**ADVANCED COMBUSTION SYSTEM FOR
INDUSTRIAL BOILERS**

FINAL REPORT, PHASE II ACTIVITIES

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1.0 EXECUTIVE SUMMARY

The overall purpose of this DOE-sponsored project is to develop an advanced coal combustion system for retrofitting industrial boilers. By using a new technique for suspension firing with the new combustion system, coal could be used as a direct replacement for oil and gas as a fuel for many existing industrial boilers. This could result in a significant increase in use of coal, and a corresponding decrease in dependence on uncertain oil and gas supplies and prices. The physical size and layout of existing oil/gas-fired boiler equipment would not change noticeably, other than for the addition of coal-storage and particulate-emission control equipment.

A commercial 200-horsepower Cleaver-Brooks gas/oil-designed firetube boiler located at the University of Tennessee Space Institute was used for the project retrofit. Coal firing rates were controlled between 2 and 7 million Btu's per hour during typical tests. This firing rate is equivalent to burning 133 to 467 pounds per hour of $\approx 15,000$ Btu-per-pound dry, ultra-fine (DUC) Upper Elkhorn No. 3 standard test coal. (Coal total moisture content was typically about 1 weight percent.)

Specific performance goals for coal firing, and corresponding UTSI achievements follow.

Goal: Greater than 99 percent combustion efficiency

Achievement: **99.3 percent long-term efficiency was demonstrated**

Goal: Greater than 80 percent boiler efficiency

Achievement: **86.5 percent long-term efficiency was demonstrated**

Table 1.1 Phase II Accomplishments

	Goal	Accomplishment
Combustion Efficiency	>99.0	99.3(1)
Boiler Efficiency	>80.0	86.5(1)
Burner Turndown Ratio	>3:1	>3.5:1(2)
Emissions, pounds per million Btu		
SO ₂	<1.2	0.81(3)
NO _x	<0.7	0.53(1); <0.3(4)
Particulates	<0.6(5)	<0.05(6)
Support Fuel	None	None(7)
Air Preheat	None	None

(1) Long-term test results.

(2) Without using any support fuel or preheating the combustion air.

(3) Coal selection.

(4) With propane reburning supplying 14% of the Btu input.

(5) Small boilers are not regulated the same as NSPS for large, coal-fired utility boilers. The 0.6 value represents a Tennessee site permit for UTSI.

(6) With low-priced bags in baghouse.

(7) Coal only, no pilot.

Goal: Greater than 3:1 burner turndown ratio

Achievement: **greater than 3.5:1 burner turndown ratio was demonstrated without using any support fuel or preheating the combustion air**

Goal: Less than 0.6 pounds of particulate emissions per million Btu burner input

Achievement: **less than 0.05 pounds of long-term particulate emissions per million Btu burner input was demonstrated**

Goal: Less than 1.2 pounds of SO₂ emissions per million Btu burner input

Achievement: **0.81 pounds of SO₂ long-term emissions per million Btu burner input was demonstrated**

Goal: Less than 0.7 pounds of NO_x emissions per million Btu burner input

Achievement: **0.53 pounds of NO_x long-term emissions per million Btu burner input was demonstrated in the normal system configuration without reburning; less than 0.3 pounds of NO_x emissions per million Btu burner input was achieved with 14% of the Btu input supplied by propane reburning during a short-term test series**

Goal: Operate without any support fuel

Achievement: **100 percent coal was burned; no pilot flame was used**

Goal: Operate without any preheating of the combustion air

Achievement: **No preheating of any of the combustion air entering the burner was used**

Issues that have been successfully addressed by UTSI, but which made this project an unusually difficult challenge include:

- exceeding present-day central-station utility-boiler combustion-speed by an order of magnitude, and doing this with lower flame temperature in a small-diameter cold-walled firetube-boiler
- burning an air/pulverized-coal suspension efficiently without using the combustion-air preheat which is required by state of the art utility boilers
- safely storing dry, ultra-fine coal, and accurately controlling dense-phase coal flow without complicated and expensive equipment which is potentially unreliable with high-maintenance requirements

- coping with grossly oversized coal particles that were present in the “ultra-fine” coals as-delivered to UTSI
- using high quality, ultra-fine Upper Elkhorn No. 3 coal with low ash content and high ash-fusion temperatures minimizes the quantity of sticky particles, but did not “prevent” major fire-side deposits from forming during periods of long-duration (110 hr) operation! This long-term deposition tendency was not observed during numerous, shorter-term tests (approximately 6 hours each) which totaled more than 500 hours of operation at UTSI.
- on-line controlling of ash deposits to maintain heat-transfer conditions required for maintaining steaming capacity of a firetube boiler
- successfully demonstrating performance of the UTSI system in a small firetube boiler, that is much more difficult to retrofit than a larger fire-tube or water-wall boiler because of increased potential for fire-side ash impingement and deposition in a small-diameter firetube, control of the lower coal-flow rates within the smaller-diameter delivery lines, combined with more rapid flame cooling and lower average combustion temperatures
- finding a commercially acceptable (price, safety, boiler & combustion efficiency, ease of handling, elimination of grossly oversized particles, controllable fire-side deposits & maintainable heat transfer, etc.) coal-preparation technique & verifying preliminary performance of “finely-

pulverized” coal (UTSI FPC-fuel) for potential commercialization of the UTSI coal-retrofit system

The UTSI advanced coal-combustion system concept includes the following components:

- a new burner design with added capabilities including use of ultra fine or specially-pulverized dry-coal fuels. The UTSI design could replace existing commercial oil-only and/or gas-only burners, even in the especially demanding applications involving firetube boilers.
- an overall burner/fuel equipment combination with versatile and economical multiple-fuel capabilities:
 - natural gas
 - propane
 - light oil
 - ultra-fine, cleaned coal
 - ultra-fine coal
 - economical specially-pulverized coal
- a coal injector that could replace the oil gun in existing burners, as an alternative to complete replacement of the burner assembly
- a coal storage and dense-phase coal-feed system with capabilities for handling commercial bulk bags containing 1800 pounds of ultra-fine or finely-pulverized coal
- an automatic control system, based on computer control with feedback from low-cost combustion-quality transducers

- on-line deposit removal and particulate cleanup equipment.

Commercialization appears to be technically feasible and economically justified.

- The UTSI program has demonstrated the technical and economic feasibility of burning coal in an efficient and environmentally acceptable manner in a firetube boiler
- **UTSI finely-pulverized coal (FPC)** with a nominal top size of approximately 425 μm (0.0167 inches or a No. 40 sieve) **potentially is the best choice for commercialization because of the very low fuel-preparation costs** that have been demonstrated for FPC and **the associated high combustion and boiler efficiencies which are expected**, based on the short-term measured performance with Illinois #6 FPC. **Additional long-term testing is needed** using a finely-pulverized coal with quality similar to Upper Elkhorn #3 with medium-to-high ash content and high ash-fusion temperatures (≈ 2.4 to 6.5 weight percent ash on an as-fired basis and ash-fusion temperatures of 2500°F or higher) **to confirm the significant cost-savings predicted using a FPC-coal retrofit vs. original equipment using natural gas, propane, or oil.**
- Finely-pulverized coal has been produced at UTSI using a unique and inexpensive batch pulverizing/drying technique with a modified commercial ball-in-race mill. The pulverized-coal product is similar to a “utility grind” for high volatile coals; however, it does not contain the

largest coal particles. This improves handling, storage and transport properties, and satisfies the retrofit requirements for very rapid and efficient burning while it greatly minimizes the possibility for fire-side erosion. Only a minor amount of energy is required to break (pulverize) the larger particles, so the process is extremely cost effective, with a total fuel cost that is considerably less than for natural gas. More than 600 hours of operation have been accumulated with the 200 BHp coal retrofit (mostly with ultra-fine coal).

- No wear or erosion has been detected in the boiler operating at a low-velocity with dense phase coal-transport system or on fire-side surfaces of the boiler itself.
- UTSI long-duration testing has demonstrated the ability to maintain high heat transfer using UTSI-designed cleaning equipment.
- Control of ash deposition is a critical issue. Success of future commercial coal-retrofits will depend on carefully matching equipment design and operation with coal properties. Although the design and operation of utility boilers are strongly influenced by ash deposition, the situation is even more critical for smaller-scale coal retrofits because of the limited space and lack of prior experience.
- Additional long-term testing is needed to evaluate commercial risk more fully, to be able to assure accurately matching of fuel, boiler design and retrofit details, automated-control algorithms, and system operational details

- Successful commercialization depends on a present fuel cost to be $\leq \$3.15/\text{MBtu}$ (or steam cost to be $\leq \$35$ per 10,000 pounds of H_2O evaporated at 212°F), high combustion and boiler efficiencies, and low costs for retrofit and operation. UTSI finely-pulverized dry coal combined with the UTSI advanced-combustor retrofit will provide these cost and efficiency requirements.
- In order to cover the significant costs associated with this commercialization plan, contract support is necessary. **The only identifiable near-term source of funding is the FY-86 Defense Appropriations Act that contained Congressional direction for the Department of Defense by 1994 to increase its use of coal at facilities in the U.S. by 1.6 million tons per year (Public Law 101-511 [H.R. 5803]: Nov. 5, 1990 Department of Defense Appropriations Act, 1991)**
- Coal (fuel) economics will have the most important impact on future commercialization. The market for boiler retrofits for coal firing will not develop unless the infrastructure is in place to make and deliver suitable coal fuels to the users at commercially-competitive prices.

2.0 PHASE I REVIEW

Detailed results of Phase I activities were reported in the "Advanced Combustion System for Industrial Boilers, Final Report, Phase I Activities, May 1990". Activities were focused on design and evaluation of R&D and prototype equipment. A review of the highlights follows.

During Phase I of the project, a coal injector was designed, fabricated, and tested. It is a direct replacement for the oil gun in the original equipment of a 200 BHp (boiler horsepower) Cleaver-Brooks fire-tube boiler. The system was tested in the existing Cleaver-Brooks swirl burner, designed for firing propane or fuel-oil, at coal-firing rates in the range of 2 to 6 million Btu per hour, firing Upper Elkhorn No. 3 (eastern bituminous, "UE3") coal supplied to UTSI in a dry, ultra-fine form by Energy International, Incorporated. For these tests, propane was used to preheat the boiler before initiation of coal firing. The propane flow was turned off after coal combustion was established. No combustion air preheat was used. During these tests, boiler efficiency was typically about 85 to 86 percent, while carbon conversion efficiency was approximately 94 percent. Concentrations of CO were less than 150 ppm. The NO_x emissions were less than 0.6 pounds per million Btu.

Following a series of laser-illuminated cold-flow-visualization tests, a new burner was designed, fabricated, and tested during Phase I. It is a two-stage, swirl burner which fits in the space previously occupied by the original Cleaver-Brooks burner, and uses the existing section of refractory. See Figure 2.1 and Figure 2.2. Air flow can be regulated independently into each of the two stages. Additionally, the angle is adjustable for individual swirl blades.

Figure 2.1 Schematic of Advanced Combustion System

Figure 2.2 Schematic of UTSI Phase I Replacement Burner

Upper Elkhorn No. 3 ultra fine coal was used as the standard fuel for most UTSI-burner tests. Firing rates were in the range of 2 to 6 million Btu per hour. Upper Elkhorn No. 3 coals were tested with three levels of ash. These were approximately 1.4%, 2.7%, and 4.8% ash, on an as-fired basis. The 2.7%-ash UE3 coal was used for most tests because it exhibited a good balance between ash content and ash-fusion characteristics. The 2.7%-ash UE3 coal also served as a reference and established a baseline for performance. Additionally, a 1.3 float fraction of a western Eagle Butte subbituminous coal was used as the fourth ultra-fine test fuel. It contained 4.4% ash on an as-fired basis.

All four test coals were supplied by Energy International, Inc. with a mean particle size of about 10 μm and a nominal top size of 44 μm (0.0017 inches). Subsequently, UTSI personnel found numerous **coal chunks that exceeded 1 inch in length**, which occasionally produced major problems with coal handling in general and specifically with controlled dense-phase transport to the burner. The coals were delivered to UTSI in plastic-lined, 55-gallon steel drums.

Propane was used to preheat the boiler before initiation of coal firing. The propane flow was turned off after coal combustion was established. No combustion air preheat was used with the UTSI burner. Boiler efficiency was approximately three percent higher with UE3 coal than in the previous test series, and typically was about 88 to 89 percent. Carbon conversion efficiency was approximately 97 to 99 percent for UE3 coals. **A very high value of 99.9 percent carbon conversion was attained with the 4.4%-ash Eagle Butte coal.**

Forty to sixty percent of the ASTM coal ash remained in the boiler. However, the deposits were powdery and easy to remove by increasing the fan speed after the conclusion of each combustion test. The increased air velocity quickly re-entrained and removed most of the previously-deposited ash, which was blown out the exhaust stack in Phase I, or into the baghouse that was installed during Phase II.

Concentrations of CO were below 100 ppm. The NO_x emissions ranged from 1.2 to 1.3 pounds per million Btu with the UE3 coals. With the Eagle Butte coal, a lower level of 0.86 pounds of NO_x per million Btu was measured.

In addition to the burner-development activities, a system was designed, fabricated, tested, and used routinely for data acquisition and manual boiler/burner control. The system is based upon a dedicated micro-computer based on the Intel-"286"-cpu-chip-architecture using UTSI-developed software. This system was used in Phase II to automate system control and data acquisition.

3.0 PHASE II

The main objective of Phase II was to move ahead from the primarily R&D oriented approach of Phase I toward commercialization of a complete coal-retrofit system. The main targets of this phase were to develop commercially-applicable equipment and to surpass the performance goals previously set for this project.

The results of Phase II activities, which were completed in November 1991, are presented in the following sections.

3.1 Overview

Results of this UTSI work show that it is feasible to convert (retrofit) oil/gas-designed industrial/commercial boilers to add the capability to efficiently and cleanly burn the most economical dry, finely-pulverized coal (FPC). (Estimated UTSI tested fuel cost is less than the natural gas cost, and the UTSI-demonstrated boiler efficiency with dry coal is ~2% higher than with propane). Dry pulverized coal delivery and dry ash removal/disposal would be safe and very convenient using the commercial equipment (25 to 33-ton road tankers and 55-ton coal-powder rail cars) that is currently employed in Europe, in particular in Germany (formerly the Federal Republic of Germany), Sweden, and the UK. Typical boiler-site-pulverized-coal-powder storage-silos have capacities in the 80 to 950 cubic meter range (2,825 to 33,549 cubic feet), and the bulk density of the coal powder is about 600 kilograms per cubic meter (37.5 pounds per cubic foot). For smaller applications, UTSI has demonstrated successful use of 1800-pound capacity bulk bags for storing and unloading both ultra-fine and

finely-pulverized coals, with bulk densities typically in the range between 30 and 40 pounds per cubic foot (481 to 641 kilograms per cubic meter).

Details of the arrangement of the UTSI advanced coal combustion system are shown schematically in Figure 3.1.

An immediate need and important opportunity for retrofit of an extensive installed capacity of Cleaver-Brooks firetube boilers follows:

- ***“The FY-86 Defense Appropriations Act contained Congressional direction for the Department of Defense by 1994 to increase its use of coal at facilities in the U.S. by 1.6 million tons per year.”***

As detailed in P.L. 99-190, LAWS OF 99th CONGRESS-1ST SESSION, the mandate is **“to rehabilitate and convert current steam generating plants at defense facilities in the United States to coal burning facilities in order to achieve a coal consumption target of 1,600,000 short tons of coal per year above current consumption levels at Department of Defense facilities in the United States by fiscal year 1994: *Provided*, That anthracite or bituminous coal shall be the source of energy at such installations: *Provided further*, That during the implementation of this proposal, the amount of anthracite coal purchased by the Department shall remain at least at the current annual purchase level, 302,000 short tons.”**

UTSI personnel have completed Phase II with a long-duration test (110 hours of cumulative operation), and have achieved all goals for NO_x, SO_x, particulate emissions, boiler efficiency, carbon burnout, no air preheat, no auxiliary fuel, and burner turndown-ratio with Upper Elkhorn No. 3 dry, ultra-fine coals (DUC's). More than 63

Figure 3.1 Schematic of UTSI Retrofit System

tons of ultra-fine dry coal have been burned during Phases I and II. Commercial bulk bags were used successfully for DUC storage, and subsequently for loading the UTSI-designed atmospheric-pressure coal-feed hopper.

An inexpensive automotive combustion-quality transducer, that was calibrated to measure exhaust gas oxygen content, functioned successfully in a UTSI-designed computer-automated variable-speed fan control loop that maintained levels of excess air chosen by the boiler operator. **Operational costs can be reduced (even with oil or gas-fired industrial boilers) by using computer-controlled excess air as opposed to the present commercial arrangement with a constant-speed fan and manually-set dampers that are locked to the boiler load control.**

Successful results for carbon burnout and boiler efficiency have also been achieved with affordable UTSI finely-pulverized coal during short test periods near the end of the 110-hour demonstration. This coal preparation technique produces a commercial fuel with a cost significantly less than the natural gas cost!

Emission of unburned carbon particles would amount to nearly 0.6 pounds of particulates per million Btu of coal when fired with a combustion efficiency of 99 percent. A goal of <0.6 pounds of particulate emissions per million Btu would not be met even if the coal were "ash free." Therefore, a baghouse is included in the UTSI system to greatly reduce particulate emissions (to less than 0.05 pounds per million Btu), and provide convenient ash collection for subsequent removal at the time of the

next pulverized-coal delivery. Additionally, the SO₂ emissions are controlled by using compliance coals.

During the long-duration test, forced shutdowns (outages) were caused by:

- accumulation of massive fire-side ash deposits with “clean” Upper Elkhorn No. 3 coals that had not produced any significant deposits during hundreds of hours of ≈6-hour-per-day tests. Overall, about 25% of the outages, 3 out of 12, were caused by deposition. Two of these outages were with Upper Elkhorn No. 3, with 2.4% ash, during normal firing conditions, and one was with Illinois No. 6 with 9.6% ash during a high firing-rate excursion.
- dense-phase coal-flow interruptions, primarily due to grossly oversized particles in “ultra-fine” Upper Elkhorn No. 3 coals as-delivered to UTSI. This type of outage represented 67% of the total, or 8 out of 12 outages.
- a power failure caused by a nearby lightning strike constituted 8% of the outages or 1 out of 12.

Before the start of the long-duration test, sootblowers were installed for cleaning the inside surfaces of individual boiler fire-tubes in the second, third and fourth passes. Two major additions to the on-line deposit removal equipment were accomplished during outages within the long-duration test period. One addition was a sootblowing lance for the main firetube; the other involved installing scrapers at the pass 1-2 turnaround area to remove deposits from the refractory lining in the endbell and the tube sheet at the entrance of the second pass tubes. Deposits were removed by hand during each outage. After the sootblower lance and scrapers were added, ash

deposition appeared to be well controlled and heat transfer rates could be maintained. However, longer-term testing is needed for confirmation.

Modifications of the fuel-handling system are needed to prevent brief outages caused by the oversized particles that interrupted coal flow. Also, automation of deposit-removal equipment is needed for commercial/industrial applications.

Control of ash deposition remains a critical issue that depends on carefully matching equipment design and operation with coal properties. By itself, selection of the “best” clean coal is not adequate to ensure successful long-duration operation in commercial applications. **UTSI personnel strongly recommend an additional long-term testing phase (contract extension) following equipment upgrading to more fully evaluate commercial risk, and to assess a low-cost finely-pulverized commercial coal-fuel with high ash-fusion-temperatures during a 100-hour test period. Additionally, propane reburning should be evaluated during a long test period to prepare for more stringent NO_x regulations. Although no wear, erosion, abrasion or corrosion has been detected in the boiler low-velocity dense-phase coal transport system or on any fire-side surfaces of the boiler itself, a long-term testing phase (100-hour test at UTSI followed by a 1,000+ hour demonstration using a retrofit of a 600 BHp firetube boiler at a DOD site) would be invaluable for additional evaluation of any potential for wear, etc. Refer to the commercialization plan later in this report for details.**

Figure 3.2 presents the arrangement of a typical firetube boiler. Generic details of a Cleaver-Brooks four-pass firetube arrangement are pointed out in Figure 3.3. The

Figure 3.2 Schematic of Typical Firetube Boiler

Figure 3.3 Schematic of Details of Four Gas Passes

200 BHp commercial Cleaver-Brooks boiler used at the UTSI test site is illustrated in Figure 3.4, and the UTSI R&D addition of a stack-gas sampling platform is displayed in Figure 3.5.

3.2 Specific Phase II Performance Goals

During Phase II the objective was to achieve the following goals:

- Decrease NO_x emissions to less than 0.7 lb/MBtu.

Although the UTSI commercial firetube boiler is fired at 6 MBtu/hour and therefore is much smaller than steam generators usually subjected to NO_x regulations, we have based our goal upon the value specified in Performance Standards for Commercial/Industrial/Institutional Steam Generation for coal-fired boilers in the 100 MBtu/h to 200 MBtu/h range; a level of 0.6 lb NO_x/MBtu is specified for coal-fired electric utility steam generators larger than 250 MBtu/hour by the Performance Standards for Electric Utility Steam Generating Units Commencing After September 18, 1978. As a supplemental goal, we chose to obtain a lower level of emissions with NO_x less than 0.6 lb/MBtu.

- Decrease particulate emissions to less than 0.6 lb/MBtu.

This is based upon the current UTSI site permit issued by the state of Tennessee; otherwise, the Tennessee particulate limit is 0.8 lb/MBtu for a 6 MBtu/h boiler such as the UTSI unit.

- Increase carbon burnout so all test coals exceed 99% efficiency at a firing rate of approximately 6 MBtu/h. This is based upon a stated DOE goal .

Figure 3.4 Photograph of Cleaver-Brooks 200 BHp Firetube Boiler and Baghouse

Figure 3.5 Photograph of Stack-Gas Sampling Platform

- Increase the turn-down ratio from the Phase I demonstrated capability of 3:1.

This is based upon extension of the Phase I UTSI achievement of the stated DOE goal of 3:1.

3.3 Approach

Work in Phase II concentrated on: a.) adapting a commercially available automotive oxygen sensor for use in the boiler control system; b.) developing a commercially oriented dense-phase coal-transport system; c.) designing, fabricating, testing, and fine-tuning an improved burner for better combustion efficiency; and d.) adding deep-air-staging capabilities to the new burner to decrease NO_x emissions.

Some specific activities in Phase II follow:

- Investigated the effects on reducing NO_x emissions by deep-staging combustion air and by deep-staging with reburning
- Added on-line cleaning capabilities for removal of fire side deposits
- Added particulate-removal equipment to reduce stack emissions well below the project goal and provide a convenient arrangement for ash collection and disposal
- Developed a higher efficiency three-stage burner
- Added a low-cost oxygen transducer for automated control of combustion air flow
- Developed a simple, reliable, and inexpensive on-line dense-phase flow-control capability with a storage hopper operating at atmospheric

pressure and suitable for reloading with coal at any time during extended periods of operation

- Automated key parts of the boiler control system
- Evaluated potential of commercial bulk bags for receiving, storing, and unloading ultra fine coal
- Demonstrated performance of a new three-stage burner
- Made an economic evaluation and developed a preliminary commercialization plan
- Demonstrated the feasibility of an integrated system with a 100-hour test operation

3.4 Test Coals

Three types of coal were burned during Phase II testing. These were Upper Elkhorn No. 3 (UE3) coal, containing approximately 2.4 percent ash, UE3 coal containing approximately 6.5 percent ash, and Illinois No. 6 coal containing about 11 percent ash, by weight. These are all bituminous coals. Typical analyses for these coals are presented in Table 3.1. The UE3 2.4 percent ash coal was the standard test coal throughout the project. The UE3 coals were micronized and were supplied to UTSI by Energy International, Inc. The Illinois No. 6 coal was pulverized at UTSI in the Coal Fired Flow Facility (CFFF) pulverizer system. Details of the CFFF pulverizer system are presented in Section 3.11. Particle size distributions for the test coals are shown in Figure 3.6. The size distribution of the Illinois No. 6 coal was smaller than a typical PC grind, but much larger than the micronized coals. In particular, the finely-ground Illinois No. 6 was prepared in a way to limit the larger (top end) particles found

Table 3.1 Coal Analyses from Long-Duration Test, Phase II

Fuel Sample	UE3, Medium Ash	UE3, High Ash	Illinois No. 6, available MHD test coal
Identification	Standard DOE test fuel used for contract: Dry, ultra-fine coal; Medium ash content; High ash-fusion temperature	Dry, ultra-fine coal; High ash content; High ash-fusion temperature	UTSI finely- pulverized; Very high ash content; Very low ash-fusion temperature
Ash % as-fired	2.4	6.5	11.4
Moisture % as-fired	0.9	0.9	3.1
Sulfur % as-fired	0.6	0.7	3.1
Nitrogen % as-fired	1.5	1.5	1.3
Volatile Matter % as- fired (VM)	36.9	35.1	36.8
Higher Heating Value, Btu/lb as-fired	14,780	13,800	11,740
Minimum Ash Fusion Temperature, °F	2,500	2,500	≤ 2,100
Lb-Coal/MBtu	67.7	72.5	85.2
Lb-Ash/MBtu	1.6	4.7	9.7
Lb-S/MBtu	0.4	0.5	2.6
Lb-N/MBtu	1.0	1.1	1.1
Lb-VM/MBtu	25.0	25.4	31.4
Elemental ash analysis:			
SiO ₂	45.5	51.7	42.5
Al ₂ O ₃	30.8	33.4	16.1
Fe ₂ O ₃	11.3	5.6	17.2
TiO ₂	1.6	1.6	0.7
CaO	1.8	2.0	3.6
MgO	1.1	0.9	0.7
Na ₂ O	1.9	0.6	0.3
K ₂ O	2.4	2.3	9.4
SO ₃	2.5	2.1	8.6
Cr ₂ O ₃	0.1	0.1	0.1
P ₂ O ₅	0.5	0.2	0.4
Median Particle Diameter, μm	9	9	39
<i>DRY BASIS:</i>			
Proximate			
Ash	2.4	6.6	11.8
Volatile Matter	37.2	35.4	38.0
Fixed Carbon	60.4	58.0	50.2
Ultimate			
Ash	2.4	6.6	11.8
Carbon	83.2	79.4	66.0
Hydrogen	5.5	5.3	4.5
Nitrogen	1.5	1.5	1.3
Sulfur	0.6	0.7	3.2
Oxygen by Difference	6.8	6.5	13.2
Btu/lb, HHV	14,910	13,930	12,120

DUC & PC: Particle Size Distributions
--UTSI (PC) has fewer large particles
than utility grind--

Figure 3.6 DUC & PC Particle Size Distributions

in typical PC preparation. This was the key to successful combustion in the advanced combustor.

The micronized coal supplied by Energy International contained quite a bit of foreign material, including unpulverized coal chunks, wood chips, and fibrous material. Typical examples of material found in the coal are shown in Figure 3.7 The oversized material caused plugging in the dense phase coal feed system. A system was installed for screening the coal as it was loaded into the feed tank which greatly reduced but did not completely eliminate the coal feed system plugging problem.

Two additional coals were burned during Phase I of the project. These were a UE3 coal containing about 1.4 percent ash and an Eagle Butte lignite containing about 4.4 percent ash. Both of these coals had been cleaned to reduce the ash content before being sent to UTSI. These coals were found to be unsuitable for long term operation in the boiler because they caused excessive slagging, and are also undesirable from an economic standpoint because of the high cost of the cleaning process. Typical analyses for the coals burned during Phase I are presented in Table 3.2

Figure 3.7 Photograph of Fibers, Woodchips & Coarse Coal Found During Phase I in As-Received Ultra-Fine Coal

Table 3.2 Typical Analysis, Test Fuels As-Fired in Phase I

	UE3 LOW-ASH	UE3 MEDIUM-ASH	UE3 HIGH-ASH	E-B 1.3 FLOAT
Ash %	1.4	2.7	4.8	4.4
Moisture %	0.6	0.9	1.3	16.5
Sulfur %	0.6	0.6	0.7	0.4
Nitrogen %	1.3	1.2	0.9	0.4
Volatile Matter %	33.3	34.2	34.1	37.5
BTU per lb, HHV	14,940	14,800	14,620	9,910
Minimum Fusion, F	2,270	2,500	2,500	2,440

All three of the Phase II test coals were burned during the long-duration test, including approximately 29,600 lbs of 2.4 percent ash UE3, 3600 lbs of 6.5 percent ash UE3, and 1800 lbs of Illinois No. 6. The coal was stored in bulk bags, each containing about 1800 lbs. Two of the bulk bags were dumped into the coal hopper at approximately 12-hour intervals during the test. Combustion test results for the three types of coal are discussed in Section 3.13.

3.5 Coal Storage and Handling System

Figure 3.8 shows the overall UTSI test-site arrangement and identifies the two major parts of the coal storage and handling system:

- the bulk-bag storage area, and
- the bulk-bag unloader & 5,000-pound-capacity coal storage and feed tank.

Figure 3.8 Schematic of Plan View of Test Site

Figure 3.9 reveals how commercially-available bulk bags serve as excellent storage containers for ultra-fine and finely-pulverized coals. Each bag holds approximately 1,800 pounds of coal.

The UTSI on-line refillable coal hopper is equipped with load cells to measure the weight of the hopper, and a commercial gyrating bin discharger, Figure 3.10, and can operate with the coal-loading inlet open to air at atmospheric pressure. A small flow of fluidizing nitrogen enters at the bottom of the hopper and blankets the coal with a nitrogen-rich atmosphere. (Carbon dioxide might be a better choice for future commercial applications due to its higher molecular weight.) Therefore, long-duration operation is feasible with coal being loaded periodically into the top of the hopper from bulk bags. This technique was used very successfully during the long-duration demonstration test. No problems were observed relative to self-heating of the fuel in the hopper.

A screen formed from 10-mesh sieve material with 2,000-micron (0.0787 inch) openings is located at the inlet to the coal hopper, and removes most oversized material from the coal as it is loaded. Smaller openings are not practical because of greatly reduced coal loading rates. (Although ultra-fine coal nominally has a top size of approximately 44 μm , the coal supplied to UTSI by Energy International had some top-end coal chunks that exceeded one inch and the larger particles are removed effectively by the 10-mesh sieve. However, particles in the 44 to 2,000 micron range that passed through the screen occasionally caused significant problems with maintaining desired coal-flow rates to the burner.) Figure 3.11 illustrates unloading of a bulk bag during the long-duration test while the boiler was operating.

Figure 3.9 Photograph of Bulk Bag Storage Area

Figure 3.10 Schematic of Atmospheric-Pressure Coal Loading/Storage System

Figure 3.11 Photograph of Dense Phase Coal Feed System with Bulk Bag Unloading

The UTSI burner is connected directly to the outlet line from the auger which is shown at the lower right of Figure 3.10 as “coal feed to burner.” Figure 3.12 discloses the simplicity of the coal discharge area. Dense-phase coal-flow control is accomplished with the burner first-stage eductor via on-line changes in motive-air pressure.

3.6 Coal Feed System

In the UTSI system, a specially designed annular eductor (also commonly referred to as an ejector or jet pump), using air at pressures ranging from 20 to 80 psig as the motive fluid, is employed to withdraw coal from the feed tank, transport it in dense phase through a 1/2 inch i.d. x 20 ft long feed line, and inject it into the burner. The eductor air flow is taken into account in setting the stoichiometry of the first stage of combustion. The eductor is shown in Figure 3.13. The motive air is accelerated to sonic velocity at the 0.030 inch wide annular area between the eductor wall and the suction tube, then expands to supersonic velocity downstream from the exit of the suction tube. Coal mixes with the motive air in the supersonic zone, and the mixture then passes through a series of shocks where the air velocity decreases and the static pressure rises to match the burner operating pressure. Static pressure in the suction section of the eductor ranges from about 9 psia to 12 psia, depending on the driving air pressure and coal flow rate. For a given driving air pressure and coal flow rate, the suction pressure is constant, so for a coal feed line with repeatable pressure drop characteristics, the coal flow rate can be controlled by varying the driving air pressure. In the system tested at UTSI, reliable control of coal flow rate was achieved over a range from 2.0 to 6.5 lb/min by varying the motive air pressure, as shown in Figure 3.14. Concurrent burner performance (turndown ratio) exceeded the fuel range of

Figure 3.12 Photograph of Closeup of Dense Phase Coal Feed Discharge Area

Figure 3.13 Annular Eductor for Pumping Micronized Coal

Figure 3.14 Coal Flow Rate and Vacuum at Feed Line Exit

3.25 to 1. This performance also exceeds the DOE goal, which is 3 to 1 for turndown. For example, the following table (Table 3.3 - Turndown Ratio) shows a 3.29 turndown ratio measured with 3 scfh of fluidizing nitrogen and Upper Elkhorn No. 3 coal:

Table 3.3 Turndown Ratio

Motive Air Pressure, psig	Motive Air Flow Rate, lb/min	Coal Flow Rate, lb/min	Coal Firing Rate, Btu/h
80	6.58	6.52	5,868,000
20	2.43	1.98	1,782,000

Coal flows that exceeded 6,000,000 Btu per hour were achieved during later testing.

The arrangement of the coal feed tank is critical for proper operation of the eductor coal feed system. The tank is designed to supply coal at the inlet of the feed line at a uniform density and pressure. The coal tank, shown in Figure 3.10, consists of a large storage volume, a gyrating bin discharger, and a fluidized discharge tank. The bin discharger, which is a commonly available commercial type, keeps coal flowing smoothly from the large upper tank into the discharge tank. A pressure cone in the bin discharger supports the weight of the coal above the entrance of the discharge tank, thus maintaining a relatively constant pressure head in the discharge tank. The discharge tank consists of a 12 inch diameter tube with a fluidizing plenum located at the bottom. The fluidizing plenum is separated from the tank by a Gore-Tex fluidizing pad supported by a wire mesh. Nitrogen is introduced into the plenum at a rate sufficient to fluidize the contents of the discharge tank. (The contents of the upper tank are not fluidized due to its large cross-section.) This arrangement ensures that coal

cannot pack at the entrance of the feed line, which would result in erratic coal flow and would eventually lead to line plugging. The fluidizing gas amounts to about 0.2 percent by weight of the coal flow. The final component associated with the feed tank is an auger located at the entrance of the feed line . The auger serves to break up any lumps of coal before they enter the feed line, and does not meter the coal flow.

The new coal feed system has a number of advantages when compared with both pressurized dense phase systems and dilute phase systems. The advantages over pressurized dense phase systems include the following:

1. The requirement for a large pressurized tank or an airlock system is eliminated.
2. The need for a control valve in the feed line to regulate flow is eliminated. A control valve in the feed line creates a restriction in the flow area, which is a source of plugging problems when feeding micronized material.
3. The flowability of micronized material is improved by transporting under vacuum rather than under elevated pressure conditions. The vacuum system tends to pull any lumps of packed material apart, while the pressure system tends to compact the material further.
4. Coal enters the combustor premixed with the eductor motive air. Based on UTSI test results, premixing improves combustion performance significantly.

Advantages over dilute phase systems include the following:

1. The feed line is much smaller, making it easier to route, and the transport velocity is much lower, greatly reducing wear on internal surfaces.
2. The need for a system to meter the coal into the feed line is eliminated.

The eductor system also has some disadvantages:

1. Length of the feed line and elevation rise between the coal tank and combustor are limited by the maximum vacuum that can be achieved by the eductor. The practical limit on feed line vacuum is probably 12-15 inches Hg (6.0-7.5 psi). Therefore, the feed tank should be located reasonably close to the burner and near the same elevation.
2. The power requirement for compressing the motive air is significant. However, as shown in the economic evaluation, total costs for generating steam are lower using the eductor system and finely-pulverized coal than using those associated with the original (commercial) Cleaver-Brooks burner and natural gas fuel. For the system tested at UTSI, the compressed air requirement was slightly less than 1 pound of air per pound of coal pumped. If the air is compressed to 80 psig and then throttled to the desired pressure, the power requirement amounts to about 0.8 percent of the heat generated by the boiler. The power requirement can be reduced by about 50 percent at low and medium firing rates if the air pressure is regulated by controlling the speed of the compressor motor. Little effort was made to optimize the performance of the eductor in terms of air required per unit mass of coal pumped, and it is probable that

significant improvements could be made. The power requirement could also be reduced by replacing air with steam as the motive fluid; however, replacing the air with steam would probably have a detrimental effect on combustion performance. Alternately, a steam turbine could be used to drive the motive air compressor, thus eliminating the electric power requirement.

3.7 UTSI Coal Burner Performance

The final UTSI burner design, shown schematically in Figure 3.15, is a three-stage device that was developed by UTSI during Phase II of the contract. Micronized or finely-pulverized coal is supplied to the burner using dense phase transport, with a burner first-stage eductor being used to transport the coal under vacuum from an atmospheric pressure hopper through a 1/2 inch diameter feed line. The eductor tail pipe serves as a premixing stage where the coal is thoroughly and very rapidly mixed with the eductor driving air. Control of the coal flow rate is achieved by varying the pressure of the driving air. Approximately 15 percent of the combustion air is added in the eductor tailpipe.

Following the first-stage eductor, the second stage is an initial combustion zone operating under reducing conditions to limit formation of NO_x . The second stage has a large refractory-lined section, with secondary air passing through an annular passage behind the refractory. Approximately 30 percent of the combustion air is added in the second stage through a set of swirl blades, which provides stabilization for the primary flame. The remaining combustion air is added at the end of the refractory-lined section through an array of eight jets. The jets are directed at a 20 degree angle relative to the

Figure 3.15 Schematic of Final Phase II Burner Configuration

combustor centerline to provide swirl counter to the direction of the primary swirl. The overall stoichiometry is 1.20. The primary zone stoichiometry of 0.55 was found experimentally to provide the best combination of combustion efficiency and low NO_x emission, and seems to correspond roughly to the lowest stoichiometry at which all carbon is converted to CO.

The second stage refractory wall contains the reducing gases and prevents their contact with boiler metal surfaces, thereby minimizing both the potential for corrosion and excessive cooling of the combustion gases. Passing the secondary combustion air between the outside of the refractory lining and the inside of the metal firetube provides some "in-burner" warming of the secondary combustion air and further protects the metal surfaces by assuring an oxidizing atmosphere.

During preliminary testing in the 200 BHp boiler, NO_x emissions of 0.44 lb/MBtu were achieved with the three-stage burner using the standard micronized Upper Elkhorn No. 3 coal with about 2.4% ash, at a firing rate of 3.6 MBtu/h. Carbon burnout during this test was 99.1%. These results exceeded the DOE goals of 0.7 lb/MBtu for NO_x emission, and 99% for carbon burnout.

Additional performance information is provided in Section 3.13, "Long-Duration Performance Accomplishments & Discussion".

Initial testing of the deep-staged burner was conducted in a 15 foot long test duct external to the boiler. The duct is cooled by an external water spray, with combustion gases exhausting directly to atmosphere. Preliminary testing in this duct made observation of the flame much easier, and also made the burner more accessible for modification. Four- and six-foot-long refractory-lined sections were tested. The

six-foot refractory-lined section was used with several arrangements of the air mixing jets. As illustrated in Figure 3.16, the jets were either opposed (upper half of the figure, right side) or set at a 20° counter-swirl position (lower half of the figure, right side). In addition, the 20° counter swirl was tested in two variations. One of these used 45° counter-current flow (lower half of the figure, left side); the other had no counter-current flow (0°, as shown in the upper half of the figure, left side). The opposed jets were tested without counter flow.

The order of increasing mixing intensity was:

opposed----> 20° counter swirl (cs)----> 20°cs/45° counter current (cc).

As a result of these tests, a six foot long refractory-lined section was selected for the final combustor design. The four foot refractory-lined section did not appear to provide enough residence time in the primary zone. The 20 degree counterswirl arrangement with no counter-current flow was selected for the secondary air jets. The counterswirl arrangement is needed for stabilization of the secondary flame, and the flame was more stable without the counter-current jet flow. In the 45° counter-current jet arrangement, the jet velocity component contributing to swirl is only about 70% of the total jet velocity. Apparently, the decrease in swirl intensity has a detrimental effect that is not offset by increased mixing intensity.

Reburning Summary

Reburning tests were also conducted in the external, fifteen-foot test duct. Propane was used as the reburn fuel. Propane was injected at the center of the six-foot refractory length, as shown in Figure 3.17. Reburn air was added in one of two ways:

Figure 3.16 Schematic of Air Jet Configuration for Deep Staging

Figure 3.17 Schematic of Propane and Reburn-Air Injectors

- through the burner primary and secondary air registers, or
- through reburn-air injectors located in the same plane as the propane injectors

The test matrix for the various configurations examined is shown in Table 3.4. Ultra-fine Upper Elkhorn #3 coal with approximately 2.7 weight percent ash, the standard UTSI test coal, was used in these tests. The coal firing rate during the tests ranged from 3 to 4 MBtu/h. Three deep-staged secondary air jet arrangements were tested along with two locations for adding propane-reburn air.

Table 3.4. Test Matrix for Reburn-Air Injection Locations During Propane Reburning Measurements

INTRODUCTION OF REBURN AIR	DEEP-STAGED SECONDARY COMBUSTION AIR JET ARRANGEMENT		
	OPPOSED JETS (0°cs/0°cc)	20°cs (20°cs/0°cc)	20°cs/45°cc (20°cs/45°cc)
WITH PRIMARY AND DEEP-STAGED SECONDARY AIR	✓	✓	✓
THROUGH REBURN AIR INJECTORS			✓

In addition to the test matrix variables of where the reburn-air was added, and how the secondary air jets were configured, the quantity of propane relative to coal was evaluated. This relationship was expressed in terms of propane, as percent of total coal-plus-propane Btu input. Tests were conducted in the range of approximately 8 to 14 percent thermal input with propane.

Another major operational variable was the air-to-fuel ratio in the primary combustion zone, in terms of stoichiometry; the symbol ϕ_p indicates the primary

stoichiometric ratio (air supplied + theoretical air required for complete combustion) in this report. For this series of tests, values of ϕ_p were in the range of approximately 0.6 to 0.8. The total (or final) stoichiometric ratio, ϕ_T , was held near 1.15.

Figure 3.18 is a composite view of NO_x results obtained in the test duct during coal-only tests with opposed, 20°cs , and $20^\circ\text{cs}/45^\circ\text{cc}$ secondary air jet configurations. Emissions of NO_x are plotted vs. the primary stoichiometric ratio for the normal six-foot refractory configuration. This information is included for comparison with the reburn data.

Figure 3.19 shows reburn results for all tests conducted with reburn air introduced through the primary and secondary combustion-air registers. Deep-staged secondary air jets were configured with either opposed or 20°cs angles. Emissions of NO_x are plotted vs. the primary stoichiometric ratio for the six-foot refractory configuration. The effect of the propane addition was to shift the curves of NO_x vs. primary stoichiometry to the left, that is, to higher values of primary stoichiometry for the same NO_x output.

Figure 3.20 shows reburn results at $\phi_p = 0.6$ with two locations for injection of propane-reburn air. Deep-staged secondary air jets were configured with $20^\circ\text{cs}/45^\circ\text{cc}$ angles. Emissions of NO_x are plotted vs. the quantity of propane used for reburning, expressed as percent of total Btu input, for the six-foot refractory configuration. When reburn air was introduced through the primary and secondary air registers, there was no reduction in NO_x emissions (dashed line). However, when the reburn air was

Figure 3.18 Graph of Influence of Stoichiometry on NO_x Summary (NO_x includes NO plus any NO_2 that might be present, all reported as the heavier NO_2)

Figure 3.19 NO_x Emissions During Reburning Tests with Reburn Air Introduced Through Primary and Secondary Air Registers

Figure 3.20 Graph of Achieved 0.3 lb NO_x Per Million Btu With Reburning

introduced through the reburn jets, a major decrease in NO_x emissions resulted. **A low value of 0.295 lb NO_x/MBtu was achieved with 13.7% of the heat input from propane.** The probable reason for the ineffectiveness of reburning when the reburn air was added at the primary and secondary air registers is that the primary stoichiometry was significantly higher than 0.6 prior to propane addition for that case, whereas for the case where the reburn air was added along with the propane, the stoichiometry was about 0.6 throughout the primary zone.

Results of the reburn tests indicate that a reduction in NO_x emission of at least 33 percent can be achieved using reburning, compared to the staged combustor performance without reburning. Greater reductions may be achieved by further refinement of the system or by more propane addition. Reburning was not tested inside the boiler, but it is expected that the NO_x reduction would be similar to that observed in the test duct. NO_x levels measured in the boiler were somewhat higher than in the test duct, probably because the rate of heat loss was greater in the test duct. The nominal NO_x level during long term boiler operation at high fire was about 0.55 lb/MBtu, so a 33 percent reduction would result in NO_x emission of about 0.37 lb/MBtu.

Cold Start Burner-Lightoff Demonstration

A cold burner lightoff on coal was demonstrated in the external test duct to determine if preheating, using an alternate fuel, could be eliminated. The normal procedure for initiating coal firing was to preheat the refractory lining by firing propane before switching to coal, in order to insure ignition and stabilize the flame. For the cold

lightoff test, the refractory was not preheated and only the propane pilot was used to ignite the coal. Combustion air preheat was not used. The coal ignited immediately and the flame was stable; however, the flame was very smokey until the refractory heated up. Cold lightoffs were not attempted in the boiler in order to minimize the amount of unburned material deposited in the boiler.

3.8 Data-Acquisition/Boiler-Control System

A microcomputer-based data acquisition and control system was developed during the program. The major components of the system are shown in Figure 3.21. The controller for the system is a 80286-based microcomputer, with a color graphics display for data presentation. Data acquisition is accomplished through an IEEE-488 interface to a high-accuracy digital multimeter. Selection of individual analog measurements for digitizing is accomplished via multiplexing with a low-level relay scanner, which also is controlled through the IEEE-488 bus. These instruments form a very adaptable and accurate system for gathering, digitizing, displaying, and storing test data.

The controls that require on/off cycling are connected through a control panel, which was designed and fabricated by UTSI personnel. This panel allows either manual or microcomputer control of the boiler system. Several safety features are incorporated in the design of the panel, including a key switch for output enable/disable, computer-control disable, and a manual emergency shutdown button. The system components that require proportional control are controlled by digital PID controllers in manual or automatic mode. The microcomputer has the capability of

Figure 3.21 Schematic of Data-Acquisition/Control-System Arrangement

providing a remote set point input to these controllers for a supervisory-mode control function.

Software for the control system was also developed at UTSI. Routines address the relay scanner and read the multimeter. A digital I/O routine is used to drive the control panel. Software displays and stores measured data. Routines also were developed for miscellaneous utility programs including calibration of sensors, as shown in the following outline:

SOFTWARE TASKS

Data acquisition

- Set scanner channel address
- Read volts
- Convert to engineering units
- Display units, status, alarms
- Save/Store

Controls

- Provide sequencing for startup, condition changes, and shutdown
- Control combustion air flow rate by fan motor speed control
- Provide proportional outputs through software PID loops for supervisory control of Honeywell controllers

Utilities

- Calibration
- Management of configuration, constraints (setup)
- Data analysis or file transfer to mainframe computer

Feedback control loops are provided for automatic control of steam pressure, coal flow, propane flow, and stack oxygen content. The control loops for steam pressure and propane flow are conventional, with process feedback to digital PID controllers. The controller output is a 4-20 milliamp signal which modulates the control valve position through an electric to pneumatic transducer:

Coal flow is similarly controlled; however, the control variable is eductor air pressure, which is maintained at a constant set point by the feedback control loop. The actual on-line coal flow measurement is derived by digital signal processing on the rate of change of coal tank weight. This coal flow measurement is not suitable for process variable feedback to the control loop due to the processing delays required, so eductor air pressure is used as the process variable. The coal flow measurement is monitored during operation, and the eductor air pressure set point is manually adjusted if necessary to maintain the desired coal flow.

The oxygen concentration in the flue gas is maintained at the desired level for maximum combustion efficiency by another control loop. This control loop is unique because the O₂ measurement and the method for controlling combustion air flow are non-standard. **The oxygen sensor is an inexpensive automobile combustion-quality sensor available off-the-shelf at any auto parts store.** The sensor has a built-in resistance heater which is powered by a DC power supply to maintain the sensor at its correct operating temperature. The output signal is non-linear and has an amplitude in the millivolt range. The sensor was calibrated and the resulting polynomial coefficients used to calculate a direct readout of stack O₂ content. A special filter was fabricated from Gore-Tex filter media to prevent fouling of the

sensor by flue gas contaminants. Oxygen concentration is used as the process feedback to a PID control loop that controls the combustion air blower speed. A variable speed AC motor drive changes the frequency and amplitude of the three phase 208 volt power to the blower motor based on the 4-20 milliamp signal from the O₂ controller. The blower speed regulates the amount of air flowing into the combustor and thus the oxygen content in the flue gas. This method of controlling combustion air flow provides the advantages of high fuel economy in the boiler, as well as electrical power savings, since the blower motor is running at the minimum speed necessary to provide the air flow, and dampers are not used.

A redundant flame detector was designed and installed in the combustor for additional safety because the new combustor design, and refractory lining in the boiler, changed the conditions that the original flame detector incorporated in the original Cleaver-Brooks burner controller would view. The new flame detector was used in a supervisory mode to either alarm the operator or automatically perform an emergency shutdown through the control computer. A photodiode with visible light sensitivity similar to those commonly used in camcorders as light sensors was used as the detector. Testing was performed with a spectrometer to determine the frequency of photoemissions during coal operation and at shutdown in order to specify an optical filter for the detector. The goal was to detect the coal flame but reject the refractory glow after flameout. A probe was fabricated and the photodiode, a Darlington™ transistor current amplifier, and the filter were mounted inside it and wired into the data acquisition and control computer. The final configuration of the flame detector was used during the long duration test and gave good performance.

3.9 Fire-Side Deposit-Removal Equipment

UTSI personnel installed sootblowers on the Cleaver-Brooks firetube boiler for cleaning the individual boiler tubes in the second, third and fourth passes. These sootblowers were installed at the pass 1-2, 2-3, and 3-4 turn-around areas. A sootblowing lance that can be inserted at the exit end of the main firetube (pass 1) was also installed to remove deposits from the firetube walls. Scrapers were installed at the pass 1-2 turnaround area to remove deposits from the refractory lining in the endbell and the tube sheet at the entrance of the second pass tubes.

The sootblowers for the individual boiler tubes consist of 1/4 inch o.d. x 0.035 inch wall stainless steel tubes which are directed toward the upstream end of each boiler tube in the second, third, and fourth passes. The second pass has 46 tubes; the third and fourth passes each have 30 tubes. The sootblower tubes are connected to three separate headers on the second pass, in groups of 16, 15, and 15. The third and fourth passes each have two separate headers, with 15 tubes per header. The sootblowing medium is 120 psi nitrogen which was readily available, but compressed air would be used for commercial retrofits. The tubes in the second pass are type 310 stainless steel, which had previously demonstrated good corrosion resistance in the firetube exit area. The tubes on the other passes are type 316 ss, which is a less expensive material. In order to install the sootblowers on the second and fourth passes, it was necessary to drill an individual hole for each tube through the boiler end bell and the refractory inside, as there was no room for headers inside the boiler. The third pass installation was much simpler, because there was room for an internal header. Installation of the sootblowers is shown in Figure 3.22. For a commercial

Figure 3.22 Photograph of Pass 2 & 4 Sootblowers

retrofit, it would probably be more practical to fabricate a new, deeper end bell which would have internal sootblower headers installed in the shop. A deeper end bell would also make it easier to remove ash at the first-pass firetube exit, and there would be more room for an ash discharge point. The sootblowers were operated during the long duration test and were effective in removing dust from the boiler tubes.

The first-pass firetube sootblower lance consists of a 1/2-inch schedule 40 carbon steel pipe. The end of the pipe is welded shut and two opposed 7/16 inch diameter holes near the end of the pipe direct the compressed nitrogen toward the firetube walls. The lance is operated in a manner similar to a typical retractable sootblower. It is slowly rotated as it is inserted into the firetube and nitrogen flow is maintained for the entire time it is inserted to prevent overheating. The lance is inserted to a depth slightly downstream of the station of the secondary air jets, and then retracted. The sootblower lance was operated during the latter part of the long duration test, and appeared to be effective in removing deposits from the firetube walls and maintaining heat transfer and exit gas temperatures.

The deposit scrapers at the pass 1-2 turnaround area were constructed from 1/2 inch o.d. x 0.125 inch wall stainless steel tubing. The scrapers were located so they could be rotated across the surface of the refractory lining in the endbell or across the tube sheet. The scrapers were permanently installed inside the boiler; a small continuous flow of cooling air was passed through the tubing to keep the metal temperature at an acceptable level. The scrapers were operated during the latter part of the long duration test, and appeared to be effective in removing deposits from the refractory and tube sheet.

3.10 Baghouse

It was necessary to install a particulate removal device on the boiler stack in order to decrease particulate emissions to less than 0.6 lb/MBtu. Use of extremely low ash coal without additional flue-gas cleanup was not a practical alternative, because the unburned carbon associated with 99% combustion efficiency produces nearly 0.6 lb-particulates/MBtu by itself (see Figure 3.23). Coal ash, based on ASTM "ash" analyses, would contribute to much larger emissions. Measurements of the particle size of the fly ash produced by combustion of micronized Upper Elkhorn coal (see Figure 3.24) indicated that a cyclone would not be effective for separating these particulates from stack gases. Conversely, a baghouse can easily reduce particulate emissions by more than an order of magnitude below the UTSI (Tennessee) site limit of <0.6 lb-particulates/MBtu. Therefore, a baghouse was selected for particulate removal on the boiler system.

The baghouse installed on the 200 BHp boiler was manufactured by Aeropulse Co. and was originally purchased in 1976 for other coal-fired research at UTSI. The baghouse contains 36 4-5/8 inch diameter x 10 ft long bags, providing approximately 436 sq ft of cloth area. A pulse-jet cleaning system is employed to remove dust from the bags. The flue gas flow at a firing rate of 6 MBtu/h is approximately 1850 acfm, providing a maximum filtration velocity of about 4.2 ft/min. Filtration velocities of around 4 ft/min are typical for pulse jet baghouse operations collecting fly ash. Based on discussions with bag vendors, a standard 16 oz woven fiberglass fabric with acid resistant finish was chosen for testing in the boiler system. Over 90 percent of coal fired boiler baghouses use this type of fabric, and the vendors did not feel that the

Figure 3.23 Stack Particulate Output versus Coal Ash Content

Figure 3.24 Particle Size Distributions, DUC & Fly Ash

unusually small particle size of the fly ash produced by combustion of micronized coal would present a problem for the standard fabric.

The layout of the baghouse installation is shown in Figure 3.25. The baghouse inlet duct is connected to the side of the existing boiler stack. Dampers are used to direct the flue gas through the baghouse or bypass it to the stack. Rather than returning the cleaned flue gas to the existing stack, a new exhaust duct was constructed. This was necessary to preclude dust leakage through the damper from influencing the particulate measurements at the baghouse exit. For a commercial boiler system, this problem would not arise, because a multiple damper system would be installed. The baghouse was bypassed during startups until the stack reached operating temperature in order to avoid condensation problems.

The baghouse was operated throughout the long-duration test, and performed adequately in terms of collection efficiency and pressure drop. Particulate samples representative of the material entering the baghouse were obtained while the baghouse was bypassed, and baghouse outlet samples were obtained at a sample port in the new exit duct. Ash from the baghouse was collected in 55 gallon drums, weighed, and sampled for chemical analysis. Detailed sample results are presented in Section 3.13.

3.11 UTSI (MHD) 5,500 Pound-per-Hour Pulverizing/Drying/Batch-Storing System

The Illinois No. 6 coal used in the project was pulverized in the CFFF pulverizer system. This system is normally used to pulverize coal for use in the MHD bottoming cycle development work presently underway at UTSI. The pulverizer system is shown schematically in Figure 3.26. The system uses a modified Babcock & Wilcox EL-35 ball

Figure 3.25 Schematic of Baghouse Arrangement

Figure 3.26 Schematic Arrangement of UTSI (MHD) 5,500 Pound-per-Hour Coal Preparation System

mill pulverizer. Approximately 4000 to 4500 cfm of inerted gas at 500 to 600°F is supplied to the pulverizer to dry 5000 to 7000 lb/hr of coal. Pulverized coal is blown from the classifier into a baghouse. The Illinois No. 6 test coal was pulverized at a rate of approximately 5500 lb/hr. This is much less than the design raw coal flow rate of the EL-35 pulverizer. Pulverized coal can be prepared very economically using this system, with a cost per million Btu less than natural gas. Fuel economics are discussed in detail in Section 4.2.

3.12 Long-Duration Test

A period of 110.1 hours of cumulative operation was completed during the long-duration test, which was conducted between July 8, and August 20, 1991. Coals burned during the test included dry, ultra fine (8 micrometer median particle diameter) high ash-fusion Upper Elkhorn #3 coals with 2.4 and 6.6 percent ash (DUC's), and a sample of Illinois #6 low ash-fusion coal with 11.4 percent ash which was finely pulverized at UTSI (39 micrometer median particle diameter). Operation times on the different test coals are summarized below:

Upper Elkhorn No. 3 DUC with 2.4% ash: first 94.8 cumulative hours

Upper Elkhorn No. 3 DUC with 6.5% ash: next 9.5 cumulative hours

Illinois No. 6 finely-pulverized with 11.4% ash: last 5.8 cumulative hours

A series of tests of the final burner configuration were conducted at medium and high-firing rates prior to starting the long-duration test, in order to determine the optimum settings for the burner. Sootblower operation was checked out during these tests, and the baghouse was successfully tested at full load with coal firing and automatic boiler-system control. During these tests, NO_x emissions ranged from 0.44

to 0.55 lb/MBtu, and carbon burnout values were from 98.4 to 99.1 percent. Soot-blowing did not measurably affect NO_x or carbon burnout.

After several hours of initial operation of the complete system, the planned 100-hour test was begun on Monday, July 8, 1991 using 2.4% ash (DUC) Upper Elkhorn coal, and ran for slightly more than eight hours. A forced shut-down occurred after eight hours for removal of ash deposits from the end bell at the exit of the main (pass 1) firetube. Ash deposits were found on the surface of the refractory lining in the end bell and on the metal surfaces of the pass two tube sheet, mostly filling the pass one-two turn around area, and enveloping the (fixed-position) sootblowers designed to clean the individual tubes in pass 2. This was the first time we had observed anything other than relatively minor deposition with UE3 2.4% ash coal. Previous testing was typically for periods of 6 hours or less, and approximately 600 cumulative hours without sootblowing had been accumulated with no indication of lane blockage. Previous deposits in the pass one-two turn-around area were in the form of a non-cohesive, easily-removed powder, which was no more than 0.25" in thickness after 40 hours of cumulative operation. After removing the lane-blocking ash deposits, the pass 2 sootblower tubes were cut off flush with the surface of the refractory in the end bell.

Subsequently, we completed an additional 60 cumulative hours of testing before operation was stopped because of ash deposition which once again had created significant blockage of the gas path in the pass 1-2 turnaround area. During this period, all efficiency and emissions goals were met. The maximum continuous period of operation during this 60-hour period was 15 hours. The second longest

continuous period was slightly longer than 14 hours. Oversized material in the DUC provided to UTSI by Energy International caused several shut downs. Another shutdown was caused by a power outage due to a nearby lightening strike. After the 60 hour period, we added a sight port for on-line viewing of the pass 1-2 turn-around area and installed additional ash-removal equipment, with a goal of permitting continuous operation for longer periods. Deposit scrapers were installed to remove ash deposits from the surface of the refractory lining and the pass 2 tubesheet, and a sootblowing lance was added for removing deposits from the firetube walls. A successful 3-hour test was then conducted using the new ash-removal equipment. In total, approximately 81 hours (cumulative) of the planned 100-hours were completed by the end of July.

On August 12, the system was tested with propane to obtain baseline data in a clean, coal-ash-free condition. At this point, the system was configured with the late-July arrangement of the added deposit scrapers for the pass 1-2 turn-around area, and an added soot-blowing lance inserted into the exit end of the main firetube (pass 1).

The July testing had provided an accumulated total of 72.2 hours of burning of the UE3 2.4% ash DUC, and, an additional 22 hours of burning of this coal (approximately 4 bags) was necessary to complete the planned schedule. On August 13-14, 22.7 hours of cumulative operation was achieved. The first part of this operation was continuous, for 21.6 hours before being stopped by a coal-line obstruction. This was followed by a final 1.1-hour continuous test period which emptied the remaining

UE3 2.4% ash coal from the feed tank. The long-duration(100-hour) test achieved 94.8 hours of cumulative operation.

On August 14, the long-duration test was continued with the higher ash DUC (UE3 6.6% ash) coal. The planned burn of this high-ash coal, with ash-fusion temperature of about 2500°F, was for a period of approximately 8 hours, to demonstrate feasibility of operation with high-ash, but otherwise good-quality ultra-fine coal. The actual test time achieved was 9.5 hours of continuous operation. Ash deposition appeared to be well controlled, with minimal deposits observed and with heat transfer rates and fire-tube pass-1 exit gas temperatures maintained at satisfactory levels using the UTSI sootblowing and deposit-scraping equipment. The long-duration (100-hour goal) test period had achieved 104.3 hours of cumulative operation with ultra-fine UE3 coals.

Operation continued on August 14 without shutting down, and one bulk bag of 11.8% Illinois #6 UTSI-pulverized coal was loaded into the coal feed tank. A minimum of 4.5 hours of operation was planned with this very high ash Illinois #6 coal, which has a very low quality ash with very low ash fusion temperatures. This Illinois coal was not an ultra-fine coal like the previous UE3's (with 8 micrometer MPD), but it represented a very economical and affordable coal fineness (39 micrometer MPD) which was produced in a normal B&W ball-in-race commercial pulverizer. The low ash fusion temperature of the Illinois No. 6 coal normally would preclude it from being chosen as a fuel for a firetube boiler experiment; an equally low cost but high ash-fusion coal with a lower ash content would be used for commercial applications. However, the finely-pulverized Illinois No. 6 coal was available for testing in the firetube boiler without

additional cost, and it offered an opportunity to add an assumed “limiting-condition” coal to the advanced-combustor fuel data base.

A period of 3.2 hours of operation with Illinois #6 followed. The pulverized coal was much easier to load and transport by dense phase eductor feeding than the ultra-fine coal. As a result, the coal feed rate to the burner increased and the initial firing rate on the Illinois No. 6 coal was over 7 million Btu per hour. This was above the maximum design firing rate for the burner/firetube configuration and produced a flame that was longer than the main (pass 1) firetube. As a result of the unplanned for conditions, a massive ash deposit formed in the pass 1-2 turnaround area, and quickly became a partially-fused slag-like material that could not be removed on-line. The unit was shut down and cleaned. Operation was resumed on August 20, and coal rates were controlled at the desired operating levels by using a lower eductor motive-air pressure. Normal operation was achieved until the coal hopper was emptied after a period of 2.6 hours. Ash scrapers and sootblowers performed well. The cumulative total test time achieved with Illinois #6 UTSI-pulverized coal was 5.8 hours. Although the final period of successful operation was relatively short, results looked very promising for efficiently burning economical UTSI-pulverized coal in the fire-tube boiler if a high ash fusion temperature coal were used.

Overall, a period of 110.1 hours of cumulative operation was completed during the long-duration testing. The final configuration of the UTSI-designed and fabricated deposit-removal equipment (with modifications and additions developed during the long-duration test) seemed to perform effectively in the course of the relatively short test periods available near the end of the long-duration test period. Ash deposition

appeared to be well controlled visually and functionally (heat transfer rates and firetube pass-1 exit gas temperatures were maintained) using the final configuration of the UTSI sootblowing and deposit-scraping equipment. However, additional long-term testing is needed to assess and minimize the potential risk of critical ash-deposition problems during commercial operation and to confirm the effectiveness of the special UTSI on-line deposit and heat-transfer control equipment. Using high quality, ultra-fine Upper Elkhorn coal with low ash content and high ash-fusion temperatures did not prevent major fire-side deposits from forming during periods of long-duration operation in the 1-2 pass turn-around region of the boiler. This deposition tendency was not observed during the numerous previous shorter-term tests, nor was it predicted from the previous test results.

3.13 Summary of Long-Duration Performance Accomplishments With Discussion

The performance goals established for the boiler system, along with the corresponding performance demonstrated during the long duration test are as follows:

Table 3.5 Phase II Accomplishments

	Goal	Accomplishment
Combustion Efficiency	>99.0	99.3 ⁽¹⁾
Boiler Efficiency	>80.0	86.5 ⁽¹⁾
Burner Turndown Ratio	>3:1	>3.5:1 ⁽²⁾
Emissions, pounds per million Btu		
SO ₂	<1.2	0.81 ⁽³⁾
NO _x	<0.7	0.53 ⁽¹⁾ ; <0.3 ⁽⁴⁾
Particulates	<0.6 ⁽⁵⁾	<0.05 ⁽⁶⁾
Support Fuel	None	None ⁽⁷⁾
Air Preheat	None	None

(1) Long-term test results.

(2) Without using any support fuel or preheating the combustion air.

(3) Coal selection.

(4) With propane reburning supplying 14% of the Btu input.

(5) Small boilers are not regulated the same as NSPS for large, coal-fired utility boilers. The 0.6 value represents a Tennessee site permit for UTSI.

(6) With low-priced bags in baghouse.

(7) Coal only, no pilot.

Goal: Greater than 80 percent boiler efficiency

Achievement: **86.5 percent long-term efficiency was demonstrated**

Goal: Greater than 99 percent combustion efficiency

Achievement: **99.3 percent long-term efficiency was demonstrated**

Goal: Less than 1.2 pounds of SO₂ emissions per million Btu burner input

Achievement: **0.81 pounds of SO₂ long-term emissions per million Btu burner input was demonstrated**

Goal: Less than 0.7 pounds of NO_x emissions per million Btu burner input

Achievement: **0.53 pounds of NO_x long-term emissions per million Btu burner input was demonstrated during the long duration**

test; results of reburning experiments indicate that NO_x emission could be reduced by about 1/3 using reburning

Goal: Less than 0.6 pounds of particulate emissions per million Btu burner input

Achievement: less than 0.05 pounds of long-term particulate emissions per million Btu burner input was demonstrated

During the long-duration test, average performance data were compiled for several test periods. Material collected in the baghouse during the timed test periods was weighed and sampled for chemical analysis in order to determine carbon conversion efficiency. There were six timed test periods while firing UE3 2.4-percent ash coal, with durations ranging from 7.6 to 15.1 hours. The average duration was 11.4 hours. There was one timed test period of 7.3 hours while firing UE3 6.6 percent ash coal, and two periods 1.1 and 2.3 hours long while firing Illinois No. 6. Burner operation was continuous during all of the timed periods. Results for the timed test periods are presented below.

Boiler efficiencies measured during the long-duration test are plotted as a function of average firing rate in Figure 3.27. Boiler efficiencies were calculated using the American Boiler Manufacturers Association (ABMA) method. Boiler efficiencies were between 86 and 87 percent during all of the test periods. Boiler efficiencies for propane firing are also plotted in Figure 3.27 for the experimental burner (EB), and the original Cleaver-Brooks burner (CB). Boiler efficiencies for propane firing were very similar for the experimental burner and the Cleaver-Brooks burner. Calculated

Figure 3.27 Boiler Efficiencies versus Firing Rate for Various Tested Fuels

efficiency based on higher heating value is higher for coal firing than for propane firing because the moisture content of flue gas produced by propane firing is higher.

Carbon conversion efficiencies measured during the long-duration test are plotted as a function of average firing rate in Figure 3.28. Carbon conversion efficiencies were between 99.2 and 99.4 percent during all of the test periods. Carbon burnout for the finely-pulverized Illinois No. 6 coal was similar to the ultra-fine UE3 coals, even though the mean particle diameter of the Illinois No. 6 was much larger (39 μm vs 9 μm). As noted earlier, the UTSI finely-pulverized coal does not contain the larger particles found at the top end of a normal PC distribution. This allows high carbon conversion efficiencies in the advanced combustor. Although ASTM as-fired coal analyses show similar volatile matter contents (VM lb per lb coal), the VM calculated on a “per million Btu” basis of the Illinois No. 6 is higher than that of the UE3 coal (31.4 vs 25.0-25.4, Table 3.1). The test results indicate that expensive micro-nizing is not required in order to achieve a high carbon conversion efficiency in a firetube boiler.

Carbon monoxide (CO) emissions during the timed test periods are shown in Figure 3.29. CO emissions were typically less than 60 ppm. The higher CO emissions measured during two of the test periods were caused by ash deposits at the firetube exit, which interfered with burner operation.

Sulfur dioxide (SO₂) emissions were limited to about 0.8 lb/MBtu during most of the test due to the low sulfur content of the UE3 coals. Emissions while firing Illinois No. 6 were much higher. Calculated SO₂ emissions are shown in Figure 3.30.

Figure 3.28 Carbon Burnout versus Firing Rate for Various Coals Tested

Figure 3.29 Typical CO Emissions versus Firing Rate for Various Fuels Tested

SO₂ EMISSIONS ARE CONTROLLED BY USING COMPLIANCE COALS

Figure 3.30 SO₂ Emissions Resulting From Different Coals Tested

NO_x emissions measured during the timed test periods are plotted as a function of firing rate in Figure 3.31. NO_x emissions were less than 0.6 lb/MBtu during all of the test periods when UE3 coals were fired. Emissions were slightly above 0.6 lb/MBtu when Illinois No. 6 was fired. It was found during earlier testing that NO_x emission is strongly dependent on primary stoichiometry, as shown in Figure 3.18. Carbon conversion efficiency suffers if the primary stoichiometry drops much below 0.55, which was the nominal value during the long term test. Therefore, it may be difficult to consistently achieve NO_x levels below about 0.55 lb/MBtu without using reburning. Results of earlier tests indicate that NO_x levels below 0.4 lb/MBtu could be achieved with reburning.

Dust emission rate and pressure drop across the baghouse bags are plotted vs. cumulative hours of baghouse operation in Figure 3.32. Dust emission rates were determined by EPA Method 17 measurements in the baghouse exit duct. The results indicate that the flyash produced by combustion of micronized UE3 coal is not particularly difficult to collect; however, the test was not long enough to confidently predict long-term performance. The data indicate that the permeability of the filter media gradually decreased during the first 30 hours of operation and then reached at least a short term equilibrium. Extrapolation of the test data indicates that a steady state pressure drop of about 2.5 inches H₂O could be maintained at a filtration velocity of 3 ft/min, or about 4.3 inches H₂O at 4 ft/min. The rate of dust emission appeared to increase significantly as the filtration velocity increased. Based on the test results, it appears that the standard woven fiberglass bag material would perform adequately in

Figure 3.31 NO_x Emissions versus Firing Rate for Various Fuels Tested

the boiler retrofit application; however, it would be worthwhile to evaluate a felted fiberglass material during future testing, particularly if lower emissions or higher filtration velocities were required.

Figure 3.32 Dust Emissions as a Function of Baghouse Operation Time and Filtration Velocity

4.0 ECONOMIC EVALUATION

The economic evaluation is based on the cost of the UTSI 200 BHp pre-commercial retrofit, UTSI retrofitted-boiler operational costs, and UTSI MHD coal preparation facility (drying, finely-pulverizing) operational costs, including purchase of coal from the mine. It is assumed that in a commercial situation, coal fuel will be dried and suitably pulverized at a central location and delivered to the individual boiler retrofit site(s). Additionally, ash would be removed from the retrofit site for disposal by the prepared-coal supplier.

Additional activities we suggest before producing a commercial retrofit are presented in Section 5.0.

A pre-commercial version of the UTSI retrofit system has been developed and tested using a commercial 200 BHp firetube boiler. Performance goals for high combustion and boiler efficiencies, a large burner turndown ratio, and low gaseous and particulate emissions were achieved, and in several instances were significantly exceeded. The retrofit is relatively insensitive to the amount of ash in individual coal fuels, the ash fusion temperatures, and the coal fineness. This permits using a wide range of fuels, and allows a choice of low cost, economical fuel.

However, forced outages did occur during the attempt to operate continuously for a 100-hour period. The outages were caused by interruptions in the coal flow (DUC only) to the burner and formation of massive deposits of coal ash inside the boiler in the pass 1 to pass 2 turnaround area (all test coals). Improvement in the

quality of the DUC fuel that was supplied to UTSI by other contractors could be accomplished by eliminating the grossly oversized coal particles and extraneous fibers and wood chips. FineFuel (finely-pulverized coal) produced at UTSI did not have this problem. Potential improvements in the UTSI coal handling and feeding system have been identified and are recommended before commercial applications. Details follow in Section 5.0. New concepts for ash deposit removal devices (UTSI RoScrape, InnerJet, modified InnerJet, and RoJet) have been conceived. Near the end of the 100-hour test the RoScrapes were installed and the InnerJets at the pass 2 inlet were modified. Short-term testing of these changes during the final hours indicated effective control of deposits in the previously troublesome area in the pass 1 to pass 2 turnaround. Even ash deposits from the Illinois #6 coal with very high ash content and low ash fusion temperatures were controlled. The new UTSI RoJet cleaning device can be evaluated in the future for control of deposits that might build up and cause problems in the area of the secondary air jets. Other modifications of the ash handling system and additional long-term testing are suggested before a commercial application. Details are presented in the commercialization plan in Section 5.0 of this report.

Results of testing with a commercial 200 BHp firetube boiler show that the pre-commercial version of the UTSI retrofit system has the potential to be developed into a successful commercial design. This small firetube application represents a much greater technical challenge than operation with larger fire- or water-tube boilers, as discussed earlier in this report. Therefore, scaled-up applications are assured of technical feasibility and improved reliability (larger

diameter coal delivery lines, etc.) even though these larger fire- and water-tube boilers have not been included within this scope of this DOE contract (Phases I & II).

Although it is too early to project specific details and final costs of future commercial retrofits, it is possible to make a preliminary evaluation based on the retrofit accomplished by UTSI with a commercial 200 BHp firetube boiler. Results of the UTSI evaluation are presented in this section, and are summarized in the following paragraph. Additionally, these results are valuable for assigning representative target levels for retrofit, operation, and fuel costs required for reasonable internal rate of return values, and break-even and amortization times.

When UTSI finely-pulverized coal (FPC) is used in a boiler retrofitted with a UTSI advanced combustion system in a commercial or industrial-scale application as a substitute for natural gas, propane, No. 2 (light) heating oil, or No. 6 (heavy) fuel oil, the following potential economic advantages could be realized:

- **substantially lower operating costs** based on UTSI demonstrated performance: **potentially more than \$52,944 annual savings with UTSI FPC substituted for propane in a 200 BHp firetube boiler** for the same steam production; **even substituting UTSI FPC for natural gas in a 600 BHp unit could save at least \$55,938 annually.** These figures are based on a typical 4,000 hours per year period of operation with load cycling that averages 75% of the boiler's rated steam output, and the annual total expense for the capital equipment (complete system retrofit financed by a 10% interest 10-year loan) has been subtracted from the above-listed operating cost-savings.

Conversely, **excessively higher** operating costs will occur with **ultra-fine DUC** substituted for propane in a 200 BHp firetube boiler for the same steam production estimated as an **\$972,356 annual loss**; Substituting **ultra-fine DUC** for natural gas in a 600 BHp unit would produce a **\$3,019,962 annual loss**. These calculations are based on \$47.28/MBtu DUC, which was the lowest 1990 verbal estimate from Energy International for near-term future UE3 2.7% ash DUC costs **if DUC fuel were to become available commercially**. This predicted commercial DUC cost is very conservative since it is far less than that of the DUC test fuels supplied by Energy International to UTSI for use in this contract. The research fuels were UE3 DUC's @ \$135.10/MBtu, and the Eagle Butte 1.3 float DUC @ \$403.63/MBtu. Refer to Section 4.2 for further details.

- annual savings with UTSI FPC become significantly more favorable as the boiler size increases above the 200 BHp level
- low capital costs for the retrofit are estimated at \$134,200 to retrofit the 200 BHp firetube boiler as used at the UTSI test site and \$235,067 estimated to retrofit a 600 BHp boiler
- capital costs per pound of steam would become significantly more favorable as the size of the boiler being retrofitted increases above the 200 BHp level (note the relative retrofit costs above)
- amortization times for the capital costs can be short, even at the 200 BHp level with a 10% loan based on 2.0 years for amortization, or \$52,944

annual savings averaged over a 10-year pay-back period with UTSI FPC substituted for propane in a 200 BHp firetube boiler; 1.1 years amortization & \$185,389 average annual savings for a similar 600 BHp retrofit

- amortization times would decrease as the boiler size being retrofitted increases above the 200 BHp level because the annual savings are proportional to the amount of steam generated per year and capital costs per pound of steam would become more favorable with the larger units

Details of the UTSI economic evaluation follow.

4.1 Capital Equipment

Table 4.1 lists the individual retrofit items that are required, and their estimated installed costs. Most of the items are similar to those installed at UTSI in terms of quality, automation and performance. Some items are improved and of a more commercial nature. These include:

- New pass 1-2 end bell with improved cooling and cleaning capabilities, and bottom ash clean-out hopper added

Table 4.1 Capital Equipment Costs

Item	Cost for 200 BHp Boiler	Cost Multiplier for 600 BHp	Cost for 600 BHp Boiler
Coal hopper ¹	\$ 17,000	1.56	\$ 26,517
Blower speed controller ²	5,000	1.00	5,000
Isolation xfmr for speed controller	1,000	1.00	1,000
Computer & I/O	3,000	1.00	3,000
Data acquisition system	5,000	1.00	5,000
PID controllers (5)	3,500	1.00	3,500
Pressure transducers (8)	4,000	1.00	4,000
Thermocouples	800	1.00	800
Gas flow venturi	1,500	1.00	1,500
Push button control panel	1,500	1.00	1,500
Software & computer supplies	1,000	1.00	1,000
Electrical & misc hardware	3,500	1.10	3,850
E/P transducers (2)	1,400	1.00	1,400
Equipment racks	2,000	1.00	2,000
Burner	10,000	1.50	15,000
New end bell ³	11,000	1.50	16,500
Burner end hopper ³	5,000	1.50	7,500
Baghouse ⁴	22,000	2.50	55,000
Storage bin for ash	2,000	2.00	4,000
Plumbing ⁵	7,000	2.00	14,000
Compressors ⁶	13,000	3.00	39,000
Receiver	3,000	2.50	7,500
Deposit removal equipment	11,000	1.50	16,500
Total	\$134,200		\$235,067

Notes:

1. Includes load cells.
2. Assumes the existing motor can be used.
3. Includes equipment for removing ash from hopper
4. Includes felt bags.
5. Assumes boiler already uses gas
6. Compressor with speed control for coal feed, separate compressor with receiver for sootblowing.

- Bottom ash clean-out hopper added to burner-side end bell
- Automated deposit-removal equipment consisting of
 - pass 1 rotating, retractable-lance blower
 - pass 1-2, 2-3, 3-4 tube ID jets blowers
 - pass 1-2 rotary scrapers

New items include:

- Storage bin for baghouse ash and end-bell bottom ash that empties pneumatically as new coal supplies are delivered. (Ash to be removed by coal delivery personnel.)
- Air compressors for combustion air, sootblowers and instrumentation; includes high-efficiency variable-speed compressor motor and automatic controls
- Compressed-air accumulator tank

4.2 UTSI FPC-Fuel Costs

The cost of fuel is the major factor influencing operating expenses (Section 4.3) and an important parameter in determining amortization times (Sections 4.1 & 4.3).

Dry, pulverized coal (finer than utility grind but not ultra fine) is considered by many to have a very low cost. Figure 4.1 illustrates generalized costs of several fuels in terms of their cost relative to natural gas (left vertical scale, which is based on \$4.50 per million Btu at UTSI) and absolute costs as \$-per-million-Btu (right vertical scale). The two fuels on the far right represent Phase I & II test fuels prepared by Energy International in small lots. Dry, ultra-fine coals really are predominately “research”

Figure 4.1 Fuel Cost, Graph I

fuels at this time. The "DUC '90 low EI est" is based on verbal communication with Energy International personnel in 1991, and indicates their estimate of 1991 prices for large-scale R&D or initial smaller-scale commercial offerings. Two references for coal water fuels (CWF) also are included. These costs should not be considered to accurately indicate future commercial prices, but rather to be some general current benchmarks.

Figure 4.2 more clearly shows the relationship to \$4.50/MBtu natural gas, and only includes fuels with costs below \$60 per million Btu's. Propane has been added (\$6.31/MBtu at UTSI). On the far left we see the low cost of finely pulverized coal (UTSI-produced FPC).

Details of the operational and raw-coal cost estimate for the finely pulverized coal produced and successfully tested by UTSI are given in Table 4.2, UTSI Finely-Pulverized Coal Costs. Note that the full horsepower ratings of the motors were used for very conservative costing. Capital equipment and maintenance costs for a centralized coal preparation facility pulverizer system (not part of retrofit site) were not considered. However, maintenance costs are expected to be very low and probably <\$0.10 per million Btu. Additionally, no attempt was made to minimize the FOB raw coal costs, which represent 73% of the total cost in Table 4.2. For reference, CQ Inc. personnel predicted a finely-pulverized coal could be produced commercially for under \$3.00 per million Btu. Results for UTSI total FPC-fuel costs were:

- \$3.15/MBtu, or
- \$71.27/ton.

Figure 4.2 Fuel Cost, Graph II

Table 4.2 UTSI Finely-Pulverized Coal (Ill. #6) Costs *

Item	Cost per Hour	Cost per Ton	Cost per MBtu
Electric power for pulverizer, blowers, pumps (total of 342 HP)	\$ 13.35	\$ 4.85	\$0.22
Natural gas (4200 scfh)	19.66	7.15	0.31
Labor	20.00	7.27	0.32
Coal	143.00	52.00	2.30
Total	\$196.01	\$71.27	\$3.15

* At UTSI, the B&W mill capacity with Illinois #6 is approximately 5500 lb/hr. Cost for Illinois #6 is \$52.00 per ton, \$2.30 \$/MBtu (22.6 MBtu per ton as-recd) FOB UTSI from Consolidation Coal Co., June 1990 contract.

4.3 Operating Expenses

In addition to the importance of fuel cost in terms of \$ per million Btu's, other factors including combustion efficiency, moisture content of the fuel and flue gases, and boiler efficiency all contribute to the cost per pound of producing steam. Thus, "operating expense" in terms of the **cost of steam is the most meaningful measure of economics** to the boiler owner/operator. As you will note later in this section, the UTSI FPC at \$35 has the lowest cost per 10,000 pounds H₂O evaporated @ 212°F. The next higher is natural gas at \$52, followed by propane at \$73 and UE3 DUC at \$561 (based on commercial DUC price predicted in 1990 Energy International estimate).

Table 4.3 summarizes the operating expenses. It shows using UTSI finely-pulverized coal in a 200 BHp boiler with a cycling load during a single 4,000-hour year could produce a savings of \$31,070 over natural

Table 4.3 Summary of Operational Costs and Amortization Years

Fuel type	Fuel cost per hr for 5175 lb/h steam	Eductor air cost per hr for 5175 lb/h steam	Fluidizing N ₂ cost per hr for 5175 lb/h steam	Combustion air cost per hr for 5175 lb/h steam	Total steam cost per hr @ 5175 lb/h
UE3 DUC	\$274.62	\$0.68	\$0.09	\$0.57	\$275.96
III. 6 FPC	18.30	0.68	0.09	0.57	19.63
Propane	37.61	0.00	0.00	0.58	38.19
Natural gas	26.82	0.00	0.00	5.58	27.40

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Fuel Type	Steam cost per hr @ 5175 lb/h	Total cost over 4000 hr year @ 5175 lb/h	Total cost over 3000 hr year @ 5175 lb/h	Total cost over 2000 hr year @ 5175 lb/h	Steam cost per hr @ 15,525 lb/h	Total cost over 4000 hr year @ 15,525 lb/h	Total cost over 3000 hr year @ 15,525 lb/h	Total cost over 2000 hr year @ 15,525 lb/h
UE3 DUC	\$275.96	\$1,103,836	\$827,877	\$551,918	\$827.88	\$3,311,508	\$2,483,631	\$1,655,754
III. 6 FPC	19.63	78,536	58,902	39,268	58.90	235,608	176,706	117,804
Propane	38.19	152,756	114,567	76,378	114.57	458,269	343,702	229,135
Natural gas	27.40	109,606	82,205	54,803	82.20	328,818	246,614	164,409

Table 4.3
(Continued)

Fuel Replacement	Savings per hr @ 5175 lb/h	Savings over 4000 hr year @ 5175 lb/h	Savings over 3000 hr year @ 5175 lb/h	Savings over 2000 hr year @ 5175 lb/h	Savings per hr @ 15,525 lb/h	Savings over 4000 hr year @ 15,525 lb/h	Savings over 3000 hr year @ 15,525 lb/h	Savings over 2000 hr year @ 15,525 lb/h
III. 6 replacing propane	\$18.56	\$74,220	\$55,665	\$37,110	\$55.67	\$222,661	\$166,996	\$111,331
III. 6 replacing natural gas	7.77	31,070	23,303	15,535	23.30	93,210	69,908	46,605

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Fuel Replacement	4000 hr year @ 5175 lb/h	3000 hr year @5175 lb/h	2000 hr year @5175 lb/h	4000 hr year @ 15,525 lb/h	3000 hr year @15,525 lb/h	2000 hr year @ 15,525 lb/h
III. 6 replacing propane, amortization years without loan interest	1.8	2.4	3.6	1.1	1.4	2.1
III. 6 replacing propane, amortization years with 10% finance rate	2.0	2.8	4.5	1.1	1.5	2.4
III. 6 replacing natural gas, amortization years without loan interest	4.3	5.8	8.6	2.5	3.4	5.0
III. 6 replacing natural gas, amortization years with 10% finance rate	5.7	8.6	20.0	2.9	4.1	7.0

gas, or a savings of \$74,220 over propane. In a hypothetical R&D situation, the savings over dry, ultra-fine UE3 coal would be \$1,025,300 (assuming \$47.28/MBtu).

Additional operating expenses due to the coal retrofit are given in Table 4.4. Labor is not included, because automatic operation comparable to gas or oil firing is assumed and only incremental costs are considered. Fuel costs assume fly ash is removed from site at no additional cost by the vendor who is delivering the coal.

Additional assumptions used in the calculations are detailed below:

The rated output of a 200 BHp (Cleaver-Brooks) firetube boiler is 6,900 lb steam @212°F per hour. Based on Cleaver-Brooks sales/service representative (J. Oakley, private communication), 75% "typical" load factor for a load cycling between medium and high, a value of 5,175 lb steam @212°F per hour will be used to represent the steam output for a "standard" hour with load cycling ($6,900 \times 0.75 = 5,175$). This definition is used for the economic evaluation.

The annual cost is assumed to be 50 weeks X 5 days per week X 16 hours per day X cost per load-cycling 200 BHp boiler hour. This is equivalent to 4,000 hours operation per year, and is identical to the value used by Cleaver-Brooks for most examples included in their "Boiler Efficiency Facts" brochure. They occasionally compared values for 3,000 and 2,000 hours in the brochure. The rated output of a 200 BHp Cleaver-Brooks firetube boiler is 6.699 MBtu/h. For a 75% load factor and the measured boiler efficiency for UE3 coals at UTSI of 86.5%, an average input value of 5.808 MBtu/h is indicated for UE3 coal with cycling operation ($6.699 \times 0.75 \times 1/0.865 = 5.808$).

Table 4.4 Operational Costs, Combustion Air & Fluidizing Nitrogen

Item	Firing rate, MBtu/h	Compressor horsepower (with speed control)	Cost per 10,000 lbs H ₂ O evap. @ 212°F for coal firing *	Cost per 10,000 lbs H ₂ O evap. @ 212°F for propane firing *
Eductor air	1.8	2.5	\$0.61	\$0.00
	3.1	4.3	0.61	0.00
	3.7	6.3	0.75	0.00
	4.1	8.3	0.89	0.00
	4.6	11.0	1.05	0.00
	5.3	13.9	1.15	0.00
	5.7	17.1	1.31	0.00

Item	Firing rate, MBtu/h	N ₂ flow rate, SCFH	Cost per 10,000 lbs H ₂ O evap. @ 212°F for coal firing *	Cost per 10,000 lbs H ₂ O evap. @ 212°F for propane firing *
Fluidizing N ₂	6.0	6	\$0.18	\$0.00

Item	Firing rate, MBtu/h	Blower Horsepower (with speed control)	Cost per 10,000 lbs H ₂ O evap. @ 212°F for coal firing *	Cost per 10,000 lbs H ₂ O evap. @ 212°F for propane firing *
Primary & Secondary Air	2.0	7.2	\$1.58	\$1.62
	4.0	11.4	1.25	1.29
	6.0	15.0	1.10	1.12

* 84.3% boiler efficiency assumed for propane, 86.5% for coal.

Table 4.5 contains additional details for fuel costs.

Table 4.5 Operational Costs, Fuel

Fuel Type	Cost of Fuel, \$/MBtu	Cost per 10,000 lb H ₂ O evap. @ 212°F (4)	Cost per Hour, 5175 lb/hr H ₂ O evap. @ 212°F (4)
UE3 DUC ¹	\$ 47.28	\$ 530.67	\$ 274.62
Ill. 6 FPC ²	3.15	35.36	18.30
Propane ³	6.31	72.67	37.61
Natural Gas ³	4.50	51.83	26.82

Notes:

1. Energy International 1990 estimate
2. UTSI estimate (see Table 4.2)
3. Current price at UTSI
4. 84.3% boiler efficiency assumed for natural gas and propane, 86.5% efficiency for coal

4.4 Analysis of Cost Savings With UTSI FPC-Fuel Over 10-Year Period After Retrofit

The economic analysis presents a consistent picture predicting excellent economics with UTSI FPC for all of the retrofits scenarios examined with only the 200 BHp natural gas retrofit returning small or marginal savings. Therefore, a retrofit coal price of \$3.15 per million Btu (i.e. a cost \$1.35 LESS than natural gas as provided by the \$3.15/MBtu UTSI FPC) is approximately the maximum for a reasonable commercial potential with the high combustion and boiler efficiencies demonstrated by the UTSI retrofit system with dry coals. This current value of \$3.15/MBtu is suggested as a goal to achieve or exceed before commercialization is feasible. It is not likely that ultra-fine coal can drop to this level from the 1990 Energy International prediction of \$47.28/MBtu! Also, the reduced long-term combustion and

boiler efficiencies associated with all coal-water fuels would require prices <\$3.15 for CWF on a \$/MBtu basis! In conclusion, successful commercialization depends on a present fuel cost $\leq$ \$3.15/MBtu and high combustion and boiler efficiencies combined with low costs for retrofit and operation.

The UTSI advanced-combustor retrofit combined with UTSI FPC fuel offer a unique potential for commercialization.

Table 4.6 and Table 4.7 contain detailed results of an economic analysis using two approaches, IRR and MIRR calculated percentages.

The internal rate of return ("IRR", EXCEL spreadsheet function) calculation commonly is used to compare one investment opportunity with another. It compares the cost of an investment with the present values of the expected inflows over a period of time. Two IRR calculations were made in order to show the influence of a complete pay back of the loan plus 10% annual interest in equal annual payments over a ten year period. Figure 4.3 presents the IRR results in terms of "predicted interest-rates to be received" for several retrofit scenarios and time periods. Results of the IRR calculations after subtracting the loan pay back are illustrated in Figure 4.4.

The modified internal rate of return ("MIRR", EXCEL spreadsheet function) reported in Tables 4.6 and 4.7 is similar to the IRR. The difference is that the MIRR takes into account the cost of the interest on the loan and the interest on the cash inflows, assuming reinvestment of the latter. The loan interest was input as 10% and the reinvestment interest was input as 8% for these calculations.

**Table 4.6 Predicted Interest Rates (Cost Savings) to be
Received for Various Retrofits**

Illinois #6 replacing propane as fuel:

	200 BHp Retrofit (\$134,200 investment)			600 BHp Retrofit (\$235,067 investment)		
Year	Annual savings	MIRR %	IRR %	Annual Savings	MIRR %	IRR %
1	\$74,220	-44.7	-44.7	\$222,661	-5.3	-5.3
2	74,220	7.3	7.0	222,661	40.4	55.6
3	74,200	21.5	30.3	222,661	45.4	77.9
4	74,200	25.6	41.5	222,661	43.7	87.0
5	74,200	26.5	47.3	222,661	40.9	91.0
6	74,200	26.3	50.6	222,661	38.1	92.9
7	74,200	25.6	52.4	222,661	35.7	93.8
8	74,200	24.8	53.5	222,661	33.5	94.3
9	74,200	24.0	54.2	222,661	31.6	94.5
10	74,200	23.1	54.6	222,661	29.9	94.6

Note: IRR calculation assumes no loan and full salvage value. MIRR calculated with 10% finance rate and 8% reinvestment rate.

**Table 4.6
(Continued)**

Illinois #6 replacing natural gas as fuel:

	200- BHp Retrofit (\$134,200 investment)			600 BHp Retrofit (\$235,067 invested)		
Year	Annual savings	MIRR %	IRR %	Annual Savings	MIRR %	IRR %
1	\$31,070	-76.9	-76.9	\$93,210	-60.4	-60.4
2	31,070	-30.6	-38.9	93,210	-9.2	-14.2
3	31,700	-9.1	-16.2	93,210	8.8	9.2
4	31,070	1.1	-3.0	93,210	15.6	21.4
5	31,070	6.3	5.1	93,210	18.4	28.2
6	31,070	9.2	10.3	93,210	19.5	32.2
7	31,070	10.9	13.8	93,210	19.8	34.7
8	31,070	11.9	16.2	93,210	19.7	36.3
9	31,070	12.5	17.9	93,210	19.5	37.4
10	31,070	12.9	19.1	93,210	19.1	38.1

Note: IRR calculation assumes no loan and full salvage value. MIRR calculated with 10% finance rate and 8% reinvestment rate.

Table 4.7 Predicted Interest Rates (Cost Savings less 10-Year Loan Principal & Interest) to be Received for Various Retrofits

Illinois #6 replacing propane as fuel:

	200 BHp Retrofit (\$134,200 investment)			600 BHp Retrofit (\$235,067 investment)		
Year	Annual savings less annual cost of loan	MIRR %	IRR %	Annual savings less annual cost of loan	MIRR %	IRR %
1	\$52,944	-60.6	-60.6	\$185,389	-21.1	-21.1
2	52,944	-9.4	-14.4	185,389	28.1	36.6
3	52,944	8.6	8.9	185,389	36.8	59.4
4	52,944	15.5	21.1	185,389	37.3	69.3
5	52,944	18.3	27.9	185,389	35.9	73.9
6	52,944	19.4	32.0	185,389	34.0	76.2
7	52,944	19.7	34.5	185,389	32.2	77.4
8	52,944	19.6	36.1	185,389	30.5	78.1
9	52,944	19.4	37.2	189,389	28.9	78.4
10	52,944	19.0	37.8	189,389	27.6	78.6

Notes: Annual cost of 10-year \$134,200 loan at 10% is \$21,276. Annual cost of \$235,067 loan is \$37,272.

IRR calculation assumes 10% loan and 100% salvage value. MIRR calculated with 10% finance rate and 8% reinvestment rate.

**Table 4.7
(Continued)**

Illinois #6 replacing natural gas as fuel:

	200 BHp Retrofit (\$134,200 investment)			600 BHp Retrofit (\$235,067 investment)		
Year	Annual savings less annual cost of loan	MIRR %	IRR %	Annual savings less annual cost of loan	MIRR %	IRR %
1	\$9794	-92.7	-92.7	\$55,938	-76.2	-76.2
2	9794	-61.0	-69.1	55,938	-29.7	-37.9
3	9794	-38.1	-49.6	55,938	-8.2	-15.3
4	9794	-24.3	-35.9	55,938	1.8	-1.9
5	9794	-15.6	-26.3	55,938	6.9	6.1
6	9794	-9.9	-19.5	55,938	9.7	11.2
7	9794	-5.9	-14.4	55,938	11.4	14.7
8	9794	-3.1	-10.6	55,938	12.3	17.0
9	9794	-1.0	-7.7	55,938	12.9	18.7
10	9794	0.6	-5.4	55,938	13.2	19.9

Notes: Annual cost of 10-year \$134,200 loan at 10% is \$21,276. Annual cost of \$235,067 loan is \$37,272.

IRR calculation assumes 10% loan and 100% salvage value. MIRR calculated with 10% finance rate and 8% reinvestment rate.

Figure 4.3 Predicted Interest-Rates (Retrofit-Cost Savings) to be Received for Various Retrofits & Investment-Periods

Figure 4.4 Predicted Interest-Rates (Retrofit-Cost Savings Minus 10-Year Loan Principal & Interest) to be Received for Various Retrofits & Investment-Periods

5.0 COMMERCIALIZATION PLAN

5.1 Introduction

As discussed earlier, results of testing with a commercial 200 BHp firetube boiler show that the pre-commercial version of the UTSI retrofit system has the potential to be developed into a successful commercial design. Additional work is necessary to bring the present UTSI retrofit system to the point of commercialization. Following this, commercialization itself will involve multiple activities.

Several potential patents and trademarks might result from this program. A partial listing of these includes FineFuel, InnerJet, RoScrape, RoJet, SmartAir, and PulseFlow. These items are included in Table 5.1 later in this section with enough detail to provide an understanding of their uses.

We assume that in a commercial situation, coal will be dried and suitably pulverized at a central location and FineFuel will be delivered to the individual boiler retrofit site(s). A boiler site will not have a pulverizer. Additionally, ash will be removed from the retrofit site for disposal by the prepared-coal supplier.

5.2 Overview

The first part of the plan is to conduct pre-commercialization activities that are necessary to resolve any problems associated with operation and control of ash deposits. There will be some equipment modifications and additions to automate operation, improve economics, assure safety, and avoid forced outages in the future. Following this, a 100-hour test is planned to demonstrate commercial-quality performance and confirm more details of the economics at the UTSI site using the upgraded retrofit of the 200 BHp Cleaver-Brooks firetube boiler.

The second part of the plan is to conduct a one-year test at a commercial site with UTSI and a major manufacturer of firetube boilers, like Cleaver-Brooks, working together to demonstrate the long-term achievement of the level of automation, safety, environmentally-clean operation, reliability, and cost effectiveness associated with commercial boilers and to provide technology transfer. In addition, UTSI would work with CQ Inc. in order to help to establish an effective commercial supplier of highly economical, finely-pulverized fuel with concurrent removal of fly ash. An architect-engineering firm would round out the team membership. The target of this combined effort is to produce steam at a cost per pound that is significantly lower than that produced in the same boiler by natural gas, propane, heating oil, coal-water fuel, or ultra-fine dry coal (DUC). A 600 BHp firetube boiler would be an ideal test site. In order to cover the significant costs associated with this commercialization plan, contract-support is necessary. **The only identifiable near-term source is a contract associated with the FY-86 Defense Appropriations Act that contained Congressional direction for the Department of Defense by 1994 to increase its use of coal at facilities in the U.S. by 1.6 million tons per year.**

The third part of the plan is to supply retrofits for burning finely-pulverized coal to the multitude of Cleaver-Brooks firetube boilers currently installed at DOD facilities. Also watertube boiler retrofits would be initiated.

The fourth part of the plan would take place when and if civilian commercial and industrial users decided to burn coal for cost savings or to reduce dependence upon

foreign oil supplies and availability. In this phase, retrofits would be the major activity, but new coal-capable boilers could be manufactured. In all phases of the plan, multi-fuel capability would be retained for optimum versatility.

UTSI and CQ Inc. are ready to proceed with the plan. Cleaver-Brooks currently is evaluating the situation. The following two sections further explain the status of the interaction with Cleaver-Brooks and the DOD broad agency announcement.

5.3 Cleaver-Brooks Visits to UTSI Test Site

The test boiler for this advanced-combustor DOE contract was manufactured by Cleaver-Brooks and is typical of a very large installed base of firetube boilers.

Cleaver-Brooks is the world's leading producer of packaged boilers, including 16 gas- and/or oil-fired firetube designs with capacities from 15 through 800 BHp (518 through 27,600 pounds H₂O evap. per hr [212°F]) that perform with high efficiency. Additionally, Cleaver-Brooks gas- or oil-fired watertube steam boilers are available in 19 models, and their sizes range from nominal steam capacities of 15 to 78 thousand pounds of steam per hour. Cleaver-Brooks offers the industry's finest parts facilities and factory starting service coast to coast and in Canada. They represent a valuable link to commercialization.

Mr. James Oakley, Executive Vice President of Boiler Supply Company of Nashville, a major distributor of Cleaver-Brooks boilers visited the UTSI test site on March 21, 1991 to review our progress. He made very positive comments about the simplicity and compactness of the coal conversion arrangement (almost as easy as burning number 2 oil), the simplicity of the coal delivery system, the usefulness of the air-flow control arrangement using a speed controller on Cleaver Brook's fan in lieu of

the factory-supplied dampers, the use of an automotive oxygen sensor to set excess air automatically, the close control of excess air over the whole firing range, whether on propane or coal, the fact that standard off-the-shelf refractory material is used in the burner construction, and the low-NO_x burner performance demonstrated with propane. Also he indicated that he was quite impressed with a number of features we have implemented with propane and the fact that we have achieved low emissions of NO_x and CO, with high carbon burnout on a wide range of fuels, combined with high boiler efficiency, over a range of boiler heat inputs without flue gas recirculation, increased excess air, etc.

Commercialization efforts continued with a visit to UTSI on May 1, 1991 by Mr. Charles W. Ebbert, Product Manager for Rotary Kiln Thermal Processing of Cleaver-Brooks Boiler Co., and Mr. Oakley. A presentation giving an overview of the project and a performance demonstration of the boiler system were provided for these visitors, and were very well received. Discussions were held concerning possible commercial application of the retrofit system by Cleaver-Brooks. Mr. Ebbert indicated he would present the information gained during his visit to Cleaver-Brooks upper management, and **said that a decision to pursue commercialization of the system would depend on a determination of whether or not a reasonable chance exists that there will be a market for small scale coal-fired boilers within the next 10 years.**

Mr. Oakley stated that coal (fuel) economics will have the most important impact on future commercialization. The market for boiler retrofits for coal firing will not develop unless the infrastructure is in

place to make and deliver suitable coal fuels to the users at commercially-competitive prices.

5.4 Opportunity for Initial Commercial Demonstration

The FY 86 Defense Appropriations Act contained Congressional direction for the Department of Defense by 1994 to increase its use of coal at facilities in the U.S. by 1.6 million tons per year represents an opportunity for commercial demonstration. Cleaver-Brooks firetube boilers collectively represent a major segment of installed capacity at targeted DOD sites.

This is a unique opportunity to initiate commercialization via:

- retrofit of a typical Cleaver-Brooks firetube boiler at a DOD site using economical FPC-fuel to be produced by UTSI/CQ Inc., and
- demonstration of commercial performance over a period of approximately one year.

In July 1991 Mr. Richard Attig, Manager of the Fuels and Environmental Department at UTSI talked with Mr. John Plant, President of Cleaver-Brooks Division (CB) of Aqua-Chem, Inc., relative to CB becoming a proposal-team member and responding to the *Coal Utilization Center Broad Agency Announcement (BAA), Ref. Sol. DAAL03-91-R-BAA3, U.S. Army Research Office, Triangle Park, N.C.* Before an agreement could be arranged, the proposal preparation activity was halted because the solicitation was withdrawn and canceled in its entirety! Since then, we have learned that the responsibility for reissue of the opportunity will be transferred to DOE from DOA/DOD. Interactions between UTSI and Cleaver-Brooks will begin again after the new RFP is issued.

CQ Inc., EPRI's first subsidiary, maintains the former Coal Quality Development Center (CQDC) research and development programs for EPRI, DOE and state agencies. Currently CQ Inc. is well known for providing technology for preparing clean fuels, conducting proprietary for-profit research for utilities, manufacturers, coal companies and other private customers, and is an active participant in the current DOE Clean Coals Program.

For transport of fuel and return of fly ash, the approach could be as follows:

Dry pulverized coal delivery and dry ash removal/disposal would be safe and very convenient using commercial equipment (25 to 33-ton road tankers and 55-ton coal-powder rail cars) currently employed in Europe, in particular in Germany (formerly the Federal Republic of Germany), Sweden, and the UK. A good safety record has been reported, even for applications in Germany which include the highly-reactive dried lignite pulverized fuel. Inerting and air tight, inlet slide-valves are used frequently, and CO blanketing and temperature monitoring are virtually standard procedures. Air is used for pneumatic unloading for delivery.

Typical boiler-site pulverized coal-powder storage silos have capacities in the 80 to 950 cubic meter range (2,825 to 33,549 cubic feet), and the bulk density of the coal powder is about 600 kilograms per cubic meter (37.5 pounds per cubic foot). For smaller applications, UTSI has demonstrated successful use of 1800-pound capacity bulk bags for storing and unloading both ultra-fine and finely-pulverized coals, with bulk densities typically in the range between 30 and 40 pounds per cubic foot (481 to 641 kilograms per cubic meter).

5.5. Detailed Plan and Schedule

Our detailed plan for commercialization is presented in the multi-paged Table 5.1. (Please note that each page has the same set of columns as those identified on the first of the pages). Individual activities are identified along with their classification as “Pre-Commercialization” or “Commercialization”. Also included is a description of the corresponding problem that is addressed, a scheduled starting month number, a scheduled duration period in elapsed working days (not actual work hours), and the organizations most likely to be involved because of their previous interests and activities. At this stage, this UTSI-prepared plan and the corresponding schedule have not been submitted to the individual organizations and therefore should not be interpreted as an indication of their commitments to specific activities at specific times.

This commercialization plan is designed to reduce commercial risk, yet provide a marketable product in a reasonable amount of time. It simultaneously develops the retrofit system and the structure for a centralized fuel supply.

Details of the schedule are shown in Figure 5.1.

It is very important to start these activities this calendar year so a timely interface is possible with the DOD retrofits and the Congressional mandate.

Table 5.1 Detailed Plan for Commercialization

Problem Addressed	Pre-Com-mer-cial-iza-tion	Com-mer-cial-iza-tion	Activity Description	Schedule: Starting Month #	Schedule: Duration in Elapsed Work Days	Organi-zations
<i>1. Deposit:</i> Control slag buildup around deep-staging air jets and in main firetube	√		Add pass 1 blower lance with rotary scraping and central plus tangential blowing action (UTSI RoJet).	0.5	30	UTSI & Cleaver-Brooks
<i>2. Deposit:</i> Eliminate refractory wall deposits in endbell & control tube sheet deposits. Remove long-term build up of bottom ash.	√		Add deep, water-cooled endbell with no refractory to reduce deposit temperature, plus reduce gas temperature and velocity. Integrate endbell hot water into boiler circuitry. Add ash hopper to deep endbell.	0.5	45	UTSI & Cleaver-Brooks
<i>3. Deposit:</i> Remove long-term build up of bottom ash	√		Add ash hopper to endbell at pass 2-3 turnaround.	0.5	20	UTSI & Cleaver-Brooks
<i>4. Operation:</i> Prevent coal-flow interruption or line blockage and minimize fuel and operating costs. Prove that FineFuel can be produced, delivered, loaded, and burned without problems produced by extraneous contaminants such as fibers, wood chips, and grossly-oversized coal particles that were present in DUC fuel previous produced by other DOE contractors for the UTSI tests.	√		Make 200 hours worth of economical UTSI FineFuel for UTSI testing using ≈2.4% ash UE3. (41 tons total for 200 6-MBtu operating hours or 16.4 pulverizing hours @ 5,000 lb/h average or ≈46 1,800-lb bulk bags) Half of the coal to be processed at CQ Inc., and the other half to be processed at the UTSI facility. CQ Inc. also would make four 1,800 lb bulk bags of Custom Coals International's Self-Scrubbing Coal/Carefree Coal using UTSI FineFuel particle size distribution specifications.	1	60	UTSI, CQ Inc. & Custom Coals International
<i>5. Operation:</i> Prevent coal-flow interruption or line blockage	√		Upgrade fuel system in the following areas: • improve fluidizing at bottom of feed tank to avoid creating a local partial vacuum • add commercial automatic bulk bag unloader with screen, and • add bucket elevator for loading feed bin.	1	80	UTSI & commercial component suppliers
<i>6. Operation:</i> Upgrade performance of baghouse.	√		Add new, higher-performance bags to meet 1987 or future utility boiler NSPS particulate emission rules. Add ID fan downstream from the baghouse.	1.5	40	UTSI & commercial component suppliers

Table 5.1
(Continued)

7. <i>Operation:</i> Eliminate need for manually setting fuel & air flows based on a requirement of current knowledge of as-fired Btu/lb of fuel. Automate controls for steam flow demands.	√		Use combustion air control (not fuel rate) as primary variable for firing rate automation with artificial intelligence (UTSI SmartAir). This eliminates needing to know about real-time variations in moisture and ash in the coal fuel, and provides a known Btu input control. Also SmartAir could link real-time efficiency to steam flow demands using neural network techniques.	2	60	UTSI & Cleaver-Brooks
8. <i>Operation:</i> Demonstrate advanced NO _x emissions reduction configuration for the advanced combustor.	√		Add reburning capability. Goal is to confirm operation near 0.3 lb NO _x per million Btu total thermal input is possible.	2	50	UTSI & Cleaver-Brooks
9. <i>Deposit & Operation:</i> Observe left half of tubesheet at entrance to pass 2	√		Add sight port to left side. Study deposition and ash removal in real time.	2	5	UTSI
10. <i>Deposit:</i> Control water-cooled wall & tube sheet deposits	√		Add two UTSI RoScrape devices to left side of pass 1-2 turnaround area.	2	10	UTSI & Cleaver-Brooks
11. <i>Deposit:</i> Observe deposit control in the main firetube	√		Add centerline port for viewing tubesheet at pass 2 entrance and for viewing the pass 1 firetube including the secondary air jets.	3	5	UTSI
12. <i>Deposit:</i> Observe deposits & deposit control in better detail than presently possible with frequently optically-thick combustion gases	√		Add: • IR viewing and photo capability through optically-thick combustion gases • temperature mapping, emissivity mapping • deposit shape/location mapping, and • state-of-the-art evaluation of ash removal efficiency.	5	60	UTSI & Diamond Power
13. <i>Deposit & Operation:</i> Check out individual modifications & additions. Demonstrate correct short-term functioning of system improvements.	√		Conduct series of short tests with UTSI 200 BHp retrofitted Cleaver-Brooks firetube boiler.	8	20	UTSI & Cleaver-Brooks
14. <i>Demonstrate POC:</i> Eliminate forced outages.	√		Conduct 100-hour demonstration with UTSI 200 BHp retrofitted Cleaver-Brooks firetube boiler. Measure potential for wear, abrasion, erosion, & corrosion.	10	20	UTSI & Cleaver-Brooks

Table 5.1
(Continued)

15. <i>Operation:</i> Demonstrate commercially available & affordable fuel delivery and ash removal service.	√		Deliver fuel and remove ash for 200 BHp demonstration. Make economic evaluation and commercialization plan for FineFuel.	9	24	UTSI & CQ Inc.
16. <i>Economics & Commercialization:</i> Demonstrate that a larger commercial retrofit is justified.	√		Evaluate 200 BHp results and predict 600 BHp commercial site values. Perform economic analysis for a retrofitted boiler firing coal vs. natural gas, propane, or fuel oil. Consider lower operating costs for fan power (due to variable speed drive) and fuel savings because of lower excess air, etc.	11	20	UTSI, Cleaver-Brooks, Diamond Power & CQ Inc.
17. <i>Operation:</i> Eliminate need for manual deposit removal.		√	Automate operation of UTSI RoScrape, InnerJet & RoJet ash deposit control equipment. Evaluate commercial potential for the UTSI devices.	12	80	UTSI, Cleaver-Brooks & Diamond Power
18. <i>Make First Commercial Retrofit:</i> Provide initial action to support congressional direction for DOD to increase its use of coal by 1994 at facilities in the U.S. by 1.6 million tons per year.		√	Design and install retrofit for 600 BHp Cleaver-Brooks firetube boiler at DOD site.	16	180	UTSI, Cleaver-Brooks, Diamond Power & AE Firm
19. <i>Prove Commercial Feasibility:</i> Operate a retrofitted firetube boiler up to approximately one year under commercial conditions.		√	Conduct 1,000+ hour demonstration at DOD site with DOD operators (up to one year, or even as long as 10,000 hours). Measure wear, abrasion, erosion, & corrosion. Make detailed performance & economic analysis and commercialization plan.	27	100 to 500	UTSI, DOD, Cleaver-Brooks, CQ Inc. & AE Firm
20. <i>Operation:</i> Demonstrate commercially available fuel preparation, distribution, fuel delivery and ash removal service.		√	Deliver fuel and remove ash for 600 BHp demonstration. Make economic evaluation and FineFuel commercialization plan.	26	118 to 500	UTSI & CQ Inc.

Table 5.1
(Continued)

21. <i>Operation:</i> Increase burner turndown ratio, promote more rapid mixing of fuel and air, improve combustion efficiency, and reduce NO _x emissions. Also prevent coal-flow interruption or line blockage over a wider range of flow rates.		√	Develop a pulsed eductor [pulsed transport air with variable controlled duty cycle (on/off ratio) like SCR square-wave form] for lower coal mass flow rates, much higher turn down ratios, for more rapid mixing, for lower NO _x , and for higher carbon burnout (UTSI PulseFlow). This approach should not require a modification of the shape of the advanced combustor nor the addition of a silencer (muffler).	34	200	UTSI & Cleaver-Brooks
22. <i>Commercialization:</i> Provide significant support for congressional direction for DOD to increase its use of coal at facilities in the U.S. by 1.6 million tons per year.		√	Retrofit the multitude of firetube boilers currently installed at DOD facilities.	34	2 to 4 years or more	Cleaver-Brooks & UTSI
23. <i>Commercialization:</i> Retrofit firetube boilers for civilian commercial and industrial users.		√	Retrofit firetube boilers at civilian sites.	34 to 45	Continuing	Cleaver-Brooks
24. <i>Make First Commercial Watertube Retrofits:</i> Provide significant support for congressional direction for DOD to increase its use of coal at facilities in the U.S. by 1.6 million tons per year.		√	Retrofit watertube boilers at DOD facilities. The advanced combustor burner assembly would be OK for external wall mounting. This would leave the internal watertube-furnace volume for even more complete combustion plus time for further lowering of NO _x . This would be a particularly effective arrangement for reburning with very low NO _x emissions.	34	2 to 4 years or more	Cleaver-Brooks, other boiler manufacturers & UTSI
25. <i>Commercialization:</i> Retrofit watertube boilers for civilian commercial and industrial users.		√	Retrofit watertube boilers at civilian sites.	34 to 45	Continuing	Cleaver-Brooks, other boiler manufacturers & UTSI

Milestone Schedule and Status Report

1. Contract Identification ADVANCED COMBUSTION SYSTEM		2. Reporting Period		3. Contract Number	
4. Contractor: Name, Address THE UNIVERSITY OF TENNESSEE SPACE INSTITUTE TULLAHOMA, TENNESSEE 37388		5. Contract Start Date SEPTEMBER 1, 1992		6. Contract Completion Date	

7. ID	ACTIVITY	MONTHS FROM CONTRACT START																																										
		CY 93												CY 94												CY 94																		
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38					
1	Add pass 1 blower lance with rotary scraping and central ...	■	■																																									
2	Add deep, water-cooled endbell with no refractory to ...	■	■	■																																								
3	Add ash hopper to endbell at pass 2-3 turnaround.	■	■																																									
4	Make 200 hours worth of economical UTSI FineFuel ...		■	■	■	■																																						
5	Upgrade fuel system in the following areas: • improve ...		■	■	■	■	■																																					
6	Add new, higher-performance bags to meet 1987 or ...		■	■	■																																							
7	Use combustion air control (not fuel rate) as primary ...		■	■	■	■	■																																					
8	Add reburning capability. Goal is to confirm operation ...		■	■	■	■																																						
9	Add sight port to left side. Study deposition and ash ...		■																																									
10	Add two UTSI RoScrape devices to left side of pass ...		■																																									
11	Add centerline port for viewing tubesheet at pass 2 ...			■																																								
12	Add: •IR viewing and photo capability through optically ...					■	■	■	■																																			
13	Conduct series of short tests with UTSI 200 BHp ...								■	■																																		
14	Conduct 100-hr demonstration with UTSI 200 BHp ...									■	■																																	
15	Deliver fuel and remove ash for 200 BHp demonstration ...										■	■																																
16	Evaluate 200 BHp results and predict 600 BHp ...											■	■																															
17	Automate operation of UTSI RoScrape, InnerJet &												■	■	■	■																												
18	Design and install retrofit for 600 BHp Cleaver-Brooks ...													■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	
19	Conduct, 1,000+hour demonstration at DOD site with ...																																											
20	Deliver fuel and remove ash for 600 BHp demonstration ...																																											
21	Develop a pulsed educator [pulsed transport air with ...																																											
22	Retrofit the multitude of firetube boilers currently ...																																											
23	Retrofit firetube boilers at civilian sites.																																											
24	Retrofit watertube boilers at DOD facilities. The ...																																											
25	Retrofit watertube boilers at civilian sites.																																											

11. Remarks:

12. Signature of Contractor's Project Manager & Date

13. Signature of Government Representative & Date

Figure 5.1 Schedule for Commercialization (Refer to Table 5.1 for complete description of individual activities)

6.0 CONCLUSIONS

- **The detailed commercialization plan identifies an approach that could lead to an automated, marketable product for retrofitting a significant number of firetube and watertube boilers and establishing an off-site commercial supplier of economical, finely-pulverized coal. With this plan, resolution of ash deposition and fuel-flow interruption issues could be accomplished via suggested equipment additions and improvements. Reliability would be established during a 100-hour demonstration with the 200 BHp Cleaver-Brooks firetube boiler at UTSI, followed by a 1,000 to 10,000-hour demonstration at a DOD (or other suitable) site with a 600 BHp firetube boiler. The planned addition of higher-performance bags should reduce particulate emissions to less than 0.03 pounds per million Btu. The planned reburning tests could prove that long-term NO_x emissions near 0.3 pounds per million Btu or lower are attainable for future, more stringent applications. A brief test planned with Custom Coals International's Self-Scrubbing Coal/Carefree Coal could show that SO₂ emissions can be reduced in a firetube boiler when using a modified particle size distribution with this DOD Fourth Round Clean Coal utility-boiler fuel.**

- The UTSI program has demonstrated the technical and economic feasibility of burning coal in an efficient and environmentally acceptable manner in a firetube boiler
- **UTSI finely-pulverized coal (FineCoal or FPC) with a nominal top size of approximately 425 μ m (0.0167 inches or a No. 40 sieve) potentially is the best choice for commercialization because of the very low fuel-preparation costs that have been demonstrated for FPC and the associated high combustion and boiler efficiencies which are expected, based on the short-term measured performance with Illinois #6 FPC. Additional long-term testing is included in the commercialization plan using a finely-pulverized coal with quality similar to Upper Elkhorn #3 with medium ash content and high ash-fusion temperatures ($\approx$ 2.4 weight percent ash on an as-fired basis and ash-fusion temperatures of 2500°F or higher) to confirm the significant cost-savings predicted using a FPC-coal retrofit vs. original equipment using natural gas, propane, or oil.**
- UTSI long-duration testing has demonstrated the ability to maintain heat transfer during testing to date using UTSI-designed cleaning equipment
- Control of ash deposition is a critical issue. Success of future commercial coal-retrofits will depend on carefully matching equipment design and operation with coal properties.

- Additional long-term testing is included in the commercialization plan to evaluate commercial risk more fully, to be able to assure accurately matching of fuel, boiler design and retrofit details, automated-control algorithms, and system operational details. Although no wear, erosion, abrasion or corrosion has been detected in the boiler low-velocity dense-phase coal transport system or on any fire-side surfaces of the boiler itself, the long-term testing phase would be invaluable for additional evaluation of any potential for wear, etc.
- Successful commercialization depends on a present fuel cost $\leq \$3.15/\text{MBtu}$ (with steam cost $\leq \$35$ per 10,000 pounds of H_2O evaporated at 212°F) and high combustion and boiler efficiencies combined with low costs for retrofit and operation. UTSI finely-pulverized dry coal combined with the UTSI advanced-combustor retrofit will provide these cost and efficiency requirements.
- In order to cover the significant costs associated with this commercialization plan, contract-support is necessary. The only identifiable near-term source is a contract associated with the FY 86 Defense Appropriations Act that contained Congressional direction for the Department of Defense by 1994 to increase its use of coal at facilities in the U.S. by 1.6 million tons per year.

- Coal (fuel) economics will have the most important impact on future commercialization. The market for boiler retrofits for coal firing will not develop unless the infrastructure is in place to make and deliver suitable coal fuels to the users at commercially-competitive prices.

7.0 RECOMMENDATIONS

Additional work is recommended to bring the UTSI coal-conversion system to the point of commercialization as well as for the commercialization effort itself. Specifically, we recommend implementing the detailed plan presented in Table 5.1. As envisioned, this would involve cooperation with DOE, DOD, Cleaver-Brooks, CQ Inc., Custom Coals International, Diamond Power, AE firms, other watertube and firetube boiler manufacturers, and civilian coal-conversion customers. New businesses could result for:

- retrofitting existing boilers or burners or incorporating coal capabilities into new boiler for burner designs,
- servicing the converted or new systems, and
- preparing and supplying finely-pulverized, dried coal to boiler sites and removing coal ash for disposal.

Highlights of the recommended plan are summarized below:

- Resolve fuel-flow interruption issue via application of **UTSI FineFuel** production techniques, plus addition of commercial bulk-bag unloading & screening equipment, plus improvement of the fluidizing air arrangement.
- Resolve ash-deposition issues via additions of improved ash-removal equipment (add two additional **UTSI RoScrapes**, one newly-conceived **UTSI RoJet**, two endbell ash hoppers, and two sight ports) and

eliminate a high-temperature refractory surface and reduce gas temperature & velocity by substituting a deep, water-cooled, steam-circuit-connected endbell on the end of the boiler at the pass 1 to pass 2 turnaround.

- Add higher-performance bags with filter media such as Gore-Tex to **reduce particulate emissions to less than 0.03 pounds per million Btu**, and add ID fan downstream from baghouse.
- Automate boiler controls for **optimum efficiency relative to steam output using an intelligent system with a unique basis for real-time Btu sensing (UTSI SmartAir concept)**. Eliminate need to input data on short-term variations in coal characteristics (as-fired Btu per pound, moisture, ash, etc.)
- Modify burner and test **reburning** with goal of long-term **NO_x emissions near or below 0.3 pounds per million Btu** for future, more stringent applications.
- As a potential **alternative to selecting compliance coals**, test Custom Coals International's **Self-Scrubbing Coal/Carefree Coal** to see if SO₂ emissions can be reduced in a firetube boiler® when using a modified particle size distribution (similar to UTSI FineFuel) with this **DOD Fourth Round Clean Coal** utility-boiler fuel. Also evaluate economics.

Carefree Coal currently is a product at the (utility boiler) demonstration stage that emits less than 1.2 pounds of SO₂ per million Btu. It is

produced using advanced physical coal cleaning with coal/sorbent reconstitution techniques to produce a utility or large industrial boiler fuel.

- Establish details of **long-term performance, reliability and economics** with a 100-hour demonstration using the upgraded retrofit of the 200 BHp Cleaver-Brooks firetube boiler at UTSI fired with UTSI FineFuel, followed by a 1,000 to 10,000-hour demonstration at a DOD (or other suitable) site with a 600 BHp firetube boiler. Also check potential for wear, abrasion, erosion, corrosion, etc.
- **Establish a commercial fuel supplier** for UTSI FineFuel (or equivalent) and **demonstrate long-term fuel delivery and coal-ash removal/disposal** capabilities.

Good coal fuel economics are required for general commercialization, and a commercial fuel source that is dependable, safe and convenient must be available. The infrastructure needed for a commercial coal supply system includes coal processors, coal deliverers, and fly-ash removers.

- **Provide significant support for Congressional mandate to increase use of coal at DOD facilities in the U.S. by 1.6 million tons per year. Prove that the UTSI advanced coal-conversion system combined with UTSI FineFuel is one of the most cost effective ways (\$ per pound of steam) for DOD to use more coal efficiently, safely, conveniently, reliably, and cleanly. Convert firetube and watertube boilers.**

- **Increase dense-phase coal-transport and coal-burner turndown ratios (goal: 4 or 5 to one) using a pulsed eductor (UTSI PulseFlow concept) with variable duty cycle (ratio of motive air on/off time during each pulse cycle). Evaluate potential for improvements in boiler automation and control, carbon-conversion efficiency, and reduction in NO_x emissions with PulseFlow.**
- **Start and continue coal conversions for civilian firetube and watertube boilers.**