DOE/PC/92159--T12

TECHNICAL PROGRESS REPORT NO. 10 JANUARY-MARCH 1995

U.S. DEPARTMENT OF ENERGY

PITTSBURGH ENERGY TECHNOLOGY CENTER

CONTRACT DE-AC22-92PC92159

FOR

ENGINEERING DEVELOPMENT OF ADVANCED COAL-FIRED LOW-EMISSION BOILER SYSTEMS

SUBMITTED BY:

ABB POWER PLANT LABORATORIES
COMBUSTION ENGINEERING, INC.

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May 17, 1995

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PATENT STATUS

Cleared by Chicago OIPC May 31, 1995.

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EXECUTIVE SUMMARY

INTRODUCTION

The Pittsburgh Energy Technology Center of the U.S. Department of Energy (DOE) has contracted with Combustion Engineering, Inc. (ABB CE) to perform work on the "Engineering Development of Advanced Coal-Fired Low-Emission Boiler Systems" Project and has authorized ABB CE to complete Phase I on a cost-reimbursable basis and Phases II and III on a cost-share basis.

The overall objective of the Project is the expedited commercialization of advanced coal-fired low-emission boiler systems. The specified primary objectives are:

- NO_X emissions not greater than one-third NSPS.
- SO_X emissions not greater than one-third NSPS.
- Particulate emissions not greater than one-half NSPS.

The specific secondary objectives are:

- Improved ash disposability and reduced waste generation.
- Reduced air toxics emissions.
- Increased generating efficiency.

The final deliverables are a design data base that will allow future coal-fired power plants to meet the stated objectives and a preliminary design of a Commercial Generation Unit.

The work in Phase I covered a 24-month period and included system analysis, RD&T Plan formulation, component definition, and preliminary Commercial Generating Unit (CGU) design.

Phase II will cover a 15-month period and will include preliminary Proof-of-Concept Test Facility (POCTF) design and subsystem testing.

Phase III will cover a 9-month period and will produce a revised CGU design and a revised POCTF design, cost estimate and a test plan.

Phase IV, the final Phase, will cover a 36-month period and will include POCTF detailed design, construction, testing, and evaluation.

The Project will be managed by ABB CE as the contractor and the work will be accomplished and/or guided by this contractor and the following team members:

- DOE Contracting Officer's Representative (COR)
- ABB Combustion Engineering Systems (ABB CES)
- ABB Environmental Systems, Inc. (ABBES)
- Raytheon Engineers and Constructors, Inc. (RE&C)
- Dr. Janos Beér, MIT and Dr. Jon McGowan, U. of Mass.
- Association of Edison Illuminating Companies - Power Generation Committee (AEIC)
- Advanced Energy Systems Corporation (AES)
- Black Beauty Coal Company
- Electric Power Research Institute (EPRI)
- Illinois Clean Coal Institute (ICCI)
- Peridot Chemicals, Inc.
- Richmond Power & Light (RP&L)
- Southern Company Services, Inc. (SCS)

SUMMARY

The project is on schedule and under budget. The current status is shown in the Milestone Schedule Report included as Appendix A. All Project Plans were updated based on the revised funding level authorized for FY95 and anticipated for FY96. Technology Transfer activities included "supplying" three executives and several team members to the LEBS Workshop, delivering a technical paper at a conference, and working on a Combustion 2000 Session for another conference.

ABBES and CeraMem reached agreement concerning Task 7 work, including ownership and disposition of project-purchased equipment to be used during Task 7 and also during Task 11. A test plan was prepared.

Task 7 activities for the Low-NO_X Firing System included computational modeling of the firing arrangement. Reasonable comparisons to experimental data previously obtained in the Boiler Simulation Facility were achieved. A kinetic evaluation for both baseline and low NO_X firing arrangements was also performed, with results indicating that the final reducing zone within the main windbox has a dominant effect on NO_X reduction, with higher temperatures being more favorable for lower NO_X. A week of combustion testing was completed in the Fundamental Scale Burner Facility to examine the impact of integrated fuel staging (NO_X reduction via the reburn mechanism), and to explore preliminary vertical staging concepts within the main windbox region. Preliminary results from this testing demonstrated the potential of vertical air staging within the main windbox to augment overfire air. Testing was performed to quantify the coal size distribution and power requirements for one (1) conventional static and four (4) dynamic classifier designs. Results from this testing show the dynamic classifier capable of producing finer grinds of coal at lower relative power requirements.

Work on the preliminary design of the Proof-of-Concept Test Facility (Task 8) continued. The following technical activities were completed:

- Final process configuration.
- Preliminary set of general arrangement drawings.
- Heat balances for the existing turbine cycle.
- Composite gas-side and steam-side heat balances.
- Evaluation of the structural capability of the existing boiler house to support a new (replacement) boiler.
- The study to develop the retrofit approach for the new control system.
- The planning phase of the licensing work was essentially completed and the implementation phase was initiated. Implementation activities completed to date include (1) preparation of the first two NEPA compliance documents, and (2) submission of a letter to the state agency requesting guidance/clarification on key licensing issues.

The subsystem Test Plan for the low-NO_X firing system was approved by DOE. The subsystem Test Plan for the SNO_X Hot Process was submitted to DOE for approval.

TASK 1 - PROJECT PLANNING AND MANAGEMENT

All work in Task 1 and all Task 1 deliverables for the reporting period were completed on schedule. All monthlyStatus, Summary, Milestone Schedule, and Cost Management Reports were submitted on schedule.

Worked with DOE and team members on revised schedule/scope budget to work within the reduced FY95 funding and anticipated FY96 funding. Updated Management Plan (which contains the updated Work Plan), Cost Plan and Milestone Plan were issued.

ABBES and CeraMem agreed to working arrangements for Task 7. ABBES will proceed in partnership with CeraMem and EPRI on testing at Plant Miller. Also, agreement was reached on ownership and disposition of project-purchased equipment.

Technology Transfer:

- The ABB Team participated in the LEBS Workshop held in Atlanta on February 22. Irving Huffman, General Manager of Richmond Power & Light, gave a talk on Power Producing Views. Carl Bozzuto, Vice President Technology, ABB Boiler Business Area gave a talk on Market for Coal-Fired Plants. John Regan, ABB LEBS Project Director presented the ABB Team's work. Karl Zaccone, President of ABB C-E Services participated as a panel member.

- Delivered a LEBS paper at the 20th International Technical Conference on Coal Utilization and Fuel Systems entitled "Achieving Compliance with Advanced Coal-Fired Low-Emissions Boiler Systems." A copy of the paper is included as Appendix B.

- Preparations for the Technical Session - "DOE's Combustion 2000 Program - LEBS and HIPPS" at the 1995 IJPGC continued.

A project Review Meeting was held January 24, 1995 with senior management of ABB Combustion Engineering Systems.

TASK 7 - COMPONENT DEVELOPMENT AND OPTIMIZATION

SNO_X™ Hot Process

The Task 7 work plan was modified to fit the reduced budget. The plan does not cover development and demonstration of the SO_2 oxidation catalyst. It is expected that this effort will be replaced by previous work done by Haldor/Topsoe. Discussions were initiated and will continue with Haldor/Topsoe concerning the SO_2 oxidation catalyst. The scope of work was adjusted to focus on CeraMem/CeraNO_X development.

Agreement was reached with CeraMem concerning Task 7 work. ABBES will proceed in partnership with CeraMem and EPRI concerning testing at Plant Miller, a 200-acfm demonstration project. Actual testing is expected to occur mid-summer. Immediate tasks include construction of the test unit and development of the test plan.

ABBES collected information on operation and design of SCR deNO_X systems, ceramic filters, and ammonia injection systems and completed the first draft of Task 7 test plan and test rig design/engineering manual. (See Appendix C.)

Low-NO_X Firing System

The overall objective of the work is to develop an advanced firing system which reduces the NO_X emission levels leaving the primary furnace (at the furnace outlet plane) to 0.10 lb/MMBtu or lower while maintaining carbon in ash at 5% or less. As such, a work plan integrating the efforts of computational modeling, fundamental scale evaluation in the Fundamental Scale Burner Facility (FSBF), characterization of pulverizer system performance utilizing the Pulverizer Development Facility (PDF), and pilot scale testing in the Boiler Simulation Facility (BSF) was prepared and submitted to the DOE. A work flow chart for this scope is presented in Figure 1.

Computational Modeling: The TFS 2000™ arrangement of the BSF was set up and run computationally using FLUENT V4.31. Results from this evaluation were compared with results from both the FLUENT V3.0 solution and to experimental data previously taken in the BSF. Overall, version 4.31 appears to be better with enhancements to the grid set up and flow calculations, along with better particle dispersions while providing a reasonable comparison to the experimental data. Two (2) additional simulations of the BSF with 2-corner firing arrangements have also been set up and are currently running.

A kinetic evaluation on the effects of windbox staging (stoichiometry build up) on NO_X emissions was performed for both a baseline (MBZ stoichiometry = 1.15) and low NO_X (MBZ stoichiometry = 0.74) firing arrangement. Results from this evaluation indicate that the final reducing zone within the main windbox has a dominant effect on NO_X reduction, with higher temperatures being more favorable for lower NO_X. It is recognized that the kinetic evaluation makes assumptions, such as perfect mixing, which are not realistic. However, the qualitative trends are believed to be useful.

Advanced Fuel Staging / Coal Reburn: Combustion testing was performed to examine the impact of integrated fuel staging (NO_X reduction via the reburn mechanism), and to explore preliminary vertical staging concepts within the main windbox region. This testing was performed on the Fundamental Scale Burner Facility (FSBF), which was modified to allow for the evaluation of reburning through integrated advanced fuel staging scenarios. The furnace was configured to fire in a tangential firing mode, simulating the mixing history (residence time and temperature) of typical commercial utility applications. Four (4) elevations of overfire air were available to set the desired main burner zone (MBZ) stoichiometry and the level of global furnace air staging. A schematic of this facility, as tested, is shown in Figure 2. Testing was performed utilizing a combination of natural gas and coal firing, at a total furnace heat input rate of approximately 5.5 MMBtu/hour.

The objective of this fuel staging work was to determine the critical parameters (stoichiometry, heat input, residence time, etc.) with respect to coal injection that can improve upon the reburn NO_X reduction process, which occurs naturally as a result of having multiple elevations of coal in a utility boiler. To meet this goal, coal was injected at varied elevations above a natural gas fired "lower" main windbox region in order to isolate the influence of the coal on the upward flowing flue gas and its corresponding NO_X emissions. Results of this work are currently being evaluated and will be presented at a later date.

In addition to this fuel staging work, initial vertically staged main windbox configurations were evaluated. For this work, the main windbox region of the FSBF was configured with three elevations of coal spaced between four (4) elevations of auxiliary air nozzles. Each of the coal nozzles included an outer, annular fuel air region. Vertical air staging was accomplished by biasing the air injection among the four (4) auxiliary air nozzles over both globally staged and unstaged furnace conditions.

For the unstaged condition (MBZ stoichiometry = 1.11) with a uniform auxiliary air distribution, flue NO_X emissions were approximately 280 ppm @ 3% O_2 (74 ppm is equivalent to 0.1 lb/MMBtu). Biasing the auxiliary air vertically within the main windbox resulted in flue NO_X emissions of 166 ppm @ 3% O_2, a 40% reduction over the uniform auxiliary air distribution condition. Under globally staged conditions (MBZ stoichiometry = 0.78) with uniform auxiliary air distribution, flue NO_X emissions were 150 ppm @ 3% O_2. Biasing the auxiliary air within the main windbox resulted in NO_X emissions of 137 ppm, a 9% reduction over the uniformly distributed auxiliary air condition. A summary of these test results are presented in Table 1.

In summary, the results of this testing demonstrate the potential of vertical air staging within the main windbox to both augment and supplant overfire air as a means of in-furnace NO_X emissions control. Further activity is both warranted and planned to increase our understanding of the potential of this NO_X reduction method. Additional activities, including additional FSBF testing, related modeling activities, and subsequent BSF testing will seek to optimize the vertical staging in the main windbox region. Additional work will also be performed to investigate the impact of ultra-fine coal grind and horizontally staged (opposed corner) firing concepts.

Table 1 - Preliminary Results of Vertical Air Staging Testing in the FSBF

	Unstaged			Staged					
MBZ Stoich.	1.11	1.11	1.11	0.78	0.78	0.78	0.78	0.78	0.78
% of Total Aux Air									
Aux 1	25%	12%	21%	25%	33%	18%	25%	25%	18%
Aux 2	25%	12%	21%	25%	33%	18%	25%	25%	18%
Aux 3	25%	20%	11%	25%	17%	37%	15%	25%	37%
Aux 4	25%	51%	47%	25%	17%	27%	35%	25%	27%
SOFA 1 Stoich.	1.13	1.13	1.13	1.0	1.0	1.0	1.0	0.8	0.8
SOFA 2 Stoich.	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15
Flue NO_X (ppm @ 3% O_2)	**279**	**178**	**166**	**185**	**186**	**155**	**176**	**150**	**137**

Coal Pulverization: Testing on the PDF was performed to characterize various classifier designs for a typical ABB pulverizer. Included in these evaluations was the conventional static classifier, which represents the baseline technology for the LEBS firing system, along with four (4) advanced dynamic classifiers. These characterizations included quantifying coal size distribution and power requirements for each classifier. A summary of these results is presented in Table 2.

Computational Fluid Dynamic (CFD) simulations of these classifiers have been initiated. Results from these simulations will be utilized for the scale up of the results from the PDF to the full scale LEBS pulverizer.

The design of a stoichiometry control system, including air flow measurement and control to each of the four (4) main windboxes in the BSF, was initiated. This system is necessary to allow for accurate testing and evaluation of various vertically and horizontally staged concepts in the BSF.

Table 2 - Summary of Pulverizer Classifier Characterization

	Static Classifier	Dynamic Classifier Designation HP1	HP2	RB1	RB2
Finest Product Size (wt%)					
+50 mesh	0.1	0.2	0.0	0.0	0.0
+100 mesh	2.4	1.2	0.6	0.5	0.6
-200 mesh	84.3	85.7	92.7	93.1	90.7
Relative Power Requirements	100	81	98	97	107

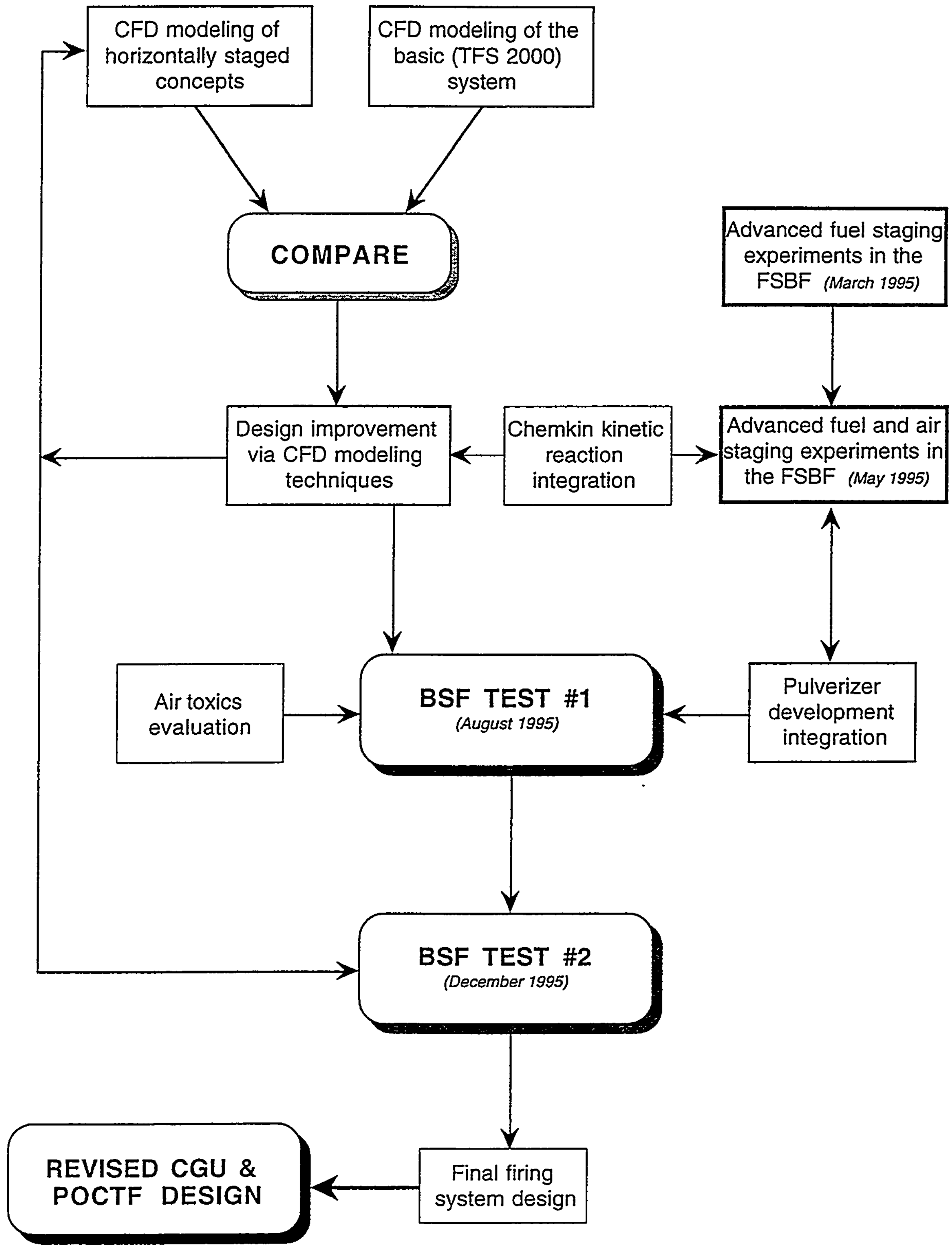


Figure 1 - LEBS Work Flow Chart

LEBS Flow Chart.rev02
04/03/95

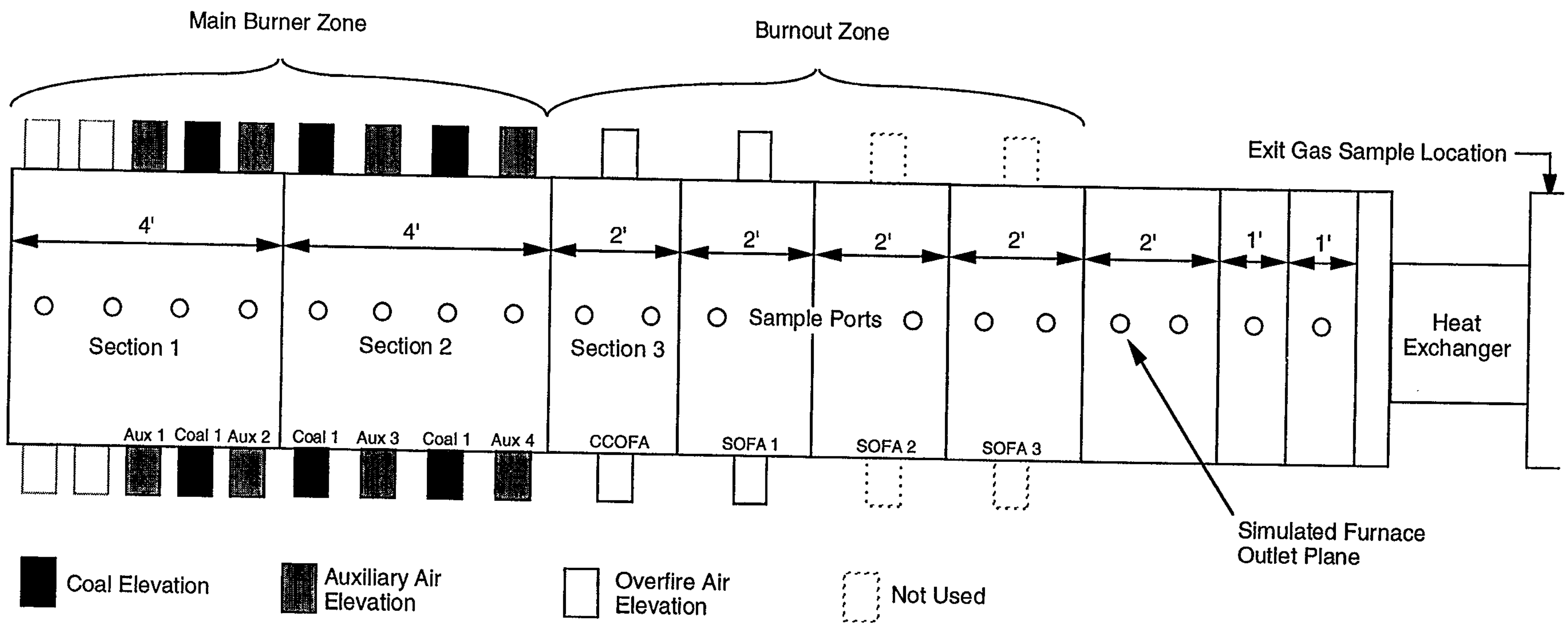


Figure 2 - Schematic of Fundamental Scale Burner Facility

TASK 8 - PRELIMINARY POC TEST FACILITY DESIGN

Site Selection

In the previous reporting period ABB CE formally accepted the Richmond Power & Light offer of Whitewater Valley Unit No. 1 as the host site for the Proof-of-Concept Test Facility.

Preliminary Design

The Work Plan for Task 8 was revised. The changes made to the original plan were primarily schedule related; no significant changes were made to the scope of work. With the exception of the licensing work, on-going preliminary design activities were brought to an orderly hold in February/March, and the balance of the work will be deferred to later this year. Work is scheduled to restart in August, with completion by the end of December. The licensing activities will continue as originally planned.

Process Configuration: The process arrangements that have been developed for the POCTF are shown in the process flow diagram - Figure 3.

Flue gas is discharged from the boiler at the economizer outlet, which is fitted with an economizer bypass arrangement so that the gas temperature can be maintained at the process-optimum value during part-load operation. Following passage through the (near-adiabatic) catalytic filter house and SO_2 reactor, initial heat recovery from the flue gas occurs in an air heater followed by an external economizer. Final cooling of the gas then occurs in the WSA condenser, where sulfuric acid collection also occurs. The ID fan takes suction on the gas-side of the condenser and discharges to the stack.

Process air, after discharge from FD fan, is used to first provide heat absorption in the WSA condenser. A portion of this air, that exceeds combustion air requirements, is discharged to the stack after heat recovery in a condensate heater unit. The balance of the process air receives final heat addition in the air heater and then provides primary and secondary combustion air requirements.

The function arrangement of the turbine system, with integration of the POCTF components, is shown in the turbine heat cycle diagram - Figure 4. The external economizer receives feedwater from the discharge of the last high pressure feedwater heater (No. 5), and following flow through the external economizer, the feedwater is then piped to the inlet of the boiler economizer. The condensate heater is supplied with condensate that is by-passed around the two low pressure feedwater heaters and then discharged into the deaerator.

General Arrangements: Preparation of a preliminary plot plan and general arrangement drawings was initiated, and then brought to an intermediate point of completion when the Task 8 work was rescheduled. This set of drawings, contained in Appendix D, is issued on a "work-in progress" basis for informational purposes.

Referring to the plot plan, the SNO_x hot process components will all be located in the yard west of the boilerhouse. The primary process components are the catalytic filter house, the SO_2 reactor, the combination air heater/economizer, the WSA condenser, and the condensate heater. These process components are, in turn, supported by the ammonia handling facility, the sulfuric acid handling facility, and an electrical building. The hot flue gas ductwork, from the boiler, leaves the boilerhouse above the existing limestone storage building and runs north, adjacent to the building wall, to the catalytic filter house. From here, the gas is ducted southward through the SO_2 reactor, air heater/economizer and WSA condenser, respectively. The ID fan is located adjacent to the condenser, taking suction on the gas discharge from this component. The flue gas is then ducted eastward, back to the boilerhouse, where the ductwork is elevated to the roof such that it will tie to the existing gas ductwork leading to the stack.

The FD fan is also located adjacent to the WSA condenser. The air discharged from the fan is first ducted through the condenser, then over to the air heater, and is finally sent to the boilerhouse. The hot air ductwork is arranged to take advantage of a duct-over-duct configuration to minimize support steel requirements, and enters the boilerhouse on the west wall, in the bay that houses the coal bunkers and mills.

The ammonia handling facility is located on the north side of the filter house, and provides for truck delivery of ammonia as well as ammonia feed to the inlet ductwork of the filter house. The sulfuric acid handling facility is located adjacent to the acid production component (e.g., the WSA condenser), and provides for acid storage and truck loading. The electrical building is a single-story frame structure and is composed of four rooms to house electrical distribution equipment, electrical support equipment, I/O cabinets and controls components, and a digital instrument repair shop.

Existing Turbine Heat Balances: Accurate knowledge of the existing turbine heat balances is a key element of the facility design because

- the interface of the new components to the existing turbine system establishes overall component sizing and
- the turbine heat cycle is used to absorb the incremental SNO_X heat recovery.

Since up-to-date heat balances were not available for the Unit 1 turbine (as a result of a turbine re-build in 1991), Raytheon worked with the original equipment manufacturer (General Electric) to establish this performance data. The resulting set of existing turbine heat balances, and an accompanying memo, are contained in Appendix E.

Heat and Mass Balances: An initial gas-side heat balance was prepared for the boiler maximum continuous rating (MCR) operating point with the design coal (Ill. No. 6). The operating conditions so defined provide the equipment design-basis requirements. To insure that the turbine is the limiting component in the power cycle, the boiler MCR steam flow is typically specified as a few percent larger than the maximum turbine steam flow.

Composite heat balances, consisting of gas-side and steam-side balances at specific turbine operating points were the next to be prepared, using both the design coal and the performance coal (Black Beauty). To date, these calculations have been completed at the maximum turbine operating point (valves wide open, 5% overpressure).

The heat balance diagrams, and a corresponding memo, are contained in Appendix F.

Boilerhouse Structural Evaluation: One of the approaches being considered for the POCTF configuration is to demolish the existing wall-fired Unit 1 boiler and to install a new corner-fired boiler that incorporates the advanced firing system. The new boiler would be installed in the existing boilerhouse.

To support the evaluation of this option, a structural analysis was conducted to assess the feasibility of supporting a new boiler in the existing boilerhouse. This study involved evaluation of the foundations and boiler support steel. New boiler (dead) loads were developed, and live loads and other design requirements were established per the current BOCA code.

It was found that the boilerhouse pile foundations are adequate for the new loads. However, the imposition of modern seismic loads will require that the existing pinned connections on the horizontal boiler-steel members will have to be modified to provide moment-type connections; some horizontal members may have to be modified or replaced also. These changes are required to limit horizontal (seismic-induced) deflections to within acceptable values.

Controls Retrofit Approach: The controls work for the facility was initiated with a study to determine the approach to be used to retrofit the new control system components. Specifically, the objectives were to

- define the modified control system architecture,
- develop a preliminary estimate of the I/O count, and
- develop a preliminary physical arrangement for the new control components.

The resulting study report is contained in Appendix G. It was recommended that a partial replacement of the existing Unit 1 controls with a distributed control system (DCS) be implemented, as follows:

- new controls
  - boiler system
  - SNO_X system
  - test facility BOP

- retain existing controls
  - turbine system
  - unit auxiliary systems
  - substation

In addition, it was determined that the operator station for the new control package would be located in the existing control room and two different options were developed for locating the control console and I/O cabinets. Details are described in the study report (Appendix G).

Cost Estimates: For study purposes, order-of-magnitude project cost estimates were prepared by Raytheon for the following POCTF configurations at Whitewater Valley station:

- Base Case: new boiler and SNO_X system for Unit 1.
- Option 1: low NO_X burner system (retrofit to the existing boiler) and SNO_X system for Unit 1.
- Option 2: new firing system (retrofit to the existing boiler) and SNO_X system for Unit 2; re-duct the LIFAC system from Unit 2 to Unit 1.

These estimates were developed by first having ABB CE and ABBES prepare budgetary estimates for the boiler system supply and SNO_X system supply, respectively. The sum of these two systems represents the large majority of all process equipment in the project. With the process equipment cost as a basis, the costs for other systems (e.g., electrical, BOP mechanical), as well as bulk materials (e.g., piping, foundations wiring, etc.), were then factored from similar projects. These cost estimates will be reviewed in the next reporting period and one configuration will be selected.

ABBES accomplished the following in support of the design effort:

- Issued final instrumentation and motor list.
- Issued final process and instrumentation diagrams.
- Completed equipment general arrangement drawing.
- Completed equipment design and purchased equipment specification.
- Completed construction summary.
- Completed and issued control description, control diagrams, and electrical diagram.

- Completed equipment weight and equipment loadings.
- Estimated plant cost for scope of supply per Raytheon's SNO_X system specification.

(Similar information on the firing system and boiler were prepared in the previous reporting period.)

Licensing

During this reporting period, the planning phase of the licensing work was essentially completed and the implementation phase was initiated.

Planning: Following discussions with RP&L's environmental counsel, an initial licensing meeting was held with the Indiana Department of Environmental Management (IDEM). The meeting served to introduce IDEM personnel to the LEBS POCTF project at Whitewater Valley Station, and to open a dialogue concerning the licensing issues that will require their input to resolve. In particular, a list of six key issues was tabled at the meeting by the project team:

- will the project trigger a PSD (prevention of significant deterioration) permit?
- assuming that PSD is triggered, can this project be exempted on the basis of a pollution control project?
- are there SO_2 nonattainment plan requirements?
- does NSPS (new source performance standards) apply?
- if PSD applies, what will be required in the permit application?
- what will the permitted emission limits be for the project?

The IDEM personnel could not respond directly to these questions, but requested that they be submitted in writing to them for in-depth consideration. However, the overall discussion did clarify a number of other issues, such that a preliminary list of required permits could be established (Table 3) and a licensing schedule could be developed (Figure 5). Most of the remaining uncertainty with regards to permitting requirements is associated with the PSD permit.

Implementation: In reference to the licensing schedule, the following activities have been completed:

- NEPA Compliance
    - The DOE Environmental Questionnaire has been completed and submitted to DOE.
    - A draft of the Environmental Information Document (EID) has been completed and is now in review.
- The formal letter to IDEM, requesting response on the six licensing issues, has been prepared and submitted to IDEM (2/15/95).

Further progress on the licensing tasks is now almost completely dependent on receiving a response from IDEM to the 2/15/95 letter.

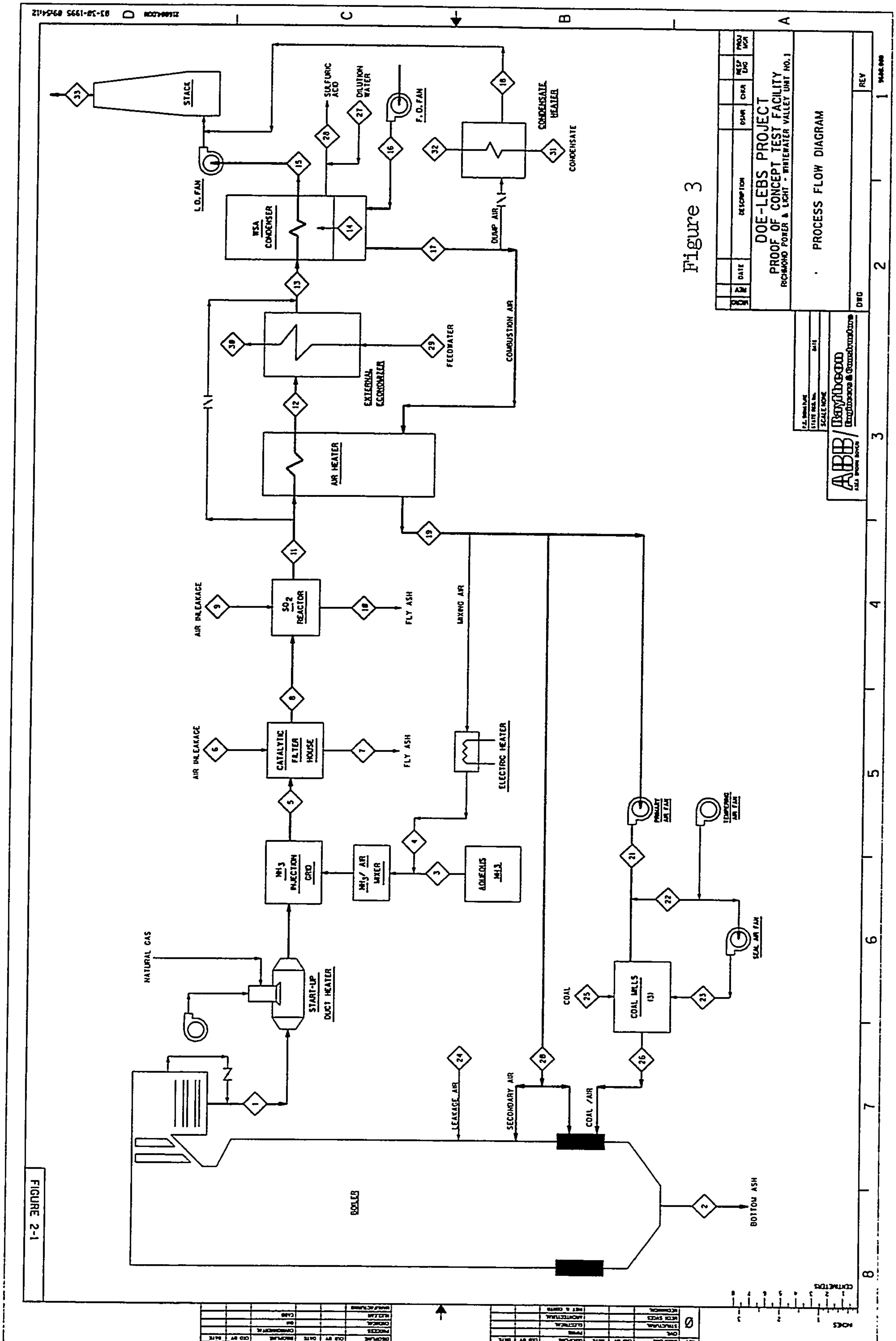
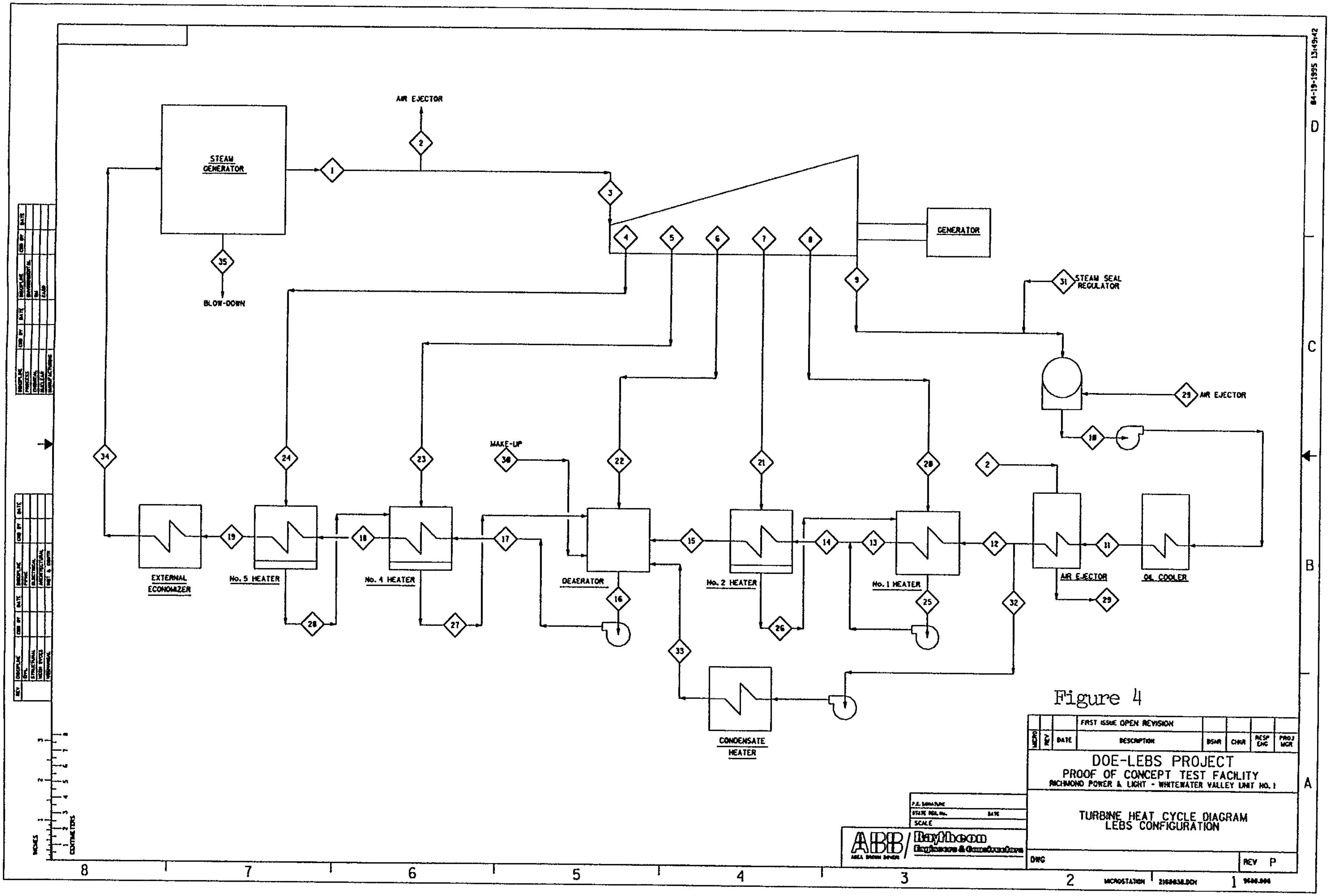


FIGURE 2-1
BOILER
BOTTOM ASH
LEAKAGE AIR
SECONDARY AIR
COAL /AIR
NATURAL GAS
START-UP DUCT HEATER
NH_3 INJECTION GRID
NH_3/ AIR MIXER
AQUEOUS NH_3
CATALYTIC FILTER HOUSE
AIR INLEAKAGE
FLY ASH
SO_2 REACTOR
ELECTRIC HEATER
MIXING AIR
COAL MILLS (3)
COAL
PRIMARY AIR FAN
TEMPERING AIR FAN
SEAL AIR FAN
AIR HEATER
EXTERNAL ECONOMIZER
FEEDWATER
COMBUSTION AIR
WSA CONDENSER
I.D. FAN
STACK
SULFURIC ACID
DILUTION WATER
F.D. FAN
DUMP AIR
CONDENSATE HEATER
CONDENSATE
DOE-LEBS PROJECT
PROOF OF CONCEPT TEST FACILITY
RICHMOND POWER & LIGHT - WHITEWATER VALLEY UNIT NO.1
PROCESS FLOW DIAGRAM
ABB/Raytheon
Figure 3



STEAM GENERATOR
AIR EJECTOR
BLOW-DOWN
GENERATOR
STEAM SEAL REGULATOR
AIR EJECTOR
MAKE-UP
EXTERNAL ECONOMAZER
No. 5 HEATER
No. 4 HEATER
DEAERATOR
No. 2 HEATER
No. 1 HEATER
AIR EJECTOR
OIL COOLER
CONDENSATE HEATER
FIRST ISSUE OPEN REVISION
DOE-LEBS PROJECT
PROOF OF CONCEPT TEST FACILITY
RICHMOND POWER & LIGHT - WHITEWATER VALLEY UNIT NO. 1
TURBINE HEAT CYCLE DIAGRAM
LEBS CONFIGURATION
ABB/Raytheon
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Figure 4

Table 3

ABB LOW - EMISSION BOILER SYSTEMS PROJECT AT RICHMOND POWER & LIGHT - WHITEWATER VALLEY UNIT 1

LIST OF PERMITS AND APPROVALS

1. ENVIRONMENTAL ASSESSMENT REPORT For DOE Leading To:
    - CATEGORICAL EXCLUSION or
    - FINDING OF NO SIGNIFICANT IMPACT or
    - ENVIRONMENTAL IMPACT STATEMENT
2. (PREVENTION OF SIGNIFICANT DETERIORATION PERMIT)
3. (NONATTAINMENT PROVISION PLAN APPROVAL)
4. INDIANA AIR CONTROL BOARD CONSTRUCTION AND OPERATING PERMITS
5. 1990 CAAA - TITLE V AIR POLLUTION PERMIT MODIFICATION
6. (STATE WATER POLLUTION TREATMENT FACILITY PERMIT)
7. (STATE INDUSTRIAL WASTE PRETREATMENT PERMIT)
8. NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM PERMIT For Process Wastewater Discharges and Storm Water Runoff
9. HAZARDOUS SUBSTANCES POLLUTION CONTINGENCY PLAN
10. SOIL EROSION AND SEDIMENT CONTROL PLAN
11. LOCAL PLANNING BOARD APPROVAL
12. LOCAL BUILDING PERMIT
13. FIRE MARSHAL CERTIFICATION

NOTE : Parentheses indicate that this permit or approval may not be needed for the project.

Form 5007 (Rev. 4/93)

Raytheon
Engineers & Constructors

GENERAL COMPUTATION SHEET

CALCULATION SET NO.			REV.	COMP. BY	CHK'D BY
			0	DJB	
PRELIM.	FINAL	VOID		DATE 1-26-95	DATE
SHEET 1 OF				DATE	DATE
J.O. 9680.008					

PROJECT LEBS POCTF

SUBJECT

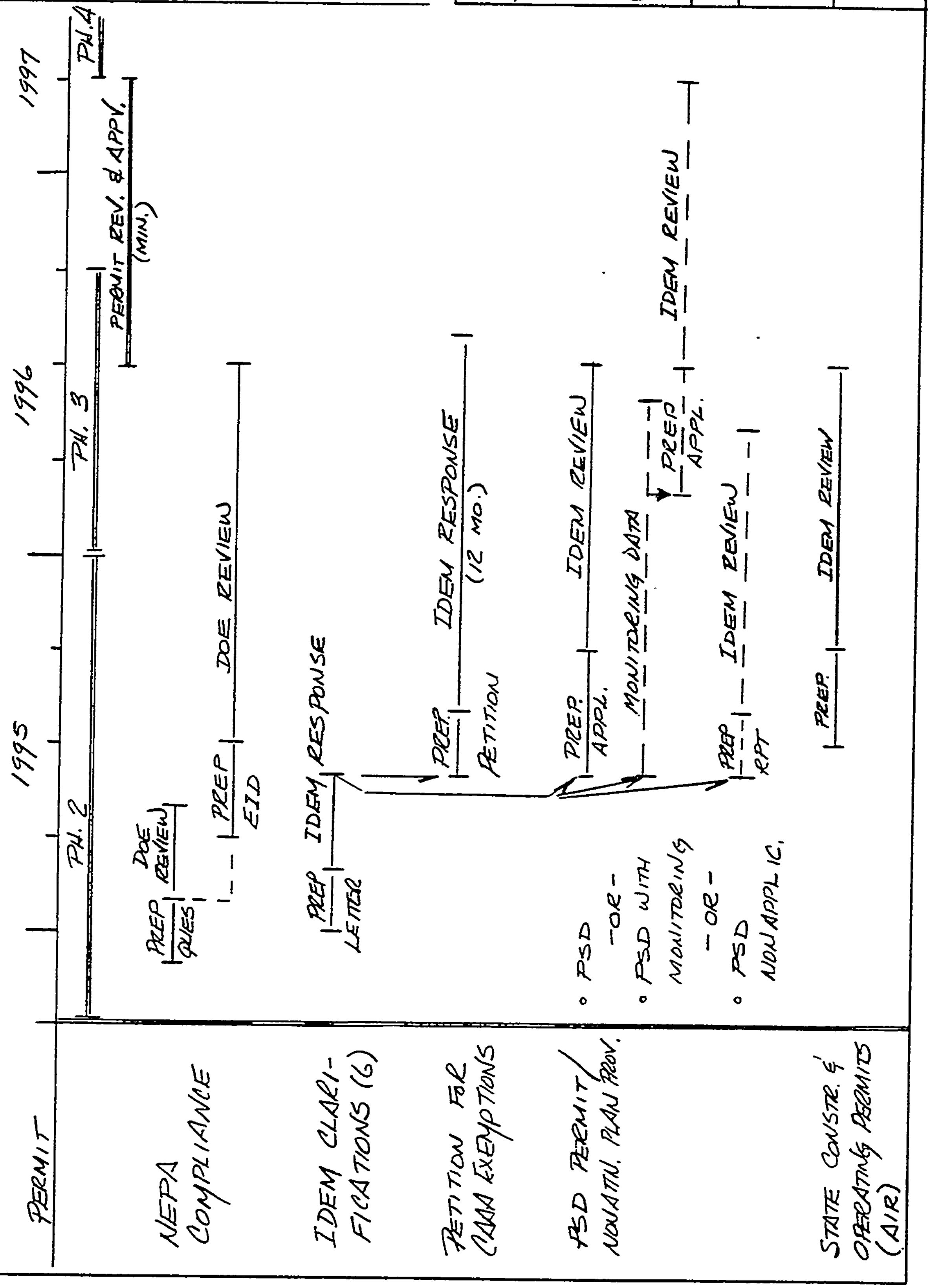

Figure 5
Sheet 1 of 2

Form 5007 (Rev. 4/93)

Raytheon Engineers & Constructors

GENERAL COMPUTATION SHEET

CALCULATION SET NO.	REV.	COMP. BY	CHK'D BY
	0	DJB DATE 1-25-95	DATE
PRELIM. / FINAL / VOID		DATE	DATE
SHEET 2 OF 2			
J.O. 9680.008			

PROJECT LEBS POCTF

SUBJECT

LICENSING SCHEDULE

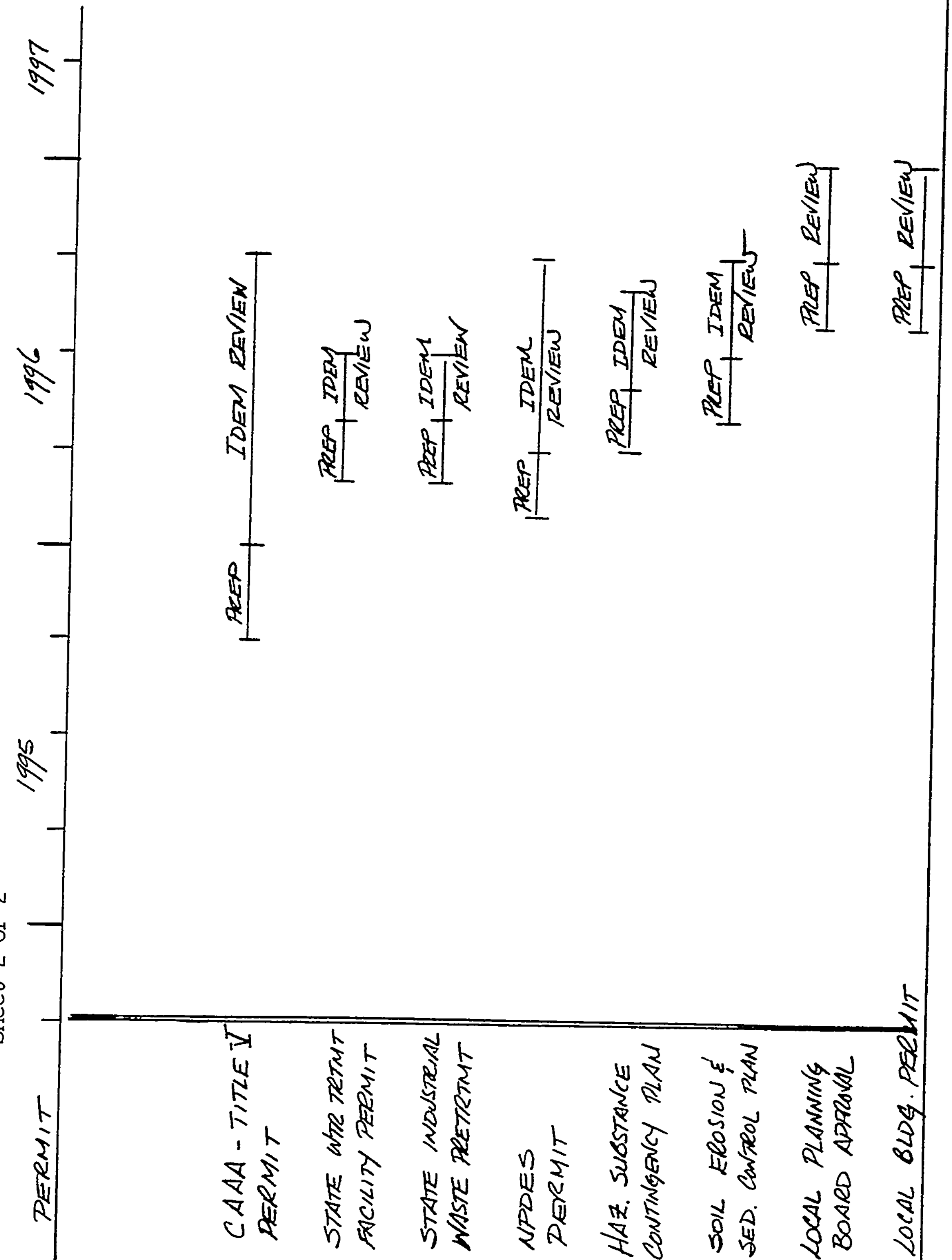

Figure 5
Sheet 2 or 2

TASK 9 - SUBSYSTEM TEST DESIGN AND PLAN

SNO_X Hot Process

Subtask 9.1 - Subsystem Test Unit Design was started by CeraMem.

A draft of the 9.2 Test Plan was submitted to DOE.

Low-NO_X Firing System

A revised NO_X control subsystem test plan was complete and submitted to the DOE for review. This plan is generally unchanged from the original plan, providing for two (2) weeks of testing in the BSF to allow for the evaluation of advanced low NO_X tangential firing systems concepts.

The design of a stoichiometry control system, including air flow measurement and control to each of the four (4) main windboxes in the BSF, was initiated. This system is necessary to allow for accurate testing and evaluation of various vertically and horizontally staged concepts in the BSF.

PLANS FOR NEXT QUARTER

Submit updated cost estimate for Phase IV.

Hold Project Review Meeting for PETC and the POCTF host at the host site.

Submit technical papers for:

- Eleventh Annual Coal Preparation, Utilization, and Environmental Control Contractors Conference (July 9-11, 1995 - Pittsburgh).
- Twelfth Annual International Pittsburgh Coal Conference (September 11-15, 1995 - Pittsburgh).
- 1995 International Joint Power Generation Conference (October 9-11, 1995 - Minneapolis).

Continue Task 7 work and licensing activities for the POCTF (Task 8).

Complete Task 9 and initiate Task 10.

APPENDIX A

DOE F1332.3
(11-84)

U.S. DEPARTMENT OF ENERGY

MILESTONE SCHEDULE ☒ PLAN ☒ STATUS REPORT

FORM APPROVED
OMB 1901-1400

1. TITLE
Engineering Development of Advanced Coal-Fired Low-Emission Boiler Systems - Phases II & III

2. REPORTING PERIOD
Oct. 1, 1994 - Mar 31, 1995

3. IDENTIFICATION NUMBER
DE-AC22-92PC92159

4. PARTICIPANT NAME AND ADDRESS
Combustion Engineering, Inc.
P.O. Box 500
Windsor, CT 06095-0500

5. START DATE
October 1, 1994

6. COMPLETION DATE
September 30, 1996

7. ELEMENT CODE	8. REPORTING ELEMENT	10. PERCENT COMPLETE: Plan	10. PERCENT COMPLETE: Actual
	PHASE II		
1.0	Prj Mgt	25	25
7.0	Comp Dev	41	35
8.0	POCTF		
8.1	Site Sel	100	100
8.2	Pre Dsn	33	22
9.0	Subsyst		
9.1	Design	75	75
9.2	Plan	65	75
10.0	Constr	4	0
11.0	Subsyst		
11.1	Oper	0	0
11.2	Test Ev	0	0
11.3	Dsn Ev	0	0
12.0	Draft Report	0	0

9. DURATION: FY95 (OCT NOV DEC JAN FEB MAR APR MAY JUNE JULY AUG SEPT), FY96 (OCT NOV DEC JAN FEB MAR), FY, FY

11. SIGNATURE OF PARTICIPANT'S PROJECT MANAGER AND DATE
John W. Regan APR. 10, 1995

DOE F1332.3
(11-84)

U.S. DEPARTMENT OF ENERGY

MILESTONE SCHEDULE ☒ PLAN ☐ STATUS REPORT

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	PHASE III										
1.0	Prj Mgt										
13.0	CGU Dsn						Δ				
14.0	POCTF										
14.1	Rev Dsn						Δ				
14.2	Test Plan						Δ				
15.0	Report						Δ				

11. SIGNATURE OF PARTICIPANT'S PROJECT MANAGER AND DATE

APPENDIX B

ACHIEVING COMPLIANCE WITH ADVANCED COAL-FIRED LOW-EMISSION BOILER SYSTEMS

John W. Regan
Richard W. Borio
Michael J. Hargrove
Mark Palkes
ABB Power Plant Laboratories
Combustion Engineering, Inc.
Windsor, Connecticut

James D. Wesnor
ABB Environmental Systems
Birmingham, Alabama

Robert S. Kaminski
Raytheon Engineers & Constructors
Philadelphia, Pennsylvania

(Presented at 20th International Technical Conference on Coal Utilization and Fuel Systems, March 23, 1993)

ABSTRACT

The paper reports on ABB's work in Phase I of the U.S. Department of Energy (DOE) project "Engineering Development of Advanced Coal-Fired Low-Emissions Boiler Systems" (LEBS) which is part of the DOE's Combustion 2000 Program. Work planned for future Phases is also described.

The overall objective of the LEBS Project is to dramatically improve environmental performance of future coal-fired power plants without adversely impacting efficiency or the cost of electricity. Near-term technologies, i.e., advanced technologies that are partially developed, will be used to reduce NO_X and SO_2 emissions to one-third current NSPS limits and particulates to one-half current NSPS limits. Air toxics must be in compliance. Waste must be reduced and made more disposable.

The work in Phase I included concept development and evaluation of several subsystems for controlling the emission of SO_2, NO_X, and particulates. Candidate technologies were then evaluated in various combinations as part of complete advanced supercritical power generation systems. One system was selected for preliminary design of a commercial generating plant.

INTRODUCTION

Combustion Engineering, Inc. (ABB CE) is one of three contractors for the US Department of Energy (DOE) Project titled "Engineering Development of Advanced Coal-Fired Low-Emission Boiler Systems". The overall objective of the Project is the expedited commercialization of advanced coal-fired low-emission boiler systems. The specified primary objectives are emissions of NO_X and SO_2 less than one-third New Source Performance Standards (NSPS), particulates less than one-half NSPS, and air toxics in compliance. Secondary objectives are improved ash disposability, reduced waste generation, and increased generating efficiency. All primary, and all or some secondary objectives must be met without increasing the cost of electricity from a current

"NSPS plant". Because emission requirements vary from site to site, ABB elected to have two NO_X targets (the contract target and approximately one quarter of that) and to favor SO_2 and particulate control technologies which can be designed for emission levels lower than the contract targets with minimum impact on costs. The final Project deliverables are a design data base that will allow future coal-fired power plants to meet the stated objectives and a preliminary design of a commercial generation unit (CGU).

In addition to the DOE - Pittsburgh Energy Technology Center, the project is being managed by ABB Power Plant Laboratories Division of Combustion Engineering, Inc. (ABB CE) as the contractor and the work is being accomplished and/or guided by this contractor and the following team members:

- ABB CE (NO_X, efficiency, waste disposability, cost of electricity)
- ABB Environmental Systems (SO_2, particulates, waste reduction)
- Raytheon Engineers and Constructors (Plant-wide evaluations, cost of electricity, A/E)
- Technical Consultants and Industry Advisors

SELECTION OF TECHNOLOGIES

The first major technical effort was concept development. The process began with the selection of coals and identification of candidate technologies through literature search and in-house sources. The team selected those candidates judged to have the potential of meeting the Project's primary objectives and one or more of the secondary objectives and to become commercially feasible within the Project's timeframe. Commercial feasibility in this sense encompasses not only technical and economic feasibility but also acceptance by the utility industry.

Near-term technologies were screened to identify those that best fit the criteria described above. From the remaining candidates, rough economic comparisons were made to compare system installation costs and annualized operation and maintenance costs. Five SO_2/particulate and five NO_X candidates were selected and subjected to comprehensive technical assessment and systems analysis and a "short list" was developed. Finally, six combinations of the short-listed subsystems were evaluated for technical, economic, and commercial feasibility as integral parts of an advanced supercritical power generation system.

Three test coals were selected and one was identified as the design coal to serve as the baseline test coal. The remaining test coals will be used in R&D and testing to determine process sensitivities to variations in coal characteristics. The test coals were selected so that the results of the engineering development work will be broadly representative of large classes of US coals whose current production is extensive, with significant remaining minable and uncommitted reserves. The sulfur content of the design coal, on entering the boiler, is at least three pounds of sulfur per million Btu. Illinois No. 6, Pittsburgh No. 8, and Upper Freeport were selected to be the project test coals and Illinois No. 6 will be the design coal.

The next step in the process was to select the plant steam cycle. A comprehensive evaluation was carried out which compared a conventional subcritical cycle with throttle conditions of 2400 psig/1000°/1000° to an advanced supercritical cycle with throttle conditions of 4500 psig/1100°/1100/1100°. The supercritical cycle was selected because of its higher plant efficiency. This not only provides performance improvements but it will reduce the amount of pollutant produced per kilowatt of electricity generated, regardless of the emissions technologies involved. The steam generator and turbine generator performance and cost values support this selection.

TECHNOLOGIES

Using the methodology described above, the team developed the following short list of subsystem technologies:

NO_X Control:

*1. Advanced Tangential Firing.
*2. Coal Reburn.
*3. High-temperature SNCR
*4. Catalytic Filter (fabric or ceramic).
5. SCR for cost comparison.

* Selected for systems analysis.

SO_2/Particulate Control:

*6. Advanced Wet Limestone Scrubber with EP or FF.
*7. Thioclear Scrubber with EP or FF.
*8. SNO_X™ Hot Process.
9. Catalytic Baghouse with WSA Tower.
10. Catalytic Baghouse with Wet Scrubber.

These subsystem technologies were evaluated as integral parts of these six advanced supercritical power generation systems.

1. Advanced Burners, Advanced Wet Limestone FGD, Advanced Electrostatic Precipitator.
2. Advanced Burners with Coal Reburn, Advanced Wet Limestone FGD, Advanced Electrostatic Precipitator.
3. Advanced Burners with High-Temperature SNCR, Advanced Wet Limestone FGD, Advanced Electrostatic Precipitator.
4. Advanced Burners, Thioclear FGD, Advanced Electrostatic Precipitator.
5. Advanced Burners, SNO_X™ Process.
6. Advanced Burners, SNO_X™ Hot Process.

Contractors were required to select one system as the basis for the commercial generating unit (CGU) design. Since all the primary and secondary objectives can be met by each of the six systems, the main evaluation criteria came down to the potential for commercial success and the cost of electricity. Based on evaluation of these concepts, the Team selected the SNO_X™ Hot Process (System 6). This system is described schematically in Figure 1.

However, for the following reasons none of the short listed subsystem technologies were abandoned: (1) They may be more suitable for a particular project or customer. (2) They may become commercially available sooner. (3) They would be fallbacks if a selected technology

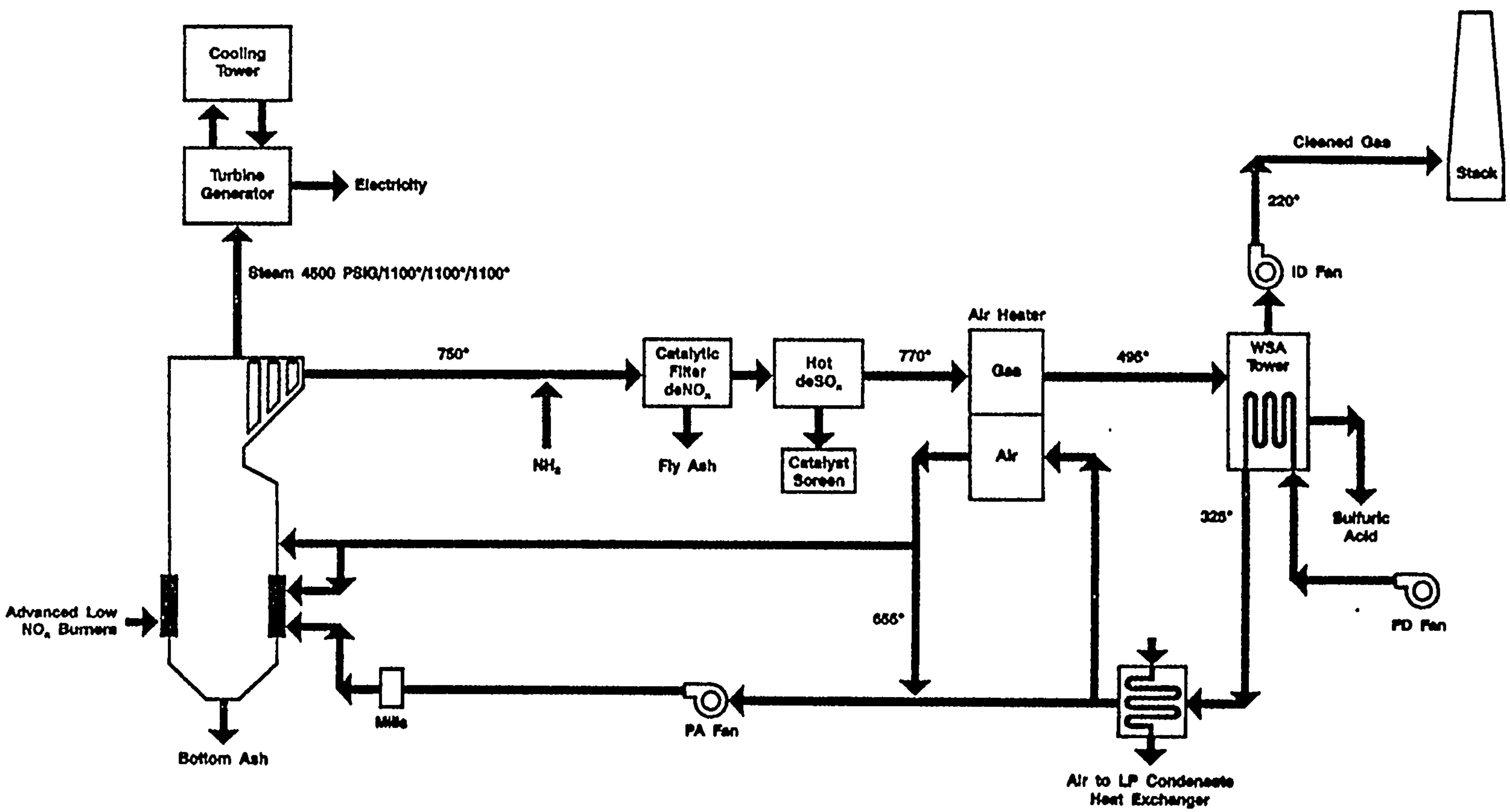


Figure 1 System Diagram

proves unsuccessful. (4) There is insufficient information to reject or select some of them at this time. (5) Their development will continue under other programs. (6) The requirement that air toxics be "in compliance" is undefinable at this time since regulations have not been established. Therefore, control technologies cannot be fixed. It is entirely possible that the final output of the Project is one system design with a menu of options for emission control subsystems.

A specific ash disposal technology was not selected. Because the choice is highly site-specific, the team only identified and assessed candidate technologies and reduced the list to three: (1) Chemical fixation with lime for stabilized landfill. (2) Production of lightweight aggregate from flyash. (3) Vitrification. The latter two are being commercialized under other projects and all three will remain as an option in future work on this Project.

Brief descriptions of each selected subsystem incorporated into the CGU design follow.

Advanced Tangential Firing. This combustion system is the basis of the low NO_X approach for the continuing evolution of tangential firing. Pilot-scale tests have demonstrated NO_X emissions below the Project's target with reasonable carbon loss. This technology will continue to be developed and advances will be applied to this Project as they evolve. The Project supports expanding the data base, component development, and system evaluations.

Catalytic Filter. The catalytic filter with SCR catalyst is an integral step in the SNO_X™ systems. (See below.) Also, post combustion NO_X reduction will facilitate an alternate, lower NO_X emission goal. The two candidate designs are the CeraMem™ catalytic ceramic filter and the University of North Dakota - Energy and Environmental Research Center catalytic fabric filter. Both are expected to be available prior to the LEBS commercial-readiness target date. The CeraMem™ filter was selected for the CGU design.

SNO_X™ Hot Process. The SNO_X™ (Sulfur and Nitrogen Oxide Reduction) technology utilizes two catalytic reactors to control NO_X and SO_2 in the flue gas stream. No sorbents are added and no sludge is formed. The process is capable of greater than 97% SO_2 removal, 80-90% NO_X removal and additional particulate removal while producing commercial grade sulfuric acid and useable heat. The process was developed in the early 1980's and has been successfully tested in Europe and Asia in pilot scale units as well as on a full scale 310 MWe coal-fired unit Denmark. In the United States, it was demonstrated under DOE's Clean Coal Program as a 35 MWe slipstream facility on a Ohio utility unit burning high-sulfur coal. Following successful demonstration, the host utility elected to continue operation on a commercial basis. The by--product sulfuric acid is sold locally.

The SNO_X™ Hot Process is an adaptation of the SNO_X Process that, by taking advantage of a high temperature (750°F) CeraMem™ catalytic filter with integral NO_X SCR catalyst, allows process simplification with reduction in capital equipment as well as an improvement in the thermal efficiency of the steam cycle. (See Figure 1.) The process is expected to achieve greater than 97% SO_2 removal and 80% NO_X removal. The CeraMem™ filter is the least "near-term" of all the technologies selected and the fallback is the high temperature fabric filter.

THE COMMERCIAL GENERATING UNIT DESIGN

The nominal 400 MWe Commercial Generating Unit (CGU) illustrated in Figure 2 is an adaptation of a conventional pulverized coal-fired steam-electric plant in which selected technologies have been introduced to achieve reduced levels of airborne emissions, increased thermal efficiency, reduced waste and improved costs. These technologies involve primarily three areas:

- An advanced low-NOx combustion system in the furnace that limits NO_X concentrations in the flue gas leaving the steam generator to 0.2 lb/MMBtu.
- The SNO_X™ Hot Process integrated with a ceramic-element gas filtration system. Here, particulates are separated, NO_X concentrations are further reduced, and SO_2 is removed from the flue gas in the form of a commercial grade sulfuric acid by-product.
- Advanced supercritical boiler and turbine with throttle conditions of 4500 psig, 1100°/1100°/1100°.

This combination of emission control processes meets or betters all of the target emission levels for the LEBS Project, while producing either benign or saleable by-products from the gas treatment. The advanced steam cycle and the SNO_X™ Hot Process enable the design to meet the efficiency objective and, indirectly, the cost of electricity objective.

The design and economic bases are summarized in Table 1. The design coal analysis is given in Table 2.

Table 2 - **Midwestern Bituminous Coal Analysis, as-received (Illinois No. 6)**

Proximate Analysis, %		Ultimate Analysis, %	
Moisture	12.0	Moisture	12.0
Volatile Matter	33.0	Carbon	57.5
Fixed Carbon	39.0	Hydrogen	3.7
Ash	16.0	Nitrogen	0.9
	100.0	Chlorine	0.1
		Sulfur	4.0
Higher Heating Value, Btu/lb	10,400	Oxygen	5.8
Grindability, Hardgrove	56.0	Ash	16.0
			100.0

The CGU design includes all of the structures, equipment and material for a complete power plant. This includes the steam generation, electricity generation, and pollution control systems. It also includes fuel storage and handling systems, cooling water and service water systems, and the switchyard.

LEGEND	
No.	DESCRIPTION
1	BOILER BUILDING
2	CERAMEM FILTER HOUSE
3	SO_2 REACTOR
4	FIRST STAGE ECONOMIZER
5	AIR HEATER
6	CONDENSATE HEAT EXCHANGER
7	WSA CONDENSERS
8	ID FANS
9	ID FAN

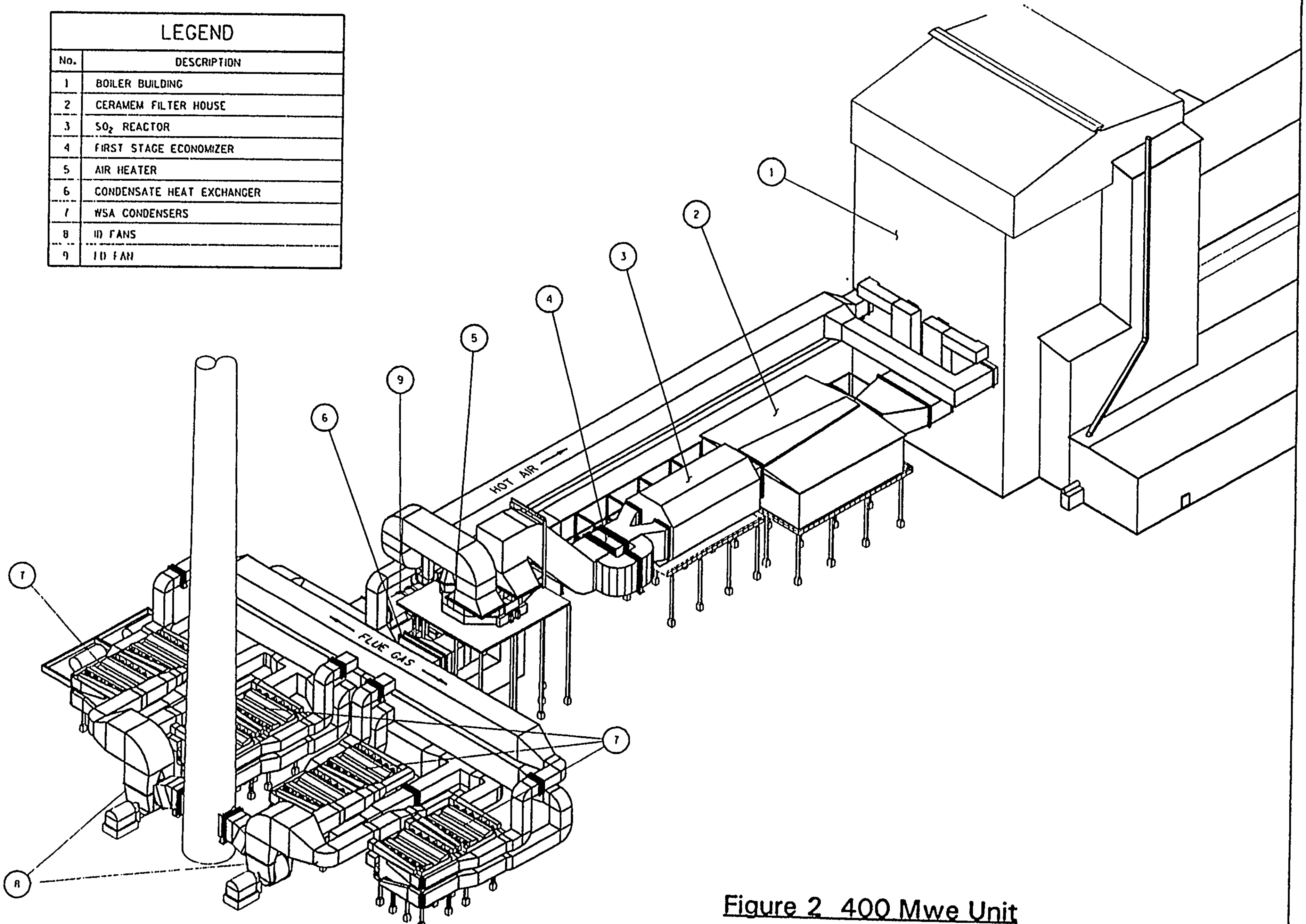


Figure 2 400 Mwe Unit

Table 1 - CGU Design Bases

GENERAL	
Site	Kenosha, WI
Number of Units	One
Net Plant Heat Rate (Btu/kWh)	8305 (2.5" Hg)
Net Plant Efficiency (%)	41.1
Net Power Output at Rated Load (MWe)	408.1 at Step-Up Transformer
Fuel	Illinois No. 6
CIVIL/STRUCTURAL	
Boiler and Turbine Building	Enclosed
Foundations	Spread Footings
MECHANICAL	
Forced Draft Fans	One, motor driven
Induced Draft	Two, motor driven
Primary Air	One, motor driven
Coal Delivery	100 Car Unit Train at 5 hour Nominal Turnaround
Coal Storage	90 Days at Rated Load, 8 hours in Silos
Coal Handling System	Track Hopper, Lowering Well, Crusher, Boiler House Transfer Tower, Trippers
Pulverizers (Total/Spares)	5/1
Stack	500 feet
Waste Disposal	Ash is Trucked Off-Site
Turbine-Generator	
a. Configuration	Tandem-Compound 2-Flow
b. Speed (RPM)	3600
c. Last Stage Blade Length (in)	33.5
Gross Turbine-Generator Output at 2.5 in-HgA (MWe)	428
Condensers	
a. Type	Single Pressure
b. Shell/Divisions per Shell	2/1
c. Arrangement	Longitudinal
d. Number of Passes	Two
e. Pressure (in-HgA)	2.5
Cooling Tower	
a. Type	Natural Draft Wet Evaporative
b. Number/Total Flow-Normal (gpm)	1/171,200

Cooling Tower Conditions (Design)	
a. Approach (°F)	16
b. Range (°F)	20
c. Wet Bulb (°F)	67
Feedwater Pumps	
a. High Pressure (number/Drive)	1/Main Turbine Shaft
b. Other (Number/Service/Drive)	1/Booster/Motor l/Start-Up Motor
Feedwater Heaters	
a. Open Stages (Number)	One
b. High Pressure Closed Stages (Number/Number Trains)	2/1
c. Intermed. Pressure Closed Stages (Number/Number Trains)	2/1
d. Low Pressure Closed Stages (Number/Number Trains)	4/1
e. Air to Condensate Heat Exchanger	One

ELECTRICAL

Connection to Off-site Power (No./kV)	2/230
Generator	
a. Rating (MVA)	500
b. Voltage (kV)	24
c. Power Factor	0.9
d. H_2 Pressure (psig)	45
Generator Disconnect	Bolted Disconnect Links
Auxiliary Power System	
a. Medium Voltage System A (kV)	6.9
b. Low Voltage System (V)	480
c. Direct Current Systems (V)	250/125
Station Service Transformers Nameplate Rating (MVA)	20/24
Unit Auxiliary Station Transformers Nameplate Rating (MVA)	20/24
Natural Gas Engine-Generator Unit	
a. Type/Number	High Speed/1
b. Voltage (V)	480
c. Rating (kW/PF)	600/0.8
Control Room Wiring	Multiplexed to Logic Cabinets in Control Room
Multiplexing of Cables	Distributed Microprocessors, metal Conductor and Fiber Optics Data Highways
Instrumentation	Independent Sensors for Computer Input

Expected emissions performance is listed in Table 3 and shown graphically in Figure 3.

Table 3 - **Emissions Reduction Performance**

	NSPS	LEBS Target	CGU	Reduction
SO2, lb/mm Btu*	0.6	0.2	0.12	80%
NOX, lb/mm Btu	0.6	0.2	0.05	91.67%
Particulate, lb/mm Btu*	0.03	0.015	0.005	0.8333

* 3 lb S and 15.4 Lb ash per million Btu in the coal.

Most inorganic air toxics should be removed at near 99% with the particulate removal equipment. Volatile organic emissions, CO and ammonia slip will be oxidized in the SO_2 oxidizer.

The CGU will produce significantly less waste than the NSPS plant. Part of this is due to the lower amount of ash produced per kWh because of the higher efficiency boiler and steam cycle and the SNO_X^{TM} Hot Process. The major portion of this reduction results from the production of sulfuric acid as a commercially saleable by-product rather than the sludge normally generated by an FGD system. A summary of waste generation and a comparison to the NSPS plant is listed in Table 4 and shown graphically in Figure 4.

Table 4 - **Waste Reduction Performance**

	NSPS	CGU	Reduction
Ash, Lb/kWh	0.148	0.128	13.5%
lb/mm Btu	15.4	15.4	0.0%
FGD Waste, Lb/kWh	0.204	0.00	100%
lb/mm Btu	21.2	0.00	100%
Total Waste, Lb/kWh	0.352	0.128	63.6%
lb/mm Btu	36.6	15.4	57.9%

The plant uses a 4500 psig, 1100°F supercritical thermodynamic cycle with two reheat streams at 1100°F each. The gross output of the generator is 428 MWe. The net plant output is 408 MWe. Net plant heat rate is 8,305 Btu/kWh for a net efficiency of 41.1% based on fuel HHV. (Note: a detailed breakdown of energy losses should be reviewed when comparing efficiencies of different systems.) There is the potential to increase net plant efficiency beyond 41.1% and this will be pursued in ongoing work.

Figure 3 **Emissions Performance Comparison**

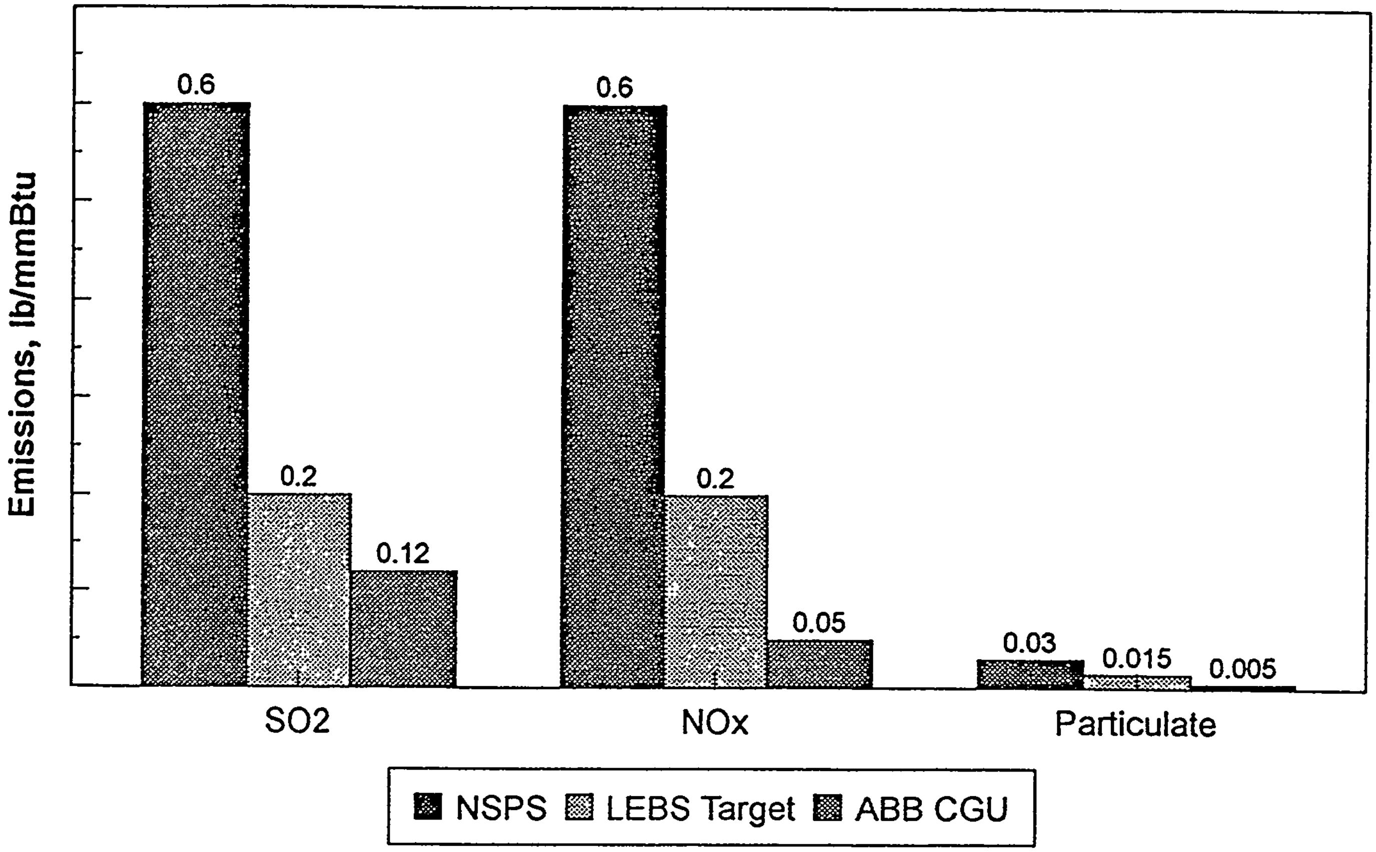
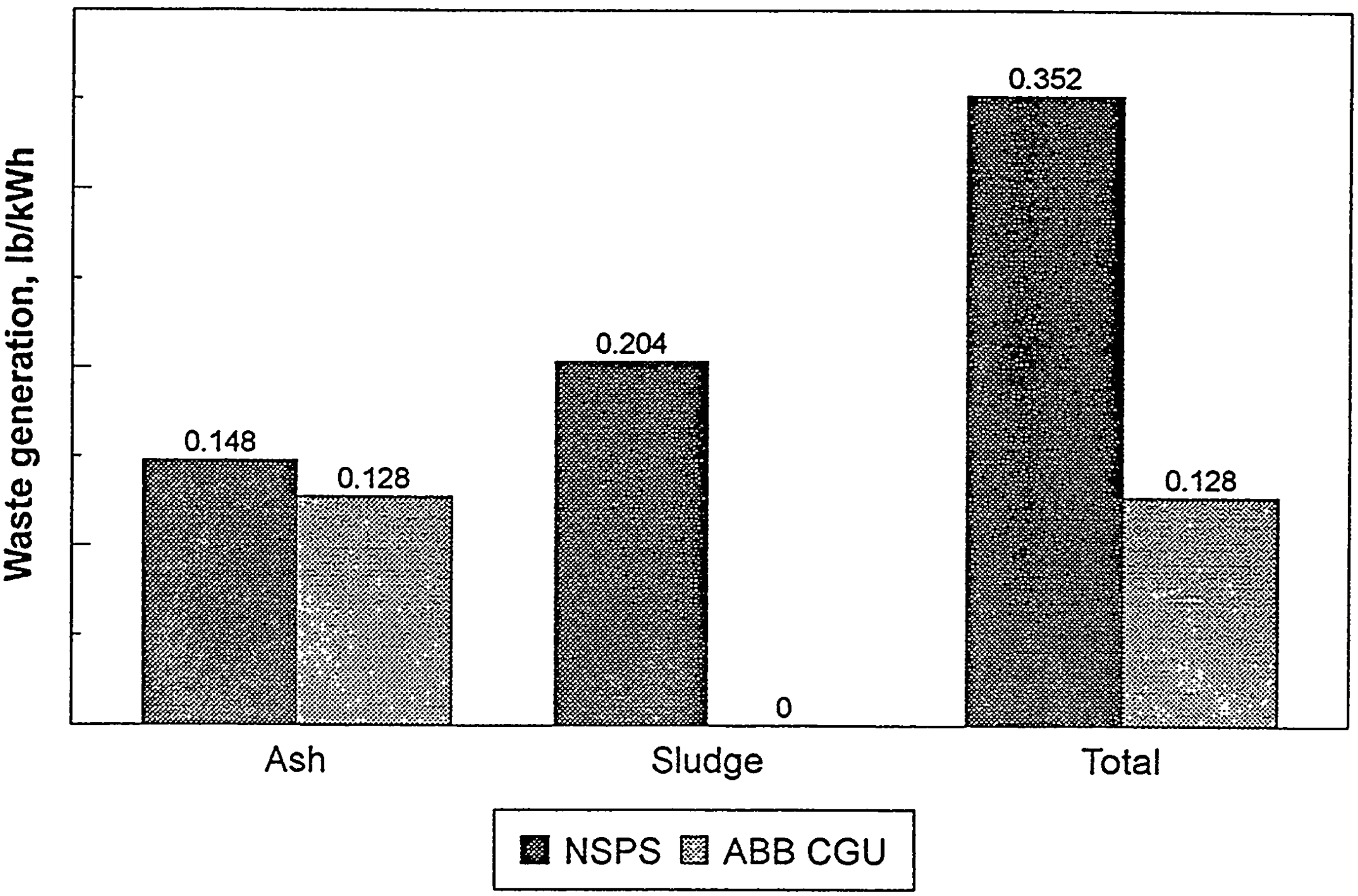


Figure 4 **Waste Generation Comparison**



The CGU has a total plant cost that is less than the cost of a current NSPS plant. The total capital requirements estimate includes the time related portions of the project estimate such as allowance for funds used during construction. The improvements come from the adoption of an aggressive commercialization plan that utilizes the concept of a "Consortium" formed to produce a number of these units on a replicated and modularized basis. These factors, coupled with ABB's commitment to a significantly reduced "cycle time" for the boiler and other key equipment results in significantly reduced schedule from award to start-up. This aggressive construction schedule improves the time-related costs.

The CGU will satisfy the objective of having a cost of electricity equal to or less than that for the NSPS plant. The calculated cost of electricity is reduced by the by-product credit received from the sale of the sulfuric acid (using a figure confirmed by an outside market study) and by an aggressive but achievable capacity factor. An independent reliability, availability and maintainability analysis was completed for the CGU. The study was based on performance data obtained from the NERC data base and utilized the industry accepted "Delphi" process to adapt the data for the CGU. Since DOE required that the cost of electricity analysis be completed assuming baseloaded operation, the equivalent availability factor estimated in this study was used for the CGU capacity factor. One reason enhanced reliability and equivalent availability are achieved is that the SNO_x™ Hot Process is "passive", i.e., it has far less mechanical equipment than is typically found in flue gas desulfurization processes that utilize lime or limestone. The simpler process, absence of mechanical equipment, and the passive character of the process results in higher reliability and availability.

The design also incorporates advanced diagnostics concepts which provide early warning of impending failures in the plant equipment. This advanced knowledge has several benefits that result in improved reliability and availability. Advanced diagnostics should enable maintenance outages to be both more effective by providing maintenance information in areas which might not be readily amenable to inspection, and shorter because preparation should be better due to a reduced number of "surprise" repairs.

Finally, the CGU was designed for access and ease of maintenance because it was designed for access and ease of construction. The plant is laid out with the "ranch" concept. This means that the stacking of equipment is minimized. Rather it is spread out in the horizontal plane. In addition, the plant design incorporates a "backbone" utility rack for piping, cable, conduit and electrical wiring. The ground level portion of this rack is used as a maintenance access corridor that runs throughout the plant. Also, organizing piping and conduit on overhead racks provides more ground level access to equipment for maintenance. Incorporating these features in the conceptual design of the plant, and coupling them with the implementation of a "design for maintainability" approach during the detailed design stage, will result in a plant with superior availability and higher capacity factor.

Some of the features of the CGU, which indirectly should make it attractive to utilities, are as follows:

- The design incorporates a supercritical cycle but a subcritical version can be provided also.

- The CGU eliminates the FGD waste disposal problem, including future licensing, because it produces commercial grade sulfuric acid which is a marketable commodity in most parts of the country. The heat rate and efficiency are improved because the design recovers the heat generated from condensation of the sulfuric acid to heat the combustion air. In addition, the SNO_X™ Hot Process has, except for small acid pumps, no mechanically driven equipment. This results in a savings in auxiliary power consumed inside the plant and reduced O&M costs.
- The passive nature of the SNO_X™ Hot Process, coupled with the incorporation of advanced diagnostics systems and an aggressive maintenance program, will enable the CGU to have high availability and increase capacity factor in baseload service. This is particularly attractive to utilities under pressure from their PUC to increase availability and lower reserve margins.
- The use of the SNO_X™ Hot Process to make sulfuric acid eliminates future licensing risk to the utility about the regulatory requirements surrounding the disposal of FGD sludge.
- The base model for the CGU is designed for baseload operation with limited cycling capability but cycling capability can be added.
- The plant is significantly more cost effective than the NSPS plant, due to in part to replication and modularization, an aggressive construction schedule, and the "ranch" and "backbone" concepts in the arrangement.

All of the foregoing features are responsive to the technical, regulatory and economic needs of the power generation industry. The superior performance of the ABB CGU coupled with efforts to minimize investor risk should make it extremely attractive to the utilities and IPPs. The near term character of the LEBS technologies chosen, coupled with the attractive performance and cost features of the ABB CGU, support a confidence in the Project Team that the proposed CGU design will be acceptable and marketable.

APPENDIX C

Low Emission Boiler System Project

Task 7 Test Plan

Plant Miller Testing

1. Executive Summary

The test plan presented here describes the goals, expected outcome, and approach to be taken for Task 7.

1.1 Goals

The principle goal of the Task 7 activities is the development of field test data needed for a later field demonstration leading to the design of a large demonstration system. These activities include the determination of feasible and reasonable operating conditions as well as life cycle estimates for the CeraNO$_x$ filter under consideration of the desired particulate and NO$_x$ removal efficiencies.

The goals of this project, to be achieved simultaneously, are:

- Particulates emissions of less than 0.015 lb/MBtu
- System clean-side draft loss of 8 in. H_2O at 4 ft/sec,
- Operation with a face velocity of at least 4 ft/sec,
- Minimum of 80 % NOx removal efficiency
- Ammonia slip of less than 15 ppm.

Information gained from demonstration and evaluation should address the following issues:

- Evaluate the effect of face velocity on the fractional and total particulate removal efficiency of the filter element, and the resulting draft loss behavior as a function of particulate build-up and cumulative operating time.
- Determine the NOx reduction efficiency as a function of flue gas composition (NOx inlet concentration, NH_3 stoichiometry, particulate removal), flue gas temperature, catalyst loading (space velocity). Of further interest is the determination of the requirements to maintain the catalytic conversion efficiency.
- Determine the draft loss as a function of face velocity, cleaning cycle characteristics, flue gas temperature and other parameters.

In addition to the field tests planned for the CeraNOx filter, data shall be requested from Haldor Topsoe and evaluated on the possibilities and requirements to increase the SO_2 conversion to at least 96.7%, up to 98%.

1.2 Expected Results

The quantitative expectations from the testing are as follows:

Particulate emissions < 0.005 lb/MBtu

Clean gas-side draft loss of 7-8 in.H_2O at a face velocity of 4 ft/sec and at a operating temperature of 775°F

Approximately 90 % NOx removal at an inlet NOx concentration of 200 ppm with an ammonia slip of less than 5 ppm (flue gas flow corrected to 4 % O_2 in the flue gas).

By evaluating the results obtained, it is expected to be able to

- Determine feasible ("pre-optimal") operating conditions for a CeraNOx filter system to achieve acceptable particulate and NOx removal at reasonable draft loss, ammonia slip and filter volume (face velocity, NH_3 / NOx ratio, cleaning effort).
- Determine the required cleaning air characteristics for sustainable operation, such as back pressure and temperature of cleaning air as well as pulse frequency and length.
- Estimate the life cycles of the substrate/membrane as well as of the catalyst.

1.3 Approach

The approach proposed is to test a system with four CeraNOx filter modules on a slip stream of about 200 acfm at Alabama Power's 700 MWe pulverized coal Plant Miller, once the NOx SCR catalytic (wall flow mode) filter modules have been developed by CeraMem and Engelhard. CeraMem already has a test facility installed at Plant Miller under an EPRI program, which needs to be adapted to be able to accommodate the LEBS requirements described above. Those activities are scheduled for March - May 1995. Following two months of testing under EPRI, two months of field testing for LEBS are scheduled from August up to November 1995.

2. Background to the Program

This section serves a more detailed discussion of the results expected, particularly from the CeraNOx research scale testing. Before getting into the details, let's recall the LEBS contract requirements, which are to be viewed as minimum requirements to be met.

2.1 LEBS Contract Requirements

- Particulate emissions - 0.015 lb/MBtu
- NOx emissions - 0.20 lb/MBtu, expected exit concentration from boiler to SCR to be approximately 0.10 lb/M Btu.
- SO_2 emissions - 0.20 lb/MBtu

2.2 CeraNOx Filter Modules

The following CeraNOx filter configuration will be employed during the testing at Plant Miller.

- Configuration: EX-66 with 3 mm channel width, 12 in. length, 5.9 in. x 5.9 in. modules, one membrane on particulate collection side, 27 ft^2 filter area
- Catalyst: clean-side catalyst, Engelhard modified Vanadium/Titanium VNX™ catalyst Four vertically oriented filter modules will be employed for testing.

2.3 Previous Test Results

2.3.1 Particulate Emissions

(later)

2.3.2 Cleaning Characteristics

(later)

2.3.3 NOx Removal

(later)

2.3.4 Draft loss

(later)

2.3.5 SO_2 Catalyst

(later)

2.4 Expected Results

2.4.1 Particulate Emissions

It is expected that the desired particulates emission of less than 0.005 lb/MBtu, which is below the contract requirement of less than 0.015 lb/MBtu, can be met. Earlier tests conducted by ABBES and CeraMem indicate that this level of performance is achievable and there is present indication that modifications to the filter required for NOx reduction would significantly affect the particulate removal efficiency or outlet emissions. Previous tests used 6 inch square by 15 inch long filters where the ceramic coatings were applied by hand, with three membranes on each side. For this application, filter coupons (3 inch square by 6 inch long) with one membrane applied to the dirty side will be used. Catalyst will be applied to the outlet side. Primary concern will be the consistency and quality of the ceramic and catalyst coatings. However, in previous testing, particulate emissions were the lesser problem compared to draft loss, filter cleaning and catalyst conversion and life.

A face velocity of at least 4 ft/sec is required for economic feasibility. Higher face velocities of 5 ft/sec are desired; at this time, a feasible upper limit on face velocity is not known.

2.4.2 Cleaning Characteristics

The decision to go along with a channel size of 3 mm in this test program is based on the previous cleaning experience with 2 mm channels, which caused some residual dust buildup on the filter surface towards the end of the channels. A larger channel size is expected to improve the cleaning efficiency of the back pulse system.

The filter modules will be set up for vertical gas flow, as opposed to horizontal gas flow of later larger units. With the vertical position having some advantage in terms of improved prevention of particulate reentrainment, field demonstration and commercial operation will be designed for horizontal operation out of space considerations. Since the main thrust for removing the collected particulates is stemming from the pulsed back pressure rather than gravity, it is not expected to see noticeable difference that would prevent the design of a horizontal system.

Based on the coal being burned at Plant Miller, the flyash properties (such as calcium content) are not expected to contribute to a cementation problem similar to that experienced in initial testing of the technology at Public Service of Colorado's Comanche Station..

One item that should be closely observed is the formation of ammonia salts from SO_3 and injected ammonia. Ammonia salts may condense as a sticky material, diminishing the filter quality, as temperature drops off. It is anticipated that operation of the subsystem in excess of 750°F will avoid this (ammonia bisulfate formation has been documented in SCR operations operating at this temperature in the literature). Once these deposits from, they are difficult to remove. It is imperative to keep the filter temperature above the ammonia bisulfite condensation temperature at all times. No problems are expected if the filter is always preheated to the required temperature in the absence of ammonia until the filter reaches the minimum operating temperature.

2.4.3 NOx Removal

The filter modules to be employed at Plant Miller will provide for use several new advances in design and catalyst.

Improvements in catalyst application should reduce the gas-side draft loss. However, these change in catalyst formulation and application should not significantly change the catalyst activity by itself. Essential to the effective catalyst activity, however, is the thickness of the catalyst layer and its pore diameter resulting from the coating procedure to be employed by Engelhard. This is unknown at this point, and it is not sure whether that information will be released by Engelhard. The pore length along with the flue gas flow rate will determine the real catalyst space velocity.

The molar ratio of ammonia to NO_x will be varied between about 0.85 to 1.1 to find out the required amount to achieve the reduction goal of > 80%. The ratio probably will end up in the upper part of the range (around 1.0) for the degree of conversion required at the given NO_x concentration, under consideration that the ammonia slip can be driven up to 10 -15 ppm without causing noticeable disadvantages.

The life of the catalyst will be determined by two factors. The first one is the mechanical integrity of the catalyst coating, while the second one is the deterioration of catalyst activity due to poisoning, sintering, etc. The first item should have improved significantly since previous tests, as the catalyst layer will be applied to the clean-side in a bonding-type process, which practically should eliminate its susceptibility to being detached and removed by backpulse air. The fact that the catalyst will be applied onto the clean-side will also reduce its exposure to poisoning compounds. These compounds, however, still may be able to penetrate through the membrane under certain conditions, such as condensation during shutdown. The impact through sintering can be avoided as long as operated within the allowable temperature range. These changes over previous designs will certainly increase the lifetime of the catalyst.

2.4.4 Gas-side Draft Loss

The gas-side draft loss is made up of flow resistance through the channels, as well as the dust layer, membrane and catalyst. At the targeted face velocity of 4 ft/sec with the 3 mm channel, the main resistance arises from the various layers that have to be penetrated. In addition to the monolith and ceramic coating itself, the catalyst layer will add a significant portion to the draft loss. At the target face velocity of 4 ft/sec and gas temperature of 775°F, the virgin draft loss is expected around 8 in. H_2O. The gas-side draft loss will cycle as particulate matter is collected and the cleaning cycle is activated. The clean draft loss will invariably increase with time from the virgin draft loss amount, due to pore blockage from particulate buildup. Some buildup is expected, and it will part of this test program to find operating conditions which limit or reduce such buildup.

Previous filter modules have employed three membrane coatings on each side, which had an unacceptably high draft loss. The filter modules to be tested will employ a single membrane coat on the clean side only, which will significantly reduce the operating draft loss. At a face velocity of 4.5 ft/sec, the draft loss at actual operating temperature of 775 ° F is expected to be around 4 in. H_2O for a non-catalyst filter and 8 in. H_2O for a catalytic filter under virgin conditions. Acceptable draft-loss increase would be no more than 2 in. H_2O after operating after 16,000 hours.

2.4.5 SO_2 Catalyst

The design of current SNOx system is able to achieve around 96 % SO_2 removal, employing space velocities around 1500/hr. Unless a different catalyst is used, which is not foreseeable at this point, the desired increase in conversion to above 96.7% (up to 98 %) will most likely require a reduction in space velocity with the consequence of increased catalyst volume. Values around 1100/hr are being discussed.

3. Design of the Test System

3.1 Materials of Construction

3.1.1 Ammonia System

Copper, zinc and silver, as well as their alloys, should not be placed in contact ammonia (pipes, instruments, etc.). It is preferable that all pipe connections should be welded, however, that is probably impractical at this scale. As removable connections will be used, flange connections with recess and projection or tongue and groove design should be specified.

Pipes should be protected against corrosion from outside, and should be coated with a heat rejecting color if exposed to sunlight. Pipe support points are especially critical and should be protected, e.g., hot-dip galvanized.

All lines and equipment used with ammonia should be grounded and bonded.

3.2 Flue Gas Temperature

The operating temperature will be approximately 775°F. The flue gas will be drawn from the gas duct leading to the existing EPRICON unit, which typically operates around 750°F. The temperature of the flue gas varies with unit load, ranging from approximately 600°F at low load to approximately 840°F at high load. The temperature into the EPRICON unit, and therefore also into the CeraNOx system, will be adjusted by adding or removing lagging. For more precise temperature control it appears that a flue gas heating system will be needed.

3.3 Ammonia Supply, Injection and Mixing System

The scale of the test system and operating conditions call for a maximum capacity of 50 - 60 grams/hr of ammonia (2 oz/hr), or about 1300 grams/day (2.8 lb/day). The ammonia will immediately be mixed with dilution air to get its concentration below the flammability and explosion limits.

If anhydrous ammonia is used, a compressed gas cylinder can be rented (e.g. 150 lb capacity) . Because of the small capacity required, the ammonia can be evaporated at ambient temperature, eliminating the need for an evaporator, which would simplify the supply system significantly. Typically, the dilution air quantity for an anhydrous ammonia system is based upon providing an ammonia vapor concentration of 3-5 % by volume.

An aqueous ammonia system would be more complex because it still require an evaporator for a typical 25% ammonia-water solution. The dilution air is typically heated to 500°F. The mass of dilution air is typically 8-12 times the mass of the aqueous ammonia required, to provide for an ammonia vapor concentration of 8-12 % by mass.

Proper injection and mixing of the ammonia is very important to get satisfactory results. The gas flow distribution upstream of the NH_3 injection should not vary more than ±15 % from the mean. The injection nozzles should be located in a horizontal duct run approximately 2 to 3 hydraulic diameters upstream of the filter modules. Design flow velocity of the injection vapor through the injection pipe should be approximately 30 ft/s at actual conditions. Design nozzle velocity should be approximately 150 ft/s. Nozzle flow should be concurrent with the flue gas flow.

To ensure proper mixing of the ammonia into the flue gas, a static mixer should be employed. For larger systems, the ammonia injection pipe grid will be arranged in such a way to ensure efficient distribution and mixing. For the tests at Plant Miller, probably one injection nozzle will suffice and mixing will have to be accomplished with a static mixer.

3.4 Gas Analysis Instrumentation and Measurement

Inlet Analysis - O_2, Particulate, NO/NOx, NH_3, SO_2.

Outlet Analysis - Particulate, NO/NOx, NH_3, SO_2, SO_3, N_2O (tentative).

O_2 - Using zirconium-cell or paramagnetic type analyzer. Requires control and calibration before and after use. Other types are acceptable as well.

Particulates - Using either a laser-light scattering instrument, hot particulate filter, or an impactor (suitable for inlet concentration, but probably not suitable for the very low outlet concentration which would require very long sampling times)

NO/NOx - Using either a chemiluminescence (Horiba, ThermoElectron) or continuous IR-type analyzer. Continuous IR-type analyzer would require control and calibration before and after use. ABB OPSYS system will not be suitable for Plant Miller testing because of the small duct diameter (path length) available for the light beam, in addition to other constraints (transmitter cleaning air ratio too high).

NH_3 - Pt-converter, detection as NOx, for the inlet. Outlet analysis would use wet chemistry for best accuracy (no reliable continuous analyzer for range up to 5 ppm) and on-line infrared absorption monitor usable in clean atmospheres (e.g. Perkin-Elmer)

SO_2 - Continuous IR- or UV/VIS-type, both of which would require control and calibration before and after use.

SO_3 - Wet chemistry. SO_3 concentration at Plant Miller is typically around 1 - 2 ppm. Measurements would be performed at the beginning, to quantify the impact of the SCR catalyst on SO_2 oxidation. After that, periodic checks would suffice.

N_2O - Separate analyzer/analysis required. A measurement at the beginning of the test program should be performed to quantify amount, if any, N_2O present. If the amount is negligible compared to NO_x, further analysis will be discontinued.

3.5 Process Control Instrumentation and Measurement

Flow rate, draft loss, temperature - Pitot-tube traverse with manometer connection and attached thermocouple.

NH_3 control - Feed-forward control of ammonia flow valve based on NO/NO_x concentration and flue gas flow rate. If further trimming is required, a NO_x signal from the filter outlet can be fed back into a controller.

4. Procedures for Start-up, Shut-down, Outages/Stand-stills

4.1 General

As already outlined above, the catalyst can only be operated within a defined temperature window from about 570-750°F (300-400°C) during any time, including startup, shutdown and normal operation, in order to avoid the precipitation of ammonia salts or to avoid damage to the catalyst structure itself. The filtration part can be operated at temperatures below that range as long as ammonia is not injected.

At all times the formation of water condensate, predominantly during start-up and shut-down, should be avoided by isolation of the filter modules and sealing them from the atmosphere. A dryer might have to be employed (RH < 50-60%) for longer outages to avoid dissolution of sodium and potassium salts from the dust on the filter in order to prevent catalyst poisoning (this may not be a problem with CeraNOx clean-side catalyst). Alkali metals such as sodium and potassium can poison the catalyst by reactions with active sites, if they penetrate through the membrane to the catalyst.

4.2 Start-up

Preheating: It would be beneficial to preheat the catalyst with clean air to a temperature above 400°F (200°C), before flue gas is admitted. This can be done with a separate electric heater on startup. The filter elements certainly will not be a limiting factor regarding maximum possible warm-up rate.

Before injecting ammonia, the dilution air flow needs to be activated and ammonia should not be injected until the catalyst temperature has reached at least 575°F (300°C).

4.3 Shut-down

The injection of ammonia needs to be terminated as soon as the catalyst temperature is getting below 575°F (300°C).

During operation of the CeraNOx SCR system, the air flow through the ammonia injection grid should be maintained even if the ammonia flow is terminated. This will purge the nozzles and minimize the potential for corrosion and pluggage due to the formation of ammonium bisulfate. This is especially critical during frequent startups and shutdowns.

4.3 Outages/Stand-stills

For extended periods of stand-still the CeraNOx filter system should be isolated and either be inertisized or vented to avoid the formation of water condensate and subsequent dissolution of sodium and potassium salts from the residual flyash on the filter modules.

4.4 Operation

The allowable maximum temperature excursions and durations for the catalyst coating need to be adhered to and must be obtained from Engelhard.

After initial startup of the test unit, the filter should only be operated in the filtration mode without injection of ammonia to allow elimination of the major initial problems related to particulates removal. This suggested "one problem at a time" approach is meant to protect the filter module from possible permanent damage caused by the presence of ammonia while still experimenting particulates removal in a broad range. Once the major operating difficulties have been resolved, ammonia injection can be added to the testing as long as the catalyst is within the allowable temperature range.

The focus during this first start-up phase will be the determination of the proper cleaning of the filter by varying the cleaning air pressure, frequency and duration which will keep the draft loss within the allowable range. Some or all of that information should be available from the tests to be performed by CeraMem prior to LEBS testing.

According to the Material Safety Data Sheet (MSDS), ammonia decomposes above 840°F (450°C), producing hydrogen. Temperature excursions of the flue gas beyond that point are to be avoided at any time.

The instructions for start-up and shut-down discussed above need to be followed.

5. Project Tasks

5.1 Development of CeraNOx SCR Catalytic Filter

In conjunction with the EPRI program, CeraMem and Engelhard will prepare the NOx SCR catalytic filters. After developing a detailed laboratory program, CeraMem will supply to Engelhard filter coupons for their catalyst work. Engelhard, using their proprietary catalyst technology(s), will modify the ceramic filters and test them in their facilities with the purpose of developing the catalyzed filters that meet the project objectives.

In addition, Engelhard may also choose to evaluate the developmental catalytic filters in their laboratory facilities in a series of process parameter tests for ABBES. The extent of the testing would be agreed upon by Engelhard, CeraMem, and ABBES. The results from these tests, if conducted, would be used in combination with field test results by ABBES to design a large demonstration plant for the LEBS program. This evaluation subtask is not a part of Task 7.

5.2 Design and Fabrication of a Research Scale NOx SCR Filter Test System

In conjunction with the EPRI project, CeraMem will design and fabricate a research scale test system to be used to evaluate the NOx SCR ceramic filters on live flue gas. The system will include the following characteristics:

- Stainless steel construction
- Full controls and remote data access
- On-line NOx and NH_3 monitors
- Four vertical filters
- 200 acfm flow (filters will not be full cross section but only 3-4" squares)
- Capability to run from 2 ft/sec to 6 ft/sec face velocity
- Temperature control and capability to 800°F
- Flexible backpulse characteristics and sequencing
- Capability for both on-line and off-line cleaning
- Ammonia injection system with feedback control to produce NH_3/NOx ratios of 0.85-1.1
- Unit to be portable for testing at other sites
- Unit lifetime of at least one year

5.3 Field Test NOx SCR Filters at Plant Miller

In conjunction with the EPRI project, CeraMem will install and operate the test system at Alabama Power's Miller Generating Station. The system will be installed working with a subcontractor recommended by SCS. In addition, CeraMem will subcontract with Southern Research Institute for some of the analytical testing. Both CeraMem and ABBES will supply field engineers for initial start-up of the unit. After the unit is operating properly and initial experiments have been conducted (approximately two weeks), the ABBES engineer will be responsible for the on-site system operation. CeraMem and ABBES personnel in Birmingham will be able to monitor the system remotely. The test matrix is discussed in the following.

Test Block 1 - Particulates Removal at Base-case Face Velocity (4 ft/sec)

This first Test Block essentially serves to get the system ready for subsequent reliable test operation. The main purpose is to identify and resolve any operational problems before starting major parametric testing. If the majority of such problems has been resolved during the EPRI/CeraMem testing preceding the LEBS test phase, that information will considered, as far as available. The major difference during the LEBS testing will be increased flue gas temperature and less stringent NOx removal requirements with larger allowable ammonia slip, in addition to larger target face velocities.

At this point it is assumed that significant information regarding limitations and requirements of the cleaning cycle will have been gathered and are available by EPRI/CeraMem to select one or more sets of corresponding cleaning parameters to be applied from this Test Block. The parameter combinations have to be decided at a later point under consideration of previous test results.

The first tests will be performed at the target flue gas velocity of 775°F without injection of ammonia. It is assumed that a face velocity of 4 ft/sec can be maintained without major drawbacks. The particulate removal efficiency and particle size distribution at the inlet and outlet along with the draft loss across the monolith will be measured and used for reference.

Key parameter settings for this Test Block are:

- Face velocity: 4 ft/sec
- Cleaning Cycle:
  - Pressure xxx psi
  - Pulse Length xxx msec
  - Frequency xxx /hr
- NH_3/NOx ratio 0 (no ammonia injected)
- NOx in 200 ppm (or whatever the flue gas NOx under full load)
- Flue Gas Temp. 775°F

Duration of this Test Block is estimated at 3-7 days depending on the information available from EPRI/CeraMem testing as well as the extent of variation of cleaning cycle conditions. Once those data are successfully obtained, Test Block 2 with ammonia injection can be started under otherwise same operating conditions.

Test Block 2 - Particulates and NOx Removal at Base-case Face Velocity (4 ft/sec)

This second Test Block is another step up in complexity of the system operation under base conditions. Ammonia injection will be actuated. The first test will be performed starting at low ammonia injection rate to avoid excess ammonia slip. Subsequent tests will be different by applying increased ammonia/NOx ratios until the ammonia slip is reaching values of 15 ppm or more. Filter cleaning will be performed employing the best parameter set found during Test Block 1. Flue gas flow rate, i.e. face velocity, and flue gas temperature will be kept constant. Since the NOx inlet concentration cannot be readily controlled, but is rather dependent on the boiler load and operation, the value of 200 ppm is simply a guess of what will be present and could range up to 400 ppm.

The following parameters will be monitored: total particulate removal, NOx inlet and outlet concentration, ammonia inlet and outlet concentration, draft loss. The tests are estimated to take 3-6 days to get reliable performance data.

Key parameter settings for this Test Block are:

- Face velocity: 4.0 ft/sec
- Cleaning Cycle:
  - Pressure xxx psi
  - Pulse Length xxx msec
  - Frequency xxx /hr
- NH_3/NOx ratio 0.75, 0.8, 0.9, 1.0, 1.1
- NOx in 200 ppm (or whatever the flue gas NOx under full load)
- Flue Gas Temp. 775°F

After completion of the first two Test Blocks, the baseline information should be complete regarding particulates and NOx removal. As mentioned above, some or all of that information might be obtained from the tests performed by EPRI/CeraMem prior to LEBS testing. In that case, LEBS testing would start with Test Block 3.

Test Block 3 - Face Velocity

The next major parameter to be varied during this section is the filter face velocity. This is a very important parameter because a 10-30 % increase in velocity can significantly improve the economics of the CeraNOx system.

Under the assumption that the base velocity in the previous blocks was 4.0 ft/sec, the flue gas flow rate will be increased in steps up to 5.0 ft/sec, possibly even 5.5 ft/sec or more, until the draft loss increases significantly. The cleaning cycle initially will be maintained at the settings found in Test Block 1.

However, new cleaning parameter sets might have to be found to adapt to the increased face velocity because the draft loss will have a higher base value in addition to building up faster due to the higher particulates collection rate. This might require an additional Test Block to be executed.

In addition to that, the space velocity of the catalyst is increasing with the face velocity. Therefore, the ammonia/NOx ratio might have to be reduced to yield the same ammonia slip when increasing face velocity. This is a possible third parameter within this Test Block.

The following parameters will be monitored: total particulate removal, draft loss, NOx inlet and outlet concentration, ammonia inlet and outlet concentration. The tests are estimated to take 8-12 days considering the multiple parameter variation. This is the most important part of this test program.

Key parameter settings for this Test Block are:

- Face velocity: 4.5, 5.0, (5.5) ft/sec
- Cleaning Cycle: (probably required as secondary parameter)
  - Pressure yyy psi
  - Pulse Length yyy msec
  - Frequency yyy /hr
- NH_3/NOx ratio taken from Test Block 2 to yield ammonia slip of 10-15 ppm
- NOx in 200 ppm (or whatever the flue gas NOx under full load)
- Flue Gas Temp. 775°F

The result from this Test Block will be a maximum useful face velocity and a corresponding set of cleaning parameters and ammonia/NOx ratios, which will be the basis for the subsequent tests.

Test Block 4 - Inlet NOx Concentration

The purpose of this Test Block is to investigate the impact of NOx inlet concentration on NOx removal efficiency. It is assumed that the concentration changes with load, i.e., some of the tests have to be performed at low load (night time) and other at full load (daytime).

Key parameter settings for this Test Block are:

- Face velocity: maximum useful found in Test Block 3
- Cleaning Cycle: parameters from Test Block 3
  - Pressure yyy psi
  - Pulse Length yyy msec
  - Frequency yyy /hr
- NH_3/NOx ratio taken from Test Block 3 to yield ammonia slip of 10-5 ppm
- NOx in 200 ppm (or whatever the flue gas NOx under full load)
- Flue Gas Temp. 775°F

The following parameters will be monitored: total particulate removal, draft loss, NOx inlet and outlet concentration, ammonia inlet and outlet concentration. The tests are estimated to take 2 - 3 days.

Test Block 5 - Flue Gas Temperature

This Test Block is concerned with the variability in flue gas temperature and its impact on particulates and NOx removal. The flue gas temperature will be varied from 700-800°F. Since the flue gas temperature changes the viscosity of the gas, the filtration characteristics will be changed. Also, the catalyst activity is going to change with operating temperature. Some of the catalyst data might be available from Engelhard prior to testing, which would allow a reduction in testing.

The filter cleaning characteristics might have to adapted to the different gas temperature as well as the ammonia/NOx ratio to yield the maximum allowable ammonia slip of 10-15 ppm.

Key parameter settings for this Test Block are:

- Face velocity: maximum useful found in Test Block 3
- Cleaning Cycle: parameters from Test Block 3
  - Pressure yyy psi
  - Pulse Length yyy msec
  - Frequency yyy /hr
- NH_3/NOx ratio taken from Test Block 3 to yield ammonia slip of 10-15 ppm
- NOx in 200 ppm (or whatever the flue gas NOx under full load)
- Flue Gas Temp. 700, 725, 750, 800°F

The following parameters will be monitored: total particulate removal, draft loss, NOx inlet and outlet concentration, ammonia inlet and outlet concentration. The tests are estimated to take 2 - 4 days.

Test Block 6 - Optimized Parameter Combinations

From the tests performed during the Test Blocks described above, one or several pre-optimum parameter combinations are expected. The testing during this Test Block is to obtain some operating experience with those parameter combinations over an extended and preferably uninterrupted period of time.

Key parameter settings for this Test Block are:

- Face velocity: optimum parameters found in Test Blocks above
- Cleaning Cycle: optimum parameters found in Test Blocks above
  - Pressure yyy psi
  - Pulse Length yyy msec
  - Frequency yyy /hr
- NH_3/NOx ratio taken from previous tests to yield ammonia slip of 10-15 ppm
- NOx in 200-400 ppm (typical range)
- Flue Gas Temp. 775°F

The following parameters will be monitored: total particulate removal, particulate size distribution in the inlet and outlet, draft loss, NOx inlet and outlet concentration, ammonia inlet and outlet concentration. The tests are planned for 6-10 days.

Once the flue gas testing is completed, one or more filter modules shall be inspected regarding residual particulates and catalyst activity.

5.4 Final Report

CeraMem will prepare a final report for inclusion in ABBES' LEBS report. In addition to informal verbal updates, CeraMem will update ABBES on technical progress throughout the program through short letter reports no more often than monthly.

5.5 Project Schedule

The project schedule is given below. The testing discussed in section 3.6 is indicated to take place between August and November of 1995. The time frames are tentative until additional planning and detailed discussions with Engelhard can be performed.

	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
5.1	------	------								
5.2	------	------	------							
5.3				------	-----x	------	------	------	------	
5.4										F

x - End of EPRI field testing.

6. Catalyst Safeguarding/ Protection

6.1 Poisoning

Arsenic present in certain coals can poison SCR catalysts by reaction and coating with the surface. The content of arsenic in the coal burned at Plant Miller is not available at this time. Arsenic resistant catalysts have been developed. It is believed that the catalyst used does not have a high tolerance to arsenic poisoning. However, as the catalyst will be used in a clean-side application, trace metal poisoning should not be a consideration during normal operation.

6.2 Allowable Process Temperatures

Ammonia salts, the reaction products of SO_3 and NH_3, condense at approximately 570°F (300°C). Precipitation of the salts onto the catalyst surface are a concern for catalyst deactivation. For sulfur containing fuels (presence of SO_3), the filter modules should always operate above condensation temperature, with the catalyst operating temperature at least 68°F (20°C) above the precipitate temperature. Although the SO_3 concentration at the location where it will be taken into the filter modules at Plant Miller typically is 1-2 ppm and therefore quite low, salt formation is still a possibility at the ammonia concentrations to be injected.

6.3 Sintering

Titania-based catalysts change their physical structure above 840°F (450°C) and the TiO_2 converts from a structure of high surface area (anatase) to a lower surface area structure (rutile). Therefore, such temperature excursions are to be avoided.

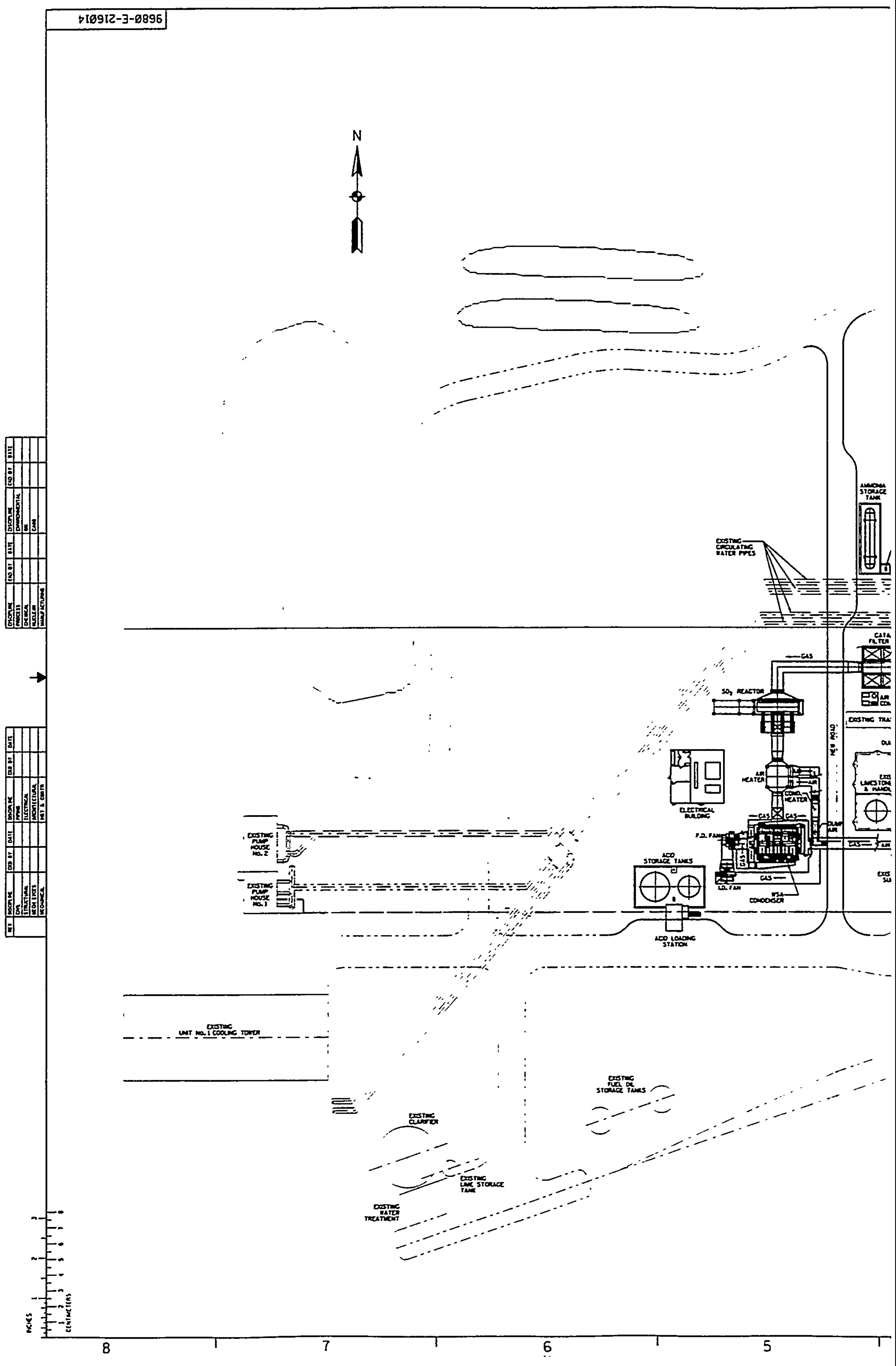
7. Ammonia Characteristics and Handling

- Flammability: lower limit 16 % by volume, upper limit 25 % by volume (Source: MSDS)
- Disintegration into H_2 and N_2 typically occurs above 930-1040°F (500-560°C). It is catalyzed by iron, which lowers the disintegration temperature to 750-840°F (400-450°C). Therefore, ammonia shall not be injected into a SCR system at a point where the flue gas temperature is above 750°F (400°C). (Source: 1.1.03)
- Leaks can be detected by passing an open bottle of concentrated HCl in the suspected area. Dense white fumes form at the leak site.
- Human detection limit 5-10 ppm, bearable concentration limit 500-1000 ppm.
- Main safety codes for anhydrous ammonia are:
  - ANSI K 61.1: "Safety Requirements for the Storage and Handling of Anhydrous Ammonia"
  - Federal Code 29 CFR (Code of Federal Regulations) Para. 1919.111: "Storage and Handling of Anhydrous Ammonia"
  - Additionally, special site requirements such as fire protections systems, ammonia venting requirements, local safety ordinances, emergency notification procedures, storage limitations, truck routing/safety requirements, etc. should be checked with the local fire marshall.

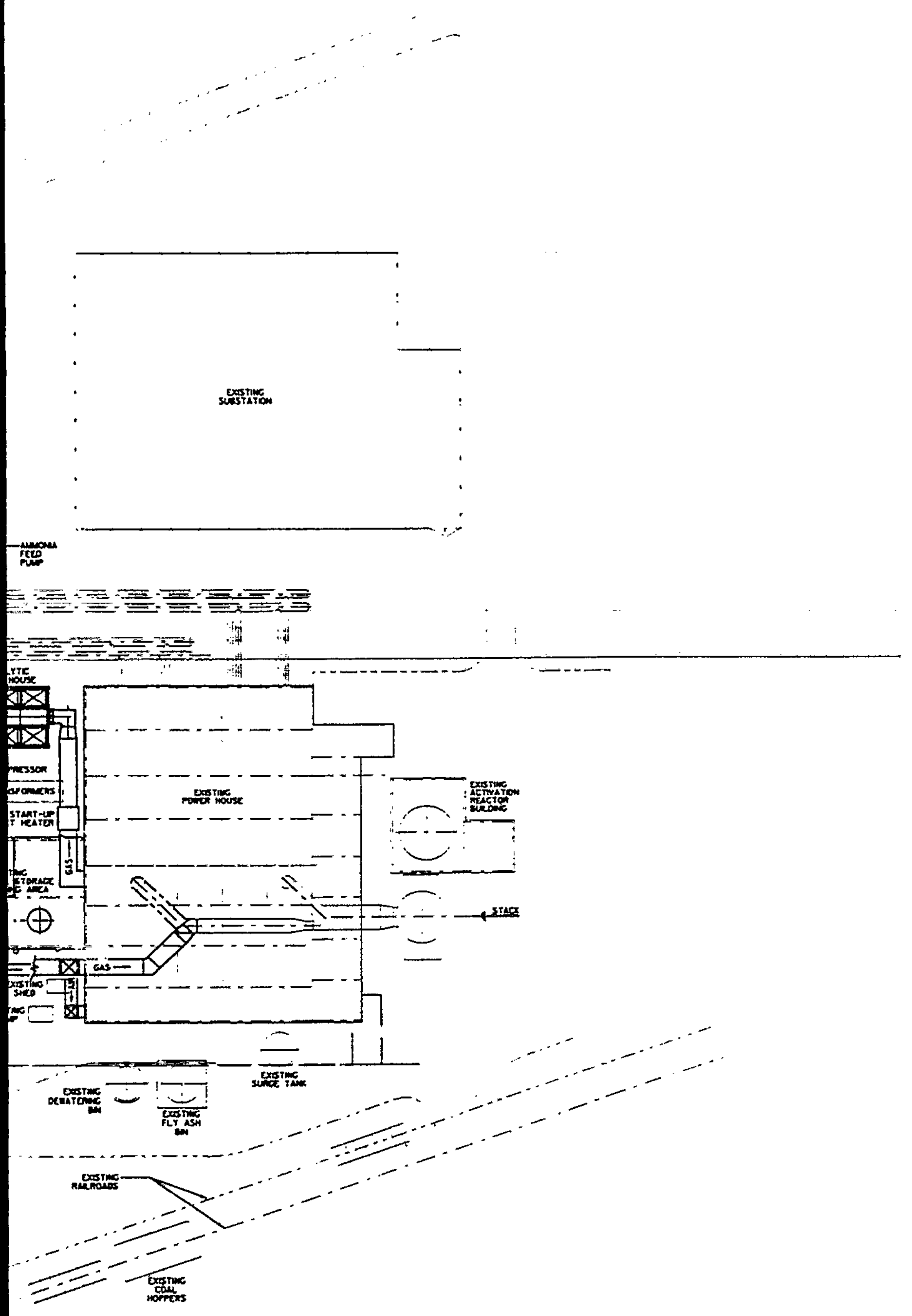
APPENDIX D

PLOT PLAN & GENERAL ARRANGEMENT DRAWINGS

1.	9680-E-216014	Plot Plan
2.	9680-E-216015	G.A., Plan At Grade
3.	9680-E-216016	G.A., Plan Above Grade
4.	9680-E-217107	G.A., Plan At Roof
5.	9680-E-216018	G.A., Section A-A
6.	9680-E-216019	G.A., Section B-B
7.	9680-E-216020	G.A., Section C-C
8.	9680-E-216021	G.A., Section D-D



9680-E-216014
N
EXISTING CIRCULATING WATER PIPES
AMMONIA STORAGE TANK
GAS
SO₂ REACTOR
NEW ROAD
AIR HEATER
COND. HEATER
ELECTRICAL BUILDING
DUMP AIR
F.D. FAN
I.D. FAN
WSA CONDENSER
ACID STORAGE TANKS
ACID LOADING STATION
EXISTING PUMP HOUSE NO. 2
EXISTING PUMP HOUSE NO. 1
EXISTING UNIT No. 1 COOLING TOWER
EXISTING FUEL OIL STORAGE TANKS
EXISTING CLARIFIER
EXISTING LIME STORAGE TANK
EXISTING WATER TREATMENT
INCHES
CENTIMETERS
8
7
6
5



WORK-IN-PROGRESS

MICRO	REV	DATE	DESCRIPTION	DSNR	CHKR	RESP ENGR	PROJ MGR
			FIRST ISSUE				

DOE-LEBS PROJECT
PROOF OF CONCEPT TEST FACILITY
RICHMOND POWER & LIGHT - WHITEWATER VALLEY UNIT NO. 1

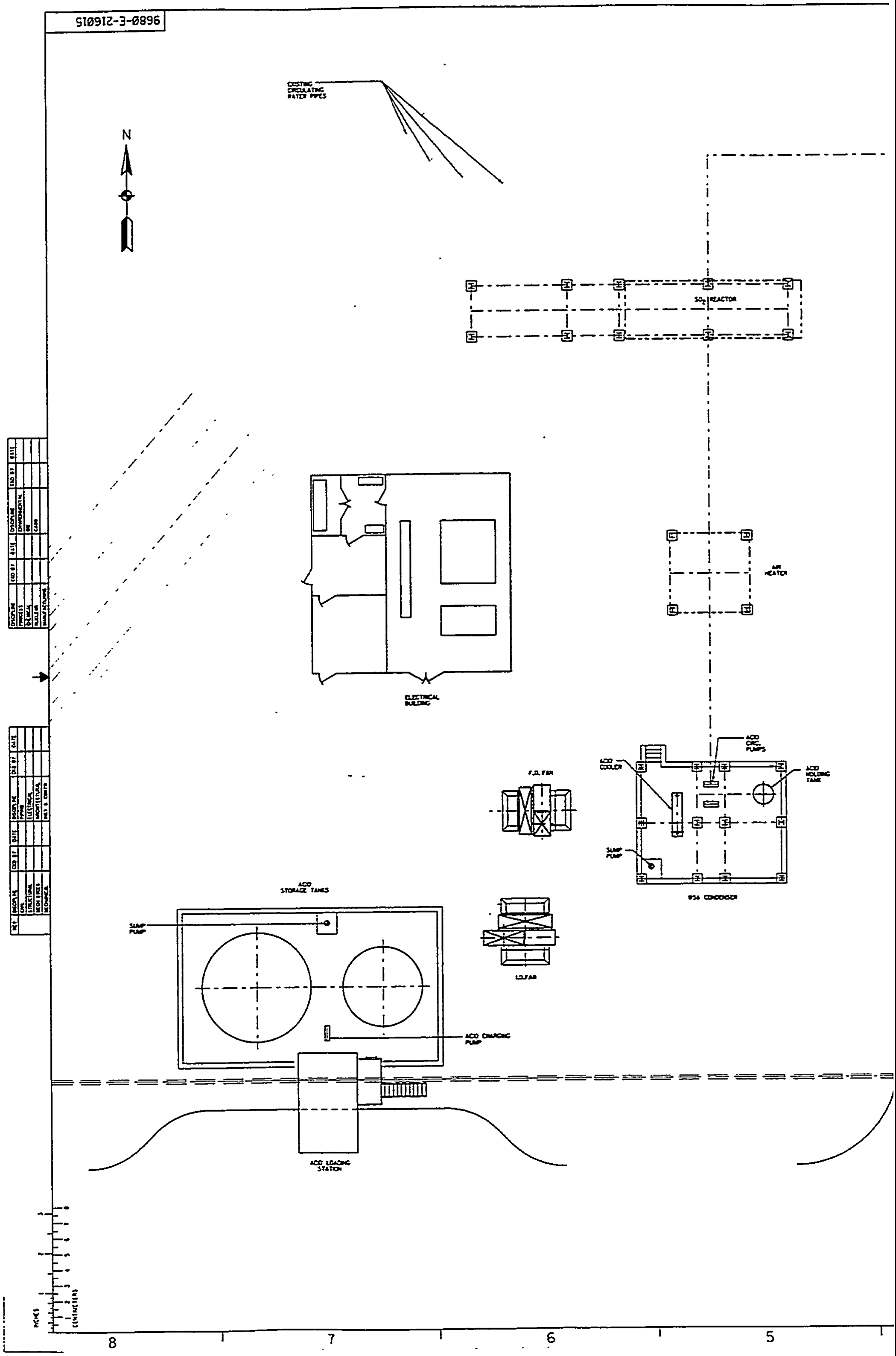
PLOT PLAN

P.E. SIGNATURE
STATE REG. No. DATE
SCALE 1"-30'-0"

ABB / Raytheon Engineers & Constructors

DWG 9680-E-216014 REV

04-18 1995 11:09:48 216014.DGN



9680-E-216015
EXISTING CIRCULATING WATER PIPES
N
SO_2 REACTOR
AIR HEATER
ELECTRICAL BUILDING
F.D. FAN
ACID COOLER
ACID CIRC. PUMPS
ACID HOLDING TANK
SUMP PUMP
WSA CONDENSER
ACID STORAGE TANKS
SUMP PUMP
I.D. FAN
ACID CHARGING PUMP
ACID LOADING STATION
INCHES
CENTIMETERS
8
7
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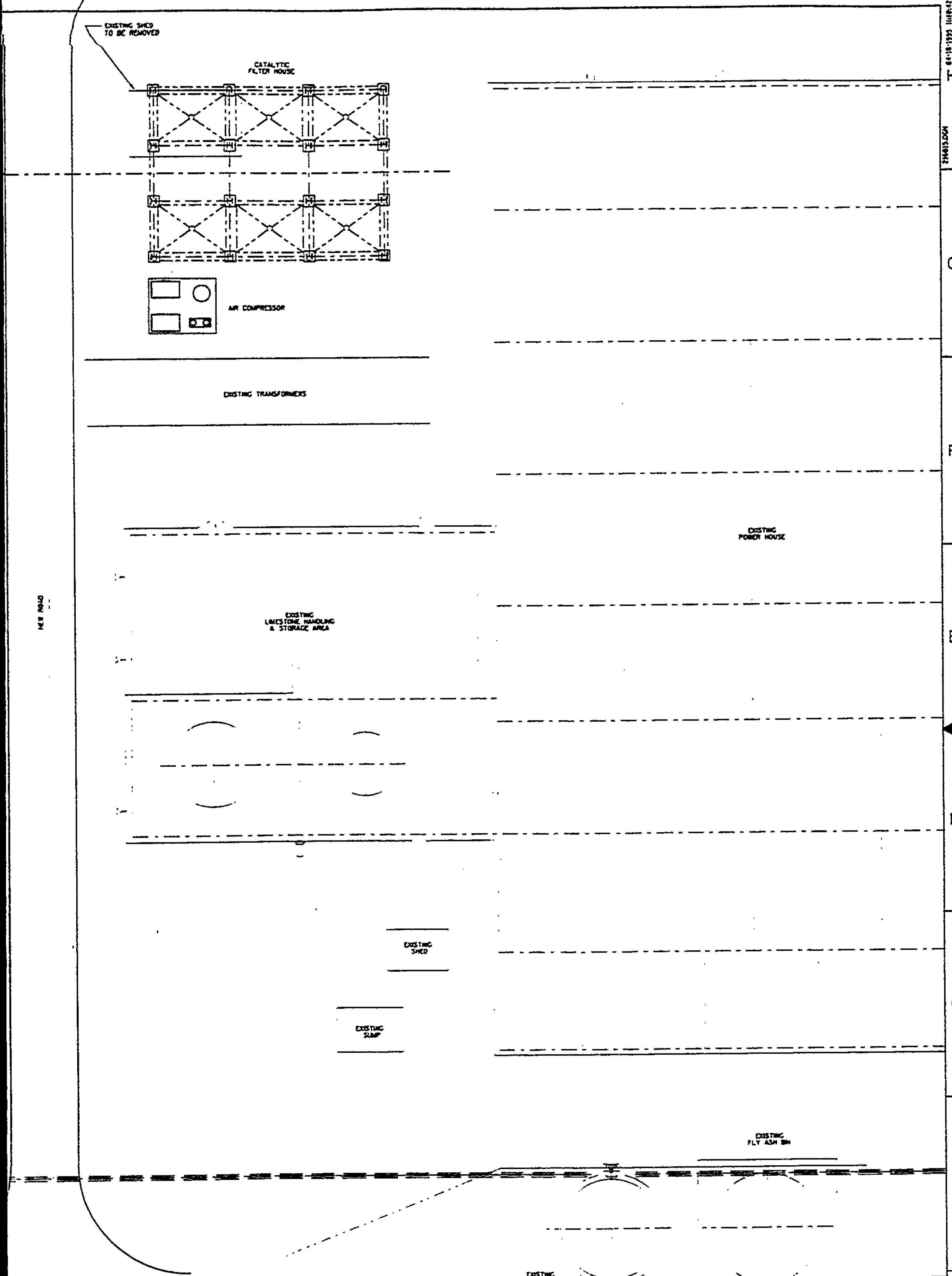

MACRO	REV	DATE	DESCRIPTION	DSNR	CHKR	RESP ENGR	PROJ MGR
			FIRST ISSUE				

DOE-LEBS PROJECT
PROOF OF CONCEPT TEST FACILITY
RICHMOND POWER & LIGHT - WHITEWATER VALLEY UNIT NO. 1

GENERAL ARRANGEMENT
PLAN AT GRADE LEVEL

P.E. SIGNATURE
STATE REG. NO. DATE
SCALE 1/8" = 1'-0"

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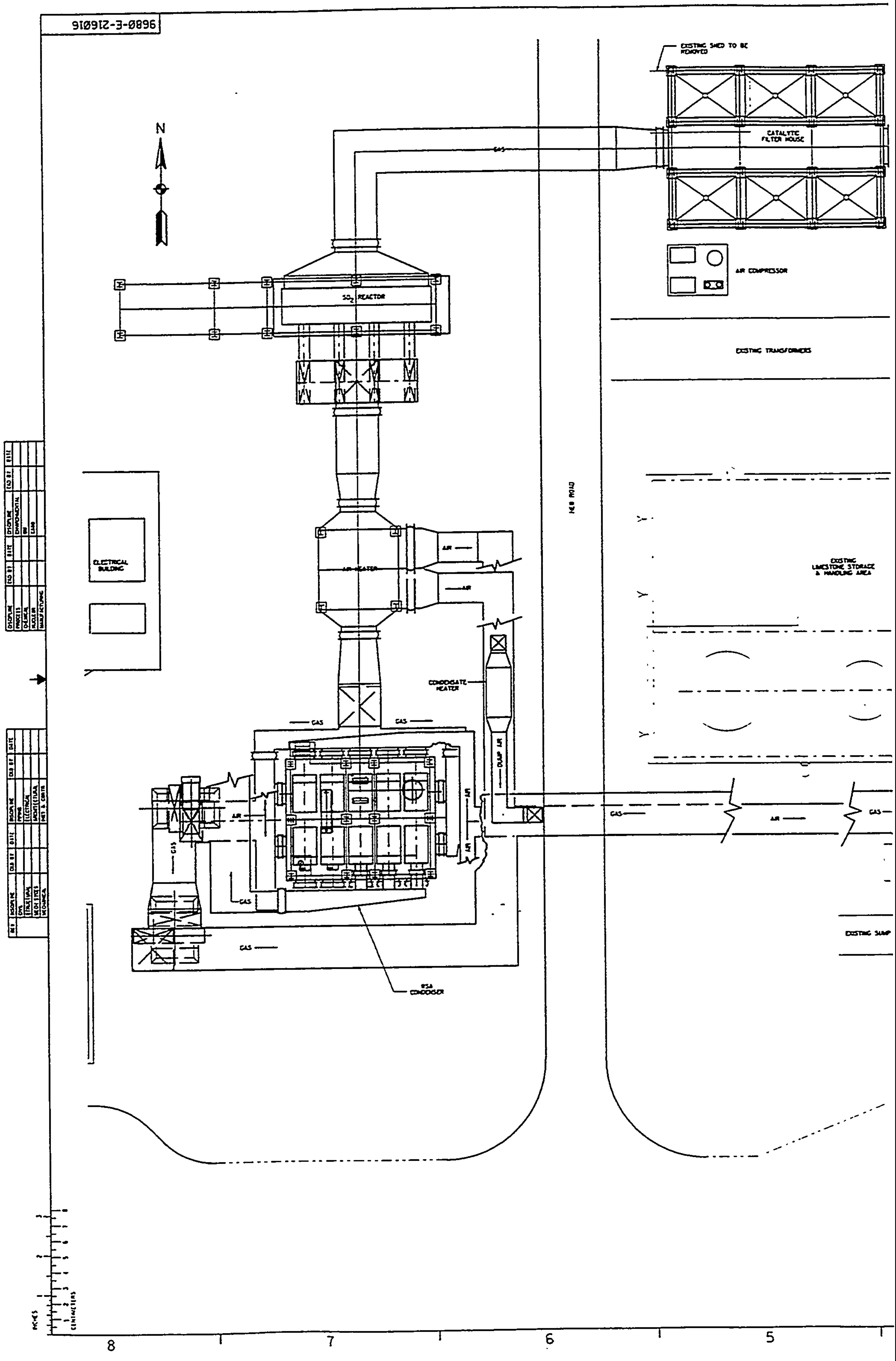
DWG 9680-E-216015 REV

WORK-IN-PROGRESS



9680-E-216016
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EXISTING SHED TO BE REMOVED
CATALYTIC FILTER HOUSE
GAS
AIR COMPRESSOR
SO2 REACTOR
EXISTING TRANSFORMERS
ELECTRICAL BUILDING
AIR HEATER
AIR
NEW ROAD
EXISTING LIMESTONE STORAGE & HANDLING AREA
CONDENSATE HEATER
DUMP AIR
WSA CONDENSER
EXISTING SUMP
8
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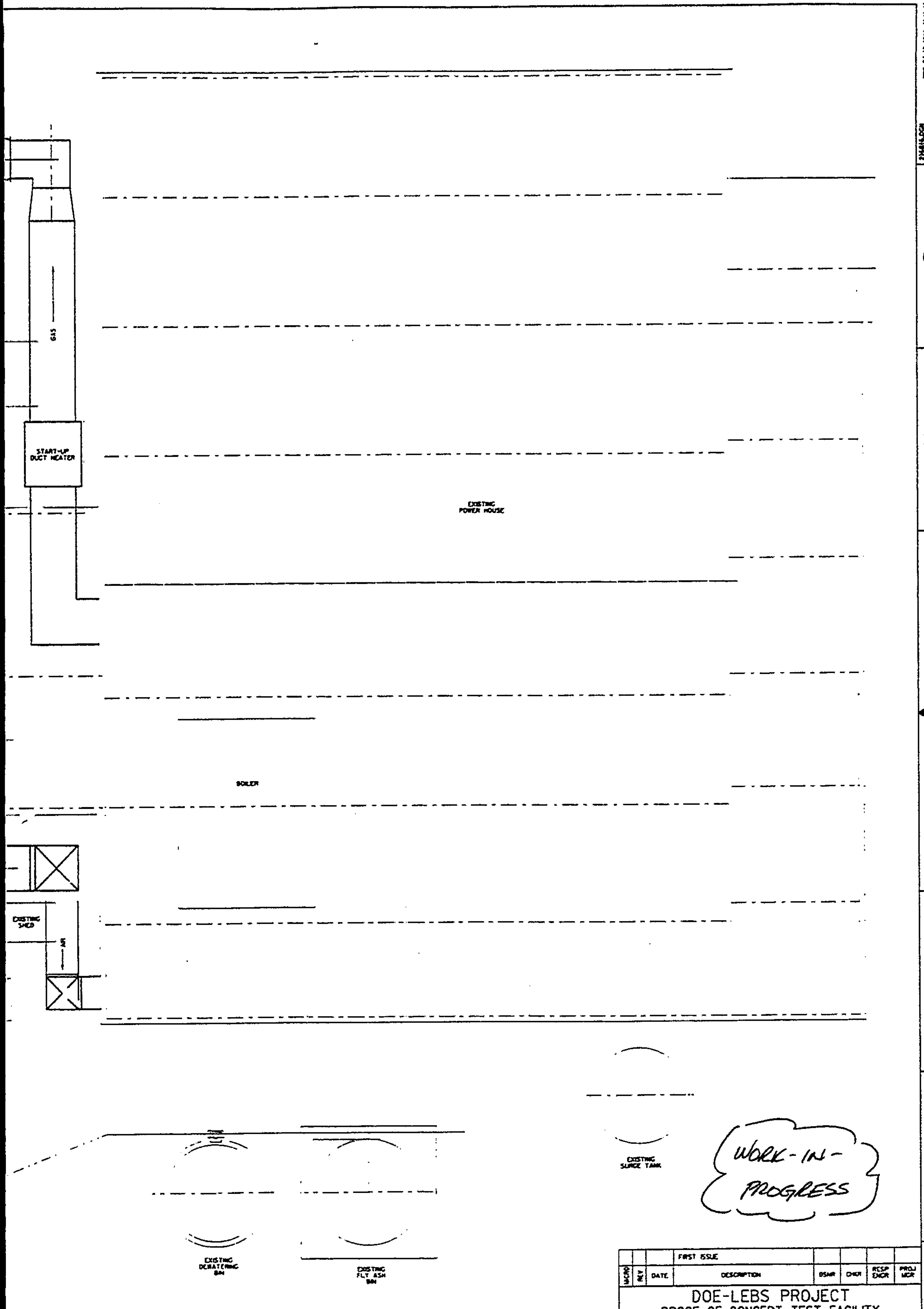


MICRO	REV	DATE	DESCRIPTION	DSNR	CHKR	RESP ENGR	PROJ MGR
			FIRST ISSUE				

DOE-LEBS PROJECT

PROOF OF CONCEPT TEST FACILITY

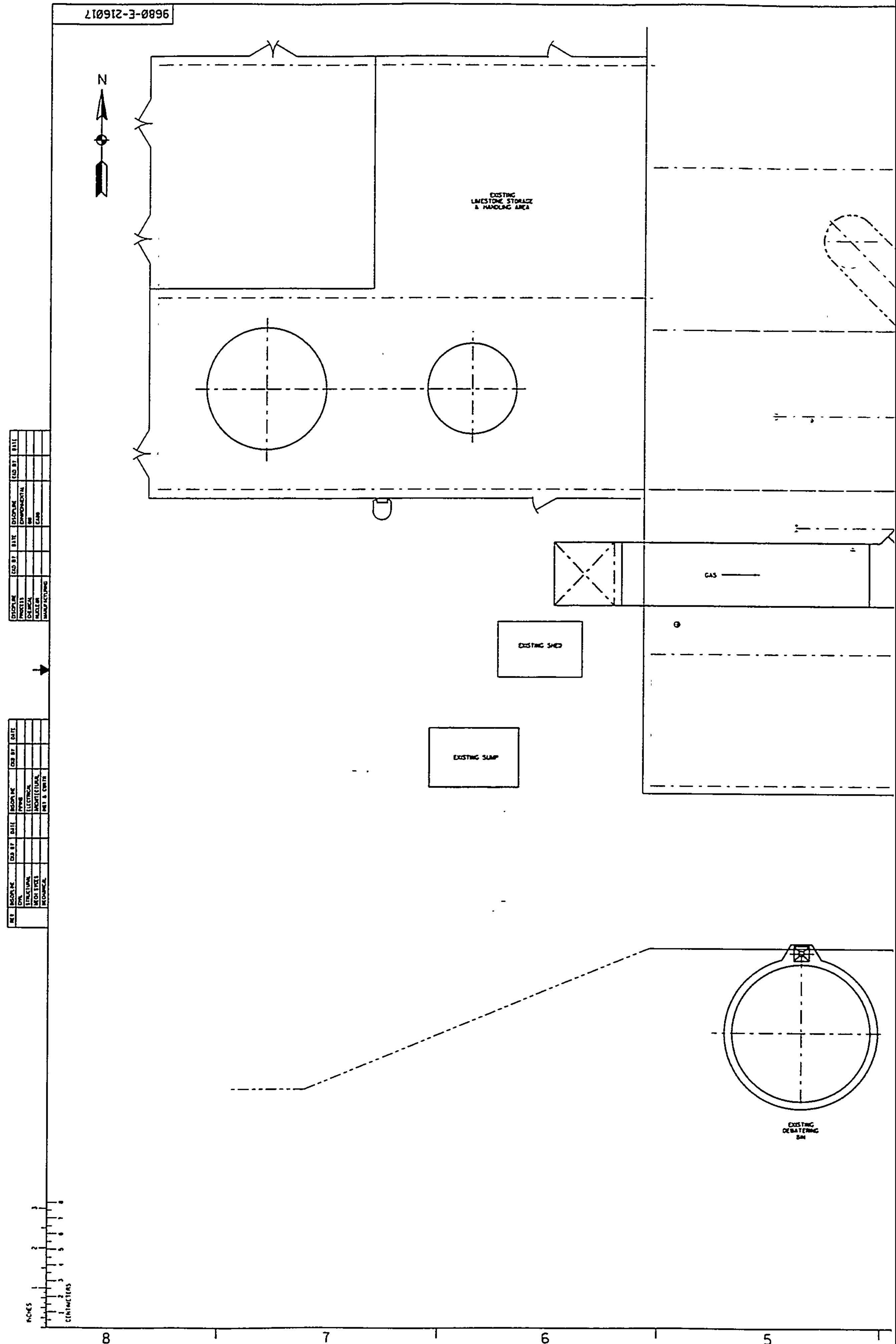
RICHMOND POWER & LIGHT - WHITEWATER VALLEY UNIT NO. 1

GENERAL ARRANGEMENT
PLAN ABOVE GRADE

SCALE 1/8" = 1'-0"

ABB / Raytheon Engineers & Constructors

DWG 9680-E-216016 REV


9680-E-216017
N
EXISTING LIMESTONE STORAGE & HANDLING AREA
GAS
EXISTING SHED
EXISTING SUMP
EXISTING DEWATERING BIN
INCHES
CENTIMETERS
8
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6
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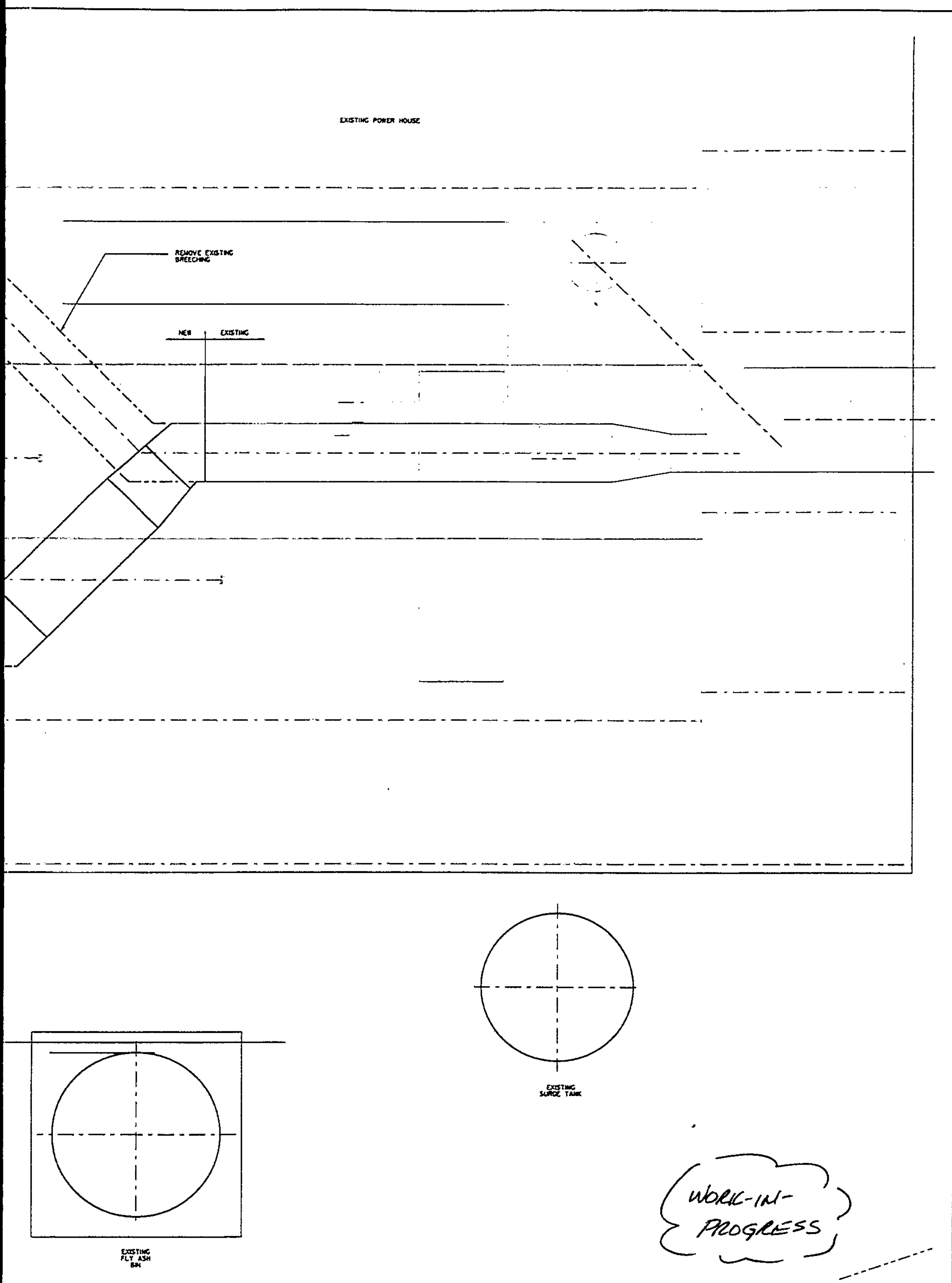

MICRO	REV	DATE	DESCRIPTION	DSNR	CHKR	RESP ENGR	PROJ MGR
			FIRST ISSUE				

DOE-LEBS PROJECT
PROOF OF CONCEPT TEST FACILITY
RICHMOND POWER & LIGHT - WHITEWATER VALLEY UNIT NO. 1

GENERAL ARRANGEMENT
PLAN AT ROOF

P.E. SIGNATURE
STATE REG. No. DATE
SCALE 3/16"=1'-0"

ABB ASEA BROWN BOVERI / Raytheon Engineers & Constructors

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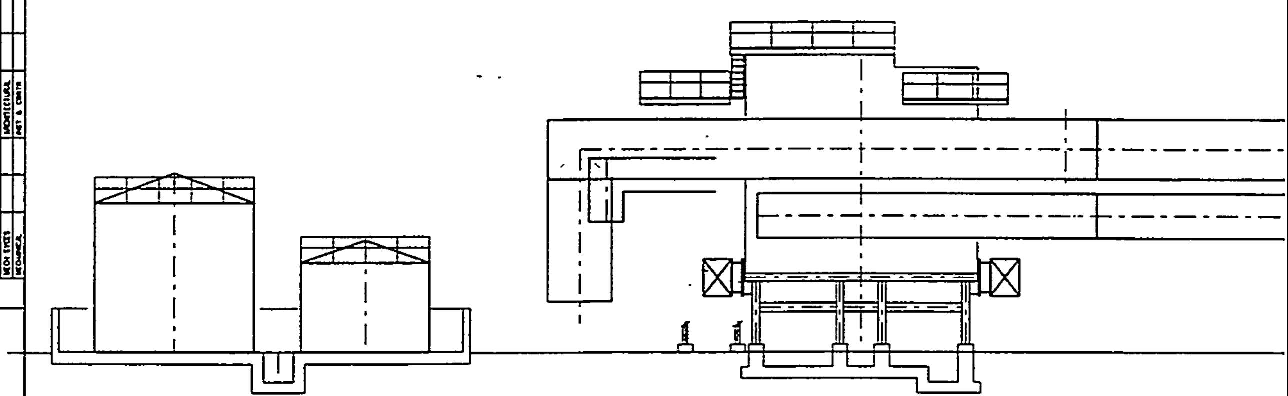
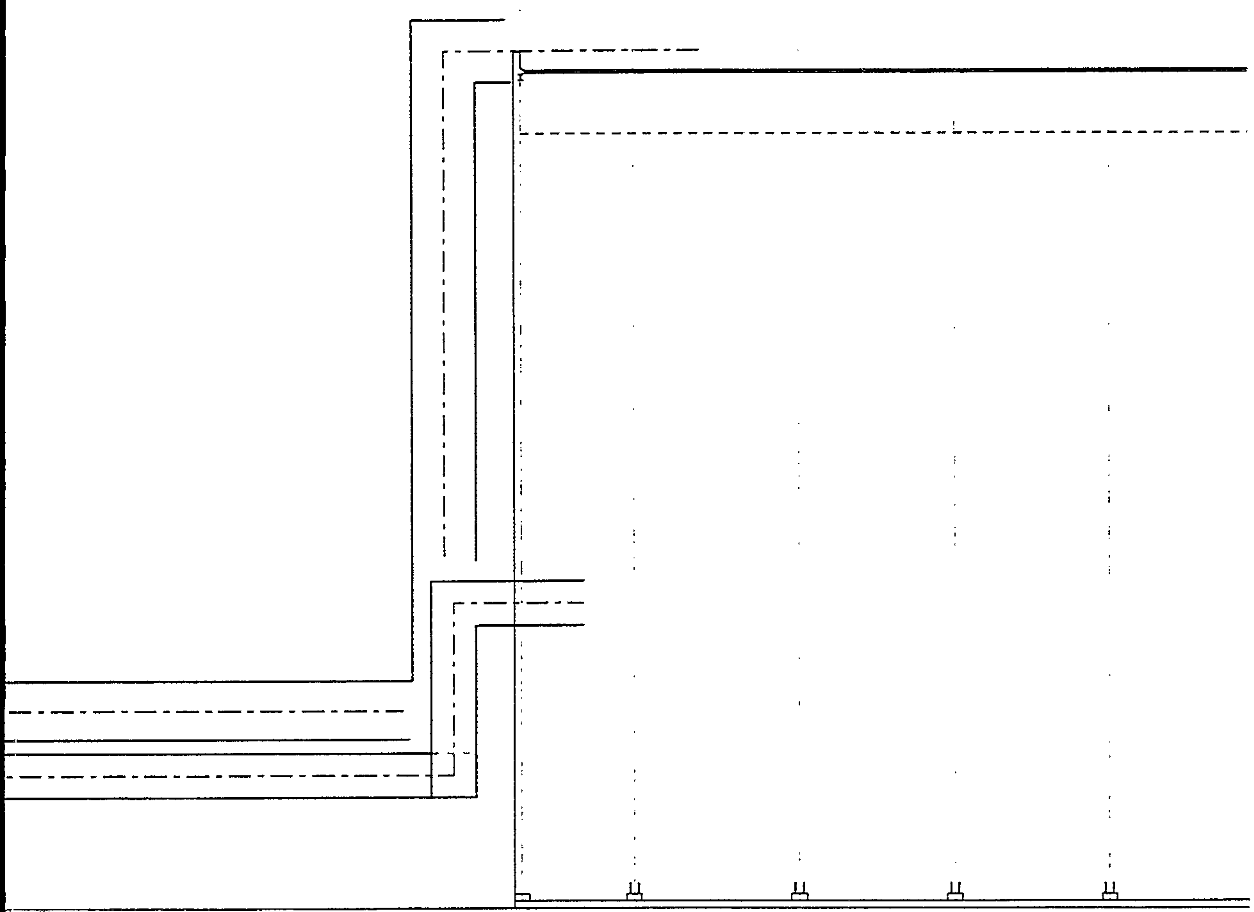
216017.DGN

9680-E-216018



8 7 6 5



WORK-IN-PROGRESS

MICRO	REV	DATE	DESCRIPTION	DSNR	CHKR	RESP ENGR	PROJ MGR
			FIRST ISSUE				

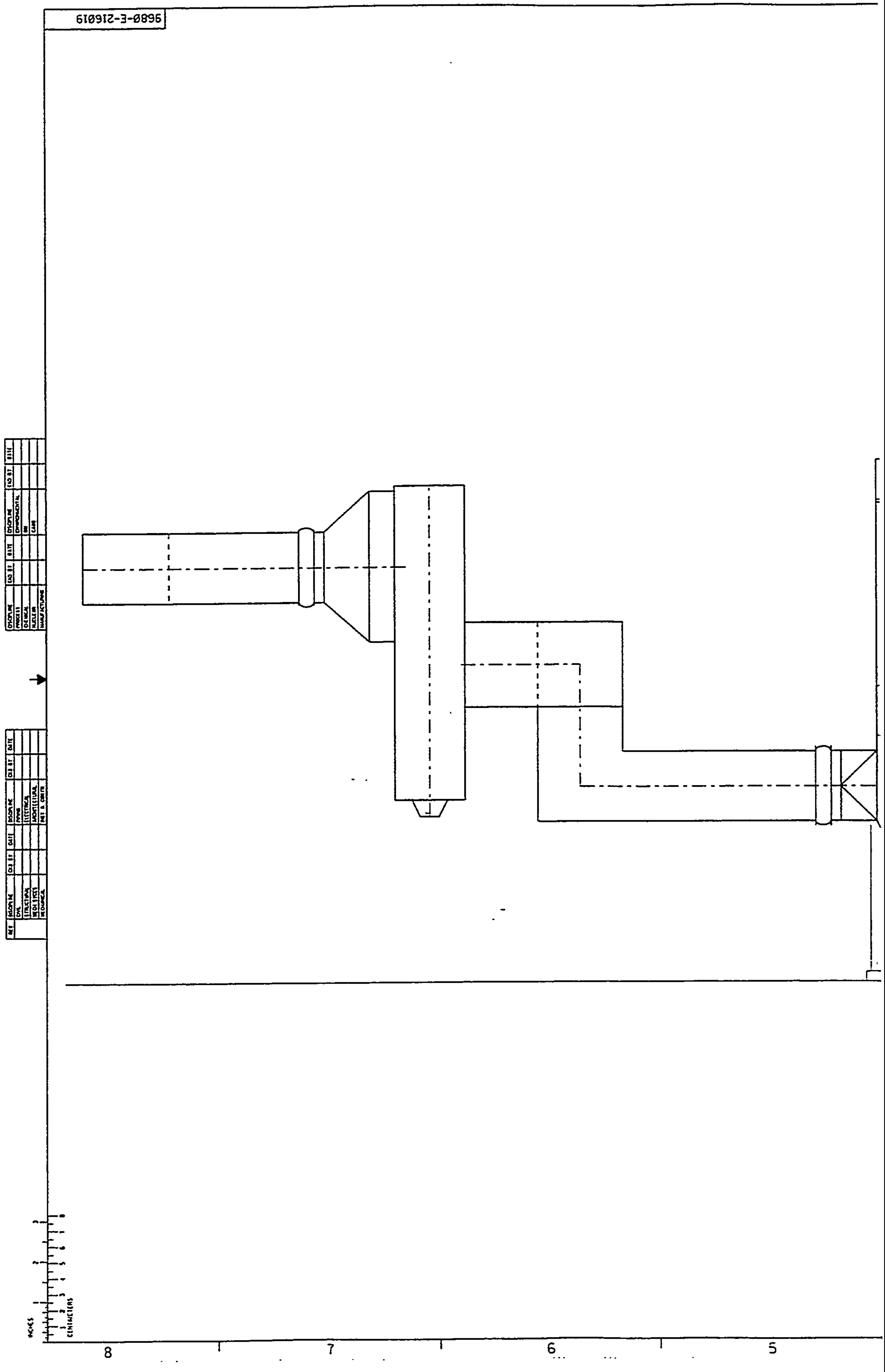
DOE-LEBS PROJECT
PROOF OF CONCEPT TEST FACILITY
RICHMOND POWER & LIGHT - WHITEWATER VALLEY UNIT NO. 1

GENERAL ARRANGEMENT
SECTION "A-A"

P.E. SIGNATURE
STATE REG. NO. DATE
SCALE 1/8" = 1'-0"

ABB ASEA BROWN BOVERI / Raytheon Engineers & Constructors

DWG 9680-E-216018 REV



9680-E-216019
8
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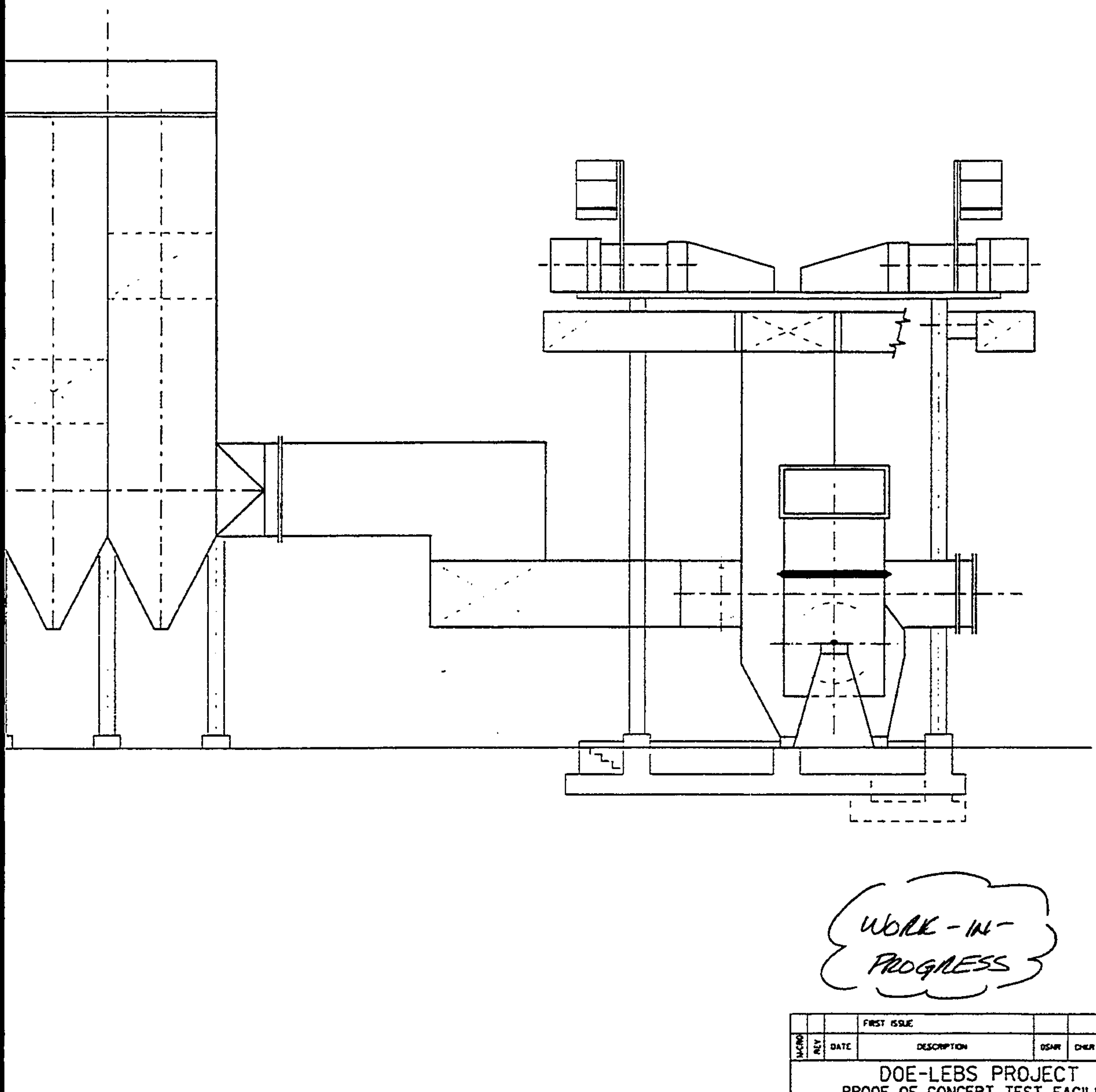


MICRO	REV	DATE	DESCRIPTION	DSNR	CHKR	RESP ENGR	PROJ MGR
			FIRST ISSUE				

DOE-LEBS PROJECT

PROOF OF CONCEPT TEST FACILITY

RICHMOND POWER & LIGHT - WHITEWATER VALLEY UNIT NO. 1

GENERAL ARRANGEMENT

SECTION "B-B"

P.E. SIGNATURE

STATE REG. No. DATE

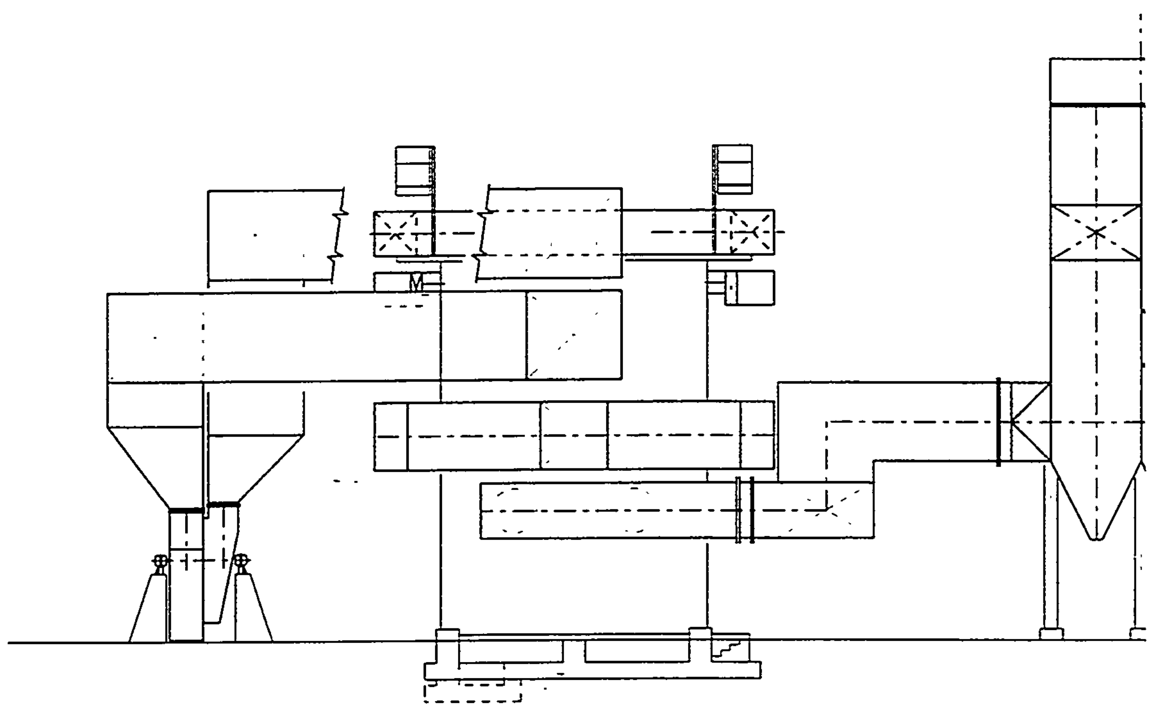
SCALE 3/8"=1'-0"

ABB / Raytheon Engineers & Constructors

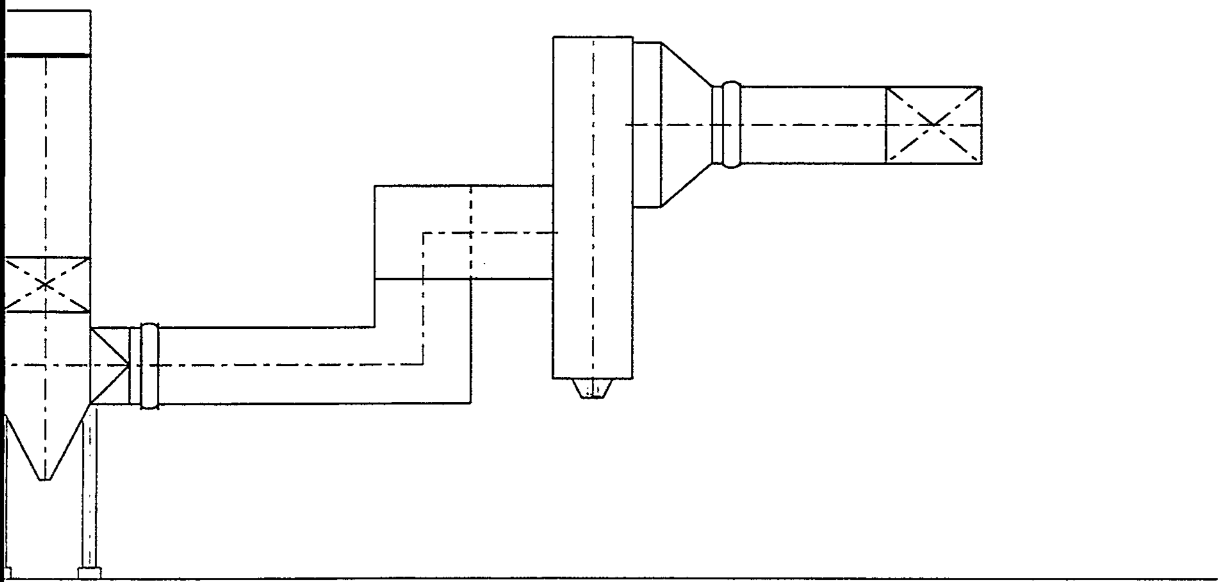
ASEA BROWN BOVERI

DWG 9680-E-216019 REV

9680-E-216020



8 7 6 5



WORK-IN-PROGRESS

MICRO	REV	DATE	DESCRIPTION	DSNR	CHKR	RESP ENGR	PROJ MGR
			FIRST ISSUE				

DOE-LEBS PROJECT
PROOF OF CONCEPT TEST FACILITY
RICHMOND POWER & LIGHT - WHITEWATER VALLEY UNIT NO. 1

P.E. SIGNATURE
STATE REG. No. DATE
SCALE 3/16"=1'-0"

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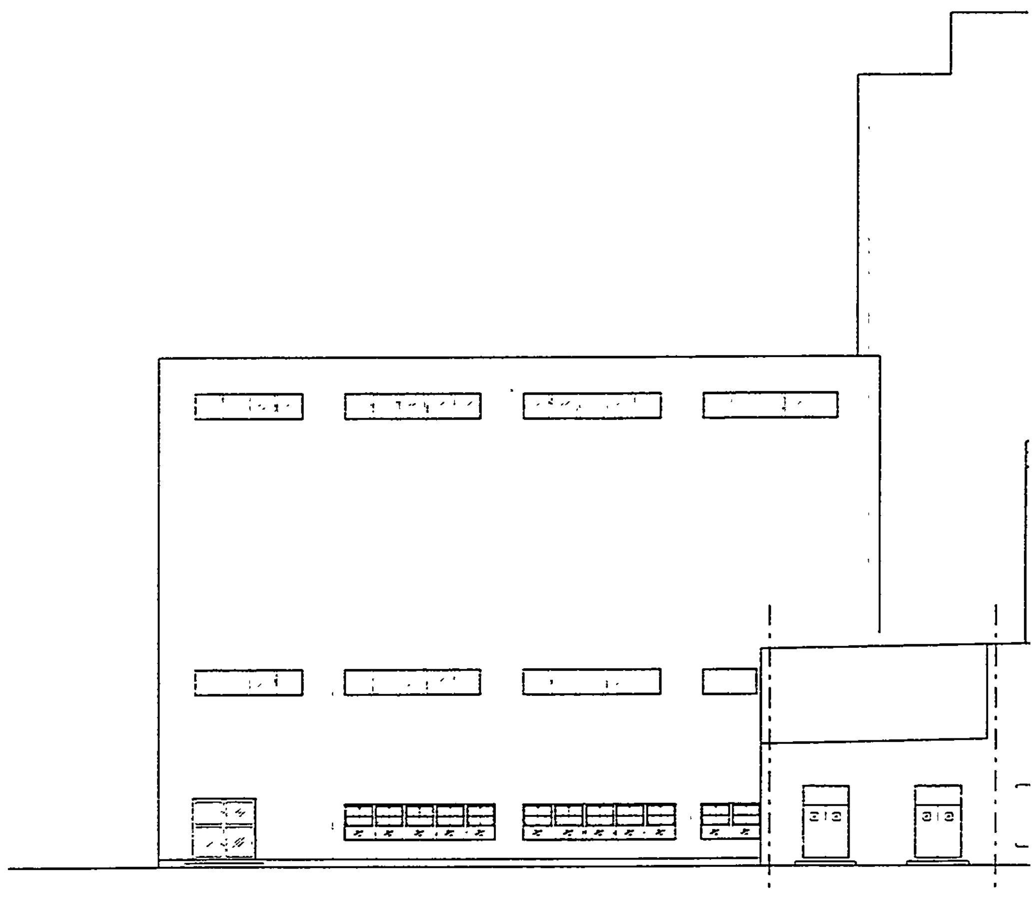
ASEA BROWN BOVERI

GENERAL ARRANGEMENT
SECTION "C-C"

DWG 9680-E-216020 REV

9680-E-216021



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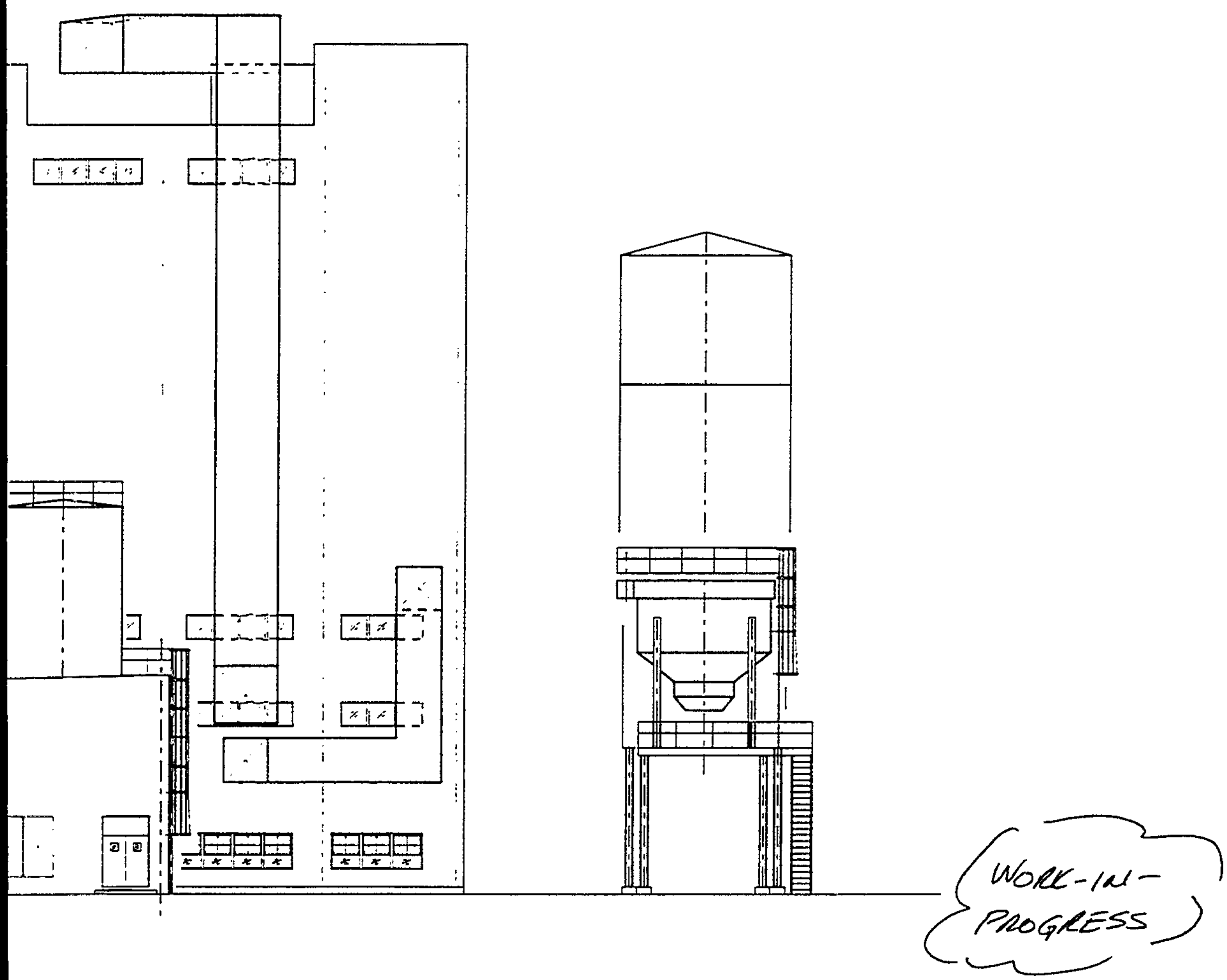

MACRO	REV	DATE	DESCRIPTION	DSNR	CHKR	RESP ENGR	PROJ MGR
			FIRST ISSUE				

DOE-LEBS PROJECT
PROOF OF CONCEPT TEST FACILITY
RICHMOND POWER & LIGHT - WHITEWATER VALLEY UNIT NO. 1

P.E. SIGNATURE
STATE REG. No. DATE
SCALE 1/8"=1'-0"

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ASEA BROWN BOVERI

GENERAL ARRANGEMENT SECTION "D-D"

DWG 9680-E-216021 REV

APPENDIX E

Form 3500
Rev. 3/93

Raytheon
Engineers & Constructors

Organization Fossil

Job Number 9680.008

File Number

Date March 7, 1995

Memo Number

To D. J. Bender

Copies

From W. L. DeLaurentis (Ext - ________)

Subject

Low Emissions Boiler System Project (LEBS)
Job No. 9680.008
Reference Turbine Heat Balances (Preliminary)

One of the tasks associated with the LEBS Project was to establish a baseline turbine heat balance for RP&L's Whitewater Valley Station Unit 1. During the past several months, we have been working with GE Power Systems (of Springdale, Ohio) in an effort to develop this information. This effort was necessary since our review of RP&L's station files and our discussions with RP&L personnel confirmed that heat balance diagrams/data did not exist for Unit 1. As such, we had to contact the turbine vendor (GE) and request his assistance in preparing the necessary diagrams/information.

Based on its records of Unit 1 and on subsequent work (after initial installation) that GE had performed on the unit, GE attempted to recreate the turbine heat balances for various conditions including: Valves Wide Open-5% Overpressure (VWO-5%OP), Design Point (100% Load), and several partial load conditions. Due to discrepancies between the GE records and the actual station arrangement, several iterations of these diagrams were developed.

Although minor inconsistencies still exist in the GE performance data, it was judged that the present information was sufficiently accurate for preliminary design purposes. Therefore, RE&C prepared the attached reference turbine heat balances for the existing plant configuration using the most recent GE performance calculations.

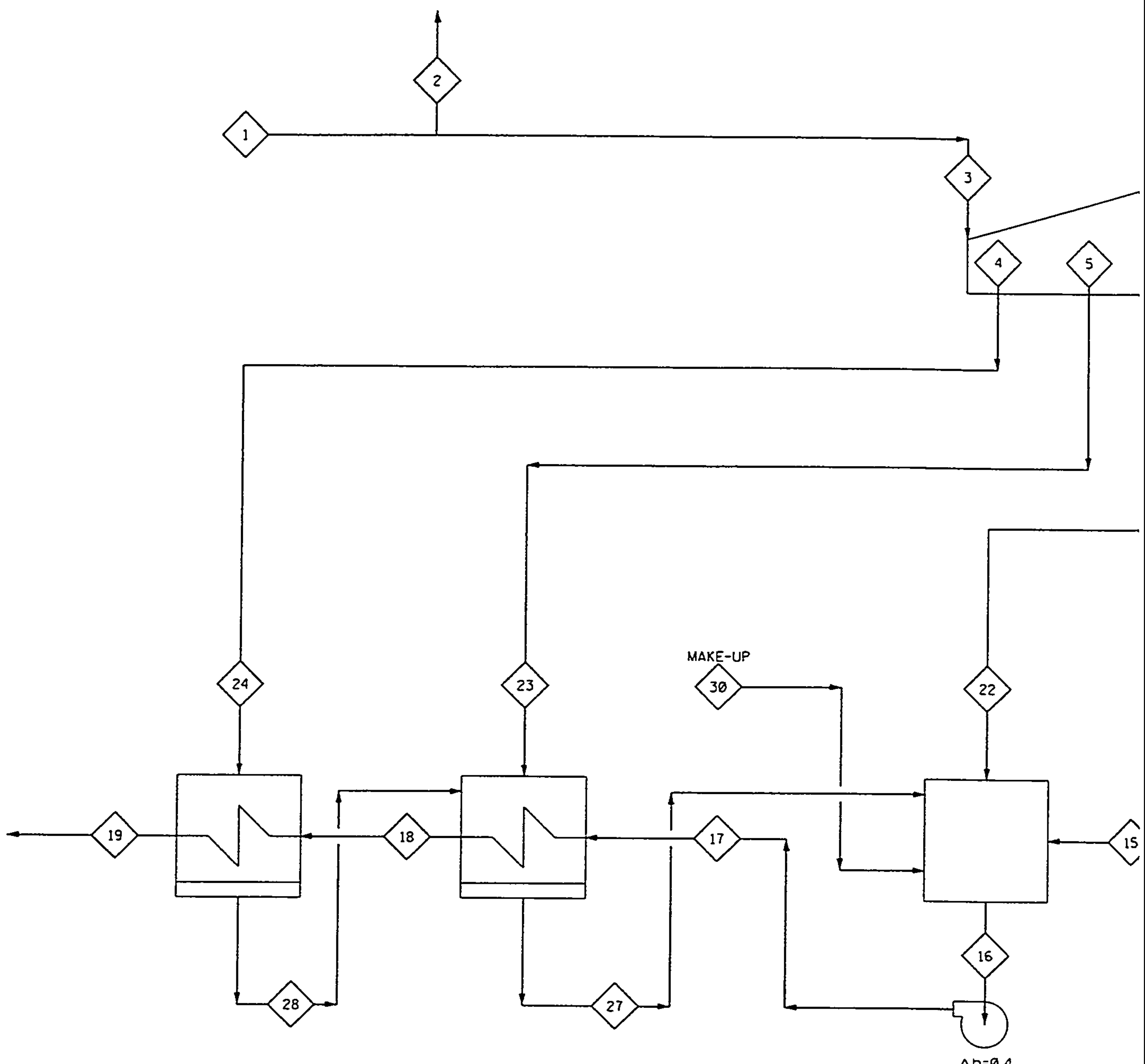
W. L. DeLaurentis

WLD/cld

2522CWP(1)

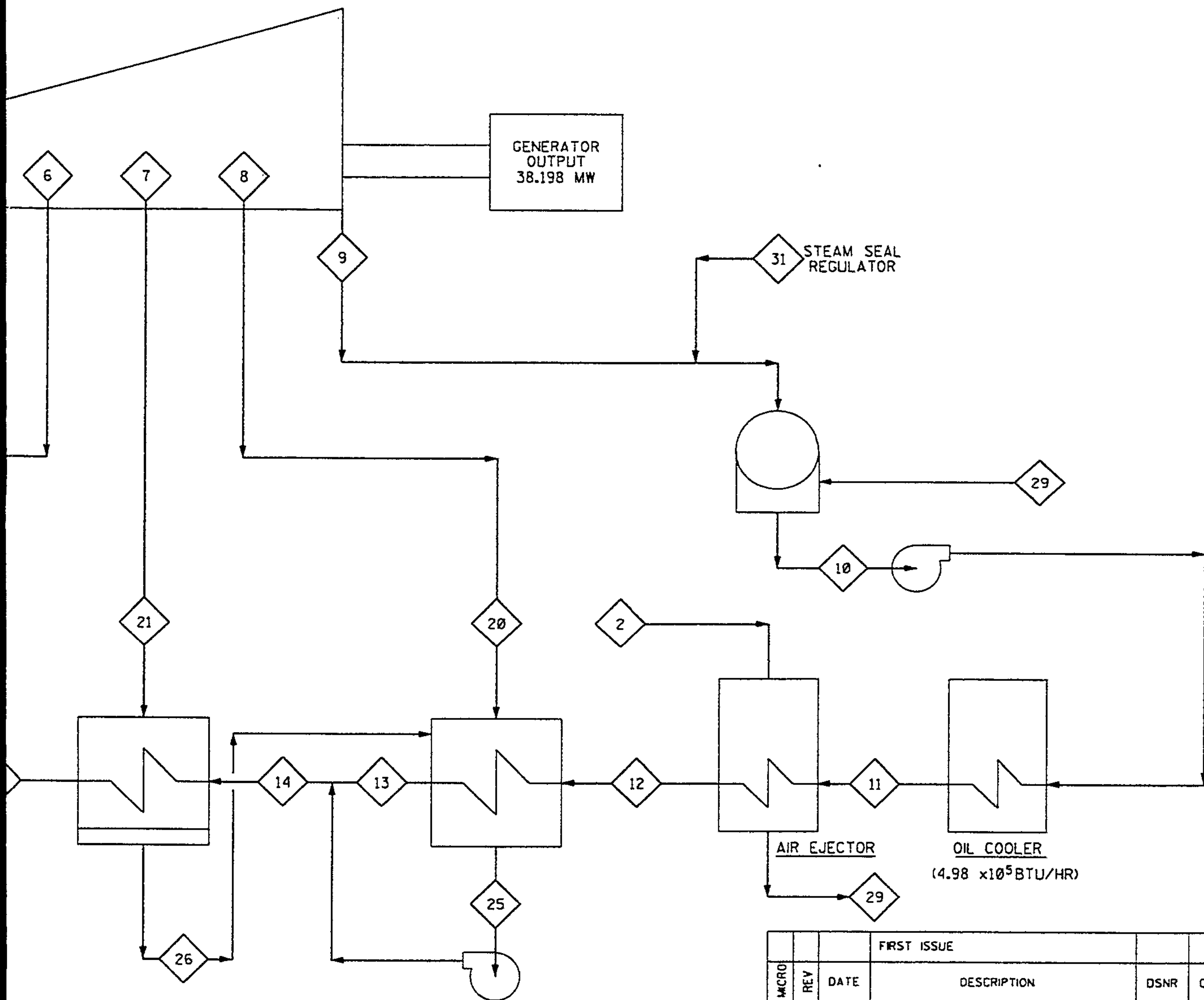
9680-D-216001 SH. 1

MEASUREMENT	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	1
FLOW RATE (LBS./HR.)	341,600	600	341,000	20,680	18,260	16,430	17,700	20,650	246,300	247,440	247,440	247,440	247,440	285,790	285,790	345,050	345
PRESSURE (PSIA)	954	954	906	352	183	85	32	9.23	0.737	0.737	—	—	—	—	68	—	-
TEMPERATURE (DEG. F.)	905	905	900	679	543	401	254	189	91.7	91.7	—	98.5	—	177	246	301	3
ENTHALPY (BTU/LB.)	1452.91	1452.91	1451.91	1354.91	1293.96	1230.52	1162.12	1088.28	987.94	59.72	—	66.65	—	144.85	214.75	270.84	27



8 7 6 5

7	18	19	20	21	22	23	24	25	26	27	28	29	30	31
.050	345,050	345,050	20,650	17,700	16,430	18,260	20,680	38,360	17,700	38,940	20,680	600	3,890	540
–	—	—	7.68	30.4	68	149	292	7.68	30.4	149	292	—	—	18
03	358	415	181	251	395	535	670	181	187	313	368	—	60	751
.74	331.64	392.36	1087.28	1161.12	1229.52	1292.96	1353.91	149.04	154.78	283.44	341.05	180.2	27	1408.71



MICRO	REV	DATE	DESCRIPTION	DSNR	CHKR	RESP ENG	PROJ MGR
			FIRST ISSUE				

DOE-LEBS PROJECT

PROOF OF CONCEPT TEST FACILITY

RICHMOND POWER & LIGHT - WHITEWATER VALLEY UNIT NO. 1

HEAT BALANCE
VWO 5% OVERPRESSURE CONDITION
EXISTING ARRANGEMENT

P.E. SIGNATURE
STATE REG. No. DATE
SCALE

ABB / Raytheon Engineers & Constructors
ASEA BROWN BOVERI

DWG 9680-D-216001 SH. 1 REV P

4 3 2 1

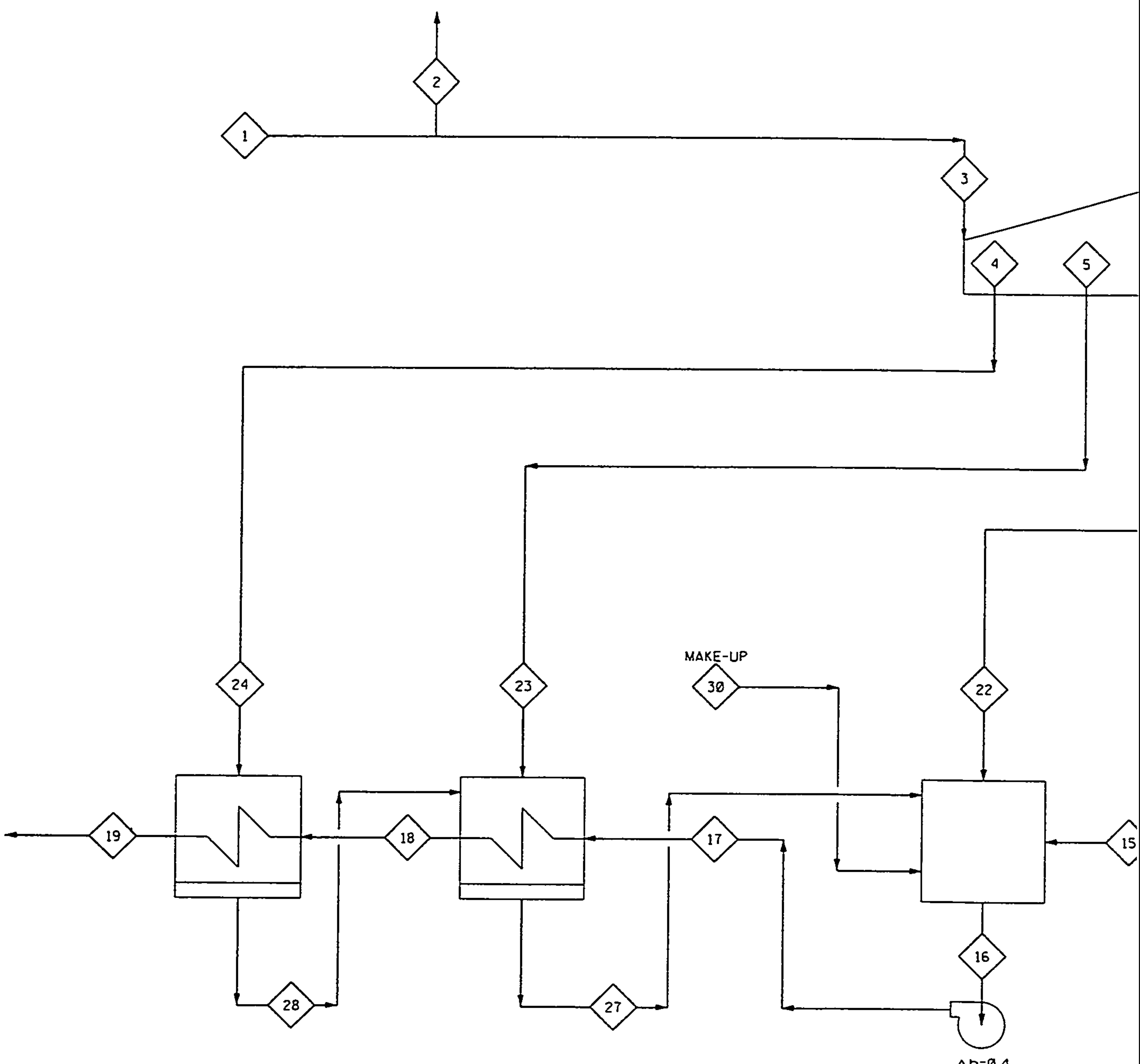
MICROSTATION 216001A.DGN 9680.008

03-27-1995 10:46:57

D C B A

9680-D-216001 SH. 2

MEASUREMENT	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	[illegible]
FLOW RATE (LBS./HR.)	310,600	600	310,000	19,250	17,460	17,230	13,690	19,450	221,940	223,080	223,080	223,080	223,080	256,220	256,220	313,740	313
PRESSURE (PSIA)	906	906	864	318	164	76	29	8.27	0.739	0.739	—	—	—	—	73.6	—	—
TEMPERATURE (DEG. F.)	905	905	900	667	530	388	248	184	91.8	91.8	—	99	—	180	243	306	3
ENTHALPY (BTU/LB.)	1454.45	1454.45	1453.45	1350.62	1288.94	1224.76	1157.2	1083.16	982.88	59.84	—	67.57	—	148.41	211.38	276.17	28



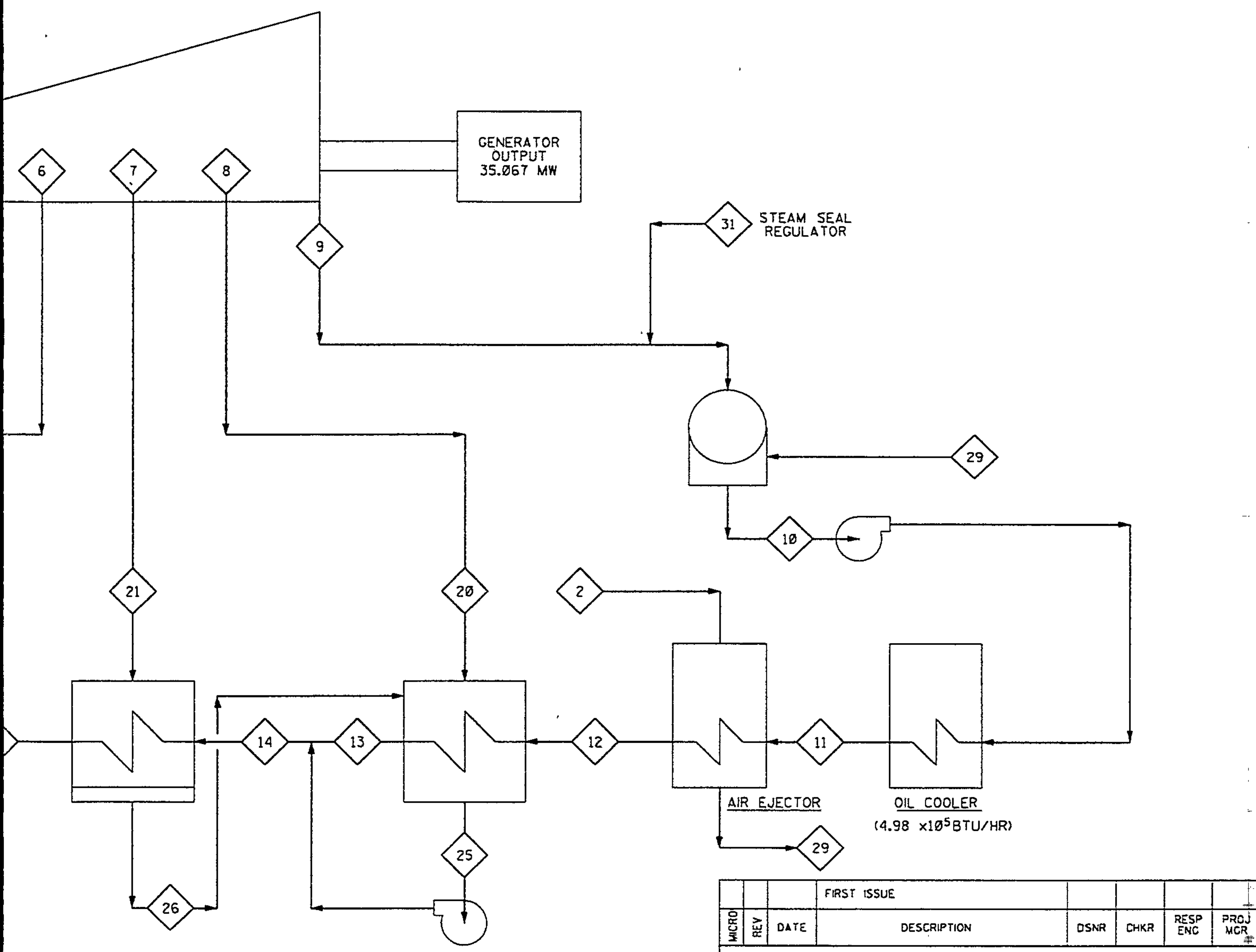
INCHES
CENTIMETERS

8 7 6 5

03-27-1995 09:45:20

7	18	19	20	21	22	23	24	25	26	27	28	29	30	31
740	313,740	313,740	19,450	13,690	17,230	17,460	19,250	33,140	13,690	17,460	19,250	600	3,140	540
--	—	—	8.18	28	74	162.4	314	8.18	28	162.4	314	—	—	18
08	365	422	184	246	385	528	665	184	246	318	375	—	60	752
.07	339.12	400.5	1082.16	1156.2	1223.76	1287.94	1349.62	152.01	214.53	288.3	348.2	180.17	27	1409.16

D



C

B

MICRO	REV	DATE	DESCRIPTION	DSNR	CHKR	RESP ENG	PROJ MGR
			FIRST ISSUE				

DOE-LEBS PROJECT

PROOF OF CONCEPT TEST FACILITY

RICHMOND POWER & LIGHT - WHITEWATER VALLEY UNIT NO. 1

A

P.E. SIGNATURE
STATE REG. No. DATE
SCALE

ABB ASEA BROWN BOVERI / Raytheon Engineers & Constructors

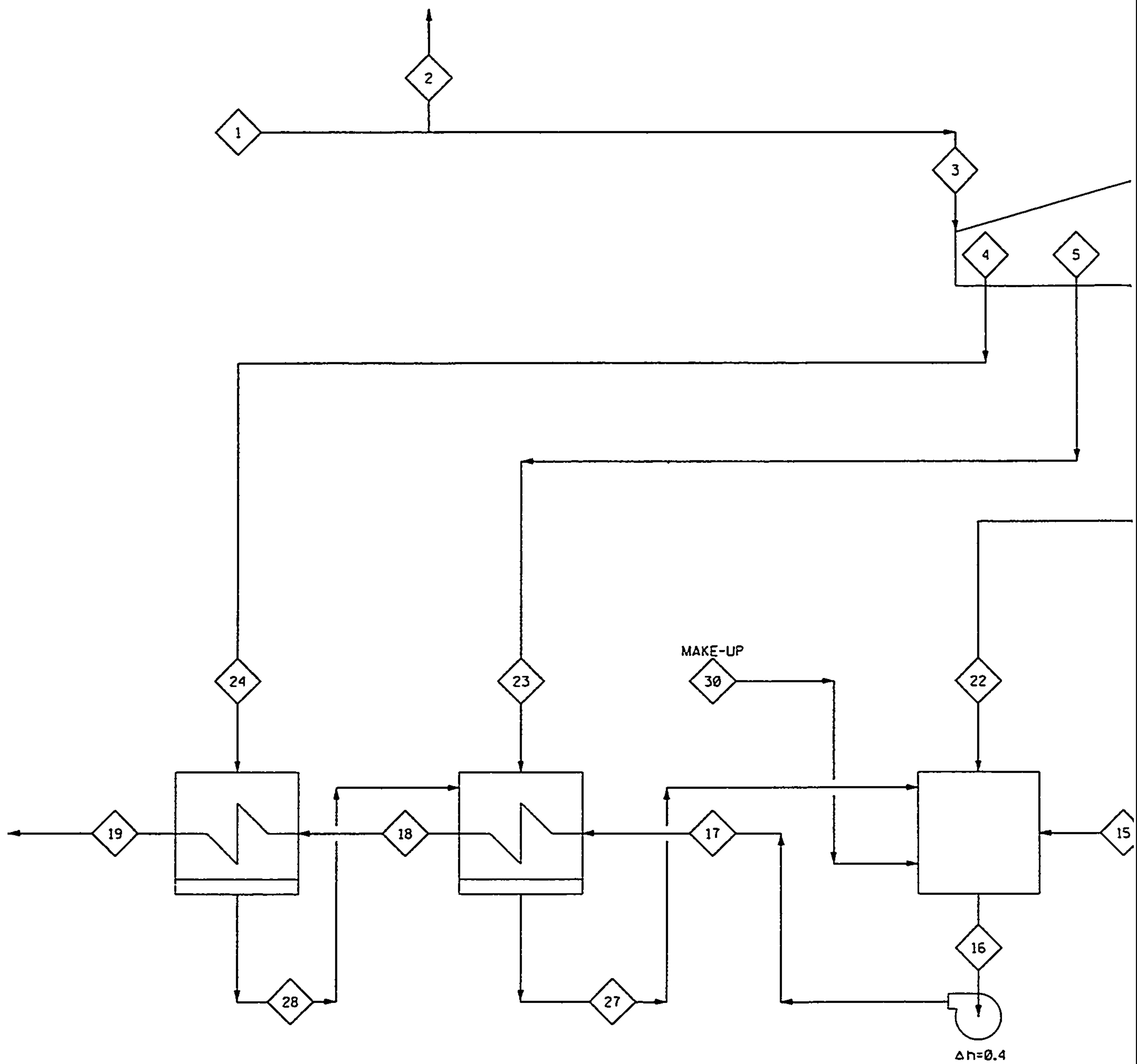
HEAT BALANCE
DESIGN CONDITION
EXISTING ARRANGEMENT

DWG 9680-D-216001 SH. 2 REV P

4 3 2 MICROSTATION 216001B.DGN 1 9680.008

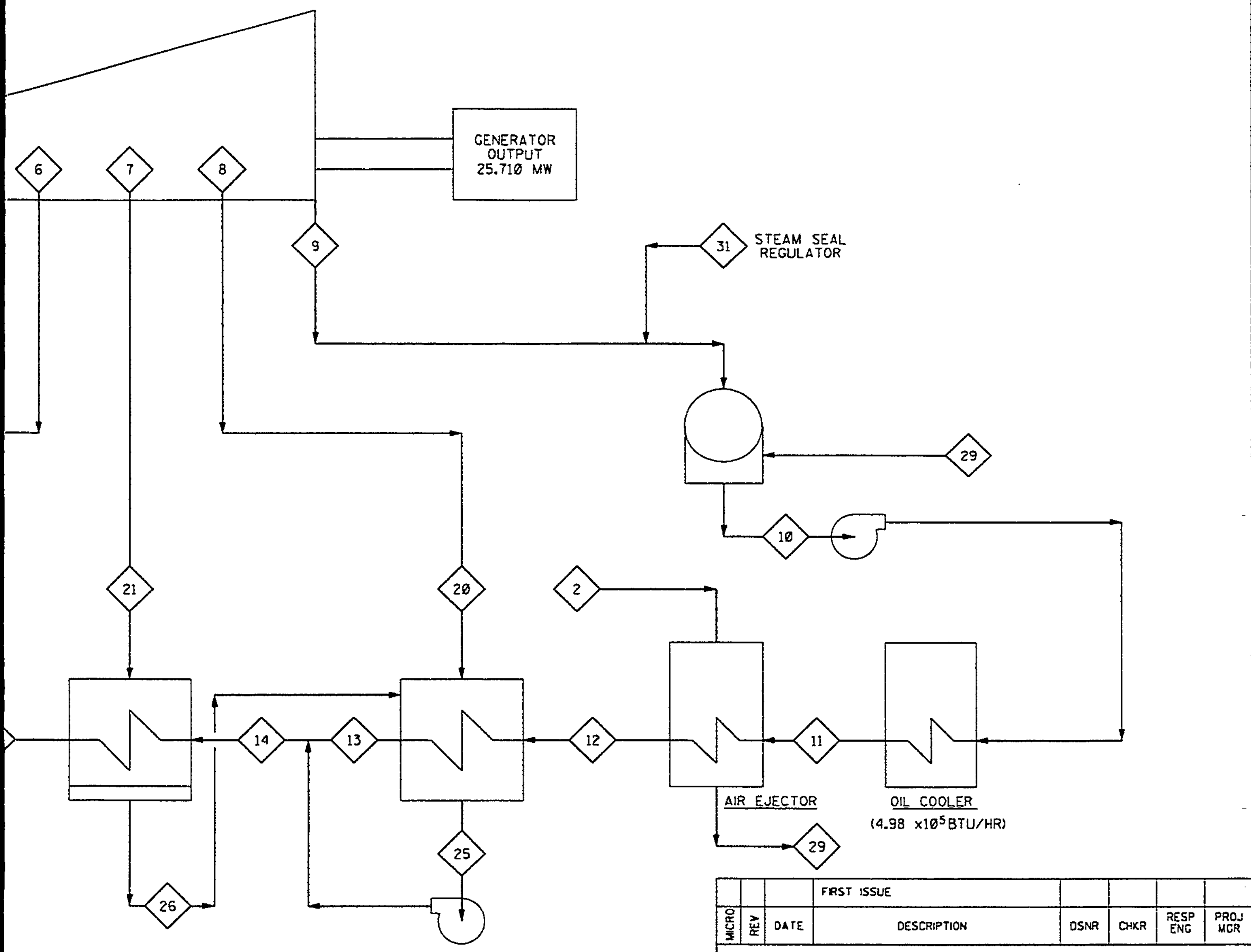
9680-D-216001 SH. 3

MEASUREMENT	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
FLOW RATE (LBS./HR.)	225,590	600	224,990	12,720	11,870	11,470	9,050	12,140	166,760	167,900	167,900	167,900	167,900	189,090	189,090	227,870	227.
PRESSURE (PSIA)	886.4	886.4	864	230	119	55.4	21.1	6.2	0.73	0.73	—	—	—	—	—	54.2	—
TEMPERATURE (DEG. F.)	903	903	900	637	505	369	231	171	91.5	91.5	—	101.6	—	169.2	228.1	285.9	288
ENTHALPY (BTU/LB.)	1454.45	1454.45	1453.45	1340.34	1280.02	1218.48	1151.96	1080.08	984.42	59.5	—	69.8	—	137.36	196.56	255.2	259



8 7 6 5

	18	19	20	21	22	23	24	25	26	27	28	29	30	31
870	227,870	227,870	12,140	9,050	11,470	11,870	12,720	21,190	9,050	24,590	12,720	600	2,280	540
	—	—	6.1	20.8	54.2	118.3	227.9	6.1	20.8	118.3	227.9	—	—	18
.2	342.3	396	171	230	366.7	502.7	635	171	174	298.2	352.3	—	60	759
.41	315.15	372.03	1079.08	1150.96	1217.48	1279.02	1339.34	138.98	141.98	267.9	324.2	180.2	27	1412.75



MICRO	REV	DATE	DESCRIPTION	DSNR	CHKR	RESP ENG	PROJ MGR
			FIRST ISSUE				

DOE-LEBS PROJECT
PROOF OF CONCEPT TEST FACILITY
RICHMOND POWER & LIGHT - WHITEWATER VALLEY UNIT NO. 1

P.E. SIGNATURE
STATE REG. No. DATE
SCALE

ABB ASEA BROWN BOVERI / Raytheon Engineers & Constructors

HEAT BALANCE
73% CONDITION
EXISTING ARRANGEMENT

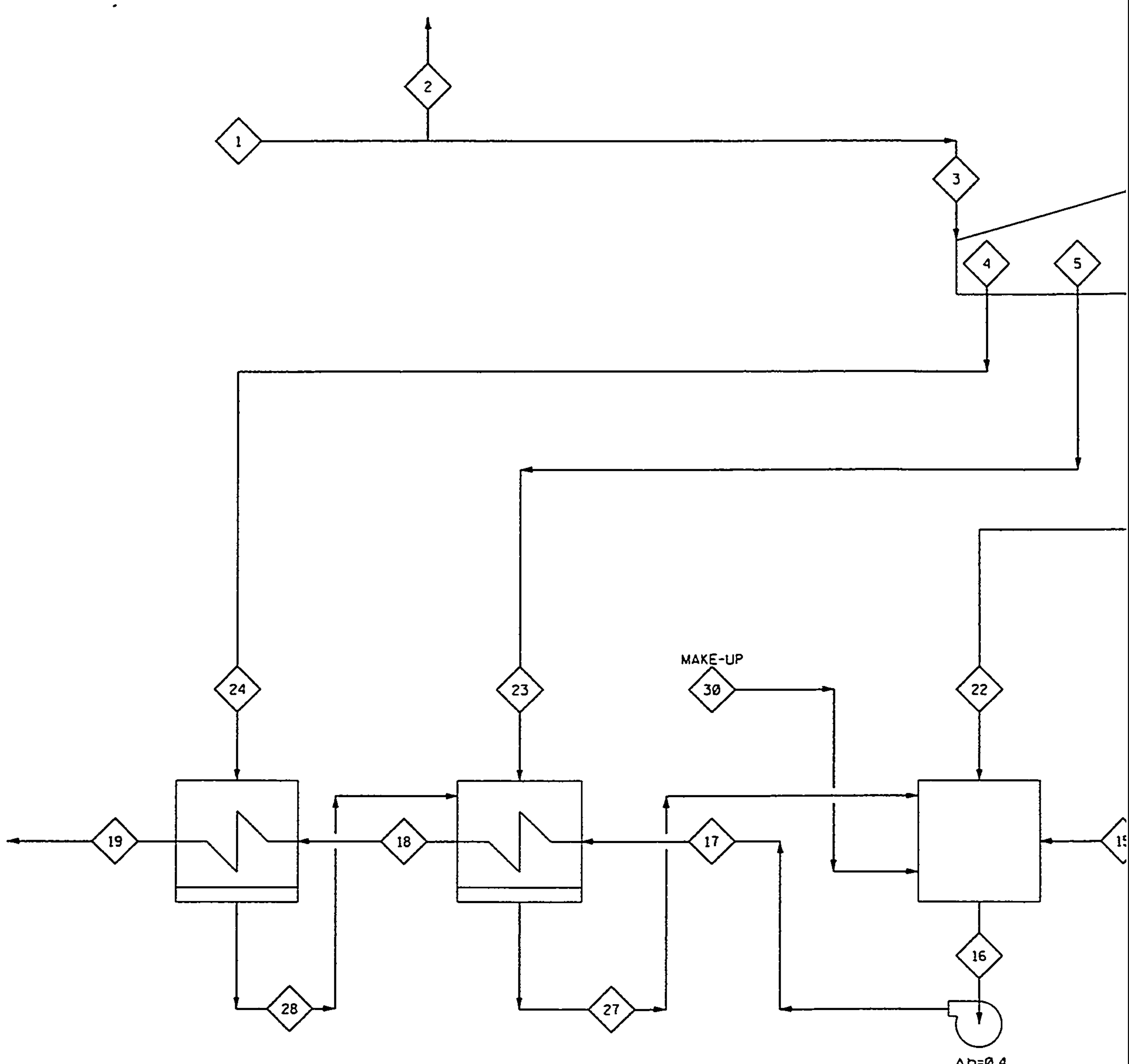
A

DWG 9680-D-216001 SH. 3 REV P

4 3 2 MICROSTATION 216001C.DGN 1 9680.008

9680-D-216001 SH. 4

MEASUREMENT	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	1
FLOW RATE (LBS./HR.)	155,600	600	155,000	7,850	7,470	7,200	5,070	6,500	119,930	121,070	121,070	121,070	121,070	132,640	132,640	157,160	157
PRESSURE (PSIA)	875	875	864	159	83	38.7	14.9	4.4	0.73	0.73	—	—	—	—	—	38	-
TEMPERATURE (DEG. F.)	903	903	900	623	494	361	213	157	91.5	91.5	—	105.7	—	156.6	211.4	266	26
ENTHALPY (BTU/LB.)	1454.45	1454.45	1453.45	1337.43	1277.96	1217.18	1151.04	1081.24	998.56	59.5	—	73.82	—	124.69	179.7	234.6	23



REV	DISCIPLINE	CKD BY	DATE	DISCIPLINE	CKD BY	DATE	DISCIPLINE	CKD BY	DATE	DISCIPLINE	CKD BY	DATE
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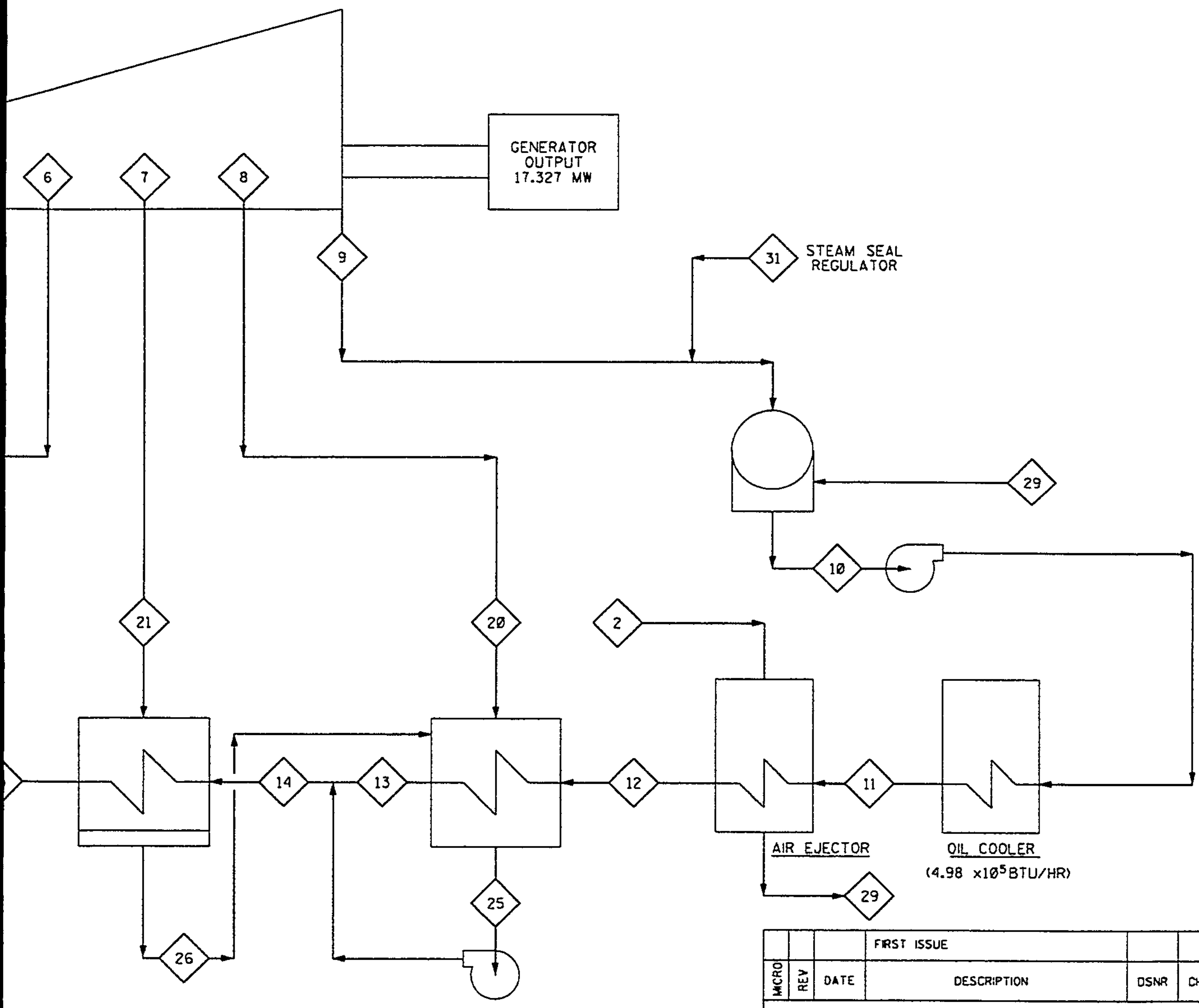
	STRUCTURAL			ELECTRICAL			CHEMICAL			CW		
	MECH SVCES			ARCHITECTURAL			NUCLEAR			CADD		
	MECHANICAL			INST & CONTR			MANUFACTURING					

INCHES 1 2 3
CENTIMETERS 1 2 3 4 5 6 7 8

8 7 6 5

7	18	19	20	21	22	23	24	25	26	27	28	29	30	31
.160	157,160	157,160	6,500	5,070	7,200	7,470	7,850	11,570	5,070	15,320	7,850	600	1560	540
-	—	—	4.4	14.8	38	82.4	158	4.4	14.8	82.4	158	—	—	18
.8	317.3	367.3	157	212.5	358.4	491.5	621.2	158.0	161.6	276.8	327.3	—	60	843
.61	289.19	341.25	1080.24	1150.04	1216.18	1276.96	1336.43	125.96	128.96	245.9	297.9	180.17	27	1454.45



MICRO	REV	DATE	DESCRIPTION	DSNR	CHKR	RESP ENG	PROJ MGR
			FIRST ISSUE				

DOE-LEBS PROJECT
PROOF OF CONCEPT TEST FACILITY
RICHMOND POWER & LIGHT - WHITEWATER VALLEY UNIT NO. 1

P.E. SIGNATURE
STATE REG. No. DATE
SCALE

ABB ASEA BROWN BOVERI / Raytheon Engineers & Constructors

HEAT BALANCE
50% CONDITION
EXISTING ARRANGEMENT

DWG 9680-D-216001 SH. 4 REV P

APPENDIX F

Form 3500
Rev 3/93

Raytheon
Engineers & Constructors

Organization		Job Number	9680.008
		File Number	4.1
Date	March 24, 1995	Memo Number	
To	File	Copies	
From	D. J. Bender (Ext. 3634)		
Subject	Composite Heat Balances		

Attached are the composite Unit 1 heat and mass balances for the maximum turbine operating point (that is, valves wide open, 5% overpressure). This combined performance estimate is composed of a gas-side heat and mass balance and a corresponding turbine heat balance. The later, the turbine balance, incorporates the heat addition from the SNO_x system.

Two gas-side balances are included here:

- 9680-D-216002 Sh. 2
- 9680-D-216002 Sh. 3

and correspond to the design coal case and the performance coal case, respectively (at VWO, 5%, OP). Two items are noted with regard to these diagrams.

1. The gas-side balances are based on an integration of performance estimates prepared by ABB CE and ABB ES. In addition, there is a minor mismatch between the gas-side and steam-side diagrams in that the boiler calculations were developed at a boiler steam generation of 340,600 lb/hr, whereas the corresponding main steam flow in the turbine heat balance is 341,600 lb/hr. At the present level of conceptual engineering, this mismatch is not considered significant.

2. The gas pressure values have not been completed in the tables on the diagrams, as the draft distribution has not yet been calculated.

It is also noted that a gas-side heat balance corresponding to boiler MCR operation (dwg. no. 9680-D-215002, Sh. 1), was issued previously. This drawing is now void as it was based on a preliminary estimate of maximum turbine steam flow

1141JWP

(of 330,000 lb/hr) that has since been revised upward (to 341,000 lb/hr) as a result of recent performance estimates from GE (see dwgs. no. 9680-D-216001, Sh. 1-4). The revised boiler MCR steam flow is therefore about 352,000 lb/hr, corresponding to 1.03 times the maximum turbine flow. The boiler performance calculations and gas-side balance will have to be revised accordingly at a later time.

With the SNO_x configuration, incremental heat is added to the turbine cycle through the condensate heater. This unit recovers heat from the hot dump air and transfer it to condensate that is by-passed around the two low pressure feedwater heaters. Because the amount of heat addition is very similar in both the design coal and performance coal cases (within 10%), only one turbine heat balance was prepared for these two gas-side conditions, corresponding to a heat addition that is an average of the two. See drawing no.

- 9680-D-216003, Sh. 1

The effect of this incremental heat addition is to increase the generator output by about 200 kWe at VWO/5% OP, from its current value of 38,198 kWe to 38,403 kWe.

Later work, in addition to updating the boiler MCR gas-side balance, will include composite gas-side and turbine balances at the turbine design point as well as two reduced load conditions.

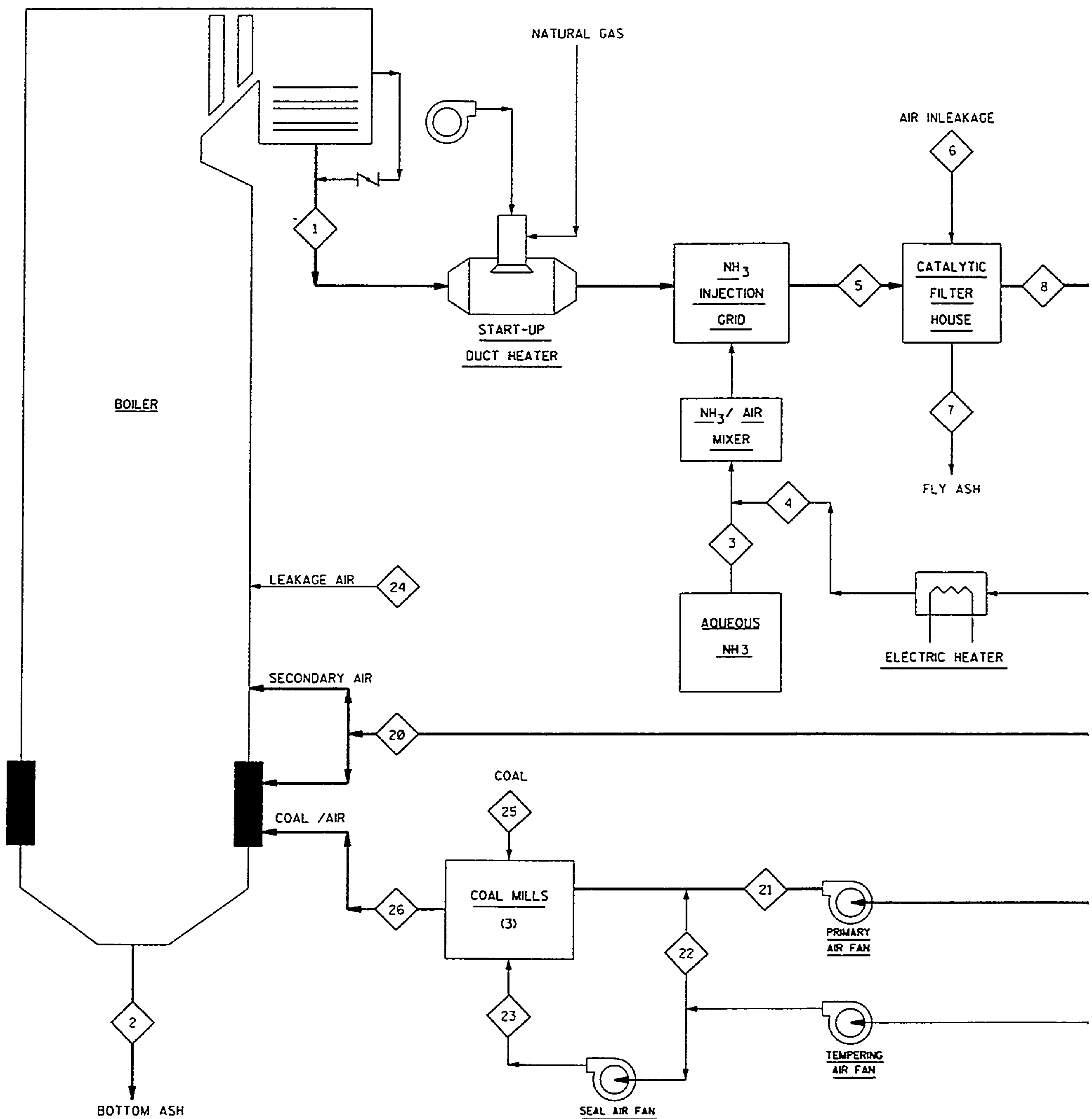
Dave Bender

1141JWP

9680-D-216002 SH.1

DESIGN CONDITIONS - BOILER OUTPUT (STEAM)-340,600 LBS./

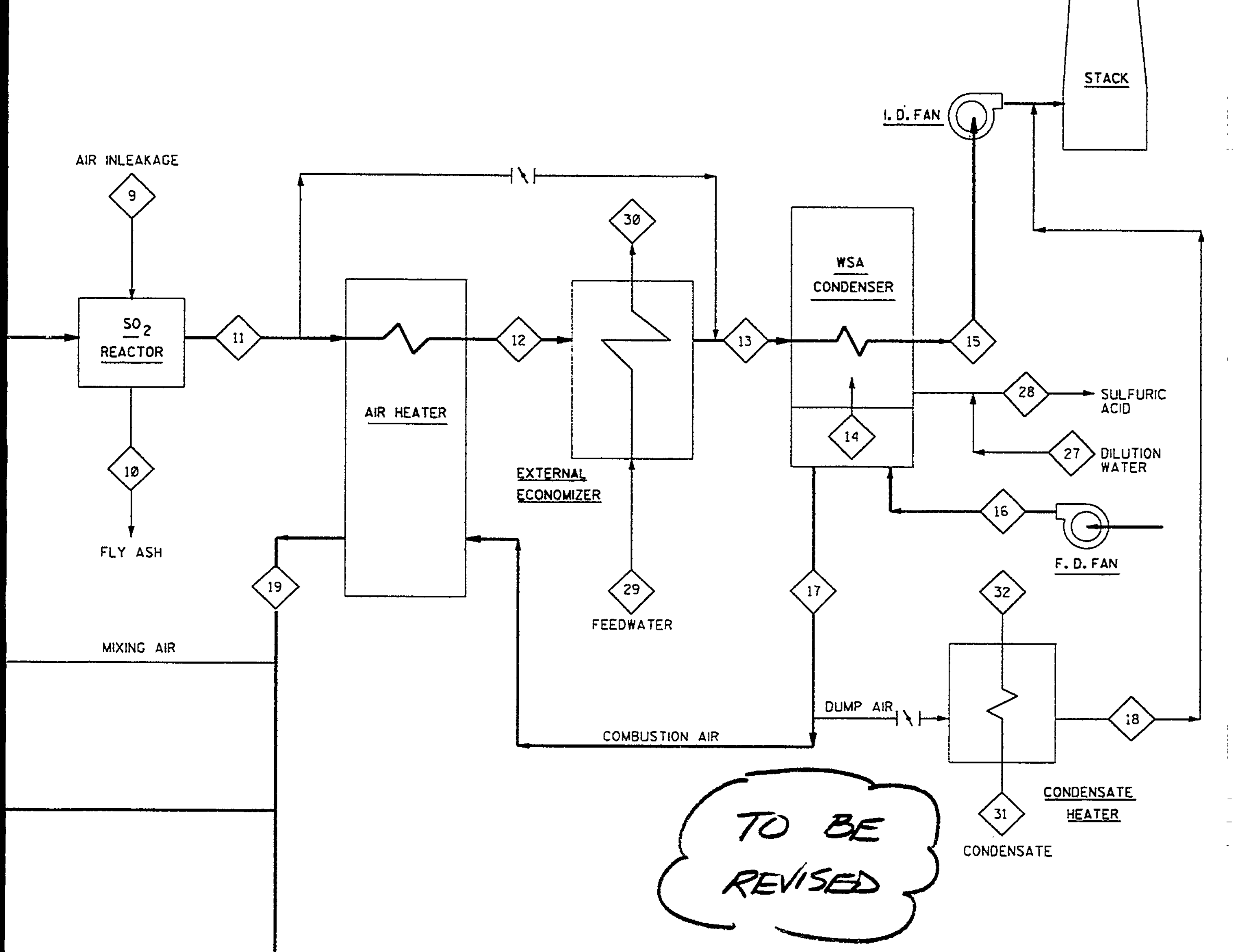
STATE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
GAS FLOW (LBS./HR.)	398,900	—	—	3,800	402,800	16,000	—	418,800	16,000	—	434,800	434,800	434,800	16,000	450,800	397,200
SOLID/LIQUID FLOW (LBS./HR.)	5,360	950	132	—	5,360	—	5,350	—	—	10	—	—	—	—	—	—
TEMPERATURE (DEG. F)	793	—	80	620	778	80	768	768	80	761	761	651	497	—	210	80
VOLUMETRIC FLOW (ACFM)	209,200	—	—		209,600		—			—				—		
PRESSURE (IN. W.G.)	(-11.0	—	—			—	—		—	—				—		



8 7 6 5

HR. FUEL HHV- 10,400 LBS./HR.

17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33
381,200	96,700	295,700	245,400	46,500	26,900	27,300	20,100	—	100,700	—	—	—	—	—	—	547,500
—	—	—	—	—	—	—	—	39,430	39,430	92	4,874	344,000	344,000	51,700	51,700	—
450	150	621	621	621	80	80	80	80	170	80	140	422	468	100	236	200
							—	—	—	—	—	—	—	—	—	
			5.0				—	—	—	—	—	1000PSI	1000PSI	100PSI	100PSI	0.0



	B		RECONFIGURED				
	A		FIRST ISSUE -FOR REVIEW				
MICRO	REV	DATE	DESCRIPTION	DSNR	CHKR	RESP ENG	PROJ MGR

DOE-LEBS PROJECT
PROOF OF CONCEPT TEST FACILITY
RICHMOND POWER & LIGHT - WHITEWATER VALLEY UNIT NO. 1

P.E. SIGNATURE
STATE REG. No. DATE
SCALE NONE

ABB ASEA BROWN BOVERI / Raytheon Engineers & Constructors

GAS SIDE
HEAT AND MASS BALANCE
DESIGN COAL, BOILER MCR

DWG 9680-D-216002 SH. 1 REV B

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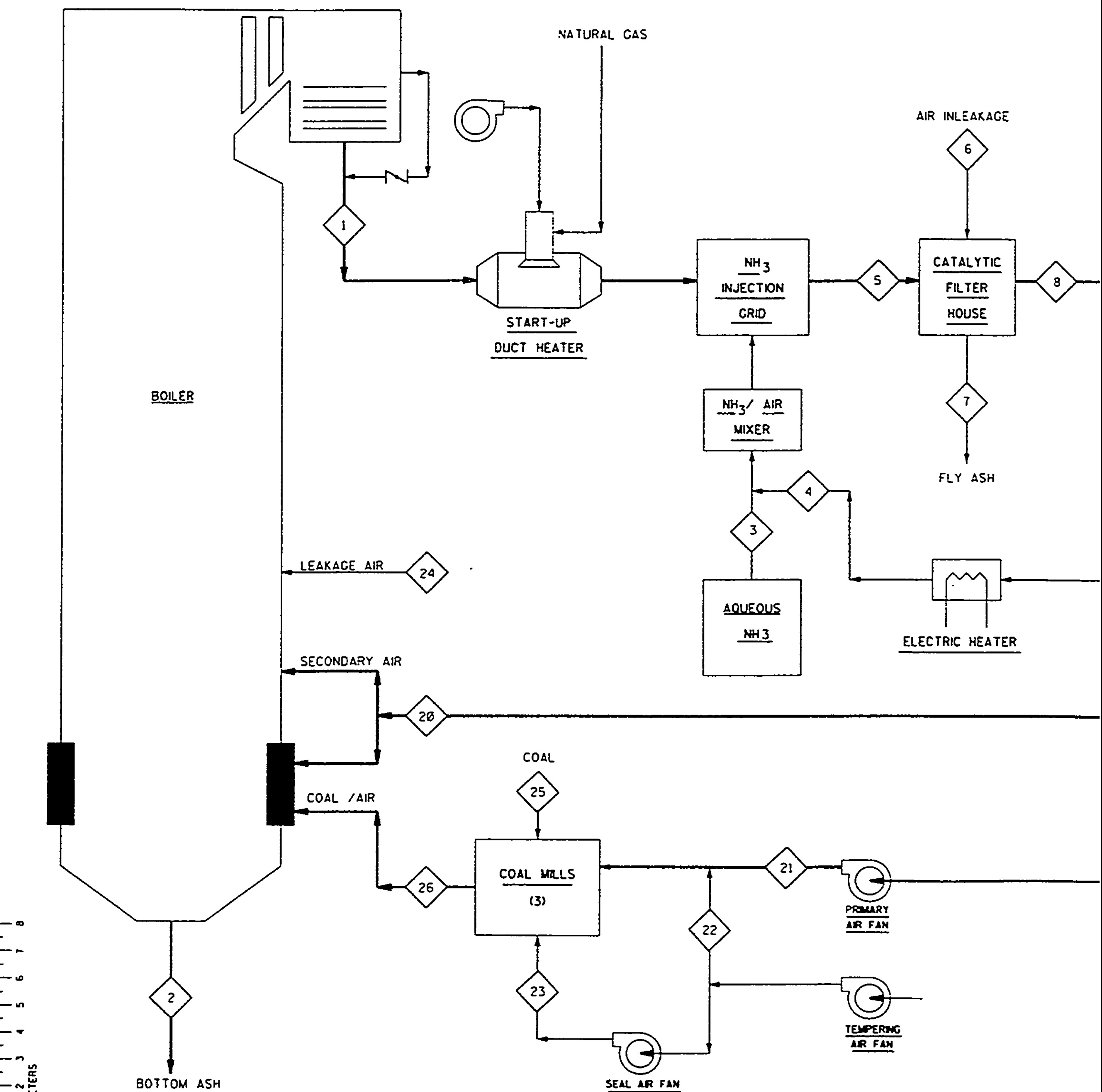
4 3 2 1 D C B A

9680-D-216002 SH. 2

DESIGN CONDITIONS - BOILER OUTPUT (STEAM)-340,600 LBS.

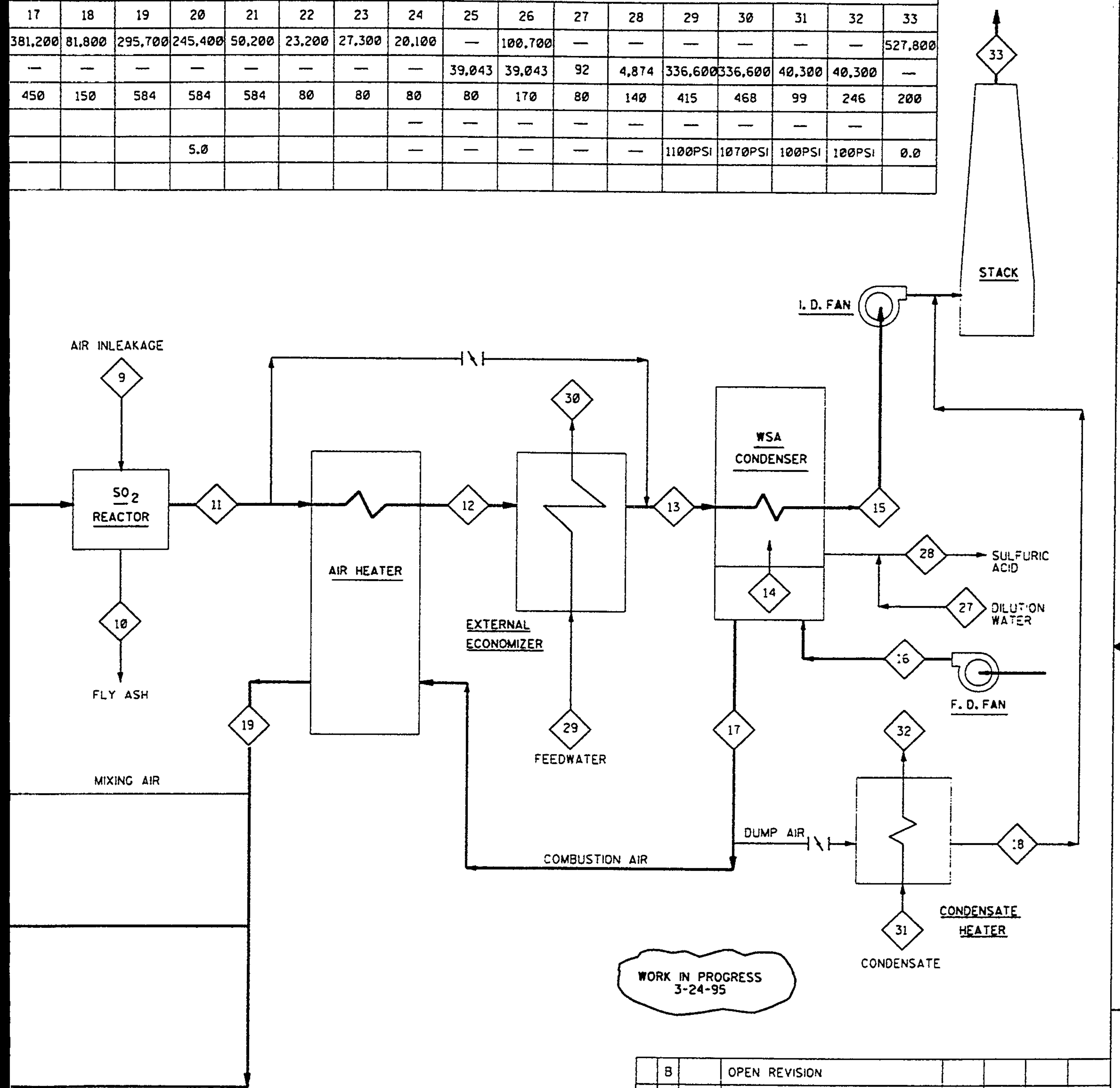
STATE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
GAS FLOW (LBS./HR.)	398,900	—	—	3,800	402,800	16,000	—	418,800	16,000	—	434,800	434,800	434,800	16,000	446,000	397,200
SOLID/LIQUID FLOW (LBS./HR.)	5,830	1,250	132	—	5,830	—	5,820	—	—	10	—	—	—	—	—	—
TEMPERATURE (DEG. F)	793	—	80	584	790	80	768	768	80	761	761	674	497	—	210	80
VOLUMETRIC FLOW (ACFM)	209,200	—	—		209,600		—			—				—		
PRESSURE (IN. W.G.)	(-)1.0	—	—	10.0		—	—		—	—				—		



8 7 6 5

/HR. FUEL HHV- 10,400 LBS./HR.

17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33
381,200	81,800	295,700	245,400	50,200	23,200	27,300	20,100	—	100,700	—	—	—	—	—	—	527,800
—	—	—	—	—	—	—	—	39,043	39,043	92	4,874	336,600	336,600	40,300	40,300	—
450	150	584	584	584	80	80	80	80	170	80	140	415	468	99	246	200
							—	—	—	—	—	—	—	—	—	
			5.0				—	—	—	—	—	1100PSI	1070PSI	100PSI	100PSI	0.0



SEE DWG. No.9680-D-216003, SH. No.1 FOR CORRESPONDING TURBINE HEAT BALANCE

MICRO	REV	DATE	DESCRIPTION	DSNR	CHKR	RESP ENG	PROJ MGR
	B		OPEN REVISION				
	A		FIRST ISSUE				

DOE-LEBS PROJECT

PROOF OF CONCEPT TEST FACILITY

RICHMOND POWER & LIGHT - WHITEWATER VALLEY UNIT NO. 1

P.E. SIGNATURE

STATE REG. No. DATE

SCALE NONE

ABB ASEA BROWN BOVERI / Raytheon Engineers & Constructors

GAS SIDE HEAT AND MASS BALANCE DESIGN COAL, 5% OP/VWO

DWG 9680-D-216002 SH. 2 REV B

4 3 2 1

D C B A

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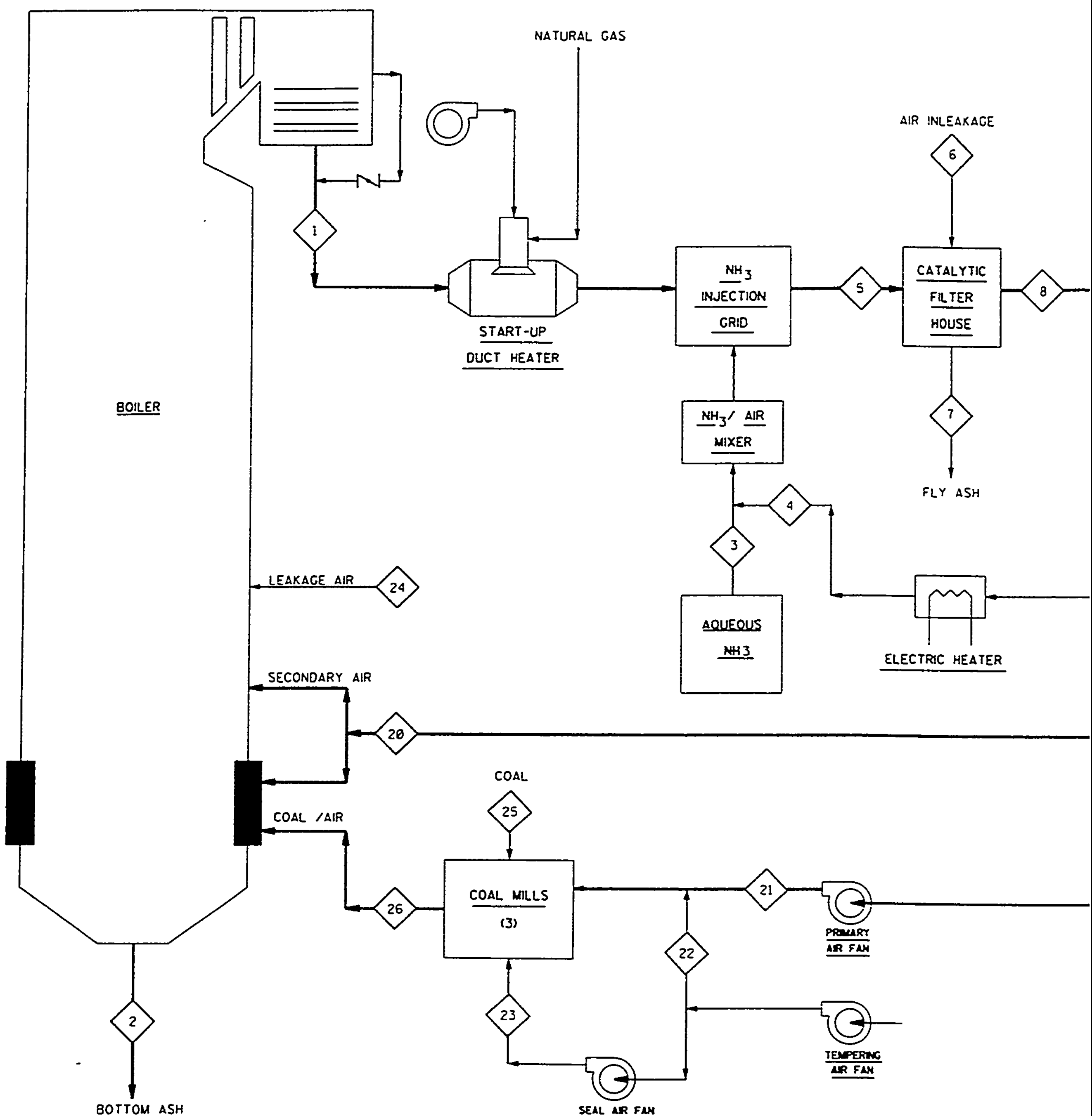
DESIGN CONDITIONS - BOILER OUTPUT (STEAM)-340,600 LBS./

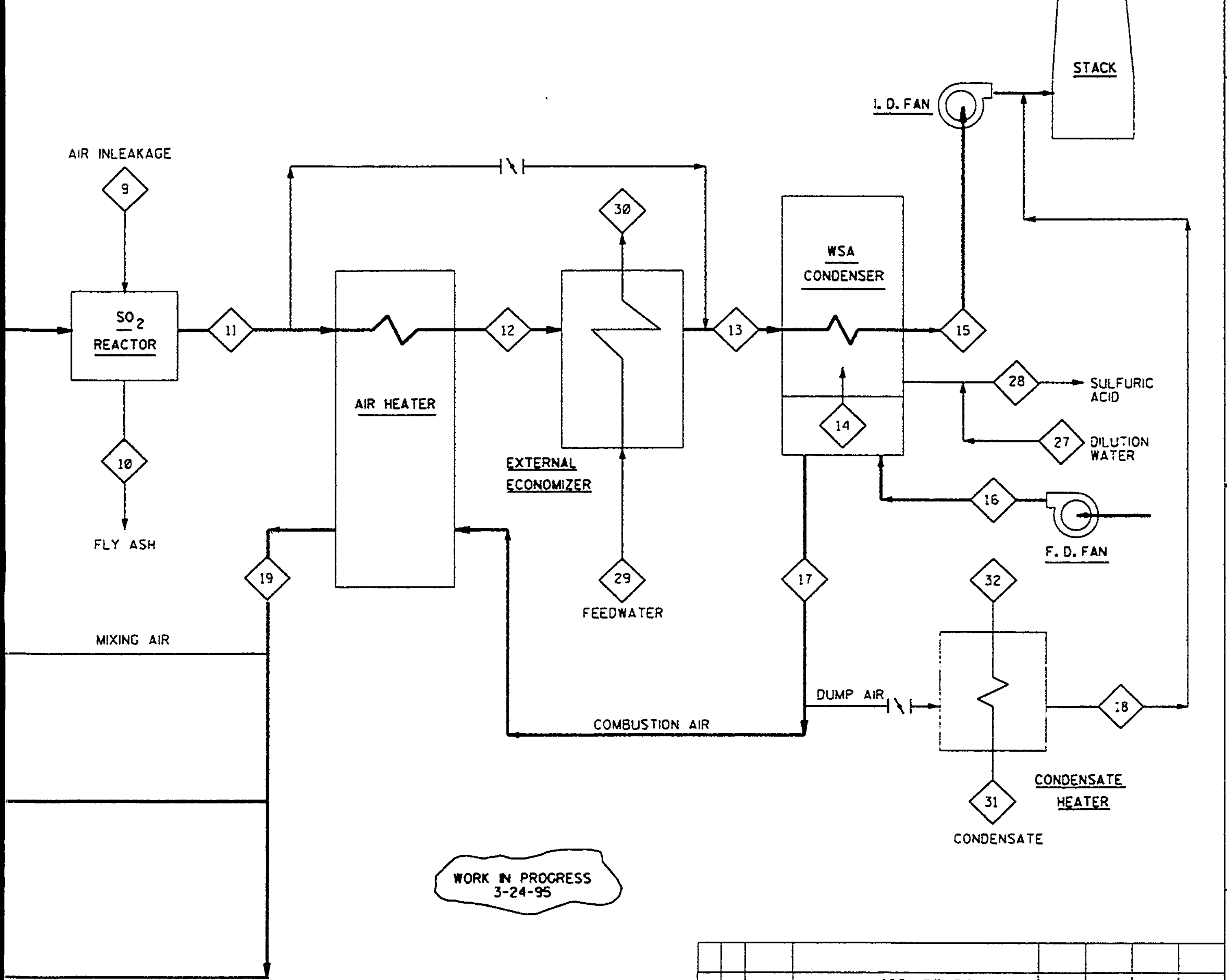
STATE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
GAS FLOW (LBS./HR.)	399,500	—	—	3,800	403,400	16,000	—	419,400	16,000	—	435,400	435,400	435,400	16,000	447,600	391,500
SOLID/LIQUID FLOW (LBS./HR.)	2,800	575	146	—	2,800	—	2,795	—	—	5	—	—	—	—	—	—
TEMPERATURE (DEG. F)	793	—	80	580	791	80	769	769	80	—	761	676	497	80	210	80
VOLUMETRIC FLOW (ACFM)	201,400	—	—				—			—						
PRESSURE (IN. W.G.)	(-)1.0	—	—	10		—	—		—	—				—		



8 7 6 5

HR. FUEL HHV- 10,400 LBS./HR.

17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33
75,500	72,800	302,700	248,400	50,500	20,600	27,300	20,200	—	98,400	—	—	—	—	—	—	520,400
—	—	—	—	—	—	—	—	35,575	35,575	160	3,940	336,300	336,300	35,900	35,900	—
450	150	580	580	580	80	80	80	80	170	80	140	415	469	99	246	200
								—	—	—	—	—	—	—	—	
							—	—	—	—	—	1100PSI	1070PSI			0.0



SEE DWG. No. 9680-D-216003,SH. No. 1 FOR CORRESPONDING TURBINE HEAT BALANCE

MICRO	REV	DATE	DESCRIPTION	DSNR	CHKR	RESP ENG	PROJ MGR
	A		OPEN REVISION				

DOE-LEBS PROJECT
PROOF OF CONCEPT TEST FACILITY
RICHMOND POWER & LIGHT - WHITEWATER VALLEY UNIT NO. 1

P.E. SIGNATURE
STATE REG. No. DATE
SCALE NONE

ABB ASEA BROWN BOVERI / Raytheon Engineers & Constructors

GAS SIDE
HEAT AND MASS BALANCE
PERFORMANCE COAL,5% OP/VWO

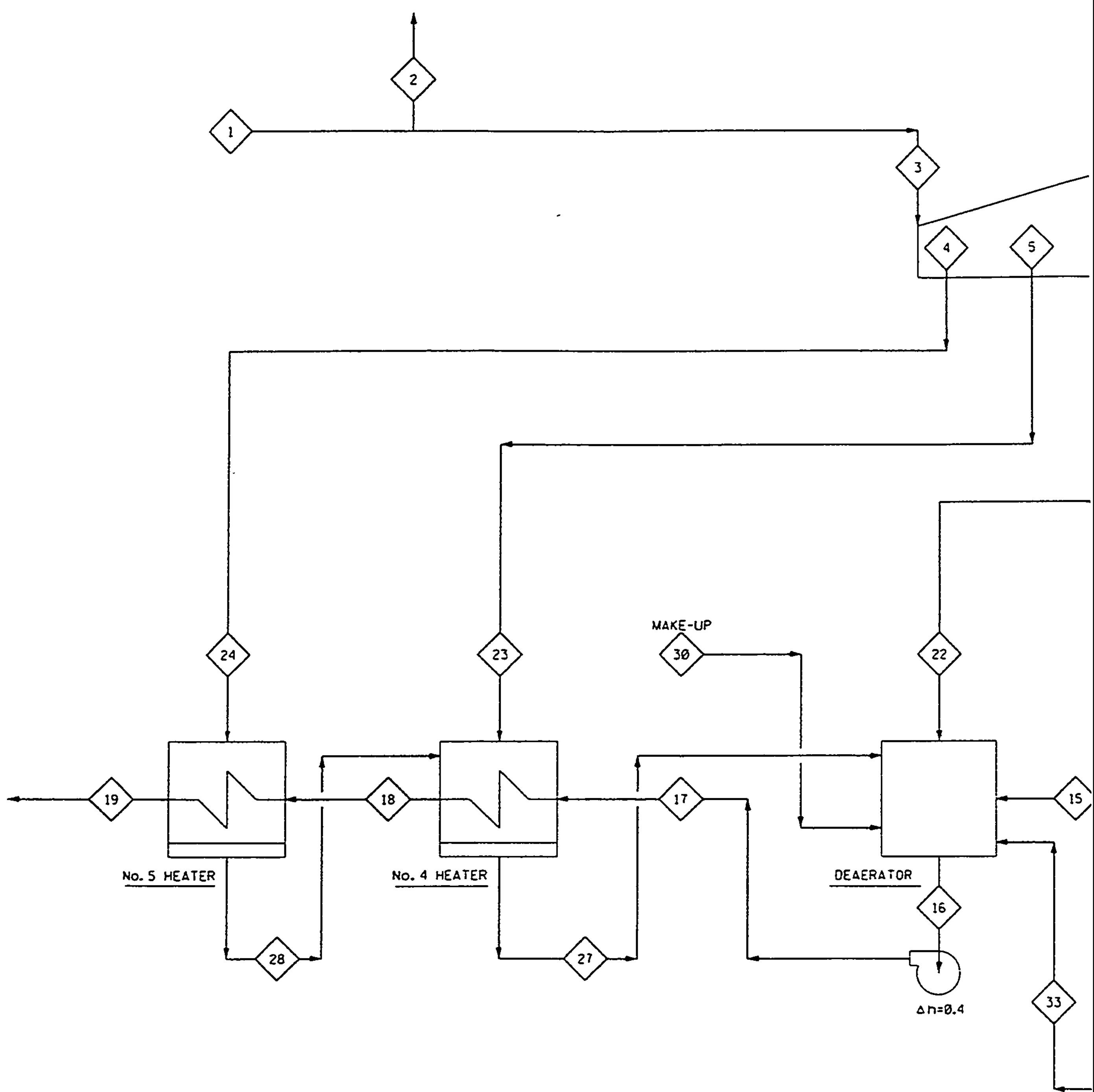
DWG 9680-D-216002 SH. 3 REV A

03-27-1995 14:56:04
216002C.DGN

D C B A 4 3 2 1

9680-D-216003

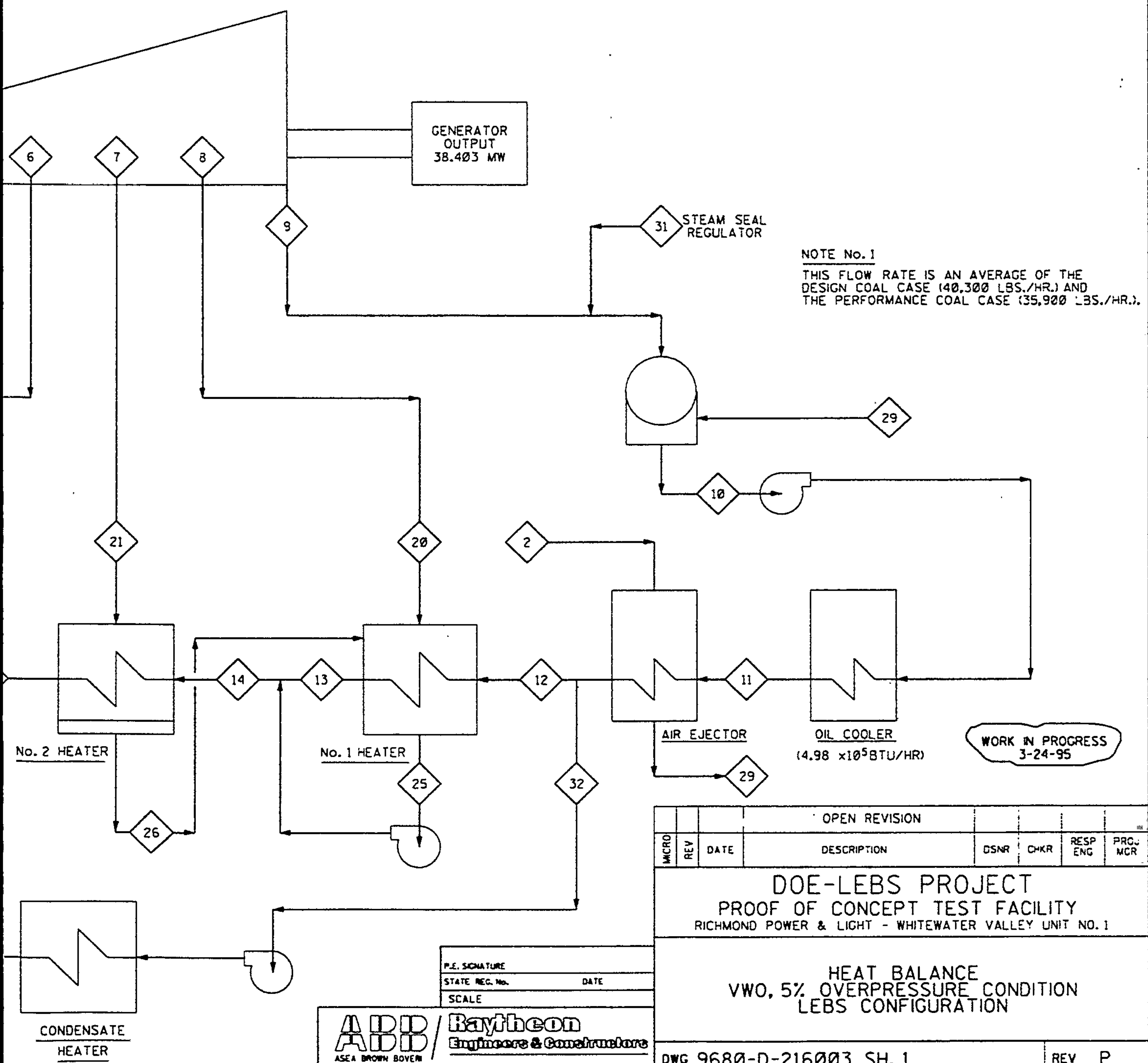
MEASUREMENT	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
FLOW RATE (LBS./HR.)	341,600	600	341,000	20,680	18,260	16,430	15,300	17,700	251,700	252,800	252,800	214,800	214,800	247,800	247,800	345,050	345,0
PRESSURE (PSIA)	954	954	906	352	183	85	32	9.23	0.737	0.737	—	—	—	—	68	—	—
TEMPERATURE (DEG. F.)	905	905	900	679	543	401	254	189	91.7	91.7	—	98.5	—	177	246	301	30
ENTHALPY (BTU/LB.)	1452.91	1452.91	1451.91	1354.91	1293.96	1230.52	1162.12	1088.28	987.94	59.72	—	66.65	—	144.85	214.75	270.84	274.



8 7 6 5

	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33
50	345,050	345,050	17,700	15,300	16,430	18,260	20,680	33,000	15,300	38,940	20,680	600	3,890	540	38,000*	38,000*
	—	—	7.68	30.4	68	149	292	7.68	30.4	149	292	—	—	18		
3	358	415	181	251	395	535	670	181	187	313	368	—	60	751	98.5	246
74	331.64	392.36	1087.28	1161.12	1229.52	1292.96	1353.91	149.04	154.78	283.44	341.05	180.2	27	1408.71	66.7	214.8

*SEE NOTE No.1



NOTE No. 1

THIS FLOW RATE IS AN AVERAGE OF THE DESIGN COAL CASE (40,300 LBS./HR.) AND THE PERFORMANCE COAL CASE (35,900 LBS./HR.).

MICRO	REV	DATE	DESCRIPTION	DSNR	CHKR	RESP ENG	PROJ MGR
			OPEN REVISION				

DOE-LEBS PROJECT

PROOF OF CONCEPT TEST FACILITY

RICHMOND POWER & LIGHT - WHITEWATER VALLEY UNIT NO. 1

HEAT BALANCE VWO, 5% OVERPRESSURE CONDITION LEBS CONFIGURATION

P.E. SIGNATURE
STATE REG. No. DATE
SCALE

ABB ASEA BROWN BOVERI / Raytheon Engineers & Constructors

DWG 9680-D-216003 SH. 1 REV P

4 3 2 1

MICROSTATION 216003A.DGN 9680.008

03-27-1995 15:16:00

APPENDIX G

Form 3500
Rev. 3/93

Raytheon
Engineers & Constructors

Organization		Job Number	9680.008
		File Number	4.1
Date	January 5, 1995	Memo Number	
To	D. J. Bender (9-U-0)	Copies	See Below
From	John D. Darab 11-U-8 (Ext. 3577)		
Subject	LEBS II Distributed Control System Overview		

A. System Criteria

The proposed control system is based on the following criteria.

- Distributed Control System (DCS) equipment and software will have demonstrated highly reliable continuous service in a fossil power generation environment.

- The DCS process input/output and functional process control will be located in plant areas where there is a high concentration of equipment interfacing with the DCS.

- Distributed functional control processors will provide modulating control, discrete (on-off) control, monitoring, alarming and data acquisition functions. These control processors will be installed in a primary/backup configuration where processors track and copy control activities to enable a bumpless control transfer upon failure of a primary processor.

- Similarly, redundancy in a primary/backup arrangement will be applied to the data highway which will provide data communication between all processors linked to the data highway.

1059JWP

- A coaxial data highway will link functional processors within a "local area". A fiber optic data highway will then link the local area with the Unit Control Room.

- DCS modular power supplies will also be redundant in a primary/backup arrangement to provide instantaneous automatic transfer to the standby power supply on loss of the operating power supply.

- Each Operator Control Station will have the capability of displaying information to monitor and control the boiler system on a 19 inch color CRT. Touch screen control combined with keyboard control will be applied (touch and key action required to initiate a control action).

- Real time process data collected through the data communications network will be stored by the DCS and available for retrieval.

- The DCS will integrate operator control of the Boiler System and the Pollution Control System from the existing Unit Control Room with existing control room manpower.

B. <u>DCS Concept</u>

1. <u>Assumptions</u>

The diagrams attached do not delineate the following underlying assumptions made to arrive at the proposed concept for a DCS.

- SNO_x, process control logic, will be configured into the selected DCS vendor's functional control processors.

- SNO_x Island is being described as including SNO_x equipment as well as certain furnace draft equipment associated with the Boiler System (ID, FD, PA Fans; ID, FD, PA Control and Isolation dampers; Air Heater and Bypass Damper; Air Compressor(s), Fuel oil pump and Seal Air Fans).

- SNO_x Island will include a building to house the related DCS functional controller, I/O files and field termination. The building will also house the electrical MCC, power centers, UPS, etc.

- Burner Management and Flame Safety logic is configured into a Programmable Logic Controller (PLC) system.

- A November site familization confirmed the impossible tasks of routing redundant coaxial data highway through the power plant to the Unit Control Room in a reasonably direct and economical manner and maintain the mandatory cable separation criteria for a fault free data communications network. Thus, a fiber optic network will be applied between the SNO_x Island and the Unit Control Room.

2. <u>Input/Output</u>

An I/O count for the Boiler System (air, flue gas, feedwater, fuel steam) resulted from studying Raytheon P&ID for a boiler similar to the POC boiler (CE, corner fired). The boiler equipment was also designated as applicable to Boiler Island or SNO_x Island.

To the I/O count, by type of I/O, for an Island was the addition of 25% spare factor. The I/O count was compiled into a card count and to the card count was the addition of 20% spare factor to allow for physical expansion space. The cards were then "slotted" into racks and the racks into cabinet assemblies.

The I/O count and cabinet assemblies are conservative - included are spare I/O, spare I/O card slots and spare space for I/O card racks and controller files.

The I/O count not only includes the Boiler System, but also a <u>selected</u> quantity of Balance of Plant alarms; e.g., DA and FW heater level alarms as well as feedwater and condensate process alarms.

A Summary of I/O is as follows:

- SNO_x process at SNO_x Island: 200 I/O
- Boiler System at SNO_x Island: 300 I/O
- Boiler System at Boiler Island: 500 I/O
- Burner Management and Flame Safety at Boiler Island: (Later)

3. Existing Unit Control Room

TO BE REVISED

The goal was to place as much of the Boiler Island equipment into space available following removal of the Unit 1 Boiler Panel and Unit 1 Soot Blower Panel. However, final placement of Unit 1 equipment considers a manner by which Unit 2 Boiler DCS equipment could eventually append to the Unit 1 POC DCS.

Except for the Unit 1 Burner Management System Cabinet(s) all Unit 1 Operator Consoles and Boiler Island Control cabinetry will arrange conveniently in the space available. However, Burner Management Cabinet(s) have been placed outside but abutting the Control Room; these cabinets can be supplied with an external cooling source.

4. Expanded Unit Control Room

TO BE REVISED

While studying control room arrangements it is prudent to consider studying an expanded control room. At this point construction costs have not been given consideration.

An expanded control room; i.e., removal of most of the existing eastern wall and creating a new eastern wall at the stair well, provided greater flexibility in arranging DCS equipment within the control room as well as permitting the placement of Burner Management Cabinet(s) within the Control Room environment.

5. DCS Equipment Placement Alternatives

It is not mandatory that all of the DCS equipment reside within the Unit Control Room or the SNO_x Island building. To reduce congestion within the Unit Control Room, the Engineering Work Station and the Archival Storage and Retrieval can be placed in another air conditioned space - perhaps somewhere in the existing office area? The demand for space would be a desk to support a personal computer (engineering work station) and room for a 30 inch square cabinet, 7 foot tall.

C. An Action Plan

The equipment arrangement in the Unit Control Room is a plan on paper. It is necessary to:

COMPLETE

a. Review the concept with ABB-PPL and ABBES for their concurrence.

b. Involve Whitewater Valley Station personnel to ascertain their concurrence with our general direction.

c. Return to the Whitewater Valley Station Unit Control Room to critically review the existing physical electrical and piping impediments to meeting the proposed plan.

d. Issue DCS Specification for budgetary quotations to confirm the quantity and hardware arrangement delineated in the diagrams is practical.

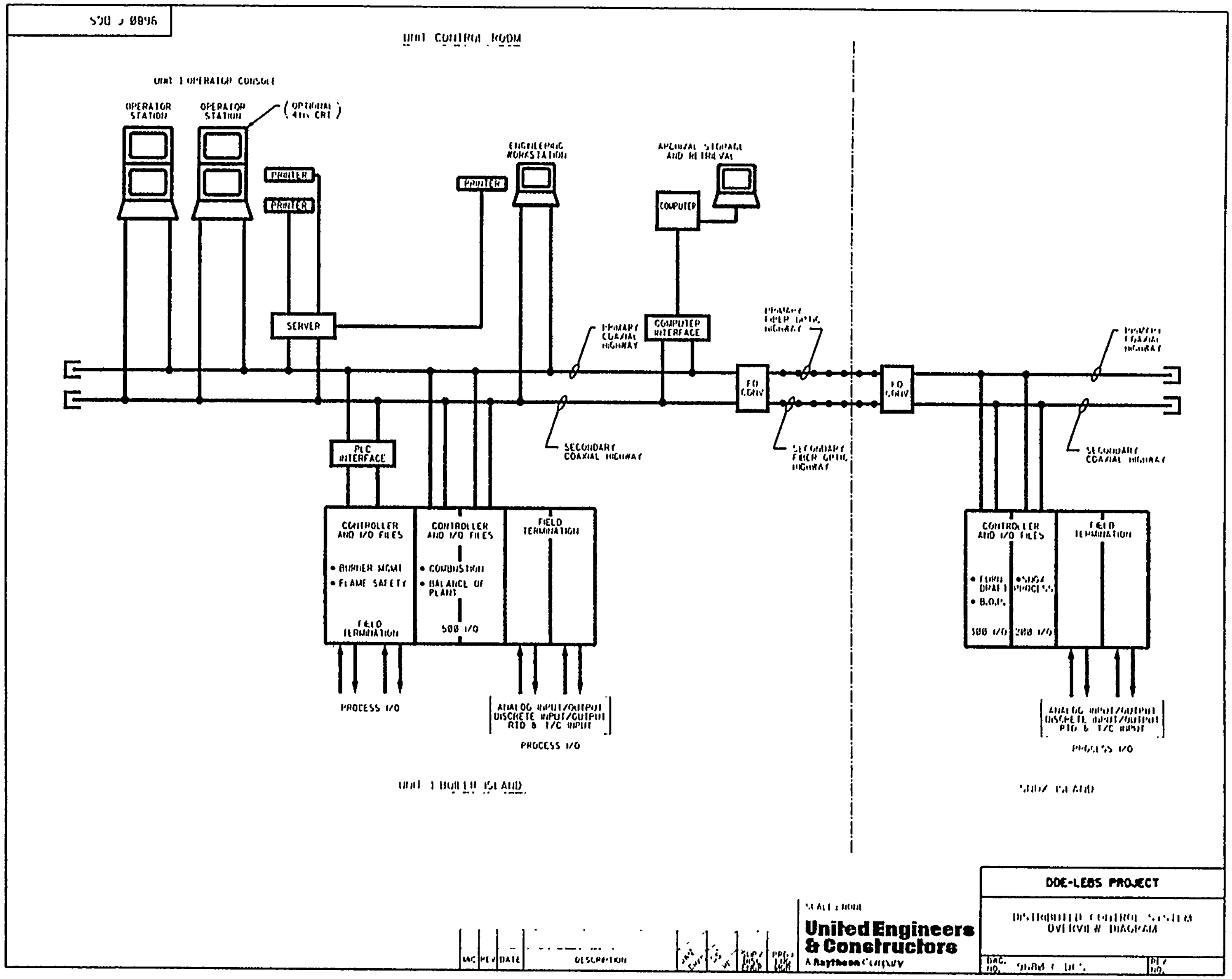
Attachments

- Distributed Control System Overview
- Unit Control Room Arrangements
- Expanded Unit Control Room Arrangements

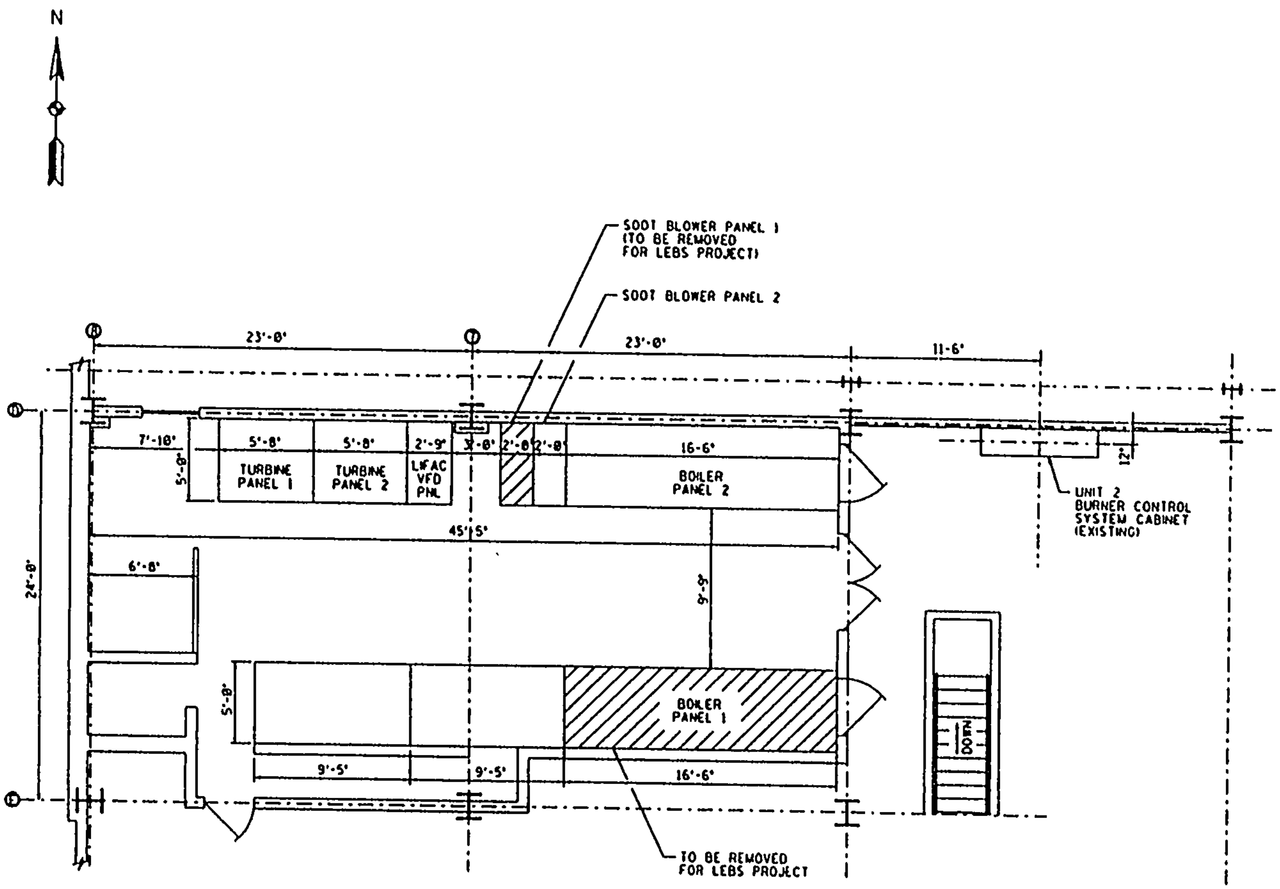
Distribution

R. S. Kaminski (12-U-6)
G. C. Weston (9-U-2)
W. L. DeLaurentis (9-U-7)
W. A. Schwegler (8-U-9)
G. C. Hatwal (9-U-8)

1059JWP



UNIT CONTROL ROOM
OPERATOR STATION
OPERATOR STATION
(OPTIONAL 4th CRT)
PRINTER
PRINTER
SERVER
PRINTER
ENGINEERING WORKSTATION
ARCHIVAL STORAGE AND RETRIEVAL
COMPUTER
COMPUTER INTERFACE
PRIMARY COAXIAL HIGHWAY
SECONDARY COAXIAL HIGHWAY
FO CONV
FO CONV
PRIMARY FIBER OPTIC HIGHWAY
SECONDARY FIBER OPTIC HIGHWAY
PRIMARY COAXIAL HIGHWAY
SECONDARY COAXIAL HIGHWAY
PLC INTERFACE
CONTROLLER AND I/O FILES
• BURNER MGMT
• FLAME SAFETY
FIELD TERMINATION
CONTROLLER AND I/O FILES
• COMBUSTION
• BALANCE OF PLANT
500 I/O
FIELD TERMINATION
PROCESS I/O
ANALOG INPUT/OUTPUT
DISCRETE INPUT/OUTPUT
RTD & T/C INPUT
PROCESS I/O
CONTROLLER AND I/O FILES
• B.O.P.
300 I/O
200 I/O
FIELD TERMINATION
ANALOG INPUT/OUTPUT
DISCRETE INPUT/OUTPUT
RTD & T/C INPUT
PROCESS I/O
DOE-LEBS PROJECT
DISTRIBUTED CONTROL SYSTEM OVERVIEW DIAGRAM
United Engineers & Constructors
A Raytheon Company
DESCRIPTION
DATE
REV



MK	REV	DATE	DESCRIPTION	DWN	CHKD	DS	RE	SUPV DISC ENGR	PROJ ENG DCR

SCALE: 3/16" = 1'-0"

United Engineers & Constructors
A Raytheon Company

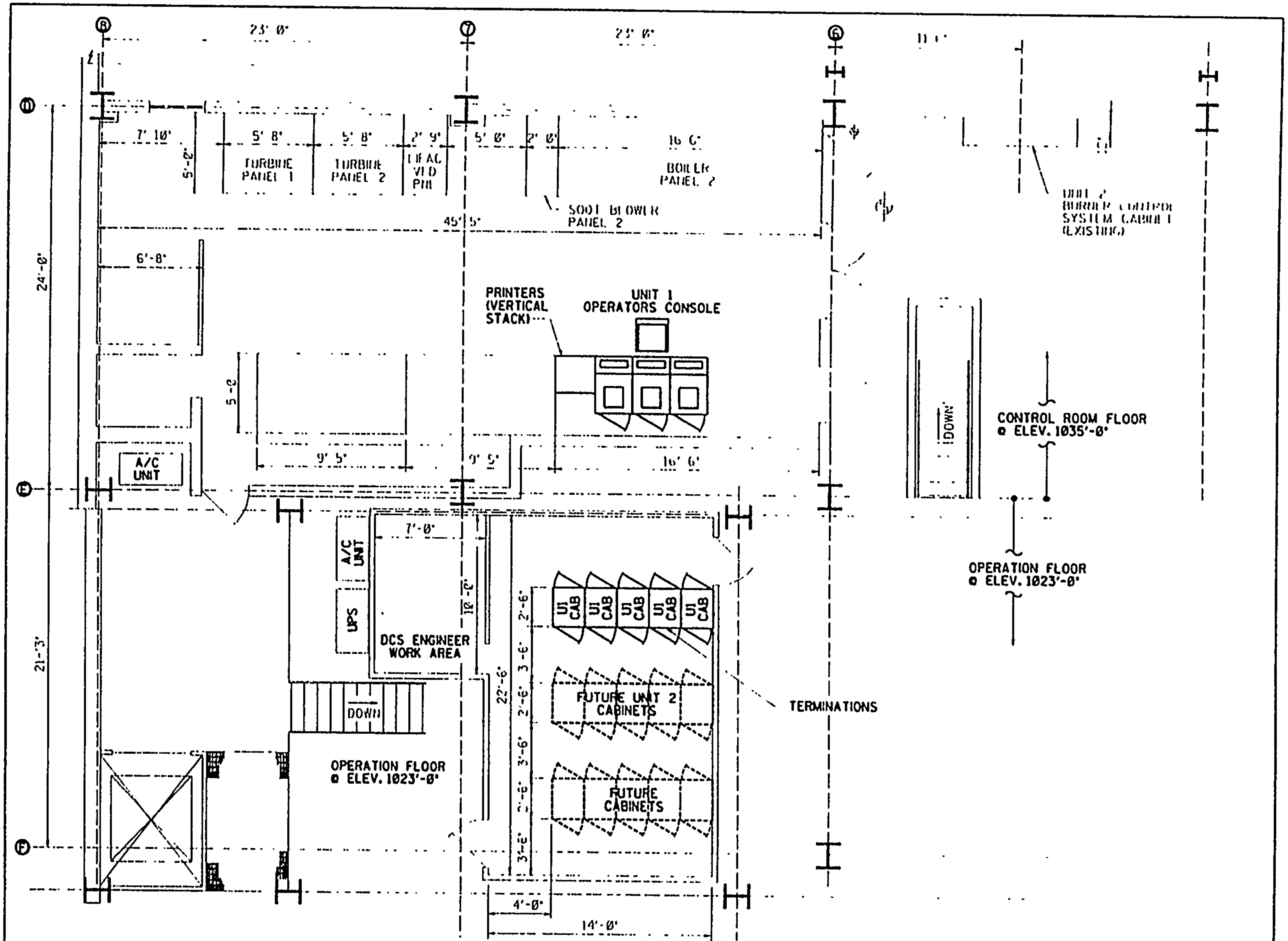
DOE-LEBS PROJECT

UNIT CONTROL ROOM
EXISTING ARRANGEMENT

DWG. NO. 9680-C-UCR REV. NO.

9680-C-UCR

9680SUCR.DGN 01-05-1995 12:21:44



ARRANGEMENT "A"

CONTROL ROOM AND OPERATION FLOOR
UNIT 1 ARRANGEMENT

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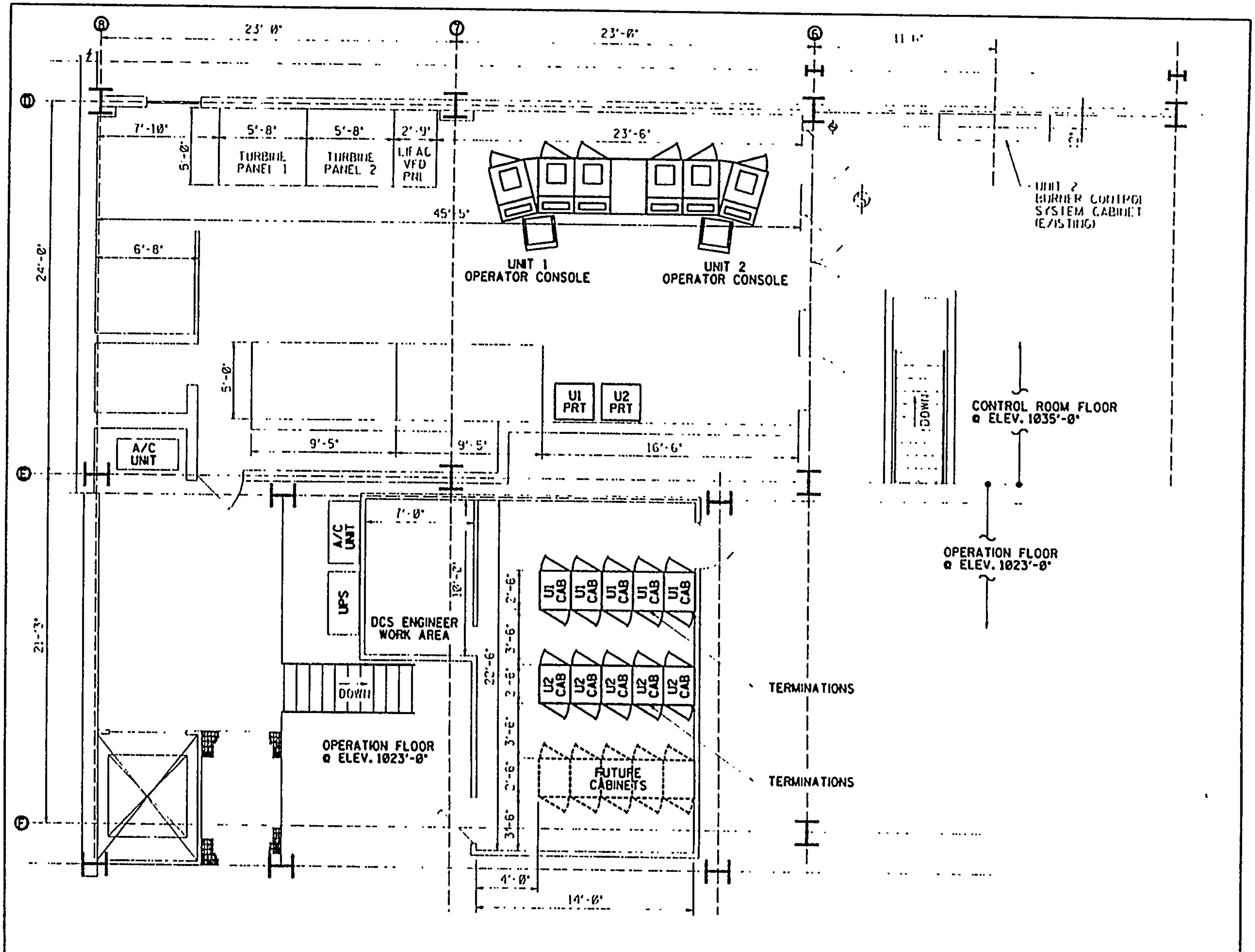

CONTROL ROOM AND OPERATION FLOOR
UNIT 1 & 2 ARRANGEMENTS

ARRANGEMENT "B"

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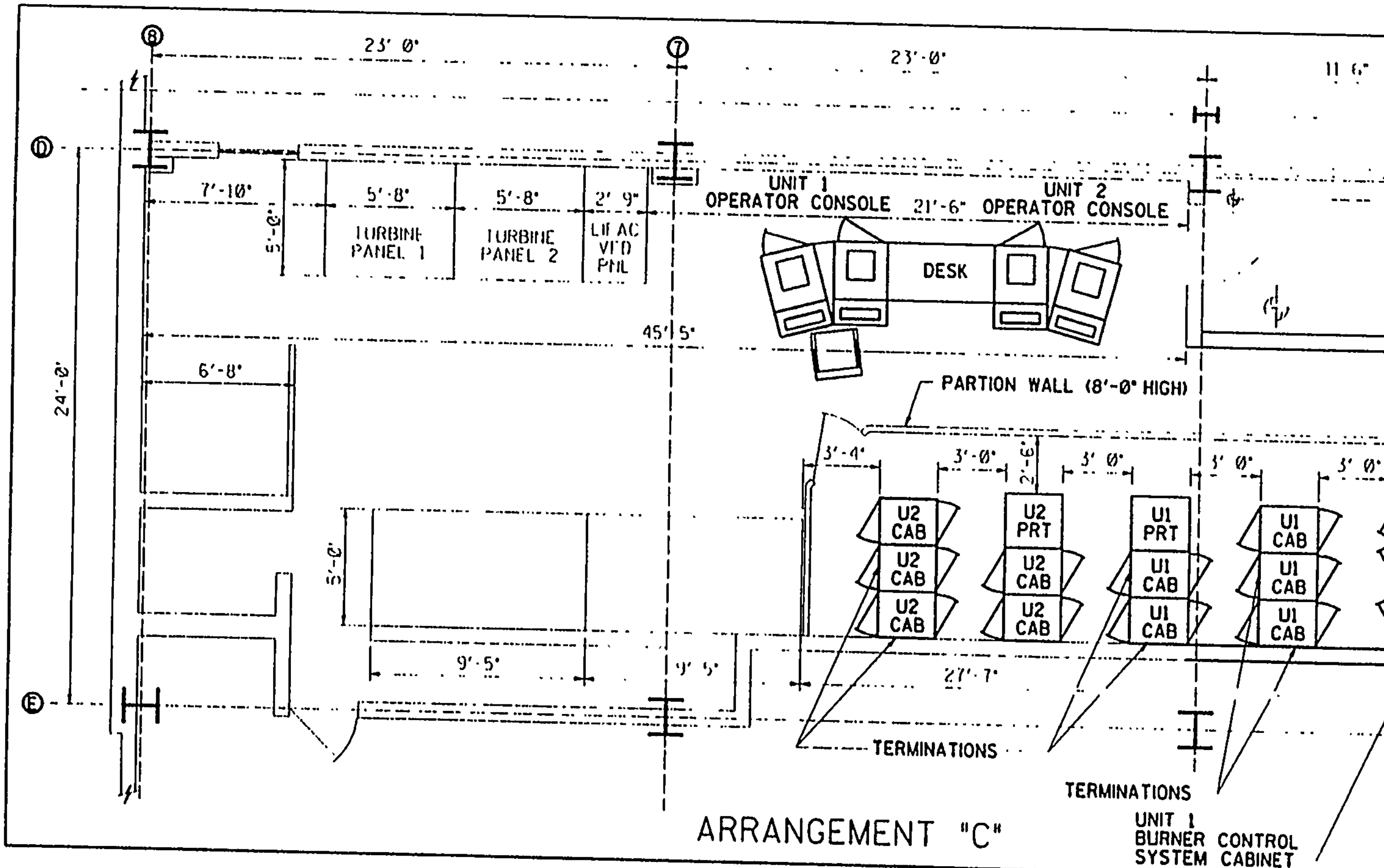

ARRANGEMENT "C"

EXPANDED CONTROL ROOM
UNIT 1 OPERATOR CONSOLE
AND
FUTURE UNIT 2 OPERATOR CONSOLE

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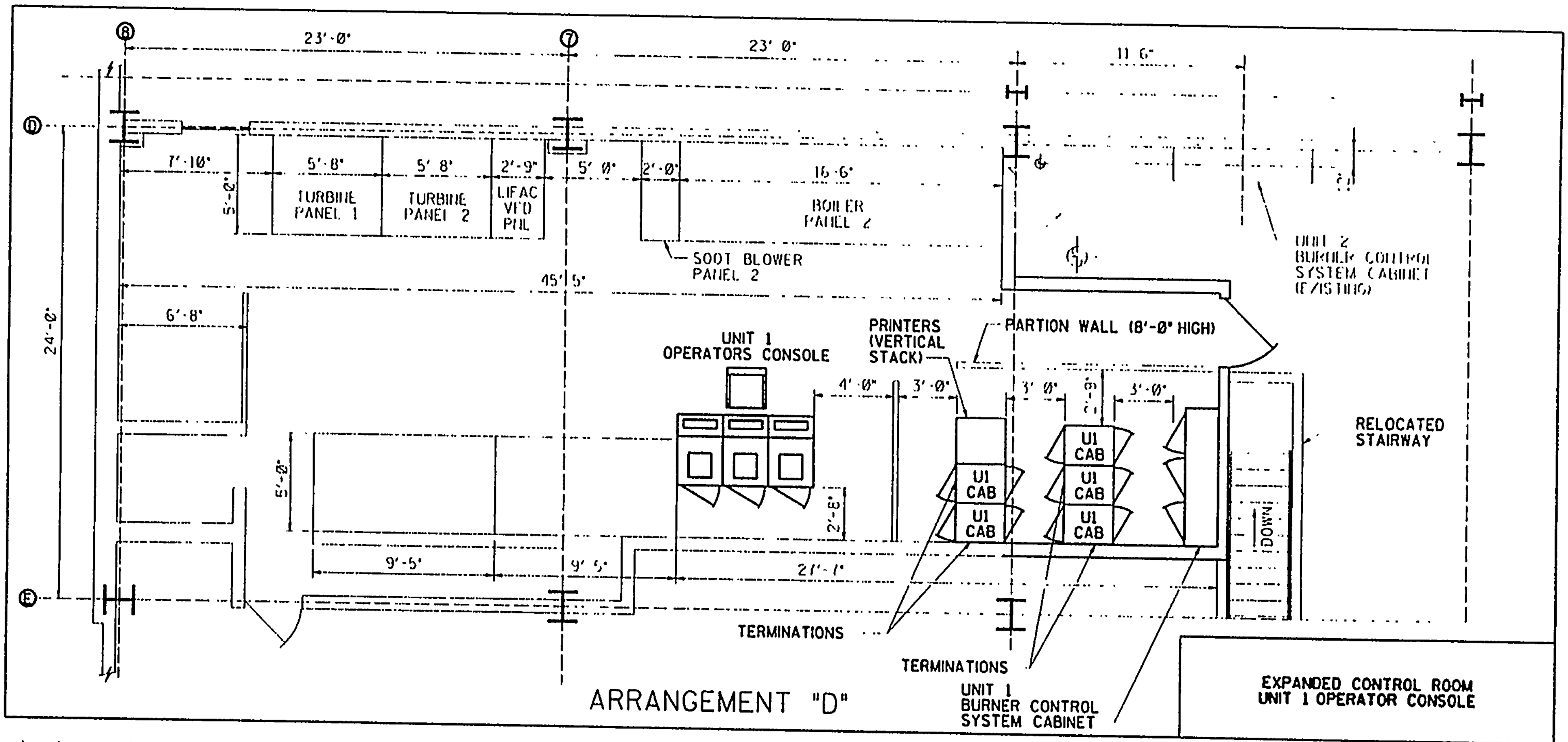

ARRANGEMENT "D"

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