Tampa Electric Company
Polk Power Station IGCC Project
Project Status

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Over the last ten years, Tampa Electric Company has taken the Polk Power Station from a concept to a reality. We continue to make solid progress toward meeting our objective of generating low cost electricity in a safe, reliable, and environmentally acceptable manner. On September 30 of this year, we completed our third year of commercial operation. This date also marked the conclusion of the best quarter in our operating history with a gasification run of record duration in progress. Our 1995 and 1996 papers at this conference reported on the permitting, design, construction, staffing, and commissioning of the plant. Our 1997 paper presented efficiency data and our startup experiences. Last year's paper covered reliability statistics and presented the detailed results of alternate fuel testing. In this year's paper, we will provide an update on the reliability statistics and discuss in more detail some of the specific problems we have encountered and resolved.

1. BACKGROUND

PARTICIPANTS

Tampa Electric Company (TEC) is the owner and operator of Polk Power Station. TEC is an investor-owned electric utility, headquartered in Tampa, Florida. TEC has about 3650 MW of generating capacity. Over 97 percent of TEC's power is produced from coal. TEC serves over 500,000 customers in an area of about 2,000 square miles in west-central Florida, primarily in and around Tampa, Florida. TEC is the principal wholly-owned subsidiary of TECO Energy, Inc., an energy related holding company.

TECO Power Services (TPS), another subsidiary of TECO Energy, Inc., provided project management services for Polk Power Station during its design, construction, and startup phases. TPS is now concentrating on commercializing this IGCC technology as part of the Cooperative Agreement with the U.S. Department of Energy. TPS was formed in the late 1980's to take advantage of the opportunities in the non-regulated utility generation market. TPS currently owns and operates 2 natural gas fired power plants, a 295 MW plant in Hardee County, Florida, and a 78 MW plant in Guatemala. In addition, TPS has several other projects at various stages of development.

The project is partially funded by the U.S. Department of Energy (DOE) under Round III of its Clean Coal Technology Program.

OBJECTIVES

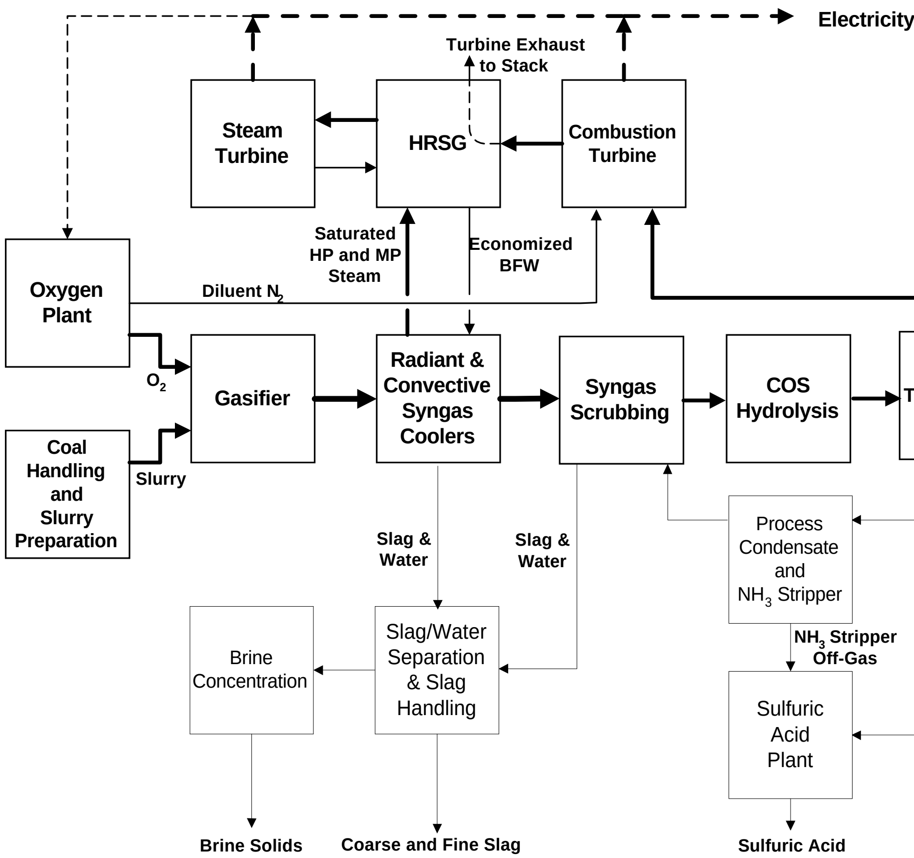
Polk Power Station is an integral part of TEC's generation expansion plan. TEC's original objective was to build a coal-based generating unit providing reliable, low-cost electric power. Integrated Gasification-Combined Cycle (IGCC) technology will meet those requirements.

Demonstration of the oxygen-blown entrained-flow IGCC technology is expected to show that such a plant can achieve significant reductions of SO_2 and NO_x emissions when compared to existing and future conventional coal-fired power plants. In addition, this project is expected to demonstrate the technical feasibility of commercial scale IGCC technology. Only commercially available equipment has been used for this project. The approach supported by DOE is the highly integrated arrangement of these commercially available pieces of hardware and systems in a new arrangement which optimizes cycle performance, costs, and marketability at a commercially acceptable size of nominally 250 MW (net).

TECHNICAL DESCRIPTION

A general flow diagram of the entire process is shown in Figure 1.

FIGURE 1
Polk Unit #1 IGCC Block Flow Diagram



This unit utilizes commercially available oxygen-blown entrained-flow coal gasification technology licensed by Texaco Development Corporation (Texaco). In this arrangement, coal is ground with water to the desired concentration (60-70 percent solids) in rod mills. The unit is designed to utilize about 2200 tons per day of coal (dry basis). An Air Separation Unit (ASU) separates ambient air into 95% pure oxygen for use in the gasification system and sulfuric acid plant, and nitrogen which is sent to the advanced combustion turbine (CT). The ASU is sized to produce about 2100 tons per day of oxygen and 6300 tons per day of nitrogen. Air Products provided the ASU.

This coal/water slurry and the oxygen are then mixed in the gasifier feed injector. They react in the gasifier to produce syngas with a heat content of about 250 BTU/SCF (LHV). The gasifier is designed to achieve greater than 95 percent carbon conversion in a single pass. The gasifier is a single vessel feeding into one radiant syngas cooler (RSC) which was designed to reduce the gas temperature to 1400°F while producing 1650 psig saturated steam.

After the RSC, the gas is split into two parallel convective syngas coolers (CSC), where the temperature is further reduced to less than 800°F and additional high pressure steam is produced. Next, the particulates and hydrogen chloride are removed from the syngas by intimate contact with water in the syngas scrubbers. The scrubbers are followed by a carbonyl sulfide (COS) hydrolysis unit which converts COS into hydrogen sulfide (H_2S), a sulfur compound which is later removed from the syngas. The COS hydrolysis unit was commissioned on August 30, 1999. It enables Polk Power Station to continue processing high sulfur feedstocks and still meet the more stringent emissions restrictions which went into effect on October 1, 1999. Following COS hydrolysis, most of the remaining sensible heat of the syngas is recovered in low temperature gas cooling by preheating clean syngas and heating steam turbine condensate. A final small trim cooler reduces the syngas temperature to about 100EF for the acid gas removal system.

The acid gas removal system is a conventional MDEA system which removes over 98% of the sulfur from the syngas. This sulfur is recovered as sulfuric acid. Monsanto provided the sulfuric acid plant. Sulfuric acid has a ready market in the phosphate industry in the central Florida area.

Most of the residual solids from gasification fall into a water pool at the bottom of the RSC and then into the slag lockhopper which discharges them from the system. These residual solids generally consist of slag (the inert mineral matter from the feed coal) and some unreacted carbon. These non-leachable products are saleable for blasting grit, roofing tiles, and construction building products. TEC has been marketing slag from its existing units for such uses for over 25 years.

All of the water from the gasification process is cleaned and recycled, thereby creating no requirement for discharging process water from the gasification system. To prevent the build-up of chlorides in the process water system, a brine concentration unit removes them in the form of marketable salts.

The key components of the combined cycle are the advanced combustion turbine (CT), heat recovery steam generator (HRSG), steam turbine (ST), and electric generators. The combined cycle General Electric provided the power block.

The CT is an advanced GE 7F machine adapted for syngas and distillate fuel firing. The initial startup of the power plant is carried out on low sulfur No. 2 fuel oil. Transfer to syngas occurs upon establishment of fuel production from the gasification plant. The exhaust gas from the CT passes through the HRSG for heat recovery, and leaves the system via the HRSG stack.

Emissions from the HRSG stack are primarily SO_2 and NO_x with lesser quantities of CO, VOC, and particulate matter (PM). SO_2 emissions are from sulfur species in the syngas which are not removed in the acid gas removal system. The CT uses nitrogen addition to control NO_x emissions during syngas firing. Nitrogen acts as a diluent to lower peak flame temperatures and reduce NO_x formation without the water consumption and treatment/disposal requirements associated with water or steam injection NO_x control methods. Maximum nitrogen diluent is injected to minimize NO_x exhaust concentrations consistent with safe and stable operation of the CT. Water injection is employed to control NO_x emissions when backup distillate fuel oil is used.

The HRSG is installed in the CT exhaust in a traditional combined cycle arrangement to provide superheated steam to the 130 MW ST. No auxiliary firing is done in the HRSG system. The HRSG high and medium pressure steam production is augmented by steam produced from the coal gasification plant's syngas coolers (HP and MP steam) and sulfuric acid plant (MP steam). All steam superheating and reheating is performed in the HRSG before the steam is delivered to the ST.

The ST is a double-flow reheat turbine with low pressure crossover extraction. The ST and associated generator are designed specifically for highly efficient combined cycle operation with nominal turbine inlet throttle steam conditions of approximately 1450 psig and 1000°F with 1000°F reheat inlet temperature.

The heart of the overall project is the integration of the various pieces of hardware and systems to increase overall cycle effectiveness and efficiency. In our arrangement, benefits are derived from using the experience of other IGCC projects, such as the Cool Water Coal Gasification Program, to optimize the flows from different subsystems. For example, low pressure steam from the HRSG and extraction steam from the ST supply heat to the gasification facilities for process use. The HRSG also receives steam energy from the syngas coolers and sulfuric acid plant to supplement the steam cycle power output. This steam is generated using boiler feedwater which had been economized in the HRSG. Additional low energy integration occurs between the HRSG and the gasification plant. Condensate from the ST condenser is returned to the HRSG/integral deaerator by way of the gasification area, where condensate preheating occurs by recovering low level heat. Probably the most novel integration concept in this project is our use of the ASU. This system provides oxygen to the gasifier in the traditional arrangement, while simultaneously using what is normally excess or wasted nitrogen to increase power output and improve cycle efficiency and also lower NO_x formation.

Part of our cooperative agreement with DOE is a five-year demonstration phase. During the first three years of this period, ten different types of coal or coal blends have been tested in the operating IGCC power plant. The results of these tests compare this unit's efficiency, operability and costs on each of these test coals against the design basis coal, a Pittsburgh #8. These results provide a menu of operating parameters and costs which can be used by utilities in the future as they make their selection on methods for satisfying their generation needs, in compliance with environmental regulations.

2. RELIABILITY GROWTH AND LOST PRODUCTION CAUSES

OVERALL

In its 3 years of commercial operation, the Polk Power Station gasifier has operated 15,350 hours. 4.2 million MWH of electricity have been generated from the syngas fuel it produced. It was on-line over 65% of the time for the last 2 years. Even when the gasifier was unavailable, the combined cycle was available for operation on distillate fuel most of the time. The combined cycle's availability was 91% for the last 2 years.

SPECIFIC HARDWARE PERFORMANCE RECORDS

Some of the Polk Power Station hardware performance records are:

Longest uninterrupted period of power generation from the combustion turbine:

> 52.1 days (7/20/98-9/10/98)
> Included 16 successful fuel transfers between syngas and distillate fuel

Longest uninterrupted gasifier run:

> 36.9 days (8/28/99-10/3/99)

Longest period of gasifier operation with interruptions of less than 8 hours duration:

> 50.6 days (7/21/99-9/10/99)
> The same gasifier burner was used throughout. It was still suitable for service afterward.

Gasifier liner life:

> 451 days operation (4/24/97-5/21/99) - Equivalent to 12 years at 80% on-stream factor.
> This was the first commercial liner. It was in the gasifier for over 2 years, and experienced 73 gasifier startups (thermal cycles) with 10 different fuels or fuel blends.

Best Operating Quarter

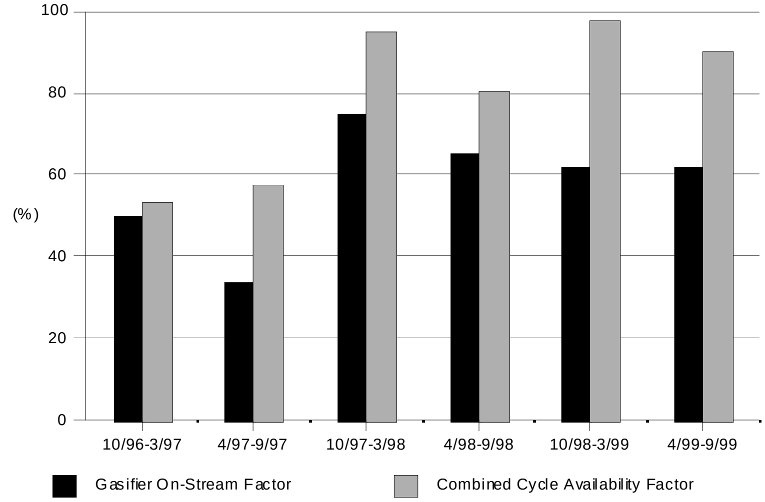
> Third Quarter, 1999
>> Gasifier On-Stream 84.4% of the time
>> 550,000 MWH generated from syngas

Fuels Tested

> Pittsburgh #8 Coal - 3 mines
> Illinois #6 Coal - 2 mines
> Kentucky #11 Coal
> Kentucky #11 Coal Blends - 2 different blends
> Kentucky #9 Coal
> Petroleum Coke Blend

SEMI-ANNUAL PERFORMANCE STATISTICS

FIGURE 2
Key Reliability Statistics - 6 Month Periods Since Initial Commercial Operation



Gasifier on-stream factor and combined cycle availability were only about 50% during the first six months of commercial operation. This is to be expected with any new facility.

During the second six-month period of commercial operation, availability of the gasifier and combined cycle were both very low due primarily to two issues discussed in our previous papers. The worst was damage to the combustion turbine on two occasions from particulates in the syngas. On the first occasion, the particulates were coal ash from tube leaks in a raw gas/clean gas exchanger. On the second occasion, the particulates were primarily pipe scale from the syngas line. The problematic exchangers were removed and a filter has been installed immediately upstream of the turbine to catch the pipe scale. A recent inspection of the turbine confirmed that these problems are behind us. The second significant issue during this 6 month period was seal leakage in the radiant syngas cooler. One seal was improperly manufactured, and it was repaired. Operating procedures were developed which effectively deal with other smaller seal leaks.

During the third six-month period of commercial operation (October, 1997, through March, 1998) the station experienced excellent gasifier on-stream factor (75%) and combined cycle availability (95%). This was consistent with our expectations for this point in the plant's life cycle.

Over the last 12 years, the combined cycle has continued to perform well, although its availability suffered slightly during the second and third quarters of 1998 (the fourth six-month period of commercial operation) due to a planned outage and steam turbine condenser tube leaks caused by human error. However, the gasifier's on-stream factor has only averaged about 63% over the last 12 year, which does not met expectations. Three specific problems have had the greatest impact. They will be discussed in more detail in the next section of this paper. They are:

a) Fuel changes causing slag removal and slurry feed problems,
b) Raw syngas line leaks, and
c) Convective Syngas Cooler pluggage

LOST PRODUCTION CAUSES

Table 1 compares the lost production causes and their impact for our second and third years of commercial operation. Although we have several remaining challenges, we were very successful in significantly reducing or eliminating many causes of lost production. Each of the lost production causes is discussed in next section of the paper.

TABLE 1
Lost Production Days

LOST PRODUCTION CAUSE	**2nd Year** **10/97-9/98**	**3rd Year** **10/98-9/99**	**COMMENTS**
RESOLVED AND NON-RECURRING:			
Syngas Piping Erosion-Scrubber Outlet (Wet)	4	23	Resolved by COS Hydrolysis
Low Sulfur Blend Fuels	-	18	Resolved by COS Hydrolysis
Black Water Piping Erosion	14	-	Resolved by Redesigns
Syngas Piping Erosion-Scrubber Inlet (Dry)	-	13	Resolved by Redesign
Radiant SGC - Dome Seal Leak	14	-	Resolved by New Techniques
Radiant SGC - Tube Leak (Flow Transmitter)	-	7	Non-Recurring
CONTINUING CHALLENGES:			
Convective SGC Boiler Pluggage	35	36	The Major Challenge
Fuel Tests / Fuel Characteristic Changes	10	5	Continuing Challenge
Miscellaneous Forced Outages/Extensions	33	12	Impact Significantly Reduced
PLANNED OUTAGES:			
Gasifier Refractory Replacement	-	16	Biannual Planned Outage
Combustion Turbine Inspection	-	10	Annual Planned Outage
TOTAL	109	140	

Note on Table 1: Lost production days in Table 1 are credited to the major cause of each outage or the major work performed during each outage. However, there is typically ongoing maintenance in several areas during every outage longer than 2 days. For example, the annual combustion turbine inspection during the second year of commercial operation took place during one of the outages when the convective SGC boilers were cleaned and repaired. Also, the refractory replacement during the third year of commercial operation took about 25 days, but part of this work occurred during that year’s 10 day combustion turbine inspection. Consequently, some of the lost production causes identified in Table 1 would have had greater impact had the plant not been down for another reason.

RESOLVED AND NON-RECURRING PROBLEMS:

Syngas Scrubber Overhead Piping Failures, and Low Sulfur Blend Fuel Problems

Compensating for higher than design COS production from the gasifier led to scrubber overhead piping failures and forced us to gasify some troublesome low sulfur fuel blends as explained below. These resulted in 4 days of lost production in our second year of commercial operation and 41 days of lost production in our third year of commercial operation. The successful commissioning of our COS hydrolysis unit on August 30, 1999, put an end to this cause of lost production.

Polk's Texaco gasification system produces more than expected of one specific sulfur compound, carbonyl sulfide (COS). Our acid gas removal system, MDEA, does not remove COS from the syngas, so any COS produced is converted to SO_2 emissions in the HRSG stack. This was not a problem with the relatively expensive design coal, Pittsburgh #8, since it only contained about 2½% sulfur. However, in an effort to reduce the cost of electricity for our ratepayers and to meet DOE requirements, we began testing various less expensive feedstocks such as Illinois #6 and Kentucky #11 coals with sulfur content up to 3.5%. These higher sulfur coals produced proportionally more COS, so our SO_2 emissions from the HRSG stack would have exceeded our permit limits except for one factor: we discovered a method during early operation to reduce the COS content of the syngas by about 30%. Specifically, by flooding the syngas scrubber overhead lines with particulate laden water, about 30% of the COS is converted (hydrolyzed) to H_2S as the syngas passes through them. This probably occurs by the reaction: $COS + H_2O$! $CO_2 + H_2S$. Flooding the scrubber overhead lines to reduce COS enabled us to operate on the higher sulfur less expensive Illinois #6 and Kentucky #11 seam coals from mid-December, 1997, until mid-November, 1998, without exceeding our emissions permits. See US Patent Application 60/112,335.

Flooding the scrubber overhead piping had one significant drawback: the scrubber overhead piping system was not designed for this turbulent three-phase operation. After only four months of operation in this manner, we experienced the first very small localized syngas leak. The first leaks were pinholes which could be easily repaired. With each repair, we reinforced and/or hard-surfaced the damaged area and intensified testing. The damage was very localized, so conventional ultrasonic testing was not completely effective in identifying damaged areas. In response, we developed an improved testing technique. We also began planning replacement of the piping system and accelerated our plans to install a conventional COS hydrolysis unit. Finally, in November, 1998, a larger leak occurred which prompted us to take a 23 day forced outage to replace the entire piping system with the upgraded materials. We also decided to no longer operate with the piping system flooded (even though the new piping system could probably accommodate it). Instead, we elected to process lower sulfur coals until we could install a COS hydrolysis unit to convert the COS to H_2S which is removed by our MDEA.

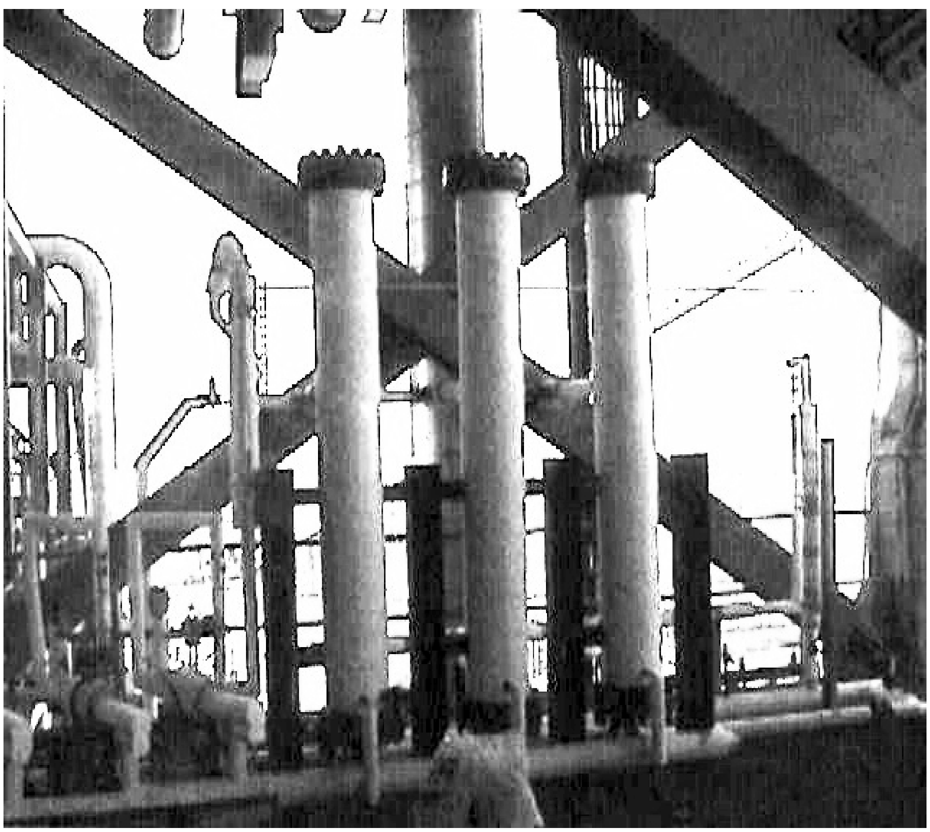
The need to temporarily gasify lower sulfur fuels prompted us to test some blends of higher sulfur Kentucky #11 (our base fuel) with lower sulfur fuels to produce a reasonable cost feedstock with an average sulfur content of about 22%. These blends introduced unexpected problems before a suitable blend was found. On 5 occasions, large slag agglomerates plugged the slag removal system at the bottom of the radiant syngas cooler, and on 1 occasion, slurry solids from a blend settled in the gasifier feed pump suction line, starving the pump. Together, problems with the low sulfur fuel blends resulted in 18 days of lost gasifier production.

COS Hydrolysis

The process design for the COS hydrolysis was done at Polk by TEC personnel. Catalyst selection was the result of the testing we performed on the actual raw syngas stream. Three parallel test reactors were used so competing catalysts could be compared side-by-side under the same actual plant conditions. Six catalysts were tested, two of which proved satisfactory.

The test reactors are shown in Figure 3.

Figure 3
COS Hydrolysis Test Reactors



The commercial COS hydrolysis unit is shown in Figure 4. A knockout drum in the foreground protects the catalyst in the reactor immediately behind it. The structure on the left contains a small superheater and the bypass and isolation valves used for startup.

Figure 4
Commercial COS Hydrolysis Unit

Figure 5 shows the COS concentration in the syngas stream dropping from 300 ppmv to less than 10 ppmv as the reactor bypass valve is slowly closed during initial commissioning of the COS hydrolysis system on August 30, 1999. The COS concentration is measured by on-line gas chromatograph. The catalyst has shown no sign of degradation in the first 40 days of operation.

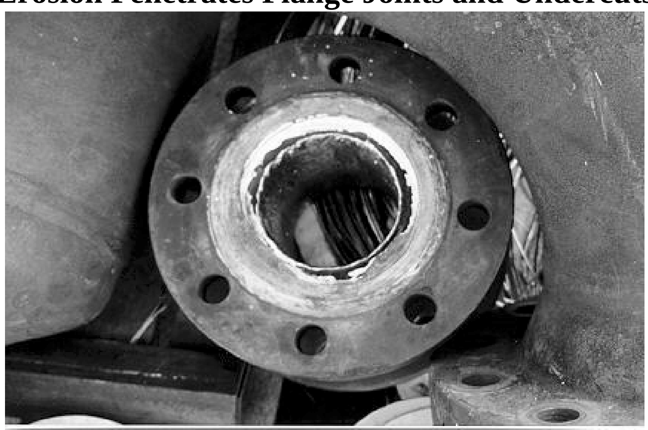
Figure 5
COS Concentration During Initial Commissioning

Black Water Piping Erosion

Another leading problem during the second year of commercial operation was black water piping erosion which caused 8 forced outages resulting in 14 days of lost production. It caused no lost production in the third year of commercial operation, so this problem seems to be under control.

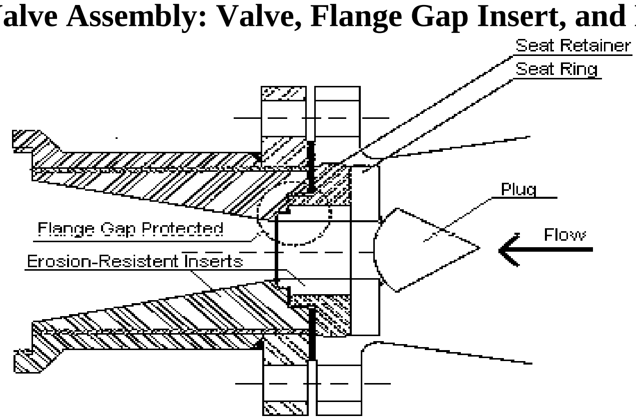
Each black water piping erosion failure is localized and has a relatively unique and sometimes interesting mechanism. For example, when the piping downstream of certain flow control valves exhibited high erosion rates, our first response was to coat the line and valve body with erosion resistant material. We found the erosion to be so persistent that it penetrated the joint between the flanges connecting the valve with the downstream piping and undercut the hard facing (Figure 6). This resulted in almost as rapid a failure as before.

FIGURE 6
Black Water Erosion Penetrates Flange Joints and Undercuts Hard Facing



The solution was to machine an assembly which consisted of the downstream piping spool and an insert to bridge the gap between it and the valve body (US Patent Application 09/243,331).

FIGURE 7
Erosion Resistant Valve Assembly: Valve, Flange Gap Insert, and Downstream Spool



Other Resolved and Non-Recurring Problems

Scrubber Inlet Piping Erosion The syngas scrubber inlet piping system experienced some deterioration due to simple erosion by the dry particulate laden syngas from the syngas coolers. Total lost production from this source was 13 days. As with the scrubber overhead piping, most erosion was localized at 90 degree bends and branches. All vulnerable areas of this piping system were upgraded in May, 1999, and there have been no problems since.

Radiant Syngas Cooler Dome Seal Leak The radiant syngas cooler is a waterwalled pressure vessel in which the sealed waterwall prevents high temperature syngas from contacting the vessel shell. In the first year of commercial operation, a leak in an inaccessible seal required a 29 day outage to repair. In November, 1997, during the second year of commercial operation, a different seal developed a leak requiring a 14 day outage to repair. Shortly after the second incident, we developed operating techniques which have precluded any subsequent lost production from this source.

Radiant Syngas Cooler Tube Leak Flow transmitters monitor cooling water flow to a few critical radiant syngas cooler waterwall sections. We experienced one waterwall tube leak due to a complicated sequence of events initiated by a failure of one of these transmitters. This cost 7 days of lost production. A mechanical stop is used to prevent recurrence.

CONTINUING CHALLENGES

Convective Syngas Cooler Plugging

Polk Power Station has horizontal fire-tube convective syngas coolers at the exit of the radiant syngas cooler. During both the second and third years of commercial operation, we suffered 35 and 36 days of lost production due to pluggage of these exchangers. Purging, cooling, cleaning, reheating, and restarting take 3 to 4 days.

This pluggage occurs via two mechanisms. First, large ash agglomerates spall from the inlet duct which instantaneously plug several tubes. This has been predominant at startup. Modified startup procedures appear to mitigate this source of plugging. The second is the gradual build-up of deposits during operation. Ash constituents of some of our fuels may accelerate this pluggage. Some recent configuration changes seem to help reduce this pluggage rate.

We monitor the progression of the pluggage with the differential pressure across the exchangers. Significant tube damage occurred on one occasion due to erosion from the pluggage, and some minor damage occurred on another occasion, so we know approximately how much pluggage we can tolerate before we must shut down for cleaning. We can now operate 25 to 40 days between cleanings. We hope that our recent changes in configuration and operating procedures will enable us to operate 45 to 60 days or more between cleanings. If not, other options are being evaluated.

Fuel Tests / Fuel Characteristic Changes

The need to temporarily gasify lower sulfur coals in response to the problem with the syngas scrubber overhead piping system prompted us to test some blends to produce a reasonable cost feedstock with an average sulfur content of about 22%. These blends introduced unexpected problems costing 18 days of lost production during the third year of commercial operation as previously discussed. In addition to this, we routinely test promising fuels or fuel blends in an effort to identify the lowest cost feedstock for the benefit of our ratepayers and to satisfy our requirements to the Department of Energy under our Cooperative Agreement to provide alternate fuel test results. This testing has resulted in slurry feed and slag removal problems costing 10 days of lost production in Polk's second commercial year and 5 days of lost production in the third commercial year.

There is no single simple solution to problems resulting from fuel changes. We have made modifications to the mechanical and process configuration of the slag removal system to help cope with large slag agglomerates. We identified a problem with one of the outside coal testing laboratories that provided critical analytical data on fuel shipments. Texaco is helping us apply some complimentary methods of characterizing slag viscosity. The ultimate solution to these difficulties probably will only come when we find a suitable feedstock and gain longer term operating experience on it.

Miscellaneous Minor Lost Production Causes

There were 23 miscellaneous incidents in the second commercial year of operation which cost 33 days of lost production. In the third commercial year, there were 22 such incidents, but their impact was significantly reduced to 12 days of lost production. A typical example is the slurry feed pump. The gasifier's slurry feed pump failed on one occasion during operation due to internal erosion/corrosion of the parts in contact with the coal/water slurry. Relatively high rates of metal loss in these parts had previously been noted. These parts were replaced with components fabricated with more corrosion-resistant materials. This has at least tripled the life of these parts. Regular maintenance and parts replacement will still be required on the pump every 1 to 3 months, but the alarmingly high rates of metal loss have been eliminated.

We still will experience occasional forced outages due to such problems, but they seem to be under control. We have taken appropriate corrective action wherever practical in this "miscellaneous" category, so we expect continued improvement. However, such sources of lost production can never be entirely eliminated.

PLANNED OUTAGES

Polk Power Station expects a 20 to 30 day planned outage every year. Activities during this outage typically center on the combustion turbine and gasifier refractory.

Gasifier Refractory Replacement

During the 1999 planned outage, routine inspection revealed that a section of the gasifier refractory had failed during the previous shutdown, so gasifier startup was delayed an additional 22 weeks to rebrick the gasifier. That liner (Polk's first high quality liner) had survived 451 operating days of service across 755 calendar days on 10 different coals and/or blends through 74 startups. We had hoped it would last until fall of 1999, even though we knew it was severely worn. Nevertheless, its performance was satisfactory considering the service it had seen. We expect at least 50% longer refractory life when we find an economically attractive and consistent feedstock and extend the mean gasifier run length. This will enable us to achieve our target 2 year liner life.

FIGURE 8
Failed Refractory Section
Excellent Condition of Backup Bricks Indicates the Failure Occurred During Cool-Down

Combustion Turbine Inspection

We perform a combustion hardware inspection every 8,000 operating hours with more extensive hot gas path inspections at 24,000 hour intervals in accordance with GE recommendations. Our 16,000 hour combustion hardware inspection in May, 1999, revealed the following:

- End covers exhibited cracks due to a manufacturing defect. They were replaced.
- Combustion liners exhibited expected minor cracking. Liners and transition pieces were replaced and the old parts are being refurbished.
- Very light deposits had accumulated on the combustion liners, nozzles, and buckets since the last inspection. Deposit formation rate was significantly reduced compared to previous inspections, indicating the new syngas filter is performing as expected.
- Some craze cracking was observed on the first stage bucket coating. These may have to be replaced in next year's outage.
- No problems were observed in the compressor but it was only marginally accessible for boroscope inspection, so this is not considered conclusive. There is a history of failure of the fourteenth compressor stage in our combustion turbine model.

Other Inspection Results

Much of the gasification plant equipment was carefully inspected, some of it for the first time since initial operation. Virtually all of it was found to be in excellent condition.

The radiant syngas cooler tubes showed no indication of metal loss. Some seals in the Radiant Syngas Cooler were modified, and these changes have significantly reduced the severity and frequency of warm spots on the RSC shell.

We detected significant thinning of the gasifier feed slurry piping at elbows and branch connections. The most critical of these have already been replaced with improved materials, and the remainder will be upgraded by the end of 1999.

FIGURE 9
New Slurry Piping Elbow

3. PLANS FOR 1999-2000

The following are some of the significant activities planned for Polk Power Station for the remainder of 1999 and into 2000.

1. Redouble efforts to reduce/eliminate **convective syngas cooler tube pluggage**.

2. Upgrade the **brine concentration system** to improve its reliability and lower overall plant heat rate. The majority of the brine concentration originally was accomplished via a vapor compression cycle. However, the vapor contained sufficient corrosive brine to make the compressor/blowers inoperable. Since the blowers have deteriorated, the system has been operated as a much less efficient direct evaporation system using low pressure steam. In late 1999, a vapor scrubber will be added. We expect this to clean the vapor so a blower can function. Once this is demonstrated, a new blower will be added in 2000 to return brine concentration to its original vapor compression configuration.

3. Upgrade the **slag handling system** to reduce O&M costs, to produce a more valuable byproduct slag, and to enable selective recycling of some fractions of the current slag product to reduce heat rate. The design for the revised system was based on the alternate fuel test results to date. Detailed design for these upgrades has been completed and much of the equipment has been purchased. The system will be installed in 2000.

4. Identify a consistent, economical base coal for normal operation and continue selective **testing of alternate fuels** to lower Polk Power Station's overall busbar cost. We expect to begin initial testing of some petroleum coke blends in late 1999 now that COS hydrolysis has been successfully commissioned.

4. CONCLUSIONS

The root cause of 30% of Polk Power Station's forced outage time in its third year of commercial operation was high carbonyl sulfide production. This has been eliminated by the successful commissioning of our COS hydrolysis unit. Many other less significant problems were either entirely eliminated or significantly reduced. However, convective syngas cooler tube plugging remains a major outstanding challenge. Steps are being taken to deal with the CSC pluggage, but that outcome is not certain. Nonetheless, we expect significant improvement in our fourth year of operation. This should bring us closer to reaching our ultimate commercial goals in the areas of high reliability and efficiency with low emissions and busbar cost.