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TAMPA ELECTRIC COMPANY

TAMPA ELECTRIC INTEGRATED GASIFICATION COMBINED-CYCLE PROJECT

PROJECT PERFORMANCE SUMMARY
CLEAN COAL TECHNOLOGY DEMONSTRATION PROGRAM

JUNE 2004

Tampa Electric Company

Tampa Electric Integrated Gasification Combined-Cycle Project

Project Performance Summary
Clean Coal Technology Demonstration Program

Advanced Electric Power Generation

Tampa Electric Integrated Gasification Combined-Cycle Project

The Tampa Electric IGCC project proved to be an environmental showcase and moved IGCC technology closer to mainstream market acceptance.

Overview

Tampa Electric Company (Tampa Electric) successfully completed a five-year demonstration of a 250-MWe integrated gasification combined-cycle (IGCC) power plant based on Texaco's pressurized, oxygen-blown, entrained-flow gasifier. Tampa Electric worked with the local community, state organizations, and environmental groups to make the project an environmental showcase, and engaged the U.S. Department of Energy (DOE) and the technical community to move IGCC closer to mainstream market acceptance. Both of these goals were met.

This project is part of DOE's Clean Coal Technology Demonstration Program (CCTDP) established to address energy and environmental concerns related to coal use. DOE sought cost-shared partnerships with industry through five nationally competed solicitations to accelerate commercialization of the most promising advance coal-based power generation and pollution control technologies. The Tampa Electric project presented here was one of 13 selected in May 1989 from 48 proposals submitted in response to the program's third solicitation.

The 250-MWe IGCC demonstration plant, Polk Power Station (PPS) Unit No. 1, consistently achieved over 97% sulfur removal when operating on high-sulfur coal and petroleum coke (petcoke) feedstocks. PPS's nitrogen oxide (NO_x) emissions, typically 0.7 lb/MWh (0.07 lb/10^6 Btu) were a fraction of the 1.6 lb/MWh New Source Performance Standards (NSPS) for power plants. Particulate matter (PM) emissions were especially low at 0.04 lb/MWh (0.004 lb/10^6 Btu). Also, the system operated at a heat rate of 9,650 Btu/kWh, which is superior to conventional coal-fired plants.

Polk's gasifier on-stream factor reached acceptable levels of 70–80% after 2½ years of working through problems normally encountered in first-of-a-kind demonstration plants. After only 1½ years, the availability of the unit to deliver power to customers was approximately 90%. This unit availability showed the flexibility of IGCC systems, which can shift to standby fuels, such as natural gas or distillates, during gasifier down times.

This project, which continues to operate commercially, has been the recipient of numerous environmental and technological achievement awards and recognition. These include the Ecological Society of America Corporate Award, the Florida Audubon Society Corporate Award, *Power* magazine's 1997 Power Plant of the Year Award. The plant was inducted into the *Power* magazine Power Plant Hall of Fame.

The Project

The 250-MWe Tampa Electric demonstration has its roots in the 100-MWe Coolwater IGCC Project sponsored by an industry consortium in the early 1980s. While the Coolwater Project did not fully integrate major subsystems, it established the promise of the Texaco gasifier in an IGCC mode.

In 1989, Tampa Electric began taking the PPS from concept to reality by adopting the essence of the Coolwater IGCC technology and transforming it into a fully integrated commercial plant design. In an unprecedented effort to satisfy environmental concerns, Tampa Electric engaged an independent committee comprised of community representatives to select the demonstration site. The committee ultimately selected an abandoned phosphate mine in southwestern Florida. Tampa Electric largely converted the phosphate mining spoils to wetlands and uplands and integrated a portion into a cooling reservoir for the PPS.

Detailed design began in April 1993. Site work ensued in August 1994. The gasification system achieved "first fire" in July 1996. Commercial operation commenced on September 30, 1996. September 30, 2001, marked the fifth year of commercial operation and the conclusion of the demonstration period. During the demonstration, over 2,500 visitors from 20 countries toured the PPS, sparking worldwide interest in adopting IGCC for a range of applications.

Over the five-year demonstration period, Tampa Electric carried out a systematic campaign to address and resolve the usual technical issues accompanying first-of-a-kind plants. Major objectives included attaining reasonable availability for the PPS IGCC, demonstrating the ultra-low pollutant emissions capability of coal-based IGCC, and identifying areas for improvement to enhance cost and performance of subsequent plants. Tampa Electric met these objectives and the PPS continued in commercial service following the demonstration.

The project evaluated the effect of 11 separate bituminous coals, petcoke, petcoke/coal blends, and biomass on plant performance. A petcoke/coal blend was determined to offer optimum service. This blend has been adopted for commercial service following the demonstration.

Project Sponsor
Tampa Electric Company

Additional Team Members
Texaco Development Corporation – gasification technology supplier
General Electric Corporation – combined-cycle technology supplier
Air Products and Chemicals, Inc. – air separation unit supplier
Monsanto Enviro-Chem Systems, Inc. – sulfuric acid plant supplier
TECO Power Services Corporation – project manager and marketer
Bechtel Power Corporation – architect and engineer

Location
Mulberry, Polk County, FL (Tampa Electric Company's Polk Power Station, Unit No. 1)

Technology
Advanced IGCC system using Texaco's pressurized, oxygen-blown entrained-flow gasifier technology

Plant Capacity/Production
316 MWe (gross), 250 MWe (net)

Coal
Illinois #5 & #6, Pittsburgh #8, West Kentucky #11, Kentucky #9, Indiana #5 & #6, (2.5-3.5% sulfur); petcoke; petcoke/coal blends; and biomass

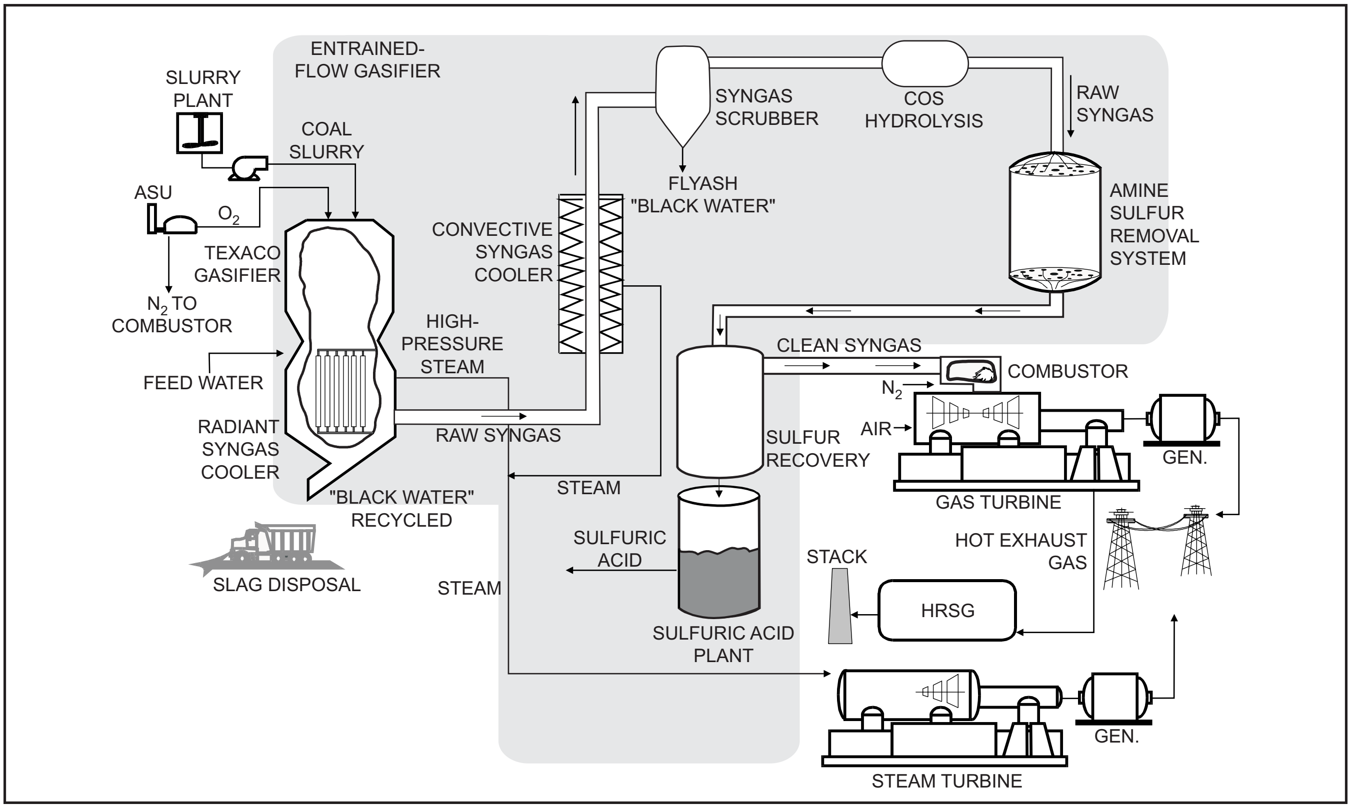
Demonstration Duration
September 1996 – September 2001

Project Funding

Total*	$303,288,446	100%
DOE	$150,894,223	49%
Participant	$152,394,223	51%

* Additional project cost overruns were funded 100% by the participant for a total project funding of $606,916,000.

The Technology



An air separation unit (ASU) cryogenically separates ambient air into its major constituents, oxygen (O_2) and nitrogen (N_2). The bulk of the O_2 stream produced by the ASU (96% pure) is used in the gasifier and approximately 2.5% of the O_2 is consumed in the sulfuric acid plant (SAP). Most of the N_2 produced goes to the combustion turbine to dilute the synthesis gas fuel for NO_x abatement and to increase power production by 15% (25 MW) as the N_2 expands through the turbine. A small portion of the N_2 is applied for purges and seals.

Coal (or other solid fuels) and water are processed in a rod mill to produce a 62–68% solids coal/water slurry concentration. The slurry is injected along with O_2 into the gasifier, which typically operates at 375 pounds per square inch gage (psig) pressure. Partial oxidation of the feedstock generates temperatures of 2,400–2,700 °F and transforms the slurry water into steam. The heat, pressure, and steam break the bonds between feedstock constituents and precipitate chemical reactions that produce synthesis gas (syngas) — primarily hydrogen (H_2) and carbon monoxide (CO). Sulfur is primarily converted to hydrogen sulfide (H_2S) and secondarily to carbonyl sulfide (COS). Minerals in the feedstock (ash) largely separate and leave the bottom of the gasifier as an inert, marketable glassy slag (frit). The remaining portion of the ash (flyash) is either entrained in the raw gas stream or separates with the frit.

The raw gas stream produced in the gasifier passes first through a radiant syngas cooler (RSC) just below the gasifier and then through two parallel fire-tube convective syngas coolers (CSC). The RSC together with the CSCs produce about two-thirds of the IGCC system high-pressure steam and drop the raw gas temperature to 700–800°F. Flyash and hydrogen chloride (HCl) are removed from the raw gas in an intensive water scrubbing step in syngas scrubbers. COS in the raw gas stream is converted through hydrolysis to the more easily removed H_2S. Nearly all the remaining heat in the raw gas stream is recovered by pre-heating clean syngas and boiler feedwater.

A circulating amine (MDEA) solution-based reactor strips H_2S from the raw gas stream. The H_2S is sent to a sulfur recovery system that oxidizes the H_2S to produce 200 tons per day of 98% pure sulfuric acid.

The flyash removed from the raw gas stream, which contains up to 30% carbon, is recycled to the slurry preparation system. This flyash includes the 40% fraction separated in the RSC and the 60% fraction captured by the syngas scrubbers. The “grey” process water resulting from the flyash separation is used in the syngas scrubbers.

The power block employs a GE-7FA combustion turbine, which generates 192 MW on syngas and diluent N_2 or 160 MW (gross) on distillate fuel. A heat recovery steam generator (HRSG) uses the 1,065 °F combustion turbine exhaust gas to preheat boiler feedwater, generate low pressure steam for the gasifier, produce about one-third of the plant's high pressure steam, and superheat and reheat all the plant's steam for the steam turbine. The steam turbine uses 1,450 psig; 1,000 °F steam to produce 123 MW (gross). The oxygen plant consumes 55 MW and auxiliaries require 10 MW, resulting in 250 MWe (net) power to the grid.

The clean syngas composition averages for both coal- and petcoke-based operation is provided in Table 1. There was relatively little variation in syngas composition among seven coals operating with three different feed injectors. Similarly, several petcoke blends displayed little syngas composition variation among them. However, the average syngas composition difference between coal- and petcoke-derived syngas is statistically significant.

TABLE 1. SYNGAS COMPOSITION

Component	Units	Coal Average	Petcoke Average
H_2S + COS	ppmv	415	282
CH_4	ppmv	532	244
CO	Vol %	44.06	48.29
CO_2	Vol %	14.73	13.61
H_2	Vol %	37.95	34.02
N_2	Vol %	2.28	3.02
Ar	Vol %	0.88	1.00
Total	Vol %	100.00	100.00
HHV	Btu/scf	263.2	264.0
LHV	Btu/scf	244.3	247.0

Radiant syngas cooler installation

Results Summary

Environmental Performance

- The PPS IGCC removed over 97% of feedstock sulfur when operated on low-cost, high-sulfur coal, petcoke, and coal/petcoke blends.
- Typical NO_x emissions were 0.7 lb/MWh, which were below the permitted limit of 0.9 lb/MWh and far below NSPS NO_x levels of 1.6 lb/MWh for electric utility units.
- PM emissions were typically less than 0.04 lb/MWh (near zero), which is about 5% of those from conventional coal-fired plants equipped with electrostatic precipitation.
- CO emissions were permitted at 99 lbs/hr and averaged 7.2 lbs/hr; volatile organic compound (VOC) emissions were negligible; and mercury emissions (on coal) without controls were half the potential release based on mercury levels in the coal.

Operational Performance

- The PPS combustion turbine logged 34,800 hours over the 5-year demonstration, of which 28,500 hours were syngas-fired. Syngas firing produced over 8.6 million MWh of electricity.
- The gasifier on stream factor steadily increased, reaching 70–80% after 2½ years. Overall PPS availability, with distillate fuel as backup, averaged 90% after 1½ years.
- Carbon conversion was lower than expected — low- to mid-90% range versus the expected 97.5–98%. This rendered the ASU design capacity inadequate because of a need to recycle flyash to increase carbon conversion, lowering plant output to 235 MWe net; and required doubling the capacity of the solids handling system.
- Essentially all carbon steel parts in contact with the slurry feedstock had to be replaced or coated with corrosion resistant materials, and high-wear areas had to be hardened.
- Refractory liner life was problematic during the demonstration largely due to frequent fuel changes and attendant undesirable fluctuations in operating conditions; but, a coal/petcoke blend was identified to eliminate the problem in commercial service.
- In the high-temperature heat-recovery systems downstream of the gasifier, the radiant syngas cooler seals underwent design changes or corrections for fabrication defects; convective syngas coolers required geometric improvements to reduce plugging; and raw gas/clean gas heat exchangers required removal due to stress corrosion.
- A COS hydrolysis unit had to be added to meet sulfur reduction targets and an ion exchange unit had to be added to prevent buildup of heat stable salts in the MDEA unit.
- "Y" strainers and a 10-micron filter system proved critical to turbine protection from pipe-scale during startups.

Economic Performance

- A capital cost of $1,650/kW (2001$) was estimated for a new 250 MWe (net) IGCC plant based on the PPS configuration incorporating lessons learned; a capital cost of $1,300/kW (2001$) was estimated for a new plant that allowed for benefits derived from economies of scale, technology improvements, and replication of proven configurations to eliminate costly reinvention.

Environmental Performance

SO_2 Emissions. PPS removed over 97% of the sulfur in the feedstock when operated on low-cost, high-sulfur coals, petcoke, and blends. A material balance on a 3.0% sulfur coal, depicted in Figure 1, showed that 6.9% of the sulfur (S) is locked up in the inert frit leaving the gasifier. The MDEA acid gas system removed 97.5% of the H_2S from the raw syngas. COS hydrolysis to H_2S proved critical to maintaining high sulfur capture efficiency because 5% of the sulfur in coal feedstocks was converted to COS (twice the amount expected) and the MDEA system was not effective in removing COS. The SAP recovered 99.7% of the sulfur it was fed. Sulfur emissions predominately were as SO_2 from the HRSG. The SAP released sulfur as sulfuric acid (H_2SO_4), but it only represented about 0.25% of the total sulfur.

The high-efficiency sulfur capture is intrinsic to gasification processes which produce concentrated gas streams, with high-partial-pressure sulfur compound constituents, relative to combustion systems. Combustion systems typically produce gas flows 100 times greater than comparable capacity IGCC systems. Partial pressures for the sulfur compound (H_2S) constituent in an IGCC raw gas stream are approximately 100 times greater than the sulfur compound (SO_2) found in typical combustion systems.

NO_x Emissions. Fuel-bound nitrogen plays no part in NO_x emissions from IGCC systems. The gasifier converts fuel-bound nitrogen to nitrogen gas (N_2) or compounds such as ammonia, which are readily removed from the syngas before being fed to the combustion turbine. NO_x emissions are due solely to "thermal" NO_x generated as a result of the combustion turbine's elevated firing temperatures. Diluent N_2 lowers NO_x emissions by reducing the heating value of the syngas, which in turn lowers turbine firing temperatures.

Permit limits on NO_x emissions during the PPS demonstration period were 25 parts per million by volume on a dry basis (ppmvd) corrected to 15% O_2. This value equated to 35 parts per million (ppm) actual, measured at the stack by a continuous emissions monitor (CEM). The permit limit is also equivalent to about 220 lb/hr NO_x or 0.9 lb/MWh. Typical Polk IGCC NO_x emissions were about 0.7 lb/MWh, or below 30 ppm as measured by a CEM. These emission rates are a fraction of those from conventional coal-fired power plants equipped with low-NO_x combustion systems. NSPS for electric utility units is 1.6 lb/MWh regardless of fuel type.

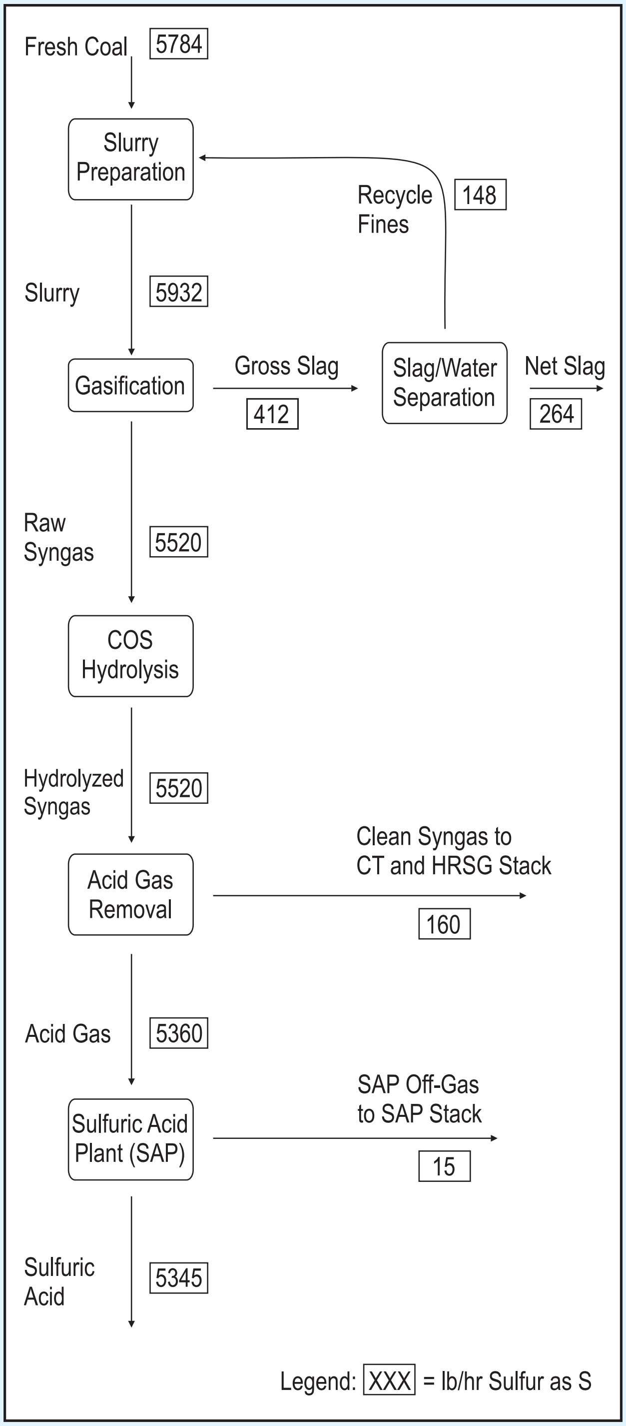


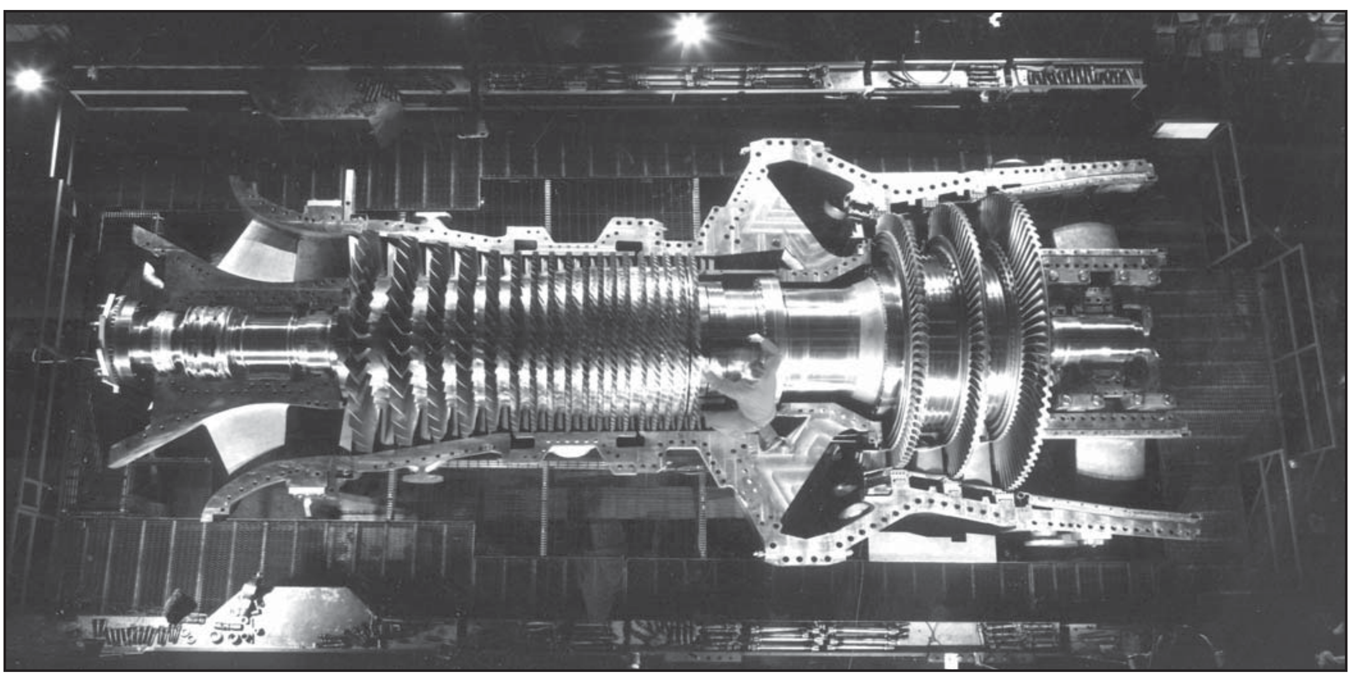
Figure 1. Sulfur Distribution

Despite excellent NO_x emission performance, the permit level at the PPS was revised to 15 ppmvd at 15% O_2, or 21 ppm by CEM as of July 2003. The revision was based on Best Available Control Technology for natural gas-based systems. This revision represents a major challenge for the coal-derived, syngas-based PPS. The PPS can neither apply selective catalytic reduction (SCR) nor the advanced dry low-NO_x (DLN) combustors used in state-of-the-art natural gas-fired combustion turbines. SCR causes precipitation of sulfur compounds on the HRSG surfaces because of residual sulfur in the syngas. DLNs rely on pre-mix of large volumes of air with the natural gas fuel prior to combustion to lower firing temperature. Syngas-based systems cannot use this principle. The high-flame-speed of the syngas hydrogen constituent would ignite upon injection of pre-mix air, drawing the flame back into the pre-mix zone. Options for the PPS include further dilution of the syngas with either N_2 or water vapor to lower the heating value. The PPS produces clean syngas with a heating value of approximately 245 Btu per standard cubic foot (SCF) on a lower heating value basis (LHV). When diluted by N_2 during the demonstration, the syngas LHV was typically about 140 Btu/SCF. The estimated syngas LHV required to achieve revised permit levels is 127 Btu/SCF. At this heating value, flame stability could become a concern.

PM Emissions. PM emissions from the PPS IGCC are typically less than 0.04 lb/MWh, which is approximately 5% of those from conventional coal-fired plants equipped with electrostatic precipitators. These near-zero emissions are the result of the concentrated, low volumetric raw syngas flow and application of intensive liquid scrubbing and no less than 15 stages of liquid gas contact.

Other Emissions. CO emissions are permitted at 99 lbs/hr and have averaged 7.2 lbs/hr. VOC emissions are permitted at 3 lbs/hr and average 0.02 lbs/hr. Mercury was not regulated, but measurements taken showed that the IGCC removed about half of the mercury constituent in coal feedstocks. Mercury removal from syngas is proven technology and will be applied as future regulations require.

Solid Waste. Solid wastes from the PPS unique to IGCCs are frit, ammonium chloride, used filters, and spent catalysts. The frit is a salable by-product, but early operational set backs initially forestalled sales, as discussed later. The brine concentration system, designed to remove chlorides from process water, produces 20 tons/month ammonium chloride that is landfilled at a cost of \$35/ton. However, ammonium chloride's sales potential is being explored. MDEA acid gas removal system filters catch non-hazardous iron oxide and iron sulfide. The filters are disposed at a rate of two 55-gallon drums per week and a cost of \$65/drum. Non-hazardous COS hydrolysis catalyst is disposed at a rate of 10–20 tons/year and a cost of \$250/ton. Hazardous SAP catalyst is disposed at a rate of 5–10 cubic yards/year and a cost of \$550/cubic yard.



GE frame 7FA gas turbine during manufacture

Operational Performance

Over the course of the demonstration, the PPS combustion turbine logged 34,800 hours of which 28,500 hours were syngas fired. The 28,500 hours of syngas firing produced over 8.6 million MWh of electricity. In producing the syngas, the gasifier typically consumed 2,500 tons/day of coal or coal/petcoke blends.

Availability. The gasifier and associated systems involved in producing clean syngas showed steady improvement in in-service (on-stream) factor over the first four years before suffering a setback in the final demonstration year. The fifth year was not considered representative. It included a lengthy planned outage to deal with gasifier refractory damage incurred by frequent feedstock changes followed by a rare ASU forced outage and the one-time removal of sootblower lances. The on-stream factors shown in Figure 2 represent the percentage of time the gasifier and associated systems were in operation over the total number of hours in the year of operation — 8,760 hours except for leap year (2000) and the partial operating period of 1996. The availability of the combined-cycle power block to produce electricity from either syngas or distillate was approximately 90% over the last four years. This is represented by the availability factor, which is the hours in service plus those available for service divided by the number of hours in the year of operation expressed as a percentage. Tampa Electric also calculated on-peak availability because of the importance of the plant in meeting peak summer demand. The on-peak availabilities for 2000 and 2001 were 94.9% and 97.7%, respectively.

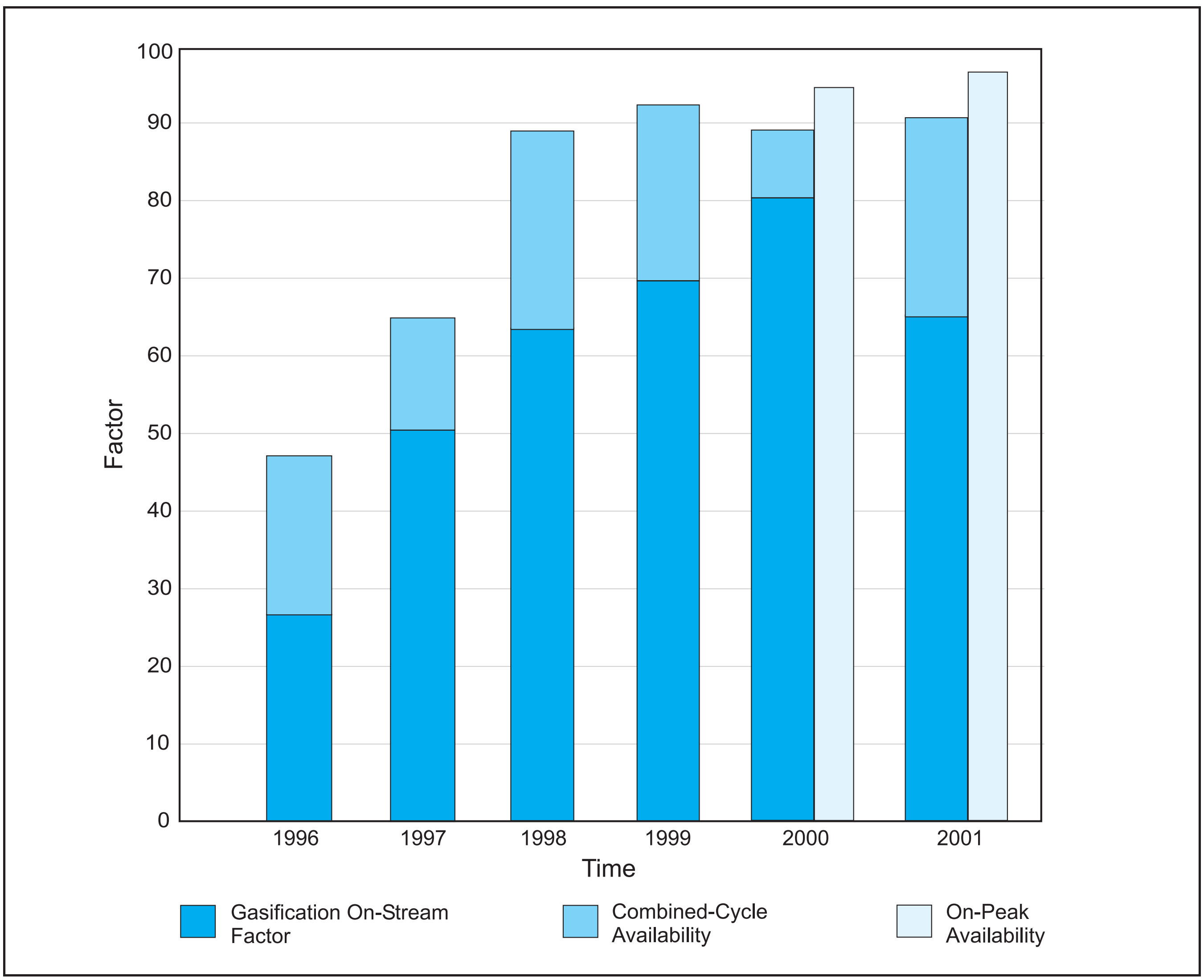


Figure 2. Availability

ASU system (far left), gasifier (center), and SAP plant (foreground)

Carbon Conversion. Lower than anticipated carbon conversion in the gasifier had major cost and performance impacts on the PPS that reverberated through the IGCC system. Carbon conversions of 97.5–98% per pass were expected based on performance of smaller Texaco gasifiers. Moreover, these carbon conversions were at conditions conducive to two-year refractory liner life. The PPS gasifier achieved per pass carbon conversion in the low- to mid-90% range and refractory liner life was a problem throughout the demonstration.

The following sequentially addresses the major PPS IGCC subsystems, highlights key issues, and reflects on the impacts of poor carbon conversion where relevant.

ASU. The major issue with the ASU was a shortfall in main air compressor (MAC) capacity. Even at design capacity, the ASU could not deliver enough air to meet the total gasifier oxygen requirements given the unexpectedly low carbon conversion and the resulting need to recycle flyash (which reduced fuel quality). Moreover, Tampa Electric desired the flexibility to process low quality fuels. The design capacity shortfall was exacerbated by steady deterioration of MAC output over the five-year demonstration. Ultimately, this deterioration was found to be a guide vane defect that was corrected. If adding N_2 diluent to meet revised NO_x emission requirements is the chosen option, MAC capacity requirements increase even more.

Slurry Preparation. Unexpectedly severe erosion/corrosion was pervasive throughout the slurry preparation system. PPS largely avoided forced outages in this area but had to take a number of steps to manage the issue. Carbon steel pipes were replaced with HDPE pipes and direction change and branch sections were overlaid with erosion/corrosion resistant material. Moyno mill discharge pumps were replaced with simple centrifugal pumps. Neither pump type would sustain more than 2–3 months generation, but the centrifugal pumps were 1/10 the Moyno pump cost and handled larger material, which eliminated a restriction at the rod mill trammel screen by allowing larger openings. Carbon steel parts of the Geho slurry feed pump in contact with the slurry had to be replaced with corrosion resistant steel or coated with epoxy. Rubber lining had to be installed on the carbon steel run tank walls and a rubber coating applied to the run tank agitator blades.

Gasifier. Tampa Electric evaluated numerous modifications to the slurry feed injectors in an attempt to resolve the carbon conversion issue. Only marginal improvement resulted.

A two-year gasifier refractory liner life commercial goal established for the PPS was not met during the demonstration period. Frequent fuel changes were the primary cause. The fuel changes introduced risk in operational settings and less than optimal operating conditions as adjustments were made. Also, the high number of start-up and shutdown cycles experienced during the demonstration period accelerated refractory spalling.

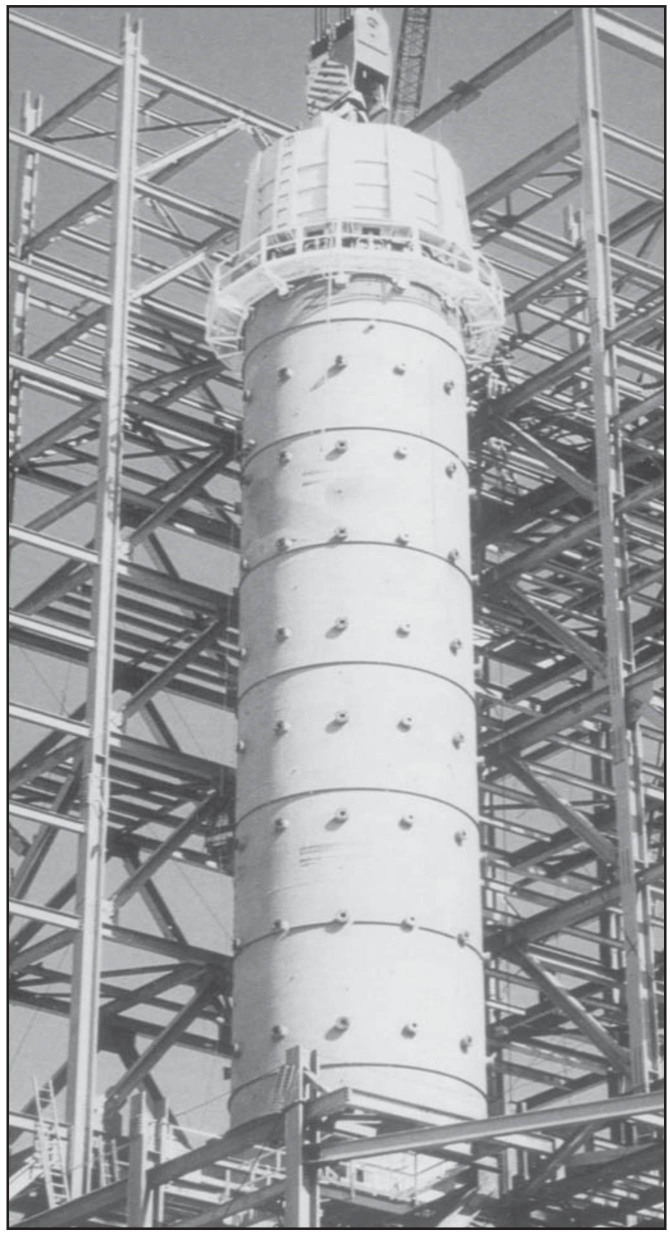
Tampa Electric carried out extensive feedstock testing during the demonstration with refractory life being a prime consideration. Testing showed that a blend of 45% Black Beauty and Mina Norte coals with 55% petroleum coke provided excellent cost and performance characteristics and the potential for long refractory liner life. PPS continued into post-demonstration commercial service on this feedstock blend.

Contributing to the refractory degradation was the inability to directly measure gasifier temperatures on a realtime basis. Thermocouples failed to survive the gasifier flow path. Gasifier temperature measurements primarily relied on "inferential measurement" based on methane formation. But, correlations had to be developed for each specific fuel. Post-demonstration plans included evaluation of an optical pyrometer developed by Texaco for realtime gasifier temperature measurement.

Monitoring and control of gasifier temperature also is critical for control of (1) slag viscosity, which is essential for prevention of slag tap plugging; and (2) flyash volume, which can overwhelm the solids handling systems if temperatures are too low.

Radiant syngas cooler in transport

Radiant Syngas Cooler. The radiant syngas cooler (RSC) essentially is a cylindrical waterwall that absorbs heat from the raw syngas stream exiting the gasifiers and protects the pressure vessel shell. RSC seals are at interfaces and waterwall penetrations — gasifier refractory/waterwall interface, steam/water header penetration in the "roof," sootblower penetrations in the vertical/cylindrical section, and pressure equalization passages for the waterwall/shell annulus at the bottom of the RSC. All seals eventually failed due to either fabrication defects or design flaws, but all of which were corrected. Other corrections included removal of all but 8 of the 122 sootblower lances. Only four lances are used as sootblowers. The other four lances serve as purge points for injection of N_2 during start-up and shutdown.



Radiant syngas cooler in structural shell

Convective Syngas Cooler. The convective syngas cooler (CSC) fire-tube heat exchanger was a source of frequent plugging and forced outages through 1999. The plugging primarily occurred at the CSC tubesheet inlet. In 1999, significant geometric improvements dramatically reduced plugging by more than half. Although not eliminated, CSC pluggage is deemed manageable.

Solids Handling. The gasifier's lower than expected carbon conversion required twice as much fly ash and associated black water to be processed than originally designed for. This volume essentially overwhelmed the solids handling system, precluded slag sales, and posed significant disposal costs.

Compounding the problem was unreliable performance of the grey water pumps providing make-up water to the syngas scrubbers and contamination of the slag with chloride and ammonia by the grey water used in the slag removal system. To resolve these issues, Tampa Electric took the following actions:

- Doubled the capacity of the fines (predominately flyash) handling system by adding a duplicate settler/vacuum filter train;
- Provided the capability to recycle 100% of the settler bottoms flyash to the gasifier slurry preparation system;
- Improved the reliability of the high-pressure grey water pumps by replacing two-stage overhung (single bearing) ANSI-rated centrifugal pumps with single-stage overhung centrifugal pumps meeting API standards;
- Eliminated chloride and ammonia contamination of slag by using condensate water instead of grey water in the slag removal system and stripping the ammonia from that condensate water; and
- Added a drag conveyor and screen to dewater and separate the fly ash from the slag exiting the slag removal system lockhopper.

With these changes, operation on 100% coal enabled sales of the slag while recycling 100% of the settler bottom flyash and generating 235 MWe (net). (Tampa Electric future plans included increasing ASU capacity to provide the rated capacity of 250 MWe (net) year round while recycling 100% of the settler bottom flyash.) Switching to the selected 55% petcoke/45% coal blend overloaded the slag/flyash separation system, preventing slag sales, but recycling 100% of the settler bottom flyash was unaffected. The reason for the slag/flyash separation system overload was lower carbon conversion with petcoke than with coal. Tampa Electric was considering either increasing the capacity of the slag/flyash separation system or continuing to use a supplemental system brought in to reduce slag/flyash inventory.

Cold restarts of the gasifier typically dislodged scale throughout much of the IGCC system, which caused plugging of the solids handling systems. It was particularly problematic in the syngas scrubbers, where accumulated deposits were up to two inches thick.

Tampa Electric considered the brine concentration system used to control chloride buildup in the process water to be developmental. As a result, a concerted effort was made to prevent any IGCC outages due to the brine concentration system. Significant progress was made toward achieving true commercial service, including: (1) an improved brine mist separator for the compressor driving the grey water evaporator, (2) a corrosion-resistant compressor replacement, (3) advances in ammonia chloride crystal recovery, and (4) identification of means to reduce scaling and plugging and to control corrosion.

Raw Gas/Clean Gas Heat Exchanger. In the original IGCC design, heat exchangers downstream of the CSC were incorporated to recover process heat by warming clean gas and diluent N_2 going to the combustion turbine. Flyash deposits from the raw syngas resulted in stress corrosion, cracking of the tubes, and turbine blade damage. These heat exchangers were removed because the heat recovery, less than 1.7% of the fuel's heating value, did not warrant the cost of redesign.

COS Hydrolysis/MDEA System. Tampa Electric incorporated a COS hydrolysis system in August 1999 following attempts at other COS control methods and after slip stream testing to identify the optimum COS catalyst option. Figure 3 shows the upgraded syngas cleanup system. An ion exchange system was subsequently added to control a high rate of heat stable salt (HSS) formation resulting from COS hydrolysis. Formic acid vapor from hydrolysis catalysts reacted with MDEA solvent to form the HSS, which impaired H_2S removal efficiency. Very fine flyash was found in the knockout drum used to protect the COS catalyst. The blowdown water contained a significant loading of less than 2-micron PM. The finding revealed a change in PM capture performance due either to flyash recycle or the switch to a petcoke/coal blend.

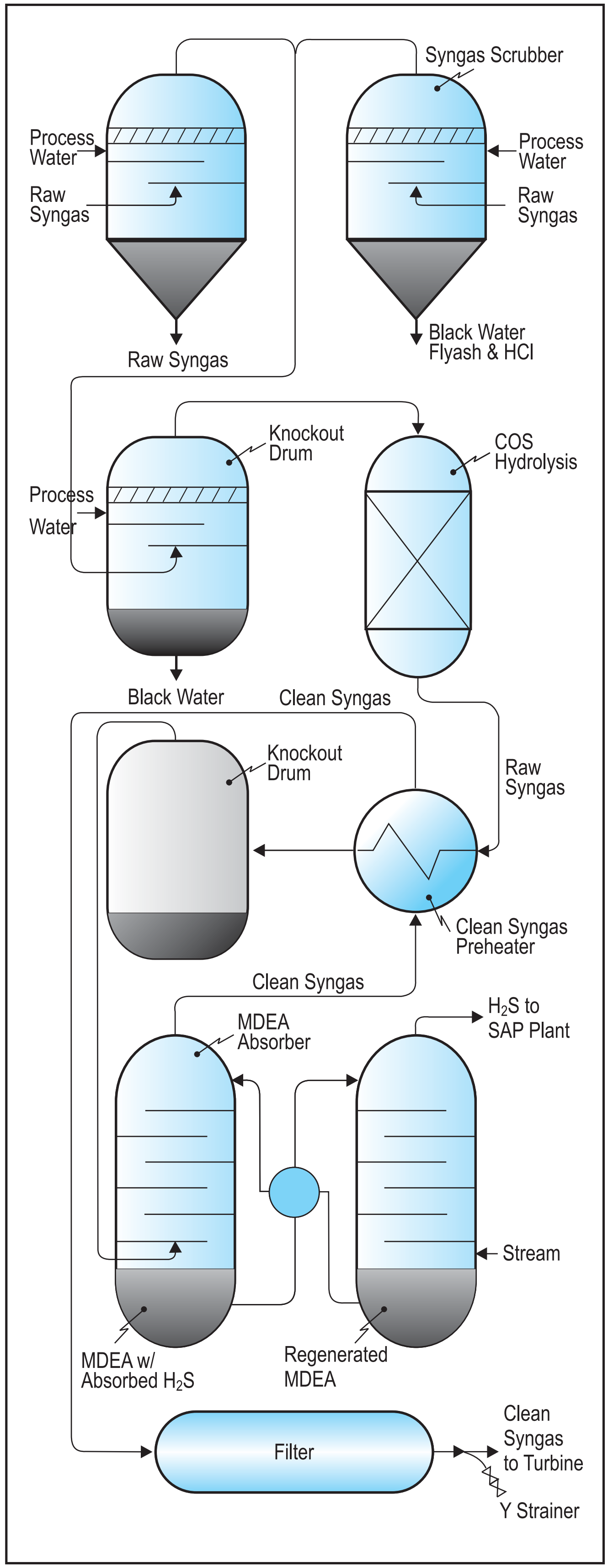
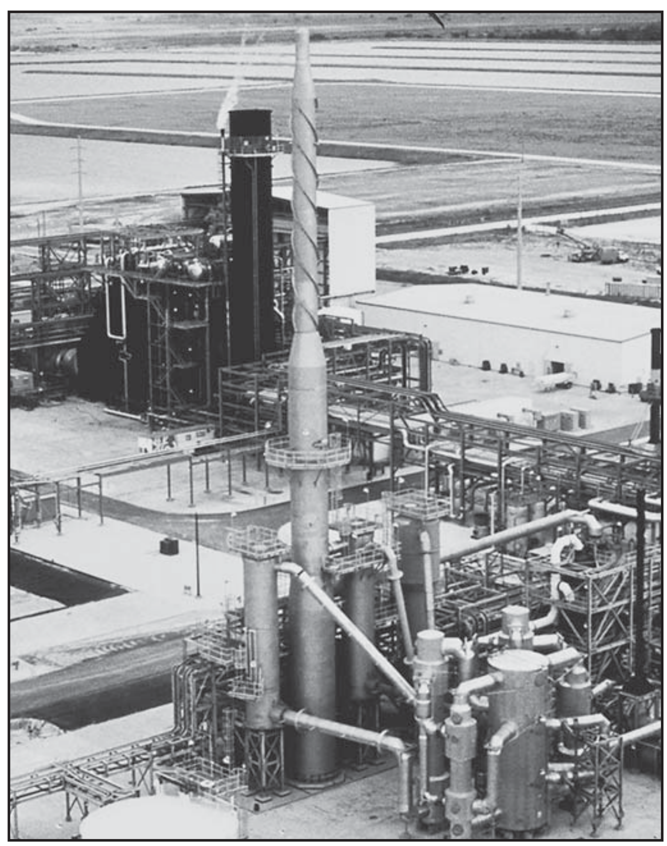


Figure 3. Syngas Cleanup

SAP System. The SAP system posed no significant threat to IGCC availability. However, decomposition furnace flame scanners proved to be a nuisance, sending signals to shut the system down when they failed to confirm the presence of flame in the furnace. Two infrared (IR) flame scanners initially used failed to detect the propane pilot flame or propane flame used in startup. The two IR flame scanners were replaced with four combination ultraviolet (UV)/IR detectors, with the UV tuned to the propane flame. The only remaining problem was alignment of all four flame detectors following burner maintenance, which sometimes took days.

Power Block. The only major power block forced outages during syngas-based operation resulted from failures of the raw gas/clean gas heat exchanger (since removed) in the absence of protective "Y" strainers. The "Y"strainers had been removed for repair. "Y" strainers subsequently proved critical for startups because of the release of large volumes of pipe scale. To increase turbine protection and reduce "Y" strainer cleaning, a 10-micron final syngas filter was installed upstream of the syngas strainers. This filter was sized to catch a year's worth of pipe scale.



Sulfuric acid plant in foreground and combustion turbine in background

Economic Performance

Capital Costs. Tampa Electric estimated a capital cost of $1,650/kW (2001$) for installing a new single-train 250-MWe (net) unit at the Polk site, based on the PPS configuration and incorporating all lessons learned. This estimate reflected the cost of the plant as if it were instantaneously conceived, permitted, and erected (overnight cost) in mid-2001. The single-train PPS configuration contributed to the high cost in that no benefits accrued from economies of scale in using common balance-of-plant systems. Tampa Electric also noted a number of site-specific factors adding to high costs. The scarcity of water in Florida required use of diluent N_2 instead of far less expensive syngas saturation for NO_x control. Prohibition of even small amounts of wastewater discharge dictated use of the expensive brine concentration system. Florida's high ambient temperatures and relative humidity led to lower steam cycle output.

Tampa Electric developed another capital cost estimate. This estimate moderated site-specific factors and allowed benefits from economies of scale, technical improvement, and replication of proven configurations to eliminate costly re-invention. Application of these benefits reduced the estimated capital cost to $1,300/kW (2001$).

Operating Cost. The highest annual PPS operating cost component is fuel. Typically, the gasifier fuel consumption would be 2,500 tons/day of solid feedstock or 16.2×10^{12} Btu/year. Propane consumption for pilot lights is 40 gallons/day or 1.3×10^{9} Btu/year.

The plant is staffed by five 10-man operating and maintenance (O&M) teams. Supporting the team are six engineers, nine specialists, three laboratory staff, and ten administrative and management personnel.

In addition to fuel, salaries, and benefits for permanent staff, the plant historically incurred the following annual costs.

Item	Annual Cost ($ million)
Catalysts and Chemicals	1.0
O&M-General and ASU	1.5
O&M-Gasification	4.5
O&M -Power Block, Common, and Water	2.0
Equipment Replacement/Upgrades	2.0
Total	11.0

Commercial Applications

Tampa Electric addressed the future of IGCC, reflecting on typical questions posed by visitors from around the world interested in this advanced technology. In regard to cost, the primary topic of discussion, Tampa Electric pointed out that (1) capital costs will be lower for next generation IGCC; (2) further IGCC demonstrations would accelerate cost reduction; and (3) higher initial costs for IGCC can be offset by long-term fuel savings. As to the associated factor of economic risk, Tampa Electric observed that (1) assumption of overall plant performance risk by a single entity rather than separate entities for individual process units would reduce the difficulty in obtaining financing; (2) a return to economic recovery in the United States would encourage potential IGCC users to take a longer-term investment view; and (3) a lasting change in the expected availability or price differential of natural gas to coal would tip the risk versus reward scale toward IGCC.

Also, because mercury is readily removed from concentrated IGCC gas streams, environmental legislation requiring mercury removal would provide economic impetus to IGCC over conventional coal-fired power generation. For similar reasons, CO_2 removal requirements would provide significant incremental economic gains for IGCC relative to both conventional coal-fired plants and natural gas combined-cycle systems.

As to availability, Tampa Electric noted that (1) PPS availability is lower than can be expected for subsequent IGCC plants incorporating lessons learned; (2) overall PPS availability, including operation on backup fuel, is very high; and (3) the PPS experience showed that availability can be effectively managed.

Regarding technical skill requirements, Tampa Electric showed through the demonstration that a modest-sized utility with expertise in coal-fired generation, can build and operate an IGCC plant. Tampa Electric cautioned, however, that careful attention must be paid to personnel selection and training to ensure success.

Inside gasifier

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