Advanced Coal-Fueled Gas Turbine Systems

Topical Report

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I. SUMMARY

An Advanced Coal-Fueled Gas Turbine System program was conducted by the Allison Gas Turbine Division of General Motors Corporation (now Allison Engine Company) with the U.S. Department of Energy (DOE), Morgantown Energy Technology Center. The overall objective of this cost shared program was to develop the technology base for environmentally sound, integrated turbine systems that produce cost-competitive energy from coal.

Extensive technology evaluations, development, and testing were used to address the challenges of operating gas turbines with coal. Tests were conducted in a number of test facilities, including a subscale coal combustion facility and a full-scale facility operating a coal combustor sized to the Allison Model 501-K industrial turbine. Systems and economics evaluations determined commercially attractive applications for coal-fueled turbines using the most promising technical approaches that had been identified by previous testing and analyses.

A rich-quench-lean (RQL), low nitrogen oxide (NO_x) combustor design incorporating hot gas cleanup was developed for coal fuels. This RQL approach should also be applicable to biomass and other alternate fuels. The RQL turbine combustor design is relatively compact, simple and highly integrated into the turbine system compared to other technologies (e.g., gasification, advanced pressurized fluidized bed combustion (PFBC), etc) being considered for operation of gas turbines with coal. Consequently, the RQL combustion design offers cost and reliability advantages over these other clean coal technologies. Furthermore, this RQL combustion approach facilitates conversion of conventionally-fueled turbine plants to operation with coal or other alternate fuels.

Tests with coal fuels of both the subscale and turbine scale combustors demonstrated NO_x and carbon monoxide (CO) emissions comparable to, or even lower than, levels for commercial turbine operating with clean fuels such as natural gas. Measured NO_x and CO emissions were each less than 20 ppm at 15% O₂.

An Allison 501-K turbine was tested for four hours using a subbituminous coal water fuel (CWF) containing 4.39% ash. The turbine experienced deposition during the test. Water washing of vanes removed from the turbine was very effective in cleaning the deposits. Methods to alleviate deposition and facilitate turbine cleaning were identified through evaluation of data from the engine test and other subscale deposition tests.

Systems and economic evaluations identified two attractive commercial applications for coal-fueled turbines using the RQL combustion approach. The first application is coal-fueled cogeneration plants based on the Allison 501-K turbine. The output of these plants is approximately 3.7MW of electricity and 23,000 lbs/hr of steam. Another attractive commercial application is coal-fueled turbine combined cycle (CFTCC) power plants based on 50MW or larger gas turbines. Both of these applications use the RQL combustor to essentially adapt conventionally fueled systems to operation with coal fuels.

Coal-fueled cogeneration plant configurations were defined and evaluated for site specific factors. At sites where sulfur compliant coal is available at prices of \$1.90/MMBtu or lower, a coal-fueled cogeneration could provide an attractive internal rate of return (IRR) of 20% at economic conditions of the early 1990s. For cogeneration systems requiring sulfur control equipment, this IRR will be achieved when delivered natural gas prices (in 1990 dollars) rise to about \$4.00/MMBtu. Alternate cogeneration systems were defined with comparable economics and which address the cost and durability issues of hot gas filters considered for the above cogeneration systems.

A coal-fueled turbine combined cycle plant design was identified that is expected to provide simplicity, compactness, and lower capital costs, with comparable efficiencies and low emissions compared to other coal technologies such as gasification and advanced PFBC.

II. INTRODUCTION

The use of coal as a fuel for combustion turbines has long been pursued. About 40 years ago, two extensive programs were initiated in the U.S. (Smith, et. al., 1966), and Australia (Interdepartment Gas Turbine Steering Committee, 1973) to develop turbines directly fired with coal for locomotive applications. While these programs did not produce commercial engines, significant progress was made in overcoming the technology barriers for coal fueled turbines.

The development of coal as a turbine fuel requires resolution of technology issues which are of little or no consequence for conventional natural gas and oil-derived fuels. These issues are primarily related to the solid form in which coal is naturally found and the high ash (often exceeding 10%) and contaminant (e.g., nitrogen, sulfur) levels in coal. Unlike refined, conventional fuels, the structure and chemistry of coal and its ash are extremely variable. Due to the solid form of coal in its natural state, different fuel storage, handling, and injection approaches must be implemented for fuel delivery systems than previously used for the traditional natural gas and oil-based fuels.

Coal also exhibits different combustion characteristics (e.g., char burnout) than typical liquid and gaseous fuels. During combustion, certain coal contaminants such as fuel bound nitrogen and sulfur can be converted to high levels of gaseous emissions. Accordingly, combustor designs different from those previously used in conventional systems are required to achieve acceptable combustion and gaseous emissions with coal.

The high ash and contaminant levels also contribute to potentially high particulate emissions into the environment. Consequently, depending on specific environmental regulations, a significant amount of ash and contaminants must be removed either in fuel processing, during combustion, or post-combustion. Furthermore, even residual levels of ash and contaminants can cause deposition, erosion, and corrosion (DEC) of system components, especially in the turbine hot section. In summary, there are critical technology issues for coal fuel systems: (1) fuel handling and injection into a combustor; (2) coal combustion; (3) degradation due to DEC; and (4) environmental emissions compliance.

Several technology advancements since the early coal-fueled turbine programs (Smith, et. al., 1966; Interdepartment Gas Turbine Steering Committee, 1973) that address the above technical issues were developing in the early 1980s. They included:

- Coal-water suspensions had been tested as a fuel form.
- Improved methods for removing ash and contaminants from coal had been identified.
- Staged combustion had been demonstrated to substantially reduce NO_x emissions from fuel bound nitrogen.
- Greater understanding of the DEC processes and methods for control had been identified.

In the early 1980s, the U.S. Department of Energy initiated new projects concerning direct coal-fired turbines (Pitrolo, 1983). Following initial systems evaluations and coal combustor tests in these projects, several Advanced Coal-Fueled Gas Turbine Systems programs were awarded to gas turbine manufacturers to develop components and conduct proof of concept tests for coal-fueled turbines. One of the programs was awarded to Allison.

The overall goal of the DOE/Allison Advanced Coal-Fueled Gas Turbine Systems (ACFTS) program was to develop and demonstrate the technological bases for economically attractive, commercial, coal fueled gas turbine systems. The methods to accomplish this goal included the following:

- identify candidate technical approaches to meet the challenges of using coal as a turbine fuel
- screen the candidate technical approaches and evaluate their effects on the economic attractiveness of commercial coal-fueled systems

- demonstrate the most promising technologies and associated components in proof-of-concept system tests

This report describes the efforts and accomplishments of the DOE/Allison ACFTS program. The report is organized into two major parts. The first part summarizes the program technical approach, briefly describes the test facilities, and discusses the major results and conclusions from the technical and commercial system economic evaluations. The second part consists of Appendices which describe in detail the work to develop each of the primary technologies and components which address the above technical issues for direct coal-fired turbines and to evaluate economics of commercial systems.

III. PROGRAM APPROACH

TECHNICAL AND ECONOMIC EVALUATIONS

The following approach was used to address the major technology issues of i) fuel handling and injection, ii) coal combustion, iii) deposition, erosion, corrosion (DEC), and (iv) environmental emissions compliance:

- screen candidate approaches that address the technical issues
- develop and test individual subscale components based on the most promising technologies
- design, fabricate and test individual full-scale components sized for the Allison 501-K turbine (3.7 MW rated output for natural gas)
- integrate full-scale components into a 501-K engine facility
- test the coal-fueled 501-K turbine system

Evaluations of commercial system economics and technology developments were used to periodically update the coal-fueled system development by the above approach.

FACILITIES

The approach outlined above involved tests in both a subscale facility (subscale component tests) and full scale facility (components scaled to 501-K turbine). In addition, a Coal Fuels Laboratory for fuels analyses and a fuel nozzle atomization test facility were used in this program. The following subsection describes the subscale and full-scale test facilities.

Subscale Facility

The subscale coal combustion facility was located in the Allison Research Combustion Laboratory. Conditioned high pressure air is available to that laboratory at pressures up to 400 psig, temperatures up to 1300°F (700°C), and flow rates up to 5 lbs/sec. The subscale coal combustion facility (7.5 MMBtu/hr) was sized at about 1/10 of flow scale for the Allison 501-K turbine to reduce costs of development testing. As the program progressed, subscale equipment was added to the combustion train to evaluate hot gas cleanup and DEC control approaches. At the end of the program, the subscale equipment included powdered and slurry coal feed systems, combustor, cyclone, hot gas filter vessel, and DEC test sections to simulate environments produced by coal combustion products in two turbine rows.

Full-Scale Facility

A test facility was commissioned for operation of the full-scale (72 MMBtu/hr) coal combustor and 501-K turbine engine. Pressurized air capabilities for that facility exceed those needed to run the combustor separately at full engine pressure (165 psia) and full mass flow rate (34 lbs/sec) with inlet temperatures up to 1000°F. A 12,000 gal fuel storage tank and slurry delivery system was used for operation with coal water fuels (CWF). The 501-KM test turbine was a Allison 501-KB5 turbine modified with a new center section to enable extraction of compressor discharge air to the external coal combustor and to receive expansion gases from the combustor. Coal ash was separated from the combustor gases before entering the turbine expander by two parallel cyclones. The turbine output shaft was connected to a gearbox which drove two 4000 hp dynamometers which applied load to the engine. A 500 hp motor was used to start the turbine.

A full-scale turbine powder coal delivery system was constructed and the preliminary design of a full-scale hot gas filter was nearly completed.

IV. RESULTS

COAL TURBINE SYSTEMS APPROACH

The direct coal-fueled turbine approach developed in the Advanced Coal-Fueled Turbine Systems (ACFTS) program is based on a patented (Wilkes, Mongia, and Tramm, 1988) staged combustion system. This system is designed for high coal combustion efficiency, low NO_x emissions, and removal of coal ash in a solid state (and possibly removal of other contaminants such as sulfur) at an intermediate stage of the combustion process. Figure 1 illustrates this staged RQL combustion turbine system.

The compressor exit air discharges into several zones of the combustor which is located external to the turbine. A portion of the compressor discharge air and the coal fuel are reacted under fuel rich conditions in the combustor rich zone (RZ) at a temperature of about 1650°C (3000°F), producing a low heating value gas containing H₂ and CO. Over 99% of the carbon from the coal is converted to CO and carbon dioxide (CO₂). NO_x formation from nitrogen in the coal is inhibited by the low oxygen levels associated with fuel rich operation of the RZ.

The products leaving the RZ are reduced in temperature to 1093°C (2000°F) or lower by water (or steam injection) into the quench zone (QZ). This freezes the molten ash produced in the RZ and allows ash removal in a solid state by a particulate separator (PS) such as a cyclone or hot gas filter. The cleaned

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Figure 1. Coal-fueled RQL turbine system.

hot gases enter the lean zone (LZ) where final combustion results from autoignition due to injection of a portion of the compressor discharge air. Combustion occurs at a sufficiently low temperature (typically 1540°C (2800°F) or lower) to inhibit formation of thermal NO_x. The hot combustion products are then lowered to turbine inlet temperature by compressor discharge air injected into the dilution zone (DZ).

Several methods of SO_x emissions control are possible for the coal fueled turbine system. These include low sulfur coals, sulfur capture between the quench and lean zones, and sulfur capture at the turbine exhaust.

Work in the ACFTS program evaluated the coal-fueled turbine approach of Figure 1 for cogeneration systems, combined cycle power plants and locomotives. Numerous advantages over other coal systems were identified. The tested RQL combustor produces high combustion efficiencies, low NO_x and enables contaminant control after the quench zone where volumetric flows were one-half to one-third that entering the turbine. This results in relatively compact and lower cost hot gas cleanup equipment. The RQL combustor was designed using gas turbine combustion technology rather than process plant reactor technology used in coal gasification and other coal systems. The results are highly integrated, simpler and more compact combustion equipment than for alternate coal technologies. The natural effect is lower cost and improved reliability.

By way of example, the residence time in the rich zone of the RQL system is typically only about 20 to 30% of that for many entrained coal gasifiers, which have the shortest residence times of the alternate coal technologies. This results in a more compact system. Combustion in the RQL system is achieved with air, thereby not requiring the complexity and high cost of the oxygen plant needed for many coal gasification systems. No equipment is necessary in the RQL combustion system to capture and recycle combustion product fines while such equipment is usually needed for efficient coal consumption in advanced pressurized fluidized bed combustion and gasification systems.

The next section summarizes promising coal-fueled turbine systems based on the Allison RQL combustion technology. The systems approaches used to meet the challenges of operating turbines with coal fuels are outlined along with economic evaluations of those systems. Following sections summarize the technology evaluations and developments for coal-fueled turbines in the ACFTS program. Details of the program systems, economics, and technology development activities are discussed in the Appendices of this report.

COMMERCIAL COAL-FUELED TURBINE PLANTS

Systems analyses in addition to technology developments in the ACFTS program were used to identify two promising commercial coal-fueled turbine applications:

- cogeneration plants based on the Allison 501-K turbine
- combined cycle plants based on ≥ 50 MW utility turbines

The systems approach for both types of plants uses the compact Allison RQL combustor to adapt conventionally-fueled plants to operation with coal. This approach minimizes complexity and the amount of new equipment development needed for commercialization. Prospects for future conversion of existing plants to coal are also facilitated.

Several promising variations of coal-fueled cogeneration systems were identified based on cost and technology considerations.

Coal-Fueled Cogeneration Plants

Reference System

Plant Description

A reference coal-fueled cogeneration system has been defined. This system is an adaptation to coal fuels of a commercially available natural gas fired cogeneration system. The commercial natural gas system is based on the Allison 501-KB5 industrial turbine, which drives a generator to provide electricity and produces an exhaust stream from which steam is generated by a heat recovery steam generator. The reference coal-fueled cogeneration plant produces 3.73 MW of electricity and 23,140 lbs/hr of steam. The turbine, gearbox, and generator, in addition to the heat recovery steam generator for the coal-fueled cogeneration system (Figure 2), are mounted on skids, in the same manner as the natural gas fuel cogeneration system.

The coal-fueled cogeneration system uses a modified 501-KB5 turbine. The center section and internal combustors are replaced by a center section designed to transfer compressor discharge air to an external skid mounted coal combustor and receive and direct combustion products into the expander. The external rich-quench-lean coal combustor includes a rich zone integrated with a ceramic (candle) filter for particulate removal and a lean burner to complete combustion of the coal gases. The flow stream leaving the rich zone is water quenched to freeze molten ash particles prior to removal by the hot gas filter. Sulfur is removed from the turbine exhaust by a commercially available, sodium based sulfur scrubber mounted on a skid. Other skid mounted components (not shown in Figure 2) of the coal-fueled cogeneration system include a dry coal grinding and delivery subsystem, ash and waste handling subsystems, a calcium based sorbent regenerator, and equipment for control of the plant.

The Allison RQL combustor produces high combustion efficiencies and low NO_x levels. CO and NO_x emissions are each less than 25 ppm at 15% O₂. The commercially available sulfur scrubber reduces SO_x

Figure 2. Reference coal-fueled cogeneration system physical arrangement.

emissions by 95% or more. Particulate emissions are controlled to under 10 ppm by the hot gas filter which also alleviates turbine flow-path erosion and deposition.

Plant Economics

The IRR, on a 1990 cost basis, was calculated for the reference plant. A coal price of \$1.80/MMBtu was chosen based on a 1990 survey of delivered coal prices. Figure 3 gives the values of electricity and steam required produce an IRR of 15% and 20% for the reference coal-fueled cogeneration plant. As shown on Figure 3, the value of steam has also been referenced to the cost of natural gas required to produce the steam at 80% efficiency. Accordingly, Figure 3 also gives the delivered natural gas price and electricity values that yield IRRs of 15% and 20%.

For plant sites where electricity and steam (or natural gas) are valued above the 15% or 20% IRR lines on Figure 3, the coal-fueled reference system provides higher IRRs than those values. At a representative value of electricity of \$0.06/kW-h, the coal-fueled cogeneration system provides an IRR somewhat higher than 15% at typical delivered gas prices of \$3.00 to \$3.20/MMBtu of the early 1990s. Figure 3 also shows that gas prices would need to rise above \$4.00/MMBtu for a more commercially attractive IRR of 20%.

An increasing demand for natural gas is expected to increase gas prices throughout the 1990s and later. For example, the ENRON Outlook of 1993 predicts that gas prices will double (in 1993 dollars) between the years 1992 and 2000. Such an increase in gas prices would result in a high IRR for the coal-fueled cogeneration system and would increase its economic attractiveness relative to conventional natural gas fired cogeneration systems.

Figure 3. Effect of value of electricity on gas prices and steam value for IRRs of 15 and 20%.

Cogeneration with Sulfur Compliant Coal

Operation of a coal-fueled cogeneration system with a sulfur compliant coal (S levels of 0.6 to 0.65%) would meet a SO_x emissions goal of ≤ 150 ppm at 15% O₂. The sulfur scrubber and regenerator of the reference system could be eliminated, thereby significantly reducing the plant capital cost and eliminating the costs of makeup sorbents and scrubber spray water. Waste disposal costs are also reduced. However, a premium price is required for low sulfur coals. Figure 4 compares the IRR for the coal-fueled cogeneration system with various sulfur compliant coal costs to the IRR for the reference cogeneration system (with scrubber and regenerator) using a non-compliant coal at a price of \$1.80/MMBtu. Figure 4 indicates that the cogeneration system using a sulfur compliant coal at prices up to about \$2.40/MMBtu provides a higher IRR than the reference system. A compliant coal price of \$1.90/MMBtu would produce an IRR greater than 20% for gas prices over \$3.00/MMBtu.

Alternate Cogeneration Systems

The cogeneration systems discussed above use a hot gas filter operated at a supplier recommended face velocity of 12 ft/min for particulate control. However, Appendix E describes durability issues for hot gas filters and indicates that a lower face velocity than the 12 ft/min might be needed at the rich zone reducing conditions. Hot gas filtration face velocities as low as 3 to 4 ft/min have been required for effective filter backflushing in some tests at coal gasifiers at reducing conditions. The cost of larger filters required for the lower face velocities needed in these pilot plant tests decreases the IRR for the cogeneration systems described above.

Because of technology and cost issues for hot gas filters, alternate cogeneration systems were identified which used cyclone cleanup and other measures rather than a filter to control particulate, meet emissions standards, and protect the gas turbine. A particulate emission standard less than 0.03 lb/MMBtu is met through a combination of cyclone cleanup, moderate ash ($\leq 5\%$) coals, and the particulate removal capabilities of the stack gas sulfur scrubber. Other measures to protect the turbine include

Figure 4. IRR for coal-fueled cogen system using sulfur compliant coal at various prices.

additional cyclones, additives, and steam cooling of turbine airfoils to reduce deposition and corrosion by decreasing surface temperatures.

Economic analyses were conducted for nine alternate systems using cyclones and other particulate control measures just mentioned. Several of the alternate systems could accommodate a higher turbine maintenance cost and provide an equivalent or higher IRR than the reference system using a filter face velocity of 12 ft/min. The IRR margins are even higher if a lower filter face velocity (and more expensive filter) is required.

Subscale DEC tests were planned to compare DEC at turbine conditions for an upstream filter versus cyclone and other turbine protection measures. Filter durability and required face velocity were to be also evaluated. Results were to be used to estimate relative turbine maintenance intervals and costs for final definition of the coal-fueled cogeneration system. The ACFTS program ended before these tests and analyses could be conducted.

Coal-Fueled Turbine Combined Cycle (CFTCC) Plants

Plant Description

The Allison RQL coal combustor that had been developed for the 3.7 MW, 501-K industrial turbine can be scaled for use with large (≥ 50 MW) industrial turbine operating in combined cycle power plants. Figure 5 illustrates a CFTCC plant based on the Allison coal combustion approach. Figure 6 is a simplified CFTCC plant schematic showing that the system consists of two major blocks. The power generation block is a combined cycle (gas turbine and steam turbine cycles) system and uses equipment designed to operate with conventional fuels (e.g., natural gas). The coal combustion/emissions control block converts the conventionally-fueled combined cycle plant to operation with coal. This block combusts the coal and cleans the combustion products for expansion in the gas turbine.

Referring to Figure 6, a portion of the gas turbine compressor discharge air is directed to the combustion/emissions control block where it is reacted with coal. Coal contaminants (e.g., sulfur and ash particulate) are removed from the combustion product stream before final combustion and expansion in the turbine. Quench water and heat extraction are used in the combustion/emissions control block to lower the temperature of the combustion products to a suitable level (727°C (1340°F)) for removal of coal contaminants and emissions control. The heat extracted in the combustion/emissions control block is used in the steam equipment of the combined cycle power generation block to produce power.

NO_x emissions are controlled in the combustion/emissions control block by the RQL combustion of the coal fuel. Tests with the RQL coal combustor sized to the Allison 501-K industrial gas turbine have demonstrated simultaneous NO_x and CO emissions to less than 20 ppm (at 15% O_2) with prospects for lower levels with further optimization of flow splits. Sulfur oxide (SO_x) is controlled in the combustion/emission block by a zinc titanate sulfur scrubber. Tests indicate that this control method should ultimately be capable of reducing SO_x emissions by over 99%.

Particulates are controlled in two stages by a cyclone separator followed by a hot gas ceramic filter. A number of high temperature filter tests have reduced gas stream particle carryover to under 10 ppmw. This level of particulate carryover meets environmental emission standards and alleviates gas turbine flowpath degradation.

The hot gas filter technology and cost issues discussed above are of less significance for the CFTCC plant. The filter operates at over 365°C (660°F) lower gas temperature than for the coal-fueled cogeneration system. Also, the filter cost associated with a low face velocity (3 to 5 ft/min) design can be better accommodated in the much larger CFTCC plant.

TE92-3981

Figure 5. Coal-fueled turbine combined cycle plant.

TE92-3680-3

Figure 6. Simplified block diagram of CFTCC plant.

Applications

The CFTCC technology can be utilized for new power plants or for re-powering of existing natural gas-fired, combined cycle power plants. Depending on the gas turbine used, this technology can provide coal-fueled power blocks with electrical outputs from about 85 MWe (e.g., for the GE MS6000 turbine) to over 350 MW (e.g., for the Westinghouse 501F turbine) and even higher outputs for future advanced turbines. Figure 5 illustrates the layout for a 100 MW plant based on the Westinghouse 251 turbine.

CFTCC Advantages

Gas turbines are built for compactness and simplicity. The RQL combustor is designed using gas turbine combustion technology rather than process plant reactor technology used in other pressurized coal systems. The rich zone residence time is only 20% to 30% that of entrained coal gasification plants, which have the shortest residence time of alternate coal technologies. The RQL system uses air (not oxygen) and does not require recycling of incompletely reacted char, unlike a number of coal systems. The result is simpler and more compact combustion equipment than for alternate technologies. The natural effect is lower cost and improved reliability.

In addition to new power generation plants, CFTCC technology will provide relatively compact and gas turbine compatible coal combustion/emissions control islands that can adapt existing natural gas-fired combined cycle plants to coal when gas prices rise to the point where conversion is economically attrac-

tive. Because of the simplicity, compactness and turbine compatibility of the RQL combustions/emission control island compared to other coal technologies, it could be a primary candidate for such conversions.

351 MW CFTCC Plant

A 351 MW CFTCC plant has been defined and evaluated. This plant utilizes the Westinghouse 501F turbine and a 2400 psig/1000°F/1000°F/2.5 in. Hg steam cycle. The plant produces 351 MW output using 112.9 tons/hour of an eastern bituminous coal containing 2.5% sulfur and 16.4% ash. A salable byproduct of the plant is elemental sulfur. About 2.7 tons/hour of sulfur is extracted from the coal combustion stream using the zinc titanate sulfur capture system.

A comparison of NO_x and SO₂ and particulate emissions from an existing 300 MW coal boiler plant without provisions for SO_x and NO_x control and the CFTCC plant shows lower emissions for the CFTCC system (see Table 1). The CFTCC emissions are also substantially lower than the Federal New Source Performance Standards (NSPS) shown in Table 1.

The efficiency of the CFTCC plant (43.8% with HHV heat rate of 7785 Btu/kW-h) is over 7 percentage points higher than that for the existing conventional coal boiler plant (36% with HHV heat rate of 9493 Btu/kW-h).

As discussed earlier, the CFTCC system design approach adapts a conventional combined cycle plant design to operation with coal by using the RQL combustion/emissions control island. Cost evaluations have indicated an incremental capital cost of \$476/kW for the coal combustion/emissions control equipment.

COAL FUELS

Coal Water Fuels (CWF)

Numerous CWF development programs were in progress at the beginning of the ACFTS Program. CWF transport, injection and combustion into pressurized combustors had been shown feasible in such projects as the DOE/Allison Gas Turbine Component Screening Program (Wenglarz, et. al., 1986). New coal cleaning processes to remove ash and sulfur and alleviate turbine DEC and environmental emissions were being developed. Such extensive CWF development activities offered promise for resolving or alleviating many of the technical issues identified above for coal-fueled turbines. Consequently, CWF was the preferred coal fuel form for much of the ACFTS program. However, for reasons to be discussed, emphasis shifted to dry powder coal fuels later in the program.

Coal Fuel Development

Through technical interactions and, in some cases, subcontracts, extensive efforts were conducted with nine fuel suppliers to develop CWF for coal-fired turbine applications. Allison conducted laboratory

Table 1.
Comparison of air emissions of 300 MWe coal boiler plant with the CFTCC plant.

<u>Emission specie (HHV basis)</u>	<u>PC boiler plant</u>	<u>CFTCC plant</u>	<u>NSPS</u>
NO ₂ , lb/MMBtu	1.24	0.113	0.50
SO ₂ , lb/MMBtu	3.96	0.101	1.20
Particulates, lb/MMBtu	0.10	0.013	0.03

analyses, atomization tests, combustion tests, and in a few cases, DEC tests to evaluate CWF formulations from the suppliers. These efforts were used to define specifications and improve characteristics of CWF. Significant fuel improvements were achieved. For example, Allison evaluations and interactions with Otisca Industries, which provided the baseline fuel for much of the program, contributed to a change in coal feedstock and additives of their standard fuel. This resulted in improved storage, handling, atomization, combustion, and deposition characteristics.

Initially, CWF specifications were defined to alleviate as many of technical issues as possible for coal-fueled turbines. Very low ash ($\leq 0.2\%$), sulfur compliance ($\leq 0.65\%$ sulfur) and small coal grinds (15 μ m top size) were commercial fuel objectives. However, as the fuel suppliers refined their production and cost estimates for commercial fuels, it became apparent that coal turbine systems using highly refined CWF could become commercially attractive only at a distant time when conventional fuels would become very expensive. Since fuel suppliers indicated that significant CWF cost reductions could be achieved by relaxing ash, sulfur, and coal grind requirements, a Low Cost Fuels effort was conducted to test CWF with specifications up to 6% ash, 2.5% sulfur and 250 micron coal top particle size. Of the fuels tested, a subbituminous CWF with 2.72% ash, less than 1% sulfur, and 43 micron coal top particle size achieved the best combustion performance of $\geq 99.4\%$ carbon burnout in the rich zone. Accordingly, a similar CWF was chosen for the coal-fueled turbine engine test.

ATOMIZATION

Atomization of the CWF to fine droplet size distributions was an important factor in achieving high CWF combustion efficiencies. Fine droplet atomization was achieved through the following:

- fuel specification
- CWF spray nozzle development

Fuel Specification

Table 2 shows specifications for bituminous CWF that produced the fine atomization (and combustion) performance appropriate to the compact (residence time ≤ 100 msec) combustor rich zone.

Specifications for the subbituminous CWF tested were found to be less restrictive, possibly due to their higher volatile content and more reactive char. For example, excellent ($\geq 99\%$) rich zone carbon burnout performance was achieved using subbituminous CWF with top coal particle sizes of about 43 microns and viscosities approaching 200 cP in the 100 to 1000 sec^{-1} range of shear rates.

CWF Spray Nozzle Development

Four CWF atomization nozzles were tested. Two were provided by commercial suppliers and two were designed by Allison. The Allison full flow nozzle produced the best atomization performance. Figure 7 compares the performance of this nozzle with the better performing of the two supplier nozzles. The Allison nozzle atomized to Sauter mean diameter (SMD) of about 40 microns for an Otisca CWF and under 20 microns for an Oxce CWF at design atomization pressure ratios of 2:1. The Allison half flow nozzle produced only about 15% higher SMDs than the full flow nozzle and subscale combustion tests

Table 2.
Bituminous CWF specifications for atomization.

Coal loading	=	50 to 52%
Coal particle top diameter	$\leq$	15 microns
CWF viscosity	$\leq$	100 cP at shear rates $\leq 1000 \text{ sec}^{-1}$

showed no distinguishable difference in combustion performance for the two Allison nozzles. Consequently, the Allison half flow design was chosen as the baseline nozzle because it offered commercial turbine system advantages of a smaller and lower cost boost compressor for atomization air.

COMBUSTION/NO_x

Subscale combustion tests were used to develop the Allison coal combustion system design through a number of modifications:

- change from radial to axial swirler and improved dome design
- change to Allison CWF atomization nozzle
- retraction of nozzle/swirler into dome to form a prechamber
- adjustment of operating parameters to lower the rich zone fuel equivalence ratio to about 1.4

These measures raised the rich zone carbon burnout from about 80% initially to over 99%. Nearly complete conversion of solid carbon in the rich zone is necessary because the particle separator located upstream of the lean combustion zone removes most of the remaining char along with the coal ash. Although combustion of CWF at an equivalence ratio of 1.4 produces a very low heating value gas after quench (as low as 20 Btu/scf for a high degree of quench), tests showed that autoignition and stable combustion of this gas occurred in the lean zone due to its high temperature.

Experience with the subscale combustor, along with flow visualization experiments guided by incompressible 3-D elliptic computer code calculations, were used to design the full-scale coal combustor. The full-scale combustor was constructed with seven CWF atomization nozzles located at the rich zone dome rather than one used in the subscale combustor. The internals of the seven full-scale nozzles were replicas of the nozzle used in the subscale combustor.

Figure 7. Comparison of commercial and Allison nozzle CWF performance.

Figure 8 shows combustion and NOx emissions data from tests of the subscale combustor and full-scale combustor taken during full scale combustion rig and engine tests. The range of data spread primarily represents the effects of combustor operating conditions (e.g., different airflow splits and water injection rates) on NOx and CO emissions. Two of the operating points on CWF during the engine test are shown to result in NOx emissions of less than 20 ppmv and CO emissions of about 10 ppmv (corrected to 15% O2). Detailed mapping of the effects on emissions of independent variations in rich, quench and lean-zone temperatures was not possible in the relatively short term test. Experience gained on the subscale combustion rig (Wilkes and Santanam, 1991 and Wilkes et al., 1990), has indicated that both CO and NOx emissions are expected to be less than 20 ppmv and that these emission levels can be maintained across the load range from idle to full power.

PARTICULATE CONTROL

Inertial Separators

As indicated earlier, an initial objective for commercial CWF specification was to consider fuels with very low ash ($\leq 0.2\%$). Such low ash levels combined with inertial separators were initially considered to protect the turbine from particulate erosion and deposition and to meet particulate environmental emissions requirements.

After screening various types of inertial particle separators, a state-of-the-art turbine inlet particle separation (IPS) design approach was chosen that had been developed by Allison for aero engines. This design is very compact, potentially low cost, and had been very effective in removing particulate entering helicopter engines.

Aerodynamic analyses and cold flow testing were used to evaluate more than six IPS designs for application to coal-fueled turbines. Efforts in the DEC task showed that even for $\geq 99\%$ combustor efficiency, the larger (≥ 5 micron) combustion product particulate from low ash ($\leq 1.25\%$) coal tests had very low densities. These particulate consisted mostly of porous, low density char. The IPS large particle re

moval efficiencies were assessed inadequate for the low density particulate. Since cyclones were determined to have higher efficiencies for the low density particulate, it was decided to conduct further testing with cyclone separators while evaluating the potential of hot gas filters for later tests.

Systems analyses indicated that particulate emissions standards could be met with coal-fueled turbine cogeneration systems operated with cyclones, moderate ash ($\leq 5\%$) coals, and an exhaust sulfur scrubber (which also removes some particulate). However, additional measures would be needed to protect the turbine from particulate. Consequently, recent advances in cyclone theory were used to explore cyclone designs tuned to alleviate turbine erosion and deposition. The decision to test such designs was delayed until a subscale hot gas filter could be tested under the conditions of the RQL coal combustor system.

Hot Gas Filters

A twenty-five candle hot gas filter vessel using a water cooled tube sheet was designed, fabricated, and installed in the subscale combustion facility. A preliminary filter design was nearly completed for coal-fueled engine test facility. This filter work was not continued due to the completion of the ACFTS program.

SO_x CONTROL

Several sulfur emissions control alternatives were explored:

- sulfur compliant coal
- sorbent injection into the combustor
- stack gas scrubber
- Zn titanate sulfur capture system

As previously indicated, evaluations during the course of this program determined that highly refined (e.g., high degree of S removal) coal fuels would not likely be commercially available in the foreseeable future. However, a limited number of coal seams could provide mine washed, sulfur compliant ($\leq 0.60\%$ to 0.65% S) coals for direct coal fueled turbine cogeneration systems. The use of sulfur compliant coals was identified as the most direct and preferred sulfur control approach at the limited number of cogeneration system sites where low sulfur coal could be obtained at a premium less than \$0.60/MMBtu over non compliant coal.

Both sorbent injection and stack gas sulfur scrubbing were considered for cogeneration systems where moderate cost sulfur compliant coal would not be available. Sorbent injection in the RQL coal combustion system must occur upstream of the separator located after the quench zone in order to prevent re-acted sorbent from entering the turbine.

Calcium sorbent injection tests in the subscale combustor and thermodynamic equilibrium analyses showed that little sulfur capture could be expected at the desired quench zone temperature of 1093°C (2000°F) for the coal-fueled cogeneration system. This is because of the unfavorable temperature and the levels of water in the gas stream produced by water quench and coal water fuels. Furthermore, cogeneration system economic analyses showed little or no economic advantage for sorbent injection over a commercially proven, Na based stack gas scrubber with a sorbent regenerator. Consequently, this stack gas scrubber was determined to be the preferred sulfur control approach for the coal-fueled cogeneration system at locations where moderately priced sulfur compliant coal is not available.

Later systems evaluations in the program considered large (≥ 100 MW) coal fueled turbine, combined cycle plants utilizing the Allison coal combustion approach. For such large systems, a zinc titanate sulfur capture approach appears attractive. Accordingly a zinc titanate sulfur capture slipstream was constructed under subcontract to Research Triangle Institute and installed with the subscale combustor. The ACFTS program ended before the zinc titanate sulfur capture tests could be conducted.

COMPONENT DURABILITY

Laboratory Analyses

Extensive analyses were conducted in the Allison Coal Fuels Laboratory to screen methods to alleviate degradation due to coal ash of refractory liners, hot gas filter and the gas turbine.

The refractories lining the combustor, cyclones, and ducting of the subscale and full-scale facilities exhibited adequate short term life needed for combustor development. However, the short term degradation levels that were experienced showed that improvements in refractory durability were needed for long term life. Laboratory tests were conducted to screen candidate refractories for greater tolerance to coal combustion environments and to identify additives that could raise coal ash melting points and decrease ash sticking tendencies.

Refractory Screening

Over 110 refractories (some coated) were screened in laboratory ash exposure tests, thermal shock tests to 1649°C (3000°F), and ASTM room temperature erosion tests. Several refractories were identified which had substantially improved durabilities over those used in earlier combustor tests. The most durable materials at both reducing and oxidizing conditions were Cohart 501M (modified) and Cohart/Abresist, both alumina, zirconia, silica (AZS) based refractories. Carborundum Hexoloy SA and ST also performed well at reducing conditions but were susceptible to ash attack under high temperature ($\geq 1371^{\circ}\text{C}$ (2500°F)) oxidizing conditions. Sections of the subscale and full-scale combustors were lined with AZS refractories but the ACFTS program was discontinued before their long term durability could be evaluated.

Additive Screening

Additives were evaluated for injection into the coal combustor for the purpose of reacting with coal ash to reduce degrading effects on system components. Laboratory tests were conducted to assess the effects of additives on ash sticking (in a furnace) in hot gas filter and turbine environments and melting (in the ASTM ash fusion test). The ash fusion test was used to screen compounds based on Al, Si, Mg, Ti, Fe, Ca, Sr, and Al/Si compounds.

Al and Al/Si compounds were found to be the most promising additives from both cost and effectiveness considerations. Specifically, aluminum hydroxide and kaolin, at costs of \$0.80/lb and \$0.33/lb, respectively, were determined to be promising additives for coals with low to moderate ash levels and with moderate to high initial ash fusion temperatures. Small additive particle sizes (0.8 micron average diameter) were chosen for a high area to mass ratio and to alleviate the potential for erosion of coal system components. More work would be needed to identify additive approaches for coals with high ash and low fusion temperatures since required additive concentrations and costs become significant for such fuels.

TURBINE PROTECTION

Evaluations

In addition to the coal-fueled turbine test described in the next section, evaluations of data from three sets of subscale tests were used to assess the effects of combustion products on coal-fueled turbine flow-paths and the benefits of various turbine protection approaches. Initial evaluations involved further analyses of test data from the previous DOE/Allison Component Screening Program. Deposition data were then obtained using the subscale combustor that had been operated earlier to develop the RQL coal combustion approach. Later tests were conducted with a dedicated deposition, erosion, corrosion combustor facility.

As discussed in the following paragraphs, the tests indicated that deposition and corrosion are the most severe turbine flowpath degradation processes. Adequate control of erosion should be achieved with cyclones based on experience in coal-fired PFBC pilot plant cascade tests and PFBC demonstration plant turbine tests. Hot-gas filters, when developed, will provide an additional measure of erosion protection.

Corrosion

Specimens that had been exposed at turbine first stator conditions to coal-water fuel combustion products in the Component Screening Program were subjected to extensive metallurgical analyses. Very aggressive corrosion attack was observed, even though the specimens were protected by a commercial corrosion resistant coating (CoCrAlY) used in turbines. The attack characteristics were not typical of past experience and produced localized penetration up to one-third of the coating depth in a few hours. Molten ash phases, possibly involving calcium, probably affected the high rates of corrosion. Later tests were directed to reducing levels of molten phases to alleviate both corrosion and deposition.

Deposition

Deposition Assessments

As discussed in Appendix H, work at Allison had been directed to developing approaches that extrapolate turbine deposition maintenance intervals using data from relatively low cost tests. The following summarizes the use of these approaches and data from the three sets of subscale tests indicated above to estimate turbine maintenance intervals for various turbine deposition protection approaches.

Products of Combustion for Low Ash Fuels

A procedure was developed to determine product of combustion mass distributions and particle densities versus diameter, which are needed to use the turbine deposition estimation approach. Application of this procedure showed that coal cleaning to produce low ash levels results in reduced particulate capture by inertial cleanup systems compared to higher ash coals. In fact, as described in the last section, this effect produced inadequate performance of a novel inertial separator that was evaluated for coal turbine applications.

Reduced inertial capture performance results from low particle densities (specific gravities ≤ 1) and inertias for the larger (e.g., diameters greater than 5 microns for 1% ash coal) combustion product particulate. This is because even for 99% carbon burnout efficiencies, the larger combustion particulate consist mostly of unburned and porous char, with only a small fraction of denser ash. Because of this effect, the net benefit of high degrees of coal cleaning to remove ash might not be as good as intended because of the resulting reduction in cleanup system performance for systems using inertial particulate clean devices.

Turbine Deposit Removal Maintenance Intervals

Turbine deposit removal maintenance intervals were estimated for several turbine protection measures. Data from the three sets of subscale deposition, erosion, corrosion (DEC) tests mentioned above were extrapolated to the Allison 501-K turbine using the approach discussed in Appendix H.

Initial evaluations considered a Blue Gem seam, coal-water fuel (CWF), containing 1.25% ash in the coal that had been tested in the previous Component Screening Program. A 501-K turbine maintenance interval of less than one hour was estimated for this fuel and operation without hot gas cleanup. The measured ash sticking fraction (about 0.06) for the Blue Gem fuel causes extremely high deposition rates for ash material delivered to surfaces at first stator conditions. For this reason and because of unfavorable slurry rheology, Allison encouraged the fuel supplier to change fuel formulations. Test of the new formulation, a Taggart seam CWF, yielded much lower deposition rates than the Blue Gem

CWF due to lower ash levels (0.55%), cyclone hot gas cleanup, and a somewhat lower ash sticking fraction. The 501-K turbine deposit removal maintenance interval estimated for this fuel using cyclone cleanup was estimated at 5.4 hr.

The benefits of additives to reduce levels of molten phases, decrease ash sticking fractions and thereby alleviate deposition rates were explored in dedicated DEC combustor tests with the Taggart CWF. Extrapolation of the data to the 501-K turbine operated with a cyclone indicated an increase in deposit removal maintenance intervals to a value in the range between 32 and 54 hr, depending on additive type and concentration. This maintenance interval might be acceptable for a commercial turbine system if the deposits were sufficiently fragile that they could be removed on-line (e.g., by nutshelling) without taking the turbine out of service.

501-K TURBINE TEST WITH CWF

As discussed in the introduction, a primary objective of the ACFTS program was a system test involving a coal-fueled turbine run. Although significant deposition rates had been predicted from extrapolation of subscale deposition test data, it was decided to proceed with a one day engine test after the full-scale coal combustor had been demonstrated. The simplified approach for predicting turbine deposition had not been verified with coal fuels and valuable data could be obtained, even if high turbine deposition rates were to be experienced. Deposition data taken in turbine tests using cyclones for hot gas cleanup could be used to obtain a rough estimate of turbine deposit removal maintenance intervals using filters. Cleanability of turbine deposits from coal could also be assessed. The relatively low cost, simplified approach for predicting turbine deposition could be evaluated.

The 501-K turbine was operated with a subbituminous CWF containing 4.39% ash and 0.41% sulfur in the coal. The coal had been processed by a hot water drying process to produce a slurry fuel with an energy content of 12801 Btu/lb (moisture and ash free HHV). After startup on distillate oil (DF No. 2), the turbine ran for one hour on DF No. 2 and CWF followed by three hours on CWF alone. The turbine was operated at part load conditions at an inlet temperature less than 816°C (1500°F). Carbon burnout efficiencies of the combustor rich zone were in the vicinity of 99%. The compressor discharge pressure continually increased during the test, indicating that deposits were forming in the turbine. Post-run data analyses estimated a 22% reduction due to deposition of first-stage vane flow area over the duration of operation with CWF. Chemical analyses of the deposits suggested that alkali sulfates were the primary deposit bonding agent. Water washing of vanes removed from the turbine was very effective in cleaning the deposits.

The turbine run data was used to obtain a rough estimate for turbine deposits removal maintenance intervals for turbine operation with the same fuel but a hot gas filter rather than cyclones. A turbine maintenance interval of 150 hr was estimated, assuming that a typical level of particulate (10 ppmw) passing the filter as measured during Grimethope coal-fueled PFBC tests. Based on other work in the ACFTS program, the use of additives and coal selection would be expected to increase the turbine deposition maintenance intervals using filters by a factor of 10 or more.

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APPENDIX A: COMMERCIAL COAL-FUELED TURBINE SYSTEMS

COMMERCIAL APPLICATIONS

Initially, Allison examined coal-fueled reference systems for both stationary as well as transportation applications. As the technology requirements evolved for each of these systems, we concluded that the transportation technology requirements for a coal-fueled gas turbine were longer term than those associated with the stationary application. For a typical locomotive installation, critical technology needs were cited in gas turbine combustor sizing and packaging, high volume gas stream cleanup, ash storage and disposal, enroute fuel handling/storage, and improvements in fuel cleanup. Additionally, the performance of the gas turbine cycle for a line-haul locomotive is penalized relative to a conventional diesel performance because of the basic utilization route structure and duty cycle involving mountain operation as well as low power yard service. The potential remains for the coal-fired turbine to power a locomotive; however, Allison feels that competitive-technology availability will require longer term investment than that required for stationary applications.

Two stationary applications were considered. The first application is a coal-fueled cogeneration system based on the Allison 501-K turbine. This turbine is currently marketed in cogeneration systems operated with conventional natural gas and petroleum fuels. Over 150 of these systems have been constructed. The second stationary application is large coal-fueled combined cycle power plants using the Allison coal combustor/gas cleanup island. The coal-fueled combined cycle plant was considered because it appeared to offer prospects for nearer term commercialization than the coal-fueled cogeneration system. The following describes commercialization aspects for both coal-fueled turbine cogeneration plants and coal-fueled turbine combined cycle plants.

COAL-FUELED COGENERATION—REFERENCE SYSTEM DEFINITION

Market Considerations

Based on market considerations, Allison has defined the broad requirements for a baseline reference system incorporating a coal-fueled turbine as follows:

- small industrial size
- modular
- flexible
- minimal operational impact to customer

Specifically, the baseline unit is directed toward a small packaged cogeneration unit, typically a 3-10 MW industrial installation. Such a modular unit permits commonality with existing subsystems thereby reducing overall acquisition costs. Furthermore, modularity in this size results in the availability of "off-the-shelf" components that are more readily available and capable of being transported as a package to the customer site. This aspect of the system is considered to be important in order to minimize unique, on-site acquisition costs. Allison's current packaged cogeneration systems are skid-mounted and easily integrated at the job site.

The baseline reference system also has to be flexible from a fuel usage/availability standpoint, as well as satisfying federal, state, and local emission regulations. The industrial operator will require latitude in alternate fuel selections to capitalize on the lowest cost, available fuels. It is assumed that the Allison baseline reference system will have to operate on DF-2 and natural gas fuels, in addition to coal operation. Future needs may also dictate the capability for other alternate fuels. Similarly, the emission goals for the system may vary greatly depending on the specific regional regulations. It is not assumed that one single system will provide the most cost effective emission compliance in all regions of the country. For example, a lower cost system using NSPS sulfur compliant coal may be suitable in one

installation, while additional sulfur cleanup capability may have to be integrated into the baseline reference system for more restrictive geographic locations. As a result, the Allison baseline reference system must be capable of different levels of emissions compliance and utilize various techniques for achieving those levels of compliance.

In addition to these broad reference system requirements dictating size, modularity, and fuel/emissions flexibility, any new system must meet the customers specific needs with minimal operational and functional impact. In the case of a new installation, site specific items can be tailored to accommodate the coal-fueled system. However, if the retrofit or replacement markets are to be considered, commonality with existing installations is imperative. The Allison baseline reference coal-fueled cogeneration attempts to maintain the features of current capabilities.

Allison Cogeneration System

Allison currently provides packaged turbine systems operated with DF-2 and natural gas for the cogeneration market. The general installation of packaged systems at Allison has been handled by Allison Energy Systems, an operating group of Allison which offers turnkey gas turbine cogeneration systems utilizing the well-proven Model 501-KB/KB5 engine.

The user typically installs a cogeneration system to produce steam for some aspect of his operation and also capitalizes on the electrical production for on-site usage. Alternately, the electrical power can be sold back to the utility grid under separate agreements covered by PURPA legislation.

The currently installed cogeneration systems are designed to provide various combinations of heat and power to match the site specific requirements of the user efficiently. The Allison Model 501-K engine is configured to burn either natural gas or diesel oil with the provision for water injection into the combustors to meet the strictest emissions requirements. The electrical output of a single system can vary from 3500 to 5800 kW, depending upon whether the steam from the waste heat recovery system is expanded through a steam turbine or supplied directly for process heating needs.

Coal-Fueled Cogeneration System

The commercially successful Allison cogeneration system using the 501-K turbine and conventional fuels can be adapted for operation with coal. Figure A-1 shows a typical industrial installation arrangement, with an insert showing the moderate changes required for the coal combustion system.

The proposed cogeneration equipment package draws upon proven design techniques and operating experience gained over the past 20 years of supplying a gas turbine technology to industrial users. The reference cogeneration system is designed to retain these proven features and to provide increased system maintainability and controlled manufacturing cost through modularized designs.

Included in the packaged coal-fueled cogeneration system are the major subsystems, namely the engine, external combustor, electrical generator, waste heat recovery system, and ancillary enclosures. Site specific items include fuel storage, fuel handling/delivery, ash handling/removal as well as the electrical, water, and steam interfaces.

The key change to the existing Allison packaged cogeneration system will be the external combustor required for coal operation. The combustor is based on Allison's water quenched, RQL concept as shown in Figure A-2. This RQL staged system permits low NO_x combustion with a wide variety of fuels. This unique combustor also allows the coal ash to be "frozen" and removed during the combustion process. To accommodate the external combustor unit, changes will also be made to the engine combustor case and transition duct. The center section of the 501-K turbine will be modified to provide transfer of compressor discharge air to the external combustor and to receive the combustion gases for expansion in the turbine section. This modified engine for an external combustion process is identified as the Allison Model 501-KM turbine.

Combustor
AGC
module replaces
DF2 combustor

2ip ind

Figure A-1. Typical Allison energy system installation schematic.

Figure A-2. Allison water quench RQL system.

Figure A-3 shows the cross section of the standard 501 series industrial turbine with internal combustors. The modular construction for this engine facilitates modification (as illustrated in Figure A-4) of the center section module for an external coal combustor. The configuration of this new center section is shown in Figure A-5.

Figure A-3. Cross-section of Model 501 series engine

Figure A-4. Modular arrangement of Model 501-K engine.

Figure A-5. Configuration of engine center section.

The cogeneration modules for the baseline reference system are depicted in Figure A-6. The cogeneration components shown on the power skid module are basically common with today's installations. The new combustor unit is assumed to be a separate packaged module. A programmable digital electronic control system is used to automate and integrate the operation of the gas turbine, combustion system, generator, switch gear, and waste heat recovery unit for starting, normal operation, and shutdown.

Figure A-6. Assembled basic power skid.

Cogeneration System Goals/Requirements

Two major overall systems requirements for the coal-fueled cogeneration system are the following:

- economic attractiveness
- environmental compliance

Economics

The coal-fueled cogeneration system is intended to serve similar markets as the current Allison natural gas-fired cogeneration systems. These markets require steam at the rate of about 25,000 lb/hr and about 3 to 5 MW of electricity. The coal-fueled cogeneration system could produce steam and power at localities where natural gas has not been available at an economical price for the natural gas fired system.

As the demand for natural gas rises over the next decade, the price of this fuel is expected to rise. Consequently, a commercial coal-fueled cogeneration system could be increasingly competitive with current natural gas fired cogeneration system if the coal system will provide an acceptably high internal rate of return on investment to the plant operator. This rate of return should be higher than a value of about 15 to 20%.

Environmental

Environmental requirements include meeting emissions regulations and other regulations such as for noise and smoke. Emission standards are specified by federal and local environmental agencies. Environmental agencies have not yet established emissions regulations for industrial coal-fueled turbine systems; consequently, environmental regulations must currently be anticipated. Table A-1 gives anticipated environmental performance goals for a coal-fueled, 3-5 MW turbine, industrial cogeneration system. These goals are based on New Source Performance Standards or expected regulations for industrial coal boiler systems and industrial turbines operating with conventional fuels.

Since the environmental performance goals in Table A-1 are anticipated, the coal-fueled cogeneration reference system design should be sufficiently flexible to meet more stringent emissions regulations that might develop in the future.

Subsystems Requirements

As indicated earlier, the coal-fueled cogeneration plant will be an adaptation of the commercially proven, Allison natural gas-fueled cogeneration plants. However, the development of coal as a cogeneration system fuel results in challenges for subsystems that are not present for the natural gas system.

Table A-1.
Environmental performance goals.

<u>Item controlled</u>	<u>Goal</u>
NOx	≤50 ppm at 15% O ₂
SOx	≤150 ppm at 15% O ₂
Particulate	≤0.03 lb/MMBtu
CO	≤0.90 lb/MMBtu heat input
HC	≤0.25 lb/MMBtu heat input
Smoke	≤ 20% opacity
Noise	≤ 87 dB at 100 ft

These challenges are primarily related to the solid form in which coal is naturally found and the high ash (often exceeding 10%) and contaminant (e.g., nitrogen, sulfur) levels in coal. Unlike natural gas, the structure and chemistry of coal and its ash are extremely variable. Due to the solid form of coal in its natural state, different fuel storage, handling, and delivery approaches must be implemented for fuel delivery systems than previously used for the traditional fuels.

Coal also exhibits different combustion characteristics (e.g., char burnout) than typical liquid and gaseous fuels. During combustion, certain coal contaminants such as fuel bound nitrogen and sulfur can be converted to high levels of gaseous emissions. Accordingly, combustor designs different from those previously used in conventional systems are required to achieve acceptable combustion and gaseous emissions with coal.

The high ash and contaminant levels also contribute to potentially high particulate emissions into the environment. Consequently, depending on specific environmental regulations, some amount of ash and contaminants must be removed either in fuel processing, during combustion, or post-combustion. Furthermore, even residual levels of ash and contaminants can cause deposition, erosion, and corrosion (DEC) of system components.

In summary, there are four critical subsystem issues for coal fuel cogeneration plants: (1) fuel handling and injection into a combustor; (2) coal combustion; (3) degradation due to DEC; and (4) environmental emissions compliance.

Systems Alternatives to Meet Requirements and Goals

The following sections discuss alternatives to meet the overall systems economic and environmental requirements and goals described earlier. Also discussed are the following fuel and subsystems choices for a reference coal-fueled cogeneration plant to meet the additional challenges (compared to natural gas-fueled cogeneration) for operation with coal:

- coal handling and injection into a combustor
- coal combustion
- emissions compliance
- degradation due to DEC

Economics

Slurry Versus Dry Coal Fuels

The economic incentive for a coal-fueled turbine system is the relatively low cost of coal compared to conventional natural gas and oil-derived turbine fuels. Consequently, the differential price between a conventional turbine fuel and the coal fuel is the primary driving force for commercialization of the coal-fueled turbine, cogeneration system. The lower the coal fuel cost is, the greater the incentive for commercialization.

The preferred fuel form for the cogeneration system was originally a micronized coal-water fuel. However, of the many CWF suppliers at the beginning of the Allison ACFTS program, none are today offering a commercial micronized coal product and nearly all have withdrawn completely from the market. Costs for the test fuels in this program have typically been in the vicinity of \$100/MMBtu compared to a price in the vicinity of \$3/MMBtu needed for the coal-fueled turbine system to be economically competitive with existing commercial systems. The large production plants (of 1 million tons/year or greater) needed for low CWF prices and the infrastructure needed for economical pipeline transport have not been developed and are not likely to be constructed in the foreseeable future.

Consequently, economic studies for the baseline system were conducted to determine whether the use of dry coal fuels might be commercially attractive. Figure A-7 shows the relative internal rate of return (IRR) for the cogeneration system using a powdered coal fuel and two slurry fuels. The powdered coal at \$1.80/MMBtu delivered price is shown to provide a higher IRR than the slurry fuels with projected delivered prices in the \$2.70 to \$3.20/MMBtu range (depending on S and ash levels).

Of particular significance are the sensitivities of cogeneration system IRRs to uncertainties in fuel prices. Figure A-7 indicates that a higher CWF price than expected causes a much greater decrease in system IRR than the same incremental increase in dry coal price. Since powdered coal fuel price uncertainties are low due to a well established coal boiler market while there is little commercial experience to accurately establish CWF prices, there is less risk in the development of powdered coal-fueled cogeneration systems than systems using CWF.

These evaluations indicate the lower price of powdered coal can offset the additional capital cost needed for grinding and feeding equipment and should produce an economically competitive system with less risk for commercialization. Due to these considerations, a decision was made to discontinue further coal slurry testing in the Allison ACFTS program and to concentrate further efforts on the development of turbine systems using powdered coal.

Powdered Coal Fuel Specifications

Since powdered coal tests have not been conducted in the Allison ACFTS program, powdered coal fuel specifications can only be currently estimated for commercial cogeneration systems. Preliminary specifications based on CWF tests to date are given in Table A-2. A review of delivered coal prices in 1990 versus coal quality indicates a delivered price of \$1.80/MMBtu for coals of the quality described in Table A-2.

Figure A-7. Coal-fueled cogen system IRR sensitivity to fuel price.

Table A-2.
Preliminary powdered coal fuel specifications.

<u>Proximate (% by weight)</u>	
Volatile carbon	≥30.0
Fixed carbon	≥40.0
Ash	≤5.0
<u>Ultimate (% by weight)</u>	
Carbon	≥70.0
Hydrogen	—
Nitrogen	≤1.5
Chlorine	≤0.1
Sulfur	≤2.0
Ash	≤5.0
Oxygen	—
<u>Higher heating value (Btu/lb)</u>	≥12,000
<u>Ash fusion temperature (°F)</u>	
Initial deformation-reducing atmosphere	>2400
Initial deformation-oxidizing atmosphere	>2400
<u>Particle size distribution</u>	
15 micron mass mean diameter, 55 micron top diameter up to boiler grade (70% through 200 mesh)	

The specifications in Table A-2 were to be updated as results of powdered coal testing become available. Since most combustion characteristics for powdered coal are expected to be superior to those for CWF, future testing with powdered coal might result in a relaxation of some of the preliminary fuel specifications in Table A-2.

Powdered Coal Handling and Injection into the Combustor

Delivered coal to the cogeneration plant will be ground on site to a particle size range suitable for efficient combustion. Although this size range was to be determined from future combustion tests, the long term objective is to operate with a pulverized grind used in coal boilers (70% through 200 mesh).

Figure A-8 illustrates the powdered coal injection system that was fabricated for full-scale combustor and engine tests. The same injection approach is expected for the commercial cogeneration system. Two tanks are used for dilute phase coal feed to the RQL combustor. While the first tank is filled from a storage vessel (bulk hauling trailer shown in Figure A-8 for full-scale tests), a second pressurized tank feeds coal into the combustor. The first tank is pressurized after filling has been completed. Valving then switches the coal feed flow from the second tank to the first tank and the second tank is refilled.

Environmental

NO_x, CO, HC Emissions

Probably the most cost effective approach to control these emissions is staged combustion at high fuel burnout efficiencies. Figure A-9 illustrates the staged RQL combustor that has been developed by

TE91-2134

Figure A-8. Full-scale powdered coal injection system.

TE91-2135-7

Figure A-9. RQL combustor schematic.

Allison for the coal-fueled turbine, cogeneration system. The first stage (RZ) gasifies the coal under fuel rich conditions to inhibit NO_x emissions from fuel bound sources. Rapid and uniform water quenching of the coal gas to 1100°C (2000°F) in the quench zone (Q) and burnout at fuel lean conditions (LZ and DZ) inhibits thermal NO_x formation. A coal ash particle cleanup system (C) is located after the quench zone to reduce particulate emissions and protect the turbine flow path from degradation due to the ash.

Figure A-10 shows combustion (CO emissions) and NO_x performance data measured for the subscale and full engine scale RQL combustors that have been tested with coal water fuels. The range of the data spread represents exploration of the effects of operating conditions (e.g., flow splits) on CO and NO_x. Even though the RQL system has not been fully optimized, the NO_x, CO, and HC emission goals have been met.

Figure A-10. CO versus NO_x emissions of Allison subscale and full-scale combustors.

SOx Emissions

Alternatives for SOx control include the following:

- sulfur compliant coal
- sorbent injection downstream of the quench zone
- stack gas sulfur scrubber

The SOx emissions goal in Table A-1 can be met using coals with sulfur levels less than about 0.65%. Although coals have been ultracleaned to this level, the cleaning costs have been high. The large volume processing plants needed to economically produce ultracleaned coals have not been developed and are not likely to be constructed in the foreseeable future. Some U.S. coals can be mined or mine-washed to 0.65% S or lower. However, their premium price in addition to transportation expenses makes their delivered costs excessive at distant locations from the mines that produce compliant coals. Another means of sulfur emissions control is needed for locations not in the proximity of mines that produce compliant coals and to accommodate prospects of more stringent emissions standards in the future.

Calcium-based sorbent injection has been evaluated for capture of sulfur after the quench zone of the RQL combustor and removal with the downstream hot gas cleanup system. However, equilibrium calculations predict only a moderate degree (maximum of about 70%) of theoretical sulfur capture, and the resulting S compounds (e.g., sulfides) are not environmentally suitable for disposal. Consequently, a separate reactor would be needed for the cogeneration plant to convert captured material to disposable compounds (e.g., CaSO_4).

Figure A-11 gives a comparison of IRRs for coal-fueled turbine cogeneration systems using sorbent injection and systems using a commercial, sodium-based, stack gas scrubber that has demonstrated up to 95% S capture at industrial coal boiler plants. Sorbent injection is shown to offer little or no economic advantage over the commercially available stack gas scrubber. One of the most important factors affecting

TE93-2120
VS91-1238

Figure A-11. IRR for candidate desulfurizers.

this result is the cost of the reactor system needed for sorbent injection to produce an environmentally disposable product.

Although sorbent injection is an option that warrants further evaluation, stack gas scrubbing is currently the most attractive sulfur control approach for locations where S compliant coals are not economically available. The commercially available Na based scrubber is capable of reducing SO_x emission to well below the goal in Table A-1.

Particulate Emissions

Although not commercially developed, hot gas filters have demonstrated extremely high particulate removal efficiencies (>99.9%) in laboratory and coal-fired PFBC pilot plant tests (e.g., Stringer and Leitch, 1991) at temperatures in the vicinity of 871°C (1600°F) and lower. Such efficiencies for filters located after the RQL quench zone would reduce cogeneration system particulate emissions well below the goal in Table A-1. Furthermore, deposition and erosion in the downstream turbine would be reduced to low levels. For these reasons, ceramic filter hot gas cleanup is the approach chosen for control of particulate emissions (and turbine protection) for the reference coal-fueled turbine, cogeneration system.

Smoke and Noise

The smoke standard in Table A-1 will be met by high combustion efficiency, moderate ash coals ($\leq 5\%$), and hot gas cleanup at the quench zone to limit char and ash particulate in the exhaust. The wet sulfur scrubber provides an additional degree of particulate removal to further reduce exhaust smoke.

The noise standard in Table A-1 will be met using the same current technology as for the Allison natural gas fired cogeneration system. The turbine is housed in an acoustic enclosure designed for a maximum noise level of 85 db at 3 ft from the enclosure.

Turbine Protection from DEC

Numerous approaches could be applied to protect the gas turbine from DEC due to coal contaminants. The final choice between these approaches will be based on subscale DEC tests and engine runs. The following describes turbine protection approaches for the reference cogeneration system based on limited test results to date. The reference system would be updated as future DEC test results become available.

Coal-fired PFBC pilot plant tests indicate that the use of ceramic filters at the quench zone should reduce particle concentrations entering the turbine to 20 ppmw or less. The combination of low particle loadings and small size distributions produced by the filter would nearly eliminate turbine erosion and greatly reduce turbine deposition.

Deposition will be further reduced by controlling levels of molten ash phases entering the turbine. This should also alleviate the corrosion observed in past tests at direct coal-fired turbine conditions (Wenglarz, Sethi, and Gonzalez, 1991).

Control of molten phases will be accomplished by choice of coals that form no or very low levels of molten ash at turbine flow-path conditions. These low levels cannot be detected with standard ash fusion tests but subscale DEC tests can be used to identify coals with favorable deposition and corrosion (and erosion) characteristics. Another approach for control of molten phases is additives to modify the compounds (and melting points) of particulate formed in the combustion products and also modify deposit strengths. Substantial reductions in deposition due to additives were demonstrated in dedicated DEC combustor tests to the Allison Advanced Coal-Fueled Gas Turbine (ACFTS) program.

Reference System Description

Schematic

The reference coal-fueled cogeneration system approach is illustrated in the schematic of Figure A-12. Air enters the turbine compressor which discharges into several zones of an external staged, rich-quench-lean combustor that operates to minimize NO_x emissions from fuel and thermal sources. The rich zone (RZ) is essentially a coal gasifier. The products leaving the RZ are reduced in temperature (to about 1100°C [2000°F]) by water injection into the quench zone (QZ). The resulting gases that contain solid phase coal ash are then cleaned by a hot gas filter to protect the turbine from erosion and deposition and reduce particulate emissions in the exhaust. The cleaned coal gases enter the lean zone (LZ) where final combustion occurs. Compressor discharge air is injected into the dilution zone (DZ) to lower the gas to the turbine inlet temperature. The combustion stream is expanded in the turbine expander section which drives the compressor and an electrical generator through a gearbox. Coatings on the turbine vanes and blades provide corrosion and erosion protection from the coal combustion products. Additives are injected, as needed, to modify ash and deposit chemistry, alleviate hot gas filter plugging and corrosion, and control turbine deposition and corrosion.

The turbine exhaust enters the boiler section of a heat recovery steam generation which produces process steam. A sodium-based sulfur scrubber downstream of the steam generator reduces exhaust SO_x emissions to environmentally acceptable levels.

Physical Arrangement

Figure A-13 illustrates the expected physical arrangement for the coal-fueled cogeneration system. The 501-K turbine, gearbox, and electrical generator are mounted and enclosed in a structural steel skid, as for the natural gas fired 501-K cogeneration system now being provided commercially by Allison. The coal-fueled turbine has a modified center section to accommodate the external combustion system.

The combustor system is mounted on an adjacent combustor skid with the hot gas filter system. The stack gas scrubber is mounted on another skid as is the dry coal fuel injection system (not shown).

Reference System Performance

Performance evaluations were conducted for the reference coal-fueled cogeneration system using 501-K turbine operating characteristics, considering water injection at the quench zone (QZ), and using appropriate pressure drops for the systems components such as the coal combustor, hot gas filter, heat recovery steam generator, and the sulfur scrubber. These evaluations determined the turbine power output

Figure A-12. Reference coal-fueled cogeneration system schematic.

Figure A-13. Reference coal-fueled cogeneration system physical arrangement.

and exhaust flow rate and enthalpy from which process steam output was obtained. Table A-3 gives the performance of the cogeneration system. The system produces about 3730 kW electrical output and 23,140 lb/hr of steam (165 psia saturated). This compares to about 3460 kW and 21,100 lb/hr of steam for the commercial 501-K natural gas-fired cogeneration system without supplemental duct firing. The somewhat higher outputs for the coal-fueled system result primarily from the additional system mass flow due to quench water injection.

Reference System Costs

Capital Costs

Table A-4 gives an installed capital cost breakdown for the coal-fueled 501-K turbine cogeneration system. The estimated total installed coal system cost is about \$6.44 million (1990).

Table A-3.
Coal-fueled cogeneration system performance.

Fuel flow (MMBtu/hr-LHV)	54.05
Electrical output (kW)	3730
Steam output (lb/hr)*	23140
Simple cycle efficiency (%)**	23.6
Overall efficiency(%)**	70.9

* Assumes 64% condensate return

** Based on lower heating value of coal

Table A-4.
Coal-fueled baseline cogeneration system capital costs (1990\$).

<u>Subsystem</u>	<u>Installed cost—\$</u>
Genset/combustor/turbine	2,762,300
Steam generation	530,100
Fuel/waste handling	1,119,600
Sulfur control	742,000
Particulate control	490,300
Miscellaneous*	<u>795,000</u>
Total cost	\$6,439,300

* Miscellaneous costs include process controller, balance of plant, and electrical interconnect.

O&M Costs

Table A-5 gives the first year (1990) annual operating and maintenance cost (O&M) breakdown for the coal-fueled 501-K turbine cogeneration system. The annual O&M costs are segmented into fuel costs, other variable O&M costs (e.g., turbine maintenance, sorbent, etc), and fixed O&M cost which are not highly dependent on operation time. The fixed O&M costs for coal components (except for the turbine) are computed at about 4.5% of the equipment costs. Lacking data, the coal-fueled 501-K turbine operating hour maintenance cost is assumed at about 22% higher than that for a natural gas fired 501-K turbine.

The estimated O&M cost is about \$1.15 million/year for the coal-fueled cogeneration system operating with dry coal at a delivered price of \$1.80/MMBtu.

Development Needs and Risks

Technology Development Needs

Technology issues to be resolved prior to commercialization of coal-fueled turbine cogeneration plants include the following:

- hot gas filter durability and performance
- combustor refractory life
- turbine life

Table A-5.
Coal-fueled baseline cogeneration system O&M costs.

	<u>Cost (million \$)</u>
Fuel	0.782
Other variable O&M	0.266
Fixed O&M	<u>0.105</u>
Total O&M	\$1.153

Costs are first year (1990) values

Fuel and other variable O&M costs assume 90% availability

Delivered coal cost of \$1.80/MMBtu

Laboratory tests indicate the potential for long term corrosion of the ceramic filter components due to alkalis and ash compounds. Cracks have developed in filter elements during pilot plant tests. Some elements have lost much of their strength in less than 10% of their desired lifetimes. A few elements have failed during tests (Stringer and Leitch, 1991). Thermal shocking due to backpulse cleaning with relatively cold gases has often been attributed as the cause of the filter element cracks.

The desired operating conditions for the filters in the coal-fueled cogeneration system are more severe than those for earlier high temperature laboratory and pilot plant tests that were conducted mostly under 871°C (1600°F) and at oxidizing conditions. The 1100°C (2000°F) gas temperature at the quench zone and reducing conditions tend to increase the potential for molten ash phases that could cause long term corrosion attack, difficulties in backpulse cleaning, and possibly even irreversible plugging. Even though many hot gas filter problems observed in past tests have been attributed to inadequate designs for flow inlets, filter element mounts, and backpulse systems, there are durability concerns for hot gas filters, particularly under the more severe conditions of the coal-fueled turbine system.

Hot gas filter costs are uncertain. The costs are particularly sensitive to the filter operating face velocity (volumetric flow/filtration area) since this affects the number of filter elements and pressure vessel size. While capital costs are reduced by increasing the face velocity as high as possible, there is a limit at which the filter can no longer be effectively cleaned by backpulsing. This limit depends on the characteristics (e.g., size distribution, cohesiveness, molten phases, etc) for the particles captured. Past filter tests at reducing conditions, as for the Allison combustor system, but at lower temperatures, indicate that the filter face velocity could be in the range from 3 ft/min to 12 ft/min.

The refractory liners in the subscale and full-scale coal combustion systems have exhibited sufficient durability for combustor development testing but insufficient durability for a commercial system. Significant cracking, spalling, and eventual entrainment into the gas stream of refractory pieces have occurred. Refractories have been identified, as discussed on the appendix on Component Durability Laboratory Analyses, but these need to be proven in long duration combustor runs.

The extent of turbine flow-path degradation due to deposition, erosion, and corrosion has only started to be evaluated in an initial engine test using cyclone hot gas cleanup. Deposits were formed in the turbine flow path. The turbine run time was too short for corrosion/erosion evaluations.

Exposure of turbine materials at turbine flow-path temperatures in subscale coal combustor tests using cyclone gas cleanup has produced significant deposition and corrosion. These and the turbine engine deposits appear to result from a small fraction of molten ash phases at turbine inlet temperatures. Use of additives to reduce levels of molten phases should result in reduced deposition and corrosion.

Technology Development Risks

There are sufficient hot gas filter durability and cost concerns (described in the section on Technology Development Needs) that Allison explored backup approaches to meet the particle emissions goals in Table A-1 and protect the turbine. The intent was to reduce the technology development and commercial cost risks associated with hot gas filters. The backup approach utilizes advanced cyclone separators at the quench zone rather than a hot gas filter.

The definition and assessment of the alternate coal-fueled cogeneration system using cyclones will be described in a later section of this appendix.

COAL-FUELED COGENERATION — REFERENCE SYSTEM ASSESSMENT

Coal-Fueled Cogeneration System Description

Figure A-6 shows the arrangement of the reference coal-fueled cogeneration system. Figure A-13 depicts more detail in its physical arrangement. The system components are shown mounted on structural steel skids. The turbine, gearbox, and generator are mounted on one skid. The coal combustor and hot gas ceramic filter vessel are mounted on an adjacent skid. The turbine exhausts through a duct to the heat recovery steam generator, on a third skid, followed by the stack gas, sodium-based scrubber on its skid. Not shown are the dry coal grinding and fuel delivery system or the regenerator for the sodium-based sorbent.

The reference coal-fueled system is an adaption for coal of the commercial Allison natural gas-fired, 501-K cogeneration system. The coal system meets operational and functional requirements for cogeneration systems that are described in detail in Reference System Definition section along with system performance and costs.

Assessment Approach

Internal Rate of Return

The reference system economic assessments utilize the internal rate of return (IRR) to the investor/operator of the coal-fueled cogeneration system. The IRR is the rate of return expected to be earned on an investment project. Since IRR is commonly used by industry to evaluate investment decisions, it was used as a measure of the commercial attractiveness of the coal-fueled cogeneration system.

The IRR is the rate which discounts a project's cash flow to a net present value of zero. The cash flow is the project revenues minus project expenses (other than depreciation) minus project capital expenditures minus project income taxes considering depreciation. For the coal-fueled cogeneration system, the project revenues are the value of the electricity and steam produced. Reference system project expenses include the system operation and maintenance costs shown in Table A-5 and the electrical utility standby charge to guarantee electricity availability in the event of cogeneration system outages.

Economic Assumptions

The economic assumptions used in the IRR evaluations for the coal-fueled cogeneration system are given in Table A-6. The assumptions concerning the value of steam and electricity produced by the cogeneration plant are conservative. The value of steam is considered to be the cost of natural gas to produce the steam at 80% thermal conversion efficiency. This assumes that the investor considering the cogeneration system has an available gas-fired steam plant to meet his steam requirements and neglects the maintenance costs for the steam plant. For an investor without an available steam facility, the value of steam would need to include the capital cost of the steam plant.

The value of the electricity produced by the cogeneration system is assumed to be the deferred cost of electricity (assumed at \$0.06/kW-h) not purchased from a utility but provided by the cogeneration system. The value of electricity could be significantly greater at some locations with higher electricity rates or for situations where the utility is required to purchase electricity from a cogenerator at avoided cost.

Consequently, depending on site specific factors such as availability of an existing steam plant, local electricity rates, and utility electricity buy-back regulations, the economic attractiveness (IRR) of the coal-fueled cogeneration system could be higher at some plant locations than will be shown for most of the assessments of this report.

Table A-6.
Economic assumptions.

Project life = 20 years

Escalation rate = 5% for all values

Availability = 90%

Base energy cost:

Electricity = \$0.06/kW-h

Standby charge = \$2.40 kW/month

Natural gas = \$3.00/MMBtu and up

Steam cost = displaced gas at 80%

Economic Assessment Criteria

Although an acceptable IRR varies with factors such as interest rates for borrowed capital, the minimum acceptable IRR for the coal-fueled cogeneration system would be no lower than 15%. As the IRR increases above this value, the coal-fueled cogeneration system becomes increasingly commercially attractive. An IRR of 20% will be considered as a nominal goal in the following evaluations.

Reference System Economics

IRR for Baseline Assumptions

Figure A-14 shows the IRR for the coal-fueled cogeneration system versus natural gas price. Since, as discussed earlier, the value of the steam is directly related to the natural gas price, the abscissa is also labeled with the first year value of steam in \$/1000 lb. Figure A-14 shows that the coal-fueled system IRR increases with increasing natural gas price. The coal-fueled system IRR increases because of the higher value of steam (and revenues) for higher natural gas prices.

Figure A-14 shows that the coal-fueled cogeneration system provides an IRR of 15% at a natural gas price of about \$2.10/MMBtu and an IRR goal of 20% at a natural gas price of \$4.00/MMBtu. The coal system curve also indicates the sensitivity of IRR to the value of steam produced. The IRR goal is achieved at a steam value of about \$5.00/1000 lb.

Sensitivity to the Value of Electricity

For these evaluations, a first year value of \$0.06/kW-h was assigned to the electricity produced by both the coal-fueled and natural gas-fueled cogeneration systems. As indicated earlier, this was assumed as the displaced cost of electricity not purchased from the local utility and produced for the cogenerator's needs. However, depending on site location, utility electrical rates to industrial users can be higher than the assumed value of \$0.06/kW-h. Figure A-15 shows the sensitivity to electricity costs of the natural gas price and value of steam at which the coal-fueled cogeneration system provides a 15% IRR and a 20% IRR. Compared to an electricity rate of \$0.06/kW-h, a value of \$0.07/kW-h results in more economically attractive IRRs for the coal-fueled cogeneration system. Coal system IRRs of 15% and 20% are achieved at natural gas prices of \$0.82/MMBtu and \$2.70/MMBtu or, equivalently, lower steam values of \$1.00/1000 lb and \$3.40/1000 lb, respectively.

Figure A-14. IRR versus gas price for coal fueled cogen system.

Figure A-15. Effect of value of electricity on gas price and steam value for IRRs of 15 and 20%.

Sensitivity to Coal Fuel Price

The economic assessments are referenced to a 1990 startup date for the cogeneration systems. The 1990 delivered coal price has been assumed at \$1.80/MMBtu. However, coal prices can range widely depending on mining costs, shipping costs, and coal quality (sulfur level, Btu content, etc). For example, the DOE Publication DOE/EIA, "Weekly Coal Production," lists state average coal prices ranging from \$1.01/MMBtu to over \$2.40/MMBtu and even higher prices (mainly due to shipping) for low sulfur western coal transported to eastern states.

Figure A-16 gives the sensitivity to delivered coal price of the natural gas price and value of steam at which the coal-fueled cogeneration system produces a 15% IRR and a 20% IRR. A coal price of \$1.20/MMBtu produces a 20% IRR at a natural gas price of \$3.00/MMBtu.

Sulfur Control Alternatives

Figure A-11 showed little or no economic (IRR) benefit of sorbent injection into the coal combustor quench zone over commercially available stack gas scrubbing for sulfur control. This section evaluates sulfur control alternatives of sulfur compliant coals (<0.65% sulfur) and operation of the reference system without a sorbent regenerator. The elimination of the calcium-based regenerator reduces capital costs but increases operating costs for the relatively expensive NaOH sorbent.

Sulfur Compliant Coal

The use of a sulfur compliant coal results in a cogeneration plant with significantly lower capital costs than the reference plant and eliminates sulfur sorbent and spray water costs. Waste disposal costs are also reduced. However, a premium price is required for a low sulfur coal. Figure A-17 compares the IRR for a coal-fueled cogeneration system with various sulfur compliant coal costs to the IRR for the reference system (with scrubber and regenerator).

Figure A-16. Effect of coal fuel price on gas price for minimum acceptable IRR and IRR goal.

Figure A-17. IRR for coal-fueled cogen system using sulfur compliant coal at various prices.

Figure A-17 shows that the cogeneration system using a sulfur compliant coal at about \$2.40/MMBtu provides about the same IRR as the reference system for natural gas prices in the \$4.00/MMBtu range. Consequently, sulfur compliant coal prices lower than \$2.40/MMBtu provide the IRR goal at a lower natural gas price (or value of steam) than the reference system using coal at a price of \$1.80/MMBtu.

Elimination of Regenerator

Table A-7 lists the IRR for the reference coal system and the same system without a sulfur sorbent regenerator. This table indicates the regenerator results in a more economically competitive system. The additional capital cost for the regenerator is more than offset by the reduced operating costs for sorbents.

Hot Gas Filter Issues

Filter Cost

As discussed in the system definition section of this report, the face velocity (volumetric flow/filtration area) for the reference system ceramic candle filter has a major effect on the filter capital cost. Increasing the face velocity reduces the filter system cost but eventually a limit is reached where the filter dust cake cannot be effectively removed by back pulsing. The maximum allowable face velocity for effective backflushing at coal turbine conditions is not currently known and could range down to

Table A-7.
Effect of sorbent regenerator on reference system IRR.

Natural gas price (\$/MMBtu)	3.00	4.00	5.00	6.00
System IRR with regenerator	17.36	20.02	22.64	25.23
System IRR without regenerator	14.68	17.64	20.50	23.31

3 ft/min (observed in some tests at a coal gasifier) from an objective of 12 ft/min, which has been assumed for the reference cogeneration system based on supplier recommendations.

Figure A-18 shows that the filter costs associated with this possible range of face velocities can significantly affect the natural gas price at which the coal-fueled cogeneration system achieves the IRR goal. This goal is reached at more than a \$1.00/MMBtu higher natural gas price for a 3 ft/min face velocity compared with a 12 ft/min face velocity.

Additives

The last section addressed cost issues for hot gas ceramic filters. Filter technology issues were also mentioned in the Reference System Definition section. An important technical issue is the desired filter operating conditions for the cogeneration system. The high temperature of 1100°C (2000°F) and reducing atmosphere produce a more severe environment than for past tests of filters due to an increased potential for molten ash phases. These molten phases could cause long term corrosion attack, difficulties in filter backflushing, and possibly even irreversible plugging.

One potential approach to reduce molten phases could be the use of additives to change the ash compounds formed in the combustion stream or in the filter cake. The modified compounds would have higher melting points, above the filter operating temperature. Two relatively low cost additives are alumina (Al_2O_3) and kaolin (alumina silicate). Laboratory tests at Allison suggest that small particle size alumina at 0.4:1 mass ratios to coal ash or kaolin at 1:1 to 2:1 mass ratios raise ash fusion temperatures to much higher than filter operating temperatures. At a 1:1 doping ratio the lower unit cost kaolin is somewhat less expensive than alumina at a 0.4:1 ratio.

Economic analyses were conducted that showed that the use of alumina or kaolin at the above doping ratios for a 5% ash coal results in significant reductions in IRRs for the reference system. The natural gas price at which the system achieves a 15% IRR and 20% IRR increase to the vicinity of \$4.50/

Figure A-18. Reference system IRR versus filter face velocity.

MMBtu and \$6.00/MMBtu, respectively, for doping with alumina. These compare to the previously discussed values of \$2.10 and \$4.00/MMBtu, respectively, for the reference system without doping.

A more economically attractive approach to use additives would be to install a cyclone upstream of the hot gas filter and inject the additive into the gas stream at a location between the cyclone and filter. Much less of the additive would be needed since most of the ash would be removed by the cyclone. Because residence time and the potential for contact of the additive with the ash in the combustion stream would be reduced, the controlling additive/ash reactions probably occur in the filter cake.

Figure A-19 compares the reference system IRR with the IRR for the reference system modified by addition of a cyclone and injection of an alumina additive between the cyclone and filter. A 90% ash removal efficiency is assumed for the cyclone and the additive is injected at the mass ratio given above to the ash passing the cyclone. The higher capital cost for the cyclone and its ash collector, the higher operating costs for additives (and disposal after capture), and the effects of increased pressure drop for the cyclone increase the natural gas price for a specified IRR goal compared to the reference system. The natural gas price to achieve a 15% IRR increases by \$0.74/MMBtu (to \$2.84/MMBtu) over that of the reference system. The natural gas price to achieve a 20% IRR increases by \$0.83/MMBtu (to \$4.83/MMBtu).

Sensitivities

The bar chart of Figure A-20 shows the sensitivity of the reference system IRR (in percent) for a natural gas price of \$3.20/MMBtu to 10% changes in system acquisition cost, natural gas cost, coal fuel cost, turbine maintenance costs, and systems availability. This chart indicates that system availability, acquisition cost, coal fuel cost, and natural gas cost are the main drivers for the economic performance of the coal-fueled cogeneration system.

Figure A-19. Effect of using alumina additive plus cyclone on reference system IRR.

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Figure A-20. IRR sensitivity to 10% change in system parameters.

ALTERNATE COGENERATION SYSTEMS

Particulate Control-Backup Approaches

The Development Needs and Risks section of this appendix discussed durability concerns for hot gas filter in the reference cogeneration system. Figure A-18 showed that even for acceptable durability, hot gas filter costs can significantly lower the IRR for the reference cogeneration system if low filtration face velocities (similar to those required in gasification plant tests) are needed for effective backflushing. Because of these filter durability and cost uncertainties, backup systems approaches were explored to meet environmental emissions standards and protect the turbine.

Cyclones are commercially proven hot gas particulate control devices. Recent advances in cyclone optimization theory (Ioia and Leith, 1990) indicate that higher performance than past cyclone designs might be achieved at acceptable pressure drops. Such advanced cyclones and ash doping to control molten phases might reduce turbine deposition and erosion to tolerable levels. If needed, steam cooling to the first two turbine rows to lower surface temperatures could also be used to freeze molten phases and thereby reduce deposition and corrosion.

Although cyclones alone do not have sufficiently high particle removal efficiencies to meet the emissions goal in Table A-1, this goal should be achieved with the combination of moderate coal ash levels ($\leq 5\%$), cyclones, and the particle removal capabilities of the stack gas sulfur scrubber, as shown by Figures A-21 and A-22. The sulfur scrubber particulate collection efficiencies needed to meet the particle emissions goal are shown in Figure A-21 versus coal ash level and various efficiencies of one cyclone (solid plots) and two cyclone (dash plots) cleanup systems. The commercial, sodium-based scrubber chosen for the cogeneration system has achieved particle collection efficiencies up to 90% and higher, depending on particle size distribution and pressure drop (Figure A-22).

Figure A-21. Sulfur scrubber particle removal performance needed to provide 0.03 lb/MMBtu particulate emissions.

Figure A-22. Sulfur scrubber particle removal performance.

System Options

Figure A-23 shows alternate system options. The emissions goals for NO_x and SO_x are achieved using the same staged coal combustor and sodium-based stack gas scrubber as for the reference system. Particulate emissions are controlled by using the combination of moderate ash coals, cyclone separator, and the particle removal benefits of the sulfur scrubber. If necessary, the particle removal efficiency can be increased by a second cyclone or a venturi scrubber provided as an option by the sulfur scrubber supplier. The venturi scrubber can be incorporated within the sulfur scrubber at a modest incremental capital cost but higher exhaust pressure drop. Also shown in Figure A-23 are options of additives and highly cooling the first two turbine rows with steam for turbine protection from deposition and corrosion. As for the reference system, coatings on the vanes and blades of all the turbine rows are used to alleviate corrosion and erosion from coal combustion products.

Tests and analyses were planned in the Allison ACFTS project to obtain the information needed to make final choices on particulate emissions control and engine protection for the coal-fueled turbine systems. Initial hot gas filter tests would explore effects of filter face velocity and operating temperature on filter performance and durability. Later tests would evaluate alternate filter materials and backflushing approaches. Advanced cyclones would be designed and tested. Subscale DEC tests using a filter and only a cyclone would be used to predict and compare short term turbine degradation for these approaches to control particulate. Predictions of turbine maintenance intervals would be facilitated by a data extrapolation approach that has been developing in recent years (Wenglarz, 1987, 1991). Systems evaluation and economic analysis, such as described in this report, would be updated for the reference and alternate systems as the data base for filters and cyclones is developed. The program ended before these planned tests and evaluations could be conducted.

Alternate Cogeneration System Configurations

Several alternate system configurations using cyclone particulate cleanup rather than hot gas filters at the quench zone were evaluated. These are described below in approximate order of increasing complexity of measures to reduce environmental particulate emissions and protect the turbine from flow path degradation due to DEC.

Baseline Alternate System — Single Cyclone Stage

This cogeneration system is the same as the reference system except the hot gas filter is replaced by one cyclone stage. Technical issues for this system are particulate emissions and turbine DEC life. The

Figure A-23. Alternate system options.

previous discussion indicates that the combination of a relatively low ash (5%) coal and particulate removal benefits of the sulfur scrubber could probably meet the emissions goal of 0.03 lb/MMBtu particulate, but this depends on the turbine exhaust particle size distribution.

Significant turbine deposition was experienced during a short term (four hours on coal) engine test at Allison using a subbituminous coal water fuel and cyclones for particulate cleanup. However, the cyclone particle removal efficiency was unexpectedly low (<50%) and subbituminous coals tend to produce higher deposition rates than bituminous coals. Advanced cyclone tests and bench scale DEC tests mentioned earlier could result in cyclones with much higher particle removal efficiencies and identification of coals with lower ash sticking fractions and reduced deposition tendencies. Furthermore, the system's alternatives described below provide additional measures over those of the baseline alternate system to alleviate particulate emissions and/or turbine flow path degradation.

Two Stages of Cyclones

This cogeneration system is the same as the reference cogeneration system except the hot gas filter is replaced by two stages of cyclones. This reduces particle loadings entering the turbine and decreases flow path deposition and erosion compared to the baseline alternate system. Particulate removal requirements on the sulfur scrubber to meet the particle emissions goal in Table A-1 are also reduced. However, the additional cyclone stage increases the plant cost and reduces the turbine power output due to an increased pressure drop between the compressor and expander.

One Cyclone Stage and Venturi Stack Scrubber

This system incorporates a venturi scrubber with the sulfur scrubber of baseline (single cyclone stage) alternate system. Exhaust emissions would be reduced well below the goal of Table A-1 but no additional turbine protection over that of the baseline alternate system is provided. The system capital cost increases only moderately because the venturi scrubbing is accomplished within the same vessel as the sulfur scrubber. However, the venturi scrubber increases the turbine exhaust back pressure, to 20 in. of H₂O, and thereby reduces the turbine power output.

One Cyclone Stage and Deposition/Corrosion Additives

Until further DEC testing is conducted, it will not be known whether the combination of advanced cyclones, coal selection, and protective coatings are adequate to protect the turbine from deposition and corrosion such as has been observed in the past short term engine test and the subscale DEC tests (Wenglarz and Fox, 1990a, 1990b). The deposition and corrosion observed in these early tests likely resulted from significant levels of molten ash phases at turbine flow-path temperatures. As indicated earlier, selection of coal with ash chemistries that result in acceptable levels of molten phases might be possible. Additional control of molten ash phases can be achieved by injecting additives such as kaolin or alumina that react with the coal ash to produce higher melting point phases. This reduces sticking fractions of ash material delivered to turbine surfaces and results in weaker deposits that are more susceptible to removal by on-line "nutshelling" or water washing.

Economic analyses described earlier have shown that, for coal ash levels of 5%, the cost of the most promising additives to date, alumina and kaolin, can adversely affect the economic attractiveness of the coal-fueled cogeneration system when injected at typical additive to ash mass ratios, 0.4:1 to 2:1, determined in laboratory tests. These analyses also showed that it is much more economical to inject the additive downstream of the cyclone at the typical mass ratios to the ash passing the separator. For the following economic evaluations of systems using additives, a 90% ash removal efficiency is assumed for the cyclones and the alumina and kaolin are injected at mass ratios of 0.4:1 and 1:1, respectively, to the ash passing the separator.

One Cyclone Stage, Highly Cooled Turbine

Another approach to alleviate turbine deposition and corrosion is to highly cool the first two rows of the turbine. This tends to freeze molten particles as they traverse the thermal boundary layers of the vanes and blades, and thereby reduce sticking fractions of the impacting particles. Sintering rates would be inhibited for those particles that are captured on the airfoil surfaces. This would decrease the strength of the deposits that are formed and would facilitate deposit cleaning. Corrosion rates would also be inhibited since the most aggressive forms of corrosion usually involve molten phases.

Steam Cooling

Steam is a superior medium to air for high levels of cooling turbine vanes and blades. (Wu and Louis, 1984; Stecco and Facchini, 1988). This is because of the higher specific heat of steam compared to air and insignificant pumping work required to provide pressurized steam. Since steam is a product of cogeneration, and combined cycle systems, it is available at little additional equipment cost for gas turbine cooling.

Three levels of steam cooling were evaluated for alternate cogeneration systems using one cyclone stage and a highly cooled turbine. These variations differ in the maximum average surface temperatures of 815°C, 649°C, and 538°C (1500°F, 1200°F, and 1000°F) for the steam cooled first-stage stator vanes and rotor blades. The value of 815°C (1500°F) has been chosen to be similar to the maximum average surface temperature of coal-fired PFBC cascades and test turbines for which airfoil corrosion rates have been controlled with a proper choice of corrosion resistant coatings. Deposition rates have also been low in PFBC tests at 815°C (1500°F) and lower gas and surface temperatures.

Turbine corrosion from alkalis has primarily been affected by airfoil surface temperature rather than gas temperature. The surface temperature of 815°C (1500°F) is between the typical threshold temperatures (Stringer, 1985) for Type I and Type II hot corrosion from alkalis (Table A-8). The surface temperature of 649°C (1200°F) is below the lower threshold for Type II hot corrosion. The lowest average surface temperature of 538°C (1000°F) for the first two rows of the 501-K turbine is expected to further reduce levels of molten phases and the potential for corrosion and deposition. Although the two lower surface temperatures are in the range for which superheater corrosion sometimes occurs in coal boilers, the turbine alloys and coatings should be much more corrosion resistant than the relatively inexpensive boiler materials.

Effects on System

High degrees of steam cooling of the first two rows of the Allison 501-K turbine could be accomplished with only a modest additional cost for a production engine and cogeneration system. The turbine casing would be modified to allow passage of steam into the same cooling channels now used for air cooling of the first stage vanes and blades. Steam could be provided by a 250 psia steam generator at the turbine exhaust similar to that currently used for Allison commercial natural gas-fired industrial turbines operating with steam injection for augmented power. Steam cooling for the coal-fueled cogeneration system also augments the turbine power output but decreases the net steam output of the plant.

Table A-8.
Approximate corrosion threshold temperatures--°C (°F).

	<u>Lower temperature</u>	<u>Upper temperature</u>
Type I hot corrosion	827 (1520)	949 (1740)
Type II hot corrosion	699 (1290)	777 (1430)

Turbine Cooling To 815°C (1500°F), Additional Particulate Cleanup

The last subsection describes alternate cogeneration systems that utilize a single stage of cyclones and three different levels of turbine cooling using steam. This subsection identifies two systems which are the same as that in the last subsection, with the first stator vanes and first rotor blades cooled to 815°C (1500°F), but with additional particulate cleanup to protect the turbine and/or meet environmental particulate emissions requirements. The first system option with additional particulate cleanup utilizes two, rather than one, stages of cyclones. The second option uses a venturi particulate scrubber incorporated into the sulfur scrubber, in addition to one stage of cyclones, to control particulate emissions.

Alternate System Performance/Costs

Table A-9 compares the performance, installed capital costs (in 1990 dollars), and first year operation and maintenance costs (in 1990 dollars) for the alternate systems just described and the reference cogeneration system using a hot gas filter. These alternate systems are labeled from 1 through 9. The installed capital costs for all the alternate coal-fueled cogeneration systems and the reference system in Table A-9 are no more than a factor of 1.85 times higher than the installed cost of the commercial natural gas fueled cogeneration system using the Allison 501-K turbine.

Cogeneration Systems Performance

Performance evaluations were conducted for the reference and alternate coal-fueled cogeneration systems using 501-K turbine operating characteristics, considering water injection at the quench zone, and using appropriate pressure drops for the systems' components such as the coal combustor, particulate cleanup equipment, heat recovery steam generator, and sulfur scrubber. These evaluations determined the turbine power output and exhaust flow rate and enthalpy from which process steam output was obtained.

The same pressure drop per particulate cleanup stage (2%) has been assumed for the hot gas ceramic filter and the cyclones. This is because the relatively high filter face velocity (12 ft/min) and operating temperature of 1100°C (2000°F) might be expected to result in a significant baseline pressure drop. The filter baseline pressure drop can be decreased by reducing the face velocity, but, as shown earlier, this increases the filter size and cost to the extent that it adversely affects systems economics. Because the filter and cyclone pressure drops are assumed the same, the power and steam outputs are the same for the reference system using a hot gas filter, and the baseline alternate system, using one stage of cyclones. These are designated as Systems 1 and 2 in Table A-9. Table A-9 shows that those alternate systems with steam cooled gas turbines produce higher electrical outputs and lower levels of process steam than the reference system and alternate systems with conventional air cooling. The higher turbine mass flow due to steam cooling increases the turbine output power but decreases the available process steam. Table A-9 shows that increased turbine steam cooling results in a reduced overall systems efficiency.

The fuel flow, simple cycle efficiency, and overall efficiency for the cogeneration systems in Table A-9 are based on the lower heating value (14825 Btu/lb) for the coal.

Cogeneration System Costs

As indicated by Table A-9, the installed costs for all but one of the alternate cogeneration systems using cyclones are less than the installed cost for the reference system using a hot gas filter. The installed cost of the alternate system using two cyclone stages and steam cooling (System 8) is only slightly (4%) higher than that of the reference system.

Table A-9.
Coal-fueled cogeneration systems performance and costs.

	Reference System	Conventional Turbine Cooling			Alternate Systems					
					Steam Cooling					
		Hot Gas Filter (12 ft/min)	Cyclone 1	Two Cyclones 2	Cyclone + Venturi 3	Cyclone + Kaolin 4	Cyclone 1500°F surf. 5	Cyclone 1200°F surf. 6	Cyclone 1000°F surf. 7	Two Cyclones 1500°F surf. 8
Electrical Output (kW)	3730	3730	3660	3590	3730	4190	4270	4380	4110	4050
Steam Output (lb/hr)	23140	23140	22440	22920	23140	18680	12760	4260	18610	19150
Fuel Flow (MMBtu/hr)	54.05	54.05	53.72	54.02	54.05	56.26	55.96	55.54	55.82	56.27
Simple Cycle Efficiency (%)	23.6	23.6	23.3	22.7	23.6	25.4	26.0	26.9	25.1	24.6
Overall Efficiency (%)	70.9	70.9	69.4	69.6	70.9	62.1	51.2	35.4	62.0	62.2
Installed Cost (\$MM)	6.439	6.047	6.344	6.127	6.047	6.180	6.180	6.180	6.477	6.260
First Year O&M Cost (\$MM)	1.128	1.113	1.119	1.116	1.162	1.147	1.143	1.137	1.153	1.151

- Steam output assumes 64% condensate return from process plant
- Fuel flow, simple cycle efficiency, and overall efficiency are based on lower heating value of the coal
- Installed cost and first year O&M cost are in 1990\$
- Delivered coal cost of \$1.80/MMBtu
- Plant availabilities of 90%

The fuel cost component of the system operation and maintenance costs is based on the upper heating value, 15120 Btu/lb, for the coal at a delivered price of \$1.80/MMBtu. As discussed earlier, this price for the 5% ash, 2% sulfur coal fuel is based on a survey of delivered coal prices versus coal quality in 1990.

No data is currently available to establish the relative turbine maintenance costs and plant availabilities for the various coal-fueled cogeneration systems. DEC tests using cyclones and filters were planned to provide data from which turbine maintenance intervals and costs were to be estimated using a data extrapolation approach being developed at Allison (Wenglarz, 1987, 1991).

Lacking data, the turbine maintenance costs for all the systems of Table A-9 have been estimated at about 22% higher per run hour than for a natural gas-fired 501-K turbine. An availability of 90% is assumed for all the systems in Table A-9, compared to a value greater than 95% experienced in the field for the Allison 501-K natural gas-fired cogeneration system.

Alternate System Assessments

Internal rates of return (IRR) to the owner/operator were used for the economic evaluations of the alternate cogeneration systems described above. The same economic assumptions (Table A-6) were used to determine the IRRs of the alternate systems as were used in the earlier evaluations of the reference system that operates with a hot gas filter.

Alternate System Economics

Baseline Alternate System

Figure A-24 compares IRRs versus natural gas price for the baseline alternate system (one cyclone stage at quench zone) and the reference system (hot gas candle filter at quench zone). Also shown are the effects of filter face velocity, and resulting filter size and cost, on the IRR for the reference system. The filter face velocity varies from the objective of 12 ft/min down to 3 ft/min. The systems capital costs in Table A-9 consider a filter face velocity of 12 ft/min and a face velocity of 3 ft/min results in more than \$900,000 additional system capital costs over those in that table.

Figure A-24 indicates that the baseline alternate system with a single stage of cyclones produces a higher IRR than the reference system using a hot gas filter. An IRR of 15% is produced by the baseline alternate system at a gas price of \$1.80/MMBtu compared to \$2.10/MMBtu for the reference system using a filter with a face velocity of 12 ft/min. A 20% IRR is achieved by the baseline alternate system at a gas price of \$3.55/MMBtu while the reference system with a 12 ft/min filter face velocity produces this IRR at a gas price of \$4.00/MMBtu. The economic advantage for the system using cyclones increases with decreasing filter face velocity. For example, the natural gas price at which the alternate cyclone system produces the 20% IRR is about \$1.60/MMBtu lower than that of the reference system operating with a filter at a face velocity of 3 ft/min.

As indicated earlier, the economic analyses for the coal systems using cyclones and filters assume the same turbine maintenance costs. However, since turbine maintenance costs are expected to be higher for cyclone cleanup without additional turbine protection measures, the above results indicate there is an increased turbine maintenance cost for use of cyclones that provides the same IRR as hot gas filters. Table A-10 shows this increase in turbine maintenance cost that would result in a 20% IRR for the baseline alternate system at the same natural gas price as for the reference system using a hot gas filter. The maintenance costs in Table A-10 are expressed in terms of percent increase over the turbine maintenance cost for a natural gas-fired 501-KB5 turbine. Table A-10 indicates that the baseline alternate system would produce a 20% IRR at a lower natural gas price than the reference system at a turbine maintenance cost increase less than 105% (2.05 times) for a 12 ft/min face velocity and 340% (4.4 times) for a 3 ft/min face velocity. These compare to an increased turbine maintenance cost of about 22% over that of a natural gas-fired system which was assumed for the reference system at all filter face velocities.

Figure A-24. IRR comparisons: baseline alternate system against reference system with various filter face velocities.

Table A-10.

Turbine maintenance cost increase below which baseline alternate system (cyclone) is competitive with reference system (filter).

Reference system* filter face velocity (ft/min)	12	9	6	3
Alternate system increased turbine maintenance cost (% over N.G. turbine)	105	130	195	340

*Reference system turbine maintenance cost is assumed at 22% higher than that for natural gas-fired turbine

Alternate Systems with Additional Particulate Cleanup

Table A-11 gives IRRs versus natural gas price for the reference system and alternate Systems 2 and 3 (see Table A-9) which use two stages of cyclones and one cyclones stage plus venturi scrubber, respectively. For a filter face velocity of 12 ft/min, the reference system achieves the IRR goal at a natural gas price of \$4.00/MMBtu compared to 19.7% and 20.2%, respectively, for the alternate systems using two cyclone stages and one cyclone stage plus venturi scrubber. If the filter must operate or lower face velocity of 6 ft/min or 3 ft/min to prevent plugging, the reference system IRRs at \$4.00/MMBtu gas price decrease to 19.0% and 17.5%, respectively.

Table A-11.
IRR for reference system and alternate systems using additional particulate cleanup.

<u>Plant configuration</u>	Natural gas price (\$/MMBtu)			
	<u>3.00</u>	<u>4.00</u>	<u>5.00</u>	<u>6.00</u>
Reference system (12 ft/min face velocity)	17.4	20.0	22.6	25.2
Reference system (6 ft/min face velocity)	16.8	19.0	21.5	24.0
Reference system (3 ft/min face velocity)	15.1	17.5	19.8	22.0
Alternate system 2 (two cyclones)	17.1	19.7	22.3	24.8
Alternate system 3(cyclone + venturi)	17.4	20.2	22.9	25.6

Alternate System with Additives

Figure A-25 gives effects on alternate system economics of additives to control molten phases and consequently gas turbine deposition and corrosion. IRRs versus natural gas price are shown for the baseline Alternate System 1 (one cyclone stage), Alternate System 4 (one cyclone and kaolin additive) and a variation of alternate system 4 that uses an alumina additive rather than kaolin. For comparison, the IRR for the reference system using a hot gas filter is also given. As discussed earlier, the kaolin and alumina for the systems using additives are assumed to be injected downstream of a 90% efficient cyclone. The injected dopant mass ratios to ash passing the separator are 1:1 and 0.4:1 for kaolin and alumina, respectively.

Additive costs of kaolin and alumina are nearly the same at the specified mass ratios to result in very little difference in the IRR for the variations of alternate System 4 using these additives. The use of additives somewhat lowers the system IRR compared to baseline Alternate System 1, but still results in a higher IRR than the reference system using a hot gas filter.

One Cyclone Stage, Steam Cooled Turbine

The above economics results are for cogeneration systems which use the 501-K turbine which is cooled conventionally with compressor discharge air. The remaining cogeneration system economic results will consider alternate systems which utilize the 501-K turbine modified to use steam for cooling the first two expander rows (first stator vanes and first rotor blades). A high degree of steam cooling is considered as an approach to alleviate turbine deposition and corrosion by freezing molten ash phases.

Alternate Systems 5, 6, and 7 (described in Table A-9) are essentially the baseline alternate system using one stage of cyclone cleanup but with three degrees of steam cooling, rather than air cooling, of the first two expander rows of the 501-K turbine. Figure A-26 gives the IRR versus natural gas price for Alternate Systems 5, 6, and 7. Also repeated for comparison are the IRRs, the reference system using filters and the baseline Alternate System 1 using one stage of cyclones and conventional air cooling of the turbine.

Figure A-25. Effective of additives on IRR for baseline alternate system.

Figure A-26. IRR for alternate systems using steam for gas turbine cooling.

Figure A-26 indicates that Alternate System 5 with turbine steam cooling to an average surface temperature of 815°C (1500°F) produces a slightly higher IRR at low natural gas prices than the same system (Alternate System 1) using air cooling. This is because revenues from increased turbine power by steam injection more than offset the loss of process steam revenues at the relatively low value of steam for low natural gas prices. As described in the economic assumptions, the value of steam is directly related to natural gas price. However, at higher natural gas prices, the loss of steam revenues becomes more significant and the baseline alternate system using conventional air cooling produces a higher IRR than the alternate system using steam cooling to 815°C (1500°F).

For natural gas prices up to \$6.00/MMBtu, Alternate System 5 (steam cooled to 815°C [1500°F]) produces a higher IRR than the reference system using hot gas filters operated at a face velocity of 12 ft/minute. The economic advantage for Alternate System 5 would be even greater should lower filter face velocities be needed for adequate backflushing of the filter. Alternate Systems 6 and 7 with the first two turbine rows cooled to 649°C (1200°F) and 538°C (1000°F), respectively, produce lower IRRs than the reference system operating with a filter at 12 ft/min face velocity. The decrease in process steam net output due to turbine cooling to these levels reduces plant revenues to adversely affect the system economics.

Steam Cooled Turbine to 1500°F, Additional Particulate Cleanup

Table A-12 shows the effects on systems economics of modifying the alternate system with the 501-K turbine steam cooled to 815°C (1500°F) by adding a second cyclone stage (Alternate System 8) or a venturi particulate scrubber (Alternate System 9). System 9 with a venturi scrubber produces a similar IRR to the reference system operating at a filter face velocity of 12 ft/min. System 8 with two cyclone stages produces a somewhat lower IRR than the reference system. Both alternate Systems 8 and 9 produce higher IRRs than the reference system operating with filter face velocities less than 6 ft/min.

Conclusions – Alternate 3-5 MW Cogeneration Systems

Comparison of Systems

Table A-13 lists IRRs for the coal-fueled cogeneration systems that have been analyzed. These are ranked according to IRR at a natural gas price of \$4.00/MMBtu, or equivalently, a value of steam of \$5.00/1000 lb. Alternate System 1 with one cyclone stage provides the highest IRR (+21.3%) of all the systems. The alternate system using one cyclone stage and turbine cooling to 815°C (1500°F) with steam yields an IRR of 20.8%. These compare to an IRR of 20% for the referenced system with hot gas filters operating at a face velocity of 12 ft/min. Five of the alternate systems provide a higher IRR than the reference system at a 12 ft/min filter face velocity. Should a lower filter face velocity of 6 ft/min be required to prevent filter plugging, the increase in filter cost results in a reference system IRR lower than that of 7 alternate systems.

Table A-12.
System IRR for 501-K steam cooled to 815°C (1500°F) and additional particulate cleanup.

<u>Plant configuration</u>	Natural gas price (\$/MMBtu)			
	<u>3.00</u>	<u>4.00</u>	<u>5.00</u>	<u>6.00</u>
Reference system (12 ft/min)	17.4	20.0	22.6	25.2
Reference system (6 ft/min)	16.8	19.0	21.5	24.0
Alternate system 8 (steam + 2 cyclones)	17.4	19.5	21.6	23.7
Alternate system 9 (steam + venturi)	17.8	20.1	22.3	24.5

Table A-13.
Cogeneration system IRR at natural gas price of \$4.00/MMBtu.

<u>System</u>	<u>IRR (%)</u>
Baseline Alternate System 1 (one cyclone stage)	21.3
Alternate System 5 (steam cooled to 1500°F, one cyclone)	20.8
Alternate System 4 with additive (one cyclone stage, kaolin/alumina)	20.7/20.5
Alternate System 3 (one cyclone + venturi scrubber)	20.2
Alternate System 9 (steam cooled to 1500°F, cyclone + venturi)	20.1
Reference system (filter at 12 ft/min)	20.0
Alternate System 2 (two cyclone stages)	19.7
Alternate System 8 (steam cooled to 1500°F, two cyclones)	19.5
Reference system (filter at 6 ft/min)	19.0
Alternate System 6 (steam cooled to 1200°F, one cyclone stage)	18.5
Reference system (filter at 3 ft/min)	17.5
Alternate System 7 (steam cooled to 1000°F, one cyclone stage)	15.0

Lacking data, these results assume the same turbine maintenance cost for all the cogeneration systems (22% higher than for a natural gas-fired turbine). Turbine maintenance costs would likely be lower for the reference system using filters than for the alternate systems using cyclones and conventional turbine cooling. However, depending on the extent of turbine corrosion and deposition alleviated by highly cooling to 815°C (1500°F) and the degree of erosion alleviated by the filter, some of the alternate systems might produce lower turbine maintenance costs than the reference system. Furthermore, filter maintenance costs for the reference system could be very high, much higher than the 4.5% of installed cost per year assumed in the analyses, unless much greater filter durability is achieved than has been observed in PFBC tests to date.

Improvements Suggested by the Economic Results

A quench zone steam generator might benefit the reference system using filters. In this case, the steam generator could reduce the gas temperature entering the filter to 871°C (1600°F) or lower and thereby produce a less severe filter operating environment. The lower temperature would reduce the potential for filter plugging, corrosion, and thermal shock degradation due to backflushing. The steam produced could provide additional revenue benefits or would be used to cool the gas turbine.

A cost estimate was obtained for a quench zone heat exchanger sized for the Allison 501-K cogeneration system. Because of the reducing conditions, ash levels, and H₂S levels in the gas stream, the heat exchanger was of special design and too expensive for a system of the scale of the cogeneration plant. However, the cost of a quench zone heat exchanger could be accommodated in a large system such as the coal-fueled turbine combined cycle plant which is described in the remainder of this appendix.

COAL-FUELED TURBINE, COMBINED CYCLE PLANTS

Allison Combustor for Large Turbines

The Allison external RQL combustor previously described is essentially an entrained flow, gasification/combustion system integrated with the turbine. The system is air blown with hot gas cleanup and, therefore, does not incur the high capital costs and efficiency penalties for the oxygen plant and cold gas cleanup equipment used in many coal gasification systems that are being developed. Consequently, the combustion system, adapted for utility turbine plants, should offer cost advantages over other systems using coal gasification. A direct comparison of the cost of electricity for a coal-fueled utility plant with that for competing coal technologies under the same economic assumptions would be expected to quantify advantages of the RQL system. However, such comparisons were not within the project scope.

A second type of stationary coal-fueled turbine application evaluated in this appendix utilizes the Allison external coal combustion approach for large combined cycle plants. The following systems evaluations for such plants have also been discussed elsewhere (Wilkes, Wenglarz, et. al., 1993).

System Description

The coal-fueled turbine, combined cycle (CFTCC) approach is illustrated by the simplified block diagram in Figure A-27. The system consists of two major blocks, the RQL coal combustion/emissions control block and the power generation block. The power generation block is a combined cycle (gas turbine and steam turbine cycle) system and uses equipment designed to operate with conventional turbine fuels (e.g., natural gas). The RQL coal combustion/emissions control block adapts the conventionally fueled combined cycle equipment to operation with coal. As to be later discussed, the coal combustion equipment uses gas turbine technology rather than process plant technology and provides compactness and cost advantages over other coal utilization systems.

Referring to Figure A-27, a portion of the gas turbine compressor discharge air is directed to the combustion/emissions control block where it is reacted with coal to produce a combustion stream from which coal contaminants (e.g., sulfur and ash particulate) are removed before final combustion and expansion in the turbine. Quench water and heat extraction are used in the combustion/emissions control block to lower the temperature of the combustion products to a suitable value of 727°C (1340°F) for removal of coal contaminants and control of emissions. The heat extracted in the combustion/emissions control block is used in the steam equipment of the combined cycle power generation block to produce power.

Combustion/Emissions Control Block

Nitrogen oxides (NO_x) are controlled in the combustion/emissions block by RQL combustion of the coal. The rich zone of the combustor operates under fuel rich conditions, which inhibit NO_x formation from

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Figure A-27. Simplified coal-fueled turbine combined cycle schematic.

fuel bound nitrogen in the coal. The quench and final lean zone combustion within the turbine involve relatively low reaction temperatures which inhibit thermal NO_x formation. As previously discussed, tests with the RQL coal combustor sized to the Allison 501K turbine have controlled NO_x and CO levels to under 25 ppmvd (at 15% O_2) with prospects for lower levels after further combustion optimization tests.

Sulfur oxides (SO_x) are controlled in the combustion/emission block by a Zn titanate sulfur sorber. Tests indicate that this control method should ultimately be capable of reducing SO_x emissions by over 99%.

Particulates are controlled in the combustion/emissions block by cyclone separators and hot gas ceramic filters. A number of high temperature filter tests have reduced gas stream particle carryover to under 10 ppmw.

Applications

The coal-fueled turbine, combined cycle (CFTCC) technology can be utilized for new power plants or for repowering of existing natural gas-fired, combined cycle power plants. Depending on the gas turbine used, this technology can provide coal-fueled power blocks with electrical outputs from about 85 MW (e.g., for the GE MS6000 turbine) to over 350 MW (e.g., for the Westinghouse 501F turbine) and even higher outputs for future advanced turbines. One RQL combustor/emissions control train would be used for plants based on 50 MW class gas turbines. Two RQL combustor/emissions control trains would be used

for plants based on 100 MW+ gas turbines. Each would be similar to the 50 MW train and would be controlled to assure uniform gas production.

CFTCC Plant Based on F Class Gas Turbine

The following describes a CFTCC plant which utilizes the Westinghouse 501F turbine. Two identical trains of coal feed, combustion, sulfur removal and particulate removal equipment provide a cleaned combustion stream to the gas turbine. The coal input rate is 112.9 tons/hr. The nominal gas turbine output is 192 MW using an Eastern bituminous coal containing 2.5% sulfur and 16.4% ash. Heat is extracted from the gas turbine exhaust by a heat recovery steam generator (HRSG) and from the coal combustor quench zone by a heat exchanger in each combustor train. This heat is utilized in a dual pressure steam cycle to produce a nominal 170 MW from a steam turbine. Plant parasitic power losses are 10.9 MW to result in a net plant output of 351.1 MW. A byproduct of the commercial plant is elemental sulfur. About 2.7 tons/hr of sulfur is extracted from the coal combustion stream using a zinc titanate sulfur capture system.

Figure A-28 gives a block flow diagram showing the major plant sections of the CFTCC commercial plant. The following describes these plant sections.

Section 100 - Coal Receiving, Preparation, and Delivery

Section 100 consists of coal receiving from trucks or trains (depending on the specific site), a coal storage pile, and two complete coal pulverization/drying and coal feeder trains. Each train consists of a coal silo used to feed the pulverizers; a pulverizer/dryer (about 60 tph capacity); a cyclone separator; a bag filter; and a complete coal pressurization, metering, and pneumatic feeder system, including a boost compressor for pressurization above the combustor operating pressure. Hot gases for drying the coal are supplied by two natural gas fired air heaters of about 10 MMBtu/hr capacity, each. Provisions are made to recycle a portion of the combustion gases from the natural gas heaters to reduce the oxygen content of the drying gases, so an inert gas system is not needed. The pneumatically transported coal/air mixture feeds the fuel nozzles in the rich zone of each combustion train (stream 1, Figure A-28).

Section 200 - Coal Combustor

This section consists of two combustor trains, each of which includes a rich zone combustor, a water quench zone, and a heat exchanger. Also included are the inlet ducting to the turbine and the internal cans that complete lean zone combustion and produce the turbine expansion gases (stream 10). The coal feed and the portion of the compressor discharge air from the gas turbine entering both combustors are given by streams 1 and 3, respectively, on Figure A-28. After combustion, the products (stream 4) are quenched with water (stream 5) to reduce the temperature of the gas (stream 6) entering the cyclone to 1100°C (2000°F). Heat is extracted from the products leaving the cyclone to reduce the temperature of the gas (stream 7) to 727°C (1340°F) which is appropriate for downstream sulfur removal and particulate cleanup with ceramic filters.

Section 300 - Sulfur Control

The sulfur control system is fed by stream 7 and terminates at the barrier filter, stream 8, in each train. Sulfur containing gases exiting the heat exchanger enter the Zn titanate circulating fluid bed (CFB) sorber, where H₂S and COS are captured as ZnS with an efficiency of >95%. The "sulfur-free" gases exit the sulfur capture system and enter the barrier filter.

Sulfur containing sorbent is transferred to the regenerator where oxygen reacts with the sulfur in the sorbent produce a gas stream containing SO₂. Oxygen also reacts with the Zn, from ZnS, to regenerate Zn titanate. The regenerated sorbent is transferred back to the sorber to capture more sulfur.

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Figure A-28. Block diagram for CFTCC plant.

The SO₂ stream enters the catalytic direct sulfur recovery (Gangwal, et al, 1991) process (DSRP) section where the SO₂ is reduced to elemental sulfur, which is removed from the system (stream 18) and sold as a byproduct. There are no gaseous sulfur emissions from this system. Any sulfur that is not removed as elemental sulfur is sent back to the sorber for a second pass.

Section 400 Particulate Control

This section includes a large cyclone and three parallel ceramic tube hot gas filter units for each of the two trains. Also included is equipment to pulse clean the filters and water cooled screws to extract captured fines from the cyclones and filters for transport to the solid waste handling system (Section 700). The cyclone captures particulate from stream 6 exiting the quench zone to alleviate the particle loading entering the downstream heat exchanger, sulfur control system and hot gas filters. The hot gas filters receive the gas flow (stream 8) from the sulfur control system and captures nearly all the entrained particulate to reduce loading in that flow (stream 9) to extremely low levels (under 10 ppm). This provides erosion and deposition protection for downstream components, including the lean combustors, turbine expander, and heat recovery steam generator. Very low environmental particle emissions (stream 12) from the plant are also provided by the hot gas ceramic filters.

Section 500 - Gas Turbine/Generator

A Westinghouse 501F gas turbine/generator and all the balance of plant equipment associated with the gas turbine installed in a combined cycle plant are included in Section 500. The balance of plant equipment associated with a combined cycle gas turbine is incorporated into Section 500 rather than balance of plant Section 800 for the purpose of later cost comparisons. Air (stream 2) enters the gas turbine compressor. A portion (stream 3) of the compressor outlet flow is directed to the rich zone to partially burn the coal. The remainder of the compressor outlet flow is split between the coal injector system, the lean zone combustors, and turbine cooling. The hot gas (stream 9) leaving the high temperature filter is completely burned out in the lean combustors within the turbine casing to produce the turbine expansion gases (stream 10). The energy extracted by the turbine expander drives its compressor and generator to produce about 192 MW electricity (nominal). The turbine exhaust (stream 11) enters the heat recovery steam generator (HRSG) which extracts additional heat for the steam cycle. The gas (stream 12) leaving the HRSG is exhausted to the atmosphere through a stack.

Section 600 - HRSG/Steam Turbine/Generator

This section consists of all the equipment for the 2400 psig/1000°F/1000°F/2.5 in. Hg steam cycle. Included are the heat recovery steam generator (HRSG), steam turbine, steam turbine generator, water treatment plant for the steam systems, and all balance of plant equipment associated with the steam cycle installed in a combined cycle plant. This balance of plant equipment associated with a combined cycle plant is incorporated into Section 600 rather than Section 800 for the purpose of later cost comparisons.

Energy from the gas turbine exhaust (stream 11) is used to produce steam (stream 13) using the HRSG. Stream 13 from the HRSG and reheat stream 15 returning from the outlet of the HP steam turbine section enter the heat exchanger located at the outlet of the cyclone. Heat is extracted in that heat exchanger from the combustion gases leaving the cyclone to produce two streams (14 and 16) to the steam turbine. Stream 14 enters the high pressure section of the steam turbine and stream 16 enters the low pressure section of the steam turbine. The energy extracted by the steam turbine produces 170 MW electricity (nominal). The steam turbine exhausts to the condenser to recover the water to be recirculated in the steam cycle.

Section 700 Solids Waste Handling

This section oxidizes the ash captured in the combustion system cyclone and barrier filters of both trains. Only one train of ash handling is used. The waste handling system includes a fluid bed ash oxidizer, a cyclone, a heat exchanger to cool the entrained ash and gases exiting the cyclone and to raise the temperature of the air entering the fluid bed, and a bag filter to remove particulate from the effluent of the fluid bed.

Ash is transferred pneumatically from the power plant particle removal equipment to the ash oxidation reactor. The ash is oxidized using the heated air stream to convert any CaS, and any other partially reduced or sulfided metals, to environmentally stable compounds (sulfates and oxides) in a fluidized-bed combustor. Most of the sulfated ash is captured by the cyclone on the outlet of the fluid bed reactor and is sent to a water cooled screw cooler. The ash that escapes the cyclone is sent with the hot gases through a heat exchanger that cools it to about 204°C (400°F). The gases and ash are separated by a bag filter. The ash from the bag filter is added to the ash from the screw cooler and all ash is removed from the pressurized system through lockhoppers (stream 17). The ash is then collected and landfilled.

Effluents from this system are ash for disposal.

Section 800 - Balance of Plant

This section consists of balance of plant associated with the coal combustion/emissions control island (Sections 100, 200, 300, 400, and 700). The balance of plant associated with the combined cycle power generation blocks has been included in Sections 500 and 600. This plant breakdown will allow the identification of the incremental cost/kW for the CFTCC plant over that for a conventionally-fueled, combined cycle plant utilizing the Westinghouse 501F turbine.

CFTCC Plant Performance

Emissions

Emissions from the 351 MW CFTCC plant are given in Table A-14 and are addressed in the following subsections. Emission rates are quoted on a higher heating value (HHV) basis when expressed as a function of heat input.

Table A-14.
Environmental emissions.

<u>Pollutant</u>	<u>Emission rate</u> <u>lb/ MMBtu coal</u> <u>(HHV basis)</u>	<u>Emission rate</u> <u>lb/kWh</u>
NO _x	0.113	9.53E-4
SO _x	0.101	8.53E-4
CO	0.029	2.49E-4
Particulate -PM	0.013*	7.74E-5
Solid waste/byproducts	Ash = 13.3	0.112
	Sulfur = 1.92	0.016

Reference coal used: Eastern Bituminous Coal

* Includes coal particulates from pulverizer/dryer plus ash from ash sulfator

Gaseous Emissions

Using the proper operating conditions in the RQL combustors, NO_x and CO emissions will be controlled below 25 ppmv (15% O_2 , dry) in the turbine exhaust. This corresponds to about 0.113 lb NO_x /MMBtu or 9.53×10^{-4} lb NO_x /kWh and 0.029 lb CO/MMBtu or 2.49×10^{-4} lb CO/kWh.

There are no SO_2 emissions from the sulfur control section (Section 300), since there are no outlets to the atmosphere. Any sulfur not captured will exit the system in the turbine exhaust, as SO_2 . Using a conservative estimate of 95% overall sulfur capture by the Zn titanate sorbent, SO_2 emissions will be 0.101 lb/MMBtu or 8.53×10^{-4} lb/kWh.

Particulate Emissions

Particulate emissions arise from three sources: fine coal particles that escape the cyclone and bag filter (Section 100), ash fines escaping the cyclone and bag filter of the solids waste handling system (Section 700) and those that escape the barrier filter (Section 400) and pass through the turbine into the exhaust. Coal particulate emissions from the coal feed system would be about 0.0078 lb/MMBtu or 6.62×10^{-5} lb/kWh. Ash particulate emissions from the waste handling system would be 0.0013 lb/MMBtu or 1.12×10^{-5} lb/kWh.

Particulate emissions from the turbine exhaust arise from ash that passes the cyclone and high temperature filter. It is assumed that these particles are all $<10 \mu\text{m}$ in diameter and so are all PM_{10} emissions. The expected overall efficiency of the combustor cyclone and high temperature filter is about 99.97%, 70% for the cyclone and 99.9% for the barrier filter. Expected emissions in the turbine exhaust will be 0.0041 lb/MMBtu or 3.50×10^{-5} lb/kWh.

Total particulate emissions from all sources are therefore 0.0132 lb/MMBtu or 11.24×10^{-5} lb/kWh.

Solid Wastes and Byproducts

The only solid waste stream in this plant is the ash which has been oxidized in the sulfidation reactor (Section 700). The ash rate for this plant is 13.26 lb ash/MMBtu or 0.112 lb/kWh. Ash contains small amounts of Zn titanate sorbent that is lost from the sulfur capture system as fine particles that have formed by attrition. This solid is included in the preceding ash rates.

Sulfur is the only byproduct in this plant. Elemental sulfur rates are about 1.92 lb/MMBtu or 0.016 lb/kWh with this system and coal. About 2.7 ton pure sulfur/hr will be obtained as a salable byproduct.

Comparison with Pulverized Coal Boiler Plant

A comparison of NO_x , SO_2 , and particulate emissions from an existing 300 MWe coal boiler plant without provision for SO_x and NO_x control and the CFTCC plant shows the lower emissions from the CFTCC system (see Table A-15). The CFTCC emissions are also substantially lower than the Federal NSPS shown in Table A-15.

Efficiency

Table A-16 shows the efficiency of the 351 MWe CFTCC plant and the efficiency of the 300 MWe pulverized coal (PC) boiler plant. The CFTCC plant efficiency is over 7 percentage points higher than that for the existing conventional power plant.

Table A-15
Comparison of air emissions of 300 MWe coal boiler plant with the CFTCC plant.

<u>Emission specie (HHV basis)</u>	<u>PC boiler plant</u>	<u>CFTCC plant</u>	<u>NSPS</u>
NO ₂ , lb/MMBtu	1.24	0.113	0.50
SO ₂ , lb/MMBtu	3.96	0.101	1.20
Particulates, lb/MMBtu	0.10	0.013	0.03

Table A-16.
Power plant efficiencies.

<u>System</u>	<u>Heat rate Btu/kW-hr HHV basis</u>	<u>HHV efficiency - %</u>
351 MW CFTCC plant	7785	43.8
300 MW PC boiler plant	9493	36.0

Costs

As discussed earlier, the CFTCC system design approach adapts a conventional combined cycle plant design to operation with coal by using the RQL combustor/emissions control island. The distinction of equipment on Figure A-28 between combined cycle equipment (plant sections 500 and 600) and coal combustion/emissions control equipment (remaining plant sections) allows identification of the incremental capital costs per kilowatt for the coal-fueled turbine, combined cycle plant compared to a combined cycle plant that uses conventional fuels. Cost evaluations have indicated a total plant incremental cost of \$476/kW for the coal combustion/emissions control equipment.

Summary and Conclusions

The direct CFTCC power plant has been described. This plant is essentially a conventionally-fueled combined cycle system adapted to coal by a RQL combustor/emissions control island. The combustion/emission control island produces cleaned coal combustion gases for expansion in the gas turbine. The gases are cleaned to protect the turbine from flow-path degradation due to coal contaminants and to reduce environmental emissions to comparable or lower levels than alternate clean coal power plant technologies.

Most of these alternate clean coal technologies have been developed by organizations that design process plants. As a result, incorporation of these coal technologies with a combined cycle power generation system requires integration of turbine equipment with a process plant. An advantage of the CFTCC system over other clean coal technologies using gas turbines results from the CFTCC system having been designed as an adaptation to coal of a natural gas-fired combined cycle plant. Gas turbines are built for compactness and simplicity. The RQL combustor is designed using gas turbine combustion technology rather than process plant reactor technology used in IGCC and other coal systems. The result is simpler and more compact combustion equipment than for alternate technologies. The natural effect is lower cost and improved reliability.

By way of example, the residence time in the rich zone of the RQL system is typically only about 20 to 30% of that for many entrained coal gasifiers, which have the shortest residence times of the alternate coal technologies. This results in a more compact system. Combustion in the RQL system is achieved with air, thereby not requiring the complexity and high cost of the oxygen plant needed for many coal gasification systems. No equipment is necessary in the RQL combustion system to capture and recycle combustion product fines while such equipment is usually needed for efficient coal consumption in advanced pressurized fluidized bed combustion and gasification systems.

In addition to new power generation plants, a future application for CFTCC technology will be relatively compact and gas turbine compatible coal combustion/emissions control islands that can adapt existing natural gas-fired combined cycle plants to coal when gas prices rise to the point where conversion is economically attractive. Because of simplicity, compactness, and compatibility of the RQL combustion/emissions control island compared to other coal technologies (e.g., coal gasification), it could be a primary candidate for such conversions.

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APPENDIX B: COAL FUEL SPECIFICATION AND DEVELOPMENT

COAL FUELS FOR TURBINES

Activity was devoted to the development of CWF during much of the ACFTS program. Tests prior to the program (e.g., in the DOE/Allison Component Screening Program [Wenglarz, et. al, 1986]), showed high combustion efficiency (>99%) with a CWF and a significant degree of NO_x reduction through staged combustion. A number of suppliers were pursuing development of CWF. Efforts included ash and sulfur cleaning of coals and formulation of those coals with additives into CWF with promising suspension stabilities and pumping characteristics.

Advanced physical and chemical coal cleaning processes were producing small batches of coal cleaned down to 0.2% ash and 0.65% sulfur (sulfur compliant). Expectations were that the continuing high level of CWF research and development efforts would produce even lower levels of ash and sulfur and further improvements in handling atomization and combustion performance.

Consequently, at the beginning of the ACFTS program, future ash cleaning and CWF development along with staged combustion were expected to resolve or alleviate most of the technical issues associated with use of coal in gas turbines. Suspension of the coal in water enabled controlled pumping of the fuel across the pressure barrier between a fuel storage container and a turbine combustor. Additives were to improve high shear viscosities and atomization. Improved atomization along with refinement of fuel specifications (e.g., coal heating value, particle size, volatile content, etc) were anticipated to produce high combustion efficiencies in compact (compared to other coal systems) coal combustors. Coal cleaning to remove much of the sulfur and ash was expected to eliminate the need for sulfur control equipment and to alleviate turbine flow path DEC degradation from coal contaminants.

FUEL DEVELOPMENT APPROACH

To facilitate specification and development of CWF for gas turbine systems, Allison interacted extensively with numerous CWF suppliers. In some cases, subcontracts were awarded to fuel developers to better define and improve CWF for gas turbines. Table B-1 lists CWF suppliers that provided fuels which Allison evaluated and tested. Table B-2 shows feedstocks and origins of coals evaluated.

Allison provided to CWF developers initial specifications expected to alleviate the technical issues associated with the use of coal in gas turbines. These specifications involved fuel properties assessed to be beneficial for fuel storage, pumping, atomization, combustion, sulfur control, and turbine flow path life. The fuel suppliers provided small quantities of CWF to meet Allison specifications in addition to quantities for which fuel properties (e.g., level of ash removable) were varied to a specified degree. Allison conducted laboratory evaluations of supplier CWF samples, including viscosity measurements and atomization tests. The suppliers were notified of any improvements in fuel properties that were

Table B-1.
Coal fuel suppliers.

Advanced Fuels Technology (AFT)	Midwest Ore Processing
Amax Extractive Research and Development	Otisca Industries
Carbon Resources	OXCE Fuel Company
CLI Corporation/Jim Walter Resources	U. of N. Dakota, Energy and Environmental Research Center

Table B-2.
Coal feedstocks evaluated and corresponding state of origin.

Blue Gem	Kentucky	Elkhorn	Virginia
Taggart	Virginia	Kentucky 4A	Kentucky
Coalburg	West Virginia	Castlegate	Utah
Elkhorn No. 3	Kentucky	Pittsburgh No. 8	Ohio
Lower Kittanning	West Virginia	Beulah-Zap	North Dakota
Lower Cedar Grove	Virginia	Kemmerer	Wyoming
Splash Dam	Virginia	Indiana No. 5	Indiana
Shamrock	Kentucky	Splint	Tennessee
Cedar Grove/No. 2 Gas (blend)	West Virginia		
Black Creek/Blue Creek (blend)	Alabama		
Spring Creek	Montana		
Elk Creek	West Virginia		
Lower Kittanning	Pennsylvania		

needed. The suppliers then attempted to modify their CWF formulations and provided samples for reevaluation in the Allison laboratory tests. Combustion tests and, in few cases, DEC tests were conducted with some of the more promising CWF obtained from the above procedure. Based on the Allison test and analyses results, the fuel specifications were revised.

Commercial CWF cost evaluations were also used to assist in the revision of CWF specifications. A CWF cost model originally formulated by AMAX (Bhasin, et. al., 1985) for another DOE project was updated by Allison with input information obtained from various coal suppliers. Use of the CWF cost model provided indications on fuel cost of using stringent fuel specifications (e.g., low ash) to address the various technical issues (e.g., turbine life) associated with coal fueled gas turbines. In cases where the effect on fuel cost was excessive, the fuel specification was relaxed and other measures (e.g., gas cleanup equipment) were chosen to address the technology issues.

Based on the CWF advancements that had been achieved by fuel suppliers by the beginning of the ACFTS program and expected future advancements, the early CWF specifications were defined to resolve or significantly alleviate most of the technical issues associated with the use of CWF for turbines. For example, initial coal ash and sulfur specifications were 0.2% and 0.6% (sulfur compliant), respectively. However, later evaluations showed that some of the stringent specifications could not be readily met at an economically attractive fuel price. This resulted in less stringent specifications. Subsequently, a low cost fuel task was conducted to evaluate CWF with significantly relaxed specifications and lower cost and greater commercial availability than most of the CWF that had been evaluated earlier. Fuel cost and availability considerations also led to consideration of coal powder fuels later in the program.

FUEL EVALUATION RESULTS

Viscosity/Atomization

A baseline fuel for much of the ACFTS program was produced by Otisca Industries. Otisca was operating a pilot plant capable of producing CWF using coals cleaned as low as 0.7% ash and 0.65% sulfur and was in the process of developing a commercial production plant for CWF to displace oil derived fuels in boilers. The possibility of producing a highly refined CWF side stream from that plant for heat engines was also being considered by Otisca.

Three Otisca CWF had been tested by Allison in an earlier DOE/Allison Component Screening Program. These fuels were based on a Blue Gem seam coal and a ammonium lignosulfonate additive for reduced viscosity. Even though combustion efficiencies over 99% had been obtained with this formulation, the fuel viscosity's were high (>400 cp at 450 sec^{-1}), some difficulty in pumping had been encountered, and heavy deposits were produced on specimens exposed to the fuel combustion products at conditions of a first turbine stator row. Because of this experience and results of atomization tests, Allison encouraged Otisca to evaluate other fuel formulations. Evaluations by Otisca resulted in a CWF formulation with improved ash characteristics and rheology. This CWF used a Taggart seam coal and a naphthalene sulfonate viscosity modifier.

Figure B-1 show the viscosity versus shear rate of the Taggart seam Otisca CWF at two coal loadings in the slurry. The viscosity increases with shear rate (sheer thickening). At a coal loading of 50% and shear rate of 450 sec^{-1} , the viscosity of the Taggart seam CWF was more than a factor of ten lower than the viscosity of the previous Blue Gem seam CWF and was below the Allison specification of 100 cp. Further significant improvements in viscosity were obtained by diluting the coal loading in the fuel from 50% to 48.7%. Also shown on Figure B-1 are viscosity curves for two OXCE CWF with two average coal sizes and loadings. As for the Otisca dilatant CWF, dilution of the OXCE Newtonian (constant viscosity with shear) CWF produced much lower viscosities.

The viscosity of CWF generally decreased as coal particle size increased. This does not mean, however, that larger particle sizes are desired. Extremely short combustor residence times dictate a need for reduced coal particle sizes, but not to the extent of adversely influencing slurry rehology. CWF formulated with larger mean coal particle diameters, greater than 12 microns, were found to contain a high number of very large particles, greater than 100 microns, which impinged on the interior of the fuel nozzle and contributed to nozzle plugging. Large coal particles also affect the mass and size of droplets at the high end of the atomization spray distribution and, consequently, the combustor residence time required for high combustion efficiencies. For bituminous coals tested, a coal particle mass mean diameter of 2 to 5 microns and a top size under 15 microns facilitated high combustion efficiencies in short resi-

Figure B-1. Comparison of CWF rheologies.

dence times. Acceptable CWF high shear (atomization) viscosity's of less than 100 cp at 1000 sec^{-1} were achieved for the small coal size distributions through viscosity inhibiting additives and moderate coal loadings of 50% or slightly lower in the slurry.

Figure B-2 shows the effects on atomization of reduced viscosity for the fuels of Figure B-1. The Allison full-flow CWF nozzle (see Fuel Delivery/Injection Appendix C) was used for these tests. Figure B-1 and B-2 suggest that a lower SMD for the atomization spray can be achieved at lower atomization air pressure ratios if high shear viscosity is reduced. Since atomization occurs at very high shear rates, above $10,000 \text{ 1/sec}$, suppression of viscosity at high shear is desired. Figure B-2 also shows that, at the design pressure ratio of two, the Allison nozzle was able to produce a droplet SMD to about 19 microns for the diluted Oxce CWF and about 40 microns for the Otisca CWF.

Char Reactivities

After a CWF has been atomized into a combustor, three phases of the combustion process are evaporation of the water, release of coal volatiles, and char burnout. The final phase, char burnout, requires the long-est time. Consequently, differences in char reactivity between fuels can significantly affect their combustion efficiencies.

Thermogravimetric analyses in the Allison Coal Development Lab were used to determine char reactivities for twelve different bituminous CWF prepared by AMAX. The coal in these fuels had varied coal volatile content (31.4 to 43.6%), porosity (high to low), and particle size (largest particles from 15 to 75 microns). Little or no difference in char reactivities was observed for the bituminous CWF. Char reactivity measurements were also conducted for CWF prepared from subbituminous and lignite coals. Char reactivity for the subbituminous and lignite chars were 0.26 mg/min and 0.28 mg/min, respectively, compared to 0.21 mg/min for the bituminous chars. Consequently, coal rank was expected to significantly affect CWF combustion performance. As described in the Coal Combustion/ NO_x Control Appendix, combustion tests with subbituminous CWF did show equal or better combustion performance

Figure B-2. Allison CWF atomization nozzle measured SMD versus nozzle pressure ratio.

than any bituminous CWF tested, even though the average and top coal particle diameters and viscosity were greater for the subbituminous CWF.

Combustion Tests with Bituminous CWF

Combustion tests were conducted for the Otisca baseline CWF and the OXCE CWF which viscosity and atomization characteristics were described in an earlier section of this Appendix. The high volatile (36%) coal of the Otisca Taggart CWF (Fuel "A") was cleaned with an advanced physical process to about 0.8% ash and 0.7% sulfur. The lower volatile (32%) Elk Creek coal of the OXCE CWF (Fuel 'C') was washed with a conventional process to about 5.5% ash and 0.7% sulfur. Combustion tests were also conducted with a CWF prepared by AMAX using an Elkhorn coal. The processed coal had a volatile content of about 33%, ash level of about 1.6% and sulfur level of about 0.6%.

A total of about 5000 gallons of CWF were used in the combustion tests of these three CWF. Test results are discussed in detail in the Coal Combustion/NO_x Control Appendix. Significant fuel parameter effects on combustion were:

- Combustion efficiencies exceeding 99% using Fuel 'A' with low ash (0.8 dry wt %), high volatile (36 wt %), high heating value coal (15,000 Btu/lb).
- Good combustion efficiency observed with high ash Fuel 'C' (5.5 dry wt %) with excellent Newtonian rheological characteristics.
- Poor performance observed with Fuel 'B' formulated with coal with high oxygen content (11 wt %), low heating value (13,500 btu/lb) induced by chemical treatment.

A comparison of combustion performance with bituminous coal properties indicated that the dry coal heating value might be a parameter of primary importance for the combined rich and lean zone combustion stability.

Fuel Cost Evaluations

Evaluations of the economics of coal-fueled cogeneration systems showed that CWF cost is one of the most significant factors affecting commercial system economic attractiveness. Consequently, the CWF cost model described above was applied to identify parameters that most affect fuel costs.

The model was used to predict commercial fuel costs as a function of source coal characteristics, fuel specification, fuel transportation factors, and cleaning method. In these studies, coal particle size, ash concentration, and raw coal and product transportation were found to most significantly affect CWF cost. Coal heating value, raw coal cost, solids loading, and commercial plant size were less significant. Figure B-3 shows the variation in cost with product ash concentration. For this analysis, coal particle size was also reduced with ash concentration and these corresponding values are shown. Coal particle size and ash concentration decrease simultaneously in the manner shown because a coal must be ground to decreasing sizes to enable additional removal of ash.

To reduce fuel cost, inquiries to CWF suppliers showed that considerable commercial fuel cost reduction can be achieved by relaxing the ash and particle size requirement from the current full-scale test fuel specification of less than 1% ash and less than 15 microns top particle size, to a specification allowing up to 6% ash and 250 microns top particle size.

Another aspect of specifying and testing fuels with these relaxed specifications was that they would be more readily available in commercial supply than the low ash fuels, since they are more typical of fuels which would be encountered in slurry-fired, utility boiler applications.

Figure B-3. Economic model prediction of CWF cost.

Low Cost Fuels

Fuels Evaluated

To assess low cost fuels, it was necessary to procure a variety of CWF for testing. A total of 12 CWF (plus the baseline fuel) from five vendors were selected. Vendors supplying these fuels were Otisca Industries, AMAX Extractive R&D, Advanced Fuel Technology, CLI/Jim Walter Resources, Midwest Ore, the University of North Dakota Energy and Environmental Research Center (UNDEERC), and the OXCE Fuel Company. A maximum of five barrels of each fuel was procured. Specifications provided to vendors varied as shown in Table B-3. Coal ash levels were specified from a minimum value of 1.5% to a maximum value of 6%. Vendors were also instructed to select coal seams which were somewhat extensive and would be typical of that used in a commercial application.

To fully characterize each low cost CWF, its chemical and physical properties were thoroughly evaluated. Whenever possible, standard ASTM analytical procedures were used.

Table B-3.
Fuel property limits.

<u>Property</u>	<u>Minimum value</u>	<u>Maximum value</u>
Ash content	1.5%	6%
Top size	30 micron	250 micron
Mean size	10 micron	100 micron
Viscosity	None	100 cp @ 1000/sec
Higher heating value	7000 btu/lb (slurry)	None
Sulfur	1.0%	2.5%
Ash fusion	2100°F	None
Solids content	49%	None
Droplet SMD at 2:1 NozPr	None	50 microns
Cost \$/MMBtu Commercial	None	\$3.20

Table B-4 lists the various fuel parameters that were determined and Table B-5 summarizes the results for the 12 fuels evaluated. Included for comparison in Table B-5 are the corresponding data for the "ul-traclean" Otisca-Taggart baseline fuel. As can be seen, the low cost fuels were selected for testing exhibited a wide range of chemical and physical properties.

Atomization Performance

The fuel atomization testing on the Low Cost Fuels program employed the Allison air assist CWF nozzle operating in a one atmosphere spray rig. Air and fuel flow and pressure are measured during the test. Droplet size distribution is measured by a Malvern 2600D Particle Sizer. The particle size distribution reported by the Malvern was used to calculate the SMD. SMD is plotted versus nozzle air assist pressure ratio in Figure B-4 for the part of the matrix of coal slurries. Figures B-5 and B-6 plot SMD versus nozzle pressure ratio for the balance of the fuels.

Table B-4.
Fuel evaluation parameters.

Proximate analysis
Heating value
Free swell index
Ultimate analysis
Sulfur forms
Ash fusion temperature
(oxidizing and reducing)

Ash chemistry
Ash differential thermal analysis
Coal particle size
Slurry solids content
Slurry viscosity
Freezing effects on viscosity
Slurry settling rate

TE93-2122
CG7/X250/9

Figure B-4. Atomization performance of various coal water fuels.

Table B-5.
Low cost fuel properties.

Supplier LAB ID	Otisca Base	AMAX AF1	AMAX AF2	CLI/JWR AF3	AFT AF4	AFT AF5	AMAX AF6	AMAX AF7	M.Ore AF8	OXCE AF9	OXCE AF10	Otisca AF11	UNDEEMRC AF12
Seam Name Location	Taggrt VA	Elkhm VA	Elkhm VA	BluCrk AL	#2 Gas WV	#2 Gas WV	Ken 4A KN	Ken 4A KN	Ind#5 IN	ElkCrk WV	ElkCrk WV	Taggrt VA	Kemmerer WY
Proximate Analysis (Dry Wt %)													
Ash	0.70	3.26	1.47	2.31	3.71	5.13	3.82	4.95	3.02	1.00	6.24	0.99	2.72
Volatiles	35.10	30.52	31.68	34.84	31.23	30.64	36.61	35.93	41.48	36.55	31.26	34.41	40.07
Fixed C	64.33	66.22	66.85	66.85	65.06	64.23	59.57	59.12	55.50	62.45	62.50	64.60	57.21
H.Value (Btu/lb maf)	15121	14961	15038	14474	14705	14486	14721	14883	14444	14916	15112	14887	12800
Ultimate Analysis (dry wt %)													
Carbon	84.96	81.97	83.40	80.54	82.56	81.54	78.75	78.59	77.60	83.88	79.51	84.74	72.31
Hydrogen	5.41	4.93	5.12	5.25	5.20	5.17	5.28	5.34	5.51	5.45	5.02	5.40	4.84
Nitrogen	2.20	1.51	1.54	2.04	1.56	1.51	1.96	1.98	1.49	1.58	1.53	1.76	1.45
Chlorine	0.08	0.20	0.18	0.11	0.22	0.17	0.24	0.17	0.11	0.07	0.13	0.13	0.08
Sulfur	0.75	0.70	0.63	0.86	0.86	0.84	0.83	0.84	1.50	0.59	0.71	0.67	0.44
Ash	0.70	3.26	1.47	2.31	3.71	5.13	3.82	4.95	3.02	1.00	6.24	0.99	2.72
Oxygen	5.90	7.43	7.66	8.89	5.94	5.59	9.12	8.13	10.77	7.43	6.86	6.41	18.16
Sulfur Forms (Dry wt %)													
Pyritic	0.08	0.10	0.06	0.19	0.13	0.13	0.06	0.09	0.41	0.09	0.21	0.04	0.10
Sulfate	0.05	0.20	0.25	0.13	0.24	0.21	0.26	0.19	0.57	0.10	0.17	0.15	0.14
Organic	0.62	0.40	0.32	0.40	0.49	0.50	0.51	0.56	0.52	0.40	0.33	0.48	0.20
Ash Fusion Temp. (Reducing-Deg F)													
Softening	2186	2351	2347	2056	2152	2699	>2700	>2700	2015	2217	>2700	2227	2022
Ash Fusion Temp. (Oxidizing-Deg F)													
Softening	2320	2597	2420	2505	2610	>2700	>2700	>2700	2321	2400	>2700	2360	2505
Ash Constituents (% of ash)													
Si Dioxide	34.83	53.62	45.09	42.66	45.57	31.78	57.29	58.51	41.64	46.73	54.22	41.80	47.88
Al Oxide	23.87	23.58	28.99	21.58	22.79	43.89	27.17	26.73	20.28	26.43	27.77	23.83	18.09
Ti Dioxide	2.89	1.04	1.14	1.11	1.59	1.14	1.09	1.26	1.53	2.51	1.49	2.73	0.94
Ferric Oxide	22.65	12.22	11.89	25.91	24.57	19.50	7.07	7.11	22.40	14.67	9.81	16.42	18.62
Ca Oxide	5.76	1.59	3.02	3.06	1.28	0.82	1.92	1.61	3.77	2.71	0.78	5.37	5.86
Mg Oxide	1.78	0.79	0.77	0.88	0.61	0.41	0.63	0.61	0.71	0.94	0.74	0.96	2.47
K Oxide	1.57	1.74	0.74	1.28	1.28	0.85	0.81	0.90	1.36	1.60	1.72	1.51	0.15
Na Oxide	0.96	1.84	3.07	0.66	0.44	0.31	1.34	1.21	3.07	1.39	0.69	1.74	0.29
S Trioxide	4.41	2.71	3.72	1.99	0.73	0.68	2.08	1.49	3.18	1.67	1.41	4.30	4.64
P Pentoxide	0.34	0.12	0.14	0.34	0.20	0.10	0.13	0.13	1.18	0.51	0.21	0.04	0.38
Sr Oxide	0.02	0.03	0.05	0.00	0.01	0.00	0.01	0.01	0.02	0.01	0.01	0.04	0.01
Ba Oxide	0.41	0.35	0.36	0.18	0.07	0.66	0.17	0.18	0.05	0.32	0.15	0.40	0.07
Mn Oxide	0.08	0.09	0.08	0.11	0.10	0.08	0.02	0.02	0.71	0.04	0.03	0.06	0.21
V Pentoxide	0.11	0.35	0.37	0.30	0.28	0.21	0.13	0.11	0.31	0.10	0.04	0.53	0.12
SLURRY CHARACTERISTICS													
Particle Size (microns)													
Mean	4.0	7.5	9.1	12.3	24.5	26.7	13.8	28.2	13.1	7.1	46.0	5.9	15.8
Top	20	44	43	48	140	135	47	122	68	32	250	38	43
Viscosity (cp) @ 1000 1/sec													
	85	89	78	97	42	43	115	70	54	17	450	54	267

Figure B-5. Atomization performance of various coal water fuels.

Figure B-6. Atomization performance of various coal water fuels.

In addition to Low Cost Fuels, Figure B-6 show atomization test results for the Otisca two variations of a fuel delivered for full scale combustion tests. These fuels are designated as 851-B, with and without a viscosity modifier. Droplet size distributions were smaller for all of these CWF than for the Otisca baseline CWF.

It appears that the droplet size produced by the Allison coal water slurry nozzle is dependent not only on initial coal particle size, but also is a function of other parameters. Note in Figures B-4 and B-5 that full AF-6 gives significantly smaller droplet SMD than AF-3, even though the grind and viscosity of the two fuels are about the same. AF-6 and AF-7 show similar SMD, but AF-7 is considerably coarser than AF-6.

Combustion Performance

Based on the results of the lab and fuel nozzle testing, several CWF were selected for operation in the Allison subscale coal combustor. The first fuel tested was a slurry prepared by AMAX given lab code AF2. This fuel exhibited poor combustion performance, with low gasification efficiency in the rich zone and unstable combustion in the lean zone of the bench scale coal combustor.

It was decided to repeat the baseline Otisca Taggart slurry next. This fuel had been used extensively in earlier development testing with good results. The most recently delivered Otisca fuel, however, performed poorly in the combustor. Although lean zone combustion was stable, rich zone gasification efficiency was only 83%.

Subsequent testing with some older Otisca fuel confirmed a change in fuel properties. The old fuel had a mean particle of 4 microns with a top size of 20 microns. The recently delivered fuel had an average particle size of 7.5 microns with a 45 micron top size, as measured by Coulter Counter. Testing with this recently delivered fuel showed dramatic improvement in burnout with increased rich zone residence time, as shown in Figure B-7.

The residence time was increased for the Otisca fuel with larger coal particles by reducing the air flow rate through the rich zone of the subscale combustor. Subsequently, the rich zone of the subscale combustor was lengthened by 25% with the addition of a 11-inch long refractory lined spool to increase residence time.

Figure B-7. Effect of residence time on burnout.

The remaining subscale combustion tests with selected CWF in the low cost fuels effort were conducted with the extended rich zone. Table B-6 identifies these fuels and their rich zone combustion performance. The subbituminous CWF produced a significantly higher rich zone combustion efficiency than the remaining bituminous CWF. The subbituminous produced a combustion efficiency equal to or greater than for the Otisca baseline CWF even though it had a larger mean and top coal diameter, lower heating value, and greater viscosity at high shear. Apparently, the high volatile content and greater char reactivity of the subbituminous CWF resulted in its high combustion efficiency.

COAL POWDER FUELS

The fuel suppliers began to scale down their efforts to develop CWF within a year after the end of the Low Cost Fuels Task. Of the many CWF suppliers available at the beginning of the program, none were working toward a commercial micronized CWF and nearly all had withdrawn from the market. Costs of test fuels in quantities for the full-scale facility had been much greater than earlier projections by the fuel suppliers. These CWF costs exceeded \$100/MMBtu compared to a price in the vicinity of \$3.00/MMBtu or lower needed for coal-fueled turbine systems to be economically competitive with existing commercial systems. The large production plants (of 1 million ton/yr or greater) needed for low CWF prices and the infrastructure needed for economical pipeline transport had not been developed and were not likely to be constructed in the foreseeable future.

Economic studies conducted for a coal-fueled cogeneration system based on the Allison 501-K turbine showed that plants using coal power fuels (CPF) could provide similar internal rates of return (IRR) to the owner/operator as plants using CWF (assuming that large CWF production facilities were available). Furthermore, the IRR for plants using CPF was less sensitive to fuel cost uncertainties than the IRR for plants using CWF. Due to the above considerations, a decision was made to discontinue further CWF testing and to concentrate further efforts on the development of turbine systems using CPF.

Initial CPF for tests were specified (see Component Durability Laboratory Analyses Appendix) and fuel delivery systems to inject into the pressurized subscale and engine scale combustor were procured. However, the program ended before CPF testing could be conducted.

Table B-6.
Rich zone combustion efficiency for low cost fuels.

<u>Fuel (source)</u>	<u>Ash level (%)</u>	<u>Mean parti- cle dia. (microns)</u>	<u>Top particle dia. (microns)</u>	<u>Coal volatiles (%)</u>	<u>Heating value (btu/lb maf)</u>	<u>RZ combus- tion effi- ciency--%</u>
AF-1 (VA-Bit.)	3.26	7.5	44	30.52	14,961	87.5-94.3
AF-4 (WV-Bit.)	3.71	24.5	140	31.23	14,705	76.4 (one test point)
AF-7 (KN-Bit.)	4.95	28.2	122	35.93	14,883	89.9-92.3
AF-8 (IN-Bit.)	3.02	13.1	68	41.48	14,444	79.5-87.2
AF-12 (WY- Subbit.)	2.72	15.8	43	40.07	12,800	>99

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APPENDIX C: FUEL DELIVERY/INJECTION

BACKGROUND

Two forms of coal fuels were tested in the Advanced Coal-Fueled Gas Turbine Systems (ACFTS) program:

- coal water fuels (CWF)
- coal powder fuels (CPF)

An advantage for CWF is that fuel transport across the pressure barrier between the fuel storage container and pressurized combustor is facilitated by pumping as a liquid so that steady and controlled transport is achieved. However, the solid/liquid suspension must be dispersed as very small droplets within the combustor by atomization so that full burnout can be achieved within a reasonably sized combustor. Atomization of CWF is substantially more difficult than for conventional liquid fuels because CWF are much more viscous, often have non-Newtonian flow properties, and the suspended coal particles in the fuel affect the minimum droplet size distribution that can be formed.

Dispersion of dry CPF by a nozzle is achieved relatively easily compared to CWF. However, steady and controlled transport of fine coal powders across the pressure barrier between the fuel storage container and the combustor is much more difficult for CPF.

The following describes work in the ACFTS program directed to overcoming the major technology challenges for each fuel form:

- atomization for CWF
- steady and controlled delivery to a pressurized combustor for CPF

ATOMIZATION OF CWF

Atomization Improvement Approaches

The following two main approaches were used to achieve fine atomization of CWF:

- control of CWF flow properties, especially viscosity at high shear rates
- atomizer design and operating conditions

Extensive interactions with CWF suppliers on the results of Allison experiments enabled fuel specifications to be set which facilitated atomization. These efforts are discussed in Appendix B, Fuel Specification and Development. The following sections discuss tests to determine CWF injector design and operating conditions that provide fine atomization.

Test Facility and Conditions

Atomization Facility

The Allison Fuel Nozzle Research Laboratory was established to evaluate the atomizers using both conventional and CWS fuels. Nozzles were mounted on a traveling stage and sprayed vertically downward into a collection tank. An exhaust fan drew air past the nozzle and through the tank to prevent recirculation of small drops into the sampling area. The tank was fitted with flow straighteners and screens to filter the liquid into a collection basin. Fuel was fed from a tank pressurized with nitrogen, and flow was measured using a coriolis force flow meter. Air was metered with an orifice tube. Flow rates, temperatures, and pressures of fuel and air were continuously monitored and recorded using a computer data acquisition system.

Drop size measurements were made with a Malvern 2600D Particle Size Analyzer. This instrument calculates drop size distribution from the Fraunhofer diffraction pattern produced by drops in the path of a laser light beam. The scattered light is focused onto a photodiode array using a 300 mm lens. The data represent a line-of-sight, spatial sample of the spray (sampling time was 30 seconds). The Malvern laser beam intersected the spray on the nozzle centerline 25 mm below the nozzle tip. The effect of multiple scattering of light in dense spray was corrected using the technique developed by Dodge, 1984. To extend the limits of the Dodge correction in very dense sprays, half the spray was shrouded from the Malvern by directing the laser beam through a tube extending to the nozzle centerline.

All drop size distributions were calculated from light distributions using Malvern's "Model Independent" algorithm, which makes no assumptions as to the shape of the drop size distribution. The commonly used two-parameter Rosin-Rammler distribution assumes a monomodal drop size distribution. This constraint may lead to underrepresentation of large drops.

Test Conditions

All atomization tests were performed at ambient pressure. To run the atomization test at design flow rates would imply expanding the atomizing air from 2 MPa to atmospheric pressure. The air velocities and expansion waves in such a jet would be completely different from the atomizing air jet in the pressurized combustor.

The objective of atomization tests was to measure a spray under scaled conditions to produce spray drop sizes corresponding to pressurized conditions. To model combustor conditions for atmospheric testing, the nozzle air-fuel mass ratio and the air pressure ratio were held constant. Thus, the air and liquid mass flow rates for atomization test are approximately one-tenth those of combustor tests.

The table below shows baseline flow conditions of atomization and combustion tests for the Allison full-flow nozzle.

	Atomization test	Combustion test
Fuel flow (kg/hr)	50	500
Airflow (kg/hr)	50	500
Air-fuel ratio	1.0	1.0
Air pressure ratio	2.0	2.0
Ambient pressure (atm)	1.0	10.0
Air temperature (°C)	20	20

Most of the drop size data reported here shows the variation of SMD with atomizer air pressure ratio at constant fuel flow. This corresponds to combustor conditions because, while atomizer pressure ratio can be varied, the fuel flow is set by the engine operating condition tested. Air temperature was also increased from baseline to 140°C (284°F).

Nozzles

Four nozzles were tested during this program:

1. Commercial Swirl-Air Nozzle 1 — This is an internal-mixing air-assist nozzle designed for industrial applications such as drying. The nozzle had an air-fuel ratio of 0.3 at design fuel flow rates and air pressure ratio.
2. Commercial Swirl-Fuel Nozzle 2 — This was the original baseline nozzle for the bench-scale testing program. It is an external-mixing, air-assist design where swirling fuel is introduced be-

tween counterrotating jets of air. The fuel swirls counter to the outer air circuit, where the bulk of the airflow is introduced. The air-fuel ratio was 1.0 at 2.0 air pressure ratio.

3. Allison Full Flow Nozzle — This external-mixing air-assist nozzle was designed at Allison and is shown in Figure C-1. CWF is introduced to the nozzle from a side inlet and runs between parallel streams of atomizing air. A conventional tangential-inlet swirl chamber is used to provide a thin sheet of slurry which is atomized by swirling high pressure air at the nozzle tip. The atomizer is easily disassembled for cleaning and inspection purposes and can be readily modified by the installation of internal pieces of alternate designs. The center air tube location with respect to the nozzle tip is adjustable to optimize performance. Atomizing airflow to the inner and outer passages may also be independently controlled by adjustment of supply pressure.
4. Allison Half-Flow Nozzle — This design is essentially identical to the Allison full-flow nozzle except that the air discharge coefficient is cut in half. The expense and power required for an external nozzle air compressor is thus reduced. The development of this nozzle is described in Roesler and Wilkes, 1989.

Comparison of Nozzles

The first stage of the atomization test program involved the two commercial nozzles 1 and 2 described above. The Sauter mean drop sizes of both nozzles were measured using water and a Taggart seam CWF. Although nozzle 1 appeared to perform comparably to nozzle 2 at the same air-fuel ratio, it produced a spray with a larger Sauter mean drop size at the same pressure ratio. Since the RQL coal combustion system is limited more by air pressure rather than mass flow, Nozzle 2 was considered more appropriate for this application.

The Allison full-flow nozzle was designed with the same air discharge coefficient as Nozzle 2. However, the sprays produced by the Allison nozzle were visibly finer than those of Nozzle 2. Drop size measurements shown in Figure C-2 indicate that the SMD from this nozzle is 50% below that of Nozzle 2. The Allison nozzle also had superior performance with water and other slurries.

The air velocity profiles of these nozzles were compared. The commercial nozzle has a more even and symmetrical profile than the Allison, though both have approximately the same swirl angle. The Allison nozzle has a broader air distribution making it less likely that ligaments and drops will leave the high velocity/high shear zone before they are fully atomized.

The Allison half-flow nozzle cut the airflow requirement by reducing the exit area of the outer air passage. The velocity profile of the half-flow nozzle is markedly different from the full-flow nozzle. The jet is narrower, it has much less swirl, and it does not have the hollow cone pattern. The reason is that the outer air passage of the full-flow nozzle chokes initially at the swirl vanes, whereas the half-

Figure C-1. Allison CWF injector cross-section.

Figure C-2. Comparison of Commercial Nozzle 2 and Allison full-flow nozzles.

flow nozzle chokes at the final exit annulus. This deswirls the air jet of the half-flow nozzle (the same thing happens to the full-flow nozzle at pressure ratios above 4.0). The higher air velocity of the half-area nozzle may have helped to compensate for the lower air-fuel ratio.

Several injector modifications, including the half-flow nozzle, were tested at atmospheric pressure conditions and scaled fuel flow rate using a CWF with 50% solids loading. The configurations studied included changes in air/liquid ratio, airflow split between inner and outer airflow paths, and geometry of the flow path. The atomizing airflow rate at a given pressure ratio was measured and compared to the baseline. Figure C-3 shows the results of the atomization test conducted over a pressure ratio range of 1 to 6:1 for both the Allison full-flow (denoted as baseline 100%) injector and modified configurations. From these data, it may be seen that the half-flow nozzle (denoted as 50% - 3 on Figure C-3) resulted in less than a 15% increase in droplet SMD while achieving a 50% reduction in atomizing air-flow rate.

As discussed in the Coal Combustion/NO_x control, Appendix D, two combustor tests were run with the half-flow nozzle for which rich zone carbon burnout was measured. No significant difference in carbon burnout was produced between the Allison half-flow and full-flow nozzles.

Full-Scale Combustor Nozzles

Multiple nozzles fed by a flow splitter were used for the full turbine scale combustor. These nozzles were identical in internal detail to the Allison half-flow nozzle design which tests were described above. Based on flow visualization testing, a single full-scale nozzle/swirler configuration was also atomization tested. This nozzle was a scaled (to 9000 pph) version of the 1000 pph nozzle used in sub-scale combustor tests. The large single nozzle for the full-scale combustor was spray tested using water at reduced flow rates. The water flow rate and the nozzle pressure ratios were varied and the atomized spray was observed. The spray angle was about 70 degrees at a nozzle pressure ratio of 2 (similar to the 1000 pph nozzle). A fine mist was observed with no streaking evident. Air and liquid side passages were calibrated. Some pulsations were noted, possibly resulting from incomplete filling of the liquid

Figure C-3. CWF droplet SMD for various atomizer configurations.

passages due to the reduced flow rates. Although the single large nozzle offered promise with further development, the more conservative multiple nozzle configuration was chosen for full-scale combustor tests.

DELIVERY OF COAL POWDER FUELS (CPF)

Powder Coal Feed System Conversion

Because most suppliers had terminated their efforts to commercialize CWF, Allison initiated efforts to convert both the subscale and full scale combustion facilities to handle CPF. To minimize delivery time, commercial systems were sought that were capable of delivering dry coal to a pressurized vessel operating at 165 psia. No manufacturer of coal conveying equipment was found that would guarantee the required mass flow stability of $\pm 2\%$ by weight measured over a period of a few seconds. Measurement of mass flow to this accuracy over short periods of time was also found to be difficult and subject to error.

Powder Coal Supply

After studying options that included grinding coal on-site, a decision was made to purchase coal from companies that offer custom grinding services. The subscale rig burns CPF at a rate of approximately 500 lb/hr while the full-scale rig burns CPF at a rate of 5000 lb/hr, requiring two independent means of coal handling.

Companies were located that custom grind small quantities of coal in the one to five ton range. Another company was found that produces and delivers ground coal commercially for electric utilities. The grind can be specified; a significant quantity is delivered at a mean diameter of 30 microns that is used for low NO_x, PC-fired burners. Initial delivery of coal for the full-scale testing was of this grind and from a Pittsburgh seam.

Subscale Coal Handling Facility

Coal for the subscale test rig was delivered ground in 64 cubic foot bags with sealed openings at the top and bottom. Each bag contained approximately two tons of ground coal. The filled bags were inerted with dry ice before delivery.

A continuous feed coal handling facility was designed and fabricated for the subscale rig. The facility included a partially enclosed tower designed to hoist the sacks of pulverized/micronized coal. Figure C-4 shows a simplified schematic of the coal flow path. The coal is allowed to fall by gravity into one of two parallel, lock-hopper pressure vessels. Coal is supplied to the combustor rig via the vessels which are alternatively pressurized and depressurized for recharging purposes. One 64 cubic foot bag provides sufficient coal for four hours of continuous running at simulated maximum power. The system is designed to permit coal supply bags to be changed without shutting down the rig and enables longer runs to be made, if required.

Subscale Rig Delivery System

A dense-phase pneumatic feed system was selected for the subscale test rig after discussions were held with a number of suppliers and workers in the MHD field. Air boosters were included to introduce additional conveying air at frequent intervals along the transportation line. After difficulties were encountered during tests run with this system, modifications were made to convert the system to operate in the dilute phase regime. The air boosters were eliminated and a critical flow restriction was included in the pneumatic air supply line. The critical flow restriction permitted control of the conveying air mass flow rate independently of the variations in transport line pressure. Control of the coal flow rate was accomplished by adjusting the pressure drop from the transport vessel to the transport line.

Full-Scale Coal Handling Facility

The use of bags for the full-scale facility was rejected because the practical limitations of local bag storage and need to change bags at a rate of up to one every six minutes. The methods used to deliver pulverized coal to utilities were studied and adopted for the full-scale rig. A leased solid material haulage trailer with three hoppers was refurbished and converted for use with coal. On-board

Figure C-4. Simplified powdered coal flow schematic.

inerting, O₂, and CO monitors were installed to provide transportation or long-term storage. Coal is removed from the trailer via a pneumatic transport system and is received in a day-hopper. The hopper can be replenished without shutting the combustor rig down, providing the capability for continuous operation.

Full-Scale Powdered Coal Feed System

As a result of experience with cold-flow and initial combustion tests run on the subscale system, a pneumatic delivery system operating in dilute phase was ordered for the full-scale combustor rig from a different supplier. Figure C-5 shows the full-scale powdered coal handling and feed system. Operation of the system is similar to the subscale rig. Two parallel lock-hopper vessels are used to alternately supply pressurized coal and recharge with coal at atmospheric pressure.

Both feed systems are installed with programmable controllers to maintain flow rate and ensure correct sequencing of valves during normal operation. The full-scale control system was capable of being interfaced with the engine control system to permit fully automatic operation of fuel control.

Powdered Coal Flow Metering

Each pressurized transporter vessel is equipped with load cells that provide a loss-in-weight measurements. A rolling one minute average of the flow rate is determined from the load cell measurement. To provide an instantaneous measurement of flow, a single-loop coriolis meter was installed in the subscale coal flow line but was found to be unreliable due to plugging. A nonintrusive straight-through meter (Grannucor) made by Endress and Hauser was purchased and tested on the subscale facility. The meter consists of two capacitance sensors mounted on a straight section of pipe. A flow computer processes the signals from the sensors and provides measurements of bulk solids concentration, velocity, and mass flow rate. The meter is calibrated before use by flowing coal from one transporter vessel to the other and determining the flow rate from the loss-in-weight and gain-in-weight load cells. Figure C-4 shows the simplified schematic for the coal flow path. After entering the transport line, the coal passes through the Grannucor meter and can be diverted back to the second transporter vessel or to the combustion chamber.

A second Grannucor meter was purchased for the full-scale test facility and was used by the feed equipment supplier for test purposes. A flow system similar to that used on the bench scale system was incorporated to enable a flow meter calibration and system check-out to be performed before each test.

Subscale Dry Coal Flow Tests

Results from the initial tests of the subscale facility are shown in Figure C-6. Mass flow rate of coal is shown as a function of time determined from the Grannucor signal and load cells during an early check-out test. The coal flow rate was found to be difficult to control and slow to respond. Load cell output indicated close to $\pm 2\%$ variation in flow rate over a rolling one minute average, but the instantaneous readings from the Grannucor indicated significant larger fluctuations, of the order of $\pm 15\%$. Improvements in short term fluctuations to approximately $\pm 5\%$ were made by decreasing the coal/transport air ratio from 5:1 to 1:1. Long term flow stability, however, was not achieved as indicated by the flow interruptions. These interruptions were caused mainly by flow instability in the pressurized transporter vessel. Both bridging and rat-holing problems were observed due to difficulties in handling the coal at the relatively low flow rate of 50 pph and the requirement to transition from the hopper exit to the transport line diameter of 0.625 in.

The subscale coal delivery system was then modified to promote steady flow and eliminate the bridging and rat-holing problems. Modifications included a variable-speed screw feeder to provide controlled powder flow from the bottom of the pressurized feed tanks. In tests, the screw feeder started

Figure C-5. Full-scale powdered coal fuel system.

Figure C-6. Dry coal flow rate versus time: load cells 1 and 2 and Grannucor.

coal flow quite reliably. Bridging and rat-holing that had plagued earlier tests were not experienced. Flow rates were controlled by varying the screw speed via an electric motor frequency controller. Coal was injected only into atmospheric pressure but dispensing pressure could be varied with little effect on coal flow rates, unlike earlier tests. As shown in Figure C-7, the flow rate varied by approximately $\pm 10\%$. The variations were attributed to coal dropping from the lock hopper and a relatively coarse screw pitch. A representative from the screw feeder manufacture (Simon-Macawber) who witnessed the test was confident that the 10% flow fluctuations could be reduced by modifying the feed system and using a screw with a finer pitch. The ACFTS program was discontinued before these modifications could be accomplished.

Full-Scale Powdered Coal Flow Tests

The full-scale powdered coal injection system was designed and constructed by Whirl-Air Flow of Minneapolis, Minnesota. It was first tested at the Whirl-Air facility on baking soda and anthracite coal at a relatively low (100 psia) pressure. A series of feed tests into a pressurized receiver was then conducted at Allison's specified receiver pressure of 165 psia with a Pittsburgh No. 8 coal finely ground to an average particle diameter of 48 microns and a top size of 185 microns.

The first test evaluated continuity of coal flow during the shifting of feed from one vessel to the other. The next two tests operated from each of the two feed vessels as long as possible to observe the smoothness of coal flow. A run was then conducted to determine whether the system could be started at a very low coal flow rate, as in transitioning the coal combustor from a start with diesel fuel No. 2. In another test, the objective was to determine the lowest coal flow rate that the system could be reliably operated.

The flow during switching feed vessels was continuous but not smooth. However, transition could probably be much better controlled with additional operating experience and tuning. The sustained coal flow

Figure C-7. Flow data from bench scale powdered coal screw feeder.

was reasonably smooth with average variations of about 3% and maximum excursions of plus or minus 4 lb/min out of about 40 lb/min. Flow would not start from a closed control valve position even after fully opening the valve. Flow would start at a minimum of about 30% open. The minimum startup flow rate was about 25 to 30 lb/min compared to the design flow (corresponding to turbine full power) of about 80 lb/min. However, the flow could be adjusted downward after starting to a minimum of about 14 lb/min. Coal flow was affected by back pressure variations (e.g., pressure pulsations when operated with a combustor) with a factor of 0.5 lb/min change in flow per 1.0 psi back pressure change. At the design full power feed rate of 80 lb/min, this factor results in 0.6% change in flow per psi of change in receiver vessel pressure.

The tests of the Whirl-Air Flow facility indicated that the full-scale coal feed system performance approached design objectives. It was judged that the design objectives could be met by further tuning its operation during additional coal feed and combustion tests. However, the ACFTS program ended before such further testing could be conducted.

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APPENDIX D: COAL COMBUSTION/NO_x CONTROL

COMBUSTION APPROACH

A new coal combustor design (Patent No. 4768446) was developed by Allison. This staged rich-quench-lean (RQL) combustion approach which was implemented for coal fuels has resulted in a compact, highly integrated, low NO_x coal combustor for gas turbines. This combustor has produced low NO_x (9 ppm and lower at 15% O₂) for a conventional natural gas fuel and should be suitable for alternate fuels that are difficult to burn and which contain high levels of fuel bound nitrogen.

Figure D-1 illustrates the Allison combustor approach. Air from the turbine compressor discharges into several zones of the external staged RQL combustor that operates to minimize NO_x emissions from fuel and thermal sources. The rich zone (RZ) is essentially a coal gasifier. The relatively low oxygen levels in the RZ inhibit the formation of NO_x from fuel bound nitrogen. The products leaving the RZ are reduced in temperature (to a value suitable for ash particulate cleanup) by water or steam injection into the quench zone (QZ). Molten ash particulates that had been formed in the RZ are frozen by the quench. The gases leaving the quench zone, which contain solid phase coal ash, are then cleaned by a particle separator to protect the downstream turbine from erosion and deposition and reduce particle emissions in the exhaust. The cleaned coal gases along with compressor discharge air enter the lean zone (LZ) where final combustion occurs. A relatively low LZ combustion temperature (<1538°C (2800°F)) inhibits the formation of thermal NO_x. Compressor discharge air is injected into the dilution zone (DZ) to lower the gas to the turbine inlet temperature.

The Allison RQL coal combustor is designed with gas turbine technologies rather than process plant technologies typically used to design most coal systems (e.g., coal gasifiers). Recirculation, mixing, and high combustion intensities in the RZ are established by properly designed and integrated swirler, injector, and dome configuration. Consequently, residence times (order of 90 millisecond) only a fraction of those of other coal systems are sufficient to produce high carbon burnout efficiencies (≥99%) in the rich zone. The RQL combustor is air blown and does not require an oxygen plant that is needed for many coal gasification systems. Unlike other coal conversion systems (e.g., gasification and advanced PFBC), recirculation of captured fines is not needed to achieve high efficiencies of coal conversion.

TE87-2596A

Figure D-1. RQL combustor schematic.

Because the Allison RQL system is air blown, compact, integrated with the turbine, and does not require recycle of fines, it has cost, simplicity and reliability advantages over alternate clean coal technologies.

A subscale combustor and a full Allison 501-K turbine scale combustor were constructed and tested in the ACFTS program to develop the coal combustion design. Coal combustor development was also supported by two- and three-dimensional computer codes and cold flow simulations.

SUBSCALE COMBUSTOR DESIGN

The subscale combustor was used for RQL coal combustion development. It operated at a flow of about one-tenth that of a full-scale combustor for the Allison 501-K turbine, which expands about 35 lb/sec of combustion products for operation with natural gas. Figure D-2 illustrates the combustor equipment used for early tests in which only the rich and quench zones were operated. The capability for very high carbon burnout (coal gasification) efficiencies had to be developed for the rich zone because most unburned char is removed by the particle separator upstream of the lean combustor zone. After satisfactory carbon burnout (coal gasification) was achieved in rich zone tests, a cyclone separator, lean zone and dilution zone were added (Figure D-3).

Modular Combustor Construction

To permit modifications and changes in configuration to be made quickly and inexpensively, the combustor system was assembled in modules constructed from steel outer casings lined with insulating and refractory materials. Figure D-2 shows an assembly of the rich and quench zones and the primary separator.

Figure D-2. Bench scale combustor rich and quench zones.

TE87-2114

Figure D-3. Bench scale combustor assembly showing the rich zone, cyclone separator and lean zone.

Four instrumentation spools included in the stack are interchangeable and include provisions for radially translating particulate sample probes. Each spool is lined with an outer layer of castable insulation and an inner layer of slag resistant refractory material. The rich zone is oriented vertically with a single air atomizing nozzle located at the top of the combustor. Combustion air is introduced into the rich zone by means of an inflow swirler surrounding the fuel nozzle.

The quench zone is a water-cooled steel spool with a larger diameter than the rich zone combustor. Water for quenching is injected into the quench zone. The discharge from the quench zone enters a primary ash collector device that is constructed from a tee-section steel pipe that is connected to a removable container at the lower end. The main purpose of the primary collector was to provide protection to the downstream refractory linings from the potential damage that may be caused by these larger pieces.

A commercially available cyclone separator lined with refractory material was selected as the main device for removing frozen slag particles in the 10 micrometers and above size range. These smaller sized particles are expected to escape from the primary collector and will be captured by the cyclone designed to remove up to 90+ % of particles larger than 10 micrometers. The separator is shown in Figure D-3.

The lean zone was designed to operate at a nominal temperature of 1538°C (2800°F). Flame stability and CO consumption were considered to be the major problems that must be overcome for the combustion system to operate successfully. A highly swirling flow induced by a tangential inlet to the lean zone chamber has been selected as a means of providing a double vortex flow pattern that promotes stability and long residence times for this purpose. Dilution air is added at the exit duct to reduce the gas temperature to the design turbine inlet temperature of about 1100°C (2000°F).

The internal diameter of the rich zone was 15.8 cm (6.2 in.) and the maximum length was 114 cm (45 in.). The length could be reduced in increments of 10 cm (4 in.) as required. The inside diameter of the quench zone was 25.4 cm (10 in.), and the length was 28 cm (11 in.). The lean zone internal diameter 30.5 cm (12 in.), and overall length was 45.7 cm (18 in.).

During the initial portion of the testing, combustion air was introduced into the rich zone by means of a variable geometry radial inflow swirler surrounding the fuel nozzle. Subsequent testing, however, showed the variable geometry feature was not required and a more conventional axial swirler configuration was fabricated and installed. Figure D-4 shows the axial swirler dome assembly with the nozzle and swirler mounted flush with the quarrel section. As to be discussed, the nozzle and swirler were recessed above the quarrel section in a later design which improved rich zone recirculation and carbon burnout performance.

Two commercially available fuel nozzles were selected for evaluation in the project, an external mix type and an internal mix type. An Allison injector design and development effort (described in the Fuel Delivery/Injection Appendix C) was very successful. The Allison nozzle achieved superior atomization performance and was used for the remaining coal water fuel tests in the program.

A powder injection nozzle was designed later in the program to operate with dry coal.

Combustor Design Support

Analytical and cold flow test capabilities were used to develop the initial combustor designs (both subscale and full-scale), interpret test data, and modify the subscale combustor for improved performance.

Thermodynamic Equilibrium Analyses Code

In order to examine the effect on air and fuel flow requirements of changes in cycle conditions, coal properties and zone temperatures, a thermodynamic analysis program was developed that is based on the NASA Chemical Equilibrium Code (CEC) written by Gordon and McBride (1971). The code calls a modified version of the CEC program as a subroutine and transfers product species at the exit of one stage to the inlet of the next stage and recalls the CEC subroutine. Adiabatic, equilibrium conditions were assumed throughout the process until a better understanding was obtained from the subscale test results. Simplified ash compounds are included and solid ash specie removal after the quench zone in the separator is accounted for. The main use of the code was to determine the airflow splits between stages for given zone temperatures, and to determine the fuel and quench water or steam mass flow rates.

Figure D-4. Subscale combustor dome cross-section.

Two-Dimensional Coal Combustor Code

A coal combustion code, PCGC2, originally developed at Brigham Young University, was used to support the experimental effort in the ACFTS program. The code is based on a model which is applicable to two-dimensional steady-state turbulent reacting pulverized coal combustion and gasification processes. When experimental data became available, the coal combustion code was calibrated and used to analyze the combustion data. The code was also used to guide the direction of the experimental program and the design of the full-scale RQL combustor.

One-Dimensional Steady-State Heat Transfer Code

To assist with the design analysis of the combustion system, a one dimensional, steady-state heat transfer code was developed that calculates and heat loss and cold face temperatures for each of the combustor zones and for the cyclonic separator. The code is capable of handling up to four layers of different materials including an external water jacket. A data base containing thermal conductivity over a range of temperatures for more than 30 commercially available castable refractory and insulating materials was added to the code and was updated periodically.

Transient One-Dimensional Heat Transfer Code

A transient-one-dimensional heat transfer code was developed to estimate the time required to achieve steady state conditions following a cold start. Use of this code has helped to plan a start-up procedure that will reduce the time required to achieve near steady-state conditions.

Combustion Simulations by Reaction Engineering International

A subcontract was awarded to Reaction Engineering International (REI) for computer simulations of the Allison subscale and full-scale combustors. The REI efforts involved axisymmetric simulations of coal water fuel and coal powder fuel combustion in the subscale combustor rich zone and three-dimensional simulation of gaseous combustion in the full-scale combustor lean zone. These simulations were used to evaluate operation with coal powder fuels of the subscale and full scale combustors which had been designed for coal water fuels.

Flow Visualization Rig

A cold flow visualization rig was constructed. The rig was used to evaluate alternate dome, swirler and nozzle configurations to increase recirculation and mixing for the rich zones of the subscale and full-scale combustors.

SUBSCALE COMBUSTOR

Combustor Development

Combustor Tests

Initial subscale combustor rich zone testing started with an Otisca Taggart seam coal water fuel (CWF), fuel equivalence ratio of 1.68, and an atomization pressure ratio of 3:1. Tests were then conducted to evaluate the effects of various inlet swirler designs, equivalence ratios, and atomization air pressure ratio. Atomization air temperature was varied from 38°C (100°F) to 171°C (340°F), but had little effect on combustion performance.

A new dome (Figure D-4) was then designed to provide increased swirl and accommodate relocation of the Coen flame detector and torch igniter. The rich zone was also lengthened. Subsequent testing with the new axial inlet swirler and dome design evaluated atomization air pressure ratio, inlet air temper-

ature, heated CWF (up to 77°C (170°F)), along with swirler recess and swirl area. Swirler modifications for these tests were chosen based on flow visualization tests which showed that, for the original design, the nozzle assist air was severely restricting flow reversal and mixing in the rich zone.

Earlier tests were conducted with one of two commercial nozzles for atomization of the CWF. These were replaced by an Allison designed nozzle.

After rich zone tests, the combustor was reconfigured to install the cyclone, lean zone, and dilution zone as shown in Figure D-3. Tests were then conducted to evaluate effects on overall combustion performance of rich zone equivalence ratio, quench zone temperature, and a modified Allison nozzle for reduced assist air flow.

The above tests identified the combustor hardware design and operating conditions for high combustion efficiency and low NO_x emissions using the Taggart seam CWF. Subsequent tests evaluated other CWF.

Rich Zone Performance

The major factors that increased the rich zone combustion performance were:

- redesigned axial swirler/improved dome to produce stable operation
- introduction of Allison design fuel atomizer to significantly improve atomization characteristics
- prechamber configuration incorporated based on flow visualization studies
- adjustment of operating parameters to demonstrate 99% + carbon burnout

The progression in improvement of rich zone carbon conversion efficiency is shown in Figure D-5 for tests with the Otisca Taggart seam CWF (about 0.8% ash in coal). Also shown are two data points for an OXCE Cedar Grove seam CWF (5.8% ash in coal).

Figure D-5. Bench scale combustor—carbon conversion efficiency progress.

Early rich zone testing with a radial swirler configuration had encountered periods of unstable operation. Installation of the reconfigured dome incorporating an axial swirler, shown in Figure D-4, eliminated this problem. Flow visualization studies of the radial swirler configuration revealed an unstable recirculation zone which contributed to poor combustion results. These studies also provided substantiation of more intense recirculation zones if the fuel nozzle/swirler were retracted to form a prechamber. This configuration change resulted in constant burnout efficiencies in the 90 - 95% range. Exploration of combustor operating parameters produced further improvements in combustor performance. As shown in Figure D-6, adjustments to the equivalence ratio identified operating conditions which yielded 99+% carbon burnout efficiency for both the baseline Allison nozzle and a modified Allison nozzle. The modified nozzle produced the same combustion efficiency with about one-half the atomization air flow of the baseline nozzle and was used for the remaining tests of the subscale combustor.

From test results shown in Figure D-6, it was concluded that the modified nozzle with an atomizing air/fuel ratio of 0.5:1 and a pressure ratio of 2:1 is acceptable for CWF injection.

Lean Zone Performance

Flammability

Early calculations indicated that operation of the lean zone at near stoichiometric conditions would minimize potential flammability problems, but nonflammable mixtures could be expected at some operating conditions. Subsequent testing of the lean zone, however, showed that a stable flame could be maintained over much broader limits than had previously been expected. This wide range of permissible operation prompted a literature search (Hart, 1988) for flammability data of low heating value fuel at elevated temperatures. Two references (DeSoete 1975, Hustad 1988) were found in which the conventional concept of flammability limits and flammability limit determination using the Le Chatelier equation were found to be invalid for hydrogen at inlet temperatures above about 449-521°C (840-970°F). Hydrogen and CO will react even at very low volumetric concentrations (about 1%) providing the inlet temperature is sufficiently high. These gases are the major combustible species leaving the quench zone at a temperature that is well in excess of that studied by DeSoete and Hustad. Experimental evidence and equilibrium calculations suggest that additional hydrogen is formed in the quench zone due the reaction of CO with steam at temperatures in the 927-1093°C (1700-2000°F) range. Only

Figure D-6. Effect of equivalence ratio and atomizer configuration on rich zone coal conversion efficiency—165 psia combustor pressure.

with bituminous CWF containing coal with heating values of less than 13,600 Btu/lb (moisture ash free) were lean zone flammability or stability problems encountered.

Lean Zone Inlet Heating Value

The effects on lean zone fuel heating values of rich and quench zone operating conditions can be calculated assuming equilibrium conditions to exist at the lean zone inlet. Figure D-7 shows the calculated values (solid lines) for a range of rich zone and quench zone temperatures. Also plotted for measured rich and quench zone temperatures are data taken during the course of the lean zone tests. These data indicate that the lean zone has successfully burned fuel with a heating value of less than 20 Btu/scf (calculated for the equilibrium mixture) without any stability or carbon monoxide burnout problems.

Lean Zone NO_x and CO Emissions

Uncontrolled fuel bound nitrogen (FBN) emissions at a yield of 50% from the CWF used (1.7% nitrogen by weight) would amount to over 400 ppmv of NO_x in the gas turbine exhaust. Control of these emissions to less than 1/10 of the NSPS for gas turbines has been achieved through the use of the water-quenched RQL staged combustion concept. NO_x and CO emission measurements made at both the rich and lean zone exit planes are shown on Figure D-8.

The emissions are stated as measured on dry basis. Due to the relatively low temperatures in each zone, no significant thermal NO_x is expected to be formed. The low values of CO and NO_x concentrations demonstrate the ability of the combustor to control both NO_x and CO to well within acceptable levels.

Figure D-7. Lean zone inlet gas heating value for a range of rich and quench zone temperatures.

Figure D-8. NOx and CO emissions corrected to 15% O₂ at lean zone exit.

Bituminous Fuel Tests

CWF Tested

Among the fuels tested were CWF from three suppliers that may be broadly categorized as low, medium, and high ash fuels. The fuel type and physical properties of each fuel are summarized in Table D-1. Fuels 'A' and 'B' exhibited dilatant rheological properties and fuel 'C' was found to be Newtonian over the range tested.

Rich Zone Performance

Figure D-9 shows the rich zone burnout results for these fuels as a function of rich zone equivalence ratio. Both fuels 'B' and 'C' result in a lower rich zone carbon burnout efficiency than the baseline fuel 'A' for a given rich zone equivalence ratio (ER). Fuel 'C', however, resulted in acceptable lean zone performance (Table D-1) and further improvements in rich zone coal burnout may be possible by reducing rich zone equivalence ratio without compromising lean zone stability or performance.

PCGC2 Computer Code Predictions

PCGC2 predictions obtained for fuel 'A' are also shown in Figure D-9. The comparison between the measurements and predictions is quite good, considering a number of uncertain parameters used in the model, particularly, those pertaining to kinetic parameters for the coal. The predicted results also suggest that the rich-zone equivalence ratio has a strong effect on the coal burnout efficiency. One of the main reasons for a strong dependence of coal burnout on the overall equivalence ratio is the rich-zone temperature which reduces with increasing equivalence ratio. The decrease in rich-zone temperature results in reduced combustor wall temperature. This in turn reduces the radiative heat transfer rate to the droplets, thus slowing down the char oxidation process making it kinetically limiting. The results of droplet mass histories at different equivalence ratios have shown the effects of reduced combustion

Table D-1.
Ultimate and proximate analyses of three CWF fuels used in subscale RQL combustor.

Supplier/seam Coal cleaning method	Fuel A Otisca/Taggart Physical	Fuel B AMAX Elkhorn Phy/Chem	Fuel C OXCE/Elk Creek Min Phys
Coal component	Average weight--%		
Carbon	84.85	78.73	80.37
Hydrogen	5.31	4.39	5.09
Oxygen	6.56	11.25	6.81
Nitrogen	1.73	4.39	1.48
Sulfur	0.68	0.56	0.73
Ash	0.78	1.61	5.45
Chlorine	0.05	N/A	0.07
Proximate analysis on dry basis:			
Ash	0.78	1.61	5.45
Volatile	36.93	32.98	31.97
Fixed carbon	62.28	65.41	62.58
Higher heating value (BTU/lb):	15,106	13,571	14,313
Solids weight %	50.50	49.7	50.1
Viscosity (cP)			
@ 100 1/sec	30.0	48.0	25.0
@ 1000 1/sec	90.0	76.0	25.0
Particle size (microns MMD)	5.1	10.0	11.0

Figure D-9. Rich zone coal conversion efficiency for 3 CWF.

temperature on the sequential processes of water vaporization, devolatilization, and char oxidation. For the highest equivalence ratio, the char oxidation process is the slowest for coal-water slurry and hardly contributes to the coal burnout rate. As the equivalence ratio is decreased, the char oxidation begins contributing to the coal burnout rate.

Lean Zone Performance

Both fuels 'A' and 'C' resulted in auto-ignition and a stable flame over a wide range of operating conditions with a controllable temperature at the exit of the lean zone. Fuel 'B' resulted in lean zone auto-ignition only when the rich zone equivalence ratio was increased to approximately 1.5 but a stable flame could not be maintained. With a lower rich zone ER auto-ignition of the lean zone was not possible.

It is anticipated that the range of CWF for the RQL combustion system could be substantially broadened with further testing. Additional testing with CWF was not conducted due to the decision to continue development of the coal-fueled turbine system on powdered coal because there was no foreseeable supplier of low cost CWF for commercial applications.

Subbituminous Fuel Tests

CWF based on bituminous coals were used in the tests described above. A subbituminous CWF was also tested. This fuel was produced by the University of North Dakota Energy and Environmental Research Center (UNDEERC) using a hot water drying process. Table D-2 compares the properties of this CWF with the Taggart seam CWF used in most of the combustor development tests. The subbituminous CWF performed as well (99+% carbon burnout in rich zone) as the Taggart seam CWF.

Even though the coal particle sizes in the subbituminous CWF were larger and heating value was lower compared to the Taggart CWF, the higher reactivity of the lower ranked coal probably resulted in its high combustion efficiency. A similar subbituminous CWF was used in the 501-K turbine run due to its good combustion performance and availability in sufficient quantities for full-scale testing.

Table D-2.
Bituminous and subbituminous coal-water slurry properties.

Fuel type	Bit	S-Bit
Seam name	Taggart	Kemmerer
Location	VA	WY
Supplier	Otisca	UNDEERC
Particle size		
(microns)		
Median	4	15.8
Top	20	43.0
Ultimate analysis		
(dry wt %)		
Carbon	84.96	72.31
Hydrogen	5.41	4.84
Nitrogen	2.20	1.45
Sulfur	0.75	0.44
Oxygen	5.90	18.16
Chlorine	0.08	0.08
Ash	0.70	2.72
MAFHHV		
btu/lb	15,121	12,800

TURBINE SCALE COMBUSTOR

Combustor Design

The design of the full turbine scale (70 MM Btu/hr thermal input) combustor was guided by the results of the subscale combustor test, 3-D incompressible combustor computer code analyses and flow visualization rig tests. Residence times in each zone were consistent with those of the subscale combustor. The full-scale combustor was scaled from the subscale design by a flow scale factor of 10.

Figure D-10 shows a cross section of the full engine scale combustor facility. Two parallel cyclones oriented vertically are located after the quench zone compared a single cyclone oriented at 15 deg from the horizontal for the subscale facility. The twin cyclones are fed by a "Y" inlet pipe and a common header collects the clean gas at the top of the cyclones.

Each zone of the full-scale combustor is lined with a soft (insulating) refractory layer and an inner hard (ash resistant) refractory layer with the exception of the region downstream of the quench zone. This region uses a soft refractory and an internal metallic liner to protect the refractory from direct impingement of the quench water spray.

Two differences between the full-scale and subscale combustor design approach concerned the number of atomization nozzles and lean zone ash collection. Seven CWF atomization nozzles/swirlers were used for the full-scale combustor. These nozzles were identical in internal detail to the single reduced flow Allison nozzle used for the subscale combustor. A seven port CWF flow divider was designed and fabricated to evenly split the flow between the seven CWF atomization nozzles.

Both lean zones of the full-scale and subscale combustors were designed with tangential entry to produce a cyclonic swirling flow. Tests with the subscale combustor showed that some ash which had passed the rich zone cyclone was captured in the lean zone through being centrifugal to the vessel walls. This ash accumulated within the lean zone since there was no collection vessel to receive the

Figure D-10. Full-scale RQL combustion system cross-section.

ash. The full-scale combustor was designed proportionally similar to its cyclones and was constructed with a collector to extract the ash from the lean zone. This enabled capture of not only ash particles which had passed the rich zone cyclones but also any refractory that had spalled from piping and lean zone walls.

The draft tube (similar to a cyclone vortex tube) leading from the lean zone to the turbine was of double wall, cooled metallic design so there was no refractory lining between the lean zone outlet and turbine expander. This eliminated the potential for refractory spalling after the final (lean zone) collector before the turbine. The metal draft tube was also designed as the combustor dilution zone with its cooling air injected into the lean zone exhaust to lower the gas temperature to the turbine inlet temperature.

Combustor Tests with CWF

The full-scale combustor was shaken down with distillate No. 2 fuel runs. Initial coal tests used the Taggart seam CWF. The combustor performed well during the initial runs with no indication of instability. Zone temperatures were easily maintained by appropriate control of fuel, air and water injection rates. The rich zone was successfully operated over a range of equivalence ratios from 1.45 to 1.55. Both temperature measurements and a particulate sample indicated over 98% burnout efficiency was achieved. Indication of auto-ignition in the lean zone was also measured.

Subsequent deliveries of the Taggart seam fuel from the first run of a new CWF production facility were found to be outside of Allison's fuel specification for ash and coal particle size and further full-scale testing was halted. A small quantity of the fuel was burned in the bench scale rig but with disappointing results when compared similar fuel from an earlier production batch. Rich zone carbon burn out was found to be almost 20% less with the new fuel compared with the old fuel that typically resulted in a 95-99% burn out.

Combustion tests later continued with a subbituminous CWF provided by UNDEERC using a hot water coal drying process. Properties (Table D-3) for this Spring Creek (MT) seam CWF were similar to those of the Kemmerer (WY) seam CWF used in the subscale combustor test described earlier.

Combustion data was also taken during the test of the 501-K turbine operated with the Spring Creek seam, subbituminous CWF. Measurements were taken of NO_x and CO emissions at the exit of the gas turbine and are plotted on Figure D-11. CO versus NO_x is shown, both corrected to 15% exhaust oxygen by volume. Also included on this plot are data recorded from earlier subscale and full-scale combustion tests. Each data point represents unique rich, quench, and lean zone operating condition.

NO_x emissions resulting from oxidation of fuel-bound nitrogen (1.20% by weight) could be expected to exceed 500-600 ppmv with a conventional diffusion flame combustor. However, by adjusting combustion zone temperatures and water injection rate at a constant turbine inlet temperature, NO_x is controlled by the RQL combustor to less than 20 ppmv while simultaneously controlling CO emissions to less than 10 ppmv. The engine test results can be seen to be well within the range of data recorded in previous combustion tests. These results clearly demonstrate the effectiveness of the RQL combustion system in controlling NO_x emissions from both thermal decomposition and fuel-bound sources.

Quench zone particulate samples and cyclone exit ash samples were taken and analyzed for carbon content, from which carbon burnout was determined. Table D-4 shows the results including particle size distribution.

Although only limited data were obtained from the quench zone due to probe plugging, the carbon burnout results agree reasonably well with those calculated from the cyclone ash samples. The average burnout of both sets of data approaches 99%.

Table D-3.
Bituminous and subbituminous coal-water slurry properties.

Fuel type	Bit	S-Bit (1)	S-Bit (2)
Seam name	Taggart	Kemmerer	Spring Creek
Location	VA	WY	MT
Supplier	Otisca	UNDEERC	UNDEERC
Particle size (microns)			
Median	4	15.8	16.9
Top	20	43.0	43.7
Ultimate analysis (dry wt %)			
Carbon	84.96	72.31	71.29
Hydrogen	5.41	4.84	4.49
Nitrogen	2.20	1.45	1.15
Sulfur	0.75	0.44	0.50
Oxygen	5.90	18.16	18.28
Chlorine	0.08	0.08	0.01
Ash	0.70	2.72	4.28
MAFHHV btu/lb	15,121	12,800	12,578

- (1) Used for subscale tests
(2) Used for full-scale tests

Figure D-11. CO versus NOx results: subscale, full-scale, and engine test rigs.

Table D-4.
501-K engine test sample ash content and particle size.

<u>Sample description</u>	<u>Ash content % wt</u>	<u>Carbon burn out %</u>	<u>D50 microns</u>	<u>Dtop microns</u>
Starting coal	4.39	--	15.0	41
Quench zone (1)	74.08	98.4	7.6	26
Quench zone (2)	76.00	98.6	9.1	28
Cyclone exit	86.39	99.3	13.0	40
Lean zone exit	99.92	99.99	8.8	29

OPERATION WITH COAL POWDER FUELS

A number of candidate suppliers were developing CWF for commercialization at the beginning of the ACFTS program. However, nearly all of these suppliers had terminated their development efforts by the time of the 501-K turbine test. Since no adequate supply of engine CWF appeared available in the foreseeable future, a decision was made to continue development of coal fueled turbines using coal power fuels.

Modifications for Powdered Coal Fuels

The primary modification required to change from CWF to coal powder fuels is the design of the fuel feed, control, and injection system. A pneumatic fuel delivery approach was chosen for this purpose and is described in the Fuel Delivery/Injection Appendix C. Combustor operating conditions using coal powder fuels change compared with CWF, which is due mainly to the decrease in rich and quench zone mass flow rates. Table D-5 shows a comparison of the combustor flow splits required for a subbituminous CWF and coal powder. Location of the hot gas cleanup system is immediately downstream of the quench zone. Since pressure and temperature of the gas in the cleanup system are the same for both fuels, the size of the cleanup pressure vessel is proportional to the mass flow rate. By changing to dry coal, it is expected that the size of this vessel can be reduced by over 60%, which will result in a corresponding decrease in cost.

The engine gross output is proportional to the mass flow rate passing through the turbine and a reduction of approximately 12% is anticipated with dry coal compared to CWF. The overall water/dry fuel ratio, however, is reduced from 2.7 to 1.1:1, which will result in an increase in overall thermal efficiency of approximately 1.5 percentage points.

Combustion Tests

A subscale full pressure combustion test was conducted with a fine coal powder fuel delivered to the combustor by a powdered coal transport system. Fluctuations in coal feed and rich zone temperature (+56°C(100°F)) were observed together with brief periodic stoppages in coal flow rate. The test was terminated after adjustments to the pneumatic transport system pressures failed to stabilize the flow. No reliable emissions data were recorded due to the unsteadiness of the operating conditions.

The subscale coal delivery systems was later modified to incorporate a screw feeder. In coal delivery tests without combustion, the modified fuel system started and operation reliability and provided good, positive control over coal flow. The program ended before the modified powdered coal feed system could be operated with the subscale combustor.

Table D-5.
Comparison of CWF and powdered coal combustor operating conditions.

<u>Operating parameter</u>	<u>Fuel type</u>	
	<u>CWF</u>	<u>Powdered coal</u>
Rich zone		
airflow, pps	14.3	5.82
fuel flow, pps	3.97	1.24
Eq. ratio	1.25	1.93
temperature, °F	3000	3000
Quench zone		
Water inj, pps	3.41	1.32
Mass flow, pps	21.6	8.4
% of total	55.9	24.8
Temperature, °F	2000	2000
Lean zone		
Airflow, pps	3.79	10.7
Mass flow, pps	25.4	19.1
Temperature, °F	2600	2800
Dilution zone		
Airflow, pps	10.2	12.4
Mass flow, pps	35.6	31.5
Temperature, °F	2085	2085
Combustor exit		
Mass flow, pps	38.6	33.8
Temperature, °F	1985	1985
Overall		
Water/dry fuel	2.71	1.06

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APPENDIX E: PARTICULATE CONTROL

PARTICULATE CONTROL FOR COAL FUELED TURBINES

Particulate control is required for coal fueled turbine systems to:

- reduce particulate emissions to environmentally acceptable levels
- alleviate degradation due to coal ash of the gas turbine and other system components

The Federal New Source Performance Standard (NSPS) of 0.03 lbs particulate/MMBtu was assumed as the exhaust emissions goal for both the commercial coal-fueled cogeneration systems and coal fueled combined cycle systems described in Appendix A. For the cogeneration system based on the Allison 501-K turbine, this corresponds to a particle loading leaving the plant of less than 18 ppmw.

The allowable particle loading entering a turbine depends on many factors such as size distribution, turbine flowpath characteristics, etc. One of the most important factors is the turbine inlet temperature compared to initial melting point of ingested particles. The significance of the turbine inlet temperature relative to particulate initial melting point is exemplified by comparison of turbine experience in PFBC demonstration plants and residual oil applications. Even though particulate loading entering the Tidd demonstration plant PFBC turbine have exceeded 100 ppm (about 5 times NSPS), turbine flow path degradation has been tolerable when upstream cyclones have operated according to design (Egnell, et. al., 1992). Little or no erosion and minor deposition on the turbine flowpath were observed, except after malfunction of the cyclone particulate removal system.

On the other hand, commercial utility turbines operated in peaking service with washed and treated residual oils that produce much lower particulate loadings than PFBC plants have been taken out of service as frequently as at 200 hr intervals for periods as long as a day for off-line water washing to remove deposits (EPRI, 1979). Representative particle loadings entering treated residual oil turbines are 5 to 10 ppmw, about one-third to one-half of NSPS. Residual oil turbine maintenance requirements have been acceptable for peaking service because these turbines have been cleaned during normal out-of-service periods. However, the above frequency and duration of turbine outages would not likely be acceptable for coal-fueled turbine cogeneration plants or intermediate and base load coal fueled utility plants unless turbine deposits are sufficiently fragile that they could be removed on-line (e.g., by "nut-shelling"). Then, deposit maintenance intervals as frequent as daily (24 hr) might be acceptable.

Comparisons of PFBC turbines with treated residual oil turbines show that the allowable particle loading entering a turbine is affected by whether or not impacting particles on turbine surfaces tend to stick and cause deposits and also on the strength of deposits which affects the method of removal and duration of turbine outages. This mainly depends on the turbine inlet temperature relative to the melting or softening temperature of the lowest melting point species of the particulate delivered to the turbine surfaces. That initial melting temperature is below the detection limit of standard laboratory analyses techniques. For example, it has been shown (Huffman, et. al., 1981) that extensive formation of molten ash phases occurs well below the initial deformation temperature measured by the standard ASTM ash cone procedure. Accordingly, the simplified deposition approach described in Appendix H has been developed to evaluate turbine deposition maintenance intervals.

Past PFBC turbine experience indicates that commercial inertial devices such as cyclones might be successfully used for coal-fueled turbine systems if levels of molten ash phases can be controlled and downstream particulate cleanup reduces emissions to acceptable levels. Past experience with residual oil turbines shows that even typical particulate loadings, (e.g., order of 10 ppm for the Grimethorpe hot gas filter tests) passing filters, while meeting emissions requirements, can produce excessive deposition if molten phases are not controlled. Ash sticking fractions and corrosion measured in deposition and corrosion tests in the DOE/Allison Component Screening Program (Wenglaz, et. al., 1986) suggest that con-

tol of molten phases might be required for coal turbine systems operating with either cyclones or hot gas filters. Measures to control molten phases are discussed in Appendix A (Commercial Coal-Fueled Turbine Systems) and G (Component Durability Laboratory Analyses). Coal turbine systems options that use cyclones and other measures to meet turbine and emissions requirements are also discussed in Appendix A. This appendix discusses work in the ACFTS program to evaluate both inertial devices and hot gas filters.

PARTICULATE CONTROL DEVELOPMENT APPROACH

The location of either type of particulate cleanup device is between the quench and lean zones of the rich-quench-lean coal combustor. This location requires gas cleanup of about one-half to one-third the volumetric flow of a device located between the combustor dilution zone and the turbine. Consequently, the size and cost of the particulate control system is reduced.

Inertial Separators

At the beginning of the ACFTS program, several fuel suppliers were evaluating methods (including chemical cleaning) to reduce coal ash levels to 0.2% or lower. Accordingly, the initial particulate control approach specified a goal of 0.2% coal ash in the turbine CWF and inertial separators to both meet the particulate emissions standard and provide turbine protection from particulate effects.

After screening several inertial separator options such as vortex tubes, Allison proceeded to evaluate a modification for coal systems of an inertial particle separator (IPS) approach that had effectively removed particulate entering helicopter and other aero engines. An IPS design applied to the Allison 501-K industrial turbine was projected to be very compact and potentially offered low cost compared to other cleanup devices. A two-stage particulate system was considered for the Allison 501-K industrial turbine. The first stage used the compact IPS and the second stage used a high temperature cyclone.

Computer codes that predicted grade efficiencies (particle removal fraction versus particle diameter) and pressure drop were used to evaluate alternate IPS designs. Overall particle removal efficiencies were calculated using the grade efficiencies and measured product of combustion (POC) size distributions from subscale combustion tests using CWF.

Promising IPS designs identified from computer analyses were further evaluated by cold flow testing. Evaluations showed a test model that matched the Reynolds number and Mach number of an engine IPS system could be operated at near ambient pressure to provide performance measurements representative of the engine system. Accordingly, an IPS rig (1.8 dimensional scale up of engine hardware) was constructed and tested at various representative operating conditions using sand and alumina particles. Six variations of IPS designs were tested.

Hot Gas Filters

Work was conducted in the ACFTS program with the objective of development, design, construction, and testing of hot gas filtration approaches under conditions of coal-fueled gas turbines. An initial test was conducted at 927°C (1700°F) quench zone reducing conditions using a single candle vessel operated on a slipstream from the subscale coal combustor. The vessel was provided by Industrial Filter and Pump (IF&P) Inc. Although candle plugging occurred, backflushing was inadequate and the filter had been contaminated by a substance believed to have originated in the water used for quenching. Post-test examination by IF&P showed that no sintering or melting of the ash had occurred in the filter cake.

A subscale, 26 candle hot gas filter with a water cooled tube sheet was then designed and constructed to operate with the full flow from the exit of the quench zone of the subscale coal combustor. A subcontract was let to IF&P to supply ceramic candles and to assist in the design of the candle sealing and back-pulse candle cleaning system. Included in IF&P efforts were cold flow rig backpulsing and pressure drop

tests using SiC and aluminum silicate candles and several types of dust, including reentrained particulate from the Curtis Wright coal-fired PFBC pilot plant.

A preliminary design was also started for a filter sized for particulate cleanup in full-scale combustor and 501-K turbine tests.

INERTIAL SEPARATOR RESULTS

Figure E-1 illustrates the compact IPS evaluated. Flow is deflected around a center body. Particles in the flow are deflected to the extreme radial positions of the flow path around the center body and are extracted with a small scavenge portion of the total flow. The extracted flow is cleaned with a compact, high efficiency cyclone or perhaps small hot gas filter and is then reintroduced into the main combustor stream by means of an ejector.

The IPS analyses and cold flow testing showed good separation efficiencies for particles with typical densities ($>155 \text{ lbs/ft}^3$) such as coal ash and sand (See Figure E-2). However, a product of combustion (POC) analyses approach (See Appendix H) developed in the ACFTS program later showed that POC from low ash CWF combustion tests have very low particulate densities (under 50 lbs/ft^3) for larger particles (See Figure H-2 of Appendix H). This reduction in density from typical values lowers particle inertia and makes separation in the IPS more difficult. The predicted effect on IPS separation efficiency for the lower densities obtained from data of a subscale coal combustor run are shown in Figure E-2. The lower efficiency results in significantly lower particle removal performance than for cyclones. Consequently, hot gas cyclones were assessed to be the preferred inertial particulate collection device and work started to evaluate hot gas filters. Meanwhile, Allison developed a cyclone performance computer code which was used to assist in identifying appropriate cyclone designs that were used in subscale and engine scale combustor and turbine tests.

Figure E-1. Inertial particle separator.

Figure E-2. IPS efficiencies for sand and char/ash particulate.

Later, cyclone optimization computer codes were written which were based on recent advancements in cyclone theory (Ioizia and Leith, 1990). These advancements offered prospects for higher efficiency cyclones than current designs.

HOT GAS FILTER RESULTS

Overall Configuration

The overall configuration of the subscale hot gas filter and subscale combustor facility is shown in Figure E-3. Based on previous experience, a hot gas filter face velocity (volumetric flow + filtration area) of 9 ft/min was chosen as the nominal design value. During testing this face velocity could be varied by adjusting combustor flow conditions or by removing one or more candles. At 9 ft/min face velocity, 26 candles were required for subscale operation with CWF.

The candle filter elements were 2.375 inches in diameter and are located with the center to center distance of 3.5 inches. The candles were 59 inches long and 0.4 inch thick. A feature of the filter system design included a cast, insulated water-cooled tube sheet that eliminated the need for expansion bellows. The design of the tube sheet (Figure E-4) was similar to that of the test-proven water quenching plate used on both the subscale and full-scale combustion systems. In addition, the system included inert gas backpulse equipment and provisions to take gas and particulate samples from various sections. Two different candle sealing mechanisms were to be studied during the tests. Testing was planned to begin on a 2 pps subscale test facility at temperatures in the 816 to 1093°C (1500 to 2000°F) range under reducing conditions.

Figure E-5 shows a cross section of the two candle mounting systems. On the right hand side of the drawing is the hemispherical candle lock up arrangement used and tested by IF&P. A set of Heet-Lok gaskets (85% mica plus binder) was to be used on the upper and lower flanged surfaces of the candles. The gaskets were to be held in position by a seal plate and a Hastelloy steel nozzle. The gasketing, flanged surfaces of the candle and the seal plate were to be held in compression with a set retaining

Figure E-3. The subscale combustor/filter configuration.

Figure E-4. Water-cooled tube sheet section.

Figure E-5. Two different candle mounting systems.

pins. An alternate system of clamping with spherical heads to also be tested on a limited number of candles is shown on the left side of Figure E-5.

The backpurge system for the bench scale filter consisted of a pressurized inert gas (nitrogen) source, five high temperature solenoid valves and an array of backpulse piping designed to admit the nitrogen purge gas into each ceramic candle.

Each of the five solenoid valves backpurges five ceramic candles. Only one group of five candles is pulsed at a given time. The pulsing frequency is once in 15 minutes. The pulse pressure is 145 to 175 psia over filter operating pressure. Pulse duration is 1 second. Pulse flow rate is 6-10 liters of high pressure nitrogen per candle. The jet pulse tube is located in the venturi inlet to promote hot gas entrainment during back purging and to limit the of thermal shock to the candles.

Candle Materials

IF&P LayCer™ candles were to be used in tests. These were formulated of a layered silicon carbide granulation with aluminum silicate binder. IF&P Fibrosic™ candles, constructed of an aluminum silicate ceramic were also procured to be used for backup should the silicon carbide candles show excessive degradation in the earlier filter tests. Typical candle dimensions are shown in Figure E-6.

Subscale Testing

As discussed in Appendix A, ceramic filter element loss of strength and plugging under reducing conditions have been identified as major filter issues in pilot plant tests in PFBC and gasification systems. The two most significant variables affecting filter element loss of strength and plugging are operating temperature and filtration face velocity. These variables also affect coal fueled turbine systems performance and costs. Higher filter operating temperatures, due to lesser quench water flows upstream of the filter, favor lean zone combustion, improve coal turbine system efficiency, reduce water consumption and would improve sulfur capture efficiency for calcium based sorbent injection into the quench zone. On the other hand, higher filter operating temperatures might reduce filter durability due to high ash reactivities and corrosion potential, increased thermal shock of filter elements during backflushing, and increased possibility of filter plugging due to higher levels of molten ash phases. Higher filtration face velocities result in lower capital costs of commercial systems due to a lesser number of filter

TE93-2134
VS90-226

Figure E-6. A typical candle filter section.

elements, and a smaller filter pressure vessel and tube sheet. However, higher face velocities increase the potential for irreversible filter plugging and the possibility of increased pressure drops across the cleanup system to unacceptable levels.

Accordingly, the objectives of the planned hot gas filter tests were to vary filter inlet gas temperature and face velocity in order to identify favorable operating conditions for durability and economic attractiveness of hot gas filter systems. The change from coal water fuels (CWF) to coal powered fuels (CPF) as the preferred fuel form facilitated these evaluations. Although the test filter system had been designed for a 9 ft/min face velocity with CWF, the lower volumetric flow in the subscale combustor associated with CPF combustion enables operation of the filter at face velocities down to 5 ft/minute. Consequently, the planned filter tests were to start at a conservative face velocity of about 5 ft/min and conservative gas temperature of 816°C (1500°F) and incrementally increase these two variables. Increasing face velocity was to be accomplished by removing filter elements and plugging their locations in the tube sheet.

Concurrent, deposition, erosion, and corrosion (DEC) tests were also planned. During the extended hot gas filter runs, specimens were to be exposed downstream of the subscale combustor at conditions representative of the vanes and blades of the first two rows of the Allison 501-K turbine.

Although the change in fuel form to CWF provided additional flexibility to operate at lower filtration face velocities, it also delayed the performance of the hot gas filter test until a powdered coal fuel delivery system could be developed. This was not completed before the end of the program so the subscale hot gas filter tests were not conducted.

Full-Scale Hot Gas Filter

To facilitate the ACFTS program schedule, a preliminary design was nearly completed by IF&P for a hot gas filter sized to the full-scale combustion and turbine test facility. Completion of the design awaited the results of the subscale filter tests to establish the filter face velocity which is required for specifying the required number of filter candles and sizing the full-scale filter vessel.

PARTICULATE CONTROL CHOICES

The first section of this Appendix indicates that either hot gas filters or inertial separators might be considered for coal-fueled turbine systems. However, hot gas filter durability needs to be proven and inertial separators require supplemental approaches to protect the turbine from particulate effects and to meet environmental emissions standards. Promising supplemental approaches have been identified in Appendix A.

The two commercial coal fueled turbine applications discussed in Appendix A are large (≥ 100 MW) CFTCC power plants and smaller (3 to 5 MW) coal-fueled cogeneration systems. For the CFTCC plant, the particulate cleanup system choice is the hot gas filter. Reasonable filter lifetimes are expected for that system because of the relatively low filter operating temperature of 727°C (1340°F). Furthermore, the capital cost of the heat exchanger to provide that temperature and a large filter with a conservative face velocity under 5 ft/min are not severely detrimental to overall system economics.

The final decision on the best particulate control system for the coal-fueled cogeneration system was awaiting the results of the planned hot gas filter tests and DEC tests representing turbine flow path conditions for operation with both filters and cyclones.

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APPENDIX F: SO_x CONTROL

SULFUR CONTROL FOR COAL-FUELED TURBINES

Emissions Goals

The two promising commercial coal-fueled turbine systems identified in the DOE/Allison ACFTS program were: (1) industrial cogeneration systems based on the Allison 501-K (3.7 MW) turbine; and (2) CFTCC power plants based on large (≥ 50 MW) utility turbines.

Environmental agencies had not established emissions regulations for coal-fueled cogeneration systems. Consequently, emissions regulations had to be anticipated. A SO_x emissions goal under 150 ppm at 15% O₂ was anticipated for the industrial coal-fueled cogeneration system based on current or expected regulations for industrial coal boiler systems and industrial turbines operating with conventional fuels. For the CFTCC power plant, the SO_x emissions goal under 1.2 lb/MMBtu of the Federal NSPS was chosen. As to be discussed, the sulfur control system eventually chosen for the CFTCC power plant was expected to achieve SO_x emissions about an order of magnitude lower than the NSPS goal.

Candidate SO_x Control Approaches

Alternatives for SO_x control include the following:

- sulfur compliant coal
- sorbent injection into the RQL coal combustor
- stack gas scrubber
- sulfur capture reactor located between the combustor quench and lean zones

Of the many options considered, the above alternatives were evaluated as the most promising for commercial coal-fueled turbine systems.

EVALUATION APPROACH

A subcontract was let to the Westinghouse Science and Technology Center to evaluate sulfur control in the coal-fueled turbine cogeneration system. Three sulfur capture locations considered were a CWF prevaporizer, the combustor quench zone, and combustor lean zone. A prevaporizer is a device evaluated early in the program which vaporizes the coal-water fuel and releases sulfur for capture before injection into the combustor. Thermodynamic equilibrium calculations were conducted for candidate sorbent compounds of over 30 elements to determine their equilibrium potential for sulfur capture at the three locations. Experiments were used to estimate the amount of sulfur release and availability for capture in the prevaporizer.

The sorbents with the highest equilibrium capture efficiencies were screened based on availability, cost, and toxicity to identify the most promising sorbents. Kinetics experiments were conducted to evaluate the performance of the promising sorbents at conditions of the three potential capture locations.

Block diagrams and components were identified for subsystems using the promising sorbents and located at the prevaporizer and the combustor quench and lean zones. Approximate capital and operating costs were estimated for the most attractive sorbents and sulfur capture subsystems.

Based on the above evaluations, recommendations were made on sulfur sorbents and capture locations for the coal-fueled turbine cogeneration system using an ultraclean and moderately clean CWF.

Sulfur capture was also evaluated experimentally using the subscale coal combustor. Dolomite was injected just upstream of the quench zone. The equilibrium chemistry and kinetics of calcium based sorbent injection into the coal combustor was also explored by Allison and through a subcontract with Reaction Engineering International. The effects of coal sulfur levels, dry versus slurry fuels, a heat exchanger to reduce the capture gas temperature, and capture residence time were evaluated.

A project goal was the evaluation of sulfur capture approaches for promising coal-fueled turbine applications identified by Allison. Coal-fueled turbine, combined cycle (CFTCC) power plants were identified later in the program as a potentially attractive application. Consequently, sulfur control approaches for CFTCC power plants were screened by Allison. Important constraints were a sulfur control location at the quench zone (for reduced volumetric flows) and very high sulfur removal efficiencies at a temperature in the range from 1300°F to 1500°F. The lower temperature limits the reduction in overall power plant efficiency associated with increased quench or heat extraction from the rich zone gases. The upper temperature reduces the risks of plugging or ceramics degradation for the hot gas filter. Higher particulate control temperatures were considered for the coal-fueled cogeneration system because a more distant commercialization date allowed more time for filter development and potentially viable particulate control options not involving filters had been identified for the cogeneration systems.

COGENERATION SYSTEM SO_x CONTROL

The subscale combustor tests involving dolomite injection showed very little sulfur capture. Equilibrium calculations by both Allison and Reaction Engineering International indicated that the quantities of water that are used to cool the gas stream leaving the rich zone and quench the slag dramatically reduced the maximum expected sulfur capture. With both bituminous and subbituminous coals, capture levels under 10% were predicted for the design condition of 1093°C (2000°F). This is because 1093°C (2000°F) is not a thermodynamically favored capture temperature. Also, water is a product of the primary CaO and H₂S reaction and high water concentrations force the equilibrium towards H₂S (and away from CaS).

Consistent with the Allison and Reaction Engineering analyses, Westinghouse also found that quench zone water inhibits effective sulfur capture at that location for inexpensive Ca-based sorbents. Of the many systems explored by Westinghouse, the sulfur control system with the best economics and least uncertainty used injection of hydrated dolomite into the combustor dilution zone. However, the Westinghouse capital cost estimate for this system was lower than a quote to sell obtained by Allison for a commercial double alkali stack gas scrubber and regenerator sized for the exhaust flow of the Allison 501-K turbine. Operating costs for the commercially proven scrubber/regenerator were also somewhat less than operating costs for the system favored by Westinghouse.

Appendix A discusses the effect of sulfur capture approaches on coal-fueled cogeneration systems economics. Figure A-11 compares the cogeneration system internal rates of return for a plant using calcium sorbent injection into the combustor quench zone compared to a plant using a commercial, sodium based, lime regenerated stack gas scrubber (mentioned above) which has demonstrated 95% S capture at coal boiler plants. Even if favorable S capture conditions could be identified for Ca sorbent injection at the quench zone, this approach offers little or no economic advantage over the commercially available stack gas scrubber. One of the most important factors affecting this result is the cost of a reactor system needed to convert captured sulfide materials to disposable compounds (e.g., CaSO₄).

The SO_x emissions goal given above for the cogen system can be met using coals with sulfur levels less than about 0.6% to 0.65%. Although coals have been ultracleaned to this level, the cleaning costs have been high. The large volume processing plants needed to economically produce ultra cleaned coals have not been developed and are not likely to be constructed in the foreseeable future. A small fraction of U.S. coals can be mined or mine washed to 0.65% S or lower. However, their premium price in addition

to transportation expenses makes their delivered costs high at distant locations from the relatively few mines which produce compliant coals.

Figure A-17 of Appendix A compares the internal rate of return for the reference cogeneration system using a hot gas filter and stack gas sulfur scrubber to a cogeneration plant operated with a sulfur compliant coal powder fuel and without the exhaust scrubber. The plant using a compliant coal produces a higher IRR than the reference plant at compliant 1990 coal prices less than \$2.40/MMBtu (\$0.60/MMBtu premium price over reference plant coal).

Consequently, for the reference coal-fueled cogeneration system using hot gas filters, the most attractive method of meeting the emission standard of 150 ppm SO_x at 15% O₂ is the use of sulfur compliant coal if this fuel can be obtained at a premium price less than about \$0.60/MMBtu over a non-compliant coal. Otherwise, use of a commercially proven sodium based stack gas scrubber with sorbent regeneration was assessed to be the most attractive means of sulfur control.

CFTCC PLANT SO_x CONTROL

Calcium sorbent injection was also explored for CFTCC plants. These larger systems could accommodate the capital cost of a reducing gas heat exchanger to produce a lower and more favorable sulfur capture temperature without injecting additional quench water. In a commercial system, heat extracted would be used to provide additional steam to that produced by the heat recovery steam generator at the turbine exhaust.

Three sorbent injection cases were studied, two with powdered coal and one with coal water slurry as a fuel. For the first case with powdered coal, the quench zone temperature was reduced to 899°C (1650°F) using water injection. The second case was run with the quench temperature fixed at 1093°C (2000°F) and the heat exchanger exit at 899°C (1650°F). The third case was run with CWF in place of powdered coal under the same conditions as case 2.

Limits of sulfur capture were determined by using thermodynamic equilibrium calculations for these three cases. Figure F-1 shows the results of the study for a range of fuel sulfur levels. Calcium was used as the sorbent to capture sulfur as CaS under equilibrium conditions. Capture efficiency was determined from the quantity of sulfur present in solid state at the exit of the heat exchanger (and therefore removed by the separator) compared to the total sulfur entering the system. Sulfur is more difficult to remove as fuel sulfur level decreases. Results for CWF show little capture with fuel sulfur levels below about 1.5% with full water quenching. A significant improvement is obtained by the addition of a heat exchanger, although capture efficiencies are still below NSPS requirements for boilers. Switching to dry coal without the heat exchanger further improves the sulfur capture efficiency. Figure F-2 shows the sulfur emissions rate for the three cases expressed in units of lbs/MMBtu heat input. The emission rates are almost independent of fuel sulfur content and is the result of the equilibrium balance between H₂S and CaS; only the sulfur present as H₂S above a minimum value is available for capture based on equilibrium. The minimum value, however, is a function of the water vapor present and hence the emission rates are lowest for the case with the least water vapor. These results are significant in that for the first time with the RQL combustor, emission rates below a standard of 0.6 lbs/MMBtu appear to be marginally attainable at a near optimum capture temperature of 899°C (1650°F). However, the downstream hot gas ceramic filter used to extract the sulfided sorbent from the gas stream would also operate at a temperature of about 899°C (1650°F). This is higher than the temperature limit mentioned above to reduce the risks of filter plugging and ceramic long term degradation.

After additional screening, a Zn titanate sulfur control system was chosen for the CFTCC system because of its potential for high capture efficiencies (≥99%) and favorable capture temperature in the vicinity of 727°C (1340°F). Also, the sorbent regeneration approach can be designed to produce elemental sulfur as a salable byproduct.

Figure F-1. Sulfur capture for calcium injected as sorbent.

Figure F-2. SO₂ emission rate for calcium injected as sorbent.

Research Triangle Institute (RTI) had been developing Zn titanate as a sorbent and had been conducting laboratory scale, fluid bed sulfur capture experiments. A subcontract was let to RTI for the design and procurement of components for a fluid bed, Zn titanate test unit for operation with a slipstream from the subscale coal combustor. Figure F-3 shows a schematic of the slipstream sulfur unit which was designed to cycle between sulfur capture and sorbent regeneration modes of operation. The sulfur capture slipstream equipment was installed at the subscale coal combustor but testing could not be conducted before the end of the ACFTS program.

Figure F-3. Slipstream schematic - sorption and regeneration.

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APPENDIX G: COMPONENT DURABILITY LABORATORY ANALYSES

LABORATORY ANALYSES

Extensive analyses were conducted in the Allison Coal Fuels Laboratory to screen materials for reduced component degradation due to ash:

- refracting liners of the combustor, cyclones, and ducting
- hot gas filters
- gas turbine

The refractories lining the subscale and full-scale systems exhibited adequate short term life needed for combustor development. However, some degradation was experienced due to ash and calcium (from sorbent injection) chemical attack, thermal shock cracking, and erosion or deposition from some fuels. The test experience showed that improvements in refractory durability were needed for commercial life. Combustor and laboratory tests were conducted to screen candidate refractories for greater tolerance to the coal combustion environments. Laboratory tests also screened additives that could be injected into the combustor stream to raise the coal ash melting points and decrease sticking tendencies. The intent of the additive work was not only to alleviate corrosion and deposition of refractories but also plugging/corrosion of filters and deposition/corrosion of the engine in coal-fueled turbine systems.

REFRACTORY SCREENING

Bricks of several refractories (Figure G-1) were exposed in the lean zone oxidizing conditions of the subscale combustor at temperatures from 1093 to 1371°C (2000 to 2500°F). The silicon carbide refractory Carbofrax A appeared to be the most durable with no evidence of thermal shocks or corrosion failure. Very minor erosion was observed in some areas of this refractory. A zirconia/silica refractory (Didier Taylor) showed both thermal shock and erosion damage. The two alumina materials (A.P. Greene 99AD and Carborundum Alfrax 101) showed extensive thermal shock and mechanical damage in addition to some erosion in the case of the 99AD refractory.

Even more durable refractories than Carbofrax A were later identified in laboratory screening tests.

Over 100 refractories (some coated) were evaluated in laboratory tests which included:

- exposure to ash and lime in a furnace
- thermal-shocking to 1649°C (3000°F) using an acetylene/oxygen flame
- ASTM room temperature erosion test (ASTM C704)

Refractory samples were typically exposed to coal ash (Pittsburgh No. 8 in later tests) and the sulfur sorbent, calcium hydroxide (Longview hydrated lime) for four hours under reducing and oxidizing conditions. Figure G-2 shows results from test of a zirconia coated refractory. Generally, if the materials withstood the corrosion tests, then thermal-shock and erosion resistances were evaluated.

A plasma sprayed zirconia coated (0.051 cm (0.02 in) thickness) alumina had good corrosion resistance under oxidizing and reducing conditions at temperatures up to 1649°C (3000°F). The coating was very adherent and resistant to thermal shock. However, more resistant refractories to mechanical damage were identified in later tests. In practice, upstream spalling of refractories or oxide could cause localized impact removal of the zirconia coating and exposure of the less resistant underlying alumina.

The laboratory screening tests identified several refractories with improved durability over those used in earlier combustion tests. The most durable material for oxidizing and reducing temperatures up to 1649°C (3000°F) were Cohart 501M (modified fusion cast manufacturing process) and Cohart/Abresist,

Figure G-1. Refractory fire bricks installed in bench scale combustor lean zone.

which are both alumina, zirconia, silica (AZS) based refractories. Carborundum Hexoloy SA and ST refractories (SiC) exhibited comparable durability under reducing conditions but experienced extensive reaction with ash under oxidizing conditions for temperatures above 1371°C (2500°F). Compared to the other AZS refractories the Cohart Promold (AZS) water cast-cured refractory exhibited somewhat lower but possibly acceptable resistance to ash and lime. A Cohart 501 (unmodified) refractory yielded the best erosion resistance in the ASTM erosion test followed by Cohart/Abresist and Hexoloy which experienced about 50% higher erosion rates. Some deviations in performance such as reduced fusion temperatures and thermal shock resistance were sometimes observed for the unmodified Cohart 501 AZS refractory due to manufacturing variations.

Sections of the subscale and full-scale combustors were lined with Cohart AZS refractories but the program was discontinued before their long term durability could be evaluated.

ADDITIVE SCREENING

Reduction of Ash Sticking

A range of additives based on Al, Si, Mg, Ti, Fe, Ca, Sr and Al/Si compounds were screened by ash fusion tests. Al and Al/Si (kaolin) based additives were determined to be the most promising from both

Figure G-2. Comparison of corrosion resistances of noncoated and ZrO₂ - coated refractories, Corhart "Promold", at 3000°F, 4 hr.

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effectiveness and cost considerations and most later laboratory tests were conducted with additives of those types. Over 15 coal ashes were used in the tests. The tests evaluated the following:

- sticking in a furnace at hot gas filter and turbine surface conditions
- melting indicated by the ASTM ash fusion cone test under reducing conditions

The objective of the sticking tests was to screen types and levels of additives that increase the temperature of ash sticking on a SiC filter material at reducing conditions to over a 1038°C (1900°F) filter operating temperature and on a nickel based alloy at oxidizing conditions to over 1204°C (2200°F) turbine inlet temperature. The objective of the fusion tests was to screen types and levels of additives that could raise ash initial fusion temperatures (reducing) to over 1649°C (3000°F) and alleviate melting at the 1649°C (3000°F) rich zone combustor temperature and all downstream locations in the coal fueled turbine system which operate at lower temperatures.

Sticking tests for the ashes of several CWF are summarized in Table G-1. Undoped ash is shown to stick on the SiC candle filter substrate at 1038°C (1900°F) reducing conditions for all fuels. Sticking of undoped ash on the nickel-based alloy at 1204°C (2200°F) oxidizing conditions occurred for all but one fuel (OXCE Elk Creek seam). Doping the ash with 1:1 ratio of a fumed alumina to ash raised the sticking temperature on the filter material to over 1038°C (1900°F) and in the nickel-based alloy to over 1204°C (2200°F) for all fuels. Doping with kaolin was not as effective as alumina at reducing conditions.

Table G-1.
Ash sticking results for alumina additive.

		U = undoped, D = doped S = sticking, N = non-sticking	
<u>Sample No.</u>	<u>Sample</u>	SiC 1038°C (1900°F) <u>reducing</u>	Nickel alloy 1204°C (2200°F) <u>oxidizing</u>
1	Otisca-Taggart-U	S	S
2	Otisca-Taggart-D	N	N
3	Otisca-Taggart-D*	S	N
4	AFT-Lower Cedar Grove-U	S	S
5	AFT-Lower Cedar Grove-D	N	N
6	AFT-Lower Cedar Grove-D	N	N
7	OXCE-Elk Creek-U	S	N
8	OXCE-Va Tech-U	S	S
9	OXCE-Va Tech-D	N	N
10	AMAX-Elkhorn B-U	S	S
11	AMAX-Elkhorn C-U	S	S
12	AMAX-Elkhorn D-U	S	S
13	AMAX-Blue Gem-U	S	S
14	AMAX-Blue Gem-D	N	N
15	AMAX-Elkhorn-U	S	S
16	AMAX-Castlegate-U	S	S
17	AMAX-Castlegate-D	N	N
18	Carbogel-U	S	S
19	Carbogel-D	N	N
20	Midwest-Black Beauty-U	S	S
21	Midwest-Black Beauty-D	N	N

*Doped with 1:1 kaolin

Further assessments of the effects of additive levels indicated that alumina to ash ratio as low as 0.2 prevented sticking, depending on the coal. Subsequent scanning electron microscope/energy dispersive X-ray (SEM/EDX) analyses of the SiC filter material revealed the sticking mechanism to be a reaction between the ash and clay binder used in the manufacture of the ceramic candle. The reaction appears to generate as low melting point eutectic or solid solution at the ash/filter interface which might be prevented with a small amount (0.2 alumina/ash ratio) of alumina for several coals. Similar SEM/EDX studies with a Spring Creek subbituminous coal ash on both SiC (Porosic) and aluminum silicate (Fibrosic) filter candle materials indicated that a maximum operating temperature to limit attack from the ash might be 1066°C (1950°F) for both ceramics at reducing conditions without additives.

Later sticking tests with Taggart seam CWF ash compared the effects of a lower cost (about \$1.04/lb) Alcan alumina (0.8 μ m) with kaolin (about \$0.33/lb) at a similar particle size. Both prevented sticking on a nickel based alloy at 1204°C (2200°F) oxidizing conditions at additive to ash ratios of 0.4 to 1. However, kaolin was less effective in preventing sticking on SiC at 1038°C (1900°F) reducing conditions. An additive to ash ratio of 2 to 1 was required for kaolin while 0.4 to 1 prevented sticking for the alumina.

The additive levels required to prevent sticking were coal dependent. For the Taggart bituminous seam CWF ash, an Alcan alumina to ash ratio of 0.6 to 1 increased the sticking temperature to 1097°C (2000°F) on SiC at reducing conditions. A ratio of 0.8 to 1 was required for the ash from a Spring Creek subbituminous CWF which had a significantly higher sodium content.

Reduction of Ash Fusion Temperatures

Based on combined effectiveness, cost and erosion considerations, the most promising additives to increase ash fusion temperatures were aluminum hydroxide (Gibbsite) at a cost of about \$0.80/lb and kaolin at a cost of about \$0.33/lb, both with an average particle diameter of 0.8 μ m. The small particle diameters and lower hardness (compared to alumina) reduce the possibilities of turbine erosion for these additives. For the same additive to ash ratio, aluminum hydroxide was somewhat more effective in increasing coal ash fusion temperatures but kaolin is less expensive so higher concentrations could be afforded. Furthermore, kaolin is known to getter gaseous phase alkali and might offer additional advantages. Magnesia was also determined to be effective in raising ash fusion temperatures but is considered less attractive because of significantly higher costs.

Ash fusion tests were conducted on four coals with promising ash characteristics to alleviate turbine deposition, erosion and corrosion. Among other desirable characteristics, the ash levels in these coals were moderate (4 to 8%) and initial ash fusion temperatures were high, ranging from 1316°C (2400°F) to over 1538°C (2800°F). Table G-2 identifies these coals and shows the aluminum hydroxide to ash mass ratios (0.2 to 0.5) that raised their initial ash fusion temperatures (reducing) to over 1649°C (3000°F).

As for sticking described above, the coal ash characteristics affected the amount of additive needed to raise the ash fusion temperature. Extensive efforts were required to identify additives that could raise the initial fusion temperatures (reducing) of Pittsburgh No. 8 coal ash to above 1649°C (3000°F). Compounds of Si, Al, Ti, Al/Si, Fe, Ca, and Mg were evaluated. Only Al and Mg compounds achieved that objective but at relatively high additive to ash ratios from 1.3 to 1.5.

Table G-2.
Aluminum hydroxide fuel additive-to-ash weight ratio comparison (initial ash fusion reducing >3000°F).

<u>Coal</u>	<u>Weight ratio</u>
Elk Horn	0.2
Elk Creek	0.2
Lower Kittanning	0.2
Black Beauty	0.5

APPENDIX H: TURBINE PROTECTION FROM DEPOSITION, EROSION, CORROSION

BACKGROUND

Probably the greatest technical challenge for coal-fueled combustion turbines is turbine flow path durability. Coal ash and contaminants can degrade the precisely designed vane and blade passages by deposition (ash buildup and blockage), erosion (impact removal), and corrosion (chemical attack). Over 10 years and thousands of hours of engine tests were directed to achieving adequate turbine flow path lifetimes in each of two major U.S. and Australian direct coal-fueled turbine programs which started in the 1940s (Smith, et al., 1966, and Interdepartment Gas Turbine Steering Committee, 1973). Although these programs did not produce commercial coal-fueled turbines, significant improvements in turbine life were achieved through increased separator particle removal efficiencies, erosion-resistant materials, and redesign of the turbines (e.g., for lower flow-path velocities).

Operation of combustion turbines with coal-fired pressurized fluidized bed combustion (PFBC) plants is approaching commercialization. Based on several thousand hours of cascade testing at facilities in Leatherhead, England, and Finsping, Sweden, turbines have been modified (ruggedized) for improved tolerances to coal combustion gases. Such turbines have been tested at the Tidd PFBC plant in Ohio, the Värtran PFBC plant in Sweden, and the Escatron PFBC plant in Spain (Egnell, et al., 1992).

The recent PFBC turbine demonstrations and the early direct coal-fired turbine projects in the U.S. and Australia show the potential for operating combustion turbines with coal. However, the deposition, erosion, corrosion (DEC) environments in the flow paths of most modern turbines are much more severe than for the PFBC turbines or the early coal-fired turbines. In those cases, the turbines were modified for reduced stage loading to substantially decrease ash particle impact rates and velocities to thereby decrease erosion (and deposition). More importantly, most modern turbines operate at inlet temperatures of 1100°C (2000°F) or higher while inlet temperatures were under 845°C (1550°F) for the PFBC turbines and the early direct coal-fired turbines tested in the U.S. and Australia. The over 255°C (450°F) higher turbine flow-path temperature of modern turbines can result in much higher levels of molten ash phases. This causes increased ash sticking on turbine surfaces with potentially much higher rates of corrosion and deposition with tenacious deposits that can be difficult to remove. High rates of corrosion and deposition were indeed experienced (Wenglarz, et al., 1986) in past tests representing modern turbine flow-path conditions using an Otisca Blue Gem seam coal water fuels at Allison.

Because the deposition and corrosion environments in modern turbines are more severe than for the past PFBC and early coal-fired turbines, a need was recognized in the Allison ACFTS program to significantly reduce the time and cost to develop turbine protection approaches and the duration of engine runs compared to past coal-fueled turbine programs. Consequently, a relatively low cost DEC test approach was further developed to better understand the DEC processes and screen turbine protection approaches and thereby reduce the number of expensive turbine tests. The following describes this DEC test evaluation approach with supporting evaluations and their application. Some of this work was supported by an Allison internal project and is discussed here to adequately describe the turbine durability evaluations.

TURBINE DEC EVALUATION APPROACH

The degradation of turbine flow paths due to fuel or airborne contaminants can be separated into two processes:

- delivery of ash and contaminant material to turbine surfaces
- interaction (e.g., sticking, impact removal, chemical attack) with those surfaces

Turbine DEC can be assessed by using and combining evaluations based on the above two processes. Delivery rates and arrival conditions of material to turbine airfoil surfaces are calculated using multiphase flow computer codes developed in recent years (Wenglarz, 1987). Relatively simple and low cost tests (compared to cascade or engine test) with the fuel of concern are used to determine interaction of contaminants with turbine materials of concern. Calculated delivery rates and conditions are combined with the data from the simplified tests to estimate turbine flow path degradation rates and maintenance intervals. This methodology has been described in detail (Wenglarz, 1987, Wenglarz, 1992) and is summarized here in a highly simplified form for purposes of brevity.

The maximum allowable thickness (d_{MAX}) loss (erosion/corrosion) or gain (deposition) of material at critical locations on a turbine airfoil is first determined. The maximum value d_{MAX} is usually limited by structural considerations or the maximum allowable loss of turbine power due to flow path degradation. The same computer codes used for aerodynamic design of the turbine flow path can be used to determine the d_{MAX} that produces the maximum allowable loss in turbine power. For a critical airfoil row, the turbine maintenance interval, T_M , can be estimated by:

$$T_M = \frac{d_{MAX}}{\frac{\dot{m}_p}{A} \left(\frac{\Delta}{\rho} \right)} \quad (1)$$

where Δ is the mass of surface removed per mass of impacting particles (i.e., erosivity) for erosion or the mass of surface buildup per mass of impacting particle (i.e., sticking fraction) for deposition. Either recession or buildup usually dominates after a brief surface conditioning period. In the case of erosion, ρ in Equation 1 is the density of the airfoil alloy. For deposition, ρ is the density of the deposit.

The term $\dot{m}_p/A$ is the mass delivery rate of ash particulate per unit area at the critical location on the turbine airfoil. By far, inertial impaction is the mechanism that produces the highest particle delivery rates for typical products of combustion (POC) size distributions (most particulate larger than a few microns). However, as to be discussed, other particle transport mechanisms such as turbulent diffusion/eddy impaction can be important under some circumstances. The term $\dot{m}_p/A$ can be computed from data on the POC particulate size distribution and particle density using multiphase flow computer codes applied to the turbine passage. Also computed are characteristics of delivery such as particle impact velocities and angles.

Since d_{MAX} and $\dot{m}_p/A$ are determined as just discussed, the remaining quantities in Equation 1 to estimate the maintenance interval T_M are Δ and ρ . Δ is measured in simplified (and relatively inexpensive) tests as a function of delivery conditions such as ash particle impact velocity and angle. ρ is the known density of the turbine alloy (for erosion) or the deposit density measured from the simplified test.

Figure H-1 illustrates significant aspects of the simplified DEC test facility that has been used to obtain the data needed to estimate turbine maintenance intervals from Equation 1. A subscale combustor is operated with the fuel of concern. The combustion stream is accelerated to turbine inlet flow velocities prior to entering the first test section. Several cooled, wedge-shaped specimens are exposed in the test section at gas and surface temperatures of the first stator vanes of the turbine of concern. The specimens are constructed with the alloys and coatings of the turbine represented and candidate alternate materials for improved DEC performance. Air is injected at the exit of the first test section to adjust the inlet temperature entering the second test section to the value of a downstream turbine row. The materials and surface temperatures of specimens used in the second test section are the same as those in the represented turbine row.

Figure H-1. DEC test facility.

Not shown in Figure H-1 is an isokinetic probe located between the combustor and the first test section. Combustion particulate are captured with the probe and their densities and size distributions are measured (e.g., using a Coulter counter). A particulate cleanup device can be located between the combustor and test sections or can be represented by modifying the measured POC loading and size distribution data using grade efficiency (removal fraction versus particulate diameter) information for the cleanup device.

ADVANCEMENT OF DEC PREDICTION CAPABILITIES

Several efforts were directed to improving DEC predictive capabilities and understanding for turbines operating with coal contaminants:

- analyses of corrosion from previous tests
- development of product of combustion (POC) analyses procedures to determine mass and density distributions
- incorporation of remaining particulate transport mechanisms into particle delivery calculation methodology

Corrosion Analyses

The Kentucky Energy Cabinet Laboratory (KECL) provided extensive metallurgical analyses of specimens that had been exposed in an earlier program to coal water fuel combustion products in at conditions of the first two rows of an industrial turbine. These analyses were interpreted by Allison. Three coal water fuels were tested, which ranged in ash content (in coal) from 1.25% to 0.69%. The exposed specimens were constructed of IN738 turbine alloy covered with a commercial corrosion resistant CoCrAlY

coating. Details of the corrosion analyses are reported in Wenglarz, Sethi, Gongalez, 1991. In summary:

- very high rates of corrosion attack were observed for specimens exposed at first stator conditions (localized corrosion penetrated to one-third the coating thickness in as little as 1.7 hr)
- the attack was unlike typical alkali induced corrosion previously experienced with conventional fuels
- calcium was the ash element most consistently associated with the attack
- the question of whether calcium in coal causes unacceptable corrosion rates at turbine conditions of materials containing chromium is important; all coal ashes contain significant levels of calcium and virtually all turbine hot section alloys and coatings contain chromium

POC Analyses Procedure

Calculation of particle delivery rates to turbine surfaces requires data on solid products of combustion (POC) mass distributions and density versus particle diameter. These are significantly affected by carbon burnout inefficiencies, particularly for low ash fuels. For example, the POC solids contain 50% carbon and 50% ash for a 1% ash coal fuel combusted at 99% carbon burnout efficiency. The carbon is not evenly distributed over the POC size distribution range because the smaller particles burn out and contain only relatively high density ash while larger particles mostly contain low density char. Due to differences in particle density with diameter, POC mass distributions can vary significantly from volumetric size distributions which are conveniently obtained through Coulter counter analyses of captured combustion particulate.

A procedure was developed to determine POC mass distributions and particle density versus diameter using volumetric size distributions and other simple laboratory analyses. Figures H-2 and H-3 show particle densities versus diameters and ratio of mass to volume distributions, respectively, which were determined from applying this procedure to POC captured by an isokinetic probe during tests of three CWFs. Figure H-2 shows that for high carbon burnout efficiency (99.4%), the particle density varied by a factor greater than 4 over the range from completely burned out small particles containing all ash to large particles containing mostly porous char. As shown, the results for fuels with lower carbon burnout efficiencies result in lower and more uniform particle densities because of a greater mass fraction of unburned char over the full measured range of particle diameters. Figure H-3 shows that the ratio of cumulative mass fractions to cumulative volume fractions is as low as 0.6 for 99.4% carbon burnout efficiency of the CWF containing 1% as in the coal. The distribution ratios are closer to unity for low carbon burnout fuels because the particle densities vary less with diameter, as shown in Figure H-2.

Extension of Turbine Deposition Prediction Capabilities

Particle Delivery Analyses

Previous Allison estimates of turbine DEC considered only inertial impaction particle delivery on airfoil pressure surfaces, which is dominant in most cases. However, deposit buildup on suction surfaces can also be important for systems using hot gas filters or fuels for which erosion dominates on pressure surfaces. For such cases, particle delivery to suction surfaces by turbulent eddy diffusion/impaction, thermophoresis, and Brownian diffusion should be considered. Consequently, the methodology to use simplified test data extrapolated to turbine by multiphase flow computer codes was extended in an Allison internal project to include the particle delivery mechanisms just mentioned. Figure H-4 shows the application of a particle delivery code that includes inertial effects and these mechanisms. Normalized particle delivery rates (deposition velocities) are given versus particle diameter at pressure and suction surface locations on the first stator of the Allison 501-K industrial turbine. Inertial impaction delivery on the pressure surface is shown to dominate for particles larger than a few microns, as indicated earlier.

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Figure H-2. CWF combustion product particle densities versus diameter.

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Figure H-3. Ratio of mass fraction > D_p to volume fraction > D_p for combustion products of fuels of the Component Screening Program.

Figure H-4. Deposition velocities on first rotor of a 501-K turbine.

Test Capabilities

The blunt wedge-shaped specimens previously used to obtain data on pressure surface impaction sticking fractions (Δ) are not convenient for obtaining turbine airfoil suction surface sticking fractions. This is because particle delivery rates (needed to determine sticking fraction) on the blunt specimen back "suction" surfaces are difficult to calculate due to wake vortices downstream of the specimens. Consequently, symmetrical airfoil-shaped specimens (shown in Figure H-5 with a mold) were designed and fabricated from turbine alloys for tests utilizing hot gas filters for which suction surface deposition can be important. The computer code described in the last section was applied to these specimens to determine particle delivery rates versus particle diameter. This information along with POC data and specimen mass buildup data from DEC test using filters can be used to estimate suction surface sticking fractions (Δ in Equation 1) and maintenance intervals for turbine operating with filters.

DEC FACILITY DEVELOPMENT/TESTS

Two combustors were used for DEC test in the ACFTS program. The first was the subscale combustor that had been utilized to develop the Allison RQL combustion approach for coal. The second was a dedicated DEC combustor designed especially for low cost tests.

Two DEC test sections were installed downstream of the subscale combustor equipped with a cyclone to remove combustion product ash. Three DEC test were then conducted using a physically cleaned Otisca-Taggart seam CWF, the same fuel doped with a kaolin additive to reduce deposition and an AMAX chemically cleaned CWF.

Attention was then directed to developing the dedicated DEC test rig. A test combustor, modified by BECON, Inc., for coal fuels, was procured. The BECON system has become an industry standard for evaluating turbine materials corrosion and erosion with conventional fuels. The computerized control system is designed for unattended operation and relatively low fuel flow rates (50 to 100 lb/hr) which reduce the manpower and fuel costs for such testing. The BECON combustor was modified according to

Figure H-5. Airfoil specimen and mold.

Allison specifications to use CWF. An air assist nozzle previously tested at Allison was incorporated into the combustor which was lengthened to increase its residence time. After initial tests showed inadequate combustion performance with CWF, the metallic combustor body was replaced with a ceramic (mullite) lined combustor tube for improved carbon burnout. The modified system was used for a series of over 14 DEC tests to evaluate additives to control deposition. Prior to latter tests in this series, a wide angle optical viewport was installed in one test section, and the deposition process was recorded by a video camera.

A new set of refractory test sections with metallic liners to prevent refractory spalling and entrainment were designed and fabricated later in the program. These test sections utilized an improved specimen mounting arrangement to facilitate removal for weighing without dislodging deposits. The test section flow area was also reduced to accommodate the change in preferred fuel form from CWF to powdered coal fuels.

DEC TEST RESULTS

Subscale Combustor Tests

As mentioned earlier, initial tests in an earlier program of Otisca Blue Gem coal seam CWF showed high rates of deposition (and corrosion) with no hot gas cleanup. The first subscale DEC test in the ACFTS program utilized a hot gas cyclone and an Otisca-Taggart coal seam CWF judged to have a lower deposition potential. The deposition rates at first stator conditions from the Taggart seam CWF were significantly lower compared to the deposition rates from the previously tested Blue Gem CWF. Figure H-6 shows the specimen deposit weight buildup rates for the 0.55% ash Taggart fuel were about 10% and 25% of those for Otisca Blue Gem fuel containing 1.25% and 0.69%, respectively. Lower ash levels, cyclone hot gas clean up and a lower ash sticking fraction contributed to the lower deposition rates for the Taggart CWF. The lower ash levels and cyclone produced most of the reduction in deposition rates. The sticking fraction for the Taggart CWF was somewhat lower than that for the Blue Gem CWF.

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Figure H-6. Deposition rates for various fuels tested.

The desired gas temperature of 1077°C (1970°F) representative of the first stator inlet of the 501-K turbine was achieved in the first DEC test with the baseline Otisca Taggart fuel. However, the highest temperatures that could be reached in the two other tests with the kaolin doped Otisca Taggart and AMAX chemically cleaned fuels were several hundred degrees below the test objectives. Deposition was significantly less in these latter two tests at lower temperatures than in the first test at the higher first stator inlet temperature. Specimens were nearly clean after the third test. However, since deposition can be highly sensitive to gas temperature, it is uncertain whether the lower deposition rates for the second and third runs were caused by differences in ash/dopant chemistry or reduced temperatures.

Dedicated DEC Combustor Tests

As discussed in Appendix G, the ASTM ash fusion tests and ash sticking experiments in a furnace were used to screen additives for deposition control. Based on these laboratory screening experiments, kaolin, and alumina were chosen for evaluation in tests using the dedicated DEC facility.

The first series of DEC tests utilized Otisca-Taggart seam CWF with no additives and doped with kaolin and alumina additives to alleviate deposition. The nickel-based alloy specimens were weighed before and after exposure in each test to determine ash deposition rates. Table H-1 gives these deposition rates with and without doping for various additive to ash weight ratios and specimen surface temperatures. Both additives are shown to substantially reduce deposition rates (by factors of 6 to over 10). Alumina was somewhat more effective than kaolin in reducing deposition rates.

After the above series of tests, spalling of the mullite combustor liner began to obscure the deposition data. A new alumina liner was installed in the combustor but subsequent tests with new batches of CWF produced low combustion efficiencies and unrepresentative DEC conditions. Budget and schedule constraints prevented further development of the dedicated DEC test combustor for improved combustion performance.

Table H-1.
Effect of additives in Otisca-Taggart CWF on ash deposition.

Additive	Additive-to ash wt ratio	Specimen temp °F	Ash deposition rate-gms/hr
Base	No additive	1800	0.691
Kaolin	0.5	1600	0.088
Kaolin	0.5	1660	0.099
Kaolin	0.5	1800	0.083
Kaolin	1.0	1800	0.116
Alumina	0.5	1800	0.066
Alumina	0.8	1800	0.065

DEC TEST DATA EXTRAPOLATIONS

Maintenance Intervals for Blue Gem CWF

The simplified test facility DEC data from tests of Blue Gem feedstock CWF in an earlier program were used to estimate the deposition maintenance interval for an Allison 501-K turbine operated with these fuels and no cyclone hot gas. Details of physical (Wenglarz, 1990a) and chemical (Wenglarz, 1990b) aspects of deposition and corrosion from Blue Gem CWF are described elsewhere. The criteria for deposit removal maintenance in this and following evaluations was 10% drop in predicted turbine power due to blockage of the first stator throats. Figure H-7 indicates a histogram of the mass distribution of products of combustion captured with an isokinetic particle probe for a combustion test which achieved over 99% combustion efficiency. Data from deposition tests conducted with a fuel formulated from the same coal feedstock indicated a fuel ash stocking fraction of 0.06 for the gas and surface temperatures of the first stator of an Allison 501-K industrial turbine. Deposit density for specimen upstream surfaces was measured to be 1.9 gm/cm³. Since deposit thicknesses were more than an order of magnitude less on downstream specimen surfaces than on the upstream surfaces, inertial impaction deposition was seen to dominate over other mechanisms of particle delivery (turbulent diffusion, Brownian diffusion, etc).

Figure H-7. Measured POC distribution from Blue Gem CWF.

Application of the deposition data extrapolation approach to the turbine first stator passages, which conditions were represented in the test, resulted in an estimated turbine deposit removal maintenance interval of less than one hour for the tested fuels. In many cases, a practical turbine deposit removal maintenance interval using on-line nut shelling might be no less than daily (24 hr). This interval is much longer than that estimated for the fuels tested without a hot gas cleanup system to remove particulate.

Cyclone Particulate Cleanup

Hot gas cleanup increases the allowable ash sticking fraction for a specified maintenance interval due to reduction of the amount of ash material that would enter a turbine and be delivered to the turbine airfoil surfaces. The following evaluates whether use of inertial separators (only proven hot gas cleanup devices up to 1100°C [2000°F]), might remove sufficient particulate to result in a one-day deposition maintenance interval for the CWF tests that were described in the last subsection.

A simple factoring of the sticking fraction and maintenance interval by the reduced gas stream particle concentrations entering the turbine often does not accurately represent the benefits of hot gas cleanup. This is because most inertial cleanup systems remove a higher percentage of larger particles than smaller particles. Since a greater fraction of large particles than smaller particles is delivered to turbine surfaces, the benefits of the inertial cleanup devices is more than proportional to the reduction in particulate levels entering the turbine.

Performance characteristics of a particulate cleanup device are often described using its grade efficiency curve. This curve gives the fraction of particulate removal by the device versus particle diameter. The grade efficiency curve for inertial separators can usually be adequately represented by an exponential function. Expressed in terms of physical performance parameters, this function can be written:

$$\begin{aligned} \text{grade efficiency} &= 1 - \exp(-1.609 (D^2 - D_0^2)/(D_{80}^2 - D_0^2)) \text{ for } D \geq D_0 \\ &= 0 \text{ for } D < D_0 \end{aligned}$$

where D_{80} is the particle diameter for which the grade efficiency is 0.8 (80% capture) and D_0 is the particle diameter for which the grade efficiency is zero (no capture).

Particle loadings and size distributions entering the 501-K turbine for cyclones located upstream of the turbine were estimated for the Blue Gem coal-water fuel tests that were described in the last subsection. These evaluations considered that a full-scale combustor operated with this fuel would produce a similar size distribution curve to that measured (Figure H-7) in the subscale combustor tests of the fuel. The cyclone grade efficiencies (expressed in terms of D_0 and D_{80}) were applied to the POC distribution of Figure H-7. The resulting loadings and distributions together with Equation 1 were used to project the fuel ash sticking fractions required to achieve a one day deposit removal maintenance interval.

Figure H-8 gives the results of these evaluations for an expected bounding range of performance parameters, D_0 and D_{80} , corresponding to cyclones sized to clean the combustor flow of the Allison 501-K turbine. The upper range of cyclone performance somewhat exceeds that ($D_0 = 1.7$ microns, $D_{80} = 7$ microns) for high efficiency Stairmand cyclones tested at the Grimethorpe coal-fired PFBC plant (Wheeldon and Burnard, 1987) which are about the size required for the 501-K turbine.

Figure H-8 shows that cyclones can increase by a factor up to 4 the sticking fraction needed to achieve a one day deposition maintenance interval for the fuel tested. However, Figure H-8 also shows that the needed sticking fraction for the fuel ash is still much less than the measured value (0.06) indicated in the last section. Consequently, the simplified deposition test and data extrapolation method indicate

Figure H-8. Sticking fraction for one day deposition maintenance interval versus cyclone performance.

that the Blue Gem seam coal-water fuels tested will not likely provide the desired one day maintenance interval for a turbine with an inlet temperature of 1100°C (2000°F), even using cyclone cleanup of the combustor effluent. These evaluations of cyclone effects were obtained without the significant additional cost of fabrication, installation, and running tests with these devices.

As shown in Figure H-6, tests of the 0.55% ash Taggart seam CWF using cyclone cleanup resulted in a factor of 9.8 lower deposition rates than the 1.25% ash Blue Gem seam CWF. A 501-K turbine deposit removal maintenance interval of 5.4 hr was estimated for the Taggart CWF and cyclone cleanup, assuming a similar particle loading and size distribution delivered to the turbine as far as for the subscale tests.

Appendix I describes a test of the Allison 501-K turbine operated with a 4.39% ash, Spring Creek seam subbituminous CWF and cyclone hot gas cleanup. The coal was dried by a hot water process before slurried. It was not possible to directly evaluate the accuracy of the turbine deposition prediction approach described above using simplified DEC tests because the turbine CWF could not be used in the subscale DEC facility. The subscale CWF fuel injection system had been removed to install a powdered coal fuel delivery system. However, indirect comparisons of results of simplified DEC tests with the turbine engine test can be made.

In the above simplified test deposition estimates, the 10% loss in turbine power for deposition maintenance corresponded to about 11% blockage in the flow area of the 501-K turbine first stator passages. The data from the 501-K turbine engine run using cyclone particulate removal indicated that 11% blockage occurred at about 1.8 hr of turbine operation with the subbituminous CWF at a reduced inlet temperature estimated in the vicinity of 816°C (1500°F). The above extrapolations of simplified DEC test data for a low ash Taggart seam CWF predicted a time of 5.4 hours to produce 11% blockage of the 501-K turbine at an inlet temperature of 1100°C (2000°F) and operated with a cyclone. The higher ash levels of the engine test fuel and low cycle efficiency resulted in a relatively short time to 11% blockage.

The first stator sticking fraction determined from the engine run data using the Spring Creek subbituminous CWF was estimated in the 0.02 to 0.03 range. As described above, a specimen sticking fraction of 0.06 was determined from a simplified DEC test of the Blue Gem bituminous CWF (which had a similar sticking fraction to the Taggart CWF). Even considering the difference in coals (subbituminous versus

bituminous), a lower sticking fraction would be expected at the 816°C (1500°F) inlet gas temperature of the first stator vanes in the engine test compared to the 1100°C (2000°F) gas temperature for the simplified DEC test.

The maintenance intervals given above consider one stage of cyclone particulate cleanup. Due to small POC sizes, additional stages of cyclone cleanup would not likely produce a one day deposit removal maintenance interval.

Additives to Control Deposition

The earlier description of dedicated DEC combustor tests using the Taggart seam CWF showed data that indicated kaolin and alumina additives can significantly reduce deposition rates. These data have been used to estimate the benefits of these additives for increasing deposition maintenance intervals of the 501-K turbine operating with the Taggart seam CWF and one stage of cyclone particulate cleanup. These evaluations indicated that kaolin and alumina increase the deposit removal maintenance interval to a range between 32 and 54 hr, depending on the additive and concentration. As discussed earlier, this interval might be acceptable for commercial operation (e.g., cogeneration systems) provided that the deposits could be removed on-line without taking the turbine out of service.

On-line deposit removal by nut shelling has been used with some success in residual oil fueled turbines. Prospects for on-line deposit removal for coal-fueled turbines depend on the tenacity of the deposits. As for deposition rates, deposit tenacity can be reduced by additives. Tests were planned in the ACFTS program to evaluate additives to further reduce deposition rates and to produce cleanable deposits. However, the project ended before these tests were conducted.

Hot Gas Filtration

The program also ended before planned tests of hot gas filters with downstream DEC tests could be conducted. Consequently, no data are available to use the deposition estimation approach described above and estimate turbine maintenance intervals. However, past experience with residual oil-fueled turbines provides some insight.

The measured levels of particulate passing filters in pilot plant tests (e.g., order of 10 ppm at the Grimethorpe PFBC plant) are similar to those entering commercial turbines operating with washed and treated residual oils. While such levels would not produce excessive deposition at lower turbine inlet temperatures (vicinity of 870°C) of first generation PFBC turbines, these levels of particulate have produced significant deposition in higher temperature (inlet temperatures > 980°C [1800°F]) commercial turbines operating with residual oils. Consequently, these levels (order of 10 ppm) of particulate could also cause significant deposition at current turbine inlet temperature ($\geq 1100^{\circ}\text{C}$ [2000°F]) operating not only in direct coal fueled applications but also in gasification and advanced PFBC applications using hot gas filters.

This is because gas turbines are high mass flow engines so that a large amount of ash material is ingested even at a few parts per million concentration in the gas entering the expander. For example, at 3.4 ppm particulate entering the turbine, considering air dilution downstream of the filter, about 3700 lb/yr of particulate enter the Allison 501-K turbine and about 85,000 lb/yr enter a large utility turbine. Less than 0.7 lb of first stator row deposits measured after the 501-K engine test in the CFTS program blocked the turbine flow area to the verge of compressor surge.

Because an excess of 10% of the combustion product particulate entering a turbine is typically delivered to the first stator vanes, significant deposition can occur even for hot gas filter cleanup at the coal ash sticking fractions (order of few percent) that have been determined in the tests described earlier at typical turbine inlet temperatures of 1100°C (2000°F). Much lower turbine inlet temperatures and the pres-

ence of sulfur sorbents for first generation PFBC turbines have resulted in insignificant levels of molten ash particulate such that inertial impaction erosion rather than deposition has dominated.

Data from the 501-K turbine test with CWF was used to obtain a rough estimate of deposition maintenance intervals for operation with the same fuel and a hot gas filter. This deposition maintenance interval was estimated by assuming the same mass of ash entering the turbine that caused a 11% first stator blockage rate (corresponding to 10% loss of power) in the engine test with cyclones would also cause the same blockage (requiring turbine maintenance) for operation with a hot gas filter. A turbine deposition maintenance interval of 150 hr was calculated considering that the particle loading passing the filter is 10 ppmw (about the same as measured for the Grimethorpe PFBC filter) and is reduced to 3.3 ppmw entering the turbine by combustor dilution air injected downstream of the filter.

This maintenance interval is similar to those for residual oil turbines which have been taken out of service for as much as a day to cool before water washing at operating intervals as frequent as a few hundred hours. Such turbine outages would be highly undesirable for intermediate or baseload coal plants. Furthermore, even very infrequent (order of thousands of hours) deposit removal maintenance intervals would be unacceptable if turbine deposits in coal systems are not amenable to "nut shelling" or water washing and require turbine dismantling for removal. Consequently, deposition is an issue, not only for direct coal-fired turbines but also for turbines in other coal systems (e.g., gasification and second generation PFBC) which operate at higher inlet temperatures ($\geq 1100^{\circ}\text{C}$ [2000°F]) with hot gas filters. Though deposit removal maintenance intervals might not be frequent, the deposits must be sufficiently fragile for nut shelling or water washing.

Additional Turbine Protection Measures

Deposition rates and tenacity can be controlled by decreasing turbine inlet temperatures to below the initial melting point of the fuel ash which is lower than detection limits of the ASTM ash fusion test. DEC tests of the Blue Gem CWF in a previous program (Wenglarz, et al., 1986) showed that ash sticking fractions and deposition rates decreased by a factor of 100 when gas temperatures decreased from 1100°C (2000°F) to 980°C (1800°F). However, low sticking fractions were not observed for the Spring Creek subbituminous CWF used in the 501-K engine test at reduced turbine inlet temperature. The ash in that coal had high Na levels (5.39%) and a low ash fusion temperature.

Since lowering the turbine inlet temperature has a negative effect on system efficiency and economics, a more attractive approach is to identify select coals for which the onset of ash melting is above the turbine inlet temperature. Preliminary fuel criteria were identified to specify coals with ash characteristics that alleviate deposition (along with erosion and corrosion). Candidate coal seams are Elkhorn, Elk Creek, Dover Spike, and Black Beauty. Analysis of coal samples from these seams showed moderate ash concentrations ($\leq 8\%$) and ash fusion temperatures ranging from 1316°C (2400°F) to 1538°C (2800°F) at reducing conditions. Sulfur contents range from 0.6 to 1.7%. An Elk Horn coal (analysis shown in Table H-2) appears to be a particularly promising coal with low Na_2O and CaO contents (0.88% and 2.83%, respectively) and near compliance (0.72%) for sulfur emissions. A shipment of Elk Horn coal was received for DEC and corrosion tests but the program ended before the test could be conducted.

The relatively high ash fusion temperatures and low alkali levels for the above four coals are expected to result in lower deposition rates and more fragile deposits than the coals previously tested. Furthermore, laboratory tests (Appendix G) indicated that initial ash fusion temperatures (reducing) for these coals could be increased to over 1649°C (3000°F) using an aluminum hydroxide additive. Only moderate additive to ash mass ratios were needed, 0.2 to 1 for the first three coals identified above and 0.5 to 1 for the Black Beauty coal. Consequently, injection of the aluminum hydroxide additive downstream of the quench zone separator would be expected to further decrease turbine deposition rates and deposit tenacity.

Table H-2.
Coal analysis

Elk Horn, Kentucky, high volatile A bituminous

<u>Proximate — wt %, dry</u>		<u>Ash chemistry, wt % (as oxide)</u>	
Ash	5.76	Silicon	50.80
Volatiles	32.49	Aluminum	31.43
Fixed carbon	61.75	Titanium	1.61
Total	100.00	Iron	6.43
Btu/lb, MAF	15412	Calcium	2.83
		Magnesium	0.97
<u>Ultimate — wt %, dry</u>		Potassium	1.53
Carbon	80.01	Sodium	0.88
Hydrogen	5.25	Sulfur	1.36
Nitrogen	1.67	Phosphorous	0.30
Chlorine	0.01	Strontium	0.23
Sulfur	0.72	Barium	0.16
Ash	5.76	Manganese	0.08
Oxygen (dif)	6.58	Vanadium	0.16
Total	100.00	Total	98.77
<u>Sulfur form — wt %</u>		<u>Particle size, microns</u>	
Pyritic	0.09	Mean	Top
Sulfate	0.01	30	83
Organic	0.62		
<u>Ash fusion-red — °F</u>			
Initial	>2700		
Soft	>2700		
Hemi	>2700		
Fluid	>2700		
<u>Ash fusion — Ox</u>			
Initial	2900		
Soft	--		
Hemi	--		
Fluid	3000		

GE cascade tests (Horner, et al., 1989) with the same Otisca-Taggart CWF used in this program have shown that both deposition rates and deposit tenacity decrease substantially by highly cooling airfoil surfaces (estimated below 538°C [1000°F] for the GE tests). This also decreases corrosion. However, increased turbine cooling reduces system power output, efficiency, and economic performance.

Appendix A discusses these systems' effects of cooling the first two expander rows of an Allison 501-K turbine used in a coal-fueled cogeneration plant. Steam provides more effective cooling than compressor discharge air. The cogeneration plant calculated IRR with steam cooling to 816°C (1500°F) and cyclone particulate cleanup resulted in about the same IRR as for conventional air cooling and a hot gas filter cleanup. This temperature also lies between the low and high temperature hot corrosion ranges and

should alleviate turbine corrosion. Steam cooling of turbine airfoil surfaces to 649°C (1200°F) and below results in an unacceptably low IRR for the 501-K cogeneration plant.

SUMMARY AND CONCLUSIONS

Significant experimental and analytical capabilities have been developed for the purpose of determining deposition, erosion, and corrosion protection approaches for coal fueled combustion turbines. Experimental facilities include an Allison 501-K industrial engine facility in addition to a subscale combustor and dedicated DEC combustor facilities. Useful data was obtained from all these facilities although funding constraints terminated final development of the dedicated DEC combustor to achieve adequate burnout of more difficult fuels to combust. The ACFTS program ended before many of the planned tests to develop turbine protection approaches could be conducted. However, data from the 501-K turbine engine test, along with data extrapolated from the two simplified DEC test facilities, led to the following conclusions for the fuels tested:

- Deposition is the dominant short-term turbine flow path degradation process. The observed high rates of deposition are attributed to ash molten phases at modern turbine inlet temperatures which cause sticking of delivered ash to the turbine airfoils. Deposition rates are much higher than for PFBC turbines which benefit from lower inlet temperatures combined with modifications of POC chemistry due to calcium sorbents to control sulfur emissions. Molten ash phases probably also produced the high rates of atypical corrosion from a Blue Gem seam CWF.
- The Allison 501-K turbine run with a subbituminous coal and simplified DEC test data extrapolated to turbine indicate additional measures over cyclone cleanup will be needed to achieve a one day deposit removal maintenance interval for the CWF tested.
- Kaolin and alumina additives increase predicted turbine maintenance intervals to over two days. This might be acceptable if deposits are sufficiently fragile that they can be removed on-line with the turbine operating, e.g. by nut shelling.
- Use of hot gas filters for particulate removal should increase the turbine deposit removal maintenance interval to the range of several hundred hours. Such intervals using filters are not only expected for direct coal-fired turbine systems but also advanced PFBC and coal gasification which operate with turbine inlet temperatures in the vicinity of 1100°C (2000°F). Deposition maintenance intervals in those systems will likely be significantly decreased for turbines with inlet temperatures 1260°C (2300°F) due to much higher levels of molten ash phases.
- A major issue for both cyclone and filter cleanup is whether turbine deposits can be removed with acceptable periods of turbine outage per year. Even an upper limit for filters of several thousands of hours between deposit maintenance activities would probably be unacceptable if dismantling the turbine is needed to remove deposits.
- The program ended before tests could be conducted on a number of approaches to increase turbine DEC lifetimes and produce fragile deposits that could be readily cleaned. These approaches included coal selection for reduced DEC, hot gas filters, additives, and reduction of surface temperatures to locally freeze ash and alleviate deposition and corrosion.

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APPENDIX I: 501 ENGINE TEST WITH A COAL WATER FUEL

BACKGROUND

The initial design of the 501-K turbine test facility included hot gas cyclones to protect the test engine from particulate effects (deposition and erosion). Much of the turbine test hardware had been fabricated by the time the turbine durability evaluations described in Appendix H predicted that operation with cyclones would result in high rates of turbine deposition. However, it was decided to proceed with a one day engine test using only cyclones for DEC control because the deposition prediction approach using data extrapolated from simplified DEC tests had not yet been verified for coal fuels, and valuable data would be obtained even if high rates of deposition occurred in the engine test. The accelerated deposition rates experienced with cyclones could be factored by the relative particle loading predicted to enter the turbine using filters to obtain a rough estimate of turbine maintenance intervals using filters. Cleanability of turbine deposits could be assessed, which, as discussed in Appendix H, is a major issue for turbine operation with either cyclones or filters. The relatively low cost, simplified DEC test approach could be verified.

TEST DESCRIPTION

Test Facility

The engine test facility is illustrated in Figure I-1. Major components of the facility are a 70 MMBtu/hr staged combustor, twin cyclones, the gas turbine engine and interconnecting ducting. The combustor, cyclones and ducting are refractory lined.

Figure I-1. Engine test facility (expanded cross-section).

CWF is injected through multiple nozzles located at the top of the rich zone of the combustor. A fraction of the turbine compressor discharge air is used to gasify the coal at temperatures above 1650°C (3000°F) in this zone under fuel-rich conditions. Products leaving the rich zone are reduced in temperature (typically to less than 1090°C (2000°F)) by water injected into the quench zone. This quench process freezes the molten coal ash for downstream capture in two parallel cyclone separators. The cleaned gases are ducted from the separators to a lean-zone, where compressor discharge air is added to complete combustion. The cyclonic lean zone design also provides further particle capture in a secondary ash collector. A draft tube discharges the lean-zone combustion products into the turbine. Additional compressor discharge air is injected into the draft tube to reduce the temperature of these combustion products to the desired turbine inlet temperature.

Figure I-2 shows a photograph of the Allison 501-KM engine used for the tests with coal. This engine is a production 501-KB5 industrial gas turbine engine (3.7MW power output with natural gas) that has been modified for an external combustor. The modification consists of a new center section to allow for the ducting of the compressor discharge air to an external combustor and receive combustion products from the external combustor.

Test Fuel

Table I-1 describes the subbituminous fuel used in the engine test. It was produced by the University of North Dakota using the hot water drying process under a contract from the DOE. The coal loading was 50.1% with an average size of 15 microns. The coal contained 4.39% ash and 0.41% sulfur. The coal ash composition is shown in Table I-2. The subbituminous coal ash contains relatively low levels of iron and relatively high levels of calcium and alkali.

Test Conditions

Distillate oil (DF No. 2) fuel was used for start-up of the engine before transition to the CWF. The engine ran for 4 hours and 30 minutes on DF No. 2, followed by one hour on DF No. 2 and CWF, and then three hours on CWF alone. The turbine was operated at part load conditions with an inlet temperature of less than 816°C (1500°F). A total of 9345 kg (20,560 lb) of CWF was used during the test.

Emissions data, including CO and NO_x, were measured during the run. A particulate probe captured gas stream particles downstream of the combustor quench zone. Pressure and temperature measurements were taken at numerous locations in the combustion system and immediately upstream and downstream of the turbine. Turbine performance parameters (power output, rotation speed, compressor back pressure, etc) were continuously monitored during the test.

TE93-2145
VS92-401

Figure I-2. Allison 501-KM coal-fueled gas turbine engine assembly.

Table I-1.
Properties of turbine test coal-water fuel.

Starting slurry		
D ₅₀ , microns		15.0
D _{top} , microns		41.0
Solids loading		50.1
Viscosity, cP		
@ 100	sec-1	270.0
@ 500	sec-1	180.0
@ 1000	sec-1	145.0
@ 1200	sec-1	135.0
Proximate analysis, % wt dry		
Ash		4.39
Volatiles		42.23
Fixed carbon		53.38
Total		100.00
MAF HHV, Btu/lb		12801
Ultimate analysis, % wt dry		
Carbon		71.38
Hydrogen		4.60
Nitrogen		1.20
Chlorine		0.01
Sulfur		0.41
Ash		4.39
Oxygen (diff)		18.01
Total		100.00
Ash fusion temperatures, °F		
Initial temp	Red.	Oxid.
	2003	2298
Softening temp	2147	2374
Hemispherical temp	2185	2393
Fluid temp	2188	2398

TEST RESULTS

High combustion efficiency and low NO_x levels (as low as 20 ppm) were achieved during the engine test. Analyses of particulate captured upstream of the cyclone indicated a rich zone carbon burnout efficiency of about 99%.

An increasing compressor discharge pressure measured during the engine run indicated that deposits were forming in the turbine. Post-test data analyses estimated the first stage turbine vane flow area reduction due to deposition. Figure I-3 gives the calculated flow areas versus time during the test. The flow area remained constant during operation with DF No. 2 but decreased at an approximately constant rate after transition to CWF.

Table I-2.
Chemistry of ash, particulate and deposit.

<u>Specie</u>	<u>Starting fuel ash</u>	<u>Quench zone particulate</u>	<u>Lean zone particulate</u>	<u>1st stator deposit</u>
Phosphorous pentoxide	0.32	0.38	0.35	0.42
Silicon dioxide	26.05	25.20	20.74	12.91
Ferric oxide	7.81	7.99	7.38	6.83
Aluminum oxide	16.26	22.22	22.78	15.76
Titanium oxide	1.38	1.73	1.57	1.23
Calcium oxide	20.46	26.75	24.23	20.34
Magnesium oxide	4.32	6.22	5.73	5.02
Potassium oxide	0.27	0.31	0.27	0.80
Sodium oxide	5.39	5.02	4.89	8.86
Sulfur trioxide	15.16	1.72	10.00	25.01
Strontium oxide	0.72	0.86	0.77	0.67
Barium oxide	1.22	1.20	0.90	1.07
Manganese oxide	0.14	0.16	0.15	0.15
Vanadium pentoxide	0.22	0.24	0.24	0.23
Totals	99.69	100.20	100.00	99.30

Figure I-3. Calculated first-stage nozzle area - CWF engine run.

The engine was dismantled after the test and inspected. Ash deposits had accumulated in the flow path. An ash mass balance indicated that about 0.2% of the ash in the fuel had deposited in the turbine. The extent of deposition was highest on the first-stage vanes (highest temperature row) and decreased in each successive row.

Table I-2 compares the chemistry of the first-stage vane deposits with that for the fuel ash and the particulate captured in the quench-zone cyclone and lean-zone ash collection vessels. The particulate captured by the cleanup system was higher in Al_2O_3 and CaO , but lower in SO_3 than the fuel ash. Primary chemistry differences between the first vane deposits and fuel ash were lower SiO_2 and Fe_2O_3 but, much higher alkali (Na_2O , K_2O) and SO_3 for the deposits.

The first-stage vane deposits were leached in water and the leachate was chemically analyzed to determine water soluble components, which are shown in Table I-3. The analysis suggests that the primary water soluble component of the first vane deposits was sodium sulfate.

Due to an apparent water soluble binder for the turbine deposits, an evaluation was conducted to assess deposit removal by water washing. Figure I-4 shows a second stage vane segment with the deposits that had accumulated during the engine run.

Figure I-5 shows the same segment after water washing and a light abrasive cleaning with impacting walnut shells. (Water washing and walnut shelling have been used in the past for commercial turbines to remove deposits from residual and crude oils.)

As illustrated by Figure I-5, the deposits were friable and easily cleaned. Most of the deposit was removed by the water wash with the exception of a very small area that was cleaned by the walnut shell treatment. Another segment was cleaned by nutshelling alone. However, this was not as effective as water washing. To simulate exposure of the vane segment to higher turbine inlet temperatures, other vane segments with ash deposits were placed in an oven and heated to 760, 871 and 982°C (1400, 1600 and 1800°F). The ash became more friable at the higher temperatures and in all cases was easily removed by water washing as before.

SUMMARY AND CONCLUSIONS

The first run of a modern industrial turbine directly fired with coal has been completed. The turbine operated for four hours with a rich-quench-lean, low NO_x combustor using a subbituminous CWF.

Table I-3.
Analysis of deposit leachate.

<u>Element</u>	<u>Conc. ppmw</u>
Sulfur	2150
Iron	<0.1
Manganese	22
Calcium	190
Sodium	2450
Potassium	160
Chlorine	28

1st-stage vane deposit sample - 32.2 gm leached ultrasonically
for 30 minutes in 250 ml water

VS91-1586
TE93-2146

Figure I-4. Coal-ash deposit on second vane segment.

TE93-2147
VS91-1587

Figure I-5. Second-stage vane segment after water-washing and light walnut shell blast.

Carbon burnout efficiency was about 99%. Emissions of CO and NO_x of less than 20 ppmv at 15% O₂ were demonstrated. Higher CO emissions were noted at increased water injection rates as the quench-zone temperature was decreased below the design value.

The turbine experienced deposition during the test. Approximately 0.2% of the ash in the fuel consumed in the test had deposited in the turbine flow path. Chemical analyses of the deposits suggest that eutectics of alkali sulfates are probably the primary bonding media for the deposits. Water washing of vanes removed from the turbine was very effective in cleaning and deposits. Light nut-shelling removed the minor deposit remaining after water washing to result in completely clean vanes.

The test results indicate that control of alkali in the coal ash will be necessary to limit deposition and long-term corrosion and deposition. Approaches to control alkali include coal selection, additives and decreased quench temperatures before the cleanup system to condense the alkali for removal. The accelerated deposition rates experienced as the engine tests with cyclones were factored by the relatively particle loading predicted to enter the turbine had hot gas filters been used. This provided a rough estimate of 150 hr for deposit removal maintenance intervals using filters (see Appendix H).