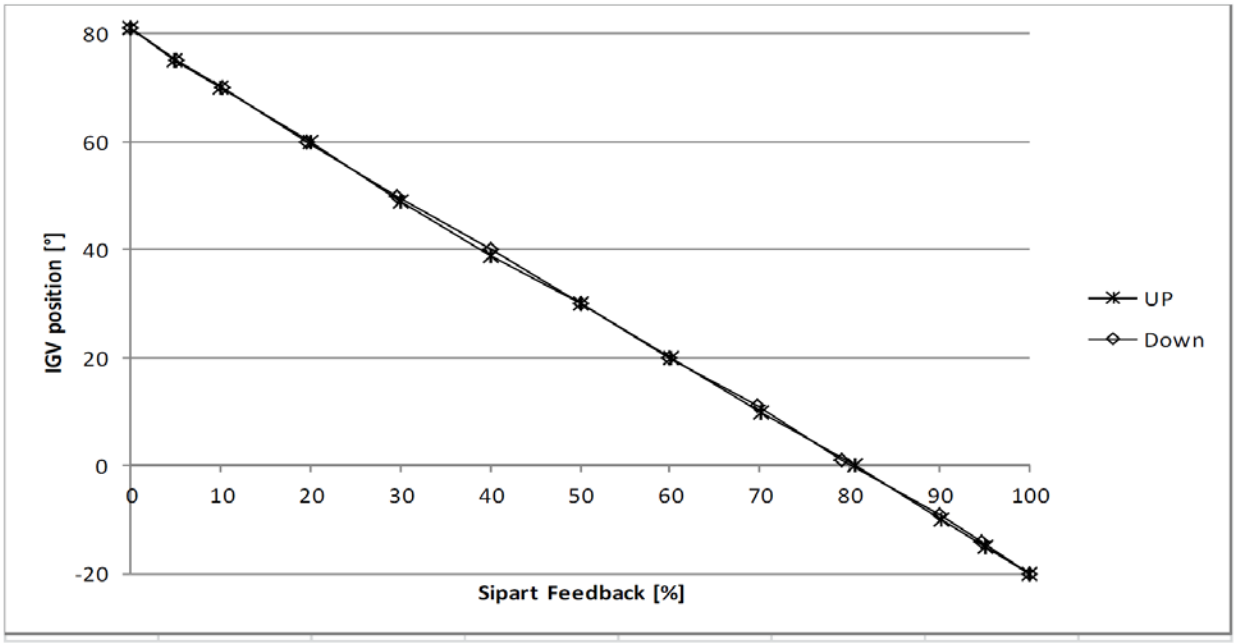


Figure 5.2-6 – IGV positioner calibration

After the IGVs and blowoff valve were tuned, the IGVs were opened from 15% to 100% with a hold at every 10% increment. This test served as the mechanical integrity testing of the compressor and to allow the bottom extent of the performance map. Figure 5.2-7 outlines the extent of the testing at the higher IGV angles.

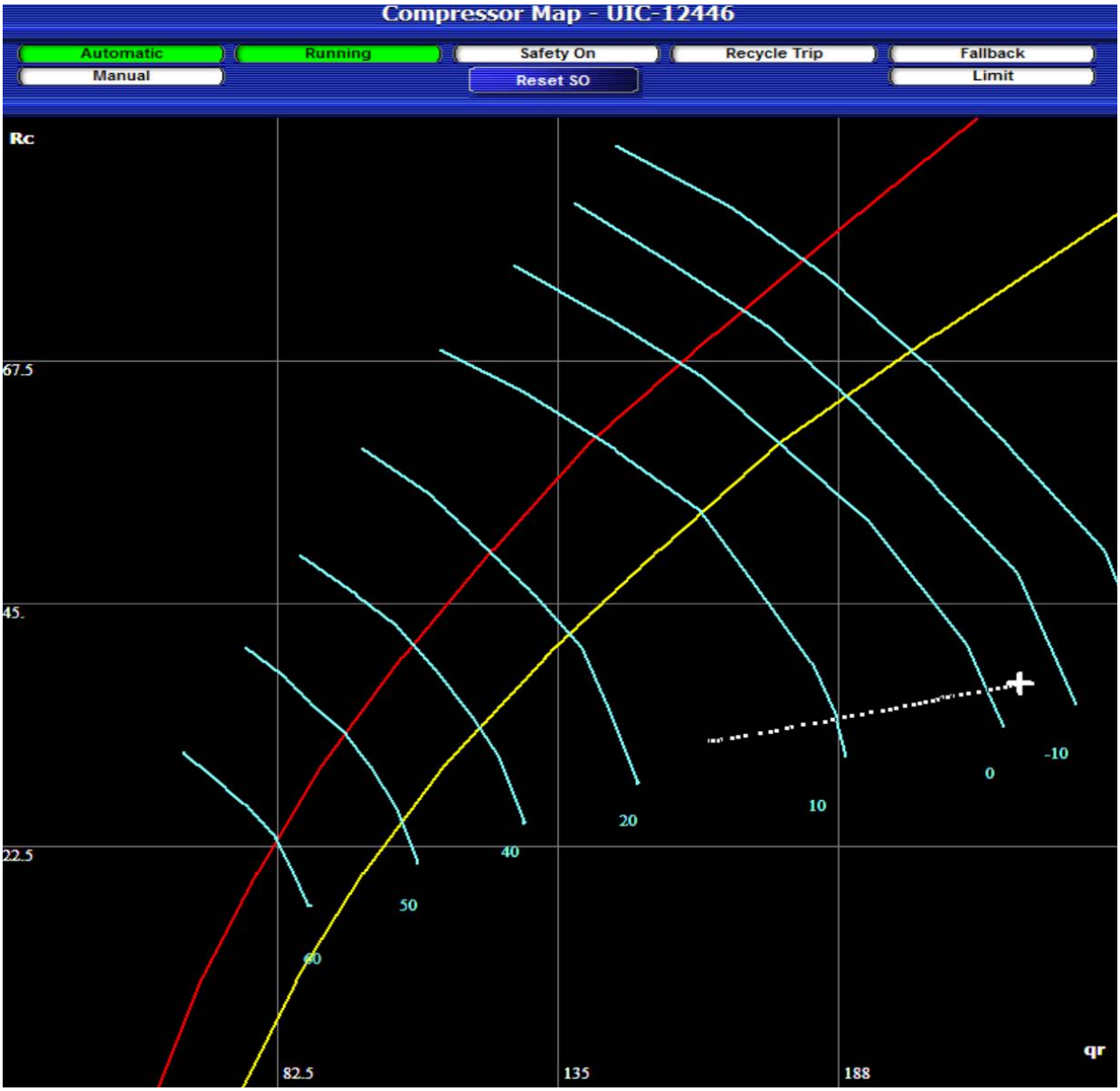


Figure 5.2-7 – PAC-2 mechanical integrity testing

Surge testing followed the completion of the mechanical integrity testing. To complete the surge test, the IGVs were moved to three separate positions likely to be near the normal operating conditions. At each IGV stop, the blowoff valve was steadily closed until a surge event was registered by the control system. Figure 5.2-8 shows the progress towards surge at one IGV position.

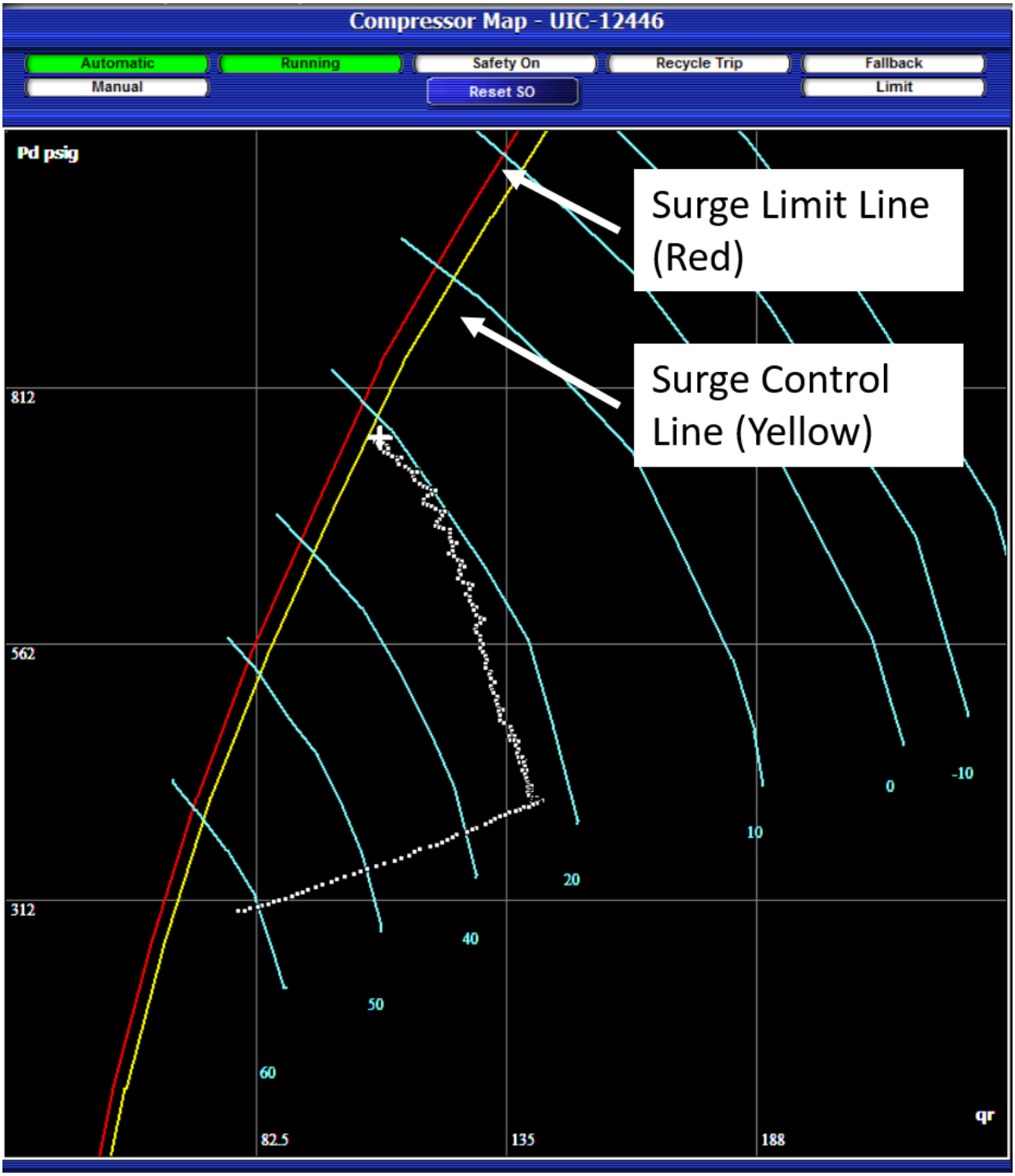


Figure 5.2-8 – PAC-2 surge testing

The surge limit line was confirmed for both applications. After surge testing, the testing moved to verification of interlock trip logic. A trip event is induced from the multiple control systems that contain trip logic (for example, Allen-Bradley PLC, DCS, SIS). Each compressor was capable of being tripped offline from all required locations. Commissioning of PAC-1 was completed in May 2014. PAC-2 was completed in June 2014.

The process air header for each train was hydroblasted from the discharge isolation valve of each compressor to the air feed valves at the gasifier. This process was initially completed on Train A to provide air to the Train A gasifier and syngas path piping during the air blows and air flow testing. Delays in the availability of gasifier A meant the Train B gasifier would be cleaned first. Cleaning activities on Train A were completed in August 2014.

Due to repairs being made to PAC-4, a temporary crossover was installed between Train A and B process air headers, between two motor operated valves used for initial pressurization of the gasifier. The piping installation was to allow one compressor to operate on one side of the plant (controlling header pressure) while one compressor flowing through the crossover was base-loaded. The base-loaded compressor had no controls capability on the opposite train. This crossover allowed for PAC-1 and PAC-3 to support the air blows and air flow testing on Train B while PAC-4 and gasifier A were being repaired. Figure 5.2-9 shows the piping location. Installation of the crossover piping was completed in October 2014.

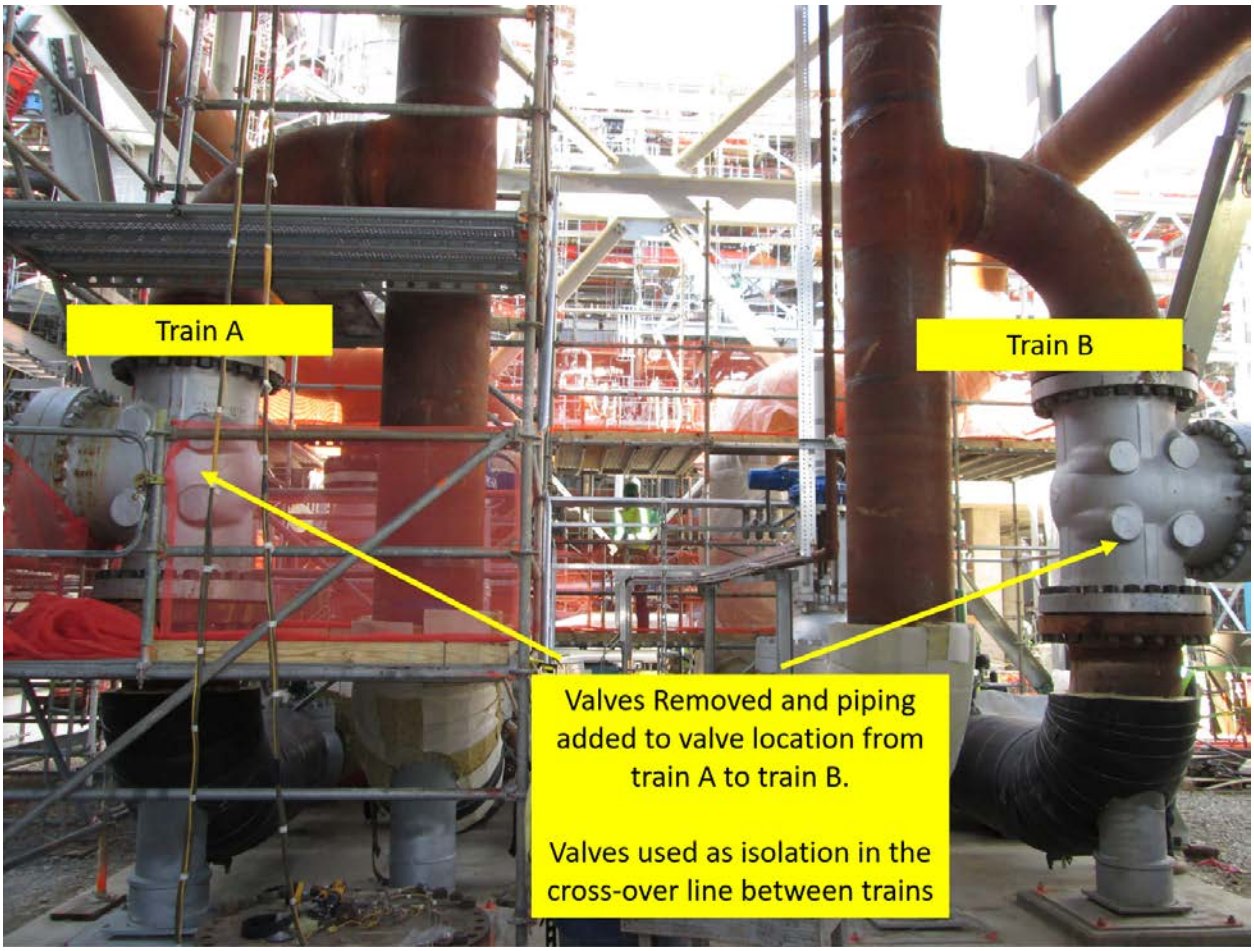


Figure 5.2-9 – Process air crossover location

To facilitate air blows on the Train B gasifier, the process header piping on Train B was hydroblasted in December 2014. The cleaning activities were completed immediately before commencement of the air blows and air flow testing.

During the PAC-4 electrical checkout, the motor rotor testing indicated that the motor contained a short. An internal inspection of the motor revealed significant corrosion and residual moisture. Due to the severity of the corrosion, the motor was removed from the foundation and shipped to a motor vendor in New Orleans. Subsequent teardown inspection indicated that the motor was repairable. The vendor was directed to clean the motor by CO_2 blasting with the vendor present to confirm the cleanliness and reassembly of the unit. The unit was returned to site and returned to the foundation. Then moisture was observed bubbling up from beneath the soleplates and the motor was removed

until the foundation could be repaired. See section 5.2.3.2, Extraction Air, for a detailed discussion of the foundation repairs. The corrosion issue was resolved in August 2014.

After the foundation repairs were complete, final preparations were made to conduct the commissioning of PAC-3 and PAC-4. Both units were commissioned in the same manner as PAC-1 and PAC-2 previously described in this section.

There were challenges in preparing to commission the process air compressors, but each compressor met all the testing objectives planned during the commissioning phase. The installation of the temporary crossover made air available while repairs were being completed. Integrated testing was delayed due to the unavailability of the process air system. Future projects should consider the benefits of cross-connected systems when developing air systems for a highly integrated process.

5.2.3.2 *Extraction Air*

- Accomplishments

EAC-1		EAC-2	
Lube oil system commissioned	6-2-2014	Lube oil system commissioned	3-14-2014
Precommissioning complete	6-8-2014	Foundation/soleplate repair complete	3-31-2015
System cleaning complete	6-20-2014	System cleaning complete	6-20-2014
Foundation/soleplate repairs complete	3-24-2015	Precommissioning complete	8-17-2015
Main motor vibration investigation complete	6-4-2015	EAC-2 commissioned	2-19-2016
EAC-1 commissioned	7-25-2016		

The commissioning of the extraction air compressors was significantly delayed due to installation and fabrication quality issues. Initial checkout and testing of the system identified these as issues in precommissioning. The repairs detailed in this section were difficult and time consuming.

Construction of the lube oil skids was completed in early 2014. Work began to complete the instrumentation and logic checkout, electrical testing, and flushing of each skid. Minor issues were found with lube oil piping pipe stress and with alignment of the lube oil pumps. These issues were corrected before flushing the oil skid. Oil flushing was completed by the oil flush contractor. Per procedure, the system was initially flushed by cycling through off-skid pumps and a sock filter. After the socks showed no visible particulate, the flushing was completed using on-skid equipment. Commissioning of the lube oil skids was completed in March 2014 for Train B and June 2014 for Train A.

Following commissioning of the lube oil skids, the process side system piping into and out of the compressor was opened for hydroblasting. The process piping was cleaned from the gas turbine isolation valve to the compressor suction. Provisions were made to clean up to and out of the suction knockout drums and heat exchanger. The compressor discharge piping and antisurge kickback line was cleaned. The cleaning activities were completed within a few weeks in June 2014.

After the system was cleaned, preparations were made to conduct the uncoupled motor run of both EAC-1 and EAC-2. Both motors were started in June 2014. Both exhibited significant vibrations levels increasing up to the trip limit for each motor. The rotors were not able to achieve a stable magnetic center and appeared to hunt in irregular patterns. Figure 5.2-10 shows the deviation between the NDE radial probes and the axial probes. Investigation into the cause was immediately started. It was initially suspected that the motor was not set correctly on the foundation. The motor was found to have significant soft-foot, and the motor soleplates were found to have a significant bow within each plate. There was significant deviation plate-to-plate.

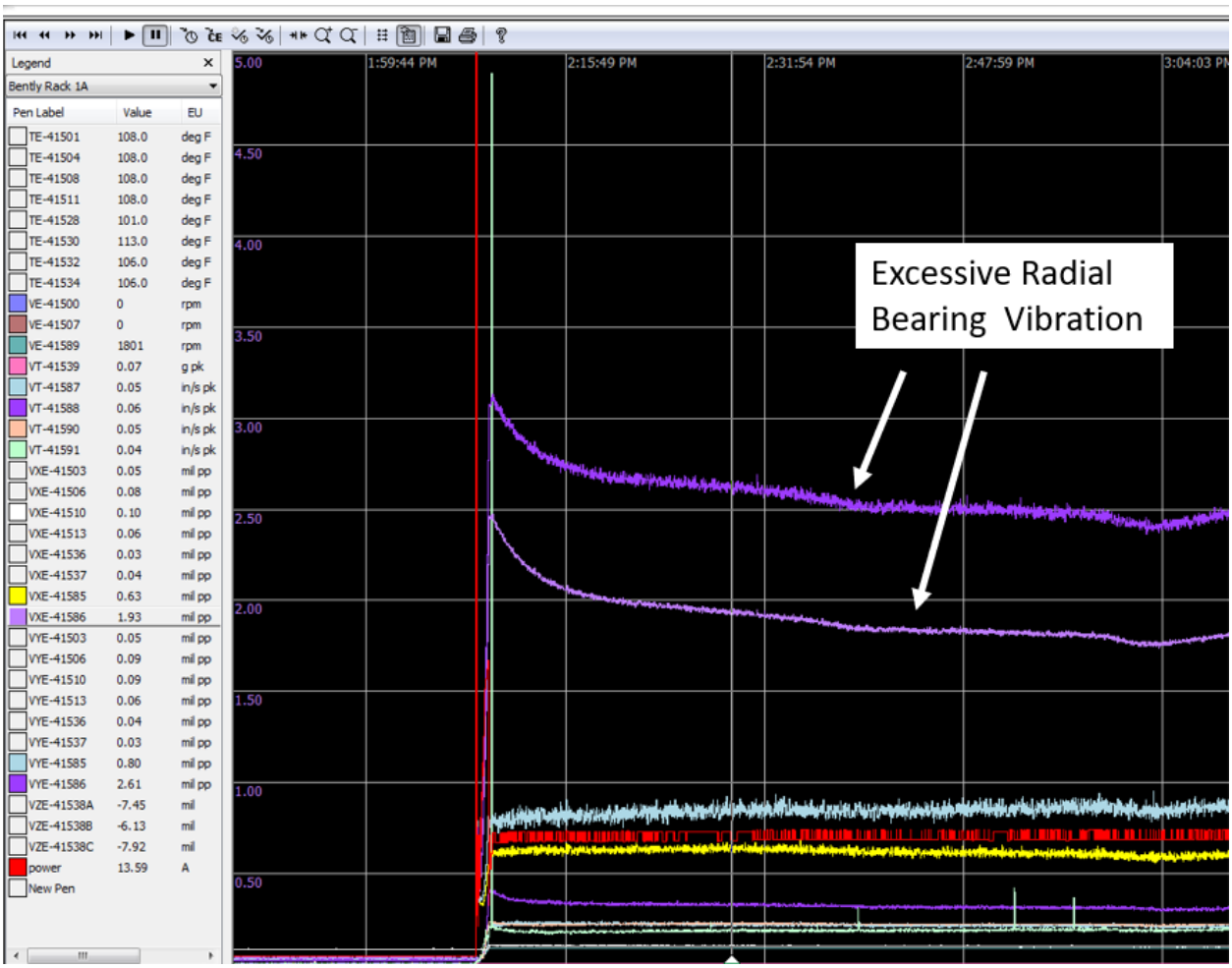


Figure 5.2-10 – NDE vibration probe deviation

Per vendor recommendation, each motor was removed to allow for better inspection of each sole plate. Vendor specifications were that the deflection plate-to-plate should not exceed 5 mil plate-to-plate. Both EACs were found to have a maximum deflection of 150 mil to 180 mil. A field machining vendor was brought onsite to restore the flatness of each plate, but the spans were too great for the machining equipment to achieve the specification. The PAC-4 motor had been removed for offsite cleaning, leaving the motor soleplates exposed, and measurements of this foundation confirmed the PAC-4 motor would have similar operating issues. While the EAC plates were being field machined, the PAC-4 was returned to site. As the motor was being placed back onto the foundation, water began to bubble up from beneath the sole plates. The decision was made to remove all the sole plates and have them shipped offsite for machining. As the plates were removed, the grout pockets were found to contain trash and nonconstruction debris. There was also no evidence that the epoxy grout had bonded to the plates.

Each sole plate was machined to within vendor flatness specification. Figure 5.2-11 shows the final measurements from the machining vendor.

Figure 5.2-11 – Soleplate machining flatness measurements

It was determined that the installation procedure for the leveling system of each sole plate was inadequate. As the epoxy was poured into the grout pocket, the plates had shifted. The heat generated by the grout warped the plates, causing both the flatness and plate-to-plate deviation to be out of specification. A different leveling system with adjustable feet was used in the reinstallation of the motor before epoxy grouting.

Foundation repairs were completed in March 2015. The operation of each motor significantly improved but was not within specification. Internal motor inspections indicated the cooling fan wheel attached to the motor internally had not been aligned to the correct balanced position. The wheel is removed for inspection during shop acceptance testing and is not a field adjustment item. The fan wheel for each motor was correctly installed, and the motor closed for final testing. Subsequent uncoupled runs confirmed that each motor operated within specification and sufficiently to proceed to coupling and performance testing of the compressor. The final uncoupled motor runs occurred in July 2015.

Following the resolution of the motor vibration issues, resources were allocated to higher priority areas. Commissioning of each EAC did not continue until December 2015. The system was maintained under a nitrogen cap for preservation.

In December, the compressor process piping was pressurized to the start pressure using temporary compressors. The board operator noticed the pressure would decrease rapidly after the temporary compressor shut off. An investigation into the source of the leakage was started. The investigation progressed slowly because insulation of the process piping had already been completed. A significant amount of insulation was removed to find all leaking connections. This removal was completed quickly on Train B (complete in February 2016), but took more effort on Train A (complete in July 2016). The compressor on each train was commissioned immediately after all leaks were identified and repaired.

Commissioning of EAC-2 commenced in February 2016. Despite the challenges encountered during precommissioning, the compressor testing progressed quickly. An initial leak check was conducted after the compressor was started. No significant leaks were found with the system at pressure.

With the system being leak tight, mechanical integrity testing was completed, which involved opening the inlet guide vanes to load the compressor. The antisurge valve remained open during this test. The bottom extent of the available compressor performance map was confirmed.

Tuning of the inlet guide vanes and antisurge valves was completed following completion of the mechanical integrity testing and before compressor surge testing. Surge testing of the extraction air compressors tracked close to the predicted performance. Three separate surge points were obtained (one at three different guide vane positions) to confirm the surge limit line in the compressor control system.

Following surge testing, interlock trip testing was completed. The testing included a trip signal being generated from the Allen-Bradley PLC, the VFD/Soft-start drive PLC, the DCS, and SIS. The test confirmed that a trip signal from any of the systems would trip the compressor if required.

Compressor testing was completed in February 2016 for EAC-2 and July 2016 for EAC-1.

Integration was not available with the gas turbine before coal feed testing. The turbine control system did not include provisions for providing extraction air in high enough volume to operate the compressor during natural gas operations.

5.2.3.3 *Transport Air*

- Accomplishments

TAC-1		TAC-2	
System cleaning complete	8-6-2014	System cleaning complete	8-6-2014
Lube oil system commissioned	9-24-2014	Lube oil system commissioned	10-15-2014
Precommissioning complete	1-12-2015	Precommissioning complete	1-12-2015
Seal modification complete	5-6-2016	Seal modification complete	4-19-2015
TAC-1 commissioned	5-11-2015	TAC-2 commissioned	4-23-2015

The commissioning of the transport air compressor initially followed the test plans closely. The compressor lube oil skids were the first items received. The commissioning of each skid consisted of instrumentation and logic verification, and uncoupled motor runs on each of the on-skid lube oil pumps. The procedure included a flush of the lube oil circuit to ensure system cleanliness before introducing oil to the compressor and the main motor bearings. The flush activity consisted of circulating the oil through an off-skid pump and sock filtration unit. After the bulk oil was sufficiently clean (no visible particles on the sock following a 4-hr run), the oil was circulated through the compressor and motor bearings with last-chance screens. The screens remained installed until they were verified clean by both vendor and Southern Company personnel.

Precommissioning and flushing activities for the train 1 lube oil skid was completed in September 2014. The train 2 lube oil skid was completed in October 2014. The skids remained in operation to the extent possible until the compressors were readied for commissioning.

Cleaning of the compressor suction and discharge process piping started in parallel with the lube oil skid commissioning. The piping is stainless steel, and the cleaning crew first considered blowing the lines clear of debris. The decision was made to use hydroblasting, because the hydroblast crew was working nearby and would be able to clean the lines more quickly. During the cleaning, the hydroblaster was inserted at twice the rate as with similar sized carbon steel piping. This process effectively flushed the lines clear. The cleaning activity and restoration were completed in August 2014.

When construction of the compressors was complete, precommissioning activities commenced with similar activities to the lube oil skids. The instrumentation and logic were verified from the element to the operator panel (HMI), and electrical testing of the cabling and main motor was completed. The main motor was operated uncoupled from the compressor to verify rotation, obtain a vibration baseline, and to confirm that each bearing received adequate lube oil flow. The inlet guide vanes were calibrated. Figure 5.2-12 shows a plot of the DCS value (%) read by the operator versus the mechanical angle of the inlet guide vanes.

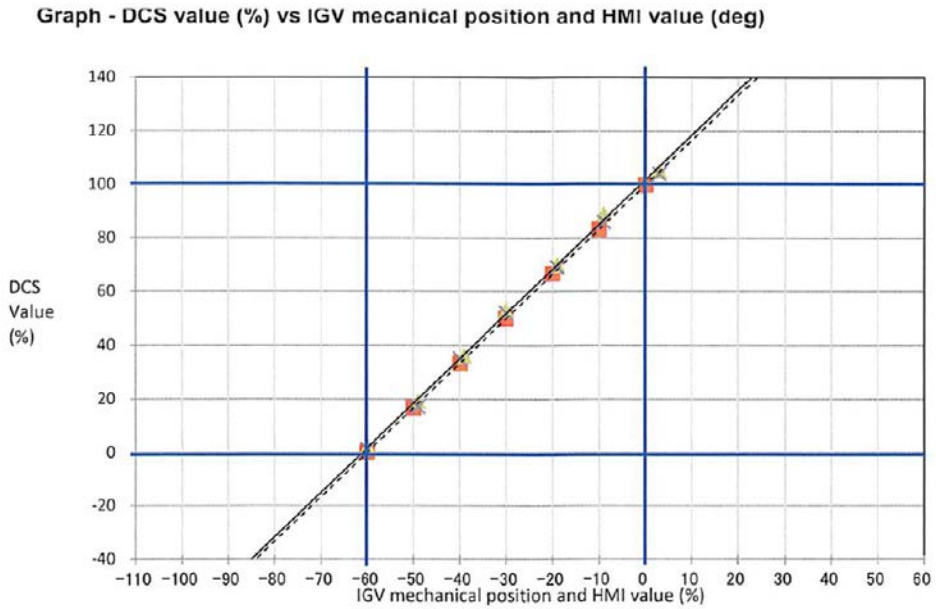


Figure 5.2-12 – DCS value vs IGV mechanical angle

All precommissioning activities were completed in January 2015. Final preparations were made to commission the transport air compressor.

Startup of the TAC required that a process air compressor charge the process air header up to the suction side of the compressor. Per procedure, the transport air suction pressure was established at 600 psig. During the initial pressurization, a low-pressure and medium-pressure leak test were conducted with no significant leaks identified.

With the leak test satisfactorily complete, an attempt was made to start the compressor. The compressor started and ran well. Shortly after startup, outside operators reported an oil leak from the lube oil overflow and rundown tank overflow. The compressor was shut down and an investigation started to determine the cause. It was noticed while reviewing trend data that radial vibration level was high at the time of the oil overflow (figure 5.2-13).

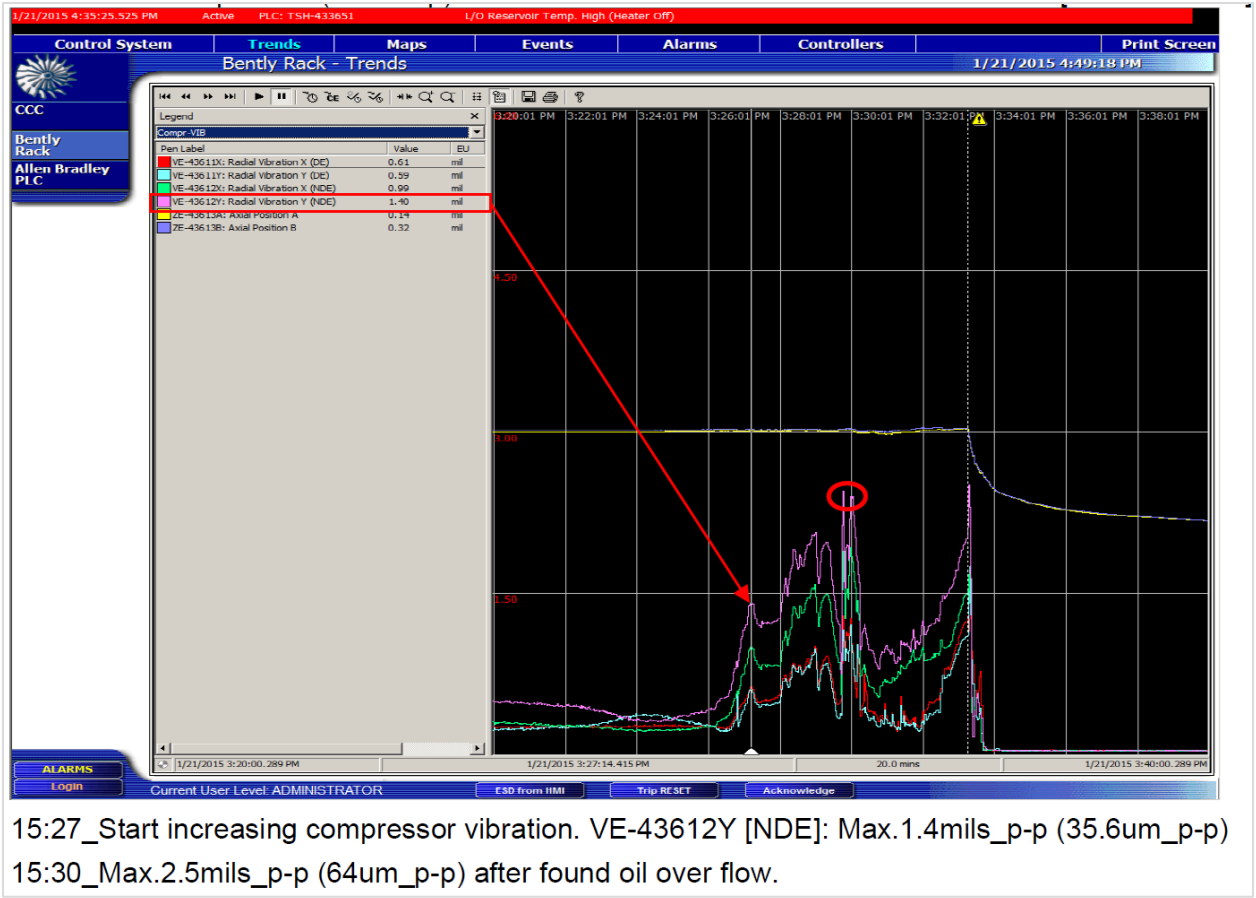


Figure 5.2-13 – NDE Y-probe high vibration

The cause was determined to be compressor labyrinth seals that were not mechanically robust enough to operate at 600 psig suction pressures. The result was that the seals were pressed against the rotor. During startup, the seals failed and allowed air to backflow into the lube oil system, causing an increase in lube oil system pressure. Figure 5.2-14 shows the damaged seals. The darker areas were pressed into the rotor.

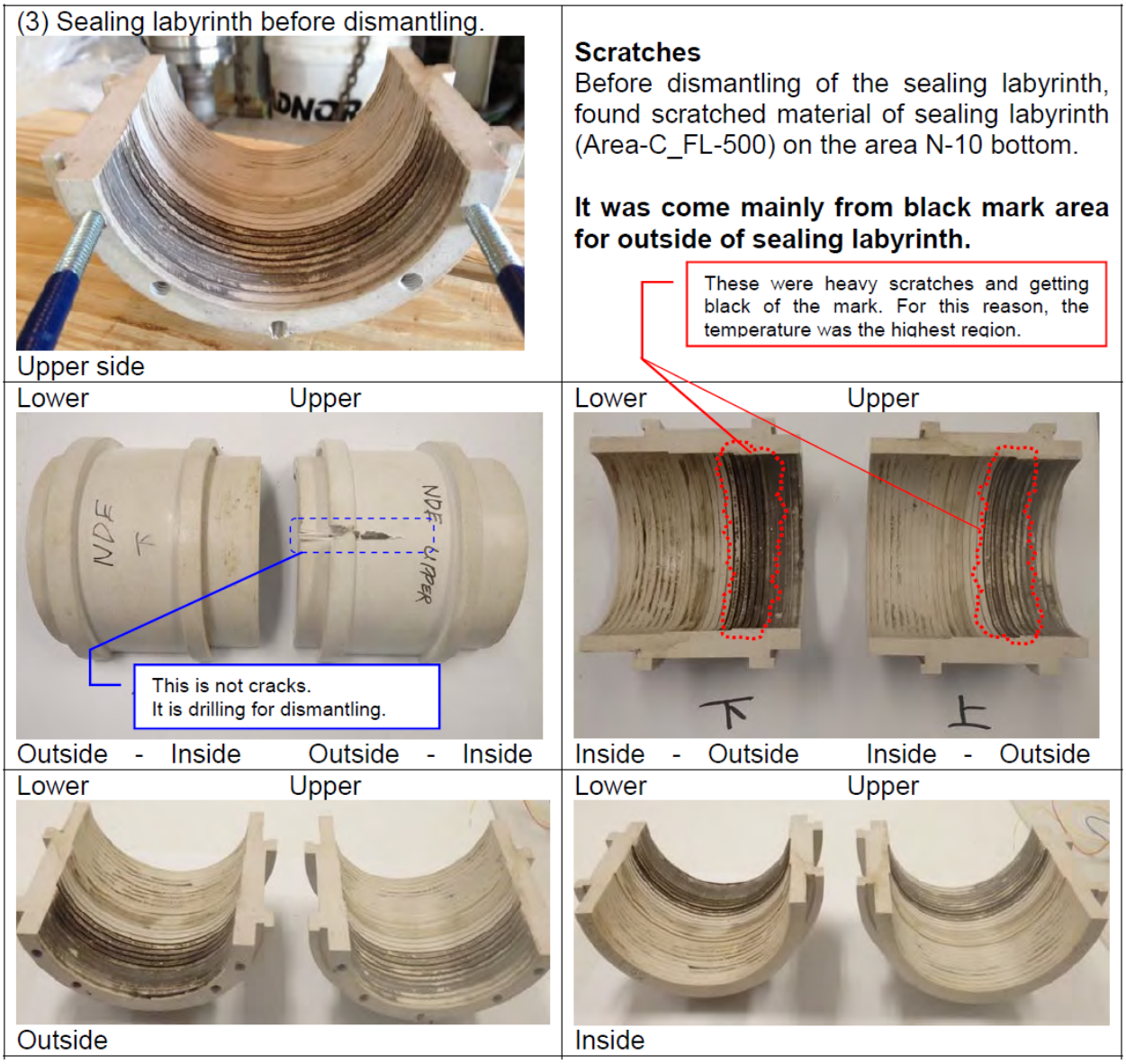


Figure 5.2-14 – Damaged seal material - TAC1

The vendor provided steel replacement seals that were able to withstand the high suction pressure of the transport air compressor without deformation.

The root cause investigation and subsequent repair were completed in May 2015, and commissioning of the transport air compressors continued.

With the new seals installed, commissioning of each compressor was completed with no issues. A high-pressure leak check was completed with no leaks observed. The labyrinth seals performed well. Figure 5.2-15 shows an overview of the lube oil operation. All process points were operating within limits.

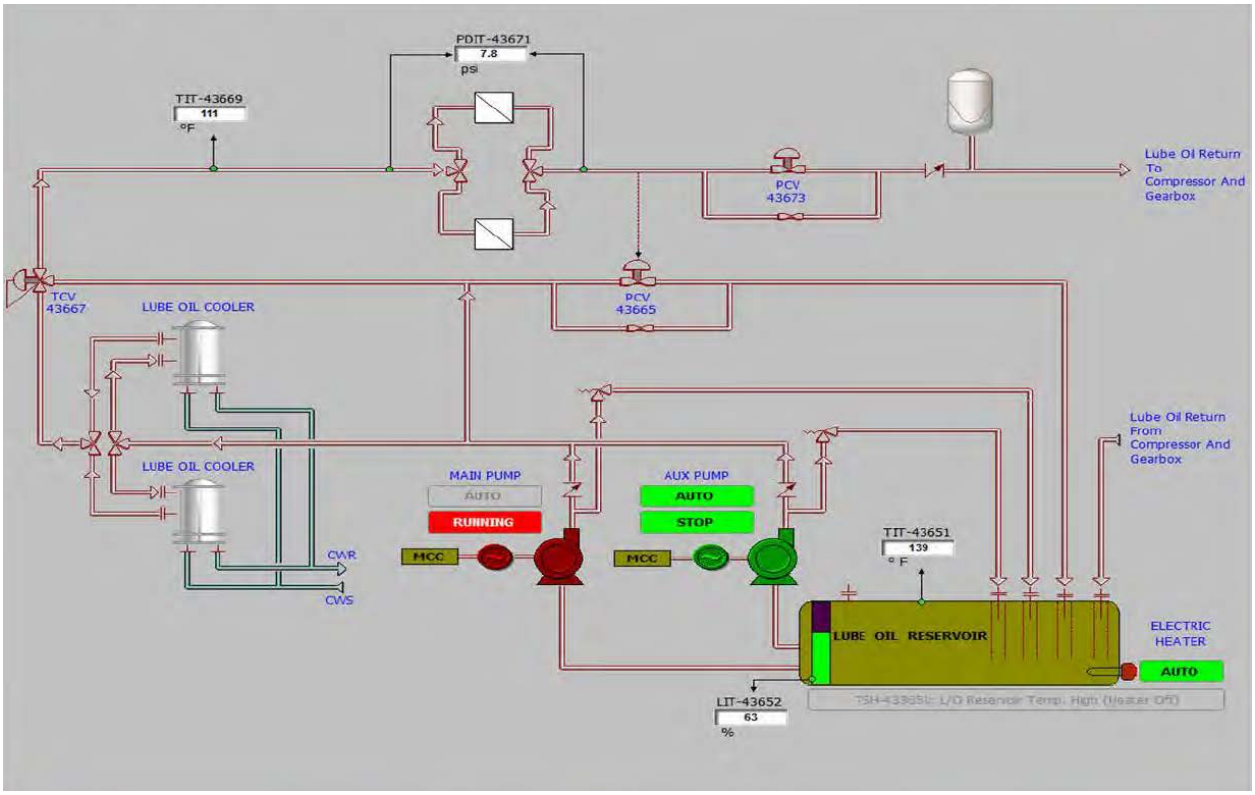


Figure 5.2-15 – TAC-1 Lube Oil Skid Overview

Tuning of the antisurge valve (ASV) was completed after stable operation of the unit had been confirmed. Immediately after the valve was tuned, the test group proceeded to surge limit line validation testing. This test was completed at multiple guide vane locations to develop a curve corresponding to the compressor surge line. Figure 5.2-16 shows the predicted versus actual performance of the TAC-1 compressor. TAC-2 performance closely mirrored that of TAC-1.

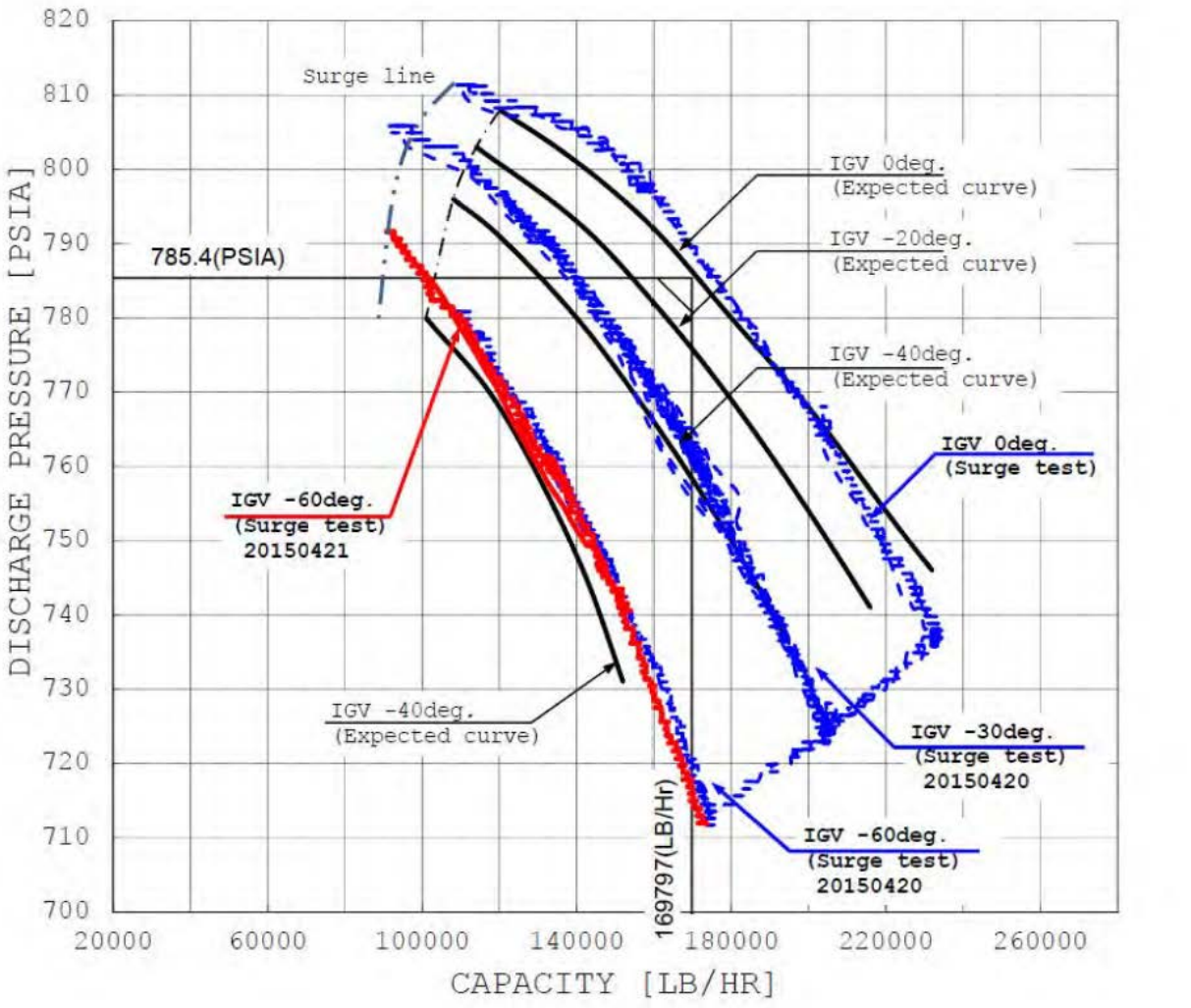


Figure 5.2-16 – TAC-1 predicted versus actual compressor performance

Interlock trip testing was completed following the completion of surge testing. An induced trip signal was generated from each of the locations that contain trip interlocks. Two of three lube oil pressure probes were valved out to induce a trip.

Commissioning and final layup of TAC-2 was completed in April 2015. TAC-1 testing was completed in May 2015.

5.2.3.4 *Transport Air Dryer*

- Accomplishments

TAD-1		TAD-2	
Precommissioning complete	1-16-2015	Precommissioning complete	1-16-2015
Desiccant loading complete	6-23-2015	Desiccant loading complete	6-23-2015
Transport air dryer commissioned	6-28-2015	Transport air dryer commissioned	6-28-2015

Commissioning of the transport air dryer sets included only items typically identified as precommissioning for larger systems: instrumentation and logic verification, electrical testing of the blower motor, and vessel inspections and leak testing.

During the checkout of the CO_2 dryers, the regeneration heater elements were found to have excessive corrosion. The terminal box contained condensation, which had corroded many of the element terminations. An inspection was conducted on the TAD heater elements, which were also found to contain corrosion. The TAD elements were not in as poor a condition as the CO_2 elements, but they still required some cleanup. The contractor brought onsite to clean the CO_2 elements was directed to do the same for the transport air. Cleaning was done with CO_2 blasting. The elements were reterminated and testing of the TAD system continued. To prevent further corrosion, the elements were continuously heated with a low voltage heat source.

The precommissioning activities were completed in January 2015. The system was placed under nitrogen layup until the desiccant contractor was ready to load the desiccant. Immediately before dessicant loading, a preliminary leak check was completed. The vessel internals were inspected to confirm suitability to accept the desiccant. Both activities passed with no significant findings. The desiccant was loaded into each chamber by dumping the material from super sacks directly into the vessel. This process was completed for all chambers in June 2015.

Following desiccant installation, the testing of each dryer system was verified by going through the regeneration sequence. Testing included verifying successful swapping operations from one chamber to the next and starting and stopping the regeneration cycle. Functional testing was completed in June 2015. To maintain the desiccant until integration testing, each chamber was regenerated once every 24 hours.

5.2.4 Final Summary

All test objectives for the process air compressors, extraction air compressors, transport air compressors, and transport air dryer were successfully completed. Integration and tuning of each of the components with the process air header was completed with few issues. While commissioning time was extended to address installation quality issues, the performance and long-term viability of each of the applications was improved by correcting the issues. The system was available in time to support the air blows and air flow testing of the gasifier and syngas path.

5.3 PDAC Coal Feed System

5.3.1 System Overview

The coal feed system is designed to transfer and feed pulverized coal to high pressure gasifier. There are six units for each gasifier train. Each unit is composed of storage bin, lock vessel, dispense vessel, PDAC feeder, and conveying line to gasifier. The unit also includes two critical rotating disk solids valves associated with each lock vessel. Except for the storage bin, all other components are high pressure equipment.

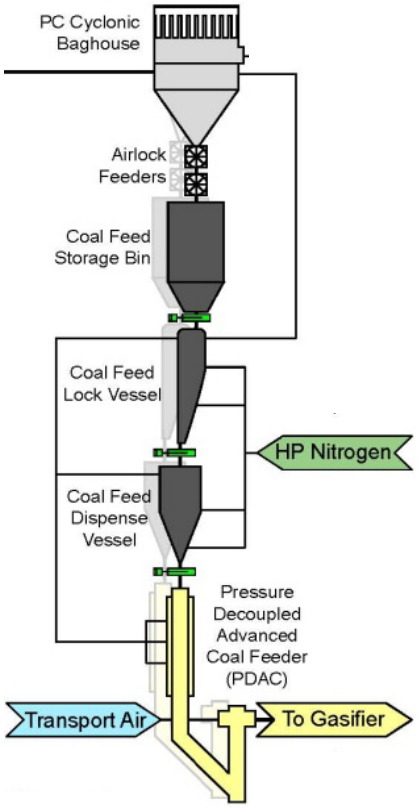


Figure 5.3-1 –PDAC feeder unit

Pulverized lignite from the lignite preparation system is transferred to a storage bin that is directly under the cyclonic baghouse and is part of the mill circulating loop. The lock vessel takes coal from the storage bin when the bottom rotating disk valve is closed and the top rotating disk valve is fully open. A slide gate valve above the top rotating disk valve regulates lignite flow to the lock vessel and ensures the lock vessel fills up in the preset desired time. After coal is adequately filled in the lock vessel, the slide gate valve is closed first, followed by closing of the rotating disk valve. High pressure (HP) nitrogen then pressurizes the lock vessel in a preset rate sequence, reaching near the dispense vessel pressure (within ±10 psi) depending on the operation mode selected.

When the level becomes low in the dispense vessel, the lock vessel bottom rotating disk valve opens to dump the lignite into the dispense vessel. After dumping is complete, the bottom rotating disk valve closes, and the lock vessel is depressurized through three orifices in a preset sequence. After the lock vessel reaches low enough desired pressure, the top rotating disk valve and slide gate valves may be opened for the next filling cycle.

The dispense vessel remains at high pressure, while the PDAC feeder below feeds coal from the dispense vessel to the conveying line at the desired rate. High pressure nitrogen controls the coal feed rate, and transport air conveys the coal through the conveying line to the coal feed nozzle in the upper mixing zone section of the gasifier.

The philosophy of the coal feed system is based on the cyclic nature of lock vessel operation. The control logic is suitable to address such cyclic operations.

The table in section 5.3.3.1 shows the milestones of recovery of units from extreme wetness during hydrostatic testing, the start of dry test dates of all feeders in trains A and B, and start and completion dates of offline tests with the coal feeders.

5.3.2 Initial Commissioning Plan

5.3.2.1 *Leak Check and Pressure Test*

For each feeder, a leak check and pressure test were planned with the unit isolated and split into two parts: the lock vessel, dispense vessel, PLD and PDAC feeder; and the conveying line and associated piping.

Per procedure, the leak check was to confirm every connection was mechanically tight. Following turnover to Startup, instrument air up to 100 psig pressure was planned to be used for leak checking, as it was readily available at multiple locations. After leak checks, a pressure test was planned to step up system pressure up to 700 psi to check for unit pressure retention performance and to find and correct remaining minor leaking points.

5.3.2.2 *Unit Functional Test*

Each PDAC feeder unit includes multiple components. The functional test checks each component on basic effectiveness of mechanical, instrumentation, and sequential operations. All valves, especially the 18-in. rotating disk valves above and below the lock vessel, needed to be cycled to test performance and ensure the valves meet open and close limits within the specified time.

Each feeder unit has elaborate and sequential control logic. After completing pressure testing and instrument and valve loop checks, the major functional check was to test the sequential control logic in the dry cycle mode of operation and ensure the unit will operate as intended.

5.3.2.3 *Offline Coal Feed Test*

An important aspect of the PDAC feed system unit commissioning was offline coal feed tests, which were critical to testing the entire feed system. Each feeder unit was designed to have the flexibility to operate in offline mode. The feed system must be tested in offline mode to confirm the unit is handling pulverized coal appropriately. The pulverized coal from the coal prep system is stored in the storage bin for the offline test. The coal exiting the feeder conveying line is returned to the storage bin, establishing an offline coal circulation loop to test all operational aspects of the feed system. The offline test subjects the feed system to multiple cycles, before operational issues arise due to finer coal from attrition. Although offline testing can be carried out only at low pressures as the conveyed coal is fed back to the storage bin, the operation allowed testing of nearly all operational parameters, all mechanical components, instrumentation, and sequencing operation including variation in coal feed rates.

5.3.3 Significant Events

5.3.3.1 *Accomplishments*

Milestone	TRAIN A	TRAIN B
Recovery of unit from wetness	05/10/2015	05/10/2015
Dry test start	04/18/2016	05/05/2016
Initial offline test start	09/04/2016 with 2A/2B	05/03/2016 with 5A/5B
Offline test all units complete	09/09/2016	07/12/2016

The original unit commissioning plan included leak and pressure tests, unit functional tests, and offline coal feed tests. These activities were delayed when there was an unexpected leakage from hydrostatic testing of lines connecting to the vessels and feeders. This leak soaked nearly all equipment with water and a large-scale effort was needed to recover the equipment, especially the PLDs located just below the dispense vessel. Draining the accumulated water, cleaning, and drying delayed the unit commissioning activities on all feed units.

5.3.3.2 *Water Contamination and Unit Recovery*

When coal feed systems were transferred from construction to startup, large quantities of water were found in feed system unit vessels and the connected piping network. The water in the feed systems was discovered as the systems were prepared for leak checks and blowout of dust and construction waste. When water accumulation was found in one coal feed system, all coal feed systems were inspected. Almost all the 12 field units had accumulated water of some amount, enough to fill a few 55-gallon drums from each individual unit when drained. Most units had water marks on all major components, including lock vessel, dispense vessel, PDAC feeder, and the pressurization, aeration, and conveying lines. Water was drained from all locations, then the system was air dried with instrument air for several days until there was no detectable moisture in the exit streams.

The primary concern for water damage was the PLD, located between the dispense vessel and the feeder. Most of the PLDs were soaked in dirty water. The PLD minimizes pressure fluctuations and is one of the key components in coal feed control. A wet PLD will not function at all when the unit is put into service. Some components can be washed and dried relatively easily, but the PLD has complicated internals could not be dried easily.

It was tedious work to recover the PLDs. The primary method was to use blanket heating and continuous instrument air blowing from inside out for several days until no moisture was detectable in the exiting air stream. Instrument air was temporarily lined up and connected to the PLD back pulse nozzle. Air flow was measured with PDAC instruments to ensure there was sufficient velocity and continuous air flow through wet internals. At the same time, the PLD shell was wrapped with a heating blanket, and a temperature controller was used to set the heating temperature.

Different methods were used to check the drying and confirm whether it was effective. One was to measure the pressure difference for resistance across the key internal layer. When the internal layer was wet, air flow resistance was high. The pressure difference decreased over several days as drying proceeded, and a differential pressure criterion was established as a reference to check for completeness of drying. Another method was measuring the humidity in the outflow air stream, as evaporated moisture from internals was carried out by the flowing air stream.

The internal layer in the PLD had a large surface area, and the air flow tended to flow through the drier areas with less resistance, making the drying process slow and tedious.

The trials established that a week of continuous drying was needed for PLD drying. The rest of the PLDs were set in batches for simultaneous drying for a 1-week period.

All PLDs were recovered and set for further use. The ad hoc dry-out procedure was effective, and no repairs or replacement of PDAC PLDs were necessary.

5.3.3.3 *Nozzle Blowing, Leak Check, and Pressure Test*

The PDAC feed system has nozzles for fluidization, pressurization, and introducing conveying gas. The illustration below shows the complexity of the system, with each vessel surrounded by these lines. In each feeder unit, two sections were separated for unit testing. The first section included the lock vessel, dispense vessel, PLD, and feeder. The second section included the conveying line from feeder exit isolation valve (dirty shutdown valve) through the blind added (for unit commissioning) upstream of two XVs (clean shutdown valves) located at the gasifier coal feed nozzles.

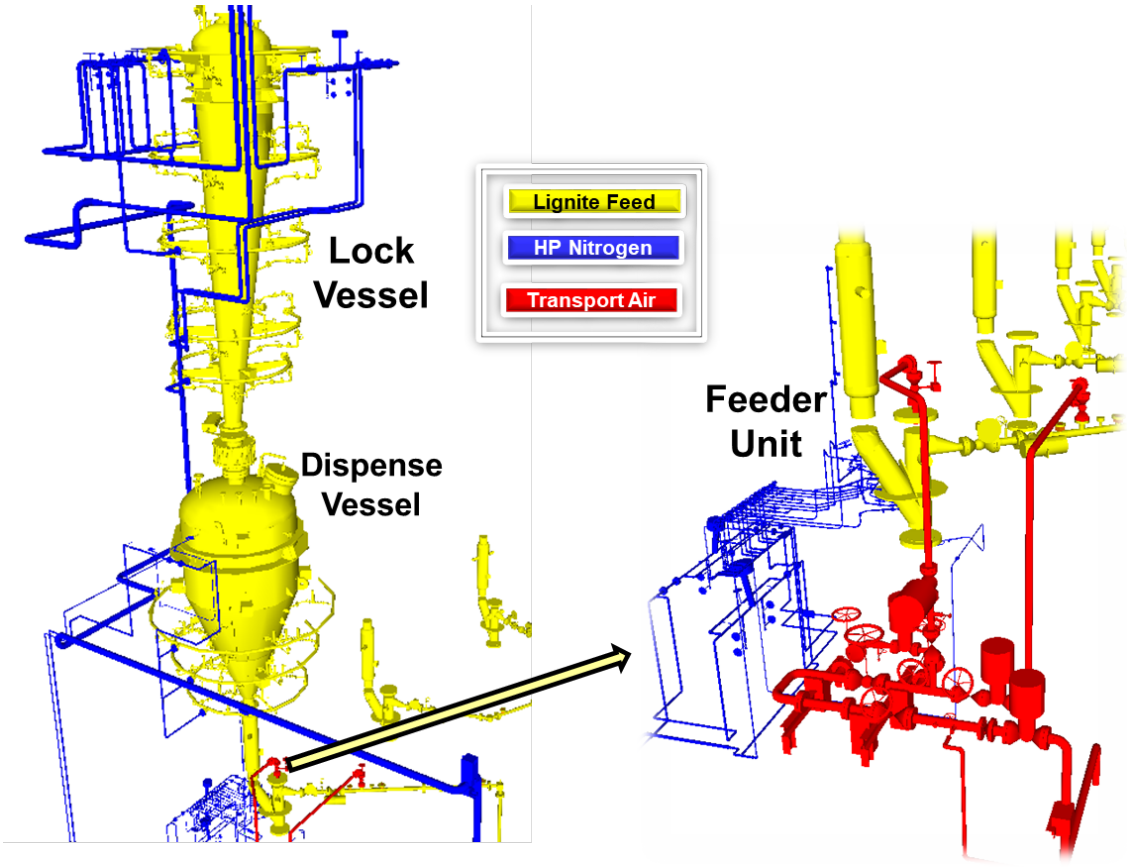


Figure 5.3-2 – PDAC coal feed system and connecting lines

Before commencing leak checks, all lines and nozzles were blown to ensure the lines were clear of any trash, confirm the installation of check valves in the right direction, and check operability of all manual valves. A few lines had construction waste cleared, water left over from hydrotesting blown out, and lines dried. During this activity, faulty instruments (pressure and flow indicators) were identified and tagged for later repair. Construction issues were generally fixed in 1 or 2 days. Temporary spool pieces were added to instrument and valve locations that took longer to fix, in order to continue with unit commissioning.

At the start of leak check, with air flow at low pressure of 30 to 50 psig, operators found obvious open points, loose connections, missing gaskets and so forth. Those issues were quickly identified, tagged, and fixed almost immediately.

After leak check and fixing all obvious leaking points, the pressure test was started. Pressures were stepped up at 100 psig, 300 psig and 700 psig after achieving acceptable decay rates.

During initial leak and pressure tests, logic was used to force open the everlasting rotating disk valve between lock vessel and dispense vessel to balance pressure between the two vessels. During later tests, this valve was closed to determine if there were any internal leaks from dispense vessel to lock vessel.

In every step, after the unit was charged to a desired pressure, the inlet flow was isolated. Field operators checked around the unit at every flanged and threaded connection, first by walking down and listening for a major leak, then by spraying soap solution. As minor leaks were noticed; some were addressed with the system pressurized and others were tagged and addressed after depressurization.

At higher pressures, up to 700 psig, pressure decay rate was the major focus. Tests were at minimum of 3 hours to observe the pressure holding effect. When an abnormally high-pressure decay rate was observed, more field checks for leaks were performed. A pressure drop rate of 5 psi per hour or less was required.

Despite efforts to eliminate external leaks, the openings to the storage bin above the rotating disk valve on top of the lock vessel could not be fully and positively isolated. The resulting internal leak across the rotating disk valve was likely the major contributor to pressure decays.

5.3.3.4 *Unit Functional Test*

The PDAC system mechanical portion of the unit functional test was conducted by exercising all valves and ensuring the valves met the limit switches. The sequence logic check of cyclic operation was one of the major steps of unit commissioning. The system has built-in logic for the half- and full-dry cycle where the lock hopper executes the pressurization and depressurization sequence. This logic was used extensively during initial unit commissioning. The coal feed system logic had been operationally checked by the OTS, and corrective actions were taken well before the start of unit commissioning activities. As part of unit commissioning, the sequence logic was checked again with actual field conditions, instrumentation and transmitters, and valves. Real field conditions introduce variables not usually found in the OTS, such as faulty instruments, spurious readings, hung valves, coal packing and bridging, aeration line pluggage, level switch failures, and failing to make limit switches. Because of the simulator testing, real-time sequence logic tests were successful and only minor logic adjustments were needed.

During unit functional testing, the lock vessel operation was set in full automatic mode to execute the entire sequence logic. With this setup, only the dispense vessel solids level need to be simulated. All valve actions, pressurization, and depressurization were automatically performed in real operating conditions. Coal feed was simulated by flowing control nitrogen and conveying gas.

The major observation for these tests was that the control nitrogen valves could not be operated, due to limited turndown issues when the differential between nitrogen header pressure and coal feed dispense vessel pressure was high (greater than 300 psid).

5.3.3.5 *Offline Coal Test*

The coal feed system unit offline test was designed to run the whole unit with coal, conducting cyclic lock vessel operation with continuous coal feed from the coal feed dispense vessel and conveying the coal back to the storage bin with the feeder unit. The coal preparation system crushed, dried, and pulverized the lignite. A batch of pulverized coal was prepared from dryer 5 and stored in storage bins 5A and 5B. On May 3, 2016, the first offline tests with PDAC systems 5A and 5B were carried out. On the first try, coal flow turned around the loop successfully, from storage bin to lock vessel, then to the dispense vessel and finally conveyed back to the storage bin with the PDAC feeder. Both 5A and 5B were independently tested and both performed well over a few cycles.

Some outstanding mechanical items were addressed, then on May 5 offline tests continued with the coal left in the storage bin from the last test. After one cycle, the lock vessel, as expected, experienced difficulties in transferring the coal to the dispense vessel. When coal passes through the whole loop multiple times, especially with higher conveying line velocities than during normal operation, coal particles are subjected to attrition and lead to more and more fines in the loop. Fines in the lock vessel tended to pack more during pressurization, and the packing effect in the lower portion of the vessel caused bridging when the lock vessel bottom valve opened to dump coal. These tests with circulating coal solids in the loop provided information on the lower limit for coal size during normal operation.

On May 6, fresh coal from the dryer was used for more tests. On each of the two feeders 5A and 5B, coal feed rates were set at low, medium, and high to check the response of the feeder unit to change in the coal feed request. For feed setpoints of 10,000 pph, 50,000 pph, and 100,000 pph, instruments indicated the coal feed rate was following demand, and coal was feeding at the desired set point. When held for sufficient time at each set point after ramping up at desired rates, stable operation was achieved, and the feed rates were determined. The coal feed set point was dropped from high to medium to low, and the indication with both the conveying line differential pressure and the coal flow meter showed the corresponding feed rate changes. The coal feed changes were repeatable with changes in setpoint.

During an offline test, coal is conveyed to the storage bin at the other end. The feed unit can be tested only at low pressures because the storage bin is at ambient pressure. The pressure effect on lock vessel operation was as expected.

The offline tests demonstrated the operability, controllability, and feed repeatability of the PDAC coal feeder and the operation of the entire coal feed system at low pressures. The offline tests were conducted with each of the 12 coal feed systems to ensure their operability.

5.3.3.6 *Transport Air Test*

Coal is conveyed to the gasifier with transport air during normal operation. For safety reasons, nitrogen is used to purge the conveying line during individual feeder startup and shutdown. This test was totally logic controlled and automatically carried out with on/off valves on both nitrogen and transport air supply lines. During later commissioning, the transport air compressor was started and air flow through the conveying line was tuned. All components in the transport air compressor system operated well.

5.3.3.7 *Solids Level Measurement*

In the coal feed system, especially with the lock vessel and dispense vessel, solids level detection is highly critical. Overall, the nuclear instrument-based level measurement in these vessels satisfactorily supported the offline tests and operation. Initial calibration was required to make the nuclear level measurements work properly.

5.3.3.8 *Control Nitrogen Header*

The functional and offline tests determined that the flow meters and flow control valves for coal feed control nitrogen flow could not work properly at low pressures because they were out of their design range. During normal operation, the coal feed to the gasifier must be started at low pressures before ramping the pressure up. The transition from low pressure gasifier startup heating system to coal feed will occur every time at the start of plant operations. A modification was designed, fabricated, and installed to add pressure regulating valves to the existing nitrogen header supplying nitrogen for coal feed control (figure 5.3-3). Effective control of supply nitrogen pressure was achieved with two parallel control valves. One was a smaller 1-in. valve in a 2-in. line for low nitrogen flow needs such as during the start of coal feed at about 40 psig with only one feeder. The other was a controller with a 2.5-in. valve in a 4-in. line for low to medium feed conditions with coal feed up to 200 psig gasifier pressure. For operations at higher pressures, the existing manual butterfly valve was left open to allow higher nitrogen flow rates.

After the modification to the nitrogen header pressure control, both offline and online control of nitrogen flow improved and effective control over the coal feed rate could be maintained.

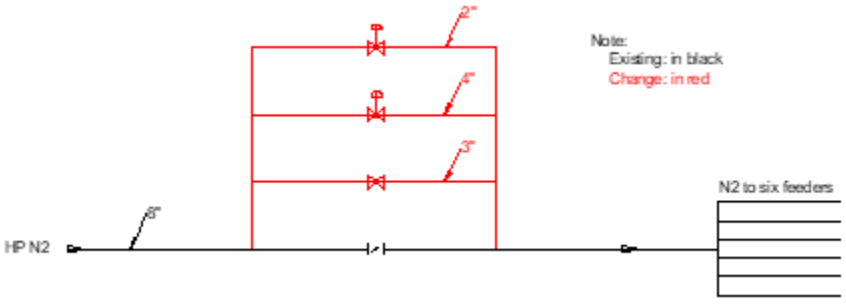


Figure 5.3-3 – Bypass system on HP nitrogen line for low flow conditions

5.3.3.9 *Components in Feeder Unit*

- Pulverized coal storage bin

The aeration to the cone section proved to be effective, and the continuous level measurement appeared to be reliable. During commissioning, spurious activation of emergency sprinkler system water in one of the cyclonic baghouses filled two connected storage bins and needed considerable effort to clean and dry the storage bin.

- Lock vessel

The lock vessel is key equipment in the feed system, where pulverized coal from a storage bin at atmospheric pressure is pressurized rapidly to high operation pressures. The lock vessel, coupled with two major rotating disk valves, was operated without any major mechanical issues. The valves functioned exceptionally well. Purge flows to the slide gate valve and the body of the rotating disk valve effectively eliminated the occasional valve hang-up from coal particles in early stages of commissioning.

The coal particles packed near the lower portion of the lock vessel and in the body of the rotating disk valve. There were no nozzles for fluidization or pressurization gas over a 3-ft distance from above the rotating disk in the valve to lowest set of nozzles in the lock vessel, because of the mechanical constraints of the 900 lb flange and the minimum distance between welds (figure 5.3-4). At higher operation pressures, the solids packing effect during pressurization could increase and lead to extended transfer time or bridging in the lower portion of the lock vessel. As a result, sometimes the lock vessel required two cycles to completely transfer the coal to dispense vessel, a regular fill cycle followed by a dry (no fill) cycle. During unit commissioning, the lock vessel operations were briefly tested at higher pressures by pressurizing the dispense vessel to about 300 psig with the discharge valve in the conveying line closed. After the dispense vessel was filled with coal, the vessel was slowly depressurized through lock vessel vent lines in multiple steps to lower pressures that were sufficient to convey the coal back to the storage bin.

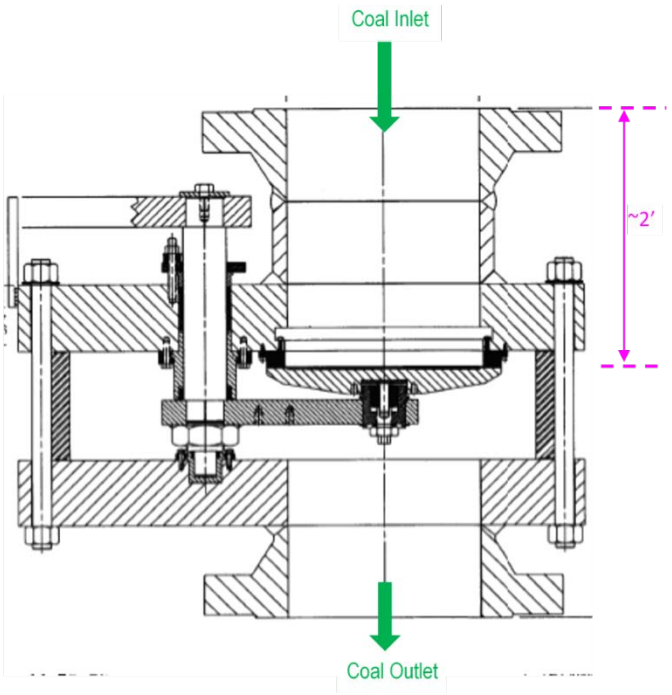


Figure 5.3-4 – Rotating disk valve below the lock vessel

The solids packing issues were addressed by several modifications including:

- Adjusting the distribution of gas flow through various sets of nozzles along the lock vessel elevation.
- Modifying the nozzle inserts to directionally introduce the gas into the lock vessel.
- Additional nozzles in the flange neck of the rotating disk valve for fluidizing gas flow and to minimize the dead space above the rotating disk in the valve
- Logic modifications and controls tuning.

A design to locally fluidize the lower portion of the lock vessel just before opening the bottom valve was developed and implemented. As commissioning, startup, and extended operations progressed, this design allowed the lock vessel to operate with less bridging and eventually allowed the coal feed system to feed coal to gasifier up to the design coal feed rate. When coal size and moisture content were in proper range, reliable lock vessel operation could be expected. However, when more fines were present in the storage bin due to issues in the coal preparation system, an extended transfer time could be needed to overcome the bridging problem. Consistent and reliable coal preparation that produces pulverized coal within specified design range is one of the key factors for better lock vessel performance.

- Dispense vessel

The dispense vessel section of the feed system operated properly by receiving coal from the lock vessel when the low-level switch was uncovered. Coal from the dispense vessel was supplied uninterrupted to the PDAC feeder located underneath.

- PLD

After PLD functionality was recovered from the water soak, the device demonstrated its intended function of introducing control nitrogen into the flowing process stream and extracting gas from the process stream to maintain desired pressure in the PDAC feeder.

- PDAC feeder

The PDAC feeder controls the coal feed rate by using control nitrogen flow into the process stream. During offline tests, this part of feed system performed beyond expectations in operating over a wide range of coal feed rates and in its response to desired changes in feed rates.

- Feed conveying line

The coal conveying line transports coal from feeder to gasifier at high velocities, up to about 45 ft/s, during normal operation. The offline tests were performed with up to normal coal conveying velocities at the feeder exit. The off-centered elbows in the conveying line and the discharge valve at the feeder exit (dirty shutdown valve) performed well. The discharge valve at the feeder exit is called the “dirty shutdown valve” because it closes on trips initiated by safety interlocks with the coal stream flowing through the valve. The functionality of the dirty shutdown valve was fully tested in offline operation by simulating various interlock trips. The coal flow meter in the conveying line had limited range and the measurements were not highly reliable. During initial integrated operation with transport air, the flow meter failed due to temperature excursions in the conveying line. The unreliability of the coal flow meter did not have any impact on operations, because the calibration of the coal rate with control motive gas was highly reliable and accurate. This calibration curve is grounded in the fundamental concepts of PDAC feeder operation and was extensively tested at PSDF. The differential pressure measurement installed in the conveying line was reliable and had good turndown but needed extensive calibration. Even when the coal feed rate was maintained constant, the differential pressure measurement naturally fluctuated, which made estimation of instantaneous coal rate difficult and less useful for integration into logic.

5.3.4 Final Summary

Commissioning of the PDAC coal feed system unit was smooth and successful. The PLDs in the unit recovered from the water soak after an intensive drying effort. All major equipment and valves functioned normally. The packing in the lower part of the lock vessel due to lack of fluidization and pressurization gas flow was addressed over time, and the changes led to gasifier operations with coal feed up to design rates. System control logic and sequence logic were tested without any major issues. After addressing issues with high nitrogen header pressure by installing additional pressure control valves, control nitrogen flow to the feeder to regulate coal feed rate was tuned. The offline test positively demonstrated unit operations with good turndown capabilities and response to desired changes in coal feed rates at low pressures. The higher-pressure operation and the effect of pressure on feeder performance could only be tested with integrated operation by feeding coal to the gasifier.

The important lessons learned during the initial commissioning activities of PDAC coal feed system include:

- Do not subject lines and vessels that handle solids to hydrotest after they are installed in the structure and integrated with other units. Other tests can be submitted to ensure appropriate pneumatic and system integrity.
- Throughout procurement, fabrication, and installation, continue engagement with process and design engineers to ensure original concepts are not compromised. (This failure to communicate was the case with the lack of pressurization nozzles in the lower portion of the lock vessel.)
- Continue exploring ways to measure coal rate reliably and directly. This measurement will be useful for integration with control and trip logic.
- Startup and all other operating scenarios should have been considered in design engineering for the PDAC coal feed system and for its integration with other systems as well. For example, the changes needed to HP nitrogen header pressure and flow rates to meet startup needs could have been addressed during design.
- Follow vendor recommendation and install purge gas to valves.

5.4 Gasifier

5.4.1 System Overview

The transport gasifier is one of the core components of the Kemper plant. It takes prepared lignite as feed and converts it to syngas at high pressure and high temperature. The gasifier has a structured loop consisting of interconnected components, each of which is refractory lined on the inside and encased in a metal shell that serves as the high-pressure boundary. Nozzles located on different parts of the gasifier allow multiple fluids and solids to flow in and out of gasifier. The nozzles also house instrument probes to aid in safe gasifier operation. A high rate of solids circulation within the gasifier loop is the fundamental feature governing transport gasifier operation.

This section describes the major events during gasifier unit commissioning before the start of coal feed to the gasifier.

The TRIG™ gasifier at Kemper converts lignite, air, and steam into low Btu syngas. At full load conditions, the syngas from the gasifier exits at approximately 635 psig at an ideal temperature of 1,740 °F. These conditions are sufficient to avoid formation of long-chained hydrocarbons (tars) while providing high carbon conversion.

The gasifier is 185-ft tall and consists of refractory-lined pipe sections. The design operating temperature range is 1,600 °F to 1,800 °F. Thermal expansion is accommodated without expansion joints, which have been problematic in high-temperature refractory-lined systems. The maximum allowed internal temperature of the gasifier is 1,850 °F.

At full load and average lignite composition, the gasifier is fueled with dried lignite at a feed rate of approximately 200 ton/hr and an air feed rate of 380 to 410 ton/hr. The pressurized gasifier is designed to convert more than 98% of the carbon in the lignite into syngas. The char (remaining carbon plus coal ash) is removed from the gasifier through the coarse ash cooling and depressurization system. Fine particulate entrained in the syngas is then removed using the sintered metal candles in the PCD filters. The gasifier bed material consists primarily of lignite ash and char carbon.

The syngas produced is a mixture of nitrogen (the Kemper gasifier is air-blown), carbon monoxide, hydrogen, methane, water vapor, and carbon dioxide, with traces of contaminants such as hydrogen sulfide, mercury, hydrogen cyanide, ammonia, and other impurities. Sulfur and other pollutants are removed from the syngas upstream of the combustion turbine (CT).

The gasifier has six coal feed lines to distribute the lignite and maintain stable gasifier operations should a single feeder fail (figures 5.4-1 and 5.4-2). If a feeder fails, the remaining feeders automatically increase their feed rate to compensate for the loss. Char carbon in the circulating solids will continue to be oxidized to maintain the gasifier temperature and syngas quality. There is sufficient margin for a second feeder to fail and still maintain desired coal feed rates with four feeders.

Lignite and air enter into the lower and upper mixing zones (LMZ and UMZ) at the base of the riser section and are mixed with circulating solids entering the mixing zone through the J-leg from the standpipe (figures 5.1-1 and 5.1-2). Lignite is fed near the top of the mixing zone, and air is fed at the bottom. The char carbon in the circulating solids is consumed by oxygen in the air, primarily forming CO and CO_2, and releases the heat required to maintain the gasifier temperature. The circulating solids absorb the released heat and provide the energy to heat the lignite rapidly to operating temperatures. This temperature minimizes tar formation. The high temperatures in the riser will crack any tar that is formed. Minimal steam is required, due to high solids circulation and heat transfer rates that convert over 98% of the feed carbon into syngas.

During startup, two dual-fuel (natural gas and diesel) fired burners heat the gasifier after it is partially filled with bed material. This material is normally coarse ash stored from previous operations. During the first startup, sand with a mean size in the range of coarse ash was used as the bed material.

The gasifier is equipped with direct diesel injection (DDI) nozzles in the lower part of the riser. These DDI nozzles are used to continue raising the gasifier temperature to near operating levels after the limits of the startup burners have been reached. Lignite is then introduced into the gasifier, and the startup fuels are gradually withdrawn while maintaining the gasifier temperature.

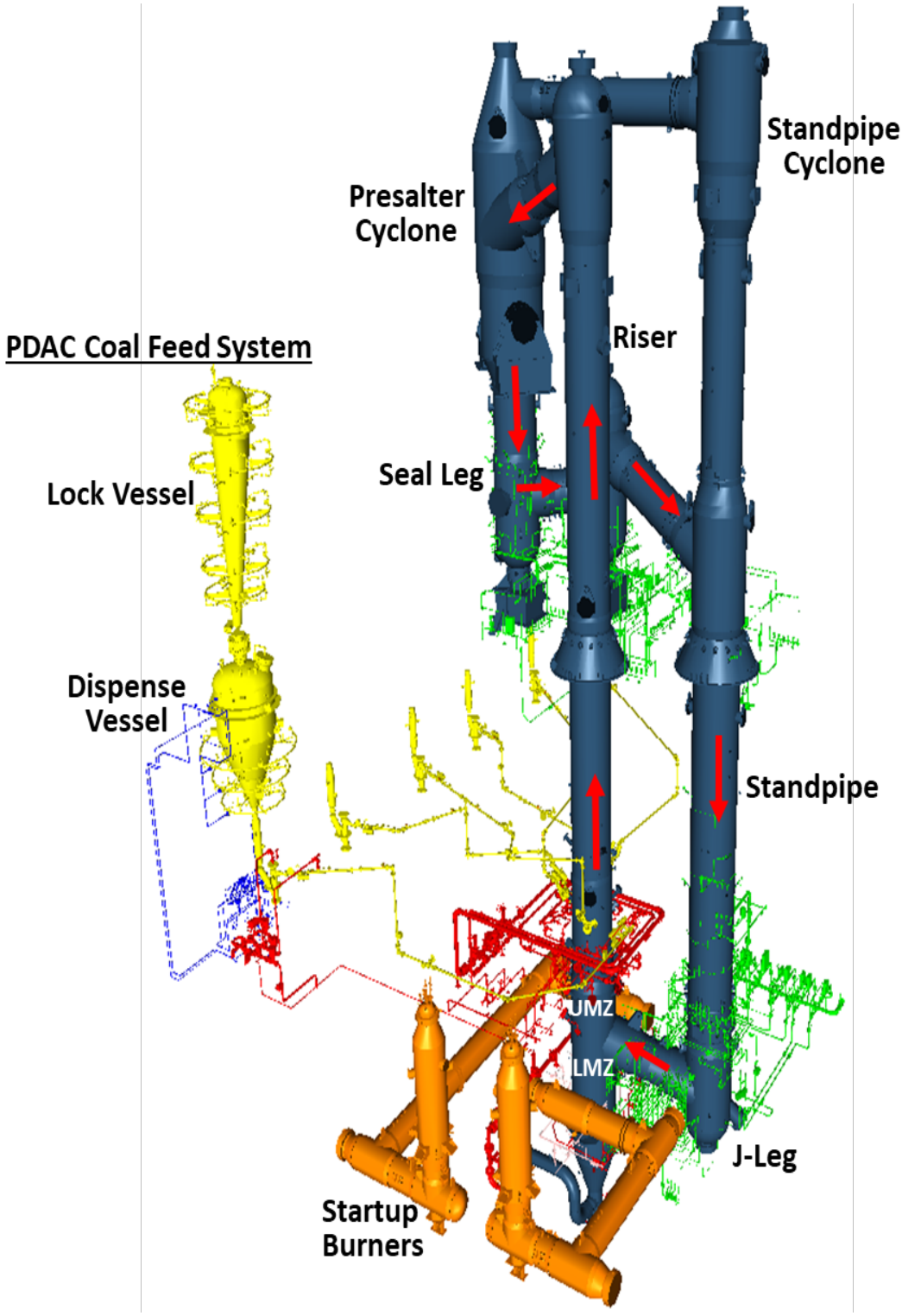


Figure 5.4-1 – Transport gasifier configuration; coal feed system and startup burners layout

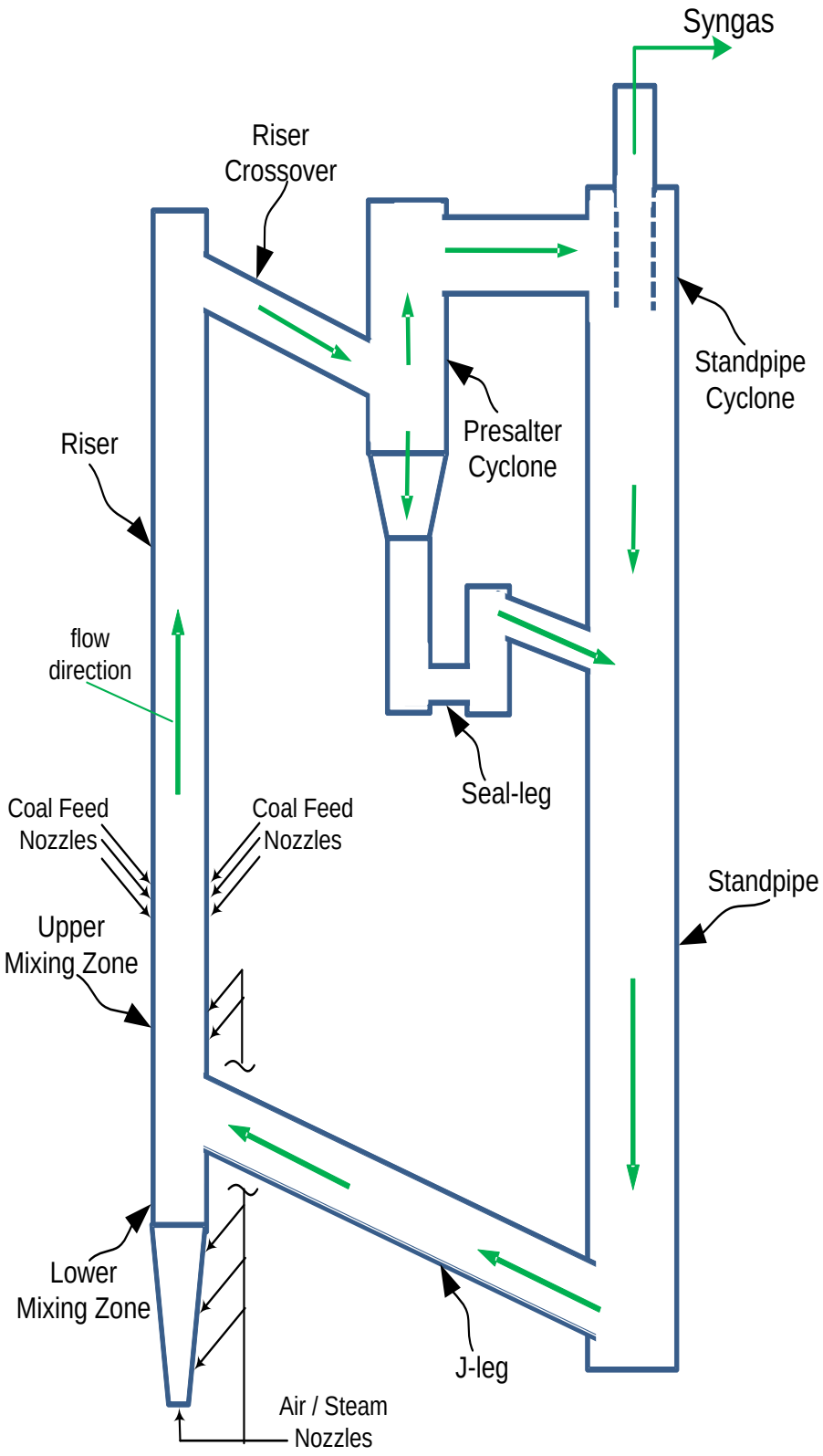


Figure 5.4-2 – Components of gasifier loop

5.4.1.1 *Gasifier Flows*

The gasifier loop consists of following components (figures 5.4-1 and 5.4-2):

- Lower mixing zone (LMZ) and upper mixing zone (UMZ).
- Riser.
- Riser crossover.
- Presalter cyclone.
- Seal leg (consists of downcomer, H-leg and riser).
- Standpipe cyclone.
- Upper and lower standpipes.
- J-leg.

Multiple nozzles in the seal leg, standpipe, J-leg, and mixing zone facilitate the flow of recycle gas to maintain the solids in a fluidized state. Air flow through other LMZ and UMZ nozzles, plus the syngas generated in the gasifier, provide sufficient velocity to transport the solids through the riser to the presalter cyclone. The air helps release heat in the mixing zone by partial and complete oxidation of char carbon in the circulating solids.

- Mixing zone

The mixing zone combines the gasification agents (air and steam), lignite, and the circulating solids. It includes two sections. The section below the solids recycle from the J-leg is the lower mixing zone (LMZ). The section above the solids recycle from the J-leg is the upper mixing zone (UMZ). Both sections are refractory lined with a carbon steel shell. The refractory has two layers. The inner layer, which is in contact with the circulating solids and syngas in the gasifier, is erosion resistant. The outer layer, between the erosion resistant refractory and the gasifier shell, insulates and protects the metal shell from overheating.

Steam is used to quench the material in the LMZ in case of high temperatures from abnormal operation. The light hydrocarbon stream collected in the sour water system, as well as the bottom stream from the ammonia purifier, also can be sent to the LMZ for destruction if necessary.

There are a number of air nozzles in the LMZ and UMZ. The air injected into these zones burns the char in the circulating solids to increase its temperature. Gasifier capacity, oxygen consumption rates in the mixing zone, and desired maximum temperature in the mixing zone will determine the required air distribution and distance between air nozzles. The temperature in the mixing zone is controlled to prevent clinker formation while achieving desired carbon conversions of the lignite coal.

Process air is injected into the LMZ through multiple flow nozzles (figure 5.4-3). The air flowing through FV14019 is injected using an innovative jetting nozzle to supply oxygen to the center core of the mixing zone. This air is then dispersed over the entire cross-section of the gasifier. A smaller amount of process air is injected through other nozzles on the periphery of the gasifier shell, to aid in initial fluidization at startup and to ensure no stationary pockets of solids develop in the mixing zone during operations. Most of the remaining process air is injected through two sets of nozzles in the UMZ, using flow controllers FIC14017 and FIC14021. The pressure of the process air is boosted with the transport air compressor and used to transfer lignite from the PDAC feeders to the lignite feed nozzles.

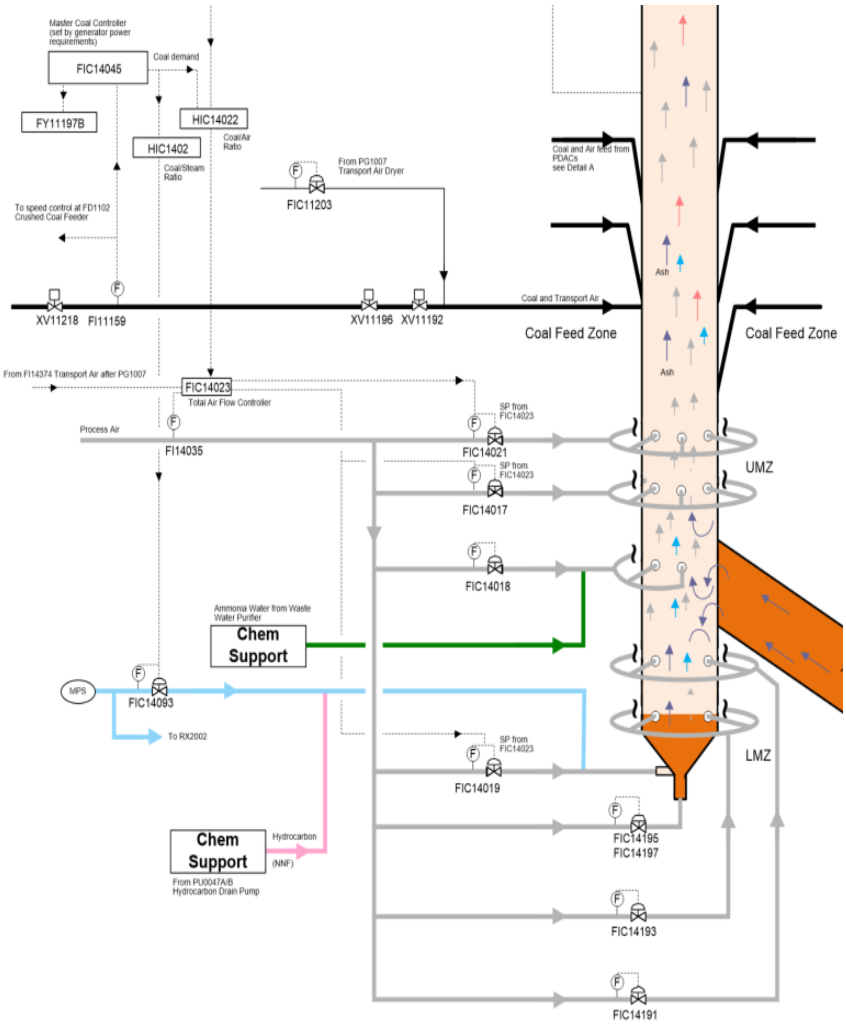


Figure 5.4-3 – Schematics of coal mixing zone and airflow

The lignite is conveyed with transport air to six coal feed nozzles in the UMZ (two nozzles at each of the three elevations). The nozzles are oriented around the gasifier to disperse the lignite fed uniformly across the cross-section of the gasifier. The temperature around the last bank of lignite feed nozzles is the highest in the entire gasifier loop due to the addition of the conveying air. The upper boundary of the mixing zone is the last bank of lignite feed nozzles.

Temperatures in the mixing zone are measured by thermocouples inserted through nozzles on the gasifier shell. Measurements of pressures at different elevations and differential pressures in the mixing zone are used as guides in managing and diagnosing gasifier operations.

The gas superficial velocity in the mixing zone after air injection must be high enough for optimum circulation and mixing of gases and solids in the gasifier loop, but not so high that the thermocouples erode. A high bulk density in the mixing zone further increases the mixing rate of gas and solids. The bulk density in the mixing zone is determined by the properties of the circulating solids and the operating solids level in the standpipe.

- Riser

The circulating solids, devolatilized lignite products, and syngas enter the riser from the mixing zone at a relatively high velocity due to the increased volume of syngas from partial char oxidation, lignite devolatilization, and other gasification reactions. To maintain optimum solids circulation, riser velocity is maintained within a specified range by manipulating

gasifier feed rate and pressure. The operating riser velocity range is sufficiently wide to maintain syngas quantity, heating value, and gasifier exit pressure within reasonable bounds during normal operation. Another benefit of controlling gas velocity in the riser is minimized erosion of the thermocouples and refractory.

The riser is designed to deliver optimum gas and solids residence time and reaction volume. This design helps maximize carbon conversion during the gasification reaction. The required reaction volume is determined by coal reactivity. In the riser portion of the gasifier, the refractory is the same design as that for the mixing zone. A pillow top bend at the riser exit near the top eliminates erosion in the transition to the riser crossover.

- Riser crossover

The riser crossover is one of the interconnecting members of the gasifier loop, connecting the riser with the presalter cyclone. The riser crossover partially separates the circulating solids and gas. The particle-laden gas exits from the top of the riser and enters the crossover. The change in flow direction and the action of gravity separate a substantial portion of the solids from the gas, depositing the solids along the bottom of the crossover. The gas velocity is higher than in the riser to minimize solids accumulation but needs to be low enough to prevent erosion and minimize pressure drop in the crossover. The design and construction of the shell and the refractory for the crossover follow the pattern established for the mixing zone and the riser.

- Presalter cyclone

Circulating solids and syngas from the riser crossover enter the presalter cyclone tangentially. The presalter cyclone separates most of the circulating solids from the gas stream while minimizing erosion of the cyclone wall. The design and the specification of superficial gas velocity at the inlet of the cyclone are based on achieving minimum erosion and maximum solids collection efficiency. While the gas and solids tangential entrance to the presalter cyclone is like a conventional cyclone, the presalter cyclone has neither a flat roof nor a vortex finder.

- Seal leg

The solids collected by the presalter cyclone flow by gravity along the cyclone wall and enter the downcomer of the seal leg, which is connected on one end to the cone of the cyclone. The seal leg has a downcomer, a horizontal leg (also known as the H-leg), a riser, and a slant leg that connects the seal leg riser to the gasifier standpipe. The seal leg feeds solids from the presalter cyclone to the standpipe.

The proprietary design of the fluidization nozzles in the seal leg and other locations in the gasifier CCAD prevents solids plugging after a trip or during startup. The nozzles were tested in the seal leg and proven to be plug free at low or nearly no fluidization gas flows for extended periods. The preferred fluidization gas for the seal leg is recycled syngas.

Most of the solids flow through the seal leg and into the standpipe. About 0.1% of the solids that passes through the seal leg is removed through the J-pipe to the CCAD primary cooler HX1030 for standpipe level control. This J-pipe connects to the bottom of the seal leg riser.

- Standpipe cyclone

The syngas stream leaving the top of the presalter cyclone flows through a refractory lined secondary crossover and enters another cyclone at the top of the standpipe. Most of the remaining particulates in the syngas are removed by the standpipe cyclone. The solids collected by the standpipe cyclone flow directly into the standpipe. The sour syngas exiting the top of the standpipe cyclone flows to the syngas cooling section and then to the fine particulate filtration section of the process.

- Standpipe

The standpipe is a refractory-lined vertical pipe that recycles the circulating mass of solids to the mixing zone and riser. It is located directly below the standpipe cyclone and connects to the seal leg and cyclone at the top and the J-leg at

the bottom. The circulating solids from the seal leg and the solids collected by the standpipe cyclone accumulate in the lower portion of the standpipe to form a dense moving bed. The height of this bed provides the hydrodynamic energy needed to recirculate the solids to the mixing zone.

The standpipe level is measured using differential pressure (DP) transmitters with impulse nozzles located in lower, middle, and upper sections of the standpipe. The measured DP can be converted to feet of solids using either lab-measured or field-measured bulk density of the solids. The bulk density in the standpipe depends on the chemical composition, shape, and size of the circulating solids, and the solids level. The best way to achieve maximum solids bed density in the standpipe is proper control of the bed height, solids circulation rate, and fluidization rate. The moving bed of solids in the standpipe is fluidized using recycled syngas.

The solids level in the standpipe is controlled by continuously removing solids from the seal leg riser through the J-pipe connected to the primary CCAD cooler HX1030. The hot solids are cooled to around 600 °F in this heat exchanger and further cooled to less than 350 °F in the secondary CCAD cooler HX1034. The cooled solids are then depressurized with the aid of pressure letdown devices (PLD) and conveyed to ash silos. The standpipe level controller receives its signal from an operator-selected standpipe DP transmitter, and adjusts fluidization gas flows to the CCAD J-pipe. The standpipe level controller works with a pressure controller to adjust the pressure in HX1034 by modulating flow in the vent gas line from the CCAD vent filter and maintain the standpipe level by withdrawing circulating solids through the seal leg riser.

- J-Leg

The J-leg is an aerated, refractory-lined, nonmechanical valve that connects the standpipe and the mixing zone. The preferred fluidization gas for the J-leg is recycled syngas, introduced through nozzles along its entire length. These fluidization nozzles are based on a proprietary design that reduces plugging by solids. The refractory structure in the J-leg is the same as the mixing zone and the riser. The J-leg is an interconnecting component of the gasifier loop, connecting the standpipe leg with the mixing zone/riser leg. To minimize stress on the J-leg, both the standpipe and the mixing zone/riser legs of the gasifier should expand to nearly the same extent downward from their support locations. Skin temperature measurements are used to ensure the differential temperatures between the legs of the gasifier are within design ranges.

All components of the transport gasifier have a carbon steel shell with dual layers of refractory inside. The inner hard surface withstands forces of friction or impact from circulation solids, and the outer layer of insulating refractory reduces the shell temperature to desired low levels. Integrity and stability of installed refractory is critical for sustainable gasifier operations with high rate of solids circulation at high temperatures.

5.4.1.2 *Startup Heating*

Initial gasifier heat-up is accomplished by using the two startup burners connected to the LMZ, and by directly injecting diesel fuel into the hot circulating solids.

During gasifier startup, two dual-fuel (natural gas/diesel) startup burners (SUB) AH1102/1202 heat the gasifier to approximately 1,200 °F before transitioning to direct diesel injection (DDI) to complete the gasifier warmup. The transition to DDI will typically be at 1,000 to 1,200 °F, though permissives allow the transition as low as 900 °F. The startup burner warmup sequence also can be used for refractory curing.

Each SUB has two natural gas-fired pilots, a natural gas igniter ring, and a diesel-fired main burner. Intermediate pressure (IP) steam is used to atomize the diesel fuel. IP nitrogen and process air are introduced to the burner for quenching and outlet flue gas temperature control. Process air is used for combustion air. Instrument air is used for pilot air.

Fuel flow (natural gas or diesel) to the burner is controlled by the target gasifier outlet temperature. The appropriate primary temperature controller in a cascaded control loop sends a set point to adjust the associated secondary fuel flow controllers, which vary the NG or diesel flow. Atomizing steam flow is controlled based on the pressure of the

diesel flowing into the burner. Combustion air flow to the burner is adjusted by a controller which receives its setpoint from either operator input or a ratio of the fuel flow rate.

Quench nitrogen and air flows to each burner are controlled with a cascade control loop where the target burner outlet temperature controller is the primary and the respective flow controllers are the secondary controllers in the loop. The burners require 80% excess air for stability, so tight control of the outlet oxygen concentration is difficult while the burners are firing. To minimize the risk of excess oxygen in the flue gas, the quench flow controllers are designed to maximize the use of available IP nitrogen to dilute the oxygen.

The gasifier outlet temperature controller and the burner outlet temperature controller can be ramped independently. The temperature ramp rates to each controller are set by the burner control logic using rate limiters on the rates of change of each controller setpoint. The startup burners can be shut down by the operator when DDI starts and should be completely shut down by the time coal feed starts. If there are issues with insufficient heat input from DDI (for example, one out of three DDIs is inoperable), then the burners can continue to be fired until start of coal feed.

In the DDI system, the warmup control scheme will precisely control the gasifier outlet temperature using a controller to adjust the set point of the diesel flow controller for each enabled DDI nozzle. Atomizing steam flow to the nozzle is controlled based on the pressure of the diesel flowing to the gasifier through the nozzle. The diesel flow rate is regulated based on the gasifier outlet temperature. The DDI system can be operated with low excess air when required by the gasifier operating state. After the DDI system is in operation, the excess air from the startup burners serves as the initial source of combustion air for the diesel injected through the DDI system. The overall excess air can be reduced to less than 0.5% without any significant increase in CO concentration in the gasifier exit stream.

Air flow control during gasifier heat-up will initially be provided by startup burners. When the DDI system starts up, the master air flow controller can be activated to regulate the flow of process air through the LMZ. Air flow must be controlled to maintain limited excess oxygen (1% to 2%) in the flue gas leaving the gasifier. Minimizing excess oxygen concentration mitigates the risk of fire in the PCD.

5.4.2 Initial Commissioning Plan

5.4.2.1 *Leak Check and Pressure Test*

The gasifier is a large piece of equipment designed to operate at pressures up to 700 psia in the lower mixing zone. There are around 370 nozzles, 117 process flow connections, 20 instrument purge connections, and other connections around the gasifier body. Figure 5.4-4 shows recycle gas flow connections to nozzles in the seal leg and J-leg as well as transport and process air connections to nozzles in both lower and upper mixing zones.

Part of the plan was a leak check to confirm that all connections and blinded nozzles were mechanically tight. The initial leak checks used 30 to 50 psi pressure. After completing leak check tests, plans were to step up the system pressure to 700 psi to check for unit pressure holding performance and identify any remaining leaks. Before conducting any leak check, the lines were blown clear of any construction waste to ensure free flow of intended process gases at desired rates.

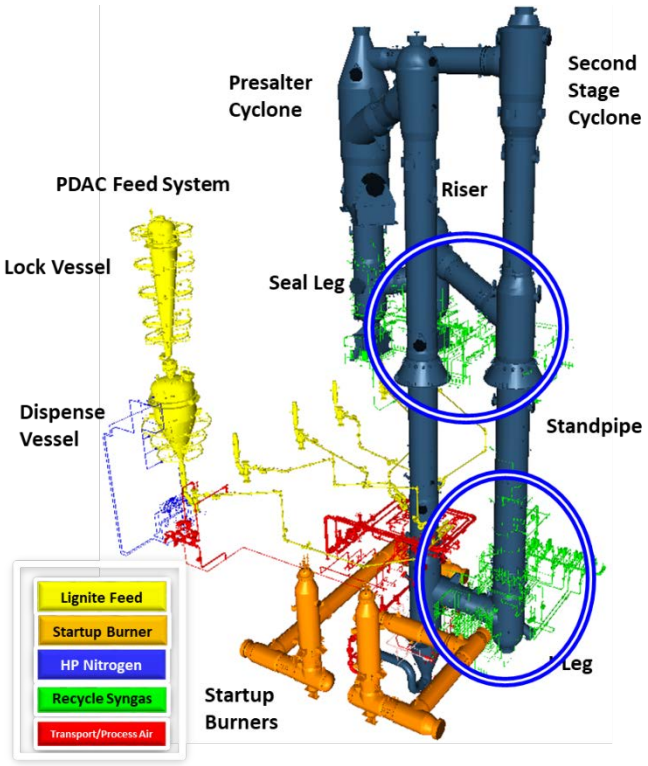


Figure 5.4-4 – Recycle gas flow connections to seal leg and J-leg; transport and process air connections to mixing zone

5.4.2.2 *Air Flow and Control Valve Tuning*

Gasifier operations are maintained by regulating nearly 30 flow control valves directly connected to the gasifier. Process gas flows into the gasifier during normal startup operations through 14 other flow control valves that adjust flows to the SUBs and DDI system during initial gasifier heat-up. All these flow control valves are strategically located around the gasifier. They are important for achieving desired mixing and solid circulation rates and maintaining the temperature profile in the gasifier. Controller tuning is one key step to check and adjust tuning parameters for optimized control.

After establishing flow through a control valve and ensuring the full range of flow without any obstruction in the line, the controller will be tuned. The tuning parameters can then be checked at different system pressures and adjusted as necessary to achieve desired control function at all operating conditions. This tuning process is repeated with each controller feeding process gas (air, nitrogen, recycle gas, and instrument purge) to the gasifier. Individual controller tuning can be further optimized by ensuring the group of controllers sharing the same header performed well when flow needed to be redistributed among the controllers for process reasons.

There are sets of flow controllers where the flow through one valve is distributed to multiple nozzles. It was anticipated that after completing controller tuning, the desired flow distribution to these nozzles would require adjustment with manual globe or needle valves in the field.

5.4.2.3 *Cold Sand Circulation Test*

Maintaining solids circulation is critical for transport gasifier operations, and it is important to understand the factors affecting solids circulation. As one of the major activities in the commissioning stage, cold sand circulation was planned per test packages TP1025 and TP2025 (gasifier trains A and B). The execution of test packages is an opportunity for the gasifiers to receive solids (sand) and initiate circulation for the first time. All connected and related systems handle solids from the gasifier, and the test package is an opportunity to commission these systems (for example, CCAD cooling and depressurization, syngas cooler, and the PCD and CFAD fines cooling and depressurization systems).

The solids loading and cold circulation tests enable plant personnel to check and confirm multiple system operations including solids loading, circulation, PCD back pulse function, CFAD fines transfer, and CCAD solids transfer.

The major steps for the sand circulation test were:

1) Preparing the gasifier by setting up all fluidization flows and process flows.
2) Preparing all connected and associated systems to handle solids and gas flows from the gasifier.
3) Preparing the gasifier inert solids feed system to load solids into the gasifier.
4) Preparing for all feasible systemic tests to initiate, vary, and maintain desired solids circulation in the gasifier.

5.4.2.4 *SUB and DDI for Refractory Curing Test*

Commissioning the startup burners (SUB) and direct diesel injection (DDI) system included performing all preliminary activities such as ensuring obstruction-free lines, leak and pressure checks, controller tuning, and briefly firing the burners to ensure their operation. After completing all the requisite preliminaries, the operation and effectiveness of the DDI system could be checked after the gasifier reached a temperature over 1,200 °F and there was excellent solids circulation around the gasifier loop.

5.4.3 Significant Events

5.4.3.1 *Initial Commissioning with Air Flow*

The gasifier and associated equipment such as process air compressors and startup burners were initially commissioned by establishing air flow through all flow control valves and the connecting nozzles on the gasifier.

See table 5.4-1 for initial commissioning test activities on gasifier A and B. See figure 5.4-5 for flow controller diagram.

The gasifier pressure is controlled by six back-pressure controllers located downstream on the stack and flare vent lines. After leak checks and pressure tests to full system operating pressure, the full range of flow capability was determined through each flow control valve at various pressures. The flow control valves and back-pressure control valves were then tuned rigorously at a given system pressure and the tuning parameters were optimized with controllability checks at other system operating pressures. It is critical to maintain solids circulation and proper gasifier loop operation by ensuring these activities: flow through all nozzles all the time (no obstruction), appropriate distribution of flows to all nozzles connected to each individual flow controller, full range of desired flow at operating pressures through each flow controller, optimum interaction of intertwined critical controllers, and well-tuned back-pressure controllers.

The back-pressure controllers are located progressively downstream in the syngas flow path (figure 5.4-6). During normal startup, the gasifier pressure is initially controlled by the stack pressure control valve as the gasifier is being heated up with slight excess oxygen. After operations transition to gasification by establishing coal feed, the pressure control is moved to the downstream controller located after the syngas scrubber to flare the startup syngas. As more downstream systems are integrated into operation by establishing syngas flow, the pressure control is progressively moved downstream. This requires a pressure control handoff to each successive controller as startup progresses. The pressure control handoff was tested, and the controllers were tuned to ensure the gasifier pressure is maintained. The handoff was tested in reverse to simulate planned shutdown by progressively isolating downstream equipment. The functionality of gasifier pressure ramps up and down was tested at desired ramp rates.

Construction was still in progress during commissioning activities. Temporary blinds were used to positively isolate commissioning test activities from construction activities on connected lines and vessels. If major repair work was identified during commissioning of a train, the commissioning activities moved to the next train so repair work and other maintenance work could be completed. See sections 5.4.3.2 through 5.4.3.18 for details of each commissioning test activity listed in table 5.4-1.

Table 5.4-1 – Kemper air flow commissioning test activities

No.	Test	Date	Comments
1	50 psig leak test gasifier B	12/23/2014	Successful with leaks at PCD fines receiver
2	100 psig leak test gasifier B	01/03/2015	Successful with minor leaks
3	PAC3 run at cold air temperature	01/07/2015	PAC3 run was stable
4	Tuning of TV24119B&TV24144B on startup burners	01/10/2015	Tuning was successful
5	Tuning and balancing of process air flow valves, gasifier overnight soak, PAC3 capacity check	01/11/2015-01/13/2015	Tuning and gasifier soak was successful, PAC3 capacity ~400,000 lb/hr
6	Air blow 1 to startup stack gasifier Train B	01/13/2015	Air blow to start up stack was successful
7	Pressure leak test by bottling up the gasifier B	01/14/2015-01/15/2015	Pressure leak of ~0.006 psi/min was observed
8	Pressure leak test and air blow 1 to startup stack gasifier Train A	01/24/2015-01/31/2015	Successful pressure leak test along with air blow to start up stack
9	Air blow 2 to HP flare PV24456 gasifier Train B	02/23/2015	Successful air blow to first flare header
10	Air blow 2 to HP flare PV144456 gasifier Train A	02/28/2015	Successful air blow to first flare header
11	Air blow 3 to HP flare PV29026 gasifier B	03/01/2015	Successful air blow to second flare header
12	Pilot light of startup burner for gasifier B	03/01/2015	Successfully lit pilot A of AH2102
13	Pilot light of startup burner for gasifier A	03/02/2015	Successfully lit pilot A&B of AH1102 and pilot A of AH2202
14	Air blow 3 to HP flare PV19026 gasifier A	03/04/2015	Successful air blow to second flare header
15	Air blow 4 to HP flare PV24503 on Train B (test for chattering MZ01 check valve)	03/14/2015–03/16/2014	Successful air blow up to gas turbine inlet
16	Air blow 4 to HP flare PV14503 on Train A (test for chattering MZ01 check valve)	03/19/2015-03/20/2015	Successful air blow up to gas turbine inlet
17	Detailed summary for MZ01 check valves' tests	03/14/2015-03/20/2015	Tested the chattering behavior of check valve

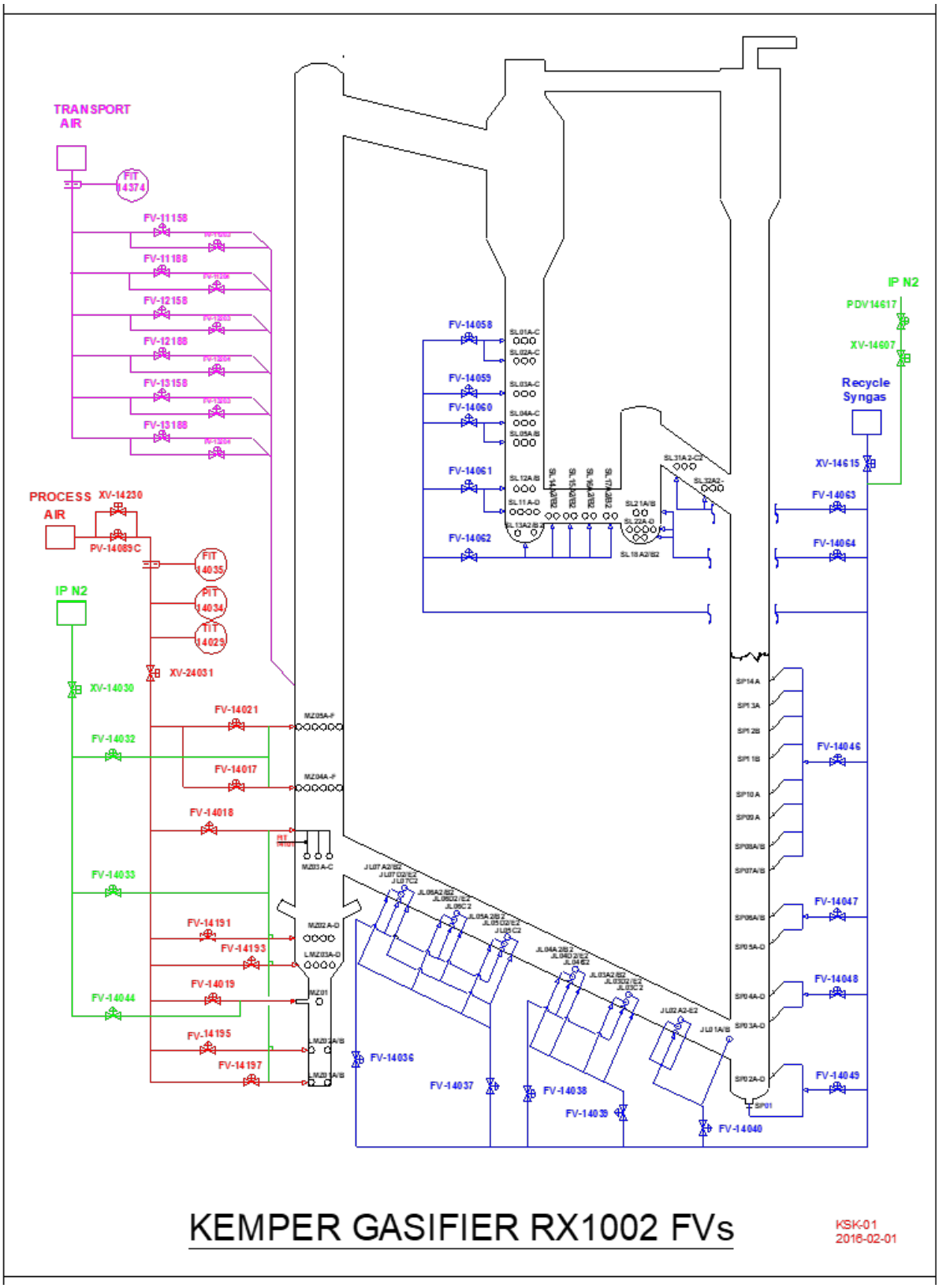


Figure 5.4-5 – Kemper RX1002 gasifier flow controllers

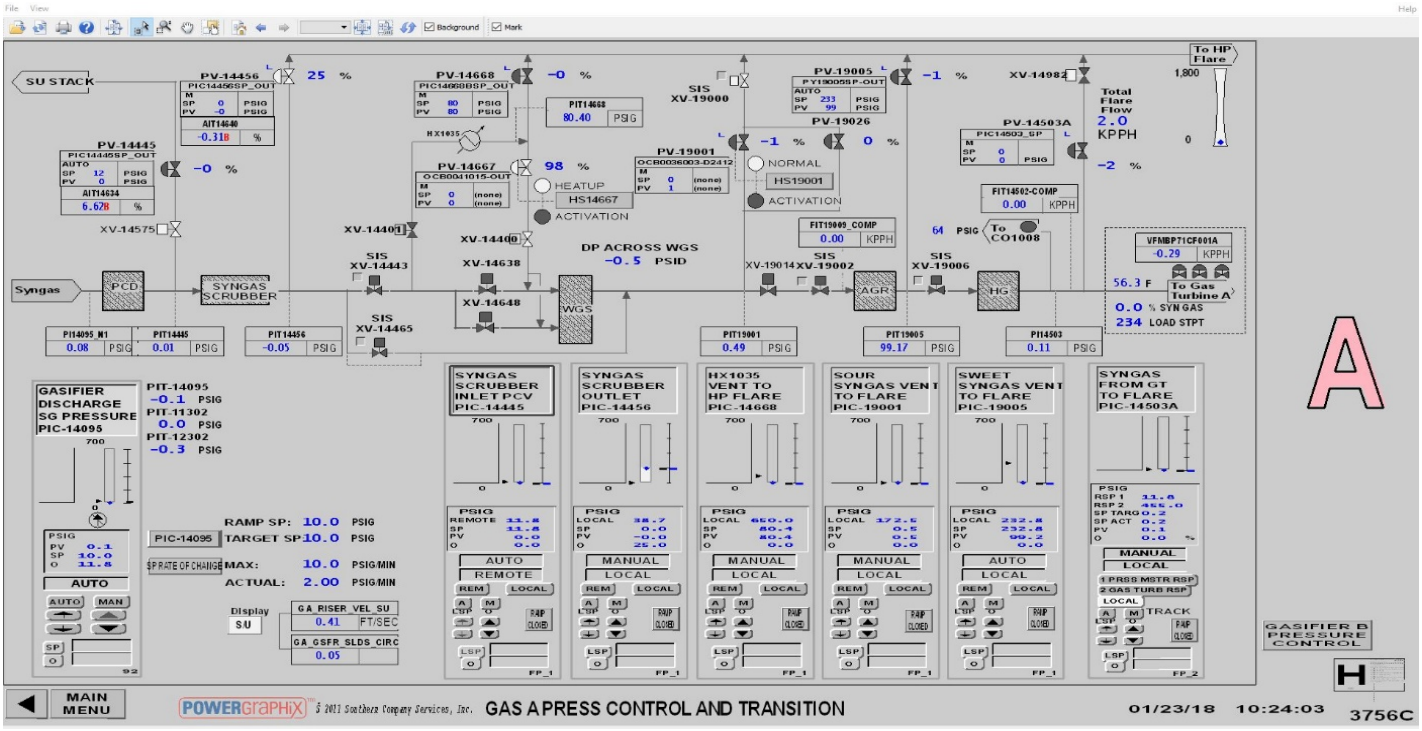


Figure 5.4-6 – Kemper process pressure control and flare vents

5.4.3.2 *50 psig Leak Test on Gasifier Train B*

Date performed: 12/23/2014

Objectives: Perform 50 psig pressure leak test and system integrity test on Train B.

Systems included: PAC3, both startup burners, gasifier, syngas cooler, PCD, startup stack, and gas clean up system up to the AGR inlet.

Outline: Gasifier B was tested for leaks up to 50 psig. Flow was established through flow path of PAC3 - startup burners - gasifier - syngas cooler - PCD - startup stack. Downstream vessels in the main process gas flow path up to CL2006 ammonia scrubber were pressurized for leak checks. PV24445 (sacrificial valve) was tuned and used to raise the gasifier pressure to 50 psig. The sacrificial valve was installed to prevent damage to the original valve and integrated diffuser from construction debris. The sacrificial valve and orifice plates provided the means to conduct tests and tuning at full flow range.

Summary:

- PAC3 tripped twice because of deviation in IGV4 valve. After tuning IGV4, PAC3 ran smoothly.
- For the first time, airflow of 50,000 lb/hr was established between the gasifier and startup stack using startup burners.
- The gasifier and other equipment were pressurized to 50 psig with minor leaks.
- Leaks in the pant leg flanges at the exit of PCD fines receiver were slated to be fixed at the end of the current leak test.
- The OIS (data acquisition system) was not receiving signals from many of the tags.
- Tuning of PV24445 was smooth, which helped in testing and maintaining the gasifier pressure.
- The system pressure was held to identify significant leaks. No major leaks were found.
- There was no signal on the DCS screens when PAC3 tripped; need to troubleshoot the alarm system.

Analysis:

- After examining the temperature profiles in the gasifier in the absence of bed material, the initial conclusion was that the air entering the gasifier through burner legs in LMZ flows through the riser as well as the standpipe (through J-leg) due to low flow rates.
- At higher flow rates, the flow is equally distributed between the two flow paths through the gasifier without any bed material. Also, if flow is not equally distributed, a means to distribute them equally is available by adjusting the J-leg flow.
- Using the valve characteristics at 8% valve opening for PV24445, a flow of ~26,000 lb/hr of air through the valve to stack at 50 psi was estimated. This flow implied an internal leak of ~24,000 lb/hr of air through the closed gasifier outlet valve to the stack. However, at such low flows, readings for valve opening and flowrates may not be accurate. No major leak to the surrounding atmosphere was detected.

Measure of success: Train B, consisting of PAC3, startup burners, gasifier, syngas cooler, PCD, startup stack, and gas cleanup up to the AGR inlet, was successfully pressurized to 50 psig and checked for leaks. The system was held stable, passing the integrity test.

5.4.3.3 *100 psig Leak Test on Gasifier Train B*

Date performed: 1/2/2015 to 1/3/2015

Objectives: Perform 100 psig pressure leak test and system integrity test on Train B with continuous air flow and bottling-up techniques.

Systems included: PAC3, both startup burners, gasifier, syngas cooler, PCD, startup stack, and gas cleanup systems up to the AGR inlet. There were no internals in the PCDs, syngas scrubber (except demister), and other gas cleanup equipment.

Outline: Gasifier B was tested for leaks up to 100 psig. Flow was established via flow path of PAC3 - startup burners - gasifier - syngas cooler - PCD - start up stack. Downstream equipment up to the AGR inlet was pressurized. The system was bottled up to observe rate of pressure loss.

Summary:

- The gasifier was pressurized to 50 psig and all leaks identified in previous tests were repaired. No major leaks were reported.
- The gasifier was further pressurized to perform the 100-psig leak test. An airflow of 80,000 lb/hr was established through the gasifier and startup stack using the startup burners.
- Air flow control valves FV24141 and FV24116 at the burner inlets were tuned along with the PV24445 (sacrificial valve) back-pressure control valve in the stack line.
- The gasifier was bottled up and system was checked for leaks using ultrasonic probes. To aid in leak detection, process noise and vibrations were eliminated by turning off PAC3 and closing the vent valve. During this procedure, a 0.26 psi/min rate of pressure loss was observed at the gasifier (17 psi over a 68-min period). The pressure loss was likely due to internal leaks through the outlet valve to the stack because no major leaks to surrounding atmosphere were detected.
- PAC3 operations were stable during this test run.

Analysis:

- After examining the pressure profile in the gasifier, the pressure loss rate after bottling up the system was 0.26 psig/min. These leaks could be internal in the system through closed valves. However, operations did not observe pressurization of any equipment outside of the pressure boundary. The leaks could be through the sacrificial valves in the stack and flare vent lines.

Measure of success: Gasifier Train B consisting of PAC3, startup burners, gasifier, syngas cooler, PCD, startup stack, and gas cleanup equipment up to the AGR inlet was successfully pressurized to 100 psig. The system was held stable, passing the integrity test. Leaks that were detected in previous and current tests were fixed.

5.4.3.4 *PAC3 Run at Cold Air Temperatures*

Date performed: 1/7/2015 to 1/8/2015

Objectives: Generate operational performance curves for PAC3 at cold air temperatures.

Systems included: PAC3, both startup burners, gasifier, syngas cooler, PCD, startup stack, and gas cleanup systems up to the AGR inlet. There are no internals in the PCD, syngas scrubber (except demister), and other gas cleanup equipment.

Outline: PAC3 was run to take advantage of cold weather to generate the operational performance curve. Flow was established via the flow path of PAC3 - startup burners - gasifier - syngas cooler - PCD - startup stack.

Summary:

- A total air flow of 80,000 lb/hr was sent through startup burners to the gasifier, exiting through PV24445 at the startup stack. The gasifier pressure was maintained at 50 psig initially and then decreased to 25 psig for the rest of the run.
- Data was collected to evaluate compressor performance at low temperatures. The compressor operation was stable.

Measure of success: PAC3 operation was stable and operations personnel collected useful performance data for the compressor at low cold air temperatures.

5.4.3.5 *Tuning of TV24119B & TV24144B on Startup Burners*

Date performed: 1/10/2015

Objectives: Tune TV24119B and TV24144B on startup burners in Train B

Systems included: PAC3, both startup burners, gasifier, syngas cooler, PCD, and startup stack

Outline: Valves TV24119B (FV24108) and TV24144B (FV24239) on the two gasifier B startup burners (AH2102 and AH2202) were tuned. These valves control the burner outlet temperatures by controlling the flow of quench air to the burner chambers. Flow was established through the flow path of PAC3 - startup burners - gasifier - syngas cooler – PCD - startup stack. PV24445 was used to raise the gasifier pressure. The cascade pressure control logic on the gasifier was verified by monitoring the median of PIT24095, PIT21302, and PIT22302.

Summary:

- PAC3 was started and flow was established from the gasifier to startup stack using the startup burners. A total air flow of 20,000 lb/hr was established initially through burner combustion air valves FV24141 and FV24116. In addition, 40,000 lb/hr were provided through both TV24119B and TV24144B.
- The gasifier was pressurized to 10 psig while 120,000 lb/hr of air flowed through the system.
- The cascade pressure control logic for the gasifier was verified while using PV24445, the back-pressure control valve in the stack line.
- Valves TV24119B (FV24108) and TV24144B (FV24239) were tuned with appropriate parameters.

Measure of success: PAC3 run was stable. Valves TV24119B (FV24108) and TV24144B (FV24239) were tuned with appropriate parameters at low pressure. The cascade pressure control logic for the gasifier was verified using the median value of PIT24095, PIT21302, and PIT22302.

5.4.3.6 *Tuning and Balancing of Process Air Flow Valves, Gasifier Overnight Soak, and PAC3 Capacity Check*

Date performed: 1/11/2015-1/13/2015

Objectives:

- Tune the process air flow valves that supply process air to the gasifier and balance the process air that flows to various nozzles through each flow control valve.
- Perform a gasifier soak test overnight.
- Check maximum capacity of PAC3.

Systems included: PAC3, both startup burners, gasifier, syngas cooler, PCD and startup stack. Gas cleanup was isolated.

Outline:

- Tune valves on process air lines that feed oxidant to gasifier mixing zone (figure 5.4-7; see figure 5.4- 5 for more detail): FV24017 (UMZ), FV24021 (UMZ), FV24018 (at J-leg and MZ intersection), FV24191 (LMZ), FV24193 (LMZ), FV24195 (below jetting nozzle in LMZ) and FV24197 (below jetting nozzle in LMZ). Valves FV24032, FV24033 and FV24044 supply nitrogen mainly during a trip to the same nozzles through which air flows to the gasifier. Flow was established through the flow path of PAC3 - startup burners - gasifier - syngas cooler - PCD - startup stack. Gas cleanup system was isolated. The field manual needle and globe valves were adjusted to balance process air flow to all interconnected nozzles from each flow control valve.

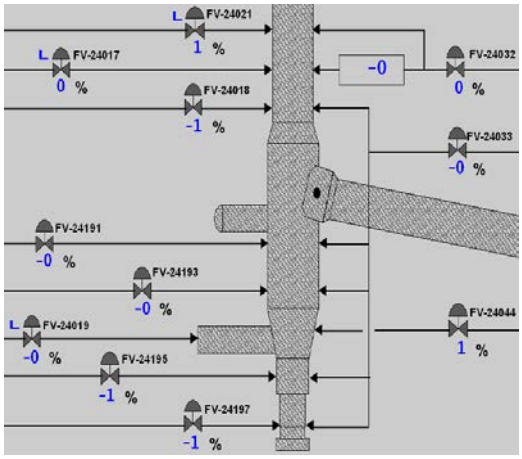


Figure 5.4-7 – Gasifier process air and nitrogen flow controllers

- Run PAC3 to check for its maximum capacity.
- Blow warm air from the compressor through the gasifier overnight to have proper soak and clear out moisture from the refractory.

Summary:

- Process air flow valves FV24017, FV24021, FV24018, FV24191, FV24193, FV24195 and FV24197 were initially tuned at a gasifier exit pressure of 80 psig. The header pressure was maintained at 50 psi over the mixing zone pressure, which is the typical differential pressure considered feasible during full load normal operation. The mixing zone pressure varies from as low as 20 psig during startup to 680 psig at normal operation.
- FV24019 could not be tuned due to a manual valve in the line being locked out for upstream construction work.
- Only nozzles that had flow through FV24018 and FV24021 needed balancing; the rest of the balancing flows through other valves were in acceptable ranges with the manual field valves in fully open positions.

- On 01/11/2015, while establishing 200,000 lb/hr of flow through the gasifier (using FV24021 and FV24017), the PAC3 discharge pressure dropped to 78 psig, but it did not choke. This occurred as the IGVs were in manual with fixed openings. The pressure was brought back up immediately.
- On 01/12/2015, after tuning the process air flow valve, PAC3 was checked for its maximum air flow capacity. A maximum flow of about 400,000 lb/hr of air from PAC3 was obtained when the gasifier exit pressure was at 100 psig. Each process air compressor has a maximum suction capacity of 315,490 lb/hr at a maximum discharge pressure of 735 psia.
- For gasifier soak, 100,000 lb/hr of air flow was established and the flow through the gasifier was maintained for 24 hours. The gasifier pressure was at 100 psig during this test. Gasifier temperatures went up to 150 °F during the soak.

Analysis:

- Tuning and balancing of flow through interconnected nozzles on process flow valves FV24017, FV24021, FV24018, FV24191, FV24193, FV24195 and FV24197 were carried out at a gasifier pressure of 80 psig. Table 5.4-2 shows the flow rate through each nozzle during balancing (all flows are in lb/hr). All these flows are in acceptable ranges (below 10% from the average).

Table 5.4-2 – Flow rates through interconnected nozzles taking feed from a flow controller

Valve	Nozzle 1	Nozzle 2	Nozzle 3	Nozzle 4	Nozzle 5	Nozzle 6
FV24197	210	180				
FV24195	750	805				
FV24193	1,030	1,000	1,040	1,040		
FV24191	680	740	700	740		
FV24018	620	830	640			
FV24017	25,900	26,800	26,400	28,100	28,200	27,500
FV24021	17,600	17,600	18,300	17,200	18,000	18,600

- PAC3 discharge pressure drop: On 1/11/2015, when air flow of 200,000 lb/hr was drawn from PAC3, the discharge pressure dropped to 78 psig. This happened because the IGVs were in manual and held at 20% open. Due to these fixed positions, there was velocity saturation between the sixth and seventh stages. This problem was resolved when the IGVs were placed in auto. This was a good learning experience for the operators.
- Gasifier soak: 100,000 lb/hr of air was passed through the gasifier at 100 psig over a 24-hr period mainly to dry the gasifier surface moisture. The gasifier refractory temperature was at about 150 °F on the surface as warm process air was flowing through the gasifier. Both the riser and standpipe had similar temperatures. The flow conditions were chosen to ensure the gas velocities in the gasifier remained in a lower range.
- Maximum flow through PAC3: After switching the IGVs to auto operation, a maximum air flow of about 400,000 lb/hr was achieved from PAC3 at 100 psig gasifier exit pressure and the process air header pressure of 35 psi over the gasifier mixing zone pressure. If a planned crossover between PAC1 and PAC3 is not available, PAC3 alone can be used to achieve the needed air blow flow rates. PAC1 and PAC2 are dedicated to gasifier A and PAC3 and PAC4 are dedicated to gasifier B; during initial commissioning activities, PAC2 and PAC4 were still being installed and were not available for operation.

Measure of success: Process air flow valves FV24017, FV24021, FV24018, FV24191, FV24193, FV24195 and FV24197 were tuned and all the interconnected nozzle lines through each flow control valve were balanced. PAC3 was run to test for the highest air flow rate that was achievable. The gasifier was soaked with warm air for 24 hr to remove refractory surface moisture before the start of the air blow tests.

5.4.3.7 *Air Blow 1 to Startup Stack on Gasifier Train B*

Date performed: 1/13/2015

Objectives: Blow the lines at sufficiently high velocities to remove any trash up to the startup stack.

Systems included: PAC3, both startup burners, gasifier, syngas cooler, PCD, startup stack. Gas cleanup was isolated.

Outline: Establish flow using flow path of PAC3 - startup burners - gasifier - syngas cooler - PCD - startup stack. Gas cleanup system was isolated. Establish sufficiently high air flow into the system to achieve desired velocities to perform the cleanup process.

Summary:

- The gasifier was soaked overnight before initiating the blow off test. By keeping the gasifier pressure at 100 psig, an air flow of ~360,000 lb/hr was established through the process flow path. Flow distribution was as follows: through startup burners – TV24119B = 30,000 lb/hr and TV24144B = 30,000 lb/hr; through LMZ – FV24116 = 25,000 lb/hr, FV24141= 25,000 lb/hr and FV24019 = 125,000 lb/hr; and through UMZ – FV24017 = 85,000 lb/hr and FV24021 = 40,000 lb/hr.
- To increase the gas velocities through the gasifier and syngas lines, the pressure was reduced from 100 psig to 25 psig at the gasifier exit. Velocities increased by almost three times and the system was maintained in this condition for about 15 min. The gasifier exit pressure was then increased to 50 psig to reduce the velocities.

Analysis:

- The purpose of the air blow at higher velocities was to achieve meaningful cleaning of loose materials and construction waste from process vessels and lines. The cleaning factor was used as a measure of cleaning efficiency. The cleaning factor is based on a ratio of drag force achieved in air blow to maximum drag force during normal operation. The goal was to achieve a cleaning factor of about 1. A cleaning factor of just over 1 was achieved during air blow operations at higher gas velocities through the gasifier and syngas lines (figure 5.4-8).

Measure of success: Based on the gas velocities and cleaning factor achieved, the air blow test was successful. PAC3 operated in stable conditions while supplying 360,000 lb/hr of air to the gasifier.

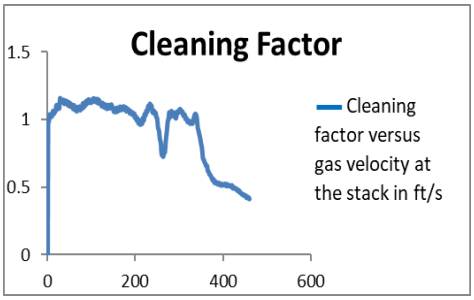


Figure 5.4-8 – Cleaning factor as measure of air blow effectiveness to clean debris and loose material from syngas flow path

5.4.3.8 *Pressure and Leak Tests by Bottling Up Gasifier*

Date performed: 01/14/2015 to 01/15/2015

Objectives: Perform pressure and leak tests at 50 psig by bottling up gasifier Train B.

Systems included: Gasifier B, syngas cooler, PCD and startup stack. Gas cleanup system was isolated.

Outline: After the gasifier exit pressure was recorded at 50 psig, the system was isolated from PAC1 (PAC1 was used through crossover tie-in) and bottled up to check for leaks and pressure decay. Startup stack valve PV24445 was fully closed and kept in manual.

Summary:

- The gasifier was bottled up at 50 psig pressure for about 21 hours from 5:00 pm on 01/14/2015 until 2:30 pm on 01/15/2015. Figure 5.4-9 shows the pressure hold at gasifier B over time during this process.
- Average pressure drop rate of 0.0063 psig/min was observed during this period.

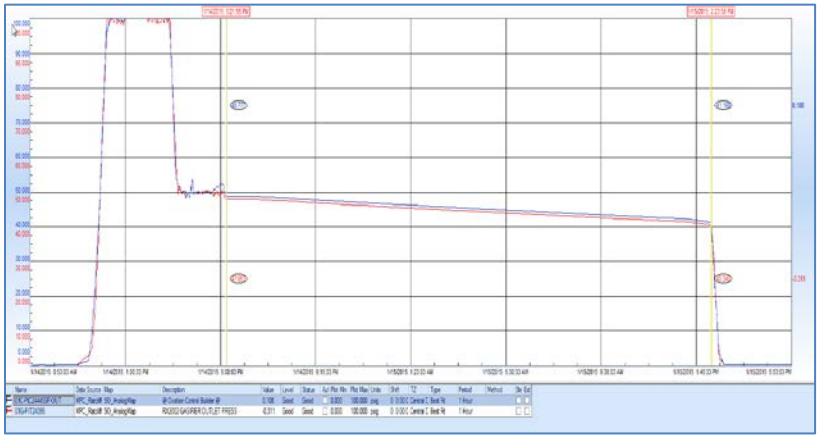


Figure 5.4-9 – Graph decay in gasifier B train during bottled up state

Analysis:

- Based on pressure reading at gasifier exit: 48 psig at 5:30 pm on 01/14/15 to 40 psig at 2:30 pm on 01/15/15; the pressure drop rate was 0.38 psig/hr.
- Table 5.4-3 shows the pressure decay and mass reduction rates:

Table 5.4-3 – Observations from gasifier B bottle-up test

1/14/2015		20:00:00	22:00:00	0:00:00	2:00:00	4:00:00	6:00:00	8:00:00	10:00:00	12:00:00
Volume	cft	54212	54212	54212	54212	54212	54212	54212	54212	54212
TI24070	F	99.415	95.68	92.6	89.58	86.63	83.67	81	78.56	76.64
PT124445	psig	48.27	47.42	46.7	45.98	45.3	44.64	43.95	43.3	42.67
	psia	62.77	61.92	61.2	60.48	59.8	59.14	58.45	57.8	57.17
Density	lb/cft	0.305	0.303	0.301	0.299	0.297	0.296	0.294	0.292	0.29
Mass	lb	16539	16425	16325	16222	16126	16035	15927	15821	15705
Mass Reduction	lb		114	100	103	96	91	109	106	116
Time Period	hr		2	2	2	2	2	2	2	2
Mass Reduction Rate	pph		57	50	52	48	45	54	53	58
%Change in 2 hrs	%		1.35%	1.16%	1.18%	1.12%	1.10%	1.17%	1.11%	1.09%

The average rate of mass reduction during the time the system was bottled up was about 52 lb/hr or about 0.32% per hour based on gas hold-up in the system. The average change in pressure over a 2-hr period was about 1.16%.

Measure of success: Pressure leak rate of 0.38 psig/hr was observed for gasifier B which is in the acceptable range. No external leaks were detected.

5.4.3.9 *Leak Test and Air Blow-1 to Startup Stack on Gasifier Train A*

Date performed: 01/24/2015 to 01/29/2015

Objectives: Perform leak test at 50 and 100 psig on gasifier Train A. Blow down the syngas flow path lines to remove loose and extraneous material to the startup stack.

Systems included: PAC1, startup burners, gasifier A, syngas coolers, PCDs, startup stack, and gas cleanup systems up to the AGR inlet. There were no internals in the PCD, syngas scrubber (except demister), and other gas cleanup equipment.

Outline:

- Establish flow using flow path of PAC1 - startup burners - gasifier - syngas cooler - PCD - startup stack. The gas cleanup area can be back pressurized up to the AGR inlet.
- Pressurize the gasifier up to 100 psig to perform the leak test and check system stability.
- Establish air flow into the system and with system pressure changes, achieve high velocities necessary to perform the cleanup process. The sacrificial startup stack valve, PV14445, controls the pressure.

Summary:

- On 01/24/2015 when flow was established from PAC1 to the startup stack through the startup burners in Train A, leaks were identified in the PCD fines receiver. The test was called off and repairs were performed overnight.
- On 01/25/2015, airflow was again established from PAC1 to the stack through the startup burners in Train A. When the gasifier was pressurized to 10 psig, seven minor flange leaks were observed. After repair, the gasifier was pressurized to 15 psig, and two major leaks were observed. The test was stopped to repair the leaks overnight.
- On 01/26/2015, the gasifier was pressurized to 50 psig and an additional seven leaks were noticed in the gasifier structure.
- On 01/27/2015, after repairing the leaks, the gasifier was pressurized to 100 psig. A few minor leaks were reported and repaired. The controller for valve PV14089C (startup header pressure control) on the process air header line was tuned.
- On 01/29/2015, the gasifier was pressurized to 80 psig and air flow of 80,000 lb/hr was established in the syngas flow path. The major process air flow control valves FV14021 (MZ05), FV14017 (MZ04) and the distribution lines to interconnected nozzles were cleaned by blowing air through the valve and briefly opening the drains. See figure 5.4-2 for details on locations of flow control and other valves.
- During these tests, modifications to the gasifier DCS graphics and logic inadvertently initiated a series of events that caused the startup stack valve to open to 100%. This resulted in rapid depressurization of gasifier A.
- The average depressurization rate was about 15 psi/min, with the initial rate as high as 40 psi/min.
- The flow at the startup stack averaged 400,000 lb/hr (based on an 80,000 lb/hr ramp rate to give a 3-psi/min pressurization rate in the system). Although unintended, this event provided the necessary cleaning factor to blow debris out of the syngas flow path.

Analysis:

- Leak test for gasifier Train A was performed successfully at 50 and 100 psig.
- Tuning of combustion and quench air flow controllers FIC14108, FIC14141, FIC14239, FIC14116 at startup burners (AH1202 and AH1102) was completed.
- During the sudden depressurization event, the average pressure drop rate observed was 15 psi/min. This corresponds to about 400,000 lb/hr flow through the startup stack valve. The gasifier refractory was to be visually inspected after completing the test to determine if any damage occurred from the sudden depressurization event. It was difficult to determine if internal damage occurred in the dual layer refractory because it experienced several quality issues during installation.

Measure of success: Based on the velocities and cleaning factor achieved during rapid depressurization, the air blow test was successful. After completing the test, the sacrificial valve in the startup stack line was replaced with the original PV14445 valve. Gasifier Train A was leak checked at pressures up to 100 psig.

5.4.3.10 *Air blow 2 to HP flare through PV24456 valve in Gasifier Train B*

Date performed: 2/23/2015

Objectives: Blow the lines to remove any trash in the lines up to the HP flare valve, PV24456, located immediately after the Train B syngas scrubber.

Systems included: PAC1 and PAC2, both startup burners, gasifier B, syngas coolers, PCDs, startup stack, and gas cleanup systems up to the AGR inlet. There are no internals in the PCDs, syngas scrubber (except demister) and other gas cleanup equipment.

Outline:

- Establish flow using flow path of PAC1 and PAC2 - startup burners - gasifier - syngas coolers - PCDs - HP Flare valve PV24456 (figure 5.4- 5).
- Establish high air flow into the system and achieve sufficient cleaning factor by adjusting pressure, and perform the cleanup process up to the syngas scrubber.

Summary:

- The gasifier was soaked for 4 hours before the blow down test. PAC1 and PAC2 were connected using a crossover to supply process air for gasifier Train B.
- By keeping the gasifier pressure at 50 psig, air flow of about 400,000 lb/hr was established through the process flow path. Flow distribution was as follows (see figure 5.4-4 for valve locations): combustion and quench air flows through the two startup burners with TV24119B = 100,000 lb/hr, FV24116 = 30,000 lb/hr, TV24144B = 100,000 lb/hr, and FV24141 = 30,000 lb/hr; and through upper mixing zone with FV24017 = 100,000 lb/hr and FV24021 = 40,000 lb/hr.

Analysis:

- The crossover from PAC1 and PAC2 to Train B turned out to be a success (originally PAC1 and PAC2 were dedicated to gasifier A). There were no major leaks found in that path. Both the PACs combined were able to easily provide a total of 400,000 lb/hr of air flow.
- The choke flow was reached at 50 psi pressure with 400,000 lb/hr of air flow at PV24445, the flare stack valve downstream of syngas scrubber. Higher mass flow could not be attained.
- Based on the air flow rate and operating pressure, a 0.56 cleaning factor was achieved at the valve.
- Because an air blow had already been performed up to the startup stack in a previous test, not much loose and extraneous material was expected in downstream lines to the flare stack valve. The lower cleaning factor achieved was deemed satisfactory and the sacrificial valve was replaced with the original PV24456 valve.

Measure of success: Based on the velocities and cleaning factor achieved, the air blow test up to the HP flare valve at the syngas scrubber was successful.

5.4.3.11 *Air Blow 2 to HP Flare Valve PV144456 in Gasifier Train A*

Date performed: 2/28/2015

Objectives: Blow the lines to remove any trash up to the HP flare valve, PV14456, located at the exit of the syngas scrubber.

Systems included: PAC1 and PAC2, both startup burners, gasifier A, syngas coolers, PCDs, startup stack, and gas cleanup systems up to the AGR inlet. There are no internals in the PCDs, syngas scrubber (except demister), and other gas cleanup equipment.

Outline:

- Establish flow using flow path of PAC1 and PAC2 - startup burners - gasifier - syngas coolers - PCDs - HP Flare PV14456 (figure 5.4-5).

- Establish the air flow into the system and achieve sufficient cleaning factor by pressure adjustment in order to effectively clean the process up to the syngas scrubber.

Summary:

- The air flow was established through the gasifier for 4 hr before the start of the air blow test.
- PAC1 and PAC2 were used to supply the process air for gasifier Train A.
- By keeping the gasifier pressure at 50 psig, air flow of about 400,000 lb/hr was established through the process flow path. Flow distribution was as follows (see figure 5.4-4 for valve locations): combustion and quench air flows through the two startup burners with TV14119B = 100,000 lb/hr, FV14116 = 30,000 lb/hr, TV14144B = 100,000 lb/hr, and FV14141 = 30,000 lb/hr; and through upper mixing zone with FV14017 = 100,000 lb/hr and FV14021 = 40,000 lb/hr.
- By changing the pressure from 50 psig to 25 psig and back to 50 psig at PV14456 multiple times, gas velocities were varied to perform the air blow test. See figure 5.4-10.

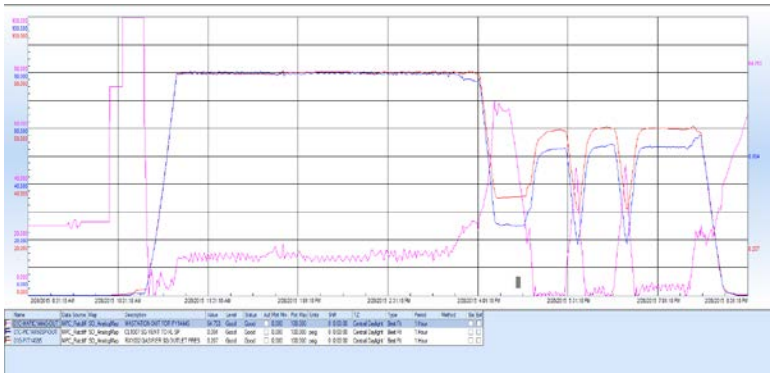


Figure 5.4-10 – Trend during air blow test. Exit gasifier pressure (red); valve openings in lines to stack (pink) and flare (blue)

Analysis:

- PAC1 and PAC2 were able to easily provide a total of about 400,000 lb/hr of air flow.
- The choke flow was reached at 50 psi pressure with 400,000 lb/hr of air flow at PV14456. Because higher mass flow could not be established, both stack and flare vent valves were used during the test.
- Based on the air flow rate and operating pressure, a cleaning factor of 0.56 was achieved. Since air blow cleaning was previously performed up to the startup stack, the lower cleaning factor was sufficient because not much loose and extraneous material was expected in the lines to the syngas scrubber. With completion of air blow clean-up, the sacrificial valve in the flare vent line was replaced with the originally designed PV14456 flare vent control valve.

Measure of success: Based on the velocities and cleaning factors achieved during the pressure swings, the air blow 2 test was successful.

5.4.3.12 *Air Blow 3 to HP Flare PV29026 in Gasifier B Train*

Date performed: 3/01/2015

Objectives: Blow the lines to remove any trash up to the HP flare valve, PV 29026, located upstream of the AGR.

Systems included: PAC1 and PAC2, both startup burners, gasifier, syngas coolers, PCDs, startup stack, and gas cleanup systems in the flow path up to the AGR inlet. There are no internals in the PCDs, syngas scrubber (except demister), and other gas cleanup equipment.

Outline:

- Establish flow using flow path of PAC1 and PAC2 - startup burners - gasifier - syngas cooler - PCD - HP flare PV29026 (figure 5.4-5).
- Establish the air flow into the system to achieve sufficient cleaning factor by pressure changes and perform the cleanup process up to the syngas scrubber.

Summary:

- Gasifier B was soaked for 4 hr before the blow off test. PAC1 and PAC2 were connected by crossover to supply process air for gasifier Train B.
- By maintaining the gasifier exit pressure at 50 psig, an air flow of about 400,000 lb/hr was established through the process flow path. Flow distribution was as follows: combustion and quench air flows through two startup burners with TV24119B = 100,000 lb/hr, FV24116 = 30,000 lb/hr, TV24144B = 100,000 lb/hr, and FV24141 = 30,000 lb/hr; and through upper mixing zone with FV24017 = 100,000 lb/hr and FV24021 = 40,000 lb/hr. See figure 5.4-4 for valve locations.
- By changing the pressure from 50 psig to 25 psig and back to 50 psig at the flare vent valve PV29026 multiple times, variations in velocities were achieved for an effective air blow (figure 5.4-11).

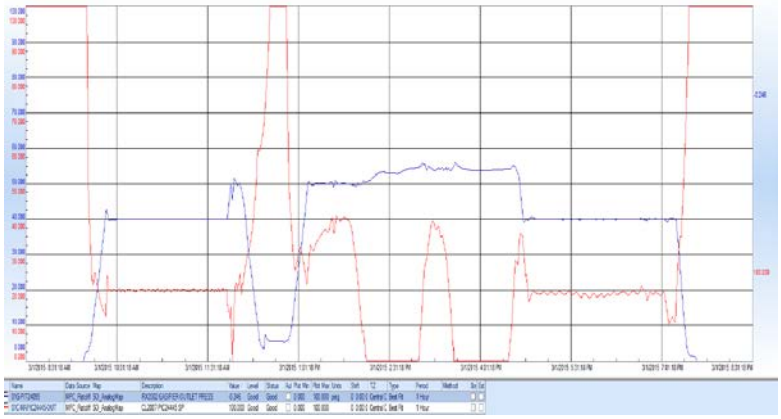


Figure 5.4-11 – Pressure (blue) variations at gasifier exit and stack valve PV24445 opening (red) during the air blow through flare vent valve PV29026.

Analysis:

- PAC1 and PAC2 together were able to easily provide a total of about 400,000 lb/hr of air flow. Based on the air flow rate and operating pressure. a cleaning factor of about 1.01 was achieved. Since a cleaning blow up to the syngas scrubber was completed previously, not much trash was expected in the lines to blow through the downstream gas conversion and cleanup systems.

Measure of success: Based on the velocities and cleaning factors achieved with pressure changes, the air blow 3 test was successful. The lines are expected to be clean up to the HP flare valve at the AGR inlet.

5.4.3.13 *Pilot Light Ignition of Startup Burners for Gasifier B*

Date performed: 3/01/2015

Objectives: Ignition of the pilots of startup burners AH2102 and AH2202

Systems included: PAC1 and PAC2, both start up burners, gasifier, syngas coolers, PCDs, and startup stack. Gas cleanup was isolated.

Outline:

- Establish flow using flow path of PAC1 and PAC2 - startup burners - gasifier - syngas coolers - PCDs - start up stack vent valve PV24445.
- Establish natural gas flow to startup burners.
- Ignite pilots A and B on both AH2102 and AH2202.

Summary:

- PAC1 and PAC2 were connected by crossover to supply process air to gasifier Train B. Natural gas and air flow was established to both the burners. All signals with burner management system (BMS) were checked. Using false firing signals, the burner trip logic was verified.
- By maintaining the gasifier pressure at 40 psig, air flow of about 300,000 lb/hr was established through the process flow path. Flow distribution was as follows: combustion and quench air flows through two startup burners with TV24119B = 34,500 lb/hr, FV24116 = 15,500 lb/hr, TV24144B = 34,500 lb/hr, and FV24141 = 15,500 lb/hr; and through upper mixing zone with FV24017 = 100,000 lb/hr and FV24021 = 40,000 lb/hr. See figure 5.4-4 for valve locations.
- Pilot A for AH2102 lit successfully after multiple attempts. It was determined that the ignitor wires for the two pilots were wired incorrectly (wires were switched). Other pilots could not be lit due to various installation issues.

Burner	Pilot A	Pilot B
AH 2102	Lit and flame detected using scanner	Installation issue
AH 2202	Installation issue	Installation issue

Analysis:

- PAC1 and PAC2 easily provided the process air flow required.
- The false firing helped to check the trip logic for the burner when the scanner does not detect the flame.
- The default flame scanner timer was not sufficient to detect the flame; the scanner timer was increased slightly. The delay in flame scanner pick-up is likely related to a dirty window.
- When pilot A was lit the exit gas temperature of burner AH2102 increased. With minimum flow through the pilot, a temperature rise of 16 ºF was observed at the exit after 3 min.

Measure of success: Ignition of pilot A on startup burner AH2102 was successful.

5.4.3.14 *Pilot Ignition of Startup Burners on Gasifier A*

Date performed: 3/02/2015

Objectives: Ignition of the two pilots in each of the two startup burners AH1102 and AH1202.

Systems included: PAC1 and PAC2, both startup burners, gasifier, syngas coolers, PCDs, and startup stack. Gas cleanup was isolated.

Outline:

- Establish flow using flow path of PAC1 and PAC2 - startup burners - gasifier - syngas coolers - PCDs - startup stack valve PV14445.
- Establish the natural gas flow to start up burners.
- Ignite pilots A and B on both AH1102 and AH1202.

Summary:

- PAC1 and PAC2 were used to supply process air to gasifier Train A. Natural gas and air flow was established to both the burners. All signals with BMS were checked. Using false firing, burner trip logic was verified.

- By maintaining the gasifier pressure at 40 psig, air flow of about 300,000 lb/hr was established through the process flow path. Flow distribution was as follows: combustion and quench air flows through two startup burners with TV14119B = 34,500 lb/hr, FV14116 = 15,500 lb/hr, TV14144B = 34,500 lb/hr and FV24141 = 15,500 lb/hr; and through upper mixing zone with FV24017 = 100,000 lb/hr and FV24021 = 40,000 lb/hr. See figure 5.4-4 for valve locations.
- Both pilots on AH1102 were lit. Even though both the pilots on AH1202 were lit, the flame scanners did not pick up the flame.

Burner	Pilot A	Pilot B
AH 1102	Lit and flame detected using scanner	Lit and flame detected using scanner
AH 1202	Flame not detected by scanner but visual confirmation and spike in exit gas temperatures supports light off	Flame not detected by scanner but visual confirmation and spike in exit gas temperatures support light off

Analysis:

- PAC1 and PAC2 to were able to provide total process air flow required.
- The false firing helps to check the trip logic for the burner when the scanner does not detect the flame.
- The default flame scanner timer was not sufficient to detect the flame; the timer was reset to a slightly higher scan time.
- Pilots A and B were lit successfully for burner AH1102 in the first two attempts, and the flame was detected by the scanner.
- Flames for Pilot A and B were not detected by scanner for AH1202, but flame could be confirmed visually through view port.
- The scanner's glass window was possibly tinted with soot which could be the reason for scanner failure.
- The rise in exit temperature of burner AH1202 and visual confirmation supports ignition for both pilots A and B. See figure 5.4-12.

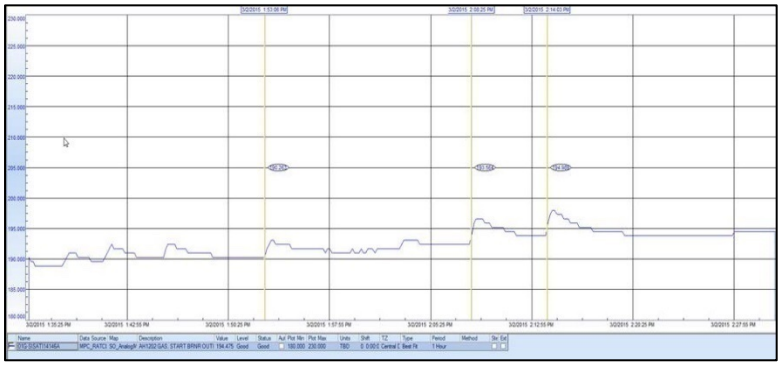


Figure 5.4-12 – Temperature spikes in exit temperature of burner AH1202 gives confirmation of flame

Measure of success: Ignition tests of both pilots on startup burner AH1102 and AH1202 were successful.

5.4.3.15 *Air Blow 3 to HP Flare PV19026 on Train A*

Date performed: 3/04/2015

Objectives: Blow the lines to remove any trash in downstream lines up to HP flare PV19026 located upstream of AGR.

Systems included: PAC1 and PAC2, both startup burners, gasifier, syngas coolers, PCDs, startup stack, and gas cleanup systems up to the AGR inlet. There are no internals in PCDs, syngas scrubber (except demister) and other gas cleanup equipment.

Outline:

- Establish flow using flow path of PAC1 and PAC2 - startup burners - gasifier - syngas coolers - PCDs - HP flare valve PV19026 (figure 5.4-5).
- Establish the air flow into the system and achieve sufficient cleaning factor by changing pressures to perform the cleanup process.

Summary:

- Flow through gasifier was maintained for 4 hours before the blow off test began. PAC1 and PAC2 were used to supply process air to gasifier Train A. By keeping the gasifier pressure at 50 psig, air flow of ~ 400,000 lb/hr was established through the process flow path. Flow distribution was as follows: combustion and quench air flows through two startup burners with TV14119B = 100,000 lb/hr, FV14116 = 30,000 lb/hr, TV14144B = 100,000 lb/hr, and FV14141 = 30,000 lb/hr; and through upper mixing zone with FV14017 = 100,000 lb/hr and FV14021 = 40,000 lb/hr. See figure 5.4-4 for valve locations.
- By changing the pressure from 50 psig to 25 psig and back to 50 psig at the flare vent valve PV19026 multiple times, variations in velocities were achieved to perform the air blow test.

Analysis:

- PAC1 and PAC2 were able to easily provide a total of 400,000 lb/hr of air flow. Based on the air flow rate and operating pressure, a cleaning factor of 1.01 was achieved. Since lines up to syngas scrubber had been cleaned through a previous air blow test, not much extraneous material was expected in the downstream lines. Following the air blow, nozzles, and manways on vessels in the gas cleanup section flow path were opened to clean out any trash accumulated in the bottom of the vessels.

Measure of success: Based on the velocities and cleaning factors achieved with induced pressure changes, air blow 3 test was successful for the lines in the gas cleanup section.

5.4.3.16 *Air Blow 4 to HP Flare PV24503 on Train B*

Date performed: 3/14/2015 – 3/16/2015

Objectives:

- Blow the lines to remove any trash in the lines up to the HP flare vent valve, PV24503, located upstream of gas turbine B.
- Perform flow variation tests to check for the chattering noise from the check valve in the line downstream of FV24019.

Systems included: PAC1 and PAC2, both startup burners, gasifier, syngas coolers, PCDs, startup stack, and gas cleanup systems up to the gas turbine inlet. There are no internals in the PCDs, syngas scrubber (except demister), and other gas cleanup equipment.

Outline:

- Establish flow using flow path of PAC1 and PAC2 - startup burners - gasifier - syngas coolers - PCDs - HP flare vent valve PV24503 (figure 5.4-5).
- Achieve 70 psig at PV24503. Establish the air flow into the system and achieve sufficient cleaning factor by changing pressures to perform the cleanup process in the lines up to the inlet of the AGR.
- Open and close FV24019 (air flow to MZ01 nozzle, figure 5.4-4) in increments to observe the chattering noise from the downstream check valve and determine the break-through point where the noise stops.

Summary:

- On 03/14/2015, flow through the gasifier was maintained for 4 hr before the blow off test. During this soak period, FV24019 was closed and opened in increments to observe the chattering noise from the downstream check valve and to identify the break-through point where the noise stops.

- When the flow path was established up to the gas turbine inlet, major leaks were observed downstream of the AGR. Tests were called off temporarily to repair the leaks.
- After completing the repairs, the gasifier was pressurized to 40 psig. The flow control valve FV24019 was closed and opened in increments to observe the chattering noise from check valve. Unlike before, no chattering noise was heard while increasing or decreasing the flow.
- By maintaining the gasifier pressure at 90 psig, an air flow rate of about 400,000 lb/hr was established through the process flow path. Due to pressure drop across the flow path, the gas turbine inlet was at about 65 psig. The gas velocity at the gasifier exit was about 45 ft/s at these conditions. In comparison, the gas velocity at gasifier exit during normal operation is 75 ft/s. Flow distribution was as follows: combustion and quench air flows through two startup burners with TV14119B = 75,000 lb/hr, FV14116 = 35,000 lb/hr, TV14144B = 75,000 lb/hr, and FV14141 = 35,000 lb/hr; and through lower mixing zone with FV14019 = 180,000 lb/hr. See figures 5.4-4 and 5.4-5 for valve locations.

Analysis:

- Chattering of MZ01 check valve in line from FV24019:

a) With no pressure in the gasifier:

The opening of valve FV24019 was increased periodically to observe the chattering noise caused by the check valve at low flow rates. It was found that up to a 35% valve opening, the valve made chattering sounds at different frequencies (figure 5.4-13). When the opening rose above 35%, the chattering noise stopped completely. But when the flow was reduced gradually in a similar manner, no chattering sound was recorded below the 35% opening.

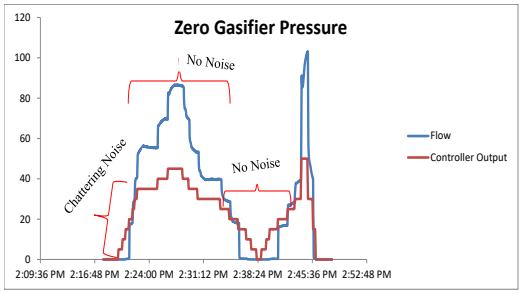


Figure 5.4-13 – Performance of check valve downstream of FV24019 with changes in valve opening at zero gasifier pressure.

When the same process was repeated to duplicate the test, no noise was heard during lower or higher flow rates as well as while increasing or decreasing the flow. See figure 5.4-13.

b) With 40 psig pressure in the gasifier:

The opening of valve FV24019 was increased periodically to observe the chattering noise caused by the MZ01 check valve at low flow rates. No chattering noise was recorded at all up to 40% valve opening (figure 5.4-14).

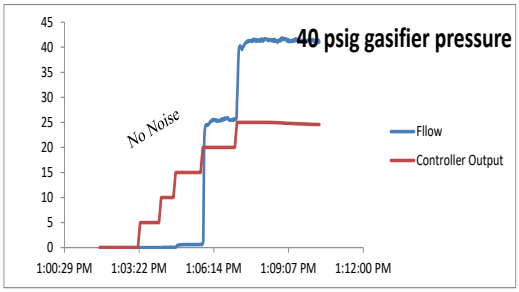


Figure 5.4-14 – Performance of check valve downstream of FV24019 with changes in valve opening at 40 psig gasifier pressure.

Tests performed at two different pressures did not demonstrate consistent chattering behavior of the check valve. Further tests were planned after a visual inspection of the check valve.

- All major leaks found downstream of the AGR were fixed. Both the PACs combined were able to easily provide a total of 400,000 lb/hr of air flow.
- Based on the air flow rate and operating pressure, a cleaning factor of 0.59 was achieved.

Measure of success: Based on the velocities and cleaning factor achieved, the air blow test up to the last HP flare valve, PV24503, at gas turbine inlet was successful.

5.4.3.17 *Air Blow 4 to HP Flare Valve PV14503 on Train A (test MZ01 chattering check valve in line from FV14019)*

Date performed: 3/19/2015 – 3/20/2015

Objectives:

- Blow the lines to remove any trash up to the HP flare vent valve, PV14503, located upstream of gas turbine A.
- Perform flow variation tests to check for the chattering noise from the check valve in the line from FV14019 that supplies process air to MZ01 nozzle at the bottom of the gasifier.

Systems included: PAC1 and PAC2, both startup burners, gasifier, syngas coolers, PCDs, startup stack, and gas cleanup systems up to the gas turbine inlet. There are no internals in PCDs, syngas scrubber (except demister), and other gas cleanup equipment. The water level in the AGR columns was in the sumps and below the inlet gas distributor.

Outline:

- Establish flow using flow path of PAC1 and PAC2 - startup burners - gasifier - syngas cooler - PCD - HP flare valve vent valve PV14503 (figure 5.4- 5) with 70 psig at PV14503.
- Achieve sufficient cleaning factor by changing pressures to perform the cleanup process.
- Open and close FV14019 in increments to observe the MZ01 check valve chattering noise and determine breakthrough point where the noise stops.

Summary:

- On 03/19/2015, flow through the gasifier was maintained for 4 hr before the blow off test. During this soak period, FV14019 was actuated in increments to observe the chattering noise from MZ01 check valve and breakthrough point where the noise stops was noted.
- With increasing pressure, major leaks were observed downstream of the AGR. The system was depressurized to repair the leaks.
- On 03/20, after repairing all known leaks, the gasifier was pressurized to 90 psig. Due to the design restriction at the AGR, the pressure ramp rate of 0.883 psi/hr was maintained.
- By maintaining the gasifier pressure at 90 psig, an air flow of about 400,000 lb/hr was established through the process flow path. With pressure drop across the flow path, the pressure at the gas turbine inlet was about 65 psig.

Analysis:

- All major leaks found downstream of the AGR were fixed. Both the PACs combined were able to provide a total of about 400,000 lb/hr of air flow. Based on the air flow rate and operating pressure, a cleaning factor of 0.59 was achieved.

Chattering of MZ01 check valve on FV14019:

- A test was performed on the MZ01 check valve on gasifier A using the test previously performed on gasifier B. The flow control valve FV14019 was opened and closed in increments of 5% while listening in the field for chattering noise.

- The check valve started chattering loudly at a flow control valve position of 10% open (flow rate less than measurable) and continued to vibrate until the control valve position was at 30% open (55,000 lb/hr). The chattering ceased with the valve at 35% open (flow rate 73,000 lb/h). The gasifier pressure was at 30 psig.
- The chattering results when flow through the MZ01 check valve was established for the first time were similar to the results of the test on gasifier B.
- In 5% steps, down from 40% to 0% control valve opening, the check valve chattering did not recur on the way down as with gasifier B. This test was done at 40 psig pressure on the gasifier. See figures 5.4-15 and 5.4-16.

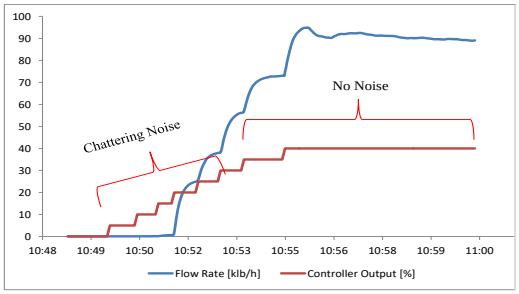


Figure 5.4-15 – Performance of check valve downstream of FV14019 with changes in valve opening at 40 psig gasifier pressure

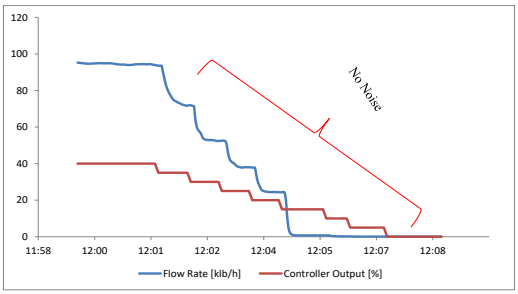


Figure 5.4-16 – Performance of check valve downstream of FV14019 with changes in valve opening at 40 psig gasifier pressure

- The check valve chattering appears to be inconsistent at low flow conditions. The same process conditions and test procedure do not always result in vibration. When the check valve does vibrate, the vibration appears to stop at flow rates above 50,000 to 70,000 lb/h.

Measure of success: Based on the velocities and cleaning factor achieved, the air blow test up to the HP flare valve vent, PV14503, at gas turbine inlet was successful. Nozzles and manways were opened to clean out any trash at the bottom of vessels. The sacrificial valve was replaced with the originally designed PV14503 valve.

5.4.3.18 *Summary for MZ01 Check Valve Tests, Inspection, and Modifications*

Date performed: 1/14/2015 – 3/20/2015

Objectives: Analyze the data on MZ01 check valve chattering noise tests on both gasifier trains. Summarize inspection and modifications.

Outline:

- On each gasifier, the 14-in. check valve in the line to MZ01 nozzle in the LMZ and downstream of the flow control valve was tested at various pressures and flowrates to verify the noise issue.

The test consisted of following steps:

- Opening the flow control valve (FV-14019/24019) from closed position in increments of about 5% at a time while listening in the field for chattering noise. The flow was increased till the noise stopped.
- Close the valve in 5% decrement until fully closed to verify the chattering behavior of the check valve at reducing flow rates.
- Repeat the test at various gasifier pressures.

Observations and analysis:

The chart in figure 5.4-17 presents a summary of the observations.

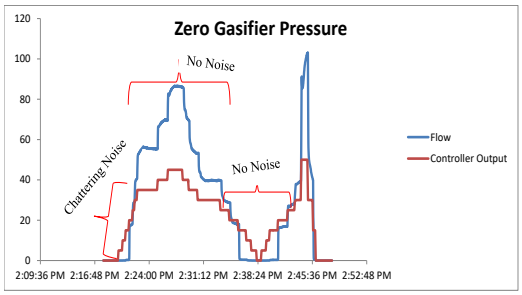


Figure 5.4-17 – Performance of check valve downstream of FV14019 with changes in valve opening at 40 psig gasifier pressure.

01/13/15: The check valve on Gasifier B started chattering loudly at a flow control valve position of 10% open (flow rate was not measurable) and continued to chatter until the control valve position was at 35% open. It did not make any noise while decreasing the flow. The test was repeated at 100 psig and the valve showed similar behavior.

– To avoid chattering, the valve was opened directly to 20% and incrementally opened from that point. The valve did not chatter at all. The valve was opened to 80% with flow rate up to 200,000 lb/hr.

- 01/14/15: In a repeat of previous day's test, the check valve did not chatter while opening the control valve from 0% to 20%, opening in 5% increments, with gasifier B pressure less than 5 psig.
- 03/14/15: After 2 months of construction work, flow was established to gasifier B. The check valve started chattering loudly at a flow control valve position of 10% open (flow rate not measurable) and continued to vibrate until the control valve position reached 30% open (55,000 lb/h). The vibration ceased with the valve at 35% open (flow rate ~85,000 lb/h). The gasifier B pressure was at 4 psig. The check valve did not chatter at all while closing all the way to 0% open. The check valve did not vibrate when the tests were repeated, opening from 0% open, in increments of 5% to 50% open and then closing the valve in 10% decrements.
- 03/16/15: The check valve on gasifier B did not chatter at all while opening from 0% to 25% open (40,000 lb/h). The gasifier pressure was at 40 psig. Since the valve did not chatter at all, it was opened to more than 50% with 180,000 lb/hr of air flow. The valve did not make any noise while closing to 0% open.
- 03/19/15: Air flow to gasifier A through MZ01 was established for the first time. The check valve on gasifier A started vibrating loudly at a flow control valve position of 10% open (flow rate not measurable) and continued to vibrate until the control valve position was at 30% open (55,000 lb/h). The vibration ceased with the valve at 35% open (flow rate 73,000 lb/h). The gasifier pressure was at 30 psig. After an hour, the flow control valve was closed in 5% decrements from 40% to 0%, and the check valve chattering did not recur. This test was done at about 40 psig pressure on the gasifier.
- 03/20/15: The check valve on gasifier A did not chatter at all in both tests while opening the control valve from 0% to 40% (65,000 lb/h). It did not make any noise while closing in 5% decrements. The gasifier pressure was at 1 psig. A similar test was performed with gasifier A pressure at 100 psig. The valve did not make any chattering noise while opening or closing between 0% and 40% valve position.

A vendor with check valve experience was selected to inspect and propose suitable modification to avoid the chattering noise. The vendor's initial observations and recommendations were:

- Visual observation did not show any damage to the valve seat or the disc.

- The check valve seat does not have enough cushion to absorb disc impact on closing.
- Machining the disc to reduce weight and external damping might help in controlled opening and closing.

Vendor recommended an external counterweight mechanism that can be adjusted and set once for low flow and density conditions, and it should work all the way up to normal operation. Setting would be by trial and error adjustment to overcome packing frictional forces. Vendor calculations on disc weight, counterweight cantilever force, hydraulic force, and frictional forces took into account the variations in operating conditions. The modifications will help in dampening the effect of gravity on disc motion.

Check valve chattering is most likely due to its applicability at low flow conditions and low-pressure operation. The check valve was designed for a minimum gas density corresponding to 400 psia and for a certain minimum gas velocity.

Check Valve Modifications

Before the process air stream enters the gasifier at MZ01, it passes through a wafer disk style check valve. This valve is a 14-in. 900# class valve made of Inconel® 625. It is the same size as the pipe going into the gasifier. During air flow tests of commissioning, the valve would vibrate across a wide range of low flow conditions. This was due to the wafer disk fluttering in the stream. It was determined that the knocking was likely to cause damage to check valve internals. Because of the valve's size, specialty metallurgy, and pressure class, it was not practical to find another valve that was the proper size for the application within the commissioning schedule time period.

As an alternative to replacement, the check valve was sent to a vendor with check valve expertise and retrofitted with a damper system to prevent low flow knocking. This was achieved by pinning the disk to the shaft and extending the shaft out of the side of the valve body through a packing gland. The extended shaft was fitted with a lever arm with an adjustable weight to ensure closure. A hydraulic actuator was also keyed to the shaft. The actuator piston chambers were tubed together so that as the shaft turned it pushed hydraulic fluid from one side of the actuator to the other. The damping could be controlled with needle valves in the tubing that restricted flow, and with a cam switch to turn damping on or off depending on the valve position. The modification provided a high degree of flexibility to prevent any knocking. The damping system was engineered as a quick solution, and there was not sufficient time to experiment and simplify the design. The check valves in large critical flow applications need to be treated like control valves and sized to handle wide range of process conditions from startup to normal operation.

5.4.4 Cold Solids Circulation Tests in Train A

After identifying and addressing the leaks in the process from coal feeder to flare vent valve just upstream of the gas turbine, completing air blow to clean the process lines of any loose and extraneous materials, and completing the pressure tests, the gasifier and associated systems were prepared for addition of inert bed material. The inert bed material is added using the FD0007 coarse ash feed (CAF) system, requiring the feeder to be dry commissioned after completing leak and pressure checks. The CAF system is a lock hopper system with a blow pot to convey the inert solids in the coarse ash silo SI0007 to the gasifier.

5.4.4.1 *Gasification Island Setup*

Coarse ash was not available for use as bed material, so sand was used to initially fill up the gasifier to the desired inventory. The mass mean size of sand was about 130 microns. The purchased sand was pneumatically transferred from truck to coarse ash silo. The activities before and after loading sand into the gasifier are listed in table 5.4-4.

Table 5.4-4 – Activities related to solids addition to gasifier

Activity	Date
Pressurize and check for leaks	09/23/15
N2 to LMZ controller tuning N2 to SUB controller tuning Recycle gas header pressure controller tuning	09/23/15

Activity	Date
Gasifier fluidization flow controller tuning	
PCD, CFAD, CCAD controller tuning	09/29/15
PCD backpulse test	09/30/15
Sparge steam to economizer for PCD warmup	10/04/15
Balance gasifier PDT meters	10/05/15
Noticed PCD and CCAD PCD backpulse accumulators control issue	10/06/15
SUB pilot light test	10/15/15
Add sand to gasifier through feeder FD0007	10/16/15
Sufficient sand in gasifier to start circulation	10/18/15
Noticed rumbling noise from gasifier	10/20/15
Start cold solids circulation	10/21/15
Shut down for vibration/noise issue	10/23/15
Restart system	10/27/15
Vibration test	10/28/15
Move solids through CCAD system	10/29/15
Light pilot AH1102	10/29/15
Resume cold solids circulation test	10/30/15
Standpipe aeration tests	10/30/15
LMZ velocity tests	
Air distribution tests (noticed high pitch sound from gasifier)	10/31/15
Lowest riser velocity test	10/31/15
Highest riser velocity test	10/31/15
Riser velocity variation tests	11/01/15
J-leg and SP aeration tests	11/01/15
Seal-leg aeration tests	11/01/15
Minimum aeration velocities test	11/1/15
Start CFAD	11/1/15
Start TAC	11/2/15
Shutdown for fixing SP01	11/3/15
Restart system	11/9/15

Before adding any solids to the gasifier for the first time, the following steps were implemented, some of which were being commissioned for the first time. These are the main steps to implement at the start of a cold startup of gasification island.

- PCD cone warmup

The system is set up to warm the PCD cone by condensing IP steam and maintain the PCD cone in warm conditions to prevent condensate from forming and rolling down the PCD cone into fine ash receiver (CFAD fines cooler). The low pressure (LP) steam is used for PCD cone warmup.

This unit was well designed and installed. The heat-up unit operated well and easily maintained the PCD cone at over 300 °F.

- Steam sparging in economizers for PCD warmup

Moisture-laden gas flow (for example flue gas from gasifier startup burners) to PCD causes moisture to condense on the PCD candles and on the upper portion of the PCD vessel. To prevent such condensation, the upper portion of the PCD is first warmed up to over 250 °F. This was carried out by initiating low flow of nitrogen from the gasifier and heating up the gas as it flowed through the syngas cooler economizer. IP steam is sparged into the closed circulation water loop that flows through the economizer (for startup purposes) to heat up the nitrogen flowing through the economizer to PCD.

Although the scheme was being implemented for the first time, the unit started easily, with the water pumping loop and temperature controller controlling the sparging steam flow. The concept and the unit worked well from initial commissioning and easily heated the PCD to over 250 °F.

- Preset fluidization gas flow in seal leg, standpipe, and J-leg;

Before adding any solids to the gasifier, a minimum preset flow is established through each flow controller in the seal leg, standpipe, and J-leg. The controllers and the nozzles to which flow is distributed are shown in figure 5.4-4.

There is a total of 16 fluidization flow control valves in the seal-leg, standpipe and J-leg, and each controller flow is distributed to multiple nozzles. During initial commissioning, fluidization gas (nitrogen/recycle gas) flow to each nozzle was field checked. Nearly uniform flow distribution to all nozzles from each controller was maintained by adjusting the needle and globe valves in the field.

When insufficient or no flow to a nozzle was detected, the line to nozzle and nozzle inserts was blown clear of any plug.

One of the major test parameters during cold solids circulation test is variation of fluidization flow through every flow valve and combination of flow distribution. Flow was varied through each controller to full range before setting the flow to minimum preset value.

- Set up gasifier with flow through process nozzles

During solids addition to the gasifier and startup, minimum nitrogen flow was established through process gas flow control valves in LMZ and UMZ.

During the first cold solids circulation, high gas flow was required to achieve desired riser velocity, so process air from PAC was used in LMZ and UMZ.

Flow variation and distribution among nozzles in LMZ and UMZ were test parameters during solids circulation tests.

- Balance differential pressure purge instruments

The gasifier has multiple PDT (pressure differential transmitter) measurements, which are critical for monitoring solids circulation. Each impulse leg of the PDTs has an instrumented purge flow with nitrogen as purge gas. It is important to balance the PDT to near zero before adding any solids to the gasifier. Minimum purge flow was set to each impulse leg and the flow was adjusted to balance the PDTs to near zero values. Figure 5.4-18 shows various differential pressure and pressure measurements around the gasifier loop, as well as temperature measurements around the gasifier loop and the location of direct density measurements in the riser, seal leg downcomer, and standpipe

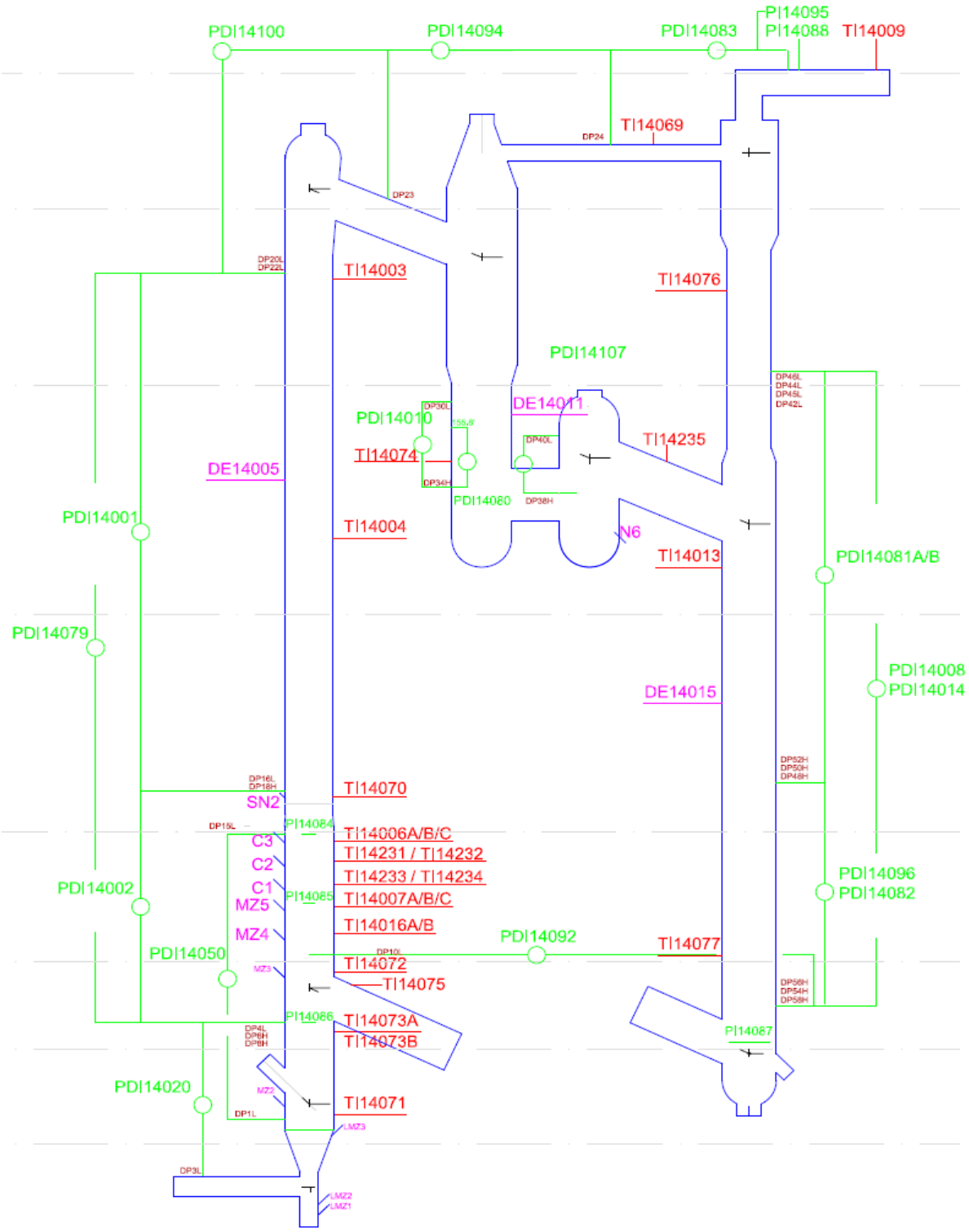


Figure 5.4-18 – Pressure, differential pressure, temperature, and density measurement locations around the gasifier A loop. For gasifier B tags, replace the first numeral 1 by 2.

In the early stages of impulse line flow set up, the flows were insufficient because flows were restricted by the 1/4-in. needle valves. These were later changed to 3/8 in.

Also, in early stages of establishing the impulse line flows, maintaining the flow was challenging. Fine dust in the lines from construction plugged the filters and the purge flow tended to decrease over time.

Another challenge with purge flow during operations was the occasional plugging of nozzle inserts. The inserts have smaller internal diameters to ensure sufficient nozzle tip velocities can be attained with low mass flow rates of purge gas.

- Set up SUBs with gas flows

As a general practice during first startup and further operation, minimum nitrogen flow through SUBs is established to prevent solids from backing into the burner gas flow path.

During cold solids circulation tests, air flow through quench and combustion air valves has been used for balancing air distribution.

The associated systems were prepared to handle solids loading, gas flow, and subsequent solids circulation tests as indicated below.

- Charge steam drum with BFW

BFW flow was established to the drum, and the level control worked well from the beginning.

- Activate PCD backpulse

PCD backpulse system was activated for cold solids circulation, and the system was tested by varying the backpulse parameters. An optimum set of parameters was set for cold solids circulation.

Observations during commissioning of the backpulse system:

1) A few backpulse valves were stuck. After maintenance, the valves operated well.
2) The accumulator pressure is controlled by a local pressure regulator and is not convenient for operations with variations in gasifier pressure. The backpulse pressure is typically 20 to 80 psi over gasifier pressure. An automatic differential pressure control system was being planned for installation on each backpulse system.

- Start CCAD primary fluidization flows

As with the fluidization gas flows in the gasifier solids circulation loop, the primary CCAD cooler has eight sets of fluidization gas flow controllers, and each controller controls flow to multiple nozzles.

After establishing flow to each nozzle, balancing the flow, and testing through the entire flow range, minimum gas flow (nitrogen initially and recycle gas during normal operation) was set through each nozzle.

- Set up gasifier outlet pressure control

The pressure controller tuning was checked for controllability during cold solids circulation tests with specific flow range at low operating pressures, which will be typical during gasifier riser velocity variation tests.

The pressure control valve to HP flare PV14456 (figure 5.4-5), located downstream of the syngas scrubber, had flow capacity limitation. The flow limitation might not be due to the valve itself but rather to restriction or other issues upstream of the valve. The causes for flow limitation will be investigated with visual inspection and more field instruments around the valve. During initial cold solids circulation tests, the pressure control valve PV14445 in the line to stack was used.

5.4.4.2 *Load Gasifier with Sand*

The controllers in coarse ash feeder FD0007 were tuned and the system was dry cycled several times before lining up the feeder to the top of the gasifier seal-leg riser. The startup solids (sand) was added starting Oct. 16, 2015. There

are two lines (3 in. and 6 in.) from the feeder to gasifier. The smaller line is for adding solids to the gasifier at high pressures, and the larger line is for adding solids to gasifier initially at gasifier pressures less than 100 psig. Both the feed lines were tested and used for sand addition at different rates. The solids level in the gasifier did not increase in proportion to the amount of solids added from the FD0007 feeder. Troubleshooting and field inspections indicated a maintenance manual valve off the conveying line from feeder to gasifier was inadvertently left open and the solids were flowing through this valve to the flare header. After replacing the maintenance valve and part of the line downstream due to erosion, operations resumed and solids addition to the gasifier was closely monitored to ensure the increase in solids level in gasifier was in proportion to the amount of solids being added from the FD0007 feeder.

The solids level in the gasifier was monitored primarily with differential pressure measurements. The pressure measurements, especially the pressure measurement at the bottom of the standpipe, and the direct nuclear based density measurements were useful to monitor the response of solids addition to the gasifier.

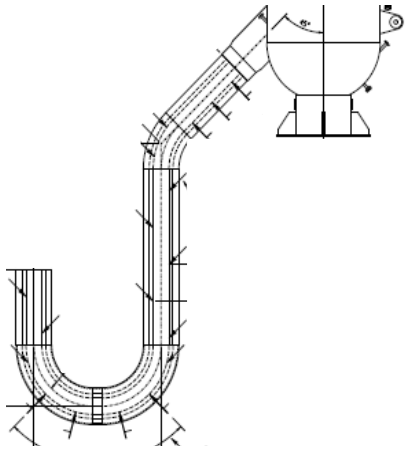


Figure 5.4-19 – CCAD J-pipe connecting seal-leg riser bottom to CCAD primary cooler

The take-off to the CCAD cooler is located at the bottom of the seal leg riser. The CCAD primary cooler is connected to the take-off in the seal leg riser with a J-pipe (figure 5.4-19). As solids to the gasifier was added through a nozzle at the top of the seal-leg riser, the CCAD cooler and the J-pipe filled up initially with solids. The CCAD primary cooler vent differential pressure measurement, PDI14208, showed gradual filling of the J-pipe and lower portion of CCAD primary cooler, inducing pressure difference between the gasifier and the CCAD secondary cooler (figure 5.4-20). The J-pipe acts as a non-mechanical valve, and it filled with solids to prevent the reverse flow of gas from gasifier to CCAD cooler. During the solids addition time in figure 5.4-20, about 15 tons of solids were added as indicated by coarse ash silo level change and number of coarse ash feeder cycles.

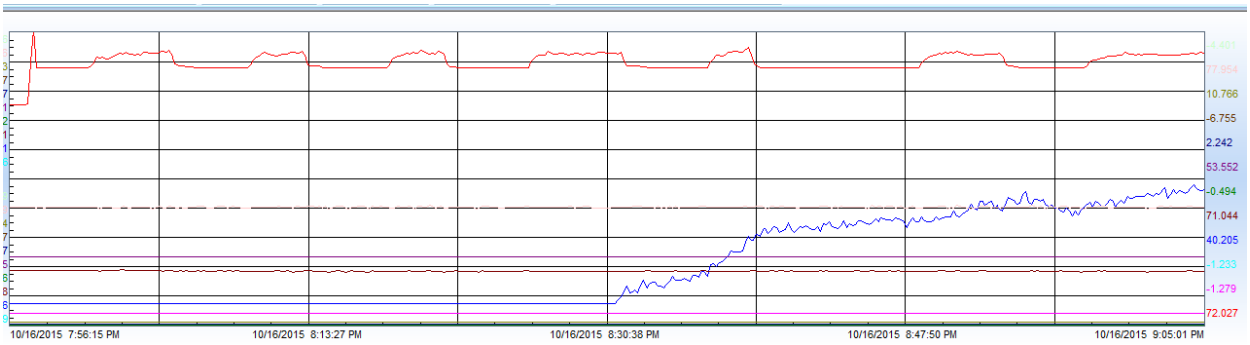


Figure 5.4-20 – Initial solids addition to gasifier, filling the CCAD J-pipe. Red line - coarse ash feeder operation indicating cyclic operation. Blue line - PDI14208, differential pressure between the gasifier and primary cooler vent.

With continued solids addition, the H-leg portion of the seal leg started to fill up. The pre-salter cyclone downcomer (seal leg downcomer) differential pressure measurement, PDT14010, started to show solids buildup as solids continued to accumulate in seal-leg riser (PDT14107). See figure 5.4-21.

As the level increases in the seal leg riser, the solids start to overflow into the standpipe. Both the seal-leg downcomer and riser differential pressures begin to level off when solids to start to overflow into the standpipe (figure 5.4-21). At this time, the H-leg is completely filled with solids.

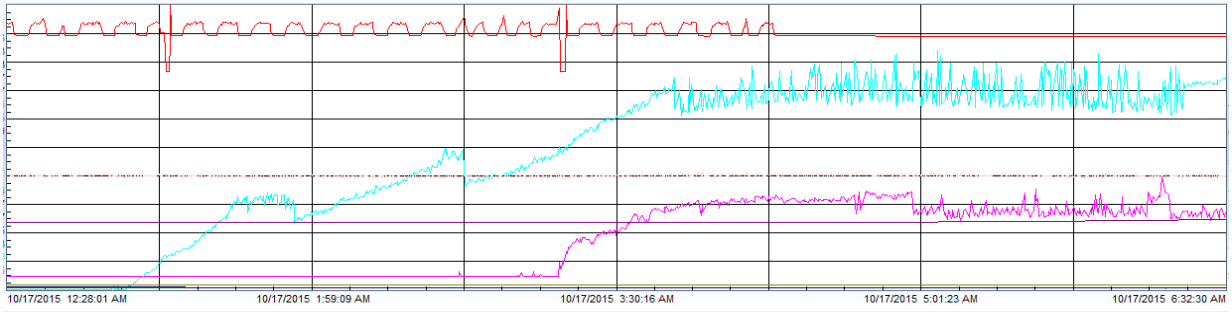


Figure 5.4-21 – Initial solids addition to gasifier: Red - coarse ash feeder operation indicating cyclic operation. Cyan - presalter cyclone downcomer DP. Pink - seal-leg riser DP.

The J-leg differential pressure measurement PDT14092 (cyan) started to increase, but initially the lower standpipe differential pressure PDT14082 (blue) did not consistently indicate any measurement, due to insufficient fluidization gas flow in the lower standpipe and a plugged impulse line filter (figure 5.4-22). These issues were corrected, and the lower standpipe differential pressure started to trend well when the solids level increased. With increasing solids level in the gasifier standpipe and J-leg, and by maintaining the J-leg in well fluidized condition, the solids started to overflow into the LMZ region of the gasifier as indicated by the increasing PDT14020 measurement (green). As the LMZ differential pressure started to stabilize with the low leg covered, the UMZ differential pressure measurement PDT14002 (pink) started to increase with continued solids addition. During this time, solids from coarse ash feeder FD0007 was being added through the smaller 3-in. conveying line at a rate of about 6 ton/hr. The increase in differential pressures in both standpipe and riser portions indicate that both the legs of the gasifier are filling at the same rate and the solids in both legs and J-leg are well fluidized.

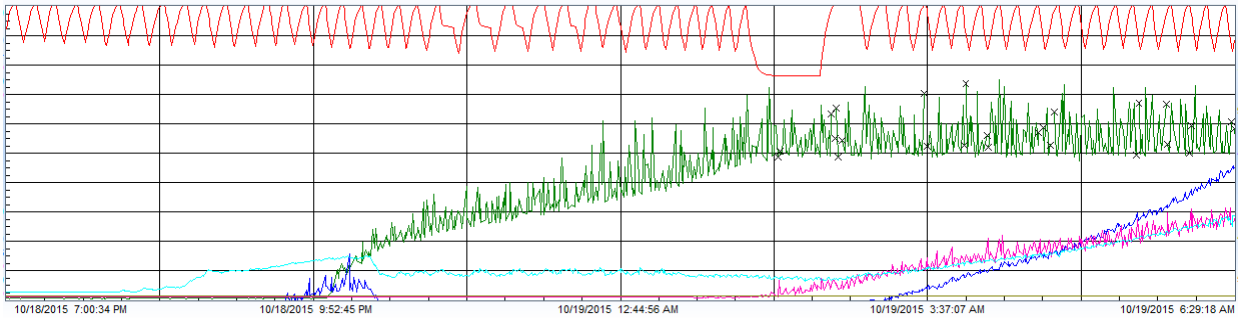


Figure 5.4-22 – Initial solids addition to gasifier: Red - coarse ash feeder operation indicating cyclic operation. Blue - lower standpipe DP. Cyan - J-leg DP. Green - LMZ DP. Pink – UMZ DP.

With continued solids addition, the solids level in the mixing zone and riser portion continued to increase along with standpipe level (figure 5.4-23) with UMZ DP PDT14002 (pink), riser DP PDT14001 (black), and lower standpipe level PDT14082 (blue). The differential pressure measurements trended consistently with each other. Solids addition through the 3-in. line from the coarse ash feeder FD0007 was stopped to line up the 6-in. line from the feeder to the gasifier for test purposes. Solids addition resumed after about 5 hr and the solids levels in the gasifier standpipe and riser started to increase again consistently (figure 5.4-23). The increase in the riser crossover (also called first

crossover or primary crossover) DP measurement PDT14100 indicates a slow solids circulation rate with increasing solids level in the riser. During this time, a number of other parallel and redundant differential pressure measurements were checked to ensure reasonableness of measurements and consistency with other measurements.

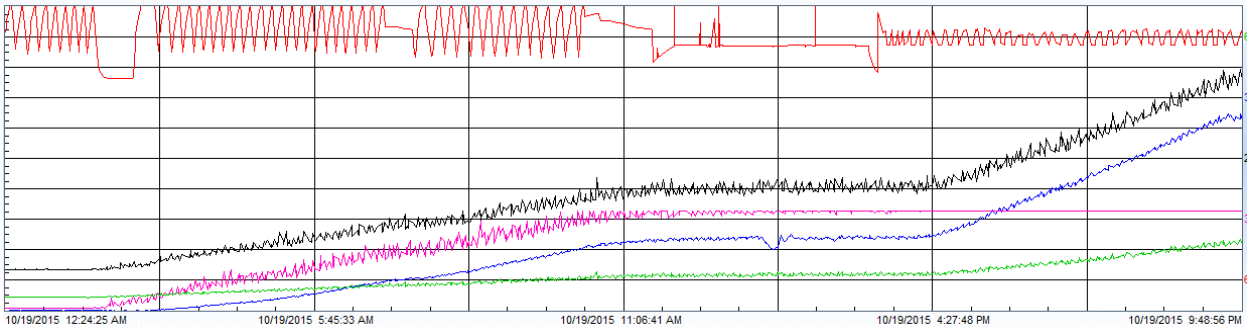


Figure 5.4-23 – Initial solids addition to gasifier: Red - coarse ash feeder operation indicating cyclic operation through smaller conveying line initially and larger conveying line later. Blue - lower standpipe DP. Pink - UMZ DP. Green - riser crossover DP. Black - riser DP.

Overall solids addition to the gasifier was smooth and successful. The coarse ash feeder system was fully commissioned with both 3-in. and 6-in. conveying lines, and the system demonstrated good control. The solids level increases in the gasifier as measured by a number of differential measurements were consistent with the amount of solids fed from the feeder and changes in solids level in the coarse ash silo.

- CCAD system operation

With sufficient solids inventory in the gasifier, the CCAD system was operated by withdrawing solids from the gasifier, discharging the solids to the coarse ash silo, then adding the solids back to the gasifier to maintain the desired solids level in the standpipe (figure 5.4-24).

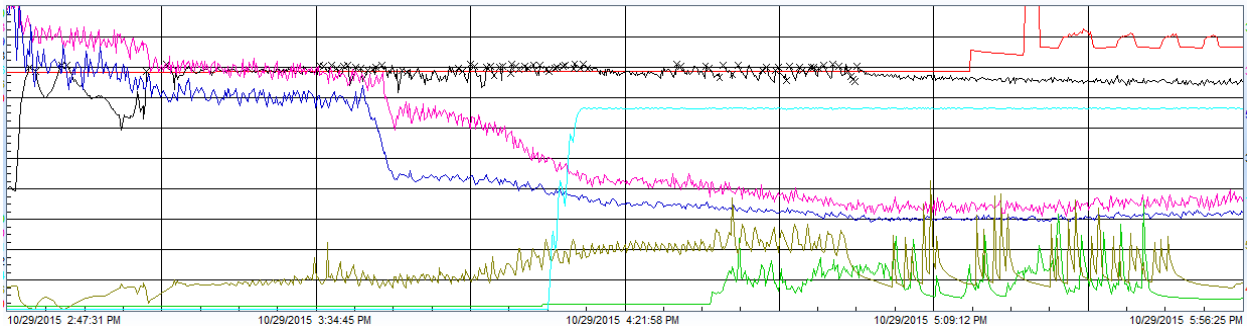


Figure 5.4-24 – Initial CCAD operation by withdrawing solids from the gasifier, discharging solids to coarse ash silo, and feeding solids back to the gasifier: Red - coarse ash feeder operation indicating cyclic operation. Pink - standpipe solids level. Blue - riser DP. Black - CCAD primary cooler DP. Dark green - CCAD unit inlet pressure. Green - CCAD discharge line pressure. Cyan - upper CCAD secondary cooler solids level

Initially during testing, the CCAD system J-pipe and primary cooler fluidization flows were tested to move the solids from the gasifier standpipe without adding any makeup solids back to the gasifier. The initial sharp increase of primary cooler bed differential pressure (black) in figure 5.4-24 line indicates accumulation of solids in the primary cooler. When the primary cooler is filled with solids as indicated by a stable bed differential pressure, further decrease in gasifier level resulted in moving the solids through the primary cooler into the CCAD's secondary cooler. The solids overflow from the primary cooler into the secondary cooler (figure 5.4-24). Solids withdrawal from the gasifier was tested by controlling the vent gas pressure from the CCAD secondary cooler (faster withdrawal) and by varying the J-pipe

fluidization gas flow (slower withdrawal). As solids started to overflow into the secondary cooler, the pressure indication (dark green line) at the bottom of the secondary cooler started to trend up. The upper section of the secondary cooler started indicating solids level (cyan) as the secondary cooler was filled with solids.

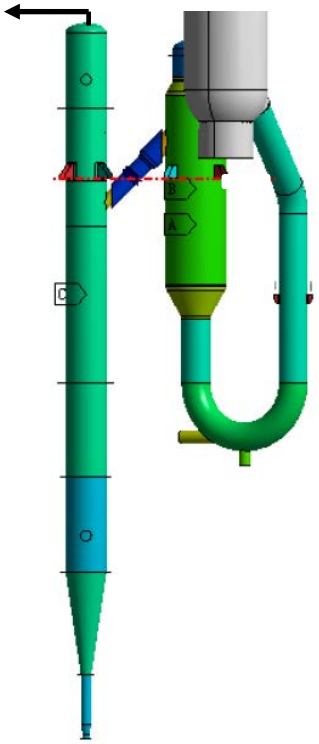


Figure 5.4-25 – CCAD cooler system

After the CCAD secondary cooler was filled with solids, the CCAD depressurization system, comprising four PLDs in series, was started by inducing the flow of solids through the PLDs and the discharge line. The discharge line pressure (green) is an indication of solids flow and flowrate. The trend shows the solids are continuously being conveyed from the secondary cooler to the coarse ash silo. In the later part of the test, the external closed solids circulation loop was in operation with solids being added from the coarse ash feeder (red), solids being discharged from the gasifier through the CCAD primary cooler to the secondary cooler and being conveyed out with the aid of the CCAD depressurization system to the coarse ash silo (figure 5.4-24). During this continuous operation of the external circulation loop, the standpipe level was maintained nearly constant, as indicated by the pink line in the trend. After the solids withdrawal from the gasifier was discontinued as indicated by the pressure measurement (dark green) at the bottom of the secondary cooler, the level in the gasifier standpipe (pink) started to trend up.

- Initial gasifier solids circulation

Figure 5.4-26 shows initial solids circulation in the gasifier with a superficial riser gas velocity around 20 ft/s. The LMZ, J-leg and seal leg differential pressures were stable. During this period, the standpipe level (pink line) decreased in steps as solids were withdrawn from the gasifier through the CCAD system as part of CCAD commissioning tests. Later, the standpipe solids level was increased by recycling the solids back to the gasifier from the coarse ash silo.

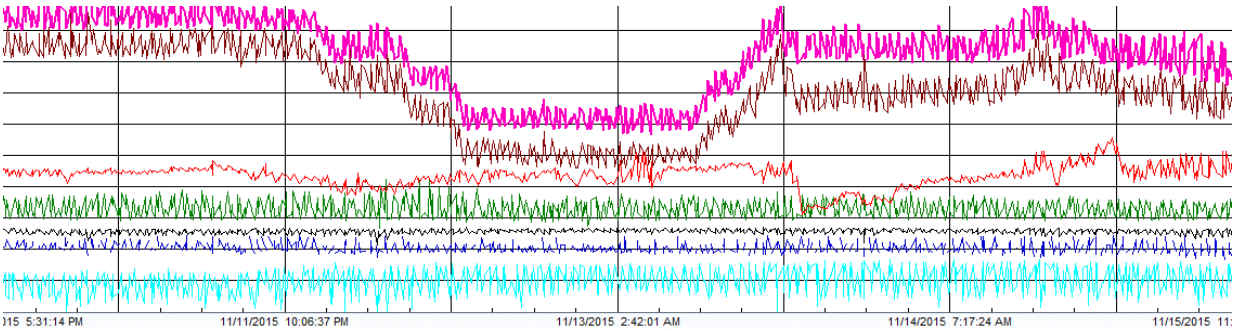


Figure 5.4-26 – Initial gasifier solids circulation: Pink - standpipe solids level. Brown - riser DP. Red - riser gas velocity. Green - LMZ DP. Black - seal-leg riser DP. Blue - seal-leg downcomer DP. Cyan - J-leg DP.

The riser DP (brown) follows the standpipe solids level closely, indicating the circulation rate can easily be changed by changing the standpipe solids level. During normal operation, the solids circulation rate primarily determines the temperature drop across the riser for a given coal feed rate due to endothermic gasification reactions in the riser. It is desirable to minimize the riser temperature drop and maintain an overall average riser temperature that is sufficiently high to ensure high carbon conversions without generating any tar. The standpipe solids level can easily be increased by accumulating the coal ash or by adding make-up solids from the coarse ash feed system. The standpipe level can easily be decreased by withdrawing the solids through the CCAD system. This demonstrates the TRIG™ solids circulation features.

5.4.4.3 *Cold Solids Circulation Tests and Observations*

After filling the gasifier to desired initial inventory for the first time with sand (100 to 120 tons), the CCAD system was operationally commissioned by moving the solids through the primary and secondary coolers and through the depressurization system to discharge the solids to the coarse ash silo. Both the CCAD system and the coarse ash feed system to feed the solids back to the gasifier performed well. With these commissioning efforts and with preliminary solids circulation in the gasifier successfully completed, the focus shifted to parametric tests to determine the effect of various controllers and gas distribution in the mixing zone on solids circulation, solids density and inventory in the mixing zone, and operational stability. The major tests and observations are described in this section. Tests included changes to:

- Standpipe aeration.
- Process air distribution.
- Riser velocity.
- J-leg aeration.
- Seal leg aeration.

1) <u>Standpipe aeration tests</u>

The gasifier standpipe has four flow controllers that distribute aeration gas flow at different elevations (figure 5.4-4). Each flow controller in turn distributes aeration gas to nozzles located around the standpipe at different elevations. The flow controller FV14049 distributes aeration gas to the lower portion of the standpipe below the J-leg. The other controllers FV14048, FV14047, and FV14046 are located at progressively higher elevations above the J-leg. Different controllers are used since the resistance to gas flow varies at different elevations of the standpipe.

With stable solids circulation in the gasifier at 40 psig gasifier exit pressure, riser velocity at about 20 ft/s range, and riser density around 10 lb/cft, the standpipe aeration flows varied over a wide range around the normal operating flow rates:

FV14046 normal flow rate 5,900 cft/hr, test range 1,475 cft/hr to 8,850 cft/hr

FV14047 normal flow rate 6,200 cft/hr, test range 1,550 cft/hr to 9,300 cft/hr

FV14048 normal flow rate 9,700 cft/hr, test range 2,425 cft/hr, to 14,550 cft/hr

FV14049 normal flow rate 6,300 cft/hr, test range 1,575 cft/hr, to 9,450 cft/hr

Variation of gasifier standpipe fluidization gas flow of 25% to 150% around normal flow rate had little effect on solids circulation, even with step changes in the gas flow rate (figure 5.4-27). In addition to initially changing the gas flow through one controller at a time, the gas flow through multiple controllers was varied simultaneously. Through all the tests, the standpipe aeration gas flow had little effect on gasifier solids circulation. Standpipe aeration is critically important when starting from cold idle condition with the packed column of solids in the standpipe. But after sufficient circulation is achieved and maintained, standpipe aeration has relatively little effect because a sufficient amount of gas is entrained with downflowing column of solids in the standpipe, which maintains the solids in fluidized conditions.

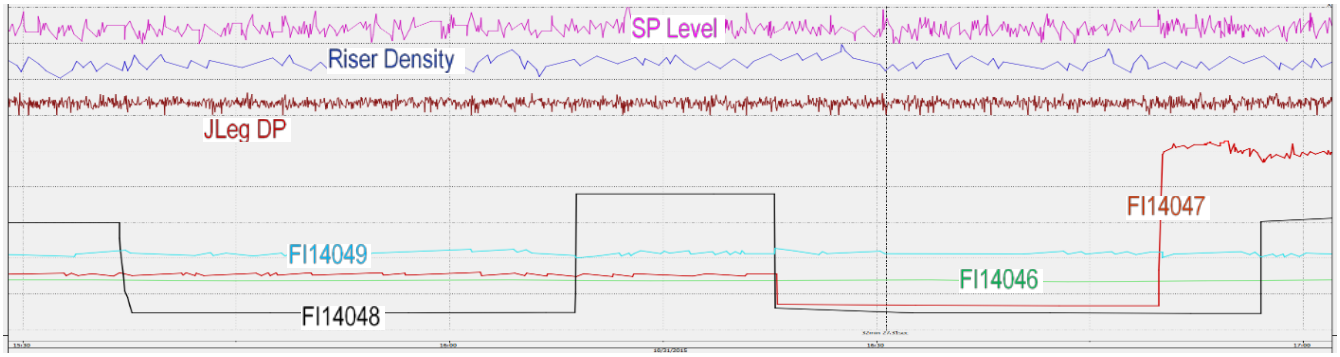


Figure 5.4-27 – Effect of standpipe aeration gas flowrate changes

2) Process air distribution tests

Sufficient gas flow to the mixing zone maintains the solids circulation rate by carrying the solids in the mixing zone (pushed through the J-leg by the column of fluidized solids in the standpipe) and depositing them back in the standpipe. The gas flow rate, superficial gas velocity, and gas density determine the solids carrying capacity of the gas flowing upward through the mixing zone and riser. Most of the gas flow enters the mixing zone through three primary controllers (figure 5.4-4): FV14019 feeds the MZ01 jetting nozzle located at the bottom of the LMZ, FV14017 feeds a ring header that in turn feeds six nozzles just above the J-leg, and FV14021 feeds another ring header that in turn feeds six more nozzles located above the FV14017 nozzle feeds. Process air flows through these nozzles all the time except during a trip situation, when a minimum amount of nitrogen flows through these nozzles. In addition to major process air flow through these three controllers, a minor amount of flow enters through other controllers in the LMZ (figure 5.4-4). The minor flows were maintained constant during the process air distribution tests. For test purposes, the purge flows through the two SUBs were varied.

During the air distribution test, the gasifier exit pressure was maintained at 40 psig, riser velocity in the 19- to 20-ft/s range, and riser density at about 10 lb/cft. Decreases in LMZ flow through controller FV14019 in steps from 160 kpph to zero, will increase the LMZ differential pressure due to lower gas velocities (figure 5.4-28). More solids were shifted from standpipe to LMZ, and with the lower standpipe level, the solids circulation rate declined. During this time the total flow through the riser was around 400 kpph, with 300 kpph flow through the two controllers in UMZ and 100 kpph flow through the two SUBs. The flow through FV14019 was increased in steps to 180 kpph in the later part of the test. With increasing velocity in LMZ, the solids density in LMZ decreased and the shift in solids inventory resulted in an

increase in standpipe level and increased solids circulation. With relatively high process air flow through LMZ, changes in UMZ flows through FV14017 and FV14021 had little effect on overall operation.

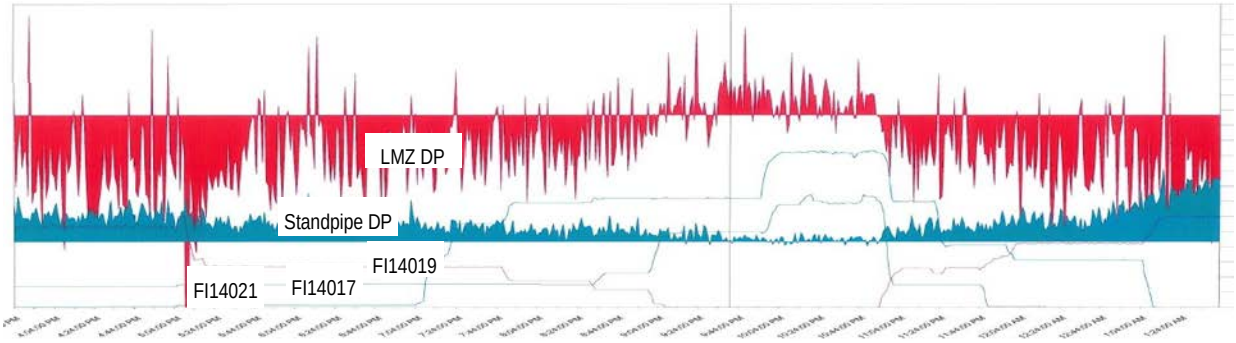


Figure 5.4-28 – Effect of air distribution in the gasifier mixing zone

Figure 5.4-29 shows another trend with changes in air distribution and SUBs purge flows at a later time during extended operation. During this time, the total nitrogen flow to LMZ through a number of small nozzles varied from 2,800 to 5,000 pph. The gasifier pressure was 160 psig with a riser temperature of 1,700 °F, riser velocity of 18 ft/s, and riser density of around 20 lb/cft. For most of the trend, there was no flow through the MZ01 nozzle (red) in the LMZ. The total purge flow through SUBs was minimum at around 7,000 pph except for a short time when the flow was increased to 50,000 pph. The minimum burner purge flow and nitrogen flows through small nozzles provided a superficial gas velocity of about 1.1 ft/s in LMZ. The trend in figure 5.4-29 shows there was no noticeable effect on overall solids circulation rates (constant riser DP and density at nearly constant standpipe level and riser velocity) in the gasifier loop in spite of no MZ01 flow through LMZ. The trend shows that, if necessary, high solids circulation rates can be maintained with minimum superficial gas velocity in LMZ and shifting all the process air flow to UMZ.

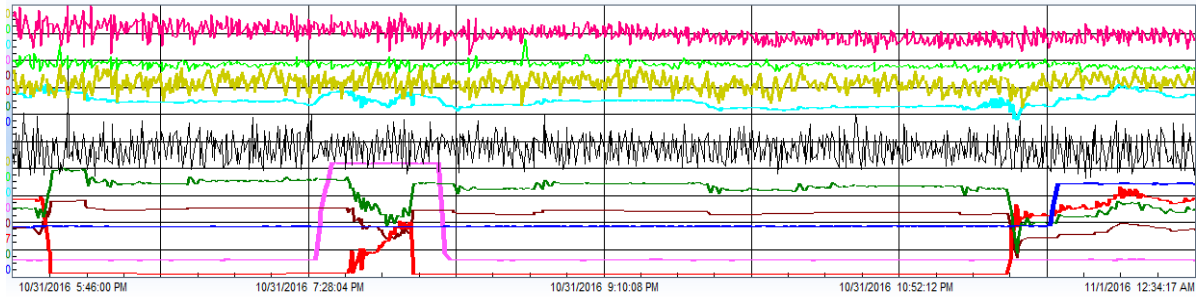


Figure 5.4-29 – Effect of air distribution in the gasifier mixing zone: Magenta - standpipe level. Green - riser DP. Olive green - riser density. Cyan - riser velocity. Black - LMZ DP. Dark green - flow to MZ4 nozzles through FV14017. Brown - flow to MZ5 nozzles through FV14021. Red - flow to MZ01 nozzle through FV14019. Pink - total flow rate through the two SUBs combined. Blue - total nitrogen flow to LMZ.

3) Riser velocity tests

The transport gasifier at Kemper is designed to operate with a superficial gas riser velocity in the range of 18 to 20 ft/s during normal operation. With the size and morphology of circulating solid particles in the gasifier, when riser velocity is below a minimum of about 8 ft/s choking velocity, the solids circulation essentially ceases. During startup with burner firing and later initial transition to coal feed, minimum riser velocity becomes critical due to constraints on percent oxygen in flue gas exiting the gasifier and on nitrogen supply. To determine the practical minimum riser velocity necessary to maintain a slow solids circulation that is operationally acceptable in commercial operations, riser velocity was varied by varying the total gas flow rate at 40 psig gasifier exit pressure. The gasifier can be operated at higher riser velocities than design, but at the risk of refractory erosion with prolonged operation, especially at the inlet of standpipe cyclone.

The riser velocity was decreased from 20 ft/s to 9.7 ft/s by gradually decreasing flows to both MZ01 and MZ04 nozzles while maintaining the standpipe level (figure 5.4-30). The lower gas flow rates reduce the solids carrying capacity of the gas. The lower gas flow rates through the mixing zone increase the solids density in the mixing zone at the J-leg and increase the resistance for solids flow from J-leg into the mixing zone. Both these factors tend to reduce the solids circulation rate. The riser density and riser differential pressure decreased with gradual lowering of solids circulation rates. At 9.7 ft/s, the circulation rate declined to minimum, which for operational purposes is used as the lower riser velocity limit to maintain a minimum solids circulation rate.

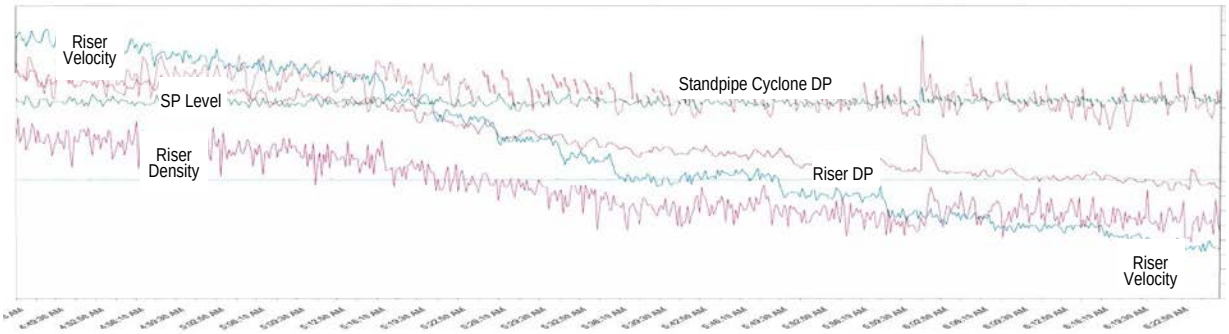


Figure 5.4-30 – Effect of riser velocity on solids circulation in the gasifier loop

4) J-Leg aeration tests

Maintaining the solids stream flowing through the gasifier J-leg in fluidized condition is critically important to maintain the solids circulation in the gasifier loop. The J-leg is equipped with 5 flow controllers that feed 32 nozzles (figure 5.4-4). While maintaining the standpipe solids level and riser velocity at a gasifier exit pressure of 40 psig, the J-leg flow controllers were gradually varied as follows (figure 5.4-31):

FV14036 normal flow rate 9,000 cft/hr, test range 2,500 cft/hr to 15,000 cft/hr

FV14037 normal flow rate 7,200 cft/hr, test range 2,000 cft/hr to 12,000 cft/hr

FV14038 normal flow rate 1,600 cft/hr, test range 500 cft/hr to 2,700 cft/hr

FV14039 normal flow rate 8,100 cft/hr, test range 2,250 cft/hr to 13,500 cft/hr

FV14040 normal flow rate 10,800 cft/hr, test range 2,600 cft/hr to 18,000 cft/hr

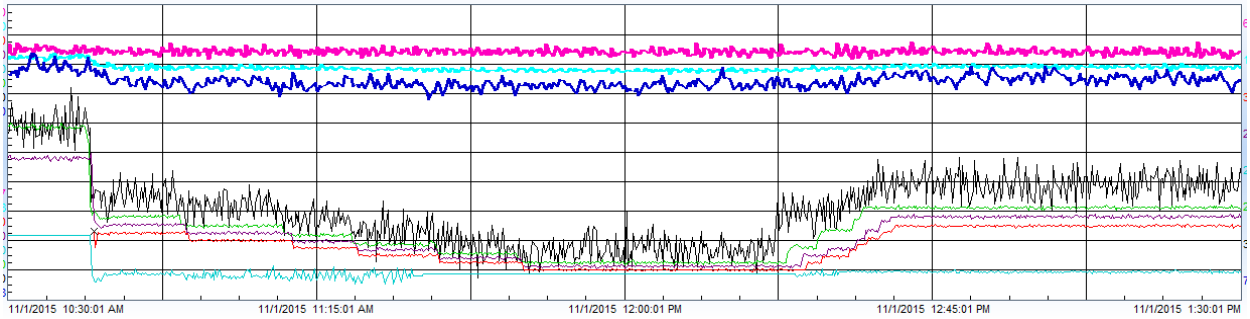


Figure 5.4-31 – Effect of aeration gas distribution in the gasifier J-leg: Magenta - standpipe level. Cyan - riser velocity. Blue - riser density. Other colors - flow through various flow controllers in the J-leg.

In the test range of J-leg aeration flow varying from 25% to 160% of normal flow, and even with such variations occurring simultaneously, there was little change in riser density and no obvious effect on solids circulation rate in the gasifier loop. The J-leg aerations are critical when starting from idle conditions with a packed bed of solids, as well as at low solids circulation rates when the solids stream in the J-leg tends to deaerate.

5) Seal leg aeration tests

The seal leg operation is maintained by four flow controllers in the downcomer and one controller each in the H-leg, seal leg riser, and slant leg through which the solids flow into the standpipe (figure 5.4-4). During the seal leg aeration flow variation tests, the gasifier exit pressure was maintained at 40 psig, riser velocity at around 19 ft/s and a constant solids level in the standpipe. The seal leg aeration flows were varied by sending varying flow through one controller at a time while maintaining flow through other controllers at their normal values (figure 5.4-32). The normal flow rate and test range for flow controllers in the seal leg downcomer upper section (FV14058, FV14059), middle section (FV14060), and lower section (FV14061) are as follows:

FV14061 normal flow rate 2,000 cft/hr, test range 500 to 2,000 cft/hr

FV14060 normal flow rate 2,500 cft/hr, test range 500 to 2,500 cft/hr

FV14059 normal flow rate 2,700 cft/hr, test range 500 to 2,700 cft/hr

FV14058 normal flow rate 2,500 cft/hr, test range 500 to 2,500 cft/hr

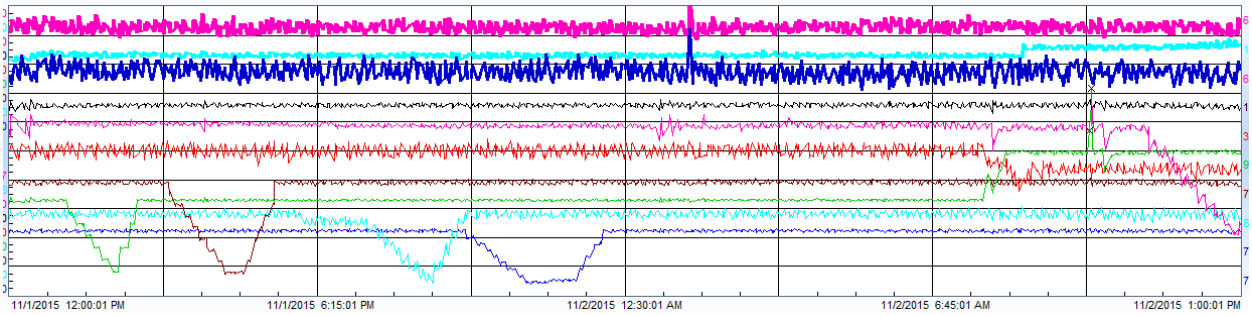


Figure 5.4-32 – Effect of aeration gas flow variation in gasifier seal leg: Magenta - standpipe level. Cyan - riser velocity. Blue - riser density. Black - FV14063 slant leg flow. Pink - FV14064 seal-leg riser flow. Red - FV14062 seal-leg H-leg flow. Brown - FV14060 middle downcomer flow. Green - FV14061 lower downcomer flow. Light cyan - FV14059 upper downcomer flow. and Light blue - FV14058 upper downcomer flow

Overall, the effect of lower aeration flow rate to seal leg downcomer, especially with flow controllers in the lower portion of the downcomer, was a decrease in downcomer differential pressure, indicating the solids in the downcomer are less fluidized. The decrease in flows in the range tested did not affect the solids circulation in the gasifier loop. The H-leg and seal leg riser flows were varied as follows:

FV14062 normal flow rate 12,000 cft/hr, test range 9,000 to 12,000 cft/hr

FV14064 normal flow rate 4,600 cft/hr, test range 1,750 to 4,600 cft/hr

The decrease in aeration to H-leg and seal leg riser resulted in an increase in seal leg downcomer differential pressure, indicating the aeration in downcomer is more effective in fluidizing the solids in the downcomer. The variation in these flows in the range tested did not affect solids circulation rate in the gasifier loop. The flow to slant leg through FV14063 was not varied and tested.

5.4.5 Refractory Cure-out

After completing the cold sand circulation tests on gasifier A, the system was prepared to cure the refractory in the gasifier. The gasifier is 185 ft tall and consists of refractory lined straight pipe sections interconnected at the top by refractory-lined crossovers and seal leg, and at the bottom by refractory-lined J-leg. A refractory-lined pillow top bend at the riser exit eliminates erosion at the bend to the riser crossover. The entire gasifier refractory design has two layers. The inner layer, which is in contact with the circulating solids and syngas in the gasifier, is erosion resistant. The outer layer, between the erosion resistant refractory and the gasifier shell, insulates and protects the metal shell

from overheating. Thermal expansion is accommodated without any expansion joints found to be problematic in high temperature, refractory lined systems.

The factory-installed refractory had significant spalling during the initial refractory dry-out. Refractory in several components of the gasifier was completely removed and reinstalled at the vendor shop, overcoming the severe shortcomings of the first installation. In some components, the refractory was completely removed and reinstalled twice but even then remained suspect. The construction schedule did not permit complete resolution before shipping. All gasifier components, including components with suspect refractory, were installed in the structure with the understanding that any refractory issues that developed would be addressed during commissioning and initial operation. A more detailed discussion on refractory related issues, field resolution and other planned changes is discussed in section 6.3.

5.4.5.1 *Refractory Cure-out Schedule*

The following refractory cure-out schedule was implemented to cure the gasifier A refractory, including the refractory in the burner legs that connect the burners to the gasifier LMZ:

1) Initiate minimum firing with SUBs pilot. Hold minimum pilot for one hour at 200 °F at the burner outlet.
2) Ramp SUBs at a maximum of 150 °F per hour at the burner outlet.
3) Using the temperature measurements in UMZ as a control point, heat the gasifier at 75 °F per hour until 1,000 °F.
4) Hold the gasifier at 1,000 °F for 6 hr. This may require reducing the firing on the SUB.
5) After the hold period, continue heating the gasifier at 50 °F per hour to 1,800 °F.
6) Using the gasifier outlet as the control point, hold the gasifier temperature at 1,800 ºF for 23 hr.
7) Using the gasifier outlet as the primary control point and the UMZ as a secondary control point, cool the gasifier at a maximum of 150 °F per hour to 400 °F.
8) After the gasifier outlet temperature is below 400 °F, cooling gas may be used to cool the gasifier to ambient.

Both the burner and gasifier refractories were air and nitrogen cured for around 24 hr by letting nitrogen, followed by air, to flow through the gasifier without any solids in the gasifier. After this step, solids were added to the gasifier and, with solids circulation, the refractory was cured with burner firing initially and later supplemented by direct diesel injection (DDI).

The following sections describe gasifier conditions, burner firing operation, and DDI operation during refractory cure, and address the challenges encountered, especially with respect to gasifier refractory.

5.4.5.2 *Train A Gasifier Refractory Cure-out*

With sand as bed material in gasifier A, refractory curing was started on Nov. 10, 2015. The plans were to cure not only the gasifier refractory but also the refractory-lined pipe at the gasifier exit and the refractory in the syngas cooler. By circulating the bed material in the gasifier, nearly uniform temperature could be maintained throughout the gasifier solids circulating loop and the entire gasifier refractory could be cured as scheduled.

The refractory in all the components of the gasifier, including the syngas cooler, had been cured at the shop to respective operating temperatures. Because nearly 2 yr had elapsed after the first cure, it was prudent to cure all the refractory pieces one more time before commencing lignite feed operations. In normal operations, the gasifier is heated with SUBs and direct diesel injection (DDI) system to near operating temperature before lignite is introduced into the gasifier. The only difference between the refractory curing process and the initial gasifier heat-up is the extended hold points during the ramp-up. The curing schedule is nearly twice as long as the normal gasifier heat-up.

Another reason to perform refractory curing at the site is related to gasifier refractory joints. The gasifier was delivered to the site as 14 components that were installed with temporary support as the structure around the gasifier was

erected. The component pieces were welded together in the field and, with the form in place, refractory was poured above and below the weld. The field refractory was locally cured to 1,000 °F and further curing to operating temperature was needed.

Refractory in some of the gasifier component pieces was defective when tested at the shop after the cure-out. These defective refractories were replaced, but some still marginally passed the testing. Since the gasifier structure could be built only with gasifier components installed in their positions, in the interest of maintaining the construction schedule the components with marginally acceptable refractory pieces were shipped to the site and installed in the structure with the understanding that refractory repairs would be performed at the site as needed. Refractory curing of the gasifier at the site would avoid exacerbating the refractory condition in these components and would be an opportunity to commission the two SUBs integrated with the gasifier and the DDI system.

The refractory curing operation started on Nov. 10, 2015 was terminated on Nov. 14, 2015 due to hotspots observed below the UMZ/riser weld joint. During this time period, both the SUBs were commissioned. The burners generated sufficient heat in the form of hot flue gases, and the heat energy was immediately absorbed by the circulating solids in the gasifier loop upon contact. Figure 5.4-33 shows trends of exit flue gas temperatures for both burners and of the gasifier mixing zone temperature where the circulating solids come in contact with the hot flue gases exiting the burners. The trend also shows the flue gas temperature exiting the standpipe cyclone (gasifier exit). Both the mixing zone and gasifier exit temperatures are nearly the same, which indicates the excellent solids circulation rates achievable in the transport reactor. Following the curing temperature schedule, the gasifier temperature reached about 670 °F before the burners were shut down due to observed hot spots.

Figure 5.4-33 – Startup burners' exit flue gas temperatures, and gasifier mixing zone and exit temperatures, during the first refractory cure of refractory components in Train A

During both cold solids circulation in gasifier A and first refractory curing, there was an observation of unexpected vibration of the gasifier, especially the mixing zone portion. The gasifier is supported near the midpoint in height, and both the lower and upper portions are free to expand. Because the lower portion of the gasifier was free-hanging, the amplitude of the vibration was largest at the lowest elevation. Similar vibrations have been observed with fluidized beds at other facilities. The NCCC at PSDF did observe vibration with a Sulfator, which is a large atmospheric fluidized bed combustor. The gasifier at PSDF did not experience any vibration; it has a three-point restraining system in the lower section for earthquake protection. Following the shutdown to address observed hot spots, the gasifier vibration issues were effectively dealt with using a robust restraining system described in section 6.2.

Following the shutdown, the solids in the gasifier were drained and the refractory around the hot spot location was inspected. The inspection at this location and at other lower sections of the gasifier confirmed refractory issues. See section 6.3 for a detailed description. Much of the refraction in the lower section of the gasifier was replaced and refractory cure-out operations on gasifier A resumed on Aug. 31, 2016. This time, the refractory cure-out was successfully completed in around a week.

After loading the initial bed material sand into the gasifier, solids circulation and the burners were started. Figure 5.4-34 shows a time trend of operation for one of the two burners. To a large extent, the operational characteristics of both burners were similar. The burner was initially fired with natural gas. The natural gas flow rate was ramped up and the

burner exit temperature was maintained at steady condition for heat to soak into the gasifier refractory. After the burner chamber temperature was sufficiently high, diesel was introduced into the burner to further heat up the gasifier. There was a persistent problem with burner operation related to burner trips due to loss of flame detection. This was a result of the scanner glass being covering with soot carbon, and because the physical location of the scanner meant it sometimes lost flame detection due to flicker.

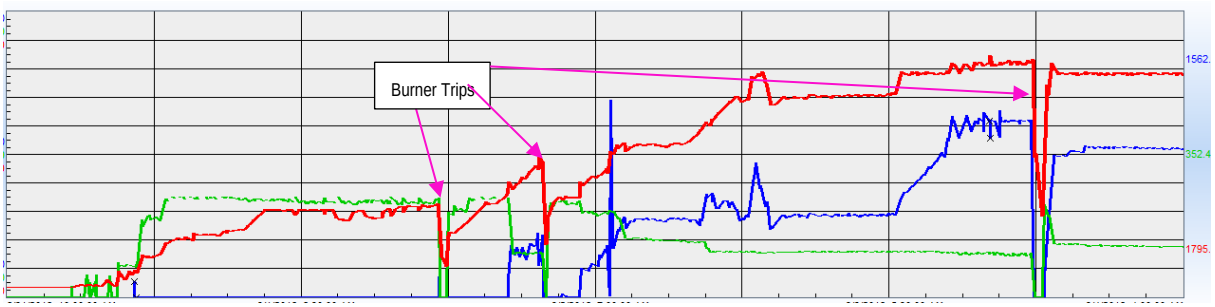


Figure 5.4-34 – The startup burner operational characteristics during gasifier A refractory cure. Green - natural gas flow rate. Blue - diesel flow rate. Red - burner exit flue gas temperature.

When the gasifier temperature reached about 1,200 °F, the DDI system was placed in service to continue heat-up of the gasifier to about 1,700 °F. This is the first time a direct diesel injection system was being used in a circulating fluidized bed for initial heat-up purposes. The DDI system at Kemper consists of three injection nozzles through which diesel is atomized with steam for injection. The circulating solids are at about 1,200 °F, well above the auto-ignition temperature of diesel, so the injected diesel is oxidized in the riser and the exothermic heat released is absorbed by the circulating solids. Figure 5.4-35 shows a trend of gasifier heat-up with both burners and DDI system. The DDI system was started at about 103 hours after initial firing of SUBs. With the ramp in DDI system diesel flow, the target gasifier exit temperature of 1,700 °F was achieved and the refractory cure-out was successfully completed. Plans were to transition to coal feed after completing cure-out, but issues with the tempered water system prevented operation of lignite dryer system. The gasifier was put on hold and the gasifier temperature was maintained at about 1,600 °F during event C in figure 5.4-35. During event D, the two SUBs were turned off and the diesel flow through the DDI system was increased by a corresponding amount to maintain the gasifier at about 1,650 °F.

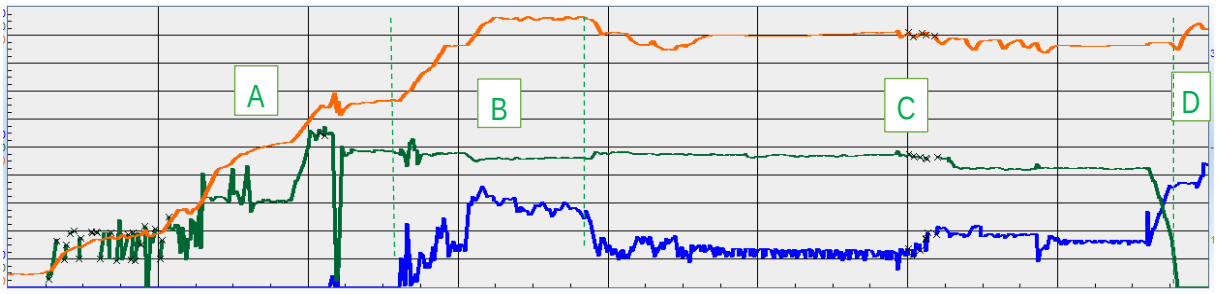


Figure 5.4-35 – Gasifier A heat-up and refractory cure with both startup burners and the DDI system. Green - total fuel flow rate to burners (diesel equivalent). Blue - DDI diesel flow rate. Red - gasifier exit flue gas temperature. Event A: gasifier heat-up with the two startup burners. Event B: gasifier heat-up with both burners and the DDI system. Event C: refractory curing complete, hold-up for start of coal feed. Event D: continuation of hold-up with DDI system.

Figure 5.4-36 shows trends of all temperature measurements around the gasifier loop. There are 18 temperature measurements. These measurements include the LMZ temperatures where the exiting hot burner flue gas comes in contact with the circulating solids, temperatures below and above the DDI injection nozzles, the top of the riser, the seal leg, the standpipe, and the gasifier J-leg. The temperature difference between various measurements was less than 20 °F. Similar low temperature difference between measurements around the gasifier loop was observed with

just the DDI system in operation (event D in figure 5.4-36). This reflects the strength of the high solids circulation rates Kemper achieved over 40 million pph solids circulation rates, more than two times higher than the previously recorded circulation rates in an FCC unit. These rates validated the concepts and models used for transport reactor scale-up. The transport reactor scale-up was successful with a remarkable ease of operation for a large reactor unit. The first-of-a-kind DDI system performed well beyond expectations.

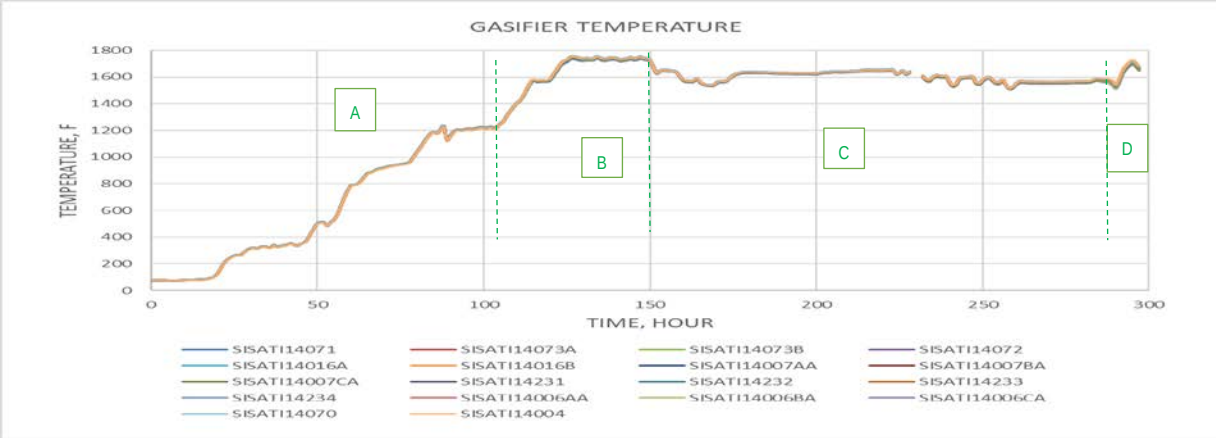


Figure 5.4-36 – Temperatures around the gasifier loop during refractory cure operations with both the SUBs and the DDI system in operation. Events A – D are as described in figure 5.4-35.

Figure 5.4-37 shows skin temperatures around the gasifier loop along with the gasifier exit temperature. The transport gasifier vessel shell (skin) temperature measurements are an indirect measure of refractory integrity. If hard-face refractory is thinned out or displaced, the loss will immediately cause a rise in skin temperature. The skin temperatures are measured with a system of long continuous fiber-optic cables wrapped around various sections of the gasifier. This system was a continuous, convenient, and economic means to monitor skin temperatures and provide necessary alarms. Additional details are provided in the final Kemper report.

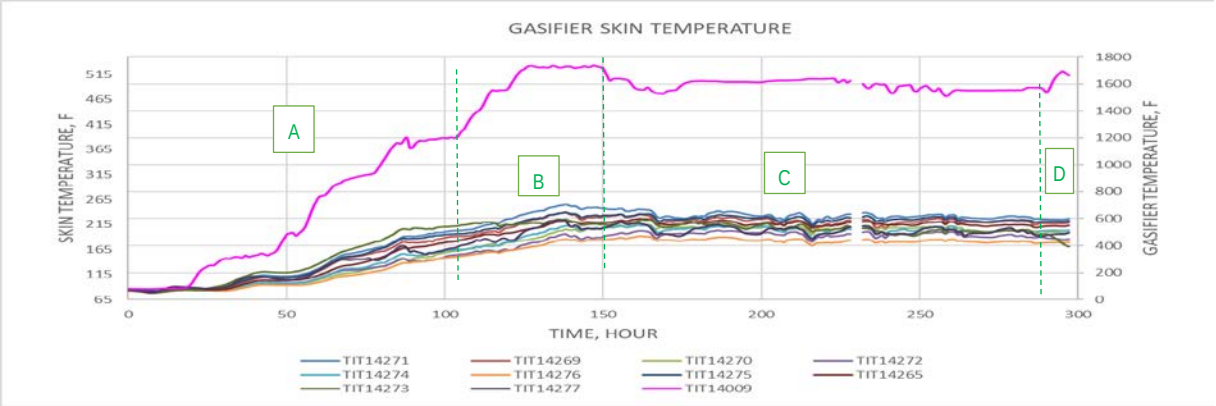


Figure 5.4-37 – Skin temperatures around the gasifier loop during refractory cure operations with both the SUBs and the DDI system in operation. Pink line is the gasifier outlet temperature. Events A – D are as described in figure 5.4-35.

Skin temperatures continued to rise during initial burner firing and ramp-up, and later with start and ramp-up of diesel injection into circulating solids (figure 5.4-37). The skin temperatures stabilized with steady gasifier operating temperature, with stable burner firing rate and diesel injection. During diesel injection with the DDI system (events C and D in figure 5.4-37), the skin temperatures ranged from about 175 °F in seal leg to 235 °F in the riser above the DDI injection nozzles. Although the gasifier temperatures are nearly uniform throughout the solids circulation loop, the range in skin temperatures are a reflection of varying refractory and shell thicknesses around the gasifier loop.

Both the gasifier burners and the DDI system operated per design to heat up the gasifier to operating temperatures. The logic design and system control were adequate and all the heat-up ramps and holds functioned well. The gasifier refractory and downstream refractory components were cured without any incidents or hot spots.

There were two operational issues encountered during heat-up. The first was SUB flame scanning system reliability, which was due to the scanner's location and its sensitivity. Sometimes the glass in the scanning port became coated with soot, with a subsequent loss in measurement. The flame intensity measurement caused several burner trips that were meant to occur on loss of flame. Almost all these trips were spurious, where the flame was stable but flickering. The trips occurred more often at low firing rates with natural gas. With diesel firing in the burner and higher heating loads, the burner was stable.

The other operational issue was an unreliable DDI insert mechanism. The diesel gun and the atomizing steam are inserted during DDI system operation and withdrawn and isolated during coal feed operation. The sealing mechanism was less than desirable, but after the gun was inserted in place, the DDI system worked well.

One of the unexpected results of several burner trips at low firing rates was the ease with which the gasifier solids circulation could be restored. When the burner trips, the solids held up in the riser and UMZ slump immediately to LMZ. With loss in solids circulation, the solids density in the lower sections of the gasifier (LMZ, J-leg and lower standpipe) increases. The solids slump and increase in density has the potential to plug the aeration nozzles and major process air nozzles. The centrally located jetting nozzle in the LMZ is a major process air nozzle and is designed to handle sudden solids slump with minimum solids penetration into the inlet U-portion of the refractory lined nozzle. The experience with the trips showed the jetting nozzle performed as expected based on the experience at the PSDF. The trips did not lead to any plugged nozzles, and the aeration gas flow and air flow were restored on restart. The solids circulation can be fully restored in less than 10 min.

5.4.5.3 *Train B Refractory Cure-out*

While the refractory in lower portions of gasifier A was being replaced, commissioning activities focused on Train B. The gasifier B refractory was inspected once again in light of gasifier A refractory issues, and patches were applied to few small sections. Each gas nozzle (for aeration gas, process air) and impulse line nozzle in the gasifier has an insert to protect the gasifier refractory and to achieve desired nozzle tip velocity. The insulating refractory was additionally protected with pipe extensions welded to the inside of the gasifier shell or with an insert sleeve attached to the inlet of the nozzle with three equally spaced tangential plates (figure 5.4-38). The length of these pipe extensions and insert sleeves was sufficient to protect the insulating refractory and terminated at the insulating – hard-face refractory boundary. Refractory inspections of gasifier A revealed that the pipe extensions and sleeves did not fully protect the insulating refractory and, at few locations, as much as 3 in. of insulating refractory was exposed, likely due to a shift in the form during refractory installation. This exposure of insulating refractory, especially in the mixing zone section of the gasifier, creates the potential for process gases to flow through the annulus space between the insert and hard-face refractory and form channels behind the hard-face refractory.

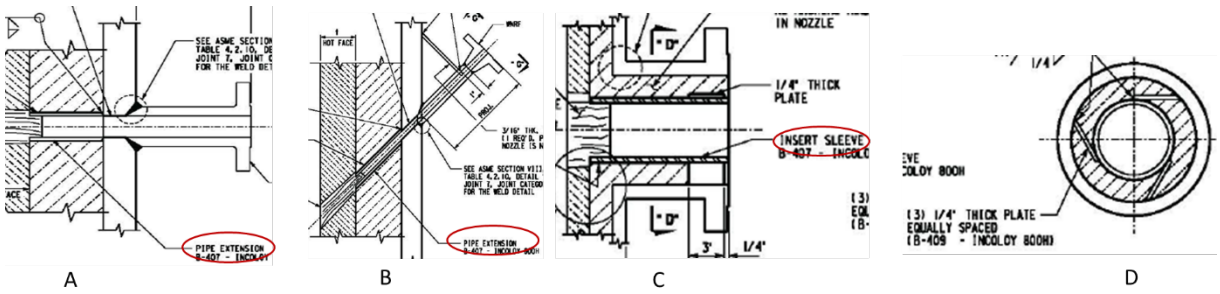


Figure 5.4-38 – Gasifier thermowells (A), impulse and small aeration nozzles (B), and large process air nozzles (C, D) showing the design intent to protect the insulating refractory with pipe extensions or insert sleeves

Before starting gasifier B operations, the pipe extensions, and sleeves (figure 5.4-39), were extended all the way to the inner surface of the gasifier to protect the insulating refractory. The annulus space between the extensions and the hard-face refractory was eliminated by filling in appropriate refractory as necessary. Similar measures were taken with other nozzles in the gasifier to protect the insulating refractory and eliminate any reverse flow of process gases.

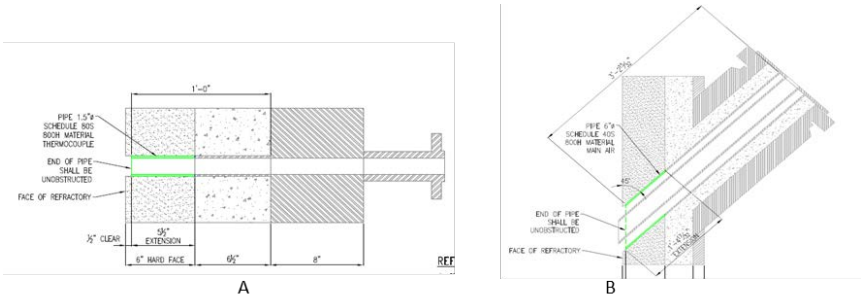


Figure 5.4-39 – Examples of measures taken to protect the gasifier insulating refractory by extending the existing pipe extension and insert sleeves through the hard-face refractory and up to the inner surface of the gasifier

After completing all the nozzle work to protect the insulating refractory and prevent reverse flow and channeling of process gases behind the hard-face refractory, gasifier B and downstream processes were checked for leaks. The initial air and nitrogen refractory cures of SUB chamber, connecting piping, gasifier refractory, and downstream refractory lined pipes and vessels were completed during the leak checks. Startup bed material was added to desired inventory levels and solids circulation on gasifier B was started on Feb. 23, 2016. The two startup burners were lit up on Feb. 26, 2016 with natural gas to start refractory cure. After the burner chambers were sufficiently warmed up, diesel was introduced into the burners through diesel guns. The total diesel equivalent fuel flowrate and gasifier exit temperature are shown in figure 5.4-40. With diesel and natural gas flow through the burners, the gasifier exit temperature was gradually increased from about 400 °F to 1,000 °F.

As with the SUBs on Train A, the SUBs on Train B experienced similar trips due to decrease in scanner intensity, especially at low heating loads. At higher heating loads with both natural gas and diesel firing in the burners, the scanner intensity was stable, and the burners were sufficiently reliable to heat up the gasifier to over 1,000 °F. The DDI system was placed in service with the gasifier temperature at about 1,100 °F and, with increase in diesel injection flow through the DDI system, the two burners' firing rate was reduced. The gasifier refractory cure-out proceeded as scheduled and the target temperature of about 1,750 °F was reached and held for more than 24 hr to complete the refractory cure-out. The DDI system operated well, except for an occasional trip of one of the three injection systems due to low differential pressure between the atomizing steam and diesel. The lower steam pressure was mainly due to constraint at that time with steam header pressure. Both the SUBs and DDI system trip issues were later corrected as operation progressed.

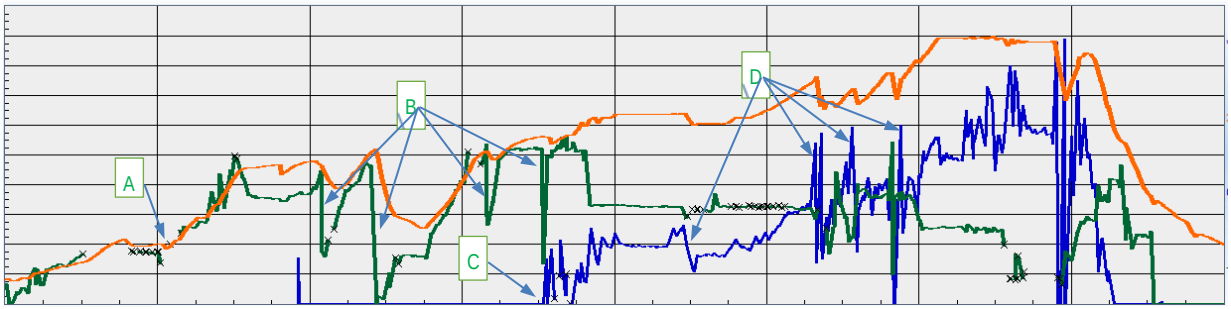


Figure 5.4-40 – Gasifier B heat-up and refractory cure with both the startup burners and the DDI system. Green - total fuel flow rate to burners (diesel equivalent). Blue - DDI diesel flow rate. Red - gasifier exit flue gas temperature. Event A - start of diesel flow to SUBs. Event B - burner trips. Event C - DDI system in operation. Event D - one of the three DDI system trip.

Figure 5.4-41 shows temperatures in different components of the gasifier loop. As with gasifier A, the temperatures around gasifier B were uniform due to high solids circulation rates. The solids circulation in the gasifier loop was easily reestablished after a trip. There were a number of burner and DDI system trips, but none of the gasifier aeration and process air nozzles plugged.

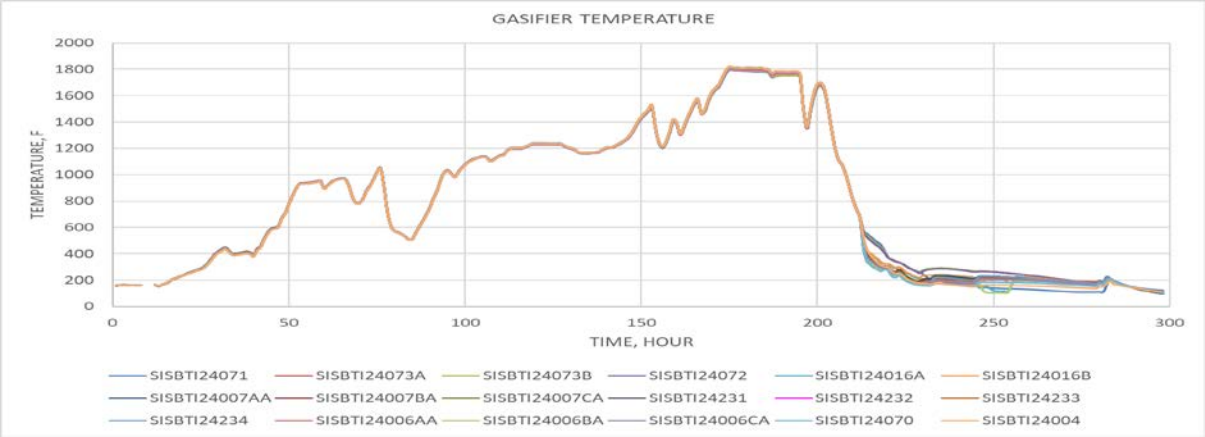


Figure 5.4-41 – Temperatures around the gasifier loop during refractory cure operations with both the SUBs and the DDI system in operation.

Figure 5.4-42 shows skin temperatures around the gasifier B loop. The gasifier shell did not experience any hot spots during the refractory cure. The seal leg had low skin temperature of about 160 °F with the gasifier exit temperature being maintained over 1,700 °F. The riser skin temperatures just above the DDI injection nozzles were the highest measured skin temperatures at about 260 °F. Before the DDI system was placed in service, the burner leg connecting the LMZ had the highest skin temperature with both natural gas and diesel firing in the burner.

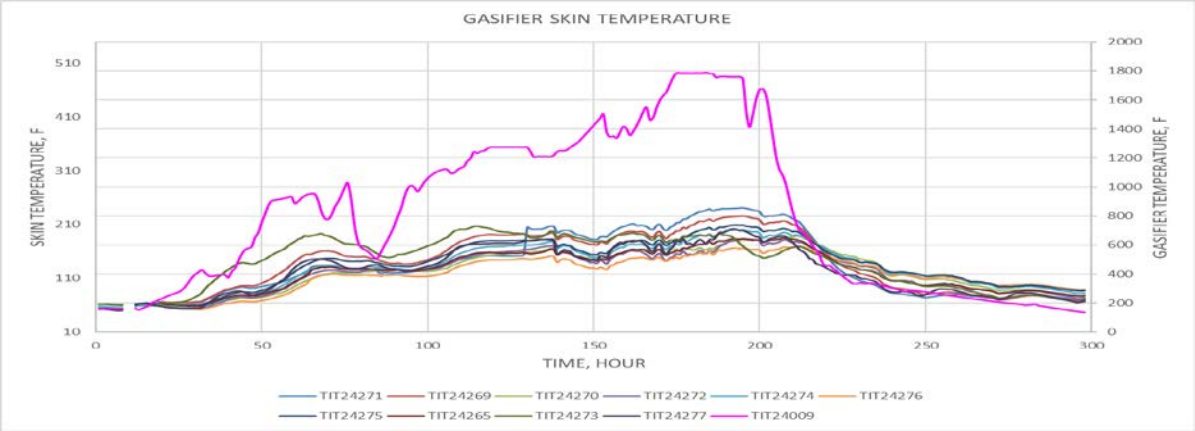


Figure 5.4-42 – Skin temperatures around the gasifier B loop during refractory cure operations with both the SUBs and the DDI system in operation. Pink line is the gasifier outlet temperature.

After completing the gasifier and downstream piping and equipment refractory cure over a 5-day period, the gasifier was shut down on Mar. 4, 2016 for refractory inspection. Most of the bed material was removed through the CCAD system while circulating solids during shut down. The remaining solids in the lower sections of the gasifier were removed through the drain pot feed and by draining to an enclosed location on the floor below the LMZ. The gasifier refractory inspections indicated that the gasifier refractory was in reasonably good shape but required some repairs.

The DDI system provided excellent control over excess oxygen. When the gasifier temperature is over 1,700 °F, the DDI system can easily be operated with less than 0.3% oxygen concentration in the flue gas exiting the gasifier. Later, just before transitioning to coal, the oxygen concentration was further reduced to less than 0.1% in flue gas.

The SUBs and DDI system on Train B worked well per design and expectations. The operators and engineers gained sufficient experience and developed a knowledge base of the operational characteristics of these systems. The experience extended to integrating operation of these systems with gasifier operations, in particular maintaining the solids circulation in the gasifier with flue gas flows from the burner and later with DDI operation.

5.4.6 Final Summary

After completing physical installation of all gasifier components, piping, and instrumentation; performing field walkdowns to check for completeness per design and P&IDs; and completing all instrument and valve functional checks; the following major gasifier related unit commissioning activities were completed:

- Air flow and pressure tests were performed to confirm equipment and process integrity.
- Cold solids circulation tests were performed to confirm operability of the solids circulation loop.
- Tests related to the gasifier startup burners (SUB) and direct diesel injection (DDI) system were performed to confirm operability of the gasifier startup heating systems.
- Additional solids circulation tests were performed while curing the gasifier refractory with the SUBs and DDI system

As the gasifier was lined up with other equipment downstream such as the syngas coolers and particulate control devices (PCD), these associated systems and equipment were commissioned along with the gasifier.

- Gasifier refractory

During initial commissioning activities, the transport gasifier operated extremely well. Except for the faulty initial refractory installation, some of which was corrected before the first coal feed, the gasifier availability was 100% during the initial commissioning activities.

Much of the lower portion of the gasifier A refractory was replaced carefully, and the new refractory performed well. A small part of the lower section of the gasifier B refractory was replaced and the remaining suspect locations were repaired. In addition to refractory patches and replacements, the designs of the aeration, process air flow, and instrumentation nozzles extending into the gasifier shell were modified to protect the insulating refractory layer and prevent reverse flow and channeling of process gas behind the hard-face refractory. These changes were sufficient to complete the two gasifiers' refractory cure.

The remaining faulty refractory in the upper portion of the gasifier, installed at the shop, experienced spalling to a lesser degree. Excessive spalling during coal feed impedes operations when coarse ash with refractory pieces from the gasifier cannot be discharged. Plans were in place to replace the upper portion of the gasifier refractories in an extended outage after sustaining operations with coal feed. Integrity and stability of installed refractory is critical to sustain gasifier operations with high solids circulation rates at high temperatures. Additional details on challenges associated with refractory installation and modifications are in section 6.3.

- Solids circulation

The successful completion of all planned gasifier-related activities before the start of coal feed was due to in-depth operator knowledge of the process, equipment, and field locations; excellent layout of DCS graphics; and logic support and execution. It was a significant achievement. The transport gasifier was scaled up by a factor of 25 (by riser cross-section), and the initial bed material in the gasifier circulation loop at Kemper was about 160 tons compared to about 2.5 tons at PSDF.

After prework to detect and address leaks, tests and performance checks were performed. These tests included pressure test and air blow cleaning of process lines and tuning of all 44 flow controllers and 7 pressure controllers. Tests were successfully completed, and performance was checked under simulations of different operating scenarios. Flow was established and distributed to all nozzles in the desired nearly equal amount. Maintaining aeration and fluidization gas flows is critically important for stable solids circulation. Commissioning activities indicated the nozzles would remain plug-free after a trip and solids circulation can be reestablished easily.

Startup bed material was added to the gasifier through the coarse ash feeder. The coarse feeder worked well, and the feed system responded well to gasifier inventory requirements. Cold sand circulation and systematic testing demonstrated the main features of the circulating fluidized bed in the transport gasifier. The solids circulation was smooth, and the solids circulation rate was well controlled over a wide range of operating parameters. The high solids circulation rates later achieved with high temperatures in the gasifier exceeded the design rates and were more than two times the highest recorded circulation rates in a circulating fluidized bed in any application before Kemper.

During both the cold and hot commissioning, the operation and control of solids circulation in the gasifier was well demonstrated and the hands-on experience gained during these initial commissioning activities prepared the operators for the upcoming coal feed operations.

- Gasifier heat-up

From a process viewpoint, the two opposing SUBs and the DDI system performed extremely well. The SUBs, as designed, were able to heat-up the gasifier to about 1,200 °F. The flue gas flow from the burners was sufficient to maintain solids circulation in the gasifier loop. From an operational viewpoint, the burners experienced a few trips from shortcomings of the flame scanning mechanism.

The DDI system operated well, even with a first-of-a-kind concept and design of diesel injection, dispersion, and flameless combustion in a high riser density, circulating fluidized bed. The system performed beyond expectations for ease of operation, precise ramp and maintenance of gasifier temperature, and precise control of low oxygen levels in the flue gas. The seal mechanism around the insertion diesel gun was an operational challenge. Future designs should incorporate a fixed diesel gun position with appropriate purge flow to protect the diesel gun when not in use.

Due to excellent performance of both gasifier and the gasifier heating systems, the curing of gasifier refractory, refractory in downstream piping, and syngas cooler refractory was completed per refractory cure-out schedule.

- Vibration

The gasifier is about 185 ft tall and is supported near the midway point. The lower and upper sections of the gasifier are free to expand. Due to the hydrodynamics of gas-solids interaction in the lower portion of the gasifier, especially in the mixing zone section, the gasifier experienced vibration. A quick installation of a temporary restraining mechanism with three cables tied to the lowest portion of the gasifier was sufficient to complete the cold flow tests and initiate initial refractory cure on gasifier A. The temporary restraining system reduced the movement by about 50% at lower solids circulation rates. Although the gasifier vibration was less with the temporary restraining system, there was excessive movement of some connected piping such as the coal feed line. A permanent and more robust restraining system was installed on both gasifiers, and the system performed well as tested during complete refractory cure on both gasifiers. Additional details on vibration measurements and implementation of a restraining system are in section 6.2.

- Observations on operation of other related systems

Many units in the process are closely associated with gasifier operation. This section presents a summary of their operation. Details of commissioning activities and operation of these units and their interaction with gasifier operation are presented in various sections of the report.

Coarse Ash Feeder. The coarse ash feeder performed well supplying bed material to the gasifier as needed. The feed rate was less than expected during initial operation, but there was room for improvement with changes in operational parameters. All mechanical components and control sequence logic operated well throughout startup and shutdown

CCAD System. The continuous coarse ash depressurization and discharge system worked consistently well, moving solids from the lower portion of the gasifier seal leg riser to the primary cooler initially when there was no extraneous material (spalled refractory pieces) in the solids circulating in the gasifier. The solids flow to the primary cooler was controlled by both vent pressure (coarse control) and J-pipe fluidization gas flow rate (fine control) controls. With these controls, the bed material from the gasifier was withdrawn over a wide range of flow rates. The solids flowed well through the primary and secondary coolers, being added to the gasifier with the coarse ash feeder while simultaneously

being withdrawn with the CCAD system Although the testing period was short, the initial operations established the ability to automatically maintain the standpipe levels and the level in the secondary cooler. More testing is needed without any spalled refractory pieces in the gasifier bed material to improve confidence in the instrument indications and operation of the CCAD system.

CFAD System. The continuous fine ash depressurization system could not be tested for its ability to depressurize the fines accumulated in the fines cooling vessel below the PCD. The bed material attrition was low and the gasifier presalter and standpipe cyclones performed well, limiting the fines carryover to the PCD. The system pressure in the PCD was too low for PLD vents operation. The fines that accumulated in the cooling vessel was conveyed to the ash silos. There was water left over from hydrotesting of various lines that had been drained and blown clean, leaving some uncertainty as to whether the system was completely dry. The successful conveying of fines to ash silo indicated that the ash conveying pathway was clear and the conveying gas was dry.

Syngas Coolers. One of the process requirements to ensure good performance of iron-aluminide sintered metal candles in the PCD is to warm up the PCD to over 250 °F before lighting the burners to heat up the gasifier. This warming prevents moisture condensation and corrosion of filter candles. The simple but first-of-a-kind concepts for warmup included using syngas cooler economizers as heaters to heat up the process gas (nitrogen initially) flowing through the economizers, with steam sparging and a dedicated closed hot-water circulating loop. This heated up the upper portion of the PCD sufficiently to prevent condensation. The lower cone portion of the PCD was kept warm with a steam jacket. The system pressure and gas flow through the two syngas coolers was not high enough during refractory curing to fully test the syngas coolers' operational characteristics and performance during gasifier unit commissioning.

PCD. The PCD filtration and backpulse skid performance could not be fully tested during gasifier unit commissioning because the fines loading and gas flow rates through the two PCDs were quite low. The backpulse system operation and logic sequences were checked during gasifier refractory curing. There were minor issues with a few backpulse valves sticking, with even flow through all backpulse valves, and with the performance of the PCME analyzer for measuring fines concentration in the exit stream.

In summary, the commissioning efforts with gasifier heat-up and refractory cure-out progressed well after the refractory issues in the lower portion of the gasifiers were addressed. Taking into account that the transport gasifier at Kemper is the first commercial implementation of the pilot scale unit at PSDF, the gasifier operated extremely well. It achieved solids circulation rates that are the highest recorded among any circulating fluidized beds anywhere in the world and in any application. The direct diesel injection system, which is also first-of-a-kind implementation, performed well and achieved excellent gasifier temperature control with very low excess oxygen requirements.

5.5 Syngas Cooling

5.5.1 System Overview

The syngas coolers take hot syngas from the pressurized transport gasifier RX1002 and cool it before the syngas is sent to the FL1106/1206 particulate control devices for solids removal. The syngas coolers recover heat from the syngas to produce high pressure (HP) superheated steam used in the steam turbine to produce power.

Each gasifier train has two parallel syngas cooler trains, each handling 50% of the syngas flow from that gasifier. Each train is equipped with five heat exchangers (one steam generator, two superheaters, and two economizers) arranged in series (figure 5.5-1). The five heat exchangers that make up each syngas cooler string are (equipment numbers are for the first syngas cooler train of the first gasifier):

- HX1110 Steam Generator.
- HX1112 Superheater 1.
- HX1113 Superheater 2.
- HX1114 Economizer 1.
- HX1116 Economizer 2.

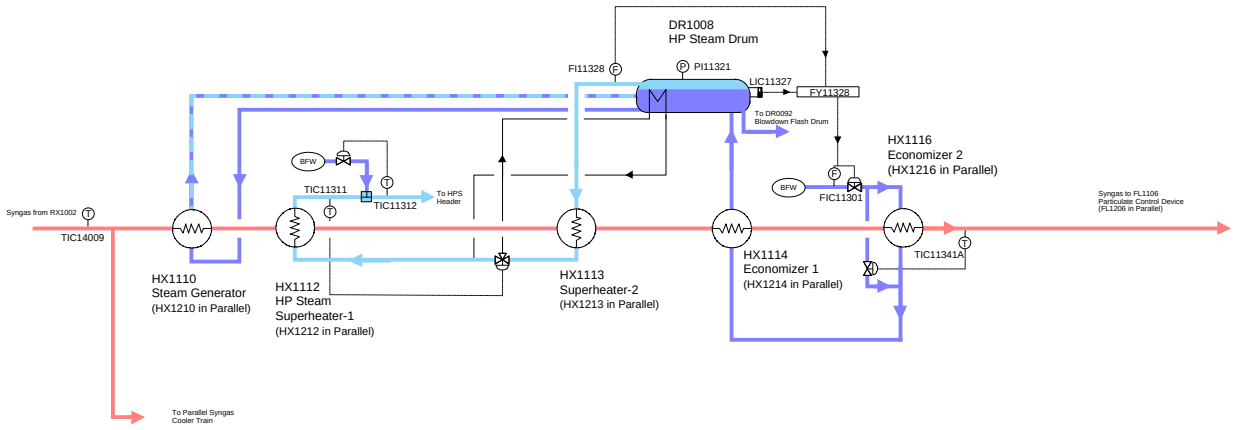


Figure 5.5-1 – Syngas cooler process flow diagram

HX1110 steam generator cools the syngas exiting the transport gasifier standpipe cyclone. Syngas flows through the exchanger tube side and is cooled by boiler feed water (BFW) on the exchanger shell side. The BFW from DR1008 HP steam drum is heated to produce saturated HP steam, which flows back to DR1008. The cooled syngas exits HX1110 steam generator and enters the shell side of HX1112 HP steam superheater 1. The normal syngas temperature at the steam generator outlet is about 1,200 °F.

The steam generator operates by natural circulation. BFW in the drum flows downward through downcomers into HX1110. The steam that is generated mixes with the remaining BFW to form a mixture of steam and water with a lower density than the BFW itself. This lower density causes the mixture to flow through risers back up to the steam drum, where the steam and water are separated, creating a siphon effect that continues to pull additional BFW down from the drum by gravity. At higher pressures in DR1008, the difference in density is decreased and higher steam generation rates are required to maintain an adequate BFW circulation rate to keep the tubes cooled.

HX1112 HP steam superheater 1 and HX1113 superheater 2 are shell and tube type heat exchangers that further cool the syngas by exchanging heat with HP steam from DR1008 HP steam drum. The superheater tubes are arranged in helical coils within the shell. There are five concentric sets of coils in each superheater and a total of 30 tubes per superheater. The steam flow in superheater 1 is concurrent to reduce the tube metal temperature near the syngas inlet. The steam flow in superheater 2 is countercurrent.

Syngas flows through HX1112 HP steam superheater 1 shell side followed by HX1113 superheater 2 shell side. HP steam flows in series through HX1113 tube side and HX1112 tube side. This arrangement allows the cleaner fluid, steam, to be flowing in the tubes, and is a lower maintenance design. The cooled syngas exits HX1113 superheater 2 and enters the tube side of HX1114 economizer 1. The normal syngas temperature at the superheater exit is about 900 °F.

To control the superheated steam temperature leaving HX1112 superheater 1 and flowing to the steam turbine, TIC11311 controls a three-way valve that routes a slip stream of HP steam from the outlet of HX1113 superheater 2 through a cooling coil immersed below the water level in DR1008 HP steam drum. The two streams of superheated steam then recombine at the steam inlet to HX1112 HP steam superheater 1.

HX1114 economizer 1 and HX1116 economizer 2 are the final heat exchangers in the syngas cooler. Both are shell and tube type heat exchangers that further cool the syngas by exchanging heat with BFW. Syngas flows through the tube side of HX1114 economizer 1 and then the tube side of HX1116 economizer 2. BFW flows through HX1116 shell side concurrently, followed by HX1114 shell side countercurrently. The preheated BFW flows to the HP steam drum.

Cooled syngas exits HX1116 economizer 2 and flows to FL1106 particulate control device (PCD) through refractory lined pipe. The normal syngas outlet temperature from the syngas cooler is about 600 °F. The syngas outlet temperature from HX1116 economizer 2 is controlled by TIC11341A, which adjusts BFW bypass flow around the exchanger to maintain the target syngas outlet temperature.

During startup, the economizers are used to preheat the PCD to prevent any condensation of flue gas on the PCD filter elements. The piping is arranged in a pumparound loop where a PCD warmup pump circulates BFW through the economizers and back to the pump suction. Steam is sparged into the circulating water before it enters economizer 2, heating the water to about 325 °F. A back-pressure controller at the BFW outlet from economizer 1 keeps the pressure in the loop high enough to prevent two-phase flow from forming. The loop is open to the steam drum, giving the water from the sparged steam a path to exit the loop and providing heat to the steam drum for preheating. Steam drum level is controlled by blowdown to the condensate system.

5.5.2 Initial Commissioning Plan

After the syngas coolers were turned over to Startup from Construction, the major commissioning activities were to include a chemical clean of the water-side piping, a hydrostatic pressure test, and testing of the PCD warmup loop. Cleaning of the gas-side piping was part of the plant steam blow activity and is discussed in the gasifier section.

Development of the commissioning plans for the chemical clean included consultations with a third-party cleaning contractor.

The procedure called for the system first to be filled to a normal operating drum level with demin water and ammonia as needed to raise the pH above 9.0. Pumps would circulate the water through an external heater to bring the water to at least 150 °F. Then a surfactant (Triton X100), a corrosion inhibitor (Cronox 240), and EDTA (ethylenediaminetetraacetic acid) would be added. This solution would be circulated for at least 16 hr at 160 - 180 °F. The solution would then be cooled to 110 - 120 °F and neutralized with ammonium hydroxide to a pH of 9.1 - 9.4. Oxygen would then be added to passivate the system. This solution would be drained to frac tanks and then rinsed twice with demin water treated with ammonia to raise the pH above 9.0.

The first test package was a hydrostatic test of the steam and water side of the exchanger. Each component of the syngas cooler system was individually hydrostatically tested before being shipped to the site, and local regulations required the entire boiler system to be tested after construction was complete. The steam drum, steam generator, steam superheaters, and economizers were to be filled with BFW. A test pump would be used to raise the pressure of the water in the system. After an initial hold at 100 psig to check for leaks, the system would be pressurized through a series of hold points until the test pressure of 3,662 psig was achieved. After a 10-min hold, the pressure would be reduced to 2,500 psig to check for leaks. On completion of the test, the system would be drained, and nitrogen used to dry the system. A nitrogen blanket would be left on the system when complete.

The final syngas cooler specific test package was the warmup loop, soon after the hydro test and without gas flowing from the gasifier. The primary purpose was to test the PCD warmup loop. The first step would be to fill the system with BFW until the steam drum was at its normal level. The piping would be lined up to the path used during startup to warm the PCD. Then steam would be opened to the heating coils on the PCD cone. The warmup recirculation pumps would then be started and after flow was established, steam would be sparged into the circulating BFW. This would test the controls associated with the PCD warmup and several of the instruments and controls on the steam drum.

5.5.3 Significant Events

5.5.3.1 *Accomplishments*

Milestone	Train A	Train B
Chemical clean	2/11/2015	2/05/2015
TP1021/1022 Hydro	8/8/2015	9/14/2015

TP1022/1023 Warmup loop	10/4/2015	2/16/2016

The syngas cooler has a drain line from the drum to the condensate header to allow water to be removed from the drum during startup for level control. Another line to the condensate system between the economizers and the drum allows extra water to be pulled through the economizers during startup to cool the flue gas to the PCDs and control the PCD temperature during startup. Both these drain lines were initially routed to the IP condensate header. The operator training simulator was instrumental in showing that during startup when these systems would be in use, the IP condensate header was at a higher pressure than the drum, and water would be unable to flow to the condensate system from either the drum or the BFW lines. These lines were rerouted to the LP condensate header, which operates at near atmospheric pressure.

In June 2014, an inspection of the syngas coolers revealed that the heat shield on steam generator HX1110 showed signs of rust and corrosion (figure 5.5-2). The other steam generators were not affected. The heat shield was a plate at the outlet tubesheet that covered the tubesheet refractory and ferrules. It was determined that the cause was a non-nickel-based filler material used on the plate. To correct the problem, it was necessary to remove the plate, grind off the fillet welds and other corroded spots, and then remount and reweld the plate.

Figure 5.5-2 - Rust and corrosion on heat shield of steam generator outlet tubesheet

From early August until late September 2014, temporary piping for the chemical cleaning and the hydrostatic test was designed, ordered, and installed. The initial plan for the chemical clean called for the circulating water to be heated using an external heat exchanger and steam as the heat source. Because of delayed availability of steam, this was changed to using engineered heat. This arrangement called for two blowers and two heaters to blow hot gas into the syngas cooler through the manway at the syngas outlet from economizer 2, and another blower and heater to put additional hot gas into the manway in the space between economizer 1 and economizer 2. This hot air would flow through the economizer sections and heat the water being used for the chemical clean. The gas would then exhaust through a manway above the steam generator. Temporary thermocouples would be used to measure the temperature during the chemical clean.

Several issues arose during the initial chemical cleaning process that potentially could have caused equipment damage. After completing an RCA, it was decided to use an external steam heat exchanger to heat the water for the chemical cleaning.

The chemical clean was then performed on all syngas coolers in early February 2015. Train B was cleaned first, followed immediately by Train A. In agreement with the RCA findings, an external steam heat exchanger was used to heat the water for the chemical cleaning. The chemical clean was repeated on Train A in February 2015, days after completing the chemical clean on Train B. Figure 5.5-7 shows key gas and water temperatures during the chemical clean on Train A. Unlike the attempt in September 2014, the highest gas temperature was less than 140 °F and was in the open-air space between the two economizers.

The hydrostatic test was expected to begin soon after the completion of the chemical clean, and the water side piping was not placed under passivation protocol. Because of delays, the hydrostatic pressure test did not take place until late May 2015.

The IGCC area steam blows occurred at the same time as the syngas cooler chemical clean iterations. The IGCC side steam blows included all the process steam headers in the gasifier island and gas clean up areas, as well as the syngas cooler superheaters and steam piping. The chemical clean applied only to the water side of the syngas cooler system, so these two activities did not interfere with each other. To introduce steam into the superheaters, the saturated steam lines were cut at the top of the drum, and a temporary steam header was installed and attached to the superheater inlet piping. The piping arrangement allowed for steam to be introduced into each side of the superheaters separately, so each heat exchanger could be selectively cleaned. Before steam was introduced into the superheaters, the vendor was consulted to approve the heating and pressurization rates of the system. Figure 5.5-3 shows a basic process flow diagram of how the steam was piped into the Train B superheaters. The temporary piping is shown in red.

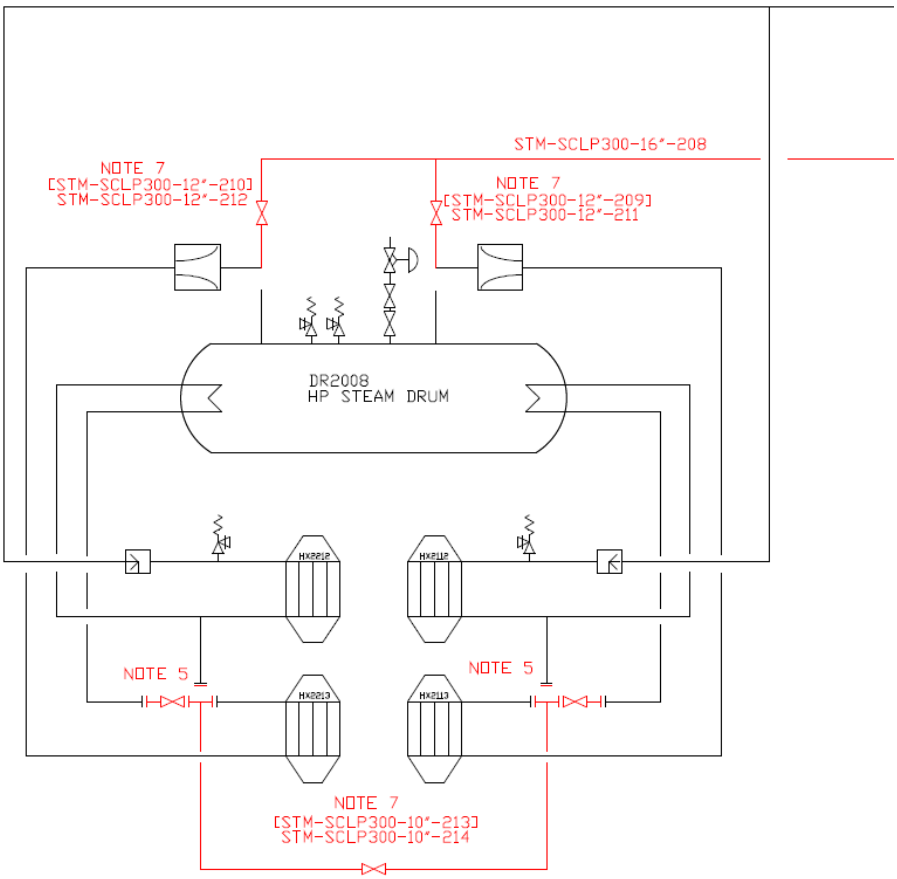


Figure 5.5-3 – Diagram of superheater steam blow process

The steam blows were executed and completed successfully in late November 2014 with no major setbacks. The process was completed several days early due to the overall success of the steam blow execution. As with the chemical clean, no provisions were made to lay up the syngas coolers after the steam blow. Due to schedule slip, the piping arrangement was left in place for several months after the completion of the steam blows, which was longer than planned.

The next major activity for the syngas coolers was the hydrostatic pressure test. The target pressure for the hydrostatic pressure was 3,662 psig or 1.5 times the maximum allowable working pressure of the steam drum. The syngas cooler manufacturer had established a maximum pressurization rate of 3 bar/min (about 44 psi/min). Individual parts of the syngas cooler were hydro tested during the fabrication process. The superheater coils were tested to 4,002 psig before installation into the shell, and the assembled superheaters were shop-tested to 4,045 psig. This testing was performed on five tubes at a time while the vessel was resting on its side, not in the installed vertical position.

On May 31, 2015, during the filling of unit A in preparation for the hydro, the unit was pressurized to 2,290 psig at a rate exceeding 600 psi/min when a steam outlet valve was inadvertently left closed. The actual hydrostatic test on unit A was 11 days later, when it was discovered that valves on the economizers were inadvertently left closed, allowing air to remain in the system. Before stopping, the syngas coolers had been pressurized to 2,610 psig at a rate exceeding 350 psi/min. The next day, superheater 1 HX1212 was found to have two leaking tubes.

Over the next month, a series of pressure tests of the system and of individual tubes revealed multiple leaking superheater tubes. An RCA of the tube leaks was started on July 14, 2015. Its results showed potential problems with

both the equipment and the conducting of the hydrostatic test. The procedure had several execution issues and resulted in a pressurization rate in excess of vendor recommendations.

All the superheater leaks occurred where the tubes were attached to the guide bar attachment with a flare bevel groove weld. The tubes were nominally 5.0 mm thick with a manufacturing tolerance of +/- 7.5%. The calculated minimum wall thickness was 4.08 mm. Field measurements of the outer tangent of the coil revealed thicknesses as low as 3.77 mm. It is believed that a combination of marginal design, weld technique, and thinner than allowable tolerances on the tubes all contributed to the leaks.

After completion of the RCA, consultation with the vendor, and updating the hydro procedure, the hydrostatic pressure test continued in August. The Train A hydro was successfully completed on Aug. 8, 2015. There were leaks identified in the initial attempt at the hydro test on Train B and the hydro was completed on Aug. 28, 2015. There was a total of five leaking tubes, out of 120 total superheater tubes, from the Train A hydrostatic testing. Using the revised procedures that followed the recommended pressurization rates, Train B experienced only one confirmed leak during the hydro, and a second tube was plugged based on visual evidence of a suspect weld.

Due to the leaks during the initial attempt at the hydrostatic test, there was a delay of about 3 months in completing the hydro testing on both trains. The refractory in the syngas coolers had to be dried after the water leaks, and those dryouts were completed in mid-September 2015.

Shortly after the refractory dryout, syngas cooler test packages TP1023 and TP1024 commenced just before starting the gasifier cold circulation and gasifier refractory dryout test packages. The syngas cooler testing on Train A was in early October 2015. Significant gasifier refractory problems were uncovered during and after the subsequent gasifier refractory dryout. There was a delay until February 2016 before the syngas cooler testing on Train B. There were numerous minor issues uncovered during these tests, but nothing that had an appreciable impact on the schedule.

5.5.4 Final Summary

The first attempt at the Train A syngas cooler chemical clean ended because the economizer 2 exit was at a high temperature when using external burners as a heat source. The chemical clean was completed in February 2015 using steam heating.

Figure 5.5-4 shows the initial PCD warmup test from October 2015. Even on the very first use of the system, the data shows the PCD warming system worked well. The control loop for the sparging steam (black line for sparging steam valve opening) was able to hold the temperature of the BFW to economizer 2 (cyan line) very steady and at several different temperature setpoints. The PCD temperature (green line) came up smoothly and within a reasonable time. The steam drum temperature can be seen to slowly rise as warm water from the warmup loop flows to the drum.

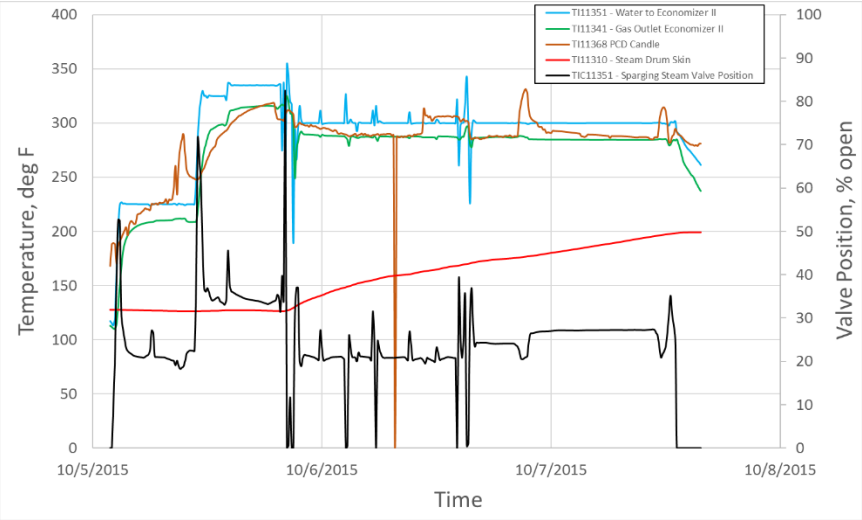


Figure 5.5-4 - Initial operation of the PCD warmup loop during TP1023 / TP1024

One of the issues uncovered during the test package was the potential for the BFW in the PCD warmup loop to flash across the backpressure control valve. Figure 5.5-5 shows one instance of this occurring during TP1023/TP1024. PI4203A is the pressure (brown line) in the suction line to the pumparound pumps. It starts declining as the water starts flashing across the valve. As the suction pressure declines, the pump discharge pressure (red) starts to decline as well. PIC4202A is the backpressure controller. As the pump discharge pressure declines, the controller (orange line) closes down on the valve and is briefly able to maintain the backpressure, but the increasing differential pressure across the valve makes the situation worse. The temperature of the water to economizer 2 increases as the water flow from the pump decreases and the sparging steam valve (black line) goes closed in response. After the backpressure control valve goes completely closed, the suction line is able to slowly refill with water and eventually the system returns to normal operation. The drum pressure was a low 10 psig during this entire event. The problem was solved by operating the drum at a higher pressure and taking very little pressure drop across the backpressure valve. The drum was pressurized to about 70 psig using LP nitrogen piped up to the drum. The pressure controller on top of the drum was set to the desired pressure, then would regulate drum pressure while venting excess nitrogen or steam out of the startup vent.

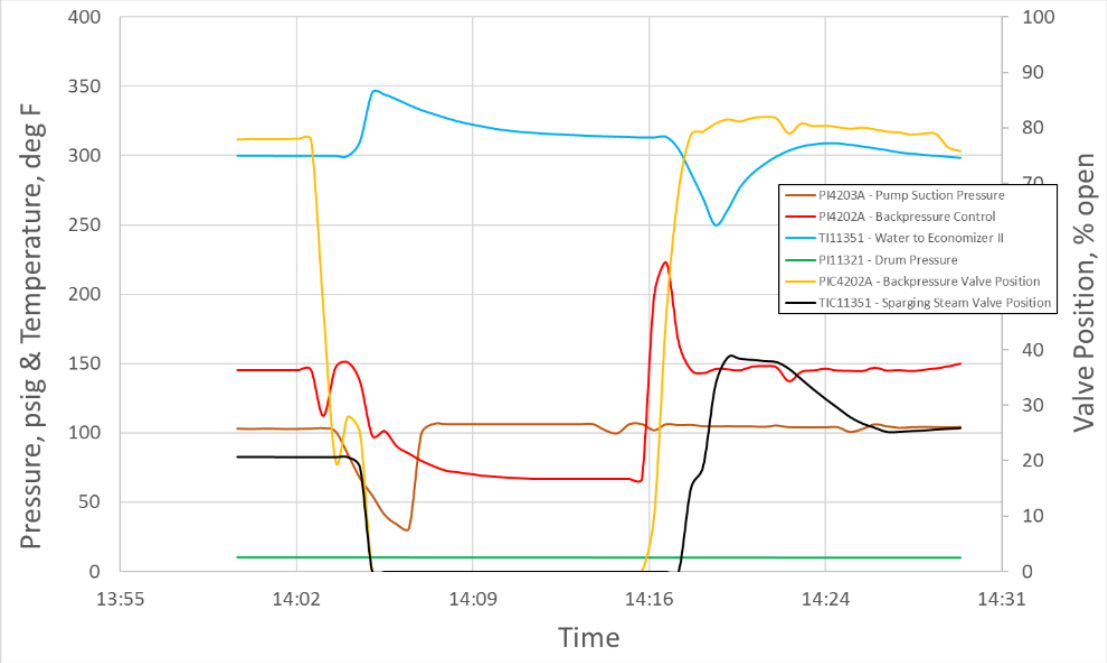


Figure 5.5-5 - Flashing across the backpressure control valve during TP1023/TP2014

One important aspect of the syngas cooler design is to not only be able to preheat the PCD to prevent condensation during startup, but also to maintain the PCD within a narrow temperature band through startup to prevent damage to the PCD. While too low a temperature can lead to condensation, too high a temperature can allow oxygen in the flue gas to ignite residual carbon in ash in the PCD. After the preheat period is compete, it is necessary to ensure the PCD temperature stays low enough to prevent combustion until the start of gasification. Figure 5.5-10 shows a complete gasifier startup. The first part of figure 5.5-6 shows the PCD preheat before lighting the gasifier startup burners. When the gasifier exit temperature (black line) begins to increase, the amount of sparging steam (cyan line for steam valve opening) needed to maintain the PCD temperature begins to decrease. Shortly after the sparging steam is stopped, cooling is needed to keep the PCD from getting too warm. Cooling is done with a slipstream from the BFW line (green line for boiler feedwater valve opening) going from the economizers to the steam drum that goes to the LP condensate header. By opening a control valve in this line, additional BFW above what is needed to maintain the steam drum level can be pulled through the economizers, decreasing the temperature of the flue gas.

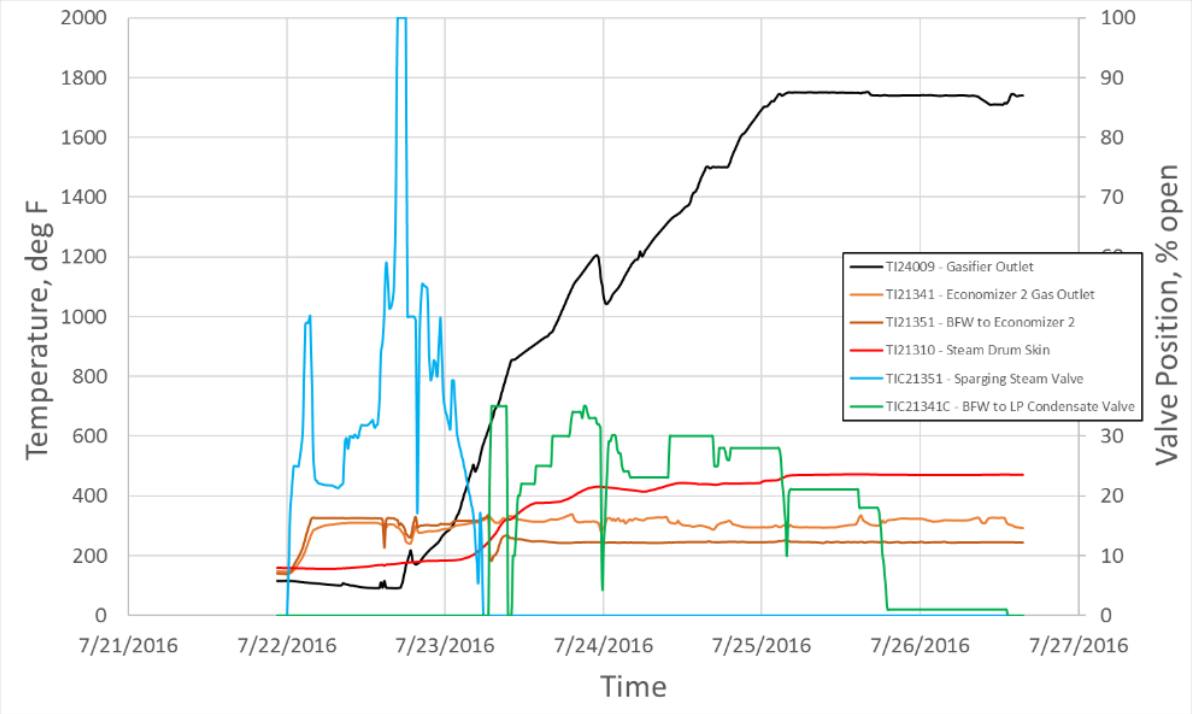


Figure 5.5-6 - Syngas cooler startup

The syngas cooler commissioning got off to a slow and challenging start with overheating of system components on the first train during the first chemical cleaning and during the steam side hydro of the system

Testing and commissioning were more successfully executed from the beginning after the syngas coolers moved from the early test packages and into larger-scale testing involving testing the PCD preheat system and supporting the refractory cure of the gasifier. The PCD preheat system worked well and continued to support testing plant components leading to first coal feed. Only minor problems were found that were relatively easily corrected and did not adversely affect the commissioning schedule. The success continued after the syngas cooler test packages were complete and the function of the coolers moved to supporting the cold circulation and refractory cure gasifier test packages.

5.6 Particulate Control Device

5.6.1 System Overview

The particulate control device (PCD) is important equipment in the TRIG™ process. There are four PCDs – two installed to each gasifier train in a parallel configuration (Figure 5.6-1). PCD equipment has tag numbers FL1106 and FL1206 in Train A, and FL2106 and FL2206 in Train B. In this section, only one PCD is referred to unless otherwise noted.

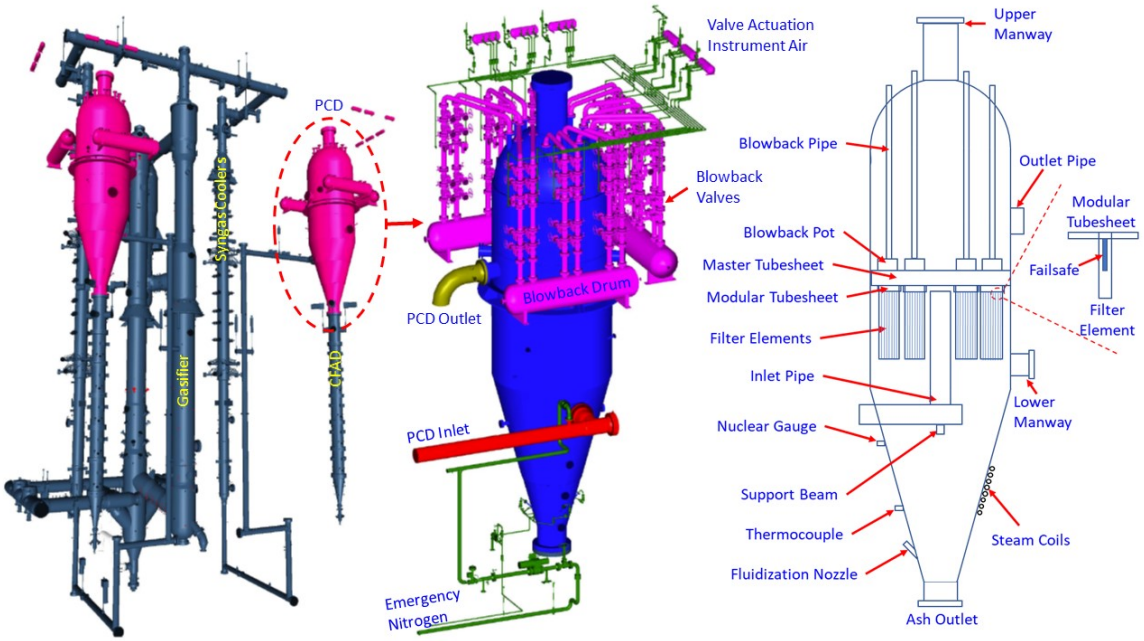


Figure 5.6-1 – PCD configuration

The purpose of the PCD is to remove essentially all the particulate in the cooled syngas flowing from the primary syngas cooler economizers, HX1116/1216/2116/2216. The PCD is a barrier filter system using metallic filter elements. The particulate collects on the outside of the filter elements and is periodically removed by injecting syngas from the recycle gas compressors, CO1008/2008, on the inside of the filter elements. The particulate falls off the filter elements and into the lower cone of the PCD before flowing through the PCD fines receivers, HX1118/1218/2118/2218, and into the continuous fine ash depressurization (CFAD) systems, FD1120/1220/2120/2220. The particulate-free syngas flows from the PCD to the syngas scrubbers, CL1007/2007.

The PCD system consists of a master tubesheet that holds 18 clusters of filter elements in a modular arrangement. Each cluster, or module, contains 38 2.5-m filter elements. In each filter element, a built-in fail-safe is installed at the mouth of the filter element. All 38 filter elements in a cluster share the same chamber above the tubesheet to gather the clean gas and receive the back-pulse gas. There are 18 back-pulse assemblies with 1 dedicated for each cluster. Outside of the PCD vessel, the 18 back-pulse assemblies are separated into three groups with six assemblies in each group. Each group has its own gas accumulator and inlet gas filter. The back-pulse event is controlled by PLC to strategically distribute the back-pulse gas to the individual clusters one at a time.

The online cleaning of the filter elements is achieved by back-pulse (or blowback) with nitrogen during startup or recycled syngas during normal operation. It employs a relatively new technology, coupled pressure pulse (CPP™), from Pall Corporation. The CPP™ technology uses low pressure gas to clean the filter elements, as compared to traditional jet pulse cleaning using a venturi device at a high pressure of about twice the system operating pressure. There are no additional high-pressure compressors needed for the CPP™ technology.

The PCD is equipped with instruments to monitor and control major operating parameters including pressure drop across the master tubesheet, temperatures on the surfaces of the strategically selected filter elements, temperatures in the cone, ash level above the cone, and back-pulse pressures in the accumulators. At the PCD inlet and outlet, gas compositions, temperatures and pressures are measured and monitored. Online particulate monitors are installed at the PCD outlet to detect any particulate leak through the PCD. Key parameters of these instruments are interlocked with operating control mechanism to maintain normal operation, detect system malfunction, and perform emergency handling.

An IP nitrogen line is installed at the PCD inlet to serve as an emergency handling source. The nitrogen can be introduced to the PCD in case of a thermal excursion due to oxygen breakthrough or in other situations. The injected nitrogen dilutes the oxygen concentration and cools the PCD components, protecting the PCD vessel and filter elements from the thermal failure.

In the unlikely situation that a filter element fails, the built-in fail-safe will effectively block the particulate and keep that filter element off filtration duty to protect the downstream equipment and processes from being damaged or hindered. The PCD is designed for a certain failure rate of the filter elements with built-in fail-safes. When the remaining filter elements can no longer perform the required filtration duty within the operating limits, the PCD should be brought offline to replace the damaged filter elements and restore the filtration capacity.

The PCD is designed to operate with an empty cone at all times. Ash accumulation in the cone can occur during abnormal process operating conditions. In the lower PCD cone, fluffing (fluidization) nozzles are installed to help convey ash accumulated in the cone. The fluffing nozzles can be used as needed, particularly during a heavy ash accumulation in the cone after an operating event in the upstream or downstream equipment.

The PCD cone is equipped with steam coils to assist in preheating the PCD during the system startup. Preheating is intended to prevent condensate draining to the CFAD system, which could cause operating difficulties during startup. Skin thermocouples are installed on the outside of the cone to monitor the preheating process. After startup, the steam flow can be kept on as needed during normal operation to compensate for excessive heat loss through the large cone surface. It also can be used to cool the PCD cone in case hot solids are carried over to the PCD in an unlikely system upset situation.

5.6.2 Initial Commissioning Plan

The commissioning of the PCDs was conducted during the gasifier cold circulation test. For the PCDs, the key component is the back-pulse system, so commissioning focused on the back-pulse function. The initial plan was to test the PCD back-pulse system to verify its functions, then modify or adjust control logic and parameters accordingly.

Each PCD is equipped with 18 lines of back-pulse valve assemblies. Each line has a quick open valve for releasing back-pulse gas into its corresponding filter element cluster. The back-pulse valve can be isolated from the process with double-block-bleed valve sets downstream and upstream. The back-pulse valves are actuated by instrument air from the bottles. Each bottle supplies instrument air to three actuators.

The back-pulse lines are arranged into three groups with six lines in each group. Each group has its own accumulator for back-pulse gas supply. One check valve is installed at the inlet to each accumulator. An optional particulate filter can be installed at the inlet if needed. All three accumulators are connected to a common header for their gas supply. As installed, the back-pulse gas was supplied by a header shared by many applications in the gasifier train including fluidization to the gasifier. Later, a dedicated pressure control was added to the back-pulse supply line to independently control the back-pulse pressure.

All 18 back-pulse valves are automatically cycled in a certain pattern among the clusters. The back-pulse sequence and operating parameters are controlled by PLC. The cycling can be either in DP mode (triggered by a preset pressure drop across the tubesheet) or continuous mode (triggered by a preset timer with back-to-back cycling without delay).

The initial test plan was to cycle the back-pulse system to verify its function, hardware operability, and control logic. A test matrix was developed based on the design ranges of major operating parameters. Both DP mode and continuous mode would be tested with varying differential pressures between the accumulator and PCD outlet. During the test, PCD system responses would be measured and evaluated. Control logic and parameters would be modified and adjusted according to the system responses.

The initial test plans for other PCD subsystems were to check instrumentation, emergency nitrogen flooding, cone fluidization, and cone steam pre-heat coils.

5.6.3 Significant Events

During the commissioning period, there were significant events in the PCD systems that required substantial repair and modification. These events significantly slowed the PCD commissioning and negatively impacted the overall system commissioning schedule.

5.6.3.1 *Missing Support Beams*

Following a sudden depressurization event during a system leak test, there was concern about the integrity of the PCD inlet pipe and the hanging support structure to the master tubesheet. During a PCD inspection while filter elements were installed, it was found that there were no beams under the inlet pipes in all four PCDs. The beam is designed to support the L-shaped inlet pipe. It was determined that the beams were not installed in the fabrication facility. Consequently, the inlet pipe was crooked, and part of the weight was applied to the hanging support of the master tubesheet. Some members of the hanging support were distorted or damaged and had to be repaired.

With field support from Pall and design support from SCS Engineering, beams were fabricated and installed. Due to space restrictions and limited access to the cone, the beams were designed in a split configuration with a plate-bolt connection. To fit the beams in the designed position, some inlet pipe sections had to be trimmed and re-welded.

As the beam work was in progress, it was found that many bolts on master tubesheet-to-vessel footing support were loose. The gap between the master tubesheet and the footing support plate was uneven, with some loose or missing shim blocks. Re-shimming and re-torqueing had to be conducted to meet the design specs.

5.6.3.2 *Back-Pulse Valve Issues*

There are 18 back-pulse valves in each PCD, or 72 total for the 4 PCDs. Each valve has its own instrument air piping for actuation that is significantly longer than the 6 ft design specification. Back-pulse testing revealed the gas discharge varied significantly from one valve to another. This would result in non-uniform filter element cleaning and could affect long-term stability of the filtration. Syngas distribution varies from one module to another because of the cake difference. Char bridging could also form in the modules not being cleaned effectively.

Analysis showed the varying gas discharge was due in part to the longer and unequal pipe lengths for the actuation, and in part to valve-to-valve hardware differences such as torque, spring force, and friction. The first factor could cause lagging and deprived actuation force. The second could be resolved by fine-tuning the valves to achieve a uniform valve action. The fine-tuning was not practical during the commissioning and startup operation but should be conducted in the future.

To minimize the impact of the long and unequal piping lengths, local actuation gas bottles were installed at the back-pulse valves for FL1106 to test the effect. Nine 20-gal bottles were installed, with one for each two adjacent valves. The back-pulse testing showed moderate improvement on the gas discharge amount, but there was still significant variation in gas discharge. This could be attributed to the valve-to-valve hardware difference. Further evaluation is needed when the system is on coal to see if the variation would affect the overall filtration performance.

There were relatively frequent fail-to-open or fail-to-close incidents of the back-pulse valves. The failed valve seemed stuck. Some failures were due to solenoid valve problems such as loose wires, and some were due to back-pulse XV valve malfunction. The fail-to-close failure often resulted in depressurization of the back-pulse accumulator and unnecessary back flow to the clean side of the PCD. The fail-to-open failures resulted in no cleaning to the filter elements in that module, which could cause char bridging in a long run.

More alarms were developed and implemented with logic to detect the valve failures and provide visual signs on the DCS screens. This would promptly alert operators to the valve inaction and remind them to quickly resolve the back-pulse valve failures.

5.6.3.3 *Leaking Flex Seals on Master Tubesheets*

During an entry inspection inside the PCD clean side chamber after a repair, a small crack was found on the master tubesheet-to-vessel flex seal in one PCD. The flex seal is a thin (2 mm) metal sheet component that connects the master tubesheet and the vessel wall. The seal absorbs thermal expansion of the master tubesheet and seals the gap between the master tubesheet and the vessel wall. The crack was in a weld seam in the flex seal. It was initially thought the crack was caused by ladder damage during the repair work. On detailed inspection, it was determined the crack was due to a weld failure. A decision was made to inspect all the seals in the four PCDs with dye penetration. The test revealed many cracks in the seal welds. The seals were constructed with many small pieces rather than three large pre-fabricated pieces as specified, and the welding of the thin pieces caused cracking in the welds. It was reasoned that the seals were installed after the PCD heads were welded to the vessel bodies. The seals were shipped to the fabrication facility in three-piece assembly, but then had to be cut into small pieces and re-assembled inside the PCDs. This required many vertical and horizontal welds in the seals, and poor welding caused the cracks.

A temporary repair plan was initiated with strip overlay on the weld seams to cover the cracks. The sole purpose of the seals is to seal the gaps with enough flexibility to handle the thermal expansion differential between the master tubesheet and the vessel. A finite element analysis (FEA) was conducted to evaluate and fine-tune the stress and impact on the flexibility of the seals. The final repair was satisfactory. For long-term reliability, the flex seals should be replaced with permanent ones (recognizing the challenge to install them with the space restriction).

5.6.3.4 *Blowback Pot Failures*

On entering a PCD clean side chamber after a short commissioning operation, it was found that many blowback pots failed with a broken top plate from the cylinder. The repeated back-pulse pressure appeared to have caused failure of the weak weld between the top plate and the cylinder. An FEA was conducted to evaluate the structural response of the pot under design specifications. This analysis revealed the pot was not designed and fabricated properly. The stress at the top plate-to-cylinder corner is very high. The cornered weld structure and the poor weld quality caused high stress that resulted in cracking at the weld. The large deformation of the flat and thin top plate contributed to the high stress at the corner. It eventually damaged the pot structure under repeated back-pulse pressurization.

As a retrofit modification, different configurations of the pot structure were proposed and an FEA was conducted to evaluate the stress and deformation. A cone-shape structure was finalized, fabricated, and installed. The retrofit was a success without any further failure.

5.6.4 Final Summary

5.6.4.1 *Back-Pulse System Functional Check*

During the cold circulation test, the PCD back-pulse systems were lined up to the nitrogen header. The PCD cones were preheated by the steam heater before the back-pulse was started. The back-pulse was started before adding sand to the gasifier. PCD FL1106 in Train A was chosen for the initial back-pulse test.

Due to the nitrogen system limitation, the system pressure was lower than the PCD designed operating pressure. The back-pulse test was conducted at PCD outlet pressures less than 500 psig. The pulse timer was fixed at 50 ms per Pall's recommendation. The differential pressure (DP) between the accumulator and the PCD outlet was varied from 30 to 130 psid per Pall's allowable design DP range. Only continuous mode was tested, which would be the intended mode during on-coal operation. Since there was no coal feeding, and thus no appreciable cake formation and tubesheet differential pressure during the commissioning period, DP mode was not tested.

Before the cold circulation test, the PCD control logic was modified to consistently arrange back-pulse firing patterns among all three groups of filter element modules. The initial sequence was not consistent in the modular clusters associated with the third accumulator (DR3). This could cause imbalanced flow resistance among all the clusters inside the PCD.

- Preliminary results
  - Tests were conducted for PCD FL1106 with PCD outlet pressures of 50, 300, and 500 psig, and back-pulse differential pressures DP of 30, 60, 105, and 130 psid. Higher system pressure was not available because of the IP nitrogen control valve fluctuation (+/-20 psi) and IP nitrogen pressure relief valve setting.
  - The accumulator pressure was fluctuating as expected because of the header fluctuation. The back-pulse mass discharge from the accumulator to the modular cluster was fluctuating, which was not expected.
  - For all the system pressures except 50 psig, the mass and volumetric discharges during back-pulses increased with the differential pressure but decreased at 130 psid.
  - With increasing system pressure, the volume of the injected back-pulse gas in the plenum decreased although the mass discharge increased.
  - Two back-pulse valves were not functioning because of wiring issues. They were brought online later.

- General conclusions and reasoning

In general, the back-pulse gas discharge was significantly lower than expected based on PSDF experience (only 1/3 at a high system pressure). These factors were identified:

1. The pulse timer was short (50 ms per Pall recommendation). The pulse timer is about 200 ms at the PSDF even though the valve type is different. Per Pall's permission, the pulse timer would be increased to 75 - 175 ms in the following tests.
2. The back-pulse valve actuation was weak due to lower instrument air (IA) pressure (< 90 psig) and longer piping (~10 times longer than required).

- New information from Pall and actions needed

Pall previously stated the normal back-pulse differential pressure was 9 bars (131 psid). All system parameters were set based on this value. However, Pall changed the design DP limit. The design differential pressure for the back-pulse was changed from 9 bar (131 psid) to 6 bar (87 psid) and the recommended operating DP was changed to 4 bar (58 psid).

With the concern about the high IP header pressure and potential damage to the PCD internals, a change request already had been established to install a local pressure control valve for the three accumulators on each PCD. This local control valve would cascade down the back-pulse pressure from the common header and would not affect other IP users. However, because of the delay in procurement, these valves were not installed before the cold circulation test.

With Pall's updated design value for the back-pulse differential pressure limit, if all other IP users on the same header could not perform well at the pressure corresponding to this lower back-pulse differential pressure, either the local control valves would need be installed before further testing could be conducted, or the IP header would have to be controlled to a value to limit the back-pulse DP to 87 psid.

After a temporary pressure control valve was installed for each PCD, the back-pulse test was resumed for PCD FL1106. The differential pressure DP now was limited to 87 psid. The pulse timer was increased from 50 ms to 75 - 175 ms. The highest PCD outlet pressure was 521 psig. The preliminary results are shown in figure 5.6-2.

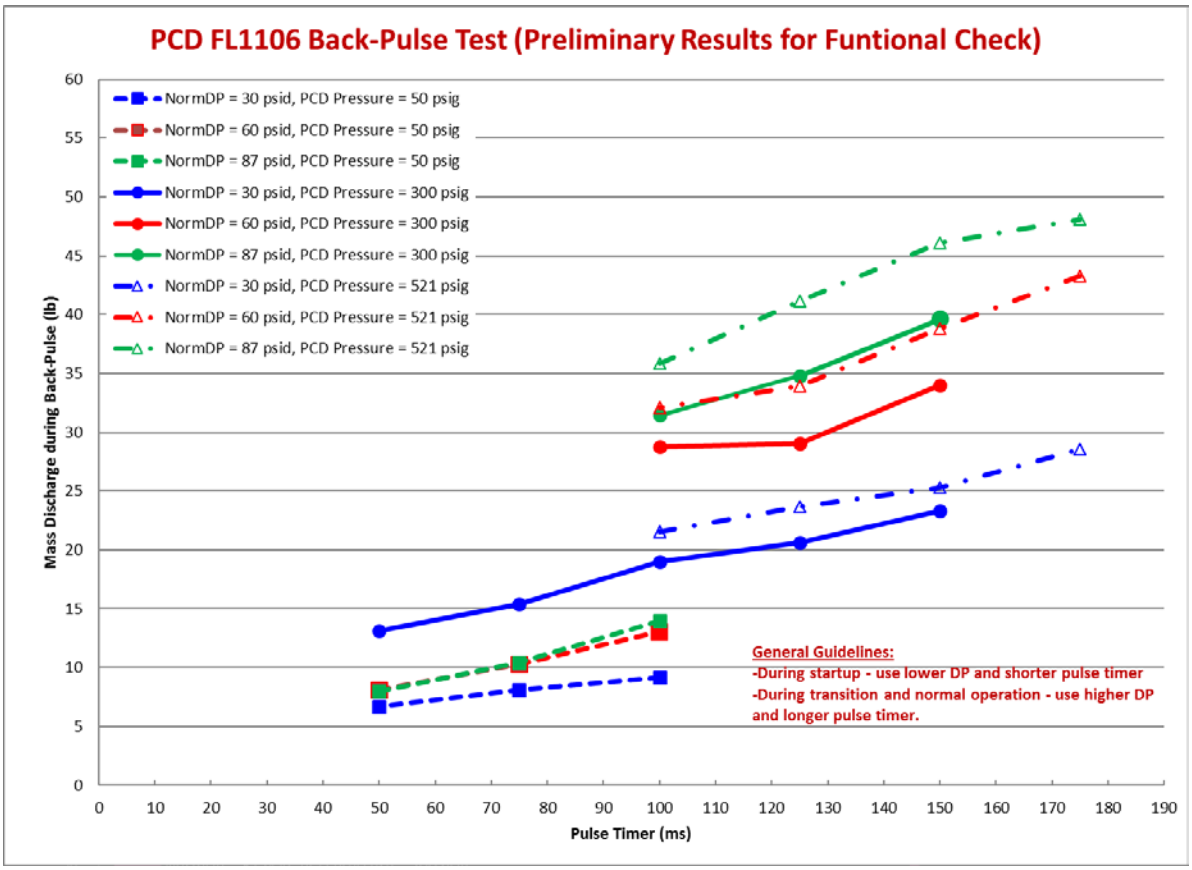


Figure 5.6-2 – Back-pulse test results

The test results show that as the pulse timer increased, the mass discharge increased for all the PCD pressures tested. Now the mass and volumetric discharge were comparable to the expected values. This trend confirmed that the back-pulse system was performing its designed function and ready for on-coal operation.

Based on the functional test results, general guidelines were given to Operations for the back-pulse operation at various stages from startup to normal operating. Design changes were proposed to install permanent local control valves for the back-pulse pressure control, and to address weak and nonuniform back-pulse valve actuation issues. Permanent pressure control valves and control logic were eventually implemented before first coal feed testing.

Based on the functional check results and the changes made for PCD FL1106, more back-pulse tests were conducted for the two PCDs in Train B later in the commissioning period.

Figures 5.6-3 and 5.6-4 show Train B PCDs FL2106 and FL2206 back-pulse mass discharges, respectively. The tests were done during system heat-up before feeding coal. The PCD pressure was 42 psig. The back-pulse DP was set at 60 psid and the back-pulse timer was set at 100 ms. The back-pulse valves are color coded based on the associated accumulators: red is accumulator DR1, blue is DR2, and green is DR3.

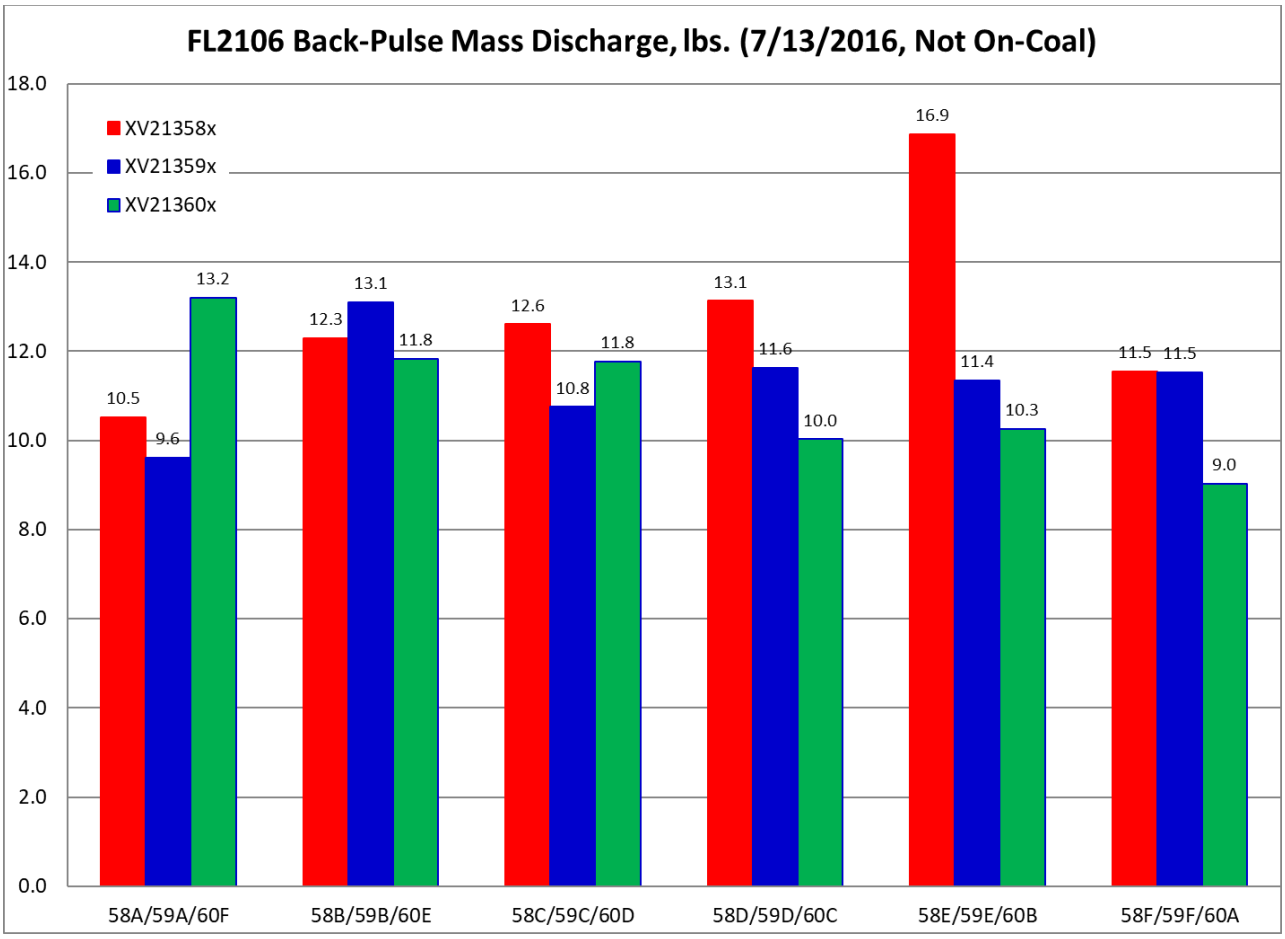


Figure 5.6-3 – PCD FL2106 back-pulse mass discharge

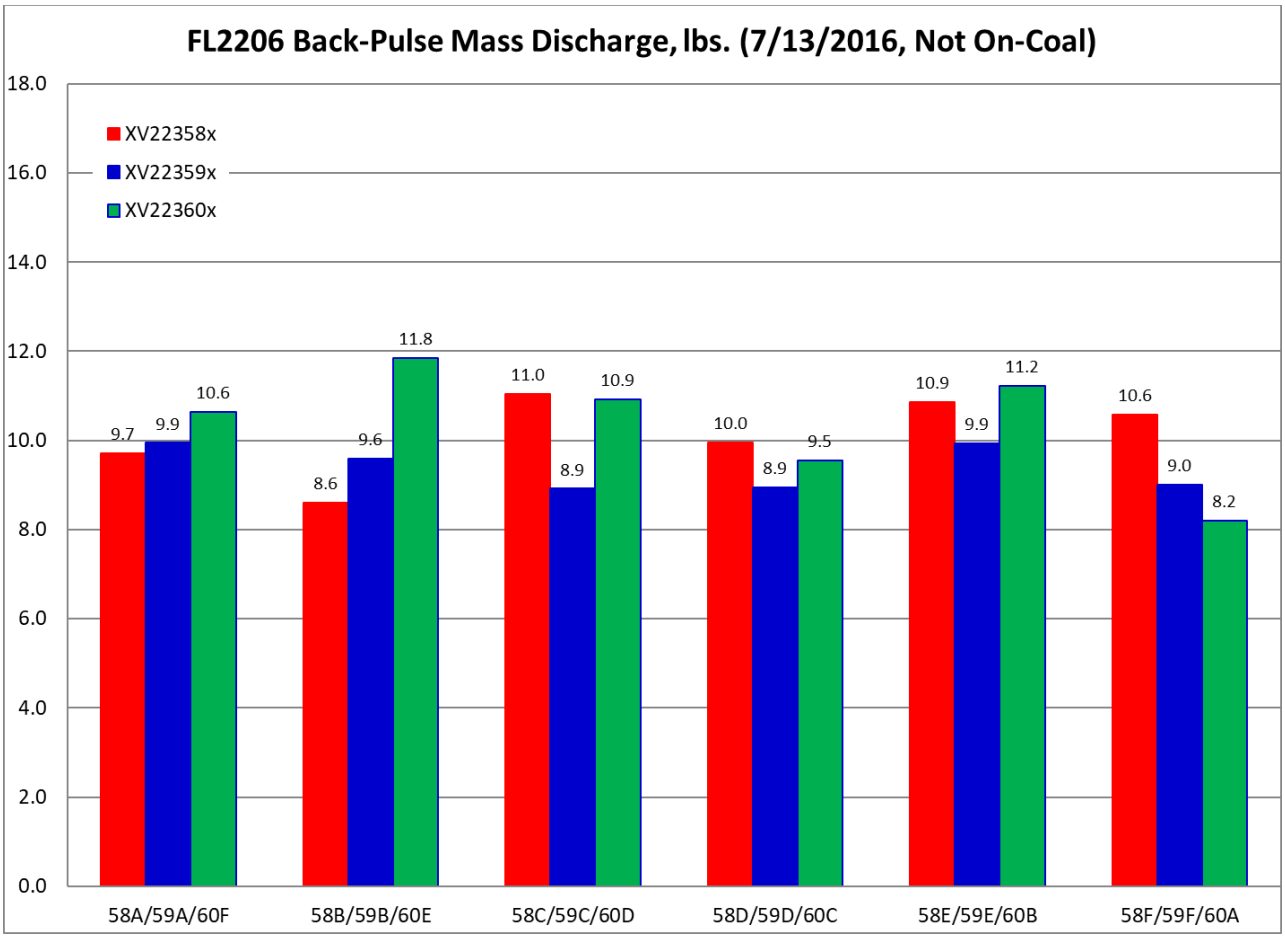


Figure 5.6-4 – PCD FL2206 back-pulse mass discharge

The mass discharge varied significantly, and it did not have any association to the accumulators. This pattern repeated itself in the back-pulse cycles, indicating each back-pulse valve was consistently acting based on its own characteristics. FL2106 had more mass discharge variation than FL2206. One hypothesis was that the variation could be the result of long and unequal length of piping for the back-pulse valve actuation, and difference in the back-pulse valve hardware. However, the test for PCD FL1106, with local instrument air bottles for actuation, showed only a slight improvement in the mass discharge amount. The significant mass discharge variation still existed. The implementation of local instrument air bottles on the other three PCDs was put on hold. The next move would be to address the issue of back-pulse valve-to-valve hardware difference. This task would require significant effort on offline tuning of the back-pulse valves with the vendor's involvement.

Despite the mass discharge variation, the absolute amount of the mass discharge was in the expected range based on performance data and experience with the PSDF PCD testing. The online cleaning effect on the filter elements was expected to be satisfactory. One concern was that the variation of the ash cake thickness on the filter elements in different clusters could affect syngas flow and ash deposit pattern, possibly resulting in undesired long-term filtration performance. Further evaluation on filtration performance would be conducted when the system was in on-coal operation during startup.

5.6.4.2 *Other PCD Subsystem Functional Tests*

The PCD cone steam pre-heating system functioned as designed without issues. Cone fluidization nozzles were exercised during the commissioning without issues.

Key instruments were functioning, including PCD inlet and outlet pressures and temperatures, tubesheet pressure differentials, filter element surface thermocouples, cone thermocouples, and cone skin thermocouples.

The PCMEs (online particulate monitors), emergency nitrogen flooding, and online gas analyzers were not tested during commissioning because of resource limitations or hardware availability.

To protect the PCD tubesheet when emergency nitrogen is introduced to the PCD during a thermal excursion, the control logic was changed from flow control to tubesheet DP control, with set point limits according to the mechanical design for the PCD tubesheet. This logic should be tested when the emergency nitrogen system is available.

During the unit commissioning period, several major PCD components experienced hardware failures. After efforts to redesign, modify, or repair these components, the mechanical problems were successfully resolved. However, the events significantly delayed the PCD commissioning progress and negatively affected the overall system commissioning schedule.

Major PCD subsystems were successfully tested with functional check, control logic verification, and hardware inspection. The PCD systems were ready for on-coal startup operation. For items not tested during the unit commissioning period, plans were to continue the functional check during the on-coal startup operation.

5.7 Ash Cooling and Depressurization

5.7.1 Coarse Ash Cooling and Depressurization (CCAD System)

5.7.1.1 *System Overview*

A CCAD system is designed to withdraw coarse ash from the gasifier at high pressure and high temperature, then maintain the solids level in the standpipe at a desired level. The two major functions of the CCAD system are ash cooling and ash depressurization. See CCAD system overview, figure 5.7-1.

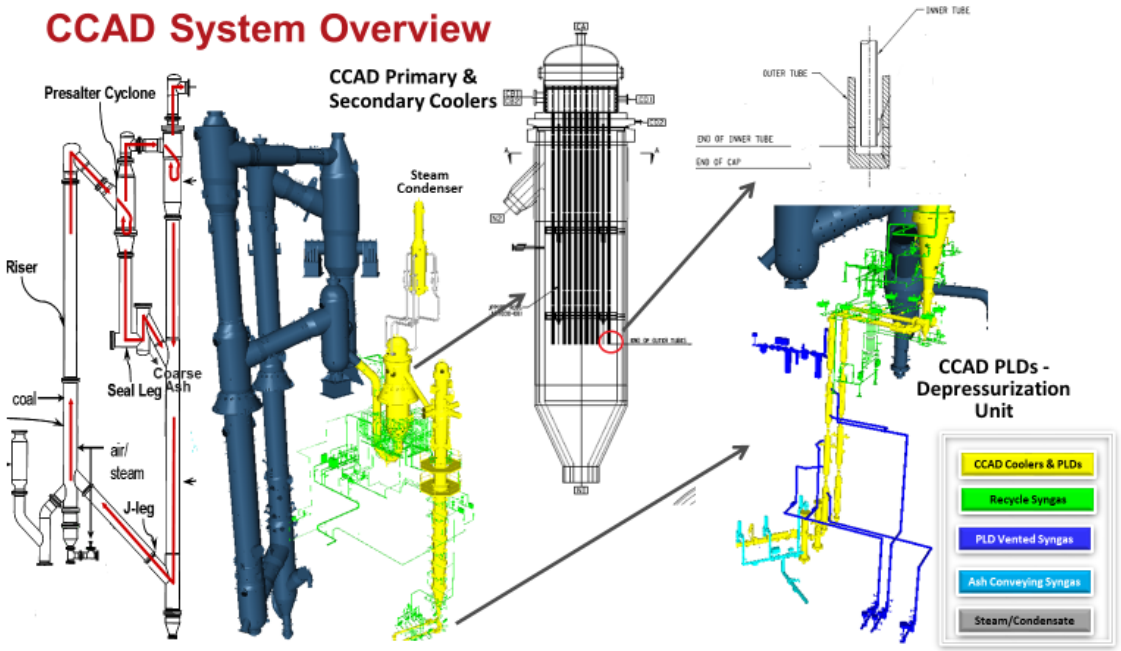


Figure 5.7-1 – CCAD system overview

The coarse ash is withdrawn from the lower section of the seal leg riser portion of the gasifier. The hot coarse ash, at about 1,750 °F, moves from the take-off point through a J-pipe and enters the lower section of the primary cooler. The ash is cooled to about 600 °F in the primary cooler fluidized bed, using an inverted bayonet type heat exchanger. A

closed loop cooling system with a steam condenser is used to cool the coarse ash and generate low pressure steam. The relatively cooler ash from the primary cooler overflows into the secondary cooler, where ash is further cooled to below 350 °F through a series of cooling bundles. The top section of the secondary cooler houses a set of filters to remove dust from vent gas before venting the clean gas to the downstream of the PCD. The cooler ash is then depressurized through a series of PLDs, reducing the pressure in the coarse ash stream to the desired discharge pressure to convey the ash to ash silos.

The CCAD system is directly connected to the gasifier. As the gasifier is loaded with startup bed material, the CCAD system also is filled with the startup bed material.

5.7.1.2 *Initial Commissioning Plan*

- Leak check and pressure test

In the CCAD system, the first isolation valve is between the secondary cooler and PLD inlet. The cooling sections, which include the primary and secondary coolers and the vent filter, are all directly linked to the gasifier with no provision for isolation. Most CCAD system leak checks and pressure tests are coordinated with gasifier activities. Depressurization of the CCAD system with PLDs and discharge could be tested separately for leaks and pressure retention.

The leak check procedure would check and confirm all connection points are mechanically tight. The initial leak check would use 30 to 50 psi instrument air, followed by further leak checks at progressively higher pressures up to 700 psi. After the leak check, the planned pressure test was at system pressures up to 700 psi, to check for unit pressure holding capability and to find and correct any remaining minor leak sources.

- Unit functional test

In the CCAD system, the vent filter (located above the secondary cooler cooling bundles) back pulse unit is in a sequential and cyclic operation, controlled by a PLC to coordinate backpulsing of four clusters of sintered metal candles. There are sequential control logic programs for transferring solids through the cooler sections and depressurization section.

The CCAD system unit functional test was to check each component on basic functional effectiveness – mechanical, instrumentation, and sequential. After completing instrument and valve loop checks, the major remaining task was to check and test the control logic.

5.7.1.3 *Significant Events*

- Nozzle cleanout, leak check, and pressure test

The CCAD system was divided into cooling and depressurization sections for leak checks and pressure tests. The cooling section consists of the J-pipe connecting the gasifier seal leg to the primary cooler inlet, the primary cooler with imbedded bayonet tubes, and the secondary cooler consisting of a top vent filter, a receiving section for the coarse ash from the primary cooler, and the cooling bundles. The depressurization section consists of the four PLDs, the clinker catcher, and the two discharge valves (dirty and clean shutdown valves). The cooling section was tested along with the gasifier loop, while the depressurization section was checked independently.

Both the J-pipe and the lower section of the primary cooler have numerous nozzles for aeration gas to flow into the coarse ash stream and fluidize the solids. The transfer of coarse ash from the gasifier to primary and secondary coolers is controlled by the degree of fluidization of solids in the J-pipe and primary cooler. It is critically important to ensure aeration gas flow is available and maintained as desired. Before initiating the leak checks, all fluidization nozzles and connecting lines were checked for flow and were blown clean.

When systems are turned over, there could be issues in the incoming lines and nozzles. Water can be left over from hydrotesting of installed lines or they fill with rain water during construction, and lines can be obstructed with

construction waste. Those potential problems were identified by blowing instrument air and fixed immediately before moving forward with leak checks and pressure tests. During the cleanup process, missing or wrong-type gaskets were detected and corrected as part of the system checkout. During the initial flow process, the installation of check valve direction was checked to ensure flow through the lines.

During the leak checks, instrument air flow at low pressures (30 to 50 psig) found many obvious open points, loose connections, and missing gaskets. Those obvious leaking points were fixed immediately.

After leak check and fixing all obvious leaking sources, the pressure test was started with pressure normally stepped up to 100 psig, 300 psig, and 700 psig.

- Unit functional test

The vent filter system at the top of the secondary cooler consisted of four clusters of iron-aluminide sintered metal filter candles. Each cluster contained 26 filter candles. The top head of the vessel and the tube sheet were removed for filter candle installation. The vent filter piping connecting the top of the internal second cyclone to the tube sheet was installed first, then the tubesheet and filter candle clusters were installed. After the installation was complete, the system was prepared for functional tests.

The vent filter backpulse is controlled by a dedicated PLC. The back pulse sequential and cyclic operation were successfully checked and tested in both continuous (timer based) mode and DP (differential pressure limit) mode. The tests included checking all backpulse valve operation in the field and checking the consistency of pressure drop in the accumulator tank during a backpulse. All parameters were tested, including the backpulse valve open timer, timer for the gap between backpulsing two successive clusters, cycle timer, and DP trigger, with positive results confirming their operational status.

The CCAD system is designed with sequential steps in logic for both the cooling section and the depressurization section. The logic covered initial one button setup, initial startup, normal continuous and batch operations, and normal and emergency shutdowns. There were necessary interlocks in both the DCS and SIS for safe operation of the CCAD system. The various logic function blocks were checked and dry tested (with no solids in the process) to the extent feasible. Along with logic checks, all field instruments and transmitters, valve actions, and limit switches were checked. Control valves were initially tuned for desired response with no solids in the process.

After initial functional checks, it was noticed that the original accumulator (backpulse gas source tank) was directly connected to the recycle gas compressor discharge piping distribution network (a similar design to the gasifier PCD backpulse system). The recycle gas compressor discharge header pressure was set based on the recycle gas flow needed to maintain solids circulation in the gasifier. With this setup, the backpulse gas pressure could not be independently adjusted to meet the requirements of the vent filter in the CCAD system or the gasifier PCD. The backpulse pressure was tightly restricted in a range much lower than the recycle gas compressor discharge header pressure necessary for gasifier operations. This range was communicated by the vendor when recalculations were done during functional checks. For both the CCAD system vent filter and the gasifier PCD backpulse accumulators, additional pressure controllers were installed, enabling adjustment of the backpulse pressures independent of the recycle gas header pressure.

There was an issue with venting the accumulator tank when the tank pressure was much higher than desired. This happens when the gasifier pressure is decreased relatively quickly after a trip. During operations at Kemper, field operators dealt with this issue manually during initial operations. Future designs should include an appropriate automatic vent to maintain desired differential pressure between the accumulator tank and the secondary cooler pressure.

For solids handling, reliable solids level measurement is one of the key factors to reliable operation. During later phases of unit commissioning with transfer of cold solids from the gasifier, it was noticed that the continuous nuclear level measurement device showed limited accuracy (figure 5.7-2). The increasing level trend while transferring solids from the gasifier did not match the observed decrease of solids inventory in the gasifier. The decreasing level trend did not match the rate at which solids were being discharged to the ash silos.

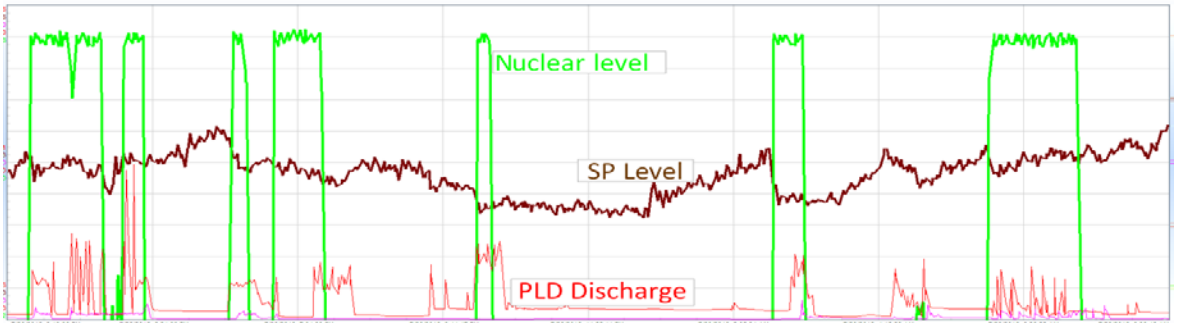


Figure 5.7-2 – Secondary cooler continuous nuclear level measurement

The inaccuracy in level trend could be related to either configuration of the level measurement device (two sources with one detector as the level was measured over 10 ft) or process issues (funnel flow, solids accumulating on one side of the vessel). Regardless of any inaccuracy in quantifying the change in levels, the level measurement was a sufficient indication to allow continued operation. Because the level measurement is critical, the original design included a parallel measurement with a different measurement type. In this alternative, four capacitance level probes were used at different elevations in the receiving section, with the middle two used as low and high working levels. These capacitance level probes never worked at Kemper, despite repeated troubleshooting including replacement of probes, discussions with vendor, on-line calibration, and offline calibration (dipping the probes in sand and in ash from PSDF). No reason for the problem could be found. Similar capacitance level probes worked extremely well in a coarse ash system for nearly 20 years at PSDF. Other instruments in the CCAD system demonstrated good performance.

Despite the high sensitivity of continuous nuclear level measurement and the inoperability of capacitance probes, the system could be operated relatively smoothly with coal feed operation by maintaining the solids level between low and high nuclear level readings instead of a constant value as was practiced at PSDF. An alternative measurement of pressure at the bottom of the secondary cooler can be used as a measure of solids level in the secondary cooler.

- Initial solids loading

Inside the secondary cooler, there are two cyclones in series that separate solids from gas as solids are transferred from the primary cooler to the secondary cooler. The second cyclone handles fines in the coarse ash stream from the gasifier; its seal leg must be prefilled before the system is charged with solids. A batch of fines from the PSDF pilot plant was collected and used for prefilling. A temporary filling device was designed and fabricated. After the dipleg of the second cyclone was sealed, the gasifier was charged with initial bed material (sand) for the first time. The dipleg of the first cyclone was not sealed to start with. It will seal immediately when solids start to transfer from the primary to the secondary cooler, due to the first cyclone's 99% efficiency and the large solids transfer rates from primary to secondary cooler.

- First solids transfer test

A startup solids feeder is used to fill the gasifier with startup bed material stored in the coarse ash silo. The conveying line from the feeder connects to the gasifier seal leg riser. Nominally 120-micron sized sand was used as the startup bed material to inventory the gasifier and CCAD system for the first time. Coarse ash generated from the process when feeding coal to the gasifier will be stored for subsequent use as bed material for the gasifier and CCAD system. With the addition of sand to the gasifier, the lower portion of the seal leg riser started to fill up first and then overflow into the connected J-pipe. The fluidization of the primary cooler was started, then the aeration flow to the J-pipe was initiated to move the solids filling the J-pipe into the primary cooler. After the primary cooler was full of solids, the solids started to overflow into the secondary cooler through the two cyclones, their diplegs, and the seal legs. A build-up of level in the secondary cooler was noticed. At the same time, the pressure difference across the tubesheet of the vent filter unit became noticeable and the filter back pulse unit was acting to maintain the pressure difference in low range. Except for the point level capacitance probe that did not indicate proper level, other instrumentation and valves related to solids transfer and aeration gas flow was demonstrated as designed.

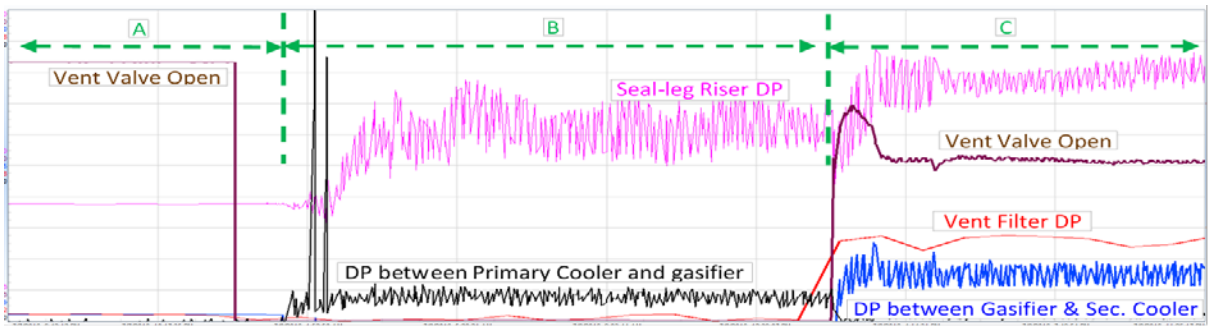


Figure 5.7-3 – Initial solids addition to CCAD cooler

In period A in figure 5.7-3, solids addition has not started, and the CCAD secondary cooler vent filter outlet control valve is fully opened for operational checkout. As expected, when there are no solids in the J-pipe, the CCAD primary and secondary coolers have the same pressure as the gasifier seal-leg, and the CCAD vent filter DP is near zero with clean gas flowing through the filter elements.

In period B, solids addition to the gasifier was started, filling the CCAD primary cooler and J-pipe. When the J-pipe was filled, solids started to accumulate in the seal leg riser. The seal leg riser differential pressure measurement increased until the seal leg riser was filled with solids and started to overflow into the gasifier standpipe. The solids in the primary cooler was minimally fluidized with gas flow through various nozzles in the cone section of the cooler. The vent valve on top of the secondary cooler was in closed position, so the primary and secondary cooler pressures were higher than the gasifier pressure. The differential pressure across the vent filter stayed around zero since there was no gas flow through the filter elements.

At the start of period C in figure 5.7-3, the vent control valve was modulated to control the differential pressure between the gasifier and the secondary cooler. With the vent valve open, gas flow was established through the filter elements. The differential pressure across the filter elements indicated cake build-up on the filter elements and subsequent backpulses.

The secondary cooler was filled with solids up to the inlet and the fluidization flow to the J-pipe was decreased to minimum to prevent solids transfer from the gasifier seal leg. Solids added to the gasifier started to accumulate in various sections of the gasifier up to desired levels. When the gasifier had sufficient inventory, the gasifier was pressurized to about 40 psig to initiate solids circulation.

After the isolation valve between the secondary cooler and PLD inlet was opened, solids started to fill the PLD column and the PLD vent pressure control was set into auto. The conveying gas (nitrogen during startup) was lined up to the clinker catcher and the discharge line, and the flows were adjusted to the desired velocities. The first solids discharge to coarse ash silo by adjusting the last stage PLD pressure went smoothly. The inventory of the CCAD system and the discharge of solids to the coarse ash silo went as expected.

- Solids transfer through CCAD system

After the gasifier standpipe accumulated to a desired level, the gasifier was pressurized to about 40 psig and solids circulation within the gasifier loop was initiated. At the same time, the CCAD system was set to continuous mode to pull solids from the gasifier circulation loop and discharge the solids to the coarse ash silo. As the CCAD was transferring solids from the gasifier, the startup solids feeder was set to continue adding solids from the coarse ash silo back to the gasifier, to hold the standpipe level in a certain operating range. This established an external solids circulation loop to commission the CCAD system.

Solids transfer capabilities through the CCAD primary cooler were tested with adjustments to J-pipe fluidization rates and by controlling the pressure difference between the gasifier and the secondary cooler. It was demonstrated that both parameters could control solids transfer rates in a certain range. The J-pipe fluidization rate modulation has the advantage of wider range of solids transfer rates, which is more convenient for operation. The solids transfer from the

gasifier can be started from idle conditions, modulated as desired, and stopped when the level in the gasifier standpipe is below the setpoint. Later tests during coal feed to the gasifier indicated that the solids can be transferred from the gasifier into the CCAD system at rates up to 84 ton/hour even though the normal required transfer rate is about 12 ton/hour. This high solids transfer rate is beneficial to effectively control the solids level in the gasifier standpipe because the solids level will respond faster to a control action.

The backpulse unit and the vent filter system in the top portion of the secondary cooler worked normally without any issues during solids flow through the CCAD system.

Even though the initial solids transfer and discharge tests were done at relatively low operating pressures, the PLD discharge was commissioned with continuous solids discharge to coarse ash silo. The solids discharge control was preliminarily demonstrated by setting it in auto mode to maintain the level (as indicated by continuous nuclear based level measurement) in the secondary cooler receiver section.

- Hot solids through CCAD system

The CCAD system was tested with hot solids transfer from the gasifier during the initial phase of gasifier heat-up with startup burners, with solids circulation in the gasifier evenly heating the gasifier loop. The startup solids feeder was set in operation to make up for the transferred solids and maintain the standpipe level. During these transfers, the hot solids through the J-pipe and primary cooler served the purpose of curing the refractory. Condensate make-up to the steam drum and tempered water for the steam condenser above the drum were put into service and performed as expected.

5.7.1.4 *Final Summary*

The CCAD system sections and functionalities were commissioned successfully, but during initial commissioning there were limitations to checking for full operability and functionality because some process conditions were different from normal operation:

1. During initial commissioning, the gasifier pressure was limited to low startup pressures, which limited the testing of the depressurization system to low pressure ranges.
2. As startup solids feeder make-up rate was limited to maintain solids level in the gasifier standpipe, the CCAD solids transfer rates were also limited to low to medium range.
3. During gasifier startup heating and refractory curing, the warm solids were transferred through the CCAD cooling system. Because solids rate was limited by the limited solids feeder make-up rates, the CCAD primary and secondary coolers cooling capabilities were not fully tested. Later tests during coal feed indicated the primary cooler and associated steam drum and condenser are capable of handling transfer rates up to 84 ton/hour.

In addition to functional checks during the unit commissioning stage, the CCAD system was successfully checked and tested with startup solids (sand) with a nominal particle mean size similar to that expected from coarse ash generated during normal operation. The CCAD system was successfully commissioned in parallel to gasifier solids circulation and heat-up by withdrawing the bed material from the gasifier through the CCAD system. The first-of-a-kind CCAD system operation and performance demonstration successfully achieved solids transfer through the primary cooler and solids discharge through the PLD at low to medium rates, without encountering any major issue. The tests planned during the initial commissioning operations were completed successfully. Further testing over a wider pressure range, greater solids rate, and higher cooling duty could only be realized during coal feed operation due to limitations on operating conditions during gasifier solids circulation and heat-up.

5.7.2 CFAD

5.7.2.1 *System Overview*

The continuous fine ash depressurization system (CFAD) allows for continuous removal of fine ash during operation. It is designed to cool the fines in the fines receiver at system pressure, then depressurize the fines for discharge to the ash silo. Syngas exiting the gasifier contains fine ash particles and char carbon with a nominal particle size of about 10 microns. The syngas enters the PCD at 600 °F and contains a nominal fines concentration of around 20,000 ppmw. These fines are removed from the syngas by passing through the sintered metal candle filters in the PCD. The fines form a cake on the exterior of the filter elements that is dislodged by backpulsing the elements. As the fines fall from each element in the PCD (FL1106), they are collected in the fines receiver HX1118 located below the PCD vessel. Each gasifier train has two PCDs, and each PCD has a fines receiver and two parallel depressurization PLD trains (FD1120A/B-1 to 6) with a clinker catcher FL1120A/B in each train at the discharge (figure 5.7-4).

In the cooling section of the fines receiver, the vessel is equipped with five stages of cooling bundles. The fines are cooled to less than 350 °F as they flow past the cooling bundles as a moving bed. After cooling, they move to the ash depressurization section, where the fines are depressurized through a series of PLDs to reduce the pressure, then the low-pressure fines stream is conveyed to ash silo.

The PCD, which filters the dust in syngas during normal operation, was fabricated with a steam jacket outside the cone section. The heated cone avoids the formation of condensate in the PCD that could drain into the CFAD system, most likely during gasifier heat-up with startup burners and direct diesel injection.

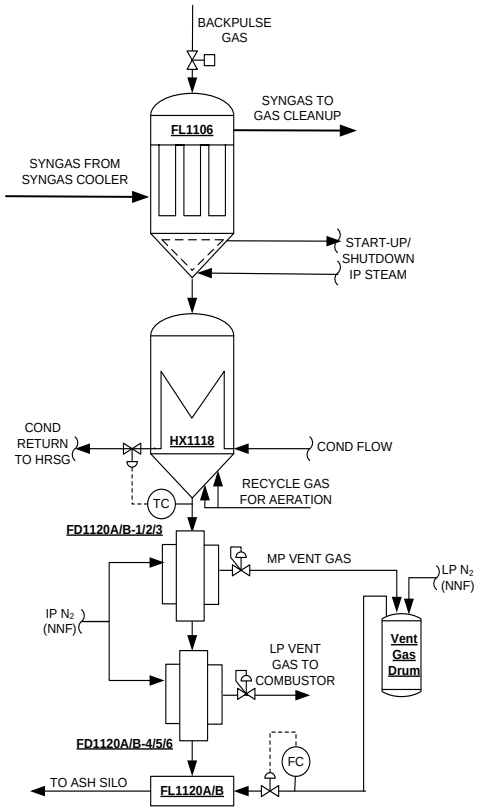


Figure 5.7-4 – The CFAD system for PCD fines cooling and depressurization

5.7.2.2 *Initial Commissioning Plan*

- Leak check and pressure test

Before initiating leak checks, all lines and nozzles were to be blown clean and flows established to ensure no blockages from construction waste, improper check valve direction, or stuck valves. Disconnecting and blowing the lines initially ensured any water left over from hydrotesting and sedimentation were blown off. If water residual was found, the line was to be blown for a considerable time with dry air until the line was dry. During this time, any inoperable or broken instruments and other parts in the line were to be identified, tagged, and fixed before moving forward for leak check and pressure test.

In the CFAD system, the first isolation valve is between the fines receiver and the inlet to the PLDs. The leak and pressure tests of the fines receiver were to be performed along with the gasifier system tests and the depressurization section with the PLDs. The discharge line was to be isolated and leak tested separately.

The procedure set an initial leak check conducted at 50 psi air to ensure the system was mechanically tight with no observable leak. Following satisfactory completion of the leak check, a pressure test was to be conducted in incremental steps up to 700 psig to ensure mechanical integrity of the system at conditions similar to normal operations.

- Unit functional test

The depressurization logic is designed with sequential steps for startup, normal operation, and shutdown. These logic functional blocks were to be tested by simulating process conditions before the introduction of solids. The testing was to confirm the performance of the control sequence, instrumentation, and proper valve function.

- Potential condensation

During initial heat-up of the gasifier with startup burners and direct diesel injection system, the warm flue gas flows through the upper portions of the large PCD vessel. The lower section of the vessel remains at ambient temperature, exposing the cold surface for moisture in the flue gas to condense and form mud upon contacting fines. One of the initial steps, before heating up the gasifier, is to set up IP steam through the PCD cone outer steam jacket and ensure the PCD cone is warmed up to desired temperature before any moisture-containing gas flows through the PCD. One of the objectives of the initial commissioning plans was to evaluate the effectiveness of PCD cone heating in avoiding condensation.

5.7.2.3 *Significant Events*

The milestones in Table 5.7-1 show activities during initial fine ash system commissioning for units in both trains A and B.

Table 5.7-1 – Fine ash system milestones

	TRAIN A	TRAIN B
Blow out and set up all fluidization flows. Establish condensate flow through cooling bundles	10/05/2015	02/04/2016
Dry test depressurization and conveying system logic	10/15/2015	02/13/2016

The CFAD system was leak checked and pressure tested. Basic functional and logic checks confirmed installed mechanical and instrument integrity. The sequence and control logic could be tested only to a limited extent during dry commissioning. During initial gasifier operations with sand circulation, the attrited sand fines carryover to the CFAD system was low and only a basic CFAD system functionality check could be completed. The lower fines carryover

resulted from both lower attrition rates with sand as bed material in the gasifier, and the gasifier cyclone systems being highly efficient. As a result, complete CFAD system operations could be tested only with coal feed to gasifier, which would result in a sufficient amount of fine ash and unconverted char carbon flow to PCD.

During first gasifier heat-up, especially during extended heating with the startup burners (SUBs) and direct diesel injection (DDI) system for refractory curing, the PCD and fines receiver operation conclusively indicated that the PCD cone warmup measures implemented were highly effective and no obvious condensate was observed in the fines receiver.

5.7.2.4 *Final Summary*

Only limited commissioning of the CFAD system could be completed before the first coal feed, because there was an insufficient amount of fines accumulated in the system. The system pressure was too low during initial sand circulation and refractory curing activities for any meaningful depressurization commissioning activities. The CFAD system was leak checked and pressure tested, and basic functional and logic checks were completed. During gasifier heat-up, the PCD cone warmup measures successfully prevented condensation in the PCD cone which would have drained into the CFAD system affecting its operation.

5.8 Ash Storage and Removal

5.8.1 Ash Storage Systems

5.8.1.1 *System Overview: Ash Storage Silos*

The facility has five ash storage silos. Four silos are for storing fine ash, mixed ash, and coarse ash and discharge to the ash mixers. One additional silo, which is smaller than the others, is used to store either sand or coarse ash to replenish ash in the gasifier standpipe. It discharges to the coarse ash feeder.

Table 5.8-1 – Silo design data

	Ash Silos, SI0008 A/B/C/D	Coarse Ash Silo, SI0007
Gross storage capacity	3,076,688 lb	1,710,090 lb
Diameter	31 ft-0 in.	30 ft-0 in.
O. A. height, discharge to dome	118 ft-6 in.	67 ft-3 in.
Silo cone angle	70.21°	69.69°
Maximum design temperature	350 °F	350 °F
Pressure rating	14.9 PSIG	14.9 PSIG
Vacuum rating	-4 in. W.C.	-4 in. W.C.
Inlet type	Multi-Inlet Target Box	Multi-Inlet Target Box
Specified design code	API 620	API 620

Flow studies were conducted by a solids-handling consultant before silo construction. One result was to use 70° cones in the silos to promote mass flow. Mass flow ensures the silos work on a first-in/first-out basis, which is critical to prevent dead zones. The silos have a three-zone fluidization system, that injects nitrogen as needed. Since the ash is conveyed with syngas, the nitrogen fluidization helps remove residual syngas from the ash.

Fine and coarse ash from the CFAD and CCAD system is conveyed pneumatically using mixed syngas. Ash is normally distributed equally between the active silos. Because ash from any CFAD or CCAD system can be conveyed to any silo, crossover vent pipes installed between the silos helped equally distribute the syngas used for conveying. The silos were originally rated for fine ash or a mix of fine and coarse ash.

The fill lines from the ash systems discharge into a target box located on the top center of each silo. The target boxes on the mixed ash silos SI0008A-D have 14 connections for coarse and fine ash, including conveying piping from:

- Coarse ash from the CCAD systems.
- Fine ash from the CFAD systems.
- Coarse ash from the coarse ash feeder.
- Mixed ash from the gasifier bottoms feeders.

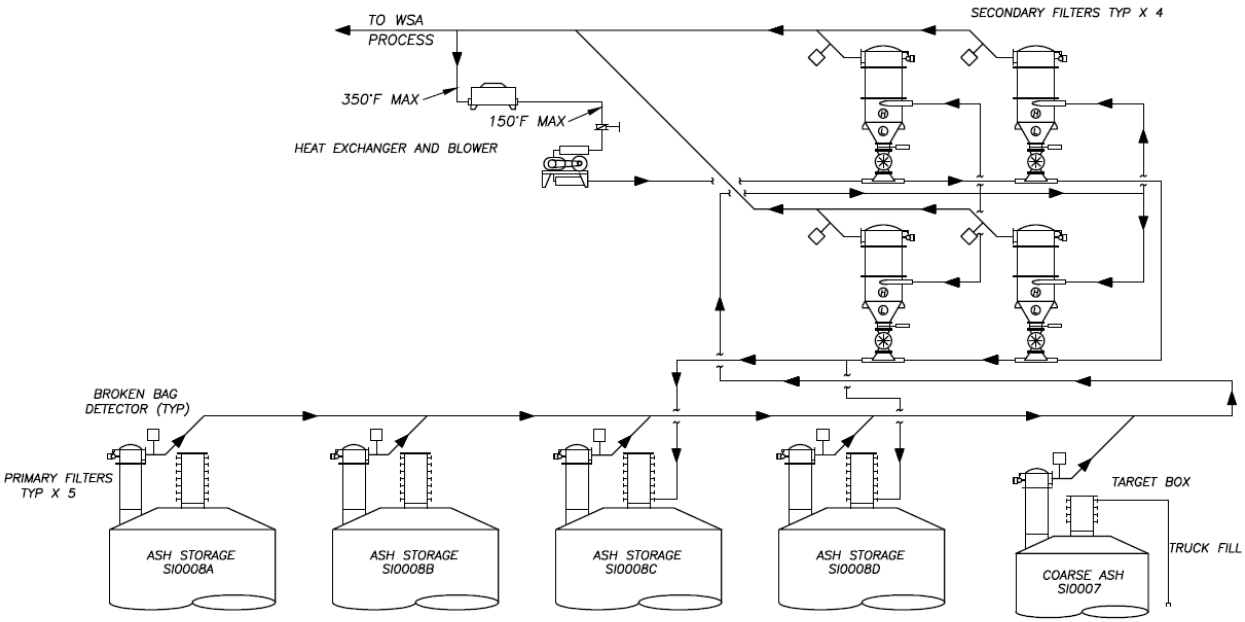


Figure 5.8-1 – Ash storage silo filter system

The target box on the coarse ash silo has only eight connections that connect:

- The four CCAD systems.
- The two gasifier bottoms drain pot feeders.
- One truck fill line for sand for use during initial gasifier loading.
- One fill line from PDAC FD2316B for PDAC testing.

The target box is used to help separate the solids from the conveying gas stream and slow the particles as they enter the silo. This helps reduce the solids loading on the silo's exhaust vent filters. Most of the ash is separated and falls into the silo. The syngas then enters the vent gas filter. The exhaust gas from all five filters is combined in the exhaust gas header.

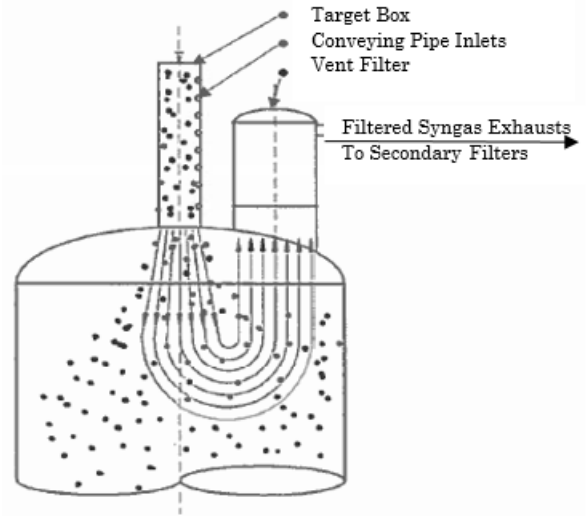


Figure 5.8-2 – Ash and gas flow through target box

The target boxes are cylindrical vessels with interior plates upon which the solids impinge. The space behind the impingement plate has multiple horizontal compartments. When the impingement plate starts to wear, the space is filled with ash solids. The resulting ash-on-ash wear significantly stops further erosion of the steel plate. The top of the target box is bolted in place and can be removed to insert new wear plates if needed. When operation ceased, all the original plates were still in place.

The design pressure rating for the silos is 14.9 psig, to allow operation with the low-pressure vent gas compressor out of service. Under that condition, the discharge pressure from CFAD and CCAD can be increased to send the exhausted syngas either to the waste sulfuric acid system (WSA system) or the flare.

The design minimum operating pressure for the silos is -4 in. W.C. The ash silos are equipped with nitrogen fed, low-pressure regulating valves. If the silo pressure drops below negative 3 in. W.C., the regulator starts to open. Nitrogen continues to feed until the pressure in the silo rises above the set point. The regulators were installed on all five ash silos.

5.8.1.2 *System Overview: Ash Storage Silo Filter System*

The syngas from conveying ash to the silos exits the bottom of the target box. Most of ash settles in the silo. The gas is exhausted through the silo filter system. Each silo has a flange-mounted bin vent filter located on the silo's top dome. The discharge from each of the filters connects to a common exhaust header. The header runs from south to north above the silos.

The crossover pipes described above connect each silo to the silos adjacent to it. They distribute the conveying gas evenly across the active filters, to reduce the gas flow through each filter and improve filtration efficiency. Isolation valves are installed in the crossover pipes and the filter outlets, to allow isolating any silo from the header for servicing. Bleed valves in the crossover pipes can vent the small amount of residual gas remaining in the crossover pipe.

The exhaust gas header continues north to a set of four secondary filters. These filters serve as fail-safes to prevent ash from being sent to the low-pressure vent gas compressor in the event of a bag failure in one of the primary filters. Each of the secondary filters can be isolated with double block valves to allow maintenance on individual filters.

Table 5.8-2 – Silo vent filter design data

	Primary Filters	Secondary Filters
Quantity of units	5	4
Filter type	Bag/cage	50 pleat cartridges
Nominal gas capacity	3000 acfm	2625 acfm
Pressure rating	14.9 psig	14.9 psig
Vacuum rating	60 in. W.C.	60 in. W.C.
Maximum design temperature	350 °F	350 °F
Pressure rating, psig	14.9	14.9
Vacuum rating, in W.C.	60	60
Element size, quantity	6 in. dia X 72 in. Lg. 80 bags	6 in. dia X 55 in. Lg. 21 pleated cartridges
Design temperature	350 °F	350 °F

The vent gas from the secondary filters enters a secondary header, which feeds the low-pressure vent gas compressor. In the event of a compressor outage, operating procedures call for the pressure from the CFAD and CCAD systems to be increased and to bypass the compressor. The silos and filters were specified for a maximum pressure of 14.9 psig to provide sufficient pressure to feed the WSA system directly or to bypass the gas to the low-pressure flare.

5.8.1.3 *Broken Bag Detection and Ash Fines Collection System*

The solids separated from the CFAD and CCAD conveying gas are discharged from the target boxes and primary filters into the ash silo. A broken bag detector was installed at the outlet of the filters before connecting to the outlet header, to warn the operator when the particulate level in the gas exceeds the set point.

The secondary filter conical hoppers have automated knife gate valves at the discharge to minimize gas leakage. Below each knife gate valve is a rotary feeder. A turbo-blower system uses filtered syngas from the header to convey any collected solids from the secondary filters to either ash silo C or D. The system is run once a shift unless a system failure is indicated by a broken bag detector, or a high hopper level is indicated.

5.8.1.4 *Initial Commissioning Plan: Ash Storage Systems*

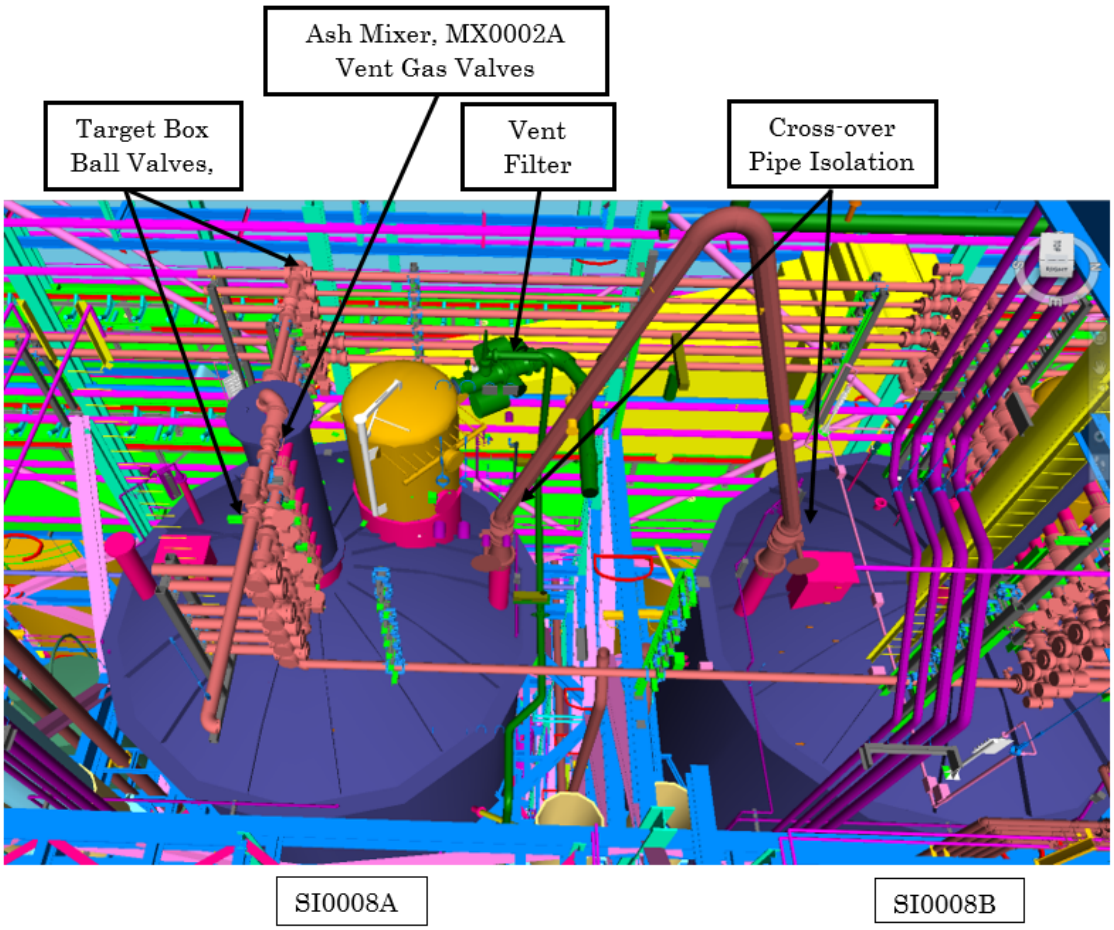
- Silo leak checks and pressure testing

Silos are not normally pressure tested. However, since these silos contain ash and syngas at an elevated internal pressure, testing was required to detect leaks. The ash silos and the filter system were designed for a maximum pressure of 14.9 psig to allow ash systems (CFAD and CCAD) to operate when the low-pressure vent gas compressor was being serviced or unavailable. In those situations, the compressor could be bypassed. The pressure in the CFAD and CCAD systems could be increased until there was sufficient pressure for the syngas to feed the WSA system. This would result in the pressure in the silo increasing to approximately 10 psig.

The original intent was to test the silos and piping as a system, with each silo system tested individually. To pressure test a silo, it had to be isolated from the other silos. This required:

- Closing all the ball valves on the conveying pipes on the target box.
- Closing the ash scrubber vent valve on the target box.
- Closing the bin vent filter exhaust valves to isolate the silo from the vent header.
- Closing the crossover vent valves.

- Closing the fluidizing nitrogen valves.
- Closing the silo discharge valves.
- Installing a seal plate at the silo discharge flange.
- Closing all small diameter nitrogen feed valves.



Aerial View of Silos SI0008A and SI0008B Showing the Target Box, Primary Vent Gas Filters, Conveying Piping, and Vent Gas Piping. Silo SI0007 Uses a Slightly Shorter Target Box Because There Are Fewer Pipe Connections. The Vent Filters Are Identical.

Figure 5.8-3 – Silos SI0008A and SI0008B

A separate procedure had to be developed for each silo system because of the complexity of setting valve positions. The plan was to first pressure test silo SI0007 and simultaneously pressure test the secondary filters and piping.

To pressure test the coarse ash silo SI0007 and parallel ash storage silos SI0008A/B/C/D, an auxiliary air compressor was connected to the sand loading line to the SI0007 target box. Initially in TP1012 Part A, the coarse ash silo, the coarse ash feeder, and secondary baghouses were tested up to 10 psig. Then, the parallel silos SI0008A/B/C/D were lined up to the common vent header from SI0007, one at a time, to be included in an additional pressure test to 10 psig. At completion of these tests, TP1008 Part A, TP1009 Part A, TP1010 Part A, TP1011 Part A and TP1012 Part A were complete and the silos were verified to be gas tight up to design pressure.

The test procedures for this series of tests were:

1. TP1012 Part A, coarse ash silo pressure test:
   - Pressure test of coarse ash silo SI0007
   - Pressure test of coarse ash feeder FD0007 (See section 5.8.4, Coarse Ash Feeder.)
   - Pressure test vent header and secondary baghouse FL0012A/B/C/D
2. TP1008 Part A, Ash Systems Test A:
   - Pressure test of ash storage silo SI0008A and baghouse FL0008A
3. TP1009 Part A, Ash System Test B:
   - Pressure test of ash storage silo SI0008B and baghouse FL0008B
4. TP1010 Part A, Ash System Test C:
   - Pressure test of ash storage silo SI0008C and baghouse FL0008C
5. TP1011 Part A, Ash Systems Test D:
   - Pressure test of ash storage silo SI0008D and baghouse FL0008D

A large compressor provided pressurized air. The sand fill line on the silo was used to connect a hose from the compressor. The system was sealed by closing all valves as described previously. Then an attempt was made to pressurize silo SI0007 to 10 psig. The leak-down rate was monitored.

5.8.1.5 *Significant Events: Ash Storage Systems*

Unit Affected	Significant Event	Date of Occurrence
SI0007	Initial pressure test failure	6/30/2015
SI0007	Silo welds failed NDE.	8/2/2015
SI0007	Welding repairs completed. Acceptable pressure test completed.	8/23/2015
SI0008C	Welding repairs completed. Acceptable pressure test completed.	8/6/2015
SI0008B	Welding repairs completed. Acceptable pressure test completed.	8/23/2015
SI0008A	Welding repairs completed. Acceptable pressure test completed.	8/10/2015
SI0008D	Welding repairs completed. Acceptable pressure test completed.	8/18/2015

The initial leak-down rate exceeded the allowable rate by a large margin. The gaskets below the target box and vent gas filter were suspect. The units were removed to inspect and seal the joints. Seal plates were installed at the silo outlets, but major pressure leak down was still a problem.

During the pressure testing, residual water was found in piping systems connected to the silos. This water was removed, and the piping was blown dry.

- Repairing silo leaks

The gaskets on the target box and vent gas filter were the source of some leakage, but it was clear there was other major leakage. During subsequent pressure tests of SI0007, air could be felt blowing from apparent weep holes in the silo eaves. These were intended to vent welding gas during construction but were never sealed on the inside of the silo to allow the silos to operate at design pressure.

Figure 5.8-4 – Interior view of silo showing weep holes that required seal welding

The silo manufacturer was contacted for repairs.

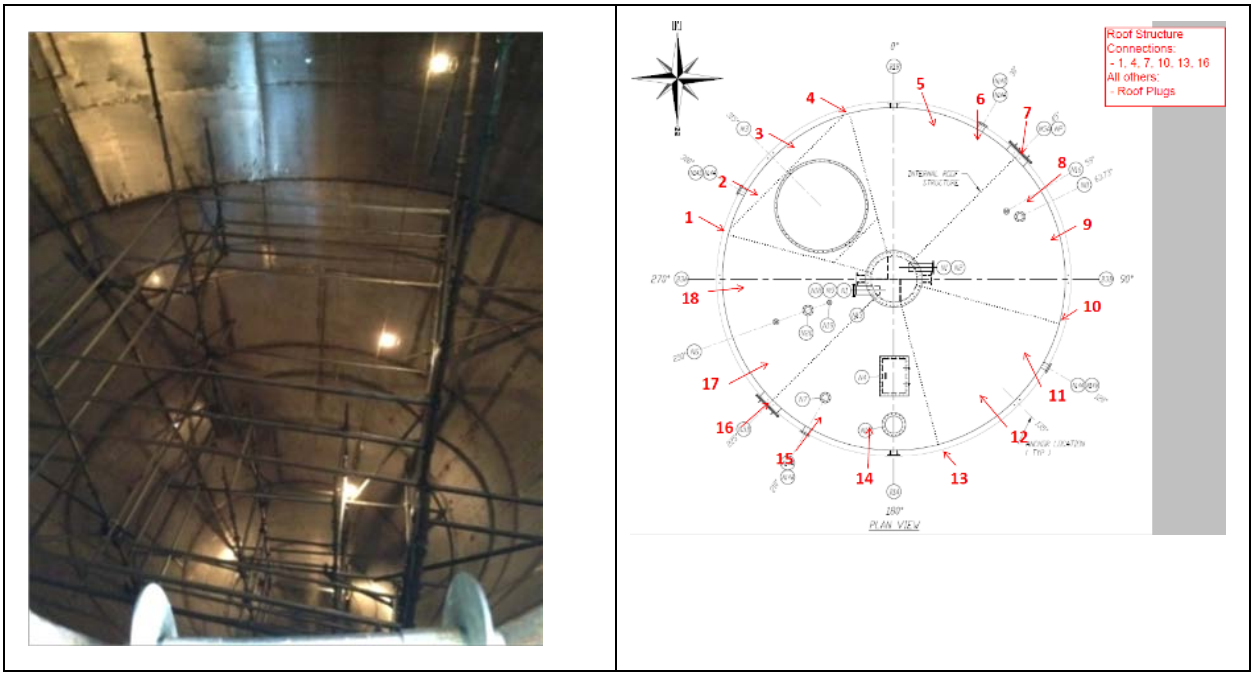


Figure 5.8-5 – View of scaffolding looking down into the silo cone (left). Drawing of silo top showing areas requiring weep hole repairs (right).

The support for the scaffold had to be from the silo cone, and the 70° cones were a considerable challenge. These silos were designed to promote mass flow for a first-in/first-out flow to eliminate stagnant material. Silo cones are at an angle determined by lab testing, which in this case was a recommended 70°. The silos have an inner liner made from stainless steel plate to prevent material from sticking to a rough or rusty surface. This liner had to be protected so ash would not adhere to any surface gouged by the scaffold legs. The repair area was at the intersection of the vertical walls and the silo top, so the scaffold had to be erected against the silo wall. This meant the scaffold legs would be close to the intersection of the cone and the vertical walls. Protective shields were fabricated from wood and placed below the scaffold feet. Scaffolding installation took around 2 wk for each silo.

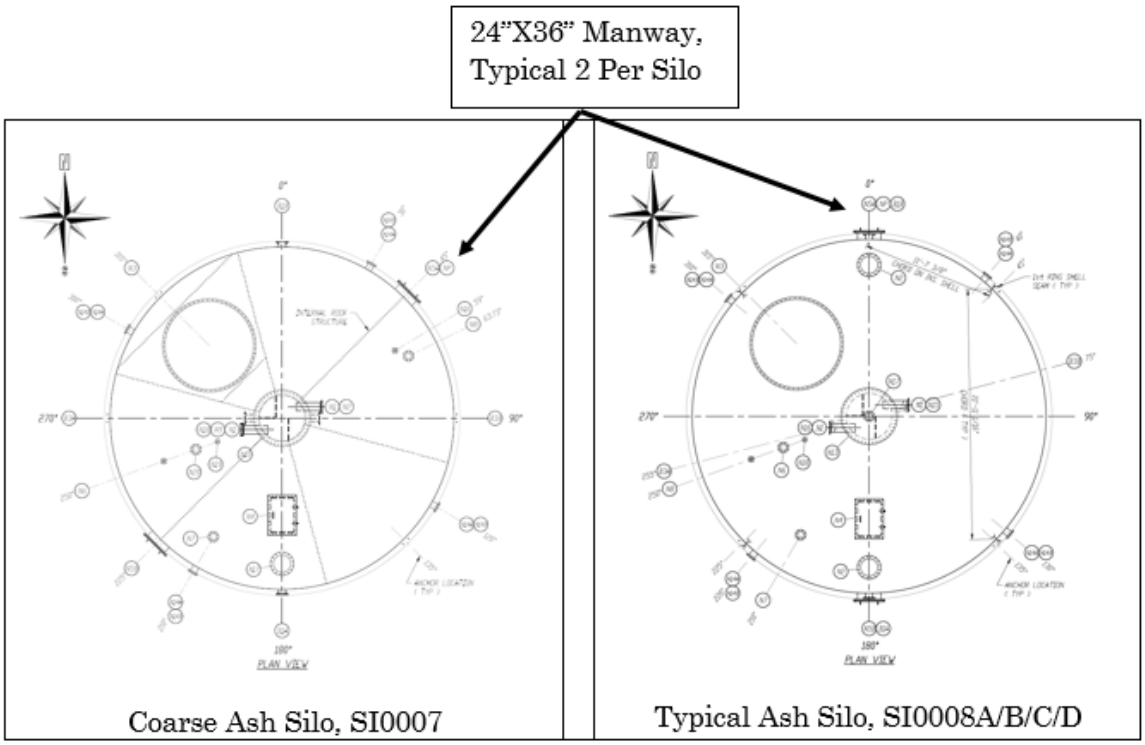


Figure 5.8-6 – Ash silo cross-section

Exhaust fans moved ambient air through the silos to vent welding fumes and to manage the temperature in the silos. Temporary lighting was also installed in the silos.

When the silo vendor completed repairs on the first silo (coarse ash silo), a pressure test was scheduled. The manways were sealed and all the valves on conveying lines and so forth were closed. The vendor supplied a blind flange for the 8-ft diameter vent gas filter opening, to allow sealing the silo roof. The silo then passed the pressure test.

Repairs were being made simultaneously to the other four silos. From discovery to completion, silo repairs took 3 months to complete.

- Removal of hydro water from conveying piping

Residual water from hydro testing was discovered in the conveying piping and several conveying vessels. This was identified during routine system checkout. Low point drains had to be opened or the pipe broken, then compressed gas had to be blown through all legs until the piping was dry. After all lines were confirmed free of liquid and debris, the pressurization and leak testing was completed per the initial commissioning plan.

- Replacement of silo vacuum breakers

The vacuum breakers initially installed on the silos did not perform properly during commissioning. Their purpose was to feed nitrogen to the system to prevent air from entering. The original units were replaced by nitrogen-fed pressure regulating valves. These valves remain closed when the silo interior pressure is higher than -3 in. W.C. They open to feed nitrogen to the silo when the pressure is lower than -3 in. W.C. These units are much more reliable than the original units.

5.8.1.6 *Final Summary: Ash Storage Systems*

Regular quality control inspections are critically important during the construction of the ash silos. Most storage silos are operated at atmospheric pressure. They are not designed to operate with internal pressure or vacuum. Since the

ash silos must operate at an internal pressure up to 14.9 psig or a vacuum of 4 in. W.C., the welds must be inspected to confirm compliance with the engineer's design. Welds should be checked regularly for porosity during fabrication. All vent holes must be welded and be gas tight. Needed repairs were completed successfully before operation commenced. The pressure testing was executed in accordance with the initial commissioning plans.

5.8.2 Ash Conveying

5.8.2.1 *System Overview: Conveying Systems*

The ash conveying systems begin at the outlet of the CFAD and CCAD systems (figure 5.8-7). Ash is conveyed using mixed syngas from the PCD fines receivers and the secondary CCAD coolers. The pressure letdown devices (PLD) in the ash systems bleed off syngas and lower the pressure from gasifier operating pressure to the pressure and gas flow necessary to convey the ash to the silos. Pressure is between 30 and 40 psi depending on the conveying rate of ash. At peak conveying rates, it can reach 60 lb/in^2. The silo pressure is normally between 10 in. and 30 in. W.C., with the exit gas going to the low-pressure vent gas compressor and subsequently to the WSA system.

The system allows ash from any source to be conveyed to any silo. The velocity as the ash enters the conveying system should be maintained at 45 to 60 ft/sec. As the gas/solids mixture travels toward the silo, the conveying gas expands, and the mixture accelerates. To control the velocity of the flow and thus the pipe wear, the conveying pipe inside diameter is increased as the flow approaches the silo. Pipe selection is limited to standard sizes and wall thicknesses. For Kemper, the systems use very heavy wall carbon steel pipe (4 in. XXS, with a 3.152-in. bore) for added erosion allowance at the beginning of the conveying system. In the horizontal pipe run at the top of the silo, the bore is increased to 3.186 in. (4 in. Sch 80). This keeps the flow above the saltation velocity at the transition point but reduces the velocity of the solids being conveyed.

Ball valves with an internal diameter to match the pipe were used to minimize obstructions in the conveying pipe. These bored-to-match-pipe (BTMP) valves feature a straight through bore, which eliminates potential plugging points. The concept and development of this type and configuration of valve had been proven in the gasifier feed piping at the NCCC before it was incorporated into the Kemper design.

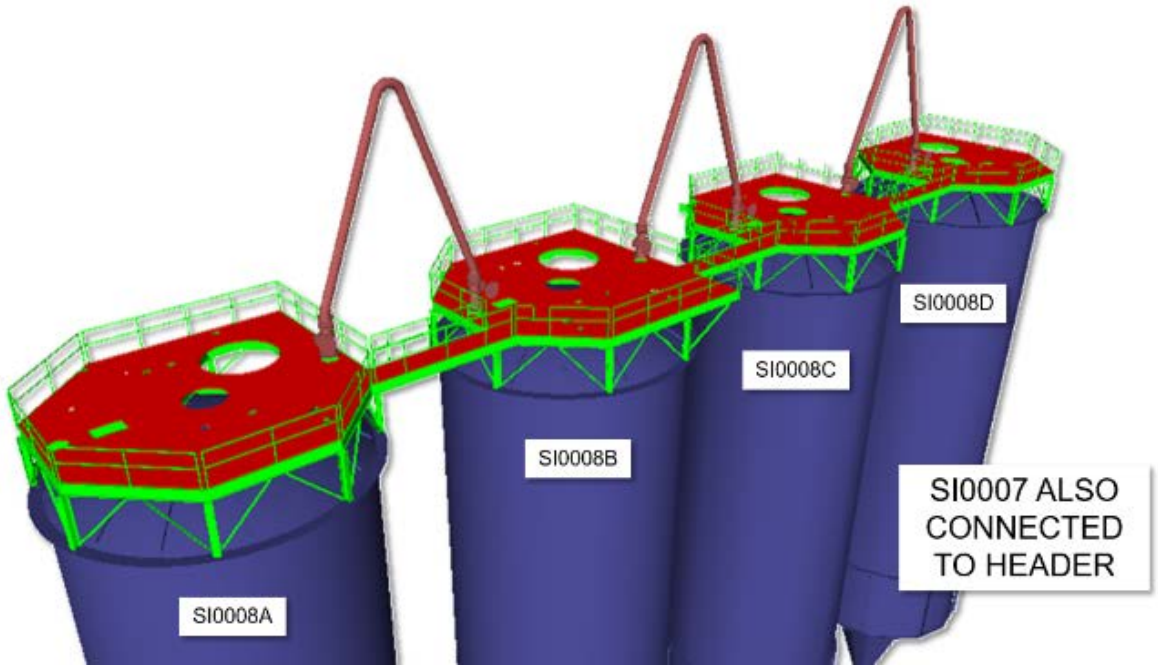


Figure 5.8-7 – Conveying system

Another unique feature of the conveying system is the use of offset conveying elbows, which were also developed and proven at the NCCC. These elbows have a circular chamber into which the offset inlet and offset outlet pipes enter, creating a swirling effect. A nitrogen injection fitting allows injecting additional fluidizing gas if necessary. The amount of booster gas required is greater ahead of long vertical pipe runs and less in horizontal pipe runs. The gas flow is set manually during commissioning.

The conveying lines terminate in the target boxes located on the top center of each silo.

All ash silos are connected by crossover pipes. The crossover pipes have an inverted V-shape so any solids in the gas stream are discharged back into the silo. The crossover pipes help distribute the conveying gas evenly between the silos. Isolation valves allow segregating a silo for service.

The syngas used for conveying continues to the secondary filter system. From there it goes to the waste sulfuric acid system or to the flare.

The operator selects the destination for the ash in the DCS. The operator has flexibility to either segregate the ash by putting coarse ash in one silo and fine ash in the others, or to mix the ash. The DCS identifies the valve settings to mix the ash at two CFADs to one CCAD and selects the shortest routing for the ash selection.

5.8.2.2 *Initial Commissioning Plan: Conveying System*

The conveying piping was already hydro tested before acceptance by the startup team. To prepare for pneumatic testing of the conveying system, the commissioning team was to complete these inspections:

- Checking gaskets.
- Checking for loose bolts.
- Verifying that check valves were installed for proper flow direction.
- Verifying that inline nitrogen filters were installed for proper flow direction.
- Stroking valves and confirming acceptable travel times.
- Verifying valve stroke times.
- Checking pressure controller setpoints.
- Verifying control sequences.

A separate procedure had to be developed for each ash conveying system because of the complexity of setting valve positions.

1. TP1008 Part B, CCAD/CFAD pressure test and airflow, which included:
    - Part 1: Pressure test CFAD trains FD1120A & FD1120B and CCAD train FD1130, including vent lines and PLD vent gas drum DR1043 and conveying lines.
    - Part 2: Air flow from DR1043 through conveying lines to SI0008A.
2. TP1009 Part B, CCAD/CFAD pressure test and airflow, which included:
    - Part 1: Pressure test CFAD trains FD1220A & FD1220B and CCAD train FD1230, including vent lines and PLD vent gas drum DR1043 and conveying lines.
    - Part 2: Air flow from DR1043 through conveying lines to SI0008B.
3. TP1010 Part B, CCAD/CFAD pressure test and airflow, which included:
    - Part 1: Pressure test CFAD trains FD2120A & FD2120B and CCAD train FD2130, including vent lines and PLD vent gas drum DR1043 and conveying lines.
    - Part 2: Air flow from DR2043 through conveying lines to SI0008C.
4. TP1011 Part B, CCAD/CFAD pressure test and airflow, which included:

- Part 1: Pressure test CFAD trains FD2120A & FD2120B and CCAD train FD2130, including vent lines and PLD vent gas drum DR1043 and conveying lines.
- Part 2: Air flow from DR2043 through conveying lines to SI0008D.

5.8.2.3 *Significant Events: Conveying System*

Unit Affected	Significant Event	Date of Occurrence
CFAD, CCAD, piping	Dewatering and drying of conveying system	September-October 2015

Piping low points were full of residual water from the hydro testing. The piping had to be broken to blow water and debris from the lines. Water was found in the PLDs in the CFAD and CCAD systems. After the piping was cleared, many of the gaskets had to be replaced and all bolts needed to be checked to verify correct bolt torque. The PLDs were dried by circulating dry gas through them. See section 5.7, Ash Cooling and Depressurization, for description of dry-out process.

5.8.2.4 *Final Summary: Conveying System*

By the end of commissioning the system was verified ready for operation. All moisture had been removed from the piping. The PLDs had been dried and verified ready for service. The correct gaskets were installed in all flanged connections. Proper bolts and bolt torques were installed and verified.

The PLDs must not get wet during pressure testing. Preferably, pressure testing should use compressed gas. If hydraulic testing is performed, the PLDs must be protected either with blinds or by removal. The piping must be verified water-free before commissioning.

Many of the conveying elbows were in inaccessible locations. All the elbows use some booster gas, with the gas flow controlled by a needle valve or other control device. It is important to locate the booster gas control valves in a valve station where the operator or engineer can reach them without scaffolding.

Routing conveying piping with the minimum number of bends is crucial to reduce conveying pressure. As conveying pressure increases, the terminal velocity of ash increases and creates more wear in the pipe and valves. The conveying routes should be determined early in design to plot the best path.

5.8.3 Ash Mixers

5.8.3.1 *System Overview: Ash Mixers*

The facility has four ash mixers, one under each ash silo (SI0008A – SI0008D). Layout requirements dictated 60-ft chutes, declined at a minimum angle of 60°, to connect the silo discharge to the ash mixer.

A de-inventory chute is connected to the discharge of each of the 12 coal feed storage bins (coal de-inventory line in figure 5.8-8). These chutes are declined at a minimum angle of 60°.

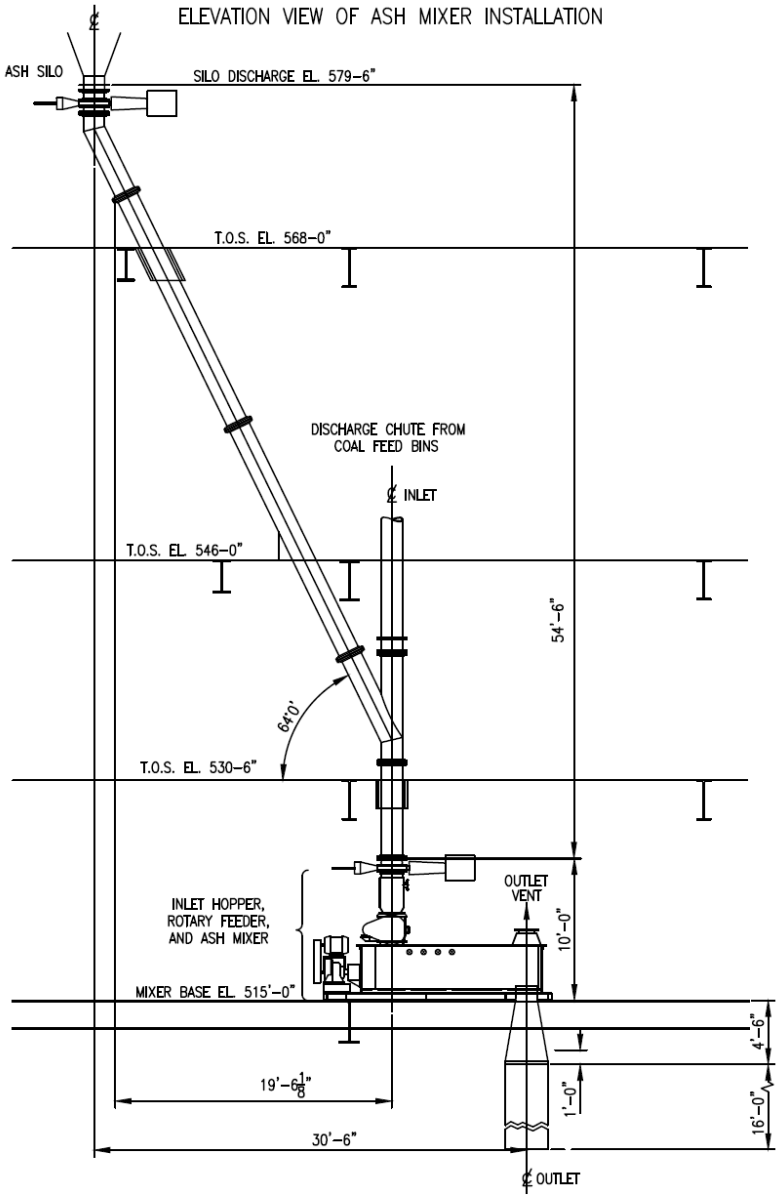


Figure 5.8-8 – Ash mixer elevation view

The discharge from the coal feed storage bins was distributed as follows:

Mixer A received pulverized coal from:

- SI1110A
- SI1110B
- SI1210A
- SI1210B

Mixer B received pulverized coal from:

- SI1310A
- SI1310B

Mixer C received pulverized coal from:

- SI2110A
- SI2110B

Mixer D received pulverized coal from:

- SI2210A
- SI2210B
- SI2310A
- SI2310B

The design throughput rate for each ash mixer is 160 ton/hr. The feed to the mixers is continuous, stopping only for truck changes. Feed rate is controlled by a variable speed rotary feeder. The design criteria specified a temperature of 350 °F.

The mixers have twin counter-rotating shafts. Spur gears are in an oil-bath housing to synchronize the shafts. The shafts are made of square steel tubing and have welded lugs to allow attaching trapezoidal steel paddles. The paddles have wear resistant facing material. The paddles are installed at an angle so that as the shafts rotate, the ash moves through the mixer. The inside of the mixer is coated with an anti-corrosion, anti-stick coating.

For ash feed, an orifice type slide gate is installed at the discharge of each ash silo. Initially this valve was operated in an on/off configuration. The valve remained closed with the chute empty unless ash was being removed from the silo.

Ash flows down an 18-in. diameter chute to the ash mixer. A second orifice valve is located at the bottom of the chute. A small surge bin provides a mounting location for a level control to sense the flow of material.

The flow of solids to the mixer is controlled by a variable speed rotary feeder. The rotary feeder uses a floating shoe — a floating inlet that allows for differential expansion when high-temperature material is fed to the ash mixer. The clearance is set cold and allows the rotor to expand without seizing against the housing.

The mixers have four spray headers. The water supplied to the first three headers is cooling tower make-up from the reclaim sump. A flow controller is provided to maintain flow in accordance with the settings in the DCS. The fourth spray header was a drilled pipe without nozzles. Blow-down from the vent gas scrubber is disposed in the mixer. The vent gas scrubber is also supplied from the reclaim sump. The combined flow is designed to yield the final ash moisture required.

The four ash mixers are aligned in one north-south row. A single drive-through lane was provided for ash trucks. A system of traffic control lights is used to control traffic. The operation was controlled initially from the central control room. An operator at the mixer site monitors the activities and is in radio communication with the control room.

The mixers are started and stopped as necessary to fill and move trucks. Ash is transported to an area at the mine designated as an ash fill.

- Mixer vent gas scrubber/condenser

Steam is released when the moistening water contacts the hot ash, so a vent scrubber is provided to collect water vapor and fugitive dust from the ash mixer. There is a vent gas hood in the mixer top cover above the discharge. A duct connects the vent to a blower located on the floor above the mixer. The vent blower feeds a small venturi scrubber and a condenser. The quenched gas is vented to the ash silo from the mixer.

The condensed water containing a small amount of solids is mixed with the spray water in the ash scrubber tank. The fourth manifold is provided in the mixer to receive the very dilute slurry and spray it into the ash. The flow rate is normally set to 80 gal/min and can be varied up to 100 gal/min.

The vent blower is equipped with both a variable speed drive and a discharge damper to allow it to operate over a broad range of back pressures while maintaining a nearly constant gas flow. It is designed for a flow of 300 acfm at pressures ranging from 30 in. W.C. to 60 in. W.C.

Nitrogen is fed through a multi-nozzle header in the ash mixer discharge chute above the flexible section of the chute. The feed of nitrogen to the discharge chute minimizes inducing air into the silo. A mechanical flow controller regulates the flow of nitrogen to a constant pre-set flow of 300 acfm.

Since the pressure in the silo can vary depending on operating conditions, a flow transmitter at the blower inlet measures gas flow and modulates a discharge damper at the blower outlet to maintain constant flow.

- Normal operation - moistening ash

Two operating modes are pre-programmed in the DCS: one for ash and one for coal. Based on preliminary test data from the PSDF at the NCCC, the water to solids ratio was set at 25% for ash and 30% for coal. The feed rate for solids is controlled by varying the speed of the rotary feeder. After the ratio is set in the DCS, a flow controller sets the water rate. The operator has the option to set each feed separately. Each mode has a start sequence, stop sequence, ESTOP sequence, and washout sequence.

The normal mode of operation is to dispose of ash. As shown in figure 5.8-9, each ash silo, SI0008A – SI0008D, has a manual knife gate valve for maintenance. This is open except during maintenance. Directly below it is the orifice style gate valve designed to open and close through a column of material.

By design, when the mixer is started the upper orifice valve opens and fills the chute. The level control in the hopper signals when material is present, and, after a time delay, the rotary feeder starts, and the lower valve opens. As the lower valve opens, the water control valves begin to open, and the sprays activate. A shutdown cycle closes the upper valve and drains the chute when the truck loading operation is complete.

The cycle was first simulated without material. During commissioning of the dryers, the mixers were operated on pulverized coal. Ash was not available until after the first feed of coal to the gasifiers.

- Alternate operation – emptying the coal feed storage bins

In order to have the dryer systems available to prepare coal for the first coal feed to the gasifiers, commissioning began well ahead of first coal feed. One function of the ash mixing system is to drain the coal feed storage bins when preparing for a shutdown. During commissioning of the dryer systems, the dried coal was sent to the coal feed storage bins. Initially, lignite was disposed in the ash conditioners, which had to be emptied as the silos became full, so the lignite was used to establish the preliminary operation of the mixer. Eventually, this system would test the coal feed system as well as the dryers.

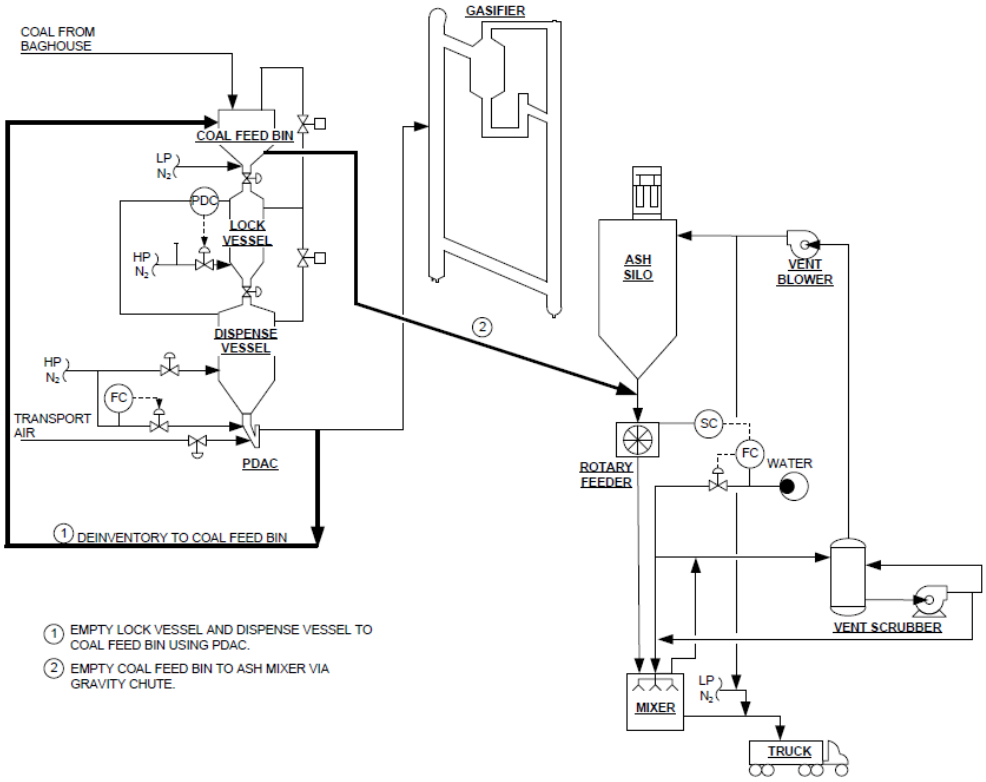


Figure 5.8-9 – Emptying the coal feed system

When the de-inventory operation is selected in the DCS, the upper orifice valve located under the ash silo remains closed. The manual knife gate valve located at the top of the bypass chute (located in the chute between the coal feed storage bin and the gasifier coal feed lock vessel) is opened. The lower orifice valve above the rotary feeder operated automatically as in the normal mode.

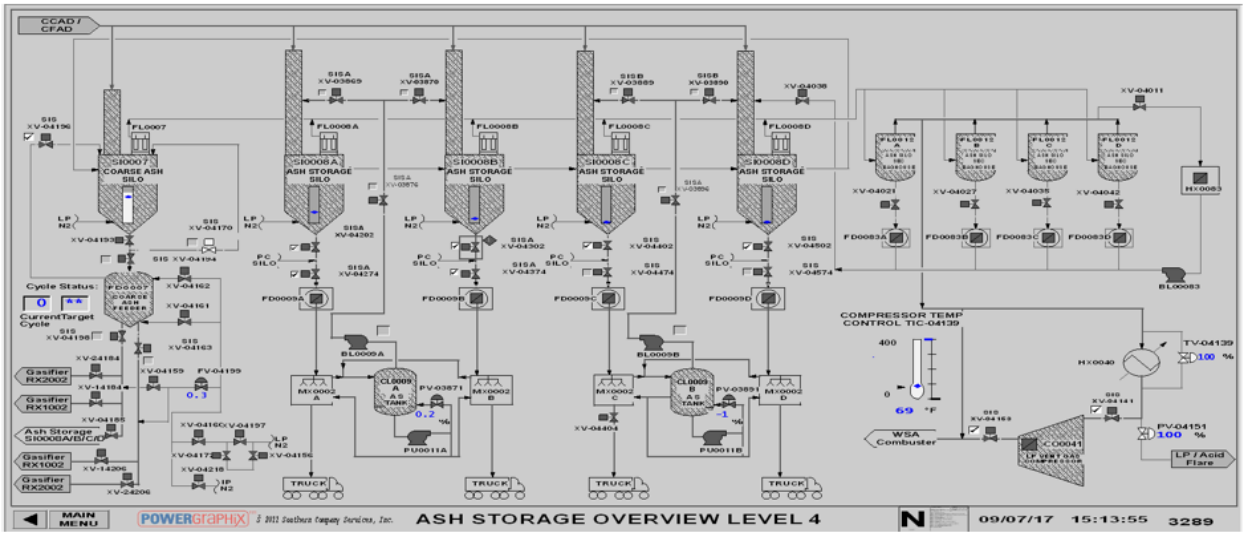
During normal operation, the preferred method for emptying the coal feed bin is to feed the coal to a gasifier until low levels in the feed bin and lock vessel are achieved. In this case, the lock vessel will be empty, but some limited amount of lignite will remain in the dispense vessel. Any residual material remaining in these vessels is purged using the PDAC system to blow it back up to the coal feed bin. This material is then emptied from the coal feed bin through an orifice valve located in the discharge chute. This system can be used when an operational upset occurs and the bin and conveying vessels must be emptied of material (figure 5.8-9).

5.8.3.2 *Initial Commissioning Plan: Ash Mixers*

A separate procedure had to be developed for each ash mixing system because of the complexity of setting valve positions and flow control valves. The test procedures had multiple steps to commission the systems in each of the modes. The procedures used were:

1. TP1008 Part C, Ash Systems Test A, which included:
    - Part 1: Dry cycle of ash mixer MX0002A in ash deinventory mode.
    - Part 2: Dry cycle of ash mixer MX0002A in coal deinventory mode.

2. TP1009 Part C, Ash System Test B, which included:
   - Part 1: Dry cycle of ash mixer MX0002B in ash deinventory mode.
   - Part 2: Dry cycle of ash mixer MX0002B in coal deinventory mode.
3. TP1010 Part C, Ash Systems Test C, which included:
   - Part 1: Dry cycle of ash mixer MX0002C in ash deinventory mode.
   - Part 2: Dry cycle of ash mixer MX0002C in coal deinventory mode.
4. TP1011 Part C, Ash System Test D, which included:
   - Part 1: Dry cycle of ash mixer MX0002D in ash deinventory mode.
   - Part 2: Dry cycle of ash mixer MX0002D in coal deinventory mode.



DCS Screen Showing the Ash Silos, Target Boxes, Silo Vent Filters, Secondary Filter System, Coarse Ash Feeder, Ash Mixers, And Vent Gas Scrubber System.

Figure 5.8-10 – DCS ash storage overview

5.8.3.3 *Significant Events: Ash Mixers*

Unit Affected	Significant Event	Date of Occurrence
MX0002A	Ready to accept ash from gasifier A	11/2015
MX0002B	Ready to accept ash from gasifier A	11/2015
MX0002C	Ready to accept ash from gasifier B	2/2016
MX0002D	Ready to accept ash from gasifier B	2/2016

The ash mixers use a single motor and a gear reducer to drive dual counter-rotating mixing shafts. The motor/gear reducer connects to one of the shafts. Spur gears in an oil-bath housing drive the second shaft. The shafts rotate at a constant speed.

The design criteria specified an ash temperature of 350 °F based on previous operating experience. The rotary feeder used a floating shoe design to compensate for thermal expansion due to high temperature differentials between the rotor and the housing. The initial clearance was set per the manufacturer's recommendation.

Each system was operated in dry cycle mode. The manual valves that isolate the coal feed storage bin, LP nitrogen purges, and water supply were kept closed. The DCS automated valves could be cycled as part of the sequence operations. The actual operation sequences in the DCS were tested, and the graphics were reviewed for correct links and necessary information.

The large orifice valves used to control ash flow in the system were stroked to verify correct operation. Stroke times were measured and recorded. The ash mixer lower knife gate valves took an excessive amount of time to open and close during the start and stop sequences. Changes were made to the control valves to increase gas flow and reduce stroke time.

The initial plan was to dry run the ash mixers while pressure testing the silos. Because silo repairs were underway (see section 5.8.1.5), the early commissioning tests were conducted separately. While coarse ash silo SI0007 was being prepared for pressure testing, ash mixer MX0002A was being readied for an operational run. These commissioning tests were run without ash and coal and were used to verify system operation before receiving coal or generating ash. The operation was conducted from the central control room.

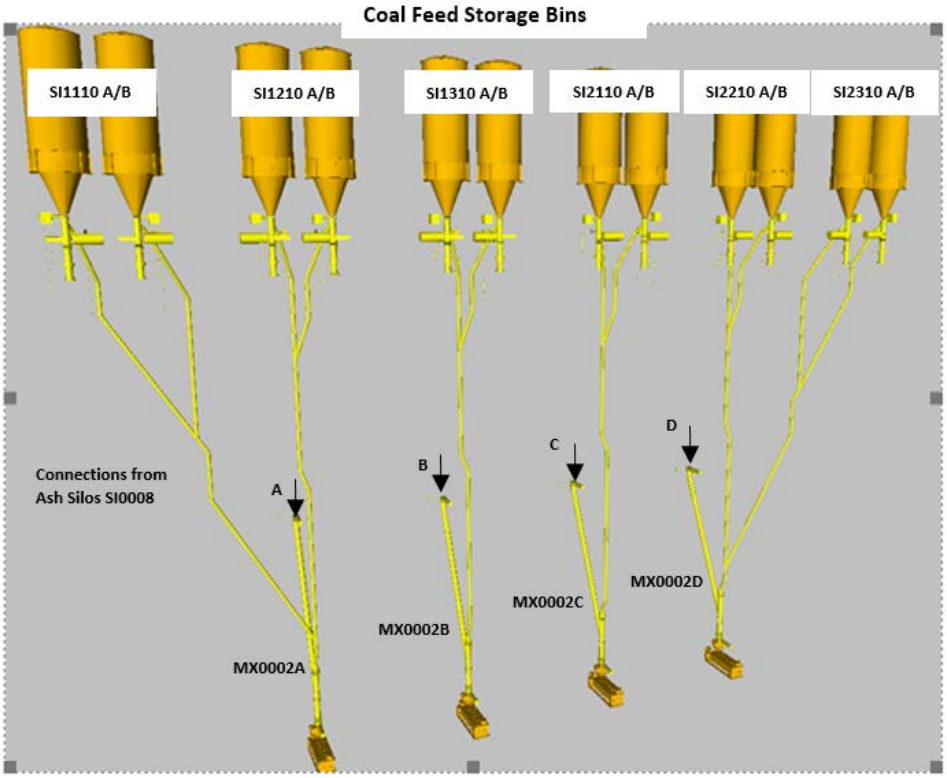


Figure 5.8-11 – Coal feed storage bins

The ash mixing system location was dictated by the need to minimize conveying distance between the coal feed storage bin/PDAC feed system and the gasifier feed nozzles. The ash mixer must discharge into the center of the truck bay. These two conditions dictated that the ash silos be located one bay west of the truck bay. A 60-ft chute, declined at a 60° angle, was required between the ash silo outlet and the feed hopper on the mixer (figure 5.8-9). This resulted in excessive aeration of ash, creating dust problems as the ash flowed into the mixer and went around the nozzles without getting moistened.

The ash mixing systems were in the middle of the Kemper facility. In upset conditions dust was released, resulting in a housekeeping issue. Because of poor moisture control, ash trucks were occasionally full of free water. Despite numerous adjustments, process improvement was limited during the commissioning period.

Traffic control was difficult because of the single lane layout. Although there were four mixing stations, it was impractical to load more than one or two trucks at a time. The outside operator did not have a proper work station to oversee multiple trucks being loaded simultaneously and the four-truck long loading bay did not give an adequate view of the trucks during loading. The DCS controlled remotely, making adjustments difficult in a dynamic environment.

Initially, the mixers were tested using pulverized coal generated during the commissioning of dryer systems. This allowed tuning the dryers before first coal feed to improve plant performance. The dry coal produced in the dryer trials was stored in the coal feed storage bins. The steeply declined de-inventory chutes from the silos were used to feed a rotary feeder located on the mixer inlet. Unstable flow made it difficult to regulate the moisture content of the pulverized coal. Ash flowing through the long chute (figure 5.8-12) from the coal feed storage bin tended to form plugs in the area around converging chutes. When this occurred, the flow of solids would stop, and the truck would flood with water. When the plug broke free, it would either trip the rotary feeder on overloads or flood the mixer with solids. Since the mixer was empty, the solids would pass through the mixer without getting wet.

One approach to the problem was to install curtains inside the mixer to help force the dust down to the rotating paddles and below the spray headers (figure 5.8-12). These were not effective because the curtains were easily deflected. Rigid curtains could not be used without interfering with the rotating paddle assemblies.

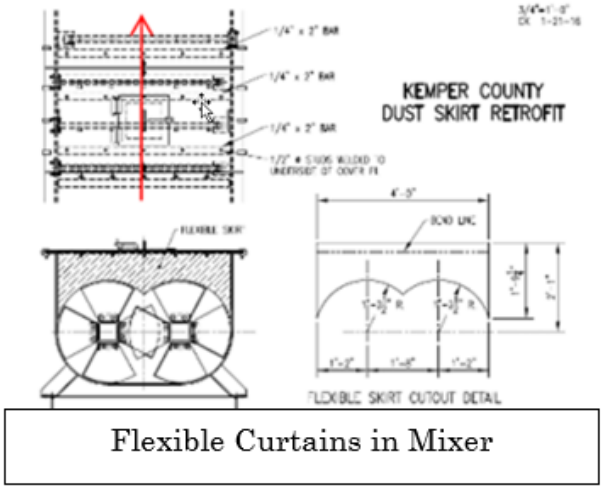


Figure 5.8-12 – Curtains installed in mixer

Two 7-headed fogging nozzle assemblies were installed in the mixer, aimed counter-flow to the solids. Their purpose was to create a fog bed in the top of the mixer.

Two 7-headed nozzles also were installed in the mixer discharge chute. See figure 5.8-13. The wide-angled nozzles were aimed diagonally toward each other to create fog in the discharge chute where dust would travel through. The fog helped reduce the amount of dust, but effectiveness was limited because there was no mixing with ash.

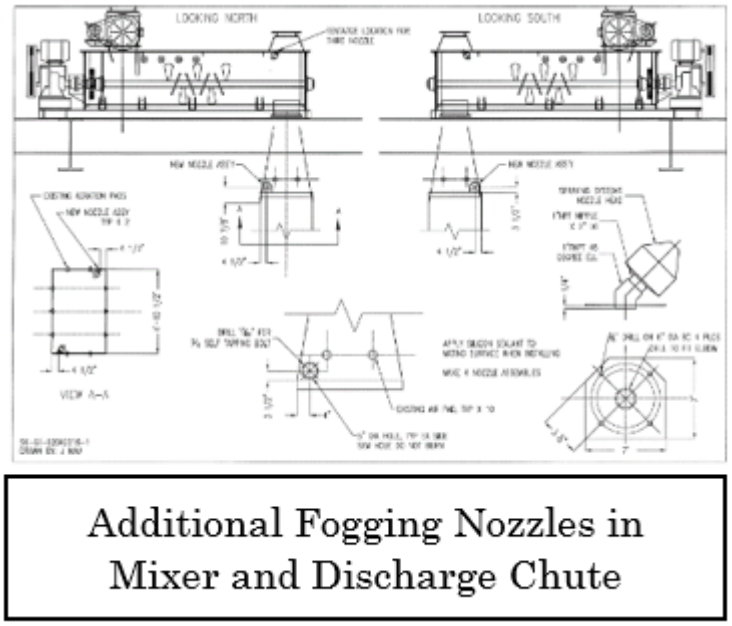


Figure 5.8-13 – Fogging nozzles

Although fine water particles are usually effective attaching to solids, they were ineffective on the pulverized coal. During subsequent trials, the nozzles were reused with limited improvement.

When coal feed began, modifications to the ash mixers continued.

At this time, it was no longer necessary to use the coal feed storage bins to continue testing the dryers. The dryers were used to prepare coal as fuel for the gasifiers. Modifications were completed to add positioners to the throttling valves in the coal feed storage bin de-inventory chutes.

5.8.3.4 *Final Summary: Ash Mixer Commissioning*

The multiple operating sequences for ash mixing were successfully tested and checked out during the commissioning period. There were no major DCS issues, but multiple graphics issues were discovered and corrected. Each of the four ash mixers was tested to operate in sequence mode and graphics updates were checked. This system was not modeled at the operator training simulator, so this was the first checkout opportunity. Testing the ash mixing system on the pulverized lignite was challenging but provided valuable operating experience for commissioning the lignite dryers and pulverizing systems. It also allowed commissioning the pyrite removal system in the coal mill loop.

The ash mixers could not handle the wide range in fines they had to process. Coarser material supported better operation. The fine material tended to stay suspended above the nozzles and flow through the mixer. Changes were made to improve the operation. Operation of the mixers remained challenging when lignite feed to the gasifiers commenced and the ash mixer operation switched to gasifier ash. System improvements continued during initiation of the gasifier operation.

5.8.4 Coarse Ash Feeder

5.8.4.1 *System Overview: Coarse Ash Feeder*

The coarse ash silo is used to keep an inventory of coarse ash or sand for startup. Engineered sand is used for fluidization tests during initial startup of the gasifier, and for the initial circulating bed material. The initial load of sand is delivered by self-unloading, pneumatic trucks. There is a 4-in. truck unloading pipe and connection point near the

north end of the drive-through bay. The conveying pipe rises through the structure and terminates in the target box on the coarse ash silo.

Figure 5.8-14 – Coarse ash feeder and conveying gas manifold

After the initial operation of either gasifier on coal, there is an adequate amount of coarse ash in the silo to not need sand. Each of the four CCAD systems and the two gasifier bottoms feeders have nozzles in the target box. This allows adding coarse ash to the silo when necessary after initial operation. The silo can be refilled through the truck fill line if needed after the initial fill.

The Coarse Ash Feeder is located below the Coarse Ash Silo and is used to unload the silo. An 18-in. diameter chute from the silo reduces to an 8-in. expansion joint and an 8-in. sliding disc valve on top of the feeder. The sliding disc valve is the pressure seal for conveying.

The feeder is an ASME Section VIII pressure vessel with these features:

- 135 cu ft capacity
- Rated for 750 psig at 350 °F
- Carbon steel construction
- 1/8-in. corrosion allowance
- 72-in. diameter, 60° cone
- O.A. height 18 ft -11 3/8 in.
- One 3-in. discharge pipe
- One 6-in. discharge pipe

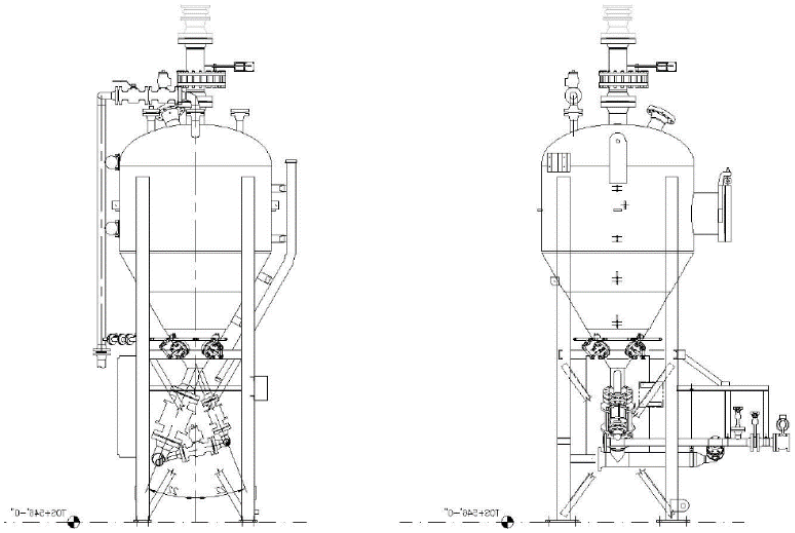


Figure 5.8-15 – Coarse ash feeder diagram

The coarse ash feeder was originally designed for four operating modes:

a. Startup Mode, 3-in. pipe: Fill either gasifier A or gasifier B using the 3-in. pipe with the gasifier near atmospheric pressure, using low-pressure nitrogen. Conveying rate: 12,000 pph.

b. Startup Mode, 6-in. pipe: Fill either gasifier A or gasifier B using the 6-in. pipe with the gasifier near atmospheric pressure, using low-pressure nitrogen. Conveying rate: 69,000 pph.

c. Normal Mode, 3-in. pipe: Fill either gasifier A or gasifier B using the 3-in. pipe with the gasifier at operating pressure, using intermediate pressure nitrogen. Conveying rate: 12,000 pph.

d. Purge Mode, 6-in. pipe: Send coarse ash to one of the mixed ash silos for disposal in one of the ash mixers. This system uses low-pressure nitrogen. Conveying rate: 69,000 pph.

Multiple modes of operation and safety requirements made the system complex. The low-pressure side of the system had to be isolated from the high-pressure side of the system. Large relief valves were required to protect the low-pressure side of the system from gas flows if there were failure of the valves that separated each half of the system.

When a gasifier is being loaded initially, the 6-in. pipe is normally used because the feeder can convey 69,000 lb/hr in this configuration. The 3-in. pipe was designed to allow adding material to the gasifier while in gasification mode at high operating pressure. The feed rate in the high-pressure configuration is limited to 12,000 lb/hr because of the 3-in. pipe size and nitrogen consumption limitations.

5.8.4.2 *Initial Commissioning Plan: Coarse Ash Feeder*

The initial commissioning plan was to load engineered sand into the coarse ash silo from pneumatic transport trucks then use the sand for initial circulation and fluidization tests. By using the coarse ash feeder to feed the gasifier, initial tests would verify the system could operate at design rates to fill the gasifier. The CCAD system was to be operated to return the sand to the silo and close-loop the test. This was an opportunity to test CCAD operation and make initial gas flow adjustments.

The conveying vessel and piping were to be pressure tested before conducting conveying tests. Pre-operational checks found several key instruments were not installed. The missing parts were ordered and installed.

The test procedures used for this series of tests were:

1. TP1012 Part A, Coarse Ash Feeder Pressure Test, which included:
    - Initial pressure test of coarse ash feeder FD0007.
2. TP1012 Part B, Coarse Ash Feeder Pressure Test and Dry Cycle, which included:
    - Pressure test of coarse ash feeder FD0007 and conveying lines to silos.
    - Dry cycle and air flow of coarse ash feeder to ash storage silos in purge mode.

5.8.4.3 *Significant Events: Coarse Ash Feeder*

Unit Affected	Significant Event	Date of Occurrence
FD0007	Complete TP1012	9/2015
FD0007	Initial operation putting sand into gasifier A	11/2015
FD0007	Initial operation putting sand into gasifier B	2/2016

A final design review was conducted before initial operation of the system. The review showed that the fluidization and pressurization controls, and the operating sequence for the coarse ash feeder, required modification. The vendor developed the revised piping and procured the required pressure control valves.

One of the major design challenges of the coarse ash feeder was the range of operating conditions. The feeder had to operate on low-pressure (LP) nitrogen for the initial filling of the gasifier. It then had to operate on intermediate pressure (IP) nitrogen for adding coarse ash to the gasifier while in gasification mode. The process hazard analysis (PHA) review findings resulted in several changes during commissioning.

The main PHA goal was to protect the low-pressure side of the system from the high-pressure side. Check valves to prevent backflow were installed in the pipe connecting the two nitrogen sources, in addition to the isolation valves.

A flow-restricting orifice was installed in the 3-in. piping upstream of the transition to the 6-in. piping to limit gas flow in the event of a valve failure in IP nitrogen supply. The pressure safety valve provided with the feeder was replaced with a much larger 10-in. x 14-in. unit to protect the 150-lb rated 6-in. piping. The two piping systems entered the gasifier through a special fitting that resembled a ram's horn. One leg adapted the 3-in. conveying pipe and one leg adapted the 6-in. pipe leg.

To completely isolate the low-pressure 6-in. piping from the high-pressure 3-in. piping, a spectacle blind was installed upstream of the two isolation valves. A bleed was installed between the isolation valves to vent any leak-by gas. The spectacle blind must be closed during high-pressure gasifier operation.

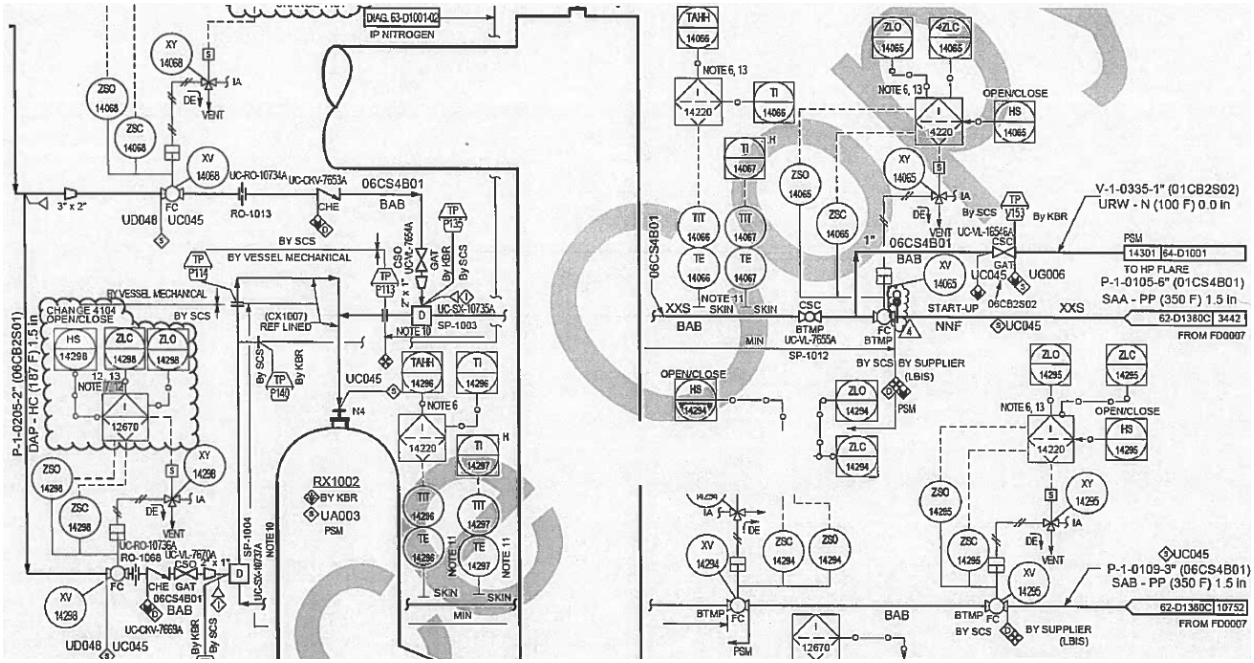


Figure 5.8-16 – View from P&ID of coarse ash feeder; 3-in. and 6-in. piping to gasifier

Modifications were also required to the gas distribution on the conveying vessel. In a semi-dense phase system such as the coarse ash feeder, the distribution of conveying gas between the top of the vessel and the conveying pipe is important. If the pressure in the vessel exceeds the pressure in the conveying pipe, an overfeeding condition can result and plug the line downstream of the vessel. The gas ratio must be managed to prevent plugging and to maximize the conveying rate. The controls systems had to be redesigned to provide the proper pressure balance.

As modifications were being completed, a pressure test indicated that the fluidizing pads in the vessel cone were not flowing properly. When the pads were disassembled and removed, they were wet and discolored. Replacement pads were ordered. Dry gas was circulated through the vessel and the piping.

After the pads were replaced and the system was dried, sand was circulated through the system. Excessive wear started to cause premature elbow failure. The elbows were modified with field fabricated wear-backs designed for the operating pressure, resolving the wear issue.

Despite the modifications, the conveying system was not able to meet the 69,000 lb/hr design conveying requirements. It could load the gasifier at a reduced rate.

5.8.4.4 *Final Summary: Coarse Ash Feeder*

The conveying lines used conventional long radius elbows (1.5 diameter bend) normally used in these systems. Wear was excessive with these elbows. The elbows were modified by field welding wear-backs to the original elbows. The wear-backs created a pocket that, as the elbow wore through, filled with coal or sand and stopped the wear. Recommendations for future systems include using commercially available flanged deflection elbows such as Smart Elbows and specifying a wear-resistant interior surface such as tungsten carbide for extended life.

During commissioning, the system piping leaked excessively. Although rated for the operating pressure, the gaskets provided by the equipment supplier did not perform. They were replaced with Flexitallic gaskets. The system was leak-tight after the gaskets were replaced. In the future, if system piping is purchased with the conveying vessel, subcomponents should be specified and verified during the approval process.

Future systems should be designed only for the low-pressure operation startup and purge cycles using the 6-in. pipe. Making up solids level in the standpipe is more efficient by increasing the coal flow to the gasifier using the PDAC system.

5.8.5 Gasifier Bottoms Drain Pot Feeders

5.8.5.1 *System Overview: Gasifier Bottoms Drain Pot Feeders*

The gasifier bottoms drain pot feeders are used to empty solids from the gasifiers in preparation for a shutdown. One feeder is located below the standpipe of each gasifier. Ash in the gasifier must be cooled to a temperature below 350 °F by recirculation around the gasifier before the emptying process begins. The gasifier is at atmospheric pressure during the emptying process.

Table 5.8-3 – Design criteria, gasifier bottoms feeders FD1011 and FD2011

Gasifier Bottoms Feeders	
Maximum feed rate	69,000 PPH
Volumetric capacity	250 cu ft
Nominal ash particle size	3,120 - 600 microns
Diameter	7 ft 0 in.
Convey pipe diameter	8 in.
O. A. height, discharge to dome	14 ft 4.5 in.
Maximum design temperature	350 °F
Vessel pressure rating	100 PSIG
Maximum horizontal pipe run	300 ft
Maximum vertical pipe run	170 ft
Operating pressure and gas flow	17 PSIG @ 1300 cfm
Pressure rating, expansion joint	25 PSIG
System relief valve setting	22.5 PSIG

The feeders transfer the residual ash in the gasifier after a shutdown to the coarse ash silo. Most of the ash should be removed by the CCAD system before the bottoms feeders are used.

The feeder vessel rated design pressure is 100 psig, well below the operating pressure of the gasifier. During normal operation of the gasifier, the feeder must be isolated. This is done with an inline spectacle blind located below a 12-in. isolation valve. Both are normally closed. The spectacle blind position is changed with the unit remaining in place, making disassembly of the chute work unnecessary.

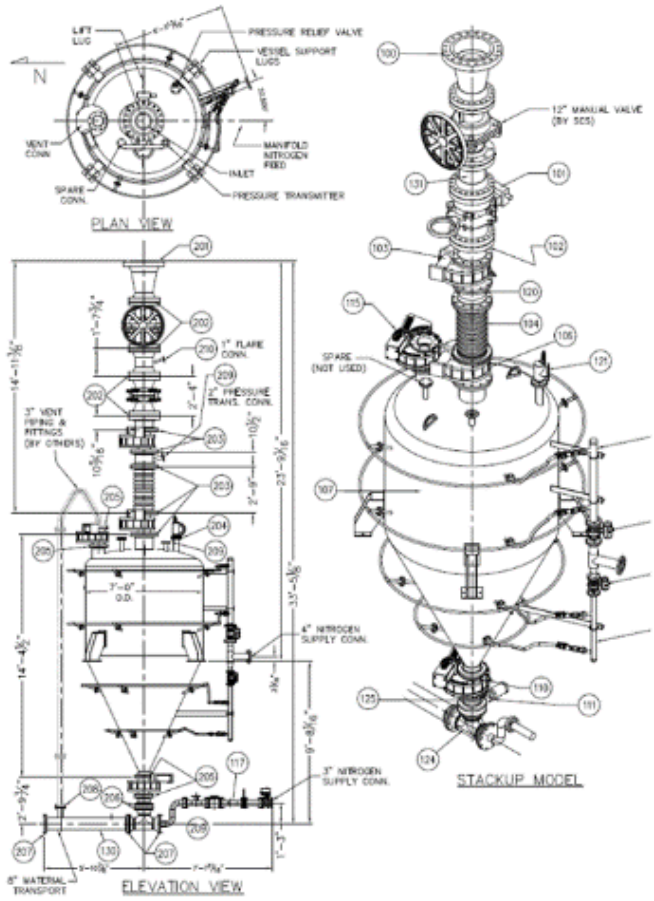
Before system operation begins, the gasifier temperature is reduced below 350 °F and the pressure is reduced to atmospheric. After verifying these conditions are met and the isolation valve is closed, the spectacle blind is switched to the open position. Then the isolation valve is reopened.

The feeders operate in batch mode. Two disc valves are located between the gasifier outlet spectacle blind and the feeder inlet. The upper valve is a dirty shut-off used to stop solids flow. The lower valve is a clean shut-off used to provide a gas seal. To start feed, the lower valve is opened. After it is fully open, the upper valve opens, starting the flow of ash. On receiving a level signal from the vessel or a preset backup timer, the upper valve closes, stopping the

flow of material. When the upper valve is closed, the lower valve is closed. Then the vessel is pressurized for conveying.

There is one disc valve at the vessel outlet, with a throttling valve below. The vessel is filled while at atmospheric pressure. The discharge valve is closed during the fill cycle.

After the discharge valve is closed, the lower inlet valve (clean shut-off) is opened. When it is open, the upper valve opens and filling begins. When the vessel is full, the upper inlet valve closes, stopping solids flow. Then the lower inlet valve closes and pressurization begins



Item No.	Item
100	18"X12" Transition
101	Spectacle Blind
102	12" Transition 600# X 150#
103	Isolation Valve, 12" Disc
104	Expansion Joint
106	Inlet Valve, 12" Disc
107	Pressure Vessel
110	8" Outlet Disc Valve
111	8" Flow Control Valve
115	8" Vent Valve
121	Pressure Relief Valve

Figure 5.8-17 – Gasifier bottoms feeder

When the vessel reaches conveying pressure, the outlet valve begins to open and conveying begins. The process is repeated until the gasifier standpipe is emptied.

After a shutdown and before refilling the gasifier, the gasifier-to-feeder isolation valve is closed. Then the spectacle blind is re-aligned to the closed position.

5.8.5.2 *Initial Commissioning Plan: Gasifier Bottoms Feeders*

The initial commissioning plan included pressure testing the vessels and piping, checking for leaks, replacing gaskets, and retorquing bolts. Valves were stroked and operating times verified to be adequate for system operation.

These test procedures were used for startup of this equipment:

1. TP1025 Appendix G, Gasifier A Drain Pot Feeder (FD1011), which included:
   - Part 1: Gasifier bottoms feeder pressure test.
   - Part 2: Gasifier bottoms feeder dry cycle.
   - Part 3: Gasifier bottoms feeder batch operation on solids.
2. TP2025 Appendix G, Gasifier B Drain Pot Feeder (FD2011), which included:
   - Part 1: Gasifier bottoms feeder pressure test.
   - Part 2: Gasifier bottoms feeder dry cycle.
   - Part 3: Gasifier bottoms feeder batch operation on solids.

The initial commissioning was done using sand that was used to cure the gasifier refractory.

5.8.5.3 *Significant Events: Gasifier Bottoms Feeders*

Unit Affected	Significant Event	Date of Occurrence
FD1011	Initial operation	11/2015
FD2011	Initial operation	3/2016

Sand is circulated during the curing of the refractory in the gasifier. When curing is complete, the sand must be removed so the gasifier refractory can be inspected and any related maintenance performed. The initial operation of the gasifier drain pot feeders was to empty the gasifiers of the sand circulated during the curing process. The feeders operate at lower temperatures and pressures.

A pre-startup check of the system revealed that the vendor-supplied control valve had the incorrect trim and the flow capacity exceeded the relief valve capacity. The trim in the control valve was replaced since the gas flow capacity was adequate with sufficient surge capacity.

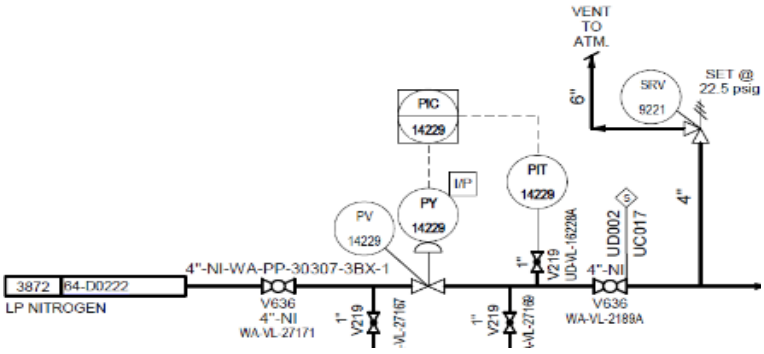


Figure 5.8-18 – Control valve schematic from P&ID

Based on years of operation and data collection at the PSDF, the maximum particle size expected while operating the gasifier bottoms feeders was 600 microns with a d50 of 120 microns. The commissioning sand was uniform and at the lower end of the size range.

The flow of material from the conveying vessel was controlled by an 8-in. throttle valve in the vessel outlet. Operating at the design conveying rate of 69,000 lb/hr, the operating pressure would be 15-16 psig, which was within the operating range of the pressure relief valves and offered a large operating margin.

During the initial operation, the throttle valve began to plug with refractory fragments, stopping the flow of material. When the valve was removed to allow the material to flow through, the flow rate exceeded the system's ability to convey. The system pressure drop exceeded the setting of the relief valve, resulting in line pluggage. The chunks that exited the feeder were sufficiently dense that they slid along the bottom of the conveying pipe until they reached the first elbow, where the flow turned vertical. The density of the refractory pieces prevented them from being conveyed by the gas. The heavy chunks collected at the first turn and eventually the pipe plugged. Removing the material was cumbersome and time consuming. This system did use pipe-cross elbows, which allowed unbolting the blind flanges to remove material collected at the elbow. This became the limiting factor for operating the feeder. During testing, the valve and conveying line plugged because of the overfeed of material and chunks of refractory. One possible solution was to raise the operating pressure of the feeder to blow the sand/ash plugs loose and clear the pipe.

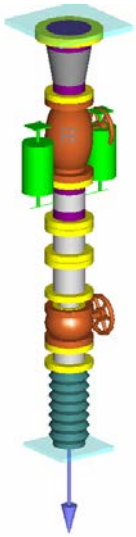


Figure 5.8-19 – Piping stack-up between gasifier and gasifier bottoms feeder showing spectacle blind, isolation valve, and expansion joint

While the conveying vessel and piping were capable of operation at 100 psig, the expansion joint that connected the vessel to the gasifier flange was limited to 25 psig to keep the reaction load on the gasifier flange within allowable limits. There are available expansion joints capable of operating at a pressure of 100 psig, but the loads that would be transmitted to the gasifier flange would exceed design limitations by a large margin. The loads transmitted to the gasifier flange by the original joints were near design limitations at maximum movement. The expansion joint rating and the system operating pressure could not be increased. This limited the ability to deal with flow surges caused by oversized chunks of refractory in the ash stream.

The ash was unusable for reloading into the gasifier without removing the oversize fragments. In the future, a different type of system should be used that can either remove the refractory or convey the refractory fragments.

5.8.5.4 *Final Summary: Gasifier Bottoms Feeders*

The original concept of the system was to save the ash from the standpipe in the coarse ash silo to be reused for startup. After the first feed to the gasifier, the coarse ash silo was maintained around 75% full with on-spec material ideal for adding to the gasifier. That material was replaced periodically by disposal in the ash mixers and replacement using the CCAD system. The residual material left in the standpipe, which contained refractory fragments and clinkers, was not needed for restarting the gasifier after a shutdown. Adding this material back into the gasifier could create new problems, since it contains unwanted refractory fragments that would not convey with the coarse ash feeder and could interfere with the gasifier operation.

For a pneumatic conveying system to function, it must be able to develop enough pressure to push the conveyable fragments through the pipe without plugging. Large chunks are not conveyable pneumatically. These were not anticipated based on previous operations at the PSDF, where this material was not typically found in the ash.

To eliminate the expansion joint, the feeder must be supported in such a way that it moves with the gasifier. This can be accomplished using spring can supports. This would eliminate the pressure limitation of the expansion joint.

The gasifier bottoms feeders never functioned as intended because of the refractory fragments in the standpipe ash. This system needs to be replaced by one that can reliably remove ash with some refractory fragments from the gasifier without plugging.

5.9 LP Vent Gas System

5.9.1 System Overview

The low-pressure vent gas system acquires filtered off-gas from the ash storage silos SI0007 and SI0008A/B/C/D through a series of interconnected headers. During operation, the composition of the gas collected could range from nearly pure nitrogen to sour syngas. Because of the potential for sour syngas, the off-gas must be processed before venting to the atmosphere.

The off-gas is at near atmospheric pressure as it exits the ash storage system and must be pressurized to enable flow of the gas to reach the WSA combustor. This is achieved by compressing the gas in the LP vent gas compressor CO0041 (figure 5.9-1).

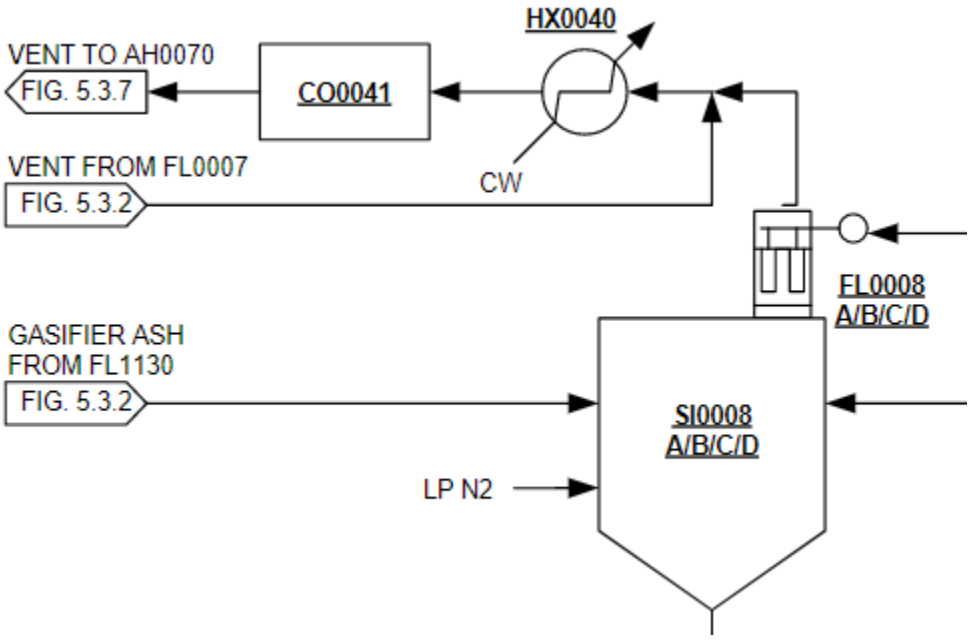


Figure 5.9-1 – Simplified overview of LP vent gas system

The effluent from the ash silo baghouses is first cooled by the LP vent gas compressor precooler HX0040. It then enters the LP Vent Gas Compressor where the pressure is increased from near-atmospheric to 25 psia. This provides sufficient head to transfer the gas from the ash storage system through the LP vent gas headers to the WSA combustor.

The LP vent gas compressor is a motor driven, single-stage, oil-flooded screw. Process control is by modulation of a slide vane that adjusts the location where the gas is admitted to the screw. There is a separate lube oil skid adjacent to the compressor. Since the application is a flooded screw, the process gas directly contacts the lube oil in the compressor. Following compression, the gas-oil mixture is separated in a series of separators that contain filter elements. Most of the oil is removed and returned to the oil skid for re-use in the compressor. There is some expected

amount of carry-over into the process gas, which should not exceed 10 ppmv and does not pose any significant operational issues within the WSA.

Near the end of detailed design, it was determined that the vent gas system might contain a significant loading of very fine (submicron) particulate. The process gas and machine lube oil are mixed together during compression. Much of the fine particulate will become trapped in the compressor lube oil skid and accumulate in bearings, the mechanical seal, and any other low flow or small-tolerance locations throughout the system. To counter this, a high efficiency particulate filter was added to the lube oil skid design.

If the lube oil becomes too particulate laden and needs to be discarded, a process bypass is provided to direct the silo off-gas around the compressor and to the WSA combustor. It is not intended as a normal operating bypass, because it requires the silos to operate as a batch process. This is not the normal configuration and it poses significant operational challenges in the ash removal system.

5.9.2 Initial Commissioning Plan

The commissioning plans for the LP vent gas system included an overall system leak check and the commissioning of the LP vent gas compressor. The system is predominantly a piping system with few unit operations, so this was sufficient to prepare the system for operation.

The leak check was to consist of connecting a temporary air supply to the process piping and pressurizing the entire system to 10 psig. When pressurized, the system flanges and instrument connections would be checked to confirm tightness before proceeding with the commissioning of the LP vent gas compressor. This test would be repeated as necessary to ensure all of the headers and bypass piping were sufficiently pipe-tight.

The LP vent gas compressor commissioning was planned to occur after the commissioning of the ash storage systems. This was to allow for the system to be purged and tested with nitrogen from the silos.

Test plans included:

- Verification of the compressor start/stop sequence. (For an oil-flooded screw, the oil injection timing sequence before compressor startup is critical to prevent flooding of the system with oil.)
- Compressor startup and mechanical integrity testing.
- Monitoring of compressor performance and recording of baseline bearing temperatures, vibration levels, and process conditions.
- Verification of critical setpoints, logic timing, and alarms.
- Tuning of the compressor slide valve.
- Tuning of the suction temperature controller.
- Conducting interlock trip testing.

After compressor testing was complete, the system was to be capped with nitrogen until the ash storage system was required to support gasifier operations.

5.9.3 Significant Events

LP Vent Gas	
Pump base modifications complete	6/5/2015
Lube oil system commissioning	11/30/2015
Precommissioning complete	11/17/2015
Compressor refurbishment complete	10/7/2016
System cleaning complete	10/16/2016
LP vent gas compressor commissioned	11/4/2016

The commissioning of the LP vent gas compressor was to occur later in the Kemper startup plan, after the coal prep and ash storage areas were complete. Due to continuing issues in those areas, alternate plans had to be made for commissioning. This proved beneficial, because there were issues with the fabrication and installation of the compressor that had to be corrected before the unit could be commissioned.

One issue was the lube oil pump base (figure 5.9-2). When attempting to align the lube oil pumps to the motors following the uncoupled motor, it was determined that the pump base was warped. The feet beneath the pump base were not co-planer as required by vendor specification. When the pump base was shimmed to correct for the deviation, it was found that the base had a permanent deflection that could not be corrected without rebuilding the base or machining the motor and pump pads. Southern Company contacted the vendor for assistance in the repair. The pump base had been installed on the skid by the vendor before delivery to site.

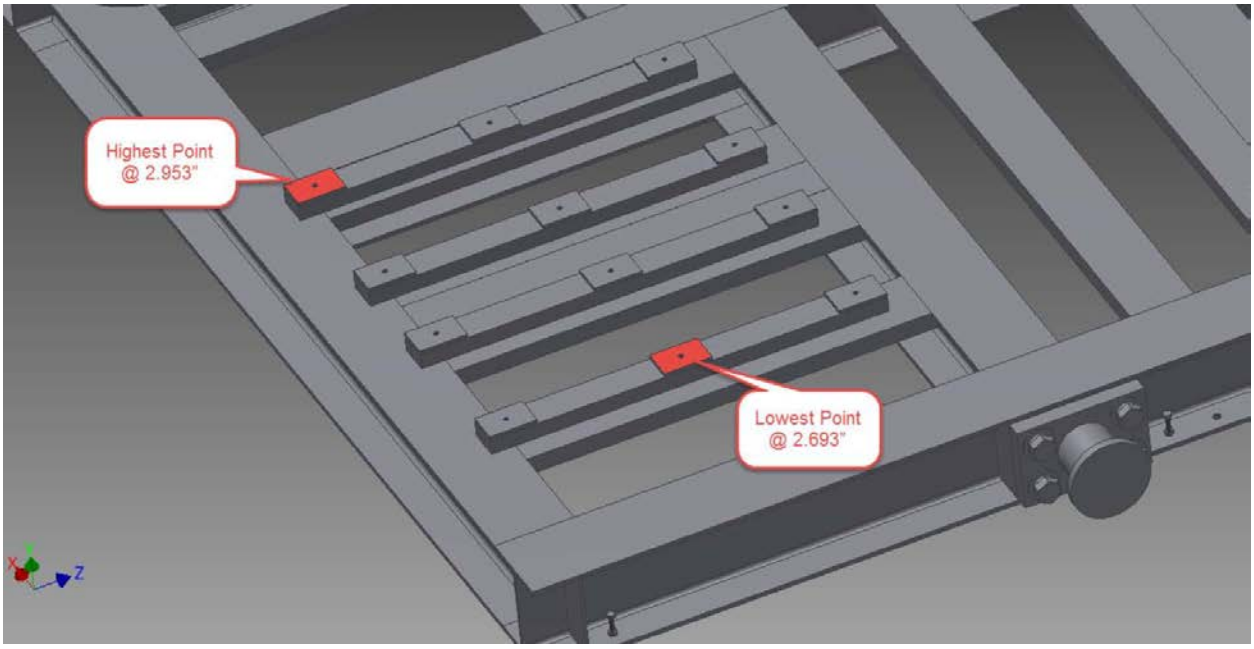


Figure 5.9-2 – Vent gas lube oil pump base pads

In discussions, the vendor indicated that in the time since the skid had been purchased, they had changed the base design and base fabrication vendor. The modifications to the base design were related to robustness issues during installation. The vendor agreed to provide the new pump base. The vendor requested that Southern Company machine the base pads to the specified pad-to-pad flatness. After machining was complete and the new pump base installed, the equipment aligned and tested properly.

There were several welds in the LP vent gas distribution headers identified as unacceptable during hydrolazing of the system piping. Access for repairs was challenging. Scaffolding and additional platforms had to be erected to reach the welds. The original welds were ground out and replaced and each new weld was radiographed for final confirmation and to ensure accuracy. This was not a significant challenge, but the additional platforms and access work took 2 months to complete and extended the time required to clean the system piping.

With the control system complete, final preparations were made to proceed with execution of the test package and initial leak checks. While installing the suction strainer, maintenance personnel noticed that installation debris had fallen into the compressor from the supply piping. These rags and general debris were retrieved from the compressor. Given the importance of the compressor to long-term plant operation, the project decided to remove the compressor and ship it to a vendor-approved facility for teardown inspection and reassembly.

The vendor arranged a hot-shot transport to the factory in Corona, Calif. During teardown inspection, no significant debris or damage was observed. The rotors and smaller internal components did have surface rust, but there was no evidence of damage. The vendor needed to remove the coupling hub to fully disassemble the unit, and as it was being removed it began to gall the rotor shaft. The decision was made to cut the hub off of the rotor rather than taking the greater risk of damaging the rotor. Figure 5.9-3 shows the galling as the hub was being removed. The damage to the shaft was repairable. Figure 5.9-4 shows the general surface rust on the male rotor. This was not significant and was cleaned off before reassembly.

Figure 5.9-3 – Rotor damage incurred as coupling hub was removed

Figure 5.9-4 – Male rotor surface rust

Except for the hub, all major components were reusable after a general cleanup. The compressor was reassembled and returned to the Kemper site for reinstallation, which was accomplished with no issues. Final preparations were made for test package execution.

The test package began with a system leak check. No significant leaks were identified. Numerous smaller leaks found with instrumentation and small-bore flange connections were addressed, and testing continued.

The vent gas compressor start sequence begins by starting the lube oil and circulating oil through the compressor before compressor start. This provides the necessary sealing and lubrication to operate the compressor. If the compressor does not start or the start timer duration is too long, the oil in the bulk oil separator/lube oil reservoir will decrease beyond the low-low level and trip the start sequence. If the timer duration is too long but not long enough to trip the start, then too much oil could be in the compressor, resulting in the motor tripping on high amps. Both of these scenarios occurred during the initial start of the vent gas compressor. With vendor guidance, the startup timers durations were adjusted until adequate to generate a smooth compressor startup.

After the compressor initially started and began to warm up, the vibrations and temperature levels were recorded as well within the allowable range. The slide valve was tuned to the extent possible during the test run. One of the challenges encountered with maintaining long duration runs was the availability of nitrogen from the ash storage system. The nitrogen flow from the silos was very low and resulted in numerous compressor trips due to low suction pressure. As a result, the vent gas compressor could not operate indefinitely unless the gasifier was in operation, resulting in increased gas throughput from the ash system. Following the baseline run, the test proceeded to interlock trip testing. A trip from the SIS had been completed during testing due to the flow limitations. An additional trip test was conducted from the DCS control panel and from the lube oil skid. The compressor was able to be tripped from all requisite locations.

During the compressor test runs, the suction temperature control valve was rough tuned. Due to the suction flow limitations, this controller would need to be tuned further during gasifier operations.

5.9.4 Final Summary

The LP vent gas compressor was the primary unit operation of the LP vent gas system. The operational commissioning of the system focused on this equipment. When the issues with cleanliness and precommissioning were addressed, the commissioning of the compressor proved to be comparatively easy. The limited availability of suction flow prevented the continuous operation of the compressor, and ash system operations were affected throughout much of commissioning. When the unit was operating, it performed as required. An oil sample was taken after the compressor was commissioned. The particle count was elevated, but this was to be expected and did not appear to be on a trajectory to limit long-term availability of the application. Testing of the LP vent gas system was completed in November 2016.

5.10 Syngas Scrubbers

5.10.1 System Description

The syngas scrubber system removes halides, hydrocarbons, and other corrosive components from the syngas, protecting components and allowing the use of lower grade metallurgy in downstream equipment. The scrubber system hydrates the syngas to the desired water-to-carbon monoxide (H_2O:CO) ratio for optimal carbon monoxide conversion ($CO + H_2O \rightarrow CO_2 + H_2$) in the downstream water-gas shift (WGS) reactors. The scrubber is operated any time the gasifier is receiving and processing lignite.

The syngas scrubber column consists of two stacked, packed-bed scrubbing sections in one vessel separated by a dished head with chimneys to allow vapor traffic (figure 5.10-1). Each scrubbing section contains a single packed bed, distributors for adding water above each bed, and a sump for collecting the scrubbing water below each packed bed. The top section sump serves as the supply for the pumparound pump. The bottom section sump supplies the bottoms pump and the facility sour water system.

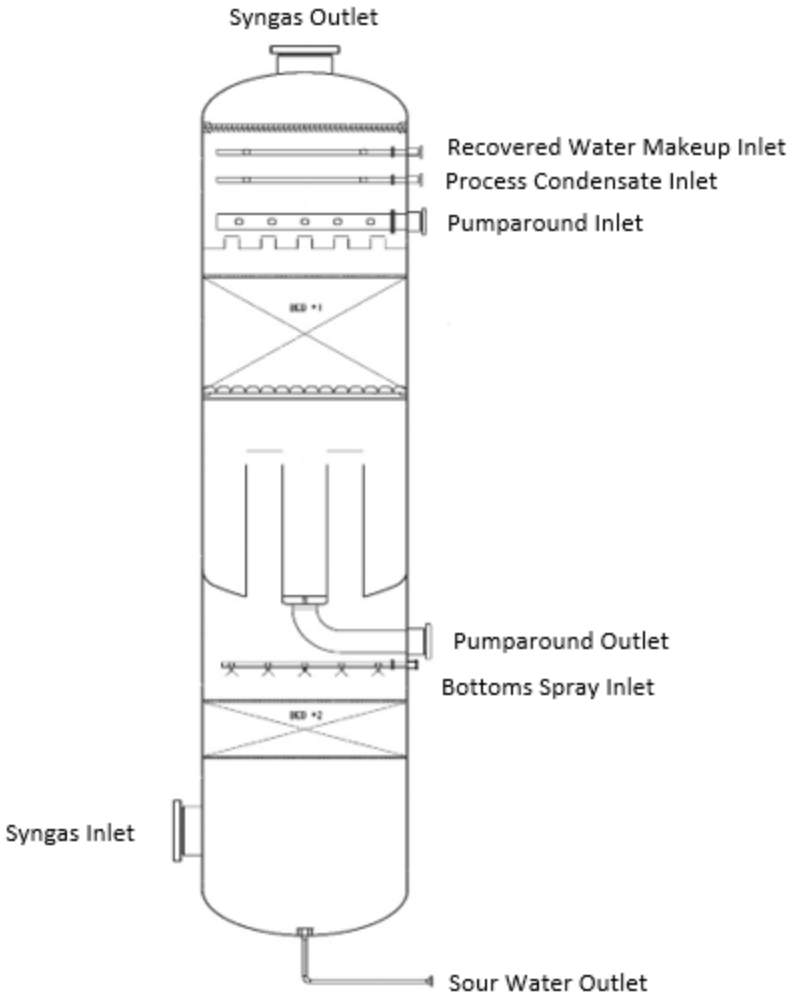


Figure 5.10-1 – Syngas scrubber

The Syngas Scrubber system includes the following major equipment (figure 5.10-2):

Train A	Train B
CL1007 Syngas scrubber	CL2007 Syngas scrubber
PU1011 Syngas scrubber bottoms pump	PU2011 Syngas scrubber bottoms pump
PU1007A/B Syngas scrubber pumparound pumps	PU2007A/B Syngas scrubber pumparound pumps
HX1007 Syngas scrubber pumparound heater	HX2007 Syngas scrubber pumparound heater
HX1008 Syngas scrubber pumparound intermediate pressure steam (IPS) heater	HX2008 Syngas scrubber pumparound intermediate pressure steam (IPS) heater

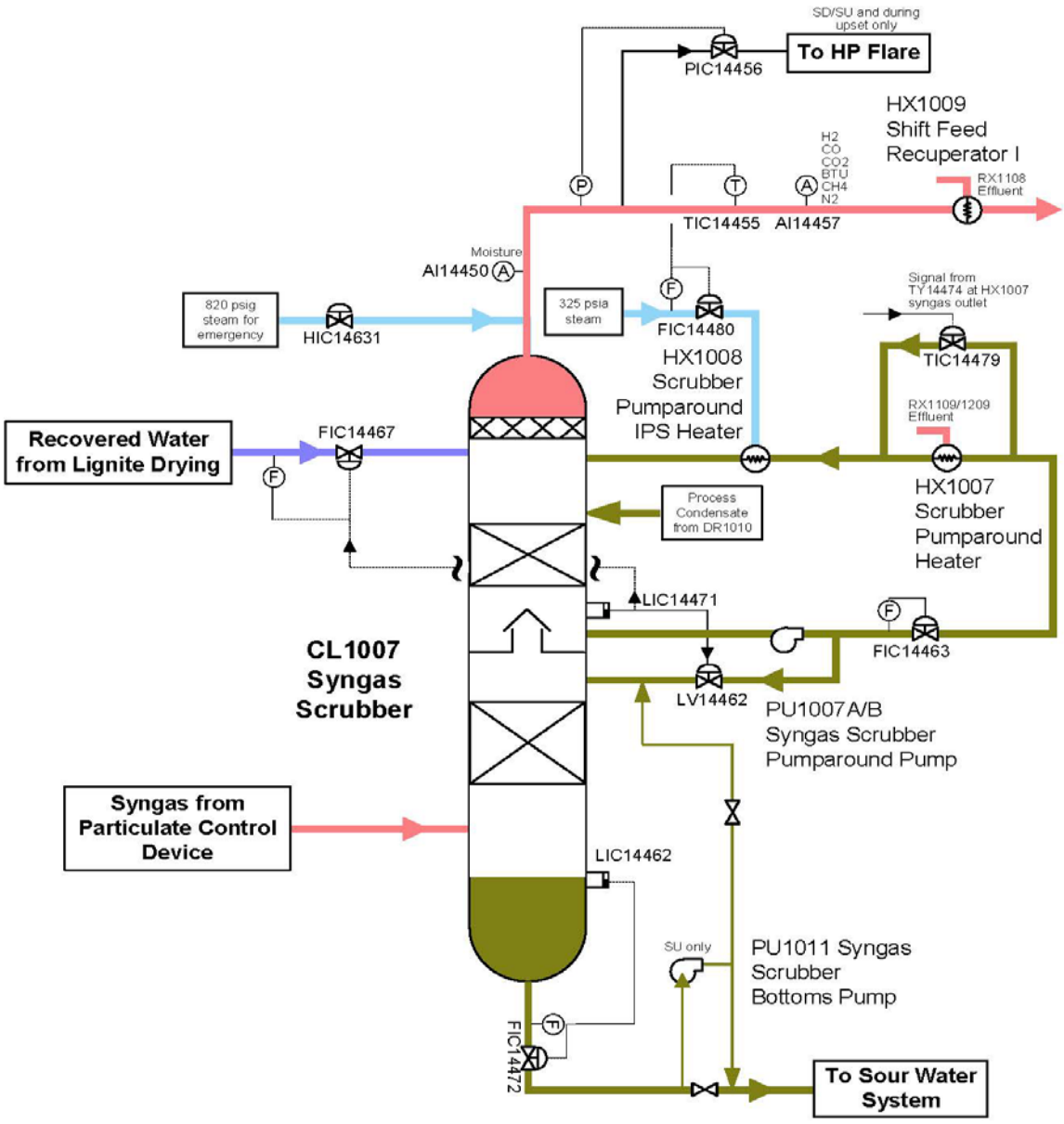


Figure 5.10-2 – Syngas scrubber system

Warm, sour syngas from the particulate control device and the CCAD cooler vent filters enters the CL1007 syngas scrubber and flows up through the bottom packed bed, where it is scrubbed with a slipstream of pumparound water from the upper section sump through the PU1007A/B pumparound pumps. Halogens, hydrocarbons, and some ammonia are removed as the syngas contacts the water in the bottom packed bed. The scrubbing water containing halogens, hydrocarbons, and ammonia collects in the bottom section sump below the packing and is either pumped through the PU1011 syngas scrubber bottoms pump or pushed with column pressure to the sour water system. The syngas scrubber bottoms pump is needed during startup primarily to overcome potential pressure mismatches between the syngas scrubber and the facility sour water system. The minimum flow kickback from the pump ensures the bottom packed bed maintains minimum wetting to provide adequate scrubbing when the pump is running.

Syngas continues into the upper section of the scrubber through chimneys in the dished head separating the two sections and is scrubbed in the upper packed bed. Water from the upper section sump is pumped in a pumparound loop from the upper sump to the distributor above the upper section packing. The pumparound contains two heat

exchangers. A HX1007 scrubber pumparound heater uses the heat released from the downstream WGS reactions to heat the scrubbing water, while the HX1008 scrubber pumparound IPS heater uses 325 psia steam extracted from the steam turbine to heat the pumparound water. These two exchangers control the overhead temperature of the syngas exiting the scrubber. The overhead temperature is adjusted to achieve the target moisture concentration, for the desired ratio of H_2O:CO in the syngas entering the water-gas shift reactors for optimal conversion. To maintain water levels in the dished head sump and replace the water evaporated with the syngas, make-up water recovered from the lignite dryers is added to the upper section of the scrubber. Any condensate recovered from the syngas after cooling it downstream of the WGS and COS hydrolysis reactors is pumped back to the upper section of the scrubber to maintain level in the upper sump.

5.10.2 Syngas Scrubber Initial Commissioning Plans – Train A and B

Commissioning plans developed for the syngas scrubbers included traditional commissioning activities (turnover packages) and two distinct operational test plans (test packages). Traditional commissioning activities included equipment and piping walk-downs, initial loop checks and safety interlock tests, instrument and motor checks, motor alignment and pipe stress testing, and final loop checks and final interlock testing.

The operational tests in the unit commissioning plans were:

- Initial filling and circulation test to tune and validate level and flow controls.
- Test using hot gas from gasifier refractory cure-out activities for TIC14455 temperature controller tuning.

The objectives of the initial fill and circulation test plan were:

- Fill the CL1007 syngas scrubber sumps with water recovered from lignite dryer testing in the lignite preparation system to verify no leaks were present.
- Operate the PU1007A/B pumparound pumps.
- Operate the PU1011 bottoms pump to send water to the sour water system.
- Ensure control valves operated correctly.
- Tune level and flow controllers.

Objectives of the temperature control tuning test plan were:

- Fill the syngas scrubber sumps with recovered water.
- Operate the PU1007A/B pumparound pumps.
- Tune the steam and temperature controllers associated with the pumparound IPS heater and the scrubber overhead temperature controller TIC14455.

After completion of these two test plans, the scrubber would be ready to be placed in service in preparation for first lignite feed.

The commissioning and startup schedule was sequenced to execute all operational testing activities for the Train A syngas scrubber before attempting Train B syngas scrubber operational tests. Experiences and observations from executing test plans on Train A led to modification of Train B plans well in advance of any attempted execution. For example, the discovery of the need for a special commissioning activity to flush the bottoms section of the syngas scrubber and the outlet piping to the sour water system on Train A resulted in changes to the Train B plan. A special flushing activity for Train B bottoms and outlet piping was immediately added to the schedule. It was executed following the Train A special flushing activity and before any other Train B operational test plans.

Mass transfer internals were installed in the syngas scrubbers before operational test plan activities were executed.

5.10.3 Syngas Scrubber Train A and B Commissioning Milestones

Commissioning Activity	Train A	Train B
Mass transfer internals installed and inspected	4/24/2015	6/17/2015
Initial fill and level control tuning test plan	5/19/2015 *(Upper section only)* 11/10/2015 *(Upper section only- with air flow)*	2/26/2016
Syngas scrubber bottoms pump construction complete	6/25/2015	7/8/2015
Syngas scrubber and bottoms pump flushing activity	11/2/2015	11/4/2015
Syngas scrubber bottoms pump operations test	9/27/2016	6/11/2016
Syngas scrubber temperature control tuning	9/27/2016	2/26/2016

5.10.4 Syngas Scrubber Train A and B Significant Events During Unit Commissioning

Before the operational tests were executed, there were challenges and delays in the traditional commissioning activities (turnover packages) related to constrained resources. Commissioning activities were repeated due to turnover in the Startup Coordinator role and to ensure their completion was properly documented.

- Train A

Initial operational tests on the Train A syngas scrubber began with a filling and circulation test plan (see section 5.10.1). Due to delays in lignite dryer testing and operation, recovered water derived from lignite was not available for the initial Train A syngas scrubber test plan execution. A temporary demin water supply skid was used for testing until the recovered water system was fully commissioned and operational. The upper section sump of the Train A syngas scrubber was filled with demin water, and the controls for the FIC14467 make-up water controller were tuned. Level transmitters in the upper section were verified against local gauges, and leak checks were performed on external flanges and welds. Safety instrumented system (SIS) interlocks to protect equipment during low level trips in the upper section were tested and response actions verified. Levels were refilled in the upper section sump and level controllers were tuned. Circulation of the upper pumparound loop was established and tuning of the FIC14463 flow controller on the pumparound loop was completed. The upper pumparound loop was operated in automatic control for a sustained period to observe operations. During operation of the upper pumparound loop, level in the bottom sump of the Train A syngas scrubber increased per LIC14462, indicating water was leaking from the upper section. Additional testing was planned to investigate this issue but was postponed when an incorrectly installed check-valve prevented filling of the bottom sump of the Train A syngas scrubber, causing operational testing activities for the bottom section of the scrubber to be postponed to a later test. Operation of the Train A syngas scrubber bottoms pump PU1011 was removed from the plan after it was determined that construction of the pump was not completed. The syngas scrubber bottoms pump was a late addition to the design after detailed startup planning revealed issues with integrating two gasifier trains during startup. New schedule activities were added to complete operational testing of the bottoms pump along with future testing in the syngas scrubber.

After construction of the Train A syngas scrubber bottoms pump PU1011 was completed, a plan was developed to operate and tune the syngas scrubber bottoms level and flow controls before the gasifier cure-out when execution of the syngas scrubber temperature control tuning test plan was originally scheduled. Ideally, the test would be executed during a period of high air flow from the Train A gasifier to determine if higher velocity through the syngas scrubber chimneys would reduce the rate of water leaking to the bottom sump. Monitoring the leak rate at various gas velocities would also help better predict leak performance during normal operation.

Traditional commissioning activities such as an uncoupled motor run and vibration analysis were first attempted on the Train A syngas scrubber bottoms pump around 1 month after construction was completed. High vibration readings and a lack of lubrication in the bearings delayed commissioning activities. It was later determined that the bottoms pump pedestal needed to be re-poured. Execution of the new bottoms pump operational test plan was first attempted approximately 3 months after construction was completed. The operational test plan required temporary connections and re-routing of the pump discharge. Commissioning and testing activities in the sour water system, the normal destination for discharge from the scrubber bottoms pump, were not completed sufficiently to accept water from the scrubbers. Temporary tanks and hoses were used to allow the test to proceed without the sour water system. The scrubber was again inventoried using the demin water supply skid used for the initial fill test plan. A static leak test was conducted to confirm the previously observed leak between the upper and lower sections of the scrubber was not due to a weld failure in the dished head. Next, circulation in the upper pumparound loop was established, and leaking from the upper section to the lower section was again observed during pumparound operation. Delays in the Train A gasifier commissioning plans prevented simultaneous testing with high air flow and no reductions in leak rate were observed. After filling the bottoms section of the scrubber with demin water and verifying level readings in the DCS, the bottoms pump was started. Sludge in the bottom of the Train A syngas scrubber resulted in multiple pump trips after minimal run time, and operational test plan activities ceased. The decision was made to develop an additional schedule activity to flush the bottom sump and the bottom outlet piping of the syngas scrubber before finalizing the commissioning of the bottoms pump and tuning of the bottom section level controls.

Execution of the bottoms sump and piping flush began approximately 1 week after the initial attempts to operate the pump. Per the plan, a temporary spool piece was installed to bypass the bottoms pump, and the pump's suction strainer upstream of the spool piece was removed to prevent clogging. Flush trim was installed in the discharge valve upstream of the spool piece, and the check valve and restriction orifice in the pump's recirculation line were removed. Flow from the recovered water system, still being supplied by a temporary demin water skid, was used to flush the vessel and piping for two 12-hr shifts over the course of 2 days. Because of the temporary spool pieces and flush trim installed in the scrubber bottoms outlet line, bottom section level controls could not be tuned in conjunction with the flushing. Operation of the bottoms pump and tuning of the bottoms controls were postponed again to be included with the revised scrubber temperature control tuning test plan.

As Train A gasifier test plan activities progressed, there was an opportunity to operate the Train A syngas scrubber upper section pumparound loop in conjunction with the gasifier testing to evaluate the impact on the water leak rate of various air velocities through the chimneys separating the upper and lower sections of the scrubber. The bottom section piping and outlet valve trim had not yet been restored from the prior flushing activities, so the equipment and piping in the bottom section was unavailable for operation. The information gained from observing the leak rate through the chimneys with significant air flow through the vessel was valuable enough to proceed with the testing. Significant leak-by of the chimney trays was observed, but the lower than expected gasifier pressures and gas velocities through the chimneys made it difficult to accurately predict the leak rate during normal operation conditions. Circulation was stopped, and the operational data was compiled and sent to engineering for analysis. Further testing was planned during future gasifier testing with lignite feed.

As Train A gasifier testing activities continued, plans were made to execute the revised operational test plan for scrubber temperature control tuning and to test the bottoms section controls and pump operation during gasifier refractory cure-out activities. Piping and valve trim from the scrubber bottoms flushing activity were restored in preparation for the test plan. A hot spot was discovered in the Train A gasifier during heating, indicating a refractory issue, and all testing activities were terminated. The decision was made to relocate resources and testing focus to Train B and other process areas that could be commissioned independently of the Train A gasifier while the gasifier refractory was repaired.

Approximately 10 months after Train A syngas scrubber test plans were suspended, the revised scrubber temperature control tuning and bottoms testing plan was executed successfully during the Train A gasifier first lignite feed test package.

- Train B

Plans for operational testing activities for the Train B syngas scrubber were modified with lessons learned from the Train A testing. As a result, many of the issues encountered in Train A did not adversely affect the testing in Train B. The Train B syngas scrubber bottoms pump construction was completed, and the bottoms sump, pump, and sour water outlet piping were flushed to remove residual sludge well ahead of operational tests. The decision was made to combine the initial fill and circulation tests with the final temperature control testing into one operational test to be conducted during the Train B gasifier refractory curing activities.

Recovered water from lignite drying was still not available, so the upper section sump of the Train B syngas scrubber was filled with demin water and the controls for the make-up water system were tuned. Level transmitters in the upper section were verified against local gauges, and leak checks were performed on external flanges and welds. SIS interlocks to protect equipment during low level trips in the upper section were tested and response actions verified. Levels were refilled in the upper section sump and level controllers were tuned. Circulation of the upper pumparound loop was established and tuning of the FIC24463 flow controller on the pumparound loop was completed. Like Train A, liquid level in the bottom sump of the Train B syngas scrubber increased during operation of the upper pumparound loop, indicating water bypassing through the chimneys of the internal dished head. Low gas flow from the Train B gasifier refractory cure and resulting low velocities through the chimneys made it difficult to accurately predict the leak rate during normal operation conditions. Additional testing was planned for after lignite feed was introduced to the gasifier. A check valve in the line to the bottom bed spray distributor was installed backwards, similar to Train A, which prevented testing and tuning of the Train B syngas scrubber bottoms level controls. This testing was postponed to coincide with the first lignite feed tests in the Train B gasifier. Testing of the PU2011 syngas scrubber bottoms pump was completed using the water leaking from the upper section to the bottoms sump through the upper section chimneys. The Train B bottoms pump was operated and the SIS interlocks to protect equipment during low level operation were tested. A wiring issue was discovered that prevented the bottoms pump from tripping appropriately on low level. The syngas scrubber bottoms discharge flow controls were tested and tuned using column pressure to push water to temporary tanks, because the facility sour water system was not yet accepting water in order to conserve inventory in the sour water tank. The syngas scrubber overhead temperature controller TIC24455 and the syngas scrubber pumparound IPS heater steam flow controls HX2008 were tested and tuned with only minor issues that were immediately addressed.

The issues identified with the Train B syngas scrubber bottoms spray check valve and bottoms pump interlocks were addressed during a subsequent outage. The scrubber bottoms pump and controls were successfully re-tested around 3 months later, before the Train B gasifier first lignite feed test. The entire Train B syngas scrubber was operated during the gasifier heat-up immediately preceding the first lignite feed milestone for Train B.

5.11 Syngas Cleanup Train A and B

5.11.1 System Overview

The syngas cleanup area consists of all equipment in the syngas flow path from the exit of the syngas scrubber system to the combustion turbine fuel skid. It is divided into four systems – the water gas shift (WGS) system, the ammonia scrubber system, the acid gas removal (AGR) system, and the mercury removal and reheat system. Due to its size, complexity, and unique commissioning requirements, the AGR system and its commissioning are detailed in section 5.13 of this report. The remaining syngas cleanup area systems are described below.

5.11.1.1 *Water Gas Shift (WGS) System*

The primary purpose of the WGS system is to use catalyst-filled reactors to convert water vapor and carbon monoxide (CO) in syngas into carbon dioxide (CO_2) and hydrogen (H_2) according to the reaction:

$$CO + H_2O \rightarrow H_2 + CO_2$$

A secondary purpose of the WGS system is to convert trace components carbonyl sulfide (COS) and hydrogen cyanide (HCN) into hydrogen sulfide (H_2S), ammonia (NH_3), and CO_2 by reacting them with water vapor.

Carbon dioxide is captured in the AGR system downstream of the WGS, then compressed and sent by pipeline to south Mississippi and Louisiana oil fields for enhanced oil recovery. Hydrogen sulfide captured in the AGR system is routed to the WSA system for production of commercial grade sulfuric acid. Hydrogen from the WGS reaction provides the majority of the heating value in the syngas being sent to the combustion turbine.

The WGS system contains two stages of shift reactors, with each stage consisting of a set of two parallel, catalyst filled reactors (figure 5.11-1). The system also includes one parallel set of catalyst-filled reactors for COS conversion. There is a recuperative heat exchanger associated with each stage of WGS reactors, where the exothermic reaction and resulting high outlet stream temperature are used to heat the inlet stream to each stage. Three additional heat exchangers transfer the heat generated from the exothermic shift reaction to other mediums. One of these exchangers heats the pumparound water in the syngas scrubber system. The other two exchangers reheat the chilled syngas exiting the AGR system before it is sent to the combustion turbines

The equipment in the WGS system during normal operation includes:

Train A	Train B
HX1009 Stage I shift feed recuperator	HX2009 Stage I shift feed recuperator
RX1108 and RX1208 Stage 1 WGS reactors	RX2108 and RX2208 Stage 1 WGS reactors
HX1020 high temperature syngas recuperator	HX2020 high temperature syngas recuperator
HX1011A/B Stage II shift feed recuperator	HX2011A/B Stage II shift feed recuperators
RX1109 and RX1209 Stage II WGS reactors	RX2109 and RX2209 Stage II WGS reactors
HX1007 scrubber pumparound heater	HX2007 scrubber pumparound heater
RX1104 and RX1204 COS hydrolysis reactors	RX2104 and RX2204 COS hydrolysis reactors
HX1022 low temperature syngas recuperator	HX2022 low temperature syngas recuperator

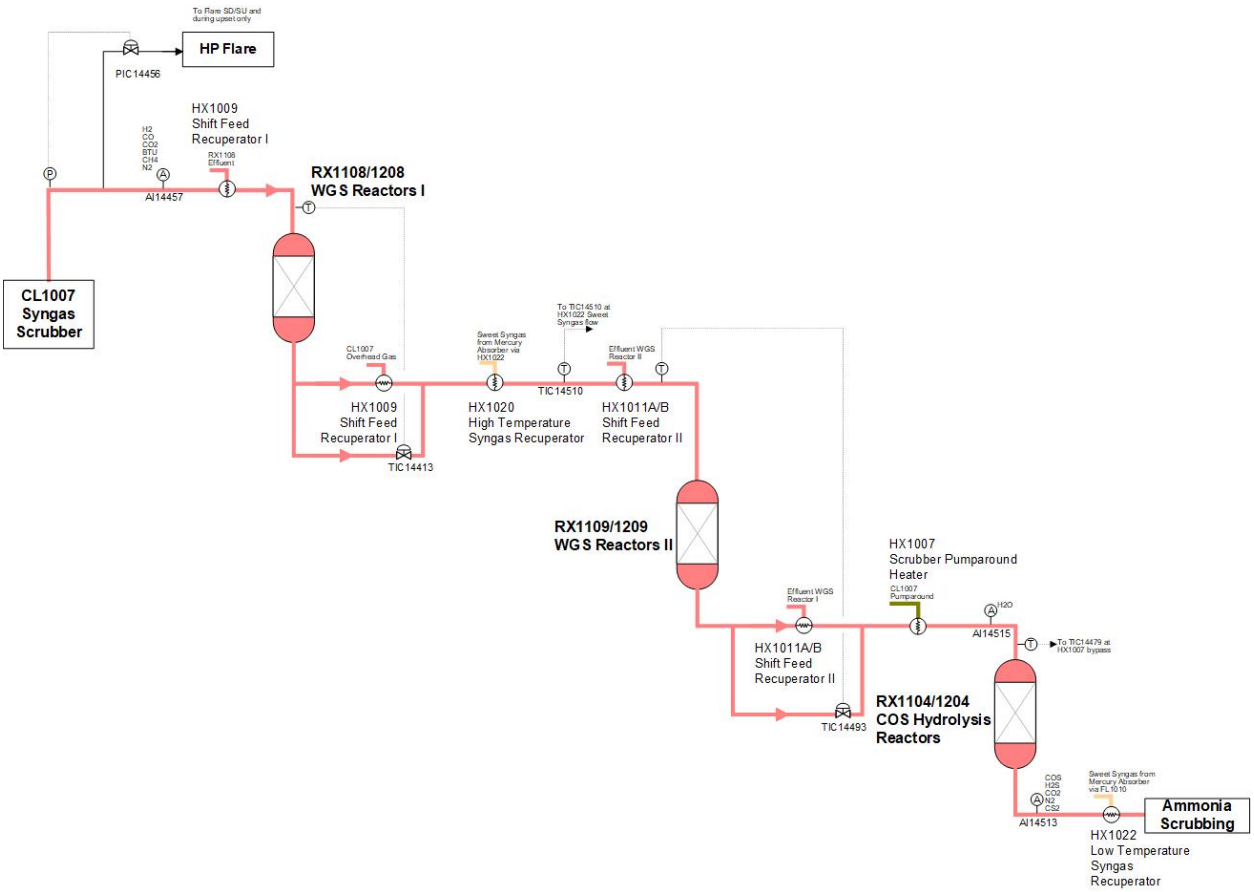


Figure 5.11-1 – Water gas shift (WGS) system

Sour syngas saturated with water from the CL1007 syngas scrubber enters the shell side of the HX1009 Stage I shift feed recuperator. It is heated to avoid condensation on the catalyst and achieve the required temperature to facilitate the shift reaction before entering the RX1108/1208 Stage I WGS reactors. The shift reaction is exothermic, and the resulting high temperature reactor outlet stream is sent back to the tube side of HX1009 as the heating source for the RX1108/1208 inlet stream. The Stage I reactor outlet stream continues from HX1009 to the shell side of the HX1020 high temperature syngas recuperator, where it heats the sweet syngas being sent to the combustion turbine.

Syngas exiting HX1020 continues to the shell side of the HX1011A/B Stage II shift feed recuperators, where it is heated by the outlet stream of the RX1109/1209 Stage II WGS reactors to the temperature required to achieve the desired total conversion of CO. Because most of the shift conversion occurs in the first stage of reactors, the reactor outlet temperature and heat transferred in RX1109/1209 are much less than in Stage I.

The shifted syngas continues from HX1011A/B to the HX1007 scrubber pumparound heater. Here, warm syngas heats the syngas scrubber pumparound water and decreases the syngas temperature for optimal COS conversion before entering the RX1104/1204 COS hydrolysis reactors. The COS concentration in syngas must be minimized before the AGR, because COS will concentrate in the CO_2 product from the AGR and make it difficult to meet CO_2 pipeline specifications. Due to the low concentration of COS in the syngas, very little exotherm occurs from the conversion. Warm, shifted sour syngas leaving RX1104/1204 enters the HX1022 low temperature syngas recuperator, where it heats sweet syngas flowing to the combustion turbine. At this point, all reactions are complete and the process objective changes to preparing the syngas to enter the acid gas removal system using the ammonia scrubber system.

5.11.1.2 *Ammonia Scrubber System*

The primary objectives of the ammonia scrubber system are to cool the syngas and to remove ammonia before it enters the AGR system. Ammonia is a potential contaminate in the AGR solvent and can concentrate in parts of the system. The ammonia scrubber system consists of multiple syngas coolers that use different cooling mediums to decrease the syngas temperature for optimal ammonia removal in the scrubber (figure 5.11-2). Before reaching the ammonia scrubber, part of the water condensed from the syngas is collected and recycled back the syngas scrubber to reduce make-up water requirements.

The equipment in the ammonia scrubber system includes:

Train A	Train B
HX1021 intermediate temp. syngas cooler	HX2021 intermediate temp. syngas cooler
DR1010 process condensate KO drum	DR2010 process condensate KO drum
DR1013 light HC drain pot	DR2013 light HC drain pot
PU1010A/B process condensate pumps	PU2010A/B process condensate pumps
HX1027 process condensate trim heater	HX2027 process condensate trim heater
HX1024 low temperature syngas cooler	HX2024 low temperature syngas cooler
HX1025 low temperature syngas trim cooler	HX2025 low temperature syngas trim cooler
CL1006 ammonia scrubber	CL2006 ammonia scrubber
PU1006A/B sour water pumparound pumps	PU2006A/B sour water pumparound pumps
DR1016 ammonia scrubber light HC drain pot	DR2016 ammonia scrubber light HC drain pot

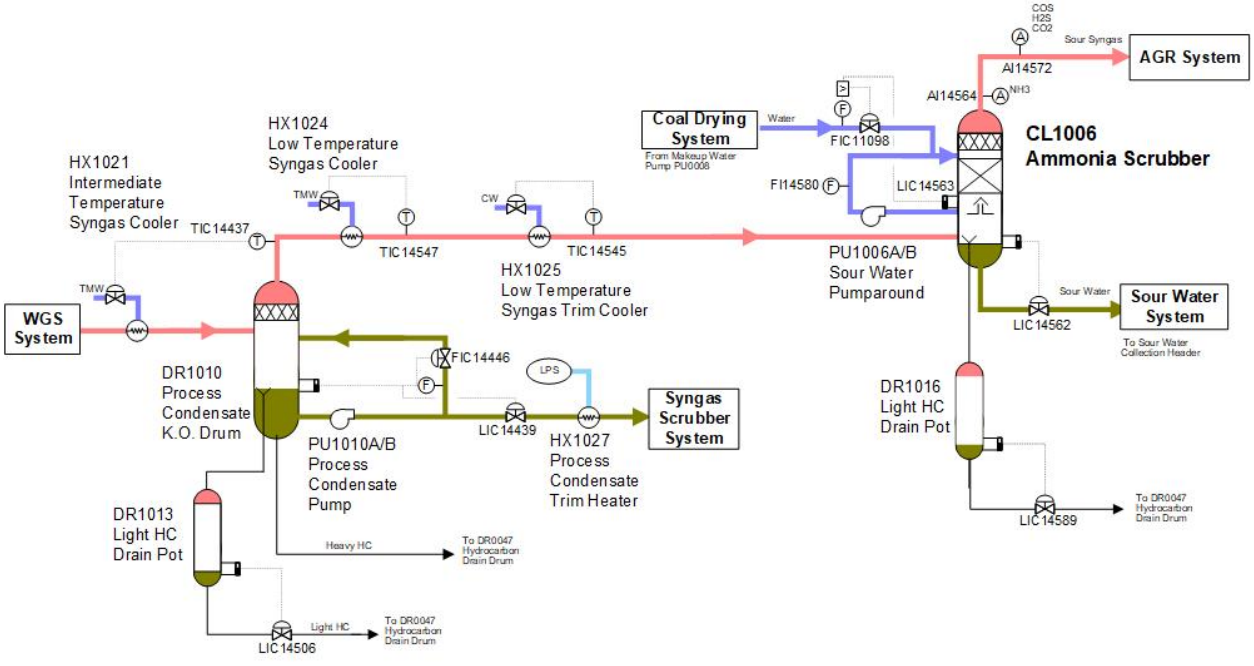


Figure 5.11-2 – Ammonia scrubber system

Exiting HX1022, sour syngas continues to the HX1021 intermediate syngas cooler, where it is cooled by tempered water. HX1021 is the largest source of heat for the tempered water system. The tempered water system recovers low

grade heat from sources throughout the facility and uses it to dry lignite in fluidized bed dryers. Tempered water is described in detail in section 4.7.4 and the lignite dryers are described in section 5.1.7.

Water condensed from sour syngas as a result of the cooling is removed in DR1010 process condensate knockout (KO) drum and returned to the syngas scrubber system using the PU1010A/B process condensate pumps. Water recycled to the syngas scrubber is heated with low pressure (LP) steam in the HX1027 process condensate trim heater to improve efficiency of the overall process. The knockout drum also provides significant residence time to allow condensed hydrocarbons and water to separate into distinct layers based on density differences. Light hydrocarbons, which have the lowest or lightest density, form the top layer and are intermittently drained by a floating skimmer to the DR1013 light HC drain pot. Heavy hydrocarbons, with higher densities, form a bottom layer that is drained from the bottom of the drum. Condensed light and heavy hydrocarbons are routed to the DR0047 hydrocarbon drain drum located in the sour water system. The sour water system is described in section 5.17 of this report.

Sour syngas exiting the process condensate knockout drum is cooled further in the HX1024 low temperature syngas cooler and the HX1025 low temperature syngas trim cooler using tempered water followed by closed loop cooling water (CLCW), before entering the CL1006 ammonia scrubber. Water condensed as a result of this additional cooling flows with the sour syngas into CL1006. Sour syngas enters the near the bottom of CL1006 and flows upward through a collection (chimney) tray into a packed bed where it is contacted with pumparound water. PU1006A/B sour water pumparound pumps recirculate sour water collected in the scrubber's chimney tray to the top of the column for distribution over the packed bed. The ammonia vapor in the sour syngas absorbs into the water and is removed from the sour syngas. Sour water condensed during syngas cooling and overflow from the chimney tray in CL1006 is collected in the column sump and sent to the sour water system to recover anhydrous ammonia for commercial sales. The water exiting the ammonia scrubber sump will contain ammonia and dissolved carbon dioxide and hydrogen sulfide. Recovered water from the coal drying system is used as make-up to maintain level on the scrubber chimney tray.

Like DR1010, the ammonia scrubber sump provides residence time to allow hydrocarbons and sour water to separate. Light hydrocarbons form the top layer and are intermittently drained using an internal standpipe to the DR1016 ammonia scrubber light HC drain pot. Sour water and heavy hydrocarbon are sent through the scrubber bottom outlet to the sour water collection header and separated further downstream.

After exiting the top of the ammonia scrubber, sour syngas is ready for the AGR system. See section 5.14 for details of the AGR system.

5.11.1.3 *Mercury Removal and Reheat System*

The mercury removal and reheat system removes mercury and filter particulates from the sweet (low to no sulfur) syngas exiting the AGR system, to comply with the environmental permit while reheating the syngas to meet the requirements for introduction into the combustion turbine. Sweet syngas from the system also supplies the recycle gas system, which compresses sweet syngas for use throughout the facility, primarily as fluidization gas in the transport gasifier and ash removal systems. See section 5.12 for details of the recycle gas system.

The mercury removal and reheat system consists of one stage of two parallel adsorber vessels filled with sorbent material, two particulate filters, two recuperative heat exchangers that use warm sour syngas from the water gas shift system to heat the sweet syngas, and one steam heater that uses medium pressure (MP) steam to heat the sweet syngas as needed during startup, shutdown, or transients (figure 5.11-3).

The equipment in the mercury removal and reheat system includes:

Train A	Train B
RX1106 and RX1206 mercury adsorbers	RX2106 and RX2206 mercury adsorbers
FL1010 micron filter	FL2010 micron filter
HX1022 low temperature syngas recuperator	HX2022 low temperature syngas recuperator

HX1020 high temperature syngas recuperator	HX2020 high temperature syngas recuperator
HX1023 export syngas trim heater	HX2023 export syngas trim heater
FL1024 GT syngas filter	FL2024 GT syngas filter

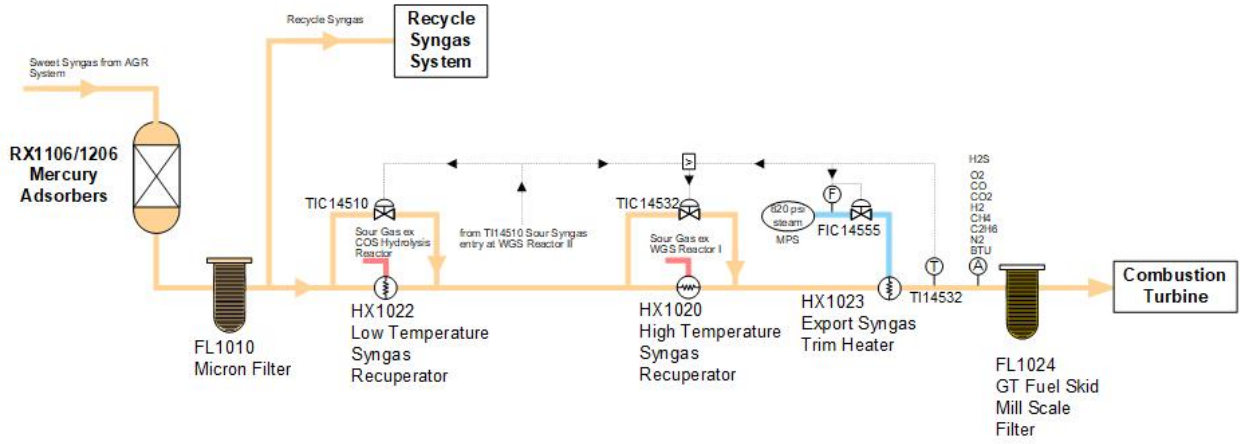


Figure 5.11-3 – Mercury removal and reheat system

Cool, sweet syngas from the AGR system enters the RX1106/1206 mercury adsorbers, where mercury is removed from the syngas. The adsorbers contain identical beds of sulfur-infused alumina sorbent. The syngas continues through the FL1010 micron filter where any particulates, such as fines from crushed sorbent, are removed from the syngas. Most of the syngas then flows to the shell side of the HX1022 low temperature syngas recuperator where it is heated with the sour syngas exiting RX1104/1204 in the water gas shift (WGS) system. A portion of the syngas is extracted and sent to the recycle gas system for use elsewhere in the facility. Sweet syngas from HX1022 is heated further in the tube side of the HX1020 high temperature syngas recuperator by sour syngas from HX1009 at the outlet of WGS stage I.

At times such as system startup, shutdown, or upsets, additional heating of the sweet syngas could be needed to meet the syngas fuel specifications of the combustion turbine. This can be accomplished in the HX1023 export syngas trim heater where MP steam is used as the heating source. An additional FL1024 GT syngas filter is included in the syngas flow path immediately upstream of the combustion turbine fuel skid to provide a final opportunity for particulate filtering.

5.11.1.4 *Nitrogen Heating System*

The syngas cleanup area includes additional equipment, piping, valves, and instruments used during startup to heat the WGS system catalyst beds before syngas is introduced. Because of the amount of water vapor present in the syngas stream leaving the syngas scrubber, special equipment and controls are in place to avoid exposing the catalyst to condensed water. The catalyst beds must be heated with an inert, dry gas to avoid condensing water that could damage the structure of the catalyst when syngas is introduced. Heated nitrogen is circulated in a closed loop through the WGS, ammonia scrubber, and mercury removal and reheat systems. The AGR system is bypassed during nitrogen heating.

The nitrogen heating system includes most of the equipment in the WGS, ammonia scrubber, and mercury removal and reheat systems, along with an additional startup heat exchanger (figure 5.11-4). It uses the recycle gas system (section 5.12) to circulate nitrogen. The nitrogen heating system flow path is created by isolating the WGS system from the syngas scrubber upstream of the first stage of WGS reactors, isolating the mercury removal and reheat system from the CT, closing the isolation valves entering and exiting the AGR system, and opening a bypass around the AGR. The nitrogen heating circulation loop is created by isolating the discharge of the recycle gas compressor from the

normal recycle gas users, then using special piping and manual valves to create a startup jumpover from the compressor discharge to the inlet of the startup heater upstream of the WGS reactors.

The additional equipment for the nitrogen heating system includes:

Train A	Train B
HX1035 startup/sulfiding heater	HX2035 Startup/sulfiding heater
DR1009 recycle gas compressor KO drum	DR2009 recycle gas compressor KO drum
CO1008 recycle gas compressor	CO2008 recycle gas compressor
HX1032 recycle gas compressor spillback cooler	HX2032 recycle gas compressor spillback cooler

Circulating nitrogen from the CO1008 recycle gas compressor enters the HX1035 startup/sulfiding heater where it is heated with intermediate pressure (IP) steam to a temperature well above the expected dewpoint of syngas leaving the syngas scrubber. The heated nitrogen flows through RX1108/1208 stage 1 WGS reactors before bypassing the tube side of HX1009. HX1009 is bypassed to avoid damaging the exchanger; there is no flow on the shell side since the nitrogen heating system is isolated from syngas scrubber downstream of the exchanger. Heated nitrogen continues to the shell side of HX1020, which also is bypassed to avoid damaging the fixed tube sheet exchanger. There is no flow through the tube side of HX1020 or the shell side of HX1022, because the circulating nitrogen leaves the mercury removal and reheat system and flows to CO1008 upstream of these exchangers. After HX1020, nitrogen flows through the shell side of HX1011A/B to the RX1109/1209 stage II WGS reactors. Leaving RX1109/1209, part of the nitrogen flows through the tube side of HX1011A/B, but the bypass of the exchanger is also fully open to minimize cooling of the hotter nitrogen entering the shell side of the exchanger. Nitrogen then flows through the shell side of HX1007, which is isolated and bypassed on the tube side to avoid cooling the circulating nitrogen with the syngas scrubber pumparound. Warm nitrogen from HX1007 flows through RX1104/1204 before bypassing the tube side of HX1022 to avoid damaging the fixed tube sheet exchanger.

The COS hydrolysis reactors are the last catalyst beds in the WGS system that need to be heated to avoid condensation when syngas is introduced. The circulating nitrogen can be cooled slightly after leaving these reactors to avoid exceeding temperature limits in the downstream recycle gas compressor while still optimizing the efficiency of the overall system. This cooling is accomplished by establishing minimum water flows on the shell side the HX1021 intermediate temperature syngas cooler, HX1024 low temperature syngas cooler, and HX1025 low temperature syngas trim cooler. Nitrogen from the HX1022 bypass is cooled by flowing through the shell side of HX1021 to the DR1010 process condensate KO drum. Leaving DR1010, nitrogen is cooled further through the shell side of HX1024 and HX1025 before entering the CL1006 ammonia scrubber. Water in DR1010 and CL1006 is drained before nitrogen heating, and the scrubber pumparound is not operated during the process to keep the circulating gas dry. From CL1006, nitrogen flows through the AGR bypass to the RX1106/1206 mercury adsorbers. The mercury adsorbers require little to no preheating compared to the catalyst beds in WGS, because the syngas exiting the refrigerated AGR system during normal operation will have a dewpoint below 30 ˚F. Leaving RX1106/1206, the nitrogen flows to the recycle gas system where it is compressed by CO1008 and routed back to the inlet of HX1035 to repeat the heating cycle.

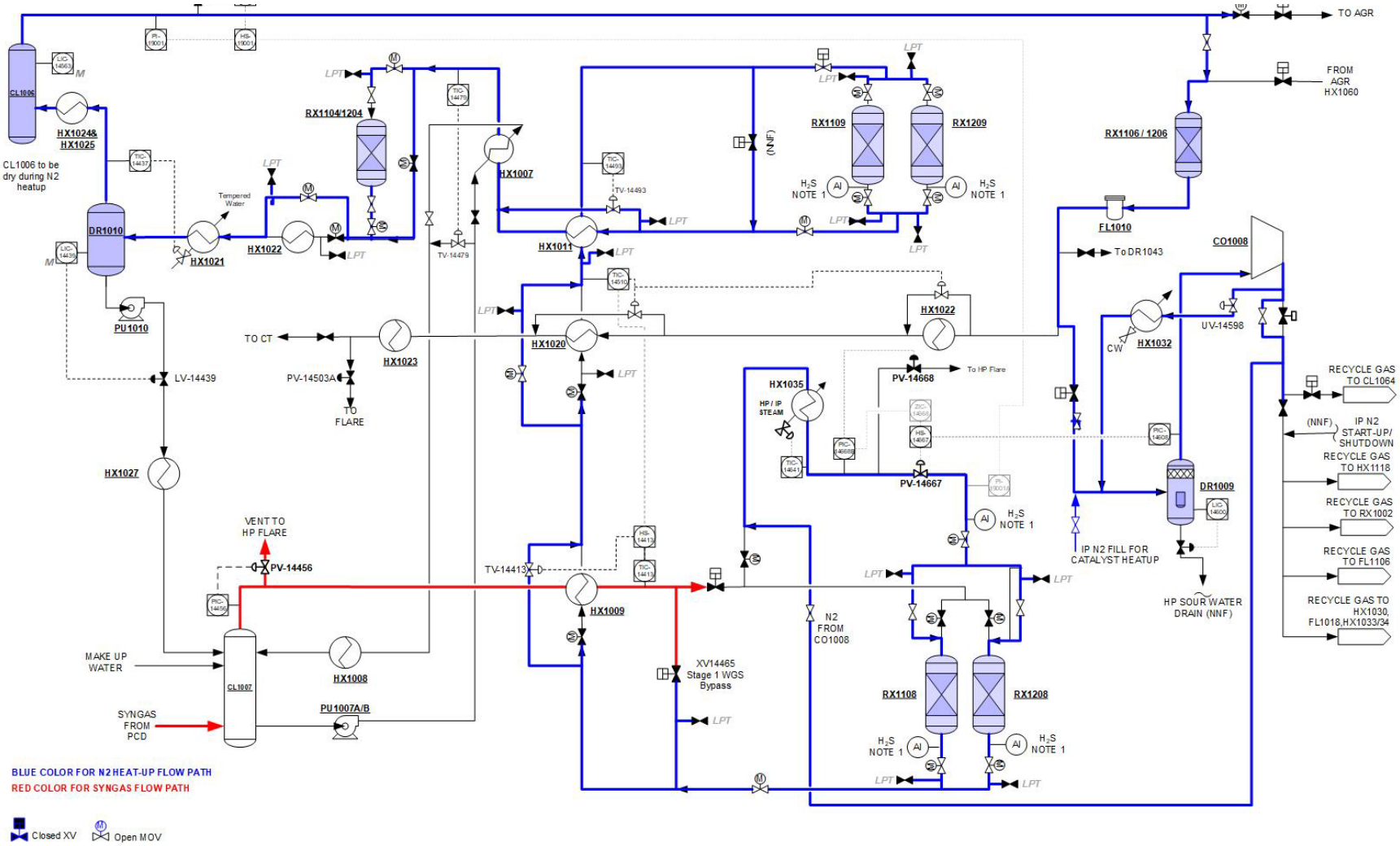


Figure 5.11-4 – Syngas cleanup nitrogen heating system

5.11.2 Initial Commissioning Plan

Commissioning plans for the syngas cleanup area in both gasification trains included traditional commissioning activities (turnover packages), three distinct operational test plans (test packages), and special activities for installing vessel internals and catalyst. Turnover package activities included equipment and piping walk-downs, instrument loop checks, safety interlock tests, motor checks and alignment, and pipe stress testing. The turnover package activities are not project specific and will not be discussed in detail. The test packages and special activities planned for syngas cleanup are described below.

5.11.2.1 *Air Flow Tuning and Testing*

The first test package planned was TP1020 (Train A) / TP2020 (Train B) - Air Flow Tuning and Testing. The objective was to use air from the process air compressors to achieve part-load operating flows through the gasifier, syngas coolers, particulate control devices (PCD), syngas scrubber and syngas cleanup area. This would evaluate hydraulic performance and tune and test major controls, particularly the system pressure controllers that vent to the high pressure (HP) flares dedicated to each gasification train. These pressure controllers are critical to control gasifier pressure during startups, shutdowns, and malfunctions. Preparatory steps were scheduled to ensure the system was ready for the testing. For air flow tuning and testing these included:

1. Inspections throughout syngas cleanup to establish the preliminary condition of equipment.
2. Installation of limited, temporary vessel internals in scrubbers and absorbers.
3. Static pressure testing up to 100 psig.
4. Cleaning air blows through progressive sections of syngas cleanup (for example, through the transport gasifier to the startup stack, then the syngas scrubber, then the AGR inlet, and finally to the CT inlet).
5. Equipment inspections to evaluate equipment conditions after cleaning air blows.

Equipment and valve vendors were consulted to establish safe test parameters, and a detailed test package procedure was developed for each phase of the test. The goal of the cleaning air blows was to achieve a cleaning factor (the ratio of relative drag forces during air blows to those expected during startup, normal operations, or trip scenarios) of greater than 1 in each system. Limited vessel internals were installed in the syngas flow path to minimize risk of damage. Steps were taken to protect select valves and equipment during the cleaning air blows. Several critical valves were temporarily replaced with sacrificial valves and, if needed, temporary orifice plates. Multiple heat exchangers in the syngas flow path were bypassed or replaced with temporary pipe spools before execution of the cleaning air blows, primarily if syngas would normally flow through the shell side of the exchangers where trash could accumulate and be difficult to remove. After each successive cleaning air blow, activities were scheduled to shut down and isolate the cleaned part of the system to perform inspections, remove debris from equipment, and replace temporary valves or equipment with permanent components before moving to the next system.

After the preparatory steps, the syngas cleanup portion of the air flow tuning test package proceeded. It was focused primarily on tuning and testing the pressure control valves used to transition syngas flow through the syngas cleanup area during startups or to respond to shutdowns and trip situations. A preliminary static pressure test up to 400 psig was planned for the entire syngas pathway to confirm systems were leak-free before air flow was established through the transport gasifier for tuning and testing multiple pressure and flow control loops in the gasifier area. See section 5.11 for details of the gasifier portion of the air flow testing. In the syngas cleanup area, tuning and testing during the air flow test was planned to simulate a normal startup with air flow venting to the high pressure (HP) flare system at progressive vent points (highlighted in red in figure 5.11-5). Tuning for the vent to the startup stack, PIC14445, was planned to be done during the previous cleaning air blow procedure.

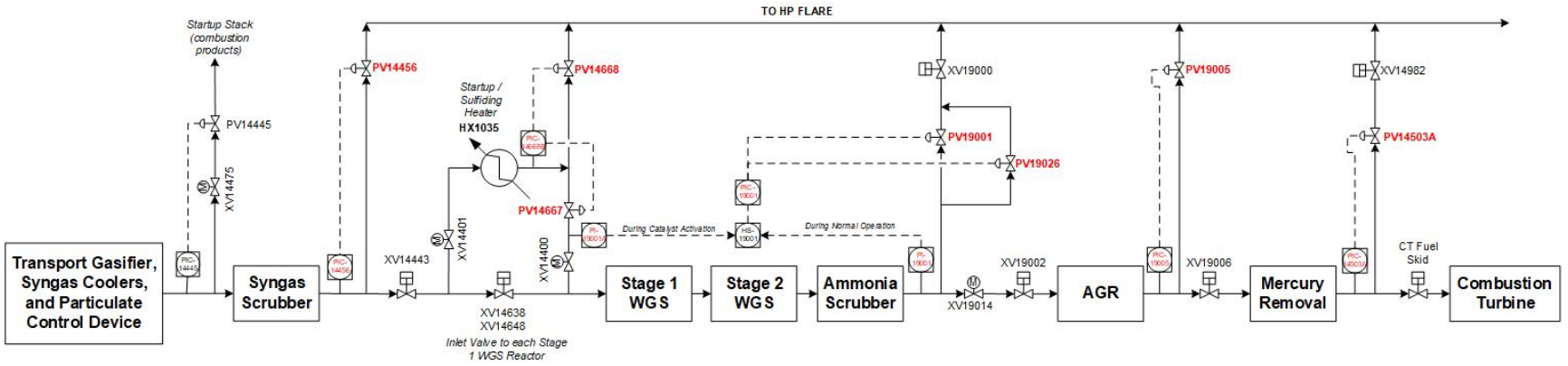


Figure 5.11-5 – Syngas cleanup controllers - vents to HP flare

Each of the pressure controllers (figure 5.11-5) operates over a wide range of pressures and flows throughout startup, so gain scheduling was included in tuning plans to maintain optimal control performance. Butterfly and equal-percentage valves used for pressure control were to be characterized to maintain optimal control performance through a wide range of flows. During a normal startup, syngas flow is sequentially admitted to downstream processes as gasifier pressure builds and operation of upstream systems stabilizes. The test package procedure specified that PIC14456, the first pressure controller downstream of the CL1007 syngas scrubbers, was the first controller in the syngas cleanup area to be tuned and tested at up to 50% of normal air flow during TP1020 / TP2020. The WGS reactors were to be pressurized but isolated from air flow during the tuning and testing. After PIC14456, air flow was then to be transferred through the HX1035 startup/sulfiding heater to the second vent to flare, PIC14668B, with the WGS reactors still isolated. After PIC14668B was tuned and tested at 40-50% air flow, the temperature controls for HX1035 were to be tuned using intermediate pressure (IP) and/or high pressure (HP) steam to heat the air. Next, both stages of WGS and the ammonia scrubber system were to be placed in service as air flow was transferred to the pressure controllers upstream of the AGR while the AGR system was isolated.

There are two parallel pressure control valves upstream of the AGR, PV19001 and PV19026. PV19001 was designed to control system pressure during a normal startup, but a second parallel pressure control valve would be needed during a startup that includes catalyst activation or sulfiding due to the large range of flows and pressures required for this unique activity. Catalyst activation is required when new WGS catalyst is installed at expected 3- to 5-year intervals. Both PV19001 and PV19026 are controlled by split-range controller PIC19001, which can receive input from either PI19001A or PI19001 (figure 5.11-5). PI19001A is input to pressure controller PIC19001 during catalyst activation to maintain the pressure entering the WGS reactors, while pressure controller PIC14668B modulates valves PV14668 and PV14667 to maintain the desired upstream gasifier pressure. PI19001 is input to pressure controller PIC19001 to control system pressure at the AGR inlet during a normal system startup. During TP1020 / TP2020, plans were developed to tune and test pressure controller PIC19001 using input from both PI19001A and PI19001 in successive steps. After the AGR inlet pressure controllers were tuned and tested, the AGR was to be placed in service as air flow was gradually transferred to the AGR outlet controller PIC19005, which was to be tuned and tested while isolated from downstream systems. In the final step of the simulated startup, the mercury removal and reheat system was to be placed in service with air flow transferred to PIC14503A at the inlet of the combustion turbine fuel skid. PIC14503A was to be tuned and tested at approximately 60% of normal air flow.

After the pressure controllers throughout syngas cleanup were tuned and tested, the final plans for TP1020 / TP2020 included testing the system response to various pressure controller transitions, and completing multiple gasifier trip tests to ensure the logic programmed in the plant control systems would place the process systems in the correct safe state. The planned pressure control transitions repeated the normal startup sequence of moving successively from PIC14456 through PIC14503A and transitioning directly from pressure controller PIC14503A at the CT inlet back to pressure controller PIC14556 at the syngas scrubber and vice versa. The final procedure steps included initiating gasifier trips while controlling system pressure at the CT inlet (PIC14503A), the AGR inlet (PIC19001), and the startup/sulfiding heater (PIC14668B), respectively, to ensure the various systems were automatically placed in the correct safe operating state.

5.11.2.2 *System Restoration and Vessel Internals Installation*

After the air flow tuning and testing test package was completed, an outage was scheduled for all the systems in the syngas cleanup area to fully restore permanent equipment and valves and install internal components in the scrubbers and drums.

5.11.2.3 *Process Condensate KO drum and Ammonia Scrubber Tuning and Testing*

With the testing of the syngas flow path complete, the second test package planned for the syngas cleanup area was flushing, tuning, and testing of the equipment and controls handling liquid in the ammonia scrubber system. During normal operation, the ammonia scrubber system receives condensed liquids from syngas along with make-up water recovered in the lignite drying process. Liquids collected in the DR1010 process condensate knockout (KO) drum and CL1006 ammonia scrubber are normally routed to either the syngas scrubber or the sour water system. Because these

systems were not yet integrated with syngas cleanup at this point of commissioning, alternate plans were developed for supply and disposal of the water used during testing including required piping modifications. The plan was to use temporary hose connections to flush debris from the ammonia scrubber's normal recovered water make-up piping, through DR1010's process condensate line, to a temporary storage tank (figure 5.11-6). Flushing plans included tuning and testing of the make-up water flow controller FIC11098. When flushing was completed, the hose connection was to be reversed (figure 5.11-7) to provide means to fill CL1006 and DR1010 with water and allow further tuning and testing.

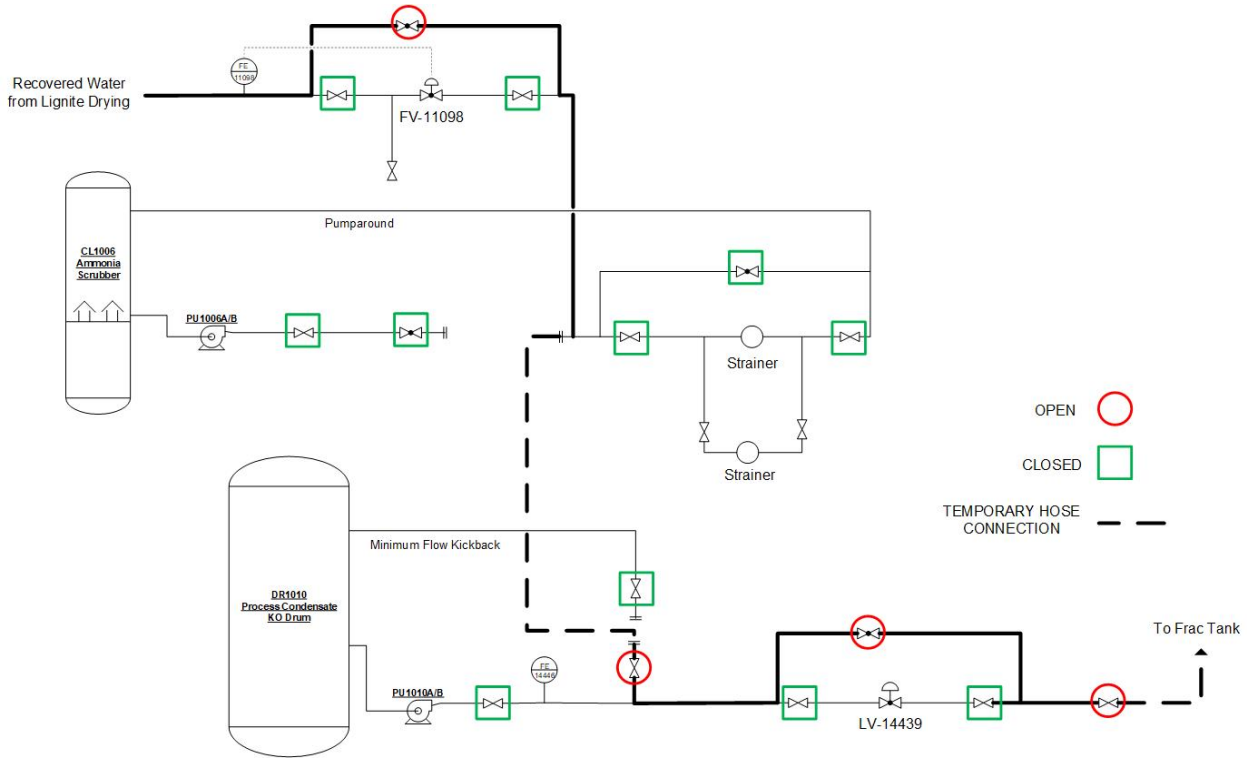


Figure 5.11-6 – Recovered water line flush flow path

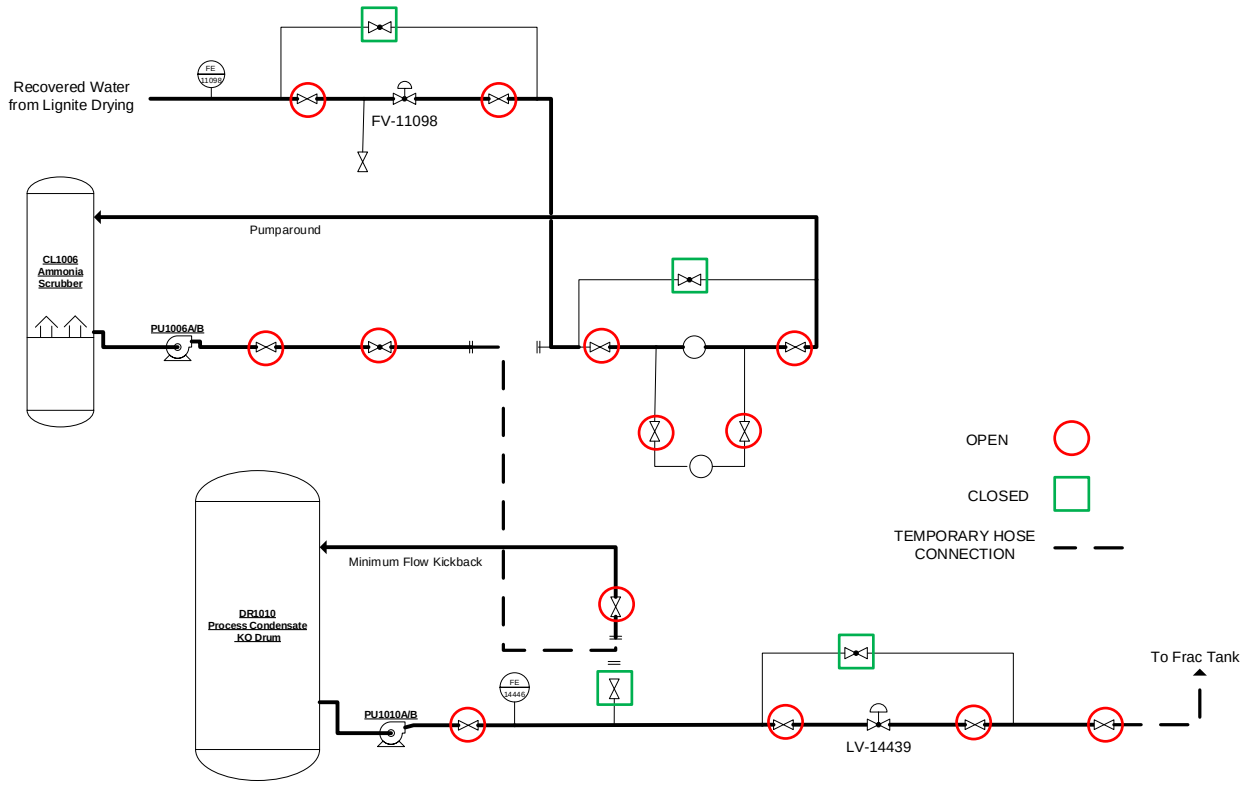


Figure 5.11-7 – Ammonia scrubber and process condensate KO drum tuning and testing flow path

See figure 5.11-2 for detailed illustration of ammonia scrubber system equipment and controls.

The tuning and testing portion of the test package included steps to fill the ammonia scrubber (figure 5.11-2) with water supplied to the CL1006 pumparound through the normal make-up water line, with strainers installed to remove any remaining debris and protect the branch liquid distributors in the top of CL1006. When consistent water supply was established, water collected on the pumparound collection tray was to be used to verify CL1006 chimney tray level instrumentation, LI14563, and supply the PU1006A/B pumparound pumps. The pumparound pumps were then to be used to fill DR1010 using the temporary hose connection (figure 5.11-7) while testing the start, stop, and low-level safety interlock functions of the pumparound pumps. With make-up water supply established and the pumparound pumps in operation sending water to DR1010, the level-to-flow cascade controller (LIC14563) for make-up water was to be tuned and tested to provide continuous, automatic make-up water flow control to the CL1006 chimney tray.

When sufficient level was established in DR1010 and the level instrumentation (LI14439) was verified, the pump start, stop, and low-level safety interlock function tests were to be repeated for the PU1010A/B process condensate pumps. Flow from PU1010A/B was to be established through level controller LIC14439 to a temporary storage tank to allow tuning and testing of the DR1010 level controls (LIC14439). With sufficient level in DR1010, operation was to be suspended so the temporary hose connection could be removed and replaced with the normal PU1010A/B kickback flow control valve, FV14446. Kickback flow controller FIC14446 was to be tuned and tested when operation of the pumps resumed.

This test package was an opportunity to tune many of the level and flow controllers in the ammonia scrubber area, but some instruments and controllers were not included in the test package plans. For example, the CL1006 sump level controller LIC14562 and associated instrumentation were not included because the sour water header was not available to receive water from the testing. The level instrumentation and controls for the light hydrocarbon drain pots, DR1013 and DR1016, respectively, were not included in the test plans. Plans to tune and test the remaining instruments and controllers in the ammonia scrubber system were included in subsequent test packages where more system integration was possible.

5.11.2.4 *Nitrogen Heating System Tuning and Testing*

The final test package planned for the syngas cleanup area was TP1028 (Train A) / TP2028 (Train B) nitrogen heating system tuning and testing. The objective of this test was to verify system dynamics and controls of the nitrogen heating system (see section 5.11.1, System Description). Because much of the syngas cleanup equipment, valves, and controls in the nitrogen heating system (figure 5.11-4) were included in the previous air flow test package, the focus for TP1028/2028 was purging the system to remove oxygen, integrating the recycle gas system to establish nitrogen circulation, and tuning and testing the nitrogen heating system pressure and temperature controls. The pressure control valve downstream of the HX1035 startup/sulfiding heater, PV14667, is used during both nitrogen heating and subsequent sulfiding but serves different purposes in each. During sulfiding, PV14667 and PV14668 are controlled by PIC14668B to maintain gasifier pressure while the downstream controller PIC19001 controls pressure in the WGS system (see section 5.11.2.1, Air Flow Tuning and Testing). During nitrogen heating, PV14667 is controlled by PIC14608 to adjust system pressure drop and maintain constant suction pressure for the CO1008 recycle gas compressor (figure 5.11-4). TP1028/TP2028 included plans to tune and test these components as well as repeat tuning and testing of the HX1035 temperature controller, TIC14641, using both IP and HP steam.

5.11.2.5 *Catalyst Installation*

After the syngas cleanup area testing was completed, an outage was scheduled to allow installation of catalyst and adsorbent in the WGS system and the mercury removal and reheat system. The reactors in the syngas cleanup systems contain a total of over 1.1 MM pounds (~26,000 ft^3) of catalyst and 1.3 MM pounds (~9,500 ft^3) of inert support or grading material between the two gasification trains.

The vast majority, more than 718,000 lb or approximately 18,000 ft^3, of oxidized Haldor Topsoe SSK-10 sour gas shift catalyst, was to be loaded in the 8 water gas shift reactors (2 gasification trains $\times$ 2 stages of WGS $\times$ 2 parallel reactors). Sour gas shift catalyst is available in two forms, oxidized or presulfided, which are based on the state of the catalytic metal on the catalyst upon delivery. The oxidized catalyst is generally easier and cheaper to ship, handle, and load, but the metals must be sulfided or activated in situ after the catalyst is loaded into the reactors. Provisions must be made for a source of heat, hydrogen sulfide, and hydrogen. Presulfided catalyst offers the advantage of a slightly abbreviated startup by avoiding catalyst activation, but involves more complicated logistics (for example, loading under inert atmosphere) and higher cost per unit. For the Kemper project, technical and economic evaluation and safety factors determined that oxidized catalyst was the better option. Because the nitrogen heating system was already required to pre-heat the catalyst, minor design modifications were made to its equipment and controls to also facilitate sulfiding. Plans were developed to use sour syngas, containing sufficient concentrations of both hydrogen sulfide and hydrogen, to activate the shift catalyst in situ. Catalyst sulfiding was planned after stable syngas production was confirmed with the first lignite feed tests conducted on the gasifier. Details are in the final project report.

An independent contractor with extensive experience in catalyst handling and installation was contracted to install the material in all Train A and Train B reactors. After installation was completed, all reactors and adsorbers were to be purged and left under slight nitrogen pressure to prevent oxygen and moisture ingress that could negatively impact future performance.

Table 5.11-1 – Syngas cleanup Train A and B commissioning milestones

Commissioning Activity	Train A	Train B
TP1020/2020 Air flow tuning and testing	April 6, 2015	May 5, 2015
Syngas flow path outage - install vessel internals	May 3, 2015	June 29, 2015
Process condensate KO drum, ammonia scrubber tuning and testing	June 6, 2015	August 20, 2015
Nitrogen heating system tuning and testing	September 14, 2015	October 25, 2015
Syngas cleanup catalyst installation	June 20, 2016	April 24, 2016

5.11.3 Significant Events

5.11.3.1 *Air Flow Tuning and Testing*

See figures 5.11-4 and 5.11-5 for illustrations of equipment and control components.

After extensive preparations, including test package procedure development, design, procurement, and installation of sacrificial valves and spools, the TP2020 Train B air flow tuning and testing package started in late December 2014. The first phase of the procedure, the 50 psig and 100 psig pressure tests, were slightly delayed by a gasket failure and a pressure relief valve prematurely lifting on the process air system supplying the transport gasifier. After those issues were resolved, flow was established from the process air header, through the gasifier, and to the startup stack while the syngas cleanup area systems were pressurized to the inlet of the AGR. The startup stack pressure controller PIC24445 (figure 5.11-5) was successfully tuned and tested with a temporary sacrificial control valve to allow continued testing. As pressure was increased during the 50 psig test, multiple leaks were identified and resolved around the particulate control device (PCD) before the testing was suspended for the holidays. Testing resumed in early January 2015 with the successful completion of static pressure testing up to 100 psig.

The Train B cleaning air blow to the startup stack was completed in mid-January 2015. Flow from one process air compressor (PAC) was re-established through the gasifier and startup stack but, unlike the previous pressure tests, downstream processes were isolated. A second PAC was brought online to increase air flow rates to between 350,000 and 400,000 lb/hr while pressure was intermittently cycled from 50 to 100 psig at PIC24445 to create disturbance and achieve the desired relative drag forces (cleaning factor). After approximately 4 hr at target flows and pressures, the cleaning air blow to the startup stack was deemed complete. Systems were shut down to enable inspections, cleanup, and installation of permanent system components while preparations continued for cleaning air blows through vents at the syngas scrubber and syngas cleanup systems to the Train B HP flare header.

Cleaning air blows transitioned to Train A in late January 2015 due to delays in the Train B HP flare header construction and commissioning. The 50 and 100 psig pressure tests for Train A were completed much like Train B with similar leaks in analogous areas of the process but of a slightly shorter duration. After pressure checks, the cleaning air blow to the Train A startup stack was initiated at the end of January 2015. The test proceeded per procedure until a DCS graphics change implemented during the testing unintentionally caused the startup stack pressure controller PIC14445 to fully open the startup stack pressure control valve PV14445, resulting in a rapid depressurization of the system. Analysis of the process data revealed the depressurization and resulting velocities were unlikely to have damaged any equipment, especially with limited vessel internals installed, but were sufficient to achieve the desired cleaning factor. The first cleaning air blow was deemed complete and, like Train B, the systems were shut down to enable inspections, cleanup, and installation of permanent system components.

The focus of cleaning air blows returned to Train B in late February 2015. Both HP flares were fully commissioned shortly thereafter, and the remaining cleaning air blows alternated between trains. The cleaning air blow to the Train B syngas scrubber was completed first. Air flow was re-established to the startup stack at conditions similar to the previous cleaning air blow tests, and pressure controller PIC24445 was re-tuned with the permanent valve installed. Flow was then transferred to the temporary sacrificial pressure control valve PV24456, and pressure controller

PIC244456 was tuned to complete the remainder of air blow. System pressure was intermittently cycled using PIC24456 to create disturbance, but temporary control valve PV24456 reached choke flow conditions before the maximum cleaning factor could be achieved. The maximum cleaning factor for the cleaning air blow was based on process flows and conditions during a system trip, but the test could only achieve 60% of the target as executed. Further analysis determined the relative drag force achieved during the cleaning air blow was greater than expected during normal operation, so the test was declared complete. The Train A cleaning air blow to the syngas scrubber through pressure control valve PV14456 was completed a few days later with similar results. After completing the air blows, both trains were temporarily shut down for inspection, cleaning, and to install the permanent PV14456/24456 valves. No notable debris beyond normal construction trash was observed.

The next cleaning air blow to the vent valves at the AGR inlet, PV29001 and PV209026, was initiated on Train B in early March 2015. For the cleaning blow, PV29001 was removed and blinded while PV29026 was replaced with a temporary sacrificial pressure control valve and downstream orifice plates. Two PACS were again used to achieve approximately 400,000 lb/hr air flow while pressure was intermittently cycled from 25 to 50 psig. Unlike the previous air blow, the additional pressure drop through the WGS and ammonia scrubber systems resulted in higher velocities at PV29026 to achieve desired cleaning factor, and the cleaning blow was declared complete after 3 to 4 hr of operation. The Train A cleaning air blow to the AGR inlet was completed a few days later with comparable results. Both trains were subsequently shut down for about 10 days for inspections and cleaning of the syngas cleanup vessels and installation of permanent valves and heat exchangers. No notable debris beyond normal construction trash was observed.

The final cleaning air blow through the AGR to the flare vent at the CT inlet (PV24503A) was conducted on Train B in mid-March 2015. PV24503A was replaced with a temporary pipe spool for the cleaning air blow while the downstream isolation valve XV24982 was replaced with a temporary sacrificial butterfly valve and orifice plates to keep all components from reaching choked flow. After a minor delay to fix leaks discovered downstream of the AGR in systems that had not previously been pressure tested, flow from the PACs was re-established at approximately 400,000 lb/hr through syngas cleanup and 60-70 psig at CT inlet. Unlike previous cleaning air blows where the pressure control valve was cycled to create disturbance, the final cleaning air blow intermittently cycled air flow between 100,000 and 400,000 lb/hr to achieve the desired cleaning factor. The maximum cleaning factor could not be achieved. The target cleaning factor for the cleaning air blow was based on process flows and conditions during a system startup, but the test could only achieve 60% of the target as executed. Further analysis determined the relative drag force achieved during the cleaning air blow was similar to that expected during normal operation, so the test was declared complete. The Train A cleaning air blow to the CT inlet was completed a few days later with comparable results. Both trains were subsequently shut down for inspections, cleaning, and installation of permanent valves and heat exchangers. No notable debris beyond normal construction trash was observed.

After the cleaning blows were completed, Train A continued with TP1020 air flow tuning and testing in late March through early April 2015. The testing was slightly delayed after the initial pressure test up to 400 psig revealed several leaks in the gasifier and PCD that needed to be addressed. The first observation during the air flow testing was that control valve PV14556 and its downstream diffuser were reaching choke flow conditions, which caused the pressure controller PIC14456 to fully open the valve and limit pressure control. Process conditions at several points were collected and sent to process engineering for further evaluation. Testing then progressed to pressure controller PIC14668 and the associated control valve PV14668 located between the HX1035 startup/sulfiding heater and the stage I WGS (figures 5.11-4 and 5.11-5). In traveling, pressure control valve PV14668 experienced sticking that affected controllability and prevented adequate tuning of ZIC14668 (figure 5.11-4) per plan. One objective of the test was to control gasifier pressure with approximately 10% of the total air flow through PV14668 while the remainder flowed through PV14667 to the vent at the AGR inlet to simulate conditions during catalyst sulfiding. PIC14668 had difficulty controlling pressure at the target flow rates due to PV14668 opening less than 5%. The minimum flow target through PV14668 was increased to 20% to move the control valve into a controllable range. As with PV14456, process conditions at several points were collected for PV14668 and sent to process engineering for further evaluation. Tuning and testing progressed to PIC19001A and PIC19001/19026 at the AGR inlet, and was completed successfully before

a significant leak develop on one of the Stage I WGS reactor flanges. Air flow was transferred back to control valve PV14445 and the syngas cleanup area was isolated to repair the leaking flange.

When air flow testing resumed, delays in testing within the Train A AGR system prevented the next step of tuning and testing the AGR outlet pressure controller PIC19905, so the project team worked through pressure control transitions for controllers upstream of the AGR (PIC14456, PIC14668, and PIC19001A, and PIC19001). While most transitions were completed successfully with minimal system impact, a problem was discovered when transitioning from startup or sulfiding conditions to normal flow conditions. A 60+ psi pressure drop across control valve PV14667, even when 100% open, created a high pressure drop across the stage I WGS reactor inlet isolation valves XV14638 and XV14648, when transitioning flow out of the startup heater and through the normal WGS flow path (figure 5.11-4 or 5.11-5). Process data was again collected and sent to process engineering for review.

After the work in the AGR system was completed, the team placed the AGR in service and attempted to tune pressure controller PIC19005 at the AGR exit but found isolation valves upstream and downstream of the control valve closed and locked out. Since scaffold was needed to access the isolation valves and remove the clearances (following the lockout/tagout procedure), the team shifted focus to pressure controller PIC14503A and control valve PV14503A at the combustion turbine inlet, then back to pressure controller PIC19005 after the isolation valves were open. Both pressure controllers were tuned successfully. The remaining pressure control transitions from the inlet of the AGR to the CT inlet were successfully tested the following day before air flow was transitioned back to pressure controller PIC14456 at the syngas scrubber, simulating a normal controlled shutdown. Finally, air flow was transferred back to pressure controller PIC14503A at the CT inlet to prepare for trip testing. The gasifier trip test was initiated but the master pressure controller did not send the correct setpoint to pressure controller PIC14456 at the syngas scrubber. The test was repeated successfully after a minor correction to control logic, and air flow testing on Train A was deemed complete on April 6, 2015. With system dynamics adequately observed during the primary trip test, the remaining trip tests were completed by evaluating the control logic responses to simulated trips within the control system.

Train B air flow testing resumed after an approximately 3-wk outage to fix components in the particulate control device (PCD). Tuning parameters from Train A were transferred to the Train B controllers to decrease the test duration. Train B demonstrated the same issues with control valves PV24456, PV24668, and PV24667 as seen in their Train A counterparts. All pressure control transitions were tested successfully. Finally, trip testing was completed successfully in two attempts after minor control logic adjustments. Train B air flow testing was completed on May 5, 2015.

The control valve issues discovered during air flow testing were analyzed and resolved by engineering in cooperation with control valve vendors. Analysis of the PV14456/24456 design revealed the valve had been specified for full operating pressure but only partial flow, which resulted in insufficient valve Cv per design. The control valve trim was replaced to increase Cv by approximately 45%. Subsequent testing in September 2015 revealed the new trim worked well for controlling gasifier pressure at two different operating points. However, problems with choke flow and insufficient valve Cv resurfaced when the project attempted to maintain higher velocities (volumetric flow) in the gasifier during subsequent testing. Field tests and calculations indicated the valve was operating per design, but the valve inlet pressure was noticeably lower than anticipated. Further tests to troubleshoot the cause of low valve inlet pressure and confirm process flows with a mass balance were delayed by a shortage of resources and lack of instrumentation. Operating and procedure modifications were implemented to limit the impact of PV14456/24456 while investigation continued, and system testing progressed.

Analysis of the PV14668/24668 design also revealed insufficient valve specifications. Control valve PV14468/24668 controls gasifier pressure over a wide range of potential startup conditions, from full operating pressure and syngas flows during a normal startup to reduced pressures and minimal syngas flow during catalyst activation. The original valve design, however, was based on a single operating case with high syngas flow and relatively low operating pressure, resulting in a large valve Cv. To resolve the issue, multiple operating scenarios were evaluated, and a series of restriction orifices was added downstream of the valve to improve operation over a wider range of conditions. The size of the control valve actuator was increased to improve valve travel across a range of conditions. Subsequent testing of PV14668/24668 indicated the modified valve/orifice design performed well during a variety of startup conditions.

While analysis of the PV14667/24667 valve design did not reveal any control issues, the overall system design of the N_2 heating and sulfiding equipment and controls did not adequately consider necessary transitions during startup. The control valve was designed correctly and performed well during operation, but the high pressure drop created across the valve created problems when transitioning out of the startup/sulfiding heater into the normal syngas flow path. To resolve the issue, a manual bypass was added in parallel with PV14667/24667. The bypass was opened along with PV14667/24667 to minimize pressure drop before the Stage 1 WGS inlet isolation valves were opened to transition syngas flow out of the startup/sulfiding heater.

5.11.3.2 *System Restoration and Vessel Internals Installation*

After air flow tuning and testing was completed, long outages were executed in April through June of 2015 to install internals and perform inspections in vessels throughout syngas cleanup. Internals installation was completed successfully but additional, unplanned steps were necessary to address carbon contamination of stainless steel cladding and repairs in multiple vessels in the syngas cleanup area of Trains A and B. See section 6.4, Vessel Internals.

5.11.3.3 *Process Condensate KO Drum and Ammonia Scrubber Tuning and Testing*

See figures 5.11-6 and 5.11-7 for illustrations of equipment and control components.

Flushing, tuning, and testing of CL1006 ammonia scrubber and DR1010 process condensate KO drum was completed successfully on Train A in early June 2015, after vessel internals were installed but before cladding repairs. The ammonia scrubber make-up water flow controller FIC11098 was tuned successfully while the make-up water line was flushed to remove debris. After flushing was completed, level controller LIC14563 on the CL1006 pumparound collection tray was successfully tuned, but level transmitter LIT14563 did not match the liquid level observed in the level gauge so the issue was referred to instrumentation technicians for investigation. Testing revealed the overflow pipe for the pumparound collection tray was approximately 18 in. instead of 22 in. as designed, which reduced the level control range but did not hinder continued operation. After level control was established on the pumparound collection tray, trip testing of the PU1006A/B sour water pumparound pumps was completed successfully with water transferred by hose to DR1010. Trip testing for PU1010A/B process condensate pumps was completed successfully while flushing process condensate lines to a temporary storage tank. Like CL1006, tuning for the DR1010 level controller LIC14439 was completed successfully with minor discrepancies between the level transmitter and local level gauge. The PU1010 minimum flow (kickback) controller FIC14446 was tuned and tested with no issues.

Flushing, tuning, and testing of the CL2006 ammonia scrubber and the DR2010 process condensate KO drum was completed on Train B in mid-August 2015 after both internals installation and cladding repairs were completed. Commencement of the test was delayed by numerous issues. These included an incorrectly installed check valve in the make-up water line, and instrumentation issues ranging from instruments not reading to instrumentation root valves being misaligned. After testing began, it was quickly suspended when the PU2006A/B sour water pumparound pumps were found to be locked out and minimum level trip logic bypassed. After regrouping and completing proper walkdowns and preparation, the test was completed successfully with results similar to Train A on August 20, 2015.

5.11.3.4 *Nitrogen Heating System Tuning and Testing*

The TP1028 nitrogen heating test package for Train A was originally to be executed in August 2015 after vessel cladding repairs were completed but was delayed due to ongoing work in other areas, clearances (LOTO) limiting the availability of the Train A HP flare and sour water headers, and limited availability of tempered water, IP nitrogen, and IP steam. The project team performed additional walkdowns and addressed instrumentation and valve alignment issues during delays. Testing commenced in early September 2015 but experienced multiple-day delays due to leaking flanges on the nitrogen recirculation line entering the HX1035 startup/sulfiding heater and in six out of the eight reactors in the WGS system. It is unclear why the reactor gaskets leaked during testing of the nitrogen heating system after pressure testing had already been conducted during the air flow test package. Valve position data suggests each stage of WGS reactors may have been bypassed at different points during air flow testing but is not conclusive because instrumentation such as valve limit switches was still being verified at that point in commissioning. After the various issues were addressed, TP1028 was executed successfully per procedure. Instrumentation issues were identified,

such as thermocouples that were not inserted fully, but the overall performance of the system was confirmed, and all controllers were sufficiently tuned and tested. The only notable discovery during the testing was when the upstream syngas scrubber system experienced a pressure increase during the nitrogen heating test even though it was out of service. The project team initially suspected an internal leak in HX1009 stage I shift feed recuperator, but further testing of the heat exchanger ruled out this possibility. Additional evaluations and testing revealed the stage I WGS bypass valve XV14465 (figure 5.11-4), was leaking nitrogen from the nitrogen circulation loop into the syngas scrubber. The valve's mechanical stops were adjusted to reduce the estimated leak rate to less than 50 lb/hr. The Train A nitrogen heating system testing was completed on Sept. 14, 2015.

Like TP1028, the Train B TP2028 nitrogen heating test package was delayed by numerous clearances (LOTO), instrumentation issues, and Train B HP flare availability. TP2028 was eventually started in late October 2015 but experienced additional delays when many steps had to be repeated to ensure compliance with the approved procedure. The test was successfully completed on Oct. 25, 2015 with results similar to Train A's TP1028. However, no leaks were discovered with the Train B stage I WGS bypass valve.

5.11.3.5 *Additional Unplanned Testing*

After all planned testing was completed in the syngas cleanup area, the project team performed additional tuning and testing while gasifier refractory and PCD repairs were completed in upstream systems. For example, the HX2027 process condensate trim heater steam controls in Train B were tuned and tested during simultaneous testing of Train B's CL2007 syngas scrubber (figure 5.11-2). A procedure was developed to fill the DR2010 process condensate KO drum using the vessel's 2-in. steam-out nozzle with a hose connection from the CL2006 ammonia scrubber's make-up water line. After level was established in DR2010, the PU2010A/B process condensate pumps were started and the HX2027 LP steam supply controls were successfully tuned while sending process condensate back to CL2007. A similar plan was developed for the Train A HX1027 process condensate heater but was not executed. Plans to tune and test additional Train A controls were moved to subsequent testing after syngas was introduced.

5.11.3.6 *Catalyst Installation*

The final step in syngas cleanup commissioning was installing catalyst and adsorbent in each train's WGS and mercury removal systems. A contractor with extensive experience in catalyst handling and loading began installing catalyst in Train B in mid-April 2016 and finished Apr. 24, 2016. Train A catalyst installation began after Train B and finished on June 20, 2016. Catalyst installation presented a significant logistical challenge due to ongoing commissioning activities and the amount of material being delivered to the site. The catalyst and inert support material had been purchased in 2013 and 2014, and most material was held in offsite storage. It had to be delivered just-in-time to the reactors being loaded to avoid degradation or damage from exposure to the environment. Some inert ceramic material, which is less susceptible to degradation, was stored onsite in temporary tents.

During catalyst loading, some super sacks containing approximately 2,000 lb of catalyst had degraded due to environmental exposure. To prevent bursting of super sacks during lifts, the material was loaded into a hopper on the ground prior to lifting.

5.11.4 Final Summary

Operational testing and preparations for introduction of syngas feed began in the syngas cleanup area in late December 2014 and were successfully completed with catalyst installation in late June 2016.

Many challenges were encountered throughout the testing activities, including construction quality such as damaged and incorrect gaskets.

Clearances or LOTO, in particular, presented challenges in executing test activities. For example, many different systems are connected to the HP flare headers for each train, so any activities requiring LOTO of the HP flare header will have a major impact on other areas and was a significant source of interruption. The clearance or LOTO process and procedures were still relatively new for the Kemper facility. It took some time for personnel conducting test package activities to become knowledgeable and efficient at executing or removing clearances. Nitrogen, steam, and water

supply were critical to operational testing in many systems, so delays in their commissioning and testing or limits to the quantity available negatively impacted the schedule.

Operational testing of the systems in the syngas cleanup area achieved essentially all of the original objectives. Notable achievements in the syngas cleanup area include:

- All systems in the syngas cleanup area were sufficiently cleaned and flushed to enable more advanced tuning and testing.
- System dynamics and controls were tested and verified. Pressure control, a particularly important operating requirement for the gasifier, was successfully demonstrated throughout the syngas cleanup flow path.
  - Pressure control was stable in each major system of the syngas cleanup flow path, pressure control transitions between systems were executed with minimal impact, and simulation of process upsets or trips demonstrated that control logic could place the system in a safe position.
- Operational testing revealed design issues with pressure control valves PV14456/24456, PV14668/24668, and PV14667/24667, all successfully resolved with valve or piping modifications.
- When problems involving PV14456/24456 resurfaced during subsequent testing, operating and procedural adjustments were implemented to allow testing and operation to proceed while technical evaluation of the root cause continued.
- Proper operation of the critical liquid handling equipment and controls within the ammonia scrubber system was confirmed with plans to finalize tuning and testing of minor components in subsequent test packages when more system integration was possible.
- The ability to protect expensive WGS catalyst from damage due to moisture during startup was demonstrated with successful operation of the nitrogen heating system.
- The equipment and controls needed to sulfide or activate WGS catalyst in situ were tested and confirmed before introduction of syngas.
- Vessel internals and catalyst were successfully installed.

Based on these achievements and the fact that activities in the syngas cleanup area never delayed overall progress of the project, the commissioning and testing of the syngas cleanup area was successful in preparing the systems for operation with syngas. The performance of the syngas cleanup area after introduction of syngas will be addressed in the final project report.

5.12 Recycle Gas Compressors

5.12.1 System Overview

After sweet syngas passes through the mercury adsorber, but before entering the low-temperature syngas recuperator, a portion of the stream is diverted to the recycle gas compressor CO1008/2008. Any free moisture in the syngas stream is removed in the recycle gas compressor knockout drum DR1009/2009 before being compressed. If forward flow to the downstream system is not possible, the recycle gas can be redirected from the discharge of the compressor to the inlet knockout drum through an antisurge kickback line. As the gas is recirculated, it is cooled in the recycle gas compressor kickback cooler HX1032/2032 to remove the heat of compression. Figure 5.12-1 provides an overview of the system.

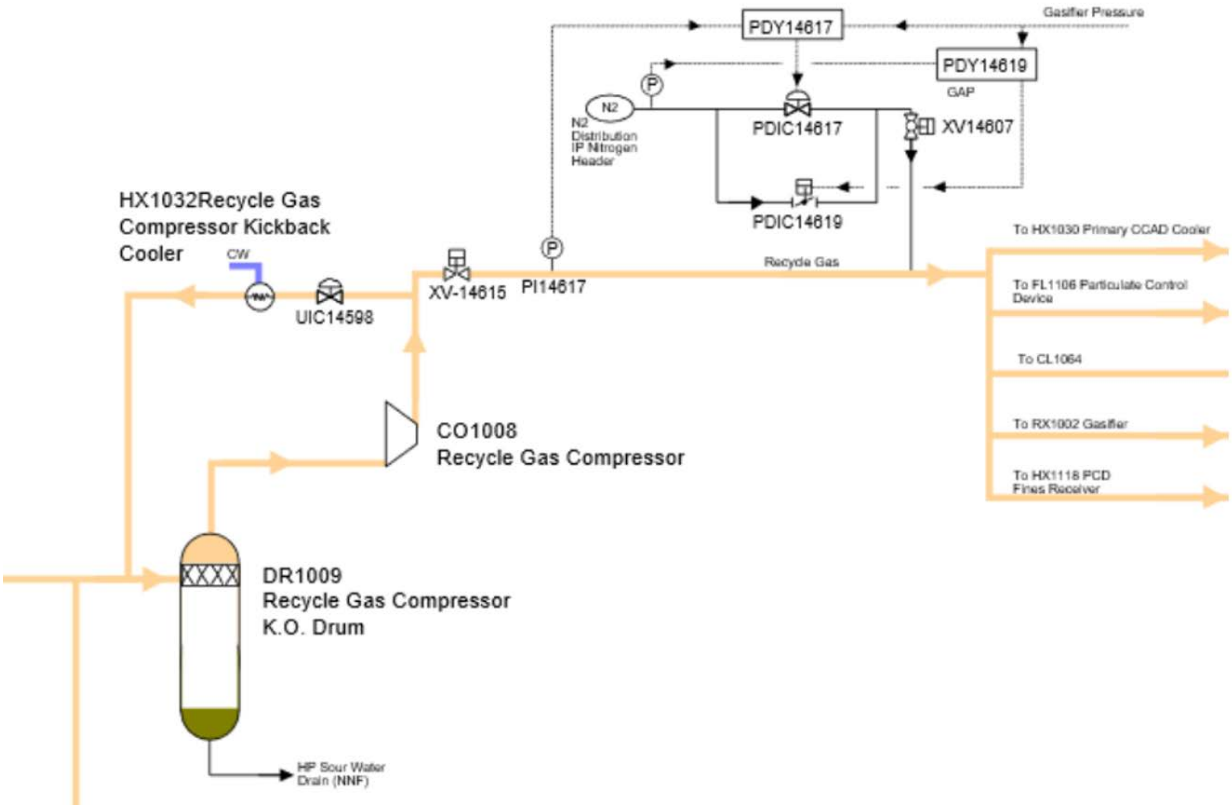


Figure 5.12-1 – Recycle gas system overview

The pressurized sweet syngas is used as a utility gas throughout the gasifier island in locations where an inert gas such as nitrogen is detrimental to process efficiency. It is primarily used for solids aeration in the gasifier, back-pulse gas in the PCD, and as a stripping gas in the AGR concentrator. The recycle gas is supplied to each of the applications through the recycle gas header.

There is one recycle gas compressor per gasifier train. Each compressor is a three-stage, horizontal split case compressor that is electric motor driven. The compressor operates on sweet syngas during normal operations and can be operated on nitrogen if sweet syngas is not available. In that case, intermediate pressure nitrogen is supplied to the compressor suction from the inlet knockout drum.

The compressor is usually started early in the plant return-to-service sequence, before sweet syngas is available, to provide back-pulse gas to the PCD and stripping gas to the AGR. There are no modifications needed to swap between nitrogen and sweet syngas. There will be a change in compressor performance due to differences in molecular weight between syngas and nitrogen.

The recycle gas compressor raises the syngas pressure from 450 psig to 690 psig. Process control is through discharge throttling. The compressor follows the resistance of the downstream system and does not have an active process control mechanism.

If the compressor trips during operation, a backup nitrogen system can supply emergency nitrogen to the recycle gas distribution header. This intermediate pressure nitrogen feed is not sized or intended for continuous full-load operation. It can supply a sufficient quantity of nitrogen to ensure a controlled shutdown or reduced load service to critical applications such as PCD backpulse.

5.12.2 Initial Commissioning Plan

The commissioning of each recycle gas compressor was to have two separate test packages, each using nitrogen as the test medium. Nitrogen would be circulated through a controlled test volume (figure 5.12-2).

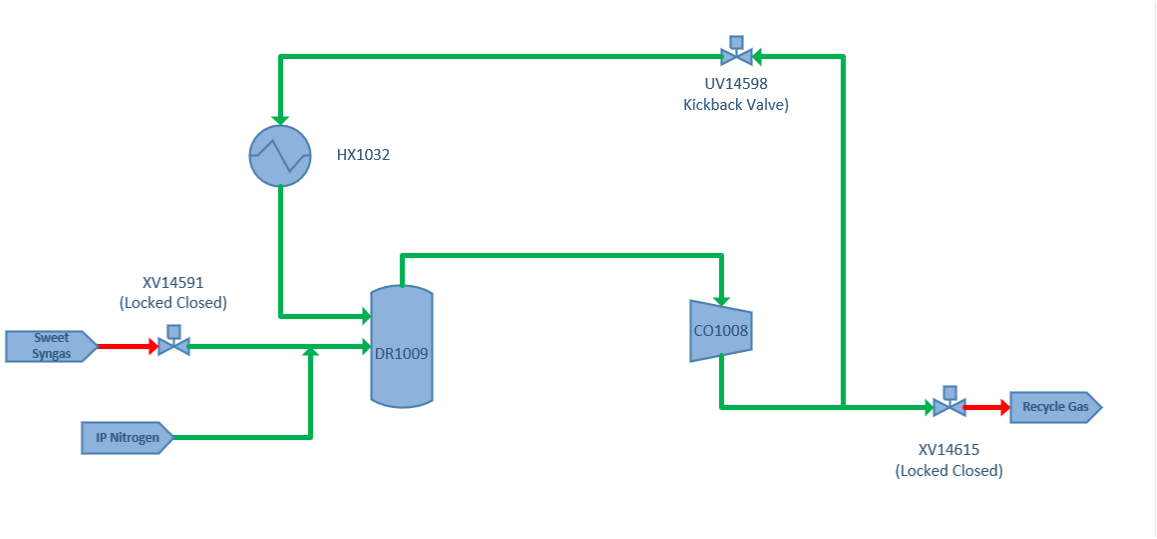


Figure 5.12-2 – Recycle gas compressor test loop

The suction and discharge isolation valves were to be closed and under clearance. The antisurge kickback valve was to remain open. Gas was to be supplied from the IP nitrogen line on the suction of the compressor to precharge the test loop to the minimum start pressure. After starting the compressor, the gas would circulate from the suction to the discharge and back to the suction through the kickback line. The kickback line contained a kickback cooler to remove the heat of compression, which would allow the test to proceed until each of the test objectives was completed.

All turnover activities were to be completed before the start of compressor testing, both items outlined by the vendor and additional items that would integrate the compressor application to the overall plant following commissioning. These activities and items included verification of installation, loop/logic checks, electrical checkout and uncoupled motor run-in, and system cleaning. The lube oil and seal systems were to be fully commissioned and available for compressor testing.

On completion of the precommissioning activities, the expectation was to be able to proceed directly into functional testing of each compressor. Functional activities included:

- Start of the seal gas system.
- System deaeration by purging with nitrogen (critical step to ensure the test medium composition was known during surge testing).
- Low-pressure leak testing.
- Compressor initial start.
- Baseline monitoring of bearing temperatures, vibration levels, and initial process conditions.
- Medium pressure leak testing.
- Verify mechanical integrity (slowly close the antisurge valve and load the machine).
- Test and tune the compressor antisurge valve.
- Verify critical alarm setpoints.
- Compressor surge testing.
- Interlock trip testing.

After compressor testing was complete, the system was to be prepared for integration with the broader plant and recycle gas distribution system.

5.12.3 Significant Events

Recycle Gas – Train A		Recycle Gas – Train B	
Lube oil system commissioned	5-9-2014	Lube oil system commissioned	5-9-2014
System cleaning complete	9-26-2014	System cleaning complete	9-26-2014
Precommissioning complete	11-15-2014	Precommissioning complete	11-15-2014
Recycle gas compressor commissioned	1-21-2015	Recycle gas compressor commissioned	1-16-2015

The commissioning of the recycle gas compressors closely followed the initial commissioning plans with a few exceptions. The limited availability of IP and LP nitrogen early in the commissioning cycle required using a temporary source. The process cleaning ran into challenges related to pipe stress that forced restoration delays to the Train A system, resulting in the need to reclean the process piping before commissioning. These specific issues are discussed in the next sections.

5.12.3.1 *Precommissioning Activities*

Startup began to prepare the system for commissioning as equipment was received from Construction, including completing instrument loop checks and logic verification of the suction knockout drum, lube oil skid, and compressor. Lube oil pump and compressor main motor uncoupled runs were completed to confirm correct rotation and obtain baseline information, such as bearing temperatures and unloaded vibration levels.

After the lube oil skid was functionally available, a third-party flush crew completed a lube oil flush of each compressor oil skid. This process included an initial off-skid circulation through sock filtration (with compressor and main motor bearings bypassed) and an on-skid flush flowing through equipment bearings with oil screens in the bearing supply lines. Restoration and final checkout of each oil skid was completed in May 2014.

In parallel with the oil skid checkout, the compressor dry-gas seals were installed. The gas seals were shipped to site in long-term storage containers to ensure they were not damaged during installation. The intent was to install them a few weeks prior to commissioning, but the project schedule only allowed an installation window in March 2014 for Train A and April 2014 for Train B. Due to limited availability of turbomachinery millwrights, the project decided to mobilize a vendor crew to complete the installation. The vendor was familiar with the seals and could install them more quickly than site personnel. The vendor completed each of the installations per the project schedule with no issues identified. After installed, the seals were kept under a nitrogen purge while the system was down.

With the auxiliary systems complete, project focus turned to cleaning the process piping and verifying cleanliness of the test path. Hydrolazing was used to wash debris and mill scale from the suction and process piping. The supply and return line to the antisurge valve and the compressor suction and discharge piping were also cleaned. The cleaning activity was completed without issue.

When the piping was opened at the compressor suction and discharge nozzle in preparation for cleaning, the piping exhibited a significant amount of stress. The piping appeared to have been welded incorrectly per the flange-face flatness criteria. Numerous segments of piping were found to have pipe stress that exceed tolerance.

The flanges had to be repaired for reassembly. The compressor suction and discharge piping needed to meet vendor stress allowances to minimize long-term impacts to compressor operation. Several of the flanges were corrected by adjusting pipe supports or taking up some of the stress in adjacent flanges. The more challenging connections required the piping to be cut and rewelded.

Final restoration of each compressor piping network was complete in September 2014. Final instrumentation checks were completed in November 2014.

5.12.3.2 *Unavailability of IP Nitrogen*

Delays in availability of nitrogen required a temporary source be obtained to proceed with commissioning per the project schedule. Since the compressor test circuit is a closed loop, it was determined the test loop could be prepressurized with nitrogen from a trailer. After the compressor was started, additional nitrogen would be charged into the system to account for the reduction in volume due to the increase in pressure across the back half of the test loop. After stable flow was established, the trailer source would be necessary only to accommodate the minimal losses across the process seals. Temporary tube trailers were already being used to maintain a nitrogen purge on the seals.

A truck was dedicated to maintaining pressure on the seals throughout operations. The bulk nitrogen was supplied by connecting a second truck to the condensate drain of the suction knockout drum.

5.12.3.3 *Commissioning*

Before the initial start of the compressor, each system was leak-tested with air. No significant leaks were identified. Smaller leaks around instrument taps and small-bore piping were addressed, and the system was readied for test package execution.

The commissioning of each compressor occurred sequentially in January 2015. This section discusses one train; the same activities were completed for both applications.

The compressor seal gas and lube oil systems were verified as operational before starting the compressor. The compressor was started and allowed to warm up and stabilize before proceeding with testing. An additional leak test was conducted with no significant leaks identified.

After the unit was stable, baseline readings were recorded for bearing temperatures, process variables, and vibration levels. All trended as expected and were within specified tolerances. Both activities were completed with no issue. Figure 5.12-3 provides an overview of the process conditions through each test.

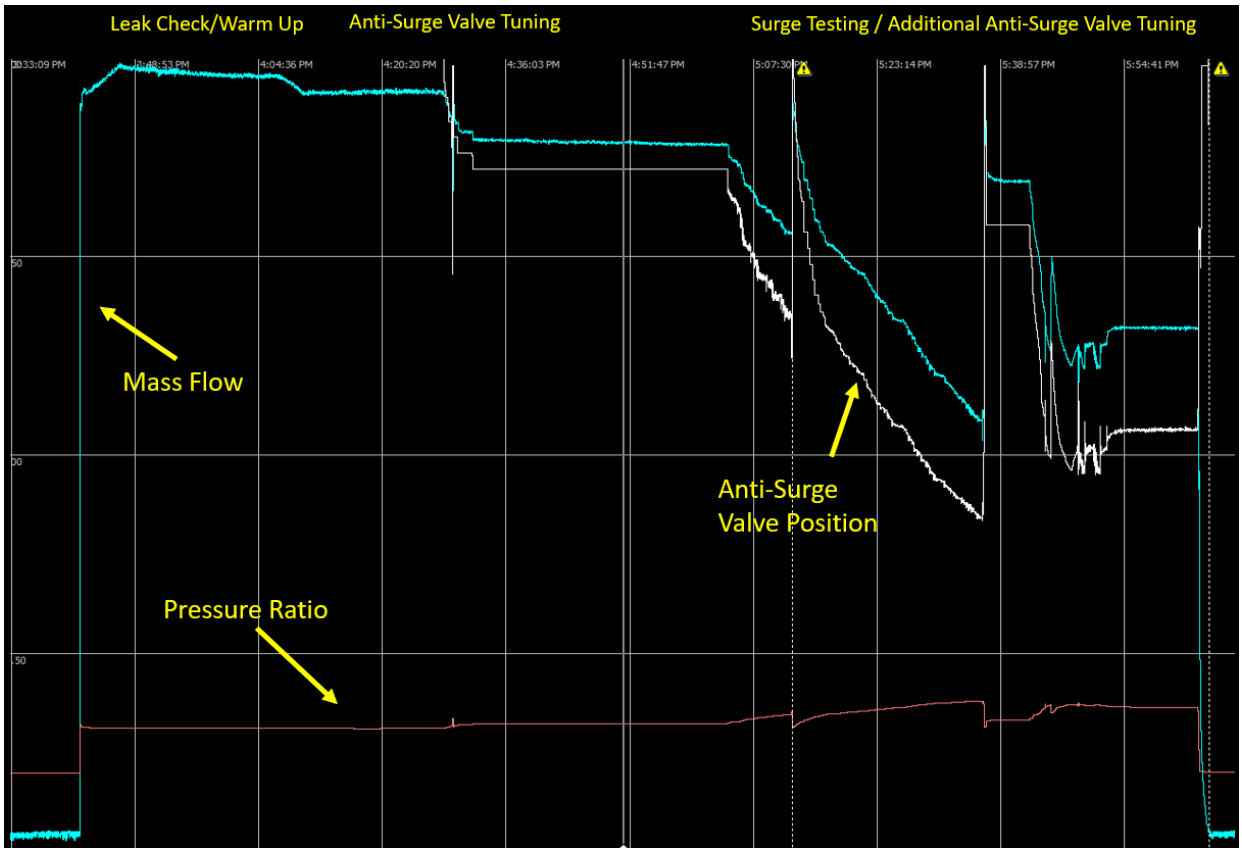


Figure 5.12-3 – Overview of Train B compressor testing

Following the early monitoring, the vendor controls representative proceeded to tuning of the antisurge valve and surge testing. Figure 5.12-4 shows the operational mapping of the surge test to the surge limit line.

Figure 5.12-4 – Train B surge test performance map

After the compressor surge point was confirmed, the compressor was subjected to a series of interlock trip tests. This test involves pulling a vibration probe or isolating two out of three voting oil header pressure gauges, and conducting an emergency stop from the DCS. The test is conducted to confirm that the trip relay from each potential control source will actually force a trip of the compressor. By procedure, a trip was initiated from the lube oil skid PLC, SIS, DCS, and the vibration monitoring system. A trip was successfully induced from each of the required control systems.

On completion of testing, each compressor system was maintained under a nitrogen cap to prevent corrosion. A continuous purge was maintained across the compressor seals.

5.12.4 Final Summary

The commissioning of the recycle gas compressors was conducted nearly in line with anticipated commissioning plans. The most significant challenges arose from the quality of the piping installation and the availability of resources. After these challenges were addressed, testing was completed using nitrogen, with each compressor performing as expected.

Additional testing and tuning activities are anticipated after syngas becomes available. These activities would be to confirm the surge point is accurately represented and that tuning parameters remain correct as the molecular weight of the gas transitions from that of nitrogen to syngas. The syngas testing is to confirm the predicted syngas operation line.

Testing of each compressor was completed well in advance of the availability of syngas. This testing resulted in the recycle gas system being placed under a nitrogen cap and a continuous nitrogen purge being established through the compressor seals. Each compressor was operated for several hours each month as a preventative maintenance precaution. Active system layup was continued until the broader supply and distributions systems were available for integration.

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5.13 Acid Gas Removal

5.13.1 System Overview

The acid gas removal system (AGR) is a multicolumn process designed to remove essentially all the H_2S and a majority of the CO_2 from the syngas stream. See figure 5.13-1, AGR diagram.

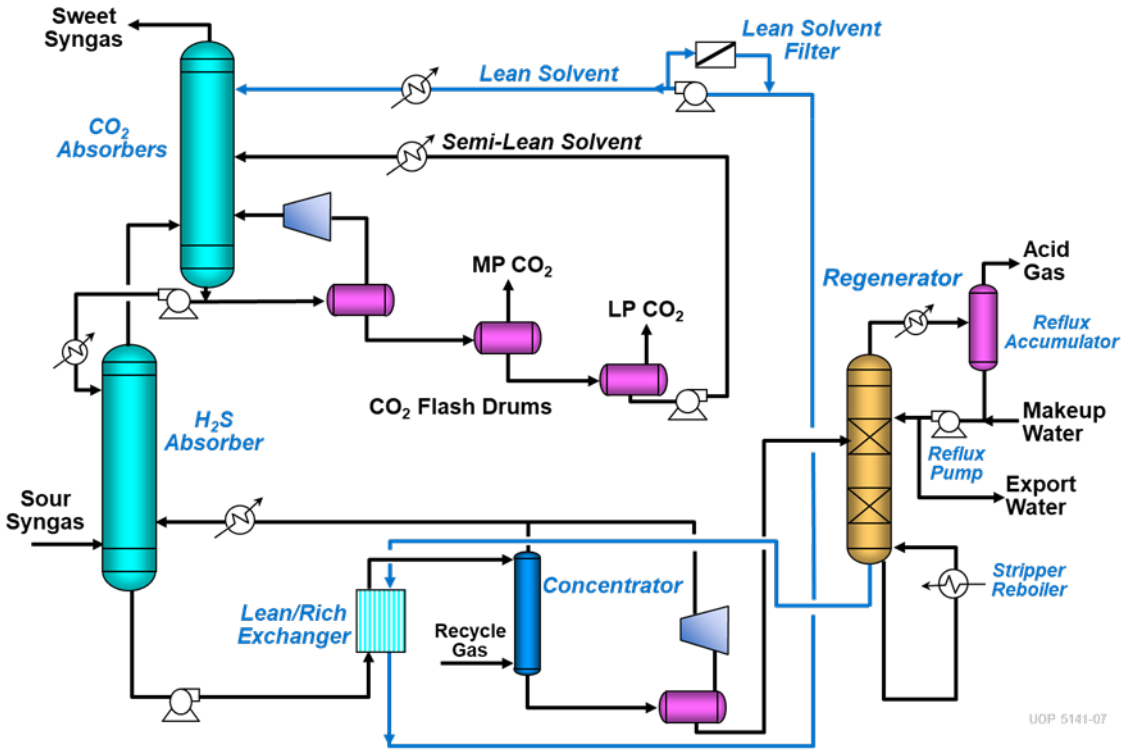

Figure 5.13-1 – Overview, acid gas removal process, Kemper County IGCC

The working fluid is SELEXOL™, a physical solvent with a high affinity for absorbing H_2S and CO_2. The process treats syngas shifted in the water-gas-shift portion of the plant. The water-gas-shift process reacts carbon monoxide with water to form carbon dioxide and hydrogen to improve carbon capture. During normal operation, shifted syngas first enters the H_2S absorber CL1060 (figure 5.13-2.). The H_2S is removed as it comes into contact with chilled solvent over a series of packed beds. The syngas then enters the CO_2 absorbers CL1161/CL1261/CL1361, where CO_2 is removed from the syngas using additional chilled solvent, creating sweet syngas. The process requires a high solvent circulation rate to absorb the large amount of CO_2 removed from the syngas. Three parallel CO_2 absorbers (figure 5.13-2) provide the volume needed for the large amount of solvent circulation required. The sweet gas exits the AGR CO_2 absorbers with virtually no H_2S remaining and enough CO_2 removed for a plant net emissions rate of 800 lb CO_2 per MWh, approximately the same CO_2 emission rate of a natural gas combined cycle plant.

Figure 5.13-2 – Kemper SELEXOL absorbers

The other AGR equipment regenerates the solvent and circulates it for reuse, while generating acid gas and CO_2 byproducts. The SELEXOL solvent circulates through the system in two separate loops. The semilean solvent loop provides solvent for the bulk of the CO_2 removal. The rich/lean solvent loop provides solvent for H_2S removal. Both streams flow through the AGR CO_2 absorbers.

The semilean solvent (figure 5.13-1) enters the AGR CO_2 absorber at an intermediate position in the column, where it comes into contact with the syngas leaving the H_2S absorber and physically absorbs the CO_2 from the syngas. Leaving the CO_2 absorber, it is loaded with CO_2 and requires regeneration by reducing the pressure of the solvent to lower the solubility of CO_2 in SELEXOL. The pressure reduction takes place in two parallel sets of vessels called the CO_2 flash drums. Each set contains a high pressure (HP), medium pressure (MP), and low pressure (LP) flash drum.

In the HP CO_2 flash drums DR1166/1266, the reduced pressure of the solvent allows lighter gases such as N_2, H_2, and CH_4 to flash from the solvent while leaving most of the CO_2 still dissolved. These gases are compressed in the AGR CO_2 recycle compressor CO1066 and returned to the AGR CO_2 absorber. The HP flash stage ensures CO_2 product purity.

After the HP CO_2 flash drum, the solvent enters the AGR MP CO_2 flash drums DR1167/1267. The pressure decreases, and a significant amount of the CO_2 evolves from the solvent. The evolved CO_2 flows to the CO_2 compression system for byproduct export. In the AGR LP CO_2 flash drums DR1168/1268, a third decrease in solvent pressure causes the remaining CO_2 to flash from the solvent. The gas flows to the CO_2 compression system for additional product export. From DR1168/1268, the solvent is pumped back up to operating pressure, chilled in the AGR semilean solvent chillers HX1168/1268/1368 and returned to the midsection of the AGR CO_2 absorber.

The rich/lean solvent loop (figure 5.13-1) is more complex. Lean solvent enters the top of the AGR CO_2 absorbers where it serves as a polishing stream to remove additional CO_2 from the syngas. Flowing through the CO_2 absorber preloads the solvent with CO_2 before it enters the AGR H_2S absorber, allowing the solvent to selectively remove H_2S from the syngas in CL1060. The lean solvent mixes with the semilean solvent in the lower section of the CO_2 absorbers, and the combined stream exits the bottom of the columns. Figure 5.13-3 shows the lower portion of the CO_2 absorber is the only part of the AGR common to both loops. The exiting solvent splits into two streams: the stream flowing to the CO_2 flash drums, and a loaded solvent stream for use in H_2S removal. The stream for H_2S removal is pumped with the AGR loaded solvent pumps PU1166/1266/1366 through the AGR loaded solvent chillers HX1169/1269/1369, where refrigerant cools the solvent before it enters the H_2S absorber to remove the H_2S from the syngas.

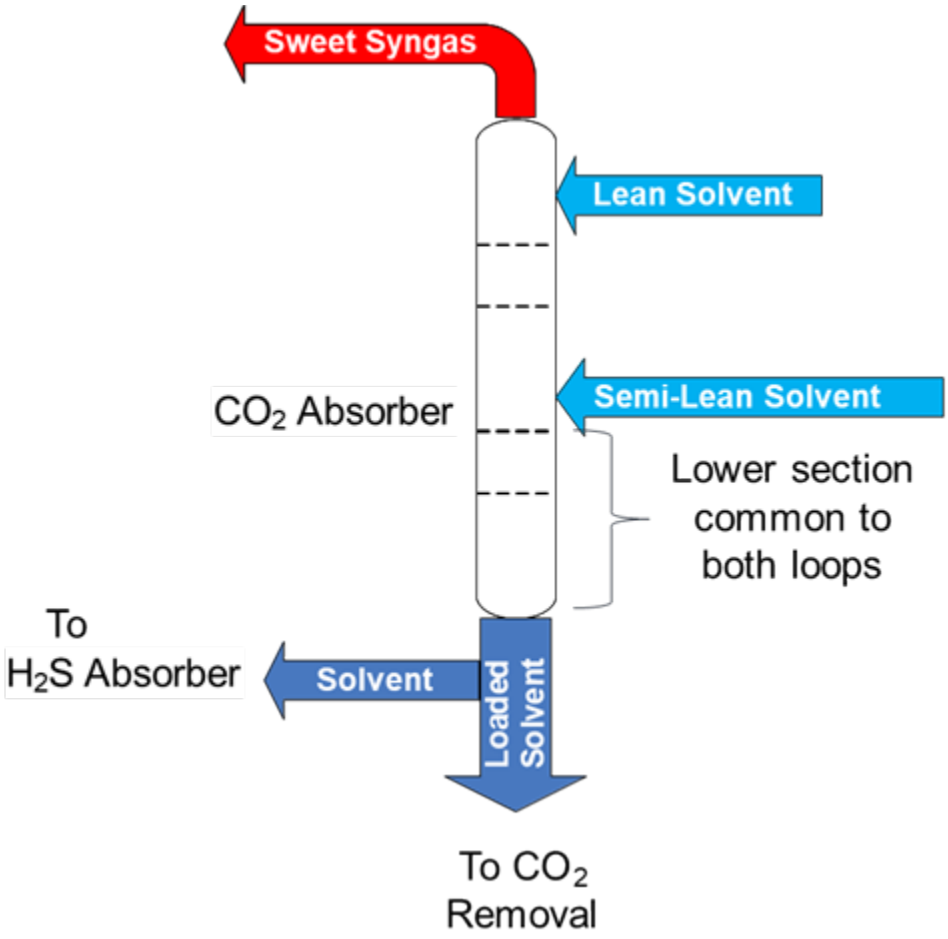

Figure 5.13-3 – Closeup of CO_2 absorber

The loaded solvent flows through the H_2S absorber, absorbing H_2S from the syngas. It is now referred to as rich solvent due to its H_2S content. The AGR rich solvent pumps PU1060 pump the rich solvent from CL1060 through the AGR lean/rich solvent exchanger HX1061 to heat the solvent before sending it to the AGR concentrator CL1064. In CL1064, sweet recycled syngas strips some of the co-absorbed gases from the solvent while leaving most of the H_2S absorbed, improving the concentration of H_2S in the final acid gas product. Since the operating pressure of CL1064 is greater than that of CL1060, the gas stripped in CO1064 will flow back to CL1060 without compression, but it is first cooled in the AGR stripped gas cooler HX1062 to improve absorption performance by keeping temperatures low in the H_2S absorber.

The rich solvent exiting the bottom of CL1064 flows through a control valve, and the resulting decrease in pressure causes additional absorbed gases (mostly CO_2) to flash out of the solvent. These gases separate from the solvent in

the AGR rich solvent flash drum DR1063. After being cooled, they flow to the AGR flash gas compressor CO1065. The compressor boosts the flashed gas pressure and diverts the gas downstream where it combines with the stripped gas from the AGR concentrator before returning to CL1060. The rich solvent flash drum also serves as the entry point for the sour water vent gas, a small waste stream from the sour water system.

Exiting the AGR rich solvent flash drum, the rich solvent flows to the AGR regenerator CL1063. In this column, steam heat strips the H_2S and remaining CO_2 from the solvent. The resulting acid gas stream flows to the WSA unit to be converted into sulfuric acid. The hot, lean solvent leaves the bottom of CL1063 and is pumped back through HX1061 where it is cooled as it heats the rich solvent leaving CL1060. The AGR lean solvent chiller HX1067 provides additional cooling to reach temperatures below ambient before sending the chilled solvent back to the top of the three AGR CO_2 absorbers to complete the loop.

Other systems (not shown in figure 5.13-1) include the solvent tank system, the antifoam injection system, the solvent sump, and the solvent filtration package. The tank system contains a large tank to provide make-up for the AGR units, the solvent transfer pumps, and a simple filter for removing any solids that collect in the tank. The antifoam system contains a small tank for mixing antifoam and a pump to supply antifoam to individual columns in the event of solvent foaming. The sump is an enclosed subterranean drum that collects solvent from the lowest portions of the vessels. It includes a pump for transport back into the system or into the storage tank. The filtration package is a barrier filter system used to remove contaminants from a slipstream of the lean solvent stream. It consists of a prefilter mixing tank, a filtration vessel with barrier filters, and a nitrogen back-pulsing/drying system for producing a dry filter cake from solid material removed from the solvent.

5.13.2 Initial Commissioning Plan

The goal of AGR commissioning was to prepare the mechanically completed system for receiving syngas. Plans were to verify system integrity, test system components, tune controllers, clean system internals, and fill the units with solvent. Since Kemper featured two separate AGR systems, commissioning would be performed twice, once for Train A and once for Train B.

The commissioning steps to prepare each unit for service were:

1. Initial system pressure test.
2. Water preflush.
3. Degreasing.
4. System rinses.
5. Air-freeing.
6. Solvent filling.
7. Reboiler commissioning.
8. Filtration package commissioning.

Most of these tasks required circulating liquid through the system similar to normal operation. Some could be performed simultaneously, such as testing pumps and tuning controllers during the various washes, rinses, and fills.

5.13.2.1 *Initial System Pressure Test*

The test was to ensure the AGR unit was suitable for pressurized operation. When maintenance required the opening of a vessel or major line, additional pressure tests were performed on the unit. Service air was the pressurization gas during the first pressure test.

5.13.2.2 *Water Preflush*

The goal for the preflush was to circulate water through the system to remove any construction debris remaining after hydrolazing. (Hydrolazing uses high pressure water in piping to remove scale or other contamination.) During the preflush, temporary piping bypassed the Packinox heat exchanger to avoid plugging its narrow passages.

5.13.2.3 *Degreasing*

The degreasing step removed the protective oil from the Raschig rings using a detergent. The UOP requirement was to use a 3 wt% solution of trisodium phosphate (TSP), circulating the solution through the normal lean/rich and semilean loops at a slightly elevated temperature for 18 hours. Circulating detergent allows the solution to break down oils and collect them. Draining the solution then removes most of the oils from the equipment.

While unavoidable, degreasing has several potential drawbacks. The TSP solution causes foaming, which in columns can disrupt circulation, hinder instrumentation, and result in liquid carryover to overhead gas lines. The high levels of phosphate in the solution make treatment of the water impractical in the plant wastewater system.

5.13.2.4 *System Rinses*

Rinsing was critical to ensure no TSP remained in the system following the degreasing step. Even a small amount of detergent can cause foaming and disrupt operations. To successfully rinse the unit, plans were to drain all detergent from the system, then add fresh water and circulate it through the lean and semilean loops for a few hours to remove the detergent.

The success of the rinse was evaluated by performing a nil foam test on the rinse water. A nil foam test consists of aerating a 50 mL sample of the rinse water for 1 minute in a graduated cylinder, recording the foam height generated and the time needed for the foam to break. To pass the test, the foam height has to be less than 10 mL and break within 3 seconds. If the sample fails the foam test, the system would require additional rinses until a sample passes.

5.13.2.5 *Air Freeing*

Best practice is to keep the solvent in an oxygen-free environment, since any H_2S dissolved in the solvent will react with oxygen in air to form elemental sulfur. There is a slight chance that oxygen will degrade the solvent at elevated temperatures (>300 °F), should any oxygen remain after the system is in service. To achieve air-freeing, plans were to pressurize the units to 40 psig with nitrogen and depressurize to 5 psig, repeating as necessary until gas monitors indicated no oxygen at designated vent locations.

5.13.2.6 *Solvent Filling*

The next step of the commissioning plan was to fill the unit with solvent, starting with the regenerator, then the CO_2 absorbers, followed by the remainder of the lean and semilean loops.

5.13.2.7 *Reboiler Commissioning*

The reboiler supplies the heat needed to distill acid gases from the solvent. To ensure the AGR could regenerate the solvent, reboiler commissioning steps were to add steam to the reboiler to boil the solvent, ensure the regenerator condenser could condense the water in the overhead line, and return it to the regenerator. Since the system could quickly overheat, commissioning required that the AGR refrigeration system be available to remove excess heat.

5.13.2.8 *Filtration Package Commissioning*

Kemper marked the first time a SELEXOL unit used this particular filtration package, a barrier filter system that produces a dry filter cake. Extensive testing was needed to adequately commission the unit. The plan called for testing the individual pumps, mixers, and instrumentation, then manually running the system through its operating sequence in stand-alone mode using water. Testing would determine the appropriate amount of filter aid (perlite, in this case) to

add and the appropriate timers for mixing the filter aid and drying the resulting filter cake. After successful stand-alone testing, the package was to be integrated into the loop, allowing it to begin filtering the solvent.

5.13.3 Significant Events

5.13.3.1 *Accomplishments*

Task	Train A	Train B
Preflush start	8/25/15	Cancelled
Preflush end	9/3/15	Cancelled
Degreasing start	9/20/15	12/11/15
Degreasing end	10/4/15	1/5/16
Rinse 1 start	10/9/15	1/21/16
Rinse 1 end	10/14/15	2/1/16
Rinse 2 start	10/16/15	2/10/16
Rinse 2 end	10/25/15	2/14/16
Rinse 3 start	11/11/15	2/20/16
Rinse 3 end	12/7/15	3/2/16
Air-freeing complete	7/14/16	6/24/16
Solvent fill complete	7/22/16	6/30/16
Reboilers commissioned	8/14/16	7/28/16
Filtration system online	8/23/16	7/25/16

5.13.3.2 *Initial Pressure Test*

Commissioning began after construction declared the system mechanically complete and crews had loaded the column packing and installed all column internals. The initial pressure test on Train A was Aug. 22, 2015. Crews found a few leaks in the CO_2 flash drum loops but were able to repair them quickly. After the repairs were complete, the test went well, maintaining 325 psig, with less than 2 psi pressure drop over 2 hours. The Train B pressure tests were Nov. 13, 2015, holding 250 psig with less than 5 psi pressure drop over 2 hours. The initial pressure tests used instrument air; later pressure tests used nitrogen to maintain a nonoxidizing environment for SELEXOL.

5.13.3.3 *Preparation for Rinses*

The multiple flushes, washes, and rinses would require a large quantity of water and produce a large quantity of wastewater that, while benign, had to be treated and reused within the plant due to the facility's zero-liquid discharge requirements. The Kemper wastewater facility could not treat the wastewater because of the amount of phosphates in the degreasing agent. Eight large temporary ponds were installed to the north side of the plant to collect the water used for flushing, decreasing, and rinsing (figure 5.13-3). Some water would be evaporated, and the remainder transported offsite.

Figure 5.13-4 – Temporary storage ponds for filling and draining AGR units

5.13.3.4 *Preflushes*

The water preflush began Aug. 25 after the pressure test was complete on Train A. It went slowly. Despite hydrolazing, an enormous amount of material continuously plugged the commissioning pump strainers. The commissioning strainers had a smaller mesh size than the normal operating strainers. Switching to the normal operating strainers was not a consideration, because the debris passing through them could have damaged the pumps. There was some tuning during the preflush for kickback lines and flow and level controllers, but most tuning was during the later degreasing, rinsing, and filling stages.

Train A achieved complete water circulation during the preflush on Sept. 3 but began to experience problems with a tar-like substance plugging the pump strainers, which required adding a small amount of TSP (about 0.1%) to allow circulation to continue, before draining the flush water to one of the temporary ponds. Due to the tar clogging the strainers on Train A, a preflush was not performed on Train B and commissioning went straight to the degreasing step.

Foaming occurred in the regenerator, causing liquid to spill over to the flare knockout drums.

5.13.3.5 *Degreasing*

After the foaming event, the water was drained to remove the contaminant causing the foaming. The small amount of TSP added to Train A was not enough the degrease the internals, requiring an additional degreasing step with 3% TSP solution. The full degreasing began Sept. 20 for Train A and Dec. 11 for Train B.

Degreasing proved difficult at Kemper. Foaming occurred in both trains, with the worst in the concentrator. The foaming disrupted level readings and impeded circulation, but minimizing flow prevented further liquid carryover to the flare knockout drums by keeping the foam level below the vapor outlet of the concentrator. Antifoam was slowly added to the system. Not only did it not adequately improve the situation, but the antifoam began to plug instrumentation and possibly exacerbated the foaming. Maintenance crews could restore the instrumentation only by disconnecting the instrumentation tubing and flushing it.

The refrigeration system at Kemper was not yet online, which resulted in high pump discharge temperatures that occasionally tripped the pumps and stopped circulation, leading to further instability. Since the entire system could

only circulate for a few hours at a time, UOP permitted 18 hours of cumulative circulation on each loop rather than requiring continuous circulation for both loops simultaneously.

Wastewater management was a challenge. Since the wastewater treatment system was incapable of handling the high level of phosphates, water had to be drained to the temporary ponds. This required coordinating the filling and draining of two separate trains, and there were delays when the ponds were full. Eventually, both units finished the degreasing step – Train A on Oct. 4 and Train B on Jan. 5 – allowing the units to proceed with the rinses.

5.13.3.6 *System Rinses*

Before rinsing, all detergent was carefully drained to the ponds (figure 5.13-4). Fresh water was then added to the unit and circulated in the lean and semilean loops. The rinsing stage went better than the degreasing stage. Foaming improved during each successive rinse, although the concentrator continued to indicate a small amount of foaming throughout the rinsing process. After circulating at near design rates for around 3 hours, the lab took a 50 mL sample of the rinse water and performed a nil foam test (figure 5.13-5).

Figure 5.13-5 – Liquid drained from degreasing into lined ponds

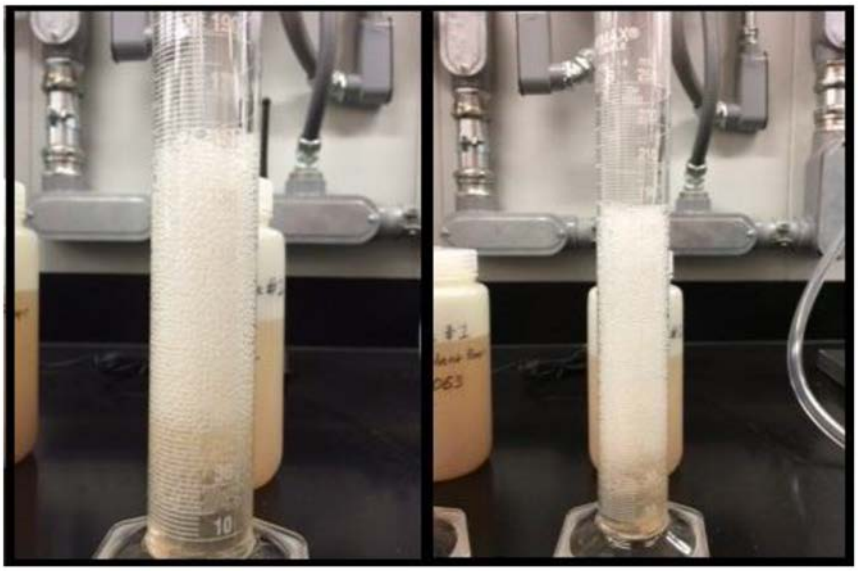

Figure 5.13-6 – First nil foam test results

As is typical for rinsing TSP, both units failed the first foam test. Train A passed the foam test on the second rinse, and Train B passed the foam test on the third rinse (figure 5.13-6). To be cautious, a third rinse was performed on Train A.

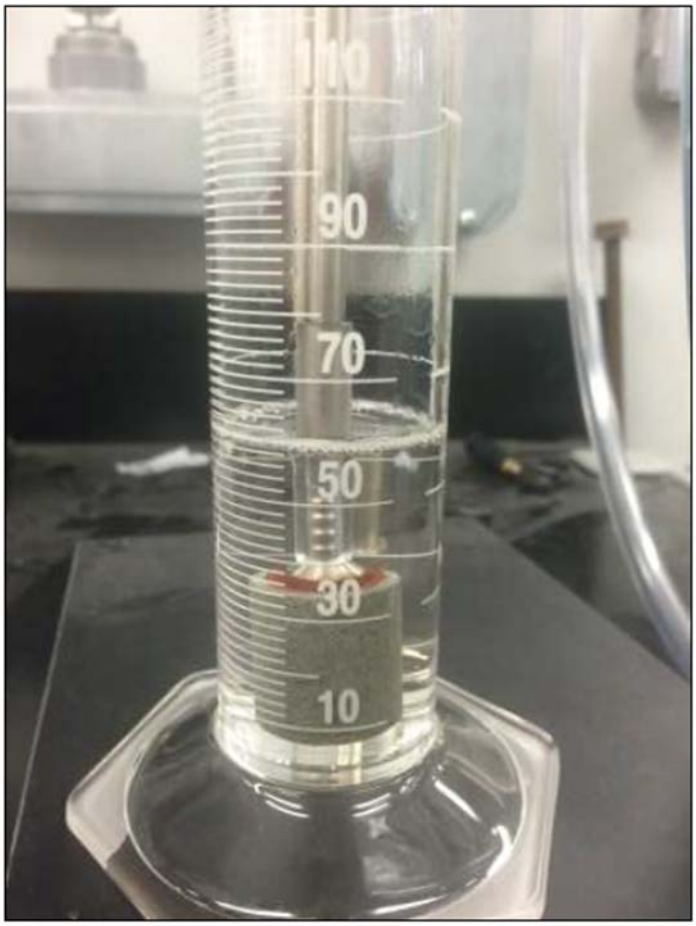

Figure 5.13-7 – Successful nil foam test results on Train B

The rinses concluded Dec. 7, 2015 for Train A and Mar. 2, 2015 for Train B. Because of heavy rains, there was not enough space in the ponds and water had to be slowly sent to the plant wastewater system. Since the plant wastewater system did not have adequate equipment to efficiently process the rinse water, the Train B rinses experienced lengthy delays. See section 5.13.3.1, Accomplishments, for the complete rinse schedule. After all rinses were complete, the bypasses around the Packinox heat exchangers were removed, restoring the normal flow paths.

5.13.3.7 *Air-freeing*

Air-freeing was performed by pressurizing the units to 40 psig with nitrogen and depressurizing to 5 psig. The air-freeing went as scheduled with one minor exception. Both trains required four pressurization cycles, rather than three, to achieve an undetectable oxygen content at the designated vent locations. Train A was air-free on July 14, 2016. Train B air-freeing occurred earlier, on June 24, 2016.

5.13.3.8 *Solvent Filling*

After the unit was free of oxygen, the SELEXOL fill began. The Train B fill began June 27, 2016, with the transfer pumps supplying SELEXOL from the tank to the Train B regenerator. From the regenerator, the high and low pressure lean solvent pumps filled the three CO_2 absorbers. The remainder of the fill admitted flow first through the semilean loop, filling the CO_2 flash drums, and then pumped the liquid through the vessels in the lean loop. Train B filling was complete on June 29, 2016. Train A filling began July 20, 2016 and concluded on July 22, 2016.

The filling was the first time the refrigeration systems were available. After the units were filled, the solvent was circulated at operating conditions to tune the refrigeration controllers and ensure chilled solvent would be available for processing syngas.

5.13.3.9 *Reboiler Commissioning*

After filling the systems, the solvent was allowed to circulate through both the rich/lean and semilean loops of both trains for several days. With the refrigeration unit now online, the controls group tuned the chiller controllers that allowed liquid ammonia to flow through the chiller tubes and cool the shell-side solvent. (See section 5.14, AGR Refrigeration.) The cooling allowed reboiler commissioning to take place. This step was to admit steam to the regenerator reboilers, which boiled the SELEXOL. The regenerator condenser then cooled and condensed the water leaving the overhead of the regenerator, recycling it back to the process. Samples taken during this period provided operations with the data needed to adjust water purge and make-up rates and ensure the optimum water concentration specified by UOP. The reboiler commissioning was completed Aug. 14, 2016 for Train A and July 28, 2016 for Train B.

5.13.3.10 *Filtration Package Commissioning*

The commissioning of the solvent filtration package began earlier, using water as a test medium. After bringing each train online, the filtration package was integrated into the train, allowing it to filter a portion of the solvent leaving the regenerator. Additional testing was required for valve timing to determine the best valve opening times for transition from filter cake application mode to online solvent filtration. If the transition was not smooth and the pressure in the filter dropped, the filter cake would fall off the filter elements before the solvent could maintain forward flow. After a short period of testing, the process worked well and was entirely automated, with Train B ready on July 25, 2016 and Train A available on Aug. 23, 2016.

5.13.4 Final Summary

After both units were purged of oxygen and filled with solvent, and the chillers, reboilers, and filtration package were online, the unit was ready to receive sour syngas. When commissioning activities were complete, solvent circulation was stopped. The unit was kept purged at the optimum startup pressure until sour syngas was available from the gasifier and water-gas-shift equipment.

5.14 AGR Refrigeration

5.14.1 System Overview

The acid gas removal (AGR) refrigeration package consists of an anhydrous ammonia-based system that chills a SELEXOL solvent to below ambient temperatures. The system is common to both AGR units. Cooling the SELEXOL solvent increases its ability to absorb H_2S and CO_2. The increased absorption reduces the required solvent circulation rates and the size of the AGR equipment.

The refrigeration system operates on a typical vapor-compression cycle (figure 5.14-1). Ammonia is compressed in eight oil-flooded screw compressors and flows to two parallel condensers, where it is condensed into liquid. The condensed liquid ammonia flows through a receiver vessel that can accommodate changes in refrigerant circulation rates as cooling demand varies.

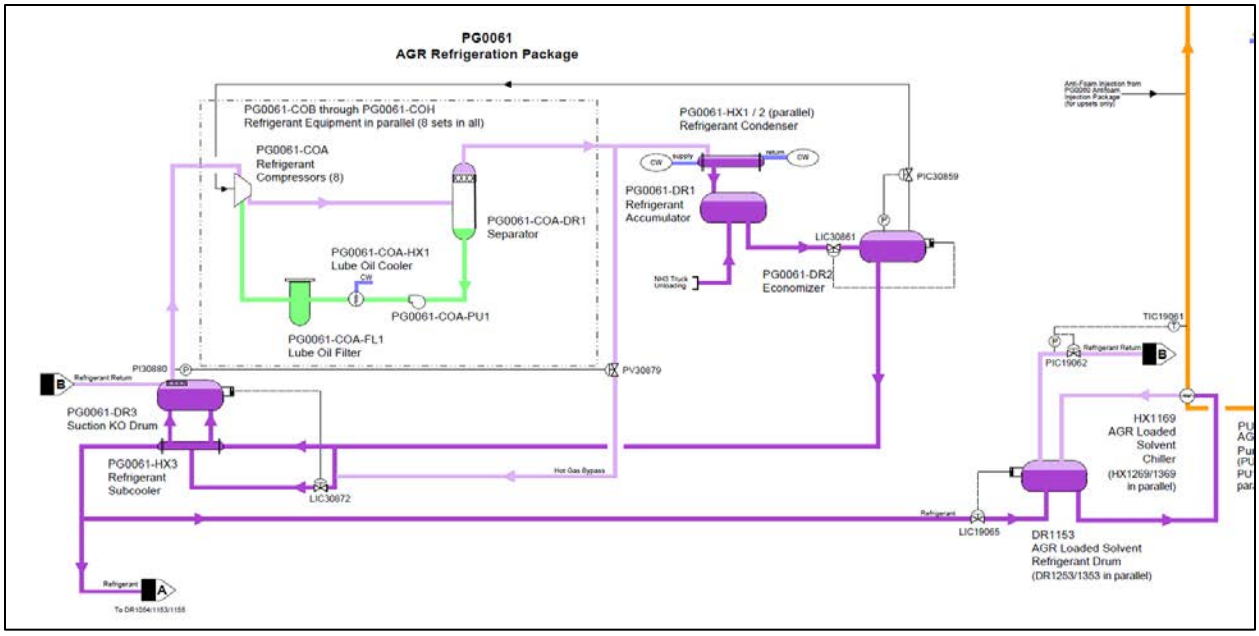

Figure 5.14-1 - Overview of AGR refrigeration system

From the receiver, liquid ammonia continues to an economizer, which flashes a small portion of the refrigerant and returns it to an interstage side port on the compressor, improving the cycle efficiency of the refrigeration system.

From the economizer, most of the liquid ammonia is directed through the refrigerant subcooler tubes, where it is subcooled to 15 °F. The remainder of the ammonia, a small slip stream, is flashed over a valve and fed to the shell side to provide subcooling to the bulk liquid ammonia stream on the tube side.

The main subcooled stream supplies chilled ammonia to the 14 refrigerant drums – two lean solvent refrigerant drums, six loaded solvent refrigerant drums, and six semilean solvent refrigerant drums. Each drum and connected SELEXOL solvent chiller forms a natural circulation loop that functions as an evaporator. The SELEXOL solvent flows through each chiller and transfers heat into the ammonia, causing it to vaporize. The vaporized ammonia returns to the refrigerant drum, where it is vented to a collection header. Figure 5.14-2 shows outlines the natural circulation loop.

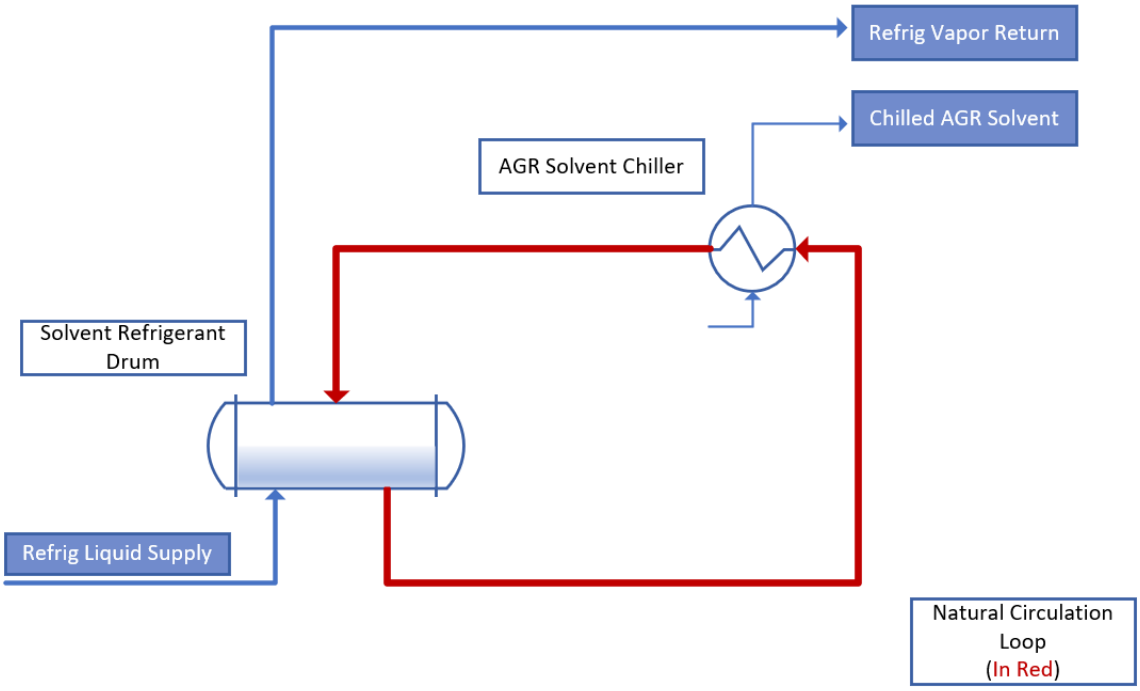

Figure 5.14-2 - Evaporator natural circulation loop

The ammonia from all solvent drum vents is collected in this common header and flows to the suction knockout drum to remove any condensed ammonia. Here, vapor combines with ammonia vaporized from the subcooler, which is physically connected directly above the subcooler by two standpipes. The combined vapor ammonia flows to the suction of the compressors for recompression, completing the cycle.

To start up the refrigeration system, one compressor is placed in service, with circulation established by a hot gas bypass valve. This valve modulates as necessary to maintain the suction pressure on the compressor as the system is initially cooled. The compressor operates under local control. As the system load increases, the suction throttle valve opens to equalize the pressure. Subsequent compressors come into service as necessary to meet the load demand. After a second compressor goes into service, system control switches to the common controller.

5.14.2 Initial Commissioning Plan

Commissioning of the AGR refrigeration system was to be conducted in accordance with American Society of Heating and Air-Conditioning Engineers (ASHRAE) standards and vendor requirements. The system would be tested to:

- Verify mechanical integrity of system piping and equipment.
- Charge ammonia to the system.
- Complete the functional checkout of each compressor.
- Establish circulation and chill the ammonia in preparation for AGR testing.

The following steps were planned to complete these objectives.

5.14.2.1 *Pneumatic Test*

A pneumatic test was to be conducted to ensure the mechanical integrity of all equipment and piping connections. Any leaks in the refrigeration system were to be tightened or plugged, or blind flanges were to be installed prior to further commissioning activities. Dry, oil-free compressed air would be used as a test medium.

During testing, an exclusion zone was to be maintained around the system for personnel safety. The preliminary boundaries included a pressure control point and limited access zone, where nonessential personnel would not be allowed during testing.

Exclusion Zone Boundary Distances		
Pressure (psig)	Pressure Control (ft)	Limited Access (ft)
25	120	275
193	275	550

Per the test procedure, the system was to be gradually pressurized to 193 psig in 25-psi increments. The pressure would be held for 10 min after each increment (from 0-175 psig) to allow the pressure to stabilize and to conduct leak checks. When the desired pressure (193 psig) was achieved, the pressure was to be held for 15 min, and then returned to 175 psig for another 10 minutes. Snoop tests were to be conducted at 25 psig, 50 psig, and final 175 psig to check for any leaks. Any leaks would be addressed before continuing the test.

5.14.2.2 *Vacuum Evacuation Test*

After pneumatic testing, a vacuum evacuation test was to be performed. Vacuum testing of the refrigeration system ensures noncondensable gases and moisture are removed in preparation for charging the system with ammonia refrigerant. A helium-sensitive leak test was planned to further ensure the system was leak-tight prior to the introduction of ammonia. This test is a more precise confirmation of mechanical integrity than the pneumatic testing. This testing was to be completed by a qualified refrigeration service and testing contractor.

5.14.2.3 *Compressor Alignment and Motor Run-ins*

The commissioning of the eight refrigerant compressors was to follow a traditional verification process. After verification of logic, instrumentation, and lube oil flushing, each compressor's main motor would be operated uncoupled. This uncoupled operation allows verification of bearing temperatures, development of baseline vibration levels, and determination of magnetic center before installation of the main coupling.

Following the installation of the coupling, a hot alignment was to be performed prior to placing each compressor in service.

5.14.2.4 *Calibrate Slide Valve*

Each compressor is controlled to adjust to changes in thermal loading of the refrigeration system. This control is accomplished by modulating a slide valve installed on each compressor. As the compressor supply header pressure changes, the slide valves are automatically adjusted to maintain pressure. A pressure indicator controller maintains the suction pressure by loading or unloading the compressor slide valve. Calibrating the slide valve for each compressor was necessary to ensure it was properly tuned to essentially load or unload based on the suction pressure demand.

5.14.2.5 *Functional PLC Check*

After each slide valve was tuned, a functional checkout of the PLC was planned to confirm control logic and trip logic, and that the interface to the plant DCS and SIS was suitable to begin system circulation.

5.14.2.6 *Charge and Commission System*

The refrigeration charge and commissioning plan was to inventory the system with ammonia refrigerant. Ammonia liquid was to be supplied to the receiver, economizer, and ammonia subcooler. The solvent refrigerant drums and chillers would then be charged to ensure an adequate volume of ammonia was available for initial startup. This test was to occur following the completion of vacuum testing, to prevent air and noncondensable gases from becoming trapped in the ammonia. The vacuum was to be broken by charging the system with ammonia.

5.14.3 Significant Events

5.14.3.1 *Key Milestones*

Task	Date
Pneumatic leak test	June 6, 2015
Vacuum test - first	Aug. 4, 2015
Compressor alignment- cold	Sep. 2015
Pneumatic leak test (with helium as trace gas)	Mar. 31, 2016
Vacuum test - second	Apr. 30, 2016
PLC functional check	June 6, 2016
Vacuum test- third	June 25, 2016
Ammonia charging - Train B	July 11, 2016
Compressor alignment- hot	Aug. 2016
Motor run-ins	Aug. 2016 (hot)
Slide valve calibration	Oct. 2016
Charge system - Train A and commission the system	Oct. 5, 2016

5.14.3.2 *Event Narrative*

The pneumatic test was the first major step in the commissioning process of the refrigeration system. The first pneumatic leak test was conducted in early June 2015 and was completed in approximately 2 weeks. Per procedure, the system was pressurized using compressed air from temporary compressors installed at several locations throughout the test loop.

The test boundary was staged for personnel safety due to the test pressures involved. The preliminary boundaries included a pressure control point and limited access zones. Nonessential personnel were not allowed in the limited access zones while the test was conducted, and no personnel were permitted to enter the compressor skid during pressurization.

The system was pressurized at 25 psig incrementally to 193 psig, using compressed air. The pressure was held for 10 min after each increment (from 0-175 psig). When the final test pressure was achieved, the pressure was held for 15 min and returned to 175 psig for another 10 min. Snoop tests using soapy water were conducted at 25 psig, 50 psig, and final 175 psig to check for any leaks. All leaks identified during the test were repaired and the pneumatic test repeated to ensure integrity in the system.

The vacuum test was scheduled to start on June 15, 2015. The testing was initially delayed due to a concern that the process piping might have not been rated for full vacuum. After it was confirmed that the system could withstand the vacuum, the evacuation test commenced July 13, 2015.

Testing was conducted by a third-party contractor. During the test, numerous leaks were identified that required repair. To ensure noncondensable gases and moisture were removed, it was critical to complete the repairs before proceeding. The system was successfully drawn down to full vacuum on July 23, 2015.

At this time, the third-party contractor began the helium testing.

Due to its small molecular weight, helium will leak from connections considered tight after testing by other means. Helium gas checkpoints included all potential leak locations, including piping fabrication welds, field welds, flanged connections, and threaded connections. The vendor's vacuum procedure, provided in the installation, operation, and maintenance (IOM) manual, was used in development of the test package procedure. The test included two vacuum sweeps of the system to 10,000 microns (10 mm Hg vacuum value). After 10,000 microns was achieved, the vacuum was breached with nitrogen gas to 0.0 psig. The vacuum pump was restarted until a final vacuum to 2,500 microns (2.5 mm Hg vacuum) was achieved. An outside-in helium gas leak test was performed on all welded and mechanical joints after the first evacuation to 10,000 microns.

The vacuum testing was completed Aug. 4, 2015, with the system at 1.4 Torr. The system was rested through the evening, and the vacuum decay resulted in a value of 9.8 Torr the following morning. The refrigeration system was padded with N_2 gas the next day, and the vacuum compressor remained connected to the system. The vacuum test was satisfactorily complete.

During system dehydration, some water could not be located that was indicated based on relative humidity. Following an investigation, water was found to be trapped in the exhaust line on the economizer drum between the drum and the compressor suction header. The line was drained, and the dehydration testing completed successfully.

The vendor visited the site for 2 weeks in September 2015 to conduct inspections of compressor oil separators and compressor oil filters. The Startup group and vendor inspected the separators' oil coalescer and replaced the oil filters elements for each compressor. All but one of these 16 vessels had internal hardware that needed to be corrected.

The vendor performed the cold compressor alignment and motor coupling and checked the compressors for soft feet. Magnetic center was determined for all eight compressors as part of the uncoupled motor runs. Each compressor operated for approximately 50 min. Each motor was verified for proper rotational direction, bearing temperature readings, and baseline vibration levels. On Sep. 22, 2015, the final cold alignments were completed, and the motors were coupled.

The compressor check valves were inspected, and it was determined that the metal seat would not perform effectively during the compressor alignment. The valves were removed and shipped to a shop in Houston, Texas for cleaning and repair to ensure the valves worked in accordance with manufacturer guidelines.

All eight compressors and vessels containing liquid ammonia (for example, accumulator, economizer, and receiver) had the pressure relief valves (PRV) pulled and shipped to a valve testing shop for a full valve inspection and recertification. Many of the valves had been installed well before testing began and were nearing the end of the

calibration period, requiring recertification. The shop recertified the valves and returned them to the site, and they were installed into the system Nov. 16, 2015.

During the commissioning phase, the plant installed isolation valves to allow the system to be commissioned, tested, or shut down in segments, or individual compressor skids. The valves could also limit the quantity of ammonia released during a system breach.

In late September 2015, I&C began the functional check on the PLC and loop checks. The PLC controls the refrigeration system, and board operators remotely control it from the DCS using the MODBUS network. A compatibility issue resulted in a time delay between the PLC and DCS. Efforts to troubleshoot the cause were hampered by the PLC coding. The program was written in a complex format that was not consistent with project specifications, which had been previously identified as issue. The PLC program was not annotated. The tag descriptions were particularly necessary, given that the code used indexed arrays instead of standard ladder logic, making initial checkout and troubleshooting extremely difficult.

The vendor was asked to provide a detailed control narrative to accommodate open program testing and to rewrite the PLC code. They were unwilling to address the issues with the coding or to comply with specifications. As a result, the project elected to independently rewrite the code based on the vendor's control narrative and controls documentation.

This rewrite of code resulted in a delay to the commissioning schedule for several months until the issue could be resolved.

The commissioning activities resumed in February 2016, with the pressure test on the compressors. The compressor leak test pressurized each compressor at 315 psig. During the test, the compressor skid's isolation valves failed to tightly seal and had small leaks. The valve seats were replaced on Mar. 8, 2016, and the compressor discharge and economizer suction valves were rebuilt with new Teflon discs for compressors, resulting in another delay to the schedule. The repairs were complete on Mar. 31, 2016, and the system was placed under a nitrogen blanket.

On Apr. 22, 2016, the vacuum evacuation began and achieved 0.75 Torr after approximately 32 hr of continuous vacuum pump down. The helium leak test was conducted, and a small amount of water was removed from the system. The team conducted four nitrogen breaks to locate the water in the system. The water was removed, and the test was declared complete Apr. 28.

The PLC reprogramming was completed, and the new logic met the conformed specification on June 1, 2016. The functional tests on the PLC substantiated the I/O functions correctly in the code; tested all inputs and outputs; and verified all valves, motors, controls, process variables, and compressors functioned as designed.

The final vacuum test started June 21 and was completed June 25. The ammonia charging was initiated by breaking the system vacuum to ensure the ammonia was not contaminated with air, noncondensable gases, or moisture.

During the charging process, additional leak checks were conducted with SO_2 sticks and litmus. Several small leaks were located, which required removing significant amounts of insulation to repair. The insulation had masked leaks during the final vacuum test before the system was filled with anhydrous ammonia. After leaks were repaired, liquid ammonia charge continued to fill the system to adequate levels for compressor testing. After compressor testing, each segment of the refrigeration system was charged with refrigerant.

The vacuum was broken on June 25 with premium-grade ammonia, with the intention of loading enough liquid ammonia to conduct the refrigeration compressor testing and commissioning. Approximately 50,000 lb was loaded for the compressor test. Initially, the compressor was tested by establishing a circulation flow path through the hot bypass valve, since the AGR system was not circulating SELEXOL. The load capacity for which the compressors were tested was limited. On July 4, 2016, each compressor was tested with the slide valve at 60% open. Later, the AGR chillers and drums on Train B were filled with ammonia and the slide valves tested again.

An additional 100,000 lb of ammonia was added to the system to fill Train A refrigerant drums and chillers. Train A was fully charged to refrigerate its respective AGR SELEXOL train on July 10.

5.14.4 Final Summary

The AGR refrigeration completed most of the commissioning plan activities before the first coal feed. The pressure, vacuum, and helium tests achieved the necessary requirements to allow Train B to be fully charged, while Train A was charged at a later date. The hot compressor alignment and slide valve calibration were postponed since the system needed to be in operation to complete those tasks.

During commissioning, the system also faced challenges and design modifications. Startup repaired the compressor check valves, recertified PRVs, installed isolation valves, and rewrote the PLC program to conform to the plant's specification. After the system was commissioned, a compressor remained in service while the AGR system sat under a purge, allowing the ammonia to circulate and not build up system pressure to the point where the PRVs relieved. The compressor was brought online after the first coal feed. Due to load limitations before first coal feed, slide valve calibration was not completed during the initial commissioning phase.

5.15 AGR Compressors

5.15.1 System Overview

Each AGR system includes two compressor applications to improve product purity: the AGR flash gas compressor CO1065 and the AGR CO_2 recycle gas compressor CO1066. Each application is discussed separately.

5.15.1.1 *AGR Flash Gas Compressor*

The AGR flash gas compressor system accepts the vapor stream from the AGR rich solvent flash drum DR1063. The stream is cooled with the AGR flash gas cooler HX1065, and any free liquid is separated in the AGR flash gas first stage knockout drum DR1065. This process ensures no moisture is entrained in the gas as it enters the AGR flash gas compressor.

The gas continues in a single stage of compression, then exits the compressor to be cooled in the AGR flash gas interstage cooler HX1086. Since the gas stream was cooled, it passes through an additional stage of moisture removal in the AGR flash gas compressor KO drum DR1080. A final stage of compression in the flash gas compressor raises the pressure to 550 psig. The gas is combined with the stripped gas venting from the AGR concentrator, and the combined stream returns to the H_2S absorber.

The resulting recirculation of CO_2 and other impurities before regeneration improves the quality of the acid gas produced in the AGR regenerator (figure 5.15-1).

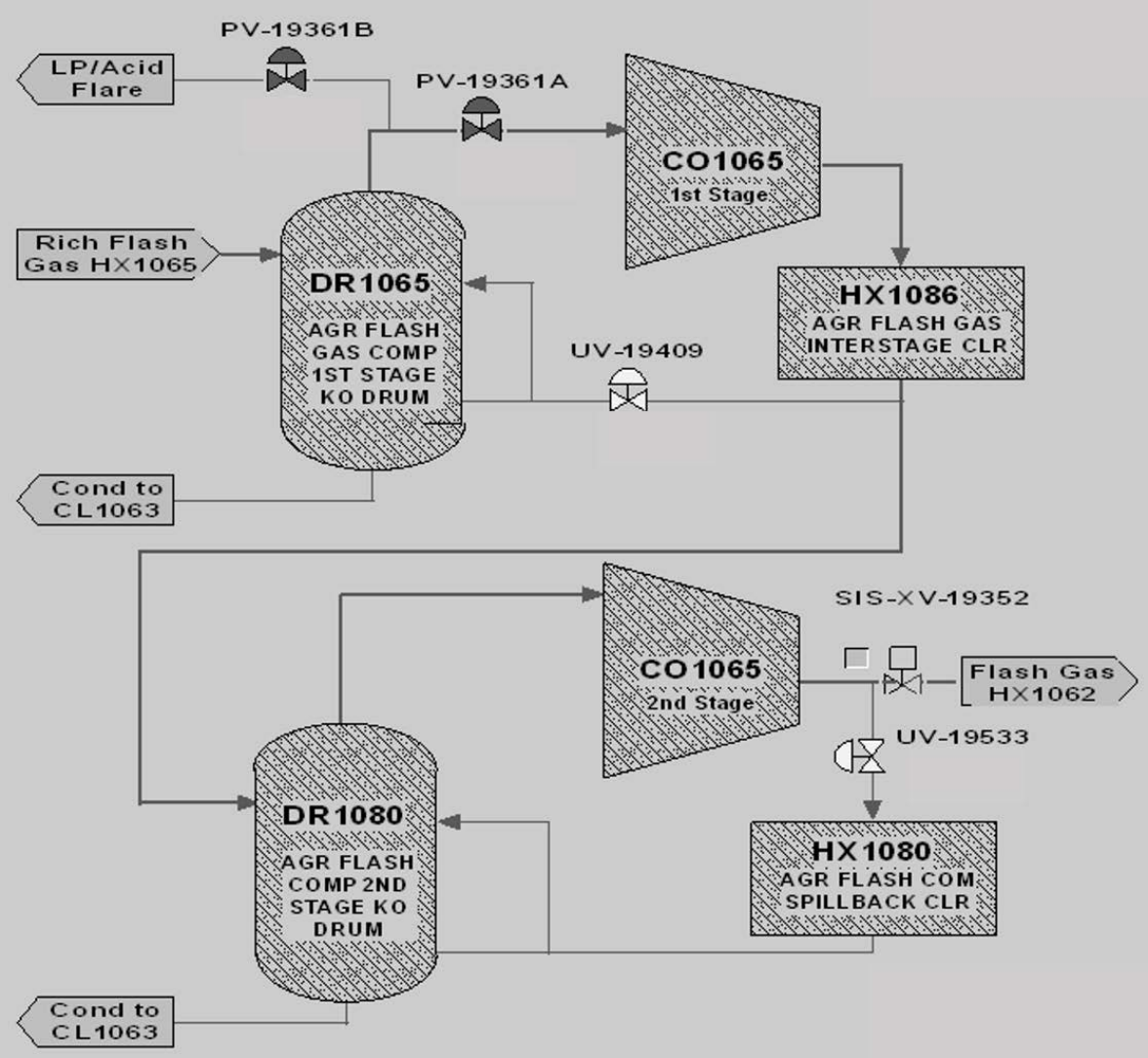

Figure 5.15-1 - Excerpt from AGR PFD - AGR flash gas compressor system

The compressor is the primary unit operation of the AGR flash gas system. The flash gas compressor is a two-stage integral gear application driven by induction motor. Process control is achieved by modulating a suction throttle valve to maintain head pressure on the AGR rich solvent flash drum, so the feed conditions to the compressor may vary slightly. During normal full-load conditions, the gas pressure typically increases from around 130 psig to 550 psig across the two compression stages.

During abnormal operations such as startup or downstream process blockage, the application includes an antisurge kickback valve. This line will redirect flow from the second stage discharge to the first stage suction, to ensure adequate flow is supplied to the compressor suction to prevent damage. A heat exchanger is included in the kickback line to remove the heat of compression. As gas is recirculated to the compressor suction, it passes through the AGR flash gas compressor spillback cooler HX1080.

The compressor is typically started using intermediate pressure nitrogen as the initial medium. As process gas becomes available, the operating medium transitions from nitrogen to acid gas. No special accommodations are required to swap the process medium. The operator will notice the change in the conditions.

The application includes an integrated lube oil skid to provide machine cooling and lubrication. To comply with API-614 redundancy requirements, each compressor skid at Kemper contains two skid-mounted lube oil pumps. The AGR

flash gas compressor has a single skid-mounted lube oil pump and a shaft-driven gear pump that are in operation while the compressor is running. This design complies with API redundancy requirements, but with a different configuration.

The application includes dry gas seals to prevent acid gas from escaping the process. During startup, primary seal gas is supplied with intermediate pressure nitrogen. After the compressor is operational, the sealing medium swaps to process gas that recirculates through the seal and to the acid gas flare.

5.15.1.2 *AGR CO_2 Recycle Gas Compressor*

During normal operation, the AGR CO_2 recycle gas compressor raises the pressure of the vent gas from the HP CO_2 flash drum. This stream includes lighter gas, such as H_2, N_2, and CH_4, that would reduce the purity of the pipeline CO_2 product if not removed. It includes a significant portion of CO_2, but most of the CO_2 does not devolve into the vent of the HP flash drum.

The HP vent stream is sufficiently cool and dry to not require precooling or inlet knockout of free moisture. The vent gas flows directly into the compressor. After compression, the stream is cooled in the AGR CO_2 recycle gas compressor aftercooler HX1066 before returning to the CO_2 absorber (figure 5.15-2).

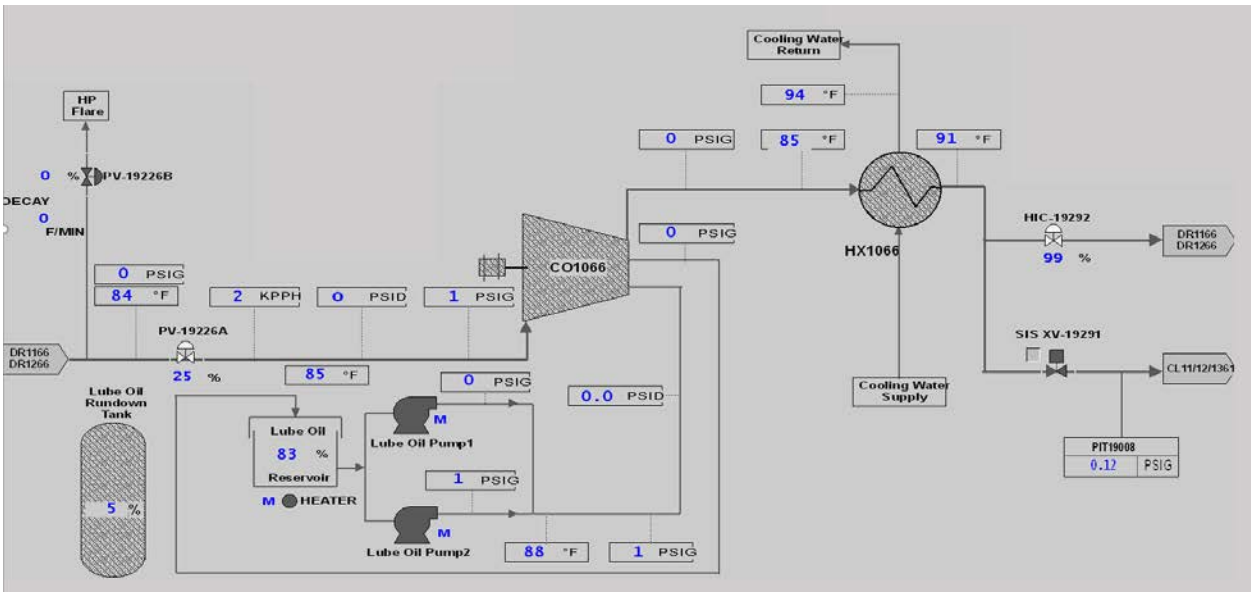

Figure 5.15-2 – Excerpt of AGR system - CO_2 recycle gas compressor

The compressor is a five-stage between-bearing compressor driven by induction motor. Like the AGR flash gas compressor, process control is achieved by suction throttling the process stream to maintain a constant head pressure on the HP CO_2 flash drum. During typical full-load conditions, the compressor increases the stream pressure from around 100 psig to over 500psig.

The CO_2 recycle gas compressor includes an antisurge kickback valve for machinery protection. To prevent the need for a spillback cooler, the kickback line offtake is downstream of the CO_2 recycle gas compressor after-cooler. When the antisurge valve is open, flow is directed from the compressor discharge back to the HP CO_2 flash drum at the compressor suction.

As with the flash gas compressor, the CO_2 recycle gas compressor is designed to operate on both nitrogen and process gas. This design improves the flexibility of the unit during operations and allow for the decoupling of the compressor startup from the startup of the AGR system. After on-spec gas is available, the compressor is transitioned from nitrogen to flash gas.

Dry gas seals are installed on the compressor to prevent acid gas from escaping the process into the atmosphere. During startup, primary seal gas is supplied by intermediate pressure nitrogen. After the compressor is operating on process gas, the sealing medium swaps to process gas that circulates through the seals to the acid gas flare.

5.15.2 Initial Commissioning Plan

The commissioning plans for the AGR flash gas and AGR CO_2 recycle gas systems are similar. To avoid redundancy, this report describes the activities only once, and covers both applications equally. The purpose of the test package was to confirm system mechanical integrity and to complete the functional checkout of the compressor. After functional testing was complete, the test would proceed to integration of the equipment with the broader AGR system.

All turnover-level activities were to be completed before commencement of compressor testing including all items related to installation verification, loop-checks, logic confirmation, and system cleaning. The lube oil and seal gas systems were to be commissioned and available to support starting the compressor.

The test medium was intermediate pressure nitrogen supplied by a purge line at the suction of the compressor. Functional activities included:

- Start the seal gas system.
- Purge the testing flow path with nitrogen. This step was critical to ensure a known gas composition was available during compressor surge testing.
- Conduct a low-pressure leak test.
- Start the compressor.
- Monitor the compressor performance and record baseline bearing temperature and vibration levels.
- Conduct a no-load leak test of all system flanges and process connections.
- Verify system mechanical integrity by slowly closing the antisurge valve.
- Test and tune the compressor antisurge valve.
- Verify functionality of critical alarms and setpoints.
- Conduct compressor surge testing.
- Tune the suction throttle valve.
- Complete interlock trip testing.

After compressor testing was complete, the system was to be laid up until integration with the overall AGR system could be carried out.

5.15.3 Significant Events

5.15.3.1 *AGR Flash Gas Compressor*

Train A		Train B	
Dry gas seals installed	9-9-2014	Dry gas seals installed	9-10-2014
Lube oil system commissioned	9-5-2015	Lube oil system commissioned	10-9-2015
System cleaning complete	9-7-2015	System cleaning complete	10-17-2015
Precommissioning complete	11-2-2015	Precommissioning complete	11-2-2015
Flash gas compressor commissioned	9-23-2016	CO_2 recycle gas compressor commissioned	11-1-2016

Because of plant startup priorities, the air compressors and recycle gas compressors took precedence when balancing resource availability between the applications. As a result, commissioning the AGR compressors took a considerable amount of time to complete, but the actual commissioning activities closely resembled the initial plans.

There was considerable effort to preserve and protect equipment and components. The dry gas seals were shipped in separate containers and were to be installed by Startup just before commissioning. The process piping and compressor were kept under a nitrogen blanket. The lube oil skids were kept in operation as much as area activities allowed.

The dry gas seals were shipped to the site in long-term storage crates to ensure they were not damaged during the installation process or during layup before compressor commissioning. The project decided to install them in late 2014 in anticipation of commissioning activities to commence shortly thereafter. All four seals were installed with no issues. The seals were kept under a nitrogen purge while the system was down. Confirmation of seal purge was included in startup operator rounds to ensure the purge was not removed by activities near the equipment, which became more significant as the project schedule began to slip. There was discussion before compressor startup of removing the seals and sending them out for refurbishment. Because of the preservation actions during the precommissioning phase, the project was able to demonstrate to the vendor that the seals were acceptable to proceed without removal.

After the seals were installed, a gearbox inspection determined that each bullgear and pinions were coated in a heavy grease. Consultations with the vendor confirmed that the substance was a shipping grease that must be removed before starting the compressor. This activity was not listed in the vendor documentation, and no time had been allocated in the project plan for removal. The vendor stated the shipping grease was part of a revised preservation policy, but it had not been updated in the project documentation. The material had to be removed before compressor startup. The gearbox cover was removed and the bullgear, pinions, and any other surface coated with the substance was hand cleaned. When the gearcase was reinstalled, the lube oil system was flushed to ensure none of the material remained in the system. This work was not difficult, but it delayed commissioning activities.

Mississippi state code requires each of the pressure vessels onsite to be certified by the state. During evaluation of the vessels in the AGR system, the state inspector was not fully satisfied that the AGR flash gas compressor knockout drums DR1080/2080 were compliant. Southern Company reviewed the vessel calculations with the EPC design firm and confirmed that the vessels were capable of being re-rated to a higher MAWP (437psig). This re-rate raised the allowable working pressure to a value higher than the compressor could generate. The re-rate satisfied the state inspector. The re-rate required the vessels to be hydrotested to ensure they were capable of holding the calculated pressure. Hydrotests on both vessels were satisfactorily completed. The preparation, testing, and restoration took 1 month to complete.

Most of the piping in the flash gas compressor loop was hydrolazed to remove mill scale and debris. System cleaning is always a critical activity but was especially important with the flash gas compressor. The pinion speeds are exceptionally high (pinion 1: 31,696 rpm, pinion 2: 24,205 rpm) and any debris passing through the compressor would have a significant impact. As a result, extra care was given to ensuring all suction, discharge, and recirculation piping was clean. Because of the way much of the piping was routed, cleanout or inspection windows had to be cut into the process piping. These windows were not engineered and added to the process design due to time constraints. To repair the cutouts to code, each window had to be welded back into place. Each weld was 100% radiographed to ensure the connection was completed. When hydrolazing was complete, inspections of the knock out drums were completed. Any debris that collected in the drums during cleaning was removed and the vessels were inspected and closed. The complexity of piping and the need to cut into piping resulted in the cleaning activity taking 3 months to complete.

When the system was clean, final preparations for commissioning the compressors were completed. Testing of CO2065 began in June 2016. Testing of CO1065 began in July 2016. Both applications exhibited what appeared to be a blockage downstream. Figure 5.15-3 depicts the operation of CO1065 during the initial tests.

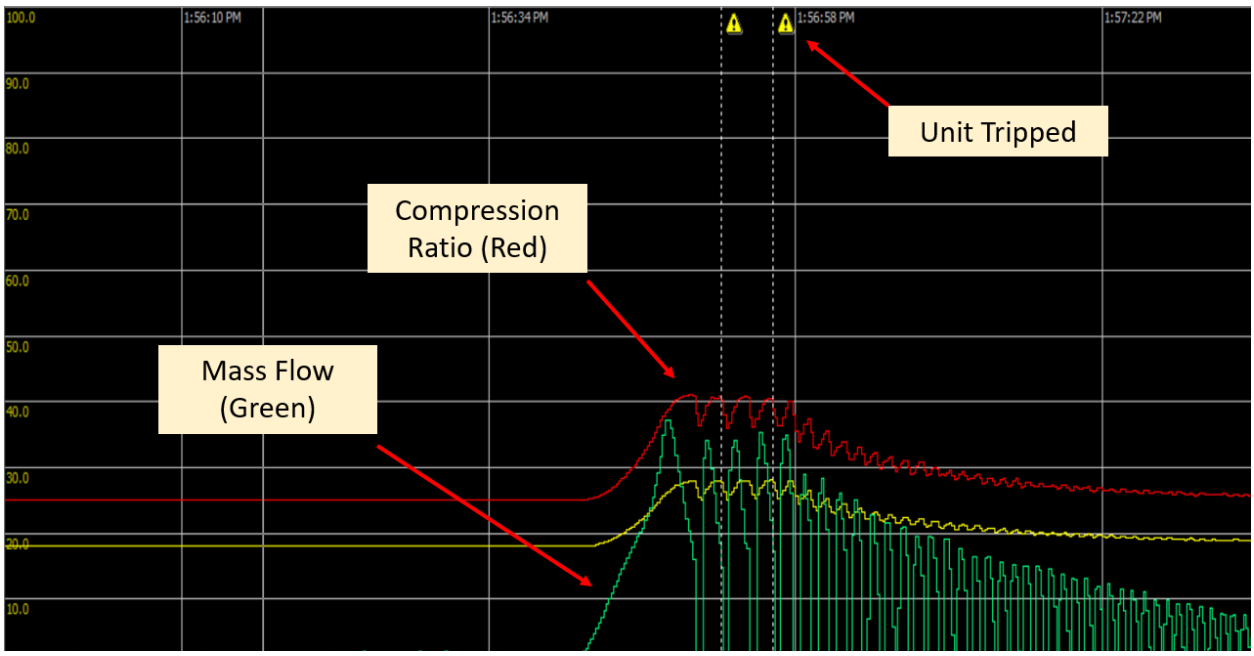

Figure 5.15-3 – Flash gas compressor - surging on startup

The green line in figure 5.15-3 is compressor flow and the red line is the first pinion compression ratio. Immediately on startup, the compressor began to surge. The graph shows the flow reversals, the automatic trip, and the continued surge as the equipment spooled back down.

The antisurge valve trim cage was suspected to have clogged immediately after startup, but inspection for both applications found no significant debris or blockage. The piping and valve body were noticeably wet, and it was suspected that there was moisture trapped in test loop piping. All drains and available piping connections were opened to locate the moisture and sections of the piping that were difficult to drain were boroscoped to the extent possible. The piping network for these applications was extensive and included sections that were inaccessible without cutting windows into piping. A section of piping in the overhead leading to the antisurge valve was found to have a low point that could possibly collect moisture. A window was cut into this segment of pipe and there was a considerable volume of debris and water collected there. It was removed, the piping repaired, and the testing of each compressor restarted.

The remainder of the testing for CO1065 proceeded without issue. The compressor trip testing, surge testing, and tuning of the antisurge controllers were completed in September 2016 (figure 5.15-4).

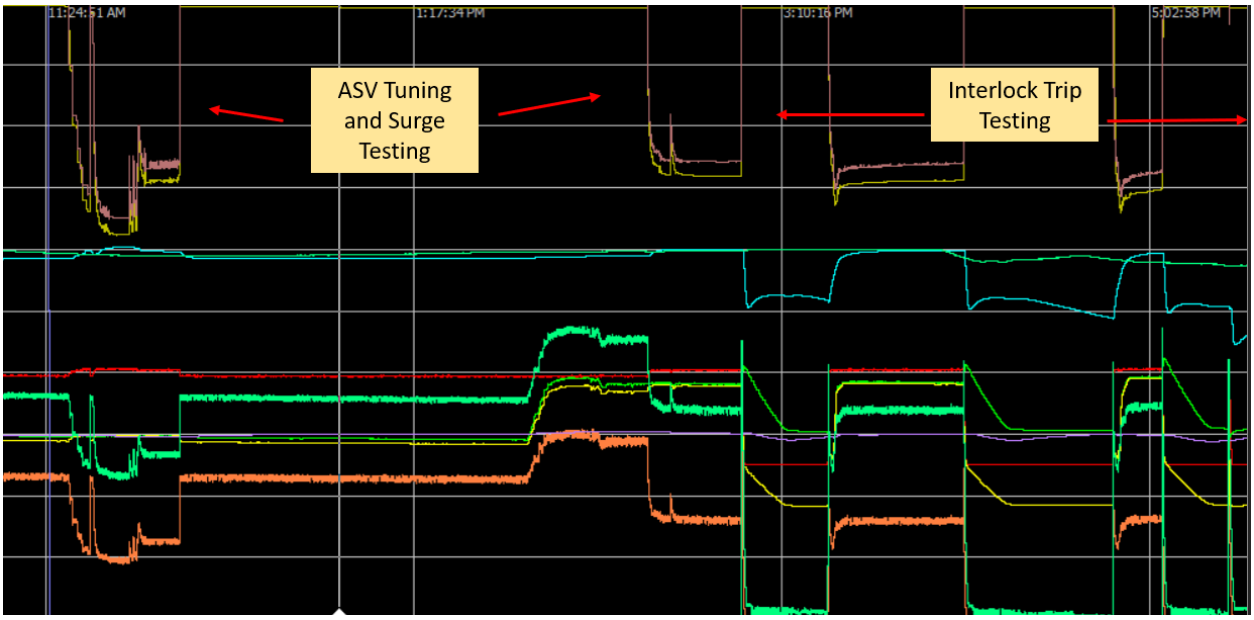

Figure 5.15-4 – CO1065 final compressor testing

In figure 5.15-4, the antisurge valve is steadily closed until the compressor nears surge conditions. When the surge point is confirmed, the antisurge valve is fully opened to return the compressor to a safe state. Figure 5.15-4 also shows a series of trips and restarts as the shutdown interlocks are tested from each of the potential trip sources.

During the testing of the CO2065 compressor, the operator noticed that the auxiliary lube oil pump would not automatically shut off per the start sequence. Oil header pressures and bearing temperatures were normal. When the operator attempted to manually stop the aux oil pump, the header pressure would drop rapidly. The aux pump would then restart to bring oil header pressures back to normal. The test lead decided to shut down the compressor and investigate before proceeding with testing.

The flash gas compressor has a gear-driven lube oil pump that operates while the compressor is rolling. The gear pump is sized to provide adequate bearing cooling as the compressor spools down to a complete stop. The aux pump starts when header pressure decreases as the shaft nears full stop. It is generally not required to maintain header pressure until the gear pump slows during the compressor wind down. As a result, the shutdown logic forces the aux lube oil pump off when a compressor stop command is generated. A few seconds after the compressor was shut down, the operator began receiving bearing temperature alarms and noticed the aux pump had restarted.

Figure 5.15-5 shows that in the few seconds it took for the auxiliary pump to restart, the compressor bearing temperatures trended high, out-of-range.

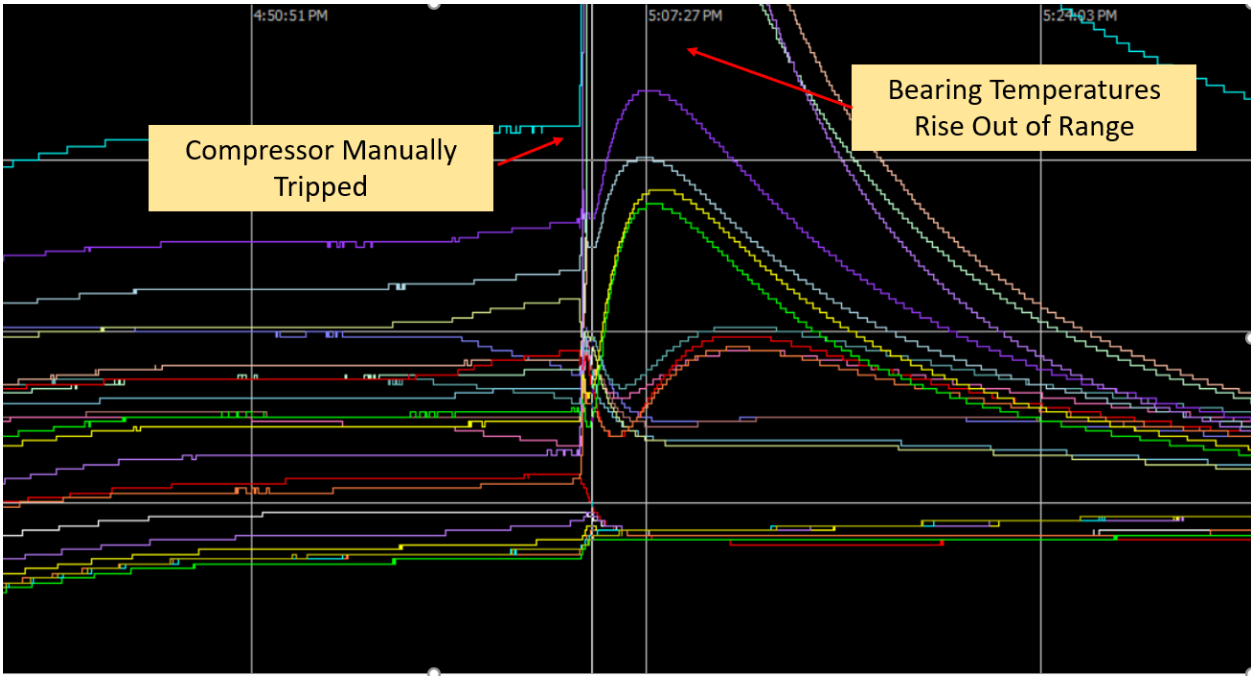

Figure 5.15-5 – CO2065 bearing temperature on compressor shutdown

The investigation found that a thin piece of metal had been inserted between the gear-driven lube oil pump and the compressor casing. The blind was not a project standard blind, and no work on the compressor required that the oil pump be blinded off. The source of the blind was never determined. The outcome was that the oil pump and compressor bearings were damaged had to be replaced with capital spares. A full inspection of the bullgear and pinions was performed. During the bullgear inspection, the mounting gear that drives the oil pump was found to be damaged. In the interest of time, the bullgear was replaced with the capital spare. After the system was reassembled, the lube oil system was flushed, and the compressor prepared to continue commissioning. The repair took 8 days to complete. To prevent the event from reoccurring, a logic change was implemented to allow the auxiliary lube oil pump to remain active through a compressor shutdown event.

The remainder of the testing for CO2065 continued with no further issue. The compressor trip testing, surge testing, and tuning of the antisurge controllers were completed in November 2016.

5.15.3.2 *CO_2 Recycle Gas Compressor*

Train A		Train B	
Dry gas seals installed	7-18-2014	Dry gas seals installed	7-23-2014
Lube oil system commissioned	10-3-2014	Lube oil system commissioned	2-27-2015
System cleaning complete	10-3-2015	System cleaning complete	10-4-2015
Precommissioning complete	10-17-2015	Precommissioning complete	10-25-2015
CO_2 recycle gas compressor commissioned	2-1-2016	CO_2 recycle gas compressor commissioned	6-13-2016

Like the commissioning of the AGR flash gas compressors, the AGR CO_2 recycle gas compressors closely followed the initial commissioning plans. After transfer of the system equipment from Construction to Startup, the checkout was

initiated of instrumentation and logic and the mechanical completeness of the application, which included commissioning of the seal gas system and the lube oil system.

In parallel, the system piping was hydrolazed to remove mill scale and debris that might have been left in the piping during fabrication or installation. The piping layout for the CO_2 recycle gas compressor was not as extensive as the flash gas compressor, but it took several months to gain access to the piping and complete the hydrolazing activity. After complete, the system was placed under a nitrogen cap until needed for compressor testing.

During final preparations for test package execution, an inspection of the CO1066 suction line was completed. Water containing TSP was found to have leaked from the main AGR system into the compressor piping during degreasing of the SELEXOL piping. An inspection of the CO2066 lines indicated similar conditions. There was no indication the water had reached the compressor. The piping layout has the compressor inlet nozzle 30 ft above the suction piping where the water was found. After the lines were drained, the TSP left behind formed small crystals that needed to be removed (figure 5.15-6). Both suction lines were opened at the suction strainer and hydrolazed to remove the TSP. As a precaution, the discharge lines were inspected. No evidence was found to indicate that TSP had leaked back to the compressor outlet.

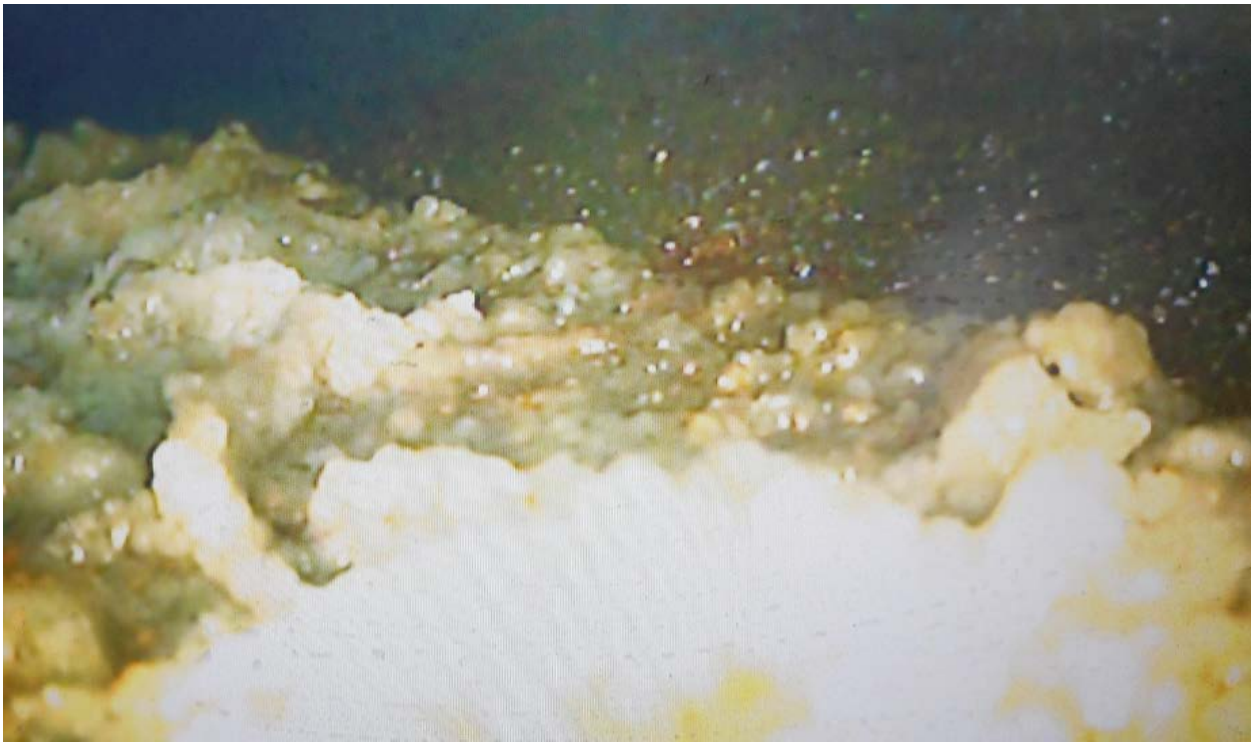

Figure 5.15-6 – Fine TSP crystals in CO_2 recycle inlet piping

Test package execution for CO1066 began in January 2016. The testing procedure was completed with only minor issues needing to be addressed. The suction throttle valve did not have a low clamp in place, and during the initial compressor start, the throttle valve fully closed, resulting in a compressor trip. After being addressed, the compressor was restarted, and testing continued. The compressor surge testing, tuning, and interlock trip testing was completed with no issue. Figure 5.15-7 shows the compressor HMI while the unit was in operation.

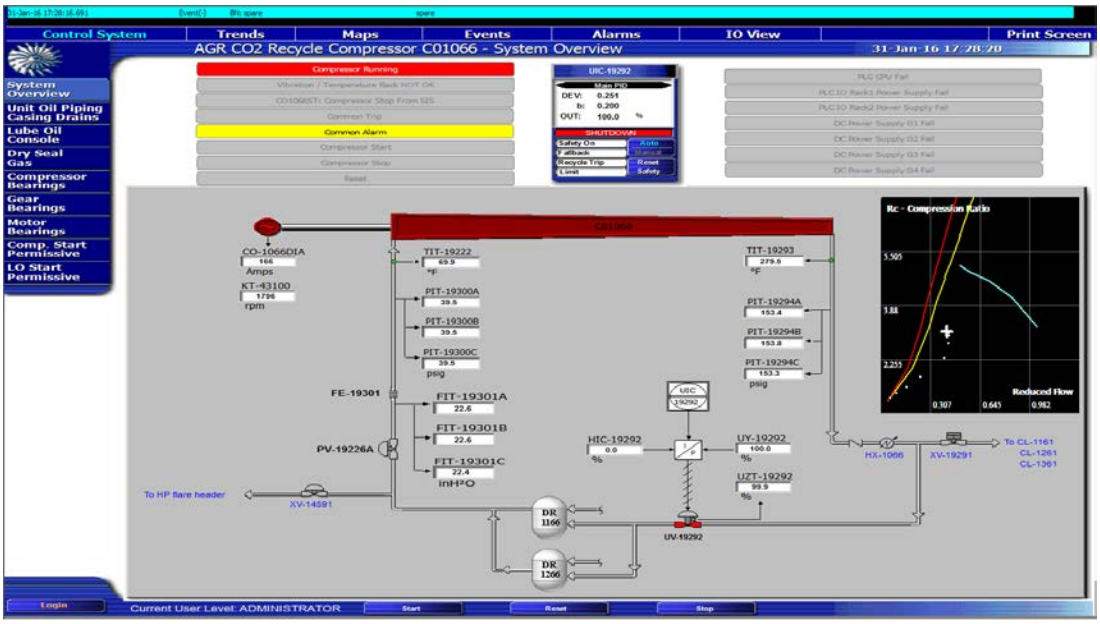

Figure 5.15-7 – CO1066 HMI console

After test package activities were completed, an inspection was conducted of the HP CO_2 flash drums DR1166/1266. This inspection was not originally part of the commissioning plans. In order to confirm that no debris had been deposited in the drum while the compressor was recirculating, the piping connections were removed and blinded. An internal inspection of both drums in February 2016 revealed a small amount of dust had collected in the drain of each vessel (figure 5.15-8). This dust was vacuumed out and the vessel restored to service.

Figure 5.15-8 – DR1166 HP CO_2 flash drum drain

The commissioning of CO2066 was delayed several months due to allocation of resources to higher priorities. Testing began in May 2016. The compressor was started and immediately began building pressure, which rapidly progressed to surge conditions, and the machine tripped on successive surges. As shown in figure 5.15-9, the compressor appeared to have a blockage in the discharge line.

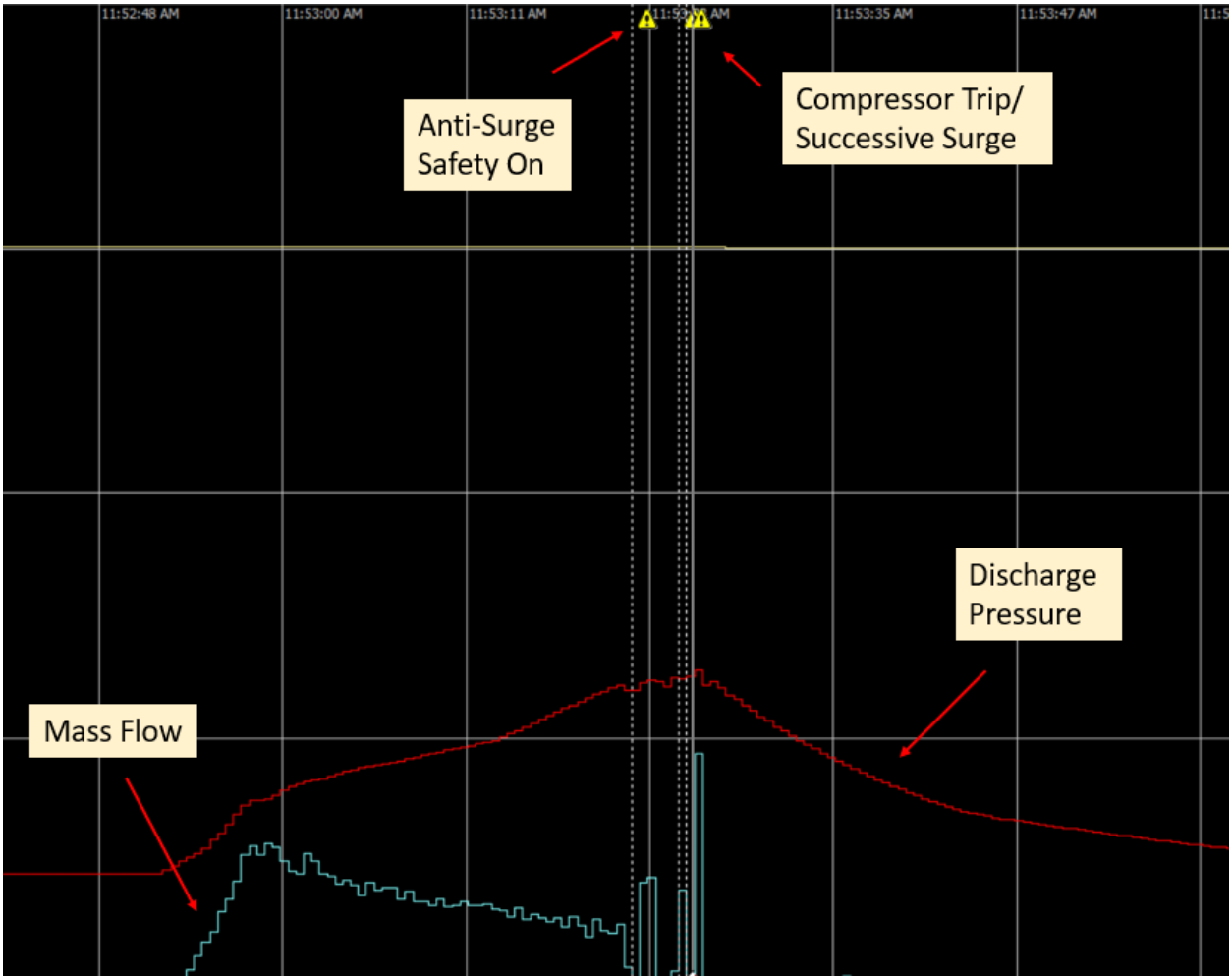

Figure 5.15-9 – CO2066 compressor discharge blockage on startup

As with the flash gas compressor, the antisurge valve cage was inspected. The valve was clean, the cage had no visible debris, and the valve body and piping were clear.

Boroscopic inspections of the accessible test loop piping did not reveal any blockage. There was some piping that was not easily accessible. Scaffolding was erected, and the piping was accessed through an inspection window cut out of the piping. As the window was being cut, water began to leak out of the pipe. It was found that this segment of piping formed a pocket that collected moisture. The piping was drained and restored. Execution of the test package was restarted.

Testing proceeded without further issue. The compressor surge testing, tuning, and compressor interlock trip testing were completed as planned (figure 5.15-10). Testing was completed in June 2016. The system was placed under a nitrogen cap until integration activities with the AGR system.

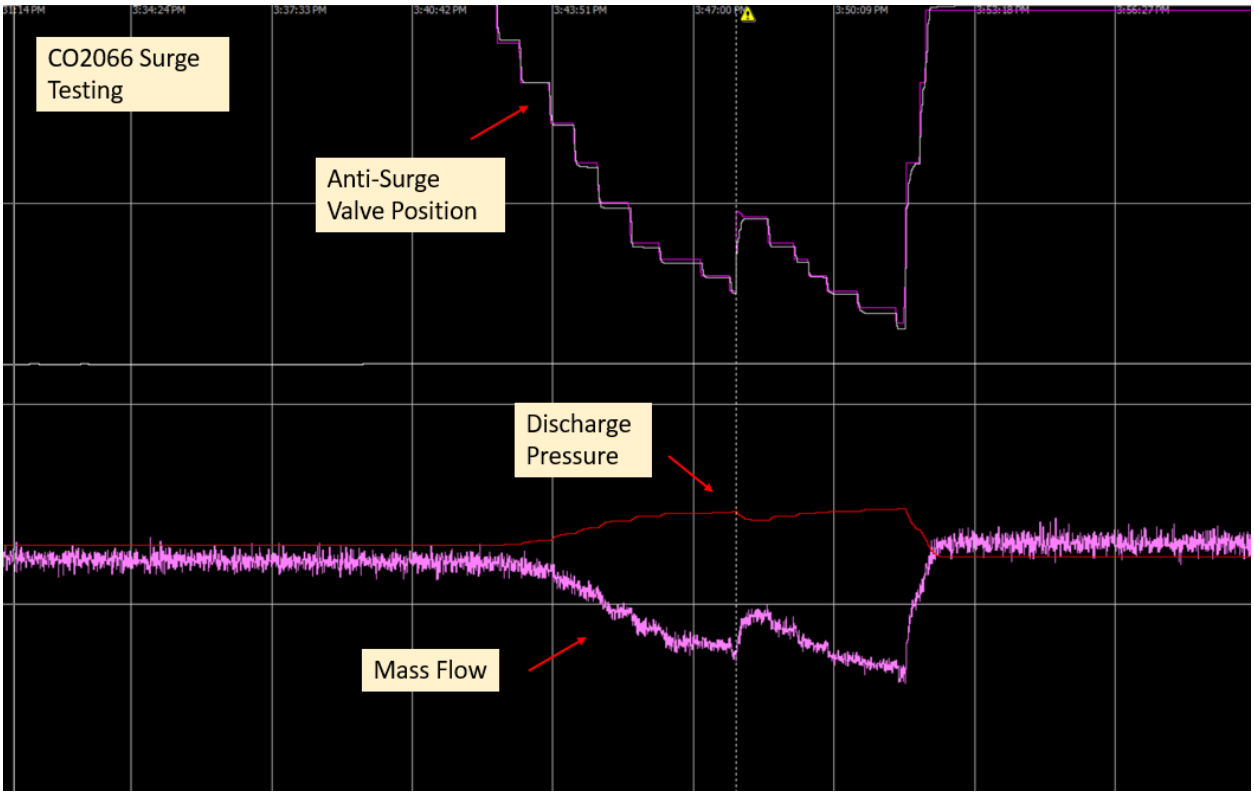

Figure 5.15-10 – CO2066 surge testing

An internal inspection of the HP CO_2 flash drums DR2166/2266 was completed. No debris was identified, and the vessels were restored to service. The inspection was completed in June 2016.

5.15.4 Final Summary

The commissioning of the AGR compressors largely proceeded according to the initial test plan. Despite several unplanned activities and delays, all the test objectives were completed in time to support AGR integration activities. All four machines performed well within the contract performance requirements

Following the completion of testing, all four systems were placed under a nitrogen cap for preservation. The compressors were operated at least once per month until integrated with the broader plant to heat each unit and maintain the equipment through a preventative maintenance run.

The capital equipment removed from the flash gas compressor was shipped to the vendor for repair and refurbishment.

5.16 CO_2 Preparation and Offtake

5.16.1 System Overview

The CO_2 compression system prepares CO_2 collected in each of the two AGR units for delivery to an offtake pipeline. The CO_2 is sold by Kemper and used by the offtaker for enhanced oil recovery (EOR). On each AGR unit, the CO_2 is liberated from the AGR semilean solvent loop at two pressure levels. Two separate, dedicated compression trains then process the two streams for each AGR, supplying the product CO_2 to a single pipeline. (For simplicity, this report discusses a single compression train.) The two streams leave the AGR train and pass through an inlet knockout drum. The low pressure (LP) stream passes through the LP CO_2 knockout drum DR1078. The medium pressure (MP) stream passes through the MP CO_2 knockout drum DR1079. Both streams then flow into different stages of multi-stage CO_2 compressor CO1080.

The low-pressure CO_2 enters the first stage of the compressor and proceeds through two stages of compression with subsequent intercooling. This overall section of the compressor is process stage 1 (PS1). Prior to the third stage, the LP stream is combined with the MP CO_2 from the MP knockout drum. The gas is then compressed in two additional stages with associated intercooling. This section of the compressor process stage 2 (PS2). See configuration diagram in figure 5.16-1.

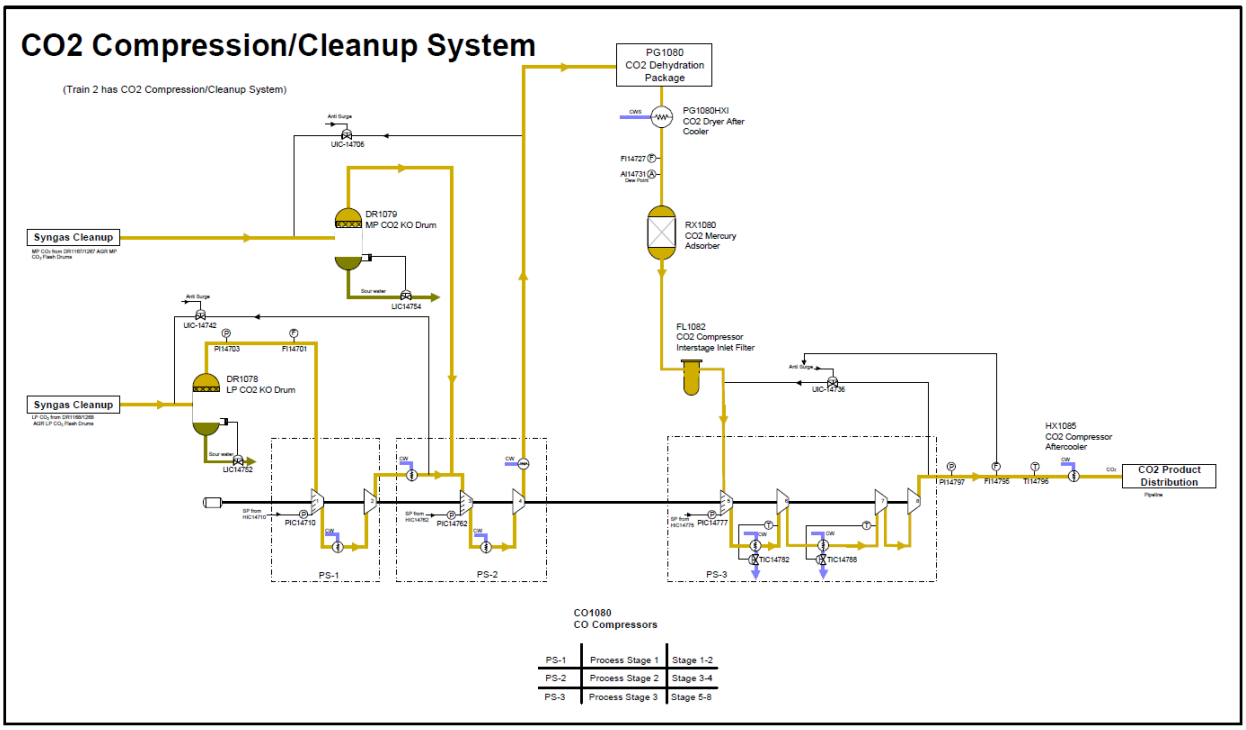

Figure 5.16-1 – CO_2 compressor and offtake system

After the fourth stage of compression, the combined gas stream exits the compressor and passes through CO_2 dehydration unit PG1080 and CO_2 mercury absorber RX1080. These additional steps are necessary to meet the purity requirements of the offtaker.

After mercury removal, the CO_2 stream returns to the compressor, where the gas is compressed into the dense phase to the final offtake pressure of up to 2,150 psig. This final section of the compressor is process stage 3 (PS3). The CO_2 is then cooled to the offtake temperature (100 °F) in the compressor aftercooler HX1085. Finally, the CO_2 streams from each gasifier train are combined and delivered to the CO_2 pipeline metering station as a co-product of the gasification process.

Each CO_2 compressor is an eight-stage, integral-gear compressor with a synchronous motor drive. Process control is achieved by automatic adjustment of the sets of inlet guide vanes located at the inlet nozzle of each process stage. Antisurge protection uses recirculating CO_2 back to the suction side of each process stage. The PS1 and PS2 streams return to the inlet knockout drum. The PS3 stream returns to the inlet of the fifth compression stage. As the gas expands across the antisurge valve in each kickback line, the gas will autorefrigerate. The resultant cooling eliminates the need for a kickback cooler.

The CO_2 dehydration unit is a dual-chamber, solid desiccant unit. CO_2 must always pass through an active chamber to ensure the moisture content in the product streams meets pipeline specifications (30 lb/MMscf). While the active chamber is in operation, the desiccant in the nonactive chamber is regenerated by blowing warm air counter-current to the normal process flow direction (figure 5.16-2).

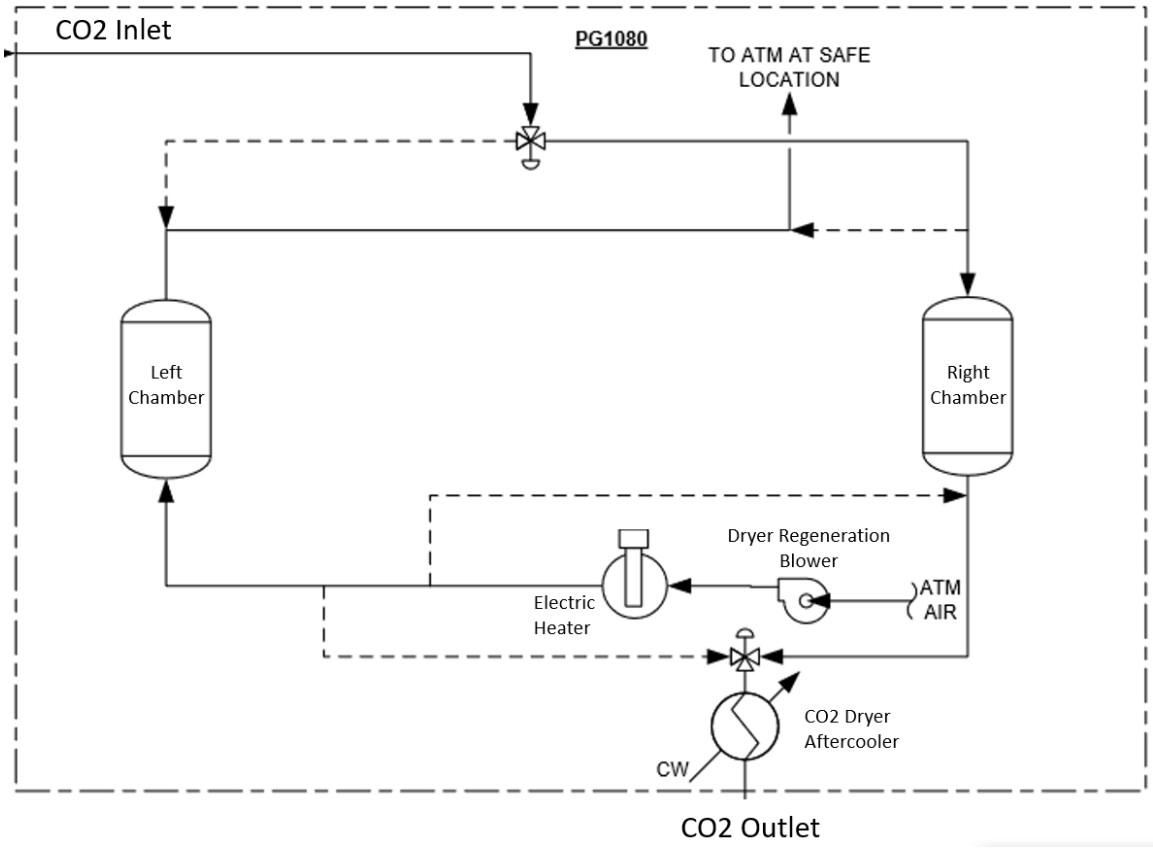

Figure 5.16-2 – CO_2 dehydration and regeneration package

The CO_2 mercury adsorber is a reactor vessel containing activated alumina. It removes any mercury from the CO_2 recovery system that might pass into the offtake system. No appreciable quantity of mercury was anticipated in the CO_2 offtake system. The pipeline specification was less than 2 ppbv. The AGR licensor was unable to guarantee that no mercury would pass into the CO_2 offtake system, so the mercury bed was added to the design as a precaution. Following mercury removal, the gas is filtered in the CO_2 compressor interstage inlet filter FL1082 before returning to the compressor.

The combined gas from both compressors is sent to a product metering station located at the edge of the plant property. The gas is metered for payment and monitored for quality with an online gas analyzer just before entering the CO_2 pipeline.

The offtake line is a 62-mi long, 16-in. CO_2 pipeline installed by Southern Company. The single source of supply for the line was the Kemper facility. The CO_2 was deliverable to an offtaker who used the CO_2 for enhanced oil recovery (EOR). The CO_2 would be geologically sequestered at the end of EOR operations.

5.16.2 Initial Commissioning Plan

The commissioning of the CO_2 compressor system and ancillary equipment had several challenges that made prior planning critical. The compressors were each a first-of-a-kind unit. At the time of purchase, they were the largest CO_2 compressors in the world by volume. Significant modeling of the gas characteristics had been conducted during design, as well as an extensive verification of prior operating experience of each major component within the compressor train. There was some concern about the transition of CO_2 into a dense-phase fluid. There was the typical challenge of testing and tuning a unit with complex control loops in series with such large volumes of CO_2.

The commissioning plans were established with the intent to account for the interconnected nature of the system but commission each process stage and the dryer independently to the extent possible. After initial commissioning was complete, final tuning and plant integration would be completed to fully prepare the system to accept, prepare, and deliver CO_2 to the offtake pipeline.

5.16.2.1 *Inspections and System Cleaning*

Cleaning of the CO_2 compression and offtake system posed several challenges. The volume required and the complexity of the piping configuration made air blows a less feasible option. The project planned to hydroblast all process piping leading to and from each CO_2 compressor.

The process piping was to be opened in several sections and the first spools for compressor stages 1, 3, 4, and 8 were to be removed. The compressor flanges were then to be blinded to prevent moisture from getting into the compressor. The plan was to then open flanges between major process components and hydroblast all piping in between. The scope of piping to be cleaned as part of the CO_2 offtake system included the discharge lines from the AGR LP and MP CO_2 flash drums to the isolation valve immediately upstream of the metering station. The piping downstream of the metering station isolation valve was cleaned by the CO_2 pipeline commissioning crew.

After each of the lines were clean, each vessel was to be inspected for cleanliness and any internals inspected and verified (table 5.15-1).

Table 5.16-1 – CO_2 vessel inspections list

Equipment Tag	Description
DR 1078/2078	LP CO_2 knockout drum
DR 1079/2079	MP CO_2 knockout drum
PG1080-DRA & B / 2080-DRA and B	CO_2 dehydration package chamber A and B
RX 1080 / 2080	CO_2 mercury adsorber

Following system cleaning and inspections, each section was to be closed and inserted while the remainder of the system was readied for commissioning.

5.16.2.2 *Leak Checks and Pressure Tests*

It was critical that the system be leak-tight before introducing CO_2. The process gas was an asphyxiant that autorefrigerated should it leak, and high operating pressures were required to achieve pipeline quality product. A series of leak checks were to be conducted leading up to commissioning of the compressor and the introduction of process gas.

The system would be broken out into multiple sections that could be leak-tested individually. This was done to limit the resources needed to complete the test. An instrument air line was to be connected to the test section and pressurized stepwise from 25 psi to 100 psi. The process connections would then be checked for leaks and repaired.

After the system was fully reassembled, a system-wide leak check was to be conducted as an initial phase of the compressor test package execution. This system check would be conducted with CO_2 as part of an air-freeing process.

When the leak check was complete, the system would be pressurized in increments of 10 psi up to 100% operating pressure (2,150 psi) during the initial mechanical integrity run of the compressor. This process was accomplished by starting the compressor and, after the system has established temperature, open the inlet guide vanes to achieve the desired pressure. Any leaks were to be addressed as encountered.

5.16.2.3 *Commissioning of CO_2 Dehydration Unit*

The CO_2 dehydration unit is similar to an instrument air dryer set used for plant air systems. The commissioning plans followed the methodology commonly used to commission air dryers and was to be completed before loading the desiccant. The procedure included:

- Complete a system leak check.
- Complete loop/logic checkout.
- Conduct an uncoupled blower motor run.
- Walk the dryer through start/stop/swap logic.

5.16.2.4 *Loading of Desiccant and Catalyst*

Loading of the desiccant in the CO_2 dehydration units and the catalysts in the CO_2 mercury adsorbers was to be handled by a third-party vendor, which recommended a loading method based on experience. Each of the vessels was to be loaded from a super sack through either a loading chute or by dumping through a manway near the top of each vessel. Each vessel was to be thoroughly cleaned and inspected before bed material was loaded.

5.16.2.5 *Commissioning of the CO_2 Compressor*

The commissioning of the CO_2 compressor, while complex, was expected to follow the typical path of large multistage compressor applications, which included initial leak checks, a verification of mechanical integrity, and finally surge testing and tuning.

The compressor LP leak test was to be conducted with the unit running at minimum load. The compressor would be started, and the antisurge valves would remain fully open with the inlet guide vanes closed to the minimum running position. Maintenance personnel would then spray each flange connection, instrument tap, and any other joints to ensure the system was tight. Any identified leaks were to be corrected before proceeding with testing. The test medium would be CO_2.

Following the initial leak check, testing would continue by opening the inlet guide vanes of each of the three process stages to maintain the compressor at the bottom range of the operating map. This process would pressurize the machine and ensure mechanical integrity of the unit. As the compressor loaded, the IGVs were to be held at each increment of 10% to allow commissioning engineers to collect operating data. Maintenance personnel were to conduct additional leak checks of each flanged connection as the IGVs were opened to 50% and 100%. Any leaks identified were to be repaired before continuing with testing.

Following mechanical integrity testing, the vendor field service personnel would proceed to a battery of additional testing including:

- Tuning of the antisurge valve.
- Rough tuning of the inlet guide vane controllers.
- Surge testing.
- Rough performance tuning.

The CO_2 compressors had been tested before shipment from the factory using ASME PTC-10 Type I testing protocol to meet the more stringent of the performance guarantees. It was important to both MPC and the compressor vendor to demonstrate the unit had sufficient operating capabilities in the field. The testing had the additional goal of demonstrating the unit performed per contractual requirements.

Following the compressor tuning, a series of safety interlock tests were to be conducted to verify the machine and personnel safety trips performed as intended. A single trip response was to be generated from each of the PLCs, DCS, and SIS locations. The normal start and stop sequence was to be tested.

5.16.2.6 *Charging of the CO_2 Pipeline*

The initial commissioning of the CO_2 pipeline was to be conducted by the third-party operator of the pipeline, including cleanliness, valve alignment, and pressure regulation downstream of the Kemper CO_2 meter station. The primary role of Kemper plant personnel would be to provide on-spec CO_2 to the pipeline interface and to maintain communication with the third-party operator should issues arise through the operation of the CO_2 compressor train or the plant AGR unit.

Until the pipeline pressure increased to the point where full forward flow could be established, the compressor was to operate at maximum turndown, with any excess CO_2 being recirculated back through each process stage to maintain volume. Any excess CO_2 would be vented to the HRSG stack through the CO_2 vent header.

5.16.3 Significant Events

5.16.3.1 *Accomplishments*

Train A		Train B	
Lube oil system commissioned	10-1-2014	Lube oil system commissioned	7-13-2015
Dryer desiccant loading complete	8-22-2015	Dryer desiccant loading complete	8-26-2015
System cleaning complete	3-1-2016	CO_2 dryer commissioned	9-7-2015
CO_2 dryer commissioned	4-18-2016	System cleaning complete	3-7-2016
Hg adsorber loading complete	6-11-2016	Underground offtake piping clean	6-1-2016
Underground offtake piping clean	6-21-2016	Hg adsorber loading complete	6-12-2016
CO_2 compressor commissioned	3-6-2017	CO_2 compressor commissioned	3-25-2017
Initial charging of CO_2 pipeline	1-31-2017		

5.16.3.2 *CO_2 Compressors*

- CO_2 snap ring repairs

In early 2013, before any commissioning activities, the CO_2 compressor vendor notified the project of a potential issue with the snap rings that hold the seal cartridges behind each impeller in place. The CO_2 compressors at Kemper were the first units produced by the vendor for dense-phase CO_2 applications. Another U.S. customer had purchased a similar unit after Kemper's purchase, but because of Kemper's extended installation schedule, the similar unit was installed and commissioned before the Kemper units.

Shortly after the similar unit was commissioned, it began to experience vibration issues in the high-pressure stages of the compressor (the final two wheels). Inspections indicated damage to the outer tips of the blades on the seventh stage and near the impeller eye of the stage 8 stage. It was determined that the snap ring behind the seventh stage impeller had failed and broken into several pieces. These parts travelled around the outside of the seventh stage and into the eighth stage.

The experience from the similar unit indicated the ring material would lose tensile strength during continued operation and fall out of the run channel in which it was normally installed. Once free, the ring was most likely broken by the movement of the impeller.

The vendor determined that the snap ring material was not robust enough for high molecular weight environments at high pressure. The vendor notified Southern Company that the material selection and operating environment of the

Kemper units were similar and that both compressors would need to be modified to ensure a similar failure did not occur. Figure 5.16-3 shows the location of the snap ring on the Kemper unit.

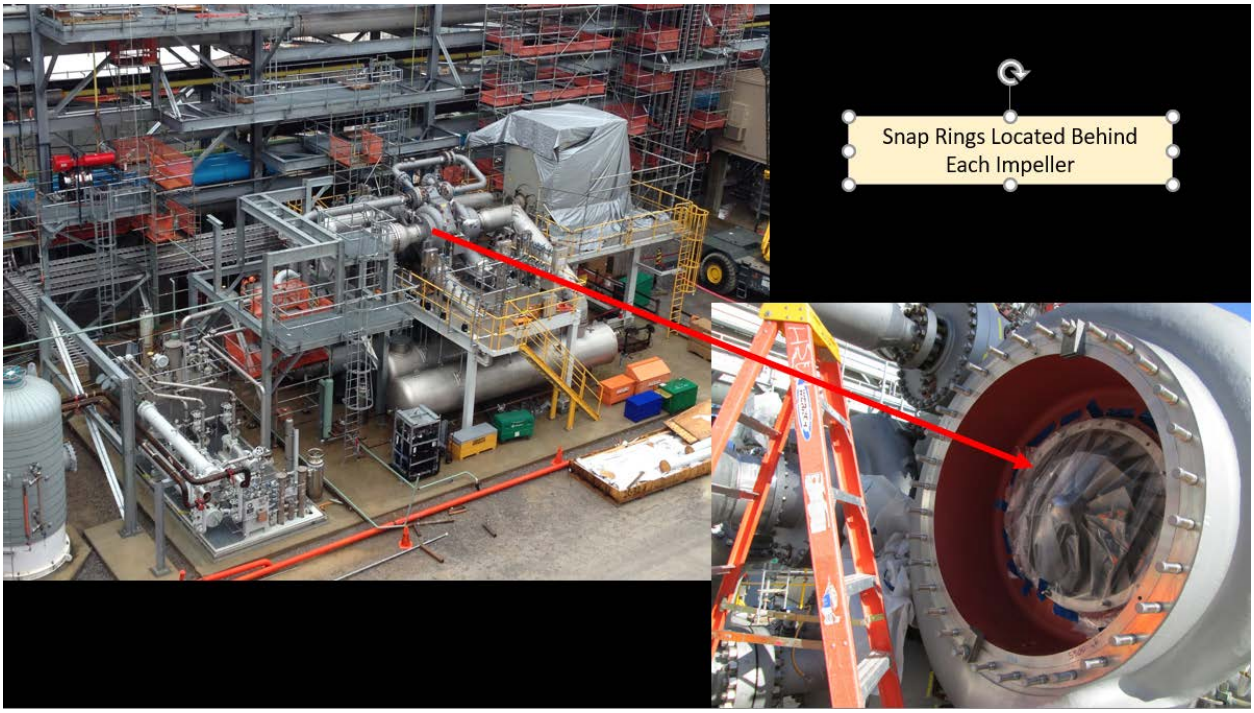

Figure 5.16-3 – Snap ring location

The vendor presented Southern Company with two options to complete the repairs. The first was to wait for a more robust material ring to be fabricated, which would address the issue of failing tensile strength. However, the lead time for a complete set of rings for both compressors was several months, which would have pushed back the overall project completion date.

The second option was to install a small block between the tool rings of the snap ring. This block would not correct for the reduced tensile strength of the ring material, but it would prevent the ring from falling out of the run channel. The vendor suggested there was only slightly more risk in the second option, and there was the benefit of not having a significant lead time to start the repairs. Southern Company selected the second option (figure 5.16-4).

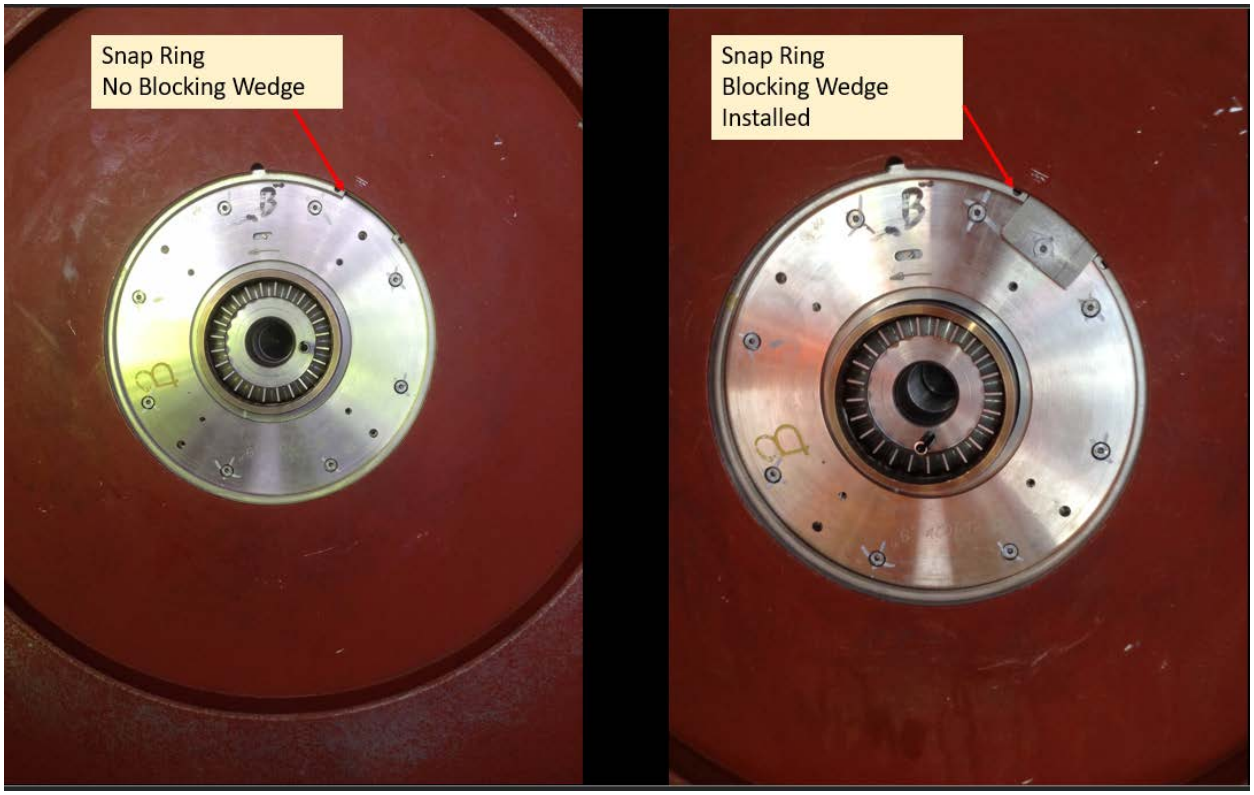

Figure 5.16-4 – Location of snap ring blocking wedge

The vendor began the modification of the Train B compressor in January 2014. The Train A compressor was modified in February 2014. The final reinstallation and closure activities were complete by mid-March 2014, allowing precommissioning activities to continue.

- Commissioned lube oil skids

Each compressor application included a separate lube oil skid to provide lubrication and cooling during operation. The commissioning of each skid consisted of instrumentation and logic verification, and uncoupled motor runs on each of the on-skid lube oil pumps. The procedure included a flush of the lube oil circuit to ensure system cleanliness before introducing oil to the compressor and the main motor bearings. The flush activity consisted of circulating the oil through an off-skid pump and sock filtration unit. After the bulk oil was sufficiently clean (no visible particles on the sock following a 4-hr run), the oil was circulated through the compressor and motor bearings with last-chance screens. The screens remained installed until they were verified clean by both vendor and Southern Company personnel.

Precommissioning and flushing activities for the Train A lube oil skid was completed in October 2014. The Train B lube oil skid was complete in July 2015. The skids remained in operation to the extent possible until the compressors were readied for commissioning.

- CO_2 dryer regeneration heater corrosion

The CO_2 dryers have a regeneration heater in the air supply line to each dryer chamber. The heated air improves the efficiency of the regeneration cycle. During precommissioning, Startup attempted to megger test each of the heater elements. When the terminal box for the Train B CO_2 dryer was opened, it contained condensation, which had corroded many of the terminations to the heater elements (figure 5.16-5).

Figure 5.16-5 – Corroded dryer terminals

An inspection of the Train A dryer heater showed a similar condition. The elements for both trains failed the megger test. To clean the terminations, each cable was removed and CO_2 blasted, which removed the corrosion and any residual moisture in the heater box (figure 5.16-6).

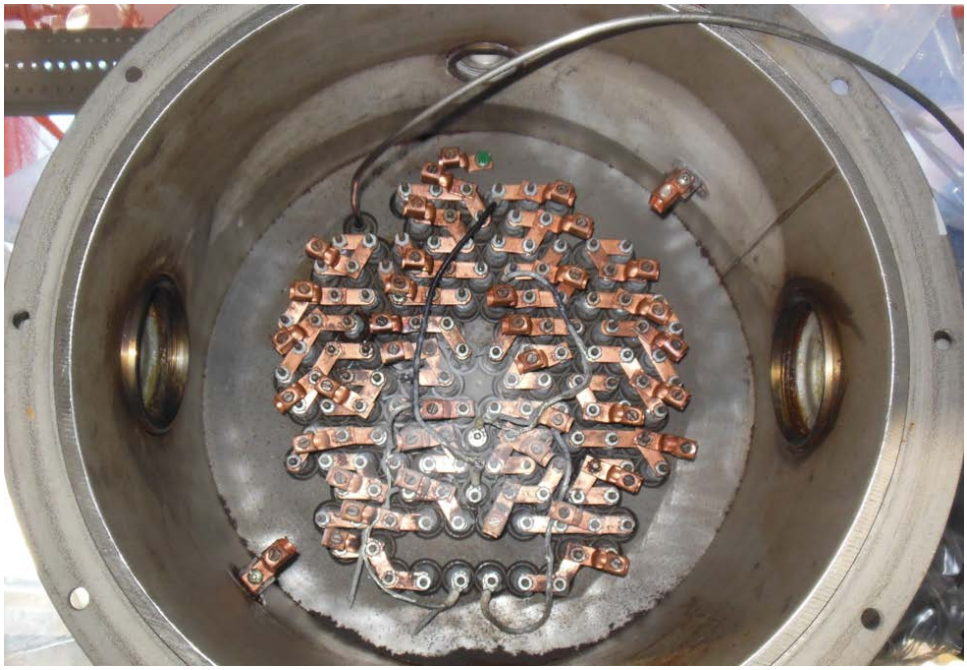

Figure 5.16-6 – CO_2 dryer heater after CO_2 blasting

To prevent further corrosion, the elements were heated with a low-voltage heat source that also served to dry out the heater elements. The elements were meggered monthly to ensure they did not need to be replaced. One element in the Train A dryer did not improve and was replaced.

- Pneumatic test of the CO_2 vent header

The plant contained a CO_2 vent header that vented captured CO_2 to the HRSG stack when the CO_2 compressors were not in operation such as during startup, shutdown, and compressor trips. After the CO_2 vent header from the AGR to the HRSG stack was turned over to Startup, a project review determined the piping required a pneumatic test. This test was not completed during Construction because the design documentation indicated it was not necessary. At the time Startup was notified that the test needed to be completed, the power block was in continuous operation. Since the CO_2 vent header piping terminated in the active exhaust of the HRSG, isolating the system to work on the piping proved difficult.

To prepare for the test, a blind needed to be installed between the HRSG and the vent header. The project decided to wait until an outage of each CT to install the blind. In the interim, the compressor side piping was prepared for the test. The PRVs were removed. Several of the PRVs were found to have substantial pipe stress and needed to be repaired by cutting and rewelding the piping.

At the next outage in 3 months, the blind was installed, and repairs made to each of the instances of pipe stress. The pneumatic test for each header was successfully completed in July 2015. Following the test, the PRVs were recertified and reinstalled. The project decided to leave the HRSG blinds installed until the entire CO_2 system was ready for commissioning.

- CO_2 desiccant loading

The dryer desiccant arrived onsite early and was stored outside in an uncovered laydown area. There was a concern that this exposure would damage the material before it was loaded into each dryer chamber, but no issues occurred. A preliminary leak check of each vessel chamber was completed before loading. After each vessel proved to be airtight, the desiccant was loaded into each chamber. There were no significant challenges encountered while completing this activity.

- Logic verification of CO_2 dryers

Following desiccant installation, the commissioning of each dryer system was completed, going through the entire regeneration sequence including conducting an uncoupled motor run of the blowers and verification of the logic steps (figure 5.16-7). The critical portions of the dryer sequence included swapping from one chamber to the next and starting and stopping of the regeneration cycle. Each of these was confirmed, and an initial regeneration cycle of the desiccant was completed. To maintain the desiccant until the commissioning of the CO_2 compressor, each chamber was regenerated once every 24 hours.

Figure 5.16-7 – DCS Screen for logic steps

- System cleaning

The process piping throughout the CO_2 offtake system was hydroblasted to remove mill scale and construction debris, which included the piping from the AGR LP and MP CO_2 flash drums to the compressor; from the compressor to the dryer, inlet, and outlet of the mercury bed; and from the compressor discharge to the CO_2 underground tap.

The cleaning took a considerable time to complete because of the extensive piping. The Train A cleaning began in June 2015 and was completed in October 2015. The Train B cleaning began in October 2015 and was completed in March 2016.

The CO_2 piping connecting the CO_2 compressor discharge to the CO_2 pipeline was installed below grade at a maximum depth of 16 ft, which proved a very difficult segment to clean. Robotic inspection confirmed the piping contained a significant amount of dirt, rocks, and construction debris. The project considered cleaning the pipe with an air blow, but this was not considered practical given the volume of air required to obtain a suitable cleaning force ratio. It was determined that the best path would be to repeatedly flood the piping and drain it by sucking the water out using a vacuum truck

Future projects should consider either routing large diameter piping above ground or including provisions for cleaning such as a pig launching station. While the piping was being cleaned, the remaining precommissioning activities were completed in preparation for final test package execution.

- CO_2 two-motor soleplate machining

An uncoupled motor run was completed in April 2016. During the test, the rotor appeared to be hunting and would not stabilize to a level that allowed the magnetic center to be marked. The investigation found the motor had a soft foot. A preliminary alignment confirmed that the motor was not alignable to the compressor with the available travel (figure 5.16-8).

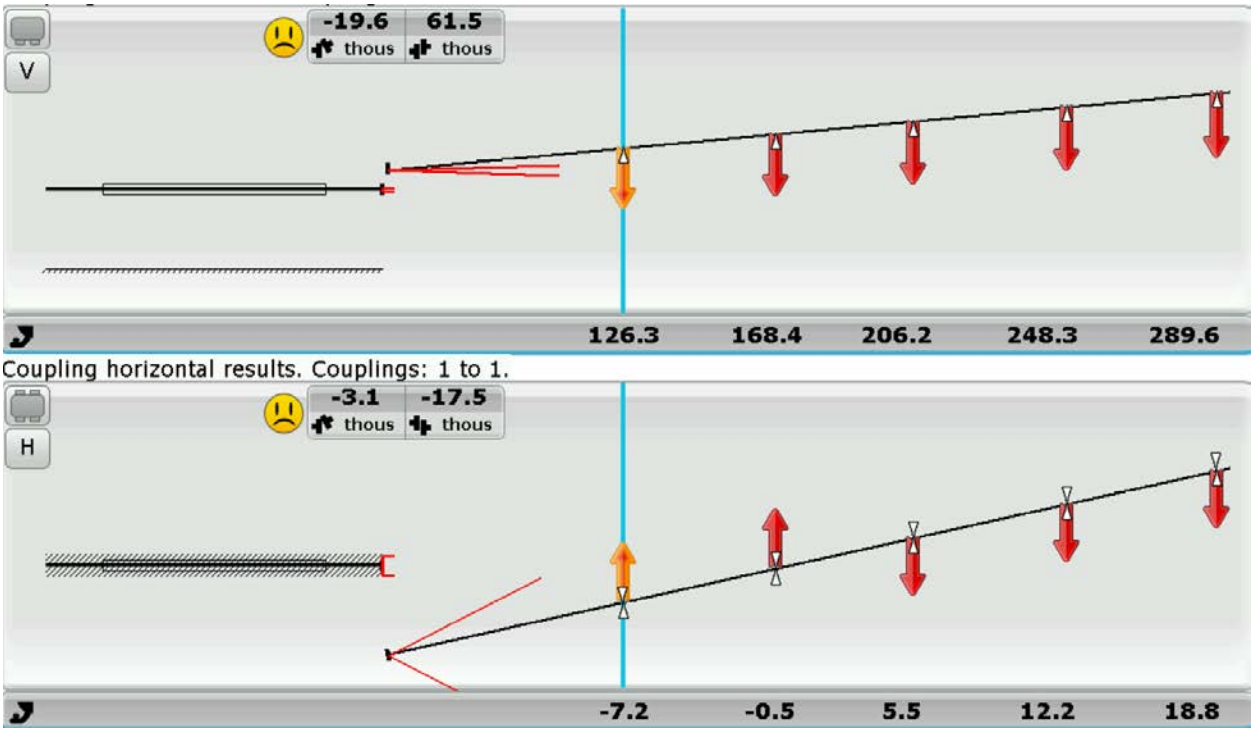

Figure 5.16-8 – CO_2 two-motor alignment results

To correct the condition, the motor sole plates had to be machined down to a level that allowed adequate adjustment clearance. Consultations with the vendor confirmed that this process was acceptable and onsite machining of each plate was completed.

There were five total plates that required machining (figure 5.16-9).

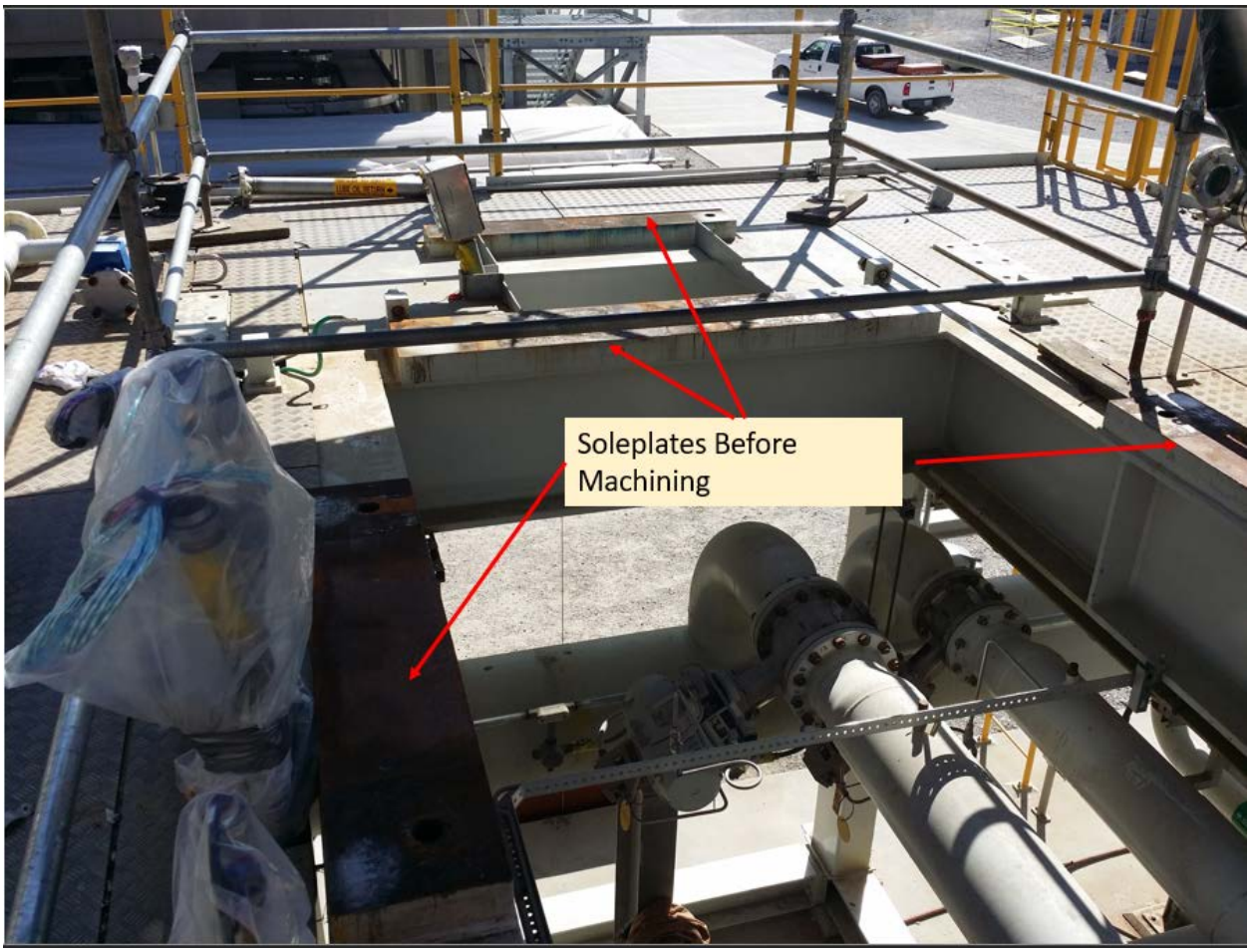

Figure 5.16-9 – CO_2 two motor soleplates

The machining and restoration of the motor was completed in 2 weeks. The final alignment of the compressor and uncoupled motor run confirmed repair was successful. Following completion of the uncoupled motor run, the coupling was installed, and the final mechanical verification was complete.

- Mercury bed catalyst loading

A third-party contractor was used to complete the loading of the mercury bed catalyst. Startup personnel leak-tested the vessel and prepared it for the loading crew. The third-party vendor loaded the materials based on the criteria listed in figure 5.12-10. The loading of each vessel was completed in June 2016.

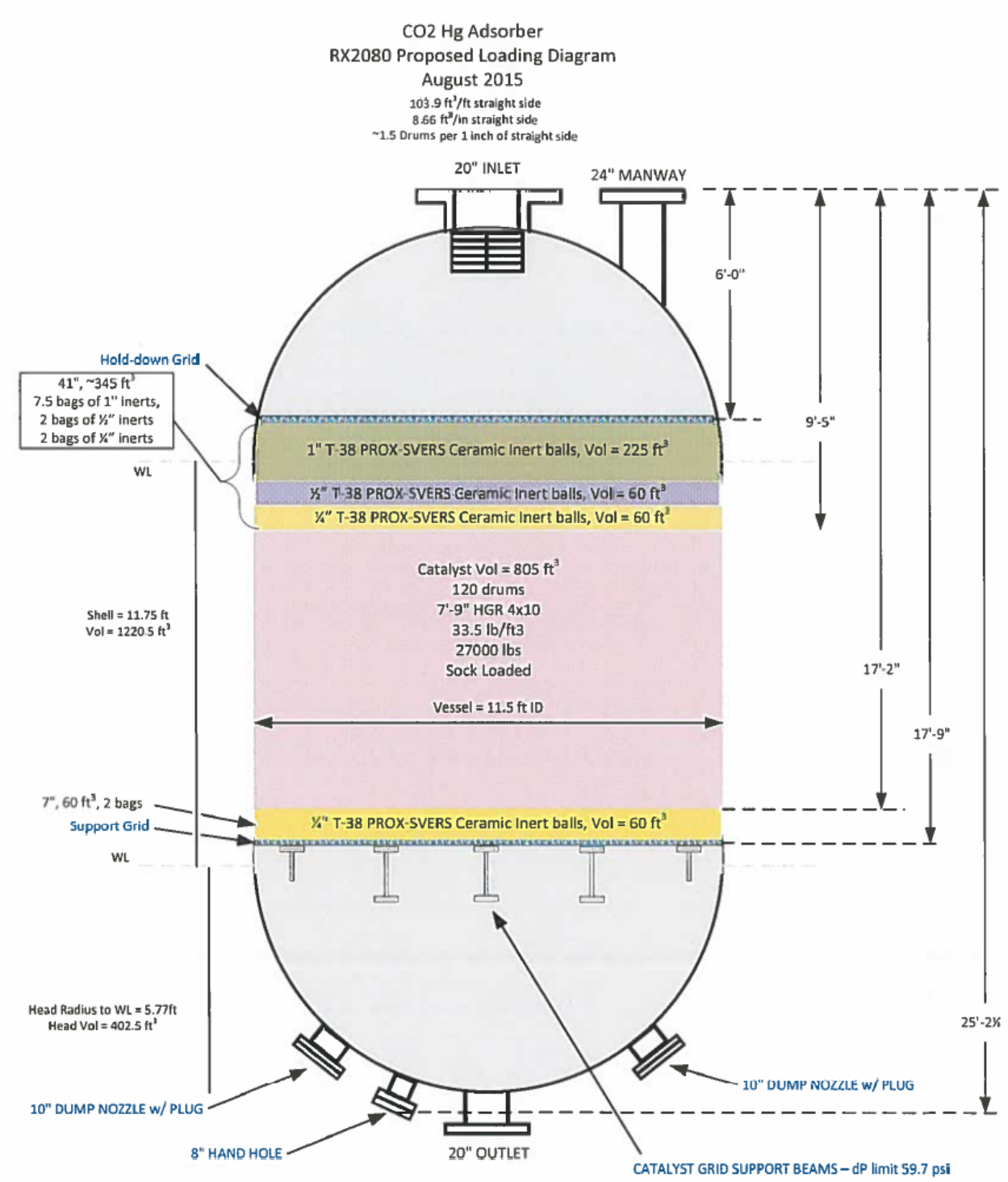

Figure 5.16-10 – Mercury bed loading criteria

- Charging of CO_2 compressors for commissioning

The CO_2 compressors are normally charged using the LP and MP CO_2 flash drums. During the commissioning of the compressors, a temporary CO_2 tank and vaporizer set was brought onsite to manually charge each process stage. The initial charging rates required up to 12 hours to reach the startup permissive pressures for each stage, and it was determined that a single vaporizer was not sufficient to provide adequate pressurization rates between compressor starts.

A single vaporizer was not sufficient to meet flow requirements to prevent the compressor from tripping on low suction pressure following synchronization. It took 1 month to obtain additional vaporization equipment and hoses suitable for CO_2 operations.

It was difficult to charge the compressors without the CO_2 in the hoses freezing from autorefrigeration. Multiple methods were employed to keep the lines free during preparation and testing. The smaller lines were heat-traced, and the larger lines used a combination of water bath and heat-tracing. Despite the challenges, the arrangement was suitable to begin commissioning the compressors.

- Compressor commissioning

The commissioning of the CO_2 compressor was a delicate balance among the vaporization rates of the temporary CO_2 source, the adjustment of the startup trip logic, and the sequencing of the inlet guide vanes for each of the three process stages.

Testing began on Train B in January 2017 and proceeded largely in line with the test plan. An initial leak check was completed before compressor start. It took several days to achieve stable operation, primarily due to the limitations of the temporary CO_2 vaporizers and the low-pressure trip interlock in the first and second process stages. One challenge was that the pressure into the second process stage would drop when the dryer isolation valves were opened. To address this issue, the dryers were precharged with CO_2 to limit the amount of mass that needed to be made up for integration of the compressor and dryer.

After stable operation was achieved, the mechanical integrity run and additional leak checks were completed satisfactorily. The inlet guide vanes for each of the three stages were opened, with the antisurge valves fully open to map the bottom of the compressor performance map.

Testing proceeded into the surge testing of each process stage. The surge testing was completed with no significant issues. Figure 5.16-11 shows the final test points of the second stage surge control line. Multiple points are mapped near the compressor normal operating range to confirm the surge limit line is accurately set. The figure is a plot of the compression ratio versus the corrected suction flow.

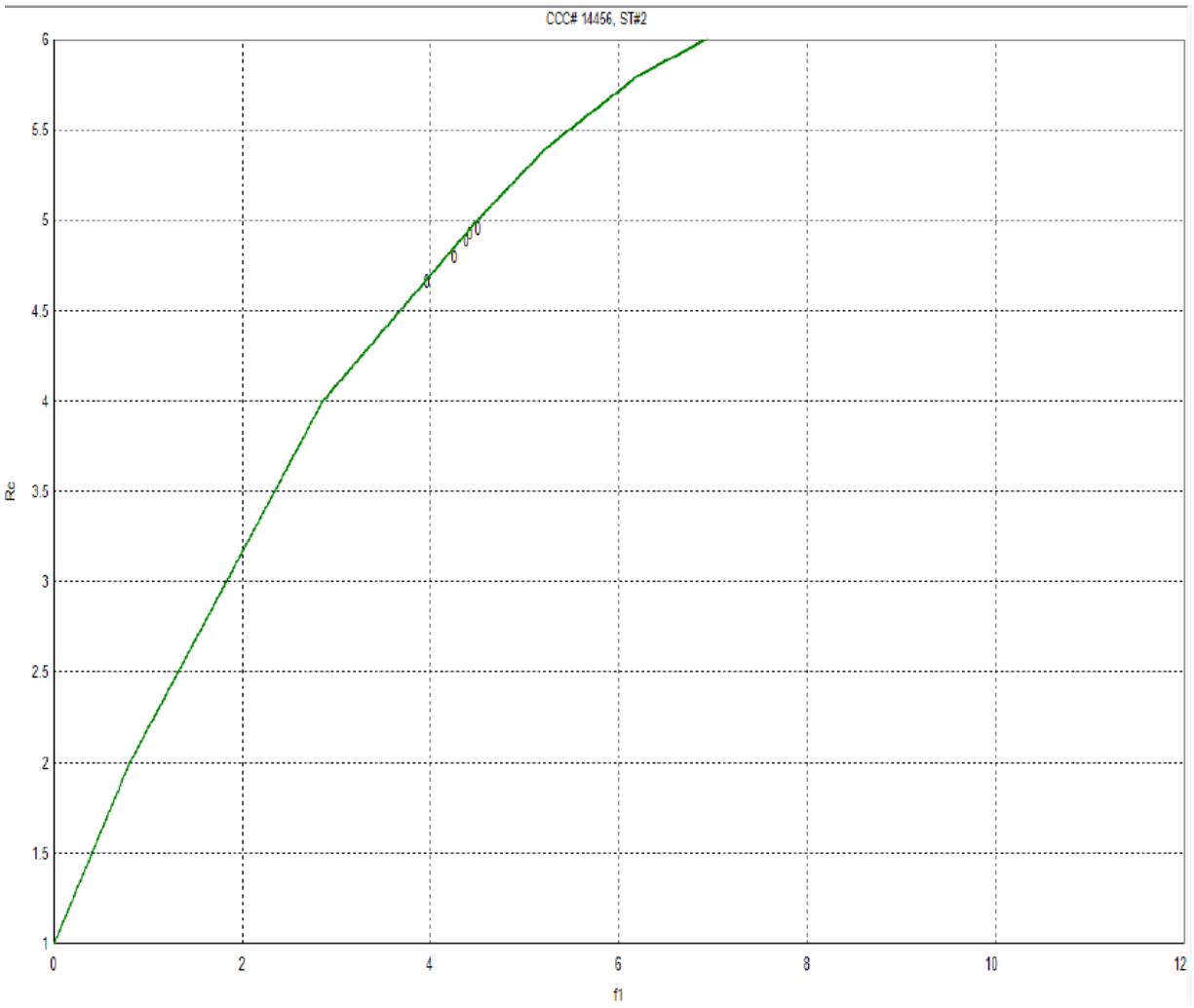

Figure 5.16-11 – Surge test results, second process stage CO2080

When the surge testing was complete, the compressor was tripped and restarted from each of the controls systems with trip logic, including the VFD, Allen-Bradley PLC, CCC PLC, DCS, and SIS. Trip confirmation testing was completed successfully.

The system was then shut down and put under a CO_2 cap in preparation for the integration testing with the AGR.

The commissioning of the Train A compressor was completed in February 2017. While similar challenges with timing and charging of CO_2 from the temporary source were observed, the testing was completed successfully. Figure 5.16-12 shows the compressor HMI with the compressor in operation.

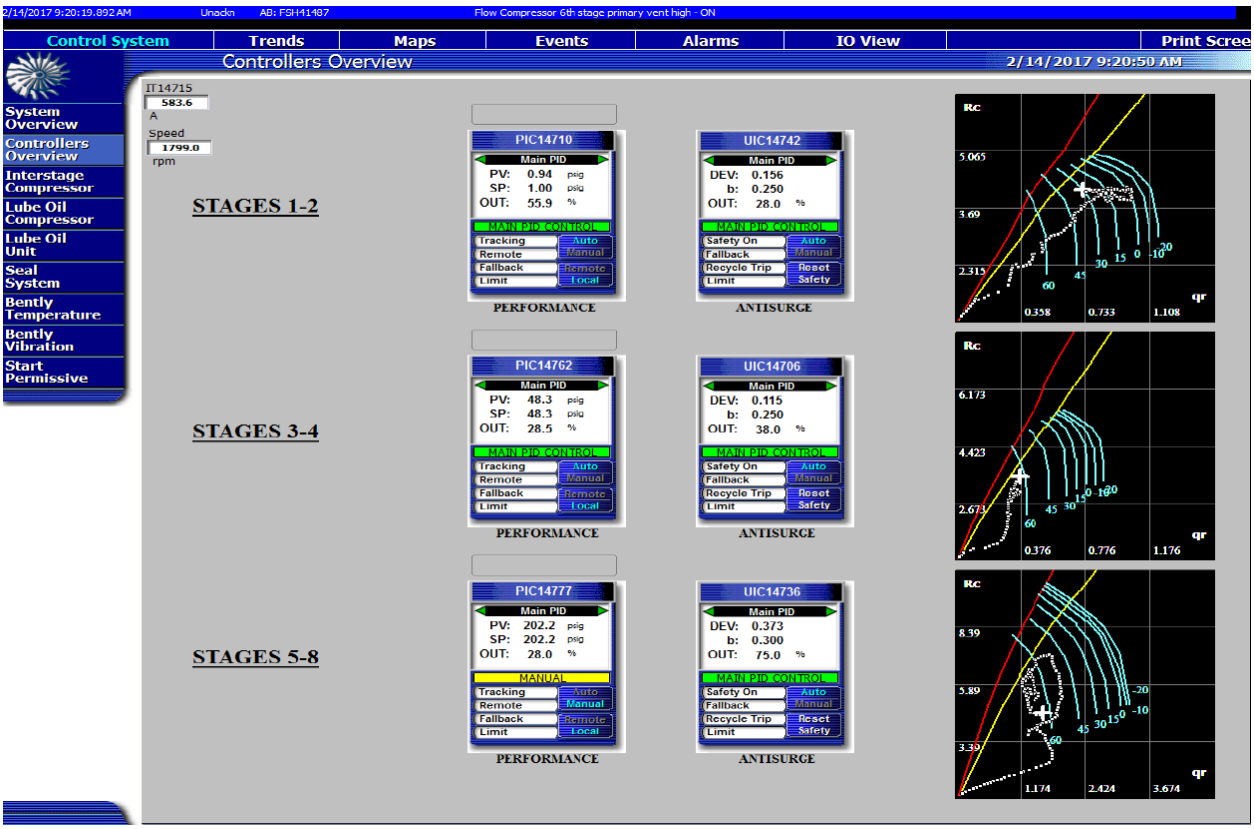

Figure 5.16-12 – CO1080 controller HMI

When all testing was completed, the CO_2 underground piping was charged to 200 psig in preparation for charging of the CO_2 pipeline. At this point, the CO_2 offtake system was ready to receive CO_2 product from both AGR trains.

5.16.4 Final Summary

The commissioning of the CO_2 offtake system posed several challenges that were largely anticipated. The CO_2 compressor is one of the more complex units available in industry based on the competing aerodynamics and controls configuration. Despite this fact, all test objectives were successfully completed.

In preparation for integration with the AGR and the charging of the CO_2 pipeline, the system remained under a CO_2 cap, partially charged to reduce the amount of startup time required to reach startup pressures.

5.17 Sour Water and Ammonia Purification

5.17.1 System Overview

The primary objective of the sour water system is to remove contaminants from the water before it is reused as make-up to the cooling towers and then processed in the waste water treatment plant as part of the facility's zero liquid discharge process. The sour water system also separates and purifies ammonia into a commercial anhydrous ammonia product. The sour water system processes wastewater from the syngas scrubbers CL1007/CL2007 and ammonia scrubbers CL1006/CL2006) in each gasification train's syngas cleanup process, and from other minor streams throughout the facility. Most of the sour water feed comes from the ammonia scrubbers.

The major constituents of sour water are water, ammonia, hydrogen sulfide, and carbon dioxide. Various hydrocarbons and dissolved halides are present in smaller concentrations. The water coming from the syngas scrubbers contains a

relatively high concentration of chlorides (approximately 3,000 ppm per design) and lower concentrations of ammonia and hydrogen sulfide due to its high operating temperature of approximately 350 °F. Water from the cooler ammonia scrubbers (~100 °F) contains higher levels of ammonia and hydrogen sulfide. Hydrocarbons formed in the gasifier are condensed from the syngas stream at the operating temperature of the scrubbers.

The concentration of ammonia and hydrogen sulfide in the scrubber water is also a function of the operating temperature and pressure of the ammonia scrubber. As pressure increases and operating temperature decreases, the concentrations of ammonia and hydrogen sulfide increase in the scrubber water. When pressure is decreased and the temperature in the column increased, the concentration of ammonia in the water will go down. The ammonia scrubber will require more or less water per unit flow of syngas as a result of operating temperatures and pressures. The concentration of ammonia and hydrogen sulfide in the sour water is dependent on the conditions in the ammonia scrubber.

Sour water from the ammonia and syngas scrubbers enters the wastewater drum DR0040 through the plant wastewater header (figure 5.17-1). The wastewater drum is used as a bulk phase separation device to increase the settling time of the combined sour water stream and allow density differences to separate light and heavy hydrocarbons from the aqueous phase. The light and heavy hydrocarbons are removed from DR0040 to the hydrocarbon drain drum DR0047, then pumped back to the gasifier to provide heat for the gasification reactions. Water from the wastewater drum can be diverted to the wastewater storage tank TK0042 for storage or sent directly for downstream processing. Sour water also can be pumped from TK0042 back to DR0040 for further processing. It should be noted that TK0042 operates at approximately atmospheric conditions. During normal operating conditions, dissolved gasses from the sour water feed stream will flash out of solution due to the drop in pressure as it enters TK0042. The composition of the sour water will change as a result of the flashing of dissolved gasses from the sour water.

Sour water from DR0040 is pumped to the carbon bed filter package PG0040, which removes residual hydrocarbons that pass through DR0040. Proper sour water system performance requires removal of hydrocarbons. Hydrocarbons cause foaming in the distillation columns, leading to poor separation and to operational and environmental problems due to insufficient ammonia and hydrogen sulfide removal from the sour water.

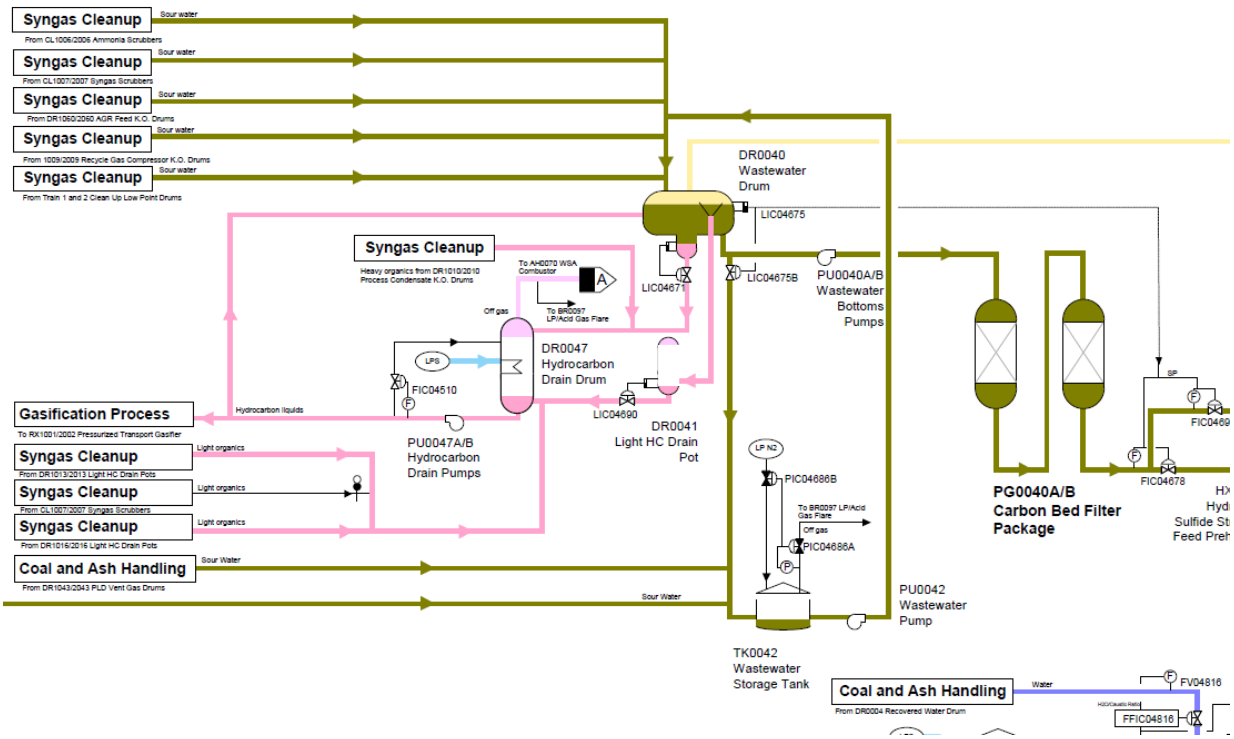

Figure 5.17-1 – Wastewater drum illustration

Following the carbon bed filter, sour water splits into separate feed streams (figure 5.17-2). Most of the sour water is preheated with the hydrogen sulfide stripper feed preheater HX0041, which uses the bottoms flow from the wastewater ammonia stripper CL0044 as the heating media for the feed stream to the hydrogen sulfide stripper CL0042. The preheated sour water enters CL0042 several trays below the top tray. The remaining sour water feed bypasses HX0041 and is fed to the top of CL0042 to provide additional scrubbing in the upper trays of the column. The hydrogen sulfide stripper removes carbon dioxide and hydrogen sulfide from the sour water by applying heat at the bottom of the column with a thermosyphon reboiler. The heat generated by the reboiler generates vapor that flows up through trays in the column. As the sour water travels down the column, the rising vapor from the reboiler strips out volatile components such as hydrogen sulfide and carbon dioxide which flow out from the top of the column to the AGR unit were the CO2 and H2S are captured. CL0042 should remove essentially all the CO_2 and about half of the H_2S in the sour water feed. The purpose of CL0042 is to minimize the amount of ammonia that is stripped out of the sour water and maximize the amount of CO_2 and H_2S removed from the sour water. If excess ammonia is stripped from the sour water in CL0042, it will ultimately end up in the AGR unit where it will form salts and foul the system. Downstream of CL0042, the sour water is dosed with a caustic solution to adjust the pH before entering the wastewater ammonia stripper CL0044. Adjusting the pH of the sour water before CL0044 creates a more favorable environment for the separation of ammonia. If the sour water pH entering CL0044 is within the acidic range, ammonia will bind with acids and exist in the ionic form. Ionic ammonia (ammonium ion) will not be stripped from solution. The pH must be adjusted in order for the distillation process to work.

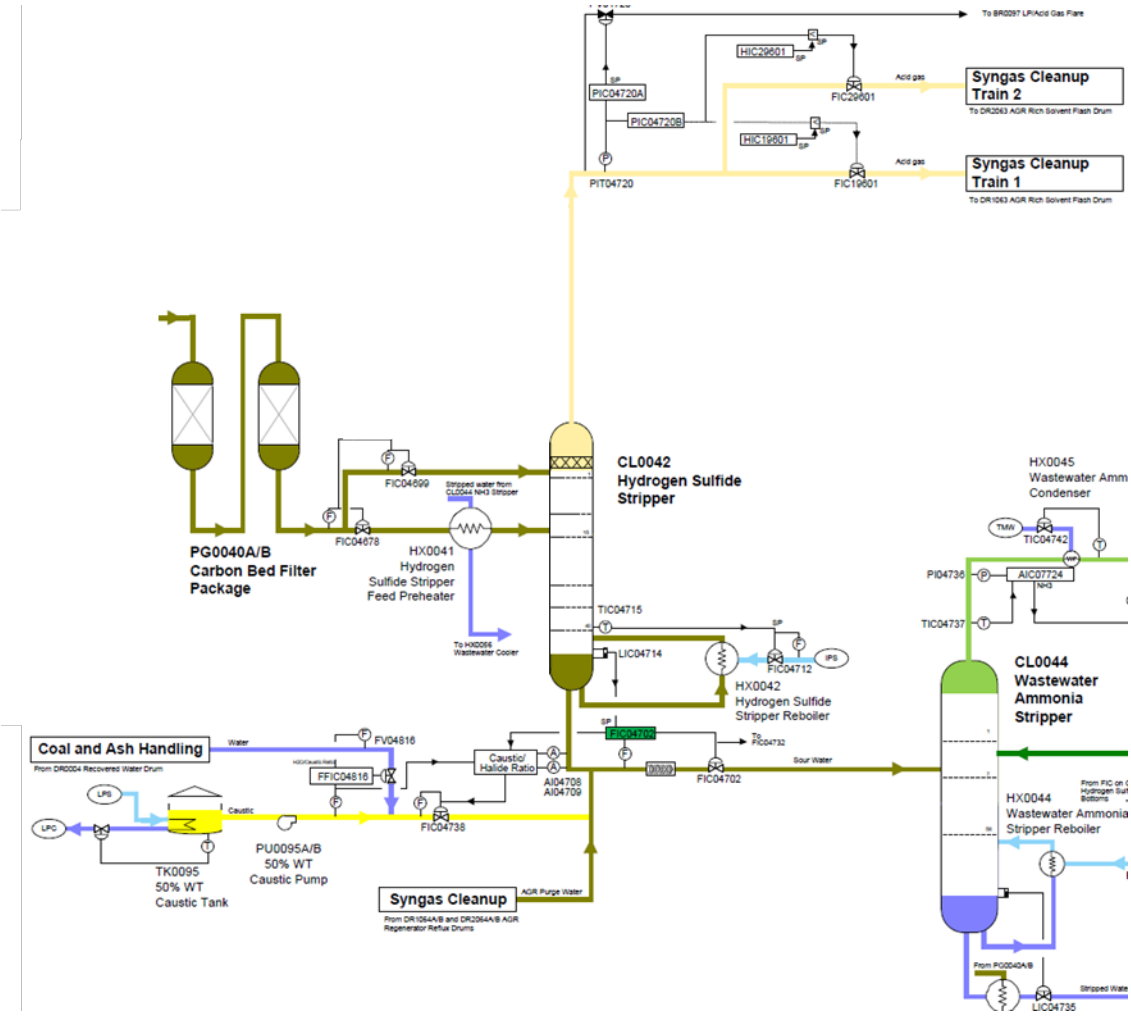

Figure 5.17-2 – Feed streams

The ammonia stripper removes the remaining ammonia and hydrogen sulfide from the sour water and generates a concentrated ammonia stream in the overhead of CL0044. After the sour water stream is dosed with caustic, it flows to CL0044 and enters the upper portion of the column. Vapor is again generated in the bottom of the column with a thermosyphon reboiler and rises up the column. The sour water entering the column flows counter-current to the flow of vapor. The two phases come into contact in the trays of the column, and the volatile components are stripped out and flow into the overhead of the column. The ammonia-rich overheads are condensed, and a portion of the material is pumped back to the column as reflux while the remainder is sent downstream for further processing. The material leaving the bottom of the column, referred to as stripped water, is essentially free of ammonia, hydrogen sulfide, and hydrocarbons. Before entering the reclaim sump, the stripped water is passed through HX0041 which preheats the bulk of the sour water feeding CL0042 as discussed earlier, and cools the stripped water going to the reclaim sump. After the cooled sour water leaves HX0041, it is further cooled in the wastewater cooler HX0056 by preheating recovered water, before entering the reclaim sump. The overhead stream from CL0044, which is rich in ammonia and contains some residual hydrogen sulfide, is totally condensed in the ammonia stripper condenser HX0045 and the ammonia stripper trim condenser HX0046 before entering the wastewater ammonia stripper reflux drum DR0045. From DR0045, the condensed liquid can either be pumped back to CL0044 as reflux or to the ammonia purifier CL0052 for further processing.

The high concentration ammonia stream from CL0044 is further purified to anhydrous ammonia in CL0052 (figure 5.17-3) using a random packed bed rather than trays like CL0042 and CL0044. The ammonia purifier has a thermosyphon-style reboiler HX0052 at the bottom of the column that provides the heat input needed for separation. The overhead of the column consists of a partial condenser HX0054, a reflux drum DR0051, and a reflux pump PU0050A/B. The vapor leaving the top of the column is partially condensed, resulting in another stage of separation in the reflux drum. The vapor leaving the reflux drum is condensed into the final anhydrous ammonia product in the ammonia product condenser HX0051. The bottoms stream leaving CL0052, consisting primarily of water, dilute ammonia, and residual hydrogen sulfide, is pumped to the transport gasifiers for disposal. At least one transport gasifier must be operating at high enough capacity to accept the bottoms stream whenever CL0052 is operating.

The anhydrous ammonia exiting HX0051 can be diverted to four different possible storage drums. From the ammonia product storage drums DR0058A/B/C/D, the ammonia can be pumped to a loading truck for removal, back to the gasifier for disposal, or back to CL0052 as additional reflux for the column.

After the ammonia product condenser, a small amount of water is added to the anhydrous ammonia to meet product specifications. Anhydrous ammonia with less than 0.2 wt% water can promote ammonia stress corrosion cracking in carbon steel equipment that does not meet NACE standards. Water is added to the condensed anhydrous ammonia and passed through a static mixer to prevent the possibility of stress corrosion cracking.

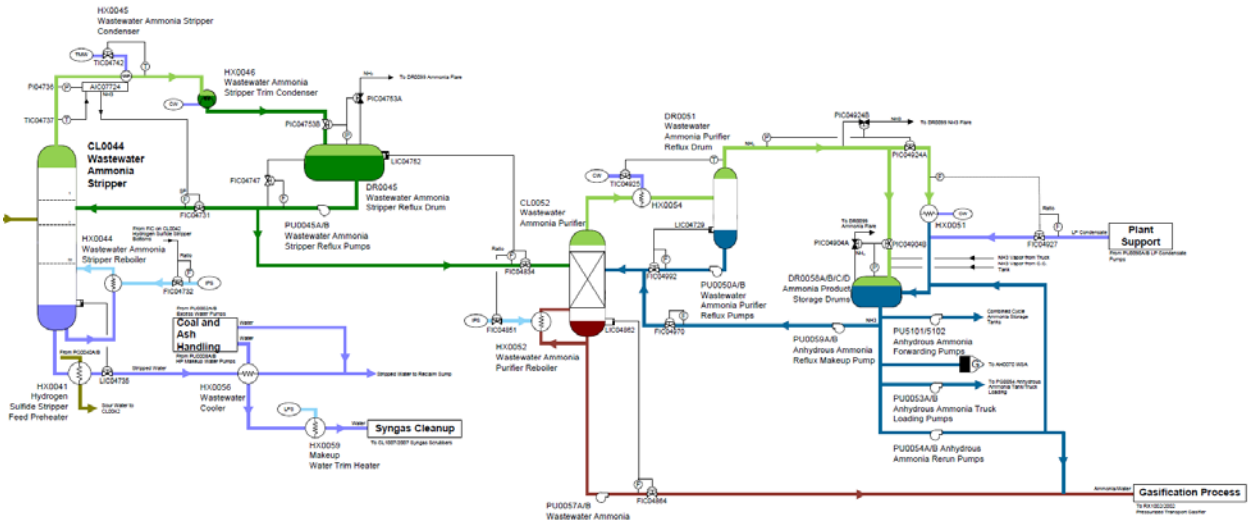

Figure 5.17-3 – Ammonia purifier

5.17.2 Initial Commissioning Plan

The first step of the sour water system commissioning plan consisted of leak testing the system with air to ensure all the flanged connections were leak tight, followed by air-freeing the system with nitrogen. After the system was free of oxygen, the next step in the commissioning process was circulating water through most of the system using appropriate pumps and tuning all level and flow control loops. Water was circulated from DR0040 through PG0040 and CL0042, then back to TK0042 where it could be pumped back to DR0040 to complete the loop. The circulation loop was then expanded to include CL0044. During the circulation test, the flow and level control loops associated with DR0040, CL0042, and CL0044 were to be tuned. Several pumps had prolonged run-ins along and the autostart functionality of the backup pumps was tested.

The ammonia purifier and anhydrous ammonia storage sections of the sour water system could not circulate water because of the risk of damaging pump seals. If water was allowed into the seals of the anhydrous ammonia pumps, the eventual mixing of anhydrous ammonia and water could expand rapidly and damage the seals. This section of the plant had to be tested using only anhydrous ammonia. The anhydrous ammonia testing consisted of unloading ammonia from a truck and filling the anhydrous ammonia storage drums. After the drums held sufficient volume of liquid ammonia, all three anhydrous ammonia pumps were tested by circulating the ammonia among the storage drums. The pump motor run-ins of the anhydrous ammonia systems were performed simultaneously while the flow control loops of the anhydrous ammonia system were tuned and tested.

After the cold-water circulation portion of the test package was complete, the next planned step was to apply heat with the stripper reboilers, HX0042 and HX0044, during circulation to allow tuning of the temperature and steam flow control loops. The final planned step in the commissioning process was to make a 5 wt% ammonia water solution in TK0042 and process the material through the system to test the remaining untuned controls in the system. Several pressure control loops were planned to be tuned and later retuned during more standard operating conditions. A high concentration ammonia-water solution was made in the ammonia purifier, and the column was tested in a total reflux mode.

5.17.3 Significant Events

Sour Water	Start Date	End Date
Turnover packages (TOPs) from Construction complete	7/1/2013	8/13/2014
Execute commissioning procedure	10/8/2014	4/1/2015
Begin leak test TP1031a	3/16/2016	3/20/2016
Execute test package (TP1030a) – cold water circulation	4/23/2016	5/6/2016
Execute test package (TP1030b) – hot water circulation	5/4/2016	5/18/2016
Anhydrous ammonia delivered	6/10/2016	6/10/2016
Execute test package (TP1031) – ammonia storage and loading	6/15/2016	7/1/2016
Execute test package (TP1030c) – 5 wt% ammonia circulation	8/7/2016	Did not complete

5.17.3.1 *Air-Free and Leak Test*

The air-free and leak test portion of the commissioning plan resulted in no significant findings. There were a few leaks found, but none warranted anything beyond tightening of bolts.

5.17.3.2 *Water Circulation Test*

Several issues were discovered during development of the test package procedures for the water circulation tests.

It was quickly realized that circulating water through the sour water system was required in order to tune level controllers. However, a closed-loop circulation was not possible with existing equipment because the bottoms stream from the ammonia stripper was routed to the reclaim sump. Since it was preferable to heat and tune the system with circulation, piping and a temporary heat exchanger were added to the system so material from the bottom of CL0042 and CL0044 could be cooled and recycled back to the sour water storage tank TK0042.

An issue with the net positive suction head available (NPSHa) for the wastewater ammonia stripper reflux pump PU0045A/B was discovered as a result of changes to CL0044 control scheme. The pressure control scheme on the wastewater ammonia stripper reflux drum DR0045 initially included a hot vapor bypass line to provide additional pressure to DR0045 directly from the CL0044. The vapor leaving the top of the distillation column CL0044 would have bypassed the condenser and gone directly into DR0045 vapor space. Liquid condensing from the condensers would be cooled before entering DR0045, allowing the maintenance of a temperature difference between the liquid entering DR0045 and the hot vapor coming directly from the vapor space of the distillation column. The vapor from the hot vapor bypass will condense into the liquid as it heats the liquid, but as new liquid is added to the drum and liquid is taken out, it is possible to maintain a temperature difference. This process of condensing and withdrawing liquid means it is possible for the liquid being condensed to be pressurized above the saturation pressure at the bulk liquid temperature in DR0045. This process results in the ability to provide additional NPSHa to the reflux pumps. Because very small changes in the temperature of a high concentration ammonia solution will result in very large changes in vapor pressure, only a very small difference in the bulk phase temperature of the liquid and vapor in DR0045 had to be maintained to ensure there was sufficient NPSHa. However, the hot vapor bypass valve was removed from the control scheme, meaning the material entering DR0045 was always at its saturation pressure at the pump inlet. The solution to this problem was to increase the elevation of DR0045 to provide additional hydrostatic head to the pumps, and to add inducers to lower the net positive suction head requirements (NPSHr) of the pump. These changes were effective in solving the net positive suction head requirements.

Motors for the ammonia purifier bottoms pump PU0057A/B and the ammonia stripper reflux pump PU0045A/B were found to be too small for startup conditions. During startup of the sour water system, the columns are cold and the ammonia concentration in the bottoms stream will be lower than normal. The specific gravity of the material being pumped would be much higher than the normal operating conditions used as the basis for design. The increase in specific gravity required a larger horsepower motor to pump material at abnormal or transient conditions.

Execution of the cold-water circulation test revealed that the level instrumentation nozzles on CL0042 were on the wrong side of the internal baffle. The level nozzles, intended to measure the level of the outlet sump, were on the baffle side of the column, which maintained a constant liquid level for the thermosyphon reboiler. The incorrectly placed instrumentation indicated the liquid level never changed, and the actual level in the bottom of the column could not be measured. Without proper level control, the risk of gas blowby into the next column was significant. Piping modifications were quickly made to use the CL0042 steam out valve, which was on the correct side of the internal baffle, for level instrumentation. This mistake was missed during design drawing and fabrication review. See figure 5.17-4 diagram of the CL0042 internal baffle.

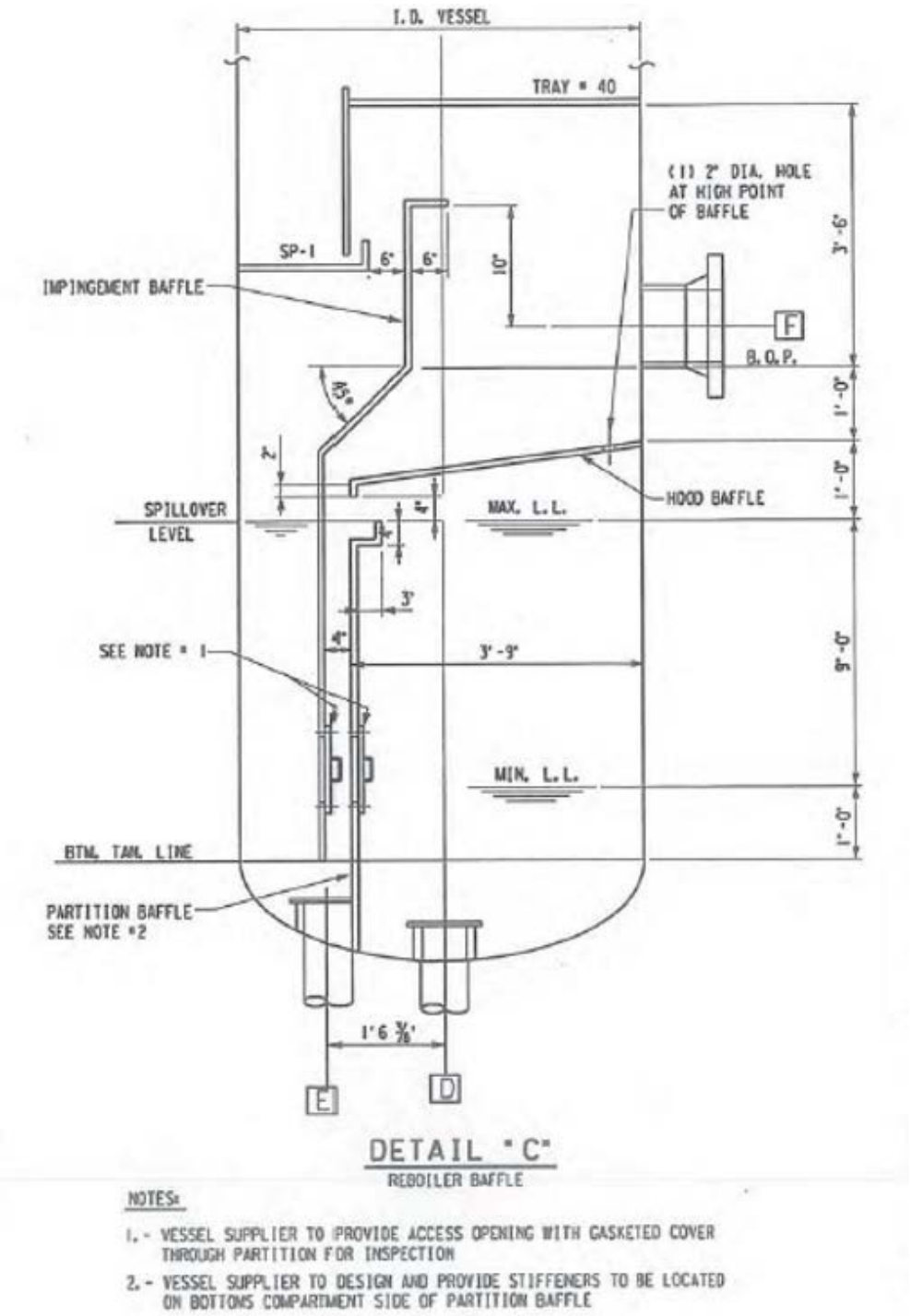

Figure 5.17-4 – Internal baffle

During the anhydrous ammonia circulation tests, several pump seal leaks developed, requiring replacement and causing delays to test package execution. Investigation revealed viton seals had been used for pumps throughout the sour water system. Viton seals are not compatible with ammonia. In addition to leaks caused by incorrect seal material, several pumps experienced frequent cavitation problems during testing. To diagnose the problem, the flow instrumentation downstream of the pumps was checked, and the pumps were operated with the discharge valve cracked open in an effort to limit flow and move the pump back on the pump curve. The net positive suction head

available (NPSHa) based on the piping layout and design was recalculated and doublechecked. Finally, the pump inlet piping was cooled with bags of ice to increase the NPSH available. Cooling the inlet piping allowed the pump to operate without cavitation, indicating the root cause was a mechanical issue with the pump. Further investigation determined the pump was missing an internal orifice on the seal loop, resulting in a large internal circulation rate. As a result, the total flow through the pump was much higher than the measured flow at the discharge of the pump. The higher flow through the pump increased the net positive suction head requirements (NPSHr) while the NPSH available did not change.

5.17.3.3 *Heat Addition to Water Circulation Test*

The next step in the commissioning process was to test the reboilers and temperature control systems around the distillation columns. While water was circulating through the system, steam was gradually added to the reboilers to test functionality and tune various control loops. The only problem encountered was difficulty tuning the steam flow controls on the CL0044 reboiler HX0044. Investigation determined the orifice plate on the steam flow transmitter did not match the design specifications. A new orifice plate was installed, which improved the flow transmitter accuracy and allowed the flow control loop to be tuned.

5.17.3.4 *5% Ammonia Water Separation*

The final step in the commissioning process was attempting to process a 5% ammonia water solution through the sour water system to produce anhydrous ammonia. The ammonia solution was made by mixing a roughly 26% solution of ammonia with a known quantity of water in TK0042. The tank was circulated to properly mix the ammonia-water solution, and lab tests were run to verify the concentration of ammonia after the mixture was made. The circulation of the sour water system was started, and heat was added using the distillation column reboilers.

While heating up the ammonia stripper CL0044, the column overhead pressure increased significantly, and the condensers were not able to lower the pressure of the column. Vapor from the column had to be vented to the flare to decrease pressure. While the vapor was being vented, column pressure dropped rapidly, resulting in a large spike in condensate collected in the reflux drum DR0045. The pressure in the column would build again and very little condensing would occur in the overheads of the column. This cycling in column pressure resulted in violent pipe hammering, which eventually broke the yoke of the pressure control valve between the partially flooded condenser HX0046 and the reflux drum DR0045. Efforts were made to stay well within the minimum flow rate requirements of liquid flow going to the distillation columns, but neither minimum steam addition requirements nor the severe pressure swing implications were realized before running the test. Figure 5.17-5 is a graph of the pressure cycling event.

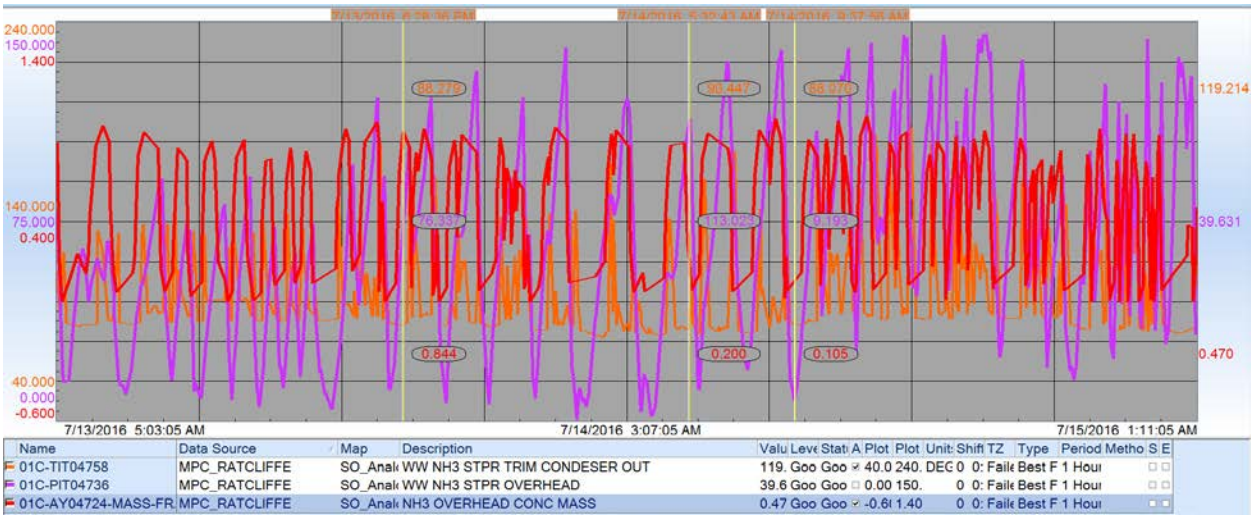

Figure 5.17-5 – Pressure cycling event

Engineering analysis determined insufficient steam was being added to the reboiler of CL0044. As a result, very little water was being vaporized, and a highly concentrated ammonia vapor was leaving the top of the column. At the rated column pressure and cooling water temperature available in the condensers HX0045 and HX0046, the concentrated ammonia essentially became a noncondensable gas. Increasing noncondensable gas in the condensers increased the column pressure, which increased the boiling point of the material in the bottom of the column. As the highly concentrated ammonia vapor was vented to the flare, noncondensable gas was removed from the overhead condensers, which quickly decreased column pressure. This problem was compounded by the fact that HX0046, the overhead condenser that was supposed to be partially flooded to limit cooling, was completely empty while noncondensable gas was concentrated in the overhead of the column. All the useful surface area of the condenser was available for heat transfer (none of the tubes in HX0046 where covered by liquid), and the condenser began to rapidly condense the vapor. This action lowered the pressure of the column, which added to the amount of boiling and vapor traffic moving up the column. The pressure cycling issue was addressed by increasing the steam to feed ratio to the reboiler, which increased heat input to the column and resulted in higher concentrations of water traveling into the overhead of the column, preventing the formation of a highly concentrated ammonia vapor that could not be condensed.

The circulating of ammonia solution revealed the minimum required kickback of the wastewater ammonia stripper reflux pump PU0045A/B was adding too much heat to the ammonia solution in DR0045. During startup and abnormal operating conditions, when less reflux to the column was required, the reflux pump must recycle liquid to the drum to stay in the correct operating range along the pump curve. Heat addition from pump work increased the temperature of the kickback returning to the reflux drum, which increased the vapor pressure in DR0045. Very small changes in temperature have a significant impact on the vapor pressure of high concentration ammonia solutions. Very little heat addition rapidly increased the pressure in the reflux drum DR0045 and impeded the ability of liquid to flow from the flooded condenser into the drum. The reflux drum pressure was frequently higher than the ammonia stripper column pressure during operation of the reflux pumps. A temporary heat exchanger was added to the kickback line from the pump back to the reflux drum DR0045, which resolved this issue.

Completion of the final test plan activities were deferred until after coal feed began. As a result of the inability to control the pressure in CL0044 and the reflux pump adding heat and pressure to DR0045, a significant portion of the ammonia in the 5% ammonia solution was depleted. With most of the ammonia stripped from the test solution, it was difficult to build pressure in the column while maintaining the proper column temperature in the overheads. The commissioning schedule would continue after ammonia was generated from coal feed to the gasifier.

5.17.3.5 *Metallurgy*

Late in the procurement process, metallurgical issues were discovered with several items in the sour water system. DR0040, PG0040, and CL0042 had to be weld-overlaid with a high-nickel alloy to protect the equipment from halide stress corrosion cracking from any level of oxygen, chlorides, and elevated temperatures. The equipment metallurgy was specified during design based on heat and material balances that did not include oxygen as a trace compound. A detailed material balance was never completed for the coal handling area of the plant, and the recovered water from coal drying was assumed to have no dissolved oxygen present. The erroneous assumption of zero oxygen present in the recovered water should have been recognized during material selection. Because the reaction mechanism for halide induced stress corrosion cracking requires only ppb levels of oxygen to be present, a better design practice would be to assume that oxygen levels cannot be controlled to such a tight standard under all conditions, and particularly in abnormal operating conditions. It was not until after fabrication had commenced that it was recognized that oxygen could be introduced to the sour water system through dilute amounts of dissolved oxygen in water recovered from the lignite drying process or demin water used for make-up to the recovered water system.

CL0044 had to be weld-overlaid to prevent the corrosion of Monel and ammonia in the column. Monel is an alloy that contains copper, which is highly reactive with ammonia. The selection of Monel cladding for CL0044 was an error in the design process. Ammonia would be present in the column under all operating conditions and readily available to react with the copper in the alloy. The vessel was weld-overlaid with a high-nickel alloy to protect the vessel from excessive corrosion, but this upgrade greatly increased the cost of the vessels. With a more rigorous review of the

materials of construction before procurement of the major pieces of equipment, the need for weld-overlay might have been avoided. See section 6.4, Vessel Internals, for discussion of the technical challenges associated with sour water metallurgy.

5.17.4 Final Summary

While much of control loop tuning in the sour water system was completed during the test packages, the sour water test packages did not validate all the control loops and operability of the sour water system. The pressure control scheme around CL0044 was not tunable due to insufficient steam added to the reboiler and to pressure building uncontrollably in DR0045 from heat generated by the reflux pump. The test packages did highlight several critical issues that were to be solved before the addition of sour water after coal feed was started. The procedure development process highlighted several startup issues that had not been previously been identified, including the need for additional startup heat exchangers. Without the added startup heat exchangers, it would not have been possible to start the sour water system up without sending a large quantity of off spec material to the reclaim sump and the wastewater treatment unit. The sour water unit did not perform as initially expected for these reasons.

In future projects, when working with volatile components such as ammonia, there should be consideration of advanced modelling of turndown scenarios to better understand the system before commissioning. For example, it was not expected that a dynamic pressure swing event could be caused by having too little steam input to the column before the test package, as was experienced when only a small quality of steam was provided to the reboiler on CL0044.

It was critically important to determine this issue during the test package phase of the process rather than during operation. If the issues with the sour water system had not been identified during the test package phase of commissioning, a large quantity of off-spec material could have made its way to the reclaim sumps and the wastewater treatment plant. The commissioning of the sour water system uncovered many pitfalls and technical issues and highlighted the importance of testing all the equipment in a logical and well-thought-out process. The goal of the commissioning process was to replicate actual operating and startup conditions in a controlled manner to determine the design flaws and system limitations. It was successful in determining a large part of the technical and mechanical issues with the system before it was run with real process material and was performed safely in a controlled and predictable manner.

5.18 Wet Gas Sulfuric Acid

5.18.1 System Overview

The wet gas sulfuric acid (WSA) unit at the Kemper County facility processes hydrogen sulfide (H_2S)-rich gas coming from the acid gas recovery (AGR) unit into commercial-grade sulfuric acid for sale in the local market. The AGR unit removes H_2S from syngas before it is sent to the combustion turbine. If the H_2S were not removed before combustion, the H_2S would form sulfur oxide compounds in the combustor and would be released into the environment. The primary feed stream to the WSA unit is the off-gas coming from the UOP SELEXOL regenerator. Other streams include the ash storage silos and off-gas from the hydrocarbon storage drum in the sour water system.

The first step in the WSA process is to combust the H_2S-rich stream, which converts the H_2S into SO_2. The H_2S-rich gas is fed into a combustor that burns the gas with excess air. Natural gas can be used to enrich the feed gas to maintain a minimum heating value for adequate combustion. In the process of converting H_2S into SO_2, nitrogen oxides (NOx) are formed from the combustion of ammonia (NH_3), and thermal NOx is generated from the high-temperature combustion with N_2 present from the air. The combustion process uses an excess quantity of air to ensure complete combustion of H_2S and to dilute the process gas so sulfuric acid vapor does not condense before entering the WSA condenser HX0074. If there is not enough excess air to dilute the exhaust gas from the combustor, the acid dew point leaving the combustor will be too low. This situation creates a risk of condensing acid inside the ductwork upstream of the WSA condenser and corroding the ductwork. The cooling air blower BL0070 supplies the cooling air to the WSA condenser HX0074. Some of the warm air from the WSA condenser HX0074 supplies the combustion air blower BL0071 with air.

The process gas from the combustor enters the waste heat steam generator HX0070, which cools the exhaust gas and generates saturated steam. The gas is cooled as it flows through the heat exchanger. The hot process gas passes through the tube side of the exchanger while water is heated on the shell side. The amount of cooling in the exchanger is controlled by a damper that can direct the hot exhaust gas through a large center pipe in the heat exchanger. This redirect essentially reduces the surface area the exhaust gas is exposed to by sending less flow through the smaller tubes of the exchanger. As the damper is closed on the large center pipe, more gas is forced to flow through the smaller tubes of the heat exchanger, and the surface area for heat transfer is increased. The steam generated in the waste heat steam generator is then super-heated using heat released by the exothermic reaction in the downstream processes before export from the WSA (figure 5.18-1).

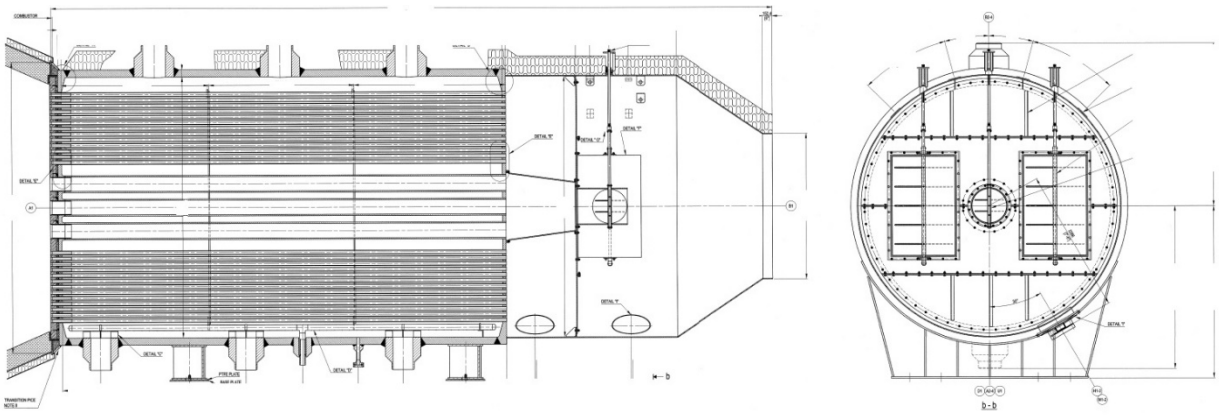

Figure 5.18-1 – Waste heat steam generator diagram

After cooling, the gas is passed through the selective catalytic reduction (SCR) reactor RX0070, where the NOx is converted to N_2 by reacting NOx with ammonia over a catalyst bed. Upstream of the SCR, vaporized ammonia and preheated air are injected into the process gas. A NOx sensor downstream of the SCR controls the addition of ammonia to the process gas.

Exiting RX0070, the process gas is sent to the SO_2 converter RX0071, where the SO_2 is converted to SO_3 in an exothermic reaction. The SO_2 converter consists of three stages of packed catalyst beds with heat exchangers between the stages. The saturated steam generated by HX0070 is used as the cooling fluid in the first two interbed coolers. The third and final stage of cooling uses liquid water from the waste heat steam generator loop. The reaction rate of SO_2 to SO_3 is more favorable at higher temperature, while the reaction equilibrium favors lower temperatures. Cooling between the stages of reaction is required to remove the heat generated by the reaction and to lower the gas to a more favorable equilibrium temperature. By cooling the gas, a total conversion rate of 99.4% is achievable in the SO_2 converter. The design temperature delta across the first catalyst bed is 194 °F and the second catalyst bed is 18 °F. Based on the amount of reaction constituents, it would be expected that most of the exotherm is generated in the first bed. The third and final stage of catalyst bed profile differential temperature goes from -6 °F, indicating more heat is lost than generated by the reaction, due to the high conversion in the first two reactor beds.

After SO_2 is converted to SO_3, the next step in the production of sulfuric acid is to hydrate SO_3 with water to form sulfuric acid (H_2SO_4). The reaction takes place in the gas phase between SO_3 and H_2O and has the chemical reaction

$$SO_3\ (g) + H_2O\ (g) \leftrightarrow H_2SO_4\ (g).$$

The reaction is exothermic and generates heat. The water for the reaction is available in the process gas from water generated during the combustion of H_2S and supplemental natural gas.

Sulfuric acid formation begins in the final stage of the SO_2 converter, then is completed during the cooling process in the WSA condenser HX0074. The condenser consists of glass tubes with a glass spiral inside the tube to increase the heat transfer area (figure 5.18-2). Cooling air from BL0070 provides a cooling medium on the shell side of the tube while the process gas flows upward through the falling-film glass tube. Condensed sulfuric acid falls down the tube counter-currently against the process gas and into the bottom of the condenser. Directly upstream of HX0074, multiple mist control units PG0070A/B/C/D inject silica particles, which act as nuclei sites for acid droplets to form. This process prevents the formation of a sulfuric acid mist, which could damage downstream equipment and be emitted to the environment. An optimum nuclei concentration in the process gas must be maintained to prevent the formation of an acid mist. An acid mist will form if the nuclei concentration is too high or too low. The operator manually adjusts the mist control unit based on the amount of mist measured downstream of the condenser, to minimize the formation of mist.

Figure 5.18-2 – Condenser

The sulfuric acid condensed in HX0074 is collected and cooled in the downstream equipment. Demin water is added to the sulfuric acid to maintain a 93 wt% concentration to meet commercial grade specifications and to prevent corrosion of carbon steel in the storage system. Sulfuric acid is least corrosive to carbon steel at a concentration of approximately 96 wt% (figure 5.18-3). As the concentration of acid increases above 96 wt%, its corrosiveness increases dramatically, so it is industrial practice to use 93 wt% sulfuric acid.

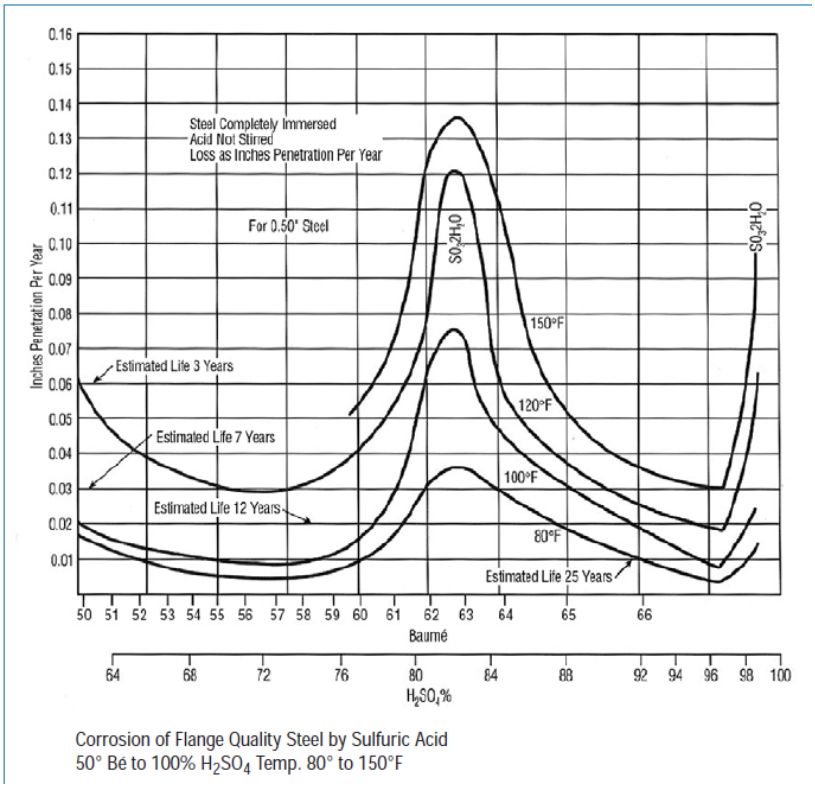

Figure 5.18-3 – Sulfuric acid corrosion

After cooling and dilution, the sulfuric acid can be pumped to storage tanks and then be loaded to trucks for transport from the site.

After leaving the WSA condenser, process gas flows through the quench column CL0070 and to the scrubber column CL0071. The quench column is a fiberglass column with a water spray at the top to cool the process gas and absorb the residual sulfuric acid leaving the condenser. The water is recirculated within the column using a recirculation pump at the bottom of the column. The water flows down the column with the flow of process gas. Make-up water is added to both the scrubber and quench columns to maintain a fixed concentration of acid in solution that scrubs the process gas and dilutes the concentrated sulfuric acid.

From the quench column, the gas enters the bottom of the scrubber column where any remaining sulfuric acid is contacted with a dilute acid solution in a packed bed, increasing SO_2 conversion and absorbing residual sulfuric acid. Hydrogen peroxide is added to the liquid to convert residual SO_2 into sulfuric acid with the chemical reaction

$$SO_2\ (g) + H_2O_2\ (l) \leftrightarrow H_2SO_4\ (l).$$

At the top of the column, wet electrostatic precipitator FL0071 removes any residual acid mist from the gas leaving the column.

The process gas exiting CL0071 is sent to the stack gas blower BL0072, where it is routed through the WSA stack ST0060 to atmosphere. The quench and scrubber columns also generate a dilute sulfuric acid stream, which is used to dilute the higher concentration sulfuric acid coming from the WSA condenser. See figure 5.18-4 for the process flow diagram of the WSA unit.

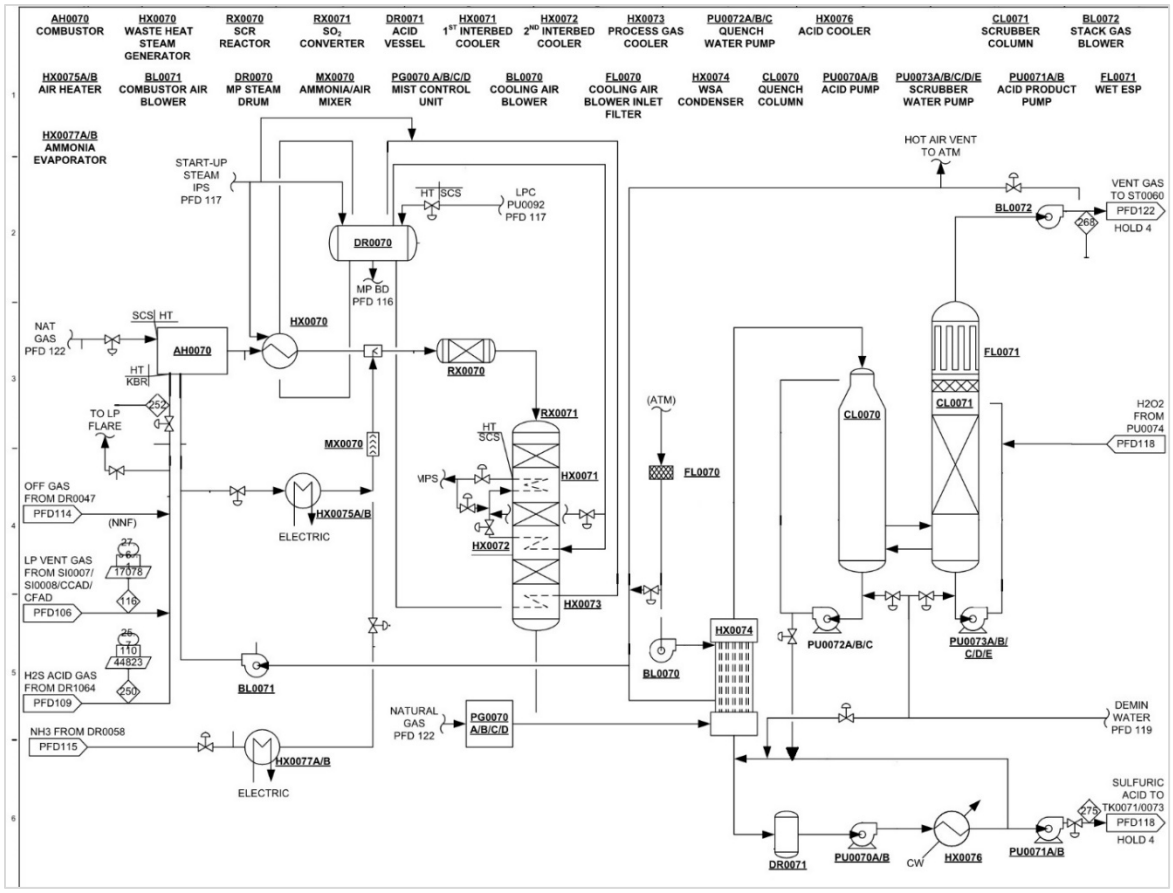

Figure 5.18-4 – WSA unit process flow diagram

5.18.2 Initial Commissioning Plan

The general commissioning plan for the WSA system was cleaning, leak-testing, boilout of the steam system, first heat-up of the system, inspection, catalyst loading, loading of packing material, loading of sulfuric acid, and treatment of the acid-resistant brick lining the WSA condenser. The general objectives were the basis of seven distinct commissioning test packages focusing on different areas of the plant.

The first test package was the pneumatic test and air circulation (TP1041). As a prerequisite, it was essential to ensure the air handling and process gas sections of the plant had been cleaned to remove rust, scale, debris, and dust. The test package itself would likely remove residual dust and debris when running the blowers. Those residual particles could clog the catalyst pores in the SCR and SO_2 converter and reduce active surface area of the catalyst.

After cleaning the system and verifying the flow path, the plan was to start the cooling air blower and begin moving air through the system. After the cooling air blower, the combustion air blower BL0071 would be started. While the blowers were running at relatively low speed, manholes were to be systematically sealed to move the airflow further down the process pathway. Finally, the stack gas blower BL0072 would be started so all the blowers in the system could be run simultaneously. Running all the blowers provided additional cleaning by forcing dust and particulate from the system. Control loops could be tuned while the blowers were running. A leak test was planned after all the ductwork was at the proper pressure.

The next phase of the commissioning plan was to flush the water side equipment of the WSA unit, which was covered in the water side flush test package TP1042. This portion of the test package would run in the pump motors and tune the flow control loops. Equipment to be tested included the quench column CL0070, scrubber column CL0071, and wet ESP FL0071. The sulfuric acid system was to be flushed to remove debris and potential contaminants from the

system. Testing and cleaning the sulfuric acid system was covered in the WSA flush and clean of the acid system test package (TP1048). The acid system was flushed and cleaned using water. Another objective planned for the sulfuric acid testing was to test offloading the acid to trucks and ensuring the control system worked as designed.

Before first heat-up of the WSA, the steam system was to be flushed and cleaned. This process would prevent potential damage to equipment from reduction in heat transfer coefficient and would remove debris that could otherwise damage valves and the piping network. Any residual debris in the steam system could reduce heat transfer, which could result in higher metal temperatures and cause erosion from scale and debris moving through the piping network at high velocities.

The next major step in the commissioning process was a boilout of the steam system. The boilout procedure was recommended by the equipment vendor, and the general guidelines followed their recommendation. The goal of the boilout procedure was to clean and remove additional rust and scale from the steam system in preparation for production of steam for export to the rest of the plant. An alkaline cleaning solution of sodium triphosphate and sodium hydroxide was to be used for the boilout process. A common process of repeatedly increasing and decreasing the steam pressure would help break up any residual scale and rust from the system. The boilout procedure in two main steps: atmospheric boilout and then a pressurized boilout. During the boilout procedure, additional control loops were tuned and tested.

Following the boilout of the WSA, the next step was to fire the combustor during the first heat-up step. The primary goal of this step was to dry out the refractory brick lining in the combustor and the acid-resistant brick lining in the WSA condenser. This procedure would be done before installation of any catalyst in either the SCR or SO_2 converter. The commissioning heat-up procedure is similar to the normal startup procedure from cold conditions. It provides a training opportunity for operators to learn the system, and for tuning and testing of additional control loops.

After the first fire and heat-up of the WSA unit, the catalyst was to be added to the reactor beds and sulfuric acid loaded to the sulfuric acid system. After acid and catalyst were loaded, the system would be ready for startup and to accept process gas from the AGR unit.

5.18.3 Significant Events

Wet Sulfuric Acid (WSA) System	Start Date	End Date	Duration
Startup acceptance of turnover packages from Construction	8/12/2013	8/22/2014	375
Execute commissioning procedure	4/3/2014	5/1/2015	393
Execute TP1041a WSA air circulation	5/3/2015	6/21/2015	49
Execute TP1041b WSA air circulation	8/12/2015	8/14/2015	2
Execute TP1042 quench and scrubber clean and flush	7/23/2015	8/8/2015	16
Execute TP1047 perform boilout and drain	9/19/2015	10/30/2015	41
Execute TP1048 flush acid/tank system and dry	8/27/2015	9/2/2015	6
Execute TP1049 first fire and heat-up	11/9/2015	2/4/2016	87

5.18.3.1 *Cleaning Ductwork and Blower Run-ins*

After the WSA system was turned over from Construction, several insulation issues were identified that had to be addressed. It is critical to follow vendor insulation specifications and procedures downstream of the SO_2 converter to avoid heat sinks and cold spots in the ductwork that would allow highly concentrated sulfuric acid to condense, leading to corrosion and leaks. Several of the duct supports did not follow Haldor Topsoe's recommendations for thermal breaks between the process and the support systems. Modifications to ductwork supports had to be implemented to prevent the support structural steel from acting as a heat sink. The congested ductwork layout of the WSA area resulted in situations where the normal insulation material could not be used. In some cases, more expensive insulation material was used to meet the required R-value, and in some locations, the desired R-value was not met.

It was discovered that the insulation of the SO_2 converter was installed incorrectly, allowing water to breach the flashing and soak the insulation. This mistake required re-insulating the entire reactor vessel to prevent cold spots that could result in acid condensation and corrosion of the vessel wall. An inspection revealed there was no rain hood on the ductwork going from the outlet of the SO_2 converter to the WSA condenser, which also could cause acid condensation. A rain hood for the ductwork had to be designed and installed, delaying WSA startup.

The first step in the commissioning plan was to run the blowers and clean the ductwork out using air from the blowers. During initial testing and commissioning of the blowers in the WSA unit, the bearings on the cooling air blower were damaged by sand contaminating the lube oil system. The lube oil system had been flushed before execution of the test package, but sand was found in the bearing after high vibration triggered a shutdown of the blower. The bearings had to be replaced, and this work delayed completion of testing and commissioning.

During the blower run-ins and ductwork cleaning, some of the expansion joints in the system leaked and had to be replaced. The expansion joint on the cooling air side of the WSA condenser leaked several times and had to be redesigned to solve the root cause of poor construction quality and installation. The expansion joint between the quench and scrubber column failed several times during blower testing and water circulation and had to be modified to resolve the leakage problem. The failure of the expansion joint between the columns was a result of not meeting the vendor support and gasket design specifications. During the pressure test, leaks were observed around the condenser lid covers, which required new gaskets, retorquing bolts, and replacement of the 60-in. process gas bellows entering the WSA condenser.

5.18.3.2 *Water Side Flush and Testing*

Before starting the water side flush and testing, some equipment installation and design issues had to be addressed. Several expansion joints on the pumps were damaged due to piping layout design and improper installation. The piping network to the pumps had to be modified for proper bolt clearances and to reduce the torsional stress on the expansion joints. The piping layout was reconfigured to limit the interference of surrounding equipment. The expansion joints had a long lead time items due to their PTFE (Teflon) lining, which was required in all piping in the area to prevent corrosion.

Another leak was detected in the quench column at the distribution plate portion of the column. The vendor design called for a single-piece distribution plate, but a two-piece design was procured and installed in an effort to reduce capital cost. The two-piece design did not form a proper seal and resulted in liquid leaking out of the quench column at the two points along the column circumference where the pieces connected. As a temporary solution, an engineered clamp and packing system was installed to prevent leakage. A replacement single-piece distribution plate was being procured but was not completed before operations were suspended.

Several issues were identified before testing of the hydrogen peroxide system that required modifications. The piping network allowed possible blocking in of hydrogen peroxide sections, which could decompose and pressurize the section of piping. Vented valves had to be installed to prevent possible pipe rupture. The peroxide holding drum did not have a flex line connection, which was required for that service. To prevent possible damage to the peroxide vessel, the piping network had to be modified for flexible connections, which resulted in schedule delays and added cost for field modifications.

5.18.3.3 *Cleaning Steam System*

During procedure development for the atmospheric and pressurized boilout of the steam system, it was determined that trisodium phosphate (TSP) was not compatible with the wastewater treatment plant. As an alternative, temporary ponds were constructed to collect the residual cleaning solution and avoid the wastewater treatment plant, and piping and an atmospheric flash tank were added to the system. The drain from the steam generator was sent to the atmospheric flash tank, where some of the hot water flashed to steam and the residual water filled the flash vessel. The remaining liquid was then pumped to a heat exchanger before sending it to the temporary pond, where the TSP could be stored, then either processed onsite with temporary equipment or trucked offsite for disposal. These modifications added complexity to the procedure as well as delays and additional cost.

When the atmospheric boilout procedure was started, it was realized that the condensate drains from the WSA heat exchangers in the SO_2 converter were incorrectly connected to the intermediate pressure (IP) condensate system. Instead of draining low-pressure condensate from the interbed heat exchangers during startup of the system, steam from flashing IP condensate was directed backward into the embed heat exchangers. This installation error caused hammering due to the slugs in the flow of steam and condensate entering the heat exchangers. Temporary connections were made to the atmospheric flash tank to allow condensate to drain from the interbed heat exchangers and prevent reverse flow of IP condensate into the system. Engineering resources had not been assigned to develop the startup and commissioning procedures before design was finalized, and several design issues were discovered during development and execution of commissioning activities.

During the atmospheric boilout procedure, it was realized there was not a sufficient number of steam traps in the steam piping network. There were not enough steam traps upstream of the WSA system, and condensate was being sent to the WSA unit. The established procedure was to introduce IP steam into the waste heat steam generator along with an additional steam injection point downstream of the water thermosyphon loop at the last interbed heat exchanger of the SO_2 converter. As steam was injected into the system, violent pipe vibrations and hammering occurred due to slugs of condensate moving through the steam line and impacting elbows and valves in the piping network. The steam lines going to the WSA unit were located a substantial distance from the steam source. The initially superheated steam was saturated by the time it got to the WSA unit, where condensate formed in the piping network and was not adequately removed from the steam line due to a lack of steam traps. The condensate impacting the elbows of the piping network ultimately resulted in a crack at the inlet to the waste heat steam generator. A steam leak on the waste heat steam generator formed during the pressurized boilout portion of the cleaning processes.

Figures 5.18-5 through 5.18-7 show the condensate's travel through the steam line and impact on the 45° and 90° elbows before it enters the bottom of the exchanger. A crack formed at the point where the steam pipe entered the bottom of the heat exchanger along the plane where the force of impact from the condensate would fatigue the weld.

Figure 5.18-5 – Formation of a steam leak coming from the waste heat steam generator. The crack formed at the point where steam is coming out.

Figure 5.18-6 – The spot where insulation is removed is the crack location.

Figure 5.18-7 – Close-up of crack at the weld were the steam piping meets the vessel nozzle.

In the process of developing a plan to fix the crack at the weld between the steam piping and the waste heat steam generator, it was realized that the steam piping did not meet vendor design specification, which limited the corrosion allowance. The weld angle was too narrow to ensure proper weld penetration. The weld crack was fixed, and the system was brought back into service, but this work delayed execution of the test package and resulted in increased cost.

During execution of the atmospheric boilout of the WSA unit, it was realized that the water quality of the boiler feed water entering the WSA unit varied wildly and was often poor. Rust-colored water was observed entering the steam generation system of the WSA from the low-pressure condensate drum DR0090. The low-pressure condensate drum receives all the condensate from the gasifier island. If any parts of the steam and condensate system in the gasifier island were not cleaned sufficiently or properly preserved, the material ended up in DR0090. Poor water quality entered the WSA unit when any part of the gasifier island steam or condensate system was started that had not been properly cleaned or preserved.

5.18.3.4 *First Fire of Combustor*

There were no significant issues with the testing and firing of the WSA combustor. A significant portion of tuning and controls work was completed during the firing of the combustor. The cure-out of the refractory brick in the combustion and downstream condenser section of the plant was completed.

5.18.4 Final Summary

Despite the many issues encountered during initial commissioning of the WSA unit, the overall objectives of the commissioning process were achieved. The WSA ductwork and air handling system was cleaned, the fan motors were run-in, and the control loops were tuned. The main objective, cleaning the WSA system in preparation for the catalyst installation was achieved, as was cleaning of the steam system. The major delays were related to construction quality or to design or installation deviations from vendor specifications or recommendations. The failure of the steam piping was a significant issue that delayed completion of the commissioning process. The added complexity and equipment required to use TSP as a cleaning solution for the system significantly delayed execution of the commissioning plan.

5.19 Flare Systems

The flare system processes liquid and off-gas from systems around the plant. The HP, LP/acid gas, and ammonia flare sections take off-gas and separate the entrained liquid. Off-gas is sent to the flare, and liquid is sent to wastewater.

This section provides an overview of the system and section on HP flare, LP/acid gas flare, and ammonia flare

5.19.1 System Overview

The air pollutants in the plant's waste streams must be managed to prevent harm to the environment. The flare system safely combusts vented waste streams to destroy these pollutants. The hydrogen sulfide concentration in the flare gas is measured before combustion.

The gas flow goes to the flare burner, where pilots provide the ignition source. Thermocouples near the pilots monitor the flame temperature and verify the pilots remain lit at all times. A high-energy igniter at each pilot provides a spark to relight the pilots in the event low temperatures are detected. The flame front generator (FFG) is the local panel used to light the flare pilots for the first time or after an extended outage. Each flare pilot ignites from the local control panel.

The flares operate only during abnormal conditions. The material flowing to each of the flares is different, but they operate in a similar fashion.

Entrained moisture is removed from the off-gas in the flare headers by slowing the velocity of the gas so the heavier water droplets can drop out.

The water in the seal drum provides a liquid seal to prevent air from flowing backward from the flare into the HP flare header, eliminating a potential combustion or flammable mixture hazard.

Regulations require specific destruction efficiency in flares. To meet that efficiency, the heating value and hydrogen content of the flare off-gas is determined with an online analyzer. That information is used to manage the flow rate to the flare and to create a set point to flow control on the natural gas addition.

The flare headers are designed to operate at a positive pressure relative to atmospheric pressure so air will not flow into the flare. Nitrogen is added to the flare header to maintain positive pressure. In the event of low pressure in the header, natural gas can be added to the header to maintain positive pressure.

- HP flare system

The high-pressure (HP) flare receives flow from the coal and ash handling system, syngas cleanup, and various vents and relief valve discharges. All incoming flows to the HP flare join a common header and are routed to DR1089 HP flare KO drum (figure 5.19-1). Any entrained liquid in the vapor can accumulate in the drum and be sent to sour water treatment. Overhead vapor from DR1089 HP flare KO drum flows to BR1098 HP flare, where the off-gas is burned.

Enrichment natural gas enters the overhead line to the flare through flow controller FIC14941. FIC14941 is controlled by BTU analyzer AIC14944. Pressure controller PIC14943 can override the enrichment flow controller FIC14941 if the pressure is too low in the flare header.

DR1098 liquid HP flare seal drum is provided in the HP flare for the purpose of protecting the flare header from air infiltration and flashback. The liquid seal is established by service water and the level of the seal is controlled by LIC14964, which adjusts the service water flow into the seal drum.

Liquid in the KO drum is pumped from the bottom of the drum using PU1089A/B HP flare KO drum bottom pumps. There is no control valve to regulate total flow from the KO drum, so LI14945 will turn on the first pump at high level, and the second pump at high-high level, to maintain level. The liquid is pumped to the wastewater storage tank in the sour water/ammonia system.

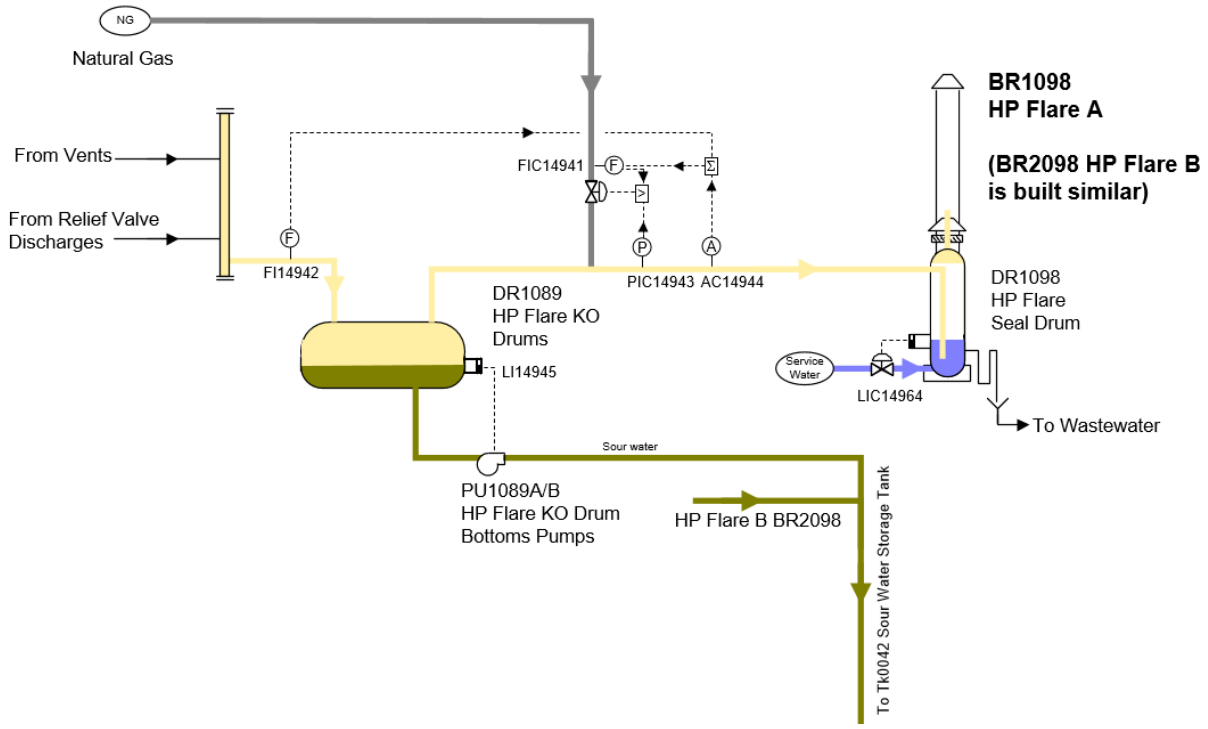

Figure 5.19-1 – Train A HP flare system

- Ammonia Flare

The ammonia flare receives off-gas from ammonia vents and ammonia relief valve discharges (figure 5.19-2).

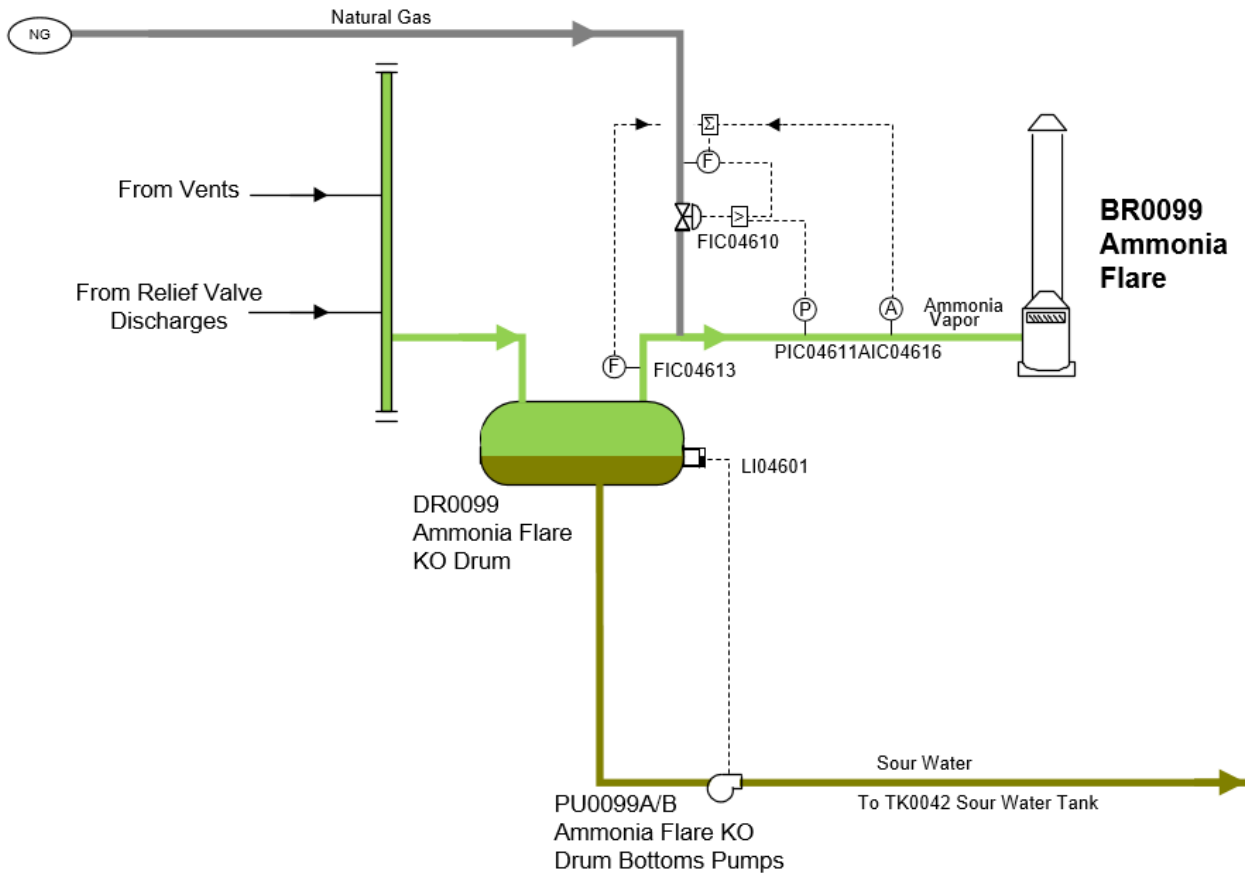

Figure 5.19-2 – Ammonia flare system

All ammonia off-gas inflows to the ammonia flare system join a common header, and are routed to DR0099 ammonia flare KO drum, where ammonia vapor and any entrained liquid in the vapor can be separated and the condensate pumped to be processed. Overhead vapor from the KO drum flows to BR0099 ammonia flare, where the ammonia off-gas is burned.

Enrichment natural gas enters the overhead line to the flare through FIC04610. FIC04610 is controlled by the BTU analyzer AIC04616. Pressure controller PIC04611 can override enrichment flow controller FIC04610 if the pressure is too low in the flare header.

Liquid in the KO drum is pumped from the bottom of the drum using PU0099A/B ammonia flare KO drum bottom pumps. The total pump flow is regulated by liquid level indicator LI04601 on the KO drum. The liquid is pumped to the wastewater storage tank in the sour water/ammonia system.

- LP/acid gas flare

The low-pressure LP/acid gas flare receives off-gas from the coal and ash handling system, sour water/ammonia system, and other relief valve discharges.

All low-pressure off-gas inflows to the LP flare system join a common header and are routed to DR0097 LP/acid gas flare KO drum (figure 5.19-3), where any entrained liquid in the vapor can be separated and pumped to be processed. Overhead vapor from the KO drum is sent to BR0097 LP/acid gas flare, where the off-gas is burned.

Enrichment natural gas enters the overhead line to the flare through FIC04969. FIC04969 is controlled by the BTU analyzer AIC04968. Pressure controller PIC04961 can override the enrichment flow controller FIC04969 if the pressure is too low in the flare header.

Liquid in the KO drum is pumped from the bottom of the drum using PU0097A/B LP/acid gas flare KO drum bottom pumps. The total pump flow is regulated by liquid level indicator LI04964 on the KO drum. The liquid is pumped to the wastewater storage tank in the sour water/ammonia system.

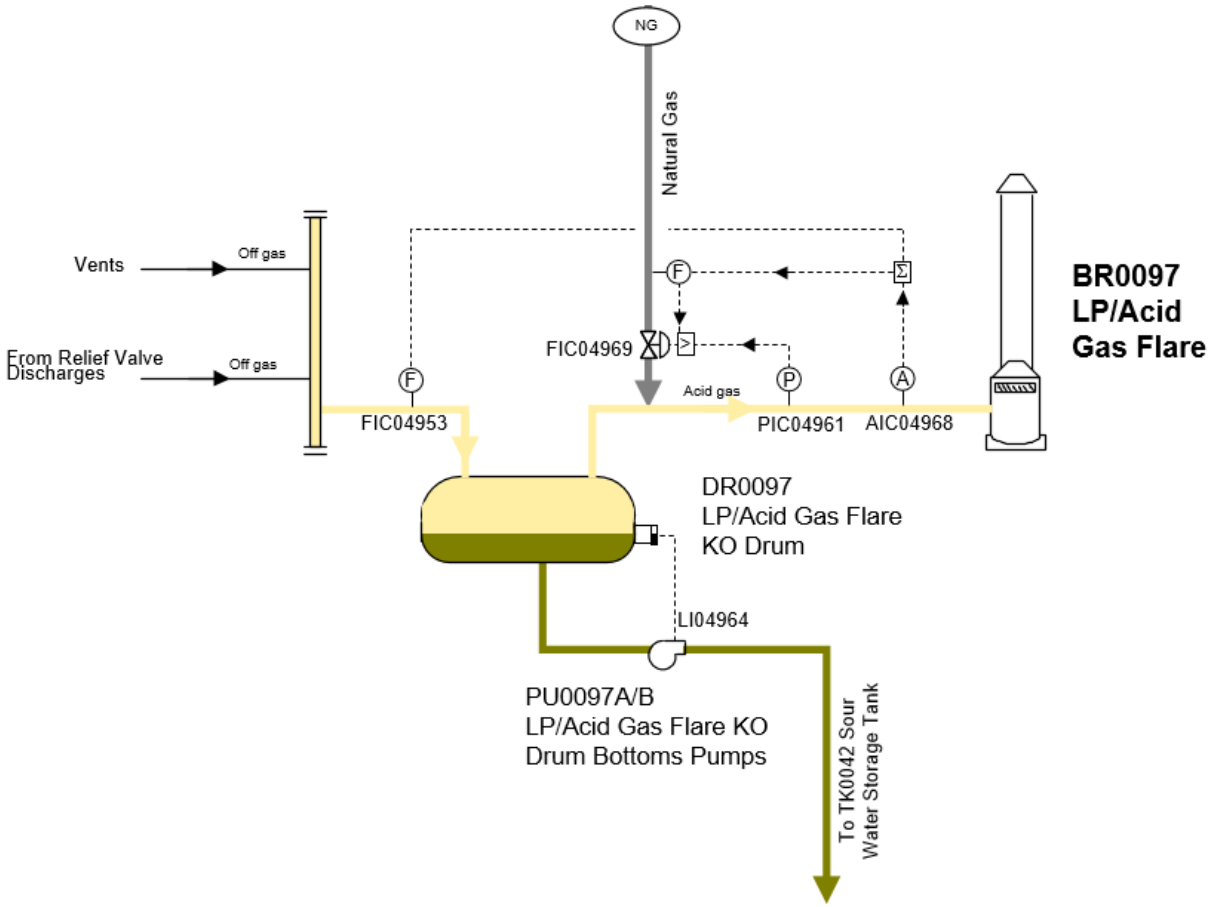

Figure 5.19-3 – LP/acid flare system

5.19.2 Initial Commissioning Plan

The objective of the HP, ammonia, and LP/acid flare commissioning plan was to verify safe and proper operation of the equipment and controls in the flare system. The commissioning plan was similar for all three systems and is only described once in this document. The plan included a system integrity test, functional test on the pumps, and to verify and tune instrumentation.

The commissioning steps needed to prepare each unit for service were:

1. Purge test.
2. Flame front generator and pilot relight functional test.
3. System enrichment test.
4. System controllers test and tuning instrumentation.

5.19.2.1 *Purge Test*

The purpose of this test was to ensure proper flow of nitrogen through the system and removal of oxygen from the flare system. It also verified the system mechanical integrity to certify no leakage in the system.

During this test, the KO drum pumps were commissioned to ensure they operated in accordance with design intent.

5.19.2.2 *Flame Front Generator and Pilot Relight Functional Test*

The purpose of the functional test was to ensure the flame front generator (FFG) would ignite its respective pilot with the proper mixture of natural gas and oxygen. This test was performed on all pilots on both trains A and B using DCS controls.

5.19.2.3 *System Enrichment Test*

The system enrichment test objective was to test and verify the natural gas enrichment control system could maintain positive pressure in the flare header, and maintain a combustible mixture supplied to the flare tip by adding natural gas when necessary over a full range of operating conditions.

The controls system test introduced nitrogen to the flare header at varying flow rates. The flare enrichment controls supplied natural gas to achieve a combustible flow through the flare header.

5.19.2.4 *System Controllers Test and Tuning Instrumentation*

The flare tuning plan reviewed the control logic in the DCS, tested control loops associated with the flares, and tested the controllers to confirm they were operational and responded to system demands. The controllers include the enrichment flow controller, the flare pressure controller, the flare BTU controller, and the HP flare seal drum level controller. The complete list of loops to be verified and tuned are listed in table 5.18-1.

Table 5.19-1 - List of flare system control loops

Controllers	HP Flare	Ammonia	LP/Acid
Pressure	PIC14943, PIC24943	PIC04611	PIC04961
Flow	FIC14941, FIC24941	FIC04610	FIC04969
Level	LIC14964 & LIC24964		
Analyzers	AIC14944A, AIC24944A	AIC04616	AIC 04968

5.19.3 Significant Events and Final Summary

5.19.3.1 *HP Flare*

Milestone	Train A	Train B
Functional test- pilot relight	Sept. 23, 2015	Mar. 5, 2016
System purge	Sept. 24, 2015	Mar. 5, 2016
Functional test- flame front generator	Sept. 24, 2015	Mar. 5, 2016
System enrichment test	Apr. 14, 2016	Mar. 5, 2016
System controllers test and tuning instrumentation	Apr. 14 2016	July 7, 2016

The original commissioning plan for the HP flare showed the purge as the first activity. Due to a lack of nitrogen, the plan was modified to test the high energy igniters (HEI 14966A–G) before execution of the purge test. On Sept. 21, 2015, Train A HEIs were verified as properly functioning in the automatic relight test. All seven HP flare pilots were lit using the HEIs rather than the flame front generator (FFG) PG0098. For this test, the natural gas isolation valve to each pilot was opened to supply natural gas. Each valve remained opened for at least 1 minute to ensure natural gas flowed to its respective pilot. With the pilot switch in auto, flare temperature alarms were monitored to confirm the low temperature alarms would become inactive after the pilots ignited. The HEI relight test successfully concluded on Sept. 23 for Train A. The header purge and FFG test followed the next day.

The purge removed oxygen from the HP flare header with nitrogen using a temporary nitrogen connection to the main header to decrease the oxygen concentration below 5%. The oxygen content was monitored at the vent valve every half hour until the desired concentrated was achieved. The test was declared complete Sept. 24 with the nitrogen flow of approximately 283 klb/h.

On the same day, the FFG test was conducted to verify its functionality. The natural gas supply valve, instrument air, and HP flare pilot isolation valves were opened. The natural gas supply mixed with the instrument air to ensure the proper blend for combustion. The first pilot ignited from FFG late that morning and the remaining six pilots were subsequently lit. The temperature increased from 70 °F to 1,060 °F, indicating successful ignition of the pilot.

With the FFG test complete, the functional testing proceeded for the flare enrichment test. It was then postponed due to issues with probes for the BTU analyzer. The probes were associated with sampling systems on BTU analyzers for both syngas and AGR lines. Approximately 14 probes installed were incorrectly sized for proper sampling. It was suspected that probes of different models were installed, and substantial disassembly was required to verify proper specification. All probes must be the proper length before supporting startup, to provide accurate process data. New probes were ordered with correct lengths and delivered to the site in Oct. 31, 2015. Construction completed installation of the probes in early November on both Trains A and B.

The flare enrichment test from Train A resumed after the probes were installed. The enrichment test confirmed the proper natural gas flow to every pilot and the operation of FFG. The maximum flow of natural gas through the enrichment flow valve to the flare header measured approximately 15,100 lb/hr. The enrichment controls were verified. The enrichment controls test ensured the natural gas controller achieved the 205 Btu/SCF target with a maximum of 100,000 lb/hr of nitrogen. Natural gas was mixed with the nitrogen to create a mixture with a lower heating value of about 205 Btu/SCF. The natural gas enrichment control system introduced the natural gas mixture to the HP flare header at varying flow rates. The flare enrichment controls added natural gas as necessary to achieve a combustible flow. Each flare pilot was ignited from the local control panel on the FFG. It was initially a struggle to lower the oxygen concentration to the desired level of <5% by volume. At this moment, the flare enrichment test using the BTUs analyzer

was postponed due to issues with the electrical connection for the new probes. Only the enrichment flowrate on HP flare train was verified. It reached 100,000 lb/h flow in October 2015, which is the requirement for the enrichment test.

The natural gas enrichment test also revealed it could take up to 12 min to see a change in the natural gas enrichment controls due to the delay caused by the online gas chromatograph (GC) used to analyze for H_2 and LHV. The response time was deemed too slow to control the flare's LHV and ensure 98% destruction efficiency as required by EPA operating guidelines. The request to replace the existing GC with a more reliable, fast-acting one was placed on hold. New rotameters were installed on the HP flare nitrogen sweep lines during February 2016 on Train A and March 2016 on Train B. The modification provided a larger rotameter to permit more nitrogen flow to purge the flare header.

The effort originally was focused on commissioning the Train A HP flare. The attention shifted to the Train B HP flare in February 2016 due to an outage to make refractory repairs in gasifier A. Within the month, the HP flare test package on Train B was completed. The test package included: purge the header, establish pilots and test enrichment on BTUs, verify the pilot automatically relit, and confirm the FFG lit pilots. Train B tested the natural gas enrichment system using the BTU analyzer; its enrichment flowrate was not substantiated.

On April 11, 2016, a nitrogen sweep and purge was performed on the Train B flare header to place it in service. HP flare A and B were placed in service on standby in July. While on standby, gas supply valve was opened to light each pilot. After the natural gas flow to pilot was established, enrichment controls were tuned. The enrichment control tuning test was based on flare gas (N_2) flow, system pressure, and flare gas composition (H_2 and Btu). The controls tuning was declared complete on July 7.

5.19.3.2 *HP Flare Final Summary*

The HP flare system completed most of the activities on the commissioning plan before the first coal feed. Testing was performed and successfully completed, including the purge test, FFG and pilot ignition functional tests, and tune and test of some controllers. The remaining control loops were tuned after the first coal feed.

During the commissioning of the system, several challenges arose, and design modifications were implemented. Startup replaced erroneously sized analyzer probes which had adversely affected the sampling in the duct and rotameters. The rotameters were replaced to increase the nitrogen flow. With the commissioning test package complete, both HP flares were placed into service but on hot standby in anticipation for gasifier operation.

5.19.3.3 *Ammonia Flare*

Milestone	
System purge	July 29, 2015
Functional test- pilot relight	July 30, 2015
Functional test- flame front generator	July 31, 2015
System enrichment test	Feb. 10, 2016
System controllers test and tuning instrumentation	May 31, 2016

The purpose of this test package was to verify the safe and proper operation of the ammonia flare system equipment and controls. The test package purged the ammonia flare, tested its functionality in manual and automatic mode, and tested its controls.

On July 29, 2015, Startup purged the ammonia flare using a temporary nitrogen line to the main header to remove oxygen. The oxygen concentration must be maintained below 5% before this test can deemed successful. The oxygen content was monitored using a local O_2 sensor every half hour until the desired concentrated was achieved. The test was declared complete on July 29 with the nitrogen flowing at approximately 260 lb/hr.

The following day, testing proceeded with testing high energy igniters (HEI 04612A–E) auto relight. The HEI was verified to properly function in automatic to relight ignitors. All five ammonia flare pilots were lit using the HEIs rather the flame front generator (FFG) PG0098. For this test, each natural gas isolation valve to pilots was opened to supply natural gas. Each valve remained opened for at least 1 minute to ensure natural gas flowed to its respective pilot. With the pilot switch in auto, the low temperature alarms remained inactive. Then the natural gas isolation valve was closed until all the low temperature alarms became active with PCV04609 bypass valve opened. In auto, the HEIs ignited and the temperature alarms subsided. The HEI relight test successfully concluded on July 30.

The FFG test followed the next day. The FFG test verified its functionality. The natural gas supply valve, instrument air, and ammonia flare pilot isolation valves were opened. The natural gas mixed with the instrument air to ensure proper blend for combustion. The first pilot ignited the FFG at 10 p.m. on July 30 and the remaining pilots were immediately lit. The temperature increased from 80 °F to 1,590 °F. The test was declared a success in the early morning hours of July 31, since the FFG responded as designed.

With the FFG test complete, testing proceeded to the flare enrichment test. Construction worked on the natural gas line, which caused a delay in the schedule. Attempts to resume the enrichment test in mid-September were unsuccessful. Challenges with the flow meters and gas analyzer probes continued to adversely impact the schedule. Flow transmitter FIT04613 failed to accurately measure the low flowrate and affected the schedule. The natural gas flowrate must be measured correctly for the enrichment test. The plant approved the purchase of new flow meters to measure low flow and issued an additional purchase order (PO) to purchase the pressure and temperature transmitter needed for flow compensation.

The analyzer probes associated with sampling systems were incorrect lengths and failed to provide actual sampling. It was suspected that probes of different models were installed. Substantial disassembly was required in order to verify proper specification. New probes were ordered and installed Nov. 6, 2015. The probes were associated with sampling systems on BTU analyzer for the ammonia lines. Construction also installed new flow elements roughly a month later. The new flow elements measured the low flowrate accurately.

Other issues arose to suspend the flare enrichment test again. The plant was uncertain if 18 pressure relief valves (PRV) required recertification due to a lack of documentation, and there were compatibility concerns with the original BTU analyzer with the ammonia flare system. By mid-January 2016, all the necessary documentation was furnished regarding the PRVs. It was confirmed that no recalibration or recertification was required. The new analyzer and flow measurement devices were installed around Jan. 25, 2016 to meet operational requirements.

With the design modifications now complete and PRV recertification resolved, the enrichment test resumed on Feb. 7. The enrichment test confirmed the proper natural gas flow to every pilot and the operation of FFG. The maximum flow of natural gas through the enrichment flow valve to the flare header measured approximately 15,100 lb/hr. The natural gas enrichment control system introduced instrument air gas mixture to the ammonia flare header at varying flow rates. In addition to testing the maximum enrichment flow, the enrichment controls were verified. The enrichment controls test ensured the natural gas controller achieved the 205 Btu/SCF target with a maximum of 100,000 lb/hr of nitrogen. The appropriate natural gas mixture was supplied to ignite the pilots from the FFG panel and declared the test compete on Feb. 10.

The ammonia flare system was placed in service on hot standby on May 13, which allowed for testing of the functionality and tuning of the new analyzer before first coal feed about 2 weeks later on May 31. The new flow elements and devices were tuned upon installation.

5.19.3.4 *Ammonia Flare Final Summary*

The ammonia flare system completed most of the activities on the commissioning plan before the first coal feed. The purge test, FFG, and pilot ignition functional tests were successfully completed. Some of the controllers were tuned and tested. The remaining control loops were tuned after the first coal feed.

During the commissioning of the system, several challenges arose, and design modifications were implemented. Startup installed erroneously sized analyzer probes which adversely affected the sampling systems, rotameters, and

analyzer. The rotameters were replaced to increase the nitrogen flow while the analyzer more suitable to satisfy operation was installed. With the commissioning test package complete, ammonia flare was placed into service on hot standby in anticipation of the AGR refrigeration and sour water systems.

5.19.3.5 *LP/Acid Gas Flare*

Milestone	
System purge	Oct. 16, 2015
Functional test- pilot relight	Oct. 17, 2015
Functional test- flame front generator	Oct. 17, 2015
System enrichment test	Nov. 24, 2015
System controllers test and tuning instrumentation	June 3, 2016

The purpose of this test package was to verify the safe and proper operation of the LP/acid flare system equipment and controls. The test package purged the LP/acid flare, tested its functionality in manual and automatic mode, and tested its controls.

Purging of the LP/acid flare system began on Oct. 16, 2015. Startup purged the system using a temporary nitrogen line to the main header to remove oxygen. The test required the oxygen concentration to be below 5%. The oxygen level was monitored using a local O_2 sensor every half hour until the desired concentrated was achieved and deemed successful. The test was declared complete on Oct. 16.

The following day, testing proceeded to the high energy igniters (HEI 04938A-D) auto relight and the FFG. The test confirmed the HEIs properly functioned in automatic to relight the ignitors. All four LP/acid flare pilots were lit using the HEIs rather the flame front generator (FFG) PG0098. For this test, each natural gas isolation valve to its pilot was opened to supply natural gas. Each valve remained opened for at least 1 minute to ensure natural gas flowed to its respective pilot. With the pilot switch in automatic mode, the low temperature alarms remained inactive as expected to ensure the pilots automatically ignited. Then, the HEI's natural gas isolation valve was closed until all the low temperature alarms become active with PCV04605 bypass valve opened. In automatic mode, the HEIs ignited and the temperature alarms subsided. The HEI relight test successfully concluded on Oct 17.

Testing continued with the FFG test. The FFG test verified its functionality where each flare pilot was ignited from the local control panel, FFG PG0098. The natural gas supply valve, instrument air, and LP/acid flare pilot isolation valves were opened. The natural gas mixed with the instrument air to ensure proper blend for combustion. The first pilot ignited the FFG late in the morning hours on Oct. 17 and the remaining pilots were immediately lit. The temperature increased from 55 °F to 1,592 °F in the span of 3 hours. FFG responded as designed. The test was declared successful.

After the completion of the FFG, testing proceeded to the flare enrichment test. This test was postponed due to slow response of the online gas chromatograph (GC) and an issue with the sample line probes. The natural gas enrichment test revealed it required approximately 12 minutes to see a change in the natural gas enrichment controls due to the delay caused by the GC used to analyze for H_2 and LHV. The response time was deemed it too slow to control the flare LHV and ensure 98% destruction efficiency per EPA guidelines. A request to replace the existing GC with a more reliable, fast-acting one was submitted.

Like the HP and ammonia flares, the analyzer probes associated with LP/acid flare sampling systems were incorrect lengths and failed to provide actual sampling results. It was suspected that probes of different models were installed in the flare lines instead those specified for these lines. All probes must be the proper length to provide accurate process data. New probes were ordered and installed on Nov. 24, 2015.

The enrichment test resumed on Nov. 25. The enrichment test confirmed the proper natural gas flow to every pilot and the operation of FFG. The natural gas enrichment control system introduced instrument air gas mixture to the LP/acid flare header at varying flow rates. In addition to testing the maximum enrichment flow, the enrichment controls were verified. The enrichment controls test ensured the natural gas controller achieved the 205 Btu/SCF target with a maximum of 100,000 lb/hr of nitrogen. The appropriate natural gas mixture was successfully supplied to ignite the pilots from the FFG panel and controlled at 250 BTUs. The test was declared complete.

The enrichment test revealed the flow transmitter FIT04953 failed to accurately measure a low flowrate. The flow transmitter should position the natural gas enrichment valve to compensate for the delay of the BTU analyzer and ensure complete combustion of vent gases sent to the flare. The result was that the plant could not operate accurately at low enrichment flow rates.

The plant approved the purchase of new flow meters to measure low flow. Construction installed a new ultrasonic flow meter that measured a flowrate as low as 1,600 lb/hr on June 3, 2016, which allowed for logic to control the nitrogen flow. When the nitrogen flowrate is above the limit, enrichment gas is added. The plant ordered and installed new pressure and temperature transmitters for flow compensation. The new flow meter and instrumentation were tuned upon installation. The LP/acid flare was placed in service but in standby on May 13.

5.19.3.6 *LP/Acid Gas Flare Final Summary*

The LP/acid flare system completed the activities on the commissioning plan before the first coal feed. Testing was successfully performed and completed, including the purge test, FFG, pilot ignition functional tests, and tune and test of new installed instrumentation. The remaining control loops were tuned after the first coal feed.

During the commissioning of the system, several challenges arose, and design modifications were implemented. Startup installed incorrectly sized analyzer probes, which adversely affected the sampling in the duct. Those probes were replaced with the proper analyzer probes. The flow, pressure, and temperature transmitters were installed to accurately measure the low flow rate. With the commissioning test package complete, LP/acid flare was placed into service but in standby in anticipation of the AGR system.

6.0 SPECIAL ACTIVITIES

6.1 Syngas Cooler Mechanical Integrity

This section documents the significant events of syngas cooler mechanical integrity during the hydro test, unit commissioning, and on-coal operation. The nature of the mechanical failures, analysis and evaluation, repair strategies, and final results are documented.

6.1.1 Significant Events

6.1.1.1 *Superheater Tube Failures During Hydro Test*

During the hydro test after the completion of the syngas cooler installation, tube leaks were suspected because of evidence of water in the gas-side space. Boroscope inspection was conducted through the manway entries. Six tubes were leaking in three superheaters: two in HX1113 (superheater II), three in HX1212 (superheater I), and one in HX2112 (superheater I). Figure 6.1-1 is a boroscope image of a typical tube leak. In this case, the leaked water sprayed onto refractory and flowed downward along the refractory wall. All six tubes were confirmed leaking by pressure test for each individual tube.

Figure 6.1-1 – Typical tube leak detected in boroscope inspection

There are five coils of tubes in each superheater, with coil I in the center and coil V on the outmost layer next to the refractory (figure 6.1-2). All the six leaking tubes were on coil V in both superheater I and superheater II. Further inspection revealed that another tube in superheater HX2113 had a crack in the weld (figure 6.1-3). Some evidence of water marks was found at this spot. This tube was on coil IV. Although it was not confirmed leaking during the boroscope inspection, a decision was made to cap it to prevent a highly-expected failure with this large crack. All these failures were located at the tube wall where the tube is connected to the support bar through a pad (figure 6.1-4) or to the rapper plate (figure 6.1-5). The rapper plate is designed to be attached onto the tubes and to take striking force from a pneumatic rapper through a nozzle on the vessel. Each coil has multiple rapper plates to distribute the rapping forces.

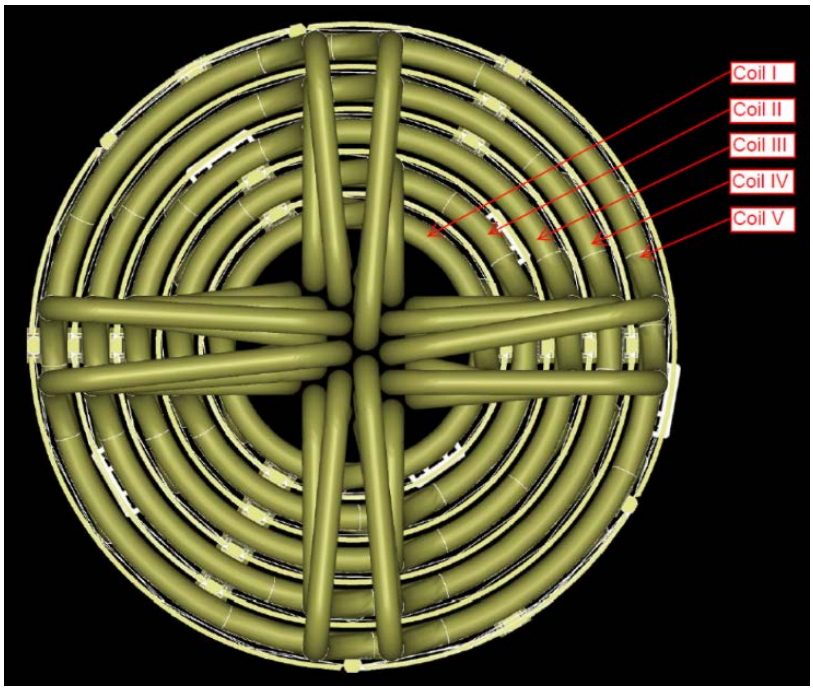

Figure 6.1-2 – Superheater coil configuration

Figure 6.1-3 – Crack on a tube in coil IV of HX2113

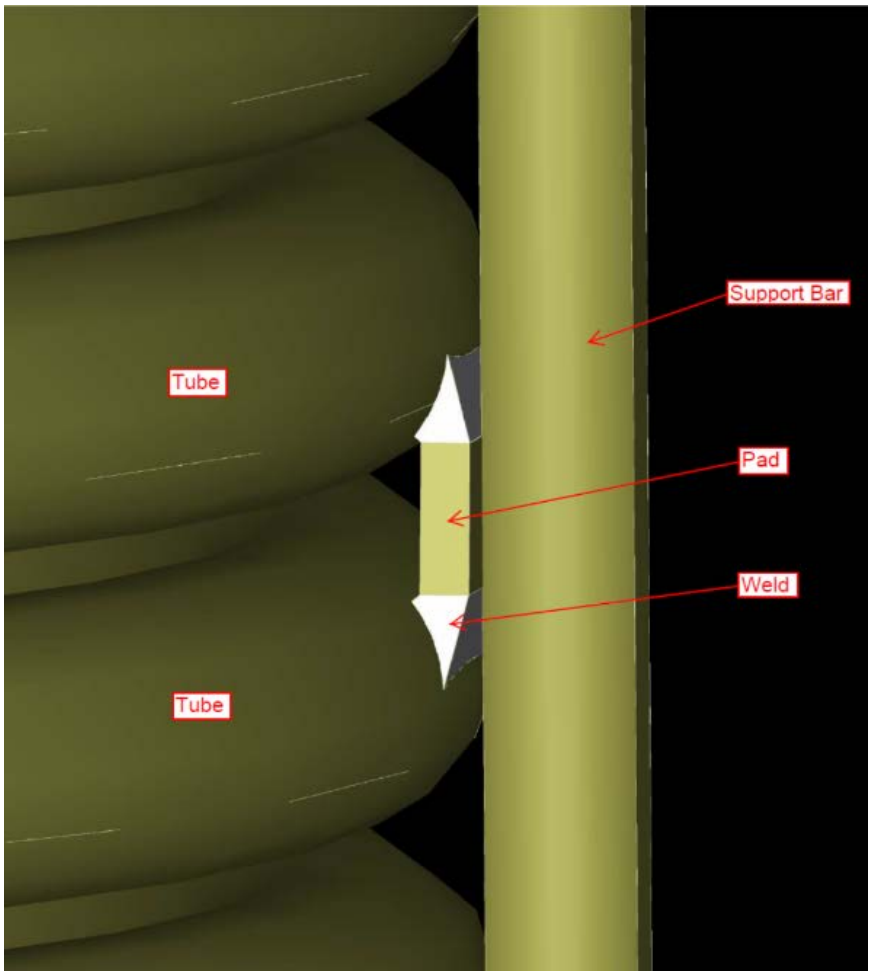

Figure 6.1-4 – Tube support structure

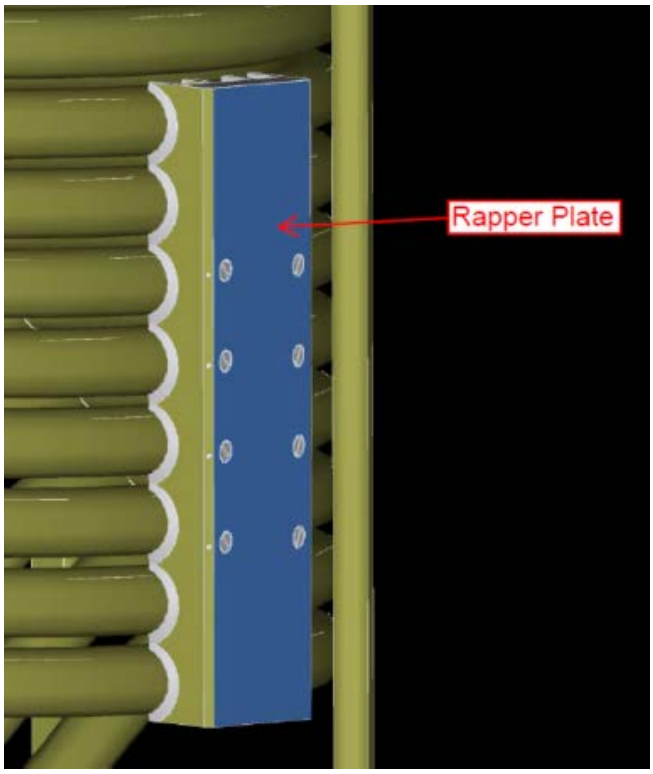

Figure 6.1-5 – Rapper plate on tubes

A review of design documents revealed that the tube thickness was determined only for pressure load per straight tube formula and had no extra margin for other mechanical loadings in actual conditions.

With this relatively thin wall, the tube is welded to the pad and then to the support bar (figure 6.1-4). There are hundreds of such connection points in each superheater. This connecting structure creates highly-concentrated stress in the tube wall in the weld vicinity. In addition, the weld used a flux-cored arc welding (FCAW) method, which is not considered suitable for this delicate structure with the thin tube wall. The boroscope inspection revealed that some welds at the connection points were not smooth. The weld has a contour that can generate local highly concentrated stress.

The tubes passed the initial hydro test at the fabrication facility. It was reasoned that in subsequent hydro tests under pressure and weight loads, the highly localized stress, together with potential weld defects, created cracks that propagated through the tube wall and caused leaking. In field work, boroscope inspections showed indications of this failure mechanism. After the failed hydro test attempt on Train A, as a proactive measure, boroscope inspection was conducted for Train B superheaters before the first in-field hydro test. Cracks were found. Additional cracking and crack propagation were found after the hydro test of Train B. A typical crack on the weld structure is shown in figure 6.1-6. Some cracks may not be visible from boroscope inspection.

Figure 6.1-6 – Typical crack on the weld structure

Based on this analysis, it was expected that certain number of cracks were already created, but not yet penetrated through the tube wall. These partial cracks would cause further leaking in the following operation, especially under high-temperature condition.

There were other factors that might have contributed to or exacerbated the situation. The hydro test pressure ramp rate was accidentally higher than the specs due to equipment issues for one train (Train A). The high pressurization rate may have shocked the system and resulted in overstressed conditions in some locations with geometry changes such as bends and curved tube sections. There was a difference between the hydro test in the fabrication facility (horizontal position) and in the field (vertical position). This difference might have affected the weight-induced stress in some parts. In the horizontal position, the support bars and the welds to the tubes were not fully loaded by the metal and water weights as they are loaded in the field (vertical position). The static head pressure is less in the horizontal position than that in the vertical position. When in field, the static pressure is even higher in the superheaters.

The superheaters were designed in a configuration with no access to the failed tube locations for repair through the manway entrance. The failed tubes were disconnected and capped outside of the vessel. Each tube has its own inlet and outlet nozzles through the vessel wall. The isolation does not affect other tubes still in service. The failed tubes left inside the superheaters will be exposed to high-temperature syngas during on-coal operation without cooling from the steam. The chance of the leaked tubes being repaired and reused is low, because repair requires a significant effort to access the leak locations.

6.1.1.2 *Superheater Tube Failures During On-coal Operation*

During on-coal operation at high temperature, 11 tubes in 3 superheaters failed. All 11 tubes were on coil V in the second superheaters: 4 tubes in HX1113, 3 tubes in HX1213, and 4 tubes in HX2113. All these failures occurred at the tube-to-support bar connection points (figure 6.1-7). The failed tubes allowed high pressure steam to impinge on and damage the adjacent tubes, pads, support bars, and refractory. The fine ash particles in the syngas entrained by the steam jet exacerbated the erosion of the tube and support members. As a result, some of the 11 tubes were damaged because of secondary failure. Figure 6.1-8 shows two adjacent tubes with a hole on each of them. The upper one is more than likely due to secondary failure, based on the erosion pattern and hole location on the tube.

Figure 6.1-7 – Typical tube failure and erosion pattern in superheater HX1213

Figure 6.1-8 – Two adjacent tube failures in superheaterHX1213

The tube leak caused refractory damage, with the entire thickness of the refractory lost in a hole with an approximate 8-in. opening (figure 6.1-9). The vessel wall and refractory anchor were exposed to the hot syngas. The erosion pattern and thinning of the vessel wall is evident in the photo. In some case, the vessel wall was eroded to thinner than the designed value. The damaged refractory caused high-temperature spots on the vessel shell, indicated by color change of the thermally sensitive paint (figure 6.1-10). A window cut on the vessel shell was performed to repair the refractory in each hot spot. In one case, the large opening on the shell allowed repair for the broken support bar (figure 6.1-11). The leaked tubes were disconnected and capped outside the vessel.

Figure 6.1-9 – Refractory damage due to tube leak

Figure 6.1-10 – A hot spot (white color) on superheater HX1213 vessel wall due to tube leak

Figure 6.1-11 – Repair for broken support bar damaged by tube leak

6.1.1.3 *Ferrule Failures During On-coal Operation*

Ceramic ferrules on steam generator tubesheets experienced failures during the on-coal operation. The ferrules are protective components that shield the metal tubes from erosion of the particulate-laden syngas. They are located at the tube entrance and exit on the tubesheets. The failures occurred at the inlet tubesheets. These ferrules are designed in a two-piece configuration, a ferrule tube and a holding block (figure 6.1-12). The ferrule assemblies are packed side by side on the tubesheet. The ferrule tube is wrapped with ceramic paper before it is inserted into the metal tube.

Figure 6.1-12 – Ferrule assembly

The leading failure modes were the ferrule tube breaking at the neck below the block (figure 6.1-13) and crushing of the block (figure 6.1-14). It was found that the broken ferrule tubes caused blocking of the metal tubes. The broken ferrules resulted in exposure of some metal tube inlets to erosion from particulate-laden syngas flow. One metal tube in HX2210 leaked at the inlet caused by the erosion (figure 6.1-15). Others showed erosion pattern and tube wall thinning but not leaking (figure 6.1-16).

Figure 6.1-13 – A ferrule tube broke at the neck below the block

Figure 6.1-14 – Crushed ferrule blocks on HX2210 tubesheet

Figure 6.1-15 – A tube leak on the top tubesheet in HX2210

Figure 6.1-16 – Erosion marks and tube thinning on the top tubesheet of a steam generator

A relatively smaller number of ferrules in the economizers experienced failure. With the much lower operating temperatures inside the economizers, the failure could be due to other reasons such as installation and misalignment.

6.1.1.4 *Refractory*

The superheaters have a single layer medium-weight refractory (Greenlite 75-28, 125 mm thick). During the hydro test and on-coal operation with the tube leaks, the refractory was wet. General industry practice is for the wet refractory to be dried to restore erosion resistance, prevent excessive steam pressure during the re-startup, and prevent potential corrosion of the vessel with excessive moisture.

After the leak in a hydro test, the wet refractory was dried out with a dedicated external heat source. The burner was inserted through the lower manway in superheater II and the hot air exited from the upper manway in superheater I. To isolate the rest of the system from this heat source, thermal blankets were installed on the top tubesheet of economizer I and the bottom tubesheet of the steam generator.

The dryout schedule (temperature ramp rate and hold time) was planned per manufacturer's specs by referencing the original dryout in fabrication. The vendor specified allowable temperature difference for the internals. Due to the large internal metal mass and heat loss, it was difficult to maintain temperature uniformity and the specified temperature difference. The temperature limit for the vessel and manways was another concern. In general, the dryout was completed successfully.

After the leaks during on-coal operation, the wet refractory was treated differently because of system availability and data gained during the previous operation. The startup burners and diesel injection systems were available to provide heating to the gasifier, while the heat source carried to the superheaters was adequate and capable for the refractory dryout. The data gained during the previous operation showed that the actual temperature ramp in the superheaters during a near normal startup process was close to the refractory dryout requirements. The actual temperature ramp in the superheaters was often slower than the maximum required value. This data established confidence in controlling and managing the refractory dryout. With these considerations, the refractory was naturally dried out during the subsequent startup with a modified gasifier startup process to accommodate the superheater refractory dryout. The heat-up process was closely monitored during the startup and appropriate corrections were made. Overall, the online dryout was successfully conducted.

To address the refractory damage caused by the steam jet from a leaked tube, proposals included drilling a small hole and injecting refractory, or accessing through the nearby rapper nozzles. The final plan was to cut a hole on the vessel wall to directly reach and repair the refractory. Due to the restriction and repair sequence, no permanent anchors were installed for the added refractory mass. There were no further on-coal operations following the repair. It remains unchecked and needs further evaluation of performance.

The refractory (AA-22S, 1 in. thick, hexmesh) in the pipeline downstream of the syngas coolers was wet due to the superheater tube leaks. AA-22S is a chemically set refractory material that does not require initial dryout after installation. Per the refractory manufacturer's specs, it requires a dryout after a wet incident (for example, a hydro test with water). The refractory in these lines was dried out together with the superheater refractory in a similar manner.

6.1.2 Final Summary

Only items with detailed analyses are discussed in this section.

6.1.2.1 *Superheater Tube Leaks*

A series of finite element analyses (FEA) were conducted for the tubes under different loading scenarios. The FEA modeling revealed a localized temperature gradient at the tube-pad-bar connecting point. This temperature gradient induces high thermal stresses in the assembly. The maximum thermal stress alone is higher than the yield stress of the tube material (Incoloy® 800). Added to the pressure-induced stress, the total stress in that region is high enough to cause certain yielding deformation. Figure 6.1-17 shows an FEA modeling result for a typical joint under pressure and thermal loads. Under repeated thermal cycles during the startup operation, the high stress and yielding deformation can promote crack formation. At a point with potential weld defects, the situation worsens. These cracks eventually propagated through the tube wall causing leaks.

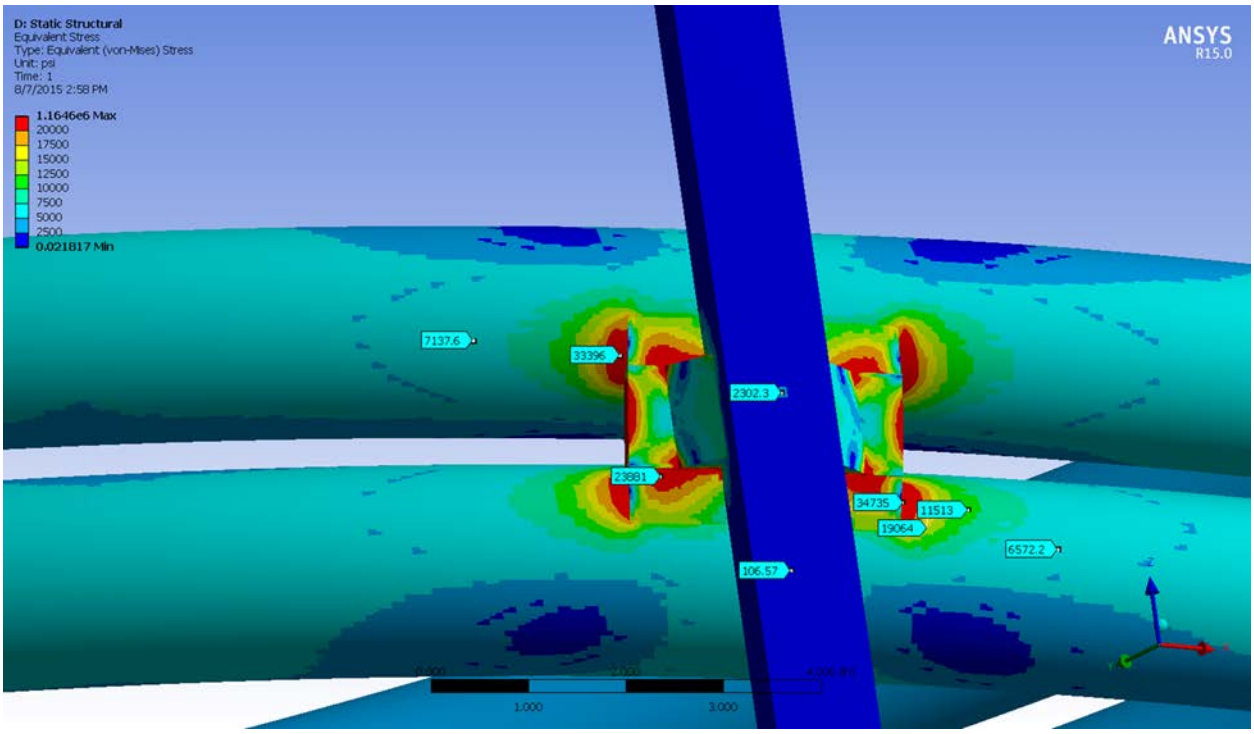

Figure 6.1-17 – Finite element analysis for a typical joint under pressure and thermal loads

Based on the tube failure pattern during the hydro test and on-coal operation, the tubes on the outer coil (coil V) seem to have a higher failure tendency than the tubes on the inner coils (coils I - IV). Several factors could contribute to this pattern.

Coil V has a larger coil diameter, which will yield larger thermal expansion radially. The larger expansion will push the tubes against the support bars. Although the bars are seating on radially sliding base, they might not slide freely in a high temperature and ash-deposit environment, and extra stress could be generated. This situation appeared to be worse near the support seat. Field observation revealed that some tubes failed in the second superheaters near the mid support seat. At this location, all the leaks occurred on the bars that shared a foot support with another bar. In comparison, the inner coils have a relatively smaller thermal expansion radially and lower extra stress. A hypothetical case of binding was modeled by a FEA, which confirmed the hypothesis.

The outer coils have larger pitch sizes and more tubes per coil in order to achieve approximately equal tube length in different coils. The larger pitch size has a larger elevation angle, which would create a larger twist action and higher stress on the tube-pad-bar weld structure. The tubes in the inner coils are closer to parallel and experience less twisting.

The vendor's computational fluid dynamics (CFD) modeling results showed higher gas flow velocity in the gap between coil V and refractory wall. This is due to tube bundle configuration and obstruction of structural members that divert more flow to the outside space. The higher flow carries more heat energy, and a higher temperature due to the heat transfer process, to the tubes in coil V. Any temperature variation from process will first affect these tubes preferentially. The flow field near inner coils is more uniform with a slower flow rate.

All the leaked tubes were on coil V, indicating that any unknown factors in designed configuration, fabrication, installation, or operation are preferentially affecting the tubes in coil V.

During the on-coal operation at high temperature, all the leaked tubes were in the second superheaters. After further analysis and process evaluation from the vendor, a risk management decision was made to proactively plug all the tubes on coil V in the second superheaters, a total of eight tubes on coil V in each superheater including the leaked

tubes. The impact on the internal structure is minimal because each coil is supported independently. The impact on the process is manageable for the further on-coal operation.

There was a joint effort with the vendor to redesign the tube-pad-bar structure to resolve the problem in the spare superheaters. The vendor proposed a forged or cast tube section with thick wall for the connection. Other support mechanisms were also considered.

6.1.2.2 *Ferrule Failures*

The ferrule blocks are packed next to each other on the tubesheet with very little cushion in between. During on-coal operation, the gaps between blocks are filled by ash particles. Thermal analysis showed excessive compression due to thermal expansion of the ferrule assembly during high-temperature operation. The vessel and the tubesheet are in relatively cooler temperatures, leaving little room for thermal expansion of the ceramic ferrule assemblies. Some blocks were crushed to fail. Field inspection revealed that most of the crushed blocks were near the outer circles of the tubesheet (figure 6.1-18), which is consistent with the thermal expansion pattern. Added to the compression, the larger thermal displacement with restrictions from individual ferrule tubes makes the blocks at the outer circles fail first.

Figure 6.1-18 – Ferrule failures on the top tubesheet of steam generator HX2110

During troubleshooting, a communication with the ferrule manufacturer revealed a design flaw. The design temperature of the ferrules is 600 °F as marked on the drawings, which is not appropriate for real operating conditions. The ferrule assembly will experience temperatures of 1,740 °F from the syngas contact (top of the block and inside diameter surface of the ferrule tube), and 600 °F from tubesheet contact (bottom of the block). The thermal expansion of the ferrule assembly and the gap between the blocks were underdesigned. The gap is roughly three times smaller than needed, so the blocks experienced excessive compression at operating temperature. A proper design of the ferrule assembly should be conducted based on the temperature profile and temperature gradient to account for the thermal expansion.

The ferrule tube failure could be due to a different issue. The designed ceramic paper wrap is too thick, resulting in a tight fit into the metal tube. Field installation personnel reported difficulty inserting and sometimes had to trim the wrap to fit. With this tight fit, any thermal movement of the block will exert a bending movement on the ferrule tube in a cantilever loading fashion. The ferrule tube will break at the maximum stress point, the neck below the block. Most of the ferrule tubes failed in this pattern. Some ferrule tubes failed inside the blocks, possibly due to the crushing of the blocks.

There were no direct indications, but thermal shock could be another reason for the ferrule assembly failure. Any appreciable temperature change from the process, increase or decrease, creates extra thermal gradient in the assembly. A ceramic component is suitable for high-temperature operation, but vulnerable to temperature gradient because of the low thermal conductivity, low tensile strength, and low material toughness (crack propagation

resistance). High thermal gradient induces a high thermal stress that could create cracks. After the crack is formed or the surface defect exists, the crack can propagate quickly to fail the ferrules.

Because of time and schedule limits, there could not be a complete redesign to reduce the failure rate during on-coal operation. Several modifications were proposed and implemented. Some metal ferrules were made, and a limited number strategically installed for testing purpose. A thinner ceramic paper wrap was used for the ferrule tubes. These measures were not thoroughly evaluated before gasification was suspended. Other designs should be considered, such as metal ferrules within a refractory bed, a redesigned ceramic ferrule assembly with proper design parameters, or a newly developed ceramic assembly with a gap-and-cap configuration.

One suggestion was a screen or grate on top of each tubesheet to prevent plugging at the top of the ferrules. It was observed several times that a small piece of refractory or ferrule from above started to plug a hole, which then became fully plugged as ash built up around the small blockage (figure 6.1-19). A simple cone-shaped screen or a grate would divert excess material to the outside of the heat exchanger tube.

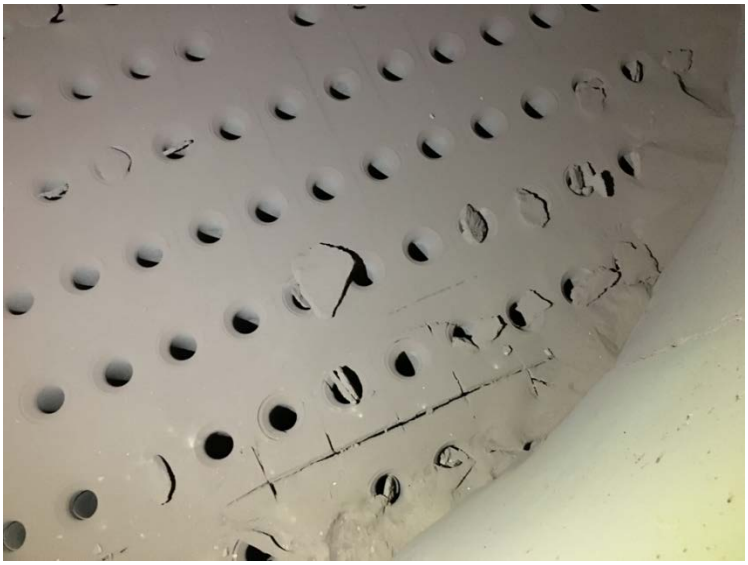

Figure 6.1-19 – Tube entrance blocking by debris in a steam generator

Most of the major mechanical components of the syngas coolers performed well during the unit commissioning and on-coal operation. The unique and complex internal structures in the superheaters accommodated the large thermal expansion as intended in the design. The vessels and external pipes are well configured and supported without any issues. The refractory performed well in thermal insulation. A unique tubesheet support mechanism in the steam generator experienced no issues.

However, two key components, superheater tubes and steam generator ferrules, experienced repeated mechanical failures. Although timely and reasonable repairs and risk management measures were implemented, these failures caused several otherwise unnecessary system shutdowns for repair and significantly affected the startup schedule. The reliability of these key components remains uncertain for further operation without a significant redesign.

6.2 Gasifier Structure Vibration During Sand Circulation

6.2.1 Significant Events

During the initial sand circulation test in gasifier A in October 2015, a strong vibration of the lower gasifier structure was observed. The vibration was accompanied by loud humming sounds from the lower gasifier. The riser, standpipe, J-leg, and the air lines from the startup burners to the mixing zone were moving with visually detectable displacements in low frequencies. The small-bore pipes connecting to the gasifier and associated valves were vibrating with even

larger displacements. Field observations reported the movement of the lower gasifier during vibration was estimated at about 10 mm.

As a reference, the gasifier at the PSDF does not have this type of problem because it is supported with hydraulic snubbers at the bottom of the standpipe. Vibration of a flexible structure is generally addressed during the design phase by performing vibration analysis and providing a proper support mechanism. The major concerns with vibration are fatigue of mechanical components and, particularly in this application, a detrimental effect on refractory structure. At Kemper, the strong vibration was one of several contributing factors to the extended refractory failure in the lower portion of gasifier A during the sand circulation test. (See section 6.3, Gasifier Refractory and Nozzle Modifications.)

Because of concerns about the gasifier's mechanical integrity, immediate actions were taken to quantify and evaluate the vibration effect so a quick and effective fix could be implemented. First, field measurements were made to determine the vibration amplitudes and frequencies under different operating conditions with varying sand circulation rates. Then, a finite element analysis (FEA) was conducted to model the gasifier vibration behavior. In the meantime, temporary fixes to reduce vibration were installed, namely, wire cables at the lowest point of the riser leg and shims at the guides of the lower standpipe leg. Finally, after detailed evaluation with the modeling and measurement results, a decision was made to install snubbers at strategic locations of both gasifiers to permanently fix the vibration problem. The fix successfully reduced the amplitude of the vibration to an acceptable level. The final field measurements confirmed the significant reduction of the vibration.

The gasifier is a slender and flexible structure (figure 6.2-1), composed of large diameter refractory-lined pipes and lumpy components in multiple loops. The riser leg, standpipe leg, J-leg, and top crossovers form the main loop, which extends to the entire gasifier height. The presalter, cyclone, and seal leg form a smaller loop on the top, and the startup burners (SUB) and air lines from SUBs to the gasifier form another smaller loop at the bottom of the gasifier.

Based on gasifier structural characteristics, multiple supports and guides are strategically installed to accommodate its weight, thermal expansion, wind and earthquake loads, and other mechanical loads. One main structural support (sliding support) is located at the middle of the riser leg, and another main support (fixed support) is located at the same level of the standpipe leg.

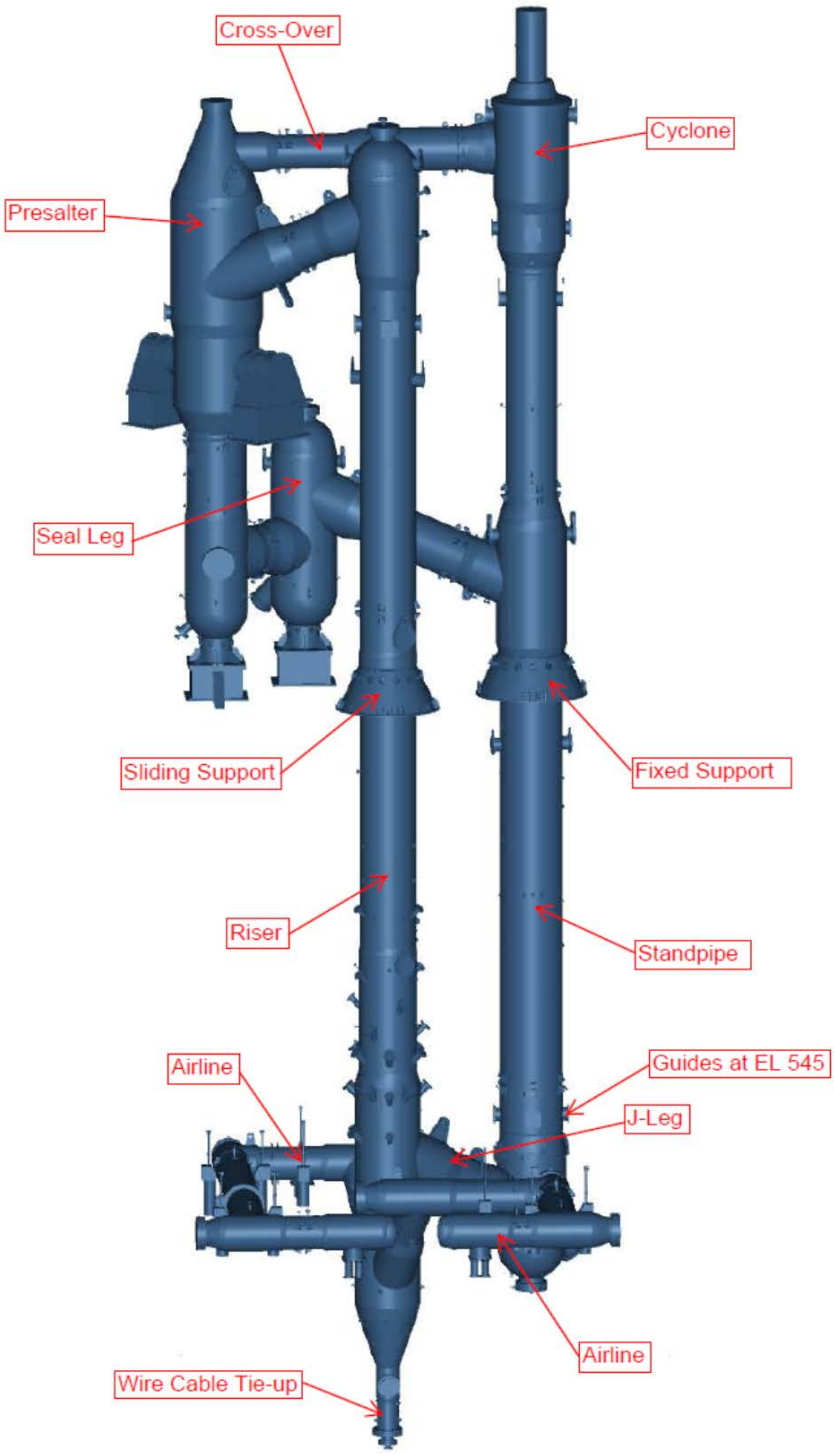

Figure 6.2-1 – Gasifier model

These two supports create two relatively independent parts, the upper and lower gasifier. When considering vibration, the lower gasifier has different characteristics than the upper portion.

The lower gasifier is hung from the two main supports with only one guide point (four guides around) at the lower standpipe leg, and with sliding supports under the SUBs. All other pipes attached to the gasifier are much smaller.

The lower gasifier behaves like a pendulum. With the asymmetric configuration of the SUB layout, the vibration modes and natural frequencies are expected to be different along their respective directions.

The vibration analysis for the gasifier structure was conducted by FEA. The primary objective was to determine the vibration mode shapes, natural frequencies, and corresponding loads so restriction devices with proper design could be installed at strategic locations and effectively reduce the vibration effect.

For the temporary fix with the wire cables and shims, a structural analysis was conducted for the gasifier with corresponding loads at the tie-up points. The loading created by the restrictions to both gasifier and floor structure was evaluated for mechanical integrity.

Vibration measurements were made with accelerometers installed on the gasifier wall surface at the locations and orientations of interest. Initial measurements were made to serve as reference for the later fixes. Multiple measurements were made for incremental implementations to determine their effectiveness. A final measurement was made under operating conditions after the permanent fix was in place.

6.2.2 Final Summary

Initial measurements were made for gasifier A while it was in sand circulation test. The peak-to-peak displacement and dominant frequency at various elevations (see figure 6.2-2) are shown in table 6.2-1. The measurement location on the standpipe at EL 515 was on the flange at the lowest point of the standpipe leg. The measurement location on the riser at EL 515 was at the same elevation as on the standpipe. The measurements were made at two sand circulation rates, 8 million lb/hr and 14 million lb/hr.

In general, the data showed three trends:

- The larger peak-to-peak displacement corresponds to the larger sand circulation rate.
- The larger peak-to-peak displacement occurs at the lower end of the gasifier structure.
- The larger peak-to-peak displacement is along the east-west (EW) direction.

These trends are expected because of the gasifier structural configuration. Under the excitation of the sand circulation, the lower gasifier swings about the main supports at EL 605. In the lowest frequency mode, the bottom end has the largest displacement. As the sand circulation rate increases, the excitation becomes stronger and produces a larger displacement. The air lines are more rigid in north-south (NS) direction than in EW direction, so the EW direction has a larger displacement than NS direction.

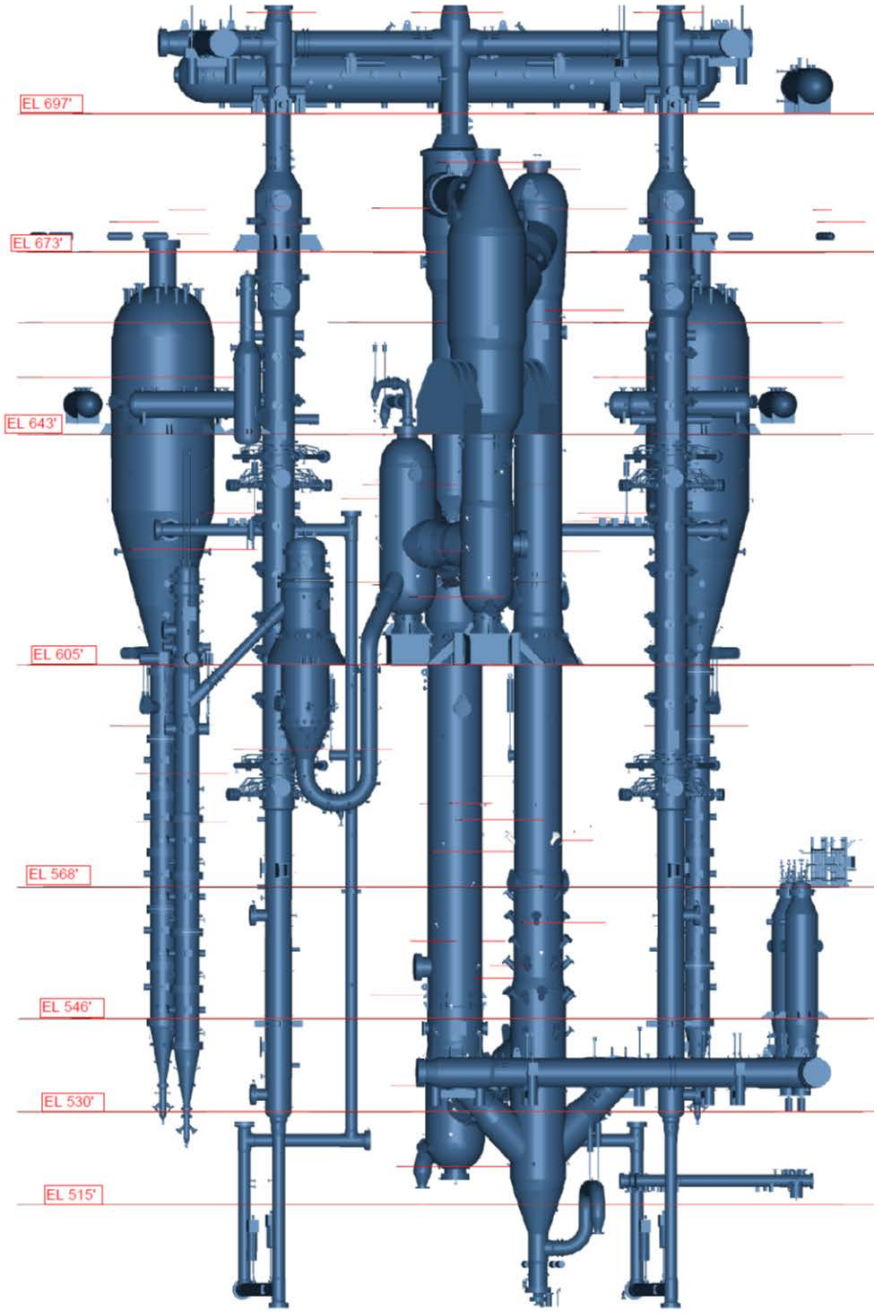

Figure 6.2-2 – Gasifier structure elevations

Table 6.2-1 – Initial vibration measurements, gasifier A

		Flow Rate - 8m lbs/hr						Flow Rate - 13m lbs/hr					
		Riser			Standpipe			Riser			Standpipe		
		Max Displ (pk-pk)		Dominant	Max Displ (pk-pk)		Dominant	Max Displ (pk-pk)		Dominant	Max Displ (pk-pk)		Dominant
Location	Direction	mils	mm	Frequency (Hz)	mils	mm	Frequency (Hz)	mils	mm	Frequency (Hz)	mils	mm	Frequency (Hz)
El 515	NS	80	2.0	2.3	85	2.2	2.3	95	2.4	2.4	150	3.8	4.1
	EW	90	2.3	1.8	100	2.5	1.8	175	4.4	1.8	285	7.2	1.8
El 530	NS	35	0.9	2.4	35	0.9	2.2	95	2.4	2.4	90	2.3	2.3/4.6
	EW	25	0.6	1.8	40	1.0	4.6	150	3.8	1.9	145	3.7	1.8
El 546	NS	20	0.5	2.2	25	0.6	2.4/4.1	55	1.4	2.3	50	1.3	2.4/4.1
	EW	35	0.9	1.8	55	1.4	1.8	120	3.0	1.8	110	2.8	1.8
El 568	NS	15	0.4	1.8/2.2	20	0.5	1.8/2.2	30	0.8	1.8/2.3	25	0.6	1.8/2.3
	EW	25	0.6	1.8	25	0.6	1.8/2.2	25	0.6	1.8/2.3	45	1.1	1.8/2.3
El 674	NS	5	0.1	2.3/4.0	5	0.1	1.2/2.2	10	0.3	1.2/2.0/3.8	10	0.3	1.2/2.3
	EW	5	0.1	1.2/1.8	5	0.1	1.2/1.8	15	0.4	1.5/2.5	10	0.3	1.2/1.5

The upper gasifier has some degree of vibration. The only measurements at the location EL 674 above the main supports (close to the top end of the gasifier) show much smaller peak displacements. The finding is consistent with field observation at various locations on the upper gasifier structure. This trend is expected because excitation from low-concentration solids flow in the upper gasifier is significantly lower than that from high-concentration solids flow in the lower gasifier. The heavy and lumpy components (presalter, cyclone, and seal leg), their triangle configuration, and multiple supports on the presalter and seal leg, make the upper gasifier more rigid in regard to vibration.

The measured dominant frequencies of the lower gasifier structure are low, in the range of 1.8 – 4.6 Hz. In general, the NS direction has a higher frequency than the EW direction because of the air line configuration.

After the initial vibration measurements, several temporary fixes were implemented on gasifier A. First, wood shims were installed at the four guides at EL 545. Based on structural modeling and analysis, the guides were designed to have specified gaps between the vessel wall and stops when initially installed. The shims essentially close the gaps to reduce the vibration amplitude. They were later replaced with steel shims (figure 6.2-3). Then, wire cables were installed at the lowest point of the riser leg (figure 6.2-4) and attached to three columns of the floor structure in a tripod configuration (figure 6.2-5). The vibration measurements at EL 515 conducted before and after the temporary fixes showed an 8% to 57% reduction in peak-to-peak displacements. This temporary fix was not rigid enough to significantly reduce the vibration amplitude, because the wire cables were too long and too flexible. In the field, the wire cables exhibited large wobbling behavior. Even so, this was encouraging because it demonstrated that the vibration could be reduced with some degree of stiffness and damping changes. The same temporary fixes were later implemented on gasifier B.

While implementing the temporary fixes, the FEA modeling was conducted. An FEA model, as shown in figure 6.2.6, was isolated from the gasifier structure to capture the vibration characteristics. The model includes the gasifier vessel, refractory layers, and sand in the standpipe and J-leg. Boundary conditions were applied at the support points according to the nature of the structural restrictions. Certain assumptions were applied to simplify the modeling conditions. The temporary fixes (wire cables and shims) were not applied to the FEA model, so the modeling results are for the original gasifier structure.

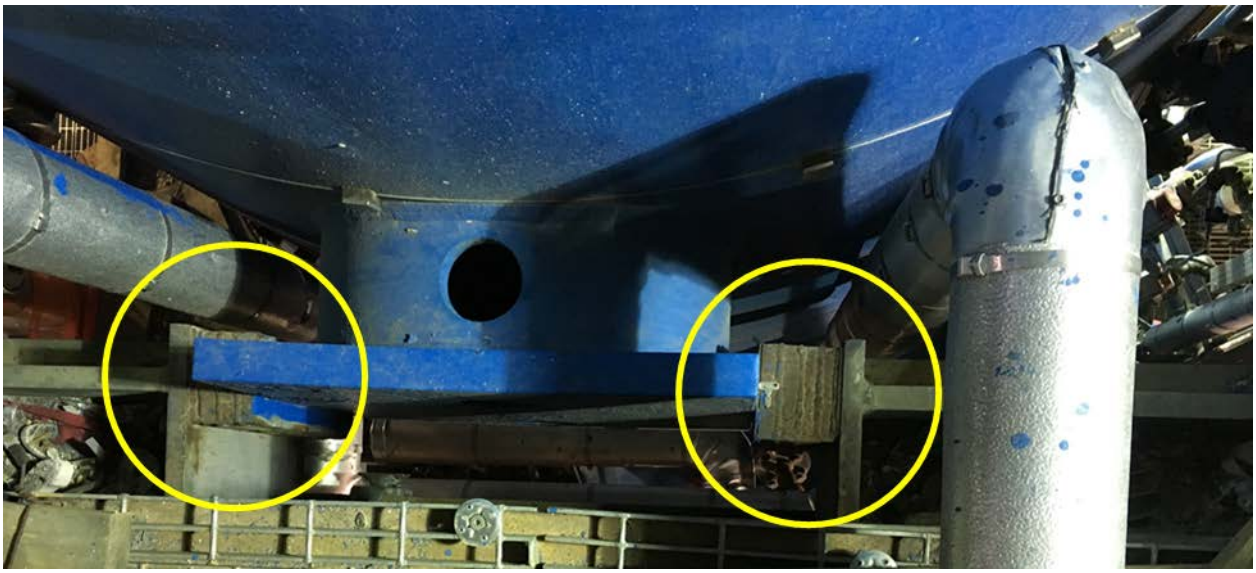

Figure 6.2-3 – Steel shims at guide point on lower standpipe

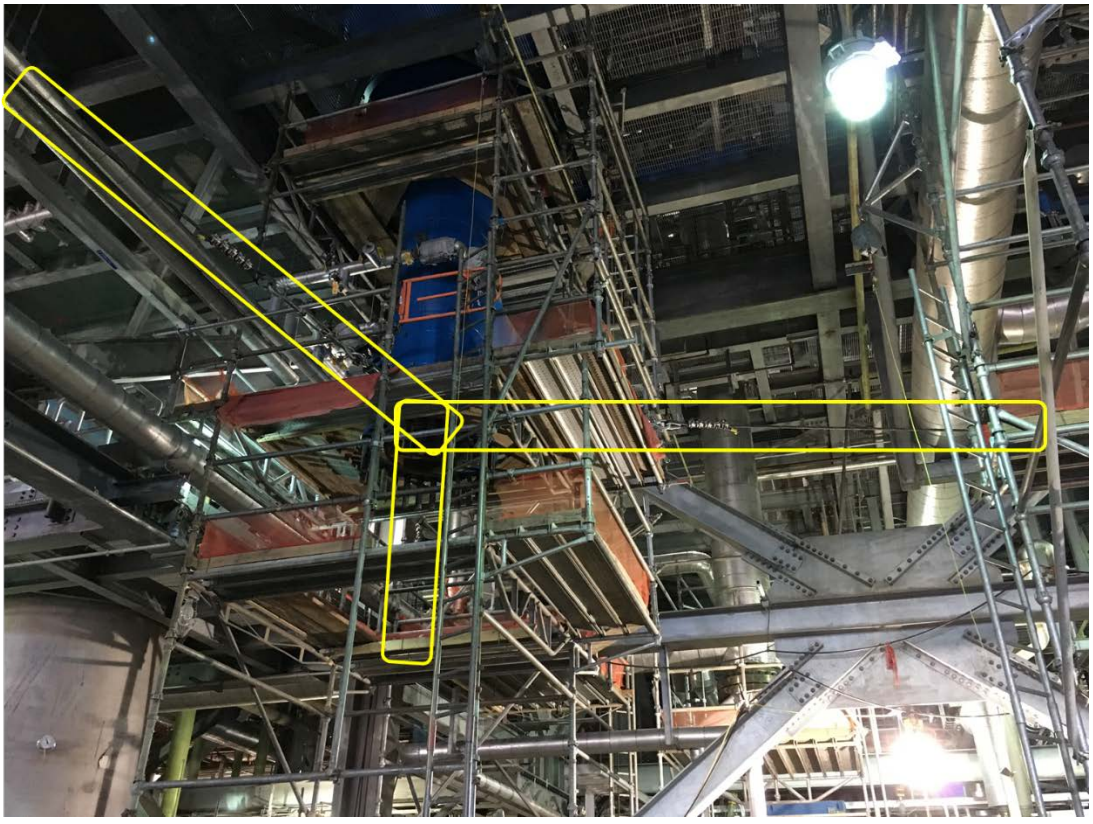

Figure 6.2-4 – Wire cables installed at lowest point of riser leg

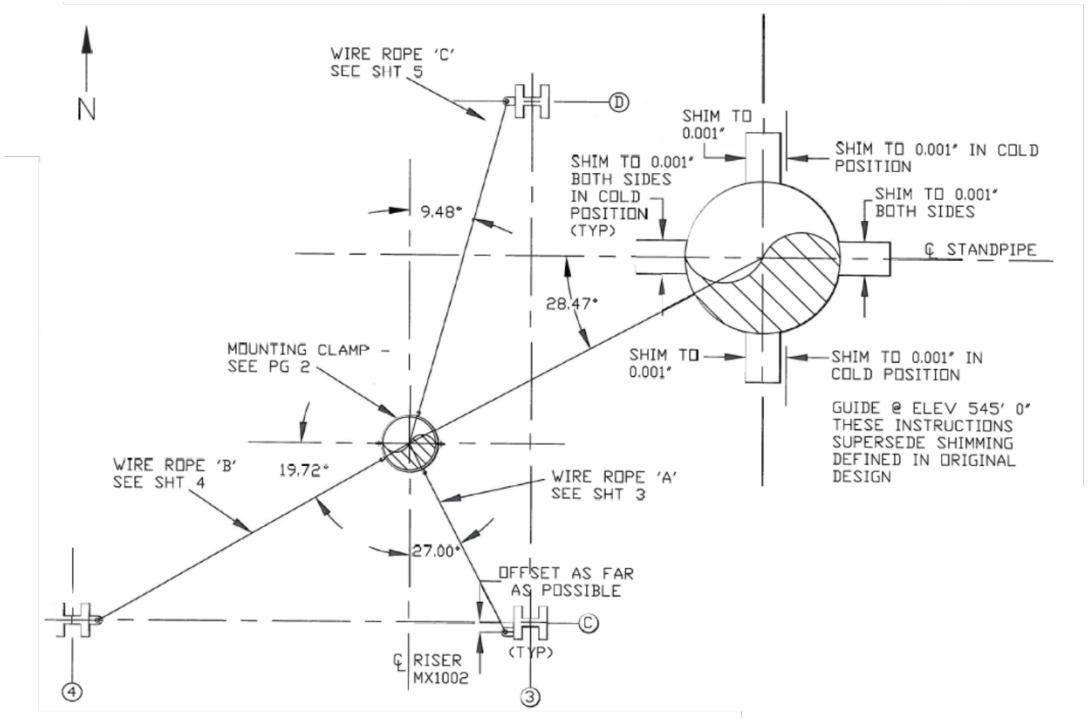

Figure 6.2-5 – Wire cable installation

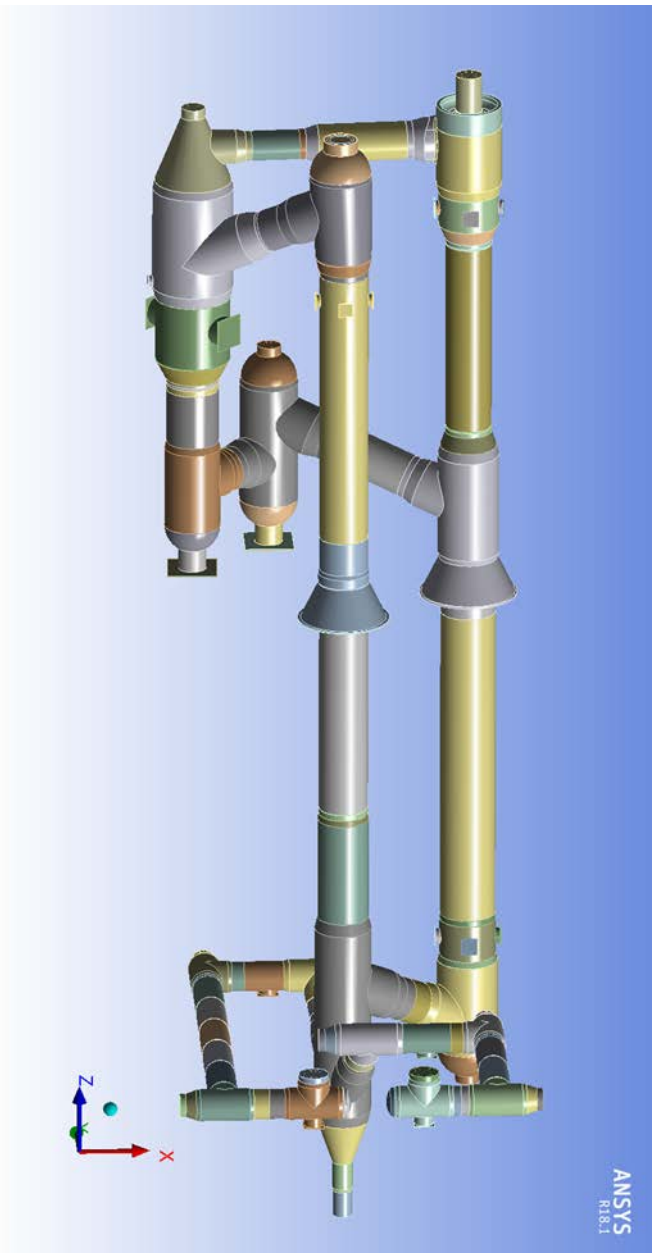

Figure 6.2-6 – FEA model for vibration analysis

For the lower gasifier portion, the lowest natural frequency along EW direction is 2.4 Hz, while the lowest natural frequency along NS direction is 3.2 Hz. Figures 6.2-7 and 6.2-8 show the lower gasifier structure vibration mode in the lowest frequency along EW direction, elevation view, and plan view respectively. Figures 6.2-9 and 6.2-10 show lower gasifier structure vibration mode in the lowest frequency along NS direction, elevation view, and plan view respectively. The difference between the natural frequencies in the two directions reflects the asymmetric structural configuration due to the layout of the air lines. The lower frequency along EW direction is due to more flexible structural response in EW direction movement.

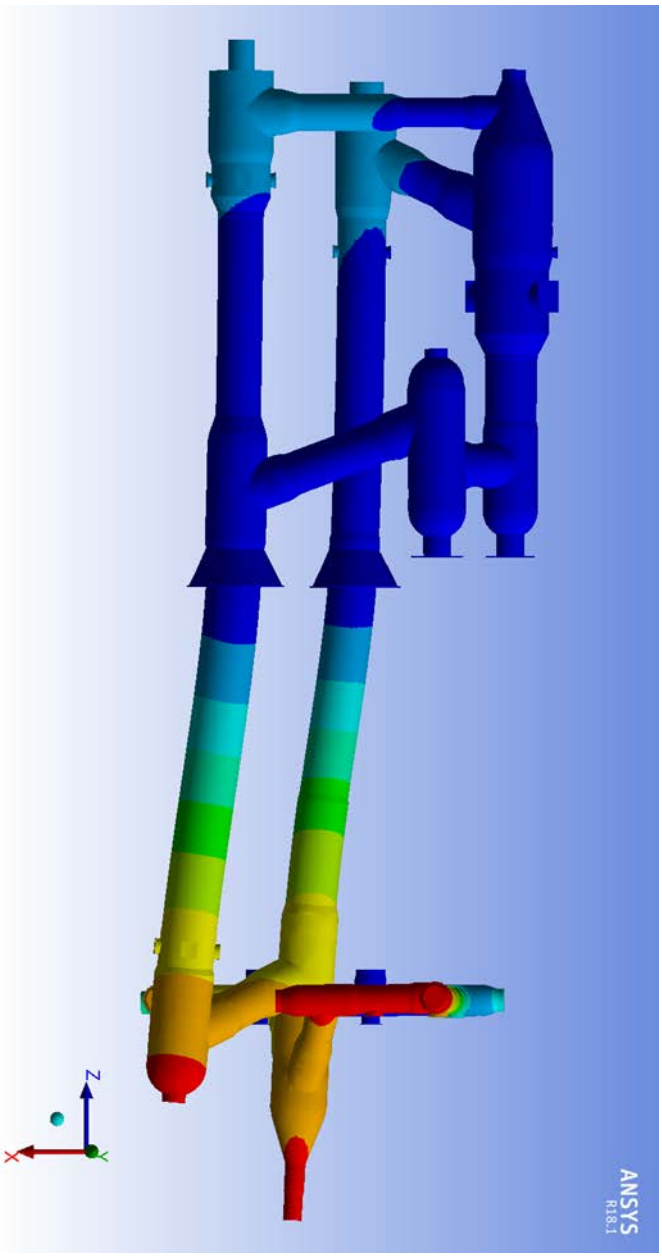

Figure 6.2-7 – Lowest vibration mode, lower gasifier, EW direction, elevation view

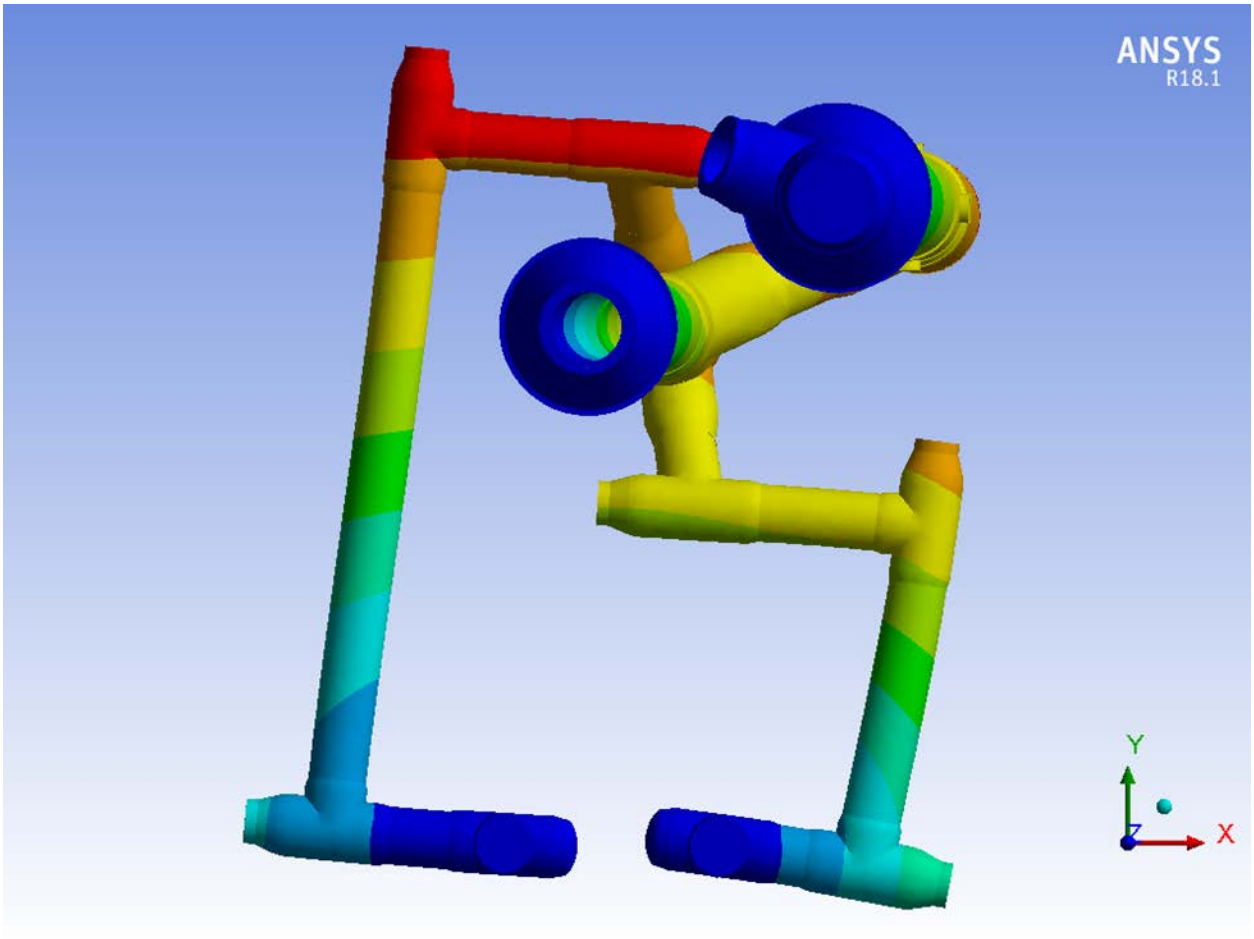

Figure 6.2-8 – Lowest vibration mode, lower gasifier, EW direction, plan view

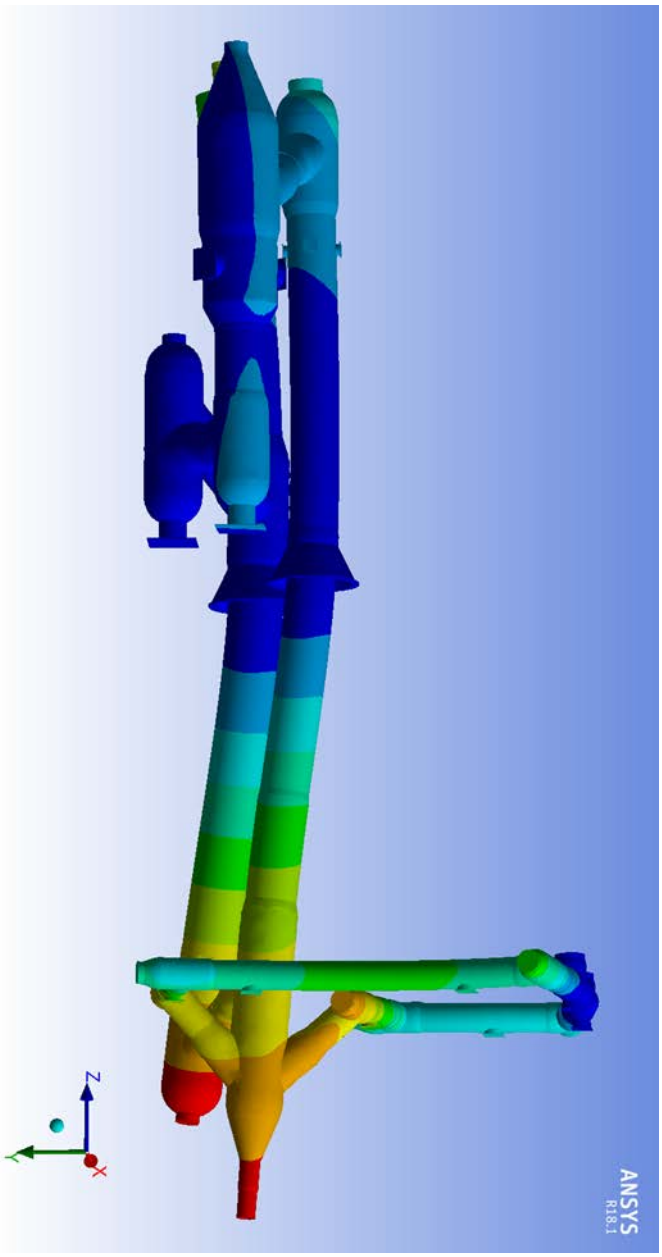

Figure 6.2-9 – Lowest vibration mode, lower gasifier, NS direction, elevation view

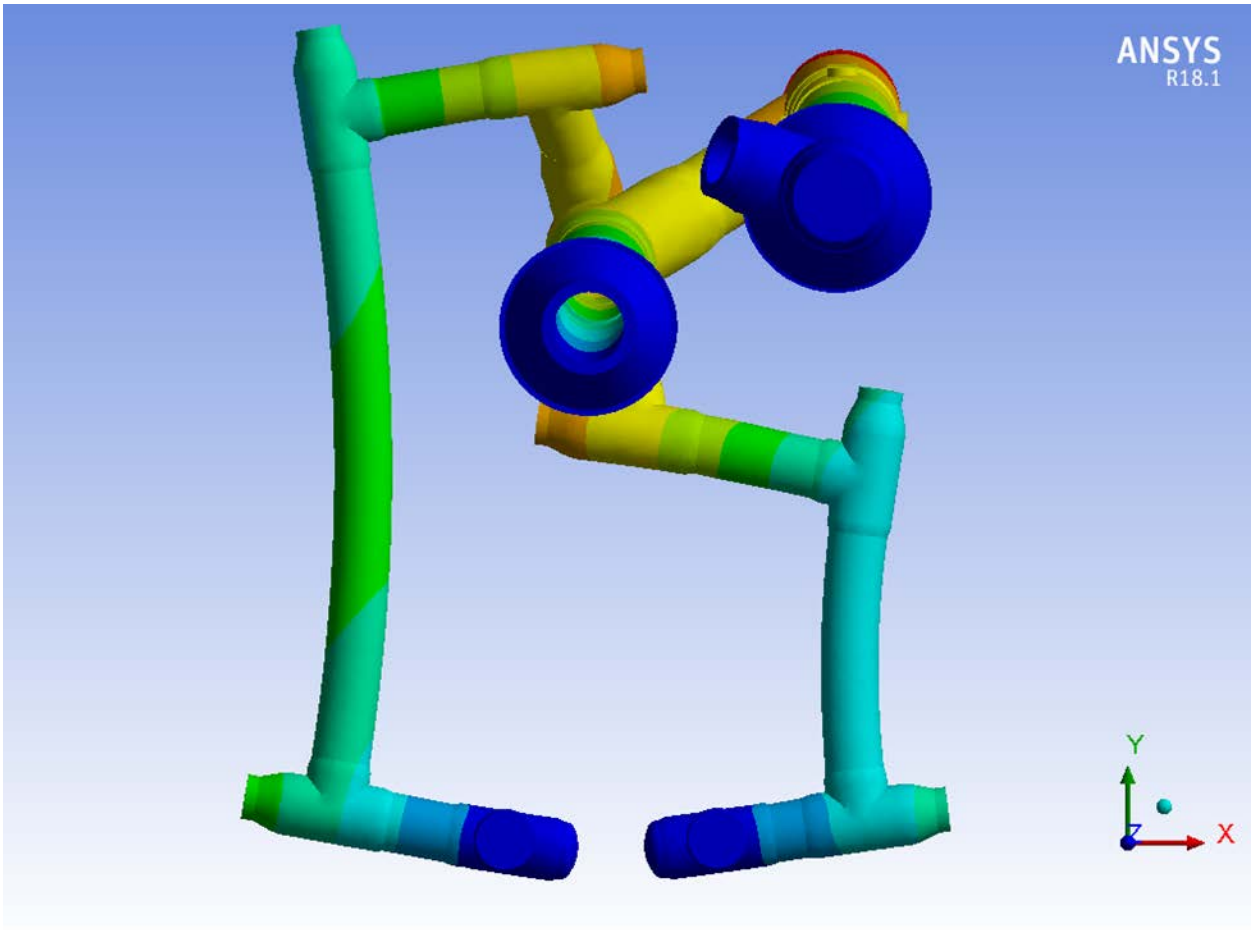

Figure 6.2-10 – Lowest vibration mode, lower gasifier structure, NS direction, plan view

The lowest natural frequencies of the lower gasifier structure are in the range of the field measured dominant frequencies during sand circulation (1.8 - 4.6 Hz). To verify the gasifier natural frequencies, an ambient vibration test was conducted while both gasifiers were not in operation and not loaded with sand, but the wire cables and shims were in place as temporary fixes. The measured lowest natural frequencies of the lower gasifier structure (EL 515) are summarized in table 6.2-2. It confirmed that the lowest natural frequency of the lower gasifier is higher in NS direction than in EW direction. It should be noted that the measured natural frequency in gasifier A is higher than in gasifier B. This difference may be due to the removal of refractory from the lower riser leg in gasifier A while the refractory was being repaired. The lighter weight of the riser leg resulted in a higher natural frequency.

Although the measured frequencies with sand circulation and with the empty gasifier are slightly different from the modeled values, the trends are clearly in agreement. The lower gasifier was vibrating in a frequency close to the lowest natural frequency under sand circulation. This finding provides the basis for a permanent solution. More restriction devices should be added for more stiffness and damping effect on the lower gasifier to reduce the vibration impact. The locations of the added restrictions should be based on the mode shapes corresponding to the lowest frequencies.

Table 6.2-2 – Ambient vibration measurements to determine natural frequencies

Ambient Vibration Measurements January 13, 2016			
		Natural Frequency (Hz)	
Location	Dir	Gasifier 'A'	Gasifier 'B'
Stand Pipe	NS	3.5	2.7
	EW	3.2	2.0
Riser	NS	3.5	2.7
	EW	3.2	2.0

After thorough evaluation of the field measurements and FEA modeling results, a permanent solution was proposed. The plan was to install hydraulic snubbers at the lower end of the gasifier. The hydraulic snubbers would dampen the vibration, but not restrict the thermal movement of the gasifier structure. To minimize the impact of the added restriction forces on the gasifier and floor structure, the snubbers would be installed at multiple points to distribute restriction forces. One pair of snubbers would be installed on the north air line (EL 537), the second pair on the south air line (EL 537), and third pair on the riser (EL 544) as shown in figure 6.2-11. The snubbers on the air lines would restrict the gasifier movement along EW direction, while the snubbers on the riser would restrict the gasifier movement along both directions. The plan view of the snubber locations is shown in figure 6.2-12. It was decided to keep the wire cables and shims in place because they had shown some degree of vibration reduction.

More FEA modeling and structural calculations were conducted to evaluate the restriction forces for the snubber design. The snubbers were fabricated and finally installed on both gasifiers in early 2016. Figure 6.2-13 shows details of typical snubbers (snubbers C and D) with model numbers, dimensions, and anchoring. A strap clamp ring with flanged split (120° each for snubbers A and B; 180° each for snubbers C, D, E, and F) was installed on the air line pipe or riser pipe at each location. Brackets were installed on the ring for snubber connection. The other end of the snubber was connected to the bracket on beam of floor structure. Figure 6.2-14 shows field installation of snubber C.

The vibration was significantly reduced after the snubber installation. In early 2017, field measurements were conducted while gasifier A was in on-coal operation with a solids circulation rate of 27.5 million lb/hr, and gasifier B was in transition from startup to on-coal operation with a solids circulation rate of 18 million lb/hr. The measurement results are shown in table 6.2-3. During these measurements, the solids circulation rates were much higher than that of the initial measurements without any fixes. Even at these high solids circulation rates, the data show that the vibration was at an acceptable level (1.1 mm peak-to-peak displacement or less at EL 515).

In summary, the gasifier vibration was effectively reduced to an acceptable level with a combination of wire cables, shims, and hydraulic snubbers. The vibration amplitudes and frequencies were measured, modeled, and evaluated for the design and installation of the restriction devices. The vibration impact on the gasifier structure and the floor structure were analyzed and evaluated for the strategic locations of the snubber installation. With these implementations, the gasifier vibration was successfully addressed. No vibration problems were encountered in the subsequent operation.

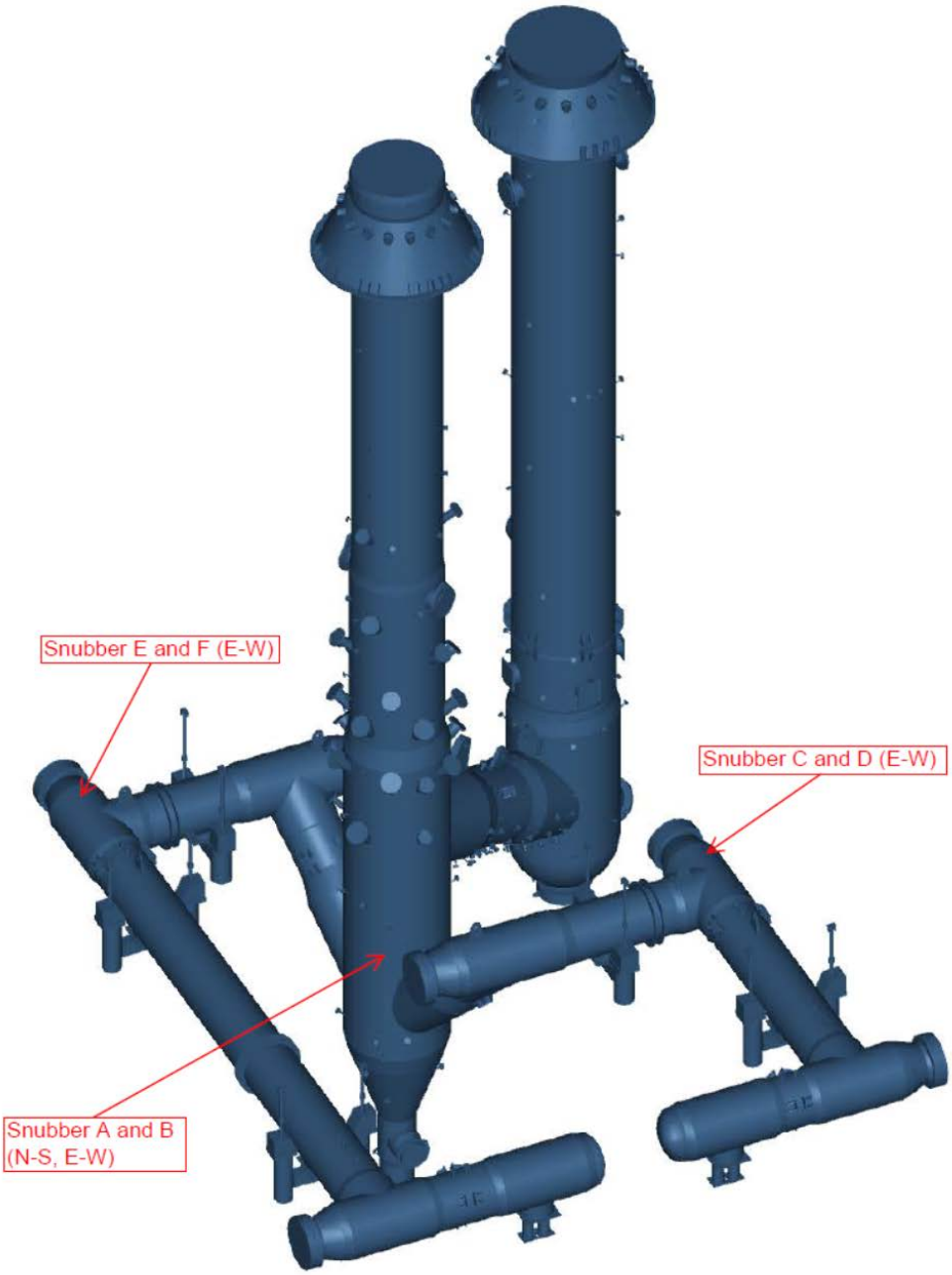

Figure 6.2-11 – Locations of hydraulic snubber installation

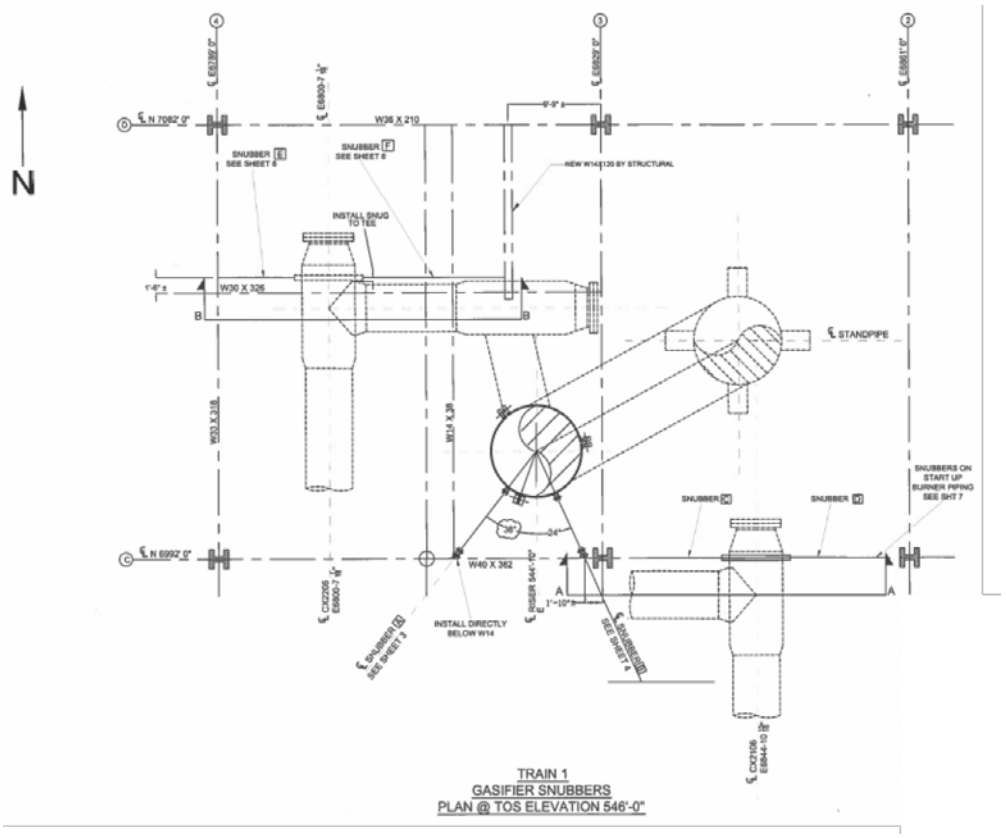

Figure 6.2-12 – Plan view, snubber locations

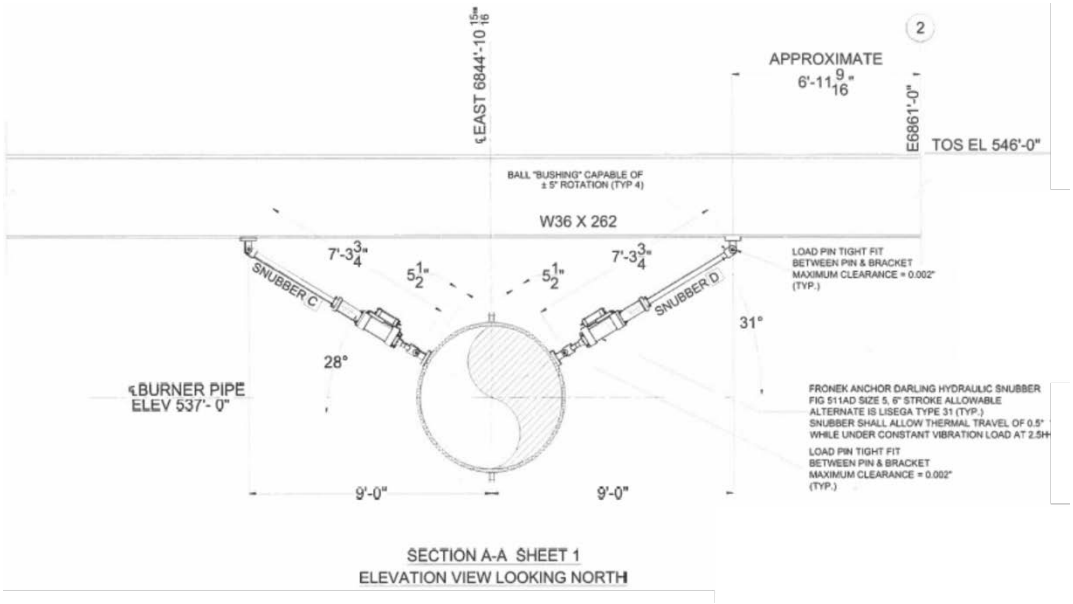

Figure 6.2-13 – Details, Snubbers C and D

Figure 6.2-14 – Field installation, snubber C

Table 6.2-3 – Final vibration measurements

Final Measurements on February 15, 2017 - El 515					
			Max Displacement (pk-pk)		
Gasifier	Location	Direction	Mils	mm	Dominant Frequency (Hz)
A	Stand Pipe	NS	26	0.7	3.0
		EW	32	0.8	2.5
	Riser	NS	34	0.9	2.9
		EW	24	0.6	3.2
B	Stand Pipe	NS	42	1.1	2.8
		EW	26	0.7	3.0
	Riser	NS	42	1.1	2.7
		EW	26	0.7	3.0

6.3 Gasifier Refractory and Nozzle Modifications

6.3.1 Introduction

Refractory serves as an insulator and erosion-resistant lining in furnaces, reactors, and other processing units subject to high temperatures and erosion. At Kemper, the refractory lining in the gasifier is vital to protect the gasifier pressure shell from erosion and temperatures that can reach 1,850 °F.

In November 2015, during the fluidization tests and the first heat-up of the gasifier Train A, hot spots were identified on the surface of the gasifier, which led to the discovery of hard-face refractory damage in both gasifier Train A and gasifier Train B. This section discusses the initial design of the refractory system, the cause of the refractory failure, and the mitigation strategy implemented to allow continued operation of the gasifiers.

6.3.2 Initial Design

The Kemper gasifier refractory system design consists of two layers of refractory, refractory anchors, and nozzle sleeves. The backup or insulating layer is a low-density refractory, and the internal or hard-face layer is a high-density refractory. The configuration of the backup layer allows a specific amount of heat transfer to the metal shell for a specific thermal expansion of the gasifier system. The hard-face layer is designed to protect the backup layer from erosion from solids circulation. The anchor system is designed to hold the refractory in place. The nozzles are designed to penetrate the refractory layers, allowing air, coal, and recycle gas injection without affecting the refractory. Other nozzle connections are designed for instrument connections such as pressure, differential pressure, and temperature.

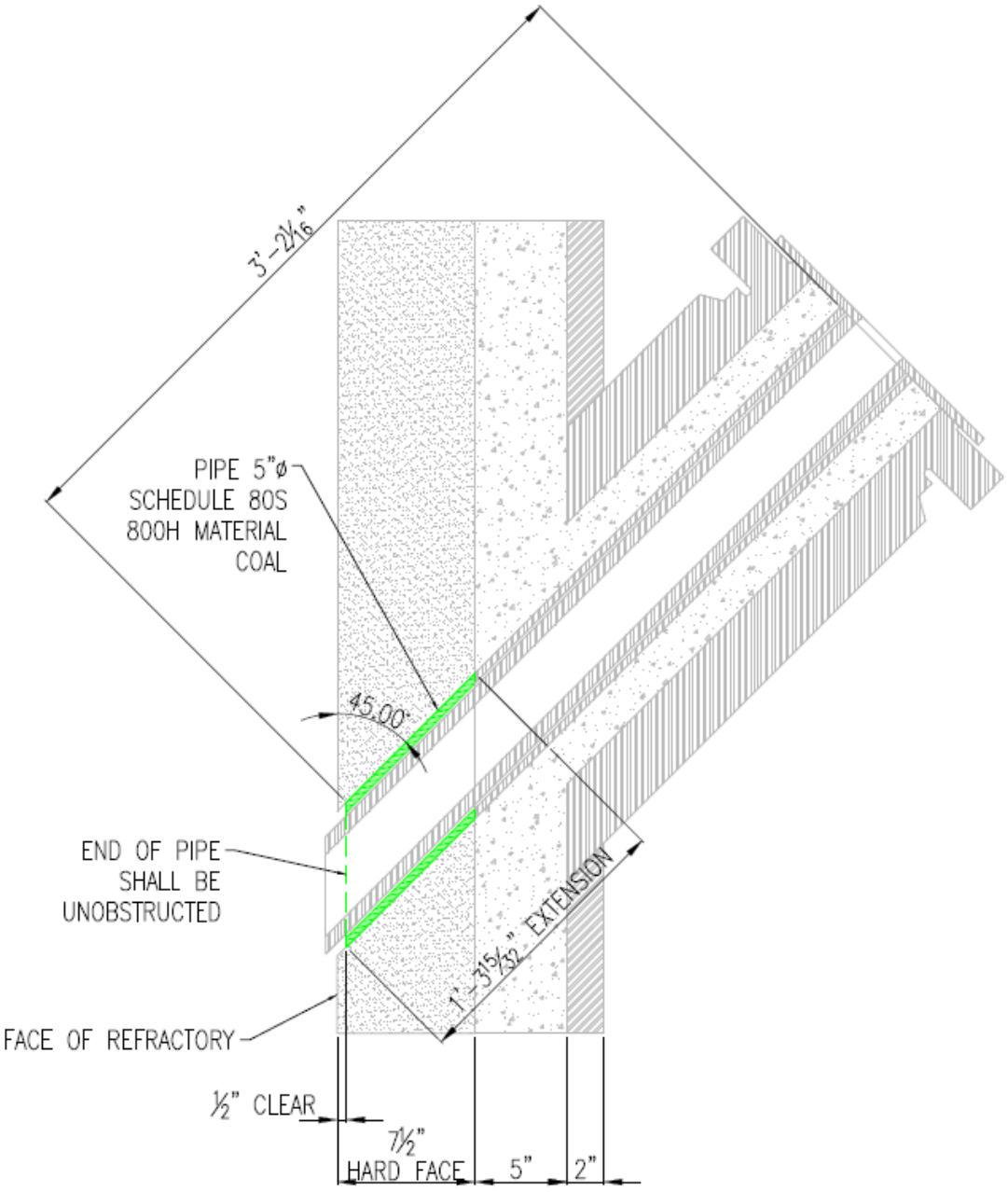

Figure 6.3-1 – Cross-section of gasifier refractory, nozzle penetration, and steel shell. Shows the extended sleeve (green) added as part of the modifications.

The thickness of the backup layer and hard-face layer varies throughout the gasifier depending on the internal atmosphere of the gasifier system. Generally, in straight sections such as the riser and standpipe, the backup layer is 5 in. thick and the hard-face layer is 5-1/2 in. thick. In areas where temperature excursions are expected, such as the mixing zone (MX1002/MX2002), the backup layer varies from 5 to 6-1/2 in. thick. In areas where erosion is more significant, such as the presalter barrel section (CY1002/CY2002), the hard-face layer is 8-1/2 in. thick.

Branch connections and spool piece transition areas can vary more significantly in thickness. The refractory system is designed to thermally expand slightly more than the outer metal shell at operating temperature, which compresses

the refractory, resulting in minimal gaps in the hard-face refractory and exposure of the backup layer to the circulating solids during normal operations.

The gasifier refractory system is designed for specific refractories and installation methods, since final refractory properties can vary based on brands and installation method. The backup layer for the gasifier is Thermal Ceramics Kaolite 2500 LI (low iron) installed by casting with gunning allowed in a few areas. This product is a low-density insulating refractory with a tested thermal resistance within the parameters required for the gasifier. The hard-face layer is Resco 88VC installed by vibracasting. This product is a high-density refractory with erosion resistance required for the gasifier.

A decision was made to address project schedule impacts by using a different material for selected spool pieces. For those pieces, during original refractory installation at the fabricator's shop, Resco Sureflow 17E installed by casting was substituted for the 88VC material. The Sureflow 17E material has similar properties to the 88VC but does not require vibracasting.

The refractory anchor system is designed to hold each layer of refractory in place. Each layer has a dedicated anchor pattern and anchor design. The backup layer's anchor system consists of 310 stainless steel, double hook stud weld anchors, with spacing based on refractory thickness and a layout pattern developed from experience. The hard-face anchor system consists of high temperature alloy threaded studs penetrating the backup layer and high temperature alloy V anchors threaded onto the studs after the backup layer is installed. The hard-face anchor system spacing is based on refractory thickness with a layout pattern based on experience.

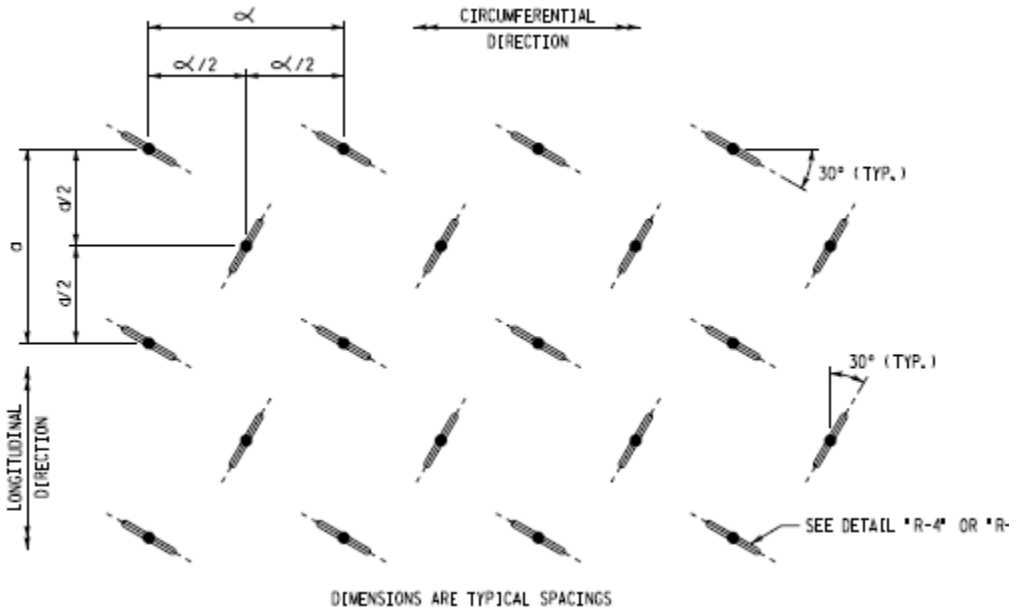

Figure 6.3-2 – Typical gasifier refractory anchor pattern

Figure 6.3-3 – Typical backup layer anchors and hard-face anchor studs welded in place.

The gasifier contains two types of nozzle penetrations depending on the diameter of the penetration. With few exceptions, all nozzles are angled downward regardless of internal gasifier flow direction. Nozzles with flange sizes 2-1/2 in. and smaller consist of long weld-neck flanges welded directly to the steel shell, a pipe extension welded to the internal metal shell and extending through the backup refractory layer, and an insert pipe extending to the internal diameter of the hard-face refractory layer. The insert pipe is connected to an insert plate sandwiched between the inlet flange surfaces. Nozzles larger than 2-1/2 in. flange size consist of an oversized long weld-neck flange with a smaller pipe extension welded to the internal diameter of the weld neck flange and extending through the backup refractory layer, and an insert pipe extending to the internal diameter of the hard-face refractory layer. The insert pipe is connected to an insert plate sandwiched between the inlet flange surfaces.

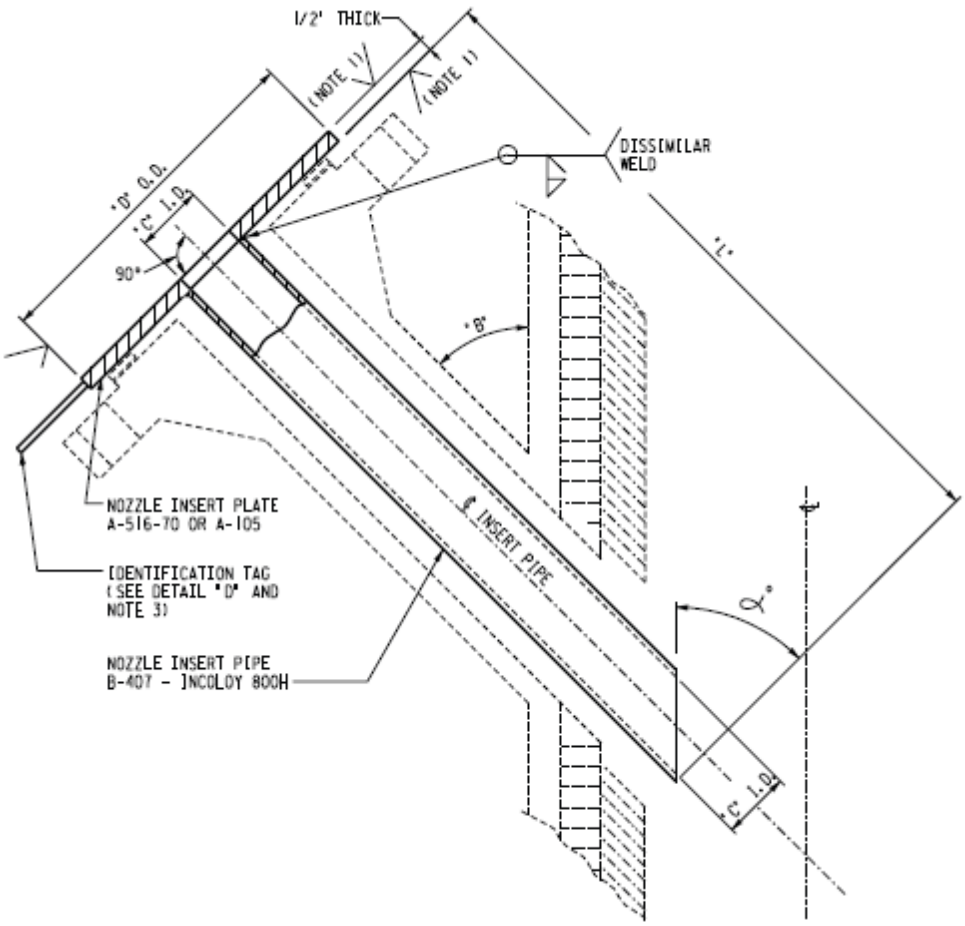

Figure 6.3-4 – Typical 2½-in. and smaller nozzle penetration

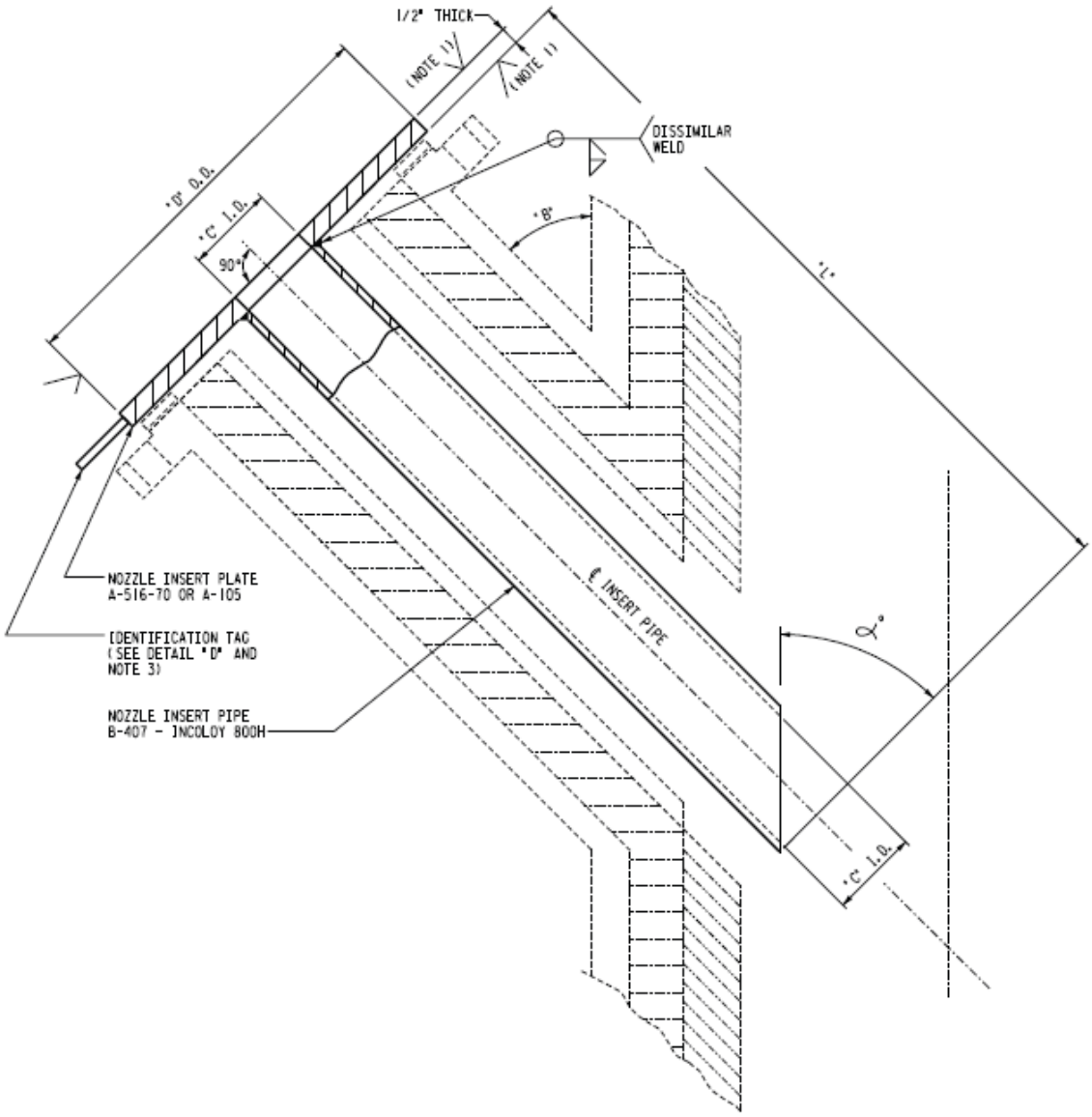

Figure 6.3-5 – Typical 3-in. and larger nozzle penetration

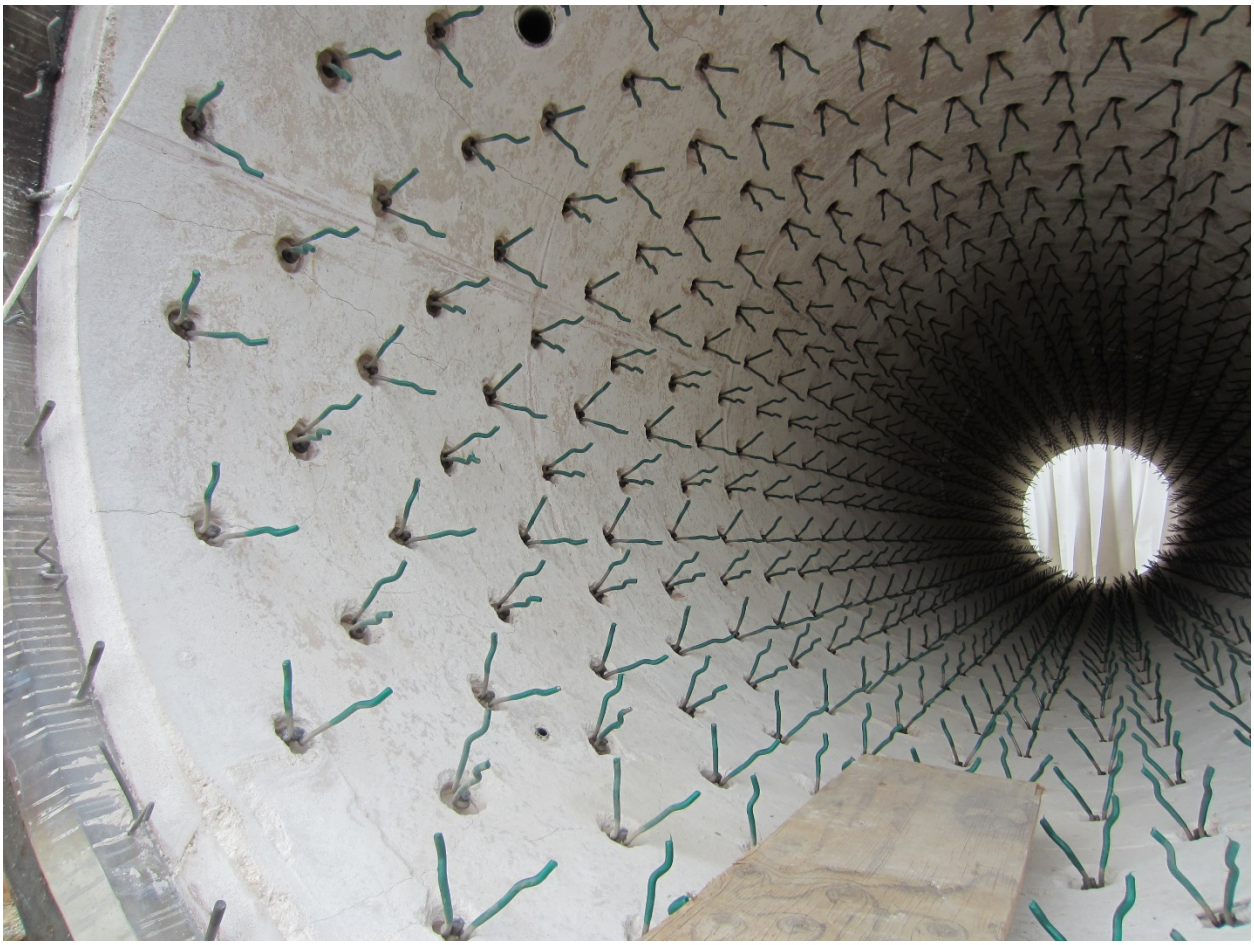

Figure 6.3-6 – Backup layer, dried out and with hard-face anchors installed, ready for hard-face form installation

6.3.3 Initial Commissioning Plan

Initial commissioning plans for the gasifier refractory were to dry the refractory during first heat-up. Most of the refractory was dried out at the shop to 1,800 °F. There were multiple spool piece joints and repair areas dried to 1,000 °F and smaller repair areas that were not dried following installation, which required the first heat-up to be slower and more closely monitored to avoid damaging the refractory.

This was the first time a commercial scale TRIG™ gasifier was heated to full operating temperature, calling for a conservative approach. The objective was to slowly heat the refractory to achieve final refractory properties and to monitor the steel shell temperatures to ensure there was no area of the shell that exceeded the expected maximum temperature. Since the gasifier is a steel loop within another steel loop, the various sections of the gasifier had to be heated evenly to avoid excessive differential expansion between the sections.

The purpose of refractory dry-out is to remove both free water and chemical water from the refractory and to set the refractory properties. Although the gasifier spool pieces were dried out to 1,800 °F at the fabricators' shop, smaller repair areas were not dried out after installation and the larger repair areas and spool piece joints were dried to 1,000 °F. The refractory absorbs ambient moisture, which was of particular concern given the length of time required to complete the gasifier installation. Some areas were further exposed to water from hydrotesting and rain water.

The process of dry-out was to slowly heat the refractory to allow the water to vaporize and migrate through the refractory into the gas flow path. As the refractory heats, it expands circumferentially and longitudinally slightly more than the steel shell, resulting in the refractory being in compression. The slow temperature ramp rate also allows the heat to

penetrate the refractory, minimizing differential temperatures and stress within the thickness of the refractory and allowing the steel shell to heat and expand per design.

6.3.3.1 *Initial Gasifier Heat-up Plan*

The ramps rates were based on the contractor's specifications and API 936 standards (American Petroleum Institute, Refractory Installation Quality Control - Inspection and Testing Monolithic Refractory Linings and Materials). The intent was to heat the gasifier refractory as quickly as possible while considering the long-term viability of the refractory system and control of the gasifier differential leg temperatures. API 936 suggests a 100 °F per hour ramp rate for single layer linings ~ 5 in. thick. Industry in general heats refractory systems between 50 °F and 200 °F per hour, with the higher ramp rates attributed to thinner linings. The Kemper refractory system has a large inner diameter, so a 75 °F per hour ramp rate was implemented.

6.3.3.2 *Initial Heat-up and Cool-down Procedure*

See section 5.4.5.2, Train A gasifier refractory cure-out, for additional information on initial heat-up.

- Establish minimum sand circulation.
- Initiate minimum startup burner (SUB) pilot. HOLD minimum pilot 1 hr at 200 °F at the burner outlet.
- Ramp SUB a maximum of 150 °F per hour at the burner outlet. For subsequent burner or pilot light-offs, HOLD 1 hr per 200 °F temperature increase.
- Using the upper MIX as a control point, heat the MIX at 75 °F per hour until MIX is 850 °F to 950 °F.
- HOLD the MIX at 850 °F to 950 °F for 12 hr.
- Using the upper MIX as the control point and the gasifier outlet as a secondary control point, heat the MIX and gasifier at 50 °F per hour to 1600 °F to 1800 °F.
- Using the gasifier outlet as the control point, HOLD the gasifier temperature at 1600 °F to 1800 °F for 23 hr.
- Using the gasifier outlet as the primary control point and the upper MIX as a secondary control point, cool the gas temperature a maximum of 150 °F per hour to 600 °F.
- After the outlet gas temperature is <600 °F, the unit shall be capped and allowed to cool naturally to <140 °F after which gas may be used to cool the gasifier to ambient.

6.3.4 Refractory Failure in Train A

In mid-November 2015, during the initial heat up of gasifier Train A, a hot spot was identified in the upper mixing zone near the coal and air inlet nozzles. Subsequent inspections revealed significant erosion damage in the backup lining of the refractory and damage to the hard-face layer of the refractory. The damage extended from the upper mixing zone, throughout the J-leg, and to a large section of the standpipe. The backup layer had significant erosion behind the hard-face layer that appeared to be caused by gas flow into a crack or nozzle penetration extending to another crack or penetration downstream of the flow path.

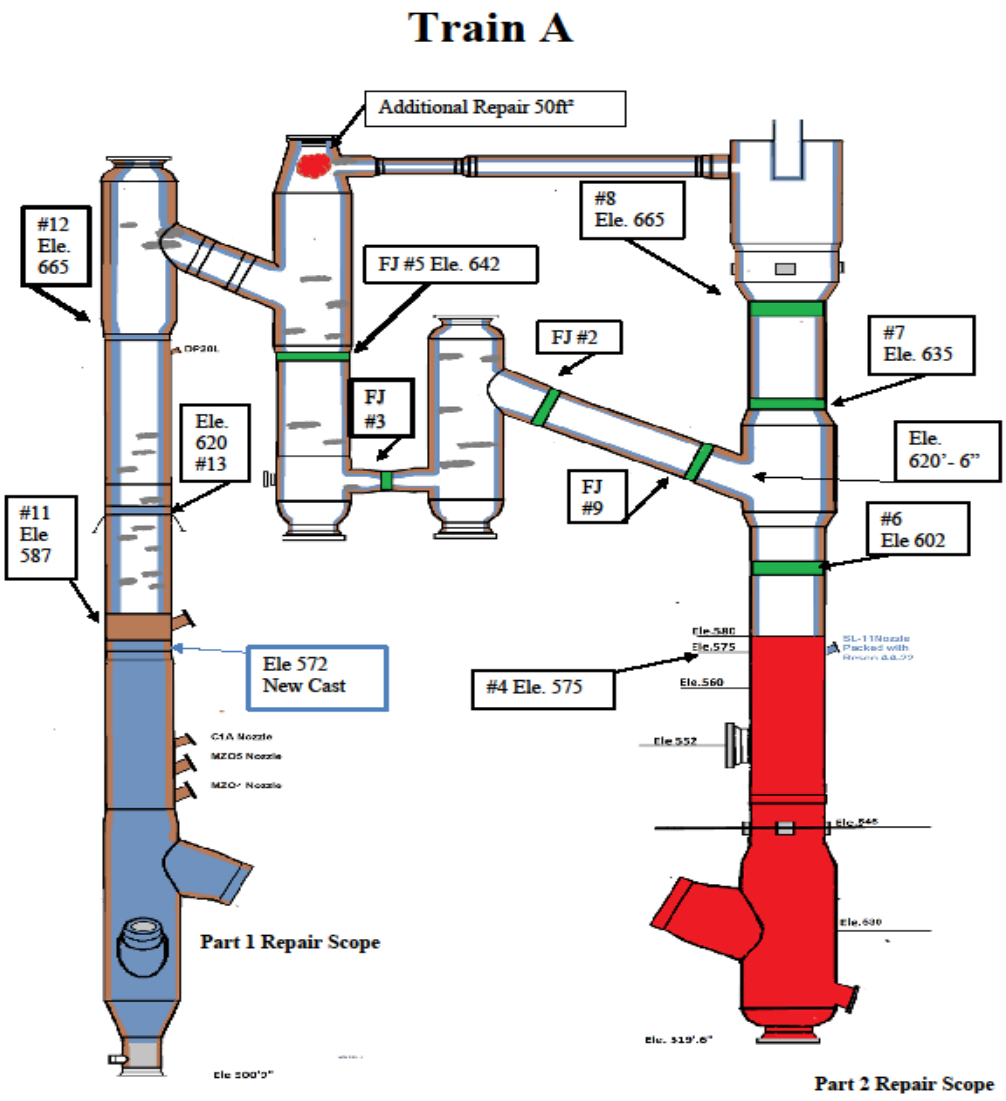

Figure 6.3-7 – Overview of the Train A refractory tear-out and repair scope

The refractory damage was attributed to cracks in the hard-face layer that penetrated to the backup layer, separation of the hard-face layer and backup layer at the interface, and backup layer exposure at the nozzle penetrations. These three mechanisms resulted in flow paths in and around the backup layer for gas and sand during cold sand circulation. High sand circulation resulted in high differential pressure driving gas into these small openings, then flowing into and over the low-density backup layer at high velocities and causing rat-holing and erosion of the backup layer.

Figure 6.3-8 – Example of erosion to the inner diameter of the shell in Train A in upper mixing zone.

Figure 6.3-9 – Example of rat-holing and backup layer erosion. Anchor in upper left is a hard-face anchor.

After the backup layer was substantially eroded away, the hard-face layer had no structural backing and failed structurally. Sand circulation induced significant vibration of the gasifier lower mixing zone and standpipe, which contributed to the hard-face structural failure.

6.3.5 Refractory Failure in Train B

While continuing to evaluate and repair the refractory in Train A, sand circulation and heat-up of Train B proceeded in February 2016. In March 2016, refractory inspection revealed damage in Train B. Although not as extensive as the damage in Train A, the type of damage in Train B was similar, that is, the backup layer refractory eroded and the hard-face was damaged. The refractory damage in Train B was primarily located in the mixing zone and J-leg area with minimal damage in the standpipe. The damage in Train B was attributed to the same causes as Train A, but sand circulation in Train B was not as significant and the refractory damage was not as extensive.

6.3.6 Development of Modified Refractory System

After the hot spot on Train A was confirmed and the gasifier shut down, the project assembled a team of knowledgeable engineers to inspect the refractory and recommend a mitigation strategy. This team included personnel from MPC, Southern Company, the engineering, procurement, and construction (EPC) contractor (that designed the refractory system), an external refractory consultant, and the refractory repair contractor.

Initial inspections were performed within a week of the shutdown. The recommendation was for the refractory contractor to initiate tear-out of the hard-face in the upper mixing zone. As tear-out of the hard-face proceeded, inspections of the backup layer, anchor system, and nozzle penetrations were performed. These inspections provided

the basis of the cause analysis that identified backup layer rat-holing and erosion due to differential pressure driving the gas behind the hard-face layer. The inspections provided evidence of gas entry and exit points within the backup layer and gas flow in the direction of process flow. A substantial number of gas entry and exit points involved nozzle penetrations, and options to minimize these points were identified and evaluated. Multiple options were evaluated for replacement of the refractory in the tear-out areas.

The approach to a mitigation strategy was to focus on long-term operation of the gasifiers. One example of this approach was the addition of a 1-in. veneer layer as an erosion-resistant layer to protect the backup layer. Inspection of the refractory damage showed significant separation of the hard-face layer from the backup layer in multiple areas. This separation provided a path for gas to flow over the backup layer and eroding it. The separation could be minimized using a layer of material that bonded to the backup layer, and this approach was determined to be beneficial to long-term operation of the refractory system. The manufacturer of the Thermbond material was consulted and provided a recommendation for several materials that would be applicable. The refractory repair contractor was commissioned to perform application and erosion testing on these materials. The tests resulted in selection of the Thermbond 2125-G material for the 1-in. veneer layer.

Figure 6.3-10 – Test panel for veneer layer product testing

The nozzle penetrations were a significant contributing factor to gas entry and exit points and backup layer erosion. All nozzles on both gasifiers would require modification to minimize gas intrusion to the backup layer. Engineers from SCS were commissioned to provide designs to modify all the nozzles by extending the sleeves to the hard-face inner diameter (ID) instead of the backup layer ID. Each type of nozzle within the tear-out scope required one design, and each nozzle type outside the tear-out scope required a different design. Each nozzle was evaluated for practical material and installation constraints.

The final mitigation plan addressed all the identified causes and contributing factors to the refractory failure in both gasifier trains. As of the suspension of gasifier operations at Kemper, the evidence suggested the mitigation plan was successful. The mitigation plan also is the basis for the next generation of refractory design for TRIG™ gasifiers.

6.3.7 Implementation of Modified Refractory System

The mitigation plan to address the causes of the refractory failure in Train A was implemented on Train A and Train B between late December 2015 and October 2016. The plan for Train A was different from Train B in some areas due to project efforts to maintain operation commissioning on one unit while the other unit was in repair.

6.3.7.1 *Train A*

The modified refractory system in Train A included changing the backup layer material and installation method, changing the hard-face layer refractory material, adding a 1-in. veneer layer over the backup layer, increasing the anchor thickness in the tear-out area, extending the nozzle sleeves to the internal diameter of the hard-face, and adding a vibration dampening system to the gasifier. The refractory repair plan for gasifier Train A was implemented and the dry-out completed on September 6, 2016.

- Hard-face layer

In the lower riser (RI1002), mixing zone (MX1002) area, and J-leg (JL1002) where the hard-face was removed due to damage, the Resco EZ 60-M HF layer was installed in lieu of the previously specified Resco 88VC or the installed Resco 17E. Due to the EZ 60-M refractory material's higher density, increased erosion resistance, and higher resistance to thermal changes than either the 88VC or 17E materials, the Resco EZ 60-M material was the updated refractory material specified by KBR for future gasifier units. The EZ 60-M refractory was not specified initially for the project due to the completion date of the gasifier's design and the timing of KBR's evaluation of various refractories for this application. In the standpipe area where the hard-face was removed, Spar, Inc. Sparcast 110P w/2% 310SS needles was installed by pump casting. The 110P material is a high-strength, medium-weight, abrasion-resistant castable designed to be installed by pumping. This material was used instead of the EZ 60-M material in the standpipe due to its better thermal resistance and because the standpipe is significantly less susceptible to erosion than the mixing zone.

- Hard-face anchors

Modified hard-face anchors were installed in the tear-out area. These anchors were a larger diameter than originally specified in order to better support the hard-face during cold sand circulation and to minimize broken or bent anchors resulting from initial cold circulation and system vibration.

Figure 6.3-11 – Train A mixing zone backup layer anchors, hot face anchor studs, and three nozzle sleeves extended to ID of hard-face prepped for backup layer gunning. Red color is dye penetrant anchor weld NDE testing stains.

- Backup layer

In areas where the backup layer was removed due to damage, Greenlite 45-L GR material installed by gunning was used instead of Kaolite 2500 LI in the straight sections of the mixing zone and standpipe. The Kaolite 2500LI G material was used in the branch bullnoses and crotches on both ends of the J-leg. These areas required the use of Kaolite 2500 LI G due to shell temperature constraints. Experience showed these areas are susceptible to higher temperatures due to the gasifier configuration and required a higher thermal-resistant material than the 45-L. The 45-L material was used to minimize the erosion of the backup layer in the event the gas and solids found a flow path to the backup layer. The 45-L GR material is a medium-density material that does not have the thermal resistance of the Kaolite 2500 LI material. Analysis determined in the areas where the 45-L GR would be used, the impact on the differential leg temperatures would be minimal. Gunning the backup layer allowed the use of internal nozzle sleeves that extended to the internal diameter of the hard-face layer.

- Veneer layer

In areas where the backup layer was removed due to damage, a 1-in. layer of Thermbond 2125-G was installed by gunning onto the new backup layer after dry-out. Thermbond 2125-G is an erosion-resistant material that chemically bonds to other refractory. Since the backup layer is susceptible to erosion if gas and solids have a flow path to the backup layer, the 2125-G material was installed to minimize the possibility of a gap between erosion-resistant material and the backup layer.

- Backup layer coating

In the lower riser (RI1002), the hard-face layer was removed, and the backup layer repaired. After repair, the backup layer was coated with 1/8-in. thick RENO COAT IN AL. This material is a protective surface treatment coating for refractory. It was used instead of the Thermbond because 1-in. thick Thermbond could not be accommodated. Since the ID of the hard-face layer is a critical process parameter, the original ID of the refractory could not be compromised.

- Nozzle sleeves

All nozzle sleeves in areas where the backup layer was removed due to damage were replaced with sleeves that extended to the ID of the hard-face layer. In areas where the backup layer was not removed, including all areas of both gasifiers whether any refractory damage was evident or not, mitigation strategies were implemented to effectively extend the sleeves to the ID of the hard-face. Extending the sleeves to the ID of the hard-face was crucial to preventing gas and solids from entering the backup layer and eroding it.

Figure 6.3-12 – Train A nozzle sleeve extension to ID of hard-face.

- Vibration dampening system

Vibration of the gasifier system was determined to be a contributing factor in the failure of the hard-face layer. A vibration dampening system was added to the lower area of the gasifiers to minimize gasifier movement as much as possible and reduce adverse impacts on the refractory.

- Cold sand circulation

Cold sand circulation was minimized, and heating of the gasifier began as soon as sand circulation was established. Heating the gasifier and refractory system expands the refractory, causing it to go into compression and closing cracks and many of the openings around the nozzles.

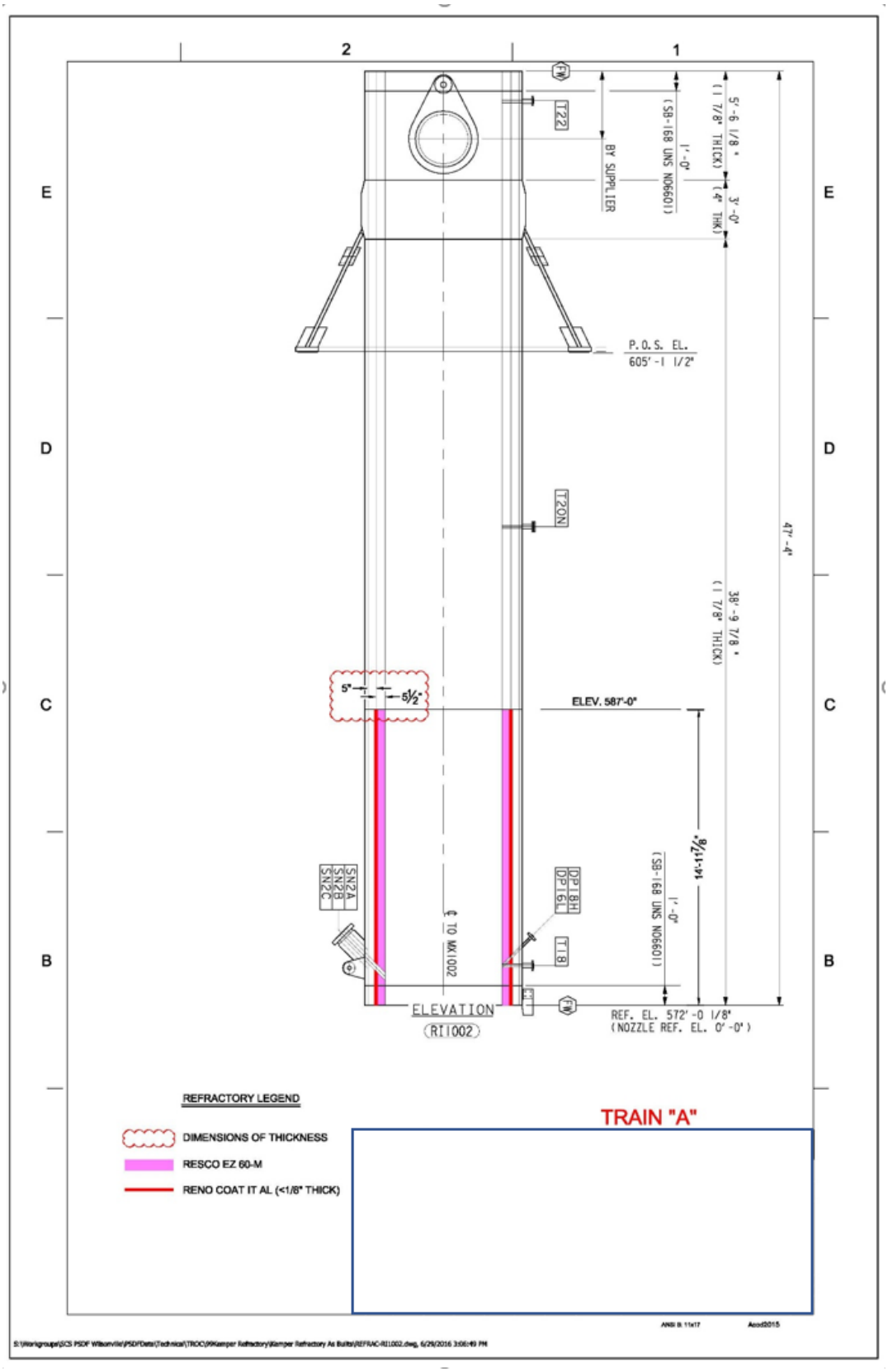

Figure 6.3-13 – Train A riser (RI1002) refractory modification as-built

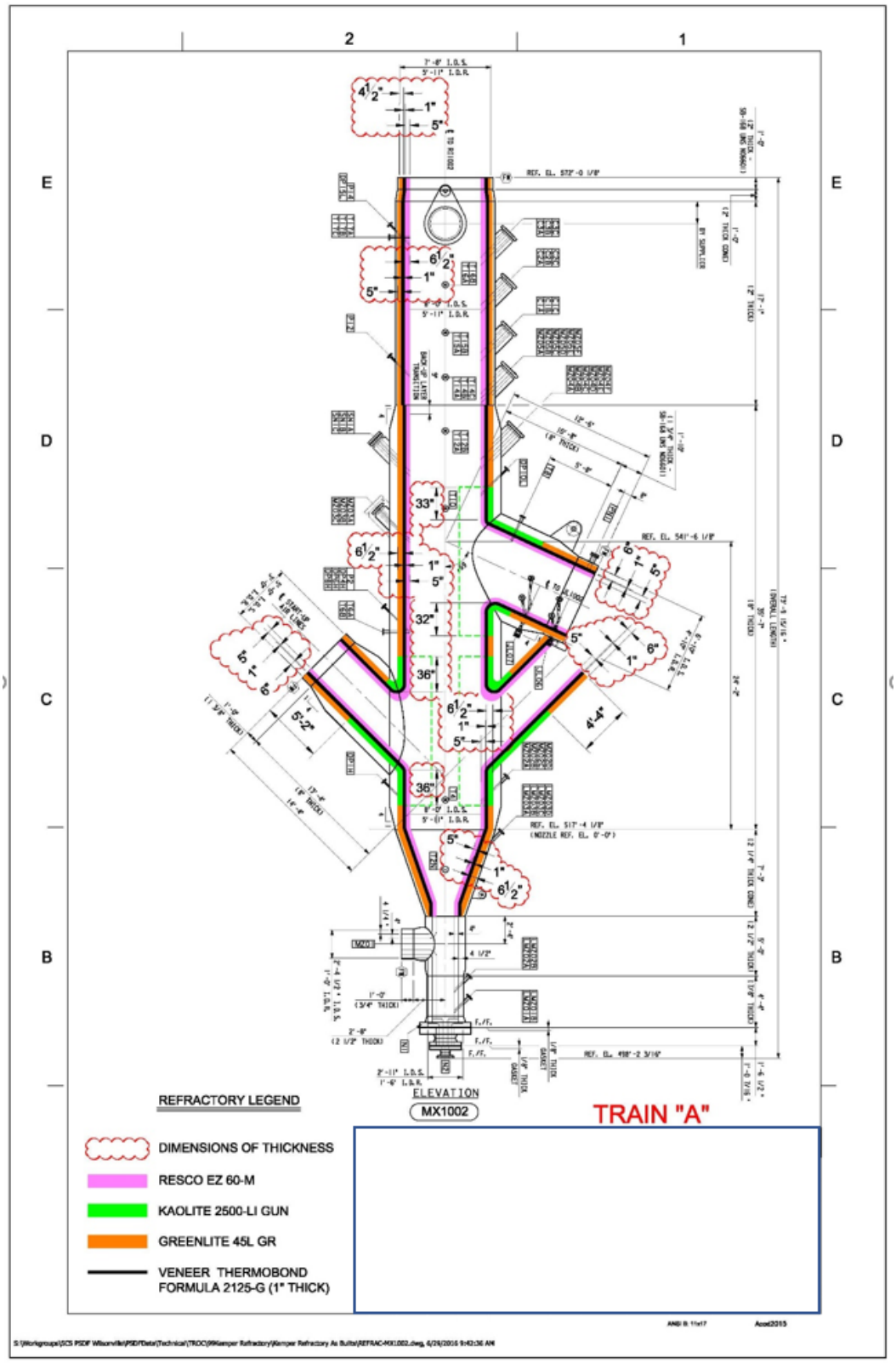

Figure 6.3-14 – Train A mixing zone (MX1002) refractory modification as-built

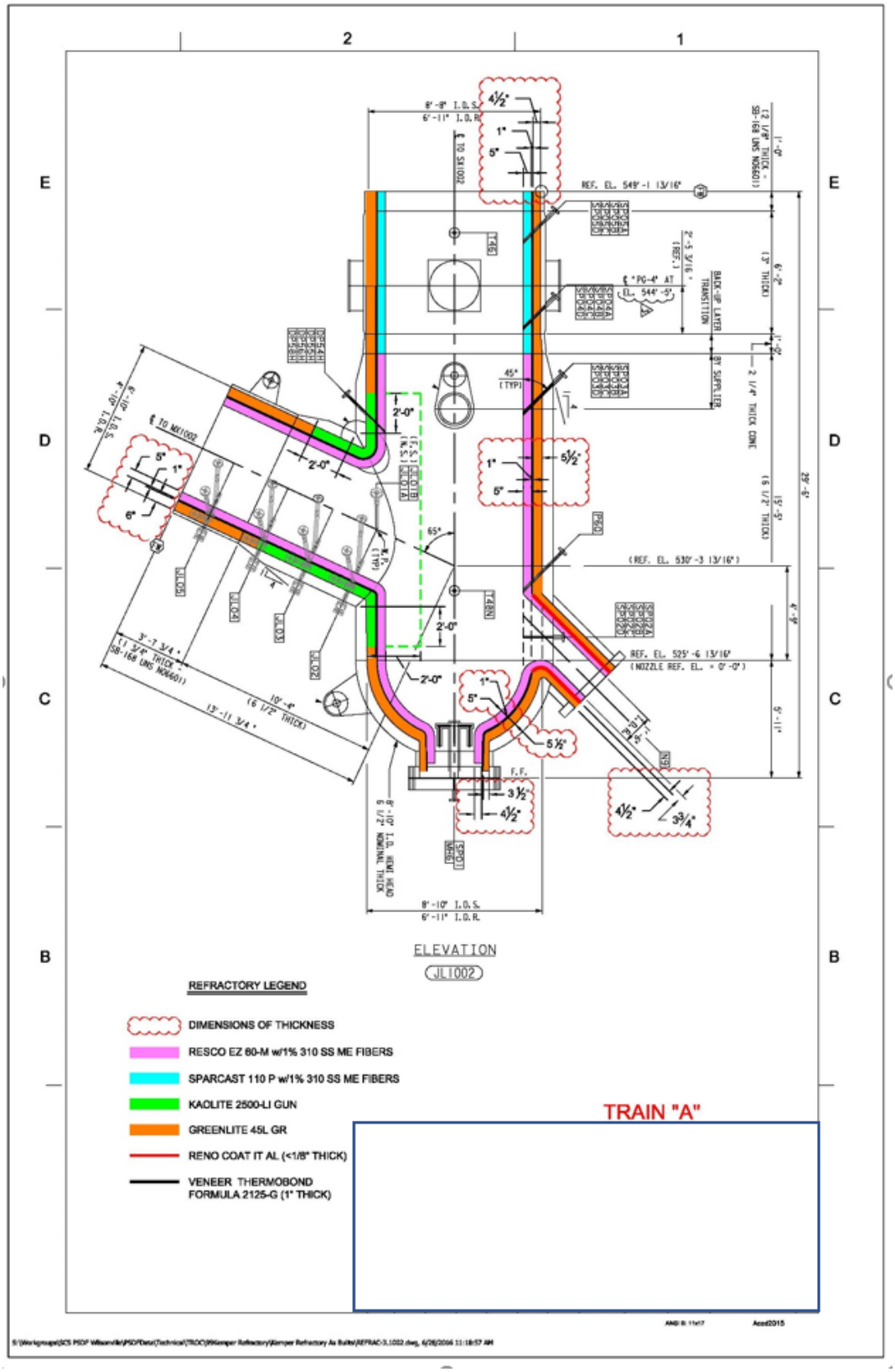

Figure 6.3-15 – Train A J-leg (JL1002) refractory modification as-built

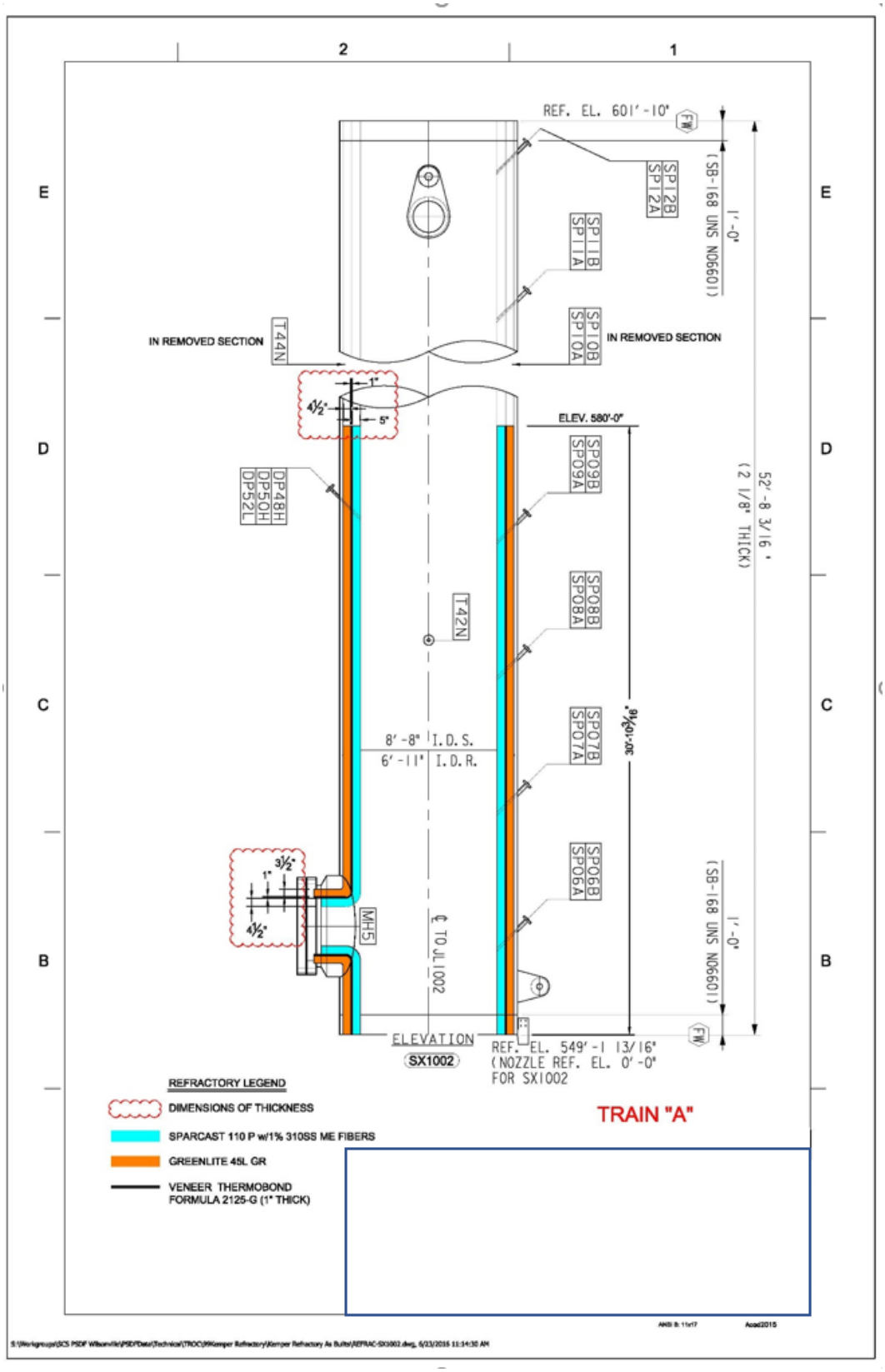

Figure 6.3-16 – Train A standpipe (SX1002) refractory modification as-built

6.3.7.2 *Train B*

The modified refractory system in Train B included repairing the backup layer material in the mixing zone (MX2002), changing the hard-face layer refractory material and installation method, adding a 1-in. veneer layer over the backup layer, extending the nozzle sleeves to the internal diameter of the hard-face, adding a vibration dampening system to the gasifier, and minimizing the cold sand circulation duration. The refractory repair plan for gasifier Train B was implemented and the dry-out completed on July 22, 2016.

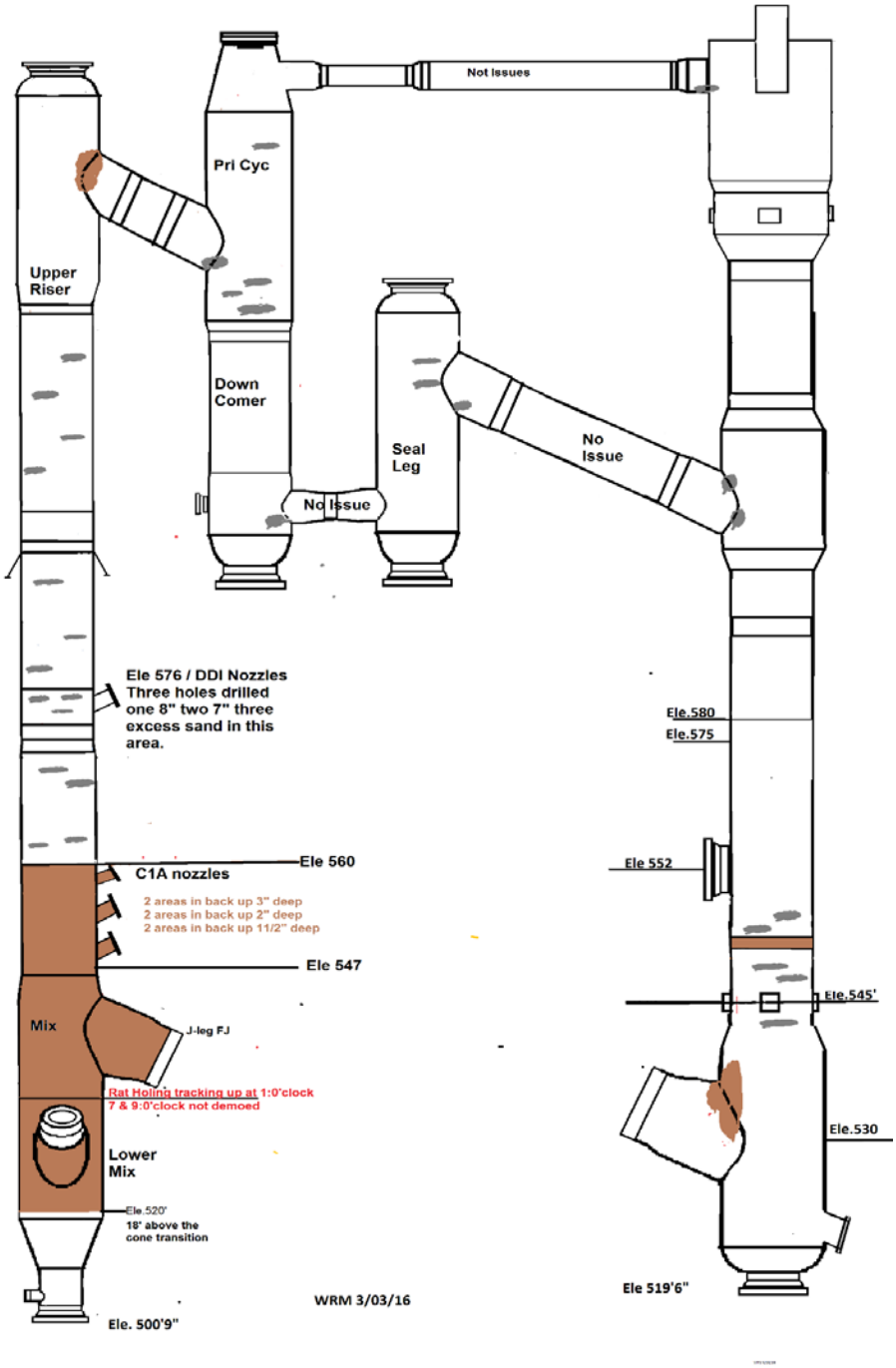

Figure 6.3-17 – Train B hard-face tear-out and replacement scope

- Hard-face layer

In all areas where the hard-face was removed due to damage, Versagun ABR Plus w/2% 310 SS ME fibers was installed by gunning. The Versagun material is a high-density and erosion-resistant material. It was installed instead of the EZ 60-M material due to the time frame required for forming and casting the EZ 60-M in the damaged area. The project determined the Versagun material would allow short-term operation of Train B while Train A was undergoing major refractory repairs.

- Backup layer

The backup layer in Train B was not removed in areas where the hard-face was damaged. The backup layer was repaired with Thermbrake 403 by hand troweling.

- Veneer layer

In areas where the hard-face layer was removed and the backup layer repaired, a 1-in. layer of Thermbond 2125-G was installed by gunning onto the repaired backup layer. Thermbond 2125-G is an erosion-resistant material that chemically bonds to other refractory. Since the backup layer is susceptible to erosion if gas and solids have a flow path to the backup layer, the 2125-G material was installed to minimize the possibility of a gap between the erosion-resistant material and the backup layer.

- Nozzle sleeves

All nozzle sleeves in the Train B gasifier were effectively extended to the hard-face ID whether any refractory damage was evident or not. Extending the sleeves to the ID of the hard-face was crucial to preventing gas and solids from entering the backup layer and eroding it.

- Vibration dampening system

Vibration of the gasifier system was determined to be a contributing factor to failure of the hard-face layer. A vibration dampening system was added to the lower area of the gasifiers to minimize gasifier movement as much as possible to reduce adverse impacts on the refractory.

- Cold sand circulation

Cold sand circulation was minimized, and heating of the gasifier began as soon as sand circulation was established. Heating the gasifier and refractory system expands the refractory, causing it to go into compression and closing cracks and many of the openings around the nozzles.

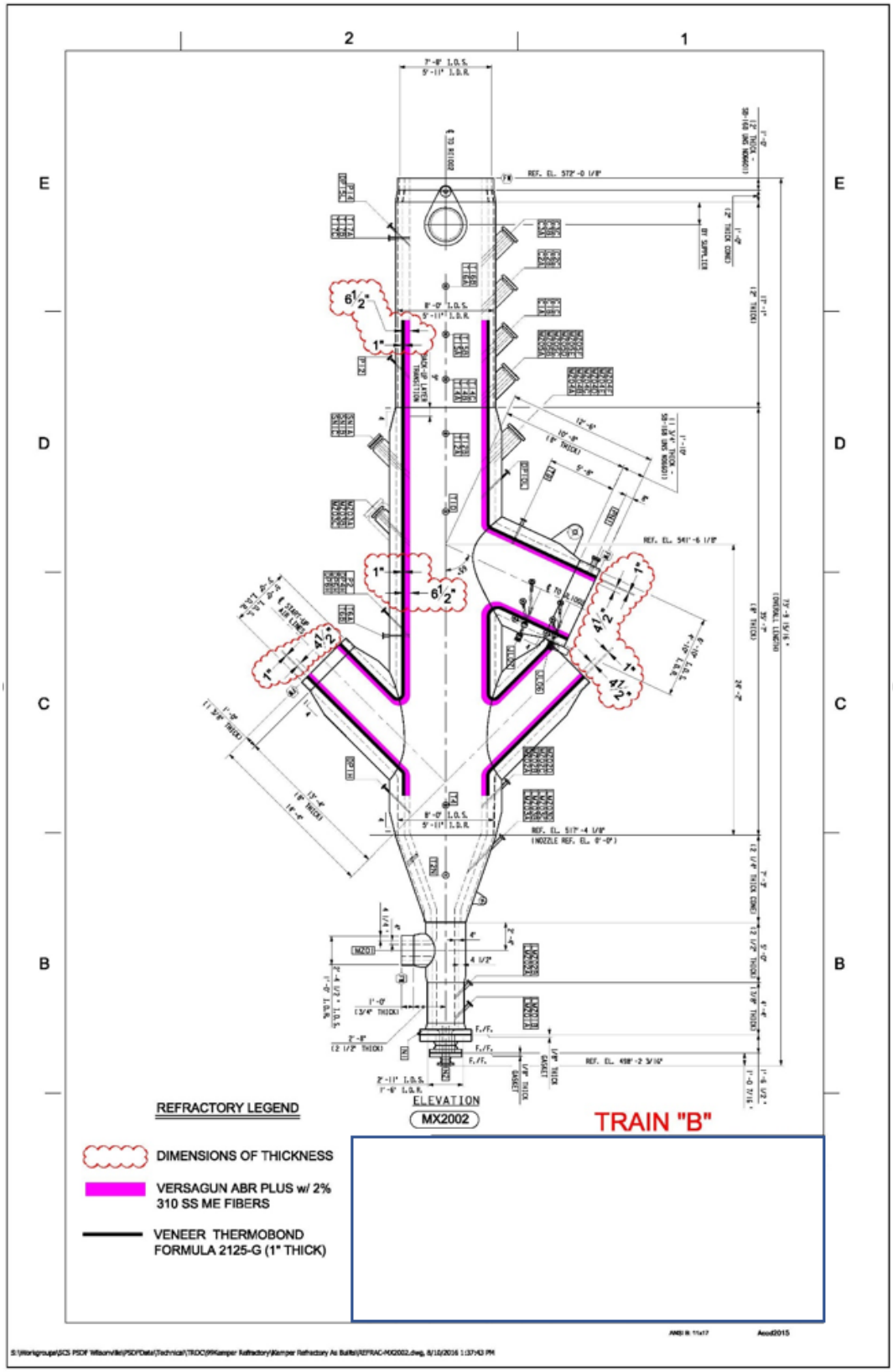

Figure 6.3-18 – Train B mixing zone (MX2002) refractory modification as-built

6.3.8 Final Summary

Operation of the Train A and B gasifiers proceeded after the refractory repairs and nozzle modifications, up to suspension of gasifier operations at Kemper in June 2017. After operation was suspended, limited inspections were undertaken to assess the condition of the refractory in both gasifiers. These inspections consisted of viewing the refractory with flashlights from manways and the lower mixing zone/J-leg area. The inspections showed the modifications were successful, but the bullnoses at angled sections of the gasifier would likely have required repairs or modifications for further operations to continue. Extending the nozzle sleeves to the hard-face ID was likely the most significant factors in allowing continued operation of the gasifiers during this time.

The modified refractory system in Train A did not experience a failure during multiple days of sand circulation and 95 days of coal feed, up to suspending operations in June 2017. After the final shutdown of Train A, the mixing zone area was inspected from the J-leg area and no compromise of the hard-face was observed. The bullnose at the mix and J-leg connection was deteriorated and would have required repairs. The angled bullnoses in the gasifier were a maintenance item at the PSDF gasifier and it appears they would have been high-maintenance items on the larger Kemper gasifiers. A modified bullnose design would probably be required for long-term operation of the larger gasifiers. Refractory in the remaining gasifiers was not inspected in detail, but inspection from available manways showed no indication of the type of damage experienced before the nozzles were modified.

After refractory and nozzle modifications, Train B was operated multiple days on sand circulation and 129 days of coal feed. As of suspension of operation at Kemper, the modified refractory system in Train B did not have hot spots. The mixing zone area hard-face had significant refractory compromise where the Versagun ABR material was installed by gunning for the hard-face. Limited inspection indicated the refractory would likely have to be removed and replaced or undergo significant repair to allow further operation of Train B. The project expected the Versagun ABR material to require significant repair or replacement at this point. The Versagun material allowed the continued commissioning activities of the Train B system while Train A was undergoing the major refractory modifications and repairs, and installation of this material is considered a success.

The refractory compromise in the gasifiers at Kemper is attributed to significant scale-up from the PSDF pilot gasifier and extended cold sand circulation. One scale-up item of note is the difficulty in form placement for casting refractory at the Kemper size (~ 6 ft IDR) versus the PSDF gasifier (~14 in. IDR). The design calls for form placement to be within 1/8 in. circumferentially to avoid backup layer exposure to the process. One way to address this difference is to design all sleeves to extend to the ID of the hard-face and gun the backup layer. This approach would significantly minimize backup layer exposure to the process and subsequent differential pressure driving the gas into the backup and eroding the backup layer. Minimizing cold sand circulation is an operational change that minimizes the time frame for gas to find a path into the backup layer and cause erosion through cracks and other minor openings in the hard-face layer. After the gasifier is heated, these cracks and minor openings close due to compression of the refractory system.

The modified refractory system and nozzle modifications implemented at Kemper were successful. The evidence suggests the gasifiers would have been capable of operating long term with the modified system. Further evaluation and modifications in the areas of the angled bullnoses and possibly the presalter inlet would likely be required for long-term operation, and those areas could be successfully addressed.

6.4 Gasifier Remote Piloted PRV Design Modification

6.4.1 Overview

6.4.1.1 *Background*

Due to fluidized solids that will be in the reactor during normal operation, the Kemper IGCC gasifiers do not have pressure relief valves (PRV) mounted directly on the vessel. To prevent fouling of the PRVs from solids, the gasifier is protected from overpressure by seven different relief valves located on each of the processes feeding the reactor.

The PRVs are pilot operated from a remote sensing line that runs directly off the overhead lines of the gasifier. The PRVs and their services are:

- PRV-14335 Process air header.
- PRV-14328 Process air header.
- PRV-14307 Process air header.
- PRV-14363 Transport air header.
- PRV-14139 High pressure nitrogen.
- PRV-14185 Medium pressure steam.
- PRV-14106 Sour water waste and off-spec ammonia.

Note: Train 2 is identical with the first numeral listed as a "2", for example, PRV-24335.

6.4.1.2 *Pilot Sensing Header Design*

The syngas flow path from the gasifier splits and flows through two 30-in. lines to the syngas coolers. A 2-in. pilot sensing header is connected to these overhead lines and runs throughout the building to the seven PRVs with remote sense pilots. The pilot sensing header is purged with nitrogen from the surge drums through a 7/64-in. diameter orifice plate. This provides a small constant flow of nitrogen into the pilot sensing header. This nitrogen purge flow goes through small diameter nozzle inserts into the syngas process stream. These nozzle inserts maintain a certain velocity of purge flow into the syngas stream to ensure solids in the syngas stream do not migrate into the pilot sensing header. The nitrogen flow rate is relatively low, which allows the pilot sensing header to ride at the same pressure of the gasifier overhead lines.

6.4.1.3 *Startup Issue*

During low pressure commissioning work on the gasifier and process air header, it was noticed that the header would not build any pressure and the air was relieving through the remote sensing PRVs protecting the gasifier. The reason was that the original design used the pressure from the remote sensing header as the driving force ported into the top (dome) of the PRV main valve. The PRVs are located on the process header upstream of the process control valve. During early commissioning activities, it was common to operate the process air header at several hundred psig with minimal pressure on the gasifier. This process resulted in pressure on the inlet of the main valve but no pressure on the charging dome, which keeps the valve closed and results in the main valve opening. The valves of concern are the process air header, transport air header, sour water waste, and steam relief valves (figures 6.6-1 and 6.6-2).

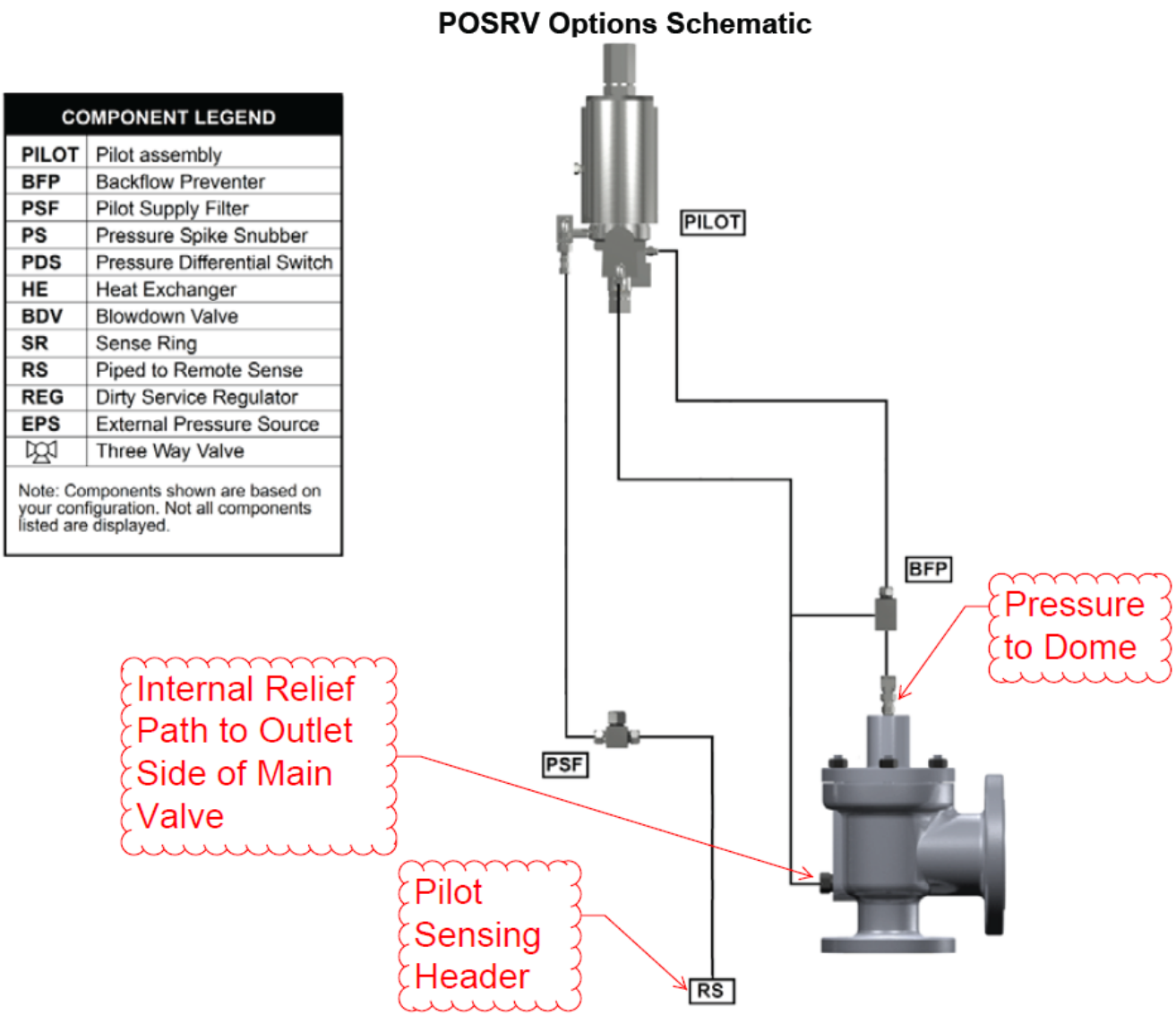

Figure 6.4-1 – Valve schematic

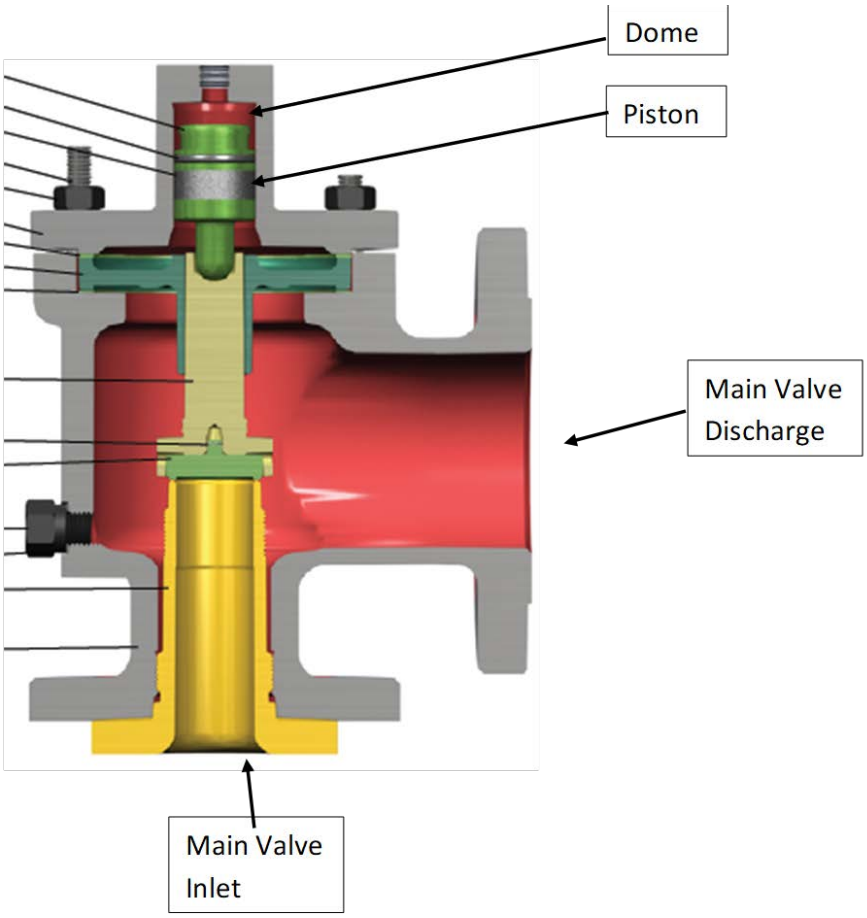

Figure 6.4-2 – Cross section of a PRV main valve

The pilot sensing header rides at the gasifier pressure and feeds this pressure signal to the pilot. If pressure is below the setpoint of the pilot (725 psig), the gas from the sensing head is ported to the dome area on top of the main valve. When the sensing header hits the pilot setpoint, the pilot opens and vents the pressure on the dome to the outlet side of the main valve. This action enables the piston inside the main valve to lift and relieve pressure under the main valve. The dome area on top of the piston is approximately 20% larger than the relief area on the process side under the piston, but this was not enough to keep the piston from lifting.

6.4.2 Long-Term Resolution

The long-term solution was to convert the pilots of these valves to what the supplier refers to as a "dirty pilot" design that uses a separate tap from the process inlet of the PRV main valve as the pressure source to the dome. This pressure source is ported to a lower chamber of the pilot. Some of the relief system process piping had to be modified to weld in a pressure tap on the inlet process piping to the main valve to provide this pressure source. The pilot valve still sensed pressure from the gasifier with the pilot sensing header, but it entered into a separate chamber within the pilot. The two separate chambers of the pilot effectively keep the pilot sensing header gas separate from the process gas source used to control the dome pressure. When the relief pressure of the gasifier of 725 psig is met, the pilot relieves the dome pressure to the outlet of the valve. This action enables the dome pressure to be at the same pressure as that of the inlet to the valve, but the relief signal is still based on the sensing line.

The high-pressure nitrogen PRV-14139 to the gasifier was already set up with this dirty pilot design, since it was well understood early in the design that the nitrogen service pressure would always be substantially above the gasifier at

the lower range of operation. All the other PRVs had to be modified to a dirty pilot design to enable them to stay closed at lower gasifier pressures (figure 6.6-3).

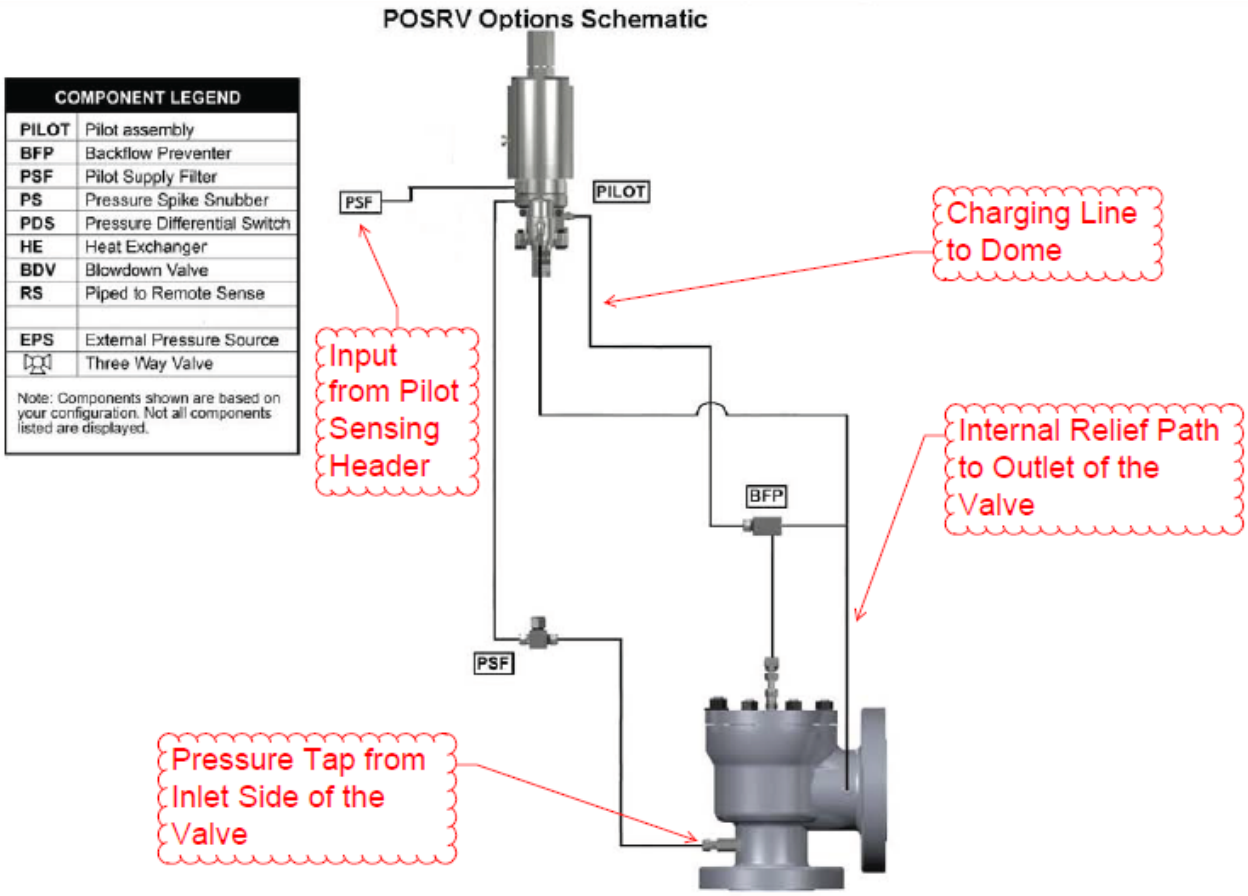

Figure 6.4-3 – Options

6.4.3 Final Summary

After the revised pilot components arrived for the permanent solution, they were installed during gasifier outages. The pilots were replaced without pulling the main valves. They were tested and certified by manufacturer trained technicians. No further issues were reported during startup or operations following installation of the modified configuration.

7.0 SIGNIFICANT FINDINGS AND CONCLUSIONS (LESSONS LEARNED)

A comprehensive discussion on the lessons learned has been developed and is included in the final report.

8.0 ACRONYMS AND ABBREVIATIONS

3D	3 dimensional
ACFM	actual cubic feet per minute
AG	acid gas
AGR	acid gas removal
ANSI	American National Standards Institute
API	American Petroleum Institute
ASHRAE	American Society of Heating Refrigeration Air Conditioning
ASME	American Society of Mechanical Engineers
ASU	air separation unit
BFW	boiler feed water
BFP	boiler feed pump
BHS	bulk handling systems
BOP	balance of plant
BTMP	bored-to-match-the-pipe
BTU	British thermal unit
CAPEX	capital expenditure
CCAD	continuous coarse ash depressurization
CEMS	continuous emissions monitoring system
CFAD	continuous fine ash depressurization system
CFD	computational fluid dynamics
CLCW	closed-loop cooling water
CPP	coupled pressure pulse
CO	carbon monoxide
CO_2	carbon dioxide
COD	commercial operation date
COS	carbonyl sulfide
CTG	combustion turbine generator
CV	flow coefficient
DCS	digital control system
DDI	direct diesel injection
DLN	dry low NOX
DOE	U.S. Department of Energy
DP	differential pressure
E&CS	Southern Company Engineering and Construction Services
EOR	enhanced oil recovery
EPC	engineering, procurement, and construction
ESP	electrostatic precipitator
FAT	factory acceptance test
FEED	front-end engineering design
FCAW	flux core arc welding
FCC	fluidized catalytic cracker
FEA	finite elemental analysis

FOAK	first of a kind
ft	foot/feet
GE	General Electric Company
GI	gasifier island
GPM	gallons per minute
GSU	generator step-up transformer
H_2O_2	hydrogen peroxide
H_2S	hydrogen sulfide
H_2SO_4	sulfuric acid
HGL	high point of ground level
HMI	human machine interfaces
HP	high pressure
hr	hour
HRSG	heat recovery steam generator
HT	Haldor Topsoe
HV	high voltage
Hz	hertz
I&C	E&CS Instrumentation and Controls
IGCC	integrated gasification combined-cycle
IGV	inlet guide vane
IP	intermediate-pressure
IRIS	internal rotary inspection system
IT	Southern Company Information Technology
kacfm	thousands of actual cubic feet per minute
KBR	Kellogg, Brown, and Root
KO	knock out
LCT	load center transformers
LDF	lignite delivery facility
LGL	low point of ground level
LMZ	lower mixing zone
LOTO	lockout/tagout
LP	low-pressure
MCC	motor control center
MOV	motor-operated valve
MP	medium pressure
MPC	Mississippi Power Company
MSDEQ	Mississippi Department of Environmental Quality
MPSC	Mississippi Public Service Commission
MZ	mixing zone
NAC	North American Coal Corp.
N_2	nitrogen
NDE	nondestructive examination
N_2O	nitrous oxide
NOX	nitrogen oxides

NPSH	net positive suction head
NPSHa	net positive suction head absolute
OIS	operating information system
OPEX	operational expenditure
OSHA	U.S. Occupational Safety and Health Administration
PC	pulverized coal
PCD	particulate control device
PDAC	pressure-decoupled advanced coal feeder
PDI	pressure differential indication
P&ID	process and instrumentation diagram
PID	proportional-integral-derivative
PLC	programmable logic controller
PLD	pressure letdown device
PRV	pressure relief valve
PSDF	Southern Company Power Systems Development Facility
PSI	pounds per square inch
PSIG	pounds per square inch gauge
PV	process variable
PWHT	post weld heat treatment
QA	quality assurance
QC	quality control
RTV	room temperature vulcanizing sealant
SAT	station auxiliary transformer
SCR	selective catalytic reduction
SCC	stress corrosion cracking
SCFM	standard cubic feet per minute
SCS	Southern Company Services
SFC	static frequency converter
SH	superheater
SIS	safety instrumented system
SO_2	sulfur dioxide
SO_3	sulfur trioxide
ST	steam turbine
SU&C	E&CS Startup and Commissioning
TECO	Tampa Electric Company
TEG	turbine exhaust gas
TEWAC	totally enclosed water-to-air cooled
TFA	technical field assistance
TOP	turnover package
TP	test package
TSP	tri-sodium phosphate
TSS	total suspended solids
TW	tempered water
TWIPS	turbine water induction protection system
TRIG™	Transport Integrated Gasification™

UOP	Universal Oil Products LLC
VFD	variable frequency drives
W.C.	water column
WGS	water gas shift
WSA	wet gas sulfuric acid
ZLD	zero liquid discharge

ATTACHMENTS

Section 3.3.2 – Turnover Package List

Turnover Code	Description	Equipment No.	Process Area	Class
AG001	Gasifier A - Pressurized Baghouse / Filter Unit 1	FD1104, FL1104, FN1105	GI	Lignite Prep
AG002	Gasifier A - Pressurized Baghouse / Filter Unit 2	FD1204, FL1204, FN1205	GI	Lignite Prep
AG003	Gasifier A - Pressurized Baghouse / Filter Unit 3	FD1304, FL1304, FN1305	GI	Lignite Prep
AG004	Gasifier B - Pressurized Baghouse / Filter Unit 1	FD2104, FL2104, FN2105	GI	Lignite Prep
AG005	Gasifier B - Pressurized Baghouse / Filter Unit 2	FD2204, FL2204, FN2205	GI	Lignite Prep
AG006	Gasifier B - Pressurized Baghouse / Filter Unit 3	FD2304, FL2304, FN2305	GI	Lignite Prep
BF001	Gasifier A - Startup Stack	ST1099	GI	Gasifier Island
BF002	Gasifier B - Startup Stack	ST2099	GI	Gasifier Island
BH001	HRSG A CEMS A		CC	Combined Cycle
BH002	HRSG B CEMS B		CC	Combined Cycle
BH004	Wet Acid Sulfuric - Stack CEMS System		CC	Gasifier Gas Cleanup
CD001	Gasifier A- Lignite Dryer 1	PG1102, HX1101, HX1102	GI	Lignite Prep
CD002	Gasifier A- Lignite Dryer 2	PG1202, HX1201, HX1202	GI	Lignite Prep
CD003	Gasifier A- Lignite Dryer 3	PG1302, HX1301, HX1302	GI	Lignite Prep
CD004	Gasifier A- Lignite Dryer Gas Feed Booster Fan 1	FN1102	GI	Lignite Prep
CD005	Gasifier A- Lignite Dryer Gas Feed Booster Fan 2	FN1202	GI	Lignite Prep
CD006	Gasifier A- Lignite Dryer Gas Feed Booster Fan 3	FN1302	GI	Lignite Prep
CD007	Gasifier A- Lignite Mill 1	FD1126, ML1108, ML1108-PU2	GI	Lignite Prep
CD008	Gasifier A- Lignite Mill 2	FD1226, ML1208, ML1208-PU	GI	Lignite Prep
CD009	Gasifier A- Lignite Mill 3	FD1326, ML1308, ML1308-PU	GI	Lignite Prep
CD010	Gasifier A- Multi-Clone 1	FL1103A, FL1103B, FL1103A-VB1, FL1103A-VB2, FL1103B-VB1, FL1103B-VB2, FL1103A-HX1, FL1103A-HX2, FL1103B-HX1, FL1103B-HX2	GI	Lignite Prep
CD011	Gasifier A- Multi-Clone 2	FL1203A, FL1203B, FL1203A-VB1, FL1203A-VB2, FL1203B-VB1, FL1203B-VB2, FL1203A-HX1, FL1203A-HX2, FL1203B-HX1, FL1203B-HX2	GI	Lignite Prep
CD012	Gasifier A- Multi-Clone 3	FL1303A, FL1303B, FL1303A-VB1, FL1303A-VB2, FL1303B-VB1, FL1303B-VB2, FL1303A-HX1, FL1303A-HX2, FL1303B-HX1, FL1303B-HX2	GI	Lignite Prep
CD013	Gasifier B - Lignite Dryer 1	PG2102, HX2101, HX2102	GI	Lignite Prep
CD014	Gasifier B - Lignite Dryer 2	PG2202, HX2201, HX2202	GI	Lignite Prep
CD015	Gasifier B - Lignite Dryer 3	PG2302, HX2301, HX2302	GI	Lignite Prep
CD016	Gasifier B - Lignite Dryer Gas Feed Booster Fan 1	FN2102	GI	Lignite Prep
CD017	Gasifier B - Lignite Dryer Gas Feed Booster Fan 2	FN2202	GI	Lignite Prep
CD018	Gasifier B - Lignite Dryer Gas Feed Booster Fan 3	FN2302	GI	Lignite Prep
CD019	Gasifier B - Lignite Mill 1	FD2126, ML2108, ML2108-PU	GI	Lignite Prep
CD020	Gasifier B - Lignite Mill 2	FD2226, ML2208, ML2208-PU	GI	Lignite Prep
CD021	Gasifier B - Lignite Mill 3	FD-2326, ML2308, ML2308-PU	GI	Lignite Prep
CD022	Gasifier B - Multi-Clone 1	FL2103A, FL2103B, FL2103A-VB1, FL2103A-VB2, FL2103B-VB1, FL2103B-	GI	Lignite Prep

Turnover Code	Description	Equipment No.	Process Area	Class
		VB2, FL2103A-HX1, FL2103A-HX2, FL2103B-HX1, FL2103B-HX2		
CD023	Gasifier B - Multi-Clone 2	FL2203A, FL2203B, FL2203A-VB1, FL2203A-VB2, FL2203B-VB1, FL2203B-VB2, FL2203A-HX1, FL2203A-HX2, FL2203B-HX1, FL2203B-HX2	GI	Lignite Prep
CD024	Gasifier B - Multi-Clone 3	FL2303A, FL2303B, FL2303A-VB1, FL2303A-VB2, FL2303B-VB1, FL2303B-VB2, FL2303A-HX1, FL2303A-HX2, FL2303B-HX1, FL2303B-HX2	GI	Lignite Prep
CD028	Gasifier - Excess Water Pumps	PU0002A/B, FL0001, DR0004, PU013A/B, FL0001PU, FL0001TK1, FL001A/B/C	GI	Gasifier Island
CD030	Gasifier - HP Make-up Water Pumps	PU0008A/B	GI	Gasifier Island
CD031	Gasifier - Filtrate Drum System	DR0002, FL0005, PU0005A/B	GI	Gasifier Island
CD032	Gasifier A Lignite Mill Feed Fan 1A	FN1106	Solid Fuel	Gasifier Island
CD033	Gasifier A Lignite Mill Feed Fan 1B	FN1206	Solid Fuel	Gasifier Island
CD034	Gasifier A Lignite Mill Feed Fan 1C	FN1306	Solid Fuel	Gasifier Island
CD035	Gasifier B Lignite Mill Feed Fan 2A	FN2106	Solid Fuel	Gasifier Island
CD036	Gasifier B Lignite Mill Feed Fan 2B	FN2206	Solid Fuel	Gasifier Island
CD037	Gasifier B Lignite Mill Feed Fan 2C	FN2306	Solid Fuel	Gasifier Island
CD038	Gasifier - Pyrite Disposal System	FD-0031, FD-0032, FD-0033, FD-0034, FD-0035, SI-0035M, FL-0035, FN-0035	GI	Lignite Prep
CD039	Gasifier - Filter Press Pumps	FL0005A-PU1, FL0005A-PU2, FL0005B-PU1, FL0005B-PU2, FL0005C-PU1, FL0005C-PU2, FL0005-PU1, FL0005-PU2	GI	Lignite Prep
CD040	Gasifier - Filter Press System	FD0028, FL0005TK3, FL0005A, FL0005B, FL0005C, FL0005ATK1, FL0005BTK1, FL0005CTK1, FD0027A, FD0027B, FD0027C, FL0005AHPU1, FL0005BHPU1, FL0005CHPU1	GI	Lignite Prep
CD041	Gasifier - Desuperheater for HX1102	UA-DS-4161	GI	Lignite Prep
CD042	Gasifier - Desuperheater for HX1202	UA-DS-4162	GI	Lignite Prep
CD043	Gasifier - Desuperheater for HX1302	UA-DS-4163	GI	Lignite Prep
CD044	Gasifier - Desuperheater for HX2102	UA-DS-4164	GI	Lignite Prep
CD045	Gasifier - Desuperheater for HX2202	UA-DS-4165	GI	Lignite Prep
CD046	Gasifier - Desuperheater for HX2302	UA-DS-4166	GI	Lignite Prep
CE001	Gasifier A - Feeder / Scale 1	FD1102, ML1107, PG1102-FD1, PG1102-FD2, FD1112, FD1102-SC1	GI	Lignite Prep
CE002	Gasifier A - Feeder / Scale 2	FD1202, ML1207, PG1202-FD1, PG1202-FD2, FD1212, FD1202-SC2	GI	Lignite Prep
CE003	Gasifier A - Feeder / Scale 3	FD1302, ML1307, PG1302-FD1, PG1302-FD2, FD1312, FD1302-SC3	GI	Lignite Prep
CE007	Gasifier A - Fluid Bed Dryer Discharger Feeder 1	FD1108, FD1122, FD1121, PG1102-FD3, PG1102-FD4	GI	Lignite Prep
CE008	Gasifier A - Fluid Bed Dryer Discharger Feeder 2	FD1208, FD1222, FD1221, PG1202-FD3, PG1202-FD6	GI	Lignite Prep
CE009	Gasifier A - Fluid Bed Dryer Discharger Feeder 3	FD1308, FD1322, FD1321, PG1302-FD3, PG1302-FD5	GI	Lignite Prep
CE010	Gasifier B - Feeder / Scale 1	FD2102, ML2107, PG2102-FD1, PG2102-FD2, FD2112, FD2102-SC1	GI	Lignite Prep
CE011	Gasifier B - Feeder / Scale 2	FD2202, ML2207, PG2202-FD1, PG2202-FD2, FD2212, FD2202-SC2	GI	Lignite Prep
CE012	Gasifier B - Feeder / Scale 3	FD2302, ML2307, PG2302-FD1, PG2302-FD2, FD2312, FD2302-SC3	GI	Lignite Prep
CE013	Gasifier B - Fluid Bed Dryer Discharger Feeder 1	FD2108, FD2122, FD2121, PG2102-FD3, PG2102-FD4	GI	Lignite Prep

Turnover Code	Description	Equipment No.	Process Area	Class
CE014	Gasifier B - Fluid Bed Dryer Discharger Feeder 2	FD2208, FD2222, FD2221, PG2202-FD3, PG2202-FD4	GI	Lignite Prep
CE015	Gasifier B - Fluid Bed Dryer Discharger Feeder 3	FD2308, FD2322, FD2321, PG2302-FD3, PG2302-FD5	GI	Lignite Prep
CN001	Cathodic Protection			
DA001	Gasifier A - Venturi Scrubber 1	CL1101A/B/C/D, CL1101DR1, PU1101, HX1104, PU1104	GI	Lignite Prep
DA002	Gasifier A - Venturi Scrubber 2	CL1201A/B/C/D, CL1201DR1, PU1201, HX1204, PU1204	GI	Lignite Prep
DA003	Gasifier A - Venturi Scrubber 3	CL1301A/B/C/D, CL1301DR1, PU1301, HX1304, PU1304	GI	Lignite Prep
DA004	Gasifier B - Venturi Scrubber 1	CL2101A/B/C/D, CL2101DR1, PU2101, HX2104, PU2104	GI	Lignite Prep
DA005	Gasifier B - Venturi Scrubber 2	CL2201A/B/C/D, CL2201DR1, PU2201, HX2204, PU2204	GI	Lignite Prep
DA006	Gasifier B - Venturi Scrubber 3	CL2301A/B/C/D, CL2301DR1, PU2301, HX2304, PU2304	GI	Lignite Prep
DA007	Gasifier - Drum Filter System DR0006	DR0006, MX0006, PU0009	GI	Lignite Prep
DA008	Dust Collector Lignite Silo's	FL0002, FD0005A/B, BL0002, FD0001	GI	Gasifier Island
DA009	Gasifier - Venturi Scrubber Pump 1	FD-0031, FD-0032, FD-0033, FD-0034, FD-0035, SI-0035M, FL-0035, FN-0035, PU0111, PU1101, PU1201	GI	Gasifier Island
DA010	Gasifier - Venturi Scrubber Pump 2	FD-0031, FD-0032, FD-0033, FD-0034, FD-0035, SI-0035M, FL-0035, FN-0035, PU0112, PU1301, PU2101	GI	Gasifier Island
DA011	Gasifier - Venturi Scrubber Pumparound 1	FD-0031, FD-0032, FD-0033, FD-0034, FD-0035, SI-0035M, FL-0035, FN-0035, PU0114, PU1104, PU1204	GI	Gasifier Island
DA012	Gasifier - Venturi Scrubber Pumparound 2	FD-0031, FD-0032, FD-0033, FD-0034, FD-0035, SI-0035M, FL-0035, FN-0035, PU0115, PU1304, PU2104	GI	Gasifier Island
DA013	Gasifier - Venturi Scrubber Pump 3	FD-0031, FD-0032, FD-0033, FD-0034, FD-0035, SI-0035M, FL-0035, FN-0035, PU0113, PU2201, PU2301	GI	Gasifier Island
DA014	Gasifier - Venturi Scrubber Pumparound 3	FD-0031, FD-0032, FD-0033, FD-0034, FD-0035, SI-0035M, FL-0035, FN-0035, PU0116, PU2304, PU2204	GI	Gasifier Island
DB001	Fuel Oil System	DB-PU-4102, DB-PU-4103	GI-BOP	Fuel Oil
DD002	Combustion Turbine A Natural Gas	DD-FL-4145A, DD-FL-4150A, DD-HX-4135A, MD-HT-3140A	CC	Combined Cycle
DD003	Combustion Turbine B Natural Gas	DD-FL-4145B, DD-FL-4150B, DD-HX-4135B, MD-HT-3140B	CC	Combined Cycle
DD004	HRSG A Natural Gas Supply	DD-SN-4301AA, DD-SN-4301AB	CC	Combined Cycle
DD005	HRSG B Natural Gas Supply	DD-SN-4301BA, DD-SN-4301BB	CC	Combined Cycle
DD006	Natural Gas Conditioning Station Filter Separator A & B	DD-SP-4160, DD-SP-4161	OSBL	Natural Gas
DD008	Natural Gas Pipeline / Slug Launcher & Receiver Stations	DD-SX-4155	OSBL	Natural Gas
DD009	Gasifier - Natural Gas Distribution		CC-BOP	Natural Gas
DD010	Combustion Turbine A Syngas Supply		CC	Syngas
DD011	Combustion Turbine B Syngas Supply		CC	Syngas
DF001	Lignite Delivery - Belt Conveyor 004A		Solid Fuel	Lignite Delivery
DF002	Lignite Delivery - Belt Conveyor 004B		Solid Fuel	Lignite Delivery
DF003	Lignite Delivery - Belt Conveyor 005A		Solid Fuel	Lignite Delivery
DF004	Lignite Delivery - Belt Conveyor 005B		Solid Fuel	Lignite Delivery
DF005	Lignite Delivery - Truck Dump FDR 001		Solid Fuel	Lignite Delivery
DF007	Lignite Delivery - Concrete Storage Dome		Solid Fuel	Lignite Delivery

Turnover Code	Description	Equipment No.	Process Area	Class
DF008	Lignite Delivery - Emer. Stockpile FDR 004		Solid Fuel	Lignite Delivery
DF009	Lignite Delivery - Belt Conveyor 008		Solid Fuel	Lignite Delivery
DF010	Lignite Delivery - Belt Conveyor 007		Solid Fuel	Lignite Delivery
DF012	Lignite Delivery - Belt Conveyor 002		Solid Fuel	Lignite Delivery
DF013	Lignite Delivery - Concrete Storage Dome FDR 003		Solid Fuel	Lignite Delivery
DF014	Lignite Delivery - Belt Conveyor 003		Solid Fuel	Lignite Delivery
DF015	Lignite Delivery - Truck Dump		Solid Fuel	Lignite Delivery
DF016	Lignite Delivery - Belt Conveyor 001A		Solid Fuel	Lignite Delivery
DF017	Lignite Delivery - Belt Conveyor 001B		Solid Fuel	Lignite Delivery
DF018	Lignite Delivery - Stacker / Reclaimer		Solid Fuel	Lignite Delivery
DF019	Lignite Handling - Screen Transfer Station		Solid Fuel	Lignite Delivery
DF020	Lignite Handling - (Silo Tripper Belt A) 006A		Solid Fuel	Lignite Delivery
DF021	Lignite Handling - (Silo Tripper Belt B) 006B		Solid Fuel	Lignite Delivery
DF022	Lignite Handling - (Transfer Station 2)		Solid Fuel	Lignite Delivery
DG007	Lignite Delivery - Crusher		Solid Fuel	Lignite Delivery
DH001	Lignite Delivery - Sampling Sys A		Solid Fuel	Lignite Delivery
DH002	Lignite Delivery - Sampling Sys B		Solid Fuel	Lignite Delivery
DK001	Gasifier A - Crushed Lignite Silo 1	FD1119, SL1102	GI	Lignite Prep
DK002	Gasifier A - Crushed Lignite Silo 2	FD1219, SL1202	GI	Lignite Prep
DK003	Gasifier A - Crushed Lignite Silo 3	FD1319, SL1302	GI	Lignite Prep
DK004	Gasifier B - Crushed Lignite Silo 1	FD2119, SL2102	GI	Lignite Prep
DK005	Gasifier B - Crushed Lignite Silo 2	FD2219, SL2202	GI	Lignite Prep
DK006	Gasifier B - Crushed Lignite Silo 3	FD2319, SL2302	GI	Lignite Prep
EA001	Combustion Turbine A Generator		CC	Combined Cycle
EA002	Combustion Turbine B Generator		CC	Combined Cycle
EA003	Steam Turbine Generator	EF-GE-4003	CC	Combined Cycle
EB001	Combustion Turbine A Excitation Sys		CC	Combined Cycle
EB002	Combustion Turbine B Excitation Sys		CC	Combined Cycle
EB003	Steam Turbine Excitation System		CC	Combined Cycle
EC001	Steam Turbine Generator Seal Oil System		CC	Combined Cycle
ED001	Combustion Turbine A ISO Phase Bus		CC	Combined Cycle
ED002	Combustion Turbine B ISO Phase Bus		CC	Combined Cycle
ED003	Steam Turbine ISO Phase Bus		CC	Combined Cycle
EF003	Steam Turbine Hydrogen Cooling	EF-TK-4001, EF-GE-4003, EF-GE-4007	CC	Combined Cycle
EF004	Steam Turbine Carbon Dioxide Sys		CC	Combined Cycle
FB001	Steam Turbine - Intermediate Pressure Steam		CC	Combined Cycle
FD001	Steam Turbine Control Oil Sys		CC	Oil System
FE001	Steam Turbine - Seal Steam		CC	Combined Cycle
FF001	Steam Turbine Lube Oil Sys	FD-TK-3001, FD-PU-3001A / B	CC	Oil System
FH001	Steam Turbine Turning Gear		CC	Combined Cycle

Turnover Code	Description	Equipment No.	Process Area	Class
FQ001	Steam Turbine Condenser Vacuum Sys	LJ-SD-3009, LJ-SD-3010	CC	Combined Cycle
FY001	Steam Turbine	FA-TU-3001, FB-TU-3001, FC-TU-3001	CC	Combined Cycle
GA001	Unit 1 230KV XFMR A1	GE-TRBZ-7101	Transmission	Transmission
GA002	Unit 1 230KV XFMR A2	GE-TRBZ-7102	Transmission	Transmission
GA003	Unit 1 230KV XFMR B1	GE-TRBZ-7201	Transmission	Transmission
GA004	Unit 1 230KV XFMR B2	GE-TRBZ-7202	Transmission	Transmission
GA005	Unit 1 230KV XFMR C1	GE-TRBZ-7301	Transmission	Transmission
GA006	Unit 1 230KV XFMR C2	GE-TRBZ-7302	Transmission	Transmission
GA007	Combustion Turbine A GSU	GA-TRBS-7001	CC	Combined Cycle
GA008	Combustion Turbine B GSU	GA-TRBS-7002	CC	Combined Cycle
GA009	Steam Turbine GSU	GA-TRBS-7003	CC	Combined Cycle
HB001	Combined Cycle Make-up Water		CC	Make-up Water
HC001	Combined Cycle Cooling Tower Chemical Feed Systems		CC	Chemical Feed
HC002	Gasifier Island Cooling Tower Chemical Feed Systems		GI	Chemical Feed
HD001	Combined Cycle Circulating Water System	HE-PU-6035, HE-PU-6036	CC	Circulating Water
HD002	Gasifier Island Circulating Water System	HE-PU-6025, HE-PU-6026	GI	Circulating Water
HD003	Gasifier Island Auxiliary Circulating Water Sys	HE-PU-6027, HE-PU-6028	GI	Aux Circulating Water
HE001	Combined Cycle Auxiliary Circulating Water Sys	HE-PU-6030, HE-PU-6031	CC	Aux Circulating Water
HE002	Combined Cycle Closed Loop Cooling Water Sys - CT Train A	MA-HX-6040A, MA-HX-6041A, MA-HX-6042A, VB-HX-6025A, VG-HX-6023A, VG-HX-6024A	CC	Closed Loop
HE003	Combined Cycle Closed Loop Cooling Water Sys - CT Train B	MA-HX-6040B, MA-HX-6041B, MA-HX-6042B, VB-HX-6025B, VG-HX-6023B, VG-HX-6024B	CC	Closed Loop
HE004	Combined Cycle Closed Loop Cooling Water Sys - Steam Turbine	FA-HX-6003, FA-HX-6004, FA-HX-6005, FA-HX-6006, FA-LO-6001, SA-CO-1001, SA-CO-1002, SA-CO-1003, SA-CO-1004, SA-CO-1006, HE-HX-6004, HE-HX-6005, HE-HX-6006, HE-ED-6121	CC	Closed Loop
HE005	Gasifier Island Closed Loop Cooling Water Sys	HE-TK-6011, HE-PU-6034, HE-PU-6032, HE-HX-6001, HE-HX-6002, HE-HX-6003, HE-HX-6045, HE-HX-6046, HE-HX-6047	GI	Closed Loop
HE006	Gasifier Island Closed Loop Cooling Water Sys	HX0046, HX0054, HX0051, HX0076	GI	Closed Loop
HE007	Gasifier Island Closed Loop Cooling Water Sys	HX2066, HX2064, HX2062, HX2085, HX2086, HX2080	GI	Closed Loop
HE008	Gasifier Island Closed Loop Cooling Water Sys	CO2080, CO2080MO, CO2080LO	GI	Closed Loop
HE009	Gasifier Island Closed Loop Cooling Water Sys	HX0003, HX0096, PG0097	GI	Closed Loop
HE010	Gasifier Island Closed Loop Cooling Water Sys	HX2025, CO1005LO, HX1006, HX1026, CO2005LO, HX2006, HX2006, HX2026, HX0040, CO0041	GI	Closed Loop
HE013	Gasifier Island Closed Loop Cooling Water Sys	CO1004, CO1004LO, CO1004M, HX1019, CO2004, CO2004LO, CO2004M, HX2019, HX1032, CO1008LO, HX2032, CO2008LO, CO1102, CO1102M, CO1102LO, CO1202, CO1202M, CO1202LO, CO2102, CO2102M, CO2102LO, CO2202, CO2202M, CO2202LO	GI	Closed Loop
HE014	Gasifier Island Closed Loop Cooling Water Sys	PG0061	GI	Closed Loop
HE015	Service Water - CO2 Area		GI	Service Water
HE017	Service Water - Gasifier A Structure		GI	Service Water

Turnover Code	Description	Equipment No.	Process Area	Class
HE018	Service Water - Gasifier B Structure		GI	Service Water
HE019	Service Water - Gasifier Waste Water Treatment Area		GI	Service Water
HE020	Service Water - Gasifier Gas Cleanup Area		GI	Service Water
HE023	Service Water - Process Compressors Area		GI	Service Water
HE024	Service Water - Sulfuric Acid Area		GI	Service Water
HE025	Service Water - Water Treatment Area		CC	Service Water
HE027	Gasifier Island Closed Loop Cooling Water Sys	CO1080, CO1080M, CO1080LO, PG1080	GI	Closed Loop
HE028	Gasifier Island Closed Loop Cooling Water Sys	HX1066, HX1064, HX1062	GI	Closed Loop
HE029	Gasifier Island Closed Loop Cooling Water Sys	HX1025	GI	Closed Loop
HE030	CC Closed Loop Cooling Water Pumps		CC	Closed Loop
HK001	Combined Cycle Cooling Tower	HK-CL-6011, HK-CL-6012, HK-CL-6013, HK-CL-6014, HK-CL-6015, HK-CL-6016, HK-CL-6016, HK-CL-6017, HK-CL-6018, HK-CL-6019	CC	Cooling
HK002	Gasifier Island Cooling Tower	HK-CL-6001, HK-CL-6002, HK-CL-6003, HK-CL-6004, HK-CL-6005, HK-CL-6006, HK-CL-6006, HK-CL-6007, HK-CL-6008, HK-CL-6009, HK-CL-6010	GI	Cooling
HT006	Process Heat Trace -Air Test A-Gas Cleanup			
HT008	Process Heat Trace -Air Test B-Gas Cleanup			
HT011	Process Heat Trace-Fluidization Trial A-Gasifier			
HT016	Process Heat Trace-AGR Commissioning A-Gas Cleanup			
HT020	Process Heat Trace-First Syngas Production A-Gas Cleanup			
HT029	Process Heat Trace-Combustion Turbine A			
HT030	Process Heat Trace-Combustion Turbine B			
HT031	Freeze Protection Heat Trace - Gasifier Water Treatment Area			
HT032	Freeze Protection Heat Trace -Gasifier 50WT% Caustic Storage			
HT033	Freeze Protection Heat Trace - Gasifier A, Gasifier Potable and Service Water Systems			
HT036	Freeze Protection Heat Trace - Gasifier A Gas Cleanup Area			
HT037	Freeze Protection Heat Trace - Gasifier B Gas Cleanup Area			
HT039	Freeze Protection Heat Trace - Gasifier B			
HT043	Freeze Protection Heat Trace -Gasifier A AGR			
HT044	Freeze Protection Heat Trace -Gasifier B AGR			
HT045	Freeze Protection Heat Trace -Air Compressor Area			
HT050	GI Instrument Enclosure Heat Trace 2			
HT051	Train 1 Sample Station Heat Trace			
HT052	GI Instrument Enclosures Heat Trace 1			
HT053	GCU Instrument Enclosures Heat Trace 1			
HT054	GCU Instrument Enclosures Heat Trace 2			
HT055	Train 2 Sample Station Heat Trace			
HT056	Heat Trace 180 Area - Added Scope			
HT057	Heat Trace 210 Area - Added Scope			

Turnover Code	Description	Equipment No.	Process Area	Class
HT058	Heat Trace 130/230 Area - Added Scope			
JL001	HRSG A Pegging Steam		GI	Combined Cycle
JL002	HRSG B Pegging Steam		GI	Combined Cycle
KD001	13.8 KV Bus A1- Gasifier	KD-SGHA-7100	GI	Main Electrical Bldg.
KD002	13.8 KV Bus A2 - Gasifier	KD-SGHA-7200	GI	Main Electrical Bldg.
KD003	13.8 KV Bus B1- Gasifier	KD-SGHB-7100	GI	Main Electrical Bldg.
KD004	13.8 KV Bus B2 - Gasifier	KD-SGHB-7200	GI	Main Electrical Bldg.
KD005	13.8 KV Bus C1 - Combined Cycle	KD-SGHC-7100	CC	Main Electrical Bldg.
KD006	13.8 KV Bus C2 - Combined Cycle	KD-SGHC-7200	CC	Main Electrical Bldg.
KD007	4.16KV Bus A1 - Gasifier	KD-SGJA-7100	GI	Main Electrical Bldg.
KD008	4.16KV Bus A2 - Gasifier	KD-SGJA-7200	GI	Main Electrical Bldg.
KD009	4.16KV Bus A3 - Gasifier	KD-SGJA-7300	GI	Gasifier Island MCC Bldg #1
KD010	4.16KV Bus A4 - Gasifier	KD-SGJA-7400	GI	Gasifier Island MCC Bldg #2
KD011	4.16KV Bus B1 - Gasifier	KD-SGJB-7100	GI	Main Electrical Bldg.
KD012	4.16KV Bus B2 - Gasifier	KD-SGJB-7200	GI	Main Electrical Bldg.
KD013	4.16KV Bus B3 - Gasifier	KD-SGJB-7300	GI	Gasifier Island MCC Bldg #1
KD014	4.16KV Bus B4 - Gasifier	KD-SGJB-7400	GI	Gasifier Island MCC Bldg #2
KD015	4.16KV Bus C1 - Combined Cycle	KD-SGJC-7100	CC	Main Electrical Bldg.
KD016	4.16KV Bus C2 - Combined Cycle	KD-SGJC-7200	CC	Main Electrical Bldg.
KD017	13.8KV Bus S1	KD-SGHS-7100	GI	Main Electrical Bldg.
KD018	13.8KV Bus S2	KD-SGHS-7200	GI	Main Electrical Bldg.
KD019	480V MCC C1C - Auxiliary Boiler	KD-MCMC-7100C	AUX	Aux Boiler
KD020	480V MCC A1AA - BOP - Combined Cycle Elect Bldg	KD-MCMA-7100AA	CC-BOP	Combined Cycle
KD021	480V MCC A - CT A - Combined Cycle Elect Bldg	1BF	CC	Combined Cycle
KD022	480V MCC A - CT B - Combined Cycle Elect Bldg	2BF	CC	Combined Cycle
KD023	480V MCC A1A - Gas Cleanup	KD-MCMA-7100A	GI	Gasifier Gas Cleanup Elect Bldg.
KD024	480V MCC A1B - Compressor Area	KD-MCMA-7100B	GI	Main Electrical Bldg.
KD025	480V MCC A2A - SELEXOL Area	KD-MCMA-7200A	GI	SELEXOL Area Electrical Bldg.
KD026	480V MCC A3A - Gasifier A	KD-MCMA-7300A	GI	Gasifier Island MCC Bldg #1
KD027	480V MCC A4A - Gasifier A	KD-MCMA-7400A	GI	Gasifier Island MCC Bldg #1
KD028	480V MCC B1BB - BOP - Combined Cycle Elect Bldg	KD-MCMB-7100BB	CC-BOP	Combined Cycle
KD029	480V MCC B1A - Gas Cleanup	KD-MCMB-7100A	GI	Gasifier Gas Cleanup Elect Bldg.
KD030	480V MCC B1B - Compressor Area	KD-MCMB-7100B	GI	Main Electrical Bldg.
KD031	480V MCC B2A - SELEXOL	KD-MCMB-7200A	GI	SELEXOL Area Electrical Bldg.
KD032	480V MCC B3A - Gasifier B	KD-MCMB-7300A	GI	Gasifier Island MCC Bldg #2
KD033	480V MCC B4A - Gasifier B	KD-MCMB-7400A	GI	Gasifier Island MCC Bldg #2
KD034	480V MCC A1AC - HRSG A PEECC Bldg	KD-MCMA-7100AC	CC	Combined Cycle

Turnover Code	Description	Equipment No.	Process Area	Class
KD035	480V MCC C1A - Gasifier Cooling Tower	KD-MCMC-7100A	GI	Gasifier Island PEECC
KD036	480V MCC C1B - Combined Cycle Cooling Tower	KD-MCMC-7100B	CC	Combined Cycle PEECC
KD037	480V XFMR C1H - Admin / WHSE / Elec. Shop	KD-TRJM-7318	GI	Admin / WHSE / Elec. Shop
KD038	480V MCC C1E - WSA Area	KD-MCMC-7100E	GI	WSA Electrical Bldg.
KD039	480V MCC C1F- CO2/NIT Area	KD-MCMC-7100F	GI	CO2 / Nitrogen Electrical Bldg.
KD040	480V MCC C1G - Flare Elec Bldg Areas 190/210	KD-MCMC-7100G	GI	Flare Elec Bldg Areas 190/210
KD041	4160V SWGR Bus A - Water Treatment		CC-BOP	Waste Water
KD042	480V MCC C2A - Gasifier Cooling Tower	KD-MCMC-7200A	GI	Gasifier Island PEECC
KD043	480V MCC C2B - Combined Cycle Cooling Tower	KD-MCMC-7200B	CC	Combined Cycle PEECC
KD044	4160V SWGR BUS B - Water Treatment	KD-SGJB-6001	CC-BOP	Water Treatment
KD045	480V MCC C2E - WSA Area	KD-MCMC-7200E	GI	WSA Electrical Bldg.
KD046	480V MCC C2F- CO2/NIT Area	KD-MCMC-7200F	GI	CO2 / Nitrogen Electrical Bldg.
KD047	480V MCC C2G - Flare Elec Bldg Areas 190/210	KD-MCMC-7200G	GI	Flare Elec Bldg Areas 190/210
KD049	480V MCC B1BD - HRSG B PEECC Bldg	KD-MCMA-7100BD	CC	Combined Cycle
KD050	480V SWGR Bus A - Combined Cycle	KD-SGMA-7000	CC	Combined Cycle
KD051	480V SWGR Bus B - Combined Cycle	KD-SGMB-7000	CC	Combined Cycle
KD052	13.8 KV Swgr 1A Lignite Delivery		Solid Fuel	Lignite Delivery
KD053	13.8 KV Swgr 1B Lignite Delivery		Solid Fuel	Lignite Delivery
KD054	13.8 KV Swgr 2A Lignite Delivery		Solid Fuel	Lignite Delivery
KD055	13.8 KV Swgr 2B Lignite Delivery		Solid Fuel	Lignite Delivery
KD056	4.16 KV MCC 1A Lignite Delivery		Solid Fuel	Lignite Delivery
KD057	480V MCC 4A Lignite Delivery		Solid Fuel	Lignite Delivery
KD058	4.16 KV MCC 1B Lignite Delivery		Solid Fuel	Lignite Delivery
KD059	480 V MCC 1A Lignite Delivery		Solid Fuel	Lignite Delivery
KD060	480 V MCC 2A Lignite Delivery		Solid Fuel	Lignite Delivery
KD061	480 V MCC 2B Lignite Delivery		Solid Fuel	Lignite Delivery
KD062	480 V MCC 3A Lignite Delivery		Solid Fuel	Lignite Delivery
KD063	480 V MCC 3B Lignite Delivery		Solid Fuel	Lignite Delivery
KD064	480 V MCC A1 Water Treatment	KD-MCMA-6101	CC-BOP	Water Treatment
KD065	480 V MCC A2 Water Treatment	KD-MCMA-6201	CC-BOP	Water Treatment
KD066	480 V MCC A3 Water Treatment	KD-MCMA-6301	CC-BOP	Water Treatment
KD067	480 V MCC B1 Water Treatment	KD-MCMB-6101	CC-BOP	Water Treatment
KD068	480 V MCC B2 Water Treatment	KD-MCMB-6201	CC-BOP	Water Treatment
KD069	480 V MCC B3 Water Treatment	KD-MCMB-6301	CC-BOP	Water Treatment
KD073	4.16KV BUS C3 Treated Effluent Pond	KD-SGJC-7300	CC-BOP	Raw Water
KD074	480V SWGR Bus A - Water Treatment		GI	Raw Water
KD075	4.16KV BUS C4 Treated Effluent Pond	KD-SGJC-7400	CC-BOP	Raw Water
KD076	480V SWGR BUS B - Water Treatment	KD-SGMB-6001	CC-BOP	Water Treatment
KD077	13.8 KV BUS A1 & A2 Static Inverter & Reactor		CC-BOP	Compressor

Turnover Code	Description	Equipment No.	Process Area	Class
KD078	13.8 KV BUS B1 & B2 Static Inverter & Reactor		CC-BOP	Compressor
KD080	480V MCC A4 - Water Treatment	KD-MCMA-6401	CC-BOP	Water Treatment
KD085	4160V SWGR BUS A - Liquid Nitrogen Plant	KD-SGJA-1000	GI-BOP	Nitrogen Plant
KD086	13.8 KV SWGR BUS B - Liquid Nitrogen Plant	KD-SGJB-1000	GI-BOP	Nitrogen Plant
KD093	4kv Water Treatment Plant Trailers			
KE001	125VDC Power System - Station Service Buss A1 & A2		GI-BOP	Main Electrical Bldg.
KE002	125VDC Power System - Combined Cycle Steam Turbine		CC	Combined Cycle
KE003	125VDC Power System - Combustion Turbine A		CC	Combined Cycle
KE004	125VDC Power System - Combustion Turbine B		CC	Combined Cycle
KE005	125VDC Power System - Station Service Buss 1B & 2B		GI-BOP	Main Electrical Bldg.
KE006	125VDC Power System - Station Service Buss 1C & 2C		GI-BOP	Main Electrical Bldg.
KE007	125VDC System Gasifier A MCC Bldg		GI	Gasifier Island
KE008	125VDC System Gasifier B MCC Bldg		GI	Gasifier Island
KE010	125 VDC Power Sys Lignite Delivery		Solid Fuel	Lignite Delivery
LB001	Gasifier - LP Condensate Pumps (PU0090 A/B)	PU0090A/B	GI	Gasifier Island
LE002	Condensate Make-up Auxiliary Boiler	LE-PU-3016, LE-PU-3017	CC	Condensate
LE003	Condensate Make-up Combined Cycle	LE-PU-3014, LE-PU-3015, LE-PU-3025	CC	Condensate
LH001	Anhydrous Ammonia Supply to Condensate Sys		CC	Combined Cycle
LH002	Combined Cycle Aqueous Ammonia		CC	Chemical Feed
LJ001	Gasifier - HRSG Condensate Sys	HX0091	GI	Combined Cycle
LJ002	Gasifier - IP & LP Condensate Drum	UA-HX-0090, UA-DR-0090, UA-DR-0091	GI	Gasifier Island
LJ006	Gasifier - Low Pressure Condensate Supply Header		GI	Gasifier Island
LJ007	Gasifier - Low Pressure Condensate Return Header		GI	Gasifier Island
LJ008	Gasifier - MP Steam Generation Condensate Pumps	PU0092A, PU0092B	GI	Gasifier Island
LJ009	Gasifier - MP Ash Cooler Condensate Pumps	UA-PU-0091A, UA-PU-0091B, UA-PU-0091C	GI	Gasifier Island
LJ010	Gasifier - MP Ash Cooler Condensate Headers		GI	Gasifier Island
LY002	HRSG A Condensate		CC	Combined Cycle
LY003	HRSG B Condensate		CC	Combined Cycle
LY004	Steam Turbine Condensate Sys		CC	Combined Cycle
MA002	HRSG A Boiler Feed Water	MA-PU-3001A, MA-PU-3002A	CC	Combined Cycle
MA003	HRSG B Boiler Feed Water	MA-PU-3001B, MA-PU-3002B	CC	Combined Cycle
MA004	Gasifier Island Feedwater Sys Train A	MA-PU-3700A	CC	Gasifier Island
MA005	Gasifier Island Feedwater Sys Train B	MA-PU-3700B	CC	Gasifier Island
MC002	HRSG B Phosphate Sys	MC-TK-3145, MC-MX-3145, MC-PU-3149A / B	CC	Combined Cycle
MC004	Gasifier Phosphate Sys	MC-TK-4709, MC-TK-4711, MC-PU-4712A / B, MC-PU-4714	CC	Combined Cycle
NA002	Water Treatment - Raw Water Forwarding Pumps	HB-PU-6080, HB-PU-6081	CC	Raw Water
NA023	Water Treatment - Treated Effluent Pipeline		OSBL	Raw Water
NA024	Water Treatment - Treated Effluent Pump Station Meridian East	HB-PU-9022, HB-PU-9023, HB-SN-9029	OSBL	Raw Water

Turnover Code	Description	Equipment No.	Process Area	Class
NA025	Water Treatment - Treated Effluent Pump Station Meridian Main	HB-PU-9001, HB-PU-9002, HB-PU-9003, HB-SN-9013	OSBL	Raw Water
NB002	Water Treatment - Filter Water Forwarding Pumps	HE-PU-6056, HE-PU-6057	CC	Raw Water
NB003	Water Treatment - Filter Water Storage Tank	HE-TK-6055	CC	Raw Water
NC001	Potable Water - Water Treatment Area		CC	Potable Water
NC003	Potable Water - CO2 Area		GI	Potable Water
NC004	Potable Water - Combined Cycle Area		CC	Potable Water
NC005	Potable Water - Combined Cycle Cooling Tower		CC	Potable Water
NC006	Potable Water - Gasifier A Structure		GI	Potable Water
NC007	Potable Water - Gasifier B Structure		GI	Potable Water
NC008	Potable Water - Gasifier Area		GI	Potable Water
NC009	Potable Water - Gasifier Cooling Tower		GI	Potable Water
NC011	Potable Water - Lignite Handling		Solid Fuel	Potable Water
NC012	Potable Water - Maintenance Shop		OSBL	Potable Water
NC013	Potable Water - Process Compressors Area		GI	Potable Water
NC014	Potable Water - Sulfuric Acid Area		GI	Potable Water
NC015	POTABLE WATER-UNDERGROUND			Potable Water
NC016	Potable Water - Added Scope			
ND001	Water Analysis System - Combined Cycle		CC	Condensate
ND002	Water Analysis System - Gasifier Island	HJ-HX-6085	GI	Condensate
NE003	Water Treatment - Condensate Storage Tank	LE-TK-3001	CC	Raw Water
NF003	Gasifier - Waste Water Storage Tank & Pump	TK0042	GI	By Products
NF004	Gasifier A - AGR Area Sump	A1065	GI-BOP	By Products
NF005	Gasifier B - AGR Area Sump	A2065	OSBL	By Products
NF006	Steam Turbine Area Sump	NF-SU-6061	CC	Combined Cycle
NF007	Warehouse Sanitary Lift Station	NF-LF-6120, NF-PU-6120 A / B	OSBL	Sanitary
NF008	Combustion Turbine B Sump	NF-SU-6049B	CC	Combined Cycle
NF010	Lignite Delivery - Barn Transfer Station Collection (Sump 002)	1WWC-BDS-002	Solid Fuel	Lignite Delivery
NF011	Waste Treatment - Sanitary Waste Treatment Plant	NE-GE-6210, NF-PU-6220 A / B	OSBL	Sanitary
NF013	Gasifier - Carbon Bed Filters (Sour Water)	PG0040	GI	By Products
NF014	Guard House Sanitary Lift Station	NF-LF-6140, NF-PU-6140A / B	OSBL	Sanitary
NF015	Gas Cleanup Area Sump		GI-BOP	Gasifier Gas Cleanup
NF016	Water Treatment - Sanitary Lift Station	NF-LF-6110, NF-PU-6110 A / B	CC	Raw Water
NF017	Gasifier Area Sanitary Lift Station	NF-LF-6170, NF-PU-6170	GI	Sanitary
NF018	Gasifier Island Waste Water Sump	A0044	GI	Gasifier Gas Cleanup
NF019	CC Elect. Bldg Dewatering Lift Station	NF-LF-6180, NF-PU-6180	OSBL	Sanitary
NF020	Water Treatment - Waste Water Storage Tank		CC	Raw Water
NF021	Combustion Turbine A Sump	NF-SU-6049A	CC	Combined Cycle
NF022	Waste Water Reclaim Sump		CC	
NF023	North Gasifier Structure Sump A0060A	A0060A	GI	Gasifier Island
NF024	Gasifier - Waste Water Drum DR0040	DR0040	GI	By Products

Turnover Code	Description	Equipment No.	Process Area	Class
NF025	Gasifier - Waste Water Drum Pumps and preheater PU0040A/B	PU0040A/B, HX0041	GI	By Products
NF027	Gasifier - AGR Sump Drum & Pump - NF-DR-0057	NF-DR-0057	GI-BOP	By Products
NF030	Sulfuric Acid Area Sump A0078	A0078	GI-BOP	By Products
NF031	Main Electrical Building - Sanitary Lift Station	NF-LF-6130, NF-PU-6130	OSBL	Sanitary
NF032	Truck Scale House Sanitary Lift Station	NF-LF-6160, NF PU-6160A / B	OSBL	Sanitary
NF034	South Gasifier Structure Sump A0060B	A0060B	GI	Gasifier Island
NF035	North Oily Water Sump NF-SU-0052	NF-SU-0052	GI	Gasifier Island
NF036	South Oily Water Sump NF-SU-0051	NF-SU-0051	GI	Gasifier Island
NF041	Lignite Delivery - Screen Transfer Station Area (Sump 006)	1WWC-BDS-006	Solid Fuel	Lignite Delivery
NF042	Lignite Delivery - Truck Dump Area (Sump 001)	1WWC-BDS-001	Solid Fuel	Lignite Delivery
NF043	Lignite Delivery - Collection (Sump 003)	1WWC-BDS-003	Solid Fuel	Lignite Delivery
NF044	Lignite Handling - Stacker/Reclaimer Dome Sump	1WWC-BDS-007	Solid Fuel	Lignite Delivery
NF081	Lignite Delivery Sanitary Lift Station	NF-LF-6150, NF-LF-6150	Solid Fuel	Sanitary
NF082	HRSG SUMP A	NF-SU-6001A	CC	Combined Cycle
NF083	HRSG SUMP B	NF-SU-6000B	CC	Combined Cycle
NF084	Ash Sedimentation Pond Intake Structure		Solid Fuel	Lignite Delivery
NF085	Train A SELEXOL Closed Drain Header		GI-BOP	By Products
NF086	Gasifier - Wastewater Collection Header		GI	By Products
NF088	Lignite Handling - Conveyor 8 Collection Sump	1WWC-BDS-005	Solid Fuel	Lignite Delivery
NF089	Lignite Handling - Conveyor 3 Collection Sump	1WWC-XDS-001	Solid Fuel	Lignite Delivery
NF091	WATER ANALYSIS SEWAGE LIFT STATION		BOP	
NF092	LDF Area Process Water			
NF093	LDF Ash Sediment Pond Intake Structure			
PA001	Admin/Control Bldg		OSBL	Admin
PA002	Auxiliary Boiler MCC Bldg.		CC-BOP	Combined Cycle
PA004	Combined Cycle Cooling Tower PEECC		CC-BOP	Combined Cycle
PA005	Combined Cycle Electrical Bldg.		CC	Combined Cycle
PA006	Combustion Turbine A PEECC		CC	Combined Cycle
PA007	Combustion Turbine B PEECC		CC	Combined Cycle
PA010	Maintenance Shop		OSBL	Maint
PA011	Raw Water Holding Pond PEECC		OSBL	Raw Water
PA013	Gasifier B MCC Bldg		GI	Gasifier Island
PA014	Guard House / Truck Scale House		OSBL	
PA015	Warehouse		OSBL	Whse
PA017	Water Analysis Bldg.		CC	Combined Cycle
PA019	Gasifier A MCC Bldg		GI	Gasifier Island
PA021	Main Electrical Bldg		GI	Gasifier Island
PA022	CO2 Compressor MCC Bldg.		GI-BOP	By Products
PA023	Gasifier Gas Cleanup MCC Bldg		GI	Gasifier Gas Cleanup
PA024	Flare Area MCC Bldg		GI-BOP	Gasifier Gas Cleanup

Turnover Code	Description	Equipment No.	Process Area	Class
PA025	Lignite Transfer Truck Dump MCC Building		Solid Fuel	Lignite Delivery
PA026	Gasifier Island Cooling Tower PEECC		GI-BOP	Gasifier Island
PA028	Oil Storage Building No.1		OSBL	
PA029	Cooling Water & Sulfuric Acid Area MCC Bldg		GI-BOP	By Products
PA030	Treated Effluent Pumping Station Electrical Bldg Meridian Main		OSBL	Raw Water
PA031	LDF Aux Control 13.8 KV Switchgear Building		Solid Fuel	Lignite Delivery
PA032	HRSG A - PEECC Bldg.		CC	Combined Cycle
PA033	HRSG B - PEECC Bldg.		CC	Combined Cycle
PA034	Lignite Delivery MCC / Control Bldg		Solid Fuel	Lignite Delivery
PA035	Lignite Delivery Facility Transfer Station #1 Bldg		Solid Fuel	Lignite Delivery
PA036	Lignite Delivery - Barn Transfer Station Bldg		Solid Fuel	Lignite Delivery
PA042	Gasifier A - Analyzer House	AH3	GI1	Gasifier Island
PA043	Gasifier B - Analyzer House	AH4	GI2	Gasifier Island
PA044	Train A Gas Clean-up - Analyzer House	AH5	GI-BOP	Gasifier Gas Cleanup
PA045	Train B Gas Clean-up - Analyzer House	AH6	GI-BOP	Gasifier Gas Cleanup
PA046	Flare/Wastewater Treatment Analyzer House	AH7	GI-BOP	Gasifier Gas Cleanup
PA047	WSA pkg - Analyzer House	AH8	GI-BOP	Gasifier Gas Cleanup
PA048	Remote I/O Enclosure - Gasifier A Control Bldg 1 LVL 515	RIE1	GI	Gasifier Island
PA049	Remote I/O Enclosure - Gasifier A Control Bldg 2 LVL 568	RIE2	GI	Gasifier Island
PA050	Remote I/O Enclosure - Gasifier A Control Bldg 3 LVL 643	RIE3	GI	Gasifier Island
PA051	Remote I/O Enclosure - Gasifier B Control Bldg 1 LVL 515	RIE4	GI-BOP	Gasifier Gas Cleanup
PA052	Remote I/O Enclosure - Gasifier B Control Bldg 2 LVL 568	RIE5	GI-BOP	Gasifier Island
PA053	Remote I/O Enclosure - Gasifier B Control Bldg 3 LVL 643	RIE6	GI-BOP	Gasifier Gas Cleanup
PA055	Gasifier Structure Freight Elevator	ME0001	GI	Gasifier Island
PA056	Gasifier Structure Personnel Elevator	ME0002	GI	Gasifier Island
PA057	Lignite Delivery - Belt Sampler 004A		Solid Fuel	Lignite Delivery
PA058	Lignite Delivery - Belt Sampler 004B		Solid Fuel	Lignite Delivery
PA059	LDF Tripper Electrical Building			
PA060	Gasifier Island Water Analysis Bldg			
PA061	Plant fueling Station			
PB001	Plant Roadway Lighting			
PB003	Aviation Lighting			
PB004	Main Elect. Bldg. Area Lighting (AREAS 105, 110, 170A, 200, 550)			
PB005	HRSG Area Lighting (AREAS 180, 510, 520, 550)			
PB006	Gasifier Lighting (AREAS 120,150,150A,170C,220,250,250A)			
PB007	Gas Treatment & SELEXOL (AREAS 130, 170B, 170G, 170K,180)			
PB008	Flare & Ammonia Area Lighting (AREAS 140,170C,170H,190,190A,210,220)			

Turnover Code	Description	Equipment No.	Process Area	Class
PB009	WSA, NIT & SELEXOL Area Lighting (AREAS 160,170E,170K,180,230,260)			
PB010	Cooling Towers Area Lighting (AREAS 580 & 590)			
PC001	Plant Emergency Notification System A			
PC002	Plant Emergency Notification System B			
PC003	Plant Emergency Notification System C			
PC004	Security Camera Stacks			
PC005	Security Camera CC Anhydrous Ammonia Tank			
PC007	Security Camera Gasifier Anhydrous Ammonia Tanks			
PC008	Security Camera Gasifier Elev 605			
PC009	Security Camera Gasifier Elev 643			
PC010	Security Camera Intake Structure Elect Bldg			
PC012	Security Camera WSA Loading Bay & Roadway			
PY006	Heat Trace Sys - HRSG A		CC	Combined Cycle
PY007	Heat Trace Sys - HRSG B		CC	Combined Cycle
PY008	Heat Trace Sys - Steam Turbine		CC	Combined Cycle
PY015	Heat Trace Sys - Lignite Delivery Facility			
QC001	Auxiliary Boiler - Boiler		AUX	Aux Boiler
RA001	Fire Water Sys - Lignite Handling		Solid Fuel	Lignite Delivery
RA002	Fire Water Sys - Combined Cycle Cooling Tower		CC	Combined Cycle
RA003	Fire Water Sys - Combined Cycle Underground		CC	Combined Cycle
RA004	Fire Water Sys - Pumps & House	RA-PU-1396, RA-PU+1397, RA-PU-1398, RA-PU-1399	OSBL	
RA006	Steam Turbine Fire Protection Sys		CC	Combined Cycle
RA007	Fire Water Sys - Gasifier Underground		GI	Gasifier Island
RA008	Fire Water Sys - Gasifier A Structure		GI	Gasifier Island
RA009	Fire Water Sys - Gasifier B Structure		GI	Gasifier Island
RA010	Fire Water Sys - Gasifier Cooling Tower		GI	Gasifier Island
RA011	Above Ground Fire Water Sys - Steam Turbine Fire Protection Sys			
RA012	Above Ground Fire Water Sys - Lignite Handling			
RA013	Above Ground Fire Water Sys - Lignite Handling Dome			
RA014	Above Ground Fire Water Sys - Combustion Turbine A			
RA015	Above Ground Fire Water Sys - Combustion Turbine B			
RA016	Above Ground Fire Water Sys - Combined Cycle			
RA017	Above Ground Fire Water Sys - Area 110			
RA018	Above Ground Fire Water Sys - Coal Crusher Silos			
RA019	Above Ground Fire Water Sys - Gasifier Island Ammonia Tanks			
RA020	Above Ground Fire Water Sys - Bunker Dust Collector			
RA021	Above Ground Fire Water Sys - PC Cyclone Baghouse			
RA022	Above Ground Fire Water Sys - Gasifier Structure			
RC001	Combustion Turbine A CO2 Fire Suppression		CC	Combined Cycle

Turnover Code	Description	Equipment No.	Process Area	Class
RC002	Combustion Turbine B CO2 Fire Suppression		CC	Combined Cycle
RC003	Above Ground Combustion Turbine A & B CO2 Fire Suppression			
RY001	Plant Fire Alarm System/Admin/Control Bldg		OSBL	
RY003	Fire Detection & Alarm System - Combined Cycle Area		CC	Combined Cycle
RY004	Gasifier- Gas Detection Alarm System	AGR	GI	Gasifier Island
RY005	Fire Detection & Alarm System - Gasifiers		GI	Gasifier Island
RY006	Fire Detection & Alarm System - Warehouse Bldg		OSBL	
RY010	FIRE DETECTION & ALARM SYSTEM - AREA 110			
RY019	Above Ground Fire Detection & Alarm System - Lignite Delivery Facilities			
SA001	Instrument Air System - Water Treatment		CC	Combined Cycle
SA002	Instrument Air System - CO2 Area		GI	By Products
SA004	Instrument Air System - Combined Cycle Steam Turbine		CC	Combined Cycle
SA005	Instrument Air System - Combustion Turbine A & HRSG A		CC	Combined Cycle
SA006	Instrument Air System - Combustion Turbine B & HRSG B		CC	Combined Cycle
SA007	Instrument Air System - Compressors & Dryers		CC	Combined Cycle
SA008	Instrument Air System - Gasifier Gas Cleanup		GI	Gasifier Gas Cleanup
SA009	Instrument Air System - Gasifier Waste Water Treatment		GI	Gasifier Gas Cleanup
SA010	Instrument Air System - Sulfuric Acid Area		GI	By Products
SA011	Instrument Air System - Gasifier A		GI	Gasifier Island
SA012	Instrument Air System - Gasifier B		GI	Gasifier Island
SA013	Instrument Air System - Lignite Delivery Compressor & Dryers		Solid Fuel	Lignite Delivery
SA015	Instrument Air System - Process Compressors Area		GI	Gasifier Island
SA016	INSTRUMENT AIR HEADER TO NITROGEN PLANT			
UA003	Gasifier A - Pressurized Transport Gasifier	RX1002	GI	Gasifier Island
UA004	Gasifier A - Startup Burner A	AH1102	GI	Gasifier Island
UA005	Gasifier A - Startup Burner B	AH1202	GI	Gasifier Island
UA006	Gasifier A - Second Startup Burners	AH1103, AH1203, AH1303	GI	Gasifier Island
UA007	Gasifier B - Pressurized Transport Gasifier	RX2002	GI	By Products
UA008	Gasifier B - Startup Burner A	AH2102	GI	Gasifier Island
UA009	Gasifier B - Startup Burner B	AH2202	GI	Gasifier Island
UA010	Gasifier B - Second Startup Burners	AH2103, AH2203, AH2303	GI	By Products
UB001	Gasifier A - Feed Dispense Vessel 1A	FD1115A	GI	Lignite Prep
UB002	Gasifier A - Feed Dispense Vessel 1B	FD1115B	GI	Lignite Prep
UB003	Gasifier A - Feed Dispense Vessel 2A	FD1215A	GI	Lignite Prep
UB004	Gasifier A - Feed Dispense Vessel 2B	FD1215B	GI	Lignite Prep
UB005	Gasifier A - Feed Dispense Vessel 3A	FD1315A	GI	Lignite Prep
UB006	Gasifier A - Feed Dispense Vessel 3B	FD1315B	GI	Lignite Prep
UB007	Gasifier A - Feed Storage & Lock Vessel 1A	FD1110A, SI1110A	GI	Lignite Prep
UB008	Gasifier A - Feed Storage & Lock Vessel 1B	FD1110B, SI1110B	GI	Lignite Prep

Turnover Code	Description	Equipment No.	Process Area	Class
UB009	Gasifier A - Feed Storage & Lock Vessel 2A	FD1210A, SI1210A	GI	Lignite Prep
UB010	Gasifier A - Feed Storage & Lock Vessel 2B	FD1210B, SI1210B	GI	Lignite Prep
UB011	Gasifier A - Feed Storage & Lock Vessel 3A	FD1310A, SI1310A	GI	Lignite Prep
UB012	Gasifier A - Feed Storage & Lock Vessel 3B	FD1310B, SI1310B	GI	Lignite Prep
UB013	Gasifier A - Feed System 1A	FD1116A	GI	Lignite Prep
UB014	Gasifier A - Feed System 1B	FD1116B	GI	Lignite Prep
UB015	Gasifier A - Feed System 2A	FD1216A	GI	Lignite Prep
UB016	Gasifier A - Feed System 2B	FD1216B	GI	Lignite Prep
UB017	Gasifier A - Feed System 3A	FD1316A	GI	Lignite Prep
UB018	Gasifier A - Feed System 3B	FD1316B	GI	Lignite Prep
UB019	Gasifier A - Multi-Clone Rotary Air Lock 1A	FD1103, FD1124, FD1125	GI	Lignite Prep
UB020	Gasifier A - Multi-Clone Rotary Air Lock 1B	FD1203, FD1224, FD1225	GI	Lignite Prep
UB021	Gasifier A - Multi-Clone Rotary Air Lock 1C	FD1303, FD1324, FD1325	GI	Lignite Prep
UB022	Gasifier B - Feed Dispense Vessel 1A	FD2115A	GI	Lignite Prep
UB023	Gasifier B - Feed Dispense Vessel 1B	FD2115B	GI	Lignite Prep
UB024	Gasifier B - Feed Dispense Vessel 2A	FD2215A	GI	Lignite Prep
UB025	Gasifier B - Feed Dispense Vessel 2B	FD2215B	GI	Lignite Prep
UB026	Gasifier B - Feed Dispense Vessel 3A	FD2315A	GI	Lignite Prep
UB027	Gasifier B - Feed Dispense Vessel 3B	FD2315B	GI	Lignite Prep
UB028	Gasifier B - Feed Storage & Lock Vessel 1A	FD2110A SI2110A	GI	Lignite Prep
UB029	Gasifier B - Feed Storage & Lock Vessel 1B	FD2110B, SI2110B	GI	Lignite Prep
UB030	Gasifier B - Feed Storage & Lock Vessel 2A	FD2210A, SI2210A	GI	Lignite Prep
UB031	Gasifier B - Feed Storage & Lock Vessel 2B	FD2210B, SI2210B	GI	Lignite Prep
UB032	Gasifier B - Feed Storage & Lock Vessel 3A	FD2310A, SI2310A	GI	Lignite Prep
UB033	Gasifier B - Feed Storage & Lock Vessel 3B	FD2310B, SI2310B	GI	Lignite Prep
UB034	Gasifier B - Feed System 1A	FD2116A	GI	Lignite Prep
UB035	Gasifier B - Feed System 1B	FD2116B	GI	Lignite Prep
UB036	Gasifier B - Feed System 2A	FD2216A	GI	Lignite Prep
UB037	Gasifier B - Feed System 2B	FD2216B	GI	Lignite Prep
UB038	Gasifier B - Feed System 3A	FD2316A	GI	Lignite Prep
UB039	Gasifier B - Feed System 3B	FD2316B	GI	Lignite Prep
UB040	Gasifier B - Multi-Clone Rotary Air Lock 2A	FD2103, FD2124, FD2125	GI	Lignite Prep
UB041	Gasifier B - Multi-Clone Rotary Air Lock 2B	FD2203, FD2224, FD2225	GI	Lignite Prep
UB042	Gasifier B - Multi-Clone Rotary Air Lock 2C	FD2303, FD2324, FD2325	GI	Lignite Prep
UB043	Gasifier A - Solids Injection Nozzle 1A		GI	Gasifier Island
UB044	Gasifier A - Solids Injection Nozzle 1B		GI	Gasifier Island
UB045	Gasifier A - Solids Injection Nozzle 2A		GI	Gasifier Island
UB046	Gasifier A - Solids Injection Nozzle 2B		GI	Gasifier Island
UB047	Gasifier A - Solids Injection Nozzle 3A		GI	Gasifier Island
UB048	Gasifier A - Solids Injection Nozzle 3B		GI	Gasifier Island

Turnover Code	Description	Equipment No.	Process Area	Class
UB049	Gasifier B - Solids Injection Nozzle 1A		GI	Gasifier Island
UB050	Gasifier B - Solids Injection Nozzle 1B		GI	Gasifier Island
UB051	Gasifier B - Solids Injection Nozzle 2A		GI	Gasifier Island
UB052	Gasifier B - Solids Injection Nozzle 2B		GI	Gasifier Island
UB053	Gasifier B - Solids Injection Nozzle 3A		GI	Gasifier Island
UB054	Gasifier B - Solids Injection Nozzle 3B		GI	Gasifier Island
UC001	Gasifier - Coarse Ash Feeder	FD0007	GI	By Products
UC002	Gasifier - Coarse Ash / Bed Make-up Silo	SI0007	GI	By Products
UC003	Gasifier - Coarse Ash Storage Silo A	SI0008A, FD0009A, MX0002A, FL0008A	GI	By Products
UC004	Gasifier - Coarse Ash Storage Silo B	SI0008B, FD0009B, MX0002B, FL0008B	GI	By Products
UC005	Gasifier - Coarse Ash Storage Silo C	SI0008C, FD0009C, MX0002C, FL0008C	GI	By Products
UC006	Gasifier - Coarse Ash Storage Silo D	SI0008D, FD0009D, MX0002D, FL0008D	GI	By Products
UC007	Gasifier - LP Vent Gas Compressor CO0041	CO0041, HX0040	GI	Compressor
UC008	Gasifier - LP Vent Gas Compressor Lube Oil Unit CO0041LO	CO0041LO, CO0041-LO-TK1, CO0041-LO-TK2	GI	Oil System
UC009	Gasifier A - Fines Ash Receiver Sys A	HX1118	GI	By Products
UC010	Gasifier A - Fines Ash Receiver Sys B	HX1218	GI	By Products
UC012	Gasifier A - Coarse Ash Cooling	HX1030, HX1033, FL1018, CX1009, HX1034	GI	By Products
UC013	Gasifier A - Coarse Ash Depressurization Sys 1A	FD1130-1, FD1130-2, FD1130-3, FD1130-4	GI	By Products
UC014	Gasifier A - Coarse Ash Depressurization Sys 1B	FD1230-1, FD1230-2, FD1230-3, FD1230-4	GI	By Products
UC015	Gasifier A - CCAD Steam Drum	DR1030, HX1031	GI	Gasifier Island
UC016	Gasifier A - PLD Vent Gas Drum (DR1043)	DR1043	GI	Gasifier Island
UC017	Gasifier A - Bottoms Drain Pot Feeder	FD1011	GI	By Products
UC020	Gasifier A - Particulate Control Device Backpulse Sys A	FL1106-DR1,2,3, FL1106-DR4,5,6, FL1106-DR7,8,9	GI	By Products
UC021	Gasifier A - Particulate Control Device Backpulse Sys B	FL1206-DR1,2,3, FL1206-DR4,5,6, FL1206-DR7,8,9	GI	By Products
UC022	Gasifier A - Fines Ash Depressurization 1A	FD1120A-1,2,3,4,5,6	GI	By Products
UC023	Gasifier A - Fines Ash Depressurization 1B	FD1120B-1,2,3,4,5,6	GI	By Products
UC024	Gasifier A - Fines Ash Depressurization 2A	FD1220A-1,2,3,4,5,6	GI	By Products
UC025	Gasifier A - Fines Ash Depressurization 2B	FD1220B-1,2,3,4,5,6	GI	By Products
UC026	Gasifier B - PLD Vent Gas Drum (DR2043)	DR2043	GI	Gasifier Island
UC027	Gasifier B - Bottoms Drain Pot Feeder	FD2011	GI	Gasifier Island
UC029	Gasifier B - CCAD Steam Drum (DR2030)	DR2030, HX2031	GI	Gasifier Island
UC030	Gasifier B - Coarse Ash Depressurization 2A	FD2130-1, FD2130-2, FD2130-3, FD2130-4	GI	Gasifier Island
UC031	Gasifier B - Coarse Ash Depressurization 2B	FD2230-1, FD2230-2, FD2230-3, FD2230-4	GI	
UC032	Gasifier B - Particulate Control Device Backpulse Sys A	FL2106-DR1,2,3, FL2106-DR4,5,6, FL2106-DR7,8,9	GI	By Products
UC033	Gasifier B - Particulate Control Device Backpulse Sys B	FL2206-DR1,2,3, FL2206-DR4,5,6, FL2206-DR7,8,9	GI	By Products
UC034	Gasifier B - Fines Ash Receiver Sys A	HX2118	GI	By Products
UC035	Gasifier B - Fines Ash Receiver Sys B	HX2218	GI	By Products
UC036	Gasifier B - Coarse Ash Cooling	HX2030, HX2033, FL2018	GI	By Products

Turnover Code	Description	Equipment No.	Process Area	Class
UC038	Gasifier B - Fines Ash Depressurization 1A	FD2120A-1,2,3,4,5,6	GI	By Products
UC039	Gasifier B - Fines Ash Depressurization 1B	FD2120B-1,2,3,4,5,6	GI	By Products
UC040	Gasifier B - Fines Ash Depressurization 2A	FD2220A-1,2,3,4,5,6	GI	By Products
UC041	Gasifier B - Fines Ash Depressurization 2B	FD2220B-1,2,3,4,5,6	GI	By Products
UC045	Gasifier A - Seal Leg Solids Feed Piping		GI	Gasifier Island
UC046	Gasifier B - Seal Leg Solids Feed Piping		GI	Gasifier Island
UC047	Gasifier A - Particulate Control Device FL1106	FL1106	GI	Gasifier Island
UC048	Gasifier A - Particulate Control Device FL1206	FL1206	GI	Gasifier Island
UC049	Gasifier B - Particulate Control Device FL2106	FL2106	GI	Gasifier Island
UC050	Gasifier B - Particulate Control Device FL2206	FL2206	GI	Gasifier Island
UC051	Gasifier - Ash Moisturizer Booster Pump	HE-PU-6102A /B	GI	Gasifier Island
UC052	Gasifier - Ash Conditioner Venturi Scrubber A		GI	Gasifier Island
UC053	Gasifier - Ash Conditioner Venturi Scrubber B		GI	Gasifier Island
UC054	Gasifier - Ash Silo Secondary Baghouse System	FL0012A, FL0012B, FL0012C, FL0012D, FD0083, FD0083B, FD0083C, FD0083D, HX0083, BL0083	GI	Gasifier Island
UD002	Gasifier - Low Pressure Nitrogen Distribution Header		GI	Gasifier Island
UD009	Gasifier A - Extraction Air Compressor CO1004	CO1004, HX1019, HX1029	GI	Compressor
UD010	Gasifier A - Extraction Air Compressor Lube Oil Unit CO1004LO	CO1004LO	GI	Oil System
UD011	Gasifier A - Process Air Supply Header & Extraction Air Recuperator	HX1028	GI	Gasifier Island
UD012	Gasifier A - HP Nitrogen Distribution Sys		GI	Gasifier Island
UD013	Gasifier A - IP Nitrogen Distribution Sys		GI	Gasifier Island
UD014	Gasifier A - Gasifier Pressure Safety Valve Sensing Header		GI	Gasifier Island
UD015	Gasifier A - Process Air Compressor CO1102	CO1102, FL1109	GI	Compressor
UD016	Gasifier B - Process Air Compressor CO1202	CO1202, FL1209	GI	Compressor
UD017	Gasifier A - Process Air Compressor Lube Oil Unit CO1102LO	CO1102LO	GI	Oil System
UD018	Gasifier A - Process Air Compressor Lube Oil Unit CO1202LO	CO1202LO	GI	Oil System
UD019	Gasifier A - Recycle Gas Compressor CO1008	CO1008, HX1032	GI	Compressor
UD020	Gasifier A - Recycle Gas Compressor KO Drum DR1009	DR1009	GI	Gasifier Island
UD021	Gasifier A - Recycle Gas Compressor Lube Oil Unit CO1008LO	CO1008LO	GI	Oil System
UD023	Gasifier A - Transport Air Compressor CO1005	CO1005	GI	Compressor
UD024	Gasifier A - Transport Air Compressor Lube Oil Unit CO1005LO	CO1005LO	GI	Oil System
UD025	Gasifier A - Transport Air Compressor PreCoolers & KO Drum DR1005	DR1005, HX1005, HX1026	GI	Gasifier Island
UD026	Gasifier A - Transport Air Dryer PG1007	PG1007	GI	Gasifier Island
UD029	Gasifier B - Extraction Air Compressor CO2004	CO2004, HX2019, HX2029	GI	Compressor
UD030	Gasifier B - Extraction Air Compressor Lube Oil Unit CO2004LO	CO2004LO	GI	Oil System
UD031	Gasifier B - Process Air Supply Header & Extraction Air Recuperator	HX2028	GI	Gasifier Island
UD032	Gasifier B - HP Nitrogen Distribution Sys			
UD033	Gasifier B - IP Nitrogen Distribution Sys		GI	Gasifier Island

Turnover Code	Description	Equipment No.	Process Area	Class
UD034	Gasifier B - Gasifier Pressure Safety Valve Sensing Header		GI	Gasifier Island
UD035	Gasifier B - Process Air Compressor CO2102	CO2102	GI	Compressor
UD036	Gasifier B - Process Air Compressor CO2202	CO2202	GI	Compressor
UD037	Gasifier B - Process Air Compressor Lube Oil Unit CO2102LO	CO2102LO	GI	Oil System
UD038	Gasifier B - Process Air Compressor Lube Oil Unit CO2202LO	CO2202LO	GI	Oil System
UD039	Gasifier B - Recycle Gas Compressor CO2008	CO2008, HX2032	GI	Compressor
UD040	Gasifier B - Recycle Gas Compressor Lube Oil Unit CO2008LO	CO2008LO	GI	Oil System
UD042	Gasifier B - Transport Air Compressor CO2005	CO2005	GI	Compressor
UD043	Gasifier B - Transport Air Compressor PreCoolers & KO Drum DR2005	DR2005, HX2005, HX2026	GI	Gasifier Island
UD044	Gasifier B - Transport Air Dryer PG2007	PG2007	GI	Gasifier Island
UD045	Gasifier B - Transport Air Compressor Lube Oil Unit CO2005LO	CO2005LO	GI	Gasifier Island
UD046	Gasifier B - Recycle Gas Compressor KO Drum	DR2009	GI	Gasifier Island
UD047	Gasifier A - Transport Air Dryer Header		GI	Gasifier Island
UD048	Gasifier A - Recycle Gas Compressor Header		GI	Gasifier Island
UD049	Gasifier A - Transport Air Cooler & KO Drums	DR1012, HX1006	GI	Gasifier Island
UD050	Gasifier A - Extraction Air Compressor KO Drum	DR1003	GI	Gasifier Island
UD051	Gasifier - Startup Air Supply		GI	Gasifier Island
UD053	Gasifier B - Recycle Gas Compressor Header		GI	Gasifier Island
UD055	Gasifier B - Extraction Air Compressor KO Drum	DR2003	GI	Gasifier Island
UD056	Gasifier B - Transport Air Cooler & KO Drums	DR2012, HX2006	GI	Gasifier Island
UD057	Gasifier B - Transport Air Dryer Header		GI	Gasifier Island
UD058	Gasifier - LP Nitrogen Area 105			
UD059	Gasifier - LP Nitrogen Area 110			
UD060	Gasifier - LP Nitrogen Area 120			
UD061	Gasifier - LP Nitrogen Area 130			
UD062	Gasifier - LP Nitrogen Area 140			
UD063	Gasifier - LP Nitrogen Area 150			
UD064	Gasifier - LP Nitrogen Area 150A			
UD065	Gasifier - LP Nitrogen Area 160			
UD066	Gasifier - LP Nitrogen Area 180			
UD067	Gasifier - LP Nitrogen Area 210			
UD068	Gasifier - LP Nitrogen Area 220			
UD069	Gasifier - LP Nitrogen Area 230			
UD070	Gasifier - LP Nitrogen Area 250			
UD071	Gasifier - LP Nitrogen Area 250A			
UD072	Gasifier - LP Nitrogen Area 260			
UD073	Gasifier - LP Nitrogen Area 500			
UE002	Gasifier - Blowdown Flash Drums DR0092/DR0095	DR0092, DR0095	GI	Gasifier Island
UE004	Gasifier - Demin Water		GI	Gasifier Island

Turnover Code	Description	Equipment No.	Process Area	Class
UE005	Gasifier - LP Steam		GI	Gasifier Island
UE006	Gasifier - IP Steam		GI	Gasifier Island
UE007	Gasifier - 325 Psig Process Steam	DR0091	GI	Gasifier Island
UE008	Gasifier - MP Steam		GI	Gasifier Island
UE009	Gasifier - Tempered Water Sys	DR0094, PU0094 DR0048, HX0094, HX0095	GI	Gasifier Island
UE010	Gasifier A - HP Steam Drum	DR1008	GI	Gasifier Island
UE011	Gasifier A - Syngas Cooling	HX1110, HX1210, HX1112, HX1114, HX1212, HX1214, HX1116, HX1216, HX1113, HX1213	GI	Gasifier Island
UE012	Gasifier B - HP Steam Drum	DR2008	GI	Gasifier Island
UE013	Gasifier B - Syngas Cooling	HX2110, HX2210, HX2112, HX2114, HX2212, HX2214, HX2116, HX2216, HX2113, HX2213	GI	Gasifier Island
UE015	Gasifier A - Header from PCD's FL1106 & FL1206 to Scrubber	FL1106, FL1206	GI	Gasifier Island
UE016	Gasifier B - Header from PCD's FL2106 & FL2206 to Scrubber	FL2106, FL2206	GI	Gasifier Island
UE017	Gasifier A - HP Bypass Header		GI	Gasifier Island
UE018	Gasifier B - HP Bypass Header		GI	Gasifier Island
UE019	Gasifier A - Syngas Cooler Warmup Recirculation Pumps		GI	Gasifier Island
UE020	Gasifier B- Syngas Cooler Warmup Recirculation Pumps		GI	Gasifier Island
UE022	Gasifier - Blowdown Tank UA-TK-4020	UA-TK-4020	GI	Gasifier Island
UE023	Gasifier - Blowdown Tank UA-TK-4030	UA-TK-4030	GI	Gasifier Island
UE024	Gasifier - Blowdown Tank UA-TK-4050	UA-TK-4050	GI	Gasifier Island
UE025	Gasifier - Blowdown Tank UA-TK-4060	UA-TK-4060	GI	Gasifier Island
UE026	Gasifier - WGS Heating / Activation Steam		GI	Gasifier Island
UE027	Gasifier A - Lower Mixing Zone Steam Piping	INJ-1001	GI	Gasifier Island
UE028	Gasifier B - Lower Mixing Zone Steam Piping	INJ-2001	GI	Gasifier Island
UG001	Gasifier - LP / Acid Flare	DR1097, BR1097, PU0097	GI-BOP	Gasifier Island
UG005	Gasifier - Flame Front Generator PG0098	PG0098	GI-BOP	Gasifier Island
UG006	Gasifier A - HP Flare	DR1089, DR1098, BR1098, PU1089	GI-BOP	Gasifier Island
UG007	Gasifier A -Combustion Turbine A Syngas Supply	DR1023, FL1024, HX1023	CC	Combined Cycle
UG008	Gasifier B - Combustion Turbine B Syngas Supply	DR2023, FL2024, HX2023	CC	Combined Cycle
UG010	Gasifier B - HP Flare	DR2089, DR2098, BR2098, PU2089	GI-BOP	Gasifier Island
UH001	Gasifier - AGR Antifoam Injection Sys PG0060 (Vendor Package)	PG0060 (Vendor Package)	GI	By Products
UH003	Gasifier A - CO2 Dehydration	PG1080	GI	By Products
UH005	Gasifier A - AGR CO2 Recycle Compressor CO1066	CO1066, HX1066	GI	Compressor
UH006	Gasifier A - AGR CO2 Recycle Compressor Lube Oil Unit CO1066LO	CO1066LO	GI	Oil System
UH007	Gasifier A - AGR Flash Gas Compressor CO1065	CO1065, HX1080, HX1086	GI	Compressor
UH008	Gasifier A - AGR Flash Gas Compressor Lube Oil Unit CO1065LO	CO1065LO	GI	Oil System
UH009	Gasifier A - CO2 MP KO Drum	DR1079	GI	Gasifier Island
UH010	Gasifier A - AGR Flash Gas Second Stage KO Drum DR1080	DR1080	GI	Compressor

Turnover Code	Description	Equipment No.	Process Area	Class
UH011	Gasifier A - AGR HS2 Absorber	CL1060, DR1062	GI	By Products
UH012	Gasifier A - AGR Lean-Rich Solvent Exchanger	HX1061	GI	
UH013	Gasifier A - AGR Third Semi-Lean Solvent Chiller	HX1368, DR1355	GI	By Products
UH015	Gasifier A - AGR Concentrator	CL1064, HX1062	GI	By Products
UH016	Gasifier A - AGR Feed Exchanger & KO Drum	HX1060, DR1060	GI	By Products
UH017	Gasifier A - AGR First CO2 Absorber	CL1161	GI	By Products
UH018	Gasifier A - AGR First HP & MP CO2 Flash Drums	DR1166, DR1167	GI	By Products
UH019	Gasifier A - AGR First Loaded Solvent Chiller	HX1169, DR1153	GI	By Products
UH020	Gasifier A - AGR First Loaded Solvent Pumps	PU1166A/B	GI	By Products
UH021	Gasifier A - AGR First LP CO2 Flash Drum	DR1168	GI	By Products
UH022	Gasifier A - AGR First Semi-Lean Solvent Chiller	HX1168, DR1155	GI	By Products
UH023	Gasifier A - CO2 Mercury Adsorber & Comp Filter	RX1080, FL1082	GI	By Products
UH024	Gasifier A - AGR HP Lean Solvent Pumps	PU1067	GI	By Products
UH025	Gasifier A - AGR Lean Solvent Chillers	HX1067A/B, DR1054	GI	By Products
UH026	Gasifier A - AGR LP Lean Solvent Pumps	PU1063A/B	GI	By Products
UH027	Gasifier A - AGR Regenerator & Condenser	CL1063, HX1063A/B, HX1064	GI	By Products
UH028	Gasifier A - AGR Regenerator Reboilers Condensate Drums	HX1063, DR1069	GI	By Products
UH029	Gasifier A - AGR Regenerator Reflux Drum	DR1064	GI	By Products
UH030	Gasifier A - AGR Regenerator Reflux Pumps	PU1064A/B	GI	By Products
UH031	Gasifier A - AGR Rich Solvent Flash & K.O. Drums	DR1063, DR1065, HX1065	GI	By Products
UH032	Gasifier A - AGR Rich Solvent Pumps	PU1060A/B	GI	By Products
UH033	Gasifier A - AGR Second CO2 Absorber	CL1261	GI	By Products
UH034	Gasifier A - AGR Second HP & MP CO2 Flash Drums	DR1266, DR1267	GI	By Products
UH035	Gasifier A - AGR Second Loaded Solvent Chiller	HX1269, DR1253	GI	By Products
UH036	Gasifier A - AGR Second Loaded Solvent Pumps	PU1266A/B	GI	By Products
UH037	Gasifier A - AGR Second LP CO2 Flash Drum DR1268	DR1268	GI	By Products
UH038	Gasifier A - AGR Second Semi-Lean Solvent Chiller	HX1268, DR1255	GI	By Products
UH039	Gasifier A - AGR Semi-Lean Solvent Pumps	PU1068A/B/C/D	GI	By Products
UH040	Gasifier A - AGR Solvent Filtration System	PU1058, FL1060	GI	By Products
UH041	Gasifier A - AGR Solvent K.O. Drum	DR1061	GI	By Products
UH042	Gasifier A - AGR Third CO2 Absorber	CL1361	GI	By Products
UH043	Gasifier A - AGR Third Loaded Solvent Chiller	HX1369, DR1353	GI	By Products
UH044	Gasifier A - AGR Third Loaded Solvent Pumps	PU1366A/B	GI	By Products
UH045	Gasifier B - AGR CO2 Recycle Compressor CO2066	CO2066	GI	Compressor
UH046	Gasifier B - AGR CO2 Recycle Compressor Lube Oil Unit CO2066LO	CO2066LO	GI	Oil System
UH047	Gasifier B - AGR Feed Exchanger & KO Drum	HX2060, DR2060	GI	Gasifier Gas Cleanup
UH048	Gasifier B - AGR First CO2 Absorber	CL2161	GI	Gasifier Gas Cleanup
UH049	Gasifier B - AGR First Loaded Solvent Chiller	HX2169, DR2153	GI	Gasifier Gas Cleanup
UH050	Gasifier B - AGR Flash Gas Compressor CO2065	CO2065, HX2080, HX2086	GI	Compressor

Turnover Code	Description	Equipment No.	Process Area	Class
UH051	Gasifier B - AGR Flash Gas Compressor Lube Oil Unit CO2065LO	CO2065LO	GI	Oil System
UH052	Gasifier B - AGR Flash Gas Second Stage KO Drum DR2080	DR2080	GI	
UH054	Gasifier B - AGR HS2 Absorber	CL2060, DR2062	GI	Gasifier Gas Cleanup
UH055	Gasifier B - AGR Lean-Rich Solvent Exchanger	HX2061	GI	
UH056	Gasifier B - AGR Second CO2 Absorber	CL2261	GI	Gasifier Gas Cleanup
UH057	Gasifier B - AGR Second Loaded Solvent Chiller	HX2269, DR2253	GI	Gasifier Gas Cleanup
UH058	Gasifier B - AGR Solvent Filtration System	PU2058, FL2060	GI	Gasifier Gas Cleanup
UH059	Gasifier B - AGR Third CO2 Absorber	CL2361	GI	Gasifier Gas Cleanup
UH060	Gasifier B - AGR Third Loaded Solvent Chiller	HX2369, DR2353	GI	Gasifier Gas Cleanup
UH061	Gasifier B - AGR Third Semi-Lean Solvent Chiller	HX2368, DR2355	GI	Gasifier Gas Cleanup
UH063	Gasifier B - AGR Concentrator	CL2064, HX2062	GI	Gasifier Gas Cleanup
UH064	Gasifier B - AGR First HP & MP CO2 Flash Drums	DR2166, DR2167	GI	Gasifier Gas Cleanup
UH065	Gasifier B - AGR First Loaded Solvent Pumps	PU2166A/B	GI	By Products
UH066	Gasifier B - AGR First LP CO2 Flash Drum	DR2168	GI	Gasifier Gas Cleanup
UH067	Gasifier B - AGR First Semi-Lean Solvent Chiller	HX2168, DR2155	GI	Gasifier Gas Cleanup
UH069	Gasifier B - AGR HP Lean Solvent Pumps	PU2067A/B	GI	Gasifier Gas Cleanup
UH070	Gasifier B - AGR Lean Solvent Chillers	HX2067A/B, DR2054	GI	By Products
UH071	Gasifier B - AGR LP Lean Solvent Pumps	PU2063A/B	GI	Gasifier Gas Cleanup
UH072	Gasifier B - AGR Regenerator & Condenser	CL2063, HX2063A/B	GI	Gasifier Gas Cleanup
UH073	Gasifier B - AGR Regenerator Reboilers Condensate Drums	HX2063, DR2069A/B	GI	By Products
UH074	Gasifier B - AGR Regenerator Reflux Drum	DR2064	GI	By Products
UH075	Gasifier B - AGR Regenerator Reflux Pumps	PU2064	GI	Gasifier Gas Cleanup
UH076	Gasifier B - AGR Rich Solvent Flash & K.O. Drums	DR2063, DR2065, HX2065	GI	By Products
UH077	Gasifier B - AGR Rich Solvent Pumps	PU2060A/B	GI	Gasifier Gas Cleanup
UH078	Gasifier B - AGR Second HP & MP CO2 Flash Drums	DR2266/67	GI	Gasifier Gas Cleanup
UH079	Gasifier B - AGR Second Loaded Solvent Pumps	PU2266A/B	GI	By Products
UH080	Gasifier B - AGR Second LP CO2 Flash Drum	DR2268	GI	Gasifier Gas Cleanup
UH081	Gasifier B - AGR Second Semi-Lean Solvent Chiller	HX2268, DR2255	GI	Gasifier Gas Cleanup
UH082	Gasifier B - AGR Semi-Lean Solvent Pumps	PU2068A/B/C/D	GI	Gasifier Gas Cleanup
UH083	Gasifier B - AGR Solvent K.O. Drum	DR2061	GI	By Products
UH084	Gasifier B - AGR Third Loaded Solvent Pumps	PU2366A/B	GI	By Products
UH085	AGR SELEXOL Storage Tank	TK0060	GI-BOP	By Products
UH086	AGR Solvent Transfer Pump	PU0062A/B	GI-BOP	By Products
UH089	Gasifier A - AGR Lean Solvent Header		GI	By Products
UH090	Gasifier A - LP CO2 Vent Header		GI	By Products
UH091	AGR Acid Gas Header		GI	By Products
UH092	Gasifier B - AGR Lean Solvent Header		GI	Gasifier Island
UH093	Gasifier B - LP CO2 Vent Header		GI	By Products
UH095	Gasifier B - CO2 MP KO Drum	DR2079	GI	By Products

Turnover Code	Description	Equipment No.	Process Area	Class
UH096	Gasifier B - CO2 Mercury Absorber & Comp Filter	RX2080, FL2082	GI	By Products
UH097	Gasifier A - LP CO2 KO Drum	DR1078	GI	By Products
UH098	Gasifier B - LP CO2 KO Drum	DR2078	GI	By Products
UH099	Gasifier B - CO2 Dehydration	PG2080	GI-BOP	By Products
UH100	Gasifier - AGR Refrigeration Supply/Return Header	PG0061	GI	By Products
UH101	Gasifier-AGR RE Compressor Skids(A-H)	PG0061	GI	By Products
UH109	CO2 Metering & Regulation Station		GI-BOP	By Products
UH110	CO2 Pipeline / Pig Launcher & Receiver Station		GI-BOP	By Products
UH111	CO2 Tellus Delivery Station		GI-BOP	By Products
UH112	CO2 Denbury Delivery Station		GI-BOP	By Products
UH113	Gasifier A - AGR Refrigeration Lube Oil Stilling Skid		GI	By Products
UH114	Gasifier B - AGR Refrigeration Lube Oil Stilling Skid		GI	By Products
UH115	Gasifier A AGR Refrigeration Sub-Headers			
UH116	Gasifier B AGR Refrigeration Sub-Headers			
UL001	Gasifier - Hydrocarbon Drain Drum	DR0047, PU0047A/B	GI	By Products
UL003	Gasifier A - Ammonia Scrubber	CL1006, PU1006	GI	By Products
UL004	Gasifier A - COS Hydrolysis Reactor	RX1104, RX1204	GI	Gasifier Island
UL005	Gasifier A - Mercury Adsorber	RX1106, RX1206, FL1010	GI	By Products
UL006	Gasifier A - First Stage WGS Reactors & Syngas Recuperators	RX1108, RX1208, DR1014, HX1009, HX1020	GI	Gasifier Island
UL007	Gasifier A - Process Condensate KO Drum	DR1010, DR1013, DR1027, HX1024, HX1025, HX1027, PU1010A/B	GI	Gasifier Island
UL009	Gasifier A - LP Vent Gas Header		GI	Gasifier Island
UL010	Gasifier A - WGS & Catalyst Reactors Warmup	DR1035, HX1035	GI	Gasifier Island
UL011	Gasifier A - Syngas Scrubber	CL1007, PU1007A/B, HX1007, HX1008, DR1007, DR1014, DR0049, HX0059	GI	Gasifier Island
UL012	Gasifier A - Second Stage WGS Reactors	RX1109, RX1209, HX1011A/B, HX1021, HX1022	GI	Gasifier Island
UL013	Gasifier B - Ammonia Scrubber	CL2006, PU2006A/B, DR2016	GI	Gasifier Gas Cleanup
UL014	Gasifier B - COS Hydrolysis Reactor	RX2104, RX2204	GI	Gasifier Gas Cleanup
UL015	Gasifier B - Mercury Adsorber	RX2106, RX2206, FL2010	GI	Gasifier Gas Cleanup
UL016	Gasifier B - Second Stage WGS Reactors	RX2109, RX2209, HX2011A/B, HX2020, HX2021, HX2022	GI	Gasifier Gas Cleanup
UL017	Gasifier B - Process Condensate KO Drum	DR2010, DR2013, HX2024, HX2025, HX2027, PU2010A/B	GI	Gasifier Gas Cleanup
UL018	Gasifier B - WGS & Catalyst Reactors Warmup	DR2035, HX2035	GI	Gasifier Island
UL019	Gasifier - Lights Hydrocarbons Drain Line		GI	Gasifier Island
UL020	Gasifier B - Syngas Scrubber	CL2007, PU2007, HX2007, HX2008, DR2007	GI	Gasifier Island
UL021	Gasifier -Heavies Hydrocarbons Drain Line		GI	Gasifier Island
UL022	Gasifier B - LP Vent Gas Header		GI	Gasifier Island
UL023	Gasifier B - First Stage WGS Reactors & Syngas Recuperators	RX2108, RX2208, HX2009,	GI	Gasifier Island
UL024	Gasifier A -Hydrocarbons Vent Line		GI	Gasifier Island
UL030	Syngas Scrubber Bottom Outlet Pump A			
UL031	Syngas Scrubber Bottom Outlet Pump B			

Turnover Code	Description	Equipment No.	Process Area	Class
UM001	Gasifier - Ammonia Storage Tank A	DR0058 A	GI	By Products
UM002	Gasifier - Ammonia Storage Tank B	DR0058 B	GI	By Products
UM003	Gasifier - Ammonia Storage Tank C	DR0058 C	GI	By Products
UM004	Gasifier - Ammonia Storage Tank D	DR0058 D	GI	By Products
UM005	Gasifier - Anhydrous Ammonia Truck Loading Pumps	PU0053, PG0054	GI	By Products
UM006	Gasifier - Anhydrous Ammonia Rerun Pumps	PU0054A/B	GI	By Products
UM008	Gasifier - Sulfuric Acid Storage Tank A	TK0072A	GI	By Products
UM010	Gasifier - Sulfuric Acid Truck Loading	PG0071, PU0077A/B/C/D	GI	By Products
UM011	Gasifier - Waste Water Ammonia Purifier Reflux Drum, Pump and Condenser	DR0051, PU0050A/B, HX0051	GI-BOP	By Products
UM012	Gasifier - Wastewater Ammonia Purifier, condenser and reboiler	CL0052, HX0052, HX0054, DR0059	GI-BOP	By Products
UM013	Gasifier - Wastewater Ammonia Stripper, condenser, reboiler, trim condenser and wastewater cooler	CL0044, HX0044, HX0045, HX0046, HX0056	GI-BOP	By Products
UM014	Gasifier - Wastewater Ammonia Stripper Reflux Drum and pump	DR0045, PU0045A/B	GI-BOP	By Products
UM016	Gasifier - Hydrogen Sulfide Stripper and reboiler	CL0042, HX0042	GI-BOP	By Products
UM017	Gasifier - 50WT% Caustic Storage	TK0095	GI	
UM018	Gasifier - AGR Water Break Drum	DR0056	GI	By Products
UM019	Gasifier - Ammonia Flare	DR1099, BR1099, PU0099	GI-BOP	Gasifier Island
UM020	Gasifier A - CO2 Product Compressor	CO1080, HX1085, PG1080HX-1	GI	Compressor
UM021	Gasifier A - CO2 Compressor Lube Oil Unit CO1080LO	CO1080LO	GI	Oil System
UM022	Gasifier B - CO2 Compressor Lube Oil Unit CO2080LO	CO2080LO	GI	Oil System
UM023	Gasifier B - CO2 Product Compressor	CO2080, HX2085	GI	Compressor
UM024	WSA - Ammonia Injection	HX0077A/B	GI-BOP	By Products
UM025	WSA - Combustion Air Blower	BL0071	GI-BOP	By Products
UM026	WSA - Combustor/Waste Heat Steam Generator	AH0070, HX0070	GI-BOP	By Products
UM027	WSA - Condenser	HX0074	GI-BOP	By Products
UM028	WSA - Cooling Filter & Blower	BL0070, FL0070	GI-BOP	By Products
UM029	WSA - Mist Control PG0070A, B C & D	PG0070A, B C & D	GI-BOP	By Products
UM030	WSA - MP Steam Drum	DR0070	GI-BOP	By Products
UM031	WSA - Peroxide Storage & Dosing Pumps	TK0070, PU0074A/B	GI-BOP	By Products
UM032	WSA - Quench Water Column	CL0070	GI-BOP	By Products
UM033	WSA - Quench Water Pumps	PU0072A, B & C	GI-BOP	By Products
UM034	WSA - SCR Reactor	RX0070	GI-BOP	By Products
UM035	WSA - Scrubber Column	CL0071, FL0071	GI-BOP	By Products
UM036	WSA - Scrubber Water Pumps	PU0073A, B, C & D	GI-BOP	By Products
UM037	WSA - SO2 Converter / Interbed Coolers / Process Gas Cooler	RX0071, HX0071, HX0072, HX0073	GI-BOP	By Products
UM040	WSA - Stack	BL0072, ST0060	GI-BOP	By Products
UM041	WSA - Acid Pumps & Cooler	PU0070A, B & C, HX0076	GI-BOP	By Products
UM042	WSA - Acid Product Pumps	PU0071A/B	GI-BOP	By Products
UM043	WSA - Hot Air Heaters	HX0075A/B, MX0070	GI-BOP	By Products
UM044	WSA - Natural Gas		GI-BOP	Natural Gas

Turnover Code	Description	Equipment No.	Process Area	Class
UM045	Waste Water Ammonia Purifier Bottom Pumps	PU0057A/B	GI-BOP	By Products
UM046	Gasifier - 50WT % Caustic Pumps	PU0095A/B	GI-BOP	Chemical Feed
UM047	Gasifier A - AGR Water Make-up Pumps	PU1069A/B	GI-BOP	Make-up Water
UM048	Gasifier B - AGR Water Make-up Pumps	PU2069A/B	GI-BOP	Make-up Water
UM049	Gasifier - Sulfuric Acid Rundown Storage	TK0071	GI-BOP	
UM050	Sulfuric Acid Rundown Pump	PU0076A/B	GI-BOP	
UM051	Gasifier Ammonia Header		GI-BOP	Gasifier Island
UM052	Gasifier WSA Combustor - Burner Management System		GI-BOP	By Products
UM053	Gasifier - Hydrogen Sulfide Vent Line		GI-BOP	By Products
UM055	Sulfuric Acid Offspec Tank (TK0073)	TK0073	GI-BOP	By Products
UM056	Sulfuric Acid Offspec Tank Pumps	PU0079A/B	GI-BOP	By Products
UM058	Gasifier – Make-up Process Water Header		GI-BOP	By Products
UM060	Sulfuric Acid Storage Tank B	TK0072B	GI-BOP	By Products
UM061	Anhydrous Ammonia Reflux Make-up Pumps	PU0059A/B	GI-BOP	By Products
VA001	Combustion Turbine A Extraction Air		CC	Combined Cycle
VA002	Combustion Turbine A Inlet Filter		CC	Combined Cycle
VA003	Combustion Turbine A Outlet Duct		CC	Combined Cycle
VA004	Combustion Turbine B Extraction Air		CC	Combined Cycle
VA005	Combustion Turbine B Inlet Filter		CC	Combined Cycle
VA006	Combustion Turbine B Outlet Duct		CC	Combined Cycle
VB001	Combustion Turbine A Lube Oil Sys		CC	Oil System
VB002	Combustion Turbine B Lube Oil Sys		CC	Oil System
VC001	Combustion Turbine A Control Oil Sys		CC	Oil System
VC002	Combustion Turbine B Control Oil Sys		CC	Oil System
VD001	Combustion Turbine A & B Static Frequency Converter		CC	Combined Cycle
VG001	Combustion Turbine A	VG-TU-3001A	CC	Combined Cycle
VG002	Combustion Turbine B	VG-TU-3001B	CC	Combined Cycle
VJ001	Combustion Turbine A - Wash Water Sys		CC	Combined Cycle
VJ002	Combustion Turbine B - Wash Water Sys		CC	Combined Cycle
VK001	Combustion Turbine A Steam Injection		CC	Combined Cycle
VK002	Combustion Turbine B Steam Injection		CC	Combined Cycle
VY002	Combustion Turbine A Turning Gear		CC	Combined Cycle
VY004	Combustion Turbine B Turning Gear		CC	Combined Cycle
WA001	Combined Cycle A Nitrogen Gas Supply		CC	Combined Cycle
WA002	HRSG A Nitrogen Sys		CC	Combined Cycle
WA003	HRSG B Nitrogen Sys		CC	Combined Cycle
WA004	Combined Cycle B Nitrogen Gas Supply		CC	Combined Cycle
WB002	HRSG A High Pressure Steam Bypass		CC	Combined Cycle
WB004	HRSG A IP Steam Bypass		CC	Combined Cycle
WB008	HRSG B Cold Reheat Steam		CC	Combined Cycle

Turnover Code	Description	Equipment No.	Process Area	Class
WB009	HRSG B High Pressure Steam Bypass		CC	Combined Cycle
WB010	HRSG B Hot Reheat Steam		CC	Combined Cycle
WB011	HRSG B IP Steam Bypass		CC	Combined Cycle
WB013	HRSG B Main Steam		CC	Combined Cycle
WH001	HRSG A Duct Burners		CC	Combined Cycle
WH002	HRSG B Duct Burners		CC	Combined Cycle
WJ001	HRSG A Blowdown		CC	Combined Cycle
WJ002	HRSG B Blowdown		CC	Combined Cycle
WJ003	Auxiliary Blowdown Tank A		CC	Combined Cycle
WJ004	Auxiliary Blowdown Tank B		CC	Combined Cycle
WJ005	Main Steam Blowdown Tank		CC	Combined Cycle
WY001	HRSG A	WG-HR-2001A	CC	Combined Cycle
WY003	HRSG B	WG-HR-2001B	CC	Combined Cycle
YA001	HRSG Anhydrous Ammonia Sys		CC	Combined Cycle
YA002	Anhydrous Ammonia Transfer Pumps			
YF001	Anhydrous Ammonia Failure & Leak Detection Sys		CC	Combined Cycle
ZB001	Control System - Auxiliary Boiler		CC-BOP	Combined Cycle
ZB002	Control System - Combustion Turbine A		CC	Combined Cycle
ZB003	Control System - Combustion Turbine B		CC	Combined Cycle
ZB004	Control System - Steam Turbine		CC	Combined Cycle
ZB005	Control System - Water Treatment Plant		CC-BOP	Raw Water
ZB007	Control System - Process Air Compressor CO1102		GI	Gasifier Island
ZB008	DCS Control Equipment - Combined Cycle Water Lab		CC-BOP	Combined Cycle
ZB009	DCS Control Equipment - Admin /Control Bldg.		GI	Gasifier Island
ZB010	DCS Cabinets - Main Elect Bldg		GI	Gasifier Island
ZB011	DCS Cabinets - Combined Cycle Elect Bldg		CC	Combined Cycle
ZB012	DCS Cabinets - Gasifier A MCC Bldg		GI	Gasifier Island
ZB013	DCS Cabinets - Gasifier B MCC Bldg		GI	Gasifier Island
ZB014	DCS Cabinets - Lignite Delivery Facility		LP	Lignite Delivery
ZB015	Gasifier A - Vibration Monitoring System		GI	Gasifier Island
ZB016	Gasifier B - Vibration monitoring System		GI	Gasifier Island
ZB017	DCS Cabinets - HRSG A PEECC		CC	Combined Cycle
ZB018	DCS Cabinets - HRSG B PEECC		CC	Combined Cycle
ZB019	DCS Cabinets - Combined Cycle Cooling Tower PEECC		CC-BOP	Combined Cycle
ZB020	DCS Cabinets - Gasifier A EL 515'		GI	Gasifier Island
ZB021	DCS Cabinets - Gasifier A EL 568'		GI	Gasifier Island
ZB022	DCS Cabinets - Gasifier A EL 643'		GI	Gasifier Island
ZB023	DCS Cabinets - Gasifier B EL 515'		GI	Gasifier Island
ZB024	DCS Cabinets - Gasifier B EL 568'		GI	Gasifier Island
ZB025	DCS Cabinets - Gasifier B EL 643'		GI	Gasifier Island

Turnover Code	Description	Equipment No.	Process Area	Class
ZB026	DCS Cabinets - SELEXOL Elec Bldg		GI-BOP	Gasifier Island
ZB027	DCS Cabinets - Gas Cleanup Elec Bldg		GI-BOP	Gasifier Island
ZB028	DCS Cabinets - Flares Elec Bldg		GI-BOP	Gasifier Island
ZB029	DCS Cabinets - Gasifier Cooling Tower PEECC		GI-BOP	Gasifier Island
ZB030	DCS Cabinets - CO2 / N2 Elec Bldg		GI-BOP	Gasifier Island
ZB031	DCS Cabinets - WSA Elec Bldg		GI-BOP	Gasifier Island
ZB032	Control System - Process Air Compressor CO1202		GI	Gasifier Island
ZB033	Control System - Process Air Compressor CO2102		GI	Gasifier Island
ZB034	Control System - Process Air Compressor CO2202		GI	Gasifier Island
ZB035	Control System - Transport Air Compressor A		GI	Gasifier Island
ZB036	Control System - Transport Air Compressor B		GI	Gasifier Island
ZB037	Control System - Extraction Air Compressor A		GI	Gasifier Island
ZB038	Control System - Extraction Air Compressor B		GI	Gasifier Island
ZB039	Control System - Recycle Air Compressor A		GI	Gasifier Island
ZB040	Control System - Recycle Air Compressor B		GI	Gasifier Island
ZB041	Control System - Refrigeration Package		GI	Gasifier Island
ZB042	Control System - Gasifier A Startup Burners PLC		GI-BOP	Gasifier Island
ZB043	Control System - Gasifier B Startup Burners PLC		GI	Gasifier Island
ZB044	Control System AGR CO2 Recycle Compressors		Gi	Gasifier Island
ZB045	Control System AGR Flash Gas Compressors		Gi	Gasifier Island
ZB046	DCS Cabinets - Gasifier Water Lab		GI	Gasifier Island
ZB047	Control System CO2 Air Compressors		CC	Combined Cycle
ZB048	DCS Cabinets - Water Intake / Reclaim Sump		CC	CC BOP
ZB049	Gasifier A - Analyzer House 3	AIT-11336, AIT-11340, AIT-11344, AIT-11353, AIT-12336, AIT-12340, AIT-12353, AIT-12344	GI	Gasifier Island
ZB050	Gasifier B - Analyzer House 4	AIT-21336, AIT-21340, AIT-21344, AIT-21353, AIT-22336, AIT-22340, AIT-22344, AIT-22353	GI	Gasifier Island
ZB051	Train A Gas Clean-up - Analyzer House 5	AIT-14450, AIT-14457 GC, AIT-14504 GC, AIT-14513 GC, AIT-14515, AIT-14528, AIT-14564, AIT-14570 GC, AIT-14572, AIT-14731, AIT-19015, AIT-19477, AIT-24731	GI	Gasifier Island
ZB052	Train B Gas Clean-up - Analyzer House 6	AIT-24450, AIT-24457 GC, AIT-24504 GC, AIT-24513 GC, AIT-24515, AIT-24528, AIT-24564, AIT-24570 GC, AIT-24572 GC, AIT-29015, AIT-29477	GI	Gasifier Island
ZB053	Flare KO pots - Analyzer House 7	AIT-04968, AIT-14944, AIT-24944	GI	Gasifier Island
ZB054	WSA pkg - Analyzer House 8	AIT-08004 GC, AIT-08044, AIT-08045, AIT-08051, AIT-08120, AIT-08176, AIT-08351	GI	Gasifier Island
ZB055	Plant Simulator			
ZB056	13.8 kv VFD MASTER PLC CABINET			

Section 3.4.3 – Test Packages Summary

Stand Alone Test Packages-First Tier

Test Package	Number	Notes
Recovered water test package	TP1000	
Tempered water system	TP1001	
Venturi scrubber test package 1	TP1002	
Venturi scrubber test package 2	TP1003	
Venturi scrubber test package 3	TP1004	
Venturi scrubber test package 4	TP2002	
Venturi scrubber test package 5	TP2003	
Venturi scrubber test package 6	TP2004	
Mill gas loop Test 1	TP1075	
Mill gas loop Test 2	TP1076	
Mill gas loop Test 3	TP1077	
Mill gas loop Test 4	TP2075	
Mill gas loop Test 5	TP2076	
Mill gas loop Test 6	TP2077	
Dryer gas loop test 1	TP1005	
Dryer gas loop test 2	TP1006	
Dryer gas loop test 3	TP1007	
Dryer gas loop test 4	TP2005	
Dryer gas loop test 5	TP2006	
Dryer gas loop test 6	TP2007	
Pyrite drag chain system	TP1013	
CCAD primary cooler hydro 1	TP1018	
CCAD primary cooler hydro 2	TP2018	
Gas clean up nitrogen circulation and heat up 1	TP1028	
Gas clean up nitrogen circulation and heat up 2	TP2028	
Sour water hydro test	TP1029	
Sour water full system test	TP1030	
Sour water ammonia storage and loading test	TP1031	
AGR piping hydro 1	TP1032	
AGR piping hydro 2	TP2032	
AGR flush test 1	TP1033	
AGR flush test 2	TP2033	
AGR degreasing 1	TP1034	
AGR degreasing 2	TP2034	
AGR purging 1	TP1035	
AGR purging 2	TP2035	
AGR SELEXOL circulation 1	TP1036	

Stand Alone Test Packages-First Tier

Test Package	Number	Notes
AGR SELEXOL circulation 2	TP2036	
AGR filtration package 1	TP1037	
AGR filtration package 2	TP2037	
AGR refrigeration	TP1038	
AGR antifoam injection package	TP1039	
SELEXOL storage tank	TP1040	
WSA pneumatic test	TP1041	
WSA water side flush	TP1042	
WSA air circulation test	TP1043	
WSA second air circulation	TP1044	
WSA steam system hydro	TP1045	
WSA steam system flush and clean	TP1046	
WSA steam system atmospheric boil out	TP1047	
WSA flush and clean of acid system	TP1048	
WSA first heating up, cure out, pressurized boil out	TP1049	
High pressure flare 1 purge	TP1050	
High pressure flare 2 purge	TP2050	
Ammonia flare purge	TP1051	
LP/acid flare purge	TP1052	
High pressure flare 1 enrichment test	TP1053	
High pressure flare 2 enrichment test	TP2053	
Ammonia flare enrichment test	TP1054	
LP/acid flare enrichment test	TP1055	
High pressure flare 1 automatic relight test	TP1056	
High pressure flare 2 automatic relight test	TP2056	
Ammonia flare automatic relight test	TP1057	
LP/acid flare automatic relight test	TP1058	
High pressure flare 1 FFG test	TP1059	
High pressure flare 2 FFG test	TP2059	
Ammonia flare FFG test	TP1060	
LP/acid flare FFG test	TP1061	
Hydrogen peroxide tank and pumps	TP1062	
Sulfuric acid storage and loading	TP1063	
Recycle gas compressor 1	TP1064	Try to do this during N2 heat-up?
Recycle gas compressor 2	TP2064	Try to do this during N2 heat-up?
AGR CO2 recycle compressor 1	TP1065	
AGR CO2 recycle compressor 2	TP2065	
AGR flash gas 1	TP1066	
AGR flash gas 2	TP2066	

Stand Alone Test Packages-First Tier

Test Package	Number	Notes
PAC 1+2	TP1067	
PAC 3+4	TP2067	
Extraction air compressor 1	TP1068	
Extraction air compressor 2	TP2068	
Transport air compressor 1	TP1069	
Transport air compressor 2	TP2069	
CO2 compression, separation, and drying package 1	TP1070	
CO2 compression, separation, and drying package 2	TP2070	
ASU compressor 2	TP1071	
LP vent gas compressor	TP1072	

Integrated Test Packages-Second and Third Tier

Test Package	Number	notes
Gasifier pneumatic test 1	TP1019	May require nitrogen, RGC, or a PAC
Steam drum and syngas coolers 1A (hydro)	TP1021	Requires condensate system checks
Steam drum and syngas coolers 1B (hydro)	TP1022	Requires condensate system checks
Gasifier air test 1 (test fire SUB)- Includes blowing through all columns	TP1020	Desire is to blow through all columns clean with no internals. However, may have to have internals installed
Ash system test A	TP1008	Test feed lines to silos, ash mixers
Ash system test 0007	TP1012	Test silo and feed system to feed to Silo 8
Cold circulation 1	TP1025	Includes CCAD and CFAD testing. May use ASU compressor to take system pressure to 100 psig to test CCAD and CFAD. Test feed PDAC feeders associated with Train #1
Lignite test 2	TP1015	Includes circulating PDAC back to PC Silo. Commissioning test of dryer. End goal is to have enough coal for gasifier startup
Lignite test 3	TP1016	Includes circulating PDAC back to PC Silo. Commissioning test of dryer. End goal is to have enough coal for gasifier startup
Lignite test 4	TP2015	Includes circulating PDAC back to PC Silo. Commissioning test of dryer. End goal is to have enough coal for gasifier startup
Lignite test 5	TP2016	Includes circulating PDAC back to PC Silo. Commissioning test of dryer. End goal is to have enough coal for gasifier startup
Ash system test B	TP1009	Test feed lines to silos, ash mixers
Ash system test C	TP1010	Test feed lines to silos, ash mixers
Ash system test D	TP1011	Test feed lines to silos, ash mixers
Lignite test 1	TP1017	Includes circulating PDAC back to PC Silo. Commissioning test of dryer. End goal is to have enough coal for gasifier startup
Lignite test 6	TP2017	Includes circulating PDAC back to PC Silo. Commissioning test of dryer. End goal is to have enough coal for gasifier startup
Steam drum and syngas coolers 1A	TP1023	Testing of cooler loops and controllers. Done Before heat to gasifier
Steam drum and syngas coolers 1B	TP1024	Testing of cooler loops and controllers. Done Before heat to gasifier
Process steam system, LP, IP, MP	TP1073	
Cure out 1	TP1026	Requires ASU compressor, Test SUBs and gasifier heat up, Performance test on Gas Coolers
First coal feed test 1	TP1027	Does not include sulfiding, may roll directly into it however
First coal feed test 1 (sulfiding, AGR, WSA)	TP1074	Using expanded Start Up After Maintenance Procedure
Gasifier pneumatic test 2	TP2019	Follows train #1 by hopefully 2 weeks

Stand Alone Test Packages-First Tier

Test Package	Number	Notes
Steam drum and syngas coolers 2A (hydro)	TP2021	Follows train #1 by hopefully 2 weeks
Steam drum and syngas coolers 2B (hydro)	TP2022	Follows train #1 by hopefully 2 weeks
Cold circulation 2	TP2025	Follows train #1 by hopefully 2 weeks
Gasifier air test 2 (test fire SUB)- Includes blowing through all columns	TP2020	Follows train #1 by hopefully 2 weeks
Steam drum and syngas coolers 2A	TP2023	Follows train #1 by hopefully 2 weeks
Steam drum and syngas coolers 2B	TP2024	Follows train #1 by hopefully 2 weeks
Cure out 2	TP2026	Follows train #1 by hopefully 2 weeks
First coal feed test 2	TP2027	Follows train #1 by hopefully 2 weeks
First coal feed test 2 (sulfiding, AGR, WSA)	TP2074	Follows train #1 by hopefully 2 weeks

Section 3.4.4 – TOP to Milestone Assignments

Milestone	System	System Description
Support for Air Liquide	HE001	Combined Cycle Auxiliary Circulating Water Sys
	HC002	Gasifier Island Cooling Tower Chemical Feed Systems
	HE008	Gasifier Island Closed Loop Cooling Water Sys
	HK002	Gasifier Island Cooling Tower
	UD051	Gasifier - Startup Air Supply
	HD003	Gasifier Island Auxiliary Circulating Water Sys
	HE005	Gasifier Island Closed Loop Cooling Water Sys
	HE009	Gasifier Island Closed Loop Cooling Water Sys
	HE005/HE006	
	HE012	Gasifier Island Closed Loop Cooling Water Sys
Test Package TP1019 Pneumatic Pressure Test of Gasifier - Train A	UD007	Gasifier A - ASU/Startup Air Compressors CO0106
	HE028	Gasifier Island Closed Loop Cooling Water Sys
	HE013	Gasifier Island Closed Loop Cooling Water Sys
	HE029	Gasifier Island Closed Loop Cooling Water Sys
	UE027	Gasifier A - Lower Mixing Zone Steam Piping
	HE006	Gasifier Island Closed Loop Cooling Water Sys
	HE024	Service Water - Sulfuric Acid Area
	DD009	Gasifier - Natural Gas Distribution
	UA004	Gasifier A - Startup Burner A
	HE007	Gasifier Island Closed Loop Cooling Water Sys
	SA011	Instrument Air System - Gasifier A
	HE014	Gasifier Island Closed Loop Cooling Water Sys
	DB001	Fuel Oil System
	HE027	Gasifier Island Closed Loop Cooling Water Sys
	UA005	Gasifier A - Startup Burner B
	UD014	Gasifier A - Gasifier Pressure Safety Valve Sensing Header
	UB043	Gasifier A - Solids Injection Nozzle 1A
	HE010	Gasifier Island Closed Loop Cooling Water Sys
	UD006	Gasifier - Nitrogen Generation System
Test Packages TP1000, TP1001 Lignite Dryer Common Utilities	CD030	Gasifier - HP Make-up Water Pumps
	CD038	Gasifier - Pyrite Disposal System
	HD002	Gasifier Island Circulating Water System
	UC052	Gasifier - Ash Conditioner Venturi Scrubber A
	HE017	Service Water - Gasifier A Structure
	DF003	Lignite Delivery - Belt Conveyor 005A
	DF004	Lignite Delivery - Belt Conveyor 005B
	DF020	Lignite Handling - (Silo Tripper Belt A) 006A
	DF021	Lignite Handling - (Silo Tripper Belt B) 006B
	UD064	Gasifier - LP Nitrogen Area 150A

Milestone	System	System Description
	CD040	Gasifier - Filter Press System
	UD071	Gasifier - LP Nitrogen Area 250A
	DA008	Dust Collector Lignite Silo's
	CD028	Gasifier - Excess Water Pumps
	DA007	Gasifier - Drum Filter System DR0006
	CD039	Gasifier - Filter Press Pumps
Test Package TP1017	CE007	Gasifier A - Fluid Bed Dryer Discharger Feeder 1
Lignite Dryer 1	CD010	Gasifier A- Multi-Clone 1
	DK001	Gasifier A - Crushed Lignite Silo 1
	UB013	Gasifier A - Feed System 1A
	UB014	Gasifier A - Feed System 1B
	DA011	Gasifier - Venturi Scrubber Pumparound 1
	DA009	Gasifier - Venturi Scrubber Pump 1
	UB008	Gasifier A - Feed Storage & Lock Vessel 1B
	CD032	Gasifier A Lignite Mill Feed Fan 1A
	UB007	Gasifier A - Feed Storage & Lock Vessel 1A
	UC054	Gasifier - Ash Silo Secondary Baghouse System
	CD001	Gasifier A- Lignite Dryer 1
	DA001	Gasifier A - Venturi Scrubber 1
	CD004	Gasifier A- Lignite Dryer Gas Feed Booster Fan 1
	UB044	Gasifier A - Solids Injection Nozzle 1B
	AG001	Gasifier A - Pressurized Baghouse / Filter Unit 1
	UB002	Gasifier A - Feed Dispense Vessel 1B
	UC004	Gasifier - Coarse Ash Storage Silo B
	UC006	Gasifier - Coarse Ash Storage Silo D
Test Package TP1020	SA001	Instrument Air System - Water Treatment
Air Flow Testing - Train A (first fire)	UD017	Gasifier A - Process Air Compressor Lube Oil Unit CO1102LO
	UD018	Gasifier A - Process Air Compressor Lube Oil Unit CO1202LO
	UG005	Gasifier - Flame Front Generator PG0098
	UD050	Gasifier A - Extraction Air Compressor KO Drum
	UD015	Gasifier A - Process Air Compressor CO1102
	UD016	Gasifier B - Process Air Compressor CO1202
	UD009	Gasifier A - Extraction Air Compressor CO1004
	UC047	Gasifier A - Particulate Control Device FL1106
	UC048	Gasifier A - Particulate Control Device FL1206
	BF001	Gasifier A - Startup Stack
	UL011	Gasifier A - Syngas Scrubber
	UL007	Gasifier A - Process Condensate KO Drum
	UH030	Gasifier A - AGR Regenerator Reflux Pumps
	UH017	Gasifier A - AGR First CO2 Absorber
	UH031	Gasifier A - AGR Rich Solvent Flash & K.O. Drums
	RA007	Fire Water Sys - Gasifier Underground
	SA008	Instrument Air System - Gasifier Gas Cleanup

Milestone	System	System Description
	UH033	Gasifier A - AGR Second CO2 Absorber
	UH026	Gasifier A - AGR LP Lean Solvent Pumps
	UH042	Gasifier A - AGR Third CO2 Absorber
	UH024	Gasifier A - AGR HP Lean Solvent Pumps
	UH032	Gasifier A - AGR Rich Solvent Pumps
	UD047	Gasifier A - Transport Air Dryer Header
	UH020	Gasifier A - AGR First Loaded Solvent Pumps
	UH089	Gasifier A - AGR Lean Solvent Header
	UG006	Gasifier A - HP Flare
	UH041	Gasifier A - AGR Solvent K.O. Drum
	UD023	Gasifier A - Transport Air Compressor CO1005
	UD025	Gasifier A - Transport Air Compressor PreCoolers & KO Drum DR1005
	UH016	Gasifier A - AGR Feed Exchanger & KO Drum
	UL003	Gasifier A - Ammonia Scrubber
	UH044	Gasifier A - AGR Third Loaded Solvent Pumps
	UE015	Gasifier A - Header from PCD's FL1106 & FL1206 to Scrubber
	UL005	Gasifier A - Mercury Adsorber
	UH027	Gasifier A - AGR Regenerator & Condenser
	UG007	Gasifier A -Combustion Turbine A Syngas Supply
	UD049	Gasifier A - Transport Air Cooler & KO Drums
	UH036	Gasifier A - AGR Second Loaded Solvent Pumps
	UA003	Gasifier A - Pressurized Transport Gasifier
	UD002	Gasifier - Low Pressure Nitrogen Distribution Header
	UH011	Gasifier A - AGR HS2 Absorber
	UB001	Gasifier A - Feed Dispense Vessel 1A
	UL004	Gasifier A - COS Hydrolysis Reactor
	UD011	Gasifier A - Process Air Supply Header & Extraction Air Recuperator
	UD026	Gasifier A - Transport Air Dryer PG1007
	UD048	Gasifier A - Recycle Gas Compressor Header
	UL012	Gasifier A - Second Stage WGS Reactors
	UD013	Gasifier A - IP Nitrogen Distribution Sys
	PA055	Gasifier Structure Freight Elevator
	UL006	Gasifier A - First Stage WGS Reactors & Syngas Recuperators
	UE009	Gasifier - Tempered Water Sys
	UC012	Gasifier A - Coarse Ash Cooling

Milestone	System	System Description
	UH015	Gasifier A - AGR Concentrator
Test Package TP2019	UB054	Gasifier B - Solids Injection Nozzle 3B
Pneumatic Pressure Test of Gasifier - Train B	UA008	Gasifier B - Startup Burner A
	UA009	Gasifier B - Startup Burner B
	UD034	Gasifier B - Gasifier Pressure Safety Valve Sensing Header
	SA012	Instrument Air System - Gasifier B
	UB027	Gasifier B - Feed Dispense Vessel 3B
	UD012	Gasifier A - HP Nitrogen Distribution Sys
	UE013	Gasifier B - Syngas Cooling
	UD032	Gasifier B - HP Nitrogen Distribution Sys
Test Package TP1025	UC017	Gasifier A - Bottoms Drain Pot Feeder
Fluidization Trial - Train A	UC051	Gasifier - Ash Moisturizer Booster Pump
	HE011	Gasifier Island Closed Loop Cooling Water Sys
	UC001	Gasifier - Coarse Ash Feeder
	UC009	Gasifier A - Fines Ash Receiver Sys A
	UC016	Gasifier A - PLD Vent Gas Drum (DR1043)
	UL009	Gasifier A - LP Vent Gas Header
	UC020	Gasifier A - Particulate Control Device Backpulse Sys A
	UC021	Gasifier A - Particulate Control Device Backpulse Sys B
	UC045	Gasifier A - Seal Leg Solids Feed Piping
	UC005	Gasifier - Coarse Ash Storage Silo C
	UC022	Gasifier A - Fines Ash Depressurization 1A
	UC024	Gasifier A - Fines Ash Depressurization 2A
	UC025	Gasifier A - Fines Ash Depressurization 2B
	UC010	Gasifier A - Fines Ash Receiver Sys B
	UC007	Gasifier - LP Vent Gas Compressor CO0041
	UC003	Gasifier - Coarse Ash Storage Silo A
	UC013	Gasifier A - Coarse Ash Depressurization Sys 1A
	UC014	Gasifier A - Coarse Ash Depressurization Sys 1B
	HT011	Process Heat Trace-Fluidization Trial A-Gasifier
	UC023	Gasifier A - Fines Ash Depressurization 1B
	UC002	Gasifier - Coarse Ash / Bed Make-up Silo
	UC036	Gasifier B - Coarse Ash Cooling
Test Package TP1030	UL019	Gasifier - Lights Hydrocarbons Drain Line
Ammonia Purification Package Commissioning	UM001	Gasifier - Ammonia Storage Tank A
	UM002	Gasifier - Ammonia Storage Tank B
	UM003	Gasifier - Ammonia Storage Tank C
	UM004	Gasifier - Ammonia Storage Tank D
	UM005	Gasifier - Anhydrous Ammonia Truck Loading Pumps
	UM024	WSA - Ammonia Injection
	UM006	Gasifier - Anhydrous Ammonia Rerun Pumps
	UM017	Gasifier - 50WT% Caustic Storage
	UM061	Anhydrous Ammonia Reflux Make-up Pumps
	UM014	Gasifier - Wastewater Ammonia Stripper Reflux Drum and pump

Milestone	System	System Description
	UM053	Gasifier - Hydrogen Sulfide Vent Line
	UM013	Gasifier - Wastewater Ammonia Stripper, condenser, reboiler, trim condenser and wastewater cooler
	UM016	Gasifier - Hydrogen Sulfide Stripper and reboiler
	UM012	Gasifier - Wastewater Ammonia Purifier, condenser and reboiler
	UM045	Waste Water Ammonia Purifier Bottom Pumps
	UL001	Gasifier - Hydrocarbon Drain Drum
	NF003	Gasifier - Waste Water Storage Tank & Pump
	NF013	Gasifier - Carbon Bed Filters (Sour Water)
	NF024	Gasifier - Waste Water Drum DR0040
	NF025	Gasifier - Waste Water Drum Pumps and preheater PU0040A/B
	UM011	Gasifier - Waste Water Ammonia Purifier Reflux Drum, Pump and Condenser
	UM046	Gasifier - 50WT % Caustic Pumps
	UM051	Gasifier Ammonia Header
	UL024	Gasifier A -Hydrocarbons Vent Line
	UL021	Gasifier -Heavies Hydrocarbons Drain Line
	NF086	Gasifier - Wastewater Collection Header
	HT020	Process Heat Trace-First Syngas Production A-Gas Cleanup
Test Package TP1038 Charge Refrigeration Unit	UH113	Gasifier A - AGR Refrigeration Lube Oil Stilling Skid
	UH114	Gasifier B - AGR Refrigeration Lube Oil Stilling Skid
	UH115	Gasifier A AGR Refrigeration Sub-Headers
	UH116	Gasifier B AGR Refrigeration Sub-Headers
	UM019	Gasifier - Ammonia Flare
	UH101	Gasifier-AGR RE Compressor Skids(A-H)
	UH100	Gasifier - AGR Refrigeration Supply/Return Header
Test Package TP1026 Refractory Cure Train A	NE003	Water Treatment - Condensate Storage Tank
	NB002	Water Treatment - Filter Water Forwarding Pumps
	NC009	Potable Water - Gasifier Cooling Tower
	MC004	Gasifier Phosphate Sys
	HE018	Service Water - Gasifier B Structure
	UE019	Gasifier A - Syngas Cooler Warmup Recirculation Pumps
	UA006	Gasifier A - Second Startup Burners
	UM058	Gasifier – Make-up Process Water Header
	HE015	Service Water - CO2 Area
Test Package TP2020 Air Flow Testing - Train B	DD011	Combustion Turbine B Syngas Supply
	UD055	Gasifier B - Extraction Air Compressor KO Drum
	UE018	Gasifier B - HP Bypass Header
	UD073	Gasifier - LP Nitrogen Area 500
	UD062	Gasifier - LP Nitrogen Area 140
	UD065	Gasifier - LP Nitrogen Area 160
	UD059	Gasifier - LP Nitrogen Area 110
	UD066	Gasifier - LP Nitrogen Area 180
	UD072	Gasifier - LP Nitrogen Area 260
	UD060	Gasifier - LP Nitrogen Area 120
	UD067	Gasifier - LP Nitrogen Area 210

Milestone	System	System Description
	BF002	Gasifier B - Startup Stack
	UD035	Gasifier B - Process Air Compressor CO2102
	UD058	Gasifier - LP Nitrogen Area 105
	UD063	Gasifier - LP Nitrogen Area 150
	UH048	Gasifier B - AGR First CO2 Absorber
	UH056	Gasifier B - AGR Second CO2 Absorber
	UH059	Gasifier B - AGR Third CO2 Absorber
	UD069	Gasifier - LP Nitrogen Area 230
	UD061	Gasifier - LP Nitrogen Area 130
	UD036	Gasifier B - Process Air Compressor CO2202
	UD042	Gasifier B - Transport Air Compressor CO2005
	UD044	Gasifier B - Transport Air Dryer PG2007
	UD068	Gasifier - LP Nitrogen Area 220
	UD029	Gasifier B - Extraction Air Compressor CO2004
	UH074	Gasifier B - AGR Regenerator Reflux Drum
	MA005	Gasifier Island Feedwater Sys Train B
	UE016	Gasifier B - Header from PCD's FL2106 & FL2206 to Scrubber
	UH065	Gasifier B - AGR First Loaded Solvent Pumps
	UD043	Gasifier B - Transport Air Compressor PreCoolers & KO Drum DR2005
	UD056	Gasifier B - Transport Air Cooler & KO Drums
	UD057	Gasifier B - Transport Air Dryer Header
	UD070	Gasifier - LP Nitrogen Area 250
	UH063	Gasifier B - AGR Concentrator
	UH054	Gasifier B - AGR HS2 Absorber
	UL017	Gasifier B - Process Condensate KO Drum
	UH077	Gasifier B - AGR Rich Solvent Pumps
	UG008	Gasifier B - Combustion Turbine B Syngas Supply
	UH047	Gasifier B - AGR Feed Exchanger & KO Drum
	UH069	Gasifier B - AGR HP Lean Solvent Pumps
	UH075	Gasifier B - AGR Regenerator Reflux Pumps
	UH076	Gasifier B - AGR Rich Solvent Flash & K.O. Drums
	UH080	Gasifier B - AGR Second LP CO2 Flash Drum
	UH083	Gasifier B - AGR Solvent K.O. Drum
	UH092	Gasifier B - AGR Lean Solvent Header
	UL014	Gasifier B - COS Hydrolysis Reactor
	UA007	Gasifier B - Pressurized Transport Gasifier
	UD033	Gasifier B - IP Nitrogen Distribution Sys
	UL015	Gasifier B - Mercury Adsorber
	UH084	Gasifier B - AGR Third Loaded Solvent Pumps
	UC049	Gasifier B - Particulate Control Device FL2106
	UC050	Gasifier B - Particulate Control Device FL2206
	UD031	Gasifier B - Process Air Supply Header & Extraction Air Recuperator
	UH072	Gasifier B - AGR Regenerator & Condenser
	UH078	Gasifier B - AGR Second HP & MP CO2 Flash Drums
	UL016	Gasifier B - Second Stage WGS Reactors
	UH064	Gasifier B - AGR First HP & MP CO2 Flash Drums
	UH071	Gasifier B - AGR LP Lean Solvent Pumps
	UG010	Gasifier B - HP Flare
	UL023	Gasifier B - First Stage WGS Reactors & Syngas Recuperators
	UL020	Gasifier B - Syngas Scrubber
	HT008	Process Heat Trace -Air Test B-Gas Cleanup
	UH066	Gasifier B - AGR First LP CO2 Flash Drum

Milestone	System	System Description
	UD053	Gasifier B - Recycle Gas Compressor Header
	UL013	Gasifier B - Ammonia Scrubber
Test Package TP1073 Back Blow of Steam System from HRSG	LE002	Condensate Make-up Auxiliary Boiler
	LE003	Condensate Make-up Combined Cycle
	LY004	Steam Turbine Condensate Sys
	UE022	Gasifier - Blowdown Tank UA-TK-4020
	UE017	Gasifier A - HP Bypass Header
	UE028	Gasifier B - Lower Mixing Zone Steam Piping
	LJ008	Gasifier - MP Steam Generation Condensate Pumps
	UE002	Gasifier - Blowdown Flash Drums DR0092/DR0095
	LB001	Gasifier - LP Condensate Pumps (PU0090 A/B)
	LJ001	Gasifier - HRSG Condensate Sys
	LJ002	Gasifier - IP & LP Condensate Drum
	LJ010	Gasifier - MP Ash Cooler Condensate Headers
	LJ009	Gasifier - MP Ash Cooler Condensate Pumps
	UE007	Gasifier - 325 Psig Process Steam
	LJ006	Gasifier - Low Pressure Condensate Supply Header
	UE004	Gasifier - Demin Water
	UE025	Gasifier - Blowdown Tank UA-TK-4060
	LJ007	Gasifier - Low Pressure Condensate Return Header
	UM037	WSA - SO2 Converter / Interbed Coolers / Process Gas Cooler
	UE005	Gasifier - LP Steam
	UE024	Gasifier - Blowdown Tank UA-TK-4050
	MA004	Gasifier Island Feedwater Sys Train A
	ND002	Water Analysis System - Gasifier Island
	UE008	Gasifier - MP Steam
	UE011	Gasifier A - Syngas Cooling
	UE006	Gasifier - IP Steam
	UE010	Gasifier A - HP Steam Drum
	UE023	Gasifier - Blowdown Tank UA-TK-4030
	UE012	Gasifier B - HP Steam Drum
LDF	NF092	LDF Area Process Water
	DF013	Lignite Delivery - Concrete Storage Dome FDR 003
	DF014	Lignite Delivery - Belt Conveyor 003
	DF007	Lignite Delivery - Concrete Storage Dome
	NF089	Lignite Handling - Conveyor 3 Collection Sump
	PY015	Heat Trace Sys - Lignite Delivery Facility

Milestone	System	System Description
	DF012	Lignite Delivery - Belt Conveyor 002
	DF018	Lignite Delivery - Stacker / Reclaimer
Test Package TP1015 Lignite Dryer 2	CE008	Gasifier A - Fluid Bed Dryer Discharger Feeder 2
	CD011	Gasifier A- Multi-Clone 2
	DK002	Gasifier A - Crushed Lignite Silo 2
	CD033	Gasifier A Lignite Mill Feed Fan 1B
	DA002	Gasifier A - Venturi Scrubber 2
	CD002	Gasifier A- Lignite Dryer 2
	CD005	Gasifier A- Lignite Dryer Gas Feed Booster Fan 2
	UB003	Gasifier A - Feed Dispense Vessel 2A
	UB010	Gasifier A - Feed Storage & Lock Vessel 2B
	UB045	Gasifier A - Solids Injection Nozzle 2A
	UB046	Gasifier A - Solids Injection Nozzle 2B
	UB004	Gasifier A - Feed Dispense Vessel 2B
	UB009	Gasifier A - Feed Storage & Lock Vessel 2A
	UB015	Gasifier A - Feed System 2A
	UB016	Gasifier A - Feed System 2B
	AG002	Gasifier A - Pressurized Baghouse / Filter Unit 2
Oil Flush	UD037	Gasifier B - Process Air Compressor Lube Oil Unit CO2102LO
	UD038	Gasifier B - Process Air Compressor Lube Oil Unit CO2202LO
	UD010	Gasifier A - Extraction Air Compressor Lube Oil Unit CO1004LO
	UD024	Gasifier A - Transport Air Compressor Lube Oil Unit CO1005LO
	UD030	Gasifier B - Extraction Air Compressor Lube Oil Unit CO2004LO
	UD045	Gasifier B - Transport Air Compressor Lube Oil Unit CO2005LO
	UC008	Gasifier - LP Vent Gas Compressor Lube Oil Unit CO0041LO
	UH006	Gasifier A - AGR CO2 Recycle Compressor Lube Oil Unit CO1066LO
	UH051	Gasifier B - AGR Flash Gas Compressor Lube Oil Unit CO2065LO
	UH008	Gasifier A - AGR Flash Gas Compressor Lube Oil Unit CO1065LO
	UH046	Gasifier B - AGR CO2 Recycle Compressor Lube Oil Unit CO2066LO
	UM021	Gasifier A - CO2 Compressor Lube Oil Unit CO1080LO
	UM022	Gasifier B - CO2 Compressor Lube Oil Unit CO2080LO
Test Package TP1049 WSA Commissioning	UM060	Sulfuric Acid Storage Tank B
	UM008	Gasifier - Sulfuric Acid Storage Tank A
	UM049	Gasifier - Sulfuric Acid Rundown Storage
	UM055	Sulfuric Acid Offspec Tank (TK0073)
	UM033	WSA - Quench Water Pumps
	UM041	WSA - Acid Pumps & Cooler
	UM040	WSA - Stack
	UM035	WSA - Scrubber Column
	UM043	WSA - Hot Air Heaters
	UM026	WSA - Combustor/Waste Heat Steam Generator
	UM027	WSA - Condenser
	UM032	WSA - Quench Water Column
	UM029	WSA - Mist Control PG0070A, B C & D
	UM034	WSA - SCR Reactor
	UM042	WSA - Acid Product Pumps
	SA010	Instrument Air System - Sulfuric Acid Area
	UM025	WSA - Combustion Air Blower
	UM030	WSA - MP Steam Drum
	UM052	Gasifier WSA Combustor - Burner Management System
	UM028	WSA - Cooling Filter & Blower
	UM036	WSA - Scrubber Water Pumps

Milestone	System	System Description
	UM010	Gasifier - Sulfuric Acid Truck Loading
	UM044	WSA - Natural Gas
	UM050	Sulfuric Acid Rundown Pump
	UM056	Sulfuric Acid Offspec Tank Pumps
	UM031	WSA - Peroxide Storage & Dosing Pumps
Test Package TP1033 AGR Commissioning - Train A	HE023	Service Water - Process Compressors Area
	UH029	Gasifier A - AGR Regenerator Reflux Drum
	HE019	Service Water - Gasifier Waste Water Treatment Area
	HE020	Service Water - Gasifier Gas Cleanup Area
	SA009	Instrument Air System - Gasifier Waste Water Treatment
	UH012	Gasifier A - AGR Lean-Rich Solvent Exchanger
	UM047	Gasifier A - AGR Water Make-up Pumps
	UH085	AGR SELEXOL Storage Tank
	UH019	Gasifier A - AGR First Loaded Solvent Chiller
	UH022	Gasifier A - AGR First Semi-Lean Solvent Chiller
	UH117	Gasifier A - AGR Acid Gas Header
	UH034	Gasifier A - AGR Second HP & MP CO2 Flash Drums
	UH037	Gasifier A - AGR Second LP CO2 Flash Drum DR1268
	UH021	Gasifier A - AGR First LP CO2 Flash Drum
	UH086	AGR Solvent Transfer Pump
	NF085	Train A SELEXOL Closed Drain Header
	UH039	Gasifier A - AGR Semi-Lean Solvent Pumps
	SA002	Instrument Air System - CO2 Area
	UH010	Gasifier A - AGR Flash Gas Second Stage KO Drum DR1080
	UH013	Gasifier A - AGR Third Semi-Lean Solvent Chiller
	UH025	Gasifier A - AGR Lean Solvent Chillers
	UH043	Gasifier A - AGR Third Loaded Solvent Chiller
	UM018	Gasifier - AGR Water Break Drum
	NF027	Gasifier - AGR Sump Drum & Pump - NF-DR-0057
	UH097	Gasifier A - LP CO2 KO Drum
	UH028	Gasifier A - AGR Regenerator Reboilers Condensate Drums
	UH091	AGR Acid Gas Header
	UH007	Gasifier A - AGR Flash Gas Compressor CO1065
	UH018	Gasifier A - AGR First HP & MP CO2 Flash Drums
	UH035	Gasifier A - AGR Second Loaded Solvent Chiller
	UH038	Gasifier A - AGR Second Semi-Lean Solvent Chiller
	UH040	Gasifier A - AGR Solvent Filtration System
	HT016	Process Heat Trace-AGR Commissioning A-Gas Cleanup
	UH090	Gasifier A - LP CO2 Vent Header
	UH009	Gasifier A - CO2 MP KO Drum
	UH005	Gasifier A - AGR CO2 Recycle Compressor CO1066
	UH023	Gasifier A - CO2 Mercury Adsorber & Comp Filter
	UH001	Gasifier - AGR Antifoam Injection Sys PG0060 (Vendor Package)
Test Package TP1016 Lignite Dryer 3	CE009	Gasifier A - Fluid Bed Dryer Discharger Feeder 3
	CD012	Gasifier A- Multi-Clone 3
	CD034	Gasifier A Lignite Mill Feed Fan 1C
	DA010	Gasifier - Venturi Scrubber Pump 2
	DA003	Gasifier A - Venturi Scrubber 3
	CD006	Gasifier A- Lignite Dryer Gas Feed Booster Fan 3
	DA012	Gasifier - Venturi Scrubber Pumparound 2
	DK003	Gasifier A - Crushed Lignite Silo 3
	CD003	Gasifier A- Lignite Dryer 3
	UB047	Gasifier A - Solids Injection Nozzle 3A
	UB048	Gasifier A - Solids Injection Nozzle 3B

Milestone	System	System Description
	UB005	Gasifier A - Feed Dispense Vessel 3A
	UB006	Gasifier A - Feed Dispense Vessel 3B
	UB011	Gasifier A - Feed Storage & Lock Vessel 3A
	UB012	Gasifier A - Feed Storage & Lock Vessel 3B
	UB017	Gasifier A - Feed System 3A
	UB018	Gasifier A - Feed System 3B
	AG003	Gasifier A - Pressurized Baghouse / Filter Unit 3
Test Package TP2015 Lignite Dryer 4	CD022	Gasifier B - Multi-Clone 1
	CE013	Gasifier B - Fluid Bed Dryer Discharger Feeder 1
	AG004	Gasifier B - Pressurized Baghouse / Filter Unit 1
	CD013	Gasifier B - Lignite Dryer 1
	CD035	Gasifier B Lignite Mill Feed Fan 2A
	DA004	Gasifier B - Venturi Scrubber 1
	DK004	Gasifier B - Crushed Lignite Silo 1
	CD016	Gasifier B - Lignite Dryer Gas Feed Booster Fan 1
	UB022	Gasifier B - Feed Dispense Vessel 1A
	UB023	Gasifier B - Feed Dispense Vessel 1B
	UB028	Gasifier B - Feed Storage & Lock Vessel 1A
	UB029	Gasifier B - Feed Storage & Lock Vessel 1B
	UB034	Gasifier B - Feed System 1A
	UB035	Gasifier B - Feed System 1B
	UB049	Gasifier B - Solids Injection Nozzle 1A
	UB050	Gasifier B - Solids Injection Nozzle 1B
Test Package TP2016 Lignite Dryer 5	CD023	Gasifier B - Multi-Clone 2
	CD045	Gasifier - Desuperheater for HX2202
	CE014	Gasifier B - Fluid Bed Dryer Discharger Feeder 2
	CD014	Gasifier B - Lignite Dryer 2
	DA005	Gasifier B - Venturi Scrubber 2
	CD036	Gasifier B Lignite Mill Feed Fan 2B
	DK005	Gasifier B - Crushed Lignite Silo 2
	AG005	Gasifier B - Pressurized Baghouse / Filter Unit 2
	CD017	Gasifier B - Lignite Dryer Gas Feed Booster Fan 2
	DA013	Gasifier - Venturi Scrubber Pump 3
	DA014	Gasifier - Venturi Scrubber Pumparound 3
	UB024	Gasifier B - Feed Dispense Vessel 2A
	UB025	Gasifier B - Feed Dispense Vessel 2B
	UB030	Gasifier B - Feed Storage & Lock Vessel 2A
	UB031	Gasifier B - Feed Storage & Lock Vessel 2B
	UB036	Gasifier B - Feed System 2A
	UB037	Gasifier B - Feed System 2B
	UB051	Gasifier B - Solids Injection Nozzle 2A
	UB052	Gasifier B - Solids Injection Nozzle 2B
Test Package TP2017 Lignite Dryer 6	CE015	Gasifier B - Fluid Bed Dryer Discharger Feeder 3
	DK006	Gasifier B - Crushed Lignite Silo 3
	UB026	Gasifier B - Feed Dispense Vessel 3A
	UB039	Gasifier B - Feed System 3B
	CD018	Gasifier B - Lignite Dryer Gas Feed Booster Fan 3
	AG006	Gasifier B - Pressurized Baghouse / Filter Unit 3
	CD015	Gasifier B - Lignite Dryer 3
	DA006	Gasifier B - Venturi Scrubber 3
	UB032	Gasifier B - Feed Storage & Lock Vessel 3A
	UB033	Gasifier B - Feed Storage & Lock Vessel 3B
	UB038	Gasifier B - Feed System 3A
Test Package TP1027	SA007	Instrument Air System - Compressors & Dryers

Milestone	System	System Description
First Syngas Production - Train A	RA004	Fire Water Sys - Pumps & House
	SA016	INSTRUMENT AIR HEADER TO NITROGEN PLANT
	NF022	Waste Water Reclaim Sump
	PA022	CO2 Compressor MCC Bldg.
	SA015	Instrument Air System - Process Compressors Area
	SA004	Instrument Air System - Combined Cycle Steam Turbine
	PA031	LDF Aux Control 13.8 KV Switchgear Building
	NF041	Lignite Delivery - Screen Transfer Station Area (Sump 006)
	NF042	Lignite Delivery - Truck Dump Area (Sump 001)
	NF010	Lignite Delivery - Barn Transfer Station Collection (Sump 002)
	PA025	Lignite Transfer Truck Dump MCC Building
	PA034	Lignite Delivery MCC / Control Bldg
	NF036	South Oily Water Sump NF-SU-0051
	NF043	Lignite Delivery - Collection (Sump 003)
	DF005	Lignite Delivery - Truck Dump FDR 001
	SA013	Instrument Air System - Lignite Delivery Compressor & Dryers
	NF035	North Oily Water Sump NF-SU-0052
	DF015	Lignite Delivery - Truck Dump
	DF019	Lignite Handling - Screen Transfer Station
	DG007	Lignite Delivery - Crusher
	DF016	Lignite Delivery - Belt Conveyor 001A
	DF017	Lignite Delivery - Belt Conveyor 001B
	DF010	Lignite Delivery - Belt Conveyor 007
	NF030	Sulfuric Acid Area Sump A0078
	DF009	Lignite Delivery - Belt Conveyor 008
	DH001	Lignite Delivery - Sampling Sys A
	DH002	Lignite Delivery - Sampling Sys B
	PA057	Lignite Delivery - Belt Sampler 004A
	PA058	Lignite Delivery - Belt Sampler 004B
	CE001	Gasifier A - Feeder / Scale 1
	CE002	Gasifier A - Feeder / Scale 2
	NF005	Gasifier B - AGR Area Sump
	PA044	Train A Gas Clean-up - Analyzer House
	DF008	Lignite Delivery - Emer. Stockpile FDR 004

Milestone	System	System Description
	PA024	Flare Area MCC Bldg
	CD007	Gasifier A- Lignite Mill 1
	CD008	Gasifier A- Lignite Mill 2
	CD041	Gasifier - Desuperheater for HX1102
	CD042	Gasifier - Desuperheater for HX1202
	NF023	North Gasifier Structure Sump A0060A
	NF034	South Gasifier Structure Sump A0060B
	DF001	Lignite Delivery - Belt Conveyor 004A
	DF002	Lignite Delivery - Belt Conveyor 004B
	NF084	Ash Sedimentation Pond Intake Structure
	PA036	Lignite Delivery - Barn Transfer Station Bldg
	PA059	LDF Tripper Electrical Building
	DF022	Lignite Handling - (Transfer Station 2)
	NF015	Gas Cleanup Area Sump
	NF018	Gasifier Island Waste Water Sump
	PA023	Gasifier Gas Cleanup MCC Bldg
	CD031	Gasifier - Filtrate Drum System
	NF004	Gasifier A - AGR Area Sump
	NC007	Potable Water - Gasifier B Structure
	HT006	Process Heat Trace -Air Test A-Gas Cleanup
	UG001	Gasifier - LP / Acid Flare
	NC003	Potable Water - CO2 Area
	NC006	Potable Water - Gasifier A Structure
	NC008	Potable Water - Gasifier Area
	NC013	Potable Water - Process Compressors Area
	NC014	Potable Water - Sulfuric Acid Area
	UC015	Gasifier A - CCAD Steam Drum
	UC053	Gasifier - Ash Conditioner Venturi Scrubber B
	NC012	Potable Water - Maintenance Shop
	NC015	POTABLE WATER-UNDERGROUND
	NF044	Lignite Handling - Stacker/Reclaimer Conveyor 3 Sump
	SB012	Merge with SA11
	SB013	Merge with SA12
Test Package TP1074	UD020	Gasifier A - Recycle Gas Compressor KO Drum DR1009

Milestone	System	System Description
Sulfidation Run - Train A	UD021	Gasifier A - Recycle Gas Compressor Lube Oil Unit CO1008LO
	UD019	Gasifier A - Recycle Gas Compressor CO1008
	UL010	Gasifier A - WGS & Catalyst Reactors Warmup
	UM020	Gasifier A - CO2 Product Compressor
	UE026	Gasifier - WGS Heating / Activation Steam
	UH003	Gasifier A - CO2 Dehydration
First Syngas to Turbine - Train A	UB021	Gasifier A - Multi-Clone Rotary Air Lock 1C
	CE003	Gasifier A - Feeder / Scale 3
	CD009	Gasifier A- Lignite Mill 3
	CD043	Gasifier - Desuperheater for HX1302
Test Package TP2026	UE020	Gasifier B- Syngas Cooler Warmup Recirculation Pumps
Refractory Cure - Train B	UA010	Gasifier B - Second Startup Burners
Test Package TP2025	UC027	Gasifier B - Bottoms Drain Pot Feeder
Fluidization Trial - Train B	UC029	Gasifier B - CCAD Steam Drum (DR2030)
	UC032	Gasifier B - Particulate Control Device Backpulse Sys A
	UC030	Gasifier B - Coarse Ash Depressurization 2A
	UL022	Gasifier B - LP Vent Gas Header
	UC046	Gasifier B - Seal Leg Solids Feed Piping
	UC033	Gasifier B - Particulate Control Device Backpulse Sys B
	UC026	Gasifier B - PLD Vent Gas Drum (DR2043)
	UC031	Gasifier B - Coarse Ash Depressurization 2B
	UC034	Gasifier B - Fines Ash Receiver Sys A
	UC035	Gasifier B - Fines Ash Receiver Sys B
	UC038	Gasifier B - Fines Ash Depressurization 1A
	UC039	Gasifier B - Fines Ash Depressurization 1B
	UC040	Gasifier B - Fines Ash Depressurization 2A
	UC041	Gasifier B - Fines Ash Depressurization 2B
Test Package TP2033	UM048	Gasifier B - AGR Water Make-up Pumps
AGR Commissioning - Train B	UH096	Gasifier B - CO2 Mercury Absorber & Comp Filter
	UH095	Gasifier B - CO2 MP KO Drum
	UH060	Gasifier B - AGR Third Loaded Solvent Chiller
	UH049	Gasifier B - AGR First Loaded Solvent Chiller
	UH057	Gasifier B - AGR Second Loaded Solvent Chiller
	UH067	Gasifier B - AGR First Semi-Lean Solvent Chiller
	UH118	Gasifier B - AGR Acid Gas Header
	UH061	Gasifier B - AGR Third Semi-Lean Solvent Chiller
	UH070	Gasifier B - AGR Lean Solvent Chillers
	UH081	Gasifier B - AGR Second Semi-Lean Solvent Chiller
	UH079	Gasifier B - AGR Second Loaded Solvent Pumps
	UH055	Gasifier B - AGR Lean-Rich Solvent Exchanger
	UH082	Gasifier B - AGR Semi-Lean Solvent Pumps
	UH073	Gasifier B - AGR Regenerator Reboilers Condensate Drums
	UH045	Gasifier B - AGR CO2 Recycle Compressor CO2066
	UH050	Gasifier B - AGR Flash Gas Compressor CO2065
	UH052	Gasifier B - AGR Flash Gas Second Stage KO Drum DR2080
	UH058	Gasifier B - AGR Solvent Filtration System
	UH098	Gasifier B - LP CO2 KO Drum
	UH093	Gasifier B - - LP CO2 Vent Header
Test Package TP1017	CE011	Gasifier B - Feeder / Scale 2
First Syngas Production - Train B	CE012	Gasifier B - Feeder / Scale 3

Milestone	System	System Description
	CD020	Gasifier B - Lignite Mill 2
	CD021	Gasifier B - Lignite Mill 3
	CD037	Gasifier B Lignite Mill Feed Fan 2C
	CD046	Gasifier - Desuperheater for HX2302
	CD024	Gasifier B - Multi-Clone 3
	PA045	Train B Gas Clean-up - Analyzer House
	UL027	Delete
Test Package TP2074 Sulfidation Run - Train B	UD046	Gasifier B - Recycle Gas Compressor KO Drum
	UD040	Gasifier B - Recycle Gas Compressor Lube Oil Unit CO2008LO
	UD039	Gasifier B - Recycle Gas Compressor CO2008
	UH099	Gasifier B - CO2 Dehydration
	UL018	Gasifier B - WGS & Catalyst Reactors Warmup
	UM023	Gasifier B - CO2 Product Compressor
First Syngas to Turbine - Train B	HB001	Combined Cycle Make-up Water
	CE010	Gasifier B - Feeder / Scale 1
	CD019	Gasifier B - Lignite Mill 1
	CD044	Gasifier - Desuperheater for HX2102
	UB053	Gasifier B - Solids Injection Nozzle 3A
Freeze Protection	HT031	Freeze Protection Heat Trace - Gasifier Water Treatment Area
	HT032	Freeze Protection Heat Trace -Gasifier 50WT% Caustic Storage
	HT033	Freeze Protection Heat Trace - Gasifier A, Gasifier Potable and Service Water Systems
	HT036	Freeze Protection Heat Trace - Gasifier A Gas Cleanup Area
	HT037	Freeze Protection Heat Trace - Gasifier B Gas Cleanup Area
	HT039	Freeze Protection Heat Trace - Gasifier B
	HT040	Freeze Protection Heat Trace - Anhydrous Ammonia Storage Area
	HT043	Freeze Protection Heat Trace -Gasifier A AGR
	HT044	Freeze Protection Heat Trace -Gasifier B AGR
	HT045	Freeze Protection Heat Trace -Air Compressor Area
	HT049	Freeze Protection Heat Trace - Ammonia Removal Area
CT "A" FF	NA002	Water Treatment - Raw Water Forwarding Pumps
	NB003	Water Treatment - Filter Water Storage Tank
	HE004	Combined Cycle Closed Loop Cooling Water Sys - Steam Turbine
CT "B" FF	VA005	Combustion Turbine B Inlet Filter
SYNC to Grid	NF006	Steam Turbine Area Sump
	QC001	Auxiliary Boiler - Boiler
Post TOD Work	PA017	Water Analysis Bldg.
	YA002	Anhydrous Ammonia Transfer Pumps
	NF031	Main Electrical Building - Sanitary Lift Station
	NF016	Water Treatment - Sanitary Lift Station
	NF017	Gasifier Area Sanitary Lift Station
	RA020	Above Ground Fire Water Sys - Bunker Dust Collector
	RA018	Above Ground Fire Water Sys - Coal Crusher Silos
	RA021	Above Ground Fire Water Sys - PC Cyclone Baghouse
	PA014	Guard House / Truck Scale House
	RA008	Fire Water Sys - Gasifier A Structure

Milestone	System	System Description
	RA009	Fire Water Sys - Gasifier B Structure
	RA012	Above Ground Fire Water Sys - Lignite Handling
	RA017	Above Ground Fire Water Sys - Area 110
	RA019	Above Ground Fire Water Sys - Coal Crusher Silos
	RA022	Above Ground Fire Water Sys - Gasifier Structure
	RY005	Fire Detection & Alarm System - Gasifiers
	RY007	FIRE DETECTION & ALARM SYSTEM GAS CLEANUP
	RY008	FIRE DETECTION & ALARM SYSTEM - SELEXOL AREA
	RY009	FIRE DETECTION & ALARM SYSTEM - WSA AREA
	RY011	Above Ground Fire Detection & Alarm System - Combined Cycle Area
	RY016	Above Ground Fire Detection & Alarm System - Gasifier Area
	RY017	Above Ground Fire Detection & Alarm System - Gasifier Cooling Tower
	RY018	Above Ground Fire Detection & Alarm System - Combined Cycle Cooling Tower
	NF011	Waste Treatment - Sanitary Waste Treatment Plant
	PB003	Aviation Lighting
	RY019	Above Ground Fire Detection & Alarm System - Lignite Delivery Facilities
	KD057	480V MCC 4A Lignite Delivery
	NF014	Guard House Sanitary Lift Station
	NF032	Truck Scale House Sanitary Lift Station
	PA056	Gasifier Structure Personnel Elevator
	PB001	Plant Roadway Lighting
	RA013	Above Ground Fire Water Sys - Lignite Handling Dome
	PB004	Main Elect. Bldg. Area Lighting (AREAS 105, 110, 170A, 200, 550)
	PB005	HRSG Area Lighting (AREAS 180, 510, 520, 550)
	PB006	Gasifier Lighting(AREAS 120,150,150A,170C,220,250,250A)
	PB007	Gas Treatment & SELEXOL (AREAS 130, 170B, 170G, 170K,180)
	PB008	Flare & Ammonia Area Lighting (AREAS 140,170C,170H,190,190A,210,220)
	PB009	WSA, NIT & SELEXOL Area Lighting (AREAS 160,170E,170K,180,230,260)
	PB010	Cooling Towers Area Lighting (AREAS 580 & 590)
	RY015	Above Ground Fire Detection & Alarm System Treated Effluent Pumping Station Electrical Bldg Median Main
	RY010	FIRE DETECTION & ALARM SYSTEM - AREA 110
	RY020	Above Ground Fire Detection & Alarm System - Gasifier Island Water Analysis Building
	RY021	Above Ground Fire Detection & Alarm System - Combined Cycle Water Analysis Building