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Nucla CFB Demonstration Project

Detailed Public Design Report

Work Performed Under Contract No.: DE-FC21-89MC25137

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
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December 1990

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Revision Record

Original
Project Public Design Report "Draft" submitted — July 1, 1990

Revision 1
Detailed Public Design Report "Camera-Ready Draft" submitted — December 7, 1990

PARTICIPANT'S
PROJECT PUBLIC DESIGN REPORT

Policy Statement

The Project Participant does hereby approve this Project Public Design Report and further designates it as the official document the Project Performer shall use and submit to DOE in accordance with the Cooperative Agreement requirements of the Selected Project in the County of Montrose, State of Colorado.

Raymond E. Keith
Executive Vice President, Operations
Colorado-Ute Electric Association, Inc.

7DEC90
Date

Acknowledgements

President Woodrow Wilson said "I'll use all the brains I have and all the brains I can borrow". This quotation exemplifies the approach used by Colorado-Ute to the Nucla Atmospheric, Circulating Fluidized Bed Combustion Demonstration Project.

The Electric Power Research Institute (EPRI) is gratefully recognized as the principal organization which conducted the testing activities, compiled resulting information and contributed several million dollars to the project. Their electric industry sponsorship and cooperation also provided staffing for the test program and the Detailed Test Plan used to guide the project direction.

The U. S. Department of Energy (DOE), Clean Coal Technology division was another major project contributor. Under Cooperative Agreement (DE-FC21-89MC25137), the 19.9 million dollar contribution provided a significant project milestone. The Morgantown Energy Technology Center administration of the Agreement likewise contributed to the project results.

The Rural Electric Administration (REA) and Cooperative Finance Corporation (CFC) project concurrence and financial support was without doubt an integral part to the project's evolution.

The many organizations which comprise the Technical Advisory Group (TAG Committee), their time and monetary support were likewise invaluable to the project.

The major and minor manufacturers, suppliers and contractors which brought together the talents of so many people to assemble the project.

The financial institutions which supported Colorado-Ute with a project of this nature also must not be forgotten.

Last but hardly least, Colorado-Ute acknowledges its 14 member cooperatives for proceeding with the project. These 14 showed the true spirit of pioneers in technology advancement.

The diverse list of participants above begins to unveil the inherent complexity of such a project which attempts to push back the frontier of knowledge. Information, what is learned, right or wrong, good or bad is the essence of scientific endeavor to improve our world and all that live within it.

This report combines, correlates, refines and presents the information and data with permission which was initially documented in the EPRI series CS-5831. It satisfies the Colorado-Ute requirements under DOE instrument No. DE-FC21-89MC25137.

OVERVIEW

Colorado-Ute Electric Association, Incorporated (CUEA) began a study to evaluate options for upgrading and extending the life of its Nucla power station in 1982 (see Figures 1 and 2). Located in southwestern Colorado, near the town of Nucla, this station was commissioned in 1959 with a local bituminous coal as its design fuel for the three identical stoker-fired units, each rated at 12.6 MW (see Figure 3). Poor station efficiency, high fuel costs, and spiraling boiler maintenance costs forced the Nucla Station into a low priority in the CUEA dispatch order as early as 1981.

Among the options Colorado-Ute (CU) considered was the possibility of becoming a host utility to demonstrate Atmospheric Fluidized Bed Combustion (AFBC) technology. The low environmental effects and attractive economics of a circulating AFBC led to Colorado-Ute's decision to proceed with the design and construction of a demonstration project in 1984 at the Nucla facility.

The company determined that the new circulating AFBC boiler technology would:

- Increase plant capacity from 36 MW to 110 MW for an investment of approximately $840/KW;

- Improve the station heat rate by approximately 15%;

- Reduce fuel costs (approximately 30%) by burning the local area, lower quality coal;

- Reduce emissions to the point where anticipated New Source Performance Standards for SO_2 and NO_x could be met; and

- Extend the plant operating life by approximately 30 years.

Many factors went into Colorado-Ute's decision to proceed with the demonstration project. Among these were two Electric Power Research Institute (EPRI)-sponsored boiler design studies conducted by Combustion Engineering/Lurgi and Pyropower Corporation in late 1983. Both manufacturers submitted firm proposals within six months. In evaluating these, Colorado-Ute:

- Reviewed the design, backup data, and experience base cited by the manufacturers;

- Identified areas of possible technical risk;

- Identified design studies and test programs that could mitigate these risks;

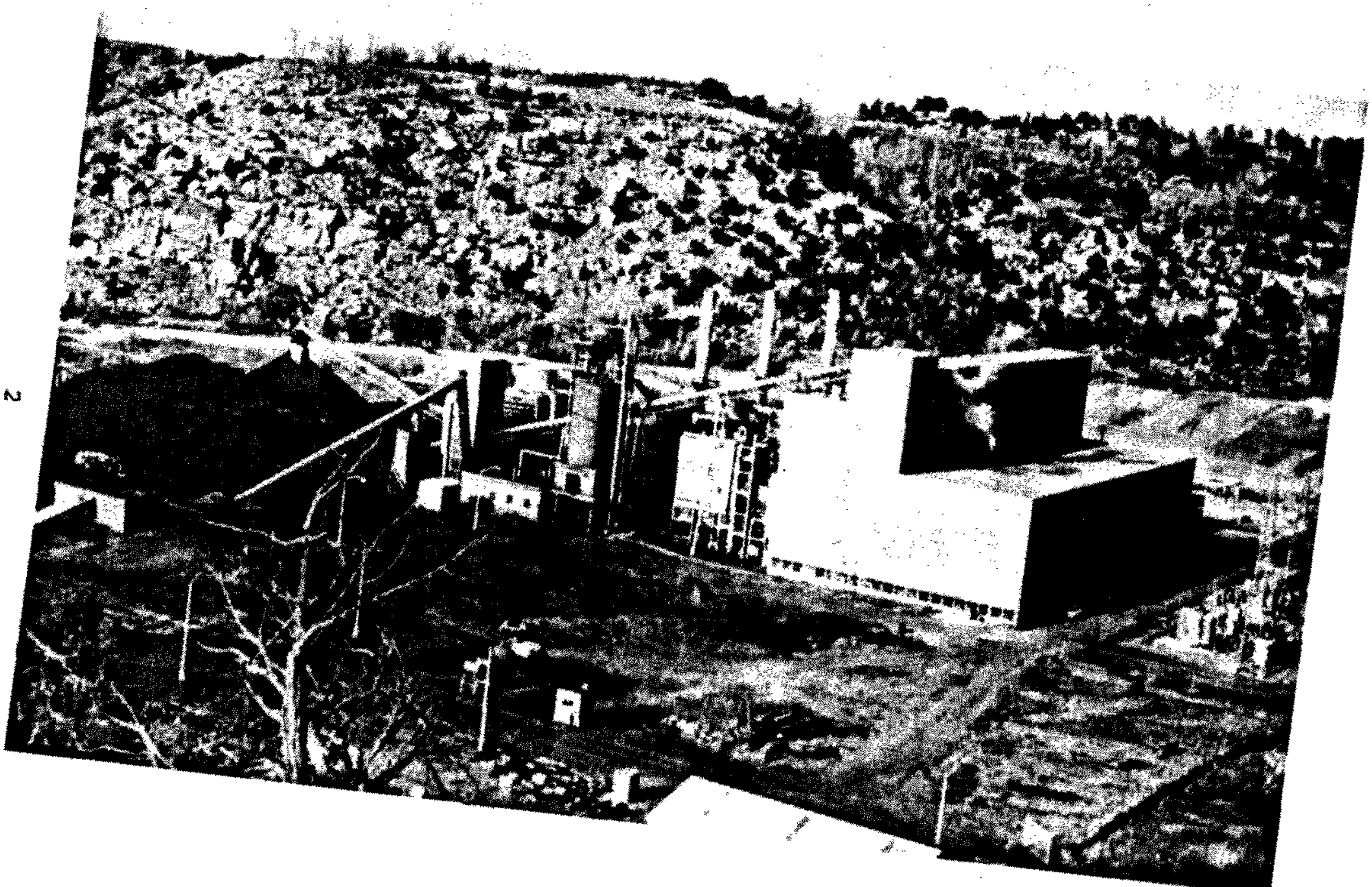


Figure 1. Nucla Station (1983) - View Looking Northwest

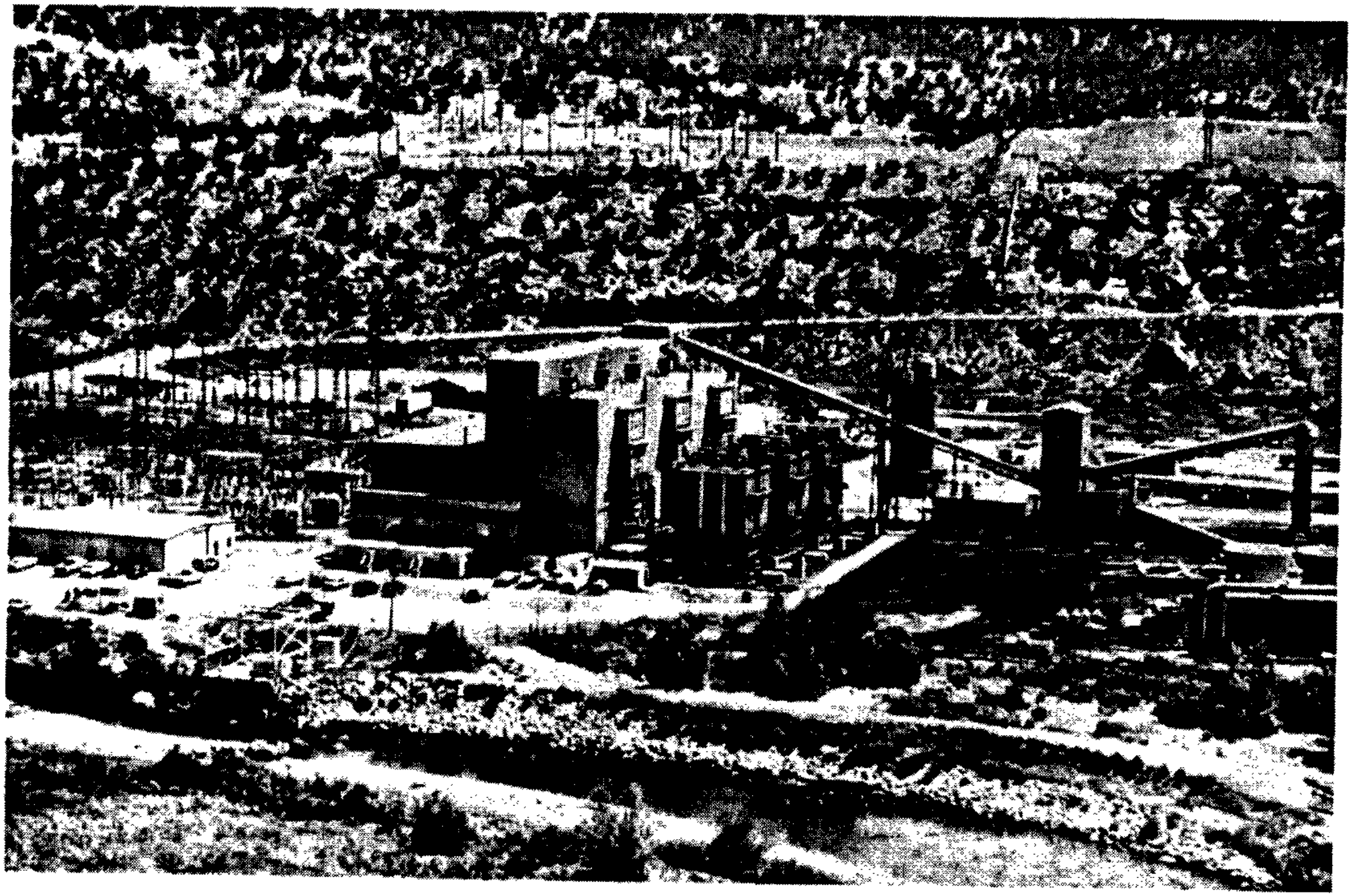


Figure 2. Nucla Station (1985) View Looking South

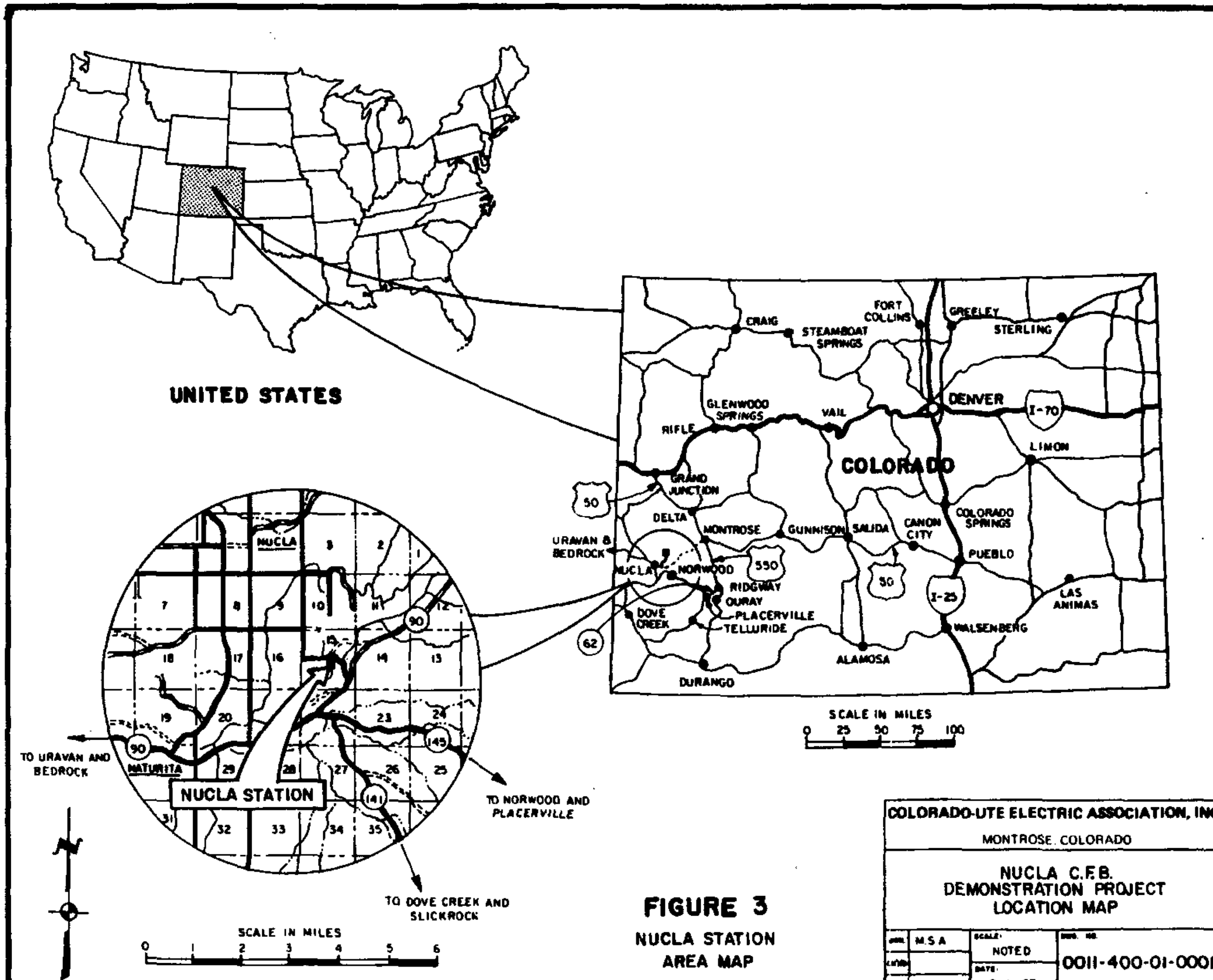


FIGURE 3
NUCLA STATION
AREA MAP

COLORADO-UTE ELECTRIC ASSOCIATION, INC.		
MONTROSE, COLORADO		
NUCLA C.F.B. DEMONSTRATION PROJECT LOCATION MAP		
M.S.A	SCALE: NOTED	DWG. NO. 0011-400-01-0001
	DATE: 6-1-89	

- Developed fallback designs in the event that selected designs did not perform as predicted;

- Assessed the risks to the utility; and

- Developed a strategy for negotiating with the equipment suppliers.

Colorado-Ute judged Pyropower's proposal had a lower combined capital and life-cycle cost, and therefore awarded it the Nucla Station circulating AFBC boiler contract.

Tests of the local Nucla coal and limestone at a small-scale pilot circulating AFBC plant in Finland produced results that enabled further refinement of the design of the boiler and complementary auxiliary equipment.

To reduce the potential technical risks assumed by Colorado-Ute in this first utility-sized circulating AFBC demonstration in the United States:

- The various equipment vendors and the architect/engineer of the project agreed to postpone payments until the unit was operational.

- EPRI funded a two-year test program to characterize performance of the plant, and assumed the risk for non-economical operation during the same period.

In 1984, the National Rural Utilities Cooperative Finance Corporation (CFC) approved a loan for the total project cost of $87 million. Regarding permits and licensing the Rural Electrification Administration (REA) gave its approval on the basis of the borrower's environmental report in a relatively short period of time. This was possible because an environmental impact statement was not required.

The Nucla Circulating AFBC demonstration project consists of in-place retirement of the three stoker-fired boilers and replacement with a new circulating AFBC boiler and balance-of-plant equipment to increase the station's generating capacity from 36 MW to 110 MW. The balance-of-plant equipment includes a new single automatic-extraction turbine-generator unit. The modification and refurbishment of the three existing steam turbine-generator units, addition of coal-handling equipment, a baghouse to the existing plant system, and installation of new limestone-handling equipment rounded out the project. A simplified overall plant layout diagram is presented in Figure 4.

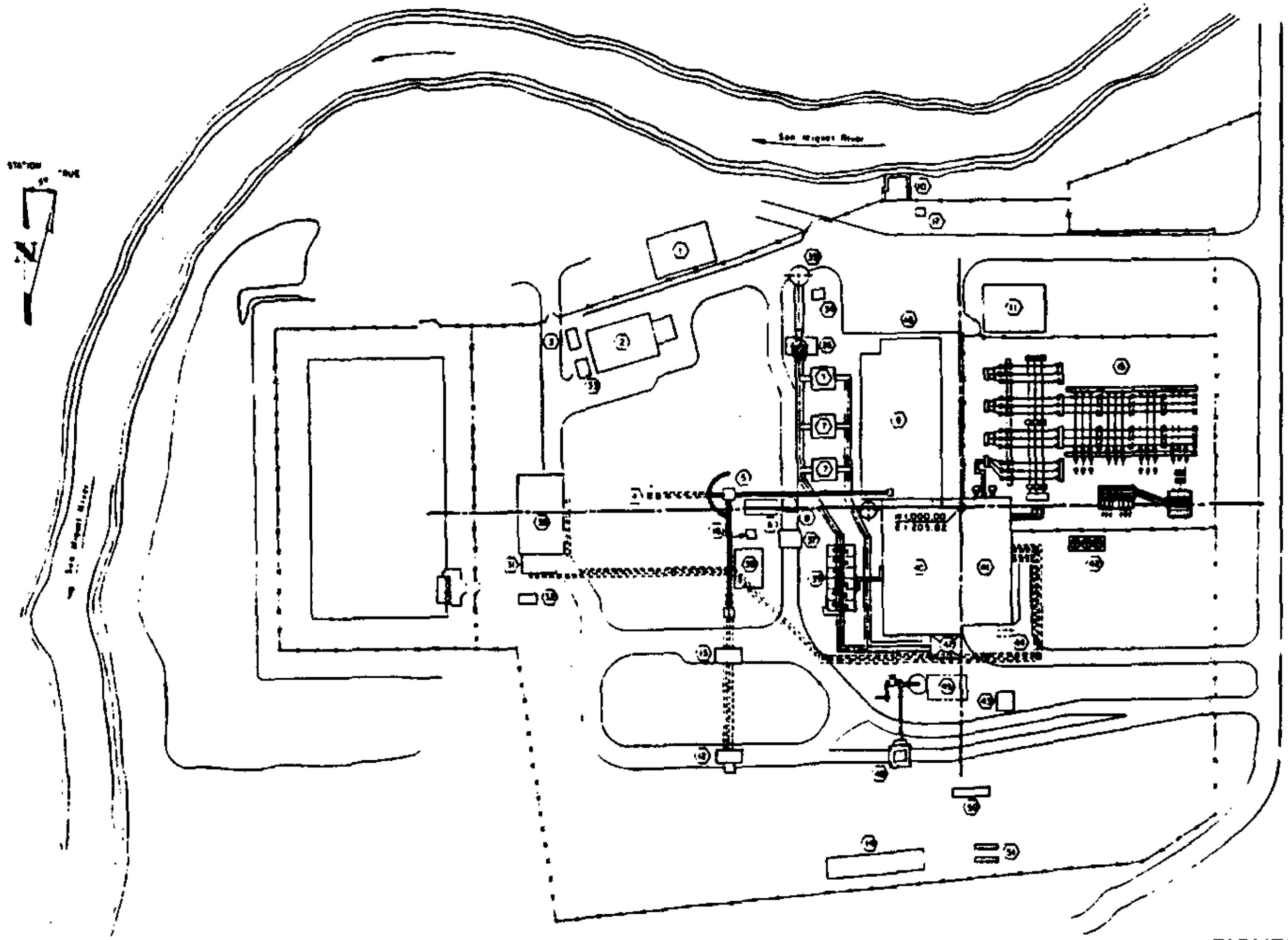


FIGURE 4
NUCLA STATION LAYOUT DIAGRAM

Photographs of the artist's conception, construction and completed Nucla Station facility are presented in Figures 5, 6, 7, 8 and 9.

The new circulating AFBC boiler is rated at 420,000 kg/hr (925,000 lb/hr) capacity with superheat steam conditions of 106 kg/cm^2 and 540°C (1510 psig and 1005°F). The circulating AFBC boiler is approximately four times larger than existing industrial circulating fluidized-bed units. This represents a significant upward sizing step in the use of a new technology that promises lower capital costs and a cleaner, more environmentally acceptable method to burn coal for central station power plants.

Twin combustion chambers and hot cyclones are featured in this circulating AFBC boiler design. The twin combustion chambers were utilized by the boiler manufacturer, Pyropower Corporation, to provide the required amount of waterwall heat transfer area and reduce the sizing scale-up factor. The Nucla boiler combustion chamber and hot cyclone scale-up factors were limited to 2 to 1 (as compared to the boiler manufacturer's largest operating circulating AFBC boiler at design time), thus the use of the twin-system concept. Some other features of the new Nucla circulating AFBC boiler are:

1. Boiler pressure parts, including water-cooled primary air distributor, combustion chambers and convection section of membrane wall construction, superheater sections (including radiant sections located in the top of the combustion chambers), economizer, steam drum and downcomers, desuperheaters (attemperators), and boiler interconnecting piping.

2. Variable-speed controlled induced-draft fan.

3. Combustion air supply, including a variable-speed controlled primary-air fan and a variable-speed controlled secondary-air fan.

4. Bed ash letdown and cooling equipment, including fluid-bed cooler/classifiers, rotary airlock valves, water-cooled screw conveyors, and an ash cooling fan.

5. Coal-feed equipment, including gravimetric feeders and rotary airlock valves.

6. Limestone-feed equipment, including gravimetric feeders, rotary airlock valves, and pneumatic injection.

7. Bed-recycle equipment, including refractory-lined hot cyclones and loop seals, and high-pressure blowers.

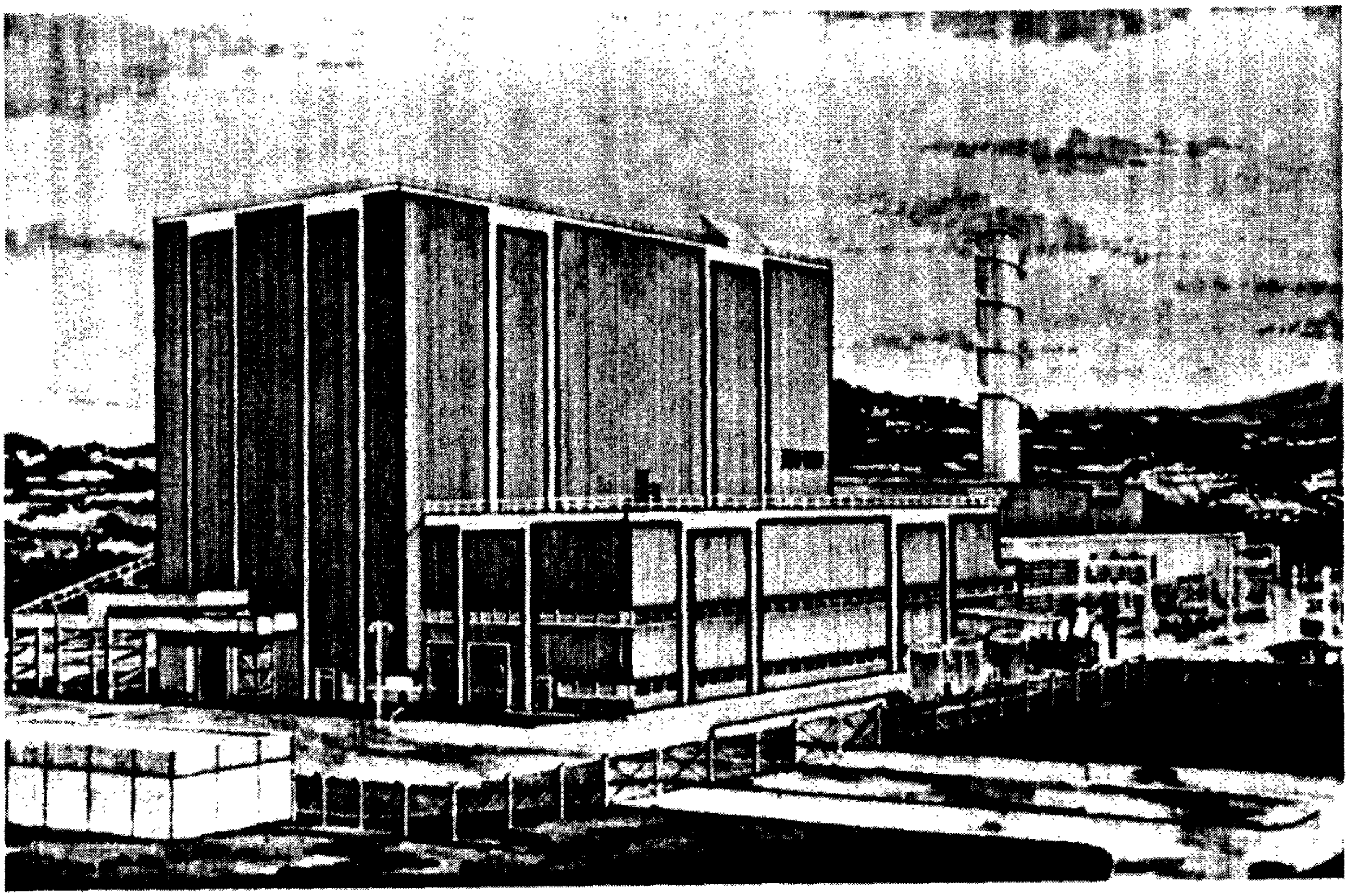


Figure 5. Artist's Conception - Nucla Station

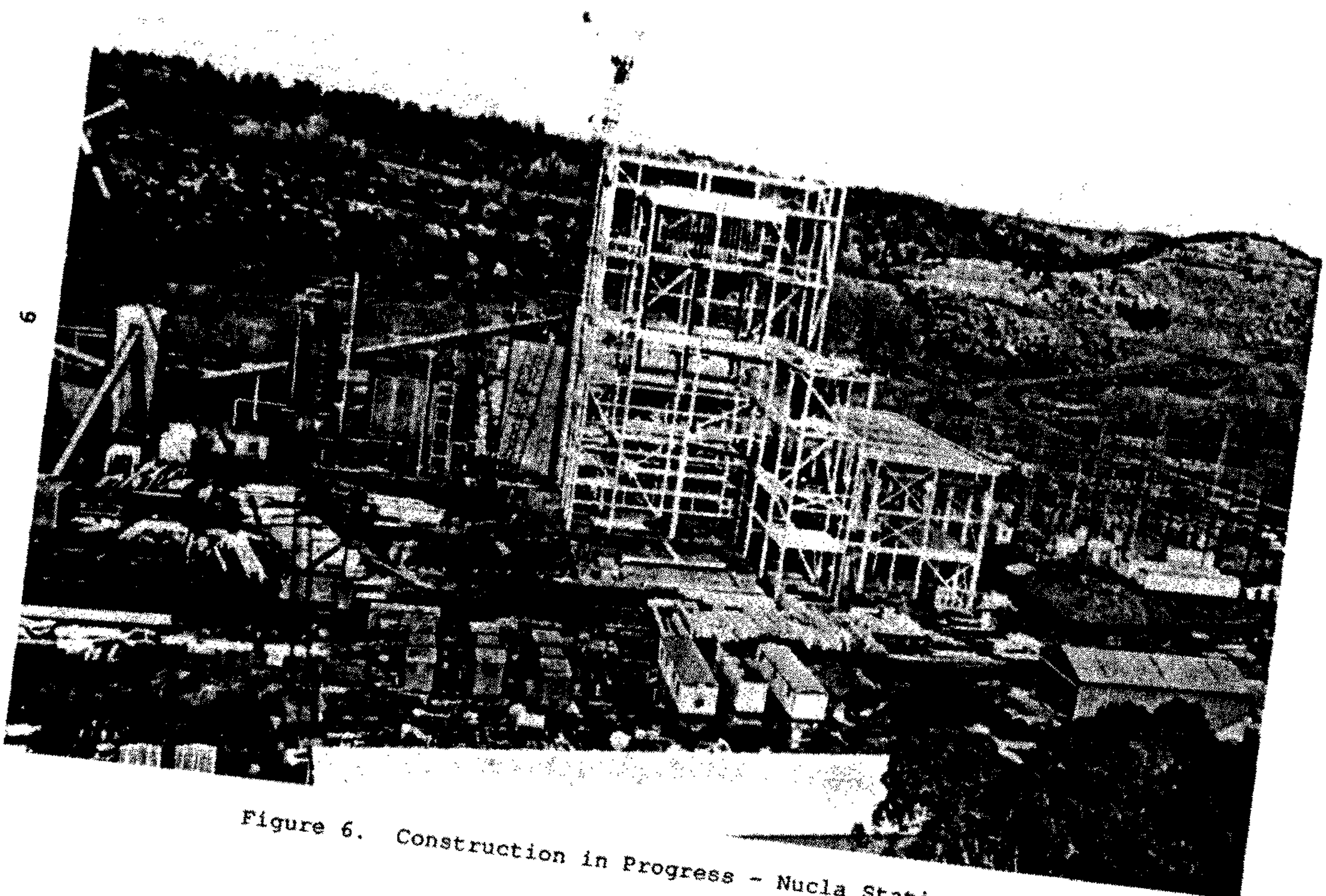


Figure 6. Construction in Progress - Nucla Station

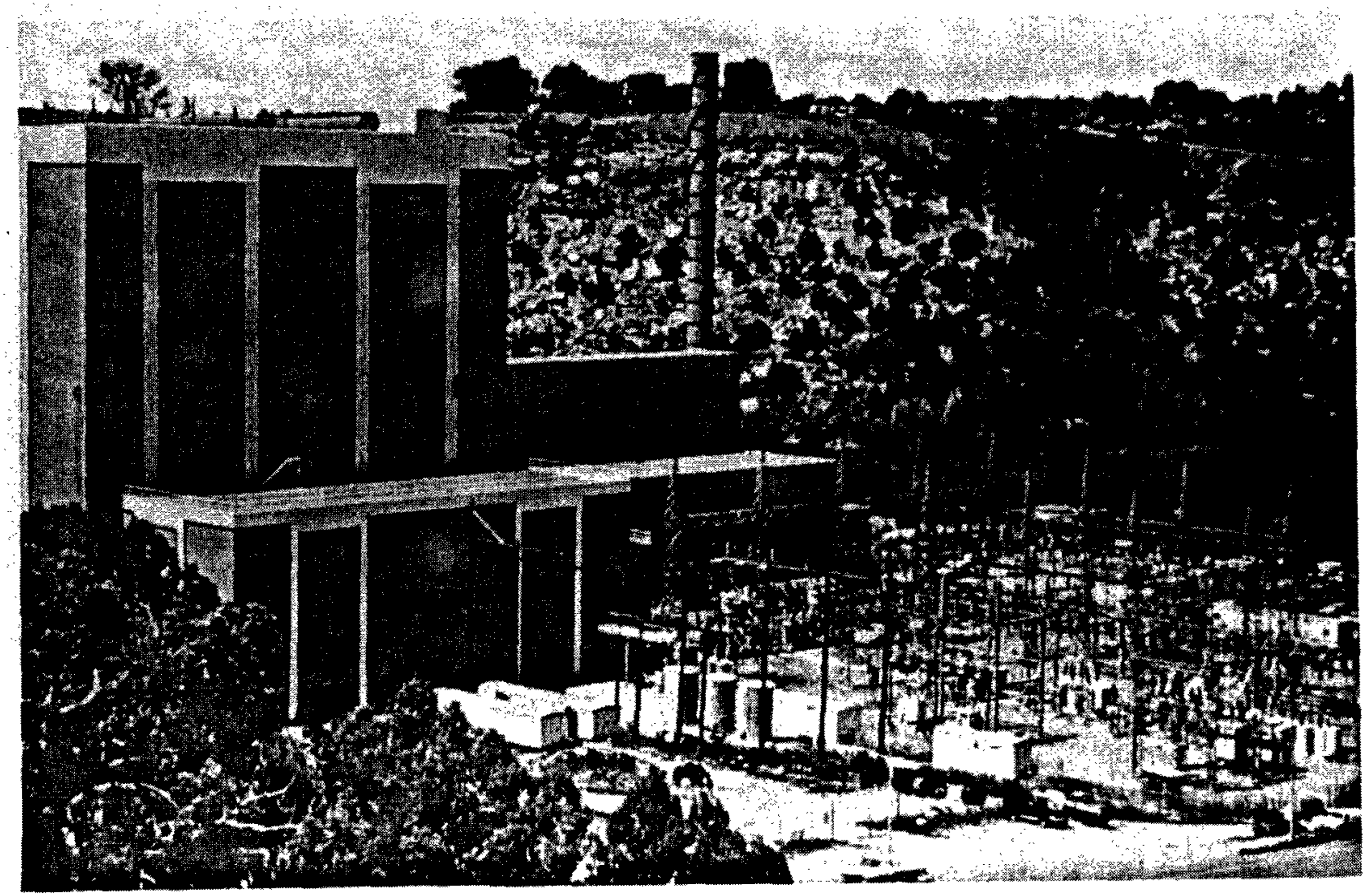


Figure 7. Nucla Station (1987) - View Looking Northwest

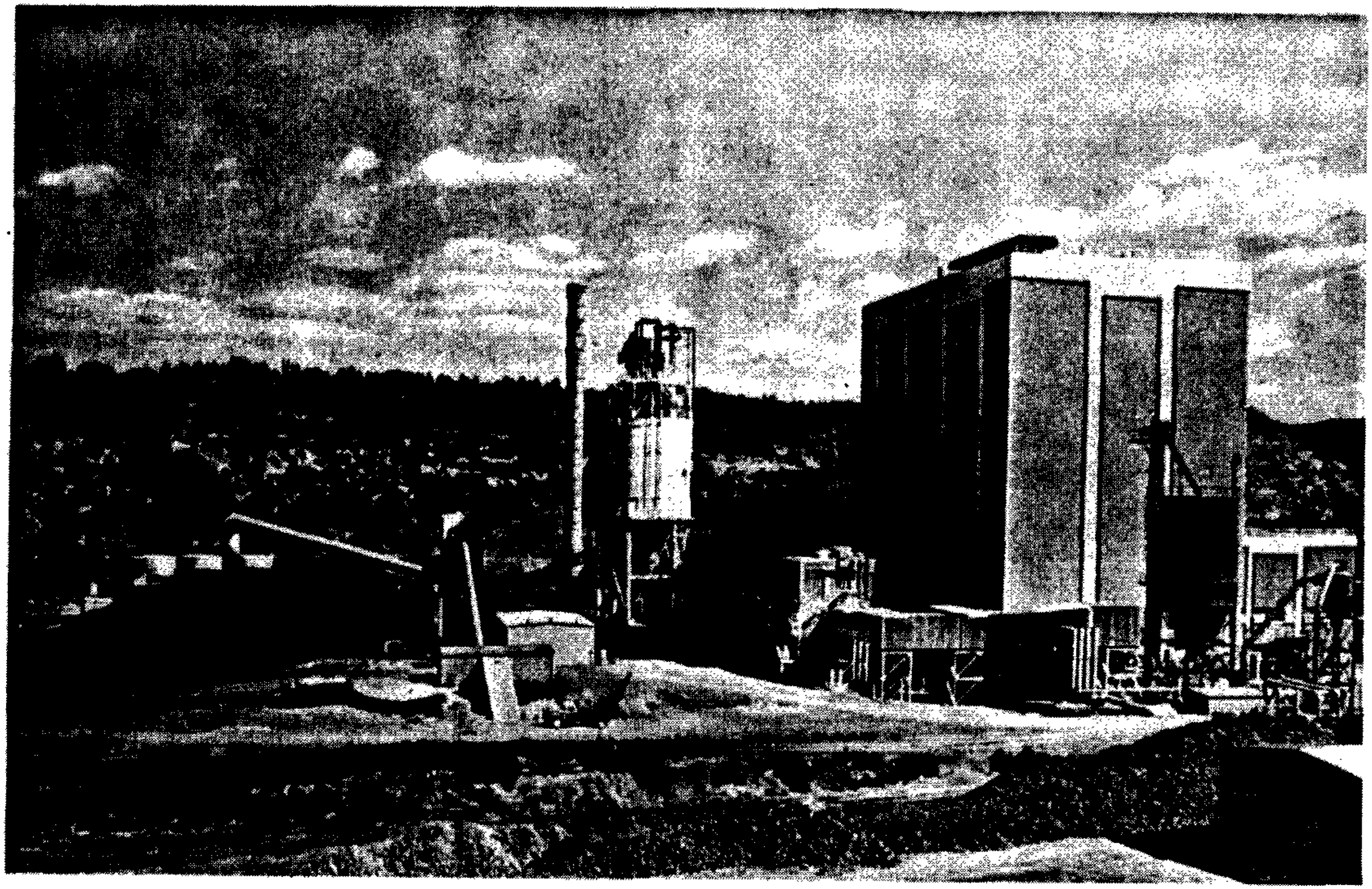


Figure 8. Nucla Station (1988) - View Looking Northeast

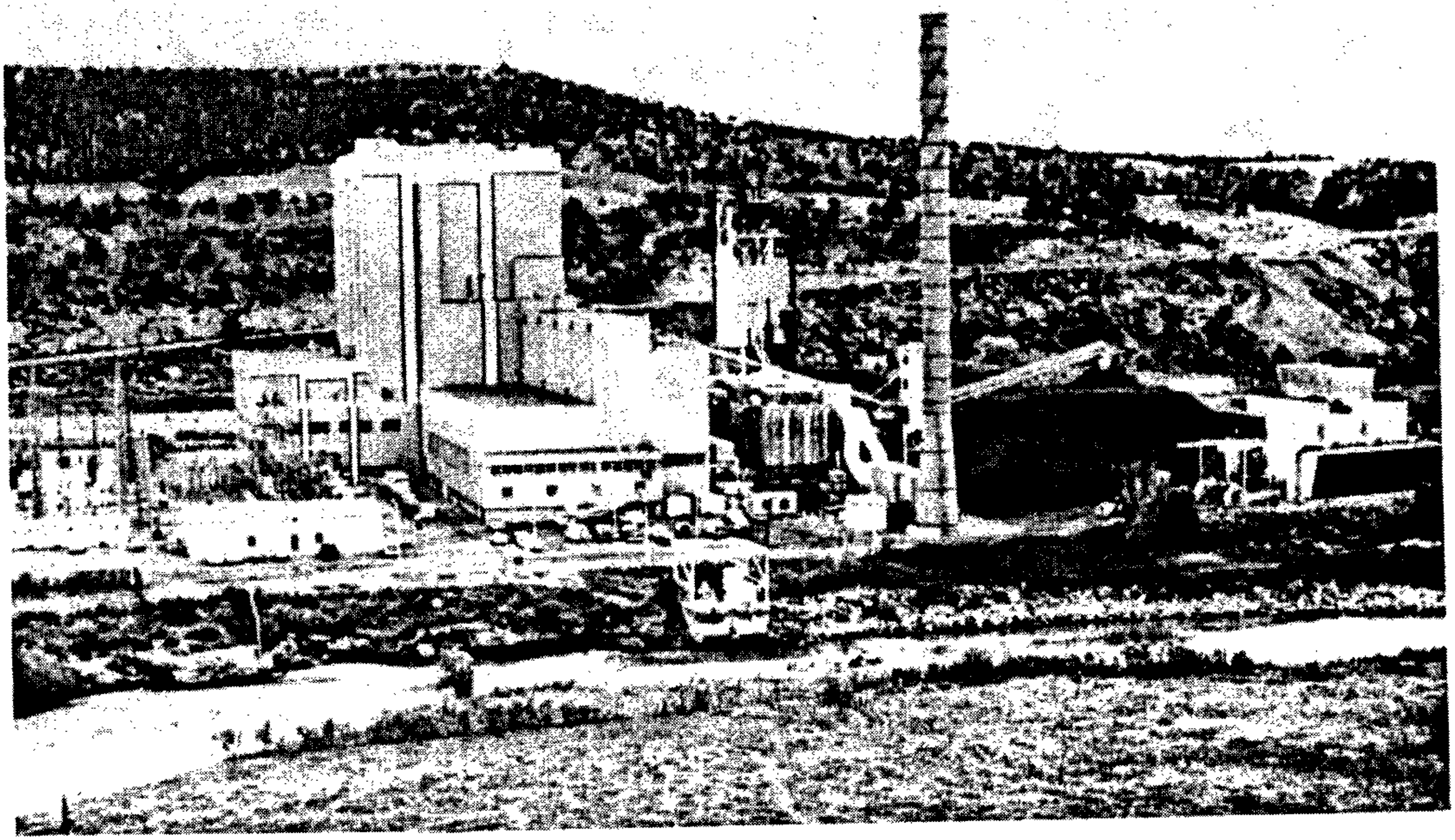


Figure 9. Nucla Station (1988) - View Looking South

8. Startup and duct burners.

9. Tubular air heater.

10. Miscellaneous boiler items, including insulation, lagging, casing, sootblowers, and boiler vent and drain equipment.

Additional boiler plant equipment and systems that support the new circulating AFBC boiler are:

11. New limestone receiving, storage, preparation, and conveying equipment.

12. A new steel stack.

13. A refurbished plant coal-handling system and new coal-handling equipment to prepare and deliver coal to the circulating AFBC boiler coal silos.

14. Three refurbished baghouses and a new baghouse, which in parallel remove particulate matter from the circulating AFBC boiler flue gas stream.

15. Refurbished, modified, and new bottom ash and fly ash handling and storage equipment.

The balance of both existing and new plant equipment and systems include:

16. The original three 12.6-MW turbine-generators now run from a new 74-MW single-automatic-extraction turbine-generator.

17. Main steam, extraction steam (including a controlled extraction from the new turbine supplying steam to the existing turbines), and auxiliary steam piping systems.

18. New high-pressure feedwater cycle equipment including boiler-feed pumps and high-pressure feedwater heaters.

19. A refurbished and a new plant circulating water cooling system, each consisting of a mechanical-draft evaporative-cooling tower and circulating water pumps.

20. Refurbished and new low-pressure feedwater cycle equipment for each turbine-generator unit including condensers, condensate hotwell pumps, low-pressure feedwater heaters, and deaerators.

21. Refurbished and new plant water systems including a new boiler makeup demineralizer system.

22. Refurbished and new miscellaneous mechanical equipment including heating, ventilating and air conditioning (HVAC) equipment, air compressors, fire protection system, and a new propane system.

23. Plant instruments and controls including a new plant distributed control system.

24. Plant electrical equipment and systems.

Because of the potential offered by use and commercialization of circulating AFBC technology to the electric power industry, Colorado-Ute Electric Association, Inc., and the Electric Power Research Institute (EPRI) initiated a program to study the Nucla circulating AFBC boiler and its operating characteristics. This project is being conducted in conjunction with two other EPRI-sponsored AFBC demonstration projects: Northern States Power Company's bubbling 130-MW Black Dog demonstration and Tennessee Valley Authority's bubbling 160-MW Shawnee demonstration. For the Nucla demonstration, EPRI installed special hardware for the program including instrumentation, data acquisition and processing equipment and facilities necessary to conduct a two-year test program.

The U. S. Department of Energy likewise participated in the project through the Clean Coal Technology Program - Phase I. The Cooperative Agreement, DE-FC21-89MC25137 was administered by DOE's Morgantown Energy Technology Center located in Morgantown, West Virginia.

Site construction was started in the spring of 1985 and startup took place during the summer of 1987. A chronology of the principal project events is presented below:

Date	Activity
Summer 1982	Colorado-Ute begins considering options that would allow its Nucla Station to continue operating.
Spring-Fall 1982	EPRI discusses with Colorado-Ute the possibility of its being a host utility to demonstrate AFBC technology.
February 1983	Colorado-Ute submits a detailed proposal to EPRI for a 100-MW bubbling AFBC demonstration unit at its Nucla Station.

Date	Activity
Spring 1983	EPRI awards the main contract for AFBC demonstration to TVA; however, Colorado-Ute continues to investigate merits of an AFBC retrofit for Nucla based on attractive economics and the need to "do something with Nucla" to prevent its closure. Colorado-Ute begins investigating the merits of circulating versus bubbling AFBC technology.
Summer 1983	Colorado-Ute decides to continue with the Nucla project, with or without outside participation.
November 1983	EPRI funds a two-task circulating AFBC boiler study. One task is Nucla site specific for a 100-MW unit; the other task is for a hypothetical 500-MW unit. Boiler studies are awarded to both Combustion Engineering/Lurgi and Pyropower with the stipulation that they be prepared to bid a circulating AFBC boiler lump sum in the spring of 1984.
Winter 1983-1984	Colorado-Ute receives results of the boiler studies and, with technical assistance from EPRI, prepares circulating AFBC boiler specifications.
April 4, 1984	Colorado-Ute issues a circulating AFBC boiler Request for Proposal to Combustion Engineering/Lurgi and Pyropower.
June 5, 1984	Both vendors submit boiler proposals to Colorado-Ute.
Winter 1983-1984 through Summer 1984	Colorado-Ute initiates permit, licensing and financing efforts. Rural Electrification Administration (REA) gives preliminary approval for the project based on borrowers' environmental report, without environmental impact statement. Loan application for total project cost approved by National Rural Utilities Cooperative Finance Corporation (CFC).
August 1984	Colorado-Ute Board of Directors gives approval to proceed with design and construction of the Nucla circulating AFBC demonstration project.

Date	Activity
September 14, 1984	Circulating AFBC boiler contract is awarded to Pyropower.
November 1984	Site preparation contractor begins grading and installing circulating water lines.
April 1985	General contractor mobilization at site.
May 1985	Concrete work starts three weeks early.
August 1985	Circulating AFBC boiler steel erection starts.
December 1985	Steam drum is raised.
October 1986	Circulating AFBC boiler is hydrostatically tested.
March 1987	Circulating AFBC boiler boilout.
May 1987	Steam to turbine and initial synchronization.
June 1987	First coal firing.
April 1988	Boiler Acceptance testing.
June 1988	U. S. Department of Energy Cooperative Agreement.
July 1988 - June 1990	EPRI test program.
August 1990	DOE Extension award.
October 1990	DOE/CUEA test program continuation.

Section 1. Introduction

This report documents Colorado-Ute Electric Association's Nucla Circulating Atmospheric Fluidized-Bed Combustion (AFBC) demonstration project. It describes the plant equipment and system design for the first U.S. utility-size circulating AFBC boiler and its support systems. Included are equipment and system descriptions, design/background information and appendices with an equipment list and selected information plus process flow and instrumentation drawings (P&IDs).

The purpose of this report is to share the information gathered during the Nucla circulating AFBC demonstration project and present it so that the general public can evaluate the technical feasibility and cost effectiveness of replacing pulverized or stoker-fired boiler units with circulating fluidized-bed boiler units.

In 1982, Colorado-Ute Electric Association began a two-year study to develop an alternate project for life extension of its outmoded Nucla Station in an effort to keep it open to help meet projected nominal load growth in the late 1980s. The company abandoned plans to develop a large new coal-fired generating station and focused on smaller, lower-cost, and shorter duration projects.

While considering future operating plans for the Nucla Station, Colorado-Ute became interested in circulating AFBC as a method of burning coal. The benefits of AFBC are low capital costs, reduced air pollution, and the ability to burn different fuels, especially low-grade coals which are abundant in and around the Nucla area.

After reviewing various alternatives and the risks associated with demonstrating the new technology, Colorado-Ute elected to proceed with construction of a 110-MW demonstration circulating AFBC boiler to extend the life and upgrade the capacity of the Nucla Station.

TECHNOLOGY BASE

The evolution of the AFBC technology is broad in scope and international in character. Sixty years ago, pulverized coal combustion was introduced into the electric utility industry for fuel conservation. Environmental issues forced major improvements on the then-applied stoker furnace designs. During the late 1930s and early 1940s, Germany developed and commercialized fluidized-bed processing for its growing coal gasification and metal-refining industries. The development and use of fluidized-bed processing accelerated after World War II, particularly in the United States where it was applied to the production of high-octane gasoline from catalytic cracking of heavy oils. From the late 1950s to the early 1960s, Great Britain's National Coal Board encouraged the development of AFBC as an improved way of burning coal and meeting environmental concerns. The principal motivation for European interest in AFBC at that time was to obtain flexibility in burning locally available and diverse fuels, but in many cases those of low-grade quality.

In contrast, the motivation in the United States was to meet the stringent new regulations imposed by the Environmental Protection Agency (EPA). The federal government, first through the EPA and thereafter through the Department of Energy (DOE), was responsible for many of the initial efforts to develop fluidized-bed technology in this country. The first U.S. utility AFBC unit was built at the Rivesville Station of the Monongehela Power Company in West Virginia. Built in the early 1970s, this unit operated from December 1976 to 1981. It burned coal and had a 136,078-kg/hr (300,000 lb/hr) steam-generating capacity (approximately 30 MW). The unit was scaled from a 0.5-MW test rig at Alexandria, Virginia. The DOE support culminated in the construction and operation of three other industrial-scale demonstration units:

- A 45,400 kg/hr (100,000 lb/hr) unit at Georgetown University, Washington, D.C.
- A 22,700 kg/hr (50,000 lb/hr) unit at the Great Lakes Naval Training Center, Illinois; and
- A 10,442 kg/hr (23,000 lb/hr) anthracite coal-burning unit in Shamokin, Pennsylvania.

Each unit is of a different prototype design; together they have accumulated several years' worth of valuable performance data.

In 1977, with encouragement from several interested utility members, the Electric Power Research Institute (EPRI) built a 2-MW (6 ft x 6 ft) pilot plant at the Babcock & Wilcox (B&W) research and development center in Alliance, Ohio. This EPRI/B&W facility provided data that enabled the Tennessee Valley Authority (TVA), B&W and EPRI to design, build and operate a 20-MW plant at the Shawnee Station near Paducah, Kentucky in 1982. This 20-MW pilot plant was designed and instrumented to:

- Simulate utility power plant conditions;
- Allow testing of different mechanical systems; and
- Provide data for designing and operating utility-scale units of 200 to 500 MW.

Since July 1982, the TVA 20-MW pilot plant has accumulated over 19,000 hours of coal-firing operation and has confirmed such AFBC features as good combustion efficiency, low level of emissions, and fuel flexibility.

Past experience with facilities in the United States and abroad has shown that AFBC systems do in fact achieve in-situ emissions control and improved fuel flexibility without sacrificing desirable attributes of operation and maintenance; unlike stoker-fired boilers. Using the experience gained from these facilities, EPRI with a number of electric utilities embarked on a program to demonstrate and commercialize AFBC technology. Three utility-sized units are included in the program:

- Northern States Power Company's conversion of an existing 100-MW pulverized coal unit (Black Dog #2) to a 125-MW bubbling AFBC unit with an overbed feed system;

- TVA's new 160-MW bubbling AFBC boiler with underbed feed at its Shawnee steam plant near Paducah, Kentucky (the unit will provide steam to the existing turbine and balance-of-plant of Unit #10); and

- Colorado-Ute's 110-MW circulating AFBC boiler for repowering its Nucla generation station.

These three projects are complementary in terms of the scope of work, time frames, equipment design, fuel fired, and locations. They will provide the electric utility industry with data to evaluate future potential of additional AFBC projects. Completion of these projects will demonstrate:

- Operability of the specific designs;

- Reliability of critical power plant components;

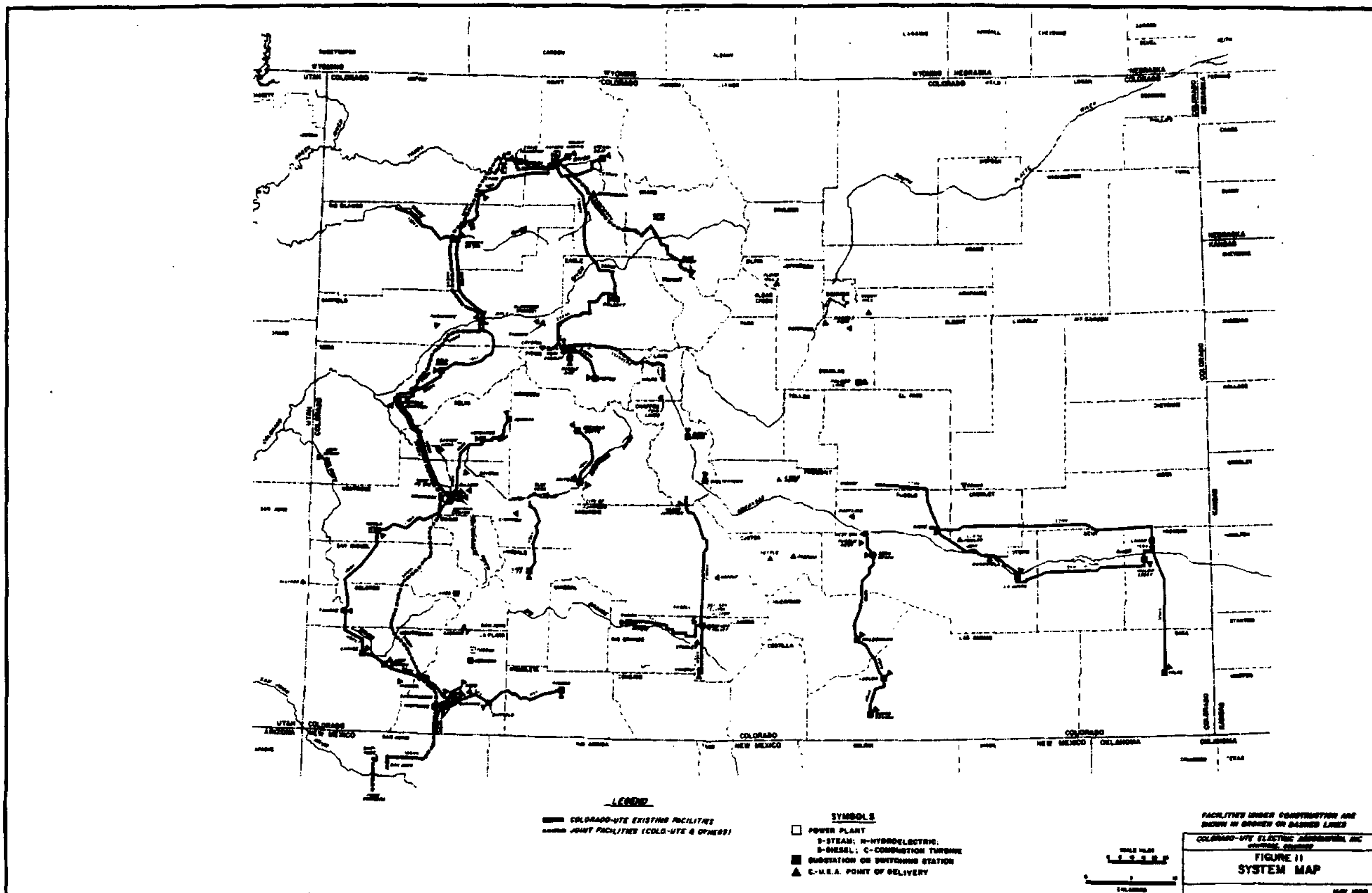
- Unique features of AFBC technology such as emission control, fuel flexibility, and good combustion efficiency; and

- Economics of AFBC technology.

COLORADO-UTE ELECTRIC ASSOCIATION, INC.

Colorado-Ute Electric Association, Inc., is a generation and transmission Rural Electrification Administration (REA) cooperative with approximately 750 employees and headquartered in Montrose, Colorado. Colorado-Ute is the operator for generating resources with an aggregate net capacity of 1,757 MW, including the existing 36-MW Nucla Station. Colorado-Ute owns 874 MW of the 1,757 MW it operates.

The company is owned by its 14-member system. Together, these systems serve more than half the land area of the state of Colorado, principally the sparsely populated western, southern and central


LEGEND
COLORADO-UTE EXISTING FACILITIES
JOINT FACILITIES (COLO-UTE & OTHERS)
SYMBOLS
POWER PLANT
S-STEAM; H-HYDROELECTRIC;
D-DIESEL; C-COMBUSTION TURBINE
SUBSTATION OR SWITCHING STATION
C-U.E.A. POINT OF DELIVERY
FACILITIES UNDER CONSTRUCTION ARE SHOWN IN BROKEN OR DASHED LINES
FIGURE II
SYSTEM MAP
WYOMING
COLORADO
NEBRASKA
KANSAS
UTAH
ARIZONA
NEW MEXICO
OKLAHOMA
TEXAS

installed by the electric power industry and successfully demonstrated the technology in the early 1970s.

A photograph of the Nucla Station is presented in Figure 12. This photograph was taken after site preparation work for the circulating AFBC demonstration project had begun and before general contractor mobilization. It shows the area immediately to the south of the existing plant cleared for the new circulating AFBC boiler.

In 1982, the plant was nearing the end of its useful life. The disadvantages of poor station efficiency, relatively high fuel costs, and increasingly higher boiler maintenance costs had forced the plant into a low position on the dispatching order. This resulted in a decreased annual coal burn with, consequently, negative effects on mining efficiency and coal costs from the local mine. In fact, for the most part, the station was being operated only during the winter peak season to burn the contracted minimum amount of coal and the coal contract was due to expire in 1984.

Colorado-Ute considered several alternatives to both extending the life of the Nucla Station and meeting projected system load growths before committing to the Nucla circulating AFBC demonstration project. Colorado-Ute's 1984 load growth projections are presented in Table 1.

The management of Colorado-Ute strongly desired to keep the Nucla facility open. The small local community had been severely affected by the downturn in the local uranium and coal mining plus forestry products industries. Closure of the Nucla facility would have cost the economically deprived area an additional 50 jobs. Colorado-Ute's management felt a strong sense of civic responsibility to help the local economy by keeping the Nucla Station open.

ALTERNATIVE SITES CONSIDERED

Colorado-Ute has existing coal-fired generating sites near Montrose, Hayden and Craig, Colorado (see figure 10). Bullock Station, located in Montrose, Colorado, is an old coal-fired steam-electric station consisting of two 6-MW units nearing retirement. It was not chosen for conversion to fluidized-bed combustion because there is no nearby coal supply, the transmission system would require modifications to accommodate a 110-MW unit, the existing equipment would not allow easy modification to install the larger unit, and the plant site is actually too small to accommodate such a large project.

Hayden Station is a coal-fired steam electric generating station, located approximately five miles east of Hayden, Colorado. It contains two units with net capabilities of 184 MW and 262 MW,

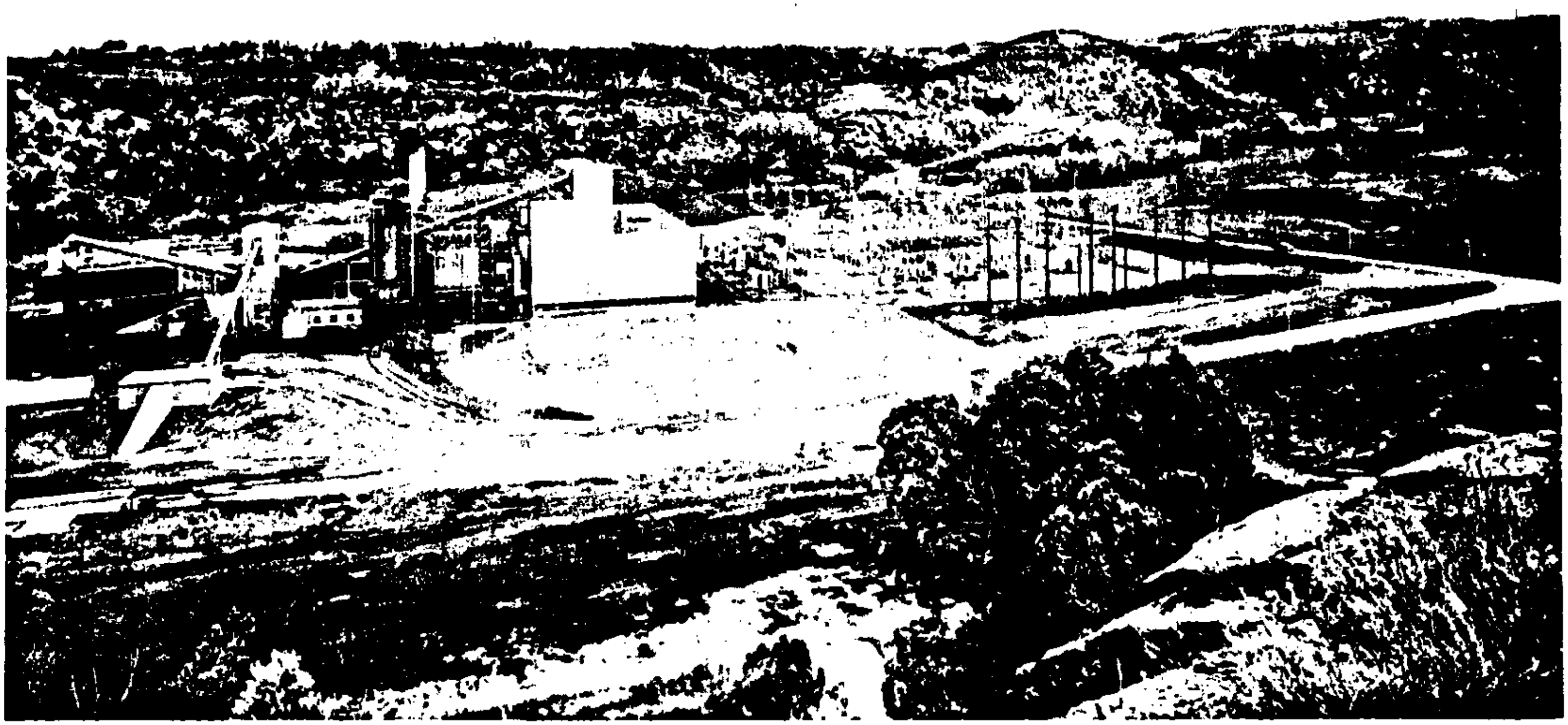


Figure 12. Nucla Station (1985) - View Looking North

TABLE 1. COLORADO-UTE ELECTRIC ASSOCIATION
TOTAL YEAR-END POWER REQUIREMENTS AND RESOURCES (megawatts)

Loads	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
Colorado-Ute Requirements (without CO_2 loads)	626	726	778	819	863	907	952	1006	1061	1130
CO_2 Pumping Loads	41	50	62	79	89	91	92	94	96	97
Reserve Requirements	100	116	126	135	143	150	157	165	172	182
Total Requirements	767	892	966	1033	1095	1148	1201	1265	1331	1399
Resources										
Capacity in Service	977	877[a]	877	877	877	877	877	877	877	977[b]
WAPA Purchase	51	51	61[c]	61	61	80[d]	80	80	80	80
Total Resources	1028	928	938	938	938	957	957	957	957	1057
Surplus/(deficit)	261	36	(28)	(95)	(157)	(191)	(244)	(308)	(374)	(342)
Nucla Station	0	0	0	0	0[e]	0	100[f]	100	100	100
Other Purchases	0	0	28	95	157	191	144	208	274	242

[a] 100-MW layoff to Public Service of Colorado from Craig Unit 3
[b] Recapture 100-MW Craig Unit 3
[c] Fryingpan-Arkansas - 10 MW
[d] Expiring WAPA contracts
[e] These are conservative estimates reflecting the assumption that no electricity will be produced on a consistent basis during the test program (1988 and 1989).
[f] Net power generation from Nucla

Source: Feasibility Study, Nucla CFB Demonstration Project", Colorado-Ute Electric Association, Inc., August 1984.

respectively. This site was not selected because none of the existing units were scheduled to be retired in the near future.

Construction of a fluidized bed unit at the Hayden site would have involved the construction of an entirely new unit and three generically different types could cause major problems with operation and maintenance functions.

Craig Station is a coal-fired generating station located approximately four miles southwest of Craig, Colorado, consisting of three similar 417-MW (each) units. This site was not selected because the three existing units were new and constructing a demonstration fluidized-bed combustion unit there would also have required construction of an entirely new facility.

A large amount of generating capacity already existed in the Craig and Hayden area of northwestern Colorado. Colorado-Ute, therefore, preferred to build the additional generation closer to the growing demand in southwestern Colorado.

PROJECT ALTERNATIVES

Colorado-Ute began the Nucla life extension study by screening the most conceivable options:

- Supplemental natural-gas firing of the existing coal-fired stoker boilers;
- Converting the existing boilers to full natural-gas firing;
- Natural-gas-fired combined cycle with a new combustion turbine;
- An external coal combustor supplying the existing turbine-generators;
- Coal gasification to supply the existing boilers;
- Coal washing;
- Rebuilding the existing boilers to efficiently burn the local coal;
- Converting the existing boilers to AFBC units;
- Building a new unit at Nucla, either pulverized coal (PC), AFBC or pressurized fluidized-bed combustion (PFBC);
- Building a new PC or AFBC boiler with a topping turbine; and

• No action, retirement.

The no-action alternative would have led to the closing of Nucla Station. Colorado-Ute found this alternative unacceptable for two reasons. First, it would have meant purchasing more expensive power from other utilities, and subsequently delivering the power to load centers near Nucla. Transmission of electric power over long distances increases the cost of power because of the associated transmission losses. Second, closing Nucla Station would have added to the problems of a community where the economy was severely depressed.

First screening of the remaining alternatives indicated that the options that did not include increased generating capacity required considerable capital outlay and were not competitive. Colorado-Ute also eliminated the PFBC system because it did not consider this process to be as close to commercialization as the AFBC technology. Therefore, Colorado-Ute focused on economic alternatives to increase generation capacity based on:

- Conventional PC combustion technology;
- Bubbling AFBC; and
- Circulating AFBC.

Installing a 100-MW PC boiler was rejected due to significantly higher capital costs, higher fuel costs, the requirements for an SO_2 scrubber for sulfur removal and the one- to two-year schedule delay required for an environmental impact statement.

Fuel costs for a PC-fired boiler would be higher than those for a fluidized-bed boiler due principally to higher coal quality requirements. This was based on the presumption that selective mining would be needed to fuel a PC boiler, as was previously employed for the stoker-fired units. In addition, there may be insufficient quantities of coal in the Nucla area of the required quality to fuel a PC-fired unit for a 30-year life extension.

Colorado-Ute, therefore, focused on the AFBC options. Both bubbling and circulating AFBC boilers operate at atmospheric pressure, and the bed temperature usually ranges between 815°C to 870°C (1,500°F to 1,600°F) which helps prevent furnace slagging and minimizes NO_x emissions. The bubbling bed operates at a lower gas velocity than the circulating and keeps a dense bed of coal and limestone suspended in a bubbling manner in the bottom of the furnace or combustor. The circulating bed operates at a higher gas velocity to entrain the coal and limestone particles in a less dense bed; the particles are then separated from the flue gas stream via a hot cyclone collector and recirculated back to the combustor, maximizing carbon and sorbent utilization.

During the summer of 1983, Colorado-Ute began seriously considering a circulating AFBC boiler for Nucla. In comparing a circulating-bed versus a bubbling-bed boiler, Colorado-Ute considered the following factors:

- Capital cost;
- Operating costs;
- Carbon utilization;
- Sulfur capture and stoichiometric Ca/S ratios;
- NO_x emissions;
- Relative design simplicity/complexity of the boiler and its fuel and sorbent feed systems;
- Auxiliary power requirements;
- Experience of boiler manufacturers; and
- Effects on the balance of the Nucla plant.

With the assistance of various organizations (EPRI, DOE, consultants, vendors, and other utilities), Colorado-Ute also investigated air heater designs (regenerative, tubular, plate, etc.), economizer designs (bare versus extended surface), and local Nucla fuel and sorbent sources.

Colorado-Ute's investigations culminated in two EPRI-sponsored boiler design studies conducted by two manufacturers who responded to Colorado-Ute's inquiry (Combustion Engineering/Lurgi* and Pyropower**). The primary objectives of the studies were to develop a preliminary design and a cost estimate for the proposed Nucla project. The result was Colorado-Ute's decision that the circulating AFBC technology was the best alternative for use at the Nucla site.

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* Combustion Engineering/Lurgi was a consortium of Combustion Engineering, Inc., of the U. S. and Lurgi Corporation. Lurgi GmbH of West Germany is the owner of circulating AFBC technology and has licensed its use and patents to Lurgi Corporation.

** Pyropower is a U. S. corporation, in San Diego, California, owned by the Ahlstrom Group, a boiler manufacturer and integrated industrial company headquartered in Helsinki, Finland.

A significant factor for the Nucla project was the capability of a circulating AFBC boiler to burn the local low-grade 5,384 - 4,440 Calories/kg (9,700 - 8,000 Btu/lb), high ash (26 - 33%) coals as mined. The Nucla coal and ash analyses are presented in Tables 2 and 3. Coal B ("Design" coal) listed in Table 2 was used for designing the circulating AFBC boiler equipment and ensures that alternative fuels can be burned during a two-year test program that EPRI funded. The Nucla Station fuel costs are expected to be reduced by 30% on an equivalent delivered heating value basis by burning the local coals as mined when compared to selective mining for the existing stoker-fired units.

At the time, both boiler manufacturers had considerable experience with industrial-size circulating AFBC boilers. The technology had been used primarily in Europe, whereas bubbling AFBC experience was primarily in the United States. By early 1984, circulating AFBC technology was judged by many to be in a stage of development equivalent to the bubbling-bed technology. The largest operating circulating AFBC boilers were an 84-MW (thermal) unit (Lurgi-W. Germany) and a 90,800-kg/hr (200,000 lb/hr), 87-kg/cm^2 (1,235 psig), 500°C (930°F) unit (Ahlstrom-Finland). The largest operating bubbling-bed boiler was TVA's 20-MW pilot unit located at the Shawnee Station. Based on their experience with industrial circulating AFBC units, the two manufacturers were willing to provide commercial guarantees for a project.

EVALUATION OF NUCLA STATION POWER CYCLE ALTERNATIVES

Colorado-Ute realized that the path to improving station heat rate was elevating the steam conditions. Therefore, to optimize cycle improvement the company turned its attention to studying steam conditions, cycle configurations, and increments of generation addition.

With main steam temperature limited to 538°C (1000°F), current state of the art, and with existing turbine steam inlet conditions of 42-kg/cm^2 (600 psig) and 440°C (825°F), Colorado-Ute identified and examined three candidate cycles.:

- a topping turbine cycle;
- a customized supercritical single reheat cycle; and
- an automatic extraction condensing turbine cycle.

The topping turbine cycle could improve turbine cycle heat rate to approximately 9.5 x 10^6 Joules/kWh (9,000 Btu/kWh) but added only 7 MW of capacity to the existing 36 MW. When the costs of a new boiler, auxiliaries, and the topping turbine were added to the station

TABLE 2

NUCLA COAL ANALYSIS

	Coal A "Performance" Coal	Coal B "Design" Coal
Source	Nucla, CO	Nucla, CO
Gradation	Uniform	Uniform
Proximate Analysis, % by weight		
Moisture	5.8	6.0
Volatile	26.9	21.0
Fixed carbon	41.2	40.0
Ash	26.1	33.0*
Total	100.00	100.00
Ultimate Analysis, % by weight		
Carbon	55.17	46.41
Hydrogen	3.63	3.60
Sulphur	0.73	2.50*
Oxygen	7.51	7.50
Nitrogen	0.98	0.90
Chlorine	0.04	0.04
Moisture	5.86	6.00
Ash	26.08	33.05
Total	100.00	100.00
Gross Heating Value as Fired:		
Calorie/kg (Btu/lb)	5,380 (9693)	4,440 (8000)
Surface Moisture as Fired:		
% by weight	3.74	4.00
Ash Softened Temperatures (reducing atmosphere), °F		
Initial deformation	2650	2650
Softening	+2700	+2700
Fluid	+2700	+2700

NOTE: Coal A constitutes the basis for all guaranteed and predicted performance data. The circulating AFBC boiler unit is capable of developing specified capacity using Coal B.

* 33.0% ash and 2.5% sulfur for Coal B do not occur at the same time.

TABLE 3

NUCLA ASH ANALYSIS

	% by Weight
Phos. Pentoxide, P_2O_5	0.1
Silica, SiO_2	56.1
Ferric Oxide, Fe_2O_3	4.7
Alumina, Al_2O_3	29.1
Titania, TiO_2	1.2
Lime, CaO	4.2
Magnesia, MgO	0.8
Sulfur Trioxide, SO_3	2.7
Potassium Oxide, Na_2O	0.3
Total	100.0

reconditioning costs, the investment became unattractive for a 9.5 x 10^6 Joules/kWh (9,000 Btu/kWh) turbine cycle heat rate. Furthermore, the 7-MW increment of generation capacity increase would have little impact on annual coal burn and mining costs.

The customized supercritical single reheat cycle with 246-kg/cm^2 (3,500 psig) and 538°C (1000°F) main steam and 440°C (825°F) reheat steam supplying the existing turbine generators could improve turbine cycle heat rate to approximately 8.4 x 10^6 Joules/kWh (8,000 Btu/kWh). However, the complication of reheat being superimposed on the evolving circulating AFBC boiler technology and the prototype nature of the small supercritical turbine seemed to be prudent. The circulating AFBC boiler manufacturers showed little enthusiasm for reheat and for a once-through boiler design. Supercritical steam conditions have most commonly been applied to machines having a rating in excess of 300 MW which is far in excess of anything considered for the Nucla Station. Furthermore, the requirements for controlling high-pressure cylinder exhaust steam pressure introduced an altogether new and complex speed/load control system. While these control aspects have been developed for auto extraction turbines, they have not been applied to a supercritical reheat turbine cycle configuration. Furthermore, reheating steam to only 440°C (825°F) is not really cost effective.

The automatic extraction condensing turbine cycle proved to be the optimum choice. Colorado-Ute determined that an automatic extraction turbine with throttle steam conditions in the area of 102 kg/cm^2 (1,450 psig) and 538°C (1000°F) could be applied. The design for such a turbine at ratings up to 75 MW were well established. However, the extraction cycle, as its name implies, requires extraction.

Automatic extraction would supply steam to the existing turbines at 42-kg/cm^2 (600 psig and 440°C (825°F). The exhaust end of the extraction turbine would be designed for the maximum inlet flow less the design extraction flow to the existing turbines. This turbine heat rate is approximately 9.3 x 10^6 Joules/kWh (8,800 Btu/kWh). The turbine cost premium for the automatic extraction feature over a conventional turbine of the same rating was of the order of 10%.

There was a limited range within which the generation increment increase could be considered. The upper limit of 100 to 150 MW was set by the plant site physical limitations and the power requirements, voltage, and stability considerations of the existing 115-kV transmission system.

Finally Colorado-Ute decided to add a new 74-MW steam turbine. The demonstration project thus called for a new circulating AFBC boiler which would supply steam to the new 74-MW turbine-generator and the three existing 12-MW turbine-generators, a new baghouse, chimney, condenser, cooling tower, feedwater system, demineralizer, transformers, and auxiliary systems. The total plant capacity would be increased to 110 MW. The new baghouse would be used in parallel with the existing baghouses to remove particulates from the new circulating AFBC boiler fuel gas. The three existing coal stoker-fired boilers would be retired in place. The majority of the remaining equipment from the three existing units would be reconditioned and utilized to the maximum extent possible to reduce the total project cost.

A simplified, overall plant flow schematic of the Nucla circulating AFBC demonstration project is shown in Figure 13. The Nucla Station layout of both existing and new equipment/buildings was previously shown in Figure 4. The project's major equipment specifications are summarized in Table 4.

PROJECT ECONOMICS AND RISK

Colorado-Ute's preliminary cost estimate for the proposed Nucla circulating AFBC demonstration project was $103.64 million or $942/kW. By the time the company decided to go ahead with the project in August 1984, it had obtained firm price quotations for the major equipment items, Lowering the project cost estimate to $86.67 million, as outlined in Table 5, or $788/kW. This was lower than the cost estimate of a 100-MW pulverized coal unit at Nucla and considerably lower than the incremental installed cost ($1,183/kW) of Colorado-Ute's newest Unit 3 at the Craig Station that was placed in service in early 1984.

Colorado-Ute kept the Nucla project cost estimates low by maximizing use of the existing facility, minimizing refurbishment costs by having this work performed in-house, performing some engineering in-house, negotiating favorable contract terms and prices, and limiting the overall project schedule to three years. The favorable contracts were possible in part because of the depressed state of activity in the power industry at the time. The schedule was made possible by preplanning, by minimizing engineering, construction, and startup schedule overlaps, and by not having to prepare an environmental impact statement.

Busbar power costs for the first year of operation were projected to be 33.40 mills/kWh based on the facility being base loaded (80% capacity factor). The existing Nucla plant, while not economically feasible to operate, still had an outstanding debt of about $8.9 million. If the plant were closed, the net book value of about $5.8 million would have to be written off. If the cost associated with the remaining plant debt and book value were assigned to generation from the Nucla circulating AFBC demonstration project, the busbar

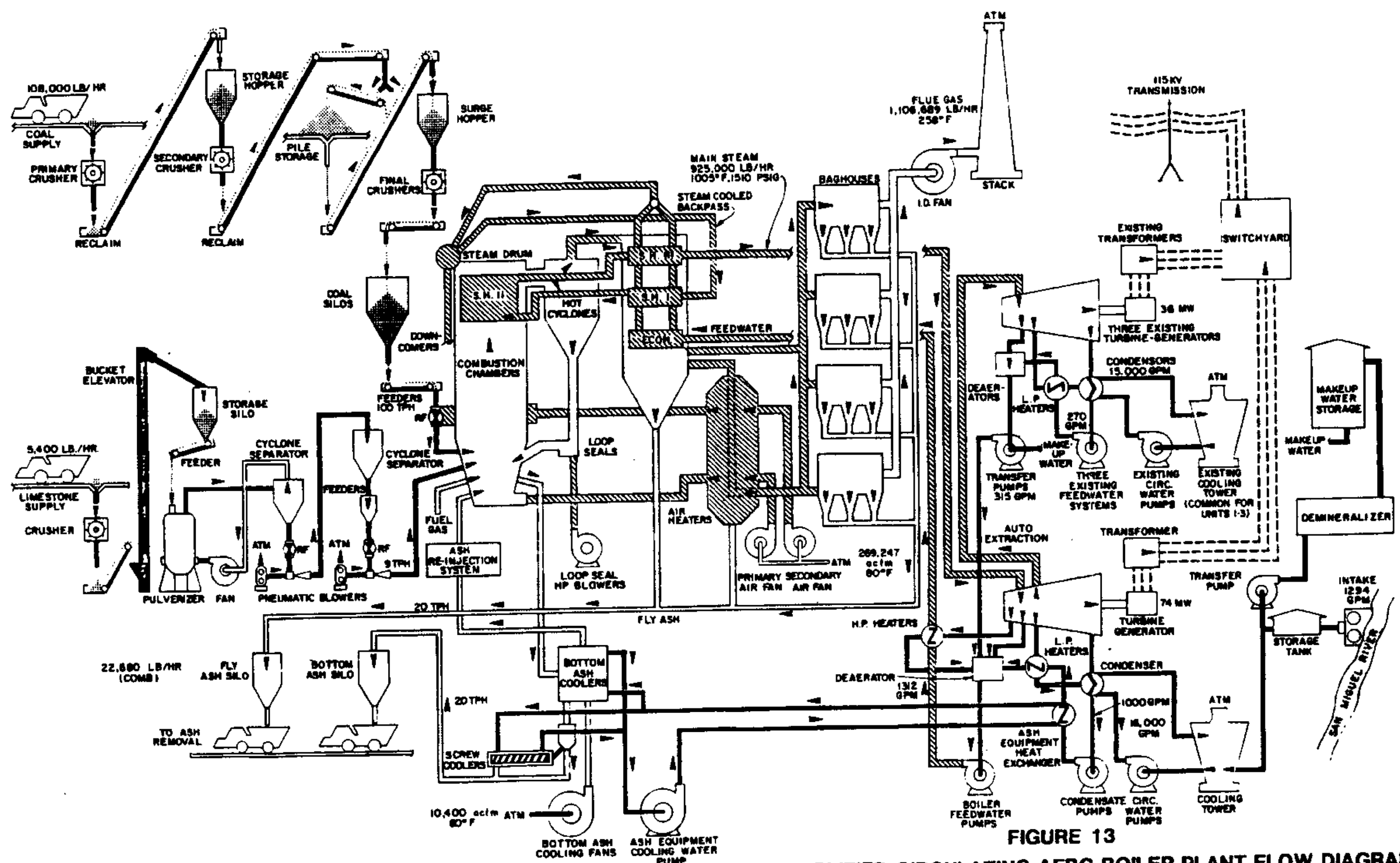

FIGURE 13

SIMPLIFIED CIRCULATING AFBC BOILER PLANT FLOW DIAGRAM

TABLE 4

SUMMARY OF EQUIPMENT SPECIFICATIONS

BOILER	PYROPOWER
Type	Dual combustion chamber, circulating fluidized-bed
Steam flow, lb/hr - max. continuous rating	925,000
Superheater outlet pressure, psig	1,510
Superheater outlet temperature, °F	1,005
Combustion rate, Btu/hr x 10^6	1,128.3
Coal consumption, ton/hr	58.2
Number of coal feeders	6
Limestone consumption, ton/hr	2.2
Number of limestone feeders	2
PRIMARY AIR FAN	AMERICAN DAVIDSON
Capacity, 1000 acfm at boiler rating	213.9
Drive	
Type	Adjustable frequency synchronous motor
HP	3,500
Manufacturer	Westinghouse
SECONDARY AIR FAN	AMERICAN DAVIDSON
Capacity, 1000 acfm at boiler rating	66.1
Drive	
Type	Adjustable frequency induction motor
HP	700
Manufacturer	Westinghouse
INDUCED DRAFT FAN	AMERICAN DAVIDSON
Capacity, 1000 acfm at boiler rating	447.8
Type	Adjustable frequency synchronous motor
HP	3,250
Manufacturer	Westinghouse
BAGHOUSES*	RESEARCH-COTTRELL/WHEELABRATOR-FRYE
Number - (1-new + 3-existing)	4
Effluent particulate loading, lb/10^6 Btu	0.03

* The new Research-Cottrell baghouse will operate in parallel with three existing Wheelabrator-Frye baghouses and will process approximately 50% of the flue gas.

** United Conveyor - new; Allen-Sherman-Hoff - existing.

TABLE 4 (Continued)

SUMMARY OF EQUIPMENT SPECIFICATIONS

ASH HANDLING FACILITIES	UNITED CONVEYOR/ALLEN SHERMAN HOFF**
Spent Bed Ash	
Type	Vacuum pneumatic
Capacity, ton/hr	20
Silo storage, cu ft	10,940
Fly Ash	
Type	Vacuum pneumatic
Capacity, ton/hr	30
Silo storage, cu ft	60,000
TURBINE GENERATOR	WESTINGHOUSE
Type	Single casing, automatic extraction, condensing
Continuous output, MW with full extraction	74
Throttle steam flow, lb/hr with full extraction	925,000
Generator continuous, KVA	88,200
Extraction steam pressure, psig	625
Extraction steam temperature, °F	800
EXISTING TURBINE GENERATORS 1,2,3	DELAVAL
Output, MW each	12.6
Steam source	Unit 4 extraction
Throttle steam flow, lb/hr each	123,000
CONDENSER	SOUTHWESTERN
Surface area, 1000 sq ft	45.7
Number of water passes	2
Air removal equipment	Steam air jet ejector
BOILER FEED PUMPS	BYRON JACKSON
Number	2
Capacity of each, gpm	1,312
Total developed head, ft	4,368
Drive	
Type	Motor
HP of each	1,750
Manufacturer	Westinghouse

* The new Research-Cottrell baghouse will operate in parallel with three existing Wheelabrator-Frye baghouses and will process approximately 50% of the flue gas.

** United Conveyor - new; Allen-Sherman-Hoff - existing.

TABLE 4 (Continued)

SUMMARY OF EQUIPMENT SPECIFICATIONS

FEEDWATER HEATERS	SOUTHWESTERN
Number of closed heaters, HP/LP	2/2
Final feedwater temperature, °F	439
DEAERATOR	GRAVER
Number	1
Type	Direct contact

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* The new Research-Cottrell baghouse will operate in parallel with three existing Wheelabrator-Frye baghouses and will process approximately 50% of the flue gas.

** United Conveyor - new; Allen-Sherman-Hoff - existing.

TABLE 5
ESTIMATED CAPITAL COSTS SUMMARY
(September 1984 Dollars)

Category	Cost (millions of dollars)			
Estimated Costs Based Upon Firm Price Quotes				
Boiler	29.98			
Turbine-Generator	7.0			
Architect/Engineer	3.2			
Total		40.18		
Estimated Costs Without Firm Price Quotes				
Earthwork	0.36			
Concrete	1.36			
Structural/Architectural	0.87			
Mechanical Equipment	9.23			
Piping	2.81			
Instrumentation and Controls	0.43			
Electrical Equipment	3.45			
Painting	0.01			
Insulation	0.92			
Demo, Reloc, and Mod	0.40			
Total		19.84		
Field Distributable Costs	4.55			
Contractor Home Office Costs and Fees	4.88			
Total		9.43		
Total field Cost and Contract Engineering			69.45	
Colorado-Ute Engineering, Startup and Construction Management			5.60	
Project Contingency			6.23	
Total Plant Cost			81.28	
AFDC			5.39	
Total Project Cost				86.67
Project Participation				(2.74)
Total with Project Participation				83.93
Additional Costs Related to Existing Plant				
Book Value				5.79
Accumulated Interest, Taxes and Insurance				2.43
Total Plant Investment				92.15

Source: "Feasibility Study, Nucla CFB Demonstration Project," Colorado-Ute Electric Association, Inc., August 1984.

power cost, for accounting purposes, would increase by 1.58 mills/kWh to 34.98 mills/kWh. This compared favorably with Colorado-Ute's 1984 wholesale rate to members of 41.17 mills/kWh. The assumptions for determining this estimate and related costs are presented in Table 6.

EPRI PARTICIPATION

In December 1981, EPRI solicited interest from various utilities to host an AFBC demonstration project in the range of 100 to 200 MW. After beginning its Nucla Station life extension study in mid-1982, Colorado-Ute became interested in the merits of the new AFBC technology for Nucla. Colorado-Ute approached EPRI in the fall of 1982, offering its Nucla Station as a candidate host site for EPRI's proposed 100-200 MW AFBC demonstration unit in an attempt to obtain technical and financial assistance for the project. EPRI invited Colorado-Ute to submit a formal proposal in accordance with published guidelines issued in November 1982.

In February 1983, Colorado-Ute prepared and submitted a detailed proposal to EPRI for its Nucla AFBC demonstration project. This initial proposal was for a new 100-MW bubbling AFBC boiler with a reheater. In mid-1983 EPRI chose to support TVA's bubbling AFBC project. Colorado-Ute then became interested in the alternative circulating AFBC technology and continued its dialogue with EPRI. Colorado-Ute obtained initial vendor capital cost estimates for a circulating AFBC type boiler that were significantly lower, approximately $8 million or $70/kW, than for the bubbling AFBC. Based on these estimates, the company decided that the proposed project was justified on its own merits without outside financial support, and in September 1983, announced its intention to proceed with the Nucla circulating AFBC project to be completed by the fourth quarter of 1987. Risk funding was the only remaining major concern.

In the fall of 1983, EPRI responded positively to Colorado-Ute's continuing efforts, with funding that totaled $177,000 for a two-part circulating AFBC design study. Part 1 of this study was to address design of a new circulating AFBC boiler applicable to the Nucla site, and Part 2 to address the issue of scaling up the circulating AFBC boiler size to 500 MW for an undetermined site.

In the winter of 1983-1984, Colorado-Ute received the study results and prepared a detailed project estimate based on two different circulating AFBC boiler designs. The estimates verified an earlier projection of $103 million for the full project. This was before Colorado-Ute received firm price quotations that subsequently lowered the final project estimate to $87 million.

TABLE 6
PROJECTED FIRST-YEAR OPERATING COSTS

Assumptions	
Total Project Cost	$86,67 million (from Table 5)
Pollution Control Equipment Cost*	$15 million
Interest Rate	12.0%
Pollution Bond Rate	6.5%
Coal Cost	$19/ton
Limestone Cost	$16/ton
Depreciation Rate	3.1% per year
Property Tax Rate	1.17%
Insurance Rate	0.15%
Net Plant Capacity	100 MW
Net Unit (Plant) Heat Rate	11,500 Btu/net kWh
Annual Capacity Factor	80.0%
Coal Required	415,000 tons/year
Net Generation	701 GWH/yr

Operating Costs Category	Costs (millions of dollars)	Busbar Costs (mills/kWh)
Interest Costs	9.248	13.20
Depreciation, Insurance, Taxes	3.706	5.29
Fixed O&M	1.420	2.03
Variable O&M	0.608	0.87
Coal	7.893	11.26
Limestone	0.219	0.31
Ash Disposal	0.163	0.23
Water	0.046	0.06
Natural Gas	0.075	0.11
General Chemicals	0.030	0.04
Total	23.408	33.40
Costs related to existing plant value and debt	1.104	1.58
Total	24.448	34.98
Colorado-Ute's present (1984) firm wholesale rate to members		41.17

* This includes the circulating AFBC boiler combustion chambers, bed letdown equipment, hot cyclones and loop seals; plus the baghouse, limestone and ash handling equipment, and stack monitoring equipment. Note that subsequently this type of financing was not chosen. However, at the time of the feasibility study it was assumed that approximately $15 million would be financed with a 6.5% interest rate.

Source: "Feasibility Study, Nucla CFB Demonstration Project," Colorado-Ute Electric Association, Inc., August 1984.

In exchange for EPRI's technical assistance and financial support, Colorado-Ute agreed to make available the circulating AFBC boiler for two years of testing. This program is part of a large EPRI effort, it also includes the bubbling AFBC projects at TVA's Shawnee Station and Northern States Power Company's Black Dog Station and it is designed to support AFBC technology development and provide the last critical link between laboratory test facilities and commercial operating power plants. Data and experience gained will broaden the knowledge base on AFBC and reduce the risk for future plant designs using the technology.

At Nucla Station, EPRI will conduct a comprehensive series of tests on the circulating AFBC generator over a two-year period. The unit size is ideal for linking small experimental and industrial-scale data and experience with future scale-up efforts. The scope of the test program includes steady-state performance testing, continuous performance monitoring of plant components and special tests to identify effects of coal characteristics on boiler operation.

EPRI's total budget commitment for the project is limited to approximately $14 million, to include the preliminary boiler studies, special test instrumentation, the two-year test program, project reporting, and compensation to Colorado-Ute for negatively affected generation revenues during the project testing phase.

DOE PARTICIPATION

The past interest in AFBC technology by the U.S. Department of Energy is well documented. This led Colorado-Ute to investigate the possibility of obtaining a Cooperative Agreement under the Clean Coal Technology Program - Phase I. In April 1986 an application was filed by Colorado-Ute with the DOE and this culminated in Cooperative Agreement, DE-FC21-89MC25137. Department of Energy assistance amounted to $19.92 million in project testing support and began in August 1988. The DOE program administration became the responsibility of the Morgantown Energy Technology Center located in Morgantown, West Virginia.

ENVIRONMENTAL AND SOCIOECONOMIC CONSIDERATIONS

On March 17, 1983, the Colorado Public Utilities Commission granted a Certificate of Public Convenience and Necessity for the Nucla Project. The remainder of the permit and licensing process was relatively easy and straightforward, primarily due to the project being a retrofit of an existing plant.

Preliminary environmental reviews by the United State Environmental Protection Agency and the Colorado Department of Health disclosed that no significant environmental impacts would be associated with the Nucla project.

The construction of a circulating AFBC project at the existing Nucla Station would not affect wetlands, flood plains, threatened or endangered species, prime farmlands, or cultural resources. The project would be constructed at the existing coal-fired Nucla Station site and no additional land would be needed. Further, no new transmission lines would be constructed in connection with it.

Circulating AFBC combustion represents a cleaner method of burning coal than currently existed at the Nucla Station, and would result in lower total emissions of SO_2 and particulates. Even though the plant output would be increased from 36 MW to 110 MW, NO_x emissions were expected to decrease based on circulating AFBC combustor testing. This included testing of the Nucla coal in a circulating AFBC pilot combustor, which showed NO_x emissions to be 0.2 to 0.3 lb/10^6 Btu.

The impacts to areas that could be susceptible to acid deposition would be reduced because the SO_2 emissions would be reduced. The Nucla project would not cause any visibility impacts in Federal Class 1 or Class 2 areas. A Prevention of Significant Deterioration (PSD) permit was required and obtained.

Water for the Nucla project is available from the San Miguel River which flows next to the station. Water quality in the San Miguel River would not be impacted by operation of the circulating AFBC unit. Nucla Station had a current Colorado Waste Water Discharge Permit. The proposed life extension modification would discharge more flow than did the existing station but effluent concentrations would be the same as in the existing permit, which could be modified to reflect these changes.

The socioeconomic impact of constructing and operating the proposed circulating AFBC unit at the Nucla site would be very positive. The Nucla area, including the towns of Nucla, Naturita, Norwood and Uravan, was hard hit by cutbacks and shutdowns in uranium mining and processing facilities. It was expected that a portion of the work force needed for construction of the Nucla project would be recruited from the Nucla area, although workers with specialized construction skills might come from outside the area.

To help ensure that local labor was used during construction, Colorado-Ute included a special feature in the "Project Labor Agreement". This feature called for utilization of the local labor force to help minimize unemployment and stabilize the local economy. The local unions were to strive to furnish 50% of the work force from the immediate Nucla area communities.

The "Project Labor Agreement" was negotiated by Colorado-Ute with 21 local unions, and their respective internationals, affiliated with the Colorado Building and Construction Trades Council. All

Colorado-Ute's contractors and subcontractors were required to become signatory to the "Project Labor Agreement".

Existing housing, law enforcement, hospitals, schools and other support facilities were considered adequate to accommodate the construction work force and their families.

Costs for constructing the Nucla circulating AFBC demonstration project were monitored throughout the project and categorized according to an AFBC code of accounts. This provides consistency, which will make future comparisons of project cost elements possible. However, this code was developed by the Electric Power Research Institute (EPRI) and although used in all AFBC demonstration projects, it is not presented herein due to availability and non-completion of this particular project.

Section 2 of this report describes the circulating AFBC boiler equipment and integral systems. The section discusses the functional boiler operating system, which include the circulating AFBC boiler (including a summary of the circulating fluidized-bed combustion process and boiler components), the coal and limestone feed systems, the combustion air and flue gas systems, the solids separation and recycle system, boiler miscellaneous equipment, plus, the boiler startup system, and boiler instrumentation and controls.

Section 3 details the boiler plant material-handling equipment and related systems. These include: the coal-handling system, the limestone-handling system, and the ash-handling systems. The general design/functional description and specific data are presented for each material-handling system plus major equipment items within. The material-handling descriptions and data include information about the old plant equipment and systems, as well as the new plant equipment and systems.

Section 4 discusses balance-of-plant mechanical equipment and systems, which are support facilities. These include piping, water supply and circulating systems, the condenser, chemical feed plus miscellaneous HVAC, air, hoist, lubrication, fire protection and startup fuel gas systems. Both new and existing plant information is included and tied together.

Section 5 presents the turbine-generator and balance-of-plant electrical equipment and inherent systems. This section discusses functional operating systems and includes all plant equipment and systems not included in the previous sections. Again, the general design/functional description and data are presented for each operational system and equipment item. The turbine and balance-of-plant descriptions and data include information about the old plant equipment and systems, as well as the new equipment and systems that comprise the balance of the overall power plant facility.

Section 6 contains the plant instrumentation and controls equipment and systems. The nerve system of a power plant includes all controls, alarms, annunciators, displays, panels and emission monitoring as well as others. Again both new and existing systems have been integrated into the discussion.

Section 7 describes special test equipment and facilities installed for EPRI's contract and two-year test program to study the Nucla circulating AFBC boiler and its operating characteristics.

Appendix A contains the plant equipment and data information list. Appendix B is bound separately and presents process flow and instrumentation drawings, which are non-proprietary. Appendix C also was bound separately and is not available for public distribution, due to Pyropower proprietary process flow and instrumentation drawings. Appendix D is included herein and provides a list of the Technical Advisory Group.

Section II. Circulating AFBC Boiler Systems

2.1 Circulating AFBC Boiler

The circulating AFBC boiler is a coal-fired, balanced draft, circulating fluidized-bed boiler supplied by Pyropower Corporation, a subsidiary of the A. Ahlstrom Corporation. It has a maximum continuous rating of 420,000 kg/hr (925,000 lb/hr) of superheated steam at 106-kg/cm^2 (1510 psig) and 540°C (1005°F).

Included in this section under the circulating AFBC boiler heading is a summary description of the Nucla circulating fluidized-bed boiler combustion process and components. The coal- and limestone-feed systems consist of independent coal and limestone equipment that regulates the flow of coal and limestone from silos into the boiler combustors. The air and flue gas system includes the boiler combustion air supply from the draft fan intakes to the combustion chambers and the flue gas discharge from the boiler to baghouses and the stack. The solids separation and recycle system contains the circulating AFBC boiler hot cyclones and loop seals that recycle bed material back to the combustion chambers. The boiler startup system is comprised of the startup and duct burners. The boiler instrumentation and controls include the boiler-mounted instruments and the circulating AFBC boiler operating procedures. Circulating AFBC boiler system equipment data is included in Appendix A together with P&ID drawings which are non-proprietary in Appendix B.

2.1.1 Process and Component Summary

The primary circulating AFBC boiler sections are:

- Two combustion chambers
- Two hot cyclone collectors
- A common convection section.

The Nucla unit design performance is summarized in Table 7. A sectional side view of the Nucla circulating AFBC boiler is presented in Figure 14.

Combustion and sulfur-absorption reactions (calcination and sulfation) take place in the combustion chambers, which are fully water cooled using a membrane-type wall construction. Primary air, which is used for fluidizing the bed and maintaining the proper air-to-fuel ratio, is introduced through

Table 7
CIRCULATING AFBC BOILER PERFORMANCE SUMMARY

Superheater outlet:		
Steam flow	420,000 kg/hr	(925,000 lb/hr)
Steam temperature	521 ± 6°C	(1005 ± 10°F)
Steam pressure	106 kg/cm²	(1510 psig)
Boiler design pressure	124 kg/cm²	(1760 psig)
Sootblowing steam:		
Flow	12,250 kg/hr	(27,000 lb/hr)
Pressure	113 kg/cm²	(1610 psig)
Temperature	427°C	(801°F)
Fuel input:		
Coal A *	52,850 kg/hr	(116,400 lb/hr)
Coal B *	65,010 kg/hr	(143,200 lb/hr)
Drum pressure:	116 kg/cm²	(1655 psig)
Economizer:		
Inlet pressure	119 kg/cm²	(1689 psig)
Inlet temperature	227°C	(440°F)
Outlet temperature	280°C	(536°F)
Excess air:	20%	20%
Primary air:		
Air temperature	190°C	(374°F)
Secondary air:		
Air temperature	184°C	(363°F)
Flue gas flow:	501,100 kg/hr	(1,103,700 lb/hr)
Heat release:	1.19×10^{12} J/hr	($1,128 \times 10^{6}$ Btu/hr)
Boiler efficiency:	88.27%	88.27%
Flue gas temperatures:		
Leaving combustors (furnace)	871°C	(1600°F)
Leaving air heater	126°C	(258°F)
Boiler emission limits:		
Particulates	13 ng/J	(0.03 lb/10^6 Btu)
NO_x	215 ng/J	(0.5 lb/10^6 Btu)
SO_2	172 ng/J	(0.4 lb/10^6 Btu)

* Reference Table 3

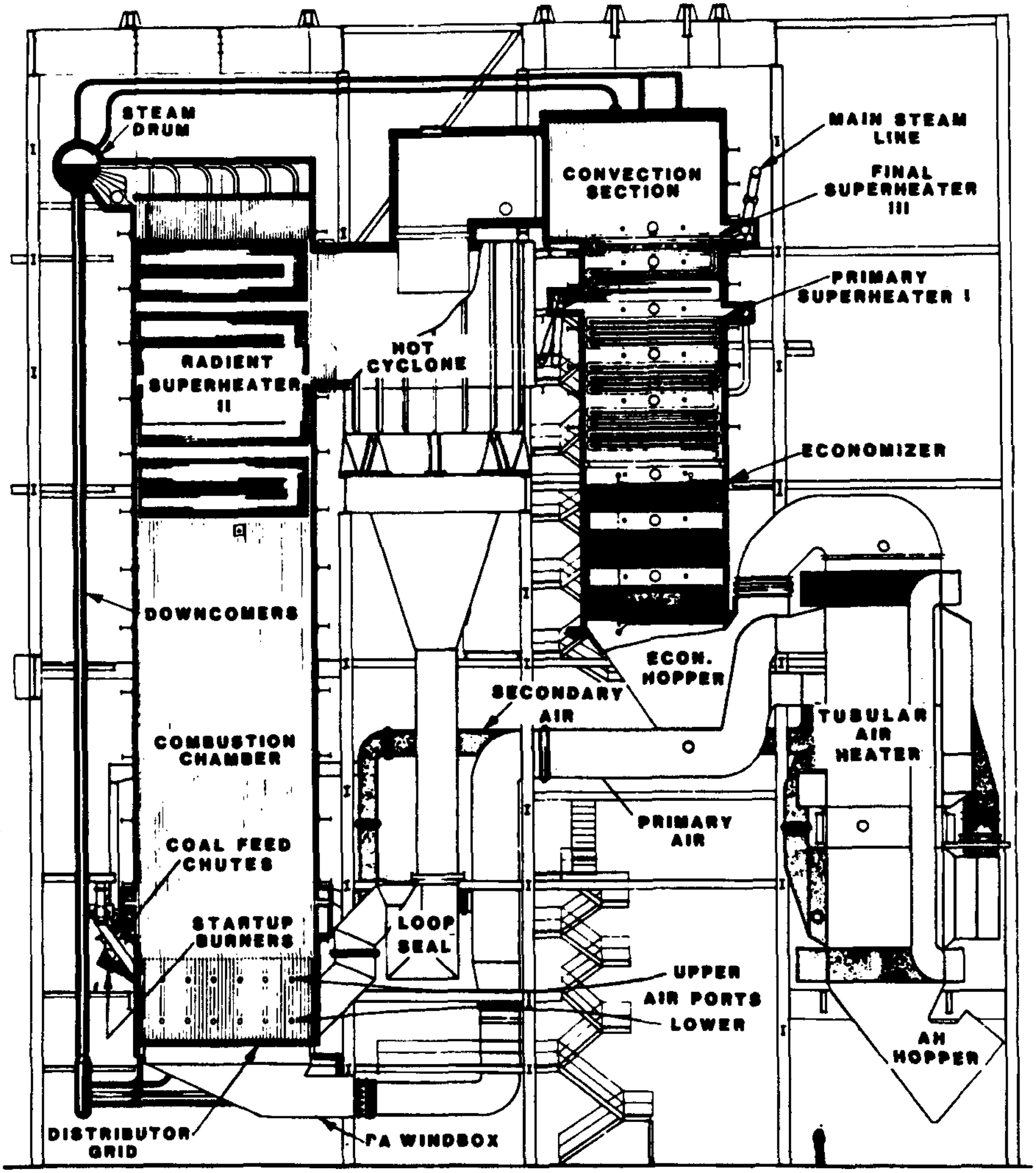

FIGURE 14

CIRCULATING AFBC BOILER - SECTIONAL SIDE VIEW
SOURCE: PYROPOWER CORPORATION

both the bottom distributor grid nozzles, where the bed material is fluidized, and the lower wall ports located in all four walls of each combustion chamber for bed mixing. Secondary air, which is used to ensure complete combustion and to reduce NO_x emissions, is introduced through wall ports located above the primary air ports in the lower zone of the combustion chambers (see Figure 14).

The fluidized-bed material consists of unreacted coal, unreacted limestone, calcined limestone, ash, and calcium sulfate. Ninety to ninety-five percent of the bed material is spent (reacted) limestone, inert ash, and calcium sulfate. Only a very small amount of the bed material is unburned coal. The slip velocity between gas and solids, as well as the turbulent nature of the circulating fluid bed, provides excellent mixing and temperature distribution, conditions necessary for optimum performance. Particles in the mid-section and upper portion of the combustors comprise the entrained, less-dense material that elutriates from the combustion chambers to the hot cyclones. The primary means of heat transfer in the combustion chambers is by a combination of conduction and convection from the fluidized bed to the waterwall enclosure and superheater surfaces.

The two combustion chambers consist of rectangular gas-tight enclosures each 6.9 m (22 ft, 8.25-in.) wide by 7.4 m (24 ft, 2.75-in.) deep and approximately 34 m (110 ft) high. Coal is fed into each combustor from three locations, two in the front wall and one in the bed recycle loop seal. The loop seal recycle port is located in the combustion chamber rear wall. Limestone is pneumatically fed into each combustor from four feed ports, with two located on the front wall, one on the outside sidewall, and one on the rear wall of each combustor. Spent bed ash is drained from each combustor to ash coolers through two bottom ash drain ports located on the outside sidewalls at the distributor grid elevation. The distributor grid floor is comprised of membrane water-cooled tubes that slope toward these spent bed ash drain ports. The ash coolers are also connected to the combustors by equalizing ports located above the spent bed ash drain ports.

Four radiant superheater sections are located in the upper zone of each combustion chamber (see Figure 14). Each combustor radiant superheater section is arranged horizontally adjacent to the combustor front and sidewalls. Heat transfer to these superheater sections is primarily by a combination of conduction and convection from the circulating bed material.

The elutriated bed material and flue gas leave each combustion chamber through a waterwall-cooled duct section connected to the top rear corner of each combustor. The combustion chamber outlet duct section is connected to each hot cyclone inlet by a refractory-lined expansion joint.

The two hot cyclone collectors, one per combustion chamber, separate entrained bed particles from the flue gas stream. The collected particles are recirculated by gravity through nonmechanical loop seals back to the lower zone of the combustion chambers.

The hot cyclones are each approximately 7 m (23 ft.) in diameter. The round cyclone flue gas outlet ducts are connected to a transition duct that, in turn, is connected to a common rectangular convection zone inlet. The loop seals are connected directly to the bottom of the cyclones. The hot cyclones, cyclone inlet and outlet ducts, and loop seals are internally lined with layers of both erosion resistant and insulating refractory with a total thickness of approximately 30 cm (12 in.).

The hot cyclone outlet transition duct is connected to the convection zone inlet by a refractory-lined expansion joint similar to the combustion chamber outlet/hot cyclone inlet connections. These circulating bed recycle section (hot cyclones and loop seals) expansion joints are provided to permit differential expansion between the bottom-supported hot cyclones and loop seals and the top-supported combustion chambers and convection section.

Flue gas leaving the two cyclone collectors continues to the common convection zone, imparting heat via convective heat transfer to the final superheater, primary superheater, and economizer areas. From the convection zone the flue gas continues through the tubular air heater, baghouses, induced draft (ID) fan, and it is then discharged to the stack.

The convection cage is formed by a steam-cooled membrane-type wall that encloses the final and primary superheater sections. The steam-cooled membrane walls comprise the inlet portion of the primary superheater. The economizer is enclosed by steel casing.

Combustion air is supplied by centrifugal, variable-speed motor-driven primary and secondary air fans. Primary and secondary air is heated in a tubular air heater before delivery to the combustion chambers. Primary air is supplied to the following locations: (1) below the air distribution grid at the bottom of the combustion chambers, (2) to lower wall ports located around the periphery of the combustion chambers, (3) to the rear-wall, loop-seal coal injection ports, and, finally, to the startup burners. Secondary air is supplied to a level of wall ports above the primary air ports located around the lower periphery of the combustor chambers and to the front-wall coal injection ports. High-pressure air (aiding the recirculation of bed materials through the nonmechanical loop seals) is supplied by either of two full-capacity, high-pressure loop seal blowers. An ash-cooling fan is supplied to cool, fluidize, and classify spent bed letdown ash entering the ash coolers. Eight limestone air blowers are provided to pneumatically convey limestone from the feeders into the combustion chambers.

Feedwater is supplied to the economizer at a temperature of 227°C (440°F) and 119 kg/cm^2 (1689 psig), where it is heated before delivery to the steam drum. From the steam drum, the boiler water is delivered via downcomers to the combustion chamber waterwalls, where it receives additional heat from the combustors and is then returned via risers as steam/water mixture to the steam drum. Boiler water circulates naturally between the steam drum and the combustion chamber waterwall heat absorption surfaces.

Steam flows from the steam drum to the convection cage section located at the outlet of the hot cyclone collectors. The saturated steam is routed through the convection cage, which forms a steam-cooled enclosure, to the primary superheater. The primary and final superheaters are located in the convection area and are supported by the economizer outlet tubes. Steam flows from the primary superheater to the final superheater via radiant superheat sections located in the upper zone of each combustion chamber. Two intermediate stages of superheater attemperation (desuperheating) are used to control final steam temperature. Two first-stage attemperators are located between the primary superheater and the combustion chamber radiant superheater, and two second-stage attemperators are located between the radiant superheaters and the final superheater section.

Fuel (coal) and sorbent (limestone) are fed from boiler silos to the combustion chambers via independent feed systems. The coal and limestone feed systems both utilize gravimetric-type feeders to provide controlled feed of both presized coal and limestone from silos into each circulating AFBC boiler combustion chamber. Coal is fed into each combustor at three locations, and limestone is fed into each combustor at four locations. A coal feeder and rotary valve are provided for each combustor coal feed port. Coal flows by gravity from the feeders and rotary valves into the combustors. One limestone feeder is provided for each combustor. Limestone is pneumatically conveyed from each feeder by four pneumatic conveying trains per combustor, one per limestone feed port.

Each combustion chamber bottom material (spent bed) is removed from the combustors to four air-and-water cooled, ash-fluidizing cooler/classifiers (two 100% capacity ash cooler/classifiers per combustion chamber). This material is discharged through rotary seal valves to surge hoppers (one surge hopper per combustion chamber). Spent bed material is discharged to the bottom ash removal system either directly from the surge hopper or using a water-cooled screw conveyor, depending on its temperature. The screw coolers are required for supplemental bottom ash cooling when the solids temperature in the surge hopper exceeds 204°C (400°F).

The principal design criteria and specifications for site environmental, fuel, ash, limestone, and water for the Nucla circulating AFBC boiler are presented in Tables 8, 9, 10, 11 and 12, respectively. A simplified process flow diagram of the Nucla circulating AFBC boiler is presented in Figure 15.

Table 8

PLANT SITE ENVIRONMENTAL DESIGN PARAMETERS

Plant altitude, elevation above mean sea level:	1,700 m (5,600 ft)
Barometric pressure, absolute:	62.9 cm Hg (24.75 in. hg) 0.841 kg/cm^2 (11.96 psia)
Seismic:	UBC Zone 1
Relative humidity:	50%
Design intake combustion air temperature:	27°C (80°F)
Outside air temperature range:	-29° to 32°C (-20° to 90°F)
Inside air temperature range:	4° to 49°C (40° to 120°F)

(The circulating AFBC boiler is enclosed.)

Table 9

COAL FUEL ANALYSIS

Coal	A* Performance Coal	B Design Coal
Source	Nucla, CO	Nucla, CO
Gradation	Uniform	Uniform
Proximate analysis, % by weight:		
Moisture	5.8	6.0
Volatile	26.9	21.0
Fixed Carbon	41.2	40.0
Ash	26.1	33.0**
Total	100.0	100.0
Ultimate analysis, % by weight:		
Carbon	55.17	46.41
Hydrogen	3.63	3.60
Sulfur	0.73	2.5 **
Oxygen	7.51	7.5
Nitrogen	0.98	0.90
Chlorine	0.04	0.04
Moisture	5.86	6.00
Ash	26.08	33.05
Total	100.00	100.00
Gross heating value as fired: J/kg:		
J/kg:	10.26×10^6	8.47×10^6
(Btu/lb)	(9693)	(8000)
Surface moisture as fired, % by weight:	3.74	4.0
Ash softening temperatures (reducing atmosphere, °C [°F]):		
Initial deformation	1454 (2650)	1454 (2650)
Softening	1482 (2700)	1482 (2700)
Fluid	1482 (2700)	1482 (2700)

* Coal analysis as tabulated in Column A constitutes the basis for all guaranteed and predicted performance data. The circulating AFBC boiler unit is capable of developing specified capacity using coal analysis as tabulated in Column B. Also, the Column B coal ensures that the boiler will be capable of burning alternative fuels during EPRI's two-year test program.

** 2.5% sulfur and 33.0% ash for coal "B" does not occur at the same time.

Table 10

ASH MINERAL ANALYSIS (% by weight)

Phos. pentoxide, P_2O_5	0.1
Silica, SiO_2	56.1
Ferric oxide, Fe_2O_3	4.7
Alumina, Al_2O_3	29.1
Titania, TiO_2	1.2
Lime, CaO	4.2
Magnesia, MgO	0.8
Sulfur trioxide, SO_3	2.7
Potassium oxide, K_2O	0.8
Sodium oxide, Na_2O	0.3
Total	100.0

Table 11

LIMESTONE ANALYSIS (% by weight)

The following analysis is typical of the limestone Colorado-Ute uses:

$CaCO_3$	80 - 98%
SiO_2	0.2 - 0.9%
$MgCO_3$	0.6 - 18.0%
Others	Trace

Table 12

WATER ANALYSIS

Boiler water concentrations:

Total dissolved solids	1000 ppm maximum
Free OH	less than 2.0 ppm
Total suspended solids	5.0 ppm
Silica	1.1 ppm

Feedwater quality:

Total dissolved solids	0.5 ppm maximum
Silica	0.01 ppm
pH	8.8 - 9.2
Oxygen	less than 0.007 ppm
Iron	less than 0.01 ppm
CO_2	less than 1 ppm
Copper	less than 0.005 ppm
Organics	less than 1 ppm

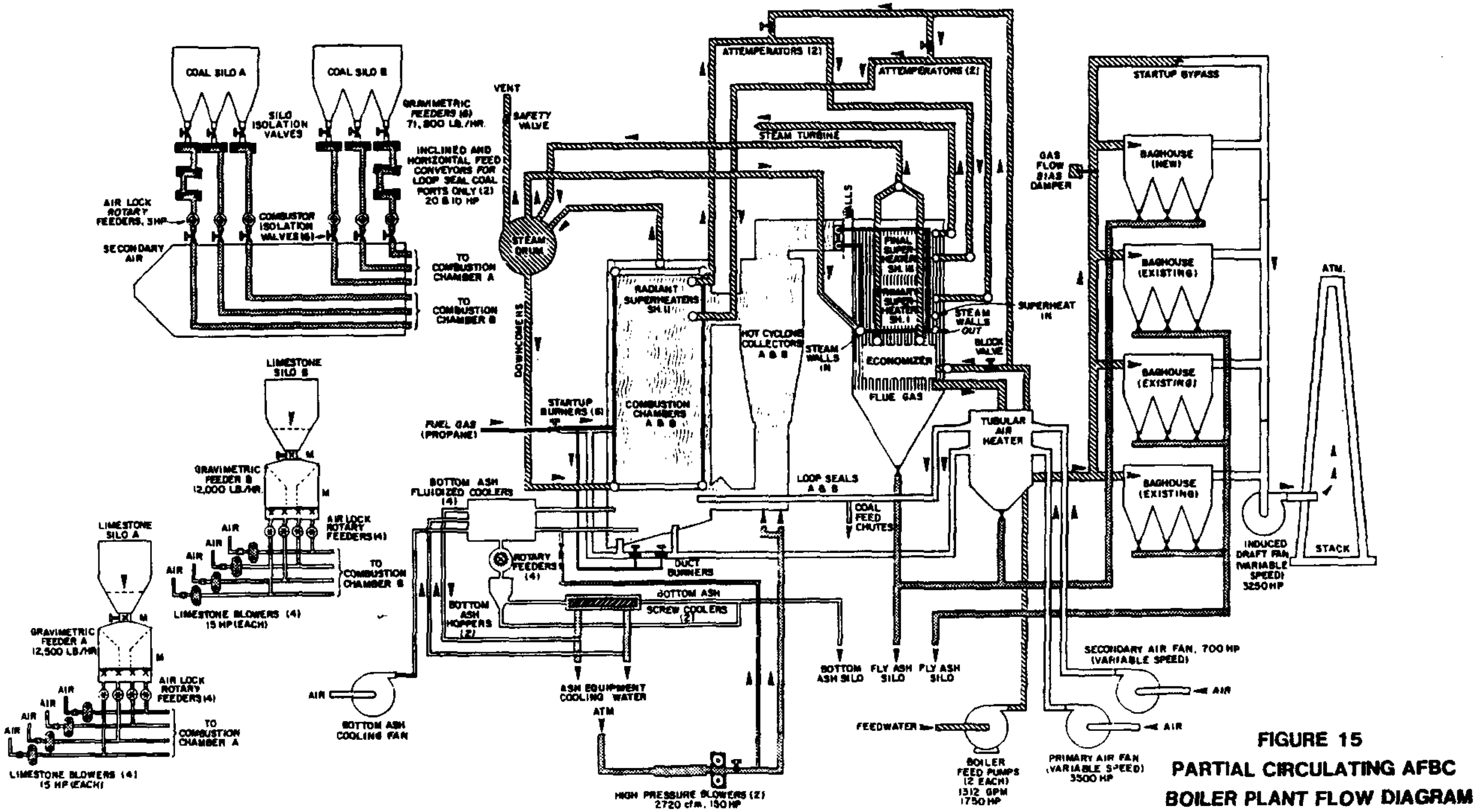

FIGURE 15

PARTIAL CIRCULATING AFBC BOILER PLANT FLOW DIAGRAM

2.1.2 Water Circulation System

The water circulation system includes all the circulating AFBC boiler water pressure parts and components, including the steam drum, waterwall enclosures, downcomers, headers, risers, and other interconnecting piping. A simplified illustration of the Nucla circulating AFBC boiler water-flow circuits is shown in Figure 14.

The steam drum is made of carbon steel with welded construction, including a cylindrical shell and dished heads. It has internal baffles and steam separating equipment to provide high-purity steam to the primary superheater. Connections are provided on the steam drum for venting and draining, safety valves, continuous blowdown, chemical feed, auxiliary stem takeoff, sampling nitrogen blanketing, internal access, level measurement, downcomers, risers, feedwater supply, and saturated steam outlets.

The combustion chamber enclosure walls are designed for natural circulation, with the downcomers and risers providing good circulation. All pressure parts are arranged to be fully drainable and are provided with vents and drains. Three downcomers are provided, one centered and one for each outer side of the two combustion chambers. The downcomers each supply a lower header section from which supply tubes feed each of eight membrane wall lower inlet headers, one for each combustion chamber wall. The membrane wall upper outlet headers are connected to the steam drum via risers.

The two combustion chambers comprise rectangular gas-tight enclosures. The lower section of the combustion chamber has the necessary openings in the surrounding membrane wall for combustion air, fuel and limestone feed, ash removal and recycle reinjection, and gas (propane) startup burners. The combustion chambers operate at a positive pressure, and the membrane walls are reinforced by channel tie bars and buckstays to withstand the operating pressure plus a design margin.

2.1.3 Combustion Chamber Superheater

There are no tube bundles located within the lower dense portion of the circulating fluidized bed. The only tube bundles that are considered to be within the combustor are the horizontal pendant superheater II, or radiant superheater platen sections located within the upper zone of the circulating AFBC and these are upstream from the hot cyclones. The superheater II platen surfaces are all physically arranged just inside and adjacent to the upper front and side combustor waterwalls.

Heat transfer to these superheater sections is predominantly by a combination of radiation and convection. The tube banks are located adjacent to the upper front and both sidewalls of the combustion chambers and are drainable. A schematic diagram of the combustion chambers radiant (secondary) superheater (SH-II) Sections is presented in Figure 16.

2.1.4 Backpass Heat Transfer Surface

The backpass heat transfer surface includes the following components:

- The convection cage steam-cooled, membrane-type walls
- The primary and final superheater tube banks
- The economizer and riser tubes
- Desuperheaters
- Superheater interconnecting piping.

Saturated steam is routed from the drum through the convection cage to form a steam-cooled enclosure. The convection cage houses superheater I (primary SH) and superheater III (final SH). The convection cage is formed of membrane-type construction. The steam-cooled membrane walls form the first section of the primary superheater. Steam flows directly from the convection enclosure membrane wall tubes through an intermediate ring distribution header to the primary superheater.

Superheater I (primary SH) is comprised of tubes arranged in three banks (levels) located within the convection cage enclosure. Superheater III (final SH) is comprised of tubes arranged in two banks (levels) located within the convection cage enclosure above the primary superheater. Remember the superheater II (secondary or radiant) is located in the combustors (one per side) and all superheaters are interconnected by insulated and external transport piping.

Control of final steam temperature is accomplished by means of two stages of spray attemperation. The first stage is between superheater section I (primary SH) and II (combustion chamber radiant SH). The second stage is located between superheater section II and section III (final SH).

There are two attemperators for each stage, one each on either side of the boiler. Each attemperator uses a venturi spray design. Together, the two desuperheating stages are capable of controlling the final steam temperature to 541±6°C (1005±10°F) over the boiler operating range of 54 to 100% of maximum continuous rating (MCR).

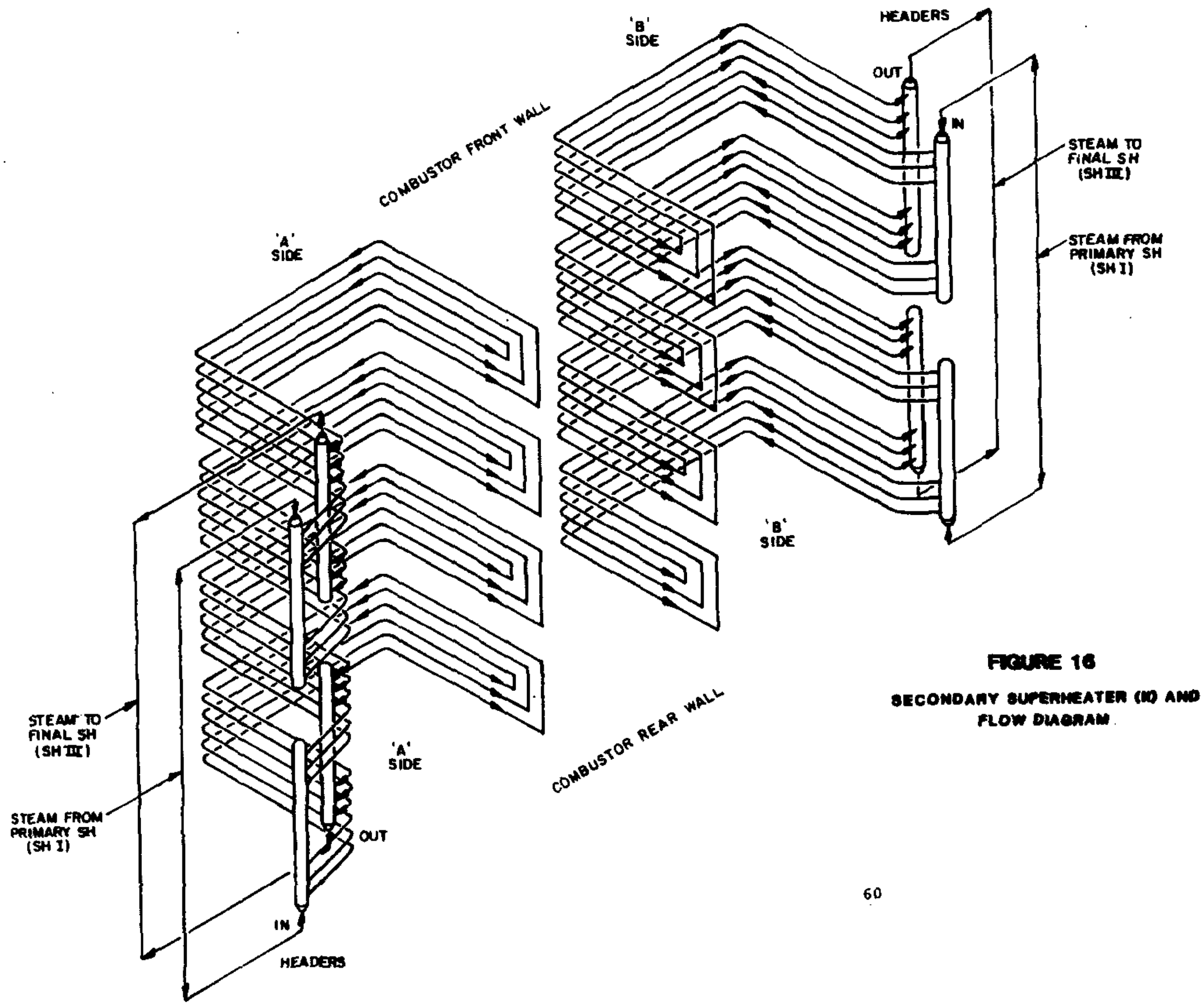

FIGURE 16

SECONDARY SUPERHEATER (II) AND FLOW DIAGRAM

The economizer uses the bare tube horizontal serpentine design arranged in three banks. Economizer inlet and outlet headers are equipped for venting and draining. The economizer inlet feedwater line is equipped with feed-stop and feed-check valves. The economizer outlet tubes (risers) form water-cooled supports for the superheater I (primary SH) and superheater III) final SH) tube banks.

Two ash hoppers are located below the economizer to reduce ash deposition inside the tubes of the downstream air heater. Each hopper is an inverted pyramidal shape and has a capacity of approximately 30 tons (33 short tons) of fly ash. The economizer is enclosed by steel casing. The economizer casing is fabricated from flanged steel panels, reinforced as required and seal welded at all joints to prevent gas leakage. The casing is insulated and lagged.

2.1.5 Sootblowers

Steam sootblowers are provided to clean the economizer and tubular air heater surfaces. The circulating AFBC boiler is provided with sootblower wall boxes in the primary (SH I) and final (SH III) sections of the convection zone for future sootblower additions, if required at a later date.

A total of 16 steam sootblowers are provided. Twelve fixed-position, lance-type sootblowers are installed in the economizer, six on each side. Four straight-line retractable sootblowers are installed on the tubular air heater cold section inlet tube sheet. Steam is used as the blowing medium. (The plant compressed air system was not sized for sootblower air requirements or pressures.) Sootblowing steam is provided from the Superheater I outlet steam header and reduced to a pressure of 600 psig.

Originally, sootblowers were not to be provided for the circulating AFBC boiler, but wallboxes for their future installation were provided. Colorado-Ute agreed to add the sootblowers during the construction phase of the project as advised by Pyropower. This decision was based on operating experience with Pyropower industrial circulating AFBC boilers which showed a steady increase in boiler flue gas outlet temperatures when sootblowers were not operated on a regular basis.

2.1.6 Boiler Insulation/Lagging/Casing

The boiler insulation/lagging/casing scope of supply includes boiler components and accessories that protect, insulate, reinforce, and provide access to the air/gas side of the boiler. This includes the combustor and the convection sections of the circulating AFBC boiler, the baghouses, air and gas ducts, and boiler interconnect piping. Also included are the penthouse casing, penthouse and combustor access openings, combustor refractory, and combustor buckstays in addition to the combustors and penthouse insulation and lagging. The convection section insulation/lagging/casing scope includes access openings, economizer casing, economizer ash hoppers, and convection pass buckstays.

The circulating AFBC boiler is insulated for heat conservation, maintenance of operating temperatures, and protection for personnel. All external surfaces of the boiler are insulated with mineral wool or calcium-silicate insulation, except the recycle system components (hot cyclone collectors, loop seals, and gas flues) which are internally lined and insulated with castable refractory. The boiler external surfaces are insulated or refractory lined (recycle system) to prevent the face surface temperature from exceeding 60°C (140°F) based on 27°C (80°F) ambient air temperature and 15 m/min (50 ft/min) air velocity.

The boiler combustor and convection section enclosures are constructed of membrane-type walls so that thermal insulation is limited to mineral fiber covered with ribbed aluminum lagging. The economizer section has an uncooled casing, but it is located in a relatively low-temperature region of the boiler so that thermal insulation requirements were not excessive.

The combustors and convection pass membrane walls are reinforced to withstand the positive and negative boiler gas side design pressure of ±102 cm (±(40 in) wg. This reinforcement includes channel tie bars that are welded to the tube walls with buckstays attached to the tie bars via slip connections. These buckstays are located externally outside the membrane wall insulation.

2.1.7 Boiler Vents and Drains

The boiler vents and drains system include all the boiler vent and drain piping, boiler safety valves, and blowdown equipment. The entire system is new.

Boiler vents are provided on the steam drum and on all other boiler pressure part high points including the economizer and superheater sections, as well as on the final superheater outlet connection to the main steam line. Boiler drains are provided at all pressure part low points. Vent and drain down lines are complete with two isolation valves to meet American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code requirements. All vents, including safety valve vent stacks, are safely routed to the atmosphere. All boiler drains are routed to the blowdown tank.

Boiler safety valves are provided on the steam drum and final superheater (SH III) outlet header in accordance with ASME Code requirements. Three boiler safety valves are located on the steam drum and one safety valve is located on the final superheater outlet header. Also, an electromatic relief valve is provided, which is included with the main steam system.

The boiler continuous blowdown line is provided with two throttling valves arranged in parallel. The continuous blowdown flow passes through the throttling valves to a blowdown flash tank which recovers blowdown flash steam. Blowdown flash steam is routed to the deaerator and the flash tank blowdown drain flow is routed to either the new Unit 4 circulating water system as makeup (normal flow path) or alternatively to the Unit 4 blowdown tank. The blowdown flash tank is also equipped with a safety valve.

In addition to receiving boiler drains and continuous blowdown flows, the blowdown tank also receives turbine drains. Blowdown tank makeup water is supplied from service water, which is regulated to maintain a minimum water level in the tank. Blowdown tank drains flow to a storm drain and to the high-quality holding pond.

2.2 Coal and Limestone Feed Systems

The circulating AFBC boiler has independent coal- and limestone-feed systems. These systems provide controlled feed of presized coal and limestone from the boiler fuel and sorbent silos to each boiler combustion chamber. The combustion chambers have separate injection ports for coal (three each) and limestone (four each). Coal is fed into each combustion chamber through two front-wall coal injection ports and a rear-wall loop seal leg port. Limestone is fed through two separate front-wall limestone injection ports, a side-wall port, and a rear-wall injection port. The Nucla circulating AFBC boiler and limestone feed systems are air- and mechanical-transport types and as shown in Figure 15.

2.2.1 Circulating AFBC Boiler Coal Feed System

The circulating AFBC boiler coal feed system provides controlled mechanical feed of prepared coal from the boiler coal silos to the boiler combustion chambers. The system includes gravimetric-feeder equipment and components located between the coal silo outlet connections and the combustion chambers.

Crushed coal, 6 mm x 0 (1/4 in x 0), flows by gravity from three coal silo pantleg outlet hoppers located on each of the two boiler coal silos. Each coal silo serves one combustion chamber. An elongated silo outlet hopper design enhances coal flow out of these silos. The crushed coal discharges from the silo outlet hoppers through 610 mm (24 in) size, chain-wheel-operated, slide-gate isolation valves into gravimetric coal feeders. A total of six gravimetric coal feeders are furnished for the circulating AFBC boiler. Three feeders connect each coal silo to each combustion chamber. There are three coal feed port locations in each combustion chamber, one per feeder train. Two are located in the front wall and one in the loop seal in the rear wall of each combustion chamber.

The operating equipment in each of the six coal feed trains consists of the following:

- A feeder inlet isolation slide-gate
- A gravimetric feeder
- A rotary valve
- A combustion chamber motor-actuated isolation gate.

Two of the six coal feed trains, those feeding to the rear-wall loop seal feed locations on each combustor, also have horizontal and inclined en-masse conveyors to physically transport the coal from the feeder discharge connection around the combustor to the rear feed port located on the loop seal leg. The rotary valves in each coal feed train act as a pressure seal between the pressurized combustion chambers and the coal feed system, which operates at atmospheric pressure.

Each gravimetric coal feeder for each combustion chamber is redundant. The capacity of each combustion chamber feed system is capable of full load. Coal feed system design data are presented in Table 13. It is expected that a reduction in carbon utilization will occur with only one or two feed systems in operation per combustor due to poorer fuel feed distribution. Each gravimetric feeder and rotary valve feeds coal into the combustion chamber through an inclined gravity feed chute connected to the combustor or loop-seal, coal-feed port. At each coal-feed port, a plenum box is provided through which secondary air acts as a purge.

Table 13

COAL FEED SYSTEM DESIGN DATA

Coal Feed System Capacity:	
Design flow Rate	195,220 kg/hr (430,000 lb/hr)
Boiler full load flow rate	
"A" coal	52,850 kg/hr (116,400 lb/hr)
"B" coal	65,300 kg/hr (143,830 lb/hr)
Number of feed trains	3 per combustor 6 total
Coal Feed Train Capacity (each):	
Design flow rate	32,600 kg/hr (71,800 lb/hr)
Boiler full load flow rate	
"A" coal	8,810 kg/hr (19,400 lb/hr),
"B" coal	10,880 kg/hr (23,970 lb/hr)
Combustor capacity/feed train	100%

The coal-feed rate is adjusted automatically, as required by the turbine-generator steam demand, and trimmed by boiler pressure. This is accomplished by changing the speed of each gravimetric feeder on a predetermined proportionate basis over the normal boiler load turndown range.

Originally, the loop-seal, coal-feed ports were provided for design flexibility in the event that improvement in actual performance (carbon utilization) should be required at a later date. The boiler manufacturer decided that these feed locations would be required to meet performance guarantees during the construction phase of the project. This decision was based on the operating experiences of their industrial circulating AFBC coal-fired boilers. This change was initiated in early 1986 during the early phases of the Nucla boiler construction.

2.2.2 Circulating AFBC Boiler Limestone Feed System

The circulating AFBC boiler limestone-feed system provides controlled pneumatic feed of prepared limestone from the boiler limestone silos into the boiler combustion chambers. The system includes all the limestone-feed equipment and components between the limestone silo outlet connections and the combustion chambers.

Pulverized and dried limestone, with an average size of 150 micron (50% passing 100 mesh screen), flows by gravity from the cone-shaped outlets of each of two limestone silos. Each limestone silo serves one combustion chamber. The premilled limestone discharges from the silo outlet hopper through a piston-actuated, slide-gate isolation valve and chute to a limestone feeder. The two limestone feeders, one per combustion chamber, are loss-in-weight type gravimetric feeders (i.e., where the rate of feed from a measured feed hopper weight is integrated over a period of time).

Each limestone-feed system utilizes a bin vibrator (located on the bottom of the limestone silo) to promote flow of limestone into the gravimetric feeder charge hopper. When the feeder charge hopper is full, as measured by its weight gain, two or more of the four hopper outlet gates open. A hopper vibrator regulates the flow rate of limestone from the hopper to the feed streams. When the feeder-charge hopper reaches a preset low limit, as measured by weight loss, the charge hopper is then refilled. Thus, the limestone feeder is a "loss-in-weight" type gravimetric feeder. The limestone gravimetric feeders are electronically monitored over a period of time to obtain an integrated rate of limestone feed. The limestone loss-in-weight type gravimetric feeders are each automatically adjusted in direct relation to combustion chamber coal flow and trimmed based on combustor/hot cyclone outlet flue gas analysis for SO_2.

Each limestone feed stream is admitted to positive pressure pneumatic conveying lines through rotary valves. There are four 50% capacity limestone feed pneumatic transport trains per combustion chamber. Each train consists of the following major equipment:

- a dedicated positive displacement conveying air blower
- rotary valve
- transport conveying line
- injection gate.

This equipment transports the limestone from the limestone gravimetric feeder to four separate feed points on each combustion chamber. With the exception of the transport line length, all eight trains are identical. Limestone and pneumatic conveying air are injected into the combustion chambers through injection ports, one port per conveying line. Each combustion chamber has two limestone injection ports on the front wall (different from the coal injection ports), one on the side-wall, and one on the rear wall at the loop seal recycle port. The limestone pneumatic conveying injection systems are sized to admit the maximum expected limestone flow quantities through any two of the four injection ports per combustion chamber. Limestone feed system design data are presented in Table 14.

2.3 Air and Flue Gas System

The combustion air and flue gas system provides the combustion air to and removes the flue gas from the circulating AFBC boiler. The system includes the combustion air supply from the primary air (PA) and secondary air (SA) forced-draft fan inlets to the boiler combustion chambers, the boiler gas path, and the means of flue gas removal from the boiler to the stack inlet connection. The major system equipment and components are comprised of the following:

- The PA, SA, and ID fans.
- The water-cooled air distributors and windboxes.
- The combustion air ducts and gas flues.

Table 14

LIMESTONE FEED SYSTEM DESIGN DATA

Ca/S Molar Ratio:

The recirculating AFBC boiler guaranteed SO_2 emission limit is 0.4 lb/million Btu heat input.

The guaranteed Ca/S molar ratio to meet this SO_2 emission limit with performance "A" coal is 1.5.

Limestone Feed System Capacity:

Design or maximum flow rate	11,350 kg/hr (25,000 lb/hr)
Full load boiler flow rate	2007 kg/hr (4420 lb/hr), "A" coal

Limestone Pneumatic Feed Train Capacity (for each of eight):

Design or maximum flow rate	1419 kg/hr (3125 lb/hr)
Full load boiler flow rate	251 kg/hr (553 lb/hr), "A" coal

- The air heater, which exchanges heat from the flue gas to the PA and SA combustion air streams.
- The baghouses.
- The stack.

The entire combustion air and flue gas system is new, including new gas flues connecting to and from the existing Unit 1-3 baghouses. The Nucla circulating AFBC boiler and flue gas system is shown schematically in Figures 13 and 15. Air and flue gas system design performance data are summarized in Table 15.

Combustion air is supplied by centrifugal PA and SA fans. Both PA and SA streams are heated in the tubular air heater before delivery to the combustion chambers. Air preheating or tempering coils are not provided upstream of the tubular air heater for either PA or SA streams.

Primary and secondary combustion air are drawn from the upper area of the boiler building by the PA and SA fans. Individual intake ducts are routed to the PA and SA fans, which are both located at the plant grade elevation. This helps boiler building ventilation, recovers boiler and plant radiation heat losses, and preheats the PA and SA air streams during reasonably warm periods. During colder periods, reversible flow, gravity air movers located in the boiler building roof direct outside air (as required) to the PA and SA fan inlets, minimizing the impact on the building heating system.

Primary air is supplied below the air distribution grid at the bottom of the combustion chambers. Primary air is also injected into the combustors through lower wall ports located around the periphery of the combustion chambers for bed mixing (lower-level SA), through the rear-wall coal ports, and through the startup burners. A PA duct burner is installed in each PA distributor windbox. The purpose of the PA duct burners is to preheat fluidizing air during boiler startups, thus avoiding bed material cooling before introducing coal to the bed.

Secondary air is supplied to wall ports located around the periphery of the combustion chambers at an elevation above the PA wall ports and also to the front-wall coal injection ports. The SA is injected into the combustor to ensure complete combustion and provide the benefits of staged combustion (i.e., high-combustion efficiency with low NO_x generation).

Table 15

AIR AND GAS SYSTEM DESIGN PERFORMANCE DATA

Data for Performance Coal "A"

Total Combustion Air Flow:	459,200 kg/hr (1,011,400 lb/hr
Excess Air:	20%
Air Heater Leakage:	0%

Flue Gas:

Flow	512,900 kg/hr (1,129,700 lb/hr)
Leaving Combustors	871°C/-0.3 cm wg (1600°F/-0.1"wg)
To Baghouses	126°C/-32.5 cm wg (258°F/-12.8"wg)
To ID Fan	126°C/-60.2 cm wg (258°F/-23.7"wg)

Additional small amounts of combustion air also enter the combustion chambers from the following sources:

- The high-pressure loop seal air blowers as fluidizing air entrained with the hot cyclone solids recycle streams.
- The bottom ash cooling fan through the bottom ash fluidizing coolers.
- Limestone pneumatic feed conveying air.
- Coal injection ports.

The two hot cyclone collectors separate entrained particles from the combustion chamber outlet flue gas streams. The collected particles are recycled through loop seals to the lower section of the combustion chambers. Flue gas from the hot cyclones continues to the common convection zone, imparting heat via convective heat transfer to the final and primary superheaters and to the economizer. After exiting the boiler convection pass economizer outlet, the flue gas passes downward through the tubular air heater tubes imparting heat to the primary and secondary combustion air streams. The flue gas continues to four baghouses arranged in parallel, one new and three existing baghouses, where entrained fly ash particles are removed to meet emission requirements. Ash is also removed directly from the lower bed section of the combustors as bottom or spent bed ash, and from fly ash collection hoppers located beneath the economizer and air heater outlets. From the baghouses, the flue gas is discharged to the stack by a centrifugal ID fan.

2.3.1 Draft Fans

Both the PA and SA forced-draft fans are equipped with a variable-frequency, speed-control drive system to provide energy-efficient service at normal and partial load conditions. The PA fan is equipped with backwardly curved inclined airfoil blades and an inlet silencer. The SA fan is equipped with airfoil blades, an inlet silencer, and inlet vanes. The SA fan inlet vanes are used in conjunction with the variable-speed drive to control the fan at low loads.

The PA fan speed is controlled to vary primary air-duct pressure. PA flow to each distribution grid windbox, to each combustion chamber wall windbox, and to each startup burner is controlled by dampers, maintaining proper air-to-fuel ratios.

The SA fan speed and inlet vanes are controlled to vary secondary air-duct pressure. SA flow to each combustion chamber wall windbox is controlled to maintain proper staging of combustion. PA and SA air flows to each combustion chamber are measured by flow meters located upstream of each of the flow control dampers.

The ID fan is also equipped with a variable-frequency control drive system to provide energy efficiency at normal and partial load conditions. The ID fan has backwardly curved inclined airfoil blades. The ID fan speed is controlled to maintain a constant furnace pressure as measured at the gas outlet of each combustion chamber. Fan test block margins were increased from those typically specified for conventional pulverized-coal-combustion technology (after considering use of a tubular type air heater, with little or no leakage) to accommodate the burning of alternative test fuels during EPRI's two-year testing program. Design performance summaries for the Nucla circulating AFBC boiler PA, SA, and ID draft fans are presented in Table 16.

2.3.2 Water-Cooled Air Distributor and Windbox

The water-cooled air distributor grids form the bottom of the combustion chambers. Hot primary air at a relatively high pressure enters the air distributor windbox and is passed up through the air grid distributor to fluidize the bed materials. The distributors are of water-cooled membrane construction and are supported from the combustion chamber lower waterwall headers. Each air nozzle is fitted with a nozzle cap. The distributor nozzle caps serve to distribute primary air and prevent bed material from entering the primary air nozzles and windbox. The design of the water-cooled air distributor plate and primary air nozzles is proprietary.

The water-cooled air distributors and lower sections of the combustor sidewalls are protected by refractory. The refractory is a high-density, abrasion-resistant castable material.

A primary air duct burner is installed immediately upstream of each air distributor windbox. The duct burners preheat primary fluidizing air during circulating AFBC boiler startups. This preheating prevents cooling the bed material before introducing coal into it.

Table 16
DRAFT FAN PERFORMANCE SUMMARIES

	Operating	Test Block
Primary Air Fan 4A		
Capacity - kg/hr (lb/hr)	336,000 (740,100)	403,230 (888,180)
- m^3/min (acfm)	5,822 (205,600)	7,512 (265,300)
Head (static) - cm wg ("wg)	137.2 (54.0)	178.3 (70.2)
kW (BHP)	1,421 (1,905)	2,416 (3,238)
Efficiency (static) - %	91.6	90.4
Speed - rpm	1,780	2,120
Inlet Air Temperature - °C (°F)	27 (80)	49 (120)
Inlet Silencer Diff Pressure - cm wg ("wg)	2.3 (0.9)	3.8 (1.5)
Secondary Air Fan 4A		
Capacity - kg/hr (lb/hr)	103,830 (228,700)	124,760 (275,800)
- m^3/min (acfm)	1,801 (63,600)	2,325 (82,100)
Head (static) - cm wg ("wg)	80.8 (31.8)	105.2 (41.4)
kW (BHP)	270 (362)	448 (601)
Efficiency (static) - %	87.9	88.9
Speed - rpm	1,785	2,115
Inlet Air Temperature - °C (°F)	27 (80)	49 (120)
Inlet Silencer Diff Pressure - cm wg ("wg)	2.3 (0.9)	3.8 (1.5)
Induced Draft Fan 4A		
Capacity - kg/hr (lb/hr)	501,080 (1,103,700)	604,040 (1,330,476)
- m^3/min (acfm)	11,553 (408,000)	14,887 (525,730)
Head (static) - cm wg ("wg)	56.1 (22.1)	81.0 (31.9)
kW (BHP)	1,231 (1,650)	2,257 (3,025)
Efficiency (static) - %	86.1	87.3
Speed - rpm	900	1,121
Inlet Static Pressure - cm wg ("wg)	-54.4 (-21.4)	-78.5 (-30.9)
Outlet Static Pressure - cm wg ("wg)	2.5 (0.98)	3.6 (1.43)
Flue Gas Temperature - °C (°F)	126 (258)	149 (300)

2.3.3 Air Ducts and Gas Flues

The air ducts and gas flues are sized for air/gas velocities not to exceed 1067 m/min (3500 ft/min). Baghouse collector branch flues are sized for lower velocities. The ducts and flues are routed in a way to minimize pressure drops and, in the case of the flue gas breaching, to reduce dust buildup.

To ensure these design objectives, the manufacturer performed a 1/16 scale, three-dimensional baghouse and gas flue model study of the air-heater outlet to ID-fan inlet during the design phase of the project. This was necessary because the three existing baghouses were utilized in conjunction with installation of the new baghouse without being relocated. Consequently, the gas flue arrangement to and from the four baghouses is more complicated than an optimum arrangement otherwise would be. The scale model design testing provided insights into areas of high potential draft loss, dust imbalance, and dust drop-out. These potential problems were minimized by modifications to the model. The full-scale gas flue arrangement replicated the final model design.

The gas flue between the ID fan and stack is designed as a long, straight section to provide a more convenient location for the stack gas monitoring equipment.

Combustion air ducts and gas flues are fabricated from carbon steel plate. All ducts and flues are fabricated from carbon steel plate. All ducts and flues are stiffened and reinforced to withstand operating and design pressures. The ducts and flues are of all-welded construction except at connections to dampers, fans, boiler, baghouses, etc. Joints are of the bolted flange type with at least 1/2-in bolts on 7.6 cm (3-in) centers and gasketing for the intended service. Combustion air ducts and gas flues are furnished with access doors, dampers, flow-measuring elements, and expansion joints, as required.

The air ducts and gas flues are externally insulated with mineral wool and are lagged with ribbed aluminum. Insulation design conditions prevent the lagging face surface temperature from exceeding 60°C (140°F) based on 27°C (80°F) ambient air temperature and 15 m/min (50 ft/min) air velocity.

The PA and SA fan suction ducts that lead from the top of the boiler enclosure to the PA and SA fan inlet silencers are round ducts fabricated from 1/8-in carbon steel plate. Round to rectangular transition sections connect to the PA and SA fan inlet silencers.

Primary air control dampers are provided to bypass the air heater cold and intermediate temperature sections, to control PA flow to each combustion chamber bottom fluidizing-grid distribution windbox, to control PA flow to each combustion chamber lower side-wall PA windbox, and to control PA flow to each of the startup burners. The PA fluidizing-grid windbox inlet flow control dampers are located in the main combustion chamber PA supply ducts downstream of airfoil-type flow elements and upstream of the PA duct burners. Primary air pressure control is achieved by speed variation of the PA fan. Manual PA dampers are provided at each combustor lower side-wall PA port and at each of the two rear-wall loop-seal, coal-injection ports.

Secondary air control dampers are provided on the double inlets to the SA fan which, in conjunction with SA fan variable-speed control, are modulated (only at SA fan minimum speeds) to maintain a constant SA supply pressure to the combustors. Flow control dampers are provided in both the SA ducts to each combustor downstream of the airfoil-type flow elements and downstream of the SA supply takeoffs to the coal-injection ports. The two SA flow control dampers are provided at each combustor SA port and at each of the four front-wall coal injection ports.

The only flue gas dampers provided are the various baghouse compartment isolation dampers, the new baghouse bypass dampers, and a single manually-operated flow control damper (l-ocated in the new baghouse inlet flue) to balance flue gas flow between the new and existing baghouses. Flue gas flow and pressure control are achieved by speed variation of the ID fan. The ID fan is modulated to maintain constant furnace pressure as measured at the combustion chamber outlets.

2.3.4 Tubular Air Heater

The tubular air heater is comprised of vertical tubes with separate sections (upper hot end and lower cold end) to facilitate cleaning. Flue gas flows inside the tubes and heats both primary and secondary air, which flow over the tubes in multiple passes. The tubular air heater is illustrated schematically in Figure 17.

The manufacturer uses the tubular type of air heater because of the relatively high pressure differentials between the combustion air and flue gas streams. Most of the Ahlstrom Group tubular air heaters employ horizontal tubes with gas flowing over the tubes. Although this usually results both in lower gas and air-side pressure drops and in space savings,

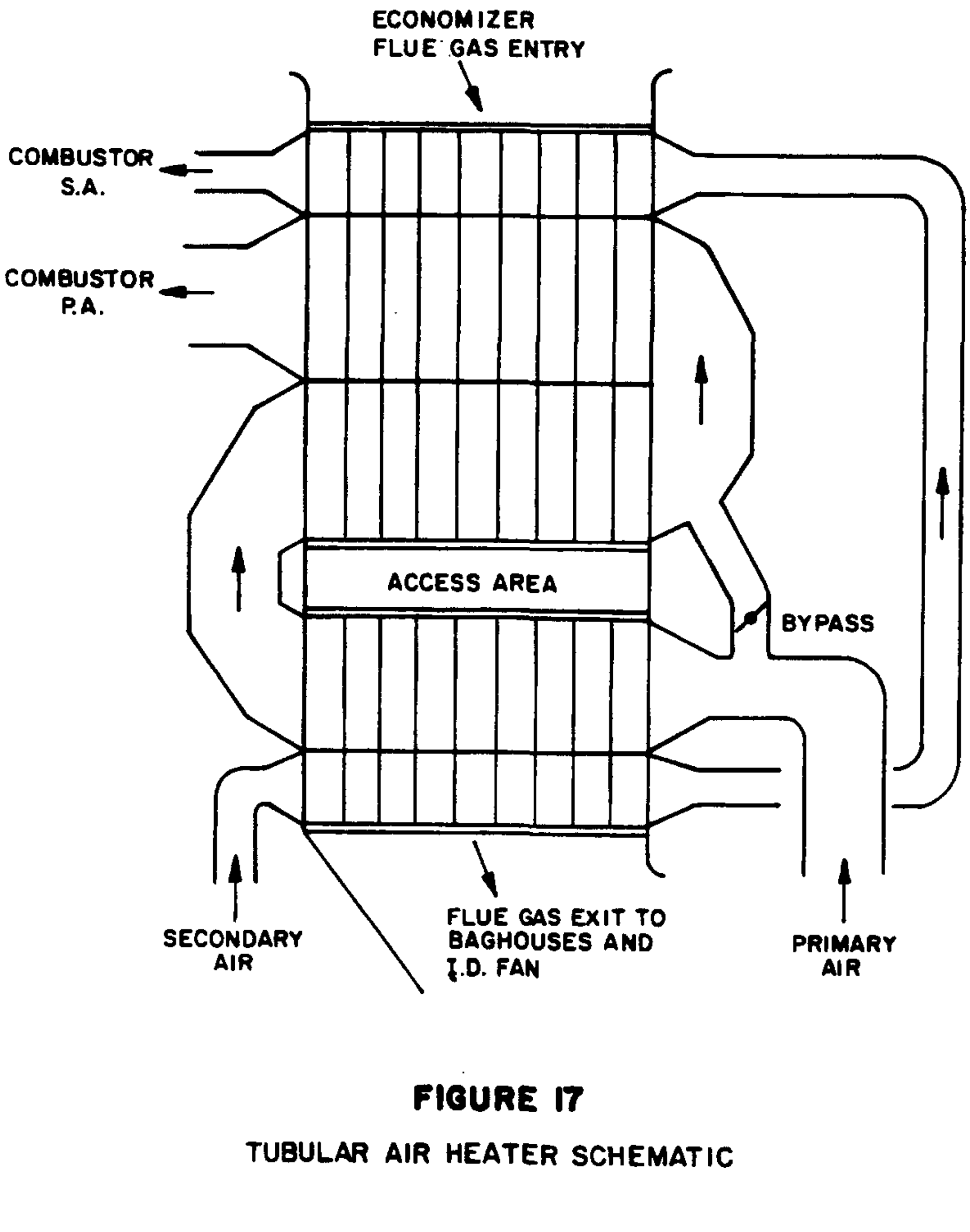

FIGURE 17

TUBULAR AIR HEATER SCHEMATIC

Colorado-Ute requested the vertical-tube design with the flue gas flowing downward inside the tubes to facilitate space savings, cleaning and maintenance.

Flue gas from the boiler economizer outlet enters the top of the air heater and flows downward inside vertically arranged tubes in a single pass through the upper hot end followed by passage through the lower cold-end section. Primary and secondary air streams pass horizontally over the tubes in a multipass crossflow arrangement. Primary air is arranged for three passes, one across the lower cold-end section and two across the upper hot-end section. Secondary air is arranged for two passes, one across the lower cold-end section and one across the upper hot-end section.

The air heater is enclosed by an uncooled casing. The casing is fabricated from flanged steel panels, reinforced as required to withstand maximum PA and SA pressures, and seal welded at all joints to prevent air and gas leakage. The casting is externally insulated with mineral wool and is lagged with ribbed aluminum. Insulation design conditions are to prevent the lagging face surface temperature from exceeding 60°c (140°F) based on 27°C (80°F) ambient air temperature and 15 m/min (60 ft/min) air velocity. Two ash hoppers are located beneath the air heater at the flue gas outlet. The ash hoppers are pyramidal in shape with a capacity of approximately 36 tons (40 short tons) of fly ash each when half full.

The air heater is sized to result in flue gas outlet temperature of 126°C (258°F) at boiler MCR with 27°C (80°F) ambient PA and SA combustion air inlet temperatures. This temperature was lowered from the originally specified 132°C (270°F) early during the design phase of the project. This change was instituted by Colorado-Ute because the present-worth savings of boiler efficiency gain (0.3%) exceeded the added cost for the additional heat transfer surface area of the air heater. The Nucla circulating AFBC boiler tubular air heater design performance is summarized in Table 17.

The SO_3 dew point and its impact on air heater cold-end corrosion is predicted to be negligible because the boiler is warmed up by firing propane before admitting coal to the fluidized bed. Also, sulfur capture during coal-firing occurs in the combustors upstream of the air heater. Water dew point is the cold-end temperature limit.

Table 17

AIR HEATER PERFORMANCE SUMMARY

Flue Gas:	
Flow	501,080 kg/hr (1,103,700 lb/hr)
Inlet/outlet temperature	258/126°C (496°/258°F)
Pressure drop	9.7 cm wg (3.8" wg)
Primary Air:	
Flow	335,960 kg/hr (740,000 lb/hr)
Inlet/outlet temperature	27/190°C (80°/374°F)
Pressure drop	12.2 cm wg (4.8" wg)
Leakage	0 kg/hr (0 lb/hr)
Secondary Air:	
Flow	103,830 kg/hr (228,700 lb/hr)
Inlet/outlet temperature	27/184°C (80°/363°F)
Pressure drop	6.9 cm wg (2.7" wg)
Leakage	0 kg/hr (0 lb/hr)

2.3.5 Baghouses

The baghouse system provides for the removal of fly ash from the circulating AFBC boiler exhaust flue gas stream to meet particulate emission requirements. The baghouse system includes the three existing (Units 1-3) baghouse collectors and a new (Unit 4) baghouse collector. All baghouses are connected in parallel to remove particulates from the new circulating AFBC boiler exhaust flue gas stream.

2.3.5.1 Existing Baghouses 1-3

Each of the now retired Unit 1-3 stoker-fired boilers were served by one of three identical baghouses. These fabric filters were retrofitted to the original plant in 1973. These units were the first to be installed by the electric power industry in the United States, successfully demonstrating fabric filter particulate control technology in the early 1970s. The existing baghouses have been incorporated into the flue gas cleanup system servicing the new circulating AFBC boiler.

Together, the three existing baghouse collectors provide approximately 48% of the required treatment capacity at a net operating air-to-cloth ratio of 2.7 to 1. Each of the three existing baghouses consists of six individual compartments. The baghouses use the shade-and-deflate cleaning-type design approach.

Each of the three existing baghouses includes six compartments, six fly ash hoppers, six bag shakers, 12 hopper heaters, 672 fiberglass bags, one repressurization (deflation air) fan to assist in bag cleaning, a duct heater for use with reverse air fan during startup, and one inlet/outlet reverse air manifold set. The existing baghouse ash hoppers are electrically heated and are capable of storing approximately a six-hour accumulation of fly ash when burning high-ash "B"-type coal. The existing baghouses have no bypass system and no ventilation system.

2.3.5.2 New Baghouse 4A

The new baghouse is provided to augment the capacity of the existing baghouses. The new baghouse provides approximately 52% of the required treatment capacity and uses shake-and-deflate cleaning. The unit consists of 12 individual compartments erected in modules. The housing is of 3/16-in thick carbon steel plate. The plan area for the new baghouse is approximately 25 m x 11 m x 14 m (82 ft x 35 ft x 47 ft high), giving a 0.9 m (3 ft) clearance startup burner has a heating capacity of 54 x 10^9 J/hr (51.2 million Btu/hr). Together, the startup burners have a total capacity of 324 x 10^9 J/hr (307.2 million Btu/hr), equivalent to about 27% of rated boiler heat input.

Primary air temperature is raised to approximately 454°C (850°F) with two propane duct burners, which are located in each combustion chamber primary air inlet plenum. Each duct burner has a heating capacity of 46 x 10^9 J/hr (44.0 million Btu/hr).

Each startup and duct burner is provided complete with an igniter, flame failure and supervisory system, instrumented gas trim valve rack with electrical enclosure, windbox, and local burner control. A common boiler master gas trip, isolation and system supply pressure control valve are provided as part of the system. In addition, a rack-mounted, pressure-reducing station is provided for each group of three startup burners per combustor and for the duct burners. Each of these three rack-mounted, pressure-reducing stations includes a regulator, relief valve, and modulating control valve plus other inherent design valves.

A burner management system provides remote (control room) burner control, purge control, indication, detection, safety shutdown, and annunciation of burner system malfunctions.

2.6 Boiler Instrumentation and Controls

The boiler instrumentation and control equipment includes only new instruments and controls provided with the circulating AFBC boiler by the boiler supplier. These were limited to hot cyclone outlet O_2 and SO_2 flue gas analyzers and boiler thermocouples. Instruments and controls provided as part of the boiler startup and duct burner management system are included in the previous section on the boiler startup system. All plant instruments and controls provided by others are included in Section 4 under "Balance-of-Plant Mechanical Equipment and Systems."

The following material provides the preliminary startup and normal operating procedures for the Nucla circulating AFBC system.

2.6.1 Starting Up

About 0.6 m (2 ft) of bed material is added to both combustors if they are empty. The boiler fans are started in the following order:

1. Induced draft fan

2. A high-pressure (loop seal) blower

3. Secondary air fan

4. Primary air fan.

The primary air is adjusted to give an even fluidization in both combustors. The air flow is adjusted to a minimum flow. The main interlocks are checked. It is necessary to perform a furnace (combustor) air purge before inserting any startup burner or igniting any duct burner if the bed temperature is less than 760°C (1400°F). It is not necessary to purge the combustors before introducing coal if the bed temperature is above 760°C (1400°F).

The firing is adjusted to warm up the bed material. The bed material is used to warm the refractory in the combustors and the cyclones slowly enough to avoid cracking. The fluidizing (primary) air temperature is raised slowly up to 454°C (850°F). (This is the temperature limit set during the initial startup period.) Secondary air flow is adjusted to meet changes in fuel flow.

The warm-up time is limited so that the refractory temperature, as measured by thermocouples, rise does not exceed 50 to 56°C (90 to 100°F) per hour from cold start to about 316°C (600°F). After that period, the refractory can be warmed at about 72°C (130°F) per hour. When the refractory temperature has reached about 593°C (1100°F), the refractory no longer limits the warm-up timing.

During the boiler warm-up, the coal-feed system is checked and started so that some coal (30 seconds at minimum feed) can be fed into the combustors when 482°C (900°F) bed temperature is reached. (This is the temperature at which the Nucla coal was observed to begin burning during the initial startup period.) The ignition of the coal is confirmed by the temperature rise. If, after adding another small dose of coal, the temperature continues to rise, a continuous coal feed is commenced and startup fuel firing rate is decreased. The coal-feed rate is slowly increased while the bed temperature is observed. When the bed temperature reaches 760°C (1400°F), all startup fuel firing is cut off. During the startup, the oxygen level in the flue gas streams is kept above 5%.

The ash coolers and the ash-cooler fan are started. The pressure drop in the bed is checked and bed material is added if it is too low. The limestone-feed system is also started. If the unit is started from warm conditions, the same procedures, in principal, are followed.

As the startup procedure continues, some control circuits (such as the furnace pressure control, secondary air pressure, drum level, and bed pressure/ash coolers controls) are switched to automatic operation. After the turbine is started, the remaining hand-operated controls (such as the combustion control, secondary air upper/lower level ratio control, and superheater temperature control) are switched to automatic operation.

2.6.2 Normal Operation

When stable firing conditions are reached, the boiler load is increased to the desired level on automatic control. Because of the twin-combustor arrangement, the fuel and air feed and the ash removal are controlled separately to load both combustors to nearly identical operating condition.

2.6.2.1 Drum Level/Feedwater Control

The drum level/feedwater control is the standard three-element type, with feedwater flow controlled by a comparison of steam and feedwater flows, and then trimmed by drum level.

2.6.2.2 Draft Controller

The draft controller adjusts the ID fan to keep about -0.6 cm (-1/4 in) wg draft in the upper part of the combustors.

2.6.2.3 Combustion Control/Load Control

The combustion air flow and coal feed are controlled in accordance with the steam pressure/steam flow measurements. The coal flow is measured to both furnaces separately. The feed rate is controlled by feeder speed.

Because of the twin combustor arrangement, the combustion control data for both furnaces are continuously compared and kept within certain tolerances.

Limestone feed follows the fuel feed and is trimmed in accordance with flue gas SO_2 analyzer readings.

2.6.2.4 Combustion Air Control

The primary air is always kept over minimum fluidizing level and follows its programmed air/fuel flow curve. The secondary air is programmed similarly, observing the ash cooler air flow (which is considered secondary air entering the combustors). The programmed secondary air flow setting is trimmed by the flue gas oxygen analyzer readings. The ratio of upper and lower secondary air is controlled by the bed temperature controller, which keeps the total amount unchanged.

Air solenoid valves are used on a periodic basis to allow air from the high-pressure blowers to convey bed material from the combustors into the ash-fluidizing cooler/classifiers via fluidizing spider pipes. The ash cooler/classifiers are fluidized with air from the ash-cooling fan. Rotary valves are used to let downcooled and classified bottom ash from the ash coolers to the bottom ash conveying system. The speed of the rotary valves is controlled manually by the operator based on combustor differential bed pressure.

2.6.3 Master Fuel Trip

A master fuel trip is caused by any of the following conditions:

- A decrease of bed temperature to less than 649°C (1200°F) if a coal feeder is running without a startup burner in service and the temperature has been above 760°C (1400°F).
- Low primary air windbox pressure in either combustor.
- A turbine trip.
- Drum level greater than maximum.
- Drum level less than minimum for more than 10 seconds.
- High combustor pressure.
- Operator emergency stop.
- All coal feeders from one combustor trip while one or two feeders from the other combustor are still on.

A master fuel trip command results in:

- A loss of the main interlocks, which will trip coal feeders, startup burners, duct burners, main propane shutoff valve, and limestone feeders.
- Reduction of PA flow to minimum.

- Reduction of SA flow to minimum.
- Reduction of ash cooling fan pressure to minimum.

2.6.4 Shut Down

The unit load is reduced to minimum. The main controls are turned to manual position and fuel feed is stopped. The bed is cooled down by air. When the bed temperature reaches 400°C (750°F), the fans can be stopped in the following order:

1. SA fan
2. PA fan
3. High-pressure blower
4. ID fan.

If a fast cooling is necessary or the unit is shut down for repairs or inspection, the bed material is removed through the ash coolers.

Section III. Material Handling Systems

There are separate material handling systems for coal, limestone, and ash. The coal- and limestone-handling systems include truck unloading, transfer, preparation, and the storage of coal and limestone. These systems interface with the circulating AFBC boiler coal and limestone feed systems at the coal and limestone silo outlet connections. The ash-handling system interfaces with the circulating AFBC boiler and baghouses at the combustor bottom ash drain ports and at the economizer, air heater, and baghouse fly ash hopper discharge connections. The ash-handling system includes all ash let down, cooling, transfer, storage, preparation, and truck loading of the bottom and fly ash. The ash handling system also provides for transfer of stored bottom ash back to the combustion chambers. This ash is used to charge the circulating AFBC boiler fluidized beds with inert spent bed ash, as required, prior to boiler startups. Material handling systems equipment data is included in Appendices A and B.

3.1 Coal Handling System

The coal-handling system provides for receiving, transferring, storing, and preparing the coal before it is fed into the circulating AFBC boiler combustion chambers. The system includes all coal handling equipment from the truck receiving hopper to, and including, the boiler coal silos. The system is comprised of a combination of both existing and new equipment items. A flow diagram of the plant coal-handling system is presented in Figure 18.

The existing Nucla station coal-handling system provides for coal receiving, two stages of crushing, sampling, ready storage/reclaim, and transfer into the plant building. The existing coal-handling system is designed for 114 tons/hr (125 short tons/hr) continuous capacity.

New equipment installed with the circulating AFBC boiler provides for transferring the coal from the existing plant conveyor to a surge bin and crushing the coal to 6 mm x 0 (1/4 in x 0) size; the crushed coal is then transferred to the two coal silos. Two new independent coal-handling trains are provided for this purpose. Each new coal-handling train has a continuous capacity of 68 tons/hr (75 short tons/hr), which is the maximum capacity of the crusher.

Raw, run-of-mine coal is delivered from local coal mine(s) to the plant by over-the-road trucks and dumped into an unloading hopper. The existing truck scale is used to weigh the coal trucks before unloading. Two half-capacity vibrating feeders deliver coal from the unloading hopper to the primary crusher.

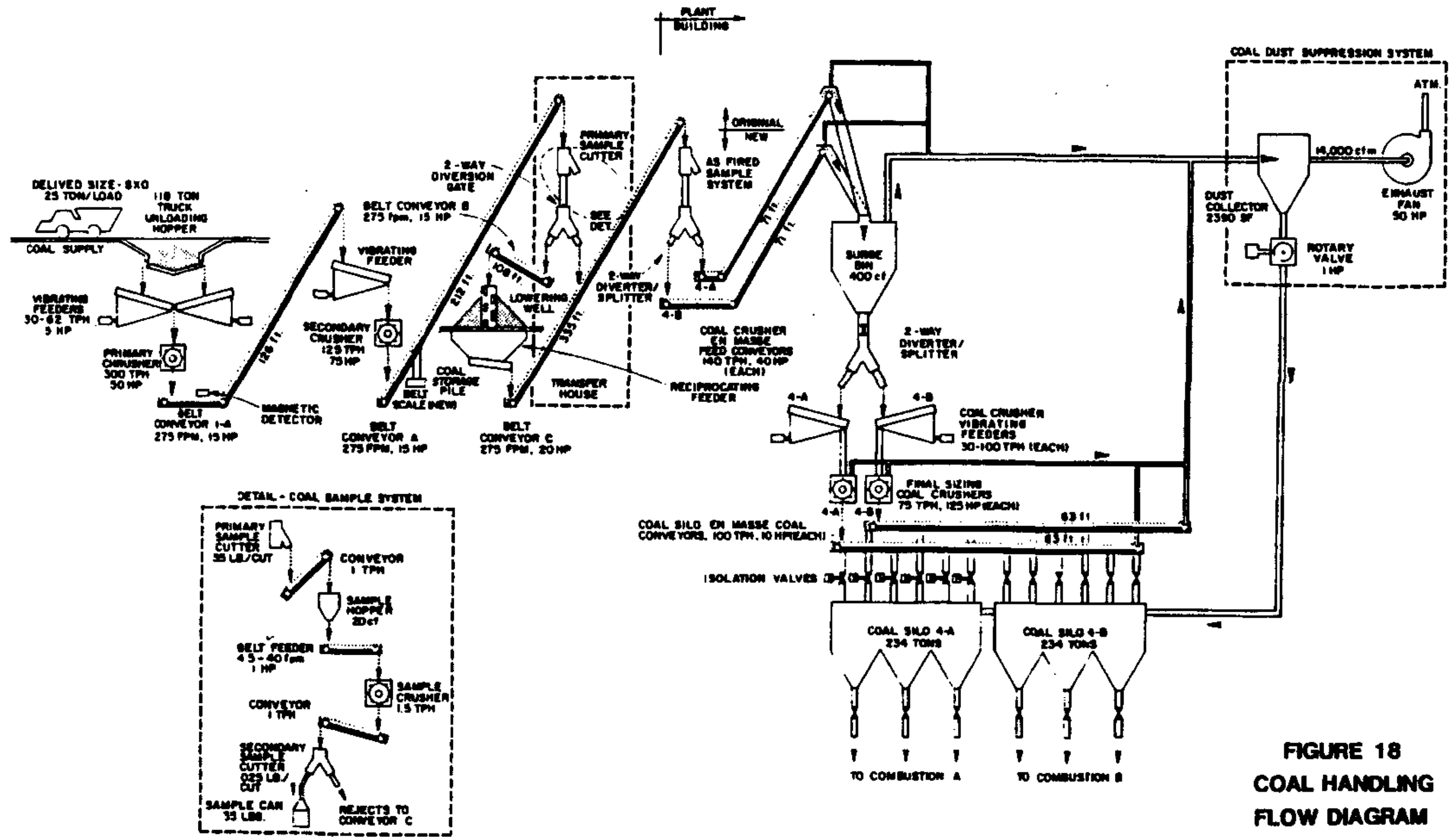

FIGURE 18
COAL HANDLING
FLOW DIAGRAM

The primary crusher is a single roll, "granulator"-type crusher that reduces up to 76 cm (30 in) cube size mine-run coal to 178 mm x 0 (7 in x 0). The primary crusher discharges onto a 61 cm (24 in) belt-type transfer conveyor (dubbed 1A) that transfers the coal to the secondary crusher feeder. The secondary crusher is fed by a single vibrating feeder.

A magnetic detector located on conveyor 1A stops conveyor 1A and the upstream coal handling equipment (primary crusher and feeders) upon the detection of any magnetic material.

The secondary crusher is also "granulator"-type crusher that reduces the coal size to 19 mm x 0 (3/4 in x 0). The secondary crusher discharges onto a 61 cm (224 in) belt-type conveyor (dubbed A) that transports the coal to the transfer house. A new integral belt weigh scale has been added to conveyor A to weigh as-received coal deliveries.

In the transfer house, coal from conveyor A drops through a diversion gate that directs the coal flow to either storage via stack-out conveyor B, or into the plant via conveyor C. The transfer house also contains an as-received coal sample system. The transfer house coal sample system consists of a primary sample cutter, a sample hopper, a sample crusher, primary and secondary sample belt feeders, and a secondary sample cutter. The primary sample cutter cuts samples of coal discharging from conveyor A entering the transfer house. Sample rejects are discharged onto plant conveyor C.

Stack-out conveyor B transfers as-received coal from the transfer house to ready storage via a lowering well. The lowering well has pivoting, self-closing doors that serve to stack the coal on the ready storage pile in a manner that minimizes dusting. The capacity of the ready reserve and adjacent long-term storage pile is approximately 45,400 tons (50,000 short tons) or 30 days. A reclaiming hopper and vibratory feeder, located beneath the lowering well of the ready coal storage pile, reclaims coal from storage and feeds it onto plant conveyor C.

Conveyor C transfers coal from storage or as-received coal from conveyor A, into the main plant building. The discharge from conveyor C has been modified to flow into a new two-way diverter/splitter that directs the coal flow onto either or both new en-masse conveyors 4A and 4B. Formerly, conveyor C discharged coal onto a tripper conveyor D that delivered the coal to the Unit 1-3 coal silos. Tripper conveyor D, and the Unit 1-3 silos and boilers have been retired. A new "as-fired" coal sample is located at the discharge of conveyor C. This sample system along with stack monitoring equipment was required by the State of

Colorado to continuously monitor SO_2 capture and other emissions for comparison to sample analysis.

In the event of equipment problems downstream of conveyor C, it was deemed desirable to have the capability to unload plant conveyor C. Accordingly, an 18-ton (20 short ton) surge hopper with capacity to store all coal from the reclaim feed point of conveyor C is provided above the final sizing crushers. The addition of the surge hopper above the crushers required coal to be elevated to 12 m (40 ft) above the existing discharge of conveyor C. Due to the vulnerability of this existing conveyor, it was decided to install two 432 mm (17-in) wide chain-type, en-masse coal crusher feed conveyors 4A and 4B, each capable of handling the full capacity of conveyor C. These conveyors lift the coal into the surge hopper and are rated at 127 tons/hr (140 short tons/hr) each. The new en-masse conveyors are designed to operate at a chain speed below 30 m/min (100 ft/min).

Two reversible impact crushers, each sized for continuous feed of 38 mm x 0 (1-1/2 in x 0) coal at a rate of 65 tons/hr (72 short tons/hr) reduce the final coal sizing to 6 mm x 0 (1/4 in x 0) required to feed the circulating AFBC boiler combustion chambers. Both crushers operate simultaneously to accept the full output of plant conveyor C. A two-way splitter/diverter and two 76 cm (30-in) wide vibratory feeders at the surge hopper discharge permit one or both crushers to be operated. In the event that one crusher is disabled, two courses of action are available. If it is anticipated that the crusher will be out of service for a short time, one crusher can be run delivering 130% of full-load coal requirement for the higher-heating value "A"-type coal or 100% full-load coal requirement for the lower-heating value "B"-type coal. If the crusher will be out of service for an extended length of time, the operating crusher can be readjusted to a larger-sized [13 mm x 0 (1/2 in x 0)] product, which will enable it to deliver 91 tons/hr (100 short tons/hr). A slight boiler efficiency decrease may occur as a result of increased coal feed sizing. This will also limit coal loading to approximately 16 hours per day with the plant at full load.

Two 33 cm x 16 m (13 in x 54 ft) long horizontal chain-type, en-masse silo feed conveyors transfer the full output of each crusher to either or both of the two boiler coal silos. Three feed points are provided from each conveyor at the top of each silo to obtain a high percentage fill. The inlet openings to coal silo 4A are equipped with remotely-operated slide gates so that this silo can be bypassed to feed coal to silo 4B. Coal silo 4B is equipped with manual slide gates for silo maintenance.

Two cylindrical coal silos, 4A and 4B, have a combined capacity of 427 tons (470 short tons). These silos are located on the front side of the circulating AFBC boiler. They are sized to provide eight-hour storage of 6 mm x 0 (1/4 x 0 in) coal at maximum continuous capacity while firing the higher heating value "A"-type coal. Each silo has three slot discharge openings designed to maintain mass flow movement to each of the six boiler gravimetric feeders. Each silo discharge is equipped with a manual slide-gate valve for isolation and feeder maintenance. These silo outlet valves were included in the circulating AFBC boiler coal-feed system.

Coal dusting from the existing portion of the plant coal handling system is minimized by a dust-suppression system. The existing dust suppression system consists of a solution tank and pump located in the transfer house, solution distribution piping, and spray nozzles. Dust-suppression fluid is sprayed at coal transfer points on the following pieces of equipment:

- Truck unloading hopper
- Primary crusher vibrating feeders
- Secondary crusher vibrating feeder
- Unloading belt conveyor 1A
- Unloading belt conveyor A
- Plant belt conveyor C at transfer house
- Plant belt conveyor C at reclaim hopper
- Stack-out belt conveyor B.

The various new components in the coal handling system are the en-masse conveyors, crushers, and silos. These components are served by a single coal dust collection system. This collection system consists of an exhaust fan capable of 400 cubic m/min (14,000 cfm), and a pulse-cleaned bag filter sized for an air-to-cloth ratio of 5 to 1. The collected dust is discharged into coal silo 4A through a rotary valve. The new dust-collection system is automatically activated upon the start of either of the new coal handling trains and remains in operation until 30 minutes after the last coal handling train is stopped.

3.2 Limestone Handling System

The limestone-handling system provides for receiving, transferring, storing, and preparing the limestone before it is injected into the circulating AFBC boiler combustors. The system includes all limestone-handling equipment from the truck receiving hopper to and including the boiler limestone silos. This system is entirely new. A flow diagram of the plant limestone-handling system is presented in Figure 19.

The circulating AFBC boiler combustion process requires limestone ground to a top size of 1000 microns and average size of 150 microns, ranging in quantity from 680 to 11,350 kg/hr (1,500 to 25,000 lb/hr) depending on the coal-feed rate, coal quality, and measured flue gas SO_2 concentration. The limestone-handling system consists of receiving facilities designed for 68 tons/hr (75 short tons/hr), and pulverizing- and pneumatic-conveying facilities designed for 8.2 tons/hr (9 short tons/hr). The limestone-receiving facilities include equipment for unloading, crushing, and conveying limestone to the storage silo. From the storage silo, the limestone is reduced to its final size by a pulverizer system and is pneumatically conveyed to either of two boiler limestone silos.

Raw limestone rock is delivered from a local quarry to the receiving system by over-the-road trucks and dumped into a receiving hopper. A vibrating feeder delivers the limestone into a primary rock crusher. The crusher is a reversible hammermill that reduces the size from 254 x 0 mm (10 x 0 in) run-of-mine rock to 19 x 0 mm (3/4 x 0 in). A crushed-rock belt conveyor, with integral belt conveyor, and bucket elevator are all rated for 68 tons/hr (75 short tons/hr). The bucket elevator lifts the crushed limestone approximately 30 m (100 ft) vertically into a 772-ton (850 short ton) capacity, elevated limestone storage silo. This represents approximately a 70-hour storage capacity at maximum boiler utilization.

The storage silo feeds the limestone pulverizer system. The limestone storage silo and pulverizer system are located outdoors adjacent to the boiler building, south side. The limestone pulverizer system is rated at 8.2 tons/hr (9 short tons/hr) and it reduces the limestone size from 19 x 0 mm (3/4 x 0 in) to 150 micron average size (50% passes 100-mesh screen size). The pulverizer also dries the limestone to 1% moisture content as required for downstream handling. Limestone from the storage silo passes through a vibratory draw-down hopper that places the limestone on a vibrating pulverizer feeder, which feeds the limestone into the pulverizer. The pulverizer is an air-swept, pendulum-type roller mill. The pulverizer outlet limestone and air mixture is classified by a motor-driven spinner separator in the top of the mill that returns larger particles to the grinding zone. From the pulverizer, the classified limestone and air mixture is routed to a cyclone separator that separates out the limestone particles. From the cyclone separator, the air returns to the pulverizer fan, which recirculates the air to the mill. The separated limestone particles drop through a rotary feeder

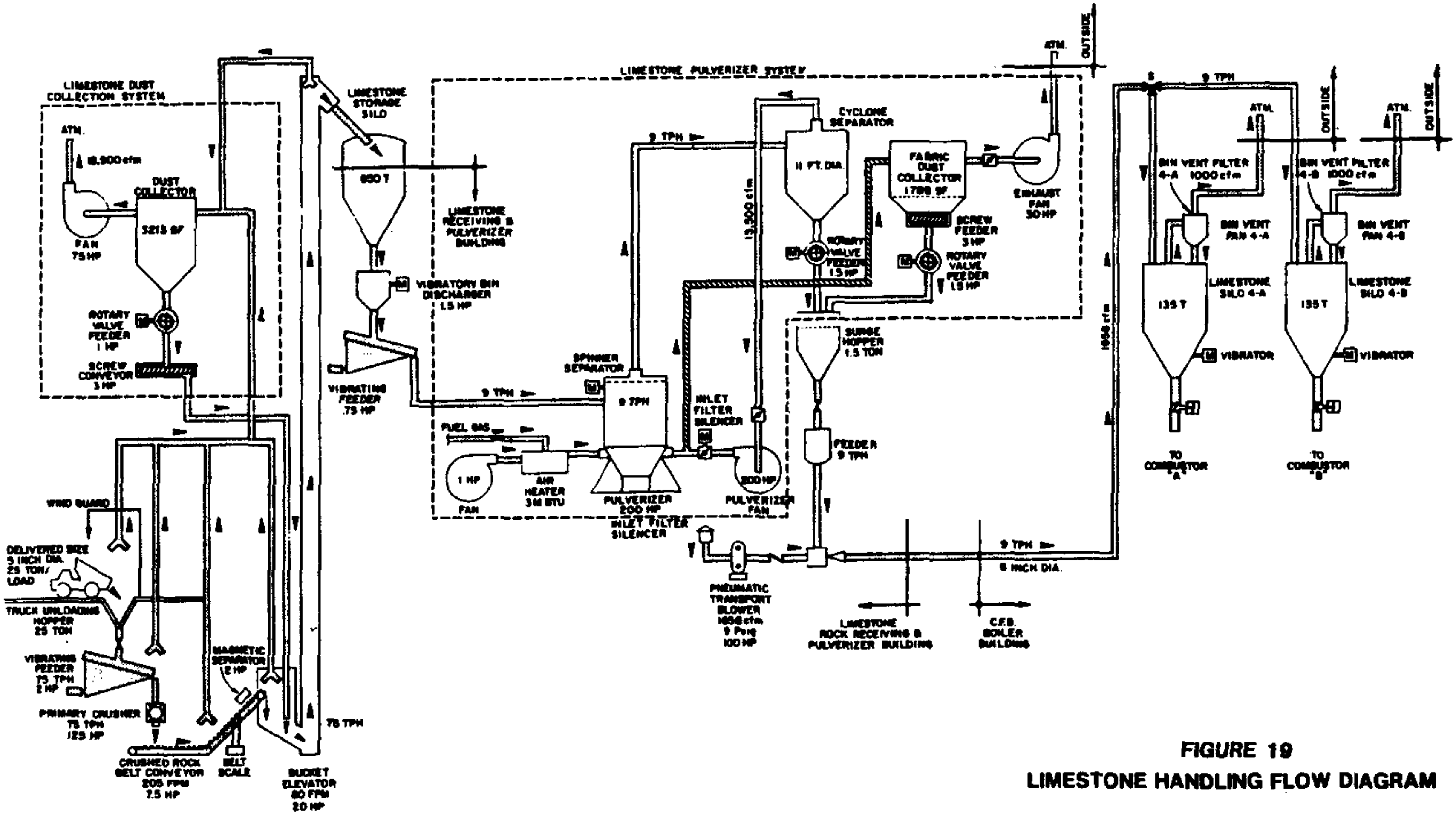

FIGURE 19
LIMESTONE HANDLING FLOW DIAGRAM

into the pneumatic conveying system surge feed hopper. Pulverizer makeup air is heated by a gas-fired heater. The heater is required to dry the final product to a specified 1% moisture content. Air is bled from the pulverizer-fan discharge to a fabric-filter collector and an exhaust fan. The entire limestone-pulverizer system is maintained at a slightly negative pressure by the fabric-filter exhaust fan. The fabric-filter discharges collected limestone dust via a screw and a rotary feeder to the pneumatic conveying system surge feed hopper.

Pulverized limestone collected in the feed-surge hopper is transported from the limestone-pulverizing area to the limestone silos (located in the boiler building) by a pressurized pneumatic conveying system rated at 8.2 tons/hr (9 short tons/hr) capacity. In addition to the surge feed hopper, the pneumatic conveying system consists of a rotary feeder, an acceleration chamber (intake tee), a rotary positive displacement conveying air blower, a pneumatic conveying line, and a three-way solenoid diverter valve to direct the limestone to the selected boiler limestone silo.

The two pulverized-limestone silos, located in the boiler building, are cylindrical in shape and each one serves one boiler combustion chamber. The capacity of the silos, 123 tons (135 short tons) each, will sustain 12 hours of boiler operation between fillings when firing the performance "A"-type coal at full load.

A silo vent fabric filter with a 5-to-1 cloth ratio is provided on each of the boiler limestone silos. The sizing of the limestone silo vents is based on the flow volume of the pneumatic system conveying limestone to the silos.

The various components of the limestone-receiving system are served by a common limestone dust-collection system. This system consists of collection ducts, a fabric-filter dust collector, and an exhaust fan. Limestone dust is collected from the truck unloading hopper, the belt conveyor vibrating feeder, the belt conveyor load skirt, the belt conveyor discharge, and the bucket elevator discharge to the storage silo. The collected dust streams are cleaned continuously by a pulse-jet fabric filter. Collected dust is reclaimed by a screw conveyor, which discharges the collected limestone dust into the bucket elevator inlet hopper.

3.3 Ash Handling and Disposal Systems

The ash handling and disposal systems are comprised of two completely independent systems: (1) the fly-ash handling and (2) the bottom or spent-bed ash handling systems. The fly-ash handling system provides for the removal, transfer, storage, and disposal of fly ash that is collected in the boiler economizer hoppers, air heater hoppers, and the various baghouse fly-ash collection hoppers. The bottom ash handling system provides for the removal, cooling, transfer, storge, and disposal of spent-bed ash drained from the bottom of the circulating AFBC boiler combustion chambers. An ash-reinjection subsystem is provided, as part of the bottom ash-handling system, to facilitate return of stored spent-bed ash from the bottom ash-storage silo to either combustion chamber. This material is used to re-establish a bed of inert material, as required for boiler startups.

The bottom/fly ash distribution for the Nucla ciculating AFBC boiler was originally predicted to be 20 to 40% bottom (bed drain) ash and 60 to 80% fly ash. This prediction was based on the manufacturers' experience when burning a wide range of coals that averaged 35% bottom ash. Combustion testing of the Nucla coal was conducted in February and March of 1985 at Ahlstrom's 1.5-MW (thermal) pilot plant in Karhula, Finland, during the design phase of the project. Bottom ash distributions for these tests was as low as 0% and averaged only 6% of the total ash. Questions arose as to whether the coal ash was very friable (easily breaks into small particles), or whether the coal samples collected for these combustion tests were representative of those in the Nucla coal mine(s). It was later learned that the samples were collected from the mine surface, and thus could be significantly different from core samples at various mine locations.

As a result of these circulating AFBC combustion tests, the fly-ash system sizing criteria was modified from handling 60 to 80% of the total ash to 100% of the total ash. The bottom ash system sizing criteria remained the same. Based on burning the design "B"-type coal, the fly-ash system is capable of handling 100% of the total ash as fly ash with a 50% fly ash- removal system duty cycle, and the bottom-ash system is capable of handling 30% of the total ash as bottom ash.

3.3.1 Fly Ash Handling System

The fly ash handling-system provides for the removal, transfer, storage, and disposal of fly ash from the economizer, air heater, and baghouse hoppers. The system includes all fly ash-handling equipment and components from the various fly ash-collection hoppers to the fly ash storage and truck-loading facility. A dual fly ash-collection network is provided. A flow diagram of the plant fly ash-handling system is presented in Figure 20.

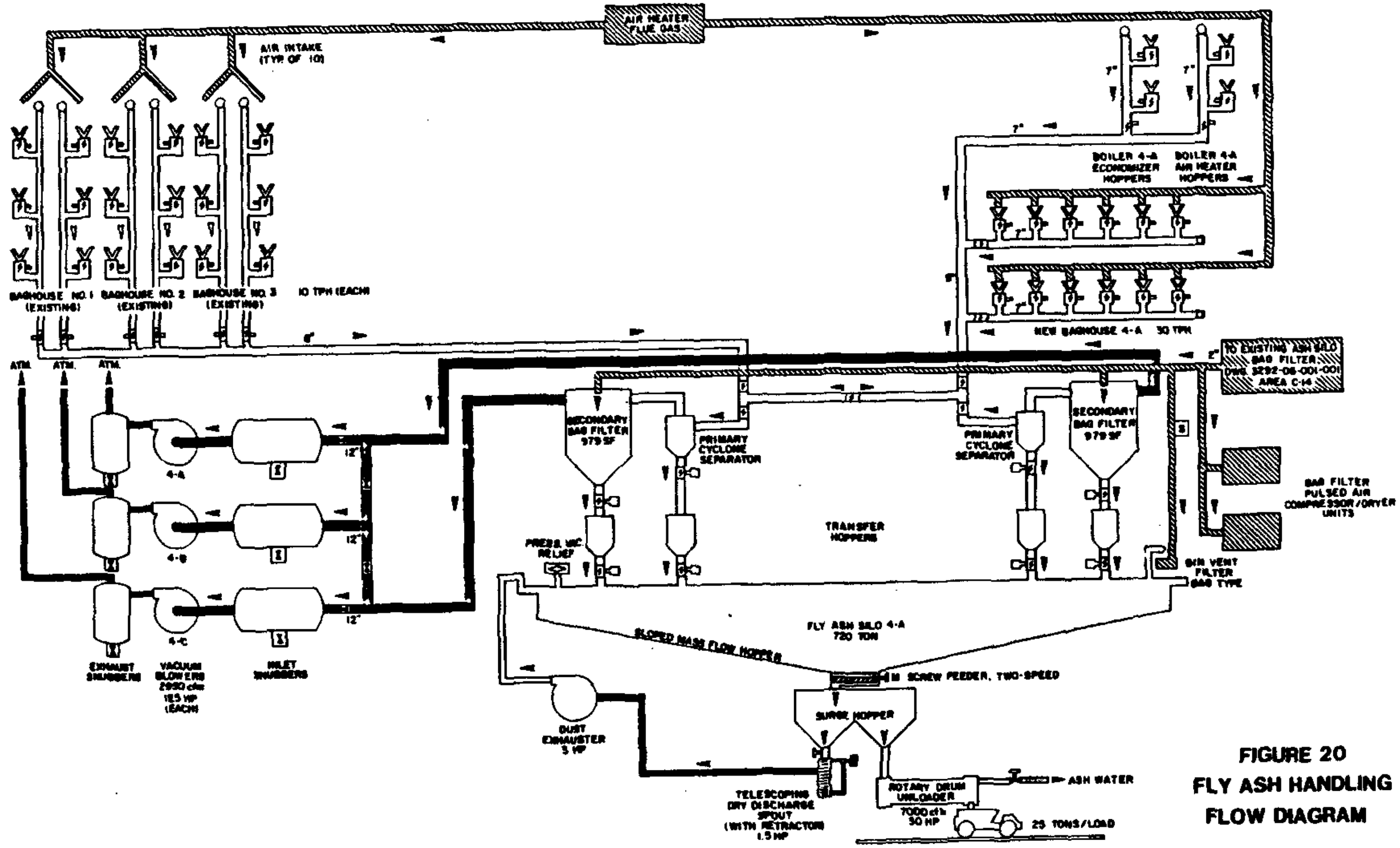

FIGURE 20
FLY ASH HANDLING
FLOW DIAGRAM

Two independent 27 ton/hr (30 short ton/hr), vacuum-type pneumatic conveying systems are provided to transfer fly ash from the collection hoppers to a new fly-ash silo. One system serves the three existing baghouses; and the second system serves the new baghouse, the boiler economizer hopper, and the air heater outlet hoppers. The fly ash is conveyed to a new 1,700 cubic m (60,000 cubic ft) mass flow silo.

To meet the desired 27 ton/hr (30 short ton/hr) conveying rate from existing baghouses 1-3, it was necessary to increase the existing branch line pipe sizes from 15 to 18 cm internal diameter (6 in to 7 in). This was accomplished by reusing the existing ash feed gates located on each of the 18 fly ash hoppers (six per baghouse), and by replacing the outlet pipe connections. This enabled the use of identical mechanical exhaust fans for both vacuum pneumatic systems. The fly-ash conveying line length is approximately 91 m (300 ft) from the existing baghouses.

Regulation of the feed of fly ash into each vacuum-conveying collection network is accomplished by a full-load regulation system. When the vacuum at the vacuum blower or exhauster exceeds a present full-load design value, the ash intake valve is automatically closed until the line vacuum falls below the full-load value, at which time the next stage intake valve automatically opens, emptying the hopper. The process continues sequentially until all hoppers on the branchline have been emptied, then continues for the next branchline until all have been emptied. When conveying from the hoppers is completed, the system then actuates a line purge. When line purging is complete, the control system sets itself for the next cycle, notifies the operator that the cycle is complete, and deactuates.

Two trains of cyclone separators continuously operate in series with a pulse-type bag filter, one train for each vacuum collection network. The bag filters are sized for a maximum air-to-cloth ratio of 3.5 to 1 based on the maximum air flow condition with the conveying system unloaded. This no-load condition occurs when the system transfers between hoppers and no ash is being conveyed. The two fly ash conveying lines are intertied immediately upstream of the cyclone and bag filter collectors to provide system operational flexibility. Three identical vacuum blowers or exhauster sets are provided, one for each fly ash-conveying network and a common spare.

The new fly ash storage silo is designed for mass flow operation. The capacity of the fly ash silo is 1,700 cubic m (60,000 cubic ft) or 817 tons (900 short tons) at a fly ash density of 480 kg/cubic m (30 lb/cubic ft). It is expected that the maximum fly ash quantity will be 90% of the total ash or 22 tons/hr (24 short tons/hr) maximum. This expectation is based on test burning of a Nucla coal conducted at Ahlstrom's Karhula, Finland, 0.6 m diameter circulating AFBC R&D pilot-test facility.

A fly ash silo dustless rotary drum unloader/conditioner with a capacity of 144 M tons/hr (160 tons/hr) is provided. This unloader enables the fly ash-storage silo to be emptied by 23-ton (25 short ton) capacity trucks in eight hours. The unloader is fed by a screw feeder equipped with a charge hopper and operates on a batch basis. The unloader mixes a controlled amount of water with the fly ash to prevent dusting during unloading, transport, and disposal.

Ash water is provided from the plant-service water system to an existing ash water storage tank. From the storage tank, the ash water is pumped by one of two 100% capacity ash-conditioning water pumps (one existing and one new) to both the fly ash and bottom ash silo rotary-drum unloaders.

The conditioned fly ash is transported by truck to a landfill or mine reclamation disposal site. It is anticipated that the cementatious reaction between the ash and spent limestone reagent will aid in the stability of the waste material in the landfill.

The circulating AFBC boiler manufacturer has identified a fly-ash handling option to improve carbon utilization, should this be required at a later date to meet boiler performance guarantees. This option would include modification of the fly-ash system to allow for the reinjection of fly ash collected in the economizer and the air heater outlet hoppers back to the combustion chambers.

3.3.2 Bottom Ash Handling System

The bottom or spent-bed ash handling system provides for the classification, removal, cooling, transfer, storage, and disposal of bottom ash from the circulating AFBC boiler. The system also provides for reinjection of bottom ash from the bottom ash storage silo back into the boiler combustion chambers when required to re-establish initial bed inventory for boiler startups. The system includes the following equipment:

- All bottom ash drain, cooling, and handling equipment.

- Components from the combustion chamber sidewall bottom ash ports to the ash haul truck-filling facility.

- Bottom ash rejection from the bottom ash silo to a rear-wall reinjection port located on each combustion chamber.

A flow diagram of the plant bottom ash-handling system is presented in Figure 21.

Depending upon the feed size and friability of the fuel, the quantity of ash removed from the bottom of the combustion chambers can vary between 10%, for "A"-type coal, to more than 40% of the total ash. The Nucla coal ash tends to break into fine particles easily (high friability index), therefore, it is expected that the bottom ash quantity will only be 10% of the total ash, or 2,450 kg/hr (5,400 lb/hr) with the high-ash, low heating value "B"-type coal. The system capacity is conservatively designed because it is based on 30%, for "B"-type coal , bottom ash split rather than the expected 10%, or 7,350 kg/hr (16,200 lb/hr). Additionally, the characteristics of the bottom or spent-bed ash is a coarse and dense fly ash that can be pneumatically conveyed.

As the fuel, limestone, and recycled ash (from the loop seals) are fed into the combustion chamber, the inventory of bed-ash particles increases. This causes a measurable increase in the differential pressure required to support and circulate the weight of the bed. The differential pressure and, consequently, the bed inventory is controlled by extracting bed ash through the bottom ash-removal system. Hot [871°C (1600°F)] bottom ash is removed through bottom ash ports located on the lower sides of each combustion chamber.

In view of the severe duty associated with bottom ash removal, two 100%-capacity, fluid-bed bottom ash coolers are used to cool and classify bottom ash before it is let down through rotary valves. One variable-speed rotary valve is located under each ash cooler. Each ash cooler and rotary valve is sized to handle the full ash output of one combustion chamber. In the event of equipment maintenance, each fluid-bed bottom ash cooler can be isolated. The cooling mediums for the bottom ash coolers consist both of cool (not preheated) combustion air provided by an ash cooling fan and water coils. The water coils are included in a closed cooling water system,

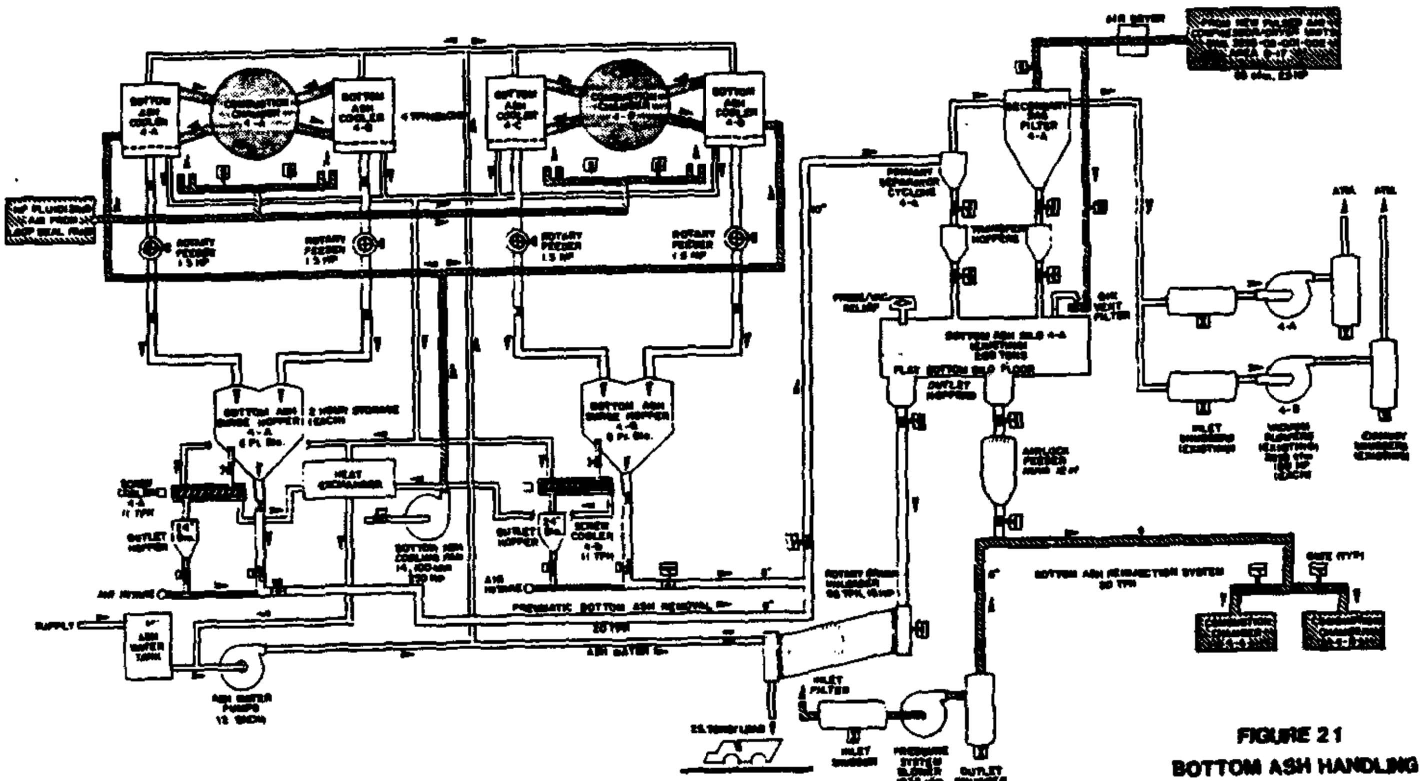

FIGURE 2.1
BOTTOM ASH HANDLING FLOW DIAGRAM

which recovers and transfers heat from the bottom ash to the low-pressure feedwater system. A single bottom ash cooling fan provides air to the bottom ash coolers to cool and fluidize the ash.

Ash is admitted to the bottom ash coolers by means of inlet fluidizing nozzles, maintaining a preset range of differential pressure. The cooling air and classified bed material flow from the top of the bottom ash coolers to the combustion chambers via upper equalization ports. Bottom ash is removed from each bottom ash cooler through a variable-speed rotary valve, which is regulated by the operator to control the inventory of combustor bed material as indicated by combustor pressure differential. The two fluid-bed bottom ash coolers serving each combustion chamber discharge into a single bottom ash surge hopper, which is mounted on load cells. At the expected 10% bottom ash rate, the bottom ash surge hoppers have an approximate three-hour storage capacity, which permits an accurate measurement of the rate of bottom-ash flow under test conditions.

When both fluid-bed bottom ash coolers are operating on one combustion chamber, the expected cooler ash exit temperature will be below 204°C (400°F). However, under conditions of high-ash or high-sulfur fuel and where only one of the two fluidized-bed bottom ash coolers is in operation for a combustor, the discharge ash temperature can exceed 204°C and require additional cooling. For this reason, a separate water-cooled screw conveyor is furnished to provide additional bottom ash cooling. The heat removed in these water-cooled screw conveyors is also rejected to the closed cooling-water system, which recovers and transfers the heat to the low-pressure feedwater system. Use of the screw conveyor cooler is optional by means of two outlets on each bottom ash surge hopper. When ash in the bottom ash surge hoppers is measured to be below 204°C (this is the expected normal condition), the bottom ash will be removed directly into the pneumatic conveying system. When the surge hopper ash temperature is above 204°C, the screw conveyor cooler will automatically be placed into service to provide supplemental cooling before the ash is admitted to the pneumatic conveying system.

An 18-ton/hr (20 short ton/hr) vacuum-type pneumatic conveying system is provided to transfer the bottom ash from the surge hoppers, or alternatively from the screw conveyor coolers, to the bottom ash-storage silo. The bottom ash-storage silo was formerly the plant fly-ash silo. A new continuously operating cyclone separator and new pulse jet bag filter are installed on the existing tile-type silo roof to separate the bottom ash from the conveying air. The bag filter is sized for a maximum air-to-cloth ratio of 3.5 to 1 at the no-load condition, which occurs when the system transfers between hoppers and no ash is being conveyed. Two existing vacuum blowers or exhauster sets, one operating and one spare, have been reconditioned and upgraded to provide the conveying motive force. The former plant fly ash system was also rated at 18 tons/hr (20 short tons/hr).

The existing flat bottom-ash silo, now used exclusively for bottom ash storage, has a capacity of 252 cubic m (8,890 cubic ft) and 181 tons (200 short tons) for a fly ash density of 720 kg/cubic m (45 lb/cf). However, the density of bottom ash is expected to be 1,200 kg/cubic m (75 lb/cf). Thus, the useful volume of the silo is limited to 60% or 151 cubic m (5,333 cubic ft), not to exceed the 182-ton (200 short ton) capacity. Bottom ash-storage silo discharge equipment includes three silo outlet hoppers (one each for the existing unloader, a dry unloading spout, and a new reinjection system pressure feeder). The unloader mixes a controlled amount of water with the bottom ash to condition it for over-the-road truck transport and final disposal in a landfill or mine reclamation disposal site.

A pressurized ash-reinjection subsystem is provided as part of the bottom ash-handling system to re-establish the fluidized bed following boiler outages. The bottom ash-reinjection system includes one airlock Nuva gravity feeder to transfer the ash from the storage silo into a pressurized pneumatic conveying line. This pneumatic system conveys the bottom ash back to the bottom of each combustion chamber through a single ash reinjection port located in the lower rear wall of each combustor. A single blower provides the pressurized conveying medium: air.

Section IV. Balance-of-Plant Mechanical Equipment and Systems

The balance-of-plant mechanical equipment and systems include the power and process piping, plant water systems, circulating water system, the condenser and accessories, chemical-feed systems and miscellaneous mechanical equipment. These are used to help convert mechanical energy to electrical and support that end. Description of the facilities and systems is included in this section, while data is provided in Appendices A and B.

4.1 Power and Process Piping

The power and process piping provides for the transfer of turbine cycle steam, condensate, and feedwater for each of the three existing units (1-3), for the new Unit 4 and integral inter-unit transfers. The power and process piping is comprised of the following systems:

- Main steam
- Extraction steam
- Auxiliary steam
- Low Pressure (LP) feedwater
- High Pressure (HP) feedwater.

4.1.1 Main Steam System

The main steam system delivers superheated steam from the Unit 4 AFBC boiler superheater III outlet connection to the Unit 4 turbine. The system consists of the new main steam line and hangers from the boiler final superheater outlet connection to the two Unit 4 turbine stop valves. Also included is main steam line instrumentation, a sample connection, a turbine gland steam connection, and an electromatic relief valve. The entire system is part of the new Unit 4 installation. The existing Unit 1-3 main steam lines have been disconnected from the boilers and have been partially dismantled.

Main steam temperature is controlled to 541°C (1005°F) at the boiler superheater III outlet by two stages of attemperation; one between superheaters I and II plus one between superheaters II and III.

Drains are provided at all low points, and a vent is provided at the high point of the main steam line. The drains are routed to the boiler blowdown tank and to the condenser via the turbine HP drain header. The vents and drains allow for warming of the main steam line prior to starting the turbine and provide a means for condensate removal to protect against turbine water induction. The main steam line drain and vent valves are all manually operated.

4.1.2 Extraction Steam System

The extraction steam system provides for the supply of throttle steam to the existing Unit 1-3 turbines from the Unit 4 turbine, and extraction steam to the feedwater heaters. The extraction steam system includes:

- The new Unit 4 turbine controlled automatic extraction nozzle to the inlet connections of the existing Unit 1-3 turbines.
- The Unit 4 turbine uncontrolled extraction connections to the inlet steam connections of the Unit 4 HP and LP feedwater heaters, including the deaerator.
- The uncontrolled extraction connections on the existing Unit 1-3 turbines to the Unit 1-3 LP feedwater heaters including the deaerators.
- The feedwater heater shell side vents and drains on all units.

The Unit 4 deaerator extraction also serves as a plant auxiliary steam source.

4.1.2.1 Units 1-3 Extraction Steam

Units 1-3 each have identical extraction steam systems. The Unit 4 turbine automatically controlled extraction is the source of the throttling steam for each of the existing turbines. This steam source is also used on each existing unit to supply the condenser steam jet air ejector, the hogging jet air ejector, the turbine steam seal regulator, and the steam turbine driven auxiliary lube oil pump. During startups and shutdowns, auto extraction header steam is supplied from the circulating AFBC boiler primary superheater outlet header auxiliary steam supply source. Auxiliary steam is also required at these times for operation of the above-listed Unit 1-3 condenser and turbine accessory equipment items. The auto-extraction header supplying the existing turbines is protected from overpressure by a safety valve set at 49 kg/cm^2 (700 psig).

The highest pressure extraction from each Unit 1-3 turbine formerly supplied steam to a HP feedwater heater on each unit that has been retired as part of the existing plant modification to incorporate the new Unit 4. For each unit, this extraction has been capped off immediately downstream of the extraction line turbine isolation shutoff and non-return check valve.

Each Unit 1-3 turbine has three remaining extraction steam lines supplying steam to a deaerator, and two LP feedwater heater stages. Each extraction steam line is provided with a manually operated shutoff valve and a non-return check valve. The non-return check valve protects the turbine against reverse flow in the extraction line, which could cause turbine overspeed and/or water induction. Each deaerator extraction line has two non-return check valves in series to provide additional turbine overspeed protection due to the large potential of flash steam in the deaerator storage tank. The extraction line low points between the turbine and the extraction line shutoff valve are drained to the condenser via steam traps.

The existing LP extraction feedwater heaters are not provided with operating vents for the continuous removal of non-condensable gases to the condenser. Atmospheric startup vents must be opened periodically to vent non-condensable gases that may be present in the heater shells. The existing deaerators are provided with both a startup and an orificed operating vent to atmosphere that remove air and other condensable gases.

On each existing unit, the higher-pressure LP feedwater heater shell drains cascade to the lower pressure LP feedwater heater shell. The lower-pressure feedwater heater shell drains to the condenser. Both LP feedwater heater shells are provided with an alternative manual drain to the condenser.

4.1.2.2 Unit 4 Extraction Steam

All Unit 4 turbine extraction steam lines contain a motor-operated shutoff valve and a power-assisted check valve. The motor-operated gate valve is provided for positive isolation of the turbine from any potential sources of water induction. The second valve, a power-assisted check valve, is provided to protect the turbine against reverse flow in the extraction lines, which could cause turbine overspeed and/or water induction. Due to the large potential for flash steam in the deaerator storage tank, the deaerator extraction line has two power-assisted check valves in series, as recommended by the turbine manufacturer.

The extraction line low points before, after, and between the shutoff and check valves are drained to the condenser via manually-operated drain valves. Continuous flow drain lines, which include flow restriction orifices, bypass the drain valves.

The feedwater heater vents and drains consist of two subsystems for removal of fluids and vapors from the shell sides of the heaters. The vents remove noncondensable materials, such as air, and the drains remove the condensed extraction steam.

The feedwater heaters have two types of vents: startup and operating. Startup vents are larger-capacity lines for fast removal of non-condensable gases accumulated in idle equipment and piping. Operating vents are lower capacity, orificed lines that are provided for continuous removal of the non-condensable gases that may be present in the extraction steam during plant operation. Vents from the HP feedwater heaters are routed to the deaerator for removal of noncondensable gases by the deaerator vent system, which is vented to the atmosphere. Vents from the LP feedwater heaters are routed to the condenser and vented by the condenser air removal system. All startup and operating vents have manual shutoff valves.

Drains for the HP feedwater heater shells cascade to the next lower-pressure heater, and finally to the deaerator. Drains from the HP heaters flow by shell pressure differential to the deaerator. LP feedwater heater drains cascade to the next lower pressure heater and then to the condenser.

Emergency shell drains to the condenser are provided for all feedwater heaters, including the deaerator. The emergency drains automatically open on high water level in the heater shell. The emergency drains provide a first line of defense against turbine water induction.

4.1.3 Auxiliary Steam System

The new auxiliary steam system supplies steam for the following Unit 4 systems:

- Deaerator steam pegging

- Condenser steam jet air ejector and priming ejector
- Condenser and deaerator storage tank warm-up spargers
- Heating system and heating deaerator.

Auxiliary steam is also supplied to the existing Unit 1-3 heating system, the preboiler water treatment system caustic regeneration heater, and to the auto extraction line for turbines 1-3. Unit 4 auxiliary steam supplies include boiler primary superheater outlet steam, turbine deaerator steam, and an auxiliary boiler. The Unit 4 auxiliary boiler is included in the system.

Auxiliary steam supply for startup pegging of the Unit 4 deaerator and the condenser steam jet air ejector is provided from a connection on the circulating AFBC boiler primary superheater (SH I) outlet header. This auxiliary steam connection is sized to supply 12,260 kg/hr (27,000 lb/hr). A pressure control station reduces the pressure of this steam to 21 kg/cm^2 (300 psig). Downstream of the pressure control station there is a safety valve set at 23 kg/cm^2 (330 psig), instrumentation, drains, and a future supply connection for steam coil combustion air preheaters.

Boiler primary superheater outlet steam is also the source of backup auxiliary steam to the automatic extraction header supplying steam to the existing turbines 1-3. A pressure reducing station is provided for this auxiliary steam supply that reduces the pressure to approximately 35 kg/cm^2 (500 psig) entering the autoextraction line. This pressure is set to a lesser value than the automatic extraction line normal operating pressure of 44 kg/cm^2 (628 psig). This backup steam is supplied for the following equipment: hogging and steam jet air ejectors, the steam seal regulator, and the auxiliary turbine lube oil pump turbine driver on each of the existing turbine units during startups and shutdowns.

Auxiliary steam supply for the Unit 4 heating system, heating system deaerator, caustic regeneration heater, Unit 4 condenser, deaerator storage tank spargers, and the existing building heating system is normally supplied from the Unit 4 turbine LP deaerator heater extraction. When Unit 4 is out of service, this auxiliary steam is supplied from the auxiliary boiler. The Unit 4 heating system auxiliary steam supply pressure is controlled to 2.1 kg/cm^2 (30 psig) by a pressure-regulating station. This 2.1 kg/cm^2 (30 psig) heating steam supply line is protected from overpressure by a safety valve set at 3.5 kg/cm^2 (50 psig).

The Unit 4 auxiliary boiler is a new equipment item. However, the auxiliary boiler is rated at 35 x 10^6 J/hr (600 boiler HP) or 9,120 kg (20,085 lb) of 9.5 kg/cm^2 (135 psig) saturated steam per hour. The auxiliary boiler is a gas-fired firetube-type boiler and is provided complete with a fan, instrumentation, controls, and safety valves. Auxiliary boiler feedwater supply is provided from the Unit 4 heating system condensate pumps.

4.1.4 Low Pressure Feedwater System

The LP feedwater system includes the primary process cycle for all four units from the condensers to, and including, the Unit 4 deaerator, deaerator storage tank, and miscellaneous condensate returns to the condensers. The system is comprised of the existing, modified, and new equipment on Units 1-3; an inter-unit LP feedwater transfer line to Unit 4; and new equipment for Unit 4.

For Unit 4, condensate from the condenser hotwell is transferred by two half-capacity, vertical-centrifugal, motor-driven condensate pumps. This condensate passes through the gland steam condenser, the steam jet air ejector, the ash equipment cooling water heat exchanger, and two stages of LP extraction feedwater heaters (4A and 4B), eventually reaching the deaerating feedwater heater (4C). Individual maintenance bypasses are provided around the gland steam condenser, ash equipment cooling water heat exchanger, and the two closed LP extraction feedwater heaters. The Unit 4 deaerator is an open heat exchanger that both heats and removes dissolved oxygen from the LP feedwater. Deaerator effluent flows, by gravity, into the deaerator storage tank, which serves as a suction surge vessel for the Unit 4 boiler feedwater pumps. LP feedwater from existing Units 1-3 is also pumped into the Unit 4 deaerator.

Units 1-3 each have identical LP feedwater systems. For each of these existing units, condensate from the condenser hotwell is pumped by two half-capacity condensate pumps through the steam jet air ejector and two stages of LP feedwater heaters (A and B) to a deaerator feedwater heater. On each of the existing units, the deaerator effluent flows, by gravity, into a deaerator storage tank; from here, it is pumped by a new full-capacity unit condensate transfer pump into a common line that delivers the LP feedwater flow from Units 1-3 to the Unit 4 deaerator. The new Units 1-3 condensate unit transfer pumps essentially replace the original boiler feedwater pumps for their respective units.

Each of the existing units had three half-capacity boiler feedwater pumps. Consideration was given to converting two of three boiler feedwater pumps on each of the existing units to the new condensate transfer duty. This would have required removing six of eight stages from the pumps to match the lower transfer head requirement. Uncertainties associated with this modification included hydraulic and dynamic balancing of the rotors. General pump refurbishment, new lower HP drive motors, and modification of the pump minimum-flow circuits would also have been required to convert these pumps. The decision to install new unit condensate transfer pumps on Units 1-3 was based on total evaluated costs and the technical uncertainties of modifying the old boiler feedwater pumps. It was more cost effective and less risky to purchase and install new unit condensate transfer pumps than to modify the old boiler feedwater pumps.

The LP feedwater system controls on the existing Units 1-3 have been modified to be "backward looking." The former deaerator level control valves in the LP feedwater lines to the deaerators have been modified to hold the condenser hotwell level constant. The unit condensate transfer pumps' discharge flow is now controlled to maintain constant deaerator storage tank level.

For Unit 4, the condenser hotwell level is controlled by gravity makeup from the condensate storage tank and by a condensate pump, and discharge pump line back to the condensate storage tank. Unit 4 deaerator storage tank level is maintained by a level control valve station located on the Unit 4 LP feedwater line upstream of the deaerator and upstream of the common Unit 1-3 LP feedwater transfer line interconnection. Provisions have been made for the future addition of an ASME test flow element in the Unit 4 LP feedwater line upstream of the deaerator in the event that an ASME turbine performance test is conducted for the Unit 4 turbine.

4.1.5 High Pressure Feedwater System

The HP feedwater system consists of the new Unit 4 primary process cycle from the Unit 4 deaerator storage tank outlet to the economizer inlet connection. The HP feedwater systems on Units 1-3 have been retired. (The HP feedwater heaters were retired in place, and the boiler feed pumps have been replaced by condensate unit transfer pumps.)

Condensate from the deaerator storage tank is transferred by two half-capacity boiler feedwater pumps through two stages of HP feedwater heaters. These units heat the feedwater before it enters the circulating AFBC boiler economizer section.

Individual bypasses are provided around each HP feedwater heater for maintenance purposes. The HP feedwater system also provides spray water for the boiler attemperators. This water comes from the feedwater pump discharge line ahead of the feedwater control valve station. Boiler feedwater flow is controlled by a level control valve station, which regulates feedwater flow to maintain a constant level in the boiler steam drum. The feedwater control valve station is located on the discharge side of the boiler feedwater pumps and upstream of the HP feedwater heaters.

Two 50%-capacity multistage, horizontal-centrifugal, motor-driven boiler feed pumps are provided. Automatic-type, minimum flow/check valves are provided on each boiler feed pump discharge line to protect the pump from low flow. The boiler feed pump minimum flow recirculation lines are each individually routed back to the deaerator storage tank.

An ASME test flow element is provided in the HP feedwater line upstream of the boiler economizer inlet connection. Provisions are available for the future addition of an ASME test flow element in the desuperheater spray water supply line, if required. These provisions will allow an ASME turbine performance test to be conducted for the Unit 4 turbine.

4.2 Plant Water Systems

Included under this heading are all water systems with the exception of the circulating water and fire protection systems. The plant water systems described here are:

- Raw/service water
- Preboiler water treatment
- Closed cooling water
- Wastewater
- Condensate storage and transfer
- Potable water.

4.2.1 Raw/Service Water System

The plant raw/service water system provides all water to the plant through a distribution system for cooling tower makeup, preboiler water treatment supply, fire protection, dust suppression, plant hose bibs, ash water supply, and miscellaneous plant water services.

The source of plant water is the San Miguel River, which flows next to the plant. River water flows through four new slotted-screen intake pipes located in the river bed and through a new valve pit into the existing service water pump sump. Two existing service water pumps move river water from the sump into the existing plant service water distribution system. A new line is provided off the service water header at the service water pump discharge to the valve pit. This line provides for backflushing of the river bed screen intake pipes when required due to river silt intake. Existing traveling water screens have been removed from the service water pump sump inlet. The new screens were installed to correct a problem with high silt in the river water during certain periods of the year.

The service water distribution system consists of an existing main header and some branch headers, both existing and new. The existing main service water header is located underground across the east side of Units 1, 2, and 3, and it extends west and south to an existing water storage tank elevated on a hill approximately 60 m (200 ft) above plant grade. This tank serves as a system head tank and provides for an emergency reserve of fire water. Level switches in the water storage tank actuate the service water pumps.

4.2.2 <u>Preboiler Water Treatment System</u>

The preboiler water treatment system extends from the plant service water system through the water treatment filters and makeup demineralizer. This system delivers high-quality makeup water to the condenser hotwell and/or to the condensate storage tank. In addition, the system includes all equipment necessary to regenerate the makeup demineralizer, including a demineralizer acid day tank, demineralizer regeneration acid educators, demineralizer caustic tank, piping, and valving. The system is comprised of both existing and new items of equipment.

Service water is supplied to two existing dual-media filters via an existing clearwell and treated water pumps. Service water is also supplied directly via two new dual-media filters that back up the existing filters. Water enters each filter from the top, flows through the filter bed, and discharges out of the bottom to the inlet of two new makeup demineralizer trains. Discharge from the existing filters is also used for the plant potable water supply. Each demineralizer train consists of a strongly acidic cation exchanger, which removes most of the cations in the water and a strongly basic anion exchanger, which removes most of the anions in the water.

From the operating demineralizer train, the water flows to a mixed bed polisher, which removes the exchangeable ions that remain after treatment by the cation and anion exchangers. The treated water discharge from the mixed bed polisher flows to the Unit 4 condenser hotwell and/or to the Unit 4 condensate storage tank.

4.2.3 Closed Cooling Water System

The closed cooling-water system is new and consists of two closed cooling water loops that are provided to cool Unit 4 equipment items. Units 1-3 equipment items are cooled by boosted circulating water. One closed cooling water loop removes useful heat from the boiler bottom ash coolers and recovers this heat by transferring it to the LP feedwater system. The other closed cooling-water loop removes low-level heat from various Unit 4 equipment items and rejects this heat to the Unit 4 circulating water system.

The ash equipment closed cooling loop is utilized because the LP feedwater system pressure is too high to be used directly in the bottom ash fluidizing-type coolers. Treated condensate is circulated in a closed loop by one of two 100%-capacity ash equipment cooling water pumps to the ash equipment cooling water heat exchanger, which transfers heat to LP feedwater. From this heat exchanger, the cooled water flows in parallel through each of the four bottom ash fluidized coolers and the two screw conveyor coolers where it is heated and returned to the pumps.

The closed cooling-water system cools equipment items requiring higher-quality water and less stringent cooling water temperature than are available directly from the circulating-water system. Treated condensate is circulated in a closed loop by one of two 100%-capacity closed cooling water pumps to two 100%-capacity closed cooling water heat exchangers. These exchangers transfer the low-level waste heat to the Unit 4 circulating water system. From these heat exchangers, the cooling water flows in parallel to cool the following equipment:

- The generator seal oil.
- The instrument air compressor (inter, after, bleed-off, and jacket coolers).
- The water sample panel.
- The turbine-generator (T-G) electro-hydraulic control unit.

- The boiler feedwater pumps (lube oil and seal water coolers).

- The primary air fan lube oil coolers.

- The secondary air fan bearings and the bottom ash cooling fan bearings.

These two closed cooling water loops are interconnected in that they share a common makeup, closed cooling water head tank, and chemical feeder pot. Corrosion inhibitor is fed from the chemical feeder pot to the pump suction lines in each loop. Closed cooling water makeup is treated condensate supplied from the Unit 4 condensate pump discharge and is controlled by the level in the common closed cooling water head tank. Makeup condensate can also be added to the closed cooling water system by the Unit 4 condensate transfer pump when the condensate pumps are not operating. The head tank also provides protection against surges and thermal changes. The head tank is actually a pipe enlargement at the top of a standpipe.

4.2.4 Wastewater System

The plant wastewater system includes the plant high-quality, low-quality, and sanitary drain collection and disposal facilities. Other than a few new drains, trenches, a septic tank and leach field, and an oil/water separator for the new Unit 4, the entire system was already in place.

High-quality plant drains, including cooling tower blowdowns, and storm drains, flow by gravity to a cooling tower blowdown (higher quality holding) pond. This holding pond is lined. The cooling tower blowdown pond provides temporary retention to allow solids to settle out. The cooling tower blowdown pond discharges to the San Miguel River.

Low-quality plant drains, including plant floor and chemical drains, are routed to a lower quality holding pond. Plant drains pass through an oil/water separator prior to entering the lower quality holding pond. This pond is unlined and has no outlet flow; seepage and evaporation equals the in-flow.

Sanitary wastes are routed to septic tanks (one replaced and two new) and leach fields.

4.2.5 Condensate Storage and Transfer

The condensate storage and transfer system consists of condensate storage tanks, transfer and deaerator feed pumps, and their associated piping. A new condensate storage tank and transfer pump are provided for Unit 4. This equipment is intertied to the existing Unit 1-3 condensate storage and transfer system.

The purpose of the condensate storage and transfer system is to store a reserve of high-purity treated water and deliver it for use by the plant steam/water cycle and other plant support systems, as needed. The source of treated water is the preboiler water treatment system.

Unit 4 condensate is stored in a lined aluminum storage tank with a capacity approximately equal to one boiler fill.

On each unit, condensate is gravity fed from the condensate storage tank to the condenser hotwell. This is a manual operation on Units 1-3, as condenser hotwell level is controlled by regulating the LP feedwater flow from the hotwell to the deaerator. For Unit 4, condensate makeup to the condenser hotwell is automatically controlled by hotwell level. On Unit 1-3, condensate can also be transferred to the deaerator or to another condensate storage tank by deaerator feed pumps. The Unit 4 condensate transfer pump is provided to transfer condensate from the Unit 4 condensate storage tank to the existing Units 1-3 condensate storage tanks, the plant heating system, the chemical feed system, and the closed cooling water system.

In addition to receiving makeup condensate from the preboiler water treatment system, the condensate storage and transfer system also receives excess condensate from the steam/water cycle on each unit, from the condensate pump discharge (hotwell high level dump), and deaerator overflow or dump (high level). Condensate is also returned to the storage and transfer system from the Unit 4 water sample panel, and from the Units 1-3 heating system.

4.2.6 Potable water System

The potable water system supplies drinking-quality, filtered, and chlorinated service water throughout the plant.

The source of potable water is the downstream side of the preboiler water treatment system, specifically following the dual media filters.

The existing potable water distribution system was simply extended to supply potable water to the new control room and maintenance shop. Potable water is distributed to toilets, wash basins, and drinking fountains. Electric hot-water heaters provide hot water to the wash basins.

4.3 Circulating Water System

The circulating water system consists of two independent evaporative cooling cycles that serve as the heat sink for the plant power cycle and provide cooling for major equipment items. An existing circulating water system commonly services Units 1-3, and a new circulating water system is provided for Unit 4.

4.3.1 Units 1-3 Circulating Water System

The Units 1-3 circulating water system transfers low-level waste heat from the Units 1-3 condensers, turbine gland leakoff condensers, turbine oil coolers, and generator air coolers to the Units 1-3 cooling tower. The cooling tower releases the waste heat to the atmosphere primarily by evaporative cooling and, secondarily, by sensible heat transfer to the atmosphere. The major system equipment includes the cooling tower, the circulating water pumps, and the cooling water (booster) pumps.

Units 1-3 circulating water is pumped from the cooling tower water basin by three common, 33%-capacity, vertical-shaft, wet pit, circulating water pumps. From the discharge of the circulating water pumps, the circulating water flows through an underground pipeline to the plant building. The flow splits and goes simultaneously to both the tube sides of the Units 1-3 condensers and to the cooling water (booster) pumps.

Three common, 33%-capacity, cooling water (booster) pumps are provided for Units 1-3 to boost the circulating water pressure. This water cools the turbine gland steam leakoff condenser, the turbine lube oil coolers, and the generator air coolers on all three existing units. Due to age and condition, the original three cooling water booster pumps were replaced with new pumps. The boosted cooling water flow through the turbine oil coolers and the generator air coolers on each unit is modulated by a temperature control valve.

The heated circulating water from the Units 1-3 condensers and equipment coolers then merges back into a single underground pipeline and flows to the Units 1-3 cooling tower. At the cooling tower, the circulating water flow is distributed by headers along the top of the tower. The warm circulating water cascades down over the cooling tower fill, releasing heat to the atmosphere, and is collected in the cooling tower basin. The cooled water then flows back to the circulating water pumps, completing the cycle.

A cooling tower, cold weather bypass is provided to return circulating water flow directly to the cooling tower basin. The cooling tower bypass is used when Units 1-3 are out of service, or at low loads during cold ambient conditions to prevent tower freezing and icing buildup.

A portion of the Units 1-3 circulating water flow is blown down to maintain acceptable chemical concentrations in the circulating water. Blowdown flow is taken upstream of the cooling tower and is routed to the cooling tower blowdown pond. Blowdown flow control is automatically modulated by blowdown conductivity. In addition to blowdown, circulating water is continuously lost as cooling tower evaporation and drift which must be continuously made up. Makeup water is provided from the service water system to the cooling tower basin and is controlled to maintain a constant basin water level.

4.3.2 Unit 4 Circulating Water System

The Unit 4 circulating water system transfers waste heat from the Unit 4 condenser, turbine lube oil coolers, generator hydrogen cooler, and closed cooling water heat exchangers to the Unit 4 cooling tower. The cooling tower releases the waste heat to the atmosphere primarily by evaporative cooling and secondarily by sensible heat transfer to the atmosphere. The major system equipment includes the cooling tower and the circulating water pumps.

Unit 4 circulating water is pumped from the cooling tower water basin by two horizontal shaft centrifugal circulating water pumps. From the discharge of the circulating water pumps, the circulating water flows through a single underground pipeline to the Unit 4 turbine building. Here the flow splits and goes simultaneously through the tube sides of the condenser, turbine lube oil coolers, generator hydrogen coolers, and the closed cooling water heat exchangers. The circulating water flow through the turbine lube oil coolers, hydrogen coolers, and closed cooling water heat exchangers is modulated by butterfly temperature control valves.

The heated circulating water then merges back into a single underground pipeline and flows to the cooling tower. At the cooling tower, the circulating water flow is distributed by headers along the top of the tower. The warm circulating water cascades down over the cooling tower fill, releasing heat to the atmosphere, and is collected in the cooling tower basin. The cooled water then flows past a chlorine diffuser back to the circulating water pumps, completing the cycle.

A cooling tower cold weather bypass also is provided by bypass return circulating water flow from Unit 4 directly to the cooling tower basin. The cooling tower bypass is used when the plant is out of service or at a lo load during cold ambient conditions to prevent tower freezing and icing buildup. The bypass is sized to pass 18.9 m^3/min (5,000 gpm) flow of circulating water.

A portion of the Unit 4 circulating water flow is blown down to maintain acceptable chemical concentrations in the circulating water. Blowdown flow is taken upstream of the cooling tower and is routed to the cooling tower blowdown pond. Blowdown flow control is automatically set by a flow recorder based on unit load index with trim from circulating water conductivity. In addition to blowdown, circulating water is continuously lost as cooling tower evaporation and drift which must continuously be made up. Makeup water is provided from the blowdown flash tank drain flow and from plant service water. Service water makeup is introduced to the cooling tower basin. Its flow is controlled to maintain a constant cooling tower basin water level.

Both circulating water systems are serviced by a common cooling tower chemical feed system, which is discussed later in this section.

A small intertie is provided between the existing Units 1-3 and the new Unit 4 circulating water systems. This intertie enabled the Unit 4 closed cooling water heat exchangers, turbine lube oil coolers, and generator hydrogen coolers to be used during initial Unit 4 commissioning activities prior to the scheduled completion of the Unit 4 cooling tower construction.

4.4 Condenser and Accessories

The condenser and accessories system includes the condenser and the condenser air-removal equipment. Identifical condensers and accessories exist for each of the three existing Units (1-3). A new condenser and condenser accessory equipment are provided for Unit 4. The following description applies for both the existing Units 1-3 and the new Unit 4 condensers.

For each unit turbine exhaust, steam is condensed by the condenser. The steam is condensed on the shell side of the condenser by exchanging its waste heat to cooler circulating water flowing through the tubes of the condenser. The Unit 1-3 condensers are serviced by a common existing circulating water/cooling tower system. The new Unit 4 condenser is serviced by a new circulating water/cooling tower system. The high-quality condensed steam or condensate flows by gravity to a condenser hot well, from where the condensate pumps move it to the LP extraction feedwater heaters on each unit.

The condenser for each unit also serves as a collection point for various high-purity cycle vents and drains including:

- LP feedwater vents and drains
- HP feedwater alternate drains for Unit 4 only
- Turbine drains
- Gland steam condenser
- Steam jet air ejector drains.

The condenser vacuum on each unit is established by a priming jet (or hogging jet on Units 1-3) air ejector, which uses auxiliary steam (turbine throttle steam for Units 1-3) to induce or draw a vacuum on the condenser prior to starting the turbine. During normal operation, condenser vacuum is maintained by a dual-stage, steam jet air ejector to remove air and other noncondensable gases from the condenser. Auxiliary steam (turbine throttle steam for Units 1-3) is also used to operate the steam jet air ejectors. The steam jet ejector induction steam flow and heat are condensed with LP feedwater flow and drained to the condenser for recovery.

4.5 Chemical Feed Systems

The chemical-feed systems include the following subsystems:

- Feedwater chemical-feed system
- Boiler chemical-feed system
- Cooling tower chemical-feed system
- Closed cooling tower chemical-feed system
- Water sampling and monitoring system.

These subsystems consist of new and/or existing equipment items which are described in the following sections.

4.5.1 Feedwater Chemical Feed System

A new feedwater chemical-feed system is provided for Unit 4. This system pumps a solution of amine and condensate to the LP feedwater line on the discharge side of the condensate pumps. It also pumps a solution of hydrazine and condensate to the LP feedwater line upstream of the deaerator inlet. This system includes two solution tanks, one for amine and one for hydrazine. Each system is complete with a mixer, three reused existing positive displacement metering pumps - one each for amine and hydrazine - and a common spare. Condensate for filling the tank is provided from the condensate transfer pump.

4.5.2 Boiler Chemical Feed System

A new boiler chemical-feed system is provided for the new circulating AFBC boiler. This system pumps a solution of mono-, di- or tri-sodium phosphate and condensate to the AFBC boiler steam drum. It consists of a solution tank with mixer and condensate inlet connection, and two diaphragm-type, positive displacement metering pumps, one of which is an installed spare.

4.5.3 Cooling Tower Chemical Feed System

The cooling tower chemical-feed system is an existing system with new components added for the Unit 4 cooling tower. The system is common for both the existing and the new cooling towers. This equipment includes the cooling tower chlorination, chemical feed, and acid feed systems.

The circulating-water systems are treated with chlorine solution on a periodic treatment cycle to prevent biological fouling in the circulating-water systems. Chlorine bottles supply chlorine gas to two chlorinators (one existing and one new chlorinator) for the existing and new cooling towers, respectively. For the new cooling tower, the chlorine gas enters an ejector where it mixes with service water to form a chlorine solution. This solution is fed to a chlorine diffuser located in the cooling tower basin. For the existing cooling tower, chlorine gas is mixed with service water in an ejector and is introduced into the circulating water line on the discharge side of the circulating water pumps.

The cooling towers are treated with a scale-inhibitor solution. A new chemical solution tank is used to mix the scale inhibitor with service water. Three positive displacement metering pumps, two existing and one new pump, transfer the scale-inhibitor solution to the cooling tower basins in proportion to cooling tower blowdown. An existing pump is a common spare for both cooling towers.

Sulfuric acid (delivered by truck) is received in the existing cooling tower acid tank. Three positive displacement metering pumps, two existing and one new pump, feed acid to control circulating water pH. One pump is a common spare for both cooling towers.

4.5.4 Closed Cooling Water Chemical Feed System

Corrosion inhibitor is fed from a new chemical feeder pot located between the closed cooling water pumps, discharge and suction headers. It is also connected to the suction side of the ash equipment cooling water pumps. The chemical feeder is included as part of the closed cooling water system.

4.5.5 Water Sampling and Monitoring System

A new water sample panel provides primary and secondary sample cooling, sample pressure and flow control, and sample analysis. Cooling water is used for primary sample cooling of high-temperature sample streams. Raw water is used for secondary sample cooling via a heat exchanger. From the sample panel, the sample streams are returned to the Unit 4 condensate storage tank and/or to plant drains.

Samples from the following locations are routed to the water sample panel (sample analysis is listed in parenthesis):

- Boiler water (specific conductivity, pH, silica, and grab sample).
- Boiler steam drum saturated steam (cation conductivity, sodium, and grab sample).
- Main steam (cation conductivity, sodium, and grab sample).
- Economizer inlet (dissolved oxygen, specific conductivity, sodium, silica, and grab sample).
- Unit 4 condensate pump discharge (dissolved oxygen, cation conductivity, and grab sample).
- Existing Unit 1-3 deaerator outlets (dissolved oxygen and grab sample).

- Existing Unit 1-3 condensate systems (cation conductivity, dissolved oxygen and grab samples).

- Preboiler water treatment mixed bed feed and discharge (silica and grab sample).

A new independent sample panel system is provided for sampling, analyzing, and recording both circulating water chemistry and blowdown flow from both circulating water systems.

4.6 Miscellaneous Mechanical Equipment

Miscellaneous mechanical equipment systems include:

- Heating, Ventilating and air conditioning (HVAC) systems
- Compressed air systems
- Cranes and hoists
- Lube oil storage and conditioning
- Fire protection
- Fuel gas supply.

These are discussed in the following subsections.

4.6.1 HVAC Systems

The HVAC systems provide for the heating, ventilating, and air conditioning of the plant facilities. The systems include both new HVAC systems to serve the new Unit 4 facilities and existing plant HVAC systems that serve the Units 1-3 plant building.

HVAC is provided for the following plant areas:

- New Unit 4 turbine and boiler building
- New control and logic rooms
- New electrical room
- New maintenance shop
- New electrical shop
- New battery room

- New variable-speed control equipment room
- New elevator machinery room
- New outlying buildings
- Existing turbine and boiler building.

4.6.1.1 New Turbine and Boiler Building HVAC

The design inside temperature is 8°C (15°F) minimum temperature in winter. Reversible power ventilators and gravity air movers are installed on the boiler room roof. Windows are installed in the turbine room walls at the grade and operating floor levels. Steam unit heaters are installed in the lower areas along exterior walls to heat incoming air at the rate of one-half total air change per hour.

For summer operation, the power roof ventilators and gravity air movers are used in conjunction with the circulating AFBC boiler combustion air fan (PA and SA fan) suctions to remove hot air accumulated at the top of the boiler building. This volume has been calculated to substantially exceed boiler combustion air requirements. Cooling air is admitted through both doors and windows. Air flow is created by the boiler area negative pressure created by the roof ventilators, boiler combustion air fans, and boiler room stack effect.

For winter operation, gravity air movers, doors, and windows are closed. Power roof ventilators are operated in reverse to provide boiler combustion air requirements, thereby minimizing negative pressure in the building and the attendant air infiltration. Some negative pressure exists because of the stack effect in the boiler area. Steam unit heaters are located in the lower areas of the turbine and boiler rooms to provide heating requirements. These heaters have individual thermostats to energize their fan. Roof-mounted gravity air mover, damper actuators are controlled by manual off-on switches located in the control room. Roof-mounted power ventilators have off-on reverse switches located in the control room.

A 2.1 kg/cm^2 (30 psig) heating steam is provided from the auxiliary steam system from either Unit 4 turbine deaerator extraction or from the auxiliary boiler. A two-pipe arrangement is used, one pipe to supply steam to the unit heaters and the second pipe to return the condensate to the heating system deaerator receiver. The condensate is then pumped by one of two full-capacity heating system condensate pumps back to the Unit 4 main cycle deaerator or to the auxiliary boiler. The heating system deaerator and heating system condensate pumps are provided new with Unit 4. However, the heating system deaerator and condensate pumps were purchased as a used-equipment package.

4.6.1.2 New Control and Logic Rooms HVAC

Design room temperatures are 21°C (70°F) in winter and 26°C 78°F) in summer. Relative humidity is not to exceed 50%. Positive pressure is maintained in each room. Two duplicate 100%-size, air-handling units are used, each equipped with filters and direct expansion coils. Supply and return ducts convey air to and from the control and logic areas. Low-velocity/low-pressure loss, air distribution ducts are used. Duplicate, roof-mounted, air-cooled condensers and compressors are provided. Electric duct heaters are utilized for final control of temperature in each room. Makeup air is provided to the suction side of the air handling units from outside.

Controls use makeup air, direct expansion coils, and duct heaters as required to satisfy room temperature. An air conditioning system control panel is located at each air-handling unit with a manual off-auto switch to allow individual units to be operated for check-out or maintenance. When either switch is in the "auto" position, the control system automatically operates the HVAC equipment. The control of the redundant system is arranged in such a way that it allows either system to be used as the main system. Electric duct heaters are controlled by room thermostats.

4.6.1.3 New Electrical Room HVAC

No space heating is provided for winter. Design summer temperature is 8°C (15°F) above outdoor ambient. A supply air fan provides ventilation and pressurization air, and an exhaust lover is provided to exhaust the air.

A thermostat with a hand-off switch override is supplied to control the fan. The fan shutter operator and exhaust lower louver operator are interlocked with fan operation to open when the fan motor is energized and to close when the fan motor is deenergized.

4.6.1.4 New Maintenance Shop HVAC

Maintenance area ventilation is provided by a wall-mounted supply fan. The fan provides six air changes per hour. The maintenance area heating requirement is provided by steam unit heaters. Design temperature is 18°C (65°F) for winter. The ventilation fan is controlled by a manual on-off switch. Unit heaters are controlled by individual thermostats.

The maintenance office is provided with a window-type combination air conditioning and heating unit. Design temperature is 27°C (80°F) for summer and 21°C (70°F) for winter in the office.

4.6.1.5 New Electrical Shop HVAC

Ventilation and heating requirements are provided by a wall-mounted supply fan and steam unit heaters, respectively. The ventilation fan is controlled by a manual on-off switch. The fan provides six air changes per hour. Unit heaters are controlled by individual thermostats. The winter design temperature is 18°C (65°F).

4.6.1.6 New Battery Room HVAC

A supply grill and exhaust fan are used for ventilation purposes. A minimum of four air changes per hour are provided. The fan is controlled by a manual on-off switch. The room temperature is maintained above 25°C (77°F) as much of the time as possible.

4.6.1.7 New Variable-Speed Control Equipment Room HVAC

This room contains the variable-frequency control equipment for the AFBC boiler PA, SA, and ID fan drives. The air conditioning equipment required for this room is provided by the AFBC boiler supplier and is included as part of the boiler air and gas system.

4.6.1.8 New Elevator Machinery Room HVAC

Ventilation is provided as required.

4.6.1.9 New Outlying Buildings HVAC

These buildings include the new stack monitoring equipment, cooling tower electrical, cooling tower chemical, limestone electrical, and the ash blower buildings. These buildings are ventilated, and some are heated. Electric unit heaters are used to heat the stack monitoring equipment, cooling tower chemical, limestone electrical buildings to 13°C (55°F). The stack monitoring equipment building is heated and cooled by a packaged heat pump. Building ventilation for each of these buildings, except the stack monitoring equipment building, consists of a wall-mounted supply fan (complete with inlet shutter) and a motor-operated wall exhaust damper. The building ventilation fan starts and the dampers open when the building temperature is 35°C (95°F) and shutoff at 27°C (80°F).

4.6.1.10 Existing Turbine and Boiler Building HVAC

The existing plant building heating system utilizes 1.5 kg/cm^2 (15 psig) steam provided from the new auxiliary steam system. This system is designed with sufficient capacity to supply the existing building heating requirements. Cross-connections are made between new and existing steam supply and condensate return lines.

4.6.2 Compressed Air Systems

The instrument and service air systems supply plant instrument and service compressed air for all plant requirements. The systems consist of a combination of new and existing equipment and distribution piping.

Instrument air is supplied by a new two-stage, oil-free, rotary screw compressor complete with an electric drive motor, intercooler, bleed-off cooler, inlet filter/silencer, control and relief valves, control panel, and instrumentation all mounted on a common skid. The instrument air compressor supplies 7.7 kg/cm^2/46°C (110 psig/115°F) air to a new instrument air skid. The instrument air skid includes an air receiver, a dryer prefilter, a desiccant-type regenerative air dryer, and a dryer afterfilter. Compressed air supply to the instrument air skid is backed up by service air. From the instrument air skid, the dried and filtered instrument air is distributed to both the new Unit 4 circulating AFBC boiler, turbine-generator, baghouse, ash system, coal handling and limestone areas, and to the existing Units 1-3 instrument air distribution network via the existing instrument air receiver. The existing instrument air compressors and air dryer have been retired.

Service air is supplied by two single-stage, oil-flooded type, rotary-screw compressors. One compressor is normally operating in an on-off mode and the other compressor is a spare in standby mode. These compressors were previously utilized for construction purposes. The service air compressors discharge air at 7 kg/cm^2 (100 psig) and 43°C (110°F).

The service air compressor discharge flow passes through an oil scrubber and filter and enters a service air receiver. From the service air receiver, the service air is distributed to the Unit 4 boiler and turbine areas: the new instrument air skid via control and check valves to back up the instrument air compressor, and the existing plant service air system. The existing plant service air system includes two compressors, a dryer, and a receiver. The existing service air compressors are available for standby duty.

4.6.3 Cranes and Hoists

The Nucla Station has two turbine bay cranes. An existing crane services Units 1-3, which share a common turbine bay. A new crane services the Unit 4 turbine bay. The arrangement of the larger Unit 4 did not permit the new turbine-generator to be situated as an extension of the existing turbine bay. The lifting service requirements for the Unit 4 turbine generator also exceeded the capacity of the existing turbine bay crane.

A boiler area maintenance hoist and an elevator are located in the Unit 4 boiler room area. The elevator is situated to serve the entire plant. The existing plant building does not have an elevator.

4.6.4 Lube Oil Storage and Conditioning

Units 1-3 turbine-generator lube oil systems are serviced by two existing centrifuge-type lube oil conditioning units. One unit commonly serves Units 1 and 2 alternately, and the other unit services Unit 3. Lube oil storage tanks are not provided for the Units 1-3 turbine-generators.

A complete lube oil storage and conditioning system is provided for the Unit 4 turbine-generator. The system consists of two lube oil storage tanks (one "clean" and one "dirty," each sized to hold one complete charge of T-G lube oil); two lube oil transfer pumps (one to transfer lube oil to/from storage and one to transfer turbine reservoir lube oil to the conditioner unit); a filtering-type lube oil conditioner unit; a waste oil sump; a waste oil sump pump; and a waste oil tank.

4.6.5 Fire Protection

Fire protection for the Nucla Station consists of a fire water system (using the service water supply), carbon dioxide gas systems for each generator, and a stand-alone deluge system for the propane storage tank.

The existing plant uses fire water supply directly from the plant service water header network. The fire water supply for Unit 4 is service water boosted by a new fire booster pump and a nes pressure maintenance pump. The Unit 4 fire water booster and pressure maintenance pumps are required because of the significantly greater height of the new AFBC boiler structure. The fire water distribution system for both the existing structure and new unit addition consists of fire hydrants, deluge systems (for the transformers), preaction sprinkler, and coal-dust suppression (explosion prevention) systems. Pressure is maintained in the service water header network supplying fire water by the elevated service water storage (head) tank which also serves as the fire water storage tank. Pressure is continuously maintained in the Unit 4 fire water header by a small-capacity, pressure maintenance pump which cycles on and off to maintain header pressure. The fire booster pump starts only if the maintenance pump fails to maintain header pressure (causing a surge in flow).

Accessory cabinets are provided that contain hose reels, hose, nozzles, hose connectors, axes, and miscellaneous fire-fighting equipment. Hand-held fire extinguishers are placed at various locations throughout the plant.

The CO_2 systems for Units 1-3 are provided for generator fire protection only (the generators are air cooled). The Unit 4 generator CO_2 system is for both fire protection and generator hydrogen purging (fire prevention).

A stand-alone deluge fire protection system is provided for and as part of the Unit 4 propane storage tank.

4.6.6 Fuel Gas Supply

Propane is used for plant fuel gas. The propane fuel gas supply includes a truck unloading station, a used and reconditioned storage tank, used and reconditioned propane vaporizers, a propane supply pump, a plant gas supply line, and system wiring and controls. The propane fuel system is provided as part of the new Unit 4 installation, and it supplies fuel gas to both the auxiliary heating boiler and the AFBC boiler startup and duct burners.

Colorado-Ute's original plan was to contract with the local gas company to run a natural gas supply line into the Nucla plant from about seven miles away. The gas burners on both the AFBC and auxiliary boilers were originally sized for natural gas. However, the cost to install a propane system was significantly less than for a natural gas line, and the energy costs were very close to being equivalent. Thus, Colorado-Ute elected to install a propane gas supply system at the Nucla Station. The only change required to switch from natural gas to propane for the various burners was to install smaller burner orifices to correct for the higher heating value of the propane fuel (approximately 2.5 times higher than natural gas on a volumetric basis).

Section V. Turbine-Generator and Balance-of-Plant Electrical Equipment and Systems

The turbine-generator and balance-of-plant electrical equipment includes the steam turbines, generators, the main power transformers, auxiliaries and bulk electrical materials needed by the plant to supply electrical energy. Description of these plant support equipment, facilities, and systems are also included in this section. Turbine-generator and balance-of-plant electrical equipment data is included in Appendices A and B.

5.1 Turbine-Generator

The turbine-generator system includes the three existing turbine-generator units (1-3), which have been modified and refurbished and the new Unit 4 turbine-generator, complete with accessories and a number of integral turbine-generator subsystems.

5.1.1 Existing Unit 1-3 Turbine-Generators

The three existing Unit 1-3 turbine-generators are each identical 11,500 kW American Institute of Electrical Engineers (AIEE)-ASME preferred standard machines. The turbines, manufactured by De Laval Steam Turbine Company, are 3,600 rpm, multistage, non-reheat, condensing units, directly coupled to the generators, manufactured by Electric Machinery Company. Throttle steam conditions are 42 kg/cm^2 (600 psig), 441°C (825°F). Four stages of uncontrolled extraction heat the feedwater. The highest pressure extraction, which originally supplied a single-stage high-pressure (HP) feedwater heater on each unit, has been capped off as part of the plant modification. The HP feedwater heaters have been retired and the low-pressure (LP) feedwater from the Unit 1-3 deaerators is now pumped to the new Unit 4 deaerator. The turbines are each rated at 12,650 kW at 3.8 cm (1.5 in) Hg exhaust pressure.

The generators are each synchronous 3,660 rpm, three-phase, 60-hertz units with air-cooled stator and rotor. The generators are each rated at 13,529 KVA at a 0.85 power factor. Because of their age, the generators had relatively high leakage rates and rewinding them was considered. Due to project budget constraints, generator rewinding was postponed to a later date. New varnish was applied to the generators which substantially improved their leakage rates.

The existing turbine-generators each include the following major subsystems and accessories:

- Turning gear

- Shaft-driven oil pump
- Steam turbine driven auxiliary oil pump
- Combined trip and throttle valve
- DC generator exciter
- Turbine governor.

5.1.2 New Unit 4 Turbine-Generator

This turbine-generator unit is a single horizontal-shaft, steam-driven, revolving-field, electrical generating unit. The turbine is a 3,600 rpm, single automatic extraction, non-reheat condensing unit mounted in a single casing and manufactured by Mitsubishi Heavy Industries, Ltd., under Westinghouse Electric Company license. The automatic extraction is provided to supply throttle steam to the existing Unit 1-3 turbine-generators. The automatic extraction is controlled to supply 42 kg/cm^2 (600 psig) to the Unit 1-3 turbines. Five stages of uncontrolled extraction are provided at lower pressures for feedwater heating (See Figure 22). The turbine is rated at 73,362 kW. Throttle steam conditions are 102 kg/cm^2 (1,450 psig), 538°C (1000°F). The generator is a synchronous 3,660 rpm, three-phase, 60-hertz unit with a hydrogen-cooled stator and rotor. The generator is rated at 88,200 KVA with 2.1 kg/cm^2 (30 psig) hydrogen cooling pressure, 0.90 power factor and a 0.85 short-circuit ratio. It was manufactured by Westinghouse Electric Company.

The turbine includes the following major subsystems and accessories:

- Turbine-mounted steam chest with stop-throttle valve and governing control valves
- Extraction control valves
- Electro-hydraulic control system
- Lube oil system
- Gland sealing system including the gland steam condenser
- Pneumatically-operated drain valves and piping from turbine to the drain valves
- Exhaust casing spray system

CALCULATION BASED ON LOCUS OF VALVE POINTS

LEGEND

W - FLOW		LB/HR
P - PRESSURE		PSIA
H - ENTHALPY		BTU/LB
T - TEMPERATURE		°F

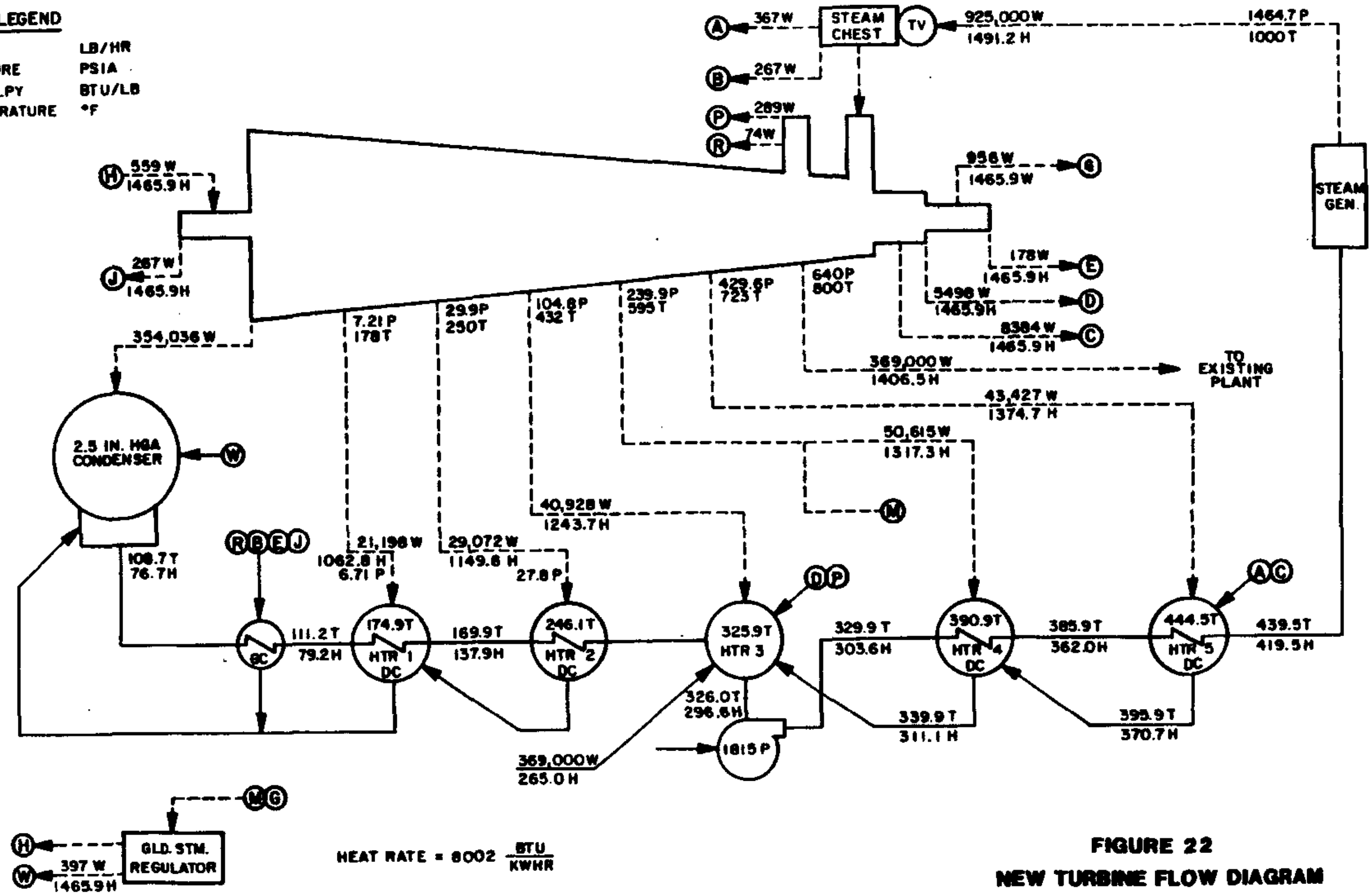

FIGURE 22
NEW TURBINE FLOW DIAGRAM

- Turning gear
- Turbine protective devices
- Turbine supervisory instruments
- Rotor-grounding device
- Insulation and lagging.

The generator includes the following major subsystems and accessories:

- Hydrogen-cooling system
- Static-excitation system
- Generator field discharge resistor
- Six high-voltage bushings with terminals
- Sixteen bushing current transformers
- Temperature detectors
- Seal oil system.

The electrical sections of the generator (excitation system, etc.) constitute part of the generator and main power transformer system.

5.1.2.1 Turbine Gland Seal System

The turbine gland seal system seals the turbine casing shaft penetrations between the turbine shell/exhaust hood and the atmosphere to prevent both leakage of air into the condenser and blow out of steam into the turbine room. The gland sealing system is provided as part of the turbine unit.

Each of the two turbine gland-shaft seals consists of labyrinth-type packing rings to restrict the flow of steam and air to a minimum. During startup, main steam is the source of gland steam. During normal operation, steam leakoff from the high pressure end (No. 1 gland) serves as the source of gland steam for the exhaust hood (No. 2 gland). Gland steam leakoff pressure is regulated by a pressure control valve that exhausts excess gland steam to the highest pressure, feedwater heater, extraction steamline. Leakoff gland sealing steam and air in-leakage is routed to the gland steam condenser which condenses the steam, returns the condensate to the condenser, and exhausts non-condensable gases (air) to the atmosphere via one of two 100%-capacity exhauster fans.

5.1.2.2 Turbine Lube Oil System

The function of the turbine lube oil system is to provide for the lubrication of turbine and generator journal bearings, the thrust bearing, and the turning gear. Additionally, the turbine lube oil system is a backup source of oil supply for the generator hydrogen seal oil system. It also provides oil pressure for the operation of the mechanical overspeed trip and manual trip mechanism.

The turbine lube oil system consists of the following major components:

- Lube oil reservoir
- Turbine shaft-driven main oil pump
- Oil ejector
- Twin oil coolers
- Auxiliary motor-driven oil pumps
- Guarded oil piping
- Loop seal tank
- Unguarded generator oil piping
- Instrumentation and protective devices.

The turbine lube oil system is a closed-loop system using oil that is cooled and pumped to various points of use. The system uses both shaft-driven and motor-driven pumps. The shaft-driven pump in the turbine governor pedestal, together with an oil ejector in the reservoir, pump the oil when the turbine is operating at a near rated speed. Motor-driven pumps are used when the main shaft-driven oil pump and oil ejector cannot supply sufficient oil pressure. The system uses two shell-and-lube oil coolers to regulate the lube oil temperature. The turbine lube oil system contains monitoring and control devices to ensure safe and reliable turbine-generator operation.

5.1.2.3 Generator Seal Oil System

The function of the generator seal oil system is to provide sealing of the generator rotor to prevent leakage of hydrogen coolant from the generator.

The generator hydrogen seals are located at the casing shaft penetrations at each end of the generator rotor. Seal oil is continuously injected to the center section of the shaft seals and flows longitudinally in both directions, both toward the generator and away from the generator, sealing the shaft to prevent hydrogen leakage. The oil is collected on both sides of the seal and drains by gravity to the skid-mounted seal oil unit. The oil drained from the generator side of the seal flows through a loop seal trap to the hydrogen side drain regulator, both of which serve to prevent hydrogen from escaping with the seal oil drain flow. From the hydrogen side drain regulator, the seal oil drain flow joins the outboard seal oil drain flow from the generator hydrogen seals and drain overflow from the turbine lube oil system generator bearing loop seal. The combined seal oil flow is routed to the seal oil vacuum tank from which any vapors are removed via the seal oil vacuum pump. From the seal oil vacuum tank, the seal oil is pumped through a cooler and filter back to the generator hydrogen seals. The turbine lube oil system serves as a backup source of oil supply for the generator seal oil system.

The skid-mounted seal oil unit consists of the following major components:

- One main seal oil pump with totally enclosed A-C motor
- One backup seal oil pump with totally enclosed D-C motor and starter
- One vacuum pump with totally enclosed A-C motor and oil separator tank
- Instrumentation and protective devices
- Piping and valving
- Gauge panel and junction box.

5.2 Electrical Equipment

The plant electrical systems include the generator and main power transformers, the auxiliary power, and the uninterruptible and DC power supply systems.

The generator and main power transformer system contains the generator, the main power transformer, and power bus. This system includes the excitation system, protective relaying, generator neutral grounding, surge protection, and voltage transformers for each of the three existing units and the new Unit 4. The auxiliary power system consists of the medium-voltage and low-voltage systems for both the existing plant and the new Unit 4 facilities. The uninterruptible and DC power supply system includes the rotary uninterruptible power supply (RUPS) and 125-volt DC distribution system.

5.2.1 Generator and Main Power Transformer System

The generator and main power transformer system includes the electrical generators, the main step-up power transformers, and power buses; also included are the excitation systems, protective relaying, generator grounding, surge protection, and voltage transformers. The mechanical portions of the generators are included in the turbine-generation system. The system consists of older components for Units 1-3 and new components for Unit 4.

5.2.1.1 Existing Unit 1-3 Generator and Step-up Transformer Systems

The system consists of three identical 13,500-kVA generators and step-up power transformers. The transmission system is 115 kV and the generator voltages are 13.8 kV. The generators are connected to the main power transformers by 750-MCM cable. The generator excitation systems are shaft-driven DC, alternator designs. Generator power factors are 0.85.

5.2.1.2 New Unit 4 Generator and Step-Up Power Transformer System

The system consists of one 88,200-kVA generator and step-up power transformer. The transmission system is 115 kV and the generator voltage is 13.8 kV. The generator is connected to the main power transformer by the isolated phase bus. A tap from the isolated phase bus connects three surge arresters and two sets of three voltage transformers. The neutral end of the generator is connected to a dry-type distribution grounding transformer with a secondary resistor.

The following relay protection is provided (type in parentheses):

- Generator differential (SA-1)
- Generator transformer differential (HU)
- Generator transformer system ground (neutral voltage, IVA, CV)
- Generator transformer system ground (broken delta voltage, IVA, CV)
- Loss of excitation (long and short reach, CEH52)
- Anti-motoring (GGP)
- Generator volts/hertz (2 stages, STV)
- Transformer volts/hertz (2 stages, STV)
- Under-frequency (2 stages, SDF)
- Out-of-step (CEX/GSY, SDBU)
- Main power transformer neutral overcurrent (IFC,CO)
- Generator system backup (CEB, KD-11)
- Negative sequence (SGC, RAR10)
- Main power transformer sudden pressure.

The excitation system is a manufacturer's standard static excitation system and interface, with accessories and characteristics required by the application. Generator voltage is the manufacturer's standard voltage, 13.8 kV.

The generator kVA rating, at rated power factor, is such that the generator is capable of matching maximum possible turbine output. The generator power factor is 0.9.

Ampacity of the isolated phase bus is a manufacturer's standard rating, but not less than generator current rating at 95% of rated voltage.

Excitation system speed of response is as required by transmission system characteristics. High initial response and power system stabilizers may be provided, if required by power system characteristics.

The main power transformer primary (LV) voltage rating is based on the ratio required to permit operation of the generator at rated voltage, kVA, and power factors. These parameters are set with the transmission system operating at rated transformer secondary voltage.

The main power transformer, secondary (HV) nominal (center tap) voltage rating is approximately the transmission system mean operating voltage.

The main power transformer, secondary (HV) surge arresters and basic impulse insulation level (BIL) are based on transmission system requirements.

The main step-up transformer kVA/65°C rise rating is based on the turbine-generator delivering maximum output when the boiler and entire plant auxiliaries are supplied by the auxiliary transformer.

5.3 Auxiliary Power System

The auxiliary power system consists of the medium-voltage and low-voltage systems. The medium-voltage system includes a new auxiliary transformer, switchgear, interconnections, and feeders for the entire plant. The low-voltage system includes load centers, motor control centers, interconnections, and feeders. The auxiliary power system design was based on an estimated total plant auxiliary transformer load of 14,000 kVA when firing the "B" coal with 100% extraction on the Unit 4 turbine. Estimated auxiliary power loads were somewhat conservative because of the lack of firm design information at the time. In addition, extra capacity was allowed for possible design changes and/or future equipment additions due to the project's demonstration nature.

Because of space limitations in the switchyard, Colorado-Ute elected to eliminate an existing startup transformer, which would allow room for the new station auxiliary transformer. Three existing PCB-filled load center transformers located within the plant were also replaced with two dry-type transformers to eliminate a possible environmental hazard. These transformers are supplied with power from the new station auxiliary transformer. All auxiliary power loads for the Nucla Station are furnished by the new station auxiliary transformer.

The plant medium-voltage system is 4160 volts supplied from the station auxiliary transformer fed from the 115-kV system. This system was the most economical one for satisfactory operation consistent with the plant design philosophy.

5.3.1 Design Load Estimate Summary

The following summary is based upon preliminary design load lists. It was anticipated that the estimated loads would be higher than actual loads due to diversity in brake horsepower loadings. This was due to the current state-of-the-art and wide differences between various suppliers. The unique configuration and technology of this project made references to historical plant auxiliary load data unreliable.

Two expected operating conditions for the circulating AFBC boiler were examined. These resulted in the estimated auxiliary plant loads summarized in Table 18. Under operation with the "A"-type coal, the combustion and fluidizing air requirements are reflected in the MCR of the ID, PA, and SA fans. The alternate operating condition was the burning of the "B"-type coal, which has a lower heating value and higher combustion and fluidizing air requirements. The load requirements of the ID, PA and SA fans are reflected in the test block conditions, plus an additional design margin established by the boiler vendor. The rated power of each fan was based on the firing of coal "B."

In addition to the 20% contingency allocated for future load growth, the boiler vendor identified another major contingency load to be a gas recirculation fan estimated at 1,112 kW (1,500 HP). This fan, if installed, would be operated only at minimum load conditions, maintaining gas recirculation in the combustion chambers and the cyclone separators. Because of the operating condition, the gas recirculation fan would not add to the maximum expected auxiliary load for the plant. Therefore, it was not included in the contingency factor.

5.3.2 New Station Auxiliary Transformer

A 12/16/20 MVA, oil self-cooled/forced-air cooled/forced-air cooled (OA/FA/FA) 65°C rise, two-winding transformer was selected because it was the next standard-size larger than 120% of the estimated maximum load imposed by the plant secondary loads. Based on available information at the time for the new circulating AFBC technology, this was the smallest size that could be recommended and still allow reasonable margin for changes and possible future load additions. The cost savings resulting from a smaller auxiliary transformer

Table 18

TABULATION OF PLANT AUXILIARY LOADS

Auxiliary Load Estimates, MVA	Coal A	Coal B
Unit 4 auxiliary load	8.7	11.7
Units 1-3 auxiliary load	2.1	2.1
Total operating load	10.8	13.8
20% contingency	2.2	2.2
Total estimated load growth	13.0	16.6
Capacity recommended for new plant auxiliary transformer	12/16/20	

(12/16 MVA, OA/FA 65°C rise), with provisions for future addition of coolers to reach 20 MVA, was very small (on the order of $7,000).

One other alternative was to install two half-sized transformers rather than one full-sized. This would have increased the cost and probably decreased reliability.

5.3.3 Medium-Voltage System

The medium-voltage system is 4160 volts supplied from a main bus and the station auxiliary transformer fed from the 115-kV system. Motors larger than 187 kW (250 HP) and 480 volt load centers derive their power from this bus.

This voltage is necessary to allow the starting of the large motors. The largest motors for across-the-line starting are on the Unit 4 boiler feed pumps (1307 kW or 1,750 HP each). A 14%-voltage dip has been calculated on the system when one of these motors is started. This drop is within acceptable limits for successful starting and operation.

The use of adjustable speed drives for the large fan drives (ID, PA, and SA fans) eliminated the high starting kVA requirements for these large drives (2425, 2611, and 522 kW or, 3,250, 3,500, and 700 HP, respectively).

The medium-voltage system is resistance grounded with adequate fault current (1000 amperes) for positive relay operation.

The 4160-volt system is extended to the Unit 4 cooling tower area via a single feed. A 500-kVA load center and two 400-ampere medium-voltage starters for the circulating water pumps are fed from this source. The primary advantage of this arrangement is that an existing duct bank could be used, thus avoiding a major construction cost for a new duct bank system to the new cooling tower. The disadvantage is that a failure of the 5-kV feeder cable will result in a complete cooling tower outage until the cable is repaired or replaced. An outage would most likely occur as a result of a cable failure even if redundant feeds to the cooling tower were installed.

5.3.4 480-Volt System

The 480-volt system consists of new and existing load centers, motor control centers, lighting and power panels, interconnections, and feeders. Voltage drops and transformer impedances were calculated in order not to exceed circuit breaker ratings (minimum impedance) and not to exceed 20% maximum voltage drops on motor starting. The largest motor that can be adequately started on the 480-volt system is 149 kW (200 HP). A voltage drop of approximately 17% while starting was calculated. This value is marginally acceptable.

5.3.5 Emergency Power

No backup 480-V power source is provided.

5.3.6 Harmonic Considerations

Harmonics generated by the adjustable-speed fan drives were analyzed for effects on the entire station electrical system. This analysis was performed by the adjustable-speed drive system supplier. The analysis was performed for the expected MCR ratings of the fans, as well as under both full load (test block) conditions, and single-channel (six-pulse) backup operation.

The adjustable-speed drives (ID, PA, and SA fans) account for approximately 50% to 60% of the total plant auxiliary load requirements and, therefore, harmonics may have a significant impact on the power system. Frequency effects on power systems have recently been under study due to the growing application of variable-frequency adjustable-speed drives, but these are not yet fully understood.

Harmonic effects on metering, relaying, transformers, motors, and resonant voltages on the power system will be monitored by Colorado-Ute. The variable-frequency drive system supplier planned to furnish all necessary filtering to stay within the 5% total harmonic distortion limit, as recommended by Institute of Electrical and Electronics Engineers (IEEE) standard 519-1981, for the auxiliary power system.

5.4 Uninterruptible and DC Power Supply

The uninterruptible and DC power supply consists of a RUPS and an 125-volt DC distribution subsystem. The RUPS system includes a battery, DC distribution center, chargers, motor-generator set switches, and control and distribution panels. The 125-volt DC distribution system includes a battery, DC distribution center, battery chargers, and 125-volt DC distribution panels. These systems are provided new with Unit 4.

5.5 Electrical Bulk Materials

The electrical bulk materials include electrical items not specified with the electrical equipment systems; i.e., those items not included in the generator and main power transformers, auxiliary power, or the uninterruptible and DC power supply systems. The plant electrical bulk materials are comprised of existing and new materials. The electrical bulk materials include the following items:

- Cable trays
- Conduits
- Communications
- Cathodic protection
- Grounding (other than for the main generators)
- Lighting
- Underground ducts
- Heat tracing
- Wire and cable.

The plant communications system is an extension of the existing "Gai-Tronics" handset and speaker stations.

Section VI. Plant Instrumentation and Controls Equipment and Systems

This system includes all plant new and existing instruments and controls, with the exception of a few instruments and controls provided by the AFBC boiler manufacturer which are described in Section II under "Boiler Instrumentation and Controls."

Plant control is accomplished using modern distributed control techniques, which use redundant processors and dual data highways to improve system reliability and availability. Operator interface to the plant is from a new central control room utilizing CRT graphic display and keyboard terminals with a minimum number of hardwired, dedicated switches and indicators to ensure safety and reliability.

The basic control mode is automatic with operator override. Safety systems are hardwired to trip. The basic display mode for information is by the broadcast method. This provides the operator with all current information required, and also automatically provides information on abnormal plant conditions.

6.1 Analog Control

The analog control system is part of the microprocessor-based system referred to as the plant Distributed Control System (DCS). Operator interface with the DCS is via CRT and keyboard terminals. The CRT displays are segregated to provide logical groupings of plant control by unit number (e.g., 1, 2, or 3), system (e.g., boiler, baghouse), and function (e.g., feedwater control, combustion control). All plant analog control requirements are performed by this system, including, but not limited to combustion, feedwater, ash handling, and baghouse controls. All loops are capable of manual or automatic operation via the main control room CRT/keyboard interface. All transfer operations are automatic balance-type to provide bumpless transfer between automatic and manual mode selection in both directions. Hardwired backup is included as required for tripping of major pieces of equipment only.

6.2 Digital Control

The digital control system, which is also part of the DCS, provides sequential, digital interlock logic control of plant equipment such as fans and pumps. Status and alarms from the digital system are displayed on the operator CRTs and recorded on hardcopy printout.

6.3 Alarms and Annunciators

Alarms are annunciated, requiring operator attention. Alarms are displayed on the appropriate operator control CRT and on hard-copy printout, grouped by system. CRT pictorial graphics (e.g., bottom ash cooling) incorporate alarm points. Some local annunciators are provided with a single output to the plant alarm system which indicates any local alarm actuated. The local annunciator also is provided with "reflash" capability so that subsequent local alarms are detected in the main plant control room. The alarm system is designed so that the operator is not overwhelmed by nuisance or unimportant alarms. All alarms are recorded on hard copy for future reference by operators and plant engineering personnel.

6.4 Pneumatic Controls

Pneumatic controls are used for single-element closed-loop, local control systems only.

6.5 Control Mode

The basic plant control mode for the AFBC boiler/turbine cycle is a boiler-follow mode. This is provided because the boiler is required to produce steam as demanded by the turbine-generators.

6.6 Control Drives

The control drives are pneumatically driven based upon the specific needs and sizes of each controlled drive unit. The control valves are also pneumatically actuated. Modulated control drives and valves are supplied with electric/pneumatic (E/P) positioners.

6.7 Displays

The DCS gathers and displays information for the operator and for the plant engineer. The basic information display functions are as follows:

- Alarming for the operator.
- Events recording for normal plant events.
- Sequence of events recording and display of plant upsets.
- Scanning of analog and digital inputs.
- Logging of trends called for by the operator.

- Logging of daily and hourly summaries of averages, totals, etc., of analog inputs within limitations of the DCS.

- Graphic display capabilities upon demand by the operator within limitations of the DCS.

6.8 Local Control Systems

The preboiler water treatment system is controlled locally (outside the main control room) by programmable controllers.

6.9 System Design Responsibilities

The following systems are integrated with the DCS and are controlled by the main plant operator. Their control philosophy and logic was developed by the equipment supplier. These systems include:

- Boiler controls

- Burner management system

- Main interlocks and purge system

- Ash handling

- Baghouse.

6.10 AFBC Boiler Furnace Safety and Fuel Automation System

The field-mounted circulating AFBC boiler furnace safety and fuel automation system hardware was purchased with the boiler to ensure that the ignition system and damper drives were correctly interfaced with the boiler equipment. The AFBC boiler supplier was responsible for control philosophy and logic.

Where possible, the furnace safety and fuel automation system was designed in accordance with National Fire Protection Association (NFPA) standards. However, due to the new circulating AFBC combustion technology being demonstrated, NFPA standards are not directly applicable.

The basic control mode is "supervisory manual" (operator initiation of start/stop of major equipment items). Redundant instrumentation is employed where necessary (two of three, trip logic, etc.) to minimize nuisance trips.

6.11 Control Panel/Cabinets

The CRT/keyboard control consoles were purchased with the main control system. One hardwired panel (Auxiliary Control Console 4A) was purchased separately. The four CRT/keyboard panels, the Auxiliary Control Console 4A (for the existing Unit 1-3 turbine-generators, and the Unit 4 turbine-generator trip panel insert) are provided in the new plant control room. One CRT/keyboard engineer's console is provided in the new logic room. Preassembled cables with plug-in module ends on each cable were employed. The distributed control equipment is located in a new remote logic room, which contains all the input/output and control cabinets for field devices except the baghouses, part of the ash system, and Units 1-3. The main logic room is located beneath the new control room. The protective relay, turbine-generator, and coal and limestone feeder cabinets are located in the logic room.

6.12 New Turbine Control System

The new turbine control system was purchased as part of the new Unit 4 turbine-generator. This system can be started manually from the main control room.

6.13 Emission Monitoring System

The stack-monitoring system consists of instrumentation for monitoring and reporting the sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon dioxide (CO_2), and the opacity of stack emissions as required by the Federal Environmental Protection Agency (EPA) and state and local pollution-control authorities.

Stack emissions monitoring instrumentation is located in the ductwork between the ID fan discharge and the stack inlet. The instruments use in-situ and extractive measurement techniques. The stack monitoring equipment is located in a building next to this duct. Analog signals from the instruments are wired to the DCS to allow the operator to monitor stack emissions and take corrective action when required.

The stack emissions monitor is a software package designed in accordance with the requirements of the Clean Air Act for new stationary sources. The combined product achieves the following functions:

- The scanning, conversion, and linearization of measured emissions concentrations.
- The computation of pollutant emissions using the methods specified by the Clean Air Act.

- Reduction of emission data as required under the Clean Air Act for data which are to be retained.

- Hourly determination of periods of excess emissions of SO_2 and NO_x using required calculations.

- Determination and logging of excess opacity emissions.

- Hourly recording of events; i.e., generation unit was in startup or shutdown, emissions analyzer was out of service for the current hour, excess emissions were determined, computer was initialized, etc.

- Data logging: The stack emissions monitor produces two different reports, a daily emissions log and a monthly excess emissions report. The daily emissions log contains all data available which should be retained as specified by the Clean Air Act. The monthly emissions report is a summary of all periods of excess emissions as determined on an hourly basis and is intended to be attached to the quarterly emissions report.

- Analyzer interface: The stack emissions monitor provides a simple interface (contact input) to allow off-line calibration and standardization.

Section VII. Special Instrumentation

The special instrumentation are includes instrumentation, data acquisition and processing equipment, and facilities installed specifically for EPRI's two-year AFBC test program. Special instrumentation equipment and facilities data is included in Appendix A.

7.1 Data Acquisition System Computer and Peripherals

This equipment provides for acquiring, monitoring, and broadcasting plant process data from the plant data highway system. The data highway is part of the plant Westinghouse WDPF distributed control system.

7.1.1 Operator's Console (OPCON)

The Operator's Console (OPCON) which includes a CRT and a membrane keyboard is a direct interface to the WDPF system. Using the CRT and the membrane keyboard, plant systems can be monitored via standard and custom display graphics, which show the status of equipment and the state of processes throughout the plant. The graphics are linked in a hierarchical manner to reflect the flow of the process. Paging keys on the OPCON keyboard allow movement to the next graphic in any of four directions. Graphics may also be selected from custom keys which have been assigned specific process graphics. Selection of the "DISP MENU" key will display an overview of the graphic hierarchy.

A multicolor printer provides a means to obtain hard copies of any CRT display. All plant control functions are locked out of this console; this unit is remotely located from the main plant control room.

7.1.2 DEC VAX 8200 Computer

The DEC VAX 8200 computer provides the hardware and software for monitoring and capturing process points from the WDPF data highway. Point data as well as other manual input test data are stored in a database to provide real time or historical data as required for analysis of plant performance. The computer can receive data only from the system and therefore cannot perform any control functions in the plant.

7.1.3 DPU11

DPU11 is a WDPF Distributed Processing Unit (DPU) which is used to monitor additional process data points that were not available as part of normal monitoring and control of the plant process systems. It serves as the interface between these process points and the data highway and consists of dual redundant microprocessors and input/output (I/O) modules. The I/O modules interface with the process sensing instruments. Each process input is defined in a local resident database which, in turn, is part of the distributed global database. Microprocessor functions and routines scan and convert input signals to required ranges and engineering units. The DPU then broadcasts these points on the data highway, making them available for capture by the DEC VAX 8200 computer.

7.1.4 Gateway

The Gateway interfaces the DEC VAX 8200 computer to the WDPF system enabling it to access data highway points.

7.2 Special EPRI Test Program Instruments

Equipment furnished consists of special or additional instruments and test ports required by EPRI for plant testing, which are not found among the main plant control and monitoring instruments. Additional access platforms and ladders for EPRI instrumentation, test weights for coal feeder and ash hopper calibrations, and the addition of 37 duct pressure tapes for flow measurement verification of associated duct flow elements are also included.

All transmitters and thermocouples that require a power source or electronic signal conditioning terminate in DPU11, which conditions signals as required. The conditioned signal is then available on the data highway for use by EPRI in the DEC VAX 8200 computer.

Special test ports/taps installed include:

- Duct pressure taps consisting of two-inch threaded nipples with reduced-port ball-valves, which were added to various combustion air ducts to allow grid pattern pitot traverses of the ducts. The traverse data will be used to verify readings on air foils being used for plant monitoring and control.

- Fifteen protractor/air lock assemblies, furnished for use with the duct pressure taps to allow insertion and orientation of the traverse probe.

- Ash sample points, installed on the economizer and air heater ash hoppers to allow collection of ash for testing. These sample points consist of full flow two-inch ball valves and pipe nipples. Samples are collected using thief sample tubes.

7.3 Facilities and Equipment to Support EPRI Test Program

Equipment and facilities are provided for the:

- Operations Center and Computer Rooms including installation of data acquisition equipment and a RUPS for the equipment.
- Chemical lab facilities and procurement of miscellaneous lab equipment.

7.3.1 Operations Center and Computer Rooms

The Operations Center and Computer Rooms were built as temporary facilities inside the future Colorado-Ute operations warehouse. These facilities consist of two air-conditioned rooms, which house the DEC VAX 8200 computer and the Westinghouse WDPF OPCON with their accessories. In addition to air conditioning, the rooms are equipped with a positive pressurization fan to protect against dust accumulation.

The first room, the Computer Room, houses the DEC VAX 8200 computer along with the 456-megabyte fixed disk, the 80-megabyte tape drive, and the WDPF Gateway equipment.

An adjacent room, the Test Operations and Data Analysis Room, houses the WDPF OPCON and associated printer, as well as, the DEC VAX 8200 system peripheral devices which include the video terminals, printers, and plotter.

The electronic equipment supplied by DEC and Westinghouse requires a stable and reliable source of 115-VAC power which is buffered from transient line voltage fluctuations and plant blackout conditions. This is provided by taking a power feed from the plant RUPS system. This RUPS equipment uses a rotary-type of motor-generator set which in normal operation is driven by house power. When house power fails, the generator is driven by a DC motor which is connected to a battery bank. The battery bank is sized for one hour of operation following house power failure; this will allow time for orderly shutdown of equipment. UPS 110 VAC receptacles provided for the electronic equipment must not be used to power any loads except those shown on the appropriate panel schedule. This will prevent unauthorized power loads from overloading the system or causing system failure by fault conditions.

Both rooms are monitored by a fire detection system. This system provides an alarm through the WDPF system to the main plant control room operator in the event of fire. It is important to note that no automatic fire-extinguishing equipment is furnished, and in the event of an alarm, an inspection must be made by a qualified observer to determine the cause of the alarm and to take the appropriate action.

An additional alarm, also through the WDPF system to the main plant control room operator, is provided in the Computer Room should the air conditioning fail and the room temperature reach 20°C (85°F), or if trouble in the fire alarm panel is detected. In the event of an alarm, the cause should be immediately investigated. If the alarm is due to room temperature at 29°C, the computer should be turned off until the problem is corrected.

7.3.2 Chemical Laboratory Facilities and Equipment

Three rooms are provided for sample preparation and sample analysis: the Sample Preparation Room, the Particulate Laboratory, and the Analysis Room. These rooms also were built as temporary facilities inside the future Colorado-Ute operations warehouse.

The Sample Preparation Room is designed to prepare all samples for chemical analysis. This may include coal surface moisture, limestone moisture, size distributions of coal, limestone, fly ash and bed material, and bulk densities of fly ash and bed material.

The Particulate Laboratory will be used to prepare isokinetic sample equipment and other specialty probes. The Analysis Room will be used for sulfur analysis of prepared samples. The Sample Preparation Room and the Particulate Laboratory are equipped with exhaust hoods for control of particulate emissions. Only the Particulate Laboratory is equipped with running water, a sink, and a drain. Since no chemical disposal is anticipated, the drain system has not been designed to accept chemical waste.

7.4 Ash Weighing System

The furnished ash weighing equipment provides for:

- Fly ash and bottom ash weighing
- Sampling devices for the following solid streams:
  - -- "As fired" coal feed
  - -- Limestone feed

-- Ash transport system

-- Baghouse catch.

7.4.1 Fly Ash Weighing

The fly ash-weighing system consists of a surge bin and a Schenck solids flow metering system located between the cyclone discharges and the fly ash silo. The Schenck metering system provides an analog output of flow rate and a digital pulse output where one pulse is equivalent to 0.01 tons. Digital alarm signals for system trouble/surge bin high level/valve misalignment are also provided. These signals are all inputs to the WDPF system. Bypasses are provided around the Schenck meter for normal operation.

The WDPF system provides operator interface for remote control of this system. A process and instrumentation diagram (P&ID) control graphic, titled FLY ASH WEIGHING, can be accessed by paging down from either the Unit 4 Fly Ash or the Units 1,2,3 Fly Ash Graphics. The system is semiautomatic. Control is a combination of local hard-wired and WDPF logic. A start of the system can be initiated either locally at the silo or remotely from a WDPF Operator's Console.

At the start of a test period, a start command (local or remote) will divert fly ash flow from bypass to the Schenck metering system. At this command, the totalized flow indication is reset to zero. Both the flow rate and the totalized flow will be displayed on the graphic and also be available on the data highway. WDPF provides conversion of the 0.01 ton pulse to an analog value in engineering units of thousands of pounds (klb). At the end of a test period, the operator will divert fly ash flow from the weigh system back to bypass with a stop command. At this point, the bypass gates are opened and the feeder gate to the Schenck meter is closed. The rotary valve will continue to run for five minutes to purge the flow meter. At approximately one minute after the rotary valve stops and the weigh system has been shut down, the WDPF will provide a digital trigger signaling that the value of the totalized flow should be read into the VAX computer. In addition, WDPF logic will provide the ability to manually reset the totalizer at any time including the period that fly ash flow is through the weighing system. This manual reset can only be done with a control room Operator's Console in the unlocked mode.

A high level in the surge/weigh bin will automatically bypass the weighing system.

7.4.2 Bottom Ash Weighing

Bottom ash weighing is accomplished with a load cell system on each of the bottom ash hoppers. Inputs to the WDPF are for Bottom Ash Hopper 4A weight and for Bottom Ash Hopper 4B weight. During a test period, the WDPF will provide digital trigger signals for each of the hoppers at their high and low-level points. There are two modes of ash operation to consider:

A. Normal operation with ash temperature less than 191°C (375°F)

The operator selects (via the OPCON keyboard)

(1) Hopper 4A "ON" or "BYP"

(2) Hopper 4B "ON" or "BYP"

(3) Bottom Ash Rotary Valves "ON".

The operator then initiates a system start. With the conveying line valve to Hopper 4B normally open and the conveying line valve to Hopper 4A normally closed: the selected exhauster, bag filter, and separator are started. When conveying air vacuum is adequate, conveying the line 4B is purged for 10 seconds and then the Bottom Ash Hopper 4B outlet valve is opened. Ash is then conveyed from Hopper 4B for a period of 90 seconds. If high load vacuum is sensed, ash conveying can be interrupted during the 90 seconds by closing the hopper outlet valve. Upon return to normal vacuum, the hopper outlet valve will reopen and conveying will continue for the remainder of the 90-second cycle. At the end of 90 seconds, the hopper outlet valve will close and the conveying line to Hopper 4B is purged for 30 seconds before conveying line valve 4B is closed and conveying line valve 4A is opened. Conveying line 4A is purged for 10 seconds and then Bottom Ash Hopper 4A outlet valve will open. Ash is conveyed from Hopper 4A in a like manner as described for Hopper 4B. At the end of Hopper 4A's 90-second cycle, the system sequences back to Hopper 4B and cycles through this 130-second purge/conveying/purge cycle until stopped by the operator.

B. Normal operation with ash temperature more than or equal to 191°C (375°F).

Should ash temperature reach more than 191°C (375°F), ash conveying will be interrupted and an alarm will sound for the operator to start Screw Cooler 4A or 4B. As an example, assume the conveying cycle was at Hopper 4A and 191°C ash is detected. At that point, ash conveying is stopped by closing Hopper 4A outlet valve, and the alarm "START SCREW COOLER 4A" is activated. The cycle timers continue to run and may even time out and switch to Hopper 4B before the operator can start Screw Cooler 4A. Ash conveying would then commence from Hopper 4B in a normal fashion, provided the temperature transmitter does not also detect 191°C ash temperature. In the meantime, the operator has started Screw Cooler 4A. It is proven ON in the control logic and the inlet valve to the screw cooler is opened. When the cycle again returns to Hopper 4A, there is the normal 10-second line purge; however, the screw cooler's outlet valve is opened instead of the hopper outlet valve. Now the ash conveying is taken from Hopper 4A via the screw cooler. The sequence timers function as previously described. When Screw Cooler 4A was started, a three-hour timer was also started. At the end of three hours, and if the ash temperature has returned to below 177°C (350°F), the inlet to Screw Cooler 4A will be closed and the screw cooler will be purged for 30 seconds before it is stopped. Bottom ash conveying logic will then return to conveying directly from the hopper.

Ash weighing is accomplished when the WDPF will provide one HIGH and one LOW hopper level digital trigger signal for each bottom ash hopper. These signals will indicate when to read the values. The low-level trigger will have two level set points depending on screw cooler On/OFF status. One set point will be at 10% of range with the screw cooler off, and the other will be at 20% of range with the screw cooler on. The high-level trigger will be set at 90% of range. Deadbands for all settings are 1% of range. Understand that actual bottom ash flow rates may require adjustments to sequence timers, trigger set points, and deadbands in order to establish a functional weighing system.

7.4.3 Coal "As Fired" Sampling*

The "As Fired" coal sampling is a manual function. Each of the six coal feeders has a pneumatically operated diverter

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Note: The "As Fired" coal sampling equipment installed for the EPRI test program, as described above, is independent and separate from the plant "As Received" and "As Fired" coal sampling equipment included with the plant coal handling system.

gate located at the outlet end of the feeder. The gate is operated by energizing a solenoid valve from a local push button station also located near the end of the feeder. The gate will divert approximately a 12.7 liter (0.45 cu ft) cut of coal flow to a sample outlet. From this point the coal sample passes through a transition section to a 10-cm (4-in) pipe with a lever-operated knifegate valve at the outlet. The sample is then manually dumped into a container for transport to the sample laboratory.

7.4.4 Limestone Sampling

Limestone sampling is also a manual function. Each of the eight limestone transport lines (four on each combustor) contains a two-inch capped sample tap located just above the rotary valve. "Thief" sample devices are used to manually extract samples from these points.

7.4.5 Ash Transport Sampling

Ash sampling is also a manual function. Sample points are located at the top of each of the bottom ash hoppers and in the fly ash weigh bin located at the top of the fly ash silo. "Thief" sample devices are also used to manually extract samples from these points.

7.5 Gas Analyzers

This equipment allows data collection on gases in Combustion Chamber 4B and at the inlet to Tubular Air Heater 4A. Future connections are available at the inlet and outlet of Cyclone 4B. Samples taken at Tubular Air Heater 4A are called EGAS samples and samples from Combustion Chamber 4B are called FGAS samples. The method of sampling is extractive, with all samples being analyzed in the E/FGAS Analyzer. The system has been designed to sample and monitor concentrations of CO_2, CO, NO_x, and SO_2. Expansion space is available to add future analyzers.

7.5.1 E/FGAS Analyzer

The E/FGAS Analyzer is a gas analysis and monitoring system designed to continuously monitor sample gas concentrations from selected sources. The sample point and measuring range are manually chosen by the system operator. Sample points which can be chosen are as follows:

1. FGAS at elevation 13.6 m (44 ft-7 in)

2. FGAS at elevation 26.4 m (86 ft-6 in)

3. EGAS at the inlet to Tubular Air Heater 4A

4. Future (Cyclone 4B inlet or outlet).

The FGAS samples are taken via traversing probes, described in more detail below, which are inserted into Combustion Chamber 4B at either boiler elevation 13.6 m (44 ft-6 in) or 26.4 m (86 ft-6 in).

EGAS sample is an average of 16 sample points. Samples are drawn by a heated valve enclosure which is located midway between the two inlet ducts to Tubular Air Heater 4A at an elevation of 28.7 m (94 ft). Each of the two inlet ducts has a 2 x 4 grid of eight sample points which terminate in the heated valve enclosure. These 16 sample points are averaged in the enclosure and sent as one sample to the E/FGAS Analyzer. The averaging enclosure is heated to prevent sample gas temperature from falling below the acid dew point.

Each of the 16 sample points also has an associated thermocouple. The eight thermocouples in each duct are averaged locally in a thermocouple averaging terminal box. The resulting two averaged temperatures are sent to DPU11 and are available separately on the data highway.

At the outlet of Tubular Air Heater 4A, two thermocouple grids have been located. These grids are identical in layout and connection to the thermocouple grids at the inlet. The resulting two averaged temperatures are also available on the data highway.

Calibration of the E/FGAS Analyzer is accomplished by drawing known concentrations of sample gas through the system at regular intervals. These calibration or span gases are located in cylinders adjacent to the E/FGAS Analyzer as follows:

Bottle	Gas
1	N_2 for zero reference
2	Low span O_2, CO, CO_2
3	High span O_2, CO, CO_2
4	Low span SO_2, NO_x
5	High span SO_2, NO_x

The E/FGAS Analyzer equipment is located at an elevation of 7.3 m (24 ft) on the turbine deck. This includes a gas-conditioning cabinet and an air-conditioned cabinet which contains the gas analyzers, a six-pen chart recorder, and other system components. An output signal from each analyzer, corresponding to the gas concentration at the analyzer, is sent to DPU11. These signals are available on the data highway. In addition, the chart recorder displays the outputs of the analyzers. Other signals are available for system alarms and range settings of the various analyzers. The output signals are summarized below.

- O_2 is measured using a Beckman Industrial Corporation Model 755 which is a paramagnetic type of analyzer.

- CO and CO_2 are measured with Beckman Industrial Corporation Model 864 analyzers which operate using the principle of infrared absorption.

- NO_x is measured with a Beckman Industrial Corporation Model 951A analyzer which operates on the principle of chemiluminescence.

- SO_2 is measured with a Western Research Model 721A sulfur dioxide analyzer which operates on the principle of energy absorption by a sample cell.

The E/FGAS Analyzer equipment was furnished by KVB Corporation. Further descriptions and detailed specifications are found in the KVB System Manual furnished with the equipment.

7.5.2 FGAS Probes

The Freeboard Gas (FGAS) Sampling Probe is designed to allow sampling of gases from inside the operating fluid bed boiler. The probe is a water-cooled design originally developed by TVA and EPRI for use in the analysis of a bubbling bed combustor. The current probe design has been modified to incorporate site specific characteristics of the Nucla circulating AFBC boiler.

The probe is designed to sample gases over a traverse distance of 3.1 m (10 ft-2 in) inside the operating combustion chamber. The probe is essentially a water-cooled, electrically heated tube, which is connected to the E/FGAS Analyzer via a heated sample line. Suction, provided by a vacuum pump at the conditioning cabinet, pulls gases from the combustion chamber into the gas analyzer system for analysis.

In operation, the combustion gases first pass through a quench tube where the gas temperature is reduced to less than the 204°C (400°F) (maximum operating temperature of the sample line). This electrically heated sample line then maintains the gas temperature above the acid dew point of the sample gas [set point of 177°C (350°F)] to minimize acid condensation and the resulting corrosion. Gases are sampled at a flow rate of approximately seven liters per minute. After exiting the sample line, the gases pass through a cyclone separator to remove any entrained solids. The sample gases are then transferred via another heated sample line to the E/FGAS analyzer for chemical characterization.

The probe itself is water cooled to protect the sample line and to maintain the structural integrity of the probe. A water flow rate of between 23 and 91 liters/min (5 and 20 gpm) is required to maintain internal temperatures below 157°C (175°F). Seven thermocouples are included in the system to allow the sampling team to monitor the operating conditions inside the probe. Cooling water passes through the length of the probe and returns to the outlet nozzle before being discarded in the plant drain system. Water flow control is maintained by a manual control valve on the cooling water inlet line.

The probe includes some optional sampling equipment. An entrainment cap is supplied to serve as both protection for the 3/8-in sample line and to reduce the entrainment of solids. A filter clamp is also provided to hold a high-temperature ceramic filter over the end of the sample line. These ceramic filters are designed to remove all particulate matter larger than 85 microns in diameter while sampling gases up to 1371°C (2500°F).

Previous experience by EPRI and TVA has indicated that the ceramic filters tend to change the composition of the gas sample as they become plugged. The quantity of ash in this unit, however, may dictate use of these filters or others.

NUCLA CFB DEMONSTRATION PROJECT

APPENDIX A

PROJECT EQUIPMENT AND DATA LIST

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
	CIRCULATING AFBC BOILER AND BOILER SYSTEMS			
	Steam Drum 4A	Fabricator: Taylor Forge Size: 63" o.d. x 49'-2.5" S/S Design Pressure: 1760 psig Design Temperature: 650°F		
	Combustion Chambers 4A & 4B	Manufacturer: Pyropower/Ahlstrom Number Downcomers: 3 Inlet Headers: 4/combustor, 1/wall Outlet Headers: 2/combustor, side walls only Tubes: Size: 2-1/2" o.d. Spacing: 3" (bottom grid 5")		
	Radiant Superheaters 4A & 4B (Pyropower Combustion Chamber Superheater II or Radiant Superheater)	Manufacturer: Pyropower/Ahlstrom No. of platen sections: 4/combustor		
	Convection Cage 4A Enclosure	Manufacturer: Pyropower/Ahlstrom		
	Primary Superheater 4A (SH I)	Manufacturer: Pyropower/Ahlstrom		
	Final Superheater 4A (SH III)	Manufacturer: Pyropower/Ahlstrom		
	Economizer 4A	Manufacturer: Pyropower/Ahlstrom Type: Bare tube		
	Coal Silo Isolation Valves 4A-4F	Manufacturer: Cleveland Armstrong Type: Chain-operated manual slide gate	6	

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
	Coal Gravimetric Feeders 4A-4F	Manufacturer: Merrick Capacity: 71,800 lb/hr Length: 24'-2 1/8" between pulleys Width: 30" belt Speed: 31.42 ft/min Motor: 2 HP Clean Out Chain Motor: 1-1/2 HP Weight: Approx 7,500 lb	6	
	Coal Feed Inclined Conveyors 4E and 4F	Manufacturer: Stephens-Adamson Model: Redler Series #1000 Capacity: 71,800 lb/hr Length: Approx. 43' including 20'-2 3/4" horiz. and 23'-5 11/16" inclined at 450 Width: 11" Motor: 20 HP	2	
	Coal Feed Horizontal Conveyors 4E and 4F	Manufacturer: Stephens-Adamson Model: Redler Series #1300 Capacity: 71,800 lb/hr Length: 13'-6" Width: 8" Motor: 10 HP	2	
	Coal Rotary Airlock Feeders 4A-4F	Manufacturer: Ducon Capacity: 71,800 lb/hr Size: 18" Motor: 3 HP	6	
	Boiler Isolation Gate Valves 4A-4F	Manufacturer: Cleveland Armstrong Size: 18" x 18" Motor Operator: 0.4 HP	6	

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
	Boiler Limestone Silo Gyrated Bin Dischargers 4A and 4B	Manufacturer: Carman Industries Type: Gyrated Capacity: 81 cubic ft Weight: 3,075 lb Motor: 3 HP	2, 1/silo	
	Limestone Silo Isolation Gates 4A and 4B	Manufacturer: DeZurick Size: 14" i.d. knife gates Operation: Pneumatic	2	
	Limestone Feeders 4A and 4B	Manufacturer: Solids Flow Control Type: Loss-in-weight gravimetric Size: 24" Capacity: 12,500 lb/hr Hopper Capacity: 47 cubic ft Sector Gates: 4/feeder pneumatically operated Motor: 1-1/2 HP	2	
	Limestone Rotary Airlock Valves 4A-4H	Manufacturer: Prater Capacity: 4,550 lb/hr Size: 6 inch	8	
	Limestone Pneumatic Feed Transport Systems 4A-4H	Manufacturer: United Conveyor Conveying Line Size: 4"	8	
	Limestone Blowers 4A-4H	Manufacturer: Gardner Denver Blower Type: Rotary Capacity: 262 CFM Pressure: 5.9 psig Motor: 15 HP	8	

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
		Accessories: Inlet filter Inlet snubber Discharge snubber		
	Primary Air Fan 4A (includes coupling and variable frequency drive system)	Manufacturer: American Davidson, Sturtevant Division Model: 71-TVAF-10 Type: Centrifugal with backward inclined airfoil blades Ambient Air Pressure: 11.96 psig, 24.36" Hg, 5,600' elevation Physical Parameters: Wheel Diameter: 74.88" Rotor Weight: 7,860 lb Rotor WK2: 16,160 lb-ft^2 Fan Weight: 26 tons Total Weight (fan and driver: 36 tons Bearings: Sleeve Lubrication: Ring oil/circ oil Inlet Silencer: Aeroacoustic Lube Oil System: Lube-Power, Inc., 150 gal reservoir, two 100% pumps each 15 gpm/100psig/2 HP each, 36,000 Btu/hr shell and tube water cooler Variable Frequency Drive System: Manufacturer: Westinghouse Model: Varichron, 12-pulse	1	

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
		Drive Motor: Westinghouse 3,500 HP synchronous with 5 HP cooling fan Drive Transformer: Westinghouse DC Reactor: Westinghouse Miscellaneous: 3/4 HP cont cab cooling fan	2	
	Secondary Air Fan 4A (including coupling and variable frequency drive system)	Manufacturer: American Davidson, Sturtevant Division Model: 52-TVAF-10 Type: Centrifugal with airfoil blades Ambient Air Pressure: 11.96 psig, 24.36" Hg 5,600 ft elevation Physical Parameters: Wheel Diameter: 54.75" Rotor Weight: 3,410 lb Rotor WK2: 2,780 lb-ft² Fan Weight: 11.5 tons Total Weight (fan and driver): 13 tons Fan Bearings: Sleeve, water cooled Lubrication: Fan-ring oiled, motor-grease lubricated Inlet Silencer: Aeroacoustic Variable Frequency Drive System: Manufacturer: Westinghouse Model: Accutrol 2000, 6-pulse Drive Motor: Westinghouse, 700 HP induction, 1 HP cooling fan	1	

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
		Drive Transformer: Westinghouse Miscellaneous: 3/4 HP cont cab cooling fan		
	Induced Draft Fan 4A (including coupling and variable frequency drive system)	Manufacturer: American Davidson, Sturtevant Division Model: 109-TVAF-7 Type: Centrifugal with airfoil blades Ambient Air Pressure: 11.96 psig, 24.36" Hg, 5,600 ft elevation Physical Parameters: Wheel Diameter: 110.25" Rotor Weight: 23,780 lb Rotor WK2: 98,340 lb-ft^2 Fan Weight: 47.5 tons Total Weight (fan and driver): 60 tons Bearings: sleeve Lubrication: Ring oil/circ oil Lube Oil System: Lube-Power, Inc., 220 gal reservoir, two 100% pumps each 24 gpm/100 psig/3HP each, two 100% oil cooling fans/2 HP each, 46,000 Btu/hr aerial cooler Variable Frequency Drive System: Manufacturer: Westinghouse Model: Varichron, 12 pulse Drive Motor: Westinghouse, 3,250 HP synchronous with 1 HP cooling fan Drive Transformer: Westinghouse	1	

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
		DC Reactor: Westinghouse Miscellaneous: 3/4 HP cont cab cooling fan	2	
	Fan VSD Room Air Conditioning Unit 4A	Condenser Fan Motors: 0.9 kW each Compressor: 30 ton, 32.5 kW AHU Fan: 7.5 HP	1 with 3 condenser fans	
	Combustion Air Ducts (PA and SA ducts)	Approximate Duct Lengths: (PA / SA) Top of Bldg to Fan: 140′ / 140′ Fan to Air Heater: 35′ / 56′ Air Heater to Combustors: 135′ / 141′ Expansion Joints: Manufacturer: Bachmann Type: Bellows Gas Flues Operating/design Temp (from AH): 258°/450°F Design Pressure: -31" w.g. Approximate Duct Lengths: Econ Outlet to Air Heater: 40′ Air Heater to Baghouse 4A: 177′ Air Heater to Baghouses 1-3: 354′ to 467′ Baghouse 4A to ID Fan: 266′ Baghouses 1-3 to ID Fan: 67′ to 180′ ID Fan to Stack: 67′		

Spec. No.	Equipment Description	Data	Quantity	Comments
		Expansion Joints: Manufacturer: Bachmann Type: Bellows		
	Air Heater 4A	Manufacturer: Pyropower/Ahlstrom Type: Tubular Physical Data: Tube Size: 2-3/8" OD Tube Material: Carbon Steel		
	Baghouses 1,2 & 3 (Existing)	Manufacturer: Wheelabrator-Frye Model: 814-264 Series 8 Type: Shake and deflate, welded modular, six compartment, continuous automatic collector Air to Cloth Ratio: 2.7 to 1 (formally 3.35 to 1) Effective Cleaning Area: Approximately 30,000 sq ft Construction: 28′ x 29′ x 50′ high with 3/16" steel housing and 4" mineral wool insulation Bags: 672 fiberglass bags, W. W. Criswell Model 445-04, woven filament warp, 550°F rating, 8" x 264" Hoppers: 97 cubic ft each Pressure Fan: Westinghouse Sturtevant, 550 acfm, 12" wg, 30 HP motor, 1,800 rpm Duct Heater: 50 kW for use with reverse fair fans during startup Hopper Heaters: Nelson 4kW	3	

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
		Bagshakers: Six/baghouse (one per compartment), motor operated eccentric Westinghouse 1.5 HP motor, 1,800 rpm		
	Baghouse 4A	Manufacturer: Research-Cottrell		
		Type: Shake and deflate		
		Construction: 12 compartment, each 12'-7" x 12'-6" x 26'-9" high, 3/8" ASTM-A36 casing, -31" wg design pressure		
		Air to Cloth Ratio: For coal "A" 2.44 to 1 with two compartments out, 2.64 to 1 with four compartments out. For coal "B" 2.68 to 1 with two compartments outs, 2.9 to 1 with four compartments out.		
		Effective Cleaning Area: 95,712 sq ft		
		Bags: 8" diameter x 22' high, woven fiberglass, 10 oz per sq ft with Teflon coating		
		Hoppers: 485 cubic ft each		
		Deflate Fan: 9,250 acfm TB, 16" wg static press, 50 HP		
		Purge Air Fan: 7.5 HP		
		Shakers: 1 per compartment, each 2 HP	12	
		Poppet Valves: 3 x 64" diameter	12	outlet,
		bypass, all with pneumatic operators	12	reverse air
		Performance:	12	purge air
		Design Inlet Dust Loading: 13 gr/ft^3		

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
		Outlet Dust Loading: 0.01 gr/ft³, 0.03 lb/106 Btu with two compartments cleaning and two compartments out for maintenance Outlet Opacity: less than 20% Temperature drop: Less than 15°F		
		Pressure Drop: No. Compartments In Service / Coal "A" / Coal "B" 8 / 7.5" wg / 9.0" wg 10 / 7.0" wg / 8.0" wg 12 / 6.8" wg / 7.8" wg		
	Stack 4A	Dimensions: 215 ft high, 18 ft base diameter, 12 ft stack diameter Flue Gas Flow: 1,109,000 lb/hr Operating Temperature: 243°F min Design Temperature: 300°F		
	Hot Cyclones 4A and 4B	Fabricator: Eaton Metal Products Diameter: Approximately 23′		
	Loop Seals 4A and 4B	Fabricator: Ahlstrom		
	Expansion Joints	Type: Fabric		
	High-Pressure Blowers 4A and 4B	Manufacturer: Hoffman Model: 74108C Type: Centrifugal, 8 stages, 3,550 rpm Motor: 150 HP Westinghouse Weight: 6,600 lb		

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
		Performance: Flow: 2,720 CFM (9,100 lb/hr) Inlet Air Temperature: 80°F Inlet Pressure: 11.95 psia Discharge Pressure: 19.95 psia Auxiliaries: Intake silencer, inlet control, damper, discharge check valve		
	Economizer Sootblowers	Manufacturer: Diamond Power Model: G9B Type: Rotating lance Blowing Medium: 600 psig steam Blowing Time: 10-19 seconds each/cycle Motor Size: 3/4 HP each	12	
	Air Heater Sootblowers	Manufacturer: Diamond Power Model: IK4MSL Straight-line Type: Retractable Blowing Medium: 600 psig steam Blowing Time: 5.5 min each/cycle Motor Size: 3/4 HP each	4 (2 hot section, 2 cold section)	
	Sootblower System Accessories	600 psig PRV station Steam piping for boiler connections to sootblowers Safety relief valve Control panel NEMA 12 starters cabinet Local sootblower start/stop pushbuttons		

Spec. No.	Equipment Description	Data	Quantity	Comments

Insulation and Lagging Schedule

Location	Hot Face Temp-°F	Insulation	Thickness -in.
Combustion Chamber	650	Mineral Wool	7.0
Convection Cage	650	Mineral Wool	7.0
Steam Drum	650	Mineral Wool	6.5
Economizer Casing	785	MW & Cal-Sil	8.0
Hot Air Ducts	400	Mineral Wool	5.0
Hot Gas Flues	350	Mineral Wool	4.5
Connecting Piping	650	Cal-Sil Block	Varies
Baghouses	350	Mineral Wool	3.5
ID Fans	350	Mineral Wool	5.0

Lagging: Flat surfaces — Ribbed Aluminum
Circular surfaces — Ribbed Aluminum

Boiler Safety Valves

Supplier: Pyropower
Manufacturer: Dresser
Type: Maxiflow
Boiler Safety Valve Schedule:

Tag No.	Location	Size	Set Press	Temp°F	Capacity lb/hr
SV-1	Drum	2-1/2"	1760	Sat.	213,100
SV-2	Drum	2-1/2"	1770	Sat.	214,444
SV-3	Drum	3"	1780	Sat.	337,125
SV-4	SH Out	3"	1585	1005	192,297

Boiler Blowdown Flash Tank 4A

Fabricator: American Steel & Iron Works
Design: 150 psig/650°F
Operating: 100 psig/345°F
Dimensions: 30" id, 4'-0" S.S.
Design Steam Inlet Flow: 9,250 lb/hr
Design: 150 psig, 650°F
Material: A285 Gr C

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
		Capacity: 200 tons Dimensions: 20' id x 35' high		
	Bottom Ash Silo Bin Vent Filter 4A	Manufacturer: United Conveyor Type: Bag filter with Nomex bags, pulsed jet cleaned	1	
	Bottom Ash Silo Primary Separator 4A	Manufacturer: United Conveyor Type: Cyclone Design Temperature: 425°F		
	Bottom Ash Silo Secondary Separator 4A	Manufacturer: United Conveyor Type: Bag filter, pulsed jet cleaned Design Temperature: 425°F Hopper Heater: 0.2 kW		
	Bottom Ash Conveying System 4A	Manufacturer: United Conveyor Capacity: 20 tons/hr Size: 8" and 10"		
	Bottom Ash Silo Rotary Unloader 4A (Existing)	Type: Drum dust mixer with integral feeder Capacity: 65 tons/hr Screw: 126 rpm driven by a 7.5 HP, 1,800 rpm motor Drum: 15 HP, 1,800 rpm motor		
	Ash Reinjection Conveying Pressure Blower 4A	Manufacturer: Gardner Denver Flow: 1,035 cfm Discharge Pressure: 8 psig		

Spec. No.	Equipment Description	Data	Quantity	Comments
		Motor: 50 HP Accessories: Inlet filter, inlet snubber, outlet snubber		
	Bottom Ash Silo Ash Reinjection Isolation Gate 4A	Type: Air-operated knife gate Size: 8"		
	Ash Reinjection Airlock Feeder 4A	Manufacturer: United Conveyor, Nuva feeder Capacity: 12 cubic ft		
	Airlock Feeder Isolation Gate 4A	Type: Air-operated knife gate Size: 6"		
	Reinjection Ash Conveying System 4A	Manufacturer: United Conveyor Capacity: 20 tons/hr Size: 6" line with two 6" combustion chamber selector gates		
	TURBINE-GENERATOR AND BALANCE-OF-PLANT EQUIPMENT AND SYSTEMS			
	Turbine-Generators Units 1, 2 and 3 (Existing)			
	Turbines	Manufacturer: DeLaval type PJ Capacity: 12,650 kW Speed: 3,600 rpm Steam Conditions: 600 psig, 825°F throttle Exhaust Pressure: 1.5" Hg absolute	3	

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
	Generators	Manufacturer: Electric Machinery Mfg Capacity: 13,529 kVA at .85 power factor Type: Synchronous Speed: 3,600 rpm Electrical Output: 3,600 Volts, 566 Amperes, 11,500 kW, 3-phase, 60 Hz Temperature Rise: 85°F armature, 60°F field	3	
	Accessories	Turning Gear: Motor operated with motor driven auxiliary oil pump Main Bearing Oil Pump: Shaft drive		
	Auxiliary Oil Pump	Steam turbine driven		
	Trip and Throttle Valve:	Operated from turbine governor		
	Gauges:	8-1/2" gauges for throttle, 1st stage and exhaust steam pressure; 4-1/2" gauges for lube oil pressures		
	DC Exciter	Electric Machinery type EDF, 50 kW, 3,600 rpm, 250 Volts, 200 Amps, shunt wound, 40°F rise		
	Turbine-Generator Unit 4A			
	Turbine	Manufacturer: Mitsubishi Type: One cylinder, single flow, 25" last row blades, indoor, impulse, condensing extraction steam turbine Output: 73,285 kW (at generator term)		

Spec. No.	Equipment Description	Data	Quantity	Comments
		Steam Conditions: 1,450 psig, 1000°F at throttle valve inlet Rated Throttle Flow: 925,000 lb/hr Exhaust Pressure: 2.5" Hg absolute Speed: 3,600 rpm Connection to Generator: Rigid coupling Controlled Extraction: 640 psig, 800°F No. of Extraction pts: 6 including one controlled, and 5 uncontrolled feed-water heater extractions. Weight: 300,000 lb complete without accessories, rotor 48,000 lb		
	Generator	Manufacturer: Westinghouse Type: Synchronous, 3,600 rpm, 3-phase, 60 Hz Capacity: 88,200 kVA at .9 power factor Rated Hydrogen Press: 30 psig Gas Volume: 1,550 cubic ft Terminal Voltage: 13,800 volts Short circuit Ratio: 0.85 Temperature Rise: Stator 54°C, Rotor 75°C Efficiency: 98.5% at rated H2 pressure and PF Terminal Connection: Isolated phase bus Exciter: Westinghouse, static type, 351 kW rating, 225 V, 1,561 Amps Telephone Infl. Factor: 70 balanced, 50 residual Rated Armature Current: 3,690 Amps Gas Volume: 1,550 cu ft		

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
		Weight: 358,700 lb complete without accessories, stator 248,200 lb, rotor 61,500 lb		
	Condensers 1,2 and 3 (Existing)	Manufacturer: Maryland Shipbuilding and Drydock Type: Surface condenser Surface Area: 12,000 sq ft Steam Flow Condensed: 84,000 lb/hr Turbine Back Pressure: 1.5" Hg absolute	3	
	Air Ejectors 1, 2 and 3 (Existing)	Manufacturer: Maryland Shipbuilding and Drydock Type: Dual stage steam jet		
	Hogging Jet Ejectors 1, 2 and 3 (Existing)	Manufacturer: Maryland Shipbuilding and Drydock Type: Single-stage steam jet		
	Condenser 4A	Manufacturer: Southwestern Engineering Type: Two-pass surface condenser Total Heat Duty: 321.5 x 106 Btu/hr Steam Flow Condensed: 354,135 lb/hr Turbine Back Pressure: 2.5" Hg absolute LMTD: 14.4°F Surface Area: 47,707 sq ft Active Hotwell Capacity: 2,750 gallons Cooling Water: 32,000 gpm flow, 82°F temperature, 20.1°F temperature rise, 6.02 ft/sec velocity, 13.7 psi pressure diff	1	

Spec. No.	Equipment Description	Data	Quantity	Comments
		Tubes: 3/4" od, 304 S.S. material, 22 gauge, 26'-0" long Design Pressure: 15 psig and full vacuum Weight: 228,500 lb empty, 228,500 lb operating, 635,000 lb flooded		
	Steam Jet Air Ejector 4A	Manufacturer: Kinema Type: 2-stage steam jet Capacity: 10 scfm Steam Consumption: 920 lb/hr Steam Pressure: 300 psig Tubes: 304 S.S.		
	Priming Ejector 4A	Manufacturer: Kinema Type: Steam jet Capacity: 200 scfm Steam Consumption: 920 lb/hr Steam Pressure: 300 psig		
	Main Steam Line	Fabricator: Dravo		

Conditions:	Operating	Design
Pressure, psig	1510 (SH outlet)	1585
	1450 (turbine inlet)	-
Temperature °F	1005	1015
Steam flow, lb/hr	925,000	-
Pressure Loss, psi 60		-

Physical Parameters:
Internal Diameter: 11.25 in/8.5 in
Minimum Wall Thickness: 1.337 in/ 1.2658 in
Material: SA335 P22

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
		Length: Approximately 225 ft Code Jurisdiction: ASME Boiler External Piping, ANSI B31.1 Power Piping		
	Electromatic Relief Valve	Manufacturer: Consolidated, Model 1533VX Size: 2-1/2" x 4" Capacity: 92,500 lb/hr Set Pressure: 1,570 psig		
	Controlled Extraction to Turbines 1-3	Fabricator: Dravo Conditions: Operating / Design Pressure, psig: 628 / 700 Temperature °F: 800 / 900 Flow, lb/hr: 369,000 total; 123,000 to each unit Physical Parameters: Material: A335 P11 schedule 40 Size: 12" with 8' branches Length: Approx 389 ft (to Unit 3) to approximately 541 ft (to Unit 1)		
	Unit 4 Feedwater Heater Extractions Heater 4E Extraction Line	Operating / Design		
	Pressure, psig	417 / 460		
	Temperature °F	723 / 765		
	Material	A334 P11 Sch 40		
	Size, "	6		
	Flow, lb/hr	43,427		

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data: Operating	Data: Design	Quantity	Comments
	Heater 4D Extraction Line	Operating	Design		
	Pressure, psig	227	265		
	Temperature°F	595	640		
	Material	A106 Gr B Sch 40			
	Size, "	6			
	Flow, lb/hr	50,615			
	Heater 4C (Deaerator) Extraction Line	Operating	Design		
	Pressure, psig	92.8	120		
	Temperature°F	432	475		
	Material	A106 Gr B Sch 40			
	Size, "	12/10			
	Flow, lb/hr	40,928			
	Heater 4B Extraction Line	Operating	Design		
	Pressure, psig	17.9	50		
	Temperature°F	250	260		
	Material	A106 Gr B Sch 40			
	Size, "	12			
	Flow, lb/hr	33,106			
	Heater 4A Extraction Line	Operating	Design		
	Pressure, psig	-4.8	50		
	Temperature°F	178	185		
	Material	A106 Gr B Sch 40			
	Size, "	24			
	Flow, lb/hr	27,062			
	Auxiliary Boiler 4A	Manufacturer: Cleaver Brooks Type: Firetube Capacity: 20,000 lb/hr (600 boiler HP)		1	

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
		Steam Pressure/Temperature: 130 psig/ 354°F (saturated) Design Pressure: 150 psig Heating Surface: 3,000 sq ft Heating Duty: 20,085 x 106 Btu/hr Accessories: 30 HP forced draft fan, two safety valves, 3/4 HP fuel oil pump, feedwater valves, instruments and controls, 5 HP compressor module		
	Condensate Pumps 1A, 1B, 2A, 2B, 3A and 3B (Existing)	Manufacturer: Peerless/FMC Type: hydroline Flow Capacity: 270 gpm, 325 ft TDH Motor: 40 HP Westinghouse		
	Low-Pressure Feedwater Heaters 1A, 2A and 3A (Existing)	Manufacturer: American Radiator & Sanitary Type: EU shell and tube Capacity: 105,203 lb/hr Surface Area: 693 sq ft Design Pressure: 150 psig		
	Low-Pressure Feedwater Heaters 1B, 2B and 3B (Existing)	Manufacturer: American Radiator & Sanitary Type: EU shell and tube Capacity: 105, 203 lb/hr Surface Area: 375 sq ft Design Pressure: 150 psig		

Spec. No.	Equipment Description	Data	Quantity	Comments
	Deaerator Feedwater Heaters and Storage Tanks 1C, 2C and 3C (Existing)	Manufacturer: American Water Softener Type: K-12,200 with vent condenser Capacity: 140,000 lb/hr Storage Tank: 84" id x 15'-6" long		
	Unit Condensate Transfer Pumps 1A, 2A and 3A (New)	Manufacturer: Ingersoll-Rand Model: 2 x 2 x 10A Type: Horizontal centrifugal, end suction, API-610 Capacity: 315 gpm, 375 ft head Shaft Seal: Mechanical with API plan 23 seal pumping ring Speed: 3,530 rpm Weight: 1,645 lb total each Motor: 50 HP		
	Condensate Pumps 4A and 4B	Manufacturer: Ingersoll-Rand Model: 14JKH Type: Vertical can, six stages Capacity: 1,000 gpm, 560 ft TDH NPSH: 3.4 ft Temperature: 108°F Pressure: 2.65 psia suction, 241 psig discharge Speed: 1,760 rpm Weight: 5,339 lb Motor: 200 HP		

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
	Low-Pressure Feedwater Heater 4A	Manufacturer: Southwestern Engineering Type: Shell and tube Performance: Condensate: 455,140 lb/hr, 63.8°F temperature rise Extraction Steam: 27,070 lb/hr Drains: 33,073 lb/hr in, 60,143 lb/hr out, 10°F drains cooler approach TTD: 5°F Heat Duty: 29.024 x 106 Btu/hr Design Pressure: 20 psig and full vacuum shell, 300 psig tube Design Temperature: 200°F shell and tube sides Tube Material: 90% Cu/10% Ni SB-395		
	Low-Pressure Feedwater Heater 4B	Manufacturer: Southwestern Engineering Type: Shell and tube Performance: Condensate: 455,140 lb/hr, 73.1°F temperature rise Extraction Steam: 33,073 lb/hr Drains: 0 lb/hr in, 33,073 lb/hr out, 10°F drains cooler approach TTD: 5°F Heat Duty: 33.491 x 106 Btu/hr Design Pressure: 35 psig and full vacuum shell, 300 psig tube Design Temperature: 260°F shell, 280°F tube Tube Material: 90% Cu/10% Ni SB-395		

Spec. No.	Equipment Description	Data	Quantity	Comments
	Deaerating Feedwater Heater and Storage Tank 4C	Manufacturer: Graver Performance: Condensate: 775,576 lb/hr Extraction Steam: 46,674 lb/hr Drains: 102,749 lb/hr in Feedwater: 925,000 lb/hr Dissolved Oxygen: .005 cc/liter max Design Pressure: 120 psig and full vacuum Design Temperature: Deaerator: 650°F Storage Tank: 350°F Storage Tank: 154,167 lb capacity, 11'-6" diameter x 30 ft long		
	Boiler Feed Pumps 4A and 4B	Manufacturer: Byron Jackson Model/Size: 4x6x10 C DVMX, 10 stages Performance: Flow: 1,312 gpm Head: 4,368 ft NPSH: 58 ft Pressures: 107 psig suction, 1,818 psig discharge Temperature: 325°F Efficiency: 83% Weight: 19,500 lb Speed: 3,560 rpm Motor: 1,750 HP, 4160 VAC, 3-phase, 60 Hz Lubrication: Pump-forced lubrication with shaft-driven lube oil pump and a 1.5 HP auxiliary lube oil pump	2, 60% cap	

Spec. No.	Equipment Description	Data	Quantity	Comments
	High-Pressure Feedwater Heater 4D	Manufacturer: Southwestern Engineering Type: Shell and Tube Performance: Feedwater Flow: 925,000 lb/hr, 56°F temperature rise Extraction Steam: 50,593 lb/hr Drains: 52,156 lb/hr in, 102,749 lb/hr out, 10°F drains cooler approach TTD: 5°F Heat Duty: 54.024 x 106 Btu/hr Design Pressure: 270 psig and full vacuum shell, 2,200 psig tube Design Temperature: 415/650°F shell, 450°F tube Tube Material: SA-688 GrTP304		
	High-Pressure Feedwater Heater 4E	Manufacturer: Southwestern Engineering Type: Shell and Tube Performance: Feedwater Flow: 925,000 lb/hr, 53.6°F temperature rise Extraction Steam: 52,156 lb/hr Drains: 0 lb/hr in, 52,156 lb/hr out, 10°F drains cooler approach TTD: 5°F Heat Duty: 53.191 x 106 Btu/hr Design Pressure: 465 psig and full vacuum shell, 2,200 psig tube		

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
		Design Temperature: 461/780°F shell, 500°F tube Tube Material: SA-688 GrTP304		
	High-Pressure Feedwater Line	Design Conditions: Pressure, psig: 1,650 operating, 2,076 design Temperature, °F: 440 operating, 450 design Flow, gpm: 2,044 operating Pressure Loss, psi: Operating: 17 line, 23 static, 30 HP heaters, 193 control valve Line Size: 10" Schedule 160 Material: ASTM A106 GrB Line Length: Approximately 200 ft		
	River Intake Screens	Type: Slotted pipes located below the river bed Size: 12" diameter x 20 ft long	4	
	Service Water Pumps (Existing)	Manufacturer: Jackson model PCE-121B Type: Vertical Capacity: 1,500 gpm at 240 ft TDH Motor: 125 HP, 480 VAC, 1,750 rpm	2	
	Water Storage Tank (Existing)	Fabricator: Pittsburgh Des Moines Steel Company Size: 15 ft diameter x 24 ft high with a conical roof Capacity: 31,000 gallons	1	

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
	Pressure Filters (Existing)	Manufacturer: American Water Softener Type: Anthracite pressure filter Size: 4" diameter x 5 ft high	2	
	Treated Water Pumps (One Existing, One Replaced)	Manufacturer: Goulds Model VIT-CT Type: Vertical Capacity: 180 gpm at 80 ft TDH Motor: 7.5 HP, 480 VAC, 3,500 rpm	2	
		Manufacturer: Worthington Type: Vertical Motor: 2 HP	2	
	Backwash Pump (Existing)	Manufacturer: Worthington Size/Model: 6ZFAO2 Motor: 7.5 HP, 3,600 rpm	1	
	Clearwell (Existing)	Size: 14'-6" x 10'-0" x 8'-0" deep		
	Demineralizer Caustic Tank 4A	Fabricator: American Steel and Iron Works Capacity: 5,000 gallons Dimensions: 8' id x 14' S-S long Material: A285 Gr C with plasite lining Design conditions: 30 psig, 115°F	1	
	Demineralizer Acid Day Tank 4A	Capacity: 276 gallons Material: Carbon steel	1	
	Cation Exchanger 4A and 4B	Manufacturer: Illinois Water Treatment Company Flow Capacity: 50 gpm	2	

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
		Vessel Size: 3 ft diameter x 15 ft high Design Pressure: 100 psig		
	Anion Exchanger 4A and 4B	Manufacturer: Illinois Water Treatment Company Flow Capacity: 50 gpm Vessel Size: 3' diameter x 12.5' high Design Pressure: 100 psig	2	
	Mixed Bed Polisher 4A	Manufacturer: Illinois Water Treatment Company Flow Capacity: 50 gpm Vessel Size: 2.5' diameter x 11' high Design Pressure: 100 psig	1	
	Demineralizer Caustic Water Heater 4A	Manufacturer: TULA model CV-2AA-66BS Type: Shell and tube Capacity: 10 gpm Outlet Temperature: 120°F Steam demand: 540 lb/hr at 50 psig Design Pressure: 150 psig	1	
	Water Treatment Filter 4A and 4B	Manufacturer: Illinois Water Treatment Company Capacity: 50 gpm Vessel Size: 3.5' diameter x 5' high Design Pressure: 125 psig	2,	dual media
	Demineralizer Acid Transfer Pump 4A	Capacity: 600 GPD Pressure: 50 psig	1	

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
	Demineralizer Caustic Regeneration Pump 4A and 4B	Manufacturer: Milton Roy model R161-96 Capacity: 57 GPD Pressure: 100 psig Motor: 1/2 HP	2	
	Demineralizer Regeneration Acid Eductor 4A, 4B and 4C	Manufacturer: Penberthy/Houdaille	3	
	Closed Cooling Water Head Tank 4A	Fabricator: American Steel and Iron Works Capacity: 58 gallons Dimensions: 12" std pipe x 10'-6" high Design Conditions: Atmospheric pressure, 150°F	1	
	Closed Cooling Water Chemical Pot Feeder 4A	Capacity: 2 gallons Design Pressure: 100 psig	1	
	Closed Cooling Water Pumps 4A and 4B	Manufacturer: Ingersoll-Rand Capacity: 400 gpm, 140 ft TDH Motor: 20 HP, 480 VAC	2,	100% capacity,
	Closed Cooling Water Heat Exchangers 4A and 4B	Manufacturer: American Standard Type: Shell and tube Flow: 400 gpm closed cooling water, 800 gpm circulating water Temperature Drop/Rise: 12°F drop for closed cooling water, 6°F rise for circulating water Terminal Temperature Diff: 12°F Design Pressures: 150 psig shell, 75 psig tube	2,	ea 100% capacity

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
	Ash Equipment Cooling Water Pumps 4A and 4B	Manufacturer: Ingersoll-Rand Size/Model: 4 x 3 x 8 HC Capacity: 460 gpm, 165 ft TDH Motor: 30 HP, 480 VAC, 3-phase, 60 Hz, 3,600 rpm	2,	100% capacity
	Ash Equipment Cooling Water Heat Exchanger 4A	Manufacturer: American Standard Type: Shell and tube Flow: 436 gpm ash equip closed cooling water, 800 gpm LP feedwater Temperature Drop/Rise: 20°F drop for ash equip. closed cooling water, 14°F rise for LP feedwater Terminal Temperature Diff: 10°F Design Pressures: 150 psig shell, 300 psig tube	1	
	Oil/Water Separator 4A	Manufacturer: AFL Industries Inc Model: VTC-50 with height extension Influent Flow: 50 gpm Influent Oil Conc: 0-350 mg/l Effluent Oil Conc: 15 mg/l Oil specific Gravity: 0.9 or less Solids Content: 5-75 mg/l pH Range: 6-9 Temperature: 60-130°F		
	Septic Tanks 1, 4A and 4B (One Replaced and Two New)	Capacity: 1,250 gallons - replaced 3,000 gallons - new septic tanks	3	

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
	Condensate Storage Tanks 1, 2 and 3 (Existing)	Size: 18'-0" diameter x 9'-9" high with conical top, fabricated from 3/8" steel plate with thermal insulation Capacity: 18,000 gallons each Pressure: Atmospheric	3	
	Condensate Storage Tank 4A	Size: 20' diameter x 24' high, conical top Capacity: 50,000 gallons Construction: 1/16" steel with plasite lining Design Conditions: Atmospheric pressure, 40-200°F	1	
	Deaerator Feed Pumps 1A, 1B, 2A, 2B, 3A and 3B (Existing)	Manufacturer: Byron Jackson Size/Model: 1-1/2 JLH, Bilton Capacity: 125 gpm, 280 ft TDH Motor: 15 HP Westinghouse 18N6269, frame 3465, 220/440 VAC, 3,465 rpm	6, ea 100% capacity per unit	
	Condensate Transfer Pump 4A	Manufacturer: Ingersoll-Rand Size/Model: 2 x 1-1/2 x 9 HC Capacity: 150 gpm, 230 ft TDH NPSH: 25 ft Motor: 20 HP, 3,600 rpm	1	
	Circulating Water Pumps 1, 2 and 3 (Existing)	Manufacturer: Peerless Div, FMC Type: Vertical wet pit Model: 30MF, 30 inch size Capacity: 15,000 gpm, 47 ft TDH Motor: 200 HP, 705 rpm, 440 V, 1.15 SF	3, 50% capacity	

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
	Cooling Water Pumps 1A, 1B and 1C (Replaced)	Manufacturer: Byron Jackson Size/Model: 6x6x11HtxR Bilton Capacity: 750 gpm, 49 ft TDH Motor: 15 HP, 1,770 rpm	3	
	Cooling Tower (Existing)	Manufacturer: Marley Type: Evaporative, mechanical draft cross-flow Model: 577-7D-3 Number of Cells: 3 Construction: Treated Douglas fir frame with PVC fill material	1	
		Fans: No. Blades: 12 each Diameter: 22 ft Motors: 100 HP, 440 VAC, 3-phase, 60 Hz, 1,775 rpm, Allis Chalmers Speed Reducer: Marley 34T right-angle type reducer resulting in 170 rpm fan speed Cell Dimensions: 20′ x 63′-6" Tower Dimensions: 84′-6" x 63′-6" x 35′-10" Dynamic Head: 24.49 ft wg	3, one per cell	
	Circulating Water Pumps 4A and 4B	Manufacturer: Warren Pumps, Model: 24DLB27 Type: Horizontally split centrifugal, single-stage, double-suction, single volute Capacity: 16,500 gpm, 45′ TDH, 9′ NPSH, 81% efficiency	2, 50% capacity	

Spec. No.	Equipment Description	Data	Quantity	Comments
		Speed: 585 rpm Design Temperature: 68°F Weight: 17,000 lb total for each pump Motor: 250 HP, 4160 VAC, 3-phase, 60 Hz		
	Cooling Tower 4A	Manufacturer: Lilie-Hoffmann Type: Counterflow, film fill, induced draft, multi-cell, rectangular, evaporative Number of Cells: 2 Construction: Costal Douglas fir structure, PVC fill, redwood deck	1	
		Fans: Air Flow: 1,171,000 acfm/cell Manufacturer: Hudson Products, model APT-28B-6, 6 blade, 28' diameter, 137.6 rpm Motors: 150 HP/cell Tower Dimensions: 48'x96'x28' high Design Parameters: Elevation: 5,600 ft, 11.96 psia barometric Dry Bulb Temp: -20°F to 100°F Wet Bulb Temp: 55°F Pumping Head: 18'-8" wg Drift: .015%	2, one per cell	
	Feedwater Chemical Feed System Hydrazine Solution Tank With Agitator 4A	Capacity: 100 gallons Agitator: 1/4 HP	1	

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
	Hydrazine Feed Pump 4A (Existing Pump Used)	Capacity: 3.2 gph, 1,350 psig Motor: 1/3 HP	1	
	Amine Solution Tank With Agitator 4A	Capacity: 100 gallons Agitator: 1/4 HP	1	
	Amine Feed Pump 4A (Existing Pump Used)	Capacity: 3.2 gph, 1,350 psig Motor: 1/3 HP	1	
	Amine/Hydrazine Spare Feed Pump 4A (Existing Pump Used)	Capacity: 3.2 gph, 1,350 psig Motor: 1/3 HP	1	
	Boiler Chemical Feed System			
	Phosphate Solution Tank With Agitator 4A	Capacity: 100 gallons Agitator: 1/4 HP	1	w/ dissolving basket
	Phosphate Feed Pumps 4A and 4B	Capacity: 6.25 gph, 2,000 psig Motor: 2 HP	1	
	Cooling Tower Chemical Feed System			
	Gas Chlorinators (One Existing and One New)	Manufacturer: Advance Corp Series 200 direct ton chlorinator Capacity: 500 lb/day	1	
	New Chlorinator 4A	Capacity: 2,000 lb/day		
	Cooling Tower Acid Tank (Existing Tank Relocated)	Capacity: 6,000 gallons		

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
	Cooling Tower Acid Feed Pumps (Two Existing and One New)	Manufacturer: Crane Co. Series 200 diaphragm-type metering, Model 20 Capacity: 0-13.5 gph, 100 psig Motor: 1/4 HP	3, ea 100% for one cooling tower	
	Cooling Tower Chemical Solution Tank 4A With Agitator	Capacity: 100 gallons Material: PPL Agitator: 1/4 HP	1	
	Cooling Tower Chemical Feed Pumps (Two Existing and One New)	Manufacturer: Milton Roy Model: AR141-144A Type: Metering Capacity: 6.25 gph Discharge Pressure: 75 psig Motor: 1/4 HP	3, ea 100% for one cooling tower	
	Water Sampling and Monitoring System	Water Sample Panel 4A Manufacturer: Johnson-March Corp Recorders: Multi-point conductivity, two-point silicon and NA, two-point dissolved O_2 Boiler Water Sample Primary and secondary sample coolers, conductivity element, pH indicator and recorder, silicone analyzer (shared) Mixed Bed/Anion Sample Silicone analyzer (shared) Unit 1-3 DA Feed Secondary sample cooler, conductivity element, dissolved O_2 analyzer (shared)	1	

Spec. No.	Equipment Description	Data	Quantity	Comments
		Main and Drum Steam Primary and Secondary sample coolers, conductivity element, Na analyzer (shared) DA Inlet Sample Secondary sample cooler, conductivity element dissolved O_2 analyzer (shared) Unit 1-3 DA Outlet Secondary sample cooler, O_2 analyzer (shared) *Economizer Inlet Sample* Primary and secondary sample coolers, dissolved O_2 analyzer (shared), Na analyzer (shared), silicon analyzer (shared), conductivity analyzer		
	Sample Panel Recirculation Pump 4A	Capacity: 56 gpm, 52 ft TDH Motor: 1-1/2 HP	1	
	Sample Cooling Heat Exchanger 4A			
	Circulating Water Sample System 4A	Analyzers Two pH, one chlorine and two conductivity analyzers Recorders Two point blowdown flow, two point conductivity, two point pH and one point chlorine		

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
	Logic and Control Room Air Handling Units AHU-4A and 4B	Air Flow: 11,470 acfm Static Pressure: 3.2" wg Motor: 15 HP each	2	full capacity
	Logic and Control Room Air Cooled Condensing Units CU 4A & 4B	Capacity: 30 tons each Electrical Load: 34 kW each	2	full capacity
	Control Room Duct Heater DH-1 and Logic Room Duct Heater DH-2	Electrical Load: 70 kW	1	of each
	Maintenance Shop Office Packaged Air Conditioner AC-1	Electrical Load: 2.65 kW	1	
	Stack Monitoring Equipment Building Packaged Heat Pump AC-2	Electrical Load: 4.1 kW	1	
	Heating System Deaerator 4A	Manufacturer: Cleaver Brooks Type/Model: Spraymaster SM45P Capacity: 45,000 lb/hr Design Operating Flows: 11,300 lb/hr cond in 4,200 lb/hr makeup, 1,120 steam, 16,620 cond out Size: 60" diameter x 11'-1 1/2" S-S with 7' stand height Oxygen Removal: Less than .005 cc/1 Operating Condition: 5 psig, 227°F Design Pressure: 50 psig Storage Capacity: 900 gallons to overflow	1	

Spec. No.	Equipment Description	Data	Quantity	Comments
		Weight: 6,900 lb empty, 19,250 lb flooded Accessories: Relief valve, instruments, controls and valves		
	Heating System Condensate Pumps 4A and 4B (Provided With Deaerator)	Manufacturer: Aurora model J6T Capacity: 58 gpm, 377 ft TDH Motor: 20 HP, 1,750 rpm	2,	full capacity
	Boiler and Turbine Room Steam Unit Heaters UH-1 Through 20	Fan Motor: 1-1/2 HP each	20	
	Electrical and Maintenance Shop Steam Unit Heaters UH-21 Through 24	Fan Motor: 1/2 HP each	4	
	Ash Blower Building Electric Unit Heaters EUH-1 and 2	Electrical Load: 20 kW	2,	50% capacity each
	Cooling Tower Chemical Building Electric Unit Heaters EUH-3 and 4	Electrical Load: 7 kW	2,	50% capacity each
	Stack Monitoring Equipment Building Electric Unit Heater EUH-5	Electrical Load: 3 kW	1	
	Ash Blower Building Electric Equipment Room Electric Unit Heater EUH-6	Electrical Load: 7 kW	1	
	Electrical Room Supply Fan F-4	Motor: 3 HP	1	
	Maintenance Shop Supply Fan F-2	Motor: 1/2 HP	1	

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
	Maintenance Shop Toilet Exhaust Fan F-6	Motor: 1/12 HP	1	
	Electrical Shop Supply Fan F-1	Motor: 1/4 HP	1	
	Boiler Room Roof Supply and Exhaust Fans F-7 Through 9	Motor: 25 HP each Weight: 6,400 lb each Damper Operators: 1/2 HP each	3,	33% capacity
	Battery Room Exhaust Fan F-3	Motor: 1/12 HP	1	
	Control Room Toilet Exhaust Fan F-5	Motor: 1/12 HP	1	
	Elevator Machine Room Supply and Shaft Supply Fans F-15 and 16	Motor: 1-1/2 HP each	2,	50% capacity each
	Cooling Tower Chemical Building Supply Fan F-11	Motor: 1/4 HP	1	
	Ash Blower Building Electrical Equipment Room Supply Fan F-12	Motor: 1/2 HP	1	
	Ash Blower Building Supply Fan F-13	Motor: 3 HP	1	
	Cooling Tower Electrical Building Supply Fan F-14	Motor: 1-1/2 HP	1	
	Standby Service Air Compressor (Existing)	Manufacturer: Joy Mfg Co., rotary type Model: TAO 320 EAA4AE Capacity: 370 cfm at 110 psig Motor: 75 HP, 480 VAC Cooling Air Fan: 3 HP		

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
	Emergency Service Air Compressor (Existing)	Manufacturer: Gardner-Denver, reciprocating type Model: WXG-7002 Capacity: 300 cfm at 100 psig Compressor Speed: 720 rpm Motor: 75 HP General Electric, 870 rpm, 22/440 VAC		
	Air Dryer (Existing)	Manufacturer: Kemp heated type Model: 200 EA Capacity: 235 scfm		
	Service Air Receiver (Existing)	Volume: 650 gallons (87 cu ft) Size: 3'-6" diameter x 8'-0" S-S Design Conditions: 125 psig, 650°F	1	
	Instrument Air Receiver (Existing)	Volume: Approximately 40 cu ft Size: 2'-6" diameter x 6'-0" S-S Design conditions: 125 psig	1	
	Service Air Compressors 4A and 4B	Manufacturer: Joy model 610 Capacity: 610 acfm No. Stages: 1 Discharge Conditions: 100 psig/110°F Design Ambient: 100°F, 11.96 psia Relative Humidity: 17% average Aftercooler: Air cooled Motor: 125 HP	2,	100% capacity each

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
	Service Air Receiver 4A	Volume: 88.2 cu ft Dimensions: 3'-6" id x 10'-9" overall height Design Conditions: 125 psig, 110°F	1	
	Service Air Oil Scrubber and Filter 4A	Type: Cartridge Capacity: 1,450 scfm Design Conditions: 125 psig, 4 psi pressure drop, 0.6 micron particle entrainment. 99.7% entrainment	1	
	Instrument Air Compressor 4A	Manufacturer: Atlas-Copco model ZR4C Type: Rotary Screw Capacity: 1,022 acfm Discharge Conditions: 110 psig, 112°F Ambient Conditions: 100°F, 11.96 psia, 17% average relative humidity No. Stages: 2 Rotor Speeds: 4,976/7,201 rpm Intercooler: Shell and tube, 22.25 gpm/100°F cooling water Aftercooler: Shell and tube, 11.75 gpm/100°F cooling water with 27°F rise Lubrication: Forced feed, shaft-driven pump, auxiliary oil pump, oil cooler Motor: 250 HP, 4160 VAC, 3-phase, 60 Hz Ventilation Fan: 2.5 HP Weight: 7,250 lb for complete package Accessories: Inlet filter, controls, valves, inlet and unloading silencers	1	

Spec. No.	Equipment Description	Data	Quantity	Comments
	Instrument Air Receiver 4A	Volume: 141.7 cu ft Size: 48" x 144" Design Conditions: 125 psig, 112°F	1	
	Instrument Air Prefilter 4A	Manufacturer: Finite OH 126 Type: Coalescing Filter Media: Microglas fiber Capacity: 1000 scfm Design Conditions: 125 psig, 112°F, 2 psi diff pressure Particle Entrainment: 3 microns, 99.9% removal	1	
	Instrument Air Dryer 4A	Manufacturer: Kemp Hydronix 1700 HRA Type: Heated, two tower, 4-hr drying time Desiccant: Activated alumina Capacity: 10000 scfm with 31.2 scfm purge Outlet Dew Point: -40°F Heaters: 26.3 kW Design Conditions: 125 psig, 112°F Weight: 6,300 lb		
	Instrument Air Afterfilter 4A	Manufacturer: Finite OHOH Capacity: 1000 scfm Filter Media: Microglas fiber Particle Entrainment: 3 microns min, 99.99% removal Design Conditions: 125 psig, 112°F, 2 psi diff pressure	1	

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
	Turbine Room Crane (Existing)	Manufacturer: Conco Engineering Works	1	
		Type: CIP electric operated		
		Capacity: 25-ton with 5-ton auxiliary hoist		
		Control: Pendent		
		Dimensions: Span 37′-1 1/2″, lift 37′-0″		
		Motors:		
		Hoist: 20 HP Westinghouse Type CIP, style 1816498, variable speed	1	
		Bridge: 5 HP Westinghouse type CIP, style 1658047, variable speed	2	
		Trolley: 10 HP Relueland frame 324	1	
	Turbine Bay Crane 4A	Manufacturer: Conco-Tellus Inc.	1	
		Capacity: Main Hook: 60 tons		
		Auxiliary Hook: 15 tons		
		Dimensions: Span 47′-9 1/2″, travel distance 150′, main hook lift 48′, auxiliary hook lift 49′		
		Motors: Main Hoist: 30 HP		
		Auxiliary Hoist: 36 HP		
		Trolley: 4 HP		
		Bridge: 2 x 5 HP		
	Plant Elevator 4A	Manufacturer: Otis	1	
		Type: Traction geared passenger		
		Capacity: 2,000 lb		
		Hoist Speed: 150 ft/min		
		Floor Stop Elevations: 0′ (grade elevation), 24, 40′, 70′, 90′, 110′, 138′		

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
	Centrifuge (1/2 (Existing for Units 1 and 2 Alternately)	Manufacturer: Alfa Laval Company Model: MAB 103 Capacity: 1,500 liters/hr	1	
	Centrifuge 3 (Existing for Unit 3)	Manufacturer: DeLaval Steam Turbine Co Model: 45-23 Capacity: 45 gallons/hr	1	
	Lube Oil Storage Tanks 4A and 4B	Fabricator: American Steel and Iron Works Capacity: 7,500 gallons each Dimensions: 10 ft id x 16 ft high, conical roof Design Conditions: Atmospheric pressure, -20 to 115°F, located outdoors		
	Turbine Lube Oil Transfer Pump 4A	Manufacturer: Viking Pump Model: K4123R Capacity: 20 gpm, 50 psig Motor: 3 HP, 1,200 rpm		
	Turbine Lube Oil Reservoir Transfer Pump 4A	Manufacturer: Viking Pump Model: HL4123D Capacity: 20 gpm, 50 psig Motor: 3 HP, 1,200 rpm		
	Turbine Lube Oil Conditioner 4A	Manufacturer: Nugent Filterbag Flow: 1,200 gallons/hr Polishing Filter: 1,200 gallons/hr		

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
		Filter Pump: 1,200 gallons/hr, 1/5 HP motor Vapor Extractor: 1/6 HP		
	Waste Oil Sump Pump 4A	Manufacturer: Peabody Barnes Model: 3SE104 Capacity: 100 gpm, 25 ft head Motor: 1 HP	1	
	Waste Oil Tank 4A	Fabricator: American Steel and Iron Works Capacity: 7,500 gallons Dimensions: 10 ft id x 16 ft high, conical roof Design Conditions: Atmospheric pressure, -20 to 115°F, located outdoors		
	Fire Booster Pump 4A	Manufacturer: Aurora Pump Model: 912, type 481-8F, size 5-481-15 Type: Horizontal centrifugal Capacity: 1,000 gpm, 170 ft TDH Pressures: 162 ft suction pressure, 144 psig discharge pressure Motor: 75 HP, 1,775 rpm	1	
	Pressure Maintenance Fire Pump 4A	Manufacturer: Aurora Pump Model: 935, size JP-173-0 Type: Horizontal centrifugal Capacity: 10 gpm, 170 ft TDH Discharge Pressure: 118 psig Motor: 1 HP, 3450 rpm	1	

Spec. No.	Equipment Description	Data	Quantity	Comments
	Automatic Water Fogging Equipment (Existing)	Manufacturer: Rockwood Sprinkler Co Service: Serves existing and new main power transformers Equipment: Complete system with all piping, nozzles, etc.		
	Propane Storage Tank Deluge System 4A	Type: Stand alone		
	Propane Truck Unloading Station (Riser Assembly and Accessories)			
	Propane Storage Tank 4A	Size: 10′ dia x 49′ long bullet-style tank Capacity: 30,000 gallons Design: ASME, 250 psig	1	
	Propane Vaporizors 4A and 4B	Capacity: one, 2,500 gallons/hr, one, 2,500 gallons/hr Type: Water bath direct-fired	2	
	Propane Backup Supply Pump 4A			
	Propane Supply Line Size: 6"	Operating Pressure: 30-35 psig		
	Main Step-Up Transformers 1, 2 and 3 (Existing)	Manufacturer: Moloney Capacity: 12,000 kVA Voltage: 115,000/13,200 V	3	

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
	Isolated Phase Buses 1, 2 and 3 (Existing)			
	Main Generator Step-Up Transformer 4A	Manufacturer: Federal Pacific/ Reliance Electric Type: 3-phase, 60 Hz, 2-winding Voltage: 115 kV primary, 13.8 kV secondary Continuous Capacity: 65°C rise, 85.5 mVA Rated Efficiency: 99.7% Cooling Type: Oil immersed, FOA cooling class Auxiliary Power: 7 kW for oil pumps and cooling fans Weight: 230,000 lb	1	
	Isolated Phase Bus 4A	Manufacturer: Westinghouse Voltage: 13.8 kV Ampacity: 4,000 Amperes	2,	100% capacity
	Unit Auxiliary Transformer 4A	Manufacturer: Federal Pacific/ Reliance Electric Voltage: 115 kV primary 4,160 V secondary Rating: 12/16/20 mVA, OA/FA/FA 3-phase, 60 Hz, continuous capacity Temperature Rise: 65°F Cooling Fans: 4 x 1/6 HP each Weight: 90,000 lb	1	

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
	Unit Auxiliary Non-Segregated Phase Bus 4A	Voltage: 4.16 kV Ampacity: 3,000 Amperes	1	
	4,160 Volt Switchgear Bus 4A	Manufacturer: General Electric Capacity: 250 mVA, 4,160 volts Continuous Current Rating: Main Circuit breaker - 3,000 Amps, other circuit breakers - 1,200 Amps	1	lineup
	Load Centers 4A and 4B	Manufacturer: BBC Brown Boveri, Inc. Load: 1,500 kW Power Transformers: 4.16 kV - 480 Volt, 3-phase, 60 Hz, 65°C rise Power Circuit Breakers: 600 Volt, 1-2,000 Ampere main breaker	2	lineups
	480 Volt Motor Control Centers 4A Through 4G	Manufacturer: BBC Brown Boveri, Inc. Capacity: 500 HP Rating: 3-Phase, 60 Hz, 480 V, 3 wire, 600 Amp buses	7	
	Relay Cabinets and Control Panels	Manufacturer: Hydrologics, Inc.		
	Rotary UPS System 4A	Manufacturer: Computer Power Products Type: Rotary motor-generator set Output Voltage: 480 V, 3-phase, 60 Hz Backup Power Supply: 125 VDC battery Backup Run Time: 1 hour	1	
	125 VDC Distribution Panel 4A	Manufacturer: C & D Battery Type: Lead Acid System Voltage: 125 VDC nominal	1	

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
	Distributed Control System 4A	Manufacturer: Westinghouse Electronics		
	Stack Monitoring System 4A	Manufacturer: Thermoelectron		
	Hard Wired Control Panel 4A	Manufacturer: Hydrologics, Inc.		
SPECIAL TEST PROGRAM INSTRUMENTATION				
	DPU11 consists of the following:	Redundant DPU's in a single cabinet	2	
		Basic Drop Electronics	2	sets
		Data Highway Interface Hardware	2	sets
		Battery Backed RAM	2	
		CAB-A Process I/O Cabinet	1	
		CAB-B Termination Cabinet	1	
	Q-line process I/O cards as follows:	Type QAV Low Level Analog Inputs (6 points/module) for thermocouple inputs	6	
		Type QAW High Level Analog Inputs (6 points/module) for 4 - 20 madc input signals	11	
		Type QCI Digital Inputs (16 points/module)	2	
		Type ORO Digital Output (6 points/module)	1	
	Present utilization of the I/O cards is as follows:	Type QAV points available, 31 points used, 5 spares for future use	36	

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
		Type QAW points available, 44 points used, 22 spares for future use	66	
		Type QCI points available, 30 points used, two spares for future use	32	
		Type QRO points available, one point used, five spares for future use	6	
	DPU11 also contains	Spare Q-Crate slots for additional cards	6	
	Gateway consists of the following:	Basic Drop Electronics	2 sets	
		Data Highway Interface Hardware	2 sets	
		DEC VAX Gateway Kit	1	
	OPCON consists of the following:	Basic Drop Electronics	1 set	
		Data Highway Interface Hardware	1 set	
		19" High Resolution Color Monitor	1	
		Display Generator	1	
		Operator Keyboard	1	
		2M byte Bubble Memory	1	
		Genicom 3404 Multicolor Printer	1	
		Pedestal Desk Console	1	
	DEC VAX 8200 Computer System consists of the following major components:	821BA-DE DEC VAX 8200 Computer with 4 MB memory	1	
		RA81-AA 456 MB Hard Disk	1	
		TU80-AA Dual density Tape Drive	1	
		DEC VT241-AA Color Video Terminals with Keyboard	3	
		DEC LXY22 600 LPM Graphics Printer	1	

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
		Dec LXY12 300 LPM Graphics Printer	1	
		DF126-AA Modem	1	
		LVP16-AA Color Graphics Pen Plotter	1	
		LA100 KSR Terminal	1	
		Q5001-8M VAX/VMS Operating System	1	
		Q5100-HM VAX/Fortran Software	1	
		Monthly Field Service Maintenance for DEC Hardware and Software for for 24 months	1	
	Data Highway Point Summary	**PTID No.** — **Description**		
		Digital Points		
		BZS300 — EPRI Computer Room Fire		
		BZS302 — EPRI Fire Detection System Trouble or Computer Room High temperature		
	Uninterruptible Power System	Manufacturer: Computer Power Products Co		
		Type: Rotary		
		Power:		
		AC Input: 480 VAC 3-phase, 60 Hz		
		DC Input: 110 vdc		
		AC Output: 480 VAC 3-phase, 60 Hz to a 480-208/120 VAC transformer		
		Output Capacity: 50 KVA		
		Regulation:		
		Voltage: ±10%		
		Frequency: ±5%		
		Battery rundown: 60 min		

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
	Laboratory Equipment			
	Lab Sample Crusher	Manufacturer: Holmes Model: 201 XL Features: 0.4 cu ft capacity hopper Power: 230/460 three-phase		
	Bench Sample Pulverizer	Manufacturer: Holmes Model: 350 Features: 60 cu in capacity hopper with five screen plates (.020", .024", .033", .040" and .0625" diameters) Power: 115 VAC one-phase		
	Sample Riffle	Manufacturer: Holmes Model: 15XL Features: 24 Stainless Steel spouts for 20 mesh material		
	Standard Sulfur Determinator Model: SC-132	Manufacturer: Leco Features: Solid state infrared detector Integral Electronic Balance Dot Matrix Printer Range: 0.001 to 99.99 Direct Reading Accuracy: ±1% of sulfur content Analysis Time: 1-2 minutes Power: 230 VAC, 15 amps, 60 Hz		
	Dual Range Electronic Analytical Balance	Manufacturer: American Scientific Model: S/P-182 Features: Adjustable integration time Auto calibration Ranges: 0-32 g and 0 to 180 g Readability: 0.01 mg and 0.1 mg Linearity: ±0.03 mg and ±0.2 mg		

Spec. No.	Equipment Description	Data	Quantity	Comments
		Pan Diameter: 75 mm Power: 115/230 VAC, one-Phase, 60 Hz		
	Top Loading Balance	Manufacturer: American Scientific Model: Z-12K Features: Auto calibration variable integration time Weighing Range: 0-12,000 g Readability: 0.1 g Power: 110/240 VAC, one-phase, 60 Hz		
	Enclosed Shatterbox Grinder and Blender	Manufacturer: Industries Model: 8510-1145/60 Features: 900 rpm grinding speed, 70 ml capacity, 1/3 HP motor, 0-6 min timer Power: 115 VAC, one-phase, 60 Hz		
	Hot Plate	Manufacturer: VWR Scientific Model: Gyrotherm II A Features: Fan-cooled drive motor Power: 120 VAC, one-phase, 60 Hz		
	Forced Convection Oven	Manufacturer: VWR Scientific Model: 137°F Features: Adjustable over-temp controller, Stainless Steel interior, 1/5 HP blower, circuit breaker protection Range: 40-240°C Power: 208-220 VAC, one-Phase, 60 Hz, 1,600 watts		

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
	Motor-Driven Sieve Shaker With Sieves	Manufacturer: Tyler Model: RX-24 Features: 500 rpm rocking action, 1/4 HP motor, 0-30 min timer Capacity: 6 full height of 13 half height pans Sieve Sizes: 1.5" (-mesh), 1.0" (-mesh), 0.75" (-mesh), 0.50" (-mesh), 0.25" (-mesh), 4.75 mm (4 mesh), 3.35 mm (6 mesh), 2.36 mm (8 mesh), 1.40 mm (12 mesh), 1.00 mm (16 mesh), 850 micron (20 mesh), 600 micron (28 mesh), 300 micron (48 mesh), 150 micron (100 mesh), 106 micron (150 mesh), 75 micron (200 mesh), 45 micron (325 mesh), 38 micron (400 mesh)		
	Large Riffle	Manufacturer: Gilson Model: SP-0 Features: 400-lb coal capacity, 1 to 6" adjustable openings, four material pans		
	Ice Machine	Manufacturer: Scotsman Model: AC55SAE-1A Features: 55 lb/day capacity, half round cube Power: 115 VAC, one-phase, 60 Hz		

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
	Desiccating Cabinet	Manufacturer: Boekel Model: 1342 Features: Stainless Steel, glass door, manual pressure relief valve Power: 115 VAC, one-phase, 60 Hz		

Spec. No.	Equipment Description	Data	Quantity	Comments

Device List
The following is a numeric/alpha listing of instrumentation included. The PTID No. refers to the data point number of the instrument if it is on the data highway.

Tag No.	PTID No.	Description
113AT301	CAT301	Relative humidity at elevation 135′
113PT302	CPT302	Barometric Pressure at elevation 135′
113TE300	CTE300	Ambient temperature at elevation 135′
201TE300	DTE300	Superheater 1 inlet steam temperature
222WM300	EWM300	BFP 4A watts
222WM301	EWM301	BFP 4B watts
230AE300A	GAE300A	Comb chamber 4B surface TC at 31′
230AE300B	GAE300B	Comb chamber 4B fluid TC at 31′
---	GHF300	Heat flux calculated from GAE300A and B
230AE301A	GAE301A	Comb chamber 4B surface TC at 34′
230AE301B	GAE301B	Comb chamber 4B fluid TC at 34′
---	GHF301	Heat flux calculated from GAE301A and B
230AE302A	GAE302A	Comb chamber 4B surface TC at 38′
230AE302B	GAE302B	Comb chamber 4B fluid TC at 38′
---	GHF302	Heat flux calculated from GAE302A and B
230AE303A	GAE303A	Comb chamber 4B surface TC at 44′
230AE303B	GAE303B	Comb chamber 4B fluid TC at 44′
---	GHF303	Heat flux calculated from GAE303A and B
230AE304A	GAE304A	Comb chamber 4B surface TC at 54′
230AE304B	GAE304B	Comb chamber 4B fluid TC at 54′
---	GHF304	Heat flux calculated from GAE304A and B
230AE305A	GAE305A	Comb chamber 4B surface TC at 66′
230AE305B	GAE305B	Comb chamber 4B fluid TC at 66′
---	GHF305	Heat flux calculated from GAE305A and B
230AE306A	GAE306A	Comb chamber 4B surface TC at 79′

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No. Tag No.	Equipment Description PTID No.	Data Description	Quantity	Comments
230AE306B	GAE306B	Comb chamber 4B fluid TC at 79'		
---	GHF306	Heat flux calculated from GAE306A and B		
230AE307A	GAE307A	Comb chamber 4B surface TC at 92'		
230AE307B	GAE307B	Comb chamber 4B fluid TC at 92'		
---	GHF307	Heat flux calculated from GAE307A and B		
230AE308A	GAE308A	Comb chamber 4B surface TC at 105'		
230AE308B	GAE308B	Comb chamber 4B fluid TC at 105'		
---	GHF308	Heat flux calculated from GAE308A and B		
230AE309A	GAE309A	Comb chamber 4B surface TC at 118'		
230AE309B	GAE309B	Comb chamber 4B fluid TC at 118'		
---	GHF309	Heat flux calculated from GAE309A and B		
230FE300	---	PA fan 4A inlet air flow		
230FE301	---	SA fan 4A inlet air flow		
230DPT311	GDPT311	Cyclone 4B loop seal differential pressure		
230FE324	---	Baghouse 4A flue gas flow element		
230FT324	GFT324	Baghouse 4A flue gas outlet flow		
230PT300	GPT300	Combustion chamber 4B pressure at 25'		
230PT301	GPT301	Combustion chamber 4B pressure at 31'		
230PT302	GPT302	Combustion chamber 4B pressure at 34'		
230PT303	GPT303	Combustion chamber 4B pressure at 38'		
230PT304	GPT304	Combustion chamber 4B pressure at 44'		
230PT305	GPT305	Combustion chamber 4B pressure at 54'		
230PT306	GPT306	Combustion chamber 4B pressure at 66'		
230PT307	GPT307	Combustion chamber 4B pressure at 79'		
230PT308	GPT308	Combustion chamber 4B pressure at 92'		
230PT309	GPT309	Combustion chamber 4B pressure at 105'		
230PT312	GPT312	Cyclone 4B loop seal pressure		
230PT318	GPT318	Air preheater flue gas outlet pressure		
230PT335	GPT335	SA fan 4A discharge pressure		
230PT336	GPT336	PA fan 4A discharge pressure		

Spec. No.	Equipment Description	Data		Quantity	Comments
Tag No.	PTID No.	Description			
230SX320	---	Baghouse 4A gas inlet sample point			
230SX321	---	Baghouse 4A gas outlet sample point			
230SX322	---	Baghouse 1,2,3 gas inlet sample point			
230SX323	---	Baghouse 1 gas outlet sample point			
230SX350	---	Combustion chamber 4B sample at elevation 86'5"			
230SX351	---	Combustion chamber 4B sample at elevation 44'6"			
230SX352	---	Cyclone 4B inlet sample point			
230SX353	---	Cyclone 4B outlet sample point			
230SX354	---	Baghouses 1,2,3,4A inlet sample point			
230SX356	---	Baghouse 2 gas outlet sample point			
230SX355	---	Baghouse 3 gas outlet sample point			
230TE310	GTE310	Cyclone 4B ash outlet temperature			
230TX325	---	Baghouse 1,2,3,4A inlet flue duct temperature			
230WM325	GWM325	PA fan 4A watts			
230WM326	GWM326	SA fan 4A watts			
230WM327	GWM327	ID fan 4A watts			
230WM328	GWM328	Loop seal fan 4A watts			
230WM329	GWM329	Loop seal fan 4B watts			
230WM330	GWM330	Bottom ash cooling fan 4A watts			
240PT300	KPT300	Boiler outlet main steam pressure			
260DPT300	PDPT300	Baghouse 4A compartment A differential pressure			
260DPT301	PDPT301	Baghouse 4A compartment D differential pressure			
260DPT302	PDPT302	Baghouse 4A compartment E differential pressure			
260DPT303	PDPT303	Baghouse 4A compartment H differential pressure			
260DPT304	PDPT304	Baghouse 4A compartment J differential pressure			
260DPT305	PDPT305	Baghouse 4A compartment M differential pressure			
293PI300	---	Bottom ash hopper 4A pressure			
293PI301	---	Bottom ash hopper 4B pressure			
293TE300	TTE300	Screw cooler 4A ash outlet temperature			
293TE301	TTE301	Screw cooler 4B ash outlet temperature			

Spec. No.	Equipment Description	Data	Quantity	Comments

Tag No.	PTID No.	Description
457FE300	---	Ash coolers cooling water flow element
457FT300	XFT300	Ash coolers cooling water flow
457TE301	XTE301	Ash equipment CW HX 4A inlet temperature

Duct pressure taps consisting of two-inch threaded nipples with reduced port ball valves were added to various combustion air ducts to allow grid pattern pitot traverses of the ducts. The traverse data will be used to verify readings on air foils being used for plant monitoring and control. Locations and quantities are as follows:

Location	Quality
a. Primary air to combustion chamber 4A at elevation 40'6	
b. Primary air to combustion chamber 4B at elevation 40'6	
c. Primary air to loop seal on combustion chamber 4A at elevation 40'2	
d. Primary air to loop seal on combustion chamber 4B at elevation 40'2	
e. Secondary air to combustion chamber 4A at elevation 50'4	
f. Secondary air to combustion chamber 4B at elevation 50'4	
g. Primary air to lower injection ports to combustion chamber 4A at elevation 24'	4
h. Primary air to lower injection ports to combustion chamber 4B at elevation 24'	4
i. Bottom ash cooling duct at elevation 20'	3
j. Startup burner 4B at elevation 28'	2

Fifteen protractor/air lock assemblies were furnished for use with the duct pressure taps to allow insertion and orientation of the traverse probe.

Ash sample points were installed on the economizer and air heater ash hoppers to allow collection of ash for testing. These sample points consist of full flow two-inch ball valves and pipe nipples. Samples are collected using thief sample tubes.

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
	Transmitters	Manufacturer: Rosemount Type: 1151 Power/Output: 2-wire 4-20 madc Accuracy: ±0.25% of calibrated span Stability: ±0.25% of upper range limit for six months		
	Ambient Conditions Monitor Relative Humidity	Manufacturer: Weathertronics Type: Thin film capacity Power/Output: 3.60 vdc/4-20 madc Range: 0-100% RH Accuracy: ±2%		
	Ambient Temperature	Manufacturer: Weathertronics Type: 100 Ohm platinum wire Power/Output: 3.60 vdc/4-20 madc Range: -50 to +50°C Accuracy ±0.3°C		
	Heat Flux Measurement	Manufacturer: B&W Company Type: Water wall element with surface and fluid chordal thermocouples TC Type: Chromel-Alumel nongrounded		
	Watt Transducers	Manufacturer: Scientific Columbus Type: XL31K5P, three-phase, three-wire Output: 4-20 madc Accuracy/Linearity: ±0.25% at 25°C		
	Annubars	Manufacturer: Dietrich Standard Type: DFF-46		

APPENDIX A. PROJECT EQUIPMENT AND DATA LIST

Spec. No.	Equipment Description	Data	Quantity	Comments
	Fly Ash Weighing System 1. Equipment			
		Surge/Weigh Bin: Nominal 90 cu ft capacity with 18" diameter discharge, two (2) 10" diameter inlets, 18" manhole and Dynatrol probe and transmitter assembly to sense high material level.		
		Schenck Weigh System: Model DLM-10 solids flowmeter including infeed adapter to the rotary valve and measuring chute vibrator. Schenck Model FCO 411 microprocessor board measuring system supplied in a NEMA 4 wall-mounted enclosure. Flow rate output 4-20 madc = 0-60 TPH pulse output isolated relay dry contact each pulse = 0.01 ton.		
		Feeder Gate: 18" pneumatic slide gate, 304 S.S. with solenoid valve and open/close limit switches.		
		Bypass: Two (2) 10" surge/weigh bin outlets with pneumatic slide gate, 304 S.S. with solenoid valve and open/close limit switches.		

Spec. No.	Equipment Description	Data	Quantity	Comments
		Rotary Valve: 18" x 24" with 3 HP constant speed drive.		
2.	Data Highway Point Summary	(see point list below)		
Bottom Ash Weighing System				
1.	Equipment	Load Cells: Eight (8) Kistler-Morse #503 microcell. Four (4) cells per hopper.		
		Transmitters: Two (2) Kistler-Morse #904XC. One (1) per hopper with 4-20 madc output to a maximum 500 Ohm load		

PTID No.	Description
Analog Points	
TFT305	Flow rate (0-60 TPH)
IP11201	Totalized flow (KLB)
Digital Points	
THS305ST	Start test period weighing
THS305SP	Stop test period weighing
TZS305A	Weigh system valve misalignment alarm
TZS305B	Weigh bin high level alarm
TZS305C	Weigh system bypassed
TZS305D	Weigh system trouble alarm
IP11003	Digital trigger to read totalized flow
IP11001	Weigh system manual reset

NUCLA CFB DEMONSTRATION PROJECT

PROJECT PUBLIC DESIGN REPORT

APPENDIX B

NON-PROPRIETARY

PROCESS AND INSTRUMENTATION DRAWING INDEX

(Bound Separately)

APPENDIX B. NON-PROPRIETARY

PROCESS AND INSTRUMENTATION DRAWING

Section Number	Contents	Exhibit Number

1. Stearns Catalytic Corporation
   Denver, Colorado
   Process Flow and Instrumentation Drawings

Section Number	Contents (Continued)	Exhibit Number

Section Number	Contents (Continued)	Exhibit Number

NUCLA CFB DEMONSTRATION PROJECT

PROJECT PUBLIC DESIGN REPORT

APPENDIX C

PROPRIETARY

PROCESS AND INSTRUMENTATION DRAWING
INDEX

(Bound Separately)

APPENDIX C PROPRIETARY

PROCESS AND INSTRUMENTATION DRAWING

Section Number	Contents	Exhibit Number

1. Pyropower Corporation
   San Diego, California
   Process Flow and Instrumentation Drawings

NUCLA CFB DEMONSTRATION PROJECT

PROJECT PUBLIC DESIGN REPORT

APPENDIX D

TECHNICAL ADVISORY GROUP
LIST OF ORGANIZATIONS

NUCLA CFB DEMONSTRATION PROJECT
TECHNICAL ADVISORY GROUP

Purpose

The Technical Advisory Group (TAG) was formed to provide a forum whereby all participants in the Nucla CFB Demonstration Project may discuss the progress of the Project and provide comments to Colorado-Ute Electric Association, Inc., to assure the Project will provide maximum benefit for all participants.

The TAG will provide direction for the test program and may be called upon to assist with specific problems that arise during the construction, start-up and testing of the Project.

Membership

Full membership of the TAG is open to all organizations that participate in the Nucla Project. Participants in the Project include Colorado-Ute, equipment suppliers that share in the project risks and other organizations that make significant contributions to the Project funding.

An Associate Membership may be obtained by those organizations that desire to obtain first hand information on the project but do not wish to contribute to the project funding. An Associate Membership will cost $50,000. Associate Members will receive all bulletins and general information that full members receive. Associate Members may also attend the TAG meetings.

Organization

The TAG will be made up of one representative of each of the participants in the Nucla CFB Demonstration Project as outlined in the Membership section.

The representative from Colorado-Ute will serve as Chairman of the TAG. Meetings will be held quarterly or as necessary to deal with unusual situations. Membership in Ad Hoc committees for direction or technical advisory functions will be limited to full members of the TAG.

APPENDIX D

TECHNICAL ADVISORY GROUP
LIST OF ORGANIZATIONS

Full Membership

Bechtel Power Corporation
PO Box 3965
San Francisco, CA 94119

Colorado-Ute Electric Association, Inc.
PO Box 1149
Montrose, CO 81402

Electric Power Research Institute
3412 Hillview Avenue
PO Box 10412
Palo Alto, CA 94303

Peabody Holding Company, Inc.
P.O. Box 373
St. Louis, MO 63166

Philadelphia Electric Company
Research and Testing Division
PO Box 8699
2301 Market Street
Philadelphia, PA 19101

Pyropower Corporation
P.O. Box 85480
San Diego, CA 92138

United Engineers & Constructors, Inc.
Stearns-Roger Division
PO Box 5888
700 South Ash Street
Denver, CO 80217

U.S. Department of Energy
PO Box 880
Morgantown, WV 26505

Westinghouse Electric Corporation
Steam Turbine-Generator Division
The Quadrangle
4400 Alafaya Trail
Orlando, FL 32826-2399

Associate Membership

AES Shady Point, Inc.
PO Box 759
Panama, OK 74951

Consolidated Edison
Four Irving Place, Room 1428
New York, NY 10003

Department of Water & Power of the
City of Los Angeles
111 North Hope Street, Room 129
P.O. Box 111, Terminal Annex
Los Angeles, CA 90051

General Electric Company
One River Road, Building 2, Room 2E
Schenectady, NY 12345

Houston Lighting & Power Company
12301 Kurland Drive
Houston, TX 77034

Kerr-McGee Chemical Corporation
P.O. Box 25861
Oklahoma City, OK 73125

National Rural Electric Cooperative Assn.
1800 Massachusetts Avenue NW
Washington, DC 20036

National Rural Utilties Cooperative
Finance Corporation
1115 30th Street NW
Washington, DC 20007

Northeast Utilties Service Company
P.O. Box 270
Hartford, CT 06141-0270

Pacific Gas & Electric
3400 Crow Canyon Road
San Ramon, CA 94583

Public Service Company of Colorado
5909 East 38th Avenue
Denver, CO 80207

Rural Electrification Administration
U.S. Department of Agriculture
14th & Independence Avenue SW, Room 0218-S
Washington, DC 20250-1500

Salt River Project
P.O. Box 52025
Phoenix, AZ 85072-2025

San Diego Gas and Electric
PO Box 1831
101 Ash Street
San Diego, CA 92124

Southern California Edison Company
PO Box 800
2244 Walnut Grove Avenue
Rosemead, CA 91770

Tennessee Valley Authority
Division of Energy Demonstrations
  and Technology
3N 41A Missionary Ridge Place
1101 Market Street
Chattanooga, TN 37402-2801

Utah Power and Light
168 North 1950 West
Salt Lake City, UT 84104

Virginia Power
Innsbrook Technical Center
5000 Dominion Boulevard
Glen Allen, VA 23260