Wabash River Coal Gasification Repowering Project

Final Technical Report

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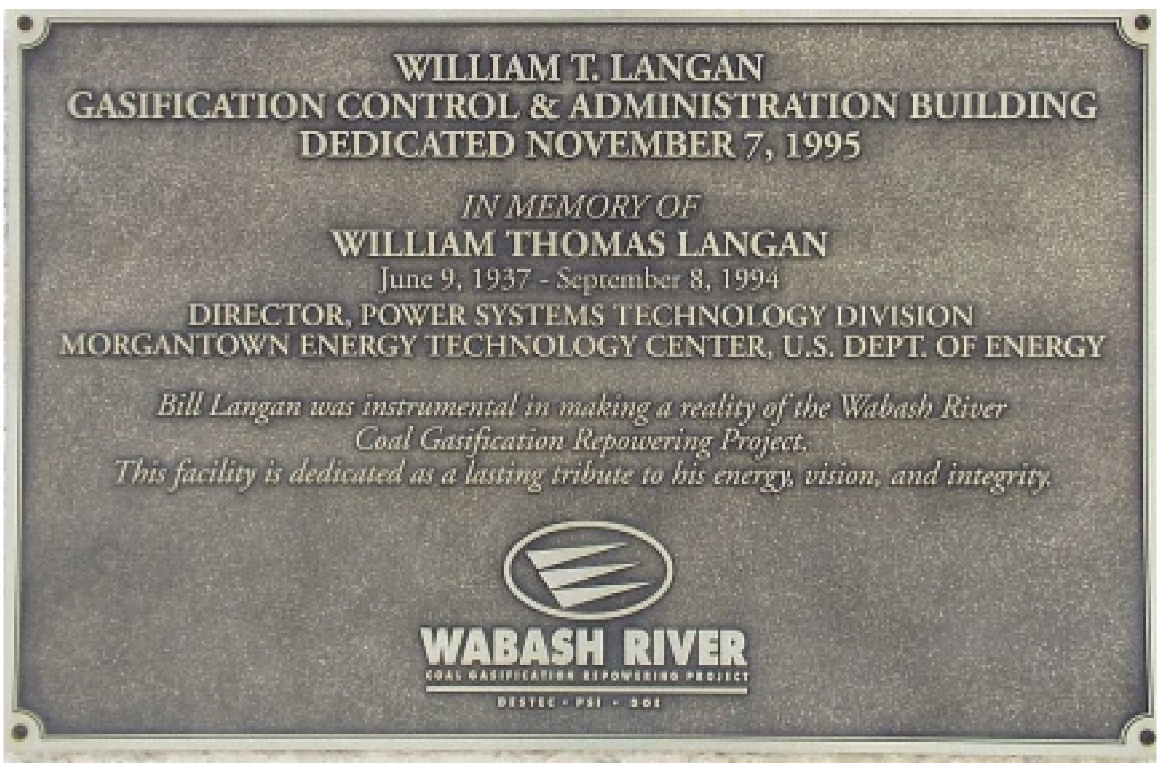

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SECTION I

Executive Summary & Project Overview

EXECUTIVE SUMMARY

i. General

The close of 1999 marked the completion of the Demonstration Period of the Wabash River Coal Gasification Repowering Project. This Final Report summarizes the engineering and construction phases and details the learning experiences from the first four years of commercial operation that made up the Demonstration Period under Department of Energy (DOE) Cooperative Agreement DE-FC21-92MC29310.

This 262 MWe project is a joint venture of Global Energy Inc. (Global acquired Destec Energy's gasification assets from Dynegy in 1999) and PSI Energy, a part of Cinergy Corp. The Joint Venture was formed to participate in the Department of Energy's Clean Coal Technology (CCT) program and to demonstrate coal gasification repowering of an existing generating unit impacted by the Clean Air Act Amendments. The participants jointly developed, separately designed, constructed, own, and are now operating an integrated coal gasification combined-cycle power plant, using Global Energy's E-Gas™ technology (E-Gas™ is the name given to the former Destec technology developed by Dow, Destec, and Dynegy). The E-Gas™ process is integrated with a new General Electric 7FA combustion turbine generator and a heat recovery steam generator in the repowering of a 1950's-vintage Westinghouse steam turbine generator using some pre-existing coal handling facilities, interconnections, and other auxiliaries. The gasification facility utilizes local high sulfur coals (up to 5.9% sulfur) and produces synthetic gas (syngas), sulfur and slag by-products. The Project has the distinction of being the largest single train coal gasification combined-cycle plant in the Western Hemisphere and is the cleanest coal-fired plant of any type in the world. The Project was the first of the CCT integrated gasification combined-cycle (IGCC) projects to achieve commercial operation.

ii. Process Overview

The E-Gas^{TM} Process (Figure ES-1) features an oxygen-blown, continuous-slagging, two-stage, entrained-flow gasifier. Coal is slurried in a rod mill and combined with oxygen in slurry mixers and injected into the first stage of the gasifier, which operates at $2,600^{o}$F and 400 psia. Molten ash falls through a taphole at the bottom of the first stage into a water quench, forming an inert vitreous slag. The syngas flows to the second stage, where additional coal slurry is injected. This coal is pyrolyzed by the hot syngas to enhance the syngas heating value and to improve overall efficiency. Syngas leaving the gasifier flows to the high temperature heat recovery unit (HTHRU), also referred to as the boiler, to produce high-pressure saturated steam. After cooling in the HTHRU, particulates in the syngas are removed in a hot/dry filter and recycled to the gasifier where the carbon in the particulates is converted into more syngas.

WRCGRP E-Gas^{TM} Gasification Process

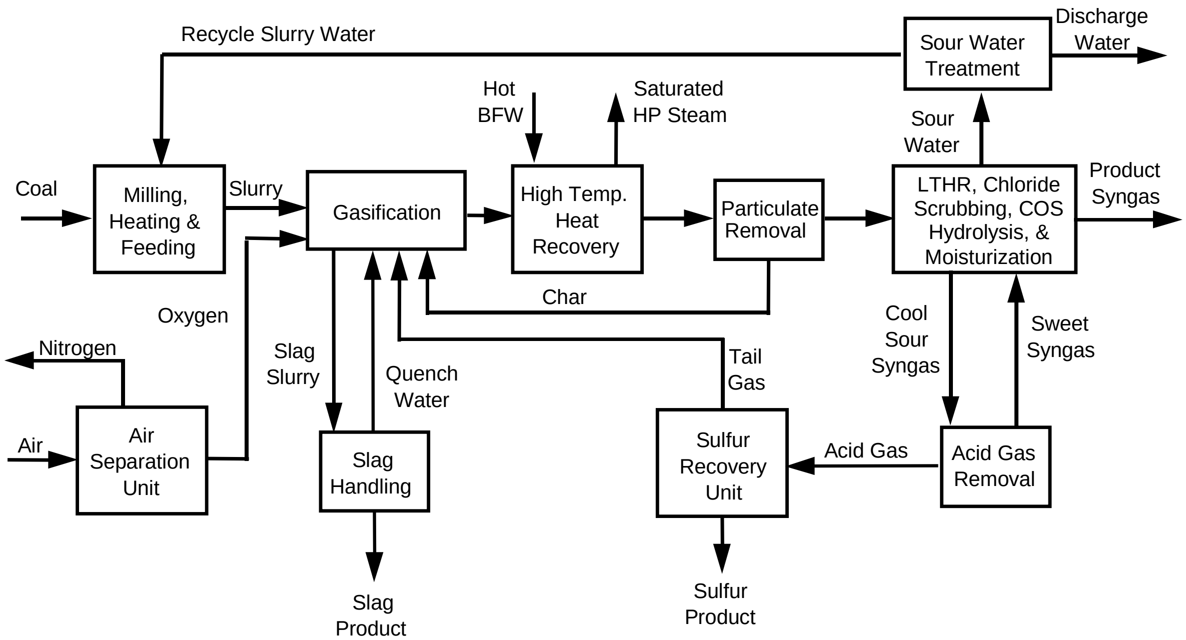


Figure ES-1: Gasification Process Simplified Block Flow Diagram

Following the particulate removal system, the syngas is further cooled in the low temperature heat recovery (LTHR) area, water-scrubbed to remove chloride, and passed through a catalyst that hydrolyzes carbonyl sulfide (COS) to hydrogen sulfide (H_2S). H_2S is removed using methyldiethanolamine (MDEA) based absorber/stripper columns. The “sweet” syngas is then moisturized, preheated, and piped over to the power block, where it is combusted in a General Electric 7FA high-temperature combustion turbine/generator to produce 192 MW electricity. The heat recovery steam generator (HRSG) configuration is optimized to utilize both the gas turbine exhaust energy and the heat energy made available in the gasification process. Steam from the HRSG and gasification process drives a Westinghouse turbine that produces 104 MW of electricity. The power from the combustion and steam turbines, less the internally used power, provides a net of 262 MW to the utility grid. An overall thermal efficiency of 8,900 Btu/kWh (HHV) has been demonstrated.

The gasification facility also produces two commercial by-products. Sulfur is removed as 99.999 percent pure elemental sulfur and marketed to sulfur users and slag from the process can be used as aggregate in asphalt roads, as structural fill in various types of construction applications, as roofing granules, and as blasting grit.

iii. Operating Overview

Commercial operation of the facility began late in 1995. Within a short time, both the gasification and combined-cycle plants successfully demonstrated the ability to run at capacity and within environmental compliance parameters. However, numerous operating problems adversely impacted plant reliability and the first year of operation resulted in only a 22% availability factor. Frequent failure of the ceramic filter elements in the particulate removal system accounted for nearly 40% of the early facility downtime. Plant reliability was also significantly hindered by high chloride content in the syngas. The high chlorides contributed to exchanger tube failures in the low temperature heat recovery area, COS hydrolysis catalyst degradation and mechanical failures of the syngas recycle compressor. Ash deposits in the post gasifier pipe spool and HTHRU created high system pressure drop, which forced the plant off line and required significant downtime to remove. Slurry mixers experienced several failures and the power block also contributed to appreciable downtime in the early years of operation.

Through a systematic problem-solving approach and a series of appropriate process modifications, all of the foregoing problems were either eliminated or significantly reduced by the end of the second operating year. In 1997, the facility availability factor was 44% and, by 1998, the availability factor had improved to 60%. As problems were solved and availability improved, new improvement opportunities surfaced. During the third year of commercial operation, the facility demonstrated operation on a second coal feedstock as well as a blend of two different Illinois No. 6 coals. The ability to process and blend new coal feedstocks improved the fuel flexibility for the site, but while learning to process varying feedstocks the plant suffered some downtime. On two occasions while processing new coals or fuel blends, the taphole in the gasifier plugged with slag.

In 1998 and 1999 a high percentage of coal interruptions and downtime were caused by the air separation unit (ASU). Ten coal interruptions in 1998 alone were due to the ASU. In 1999, failure of a blade in the compressor section of the combustion turbine required a complete rotor rebuild that idled the Project for 100 days. Run-time in 1999 was also impacted by a syngas leak in the piping system of the particulate removal system, a main exchanger leak in the air separation unit, another plugged taphole, and a failure of a ceramic test filter in the particulate removal system. Consequently, the availability factor for the Project in 1999 dropped to 40%.

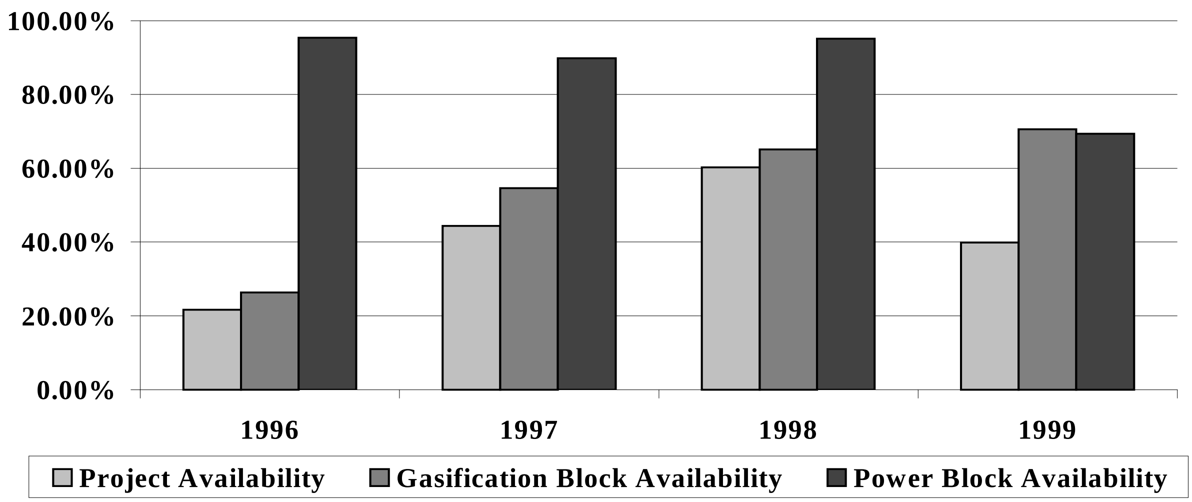


Figure ES-2: Project Syngas Block and Power Block Availability

However, 1999 clearly marked significant advances in the application of commercial IGCC as demonstrated at Wabash River. During the third quarter of 1999, the gasification block produced a record 2.7 trillion Btu of syngas, operated continuously without any interruption for 54 days and finished the year at 70% availability. Figure ES-2 demonstrates how the reliability of the technology has advanced during the Demonstration Period. The continuous improvement trend for the gasification block, where the majority of the novel technology was demonstrated, is encouraging and is expected to continue.

Future operating improvements will continue to advance the technology and eliminate cost and availability barriers. Some of the more significant achievements and activities for the demonstration project are highlighted in Table ES-1.

Table ES-1: Significant Operating Achievements

First coal fire in gasifier	August 17, 1995
Commercial operation begins	December 1, 1995
Start-up of chloride scrubbing system	October 1996
Initiated use of metal filter elements	December 1996
Conducted 10-day test run of petroleum coke	November 1997
1998 Governor's Award for Excellence in Recycling	May 1998
Began running new coal feed (Miller Creek)	June 1998
Completed 14-month OSHA recordable-free period	September 1998
Surpassed 1,000,000 tons of coal processed	September 1998
Surpassed 10,000 hours of coal operation	September 1998
Surpassed 100,000,000 pounds equivalent of SO_2 captured	January 1999
Record quarterly production (2,712,107 MMBtu)	3rd Quarter 1999
Longest continuous uninterrupted run (1,305 hrs)	August 12 – October 6, 1999
Conducted second successful petroleum coke run	September 1999
Record coal hours between gas path vessel entries (2,240 hr)	June to October 1999
Completed 2nd 14-month OSHA recordable-free period	December 1999

iv. Significant Findings and Modifications

The knowledge gained during the four years of the Demonstration Period has been tremendous and has been used to make hardware and operating changes that improve the reliability and cost effectiveness of the facility. Many of these findings and resulting modifications are discussed in detail in the main body of the Final Report. Some examples of significant learning experiences have been culled from the detailed report and are briefly described by area in this section of the Executive Summary.

Environmental

Under the requirements of the Cooperative Agreement, a comprehensive Environmental Monitoring Plan (EMP) has been established and followed. The solids, water and gas discharge points as well as internal streams have been sampled and analyzed. Both on-site laboratory personnel and contracted independent laboratories were utilized to fulfill the requirements of the EMP. The EMP has produced a wealth of valuable data and contributed immensely to the understanding of component partitioning throughout the gasification and combustion processes.

The collective data indicate that arsenic, selenium and cyanide (among others) either fully or partially partition into the gas phase. Although portions of these components deposit as solids on equipment surfaces, they typically end up in the condensed vapor stream creating elevated levels in plant process waste water. As a result, process waste water arising from use of the current feedstock, remains out of permit compliance due to elevated levels of arsenic, selenium and cyanide. To rectify these concerns, plant personnel have been working on several potential equipment modifications and treatment alternatives to bring the discharge back into compliance. Wabash River is currently obligated to resolve this issue by September of 2001.

Turning to air emissions, WRCGRP has met or exceeded every expectation outlined in the pre-construction literature. The following table represents total air emissions based on all sources monitored or calculated at the site during the years of 1997 and 1998. These emissions are the lowest from any commercially sized coal-fired power plant.

Table ES-2: Component Emissions in Pounds per MMBtu of Dry Coal Feed

	1997	**1998**
Sulfur Dioxide	0.13	0.13
Nitrogen Oxides	0.024	0.021
Carbon Monoxide	0.056	0.033
Volatile Organics	0.002	0.0021
PM_{10}	0.012	0.011

Air Separation Unit

Despite the high availability typical of industrial air separation units (ASU), the 2,060 ton per day oxygen plant installed for WRCGRP has not been typical and has suffered more than expected downtime. In 1998 and 1999, the ASU has been responsible for 11 coal interruptions to the gasifier resulting in more than 30 days of downtime. The root causes for the majority of these coal interruptions fall into three categories. First, failures associated with a poorly designed main air compressor inlet guide vane actuator system. Second, poorly designed and incorrectly installed control instrument subsystems. Third, critical components not properly designed for outdoor service such as non-weatherproof motor enclosures for 10,000 and 30,000 horsepower motors. The inlet guide vane system has been replaced with a new design. Many of the questionable instrument subsystems have been modified and improved. Purges and heater systems for the motor enclosures have been added and fixed, respectively, and the enclosures have been made less susceptible to weather. These modifications have improved reliability, but further enhancements are needed.

The initial performance test of the air separation unit did not meet the design nitrogen production or power consumption targets. The original equipment manufacturer added an ancillary nitrogen vaporizer and installed a new high-pressure oxygen recycle line, which improved production. However, the improvements still fell short of the targeted nitrogen production. Both the shortfalls have resulted in higher than expected operating and maintenance cost for imported nitrogen and power.

Coal Handling

The suction line between the slurry storage tank and the slurry recirculation pumps experienced numerous plugging incidents, which interrupted coal operation six times during the Demonstration Period. Investigation revealed that the agitator in the slurry storage tank was undersized, resulting in coal settling around the perimeter of the tank and in the vicinity of the suction line to the slurry recirculation pumps. Once the solids around the pump suction reached a critical mass, the solids would collapse and plug the suction line. The blade length of the agitator has been optimized to promote thorough mixing without excessive erosion of the tank walls.

Gasification

Reliable and direct temperature measurement within the first stage gasifier continues to be a challenge, requiring a heavy reliance on indirect observations to control temperature of the gasifier. The gasifier must be hot enough to ensure that molten slag flows from the taphole but not so hot that excessive syngas is consumed, thereby reducing the heating value of the product gas. During the Demonstration Period, five taphole-plugging incidents resulted in significant downtime. These plugging events have occurred as a direct result of learning to process new coal feeds or blends. Investigations after each plugging event have culminated in feed-specific operating guidelines that ensure that proper slag flow from the gasifier is maintained.

Ash deposits formed on the walls of the second stage gasifier and downstream piping systems significantly hampered early plant operation. As the deposit mass increased, either system differential pressure increased or deposits broke free and plugged downstream lines or the HTHRU tubes, forcing the plant off line. Downtime in the first two years from ash-related problems totaled more than 47 days. Study of the ash deposits and formation patterns combined with computational fluid dynamic modeling provided understanding of ash behavior that suggested three solutions: first, the refractory of the second stage reactor was replaced with material that did not form tenacious bonds with the ash. Second, the piping system was replaced to eliminate high velocity impact zones where ash deposits preferentially formed. Third, a screen was installed at the inlet to the boiler to catch any remaining deposits that were too big to pass through the boiler tubes. Since installation of these modifications in 1997, not a single hour of downtime has resulted from ash deposition.

Failures of slurry mixers have interrupted coal operation 8 times resulting in nearly 24 days of downtime. An investigation team has studied the failure mechanisms of slurry mixers, how to properly start-up and shutdown mixers, and how to fabricate mixers for maximum run-time and enhanced mixing performance. Since the initial slurry mixer design, the mixer life has been improved by more than four-fold and the average carbon content in the slag (a measure of carbon conversion and, thus mixer performance) has been reduced more than 50%.

High Temperature Heat Recovery

Fouling of the boiler tubes increases the temperature of the downstream filter elements in the particulate removal system. The higher temperature accelerates corrosion and increases the blinding rate of the elements. Operating conditions have been identified that minimize the fouling rate and maintenance personnel have devised cleaning mechanisms that can remove the hard and tenacious deposits during scheduled outages, thus restoring the HTHRU to design heat transfer conditions after outages.

Particulate Removal

Significant knowledge and experience has been gained in the particulate removal area of the plant because frequent downtime focused plant personnel's efforts on this challenging unit operation from the outset of plant operation. In 1996, the particulate removal system caused more than 100 days of downtime. Through a significant development effort, this system accounted for only 7 days of downtime in 1998.

During maintenance, over 10,000 pieces of hardware need to be assembled without error to ensure that this system is reliable. Consequently, the quality assurance program over the last four years has grown to encompass filter vendors, hardware suppliers, maintenance contractors, and Operations personnel. The disciplined adherence to this quality assurance program is a major contributor to the improved performance of the system.

Solutions for many of the problems associated with the particulate removal system during the first year of operation were implemented with success, but with each solution a new problem was discovered. After many attempts to improve the filter hardware system, it became evident that many of these design problems were quite complex and as a result, the system was retrofitted with metal filter elements late in 1996. Metal elements immediately improved reliability of the system and improvement efforts were turned to developing a filter with a lower operating and maintenance (O&M) cost.

Essentially all applicable commercially available filters for this type service have been tested in the on-site slipstream unit. Off-line cleaning techniques have been developed and improved.

Filter blinding and corrosion mechanisms remain an intense area of study. Computational fluid dynamic models have been employed to optimize the gas distribution systems within the filter vessels. Hands-on project engineers work directly with metallurgists and vendors to minimize errors and leverage each other's expertise. The ejector system that returns the particulates to the reactor has also been studied and optimized for maximum reliability and lower O&M cost. Process conditions have been evaluated and modified to minimize element corrosion and provide a balanced flow of syngas to each cluster of elements. The control system has been improved to optimize the operation of the pulse cleaning system. A sophisticated control algorithm and alarm provides operating personnel with advanced warning of potential filter system problems so that immediate corrective actions can be taken before the filters become inoperable. Indeed, Global Energy's filter improvement program is not only wide in its breadth but deep as well.

Low Temperature Heat Recovery

The low temperature heat recovery system accounted for more than 40 days of downtime in the first year of operation and cost the Project significant dollars to repair or replace failed exchangers and replace spent catalyst. Investigation of the root cause revealed that trace chlorides and metals from the coal remained in the syngas and that these trace components rapidly poisoned the COS hydrolysis catalyst. Investigators also determined that water condensing from the syngas concentrated chlorides in the tubes of the low temperature heat exchangers resulting in chloride stress-corrosion-cracking of the exchanger tubes. Expensive catalyst replacement and frequent repairs to exchanger tubes initiated a fast-track project to install a chloride scrubbing system and replace the failing exchangers with exchangers manufactured from alloys impervious to chloride attack. The scrubber project went from inception to operation in 6 months, and the low temperature heat recovery system has not experienced a single hour of downtime related to chlorides since the scrubber went into operation in October of 1996.

Concurrent with the design and installation of the chloride scrubber, a slipstream unit was installed to test various COS hydrolysis catalysts. The object was to find a catalyst with a probable 5-year life. An appropriate catalyst was found and installed after start-up of the chloride scrubber system. Samples taken of the catalyst after two years of operation indicate that the 5-year life is easily obtainable.

Acid Gas Removal

One problem that beset this system in the first three years of operations was the build-up of heat stable salts in the amine solution. Heat stable salts decrease the removal efficiency of the amine solution, ultimately resulting in higher sulfur emissions from the facility. Although the WRCGRP initially included a process to remove heat stable salts, the initial system was unreliable, costly, and required frequent maintenance. As a result, frequent and costly on-site vacuum distillation or solution replacement was required during the early operation. Numerous process improvements and changes improved reliability of the system and then, in August of 1999, a capacity expansion was installed which satisfied all the remaining system limitations. Since that modification, the system has proved to be very reliable and removes heat stable salts faster than they are formed.

v. Plant Performance

Despite reliability issues during the first two years of operation, the actual performance of the plant during coal operation compares favorably with design as indicated in Table ES-3.

Table ES-3: Performance Summary

	Design	Actual
Syngas Capacity, MMBtu/hr	1,780	1,690 (1825 max)
Combustion Turbine Capacity, MW	192	192
Steam Turbine Capacity, MW	105	96
Auxiliary Power, MW	35.4	36
Net Power, MW	262	252
Plant Heat Rate, Btu/kWh	9,030	8,900
Sulfur Removal Efficiency, %	>98	>99
SO_2 Emissions, lbs/MMBtu	<0.2	<0.1
Syngas Heating Value (HHV)	280	275-280
Syngas Sulfur Content (ppmv)	<100	<100

The plant has demonstrated a maximum capacity of 1,825 MMBtu/hr but requires only 1,690 MMBtu/hr to satisfy the requirements of the combustion turbine at full load. The noted steam turbine capacity shortage requires a HRSG feedwater heater modification to bring output up to design. With this modification, the overall plant heat rate will drop to 8,650 Btu. The air separation unit was unable to meet the guaranteed power specification, which accounts for the difference in auxiliary power. As indicated previously, the environmental performance of the plant has been superior. Sulfur removal efficiencies all exceed design and total demonstrated sulfur dioxide emissions have been as low as 0.03 lb/MMBtu of dry coal feed. This quantity is 1/40 that of the SO_2 emissions limit of 1.2 lb/MMBtu with at least a 90% reduction. Likewise, NOX, CO and particulate emissions average 0.022, 0.044 and 0.012 lb/MMBtu respectively. Based on these data, the WRCGRP is the cleanest coal-fired power plant in the world.

Operation in 1998 was highlighted by several months where syngas production exceeded one trillion Btu of gas produced. This production milestone was met in March, April, October and November of 1998. As previously indicated, the highest quarterly production of syngas occurred in the third quarter of 1999 in which 2,712,107 MMBtu of gas were produced. Syngas production in September of 1999 was 1,204,573 MMBtu, the highest ever for a month. Furthermore, the combustion turbine operated at maximum capacity for all but 7 hours in September. Key production statistics for the Demonstration Period are presented in Table ES-4.

Table ES-4: Wabash River Coal Gasification Repowering Project Production Statistics

Time Period	On Coal (Hr)	Coal Processed (tons)	On Spec. Gas (MMBtu)	Steam Produced (Mlb)	Power Produced (MWh)	Sulfur Produced (tons)
Start-up ‘95	505	41,000*	230,784	171,613	71,000*	559
1996	1,902	184,382	2,769,685	820,624	449,919	3,299
1997	3,885	392,822	6,232,545	1,720,229	1,086,877	8,521
1998	5,279	561,495	8,844,902	2,190,393	1,513,629	12,452
1999 ✧	3,496	369,862	5,813,151	1,480,908	1,003,853	8,557
Overall	15,067	1,549,561	23,891,067	6,383,767	4,125,278	33,388

* Estimates. ✧***Note: The combustion turbine was unavailable from 3/14/99 through 6/22/99***.

Early identification of availability-limiting process problems led to aggressive implementation of improvement projects which resulted in 224% more syngas produced during the second year than in year one. The syngas produced during the third year exceeded the second year's production by an additional 42%. Assuming the availability factor during the combustion turbine outage was the same as in 1998, the facility production in 1999 would have favorably matched 1998's output. Figure ES-3 depicts this continuous improvement trend over the last four years as measured by total syngas production.

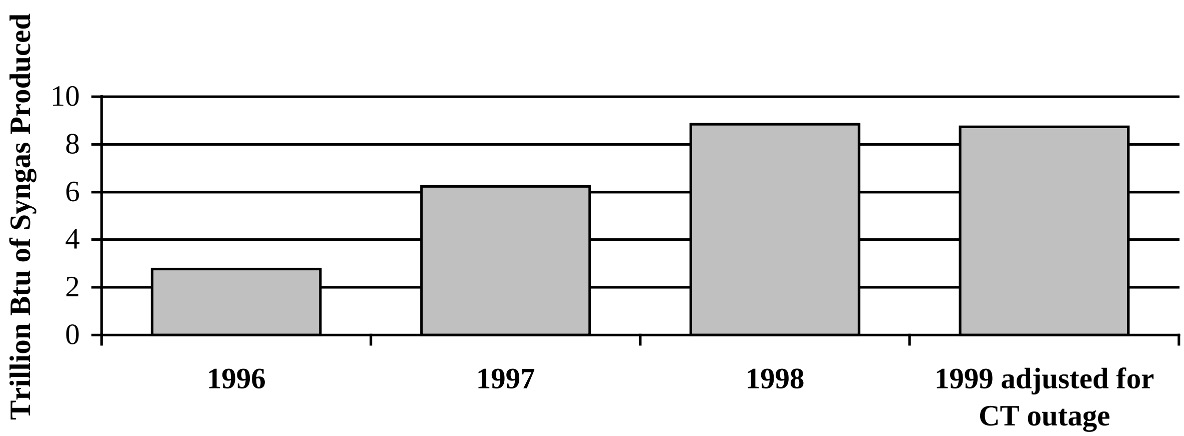


Figure ES-3: Syngas Production by Year

vi. Economics and Commercialization

The initial budgeted cost for the construction of the Wabash River facility was $248 million for the syngas facility (Destec scope) and approximately $122 million for the new power block and modifications to the existing Wabash River Generating Station (PSI Energy scope). The installed cost of the overall IGCC facility including start-up was about $1590/kW (1994$). Allowing for new equipment that would have been required if this had been a greenfield project instead of repowering, the installed cost figure on this demonstration project was $1700/kW (1994$).

As shown in Table ES-5, nearly all cost areas within the syngas facility were completed under budget, with the exception of the construction cost and the pre-operations management cost of the syngas facility. Overruns of the power block budget were in the same areas. The construction cost was nearly double the budgeted amount, due to four factors, many beyond the control of the Project participants. Weather delays, equipment shipping problems, mechanical contracting and a prolonged start-up period combined to escalate the construction cost. Despite the construction delays, start-up of the facility occurred on schedule and only three years and four months from the DOE award date, significantly shorter than any other IGCC project. Even with the cost overruns, the Project was by far the least expensive of the first generation coal gasification combined cycle plants built in the 1992-2000 timeframe. The other coal IGCC's, two in the U.S. and two in Europe, all first generation at this scale, have been reported to have cost $2000/kW and over.

Table ES-5: Wabash River Coal Gasification Repowering Project Costs

Cost Area	Budget	Actual
SYNGAS FACILITY		
Engineering & Project Management	29.6	27.3
Equipment Procurement	98.3	84.5
Construction	55.5	106.1
Construction Management	7.9	8.1
ASU	36.9	32.8
Pre-operations Management	19.8	21.7
POWER BLOCK	121.8	136.2
Total $MM, 1994 average	**369.8**	**416.6**

Future IGCC facilities based on the E-Gas™ technology will benefit from the lessons learned at Wabash River. A realistic number for a current generation plant is $1,250 - $1,300/kW (2000$) with a heat rate of 8,250 Btu/kW (HHV) for a greenfield facility. A new, stand-alone greenfield IGCC to produce power, but no other products, and utilizing petroleum coke as fuel has an approximate installed cost of $1100 - $1200/kW (2000$), based on reduced equipment requirements with petroleum coke feeds.

The IGCC model developed by Nexant LLC for the DOE was used to evaluate the rate of return for projects financed IGCC's at today's fuel and power prices. As evidenced in Table ES-6, the strongest driver of overall plant economics is fuel cost. The economic analyses of project returns with coal as a feedstock reach a credible economic condition of 12% IRR at power pricing of \$38 - \$49/MWh, depending on how capital and O&M costs are set and on the availability that is assumed. Plant design and operation based on petroleum coke is economically stronger, due not only to the lower fuel cost, but also the incrementally improved capital and operating costs for a plant designed for petroleum coke initially.

Table ES-6: Results of Economic Analysis for Wabash River Style IGCC

	Coal	Petroleum Coke
Plant Net Generation, MW	270	271
Plant Heat Rate, Btu/kWh (HHV)	8910	8790
Plant Capital Cost, \$/kW	1275	1150
Plant Operating Cost, % of capital	5.2	4.5
Annual Availability	75%	80%
NPV_{10}, Millions \$	(128)	45
Internal Rate of Return, at \$35/MWh power	NA	14%
Sensitivity Analysis Cases, 12% IRR	**Required \$/MWh in first year**	
10% reduction in capital	46	30
10% reduction in O&M	49	32
10% increase in availability	42	27
10% reduction in capital, O&M 10% increase in availability	38	24

O&M costs have been relatively high for IGCC plants compared to conventional coal-fired plants. Using 1999 budgeted costs as a basis, the non-fuel O&M cost for the syngas facility was 7.1% of installed capital based on a 75% operating rate. Since Global Energy manages the Wabash River facility as a stand-alone plant, all the infrastructure and support base for labor and maintenance must be provided at the site. This includes contract administration, accounting, inventory, human resources, engineering, environmental and safety, laboratory staff and a base maintenance and operating staff. Since the first year of operation, the syngas facility has reduced

O&M spending by 30% and further areas for reduction have been identified. Projected O&M for a mature Wabash River syngas facility is 5.2% of installed capital. O&M savings for future plants can be realized by sharing infrastructure cost within, for example, a large petrochemical facility.

Market penetration for gasification technologies is rapidly increasing. Gasification-produced megawatts will increase ten-fold from 1992 to 2002, based on plants already in operation or construction. The current opportunities are not primarily in power generation, however. The opportunities are in co-production facilities, especially those able to use opportunity fuels. Exploring low-cost feedstocks and high-value products stretches both ends of the economic equation. These facilities seem to be primarily in the refining sector, and it is expected that most of the next generation of solid fuel gasification plants will be inside the fences of refineries, as opposed to the entire first generation of greenfield and repowering applications for power generation facilities.

vii. Conclusions

Despite firm technical and operating experience gained at Dow's gasification plant in Louisiana (LGTI), several operating differences set the Wabash River plant apart from its predecessor. In addition, Wabash River incorporated several technical advances never attempted at the LGTI facility.

During the Demonstration Period the operating differences have been resolved and the technical advances have proven successful. Operation of the E-Gas™ technology on several different high sulfur bituminous coals and blends has been achieved with the lowest environmental emissions of any coal-fired power plant. Even though it had never been previously attempted, the Project repowered a 40 year old utility plant as an IGCC with a high level of integration between the gasification heat recovery unit, the combustion turbine HRSG and the reheat steam turbine. The facility initiated use of one of the first ten General Electric "F" class machines and the first such machine operating on syngas. The Project considerably advanced the technology of particulate filtration and the Wabash River system represents one of the few systems of this size and with much higher particulate loading than other operating systems. Ash deposition, an early downtime cause, has been completely eliminated. Previous gasification operating expertise has been magnified and a new generation of engineers and operators has been developed to operate the plant safely and reliably, with ever-increasing availability.

Significant challenges were met and overcome in areas outside of the primary demonstration objectives, including technical, commercial and organizational challenges. The Project also demonstrated success in some areas that were not planned at the outset – operation on petroleum coke, for instance, and operation on a blend and combination of coals that sometimes changes daily. The Project operates today as part of the utility power generation system, competing with Cinergy's alternative market options for on-peak and off-peak power. Competitive market-based pricing allows the syngas facility to run as base load in Cinergy's system

All of these advances demonstrated at the Wabash River Coal Gasification Repowering Project are leading to more confidence in the commercialization of the technology in other settings besides coal and power. These advances in the technology will be leveraged into the next generation of power and chemical production megaplexes as Global Energy participates in the DOE's "Vision 21" program and other viable commercial projects.

1.0 INTRODUCTION

The Wabash River Coal Gasification Repowering Project (WRCGRP or "Project") is currently the largest single-train gasification facility in the United States, as well as the cleanest coal fired plant of any kind in the world. Its design allows for lower emissions than other high sulfur coal fired power plants and a resultant heat rate improvement of approximately 20% over the previous plant configuration. The Wabash River gasification facility was developed, designed, constructed, started-up and is currently operated by what are now Wabash River Energy Ltd. (WREL) personnel. Wabash River Energy Ltd. is a wholly owned subsidiary of Global Energy Inc. The Project successfully operated through a Demonstration Period from November of 1995 through December of 1999.

The original Project participants, Destec Energy, Inc. (which was later acquired by Dynegy Power Corporation (Dynegy) of Houston, Texas, and PSI Energy, Inc. (PSI), of Plainfield, Indiana, formed a Joint Venture (JV) to participate in the United States Department of Energy's (DOE) Clean Coal Technology (CCT) program to demonstrate coal gasification repowering of an existing generating unit impacted by the Clean Air Act Amendments (CAAA). The participants jointly developed, separately designed, constructed, own, and are now operating an integrated coal gasification combined-cycle power plant, using Destec's coal gasification technology (now known as E-Gas™ Technology) to repower the oldest of the six units at PSI's Wabash River Generating Station in West Terre Haute, Indiana. In 1999, Global Energy acquired the Project and the gasification technology from Dynegy. The gasification process is integrated with a new General Electric 7FA combustion turbine generator and a heat recovery steam generator in the repowering of a 1950's-vintage Westinghouse steam turbine generator using some pre-existing coal handling facilities, interconnections and other auxiliaries. The Project processes locally-mined Indiana high sulfur coal to produce 262 net megawatts of electricity.

The Project has demonstrated the ability to run at full load capacity while meeting the environmental requirements for sulfur and NO_x emissions. Cinergy, PSI's parent company, dispatches power from the Project, with a demonstrated heat rate of under 9,000 Btu/kWh

(HHV), second only to their hydroelectric facilities on the basis of environmental emissions and efficiency.

In late 1998, PSI Energy reached agreement to purchase the gasification services contract from Dynegy subject to regulatory approval. Regulatory approval was granted in September of 1999 and the sale was completed in October of 1999
This agreement allowed PSI to purchase the remaining term of the 25-year contract, which had become “out-of-market” in comparison to today’s alternate sources for power. WREL explored alternatives for continued operation of Wabash River in a more “market-based” mode. In June of 2000, Global Energy Inc. announced that WREL had entered into a competitive market contract with PSI for the sale of syngas. Syngas, sold under this market-based three year agreement, is priced to allow the power produced from the syngas to compare favorably year-round to PSI’s alternate sources for on-peak and off-peak power.

This recent development, coupled with efforts to improve the commercial viability of the Wabash River Coal Gasification Repowering Project, has sharpened the focus to make the technology competitive in today’s market. Building on the lessons learned and the many successes to date, every effort is being made to look past just syngas-to-power and to pursue value-added uses for syngas produced from coal or other feeds such as is envisioned through forward-thinking concepts like the Department of Energy’s “Vision 21” initiative. In the face of the current market for gasification, WREL and Global Energy will pursue the application of this technology forward as an economically viable tool for converting carbon feedstocks to higher value products.

Global Energy is an Independent Power Producer (IPP) with gasification technology experience. A founding member of the Gasification Technologies Council (GTC) in Washington D.C., Global Energy is one of the most experienced and innovative companies in the commercial gasification business. Global Energy will market the E-Gas™ technology through its subsidiary, Gasification Engineering Corp., a company formed by Global Energy after acquiring all the gasification assets of Dynegy, Inc. in late 1999.

Gasification Engineering Corp. and WREL personnel, have over 1000 years of combined industrial experience. Nearly one third of this experience, about 300 years, is directly related to the design, implementation and operation of gasification plants. This expertise is a complementary addition to Global Energy's existing gasification experience base, which also totals approximately 300 years of combined experience.

This group has a wide-ranging theater of operations, from the daily operation of the Wabash River facility and gasification project development and construction to research and development in several gasification-related fields. Although the group has a vast network of contacts in related industries for ceramic, refractory, metallurgy, instrumentation and other technologies with applications in gasification, most expertise exists in-house in the areas of operations, process modeling, process design, gasification component design (such as slurry mixers), char filtration, and mechanical equipment applications.

1.1 Objectives

For CCT Round IV, Public Law 101-121 provided $600 million to conduct cost-shared CCT projects to demonstrate technologies that are capable of replacing, retrofitting or repowering existing facilities. To that end, a Program Opportunity Notice (PON) was issued by the Department of Energy in January 1991, soliciting proposals to demonstrate innovative energy-efficient technologies that were capable of being commercialized in the 1990's. These technologies were to be capable of: (1) achieving significant reductions in the emissions of sulfur dioxide and/or nitrogen oxides from existing facilities to minimize environmental impacts such as transboundary and interstate pollution and/or; (2) providing for future energy needs in an environmentally acceptable manner.

In response to the PON, the DOE received 33 proposals in May 1991. After evaluation, nine projects were selected for award. These projects involved both advanced engineering and pollution control technologies that can be "retrofitted" to existing facilities and "repowering" technologies that not only reduce air pollution but also increase generating plant capacity and extend the operating life of the facility.

In September 1991, the United States Department of Energy selected the Wabash River Coal Gasification Repowering Project, as one of nine projects, for funding under Round IV of the DOE's Clean Coal Technology Demonstration Program. This was followed by nine months of negotiations and a congressional review period. The DOE executed a Cooperative Agreement on July 28, 1992. The Project's sponsors, PSI Energy, Inc., and Global Energy, are demonstrating, in a fully commercial setting, coal gasification repowering of an existing generating unit affected by the Clean Air Act Amendments (CAAA). The Project also demonstrates important advances in the coal gasification process for high sulfur bituminous coal. After receiving the necessary state, local and federal approvals, this Project began construction in the third quarter of 1993 and started commercial operations in the third quarter of 1995. This facility, originally scheduled for a three-year Demonstration Period and 22-year Operating Period (25 years total), extended the demonstration to span four years and successfully completed this demonstration in December of 1999.

The demonstration confirmed the successful design, construction, and operation of a nominal 2500 ton-per-day, 262 net MWe integrated gasification combined cycle (IGCC) facility using the advanced two-stage, oxygen blown Destec (now E-Gas™) technology. The DOE's share of this Project cost was $219 million.

1.2 General

The IGCC system consists of:

- The E-Gas™ oxygen-blown, entrained flow, two stage coal gasifier, which is capable of utilizing high sulfur bituminous coal;
- An air separation unit;
- A gas conditioning system for removing sulfur compounds and particulates;
- Systems or mechanical devices for improved coal feed and all necessary coal handling equipment;
- A combined cycle power generation system wherein the gasified coal syngas is combusted in a combustion turbine generator;
- A heat recovery steam generator.

The result of repowering is an IGCC power plant with low environmental emissions (SO_2 of less than 0.25 lbs/MMBtu and NO_x of less than 0.1 lb/MMBtu) and high net plant efficiency. The repowering increases unit output, providing a total IGCC capacity of nominal 262 net MWe. The Project demonstrates important technological advancements in processing high sulfur bituminous coal.

In addition to the original Joint Venture members, PSI and Destec, the Phase II project team included Sargent & Lundy, who provided engineering services to PSI, and Dow Engineering, who provided engineering services to Destec.

The potential market for repowering with the demonstrated technology is large and includes many existing utility boilers currently fueled by coal, oil or natural gas. In addition to greater, more cost-effective reduction of SO_2 and NO_x emissions attainable by using the gasification technology, net plant heat rate is improved. This improvement is a direct result of the combined cycle feature of the technology, which integrates a combustion topping cycle with a steam bottoming cycle. This technology is suitable for repowering applications and can be applied to any existing steam cycle located at plants with enough land area to accommodate coal handling and storage and the gasification and power islands.

One of the Project objectives is to advance the commercialization of coal gasification technology. The electric utility industry has traditionally been reluctant to accept coal gasification technology and other new technologies as demonstrated in the U.S. and abroad because the industry has no mechanism for differentiating risk/return aspects of new technologies. Utility investments in new technologies may be disallowed from rate-base inclusion if the technologies do not meet performance expectations. Additionally, the rates of return on these are regulated at the same level as established lower risk technologies. Therefore, minimal incentives exist for a utility to invest in, or develop, new technologies. Accordingly, the supplier has traditionally assumed most of the risk in new technologies.

The factors described above are constraints to the development of, and demand for, clean coal technologies. Constraints to development of new technologies also exist on the supply side. Developers of new technologies typically self-finance or obtain financing for projects through lenders or other equity investors. Lenders will generally not assume performance and operational risks associated with new technology. The majority of funds available from lending agencies for energy-producing projects are for technologies with demonstrated histories in reliability, maintenance costs and environmental performance. Equity investors who invest in new energy technologies also seek higher returns to accept risk and often require the developer of the new technology to take performance and operational risks.

Consequently, the overall scenario results in minimum incentives for a commercial size development of new technologies. Yet without the commercial size test facilities, the majority of the risk issues remain unresolved. Addressing these risk issues through utility scale demonstration projects is one of the primary objectives of DOE's Clean Coal Technology Program.

The WRCGRP was developed in order to demonstrate the E-Gas™ Coal Gasification Technology in an environment, and at such a scale, as to prove the commercial viability of the technology. Those parties affected by the success of this Project include the coal industry, electric utilities, ratepayers and regulators.

Also, the financial community, which provides the funds for commercialization, is keenly interested in the success of this Project. Without a demonstration satisfying all of these interests, the technology will make little advancement. Factors of relevance to further commercialization are:

- The Project scale (262 net MWe) is compatible with all current, commercially available advanced gas turbines and thus completely resolves the issue of scale-up risks.

- The operational term of the Project is expected to be approximately 25 years including the DOE Demonstration Period of the first 3 years (actually 4 years). This should alleviate any concerns that the demonstration does not define a fully commercial plant from a cost and operational viewpoint.

- The Project dispatches on a utility system and is called upon to operate in a manner similar to other utility generating units.

- The Project operates under a service agreement that defines guarantees of environmental performance, capacity, availability, coal to gas conversion efficiency and maximum auxiliary power consumption. This agreement serves as a model for future commercialization of the E-Gas™ Coal Gasification Technology and defines the fully commercial nature of the Project.

- The Project is designed to accommodate most coals available in Indiana and typical of those available to midwestern utilities, thereby enabling utilities to judge fuel flexibility. The Project also enables testing of varying coal types and other feedstocks in support of future commercialization of the E-Gas™ Coal Gasification Technology.

1.3 Project Phase Description

The Project Cooperative Agreement (CA) was signed on July 28, 1992, with an effective date of August 1, 1992. Under the terms of the CA, the Project activities were divided into three phases:

- Phase I Engineering and Procurement
- Phase II Construction and Start-up
- Phase III Demonstration

1.3.1 Phase I Activities – Engineering and Procurement

Under the provisions of the CA, the work activity in Phase I (engineering and procurement) focused on detailed engineering of both the syngas and power plant elements of the Project which included design drawings, construction specifications and bid packages, solicitation documents for major hardware and the procurement. Site work was undertaken during this time period to meet the overall construction schedule requirements. The Project team included all necessary management, administrative and technical support.

The activities completed during this period were those necessary to provide the design basis for construction of the plant, including capital cost estimates sufficient for financing, and all necessary permits for construction and subsequent operation of the facility.

The work during Phase I can be broken down into the following main areas:

- Project Definition Activities
- Plant Design
- Permitting and Environmental Activities

Each of these activities is briefly described below. All Phase I activities were complete by 1993.

Project Definition Activities

This work included the conceptual engineering to establish the Project size, installation configuration, operating rates and parameters. Definition of required support services, all necessary permits, fuel supply, and waste disposal arrangements were also developed as part of the Project Definitions Activities. From this information, the cost parameters and the Project economics were established (including capital costs, project development costs and operation and maintenance costs). Additionally, all project agreements necessary for construction of the plant were concluded. These include the CA and the Gasification Services Agreement (GSA).

Plant Design

This activity included preparation of design and major equipment specifications along with plant piping and instrumentation diagrams (P&ID's), process control releases, process descriptions and performance criteria. These were prepared in order to obtain firm equipment specifications for major plant components, which established the basis for detailed engineering and design.

Permitting and Environmental Activities

During Phase I, applications were made and received for the permits and environmental activities necessary for the construction and subsequent operation of the Project.

1.3.2 Phase II Activities – Construction

Construction activities occurred in Phase II and included the necessary construction planning and integration with the engineering and procurement effort. Planning the construction of the Project began early in Phase I. Separate on-site construction staffs for both Destec and PSI were provided to focus on their respective work for each element of the Project. Construction personnel coordinated the site geo-technical surveys, equipment delivery, storage, and lay down space requirements. The construction activities included scheduling, equipment delivery, erection, contractors, security and control.

The detail design phase of the Project included engineering, drawings, equipment lists, plant layouts, detail equipment specifications, construction specification, bid packages and all activities necessary for construction, installation, and start-up of the Project.

Performance and progress during this period were monitored in accordance with previously established baseline plans.

1.3.3 Phase III Activities – Demonstration Period

Phase III consisted of a three-year (extended to four years) Demonstration Period. The operation effort for the Project began with the development of the operating plan including integration with the early engineering and design work of the Project. Plant operation input to engineering was vital to assure optimum considerations for plant operations and maintenance and to assure high reliability of the facilities. The operating effort continued with the selection and training of operating staff, development of the operating manuals, coordination of start-up with construction, planning and execution of plant commissioning, conduct and documentation of the plant acceptance test, and continued operation and maintenance of the facility throughout the Demonstration Period.

Phase III activities were intended to establish the operational aspects of the Project in order to prove the design, operability and longevity of the plant in a fully commercial utility environment.

1.4 Project Organization

The WRCGRP Joint Venture (JV) established a Project Office for the execution of the Project. The Project Office was originally located at Dynegy's corporate offices in Houston, Texas. All management, reporting and project reviews for the Project are carried out as required by the Cooperative Agreement. The JV partners, through a JV Agreement, are responsible for the performance of all engineering, design, construction, operation, financial, legal, public affairs and other administrative and management functions required to execute the Project. A JV Manager was designated as responsible for the management of the Project. The JV Manager was the official point of interface between the JV and the DOE for the execution of the Cost Sharing Cooperative Agreement. The JV Manager was responsible for assuring that the Project is conducted in accordance with the cost, schedule, and technical baseline established in the Project Management Plan (PMP) and subsequent updates.

1.5 Project Location and Original Equipment Description

The site of the Project is PSI's Wabash River Generating Station, located on approximately 437 acres northwest of Terre Haute, Indiana in Vigo County. Indianapolis, the state capital, is located approximately 65 miles to the east-northeast of Terre Haute. The Illinois border is located approximately 7 miles to the west of Terre Haute. A general location map depicting the location of the Project, in reference to the existing Wabash River Generating Station Station is shown in Figure 1.5A. The region surrounding the property may be described as wooded with gently rolling terrain to the north, west and south and river valley (Wabash River) to the east. The Project is located within Vigo County, but outside the municipal limits of Terre Haute, Indiana.

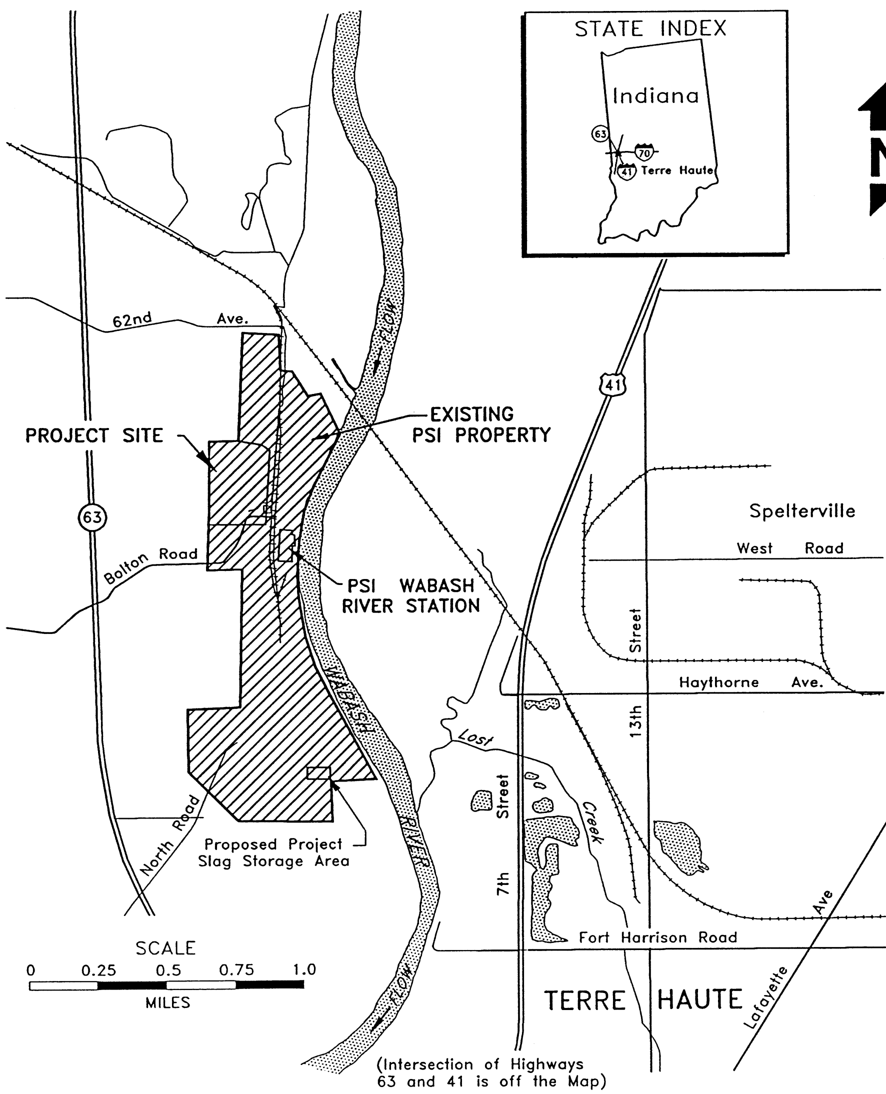


Figure 1.5A: Project Site General Location Map

PSI's existing equipment at the Wabash River Station consisted of six pulverized-coal generating units. Units 1 through 4 boilers were manufactured by Foster-Wheeler, the Unit 5 boiler was manufactured by Riley Stoker, and the Unit 6 boiler was manufactured by Combustion Engineering. At the time of initial Project development each unit featured a Research-Cottrell electrostatic precipitator, shared a common 450-foot tall exhaust stack, and was fueled by pulverized bituminous coal, while fuel oil was used for start-up and flame stabilization. Natural gas was not used at the Station, although a main transmission line of Indiana Gas Company was located approximately 1 mile west of the powerhouse.

The Unit 1 steam turbine, repowered by implementation of the Project, was permitted at 99 MW under the Station's existing air quality permit (limited to 90 MW during routine operations). This unit was put into service in 1953. An electrostatic precipitator (two units in parallel with a 98.5 percent collection efficiency) was used for the control of particulates.

The Wabash River was and is the sole water source for all consumptive and nonconsumptive water systems at the Station.

1.6 Permitting and Environmental Activities

During Phase I, applications were made and received for the permits and environmental activities necessary for the construction and subsequent operation of the Project. The major permits for the Project included:

- Indiana Utility Regulatory Commission – The state authority reviewed the Project (under a petition from PSI for a Certificate of Necessity) to ensure the Project will be beneficial to the state and PSI ratepayers. The technical and commercial terms of the Project were reviewed in this process.

- Air Permit – This permit details the allowable emission levels for air pollutants from the Project. It was issued under standards established by the Indiana Department of Environmental Management (IDEM) and the United States Environmental Protection Agency (EPA) Region V and administered by Vigo County Air Pollution Control. This permit also included within it the authority to commence construction.

- NPDES Permit – This National Pollutant Discharge Elimination System permit details and controls the quality of waste water discharge from the Project. It was reviewed and issued by the Indiana Department of Environmental Management. For this Project, this constituted a modification of the existing permit for PSI's Wabash River Generating Station.

- NEPA Review – The National Environmental Policy Act review was carried out by the DOE based on Project information provided by the participants. The scope of this review was comprehensive in addressing all environmental issues associated with potential Project impacts on air, water, terrestrial, quality, health and safety, and socioeconomic impacts.

Miscellaneous permits and approvals necessary for construction and subsequent operation of the Project included the following.

- FAA Stack Height/Location Approval
  Controlling Authority: Federal Aviation Administration

- Industrial Waste Generator
  Controlling Authority: Indiana Department of Environmental Management

- Solid Waste
  Controlling Authority: Indiana Department of Environmental Management

- FCC Radio License
  Controlling Authority: Federal Communications Commission

- Spill Prevention Plan

- Waste Water Pollution Control Device Permit
  Controlling Authority: Indiana Department of Environmental Management

2.0 TECHNOLOGY DESCRIPTION

The E-Gas™ (Destec) Gasification Process features an oxygen-blown, continuous-slagging, two-stage, entrained-flow gasifier (Figure 2.0A). Coal or coke is milled with water in a rod mill to form a slurry. The slurry is combined with oxygen in mixer nozzles and injected into the first stage of the gasifier, which operates at 2600°F and 400 psig. A turnkey 2,060-ton/day low-pressure cryogenic distillation facility that WREL owns and operates supplies 95% pure oxygen.

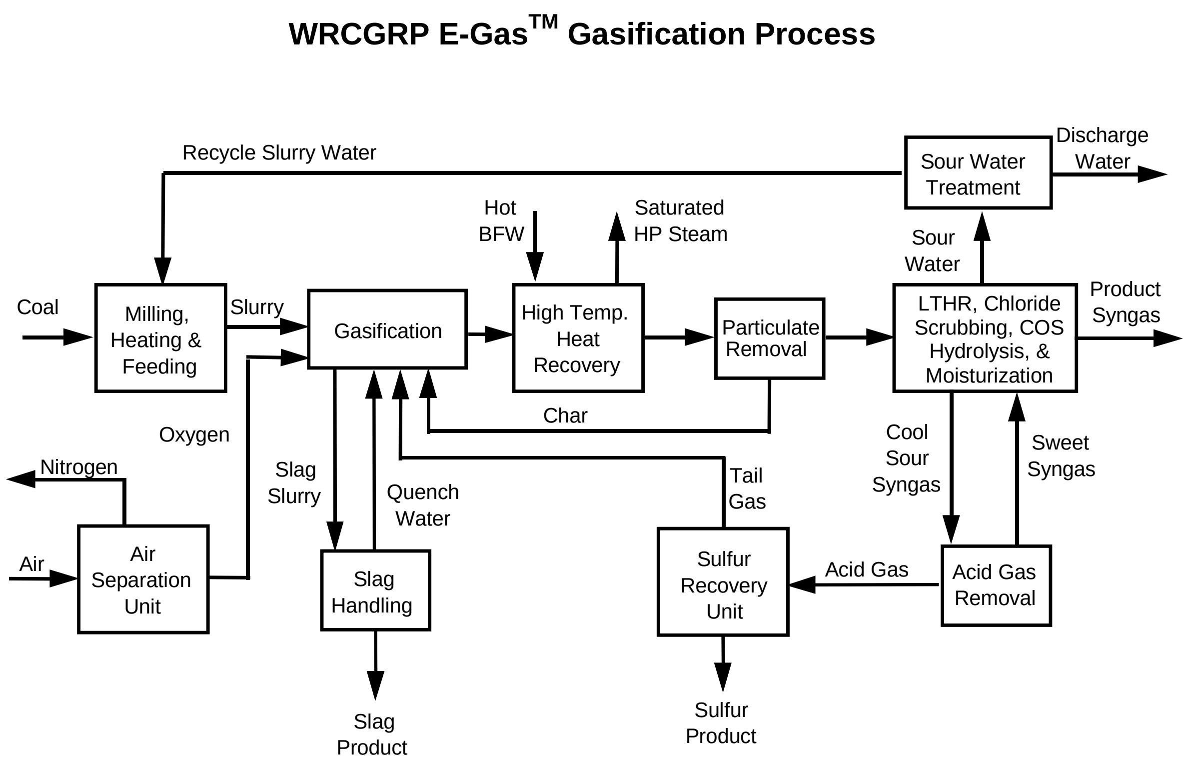


Figure 2.0A: Gasification Process Simplified Block Flow Diagram

In the first stage, slurry undergoes a partial oxidation reaction at temperatures high enough to bring the coal's ash above its melting point. The fluid ash falls through a taphole at the bottom of the first stage into a water quench, forming an inert vitreous slag. The syngas then flows to the second stage, where additional coal slurry is injected. This coal is pyrolyzed in an endothermic reaction with the hot syngas to enhance syngas heating value and to improve overall efficiency.

The syngas then flows to the high-temperature heat-recovery unit (HTHRU), essentially a firetube steam generator, to produce high-pressure saturated steam. After cooling in the HTHRU, particulates in the syngas are removed in a hot/dry filter and recycled to the gasifier where the carbon in the char is converted to syngas. The syngas is further cooled in a series of heat exchangers, water-scrubbed to remove chlorides, and passed through a catalyst that hydrolyzes carbonyl sulfide to hydrogen sulfide. Hydrogen sulfide is removed using methyldiethanolamine (MDEA) absorber/stripper columns. The "sweet" syngas is then moisturized, preheated and piped over to the power block, where it is burned in a General Electric 7FA high-temperature combustion turbine/generator to produce 192 MW of electricity.

The HRSG configuration was specifically optimized to utilize both the gas-turbine exhaust energy and the heat energy made available in the gasification process. Superheated high-pressure steam, when fed to the repowered Westinghouse reheat steam turbine, produces 104 MW, by design, of additional electricity. When combined with the combustion turbine generator's 192 MW and the system's auxiliary load of approximately 34 MW, a net of 262 MW is produced to feed the Cinergy grid. An overall thermal efficiency of less than 9,000 Btu/kWh (HHV), which is lower than the design, has been demonstrated. Please note that a lower heat rate indicates greater thermal efficiency.

The gasification facility also produces two commercial by-products. Sulfur is removed as 99.999% pure elemental sulfur and marketed to sulfur users. Slag is being marketed as an aggregate in asphalt roads, as structural fill in various types of construction applications, as roofing granules, and as blasting grit.

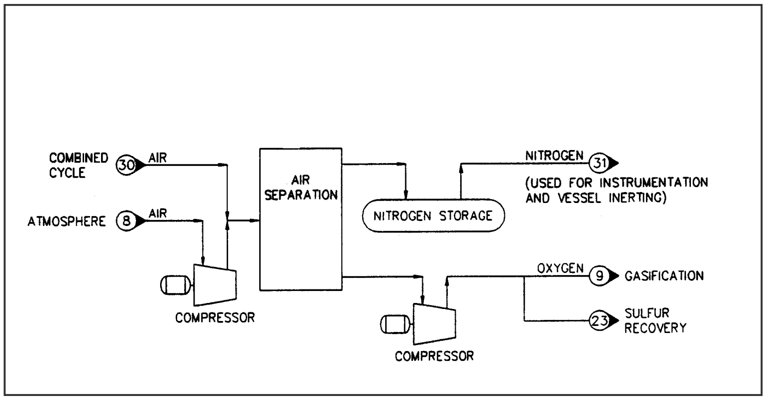
3.0 DETAILED PROCESS DESCRIPTION

The E-Gas™ gasification process is based on slurry (or liquid) feed utilizing a two-stage gasifier with total solids recycle and coupled with a unique high temperature heat recovery unit. Gasification is accomplished by partial combustion of the feedstock with air or high purity oxygen in the first stage creating hot synthetic gas with the mineral content forming a molten slag. The slag is continuously removed from the gasifier via E-Gas™'s proprietary low-profile slag removal system. This avoids expensive, structure-elevating and maintenance-prone lock hoppers. In the second stage, the heat content of the hot syngas from the first stage is used to vaporize and gasify additional coal slurry introduced in the second stage. The syngas exiting the gasifier is cooled and cleaned, and is then moisturized prior to use in an advanced gas turbine for the generation of power (or conditioned further for the production of chemicals such as hydrogen, methanol, urea, Fischer-Tropsch products, etc.). A solid/water slurry approach minimizes feed preparation and storage cost and allows for safe and accurate control of fuel to the gasifier. The two-stage gasifier, coupled with E-Gas's™ unique application of a firetube syngas cooler design, minimizes the size and temperature level requirements for the high temperature heat recovery system. This is cost effective and yields high conversion efficiencies both for thermal and chemical energy. Raw syngas exiting the gasifier contains entrained solids that are removed and recycled to the first stage of the gasifier. Recycle of these solids also enhances efficiency and consolidates the solid effluent from the process in one stream, the slag leaving the gasifier.

The E-Gas™ two-stage entrained flow gasification process offers an environmentally superior coal-based power generation source with emissions a fraction of the 1990 Clean Air Act Amendments limits. The process, as demonstrated at Wabash River, can convert coal, petroleum coke, and other solid as well as liquid fuels or wastes into a clean syngas which is used as a fuel gas for power generation in the GE 7FA advanced combustion turbine. The conversion of coal to electric power at Wabash River yields a 38 to 45% overall efficiency. With these high efficiencies, the emission of carbon dioxide (CO_2) is significantly lower than for conventional coal-based power generation technology.

Detailed descriptions are given below for the subsystems based on the E-Gas™ technology. The subsystems included are oxygen supply, slurry preparation, gasification, slag handling, syngas cooling, particulate removal, syngas scrubbing, low temperature heat recovery, acid gas removal, sulfur recovery, tank vent collection, sour water treatment and combined cycle power block.

3.1 Air Separation Unit

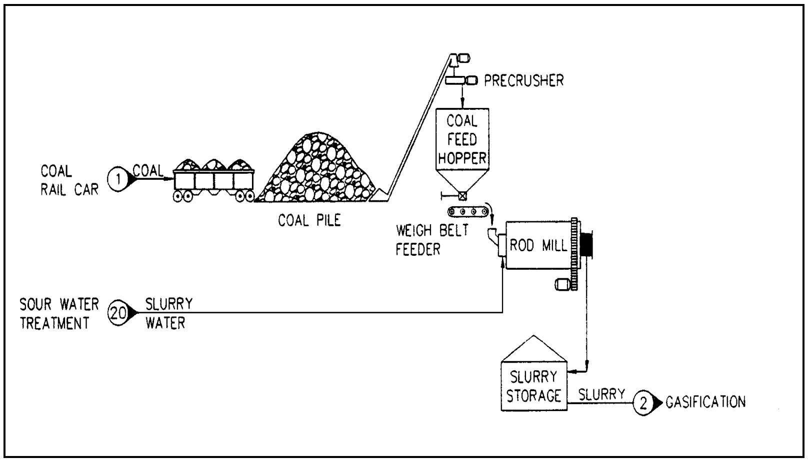


The Air Separation Unit (ASU), or oxygen plant, contains an air compression system, an air separation cold box, an oxygen compression system and a nitrogen compression system.

Atmospheric air compressed by a multi-stage centrifugal compressor is cooled to approximately 40°F (5°C) and directed to the molecular sieve adsorbers where moisture, carbon dioxide and contaminants are removed to prevent them from freezing in the colder sections of the plant. The dry, carbon dioxide-free air is filtered before being separated into oxygen, nitrogen and waste gas in the cryogenic distillation system (cold box). An oxygen stream containing 95% oxygen is discharged from the cold box and compressed in another multi-stage centrifugal compressor, then fed to the gasifier.

The remaining portion of the air is mainly nitrogen and leaves the separation unit in two nitrogen streams. A small portion of the nitrogen is high-purity, greater than 99.9%, nitrogen, and is used in the gasification plant for purging and inert blanketing. The larger portion of the nitrogen produced, containing 1% to 2% oxygen, can be compressed and sent to the combustion turbine for NO_x control as well as power augmentation. However, at Wabash River, this level of integration was not implemented, so the balance of the nitrogen is discarded.

3.2 Coal Handling



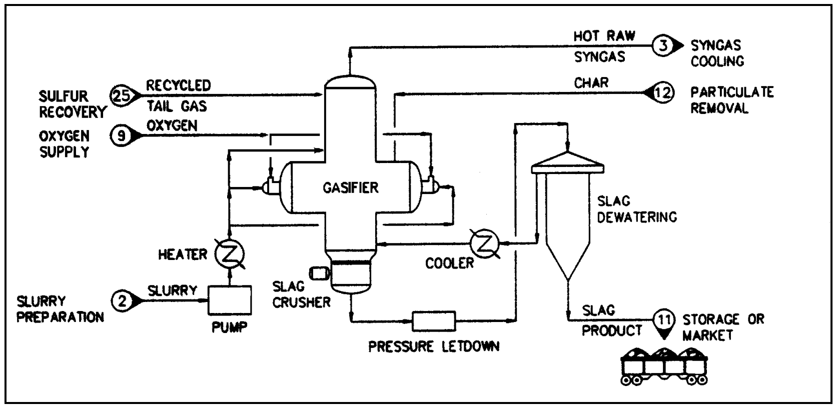
In the slurry preparation area, recycled water and the solid feed are metered to a grinding mill to produce a slurry feedstock. Slurry can be stored in sufficient quantities to accommodate uninterrupted feedstock for the gasifier. Slurry feeding allows for accurate and safe introduction of the solid fuel into the gasifier. The solid fuel comes into the plant with a two-inch maximum top size and enters the feed hopper. To produce slurry, the solid fuel is placed on a weigh belt feeder and directed to the rod mill where it is mixed and ground with treated water and slag fines that are recycled from other areas of the gasification plant. A fluxing agent is sometimes added to the solid feed to adjust the ash fusion temperature of the mineral content of the solid. The use of a wet rod mill reduces potential fugitive particulate emissions from the grinding operations. Collection and reuse of water within the gasification plant minimizes water consumption and discharge.

Prepared slurry is stored in an agitated tank. The capacity of the tank is sufficiently large to supply the gasifier needs without interruption while the rod mill and weigh belt feeder undergo most expected maintenance requirements.

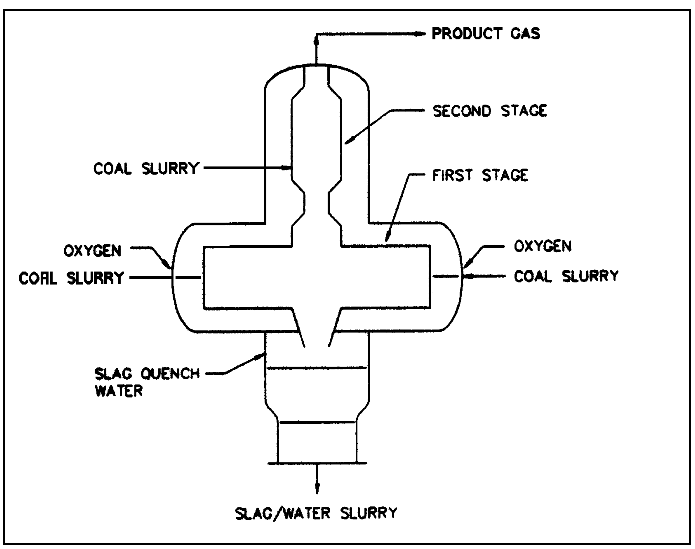
All tanks, drums, and other areas of potential atmospheric exposure of the product slurry or recycle water are covered and vented into the tank vent collection system for vapor emission control. The entire slurry preparation facility is paved and curbed to contain spills, leaks, wash down, and rain water runoff. A trench system carries this water to a sump where it is pumped into the recycled solids storage tank.

3.3 Gasification

3.3.1 Gasification and Slag Handling



The E-Gas™ gasification process accepts solid feed that can contain varying amounts of fixed carbon, volatile matter and mineral matter (ash). During the gasification of the solid fuel, a raw particulate-laden syngas is produced as well as a residual solid stream containing the ash content of the feed. The ash of the feedstock exits the bottom of the gasifier as water slurry and is dewatered in the slag handling system.

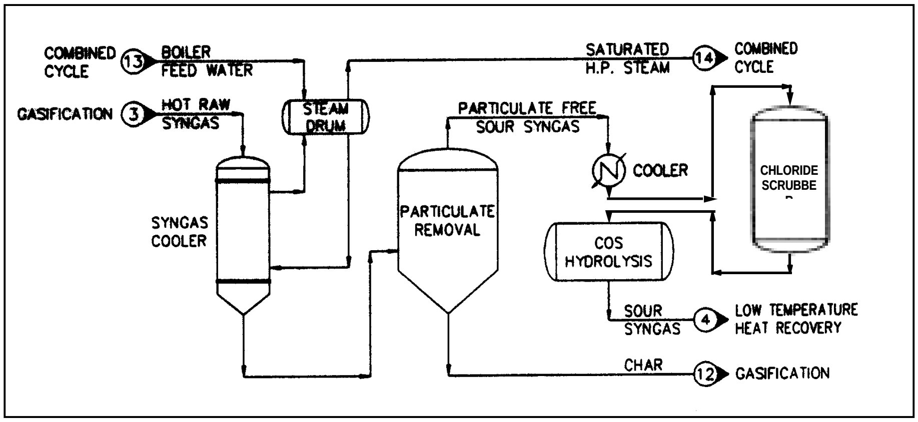


The E-Gas™ gasifier consists of two stages, a slagging first stage, and an entrained-flow, non-slagging second stage. The first stage is a horizontal, refractory-lined vessel in which carbonaceous fuel is partially combusted with oxygen at elevated temperature and pressure, 2500°F/420 psia (1400°C/29 bar). Oxygen and preheated slurry are fed to each of two opposing mixing nozzles, one on each end of the horizontal section of the gasifier. E-Gas™ has developed its own proprietary design for these slurry mixers. Oxygen feed rate to the mixers is carefully controlled to maintain the gasification temperature above the ash fusion point to ensure good slag removal and high carbon conversion. The fuel is almost totally gasified in this environment to form syngas consisting principally of hydrogen, carbon monoxide, carbon dioxide and water. Sulfur in the fuel is converted to primarily hydrogen sulfide (H_2S) with a small portion converted to carbonyl sulfide (COS). With appropriate processing downstream, over 98-99% of the total sulfur can be removed from the feedstock prior to combustion in the combustion turbine.

Mineral matter in the fuel and any added fluxing agent forms a molten slag that flows continuously through a taphole in the floor of the horizontal section into a water quench bath, located below the first stage. The solidified slag exits the bottom of the quench section, is crushed and flows through a continuous slag removal system as a slag/water slurry. This continuous slag removal technique eliminates high maintenance, problem-prone lock hoppers and completely prevents the escape of raw gasification products to the atmosphere during slag removal. The slag/water slurry is then directed to a dewatering and handling area described as follows. The slag/water slurry flows continuously into a dewatering bin. The bulk of the slag settles out in the bin while water overflows into a settler in which the remaining slag fines are settled. The clear water from the settler is passed through heat exchangers where it is cooled as the final step before being returned to the gasifier quench section. Dewatered slag is loaded into a truck or rail car for transport to market or its storage site. The slurry of fine slag particulates from the bottom of the settler is recycled to the slurry preparation area. This final recycle step enhances overall carbon utilization from the incoming solid feedstock.

The raw syngas generated in the first stage flows up from the horizontal section into the second stage of the gasifier. The second stage is a vertical refractory lined vessel in which additional slurry is reacted with the hot syngas stream exiting the first stage. The fuel undergoes devolatilization and pyrolysis thereby generating additional syngas with a higher heating value since no additional oxygen is introduced into the second stage. This additional fuel serves to lower the temperature of the syngas exiting the first stage to 1900°F (1030°C) by the endothermic nature of the devolatilization and pyrolysis reactions. In addition to the above reactions, the water reacts with a portion of the carbon to produce carbon monoxide, carbon dioxide and hydrogen. Unreacted fuel (char) is carried overhead with the syngas.

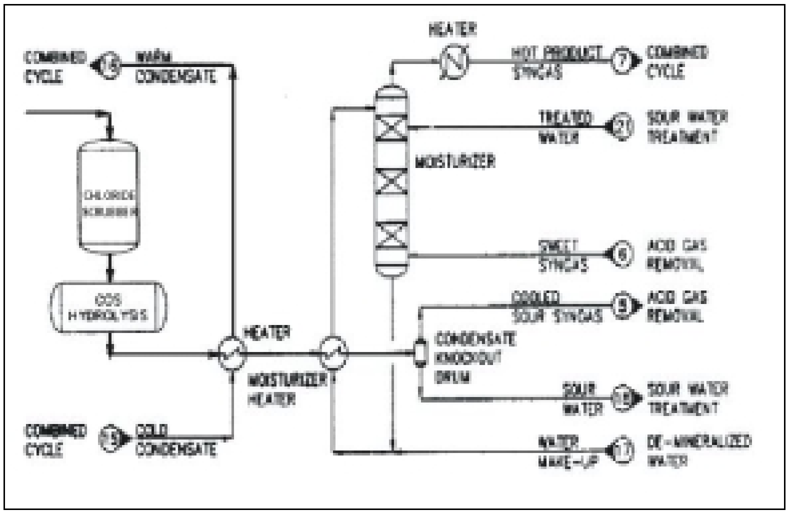
3.3.2 Syngas Cooling, Particulate Removal



The next two steps in the E-Gas™ process are to cool the syngas and then remove the particulate for recycle to the gasifier. Because of the high temperature of the syngas exiting the second stage of the gasifier, further cooling is accomplished by producing steam. With cooling preceding the particulate removal step, the filtration of the particulates can be accomplished in a temperature range more forgiving to the particulate removal unit. The hot raw syngas with entrained particulate matter exiting the gasifier system is cooled from 1900 to 700°F (1040 to 370°C) in the syngas cooler. The syngas cooler is a vertical firetube heat recovery boiler system with the hot syngas on the tube side. This unit generates saturated high-pressure steam, up to 1600 psia. Steam from the high-temperature heat recovery system is super heated in the gas turbine heat recovery system for use in power generation. Alternatively, syngas can be superheated in the syngas cooler.

After cooling the raw syngas, the gas is directed to the particulate removal system. The filter vessels contain numerous porous filter elements on which the particulate collects and the syngas flows through the elements and exits the unit as a particulate-free syngas. Particulate removal efficiency is better than 99.9%. Periodically the elements are back-pulsed with high-pressure syngas to remove particulate cake formed on the surface of the elements. The particulate cake falls to the bottom of the vessel and is pneumatically transferred to the first stage of the gasifier with high-pressure syngas. With the char recycled to the gasifier, nearly complete gasification of the carbon content of the feedstock is obtained. The particulate-free syngas proceeds to the low temperature heat recovery system.

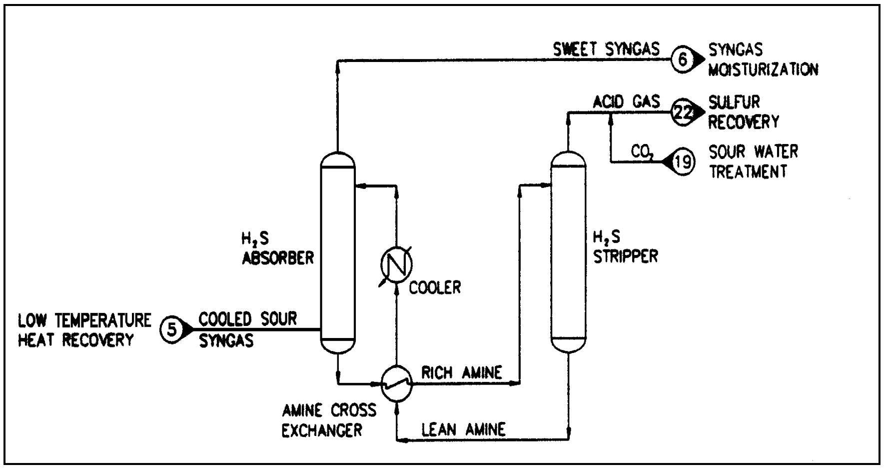
3.3.3 Low Temperature Heat Recovery, Chloride Scrubbing, and Syngas Moisturization



With particulates removed from the syngas, additional gas cleanup and cooling steps can be more easily performed. The syngas is scrubbed to remove troublesome chlorides and trace metals. These components are removed to reduce the potential of corrosion within the piping and vessels as well as reduce the formation of undesirable products in the acid gas removal (AGR) system. The syngas is cooled further before being directed to the sulfur removal step.

Before being water-scrubbed, the particulate-free sour syngas (i.e., syngas with a significant amount of sulfur compounds present) is further cooled. Scrubbing the syngas removes the chlorides and most of the volatile trace metals released from the feedstock during gasification. The syngas is scrubbed with sour water (i.e., water with dissolved sulfur compounds) condensed from the syngas. After scrubbing and reheating, the syngas enters the COS hydrolysis unit where COS in the gas is converted to H_2S for effective removal of sulfur in the AGR system. The syngas is then cooled through a series of shell and tube heat exchangers to less than 100°F (35°C) before entering the acid gas removal system. This cooling condenses water from the syngas. Most of the ammonia (NH_3) and some of the carbon dioxide (CO_2) and H_2S present in the syngas are absorbed in the water as dissolved gases. The water is collected and sent to the sour water treatment unit. The low temperature heat removed prior to the AGR system is used to heat the product syngas, to heat cold condensate, to provide syngas moisturization heat and to provide process heat in the AGR. The cooled sour syngas is fed to the AGR system where the sulfur compounds are removed to produce a sweet syngas (i.e. syngas with very few sulfur compounds present). The sweet syngas is returned to the low temperature heat recovery area where the syngas is moisturized. The sweet, moisturized syngas is superheated in an exchanger using heat from hot boiler feedwater prior to use in the combustion turbine.

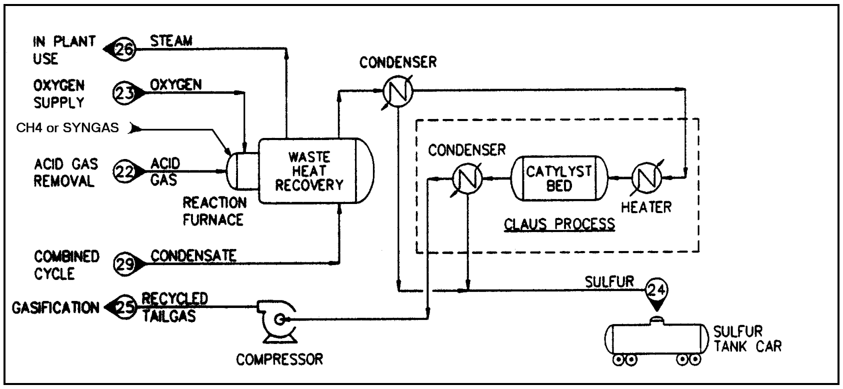
3.3.4 Acid Gas Removal



After the syngas has been sufficiently cooled, the sulfur is removed via the acid gas removal system. The principle acid gas removed at this point is hydrogen sulfide. This process contacts the cool sour syngas with a solvent to remove the H_2S and produce a product syngas ready to be used as feed to the combustion turbine. The solvent is continuously regenerated and recycled for reuse. A concentrated acid gas stream containing the removed H_2S and CO_2 is produced during the regeneration. This acid gas is the feed for a sulfur recovery unit (SRU).

For selective and efficient sulfur removal from the syngas, an AGR system was chosen based on methyldiethanolamine (MDEA), which chemically bonds with H_2S, yet the bond can be easily broken with low-level heat to effect a regeneration of the absorbent. The H_2S is absorbed from the syngas by contacting the gas with MDEA at a system pressure of about 375 psia (25.9 bar) within the H_2S absorber column. A portion of the carbon dioxide is absorbed as well. The H_2S-rich MDEA from the bottom of the absorber flows under pressure to a cross exchanger to recover heat from the hot, lean MDEA coming from the stripper. The heated, rich MDEA is then directed to the H_2S stripper where the H_2S and CO_2 are steam-stripped in a reboiled column at near atmospheric pressure. A concentrated stream of H_2S in CO_2 exits the top of the stripper and flows to the SRU. The lean MDEA is pumped from the bottom of the stripper to the cross exchanger. The lean amine is further cooled to about 100°F (35°C) to remove residual heat before being stored and then circulated back to the absorber. The AGR system does not produce any emissions to the atmosphere.

3.3.5 Sulfur Recovery



The H_2S leaving in the acid gas from the AGR system is converted to elemental sulfur in the sulfur recovery unit (SRU). This technology is based on the Claus process involving the partial oxidation of the H_2S to sulfur gas and steam. The sulfur is selectively condensed and collected. The residual gas, or tail gas, has very little sulfur content; nevertheless, this stream is compressed and recycled to the gasifier, thereby allowing for very high sulfur removal efficiency and, thus, minimal sulfur emissions.

The H_2S stream from the AGR stripper and the CO_2 /H_2S stripped from the sour water are fed to the SRU. First, a third of the H_2S is combusted with oxygen to thermally produce sulfur gas in a reaction furnace at about 1950°F. A waste heat boiler is used to recover heat before the furnace off-gas is cooled to condense the first increment of sulfur. Medium-pressure steam is produced in the waste heat boiler. Gas exiting this first sulfur condenser is fed to a series of heaters, catalytic reaction stages, and sulfur condensers where the H_2S is incrementally converted to elemental sulfur. The sulfur is recovered as a molten liquid and sold as a very pure (99.999%) by-product. The off-gas from the SRU, which is composed mostly of carbon dioxide and nitrogen, with trace amounts of H_2S, exits the last condenser. The SRU off-gas is catalytically hydrogenated to convert all the remaining sulfur species to H_2S. This results in a tail gas that is cooled to condense the bulk of the water, compressed and then directed to the gasifier. This allows for a very high overall sulfur removal in the process with minimal recycle requirements. The overall sulfur removal efficiency for the Wabash River process has been greater than 98%.

An incineration system is used to convert trace acid gas components in the tank vents to oxide form (SO_2, NO_x, H_2O, CO_2). The tank vent stream is primarily composed of air purged through various in-process storage tanks, and may contain very small amounts of acid gas. The high temperature produced in the incinerator thermally converts any hydrogen sulfide present in the tank vents to SO_2 before the gas is vented to the atmosphere. Heat recovery is provided in the hot exhaust gas of the incinerator to produce medium pressure steam before the vent gas is directed to a tall stack for dispersion in the atmosphere

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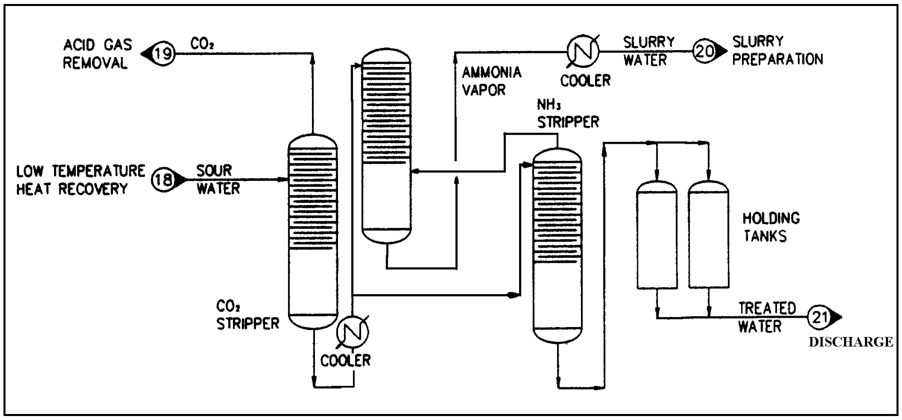
3.3.6 Sour Water Treatment



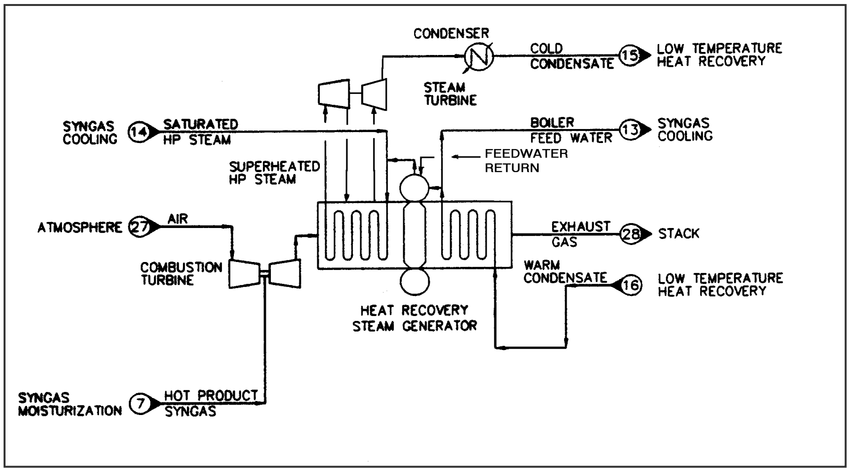
Process water produced within the gasification process must be treated to remove dissolved gases before recycling to the slurry preparation area or being discharged to the water outfall. Dissolved gases are driven from the water using steam-stripping techniques. The steam provides heat and a sweeping medium to expel the gases from the water, resulting in a degree of purification sufficient for discharge within permissible environmental levels.

Water blown down from the process and condensed during cooling of the sour syngas contains small amounts of dissolved gases. The gases are stripped out of the sour water in a two-step process. First, the CO_2 and the bulk of the H_2S are removed in the CO_2 stripper column by steam stripping. The stripped CO_2 is directed to the SRU. The water exits the bottom of this column, is cooled and a major portion is recycled to slurry preparation. Any excess water is treated in an ammonia stripper column to remove the ammonia and remaining trace components. The stripped ammonia is combined with the recycled slurry water.

Reuse of the water within the gasification plant minimizes water consumption and water discharge. Recycle of the ammonia in this manner is the simplest approach. The ammonia could be destroyed via the reaction furnace of the SRU; however, this may require operation of the furnace at less than optimum conditions to insure complete destruction of the ammonia. Alternatively, if desired, the gasification plant could be configured to recover ammonia as a saleable by-product of the process.

Water from the bottom of the ammonia stripper is purified sufficiently so that it can be discharged through the permitted outfall. If, for any reason the discharge is out of specification, the treated water can be stored in holding tanks for further testing and possible recycle before final disposition.

3.4 Power Block



The combined-cycle system consists of a combustion turbine generator, heat recovery steam generator, reheat steam turbine generator, condenser, flash drums, condensate pumps and boiler feedwater pumps.

Preheated, moisturized syngas and compressed air are supplied to the combustor. The hot gas exiting the combustor flows to the turbine, which drives the generator and air compressor section of the combustion turbine. Hot exhaust gas from the expander is ducted to the heat recovery steam generator (HRSG).

The HRSG provides superheat to the 1600 psia high-pressure (HP) steam produced from the gasification process and reheat to the intermediate-pressure (IP) steam. It also generates HP steam and preheats boiler feedwater for the syngas cooler.

The steam turbine generator is comprised of HP, IP and low-pressure (LP) power turbines and a generator. Reheated IP steam is supplied to the IP power turbine. The LP power turbine exhausts to the surface condenser. Process heat from the gasification process is used to preheat the condensate from the steam turbine condenser before it is returned to the HRSG.

4.0 DEMONSTRATION PERIOD

In preparation for the start of the Demonstration Period for the Project, the participants completed the transition from construction to operation through an organized program of equipment commissioning, system turnover and operator training. The months of preparation by Operations personnel to systematically prepare each section of the plant for acceptance testing and operating procedure development led to the plant being turned over from Construction to Operations system by system. "First-fire" of the combustion turbine on fuel oil occurred on June 6, 1995, followed by first coal slurry to the gasifier on August 17, 1995. For the next three months, the plant worked through the start-up phase, which culminated in the Project achieving commercial operations status and entering the Phase III Demonstration Period under the Cooperative Agreement on November 18, 1995. Significant in the start-up phase was the successful demonstration of the thermal integration of the combined operations. Except for minor feedwater control problems, which contributed to early syngas interruptions, there were no substantial problems integrating the steam and water systems. The plant completed demonstration testing to qualify for commercial status on November 18, 1995, and then entered a short outage from November 18 through early December prior to starting operation under the Demonstration Period. In December of 1995, the gasification plant operated for a total of 84 hours on coal, with the combustion turbine operating on syngas feed for 49 hours. The following section details operations and maintenance of the facility for the 1996 through 1999 years considered as the Demonstration Period.

Section 5.0 Technical Performance of this Final Technical Report analyzes a 12-month period within the four-year Demonstration Period and provides greater detail on subsystem equipment reliability, availability and maintainability as defined in Section 5.0. Due to the nature of this more technical analysis and the fact that it encompasses a portion of the Demonstration Period, Section 5.0 Technical Performance includes some information similar to that contained in the following section. This redundancy is intentional, allowing these two sections of the Final Technical Report to be reviewed independently.

Also within Section 4.0 are special sections that review alternate fuel tests conducted during this period and also analyze critical components within the gasification system.

4.1 Operation, Maintenance and Technical Impacts

Commercial operation of the facility began late in 1995. Within a short time, both the gasification and combined-cycle plants successfully demonstrated the ability to run at capacity and within environmental parameters. However, numerous operating problems impacted plant performance and reliability and the first year of operation resulted in only a 22% availability factor. Frequent failure of the ceramic filter elements in the particulate removal system accounted for nearly 40% of the early facility downtime. Plant reliability was also significantly hindered by high chloride content in the syngas. The high chlorides contributed to exchanger tube failures in the low temperature heat recovery area, COS hydrolysis catalyst degradation, and mechanical failures of the syngas recycle compressor. Ash deposits in the post gasifier pipe spool and HTHRU created high system pressure drops, which forced the plant off line and required significant downtime to remove. Slurry mixers experienced several failures and the power block also contributed to appreciable downtime in the early years of operation.

Through a systematic problem-solving approach and a series of appropriate process modifications, all of the foregoing problems were either eliminated or significantly reduced by the end of the second operating year. In 1997, the facility availability factor was 44% and, by 1998, the availability factor had improved to 60%. As problems were solved and availability improved, new improvement opportunities surfaced. During the third year of commercial operation, the facility demonstrated operation on a second coal feedstock as well as a blend of two different Illinois No. 6 coals. The ability to process and blend new coal feedstocks improved the fuel flexibility for the site but, while learning to process varying feedstocks, the plant suffered some downtime. On two occasions while processing new coals or fuel blends, the taphole in the gasifier plugged with slag.

In 1998 and 1999 a high percentage of coal interruptions and downtime were caused by the air separation unit (ASU). Ten coal interruptions in 1998 alone were due to the ASU. In 1999, failure of a blade in the compressor section of the combustion turbine required a complete rotor rebuild that idled the Project for 100 days. Run-time in 1999 was also impacted by a syngas leak in the piping system of the particulate removal system, a main exchanger leak in the air separation unit, another plugged taphole, and a failure of a ceramic test filter in the particulate removal system. Consequently, the availability factor for the facility in 1999 dropped to 40%. However, 1999 clearly marked significant advances in the application of commercial IGCC as

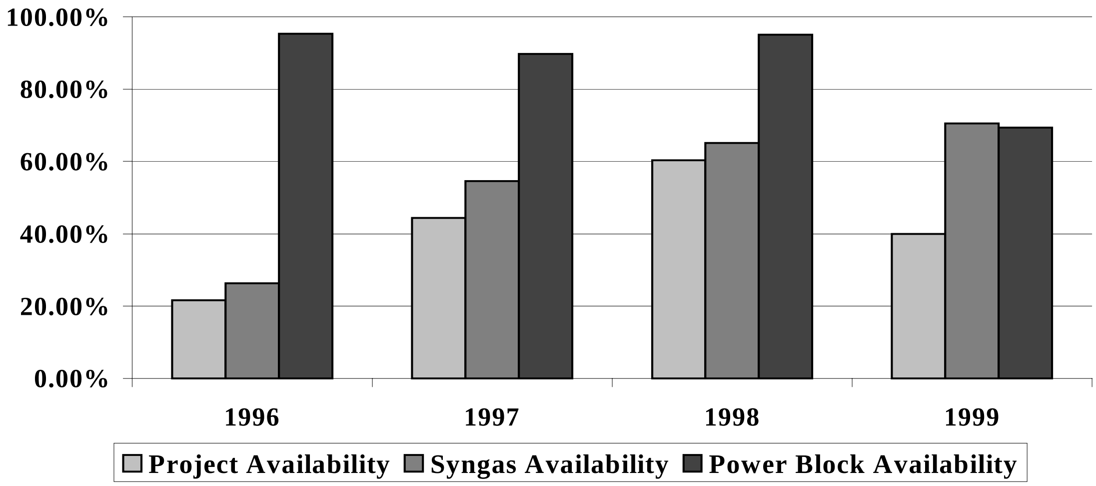


Figure 4.1A: Project, Syngas Block and Power Block Availability

demonstrated at Wabash River. During the third quarter of 1999, the gasification block produced a record 2.7 trillion Btu of syngas, operated continuously without interruption for 54 days and finished the year at 70% availability. Figure 4.1A demonstrates how the reliability of the technology has advanced during the Demonstration Period. The continuous improvement trend for the gasification block, where the majority of the novel technology was demonstrated, is encouraging and is expected to continue. Future operating improvements will continue to advance the technology and eliminate cost and availability barriers. Some of the more significant achievements and activities for the Demonstration Project are highlighted in Table 4.1A.

Table 4.1A: Significant Operating Achievements

First coal fire in gasifier	August 17, 1995
Commercial operation begins	December 1, 1995
Start-up of chloride scrubbing system	October 1996
Initiated use of metal filter elements	December 1996
Conducted 10-day test run of petroleum coke	November 1997
1998 Governor's Award for Excellence in Recycling	May 1998
Began running new coal feed (Miller Creek)	June 1998
Completed 14-month OSHA recordable-free period	September 1998
Surpassed 1,000,000 tons of coal processed	September 1998
Surpassed 10,000 hours of coal operation	September 1998
Surpassed 100,000,000 pounds equivalent of SO_2 captured	January 1999
Record quarterly production (2,712,107 MMBtu)	3rd Quarter 1999
Longest continuous uninterrupted run (1,305 hrs)	August 12 – October 6, 1999
Conducted second successful petroleum coke run	September 1999
Completed 2nd 14-month OSHA recordable-free period	December 1999
Record coal hours between gas path vessel entries (2,240 hr)	June to October 1999

Despite reliability issues during the first two years of operation, the actual performance of the plant during coal operation compares favorably with design as indicated in Table 4.1B. The plant has demonstrated a maximum capacity of 1825 MMBtu/hr but requires only 1,690 MMBtu/hr to satisfy the requirements of the combustion turbine at full load. The noted steam turbine capacity shortfall requires a HRSG feedwater heater modification to bring output up to design. With this modification the overall plant heat rate will drop even lower to 8,650 Btu. The air separation unit was unable to meet the guaranteed power specification, which accounts for the difference in auxiliary power.

The environmental performance of the plant has been superior. Sulfur removal efficiencies all exceed design and total demonstrated sulfur dioxide emissions have been as low as 0.03 lb/MMBtu of dry coal feed. This quantity is 40 times lower than the year 2000 Clean Air Act Amendment standards. Likewise NO_x, CO and particulate emissions average 0.022, 0.044

and 0.012 lb/MMBtu respectively. The WRCGRP is the cleanest coal-fired power plant in the world.

Table 4.1B: Performance Summary

	Design	**Actual**
Syngas Capacity, MMBtu/hr	1,780	1,690 (1825 max)
Combustion Turbine Capacity, MW	192	192
Steam Turbine Capacity, MW	105	96
Auxiliary Power, MW	35.4	36
Net Power, MW	262	252
Plant Heat Rate, Btu/kWh	9,030	8,900
Sulfur Removal Efficiencies, %	>98	>99
SO_2 Emissions, lbs/MMBtu	<0.2	<0.1 (0.03)
Syngas Heating Value (HHV)	280	275-280
Syngas Sulfur Content (ppmv)	<100	<100

Operation in 1998 was highlighted by several months during which syngas production exceeded one trillion Btu of gas produced. This production milestone was met in March, April, October and November of 1998. As previously indicated, the highest quarterly production of syngas occurred in the third quarter of 1999 in which 2,712,107 MMBtu of gas was produced. Syngas production in September of 1999 was 1,204,573 MMBtu, the highest ever for a month. Furthermore, the combustion turbine was at maximum capacity for all but 7 hours in September. Key production statistics for the Demonstration Period are presented in Table 4.1C.

Table 4.1C: Wabash River Coal Gasification Repowering Project Production Statistics

Time Period	On Coal (Hr)	Coal Processed (Tons)	On Spec. Gas (MMBtu)	Steam Produced (Mlb)	Power Produced (MWh)	Sulfur Produced (Tons)
Start-up '95	505	41,000*	230,784	171,613	71,000*	559
1996	1,902	184,382	2,769,685	820,624	449,919	3,299
1997	3,885	392,822	6,232,545	1,720,229	1,086,877	8,521
1998	5,279	561,495	8,844,902	2,190,393	1,513,629	12,452
1999 ✧	3,496	369,862	5,813,151	1,480,908	1,003,853	8,557
Overall	15,067	1,549,561	23,891,067	6,383,767	4,125,278	33,388

* ESTIMATES. ✧***NOTE: THE COMBUSTION TURBINE WAS UNAVAILABLE FROM 3/14/99 THROUGH 6/22/99.***

Early identification of availability-limiting process problems led to aggressive implementation of improvement projects which resulted in 224% more syngas produced during the second year than in year one. The syngas produced during the third year exceeded the second year's production by an additional 42%. Assuming that the availability factor during the combustion turbine outage was the same as in 1998, the facility production in 1999 would have matched 1998's output. Figure 4.1B illustrates this continuous improvement trend over the last four years as measured by total syngas production.

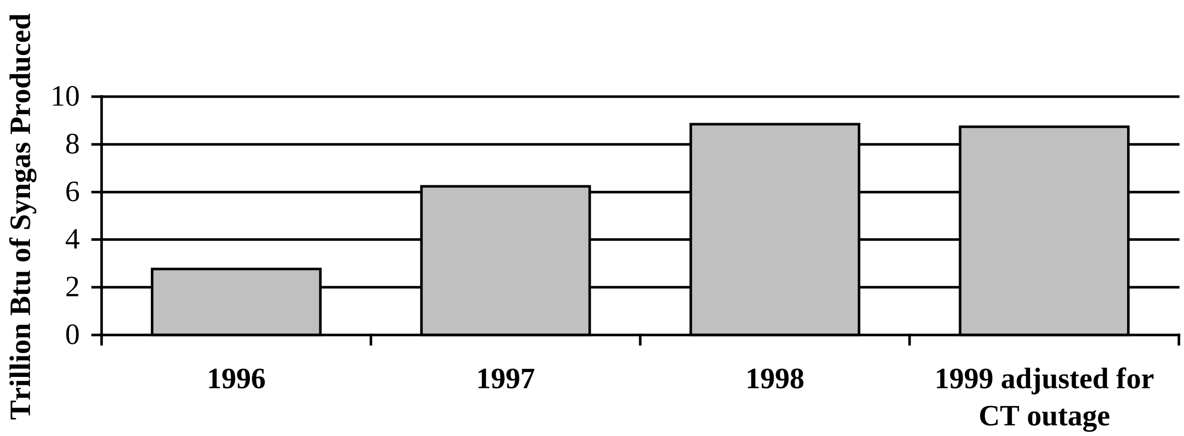


Figure 4.1B: Syngas Production by Year

The remainder of this section of the report will summarize the chronological history of plant operation by area for the four-year Demonstration Period.

4.1.1 Air Separation Unit

<u>Opportunities and Improvements</u>

During the first quarter of 1996, prior to contractual performance testing of the Air Separation Unit (ASU), a production shortfall of nitrogen was identified. Liquid Air Engineering, the supplier of the ASU, identified a process change to enhance nitrogen production. The change involved the installation of a new heat exchanger to recover the refrigeration lost during the vaporization of nitrogen for high-pressure gaseous nitrogen production. The original design used steam energy to vaporize and heat the liquid nitrogen for continuous delivery to the gasifier systems. The new exchanger allows more cooling of inlet air to the distillation column, resulting in higher production of product nitrogen.

One negative side effect of the new exchanger was that the airflow to the main heat exchanger was reduced, causing liquefaction of the waste nitrogen to occur upstream of the exchanger. A follow-up project was required to correct this side effect. A second project to re-route a high-pressure oxygen recycle stream to the main exchanger was implemented, which served to keep the waste nitrogen from liquefying, thus eliminating potential damage which can be caused by two-phase flow. This modification along with the addition of the new exchanger, results in higher nitrogen production. However, the ASU never achieved the full performance guarantees for simultaneous delivery of all product streams.

With the frequent plant interruptions and shorter duration runs characteristic of the early operation, the ASU could not maintain nitrogen production at the rate of consumption in the gasifier island. This required additional liquid nitrogen to be trucked into the facility at additional costs. Efforts to identify potential sources for conservation throughout the year resulted in a decrease in demand. Nitrogen conservation projects, identified during the fourth quarter of 1996, will be discussed later in this section.

Additional minor issues addressed in the ASU in 1996 included:

- A gradual reduction in flow rate from the liquid oxygen pumps during the second quarter created concern over system reliability. Inspection of the pumps and related equipment revealed that the suction strainers had been improperly installed during construction resulting in excessive particulate build-up within the pumps. Following total pump overhauls within the quarter, performance was restored to design specifications.
- A manufacturer's inspection in September, following numerous valve failures, uncovered a design flaw in the bushings of the adsorber bed sequencing valves. The manufacturer agreed to produce one set of modified valves with a new bushing design, with a plan to use the extra valves to systematically change out valves and upgrade the bushings over an 18-month period.
- In December of 1996, the main air compressor surged and shutdown due to a failure of the third stage guide vane controller. The guide vanes went to the closed position after a rupture of a connector attached to the third stage actuator. This failure caused a four-day interruption in syngas delivery to repair the actuator and restore gasifier operation. No long-term negative effects to the compressor were observed as a result of this compressor surge.

In 1997, nitrogen production shortfall continued as a critical key production issue. Excessive nitrogen usage, especially during start-up periods, required supplemental nitrogen to be brought in via truck to facilitate start-up of the gasification island. Operational procedures were modified to minimize and balance the usage and high volume uses were targeted for improvement opportunities addressed as follows:

The heat-up process utilized by the dry char filtration system and the carbonyl sulfide (COS) catalyst vessels, which require inert heating, were requiring significant time and nitrogen quantities to heat at start-up. Corrective measures included the installation of three new heat exchangers, and the installation of recycle piping, which allows faster heat-up and cool down of these systems using significantly less nitrogen than the previous once through system. Optimization of nitrogen purges on various equipment and instrumentation in the gasifier system.

By focusing on these critical areas, significant reductions in additional nitrogen purchases were possible as well as reduction in start-up and shutdown timing. By the end of 1997, nitrogen demand had been closely matched to nitrogen production. Deliveries of external nitrogen decreased from a 1997 high of 15 trucks per month (9 million standard cubic feet) down to two trucks per month (1.2 million standard cubic feet).

Oxygen production during 1997 was sufficient to meet the demands of the gasification island. Total annual production was approximately 328,000 tons of 95% purity oxygen. Several trips of the main air compressor (MAC) caused shutdowns of the gasification process due to the inability to supply oxygen to the slurry mixers (there is no oxygen storage capability at the facility). The first, in the second quarter of 1997, was due to an electrical design flaw in the ancillary systems of the main air compressor. Several of the ancillary systems were not adequately fuse protected. Therefore, when an over-amperage condition occurred on one of the auxiliary pieces of equipment it was sufficient to trip the main circuit breaker for the MAC. Corrective action included inspection and replacement as necessary of all susceptible fuses. During the third quarter, a loose fuse resulted in the failure of an oxygen vent valve, which subsequently tripped the main air compressor and the gasification process. It is suspected that the fuse was not properly seated after the inspection/replacement that occurred during the second quarter. All fuses were rechecked to prevent recurrence of this problem.

A potential preventative maintenance issue was identified when, in December, the alternate oxygen pump suffered a failure of the lower impeller shaft bearing. Wabash River personnel worked with the manufacturer to identify a new lower impeller design for installation at the next available outage.

Additional upgrades to the ASU during 1998 included the following:

- A lube oil system upgrade was made to facilitate oil changes to the main air compressor.
- The main air compressor guide vanes (all stages) were put on a more aggressive preventative maintenance schedule due to a second stage guide vane failure in December.

In 1998 the ASU contributed 397 hours of gasification plant downtime (approximately 20.4% of total downtime) compared to 198 hours (or approximately 7.1%) in 1997. While these hours are elevated for 1998, it is important to note that oxygen production from the ASU increased from approximately 328,000 tons in 1997 to over 442,000 tons in 1998. Nitrogen shortfalls, while still occurring in 1998, were reduced by careful application of operating and start-up procedures incorporated into the system in 1997 and continuing in 1998.

Several key outages occurred in 1998 which led to the increase in ASU contributions to plant downtime. Those occurrences were:

- In January, a control system I/O power supply experienced a blown fuse resulting in loss of power to multiple automatic operated valves. This, in turn, forced a gasification plant trip via an oxygen compressor shutdown in the ASU resulting in five hours of lost production. Evidence suggested the incident was a result of an amperage load imbalance for the control circuit and a relatively simple redistribution of load proved successful in preventing further occurrence.
- A second lost production incident occurred later in January when the anti-surge valve protecting the MAC failed and ultimately caused the pressure safety valves (PSV's) to open. The PSV's which failed to reseat on closing and consequently required repair resulting in 35 lost production hours. The sticking surge valve was related to actuator corrosion due to extended operation with only minor valve movement. A simple preventative maintenance plan was implemented which calls for full-stroke actuator operation and lubrication during all shutdown periods.
- A third event occurred in January, when the MAC tripped due to excessive vibration resulting from malfunction of the inlet guide vane electronic positioning system, which loads the compressor. The net effect was a production loss of 53 hours. Design deficiency was responsible for the guide vane failure resulting in increased system maintenance (short term) and a request for proposal to replace the actuator system. Guide vane actuator replacement is discussed later in this section and in Section 5.0 Technical Performance.
- In February, a high voltage switchgear fuse (15 kV) failed forcing both the MAC and oxygen compressors to shutdown resulting in 33 hours of downtime. No apparent cause was found

for the blown fuse in the high voltage system, so no modifications or predictive measures could be identified to prevent recurrence of this event.

- On June 8th and 9th, production delays occurred resulting from packing fires inside the chiller tower during vessel entry work. A total of 61 hours in start-up delays resulted from this event. Evidence suggested the incident resulted from inadequate fire barriers and failure to use a low energy welding technique such as heli-arc versus stick welding.
- On August 9th, a production interruption occurred when the power card for the MAC inlet guide vane, programmable logic controller failed. Difficulties in lining out the ASU after the controller failed prevented gasification operation for 110 hours. A voltage surge consistent with a probable lightning strike was identified as the root cause for the power card failure.
- On August 15th, production was lost when a high voltage (15 kV) potential transformer (PT) blew a primary fuse in the motor control center (MCC) switchgear. Both the oxygen compressor and MAC utilize the PT for voltage reference and for under-voltage protection. Although neither machine suffered a failure, the blown fuse shutdown both compressor motors instantaneously via the power factor relay. All testing confirmed no problem with the potential transformer equipment but suggested a problem upstream of the primary side of the PT fuse itself or the 15 kV system. The PT was swapped with an identical type from less critical service, and no repeat failures have occurred.
- On August 4th, a nine-hour production loss occurred when the oxygen compressor shutdown from the simultaneous activation of six safety interlocks. The root cause was determined to be a loose wire on the power supply to the fast digital input card for the oxygen compressor.
- On October 8th, a five-hour production interruption occurred due to a power disruption to the vibration monitoring cabinet. A technician accidentally tripped the power toggle while working inside the cabinet for installation of a new data collection system. This resulted in all vibration interlocks “failing safe”, shutting down both MAC and oxygen compressors. Work within the vibration cabinet was postponed until the next scheduled outage to prevent further production interruptions. Additionally, a sign was posted on the cabinet door warning of plant shutdown potential due to unprotected power switching inside the cabinet.
- A ten-hour interruption occurred on October 27th and followed actuator problems associated with the adsorption process valves. The actuator worked itself loose from the valve resulting in a limit switch failure, which prevented the regeneration sequence from completing. This

halted operation until a full regeneration cycle could be completed for the adsorption bed. Training was initiated for all ASU operators regarding the maintenance work request policy and all related aspects of adsorption process control troubleshooting. New and modified alarms were placed in the distributed control system (DCS) control logic to facilitate problem identification.

Several projects were implemented in the ASU in 1998 to enhance industrial hygiene and plant performance. Those projects were:

- In the second quarter, an ancillary silencer was placed onto the adsorber tower exhaust vents reducing peak noise levels in the area from 105 dB to below 87 dB.
- The nitrogen vaporizer bellows trap and condensate pump systems were eliminated in favor of a float and thermostatic steam trap. Enhanced performance and energy and maintenance savings have resulted.
- The adsorber regeneration heater gas distribution system was overhauled with enhanced stiffening supports. Once installed, the regeneration heat peaks improved approximately 25°F, increasing efficiency and reducing cycle time.
- The failed water distribution system within the chiller tower was reinforced with stiffening elements to prevent liquid channeling and inherent performance problems. A temperature improvement of 5°F is attributed to the better water distribution.
- In the fourth quarter, both liquid oxygen pumps were fitted with a solids purge system. This new system will improve oxygen pump bearing life by eliminating the primary source of bearing wear, namely particulate.

In 1999 the ASU contributed 340 hours of gasification plant downtime (approximately 10.5% of total downtime) compared to 397 hours (or approximately 20.4%) in 1998. The key occurrences that contributed to plant downtime were:

- In January, there was a 15-hour delay of plant start-up when the nitrogen storage tank ran short of liquid. Emergency road conditions consisting of ice and snow prevented the requested nitrogen delivery, which delayed gasifier start-up. In response to this shortfall, two new contracts have been negotiated with spot market nitrogen suppliers as a hedge against delivery and production problems.

- A second short production delay of 11 hours occurred in February, due to the performance of a safety test on the ASU's distillation exchanger to look for evidence of hydrocarbon accumulation in the cryogenic system. The supplier recommended the test after having two ASU plant explosions worldwide on similarly designed units. The test results indicated that the ASU at Wabash River was at very low risk.
- The failure of an automatic valve to properly seat prevented depressurization of an adsorber bed that interrupted oxygen supply and resulted in 15 hours of gasifier downtime. A temporary fix involving manual operation was implemented until the valve was repaired during the next scheduled outage.
- Failure of the derime header inside the main exchanger cold box resulted in 14 days of downtime in August. The root cause was determined to be insufficient weld penetration at the socket welds in the header during plant construction. The weld repairs required only two days but entry into the cold box required the removal of 10,000 cubic feet of insulation and a subsequent process derime to remove moisture and organics from the system. The repaired header was dye tested to insure full weld penetration and supports were added to further enhance reliability. This repair is covered in more detail in Section 5.0 Technical Performance.

Several projects were implemented in the ASU in 1999 to enhance plant performance. Those projects were:

- The adsorber sequencer valve solenoids, which were not rated for outdoor service, were upgraded to prevent the actuator from working itself loose from the valve. This problem was identified in the fourth quarter of 1998 when the actuator separated from the valve and resulted in a limit switch failure that prevented the regeneration sequence from completing. Additionally, a new bushing design was implemented on the adsorber system valve to correct previously identified problems.
- The inlet guide vane system on the MAC was replaced with upgraded actuators and several other modifications were made to insure reliability. These improvements are expected to

eliminate the ASU’s major cause of downtime since 1997 and are discussed further in Section 5.0 Technical Performance.

- Modifications to the water distribution trays in the water chiller tower were performed to address nitrogen production limitations experienced during the summer of 1999.

In addition to these projects, the ASU underwent a complete “derime” during an extended outage in the second quarter. A derime involves evacuation of all cryogenic liquids and warming the plant to drive all moisture and impurities from the system. This process is recommended at the frequency of every two years to ensure safe, reliable operation, free of ice and hydrocarbons.

4.1.2 Coal Handling

Production Information

Throughout the Demonstration Period, the gasifier operated on two different base coals, both individually and in a blended mode, as well as petroleum coke on a test basis. The gasifier is capable of handling feedstocks with a relatively wide range of characteristics; however, variations too far from the design basis coal could result in syngas and steam production limitations. Also, sudden changes in feedstocks, and thus their constituents, can be problematic if undetected; therefore, attempts were made to stay on top of feedstock analysis and blending activities.

Table 4.1.2A illustrates the average analysis by year for each feedstock during the Demonstration Period:

Table 4.1.2A: Feedstock Analysis

		Dry Analysis						Heating Value	
Year	**Feedstock**	**% Carbon**	**% Hydrogen**	**% Nitrogen**	**% Oxygen**	**% Sulfur**	**% Ash**	**Btu/lb – as received**	**Btu/lb - dry basis**
1996	Hawthorne Coal	70.2	4.56	1.45	7.91	2.42	13.46	10,733	12,483
1997	Hawthorne Coal	70.15	4.84	1.32	8.13	2.57	12.93	10,812	12,652
1997	Pet coke	87.49	2.74	0.99	3.08	5.17	0.52	14,282	15,353
1998	Hawthorne Coal	69.58	4.55	1.08	8.48	2.85	13.5	10,645	12,566
1998	Miller Creek Coal	65.89	4.0	1.38	7.06	3.45	12.07	10,765	12,890
1999	Hawthorne / Miller Creek Blended Coal	69.66	4.85	1.44	8.48	2.95	11.23	10,645	12,566

In 1996, a total of approximately 184,382 tons (as received) of coal was processed through the rod mill with an equivalent heat rating of approximately 4,341,382 MMBtu.

In 1997, a total of approximately 374,822 tons (moisture free) of coal was processed through the rod mill. An additional 18,000 tons of petroleum coke (pet coke) were also processed during a trial run late in the fourth quarter. This accounted for an equivalent heat rating of approximately 8,910,111 MMBtu processed through the rodmill. Petroleum coke, while having a higher Btu value and lower ash content than Hawthorne coal, was blended with coal-generated slag to enhance slag flow characteristics (coal generated slag was used as a fluxing agent). Its effect on gasifier operation will be discussed later in this report.

In 1998, a total of approximately 561,495 tons (moisture free) of coal was processed through the rod mill with an equivalent heat rating of approximately 12,071,728 MMBtu.

Hawthorne and Miller Creek coals were fed at various ratios during 1998. Blends ratios were adjusted as necessary to ensure consistent gasifier performance.

In 1999, a total of approximately 369,589 tons (moisture free) of coal was processed through the rod mill. Slurry fed to the gasifier totaled approximately 7,772,568 MMBtu.

Opportunities and Improvements

Incoming coal fed to the rod mill is sampled via an automated sampling system. During 1996, extreme weather conditions contributed to two major mechanical failures of this automated sampling system. First, heavy snowfall resulted in a wet, sticky coal supply, which caused plugging problems with the sampler. To solve this problem, mechanical scrapers and vibrators were installed during the first quarter. With the additional installation of a non-stick coating to the inlet crusher chute in the second quarter, overall system reliability improved. The second problem resulted from coal dust during dry periods. Coal dust, dispersed by air movement generated by the system components, tended to collect around the pulleys of the belt conveyor and interfere with conveyor movement. To correct this problem, additional seals were installed in the system to limit air movement thereby limiting the amount of dust accumulation in this system. During periods when the mechanical samplers were out of service, Operations personnel hand sampled the coal to ensure feedstock consistency.

The rod mill is designed to crush the coal to a desired particle size distribution to ensure stable “slurryability” and optimum carbon conversion in the gasifier. In the third quarter of 1996, it was determined that the rod mill rod charge was insufficient to generate the optimum grind. Problems with coal slurry flow variations resulted from large coal particles in the check valves of the positive displacement gasifier feed pumps. Subsequent analysis of particle size distribution indicated that there was a significant increase in the distribution of larger particles, which warranted the addition of rods to the rod mill. Wear rate of the rod mill rods was within the manufacturer specifications for the number of hours of operation. Operation of the gasifier feed pumps returned to normal after adding the rods. A program was established to monitor the rod charge and rod mill performance more frequently for the need to adjust the rod charge. Areas of localized erosion and corrosion were identified throughout the slurry handling system during the year. Erosive and corrosive wear affected centrifugal slurry recirculation pumps, stainless steel pipe fittings, the inlet chute to the rod mill and piping in the slurry handling system. Where possible, hardened metal internal coatings were placed in the system while, in some cases, metallurgy had to be changed to improve equipment life.

The primary problems encountered in this area in 1997 centered around foreign material in the coal which caused rod mill wear and damage, especially on the trommel screen, which is designed to prevent oversized particles and debris from entering the coal slurry feed tank. During the second quarter of the year an excessive quantity of oversized limestone and other foreign material (e.g., metal objects) entered the mill causing an excess of large particles in the slurry (objects that lodge themselves between the rods during milling prevent effective crushing of the coal). This foreign material punched holes in the trommel screen allowing the oversized foreign material to pass to the slurry storage tank. This material eventually ended up partially plugging the check valves to the slurry feed pumps resulting in a plant shutdown due to fluctuations in slurry feed to the gasifier.

Fluctuations in slurry feed also caused slag flow problems in the gasifier, which eventually led to plugging of the taphole. Foreign material in the coal continued to be a problem in the third quarter, which prompted discussions of this problem with the mine operators. Diligence in the mining/blending operations and coal handling upgrades (magnetic separators on the belt feeder) resolved the problems.

Due to problems encountered in 1997 with foreign material from the coal pile, rod mill rod charge and discharge trommel screen damage was monitored throughout the year. To reduce the occurrences of holes in the screen, a steel band was added to the end of the screen. Preventative maintenance (PM) inspections have been increased on the screen and the incidences of failure were minimized. Optimum slurry concentration (62-63%) was monitored and rods replaced as necessary to ensure adequate system performance. In the fourth quarter, a slight increase in routine rod charge was implemented which led to finer slurry grind than normal. This resulted in increased reactivity of the slurry in the gasifier, and had a slight positive impact on the cold gas efficiency for the quarter. Overall, the coal preparation and slurry area was responsible for only 0.3% of the total plant downtime in 1998.

During the first quarter of 1999, the trommel screen was replaced during an outage. The screen replacement provided the opportunity for some metallurgical improvements and the addition of erosion-resistant materials in the mill outlet chute. As a result of this project no further rod mill trommel screen failures were encountered during the Demonstration Period.

The ventilation system from the rod mill trommel screen shroud was upgraded as well. The ventilation upgrade increased the efficiency of the vent collection system thus lowering the ammonia (from recycled water) concentration in and around the rod mill building. Data from air monitoring collected during the second quarter, indicates more than an 80% reduction in ammonia concentration has been realized since implementation of this improvement.

In 1999, the coal handling area accounted for 61 hours of overall plant downtime (approximately 1.9% of total gasification plant downtime). In comparison, approximately 10 hours of total downtime was experienced in 1998 in this area. The following is a brief description of the causation factors and corrective measures that occurred in 1999:

- During a start-up in early February, the slurry feed system logged 23 hours of downtime due to problems with pumps and instrumentation. During two transfers to coal operation, a slurry pressure transmitter failed low, resulting in a slurry mixer trip. The associated shutdown alarm code was re-written in the second quarter to require low signals from both of the redundant pressure transmitters before initiating a slurry mixer trip.

- Additionally, during the same start-up period, a piston failure occurred on one of the positive displacement gasifier feed pumps. This resulted in contamination of the piston flush water with coal slurry, which necessitated shutting down of the remaining positive displacement pumps on this common flush system, interrupting coal operation for 5 hours. The root cause of the failure was prolonged use of a hard water supply for the piston flush system. Piston flush water is now supplied only from soft water sources.
- In June, July, September and December, failures in the slurry feed system resulted in trips off of coal operations resulting in a total of 16 hours of plant downtime. In each event, the suction of the slurry recirculation pump plugged, causing an interruption of slurry to the positive displacement gasifier feed pumps. The root cause of the problem was identified as excessive agitator blade wear in the slurry storage tank. The loss of effective agitation resulted in the accumulation of solids near the pump suction in the tank. When the accumulation became significant, the corresponding solids would dislodge and plug the suction of the recirculation pumps. To correct the problem, the blades on the agitator will be lengthened and coated with wear-resistant material during the spring outage in 2000. This issue is discussed in more detail in Section 5.0 Technical Performance.
- Erosion of slurry piping components was responsible for stopping coal feed three times in October, which resulted in 22 hours of downtime. Two of the failures were attributed to inadequate material selection for valves in the coal slurry piping system. During the November outage, the failed valves, as well as some others, were upgraded to a more erosion/corrosion-resistant metallurgy.

4.1.3 Gasification

4.1.3.1 Gasification And Slag Handling

Production Information

Figure 4.1.3A indicates the hours of operation, by quarter, for the gasifier during the Demonstration Period. The gasifier and downstream equipment is heated up from a cold start via the use of natural gas burners, which are referred to throughout the report as methane burners along with the period of heat-up as methane operations. At Wabash River, the natural gas used for this heat-up process is primarily composed of methane, hence the term methane operations. It must be reiterated that syngas generated during heat-up operations is not suitable for use as fuel for the combustion turbine and that coal/methane mix is simply a measure of transition from methane heat-up to coal operation. Methane operations presented in each graph indicate the total methane and coal/methane mix hours for heating of the gasifier and associated equipment and the transition into full coal operations.

During the operational campaigns in 1996, the gasifier operated on coal for 1,902 hours. During heat-up operations, the gasifier operated on methane and a blend of coal/methane for 1,990 hours. In 1997, gasifier operation improved over 1996. Coal operating hours increased approximately 200% over the previous year as the gasifier operated on coal for over 3,885 hours. A 215 hour run on pet coke in November of 1997 is included in the coal hours for 1997. During heat-up operations, the gasifier operated on methane and a blend of coal/methane for 1,490 hours. During the 1998 operational period the gasifier operated on coal 5,278 hours, which represented an increase over 1997 operations of 144%. During heat-up operations in 1998, the gasifier operated on methane and a blend of coal/methane for 976 hours. The 1998 methane operation hours were substantially reduced from the 1997 total, illustrating increased operator experience, newly established procedures to limit start-up time, and fewer unscheduled outages. Finally, in 1999, the gasifier operated on coal 3,496 hours. Included in the coal hours for 1999 is a 77-hour run on pet coke. During heat-up operations in 1999, the gasifier operated on methane and a blend of coal/methane for 933 hours.

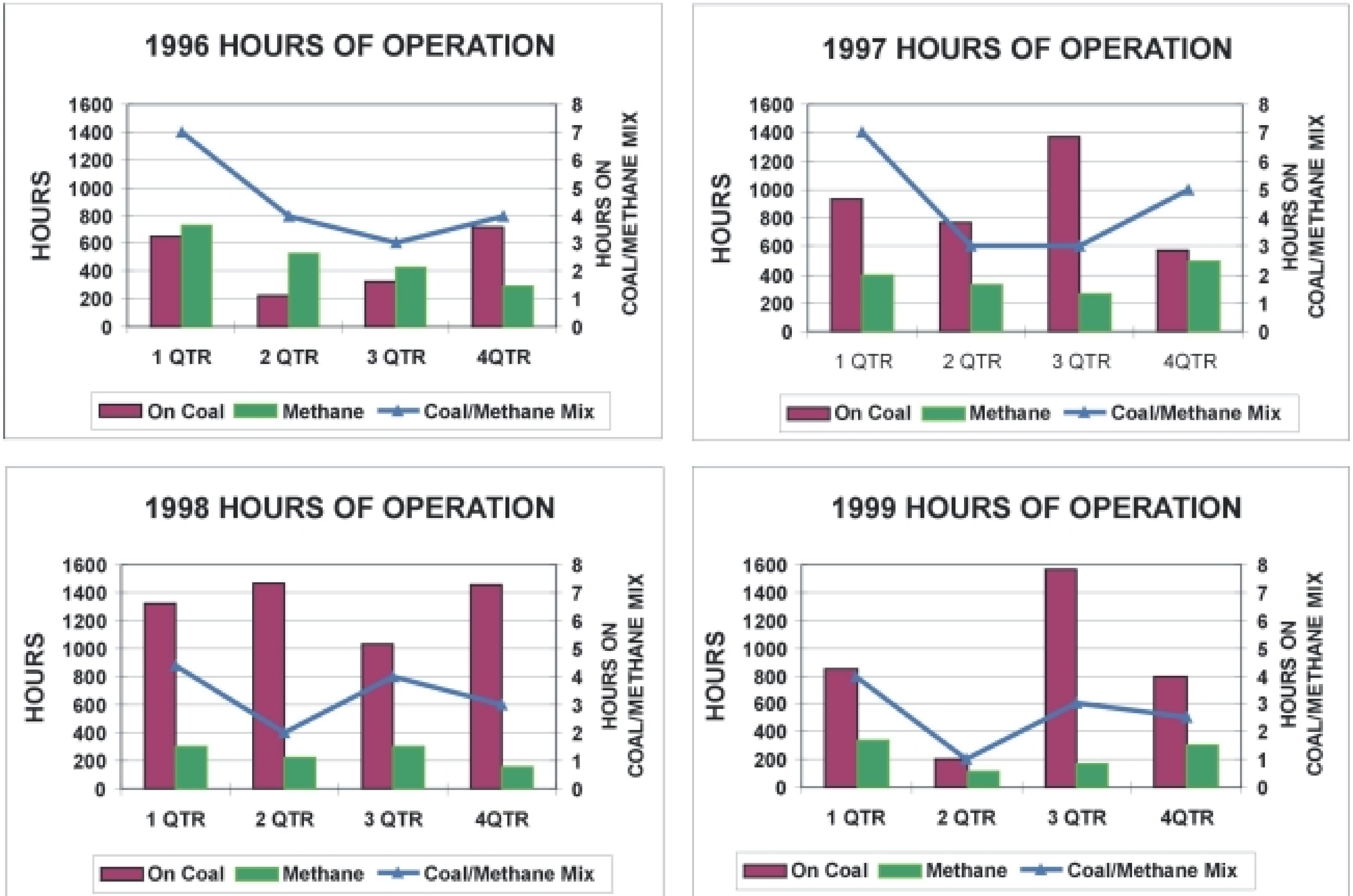


Figure 4.1.3A: Hours of Operation for Demonstration Period

Table 4.1.3B indicates the tons of coal fed to the gasifier by month for the duration of the Demonstration Period. In 1996, coal to the gasifier totaled over 180,000 tons and oxygen from the ASU to the gasifier totaled in excess of 160,000 tons. This combined feed was utilized in the production of over 2,769,600 MMBtu of syngas. By-product slag from the process totaled approximately 23,288 tons. With the increase of coal operation hours in 1997, coal to the gasifier also increased, totaling over 374,822 tons for 1997. Additionally, 18,000 tons of pet coke were processed in the gasifier. Oxygen from the ASU to the gasifier totaled 328,600 tons. Syngas production topped 6,200,000 MMBtu while 51,417 tons of by-product slag was produced. The production increase in 1998 was also significant. Coal feed to the gasifier totaled 561,494 tons for 1998 and oxygen feed from the ASU to the gasifier totaled 442,000 tons. The production of 8,884,902 MMBtu of on-spec syngas represents a significant increase over 1997 production. The amount of by-product slag produced from the process totaled approximately 70,228 tons. Finally, coal and pet coke feed to the gasifier totaled 315,951 tons for 1999 and oxygen feed from the ASU to the gasifier was 289,930 tons. This combined feed was utilized in the production of 5,813,151 MMBtu of on-spec syngas. Production was significantly impacted by a combustion turbine failure in mid-March lasting into June and by failure of a recycle line in the particulate removal system in November. More detail on these outages is contained in the following sections. The amount of by-product slag produced from the process in 1999 was 45,216 tons.

<u>Opportunities and Improvements</u>

Three areas of concern in the gasifier system were identified in 1996 that were run limiters or represented potential reductions of equipment service life. Those three areas were:

- Burner Longevity
- Refractory Life
- System Ash Deposition

In the first quarter of 1996, the plant experienced three failures of slurry mixers on the gasifier. Investigation revealed that all three failures were similar in nature and were attributed to coal slurry backing into the oxygen space in the burner during the transition to coal operations. Valve sequence timing modifications were completed to prevent recurrence. No similar failures occurred during the remainder of 1996.

In an effort to reduce ash deposition and increase gasifier efficiency, new offset mixers were installed in the fourth quarter of 1996. The offset mixer operation seemed to result in a reduction in ash deposition downstream of the gasifier; however, the carbon content in the slag was elevated, indicating possible lower gasification efficiency. Further testing of offset mixers was discontinued in lieu of alternate initiatives to address ash deposition and mixer efficiency. Later in the third quarter, a new refractory was tested in the gasifier outlet piping where ash deposition was a problem. The results showed promising reductions in ash deposition from the previous refractory, all of the entire outlet pipe refractory was replaced on the next outage. Deposition occurring in the second stage gasifier and continuing through the high temperature heat recovery unit (high pressure steam boiler) created difficulty in maintaining operation and extended scheduled shutdowns due to the necessity to remove the deposits. Plugging of the boiler tubes by material spalled from ash deposits increased equipment downtime due to the time required to remove the deposits. Minor changes have occurred through 1996, from varying operational temperatures in the gasifier and associated equipment, to changes in the type of brick in the system. The rate of ash deposition is also proportional to the number of thermal cycles (full or partial load trips) experienced in the system.

In 1996, there were 51 separate trips of the gasifier off of coal operation that contributed to ash deposition and subsequent spalling of these deposits. With increased run-time on the gasifier, increased operational experience was gained and more reliable equipment operation was achieved, thereby reducing the number of thermal cycles on the gasification system and subsequently reducing the potential for system deposition and associated problems downstream.

During a routine inspection of the first stage gasifier refractory lining, the wear rate was found to be significantly greater than anticipated. Core sampling of the lining indicated a failure associated with the bond matrix of the refractory brick. An alternate refractory brick test panel was placed in service to evaluate it for future use.

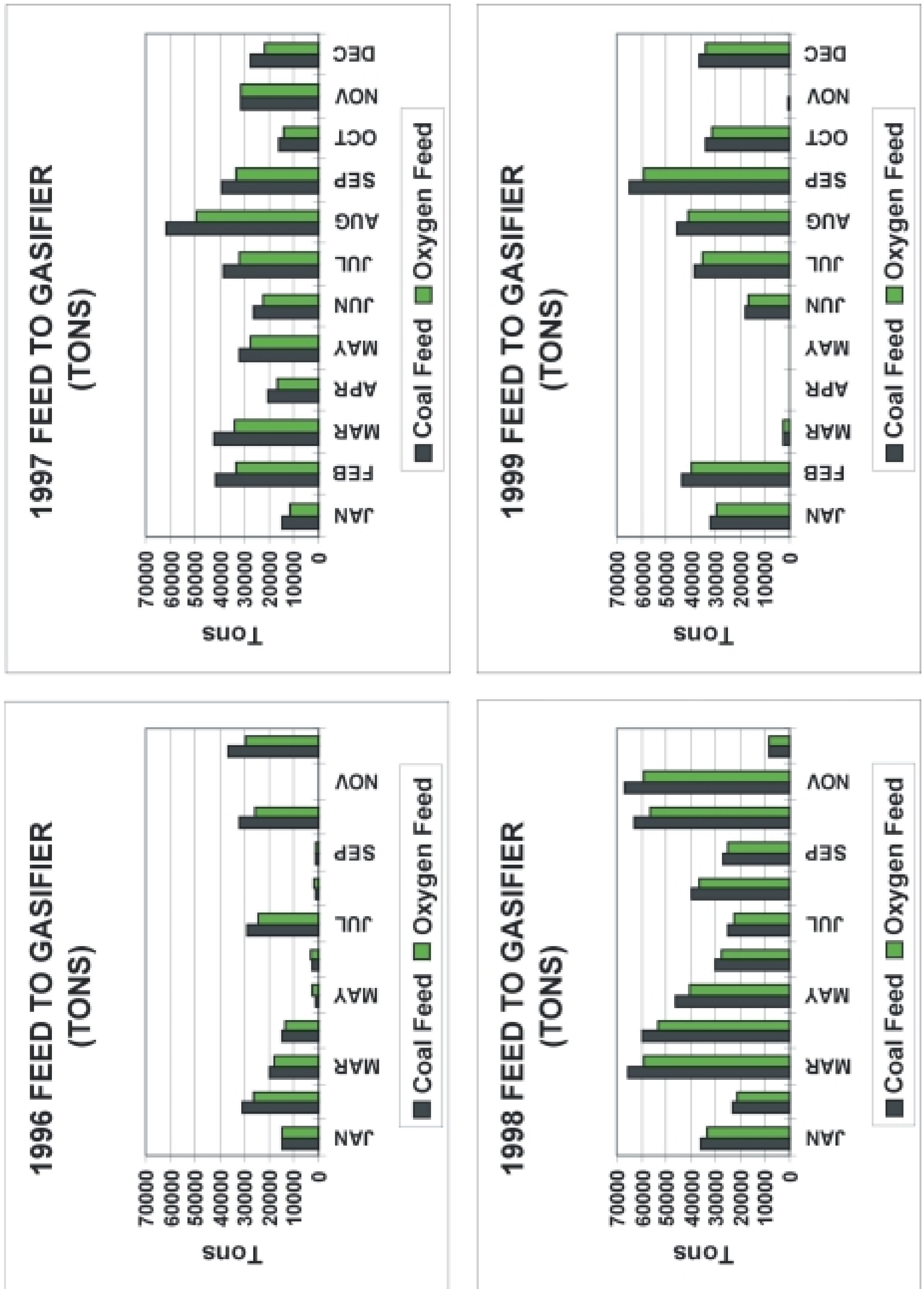


Figure 4.1.3B: Feed to Gasification Reactor for the Demonstration Period

In October of 1996, a failure in the gasifier water-cooled nozzle system caused a plant outage. Several devices on the gasifier are cooled by water contained in a closed-loop system. In the event of a leak in a device or in the piping, this closed-loop system receives make-up water from a high-pressure (1,800 psig) boiler feedwater source. Flashing of the 1,800 psig water stream as it flows into the lower pressure (450 psig) cooling loop caused a piping failure and subsequent failure of the cooling system. The make-up piping was re-designed to eliminate these problems.

The following modifications took place in 1997 to improve overall performance:

- As a follow-up to the gasifier nozzle water-cooling system failure in 1996, the source of the make-up water to this system was changed from high-pressure boiler feedwater to medium pressure cold condensate. The new make-up source has eliminated the vibration experienced from the flashing flow of the boiler feedwater.

In addition to the problems associated with the cooling water loop above, failure of tubes in the cooling water loop heat exchanger also occurred. Shell-side boiling of the cooling water along with induced vibration, eventually caused damage to the exchanger tubes. Corrective measures included increasing cooling water flow to the exchanger and installation of a new cold condensate makeup line.

During a third quarter inspection of the first stage gasifier in 1997, it was noted that there was substantial refractory wear in certain areas. While the gasifier could have been repaired in the worn areas and put back into service for the next operational run, the decision was made to swap to the spare gasifier. The spare gasifier had been equipped with new brick material based on the information gained from the wear rate data experienced in the “running” gasifier. Re-bricking of the gasifier that was taken out of service with upgraded materials could now be accomplished while running on the spare gasifier.

One project, identified to extend run-time by reducing deposition, was implemented in the third quarter. It involved a redesigned piping arrangement between the gasifier and the post gasifier residence vessel. The new post-gasifier pipe spool was designed to reduce deposition and help eliminate stress between the two vessels. By design, the new transition piece created a smoother gas flow path between the two vessels for the particulate-laden raw syngas. The old design utilized a straight piece of transitional piping that connected to the gasifier second stage and the post gasifier residence vessel just below the tops of both vessels. The abrupt change in the gas flow direction caused solids impingement resulting in ash deposition. This resulted in problems related to vessel hot spots and spalling of deposits. The new transition pipe was very successful in resolving the problems encountered.

Several minor problems were identified in 1997, which led to a decrease in gasifier efficiency or the shutdown of the operation. Those specific problems and corrective actions are identified below:

- During the first quarter of 1997, slag flow was lost due to insufficient flow of extraction gas (raw syngas utilized during normal operation to enhance slag flow) through the taphole. Loss of extraction gas flow caused a taphole plug, which eventually led to a shutdown of the gasifier. An investigation into the problem indicated that there was no mechanical process that needed evaluation or correction, but the problem existed in the computer control code for the gasifier. The control code was revised to ensure the presence of adequate extraction gas flow and to give operators a more accurate means of monitoring flow measurement. Once the control code was modified, no further problems with gasifier operation were noted due to extraction gas flow control.
- In the second quarter, following an inspection of the slag handling system, a significant amount of scaling was identified in the piping and equipment downstream of the slag crushers. Following laboratory testing, a scale inhibitor was added to the flow stream to reduce scale formation and the potential for slag flow reduction due to restriction of the lines.
- A raw syngas analyzer failed in the third quarter due to erosion from a high velocity of particulate-laden gas passing through the flow meter and associated piping. The situation was temporarily corrected by increasing the piping diameter for the flow meter to reduce velocity. Following a recurrence of the problem in September, it was decided that the analyzer would have to be isolated from the main gas path if the problem was going to be corrected. The analyzer inlet configuration was subsequently rearranged, utilizing a side stream path with less velocity. No further problems were directly associated with this unit.

During the first operational run in September, the redundant slurry flow meters (measuring flow to the gasifier) began deviating (from set point) significantly, which reduced the stability of the slurry flow to the gasifier (which is a primary control point for gasifier operation). The deviations became so severe that they eventually caused a shutdown of the gasifier due to the inability of the control system to properly adjust oxygen-to-coal ratios to the flow deviations. To correct this problem, a more aggressive preventative maintenance schedule for the flow meters was implemented.

- In the fourth quarter, an area of the gasifier steel shell developed a “hot spot” that required the application of cooling water to prevent thermal damage to the shell. When applying the cooling water spray, the water ran down one side of the gasifier creating unequal thermal growth between sides of the vessel and subsequent vessel movement. This, in turn, caused a misalignment of the slag crushers that ultimately caused a failure of one of the crusher couplings. The cooling water flow was drastically reduced to a “mist” which alleviated the problem of unequal thermal growth and no further failures were encountered. The hot spot was repaired internally during the next scheduled outage.

During November of 1997, a successful test run on an alternate feedstock (pet coke) was completed. From November 17-26, approximately 18,000 tons of petroleum coke were successfully gasified and used for power generation. Due to the higher Btu value of the pet coke, full syngas capacity was achieved at substantially lower slurry feed rates than are necessary with coal. Slag production decreased due to the much lower ash content of the feedstock. Additionally, the sulfur recovery unit operated at peak efficiencies during the trial run due to the higher sulfur content of the pet coke.

In 1998 the gasification and slag handling area contributed approximately 14.7%, or 286 hours, of downtime due to associated equipment failures or operational difficulties encountered with the alternate coal feedstock. Ash deposition from the gasifier to the inlet of the high temperature heat recovery unit did not contribute to downtime in 1998, an indication that prior actions have alleviated this problem.

Slurry Mixers

Slurry mixers continued to be a source of downtime due to the corrosive/erosive nature of the slurry (and slurry/oxygen mix) and efforts continued throughout 1998 to improve the design and operation of these units. The following is an overall summary of downtime contributors and the corrective actions taken, or in progress, for 1998:

- Two coal runs in early January ended due to slurry mixer failures. A third, similar mixer failure occurred during the first run of February. Investigation of these incidents revealed that the slurry flow rate at the time oxygen was introduced to the mixers was 40% higher than in previous coal start-ups. The oxygen flow controller exceeded the set point at the higher slurry flow resulting in a high transient temperature during the start-up, which damaged the mixer. Following these failures, the slurry flow set point for start-up was lowered and emphasized in operator run plans.
- Despite the above operating improvements, a fourth slurry mixer failure occurred in early March. However, unlike the previous three failures, which exhibited excessive cooling media loss, this failure was traced to a failure in the oxygen feed section of the mixer. The other mixer was shutdown in a controlled fashion to take the gasifier off line and allow change out of the failed mixer, which was eroded by the coal/water slurry. Inspections of these parts are now carried out with greater scrutiny during mixer rebuilds to accurately identify necessary repairs or component replacements.
- In early August, following an oxygen compressor trip, some difficulty was experienced returning to coal operations. As oxygen feed was initiated to the mixer, the gasifier tripped on high temperature. The root cause was traced to a slag mound in front of the mixer, which prevented proper mixing of the oxygen and slurry and resulted in high temperatures. Characteristic of sudden losses of oxygen (as is the case with an oxygen plant trip) slag quickly freezes in the gasifier and must be heated above melting points on re-start to allow de-slagging prior to reintroduction of slurry. To remove slag mounds after oxygen plant trips, a procedural change was implemented, requiring the reactor to be de-slagged longer before returning to coal operations.
- Newly designed mixers, intended to enhance slurry/oxygen mixing, were installed in the gasifier late in the third quarter of 1998. While they were in service, the gasification plant

was able to make syngas capacity at slurry rates 4-6% lower than normal, indicating improved conversion efficiency.

- In early October, an internal cooling media leak was detected on one of the new mixers, previously mentioned, so both were replaced at the next opportunity. Internal inspection of the mixers revealed that swirling flow characteristic of the new design, accelerated the erosion of the mixer, which significantly shortened the mixer life. Standard mixers were reinstalled and coal operations resumed.

Taphole Plugging

The "taphole" refers to the transition opening located in the center of the horizontal section of the gasifier that allows slag to flow into the slag quenching section. Plugging becomes a problem when characteristics of the slag change, which decrease its ability to flow as a liquid. The following events contributed to downtime in 1998 as a direct result of taphole plugging:

- An extended outage of 20 days occurred when a gasifier taphole plug forced the unit off of coal operations in late June. Subsequent de-slagging attempts on methane operations were unsuccessful so the gasifier was shutdown for manual removal of the plug. Investigation revealed that slag had not only plugged the taphole but bridged over the grinders as well, which prevented slag from exiting the gasifier. The root cause of the incident appears to have been a combination of events. Higher slag viscosity in the Miller Creek coal was the primary factor, but this was exacerbated by the fact that the gasifier was run slightly cooler due to fouling problems in the high temperature heat recovery boiler and high-level excursions in the dry char recovery vessel. Improved knowledge of Miller Creek slag behavior and new operating guidelines allowed successful gasifier operation on various blends of Miller Creek and Hawthorn coal for the remainder of the year. Since establishing new guidelines, no unusual slag flow or ash deposition problems have been noted as a result of using Miller Creek coal.
- A taphole plug during methane operation shutdown coal operations in late December. Preliminary investigation indicates that an ash deposit fell from the second stage gasifier and blocked the taphole. Maintenance personnel were able to clear the plug within four days and heat-up operations were reinitiated.

In 1999, the gasification and slag handling area contributed 806 hours of downtime due to associated equipment failures or operational difficulties encountered with the alternate coal feedstock. The following represents some specific equipment and operational issues encountered and resolved in 1999.

Operations were terminated in January of 1999 due to plugging of the gasifier slag taphole. The cause of the taphole plug was related to a batch of coal with abnormally high ash fusion temperature. Increased number of lab analyses of the slurry fed to the gasifier have been implemented in an effort to catch feed abnormalities and respond more quickly in the future. Improved guidelines relative to the gasifier operating temperature have also been established.

Testing conducted in the first quarter on scale model mixers resulted in a new mixer design that was installed in the gasifier during the second quarter. The new mixers demonstrated good performance from the outset as evidenced by increased cold gas efficiency and lower carbon content in the slag. By the end of the third quarter, the new mixers had exceeded expectations by accumulating over 1,800 coal hours with no evidence of degraded performance. In October, after approximately 1,980 hours of operation, one of the mixers failed due to thermal stress in the metallic mixer face. At the time of this failure, inspection of the other slurry mixer revealed minimal wear; however, the mixer was not placed back in service but, was disassembled and inspected further for learning value. The geometry of future mixer faces was modified to relieve some of the stress and the metallurgy of the mixer face will be upgraded to better resist stress cracking.

During 1999 some mechanical difficulties that led to plant downtime were identified in the slag system and are described below:

- During the first quarter, a slag precrusher motor trip resulted in transfer off of coal. The root cause of the problem was identified as reversed wiring of the slag pre-crusher motor causing it to run backwards. The motor was rewired and no further problems were noted.

- Slag crusher packing leaks resulted in 2.5 days of downtime in August. A manufacturer applied (owner specified) coating on the grinder shafts was found to be incompatible with the shaft metal, which caused the coating to break loose from the shaft and begin cutting into the packing. A packing injection pump was installed in early August to enable packing additions; but the situation deteriorated until it became impossible to maintain an adequate seal. Subsequently, an additional packing ring follower and packing was installed over the existing stuffing box, which minimized leakage so that operations could continue safely without excessive packing addition. Due to the time required to facilitate a shaft replacement, a suitable coating will be applied to the grinder shaft when the on-line gasifier is taken out of service for re-bricking in 2000. The crusher shafts for the off-line gasifier have been re-coated with the proper material to ensure that this problem does not recur when the off-line gasifier is placed back in service.
- In late December of 1999, the slag crusher began experiencing packing leaks similar to those encountered on the slag pre-crusher. The addition of an auxiliary packing ring installed over the stuffing box was not successful in stopping the leak. To properly repair the leak, the plant was down for 42 hours to add larger packing to the stuffing box. The root cause of this failure was identified as inappropriate coating on the grinder shaft, as was the case with the slag pre-crusher.

4.1.3.2 Syngas Cooling, Particulate Removal And COS Hydrolysis

Syngas Cooling

Figure 4.1.3A indicates total high-pressure steam production from the High Temperature Heat Recovery Unit (HTHRU) by month for the Demonstration Period. Steam production, as shown in each graph, tracks the operational run history of the gasifier but is also impacted by deposition problems in the heat recovery boiler.

Total 1,600 psig steam production for 1996 was approximately 820 million pounds. Total steam production for 1997 increased over 200% from 1996, as did most other operational parameters. While the HTHRU continued to experience fouling problems, new methods of cleaning the tubes were incorporated into the maintenance program allowing operations to come back on line with an outlet temperature close to design. Steam production for 1998 was approximately 2,190 million pounds. This figure represents a production increase of approximately 129% over 1997 and a production in excess of 269% over 1996 steam production figures. In 1999, total 1600 psig steam production was approximately 1,481 million pounds. This decrease from 1998 was primarily due to the loss of the availability of the combustion turbine late in the first quarter. Additionally, production figures were low in November due to a planned outage and the failure of a recycle line in the particulate removal system and subsequent fire, which caused significant damage to the electrical circuitry of the main gasifier structure.

Opportunities and Improvements

Ash deposition in the HTHRU and associated equipment was of great concern during the early operation. As discussed in the gasification section, thermal cycles of the hot gas path were a leading contributor to HTHRU plugging due to spalling of ash deposits in upstream equipment and piping. Solids accumulation at the tubesheet causes tube plugging and high differential pressures. At some point, the solids-laden gas through the open tubes reaches a velocity high enough to cause erosion. To help control ash deposition in the tubes of the HTHRU, a boiler inlet screen was installed in the third quarter of 1996 to prevent large particles from reaching the tubesheet.

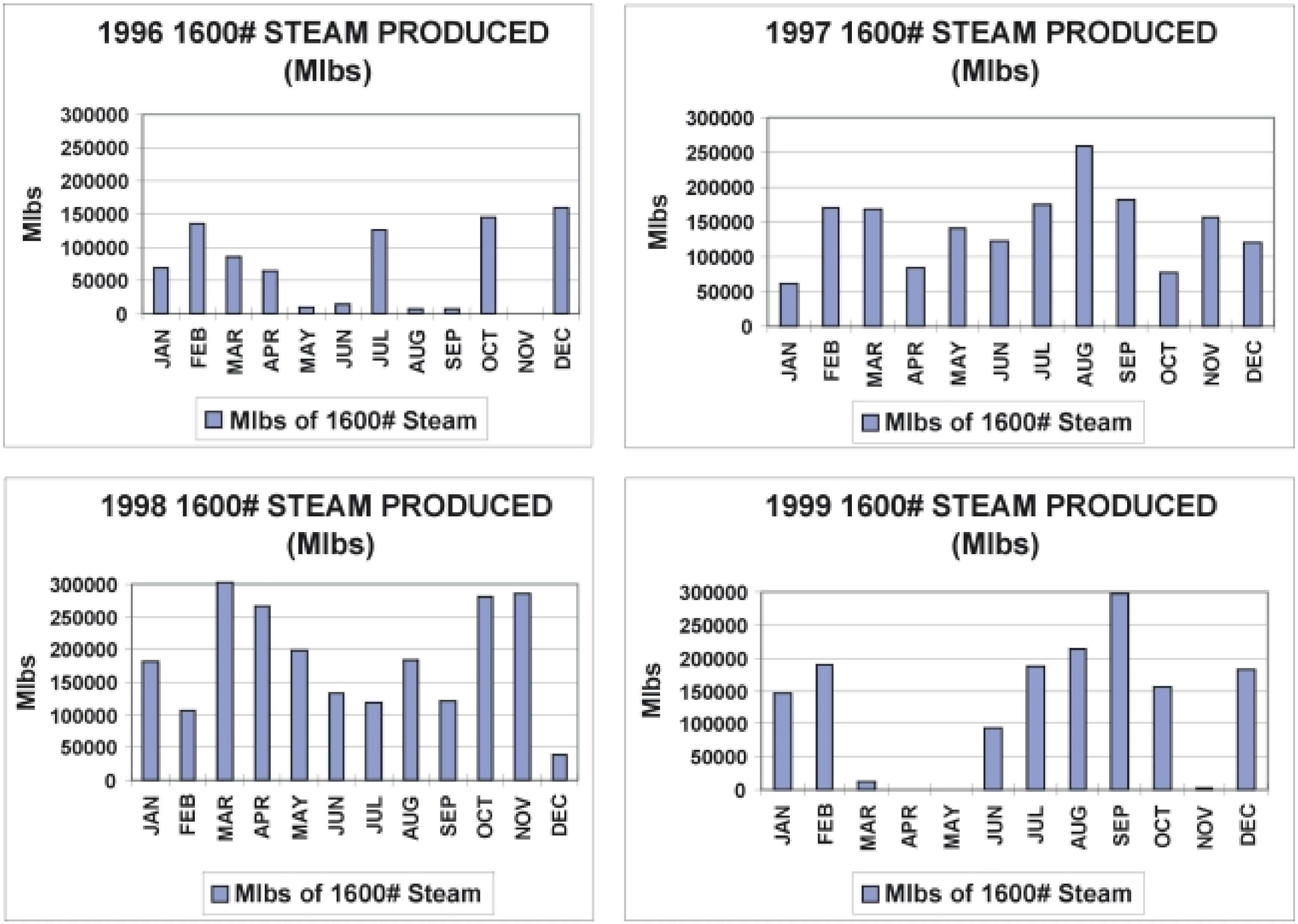


Figure 4.1.3C: 1600 psig Steam Produced for Demonstration Period

Deposition and corrosion within the HTHRU continued to be addressed in 1997. Several major projects and improvements occurred during the year to enhance system performance and improve reliability. Those include:

- The post gasifier pipe spool was replaced with a long, sweeping, 180 degree ell that provides significantly lower velocities between the second stage gasifier and the post gasifier residence vessel. This modification dramatically reduced ash deposition near the exit of the gasifier, meaning less ash deposits to break loose and plug the HTHRU.
- Thermal cycles (shutdown and start-up) not only affected deposition in the system but also served to accentuate installation flaws within the piping scheme. In March of 1997, due to misalignment of a piping spool during construction/installation, a syngas leak developed in a spool piece on the outlet of the HTHRU. The released gas combusted as it leaked from the process causing a small fire and subsequent shutdown of the gasification process. In the process of purging the system with nitrogen, the flare pilot was extinguished resulting in an odor noticeable in the surrounding area (due to minor concentrations of hydrogen sulfide in the purge gas). After this release, the spool flanges were re-machined and the pipe reconnected with a new gasket. Later in the Demonstration Period, the flanged pipe spool was permanently removed and replaced with a welded-in piping section to eliminate this potential source of leakage.

Into the third year of the Demonstration Period (1998), an upgraded boiler inlet screen was installed. Due to the corrosive/erosive service, upgraded materials of construction and design changes were implemented to extend the life of the screen. Following the installation of the new screen early in the second quarter of 1998, the screen remained in place for the remainder of the year, experiencing only normal wear while limiting deposition on the boiler inlet.

The post gasifier pipe spool installed in 1997 dramatically reduced ash deposition in the gas path. However, inlet screen corrosion and the maintenance required to remove boiler tube fouling resulted in 160 hours of downtime in 1998.

- Although not directly responsible for downtime, heavy fouling of the HTHRU tubes during 1998 caused the unit to operate at elevated syngas outlet temperatures. While this does not pose an imminent problem with the HTHRU, itself, elevated syngas temperatures (in combination with the acid gas environment) cause accelerated corrosion rates downstream. Attempts to remove the deposits off line with high-pressure hydro-blast rigs, mechanical scrapers and knockers were only marginally successful.
- In the third quarter, chemical cleaning of the boiler tubes was completed with excellent results. Upon returning to operation, an approximate 100°F decrease in heat recovery boiler syngas outlet temperature was noted, which essentially restored the heat transfer area to near new conditions. Although the chemical cleaning was very successful, it was also very costly and presented an increased risk of chemical exposure to plant personnel. Therefore, an effort to develop acceptable mechanical cleaning methods is ongoing.
- Boiler fouling accelerated in June of 1998 while operating with Miller Creek coal as a primary feedstock. A significant increase in boiler syngas outlet temperature was observed as the unit continued to operate on this Miller Creek coal feedstock. By the end of June, when the boiler was opened during an outage, an increased degree of deposition was found on the tubesheet screen and boiler tubes. The boiler fouling experienced while processing Miller Creek coal was caused by the higher iron content in the ash. Iron reduces the viscosity of molten ash entrained in the gas, which increases its tendency to adhere to surfaces such as the boiler screen and tube walls. It was found that by running the boiler inlet temperature cooler, the ash viscosity increases, thus minimizing its fouling characteristics.
- In August of 1998, utilizing modified operating parameters, the plant successfully processed a 25% Miller Creek/Hawthorne blend with acceptable boiler fouling when compared to the initial run in June. However, boiler fouling continued to be a run-limiting concern during the fourth quarter campaign. During a scheduled December outage, cleaning of the boiler deposits continued to result in higher-than-desired maintenance cost. Various mechanical cleaning methods were utilized to clean the boiler tubes. Although improvements to cleaning methods were noted, continual investigation into improved cleaning methods was necessary during the fourth year of the Demonstration Period.

The boiler fouling "opportunity" became a strong focus for plant personnel in 1999. During the extended outage following the combustion turbine compressor failure in March 1999, a new process to mechanically clean the boiler tubes was developed. The new process utilizes core-drilling bits and apparatus developed on-site. The new method restored the boiler tubes to "like-new" condition during a planned 3-week outage. The outlet temperature of the boiler, when returned to operation, was approximately 20-40^{o}F lower than it had been in the previous two years, which is an indication of significantly improved heat transfer. The lower temperature should reduce the corrosion rate of the downstream metallic particulate removal system filter elements and appears to have decreased the filter-blinding rate as well. Modified HTHRU operating parameters have reduced the fouling rate, such that current projections indicate that six months of run-time can be achieved before process-side boiler cleaning is required.

During the October 1999 outage, the HTHRU tubes were again successfully cleaned to "like-new" condition, although approximately 8 days of the downtime was required for the cleaning. Continued optimization of operating and cleaning methods will remain a focus after the Demonstration Period.

Particulate Removal

During the first quarter of 1996, 5 different interruptions in coal operation occurred due to the particulate removal system filters. One interruption was caused by erosion in the char recycle line that transports the filtered char back to the first stage gasifier. Erosion-resistant linings were used to address this problem. The other four interruptions were due to high blinding rates of the filter elements. As the filter element pores are permanently blinded, the differential pressure across the filters increases until the system design constraints are exceeded and the unit must be shutdown.

During this first year of the Demonstration Period, localized erosion in several areas of the char filtration system was encountered, including the filter elements, gas distribution piping, char conveying ejectors, and the char recycle piping. These problems were systematically addressed as they occurred and began an ongoing improvement effort that would extend well into the balance of the Demonstration Period.

The primary cause of char filtration related downtime during this first year of operation stemmed from repeated problems with leakage of char through the tie-rod candle filter elements. Three outages were caused directly from either breakage of ceramic candle elements or leakage of gasketing used in the primary filter system. Although the plant utilized a secondary filter system, this backup system was not adequate to sustain operation with appreciable leakage of char through the primary system. Improvements to the particulate removal system in 1996 included the previously mentioned upgrades to manage localized erosion. Other improvements were: increasing the effectiveness of the primary and secondary pulse gas systems, modifying the gas distribution system to provide more even flow distribution in the vessels to prevent filter system erosion and char bridging, and a replacement of the ceramic tie-rod type filter elements with more robust metal filter elements.

The installation of metal elements in late 1996 immediately improved the reliability of the particulate removal system and started a learning curve on metal filter elements that would last for the remainder of the Demonstration Period. In conjunction with the installation of metal filters, a heat exchanger was installed to increase the temperature of filter pulse gas above the syngas dew point, thereby reducing the tendency for fouling and corrosion of the elements due to syngas condensation.

Although the dry char filtering system continued to demonstrate improved performance throughout 1997, the system was still on a steep improvement curve in the operational area and in the area of design and metallurgy. Significant events during the year include:

- During the first quarter 1997, and after installation of first generation metal filter candles in the fourth quarter of 1996, a single gasifier trip in January was caused by primary filter failure. The failure was due to a combination of corrosion-weakened metal filters and flow surges through the vessels caused by backpulse valve failures. The failure of the backpulse valves prevented the cleaning of certain element clusters, causing them to blind off the flow through the filters. During that time, flow imbalances caused a significantly increased flow of gas through the clean filters, damaging the already weakened filter elements. Some of the experimental metallurgy utilized for filter construction during this run showed evidence of corrosion after only 523 hours of service and one type was corroded to the extent that the filters lost strength and ductility. During the ensuing plant outage, all of the filters of this type were replaced with filters of alternate metallurgies that demonstrated superior resistance to corrosion. All of the pulse valves were disassembled and many were found to have extensive seat damage. The valves were rebuilt and the pulse gas heat exchanger was taken out of service for the next run, since the hotter pulse gas was believed to be contributing to the valve failures. Leakage of the valve seats effectively stopped after this correction. Overall, the particulate removal system continued to operate acceptably until additional problems occurred in the fourth quarter of 1997, when it caused the plant to be brought off line four times. Three of the four occurrences were caused by flow imbalances between the two vessels and poor char recycle ejector performance, preventing the flow of char from the vessels. A dimensional discrepancy in one of the recently-fabricated ejector internal parts was determined to be the cause of this failure.

- High primary filter blinding rates continued in the fourth quarter of 1997 and, as a result, the filters were removed and externally cleaned during an extended plant outage in October. The high blinding rate was partially caused by a HTHRU tube leak. Filter blinding rates were again high during the period preceding the pet coke test in September 1997. Upon completing this test, the filters were again cleaned in early December, utilizing a new cleaning procedure that proved more effective. As a result, the primary char filter vessel differential pressures in December were much lower compared to the October start-up.

Other enhancements to the system in 1997, including a modification to the internal inlet gas distribution system in the dry char vessels and installation of a new test unit, continued to provide longer operational time frames. Specifically, those items were:

- A design change was made to provide more uniform flow distribution throughout the vessel, thereby reducing both the gas velocity in the high-wear areas of the inlet distributor piping and the particle impingement velocity on the filters.
- Initial construction began on a new Dry Char Slipstream unit (DOE Cooperative Agreement No. DE-FC26-97FT34158), which will provide the opportunity to test filter elements and

materials of construction outside of the primary filtration vessels. The project was completed and put into service during the fourth quarter of 1997.

In 1997 the particulate removal system accounted for approximately 25% (706 hours) of total plant downtime. In 1998, through an increased understanding of system operation and continuing research into filter element composition and design, plant downtime due to the particulate removal system was reduced to 180 hours or only 9.3% of total downtime for the plant.

The following key areas of operation and mechanical malfunction were responsible for the majority of the downtime for 1998:

- The particulate removal system continued to experience high primary filter blinding rates, initially experienced in the fourth quarter of 1997, until the February 1998 outage. In this outage, new filter elements with increased resistance to blinding were installed. The particulate removal system operated with minimal primary filter blinding until early in the third quarter when, during an outage, the filter system required cleaning and some replacements of filter elements. Due to supply constraints of the newer filter elements, older elements more susceptible to blinding were reinstalled in July. The high blinding rate limited the length of the subsequent run to 846 hours, forcing a plant outage in early September. A combination of old and new style elements was installed in September to maximize run-time and minimize cost.
- In April 1998, one of the char ejectors was replaced with a modified ejector, designed for improved erosion-resistance. Later in the run, the ejector failed due to a manufacturing error during the unit's previous rebuild. The failure resulted in a high level in the dry char vessel that resulted in fluctuations in the gasifier temperature when char was emptied from the vessel. These thermal excursions, combined with the high slag viscosity associated with Miller Creek coal, resulted in gasifier taphole plugging problems that caused a plant outage. Failed dry char ejectors again contributed to downtime in July and August, however the downtime was limited to only 3-4 hours in each instance. Further improvements were made to the dry char ejectors and new ejectors were in service for the remainder of 1998. While

changing the failed ejector in August, a backpulse valve was also changed due to leak-by when in the closed position. Upon return to coal operations, a second backpulse valve was discovered to be leaking. The run was terminated to allow replacement of the valve. The root cause of the failures was high pulse gas temperatures that resulted when the pulse gas heater, used during start-up operations, was left in service after coal operation was established. Operations personnel were re-instructed on the proper use of this heater to prevent future pulse valve failures.

- The first run following the third quarter 1998 scheduled outage was terminated due to a leak, and subsequent fire, on the primary char filter vessel inlet flange. The leak is suspected to have resulted from pipe movement encountered when new primary char filter vessel inlet isolation block valves were installed in this system (discussed below). Installation of the new valves did not include inspection of downstream piping so it is possible that a shift in the flanges would lead to a breach in the gasket-sealing surface. The leak was wire wrapped and clamped to allow safe return to operation with a permanent repair made at the next planned outage. Inspection during a fourth quarter outage confirmed that misalignment of the sealing surfaces was indeed the root cause of this incident. This was an isolated case that can be associated with project implementation in a very specific area.

Several projects/equipment enhancements were made to the particulate removal system to enhance performance and/or to improve operability. The following were accomplished in 1998:

- A test cluster of ceramic filters, previously tested in the slipstream unit, was installed in one of the primary vessels for evaluation. To avoid jeopardizing plant availability, fail-safe devices were installed to prevent char breakthrough if a filter element failed. The fail-safe devices were installed after extensive testing and evaluation and are used as a back up to the primary dry char filters. The fail-safe device is a highly porous filter used to capture solids that might breakthrough the primary filter elements. These devices were installed on all alloy filter elements that were most susceptible to corrosion-related failures.
- Additionally, testing continued on several corrosion-resistant filter alloys, which yielded some promising results. Corrosion rate data suggested that one of these alloys could more than double the life of the filters currently in service.

- The butterfly valves at the inlet to the particulate removal system were replaced with ball valves during the September outage. Positive shutoff with the previous valves was impossible, resulting in extended cooling and heating times for shutdowns and start-ups, respectively.
- Initial testing of an improved seat design for primary char filter system backpulse valves was conducted. The evaluation proved the new design to be much more reliable than the original style valve seats. Consequently, all backpulse valves were converted to the improved seat design. This eliminated all of the valve failure problems previously associated with seat failures.

In 1999, the particulate removal system accounted for approximately 12.9% of total facility downtime (772 hours) primarily due to the failure of the inlet line and char breakthrough in the system due to a ceramic element failure. Comparatively, 1999 downtime hours are significantly higher than the 1998 total of 180 hours and slightly higher than the total 1997 hours of 706.

The following key areas of operation and mechanical malfunction were responsible for the majority of the downtime for 1999:

- During the first quarter, a failure of a ceramic filter element in the particulate removal system resulted in a transfer off of coal and nearly two weeks of downtime. During the December 1998 outage, a test cluster of ceramic filters (previously tested successfully in the slipstream unit) was installed in one of the primary char filter vessels. A defect in the element support hardware resulted in a premature failure of one of the filter elements.
- During the October outage, high-wear areas of the dry char recycle piping were replaced with erosion-resistant material. Shortly after returning the unit to coal operations in November, a failure occurred in one of the new segments of erosion-resistant pipe, which resulted in a syngas leak. The leak ignited and the subsequent fire caused damage to an adjacent cable tray. The cause of the piping failure was traced to pieces of polyvinyl chloride left in the piping by the manufacturer during installation of the lining. The material decomposed at process temperatures and resulted in excessive and rapid chloride stress-corrosion-cracking of the piping. Subsequently, all of the recently installed piping was replaced with new piping

in which tighter quality control of the manufacturing process was exercised, including having a company representative personally witness the assembly of the piping. Approximately 18 days of downtime resulted from the failure and the associated replacement of piping, burned instrument wiring, and cable tray repairs.

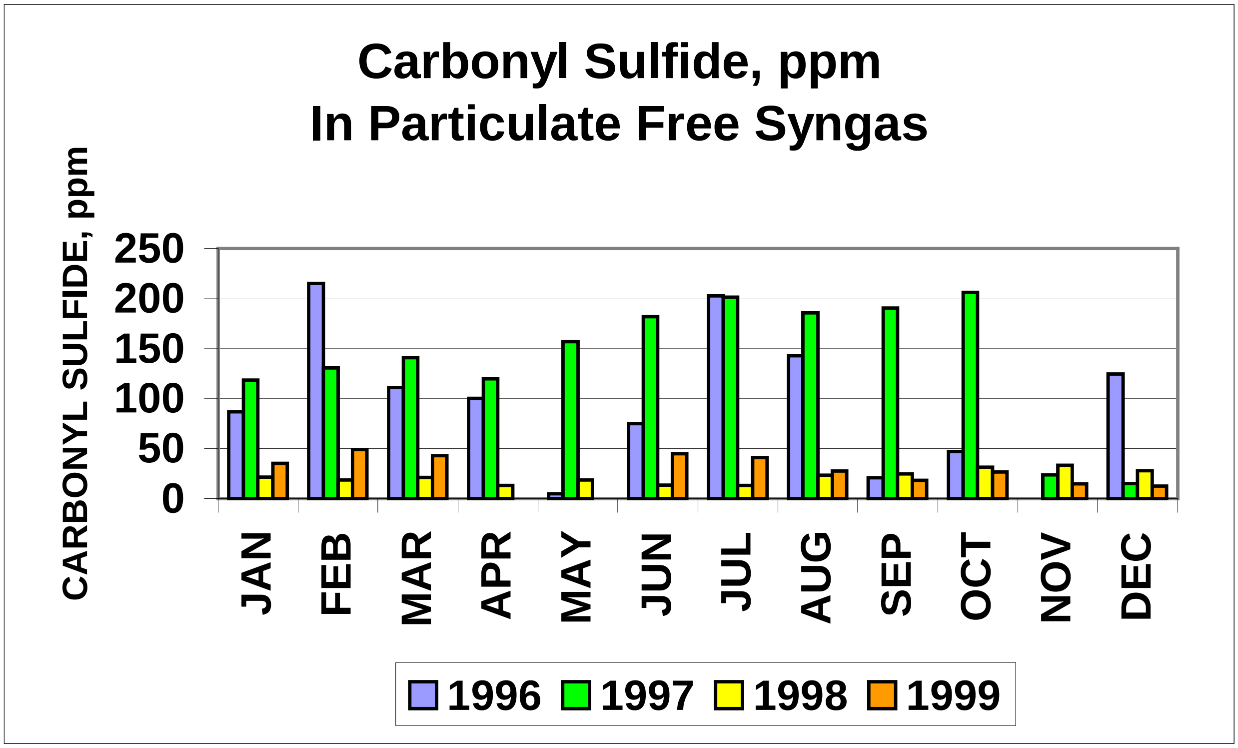
Key positive indicators of particulate removal system performance during 1999 include:

- The dry char ejectors have shown no evidence of degraded performance since their installation in 1998.
- The dry char filter-blinding rate during the initial campaign after the combustion turbine outage was exceptionally positive. Projections based on third quarter 1999 data indicate that filter life (limited by blinding) could exceed one year. The blinding rate of the char filters increased in late September. This increase was attributed to the pet coke test. During the pet coke test, the char filters were subjected to approximately 100% more char loading which may have resulted in some element bridging. This bridging can be avoided during future pet coke operation by increasing the backpulse frequency of the filter elements.

<u>Carbonyl Sulfide Hydrolysis</u>

Figure 4.1.3D depicts ppm levels of COS on a comparative basis between 1996, 1997, 1998 and 1999. As illustrated by this graph, significant progress has been made in the control of COS from the hydrolysis unit and in operating the system on a more consistent basis. In 1996 the average ppm level of COS leaving the hydrolysis unit was 102.9 ppm. The 1997 average increased to 139.4 ppm. This increase was due to catalyst contamination by trace metals and chlorides in 1996, and to partial degradation in 1997 resulting from a deflagration incident that reduced the total surface area of the catalyst and promoted channeling through the reactor bed. The first year of optimum operation occurred in 1998, as is indicated by an average value of 26.8 ppm of COS in the product syngas. This was achieved following catalyst bed replacement in the fourth quarter of 1997, and illustrates the capabilities of this unit when it is properly operated and maintained. This trend continued in 1999 with an overall average COS concentration in the product syngas of 26.2 ppm.

Figure 4.1.3D: Carbonyl Sulfide in Particulate Free Syngas



During runs early in the first quarter of 1996, COS removal efficiency in the catalyst beds began to decline. It was determined through sampling and analysis that the catalyst was being poisoned and blinded by trace metals and chlorides present in the syngas system. Catalyst degradation required the catalyst to be replaced during a February 1996 outage. Slipstream testing was initiated at this time to determine alternate catalyst selection. Catalyst efficiencies during the second quarter of 1996 continued to decline indicating the need for an alternate catalyst or a means of eliminating the contaminating agents. Through the use of the slipstream unit, an alternate catalyst was selected which showed a greater resistance to poisoning. Additionally, an improvement project was identified which required the installation of a system to remove chlorides from the syngas stream. The project would be beneficial, not only in the COS hydrolysis system, but also in equipment downstream from the installation (see section 4.1.3.3).

In the third quarter 1996, a new chloride scrubbing system (CSS) was installed along with a new catalyst for COS hydrolysis. The new catalyst was not only lower in cost, but testing indicated that it would be more efficient and less vulnerable to poisoning. While initial start-up and subsequent operation of this system went smoothly, a later system start-up in November led to a deflagration event in the system that partially reduced the surface area of the catalyst and damaged the CSS. The cause of this event was found to be the use of ambient air for pressure testing which created a spontaneous combustion event within the still-hot core of the COS catalyst bed.

The investigation and repair of the system was completed and the plant returned to operation in December 1996. Damage to the catalyst was not enough to warrant replacement; however, some degradation of activity was seen in an elevation in the amount of COS in the product syngas for the month of December. COS levels between 50 to 100 ppm were normal during operation, up from less than 50 ppm previously. However, overall sulfur in the product gas was still well within environmental and contractual requirements in the product syngas.

The COS catalyst system ran well within limits during the entire year for 1997, although the damage done in 1996 would require a premature replacement of the catalyst. The catalyst was replaced in the fourth quarter of 1997 and the system performance was restored to very low levels of COS in the product syngas.

The CSS, installed in 1996 after chlorides were identified as a contaminant to the COS catalyst, plays an essential role in syngas preparation prior to COS hydrolysis. By removing a substantial portion of the chlorides entrained in the syngas, it not only protects the COS catalyst but also reduces the potential of chloride stress-corrosion-cracking in the low temperature heat recovery unit (LTHRU). The CSS operated within design specification during 1998 with only minor problems associated with fouling of the demister pads and associated vessel packing.

The COS hydrolysis unit continued to provide stable operation throughout the Demonstration Period, and has proven to be a very reliable process operation within the Wabash River gasification facility.

Syngas Recycle Compressor

The syngas recycle compressor recycles particulate-free raw syngas back to the dry char filtration system for use in filter backpulse cleaning, and to the gasifier for use in the second stage gasifier for syngas quenching. Recycled syngas is also used to atomize coal slurry in the second stage gasifier slurry nozzle and to prevent nozzle plugging in the methane burners. Additionally, recycled syngas purges are used to prevent obstruction of gasifier instrumentation.

Syngas production was limited due to difficulties with the recycle syngas compressor in both January and March of 1996. At the end of January, a steady decline in the machine's second stage performance necessitated a compressor overhaul. The source of the problem was ammonium chloride deposition due to condensate carryover into the compressor during methane operation. In lieu of re-opening the machine, the deposits were successfully removed using a water-wash process. Because condensate carryover also occurs at a slower rate during coal operations, two improvement projects were instituted to minimize the long-term effects of this problem.

During the third quarter 1996 the compressor tripped on two separate occasions, preventing the plant from going to coal operations. In early August, a discharge-end labyrinth shaft seal failed. The cause of the failure was identified as chemical attack of the seal material. The seal was replaced with a material similar to that used in the inter-stage seals. The shaft sleeve was also damaged when the seal failed, which required a rotor assembly replacement. Shortly after restart, the new seal failed and was replaced with an upgraded material, which has operated since then without failure.

An interruption of coal operation in late August 1996 was caused by the failure of one of the compressor impellers, which was found to have cracked and moved on the shaft. The cause of the crack was determined to be mechanical in nature, although it propagated due to chemical attack. The rotor assembly was replaced and the compressor operated for the rest of the quarter with no mechanical problems.

The recycle syngas compressor was disassembled, cleaned and re-assembled during the October/November 1996 outage. Although the compressor had not affected plant performance prior to the outage, operational data indicated that it was slightly fouled. After the initial problems encountered during the first year of the Demonstration Period, the syngas recycle compressor has not required any major maintenance and has been a very reliable piece of equipment.

Chloride Scrubbing System

As mentioned earlier, the chloride scrubbing system was installed in the third quarter of 1996 to remove chlorides and other impurities from the syngas.

Some problems were observed with the chloride scrubber system upon initial operation due to ammonia accumulation. Due to the scrubbing of hot syngas with sour water, the chloride scrubber was also functioning as an ammonia stripper. This resulted in ammonia water being recycled to the sour water receiver, which in turn, was sent back to the CSS. Within two days of operation, ammonia levels had exceeded 4% (40,000 ppm) in the scrubber water. This reduced efficiency and created some pluggage problems in the low temperature heat recovery unit due to the formation of carbonate and bicarbonate salt-based scales. To abate further operational problems with the system, a blowdown was taken from the sour water tank directly into the sour water system to provide a purge of ammonia from the system. During the November shutdown, control of the blow down was automated to provide consistent control of ammonia levels.

The chloride scrubbing system exhibited effective scrubbing from the outset of operation. However, the demister packing in the top of the vessel began to plug due to coal tar in the raw syngas. During the second quarter of 1997, the plugging began to cause liquid carry over into the gas path requiring a shutdown.

The root cause of the incident was determined to be tar deposits on the packing, which impeded gas and liquid flow through the column. Mitigation of tar accumulation was achieved by modifying the second stage gasifier operations to maximize tar destruction. The column packing was cleaned and put back into service prior to the third quarter 1997 run. Towards the end of the run the column began exhibiting a high differential pressure, again, as a result of tar plugging. This time, however, the tar deposition was related to reduced rate gasifier operations.

To correct the problem, manual flushes were periodically implemented during reduced rate operations. Additionally, operating guidelines were revised to limit the time spent at low operating rates during which heat loss from the system is too great to maintain temperatures sufficient to destroy tars.

4.1.3.3 Low Temperature Heat Recovery And Syngas Moisturization

Production Information

Figure 4.1.3E illustrates syngas production by month throughout the Demonstration Period. Syngas production for 1996 totaled 2,769,685 MMBtu and increased considerably in 1997 to approximately 6,232,545 MMBtu. Production in 1998 further increased to 8,844,902 MMBtu, or 143% of the production record set in 1997. Fourth quarter of 1998 production also set a new quarterly production record of 2,503,587 MMBtu. This quarter included a scheduled December outage for maintenance and repair. Product syngas in 1999 totaled 5,813,151 MMBtu. Severely impacting production for 1999 was the unplanned combustion turbine outage between March and June. Additionally, failure of the newly installed dry char recycle line in November negatively impacted production in the fourth quarter. On a more positive note, however, third quarter syngas production exceeded all previous quarterly results by producing 2,712,107 MMBtu, and by more than doubling the previous continuous hours-on-coal record by operating 1,304 continuous hours.

Sweet syngas moisturization operated efficiently and provided consistent product gas moisture content of approximately 20%-23% throughout the Demonstration Period. Product syngas quality remained high and can be reviewed for all time periods in the Demonstration Period in Table 4.1.3A.

Product syngas quality remained relatively consistent throughout 1996. One of the primary reasons for this was the use of a single coal source for the year. Minor variations during 1996 in hydrogen sulfide and carbonyl sulfide concentrations (in ppm) were primarily due to equipment problems in the COS catalyst reactor and acid gas recovery systems. Variations in hydrogen content, carbon dioxide and carbon monoxide concentrations and methane content were directly related to operational characteristics of the system (and more specifically to variations in the oxygen-to-coal ratios of the gasifier feed) and cannot be attributed to variations in coal feedstock.

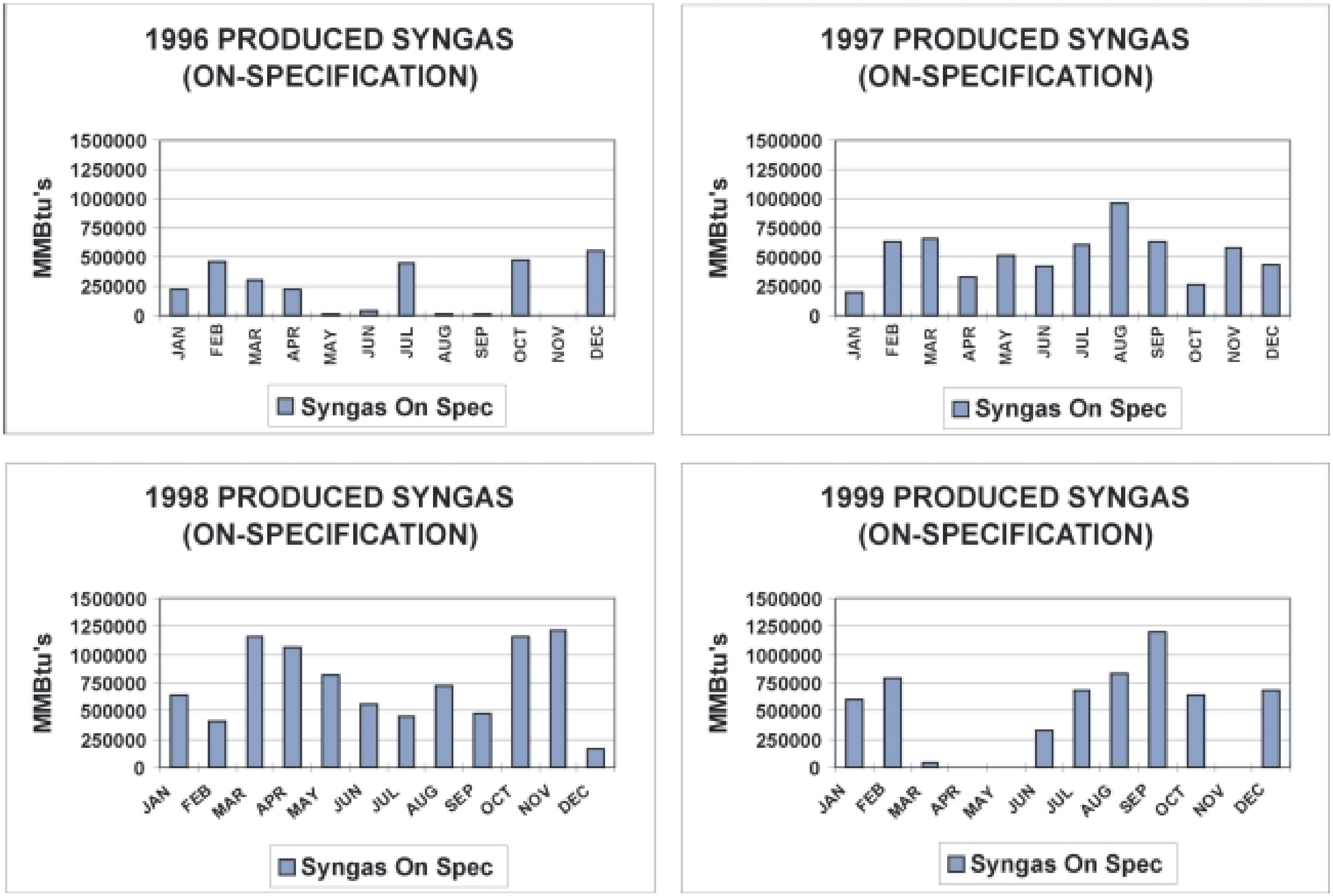


Figure 4.1.3E: Produced Syngas for Demonstration Period

Table 4.1.3A: Product Syngas Quality

Product Syngas Quality								
	1996		1997		1998		1999	
	Low	High	Low	High	Low	High	Low	High
Hydrogen Concentration (%)	32.87	34.21	32.9	34.4	32.71	33.82	32.31	33.44
Carbon Dioxide Concentration (%)	14.89	17.13	16.6	16.9	14.92	16.06	15.25	16.22
Carbon Monoxide Concentration (%)	42.34	46.03	42.2	46.7	44.25	46.73	44.44	46.31
Methane Concentration (%)	1.26	1.99	1.04	2.02	1.91	2.29	1.88	2.17
Hydrogen Sulfide Concentration (ppmv)	17.28	83.36	43.08	106.5	23.48	107.24	86.32	106.03
Carbonyl Sulfide Concentration (ppmv)	36.26	162.13	22.59	111.78	9.03	36.63	11.36	24.22

Syngas quality during 1997 was comparable to 1999; however, some assumptions can be made for variations in syngas composition due to the petroleum coke trial in the month of November. Despite the introduction of a new coal feedstock (Miller Creek coal), syngas quality in 1998 remained consistent. The same can be said for quality during 1999 when the gasifier operated on various blends of Miller Creek and Hawthorne feedstocks.

Opportunities and Improvements

While operations within the low temperature heat recovery unit (LTHRU) were within design parameters, three of the exchangers suffered tube failures in 1996 due to chloride stress-corrosion-cracking of the stainless steel tubes. Two of these exchangers serve to transfer heat between sour syngas and water from the syngas moisturizing system. A third exchanger cross-exchanges sour syngas with amine from the acid gas removal system.

The plant had to be taken off of coal operation in early April 1996 due to excessive tube leaks from the syngas/amine exchanger. Leaking tubes were plugged in this exchanger as well as additional tubes in one of the sour syngas/water exchangers. Replacement exchangers for the syngas/amine exchanger and one of the syngas/water exchangers were built on an expedited basis and were installed during the June 1996 outage. The replacements were constructed of an upgraded material that is not vulnerable to chloride stress-corrosion-cracking. Tests were performed on tubes within the remaining syngas/water exchanger during the outage, and, an additional 10% of the tubes in this exchanger were deemed suspect to cracking and were plugged to prevent future tube failures. Later in 1996, with the installation of the chloride scrubbing system, the potential for chloride stress-corrosion-cracking in the remaining stainless steel components was effectively minimized.

The syngas flare system is considered part of the overall low temperature heat recovery and moisturization process. During a syngas leak and subsequent flange fire event in the first quarter of 1997 (previously mentioned), the flare system malfunctioned by losing flame and causing a release of purge gas containing a trace quantity of hydrogen sulfide. The malfunction was attributable to a marginally combustible purge stream being routed to the flare and "snuffing" the flame on the flare pilot, allowing the purge gas to escape unburned. To correct the problem, three new "windproof" pilots were installed on the flare tip during the second quarter 1997 outage. The process control program for the flare purge initiation was also upgraded to ensure that a sufficient volume of natural gas is added to the flare gas to ensure combustion during system purge.

Another flare modification was implemented during the third quarter of 1997 to reduce noise levels during flare operation. Noticeable noise levels were a concern in the surrounding neighborhood, so a project was implemented to install a larger diameter flare tip, which effectively reduced the noise to acceptable levels due to reduced exit gas velocity.

The LTHRU contributed a total of 7 hours of plant downtime in 1998. While this is not significant enough to warrant concern, several key opportunities for operation and maintenance improvements were identified. The following areas of concern were noted during the 1998 operational period:

- Following an off-line cleaning during a maintenance outage, one of the LTHRU exchangers was hydro-tested for leaking tubes due to suspected failure. Approximately twenty tubes were found leaking and were subsequently plugged on both ends. One tube was extracted for failure analysis. The root cause was attributed to vibration, which is suspected to have occurred during use of a tubesheet spray intended for on-line cleaning. This spray creates thermal shock on the inlet tubesheet. The tubesheet spray had been used quite frequently in an attempt to lower the exchanger differential pressure. This activity has been discontinued due to its limited efficacy and its contribution to tube failures.
- The plant had to be taken off line during the third quarter of 1998 due to problems associated with the LTHRU. A temperature transmitter on the outlet of a condensate/syngas cross exchanger began reading erratically causing syngas flow through the exchanger to be automatically bypassed. When the reading returned to normal, the bypass valve closed before the main exchanger inlet valve opened, causing the gasifier system to overpressure and trip the plant off coal operations. Control program changes were made to prevent this from recurring.

During 1999, the LTHRU contributed a total of 10 hours of plant downtime when an unused tubesheet spray nozzle on an exchanger in that section of the plant failed causing a brief release of syngas. The piping failure was due to chloride stress-corrosion-cracking that developed prior to installation of the chloride scrubber in 1996. Other than this event, the LTHRU operated extremely well for the remainder of the Demonstration Period.

4.1.3.4 Acid Gas Removal

Production Information

Figure 4.1.3F illustrates the hydrogen sulfide (H_2S) removal efficiencies for the acid gas removal (AGR) system, by month, during the Demonstration Period. The efficiency calculation uses total combustion turbine stack and flare stack syngas emissions (as sulfur) compared to the total sulfur feed to the gasification plant (sulfur, dry-weight percent) for the most conservative estimate of performance.

Hydrogen sulfide removal efficiencies remained fairly consistent throughout 1996. A drop in efficiency can be noted in August of 1996 due to problems with the methyldiethanolamine (MDEA) reclaim unit, which keeps the amine solvent low in heat stable salts (HSS). High HSS concentration in the amine causes lower absorption efficiencies. Despite continued high solvent HSS loading, the AGR system performance increased in the final quarter of 1996 due to cooler ambient temperatures, which allows cooler amine process temperatures. November had no unit operating days and contributed nothing to quarterly performance.

Hydrogen sulfide removal efficiencies for 1997 also were consistent. During the fourth quarter, efficiencies were slightly higher, when compared to the first nine months of 1997, due to a decrease in activity in the COS reactor catalyst beds and in their ability to convert carbonyl sulfide to hydrogen sulfide.

Hydrogen sulfide removal efficiencies remained fairly consistent throughout 1998 and 1999 due to improvements in the system and more consistent operation of the acid gas removal system and sulfur recovery unit. Removal efficiency for the first quarter of 1998 decreased slightly compared to the fourth quarter of 1997 even though the plant processed an impressive 65% increase in syngas production. A vacuum distillation was performed on the MDEA to remove HSS in the fourth quarter of 1997. The distillation effectively restored the H_2S removal efficiency of the amine solution.

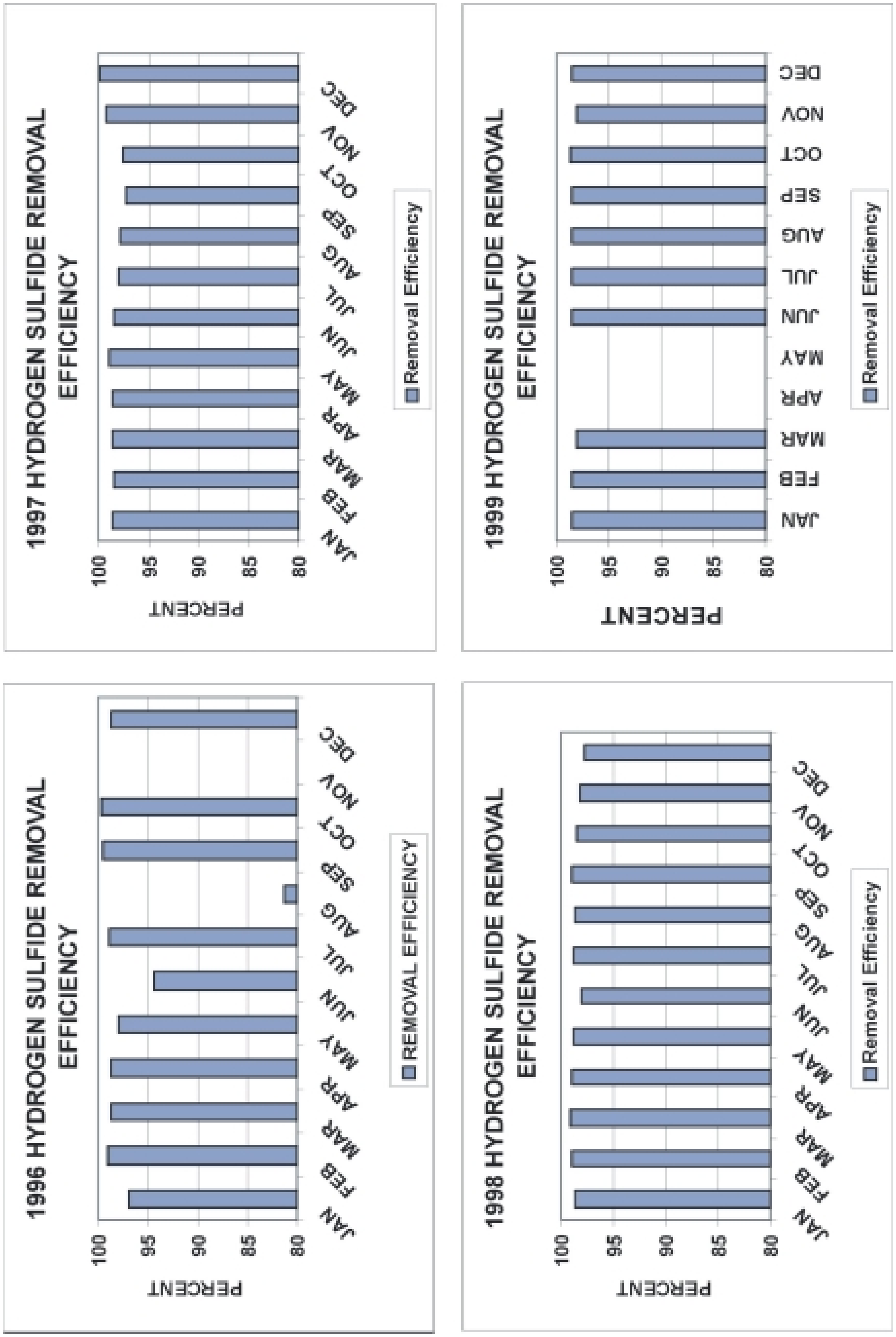


Figure 4.1.3F: Hydrogen Sulfide Removal Efficiency for Demonstration Period

In June of 1998, H_2S removal efficiency dropped to 98.1%. This small decrease can be attributed to a combination of factors. First, upon start-up in June, there was a change in the gasifier coal feedstock to Miller Creek coal. This coal contains higher weight-percent sulfur. This created a greater load on the AGR system, leading to a slightly higher level of H_2S slippage from the removal system. Second, rising ambient air temperatures during the summer months increased the average amine solution temperature, which, in turn, decreased its stripping efficiency.

<u>Opportunities and Improvements</u>

The following small-scale project improvements were completed within the AGR area in 1996:

- Design oversights for the internals of the acid gas stripper were identified in the first quarter of 1996. As a result of the deficiency, operation and maintenance costs increased due to solvent attrition, higher start-up quench water requirements, increased ammonia breakthrough to the sulfur recovery unit, reduced solvent strength and a slight efficiency penalty due to reduced solvent inventory. Redesign of the internals incorporated to the system in May rectified the problem.
- The lean amine pumps were modified during the second quarter by the addition of automatic recirculation valves incorporated at each pump discharge in place of a minimum flow orifice. These valves ensure that each pump has minimum safe flow during all periods of operation. The minimum flow orifice system was causing pipe erosion at low flow conditions due to flashing in the piping downstream of the orifice.
- In the third quarter, a pressure drop reduction project was installed for the lean amine return piping. An increase in pipe size in one section of the line allowed for a reduction in system head pressure and corresponding increase in pump flow. The added flow is helpful when higher amine circulation rates are required, such as during warmer weather.
- The MDEA reclaim unit, designed to remove HSS from the MDEA, experienced operational problems throughout the year. Early in 1996, efforts were undertaken to increase salt removal capacity through regenerant feed system modifications. By the second quarter, HSS loading on the MDEA increased to the point where it was necessary to call in an outside vendor to remove the salts via a transportable vacuum distillation process. This process

reduced the salts to a satisfactory level and restored the amine absorption capability to an acceptable level. Feed system modifications completed late in the second quarter were designed to boost capacity and utilize downtime for solvent reclaim process operation. A condensate cooler was installed to prevent thermal shock to the resin, resulting from elevated chemical feed dilution temperatures.

- During the third quarter, a project was implemented to install chemical feed pulsation dampeners in the MDEA reclaim unit to improve feed consistency and reduce chemical attack of the resin by better controlling the added chemicals concentration.

In early January 1997, the acid gas absorber internals sustained damage resulting from excess loading of the trays. To compensate for the reduced effective contact area, the amine was fed at a higher level on the column. The tray damage to the column was repaired during the late April outage and the feed point and the column performance returned to normal.

Reduced efficiencies encountered in the third quarter of 1997, can be directly attributed to the increase in solvent temperature occurring in the summer months and continued degradation of the COS catalyst, causing higher levels of COS in the absorber column inlet. A single event also occurred in the third quarter directly effecting absorber efficiency when column performance was compromised due to a collapse of a gas-liquid contact tray. Solvent anti-foaming compound was exhausted, and went unnoticed, ten days prior to this event and consequential solution foaming created a high differential pressure across the tray causing it to collapse. This event eventually led to a sulfur dioxide air permit exceedance at the flare when product syngas had to be flared because the product syngas sulfur limit was exceeded.

In the fourth quarter of 1997, because of an ever-increasing HSS loading of the amine, a vacuum distillation was performed on the entire absorbent inventory to remove the salts. The distillation recovered 82% of the solvent while removing the HSS. Efficiency increases can be attributed to the fresh solvent application.

The primary system modifications required in the acid gas removal system during 1998 centered on the MDEA reclaim unit. The following represent key improvement projects developed for the unit in 1998:

- In the second quarter of 1998, the canisters containing the ion exchange resin started experiencing reliability problems. It appeared that the resin canisters were being chemically attacked by the combination of chemicals used within the unit. A test canister, constructed of an alternate material, was placed in service for an evaluation period. Also, test coupons were installed to determine the chemical resistance of other potential alternative materials.
- In the fourth quarter of 1998, plans for an expansion of the unit were developed. The expansion included increasing the canister capacity and changing the material of construction from fiberglass to a metal alloy for increased mechanical integrity. These modifications were completed in 1999 and enabled the unit to remove HSS at the rate of formation, thus eliminating the HSS accumulation problem.

The most significant impact on AGR system performance in 1999 was continued project improvements associated with the MDEA reclaim unit. These improvements will reduce the operation and maintenance cost of the facility in two ways. First, the amount of amine purchased annually can be reduced. In the past, HSS accumulation deteriorated the performance of the amine plant, necessitating the purchase of new amine solution. This additional amine solution effectively reduced the concentration of HSS allowing the plant to continue operation. Now, amine should only need to be purchased to replace solution lost due to thermal degradation, blowdown of the regeneration column, and rinsing of the MDEA reclaim unit. The second cost reduction will come from the reduced need for third-party amine reclamation, such as the vacuum distillation process used in the earlier years. The need for these reviews should now be eliminated.

4.1.3.5 Sulfur Recovery

Production Information

Figure 4.1.3G indicates the recovery efficiencies for the sulfur recovery unit (SRU), by month, for the duration of the Demonstration Period. Sulfur recovery efficiencies indicated are split into two specific areas. The left columns indicate the efficiency of the SRU by comparing total stack emissions with total sulfur feed to the SRU. Overall plant removal efficiencies (right columns) compare total Joint Venture emissions (as sulfur) versus total sulfur feed to the gasifier.

Overall, the 1996 graph follows directly with the reduction in reactivity of the COS catalyst and is representative of degradation and replacement over the course of 1996. Fourth quarter, following the installation of the chloride scrubbing system and improvements in the AGR system, shows a significant increase in the removal efficiency of the SRU. A total of 3,289 tons of sulfur was recovered during 1996.

Again in 1997, sulfur recovery compares directly with the reduction in reactivity of the COS catalyst and illustrates a clear degradation over the course of the year. Fourth quarter replacement of the catalyst resulted in a significant increase in the overall Joint Venture removal efficiency. A total of 8,568 tons of sulfur was recovered during 1997.

In 1998, there were no major changes to the AGR system that would have a direct effect on the sulfur recovery efficiencies. Efficiencies remained very consistent throughout the year, thus sulfur recovery averaged between 97.5 to 98.5%.

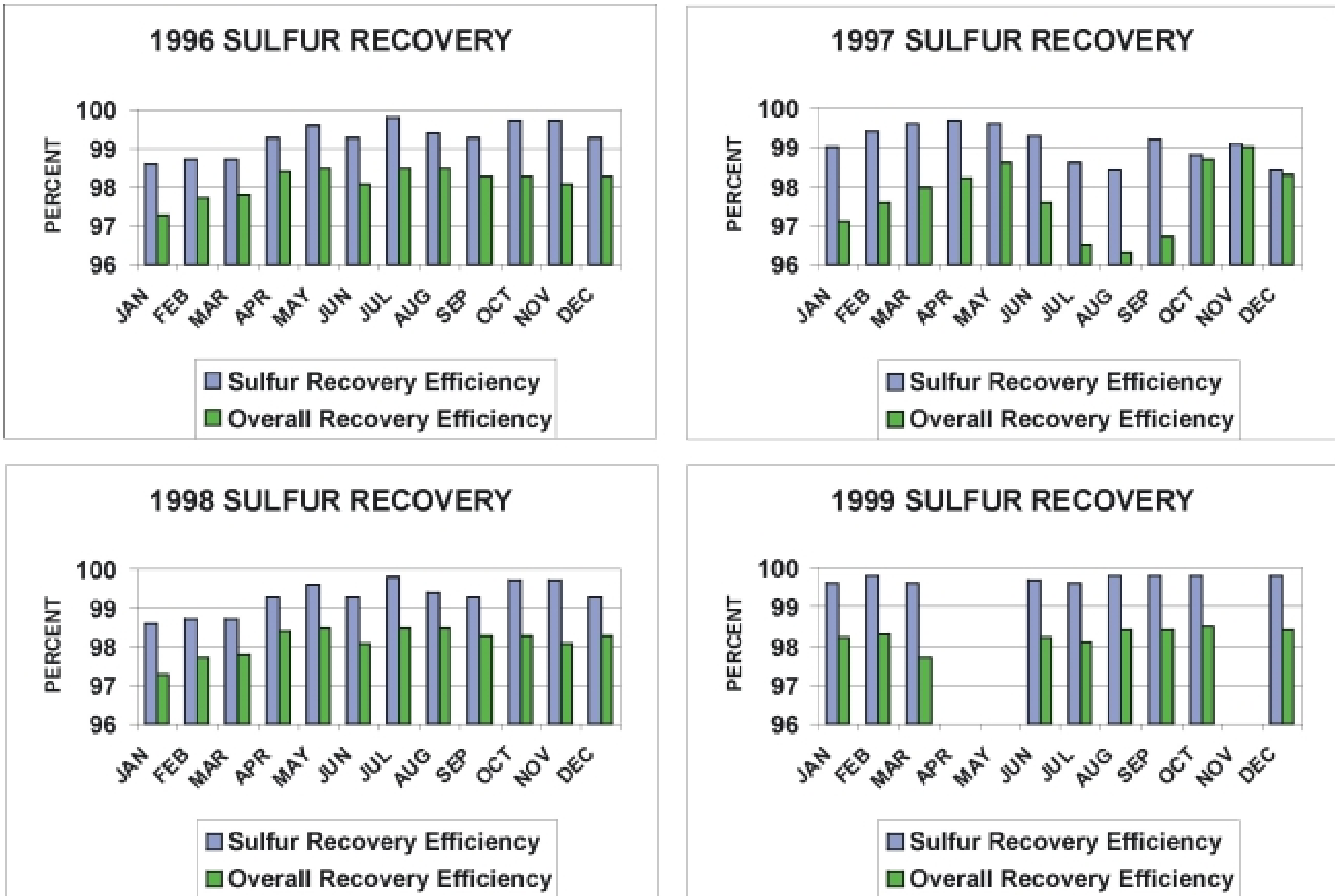


Figure 4.1.3G: Sulfur Recovery Efficiency for Demonstration Period

In 1999, continuous operation from June to October contributed to consistent sulfur recovery. Both the SRU sulfur recovery efficiency and the overall sulfur recovery efficiency for the third quarter increased slightly from the second quarter averages. Much credit for this increase can be given to continuous operation of the plant. However, the SRU received the highest average acid gas concentration of any previous quarter. Because the Modified-Claus process is a series of equilibrium driven reactions, higher acid gas concentrations increase the driving force for the formation of elemental sulfur, thereby increasing the single pass recovery efficiency. The increase in acid gas concentration is a result of lower amine circulation rates and higher sulfur feedstock to the gasifier such as Miller Creek coal and petroleum coke.

Opportunities and Improvements

As with operation of most new systems, the early operation of the sulfur recovery unit was characterized by a learning curve, which identified some unit shortcomings and improvement opportunities. The improvements in 1996 include:

- A bypass line was installed around the hydrogenation reactor, which allowed re-sulfiding of the catalyst to take place on line. This alleviated early problems with sulfur formation and pluggage of the tail gas handling system.
- Modifications to strainers on the tail gas recycle compressor suction lines allowed discretionary filtering, permitting small particle passage while retaining machine protection and reducing the rate of strainer pluggage and compressor downtime. As the tail gas recycle rate increased, sulfur plant recovery efficiency and production increased.
- A project to enhance sulfur area safety and storage tank capacity was implemented in the second quarter 1996. The project consisted of a new vent line to the tail gas incinerator allowing the sulfur tank to operate at lower pressure. The sulfur storage tank usable capacity was increased from 40% to 100% in the second quarter with implementation of the new steam-jacketed vent line. The new line isolates the tank from SRU process pressures, resulting in maximum safe capacity.
- In September, a new project was implemented allowing acid gas feed to the SRU prior to coal feed to the gasifier. This increases total recovery by allowing high recovery during start-ups as is reflected in the increase in efficiency for the last month in the third quarter. In

October, new process-control implementation allowed acid gas feed to the SRU after coal operations cease, thereby reducing emissions at the acid gas flare.

- Some projects designed to enhance safety and reduce O&M costs were implemented for the SRU in the fourth quarter. A rail car level transmitter replaced the originally installed detection systems, which allows more consistent sulfur rail car loading and reduced the potential for overfilling. Several lines in the SRU were modified to include double block and bleed (DBB) isolation in strategic locations. This eliminates significant line blinding efforts for vessel entry and allows SRU steam and condensate outages without forcing plant-wide steam outages. Finally, the SRU area steam trap system was reconfigured to eliminate ice hazards as well as providing a net reduction of 28 obsolete traps.
- SRU support systems also received project improvements. The tail gas quench cooler required installation of upgraded tie rods to minimize tube vibration. The suction vent gas blower knockout pot level monitoring system was redesigned for earlier high-level warning. One of the two lower explosive limit (LEL) metering systems within the tank vent system was relocated to a position where positive blower pressures would not affect accuracy, reducing nuisance alarming and excessive re-calibration. These improvements will positively impact operability and reduce maintenance needs.

During 1996 several incidents in the SRU led to either production turndowns, or complete shutdowns of the gasification process.

- In the first quarter, several minor problems associated with a plugged condenser and a plugged tank vent on the sulfur storage unit caused several hours of reduced production. Both of these problems were quickly resolved and full production rates restored without further incident. Corrective measures were written into the operating procedure and maintenance guide and no further problems of this nature occurred during the year.
- In November, the pressure safety valve protecting the acid gas stripping column failed, relieving at a pressure less than set point. Acid gas from the column was relieved into the flare header, resulting in an exceedance of permitted limits for sulfur dioxide at the flare. Investigation into the mechanism of failure revealed that debris in the pilot valve prevented proper seating. This allowed the main valve to remain open at pressures below the relief set

point. The pressure safety valve was subsequently removed and an alternate overpressure protection device has been employed.

Several projects were implemented in 1997 and 1998 in the SRU to improve overall reliability and maintainability. Those projects were:

- The steam generator for the tail gas incinerator was improved to lower incidences of leaks in the low-pressure steam drum safety valves. Rupture disks now isolate the safety selector valve from the safety valves themselves. This has significantly reduced maintenance costs associated with repair of the valves.
- In the second quarter of 1999, a project designed to enhance safety, reduce emissions, increase availability and lower O&M costs was instituted. A sulfur seal leg was installed at the hydrogenation pre-heater along with an ancillary heating system. The project was designed to ensure liquid flow at the look box and prevent overpressure by not allowing a solid plug of sulfur to form in that area. Personnel exposure and disposal costs have been reduced as a direct result of this project.
- One project in the first quarter of 1998 was intended to lower O&M costs and reduce the risk of exposing operators to molten sulfur. The seal leg for the first sulfur condenser was modified to facilitate removal of material causing flow restrictions. The new design allows for removal of the material collecting in the bottom of the seal leg without cutting apart the seal leg. Seal leg drain modifications have also been made which will reduce the potential to expose operators to liquid sulfur.
- Another project, implemented in the second quarter of 1998, is intended to improve safety and increase tail gas recycle compressor reliability. The seal legs of the first stage suction drums on the tail gas recycle compressors continuously over-pressured, allowing tail gas to escape into a sump where it was recovered by the tank vent system. To prevent the seal legs from over-pressuring, they were routinely blocked-in, requiring Operations personnel to manually drain the condensed liquid from the suction drum. Occasionally, the unit would go unchecked until a high liquid level would trip the compressor. During the June outage, the seal legs were extended to prevent over-pressuring, thus reducing operator exposure to tail gas and increasing compressor reliability.

- Another project was implemented during the outage in early September. Because of a hydrogenation bypass valve leak, sulfur dioxide reacted with the H_2S in the tail gas quench column, forming elemental sulfur. This sulfur plugged the column, heat exchanger and filters within the quench loop. Once the bypass valve was repaired, the entire quench loop was flushed with a heated 25% caustic solution. The flush was successful and there has been no more evidence of sulfur formation within the column.

Downtime attributed to the SRU during 1999 is summarized as follows:

- During the first quarter of 1999, 8 hours of outage time were attributed to the SRU. During a plant start-up in March, prior to acid gas addition to the SRU, combustion products from the Claus reaction furnace were released from a sulfur seal leg. The subsequent investigation concluded that the combination of a vacuum downstream and normal controlled pressure upstream was sufficient to de-inventory the seal leg. The vacuum was created while pumping down the liquid sulfur storage tank. The normal pressure control set point for the SRU during outages has been reduced to avoid any recurrence of this incident.
- In July, the gasifier tripped due to slurry feed problems. Shortly after transferring back to coal operation, the SRU air demand analyzer, the instrument responsible for determining fine adjustments to the Claus furnace oxygen supply, experienced an undetected plug in the sample line. Hours later, the accumulating error in the air demand analyzer caused an elevated SO_2 concentration in the catalyst beds, necessitating the addition of supplemental hydrogen in the tail gas hydrogenation reactor. When the hydrogen was added, the SRU pressure controller misinterpreted the signal from a pressure transmitter. The controller opened the SRU pressure control valve, bypassing the tail gas recycle compressors and allowing tail gas to flow to the tail gas incinerator. As a result, the SO_2 flow from the permitted tail gas incinerator stack reached a reportable level and coal operation was immediately suspended. Since this incident, the pressure controller has been modified to prevent a recurrence. Additionally, there is a project currently being implemented that will give Operations an indication when the air demand analyzer signal is not reliable.
- In early December of 1999, 69 hours of downtime were attributed to the sulfur recovery unit. It was determined that the hydrogenation unit bypass valve was damaged and failing to open

completely. Upon inspection, it was found that a mass of material had accumulated against the valve, preventing it from opening. The valve then sustained damage when the actuator attempted to open the valve. The material was a mixture of ammonium sulfate, iron sulfide and elemental sulfur. The sulfur can be melted with current heat tracing but the other materials have higher melting points. The reasons that these other materials are present in this location are still being investigated.

4.1.3.6 Sour Water Treatment

Production Information

Figure 4.1.3H illustrates the sour water outfall from the sour water treatment system by month for the duration of the Demonstration Period.

Sour water to the outfall remained fairly consistent in volume from 1996 to 1998, but varied in 1999 from a high in September of 7.2 million gallons to a low in April and May of zero. During the third quarter of 1998 there was a short period of atypical operation. The lower slurry rates combined with the lower moisture content of the petroleum coke feed at the end of September caused the sour condensate conditioning unit to see approximately 40% less flow. Typically, this reduction in feed causes unfavorable hydraulics within the conditioning columns, resulting in the production of off-spec water. However, during this period, a process of false loading was employed. Using existing piping, conditioned water was transferred to the tail gas quench column and then back to the front of the sour condensate conditioning unit. In doing so, proper column hydraulics and in-spec water were maintained without upset or addition of supplemental water.

Opportunities and Improvements

In the third quarter of 1996, operating data revealed the acid degassing and ammonia stripping columns were exhibiting signs of tray damage. Inspections confirmed the diagnosis and revealed significant damage, which was likely due to liquid flooding of the columns. In addition, damage patterns suggested flashing liquid feed flow to the stripping column was responsible for the loss of about 20% of the column trays. A new liquid feed distributor was installed to control hammering of the trays. Operating parameters were revised with the inclusion of new control system alarms to warn of impending flooding.

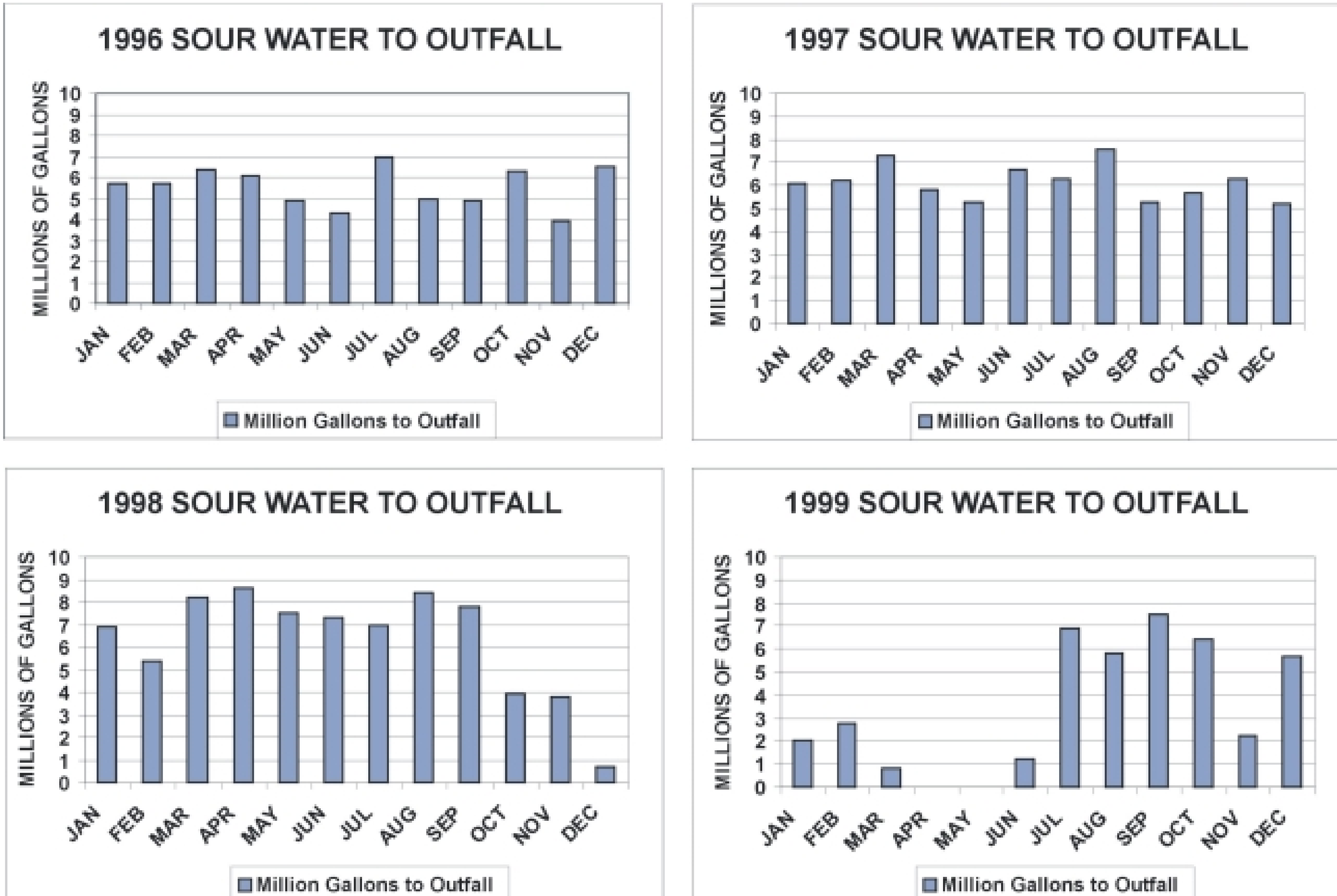


Figure 4.1.3H: Water Outfall for Demonstration Period

In the third quarter of 1997, a sour water carbon-filter vent containment system was installed to prevent fugitive odors. This project enhances both safety and environmental stewardship by eliminating another source of fugitive emissions. Fourth quarter enhancements to the system included the conversion of an existing activated carbon storage tank to serve as a caustic tank. Caustic has been added to the ammonia stripping column to further reduce the concentration of ammonia to the permitted outfall. Until this project, the caustic source was the caustic feed to the MDEA reclaim unit. Recognizing that a lower, less expensive grade of caustic could be used, a drum was retrofitted to serve as the supply for the ammonia-stripping column. This project should serve to significantly lower operating costs for the sour water unit.

In the second quarter of 1998, a significant amount of work was done on the carbon beds. High differential pressures across the beds caused damage to the vessel internals. During the June outage, structural modifications were made to ensure the vessel could withstand the higher differential pressures.

The sour water treatment system operated very well except for the aforementioned items.

4.1.4 Power Block

Table 4.1.4A illustrates power production by quarter for the duration of the Demonstration Period.

Table 4.1.4A: Power Block Production

	Combined Cycle Operating Hours On Syngas	Longest Continuous Run Hours On Syngas	Maximum CT Output (MW)	Maximum ST Output (MW)	Total Gross Generation (MWHours)
1996 1QTR	535	127	192	96	163,088
1996 2QTR	148	115	189	89	45,332
1996 3QTR	289	152	186	92	80,230
1996 4QTR	580	130	180	90	95,710
1996 TOTAL	**1,552**				**384,360**
1997 1 QTR	870	330	192	96	240,000
1997 2QTR	730	185	192	100	205,000
1997 3QTR	1,329	360	192	100	307,274
1997 4QTR	766	230	192	100	189,410
1997 TOTAL	**3,695**				**941,684**
1998 1 QTR	1,270	475	192	98	359,689
1998 2QTR	1,449	510	192	98	395,683
1998 3QTR	993	257	192	98	254,000
1998 4QTR	1,427	427	192	98	420,188
1998 TOTAL	**5,139**				**1,429,560**
1999 1 QTR	821	425	192	98	229,814
1999 2QTR	199	179	192	98	54,052
1999 3QTR	1,621	1,115	192	98	444,364
1999 4QTR	780	318	192	98	203,713
1999 TOTAL	**3,421**				**931,943**

During 1996, the power generation block required no improvement projects or major equipment modifications. Equipment operated as designed and the only key area of change was the identification of proper operating parameters for the combustion turbine and steam turbine during the first commercial year.

In 1996, the water treatment systems processed over 420.8 million gallons of water from the Wabash River for use in the gasification and re-powering areas of the facility. Of this total, approximately 110.6 million gallons were demineralized for use within the High Temperature Heat Recovery Unit (HTHRU) of the gasification process and the Heat Recovery Steam Generator (HRSG) at the exhaust of the combustion turbine.

The third quarter of 1997 produced the largest total power output for that year. In the month of August, figures for total gross generation exceeded 160,000 megawatts for the first time since Project start-up. The months of March, May, July, August, September, November and December show generation in excess of 60,000 megawatts on the combustion turbine with syngas. Electricity production for the year realized an increase of over 200% over 1996.

The fourth quarter of 1998 produced the largest total power output for that year. October and November were back-to-back high peak months, the best two consecutive months accomplished by the facility since beginning operation in 1995. Additionally, 1998 was another record power production year for the Project.

During 1999, July, August and September were high peak months of operation. Second quarter activities were severely curtailed when, on March 13 a vibration alarm was detected on the #1 combustion turbine bearing seismic probe. The unit ultimately tripped 6 minutes later from high exhaust temperature. Following investigation, it was determined that the compressor had failed. PSI decided at that time to inspect all machine components due to the level of teardown required. The inspection for all components, except the compressor, indicated normal wear for the number of starts and run-time on the machine. The turbine had experienced 412 starts and over 14,000 hours of operation prior to this failure.

The compressor failure actually occurred in the 14^{th} stage stator blades and propagated downstream. Damage from the 14^{th} stage downstream was catastrophic in nature and required complete replacement of all rotating and stationary material. Due to schedule considerations and opportunities to upgrade the compressor, PSI decided to purchase and install a new upgraded compressor from General Electric. The unit was returned to service on June 12, 1999 and has run successfully since that time.

4.2 General Information

4.2.1 Stream Data

Table 4.2.1A lists the main process streams for the Wabash River Coal Gasification Repowering Project and their Proprietary/Non-Proprietary classification as agreed to in the Environmental Monitoring Plan (EMP). Figure 4.2.1A illustrates the location of these streams within the process. A complete summary discussion and an analysis review of these streams can be found under Section 6.0 Environmental Performance of this Final Technical Report. Additional information, on a year-by-year basis, can be found in the Annual EMP reviews reported to the DOE for the years 1995-1999.

Table 4.2.1A: Key to Monitoring Locations

Location Designator	Proprietary (P) Non-Proprietary (NP) Status	Description of Monitoring Location
1	NP	Coal Slurry
2	P	Raw Syngas
3	P	Sour Syngas
4	P	Sour Water
5	P	Acid Gas
6	P	Tail Gas
7	NP	Tail Gas Incinerator Stack Gas
8	NP	Sweet Syngas
9	NP	GT/HRSG Stack Gas
10	NP	Slag
11	NP	Sulfur
12	NP	Non-Contact Cooling Water (Outfall 001)
13	NP	Process Waste Water (Gasification Plant)
14	NP	Treatment Pond Discharge to Ash Pond (Outfall 102)
15	NP	Ash Pond Effluent (Outfall 002)
16	NP	Equipment Leak Fugitive Emissions
17	NP	Slurry Facility Fugitive Emissions
18	NP	Slag Handling Fugitive Emissions
19	NP	Coal Handling Fugitive Emissions
20	NP	Slag Transport and Storage Fugitive Emissions

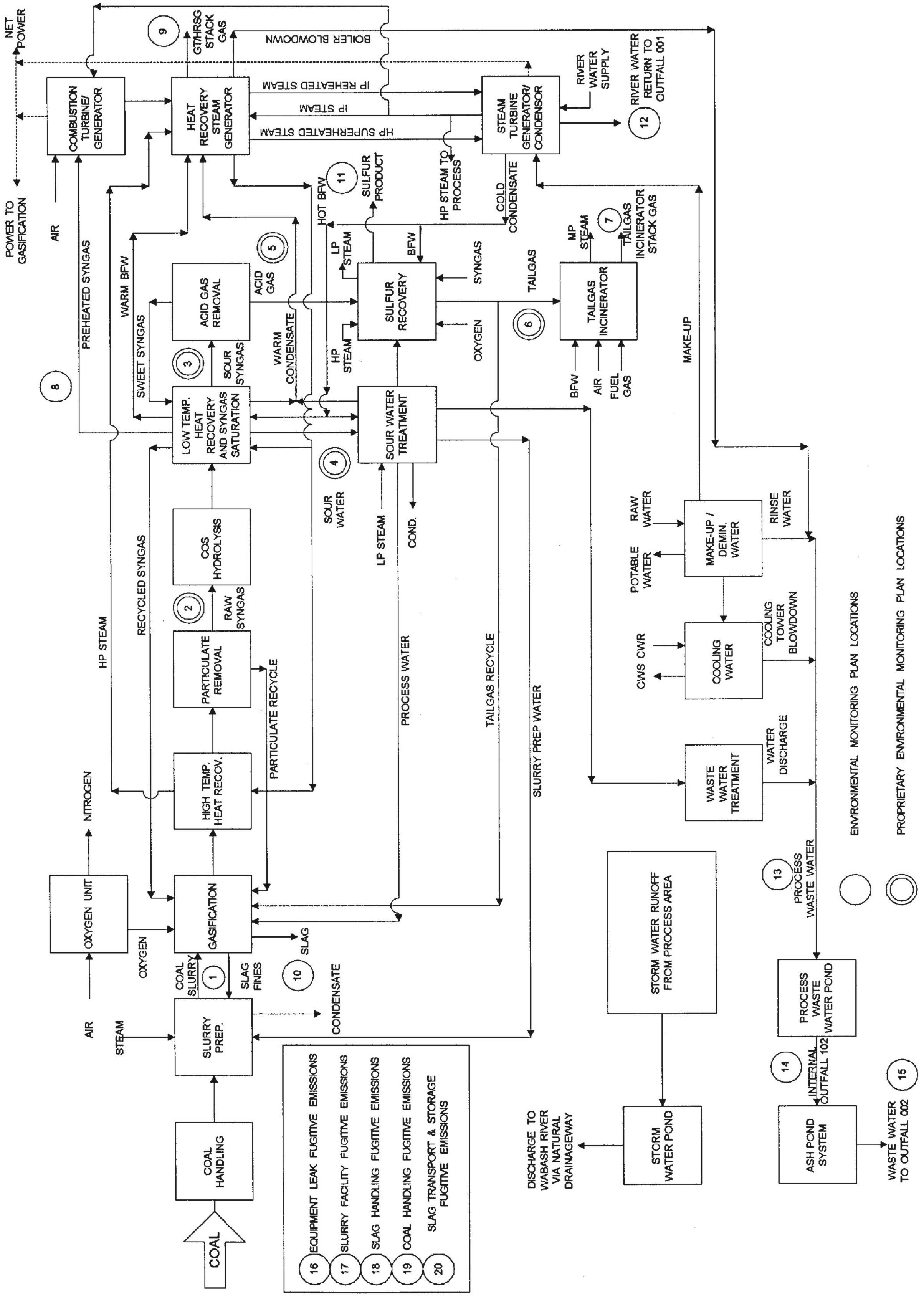


Figure 4.2.1A: Monitoring Locations

4.2.2 Alternative Fuel Testing

This section presents the results from testing of an alternate fuel, petroleum coke (also referred to as coke or pet coke). Approximately 20,000 tons of a 5% sulfur petroleum coke was processed in the Wabash River plant with favorable performance and environmental results. Plant efficiency, emissions of SO_2 and other air contaminants, trace metals balance, performance of the COS hydrolysis catalyst, and sulfur removal system, are presented. Observations on plant operation, including slurry preparation, flux addition, ash deposition, and gas stream metallurgical testing are discussed. Results indicate that future projects that utilize this alternate fuel could be implemented at a lower cost than Wabash River by reduction in the size or elimination of some of the equipment. Global Energy believes this demonstration of the inherent fuel flexibility of its E-Gas™ gasification technology will result in applications with other opportunity fuels, including coal fines, renewables, or waste materials.

Introduction

Because of the availability of relatively low cost natural gas, coal-based integrated gasification combined cycle (IGCC) power is not currently economical in areas where natural gas is available. Low cost natural gas also impacts the use of coal to produce chemicals. For example, steam reforming of natural gas is the leading source of hydrogen in North America. This has led to the current trend in the advancement of gasification technology in the global market, to utilize "low value" or opportunity fuels. Petroleum coke, a main by-product of refineries, is a prime candidate fuel to link the gasification and refining industries.

Petroleum coke is produced in the processing of oil residue where lighter components are extracted from the heavier fractions to maximize the yield of high value products such as gasoline and jet fuel. For many refiners, this is economically more attractive than the alternative option of selling the heavy fraction as residual fuel oil. Petroleum coke possesses energy content equivalent to, or higher than, bituminous coal and is sold as a fuel to utilities and cement producers. Even though petroleum coke is an undesired by-product in the refining process, its production in the U.S. increased dramatically over the last decade. A dwindling supply of high-quality, low-sulfur crude has driven refiners towards heavier and higher sulfur crude.

According to the Energy Information Administration (EIA), as of January 1, 1997 there were 152 operating refineries in the U.S., with an aggregate total capacity of 16.3 million bbl/d. Of these refineries, 54 operate coking units, and represent 59% of the total domestic crude oil distillation capacity. In 1996 they produced 31.7 million tons of coke, which was 95% of total U.S. coke production and roughly 70% of world coke production. Of this tonnage, 66% (roughly 22 million tons of coke) was exported, with Europe, Japan, Canada, and Turkey being the lead importers.

Over the ten year period between 1987 and 1996, the trend in feedstock to U.S. refineries has been toward heavier crude, from an average API gravity of 32.3° to 31°, and higher sulfur content from an average 1.02 wt. % to 1.2 wt. %. Both of these trends have the impact of increasing coke production per barrel of oil processed. It has been estimated that U.S. petroleum coke production could easily reach 32.9 million tons/year by the year 2000.

As coke production has increased, the coke market has become more constrained due to the higher sulfur content. There also has been an increase in the number of refineries constructed and installation of coker units overseas. Environmental restrictions on air emissions, especially in developed and developing countries where much of the offshore refining capacity exists, has also become more stringent. These facts lead to the conclusion that the already volatile coke market is shrinking for U.S. exporters. This presents a unique opportunity for gasification technology, which can effectively convert the low value petroleum coke to power or higher value chemicals. Locating a gasification plant adjacent to a refinery also offers many synergistic advantages to both the power and refining industries.

With these facts in mind, the significance of implementing this test program on the future marketability of the E-Gas™ gasification process is obvious.

<u>Wabash River Petroleum Coke Test</u>

The idea behind the Wabash River test was to utilize petroleum coke as the primary feed, while operating in a commercial environment. A rigorous program of preparation for the petroleum coke test was followed. This included: laboratory analysis of coke properties and ash characteristics; bench scale testing to determine the reactivity, grinding and slurrying characteristics of the petroleum coke; computer simulations of process and thermal performance; industrial hygiene review; and development of coke/flux blending equipment.

Eighteen thousand tons of a delayed sponge coke (Table 4.2.2A) were processed from November 17 through November 27, 1997. The plant switched from coal to pet coke feed "on-the-fly" without interrupting operation. As-received 100% petroleum coke was used with no coal blend. The coke had a sulfur content of 5%, which is well within the sulfur design limit of the Wabash River plant. Laboratory ash composition and ash fusion analyses indicated the pet coke would be difficult to slag-tap at typical gasifier operating temperatures. This necessitated the addition of a fluxing compound to the feed prior to slurry preparation. Slag from an earlier coal run was chosen because of its availability and its known ash flow characteristics. In the gasifier, the slag captures most trace metals such as vanadium and nickel into its matrices. Encapsulated in the inert, non-leaching slag, these trace metals were rendered safe for non-hazardous disposal or reuse.

Table 4.2.2A: Fuel Analyses

	Typical Coal	Petroleum Coke
Analyses: Moisture, %	15.2	7.0
Ash, %	12.0	0.3
Volatile, %	32.8	12.4
Fixed Carbon, %	39.9	80.4
Sulfur, %	1.9	5.2
Metals in Ash:		
NiO, % of ash	Trace	11.8
V_2O_5, % of ash	Trace	28.4
Heating Value, as received, Btu/lb	10,536	14,282

Overall Plant Performance

Plant operation was steady during the petroleum coke testing period, although the plant tripped twice for brief periods: once because of a slurry feed pump trip, and once due to the dry char particulate filtration system. Neither of these trips was related to the change in feedstock. Operation at full load was achieved with 100% petroleum coke fuel supply while meeting all environmental emission criteria. Operation was maintained at approximately 90% of syngas facility capacity for the greater part of the test to match the combustion turbine fuel requirements (Figure 4.2.2A).

Overall thermal performance (Table 4.2.2B) was slightly improved during petroleum coke operation, with overall plant efficiency at 40.2% (HHV). The syngas consumption by the combustion turbine in the "actual cases" was somewhat lower than predicted by the computer simulation.

Figure 4.2.2A: Wabash River Plant Performance on Pet Coke

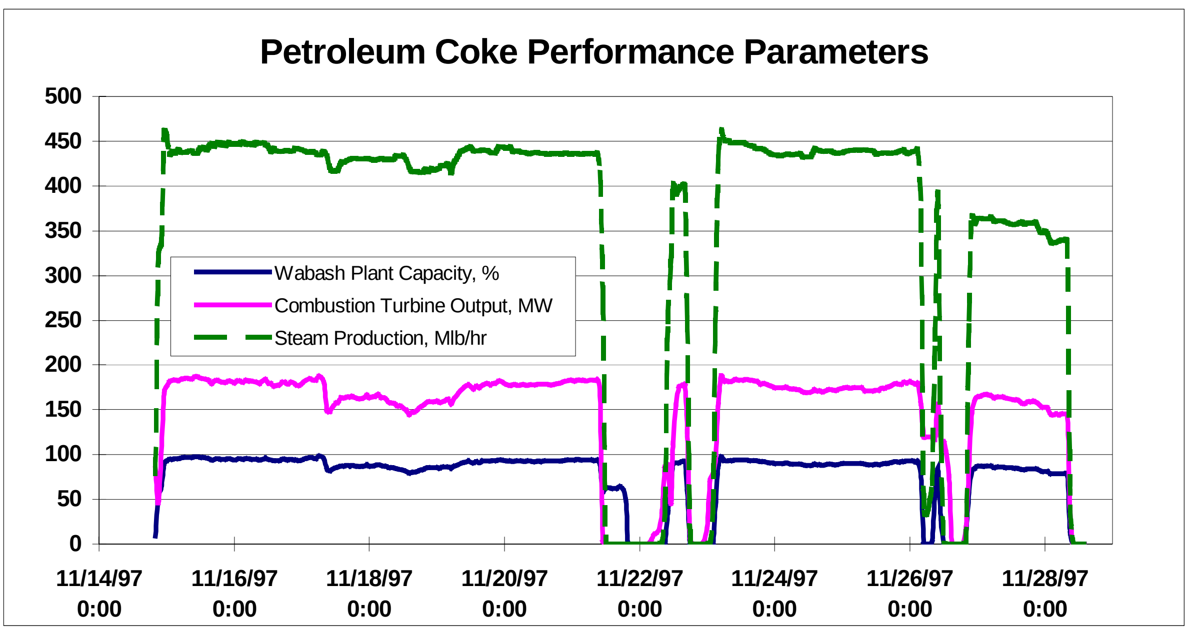


Table 4.2.2B: Thermal Performance Summary

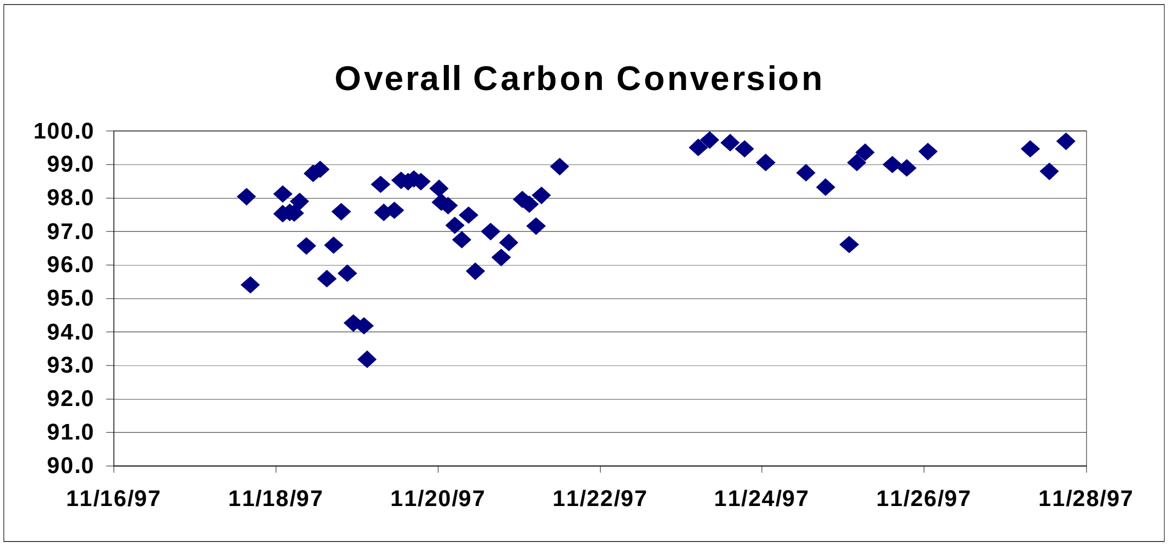
	Design Coal	Actual	
		Coal	Pet Coke
Nominal Throughput, tons/day	2550	2450	2000
Syngas Capacity, MMBtu/hr	1780	1690	1690
Combustion Turbine MW	192	192	192
Steam Turbine MW	105	96	96
Auxiliary Power MW	35	36	36
Net Generation, MW	262	252	252
Plant Efficiency, % (HHV)	37.8	39.7	40.2
Sulfur Removal Efficiency, %	>98	>99	>99

Process Observations

Slurry: Grinding of the petroleum coke proceeded with no problem for the duration of the testing. Slurry with a solids content of approximately 63%, and good flow characteristics for pumping, was consistently produced. Additional rods were added to the rod mill midway through the test to further reduce the particle size of the slurry, but no significant change in the solids content was noticed.

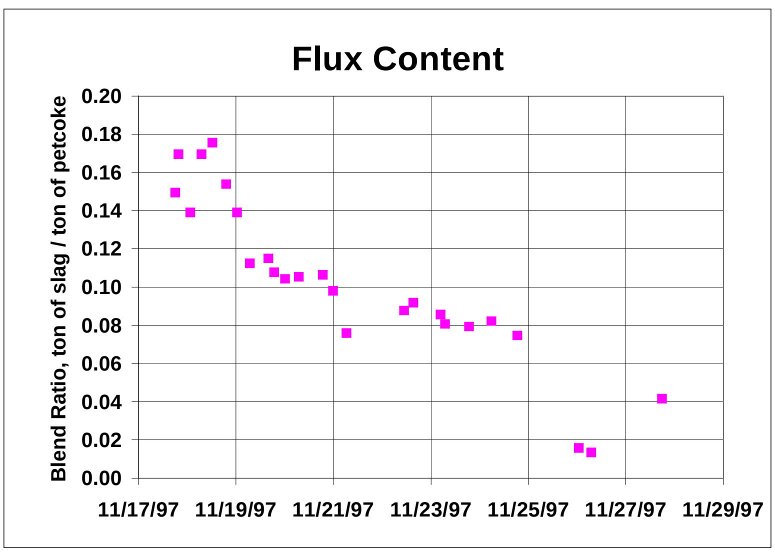
Reactivity: Laboratory tests prior to on-line operation, showed that the petroleum coke would be much less reactive than the coal fuels. Initially, an average carbon conversion rate of about 97.5% was seen during the petroleum coke operation. Following the addition of the grinding rods discussed above, and a resultant smaller particle size, overall carbon conversion improved to above 99% (Figure 4.2.2B).

Figure 4.2.2B: Petroleum Coke Test Overall Carbon Conversion



Flux Addition and Slag Flow: Based on laboratory ash fusion and high temperature slag viscosity tests, a range of flux addition of 5 to 10 tons of slag per 100 tons of petroleum coke was targeted for the test. However, problems with the blending equipment resulted in the test starting at a ratio of about 20 tons/100 tons, or about 20% flux. This was corrected to the target ratio by the third day of testing. Near the end of the test, the flux ratio was purposely reduced to about 2 tons/100 tons (Figure 4.2.2C). No slag-tapping problems were encountered during the test.

Figure 4.2.2C: Petroleum Coke Test Flux Content



Syngas Quality: Product syngas characteristics were very similar to operation utilizing bituminous coal feeds, as shown in Table 4.2.2C.

Table 4.2.2C: Product Syngas Analyses

	Typical Coal	**Petroleum Coke**
Nitrogen, (N_2) Vol. %	1.9	1.9
Argon (Ar), Vol. %	0.6	0.6
Carbon Dioxide (CO_2), Vol. %	15.8	15.4
Carbon Monoxide (CO), Vol. %	45.3	48.6
Hydrogen (H_2), Vol. %	34.4	33.2
Methane (CH_4), Vol. %	1.9	0.5
Total Sulfur, ppmv	68	69
Higher Heating Value, (HHV) Btu/scf	277	268

Trace Metals: The ash component of the petroleum coke contained approximately 12% NiO and 28% V_2O_5. The nickel and vanadium trace metal species are often of great concern in utility boiler operation. Vanadium pentoxide has been found to aggressively attack boiler metals, and nickel vapor is a known toxic even at very low levels. Process samples from solid, liquid and gas streams were taken at various points in the process during testing in order to quantify trace metal contents. About 80% of the nickel and 99% of the vanadium were captured in the silicate matrix of the slag and rendered inactive in the inert, non-leaching solid, as confirmed by the TCLP environmental leachate test. Some nickel components were found in ash depositions as expected. Liquid and product gas streams contained less than 1 ppm levels of nickel and vanadium species. The process, as currently configured, handles the trace metals more than adequately.

Refractory: Based on analysis of slag samples from the gasifier, refractory wear rate, even at the elevated temperatures required for pet coke operation, was similar to that while on coal operation. No unusual chemical interactions were observed.

Corrosion: No adverse impact on the metallurgy of the existing equipment was observed. Analysis of test coupons placed throughout the system indicated that corrosion conditions were not much different than coal operation. In particular, the metallic filters showed approximately the same corrosion rates as had been evidenced during coal runs.

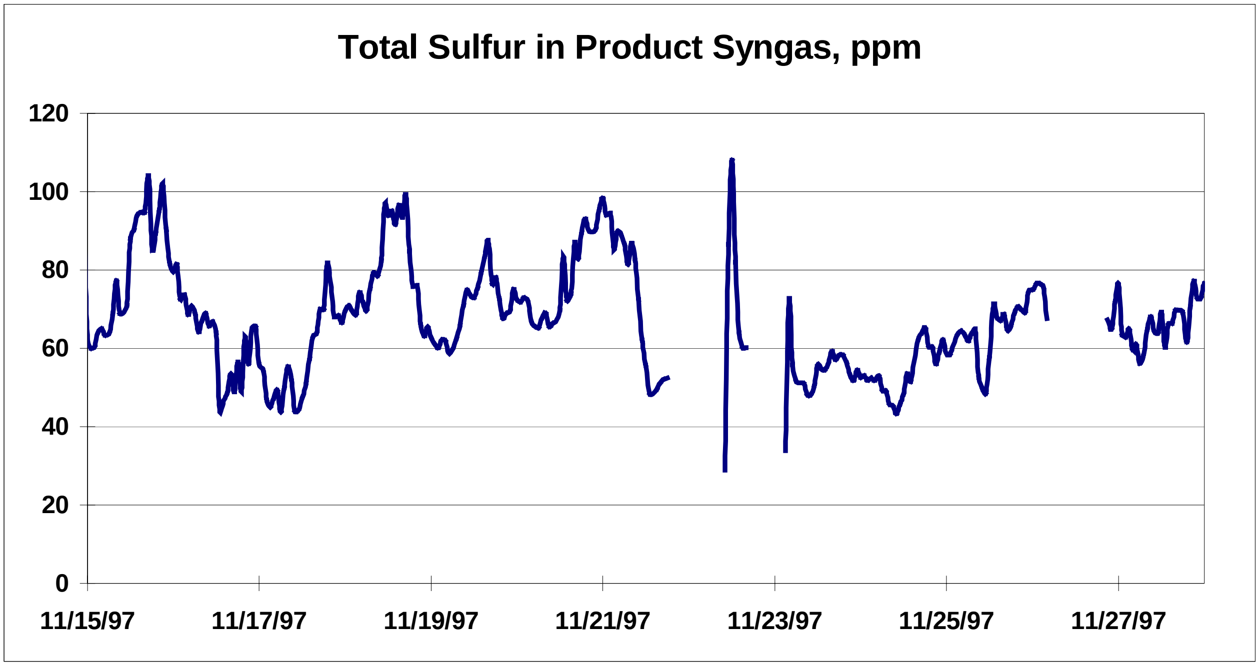
Ash Deposition: Ash deposition at the boiler inlet was slightly higher than normal operation, especially when temperatures within the second stage of the gasifier were increased. No additional deposition was noted in other areas.

Char and Tar Characteristics: Because of the lower reactivity of the petroleum coke, char loading to the dry char particulate removal filters was higher than coal operation at similar rates. No filtration problems due to the higher solids loading were observed. Sampling of the syngas at the gasifier outlet showed negligible amounts of tar formation. This may indicate that the second stage of the gasifier could operate at lower temperatures than during the test, which would enhance conversion efficiencies.

Sulfur Removal: Although designed to operate with up to 5.9% sulfur content coal, most of the Wabash River plant operation has been with coals having 2-3% sulfur content. As expected, both H_2S and COS levels in the raw syngas were much higher during the petroleum coke test due to the greater amount of sulfur in the feed. However, total sulfur in the product syngas was maintained at levels similar to coal operation (Table 4.2.2C and Figure 4.2.2D). No problems were encountered with sulfur removal or recovery. In particular, the COS catalyst performed well and higher conversion rates were indicated. No adverse impact on the catalyst was detected in post-test analysis of catalyst core samples.

Air Emissions: Extensive testing was conducted at two stack locations: the gasification facility incinerator stack and the combustion turbine HRSG stack. Tests were made during both coal and petroleum coke operation. Particulate emission levels were low in both coal and coke cases, totaling about 30 lb/hr for both stacks. No nickel or vanadium components were detected at the incinerator stack. No testing for these components was done in the HRSG stack since the product syngas was being tested. Unburned hydrocarbon emissions were nearly identical for both coal and coke operation (both were less than 1 ppm). Overall combined sulfur dioxide emissions were significantly less than 0.2 lb SO_2 per MMBtu of coal.

Figure 4.2.2D: Total Sulfur in Product Syngas



<u>Conclusions</u>

The overall conclusion from the testing is that petroleum coke operation was not significantly different than coal operation, and that the equipment and systems in place at Wabash River were adequate for this operation without modification. Other observations:

- Thermal efficiency greater than 40% was demonstrated at Wabash River with an "F" class combustion turbine and a repowered steam turbine. Future facilities should be able to approach 42-44% efficiency with the "H" class turbines.
- Gasifier operation on petroleum coke, although requiring somewhat higher temperatures, was much simpler than coal operation, primarily due to the reduced volume of ash components. Gasifier operation was proven down to a level of 2% flux addition.

- Trace metal components were captured in the slag, which passed leachate testing and thus is a non-hazardous material. Nickel and vanadium did not appear in the liquid or gas streams resulting from gasification of the pet coke.
- Tar presence in the syngas was negligible.
- Industrial hygiene considerations were the same as for coal operation.
- Additional char was produced, but can be handled utilizing dry char particulate removal systems of the current design.

It appears that future units designed to utilize petroleum coke as their primary fuel source can be similar to Wabash River, but with some improvements to reduce costs or improve operability. Low flux requirements demonstrated at Wabash River mean that the slag, ash and flux systems in future plants can be downsized considerably. The low reactivity of the petroleum coke will mean elimination of certain equipment at Wabash River intended to minimize tar formation. Because of the higher energy content and less tonnage requirement for petroleum coke, the coal handling and slurry preparation systems can be downsized as well. Operation should continue to be smoother than coal, indicating improved availability and capacity factors for a petroleum coke facility.

<u>Future Alternative Fuel Testing</u>

Similar tests of other alternative fuels are also being planned. Coal fines, a promising fuel in the locality of the Wabash River facility, are being produced by existing mine operations and also are available from surface reserves where the fines have been landfilled in the past. Coal fines may be available at 40-60% less than the delivered cost of coal to the facility. Major plant modifications may not be necessary to utilize the coal fines fuel. A survey on coal fines availability in the area has been completed and initial laboratory analysis has begun.

Biomass or “renewables” and various waste materials are other alternate fuels being investigated. With concern on global climate changes, there will be more emphasis to reduce emission of greenhouse gases such as CO_2 from fossil fuel use. Materials such as sewage sludge, municipal solid waste (MSW), refuse derived fuel (RDF), wood residues, railroad ties, and used tires are potential feedstock candidates. Since most biomass materials are relatively reactive, the two-stage design of the Global Energy E-Gas™ gasifier is uniquely suitable for co-feeding with coal. Coal will still be fed to the high temperature first stage with oxygen, and the alternate fuels will be fed to the lower temperature and longer residence time second stage. A high conversion of the reactive alternate fuel will still be achieved utilizing the thermal energy from the first stage.

The biomass feedstock will also be prepared and handled separately from the coal and coal slurry. Because biomass has characteristics different from coal in terms of handling, a method to prepare and feed the biomass material to the gasifier is being investigated.

Building on the lessons learned and the many successes to date, the Wabash River Coal Gasification Repowering Project gasification plant looks forward to continued demonstration of the viability of the technology in its use of alternate fuels. The advanced gasification technology demonstrated at the Wabash River facility has met the objectives of the Clean Coal Technology Program as outlined in this Final Technical Report and is well positioned to provide the solution to the growing global demand for efficient, environmentally superior, competitive energy conversion to power from coal or alternate feedstocks. Additionally, efforts are underway to incorporate and pursue value-added uses for syngas produced, such as is envisioned through forward-thinking concepts like the DOE's "Vision 21" initiative.

4.3 Critical Component Failure Report

A critical component is defined as any piece of equipment whose failure, or failure of the equipment's associated piping, valving or instrumentation, has resulted in a coal interruption. The likelihood of a critical component failure is substantially higher during a transient condition such as plant start-up or shut-down than during steady operation on coal. Consequently, understanding the root cause of a coal interruption is not only key to reducing future occurrences but also key to reducing other component failures brought on by the transient condition of the interruption. A summary of the causes for coal interruptions by plant area for the four-year Demonstration Period is shown in Table 4.3A.

Table 4.3A: Summary of Critical Components by Plant Area

Plant Area	Number of Coal Interruptions				
	1996	**1997**	**1998**	**1999**	**Total**
Power Block	11	12	5	5	**33**
Particulate Removal	10	6	6	3	**25**
First Stage Gasifier	8	5	6	2	**21**
Slurry Feed	2	3	4	7	**16**
High Temperature Heat Recovery	8	7	1		**16**
Air Separation Unit	1	2	10	1	**14**
Slag and Solids Handling	2	3		3	**8**
Low Temperature Heat Recovery	6		2		**8**
Sulfur Recovery	3		1	1	**5**
Chloride Scrubber		2	1	1	**4**
Scheduled Maintenance		2	3	1	**6**
Acid Gas Removal		3			**3**
Total	**51**	**45**	**39**	**24**	**159**
Total hrs on Coal	1,915	3,886	5,278	3,496	
Average coal hours/run	38	86	135	146	

The greatest improvements in key component failures have occurred in the areas where the most attention has been focused, namely the power block, the particulate removal system, the first stage gasifier, and the high temperature heat recovery unit. Interface problems between the gasification block and the power block resulting in coal interruptions were frequent in the first two years of operation. For example, 10 coal interruptions were caused by the loss of boiler feedwater supply from the power block to the gasification block in the first two years. Only 1 interruption occurred in the subsequent two years. A significant effort to improve the particulate removal system has resulted in one of the most reliable particulate removal systems in the world. The reliability of the first stage gasifier continues to improve, and since system modifications in the fall of 1997, the high temperature heat recovery unit has been nearly trouble-free. More detailed information on the improvements in these areas can be found in Section 5.0 of this report.

Three exceptions to the flat or decreasing number of interruptions for most of the areas are worth noting. First, the slurry feed system has seen an increasing number of interruptions. Eight of the eleven interruptions in the last two years have been due to valve failures or a plugged suction line between the low-pressure slurry pump and the slurry storage tank. By early 2000, both of these problems should be greatly reduced if not eliminated. The valve failures resulted from poor material specifications that will be upgraded and the occurrence of plugged suction lines will be reduced with the installation of a larger diameter agitator in the primary slurry storage tank. Second, the air separation unit has not been as reliable as anticipated. However, several improvements, discussed in more detail in Section 5.0, were made in the summer of 1999 that should increase reliability. Third, the scheduled maintenance interruptions are increasing. This increase indicates that the process is becoming more predictable. It is not coincidental that the best production year for the plant was also the year of the most scheduled outages. Had the combustion turbine rotor failure not occurred, a similar trend in 1999 could have been noted.

The average hours per campaign demonstrate a steady increase and should continue as future improvements to the process and operating practices are completed.

Coal Interruptions Prioritized by Downtime Severity

Since the duration of the downtime associated with each of the interruptions noted in Table 4.3A ranged from 46 minutes to 101 days, a second summary, Table 4.3B, prioritizes the downtime severity for each of the coal interruptions. Table 4.3B divides the downtime associated with a coal interruption into five types. These types are defined as follows;

A Coal interruptions that result in downtime greater than two weeks.

B Coal interruptions that result in downtime greater than one week but less than two.

C Coal interruptions that result in downtime greater than 72 hours but less than one week.

D Coal interruptions that result in downtime greater than 24 hours but less than 72 hours.

E Coal interruptions that result in downtime less than 24 hours.

In Table 4.3B, as in Table 4.3A, improvement trends are evident. However, four critical opportunities are noteworthy, some of which are not obvious from the data presented. These four areas constitute the primary critical areas where teams have been formed to address the specific problems mentioned. Although other areas force the plant off line, these interruptions are addressed primarily by improving the preventative maintenance program or the plant's operating discipline.

First Stage Gasifier

First, plugging of the taphole associated with the first stage gasifier must be eliminated. Plugged tapholes accounted for 4 of the 5 first stage gasifier coal interruptions with downtime severity of A or B. These incidents are avoidable and improved operating guidelines have been instituted that should eliminate these occurrences. Second, of the 21 coal interruptions for the first stage gasifier in the last four years, 11 were due to slurry mixer failures. Fortunately, continuous root cause investigations into failures, design improvements of the slurry mixer and control logic enhancements are reducing the trips associated with failed slurry mixers. In 1999, only one coal interruption was due to a slurry mixer failure.

Particulate Removal

The particulate removal system is a critical component that has driven overall plant availability. In years such as 1998 and 1999, when the particulate removal system brought the plant down less than twice per year, overall plant availability was high. An aggressive improvement effort coupled with a disciplined quality assurance process has contributed to the improved availability of the particulate removal system. The type A downtime event in 1999 was not associated with the filter elements, but with the char return piping system to the first stage gasifier. The type B downtime event was associated with an experimental filter cluster. With the char return piping system permanently fixed and more conservative risk management with respect to experimental filters, future coal interruptions attributed to this system should be minimal.

Table 4.3B: Downtime Consequences of Critical Components by Operational Area

Plant Area	Number of Trips				
A - Downtime Consequence Greater than 2 weeks	**1996**	**1997**	**1998**	**1999**	**Total**
Scheduled Maintenance		2*	3	1	**6**
Particulate Removal	4	1	1	1	**7**
High Temperature Heat Recovery	4	1			**5**
Power Block				2	**2**
First Stage Gasifier	1	1	1		**3**
Chloride Scrubber		1			**1**
*Forced into an outage early. **Total**	**9**	**6**	**5**	**4**	**24**
B - Downtime Consequences 1 to 2 weeks	**1996**	**1997**	**1998**	**1999**	**Total**
First Stage Gasifier	1	2		1	**4**
Low Temperature Heat Recovery	2				**2**
Particulate Removal				1	**1**
Total	**3**	**2**	**0**	**2**	**7**
C - Downtime Consequences 72 hours -7 days	**1996**	**1997**	**1998**	**1999**	**Total**
Air Separation Unit	1		4		**5**
First Stage Gasifier		1		1	**2**
High Temperature Heat Recovery	1	1			**2**
Acid Gas Removal		1			**1**
Low Temperature Heat Recovery	1				**1**
Power Block	1				**1**
Slag and Solids Handling	1				**1**
Slurry Feed	1				**1**
Total	**6**	**3**	**4**	**1**	**14**
D – Downtime Consequence 24-72 hours	**1996**	**1997**	**1998**	**1999**	**Total**
First Stage Gasifier	2		4		**6**
Air Separation Unit		1	4		**5**
Particulate Removal	2		1	1	**4**
Slag and Solids Handling		2		2	**4**
High Temperature Heat Recovery		3			**3**
Power Block	1	2			**3**
Acid Gas Removal		1			**1**
Chloride Scrubber		1		1	**2**
Slurry Feed		1		1	**2**
Low Temperature Heat Recovery	1				**1**
Sulfur Recovery	1				**1**
Total	**7**	**11**	**9**	**5**	**32**
E – Downtime Consequences Less than 24 hours	**1996**	**1997**	**1998**	**1999**	**Total**
Power Block	9	10	5	3	**27**
Particulate Removal	4	5	4		**13**
Slurry Feed	1	2	4	6	**13**
First Stage Gasifier	4	1	1		**6**
High Temperature Heat Recovery	3	2	1		**6**
Air Separation Unit		1	2	1	**4**
Low Temperature Heat Recovery	2		2		**4**
Sulfur Recovery	2		1	1	**4**
Slag and Solids Handling	1	1		1	**3**
Acid Gas Removal		1			**1**
Chloride Scrubber			1		**1**
Total	**26**	**23**	**21**	**12**	**82**

Air Separation Unit

This reliability of this system has not been near that expected. In 1998, the air separation unit was responsible for 10 coal interruptions and more than 16 days of downtime. Although the air separation unit caused only one coal interruption in 1999, over 14 days of downtime was associated with this system. Since the demonstrated industry reliability of air separation units is relatively high compared to gasification processes, the Project's air separation unit should cause no coal interruptions. Although several improvements have been implemented to enhance the unit's reliability, this air separation unit is still not up to industry standards and additional improvements are being pursued.

High Temperature Heat Recovery

Coal interruptions due to this system have been virtually eliminated with only one incident in the last two years. However, the length of scheduled outages is often determined by the time required to clean the boiler tubes and perform the associated maintenance. Tube side deposits are tenacious and very hard. Mechanical and chemical cleaning methods have been improved to dramatically reduce the cleaning time, but improvements are still needed in this area and are being pursued.

The team approach utilized to address the four critical components outlined above, coupled with the plant's continually improving operating discipline, will ensure that fewer and fewer critical components show up on future critical component reports.